Norwegian Petroleum Directorate

ANNUAL REPORT 1997

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The Norwegian Petroleum Directorate shall provide for a highest possible creation of value and contribute to a safe conduct of the petroleum activities and a sound exploitation of the resources, while having due consideration for the environment.

The Norwegian Petroleum Directorate was established in 1972, and the number of positions is around 350. It comes under the Ministry of Petroleum and Energy with regard to resource management and administrative matters, and to the Ministry of Local Government and Regional Development in questions relating to safety and working environment. Within the area of CO_2 tax, the Norwegian Petroleum Directorate exercises authority on behalf of the Ministry of Finance.

The most important duties of the Norwegian Petroleum Directorate comprise having the best possible knowledge of discovered and undiscovered petroleum resources on the Norwegian continental shelf, supervising that the licensees manage the resources in an effective and sound manner, and supervising that statutory requirements are complied with so that a fully satisfactory level of safety and working environment is established, upheld and developed further. Another important role of the Norwegian Petroleum Directorate is to influence the industry to develop solutions which are beneficial to society.

The Norwegian Petroleum Directorate gives advice to superior ministries and is delegated authority to issue regulations and to make decisions relating to consents, orders, exemptions and approvals pursuant to the rules and regulations.

Through the exercising of its duties, the Norwegian Petroleum Directorate shall contribute to Norway becoming a pioneering country in environmental matters.

The Norwegian Petroleum Directorate shall also provide neutral information about the petroleum activities to the industry, the media and society as a whole.

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Preface

Resource growth and production

The total resource growth in fields and discoveries on the Norwegian shelf in 1997 has been estimated to be approximately 200 million Sm^3 oil, approximately 100 billion Sm^3 gas and 50 million tonnes NGL. This means that the estimates for the total recoverable petroleum resources are approximately 12.8 billion Sm^3 oil equivalents, divided between about 6.5 billion Sm^3 o.e. oil/NGL and about 6.3 billion Sm^3 o.e. gas. The resource growth as a consequence of new discoveries in 1997 constitutes approximately 100 million Sm^3 oil/NGL and approximately 200 billion Sm^3 gas. Adjustments of the estimates for the recoverable resources in connection with older fields and discoveries comprise an increase of about 150 million Sm^3 oil and a reduction of about 50 billion Sm^3 gas. The estimates for undiscovered resources have not been changed during 1997. The calculated average rate of recovery for the oil resources in oil fields currently in production and under development has increased from about 41% in 1996 to about 43% in 1997. This is equal to a volume of approximately 100 million Sm^3 oil which has been moved in the value chain from being oil resources from possible future measures to promote increased recovery, to being included as a part of the oil reserves in the fields.

In 1997, approximately 176 million Sm^3 oil (3.06 million barrels per day), 10 million tonnes NGL/condensate and approximately 67 billion Sm^3 gas were produced. Two-thirds (about 44 billion Sm^3 gas) was sold, while the remaining one-third was used for injection on the Norwegian shelf in order to extract more oil. The production of oil and NGL/condensate in 1997 was approximately 2 million Sm^3 o.e. higher than in the previous year. This was about 4% lower than the prognosis, and is a consequence partly of delayed production start-up for certain new fields and partly of technical conditions on fields which are already in production.

Increased recovery

During 1997, the Norwegian Petroleum Directorate continued its work on the challenges connected with measures to increase recovery. Among other things, the experience so far with gas injection and water-alternating-gas injection (WAG), as well as the potential for increased oil recovery and the authorities' mechanisms in this context were evaluated. A publication regarding increased oil recovery was published in November 1997. This is also available on the Norwegian Petroleum Directorate's home page on the internet. The report discusses resource potential, technology development, gas injection, industry cooperation and environmental considerations linked with the various measures. The industry cooperation forum FORCE had yet another active year. Several seminars on increased recovery were arranged, and through FORCE, work proceeded on identifying which problem areas must be solved in order to realize even more of the identified recovery potential for oil. As of 31 December 1997, this is estimated to be 840 million Sm^3 oil.

In 1997, a methodology has been established for estimating the potential for increased recovery on the basis of the Norwegian Petroleum Directorate's new resource classification system. Generally, there has been great international interest in the experiences gained in order to increase the recovery from the fields on the Norwegian Shelf. The Norwegian Petroleum Directorate is represented on the management committee for the International Energy Agency cooperation on increased oil recovery.

Development

The Norwegian Petroleum Directorate has considered the plan for development and operation of the Yme-Gamma Sørøst deposits, the Ula Triassic deposits, Jotun, Troll Olje gas province, Eldfisk water injection, Oseberg Sør and Gullfaks Satellites Phase 2. In addition, a conditional plan for Valhall water injection has been evaluated. The Norwegian Petroleum Directorate has considered plans for installation and operation of gas export from Norne, Heidrun and Gullfaks Sør, as well as for Troll Oljerør II.

1997 has been marked by the work of making decisions in order to meet delivery commitments for gas to the Continent and simultaneously provide for the growing injection market on the shelf. The Norwegian Petroleum Directorate has evaluated the various alternatives and associated tie-in points in order to clarify the optimal field development and use of infrastructure from a socioeconomic viewpoint.

In 1997, the Norwegian Petroleum Directorate presented an updated report with an overview of petroleum discoveries on the Norwegian continental shelf which have not yet been approved for development. Only a small number of the discoveries are time-critical, i.e., that they must be developed during the course of the next few years in order to be able to make use of nearby infrastructure. These discoveries lie in the vicinity of the Frigg and Heimdal installations and they mainly contain gas.

New discoveries

The most important event of 1997 with regard to exploration for oil and gas was the commencement of exploration drilling in the two deep water areas, the Møre basin and the Vøring basin. Two wells were completed in 1997 and both made significant discoveries of gas. Approximately 40 billion Sm^3 recoverable gas was proven on Nykhøgda (6707/10-1) and approximately 100 billion Sm^3 recoverable gas on the Ormen Lange dome (6305/5-1). Both discoveries may contain more resources than have been proven so far; this applies particularly to the discovery on the Ormen Lange dome. A total of 35 wildcat wells and 12 appraisal wells were completed, as well as one wildcat well that was abandoned. A total of seventeen new discoveries were made; eleven in the North Sea and six in the Norwegian Sea; ten oil discoveries and seven gas or gas/condensate discoveries. On Haltenbanken, the large gas/condensate discovery 6406/2-3 Kristin was proven. Work is already underway on development plans for this discovery in a coordinated development with previous discoveries in what has initially been called the Haltenbanken Sør development. A number of oil discoveries and gas/condensate discoveries were made in the North Sea. The most interesting discoveries are those which lie in areas where there is infrastructure, such as 25/7-5, 25/8-10 S and 25/8-11 near Jotun and Balder, 9/2-7 S near Yme, as well as the promising 16/7-7 S gas/condensate discovery near Sleipner. The other discoveries made have been small. Several successful appraisal drillings have been conducted which have led to upward adjustments of the resource estimates for discoveries which have been made previously. This applies to the 15/5-5 discovery and the 35/11-4 R Fram discovery, among others. The total resource growth from exploration activities in 1997 is estimated to be approximately 100 million Sm^3 oil/condensate and more than 200 billion Sm^3 gas.

Environment

The increasing attention surrounding environmental issues and the Directorate's responsibility and tasks in the area of the environment have become more visible through main objective and activity plans.

Prognoses for emissions of CO_2, NO_x, NMVOC, CH_4 and KFK have been prepared. The routines for preparing prognoses of emissions to the air have been changed and are now based on reporting from the operators to a greater degree than before. Over the long term, the transition will entail a streamlining benefit and will provide improved quality for the emission prognoses. The prognoses show a certain rise in the expected emissions in the years to come. Therefore, it is gratifying that the industry is making increasing use of new, environmentally-friendly technology in connection with new development plans. At the same time, measures to reduce the emissions on both new and older installations has been defined as a commitment area for all of the companies.

In 1997, CO_2 emissions from activities subject to the CO_2 tax were about 8.4 million tonnes, which is equivalent to an increase of about 6 percent compared with 1996. The CO_2 emissions per produced unit increased by approximately 1.7 percent.

Extensive work has been done in connection with surveying the possibilities of supplying installations on the Norwegian shelf with electricity from land. A report on this has been prepared in cooperation with the Norwegian Water Resources and Energy Administration. The work has provided valuable insight into technology alternatives and financial consequences in connection with electrification. The results may be useful in connection with the evaluation of new development projects in order to arrive at the most energy efficient solutions possible.

As a part of the authorities' follow-up of the MILJØSOK work, the Norwegian Petroleum Directorate arranged a seminar on the exchange of environmental experience in close cooperation with the operating companies. The seminar drew great interest in the industry and the future work will be followed up in close collaboration with MILJØSOK's council and secretariat.

The fields' final phase

The Norwegian Petroleum Directorate has commenced the work of finding methods for evaluating the operational efficiency of the large fields which are in or approaching their final phase. Focus has been placed on a general description of the operations phase, the use of indicators and comparisons between the fields with regard to operational efficiency, and in particular, the problems which we can expect will occur in the final phase on a field.

The cessation plans for Tommeliten Gamma and Øst Frigg have been considered. The Norwegian Petroleum Directorate has been concerned with ensuring that the remaining resources are produced to the greatest degree possible prior to shut-down.

Data management

In a situation where both the amount of information is increasing and information technology is developing at a rapid pace, it is crucial for the effectiveness of the oil industry that new technology is put into use. The Norwegian Petroleum Directorate has made significant efforts to establish common data solutions for many oil companies through the DISKOS project, and goal-oriented work to reduce unnecessary reporting to the authorities. At the same time, the Norwegian Petroleum Directorate expends considerable resources on improving the quality of the data which has already been reported. This is in order to ensure that data which is incorporated in the Norwegian Petroleum Directorate's many reports, analyses and prognoses, is of the best quality possible. The Directorate also places great emphasis on ensuring that data which is released is made available to the industry in an efficient manner. The Norwegian Petroleum Directorate has participated in various industry initiatives for standardization of data models and use of terminology. The Petroleum Register, which is now the responsibility of the Norwegian Petroleum Directorate, is kept up to date with regard to both software tools and data content.

Accidents and events

There were no fatal accidents within the Norwegian Petroleum Directorate's sphere of responsibility in 1997. On 8 September 1997, however, there was a tragic accident which claimed 12 lives when a Super Puma helicopter crashed during a flight from Brønnøysund to the Norne field off the Helgeland coast. The accident has contributed to bringing the spotlight to bear on the increasing use of helicopter transportation as a result of insufficient living quarters capacity on the installations. Pressure on the living quarters capacity is inter alia due to an increased time pressure in the development projects. In several cases, installations have been installed on the field before they are completed, which has meant that parts of the workforce must commute to other installations on a daily basis because the living quarters are not designed for a temporary increase in manning.

In 1997 there were no accidents which entailed serious damage to the environment or loss of material values and interruptions in production. However, there continue to be many gas leaks on the installations. This concerns the Norwegian Petroleum Directorate, first and foremost because of the great damage and injury potential in connection with this type of undesirable event.

The rate of accidents with personal injury has stayed at about the same level for the last five years. Even though the Directorate does not regard the injury rate in the petroleum activities as a whole to be particularly high, it believes nevertheless that injuries can be avoided, and that a goal-oriented commitment in this area is still necessary. The Directorate registers, investigates and follows up accidents, injuries and events, and uses the results as an important part of the basis for prioritizing measures. These priorities provide guidelines for the supervision, regulatory work, information activities and further development of the Directorate's own expertise.

The number of notifications of work-related diseases has continued to increase in 1997, but the Directorate has reason to believe that this is related to improved reporting of such diseases. In addition to the suffering experienced by the individual, work-related diseases cost the companies and society enormous amounts of money. Therefore, it is important that the companies contribute to a better foundation for setting priorities for efforts in this area through good reporting.

Safety challenges

Experience gained from supervision shows that the petroleum activities on the whole take place within prudent frameworks and largely in accordance with regulatory requirements for safety and working environment. The supervision has, however, shown that there is still a potential for improvement in the management systems of certain partcipants. It is a prerequisite for the authorities' supervision that these systems are in place, that they function as expected and that they contribute to a continuous improvement which leads to measurable results.

Internationalization, vulnerability to competition and low oil prices for an extended period of time have led to increased demands on cost-effectiveness in connection with development and operations. The technological development has contributed to making it possible to meet these demands, while simultaneously creating opportunities for exploration and development in new, demanding areas. The development nonetheless represents a number of challenges for the industry, not least in the exercise of the management tasks connected with safety and the working environment.

Increased use will be made of mobile installations in future developments, also for production purposes. In 1997 the Directorate has continued the work on providing for accommodation of the industry's need for increased predictability for mobile installations in relation to the Shelf regulations.

International cooperation

As in previous years, the Norwegian Petroleum Directorate has had a significant international involvement in 1997. The ongoing internationalization process in the Norwegian petroleum industry has led to organizational adjustments in the Norwegian Petroleum Directorate. A separate unit was established in order to coordinate and streamline our work. An internal group has been working on surveying the overall involvement and promoting suggestions for further activities. There has been broad participation in international professional forums and the professional cooperation in the North Sea region has been safeguarded. The Norwegian Petroleum Directorate has established good contact with INTSOK, which coordinates a collaboration between the industry and the authorities to strengthen the internationalization. The cooperation with NORAD so as to assist developing countries within the field of petroleum management has continued in 1997. Similarly, the Norwegian Petroleum Directorate has assisted PETRAD in the implementation of a number of seminars and conferences both in Norway and abroad.

There continues to be substantial interest in the Norwegian model for management of safety and working environment in offshore petroleum activities. A number of countries want to establish regulations which set clear goals for the activities through result-oriented requirements, as well as a supervision arrangement where comprehensive ideas, coordination on the part of the authorities and cooperation on the part of the parties involved are key elements. These countries have asked for the Norwegian Petroleum Directorate's assistance in the work on development of such a management model.

Regulatory development

A new Petroleum Act came into force as of 1 July 1997. From the same date, a number of regulations at the Royal Decree level also took effect. The Norwegian Petroleum Directorate has assisted the Ministry of Petroleum and Energy and the then Ministry of Local Government and Labour in preparing these regulations, which include the petroleum regulations, the safety regulations, the management systems regulations, the reimbursement regulations and the petroleum register regulations.

Led by the Ministry of Petroleum and Energy, work has commenced in the area of resource management on preparing topical guidelines for central areas under the petroleum regulations. In addition, work is underway to modernize the regulations with a view towards simplifying and making the regulations more functional, inter alia by preparing collective regulations for the area of resource management.

The Directorate's goal is to further develop the regulatory framework so that it is adapted to national and international development and emerges as an appropriate management tool.

In relation to safety management, the new Act does not entail any significant changes which will have direct consequences on the level of safety in the petroleum activities. The Act does, however, provide a better clarification of the participants' responsibility to manage their own activities.

On the basis of the new legislation, the Norwegian Petroleum Directorate started work in 1997 on a further simplification and clarification of the regulations. The new regulations are scheduled to take effect in the year 2000. Work is proceeding on an outline where the number of topical regulations is reduced from the current 14 to four regulations, within the areas of management, operation, technology and documentation.

The regulatory reform does not have the objective of tightening the requirements on the activities, but will continue the current regulation within the frame of a new regulatory structure. The change will make the regulations more accessible and will provide the supervision authorities with a more comprehensive and effective management instrument. In addition, the objective is to provide for greater use of recognized industry standards, as well as to improve the predictability in connection with application of the regulations vis-à-vis mobile installations.

As a part of the work on transferring as much as possible of the Norwegian Petroleum Directorate's guidelines to industry standards, the Directorate has also participated actively in 1997 in international and national standardization work with relevance for safety and the working environment in the petroleum activities. In this context, the Norwegian Petroleum Directorate has reviewed the draft standards which were prepared under the NORSOK initiative. With a few exceptions, the standards satisfy the Directorate's requirements for safety and working environment, and may thus be referred to in future regulations.

Stavanger, 20 April 1998

Gunnar Berge
Director General

Contents

Contents

1. Resource management on the Norwegian continental shelf

An efficient management of the petroleum resources which provides the highest possible creation of value for society in general, demands that the Norwegian Petroleum Directorate continuously has the best possible overview of the total resources in producing fields and in discoveries, as well as estimates of the undiscovered resources in all parts of the Norwegian shelf.

Within the area of resource management, the Norwegian Petroleum Directorate shall assist the Ministry of Petroleum and Energy with expert advice and alternative strategies in connection with exploration, development, operations and decommissioning/disposal matters. The oil industry is capital-intensive and significant personnel resources are used in order to promote individual matters. Therefore, it is important that the authorities have continuous follow-up at a high level of technical expertise, in order to ensure that the overall socio-economic consequences are properly addressed.

1997 was yet another year with a strong increase in the level of activity on the Norwegian shelf. The number of producing fields increased and the infrastructure became increasingly complex. The greatest attention was focused on the exploration activity commencing in deep water in the 15th round blocks, while the significant interest for the areas in the Barents Sea Project was also gratifying. New information from awarded areas in the Barents Sea Project will be available when drilling commences in 1999/2000. Management of the gas resources so that withdrawal from the large gas fields which also contain liquid resources takes place in such a way as to also ensure good recovery of the liquid resources, was an important factor in 1997, and will remain in focus in the years to come. The importance of gas injection as a method to increase the oil recovery from several fields also contributes to the creation of greater interest in gas development and for exploration for gas near the existing infrastructure.

Investment and emission prognoses received increased attention in the past year. The founding of the cooperative forum with the industry, FUN, as well as the activity in this forum, underline the significance which both the authorities and the companies place on the work to further develop all types of prognoses in connection with the petroleum activities.

In 1997, the Norwegian Petroleum Directorate worked on streamlining the reporting from the companies, standardization of concepts and data formats, as well as quality control of old data for re-use in the oil companies. This includes the DISKOS data cooperation and the internal project, SAMBA. Efforts have been made to continue the FIND cooperation for the exploration phase and FORCE for increased recovery and improved exploitation of resources. Both of these projects have been continued in 1997.

The work on modernizing the regulations and issuing topical guidelines is continuing under the leadership of the Ministry.

New petroleum regulations, new reimbursement regulations and new petroleum register regulations took effect from 1 July 1997, simultaneously with the new Petroleum Act.

In terms of resource management, 1997 has given rise to an increased focus on environmental commitment.

The year 1997 was also characterized by cost increases, supplementary investments in profitable projects and new infrastructure, as well as investment in the land facilities. Capacity limitations with regard to drilling installations and on the supplier side led to delays and some projects were not completed as planned. The production of oil was therefore lower than expected, even though there was once again a small increase as compared with the previous year.

1.1 RESOURCE ACCOUNTING

The Norwegian Petroleum Directorate's resource accounting includes an overview of both the original marketable and remaining petroleum volumes on the Norwegian continental shelf. Changes in the resource accounting are inter alia due to new discoveries or that the resource estimates for existing fields and discoveries are adjusted based on new surveys or new production technology. The remaining resources are also reduced by production. The total resource accounting for the Norwegian continental shelf is shown in Table 1.1.a.

The resource classification system

This year, the Norwegian Petroleum Directorate has made some adjustments in the way the discovered resources are classified and entered into the resource accounts. The resources are divided into 12 different classes: Classes 0 to 7 are for the discovered, recoverable resources, Class 8 is for the resources from possible future measures to increase the recovery factor and Classes 9 to 11 for undiscovered resources. The classes are:

- Class 0: Reserves where production has ceased
- Class 1: Reserves in production
- Class 2: Reserves with an approved development plan
- Class 3: Resources in a late planning phase (PDO approval within 2 years)
- Class 4: Resources in an early planning phase (PDO approval within 10 years)
- Class 5: Resources which may be developed in the long term
- Class 6: Resources where development is not very likely
- Class 7: Resources in new discoveries for which the evaluation is not complete
- Class 8: Resources from possible future measures to increase the recovery factor (measures which are not planned, possibly exceeding present-day technology)
- Class 9: Resources in prospects
- Class 10: Resources in leads
- Class 11: Unmapped resources

Class 8 expresses the Norwegian Petroleum Directorate's expectation that the average future rate of recovery on the Norwegian shelf will be 50 percent for oil and 75 percent for gas. The class comprises the volume of oil and gas which may be recovered from current fields and discoveries, in addition to the resources from those measures which have already been identified and registered in the ordinary resource accounts.

The main principle in the new classification system is that the original recoverable reserves in a field or a discovery shall be classified according to where they are located in the development chain - from when a discovery is made, or a new measure to increase the recoverable resources in a field is identified, and up to when the production has ceased. The system takes into account that a field or a discovery may have resources in several classes, i.e., resources of varying maturity in the development chain.

Resources is a generic term used for all types of petroleum volumes.

Reserves comprise recoverable resources in accordance with approved plans for fields in production and for fields under development. In other words, reserves are distributed among the first three classes. Distinction can be made between original recoverable and remaining reserves.

A *deposit* is an accumulation of petroleum in a geological unit, delimited by rocks with structural or stratigraphic boundaries, contact surfaces between petroleum and water in the formation, or a combination of these, so that the petroleum concerned is in continuous pressure communication through fluid or gas.

A *discovery* is a deposit or several deposits together, which through testing, sampling or logging, have shown probable mobile petroleum.

A *field* is one or more discoveries together which the licensees have decided to develop and for which the authorities have either approved a Plan for Development and Operation (PDO), or have granted an exemption from the PDO requirement.

There is only one discovery well for each discovery and each field. This means that wildcat wells which prove resources which are or will be included in the resource figures for an existing discovery or field are not considered to be new discovery wells. The discovery year is the year the discovery well was temporarily abandoned or completed.

Undiscovered resources comprise both mapped prospects (Classes 9 and 10) and unmapped resources in areas where play models have been defined (Class 11). There is always great uncertainty connected with analyses of undiscovered resources. The size stated for undiscovered resources is the statistical expected value.

Changes in 1997

Older fields and discoveries

For older fields and discoveries (i.e., discoveries made before 1997), the oil resources have increased by 6 million Sm^3 and the gas resources by 16 billion Sm^3. The NGL resources have increased by 5 million tonnes.

The changes are based on revisions to the resource estimates for a number of the fields and discoveries. All of the adjustments are shown in Table 7.5.e, major changes are described below. Additional details concerning the individual fields and discoveries are provided in Chapters 1.3-1.6.

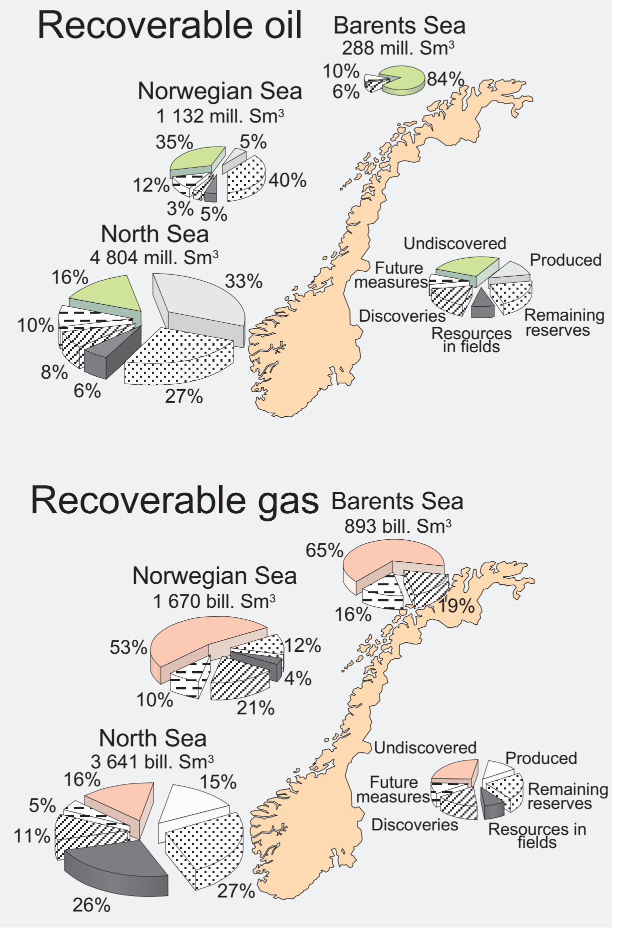
New discoveries

During 1997, discoveries were made in 17 exploration wells (10 wells were not completed as of the end of the year). Evaluation has only been completed for less than half of the discoveries, and the preliminary estimate is that the resource growth due to new discoveries in 1997 will be in excess of 300 million Sm^3 o.e.

Production

Recovery of petroleum on the Norwegian continental shelf in 1997 was 176 million Sm^3 of oil, 43 billion Sm^3 of gas and 8 million tonnes of NGL (including condensate).

Figure 1.1.a
Geographical distribution of petroleum resources on the Norwegian continental shelf



The resource estimates shown in the figure are divided according to category of resources and the main areas of the shelf. The figures are base estimates of each area.

Resource status

The resource accounting for the Norwegian continental shelf is presented in Table 1.1.a, and the geographical distribution of resources is shown in Figures 1.1.a and 1.1.b. The resources on the Norwegian continental shelf are divided according to the Norwegian Petroleum Directorate's resource classification system.

Fields where production has ceased

There were no fields which ceased production in 1997. The resources in the three fields where production has ceased (Resource Class 0) are shown in Table 7.5.b.

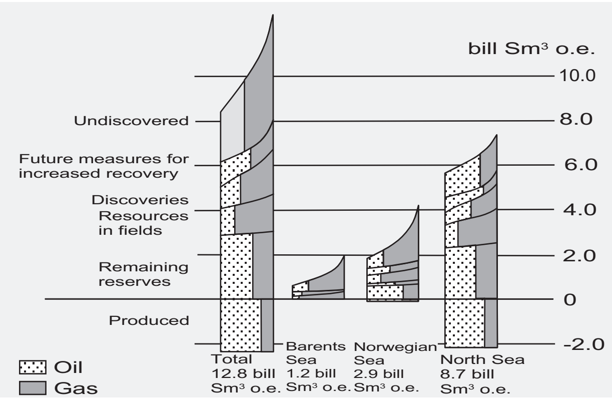
Reserves in fields which are in production/approved for development

As of 31 December 1997, 56 fields on the Norwegian continental shelf have been approved for development (including the three fields where production has ceased). The Troll field is considered to be one field, in spite of the fact that it consists of separate developments with different operators. The two fields which were approved for development during 1997 are Jotun and Oseberg Sør.

Three new fields started production in 1997; Vigdis, Njord and Norne. At the end of the year, 43 fields were producing on the Norwegian continental shelf (Table 7.5.b). 10 fields have been approved for development, but have not yet started production (Table 7.5.b).

As a consequence of the adjustments in the Norwegian Petroleum Directorate's system for classification of the resources, there will be some minor changes in the registration of reserves and resources in the fields. In Table 7.5.b in chapter 7.5, it is only the reserves, that is, the resources in the fields which are covered under approved development plans, which are reported. Previously, the estimates for some of the fields have included resources from certain planned measures for increased recovery, subsequent development phases or additional resources. For the last two years, these have been reported separately. This year, these are compiled together at the bottom of Table 7.5.b. This change will provide a better overview of what has actually been approved for development for the individual fields, while simultaneously providing a more unified representation. The fields which have been particularly affected by the change this year are described in the paragraph entitled "Changes in resource estimates".

Figure 1.1.b
Geographical distribution of resources on the Norwegian continental shelf - with range of uncertainty



The total range of uncertainty in the resource estimates are shown in the figure in that for each category is shown a low estimate (left part of the column) and a high estimate (right part of the column). The base estimate is shown below the column for each category of resources.

The total, original recoverable reserves in fields approved for development are 5306 million Sm^3 o.e., divided between 3598 million Sm^3 o.e. oil/NGL and 1708 billion Sm^3 gas. This is shown in Table 1.1.a. In addition, resources totaling 1396 million Sm^3 o.e. have been identified in the form of additional resources and resources from measures for increased recovery which are not approved for development or implemented. These are divided between 381 million Sm^3 o.e. oil/NGL and 1015 billion Sm^3 gas (including Troll III (Troll Vest gas)) (Table 1.1.a and Table 7.5.b).

Up to 31 December 1997, a total of 1741 million Sm^3 o.e. oil/NGL and 534 billion Sm^3 o.e. gas has been produced. This constitutes 40 percent of the registered, discovered oil and 15 percent of the registered, discovered gas. The registered additional resources and resources from the measures for increased recovery in the fields are included, but not the resources in Class 8.

Resources in discoveries in the late planning stages

At the end of the year, there were 16 discoveries in the late planning stages (Table 7.5.c). This includes discoveries which have plans for development and operation under consideration by the authorities. This category also includes discoveries where it has been indicated that such plans will be submitted in the near future, and where it is assumed that the development will be approved by the authorities within 2 years. The petroleum resources in these discoveries constitute a total of 408 million Sm^3 o.e. This includes all of the registered resources in these discoveries, regardless of resource classification.

Resources in discoveries in the early planning stages

Table 7.5.c provides an overview of discoveries on the Norwegian shelf which are in the early stages of planning for development, i.e., discoveries where it is assumed that a plan for development and operation will be approved during the course of 2-10 years.

There are plans to develop all of the 14 discoveries which have been placed in this category, however, appraisal or evaluation work is still needed for several of the discoveries. In addition, some of the discoveries await available processing capacity on nearby installations or gas allocation. The resource volume constitutes a total of 340 million Sm^3 o.e.

Table 1.1.a
The total petroleum resources on the Norwegian continental shelf

		Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Total 10^6 Sm^3 o.e.
	Fields				
0	Reserves where production is ceased	0	39	0	40
1-2	Reserves in production or with an approved development plan	3 403	1 669	150	5 266
	Sum reserves	**3 403**	**1 708**	**150**	**5 306**
	Sold by 31.12.97	1 668	534	56	2 275
	Remaining reserves	1 735	1 173	94	3 031
	Resources				
3	Resources in late planning phase	203	531	12	749
4	Resources in early planning phase	139	418	6	565
5	Resources which may be developed in the long term	10	65	1	77
6	Resources where development is not very likely	4	1	-	5
	Sum resources related to fields	**356**	**1 015**	**19**	**1 396**
	Sum resources and reserves related to fields	**3 759**	**2 723**	**169**	**6 702**
	Discoveries [1]				
3	Resources in late planning phase[2]	195	159	41	408
4	Resources in early planning phase	85	208	36	340
5	Resources which may be developed in the long-term	98	366	17	486
6	Resources where development is not very likely	20	51	1	73
7	Resources in new discoveries for which the evaluation is not complete	37	147	10	197
	Sum discoveries	**435**	**931**	**105**	**1 504**
	Of the above, new discoveries in 1997	49	206	47	317
	Sum fields and discoveries	**4 194**	**3 654**	**274**	**8 205**
	Other resources				
8	Possible future measures to increase the recovery factor	630	480	-	1 110
9-11	Undiscovered	1 400	2 070	-	3 470
	Total recoverable potential	**6 224**	**6 204**	**274**	**12 785**
	Sold by 31.12.1997	1 668	534	56	2 275
	Remaining	**4 556**	**5 670**	**219**	**10 510**

1 Some discoveries have resources in several resource classes. The table summarises the resources for the lowest resource class of the discoveries. The table is therefore comparable with the resources for discoveries shown in table 7.5.c.
2 A minor part of the resources, which are planned for a long-term test production, are accounted for in resource class 2.

The table contains the total recoverable resources and reserves in each resource class on the Norwegian continental shelf distributed on fields and discoveries. Some fields and discoveries have resources in more than one resource class.

Table 1.1.b
Change in the discovered resources

		Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Total 10^6 Sm^3 o.e.
0	Technical changes in fields where production is ceased		1		1
1-2	Reserves in fields approved before 1997	169	-277	-3	-111
1-2	New fields in 1997 (Jotun and Oseberg Sør)	84	12		96
3-6	Resources in fields	1	326	-7	318
3-7	Resources in discoveries before 1997	-88	-106	15	-175
3-7	Resources in new discoveries in 1997	49	206	47	317
8	Resources from possible future measures to increase the recovery factor	-160	60		-100
	Change in total recoverable resources	**55**	**222**	**52**	**346**
	Production in 1997	176	43	8	229
	Change in remaining	-120	180	44	116

Resources in discoveries which may be developed over the long term

A total of 50 discoveries have been identified in this category (Table 7.5.c) which contains discoveries which the Norwegian Petroleum Directorate believes may be developed over the long term, even though, at the present time, many of the discoveries are not considered to be profitable by the licensees. This class also includes some discoveries in relinquished areas, which the Norwegian Petroleum Directorate nevertheless assumes will be re-awarded and developed over the long term.

The resource volume constitutes 468 million Sm^3 o.e., of which 353 million Sm^3 o.e. are located in the North Sea, 46 million Sm^3 are located in the Norwegian Sea and 87 million Sm^3 o.e. are located in the Barents Sea.

Resources in discoveries where development is not very likely

The Norwegian Petroleum Directorate's resource accounts show 35 discoveries for which profitable development is not expected without significant changes in technology or price (Table 7.5.c). Most of these discoveries are very small. Moreover, some have such poor reservoir properties that they cannot be produced profitably with today's technology. There is great uncertainty with regard to the resource estimate, however, the Norwegian Petroleum Directorate estimates that technically about 73 million Sm^3 o.e. may be produced from these discoveries.

Resources in discoveries where evaluation is not complete

The class contains twelve of the discoveries from 1997, as well as two older discoveries which have not yet been completely evaluated (Table 7.5.c.) The preliminary estimates for these discoveries total 197 million Sm^3 o.e.

Undiscovered resources

The Norwegian Petroleum Directorate estimates that the undiscovered resources constitute 2 - 6 billion Sm^3 o.e. The statistical expected value is roughly 3.5 billion Sm^3 o.e. Figures 1.1.a and 1.1.b show the geographic distribution of these resources. Figure 1.1.b also attempts to illustrate the uncertainty by indicating a low estimate and a high estimate for each area. It is expected that about 60 percent of the undiscovered resources are gas.

Changes in resource estimates since the last annual report

A number of adjustments have been made to the resource and reserves estimates for fields and discoveries during 1997. The total changes are shown in Table 1.1.b. Table 7.5.e in chapter 7.5 shows all the changes from 1996 to 1997. The most important changes are discussed below:

Fields where production has ceased

Nordøst Frigg and Odin

Minor technical changes have been made in relation to last year's resource report. The reserves are now identical with the delivered volumes.

Fields in production

Brage

The estimate of reserves has been increased as a result of new and improved volume calcuation.

Draugen

The reserves estimate has been increased as a result of updated reservoir studies.

Eldfisk

The reserves estimate has been increased as a result of improved recovery and expectations of a longer lifetime.

Frigg

The estimate of reserves has been increased due to the inflow of gas in the reservoir.

Gullfaks

The reserves estimate has been increased as a consequence of improved recovery and new additional resources.

Jotun

New approved field consisting of the 25/7-3, 25/8-5 S and 25/8-8 S discoveries.

Njord

The estimate of reserves is reduced somewhat in connection with the transition from the Norwegian Petroleum Directorate's estimate to the operator's estimate.

Oseberg

The oil reserves have been changed on the basis of new mapping and improved rate of recovery. The gas reserves have been reduced as a consequence of changes in the classification system. With regard to gas, only allocated sales volumes are reported as reserves.

Oseberg Sør

New approved field consisting of the following discoveries: 30/9-3, 30/9-4, 30/9-5 S, 30/9-6, 30/9-9, 30/9-10, 30/9-13 S, 30/9-14, 30/9-15 and 30/9-16. Insignificant changes from previous reporting of these discoveries. A number of minor gas resources are no longer included in the accounts.

Statfjord

The reserves have been increased due to new geological evaluation and updated simulation studies.

Troll I (Troll Øst)

The reserves have been reduced because now only gas production up to the expiration of the production license is reported. Other resources are now reported in resource Class 3.

Troll II (Troll Olje)
The reserves have been increased because resources which were previously Class 3 have now been registered as Class 2 reserves.

Varg
The reserves have been reduced on the basis of re-evaluations in connection with the change of operator.

Discoveries in a late planning phase

25/11-15 Grane
The resource estimate has been increased as a consequence of expected improved recovery.

30/6-18 Kappa
In 1996, the resources were registered as a part of Oseberg Vest. They are now reported as an independent discovery.

34/7-21
A small part of the resources are registered in Class 2 as a consequence of plans for test production. The remainder of the discovery is registered as resource Class 3.

34/11-1 Kvitebjørn
The resources estimate has been reduced somewhat in connection with transition from the Norwegian Petroleum Directorate's estimate to the operator's estimate.

35/11-4 R Fram
Updated reservoir study on the basis of new well data has led to a minor downward adjustment of the gas resources.

Discoveries in the early planning phase

15/9-19 SR Volve
Sidetracked drilling has provided a basis for increasing the estimated oil resources.

35/9-1 R Gjøa
A new reservoir study has led to adjustments in the resource estimates.

6406/2-1 Lavrans
The estimate for recoverable reserves has been adjusted downwards inter alia as a consequence of reduced estimates for reserves in place.

7121/4-1 Snøhvit
The estimate for recoverable reserves has been changed due to a new planned development solution.

25/8-4
The resources have not been previously reported.

25/11-16
As unitization and development have not yet been clarified, 25/11-16 is registered as a separate discovery. In 1996 it was reported as a part of 25/11-15 Grane.

Discoveries which may be developed over the long term

30/8-1 S
A new well (30/5-2) in the adjacent block indicates additional resources.

35/10-2
Re-evaluation has led to a downward adjustment of the resource estimate.

6506/11-2 Lange
Re-evaluation has led to a downward adjustment of the resource estimate.

7120/9-1 Albatross
Re-evaluation has led to a downward adjustment of the recoverable reserves.

Discoveries where development is not very likely

2/4-14
2/4-14 is now considered to be a discovery.

34/11-2 S
The discovery was new in 1996 and the estimate from last year was preliminary in nature. The estimate has been decreased in accordance with the discovery assessment report received in 1997.

Name changes made in 1997
Name changes are normally made upon application from the operator. Discoveries which have an approved field name change names when the plan for development and operation is approved, as the discovery well in front of the name is then dropped.

Some discoveries have unofficial names which are in common use. In some cases, these names are also used in this annual report, together with the discovery well. If the operator applies for approval of a different name, the name will be changed. The discovery well, however, will remain the same. In addition to the changes mentioned here, certain discoveries have been registered under other fields or discoveries (Table 7.5.a).

The name changes made in 1997 are as follows:

Present name	Previous designation
Jotun*	25/7-3
Oseberg Sør*	30/9-3 Omega Nord
15/9-19 SR Volve	15/9-19 SR
25/11-15 Grane	25/11-15 Hermod
34/11-1 Kvitebjørn	34/11-1
6407/1-2 Tyrihans Sør	6407/1-2 Tyrihans

* A number of discoveries are incorporated in the Jotun and Oseberg Sør fields, only the discovery well for the first discovery is mentioned here.

1.2 FIELDS WHERE PRODUCTION HAS CEASED

1.2.1 MIME

Production license:	**070**	**Block:**	**7/11**
Operator: Norsk Hydro Produksjon AS			
Discovery		Year:	1982
Development approved:	1992	Prod.start:	1992
		Prod.cease:	1994
Reserves, recovered:		0,4 million Sm^3 oil	
		0,1 billion Sm^3 gas	
Total investments (firm 1997-NOK):		346 million	
Estimated disposal cost:		23,5 million	

Disposal
The cessation plan for Mime was approved in 1996. The installation will be brought to land for scrapping and condemnation. Disposal of the pipeline to Cod will be determined in light of the ongoing clarification program for pipelines.

1.2.2 NORDØST FRIGG

Production license:	**024**	**Block:**	**25/1**
Operator: Elf Petroleum Norge AS			
Discovery		Year:	1974
Development approved:	1980	Prod.start:	1983
		Prod.cease:	1993
Reserves, recovered:		11,6 billion Sm^3 gas	
		0,04 million tonnes NGL	
Total investments (firm 1997-NOK):		approx. NOK 3,4 billion	
Accrued disposal costs:		approx. NOK 150 million	

Disposal
The control station and foundation on Nordøst Frigg were disconnected from the bottom and transported to land as one unit. The deck has been deposited on land and functions as a training center, the steel column is used as a breakwater in a marina for small boats, and the concrete foundation is used as an anchoring point for the breakwater.

The subsea installation has been brought ashore for scrapping.

1.2.3 ODIN

Production license:	**030**	**Block:**	**30/7**
Operator: Esso Expl & Prod Norway A/S			
Discovery		Year:	1974
Development approved:	1980	Prod.start:	1984
		Prod.cease:	1994
Reserves, recovered:		27,3 billion Sm^3 gas	
		0,1 million tonnes NGL	
Total investments (firm 1997-NOK):		approx. NOK 4,8 billion	
Accrued disposal cost:		NOK 214 million	

Disposal
The installations on the Odin field have been transported to land for scrapping and recycling. Disposal of the pipeline to Frigg will be determined in light of the ongoing clarification program for pipelines.

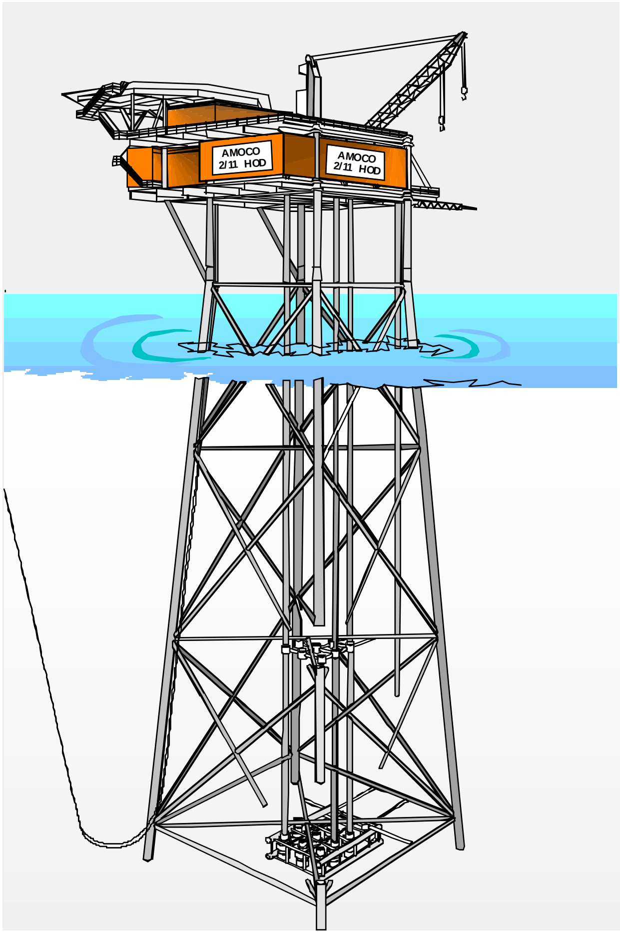
1.3 FIELDS IN PRODUCTION AND FIELDS APPROVED FOR DEVELOPMENT

1.3.1 HOD

Production license:	033	**Block:**	2/11
Operator: Amoco Norway Oil Company			
Licensees:			
Amoco Norway Oil Company		25,00000 %	
Amerada Hess Norge AS		25,00000 %	
Enterprise Oil Norwegian AS		25,00000 %	
Elf Petroleum Norge AS		25,00000 %	
Discovery well:	2/11-2	Year:	1974
Development approved:	1988	Prod.start:	1990
Recoverable reserves:		8,4 million Sm^3 oil	
		1,8 billion Sm^3 gas	
		0,3 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 1,5 billion	
Operating costs 1997 incl. CO_2 tax, excluding tariffs and insurance:		NOK 47 million	

Production
The Hod field is the southernmost chalk field in the Norwegian part of the North Sea, and produces from reservoir

Figure 1.3.1
Installation on Hod



zones in the Ekofisk, Tor and Hod formations. The field is divided into the three structures Hod Vest, Hod Øst and Hod Sadel. Both the western and the eastern structure were proven in 1974. Oil was proven in the Hod Sadel area in 1994.

The field is produced with the aid of depressurization. A total of eight wells have been drilled. Five of these wells were in production at the end of 1997. The operator plans to drill a multibranched well in order to improve resource exploitation in the Hod Saddle area.

Development

The development features an unmanned production installation, Figure 1.3.1. The installation is remote-controlled from the Valhall field, 13 kilometers to the north. Oil and gas are separated by means of a separation unit and then metered before being transported via pipeline to Valhall for further processing. Oil and gas are transported in a common pipeline to Valhall and then in the existing transportation systems to Teesside and Emden. The production installation has an oil production capacity of 1500 Sm^3 oil/day and a gas treatment capacity of 320,000 Sm^3 gas/day.

1.3.2 VALHALL

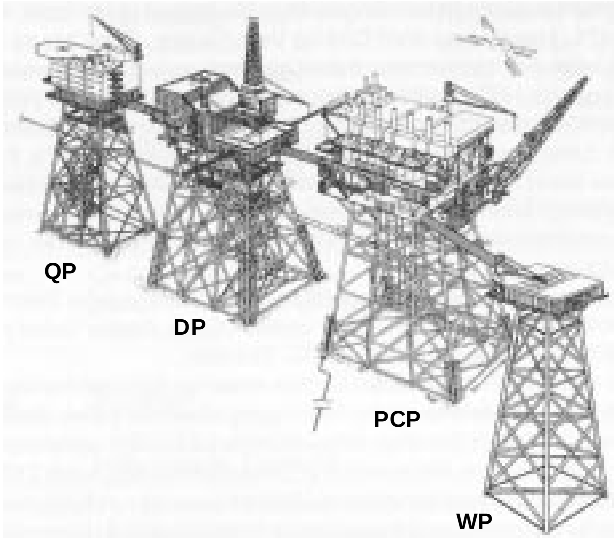
Production licenses: 006 and 033	**Block:** 2/8 and 2/11
Operator: Amoco Norway Oil Company	
Licensees:	
Amoco Norway Oil Company	28,09377 %
Amerada Hess Norge AS	28,09376 %
Enterprise Oil Norwegian AS	28,09376 %
Elf Petroleum Norge AS	15,71871 %
Discovery well: 2/8-6	Year: 1975
Development approved: 1977	Prod.start: 1982
Recoverable reserves:	116,8 million Sm^3 oil 27,8 billion Sm^3 gas 4,0 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 22,7 billion
Operating costs 1997 incl. CO_2 tax, excluding tariffs and insurance	NOK 670 million

Production

The Valhall field produces from limestone in the Ekofisk, Tor and Hod formations from the early Paleocene to the Upper Cretaceous Age. The production strategy on Valhall is based on depressurization with a high degree of compacting drive. Compacting of the reservoir rocks has led to subsidence of the seabed estimated at about 3.4 meters at the end of 1997. At the end of 1997, 34 production wells were producing on the field.

In order to increase the recovery rate of the oil, the operator is considering the possibility of starting water injection on the field. A test project with water injection in a well centrally located on the field was performed during the period 1990-1993.

Figure 1.3.2
Installations on Valhall



Development

Valhall was originally developed with three installations, one for living quarters, one drilling and one production installation. In May 1996, a new riser installation was installed with room for 19 wells. The four installations are connected to each other by gangways. Figure 1.3.2 shows these installations.

Oil is separated from gas on Valhall by means of two separation units. The gas is compressed, dried and the dewpoint is checked. The heavier gas fractions, NGL, are separated on Valhall using a fractionating tower and are then mainly transported in the oil stream.

Oil and NGL are transported by pipeline to Ekofisk for further transportation to Teesside. Gas is transported in a separate pipeline to Ekofisk for further transportation to Emden. The oil production capacity is 27,000 Sm^3 oil/day and the gas treatment capacity is 10.7 million Sm^3 gas/day. Oil and gas are fiscally metered on the 2/4-G riser installation. The metering system is part of the Ekofisk hydrocarbon distribution system.

Establishment of the new field center on Ekofisk in 1998 will lead to changes in the transportation and metering systems for petroleum from the Valhall and Hod fields. A new plan for installation and operation (PIO) of the Valhall gas export system was approved in 1997. Work will be underway until August 1998 for installation and preparation of a new oil and gas metering system, as well as other necessary equipment for rearrangement of gas and oil transportation from the field.

1.3.3 TOMMELITEN GAMMA

Production license: 044	**Block:** 1/9
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 42,38 %)	70,64000 %
Fina Production Licences AS	20,23000 %
Norsk Agip AS	9,13000 %
Discovery well: 1/9-4	Year: 1978
Development approved: 1986	Prod.start: 1988
Recoverable reserves:	3,9 million Sm^3 oil 9,2 billion Sm^3 gas 0,6 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 3,2 billion
Operating costs 1997 incl. CO_2 tax, Excluding tariffs and insurance	NOK 10 million

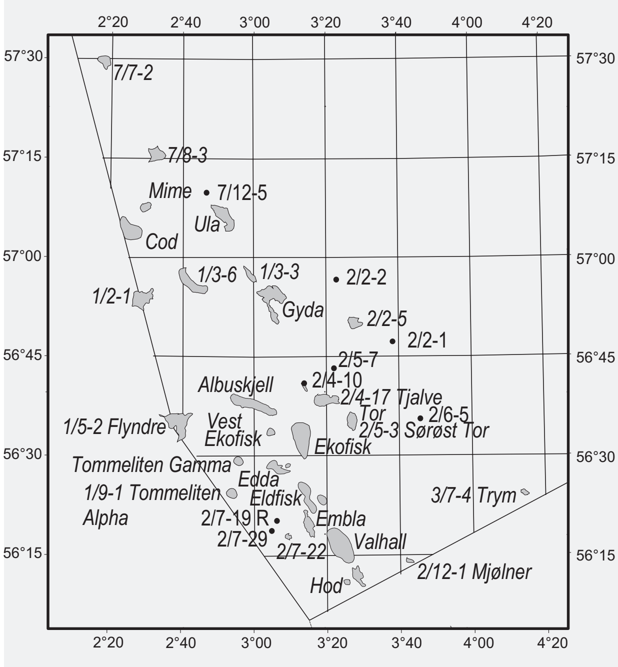
Production

The Tommeliten Gamma reservoir lies at a depth of about 3000 meters and consists of jointed Cretaceous rocks belonging to the Ekofisk and Tor formations. The structure is formed as an anticlinal over a salt diapir.

Development

Tommeliten Gamma is developed with subsea completed wells. All production is transported to Edda for first stage separation and metering, then on to the Ekofisk Center for transportation through Norpipe to Emden and Teesside. Some of the gas is used for gas lift on Edda. According to current plans, production from Tommeliten Gamma will cease when Edda is shut down in August 1998.

Figure 1.3.4.a
Fields and discoveries in the Ekofisk area



1.3.4 EKOFISK AREA

Production licenses:	018 and 018B		018 and 006	
Fields:	Albuskjell, Cod, Edda, Ekofisk, Eldfisk, Embla, Vest Ekofisk		Tor	
Block:	2/4, 2/7, 7/11, 1/6		2/4, 1/5	
Operator:	Phillips Petroleum Co. Norway		Phillips Petroleum Co. Norway	
Licensees:	Norsk Agip AS	13,04000 %	Norsk Agip AS	11,29740 %
	Elf Petroleum Norge AS	8,44900 %	Amerada Hess Norge AS	8,73760 %
	Fina Production Licences AS	30,00000 %	Elf Petroleum Norge AS	11,94570 %
	Norsk Hydro Produksjon AS	6,70000 %	Fina Production Licences AS	25,99090 %
	Phillips Petroleum Co. Norway	36,96000 %	Norsk Hydro Produksjon AS	5,80460 %
	Saga Petroleum ASA	0,30400 %	Phillips Petroleum Co. Norway	32,02080 %
	Den norske stats oljeselskap a.s	1,00000 %	Saga Petroleum ASA	0,26330 %
	Total Norge AS	3,54000 %	Den norske stats oljeselskap a.s	0,86630 %
			Total Norge AS	3,07300 %

Production license 018 includes the fields Cod, Edda, Ekofisk, Eldfisk, Embla and Vest Ekofisk. Cod is located in block 7/11, Edda, Embla and Eldfisk in block 2/7 and Ekofisk and Vest Ekofisk in block 2/4, see Figure 1.3.4.a.

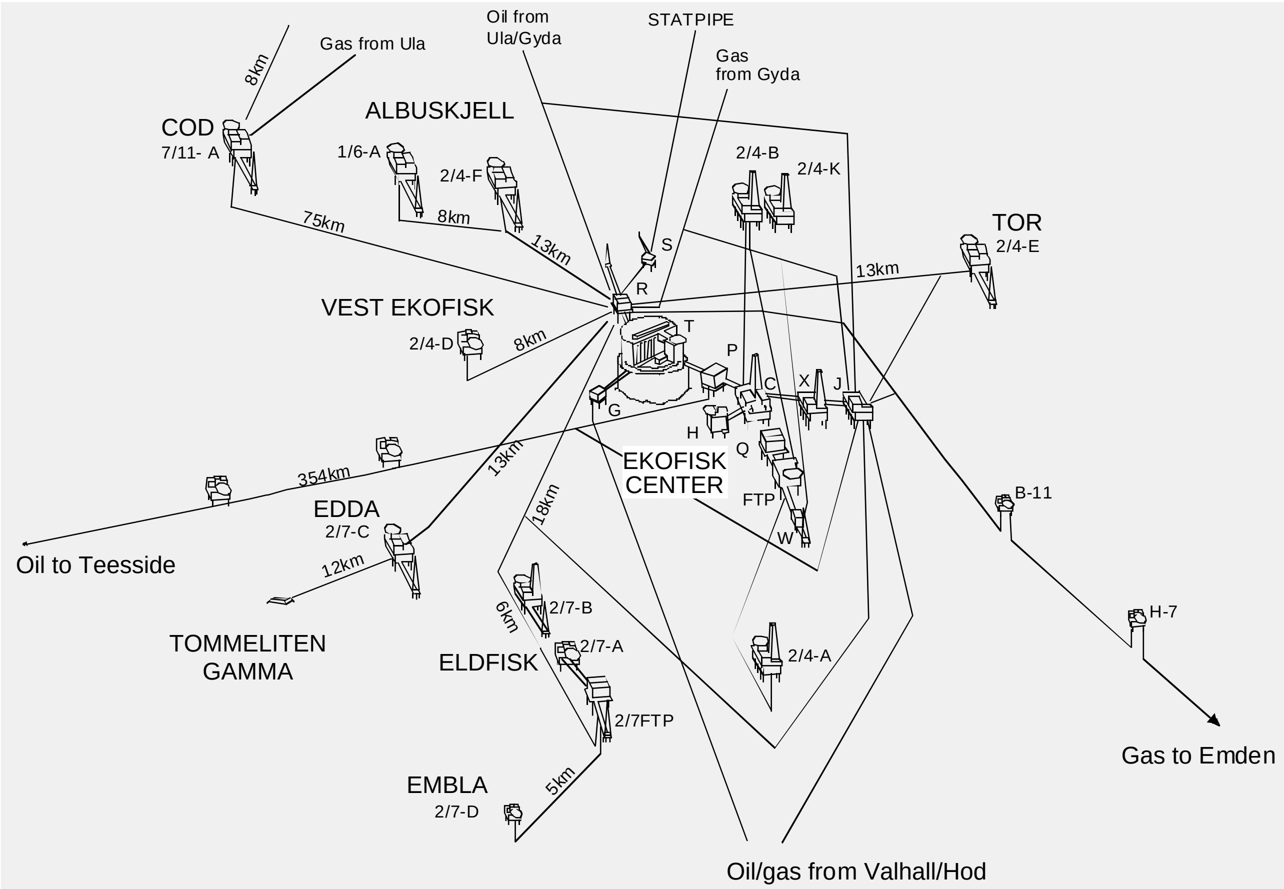
Production license 018B comprises the portion of Albuskjell which lies in block 1/6.

The Tor field lies in blocks 2/4 and 2/5, and is divided between production licenses 018 and 006. Amoco Norway Oil Company and Enterprise Oil Norwegian AS have relinquished their rights in Tor, while Amerada Hess Norge AS and Elf Petroleum Norge AS have retained their rights.

As of 1 January 1999, the ownership structure in production license 018 will be changed. SDFI will receive a 5% share and the licensees' shares will be reduced accordingly.

Production from Ekofisk started in 1971, and during

Figure 1.3.4.b
Installations in the Ekofisk area



the first years the field was produced to loading ships from four wells until the concrete tank was in place from 1973. The Cod, Tor and Vest Ekofisk fields were developed and tied in to the Ekofisk Center from 1976-1978. At the same time, an oil pipeline was laid to Teesside and a gas pipeline to Emden. In 1979, the Albuskjell, Edda and Eldfisk fields were tied in to the Ekofisk Center. Production from Embla started in May 1993. Due to the subsidence of the seabed under Ekofisk, and an expectation of production from the field well into the next century, development and operation of Ekofisk II was approved in 1994. Ekofisk II will be in production from August 1998. According to current plans for Ekofisk II, Eldfisk, Tor and Embla will be connected to the new field center. Figure 1.3.4.b shows the installations in the Ekofisk area at the end of 1997. A mobile module-based installation is being built for plugging and drilling operations on the fields in the area. The installation is scheduled to be completed in May 1998. During 1997, old drilling rigs on many of the fields have been removed and transported to land.

Embla

Production license:	018	**Block:**	2/7
Operator:	Phillips Petroleum Co. Norway		
Discovery well:	2/7-20	Year:	1988
Development approved:	1990	Prod.start:	1993
Recoverable reserves:			8,8 million Sm^3 oil 6,3 billion Sm^3 gas 0,7 million tonnes NGL
Total investments (firm 1997-NOK):			NOK 2,3 billion
Operating costs 1997 incl. CO_2 tax, Excluding tariffs and insurance			NOK 37 million

Production

Embla is a sandstone reservoir of the Devonian and Jurassic Ages which lies at a depth of over 4000 meters. The field produces from two separate sand layers through four wells, with depressurization as the drive mechanism. Complex geology and poor seismic data have made surveys of the field difficult. New surveys conducted in 1997 have shown that Embla may have larger resources than previously estimated.

Development

Embla is developed with an unmanned wellhead installation which is remote-controlled from Eldfisk. Oil and gas are transported to Eldfisk and on to the Ekofisk Center. Embla will be connected to the new Ekofisk Center in 1998 and is expected to produce until around 2020.

Eldfisk

Production license:	018	**Block:**	2/7
Operator: Phillips Petroleum Co. Norway			
Discovery well:	2/7-1	Year:	1970
Development approved:	1975	Prod.start:	1979
Recoverable reserves:		112,4 million Sm^3 oil 56,1 billion Sm^3 gas 4,9 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 29 billion	
Operating costs 1997 incl. CO_2 tax, excluding tariffs and insurance		NOK 580 million	

Production

Eldfisk is the second largest field in the Ekofisk area. The Eldfisk reservoir lies at a depth of about 2800 meters and consists of jointed chalk rocks belonging to the Tor and Ekofisk formations. The field produces from three separate structures, Alfa, Bravo and Øst Eldfisk, all with depressurization as the drive mechanism. In the summer of 1997, a plan for development and operation of Eldfisk with full field water injection was submitted to the authorities. The plan was approved by the King in Council in December 1997. Water injection is expected to increase the rate of recovery of oil from 19 percent to 27 percent.

Development

Eldfisk is developed with three installations. Eldfisk B is a combined drilling, wellhead and process installation, while Eldfisk A and FTP are a wellhead installation and a process installation connected with a gangway. The drilling rig on 2/7-B was upgraded in 1995/96, while drilling of wells from 2/7-A is done with a jack-up installation. Oil and gas are transported in two pipelines to the Ekofisk Center for further processing and transportation to Teesside and Emden. The Embla field is tied in to Eldfisk with remote control from 2/7-FTP. Eldfisk will be tied-in to the new Ekofisk Center in 1998 and is expected to produce until around 2020. A new installation will be built for water injection, connected by gangway to FTP. The installation will also supply the Ekofisk field with some water through the laying of a water pipeline from Eldfisk to Ekofisk 2/4-K. The installation will be in operation from January 2000. At the same time, existing installations on Eldfisk are being modernized. Among other things, 2/7-B will be remote-controlled from 2/7-FTP.

Edda

Production license:	018	**Blcokk:**	2/7
Operator: Phillips Petroleum Co. Norway			
Discovery well:	2/7-4	Year:	1972
Development approved:	1975	Prod.start:	1979
Recoverable reserves:		4,8 million Sm^3 oil 2,1 billion Sm^3 gas 0,2 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 5,9 billion	
Operating costs 1997 incl. CO_2 tax, excluding tariffs and insurance		NOK 115 million	

Production

The main reservoir on Edda consists of chalk rocks of the Tor formation, and lies at a depth of around 3100 meters. The field is produced with depressurization as the drive mechanism. Edda has produced longer than originally expected, which is presumed to be due to pressure support from areas to the north of the field. Since 1988, gas from Tommeliten Gamma has been transported to Edda and used for gas lift in the wells.

Development

Edda is developed with a manned wellhead installation and oil/gas is transported to the Ekofisk Center. The plan is to permanently shut down the field when Ekofisk II is put into use in August 1998, but the final decision has not yet been made.

Ekofisk

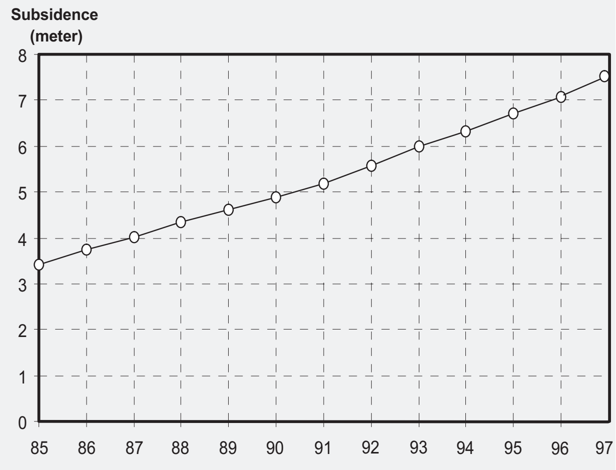
Production license:	018	**Block:**	2/4
Operator: Phillips Petroleum Co. Norway			
Discovery well:	2/4-2	Year:	1969
Development approved:	1970	Prod.start:	1971
Recoverable reserves:		404 million Sm^3 oil 153,2 billion Sm^3 gas 15,5 million tonnes NGL	
Total investments (firm 1997-NOK):		Ekofisk I: NOK 51 billion Ekofisk II: NOK 20 billion	
Operating costs 1997 incl. CO_2 tax, excluding tariffs and insurance		NOK 2 583 million	

Production

The reservoir on Ekofisk lies at a depth of about 3000 meters and consists of jointed chalk rocks from the Tor and Ekofisk formations. Ekofisk is the largest field in the area, and the second largest oil field on the Norwegian continental shelf. After 25 years of production, a little over half of the field reserves have been produced. Ekofisk was originally developed with depressurization as the drive mechanism. Subsequently, limited gas injection and comprehensive water injection have contributed to a considerable increase in the rate of recovery of oil, from the original approximately 18 percent to the current 40 percent. Large- scale water injection began in 1987, and in the subsequent years the area for water injection has been expanded in several stages. Every day about 130,000 m^3 of water is distributed in the reservoir through 38 injection wells. Experience has shown that the water's displacement of the oil is more effective than expected, and the reserves estimate has been adjusted accordingly. In addition to water injection, the compacting of the soft chalk rocks also provides an extra drive for drainage of the field. This is reinforced by the fact that the injected water contributes to the weakening of the chalk. Ekofisk is expected to produce until 2029.

Measurements of the subsidence of the seabed at Ekofisk show a total subsidence as of December 1997 of 7.47 meters at Ekofisk H. Figure 1.3.4.c shows the measured subsidence values at 2/4-H during the period 1985-1997. The subsidence rate in 1997 was approximately 40 cm.

Figure 1.3.4.c
Subsidence at Ekofisk Complex



Development
Figure 1.3.4.b shows the installations in the Ekofisk area. In all there are around 27 different permanent installations connected to the fields in the area, of which 17 are located on the Ekofisk field. The Ekofisk complex consists of 14 installations connected by gangways. 2/4-K and 2/4-W are water injection installations for Ekofisk. Oil and gas are routed from the fields in the area to the export pipelines via 2/4-R and 2/4-P on Ekofisk. The gas from the Ekofisk area is transported via pipeline to Emden, while the oil, which contains the NGL fractions, is sent by pipeline to Teesside. Total transportation capacity for oil is more than 95,000 Sm^3 per day.

In 1996, a new drilling and wellhead installation for 50 wells, 2/4-X, was installed on the field. As of December 1997, ten production wells have been drilled from this installation. In 1997, a new process and transportation installation, 2/4-J, was installed. The plan is to begin using 2/4-J in August 1998. The new installations are designed to withstand 12 meters of additional subsidence of the seabed. Several of the old installations will be shut down and various disposal alternatives will be evaluated. A total of 8-10 installations on Ekofisk will be superfluous when Ekofisk II commences operations in August 1998. Old installations which will remain in use have been modified during recent years in order to withstand further subsidence. In order to ensure continued use of the 2/4-H living quarters installation, the plan is to move the hotel to a new and higher substructure on the east side of the complex.

Vest Ekofisk

Production license:	018	**Block:**	2/4
Operator: Phillips Petroleum Co. Norway			
Discovery well:	2/4-6	Year:	1970
Development approved:	1973	Prod.start:	1977
Recoverable reserves:		12,1 million Sm^3 oil 26,9 billion Sm^3 gas 1,4 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 2,6 billion	
Operating costs 1997 incl. CO_2 tax, excluding tariffs and insurance		NOK 41 million	

Production
The Vest Ekofisk reservoir lies at a depth of approximately 3100 meters and contains gas/condensate in jointed chalk rocks from the Tor and Ekofisk formations. The field is produced with depressurization as drive mechanism.

Development
Vest Ekofisk is developed with a wellhead installation which, as of January 1994, has been remote-controlled from Ekofisk. Gas and oil are transported to the Ekofisk Center. The plan is to shut down Vest Ekofisk when Ekofisk II is put into operation in August 1998, however, the final decision has not yet been made.

Albuskjell

Production licenses:	018 and 018B	**Block:**	2/4 and 1/6
Operator: Phillips Petroleum Co. Norway			
Discovery well:	1/6-1	Year:	1972
Development approved:	1975	Prod.start:	1979
Recoverable reserves:		7,4 million Sm^3 oil 16,1 billion Sm^3 gas 1,0 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 8 billion	
Operating costs 1997 incl. CO_2 tax, excluding tariffs and insurance		NOK 18 million	

Production
The main reservoir on Albuskjell contains gas/condensate in chalk rocks of the Tor formation, and lies at a depth of around 3200 meters. The overlying Ekofisk formation has poorer production properties and therefore drainage is minimal. The field has been produced with depressurization as the drive mechanism.

Development
Albuskjell is developed with two similar installations,

1/6-A and 2/4-F, with transportation of oil and gas by pipeline to the Ekofisk Center. 2/4-F has been shut down since 1990. On 2/4-A, the process has been streamlined and much of the equipment has been taken out of operation in recent years. The plan is to shut down the rest of the field permanently by August 1998, however, the final decision has not yet been made.

Tor

Production license: 018 and 006		**Block:** 2/4 and 2/5	
Operator: Phillips Petroleum Co. Norway			
Discovery well:	2/5-1	Year:	1970
Development approved:	1973	Prod.start:	1978
Recoverable reserves:		26,7 million Sm^3 oil 11,6 billion Sm^3 gas 1,3 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 6,0 billion	
Operating costs 1997 incl. CO_2 tax, excluding tariffs and insurance		NOK 153 million	

Production

The main reservoir on Tor lies at a depth of about 3200 meters and consists of jointed chalk rocks belonging to the Tor formation. The Ekofisk formation also contains oil, but has poorer production properties. In 1992, limited water injection was implemented on Tor. About 3500 m^3 water is injected daily in two wells on the field. The water injection equipment will be upgraded in 1998 to 5700 m^3 water per day and the water injection is expected to last throughout the lifetime of the field. The drilling of two new horizontal production wells is planned in 1998.

Development

The Tor field is developed with a combined wellhead and process installation with transportation through pipelines to the Ekofisk Center. Tor will be tied in to the new Ekofisk Center in 1998 and is expected to produce until around 2014.

Cod

Production license: 018		**Block:** 7/11	
Operator: Phillips Petroleum Co. Norway			
Discovery well:	7/11-1	Year:	1968
Development approved:	1973	Prod.start:	1977
Recoverable reserves:		2,9 million Sm^3 oil 7,4 billion Sm^3 gas 0,5 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 3,3 billion	
Operating costs 1997 incl. CO_2 tax, excluding tariffs and insurance		NOK 96 million	

Production

The Cod reservoir contains gas/condensate in sandstone from the Paleocene Age, and is located at a depth of about 2900 meters. The field is produced through depressurization as the drive mechanism and is now in its final stages, with two wells in production. The Cod cessation plan was approved by the authorities in the summer of 1997. When the field is shut down, more than 70 percent of the estimated gas in place will have been produced.

Development

Cod is developed with a manned wellhead installation with equipment for water separation. Produced water is reinjected in the reservoir. Gas and oil are sent in a common pipeline to the Ekofisk Center. The plan is to shut down Cod permanently in the summer of 1998.

1.3.5 GYDA AND GYDA SØR

Production license: 019B		**Block:** 2/1
Operator: BP Petroleum Dev. of Norway AS		
Licensees:		
Den norske stats oljeselskap a.s (SDFI 30 %)		50,00000 %
BP Petroleum Dev. of Norway		26,62500 %
Norske Conoco A/S		9,37500 %
Norske AEDC A/S		5,00000 %
Norske MOECO A/S		5,00000 %
AS Pelican		4,00000 %
	Discovery well:	Year:
Gyda:	2/1-3	1980
Gyda Sør:	2/1-9	1991
	Development approved:	Prod.start:
Gyda:	1987	1990
Gyda Sør:	1993	1995
Recoverable reserves:		
Gyda		29,0 million Sm^3 oil 3,9 billion Sm^3 gas 1,6 million tonnes NGL
Gyda Sør		3,1 million Sm^3 oil 1,5 billion Sm^3 gas 0,3 million tonnes NGL
Total investments (firm 1997-NOK):		
Gyda and Gyda Sør		NOK 10 billion
Operating costs 1997 incl. CO_2 tax, Excluding tariffs and insurance		
Gyda and Gyda Sør		NOK 348 million

Production - Gyda

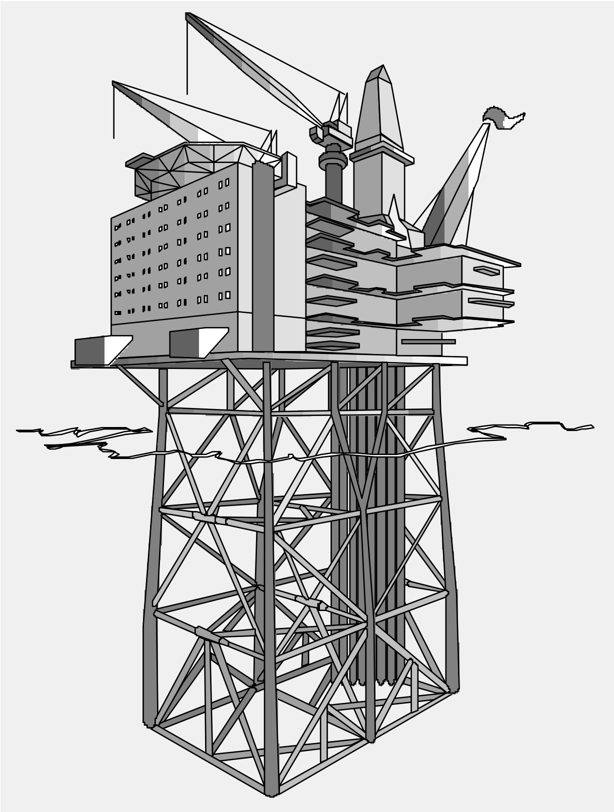
The reservoir is made up of Upper Jurassic sandstone. Gyda is produced using water injection as the drive mechanism. There are a total of 18 production wells and 10 injection wells on the field. Water production is increasing and measures to reduce water production are being evaluated continuously. Additional wells are being considered in order to increase the recovery.

Development - Gyda

The development solution for the field consists of a combined drilling, living quarters and processing installation with a steel jacket, see Figure 1.3.5. Production capacity is currently 14,300 Sm^3 oil per day and 1.8 million Sm^3 gas per day. Water injection capacity is 24,500 m^3 per day.

The oil is transported to Ekofisk via the oil pipeline from Ula, and then on to Teesside. The gas is transported

Figure 1.3.5
Installation on Gyda



in a separate pipeline to Ekofisk for further transport to Emden. The oil and gas production is metered to fiscal standards prior to pipeline transport to Ekofisk. The metering systems are included in the Ekofisk system for distribution of hydrocarbons.

Production - Gyda Sør

Gyda Sør is produced using depressurization with the aid of two long-range wells from Gyda. No pressure communication has been observed between Gyda Sør and Gyda, although it is possible that there is pressure communication in the water zone. Gyda Sør is produced through two wells and drilling of a third well has commenced. The third well will be used for water injection.

Development - Gyda Sør

The wellstream is treated in existing facilities on Gyda.

1.3.6 ULA

Production license:	019A	**Block:**	7/12
Operatør: BP Petroleum Dev. of Norway AS			
Licensees:			
BP Petroleum Dev. of Norway AS		80,00000 %	
Svenska Petroleum Exploration AS		15,00000 %	
AS Pelican		5,00000 %	
Discovery well:	7/12-2	Year:	1976
Development approved:	1980	Prod.start:	1986

Recoverable reserves:	69,3 million Sm^3 oil 3,5 billion Sm^3 gas 2,6 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 14 billion
Operating costs 1997 incl. CO_2 tax, Excluding tariffs and insurance	NOK 382 million

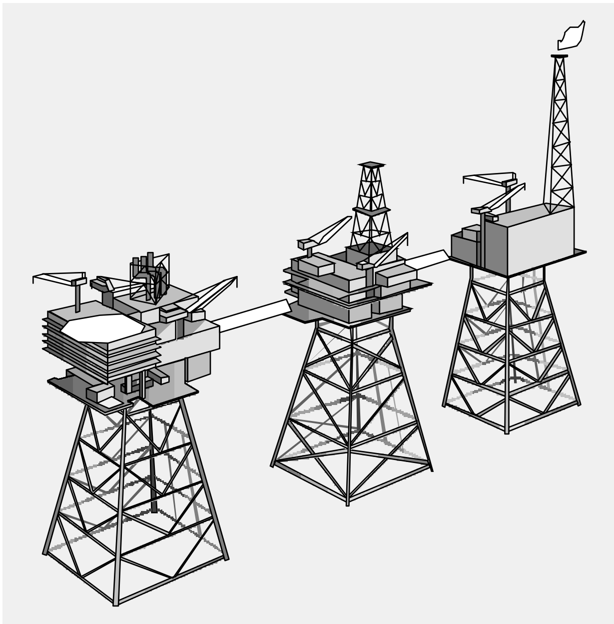
Production

The reservoir consists of Jurassic sandstone and is produced using water injection as the drive mechanism. Production now has a high and increasing quantities of water. The operator is continuously evaluating various measures to halt the water. The use of gel to block water-producing strata was attempted in 1997. At the end of 1997, there were 14 wells producing while 5 wells were used for water injection.

A new gas injection system will be put into operation during 1998 for reinjection of produced gas. The WAG project (alternating water/gas injection) is initially planned for two wells. An injection test was performed in September 1997.

The first well in the overlying reservoir zone began to produce in 1997. In order to improve the exploitation of the remaining reserves, the operator plans to drill new horizontal wells. The operator has conducted test production from the underlying Triassic reservoir. The test commenced in late 1995, but due to production problems, the test was extended to the end of 1996. The objective of the test was to evaluate the volume, productivity and possible communication with the reservoir in the Ula formation. A plan for development and operation of the Ula Triassic deposits was submitted to the authorities in 1997.

Figure 1.3.6
Installations on Ula



Development

The development concept consists of three steel installations for production, drilling and living quarters respectively, see Figure 1.3.6. Production capacity is currently 24,000 Sm³ oil per day and 1.6 million Sm³ gas per day. Water injection capacity is 32,000 m³ per day. The capacity for treatment of produced water is approximately 19,000 m³ per day. All produced water on Ula is reinjected.

The oil is transported by pipeline via Ekofisk to Teesside. Statoil is the operator of the pipeline. For the time being, the gas is transported by pipeline via Cod to Ekofisk and then on to Emden. The oil and gas production is metered to fiscal standards prior to pipeline transportation to Ekofisk. The metering systems are included in the Ekofisk system for distribution of hydrocarbons.

1.3.7 YME

Production licenses: 114 and 114B	**Block:** 9/2 and 9/5
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 30 %)	65,00000 %
Saga Petroleum ASA	25,00000 %
Deminex Norge AS	10,00000 %
Discovery well: 9/2-1	Year: 1987
Development approved: 1995	Prod.start: 1996
Recoverable reserves:	9,6 million Sm³ oil
Total investments (firm 1997-NOK):	NOK 1,8 billion
Operating costs 1997 incl. CO_2 tax, Excluding tariffs and insurance	NOK 766 million

Production

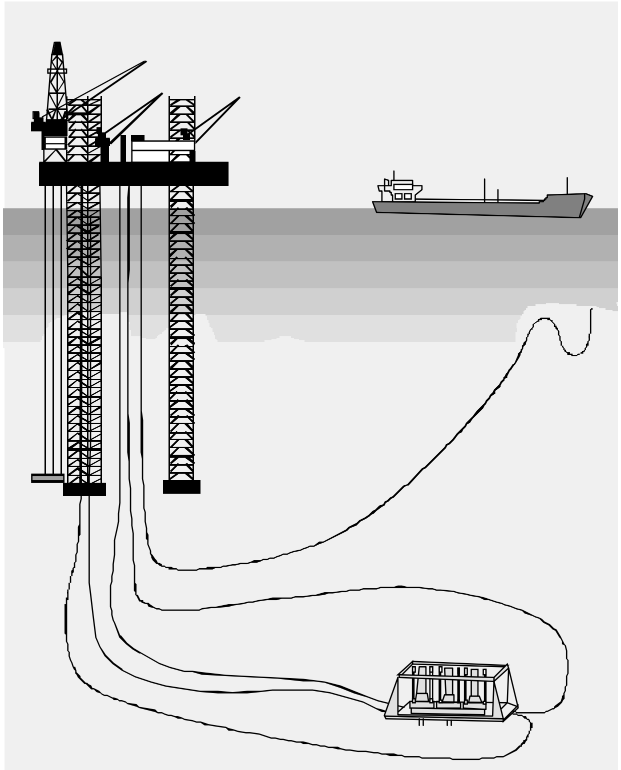
Development of the Yme field will be carried out in several phases. Oil is produced from the Gamma Vest, Gamma Sørøst and Beta Øst structures. The oil is found in the Sandnes formation which belongs to the Middle to Late Jurassic Age.

The main reservoir on Yme is in the Gamma Vest structure. The reservoir will for the most part be produced by depressurization, but limited water injection and the use of downhole pumps are also planned. Development of the deposits in Beta Øst was approved in November 1995. These deposits are produced with two subsea-completed wells. Depressurization with gas lift has been chosen as the drive mechanism. Development of the deposits in Gamma Sørøst was approved in February 1997. These deposits will be drained using depressurization.

In June 1997, well 9/2-7 S proved oil in the Beta Vest structure. The intention is to submit the plan for development and operation of the Beta Vest deposits in 1998, based on production via the Beta Øst subsea installation.

At the end of 1997 there were seven production wells. The original plan was to inject surplus gas into a water-filled reservoir under the main field. Due to injection problems in the water-filled reservoir, however, the gas is now temporarily injected into the main reservoir.

Figure 1.3.7
Installations on Yme



Development

The field development concept consists of a jack-up installation and a storage tanker with buoy loading to shuttle tankers, Figure 1.3.7. The subsea installation on Yme Beta Øst is linked to Yme. There is no other infrastructure in the area. All oil from Yme is transported by ship to Mongstad for final separation of water and for fiscal metering.

The production installation has an oil production capacity of 8000 Sm³ per day with the potential for upgrading. The gas treatment capacity is 800,000 Sm³ gas per day, whereof 400,000 Sm³ gas per day may be recirculated for gas lift.

1.3.8 VARG

Production license: 038	**Block:** 15/12
Operator: Saga Petroleum ASA	
Licensees:	
Saga Petroleum ASA	35,00000 %
Den norske stats oljeselskap a.s (SDFI 30,000 %)	65,00000 %
Discovery well: 15/12-4	Year: 1984
Development approved: 1996	Prod.start: 1998
Recoverable reserves:	5,5 million Sm³ oil 0,2 billion Sm³ gas 0,02 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 3,3 billion
Operating costs 1997 incl. CO_2 tax, Excluding tariffs and insurance	NOK 69 million

Production

The field contains oil in a greatly faulted sandstone reservoir from the Upper Jurassic Age. The production strategy is based on the use of WAG (alternating water/ gas injection). The total number of wells is estimated to be 13. Because of the results of an appraisal well drilled on the northern part of the field in autumn of 1996, the recoverable reserves have been reduced compared with the PDO.

Development

The plan for development and operation was approved in May 1996. Varg will be developed with a production ship tied to a wellhead installation. The wellhead installation was installed on the field in the summer of 1997, and pre-drilling of the production wells was to start in early autumn. Due to delays in connection with upgrading of the jack-up drilling installation and delays due to bad weather, the drilling did not commence until the end of the year. Construction of the production ship is also delayed. Production start-up is planned for the summer of 1998.

Planned production capacity is 9000 Sm³ oil per day.

1.3.9 SLEIPNER AREA

Sleipner Øst

Production license: 046	**Block:** 15/9
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s	
(SDFI 29,6 %)	49,60000 %
Esso Expl & Prod Norway AS	30,40000 %
Norsk Hydro Produksjon AS	10,00000 %
Elf Petroleum Norge AS	9,00000 %
Total Norge AS	1,00000 %
Discovery well: 15/9-9	Year: 1981
Development approved: 1986	Prod.start: 1993
Recoverable reserves:	38,4 billion Sm³ gas 25,0 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 24,7 billion
Operating costs 1997 incl. CO_2 tax, Excluding tariffs and insurance	NOK 703 million

Loke

Production license: 046	**Block:** 15/9
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s	
(SDFI 29,6 %)	49,60000 %
Esso Expl & Prod Norway AS	30,40000 %
Norsk Hydro Produksjon AS	10,00000 %
Elf Petroleum Norge AS	9,00000 %
Total Norge AS	1,00000 %
Discovery well: 15/9-17	Year: 1983
Development approved: 1991	Prod.start:1993
Recoverable reserves:	3,5 billion Sm³ gas 1,5 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 0,67 billion

Sleipner Vest

Production licenses: 046 and 029	**Block:** 15/9 and 15/6
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s	
(SDFI 32,3745 %)	49,50290 %
Esso Expl & Prod Norway AS	32,23940 %
Norsk Hydro Produksjon AS	8,84650 %
Elf Petroleum Norge AS	8,47010 %
Total Norge AS	0,94110 %
Discovery well: 15/6-3	Year: 1976
Development approved: 1992	Prod.start: 1996
Recoverable reserves:	128,1 billion Sm³ gas 29,6 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 18,0 billion
Operating costs 1997 incl. CO_2 tax, Excluding tariffs and insurance	NOK 337 million

Gungne

Production license: 046	**Block:** 15/9
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s	
(SDFI 34,4 %)	52,50000 %
Esso Expl & Prod Norway AS	28,00000 %
Norsk Hydro Produksjon AS	9,40000 %
Elf Petroleum Norge AS	9,00000 %
Total Norge AS	1,00000 %
Discovery well: 15/9-15	Year: 1982
Development approved: 1995	Prod.start:1996
Recoverable reserves:	4,5 billion Sm³ gas 1,7 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 0,35 billion
Operating costs 1997 incl. CO_2 tax, lease of well slot, excl. tariffs and insurance	NOK 63 million

Production

Sleipner Øst, Loke and Gungne

The fields contain gas and condensate in reservoirs of the Tertiary and Jurassic/Triassic Age. The gas contains a relatively high quantity of condensate. The Tertiary reservoir in Sleipner Øst is produced using reinjection of dry gas in order to extract more condensate than is achieved through depressurization. The injection gas may be taken from both Sleipner Øst and Sleipner Vest. Because of the fact that an injection well drilled on the west flank of the field in the autumn of 1996 did not find reservoir sand, the reservoir volume, and thereby the recoverable reserves, have been reduced. Large volumes of gas have been injected in 1997 and the reservoir pressure has stabilized or risen somewhat.

Loke contains gas/condensate in reservoirs of the Tertiary and Triassic Age. The Tertiary reservoir in Loke was drained with one well, which was shut down in May 1997 due to water and sand production. The plan is to extend this well later on for production from the Triassic reservoir.

New seismic interpretation and new well information on Gungne have resulted in an increase in the estimate of gas in place and recoverable reserves. Drilling of an extra production well is being evaluated.

Sleipner Vest

The field contains gas/condensate. The reservoir lies in the Hugin formation from the Jurassic Age. The field consists of several fault blocks and the communication conditions in the reservoir are uncertain. The field is produced through depressurization. The gas in Sleipner Vest contains up to 9 volume percent CO_2, which is separated from the gas and injected into a sand layer in the Utsira formation.

Some oil has also been proven in the northern part of the field. The extent of this oil and the ability to produce it is uncertain, therefore, the operator drilled a production well into this area in the autumn of 1997. This well proved more oil than expected and preliminary results indicate that the oil is in partial communication with the gas reservoir. Additional studies in order to map the extent of the oil are planned.

Development

Sleipner Øst, Loke and Gungne are developed with an integrated process, drilling and living quarters installation with a four-shafted concrete gravity base structure (Sleipner A). In addition, a separate riser installation has been built (Sleipner R) with gangway connection to Sleipner A. A subsea template has been installed for draining of the northern part of Sleipner Øst and one for draining of Loke. Gungne is produced via a well from Sleipner A.

The first phase of the development of Sleipner Vest includes a wellhead installation, Sleipner B, and an installation for processing and removal of CO_2, Sleipner T. Sleipner B is located in the southern part of Sleipner Vest with wellstream transfer to Sleipner T, which has a gangway connection with Sleipner A. These installations use common utilities.

The production facilities in the Sleipner area are shown in Figure 1.3.9.

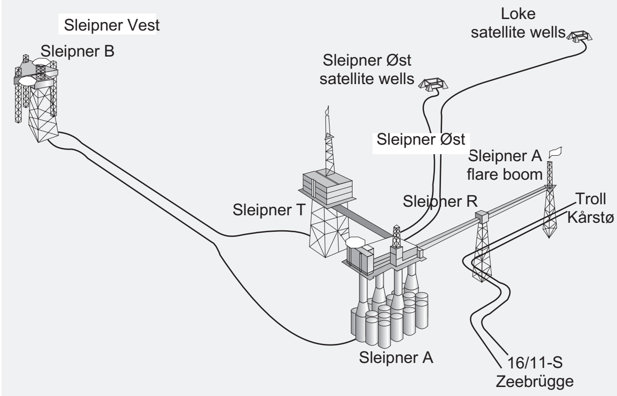
There have been some problems with the facilities for separation of CO_2 from the gas and injection of CO_2, but the separation facilities are now functioning better and the problem in the well has been solved.

An agreement has been signed concerning sales and injection cooperation among the Sleipner fields. Sleipner Vest has been allocated gas sales under the contracts which were signed in 1991 in connection with the exercise of the 30 percent options under the Troll gas sales agreement. The gas is transported via pipeline, both to Zeebrügge in Belgium through Statpipe/Norpipe and through the Europipe system to Emden in Germany.

The condensate from these fields is landed at Kårstø through a 250-kilometer pipeline from Sleipner R to Kårstø.

Total produced gas and condensate is metered to fiscal standard on the field.

Figure 1.3.9
Installations in the Sleipner area



1.3.10 BALDER

Production licenses: 001 and 028	**Block:** 25/11 and 25/10
Operatør: Esso Expl & Prod Norway A/S	
Licensees: Esso Expl & Prod Norway A/S	100 %
Discovery well: 25/11-1	Year: 1967
Development approved: 1996	Prod.start: 1999
Recoverable reserves:	27,2 millon Sm^3 oil 0,8 billion Sm^3 gas
Total investments (firm 1997-NOK):	NOK 7,9 billion
Operating costs 1997 incl. CO_2 tax, Excluding tariffs and insurance	NOK 300 million

Production

The Balder reservoir is sandstones from the Tertiary Age. They are poorly consolidated, but have good reservoir properties and contain relatively viscous oil. An extended test was carried out in summer 1991 by the production ship Petrojarl I. During the test valuable production information was collected. The Balder field consists of several separate structures. Six structures are included in the plan for development and operation. Five other structures have been mapped and as of the present time are considered to be prospects. It is expected that these will be included in the field in the future.

The field will be produced using natural water drive and water injection. A total of 10 wells are planned for oil production, three for water injection and one for gas injection. In addition, a well will be drilled for production of injection water from the Utsira formation.

Development

The plan for development and operation (PDO) was submitted to the authorities in October 1995, and was approved in February 1996. The development concept is based on seabed wells which are connected to a production and storage ship. The oil will be exported via tankers. In the PDO, the plan was for production to start between November 1996 and March 1997, however, completion of the ship has taken considerably longer than anticipated and has cost more than expected. Production start-up is now expected in the summer of 1999.

The field contains little gas and, according to the PDO, the plan was to inject the gas into a water-filled structure. New data showed that there were no suitable structures in the area, therefore, in the summer of 1996, the operator submitted a plan for installation and operation (PIO) for export of the gas via Statpipe. Due to problems with the quality of the gas (high dewpoint), agreement was not reached with the Statpipe owners, and the plan is now to inject gas for a period of time while the final solution is resolved.

Pre-drilling of production wells is underway and several wells will be ready to start production when the production ship is ready. Planned average plateau production of oil is 11,900 Sm^3 per day (75,000 barrels per day).

1.3.11 JOTUN

Production licenses: 027 P and 103	**Block**: 25/8 and 25/7
Operator: Esso Expl & Prod Norway AS	
Licensees:	
Esso Expl & Prod Norway AS	45,00 %
Enterprise Oil Norwegian AS	45,00 %
Den norske stats oljeselskap a.s (SDFI 3,00 %)	5,00 %
Norske Conoco A/S	3,75 %
Amerada Hess Norge AS	1,25 %
Discovery well: 25/8-5S	Year: 1994
Development approved: 1997	Prod.start: 1999
Recoverable reserves:	30,7 million Sm^3 oil 0,7 billion Sm^3 gas
Total investments (firm 1997-NOK):	NOK 6,3 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 12 million

Production

Jotun comprises the discoveries 25/8-5 S, 25/7-3 and 25/8-8 S, all of which were proven in 1994 and 1995. In all of the structures, oil was found in the Heimdal formation from the Paleocene Age. In the 25/8-8 S discovery, some free gas was also proven. The majority of the resources lie in production license 027P, and Esso is the operator for the development. The plan for development and operation was submitted to the authorities in January 1997 and approved in June. An agreement concerning unitization between the two production licenses was signed in the autumn of 1997. Water injection, possibly in combination with natural water drive, is the planned drive mechanism.

Development

A wellhead installation and production ship have been outlined as the development concept, and construction of the installations was started in the autumn of 1997. The oil will be loaded on the field and connection to Statpipe is planned for export of gas which exceeds the need for fuel on the field.

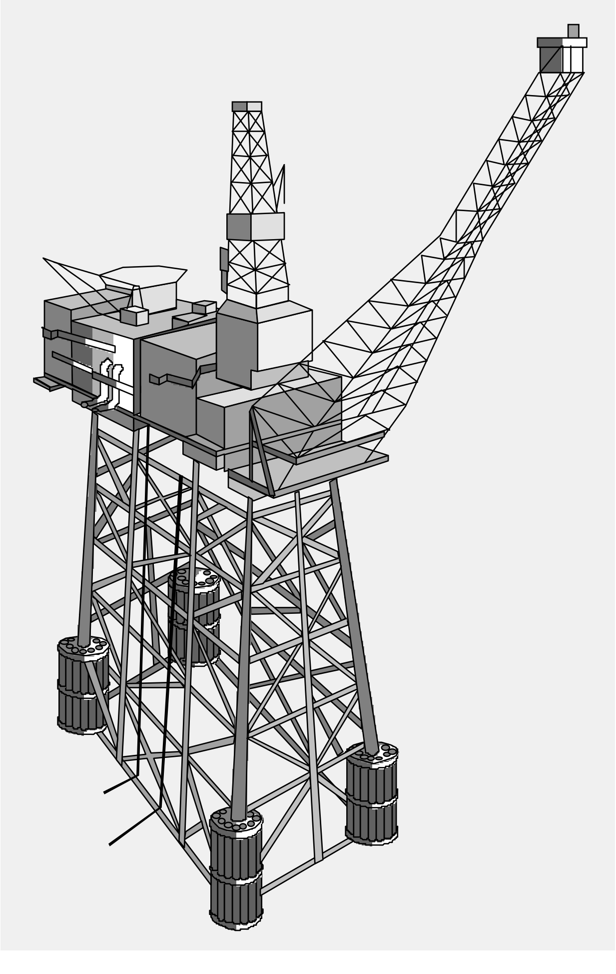
1.3.12 HEIMDAL

Production license: 036	**Block:** 25/4
Operator: Norsk Hydro Produksjon AS	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 20 %)	40,00000 %
Marathon Petroleum Norge AS	23,79800 %
Elf Petroleum Norge AS	11,93900 %
Norsk Hydro Produksjon AS	15,80300 %
Total Norge AS	4,82000 %
Saga Petroleum ASA	3,47100 %
Ugland Construction Company AS	0,16900 %
Discovery well: 25/4-1	Year: 1972
Development approved: 1981	Prod.start: 1985
Recoverable reserves:	6,7 million Sm^3 oil 40,3 billion Sm^3 gas
Total investments (firm 1997-NOK):	NOK 14,7 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 271 million

Production

The field produces from sandstones in the Heimdal formation. Ten wells have been drilled from the installation on the field, nine production wells and one observation well. Because of the powerful water drive in the field, pressure

Figure 1.3.12
Installation on Heimdal



development and water ascent are both carefully monitored.

Development

The Heimdal field has been developed with an integrated steel jacket structure with combined drilling, production and living quarters functions, see Figure 1.3.12. The deliveries of gas via Emden began in February 1986.

The gas from the Heimdal field is transported in Statpipe. The pipeline from Heimdal is tied into the Statpipe system at the Draupner riser installation. The condensate is transported from Heimdal to Brae in the British sector through a separate pipeline. From the Brae field the condensate goes to Cruden Bay in Scotland. According to the current plan, the field will produce until 1999.

1.3.13 FRIGG AREA

Frøy

Production licenses: 026 and 102	**Block:** 25/2 and 25/5
Operator: Elf Petroleum Norge AS	
Licensees:	
Den norske stats oljeselskap a.s	
(SDFI 41,616 %)	53,96000 %
Elf Petroleum Norge AS	24,75730 %
Total Norge AS	15,23460 %
Norsk Hydro Produksjon AS	6,04810 %
Discovery well: 25/5-1	Year: 1987
Development approved: 1992	Prod.start:1995
Recoverable reserves:	6,7 million Sm^3 oil 1,6 billion Sm^3 gas 0,1 million tonnes NGL
Total investments (firm 1997-NOK):	Nok 5,9 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 159 million

Production

Frøy is an oil field. The reservoir lies in the Brent group of the Upper Jurassic Age. The production strategy is based on water injection. The field has 10 wells, of which six are production wells. Some of these have not been operative in periods due to problems in connection with water production. The operator has reduced in-place and recoverable reserves based on experience with production wells and a new geological model. Frigg may become unprofitable after the year 2000 and cease production. After that time, Frøy will incur higher operating costs and the risk of unprofitable operations.

Development

The field is developed by means of a wellhead installation. Oil and gas are transferred in separate pipelines to Frigg for further processing and metering. The gas is transported on to St. Fergus. The oil is transported in Frostpipe to Oseberg, and from there on to the oil terminal at Stura. (Figure 1.3.13.a shows an overview of the fields and discoveries in the Frigg area).

Øst Frigg

Production licenses: 024, 026 and 112	**Block:** 25/1 and 25/2
Operator: Elf Petroleum Norge AS	
Licensees:	
Den norske stats oljeselskap a.s	
(SDFI 1,4613 %)	10,43100 %
Elf Petroleum Norge AS	37,22500 %
Norsk Hydro Produksjon AS	32,11200 %
Total Norge AS	20,23200 %
Discovery well: 25/2-1	Year: 1973
Development approved: 1984	Prod.start:1988
Recoverable reserves:	9,3 billion Sm^3 gas
Total investments (firm 1997-NOK):	NOK 3,0 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 28 million

Production

Øst Frigg is a gas field consisting of two main structures, Alpha and Beta, which are a part of the same pressure system as the Frigg field. The reservoir lies in the Frigg formation of the Eocene Age. The field will probably cease production in 1998.

Development

Development of Øst Frigg is based on subsea technology with two subsea templates for the wells and a central manifold station which links the systems together. The production systems are remote-controlled from Frigg. From the manifold, a gas and service line goes to TCP2 at Frigg where the gas is processed and metered before it is sent into the Frigg field transportation system to St. Fergus.

Lille-Frigg

Production license: 026	**Block:** 25/2
Operator: Elf Petroleum Norge A/S	
Licensees:	
Den norske stats oljeselskap a.s	5,00000 %
Elf Petroleum Norge A/S	41,42000 %
Total Norge AS	20,71000 %
Norsk Hydro Produksjon AS	32,87000 %
Discovery well: 25/2-4	Year: 1975
Development approved: 1991	Prod.start:1994
Recoverable reserves:	1,3 million Sm^3 oil 2,4 billion Sm^3 gas
Total investments (firm 1997-NOK):	NOK 4,2 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 68 million

Production

Lille-Frigg is a gas/condensate field. The reservoir is located in the Brent group in a fault block which is an extension of the Heimdal ridge. Production is based on three production wells with depressurization as the production mechanism. The field is currently producing from only one well due to problems in connection with water production. The recoverable reserves were 7 billion Sm^3 gas when the field was approved, and the estimate has now been reduced to 2.4 billion Sm^3 due to a more rapid pressure decline and water production. Frigg may become unprofitable after the year 2000 and will cease to produce. After that time, Lille-Frigg will incur higher operating expenses and the risk of unprofitable operation.

Development

Lille-Frigg is developed with a subsea installation which is remote-controlled from Frigg. The untreated well-stream is transferred under high pressure directly to Frigg for processing. The gas is transported via pipeline to St. Fergus. Stabilized condensate is transported via Frost-pipe to Oseberg, and from there is sent to the oil terminal at Stura. Metering of condensate and gas takes place on Frigg.

Frigg

Production license: 024	**Blocks:** 25/1 and 30/10 on the Norwegian shelf and 10/1, 9/5 and 9/10 on the British shelf
Operator: Elf Petroleum Norge AS	
Licensees:	
Norwegian share (60,8200%)	
Elf Petroleum Norge AS	25,19100 %
Norsk Hydro Produksjon AS	19,99200 %
Total Norge AS	12,59600 %
Den norske stats oljeselskap a.s	3,04100 %
British share (39,1800%)	
Elf Exploration UK Ltd	26,12000 %
Total Oil Marine Ltd	13,06000 %
Discovery well: 25/1-1	Year: 1971
Development approved: 1974	Prod.start: 1977
Recoverable reserves:	
(Norwegian share)	119,2 billion Sm^3 gas
(Norwegian share)	0,4 million tonnes NGL
Total investments (firm 1997-NOK):	Approx. NOK 26 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 388 million

Production

The field produces gas from the Frigg formation, which consists of sandstone from the Eocene Age. The production wells on CDP1 are permanently plugged. On DP2, 12 wells were available for production in 1997. All of these have reduced production potential due to water influx in the wells. Measurements show that there is migration of gas in to the Frigg field. Future development of produced water volume will be a crucial factor in determining when the field will be shut down. The estimated last year of production is 2001. Shutdown of Frigg will affect the Frøy and Lille-Frigg fields which deliver oil and gas to Frigg for treatment.

Development

The field was developed in three phases. Phase I consists of one production and one treatment installation on the British part of the field, as well as a living quarters installation (CDP1, TP1 and QP). Production from Phase I started in 1977.

Phase II consists of one production and one treatment installation located on the Norwegian part of the field (DP2 and TCP2). Production from Phase 2 started in 1978. Figure 1.3.13.b shows the installations in the Frigg area.

Phase III of the development comprises the installation of three turbine-driven compressors on TCP2. The compressor system is necessary in order to compensate for reduced reservoir pressure. These facilities were put into operation in the autumn of 1981.

Gas from Øst Frigg and Lille-Frigg is treated and metered on TCP2. In 1995, a new module was installed

Figure 1.3.13.a
Fields and discoveries in the Frigg area

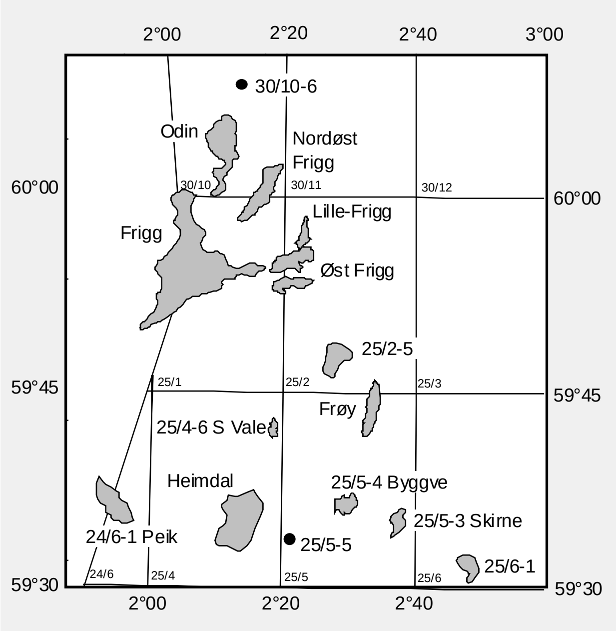
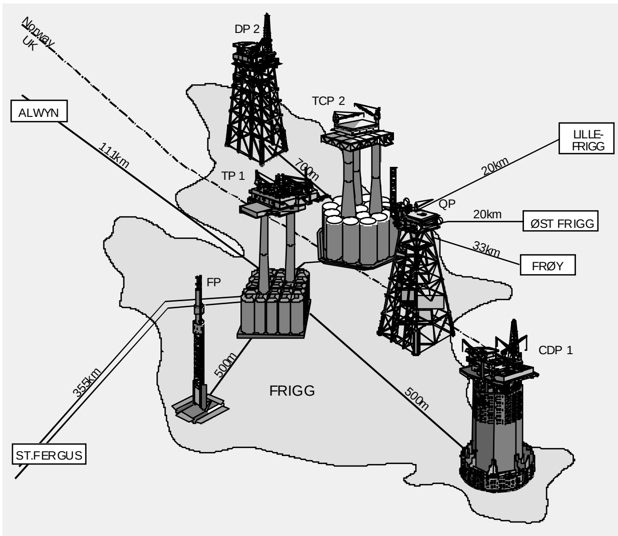


Figure 1.3.13.b
Installations in the Frigg area



on this installation in order to treat oil and gas from Frøy. Prior to their shutdown, gas from Nordøst Frigg and Odin was also treated on Frigg. Transportation of gas from the Alwyn North field on the British side takes place via TP1.

TP1 has been converted from a processing installation to a riser installation.

The gas is transported 355 km to St. Fergus in Scotland via two pipelines, each with a diameter of 813 millimeters. The liquid is transported in Frostpipe via Oseberg to Stura.

1.3.14 OSEBERG AREA

Oseberg

Production licenses: 053 and 079	**Block:** 30/6 and 30/9
Operator: Norsk Hydro Produksjon AS	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 50,7838 %)	64,78380 %
Norsk Hydro Produksjon AS	13,68190 %
Saga Petroleum ASA	8,55280 %
Elf Petroleum Norge AS	5,76940 %
Mobil Development Norway AS	4,32720 %
Total Norge AS	2,88500 %
Discovery well: 30/6-1	Year: 1979
Development approved: Phase I 1984, Phase II 1988, Phase III 1996	Prod.start: 1988
Recoverable reserves:	326,0 million Sm^3 oil 16,4 billion Sm^3 gas 6,0 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 54 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 1221 million

Production

The first discovery proved gas in 1979, while subsequent drilling proved oil with a gas cap. The field consists of several reservoirs in the Brent group, divided among several structures. The main reservoirs are in the Oseberg and Tarbert formations. The use of horizontal production wells was not included in the original plans, but most of the production wells are now drilled horizontally with good results.

Development

Figure 1.3.14.b shows fields and discoveries in the Oseberg and Troll area. The oil part of the Oseberg field has been developed in two phases, see Figure 1.3.14.a. Phase I is developed with a field center in the south with two installations. Oseberg A comprises one processing and one living quarters installation with concrete gravity bases, and Oseberg B comprises one drilling and water injection installation with a steel jacket. The middle part of the field is drained by two subsea completed wells tied into the field center. Average oil processing capacity is about 55,000 Sm^3 per day.

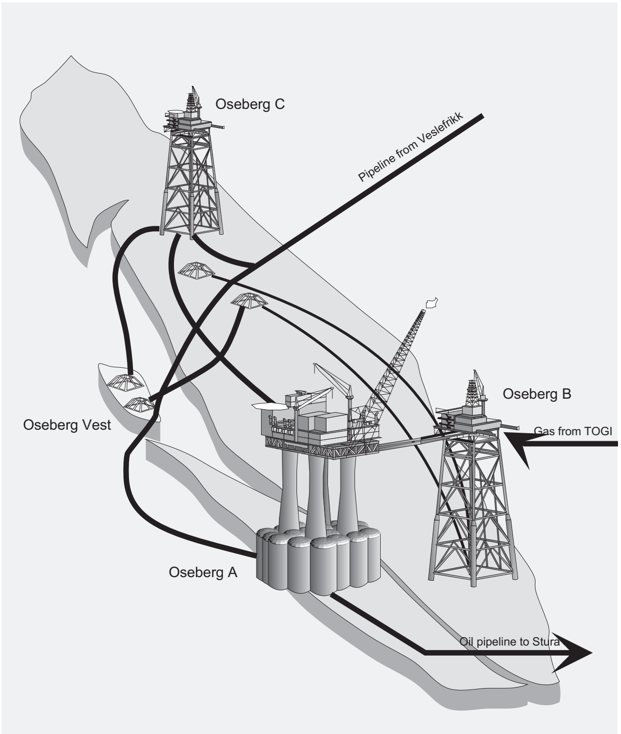
Phase II comprised development of the northern part of the field. The Oseberg C installation is an integrated production, drilling and living quarters installation (PDQ). Average oil processing capacity is about 23,000 Sm^3 per day.

The plan for development and operation for the gas phase (Phase III) of Oseberg was approved in 1996. Oseberg gas phase will start production in 1999/2000 with a gas allocation of 2 billion Sm^3 per year from the year 2000.

The gas phase will be developed with a new installation for processing of dry gas. The gas will be transported in a new gas pipeline to the Statpipe system at the Heimdal installation. The gas installation will have a capacity of 10 billion Sm^3 per year.

Oseberg A and Oseberg C are equipped with metering stations for fiscal metering of stabilized oil prior to pipeline transport to Stura. Injection gas from Troll (TOGI) is metered via the fiscal gas metering station installed on Oseberg A. Stabilized oil is exported from the terminal at Stura via two quay facilities which are linked to two identical fiscal oil metering stations.

Figure 1.3.14.a
Installations on Oseberg



Oseberg Vest

Production license:	053	**Block:**	30/6
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s			
(SDFI 50,7838 %)		64,78380 %	
Norsk Hydro Produksjon AS		13,68190 %	
Saga Petroleum ASA		8,55280 %	
Elf Petroleum Norge AS		5,76940 %	
Mobil Development Norway AS		4,32720 %	
Total Norge AS		2,88500 %	
Discovery well:	30/6-15	Year:	1984
Development approved:	1988	Prod.start:	1991
Recoverable reserves:		1,6 million Sm^3 oil 6,0 billion Sm^3 gas	
Total investments (firm 1997-NOK):		NOK 837 billion	

Hereafter, Oseberg Vest comprises only the 30/6-15 Gamma Nord structure. This is a change compared with the 1996 annual report. The structure consists of a rotated fault block where the hydrocarbon-bearing zones are found in the Statfjord formation of the Lower Jurassic.

A rich, coal-bearing shale zone divides the Statfjord formation into an upper and a lower reservoir zone. Gas was proven first with a thin oil zone in the upper reservoir zone. In order to produce as much of the oil as possible, a production solution with two horizontal production wells was chosen. In connection with the drilling of the first production well, oil was also discovered in the lower reservoir zone. The field is produced with depressurization, but has natural pressure support from the gas cap.

Development

The field is developed with two horizontal production wells. The first production well, which started producing in 1991, is tied to Oseberg C, while the second well, completed in 1996, is tied to Oseberg B. All produced gas is injected into the Oseberg field.

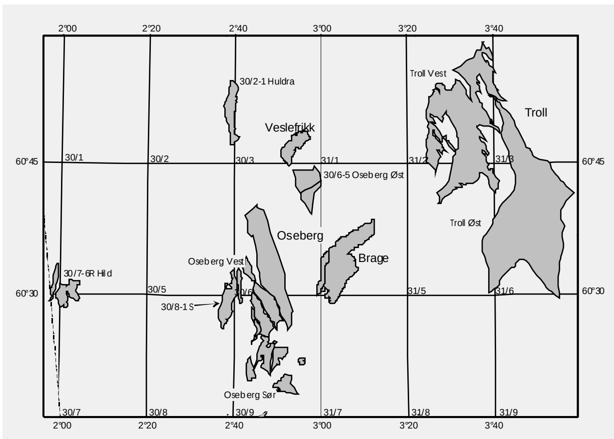
Production

The field consists of two structures which are separated by a sealed fault. Both structures contain several oil-bearing layers within the Brent group with varying porosity and permeability, as well as several different oil/water contacts. The intention is to maintain pressure with the aid of water and WAG injection. The field will be produced with six production, six injection and two water production wells.

Development

The field will be developed with a new installation with living quarters, drilling equipment and first stage separation of oil, water and gas. Processing will be completed at the Oseberg field center. The installation will have the capacity to process 12,000 Sm^3 oil and 13,300 Sm^3 water per day. The maximum gas injection rate will be 1.4 million Sm^3 per day. The oil from the field will be transported in the Oseberg Transport System to Stura.

Figure 1.3.14.b
Fields and discoveries in the Oseberg and Troll area



Oseberg Øst

Production license:	053	**Block:**	30/6
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s			
(SDFI 45,40 %)		59,40000 %	
Norsk Hydro Produksjon AS		12,25000 %	
Saga Petroleum ASA		7,35000 %	
Elf Petroleum Norge AS		9,33000 %	
Mobil Development Norway AS		7,00000 %	
Total Norge AS		4,67000 %	
Discovery well:	30/6-5	Year:	1981
Development approved:	1996	Prod.start:	1998
Recoverable reserves:		23,5 million Sm^3 oil 0,8 billion Sm^3 gas	
Total investments (firm 1997-NOK):		NOK 3,8 billion	
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance		NOK 72 million	

Oseberg Sør

Production licenses: 079, 104 and 171		**Blocks:** 30/6, 30/9 and 30/12	
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s.			
(SDFI 38,36 %)		56,58000 %	
Norsk Hydro Produksjon AS		21,88000 %	
Saga Petroleum ASA		10,14000 %	
Norske Conoco A/S		7,700000 %	
Mobil Development Norway AS		3,700000 %	
Discovery well:	30/9-3	Year:	1984
Development approved:	1997	Prod.start:	2000
Recoverable reserves:		53,5million Sm^3 oil 11,4 billion Sm^3 gas	
Total investments (firm 1997-NOK):		NOK 7,8 billion	

Production

Ten potential reservoir structures lie within the area defined by the operator as Oseberg Sør. Seven of these are incorporated in the basic estimates for Oseberg Sør. Hydro is the operator and the field is unitized.

Development

The field will be developed with one installation with living quarters, drilling module and first stage separation of oil and gas. Processing will be completed at the Oseberg field center. The oil will be transported in the Oseberg Transport System to Stura. A part of 30/9-3 Omega Nord can be reached by wells from the Oseberg field center, and will be produced from there.

1.3.15 BRAGE

Production licenses: 053, 055 and 185	**Blocks:** 30/6, 31/4 and 31/7
Operator: Norsk Hydro Produksjon AS	
Licensees:	
Den norske stats oljeselskap a.s	
(SDFI 34,2567 %)	46,95680 %
Norsk Hydro Produksjon AS	22,41820 %
Esso Expl and Prod Norway A/S	16,34340 %
Neste Petroleum AS	12,25750 %
Elf Petroleum Norge AS	0,66640 %
Saga Petroleum ASA	0,52480 %
Mobil Development Norway AS	0,49980 %
Total Norge AS	0,33320 %
Discovery well: 31/4-3	Year: 1980
Development approved: Fase I 1990	Prod.start: 1993
Recoverable reserves:	52,8 million Sm^3 oil 2,9 billon Sm^3 gas 0,8 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 11,6 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 410 million

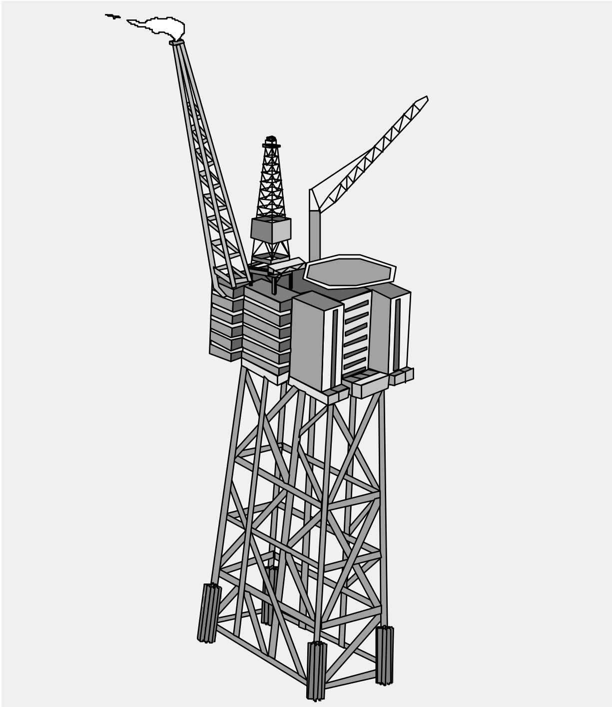
Production

Oil has been proven in two formations in the unitized part of Brage: Statfjord and Fensfjord. Oil and gas have been proven in the Sognefjord formation. Test production from the Sognefjord formation was started in the autumn of 1997 and is still in progress. The test production will have a duration of up to one year. The plan for development and operation of the resources in the Sognefjord formation may be submitted in 1998.

Development

The Brage field is developed with an integrated production, drilling and living quarters installation with a steel jacket, see Figure 1.3.15. The oil is transported via pipeline to Oseberg and further through the Oseberg line to Stura. A pipeline for gas is connected to Statpipe.

Figure 1.3.15
Installation on Brage



1.3.16 VESLEFRIKK

Production license: 052	**Block:** 30/3
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s	
(SDFI 37 %)	55,00000 %
Total Norge AS	18,00000 %
Deminex Norge AS	11,25000 %
Norsk Hydro Produksjon AS	9,00000 %
Svenska Petroleum Expl AS	4,50000 %
Norske Deminex AS	2,25000 %
Discovery well: 30/3-2	Year: 1980
Development approved: 1987	Prod.start: 1989
Recoverable reserves:	54,5 million Sm^3 oil 5,2 billion Sm^3 gas 1,8 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 11,4 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 483 million

Production

The field produces from reservoirs in the lower part of the Brent group and the Dunlin group (Intra Dunlin Sand).

The production strategy for the reservoirs in the Brent group and the Dunlin group is to maintain pressure in the reservoir with the aid of water injection. Some of the wells will, however, be controlled with a lower well pressure than boiling point pressure. Implementation of WAG injection in the main field has been decided.

Production from the Statfjord formation started in 1997. The plan is to drain the reservoir with a horizontal producer, and the recovery will be increased by recirculating the gas in a horizontal injector. The Statfjord formation has a gas cap and a higher content of associated gas than the other reservoirs.

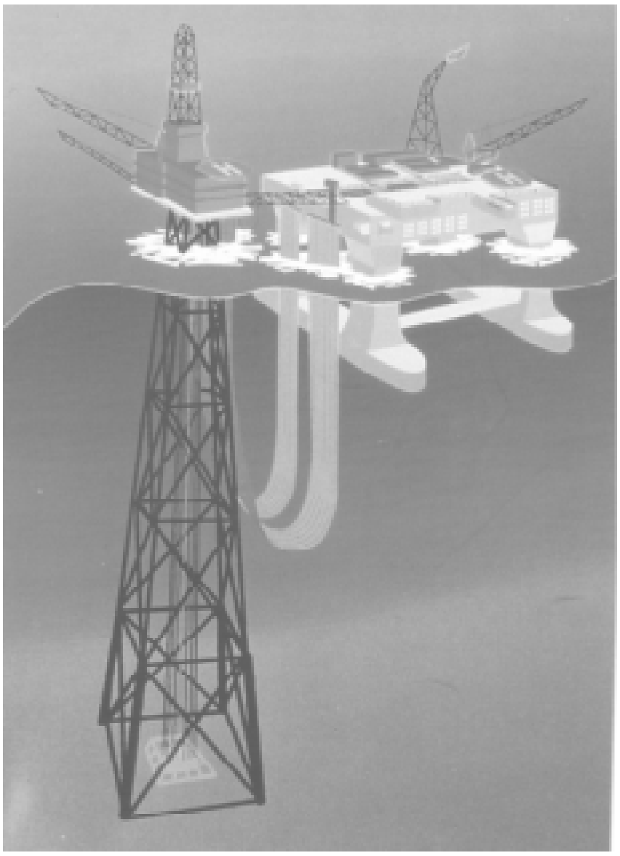
A small discovery was made during the drilling of well 30/3-7 S in 1995. The well was tested in 1997.

Development

The field has been developed with a permanent wellhead installation with a steel jacket and a semi-submersible installation with process facilities and living quarters, see Figure 1.3.16. There are 13 production wells and seven water injection wells. The semi-submersible installation is anchored and connected to the permanent wellhead installation.

An oil pipeline is connected to the Oseberg Transport System for transport to the Sture terminal. Gas is transported via the Statpipe system. A temporary agreement has been signed for exchange of produced gas volumes between Veslefrikk and Heimdal.

Figure 1.3.16
Installation on Veslefrikk



1.3.17 TROLL

Production licenses:	054 and 085	**Blocks:**	31/2, 31/3, 31/5 and 31/6
Operator:	Den norske stats oljeselskap a.s Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 62,696 %)			74,57600 %
A/S Norske Shell			8,28800 %
Norsk Hydro Produksjon AS			7,68800 %
Saga Petroleum ASA			4,08000 %
Elf Petroleum Norge AS			2,35344 %
Norske Conoco A/S			1,66113 %
Total Norge AS			1,35343 %
Discovery well:	31/2-1	Year:	1979
Development approved:		Prod.start:	1991
Phase I	1986		
Phase II	1992		
Recoverable reserves:			208,5 million Sm^3 oil 647,2 billion Sm^3 gas
Total investments (firm 1997-NOK):			NOK 94,723 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance			NOK 1940 million

Structurally, the Troll field lies on the northwestern part of the Horda platform. The field consists of three relatively large, rotated fault blocks with an eastern slope and extending over an area of 750 square kilometers. The water depth in the area is over 300 meters. The hydrocarbon-bearing layers are mainly sandstones of the Sognefjord formation, from the Middle to Late Jurassic Age. The field's gas column, which is more than 200 meters thick in the east, diminishes to the west, while the oil column drops from 22-26 meters in the west to 0-4 meters in the east. The development of the field has taken place in several phases. The Troll field was unitized in 1986.

In addition to the reported recoverable oil reserves, significant potential additional resources have been identified in Troll Vest. The total recoverable gas resources in the Troll field amount to 1348 billion Sm^3.

TOGI

The subsea system Troll Oseberg Gas Injection (TOGI) is controlled from the Oseberg Field Center and produces gas from Troll Øst for injection in the Oseberg field. Production and delivery of gas via TOGI started in February 1991. Up to the end of 1997, TOGI had delivered approximately 18.4 billion Sm^3 gas to Oseberg. In all, the plan is to deliver 22.2 billion Sm^3 gas by the end of 2002. Norsk Hydro was responsible for the development of TOGI and is the operator in the operations phase.

Troll Phase I: Development of the gas reserves in Troll Øst

Production

A/S Norske Shell was the development operator for Troll Phase I. Statoil assumed the role of operator for the operation of the field in June 1996. By the end of 1997, 27 out of a total of 39 gas producers had been drilled from the Troll A installation.

In May 1996, gas export started from Troll A to Kollsnes and on to the Continent via the Zeepipe IIA pipeline. The gas which was produced in connection with completion of the first gas treatment unit at the Kollsnes facility was sold under separate, temporary agreements. Gas deliveries to the initial buyers under the Troll gas sales agreements (TGSA), which were concluded in 1986, started as planned on 1 October 1996. Only a part of the gas from the field has been sold. Due to internal communication in the field, the production from one province may have a great effect on future production from other provinces. Therefore, great emphasis is placed on finding an optimal production strategy for oil and gas for the entire Troll field.

Development

The gas reserves in Troll Øst are produced from Troll A, which is a permanent wellhead installation with a concrete gravity base structure. The gas from Troll Øst and Troll Vest is transported from Troll A via two multi-phase pipelines to the gas treatment facility at Kollsnes. At the land facilities, the condensate will be separated from the gas and transported through a pipeline to the Stura terminal for further export to the market. The condensate will be flow-metered in a fiscal metering station before it leaves the Kollsnes terminal. The dry gas will be compressed and exported via pipeline to the Continent.

The Kollsnes facility has an export capacity of approx. 100 million Sm^3 gas per day. Metering of the gas to fiscal standard takes place through two identical metering stations for Zeepipe and Statpipe respectively. Each metering station has a capacity of about 58.8 million Sm^3 per day. The gas treatment facilities at Kollsnes are arranged so as to accommodate additional expansion.

Troll Phase II: Development of the oil reserves in Troll Vest oil province and Troll Vest gas province

Production of oil from Troll Vest oil province

The oil province comprises the westernmost part of the field, with a 22-26 meter oil column under a small gas cap. Production started in September 1995. Up to the end of 1997, 17 horizontal production wells and one gas injector had been drilled. Production experience so far shows lower production of water and later gas breakthrough than previously anticipated.

The production strategy depends on conditions such as pressure development and communication with other areas of the field. In the southern part of the oil province, therefore, parts of the produced gas are reinjected, while a controlled production of free gas together with oil will gradually become the strategy in the northern part of the province. The wells in the oil province are divided among four subsea installations which are tied into Troll B.

Production of oil from Troll Vest gas province

The gas province comprises the middle portion of the field with an oil column of 11.5-14.5 meters and a gas column of up to 200 meters. Production of the oil reserves in Troll Vest is time-critical in relation to the withdrawal of gas from both Troll Øst and Troll Vest. The development will take place in stages, as it was important to acquire some production experience from the area before a decision was made as to further oil development of the entire gas province.

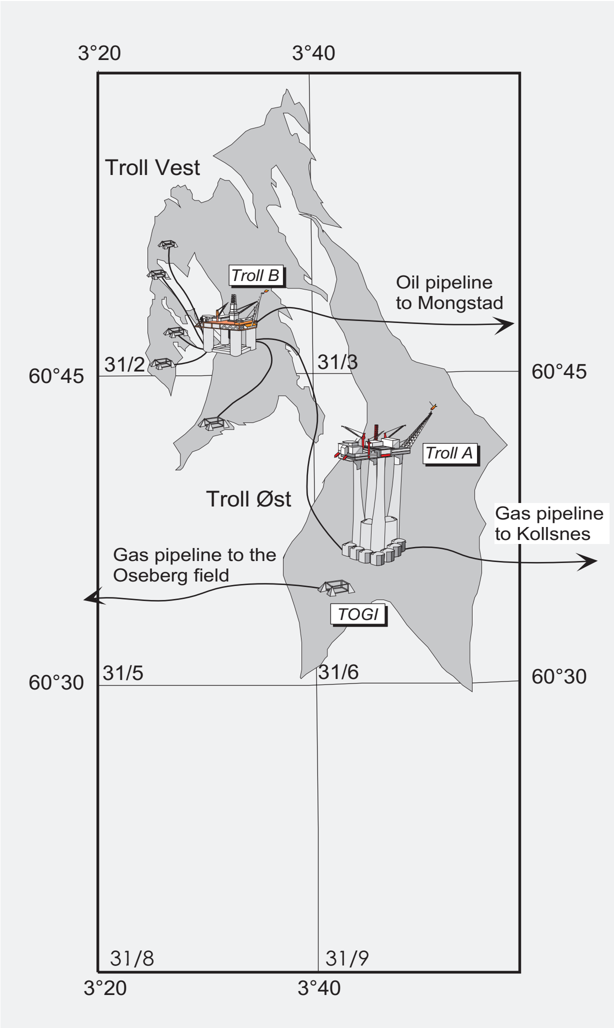
The plans for development and operation of the first two subsea installations in the southern part of the Troll Vest gas province (well groups H and I) were approved by the authorities in May 1994 and October 1996 respectively. Production from the H wells started in November 1995 and experience so far has been good. At the end of the year, six wells were producing. Production from well group I is delayed and will commence in the spring of 1998.

A continued plan for development and operation of the oil in Troll Vest gas province was approved by the authorities in the spring of 1997. The development plan includes nine subsea installations (well groups) with a total of 50 horizontal production wells, whereof several multibranched wells. Three well groups with 18 wells in the southern part of the gas province will be connected to Troll B, while six well groups with 32 wells in the northern part of the province will be connected to a new installation, Troll C. New field data and updated studies indicate, however, that there may be a need for an increase in the number of wells and subsea templates. Planned production start-up for this development is July 1998 for Troll B and September 1999 for Troll C. Several observation wells have been drilled during 1997, inter alia in order to obtain more information regarding the communication between the provinces and regarding how time-critical the resources are.

Development

The oil reserves in the Troll Vest oil province and the southern part of the Troll Vest gas province are produced via Troll B, a floating concrete installation without storage capacity. A total of nine well clusters will be connected to Troll B. Necessary modifications must be carried out on the installation in connection with the tie-in of well groups in the gas province. With small modifications on the Troll B installation, it has been possible to increase the production level gradually from 30,000 to 42,500 Sm^3 oil per day. The oil is transported through Troll Oljerør (Troll oil pipeline) approx. 90 km to Mongstad. Gas which is produced together with the oil is transported via Troll A to Kollsnes for treatment and further export to the market, see Figure 1.3.17.

Figure 1.3.17
The Troll field



Six well groups in the northern part of the gas province will be connected to a new installation, Troll C, which will be a semi-submersible steel installation. The installation will have an oil treatment capacity of 20,000 Sm^3 per day. A separate oil pipeline will be laid from Troll C to Mongstad, and a gas pipeline will be laid to Troll A in order to utilize existing transportation opportunities to Kollsnes and on to the export market.

Troll Phase III: Development of the gas resources in Troll Vest gas province

Development

Troll Vest gas province has a gas column of up to 200 meters over the oil zone. Approved and future recovery of the oil resources is time-critical in relation to production of gas from Troll. Therefore, it is uncertain when major gas withdrawals from Troll Vest should start. The consideration for the optimal recovery of oil and gas, the Troll field's total commitments and physical delivery capability for gas, seen in context with gas supply solutions for the Norwegian Shelf, will be included in the evaluations of the timing for development of Troll Phase III.

1.3.18 GULLFAKS AREA

Gullfaks and Gullfaks Vest

Production licenses: 050 and 050B	**Block:** 34/10
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 73 %)	85,00000 %
Norsk Hydro Produksjon AS	9,00000 %
Saga Petroleum ASA	6,00000 %
Discovery well: 34/10-1 Gullfaks	Year: 1978
34/10-34 Gullfaks Vest	Year: 1991
Development approved:	Prod.start:
Phase I 1981	Dec 1986
Phase II 1985	
Gullfaks Vest 1993	
Lunde formation 1995	
Recoverable reserves: Gullfaks	313,6 million Sm^3 oil 23,8 billion Sm^3 gas 2,3 million tonnes NGL
Recoverable reserves: Gullfaks Vest:	3,1 million Sm^3 oil 0,3 billion Sm^3 gas
Total investments (firm 1997-NOK):	
Gullfaks	NOK 76,6 billion
Gullfaks Vest	NOK 0,2 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	2022 million

Production

The Gullfaks field, see Figure 1.3.18.a, contains oil in sandstone from the Jurassic and Triassic Ages. The reservoir lies relatively shallow, and is made up of several angled fault blocks. The blocks have variable slope degrees and parts of the area are heavily eroded. The field is complicated to produce due to the many faults.

The reservoirs in Phase 1 and 2 are separated by a major north-south fault. Some communication across the fault has been proven in the northern area. Faults with more than 1000 meter skip distance delimit the field in the south, east and northeast.

The drive mechanism on the field is primarily pressure maintenance by means of water injection. Alternating injection of water and gas (WAG) is carried out where the method is appropriate. The use of gel to block water-producing layers has been attempted with successful results.

The number of operative wells, which varies over time, is approximately 100. Drilling of long range wells and sidetrack drilling from existing wells are important methods for increased oil recovery on Gullfaks.

Based on the basis reserves for the entire Gullfaks area, the last production years for Gullfaks A, B and C are 2011, 2006 and 2013, respectively. However, the lifetime may increase somewhat depending on discoveries in prospects and third-party use of the facilities.

Gullfaks Vest is an oil field which lies to the west of Gullfaks in block 34/10, see Figure 1.3.18.a. Production is based on natural water drive.

Development

The Gullfaks installations are the Condeep-type concrete gravity base structures with steel frame topside, see Figure 1.3.18.b. The C installation is basically built as a copy of Gullfaks A. All three are fully-integrated process, drilling and living quarters installations, while Gullfaks B has a simplified process facility with only first stage separation.

Gullfaks A, which is situated on the southwestern part of the field, started production in December 1986. Treatment capacity for oil is 60,000 Sm^3 per day, while capacity for water is 35,000 m^3 per day. Water injection capacity on Gullfaks A is 75,000 m^3 per day. Gullfaks A is also equipped for gas injection with a capacity of 3.2 million Sm^3 per day.

Gullfaks B is situated on the northwestern part of the field and was put into production in February 1988. It has a first stage liquid capacity of 45,000 Sm^3 per day. The oil from Gullfaks B is transferred to Gullfaks A and Gullfaks C for further processing and storage. The water injection capacity is 30,000 m^3 per day. Injection water is transferred from Gullfaks A.

Gullfaks C was located on the eastern part of the field for production from the reserves in Phase II. Production started at the turn of the year 1989/1990. The process capacity of the installation is 60,000 Sm^3 oil and 30,000 m^3 produced water per day. Up to 60,000 m^3 water can be injected per day. At the end of 1995, a compressor was installed for injection of gas on Gullfaks C also, with a capacity of 2.2 million Sm^3 per day.

Gullfaks A and C have storage cells for storage of stabilized oil. The oil is fiscally metered and exported via loading buoys to tankers. Processed rich gas is fiscally metered on Gullfaks A and C before it is sent into Statpipe via Statfjord C. Oil from Gullfaks Vest is metered with the aid of a test separator on Gullfaks C. The Tordis wellstream is metered after first stage separation on Gullfaks C. The metered and analyzed volumes are then further treated in the process facilities on Gullfaks C before the oil is loaded via the single-point buoy mooring system and the gas is delivered to Statpipe. Oil from Vigdis will be fiscally metered on Snorre prior to loading from Gullfaks A. The plan is also to load oil from the Visund field

Fig. 1.3.18.a
Fields and discoveries in the Gullfaks, Statfjord and Snorre area

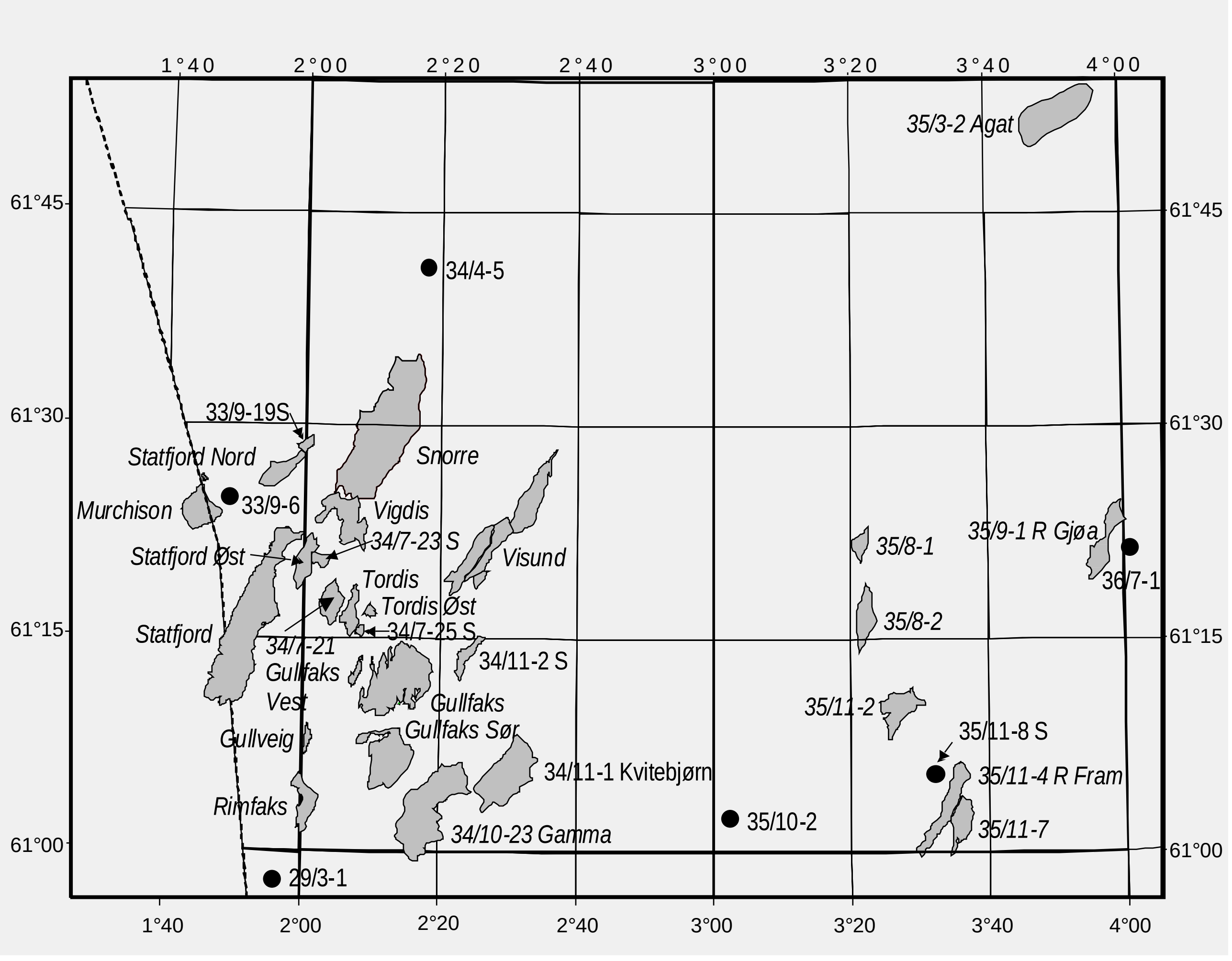
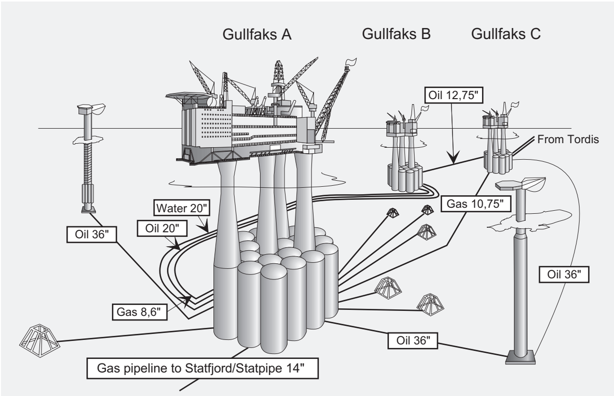


Figure 1.3.18.b
Installations on Gullfaks



from Gullfaks A. Gas and liquid from Gullfaks Sør, Rimfaks and Gullveig will be metered using multi-phase meters in connection with a test separator.

Gullfaks as infrastructure
In addition to Gullfaks Vest, the installations on Gullfaks will also be used in connection with production from Tordis, Tordis Øst, Vigdis, Visund, Rimfaks, Gullfaks Sør and Gullveig.

May 1994 saw the beginning of deliveries from Tordis to Gullfaks C, where the oil is processed. A new first stage separator has been built on Gullfaks C, otherwise existing equipment is utilized. In 1995, approval was also granted to tie Tordis Øst into Gullfaks C. In 1994, it was decided that processed oil from Vigdis (via Snorre) would be delivered to Gullfaks A for storage and loading to tankers. A similar agreement for Visund was made in December 1995.

Development of the oil resources (Phase I) in Gullfaks Sør, Rimfaks and Gullveig was approved by the authorities in 1996, and will be tied into Gullfaks A. According to the plan, Gullfaks Sør Brent Phase II, which comprises production of gas and associated liquid, will be tied into Gullfaks C. In 1995, the Gullfaks licensees, production license 050, were awarded previously relinquished areas of block 34/10. The Gullfaks installations can also be used for new discoveries in this area. There are also other discoveries which may be developed towards Gullfaks.

Gullfaks Sør

Production licenses: 50 and 50B		**Block:**	34/10
Operator: Den norske stats oljeselskap a.s			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 73 %)		85,00000 %	
Norsk Hydro Produksjon AS		9,00000 %	
Saga Petroleum ASA		6,00000 %	
Discovery well:	34/10-2	Year:	1978
Development approved:		Prod.start:	
Phase I	1996	1998	

Recoverable reserves:	Phase I:	21,5 million Sm^3 oil/condensate 1,7 billion Sm^3 gas
Recoverable reserves:	Phase II:	14,3 million Sm^3 oil/condensate 58,5 billion Sm^3 gas
Total investments (firm 1997-NOK):		
Phase I:		NOK 3,49 billion
Phase II:		NOK 4,83 billion
Operating costs 1997 incl. CO_2 tax, excl. tariffs and insurance		
Phase I:		NOK 99 million
Phase II:		NOK 210 million

Gullfaks Sør lies about 9 km to the south of Gullfaks, see Figure 1.3.18.a, and contains oil and gas in sandstone from the Jurassic and Triassic Ages. The Brent reservoir contains oil and a gas cap with high condensate content. Several independent gas/oil and oil/water contacts have been observed. The Statfjord reservoir has a thicker oil zone and a smaller gas cap than the Brent reservoir. There is also oil and gas in the Lunde formation.

Phase I
Production
Gullfaks Sør Phase I comprises production of oil and condensate. The plan for development and operation of Phase I was approved in 1996 together with Rimfaks and Gullveig.

Development
The plan is to produce the liquid resources in Phase I using gas injection. The development solution comprises four subsea templates with 12 wells. Development and operation will be integrated with Rimfaks and Gullveig. Processing of the wellstream will take place on Gullfaks A.

Production start-up for Phase I is planned for 1 September 1998. The field is expected to produce 13,000 Sm^3 oil/ condensate per day which will be stored on Gullfaks A and shipped. Produced gas will be reinjected in the reservoir. The initial gas injection capacity is planned to be 2.7 million Sm^3 per day. Gas will also be sent to Rimfaks for injection.

Phase II
Production
Gullfaks Sør Phase II comprises production of gas and associated liquid. In 1997, Gullfaks Sør Brent was allocated gas deliveries from 1999. The plan for development and operation for Phase II was submitted to the authorities on 3 September 1997. A supplement to the plan for development and operations was submitted on 27 November 1997.

Development

The plan comprises two new subsea templates and 13 wells, of which one is drilled from one of the existing templates from Phase I. In addition, provision will be made for installation of an extra subsea template with the possibility of drilling up to four extra wells. The plan is to process the wellstream on Gullfaks C. Planned production start-up is the year 2000. Early gas sales in 1999 are secured by using gas from Phase I or by borrowing gas from the Gullfaks main field.

Rimfaks

Production licenses: 50 and 50B	**Blocks:** 34/10 and 33/12
Operator: Den norske stats oljeselskap a.s	
Licensees: Den norske stats oljeselskap a.s (SDFI 73 %) Norsk Hydro Produksjon AS Saga Petroleum ASA	 85,00000 % 9,00000 % 6,00000 %
Discovery well: 34/10-17	Year: 1973
Development approved: Phase I: 1996	Prod.start:1998
Recoverable reserves: Phase I	19,9 million Sm^3 oil/condensate -1,7 billion Sm^3 gas
Total investments (firm 1997-NOK): Phase I	 NOK 3,19 billion
Operating costs 1997 incl. CO_2 tax, excl. tariffs and insurance	NOK 125 million

Production

Rimfaks, which lies approx. 15 kilometers southwest of Gullfaks, see Figure 1.3.18.a, contains oil and gas in sandstone from the Jurassic Age. The main part of the field lies in block 34/10, production license 050, while a small part extends into block 33/12. An agreement has been signed with production license 037 regarding production of the deposit which extends into block 33/12.

The Statfjord reservoir is filled with oil while the Brent reservoir contains an oil column of about 40 meters and a gas cap with high condensate content.

The plan for development and operation of Phase I, which comprises the liquid phase, was approved in 1996 together with Gullfaks Sør and Gullveig. Phase II, which consists of the gas phase, is not included in this plan.

Development

The plan is to develop the field using gas injection and the development concept includes three subsea templates with 10 wells. Development and operation will be integrated with Gullfaks Sør and Gullveig. Processing of the wellstream will take place on Gullfaks A. Production start-up is planned for 1 October 1998. The field is expected to produce 13,500 Sm^3 oil/ condensate per day, which will be stored on Gullfaks A and shipped. The gas from the field will be reinjected in the reservoir. Rimfaks will also receive gas from Gullfaks Sør for injection. Initial gas injection capacity is planned to be 7.5 million Sm^3 per day.

Gullveig

Production licenses: 50 and 50B	**Block:** 34/10
Operator: Den norske stats oljeselskap a.s	
Licensees: Den norske stats oljeselskap a.s (SDFI 73 %) Norsk Hydro Produksjon AS Saga Petroleum ASA	 85,00000 % 9,00000 % 6,00000 %
Discovery well: 34/10-37	Year: 1995
Development approved: 1996	Prod.start:1998
Recoverable reserves:	2,7 million Sm^3 oil/condensate 1,2 billion Sm^3 gas
Total investments (firm 1997-NOK):	NOK 0,5 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 10 million

Production

Gullveig contains oil in sandstones from the Brent group of the Jurassic Age. The plan is to produce the field by means of depressurization using two wells which are connected to a subsea template.

Development

The plan is to integrate the field with the development and operation of the Gullfaks Sør and Rimfaks fields. Planned production start-up is 1 September 1998. Processing of the wellstream will take place on Gullfaks A.

1.3.19 STATFJORD AREA

Statfjord

Production license: 037		**Blocks:** 33/9 and 33/12
Operator: Den norske stats oljeselskap a.s (1)		
Licensees: Norwegian share (85,46869 %) Den norske stats oljeselskap a.s Mobil Development Norway AS Norske Conoco A/S Esso Expl & Prod Norway A/S A/S Norske Shell Saga Petroleum ASA Amerada Hess Norge AS Enterprise Oil Norwegian AS		 42,734348 % 12,820304 % 9,437169 % 8,546869 % 8,546869 % 1,602534 % 0,890300 % 0,890300 %
British share (14,53131 %) Conoco North Sea Inc BP Petroleum Development Ltd. Chevron U.K. Ltd.		 4,843769 % 4,843769 % 4,843769 %
Discovery well:	33/12-1	Year: 1974
Development approved:	1976	Prod.start:1979
Recoverable reserves: 2)		555,7 million Sm^3 oil 54,9 billion Sm^3 gas 15,6 million tonnes NGL
Total investments (firm 1997-NOK):		NOK 87,169 billion

Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 2201 million

1) Mobil was operator of the field until 1 January 1987 when Statoil assumed responsibility as operator.
2) Norwegian share (85.46869 %)

Production

The Statfjord field consists of a large fault block sloping to the west, as well as a number of smaller fault blocks along the east flank. A smaller portion of the field extends onto the British continental shelf. The reservoirs on the Statfjord field consist of sandstones from the Brent group, the Cook formation and the Statfjord formation. In 1997, the reserves estimate for the field was adjusted from 535.0 to 555.7 million Sm^3 oil (Norwegian share).

The Brent reservoir is produced with the aid of pressure support from water injection. Production and injection are balanced so that the reservoir pressure is kept as stable as possible. A test project with WAG injection has been implemented in the lower Brent to look at the effect of supplementary gas injection. Based on the results of the project and reservoir studies conducted, it is now being evaluated whether the production strategy for Brent should be changed. A decision regarding this is expected during the course of 1998.

The Statfjord formation has been produced with the aid of pressure support from gas injection. In lower Statfjord, upflank gas injection has now been terminated, both to avoid circulation of gas in the oil producers and to prepare for conversion to downflank WAG injection. Implementation of a new production strategy for the Statfjord formation, with upflank water injection and supplementary gas injection in the upper Statfjord and downflank WAG injection in lower Statfjord, is being considered. Tests with WAG injection in lower Statfjord commenced in the autumn of 1994. Tests using water injection in the upper Statfjord started in February 1996. The future implementation of a new production strategy will take place in stages and will depend on the results from the pilot projects.

The Cook reservoir came onstream in 1994. The production strategy for Cook is based on phasing in wells which have already penetrated the reservoir, and possibly deepening of existing wells. Production will receive pressure support from water injection.

In order to achieve better exploitation of the remaining reserves, the operator is continually updating the production strategy for the field. The strategy entails both more wells and extensive re-use of the wells in several reservoir zones. Use of horizontal wells and long-range, high-deviation wells is also included in the strategy.

Development

The field is developed in three phases with the fully integrated installations A, B and C, see Figure 1.3.19. The Statfjord A installation is located near the center of the Statfjord field. It is a fully integrated installation with a concrete gravity base composed of 14 storage cells and three shafts. Processing capacity for oil is roughly 67,000 Sm^3 per day, while the oil storage capacity is 175,000 Sm^3. The capacity for water injection on Statfjord A is about 69,000 m^3 per day. Statfjord A started producing in November 1979. Loading of oil takes place via one of the three oil loading systems on the field.

From August 1992, production from Snorre has been received at Statfjord A after second stage separation. This has enabled good utilization of Statfjord A's available process capacity.

The Statfjord B installation is located in the southern part of the Statfjord field. It is a fully integrated installation with a concrete gravity base composed of 24 storage cells and four shafts. Production capacity is approximately 40,000 Sm^3 per day. The installation has its own storage capacity for oil, 302,000 Sm^3. Capacity for water injection on Statfjord B is approx. 64,000 m^3 per day. Statfjord B started production in November 1982.

The Statfjord C installation is located in the northern part of the Statfjord field. It is a fully integrated installation, structurally identical to Statfjord B. The production capacity is now approximately 52,000 Sm^3. The capacity for water injection on Statfjord C is about 62,000 m^3 per day. Statfjord C came onstream in June 1985. The Statfjord satellites have their own intake separator on Statfjord C with a capacity of roughly 25,000 Sm^3 oil.

Gas is transported via the Statpipe pipeline and sold in Emden, while NGL is removed at Kårstø and sold there. The United Kingdom takes its share of the gas through NLGP (Northern Leg Gas Pipeline) from Statfjord B to Shell's terminal in St. Fergus, Scotland where the gas is sold. Stabilized oil is stored in storage cells on each installation prior to being pumped onto tankers via one of the three loading systems on the field.

Oil and gas are metered to fiscal standard on each of the three installations. After Snorre started production, Statfjord A production is determined as the difference between the total volume metered on Statfjord A and the volume metered on Snorre.

A similar concept is used for determination of Statfjord C production after the Statfjord satellites began producing. The distribution between the satellites will be based on test separator metering, while the total volume from the satellites will be metered to fiscal standard.

The north flank of the Statfjord field will be developed with subsea installations tied to Statfjord C. There are also plans to tie in other satellite fields to Statfjord.

Statfjord Øst

Production licenses: 037 (50 %) 089 (50 %)	**Blocks:** 33/9 and 34/7
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 40,5 %)	52,70000 %
Esso Expl & Prod Norway A/S	10,25000 %
Mobil Development Norway AS	7,50000 %
Norske Conoco A/S	5,52000 %
A/S Norske Shell	5,00000 %
Idemitsu Petroleum Norge AS	4,80000 %
Saga Petroleum ASA	4,79000 %
Norsk Hydro Produksjon AS	4,20000 %
Elf Petroleum Norge AS	2,80000 %
Deminex Norge AS	1,40000 %
Amerada Hess Norge AS	0,52000 %
Enterprise Oil Norwegian AS	0,52000 %
Discovery well: 33/9-7	Year: 1976
Development approved: 1990	Prod.start: 1994
Recoverable reserves:	32,0 million Sm^3 oil 4,5 billion Sm^3 gas 0,7 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 4,056 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 71 million

Production

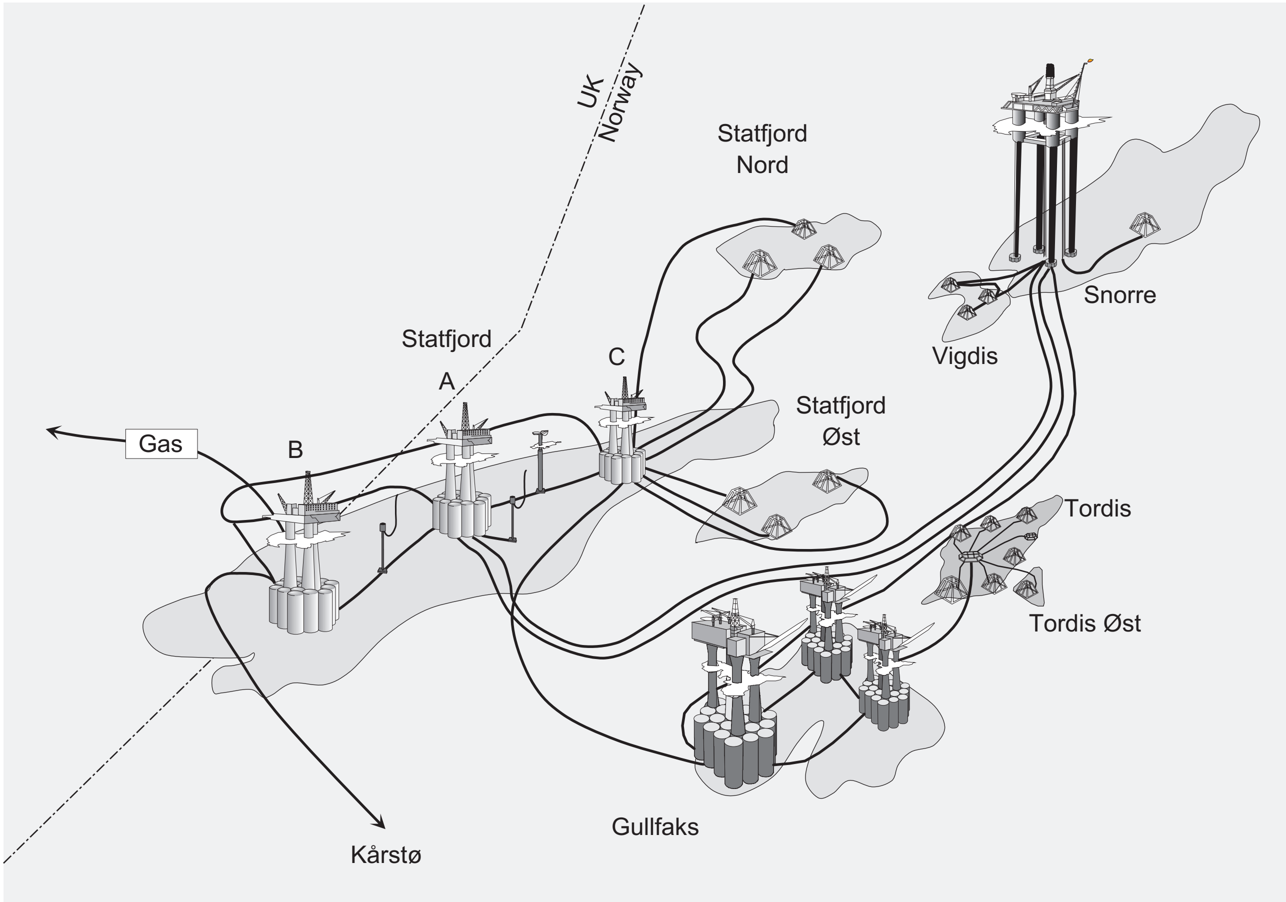
The reservoir on the Statfjord Øst field consists of sandstone in the upper and lower part of the Brent group. The plan is to produce the field using pressure maintenance assisted by water injection, with a total of six production wells and three injection wells. The need for a fourth injection well on the field is continuously under evaluation.

Development

The field is developed with subsea installations which are coupled to the Statfjord C installation. The subsea installations consist of three templates, two for production and one for water injection, see Figure 1.3.19. The wellstream will be transferred via two pipelines to Statfjord C for processing, storage and further transportation. Statfjord Øst and Statfjord Nord utilize common facilities on Statfjord C. The inlet separator on Statfjord C has a production capacity of about 25,000 Sm^3 oil per day. The water injection capacity is approx. 18,500 m^3 per day.

The Statfjord satellites are metered to fiscal standard in a common metering system on Statfjord C. Return allocation to the individual satellite field is done on the basis of test separator metering.

Figure 1.3.19
Infrastructure in the Statfjord, Gullfaks and Snorre area



Statfjord Nord

Production license:	037	**Block:**	33/9
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 30 %)		50,00000 %	
Mobil Development Norway AS		15,00000 %	
Norske Conoco A/S		11,04167 %	
A/S Norske Shell		10,00000 %	
Esso Expl & Prod Norway A/S		10,00000 %	
Saga Petroleum ASA		1,87500 %	
Amerada Hess Norge AS		1,04167 %	
Enterprise Oil Norwegian AS		1,04167 %	
Discovery well:	33/9-8	Year:	1977
Development approved:	1990	Prod.start:	1995
Recoverable reserves:		41,1 million Sm^3 oil 3,1 billion Sm^3 gas 0,6 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 4,838 billion	
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance		NOK 108 million	

Production

The reservoir on Statfjord Nord consists of sandstone belonging to the Brent group (Middle Jurassic) and sandstone of the Late Jurassic Age. The plan is to produce the field by means of pressure maintenance aided by water injection with a total of eight production wells and three injection wells.

Development

The field is developed with subsea installations connected to the Statfjord C installation. The subsea installations consist of three templates, of which two are for production and one for water injection, see Figure 1.3.19. The wellstream is transferred via two pipelines to Statfjord C for processing, storage and further transport. Statfjord Nord and Statfjord Øst use common facilities on Statfjord C. The inlet separator on Statfjord C has a production capacity of approximately 25,000 Sm^3 oil per day. The capacity for water injection is approximately 15,500 Sm^3 per day.

The Statfjord satellites are metered to fiscal standard in a common metering system on Statfjord C. Return allocation to the individual satellite field is done on the basis of test separator metering.

Production from the Statfjord satellites has contributed to, and will over the next few years continue to contribute to, very good exploitation of the process facilities on Statfjord C.

1.3.20 TORDIS

Production license:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 51 %)		55,40000 %	
Esso Expl. & Prod. Norway A/S		10,50000 %	
Idemitsu Petroleum Norge AS		9,60000 %	
Norsk Hydro Produksjon AS		8,40000 %	
Saga Petroleum ASA		7,70000 %	
Elf Petroleum Norge AS		5,60000 %	
Deminex Norge AS		2,80000 %	
Discovery well:	34/7-12	Year:	1987
Development approved:	1991	Prod.start:	1994
Recoverable reserves:		29,1 million Sm^3 oil 2,1 billion Sm^3 gas 0,7 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 4,229 billion	
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance		NOK 114 million	

Production

The reservoir on the Tordis field consists of sandstone in the upper and lower part of the Brent group from the Middle Jurassic Age. Faults divide the field into three main segments, one southern, one western and one eastern segment.

The plan is to develop the field with pressure maintenance with the aid of water injection. The field is produced with five production wells and the drilling of two injection wells is planned. Drilling of the injection wells has been postponed as the reservoir has more natural pressure support from the water zone than expected. Drilling of the first injection well is planned for 1998.

Development

The field is developed with a subsea installation which is connected to the Gullfaks C installation. The subsea installation consists of a central manifold with connection points for satellite wells and other well templates, see Figure 1.3.19.

The wellstream from Tordis is transferred to Gullfaks C and is separated in a separate one-stage process. Processing capacity for liquid from Tordis on Gullfaks C is 16,000 Sm^3 per day. Oil and gas are metered prior to further treatment in the existing process facilities on Gullfaks C. The oil is exported via loading buoys to tankers. The gas is transported in the Statpipe system. Due to larger production from the Tordis facility, the oil metering station was upgraded in 1996.

In order to achieve good exploitation of the installations and the process capacity on Tordis, it was decided in 1995 that Tordis Øst would be connected to the central manifold for the Tordis subsea installation.

1.3.21 TORDIS ØST

Production license:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 51 %)		55,40000 %	
Esso Expl. & Prod. Norway A/S		10,50000 %	
Idemitsu Petroleum Norge AS		9,60000 %	
Norsk Hydro Produksjon AS		8,40000 %	

Saga Petroleum ASA		7,70000 %	
Elf Petroleum Norge AS		5,60000 %	
Deminex Norge AS		2,80000 %	
Discovery well:	34/7-8	Year:	1986
Development approved:	1994	Prod.start:	1997
Recoverable reserves:		28,8 million Sm^3 oil 2,0 billion Sm^3 gas	
Total investments (firm 1997-NOK):		NOK 4,486 billion	
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance		NOK 94 million	

Production

The field consists of two main segments, a northern and a southern segment, separated by an east-west oriented fault. For the most part, the reserves are found in the Tarbert formation belonging to the Brent group of the Middle Jurassic Age.

The production plan for the field is to use one production well and one water injection well. The decision regarding the need for the injection well will be made after some production experience has been gained, and is dependent on the communication across the fault, as well as the amount of natural pressure support the field has from the underlying water zone. Planned production start-up, which was planned for 1997, has been postponed until the autumn of 1998 due to the lack of drilling installations.

Development

The field is developed by means of a four-well subsea template which is tied into the existing subsea manifold on the Tordis field. The wellstream from Tordis and Tordis Øst will be mixed and then transported through existing field pipelines to the Gullfaks C installation for processing, metering, storage and shipping. If there is a need for water injection, Tordis Øst will receive injection water from Tordis.

Tordis Øst will use at least one of the well slots on the subsea template. A well slot on the subsea template will also be used for test production of the 34/7-21 discovery in 1998. The remaining available slots on the subsea template may be used for other discoveries and prospects in the area. There is also the possibility of connecting an additional two wells to the Tordis Øst subsea template.

1.3.22 VISUND

Production license:	120	**Blocks:**	34/8 and parts of 34/7
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 49,6 %)		62,90000 %	
Norsk Hydro Produksjon AS		16,10000 %	
Elf Petroleum Norge AS		7,70000 %	
Norske Conoco AS		9,10000 %	
Saga Petroleum ASA		4,20000 %	
Discovery well:	34/8-1	Year:	1986
Development approved:	1996	Prod.start:	1998
Recoverable reserves:		48,5 million Sm^3 oil	
Total investments (firm 1997-NOK):		NOK 8,72 billion	
Operating costs 1997 incl. CO_2 tax, excl. tariffs and insurance		NOK 485 million	

Production

The Visund field lies about 22 kilometers to the northeast of Gullfaks, see Figure 1.3.18.a, and contains oil and gas in sandstone from the Jurassic and Triassic Ages.

The reservoir is made up of tilted and rotated fault blocks. The field contains several separate liquid systems and is complicated to produce.

During production of the oil phase (Phase I), the drive mechanism will be pressure maintenance through water injection and gas injection. The drilling of 23 wells is planned in Phase I. All gas will be reinjected into the reservoir until a gas sales agreement has been realized.

Development

According to the plan for development and operation, the field will be developed with a semi-submersible steel installation equipped for complete stabilization of oil and injection of gas and water. The installation is designed to produce 16,000 Sm^3 oil per day, which will be transported via a pipeline to Gullfaks A for storage and shipping.

The initial planned gas injection capacity will be 10 million Sm^3 per day. Water from the Utsira formation and produced water will be injected with a capacity of 18,000 Sm^3 per day. Drilling and well maintenance will be carried out from the installation. Planned production start-up is 1 July 1998.

1.3.23 VIGDIS

Production license:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 51 %)		55,40000 %	
Esso Expl. & Prod. Norway A/S		10,50000 %	
Idemitsu Petroleum Norge AS		9,60000 %	
Norsk Hydro Produksjon AS		8,40000 %	
Saga Petroleum ASA		7,70000 %	
Elf Petroleum Norge AS		5,60000 %	
Deminex Norge AS		2,80000 %	
Discovery well:	34/7-8	Year:	1986
Development approved:	1994	Prod.start:	1997
Recoverable reserves:		28,8 million Sm^3 oil 2,0 billion Sm^3 gas	
Total investments (firm 1997-NOK):		NOK 4,486 billion	
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance		NOK 94 billion	

Production

The field consists of three separate main segments, one western, one middle and one eastern segment. The reservoir in the western and middle segment, which has been approved for development, consists of sandstones in the upper and lower part of the Brent group from the Middle

Jurassic Age. In the eastern segment (Vigdis Øst), oil has been proven in Upper Jurassic sand and in the Statfjord formation. A decision on potential production from the Vigdis Øst segment will be made when the results from a new appraisal well are available.

The plan is to produce Vigdis using pressure maintenance aided by water injection. A total of eight production wells and four injection wells are planned.

There is a potential for additional resources in the surrounding structures, particularly in the eastern segment. Phase-in of potential additional resources can take place through the connection of new wells to the subsea templates or by using slots which are freed when other wells are phased out due to high water production.

Development

The field is developed with subsea installations tied in to Snorre TLP. The subsea installations consist of three subsea templates, of which two are for production and one for water injection. Each subsea template contains four well slots. The wellstream is transferred to Snorre TLP for processing and metering. The process module for Vigdis on Snorre TLP is designed for an oil capacity of 18,000 Sm^3 per day. The stabilized oil is sent via a separate pipeline to Gullfaks A for storage and shipping. The gas will be injected into the Snorre reservoir and will contribute to increased oil recovery on Snorre.

Snorre TLP will also deliver injection water to Vigdis. The capacity for water injection is estimated to be approx. 22,000 m^3 per day.

Production from the field started on 28 January 1997. This was considerably earlier than originally planned. Various interruptions of operations, mainly related to the gas injection compressor, have nevertheless entailed that 1997 production was significantly lower than expected.

Total investments (firm 1997-NOK):	NOK 5,266 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 84 million

1) Oryx took over as operator of the field on 9 January 1995.

2) Norwegian share (22.2 %).

1.3.24 MURCHISON

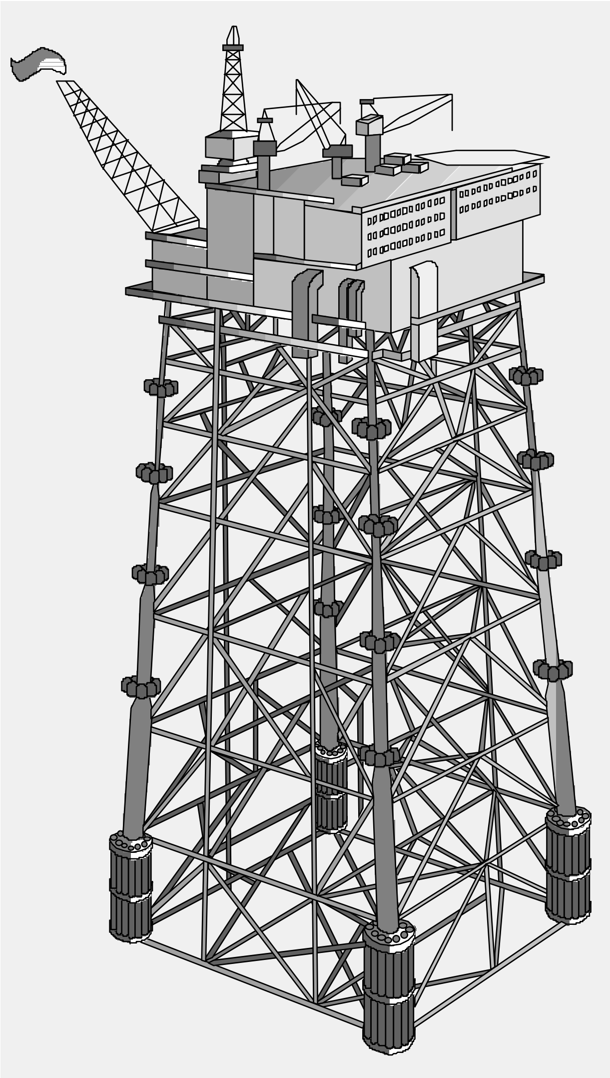
Production license: 037		**Block:**	33/9
Operator: Oryx UK Energy Company [1]			
Licensees:			
Norwegian share (22,2 %)			
Den norske stats oljeselskap a.s	11,10000 %		
Mobil Development Norway AS	3,33000 %		
Norske Conoco A/S	2,45130 %		
Esso Expl & Prod Norway AS	2,22000 %		
A/S Norske Shell	2,22000 %		
Saga Petroleum ASA	0,41620 %		
Amerada Hess Norge AS	0,23125 %		
Enterprise Oil Norwegian AS	0,23125 %		
British share (77,8 %)			
Oryx UK Energy Company	68,72333 %		
Ranger Oil UK Ltd	9,076655 %		
Discovery well: 211/19-2		Year:	1975
Development approved: 1976		Prod.start:	1980
Recoverable reserves: [2]	13,3 million Sm^3 oil 0,4 billion Sm^3 gas 0,4 billion tonnes NGL		

Production

The Murchison reservoir consists of sandstones belonging to the Brent group. The field has produced at nearly maximum liquid processing capacity since 1981, and water treatment capacity has been increased several times. Most of the production wells are now producing with a high water cut and some production wells have been shut down due to mechanical problems or very high production of water. Gas lift is used in some wells.

In order to increase oil production and extend field lifetime, damaged wells are repaired and new wells are drilled in undrained areas. In the autumn of 1996, the Northeast horst, a small, separate structure within the unitized Murchison field, was drilled and put into production.

Figure 1.3.24
Installation on Murchison



Development

The field has been developed with an integrated steel installation with a production capacity of 26,200 Sm^3 oil per day, see Figure 1.3.24.

Oil from Murchison is sent via pipeline to Sullom Voe on Shetland. The Norwegian share of the Murchison gas is landed via the NLGP pipeline (Northern Leg Gas Pipeline) to the Brent field on the British side, and on to St. Fergus, Scotland in the FLAGS pipeline (Far North Liquified and Associated Gas Gathering System). Gas deliveries through NLGP started in July 1983.

1.3.25 SNORRE

Production licenses: 089 and 057	Blocks: 34/7 and 34/4
Operator: Saga Petroleum ASA	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 31,4 %)	41,40000 %
Saga Petroleum ASA	11,94470 %
Esso Expl. & Prod. Norway A/S	10,33230 %
Deminex Norge AS	10,03480 %
Idemitsu Petroleum Norge AS	9,60000 %
Norsk Hydro Produksjon AS	8,26580 %
Elf Petroleum Norge AS	5,51060 %
Amerada Hess Norge AS	1,45590 %
Enterprise Oil Norwegian AS	1,45590 %
Discovery well: 34/4-1	Year: 1979
Development approved: Snorre Phase I 1988 Snorre - amended plan [1] 1994	Prod.start: 1992
Recoverable reserves: Phase I	167,7 million Sm^3 oil 5,7 billion Sm^3 gas 3,6 million tonnes NGL
Recoverable reserves: Phase II	57,6 million Sm^3 oil
Total investments (firm 1997-NOK): Phase: 1 Phase: 2	NOK 34,017 billion NOK 11,553 billion
Total investments (firm 1997-NOK): Excl. tariffs and insurance	NOK 912 million

1) The amended plan for development and operation, which includes development of the upper portion of the Lunde formation in the reservoir zones L02-L05, upgrading of the process capacity on Snorre and increased use of gas injection in the reservoir, was approved in December 1994.

Production

The Snorre field consists of several larger fault blocks which are not generally regarded as having communication with each other. The reservoir rocks are fluvial sandstones in the Statfjord and Lunde formations. The reservoir intervals vary from broad, continuous channel belts where reservoir communication is good, to narrower, isolated channel belts where the communication conditions are poorer.

Originally, the plan was to produce the field with water injection as the drive mechanism. Based on inter alia a pilot project in 1994 with WAG injection in the Statfjord formation, a decision was made to change the production strategy from water injection to downflank WAG in the entire Statfjord formation. Further optimization of the production strategy has also led to a change from water injection to upflank WAG in the Statfjord and Lunde formations in the eastern fault block. Use of horizontal and high deviation wells drilled from the installation are also a part of the strategy.

In connection with preparation of a plan for development and operation (PDO) for the northern areas of the field (Snorre 2), a decision has been made to implement WAG injection as a production strategy for the entire field. The decision is based on comprehensive reservoir studies and results from WAG injection in the southern areas.

Development

The Snorre field development has been planned in two phases. Phase I consists of a floating tension leg platform in the south (Snorre TLP), and a subsea template connected to Snorre TLP in the central part of the field, see Figure 1.3.25. Oil and gas are separated in two stages on Snorre, metered to fiscal standard, and transported further in separate oil and gas pipelines to Statfjord A for further processing. The oil from Snorre is exported via the loading system on Statfjord A. The gas is transported in the Statpipe system via Statfjord A.

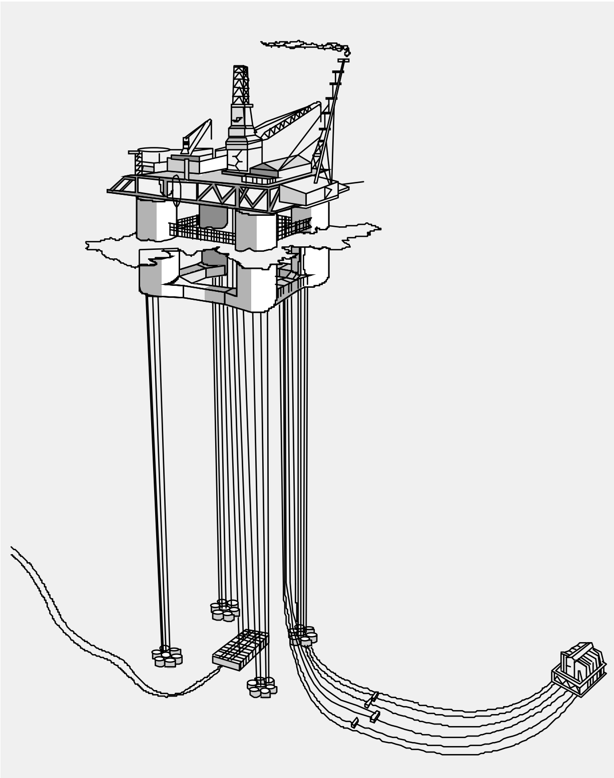
The increased reserves basis and increased need for gas injection have necessitated the upgrading of the process facilities on Snorre. Among other things, the capacity for oil processing and gas injection will be increased to 39,000 Sm^3 and 5 million Sm^3 per day, respectively. This upgrade was completed in 1997.

In connection with the development of Vigdis, a new process module for Vigdis was installed on Snorre TLP in 1996. The module contains a three stage separation train for full stabilization of oil from Vigdis, and is designed for an oil capacity of 18,000 Sm^3 per day. Oil from Vigdis is metered to fiscal standard and sent via a separate pipeline to Gullfaks A for storage and shipping.

A crossover pipeline has been laid between the Snorre and Vigdis process lines so that produced oil volumes from Vigdis can be transported both to Gullfaks and to Statfjord. Similarly, about half of the Snorre production may be transferred through this pipeline for processing on Gullfaks. This has been done to achieve a more flexible system.

Phase II of the Snorre development (Snorre 2) comprises production from the northern part of the field. On 19 December 1997, the authorities received an application from the licensees in the unitized Snorre field for approval of the plan for development and operation of Snorre 2. The operator's plan for Snorre 2 is based on development with a semi-submersible steel production installation with drilling and injection facilities. The oil will be transferred to Statfjord B for storage and loading, while the gas will be reinjected in the Snorre reservoir in order to increase oil production.

Figure 1.3.25
Installations on Snorre



1.3.26 NJORD

Production licenses: 107 and 132	**Blocks:** 6407/7 and 6407/10
Operator: Norsk Hydro Produksjon AS	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 30 %)	50,00000 %
Norsk Hydro Produksjon AS	22,50000 %
Mobil Development Norway AS	20,00000 %
Petro-Canada Norge a.s.	7,50000 %
Discovery well: 6407/7-1 S	Year: 1986
Development approved: Phase I 1995	Prod.start: 30.9.1997
Recoverable reserves:	31,6 million Sm^3 oil
Total investments (firm 1997-NOK):	NOK 7,408 bill.
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 430 million

Production

Njord began producing on 30 September 1997. By the end of the year, one oil producer and one gas injector were on stream. The field is now expected to reach plateau production of 11,000 Sm^3 per day towards the end of the second quarter of 1998.

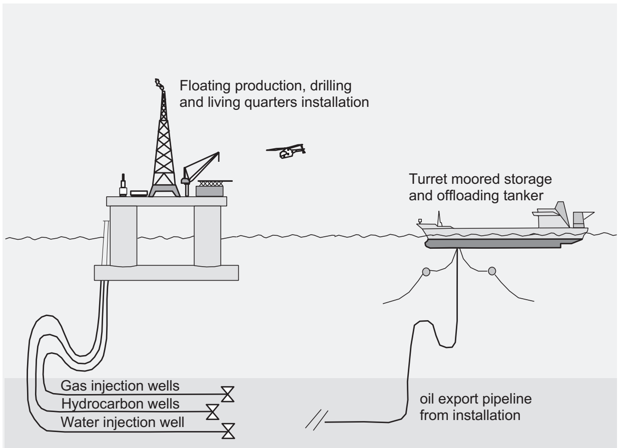
The field consists of sandstones from the Early and Middle Jurassic Age and is divided into a western and an eastern segment with a complicated fault pattern. The western segment, which contains oil and a minor gas deposit, will be produced by depressurization and limited water injection, while pressure maintenance through gas injection constitutes the draining mechanism for the oil-bearing eastern segment. The injection gas will mainly come from the oil production. Production experience may, however, lead to alternative draining mechanisms. Of the field's 15 planned subsea wells, 10 are oil producers, four are gas injectors and one well will account for water injection.

The operator has also mapped additional resources in the main structure and in adjoining areas. Initially, the installation has three available well slots for phase-in of additional resources. Reproduction and export of injected gas will be investigated by the operator when sufficient operating experience from the field is available.

Development

The Njord production installation will consist of a spread catenary moored, semi-submersible production, drilling and living quarters installation, Figure 1.3.26. The installation will be placed directly over the field's subsea wells, which will be connected to the installation via flexible risers. Water treatment and water injection capacity will each be 2,500 m^3 per day, with the potential for upgrading. The gas treatment and gas injection capacities will amount to 10 million Sm^3 per day.

Figure 1.3.26
Installations on Njord



Stabilized oil will be transferred to the storage ship 2.5 kilometers from the installation for storage and loading onto shuttle tankers. The oil metering station is located on the deck of the storage ship and stabilized oil will be metered to fiscal standard in connection with transfer from the storage ship to shuttle tankers.

1.3.27 DRAUGEN

Production license: 093	**Block:** 6407/9
Operator: A/S Norske Shell	
Licensees: Den norske stats oljeselskap a.s (SDFI 57,88 %) A/S Norske Shell BP Petroleum Devel. of Norway AS	 65,44000 % 16,20000 % 18,36000 %
Discovery well: 6407/9-1	Year: 1984
Development approved: Phase I 1988	Prod.start: 1993
Recoverable reserves:	111,3 million Sm^3 oil
Total investments (firm 1997-NOK):	NOK 16,47 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 600 million

Production

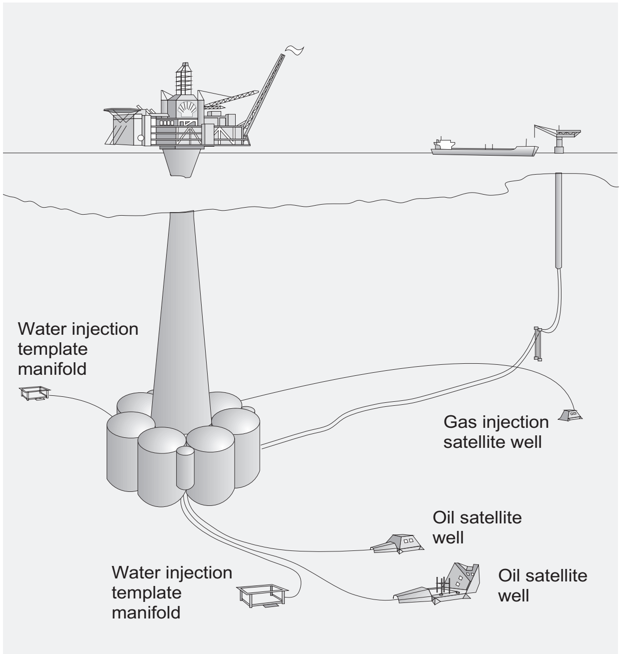
The main reservoir consists of sandstone from the Late Jurassic Age. Additional resources in the western part of the field have been proven in sandstones from the Middle Jurassic Age. The plan is to phase-in additional resources when the field starts to come off plateau in the year 2001/2002.

The field produces from five wells on the installation and two subsea-completed wells. Pressure support for oil production is ensured by five subsea-completed water injection wells. Associated gas is injected via a gas injection well in a nearby water-bearing structure. The operator is considering commercial application of the gas.

Development

The field is developed with a concrete installation resting on the seabed with integrated topsides, see Figure 1.3.27. The installation has ten well slots and a total of 34

Figure 1.3.27
Installations on Draugen



conductor casings. Production capacity was upgraded in 1997 to more than 31,500 Sm^3 per day. The water injection capacity was upgraded to 42,000 m^3 per day. Treatment capacity for produced water amounts to 12,000 m^3 per day. The design capacities for gas treatment and gas injection are 1.2 and 1.04 million Sm^3 per day respectively. The daily production and injection of gas are well above the design capacities without resulting in limitations for the production of oil.

Stabilized oil is stored in tanks in the bottom of the installation. Oil is fiscally metered prior to export via floating loading buoys to tankers.

1.3.28 ÅSGARD

Production licenses: 094, 134, 062 and 074	**Block:** 6506/11, 6506/12, 6507/11 and 6407/02
Operator: Den norske stats oljeselskap a.s	
Licensees: Den norske stats oljeselskap a.s (SDFI 46,95 %) Norsk Agip AS Total Norge AS Mobil Development Norway AS Neste Petroleum AS Saga Petroleum ASA Norsk Hydro Produksjon AS	 60,50000 % 7,90000 % 7,65000 % 7,35000 % 7,00000 % 7,00000 % 2,60000 %
Discovery well: 6507/11-1 Midgard 6506/12-1 Smørbukk 6506/12-3 Smørbukk Sør	Year: 1981 1984 1985
Development approved: 1996 Phase I Phase II	Prod.start: Phase I: 1.10.1998 Phase II: 1.10.2000
Recoverable reserves:	132,3 million Sm^3 oil 191 billion Sm^3 gas 24 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 32,7 billion
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance	NOK 1 700 million

Åsgard comprises the development of the Smørbukk, Smørbukk Sør and Midgard discoveries, which are incorporated in a unitization agreement between the licensees in production licenses 062, 074, 094 and 134. The unitization agreement was approved by the Ministry of Industry and Energy in the spring of 1995. As a consequence of the agreement, Statoil and Saga are working in an integrated project with Statoil as operator. The agreement covers the development and construction periods.

Åsgard lies mainly within blocks 6506/11 and 6506/12 (Smørbukk), 6506/12 (Smørbukk Sør) and 6507/11 and 6407/2 (Midgard) on Haltenbanken, about 200 kilometers from land and 50 kilometers south of the Heidrun field. Åsgard is located in an area where water depth varies from 240 and 300 meters. Recoverable reserves are estimated to be 191 billion Sm^3 gas, 132.3 million Sm^3 oil and 24 million tonnes NGL.

Production - 6506/12-1 Smørbukk

Blocks 6506/11 and 6506/12 were awarded under production licenses 094 and 134 in 1984 and 1987 respectively. Statoil was responsible for the Smørbukk discovery in 1984.

The Smørbukk discovery lies on a rotated fault block limited by faults to the west and north and structurally deeper areas towards the south and east. The reservoir formations Garn, Ile, Tofte, Tilje and Åre are from the Jurassic Age and contain gas, condensate and oil with a relatively high oil/gas ratio. The reservoir is located at depths of up to 4850 meters, which has led to the fact that a large portion of the reservoir has poor flow properties.

In the PDO, the operator planned to produce the Smørbukk discovery with a total of 38 wells, of which 22 are producers and 16 are gas injectors. Drilling of new wells resulted in some reduction in the estimates for in-place and recoverable resources. The new wells showed that the resource basis was smaller in the southern part of the Smørbukk discovery than previously assumed. This has led to adjustment of the production strategy and number of wells as compared with the PDO. The production strategy is initially based on reinjection of gas in order to optimize liquid recovery. The Smørbukk discovery will subsequently be produced using depressurization.

The recoverable reserves are estimated to be 70.7 billion Sm^3 gas, 86.8 million Sm^3 oil and 13.8 million tonnes NGL.

Production - 6506/12-3 Smørbukk Sør

Statoil discovered Smørbukk Sør in 1985. The petroleum trap in the Smørbukk Sør discovery is a salt dome to the northwest on the Haltenterrassen. The reservoir rocks in the Garn, Ile and Tilje formations are from the Early to Middle Jurassic Age and contain oil, gas and condensate.

In the PDO, the operator planned to produce the Smørbukk Sør discovery with a total of ten wells, of which seven are producers and three are injectors. Subsequent optimization of the production strategy has resulted in changes to this. The production strategy is initially based on reinjection of gas in order to optimize oil recovery. Subsequently, the Smørbukk Sør discovery will be produced using depressurization.

Recoverable reserves are estimated to be 19.4 billion Sm^3 gas, 29.8 million Sm^3 oil and 2.4 million tonnes NGL.

Production 6507/11-1 Midgard

Blocks 6507/11 and 6407/2 were awarded under production licenses 062 and 074 in 1981 and 1982 respectively. Saga discovered Midgard in 1981.

The petroleum trap which forms the Midgard discovery is a standing fault block (horst). The discovery is divided into four structural segments with main reservoirs in the Garn and Ile formations from the Middle Jurassic Age.

In the PDO, the operator planned to produce the Midgard discovery with a total of 12 production wells. The Midgard discovery will be produced using depressurization.

Recoverable reserves for the gas zone are estimated to be 100.9 billion Sm^3 gas, 15.7 million Sm^3 oil and 7.8 million tonnes NGL.

Under the gas cap on the Midgard discovery there is a thin (11.5 meter) oil zone. An appraisal well (6507/11-5 S) was drilled in 1997 which confirmed the estimates of the oil resources on Midgard. The operator will present a recommendation regarding production of the thin oil zone during 1998.

Development

The plan for development and operation (PDO) of Åsgard was approved by the Storting in June 1996.

Åsgard will be developed in two phases; an early liquid phase with planned production start on 1 October 1998, and a gas export phase with delivery of gas from 1 October 2000.

Åsgard will be developed with subsea-completed wells connected to a semi-submersible installation for gas and condensate treatment (Åsgard), and a production and storage ship for oil (Åsgard A). A storage ship for condensate will also be connected to the gas center. In Smørbukk and Smørbukk Sør, parts of the gas will be reinjected so as to increase the liquid recovery.

The total treatment capacity is 48 million Sm^3 per day for gas, 32,000 Sm^3 per day for oil and 15,000 Sm^3 per day for condensate.

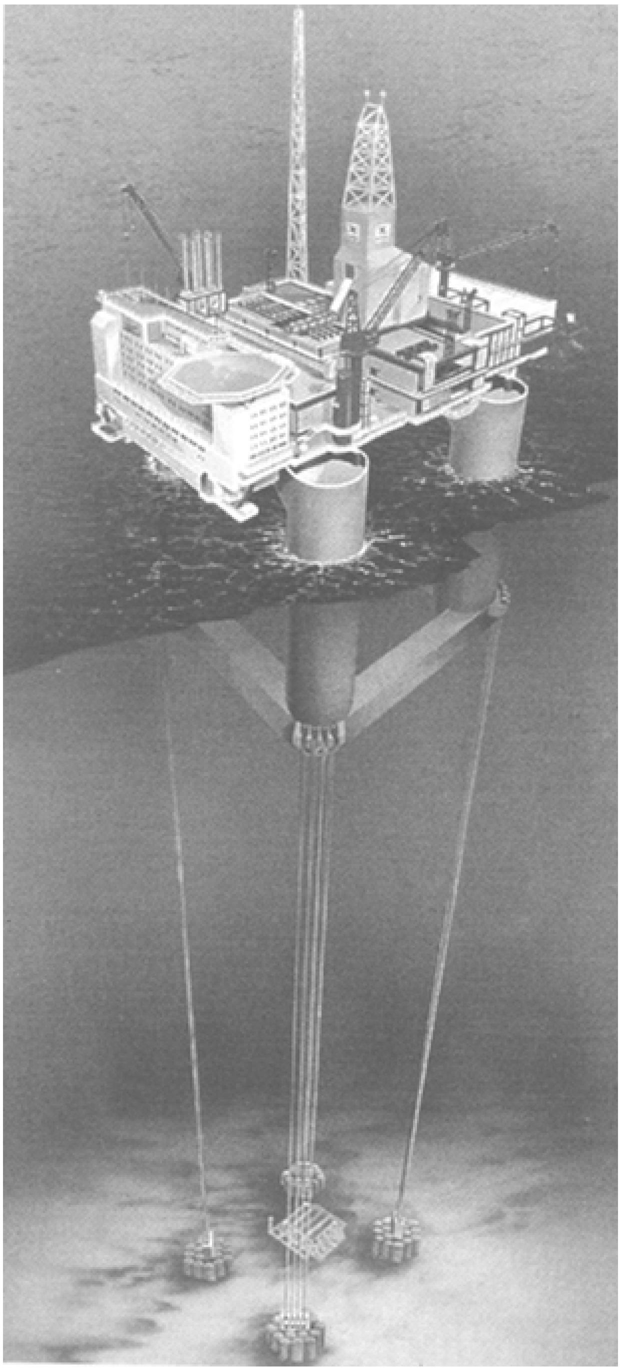
Oil and condensate will be stored temporarily on the field and transported to land using shuttle tankers. The gas will be exported in a planned gas pipeline from Åsgard to Kårstø.

Oil, gas and condensate will be fiscally metered on the field. The gas volumes which go to export will be metered using ultrasound meters.

1.3.29 HEIDRUN

Production licenses:	095 and 124	**Block:**	6507/7 and 6507/8
Operator:	Den norske stats oljeselskap a.s		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 65 %)		76,87500 %	
Norske Conoco A/S		18,12500 %	
Neste Petroleum AS		5,00000 %	
Discovery well:	6507/7-2	Year:	1985
Development approved:		Prod.start:	
Phase I	1991	1995	
Phase II	Gas to Tjeldbergodden 1992	1996	
Recoverable reserves:		155,0 million Sm^3 oil 12,8 billion Sm^3 gas	
Total investments (firm 1997-NOK):		NOK 34,711 billion	
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance		NOK 680 million	

Figure 1.3.29
Installation on Heidrun



Production

The field contains oil with an overlying gas cap. The reservoir consists of several geological formations and fault segments. The reservoir rocks are sandstones from the Early and Middle Jurassic Age. The upper part of the reservoir is produced with the aid of water and gas injection. Production from the lower part of the reservoir is based on water injection. At the end of 1997, 13 oil producing wells, eight water injection wells and one gas injection well had been drilled.

Export of released gas to the methanol plant at Tjeldbergodden started in December 1996. Potential future export solution for gas is a pipeline connection to the Åsgard pipeline and further export to Kårstø and the Continent.

Development

The field has been developed with a floating tension leg platform of concrete, installed over a subsea template with 56 well slots, see Figure 1.3.29. Production capacity is 41,000 Sm^3 per day. Water treatment capacity is 24,600 m^3 per day, and water injection capacity is 52,500 m^3 per day. The design capacity for gas treatment and gas injection is 4.7 and 4.3 million Sm^3 per day respectively. The daily rates for production and injection of gas are largely higher than the design capacities. In order to maintain production at plateau, it is necessary to upgrade the liquid and gas treatment capacities.

The oil on Heidrun is metered to fiscal standard prior to export to Mongstad and Tetney (UK) using direct tanker transportation without using oil storage on the field.

1.3.30 NORNE

Production license: 128		**Blocks:**	6608/10 6608/11
Operator: Den norske stats oljeselskap a.s			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 55 %)		70,00000 %	
Saga Petroleum ASA		9,00000 %	
Norsk Hydro Produksjon AS		7,50000 %	
Norsk Agip AS		7,50000 %	
Enterprise Oil Norwegian AS		6,00000 %	
Discovery well:	6608/10-2	Year:	1992
Development approved:		Prod.start:	
Phase I	1995	6.11.1997	
Recoverable reserves:		72,4 million Sm^3 oil	
Total investments (firm 1997-NOK):		NOK 9,238 billion	
Operating costs 1997 incl. CO_2 tax, Excl. tariffs and insurance		NOK 460 million	

Production

Norne started producing on 6 November 1997 and at the end of the year three oil producers and one gas injector were in operation. The reservoir consists of sandstone from the Early and Middle Jurassic Ages. The plan is to produce Norne using 11 production wells, five water injection wells and two gas injection wells. The licensees have applied for gas export from 1 October 2000.

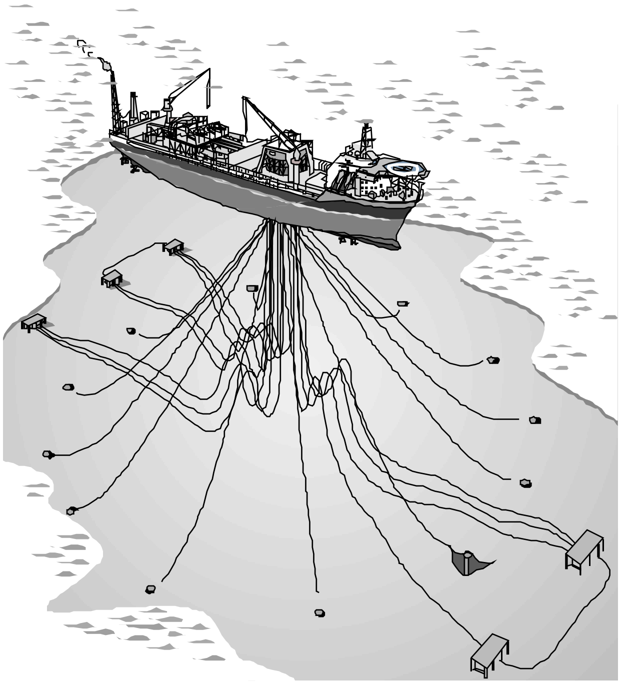
Development

Field development is by means of a subsea well system linked to a combined production and storage ship, see Figure 1.3.30. The subsea system consists of five well templates with four wells each and the possibility to tie in satellite wells. Production capacity for oil is 35,000 Sm^3 per day. The water treatment capacity is 20,000 m^3 per day and the water injection capacity is 40,000 m^3 per day.

The ship will have a gas treatment capacity of 7 million Sm^3 per day, while the gas injection capacity is 6.7 million Sm^3 per day. Studies have been implemented with regard to increasing the treatment capacities as the current design capacities may pose limitations to the oil production at an early stage.

The oil will be stored in the ship before it is loaded onto shuttle tankers via a loading system aft on the production ship. The most likely transportation solution for gas export is a pipeline connection to the Åsgard pipeline for further transportation to Kårstø and the Continent.

Figure 1.3.30
Installations on Norne



1.4 DISCOVERIES IN THE LATE PLANNING STAGES

1.4.1 16/7-4

Production license:	072	**Block:**	16/7
Operator:	Esso Expl & Prod Norway AS		
Discovery well:	16/7-4	Year:	1982
Earliest production start:		Year:	2000
Recoverable reserves:		1,8 million Sm^3 oil 5,0 billion Sm^3 gas 1,0 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 0,8 billion	

This discovery lies about 12 kilometers southeast of Sleipner A. The discovery was made in the Skagerrak formation and contains gas/condensate. A new well (16/7-7) was drilled in 1997 on what was believed to be an extension of the discovery towards the east, however, the preliminary result from this drilling indicates that this is a new discovery with a different liquid composition. Development of the discovery as a satellite to Sleipner A is being considered. The gas may be used for injection in Sleipner Øst. Both subsea wells and a wellhead installation are being evaluated.

1.4.2 2/12-1 MJØLNER

Production license:	113	**Block:**	2/12
Operator: Amerada Hess Norge AS			
Licensees: Den norske stats oljeselskap a.s. (SDFI 30 %) Amerada Hess Norge AS		50,00000 % 50,00000 %	
Discovery well:	2/12-1	Year: 1987	
Earliest production start:		Year: 2000	
Recoverable reserves:		2,3 million Sm^3 oil 0,4 billion Sm^3 gas 0,1 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 642 million	

The discovery lies near the dividing line between the Norwegian and Danish shelves. Mjølner lies in a complex faulted area between Fedagraben in the west and Gertrudgraben in the east. The reservoir is in Upper Jurassic sand at a depth of about 4900 meters. Faults segment the reservoir, and the field can be divided into separate fault blocks. The reservoir is deep and the reservoir pressure is one of the highest on the Norwegian shelf. The declaration of commerciality was submitted in June 1992.

In 1995, work was begun with a view towards further development of the Mjølner discovery. The licensees plan a joint development with the Gert discovery on the Danish shelf.

The plan is to develop the Mjølner and Gert discoveries with a single wellhead installation with four to six well slots. Various solutions for transportation of oil are being evaluated. Alternative solutions are connection to Valhall, Harald or Syd Arne on the Danish side.

1.4.3 3/7-4 TRYM

Production license:	147	**Blocks:**	3/7 and 3/8
Operator: A/S Norske Shell			
Licensees: Den norske stats oljeselskap a.s (SDFI 30 %) A/S Norske Shell		50,00000 50,00000	
Discovery well:	3/7-4	Year:	1990
Earliest production start:		2000	
Recoverable reserves:		2,9 billion Sm^3 gas 0,7 million NGL	
Total investments (firm 1997-NOK):		NOK 420 million	

The Trym and Lulita discoveries lie on the same salt-induced structure. The structures cross the boundary between the Norwegian and Danish shelves. Trym is considered to be 100% Norwegian while it is assumed that Lulita extends onto the Norwegian shelf.

It is assumed that Trym is separated from Lulita, but with possible pressure communication in the water zone. The reservoirs lie in the Lindesnes and Bryne formations in the Upper and Middle Jurassic. The Lindesnes formation is relatively homogeneous with good reservoir properties, while the Bryne formation is extremely heterogeneous with varying reservoir quality.

Development of the Danish part of Lulita has been approved by means of tying the development to the adjacent Harald field. Shell is considering developing the Norwegian part of Lulita be drilling a production well from the Harald installation. The operator is considering various development alternatives for Trym. Both a subsea installation and a simple wellhead installation are of interest, but Trym may also be developed with long range production wells from Harald.

1.4.4 25/4-6 S VALE

Production license:	036	**Block:**	25/4
Operator:	Elf Petroleum Norge AS		
Discovery well:	25/4-6 S	Year:	1991
Earliest production start:		Year:	2000
Recoverable reserves:		5,9 million Sm^3 oil 3,9 billion Sm^3 gas	
Total investments (firm 1997-NOK):		NOK 0,730 billion	

Gas/condensate has been proven in reservoirs from the Brent group of the Middle Jurassic Age. The drive mechanism is depressurization. The plan is to develop the discovery with a subsea installation, most likely linked to Heimdal.

1.4.5 25/11-15 GRANE

Production license:	169	**Block:**	25/11
Operator:	Norsk Hydro Produksjon AS		
Production licenses:	001	**Block:**	25/11
Operator:	Esso Expl & Prod Norway A/S		
Discovery well:	25/11-15	Year:	1991
Earliest production start:		Year:	2001
Recoverable reserves:		95,8 million Sm^3 oil	

The discovery is located about 7 kilometers east of Balder. The largest portion of the discovery lies in production license 169, however, parts extend into production license 001. The reservoir contains relatively heavy oil and lies in sand with good reservoir quality in the Heimdal formation of the Paleocene Age. In 1996, a 2-month test production was carried out from a horizontal well on the structure. A total of 77,000 Sm^3 oil was produced. The test production provided valuable information concerning production and processing of the oil in the discovery.

Injection of water or gas is being considered, and the final choice has not been made. Gas injection is used as a basis for the estimate of recoverable reserves and has led to an increase in this. If gas injection is chosen, there will be a need for import of gas. The plan is to use two installations sitting on the seabed for development, one for drilling and one for production and living quarters. The intention is to submit the plan for development and operation in the autumn of 1998.

There are several discoveries/prospects surrounding the Grane discovery. The preliminary development plans also include the 25/11-16 and 25/8-4 discoveries, and what is called the F prospect, which is probably an extension of the Grane discovery to the north. Total recoverable oil including these structures is about 102 million Sm^3 oil.

1.4.6 25/5-3 SKIRNE

Production license:	102	**Block:**	25/5
Operator:	Elf Petroleum Norge AS		
Discovery well:	25/5-3	Year:	1990
Earliest production start:		Year:	2000
Recoverable reserves:		5,1 billion Sm^3 gas 0,7 million tonnes NGL	
Total investments (firm 1997-NOK)		NOK 0,626 billion	

Gas has been proven in reservoirs of the Brent group from the Middle Jurassic Age. The drive mechanism is depressurization. The plan is to develop the discovery with a subsea installation tied in to Heimdal.

1.4.7 30/2-1 HULDRA

Production licenses:	051 and 052	**Blocks:**	30/2 and 30/3
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	30/2-1	Year:	1982
Recoverable reserves:		7,2 million Sm^3 oil 18,9 billion Sm^3 gas 0,3 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 4,3 billion	

Huldra is a gas discovery which lies to the northwest of Veslefrikk, Figure 1.3.14.b. Gas has been proven in the Brent group of the Middle Jurassic Age. Structurally, the Huldra discovery consists of a rotated fault block which slopes to the east. Under the main reservoir, there is a prospect in the Statfjord formation which will be drilled. Huldra has been granted gas allocation with planned production start-up in the year 2001.

The plan for development and operation of the Huldra discovery and the plan for installation and operation of the pipelines have been submitted to the authorities for approval. The plan is to develop the Huldra discovery with a permanent installation and drilling is planned with a jack-up installation. Six production wells are planned. After first stage separation, gas and condensate will be transported to existing process facilities for final processing. The condensate will be transported to Veslefrikk.

The tie-in point for the gas has not yet been decided.

1.4.8 30/6-18 KAPPA

Production licenses: 053 and 079	**Block:** 30/6 and 30/9
Operator: Norsk Hydro Produksjon A/S	
Discovery well: 30/6-18	Year: 1985
Earliest production start:	Year: 2001
Recoverable reserves:	3,5 million Sm^3 oil 5,4 billion Sm^3 gas

30/6-18 Kappa is an oil field with a gas cap in the Statfjord formation in a structure west of Oseberg. The discovery will probably be developed with horizontal production wells from a subsea template in order to take out oil before gas.

1.4.9 33/9-19 S

Production license: 037		**Block:** 33/9
Operator: Den norske stats oljeselskap a.s		
Production licenses: 089		**Block:** 34/7
Operator: Saga Petroleum ASA		
Discovery well:	33/9-19 S	Year: 1996
Earliest production start:		Year: 2000
Recoverable reserves:		11,0 million Sm^3 oil 0,7 billion Sm^3 gas
Total investments (firm 1997-NOK):		NOK 1,368 billion

The 33/9-19 S discovery has proven oil in sandstone from the Jurassic Age. Sidetrack 33/9-19 S was drilled to obtain additional information. Pressure support from water injection is assumed to be necessary in order to produce the discovery. There is also a potential for additional resources in nearby prospects. Two prospects will be drilled during the first half of 1998.

Several development alternatives are under evaluation. Phase-in towards Statfjord C, Snorre or Vigdis are potential development concepts. A plan for development and operations could be submitted to the authorities during 1998.

1.4.10 34/7-21

Production license: 089		**Block:** 34/7
Operator: Saga Petroleum ASA		
Licensees:		
Den norske stats oljeselskap a.s (SDFI 51 %)		55,40000 %
Esso Expl. & Prod. Norway A/S		10,50000 %
Idemitsu Petroleum Norge AS		9,60000 %
Norsk Hydro Produksjon AS		8,40000 %
Saga Petroleum ASA		7,70000 %
Elf Petroleum Norge AS		5,60000 %
Deminex Norge AS		2,80000 %
Discovery well:	34/7-21	Year: 1992
Earliest production start:[1)]		Year: 1999
Recoverable reserves:		9,4 million Sm^3 oil 1,1 billion Sm^3 gas
Total investments (firm 1997-NOK):		NOK 0,719 billion

[1)] Test production started in 1998

The 34/7-21 discovery has proven oil in rocks deposited during the late Jurassic Age. A sidetrack, 34/7-21 A, was drilled to delimit the oil discovery. The sidetrack confirmed the discovery, but showed that the lateral development and extent of the reservoir sand is difficult to map.

Due to the uncertainty connected with the extent of the sand and communication conditions in the reservoir, the operator will perform a test production from the discovery. The objective of the test production is to optimize the production strategy and development concept. A well slot on the Tordis Øst subsea template will be used for the test production, which is planned to take place during 1998. It is assumed that pressure support through water injection will be necessary in order to produce the discovery.

Based on the proven resource basis, the operator is considering a development with subsea wells connected to the existing subsea manifold on the Tordis field.

The operator also plans to drill an appraisal well in the area (H north) in 1998. Results from this well and the test production from the 34/7-21 discovery will be crucial factors in the selection of development concept.

1.4.11 34/7-23 S

Production licenses: 089		**Block:** 34/7
Operator: Saga Petroleum ASA		
Licensees:		
Den norske stats oljeselskap a.s (SDFI 51 %)		55,40000 %
Esso Expl. & Prod. Norway A/S		10,50000 %
Idemitsu Petroleum Norge AS		9,60000 %
Norsk Hydro Produksjon AS		8,40000 %
Saga Petroleum ASA		7,70000 %
Elf Petroleum Norge AS		5,60000 %
Deminex Norge AS		2,80000 %
Discovery well:	34/7-23 S	Year: 1994
Earliest production start:		Year: 2001
Recoverable reserves:		2,0 million Sm^3 oil 0,3 billion Sm^3 gas
Total investments (firm 1997-NOK):		NOK 0,349 billion

Discovery 34/7-23 S has proven oil in rocks deposited in the Late Jurassic Age. In order to improve the delimitation of the reservoir, a sidetrack was drilled from the well 34/7-23 A. The sidetrack confirmed the discovery.

It is assumed that pressure support from water injection will be required to produce the discovery. The preliminary plan is for production with one production well and one injection well.

Based on the proven resource basis, the operator is considering a development with subsea wells phased in to Vigdis.

The operator plans to drill an appraisal well in the area (H north) in 1998. Results from this well and the planned test production of the 34/7-21 discovery will be crucial factors for the selection of a development concept.

1.4.12 34/7-25 S

Production license: 089	**Block:** 34/7
Operator: Saga Petroleum ASA	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 51 %)	55,40000 %
Esso Expl. & Prod. Norway A/S	10,50000 %
Idemitsu Petroleum Norge AS	9,60000 %
Norsk Hydro Produksjon AS	8,40000 %
Saga Petroleum ASA	7,70000 %
Elf Petroleum Norge AS	5,60000 %
Deminex Norge AS	2,80000 %
Discovery well: 34/7-25 S	Year: 1996
Earliest production start:	Year: 1999
Recoverable reserves:	2,3 million Sm^3 oil 0,2 billion Sm^3 gas
Total investments (firm 1997-NOK):	0,349 billion

The 34/7-25 S discovery has proven oil in rocks deposited in the Late Jurassic Age. There is uncertainty connected with the extent of the reservoir sand and volume calculations for the discovery. Pressure support from water injection is presumed necessary to produce the discovery.

Based on the proven resource basis, the operator is considering a development with subsea wells tied to the Tordis Øst subsea template or the Tordis subsea manifold. The plan is to submit the plan for development and operation to the authorities during 1998.

1.4.13 34/11-1 KVITEBJØRN

Production license: 193	**Block:** 34/11
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 40 %)	80,0000 %
Norsk Hydro Produksjon AS	15,0000 %
Elf Petroleum Norge AS	5,0000 %
Discovery well: 34/11-1	Year: 1994
Earliest production start:	Year: 2001
Recoverable reserves:	18,0 million Sm^3 oil 44,9 billion Sm^3 gas 0,4 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 5,09 billion

34/11-1 Kvitebjørn lies about 17 kilometers southeast of the Gullfaks field, see Figure 1.3.18.a. Two exploration wells on the field have proven gas/condensate in sandstone in the Brent group of the Jurassic Age. The licensees plan to apply for gas allocation in 1998. An exploration well is planned in a saddle area towards 34/10-23 Gamma, inter alia in order to reduce the uncertainty with regard to potential communication between these discoveries. A wellhead installation which will be tied in to existing production facilities is being evaluated as an interesting development concept.

1.4.14 35/11-4 R FRAM

Production license: 090	**Block:** 35/11
Operator: Norsk Hydro Produksjon AS	
Licensees:	
Den norske stats oljeselskap a.s. (SDFI 30 %)	50,0000 %
Norsk Hydro Produksjon a.s.	25,0000 %
Mobil Development Norway A/S	25,0000 %
Discovery well: 35/11-2	Year: 1987
Earliest production start:	Year: 2001
Recoverable reserves:	31,3 million Sm^3 oil 11,2 billion Sm^3 gas
Total investments (firm 1997-NOK):	NOK 8,6 billion

Production license 090 in block 35/11 was awarded in 1984. So far, ten wells have been drilled, of which two during 1997. Oil and gas have been proven in several reservoir strata in Jurassic sandstones. The estimate of recoverable resources has been increased based on updated studies conducted in 1997. An appraisal well is planned for 1998.

An independent development which will initially comprise the H, F Øst and C Vest structures is planned. A final decision regarding selection of concept will be made in the spring of 1998. Submission of the development plan to the authorities is planned for the spring of 1998.

1.4.15 6406/2-3 KRISTIN

Production license: 199	**Block:** 6406/2
Operator: Saga Petroleum ASA	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 45 %)	60,00000 %
Mobil Development Norway AS	15,00000 %
Saga Petroleum ASA	25,00000 %
Discovery well: 6406/2-3	Year: 1997
Development approved: Phase I	Prod.start: Earliest year 2002
Recoverable reserves:	58,6 billion Sm^3 gas 37,4 million tonnes NGL
Total investments (firm 1997-NOK):	NOK 15,62 billion

Well 6406/2-3 in production license 199 was drilled at the turn of the year 1996/1997. The well proved gas condensate in sandstones of the Jurassic Age. Appraisal well 6406/2-5 was drilled in 1997 in order to clarify the gas/water contacts in the Garn and Ile formations. This well was dry. Later in 1997, a sidetrack was drilled (6406/2-5 A) in order to clarify the resource base in the discovery. Evaluation of the results from this drilling has not yet been completed.

The most likely production strategy is injection of gas in order to optimize liquid recovery. However, a high initial reservoir pressure, combined with a relatively low dewpoint, means that gas injection will not take place until after a few years of gas production.

The licensees plan to apply for gas allocation in 1998. The most interesting development solution appears to be a tension leg installation.

Plans for unitized development

At the turn of the year 1997/1998, work was underway to establish a unitized development of the 6406/2-3 Kristin, 6406/2-1 Lavrans, 6406/3-2 Trestakk, 6407/1-2 Tyrihans Sør and 6407/1-3 Tyrihans Nord discoveries.

1.4.16 6507/8-4 HEIDRUN NORD

Production license:	124	**Block:**	6507/8
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	6507/8-4	Year:	1990
Earliest production start			1999
Recoverable reserves:		4,9 million Sm^3 oil 0,4 billion Sm^3 gas	

The discovery lies in a fault block with sandstones from the Early Jurassic Age (the Åre formation).

Development as a satellite to Heidrun is being considered.

1.5 DISCOVERIES IN THE EARLY PLANNING STAGES

1.5.1 1/3-3

Production license:	065	**Block:**	1/3
Operator:	BP Petr. Dev. of Norway A/S		
Discovery well:	1/3-3	Year:	1983
Recoverable reserves:		4,3 million Sm^3 oil	

This is a small oil discovery made in the Ula formation from the Late Jurassic Age. BP took over Elf's interest as well as operatorship in the production license.

The plan is to develop the discovery through depressurization and with two horizontal wells. The operator is considering a development with a subsea installation linked to the Ula field. According to the plan, produced gas will be injected in the Ula reservoir as a part of the Ula WAG project.

1.5.2 1/9-1 TOMMELITEN ALPHA

Production license:	044	**Block:**	2/4
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	1/9-1	Year:	1977
Recoverable reserves:		3,2 million Sm^3 oil 3,5 billion Sm^3 gas 0,3 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 1,6 billion	

The Tommeliten Alpha discovery lies to the south of Tommeliten Gamma and was Statoil's first discovery on the Norwegian shelf as operator. The discovery contains gas and oil in the Tor and Ekofisk formations of the upper Cretaceous / Lower Tertiary Age. The structure is a salt stock dependent anticline which lies at a depth of about 3000 meters.

A feasibility study in 1995 concluded that there was a need to prove additional resources before further development. A new well is planned on the structure in order to test deeper strata.

1.5.3 2/4-17 TJALVE

Production license:	018	**Block:**	2/4
Operator:	Phillips Petroleum Co Norway		
Discovery well:	2/4-17	Year:	1992
Earliest production start:		Year:	2007
Recoverable reserves:		1,2 million Sm^3 oil 2,2 billion Sm^3 gas 0,1 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 300 million	

The Tjalve discovery contains gas/condensate in a 50-meter thick sandstone reservoir in the lower Ula formation from the Upper Jurassic Age. The structure is a combined fault-conditional and stratigraphic trap which lies at a depth of about 4300 meters. The drive mechanism for production will be gas expansion through depressurization. The discovery well has been temporarily abandoned and may be used for subsequent production.

The discovery has been evaluated for a development with transportation via the Tor field to Ekofisk II, either through a seabed installation and pipeline or through a production well drilled from Tor, which lies at a distance of about 7 kilometers from the Tjalve discovery. The timing of phase-in to Ekofisk II is being evaluated.

1.5.4 15/5-5

Production license:	048	**Block:**	15/5
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	15/5-5	Year:	1995
Earliest production start:		Year:	2000
Recoverable reserves:		8,7 million Sm^3 oil 0,5 billion Sm^3 gas	

This is an oil discovery in the Heimdal formation on the G structure in block 15/5. In 1997, the 15/5-6 appraisal well was drilled on the discovery. It found oil, but in a thinner layer than the operator expected and the estimate for recoverable oil was therefore reduced. Various development concepts are being evaluated and unitization with other discoveries in the Sleipner area (15/9-19 Theta Vest and the oil in Sleipner Vest) is also a possibility.

1.5.5 15/9-19 SR VOLVE

Production license: 046		**Block:**	15/9
Operator: Den norske stats oljeselskap a.s			
Discovery well:	15/9-19 SR	Year:	1993
Earliest production start:		Year:	2000
Recoverable reserves:		12,5 million Sm^3 oil 2,0 billion Sm^3 gas	

This oil discovery was made in 1993 in rocks from the Jurassic/Triassic Age on the Theta Vest structure just north of Sleipner Øst. In 1997, a new well was drilled as a sidetrack to the original well (15/9-19 A). This well proved considerably more oil than expected. This gave a doubling in the estimate for recoverable oil, and also the basis for further appraisal in the area.

Work is proceeding on plans for a unitized development of this discovery with a potential produceable oil zone in Sleipner Vest and with oil discoveries in block 15/5 (production license 048).

1.5.6 25/5-5

Production license: 102		**Block:**	25/5
Operator: Elf Petroleum Norge AS			
Discovery well:	25/5-5	Year:	1995
Earliest production start		Year:	2003
Recoverable reserves:		4,3 million Sm^3 oil	

25/5-5 lies to the east of Heimdal. One production well is planned.

Development with subsea facilities which are tied in to other installations is being considered. Production start depends on the timing of available capacity.

1.5.7 25/11-16 AND 25/8-4

These discoveries are discussed under the Grane discovery, Chapter 1.4.5.

1.5.8 30/6-17 R

Production license: 053	**Block:** 30/6
Operator: Norsk Hydro Produksjon AS	
Discovery well: 30/6-17 R	Year: 1986
Earliest production start	Year: 2002
Recoverable reserves:	0,5 million Sm^3 oil 1,4 billion Sm^3 gas

This is a small oil and gas discovery in the Cook formation under the main reservoir on the Oseberg field. The deposit will be produced with one well from the installation when a slot becomes available on Oseberg.

1.5.9 35/9-1 R GJØA

Production license: 153		**Block:** 35/9 og 36/7	
Operator: Norsk Hydro Produksjon AS			
Discovery well:	35/9-1	Year:	1989
Earliest production start		Year:	2002
Recoverable reserves:		11,4 million Sm^3 oil 33,3 billion Sm^3 gas 2,5 million tonnes NGL	

In addition to the three wells which have been drilled previously on various segments in the A structure, two new wells were drilled in 1997 on other structures in the production license. Discovery of hydrocarbons was made both in the J2 and C3 prospects. An appraisal well on Gjøa is planned for drilling in early 1998. About half of the area in the production license will be relinquished in July 1998.

Updated studies indicate that recoverable resources in the central structures on Gjøa may be considerably higher than the current estimate. Field development studies are ongoing. The date for selection of development concept is set for February 1999 and submission of the development plan to the authorities has been postponed until August 1999.

1.5.10 6406/2-1 LAVRANS

Production license: 199		**Block:** 6406/2	
Operator: Saga Petroleum ASA			
Licensees:			
Den norske stats oljeselskap a.s (SDFI 45 %)		60,00000 %	
Mobil Development Norway AS		15,00000 %	
Saga Petroleum ASA		25,00000 %	
Discovery well:	6406/02-1	Year:	1996
Earliest production start: Phase I		Earliest year 2002	
Recoverable reserves:		72,6 billion Sm^3 gas 23,1 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 3,86 billion	

Well 6406/2-1 in production license 199 was drilled in 1996 and proved condensate/gas in sandstones from the Jurassic Age. The Garn, Ile, Tofte and Tilje reservoir formations lie at depths of up to 4400 meters. In 1996, an appraisal well, 6406/2-2, was drilled which proved new resources. The operator assumes production through depressurization.

The licensees plan to apply for gas allocation in 1998. The most interesting development solution appears to be a subsea installation tied to the planned tension leg installation on the Kristin discovery.

Plans for coordinated development

At the turn of the year 1997/1998, work was underway to establish a coordinated development of the 6406/2-3 Kristin, 6406/2-1 Lavrans, 6406/3-2 Trestakk, 6407/1-2 Tyrihans Sør and 6407/1-3 Tyrihans Nord discoveries.

1.5.11 6406/3-2 TRESTAKK

Production license:	091	**Block:**	6406/3
Operator: Den norske stats oljeselskap a.s			
Licensees:			
Den norske stats oljeselskap a.s			
(SDFI 30 %)		50,00000 %	
Mobil Development Norway AS		33,00000 %	
Saga Petroleum ASA		17,00000 %	
Discovery well:	6406/3-2	Year:	1986
Earliest production start:		Year:	2002
Recoverable reserves:		6,2 million Sm^3 oil	
Total investments (firm 1997-NOK):		NOK 1,39 billion	

The Trestakk discovery was proven in 1986 in production license 091 (see Figure 1.5.11). Recoverable resources are estimated to be 6 million Sm^3 oil if associated gas is reinjected. This is based on an evaluation of the Trestakk discovery as a satellite of the Tyrihans discovery, which means that the production period will be limited. The reservoir is from the Middle Jurassic Age, has low permeability and lies deep. This is expected to give low well productivity.

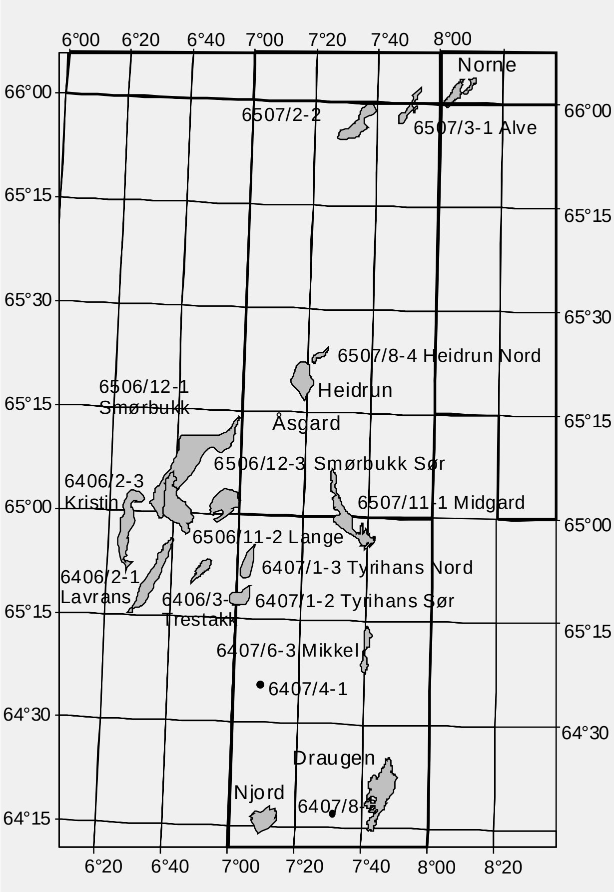
Plans for coordinated development

At the turn of the year 1997/1998, work was underway to establish a coordinated development of the 6406/2-3 Kristin, 6406/2-1 Lavrans, 6406/3-2 Trestakk, 6407/1-2 Tyrihans Sør and 6407/1-3 Tyrihans Nord discoveries.

1.5.12 6407/1-2 TYRIHANS SØR AND 6407/1-3 TYRIHANS NORD

Production license:	073	**Block:**	6407/1
Operator: Den norske stats oljeselskap a.s			
Licensees:			
Den norske stats oljeselskap a.s			
(SDFI 30 %)		50,00000 %	
Norsk Hydro Produksjon AS		16,66700 %	
Total Norge AS		33,33300 %	
Discovery well:	6407/1-2 Tyrihans Sør	Year:	1983
	6407/1-3 Tyrihans Nord		1984
Earliest production start:		Year:	2002
Recoverable reserves:		17,9 million Sm^3 oil 31,7 billion Sm^3 gas 6,2 million tonnes NGL	
Total investments (firm 1997-NOK):		NOK 7,6 billion	

Figure 1.5.11
Fields and discoveries in the Norwegian Sea



The Tyrihans Sør discovery was proven in 1983 and the Tyrihans Nord discovery was proven in 1984 in production license 073. The discoveries are probably in pressure communication through a common water zone. Tyrihans Sør is characterized as a gas/condensate discovery, while Tyrihans Nord contains an oil zone with overlying gas cap. The reservoirs are from the Middle Jurassic Age. An appraisal well was drilled on Tyrihans Nord in 1996. The well showed gas, oil and water. The transition zone makes it difficult to determine the oil/water contact exactly. The size of the oil zone in Tyrihans Nord is uncertain since the oil/water contact has not been proven.

The most likely production strategy is based on depressurization of Tyrihans Nord and gas injection in Tyrihans Sør in order to optimize liquid recovery. The licensees plan to apply for gas allocation in 1998. Several potential development concepts are being evaluated. The discoveries will most likely be produced with subsea-completed wells connected to either a separate production and storage ship or coordinated with other fields in the area.

Plans for coordinated development

At the turn of the year 1997/1998, work was underway to establish a coordinated development of the 6406/2-3 Kristin, 6406/2-1 Lavrans, 6406/3-2 Trestakk, 6407/1-2 Tyrihans Sør and 6407/1-3 Tyrihans Nord discoveries.

1.5.13 7121/4-1 SNØHVIT

Production licenses: 097, 099 and 110	**Block:** 7120/6,7121/4, 7121/5,7120/5
Operator: Norsk Hydro Produksjon AS for 097 Den norske stats oljeselskap a.s for 099 and 110	
Discovery well: 7121/4-1	Year: 1984
Earliest production start:	Year: 2003
Recoverable reserves:	10,2 million Sm^3 oil 60,9 billion Sm^3 gas 4,2 million tonnes NGL

The Snøhvit discovery is a gas/condensate discovery with a thin oil zone. The reservoir consists of an east-west running, fault-controlled structure centrally located in the Hammerfest basin. The structure has wide lateral extension, about 130 km^2. The reservoir is from the Jurassic Age.

For the gas phase, the plan is to develop the discovery with a subsea installation. The gas will be transported to land via pipeline for processing and conversion to liquid gas (LNG). For production of the 14-16 meter thick oil zone, the plan is to use a floating production installation. About 80 million Sm^3 oil in place has been proven in Snøhvit, and the amount of recoverable resources will largely depend on the development solution. The operators are considering locating the LNG terminal at Melkøya just outside of Hammerfest.

1.6 EXPLORATION ACTIVITY

1.6.1 GEOPHYSICAL SURVEYS

A total of 460,794 km of seismic data were collected on the Norwegian Shelf in 1997. The number of kilometers refers to cmp-line kilometers.

In the North Sea, a total of 329,096 km seismic data were collected, in addition to 87,253 kilometers in the Norwegian Sea and 44,445 kilometers in the Barents Sea.

The Norwegian Petroleum Directorate gathered a total of 3,878 kilometers, while oil companies and seismic contractor companies gathered a total of 456,916 kilometers. Of this total, Norwegian oil companies collected 364,070 kilometers and foreign oil companies collected 3,428 kilometers. The contractor companies Geco, Geoteam, Nopec, PGS Exploration and CGG Norge collected 89,418 kilometers for their own accounts.

Of the total seismic data collected, 3D seismic accounts for 415,945 kilometers, 318,082 in the North Sea, 72,170 kilometers in the Norwegian Sea and 25,701 kilometers in the Barents Sea. Figure 1.6.1 provides an overview of recent years' development with regard to the number of cmp-line kilometers collected.

1.6.2 EXPLORATION DRILLING

At the turn of the year 1996/1997, drilling of eight exploration wells was in progress, one of these was reopened.

Figure 1.6.1
Seismic surveys on the Norwegian continental shelf 1962-1997

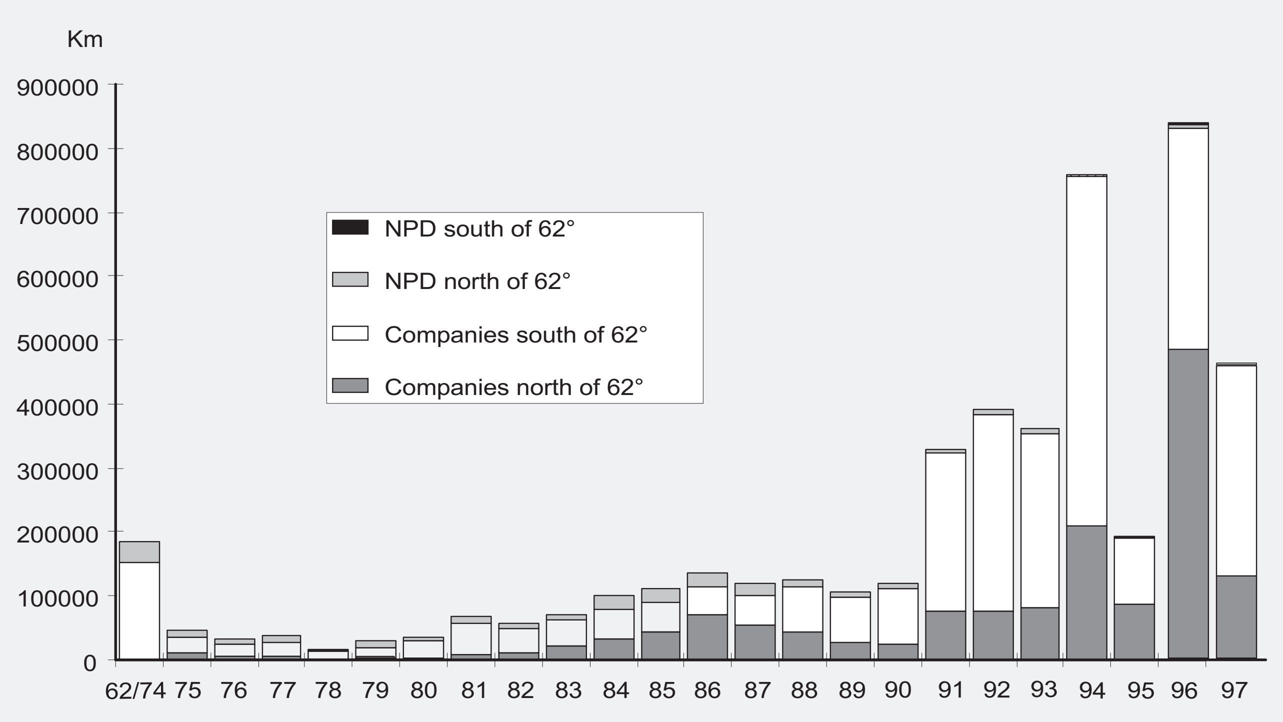
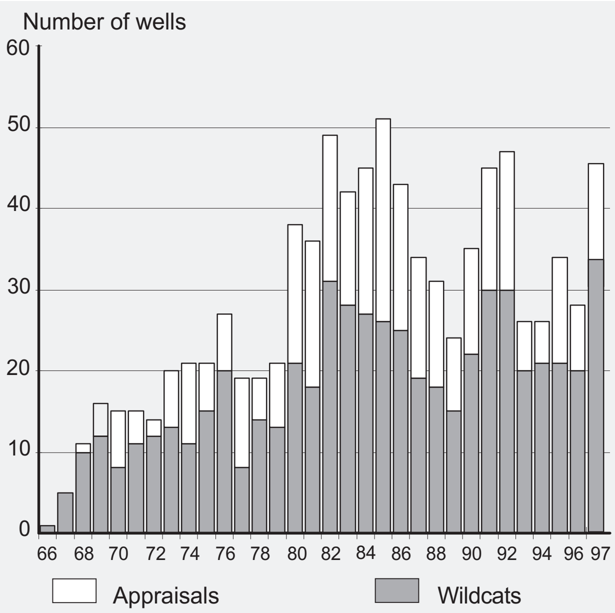


Figure 1.6.2
Exploration wells completed per year after re-classification



50 new exploration wells were spudded in 1997, of which 38 were wildcats and 12 were appraisal wells. Drilling activities in 1997 comprised 25 wildcat and eight appraisal wells in the North Sea and 13 wildcat and four appraisal wells in the Norwegian Sea. In addition, five temporarily abandoned exploration wells were re-entered for further work; three in the North Sea and two in the Norwegian Sea.

At the turn of the year 1997/1998, nine exploration wells were being drilled.

As of 31 December 1997, a total of 916 exploration wells had been spudded on the Norwegian continental shelf. These are divided between 655 wildcat wells and 261 appraisal wells, see Table 7.3.a.

In 1997, 54 exploration wells were completed or temporarily abandoned after having reached the planned depth on the Norwegian shelf. Six of these were re-entries, either for additional operations or for permanent plugging. After well 25/8-9 A was reclassified from wildcat well to appraisal well, the wells consisted of 40 wildcat wells and 14 appraisal wells. The geographical distribution of the wells is as follows: 26 wildcat and 10 appraisal wells in the North Sea, and 14 wildcat and four appraisal wells in the Norwegian Sea.

The operators for the wells completed or temporarily abandoned in 1997 were as follows: Statoil 14, Hydro 8, Esso 8, Saga 7, BP 3, Amerada 3, Shell 3, Amoco, Conoco and Deminex with 2 each and Mobil and Agip with 1 each.

A wildcat well is a well which is drilled in order to investigate whether petroleum may be found in a new, clearly defined geological unit delimited by rock formations with structural or stratigraphic limits. An appraisal well is a well drilled in order to determine the extent and size of a petroleum deposit which has already been proven by a wildcat well. All exploration wells have one of these classifications when they are spudded. If it should later prove that a well does not meet the criteria for the classification it was originally given, it is reclassified. 75 exploration wells on the Norwegian shelf have been reclassified, 71 of these from wildcat to appraisal wells and four from appraisal to wildcat wells.

As of 31 December 1997, 907 exploration wells were completed or temporarily abandoned on the Norwegian shelf. After reclassification, these comprise 581 wildcat and 326 appraisal wells.

Table 7.3.f provides an overview of spudded and/or completed exploration wells in 1997.

As of year-end, a total of 49 exploration wells have been temporarily abandoned on the Norwegian continental shelf.

The temporarily abandoned exploration wells on the Norwegian shelf with equipment remaining on the seabed are:

2/01-09 A	25/05-04	31/05-04 AR
2/01-11	25/08-06	31/05-05
2/04-15 S	25/08-11	34/04-07
2/04-17	25/11-16	34/07-26 S
2/07-23 S	25/11-21 A	34/08-04 A
2/07-25 S	30/02-01	34/10-34
2/10-02	30/03-04	34/10-37 A
2/12-02 S	30/08-01 SR	34/11-02 A
7/12-08	30/09-07	6305/05-01
7/12-09	30/09-08 R	6406/02-02
9/02-07 S	30/09-09	6407/07-02 R
15/12-06 S	30/09-10	6407/07-04
15/12-09 S	30/09-12 A	6506/11-04 S
15/12-10 S	30/09-13 S	6506/11-05 S
25/02-13	31/02-16 SR	6506/12-08
25/04-06 S	31/02-18 A	6507/08-04
		6507/11-05 S

The Norwegian companies Statoil, Hydro and Saga have been the operators of 29 of the spudded wells in 1997, representing 58%. The remaining 21 wells were divided among Esso, Amoco, BP, Amerada, Conoco, Deminex, Shell and Agip. This is illustrated in Table 7.3.c.

1.6.3 EXPLORATION TARGETS

Exploration activity in 1997 has largely continued to target Jurassic sandstone prospects. The number of wells drilled towards prospects in the Tertiary and Cretaceous showed a marked increase compared with the previous year. Of the 50 exploration wells spudded in 1997, 27 had Jurassic as the main prospect, 11 had the Tertiary, eight had the Cretaceous, three had the Triassic and one had the Permian as the main prospect. In addition to the main prospect, secondary prospects were also the subject of investigation. These were divided among six in the Tertiary, seven in the Cretaceous, six in the Jurassic and three in the Paleozoic.

1.6.4 NEW DISCOVERIES IN 1997

17 discoveries have been made, of which seven have been confirmed through formation testing. Eleven discoveries have been made in the North Sea and six in the Norwegian

Sea, see Table 1.6.4. A more detailed description of the various discoveries may be found in Chapter 1.6.5.

1.6.5 DETAILED DESCRIPTION OF DRILLING IN 1997

Southern part of the North Sea

Six exploration wells were completed in the southern part of the North Sea in 1997 (Table 1.6.5.a). All six are wildcat wells. One of the six (2/8-16 SX) had to be abandoned due to technical problems. In addition, two wildcat wells (2/8-17 and 9/2-8 S) were spudded, but not completed as of the end of the year. Three discoveries of hydrocarbons were made in the area in 1997. Wildcat well 2/6-5 was completed in 1997, but the oil discovery was included in the resource accounts for 1996.

Well 2/1-11, which was drilled south of the Gyda field, proved oil in sandstones from the Early and Middle Jurassic. Formation testing was not performed. The discovery is presumed to be quite small.

Well 2/5-11, which was drilled to the north of the Tor field, struck oil in limestone from the Paleocene Age. Two formation tests were conducted. The best test produced some oil, but mostly water. This is due to low oil saturation in the reservoir.

Well 9/2-7 S, drilled southwest of the Yme field, struck oil in sandstone from the Middle and Late Jurassic Ages. This is a small discovery which was not formation tested.

The Sleipner / Balder area

15 exploration wells were completed in the Sleipner and Balder area in 1997 (Table 1.6.5.b). Twelve of the exploration wells were wildcat wells and three were appraisal wells. In addition, an appraisal well (15/9-19 B) was spudded, but was not completed by the end of the year. Six discoveries of hydrocarbons were made in the area in 1997.

Well 16/7-7 S, which was drilled southeast of Sleipner Øst, struck gas/condensate in rocks from the Triassic Age. Two formation tests were carried out. The maximum production rate was measured at 556 Sm^3 liquid and 265,000 Sm^3 gas per day through a 17.5 mm choke. The well was drilled right next to the 16/7-4 discovery from 1982, but pressure and liquid data show that it has proven a new deposit.

Well 25/7-5, drilled southwest of the Heimdal field, proved oil in Paleocene rocks. A formation test was conducted with a production rate of 960 Sm^3 and 81,000 Sm^3 gas through a 17.5 mm choke. There is great uncertainty associated with the size of the discovery, with an estimate of recoverable petroleum resources of 10-60 million Sm^3.

Well 25/8-9, which was drilled to the east of the Jotun field, struck oil in Paleocene rocks. The well was not formation tested. This is an extremely small discovery.

Well 25/8-10 S, drilled northeast of the Balder field, struck oil in rocks from the Paleocene. A formation test was conducted with a production rate of 413 Sm^3 oil and 147,000 Sm^3 gas through a 14.4 mm choke. The size of the discovery is estimated to be 9 million Sm^3 recoverable oil.

Well 25/8-11, drilled 10 kilometers north of the Balder field, struck oil in rocks from the Paleocene and Early Jurassic. A formation test was run in the reservoir zone from the Early Jurassic, with a production rate of 520 Sm^3 oil and 23,000 Sm^3 gas through a 16 mm choke. The estimate for recoverable petroleum reserves is 3-12 million Sm^3.

Well 25/10-8, which was drilled southwest of the Balder field, proved oil and gas in rocks from the Early Jurassic. A formation test was conducted in the oil zone, with an average production rate measured to 672 Sm^3 oil and 77,600 Sm^3 gas per day through a 16 mm choke. This is a small discovery.

The Oseberg and Troll area

Seven exploration wells were completed in the Oseberg and Troll area in 1997 (Table 1.6.5.c). Four of these were wildcat wells and three were appraisal wells. In addition, two wildcat wells (30/3-7 A and 30/8-3) have been spudded, but were not completed as of year-end. Two discoveries of hydrocarbons were made in the area in 1997.

Well 35/9-3, which was drilled north of the 35/9-1 Gjøa discovery, struck gas in rocks from the Late Cretaceous and oil and gas in Early Cretaceous rocks. There was no formation testing of the well. The discovery is probably small, but it is interesting with a view towards future exploration activity in the area.

Well 36/7-2, drilled east of the 35/9-1 Gjøa discovery, struck oil in rocks from the Late Jurassic. The well was not formation tested. This is a small discovery.

The Gullfaks, Statfjord and Snorre area

Five exploration wells were completed in this area in 1997 (Table 1.6.5.d). Two of the exploration wells were wildcat wells and three were appraisal wells. One of the three appraisal wells (34/7-26 S) has been temporarily abandoned above the reservoir level. In addition, one wildcat well (34/7-28) was spudded, but not completed as of the end of the year. No new discoveries of hydrocarbons were made in the area in 1997.

The Norwegian Sea

15 exploration wells were completed in this area in 1997 (Table 1.6.5.e), of which one (6406/2-4 S) has been temporarily abandoned. Twelve of the exploration wells were wildcat wells and three were appraisal wells. One of the twelve wildcat wells (6204/10-2 A) was reclassified to an appraisal well in January 1998. One of the three appraisal wells (6406/2-4 S) has been temporarily abandoned. In addition, two wildcat wells (6507/5-1 and 6706/11-1) and one appraisal well (6406/2-5 A) were spudded, but were not completed as of the end of the year. Six discoveries of hydrocarbons were made in the area in 1997.

Well 6204/10-2 R, drilled to the northeast of the Agat discovery, struck gas in a thin sandstone from the Late

Table 1.6.4
New discoveries in 1997

Exploration well	Operator	Hydro-carbon type	Reservoir level	Forma-tion tested	Production rate (per day)	Choke	Size of discovery (recoverable) Oil/condensate (mill Sm^3)	Size of discovery (recoverable) Gas (bill Sm^3)
2/1-11	BP	oil	Early & Middle Jurassic	no			< 1	
2/5-11	Agip	oil	Paleocene	yes	90 Sm^3 oil 9 600 Sm^3 gas	14.4 mm	1-2	
9/2-7 S	Statoil	oil	Middle & Late Jurassic	no			1-5	
16/7-7 S	Esso	gas/cond	Triassic	yes	556 Sm^3 cond 265 000 Sm^3 gas	17.5 mm	5-10	2-5
25/7-5	Hydro	oil	Paleocene	yes	960 Sm^3 oil 81 000 Sm^3 gas	17.5 mm	10-60	
25/8-9	Amerada	oil	Paleocene	no			1	
25/8-10 S	Esso	oil	Paleocene	yes	413 Sm^3 oil 147 000 Sm^3 gas	14.4 mm	9	< 1
25/8-11	Esso	oil	Paleocene & Early Jurassic	yes	520 Sm^3 oil 23 000 Sm^3 gas	16 mm	3-12	
25/10-8	Esso	oil/gas	Early Jurassic	yes	672 Sm^3 oil 77 600 Sm^3 gas	16 mm	2-5	< 1
35/9-3	Hydro	oil/gas	Early & Late Cretaceous	no			< 1	< 1
36/7-2	Hydro	oil	Late Jurassic	no			1-3	
6204/10-2 R	Statoil	gas	Late Cretaceous	no				< 1
6305/5-1	Hydro	gas	Paleocene	no				> 100
6306/5-1	Amerada	gas	Paleocene	no				< 1
6406/2-3	Saga	gas/cond	two Middle Jurassic reservoir zones	yes	Lower zone: 840 Sm^3 cond 880 000 Sm^3 gas Upper zone: 960 Sm^3 cond 750 000 Sm^3 gas	18 mm	37	59
6507/7-11 S	Conoco	gas	Early Jurassic	no				< 1
6707/10-1	BP	gas	Late Cretaceous	no				38

Table 1.6.5.a
Exploration wells drilled in the southern North Sea

Exploration well	Well classification	Production license	Operator	Total depth (MSL)	Total depth (age)	Status
1/3-8	wildcat	011	Amoco Norge	5161	Triassic	dry
2/1-11	wildcat	019 B	BP	4702	Triassic	oil
2/5-11	wildcat	067	Norsk Agip	3511	Late Cretaceous	oil
2/6-5	wildcat	008	Saga	3237	Basement	oil
2/8-16 SX	wildcat	006	Amoco Norge	3095	Miocene	junked
2/8-17	wildcat	006	Amoco Norge			
9/2-7 S	wildcat	114	Statoil	3370	Middle Jurassic	oil
9/2-8 S	wildcat	114	Statoil			

Cretaceous. No formation testing of the well was conducted. This is an extremely small discovery.

Well 6305/5-1, which was drilled about 100 kilometers northwest of Kristiansund, struck gas in Paleocene sandstones on the Ormen Lange dome. Regular formation testing of the well was not carried out. Preliminary evaluations show at least 100 billion Sm^3 recoverable gas. The discovery may prove to be considerably larger, but new wells are needed in order to clarify this. Additional drilling on the structure is planned for 1998.

Well 6306/5-1, drilled east of the Ormen Lange dome, struck small quantities of gas in Paleocene rocks. The well was not formation tested. This is a small discovery.

Well 6406/2-3, drilled southwest of the Smørbukk discovery (part of the Åsgard development), struck gas and condensate in two reservoir zones from the Middle Jurassic. Both of the reservoir zones were formation tested. 880,000 Sm^3 gas and 840 Sm^3 condensate per day were produced through an 18 mm choke from the deepest zone. From the shallowest zone, 750,000 Sm^3 gas and 960 Sm^3 condensate per day were produced through an 18 mm choke. This is a large gas/condensate discovery. One appraisal well (6406/2-5) was completed on the Kristin discovery in 1997, and at year-end an additional appraisal well (6406/2-5 A) was being drilled on the discovery.

Well 6507/7-11 S, which was drilled southwest of the Heidrun field, struck a thin gas zone in Early Jurassic rocks. There was no formation testing of this well. This is a very small discovery.

Well 6707/10-1, which was drilled 250 km southwest of Lofoten, struck gas in sandstones from the Late Cretaceous. No formation testing was conducted on the well. The discovery is estimated at 38 billion Sm^3 recoverable gas. The drilling, which was made on Nykhøgda in the new exploration area called the Vøring basin, was the first deep water drilling on the Norwegian shelf. The water depth was 1274 meters.

Table 1.6.5.b
Exploration wells drilled in the Sleipner and Balder area

Exploration well	Well classification	Production license	Operator	Total depth (MSL)	Total depth (age)	Status
15/5-6	appraisal	048	Statoil	2700	Late Cretaceous	oil
15/6-8 S	wildcat	166	Deminex	3148	Triassic	dry
15/6-8 A	wildcat	166	Deminex	2422	Paleocene	dry
15/9-19 A	appraisal	046	Statoil	3335	Triassic	oil
15/9-19 B	appraisal	046	Statoil			
15/12-11 S	wildcat	116	Saga	3441	Triassic	dry
16/7-6	wildcat	072	Esso Norge	2700	Triassic	dry
16/7-7 S	wildcat	072	Esso Norge	2701	Triassic	gas/cond
25/7-4 S	wildcat	103	Conoco	2523	Late Cretaceous	dry
25/7-5	wildcat	203	Norsk Hydro	2714	Late Cretaceous	oil
25/8-9	wildcat	189	Amerada Hess	2515	Early Jurassic	oil
25/8-9 A	appraisal	189	Amerada Hess	2198	Paleocene	oil
25/8-10 S	wildcat	027	Esso Norge	1859	Late Cretaceous	oil
25/8-11	wildcat	027	Esso Norge	1976	Early Jurassic	oil
25/10-8	wildcat	028 P	Esso Norge	2628	Permian	oil/gas
25/10-8 A	wildcat	028 P	Esso Norge	2537	Late Jurassic	dry

Table 1.6.5.c
Exploration wells drilled in the Oseberg and Troll area

Exploration well	Well classification	Production license	Operator	Total depth (MSL)	Total depth (age)	Status
30/3-7 A	wildcat	052	Statoil			
30/8-3	wildcat	190	Norsk Hydro			
30/11-5	wildcat	035	Norske Shell	3702	Early Jurassic	dry
35/4-1	wildcat	194	Hydro	4905	Triassic	dry
35/9-3	wildcat	153	Hydro	2759	Basement	oil/gas
35/11-9	appraisal	090	Hydro	2801	Late Jurassic	oil/gas
35/11-10	appraisal	090	Hydro	2928	Early Jurassic	oil
35/11-10 A	appraisal	090	Hydro	2867	Early Jurassic	dry
36/7-2	wildcat	153	Hydro	1413	Basement	oil

Tabell 1.6.5.d
Exploration wells drilled in the Gullfaks, Statfjord and Snorre area

Exploration well	Well classification	Production license	Operator	Total depth (MSL)	Total depth (age)	Status
33/6-2	wildcat	206	Mobil	3920	Early Jurassic	dry
34/4-9 S	appraisal	057	Saga	3415	Triassic	oil
34/7-26 S	appraisal	089	Saga	2215	Cretaceous	suspended
34/7-28	wildcat	089	Saga			
34/10-41 S	wildcat	050	Statoil	2600	Early Jurassic	dry
34/11-3	appraisal	193	Statoil	4451	Early Jurassic	gas/cond

Table 1.6.5.e
Exploration wells drilled in the Norwegian Sea

Exploration well	Well classification	Production license	Operator	Total depth (MSL)	Total depth (age)	Status
6204/10-2 A	wildcat*	175	Statoil	2026	Early Cretaceous	gas
6204/10-2 R	wildcat	175	Statoil	2067	Basement	gas
6204/11-2	wildcat	175	Statoil	2896	Late Jurassic	dry
6305/5-1	wildcat	209	Hydro	3027	Late Cretaceous	gas
6306/5-1	wildcat	197	Amerada	2018	Late Cretaceous	gas
6406/2-3	wildcat	199	Saga	5232	Early Jurassic	gas/cond
6406/2-4 S	appraisal	199	Saga	4434	Early Jurassic	suspended
6406/2-5	appraisal	199	Saga	5416	Early Jurassic	dry
6406/2-5 A	wildcat	199	Saga			
6407/8-3	wildcat	158	BP	1937	Early Jurassic	dry
6507/3-2	wildcat	159	Statoil	2008	Triassic	dry
6507/5-1	wildcat	212	Amoco			
6507/7-11 S	wildcat	095	Conoco	3726	Early Jurassic	gas
6507/11-5 S	appraisal	062	Statoil	2576	Early Jurassic	dry
6510/2-1	wildcat	214	Shell	4682	Early Triassic	dry
6608/8-1	wildcat	200	Statoil	2985	Permian	dry
6706/11-1	wildcat	217	Statoil			
6707/10-1	wildcat	218	BP	5039	Late Cretaceous	gas

*6204/10-2 A was reclassified as an appraisal well January 1998.

Figure 1.6.5.a
Exploration wells drilled in the southern North Sea

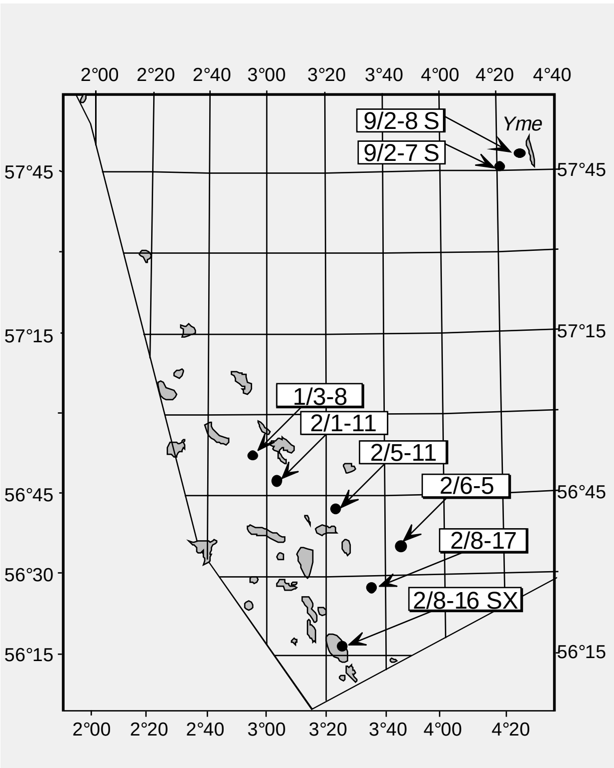


Figure 1.6.5.b
Exploration wells drilled in the Sleipner and Balder area

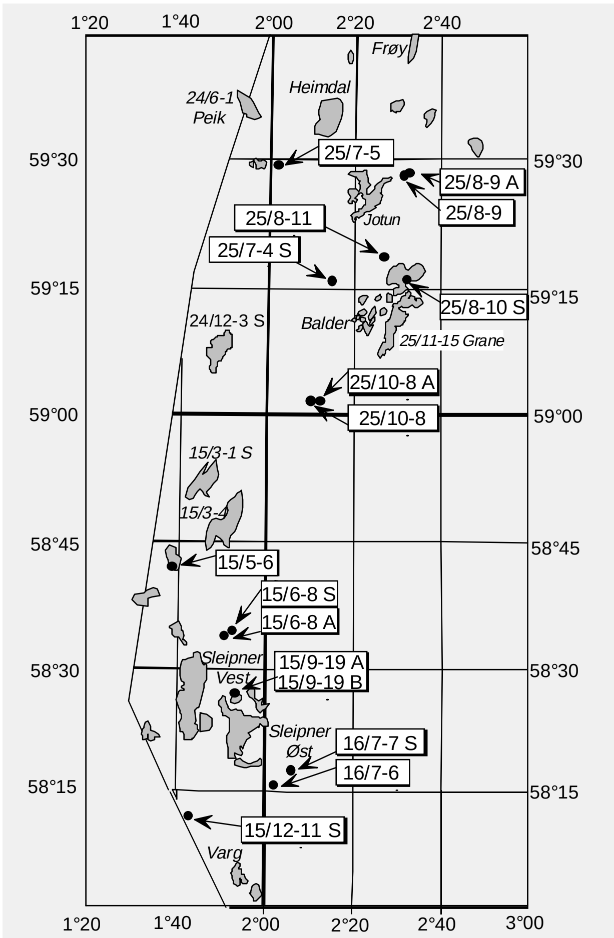
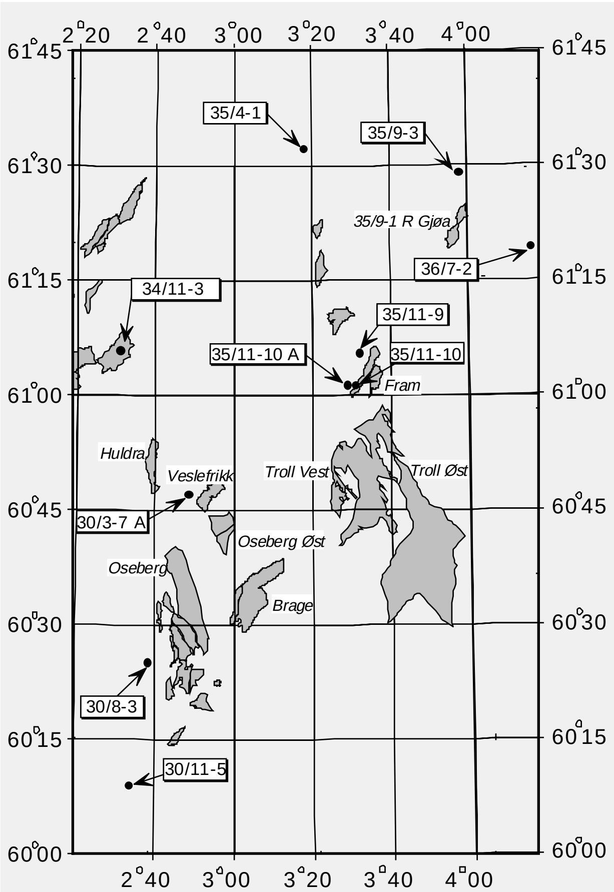
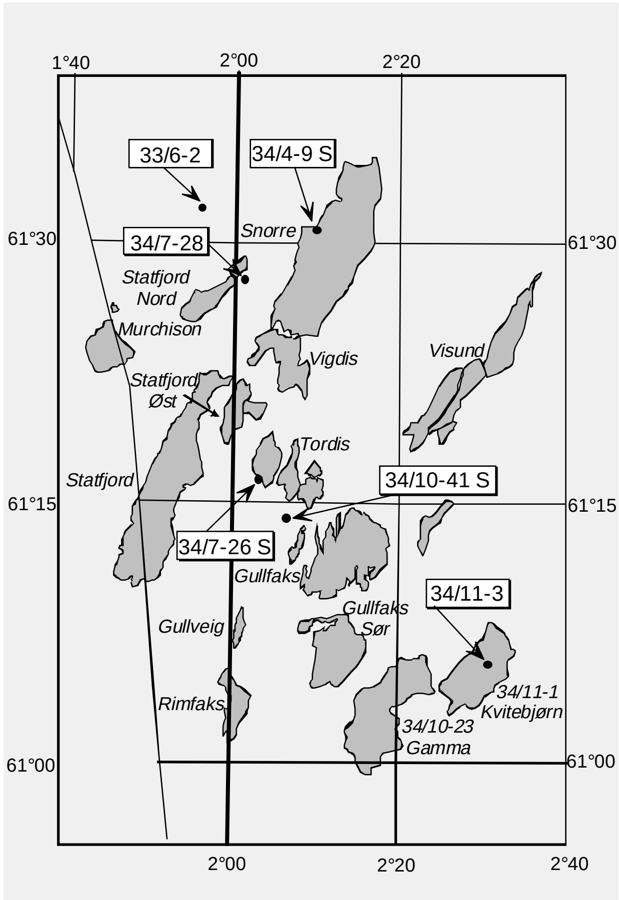


Figure 1.6.5.c
Exploration wells drilled in the Oseberg and Troll area



Figur 1.6.5.d
Exploration wells drilled in the Gullfaks, Statfjord and Snorre area



1.7 TRANSPORTATION SYSTEMS FOR OIL AND GAS

1.7.1 EXISTING TRANSPORTATION SYSTEMS

The various transportation systems for gas and oil/condensate from the Norwegian continental shelf are shown in Figure 1.7.1. Some of the transportation systems are British, where the Norwegian share of the transported volume comprises only a small part. This applies to:

- Northern Leg Gas Pipeline (NLGP), where Statfjord gas (British share) is transported to Shell's terminal at St. Fergus
- The Brent pipeline which transports Murchison oil to Sullom Voe on Shetland
- The Brae-Forties system which transports Heimdal condensate to BP's Kinneil terminal outside Edinburgh.

Gas transportation, Statpipe

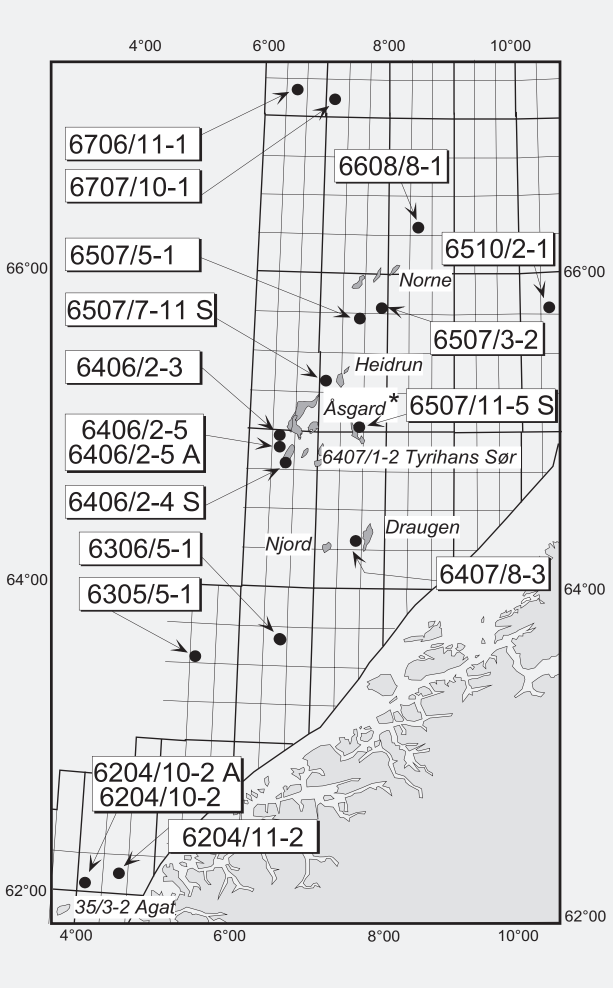
Ownership structure:

Den norske stats oljeselskap a.s.	58,25000 %
Elf Petroleum Norge AS	10,00000 %
Norsk Hydro Produksjon AS	8,00000 %
Mobil Development Norway AS	7,00000 %
Esso Expl. & Prod. Norway A/S	5,00000 %
A/S Norske Shell	5,00000 %
Norske Conoco A/S	2,75000 %
Saga Petroleum ASA	2,00000 %
Total Norge AS	2,00000 %

Statoil is the operator for operation of the system which includes:

- a rich gas pipeline from Statfjord to Kårstø. The transportation capacity for pipelines from Statfjord to Kårstø is 8 billion Sm^3 per day. The pipeline has an inner diameter of 710 mm (outer diameter 30").
- separation and fractionating plant at Kårstø, plus storage and loading facility
- dry gas pipeline from Heimdal to the Draupner S riser installation with a length of 155 kilometers and an inner diameter of 870 mm (outer diameter 36"), dry gas pipeline from Kårstø to Draupner S with a length of 228 kilometers and an inner diameter of 760 mm (outer diameter 28"), and a pipeline from Draupner S to the 2/4-S riser installation at the Ekofisk Center with a length of 190 kilometers and an inner diameter of 870 mm (outer diameter 36").

Figure 1.6.5.e
Exploration wells drilled in the Norwegian Sea



After production start, the Gullfaks, Veslefrikk, Snorre and Brage fields were connected to the Statpipe system upstream of the Kårstø facility. Sleipner has also been connected to Statpipe via a branch pipeline to Draupner.

Kårstø

The first North Sea gas was landed at Kårstø in March 1985. Delivery of dry gas from the terminal began in October 1985. The process facilities at Kårstø have a capacity of 25 million Sm^3 per day.

At Kårstø, the heavy hydrocarbons are removed from the wet gas and sold as propane, butane, methyl propane and naphtha. Condensate from Sleipner is received at Kårstø via a separate pipeline from the Sleipner field. At Kårstø, the condensate is split into propane, butane, methyl propane and condensate and shipped on to the customers.

Both propane, butane, methyl propane, naphtha and condensate are stored in separate tanks, prior to being pumped via fiscal metering equipment to tankers.

Gas transportation, Norpipe

The pipeline system for transportation of natural gas from the Ekofisk Center to Emden in Germany is owned by Norpipe A/S. Gas from the Ekofisk area and Statpipe is delivered to Norpipe. Norpipe A/S is a corporation which is owned 50/50 by Statoil and the Phillips group.

Phillips Petroleum Company Norway is the technical operator of the pipeline, while Statoil is responsible for the economic and administrative functions.

A bypass line from Statpipe to Norpipe bypassing the Ekofisk Center is planned in connection with the building of Ekofisk II.

The gas pipeline is 442 kilometers long and has an inner diameter of 869 mm (outer diameter 36"). There are two compressor stations on the gas pipeline, both on the German continental shelf.

Design capacity of the gas pipeline is approximately 19 billion Sm^3 per year. This capacity will be reduced after installation of a new bypass line.

Norpipe Gas

Ownership structure:

Phillips Petroleum Company Norway	15,89000 %
Fina Production Licences AS	12,90000 %
Norsk Agip AS	8,62000 %
Elf Petroleum Norge AS	5,04000 %
Norsk Hydro Produksjon AS	4,43000 %
Total Norge AS	2,36000 %
Den norske stats oljeselskap a.s.	50,00000 %
Elf Rex Norge AS	0,56000 %
Saga Petroleum ASA	0,30000 %

The gas pipeline is owned by Norpipe a.s., which in turn is a wholly-owned subsidiary of Norsea Gas A/S.

Phillips Petroleum Norsk AS is operator on behalf of the Phillips group.

The facilities are connected to Europipe, so that the Norpipe gas can be delivered through the Europipe system and vice versa.

Etzel gas storage

Ownership structure:

Ruhrgass	74,80000 %
Den norske stats oljeselskap a.s	20,10000 %
Norsk Hydro Produksjon AS	2,40000 %
Saga Petroleum ASA	1,20000 %
Elf Petroleum Norge AS	0,68955 %
Norske Conoco A/S	0,42090 %
Total Norge AS	0,38955 %

As of 31 December 1995, Ruhrgass took over Esso's and Shell's interests in the Etzel gas storage facility.

Gas transportation, Frigg

The Frigg Norwegian pipeline (FNA) is owned by the Norwegian Frigg licensees.

Ownership structure:

Norsk Hydro Produksjon AS	32,87000 %
Elf Petroleum Norge AS	26,42000 %
Den norske stats oljeselskap a.s	24,00000 %
Total Norge AS (operatør)	16,71000 %

Some British fields are connected to the Frigg Norwegian line via MCP-01. While the installation was manned, the volumes from the British fields were metered on MCP-01. After demanning, the volumes from the British fields are metered on the individual installation.

St. Fergus

The terminal is owned by the Frigg Norwegian licensees and the Frigg British licensees (Elf UK 66-2/3 %, Total UK 33-1/3%). Total Oil Marine UK is the operator.

Zeepipe

Ownership structure:

Den norske stats oljeselskap a.s	70,00000 %
Norsk Hydro Produksjon AS	8,00000 %
A/S Norske Shell	7,00000 %
Esso Expl. & Prod. Norway A/S	6,00000 %
Elf Petroleum Norge AS	3,29850 %
Saga Petroleum ASA	3,00000 %
Norske Conoco A/S	1,70150 %
Total Norge AS	1,00000 %

Zeepipe is a gas transportation system which is to transport gas from Kollsnes in Øygarden to the Continent. Phase I of the project comprises an 800 km long pipeline with an inside diameter of 966 mm (outer diameter 40") from Sleipner to Zeebrügge in Belgium. In addition, an approximately 40 km long line has been laid from Sleipner to the Draupner installation (16/11S). Phase I, including the Zeebrügge terminal, was completed in 1993. The capacity without compression will be about 12.6 billion Sm^3 per year.

Phase II comprises two pipelines from Kollsnes to Sleipner R and the Draupner installation respectively. The inner diameter is 966 mm (outer diameter 40"). The pipeline to Sleipner R, Phase II-A, was put into operation in 1996 and the pipeline to Draupner, Phase II-B, was put into operation in 1997.

Statoil is the operator.

Europipe

Ownership structure

Den norske stats oljeselskap a.s	70,00000 %
Norsk Hydro Produksjon AS	8,00000 %
A/S Norske Shell	7,00000 %
Esso Expl. & Prod. Norway A/S	6,00000 %
Elf Petroleum Norge AS	3,29850 %
Saga Petroleum ASA	3,00000 %
Norske Conoco A/S	1,70150 %
Total Norge AS	1,00000 %

This pipeline goes from Draupner (16/11E) to Emden in Germany and is about 620 kilometers long. The pipeline has an inner diameter of 966 mm (outer diameter 40"). The capacity without compression is approximately 13 billion Sm^3 gas per year. Gas deliveries started as planned on 1 October 1995.

Statoil is the operator.

NorFra

NorFra is an 840 kilometer long pipeline with an inner diameter of 1016 mm (outer diameter 42") between Draupner (16/11E) and Dunkerque in France. The pipeline has an initial capacity of 11.4 billion Sm^3 per year. The plan is for gas deliveries to start on 1 October 1998.

Ownership structure:

Den norske stats oljeselskap a.s (SDFI 60 %)	69,70880 %
Norsk Hydro Produksjon AS	6,47250 %
Saga Petroleum ASA	5,17800 %
Esso Expl. & Prod. Norway A/S	3,88350 %
Mobil Development Norway AS	3,88350 %
Total Norge AS	2,91260 %
Elf Petroleum Norge AS	2,13590 %
Norsk Agip AS	1,94170 %
A/S Norske Shell	1,29450 %
Neste Petroleum AS	1,29450 %
Norske Conoco A/S	1,29450 %

Statoil is the operator for the construction phase. The Ministry will designate the operator for the operations phase at a later date.

Haltenpipe

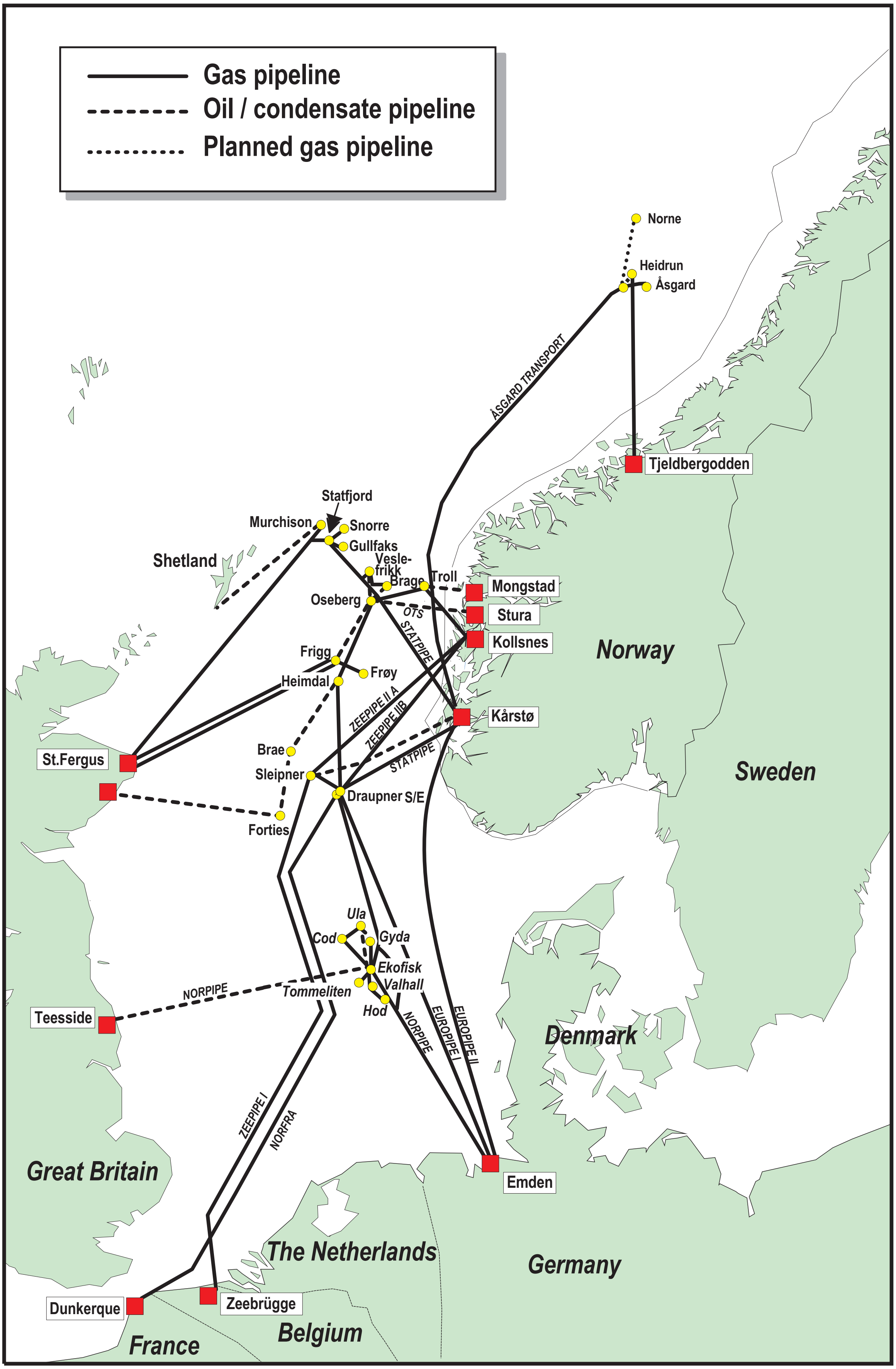
Haltenpipe is a 245 kilometer pipeline with an inner diameter of 381 mm (outer diameter 16") for transportation of gas from Heidrun to Tjeldbergodden. The pipeline has a capacity of 2-2.5 billion Sm^3 per year. The pipeline was put into operation in 1997. The owners are the same as for Heidrun and Statoil is the operator.

Oil transportation, Norpipe

The pipeline system for transportation of oil from the Ekofisk Center to Teesside in England is owned by Norpipe A/S. Norpipe receives oil from the fields in the Ekofisk area and the nearby Valhall, Hod, Ula, Gyda and Tommeliten Gamma fields. The British fields Judy and Joanne are connected to Norpipe and started production in October 1995. In addition, the Fulmar, Clyde, Auk and Gannet fields were tied into the Judy and Joanne pipeline in 1996.

Norpipe A/S is a corporation owned 50/50 by Statoil and the Phillips group. Phillips Petroleum Company Nor-

Figure 1.7.1
Transportation systems for oil and gas from Norwegian fields



way is technical operator of the pipeline, while Statoil is responsible for the economic and administrative functions.

Teesside

The ownership structure for the facilities at the Teesside terminal are split between Norpipe A/S and the Phillips group, through the Norpipe Petroleum UK Ltd. and Norsea Pipeline Ltd. companies. Phillips Petroleum Company UK Ltd. is the operator of the facilities.

Oil transportation, Oseberg Transport System (OTS)

A pipeline for transportation of stabilized oil from Oseberg to the Sture terminal was laid in the summer of 1987. The pipeline has an inner diameter of 670 mm (outer diameter 28") and has a design capacity of approximately 95,000 Sm^3 per day. By adding drag reducers, the capacity has been increased to about 117,000 Sm^3 per day.

The plant, including the Sture terminal, is owned and operated by a separate joint venture, I/S Oseberg Transport System. The participants in the company are the licensees in the Oseberg field. Norsk Hydro is the operator of the pipeline and the terminal. OTS was put into operation when production started from Oseberg. Veslefrikk, Brage, Frøy and Lille-Frigg have subsequently been connected to OTS.

Troll oil pipeline (Troll Oljerør)

Ownership structure:

Den norske stats oljeselskap a.s	74,57600 %
A/S Norske Shell	8,28800 %
Norsk Hydro Produksjon AS	7,68800 %
Saga Petroleum ASA	4,08000 %
Elf Petroleum Norge AS	2,35344 %
Norske Conoco A/S	1,66113 %
Total Norge AS	1,35343 %

Troll oil pipeline transports oil from the Norsk Hydro-operated Troll oil installation to the terminal at Mongstad. The inner diameter is 381 mm (outer diameter 16").

Statoil is the operator of the pipeline which was put into operation in the summer of 1995.

Frostpipe

Ownership structure:

Den norske stats oljeselskap a.s	50,00000 %
Elf Petroleum Norge AS (operatør)	22,00000 %
Total Norge AS	14,25000 %
Norsk Hydro Produksjon AS	13,75000 %

Frostpipe is an approximately 80 kilometer long pipeline with an inner diameter of 374 mm (outer diameter 16") for transportation of stabilized oil and condensate from Frigg to Oseberg. The transportation system has a capacity of about 16,000 Sm^3 per day. Production start was in the spring of 1994.

Sleipner condensate pipeline

Den norske stats oljeselskap a.s (SDFI 29,6 %)	49,60000 %
Norsk Hydro Produksjon AS	10,00000 %
Esso Expl. & Prod. Norway A/S	30,40000 %
Total Norge AS	1,00000 %
Elf Petroleum Norge AS	9,00000 %

Deliveries of condensate from Sleipner Øst started in 1993 and from Sleipner Vest in 1997. The condensate is transported unprocessed through the 245 kilometer long pipeline to the terminal at Kårstø, where it is fractionated into commercial wet gas products and stabile condensate. The pipeline has an inner diameter of 474 mm (outer diameter 20"), and the transport capacity is 32,000 Sm^3 per day. The Storting approved the construction of the pipeline in December 1989.

1.7.2 PROJECTED TRANSPORTATION SYSTEMS

Åsgard Transport

Åsgard Transport will be a 745 kilometer pipeline with an inner diameter of 1016 mm (outer diameter 42") for transportation of gas from Åsgard and other fields on Haltenbanken to Kårstø. The pipeline will have a capacity of 17.5 - 18.5 billion Sm^3 per year. The plan is for the pipeline to commence operations on 1 October 2000.

Ownership structure:

Den norske stats oljeselskap a.s (SDFI 46,9 %)	60,50000 %
Saga Petroleum ASA	7,00000 %
Norsk Agip AS	7,90000 %
Total Norge AS	7,65000 %
Mobil Development Norway AS	7,35000 %
Neste Petroleum AS	7,00000 %
Norsk Hydro Produksjon AS	2,60000 %

Europipe II

Europipe II will be a 653 kilometer pipeline with an inner diameter of 1016 mm (outer diameter 42") for transportation of gas from Kårstø to Emden. The pipeline will have a capacity of 20.8 billion Sm^3 per year and the plan is for the pipeline to commence operations on 1 October 1999.

Ownership structure:

Den norske stats oljeselskap a.s (SDFI 60 %)	60,01000 %
Norsk Hydro Produksjon AS	4,72490 %
Saga Petroleum ASA	10,63090 %
Esso Expl. & Prod. Norway A/S	7,67790 %
Mobil Development Norway AS	1,18120 %
Total Norge AS	5,90610 %
Elf Petroleum Norge AS	0,00590 %
Norsk Agip AS	2,36240 %

A/S Norske Shell	1,18120 %
Neste Petroleum AS	3,66180 %
Norske Conoco A/S	2,65770 %

Statoil is the operator for the development phase. The Ministry will designate the operator for the operations phase at a later date.

Oseberg Gas Transport
Oseberg Gas Transport will be a 108 kilometer pipeline with an inner diameter of 869 mm (outer diameter 36") for transportation of gas from Oseberg to Statpipe at or near Heimdal. A decision on whether to tie the pipeline into the Heimdal installation or directly to Statpipe downstream of Heimdal is scheduled to be made in early 1998. The pipeline will have a capacity of about 14.5 billion Sm^3 per year and planned operations start-up is 1 October 2000. Norsk Hydro is the operator of the pipeline.

Ownership structure

Den norske stats oljeselskap a.s. (SDFI 50,7838 %)	64,78379 %
Norsk Hydro Produksjon AS	13,68190 %
Saga Petroleum ASA	8,55276 %
Elf Petroleum Norge AS	5,76959 %
Mobil Development Norway AS	4,32720 %
Total Norge AS	2,88480 %

Heidrun Gas Transport
Heidrun Gas Transport will be a 37 kilometer pipeline with an inner diameter of 425-525 mm (outer diameter 18-22") for transportation of gas from Heidrun to Åsgard Transport at Åsgard. The pipeline will have a capacity of 4-6 billion Sm^3 per year depending on the diameter selected. The plan is to put the pipeline into operation on 1 October 2000. Statoil is the operator of the pipeline.

Ownership structure

Den norske stats oljeselskap a.s. (SDFI 65,00000 %)	76,87500 %
Norske Conoco A/S	18,12500 %
Neste Petroleum AS	5,00000 %

Norne Gas Transport
Norne Gas Transport will be an 80 kilometer pipeline with an inner diameter of 270-381 mm (outer diameter 12-16") for transportation of gas from Norne to Heidrun Gas Transport. A decision regarding tie-in point will be made in early 1998. The pipeline will have a capacity of 2 billion Sm^3 per year and planned start-up of operations is 1 October 2000. Statoil is the operator of the pipeline.

Ownership structure

Den norske stats oljeselskap a.s (SDFI 55,00000 %)	70,00000 %
Saga Petroleum ASA	9,00000 %
Norsk Hydro Produksjon AS	7,50000 %
Norsk Agip AS	7,50000 %
Enterprise Oil Norwegian AS	6,00000 %

1.8 PETROLEUM ECONOMY

The petroleum makes a significant contribution to the overall creation of wealth in Norway. The sector's share of the gross national product has been approximately 13% in recent years.

The petroleum sector also accounts for a large and increasing share of total exports from Norway. In the beginning of the 1990s, the share was about 33%, while it has been approximately 38% in the two last years.

The petroleum activities lead to employment both off-shore and on land. About 79,600 people were employed in petroleum-related activities in Norway in 1997.

1.8.1 EXPLORATION AND PLANNING ACTIVITIES

In 1997, 50 exploration wells were spudded, while the number of exploration wells in 1996 was 30. 38 wildcat wells and 12 appraisal wells were spudded in 1997. Corresponding figures for 1996 were 21 and 9. On average over the period from 1966-1997, the number of spudded wildcat and appraisal wells has been 20 and 8, respectively.

Figure 1.8.1.a shows the costs of exploration and planning activities from and including 1980. The costs include exploration drilling, general surveys, field evaluations and administration. According to figures reported to the Norwegian Petroleum Directorate, the total exploration costs in the years 1980-1997 amount to approximately 143 billion 1997-NOK.

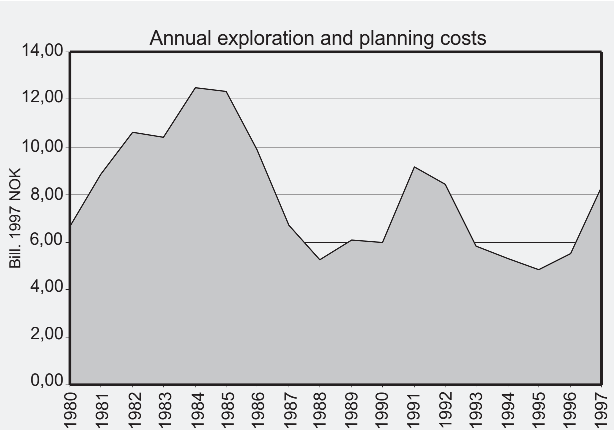
Exploration and planning costs for 1997 divided among the various types of costs are shown below. The figures are based on data reported by the operating companies. The same figures are used as a basis for Figure 1.8.1.b, which shows the percentage distribution of the costs.

Exploration and planning costs	**Million NOK**
Exploration drilling	5349
General surveys	1024
Field evaluations	618
Administration[1]	1336
Total	**8328**

1) Administration costs include area fees.

In 1997, the share of exploration costs related to exploration drilling was 65 percent, while the corresponding figure for 1996 is 50 percent. The share of costs related to general surveys is 12 percent in 1997

Figure 1.8.1.a
Annual exploration and planning costs



compared with 22 percent in 1996. General surveys include inter alia collection of seismic data.

Figure 1.8.1.c shows the average drilling costs per exploration well. In 1997, drilling was carried out at a cost of around NOK 5.3 billion, and the cost per well is estimated to be about NOK 107 billion. This is an increase compared with 1996 when drilling was carried out for about NOK 2.7 billion, which constituted approx. NOK 91 million per well.

Figure 1.8.1.d shows the average drilling costs per day and per meter drilled in the years 1980-1997.

Figure 1.8.1.b
Percentage distribution of the costs

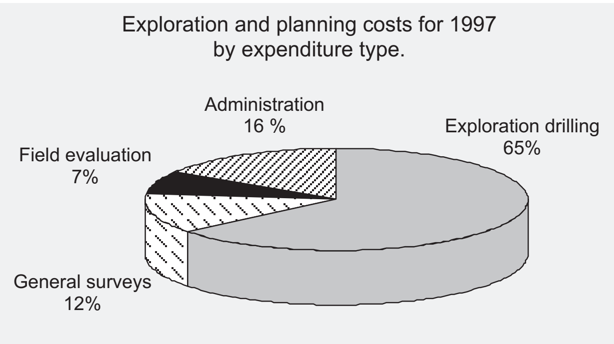


Figure 1.8.1.c
Average drilling cost per exploration well

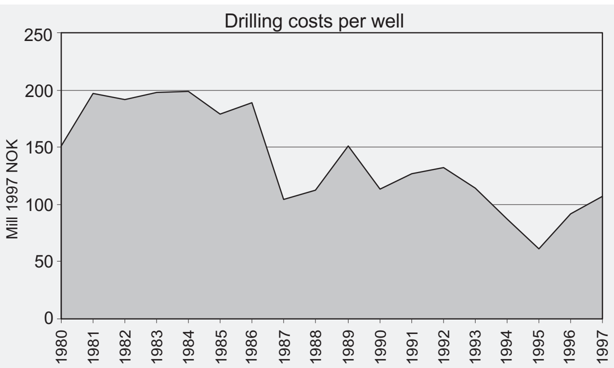
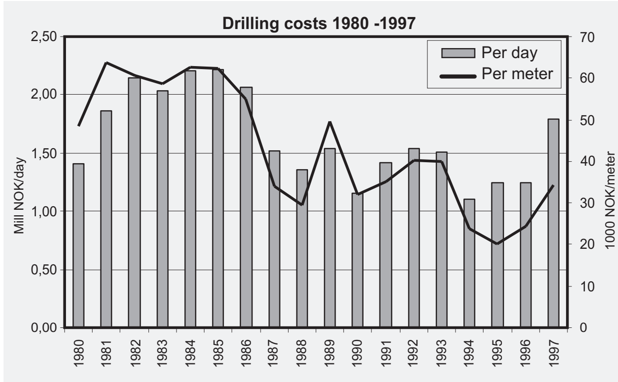


Fig. 1.8.1.d
Average drilling costs per day and per meter drilled in the years 1980 - 1997



1.8.2 THE STATE'S DIRECT FINANCIAL INTEREST

The State's Direct Financial Interest (SDFI) in the petroleum activities was established with effect from 1985. Statoil's ownership interests were then split into a financial interest to Statoil and a direct financial interest to the state. Up until the 14th licensing round, both Statoil and SDFI were normally awarded ownership interests in all production licenses which were awarded. From and including the 15th round, blocks were awarded without SDFI participation. In addition, interests were awarded to SDFI without Statoil receiving corresponding interests. Statoil is responsible for the operational and financial follow-up of the state's direct interest.

An important consideration in the formulation of petroleum policy has been that the state shall collect a significant share of economic rent in the oil activities. SDFI, together with the petroleum taxation system, fees and dividends from Statoil, comprise the state's revenues from the petroleum activities.

The SDFI arrangement entails that the state pays a share of the investments and operating costs in a project corresponding to its interest. In the same way as all other licensees, the state will get its corresponding share of the production and revenues.

As a consequence of significant ownership interests in the vast majority of licenses, SDFI is the largest investor on the Norwegian shelf, and is represented with a considerable volume in the exploration, development and operations phases.

The state's direct investments in petroleum activities in recent years have resulted in high yields. The increase is a consequence of the fact that SDFI is on the way from a build-up to an operational phase. SDFI's net cash flow is expected to increase further in the next few years. Over the long term, SDFI's net cash flow is expected to account for over half of the state's revenues from the petroleum activities.

1.8.3 CRUDE OIL MARKET

Global oil production in 1997 (excluding NGL) is estimated to be about 65 million barrels per day (Source: Oil and Gas Journal (OGJ) December 1997). This corresponds to more than 3.7 billion Sm^3 per year, and means an increase of 2.5 percent from 1996 to 1997. Production from the OPEC countries increased by about 4 percent, or well over the average. OPEC's production in 1997 was thus a scant 27 million barrels per day, compared with a scant 26 million barrels per day for the previous year. The greatest increase was in Iraq. In Eastern Europe and the countries in the former Soviet Union, production increased by a little more than 1 percent, compared with a 1 percent decrease from 1995 to 1996. Other regions, including the North Sea, showed an overall increase in production.

Norwegian oil production was approximately unchanged at more than 3 million barrels per day, accounting for a scant 5 percent of global production in 1997. OPEC's market share was just over 41.5 percent, up 0.5 percent.

According to OGJ, the global proven oil reserves at the end of 1997 were 162 billion Sm^3, approximately unchanged from 1996. The resources constitute 43 years of production at 1997 level. Most countries report unchanged resource estimates as compared with the end of 1996. Based on the resource estimates, the largest oil-producing areas in the future will be OPEC and the Middle East.

At the beginning of 1997, the price of Brent Blend oil was about 24 dollars (USD) per barrel, compared with approximately 18 dollars per barrel in January 1996. The oil price fell during the spring to around 17 dollars in mid-April. The reason for the fall was a strong increase in production of oil and relatively mild weather. High growth in demand and the absence of Iraqi oil export helped to hold the prices between 17-20 dollars up until the autumn, when the oil price once again started to weaken. In December, the price was about 17 dollars. A weakened oil price measured in dollars was partially offset by an increased exchange rate for the dollar.

This meant that the average norm price for Norwegian-produced oil was approximately 19 dollars per barrel; or just over NOK 136. In comparison, the price of Norwegian-produced oil in 1996 was an average of about NOK 135 per barrel (about 21 dollars).

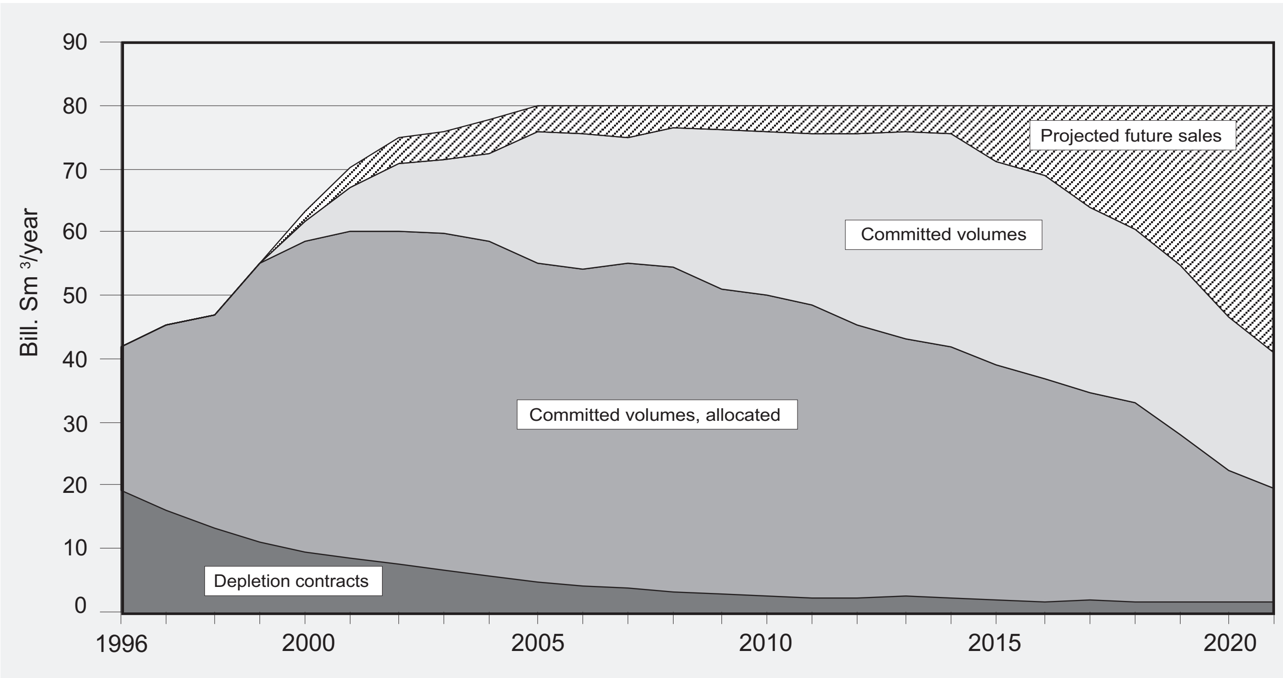
1.8.4 NATURAL GAS MARKET

In 1997, Norway exported gas to the United Kingdom, Germany, the Netherlands, Belgium, France, Spain and Austria and Czechia. Figure 1.8.6.c shows the distribution of gas sales to the various buyer countries.

In 1997, export from Norway constituted 42.3 billion Sm^3, an increase of about 4.2 billion Sm^3 gas compared with the previous year.

The first gas sales were primarily based on depletion of accessible reserves in the individual fields. Norway entered a new era as a gas supplier on 1 October 1993 when deliveries under the Troll agreements (TGSA) got underway. These are sales contracts which offer the customers fixed annual volumes, where also other fields than Troll may provide deliveries. In connection with the Troll agreements, through the establishment of the Troll commercial model, the authorities have established an opportunity for the sale of associated gas and smaller gas fields.

Figure 1.8.4
Committed and projected future gas sales



Organization of Norwegian gas sales

In recent years, the sale of Norwegian gas has been coordinated by a Gas Negotiation Committee (GFU) under the leadership of Statoil, and with participation by Norsk Hydro and Saga. The GFU negotiates contracts with purchasers of Norwegian gas. Other companies have also been involved in the negotiation of certain gas sales contracts. Within the framework of the existing gas organization, the authorities set up the Gas Supply Committee (FU) in 1993. This committee, which consists of the largest resource owners on the Norwegian continental shelf, shall have an advisory role towards the Ministry of Petroleum and Energy in questions related to development and management of gas fields and transportation systems for gas. The Ministry of Petroleum and Energy and the Norwegian Petroleum Directorate participate as observers in the committee.

Existing commitments

Field contracts

The fields which currently deliver under field contracts are Statfjord, Gullfaks, as well as fields in the Frigg and Ekofisk areas. Production from these fields is now in the decline phase, but they will still deliver gas for many years to come. Gas deliveries from the Ekofisk and Frigg areas started in 1977, from Statfjord in 1985, from Heimdal in 1986 and from Gullfaks in 1987. The gas from the Frigg area is delivered to the United Kingdom, while the other fields deliver to buyers on the Continent.

Troll gas sales agreements from 1986 (TGSA)

The TGSA agreements were signed in 1986 between the Troll licensees and buyers on the Continent. The buyer countries are Germany, the Netherlands, Austria, France, Belgium and Spain. At plateau (2005), the Troll agreements comprise 44.7 billion Sm^3 per year, including exercised purchase options.

Newer commitments

In 1992, the Electrabel contract (Belgium) was signed. In 1993, two new contracts were signed for the sale of additional volumes to Ruhrgas and VNG (Germany). The following year, contracts were signed with MEEG (Germany) and GdF (France). In 1995, contracts were signed for additional sales to GdF (France). During the course of 1997, contracts have been signed with the Italian company SNAM and the Czech company Transgas.

Potential new sales

During 1997, negotiations and discussions have been conducted with possible buyers in several countries.

The Norwegian Petroleum Directorate believes that there is a potential that Norway's total gas sales over the long term may reach 80 billion Sm^3 per year. Figure 1.8.4 shows committed and potential new sales. Committed volumes are divided between field contracts, allocated volumes and non-allocated volumes. The Ministry of Petroleum and Energy allocates volumes after consultation with the Norwegian Petroleum Directorate and the Gas Supply Committee.

Use of gas in Norway

In 1995, the Ministry of Petroleum and Energy presented a separate report to the Storting regarding the use of gas in Norway. The Storting report presents the government's objectives and the possibilities for use of natural gas in Norway.

The most important Norwegian gas market is now found on the continental shelf. The largest buyers are Oseberg and Ekofisk. The gas is injected in Oseberg in order to achieve increased oil recovery. Ekofisk buys gas from several fields for fuel. Gas is also the most important source of energy for operation of field and transportation systems. It is primarily gas produced from the field itself which is used for these purposes. In 1997, a total of 22.6 billion Sm^3 gas was used for injection and 3 billion Sm^3 was used as fuel on the shelf. Gas has been landed in Norway since Statpipe began operation in 1985. The gas is landed at Kårstø in northern Rogaland. From 1996, gas has also been landed at Kollsnes (Hordaland) and Tjeldbergodden (Møre og Romsdal).

In February 1992, the Storting approved Heidrun's delivery of approximately 0.7 billion Sm^3 gas per year to a methanol factory at Tjeldbergodden starting in 1996. In northern Rogaland, an agreement has been signed for smaller deliveries to the distribution company Gasnor. All of Gasnor's customers have previously used fuel oil as a source of energy. Deliveries commenced in 1994. The Vestgass company is considering distribution of gas from Kollsnes.

In 1994, Statkraft, Statoil and Norsk Hydro set up a joint company, Naturkraft. In 1996, Naturkraft received a concession for development and operation of two gas power plants and has now applied for a discharge/emission permit from the State Pollution Control Authority. The plan is for the power plants to be established at Kårstø and Kollsnes. Total consumption of gas in the gas power plants will be 0.9 billion Sm^3 gas per year.

1.8.5 SALE OF PETROLEUM FROM THE NORWEGIAN CONTINENTAL SHELF

In 1997, 148.9 million tonnes of crude oil was sold from the Norwegian continental shelf. This represents an increase of 0.5 percent compared with 1996. The United Kingdom was the largest recipient with 19.7 percent of the shipments, the Netherlands received 18.7 percent, Norway 12.4 percent, France 11.6 percent and Germany 5.3 percent. In 1996, Norway received 12.2 percent. Figure 1.8.5.a shows crude oil sales distributed by country in the period 1981-1997.

Up to 1988, Belgium and Canada are included in the group "others". Sale of NGL (including condensate) from the Norwegian continental shelf in 1997 reached 8.3 mil-

Figure 1.8.5.a
Sale of crude oil from the Norwegian continental shelf

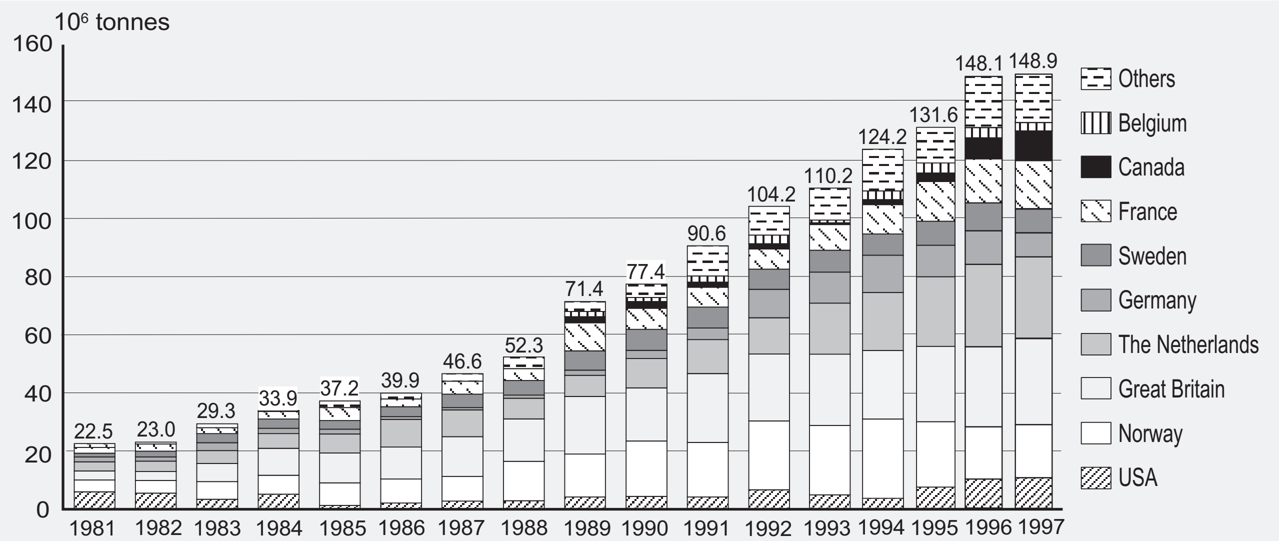


Figure 1.8.5.b
Sales quantities of oil/NGL (excl. condensate) per licensee in 1997

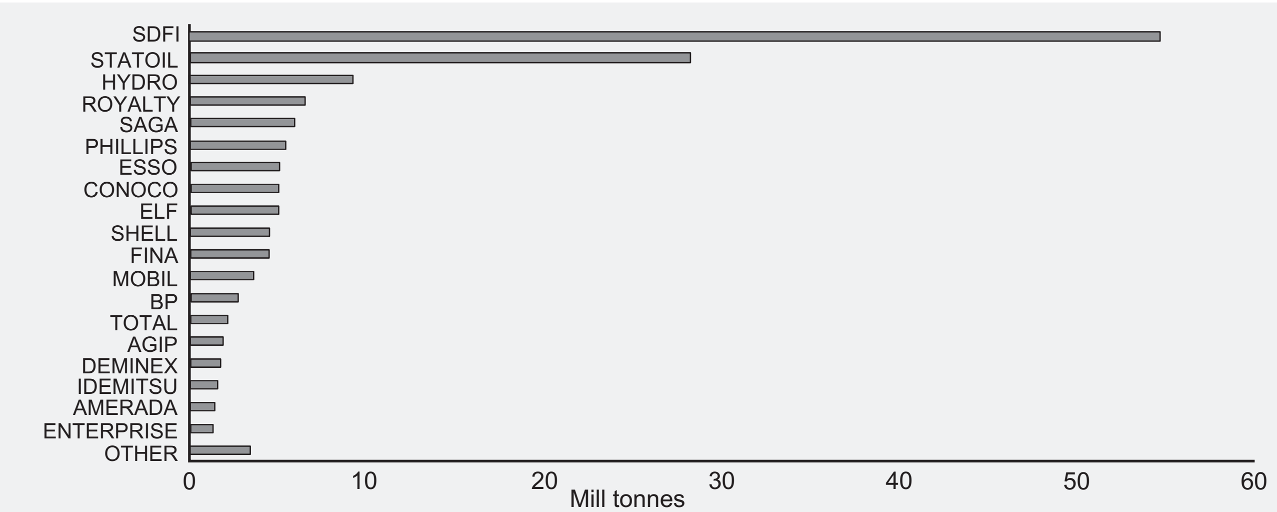
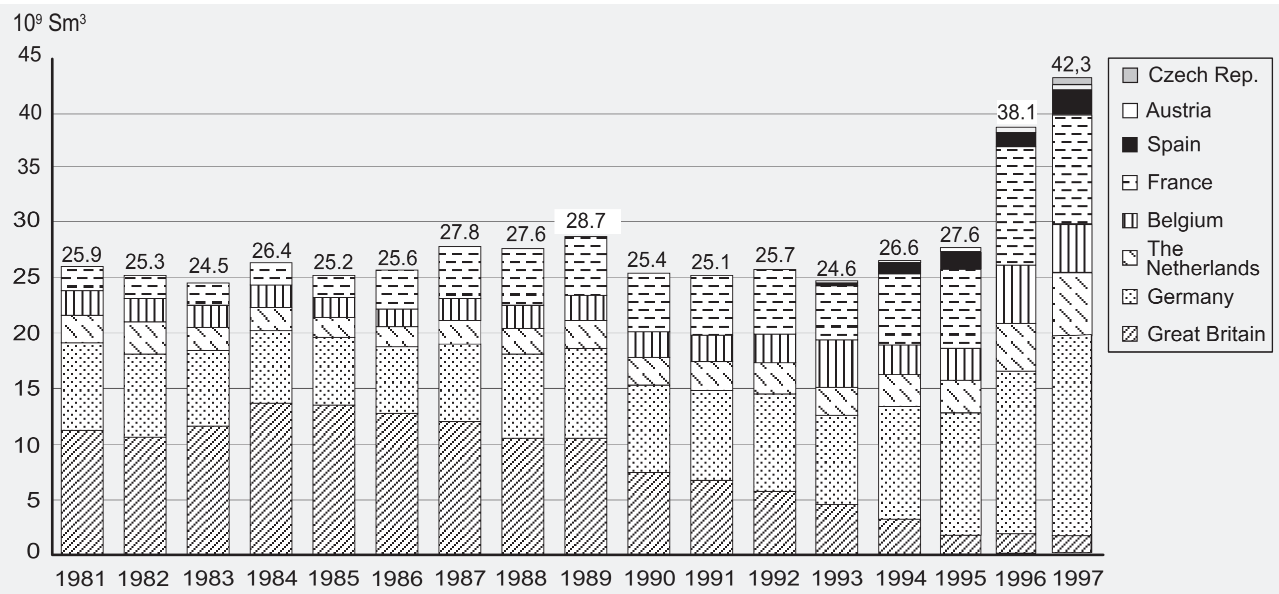


Figure 1.8.5.c
Sales quantities of gas per country



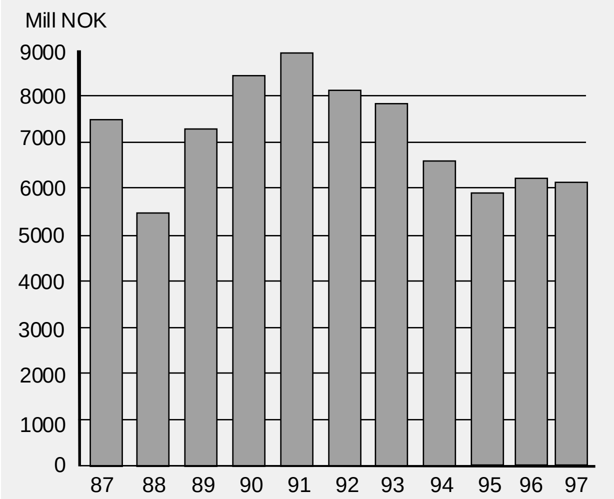
lion tonnes. This is 1.2 million tonnes more than in 1996. Figure 1.8.5.b shows the sale of crude oil and NGL in 1997 distributed by licensees.

Norway exported 42.3 billion Sm^3 gas in 1997. This is an increase of 11 percent compared with 1996. 17.9 billion Sm^3 was sold to Germany, 1.3 billion Sm^3 to the United Kingdom, 10.3 billion Sm^3 to France, 5.6 billion Sm^3 to the Netherlands, 4.2 billion Sm^3 to Belgium, 1.9 billion Sm^3 to Spain, 0.7 billion Sm^3 to Czechia and 0.3 billion Sm^3 to Austria, see Figure 1.8.5.c. Figure 1.8.5.d shows the gas sales distributed by licensees. Sales under the TGSA agreements are divided among the Troll licensees. In the column labeled "others", companies are not specified as this column contains figures from several small fields and it would be very inaccurate to specify them.

1.8.6 ROYALTY

The Norwegian Petroleum Directorate has been delegated the responsibility for collection of royalty from petroleum production. Production royalty is calculated according to the provisions of the Act relating to Petroleum Activities. The formula for calculation of the royalty is the value of the produced petroleum at each production area's loading point. As it is not customary to calculate the price of petroleum products at the loading point, in practice the formula applied is the difference between the gross sales value and the costs incurred between the taxation point and the point of sale.

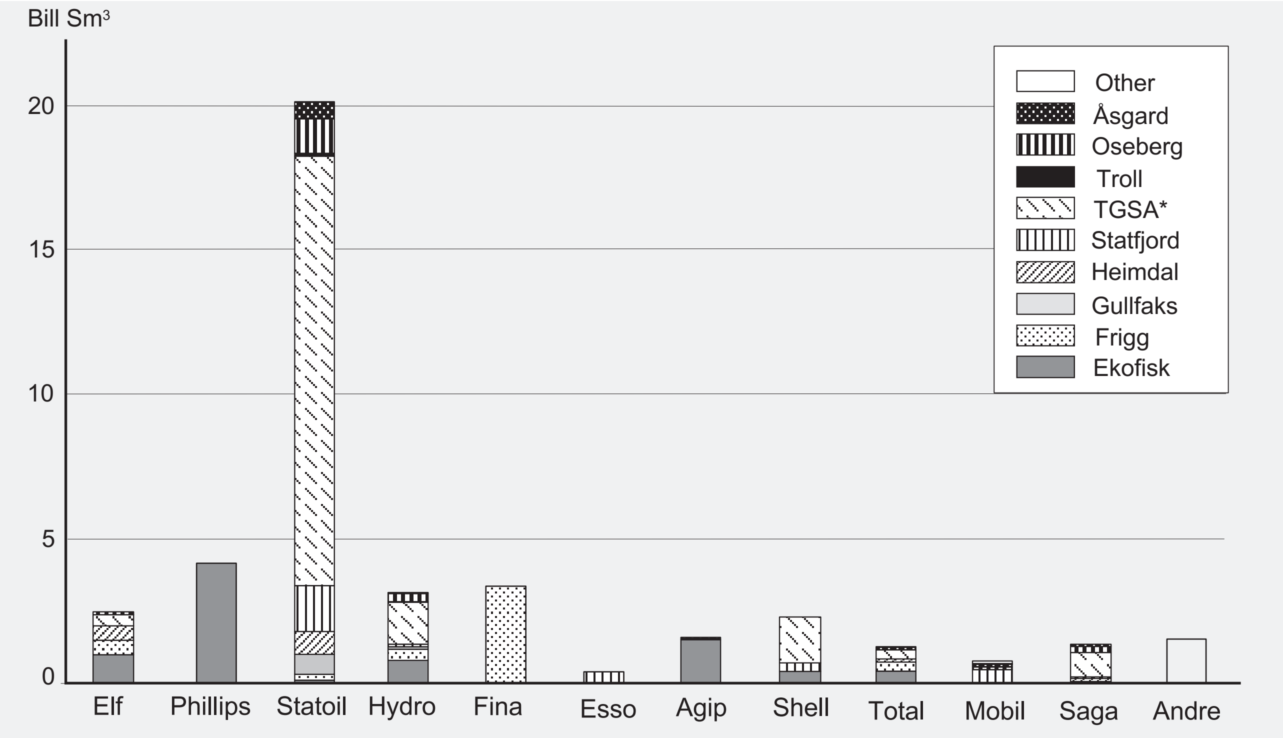
Figure 1.8.6
Royalties paid 1987-1997



No production royalty shall be paid on production from deposits where the development plan is approved or requirements for a plan for development and operation terminate after 1 January 1986, cf. Section 4-9 of the Petroleum Act.

Interpretation and enforcement of the current laws and regulations in connection with calculation of royalties include problems of a legal, economic, processing and metering nature.

Figure 1.8.5.d
Sales quantities of gas per licensee in 1997



* Sales under TGSA are divided between Troll-licensees

Table 1.8.6.a
Royalty paid in 1996 and 1997 (million NOK)

Product	Field/area	1996	1997
Oil	Ekofisk area, Ula and Valhall	1 766.8	1 968.7
"	Statfjord	2 457.6	2 126.7
"	Murchison	13.2	13.6
"	Heimdal	6.2	21.1
"	Oseberg	1 164.9	1 170.2
"	Gullfaks	864.7	882,9
NGL	Ekofisk area	21.5	27.1
"	Valhall	4.3	5.3
"	Ula	1.9	2.0
"	Murchison	0.1	1.1
"	Frigg area	0.0	*1.6
"	Heimdal	0.1	0.0
Total		6 301.3	6 220.3

* Paid royalty for gas for previous years

From 1 January 1992, the royalty rate for gas was set to nil, cf. Section 31 of the Petroleum Regulations. This means that from now on, royalty will only be levied on oil.

Since on some fields oil and NGL are a single product at the loading point, and the NGL is separated at a later stage, then for those fields royalty will be paid on the NGL. On the other hand, royalty will not be levied on NGL in those fields where NGL is part of the gas at the loading point.

Total royalty
In 1997, licensees on the Norwegian shelf paid royalties totaling NOK 6,220,275,813 to the Norwegian Petroleum Directorate. Table 1.8.6.a shows the breakdown for the various petroleum products for 1996 and 1997. Figure 1.8.6 shows paid royalties from 1988-1997.

Royalty on oil
In 1997, NOK 6,183,198,720 was paid in royalties for oil from the Ekofisk area, Ula, Valhall, Statfjord, Murchison, Heimdal, Oseberg and Gullfaks, see Table 1.8.6.b. The royalty on oil is usually taken out in oil, but the Ministry of Petroleum and Energy has determined that the royalty on oil from Heimdal shall be taken out in cash as from 1 April 1993. Sale of the State's royalty oil is the responsibility of Statoil. Payment from Statoil to the Norwegian Petroleum Directorate is on a monthly basis. Settlement is at the norm price stipulated by the Petroleum Price Council. The received quantity of royalty oil has been reduced by about 6.5 percent in 1997 due to lower production from those fields where there is a royalty. However, the royalty for oil has nevertheless only decreased by 1.3 percent compared with the previous year as a consequence of higher oil prices.

Table 1.8.6.b
Royalty paid on oil (NOK)

Field/area	1st half	2nd half	Total 1997
Ekofisk area, Ula and Valhall	883 635 250	1 085 087 625	1 968 722 875
Statfjord	1 039 973 065	1 086 755 647	2 126 728 712
Murchison	5 979 622	7 605 113	13 584 735
Heimdal	10 767 970	10 301 746	21 069 716
Oseberg	561 803 820	608 349 953	1 170 153 773
Gullfaks	474 955 829	407 983 080	882 938 909
TOTAL	2 977 115 556	3 206 083 164	6 183 198 720

Figure 1.8.7.a
Area fees 1973-1997

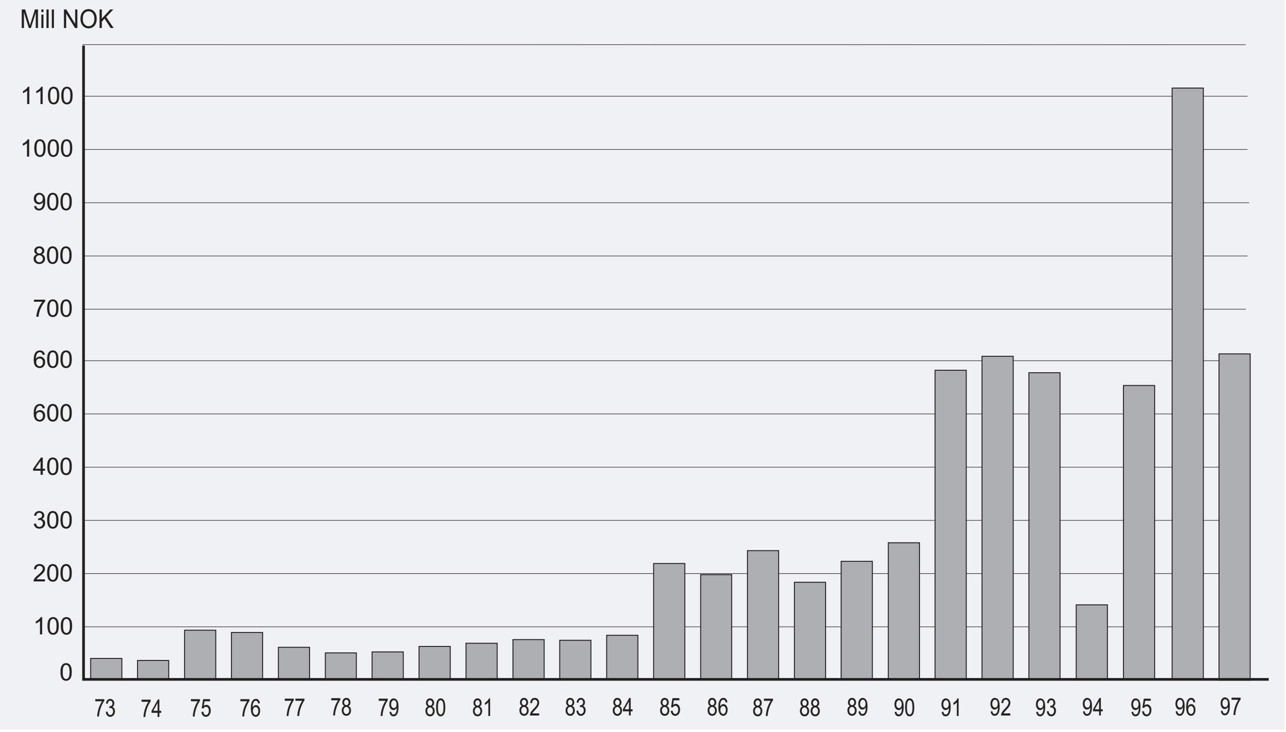


Table 1.8.6.c
Royalty paid on NGL (NOK)

Field/area	1st half	2nd half	Total 1997
Ekofisk area			
Phillips group	14 453 941	12 449 901	26 903 842
Amoco group (Tor)	21 601	93 031	114 632
Dyno/Methanor	59 110		59 110
Total Ekofisk area	**14 534 652**	**12 542 932**	**27 077 584**
Valhall	2 559 782	2 742 777	5 302 559
Ula	1 112 112	852 279	1 964 391
Murchison	35 445	1 079 541	1 114 986
Frigg area	1 617 573		1 617 573
Total all fields	**19 859 564**	**17 217 529**	**37 077 093**

Royalty on NGL
In 1997, NOK 37,077,093 has been paid in royalties on NGL. Table 1.8.6.c shows payments divided semi-annually per company/group.

Settlement of royalties paid in cash is on a six month basis, with a three month term for payment. The settlement for NGL has been made at contract prices which vary for the individual fields/groups.

Deliveries of gas to Dyno/Methanor ceased effective 1 July 1984. The receipts from Dyno/Methanor are related to the transportation and processing of gas already received and paid for.

There is an increase in the paid royalty on NGL from 1996 to 1997 of nearly 33 percent.

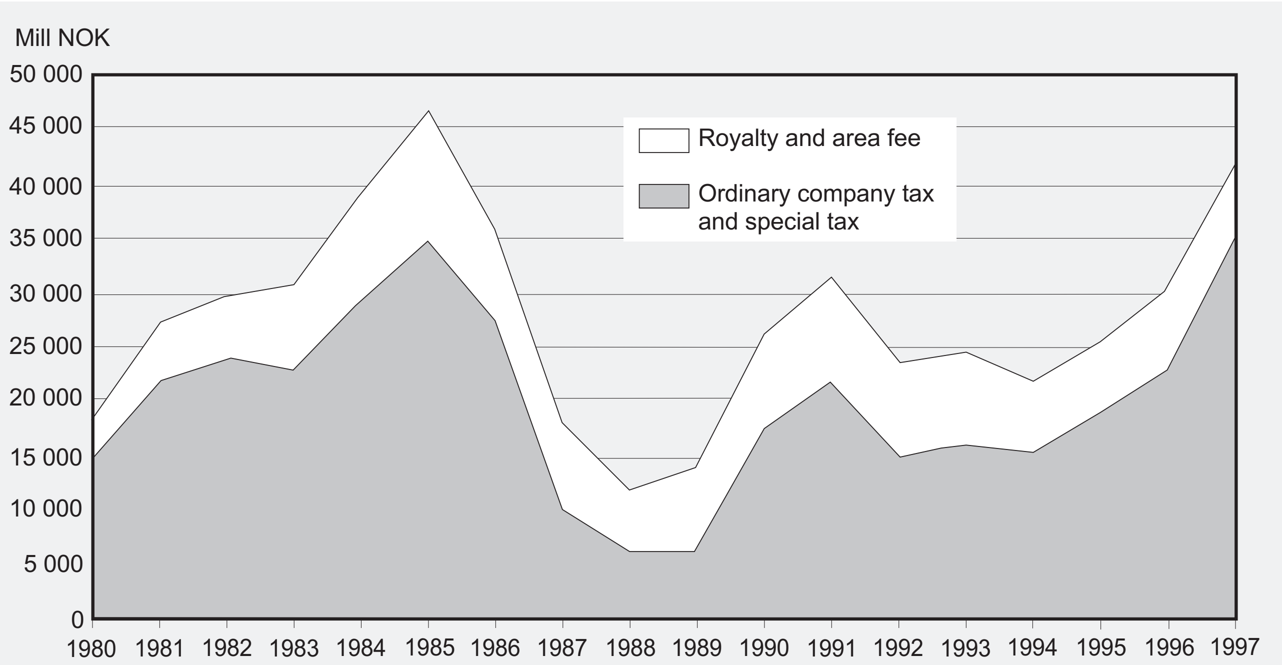
1.8.7 AREA FEES ON PRODUCTION LICENSES
In 1997, the Norwegian Petroleum Directorate collected NOK 719,881,749 in area fees. The amount is broken down among production licenses as shown in Table 1.8.7.

The Norwegian Petroleum Directorate has refunded

Table 1.8.7
Area fees in production licenses

Production licenses awarded	NOK
1965	91 929 962
1969	52 821 000
1971	4 137 000
1973	35 478 000
1975	4 981 500
1976	73 872 000
1977	35 990 704
1978	42 403 500
1979	133 407 000
1981	57 657 836
1982	34 739 873
1984	30 348 116
1985	31 504 206
1986	11 404 415
1987	8 557 326
1988	21 375 370
1989	8 895 000
1991	40 378 941
Total	**719 881 749**

Figure 1.8.7.b
Total taxes and royalties



NOK 102,817,730 in area fees in 1997. This represents the deductible portion of the area fee in the royalty settlement for production licenses 006, 018, 019A, 033, 037, 050, 053 and 079.

Figure 1.8.7.a shows the net area fee receipts for 1974-1997. For 1997, there was a reduction of more than NOK 500 million compared with 1996. The reason for this is that in 1997 there have only been payments for 1998, while in 1996 there were payments for both 1996 and 1997. Production royalties and area fees in 1997 accounted for 16 percent of the total taxes and fees paid from the petroleum activities. The proportion of the fees has varied over time. The highest proportion was in 1989 at 53%.

1.8.8 CARBON DIOXIDE TAX

The Act of 21 December 1990 No. 72 relating to tax on discharge of CO_2 in the petroleum activities on the continental shelf entered into force on 1 January 1991. The Norwegian Petroleum Directorate is given the authority to collect the CO_2 tax and to make administrative decisions necessary to enforce the law. The tax is calculated on petroleum flared and natural gas or pure CO_2 released to the atmosphere from installations used in connection with production or transportation of petroleum. This tax is also levied on Norwegian systems for transportation of petroleum which extend beyond the continental shelf. For fields which extend over the median line in relation to another state, the CO_2 tax is only calculated on the Norwegian share.

In 1996 and 1997, the CO_2 tax was fixed at NOK 0.85 and 0.87 per Sm^3 gas and NOK 0.85 and 0.87 per liter diesel, respectively. The tax, payable on a six month basis with three months' due date (at 1 October and 1 April in the following year), is levied on the operators of the individual fields and installations. Table 1.8.8 shows the total tax paid in 1997. The tax is broken down by the individual fields and transportation systems. Corrections relating to previous six month periods are included. A total of NOK 3,043,371,370 was paid in 1997.

Table 1.8.8
CO_2 tax paid in 1997 (NOK)

Field:	1st half	2nd half	Total 1997
Ekofisk area	357 876 826	356 115 241	713 992 067
Frigg area	12 217 539	9 469 674	21 687 213
Gullfaks A+B+C	157 563 816	176 190 964	333 754 780
Yme	39 780 047	24 317 097	64 097 144
Gyda	16 317 135	16 481 088	32 798 223
Heimdal	24 464 183	23 140 716	47 604 899
Hod	70 210	69 339	139 549
Murchison	9 494 844	13 535 421	23 030 265
Oseberg A+B+C	152 582 492	146 806 410	299 388 902
Brage	32 787 900	32 665 020	65 452 920
Sleipner	109 771 084	143 287 050	253 058 134
Statfjord A+B+C	222 836 138	237 007 139	459 843 277
Ula	23 684 232	22 288 344	45 972 576
Valhall	39 167 378	42 464 921	81 632 299
Veslefrikk	27 297 435	28 517 083	55 814 518
Snorre	49 334 577	69 183 441	118 518 018
Draugen	24 410 498	28 343 709	52 754 207
Troll A	1 502 735	626 267	2 129 002
Troll B	37 915 356	37 058 520	74 973 876
Heidrun	64 512 152	70 998 012	135 510 164
Transport systems:			
Norpipe	68 993 779	86 080 432	155 074 211
Statpipe	3 310 849	2 834 277	6 145 126
Total	**1 475 891 205**	**1 567 480 165**	**3 043 371 370**

2. Safety and working environment administration

The Norwegian Petroleum Directorate aims at providing continuity, systematism and a long-term perspective in the supervision of safety and working environment. In order to achieve this, the Directorate seeks to form an image of the development trends in this area over time, both in the industry as a whole and in the individual company. In areas where the development is not as expected, the Norwegian Petroleum Directorate can then prioritize measures vis-à-vis the industry as a whole, directed towards the licensees in a production license or towards an individual operating company.

The Norwegian Petroleum Directorate's performance of its administrative duties in the petroleum activities is based on a comprehensive management of safety, working environment and resources. The Norwegian Petroleum Directorate has a coordinating role in relation to other public authorities which have individual supervisory responsibility under the Petroleum Act. Furthermore, the Directorate draws upon expert assistance in areas where it has no expertise of its own.

Administration of safety and the working environment is based on the principle of the industry's control over its own activities. This assumes that regulations and supervision are designed and implemented in a way which supports the participants' perception of their responsibility to ensure prudent operations in accordance with the formal framework related to petroleum activities.

This principle means that the supervision is directed at the industry's obligation to carry out internal control, that is, the Norwegian Petroleum Directorate's supervisory activities are first and foremost aimed at the licensees' control systems and decision-making processes which have significance for safety and the working environment.

The supervision thus has its point of departure in the companies' own ambitions for further development of the level of safety and working environment, as these are expressed in the companies' action and supervision plans. Through its supervision work, the Norwegian Petroleum Directorate tries to stimulate improvement processes in the companies, as well as to evaluate the companies' ability to manage their activities in accordance with the authorities' and the company's own requirements and ambitions.

Internationalization, vulnerability to competition and low oil prices for an extended period of time, have led to increased demands on cost-effectiveness in connection with development and operations. The technological and organizational development has contributed to making it possible to meet these demands, while simultaneously creating opportunities for exploration and development in new, demanding areas. The development nonetheless represents a number of challenges for the industry, not least in the authorities' exercise of the management tasks connected with safety and the working environment.

2.1 THE SITUATION ON THE MARKET FOR DRILLING INSTALLATIONS - CONSEQUENCES FOR SAFETY AND THE WORKING ENVIRONMENT

2.1.1 STOPPING OF DRILLING INSTALLATIONS

During 1997, the Norwegian Petroleum Directorate has formally intervened in the activities on two mobile drilling installations. The operators that had contracts with the relevant companies were ordered to submit new applications for consent for exploration drilling with these installations. In practice, this means that the activities are halted until the unacceptable conditions have been rectified.

The Norwegian Petroleum Directorate's decisions in these cases have been based on an overall evaluation where the sum of a number of blameworthy conditions - of which some were regarded as being serious - has led to the conclusion that the preconditions for the original consent were not fulfilled.

These conditions included:

- poor maintenance, both with regard to management planning and the actual execution,
- deficient safety precautions in connection with the performance of critical work (permits for hot work, safe job analyses, work over the open sea, etc.),
- deficient follow-up of orders from the Norwegian Petroleum Directorate,
- little knowledge concerning existing deviations from the regulations and internal company requirements.

With regard to mobile installations, the development appears to reflect the industry paradox that when times are good, the industry *does not have time* to carry out proper maintenance, while when times are bad, the industry *does not have the money.* The operating companies' processes for qualification of installations must improve. There are no formal requirements in the regulations which exclude installations over a certain age. Nevertheless, the Norwegian Petroleum Directorate believes that the companies must become more aware of the costs connected with upgrading, maintenance, etc., and include these in the total costing. Experience has shown that a unilateral focus on low daily rates can result in poor overall economy.

2.1.2 DRILLING IN DEEP WATER

During 1997, three exploration wells have been drilled in deep water - from 889 to 1274 meters. Two of the drillings were carried out without problems which were specially related to the water depth. During the third drilling, some problems occurred during installation of the wellhead. The operator had chosen wellhead equipment which the operator and the drilling contractor were not very familiar with.

The three wells were drilled from a foreign installation which is specially equipped for drilling in deep water, and with a drilling contractor that has considerable experience with deep water drilling. Before the installation was put into use on the Norwegian shelf, it was upgraded inter alia with regard to Norwegian regulatory requirements, primarily the requirement for automatic handling of drill pipe.

In addition, a number of deviations from the regulations were identified where the Norwegian Petroleum Directorate found that exemptions could be granted. A significant number of these deviations have been corrected during the period. The remaining deviations are of lesser significance with regard to safety, and the costs of upgrading to achieve compliance with the regulations are too high compared with the utility value of the upgrade.

The installation is equipped with a dynamic positioning unit with capabilities which indicate a so-called equipment class 2. The Norwegian Petroleum Directorate assesses this type of operation such that the regulatory requirements mean that the unit must be in equipment class 3. After a careful evaluation, the Norwegian Petroleum Directorate found that it could exempt from this requirement. However, conditions regarding compensatory measures were made in the decision concerning the exemption.

The Norwegian Petroleum Directorate has indicated vis-à-vis the industry that deviations from the requirement for equipment class 3 may be assumed for a transition period equivalent to the drilling of five wells by this drilling installation, assuming that necessary compensatory measures, adapted to the individual activity, are implemented until the deviation has been permanently corrected. The owner of the installation has therefore prepared a plan for implementation of corrective measures which will entail an increase of the overall safety level on the installation. The individual operator that is responsible for the relevant drilling must ensure that these measures are implemented in accordance with this plan.

2.1.3 WORKING ENVIRONMENT ON MOBILE INSTALLATIONS

As a part of its ongoing supervision, the Norwegian Petroleum Directorate has also in 1997 examined the status of compliance with the *regulations relating to systematic follow-up of the working environment in the petroleum activities*, with particular emphasis on the conditions on mobile installations. In general, the Norwegian Petroleum Directorate notes that the industry is now familiar with the regulations, which took effect in 1995. The companies concerned have largely established satisfactory systems in order to comply with the requirements in the regulations.

The goals which the companies establish for the working environment are appropriate to navigate by, and they can be realized. In this work, working environment programs are prepared based on the results of surveys of the working environment.

The Norwegian Petroleum Directorate has, however, noted that there is not always concurrence between the resources which are spent on surveying the working environment and the resources which are allocated for implementation of measures. In its supervision, the Norwegian Petroleum Directorate has therefore focused on how the companies follow up the surveys which have been conducted with concrete measures, which measures have been given priority, what resources have been made available, who is responsible for following up, and what deadlines have been set for implementing the measures.

2.1.4 CAPACITY AND COMPETENCE

Generally speaking, the number of assignments in the petroleum activities on the Norwegian shelf have increased more than the supply of labor. This has created increasing challenges related to employees' competence and capacity. The Norwegian Petroleum Directorate has registered a number of somewhat worrisome effects of this development with significance for safety and the working environment.

- Working hours regulations are exploited more and more to the maximum limits allowed by law
- The number of applications for extended stays has increased
- A larger number of foreign employees has led to language problems
- As a consequence of increasing work pressure, line managers do not have enough time for line follow-up of the working environment
- The safety delegate cannot perform his/her function within normal working hours, and must use overtime for this.

On the whole, the Norwegian Petroleum Directorate is satisfied with the companies' control of the daily working hours and overtime on the individual installations.

2.1.5 NOISE

Noise is the working environment factor which has proven to be the most difficult to improve on mobile installations. The problem is greatest on older installations, which often have a lot of noisy equipment integrated into the actual structure of the installations. Noise is also still a pervasive problem on permanent installations. Hearing injuries can only be prevented, because injuries caused by noise are permanent and therefore cannot be cured.

In 1997, the Norwegian Petroleum Directorate approached the industry to obtain a status regarding noise and in order to see what opportunities were available for additional technical improvement measures on the individual installations.

It proved to be the case that most of the companies have prepared noise requirements by areas, and have carried out surveys of the noise conditions. Most of the companies have worked on identifying deviations from regulatory requirements. Some of the companies are working on surveying the extent to which the employees are exposed to noise, and are planning new surveys.

Many companies have implemented measures in the form of campaigns, procedures for the use of ear protection and reviews of marking of noisy areas. However, it appears that both operating companies and contractors provide little follow-up with technical and financial evaluations, prioritization of technical measures to fight noise and implementation of such measures on installations during the operations phase. Therefore, in 1998 the Norwegian Petroleum Directorate will carry out supervision with regard to how the industry follows up identified deviations and prioritizes and implements technical measures to fight noise.

2.2 EARLY PREPARATIONS FOR DRILLING ACTIVITIES

In 1997, the Norwegian Petroleum Directorate has put the spotlight on the operating companies' safeguarding of safety and working environment during preparations for both traditional drilling activities and more unusual activities, for example, drilling in deep water and in particularly sensitive environmental areas. The supervision has included both long-term collaborations between operator/vessel owner and more temporary cooperation constellations.

After this supervision, the Norwegian Petroleum Directorate has concluded that the operating companies have a potential for improvement with regard to

- understanding of how binding an application for consent is for the company,
- concurrence between information which emerges in the application for consent and the actual technical condition on the installations,
- clarity in the distribution of tasks between the various participants with regard to verifications, overview of deviations from the regulations and follow-up of these deviations,
- observance of deadlines for complying with orders from the flag country authorities or classification society,
- understanding that deviations from maritime regulations may also entail deviations from the shelf regulations and must be treated as such,
- translation of results from risk and preparedness analyses into practice,
- maintenance of mobile installations, particularly installations which have not operated on the Norwegian shelf for a period of time,
- follow-up of the authorities' orders and of observations made during own supervision,
- the culture of the individual vessel owner with regard to management and prioritization of safety conditions.

The supervision has, however, also shown that improvements have been achieved on a number of points. The positive experiences the Norwegian Petroleum Directorate has had with regard to the companies' preparations for drilling activities include:

- The quality of the applications for consent has generally improved. This improvement is clearer for some of the operators than for others. Some of the improvements noted in the applications reflect a real improvement in the companies' preparation and control of the upcoming activities.
- The Norwegian Petroleum Directorate has noted that there is better communication in connection with changes, for example in relation to deadlines for correction of deviations.
- The Directorate has observed a more systematic follow-up of deviations and updating of deviation lists as the deviations are rectified.
- Some of the companies have prepared risk analysis methods for work in this phase, and work has been initiated to clarify and reinforce internal requirements for risk analysis and preparedness analysis, and for coordination with the vessel owner's risk analysis in this connection.
- The operators have intensified their own supervision towards the vessel owners and their service suppliers. The operators' drilling departments are also subject to more supervision from higher levels in the company. Some operators have intensified the supervision towards the support apparatus for the drilling departments and have allocated more resources. Some companies have revised acceptance procedures and contract terms with vessel owners.
- The use of a consortium for installations ("pool" system) has led to better cooperation, more continuity in the supervision and better exchange of experience between the operators.
- The efforts vis-à-vis applications for consent prior to drilling operations have also had a positive effect on the quality of other types of applications for consent from some operators.
- The Norwegian Petroleum Directorate's increased efforts in the supervision of mobile installations has meant that, in certain instances, the Directorate has carefully followed up operators that have taken over an installation after it had been in the service of another operator for a lengthy time period. Those operators that have conducted thorough evaluations have likely uncovered deviations from the regulations which have previously been overlooked, or which in any event the authorities were not aware of.

2.3 SAFETY AND WORKING ENVIRONMENT TOWARDS THE END OF THE OPERATIONS PHASE

An increasing number of installations are in or approaching the end of their production phase. In this phase, the operating companies have a particular motive for trying to minimize the operating costs, and thereby extend the profitable operations. This provides an increased exploitation of resources, which conforms with a central principle in the management of the Norwegian petroleum resources. However, this development means that both installations and equipment are often used beyond the original planned lifetime. Therefore, in 1997 the Norwegian Petroleum Directorate has prioritized supervision to ensure that safety and working environment are properly maintained in this phase.

Through the supervision, the Directorate has registered several positive development trends in the companies' management of their activities in this phase, for example:

- The supervision appears to have contributed to the industry itself giving increased attention to maintenance.
- Management in the companies is getting involved to a greater degree in the preparation and implementation of maintenance strategies.
- The companies have implemented various improvement and development projects in the area of maintenance and maintenance management.
- "Basis study - maintenance management", which is a methodology for comprehensive and systematic evaluation of the company's own management system for safety-related maintenance, has been tested by four operators in 1997. So far, the project has gained positive attention in the industry.
- Several operating companies with challenges related to aging installations have become better at developing and utilizing the risk analyses as an active tool for control of various types of risk in the operations phase.

2.4 NEW ORGANIZATION AND COOPERATION MODELS

In order to meet demands for profitability, the industry has increasingly implemented organizational changes and adjustments so as to achieve more efficient development and operations. New development projects have ambitious plans with regard to implementation time and economy. New project implementation models have been put into use which are characterized by new contract and collaboration forms between operator and contractor, as well as a greater degree of parallel activities.

Up to this time, all of the operating companies on the Norwegian shelf, with the exception of one, have been designated from among the licensees. The petroleum legislation, however, grants the Ministry of Petroleum and Energy the power to appoint an operator that is not among the licensees. Such solutions may be relevant for development and operation of smaller discoveries, and possibly also for the final stage of the production phase on larger fields.

It is particularly solutions which entail use of mobile production installations that could make it relevant for others than licensees to be the operator, for example, vessel owners/owners of mobile installations, contracting companies and/or groups of such companies.

To the extent it becomes relevant to use this opportunity in the petroleum activities on the Norwegian shelf, such an applicant for operatorship will be subject to the same requirements as to competence, capacity, etc. as for operators which are designated in the traditional manner from among the licensees in the particular production license. The scope of and the priorities for the authorities' supervision are based on the operating companies having established the necessary management systems so that they themselves can assure prudent operations in all phases, without any form of detailed management on the part of the authorities. Other companies/constellations than pure oil companies must therefore be able to present satisfactory management systems in order to take care of their obligations according to the regulations in a comprehensive manner.

Changes which may have significance for safety and working environment take place on all organizational levels. Most operating companies have carried out or are planning adjustments which will include the entire organization, in other words, both on land and on the installations on the shelf. In other companies, it is largely the organizations on board the installations which are experiencing changes, for example through the changing of systems and routines for operations and maintenance. The least comprehensive changes, which may nevertheless have great consequences with regard to safety and working environment, may be related, i.e., to reductions in manning within various professional groups on the installations, and changing or discontinuation of individual positions or functions.

Typical development trends in connection with organizational adjustments are:

- The organizations are changing from traditional, hierarchical line organizations to flatter organization forms with extensive use of project groups,
- The organizational units are changed from function-oriented departments to inter-disciplinary groups,
- The individual's work tasks are changed from being specialized to being inter-disciplinary,
- The nature of the work is characterized by larger and more comprehensive tasks,
- The managers' span of control increases - the role is changed from "supervisor" to "team leader",
- The employees' work situation changes from being guided and controlled to being informed and empowered.

Generally, such a development can be positive for the individual's safety and working environment. This depends, however, upon the companies, the employee organizations and the authorities all getting involved in how to secure continuity in the work on creating and further developing safety and working environment.

The safety delegate service and the unions represent two different channels within the companies' decision-making systems. A lack of knowledge regarding the roles and tasks the two systems encompass may create frustration and cooperation problems between the parties and in relation to the authorities.

The authorities' role in the work to develop good cooperative relationships is to contribute guidance and by exercising control through the supervision activities. This is done inter alia by contributing to the development of expertise among the parties, by providing for exchange of experience, and through meetings. The Norwegian Petroleum Directorate's experience is that operating companies that have established good cooperative relationships have a better chance of carrying out change processes with constructive contribution from both parties, thereby achieving good results.

There is also an ongoing development whereby the operating companies analyze their own activities with a view towards separating certain services from their own organization, and then purchasing similar services based on the need at any given time. The intention of such changes is partly to achieve savings through more simplified adjustments of the manning level to the current activity level, and is partly based on a general trend in the direction of cultivating the company's primary activity, which is producing and selling oil and gas.

This means that the companies increasingly outsource peripheral services in relation to the primary activity, such as health services, catering, etc., and to some extent also more technical activities, such as in the field of maintenance.

The petroleum legislation requires that every participant in the petroleum activities has an independent responsibility for complying with acts and regulations relating to safety and working environment. However, the regulations place a special obligation on the operating company to follow up and check that everyone who participates in the activities, which the operator has the paramount responsibility for, is competent and qualified to perform the relevant services in a prudent manner. Such control must be carried out both before and during contract signing and during the implementation of the activities.

The development may imply increased use of resources for the supervision authorities in that there will be a larger number of participants to deal with in connection with exercising supervision. The bulk of the supervision activities will continue to be aimed at the operator, who bears the primary responsibility for the activities. Follow-up of the suppliers of goods and services will, however, be carried out in order to verify that the operator places adequate demands on the services and that these are fulfilled.

A common characteristic of the outlined development, both in the development and operations phases, is that it is largely based on expectations as opposed to being based on experience. Untried organization forms, new forms of cooperation between operating companies and between operator and contractor, while simultaneously testing new technology, demands goal-oriented efforts in the authorities' overall supervision of resource management as well as for safety and working environment.

2.4.1 EMPLOYEE PARTICIPATION

During the course of the year, the Norwegian Petroleum Directorate has received complaints from employees because they have not been involved in the change processes as stipulated in the regulations. After having investigated the matters, the Norwegian Petroleum Directorate has upheld the employees' complaints in some of the cases and has ordered the employers to change their way of working in such processes.

There have also been some cases where a safety delegate, chief safety delegate and employee's representatives have considered resigning from their offices due to a poor climate of cooperation. In these cases, the Norwegian Petroleum Directorate has reminded the parties that the safety delegate and chief safety delegate cannot simply resign from their offices, as employees have an obligation to assume these functions. However, the Norwegian Petroleum Directorate is concerned that, in some companies, it appears to be a burden to take on these offices. During 1997, the Directorate has had several meetings with the parties in order to discuss how the employer can organize matters so that the delegate functions required by law may become more attractive for the employees to take on, thereby enabling them to function better.

2.5 MOBILE PRODUCTION INSTALLATIONS - THE OPERATORS' MANAGEMENT IN THE PROJECT PHASE

During 1997, the Norwegian Petroleum Directorate has prioritized supervision of the operating companies' management of projects which entail planning and construction of mobile production installations.

The Norwegian Petroleum Directorate has noted that parts of the industry claim that the shelf regulations increase costs and are not very predictable. This is in contrast to the fact that the industry as a whole supports the principles in the regulations through the established cooperation on regulatory development.

A closer inspection reveals that, in most cases, the dissatisfaction is related to lack of knowledge and understanding of the requirements of the shelf regulations.

In this context, it has also been proven that both the operating companies and other involved participants often have an ambiguous understanding of the role and responsibility of the classification societies in relation to mobile production installations.

The complexity of the development projects, as well as the number of participants in these may, in some cases, lead to ambiguities in the understanding of where the responsibility lies.

The short project implementation times, which inter alia entail a high degree of parallel activities, have in some cases led to the results from risk and preparedness analyses not being available early enough to influence key decisions which have significance for safety and working environment.

There is now a trend on the part of several operators to depart from the current practice with regard to system supervision and quality assurance in favor of more traditional methods of quality control. System-oriented supervision is replaced to some extent by traditional inspections, as well as a closer follow-up on the construction sites and of the contractors. The construction site teams now have much higher manning levels than what has been common in a more system-oriented supervision. The Norwegian Petroleum Directorate views this development as a necessary adjustment based on some experience gained by the operating companies which shows that certain parts of the contractor industry are not yet fully prepared to deliver the desired quality within a framework of functional requirements.

Tight schedules and low manning in the projects appear to result in the companies often falling behind in their preparations. Lack of operational experience from such projects on the Norwegian shelf also represent significant challenges, combined with the introduction of new participants and thereby also new models for operation and cooperation. For example, cooperation problems often arise due to a "collision of cultures" between maritime personnel and personnel with experience from work on permanent installations.

The quality of the work performed and the technical condition of the installations which are built have in many cases created difficulties for the industry. Qualification and use of new materials have also proven to be a challenge with these participants. It has been necessary to make comprehensive modifications and repairs because the installations have neither satisfied government requirements nor the company's own requirements.

As a consequence of this, several projects have experienced cost overruns, some of these substantial. This is partly due to the actual cost of the improvement work, and partly to the resulting delay in the projects in relation to the original plans, so that production start-up has been postponed.

The Norwegian Petroleum Directorate's supervision in this area has, however, also shown several positive development trends, such as:

- Improved transfer of experience has been observed between the participants, particularly the Norwegian participants, that have development projects which are covered under the supervision in this commitment area.
- It has been noted that the operators have improved the focus on their own supervision and that this is more in concurrence with the authorities' perception of what should be prioritized.
- The industry shows a clearer understanding of the classification society's limited role and responsibility in relation to the petroleum regulations' application for mobile installations in the petroleum activities.
- The operators and the industry in general have reported the utility value of the authorities' supervision.

Several installations for floating production are being planned and built with a view towards possible assignments on the Norwegian shelf, although the owners have not entered into contracts with operating companies concerning specific application. These have not been subject to supervision activities on the part of the Norwegian Petroleum Directorate. The Directorate has, however, had a number of meetings with the vessel owners, owners and builders of such installations, where explanations have been given of the main principles of regulatory application, and of the main features in the regulations and the supervision system. In addition, certain technical issues have been discussed on a general basis.

2.6 CHANGE OF OPERATOR ON HEIMDAL

The Norwegian Petroleum Directorate has carried out supervision of how safety and the working environment have been safeguarded during the preparations for the change of operator on Heimdal. Norsk Hydro took over the operatorship from Elf on 1 January 1998.

There has been good cooperation between the authorities, the companies and the employees who are affected by the change. The entire crew on the installation has been employed by Norsk Hydro, and the installation will largely be operated in the same manner as before.

Norsk Hydro has performed a survey of the installation's technical condition and operational conditions, and has found them to be satisfactory. The Norwegian Petroleum Directorate has not registered any problems related to the change, and has granted the new operator a consent for use without any special conditions.

2.7 SAFETY MANNING DURING LABOR DISPUTE

After negotiations between the Federation of Oil Workers Trade Union (OFS) and the Norwegian Shipowners' Association broke down, OFS gave notification of a walk-out by 343 members on five mobile installations from 23 August 1997. On 10 September 1997, OFS expanded the conflict to include an additional three mobile installations and 113 members.

The Norwegian Shipowners' Association called for a lockout from 8 October 1997 for an additional 270 OFS members on 13 mobile installations. It then appeared that a total of 21 mobile installations would be involved in the dispute. However, the Act relating to wages board consideration was approved by the King in Council on 3 October 1997, thereby ending the conflict and causing work to be resumed.

Labor disputes are primarily matters of civil law. Assuming that the regulatory requirements with regard to safety are fulfilled, the Norwegian Petroleum Directorate, as a public administration body, has no role to play in the actual dispute. The Norwegian Petroleum Directorate's role will therefore be to provide information and regulatory interpretation when the parties disagree on matters which fall under the Norwegian Petroleum Directorate's sphere of responsibility.

During the conflict, questions were raised as to the Petroleum Act's area of application, as the employer side was of the opinion that mobile installations that must pull anchors due to storm, or which for some other reason remove all connection with the well, do not fall under the petroleum regulations and the safety regulations. The Norwegian Petroleum Directorate's interpretation of the regulations in this respect is that even though all connections with the well are removed, but the installation is not moved away from the field, then the activities must still be regarded as being petroleum activities.

A special situation arose for a mobile storage installation. The entire crew, which was relatively small, was included in the safety manning in connection with a labor dispute. The shipowner, however, believed that only part of the crew was necessary in order to maintain operations. As the labor dispute only included part of the crew, a disagreement arose as to whether operations could be maintained during the conflict. The Norwegian Petroleum Directorate demanded that the field operator present documentation to the effect that it was prudent to maintain the operation with significantly lower manning than what was described in the original plans for operation.

Disagreement arose between the parties regarding interpretation of Section 39 of the safety regulations regarding "safety manning in connection with labor dispute." OFS claimed that the signed agreements were deficient in relation to the Petroleum Act as the nurse, radio operator or safety service were not always included in the safety manning.

The Regulations relating to health services in the petroleum activities require that a nurse be on board the installation at all times. The wording of the requirement makes it unconditional, in other words, it also applies during a labor dispute. In the future, the Norwegian Petroleum Directorate, in consultation with the health authorities, will consider whether the regulations should be changed on this point.

With regard to the radio operator's participation in the safety manning, it follows from the regulations relating to safety and communications systems that there shall be two independent communication channels to land. In addition, the possibility of communicating with vessels, including aircraft, is required. The person who is to operate the relevant communications equipment must have the competence and/or the certificates required by the relevant equipment.

With regard to the safety service, the activity and the relevant safety areas will be greatly reduced during a labor dispute. If a safety delegate is not already included in the safety manning, it would be natural that a safety delegate be appointed/elected from among the personnel who are included in the safety manning for the duration of the dispute.

As in a number of previous cases, disagreement between the parties also arose in connection with this labor dispute as to what constitutes a safe and proper shutdown of wells, and what is entailed by employees being obligated to participate in necessary securing work. The Norwegian Petroleum Directorate made it clear to the parties that the regulations must be understood to mean that the requirement applies to the securing work which is necessary to shut down the well as soon as possible in a safe and prudent manner. Therefore, the operator is not allowed to use shutdown procedures which may take several weeks to implement, insofar as safe and proper procedures are available which take less time.

The Norwegian Petroleum Directorate's opinion is that the parties safeguarded considerations for safety and working environment in a satisfactory manner during the labor dispute, even though the "temperature" between the parties was sometimes high. Safety manning was introduced in accordance with established agreements.

However, the Norwegian Petroleum Directorate takes a serious view of the fact that four of the installations concerned did not have established agreements regarding safety manning in connection with labor disputes.

Furthermore, the Norwegian Petroleum Directorate believes that it is important that the Directorate's role as a coordinating body on the authorities' side must also be respected during labor disputes.

2.8 TECHNOLOGICAL CHALLENGES

2.8.1 MICROBIOLOGICAL CORROSION

Early in 1997, Phillips had to stop production on Ekofisk twice due to so-called microbiologically influenced corrosion. This is corrosion which is affected by bacteria which produce the toxic gas hydrogen sulfide (H_2S) from the sulfur content in the water which is produced together with the oil. When H_2S is dissolved in water, a corrosive mixture is formed which reinforces corrosion of steel.

This phenomenon has been considered not very relevant on the Norwegian shelf. This was also the conclusion of an earlier collaboration project between the operating companies, Sintef and the Norwegian Petroleum Directorate regarding corrosion and erosion in pipe systems.

Phillips has determined that the microbiologically influenced corrosion has occurred as a consequence of changed operating conditions, inter alia changes in the use of chemicals, and changed operational conditions related to the treatment of produced water. The company has also concluded that it must be expected that similar damage will occur in the future.

Unlike normal corrosion, microbiological corrosion can be difficult to discover through traditional inspection of condition, because the damage is concentrated in small, smooth semi-spherical grooves in the surface.

Therefore, in addition to preventive work to prevent or reduce the likelihood of such damage occurring, Phillips has started extensive work to optimize the injection program, improve inspection methods, introduce new inspection methods and train inspectors in the observation of this type of corrosion damage.

The Norwegian Petroleum Directorate assumes that this corrosion mechanism may also occur on other fields on the Norwegian shelf, and will follow how the other operators address the experience which has been gained here.

2.8.2 LARGE-SCALE EXPLOSION TEST IN THE UNITED KINGDOM

In connection with an industry project in the U.K. where three Norwegian oil companies and two Norwegian scientific institutions participated, a number of large-scale fire and explosion tests have been carried out. The project's first objective was to obtain information regarding characteristic qualities of fires and explosions, as well as methods to reduce the dangers. The second objective was to acquire exact information and data for use in connection with evaluation and improvement of fire and explosion models. The project was concluded in 1997 and the most significant conclusions were published. These were, in brief:

- Higher explosion pressure was measured than was indicated by the calculation models
- Some higher fire temperatures were measured than what was calculated
- Use of water (sprinklers and deluge) had a favorable effect on all types of fires and explosion pressure

The conclusions from the project represent a challenge to the operating companies, perhaps particularly in relation to existing installations where the design may prove to have been based on explosion pressures which were too low. The Norwegian Petroleum Directorate has not participated in the project itself, but has been informed inter alia by the British authorities. Cooperation with the British authorities has been initiated with a view towards arriving at the best coordinated measures possible.

2.8.3 IT PROBLEMS IN CONNECTION WITH THE NEW MILLENNIUM

It has long been recognized that the transition to the year 2000 will entail problems for many information technology and automated solutions which are used in the oil industry. These problems could have consequences for the safety of people, the environment and financial values, including operational regularity. Each installation has a large number of such solutions. Therefore, the task of mapping which of these could cause problems is quite extensive. On this basis, the Norwegian Petroleum Directorate sent an identical letter to all operators on the Norwegian shelf. In this letter, the operators were asked to explain how they organized this work, progress plans, use of analyses and tools, safeguarded of responsibilities vis-à-vis contractors and suppliers, as well as internal supervision plans concerning the above-mentioned problems. In its continued follow-up, the Norwegian Petroleum Directorate will use consultants in order to evaluate how the operators are maintaining safety in this connection.

2.8.4 LIFTING GEAR

Once again, several serious undesirable incidents occurred in connection with the use of lifting gear in the petroleum activities in 1997. The incidents have occurred on both permanent and mobile installations. The incidents are also related to the loading and unloading of supply vessels.

One of the incidents resulted in personal injury, and several of the incidents had a high potential for danger.

Insufficient organization and planning of lifting operations, as well as deficient control and maintenance, are regarded as being the causes of several of the incidents.

With the great potential for danger represented by lifting operations, additional focus must be placed on the overall planning of lifting operations, use and maintenance of lifting gear. This will be a prioritized supervision activity for the Norwegian Petroleum Directorate in 1998.

2.8.5 REMOTE-CONTROLLED DRILLING EQUIPMENT

On the basis of experience gained in recent years, the Norwegian Petroleum Directorate has initiated an internal assessment in order to compile the status and experience relating to remote-controlled pipe handling on permanent and mobile installations. The assessment will be based on applications for exemption from the regulations during the period 1992-1997, as well as other information obtained from the industry. In addition, the Directorate will review internal databases and information concerning accidents and incidents, in order to reveal any trends in injuries and accidents related to this type of equipment and operations. The result from this assessment will have significance for regulatory development and supervision in this area.

2.8.6 MOBILE PRODUCTION INSTALLATIONS

The special conditions which a mobile production installation is exposed to, inter alia through lying constantly in one direction in relation to waves and wind, means that the stresses will be different than for trade vessels. Therefore, a sturdier design is necessary to guard against fatigue in certain parts of the hull.

The fatigue capacity depends inter alia on the design of the longitudinal stays on the side of the hull, as well as the distance between these, and the mutual distance between crosswise frames. Therefore, the capacity varies from ship to ship.

In connection with verification of the mobile Balder installation, the operator uncovered inadequate fatigue capacity in some areas, and therefore found it necessary to make reinforcements on the hull. This, together with several other factors, contributed to delays and cost overruns on the project.

2.9 AUTHORITIES' COOPERATION ON INJURY STATISTICS

A couple of years ago, the British Health & Safety Executive (HSE) and the Norwegian Petroleum Directorate started a collaboration in connection with preparation of injury statistics which the two authorities could exchange. The objective was to present statistics in the same form and to possibly uncover common problems. This initially proved to be difficult due to different areas of responsibility, regulatory requirements and registration methods. Therefore, statistics were first presented in separate reports. Nonetheless, the collaboration has resulted in the Norwegian Petroleum Directorate presenting a joint report containing British and Norwegian accident data at the end of 1997. The group that has worked on this also suggested that, in a long-term perspective, the joint statistics could be submitted to the industry.

As mentioned, there are a number of differences between the British and the Norwegian system for reporting and registration of accidents. Both the HSE and the Norwegian Petroleum Directorate are now in the process of revising the registration systems, and will test these in 1998. These bodies have started a collaboration and will, insofar as possible, try to develop the most compatible classifications possible for description of accidents. This will lead to improved opportunities for comparison of the accident statistics. The cooperation started in 1997 when HSE and the Norwegian Petroleum Directorate had a joint meeting with the Directorate of Labor Inspection in Denmark, which is a central link in connection with harmonization of accident statistics in Europe. The intention is to prepare joint statistics that can be presented to the industry when sufficient registration is available in the new systems, hopefully around the turn of the year 1998-1999.

2.10 FRAMEWORK FOR THE ACTIVITIES

A new Petroleum Act with appurtenant regulations laid down by Royal Decree, entered into force on 1 July 1997. In relation to safety management, the new paramount regulations do not entail significant changes which will have a direct impact on the safety level in the petroleum activities. However, the Act does provide better clarification of the individual participant's responsibility to manage its own activities and imposes a duty upon them to establish management systems to ensure that this is done in a systematic manner.

Together with the State Pollution Control Authority and the Norwegian Board of Health, the Norwegian Petroleum Directorate has initiated a substantial task in connection with revision of underlying regulations in areas which deal with safety, working environment and the external environment. The objective is that the future underlying shelf regulations will consist of four regulations for the areas:

- management
- operations
- technology
- documentation

In addition, there is a goal that the four new regulations shall be issued and enforced by the three authorities jointly in accordance with the principles laid down in the system for coordinated supervision on the shelf.

The proposal has also been presented to the parties in the established three-party regulatory forum "External Reference Group for Regulatory Development" (ERR), which has in principle given its support to this.

The revision work does not have the goal of tightening the technical requirements on the activities, but to continue the current regulation within the framework of a new regulatory structure. In the opinion of the Directorate, such a reorganization will make the regulations more accessible and provide the supervisory authorities with more comprehensive and effective management instruments. Furthermore, the objective is to provide for the use of recognized industry standards to a greater degree, improve predictability in connection with the application of the regulations vis-à-vis mobile installations, provide for more comprehensive and inter-disciplinary approaches to various areas and adaptation of the regulations to better fit the structure of the EEA regulations.

2.10.1 ANNUAL UPDATES OF THE REGULATIONS

The Norwegian Petroleum Directorate conducts annual updates of the regulations in order to ensure that they are as appropriate as possible and are adapted to national and international development at all times. Thus, an assessment was also made in 1997 of the need for changes and updates to the prevailing regulations for safety, working environment and resource management. The proposal for changes in the regulations which will apply for 1998 has been out for consultation in the industry. A proposal for incorporation of references to 36 NORSOK standards with corresponding proposals to reduce the scope of the Directorate's guidelines in the same areas, has also been out for consultation. Nine of the technical guidelines will be entirely discontinued. The contents of the guidelines will largely be replaced by references to relevant recognized norms, including NORSOK standards. In addition, it is proposed that three other technical guidelines be significantly shortened, in addition to references being made to recognized norms.

2.10.2 REFERENCES TO NATIONAL AND INTERNATIONAL INDUSTRY STANDARDS IN THE SHELF REGULATIONS

The Norwegian Petroleum Directorate is concerned with forming the overall regulations for safety and working environment in the petroleum activities in the most efficient way possible, inter alia through references being made insofar as possible to recognized national and international industry standards in the regulations. Thus, the Norwegian Petroleum Directorate has continued its cooperation with the Norwegian Technology Standards Institution (NTS) with a view towards incorporating references to NORSOK standards in the shelf regulations. Furthermore, in 1997 there has also been a continuous follow-up of international standardization work under the direction of ISO/IEC and CEN/CENELEC in those areas which touch on the regulations.

2.11 INJURIES AND ACCIDENTS

2.11.1 PERSONAL INJURIES

The Norwegian Petroleum Directorate receives continuous reports regarding personal injuries in connection with petroleum activities on permanent and mobile installations. Depending on the circumstances, this may either be notification or reporting of such injuries.

Notification

In case of fatalities, serious personal injuries and other serious incidents which are of significance for safety, the Directorate shall be notified immediately. The purpose of this immediate notification is so that the Directorate may assess the need for measures and additional follow-up as quickly as possible. These follow-up activities may include on-site investigation of the incident in cooperation with the police, review of the operating company's own investigation of the accident, or other supervisory activity.

Reporting

In addition to the notification of serious personal injuries and fatalities, all personal injuries which require medical treatment or which lead to absence during the following 12-hour shift shall be reported to the Norwegian Petroleum Directorate. It is the responsibility of the individual employer in the petroleum activities to report the injuries. This reporting is used as a basis for statistics, such as those presented in the Norwegian Petroleum Directorate's Annual Report.

The regulations also require that the operating companies have an overview of accidents and incidents on their own installations. Therefore, the statistical base material registered in the Norwegian Petroleum Directorate, on the basis of the individual employers' duty of notification is compared each year with the overviews from the operating companies, so that under-reporting and any registration errors may be corrected. In 1997, this inspection led inter alia to 67 reported injuries being reclassified as first-aid cases or near misses, which are not included in the statistical summary presented in the Annual Report. These are incidents which have been reported based on possible subsequent complications, or because there was not enough information at the time of reporting to clearly ascertain the consequences. The Norwegian Petroleum Directorate also receives retrospective reporting of personal injuries which the companies themselves have subsequently identified as fulfilling the criteria for reporting. Thus, 15 injuries were reported in 1997 which occurred in 1996. These injuries are included in this year's statistics.

Such an extensive reporting system will have a number of possible sources of error, and the Directorate continues to note a somewhat variable understanding and knowledge of reporting criteria and routines. The statistical summaries presented in the Annual Report should nevertheless provide a reasonably accurate expression of the injury scenario on the Norwegian continental shelf.

2.11.2 FATAL ACCIDENTS

On 8 September 1997, a tragic accident occurred, claiming 12 lives. The accident occurred when a Super Puma helicopter crashed on a flight from Brønnøysund to the Norne field off the coast of Helgeland.

Transportation of personnel to and from the installations is considered to be air traffic, and thus does not directly fall under the petroleum authorities' sphere of responsibility. However, the incident has contributed to bringing the spotlight to bear on sufficient living quarters capacity on the installations as an alternative to helicopter transportation. Time pressure in the development projects has in several cases resulted in installations being installed on the field before they are completed. This leads to a significant need for labor which must commute on a daily basis because the living quarters are not designed for a temporary increase in manning. Similar problems also often occur in connection with modification and maintenance work on installations in the operations phase.

Therefore, the Norwegian Petroleum Directorate has taken the initiative of contacting the involved parties in order to evaluate the problems involved with daily commuting to and between offshore installations. This includes inter alia factors connected with accommodations. From the employee's perspective, it has been pointed out that daily commuting constitutes a "special risk" which some employee groups are exposed to, as it is primarily personnel from contracting companies who are subjected to daily commuting.

2.11.3 PERSONAL INJURIES ON PERMANENT INSTALLATIONS

In 1997, the Norwegian Petroleum Directorate registered 539 personal injuries on permanent installations, compared with 560 in 1996. The total number of man-

Table 2.11.3.a
Injuries/fatalities per million hours worked on fixed installation (1988-97)

Year	Hours worked	Number of injuries/fatalities	Injuries and fatalities per million hours worked	Fatalities
1988	19 878 727	638	32,1	0
1989	19 935 637	597	29,9	1
1990	19 852 093	571	28,8	1
1991	22 263 572	589	26,5	0
1992	22 203 641	583	26,3	0
1993	25 411 735	642	25,3	2
1994	21 542 463	554	25,7	1
1995	21 902 897	590	26,9	1
1996	21 123 859	560	26,5	0
1997	21 337 937	539	25,3	0
Total/average	**215 452 561**	**5863**	**27,2**	**6**

hours on permanent installations increased by about 1%. This means that the total injury frequency has been reduced from 26.5 to 25.3 injuries per million man-hours. The proportion of injuries which caused absence extending into the next 12-hour shift in 1997 is approximately 25%, the same as for the previous year. Thirty-seven off-duty injuries have been reported in 1997, compared with 38 in 1996. As in previous years, these are mainly injuries connected with exercise activities.

Table 2.11.3.a shows a summary of personal injuries per million man-hours on permanent installations for the period from 1988-1997. The figures also include mobile installations which have a permanent gangway connection to permanent installations which are involved in production activities. For statistics from the period prior to 1987, the Norwegian Petroleum Directorate refers to previous annual reports.

Figure 2.11.3.a shows the development of personal injury frequency in injuries per million man-hours for the various main activities over the last ten years. In 1997, we have registered a reduction in the injury frequency within all activity areas as compared with 1996. Drilling and well operations have the lowest injury frequency ever recorded. The same is true of the overall injury frequency, which has fallen to the same level as for 1993.

Table 2.11.3.b shows the distribution of injuries, man-hours and injury frequency per million man-hours within the main activities divided by operator and contractor employees over the past ten years. All groups have experienced a reduction in injury frequency from 1996 to 1997. The contracting companies account for about 60 percent of the total man-hours on permanent installations, while more than 76 percent of the injuries affect this group.

However, the personnel group of contractor employees within construction and maintenance have had the greatest reduction in injury frequency. As in 1996, the types of injuries in this group are divided among scrapes, cuts and bruising injuries as the most common injuries and the hands as the most vulnerable body part. There has been a relative increase in the frequency of head injuries, but a reduction of eye injuries caused by splinters and sprays in this personnel group. The proportion of serious injuries among construction and maintenance workers has increased slightly.

Catering represents about 10 percent of the man-hours and about 9 percent of the total number of injuries on permanent installations. The injuries in this group are mainly cuts and bruises to the hands in connection with the handling of kitchen equipment. Some of the injuries entailed

Figure 2.11.3.a
Personal injury frequency on fixed installations (1988-1997)

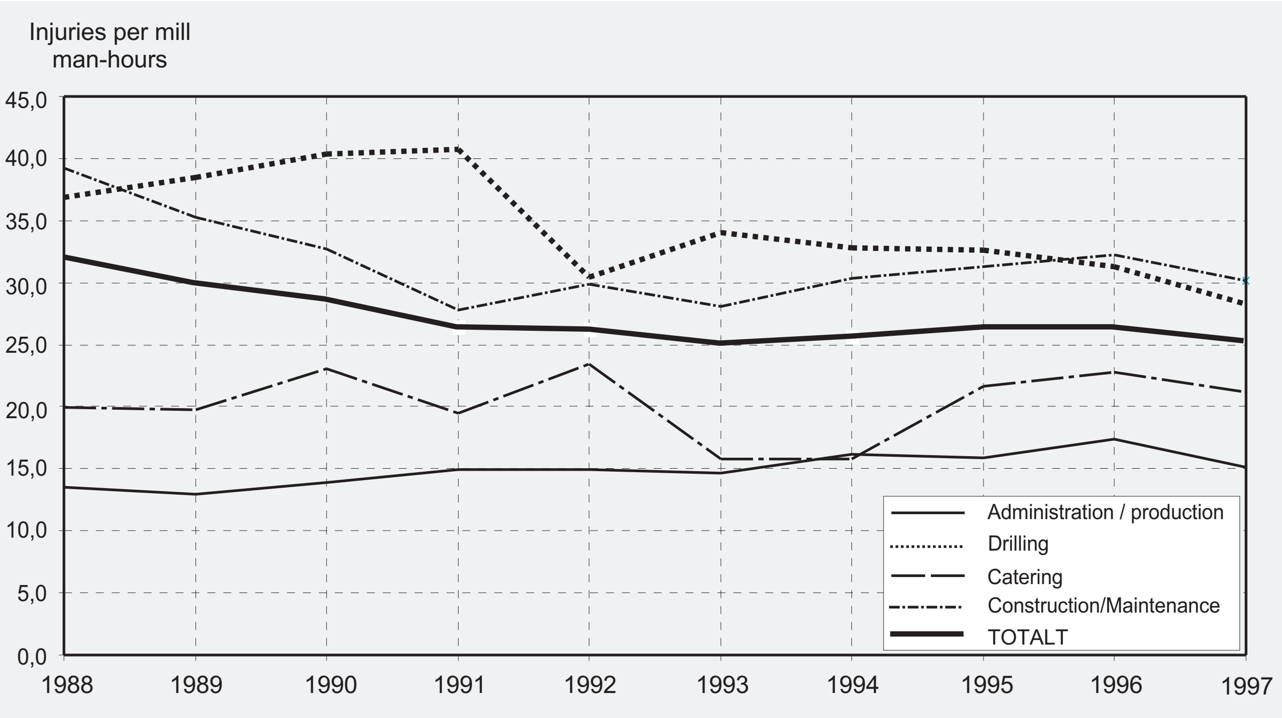
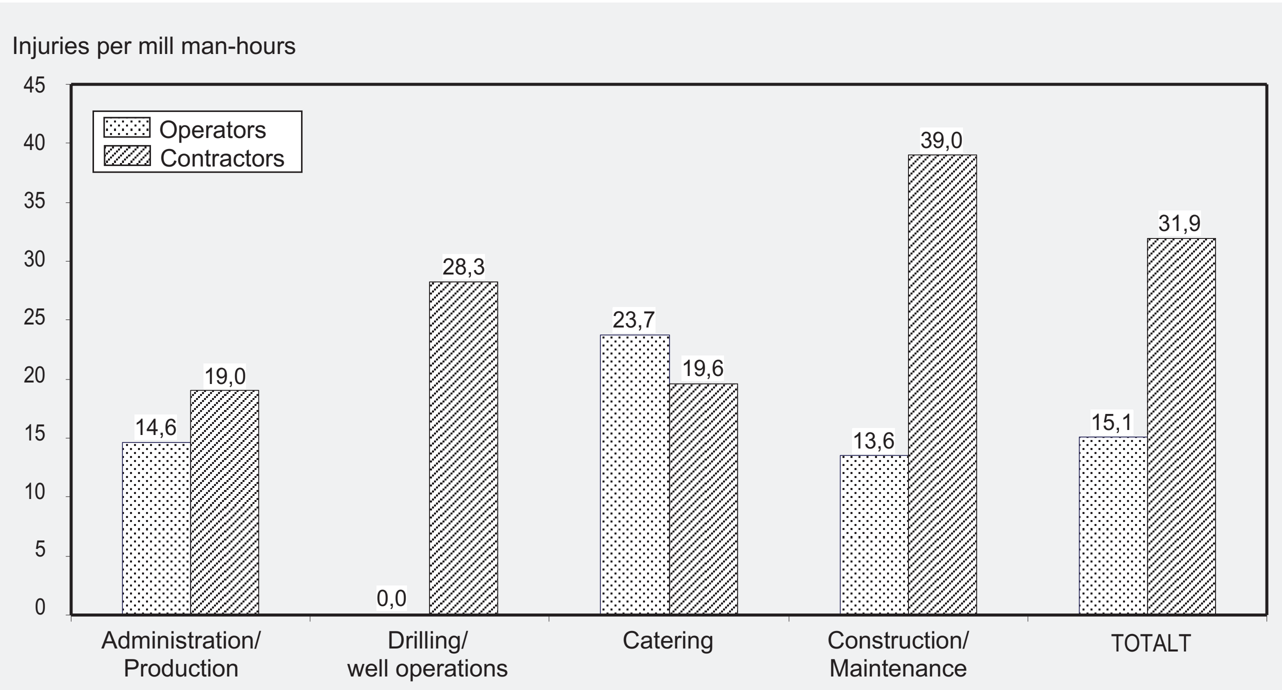


Table 2.11.3.b
Distribution of injuries and man-years on operator and contractor employees on fixed installations (1988 - 1997)

FUNCTION		1988	1989	1990	1991	1992	1993	1994	1995	1996	1997	
Administration	Man-years	3 199 820	3 383 588	3 641 508	3 813 992	4 028 388	4 202 484	4 869 852	4 737 668	4 497 590	4 445 400	Operator
Production		731 848	473 928	806 000	683 488	594 828	776 984	754 416	1 065 532	2 053 363	630 756	Contractor
	Injuries	47	44	50	53	54	59	76	72	72	65	o
		6	6	12	14	15	14	15	20	42	12	c
	Injury frequ.	14,7	13,0	13,7	13,9	13,4	14,0	15,6	15,2	16,0	14,6	o
		8,2	12,7	14,9	20,5	25,2	18,0	19,9	18,8	20,5	19,0	c
Drilling	Man-years	0	0	0	0	0	0	0	0	0	0	o
Well operations		3 035 396	3 430 336	3 267 524	3 609 268	3 772 080	4 175 080	4 268 576	4 676 412	4 670 118	4 913 477	c
	Injuries	0	0	0	0	0	0	0	0	0	0	o
		112	132	132	147	115	142	140	152	146	139	c
	Injury frequ.	0	0	0	0	0	0	0	0	0	0,0	o
		36,9	38,5	40,4	40,7	30,5	34,0	32,8	32,5	31,3	28,3	c
Catering	Man-years	336 908	548 080	638 352	720 564	747 968	802 776	731 848	707 668	779 369	842 930	o
		1 421 784	1 431 456	1 399 216	1 536 236	1 429 844	1 541 072	1 352 468	1 381 484	1 281 085	1 329 453	c
	Injuries	4	3	13	13	17	12	10	19	21	20	o
		31	36	34	31	34	25	23	26	26	26	c
	Injury frequ.	11,9	5,5	20,4	18,0	22,7	14,9	13,7	26,8	26,9	23,7	o
		21,8	25,1	24,3	20,2	23,8	16,2	17,0	18,8	20,3	19,6	c
Construction	Man-years	3 867 188	3 838 172	3 810 768	3 999 372	4 088 032	4 342 728	3 199 820	3 149 848	3 137 696	3 171 689	o
Maintenance		7 286 240	6 830 044	6 288 412	7 898 800	7 542 548	9 570 444	6 365 788	6 183 632	4 704 639	6 004 233	c
	Injuries	51	70	63	65	80	39	48	45	46	43	o
		387	306	267	266	268	351	242	246	207	234	c
	Injury frequ.	13,2	18,2	16,5	16,3	19,6	9,0	15,0	14,3	14,7	13,6	o
		53,1	44,8	42,5	33,7	35,5	36,7	38,0	39,8	44,0	39,0	c
TOTAL	Man-years	7 403 916	7 769 840	8 090 628	8 533 928	8 864 388	9 347 988	8 801 520	8 595 184	8 414 655	8 460 019	o
		12 475 268	12 165 764	11 761 152	13 727 792	13 339 300	16 063 580	12 741 248	13 307 060	12 709 204	12 877 918	c
	Injuries	102	117	126	131	151	110	134	136	139	128	o
		536	480	445	458	432	532	420	444	421	411	c
	Injury frequ.	13,8	15,1	15,6	15,4	17,0	11,8	15,2	15,8	16,5	15,1	o
		43,0	39,5	37,8	33,4	32,4	33,1	33,0	33,4	33,1	31,9	c

Figure 2.11.3.b
Personal injury frequency by operators and contractors - 1996 on fixed installations



relatively serious cuts and three cases have been registered where fingers were cut off.

In 1997, drilling and well operations accounted for about 23 percent of the work and about 26 percent of the injuries. The injury frequency of 28.3 injuries per million hours is the second lowest ever registered by the Directorate for this category. The most common type of injury in 1997 continued to be bruising injuries in connection with handling of tools and equipment, but there has been a significant reduction in the number of cut and scrape injuries. The second most frequent injury type in 1997 within drilling and well operations was sprains, most often caused by wet and slippery decks. Most of these injuries did not occur on the drill floor, but in other deck areas. The number of injuries caused by falling objects was just two in 1997, compared with 15 in 1996 for drilling and well personnel.

Table 2.11.3.c
Work accidents 1992-96 and 1997 on fixed installations. Injury incident / occupation

Injury incident	Occupation YEAR	Administration	Drill floor worker (roughneck)	Driller	Electrician	Caterer	Assistant	Cook	Crane operator	Painter / Grit blaster	Mechanic / Motorman	Operator	Plateworker / Insulator	Pipeworker / Plumber	Service technician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Contact with objects or machinery in motion	1992-96	4	69	12	2	2	49		2		10	6			13		3	14	1	187	28,2%
	1997	1	16	1		1	14	1	1		3	2				1	1	2		44	21,2%
Fire Explosion	1992-96						1													1	0,2%
	1997																			0	0,0%
Fall to lower level	1992-96	4	5	2	1		7				3				3		5	3		33	5,0%
	1997		2				3		1	1		2			1		1	1		12	5,8%
Fall at same level	1992-96	3	4	2		1	8	1	3		1				4		2	2	1	32	4,8%
	1997		2				2	1			1	1			2			1		10	4,8%
Missteps tripping	1992-96	3	13	3	1		7	1	4					1	9	1		7		50	7,6%
	1997		2			1	5					1			2			1		12	5,8%
Falling objects	1992-96	1	12	3		1	6	1	4		2				6	1	4	2		43	6,5%
	1997	1	5				2		1			1			1			1		12	5,8%
Contact with objects at rest	1992-96	4	10	2	3	2	4	1	1		1	1		1	8		2	7		47	7,1%
	1997	1	6		3	1	4		2		3	1	1		4		2	3		31	14,9%
Handling accidents	1992-96	4	44	4	1	5	19	10	1		10	1		2	7	1	5	6	1	121	18,3%
	1997	2	14	1		1	8	4	1		5	3		1	2	1	1	1	3	48	23,1%
Contact with chemical or physical compound	1992-96	1	2		1	1	2				5			1	6		1	1		21	3,2%
	1997		2		1		3				1				1		1	1		10	4,8%
Muscular strain	1992-96	3	23	5	2	2	9		4		2	1			13			9		73	11,0%
	1997	2	6		1		1	1				1			1			2		15	7,2%
Splinter and splashes	1992-96	3	8		3	1	5	2	1	1	5	1	1		3		10	3		47	7,1%
	1997		1				3						1		1		2			8	3,8%
Electrical current	1992-96																	1		1	0,2%
	1997																			0	0,0%
Extreme temperature	1992-96					1		1			1			1			1			5	0,8%
	1997	1						1			1									3	1,4%
Other	1992-96			1																1	0,2%
	1997	1					2													3	1,4%
TOTAL	1992-96	30	190	34	14	16	117	17	20	1	40	10	1	6	72	3	33	55	3	662	100,0%
	1997	9	56	2	5	4	47	8	6	1	14	12	2	1	15	2	8	13	3	208	100,0%
%	1992-96	4,5%	28,7%	5,1%	2,1%	2,4%	17,7%	2,6%	3,0%	0,2%	6,0%	1,5%	0,2%	0,9%	10,9%	0,5%	5,0%	8,3%	0,5%	100,0%	
	1997	4,3%	26,9%	1,0%	2,4%	1,9%	22,6%	3,8%	2,9%	0,5%	6,7%	5,8%	1,0%	0,5%	7,2%	1,0%	3,8%	6,3%	1,4%	100,0%	

The administration/production function had the lowest injury frequency with 15.7 injuries per million man-hours. This is a reduction of 2.2 injuries per million man-hours compared with 1996. Accidents in connection with handling of tools have been the most common in this group. The 1997 registration shows that such incidents have been cut in half. Therefore, there has also been a significant reduction in bruising and scraping injuries within this group. It appears that injuries in this personnel category are often caused by poor ergonomics and difficult access to the work site.

Figure 2.11.3.b shows the injury frequency divided by operator employees and contractor employees in the main activity categories for 1997.

Table 2.11.3.c shows the distribution of injury types in the various occupational categories. The table shows last year compared with accumulated values for the five previous years. The Norwegian Petroleum Directorate refers to previous annual reports for figures showing accumulated values since registration began in 1979.

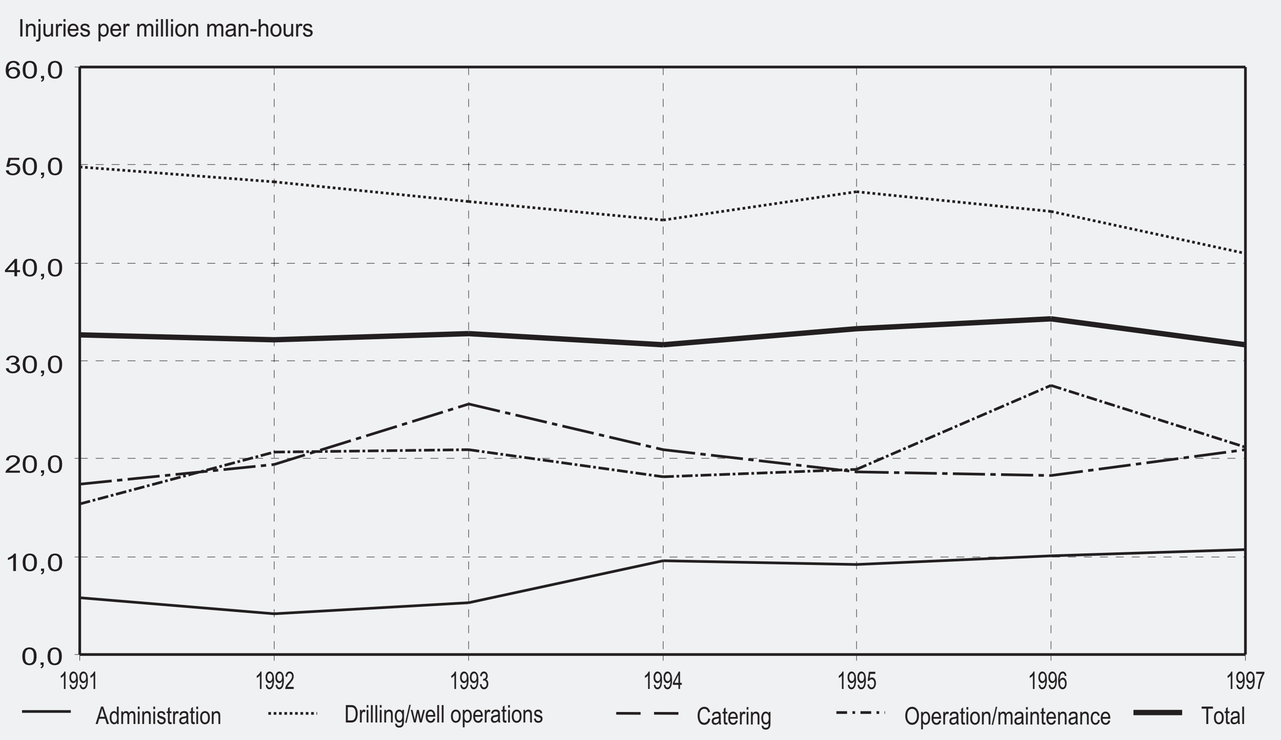
2.11.4 PERSONAL INJURIES ON MOBILE INSTALLATIONS

In 1997, there was also a significant increase in the activity with mobile installations compared with the previous year. The number of man-hours increased by approximately 24 percent. 208 personal injuries were registered in 1997, of which ten were serious, compared with 178 total and 14 serious in 1996. The total injury frequency for mobile installations in 1997 is thus 31.8 injuries per million man-hours compared with 35.7 for 1996. The Directorate has

Table 2.11.4.a
Injuries/fatalities per million hours worked on mobile installations (1989-1997)

Year	Hours worked	Number of injuries (incl. fatalities)	Injuries and fatalities per million hours worked	Fatalities
1989	3584740	92	25,7	2
1990	4328907	139	32,1	1
1991	4878152	159	32,6	0
1992	4380013	141	32,2	0
1993	4205431	138	32,8	2
1994	3513753	111	31,6	0
1995	2821541	94	33,3	0
1996	4989985	178	35,7	0
1997	6541619	208	31,8	0
Total/average	**39244141**	**1260**	**32,1**	**5**

Figure 2.11.4
Personal injury frequency on mobile installations 1991 -1997



registered five off-duty injuries on mobile installations in 1997, compared with seven in 1996.

Table 2.11.4.a shows a summary of personal injuries per million man-hours on mobile installations during the last nine years.

Figure 2.11.4 shows the injury frequency for the main activities on mobile installations for the last seven years.

Drilling and well activities account for about 59 percent of the work, and about 74 percent of the injuries. This nevertheless led to a reduction in the injury frequency of nearly five injuries per million man-hours. The registration shows an increasing proportion of bruise and scrape injuries compared with 1996. The injuries most often occur in connection with incorrect handling of equipment on the drill floor, and when the injured person has positioned himself/herself inappropriately in relation to equipment and material which is in motion. The proportion of injuries to drilling and well personnel which actually take place on the drill floor has, on the other hand, been reduced from approximately 60 percent in 1996 to approximately 40 percent of reported injuries in 1996. Hands and fingers are still the most vulnerable body parts.

Within the areas of maintenance and operation on mobile installations, there has been a marked reduction in injury frequency. The total number of injuries in this category is 34. These relate mainly to bruising injuries. The changes in the injury frequency for catering and administration personnel on mobile installations are small and the number of injuries is low, 12 in catering and 7 for administrative personnel.

On mobile installations, operator employees account for only about 5 percent of the work, and this is substantially work of an administrative nature. One injury to an operator employee was reported in connection with work on mobile installations in 1997.

Table 2.11.4.b shows a cross-reference of the distribution of the various types of accidents in the various occupational categories. The table shows figures for 1997 compared with accumulated figures for the five previous years.

Table 2.11.4.b
Work accidents 1992-96 and 1997 on mobile installations. Injury incidents / occupation

Injury incident	Occupation YEAR	Administration	Drill floor worker (roughneck)	Driller	Electrician	Caterer	Assistant	Cook	Crane operator	Painter / Grit blaster	Mechanic / Motorman	Operator	Plateworker / Insulator	Pipeworker / Plumber	Service technician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Contact with objects or	1992-96	4	69	12	2	2	49		2		10	6			13		3	14	1	187	28,2%
machinery in motion	1997	1	16	1		1	14	1	1		3	2				1	1	2		44	21,2%
Fire	1992-96						1													1	0,2%
Explosion	1997																			0	0,0%
Fall to	1992-96	4	5	2	1		7				3				3		5	3		33	5,0%
lower level	1997		2				3		1	1		2			1		1	1		12	5,8%
Fall at	1992-96	3	4	2		1	8	1	3		1				4		2	2	1	32	4,8%
same level	1997		2				2	1			1	1			2			1		10	4,8%
Missteps	1992-96	3	13	3	1		7	1	4					1	9	1		7		50	7,6%
tripping	1997		2			1	5					1			2			1		12	5,8%
Falling	1992-96	1	12	3		1	6	1	4		2				6	1	4	2		43	6,5%
objects	1997	1	5				2		1			1			1			1		12	5,8%
Contact with	1992-96	4	10	2	3	2	4	1	1		1	1		1	8		2	7		47	7,1%
objects at rest	1997	1	6		3	1	4		2		3	1	1		4		2	3		31	14,9%
Handling	1992-96	4	44	4	1	5	19	10	1		10	1		2	7	1	5	6	1	121	18,3%
accidents	1997	2	14	1		1	8	4	1		5	3		1	2	1	1	1	3	48	23,1%
Contact with chemical	1992-96	1	2		1	1	2				5			1	6		1	1		21	3,2%
or physical compound	1997		2		1		3				1				1		1	1		10	4,8%
Muscular	1992-96	3	23	5	2	2	9		4		2	1			13			9		73	11,0%
strain	1997	2	6		1		1	1				1			1			2		15	7,2%
Splinter and	1992-96	3	8		3	1	5	2	1	1	5	1	1		3		10	3		47	7,1%
splashes	1997		1				3						1		1		2			8	3,8%
Electrical	1992-96																	1		1	0,2%
current	1997																			0	0,0%
Extreme	1992-96					1		1			1			1			1			5	0,8%
temperature	1997	1						1			1									3	1,4%
	1992-96			1																1	0,2%
Other	1997	1					2													3	1,4%
	1992-96	30	190	34	14	16	117	17	20	1	40	10	1	6	72	3	33	55	3	662	100,0%
TOTAL	1997	9	56	2	5	4	47	8	6	1	14	12	2	1	15	2	8	13	3	208	100,0%
	1992-96	4,5%	28,7%	5,1%	2,1%	2,4%	17,7%	2,6%	3,0%	0,2%	6,0%	1,5%	0,2%	0,9%	10,9%	0,5%	5,0%	8,3%	0,5%	100,0%	
%	1997	4,3%	26,9%	1,0%	2,4%	1,9%	22,6%	3,8%	2,9%	0,5%	6,7%	5,8%	1,0%	0,5%	7,2%	1,0%	3,8%	6,3%	1,4%	100,0%	

2.11.5 SUMMARY

The total injury frequency still appears to have stabilized at a level of a little more than 25 injuries per million man-hours for permanent installations and 30 injuries per million man-hours for mobile installations. It is nevertheless positive to register a reduction in the injury frequency for most personnel categories, and that the proportion of serious injuries appears to have stabilized at a lower level than for previous years.

Bruising injuries are still the most common type of injury. In 1997, this type of injury mainly occurred in connection with handling of heavier equipment and materials. The Norwegian Petroleum Directorate has also registered a doubling of back injuries triggered by overloading and incorrect working position. The proportion of injuries in connection with the use of hand tools is considerably lower in 1997 than in 1996. This has led to fewer pure cut and scrape injuries requiring medical attention.

In 1998, the Norwegian Petroleum Directorate will begin to use a new registration system for personal injuries in the petroleum activities. During the year, a new form for reporting personal injuries to the National Insurance Administration and the Norwegian Petroleum Directorate will be issued. The Directorate hopes that the positive cooperation with the industry concerning the reporting system can continue.

Correct and completely filled out report forms are crucial in order to achieve sufficient quality of registered data. Therefore, the Directorate wants a continuous dialogue in order to achieve a common understanding of reporting routines and criteria.

2.12 WORK-RELATED DISEASES

The incidence of work-related diseases can be an indicator of the quality of the working environment. During recent years, the Norwegian Petroleum Directorate has worked towards the goal of getting the companies to establish this as a working environment indicator and make vigorous use of it in their preventive safety and environmental work. Therefore, it is gratifying that more and more companies are beginning to compare the frequency of work-related diseases with injury frequency.

Figure 2.12.a
Distribution of work-related diseases on diagnosis groups 1995 - 1997

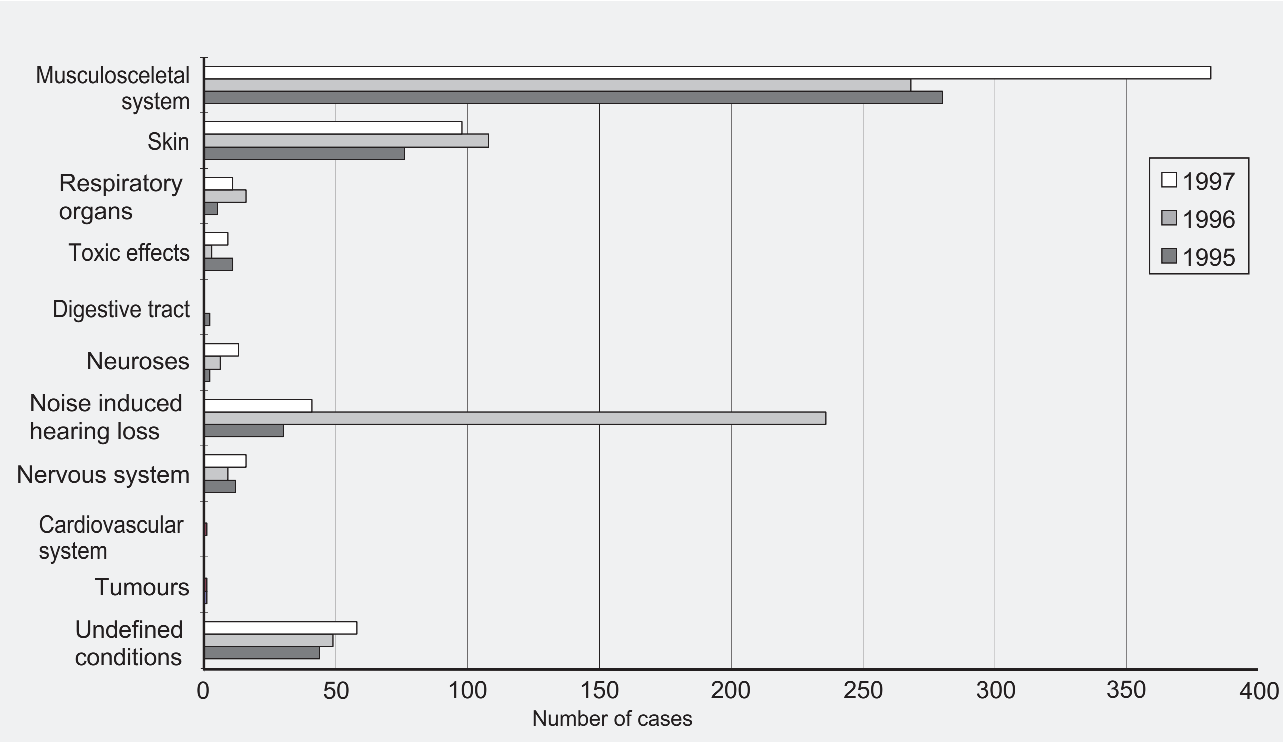
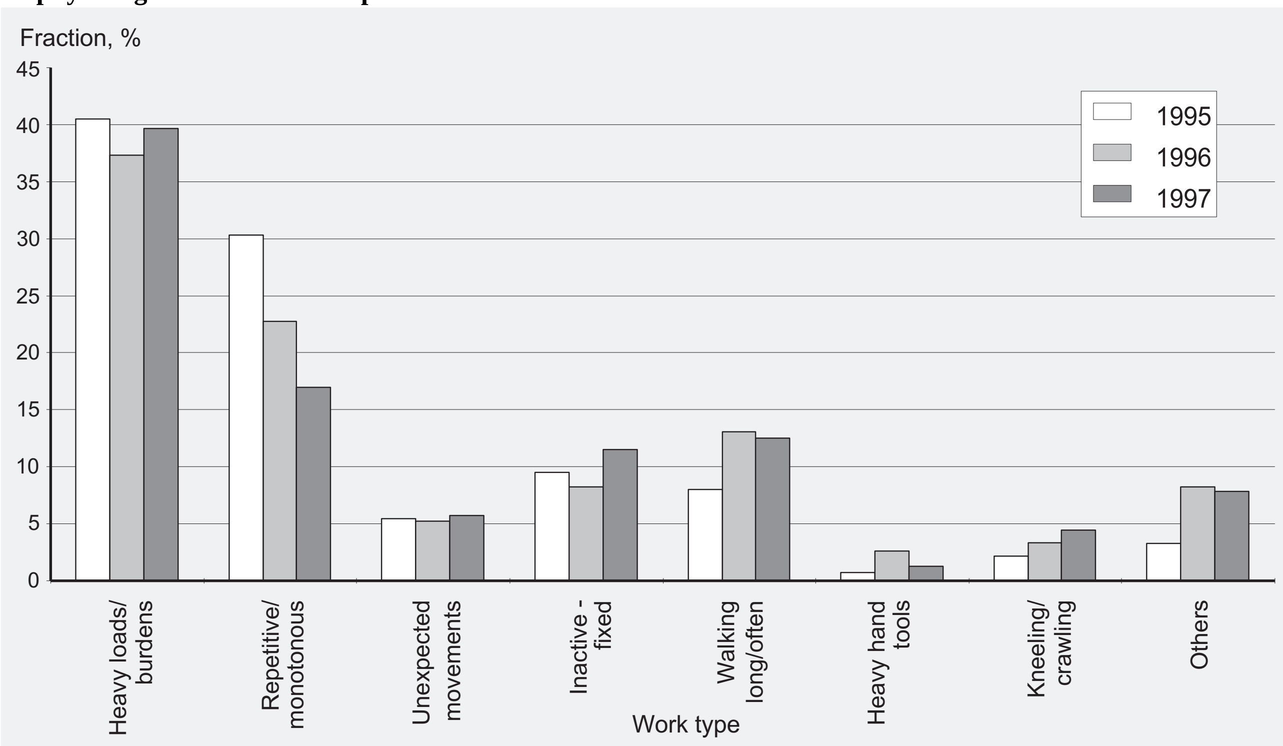
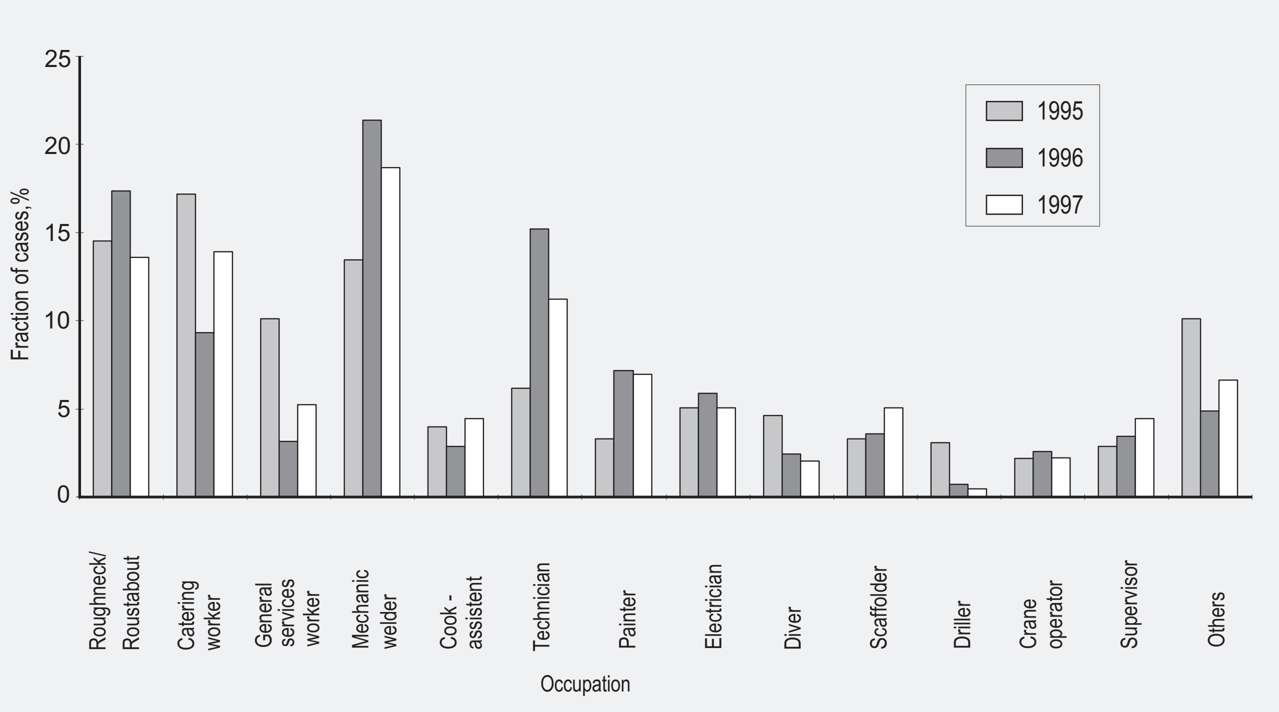


Figure 2.12.b
Unphysiological work - work positions



628 notifications regarding work-related disease were received by the Directorate in 1997, divided between 154 for operator employees and 474 for contractor employees. This is a decrease of nearly 10% from 1996, giving a notification frequency of 29.4 incidents per million man-hours. The decrease is due to the fact that considerably fewer reports of noise-induced hearing loss have been received; 41 in 1997 compared with 236 in 1996. This may be due to the fact that the reporting obligation for this type of disease was changed during the period to conform with the Directorate of Labor Inspection's regulations. While these cases previously had to be reported

Figure 2.12.c
Occupations - work categories



summarily, they are now to be reported individually. This will provide improved opportunities for following up individual cases. The number of reported cases of other diseases than hearing injuries due to noise has increased by 28%.

If we disregard hearing injuries due to noise, the frequency of other diseases will be 27.5 cases per million man-hours. This is considerably higher than what has been reported for land-based industry. There may nevertheless still be a certain amount of under-reporting, as there are still few reports received from some companies that have many employees on the shelf. The Norwegian Petroleum Directorate will work to achieve a more uniform reporting practice through contact with the companies, inter alia in the supervision context.

Figure 2.12.a shows the diagnosis group distribution of work-related diseases registered during the period 1995-1997, in accordance with the ICD classification. As a consequence of the change in the requirement for reporting of noise-induced hearing loss, this is now reported as a separate group. However, there is reason to believe that considerably more new cases of this type are registered than are reported to the Directorate.

The picture is as previously dominated by skeleto-muscular disorders (including disorders of the connective tissues). These types of disorders are normally referred to as repetitive-strain injuries. They include back disorders, tendinitis and various forms of muscular pain. The number and the proportion of repetitive strain injuries has increased compared with the previous year. It is difficult to say whether this is due to a change in reporting practice or an actual increase in the number of cases. In any event, the reports show that it is important to make a commitment towards preventive action in this type of disorder. Not surprisingly, the stated causes of the cases in this group are largely manual labor within the areas of drilling, maintenance and catering.

The exposures which are listed as the causes of these repetitive strain injuries are summarized in Figure 2.12.b. This figure includes data for the last three years.

The figure shows that handling of heavy loads and heavy lifts were listed as the most important causes of diseases in the skeleto-muscular system in 1997, and that this proportion was nearly unchanged compared with the previous year. Another important cause of this type of injury was repetitive, monotonous work, even though it may seem as though this has become less significant as a cause during the last three years. Both heavy and repetitive monotonous work are listed as causes of inter alia tendinitis and muscle pain. The proportion of cases of degenerative changes in knees and hips attributed to extensive walking on hard surfaces is relatively high, but is unchanged compared with the previous year. This may be related to a general aging of the workforce on the shelf. Heavy lifts, sudden movements and inactive/stationary work have often resulted in back problems (lumbago/sciatica). Difficult access, which means that work must be performed in a crawling position or while kneeling, is another frequent cause of various knee ailments.

Another large diagnosis group is skin conditions, and the number of incidents in this group was basically unchanged compared with 1996. More than 50% of the cases (49 of 97) relate to eczema on the hands after having been in contact with oil-based drilling mud. Some cases can also be attributed to other organic compounds, while epoxy is listed as the cause of nine cases of contact eczema, the same as in the previous year. Other cases in this group are presumed to be caused by inorganic compounds such as various metals and well chemicals.

Disorders of the respiratory system are asthma and bronchitis, as well as incidents of respiratory irritation due to airborne irritants such as oil vapor and welding smoke. In addition, five cases of asbestos-related lung disease have been reported. These are employees who have been exposed in previous work, particularly on ships, and who have now developed asbestos-specific changes in the lung membrane.

The diagnoses grouped as toxic effects are a compilation of different symptoms occurring after exposure to various chemicals or gases.

In 1997, there was an increase in the number of reported cases of mental disease. This refers to employees who suffer from anxiety, stress and adjustment problems. Some of them have been exposed to traumatic experiences, while others have problems due to heavy work pressure and a difficult climate of cooperation. In this group, supervisors are over-represented in relation to the total number of employees.

Noise-induced injuries have been discussed above. With regard to the overall nervous system, this group contains a wide range of conditions such as solvent-related injuries (from previous employment), vibration-induced nerve damage and irritation of the eyes.

Undiagnosed conditions include various symptoms that are due to exposure to undesirable working environment factors, but which are difficult to classify as disease. These also include sleep disturbances. It seems obvious that many people experience sleep disturbances after having worked a so-called swing shift, as this shift system was listed as the cause in 43 such cases.

The various position categories which were exposed to work-related diseases are shown in Figure 2.12.c. Since in recent years there have been relatively many reports for employees in management positions, these have been put into a separate category.

The diagram may give the impression that workers within the drilling sector were particularly vulnerable. However, taking into account that this function performed more than 23% of the total man-years, the number of cases is therefore considerably lower than may be expected. The proportion of reports for the catering staff group increased somewhat compared with 1996, and was approximately equivalent to the number of man-years for this group. There was a decline in 1997 of reported incidents in the construction and maintenance group. This group was responsible for 43% of the total man-years, but accounted for 32.9% of the reported incidents of disease.

2.13 GAS LEAKS, FIRES AND NEAR-FIRES

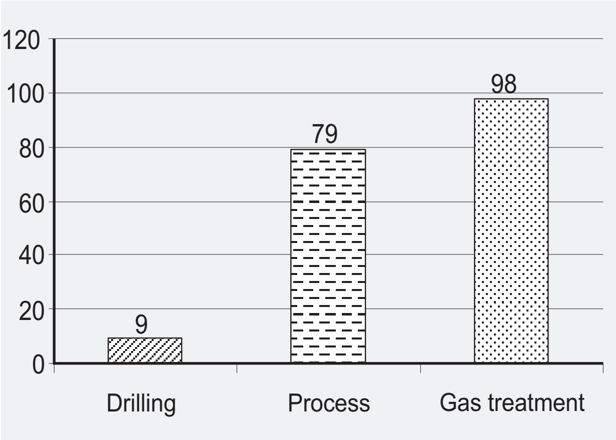
2.13.1 GAS LEAKS

The Norwegian Petroleum Directorate has received reports of 186 hydrocarbon gas leaks in 1997 compared with 156

Table 2.13.1.a
Distribution of gas leaks according to degree of severity and method of detection

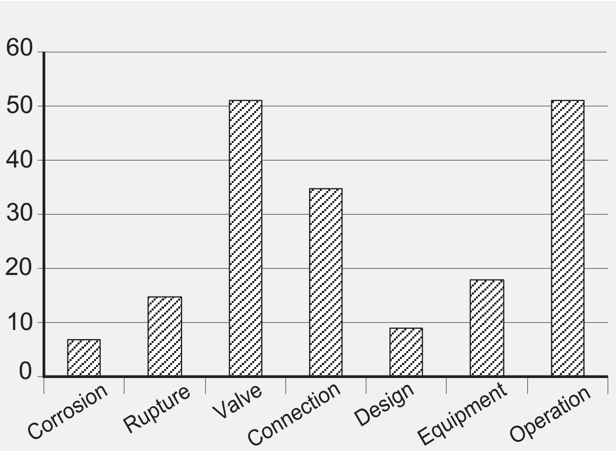
Severity	Number of leaks	Automatically detected	Manually detected
Major	3	3	0
Middle	27	14	13
Minor	156	52	104
Total	186	69	117

Figure 2.13.1.a
Area where gas leaks occurred



Process (oil): Systems containing oil (wells, separators, etc.)
Drilling: Areas for drilling and well activities
Gas treatment: Systems containing gas only (compression, injection, flare)

Figure 2.13.1.b
Main group of faults resulting in gas leaks



Connections: Flanges, connections, seals
Equipment: Equipment and instruments
Operation: Procedual faults, faults operation, lack of planing

Table 2.13.1.b
Gas leaks - causes and degree of severity

	Major	Medium	Minor	Total
Corrotion/erosion	2	1	4	7
Fracture (cracks/holes)	0	5	10	15
Valve	0	2	49	51
Flange	0	5	30	35
Faulty design	0	0	9	9
Equipment/instrumentation	0	3	15	18
Operation error	1	12	38	51
Total	3	28	155	186

in 1996. See Figures 2.13.1.a and b and Tables 2.13.1.a and b.

Three of the leaks were considered to be major, based on an evaluation including the quantity of the emission, danger potential and causal relation. Two of the leaks were caused by corrosion/erosion, while one occurred as a result of incorrect operation of equipment.

Seen in relation to the number of installations in operation and produced petroleum, the Directorate believes that the situation and the danger scenario are stabile with regard to the trend in the number and severity of the reported leaks. An increase in minor leaks has been reported, which indicates an increased willingness to also report the smallest leaks.

It is a challenge, both for the participants in the petroleum activities and for the Norwegian Petroleum Directorate, to continue and increase efforts to reduce the number of leaks. In this context, exchange of information between operating companies regarding causal relation may be a good basis for evaluating the dominant and repetitive causes of leaks, thereby enabling implementation of efficient and goal-oriented measures.

A new database for registration of gas leaks is being set up by the oil companies on the Norwegian shelf. The purpose of the database is to provide a better data foundation for determining the ignition probability for gas leaks, but the data will also provide an important contribution in the work towards preventing gas leaks.

There are few incidents which are due to corrosion, however, these are often serious incidents when they occur. Thus, two of the three major incidents which may be categorized as serious were due to corrosion and/or erosion.

The third major gas leak is due to a missing blind flange on a pipe in the flare system. Gas leaked out in an area where hot work was being performed. If the gas had ignited, the damage could have been quite extensive.

Together with valve defects, most often leaks in gaskets and service plugs, operational errors account for the majority of minor gas leaks. Typical operational errors are:

- valve left in incorrect position
- lack of insulation towards flare/drain
- leaking during bleed-off, flaring and draining
- deficient planning and use of safe job analysis
- communication breakdown
- inadequate procedures

2.13.2 FIRES AND NEAR-FIRES

The Norwegian Petroleum Directorate has registered 25 fires and near-fires in 1997, compared with 19 in 1996.

Table 2.13.2
Fires - causes and degree of severity

	Ignition sources				
	Welding	Torch cutting	Electrical/ short-circuit	Temperature	Total
Major		1			1
Medium				2	2
Minor	6		2	14	22
Total	6	1	2	16	25

Most fires in1997 were caused by high temperatures. High temperatures were due to:

- overheating of engines, pumps, bearings, etc.
- hot exhaust canals
- defect in thermostat for heating element

Fire on Transocean Arctic

The fire, which is characterized as major, occurred on Transocean Arctic on 19 June 1997. The fire was caused by torch cutting, probably when remnants from the cutting fell down into a room below, igniting cables or oil remnants in the room. The fire was brought under control after about one-half hour. The extent of the damage was restricted to ruined cables, fittings, hoses and the like. If the fire had lasted longer, a tank of drilling mud in the area could have been ignited and the damage development could then have been much more extensive.

2.14 DAMAGE TO LOAD-BEARING STRUCTURES AND PIPELINES

The Norwegian Petroleum Directorate receives reports of damage to and incidents involving load-bearing structures and pipeline systems. The information is gathered in the CODAM database, which now contains data concerning approximately 3200 incidents related to load-bearing structures and approximately 2200 related to pipeline systems.

2.14.1 PIPELINES AND RISERS

The majority of the damage to and incidents involving pipeline systems is in the categories of "insignificant" and "minor". These are incidents which do not require much repair or follow-up. Incidents in the "major" category include, for example, leaks in pipelines and risers, incidents involving buckling of pipelines, as well as external and internal corrosion, etc., depending on the scope of the damage and the criticality.

In 1997, two major incidents occurred which are related to pipelines:

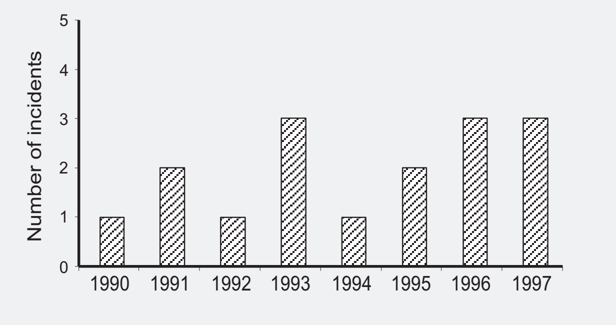
In the "Leaks" category, one incident was reported in 1997 which is classified as "major." A leak occurred in a flexible water injection riser during pressure testing. A closer inspection revealed an opening in the pressure reinforcement. The exact cause of the damage has not yet been proven, but the most likely cause is either too great a bend on the pipe or damage due to a falling object.

In the other incident, it was discovered that a stone block of approximately 5-10 m^3 was partially resting on a 16-inch condensate pipeline. The stone block was removed in September and subsequent inspection revealed no significant damage to the pipeline.

2.14.2 LOAD-BEARING STRUCTURES

Figure 2.14.2 illustrates the number of ship collisions with installations on the Norwegian shelf during the period 1990-1997. Three ship collisions were reported to the Directorate in 1997, the same number as in 1996.

Figure 2.14.2
Number of ship collisions with installations, 1990 -1997.



A stand-by vessel bumped into the protective frame on a riser on an installation anchored to the seabed, while the vessel performed a loading operation. The collision resulted in a bent stay in the protective frame.

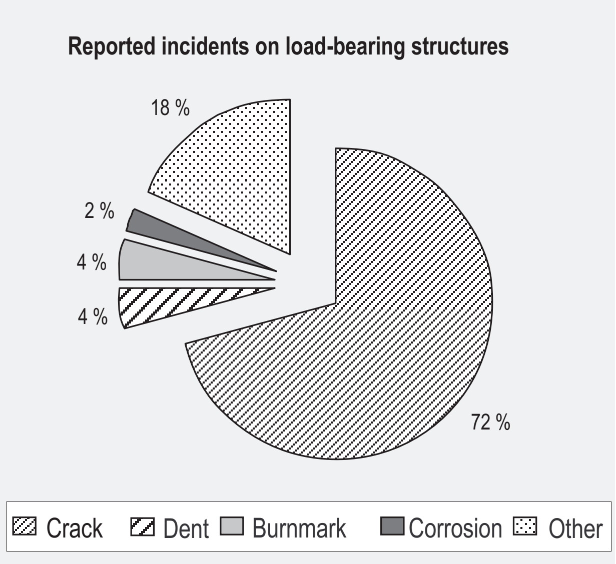
The two other incidents in 1997 were related to collisions between drilling installations and a stand-by vessel and supply vessel respectively. These incidents caused only minor damage to the installations.

2.14.3 FISSURATION ON LOAD-BEARING STRUCTURES

The Directorate has received a report of a serious case of fissures in a tank in the crossover between pillar and the pontoon. The fissure caused a leakage of 3-8 m^3 sea water into the tank per day. Welding work was commenced to repair the fissures and this work was completed in April and June 1997.

Figure 2.14.3 shows that fissures account for about ¾ of the total reported incidents for load-bearing structures. The incidents are divided according to severity with about 97% of the incidents in the category “insignificant” or “minor” and 3% in the category “major.”

Figure 2.14.3
Percentage distribution of damages and incidents on load-bearing structures



2.15 DIVING

2.15.1 DIVING ACTIVITY LEVEL

During 1997, 527 surface-oriented dives and 870 bell runs totaling 101,000 man-hours in saturation were carried out on the Norwegian shelf and in connection with Norwegian pipelines in foreign sectors. This is approximately ten times as many surface-oriented dives and three times as many saturation dives as in 1996.

The average length of bell dives for saturation diving was 5.0 hours in 1997, which is approximately 1.4 hours less than in 1996. The average saturation period was 14.1 days, an increase of 1.7 days from the previous year. The average time in the water for surface-oriented diving in 1997 was 1.3 hours, which is about the same as in 1996. The diving operations have been conducted from nine different vessels and installations.

Diving activities have been divided among inspection, maintenance and construction activities on fields where Elf, Saga, Phillips, Statoil and Amoco are the operators. Diving in connection with construction work has constituted a large portion of the activity. This work has mainly been related to connection of pipelines and assistance with installation of structures.

2.15.2 TRAINING

No saturation divers were trained in 1997. The Norwegian Professional Divers’ School and the National Divers’ School have trained a total of 69 divers in 1997 who have been issued Class 1 certificates.

2.15.3 RESEARCH AND DEVELOPMENT

In 1997, the Norwegian Petroleum Directorate has continued its participation as a member of the board and project management group in the diving-related research program, OMEGA. This involvement helps to ensure that the Directorate's professional and technical staff is kept up to date with regard to ongoing research and development activities in this field.

In November 1997, the annual diving seminar was held as a joint seminar for both open sea diving and diving in sheltered waters.

2.15.4 PERSONAL INJURIES IN DIVING ACTIVITIES

Figures 2.15.4.a and 2.15.4.b present a summary of the number of incidents reported to the Norwegian Petroleum Directorate for the years 1985-1997 in connection with diving activities. The incidents are subdivided into the categories near-accident, accident and fatal accident. An accident is defined as being incidents which lead to some form of personal injury. Infections, such as inflammation of the external auditory canal, are consequently also registered as accidents.

No fatal accidents have occurred in connection with diving activities since 1987. The number of reported accidents entailing personal injury related to saturation diving has increased compared with 1996, more or less in concurrence with the increase in the activity level. Of the 19 reported personal injuries, none were serious. Most (11 incidents) concern infections in the form of inflammation of the external auditory canal and skin infections.

Of the 19 near-accidents reported in connection with saturation diving in 1997, six are characterized as serious.

Figure 2.15.4.a
Incidents in saturation diving

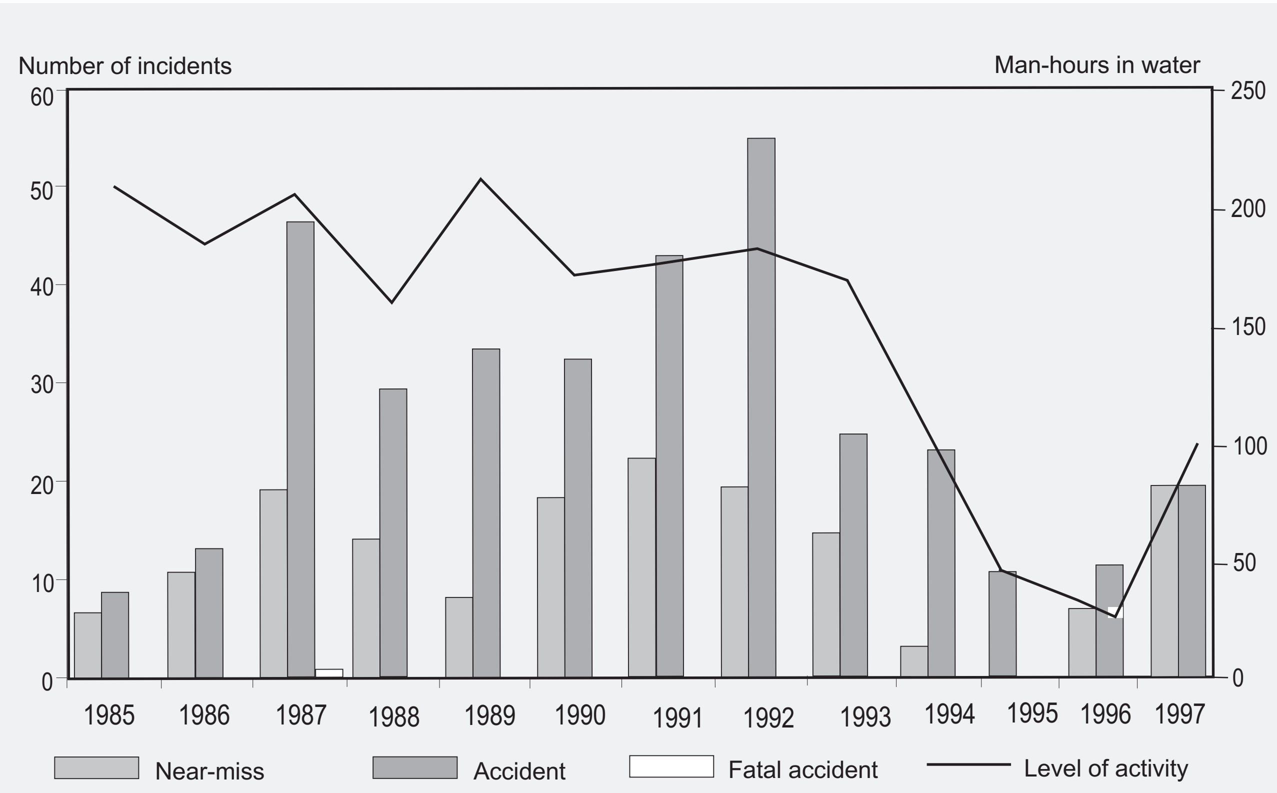
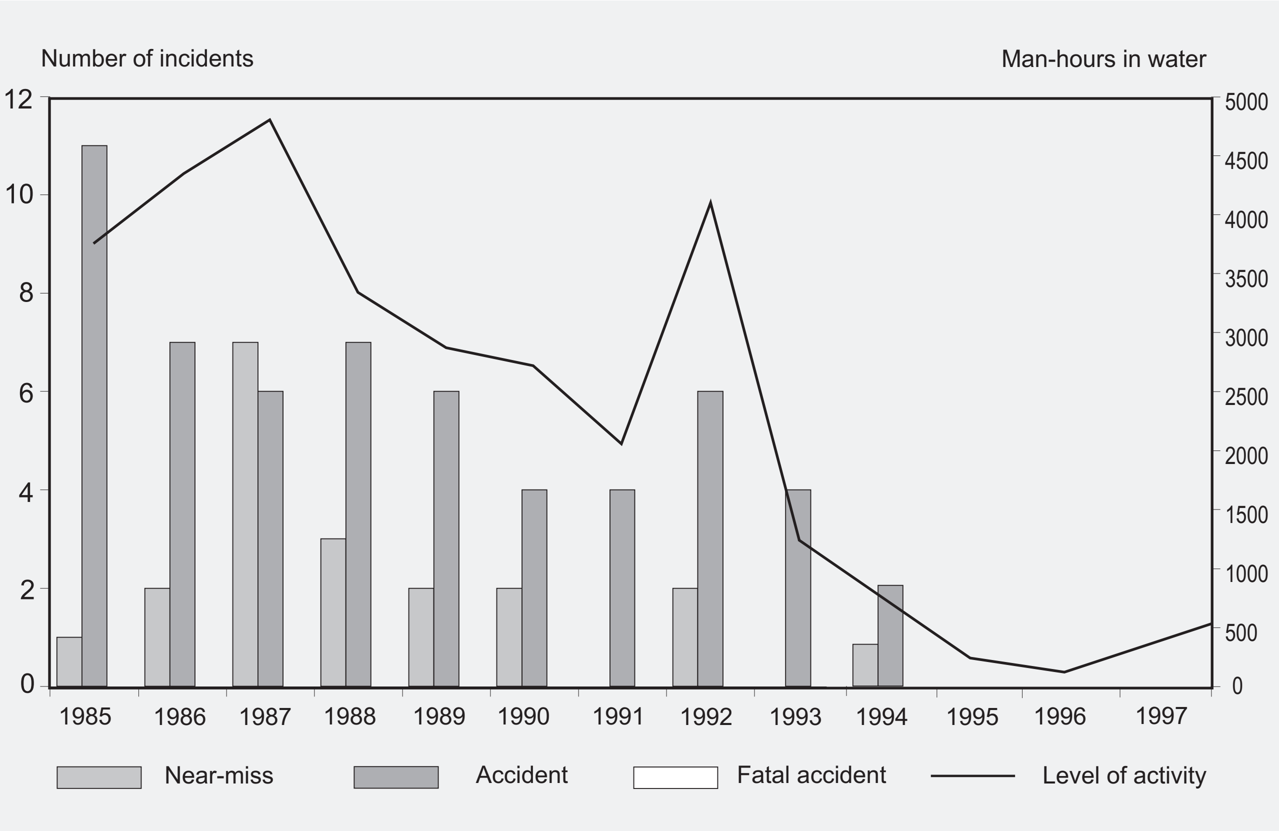


Figure 2.15.4.b
Incidents in surface oriented diving



2.15.5 EXPERIENCE GAINED FROM SUPERVISION OF THE DIVING ACTIVITIES

In 1997, the Norwegian Petroleum Directorate has directed attention towards the industry's measures to familiarize divers with work plans, equipment, procedures and experiences, as a part of the preparations for the annual season and for the respective assignments ("familiarization").

Pursuant to this, the Norwegian Petroleum Directorate believes that these activities can be improved with regard to making use of conclusions from experience reports, as well as in purely general terms in order to include safety-related information to a greater degree.

The supervision has also been aimed at the industry's strategies for hyperbaric evacuation, which are undergoing a change. A relevant topic in this context is whether equipment units which are included in the preparedness for emergency situations in connection with hyperbaric diving must be available where the diving takes place, or whether it is sufficient that the equipment is available on land.

In addition, the Norwegian Petroleum Directorate has noted that uncertainty prevails in the industry regarding the quality of equipment and procedures which are involved in the evacuation of divers. There is still work to be done in order to bring the preparedness for hyperbaric evacuation up to a satisfactory level.

With regard to equipment for spare gas supply for divers, during the last two years, the Norwegian Petroleum Directorate has received reports of 13 incidents, mainly related to leaks and activation problems. Therefore, the Norwegian Petroleum Directorate plans to follow up this problem area in 1998. It is necessary that both manufacturers, contractors/users and operating companies assume an active role in order to solve the problems related to equipment for spare gas supply.

During 1997, several operators have applied for an extension of the limit for time in water from 4 to 6 hours. The Norwegian Petroleum Directorate has exempted from the regulatory requirement on this point with a number of preconditions. One of these has been that the diver returns to the bell and is given a break with access to fluids after 3-4 hours in the water. The Norwegian Petroleum Directorate has received positive feedback from divers with regard to this extension. In this context, the Norwegian Petroleum Directorate has initiated a research project on the loss of fluids during diving. The project has provided the necessary background knowledge to enable consideration of the applications for exemption. On the basis of new knowledge and these experiences, the Directorate will evaluate whether the regulations should be changed as regards this point.

The supervision of the diving activities has shown that there is still a potential for improvement with regard to integrating safety and working environment factors into the work routines. The companies often perform risk analyses and other safety evaluations which are of high quality, but they appear to have difficulty in translating the conclusions into concrete actions.

3. Environmental measures in the petroleum activities

3.1 CONSIDERATION FOR THE ENVIRONMENT

The Norwegian Petroleum Directorate has noted that attention surrounding environmental aspects has increased significantly during the course of the year. Environmental considerations have gradually attained a central position in the formulation of petroleum and energy policy. The Directorate's new main objective and goals more clearly reflect the Norwegian Petroleum Directorate's responsibility and tasks regarding the environment. The consideration for the environment is addressed as part of the work to ensure sound management of the Norwegian petroleum resources.

The main activities in this work are preparation of regulations and other frameworks for the activities, preparation of reports and consulting activities for the responsible ministries, and supervision of the activities carried out by the operating companies. Other activities are participation in national and international forums which work on environmental considerations, information work and cooperation with other authorities, particularly the State Pollution Control Authority (SFT).

3.2 MILJØSOK

MILJØSOK was established in 1995 in order to stimulate a more binding cooperation between the authorities and the oil and gas industry in order to solve the most important environmental challenges. The MILJØSOK report was submitted to the Ministry of Petroleum and Energy in December 1996. The report provides a comprehensive environmental status and description of the environmental challenges for Norwegian petroleum activities, a review of technical/economic alternatives and an evaluation of the means used in climatic and environmental policy.

The next phase of MILJØSOK started in October 1997 when a secretariat was established in connection with OLF (Norwegian Oil Industry Association), as well as a separate Council and Cooperation Forum. The Norwegian Petroleum Directorate participates in the MILJØSOK Council and the Directorate places emphasis on good cooperation and active participation in the MILJØSOK context.

In 1997, the Norwegian Petroleum Directorate has followed up the MILJØSOK report in cooperation with the Ministry of Petroleum and Energy and other concerned authorities.

3.3 AUTHORITIES AND FRAMEWORKS

The Norwegian Petroleum Directorate and the State Pollution Control Authority both have independent authority in the petroleum activities under the Petroleum Act and the Pollution Act. The Norwegian Petroleum Directorate also enforces the Act concerning CO_2 tax.

The petroleum legislation requires that all activities be carried out in a responsible manner which safeguards the safety of personnel, the environment and financial values.

The Pollution Act has the objective of ensuring proper environmental quality so that pollution and waste do not lead to health hazards, do not affect general well-being or harm nature's capabilities of production and self-renewal.

The regulations regarding management systems, risk analyses and preparedness have authority in both of the central acts mentioned above, and are administered by the Norwegian Petroleum Directorate together with the rest of the technology regulations and the Working Environment Act. The supervisory responsibility among the authorities is distributed through the directive for organization of the supervision.

3.4 SUPERVISION OF THE ACTIVITIES

Security against pollution is covered under the safety concept as it is applied in the shelf activities, and supervision of environmental measures and environmental activities is an integral part of the supervision activities. The Norwegian Petroleum Directorate carries out supervision of internal control systems for operators and contractors in order to ensure that the activities are planned and implemented in accordance with the authorities' requirements and goals and acceptance criteria in the companies. The Norwegian Petroleum Directorate evaluates the overall safety, resource and economic aspects of environmental measures.

The comprehensive integrity of the authorities' supervision work is ensured through the Norwegian Petroleum Directorate's coordinating role in relation to the State Pollution Control Authority in the supervision activities. The common guidelines for the authority which lie inter alia in the Norwegian Petroleum Directorate's management of the supervision system and the regulations regarding management systems, risk analysis and preparedness, also contribute to this. This area is also addressed in more detail in Chapter 2 - Safety and Working Environment.

In its supervision of exploration drilling in environmentally sensitive areas, the Norwegian Petroleum Directorate has placed particular emphasis on preventive measures which the operators implement, and work is in progress to look at how the companies' risk and preparedness analyses safeguard the consideration for environmental sensitivity in the actual planning of drilling operations. In addition, the Norwegian Petroleum Directorate has followed the operators' work on stipulating acceptance criteria for environmental risk, in other words, the risk the operator itself can accept for its activity.

The Norwegian Petroleum Directorate also carries out supervision of the use of equipment which measures fuel consumption and the quantity of gas used for flaring and cold venting. Collection of the CO_2 tax on the shelf is the responsibility of the Norwegian Petroleum Directorate,

Figure 3.4.a
Emissions of CO_2 per Sm^3 oe. Emissions from use of diesel are not included.

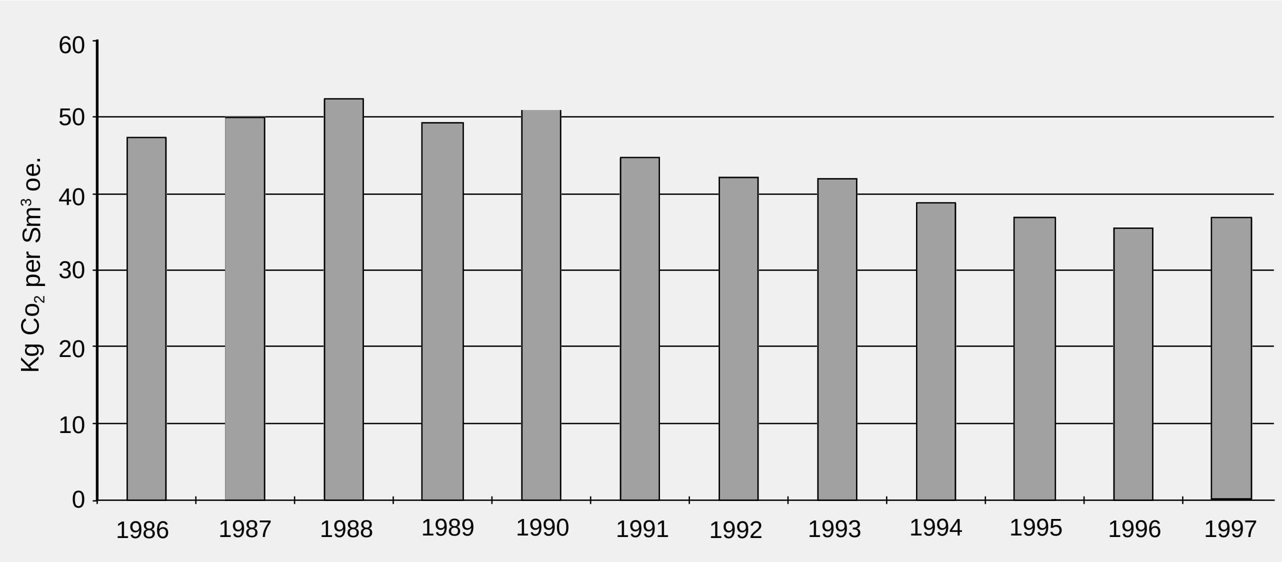
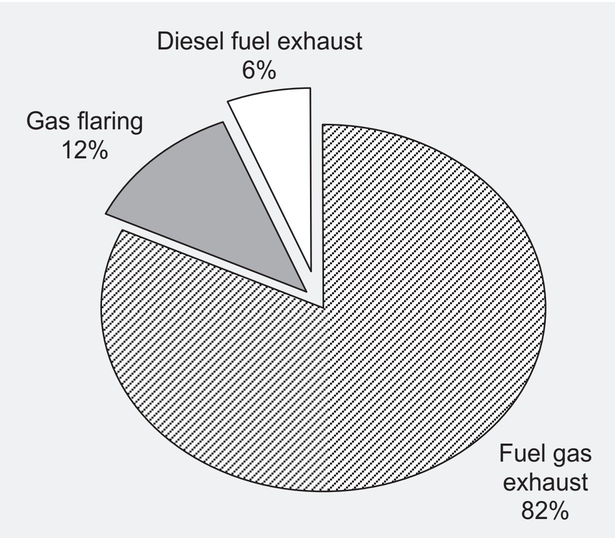


Figure 3.4.b
CO_2- emission sources



and the Directorate makes an annual evaluation of the tax which contributes to reducing CO_2 emissions in an efficient manner. In 1997, the tax rate has been 87 øre per Sm^3 natural gas burned and cold vented and 87 øre per liter diesel consumed.

The total CO_2 emissions from taxable activities were 8.4 million tonnes in 1997, while the total emissions from the sector were about 10 million tonnes. For taxable activities, this is an increase of 0.7 million tonnes compared with 1996. There are minor changes in the CO_2 emissions per produced unit as illustrated in Figure 3.4.a. Figure 3.4.b shows how the emissions are divided by source.

3.5 THE EXTERNAL ENVIRONMENT

When the Norwegian Petroleum Directorate evaluates consequence analyses, plans for development and operation and applications for consent, the environmental aspects are a natural part of and fully integrated with the rest of the Norwegian Petroleum Directorate's evaluation. Great emphasis is placed on the ability to make use of technology which reduces the volume of emissions, electrification, CO_2 separation and injection.

Within the Norwegian Petroleum Directorate's sphere of responsibility, the Directorate follows up the environment-related conditions which are evident from Storting documents. In 1997, the Norwegian Petroleum Directorate has worked together with the Norwegian Water Resources and Energy Administration to prepare the study "Electricity from land to the oil and gas activities", which examines the costs of supplying offshore installations with electric power from land. This work is a follow-up to Storting Report No. 41 (1994-95), Recommendation S No. 144 (the Climate Report).

The Norwegian Petroleum Directorate also prepares prognoses for emissions of CO_2, nitrogen oxides, methane, KFK and NMVOC. Significant resources have been spent on implementing new routines for making prognoses for emissions to the air. Over the longer term, the changeover will mean an efficiency gain and improved quality for the prognoses. The prognoses are an important basis from which to evaluate means so that national and international commitments may be followed up. In addition, there has been a collaboration with the State Pollution Control Authority (SFT) in connection with reporting of emissions and discharges. This collaboration will continue in 1998.

As a step in the authorities' follow-up of the MILJØSOK work, the Norwegian Petroleum Directorate arranged a seminar, in cooperation with the operating companies, regarding the sharing of experience in environmental matters. The seminar drew 170 participants and will be followed up in close cooperation with MILJØSOK's Council and secretariat.

In addition, the Norwegian Petroleum Directorate is working to influence the industry to develop efficient and environmentally friendly solutions which, at the same time, provide the best possible economy.

3.6 DISPOSAL OF INSTALLATIONS

A separate chapter regarding the cessation of petroleum activities is included in the new Petroleum Act which took effect on 1 July 1997. According to this Act, the licensees shall submit a cessation plan 2-5 years before the expected termination of the use of an installation or the expiration of the license. The plan shall contain a proposal for continued production or shutdown of production and disposal of the installations.

Norwegian authorities have appointed an inter-ministry committee whose purpose is to develop a national policy for disposition of installations which have been used in the petroleum activities. This committee also contributes to the ongoing international work, mainly under the Oslo and Paris Convention (OSPAR).

An assessment program has also been initiated in order to evaluate disposal of pipelines. The plan is to complete the program in the year 2000. The Norwegian Petroleum Directorate is a key contributor of terms to the Ministry of Petroleum and Energy.

The guidelines of the International Maritime Organization (IMO) also provide guidance in connection with disposition of installations which are no longer in service. Two key conditions in these guidelines are:

- Installations which are located at a depth of less than 75 meters and have a supporting structure which weighs less than 4,000 tonnes shall be removed. (The water depth has been increased to 100 meters for all installations which are deployed after 1 January 1998).

- Should an installation be removed to below the sea surface, a free height of a minimum of 55 meters of water shall be left from the sea surface down to the part of the installation which remains.

In addition, the Norwegian Petroleum Directorate contributes with evaluations connected with the cessation plans for the individual fields. The plans for disposal of Øst Frigg and Tommeliten Gamma have been considered in 1997.

4. International cooperation

4.1 COOPERATION WITH NORAD

In 1997, the Norwegian Petroleum Directorate's NORAD assistance, which amounted to approximately 5.1 man-years, was financed by NORAD. The majority of the assistance has been directed towards the following cooperating countries: Namibia, South Africa, Mozambique, Eritrea, India, Vietnam and Nicaragua. The Norwegian Petroleum Directorate has also continued its cooperation with the Coordinating Committee for Coastal and Offshore Geoscience Programmes in East and South-east Asia (CCOP). One of the Norwegian Petroleum Directorate's employees was stationed as project coordinator at the technical secretariat in Bangkok in 1997.

The Norwegian Petroleum Directorate has come a long way towards meeting NORAD's objective of establishing long-term cooperation agreements with relevant institutions in the countries concerned. All main projects are governed by such agreements, and work or evaluations are proceeding for new agreements with Angola, South Africa and Bangladesh.

In addition to personnel from the Norwegian Petroleum Directorate, extensive use is made of Norwegian suppliers of goods and consultant services in connection with implementation of the individual projects. Consultants are often selected in competition with international companies. Within this type of service, Norwegian expertise ranks at the top in an international perspective.

The following is a brief overview of the activities in the main development assistance countries and new projects which are planned:

Namibia

The Norwegian Petroleum Directorate has assisted in the formulation of regulations and follow-up of drilling operations. Namibia has built up a small, but highly qualified petroleum management system. The decision in 1997 regarding first phase development of the Kudu gas field and continuing oil exploration are main challenges. NAMCOR (state oil company) is the main cooperation partner on behalf of the Ministry of Mines and Energy.

Mozambique

The Norwegian Petroleum Directorate has continued its support in the formulation of legislation, resource, pipeline and safety regulations and model contracts for the petroleum activities. Treaty negotiations with South Africa have also been concluded under Norwegian leadership. This work is carried out using Norwegian and international consultants in addition to the Norwegian Petroleum Directorate's own expertise. A special challenge has consisted of assisting Mozambique in separating the administration functions from the state oil company, ENH, and transferring this to DNCH (Directorate and main cooperation partner), while at the same time assisting ENH in continuing its commercial tasks.

Plans for development of the Pande gas field and build-up of gas-based iron and steel industry in Maputo (Mozambique) based on ore from South Africa were submitted in December. Norwegian experts are assisting Mozambique in the evaluation of these plans. If the project is realized, it will be one of the largest industrial projects in Africa.

In addition, follow-up of drilling operations, data security and general institutional support have been important activities. Further resource mapping is an important task for the cooperation institutions in Mozambique. An increasing number of international companies have shown interest in exploration for oil, particularly in the deep sea areas, and for development of gas resources.
A new 4-year program for institutional support was approved by NORAD in 1997.

Tanzania

The assistance has included negotiation support concerning development of the Songo-Songo gas field and assistance concerning data management. TPDC (state oil company) is the main cooperation partner. NORAD has decided not to continue institutional support within the petroleum sector.

Eritrea

The Norwegian Petroleum Directorate has provided assistance concerning establishment of framework conditions, resource planning, assessment of environmental impact, promotion of exploration areas, data storage and seismic surveying. The Ministry of Energy and Mineral Resources is the main cooperation partner.

India

The Norwegian Petroleum Directorate has assisted our cooperation partner, DGH, with transfer of experience concerning a large part of the Directorate's sphere of responsibility. Storage of large quantities of data, general data management, resource evaluation, development planning and implementation of safety audits are areas of focus for the assistance. Several delegations from DGH have visited comparable technical milieus in the Norwegian Petroleum Directorate, and technical personnel from the Norwegian Petroleum Directorate have visited DGH. An evaluation is now being made of whether the program, scheduled to end in 1998, will be continued for a new 3-year period.

Vietnam

The Norwegian Petroleum Directorate has continued its assistance concerning development of safety regulations and training in the area of safety management. The main cooperation partner is Petrovietnam (state oil company). SFT is cooperating in the same project.

CCOP

The Norwegian Petroleum Directorate has provided assistance to the cooperation organization in Eastern and Southeastern Asia which works for the mapping of petroleum resources in the area and lays plans for exploitation of these resources. A geo-professional expert from the Norwegian Petroleum Directorate has worked at CCOP's secretariat in Bangkok as a consultant. A number of professional seminars have been arranged in the area, inter alia in Korea and Cambodia (spring of 1997), for the organization's members. Assistance has also been provided in the form of software and training in the use of modern analysis methods.

Nicaragua
The Norwegian Petroleum Directorate has provided assistance concerning promotion, mapping of the resource potential and securing of data. Seminars have also been arranged in the country in cooperation with PETRAD. INE is the main cooperation partner (office answers to the Ministry of Energy). Further activities in Nicaragua depend on the final approval of the new Petroleum Act.

Bangladesh
The recently established "Hydrocarbon Unit" in the Ministry of Oil and Energy in Dhaka has requested assistance from NORAD. The Norwegian Petroleum Directorate has assisted NORAD in evaluating the request and an institutional cooperation is being considered.

South Africa
The Norwegian Petroleum Directorate has assisted NORAD and the Department of Mineral Resources and Energy in connection with identification of assistance needs in the petroleum sector and formulation of project applications. Organization of upstream oil and gas activities, establishment of framework conditions for marketing of natural gas in South Africa, organization of sales of petroleum, organization of state ownership interests in the petroleum sector and training are important areas for potential future Norwegian assistance.

Angola
In cooperation with PETRAD, a petroleum policy seminar was arranged in Luanda. Plans for further cooperation are being prepared, so that a decision concerning a possibly more extensive institutional cooperation will probably be made in 1998.

In addition, general assistance has been given to NORAD in the evaluation of other new project plans. An attempt has been made to improve the exchange of experience with other institutions that provide similar support.

4.2 COOPERATION WITH PETRAD

As a result of a pilot project carried out by the Norwegian Petroleum Directorate for NORAD during the period 1989-1993, PETRAD was established as an independent foundation by the Norwegian Petroleum Directorate and NORAD on 1 January 1994.

The objective of the foundation is to place Norwegian expertise and competence in the fields of management and administration of petroleum resources at the disposition of managers from the authorities and national oil companies in Africa, Asia, Latin America, Oceania and Russia/ CIS (Commonwealth of Independent States). This is accomplished by adapting seminars according to inquiry and need by the authorities in the above-mentioned regions, in addition to the organizing of two eight-week courses each year, "Petroleum Policy and Management" and "Management of Petroleum Operations". The courses are held in Stavanger.

All PETRAD activities are aimed at senior and middle management personnel.

The activities are carried out through PETRAD engaging people who have a high level of competence in the petroleum activities. Up to now, PETRAD has made use of more than 300 experts from around fifty companies, institutions and authorities as lecturers and resource people in its courses and seminars. The eight-week courses in Stavanger integrate the overall Norwegian experience and expertise within petroleum administration and management. PETRAD also provides its course participants with comprehensive insight into the Norwegian petroleum industry and Norwegian culture through excursions and social arrangements.

With the Norwegian Petroleum Directorate and NORAD as founders, PETRAD is viewed as a neutral representative and conveyer of knowledge from the Norwegian public authorities. The response shows that PETRAD has had a significant effect as a "door opener" and a creator of contacts in many countries.

The location of PETRAD in the Norwegian Petroleum Directorate means that the Directorate has a close and profitable cooperation with the foundation. The Norwegian Petroleum Directorate participates with lecturers and resource personnel both at courses and seminars in Norway and abroad.

In 1997, the Norwegian Petroleum Directorate contributed to the implementation of PETRAD's two annual 8-week courses "Management of Petroleum Development and Operations" and "Petroleum Policy and Management", held in the Norwegian Petroleum Directorate's offices, this time with 47 participants from 27 nations.

The Norwegian Petroleum Directorate has also contributed to the implementation of the following seminars in 1997:

- Seminar on Petroleum Policy and Management, Bangkok, Thailand
- Seminar on Petroleum Policy and Management, Phnom Penh, Cambodia
- Seminar on the Petroleum Industry, Managua, Nicaragua
- Petroleum Economic, workshop for participants from Kazakhstan, Stavanger
- Workshop on Commercialization of Natural Gas, Nairobi, Kenya
- Seminar on Petroleum Policy and Management, Hanoi, Vietnam

- Reservoir Management, Baku, Azerbaijan
- Upstream Petroleum Policy and Fiscal Framework, Riga, Latvia
- Petroleum Resource Management, Luanda, Angola
- Advanced Reservoir Management, Kunming, China

This activity contributes to professional exposure to and understanding of different cultures, while, at the same time, it increases the total expertise for those employees of the Directorate who are involved.

The Norwegian Petroleum Directorate is also involved in connection with PETRAD's commitment in relation to Russia. This commitment is mainly coordinated under the Norwegian-Russian Forum for Energy and Environment, which is led by the Ministry of Petroleum and Energy. Under the forum, several working and expert groups have been established which are administrated by PETRAD with participation from Russia and Norway. The Directorate participates in all of these expert groups. The work is often carried out in the form of active work seminars.

4.3 COOPERATION WITHIN RESOURCE MANAGEMENT

Annual meetings with Danish and British authorities

As an oil and gas province, the North Sea is basically divided between the U.K., Norway and Denmark. Even though the individual fields are quite different, there are many similarities among the fields in the North Sea area. The petroleum resource management problems encountered by government agencies in the three countries are therefore similar in many ways.

Consequently, for many years the Norwegian Petroleum Directorate has carried out regular meetings with British and Danish resource management authorities who share basically the same responsibilities for their sectors as the Norwegian Petroleum Directorate does for the Norwegian shelf. For the U.K. shelf, it is the technical section of the Oil and Gas Division in DTI (Department of Trade and Industry) which is responsible for the resource aspect of exploration, development and operation activities. For the Danish shelf, the Danish Energy Agency (Energistyrelsen) has a comparable responsibility.

The objective of the meetings is primarily to exchange opinions and experience from the respective activities. The U.K. activities are a few years ahead of us. It has therefore been very useful to draw on their experiences with regard to improved oil recovery, development of small fields and unitization. The Danes have particular problems related to chalk fields. It has therefore been valuable to acquire first hand information on their experiences. Data management and the environment are other areas where it has been very useful to exchange experience. Close cooperation is envisaged also in these areas.

During the year, one meeting was held with the Danish authorities and one with the British. This year's meeting with the Danes took place on Svalbard on 16-19 August. The main topic was exploration and development in new areas. The Danes gave an account of their experiences on Greenland, while we explained the plans for the areas outside of Mid-Norway. In terms of geology, these areas represent many of the same challenges. In addition to the exchange of information regarding the status in the respective areas, there was a special focus during the Svalbard meeting on environmental factors and the problems we face in this connection. The unique surroundings on Svalbard created a nice frame for the meeting.

The 1997 meeting with the British authorities was held in London on 2-3 December. The general theme this time was exploration, development and production, as well as environmental factors. The British authorities talked about their experiences, while we contributed with an account of the conditions on the Norwegian shelf.

Annual meetings with other countries' authorities - exploration phase

Since 1983, annual meetings on technical issues have taken place between the Norwegian Petroleum Directorate and state administration units in other Northern and Western European countries with responsibility for exploration for oil and gas.

In the beginning, England, Ireland, Denmark, Germany, the Netherlands and Norway took part in these meetings. Subsequently, France, the Isle of Man and the Faeroe Islands have joined.

The responsibility for hosting the meetings is on a rotation basis among the various countries. Norway has hosted these meetings twice previously (1988 and 1995).

The main issues of discussion at the meetings are geotechnical, exploration technology and data management issues, as well as challenges faced by the various countries in their efforts towards efficient discovery of new oil and gas resources.

The combined expertise and experience at these meetings is substantial, and the access to information is important for each individual participating country with a view towards developing optimal exploration strategies.

Annual meetings with other countries' authorities - fiscal metering

In those countries where Norwegian petroleum is landed, the authorities' responsibility and roles are stipulated in treaties and cooperation agreements. There is extensive cooperation on the part of the authorities in order to take care of the individual country's requirements for fiscal metering. An important forum in this cooperation is annual meetings in which status and future activities in the area of metering technology are reviewed. The Norwegian Petroleum Directorate has cooperation agreements with German and Belgian authorities. In 1997, a cooperation agreement with France was negotiated. Final signing will take place during 1998. An initiative has also been made vis-à-vis the British authorities with a view towards developing a metering technology cooperation agreement under existing treaties.

International research cooperation regarding improved oil recovery
Since 1979, Norway has participated in international research cooperation under the direction of the International Energy Agency (IEA) regarding improved oil recovery using advanced methods. Nine countries currently participate, and the cooperation largely consists of a commitment for a certain scope of research in specific areas and the exchange of the results. For the period 1986-1995, the Norwegian aspect of this cooperation has been taken care of through the state research programs SPOR and RUTH, which have been led by the Norwegian Petroleum Directorate. From 1996, the cooperation projects have been financed through the RESERVE program of the Research Council of Norway.

Since 1986, the Norwegian Petroleum Directorate has represented Norway in the international management committee for this IEA cooperation.

Lecture activities
Also in 1997, the Norwegian Petroleum Directorate's staff members have been involved as lecturers in a number of international conferences, workshops and the like, in reference to issues relating to resources. These activities are in demand and they are regarded as being very important in order to contribute to a mutual exchange of information and experience. The Norwegian shelf receives international focus with regard to exploration efficiency, development solutions, resource exploitation and use of new technology. Openness regarding both the overall resource scenario and solutions chosen on specific fields has provided a basis for stimulation of technology and promising cooperative relations between participants on the shelf. There is still considerable interest on the part of other countries in gaining insight into Norwegian resource management and the authorities' active instigator role in this context.

4.4 COOPERATION WITHIN MANAGEMENT OF SAFETY AND WORKING ENVIRONMENT

BORIS - development of safety regulations for offshore petroleum activities in Russia
The Norwegian Petroleum Directorate's cooperation project with the Russian supervisory directorate responsible for the supervision of safety in the industry, Gosgortekhnadzor, was concluded at the end of 1997 as planned. During the three-year BORIS project (Bilateral Cooperation on Development of Russian Regulations concerning Industrial Safety), the Norwegian Petroleum Directorate has assisted the Russian authorities in their development work to establish a supervision system and relevant regulations which are to ensure safety in the petroleum activities on the Russian continental shelf. The Norwegian project activity has been financed by the Ministry of Foreign Affairs.

The goal of the project has been to develop a foundation so that Russian authorities can meet the petroleum activities in their northern waters with modern safety management of international standard. This is particularly important to Russia as the country wants to attract international oil companies as investors and partners.

In 1997, the project activities have largely been focused on working on a proposed future supervision system for the petroleum activities on the Russian shelf. Important, and for the Russian authorities, new elements of the project proposal have been the emphasis on the industry's own responsibility for safety, recommendations that the companies establish management systems that include safety, introduction of a consent system, as well as emphasis on supervision efficiency through a greater degree of coordination of the various supervisory bodies' regulations, activities and decisions. The project proposal has been sent from the Gosgortekhnadzor for future consideration by relevant political bodies in Russia.

As an important sub-activity in this connection, studies have been carried out on both the Russian and the Norwegian sides in order to see how the companies ensure the safety of their facilities. On the basis of the Russian project participants' understanding of the experiences which companies on the Norwegian shelf have with regard to safety management and the recommendations the Norwegian Petroleum Directorate has made after studies of Russian petroleum activities, the Gosgortekhnadzor wants to change its strategy from control to management in the supervision of safety in the Russian offshore petroleum activities.

In addition to the proposal for a supervision system, a proposal has been presented for paramount framework regulations for safety in the petroleum activities on the Russian continental shelf. On the Russian side, this proposal has been used as a basis for development of safety regulations.

During the three years the Boris project lasted, the two cooperating partners have developed extensive knowledge concerning each others' philosophy, methodology and organization with regard to regulation of petroleum activities. For the Norwegian Petroleum Directorate, this means increased insight into the Russian authorities' framework for the planned petroleum activities in our neighboring waters in the north. For the Gosgortekhnadzor it has meant, in addition to the specific proposals presented, an opportunity to learn from the experience of others and to create a broad basis for the future decisions to be made in the development of a progressive management of safety on the shelf.

RUN ARC - comprehensive safety and environment regime for oil and gas activities on the Russian continental shelf
The experience and the knowledge gained from the Norwegian Petroleum Directorate's and the Gosgortekhnadzor's involvement in the Boris project will be carried on in a new, expanded cooperation project where

the Norwegian Petroleum Directorate, the Gosgortekhnadzor and several other Russian authorities, as well as the American Minerals Management Service (MMS), participate.

In this trilateral collaboration between Russia, USA and Norway (RUN), the American and Norwegian technical authorities will assist their Russian colleagues in the development of a comprehensive safety and environment regime for the oil and gas activities on the part of the Russian continental shelf which lie in the Arctic (ARC). The Ministry of Natural Resources leads the project work on the Russian side. The Ministry cooperates closely with other authorities in Russia which are responsible for different aspects of regulation of the oil and gas activities in the country. The USA will be represented by MMS, the technical authority on safety and the environment for inter alia offshore oil and gas activities. Based on the experiences from the Boris project, the Norwegian authorities have asked the Norwegian Petroleum Directorate to take responsibility for the Norwegian cooperation. The Ministry of Foreign Affairs finances the Norwegian part of the project.

The plan is to implement the project in three phases: preliminary study, development and implementation.

The first phase of the project will take place from September 1997 to September 1998. This is a preliminary study to examine the current situation in Russia in the areas of safety and environmental legislation, safety management, preparedness, environmental monitoring, etc. The preliminary study also includes a survey of other national and international projects within the same fields. In addition, the study shall describe what is necessary in order to create a new system. Recommendations and conclusions in the preliminary study will depend on the goals Russia sets for the future management of safety and the environment. The primary goal of the first phase, however, is to investigate whether it is technically, politically and financially feasible to carry out a project which has the goal of establishing administration which will ensure a uniform safeguarding of safety and the environment on the Russian shelf. If the project is to succeed, it is crucial that it receives the necessary financial and technical resources available in Russia, and that the relevant political authorities support and place demands on the implementation of the project.

On the Russian side, a working group has been established to gather information and analyze the situation in Russia. The contributions from the American and Norwegian sides have so far been to participate in the formulation of project plans and obtain information as to how oil and gas activities are managed in other countries. The Norwegian Petroleum Directorate is also responsible for coordination of activities and information among the three parties.

If the preliminary study shows that it is possible to implement all of the phases of the project, Phase 2 will be to develop a management system which includes the necessary elements. The Russian authorities themselves will have to decide what frameworks will apply to the petroleum activities on the shelf, with regard to national priorities, choice of principle foundation for regulations and supervision, distribution of responsibility, use of resources, etc.

The final phase will be to implement the solutions which are selected. This will require a build-up of competence, establishment of the necessary organization and establishment of regulations and methods for carrying out supervision of all aspects of the activities.

Safety and working environment

The Norwegian Petroleum Directorate cooperates extensively with international technical institutions and government agencies, either directly or indirectly through Norwegian government agencies. The purpose of this cooperation is to:

- contribute to ensuring that safety and the working environment in the petroleum activities at least meet accepted international standards,
- ensure access to relevant information for competence building and regulatory development,
- contribute insight and experience on the international level in order to promote positive development in safety and working environment issues.

In general, the cooperation has consisted of participation in international governmental cooperation in European and United Nations agencies, but also more direct cooperation with the various types of international and regional professional institutions. The most important partners in 1997 have been:

- NSOAF - North Sea Offshore Authorities Forum,
- the EU Commission, in cooperation with the Ministry of Local Government and Regional Development, on safety and the working environment,
- the United Nations' organizations IMO and ILO regarding safety at sea and the working environment, respectively,
- European Diving Technology Committee (EDTC) and the Association of Offshore Diving (AODC) regarding diving safety,
- Marine Technology Directorate (MTD), United Kingdom, regarding inspection and maintenance of installations,
- Welding Institute, United Kingdom, regarding research and development of materials and welding,
- American Petroleum Institute (API), participation in annual conference on technical petroleum topics and standardization,
- National Association of Corrosion Engineers (NACE), USA, participation in the annual conference on corrosion and surface treatment,
- CENELEC, cooperation on electrical engineering standardization in Europe through the Norwegian Electrotechnical Committee (NEK).

NSOAF - North Sea Offshore Authorities Forum
In the field of safety management, the Norwegian Petroleum Directorate participates in the North Sea Offshore Authorities Forum (NSOAF), where representatives from all the North Sea countries' governmental authorities in charge of supervision of offshore petroleum activities take part.

In May 1992, NSOAF established two working groups in which the Norwegian Petroleum Directorate is represented. One of the groups is to consider whether an NSOAF plan should be established with the aim of mutual acceptance of methods of documenting compliance with national regulatory requirements, such as the "Safety Case", which is specific to the individual mobile installation. This group is chaired by a Norwegian.

The other group, which has a Danish chairman, will seek to harmonize the requirements for safety training in the various North Sea countries.

The EU Commission
Since 1982, Norway, represented by the Norwegian Petroleum Directorate, has held observer status in the EU proceedings on safety and the working environment in offshore petroleum activities.

This work comes under the EU's "Safety and Health Commission for the Mining and Other Extractive Industries" (SHCMOEI), and was until early 1993 carried out by a working group called "Working Party on Oil, Gas and Other Minerals Extracted by Borehole". The SHCMOEI activities were reorganized in 1993 and the working group is now called "Committee on Borehole Operations", (the Borehole Committee).

In 1996, the Borehole Committee also raised issues connected with harmonization of the requirements for safety training in the North Sea countries; an issue which has also been under consideration in the NSOAF context since 1992. The issue has been passed on to SCHMOEI, which agreed to arrange a working conference under the direction of EU in Luxembourg in June 1997 to discuss common recognition of instruction/training certificates. The conference drew broad participation from representatives of employers, employees and the authorities, as well as other concerned organizations and institutions. A draft report from the conference has been sent out for comments, and the final report is expected to be adopted by SHCMOEI during 1998.

The Borehole Committee is also continuing its work regarding personal injury statistics for the offshore petroleum activities.

Electrotechnical standards and regulations
The Norwegian Petroleum Directorate participates in the following committees on this subject:

a) Norsk Elektroteknisk Komité (NEK) (Norwegian Electrotechnical Committee), Standards Committee (NK) 18, Shipboard Installations,
b) NEK, NK 31 - Electrical Equipment for Explosion-Hazard Areas,
c) International Electrotechnical Commission (IEC), Technical Committee 18 (TC 18) - Electrical installations of ships and of mobile and fixed offshore units

In addition, the Norwegian Petroleum Directorate's participant in the IEC work is the link between IEC/TC 18 and ISO/TC 67: "Materials equipment and offshore structures for petroleum and natural gas industries".

IEC is developing a series of international standards for electrical installations on fixed and mobile units: "IEC 1892 Mobile and fixed offshore units - electrical installations". The work takes place in TC 18, where the development of proposals for such standards takes place in Working Group 18 (WG 18), where the Norwegian Petroleum Directorate's participant is the project manager.

Lecture and information activities
In 1997, the Norwegian Petroleum Directorate's staff members have again been involved as lecturers and chairpersons in a number of conferences, courses and the like, regarding safety and working environment issues both in Norway and abroad. These activities are regarded as being very important in a mutual exchange of information and influence, not least in light of the increasing internationalization of regulations, etc.

The Norwegian Petroleum Directorate continues to note a great deal of interest in the Norwegian model for management of safety and working environment in offshore petroleum activities. A number of countries want to establish regulations which, through result-oriented requirements, set clear goals for the activities, as well as a supervision system where comprehensive thinking, coordination by the authorities and cooperation among the participants are key elements, and they have requested the Norwegian Petroleum Directorate's assistance in the work to develop such a management model.

5. Projects

5.1 PROJECTS WITHIN RESOURCE MANAGEMENT

5.1.1 INDUSTRY COOPERATION

FORCE

FORCE *("FOrum for Reservoir Characterization and reservoir Engineering")* is a cooperation forum on problems related to improved oil recovery. FORCE started in 1995 and has 19 oil companies, the Research Council of Norway and the Norwegian Petroleum Directorate as members. All participants are represented on the board. Statoil holds the chairmanship, and the secretariat is located in the Norwegian Petroleum Directorate.

The main goal of FORCE is to contribute to increasing oil recovery on the Norwegian continental shelf. The potential for improved oil recovery is large and, to some extent, time-critical. FORCE provides the companies with a forum in which to discuss important issues with each other, with the authorities and with representatives from the research and the supplier industry. In their respective organizations, the FORCE members have broad expertise and experience which provides a unique opportunity for solving problems together, or initiating cooperation projects with external suppliers. The participants in FORCE discuss and initiate research, development and demonstration of methods and tools which can contribute to future improved oil recovery.

A special FORCE group with participants from eight companies and the Norwegian Petroleum Directorate has worked during 1997 to identify common problems which are critical in order to be able to realize the potential for improved oil recovery. A "bottleneck" analysis has been conducted, and the results will be used as a basis for further work in FORCE.

In 1997, "Problem Defining Workshops" were organized in the areas of well testing and use of propping agents in connection with fracturing in wells. FORCE also organized seminars on the following topics: "IOR Challenges on the Norwegian Continental Shelf", "Relative Permeability" and "Seismic Reservoir Monitoring. These FORCE meetings have been of high quality and have contribute to improved understanding of the challenges in the various areas. All of the FORCE arrangements have been very well attended.

A total of 12 projects have been initiated in 1997 through the cooperation forum. Preliminary work in FORCE led to the commencement of Phase V of the chalk research program "Joint Chalk Research" (JCR) in the autumn of 1997. Phase V of JCR contains eight projects concerning central topics such as reservoir description, modeling of rock mechanics problems and recovery methods such as air injection and WAG. Nine oil companies now support the chalk research program which is administered by Phillips Petroleum.

FIND

FIND was established in 1996 as a cooperation forum for the exploration phase. 20 oil companies as well as the Norwegian Petroleum Directorate are members. All of the members are represented on the Board, and Saga is the chairman.

The main objective of FIND is to focus on cooperation with regard to planning and implementation of projects with significance for future exploration on the Norwegian shelf. So far, three projects have been started.

The "Super grid" project has the objective of establishing a joint coordinate system for handling of digital seismic data. 15 companies have participated in the pilot project which has been carried out by two contractors. Western Geophysical has developed a test data set consisting of 21 3D surveys in the northern part of the North Sea. The seismic has been rotated, re-gridded and adapted with regard to phase and amplitude. IBM has developed the Petrobank software, and emphasis has been placed on simple definition of cubes and random lines, automatic prioritization of one 3D survey in overlap zones, as well as easy retrieval of 3D surveys to the work stations which are used most often.

After a technical evaluation of the pilot project has been completed, a potential extension of the project will be considered.

The first phase of the "Evaluation of Well Results" project has consisted of reporting prognoses for drilling and results from drilling all of the 163 exploration wells which were drilled during the period from 1990 to 1996. All of the FIND members participate in the project. The result from the project confirms that the oil companies over-estimate the resources prior to drilling and under-estimate the likelihood of making a discovery, particularly for high risk prospects. In addition, the project shows that the estimated uncertainty for most project parameters is too small. Statistical correlations show no connection between the specified probability for hydrocarbon sources in a prospect and whether the companies report lack of hydrocarbon sources as the reason for dry prospects. The project has shown that there is a great potential for improvement in the filing of prognoses and results of drilling on the part of the companies. It has been decided that the first phase of the project shall be extended so that the companies can report more and better data for the wells which have already been reported, perform a better analysis of dry wells, as well as report exploration wells completed in 1997. New analyses are scheduled for completion in the summer of 1998.

The project "The Effects of Drilling Mud Components on the Quality of Geological Data" started in September. Twelve companies participate in the project. One of the objectives is to document the effects modern drilling mud has on the quality of data from the exploration wells. The project is scheduled for completion in December 1998.

In addition, a working group is working on the final definition of the project "Basin Analysis and Applied Thermochronology on the Mid-Norwegian Shelf". The project has a planned duration of five years, and will involve staff and laboratories from universities, the Geological Survey of Norway and the oil industry.

FUN

FUN (Forum for Forecasting and Uncertainty Evaluation Related to Petroleum Production) is a cooperative forum relating to problems within the areas of preparing prognoses and uncertainty evaluations for future oil and gas production. FUN was started in May 1997 and has 18 oil companies and the Norwegian Petroleum Directorate as members. The Ministry of Petroleum and Energy and OLF (Norwegian Oil Industry Association) are observers in the forum. The forum is organized with a Board consisting of representatives from all of the members. Norsk Hydro is the chairman, while the Norwegian Petroleum Directorate is responsible for the secretariat.

The main objective of FUN is to develop better practice and methods with regard to estimating of hydrocarbon resources, forecasting future production with associated emissions and discharges, uncertainty evaluations and decision processes. Two working groups have been set up. Working group 1 is to focus on improved information and reporting routines among the companies and between the companies and the authorities. Working group 2 is responsible inter alia for initiating and being a program committee for workshops and seminars for managers and technical personnel.

In 1997, a management seminar and a workshop were arranged. The title of the seminar held on 10 September was "Use for Forecasting and Uncertainty Evaluation in Petroleum Related Decisions." There were nearly 100 participants from most of the oil companies on the Norwegian shelf, as well as participants from universities and research institutions. The program included presentations which covered a wide range within the field of practical use of prognoses and uncertainty evaluations on the field, company and national level.

A workshop with the title "Forecasting Development and Production from Improved Recovery" was organized on 4 November. The focus of this workshop was methods of forecasting and uncertainty evaluation in connection with projects for improved oil recovery.

DISKOS

The DISKOS project started as a cooperation between Saga Petroleum, Norsk Hydro, Statoil and the Norwegian Petroleum Directorate in 1993 for development and operation of a common data base for technical petroleum data. The project has now been significantly expanded, and includes a total of 17 oil companies as well as the Norwegian Petroleum Directorate.

The data base includes most of the processed 2D and 3D seismic from the Norwegian shelf. This is largely the oil companies' own data, but contracting companies have also loaded in seismic data. Data access is controlled and governed by the rules and agreements for usage rights which the parties have entered into, or which are stipulated in the Petroleum Act. A comprehensive access rights system in the data base prevents unauthorized access to confidential data.

The data base also contains quality-controlled data from exploration wells. The Norwegian Petroleum Directorate delivers weekly quality-controlled administrative data to the data base. This data describes production licenses, blocks, fields, seismic navigation, well locations, pipelines, etc. The data base now contains more than eight terabytes of data.

The data base and the network which the DISKOS members are connected to is operated by PetroData A/S. IBM E&P Solutions in Stavanger has developed the software which is in use. New versions which handle new types of data will be launched in 1998 and 1999.

The cooperation in the DISKOS group is headed by the Norwegian Petroleum Directorate. The costs for development and operation will be divided among the users of the system.

5.1.2 OTHER PROJECTS

THE NORWEGIAN PETROLEUM DIRECTORATE'S GEOPHYSICAL SURVEYS IN 1997

The Norwegian Petroleum Directorate acquired a total of 3,878 km 2D seismic during 1997.

Coastal areas - During the month of June, shallow seismic surveys were made of the stretch from Molde in the south to Beitstadfjorden in the north. Approximately 900 boat-kilometers of seismic data were collected (Figure 5.2.2.a). At the same time, registration of data from an extra small sound source was conducted to enable study of the geology just under the seabed. With the aid

Figure 5.2.2.a
Offshore shallow seismic surveys extending from north of Molde and into Beitstadfjorden

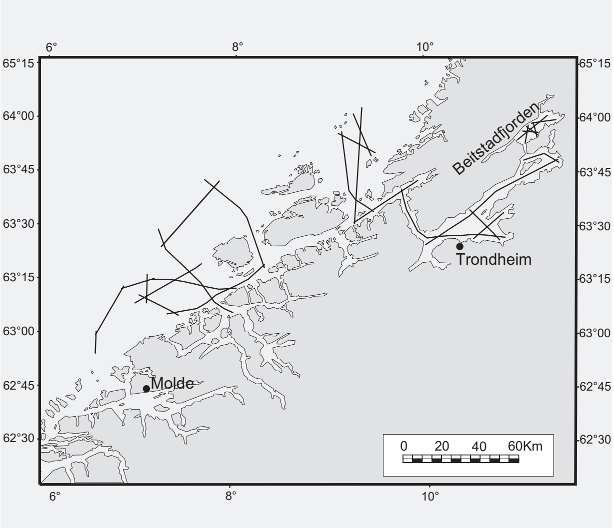
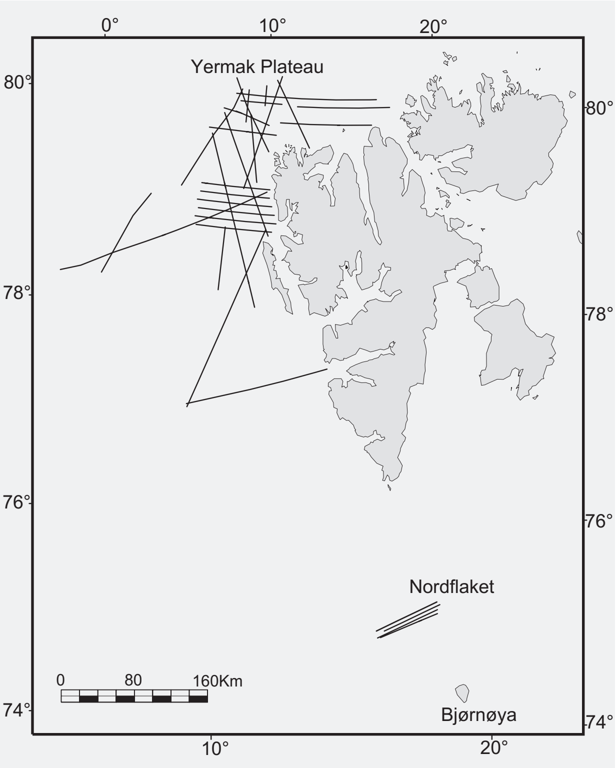


Figure 5.2.2.b
Seismic surveys in the Northern Barents Sea



of multi-beam soundings, bathymetric data was gathered along the lines and surface-covering bathymetry in Beitstadfjorden, Trondheim harbor, Orkdalsfjorden, Korsfjorden and Gaulosen.

The northern Barents Sea - In spite of difficult ice conditions, approximately 2,700 boat-kilometers of seismic were collected on the Jermak plateau. In addition, about 300 boat-kilometers of seismic were collected on Nordflaket to the north of Bjørnøya (Figure 5.2.2.b). Simultaneously with these investigations, data was registered so as to enable a study of the geology just under the seabed.

Gravimetric data - At the same time as the seismic data was collected, approximately 3,900 kilometers of gravimetric data were acquired. The data is inter alia incorporated in gravimetric maps of Norway with ocean areas, which are currently being produced by the Geological Survey of Norway.

Along the west margin of the Barents Sea and on the Jarmak plateau, variable seismic data quality and complex geological structures make it difficult to arrive at a uniform seismic interpretation of main structural characteristics. The Norwegian Petroleum Directorate has achieved an increased understanding of the basin configuration and development of the structure elements in the area through conducting modeling studies where seismic interpretations are correlated with observed and modeled gravimetric and magnetic data. In this connection, the Norwegian Petroleum Directorate's geologists and geophysicists have cooperated with the external consultant Nopec International as and the University of Oslo.

NEWSLETTER

Two issues of the newsletter have been published in 1997. The newsletter is intended to cover relevant news within the entire technical spectrum of resource management. The newsletter is distributed to a number of organizations both in Norway and abroad, and may also be ordered from the Norwegian Petroleum Directorate. The main topic in issue Number 10, published in June, is an updating of the potential for improved oil recovery, while Number 11 deals inter alia with the most important exploration results in 1997.

PUBLICATION CONCERNING IMPROVED OIL RECOVERY

In 1997, the Norwegian Petroleum Directorate continued its work on challenges related to measures for improved oil recovery. An important part of this has been releasing a publication on this topic. The publication addresses inter alia the resource potential, challenges and the authorities' role in order to realize these resources, technological development and status of implementation of new technology on the fields. Special emphasis has been placed on use of gas for injection in order to increase the recovery rate for oil, and on environmental challenges linked with the various measures.

The publication is in Norwegian (YA 792) and English (YA 793). It is also available on the Norwegian Petroleum Directorate's home page on the Internet.

SAMBA

In recent years, the Norwegian Petroleum Directorate has been far in the forefront with regard to the use of data bases and analysis tools. This has provided great advantages in connection with production of reports and analyses. In order for the Norwegian Petroleum Directorate to maintain this advantage in the future, the objective of the SAMBA project is to prepare a new generation of administrative data bases built on modern IT technology.

Particular emphasis is placed on systematizing information which provides the Norwegian Petroleum Directorate with an overview of the activities on the shelf. The SAMBA data base will contain information regarding production licenses, companies linked to the Norwegian Shelf, unitizations, resource estimates for discoveries and fields, historical and forecasted oil and gas production, costs, investments and income.

The project has chosen to use national and international standards. POSC's (Petrotechnical Open Software Cooperation) Epicentre data base is used in the data modeling.

SAMBA was started as a pilot project in 1996, and the first system modules were put into use by the Norwegian Petroleum Directorate in 1997.

ESTABLISHMENT OF NORWEGIAN GEOCHEMICAL STANDARD SAMPLES FOR OIL AND SOURCE ROCK ANALYSIS

This project was begun in 1994 to establish standard samples to ensure better calibration in connection with organic geochemical analyses. 200 kg organically rich source rock samples from Yorkshire and 400 kg from Svalbard have been collected, as well as about 1000 liters of oil from the Oseberg field. These samples have been sent out to around 50 laboratories all over the world for calibration. The establishment of standards is expected to have a positive effect on internal quality control in the laboratories and increase comparability between data from different laboratories. The result of this work was made available to the industry in 1997. This has been a cooperative effort by the Norwegian Petroleum Directorate, Saga, Norsk Hydro and Statoil.

DIGITALIZATION OF BIOSTRATIGRAPHIC DATA

The purpose of the project is to develop the Norwegian Petroleum Directorate's base of biostratigraphic data from exploration and production wells on the Norwegian shelf. The data base consists of biostratigraphic routine reports, as well as internal studies performed in the Norwegian Petroleum Directorate's laboratory. The data files are used in connection with the release of raw biostratigraphic data.

DINIUM-ALPHA:
CHRONOSTRATIGRAPHIC SPREAD, MORPHOLOGY AND PHOTOMICROGRAPHY DATA BASE FOR MICROPLANKTON SPECIES

Dinium-Alpha is a Windows 95/NT-based data base and interface which retrieves chronostratigraphic spread, morphological criteria and digital photomicrography of microplankton species based on searchable morphological and stratigraphic criteria. More than 500 morphological criteria are represented on a user-friendly interface. Dinium-Alpha's area of application is adapted to both single and multi-user environments in order to function as a consistent, morphological/chronostratigraphic platform.

5.2 PROJECTS IN THE AREAS OF SAFETY AND WORKING ENVIRONMENT

5.2.1 MANAGEMENT SYSTEMS

Management of simultaneous projects

The project is a continuation of a project which was started in 1995, and has the goal of identifying risk factors in connection with simultaneous operating and modification activities. The project has the following secondary objectives:

- Assess potential statistical connection between activity level and number of medium/major fires and gas leaks.
- Chart other research on this and related topics.
- Prepare models which can contribute to explaining the observed increase in undesirable events.

Through this project, a better understanding has been obtained of the management mechanisms for parallel modification and operations activities. The Norwegian Petroleum Directorate has benefited from this knowledge in connection with consideration of applications for consent for modification of installations. In addition, the project has provided a useful background for the Directorate's supervision of the operating companies' measures to prevent major accidents in the petroleum activities.

The risk level in the petroleum activities

In 1997, the Norwegian Petroleum Directorate has commissioned Preventor to chart the historic risk in the petroleum activities on the Norwegian shelf during the period 1987-1996, and, on this basis, to give an indication of the risk scenario which may be expected in the next ten years. The project has included:

- permanent and mobile production installations
- mobile drilling installations, including movement of such
- stand-by, supply and anchor-handling vessels
- diving vessels
- pipelaying and crane vessels
- helicopter transportation to and between the installations
- pipeline transportation of oil and gas, as well as oil transportation by tanker

and has assessed the risk related to human life and health, the environment and financial values.

Experiences with the use of risk analysis

The regulations for safety and working environment in the petroleum activities are built upon the assumption that the industry takes an analytical approach to the various types of risk. In 1997, the Norwegian Petroleum Directorate has financed a project carried out by Scanpower, which had the objective of providing an overview of how risk analyses are carried out in the activities, and what experiences the industry has acquired in this area. The experiences from the project have contributed to a strengthening of the Directorate's competence in risk analysis areas, and will be incorporated in the Directorate's basis for supervision of the operators' activities in this area.

Framework conditions for project administration in the petroleum activities

Through a project with SEVU in 1997, the Norwegian Petroleum Directorate has increased its competence regarding management and administration of projects in the petroleum activities. The need for increased competence in this area is connected with the increased commitment to supervision aimed at the operating companies' management systems, and the planned new regulations which will express the authorities' requirements regarding this. The project has primarily focused on internal competence building in the Directorate, and has added valuable knowledge which will be incorporated in the work on the new regulations, as well as in the supervision carried out in this area.

Supervision of maintenance management in the operations phase

The Norwegian Petroleum Directorate has conducted a project in 1997 in order to strengthen the foundation for regulatory development and supervision in the area of maintenance management. The project has charted relevant strategies and methods for maintenance, with regard to planning, organization, follow-up as well as frameworks for maintenance in the form of regulations, standards, etc.

5.2.2 WORKING ENVIRONMENT

Survey of cancer risk

The Norwegian Petroleum Directorate participates with financial and professional support in a project started by the Cancer Registry of Norway in order to survey cancer risk among employees in offshore petroleum activities. The project also receives financial support from the Norwegian Oil Industry Association, the Norwegian Federation of Trade Unions, the Confederation of Norwegian Business and Industry and the Ministry of Local Government and Regional Development.

The background for the project is the recognition of the fact that a number of physical, chemical and psychosocial working environment factors are unique to the petroleum activities. In addition, the organization of the work has consequences for nutrition, living conditions, social life and lifestyle. The project aims at surveying the frequency of cancer among former and current employees in the activities, and to examine whether a potential excess frequency may be related to the working environment and/ or social conditions.

The work to identify persons who have, or have had, their workplace on the Norwegian continental shelf has been completed. These employees will be followed for many years in the future with regard to the development of cancer, and it will probably take many years before any conclusion can be drawn as to whether work on the shelf entails increased cancer risk. A questionnaire has been prepared which will be used to survey the employees' exposure to potential carcinogenic substances.

Registration system for personal injuries

The Norwegian Petroleum Directorate has started work on developing a registration system for personal injuries in the petroleum activities in cooperation with the National Insurance Administration. The work is based on a system developed by the Danish Directorate for labor inspection. The method tool was purchased in 1997 and has been adapted with a view towards Norwegian conditions. A new RTV form has been prepared in collaboration with the National Insurance Administration and persons who are to use the new system have received training in this. The plan is to start using the new system in the first half of 1998.

The new registration system will be more modern and will increase the value of the information in the Norwegian Petroleum Directorate's personal injury register. This creates increased possibilities for systematizing the data for use in prioritization of the Directorate's supervision of the activities. It will also be easier to compare data from the petroleum activities on the Norwegian shelf with other European injury statistics.

5.2.3 DRILLING AND WELL TECHNOLOGY

Well control in deep water

The Norwegian Petroleum Directorate has participated, together with a number of operating companies and drilling contractors, in the financing of a project carried out by Rogaland Research in order to explore the special problems which are related to well control in connection with drilling and well operations in deep water.

The project is expected to be completed in 1998, and for the Directorate, it has provided a significant contribution to the build-up of competence in this area. Experience from the project will be incorporated in the basis for further development of the regulations and for planning and implementation of supervision of operators who carry out activities in deep water.

Stochastic modeling and quantification of well kick and blowout risk in connection with exploration drilling

The Norwegian Petroleum Directorate participates in a project which Rogaland Research is carrying out for Agip where the goal is to establish a stochastic model for well-specific analysis of blowout risk and for evaluation of measures to reduce risk. The results from the project shall contribute to strengthening the basis for decision-making in connection with preparations of drilling programs, as well as to identify and select risk-reducing measures which ensure both safety and cost-effectiveness.

The first phase of the project began in 1997, and is expected to be completed during the first quarter of 1998. The plan is for the entire project to be concluded in 1999.

Technological development within safety systems

Development within electronics and signal conditioning is very rapid, and the Norwegian Petroleum Directorate is concerned with maintaining competence in order to continuously evaluate new solutions in relation to the functional requirements in the regulations with regard to the reliability of the safety systems. The project was started in 1996 and continued in 1997. SINTEF has been responsible for implementation of the project, which has included an evaluation of relevant solutions for signal transmission and conditioning, and has inter alia proven several potential problems related to reliability and integrity in relevant conditions and situations. A review and evaluation has also been made of the relevant standards in this area.

5.2.4 PROCESS TECHNOLOGY

Framework conditions, construction and operation of process facilities

In 1997, the Norwegian Petroleum Directorate has implemented a project with SEVU, which has had the objective of strengthening the competence regarding oil and gas processing as a basis for the Directorate's framework-setting activities in the area of process technology. The project has included charting of international frameworks (directives, etc.), relevant standards, operational factors and new technology in the area.

5.2.5 DIVING

Loss of fluid in connection with diving

The project builds on experience from previous projects concerning technical-operational aspects of manned underwater operations, which in some instances have shown significant loss of fluids for some divers during operational diving. The results from the project, which was implemented at NUTEC in 1997, conclude that the size of the fluid loss during diving with warm water suits depends on the thermal conditions connected with the temperature of the warm water and not on individual factors. Results and recommendations from the project will be used in the Norwegian Petroleum Directorate's consideration of issues relating to inter alia length of time in water.

Hyperbaric evacuation

In 1997, the Norwegian Petroleum Directorate has commissioned a project through SINTEF where the objective has been to develop guidelines for safe, efficient and practical solutions for hyperbaric evacuation based on current lifeboats. The project report contains recommendations with regard to information necessary to make decisions regarding the individual hyperbaric lifeboat in the relevant operations, and regarding areas where improvements of current solutions are needed.

5.2.6 MATERIALS TECHNOLOGY

Mechanical connections on risers over water

The project has its background in the fact that the companies are planning for increasing use of mechanical couplings on risers over water, where welded connections have been used previously. The project is a continuation of a project which started in 1996 and was concluded in 1997. In the first phase of the project, the Norwegian Petroleum Directorate had illuminated which evaluations should be made in order to judge whether a mechanical coupling is equal to a welded connection in terms of safety. The consultant which has performed that assignment has also proposed requirements for testing in connection with installation and use, as well as condition inspections during the use phase. The project was expanded in 1997 to also include mechanical couplings on dynamic risers to floating installations. Also, the industry's comments on the first phase of the project were collected and evaluated.

Use of lightweight construction concrete in the petroleum activities

The Norwegian Petroleum Directorate participates in a project concerning the use of lightweight concrete for various applications within building and construction activities with a view towards increasing knowledge regarding the possibilities of using lightweight concrete in the offshore petroleum activities. The project has also examined the durability of lightweight concrete by monitoring current drainage to the reinforcement, and by testing core samples from existing concrete bridges in Norway. The experiments have been carried out by Sintef Bygg og Miljøteknikk, and provide important contributions towards development of design criteria for cathodic protection and covering of reinforcements in lightweight concrete structures.

Reliability-based design methods for pipelines

On the basis of a previous research project concerning reliability-based design methods for pipelines, the Norwegian Petroleum Directorate implemented a project in 1997 to evaluate these results. The work was performed by Advanced Mechanics & Engineering Ltd in the U.K., and had the objective of evaluating whether the proposed methods are sufficient for use as a basis in connection with construction of pipelines. Among other things, the Norwegian Petroleum Directorate will use this evaluation as a basis for assessment of NORSOK and ISO standards in relation to the regulations in this area.

Disposal of concrete installations

In 1997, the Norwegian Petroleum Directorate has participated in a project led by the company Dr tech O Olsen AS, with the objective of evaluating the possibility of getting existing concrete installations to float for removal, without having to remove the deck facilities or perform other extensive work. The evaluations have been made using Gullfaks A as an example for the detailed calculations. The preliminary conclusions indicate that it could be technically feasible to remove the installations by reversing the installation process. The greatest challenges are linked with the calculation of the weight of the deck facilities, plugging of holes in the drill shaft, and the uncertainty as to what degree the pipe systems used during installation may be used again.

5.2.7 INFORMATION TECHNOLOGY

Drilling data base - DDRS

With background inter alia in needs expressed by the operating companies, the Norwegian Petroleum Directorate conducted a project in 1997 to provide for access to data from the Directorate's drilling data base (DDRS). The work was performed by ISI A/S, and has included a survey of various alternatives for external access to the data base.

6. Organization

6.1 DELEGATIONS

The duties of the Norwegian Petroleum Directorate are set out in the special instructions of 1 October 1992. Duties have also been assigned to the Norwegian Petroleum Directorate by delegation of authority. Such authority is delegated either directly pursuant to acts/regulations or by individual administrative decisions by a superior authority. Delegation applies to parts of:

a) The Petroleum Act, Act 29 November 1996 no 72,
including
- the Petroleum Regulations, Royal Decree 27 June 1997
- the Safety Regulations, Royal Decree 27 June 1997
- the Management Systems Regulations, Royal Decree 27 June 1997
- the Safety Zone Regulations, Royal Decree 9 October 1987

b) The Working Environment Act, Act 4 February 1977, no 4,
Including:
- the Working Environment Regulations, Royal Decree 27 November 1992

c) The CO_2 Act, Act 21 December 1990, no 72
d) The Tobacco Act, Act 9 March 1973, no 14
e) Act relating to scientific research and exploration for and exploitation of subsea natural resources other than petroleum resources, Act 21 June 1963 no 12,
Including:
Regulations relating to scientific research for natural resources on the Norwegian continental shelf, etc., Royal Decree 31 January 1969
f) Regulations concerning safe practices in scientific research and exploration for petroleum deposits on Svalbard, Royal Decree 25 March 1988

6.2 ORGANIZATIONAL CHANGES

The Division for Resource Management was reorganized effective 1 January 1997. The Strategy and Planning Department was converted into a staff department. Responsibility for international cooperation was delegated to a new staff unit, International Cooperation. A new project department, Prognoses and Resource Analyses, was also established under the division. Furthermore, two new project coordinator positions were created in the Exploration Department.

As of 1 May, the regional office in Harstad was converted into a department under the Division for Resource Management.

6.3 STAFF

At the end of 1997, the Norwegian Petroleum Directorate had 366 employees. Eighteen employees were on leave.

Eighteen new employees were hired in permanent positions. Of these, seven came from the oil industry or oil-related activities, four from other private industry, five from the public sector and two were recent graduates.

Twenty-eight staff members have left their positions, seven of these as retirees. This represents 7.9% of the positions.

There has been an increased commitment in comprehensive development of competence in 1997. With a point of departure in the units' competence needs and plans, the Norwegian Petroleum Directorate has started a process which shall ensure optimum cooperation within technical disciplines, management and work processes and relationship-building throughout the Directorate.

6.4 PREMISES

The annex of 3000 m² was completed in September and opened in connection with His Majesty King Harald's visit on 17 October 1997.

6.5 BUDGET/ECONOMY

Expenses

A total of NOK 263,552,850 was spent on the Norwegian Petroleum Directorate's operations in 1996.

The amount was appropriated as follows:

Operating budget	NOK	222 541 863,-
Supervision costs	”	11 980 524,-
Geological and geophysical surveys	”	29 030 463,-
Total	**NOK**	**263 552 850,-**

Of the operating budget, payroll costs account for NOK 138,912,783, lease and operation of buildings NOK 27,513,881, and collection of meteorological and oceanographic data in the Barents Sea NOK 497,144. Consultancy assistance to the Division for resource management accounted for NOK 5,997,012, to the Division for safety and working environment NOK 3,140,843 and to the Administration department NOK 161,032.

The remainder covers expenses related to travel, training, electronic data processing (EDP) operations, new investments in equipment, etc.

In addition to its regular operations, the Norwegian Petroleum Directorate is responsible for:

Cooperating projects	NOK	3 040 761,-
Administration of research program	”	950 736,-
Contribution to the PETRAD foundation	”	1 000 000,-
Project cooperation vis-á-vis Eastern Europe	”	1 200 706,-

Revenues

In addition to paid production royalties, area fees and carbon dioxide taxes totaling NOK 9,856,897,201, the Directorate received NOK 86,235,288 in revenues:

Exploration fees	NOK	1 700 000,-
Commission fees	”	1 449 798,-
Reimbursed supervision costs	”	58 974 291,-
Sale of publications	”	4 608 236,-
Kindergarten fees – parents’ fees/public subsidy	”	2 703 928,-
Miscellaneous income	”	1 412 041,-
Reimbursed for job schemes	”	650 730,-
Reimbursed from National Insurance Administr.	”	1 487 116,-
Reimbursed from other government agencies	”	4 169 806,-
Sale of seismic survey data	”	6 931 582,-
Cooperation projects	”	2 147 760,-
Total	**NOK**	**86 235 288,-**

6.6 INFORMATION

The Annual Report occupies a central position in the Directorate's information activities, as does the continental shelf map, which was published with production licenses updated as of 1 June 1997. In addition, the Directorate issued a number of publications, which are listed in the next section. Sixty-seven press releases have been issued during the year, most in connection with the conclusion of exploration wells. As planned, four issues of the Directorate's internal magazine Oss Direkte were published.

The Norwegian Petroleum Directorate's home page on Internet may be found at http://www.npd.no, and contains inter alia special reports and information concerning the Directorate's sphere of responsibility. Press releases, job vacancies and references to new publications are entered continuously. The information is available in both Norwegian and English, and is searchable. The public can subscribe to press releases by registering their e-mail address on the home page. There were an average of 25,800 visits to the home page per month, half from Norway and the remainder divided among 65 countries.

The OIL reference data base was made available on the Internet free of charge at http://www.interpost.no/oil. The data base is updated on a weekly basis. It contains approximately 50,000 references to Nordic petroleum literature, which may be borrowed from the Norwegian Petroleum Directorate's library. The data base has received positive feedback from the oil industry, and had an average of 2750 visits per month.

Nearly 600 inquiries for inspection of documents under the Freedom of Information Act were processed. This is the highest number of inquiries to date in the 1990s.

6.7 PUBLICATIONS RELEASED IN 1997

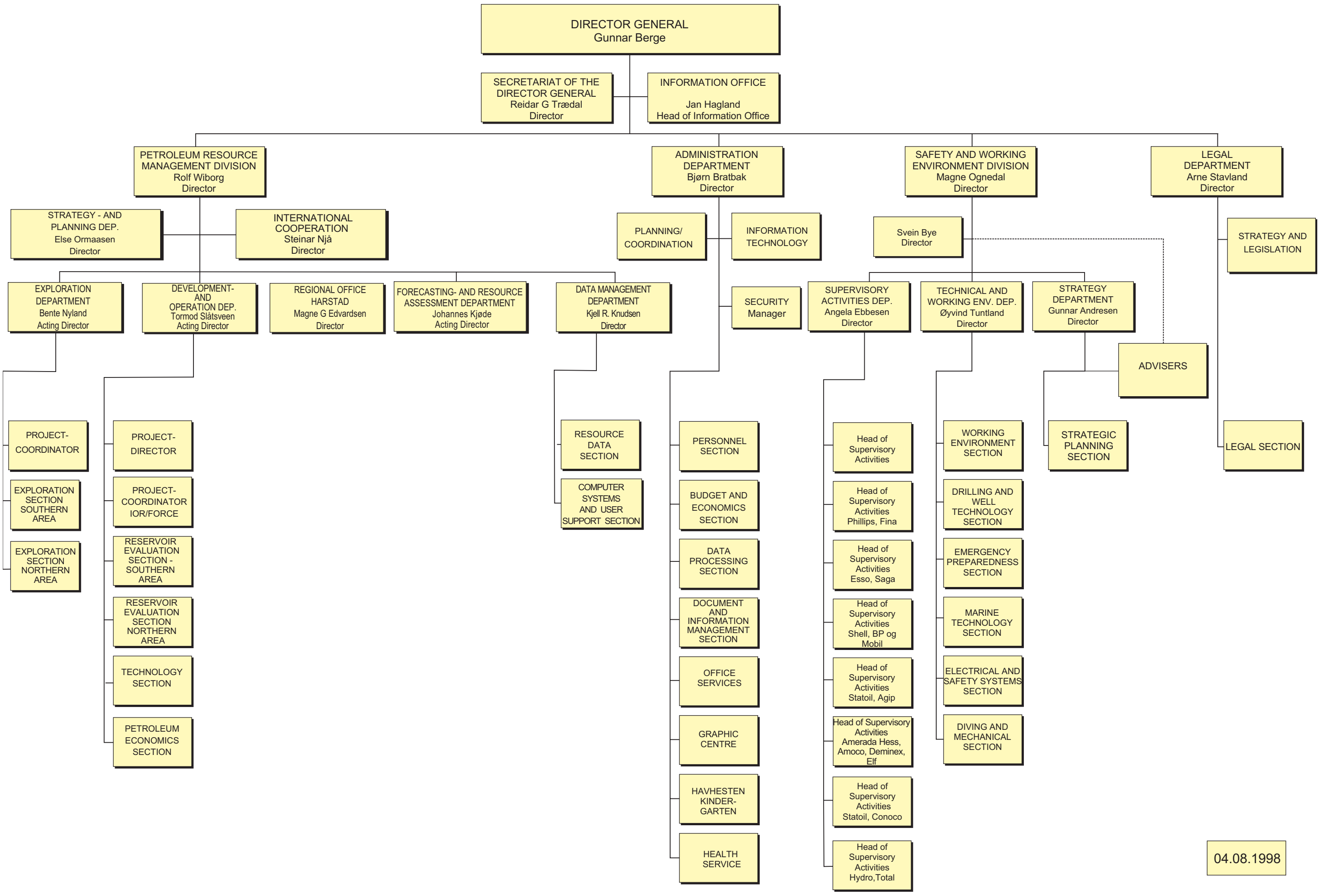
Acts, regulations and guidelines

- Compilation of Acts, regulations and provisions for the petroleum activities in 1997. An updated compendium of the acts, regulations and guidelines applicable to the Norwegian continental shelf.
  Issued 1 April 1997.
- Act relating to petroleum activities
- Act relating to worker protection and working environment
- Regulations to Act relating to petroleum activities
- Regulations relating to the Petroleum Register
- Regulations relating to safety in the petroleum activities
- Regulations relating to management systems to comply with authority requirements, etc.
- Regulations relating to reimbursement of expenses for supervision of safety, working environment and resource management, etc.
- Comparison of various countries' regulations for diving

Other publications

- List of publications issued by the Norwegian Petroleum Directorate (Norwegian)
- 1001 wells (Norwegian)
- Norwegian Petroleum Directorate Annual Report 1996 (Norwegian and English versions)
- Jet-fire resistance test of passive fire protection materials
- Requirements for use of Mechanical Connections on the Pipeline Side of Risers Above the Water
- Report from the DSYS diving data base in 1996 (Norwegian)
- Loss of fluids in connection with diving (Norwegian)
- Comparison of various countries' regulations for diving (Norwegian)
- Clean-up of the seabed in the North Sea 1996 (Norwegian)
- Discoveries on the Norwegian continental shelf (Norwegian and English versions)
- Petroleum resources on the Norwegian continental shelf (Norwegian and English versions)
- Classification of petroleum resources on the Norwegian continental shelf (Norwegian and English versions)
- Licenses, Areas, Area-coordinates, Exploration Wells
- Borehole list - Exploration Drilling
- Development Wells
- Improved Oil Recovery (IOR) (Norwegian and English versions)

6.8 ORGANIZATION CHART



7. Statistics and summaries

7.1 EXPLORATION LICENSES AND PRODUCTION LICENSES

7.1.1 NEW EXPLORATION LICENSES

As of 31 December 1997, a total of 247 exploration licenses have been awarded. These licenses are valid for three years. The following licenses were awarded in 1997:

Company	License No.
Norske Conoco AS	242
A/S Norske Shell	243
Geoteam AS	244
Nopec International ASA	245
Surface Geochemical Services AS	247

7.1.2 SCIENTIFIC EXPLORATION

As of 31 December 1997, a total of 306 licenses for scientific exploration have been awarded on the Norwegian continental shelf. As illustrated in Table 7.1.2, six such licenses have been awarded in 1997.

7.1.3 NEW PRODUCTION LICENSES

Production licenses in connection with the Barents Sea project were awarded on 30 May 1997. Award of areas to the companies took place using one of the two following models: Award of production licenses under Model I follows the previously established practice for awards on the Norwegian continental shelf. For award of production licenses under Model II, the conditions were stipulated in line with the established practice for awards on the Norwegian continental shelf, but with some modifications. The companies have initially received a larger defined area (the seismic area) where a seismic work commitment must be performed within a certain period of time. When the seismic work commitment has been completed, the licensees stipulate the geographic area for the production licenses upon application. This may be done at any time before the expiration of the initial period, but is subject to the Ministry's consent.

The award consisted of 16 production licenses; three production licenses under Model I and thirteen production licenses (divided among four seismic areas) under Model II. Six companies were awarded operatorships. Saga received two and Hydro, Elf, Mobil, Agip and Statoil received one each, see Table 7.1.3.a.

An overview of the licensing rounds for production licenses, awarded area, relinquished and current area is show in Table 7.1.3.b. Table 7.1.3.c shows Norwegian and foreign shares in the licensing rounds. Licensees, operators and other information on active production licenses is shown in Table 7.1.6.

Table 7.1.2
Licenses for scientific exploration for natural resources

License	Institution	Subject			Area
		Geo-physics	Geo-logy	Other	
301/97	University of Bergen			Multichannel reflection seismic	Norwegian Trench
302/97	University of Tromsø	X	X	Marine geological	Balsfjorden and Malangen
303/97	University of Bergen	X			Beitstadfjorden
304/97	Wegener Institut für Polar und Meeresforschung	X	X	Oceanographic Biological	West and north of Svalbard and Norwegian Sea
305/97	Norges Geologiske Undersøkelse	X		Shallow seismic	Troms – Ramsundet and Tjeldsundet
306/97	Ocean Drilling Program			Paleoceano graphic	Bouvet Isl.

Table 7.1.3.a
Awards: Barents Sea Project

Prod. Lic.	Awarded valid to:	Blocks:		Licensees:	Share:	SDFI:
221	97/05/30			Elf Petroleum Norge AS	10,000000	
	07/05/15		O	Norsk Hydro Produksjon AS	20,000000	
				Mobil Development Norway AS	15,000000	
				Saga Petroleum ASA	10,000000	
				Den norske stats oljeselskap a.s	45,000000	(30,000)
222	97/05/30			Elf Petroleum Norge AS	10,000000	
	07/05/15		O	Norsk Hydro Produksjon AS	20,000000	
				Mobil Development Norway AS	15,000000	
				Saga Petroleum ASA	10,000000	
				Den norske stats oljeselskap a.s	45,000000	(30,000)
223	97/05/30			Elf Petroleum Norge AS	10,000000	
	07/05/15		O	Norsk Hydro Produksjon AS	20,000000	
				Mobil Development Norway AS	15,000000	
				Saga Petroleum ASA	10,000000	
				Den norske stats oljeselskap a.s	45,000000	(30,000)
224	97/05/30	7217/ 9	O	Elf Petroleum Norge AS	30,000000	
	05/05/15	7217/12		Mobil Development Norway AS	25,000000	
		7218/ 7		Phillips Petroleum Company Norway	25,000000	
		7218/ 8		Den norske stats oljeselsskap a.s	20,000000	(20,000)
		7218/10				
		7218/11				
225	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Enterprise Oil Norwegian AS	15,000000	
				Neste Petroleum AS	10,000000	
			O	Saga Petroleum ASA	20,000000	
				Den norske stats oljeselskap a.s	40,000000	(20,000)
226	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Enterprise Oil Norwegian AS	15,000000	
				Neste Petroleum AS	10,000000	
			O	Saga Petroleum ASA	20,000000	
				Den norske stats oljeselskap a.s	40,000000	(20,000)
227	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Enterprise Oil Norwegian AS	15,000000	
				Neste Petroleum AS	10,000000	
			O	Saga Petroleum ASA	20,000000	
				Den norske stats oljeselskap a.s	40,000000	(20,000)
228	97/05/30	7222/ 6		Norsk Hydro Produksjon AS	20,000000	
	05/05/15	7222/ 8	O	Saga Petroleum ASA	30,000000	
		7222/ 9		Den norske stats oljeselskap a.s	50,000000	(30,000)
		7222/11				
		7222/12				
		7223/ 4				
		7223/ 5				
		7223/ 6				
229	97/05/30	7122/ 7	O	Norsk Agip AS	25,000000	
	05/05/15	7122/ 8		Enterprise Oil Norwegian AS	15,000000	
		7122/ 9		Neste Petroleum AS	15,000000	
		7122/10		Phillips Petroleum Company Norway	25,000000	
		7123/ 7		Den norske stats oljeselskap a.s	20,000000	(20,000)

Prod. Lic.	Awarded valid to:	Blocks:		Licensees:	Share:	SDFI:
230	97/05/30			Amerada Hess Norge AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
			O	Mobil Development Norway AS	20,000000	
				Saga Petroleum ASA	15,000000	
				Den norske stats oljeselskap a.s	35,000000	(20,000)
231	97/05/30			Amerada Hess Norge AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
			O	Mobil Development Norway AS	20,000000	
				Saga Petroleum ASA	15,000000	
				Den norske stats oljeselskap a.s	35,000000	(20,000)
232	97/05/30			Amerada Hess Norge AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
			O	Mobil Development Norway AS	20,000000	
				Saga Petroleum ASA	15,000000	
				Den norske stats oljeselskap a.s	35,000000	(20,000)
233	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)
234	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)
235	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)
236	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)

Table 7.1.3.b
Production licenses and acreages as of 31 December 1997.

License round	Awarded date	Production License no	Number of blocks* Awarded	Relinquish.	Area awarded km^2	Area relinquished km^2	Area in awards km^2
1.	1.9.1965	001-021	74	59	39842,476	37018,724	2823,752
	7.12.1965	022-022	4	4	2263,565	2263,565	
or.	25.8.1995	018B	1		102,503		102,503
	12.9.1977	019B	2		617,891	152,037	465,854
2.	23.5.1969	023-031	9	2	4107,833	2682,948	1424,885
	30.5.1969	032-033	2		746,285	376,906	369,379
	14.11.1969	034-035	2		1024,529	564,837	459,692
	11.6.1971	036-036	1		523,937	326,571	197,366
or.	10.8.1973	037-037	2		586,834	295,157	291,677
3.	1.4.1975	038-040					
		and 042	7	5	1840,547	1665,310	175,237
	1.6.1975	041	1	1	488,659	488,659	

License round	Awarded date	Production License no	Number of blocks* Awarded	Relinquish.	Area awarded km²	Area relinquished km²	Area in awards km²
	6.8.1976	043	2		604,558	555,553	49,005
	27.8.1976	044	1		193,076	90,417	102,659
	3.12.1976	045-046	4	2	1270,682	814,708	455,974
	7.11.1977	047	2	2	368,363	368,363	
	18.2.1977	048	2	1	321,500	203,498	118,002
	23.12.1977	049	1	1	485,802	485,802	
or.	16.6.1978	050	1		500,509	151,962	348,547
or.	11.8.1995	050B	1		98,403		98,403
4.	6.4.1979	051-058	8	2	4007,887	2663,296	1344,591
5.	18.1.1980	059-061	3	3	1108,078	1108,078	
	27.3.1981	062-064	3	1	1099,522	876,292	223,230
	23.4.1982	073-078	6	2	2311,912	1890,425	421,487
6.	21.8.1981	065-072	9	3	3218,945	2263,008	955,937
or.	20.8.1982	079-079	1		102,167		102,167
7.	10.12.1982	080-084	5	5	2082,966	2082,966	
or.	8.7.1983	085-085	3		1621,160	725,816	795,344
or.	11.9.1992	085B	2		27,166		27,166
8.	9.3.1984	086-100	17	3	6338,273	4383,944	1954,329
9.	1.3.1985	101-111	13	3	5293,054	3709,722	1583,332
or.	26.7.1985	112-112	1		260,215	249,821	10,394
10a	23.8.1985	113-120	9	2	3075,433	2334,158	741,275
or.	11.8.1995	114B	1		11,059		11,059
10b	28.2.1986	121-128	9	3	3828,258	2922,587	905,671
or.	11.7.1986	129-129	1	1	225,393	225,393	
11.	10.4.1987	130-137	11	7	4163,711	3873,036	290,675
	29.5.1987	138-142	11	8	2975,807	2629,076	346,731
12a	8.7.1988	143-153	16	2	4701,019	2223,615	2477,404
12b	9.3.1989	154-162	13	7	5031,262	3253,553	1777,709
13.	1.3.1991	163-184	36	12	12076,889	4739,505	7337,384
or.	13.9.1991	185-185	1		25,535		25,535
14.	10.9.1933	186-202	31		10509,915		10509,915
15.	2.2.1996	203-220	47		17405,807		17405,807
BSP	30.5.1997	221-236	19		5182,108		5182,108
			395	141	152571,493	90713,882	61857,611

* block or part of blocks or = awarded outside licensing rounds

Table 7.1.3.c
Licensing rounds. Norwegian and foreign shares and operatorships

Licens. round	Year	Number of blocks	Share % Norwegian	Share % Foreign	Operator % Norwegian	Operator % Foreign
1	1965	78	8	92	0	100
2	1969-1971	14	15	85	0	100
Statfjord (037)	1973	2	52	48	0	100
3	1974-1978	22	58	42	63	37
Prod.lic. 018B	1995	1	8	92	0	100
Ula (19B)	1977	2	50	50	0	100

Licens. round	Year	Number of blocks	Share % Norwegian	Share % Foreign	Operator % Norwegian	Operator % Foreign
Prod.lic. 050B	1995	1	100	0	100	0
4	1979	8	58	42	68	32
5	1980	12	66	34	92	8
6	1981	9	64	36	50	50
Oseberg (079)	1982	1	100	0	100	0
7	1982	5	60	40	80	20
Troll (085)	1983	3	100	0	100	0
Prod.lic. 085B	1992	2	69	31	100	0
8	1984	17	60	40	60	40
9	1985	13	60	40	55	45
Prod.lic. 112	1985	1	67	33	0	100
10A	1985	9	64	36	67	33
Prod.lic. 114B	1995	1	90	10	100	0
10B	1986	9	65	35	56	44
Prod.lic. 129	1986	1	67	33	100	0
11	1987	22	59	41	62	38
12A	1988	16	58	42	38	62
12B	1989	13	64	36	67	33
13	1991	36	66	34	64	36
Prod.lic. 185	1991	1	69	31	100	0
14	1993	31	68	32	100	0
15	1996	47	53	47	44	56
Barents Sea project	1997	19	56	44	69	31

7.1.4 TRANSFER OF INTERESTS AND CHANGES IN OPERATOR

Transfer of interests
During 1997, 47 transfers of interest have been approved under the Act of 22 March 1985 No. 11 or the Act of 29 November 1996 No. 72 relating to petroleum activities. These are shown in Table 7.1.4.

Changes in operator
Seven changes in operator were approved in 1997:

Production license 025
Operator: Den norske stats oljeselskap a.s. took over the operatorship from Elf Petroleum Norge AS on 1 January 1998.

Production license 036
Operator: Norsk Hydro Produksjon AS took over the operatorship from Elf Petroleum Norge AS on 22 December 1997.

Production license 048
Operator: Den norske stats oljeselskap a.s. took over the operatorship from Norsk Hydro Produksjon AS on 27 January 1997.

Production license 065
Operator: BP Petroleum Dev. of Norway AS took over the operatorship from Elf Petroleum Norge AS on 30 May 1997.

Production license 142
Operator: Den norske stats oljeselskap a.s took over the operatorship from Elf Petroleum Norge AS on 30 May 1997.

Production license 186
Operator: Saga Petroleum ASA took over the operatorship from Amoco Norway AS on 4 July 1997.

Production license 196
Operator: Den norske stats oljeselskap a.s took over the operatorship from BP Petroleum Dev. of Norway AS on 30 November 1997.

Table 7.1.4
Transfer of interest 1997 N=North Sea, M=Norwegian Sea, B=Barents Sea

Prod. lic.	From:	To:	Share:	Date:	Area:
009	Elf Rex Norge AS	Elf Petroleum Norge AS	3,420000 %	97.02.24	N
011	Amoco Norway Oil Company	Norske Conoco A/S	20,000000 %	97.01.01	N
018	Elf Rex Norge AS	Elf Petroleum Norge AS	0,855000 %	97.01.01	N
018B	Elf Rex Norge AS	Elf Petroleum Norge AS	0,855000 %	97.01.01	N
019	Norske Conoco A/S	BP Petroleum Dev. of Norway AS	10,000000 %	97.05.15	N
019	Den norske stats oljeselskap a.s	BP Petroleum Dev. of Norway AS	12,500000 %	97.11.06	N
019B	Norske Conoco A/S	BP Petroleum Dev. of Norway AS	9,375000 %	97.05.15	N
019B	Den norske stats oljeselskap a.s	BP Petroleum Dev. of Norway AS	20,000000 %	97.11.06	N
025	Total Norge AS	Den norske stats oljeselskap a.s	15,000000 %	97.10.13	N
025	Elf Petroleum Norge AS	Den norske stats oljeselskap a.s	20,000000 %	97.01.01	N
036	Elf Petroleum Norge AS	Norsk Hydro Produksjon AS	15,000000 %	97.12.22	N
048	Elf Petroleum Norge AS	Den norske stats oljeselskap a.s	4,500000 %	97.01.01	N
048	Norsk Hydro Produksjon AS	Den norske stats oljeselskap a.s	8,000000 %	97.01.27	N
048	BP Petroleum Dev. of Norway AS	Den norske stats oljeselskap a.s	2,500000 %	97.02.12	N
048	BP Petroleum Dev. of Norway AS	Elf Petroleum Norge AS	4,500000 %	97.06.27	N
048	BP Petroleum Dev. of Norway AS	Den norske stats oljeselskap a.s	3,900000 %	97.11.06	N
065	Den norske stats oljeselskap a.s	BP Petroleum Dev. of Norway AS	10,000000 %	97.02.12	N
065	Elf Petroleum Norge AS	BP Petroleum Dev. of Norway AS	16,667000 %	97.06.27	N
092	BP Petroleum Dev. of Norway AS	Saga Petroleum ASA	2,000000 %	97.04.24	M
093	Den norske stats oljeselskap a.s	BP Petroleum Dev. of Norway AS	7,560000 %	97.11.06	M
115	Den norske stats oljeselskap a.s	Deminex Norge AS	27,000000 %	97.04.18	N
120	Den norske stats oljeselskap a.s	Norsk Hydro Produksjon AS	3,000000 %	97.01.27	N
120	Elf Petroleum Norge AS	Norsk Hydro Produksjon AS	2,000000 %	97.12.22	N
121	BP Petroleum Dev. of Norway AS	Saga Petroleum ASA	2,000000 %	97.04.24	M
142	Elf Petroleum Norge AS	Saga Petroleum ASA	20,000000 %	97.05.29	N
142	Elf Petroleum Norge AS	Den norske stats oljeselskap a.s	20,000000 %	97.05.29	N
143	Den norske stats oljeselskap a.s	Norsk Hydro Produksjon AS	20,000000 %	97.10.13	N
144	BP Petroleum Dev. of Norway AS	Enterprise Oil Norw. AS	25,000000 %	97.11.13	N
152	BP Petroleum Dev. of Norway AS	Den norske stats oljeselskap a.s	30,000000 %	97.11.06	N
164	Norske Conoco A/S	Amoco Norway Oil Company	10,000000 %	97.02.24	N
186	Amoco Norway AS	Saga Petroleum ASA	10,000000 %	97.04.22	N
187	Norsk Hydro Produksjon AS	Den norske stats oljeselskap a.s	10,000000 %	97.10.13	N
190	Den norske stats oljeselskap a.s	Elf Petroleum Norge AS	10,000000 %	97.01.01	N
193	BP Petroleum Dev. of Norway AS	Den norske stats oljeselskap a.s	15,000000 %	97.11.06	N
193	Norsk Hydro Produksjon AS	Elf Petroleum Norge AS	5,000000 %	97.12.22	N
195	Den norske stats oljeselskap a.s	Norsk Hydro Produksjon AS	10,000000 %	97.10.13	N
196	Norsk Hydro Produksjon AS	Den norske stats oljeselskap a.s	5,000000 %	97.10.13	N
196	BP Petroleum Dev. of Norway AS	Den norske stats oljeselskap a.s	25,000000 %	97.11.06	N
201	Den norske stats oljeselskap a.s	Norsk Agip AS	5,000000 %	97.03.13	B
201	Den norske stats oljeselskap a.s	Neste Petroleum AS	5,000000 %	97.03.13	B
201	Den norske stats oljeselskap a.s	Enterprise Oil Norwegian AS	5,000000 %	97.03.13	B

7.1.5 RELINQUISHMENTS AND SURRENDERS

There have been 16 relinquishments/surrenders of production licenses in 1997. In two of the production licenses the total area was relinquished. This is shown in Table 7.1.5.

Table 7.1.5
Relinquishments

Production licenses	Operator	Block	Original area km^2	Relinquished area km^2 in 1997	Area in prod. lic. km^2
019B	BP	2/1, 7/12	617,890	152,037	465,854
038	Saga	15/12	442,226	61,841	134,243
062	Statoil	6507/11	436,310	8,750	59,798
069	Saga	7/8	558,364	113,650	108,123
074	Statoil	6407/2	440,392	40,955	170,221
086	Saga	6/3	594,788	35,142	21,579
101	Agip	16/10	546,986	54,574	180,252
116	Saga	15/12	188,465	14,714	79,044
127	Elf	6607/12	419,895	65,894	144,441
134	Statoil	6506/11	436,310	217,803	218,507
142	Elf	29/9, 30/7, 30/10	512,309	258,319	253,990
143	BP	1/2	319,068	161,060	158,008
146	Saga	2/4	221,748	111,860	109,888
147	Shell	3/7, 3/8	467,778	234,868	232,910
164	BP	2/1, 7/12, 8/10	783,712	783,712	0,0
170	Hydro	30/6	174,407	174,407	0,0

7.1.6 LICENSEES IN ACTIVE PRODUCTION LICENSES

Table 7.1.6
Licensees in active production licences as of 31 December 1997

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
001	65/09/01	25/11	O	Esso Expl. & Prod. Norway A/S	100,000000	
	11/09/01					
001 P	65/09/01	16/ 1		Enterprise Oil Norwegian AS	50,000000	
	11/09/01		O	Esso Expl. & Prod. Norway A/S	50,000000	
006	65/09/01	2/ 5		Amerada Hess Norge AS	28,333333	
	11/09/01	2/ 8	O	Amoco Norway Oil Company	28,333333	
		3/ 4		Elf Petroleum Norge AS	15,000000	
				Enterprise Oil Norwegian AS	28,333333	
008	65/09/01	2/ 6		Amerada Hess Norge AS	50,000000	
	11/09/01		O	Saga Petroleum ASA	50,000000	
009	65/09/01	9/ 5	O	Elf Petroleum Norge AS	69,032000	
	11/09/01			Phillips Petroleum Company Norway	14,780000	
				Total Norge AS	16,188000	
011	65/09/01	1/ 3	O	A/S Norske Shell	50,000000	
	11/09/01	1/ 6		Amoco Norway Oil Company	30,000000	
		1/ 6		Norske Conoco A/S	20,000000	
		1/ 6				
018	65/09/01	1/ 5		Den norske stats oljeselskap a.s	1,000000	
	28/12/31	2/ 4		Elf Petroleum Norge AS	8,449000	
		2/ 7		Fina Production Licenses AS	30,000000	
		7/11		Norsk Agip AS	13,040000	
				Norsk Hydro Produksjon AS	6,700000	
			O	Phillips Petroleum Company Norway	36,960000	
				Saga Petroleum ASA	0,304000	
				Total Norge AS	3,547000	
018 B	95/08/25	1/ 6		Den norske stats oljeselskap a.s	1,000000	
	98/12/31			Elf Petroleum Norge AS	8,449000	
				Fina Production Licenses AS	30,000000	
				Norsk Agip AS	13,040000	
				Norsk Hydro Produksjon AS	6,700000	
			O	Phillips Petroleum Company Norway	36,960000	
				Saga Petroleum ASA	0,304000	
				Total Norge AS	3,547000	
019	65/09/01	7/12		AS Pelican	5,000000	
	11/09/01		O	BP Petroleum Dev. of Norway AS	80,000000	
				Svenske Petroleum Exploration AS	15,000000	
019 B	77/09/12	2/ 1		AS Pelican	4,000000	
	11/09/01	7/12	O	BP Petroleum Dev. of Norway AS	56,000000	
		7/12		Den norske stats oljeselskap a.s	30,000000	(30,000)
				Norske AEDC A/S	5,000000	
				Norske MOECO A/S	5,000000	
024	69/05/23	25/ 1		Den norske stats oljeselskap a.s	20,000000	
	15/05/23		O	Elf Petroleum Norge AS	26,420000	
				Norsk Hydro Produksjon AS	32,870000	
				Total Norge AS	20,710000	
025	69/05/23	15/ 3		Elf Petroleum Norge AS	33,200000	
	15/05/23			Norsk Hydro Produksjon AS	10,000000	
			O	Den norske stats oljeselskap a.s	35,000000	
				Total Norge AS	21,800000	

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
026	69/05/23	25/ 2		Den norske stats oljeselskap a.s	5,000000	
	15/05/23		O	Elf Petroleum Norge AS	41,420000	
				Norsk Hydro Produksjon AS	32,870000	
				Total Norge AS	20,710000	
027	69/05/23	25/ 8	O	Esso Expl. & Prod. Norway A/S	100,000000	
	15/05/23					
027 P	69/05/23	25/ 8		Enterprise Oil Norwegian AS	50,000000	
	15/05/23		O	Esso Expl. & Prod. Norway A/S	50,000000	
028	69/05/23	25/10	O	Esso Expl. & Prod. Norway A/S	100,000000	
	15/05/23					
028 P	69/05/23	25/10		Enterprise Oil Norwegian AS	50,000000	
	15/05/23		O	Esso Expl. & Prod. Norway A/S	50,000000	
029	69/05/23	15/ 6	O	Esso Expl. & Prod. Norway A/S	100,000000	
	15/05/23					
031	69/05/23	2/10		Fina Production Licenses AS	30,000000	
	15/05/23			Norsk Agip AS	18,260000	
			O	Phillips Petroleum Company Norway	51,740000	
032	69/05/30	2/ 9		Amerada Hess Norge AS	35,000000	
	15/05/30		O	Amoco Norway Oil Company	25,000000	
				Elf Petroleum Norge AS	15,000000	
				Enterprise Oil Norwegian AS	25,000000	
033	69/05/30	2/11		Amerada Hess Norge AS	25,000000	
	15/05/30		O	Amoco Norway Oil Company	25,000000	
				Elf Petroleum Norge AS	25,000000	
				Enterprise Oil Norwegian AS	25,000000	
034	69/11/14	30/ 5	O	A/S Norske Shell	100,000000	
	15/11/14					
035	69/11/14	30/11	O	A/S Norske Shell	100,000000	
	15/11/14	30/11				
036	71/06/11	25/ 4		Elf Petroleum Norge AS	18,702000	
	21/06/11			Marathon Petroleum Norge AS	46,904000	
			O	Norsk Hydro Produksjon AS	21,920000	
				Saga Petroleum ASA	6,611000	
				Total Norge AS	5,541000	
				Ugland Construction Company AS	0,322000	
037	73/08/10	33/ 9		A/S Norske Shell	10,000000	
	09/08/10	33/ 9		Amerada Hess Norge AS	1,041667	
		33/12	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
				Enterprise Oil Norwegian AS	1,041667	
				Esso Expl. & Prod. Norway A/S	10,000000	
				Mobil Development Norway AS	15,000000	
				Norske Conoco A/S	11,041667	
				Saga Petroleum ASA	1,875000	
038	75/04/01	15/12		Den norske stats oljeselskap a.s	65,000000	(30,000)
	11/04/01	15/12	O	Saga Petroleum ASA	35,000000	
040	75/04/01	29/ 9		Den norske stats oljeselskap a.s	50,000000	(30,000)
	11/04/01	30/ 7		Elf Petroleum Norge AS	28,800000	
			O	Norsk Hydro Produksjon AS	6,800000	
				Total Norge AS	14,400000	
043	76/08/06	29/ 6		Den norske stats oljeselskap a.s	50,000000	(30,000)
	12/08/06	30/ 4	O	Total Norge AS	50,000000	

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
044	76/08/27	1/ 9	O	Den norske stats oljeselskap a.s	71,880000	(30,000)
	12/08/27			Fina Production Licenses AS	15,000000	
				Norsk Agip AS	13,120000	
046	76/12/03	15/ 8	O	Den norske stats oljeselskap a.s	52,600000	(34,400)
	14/09/03	15/ 8		Elf Petroleum Norge AS	9,000000	
		15/ 9		Esso Expl. & Prod. Norway A/S	28,000000	
				Norsk Hydro Produksjon AS	9,400000	
				Total Norge AS	1,000000	
048	77/02/18	15/ 5		Norsk Hydro Produksjon AS	9,300000	
	13/02/18		O	Den norske stats oljeselskap a.s	68,900000	(30,000)
				Elf Petroleum Norge AS	21,800000	
050	78/06/16	34/10	O	Den norske stats oljeselskap a.s	85,000000	(73,000)
	16/06/30			Norsk Hydro Produksjon AS	9,000000	
				Saga Petroleum ASA	6,000000	
050 B	95/08/11	34/10	O	Den norske stats oljeselskap a.s	85,000000	(73,000)
	01/08/11			Norsk Hydro Produksjon AS	9,000000	
				Saga Petroleum ASA	6,000000	
051	79/04/06	30/ 2	O	Den norske stats oljeselskap a.s	50,000000	(31,400)
	15/04/06			Norske Conoco A/S	25,000000	
				Total Norge AS	25,000000	
052	79/04/06	30/ 3		Deminex Norge AS	11,250000	
	15/04/06	30/ 3	O	Den norske stats oljeselskap a.s	55,000000	(37,000)
				Petro-Canada Norge AS	9,000000	
				Norske Deminex AS	2,250000	
				Svenske Petroleum Exploration AS	4,500000	
				Total Norge AS	18,000000	
053	79/04/06	30/ 6		Den norske stats oljeselskap a.s	59,400000	(45,400)
	17/04/06	30/ 6		Elf Petroleum Norge AS	9,333000	
				Mobil Development Norway AS	7,000000	
			O	Norsk Hydro Produksjon AS	12,250000	
				Saga Petroleum ASA	7,350000	
				Total Norge AS	4,667000	
054	79/04/06	31/ 2		A/S Norske Shell	25,900000	
	30/09/30		O	Den norske stats oljeselskap a.s	58,800000	(40,800)
				Elf Petroleum Norge AS	3,104500	
				Norsk Hydro Produksjon AS	4,900000	
				Norske Conoco A/S	5,191020	
				Total Norge AS	2,104480	
055	79/04/06	31/ 4		Den norske stats oljeselskap a.s	46,000000	(33,400)
	17/04/06			Esso Expl. & Prod. Norway A/S	17,600000	
				Neste Petroleum AS	13,200000	
			O	Norsk Hydro Produksjon AS	23,200000	
057	79/04/06	34/ 4		Amerada Hess Norge AS	4,900000	
	15/04/06			Deminex Norge AS	24,500000	
				Den norske stats oljeselskap a.s	41,400000	(31,400)
				Enterprise Oil Norwegian AS	4,900000	
				Idemitsu Petroleum Norge a.s.	9,600000	
			O	Saga Petroleum ASA	14,700000	
062	81/03/27	6507/11	O	Den norske stats oljeselskap a.s	51,000000	(31,400)
	21/03/27			Neste Petroleum AS	9,800000	
				Norsk Hydro Produksjon AS	4,900000	
				Saga Petroleum ASA	9,800000	
				Total Norge AS	24,500000	
064	81/03/27	7120/ 8	O	Den norske stats oljeselskap a.s	74,250000	(30,000)

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
	17/03/27			Elf Petroleum Norge AS	5,000000	
				Norsk Hydro Produksjon AS	20,750000	
065	81/08/21	1/ 3		A/S Norske Shell	15,000000	
	22/01/01	1/ 3	O	BP Petroleum Dev. Of Norway AS	35,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
				Enterprise Oil Norwegian AS	20,000000	
066	81/08/21	2/ 2		Amerada Hess Norge AS	20,000000	
	20/01/01			Den norske stats oljeselskap a.s	50,000000	(30,000)
			O	Saga Petroleum ASA	25,000000	
				BP Petroleum Dev. Of Norway AS	5,000000	
067	81/08/21	2/ 5		Den norske stats oljeselskap a.s	50,000000	(30,000)
	18/01/01		O	Norsk Agip AS	40,000000	
				Phillips Petroleum Norsk AS	10,000000	
069	81/08/21	7/ 8		Deminex Norge AS	5,000000	
	18/01/01			Den norske stats oljeselskap a.s	50,000000	(30,000)
				Norsk Hydro Produksjon AS	15,000000	
			O	Saga Petroleum ASA	30,000000	
070	81/08/21	7/11		Amoco Norway AS	14,700000	
	18/01/01	7/11		Den norske stats oljeselskap a.s	51,000000	(31,400)
			O	Norsk Hydro Produksjon AS	24,500000	
				Saga Petroleum ASA	9,800000	
072	81/08/21	16/ 7		Den norske stats oljeselskap a.s	50,000000	(30,000)
	18/01/01		O	Esso Expl. & Prod. Norway A/S	40,000000	
				Norsk Hydro Produksjon AS	10,000000	
073	82/04/23	6407/ 1	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
	18/04/23			Norsk Hydro Produksjon AS	16,667000	
				Total Norge AS	33,333000	
074	82/04/23	6407/ 2	O	Den norske stats oljeselskap a.s	51,000000	(31,400)
	18/04/23			Mobil Development Norway AS	9,800000	
				Neste Petroleum AS	14,700000	
				Norsk Agip AS	14,700000	
				Saga Petroleum ASA	9,800000	
077	82/04/23	7120/ 7	O	Den norske stats oljeselskap a.s	75,000000	(30,000)
	18/04/23			Norsk Hydro Produksjon AS	15,000000	
				Total Norge AS	10,000000	
078	82/04/23	7120/ 9		Den norske stats oljeselskap a.s	50,000000	(30,000)
	18/04/23			Elf Petroleum Norge AS	15,000000	
			O	Norsk Hydro Produksjon AS	25,000000	
				Total Norge AS	10,000000	
079	82/08/20	30/ 9		Den norske stats oljeselskap a.s	73,500000	(59,500)
	18/08/20		O	Norsk Hydro Produksjon AS	16,000000	
				Saga Petroleum ASA	10,500000	
085	83/07/08	31/ 3	O	Den norske stats oljeselskap a.s	82,000000	(73,000)
	30/09/30	31/ 5		Elf Petroleum Norge AS	2,000000	
		31/ 6	O	Norsk Hydro Produksjon AS	9,000000	
			O	Saga Petroleum ASA	6,000000	
				Total Norge AS	1,000000	
085 B	92/09/11	31/ 9	O	Den norske stats oljeselskap a.s	82,000000	(73,000)
	30/07/08	32/ 4		Elf Petroleum Norge AS	2,000000	
			O	Norsk Hydro Produksjon AS	9,000000	
			O	Saga Petroleum ASA	6,000000	
				Total Norge AS	1,000000	

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
086	84/03/09	6/ 3		Amerada Hess Norge AS	10,000000	
	20/03/09			Den norske stats oljeselskap a.s	70,000000	(30,000)
				Norsk Hydro Produksjon AS	10,000000	
			O	Saga Petroleum ASA	10,000000	
088	84/03/09	24/ 6		Den norske stats oljeselskap a.s	50,000000	(31,400)
	22/03/09		O	Total Norge AS	50,000000	
089	84/03/09	34/ 7		Deminex Norge AS	2,800000	
	24/03/09			Den norske stats oljeselskap a.s	55,400000	(51,000)
				Elf Petroleum Norge AS	5,600000	
				Esso Expl. & Prod. Norway A/S	10,500000	
				Idemitsu Petroleum Norge a.s.	9,600000	
				Norsk Hydro Produksjon AS	8,400000	
			O	Saga Petroleum ASA	7,700000	
090	84/03/09	35/11		Den norske stats oljeselskap a.s	50,000000	(30,000)
	24/02/09			Mobil Development Norway AS	25,000000	
			O	Norsk Hydro Produksjon AS	25,000000	
091	84/03/09	6406/ 3	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
	20/03/09			Mobil Development Norway AS	33,000000	
				Saga Petroleum ASA	17,000000	
092	84/03/09	6407/ 6	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
	20/03/09			Mobil Development Norway AS	40,000000	
				Saga Petroleum ASA	10,000000	
093	84/03/09	6407/ 9	O	A/S Norske Shell	16,200000	
	24/03/09			BP Petroleum Dev. of Norway AS	18,360000	
				Den norske stats oljeselskap a.s	65,440000	(57,880)
094	84/03/09	6506/12	O	Den norske stats oljeselskap a.s	44,000000	(26,400)
	24/03/09			Mobil Development Norway AS	14,700000	
				Neste Petroleum AS	9,800000	
				Norsk Agip AS	9,800000	
				Norsk Hydro Produksjon AS	4,900000	
				Saga Petroleum ASA	7,000000	
				Total Norge AS	9,800000	
095	84/03/09	6507/ 7		Den norske stats oljeselskap a.s	75,000000	(65,000)
	24/03/09			Neste Petroleum AS	5,000000	
			O	Norske Conoco A/S	20,000000	
097	84/03/09	7120/ 6		Amerada Hess Norge AS	11,250000	
	20/03/09	7120/ 6		Deminex Norge AS	10,000000	
				Den norske stats oljeselskap a.s	56,250000	(30,000)
			O	Norsk Hydro Produksjon AS	22,500000	
099	84/03/09	7121/ 4	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
	20/03/09			Norsk Hydro Produksjon AS	12,500000	
				Total Norge AS	37,500000	
100	84/03/09	7121/ 7		Deminex Norge AS	4,000000	
	20/03/09		O	Den norske stats oljeselskap a.s	51,000000	(30,000)
				Elf Petroleum Norge AS	35,000000	
				Svenske Petroleum Exploration AS	10,000000	
101	85/03/01	16/10		Deminex Norge AS	5,000000	
	22/03/01			Den norske stats oljeselskap a.s	50,000000	(30,000)
			O	Norsk Agip AS	45,000000	
102	85/03/01	25/ 5		Den norske stats oljeselskap a.s	50,000000	(30,000)
	25/03/01		O	Elf Petroleum Norge AS	30,000000	
				Total Norge AS	20,000000	

PROD. LIC.	AWARDED	BLOCKS	LICENSEES		SHARE %	SDFI %
103	85/03/01	25/ 7		Amerada Hess Norge AS	12,500000	
	21/03/01			Den norske stats oljeselskap a.s	50,000000	(30,000)
			O	Norske Conoco A/S	37,500000	
104	85/03/01	30/ 9		Den norske stats oljeselskap a.s	50,000000	(30,000)
	25/03/01			Mobil Development Norway AS	5,000000	
			O	Norsk Hydro Produksjon AS	24,000000	
				Norske Conoco A/S	11,000000	
				Saga Petroleum ASA	10,000000	
107	85/03/01	6407/ 7		Den norske stats oljeselskap a.s	50,000000	(30,000)
	21/03/01			Mobil Development Norway AS	20,000000	
				Petro-Canada Norge AS		7,500000
			O	Norsk Hydro Produksjon AS	22,500000	
109	85/03/01	7120/ 2		Den norske stats oljeselskap a.s	61,945000	(30,000)
	22/03/01	7120/ 3		Mobil Development Norway AS	15,000000	
			O	Norsk Hydro Produksjon AS	23,055000	
110	85/03/01	7120/ 5		Amerada Hess Norge AS	8,330000	
	21/03/01	7121/ 5	O	Den norske stats oljeselskap a.s	50,000000	(30,000)
		7121/ 5		Elf Petroleum Norge AS	20,000000	
				Fina Production Licenses AS	5,000000	
				Norsk Hydro Produksjon AS	16,670000	
112	85/07/26	25/ 2		Den norske stats oljeselskap a.s	50,000000	(30,000)
	21/07/26		O	Elf Petroleum Norge AS	21,800000	
				Norsk Hydro Produksjon AS	17,300000	
				Total Norge AS	10,900000	
113	85/08/23	2/12	O	Amerada Hess Norge AS	50,000000	
	21/08/23			Den norske stats oljeselskap a.s	50,000000	(30,000)
114	85/08/23	9/ 2		Deminex Norge AS	10,000000	
	22/08/23		O	Den norske stats oljeselskap a.s	65,000000	(30,000)
				Saga Petroleum ASA	25,000000	
114 B	95/08/11	9/ 5		Deminex Norge AS	10,000000	
	01/08/11		O	Den norske stats oljeselskap a.s	65,000000	(30,000)
				Saga Petroleum ASA	25,000000	
115	85/08/23	9/ 3	O	Den norske stats oljeselskap a.s	73,000000	(30,000)
	21/08/23			Deminex Norge AS	27,000000	
116	85/08/23	15/12		Amerada Hess Norge AS	10,000000	
	22/08/23	15/12		Den norske stats oljeselskap a.s	70,000000	(30,000)
				Norsk Hydro Produksjon AS	10,000000	
			O	Saga Petroleum ASA	10,000000	
117	85/08/23	25/ 6		Amerada Hess Norge AS	10,000000	
	22/08/23			Den norske stats oljeselskap a.s	50,000000	(30,000)
				Fina Production Licenses AS	15,000000	
			O	Saga Petroleum ASA	25,000000	
120	85/08/23	34/ 7		Den norske stats oljeselskap a.s	47,000000	(28,000)
	23/08/23	34/ 8		Elf Petroleum Norge AS	11,000000	
			O	Norsk Hydro Produksjon AS	23,000000	
				Norske Conoco A/S	13,000000	
				Saga Petroleum ASA	6,000000	
121	86/02/28	6407/ 5	O	Den norske stats oljeselskap a.s	50,000000	(40,000)
	22/02/28			Mobil Development Norway AS	20,000000	
				Norsk Hydro Produksjon AS	20,000000	
				Saga Petroleum ASA	10,000000	
122	86/02/28	6507/ 2		Amerada Hess Norge AS	20,000000	

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
	25/02/28			Den norske stats oljeselskap a.s	50,000000	(30,000)
				Mobil Development Norway AS	10,000000	
			O	Norsk Agip AS	20,000000	
124	86/02/28	6507/ 8	O	Den norske stats oljeselskap a.s	65,000000	(30,000)
	25/02/28			Neste Petroleum AS	10,000000	
				Norske Conoco A/S	25,000000	
127	86/02/28	6607/12		Den norske stats oljeselskap a.s	50,000000	(30,000)
	23/02/28		O	Elf Petroleum Norge AS	35,000000	
				Fina Production Licenses AS	15,000000	
128	86/02/28	6608/10	O	Den norske stats oljeselskap a.s	50,000000	(25,000)
	26/02/28	6608/11		Enterprise Oil Norwegian AS	10,000000	
				Norsk Agip AS	11,500000	
				Norsk Hydro Produksjon AS	13,500000	
				Saga Petroleum ASA	15,000000	
132	87/04/10	6407/10		Den norske stats oljeselskap a.s	50,000000	(30,000)
	23/04/10			Mobil Development Norway AS	20,000000	
				Petro-Canada Norge AS	7,500000	
			O	Norsk Hydro Produksjon AS	22,500000	
134	87/04/10	6506/11	O	Den norske stats oljeselskap a.s	53,000000	(25,000)
	27/04/10			Norsk Agip AS	30,000000	
				Saga Petroleum ASA	7,000000	
				Total Norge AS	10,000000	
138	87/05/29	7122/ 6		Amerada Hess Norge AS	13,000000	
	23/05/29			Den norske stats oljeselskap a.s	50,000000	(30,000)
			O	Total Norge AS	37,000000	
142	87/05/29	29/ 9	O	Den norske stats oljeselskap a.s	70,000000	(30,000)
	27/05/29	30/ 7		Saga Petroleum ASA	30,000000	
		30/10				
143	88/07/08	1/ 2		Amoco Norway AS	10,000000	
	27/07/08			Den norske stats oljeselskap a.s	30,000000	(30,000)
				Enterprise Oil Norwegian AS	15,000000	
			O	BP Petroleum Dev. Of Norway AS	15,000000	
				Norsk Hydro Produksjon AS	20.000000	
				Phillips Petroleum Norsk AS	10.000000	
144	88/07/08	1/ 5		Enterprise Oil Norwegian AS	25,000000	
	98/07/08	1/ 6		Den norske stats oljeselskap a.s	50,000000	(30,000)
		1/ 6	O	Norske Conoco A/S	25,000000	
145	88/07/08	1/ 9	O	Phillips Petroleum Norsk AS	40,000000	
	24/07/08	2/ 7		Den norske stats oljeselskap a.s	40,000000	(30,000)
				Norsk Agip AS	10,000000	
				Norsk Hydro Produksjon AS	10,000000	
146	88/07/08	2/ 4		Amerada Hess Norge AS	10,000000	
	27/07/08			Den norske stats oljeselskap a.s	30,000000	(30,000)
				Elf Petroleum Norge AS	20,000000	
				Phillips Petroleum Norsk AS	20,000000	
			O	Saga Petroleum ASA	20,000000	
147	88/07/08	3/ 7	O	A/S Norske Shell	50,000000	
	27/07/08	3/ 8		Den norske stats oljeselskap a.s	50,000000	(30,000)
148	88/07/08	7/ 4		Amerada Hess Norge AS	25,000000	
	24/07/08	7/ 7		Amoco Norway AS	10,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(30,000)
				Total Norge AS	15,000000	

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
150	88/07/08	24/ 9		Den norske stats oljeselskap a.s	40,000000	(30,000)
	24/07/08			Enterprise Oil Norwegian AS	40,000000	
			O	Fina Production Licenses AS	10,000000	
				Saga Petroleum ASA	10,000000	
152	88/07/08	33/12		Idemitsu Oil Exploration (Norsk) a.s.	10,000000	
	25/07/08		O	Den norske stats oljeselskap a.s	80,000000	(30,000)
				Mobil Development Norway AS	10,000000	
153	88/07/08	35/ 9		A/S Norske Shell	12,000000	
	97/07/08	36/ 7		Deminex Norge AS	8,000000	
				Den norske stats oljeselskap a.s	50,000000	(30,000)
			O	Norsk Hydro Produksjon AS	20,000000	
				Saga Petroleum ASA	10,000000	
156	89/03/03	6406/11		Amerada Hess Norge AS	10,000000	
	99/03/03			Den norske stats oljeselskap a.s	50,000000	(30,000)
			O	Saga Petroleum ASA	40,000000	
157	89/03/03	6406/12	O	Den norske stats oljeselskap a.s	50,000000	(20,000)
	99/03/03			Norske Conoco A/S	10,000000	
				Phillips Petroleum Norsk AS	15,000000	
				Saga Petroleum ASA	25,000000	
158	89/03/03	6407/ 8	O	BP Petroleum Dev. of Norway AS	40,000000	
	98/03/03			Den norske stats oljeselskap a.s	50,000000	(30,000)
				A/S Norske Shell	10,000000	
159	89/03/03	6507/ 3	O	Den norske stats oljeselskap a.s	50,000000	(20,000)
	99/03/03			Norsk Hydro Produksjon AS	20,000000	
				Saga Petroleum ASA	10,000000	
				Total Norge AS	20,000000	
163	91/03/01	2/10		Amerada Hess Norge AS	10,000000	
	00/03/01	2/10		Den norske stats oljeselskap a.s	50,000000	(35,000)
				Norsk Agip AS	10,000000	
			O	Saga Petroleum ASA	30,000000	
166	91/03/01	15/ 6		Den norske stats oljeselskap a.s	70,000000	(30,000)
	99/03/01		O	Deminex Norge AS	30,000000	
167	91/03/01	16/ 1		Amoco Norway AS	10,000000	
	99/03/01		O	Den norske stats oljeselskap a.s	50,000000	(20,000)
				Norsk Hydro Produksjon AS	30,000000	
				Phillips Petroleum Norsk AS	10,000000	
168	91/03/01	25/10		Amerada Hess Norge AS	20,000000	
	99/03/01			Fina Production Licenses AS	15,000000	
			O	Den norske stats oljeselskap a.s	65,000000	(20,000)
169	91/03/01	25/ 8		Den norske stats oljeselskap a.s	50,000000	(35,000)
	00/03/01	25/11		Esso Expl. & Prod. Norway A/S	10,000000	
			O	Norsk Hydro Produksjon AS	40,000000	
171	91/03/01	30/12		Den norske stats oljeselskap a.s	50,000000	(35,000)
	00/03/01		O	Norsk Hydro Produksjon AS	30,000000	
				Mobil Development Norway AS	10,000000	
				Saga Petroleum ASA	10,000000	
172	91/03/01	33/ 9		Amerada Hess Norge AS	10,000000	
	25/03/01	33/ 9		Den norske stats oljeselskap a.s	50,000000	(35,000)
			O	Mobil Development Norway AS	25,000000	
				Norske Conoco A/S	15,000000	
173	91/03/01	35/10	O	Den norske stats oljeselskap a.s	50,000000	(20,000)
	99/03/01			Elf Petroleum Norge AS	15,000000	

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
				Mobil Development Norway AS	20,000000	
				Norsk Hydro Produksjon AS	15,000000	
174	91/03/01	35/12		Den norske stats oljeselskap a.s	50,000000	(35,000)
	99/03/01		O	Saga Petroleum ASA	30,000000	
				Norske Conoco A/S	20,000000	
175	91/03/01	6204/10	O	Den norske stats oljeselskap a.s	50,000000	(25,000)
	99/03/01	6204/11		Enterprise Oil Norwegian AS	10,000000	
				Neste Petroleum AS	10,000000	
				Phillips Petroleum Norsk AS	20,000000	
				Saga Petroleum ASA	10,000000	
176	91/03/01	6407/11	O	A/S Norske Shell	30,000000	
	98/03/01	6407/12		Den norske stats oljeselskap a.s	50,000000	(35,000)
				Fina Production Licenses AS	10,000000	
				Norsk Hydro Produksjon AS	10,000000	
177	91/03/01	6610/ 2		BP Petroleum Dev. of Norway AS	20,000000	
	99/03/01	6610/ 3	O	Den norske stats oljeselskap a.s	50,000000	(20,000)
				Saga Petroleum ASA	30,000000	
181	91/03/01	7128/ 6		Amoco Norway AS	15,000000	
	99/03/01	7128/ 9	O	Den norske stats oljeselskap a.s	70,830000	(30,000)
		7129/ 4		Elf Petroleum Norge AS	14,170000	
182	91/03/01	7219/ 7		Den norske stats oljeselskap a.s	50,000000	(30,000)
	00/03/01	7219/ 8		Enterprise Oil Norwegian AS	20,000000	
			O	Saga Petroleum ASA	30,000000	
185	91/09/13	31/ 7		Den norske stats oljeselskap a.s	46,000000	(33,400)
	15/04/06			Esso Expl. & Prod. Norway A/S	17,600000	
				Neste Petroleum AS	13,200000	
			O	Norsk Hydro Produksjon AS	23,200000	
186	93/09/10	7/10		Amoco Norway AS	15,000000	
	99/09/10	7/11		Den norske stats oljeselskap a.s	50,000000	(40,000)
			O	Saga Petroleum ASA	20,000000	
				Total Norge AS	15,000000	
187	93/09/10	15/ 2	O	Amoco Norway AS	25,000000	
	99/09/10	15/ 3		Den norske stats oljeselskap a.s	65,000000	(40,000)
		15/ 3		Norsk Hydro Produksjon AS	10,000000	
188	93/09/10	17/ 3		Amerada Hess Norge AS	15,000000	
	99/09/10			Den norske stats oljeselskap a.s	40,000000	(30,000)
			O	Elf Petroleum Norge AS	25,000000	
				Norsk Agip AS	20,000000	
189	93/09/10	25/ 8	O	Amerada Hess Norge AS	20,000000	
	99/09/10	25/ 9		Den norske stats oljeselskap a.s	70,000000	(45,000)
				Saga Petroleum ASA	10,000000	
190	93/09/10	30/ 8		Den norske stats oljeselskap a.s	50,000000	(50,000)
	99/09/10			Enterprise Oil Norwegian AS	15,000000	
				Elf Petroleum Norge AS	10,000000	
			O	Norsk Hydro Produksjon AS	25,000000	
191	93/09/10	31/ 1		Den norske stats oljeselskap a.s	60,000000	(45,000)
	99/09/10	31/ 2		Mobil Development Norway AS	10,000000	
		31/ 4		Neste Petroleum AS	10,000000	
		31/ 5	O	Norsk Hydro Produksjon AS	20,000000	
192	93/09/10	34/ 5		Den norske stats oljeselskap a.s	62,000000	(35,000)
	99/09/10		O	Mobil Development Norway AS	18,000000	
				Norske Conoco A/S	20,000000	

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
193	93/09/10	34/11		Norsk Hydro Produksjon AS	15,000000	
	99/09/10		O	Den norske stats oljeselskap a.s	80,000000	(40,000)
				Elf Petroleum Norge AS	5,000000	
194	93/09/10	35/ 4		Den norske stats oljeselskap a.s	55,000000	(45,000)
	99/09/10	35/ 5		Elf Petroleum Norge AS	10,000000	
			O	Norsk Hydro Produksjon AS	25,000000	
				Saga Petroleum ASA	10,000000	
195	93/09/10	35/ 8	O	BP Petroleum Dev. of Norway AS	25,000000	
	99/09/10			Den norske stats oljeselskap a.s	35,000000	(35,000)
				Norsk Hydro Produksjon AS	25,000000	
				Norske Conoco A/S	15,000000	
196	93/09/10	35/ 6		Norsk Hydro Produksjon AS	15,000000	
	99/09/10	36/ 4	O	Den norske stats oljeselskap a.s	75,000000	(25,000)
				Idemitsu Petroleum Norge a.s.	10,000000	
197	93/09/10	6306/ 2	O	Amerada Hess Norge AS	70,000000	
	99/09/10	6306/ 5		Den norske stats oljeselskap a.s	30,000000	(30,000)
198	93/09/10	6306/ 6	O	Den norske stats oljeselskap a.s	65,000000	(40,000)
	99/09/10			Elf Petroleum Norge AS	15,000000	
				Norsk Hydro Produksjon AS	20,000000	
199	93/09/10	6406/ 2		Den norske stats oljeselskap a.s	60,000000	(45,000)
	99/09/10			Mobil Development Norway AS	15,000000	
			O	Saga Petroleum ASA	25,000000	
200	93/09/10	6608/ 7	O	Den norske stats oljeselskap a.s	65,000000	(40,000)
	99/09/10	6608/ 8		Neste Petroleum AS	15,000000	
				Phillips Petroleum Norsk AS	20,000000	
201	93/09/10	7018/ 3		Den norske stats oljeselskap a.s	25,000000	(25,000)
	99/09/10	7019/ 1		Enterprise Oil Norwegian AS	25,000000	
				Neste Petroleum AS	15,000000	
			O	Norsk Agip AS	35,000000	
202	93/09/10	7227/11		Amerada Hess Norge AS	25,000000	
	99/09/10	7227/12	O	Den norske stats oljeselskap a.s	55,000000	(30,000)
		7228/ 7		Saga Petroleum ASA	20,000000	
		7228/10				
203	96/02/02	24/ 6	O	Norsk Hydro Produksjon AS	35,000000	
	02/02/02	25/ 4		Norske Conoco A/S	20,000000	
		25/ 7		Amoco Norway AS	15,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
204	96/02/02	24/ 9	O	Den norske stats oljeselskap a.s	65,000000	(30,000)
	02/02/02	24/11		Amerada Hess Norge AS	20,000000	
		24/12		Enterprise Oil Norwegian AS	15,000000	
205	96/02/02	32/ 1	O	Phillips Petroleum Norsk AS	30,000000	
	00/02/02	32/ 2		Norsk Hydro Produksjon AS	20,000000	
		32/ 4		Total Norge AS	20,000000	
		32/ 5		Den norske stats oljeselskap a.s	30,000000	(30,000)
206	96/02/02	33/ 5	O	Mobil Development Norway AS	75,000000	
	02/02/02	33/ 6		Saga Petroleum ASA	25,000000	
		34/ 4				
207	96/02/02	6302/ 4	O	Esso Expl. & Prod. Norway A/S	35,000000	
	04/02/02	6302/ 5		Den norske stats oljeselskap a.s	55,000000	(30,000)
		6302/ 7		Saga Petroleum ASA	10,000000	
		6302/ 8				

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
208	96/02/02	6304/ 9	O	BP Petroleum Dev. of Norway AS	45,000000	
	04/02/02	6305/ 7		A/S Norske Shell	25,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
209	96/02/02	6305/ 1	O	Norsk Hydro Produksjon AS	25,000000	
	06/02/02	6305/ 2		A/S Norske Shell	15,000000	
		6305/ 4		Esso Expl. & Prod. Norway A/S	10,000000	
		6305/ 5		Den norske stats oljeselskap a.s	50,000000	(35,000)
210	96/02/02	6404/ 3	O	A/S Norske Shell	30,000000	
	06/02/02	6405/ 1		Norsk Hydro Produksjon AS	20,000000	
		6504/ 9		Den norske stats oljeselskap a.s	50,000000	(30,000)
		6504/12				
		6505/ 7				
		6505/10				
211	96/02/02	6506/ 6	O	Mobil Development Norway AS	30,000000	
	02/02/02	6507/ 4		Norsk Agip AS	20,000000	
				Elf Petroleum Norge AS	20,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
212	96/02/02	6507/ 5	O	Amoco Norway AS	30,000000	
	02/02/02	6507/ 6		Enterprise Oil Norwegian AS	25,000000	
				Mobil Development Norway AS	15,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
213	96/02/02	6508/ 1	O	Saga Petroleum ASA	25,000000	
	02/02/02			Den norske stats oljeselskap a.s	55,000000	(30,000)
				Phillips Petroleum Norsk AS	20,000000	
214	96/02/02	6510/ 1	O	A/S Norske Shell	30,000000	
	02/02/02	6510/ 2		Mobil Development Norway AS	20,000000	
				Elf Petroleum Norge AS	20,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
215	96/02/02	6604/ 2	O	Saga Petroleum ASA	25,000000	
	04/02/02	6604/ 3		Norsk Hydro Produksjon AS	20,000000	
		6704/12		Norske Conoco A/S	15,000000	
		6705/10		Mobil Development Norway AS	10,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
216	96/02/02	6610/ 1	O	Amoco Norway AS	30,000000	
	02/02/02			Total Norge AS	25,000000	
				Enterprise Oil Norwegian AS	15,000000	
				Den norske stats oljeselskap a.s	30,000000	(30,000)
217	96/02/02	6706/11	O	Den norske stats oljeselskap a.s	65,000000	(30,000)
	06/02/02	6706/12		BP Petroleum Dev. of Norway AS	20,000000	
				Norske Conoco A/S	15,000000	
218	96/02/02	6706/12	O	BP Petroleum Dev. of Norway AS	25,000000	
	06/02/02	6707/10		Den norske stats oljeselskap a.s	50,000000	(35,000)
				Esso Expl. & Prod. Norway A/S	15,000000	
				Saga Petroleum ASA	10,000000	
219	96/02/02	6710/ 6	O	Norsk Hydro Produksjon AS	45,000000	
	06/02/02			Norsk Agip AS	40,000000	
				Fina Production Licenses AS	15,000000	
220	96/02/02	6710/10	O	Den norske stats oljeselskap a.s	70,000000	(30,000)
	06/02/02			Amerada Hess Norge AS	15,000000	
				Amoco Norway AS	15,000000	
221	97/05/30			Elf Petroleum Norge AS	10,000000	
	07/05/15		O	Norsk Hydro Produksjon AS	20,000000	

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
				Mobil Development Norway AS	15,000000	
				Saga Petroleum ASA	10,000000	
				Den norske stats oljeselskap a.s	45,000000	(30,000)
222	97/05/30			Elf Petroleum Norge AS	10,000000	
	07/05/15		O	Norsk Hydro Produksjon AS	20,000000	
				Mobil Development Norway AS	15,000000	
				Saga Petroleum ASA	10,000000	
				Den norske stats oljeselskap a.s	45,000000	(30,000)
223	97/05/30			Elf Petroleum Norge AS	10,000000	
	07/05/15		O	Norsk Hydro Produksjon AS	20,000000	
				Mobil Development Norway AS	15,000000	
				Saga Petroleum ASA	10,000000	
				Den norske stats oljeselskap a.s	45,000000	(30,000)
224	97/05/30	7217/ 9	O	Elf Petroleum Norge AS	30,000000	
	05/05/15	7217/12		Mobil Development Norway AS	25,000000	
		7218/ 7		Phillips Petroleum Company Norway	25,000000	
		7218/ 8		Den norske stats oljeselskap a.s	20,000000	(20,000)
		7218/10				
		7218/11				
225	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Enterprise Oil Norwegian AS	15,000000	
				Neste Petroleum AS	10,000000	
			O	Saga Petroleum ASA	20,000000	
				Den norske stats oljeselskap a.s	40,000000	(20,000)
226	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Enterprise Oil Norwegian AS	15,000000	
				Neste Petroleum AS	10,000000	
			O	Saga Petroleum ASA	20,000000	
				Den norske stats oljeselskap a.s	40,000000	(20,000)
227	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Enterprise Oil Norwegian AS	15,000000	
				Neste Petroleum AS	10,000000	
			O	Saga Petroleum ASA	20,000000	
				Den norske stats oljeselskap a.s	40,000000	(20,000)
228	97/05/30	7222/ 6		Norsk Hydro Produksjon AS	20,000000	
	05/05/15	7222/ 8	O	Saga Petroleum ASA	30,000000	
		7222/ 9		Den norske stats oljeselskap a.s	50,000000	(30.000)
		7222/11				
		7222/12				
		7223/ 4				
		7223/ 5				
		7223/ 6				
229	97/05/30	7122/ 7	O	Norsk Agip AS	25,000000	
	05/05/15	7122/ 8		Enterprise Oil Norwegian AS	15,000000	
		7122/ 9		Neste Petroleum AS	15,000000	
		7122/10		Phillips Petroleum Company Norway	25,000000	
		7123/ 7		Den norske stats oljeselskap a.s	20,000000	(20.000)
230	97/05/30			Amerada Hess Norge AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
			O	Mobil Development Norway AS	20,000000	
				Saga Petroleum ASA	15,000000	
				Den norske stats oljeselskap a.s	35,000000	(20,000)
231	97/05/30			Amerada Hess Norge AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
			O	Mobil Development Norway AS	20,000000	
				Saga Petroleum ASA	15,000000	

PROD. LIC.	AWARDED	BLOCKS		LICENSEES	SHARE %	SDFI %
				Den norske stats oljeselskap a.s	35,000000	(20,000)
232	97/05/30			Amerada Hess Norge AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
			O	Mobil Development Norway AS	20,000000	
				Saga Petroleum ASA	15,000000	
				Den norske stats oljeselskap a.s	35,000000	(20,000)
233	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)
234	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)
235	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)
236	97/05/30			Norsk Agip AS	15,000000	
	07/05/15			Norsk Hydro Produksjon AS	15,000000	
				Saga Petroleum ASA	20,000000	
			O	Den norske stats oljeselskap a.s	50,000000	(20,000)

7.2 SALE AND RELEASE OF DATA

7.2.1 REPORTING OF MATERIAL FROM THE SHELF

In connection with the Norwegian Petroleum Directorate's follow-up of the petroleum activities on the Norwegian continental shelf, the Norwegian Petroleum Directorate receives inter alia copies of reports, borehole logs and representative samples of drill cuttings and cores. The Norwegian Petroleum Directorate also receives oil samples from all tested wells.

As of 31 December 1997, the Norwegian Petroleum Directorate has stocked 103,500 meters of core material from 1,144 wells, 424,797 samples of washed cuttings from 1,167 wells and 509,092 wet samples from 1,459 wells. In addition, there are oil and condensate samples from 311 wells. This includes material from Svalbard, Hopen and Andøya as well as from some foreign wells, mostly from the U.K. sector of the North Sea. In connection with NORAD assignments, the Norwegian Petroleum Directorate has also received material from Tanzania and Mozambique.

In 1997 the Norwegian Petroleum Directorate received 5,135 meters of cores, 16,867 samples of washed cuttings, 20,947 wet samples and 10 oil samples.

7.2.2 RELEASE OF DATA

The Norwegian Petroleum Directorate is responsible for publishing data and releasing material inter alia for the purposes of education and research. Geological and technical reservoir data are normally released five years after well completion. The licensees' interpretations are not released. "Well Data Summary Sheets" (WDSS) are issued annually. This publication shows which wells have been released and which core and log materials are available from the various wells. In addition, some technical data and test results are also given, as well as a composite log with lithology description of each well.

In addition to the WDSS, the Norwegian Petroleum Directorate issues the annual publication "Licenses, Areas, Area-coordinates, Exploration Wells", which contains an overview of each production license on the Norwegian continental shelf; license number, award date, operator, awarded area, current area, licensees and their shares, geographical coordinates for the areas, some data about each well drilled in the license and a map of the area with the wells plotted in. Some historical data and tables from the drilling activities are also included. This publication is issued annually with half-yearly update.

The Norwegian Petroleum Directorate has experienced a growing demand for released data as more data types with improved quality are made available. Some types of data can also be delivered in digital format on diskette or magnetic tape. Reference is otherwise made to the Norwegian Petroleum Directorate's list of publications.

The Norwegian Petroleum Directorate received 103 orders for data from a total of 590 wells. 66 orders were for film/hard copies from 265 wells, 27 were for digital data sets from 231 "High Quality Log Data project" (HQLD) wells, 5 were orders for digital core analyses from 79 wells and 5 were for digital direction data from 15 wells. This is an increase of 17 percent compared with 1996.

The Norwegian Petroleum Directorate has delivered 65 other digital data collections. The most common are well lists (exploration and production wells), production licenses (current and historic), exploration areas and blocks, installations, pipelines and other collections listed in the Directorate's publications list. In addition, several special collections have been made to order.

In the Norwegian Petroleum Directorate's two core study rooms it is possible to examine core materials, drill cuttings and wet samples. In special cases, material may be made available for studies and analyses performed outside of the Directorate. Applications for release of data should be addressed to the Release Committee at the Norwegian Petroleum Directorate. Thirty applications have been considered in 1997. One of these was for organic geochemistry studies, eight for biostratigraphic, 16 for sedimentology/petrophysical and five for oil-condensate samples. A total of about 104 kg of sample material and 559 ml of oil was released.

In 1997, the Norwegian Petroleum Directorate's core study rooms were used by 43 different companies/ institutions for examination of cores and/or geological sampling. The core study rooms have been used by external guests on 104 days, in addition to 109 days of use by employees of the Norwegian Petroleum Directorate.

Release of seismic data occurs mainly through PetroBank. Members of the DISKOS project have access to data directly through PetroBank. Companies that are not members can gain access through the Norwegian Petroleum Directorate. As of 31 December 1997, the Norwegian Petroleum Directorate has released 897 seismic surveys on the Norwegian continental shelf, which is equivalent to 1,433,716 cmp km. A summary of the released surveys may be found on the Norwegian Petroleum Directorate's and DISKOS' home pages on the Internet.

A list of these surveys may be found in the publication "Released seismic surveys, Volume A and B". "Volume A" contains data packages for the North Sea, while "Volume B" contains packages for the Norwegian Sea.

7.2.3 SALE OF THE NORWEGIAN PETROLEUM DIRECTORATE'S SEISMIC DATA

Table 7.2.3
Survey of seismic data packages (NPD-seismic)

Package No	Name	1997	Total
001a	Møre-Trøndelag-Regional-Pk-1	1	35
002	Møre-Trøndelag-Regional-Pk-2	1	28
003	Tampen-Spur		22
004	Møre-South-84		22
005	Trøndelag-Regional		25
006	Haltenbanken-Vest-84		24
007	Frøyabanken-84		27
008	Møre-Trøndelag-Pk-2 #)		22
009	Møre-Trøndelag-Pk-3 #)		28
010	Trænabanken		30
011	Reg-Data-Nordland-Ryggen		22
012	Nordland-IV-85		13
013	Reg-Data-Midt-N-Sokkel		21
014	Nordland-II-83	1	24
015	Nordland-III-84		17
016	Troms-II		13
017	Regional-Data-Troms-Øst		18
018	Finnmark-Vest-83		19
019	Finnmark-Vest-84		20
020	Nordland-III-85		16
021	Møre-Sør-Test-84 #)		5
022	Storegga-85		13
023	Vøringplatået		15
024	Vøringbassenget-85/86	1	16
025	Lofoten-Vest-86	1	18
026	Jan-Mayen-85		1
027	Jan-Mayen-79/85		0
028	Vøringbassenget-87		15
029	Nordland-VI-87		18
030	Nordland-VII-87		13
031	Nordland-V-87		12
032	Nordland-VI-88		18
033	Nordland-VII-88		13
034	Nordland-V-73-79		12
035	Nordland-VI-73-79		18
036	Nordland-VI-89		18
037	Nordland-VII-89		13
038	Nordland-VII-74/75		13
039	Nordsjøen-Sør-Test-89 #)		1
040	Vøringbassenget-88		15
041	Vøringbassenget-Merlin-89		15
042	Vøringbassenget-Westem-89		15
043	Møre-Bassenget-88		12
044	Typeprofiler-Barentshavet #)		2
045	Vøringbassenget-I-90		15
046	Storegga-90		13
047	Vikinggraben-Sør-Test-91 #)		1
048	Vikingbanken-Test-91 #)		3
049	Norskehavet-74/79		1
050	Vøringbassenget-II-Ensign-91		13
051	Vøringbassenget-II-Digicon-91		13
052	Mørebassenget-91		13
053	Jan-Mayen-88		1
054	Vøringbassenget-II-92		13
055	Mørebassenget-Ensign-92		13
056	Mørebassenget-Digicon-92		13

#) not compulsory

7.3 EXPLORATION DRILLING STATISTICS

As of 31 December 1997, a total of 916 exploration wells had been spudded on the Norwegian continental shelf since drilling commenced in 1966. Of these, 655 were wildcats and 261 were appraisal wells.

Figure 7.3.a
Regional spread of exploration wells per operator

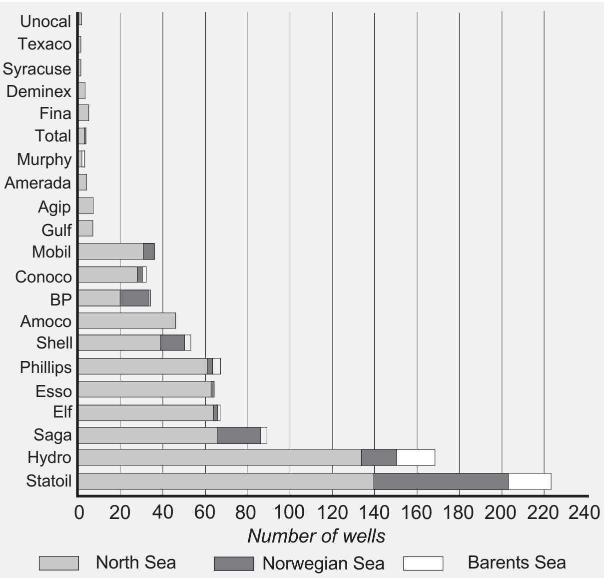


Figure 7.3.b
Rig days per operator

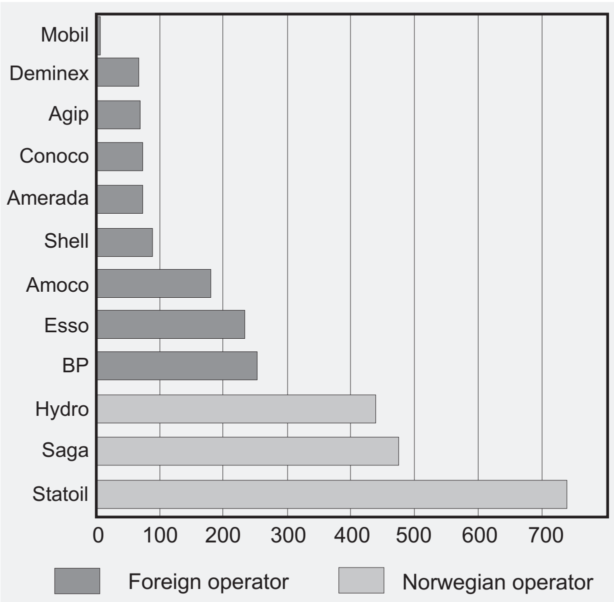
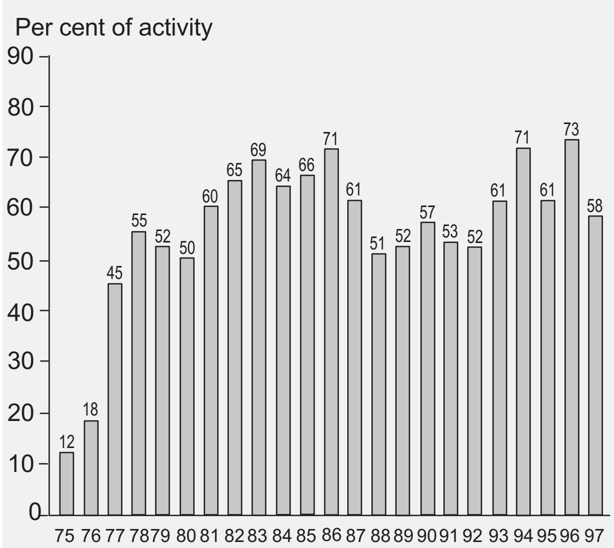


Figure 7.3.c
Participation of Norwegian operators in exploration drilling activity per year



907 exploration wells have been completed and 49 wells were temporarily abandoned for various reasons. Some have been temporarily abandoned with a view to subsequent testing, possible completion as production wells, continued drilling or subsequent plugging.

The northernmost well on the Norwegian shelf is 7316/5-1, which was drilled in 1992 with Norsk Hydro as operator, the easternmost is 7229/11-1, drilled in 1993 by Shell, and the westernmost is 6201/11-2 drilled by Statoil in 1991.

The exploration wells have been drilled by 21 different operating companies. Regional distribution of total wells per operator is shown in Figure 7.3.a.

The number of operating days per company in 1997 is shown in Figure 7.3.b. Figure 7.3.c shows the Norwegian operating companies' share of the drilling activities.

As of 31 December 1997, 2,962,181 meters have been drilled during exploration drilling, of this 156,415 meters in 1997.

Average total depth for exploration wells which reached total depth in 1997 is 3,242 meters.

Exploration well 6406/2-1 R, drilled in 1995 by Saga Petroleum ASA, is the deepest well drilled so far on the Norwegian shelf with a depth of 5,767 meters MSL.

The longest well path for an exploration well so far is 6506/12-10 A, which was drilled by Statoil in 1995. The well path was 6,260 meters RKB (6,236 m MSL), but the well was drilled at an angle and did not reach the same depth under the seabed as well 6406/2-1 R.

The deepest water ever drilled in on the Norwegian shelf is 1,274 meters. The well is 6707/10-1, which was drilled in 1997 with BP as operator. This is 751 meters deeper than the previous record.

The average water depth for exploration wells drilled in 1997 was 234 meters. Table 7.3.d shows the average water depth for exploration wells drilled during the period 1966-1997.

Table 7.3.a
Regional spread of spudded exploration and development wells per year

Year spudded	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	90	91	92	93	94	95	96	97	Sum
North Sea																																	
Wildcats	2	6	10	12	11	11	11	17	12	18	20	12	14	18	23	19	27	20	22	13	14	9	9	15	18	23	21	14	13	19	19	25	497
Appraisals			2	1	6	5	3	5	6	8	3	8	5	10	10	15	13	7	11	14	5	8	10	6	9	13	14	5	3	11	5	8	229
Norwegian Sea																																	0
Wildcats															1	2	5	7	6	10	10	10	5	2	7	8	5	4	5	3	2	13	105
Appraisals																	0	0	1	6	5	4	1	1	1	0		2	0	3	4	4	32
Barents Sea																																	0
Wildcats															2	3	4	5	7	7	2	5	4	4	1	3	3	2	0				52
Appraisals																	0	1	0	0													1
																																	0
Exploration total																																	0
Wildcats	2	6	10	12	11	11	11	17	12	18	20	12	14	18	26	24	36	32	35	30	26	24	18	21	26	34	29	20	18	22	21	38	654
Appraisals	0	0	2	1	6	5	3	5	6	8	3	8	5	10	10	15	13	8	12	20	10	12	11	7	10	13	14	7	3	14	9	12	262
Exploration wells	2	6	12	13	17	16	14	22	18	26	23	20	19	28	36	39	49	40	47	50	36	36	29	28	36	47	43	27	21	36	30	50	916
Development wells								1	18	24	7	34	50	36	27	16	22	23	33	47	47	48	55	66	60	64	86	105	120	109	141	132	1371
Total wells	**2**	**6**	**12**	**13**	**17**	**16**	**14**	**23**	**36**	**50**	**30**	**54**	**69**	**64**	**63**	**55**	**71**	**63**	**80**	**97**	**83**	**84**	**84**	**94**	**96**	**111**	**129**	**132**	**141**	**145**	**171**	**182**	**2287**

82 different drilling rigs have been utilized for drilling on the Norwegian continental shelf, 16 of these under two different names. Of these, 54 have been semi-submersibles, 17 jack-ups, 5 drilling ships and 6 permanent installations.

During 1997, 13 different drilling rigs have been active in exploration drilling on the Norwegian shelf. Tables 7.3.a to 7.3.e contain statistics on exploration drilling on the Norwegian continental shelf.

Table 7.3.b
Exploration drilling in 1997 (Regional spread)

Operator	North Sea			Norwegian Sea			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	4	3	7	6	1	7				10	4	14
Hydro	4	3	7	1		1				5	3	8
Phillips												
Elf												
Saga	2	2	4		3	3				2	5	7
Esso	6		6							6		6
Shell				1		1				1		1
Amoco	2		2	1		1				3		3
Conoco	1		1	1		1				2		2
Mobil												
BP	1		1	2		2				3		3
Gulf												
Murphy												
Total												
Agip	1		1							1		1
Deminex	2		2							2		2
Syracuse												
Texaco												
Unocal												
Fina												
Amerada	2		2	1		1				3		3
Wildcats	25			13						38		
Appraisals		8			4						12	
Exploration wells			33			17						50

W = wildcats A = appraisals E = exploration wells

Table 7.3.c
Exploration wells by operating company and region

Operator	North Sea			Norwegian Sea			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	81	59	140	50	13	63	19	1	20	150	73	223
Hydro	90	44	134	14	2	16	18		18	122	46	168
Phillips	43	20	63	1		1				44	20	64
Elf	46	18	64	2		2	1		1	49	18	67

Saga	52	14	66	16	4	20	3		3	71	18	89
Esso	37	24	61	2		2	4		4	43	24	67
Shell	28	11	39	6	5	11	3		3	37	16	53
Amoco	33	13	46	1		1				34	13	47
Conoco	20		20	5	8	13	1		1	26	8	34
Mobil	19	9	28	2		2	2		2	23	9	32
BP	17	14	31	5		5				22	14	36
Gulf	7		7							7		7
Murphy	3	1	4							3	1	4
Total	2		2				1		1	3		3
Agip	7		7							7		7
Deminex	3		3							3		3
Syracuse	1		1							1		1
Texaco	1		1							1		1
Unocal	1		1							1		1
Fina	2	1	3							2	1	3
Amerada	4		4	1		1				5		5
Wildcats	497			105			52			654		
Appraisals		228			32			1			261	
Exploration wells			725			137			53			915

W = wildcats A = appraisal E = exploration wells

Table 7.3.d
Average water depth and drilling depth

Year	Average water depth (m)	Average total depth (m)
1966	94	3 015
1967	100	2 682
1968	81	3 303
1969	74	3 276
1970	92	2 860
1971	79	3 187
1972	78	3 742
1973	85	3 075
1974	106	3 163
1975	106	3 173
1976	108	3 314
1977	104	3 450
1978	110	3 432
1979	157	3 444
1980	179	3 209
1981	164	3 243

Year	Average water depth (m)	Average total depth (m)
1982	163	3 457
1983	192	3 287
1984	212	3 247
1985	224	3 367
1986	234	3 248
1987	236	3 386
1988	248	3 598
1989	188	3 331
1990	156	3 619
1991	194	3 639
1992	225	3 560
1993	185	3 474
1994	185	3 371
1995	152	3 084
1996	221	3 982
1997	234	3 242

Table 7.3.e
Drilling installations active on the Norwegian continental shelf as of 31.12.1997

Installation	Number of wells	Number of re-entries	Type of installation
Aladdin	1		Semi-submersible
Arcade Frontier (was Norjarl)	7		"
Borgny Dolphin (was Fernstar)	27	8	"
Borgsten Dolphin (was Haakon Magnus)	9		"
Bucentaur		1	Drillship
Byford Dolphin (was Deepsea Driller)	38	2	Semi-submersible
Chris Chenery	2		"
Deepsea Bergen	57	3	"
Deepsea Saga	16	3	"
Deepsea Trym	11	1	"
Drillmaster	5	1	"
Drillship	1		Drillship
Dyvi Beta	6	1	Jack-up
Dyvi Gamma	1		"
Endeavour	2		Jack-up
Glomar Biscay II (was Norskald)	39	1	Semi-submersible
Glomar Grand Isle	11	3	Drillship
Glomar Moray Firth I	2		Jack-up
Gulftide	3		"
Henry Goodrich	2		Semi-submersible
Hunter (was Treasure Hunter)	6	3	"
Kolskaya		1	Jack-up
Le Pelerin	1		Drillship
Mærsk Explorer	7		Jack-up
Mærsk Gallant	2		"
Mærsk Giant	3		"
Mærsk Guardian	4	1	"
Mærsk Jutlander	13	2	Semi-submersible
Neddrill Trigon	3	1	Jack-up
Neptune 7 (was Pentagone 81)	13		Semi-submersible
Nordraug	12		"
Nortrym	32	3	"
Ocean Alliance	3		”
Ocean Tide	5		Jack-up
Ocean Traveller	9		Semi-submersible
Ocean Victory	1		"
Ocean Viking	28	1	"
Ocean Voyager	2		"
Odin Drill	3		"
Orion	7		Jack-up
Pentagone 84	2	1	Semi-submersible
Polar Pioneer	31	6	"
Polyglomar Driller	11		"
Ross Rig	29		"
Saipem II	1		Drillship
Scarabeo 5	3		Semi-submersible
Sedco 135 G	3		"
Sedco 703	3	1	"
Sedco 704	3		"
Sedco 707	8		"
Sedco H	2		"
Sedneth I	3		"
Sovereign Explorer	3	1	"
Stena Dee (was Dyvi Stena)	25	2	"

Installation	Number of wells	Number of re-entries	Type of installation
Transocean Arctic (was Ross Rig (new))	31	3	"
Transocean Leader (was Transocean 8)	19	2	"
Transocean Nordic	4		Jack-up
Transocean Prospect (was Treasure Prospect)	1	1	Semi-submersible
Transocean Searcher (was Ross Isle)	35	12	"
Transocean Wildcat (was Vildkat Explorer)	41	5	"
Transocean Winner (was Treasure Saga)	56	6	"
Transworld Rig 61	2		
Treasure Scout	23		
Treasure Seeker	24	5	"
Vinni	5		
Waage Drill I	2		
West Alpha (was Dyvi Alpha)	23	3	"
West Delta (was Dyvi Delta)	38	5	"
West Epsilon	1		Jack-up
West Vanguard	43	11	Semi-submersible
West Venture	12	2	"
West Vision	1		"
Yatzy	1		"
Zapata Explorer	13		Jack-up
Zapata Nordic	5		"
Zapata Ugland	5	1	Semi-submersible
	906	103	
In addition 9 wells have been drilled from fixed installations:			
Cod	1	1	
Ekofisk B	1		
Gullfaks B	1		
Sleipner A	1		
Ula A	1		
Veslefrikk A	4		
	915	104	

Table 7.3.f
Spudded and/or completed exploration wells in 1997

R=re-entry, X=junked due to technical problems, S=side drilled, A/B/C=sidetracked new well

Well		Reg. no Prod. lic. no	Position north east	Spudded Completed	Operator Drilling installation	Well classification Completion status	Water depth KBE	TD (RKB) Age at TD
1/03-08		855	56 52 07.14	96.12.12	Amoco	Wildcat	70	5201
		011	02 53 20.75	97.05.27	Transocean Nordic	Shows	40	Triassic
2/01-11		877	56 47 35.28	97.01.14	BP	Wildcat	68	4725
		019 B	03 03 58.16	97.05.07	Mærsk Jutlander	Suspended	23	
2/05-11		905	56 42 16.23	97.09.06	Agip	Wildcat	65	3550
		067	03 23 01.65	97.11.14	Transocean Nordic	Oil discovery	39	
2/06-05		866	56 35 36.69	96.11.17	Saga	Wildcat	70	3260
		008	03 45 42.73	97.01.11	Deepsea Bergen	Oil discovery	23	Basement
2/08-16	SX	874	56 16 40.75	97.02.08	Amoco	Wildcat	69	3139
		006	03 23 43.61	97.03.14	Valhall A	Junked	44	
2/08-17	S	912	56 27 21.36	97.12.04	Amoco	Wildcat	68	0
		006	03 36 05.00	00.00.00	Transocean Nordic		40	
9/02-07	S	887	57 45 15.15	97.04.22	Statoil	Wildcat	77	4099
		114	04 21 21.75	97.06.18	Byford Dolphin	Suspended. Oil discovery	25	M.Jurassic
9/02-08	S	895	57 49 07.58	97.06.24	Statoil	Wildcat	93	0
		114	04 31 11.00	00.00.00	Mærsk Giant		42	
15/05-06		893	58 41 46.95	97.06.20	Statoil	Avgrensningsbrønn	110	2725
		048	01 39 03.59	97.07.16	Byford Dolphin	Oil	25	Cretaceous
15/06-08	S	878	58 32 57.58	97.02.10	Deminex	Wildcat	102	3225
		166	01 52 55.90	97.04.04	Byford Dolphin	Dry hole	25	Triassic
15/06-08	A	886	58 32 57.58	97.04.05	Deminex	Undersøkelsesbrønn	102	2480
		166	01 52 55.90	97.04.18	Byford Dolphin	Tørt hull	25	Paleocene

Well		Reg. no Prod. lic. no	Position north east	Spudded Completed	Operator Drilling installation	Well classification Completion status	Water Depth KBE	TD (RKB) Age at TD
15/09-19	SR2	749	58 26 09.08	97.07.18	Statoil	Wildcat	84	3580
		046	01 55 47.26	97.07.25	Byford Dolphin	Oil	25	
15/09-19	A	898	58 26 09.25	97.07.25	Statoil	Appraisal	84	4131
		046	01 55 47.05	97.11.09	Byford Dolphin		25	
15/09-19	B	916	58 26 09.08	97.11.09	Statoil	Appraisal	84	0
		046	01 55 47.26	00.00.00	Byford Dolphin		25	
15/12-11	S	881	58 12 09.78	97.04.10	Saga	Wildcat	99	3597
		116	01 42 39.38	97.05.19	Deepsea Bergen	Dry hole	23	Triassic
16/07-06		882	58 15 39.23	97.06.28	Esso	Wildcat	78	2725
		072	02 02 36.04	97.07.24	Stena Dee	Dry hole	25	Triassic
16/07-07	S	913	58 17 06.53	97.10.20	Esso	Wildcat	78	2993
		072	02 03 51.01	97.12.29	Stena Dee	Gas/condensate discovery	25	Triassic
25/07-04	S	879	59 15 30.00	97.06.02	Conoco	Wildcat	126	2560
		103	02 15 58.99	97.06.21	Mærsk Jutlander	Dry hole	23	Cretaceous
25/07-05		896	59 29 39.81	97.07.16	Hydro	Wildcat	124	2736
		203	02 01 09.42	97.08.30	West Vanguard	Oil discovery	22	Cretaceous
25/08-05	SR	793	59 27 27.10	97.07.27	Esso	Wildcat	128	3420
		027 P	02 21 52.15	97.08.03	Stena Dee		25	
25/08-09		871	59 28 06.08	97.01.05	Amerada	Wildcat	125	2548
		189	02 30 24.90	97.01.28	Byford Dolphin	Oil discovery	25	L.Jurassic
25/08-09	A	880	59 28 06.08	97.01.29	Amerada	Appraisal	125	2687
		189	02 30 24.90	97.02.14	Byford Dolphin	Oil	25	Tertiary
25/08-10	S	883	59 16 22.69	97.04.29	Esso	Wildcat	129	1890
		027	02 32 06.40	97.06.04	Deepsea Trym	Oil discovery	25	
25/08-11		909	59 18 07.00	97.10.16	Esso	Wildcat	128	1994
		027	02 26 51.00	97.12.02	West Alpha	Suspended. Oil discovery	18	Jurassic
25/10-08		867	59 01 48.48	97.02.17	Esso	Wildcat	115	2653
		028 P	02 13 25.35	97.04.07	Deepsea Trym	Oil/gas discovery	25	Permian
25/10-08	A	889	59 01 48.48	97.04.08	Esso	Wildcat	115	3460
		028 P	02 13 25.35	97.04.27	Deepsea Trym	Dry hole	25	Jurassic
25/11-19	SR	811	59 12 48.71	97.05.01	Esso	Appraisal	129	2250
		001	02 24 06.82	97.05.06	West Alpha	Oil	25	
30/03-07	A	903	60 46 57.76	97.10.27	Statoil	Wildcat	175	0
		052	02 53 52.59	00.00.00	Veslefrikk A		56	
30/08-03		914	60 26 40.54	97.11.13	Hydro	Wildcat	93	3720
		190	02 38 58.02	00.00.00	West Vanguard	Gas/condensate discovery	22	
30/11-05		868	60 08 50.39	96.12.05	Shell	Wildcat	105	3726
		035	02 33 59.57	97.01.09	Mærsk Jutlander	Shows	23	L.Jurassic
33/06-02		864	61 32 15.87	96.10.28	Mobil	Wildcat	317	3950
		206	01 56 36.00	97.01.02	Byford Dolphin	Shows	22	L.Jurassic
34/04-09	S	865	61 30 44.71	97.01.08	Saga	Appraisal	337	3440
		057	02 10 18.10	97.02.15	Scarabeo 5	Oil	26	
34/07-26	S	902	61 16 29.38	97.08.18	Saga	Appraisal	201	4193
		089	02 07 11.41	97.09.13	Scarabeo 5	Suspended	25	
34/07-28		921	61 28 06.70	97.12.30	Saga	Wildcat	305	0
		089	02 01 05.10	00.00.00	Transocean Leader		24	
34/10-41	S	890	61 13 54.34	97.07.13	Statoil	Wildcat	141	3420
		050	02 05 42.30	97.08.28	Deepsea Trym	Dry hole	25	L.Jurassic
34/11-03		853	61 05 45.25	96.08.01	Statoil	Appraisal	207	4230
		193	02 31 06.51	97.01.16	Deepsea Trym	Gas/condensate	25	L.Jurassic
35/04-01		870	61 32 00.55	96.12.23	Hydro	Wildcat	378	4936
		194	03 18 08.26	97.05.24	Treasure Saga	Shows	26	Triassic
35/09-03		906	61 28 51.76	97.09.23	Hydro	Wildcat	346	2783
		153	03 58 30.17	97.11.11	West Vanguard	Oil/gas discovery	22	
35/11-09		875	61 03 54.23	97.03.02	Hydro	Appraisal	357	2830
		090	03 30 06.95	97.05.01	West Delta	Oil /gas	29	Jurassic
35/11-10		891	61 01 10.54	97.05.19	Hydro	Appraisal	354	2950
		090	03 31 26.29	97.06.23	West Vanguard	Oil	29	L.Jurassic
35/11-10	A	899	61 01 10.54	97.06.23	Hydro	Appraisal	354	3259
		090	03 31 26.29	97.07.14	West Vanguard	Dry hole	29	L.Jurassic
36/07-02		869	61 18 23.50	97.09.02	Hydro	Wildcat	270	1435
		153	04 19 47.00	97.09.22	West Vanguard	Oil discovery	26	Basement
6204/10-02		872	62 02 41.24	97.01.19	Statoil	Wildcat	172	1145
		175	04 07 04.59	97.02.12	Deepsea Trym	Suspended at 13 3/8”	25	
6204/10-02	R	872	62 02 41.24	97.11.04	Statoil	Wildcat	172	2095
		175	04 07 04.59	97.11.21	Deepsea Trym	Gas discovery	25	Basement
6204/10-02	A	920	62 02 41.24	97.11.22	Statoil	Wildcat	172	2105
		175	04 07 04.59	97.12.04	Deepsea Trym	Dry hole	25	Cretaceous
6204/11-02		915	62 11 50.47	97.12.04	Statoil	Wildcat	222	2920
		175	04 26 37.67	97.12.28	Deepsea Trym	Oil shows	25	
6305/05-01		900	63 32 27.50	97.07.27	Hydro	Wildcat	886	3053
		209	05 20 14.90	97.10.07	Ocean Alliance	Suspended. Gas discovery	26	L. Cretaceous
		175	04 07 04.59	97.11.21	Deepsea Trym	Gas discovery	25	Basement
6204/10-02	A	920	62 02 41.24	97.11.22	Statoil	Wildcat	172	2105
		175	04 07 04.59	97.12.04	Deepsea Trym	Dry hole	25	Cretaceous
6204/11-02		915	62 11 50.47	97.12.04	Statoil	Wildcat	222	2920
		175	04 26 37.67	97.12.28	Deepsea Trym	Oil shows	25	
6305/05-01		900	63 32 27.50	97.07.27	Hydro	Wildcat	886	3053
		209	05 20 14.90	97.10.07	Ocean Alliance	Suspended. Gas discovery	26	L. Cretaceous

Well		Reg. no Prod. lic. no	Position north east	Spudded Completed	Operator Drilling installation	Well classification Completion status	Water Depth KBE	TD (RKB) Age at TD
6306/05-01		892	63 41 56.42	97.06.08	Amerada	Wildcat	228	2050
		197	06 33 35.29	97.07.10	Deepsea Trym	Gas discovery	25	
6406/02-03		851	64 58 40.80	96.08.24	Saga	Wildcat	373	5258
		199	06 24 37.71	97.04.15	Transocean Arctic	Gas/condensate discovery	24	L. Jurassic
6406/02-04	S	876	64 47 58.34	97.01.18	Saga	Appraisal	274	4546
		199	06 32 29.26	97.04.03	Deepsea Bergen	Suspended at 9 5/8”	24	
6406/02-05		894	64 55 54.83	97.06.03	Saga	Appraisal	341	5439
		199	06 26 58.65	97.09.29	Deepsea Bergen	Dry hole	23	
6406/02-05	A	908	64 55 54.83	97.10.02	Saga	Appraisal	23	0
		199	06 26 58.65	00.00.00	Deepsea Bergen		23	
6407/08-03		888	64 18 02.00	97.05.13	BP	Wildcat	290	1960
		158	07 37 41.60	97.05.27	Mærsk Jutlander	Dry hole	23	Jurassic
6506/12-11	SR	849	65 05 07.20	96.11.12	Statoil	Appraisal	289	5268
		094	06 40 54.75	97.02.01	Transocean Searcher	Oil	22	
6507/03-02		884	65 45 25.29	97.04.05	Statoil	Wildcat	410	2032
		159	07 55 18.79	97.04.26	Transocean 8	Dry hole	23	Triassic
6507/05-01		919	65 44 36.20	97.12.24	Amoco	Wildcat	322	0
		212	07 39 05.10	00.00.00	Mærsk Jutlander		25	
6507/07-11	S	897	65 18 04.80	97.06.25	Conoco	Wildcat	274	3749
		095	07 07 42.27	97.08.14	Mærsk Jutlander	Gas discovery	23	Jurassic
6507/11-05	S	904	65 00 18.57	97.09.04	Statoil	Appraisal	257	2695
		062	07 33 25.23	97.10.28	Deepsea Trym	Suspended	25	
6510/02-01		901	65 47 15.60	97.08.16	Shell	Wildcat	325	3102
		214	10 25 51.33	97.10.10	Mærsk Jutlander	Suspended at 9 5/8”	23	
6510/02-01	R	901	65 47 15.60	97.11.05	Shell	Wildcat	325	4707
		214	10 25 51.33	97.12.19	Mærsk Jutlander	Shows	23	
6608/08-01		873	66 18 32.69	97.02.01	Statoil	Wildcat	334	3013
		200	08 30 58.84	97.03.30	Transocean 8	Dry hole	23	Permian
6706/11-01		907	67 04 24.77	97.10.12	Statoil	Wildcat	1232	0
		217	06 27 47.70	00.00.00	Ocean Alliance		26	
6707/10-01		885	67 04 07.85	97.04.19	BP	Wildcat	1274	5039
		218	07 00 36.51	97.07.23	Ocean Alliance	Gas discovery	25	L. Cretaceous

7.4 DEVELOPMENT DRILLING STATISTICS

Since 1973, 1371 development wells have been spudded on the Norwegian continental shelf; 1312 of these in the North Sea, and 59 in the Norwegian Sea where drilling started in 1992. 1021 are production wells, 247 are water or gas injection wells and 103 are observation wells. 542 are currently out of service, temporarily abandoned for later completion, or shut down for other reasons.

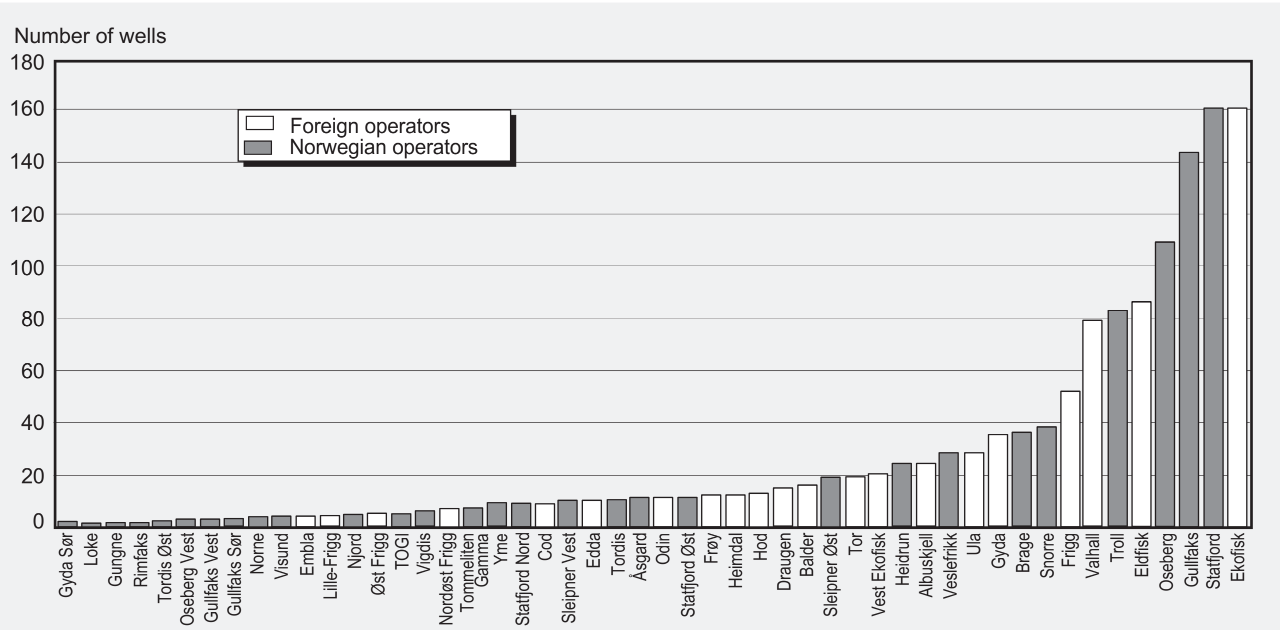
The wells have been drilled from 92 permanent installations (stationary, floating or subsea templates).

Drilling was in progress on 21 development wells as of 31 December 1997. Figure 7.4.b shows development wells spudded per year during the period 1973-1997.

As of 31 December 1997, production or injection is carried out from 73 installations divided among 40 fields.

Three new fields have started producing in 1997: Vigdis, Njord and Norne.

Figure 7.4.a
Development wells per field



Three fields have terminated production: Nordøst Frigg, Odin and Mime. In addition, the F installation on Albuskjell has been shut down.

Development wells categorized by the various fields are shown in Figure 7.4.a. Figure 7.4.c shows development wells categorized by operating companies.

Drilling of the first development wells on the Gullfaks Sør, Rimfaks, Tordis Øst, Visund and Åsgard fields commenced in 1997.

In 1997, 132 development wells were spudded on 27 fields. 62 of the wells, i.e. 47.0 percent, were drilled from 14 different mobile units, see Figure 7.4.d.

The number of subsea-completed wells has shown a strong increase over the last five years. This increase was particularly marked from 1995 to 1997 when the number of subsea-completed wells went up from 25 to 45, see Figure 7.4.e. This means that the percentage of subsea-completed wells drilled per year has increased from 7% in 1992 to 34% in 1997.

Information on development wells is set out in Tables 7.4.a, 7.4.b and 7.4.c.

Figure 7.4.b
Development wells on the Norwegian continental shelf

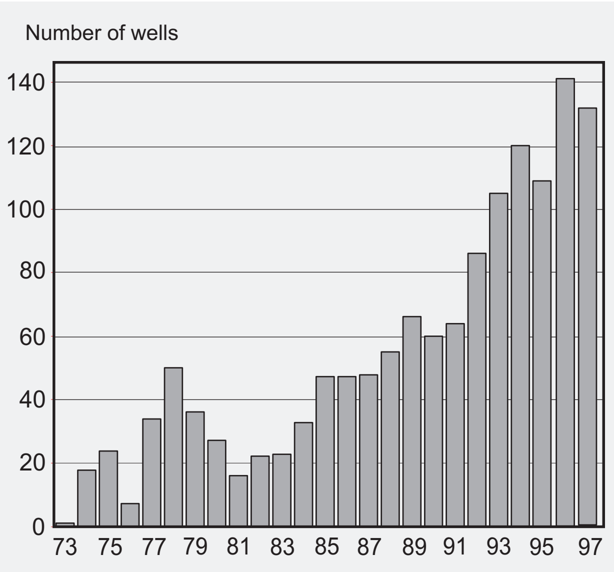


Fig. 7.4.d
Development drilling by mobile installations

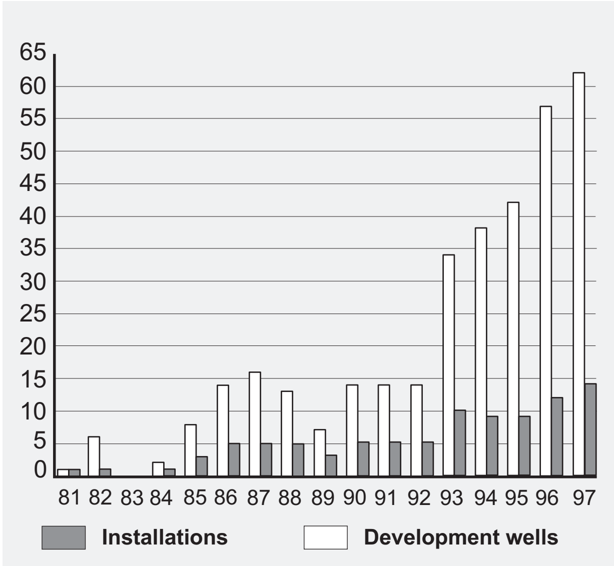


Figure 7.4.c
Development wells per operator

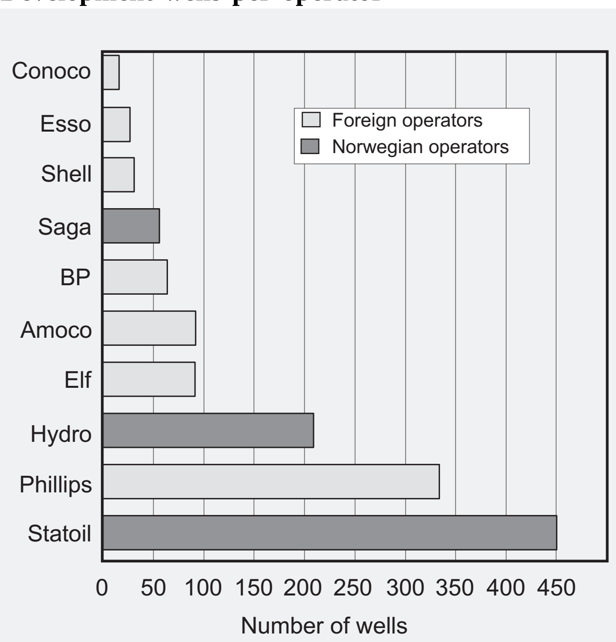


Fig. 7.4.e
Subsea completed wells per year

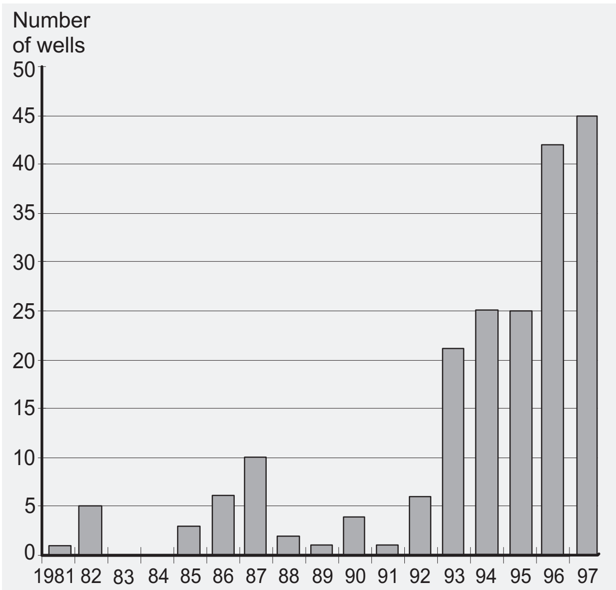


Table 7.4.a
Development drilling

Field/installation	Drilled total	Drilled 1997	Producing Oil	Cond.	Gas	Injecting	Drilling	Closed/Susp.
Albuskjell A	11			5				6
Albuskjell F	13							13
Balder A, B, C, D	16	5					1	15
Brage	36	7	18			8	1	9
Cod	9			3				6
Draugen A	10		7			1		2
Draugen B	3					3		
Draugen C	2					2		
Edda	10		5					5
Ekofisk A	35		18					17
Ekofisk B	40		22					18
Ekofisk C	33		21					12
Ekofisk K	31					30		1
Ekofisk W	8					8		
Ekofisk X	14	11	6				2	6
Eldfisk A	45		22					23
Eldfisk B	42	2	17					25
Embla	4		4					
Frigg (UK)	24							24
Frigg	28				10			18
Frøy	12		6			4		2
Gullfaks A	59	1	30			9	1	19
Gullfaks B	44	2	20			9		15
Gullfaks C	41	1	26			6	1	8
Gullfaks Sør	3	3					1	2
Gullfaks Vest	3		2					1
Gungne	1				1			
Gyda	35	2	12			11	1	11
Gyda Sør	1		1					
Heidrun A	18	4	13			2	1	2
Heidrun B	3					2		1
Heidrun C	3					3		
Heimdal	12			8				4
Hod	13		5					8
Lille-Frigg	4		1					3
Loke	1							1
Njord	5	1				1		4
Norne B, C, D	4	1	3				1	
N-Ø Frigg	7							7
Odin	11							11
Oseberg B	61	6	23			10	1	27
Oseberg C	48	1	17			6		25
Oseberg Vest	3		1					2
Rimfaks	1	1						1
Sleipner A	17				12	4		1
Sleipner D	2					2		
Sleipner Vest	10	3			8		1	1
Snorre A	11		7			3		1
Snorre P	27	3	14			9		4
Statfjord A	58	2	25			12		21
Statfjord B	55	5	31			11		13
Statfjord C	47	5	27			13	1	6
Statfjord G	1							1

Field/installation	Drilled total	Drilled 1997	Producing Oil	Cond.	Gas	Injecting	Drilling	Closed/Susp.
Statfjord Nord	9	1	6			2		1
Statfjord Øst	11			6		3		2
TOGI	5				5			
Tommeliten Gamma	7			6				1
Tor	19		11			2		6
Tordis	10		5					5
Tordis Øst	2	2						2
Troll A	36	17			26		1	9
Troll B	1					1		
Troll D,E,F,G,H	46	15	26				1	19
Ula	28	1	9			7		12
Valhall A	69	5	27				1	41
Valhall F	10	4	7				1	2
V. Ekofisk	20			3				17
Veslefrikk	28	1	12			9		7
Vigdis	6	3	5					1
Visund	4	4					1	3
Yme A, B	9	2	6			1		2
Øst Frigg A	3							3
Øst Frigg B	2		1					1
Åsgard	11	11					3	8
	1371	**132**	**519**	**31**	**62**	**194**	**21**	**544**

Table 7.4.b

Development wells spudded and/or completed in 1997

H=sub-sea completed, A/B/C=sidetracked new well, X=junked well

Well	Reg.no Lic.no	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
2/01-A-21	1384	56 54 17.25	97.11.27	BP	Oil producer	m
	019 B	03 05 06.49	00.00.00	Gyda		
2/01-A-29	1346	56 54 17.13	97.08.19	BP	Oil producer	6211 m
	019 B	03 05 06.28	97.10.24	Gyda	Suspended at TD	
2/04-X-01	1348	56 32 50.93	97.10.22	Phillips	Oil producer	5284 m
	018	03 13 07.98	97.12.13	Mærsk Gallant	Suspended at TD	
2/04-X-03	1317	56 32 50.90	97.06.22	Phillips	Oil producer	7812 m
	018	03 13 08.25	97.10.24	Mærsk Gallant	Suspended at TD	
2/04-X-04	1276	56 32 50.89	97.03.10	Phillips	Oil producer	3990 m
	018	03 13 08.39	97.04.04	Mærsk Gallant	Oil	
2/04-X-06	1255	56 32 50.99	97.01.23	Phillips	Oil producer	4812 m
	018	03 13 08.14	97.03.09	Mærsk Gallant	Oil	
2/04-X-08	1230	56 32 50.96	96.12.13	Phillips	Oil producer	3889 m
	018	03 13 08.41	97.01.22	Mærsk Gallant	Oil	
2/04-X-09	1306	56 32 51.08	97.04.05	Phillips	Oil producer	4033 m
	018	03 13 08.03	97.06.22	Mærsk Gallant	Suspended at TD	
2/04-X-10	1399	56 32 51.08	97.12.14	Phillips	Oil producer	m
	018	03 13 08.14	00.00.00	Mærsk Gallant		
2/04-X-31	1371	56 32 51.79	97.11.25	Phillips	Oil producer	m
	018	03 13 08.26	00.00.00	Ekofisk X		
2/04-X-35	1287	56 32 51.87	97.03.20	Phillips	Oil producer	3882 m
	018	03 13 08.28	97.05.14	Ekofisk X	Oil	
2/04-X-42	1309	56 32 51.91	97.05.15	Phillips	Oil producer	3997 m
	018	03 13 08.72	97.07.02	Ekofisk X	Suspended at TD	
2/04-X-45	1256	56 32 52.00	97.02.09	Phillips	Oil producer	3942 m
	018	03 13 08.61	97.03.20	Ekofisk X	Oil	
2/04-X-46	1235	56 32 51.98	96.12.08	Phillips	Oil producer	4582 m
	018	03 13 08.75	97.02.09	Ekofisk X	Oil	
2/04-X-47	1330	56 32 52.10	97.07.02	Phillips	Oil producer	5101 m
	018	03 13 08.36	97.09.04	Ekofisk X	Suspended at TD	
2/07-B-01 B	1212	56 25 08.94	96.12.08	Phillips	Oil producer	4762 m
	018	03 13 06.46	97.02.14	Eldfisk B	Oil	

Well			Reg.no Lic.no	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
2/07-B-05	B		1353	56 25 09.59	97.09.03	Phillips	Oil producer	3174 m
			018	03 13 06.22	97.10.01	Eldfisk B	Suspended at TD	
2/07-B-14	B		1270	56 25 09.11	97.03.23	Phillips	Oil producer	4564 m
			018	03 13 06.13	97.08.01	Eldfisk B	Suspended at TD	
2/08-A-03	B		1233	56 16 41.08	96.11.29	Amoco	Oil	2700 m
			006	03 23 44.30	97.01.02	Valhall	Oil producer	
2/08-A-05	B		1362	56 16 41.05	97.10.24	Amoco	Oil producer	m
			006	03 23 43.68	00.00.00	Valhall		
2/08-A-09	A		1349	56 16 40.92	97.07.28	Amoco	Oil producer	2700 m
			006	03 23 43.55	97.09.08	Valhall	Suspended at TD	
2/08-A-20	B		1300	56 16 40.74	97.03.17	Amoco	Oil producer	4758 m
			006	03 23 43.61	97.05.04	Valhall	Suspended at TD	
2/08-A-20	C		1314	56 16 40.74	97.05.04	Amoco	Cutting injector	4990 m
			006	03 23 43.61	97.05.30	Valhall	Suspended at TD	
2/08-A-20	D		1338	56 16 40.74	97.05.31	Amoco	Cutting injector	3322 m
			006	03 23 43.61	97.06.28	Valhall	Suspended at TD	
2/08-F-06			1211	56 16 35.57	96.12.06	Amoco	Oil producer	4460 m
			006	03 23 46.96	97.01.28	Mærsk Guardian	Oil	
2/08-F-07			1315	56 16 35.60	97.05.12	Amoco	Oil producer	5066 m
			006	03 23 47.17	97.07.07	Mærsk Guardian	Suspended at TD	
2/08-F-08			1332	56 16 35.00	97.07.17	Amoco	Oil producer	4690 m
			006	03 23 47.00	97.08.24	Mærsk Guardian	Suspended at TD	
2/08-F-09			1254	56 16 35.46	97.01.28	Amoco	Oil producer	5188 m
			006	03 23 47.22	97.04.13	Mærsk Guardian	Suspended at TD	
2/08-F-17			1365	56 16 35.52	97.10.02	Amoco	Oil producer	m
			006	03 23 47.25	00.00.00	Mærsk Guardian		
7/12-A-10	A		1269	57 06 41.19	97.02.21	BP	Oil producer	5690 m
			019	02 50 50.73	97.05.04	Ula	Oil	
9/02-A-02			1238	57 49 07.54	96.12.14	Statoil	Oil producer	5518 m
			114	04 31 10.87	97.04.17	Mærsk Giant	Suspended at TD	
9/02-A-02	A		1271	57 49 07.54	97.04.17	Statoil	Oil producer	5040 m
			114	04 31 10.87	97.05.30	Mærsk Giant	Suspended at TD	
9/02-A-06			1286	57 49 07.47	97.03.11	Statoil	Oil producer	5191 m
			114	04 31 10.95	97.03.29	Mærsk Giant	Suspended at TD	
15/09-B-04			1379	58 25 04.78	97.07.01	Statoil	Gas producer	6476 m
			046	01 43 04.38	97.11.28	West Epsilon	Suspended at TD	
15/09-B-17			1283	58 25 04.42	97.04.21	Statoil	Gas producer	5911 m
			046	01 43 04.17	97.07.04	West Epsilon	Suspended at TD	
15/09-B-22			1393	58 25 04.31	97.11.29	Statoil	Gas producer	m
			046	01 43 04.48	00.00.00	West Epsilon		
15/09-B-24			1244	58 25 04.40	96.12.30	Statoil	Gas producer	7020 m
			046	01 43 04.77	97.07.12	West Epsilon	Suspended at TD	
25/11-A-04	A	H	1236	59 11 28.37	96.12.04	Esso	Oil producer	2122 m
			001	02 21 34.86	97.08.11	West Alpha	Suspended at TD	
25/11-A-05	A	H	1221	59 11 30.22	96.11.04	Esso	Oil producer	3068 m
			001	02 21 34.19	97.08.23	West Alpha	Plugged	
25/11-A-05	B	H	1364	59 11 30.22	97.08.23	Esso	Oil producer	2988 m
			001	02 21 34.19	97.09.10	West Alpha	Suspended at TD	
25/11-A-06		H	1210	59 11 28.42	96.10.07	Esso	Oil producer	1807 m
			001	02 21 37.38	97.07.30	West Alpha	Suspended at TD	
25/11-A-08		H	1237	59 11 29.83	96.12.11	Esso	Water producer	m
			001	02 21 32.62	97.09.30	West Alpha	Suspended at TD	
25/11-B-07		H	1245	59 10 40.45	96.12.17	Esso	Observation	2362 m
			001	02 22 46.46	97.01.13	West Alpha	Plugged	
25/11-B-07	A	H	1253	59 10 40.45	97.01.14	Esso	Oil producer	2891 m
			001	02 22 46.46	97.03.08	West Alpha	Suspended at TD	
25/11-C-03	A	H	1401	59 11 00.62	97.12.13	Esso	Observation	2273 m
			001	02 24 32.52	97.12.20	West Alpha	Suspended at TD	
25/11-C-03	B	H	1402	59 11 00.62	97.12.21	Esso	Oil producer	m
			001	02 24 32.52	00.00.00	West Alpha		
25/11-C-13		H	1310	59 10 59.87	97.05.07	Esso	Oil producer	2725 m
			001	02 24 34.62	97.07.05	West Alpha	Suspended at TD	
25/11-D-01		H	1162	59 12 01.03	96.05.25	Esso	Gas injector	2773 m
			001	02 24 37.02	97.04.30	West Alpha	Suspended at TD	
25/11-D-02	A	H	1193	59 11 59.60	96.08.13	Esso	Oil producer	2773 m
			001	02 24 33.19	97.04.06	West Alpha	Suspended at TD	
30/03-A-02	A		1267	60 46 57.87	97.07.02	Statoil	Water/gas inj	4653 m

Well			Reg.no Lic. no	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
			052	02 53 52.38	97.08.28	Veslefrikk A	Suspended at TD	
30/06-C-07	C		1241	60 36 29.42	96.12.18	Hydro	Oil producer	6093 m
			053	02 46 33.72	97.02.25	Oseberg C	Oil	
30/06-C-13	A		1275	60 36 29.49	97.04.14	Hydro	Oil producer	6820 m
			053	02 46 33.13	97.06.06	Oseberg C	Suspended at TD	
30/09-B-20	A		1388	60 29 36.15	97.11.29	Hydro	Gas injector	4000 m
			079	02 49 42.59	97.12.22	Oseberg B	Suspended at TD	
30/09-B-24	A		1242	60 29 36.22	97.01.07	Hydro	Oil producer	5800 m
			079	02 49 43.26	97.03.24	Oseberg B	Oil	
30/09-B-26	A		1340	60 29 36.07	97.08.13	Hydro	Observation	5636 m
			079	02 49 42.63	97.09.03	Oseberg B	Plugged	
30/09-B-26	B		1341	60 29 36.07	97.09.03	Hydro	Observation	5553 m
			079	02 49 42.63	97.10.08	Oseberg B	Suspended at TD	
30/09-B-27	A		1288	60 29 36.08	97.05.03	Hydro	Observation	3512 m
			079	02 49 42.79	97.05.23	Oseberg B	Suspended at TD	
30/09-B-27	B		1289	60 29 36.08	97.06.19	Hydro	Oil producer	6075 m
			079	02 49 42.79	97.08.13	Oseberg B	Suspended at TD	
31/02-D-05		H	1350	60 51 25.74	97.07.26	Hydro	Observation	1944 m
			054	03 26 34.49	97.08.09	Polar Pioneer	Plugged	
31/02-D-05	A	H	1351	60 51 25.74	97.08.09	Hydro	Oil producer	3800 m
			054	03 26 34.49	97.10.08	Polar Pioneer	Suspended at TD	
31/02-D-10		H	1369	60 51 11.06	97.10.09	Hydro	Oil producer	1723 m
			054	03 29 15.68	97.10.29	Polar Pioneer	Suspended at TD	
31/02-E-06	A	H	1248	60 47 51.30	96.12.31	Hydro	Observation	1740 m
			054	03 26 43.10	97.01.12	Polar Pioneer	Plugged	
31/02-E-06	B	H	1260	60 47 51.30	97.01.12	Hydro	Oil producer	3355 m
			054	03 26 43.10	97.02.01	Polar Pioneer	Oil	
31/02-F-04		H	1264	60 46 31.51	97.02.13	Hydro	Observation	1690 m
			054	03 26 04.76	97.02.25	Polar Pioneer	Plugged	
31/02-F-04	A	H	1274	60 46 31.51	97.02.26	Hydro	Oil producer	3320 m
			054	03 26 04.76	97.03.17	Polar Pioneer	Oil	
31/02-G-01	A	H	1217	60 45 04.72	96.10.23	Hydro	Oil producer	4070 m
			054	03 26 11.19	97.02.12	Polar Pioneer	Oil	
31/02-M-41			1297	60 55 55.99	97.03.19	Hydro	Observation	1730 m
			054	03 36 25.11	97.04.05	Polar Pioneer	Plugged	
31/02-P-41			1370	60 53 11.46	97.10.30	Hydro	Observation	1725 m
			089	03 31 21.54	97.11.21	Polar Pioneer	Suspended at TD	
31/04-A-11			1328	60 32 33.34	97.10.20	Hydro	Observation	3573 m
			055	03 02 50.35	97.11.12	Brage	Plugged	
31/04-A-11	A		1368	60 32 33.34	97.11.28	Hydro	Oil producer	4660 m
			055	03 02 50.35	97.12.21	Brage	Suspended at TD	
31/04-A-16			1240	60 32 33.34	96.12.16	Hydro	Water/gas inj	5321 m
			055	03 02 51.03	97.02.01	Brage	Suspended at TD	
31/04-A-19			1282	60 32 33.34	97.04.14	Hydro	Oil producer	5645 m
			055	03 02 50.52	97.05.31	Brage	Suspended at TD	
31/04-A-20			1392	60 32 33.51	97.12.26	Hydro	Oil producer	m
			055	03 02 50.35	00.00.00	Brage		
31/04-A-37			1318	60 32 33.34	97.07.27	Hydro	Observation	5049 m
			055	03 02 50.69	97.09.03	Brage	Plugged	
31/04-A-37	A		1319	60 32 33.34	97.09.04	Hydro	Observation	6474 m
			055	03 02 50.69	97.09.17	Brage	Plugged	
31/04-A-37	B		1320	60 32 33.34	97.09.18	Hydro	Oil producer	7080 m
			055	03 02 50.69	97.10.19	Brage	Suspended at TD	
31/05-H-03		H	1302	60 42 51.32	97.04.07	Hydro	Observation	2377 m
			085	03 30 49.38	97.04.22	Polar Pioneer	Plugged	
31/05-H-03	A	H	1303	60 42 51.32	97.04.23	Hydro	Oil producer	4630 m
			085	03 30 49.38	97.05.26	Polar Pioneer	Suspended at TD	
31/05-H-03	B	H	1304	60 42 51.32	97.05.27	Hydro	Oil producer	1409 m
			085	03 30 49.38	97.07.10	Polar Pioneer	Suspended at TD	
31/05-I-21		H	1385	60 43 42.50	97.11.24	Hydro	Observation	1947 m
			085	03 34 39.81	97.12.11	Polar Pioneer	Plugged	
31/05-I-22		H	1395	60 43 42.75	97.12.11	Hydro	Observation	2002 m
			085	03 34 39.35	97.12.19	Polar Pioneer	Plugged	
31/05-I-22	A	H	1396	60 43 42.75	97.12.19	Hydro	Oil producer	m
			085	03 34 39.35	00.00.00	Polar Pioneer		
31/05-J-41			1333	60 43 27.22	97.07.11	Hydro	Observation	1760 m

Well	Reg. no	Position	Spudded	Operator	Classification	TD
	Lic. no		Completed	Installation	Status	(RKB)
	085	03 39 28.93	97.07.26	Polar Pioneer	Suspended at TD	
31/06-A-01	1250	60 38 44.98	97.02.03	Statoil	Gas producer	1626 m
	085	03 43 35.08	97.03.11	Troll A	Gas	
31/06-A-04	1373	60 38 45.01	97.10.09	Statoil	Gas producer	1543 m
	085	03 43 35.23	97.11.17	Troll A	Suspended at TD	
31/06-A-05	1251	60 38 44.98	97.01.26	Statoil	Gas producer	1580 m
	085	03 43 35.23	97.03.20	Troll A	Gas	
31/06-A-08	1380	60 38 44.75	97.10.26	Statoil	Observation	1430 m
	085	03 43 35.23	97.12.24	Troll A	Plugged	
31/06-A-09	1372	60 38 45.05	97.10.20	Statoil	Gas producer	1554 m
	085	03 43 35.39	97.11.24	Troll A	Suspended at TD	
31/06-A-13	1268	60 38 45.05	97.02.08	Statoil	Gas producer	1544 m
	085	03 43 35.53	97.12.05	Troll A	Suspended at TD	
31/06-A-14	1252	60 38 44.98	97.01.19	Statoil	Gas producer	1590 m
	085	03 43 35.53	97.03.30	Troll A	Gas	
31/06-A-18	1296	60 38 44.98	97.08.01	Statoil	Gas producer	1563 m
	085	03 43 35.68	97.12.09	Troll A	Suspended at TD	
31/06-A-19	1295	60 38 44.90	97.07.29	Statoil	Gas producer	m
	085	03 43 35.68	97.11.29	Troll A	Suspended at TD	
31/06-A-20	1294	60 38 44.83	97.07.27	Statoil	Gas producer	m
	085	03 43 35.68	97.08.25	Troll A	Suspended at 14"	
31/06-A-24	1375	60 38 43.84	97.12.25	Statoil	Gas producer	m
	085	03 43 35.23	97.12.30	Troll A	Suspended at 14"	
31/06-A-25	1214	60 38 43.77	96.11.08	Statoil	Gas producer	1603 m
	085	03 43 35.23	97.01.08	Troll A	Gas	
31/06-A-28	1321	60 38 43.54	97.05.09	Statoil	Gas producer	m
	085	03 43 35.23	97.11.05	Troll A	Suspended at 9 5/8"	
31/06-A-32	1293	60 38 43.54	97.04.20	Statoil	Gas producer	1587 m
	085	03 43 35.38	97.05.25	Troll A	Suspended at TD	
31/06-A-33	1311	60 38 43.83	97.03.31	Statoil	Gas producer	1870 m
	085	03 43 35.53	97.06.28	Troll A	Suspended at TD	
31/06-A-34	1213	60 38 43.77	96.10.28	Statoil	Gas producer	1619 m
	085	03 43 35.53	97.01.18	Troll A	Gas	
31/06-A-38	1290	60 38 43.77	97.04.06	Statoil	Gas producer	1671 m
	085	03 43 35.68	97.09.05	Troll A	Suspended at TD	
31/06-A-39	1291	60 38 43.69	97.04.11	Statoil	Gas producer	1588 m
	085	03 43 35.68	97.07.09	Troll A	Suspended at TD	
31/06-A-40	1292	60 38 43.62	97.04.16	Statoil	Gas producer	m
	085	03 43 35.68	97.06.01	Troll A	Suspended at TD	
33/09-A-38 A	1354	61 15 19.73	97.09.01	Statoil	Water/gas inj	4775 m
	037	01 51 14.20	97.10.13	Statfjord A	Suspended at TD	
33/09-A-40 A	1199	61 15 19.72	96.11.25	Statoil	Oil producer	4689 m
	037	01 51 13.87	97.01.20	Statfjord A	Oil	
33/09-A-41 A	1366	61 15 20.46	97.12.14	Statoil	Oil producer	m
	037	01 51 13.95	00.00.00	Statfjord A		
33/09-C-08	1273	61 17 48.02	97.03.13	Statoil	Oil producer	3300 m
	037	01 54 11.45	97.04.11	Statfjord C	Oil	
33/09-C-11 A	1258	61 17 48.01	97.01.28	Statoil	Water injector	3557 m
	037	01 54 11.11	97.02.22	Statfjord C	Water injector	
33/09-C-19 A	1383	61 17 47.69	97.11.16	Statoil	Oil producer	m
	037	01 54 09.15	00.00.00	Statfjord C		
33/09-C-23	1307	61 17 47.70	97.05.01	Statoil	Oil producer	m
	037	01 54 09.16	97.06.11	Statfjord C	Plugged	
33/09-C-23 A	1308	61 17 47.70	97.06.11	Statoil	Oil producer	4770 m
	037	01 54 09.16	97.07.22	Statfjord C	Suspended at TD	
33/09-C-29	1207	61 17 46.83	96.10.13	Statoil	Oil producer	5205 m
	037	01 54 10.41	97.01.05	Statfjord C	Oil	
33/09-E-04 H	1197	61 26 03.01	96.09.25	Statoil	Oil producer	2938 m
	037	01 55 30.23	97.03.12	Treasure Prospect	Oil	
33/09-F-03 H	1232	61 26 40.82	97.03.14	Statoil	Oil producer	3450 m
	037	01 57 23.99	97.05.09	Treasure Prospect	Suspended at TD	
33/09-G-03 H	1229	61 21 56.57	96.12.09	Statoil	Oil producer	3815 m
	037	01 56 05.94	97.01.22	Transocean 8	Suspended at TD	
33/12-B-14 A	1284	61 12 24.88	97.04.09	Statoil	Water injector	4226 m
	037	01 49 50.29	97.05.09	Statfjord B	Suspended at TD	
33/12-B-22 A	1316	61 12 24.14	97.05.19	Statoil	Oil producer	2931 m

Well			Reg. no Lic. no.	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
			037	01 49 51.06	97.06.02	Statfjord B	Suspended at TD	
33/12-B-28	B		1246	61 12 24.00	97.01.30	Statoil	Observation	3487 m
			037	01 49 51.26	97.02.19	Statfjord B	Plugged	
33/12-B-28	C		1266	61 12 24.00	97.02.20	Statoil	Oil producer	4497 m
			037	01 49 51.26	97.04.02	Statfjord B	Suspended at TD	
33/12-B-38	A		1325	61 12 24.88	97.06.18	Statoil	Water/gas injector	4589 m
			037	01 49 50.29	97.07.20	Statfjord B	Suspended at TD	
34/07-B-01		H	1265	61 23 49.46	97.02.21	Saga	Observation	4220 m
			089	02 07 03.95	97.04.08	Scarabeo 5	Plugged	
34/07-B-01	A	H	1313	61 23 49.46	97.05.18	Saga	Oil producer	3650 m
			089	02 07 03.95	97.06.17	Scarabeo 5	Suspended at TD	
34/07-B-02		H	1301	61 23 49.33	97.04.09	Saga	Oil producer	3113 m
			089	02 07 03.76	97.10.14	Scarabeo 5	Suspended at TD	
34/07-J-07		H	1305	61 17 29.81	97.07.02	Saga	Observation	2585 m
			089	02 09 48.39	97.07.19	Scarabeo 5	Plugged	
34/07-J-07	A	H	1347	61 17 29.81	97.07.19	Saga	Observation	2800 m
			089	02 09 48.39	97.08.10	Scarabeo 5	Plugged	
34/07-P-18	A		1331	61 26 57.21	97.07.07	Saga	Oil producer	3283 m
			089	02 08 37.09	97.08.23	Snorre P	Suspended at TD	
34/07-P-23			1243	61 26 57.47	97.02.17	Saga	Oil producer	7028 m
			089	02 08 37.08	97.06.13	Snorre P	Suspended at TD	
34/07-P-25	A		1257	61 26 57.73	97.01.16	Saga	Water/gas injector	3324 m
			089	02 08 36.81	97.02.13	Snorre P	Water injector	
34/08-A-01		H	1322	61 22 12.57	97.07.04	Hydro	Observation	1110 m
			120	02 27 35.13	97.07.14	West Delta	Plugged	
34/08-A-01	A	H	1323	61 22 12.57	97.07.14	Hydro	Observation	4582 m
			120	02 27 35.13	97.09.13	West Delta	Suspended	
34/08-A-02		H	1381	61 22 12.80	97.11.16	Hydro	Gas injector	m
			120	02 27 35.09	00.00.00	West Delta		
34/08-A-07		H	1360	61 22 13.26	97.10.06	Hydro	Oil producer	3642 m
			120	02 27 32.83	97.11.15	West Delta	Suspended at TD	
34/10-A-07	A		1228	61 10 34.77	96.12.01	Statoil	Oil producer	4317 m
			050	02 11 21.80	97.02.08	Gullfaks A	Oil	
34/10-A-19	A		1382	61 10 33.89	97.11.30	Statoil	Oil producer	m
			050	02 11 22.99	00.00.00	Gullfaks A		
34/10-B-13	A		1312	61 12 09.97	97.05.12	Statoil	Oil producer	3226 m
			050	02 12 06.08	97.06.01	Gullfaks B	Suspended at TD	
34/10-B-37			1198	61 12 10.04	96.09.15	Statoil	Oil producer	4988 m
			050	02 12 05.99	97.03.19	Gullfaks B	Oil	
34/10-B-38			1324	61 12 10.08	97.06.02	Statoil	Oil producer	m
			050	02 12 06.13	97.06.13	Gullfaks B	Suspended at 20"	
34/10-C-35			1181	61 12 53.38	96.08.11	Statoil	Oil producer	3506 m
			050	02 16 27.69	97.03.14	Gullfaks C	Suspended at TD	
34/10-C-36			1205	61 12 54.77	96.10.05	Statoil	Observation	4903 m
			050	02 16 26.79	97.05.30	Gullfaks C	Suspended at TD	
34/10-C-36	A		1280	61 12 54.77	97.05.30	Statoil	Injector/producer	m
			050	02 16 26.79	00.00.00	Gullfaks C		
34/10-F-04		H	1336	61 05 51.88	97.08.09	Statoil	Observation	4320 m
			050	02 16 35.62	97.10.07	Transocean Wildcat	Plugged	
34/10-F-04	A	H	1337	61 05 51.81	97.10.07	Statoil	Oil producer	m
			050	02 16 35.81	00.00.00	Transocean Wildcat		
34/10-G-02		H	1272	61 05 50.23	97.04.09	Statoil	Oil producer	3559 m
			050	02 16 36.25	97.05.22	Transocean Wildcat	Suspended at TD	
34/10-J-01		H	1285	61 03 50.67	97.06.08	Statoil	Gas injector	4459 m
			050	02 00 10.58	97.07.27	Transocean Wildcat	Suspended at TD	
6407/07-A-08		H	1231	64 16 15.25	96.11.27	Hydro	Gas injector	3625 m
			107	07 12 08.68	97.02.10	West Vanguard	Suspended at TD	
6407/07-A-10		H	1261	64 16 15.78	97.02.11	Hydro	Observation	3764 m
			107	07 12 09.44	97.04.04	West Vanguard	Plugged	
6407/07-A-10	A	H	1277	64 16 15.78	97.12.09	Hydro	Oil producer	m
			107	07 12 09.44	00.00.00	Njord		
6407/07-A-15	A	H	1218	64 16 16.53	96.11.02	Hydro	Oil producer	4150 m
			107	07 12 05.58	97.05.08	West Vanguard	Suspended at TD	
6506/11-G-03		H	1298	65 05 17.79	97.04.23	Statoil	Gas injector	5352 m
			134	06 39 43.22	97.07.10	Transocean Arctic	Suspended at TD	
6506/11-G-04		H	1335	65 05 17.80	97.07.10	Statoil	Gas injector	3111 m

Well	Reg. no Lic. no	Position	Spudded Completed	Operator Installations	Classification Status	TD (RKB)
	134	06 39 43.59	97.08.02	Transocean Arctic	Suspended at TD	
6506/12-K-02 H	1339	65 08 01.90	97.08.21	Statoil	Gas injector	6003 m
	094	06 42 24.87	97.10.27	Transocean Winner	Suspended at TD	
6506/12-K-03 H	1358	65 08 01.97	97.06.24	Statoil	Gas injector	4664 m
	094	06 42 25.10	97.08.20	Transocean Winner	Suspended at TD	
6506/12-L-01 H	1299	65 08 17.89	97.04.12	Statoil	Oil producer	6719 m
	094	06 46 57.32	97.06.26	Transocean Searcher	Suspended at TD	
6506/12-L-02 H	1329	65 08 17.72	97.06.28	Statoil	Oil producer	m
	094	06 46 57.36	00.00.00	Transocean Searcher		
6506/12-P-03 H	1326	65 01 22.92	97.08.07	Statoil	Oil producer	6365 m
	094	06 52 45.65	97.11.09	Transocean Arctic	Plugged	
6506/12-P-03 A H	1327	65 01 22.92	97.11.09	Statoil	Oil producer	6540 m
	094	06 52 45.65	97.12.20	Transocean Arctic	Suspended at TD	
6506/12-R-01 H	1259	65 01 59.96	97.02.01	Statoil	Gas injector	5300 m
	094	06 54 07.17	97.04.03	Transocean Searcher	Suspended at TD	
6506/12-R-04 H	1387	65 02 00.27	97.12.25	Statoil	Gas injector	m
	094	06 54 07.05	00.00.00	Transocean Arctic		
6506/12-S-01 H	1355	65 00 57.87	97.10.30	Statoil	Observation	m
	094	06 56 45.38	00.00.00	Transocean Winner		
6507/07-A-07	1367	65 19 33.14	97.07.12	Statoil	Oil producer	m
	095	07 19 04.05	00.00.00	Heidrun		
6507/07-A-28	1334	65 19 32.71	97.08.14	Statoil	Oil producer	3005 m
	095	07 19 03.27	97.10.21	Heidrun	Suspended at TD	
6507/07-A-36	1247	65 19 32.64	97.01.12	Statoil	Oil producer	4658 m
	095	07 19 03.33	97.06.10	Heidrun	Oil	
6507/07-A-46	1223	65 19 32.58	96.11.17	Statoil	Oil producer	2941 m
	095	07 19 04.00	97.01.12	Heidrun	Oil	
6608/10-B-02 H	1239	66 00 55.04	96.12.13	Statoil	Oil producer	3862 m
	128	08 03 17.00	97.12.09	Transocean Wildcat	Suspended at TD	
6608/10-C-04 H	1226	66 00 52.20	96.11.18	Statoil	Gas injector	2900 m
	128	08 03 21.72	97.08.18	Transocean Wildcat	Suspended at TD	
6608/10-D-02 H	1249	66 00 49.15	97.01.09	Statoil	Oil producer	4174 m
	128	08 03 28.53	00.00.00	Transocean Wildcat		

Table 7.4.c
Development wells drilled from mobile units 1997

H=sub-sea completed, A/B/C=sidetracked new well, X=junked well

Well	Reg.no Lic. no	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
2/04-X-01	1348	56 32 50.93	97.10.22	Phillips	Oil producer	5284 m
	018	03 13 07.98	97.12.13	Mærsk Gallant	Suspended at TD	
2/04-X-03	1317	56 32 50.90	97.06.22	Phillips	Oil producer	7812 m
	018	03 13 08.25	97.10.24	Mærsk Gallant	Suspended at TD	
2/04-X-04	1276	56 32 50.89	97.03.10	Phillips	Oil producer	3990 m
	018	03 13 08.39	97.04.04	Mærsk Gallant	Oil	
2/04-X-06	1255	56 32 50.99	97.01.23	Phillips	Oil producer	4812 m
	018	03 13 08.14	97.03.09	Mærsk Gallant	Oil	
2/04-X-09	1306	56 32 51.08	97.04.05	Phillips	Oil producer	4033 m
	018	03 13 08.03	97.06.22	Mærsk Gallant	Suspended at TD	
2/04-X-10	1399	56 32 51.08	97.12.14	Phillips	Oil producer	m
	018	03 13 08.14	00.00.00	Mærsk Gallant		
2/08-F-07	1315	56 16 35.60	97.05.12	Amoco	Oil producer	5066 m
	006	03 23 47.17	97.07.07	Mærsk Guardian	Suspended at TD	
2/08-F-08	1332	56 16 35.00	97.07.17	Amoco	Oil producer	4690 m
	006	03 23 47.00	97.08.24	Mærsk Guardian	Suspended at TD	
2/08-F-09	1254	56 16 35.46	97.01.28	Amoco	Oil producer	5188 m
	006	03 23 47.22	97.04.13	Mærsk Guardian	Suspended at TD	
2/08-F-17	1365	56 16 35.52	97.10.02	Amoco	Oil producer	m
	006	03 23 47.25	00.00.00	Mærsk Guardian		
9/02-A-02 A	1271	57 49 07.54	97.04.17	Statoil	Oil producer	5040 m
	114	04 31 10.87	97.05.30	Mærsk Giant	Suspended at TD	
9/02-A-06	1286	57 49 07.47	97.03.11	Statoil	Oil producer	5191 m
	114	04 31 10.95	97.03.29	Mærsk Giant	Suspended at TD	
15/09-B-04	1379	58 25 04.78	97.07.01	Statoil	Gas producer	6476 m
	046	01 43 04.38	97.11.28	West Epsilon	Suspended at TD	
15/09-B-17	1283	58 25 04.42	97.04.21	Statoil	Gas producer	5911 m
	046	01 43 04.17	97.07.04	West Epsilon	Suspended at TD	

Well		Reg. no Lic. no.	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
15/09-B-22		1393	58 25 04.31	97.11.29	Statoil	Gas producer	m
		046	01 43 04.48	00.00.00	West Epsilon		
25/11-A-05 B	H	1364	59 11 30.22	97.08.23	Esso	Oil producer	2988 m
		001	02 21 34.19	97.09.10	West Alpha	Suspended at TD	
25/11-B-07 A	H	1253	59 10 40.45	97.01.14	Esso	Oil producer	2891 m
		001	02 22 46.46	97.03.08	West Alpha	Suspended at TD	
25/11-C-03 A	H	1401	59 11 00.62	97.12.13	Esso	Observation	2273 m
		001	02 24 32.52	97.12.20	West Alpha	Suspended at TD	
25/11-C-03 B	H	1402	59 11 00.62	97.12.21	Esso	Oil producer	m
		001	02 24 32.52	00.00.00	West Alpha		
25/11-C-13	H	1310	59 10 59.87	97.05.07	Esso	Oil producer	2725 m
		001	02 24 34.62	97.07.05	West Alpha	Suspended at TD	
31/02-D-05	H	1350	60 51 25.74	97.07.26	Hydro	Observation	1944 m
		054	03 26 34.49	97.08.09	Polar Pioneer	Plugged	
31/02-D-05 A	H	1351	60 51 25.74	97.08.09	Hydro	Oil producer	3800 m
		054	03 26 34.49	97.10.08	Polar Pioneer	Suspended at TD	
31/02-D-10	H	1369	60 51 11.06	97.10.09	Hydro	Oil producer	1723 m
		054	03 29 15.68	97.10.29	Polar Pioneer	Suspended at TD	
31/02-E-06 B	H	1260	60 47 51.30	97.01.12	Hydro	Oil producer	3355 m
		054	03 26 43.10	97.02.01	Polar Pioneer	Oil	
31/02-F-04	H	1264	60 46 31.51	97.02.13	Hydro	Observation	1690 m
		054	03 26 04.76	97.02.25	Polar Pioneer	Plugged	
31/02-F-04 A	H	1274	60 46 31.51	97.02.26	Hydro	Oil producer	3320 m
		054	03 26 04.76	97.03.17	Polar Pioneer	Oil	
31/02-M-41		1297	60 55 55.99	97.03.19	Hydro	Observation	1730 m
		054	03 36 25.11	97.04.05	Polar Pioneer	Plugged	
31/02-P-41		1370	60 53 11.46	97.10.30	Hydro	Observation	1725 m
		089	03 31 21.54	97.11.21	Polar Pioneer	Suspended at TD	
31/05-H-03	H	1302	60 42 51.32	97.04.07	Hydro	Observation	2377 m
		085	03 30 49.38	97.04.22	Polar Pioneer	Plugged	
31/05-H-03 A	H	1303	60 42 51.32	97.04.23	Hydro	Oil producer	4630 m
		085	03 30 49.38	97.05.26	Polar Pioneer	Suspended at TD	
31/05-H-03 B	H	1304	60 42 51.32	97.05.27	Hydro	Oil producer	1409 m
		085	03 30 49.38	97.07.10	Polar Pioneer	Suspended at TD	
31/05-I-21	H	1385	60 43 42.50	97.11.24	Hydro	Observation	1947 m
		085	03 34 39.81	97.12.11	Polar Pioneer	Plugged	
31/05-I-22	H	1395	60 43 42.75	97.12.11	Hydro	Observation	2002 m
		085	03 34 39.35	97.12.19	Polar Pioneer	Plugged	
31/05-I-22 A	H	1396	60 43 42.75	97.12.19	Hydro	Oil producer	m
		085	03 34 39.35	00.00.00	Polar Pioneer		
31/05-J-41		1333	60 43 27.22	97.07.11	Hydro	Observation	1760 m
		085	03 39 28.93	97.07.26	Polar Pioneer	Suspended at TD	
33/09-F-03	H	1232	61 26 40.82	97.03.14	Statoil	Oil producer	3450 m
		037	01 57 23.99	97.05.09	Treasure Prospect	Suspended at TD	
34/07-B-01	H	1265	61 23 49.46	97.02.21	Saga	Observation	4220 m
		089	02 07 03.95	97.04.08	Scarabeo 5	Plugged	
34/07-B-01 A	H	1313	61 23 49.46	97.05.18	Saga	Oil producer	3650 m
		089	02 07 03.95	97.06.17	Scarabeo 5	Suspended at TD	
34/07-B-02	H	1301	61 23 49.33	97.04.09	Saga	Oil producer	3113 m
		089	02 07 03.76	97.10.14	Scarabeo 5	Suspended at TD	
34/07-J-07	H	1305	61 17 29.81	97.07.02	Saga	Observation	2585 m
		089	02 09 48.39	97.07.19	Scarabeo 5	Plugged	
34/07-J-07 A	H	1347	61 17 29.81	97.07.19	Saga	Observation	2800 m
		089	02 09 48.39	97.08.10	Scarabeo 5	Plugged	
34/08-A-01	H	1322	61 22 12.57	97.07.04	Hydro	Observation	1110 m
		120	02 27 35.13	97.07.14	West Delta	Plugged	
34/08-A-01 A	H	1323	61 22 12.57	97.07.14	Hydro	Observation	4582 m
		120	02 27 35.13	97.09.13	West Delta	Suspended at TD	
34/08-A-02	H	1381	61 22 12.80	97.11.16	Hydro	Gass injector	m
		120	02 27 35.09	00.00.00	West Delta		
34/08-A-07	H	1360	61 22 13.26	97.10.06	Hydro	Oil producer	3642 m
		120	02 27 32.83	97.11.15	West Delta	Suspended at TD	
34/10-F-04	H	1336	61 05 51.88	97.08.09	Statoil	Observation	4320 m
		050	02 16 35.62	97.10.07	Transocean Wildcat	Plugged	
34/10-F-04 A	H	1337	61 05 51.81	97.10.07	Statoil	Oil producer	m
		050	02 16 35.81	00.00.00	Transocean Wildcat		
34/10-G-02	H	1272	61 05 50.23	97.04.09	Statoil	Oil producer	3559 m
		050	02 16 36.25	97.05.22	Transocean Wildcat	Suspended at TD	
34/10-J-01	H	1285	61 03 50.67	97.06.08	Statoil	Gass injector	4459 m
		050	02 00 10.58	97.07.27	Transocean Wildcat	Suspended at TD	
6407/07-A-10	H	1261	64 16 15.78	97.02.11	Hydro	Observation	3764 m

Well		Reg. no Lic. no.	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
		107	07 12 09.44	97.04.04	West Vanguard	Plugged	
6506/11-G-03	H	1298	65 05 17.79	97.04.23	Statoil	Gas injector	5352 m
		134	06 39 43.22	97.07.10	Transocean Arctic	Suspended at TD	
6506/11-G-04	H	1335	65 05 17.80	97.07.10	Statoil	Gas injector	3111 m
		134	06 39 43.59	97.08.02	Transocean Arctic	Suspended at TD	
6506/12-K-02	H	1339	65 08 01.90	97.08.21	Statoil	Gas injector	6003 m
		094	06 42 24.87	97.10.27	Transocean Winner	Suspended at TD	
6506/12-K-03	H	1358	65 08 01.97	97.06.24	Statoil	Gas injector	4664 m
		094	06 42 25.10	97.08.20	Transocean Winner	Suspended at TD	
6506/12-L-01	H	1299	65 08 17.89	97.04.12	Statoil	Oil producer	6719 m
		094	06 46 57.32	97.06.26	Transocean Searcher	Suspended at TD	
6506/12-L-02	H	1329	65 08 17.72	97.06.28	Statoil	Oil producer	m
		094	06 46 57.36	00.00.00	Transocean Searcher		
6506/12-P-03	H	1326	65 01 22.92	97.08.07	Statoil	Oil producer	6365 m
		094	06 52 45.65	97.11.09	Transocean Arctic	Plugged	
6506/12-P-03 A	H	1327	65 01 22.92	97.11.09	Statoil	Oil producer	6540 m
		094	06 52 45.65	97.12.20	Transocean Arctic	Suspended at TD	
6506/12-R-01	H	1259	65 01 59.96	97.02.01	Statoil	Gas injector	5300 m
		094	06 54 07.17	97.04.03	Transocean Searcher	Suspended at TD	
6506/12-R-04	H	1387	65 02 00.27	97.12.25	Statoil	Gas injector	m
		094	06 54 07.05	00.00.00	Transocean Arctic		
6506/12-S-01	H	1355	65 00 57.87	97.10.30	Statoil	Observation	m
		094	06 56 45.38	00.00.00	Transocean Winner		
6608/10-D-02	H	1249	66 00 49.15	97.01.09	Statoil	Oil producer	4174 m
		128	08 03 28.53	00.00.00	Transocean Wildcat		

7.5 RESOURCES IN DISCOVERIES AND FIELDS ON THE NORWEGIAN CONTINENTAL SHELF

Table 7.5.a
Discoveries that in 1997 are reported jointly as part of another field/discovery

Discovery	Reported as
2/7-8	Eldfisk
2/11-10 S	Hod
9/2-3	Yme
15/9-20 S	Sleipner Øst
15/12-10 S	Varg
24/9-6	24/9-5
30/3-6 S	Veslefrikk
30/6-18 Kappa	Oseberg Vest
30/6-19 Beta Sadel	Oseberg Øst
30/7-2	30/7-6 R Hild
34/7-13 Snorre Vest	Vigdis

Discovery	Reported as
34/8-4 S	Visund
34/10-21	Gullfaks Sør
35/11-7	35/11-4 R Fram
35/11-8 S	35/11-4 R Fram
36/7-1	35/9-1 Gjøa
6407/1-3 Tyrihans Nord	Tyrihans Sør
6608/10-4	Norne
7120/7-1 Askeladd Vest	Snøhvit, Albatross, Askeladd
7120/7-2 Askeladd Sentral	Snøhvit, Albatross, Askeladd
7121/7-2 Albatross Sør	Snøhvit, Albatross, Askeladd

Table 7.5.b
Reserves and resources in fields

	Oil	Gas	NGL	o.e.	Year of discovery[3)]
	10^6 Sm^3	10^9 Sm^3	10^6 tonnes	10^6 Sm^3	
Reserves where production is ceased (class 0) [1)]					
Mime	0.4	0.1		0.5	1982
Nordøst Frigg		11.6	0.0	11.7	1974
Odin		27.3	0.1	27.4	1974
Total	**0.4**	**39.0**	**0.1**	**39.5**	

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	o.e. 10^6 Sm^3	Year of discovery[3]
Reserves in production or with an approved development plan (class 1 and 2)					
Albuskjell	7.4	16.1	1.0	24.8	1972
Balder[2)]	27.2	0.8		28.0	1967
Brage	52.8	2.9	0.8	56.7	1980
Cod	2.9	7.4	0.5	11.0	1968
Edda	4.8	2.1	0.2	7.2	1972
Ekofisk	404.0	153.2	15.5	577.4	1969
Eldfisk	112.4	56.1	4.9	174.9	1970
Embla	8.8	6.3	0.7	16.0	1988
Frigg		119.2	0.4	119.7	1971
Frøy	6.7	1.6	0.1	8.4	1987
Gullfaks	313.6	23.8	2.3	340.4	1978
Gullfaks Sør[2)]	21.5	1.7		23.2	1978
Gullfaks Vest	3.1	0.3		3.4	1991
Gullveig[2)]	2.7	1.2		3.9	1995
Gungne		4.5	1.7	6.7	1982
Gyda	29.0	3.9	1.6	35.0	1980
Gyda Sør	3.1	1.5	0.3	5.0	1991
Heimdal	6.7	40.3		47.0	1972
Hod	8.4	1.8	0.3	10.6	1974
Jotun[2)]	30.7	0.7		31.4	1994
Lille-Frigg	1.3	2.4		3.7	1975
Loke		3.5	1.5	5.5	1983
Murchison	13.3	0.4	0.4	14.2	1975
Oseberg	326.0	16.4	6.0	350.2	1979
Oseberg Sør[2)]	53.5	11.4		64.9	1984
Oseberg Vest	1.6	6.0		7.6	1984
Oseberg Øst[2)]	23.5	0.8		24.3	1981
Rimfaks[2]	19.9	-1.7		18.2	1983
Sleipner Vest		128.1	29.6	166.6	1974
Sleipner Øst		38.4	25.0	70.9	1981
Snorre	167.7	5.7	3.6	178.1	1979
Statfjord	555.7	54.9	15.6	630.9	1974
Statfjord Nord	41.1	3.1	0.6	45.0	1977
Statfjord Øst	32.0	4.5	0.7	37.4	1976
Tommeliten Gamma	3.9	9.2	0.6	13.9	1978
Tor	26.7	11.6	1.3	40.0	1970
Tordis	29.1	2.1	0.7	32.1	1987
Tordis Øst[2)]	5.5	0.5	0.2	6.3	1993
Troll I	15.5	582.2		597.7	1983
Troll II	193.0	65.0		258.0	1979
Ula	69.3	3.5	2.6	76.2	1976
Valhall	116.8	27.8	4.0	149.8	1975
Varg[2)]	5.5	0.2	0.0	5.7	1984
Veslefrikk	54.5	5.2	1.8	62.0	1981
Vest Ekofisk	12.1	26.9	1.4	40.8	1970
Vigdis	28.8	2.0		30.8	1986
Visund[2)]	48.5			48.5	1986
Yme	9.6			9.6	1987

	Oil 10⁶ Sm³	Gas 10⁹ Sm³	NGL 10⁶ tonnes	o.e. 10⁶ Sm³	Year of discovery[3]
Øst Frigg		9.3		9.3	1973
Sum North Sea	*2 900.2*	*1 464.8*	*125.9*	*4 528.6*	
Draugen	111.3			111.3	1984
Heidrun	155.0	12.8		167.8	1985
Njord	31.6			31.6	1986
Norne	72.4			72.4	1992
Åsgard[2)]	132.3	191.0	24.0	354.5	1981
Sum Norwegian Sea	*502.6*	*203.8*	*24.0*	*737.6*	
Total reserves in fields	**3 402.8**	**1 668.6**	**149.9**	**5 266.2**	
Resources in fields					
Resources in late planning phase (class 3)	202.6	531.1	12.0	749.3	
Resources in early planning phase (class 4)	138.8	418.0	6.1	564.7	
Resources which may be developed in the long term (class 5)	10.2	65.0	1.0	76.5	
Resources where development is not very likely (class 6)	4.2	1.1		5.3	
Total resources in fields	**355.8**	**1 015.2**	**19.1**	**1 395.9**	
Total reserves and resources in fields	**3 759.0**	**2 722.8**	**169.2**	**6 701.7**	

1) Originally recoverable reserves in fields where production is ceased equals the volume delivered. Any remaining recoverable resources are included in appropriate resource classes. No remaining recoverable resources are accounted for in the three fields where production is ceased.
2) Fields with an approved development plan where production has not started as of 31.12.1997
3) Year of discovery is defined by the oldest discovery well, included in the field.

Table 7.5.c
Resources in discoveries[1)]

	Oil 10⁶ Sm³	Gas 10⁹ Sm³	NGL 10⁶ tonnes	o.e. 10⁶ Sm³	Year of discovery[e)]
Resources in a late planning phase (class 3)					
34/7-21 [2)]	9.4	1.1		10.5	1992
2/12-1 Mjølner	2.3	0.4	0.1	2.8	1987
3/7-4 Trym		2.9	0.7	3.8	1990
16/7-4	1.8	5.0	1.0	8.1	1982
25/4-6 S Vale	5.9	3.9		9.8	1991
25/5-3 Skirne		5.1	0.7	6.0	1990
25/11-15 Grane	95.8			95.8	1991
30/2-1 Huldra	7.2	18.9	0.3	26.5	1982
30/6-18 Kappa	3.5	5.4		8.9	1985
33/9-19 S	11.0	0.7		11.7	1996
34/7-23 S	2.0	0.3		2.3	1994
34/7-25 S	2.3	0.2		2.5	1996
34/11-1 Kvitebjørn	18.0	44.9	0.4	63.4	1994
35/11-4 R Fram	31.3	11.2		42.5	1992
Sum North Sea	*190.5*	*100.0*	*3.2*	*294.7*	
6406/2-3 Kristin		58.6	37.4	107.2	1997
6507/8-4 Heidrun Nord	4.9	0.4		5.3	1990
Sum Norwegian Sea	*4.9*	*59.0*	*37.4*	*112.5*	
Total	**195.4**	**159.0**	**40.6**	**407.2**	

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	o.e. 10^6 Sm^3	Year of discovery[e)]
Resources in an early planning phase (class 4)					
1/3-3	4.3			4.3	1983
1/9-1 Tommeliten Alpha	3.2	3.5	0.3	7.1	1977
2/4-17 Tjalve	1.2	2.2	0.1	3.5	1992
15/5-5	8.7	0.5		9.2	1995
15/9-19 S R Volve	12.5	2.0		14.5	1993
25/5-5	4.3			4.3	1995
25/8-4	1.0			1.0	1992
25/11-16	3.6			3.6	1992
30/6-17 R	0.5	1.4		1.9	1986
35/9-1 R Gjøa	11.4	33.3	2.5	48.0	1989
Sum North Sea	*50.7*	*42.9*	*2.9*	*97.4*	
6406/2-1 Lavrans		72.6	23.1	102.6	1995
6406/3-2 Trestakk	6.2			6.2	1986
6407/1-2 Tyrihans Sør	17.9	31.7	6.2	57.7	1983
Sum Norwegian Sea	*24.1*	*104.3*	*29.3*	*166.5*	
7121/4-1 Snøhvit	10.2	60.9	4.2	76.6	1984
Total	**85.0**	**208.1**	**36.4**	**340.4**	
Resources which may be developed in the long term (class 5)					
1/2-1	0.1			0.1	1989
1/3-6	1.5	0.9	0.1	2.5	1991
1/5-2 Flyndre	5.1	1.6		6.7	1974
2/2-1	0.4			0.4	1982
2/2-5	2.4			2.4	1992
2/5-3 Sørøst Tor	0.9	0.3		1.2	1972
2/6-5	0.9			0.9	1997
2/7-22		0.6		0.6	1990
2/7-29	3.0			3.0	1994
7/7-2	2.4	0.1		2.5	1992
7/8-3	1.5			1.5	1983
15/3-1 S	4.0	14.6	1.8	20.9	1975
15/3-4	2.2	1.1		3.3	1982
15/5-1 Dagny		5.9	1.3	7.6	1978
15/8-1 Alpha		4.1	1.3	5.8	1982
16/7-2	0.5	1.8	0.3	2.7	1982
18/10-1	1.2			1.2	1980
24/6-1 Peik	3.0	9.1		12.1	1985
24/9-3	2.0	0.1		2.1	1981
24/9-5	5.0			5.0	1994
24/12-3 S	3.5	0.2		3.7	1996
25/5-4 Byggve		3.1	0.5	3.8	1991
25/6-1	1.2			1.2	1986
25/8-9	0.9			0.9	1997
25/8-10 S	9.1	0.3		9.4	1997
30/7-6 R Hild	13.1	33.4		46.5	1978
30/8-1 S		28.6	7.2	38.0	1995
30/10-6		5.7		5.7	1992
34/4-5	2.2	0.3		2.5	1984

	Oil 10⁶ Sm³	Gas 10⁹ Sm³	NGL 10⁶ tonnes	o.e. 10⁶ Sm³	Year of discovery[e)]
34/7-18	1.7			1.7	1991
34/10-23 Gamma	6.0	69.0		75.0	1985
35/3-2 Agat		43.0		43.0	1980
35/8-1	1.9	13.5		15.4	1981
35/8-2	2.6	7.0		9.6	1982
35/10-2		2.6		2.6	1996
35/11-2	1.5	4.9	2.6	9.8	1987
36/7-2	2.0			2.0	1997
Sum North Sea	*81.8*	*251.8*	*15.1*	*353.2*	
6407/6-3 Mikkel	4.0	17.0		21.0	1987
6407/8-2	0.4	1.4		1.8	1994
6506/11-2 Lange	3.5	1.8		5.3	1991
6507/2-2		7.7		7.7	1992
6507/3-1 Alve	1.6	8.5		10.1	1990
Sum Norwegian Sea	*9.5*	*36.4*		*45.9*	
7120/8-1 Askeladd		41.0	1.3	42.7	1981
7120/9-1 Albatross		10.6	0.5	11.3	1982
7120/12-2		10.7		10.7	1981
7120/12-3		4.1		4.1	1983
7121/4-2 Snøhvit Nord		3.0	0.1	3.1	1985
7121/5-2 Beta	3.2	0.5		3.7	1986
7122/6-1	3.2	5.7		8.9	1987
7124/3-1		2.1		2.1	1987
Sum Barents Sea	*6.4*	*77.7*	*1.9*	*86.6*	
Total	**97.7**	**365.9**	**17.0**	**485.6**	
Resources where development is not very likely (class 6)					
1/3-1					1968
2/2-2		0.9		0.9	1982
2/3-1					1969
2/4-10	2.4			2.4	1973
2/4-11					1974
2/4-14					1989
2/5-4					1972
2/5-7	2.9			2.9	1984
2/7-2					1971
2/7-19 R	2.0			2.0	1990
6/3-1 Pi	0.3			0.3	1985
7/12-5	1.1			1.1	1981
15/5-2		2.4	0.5	3.1	1978
15/12-8	0.5	1.0		1.5	1991
17/3-1					1995
17/12-1 Bream	1.0			1.0	1971
17/12-2 Brisling	0.2			0.2	1973
25/2-5 Lille Frøy	1.5	1.6	0.2	3.4	1976
25/7-2	1.0	1.0		2.0	1990
25/8-1					1970
25/10-8	2.7	0.3		3.0	1997
29/3-1	0.6	1.0		1.6	1986
30/6-14					1984

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	o.e. 10^6 Sm^3	Year of discovery[e)]
30/6-16					1985
33/9-6					1976
34/8-7 R					1993
34/10-40 S		0.6		0.6	1995
34/11-2 S	1.7	2.7		4.4	1996
Sum North Sea	*17.9*	*11.5*	*0.7*	*30.3*	
6201/11-1	1.0	0.3		1.3	1987
6204/11-1		10.3	0.4	10.8	1994
6407/4-1					1985
Sum Norwegian Sea	*1.0*	*10.6*	*0.4*	*12.1*	
7119/12-3		4.1		4.1	1983
7128/4-1	0.9	0.1		1.0	1994
7226/11-1	0.6	24.0		24.6	1988
7316/5-1		1.2		1.2	1992
Sum Barents Sea	*1.5*	*29.4*		*30.9*	
Total	**20.4**	**51.5**	**1.1**	**73.3**	
Resources in new discoveries for which the evaluation is not complete (class 7)					
2/1-11	0.3			0.3	1997
2/5-11	≤1			≤1	1997
9/2-6 S	0.2			0.2	1996
9/2-7 S	2.5			2.5	1997
16/7-7 S		5.0	10.0	18.0	1997
25/7-5	22.0			22.0	1997
25/8-11	8.0			8.0	1997
30/3-7 S	3.0			3.0	1995
35/9-3		≤1		≤1	1997
6204/10-2		≤1		≤1	1997
6305/5-1		100.0		100.0	1997
6306/5-1		1.0		1.0	1997
6507/7-11 S		≤1		≤1	1997
6707/10-1		38.0		38.0	1997
Total	**37.0**	**147.0**	**10.0**	**197.0**	
Total resources in discoveries	**435.4**	**931.5**	**105.1**	**1 503.6**	

1) Some discoveries have resources in several resource classes. These resources are jointly accounted for in the lowest resource class.
2) A small part of the resouces in 34/7-21 will be produced in a long-term test. These reserves are accounted for in resource class 2, but are here reported in resource class 3.
3) Year of discovery is defined by the oldest discovery well if several discoveries are jointly accounted for.

Table 7.5.d
Original and remaining reserves in fields

	Original recoverable				Remaining			
	Oil	Gas	NGL	o.e.	Oil	Gas	NGL	o.e.
	10^6 Sm^3	10^9 Sm^3	10^6 tonnes	10^6 Sm^3	10^6 Sm^3	10^9 Sm^3	10^6 tonnes	10^6 Sm^3
Reserves where production is ceased (class 0)								
Mime	0.4	0.1	0.0	0.5		0.0[1]		
Nordøst Frigg		11.6	0.0	11.7		0.0[1]		
Odin		27.3	0.1	27.4		0.0[1]		
Reserves in production (class 1)								
North Sea								
Albuskjell	7.4	16.1	1.0	24.8	0.1	0.7	0.0	0.8
Brage	52.8	2.9	0.8	56.7	27.9	1.8	0.4	30.2
Cod	2.9	7.4	0.5	11.0	0.0	0.2	0.0	0.2
Edda	4.8	2.1	0.2	7.2	0.0	0.1	0.0	0.2
Ekofisk	404.0	153.2	15.5	577.4	171.1	47.3	6.3	226.6
Eldfisk	112.4	56.1	4.9	174.9	49.3	26.7	2.0	78.5
Embla	8.8	6.3	0.7	16.0	3.7	4.6	0.5	9.0
Frigg		119.2	0.4	119.7		7.6	0.4	8.1
Frøy	6.7	1.6	0.1	8.4	2.7	0.8	0.1	3.6
Gullfaks	313.6	23.8	2.3	340.4	90.4	8.5	0.8	99.9
Gullfaks Vest	3.1	0.3		3.4	1.3	0.3		1.6
Gungne[2)]		4.5	1.7	6.7		Included in Sleipner[2)]		
Gyda	29.0	3.9	1.6	35.0	4.2	0.2	0.2	4.7
Gyda Sør[3)]	3.1	1.5	0.3	5.0		Included in Gyda[3)]		
Heimdal	6.7	40.3		47.0	0.9	0.1		1.0
Hod	8.4	1.8	0.3	10.6	2.4	0.7	0.1	3.2
Lille-Frigg	1.3	2.4		3.7	0.1	0.4	0.0	0.4
Loke[2]		3.5	1.5	5.5		Included in Sleipner[2)]		
Murchison[4)]	13.3	0.4	0.4	14.2	1.1	0.1	0.1	1.2
Oseberg	326.0	16.4	6.0	350.2	102.9	16.4	6.0	127.1
Oseberg Vest	1.6	6.0		7.6	1.6	6.0		7.6
Sleipner Vest[2)]		128.1	29.6	166.6		127.7	27.0	162.8
Sleipner Øst[2)]		38.4	25.0	70.9		13.3	11.3	27.9
Snorre	167.7	5.7	3.6	178.1	115.7	3.2	1.9	121.5
Statfjord[4)]	555.7	54.9	15.6	630.9	87.8	17.8	5.3	112.4
Statfjord Nord	41.1	3.1	0.6	45.0	31.3	2.5	0.4	34.3
Statfjord Øst	32.0	4.5	0.7	37.4	20.7	3.9	0.5	25.2
Tommeliten Gamma[5)]	3.9	9.2	0.6	13.9	0.1	-0.2	0.1	-0.0
Tor	26.7	11.6	1.3	40.0	6.3	1.2	0.2	7.7
Tordis	29.1	2.1	0.7	32.1	14.8	1.0	0.4	16.2
Troll I (Troll Øst)	15.5	582.2		597.7	14.6	562.9		577.5
Troll II (Troll Oil)	193.0	65.0		258.0	161.5	64.5		226.0
Ula[5)]	69.3	3.5	2.6	76.2	12.6	-0.2	0.4	12.9
Valhall	116.8	27.8	4.0	149.8	65.5	17.4	2.1	85.5
Veslefrikk	54.5	5.2	1.8	62.0	23.8	3.9	0.9	28.8
Vest Ekofisk	12.1	26.9	1.4	40.8	0.0	1.0	0.0	1.0
Vigdis	28.8	2.0		30.8	27.2	2.0		29.2
Yme	9.6			9.6	6.4			6.4
Øst Frigg		9.3		9.3		0.1		0.1
Norwegian Sea								
Draugen	111.3			111.3	81.4			81.4
Heidrun	155.0	12.8		167.8	128.4	12.8		141.2
Njord	31.6			31.6	31.2			31.2
Norne	72.4			72.4	72.0			72.0

1) Original recoverable reserves in fields where production is ceased, equals the delivered volume. Remaining resources are accordingly equal to zero.

2) The combined gas production from the Sleipner area is measured as one. The production in this area is subtracted from the reserves in Sleipner Øst.
3) The combined production from Gyda and Gyda Sør are measured as one. The production is subtracted from the reserves in Gyda.
4) Norwegian share only.
5) Minor negative figures for remaining resources are due to mismatch between the approximate original recoverable resources and the exact production figures. The figures are included for accounting reasons.

Table 7.5.e

Changes in petroleum reserve / resource estimates, annual reports 1996-1997. Major deviations are discussed in chapter 1.1 and 1.4 to 1.6.

	Resources 1997			Resources 1996			Difference 97-96		
	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tonnes
Reserves where production is ceased									
Mime	0.4	0.1		0.4	0.1				
Nordøst Frigg		11.6	0.0		11.8	0.1		-0.2	-0.1
Odin		27.3	0.1		26.6			0.7	0.1
Reserves in production or with an approved development plan									
North Sea									
Albuskjell	7.4	16.1	1.0	7.4	16.1	1.0			
Balder	27.2	0.8		27.2	0.8				
Brage	52.8	2.9	0.8	46.6	1.4	0.5	6.2	1.5	0.3
Cod	2.9	7.4	0.5	2.9	7.4	0.5			
Edda	4.8	2.1	0.2	4.9	2.1	0.2	-0.1		
Ekofisk	404.0	153.2	15.5	404.0	150.4	15.2		2.8	0.3
Eldfisk	112.4	56.1	4.9	81.3	58.7	4.6	31.1	-2.6	0.3
Embla	8.8	6.3	0.7	8.3	6.0	0.6	0.5	0.3	0.1
Frigg		119.2	0.4		111.9	0.4		7.3	
Frøy	6.7	1.6	0.1	11.0	2.3	0.2	-4.3	-0.7	-0.1
Gullfaks	313.6	23.8	2.3	307.7	23.0	2.4	5.9	0.8	-0.1
Gullfaks Sør	21.5	1.7		20.7	2.1		0.8	-0.4	
Gullfaks Vest	3.1	0.3		3.1				0.3	
Gullveig	2.7	1.2		2.1			0.6	1.2	
Gungne		4.5	1.7		2.1	0.9		2.4	0.8
Gyda	29.0	3.9	1.6	30.0	3.7	1.6	-1.0	0.2	
Gyda Sør	3.1	1.5	0.3	2.1	1.1	0.3	1.0	0.4	
Heimdal	6.7	40.3		6.6	40.5		0.1	-0.2	
Hod	8.4	1.8	0.3	8.7	2.2	0.3	-0.3	-0.4	-0.0
Jotun	30.7	0.7		30.7				0.7	
Lille-Frigg	1.3	2.4		1.6	3.5		-0.3	-1.1	
Loke		3.5	1.5		3.5	1.5			
Murchison	13.3	0.4	0.4	12.8	0.4	0.4	0.5		
Oseberg	326.0	16.4	6.0	319.3	88.9	6.0	6.7	-72.5	
Oseberg Sør	53.5	11.4		54.4	25.1		-0.9	-13.7	
Oseberg Vest	1.6	6.0		1.8	7.5	0.2	-0.2	-1.5	-0.2
Oseberg Øst	23.5	0.8		23.5	1.4		-0.1	-0.6	
Rimfaks	19.9	-1.7		18.9			1.0	-1.7	
Sleipner Vest		128.1	29.6		129.4	33.7		-1.3	-4.1
Sleipner Øst		38.4	25.0		41.5	27.3		-3.1	-2.3
Snorre	167.7	5.7	3.6	169.1	5.0	2.3	-1.4	0.7	1.3
Statfjord	555.7	54.9	15.6	535.0	53.9	15.1	20.7	1.0	0.5
Statfjord Nord	41.1	3.1	0.6	40.9	2.5	0.5	0.2	0.6	0.1
Statfjord Øst	32.0	4.5	0.7	29.8	3.6	0.7	2.2	0.9	
Tommeliten Gamma	3.9	9.2	0.6	3.8	9.2	0.5	0.1		0.1
Tor	26.7	11.6	1.3	25.5	11.4	1.2	1.2	0.2	0.1
Tordis	29.1	2.1	0.7	28.9	2.3	0.7	0.2	-0.2	
Tordis Øst	5.5	0.5	0.2	5.6	0.4	0.1	-0.1	0.1	0.1
Troll I	15.5	582.2		19.9	834.9		-4.4	-252.7	
Troll II	193.0	65.0		94.0	19.9	0.4	99.0	45.1	-0.4
Ula	69.3	3.5	2.6	69.2	3.6	2.6	0.1	-0.1	
Valhall	116.8	27.8	4.0	115.4	32.1	4.8	1.4	-4.3	-0.8

	Resources 1997			Resources 1996			Difference 97-96		
	Oil	Gas	NGL	Oil	Gas	NGL	Oil	Gas	NGL
	10^6 Sm^3	10^9 Sm^3	10^6 tonnes	10^6 Sm^3	10^9 Sm^3	10^6 tonnes	10^6 Sm^3	10^9 Sm^3	10^6 tonnes
Varg	5.5	0.2	0.0	10.7			-5.2	0.2	0.0
Veslefrikk	54.5	5.2	1.8	54.4	2.6	1.0	0.1	2.6	0.8
Vest Ekofisk	12.1	26.9	1.4	12.1	26.9	1.4			
Vigdis	28.8	2.0		33.9	2.4		-5.1	-0.4	
Visund	48.5			48.5					
Yme	9.6			8.7			0.9		
Øst Frigg		9.3			9.5			-0.2	
Norwegian Sea									
Draugen	111.3			94.5			16.8		
Heidrun	155.0	12.8		155.0	13.2			-0.4	
Njord	31.6			37.5			-5.9		
Norne	72.4			72.4					
Åsgard	132.3	191.0	24.0	132.3	191.0	24.0		0.0	
Resources in fields									
Resources in a late planning phase	202.6	531.1	12.0	248.4	136.6	5.6	-45.8	394.5	6.4
Resources in an early planning phase	138.8	418.0	6.1	68.3	148.8	19.3	70.5	269.2	-13.2
Resources which may be developed in the long term	10.2	65.0	1.0	25.0	23.2	0.8	-14.8	41.8	0.2
Resources where development is not very likely	4.2	1.1		4.2	0.9			0.2	
Resources in a late planning phase, discoveries									
34/7-21	9.4	1.1		10.2	1.3		-0.8	-0.2	
2/12-1 Mjølner	2.3	0.4	0.1	3.5	0.6		-1.2	-0.2	0.1
3/7-4 Trym		2.9	0.7		2.9	0.5			0.2
16/7-4	1.8	5.0	1.0	0.9	8.0	0.5	0.9	-3.0	0.5
25/4-6 S Vale	5.9	3.9		3.5	4.0		2.4	-0.1	
25/5-3 Skirne		5.1	0.7		5.1	0.4			0.3
25/11-15 Grane	95.8			84.5			11.3		
30/2-1 Huldra	7.2	18.9	0.3	7.9	22.3		-0.7	-3.4	0.3
30/6-18 Kappa	3.5	5.4			Not reported separately in 1996				
33/9-19 S	11.0	0.7		11.0	0.8			-0.1	
34/7-23 S	2.0	0.3		3.6	0.4		-1.6	-0.1	
34/7-25 S	2.3	0.2		7.1	0.7		-4.8	-0.5	
34/11-1 Kvitebjørn	18.0	44.9	0.4	20.0	50.0		-2.0	-5.1	0.4
35/11-4 R Fram	31.3	11.2		26.6	19.9		4.7	-8.7	
6406/2-3 Kristin		58.6	37.4		New discovery in 1997				
6507/8-4 Heidrun Nord	4.9	0.4		3.4	0.5		1.5	-0.1	
Resources in an early planning phase, discoveries									
1/3-3	4.3			4.3					
1/9-1 Tommeliten Alpha	3.2	3.5	0.3	3.2	3.5	0.3			
2/4-17 Tjalve	1.2	2.2	0.1	1.2	2.2	0.2			-0.1
15/5-5	8.7	0.5		11.4			-2.7	0.5	
15/9-19 SR Volve	12.5	2.0		6.1	1.0		6.4	1.0	
25/5-5	4.3			1.7			2.6		
25/8-4	1.0				Not reported separately in 1996				
25/11-16	3.6				Not reported separately in 1996				
30/6-17 R	0.5	1.4					0.5	1.4	
35/9-1 R Gjøa	11.4	33.3	2.5	13.6	26.4		-2.2	6.9	2.5
6406/2-1 Lavrans		72.6	23.1	26.0	84.0	11.0	-26.0	-11.4	12.1
6406/3-2 Trestakk	6.2			4.8			1.4		
6407/1-2 Tyrihans Sør	17.9	31.7	6.2	16.0	25.0	6.0	1.9	6.7	0.2
7121/4-1 Snøhvit	10.2	60.9	4.2	6.7	78.0	9.2	3.5	-17.1	-5.0
Resources which may be developed in the long term, discoveries									
1/2-1	0.1			0.1					
1/3-6	1.5	0.9	0.1	1.5	0.9	0.1			

	Resources 1997			Resources 1996			Difference 97-96		
	Oil	Gas	NGL	Oil	Gas	NGL	Oil	Gas	NGL
	10^6 Sm^3	10^9 Sm^3	10^6 tonnes	10^6 Sm^3	10^9 Sm^3	10^6 tonnes	10^6 Sm^3	10^9 Sm^3	10^6 tonnes
1/5-2 Flyndre	5.1	1.6		5.1	1.6				
2/2-1	0.4			0.4	1.1			-1.1	
2/2-5	2.4			0.9			1.5		
2/5-3 Sørøst Tor	0.9	0.3		0.9	0.3		-0.0	0.0	
2/6-5	0.9			2.0			-1.1		
2/7-22		0.6			0.6				
2/7-29	3.0			3.0					
7/7-2	2.4	0.1		2.4	0.1				
7/8-3	1.5			3.6	0.2		-2.1	-0.2	
15/3-1 S	4.0	14.6	1.8	4.0	14.6	1.8			-0.0
15/3-4	2.2	1.1		2.2	1.1				
15/5-1 Dagny		5.9	1.3		5.9	1.3			
15/8-1 Alpha		4.1	1.3		4.1	1.3			
16/7-2	0.5	1.8	0.3	0.5	1.8	0.3			
18/10-1	1.2			1.2			-0.1		
24/6-1 Peik	3.0	9.1		3.0	9.1				
24/9-3	2.0	0.1		3.0			-1.0	0.1	
24/9-5	5.0			0.7			4.3		
24/12-3 S	3.5	0.2		5.0			-1.5	0.2	
25/5-4 Byggve		3.1	0.5		3.9	0.5		-0.8	
25/6-1	1.2			1.2					
25/8-9	0.9					New discovery in 1997			
25/8-10 S	9.1	0.3				New discovery in 1997			
30/7-6 R Hild	13.1	33.4		13.1	33.4		0.0	0.0	
30/8-1 S		28.6	7.2		20.0			8.6	7.2
30/10-6		5.7			1.0			4.7	
34/4-5	2.2	0.3		2.0			0.2	0.3	
34/7-18	1.7			1.7					
34/10-23 Gamma	6.0	69.0		6.0	69.0				
35/3-2 Agat		43.0			43.0				
35/8-1	1.9	13.5		1.9	13.5				
35/8-2	2.6	7.0		2.6	7.0				
35/10-2		2.6			8.0			-5.4	
35/11-2	1.5	4.9	2.6	1.5	4.9	2.6			
36/7-2	2.0					New discovery in 1997			
6407/6-3 Mikkel	4.0	17.0			17.1	3.4	4.0	-0.1	-3.4
6407/8-2	0.4	1.4		0.4	1.4				
6506/11-2 Lange	3.5	1.8		7.9	4.6		-4.4	-2.8	
6507/2-2		7.7			7.7			-0.0	
6507/3-1 Alve	1.6	8.5			8.5		1.6		
7120/8-1 Askeladd		41.0	1.3		40.0			1.0	1.3
7120/9-1 Albatross		10.6	0.5		39.1	1.6		-28.5	-1.1
7120/12-2		10.7			10.7			-0.0	
7120/12-3		4.1			4.1			-0.0	
7121/4-2 Snøhvit Nord		3.0	0.1		3.5			-0.5	0.1
7121/5-2 Beta	3.2	0.5		3.0	0.5		0.2		
7122/6-1	3.2	5.7		3.2	5.7				
7124/3-1		2.1			2.1				
Resources where development is not likely, discoveries									
1/3-1									
2/2-2		0.9			0.9				
2/3-1									
2/4-10	2.4			2.4					
2/4-11									
2/4-14						Previously not reported			
2/5-4									
2/5-7	2.9			2.9					
2/7-2									
2/7-19 R	2.0			2.0					
6/3-1 Pi	0.3			0.8	0.4		-0.5	-0.4	

	Resources 1997			Resources 1996			Difference 97-96		
	Oil	Gas	NGL	Oil	Gas	NGL	Oil	Gas	NGL
	10^6 Sm^3	10^9 Sm^3	10^6 tons	10^6 Sm^3	10^9 Sm^3	10^6 tons	10^6 Sm^3	10^9 Sm^3	10^6 tons
7/12-5	1.1			1.1			-0.0		
15/5-2		2.4	0.5		2.9	0.1		-0.5	0.4
15/12-8	0.5	1.0				1.0	0.5	1.0	-1.0
17/3-1									
17/12-1 Bream	1.0			1.0					
17/12-2 Brisling	0.2			0.2					
25/2-5 Lille Frøy	1.5	1.6	0.2	1.5	1.6	0.2			
25/7-2	1.0	1.0		1.0	1.0				
25/8-1									
25/10-8	2.7	0.3				New discovery in 1997			
29/3-1	0.6	1.0		0.6	1.0		-0.0		
30/6-14									
30/6-16									
33/9-6									
34/8-7 R									
34/10-40 S		0.6			0.6				
34/11-2 S	1.7	2.7			9.0		1.7	-6.3	
6201/11-1	1.0	0.3		1.0	0.3			-0.0	
6204/11-1		10.3	0.4		10.3	0.4			
6407/4-1									
7119/12-3		4.1			4.1				
7128/4-1	0.9	0.1		0.9	0.1				
7226/11-1	0.6	24.0		0.6	24.0		-0.0		
7316/5-1		1.2			1.2			-0.0	
Resources in new discoveries for which the evaluation is not complete									
2/1-11	0.3					New discovery in 1997			
2/5-11	≤1								
9/2-6 S	0.2			2.0			-1.8		
9/2-7 S	2.5								
16/7-7 S		5.0	10.0			New discovery in 1997			
25/7-5	22.0								
25/8-11	8.0								
30/3-7 S	3.0			3.0					
35/9-3		≤1							
6204/10-2		≤1							
6305/5-1		100.0				New discovery in 1997			
6306/5-1		1.0							
6507/7-11 S		≤1							
6707/10-1		38.0							

UNITS OF MEASUREMENT FOR OIL AND GAS

Oil and gas are often measured in volumetric units under certain defined ISO standard conditions (temperature = 15°C and pressure = 1,01325 bar). Oil volumes are stated in million standard cubic meters (106 Sm^3) and gas volumes in billion standard cubic meters (109 Sm^3).

Conversion from volume units to oil equivalents for oil and gas volumes is used for the purpose of totalling or comparing oil and gas resources, and when exact quantities are not required.

Conversion to oil equivalents is based on the amount of energy released during combustion of oil and gas.

As from 1 January 1996, the Norwegian Petroleum Directorate states the total petroleum resources in Sm^3 oil equivalents (Sm^3 o.e.). Consequently, when adding up or comparing oil and gas volumes we will use the conversion formula above:

1 000	Sm^3 gas equals:	1 Sm^3 o.e.
1	Sm^3 oil equals:	1 Sm^3 o.e.
1	tonnes NGL equals:	1,3 Sm^3 o.e.

Conversion from the NGL unit of weight to Sm^3 oil equivalents is somewhat more uncertain, since the composition of the light hydrocarbon components can vary considerably from one field to another. The Norwegian Petroleum Directorate has chosen to use a constant conversion factor of 1.3 tonnes NGL/condensate to Sm^3 o.e.

7.6 PRODUCTION OF OIL AND GAS

Production of oil and gas on the Norwegian continental shelf amounted to 229.2 x 10^6 Sm^3 o.e. in 1997. Production in 1996 was 222.1 x 10^6 Sm^3 o.e. Table 7.6.a and Figures 7.6.a and 7.6.b describe the production in greater detail.

For the Statfjord, Frigg and Murchison fields, Table 7.6 shows the Norwegian share of the production.

Table 7.6
Production in million Sm^3 oil equivalents

	PRODUCTION ------------>			CONSUMPTION -------->		MARKETABLE PRODUCTS------>			
1997	**Oil**	**Gas**	**Cond.**	**Gas Flared**	**Gas Fuel**	**Oil**	**Gas**	**NGL/ Cond.**	**Total**
Brage	5,914	0,616		0,010	0,062	5,869	0,230	0,103	6,203
Draugen	10,452	0,547		0,008	0,055	10,452			10,452
Ekofisk area	18,617	7,968		0,007	0,967	17,195	7,248	0,736	25,179
Embla	0,802	0,329				0,739	0,299	0,039	1,077
Frigg area	1,453	1,141	0,277	0,004	0,037	1,528	1,136	0,016	2,680
Gullfaks	23,835	3,044		0,041	0,282	23,835	1,684	0,137	25,656
Gullfaks Vest	0,287	0,037				0,287			0,287
Gyda (incl. Gyda Sør)	3,281	0,952		0,002	0,039	2,505	0,581	0,196	3,282
Heidrun	13,190	1,934		0,027	0,127	13,411			13,411
Heimdal		2,841	0,414	0,001	0,042	0,405	2,712		3,119
Hod	0,490	0,103		0,001	0,007	0,465	0,095	0,017	0,578
Murchison	0,312	0,079		0,013	0,016	0,280	0,011	0,007	0,298
Njord	0,368	0,084		0,017	0,005	0,367			0,367
Norne	0,415	0,046		0,011	0,005	0,415			0,415
Oseberg	27,323	6,809		0,021	0,279	27,199			27,199
Oseberg Vest	0,112	0,394		0,001	0,003	0,071			0,071
Sleipner area		14,870	8,989	0,026	0,259		7,943	7,409	15,352
Snorre	10,733	1,211		0,051	0,087	10,770	0,577	0,399	11,747
Statfjord	19,155	7,256		0,094	0,430	19,154	3,094	1,021	23,269
Statfjord Nord	3,946	0,285				3,935	0,173	0,065	4,173
Statfjord Øst	4,147	0,588				4,150	0,256	0,097	4,503
Tommeliten Gamma	0,243	0,708				0,141	0,648	0,045	0,834
Tordis	4,122	0,425		0,007	0,039	4,122	0,390	0,138	4,650
Troll area	14,542	15,980	0,417	0,010	0,106	14,765	14,317		29,082
Ula	2,349	0,220		0,002	0,048	2,222	0,146	0,083	2,452
Valhall	4,868	1,006		0,011	0,073	4,530	0,940	0,167	5,638
Veslefrikk	3,455	0,673		0,010	0,050	3,475	0,139	0,060	3,674
Vigdis	1,607	0,111				1,573			1,573
Yme	2,001	0,085		0,030	0,004	1,980			1,980
Sum 1997	178,285	70,340	10,133	0,404	3,020	175,843	42,622	10,737	229,202
Sum 1996	177,283	59,454	8,400	0,428	2,817	175,496	37,398	9,242	222,135
Sum 1995	158,235	47,192	6,975	0,409	2,640	156,622	27,813	8,439	192,874
Sum 1994	147,674	45,392	4,588	0,364	2,630	146,282	26,841	7,143	180,267
Sum 1993	133,770	41,576	1,280	0,340	2,544	131,843	24,804	4,156	160,803
Sum 1992	125,936	42,444	0,573	0,309	2,449	123,999	25,834	3,369	153,203
Sum 1991	110,513	39,717	0,563	0,356	2,257	108,510	25,027	3,312	136,849
Sum 1990	96,844	37,065	0,521	0,556	2,132	94,542	25,479	3,420	123,442
Sum 1989	88,266	39,320	0,547	0,474	2,013	85,983	28,738	3,327	118,048
Sum 1988	66,882	36,302	0,588	0,336	1,818	64,723	28,330	3,303	96,355
Sum 1987	58,538	34,499	0,577	0,434	1,443	56,959	28,151	2,813	87,923
Sum 1986	50,579	33,924	0,355	0,258	1,311	48,771	26,090	2,630	77,491
Sum 1985	47,339	34,102	0,030	0,304	1,190	44,758	26,186	1,980	72,924

Figure 7.6.a
Oil and gas production on the Norwegian shelf 1971-1997

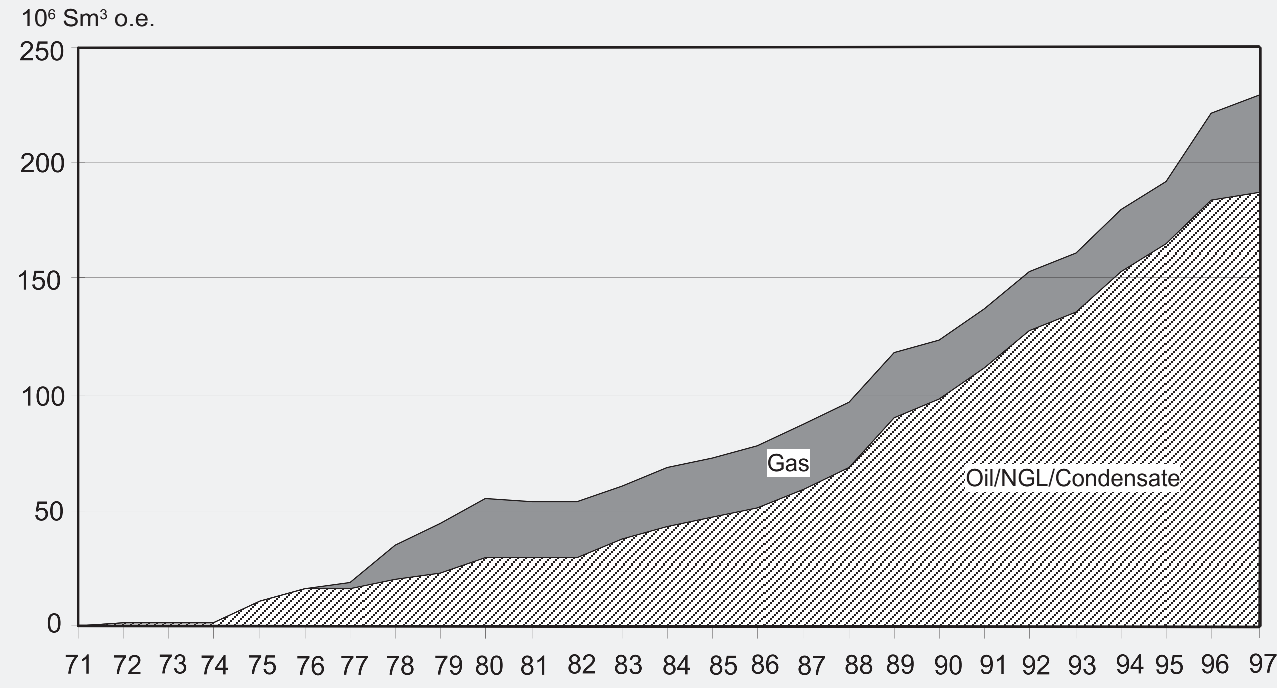


Figure 7.6.b
Oil and gas production on the Norwegian shelf 1977-1997