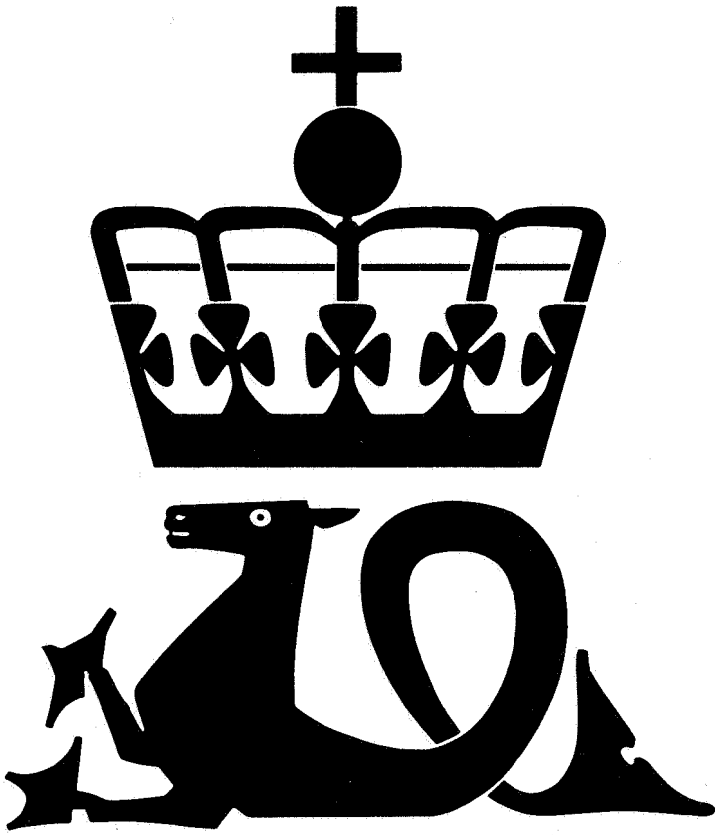

Norwegian Petroleum Directorate

ANNUAL REPORT 1996

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The Norwegian Petroleum Directorate shall contribute to a responsible management of the Norwegian petroleum resources through a balanced administration of the natural, safety, environmental, technological and economic aspects of the activities, within the framework of an overall social assessment.

The Norwegian Petroleum Directorate was established in 1972 and has 354 permanent positions. It has its head offices in Stavanger and a branch office in Harstad. The Norwegian Petroleum Directorate answers to the Ministry of Petroleum and Energy with regard to resource management and administrative matters, and to the Ministry of Local Government and Labour for matters 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 Norwegian Petroleum Directorate exercises management authority in connection with exploration for and production of petroleum deposits on the Norwegian continental shelf and on Svalbard. The Norwegian Petroleum Directorate has the authority to stipulate regulations and to make decisions regarding consent, orders, exemptions and approvals pursuant to the regulations.

The Norwegian Petroleum Directorate has a key role within the field of petroleum management and is thereby an important advisory body for the superior ministries. The Norwegian Petroleum Directorate shall ensure the best possible knowledge of discovered and undiscovered petroleum resources. It shall also carry out supervision to ensure that licensees manage the resources in a responsible manner, and that a prudent level of safety and working environment is established, maintained and developed further within the Directorate's spheres of authority.

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Preface

Resource growth

The Norwegian Petroleum Directorate has conducted a new assessment of the petroleum resources on the Norwegian shelf. The new estimates show an increase in recoverable reserves of as much as 1.7 billion Sm^3 o.e. (oil equivalents) compared with the previous analysis which was performed in 1994. The large increase is mainly due to the fact that the Norwegian Petroleum Directorate expects technological development which will make it possible to increase recovery from the Norwegian shelf. The estimates are based on an anticipated average recovery rate of 50% for oil and 75% for gas from all discoveries and fields. The Norwegian Petroleum Directorate's new estimates of recoverable petroleum resources are 12.5 billion Sm^3 o.e., divided between 6.5 billion Sm^3 o.e. oil and 6.0 billion Sm^3 o.e. gas.

The increase in the estimates for the recoverable reserves has also led to an upgrading of the prognoses for future oil production. Based on the new estimates, oil production is expected to reach a peak of approx. 215 million Sm^3 per year (approx. 3.7 million barrels per day) in the years 2000 and 2001.

The total resource growth from the activities on the Norwegian continental shelf in 1996 was approx. 195 million Sm^3 o.e. About 55% (110 million Sm^3 o.e.) of this comes from the upward adjustment of the resources in existing discoveries and fields and about 40% (85 million Sm^3 o.e.) from new discoveries. The resource growth from new discoveries is distributed about equally between oil and gas. If we compare the resource growth in 1996 with the production during the same period, it is apparent that these lie at about the same level, with regard to both oil and gas.

Increased recovery

As in previous years, the results from 1996 show that the strong commitment to technological development of methods to increase the recovery of oil provides results. Better mapping of the reservoirs, more advanced drilling and completion technology and more comprehensive injection programs are important factors in this context. There is good reason to believe that this development will continue, however, the work is becoming increasingly demanding. Therefore, it is gratifying to see that the industry is cooperating actively on these issues through the FORCE program. At the end of 1996, as many as 10 different projects have been initiated in FORCE.

Development

1996 has been an active year with regard to new field developments and development of transportation systems on the Norwegian shelf. The Norwegian Petroleum Directorate has processed plans for development and operation for Gullfaks Sør, Gullveig, Oseberg Øst, Oseberg gas phase, Varg and Åsgard, as well as plans for installation and operation for Balder gas transportation, Ekofisk bypass pipeline, Europipe II and Åsgard Transport.

Of these, Gullfaks Sør, Gullveig, Oseberg Øst and Varg as well as Balder gas transportation were approved for development with background in oil recovery. Europipe II and Ekofisk bypass will be developed so as to transport sold gas volumes to the Continent. Oseberg gas phase, Åsgard and Åsgard Transport were approved for development in connection with allocation of gas sales contracts.

New discoveries

Exploration activities have led to 10 new discoveries, all in the North Sea. These comprise six oil discoveries, one gas discovery and three gas/condensate discoveries. None of the discoveries are large compared with the fields which are currently in production. The majority will nevertheless be candidates for development because they are located close to existing or planned production facilities, and because the costs in connection with development of smaller discoveries has gone down in recent years.

The discovery rate on the Norwegian shelf in recent years has been around 50%. This is high compared with many other oil and gas provinces in the world, and is due to a strong commitment to the development of new technology, good routines for exchange of data between the various participants and good mapping of prospects before drilling. As a part of the work to maintain the high discovery rate, in 1996 the Norwegian Petroleum Directorate took the initiative to establish FIND, which is an exploration technology cooperation between the oil companies in Norway and the Norwegian Petroleum Directorate. FIND has implemented several activities where results will be available as early as 1997.

Environment

The Norwegian Petroleum Directorate is also responsible for total overviews and prognoses for emission of so-called greenhouse gases from the petroleum activities. These are important but complex tasks which have been the focus of much work in 1996.

The annual overview of the emission of greenhouse gases shows that the production of petroleum has become more energy efficient. Even though the emissions of greenhouse gases increase as a consequence of greater production, the industry can point to a reduction in emissions per produced unit. In 1996, CO_2 emissions from taxable activities were approx. 7.9 million tons, which is equivalent to an increase of about 6% compared with 1995. The CO_2 emissions per produced unit (kg CO_2/Sm^3 o.e.) during the same period were reduced by about 8%. It will be a challenge to maintain high energy efficiency when the large oil fields stop producing at plateau and gas production from the Norwegian shelf increases. Development of new technology will be necessary to prevent a new growth in the emissions.

Data management
In order to operate efficiently in all phases of the activity (exploration, development and operation), it is crucial that the activities as a whole have good information and communication systems. Technology is important in this context, but upgrading of the information quality to and from the authorities and among the companies is also important. The work on standardization must be continued and implemented by the industry. The Norwegian Petroleum Directorate has also been an active initiator in this work in 1996, inter alia through the continuation of the DISKOS cooperation and implementation of new projects with a point of departure in DISKOS.

International cooperation
As in previous years, the Norwegian Petroleum Directorate has had a significant international involvement in 1996. In addition to the activity which is connected with participation in international forums and professional cooperation in the North Sea region, the Norwegian Petroleum Directorate has participated actively in the INTSOK work. Furthermore, the Norwegian Petroleum Directorate has cooperated with NORAD so as to assist developing countries within the field of petroleum management, and has assisted PETRAD in the implementation of a number of seminars and conferences both within Norway and abroad.

Accidents and events
There were no fatal accidents within the Norwegian Petroleum Directorate's sphere of responsibility in 1996. However, there were three fatal accidents on vessels connected with petroleum activities which have caused the Norwegian Petroleum Directorate to implement a cooperation with other concerned organizations and authorities so as to improve the safety in connection with similar operations.

The rate of accidents with personal injury has stayed at about the same level for the last four years. The Norwegian Petroleum Directorate does not regard the injury rate in the petroleum activities to be particularly high, but believes nevertheless that injuries and accidents can be avoided.

The number of notifications of work-related diseases has continued to increase in 1996. The Norwegian Petroleum Directorate believes that this is due among other things to improved reporting, which is a desirable development in order to be able to increase the efforts towards reducing the number of work-related diseases.

In 1996 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, and this concerns the Norwegian Petroleum Directorate, first and foremost because of the great damage potential in connection with this type of undesirable event. Two situations where wells nearly got out of control illustrate that the companies continue to face challenges related to risk control in connection with drilling and well operations.

The experiences with safety and the working environment in the past year establish that the petroleum activities on the Norwegian shelf take place within the proper framework and largely in accordance with our regulations. At the same time, it has been revealed that certain participants have a potential for improvement with regard to management systems which must be in place in order to achieve measurable results within the area of safety and working environment.

Challenges
The development in the years to come entails a number of challenges for the industry, including exploration and production in deep waters, deep drilling in connection with high temperatures and high pressure, and requirements with regard to cost efficient solutions for development and operation. Mobile installations will increasingly be utilized in the future, also for production. Therefore, throughout 1996 the Directorate has continued its work to provide for increased predictability with regard to the relationship of floating installations to the regulations.

Legislation
A new Petroleum Act was adopted by the Storting on 29 November 1996. The Norwegian Petroleum Directorate has assisted the Ministry of Industry and Energy and the Ministry of Local Government and Labour in revising the accompanying overarching regulations under the Petroleum Act. It is assumed that these regulations will enter into force simultaneously with the new Petroleum Act.

In the area of resource management, the Norwegian Petroleum Directorate is working on updating the regulations.

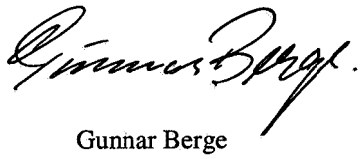
The Norwegian Petroleum Directorate has also submitted a proposal to the Ministry of Local Government and Labour concerning a new regulatory structure which will provide for a greater degree of comprehensive thought across the boundaries of traditional fields.

The Directorate's goal is for the regulations to be adapted to national and international development at all times. National and international standards are acquiring an increasingly important role as clarifying and supplementary documentation in relation to the shelf regulations. Thus the Norwegian Petroleum Directorate participates actively in national and international standardization work, inter alia to see whether NORSOK standards may be used as recognized norms in the shelf regulations and whether the Norwegian Petroleum Directorate's technical guidelines may be replaced by updated or future new NORSOK standards.

Information technology

During the course of the year, the Directorate has made a further commitment to the use of information technology and new information systems. Visits to our home page on the Internet, which offers access to special reports, maps and press releases, is increasing. The response to the national data base DISKOS is very gratifying. An increasingly larger segment of the reporting from the oil companies and the release of data to the companies takes place electronically. This development is necessary if the industry and the authorities are to handle the wave of information which is washing over us.

Stavanger, 21 April 1997



Gunnar Berge
Director General

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The Norwegian Petroleum Directorate shall contribute to a responsible management of the Norwegian petroleum resources through a balanced administration of natural, safety, environmental, technological and economic aspects of the activities, within the framework of an overall social assessment. An objective such as this can only be achieved by the Norwegian Petroleum Directorate having a good overview of the petroleum resources at all times, and by evaluating alternative methods for the optimum exploration, development and production of the resources. Such overviews and evaluations form the basis for advice to the central authorities with respect to the best possible management of the petroleum resources.

Activities on the Norwegian Shelf in 1996 were also characterized by a high level of activity in exploration, development and operation. A significant upward adjustment of the reserves basis for discoveries and fields has been made, and a number of new discoveries have been registered.

The Norwegian Petroleum Directorate has worked on a number of important tasks, including the 15th licensing round, evaluation of new field development plans, improved resource utilization for fields in production, new resource estimates, new production and environmental prognoses, implementation of FIND, continuation of FORCE and DISKOS, and revision of the Petroleum Act.

At the turn of the year 1991/1992, the Norwegian Petroleum Directorate started work on methodical regulatory development in the area of resource management (the MR project) with the understanding of what was then known as the Ministry of Petroleum and Energy.

From 1994, the regulatory development work became focused on a new act relating to petroleum activities (PROLO-94) under the leadership of the Ministry of Industry and Energy. Circumstances which have guided this work include conditions in the EEA Agreement, the need for regulation by law of the final disposition of installations, follow-up of Storting Report No. 26 (1993-94) and follow-up of recommendations from the industry in connection with NORSOK. This work was completed in 1996 and a new Petroleum Act was passed by the Storting in November 1996.

In the spring of 1996, work began on new regulations supplementing the Act relating to petroleum activities under the leadership of what was then known as the Ministy of Industry and Energy.

In addition to assisting the Ministry of Industry and Energy in the work pertaining to a new Petroleum Act and petroleum regulations, work has commenced regarding necessary thematic guidelines to the overarching regulations and a revision of the secondary regulations.

As a natural consequence of the successive development of a new Petroleum Act and regulations, a gradual adjustment of the secondary regulations is necessary in order to accommodate changes both in the content and the structure of the overarching regulations.

The objective of the Norwegian Petroleum Directorate's regulatory development activities in the resource management area is to ensure that the formal framework for the petroleum activities always emerges as an appropriate guiding tool in order to safeguard the efficient and proper management of resources.

Key objectives in this work are:

- to develop structured and comprehensive regulations which inter alia accommodate the need for predictability and efficiency
- to ensure conformity between the overarching and secondary regulations
- to safeguard coordination with adjoining regulations
- to strive for simplification and functionality

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 accounts 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 accounts for the Norwegian continental shelf are shown in Table 1.1.a.

Classification system for discovered resources

This year, the Norwegian Petroleum Directorate has made some adjustments in the way the discovered resources are classified and registered. 8 separate classes of resources are registered in the resource accounts, as well as two classes for future measures for increased recovery and for prospects which may be connected to a field. The classes are:

Class 0: reserves where production has ceased
Class 1: reserves in production
Class 2: reserves with approved development plan
Class 3: resources in the late planning stage (approved development plan within 2 years)
Class 4: resources in the early planning phase (approved development plan within 10 years)
Class 5: resources which may be developed over the long term
Class 6: resources where development is very uncertain
Class 7: resources in new discoveries where evaluation is not yet complete
Class MT: possible measures for increased recovery (measures not planned, possibly measures beyond current technology)
Class TP: additional resources in the form of prospects which may be connected to a field

The MT class expresses the Norwegian Petroleum Directorate's assumption that the average future degree of recovery on the Norwegian shelf will be 50% for oil

and 75% 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. Class TP comprises the total, risk-weighted resources in prospects which the operators have informed the Norwegian Petroleum Directorate that they plan to connect to existing fields.

Two main principles are used as a basis for the Norwegian Petroleum Directorate's method. Firstly, the classification is built up around the development, starting when a new discovery is made until the point at which it may start production, and continuing until production is complete. Secondly, it is the resources, not the fields and the discoveries, which are classified. Therefore, a field or a discovery may have resources in several classes.

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 stratigraphical 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 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

The undiscovered resources comprise both mapped prospects and unmapped resources in areas where play models have been defined. There is always great uncertainty connected with such analyses. The size stated for undiscovered resources is the statistical expected value.

Changes in 1996

Older fields and discoveries

For older fields and discoveries (that is, discoveries made before 1996), the oil resources have increased by 155 million Sm^3 and the gas resources by 1 billion Sm^3. The NGL resources have been reduced by 36 million tonnes, largely due to the fact that petroleum which was previously registered as NGL is now regarded as oil (see Table 1.1.b).

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.j. In addition, as mentioned above, an estimate of future increased recovery, which is not specifically planned as of today, has been introduced. These resources, Class MT, account for a large share of the so-called IRE potential (improved resource exploitation). The IRE term also encompasses the planned measures for increased recovery and additional resources which are already registered for the individual fields, and which are shown in total in Table 7.5.d, and additional resources in the form of prospects, Class TP.

New discoveries

During 1996, discoveries were made in 10 exploration wells. These wells are 2/6-5, 9/2-6 S, 15/12-10 S, 24/12-3 S, 33/9-19 S, 34/7-25 S, 34/11-2 S, 35/10-2, 35/11-8 S and 36/7-1 (well 2/6-5 was not completed as of the end of the year). Evaluation has only been completed for about half of the discoveries, but the preliminary estimate is that the resource growth due to new discoveries in 1996 will be about 85 million Sm^3 o.e. The estimate varies between 60-110 million Sm^3 o.e.

Production

Recovery of petroleum on the Norwegian continental shelf in 1996 was 175.5 million Sm^3 of oil, 37.4 billion Sm^3 of gas and 7.1 million tonnes of NGL (including condensate).

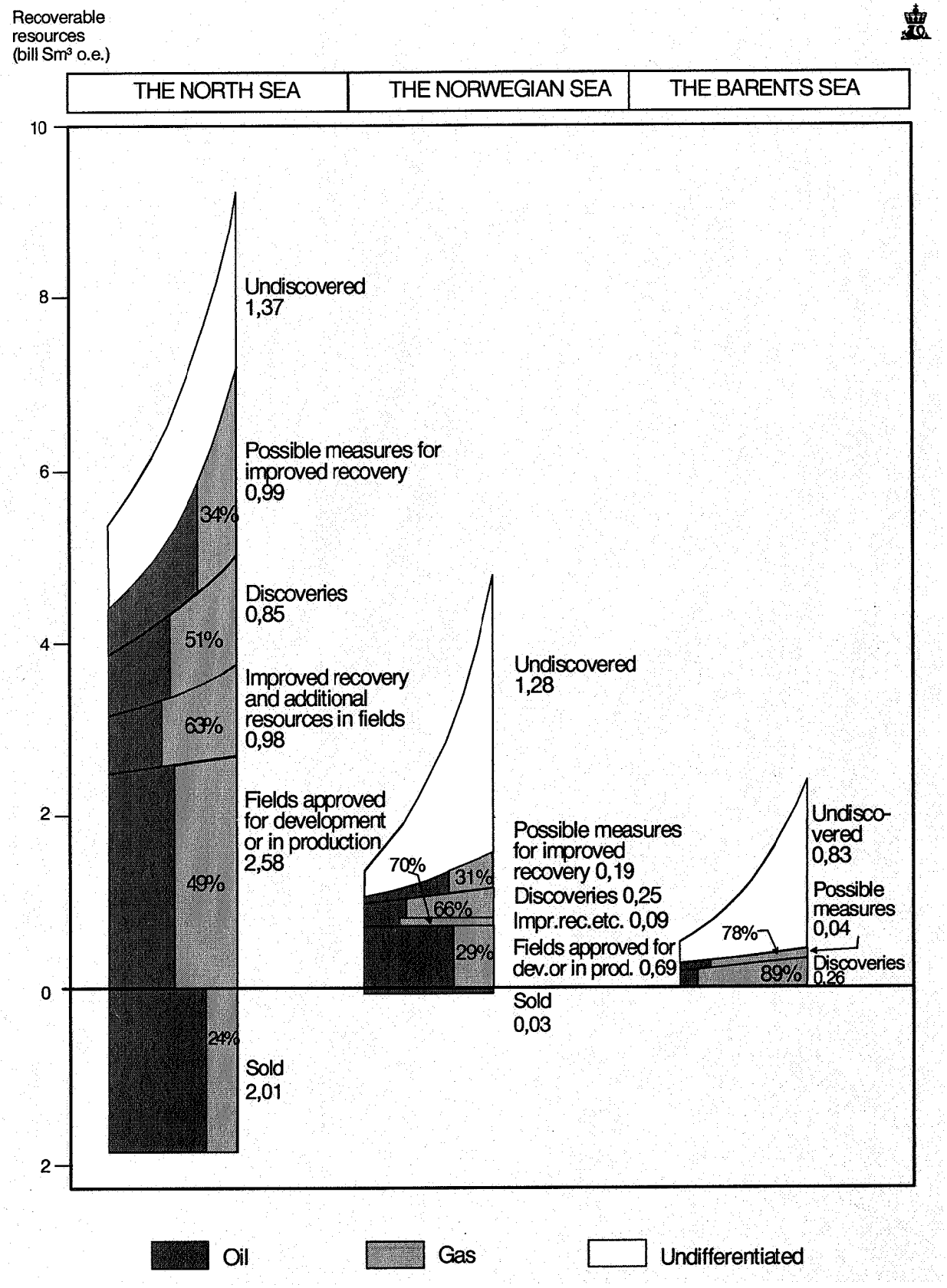
Resource status

The resource accounting for the Norwegian continental shelf is presented in Table 1.1.a, and the geographical distribution of resources is shown in Figure 1.1. The resources on the Norwegian continental shelf are divided according to the Norwegian Petroleum Directorate's resource classification system. Table 1.1.c shows the total resources in fields. Table 1.1.d shows the total resources in discoveries which have not yet been approved for development.

Fields where production has ceased

There were no fields which ceased production in 1996. The three fields on the Norwegian continental shelf where production has ceased are shown in Table 7.5.a.

Figure 1.1
Geographical distribution of resources on the Norwegian continental shelf



The base estimate is given next to the colu[illegible] for every category of resources.The statistical distribution of the resource estimates is shown with a low estimate (left part of the column) and a high estimate (right part of the column)

Reserves in fields which are in production/approved for development

As of 31 December 1996, it has been decided to develop 54 fields on the Norwegian continental shelf (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 eight fields which were approved for development during 1996 are: Balder, Gullfaks Sør, Gullveig, Oseberg Øst, Rimfaks, Varg, Visund and Åsgard.

Three new fields started production in 1996; Gungne, Sleipner Vest and Yme. In addition, gas production from Troll I (Troll Øst) was also commenced. At the end of the year, 39 fields were producing on the Norwegian Continental Shelf (Table 7.5.b). 12 fields have also been approved for development, but have not yet started production (Table 7.5.c), which is four more than at the same time last year.

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 Tables 7.5.b and 7.5.c 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

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 tons	Total 10^6 Sm^3 o.e.
0 Reserves where production has ceased	0	39	0	39
1 Reserves in production	2 702	1 639	122	4 499
2 Reserves with approved development plans	448	294	31	782
Sum reserves	3 150	1 972	153	5 320
3 Resources in late planning phase	540	359	23	928
4 Resources in early planning phase	120	587	21	734
5 Resources which can be developed in the long term	136	509	24	677
6 Resources where development is very uncertain	24	47	1	72
7 Resources in new discoveries	10	17	0	27
Sum booked resources in fields and discoveries	3 980	3 491	222	7 758
MT Possible, future measures for increased recovery	790	420		1 210
Sum recoverable resources in fields and discoveries	4 770	3 911	222	8 968
Undiscovered resources	1 400	2 070		3 470
Total recoverable potential	6 170	5 981	222	12 438
Sold by 31st December 1996	1 493	492	48	2 046

The table comprises the total resources and reserves in each resource class on the Norwegian continental shelf. A number of fields and discoveries have resources in more than one resource class.

Table 1.1.b
Change in discovered and total resources

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	Total 10^6 Sm^3 o.e.
New discoveries	50,0	35,0		85,0
Change in estimates	155,0	1,0	-36,0	109,0
Total change in original recoverable resources	205,0	36,0	-36,0	194,0
Change in estimate of future potential of improved recovery	790,0	420,0		1 210,0
Overall change in total estimate for fields and discoveries	995,0	456,0	-36,0	1 404,0
Production	-175,5	-37,4	-7,1	-222,1
Overall change in remaining discovered resources	819,5	418,6	-43,1	1 181,9
Change in undiscovered resources	15,0	60,0		75,0
Overall change in remaining total resources	**834,5**	**478,6**	**-43,1**	**1 256,9**

Table 1.1.c
Reserves and resources in fields

Resource class	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	Total 10^6 Sm^3 o.e.
0 Reserves where production has ceased	0	39	0	39
1 Reserves in production	2 702	1 639	122	4 499
2 Reserves with approved development plans	448	294	31	782
Sum reserves (class 0-2)	3 150	1 972	153	5 320
Sold*	1 493	492	48	2 046
Remaining reserves	1 657	1 480	105	3 274
3 Resources in late planning phase	248	137	6	393
4 Resources in early planning phase**	78	528	19	631
5 Resources which can be developed in the long term	25	23	1	49
6 Resources where development is very uncertain	4	1	0	5
Sum resources in booked IOR measures and additional resources (class 3-6) in fields	355	689	26	1 078
Sum booked resources in fields	3 505	2 661	179	6 398
MT Possible, future measures for increased recovery	510	220		730
TP Additional resources as prospects	215	163	4	383
Total recoverable resources in fields (excl. of TP)	**4 015**	**2 881**	**179**	**7 130**

* does not include consumption on the fields
** includes Troll III

Table 1.1.d
Resources in discoveries

Resource class	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	Total 10^6 Sm^3 o.e.
3 Resources in late planning phase	291	223	17	536
4 Resources in early planning phase	42	59	2	103
5 Resources which can be developed in the long term	111	486	23	628
6 Resources where development is very uncertain	20	46	1	67
7 Resources in new discoveries	10	17	0	27
Sum booked resources in discoveries	474	831	43	1 360
MT Possible, future measures for increased recovery	280	200		480
Total recoverable resources in discoveries	**754**	**1 031**	**43**	**1 840**

additional resources. This year, these are shown together in Table 7.5.d. 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 this change are described in the paragraph entitled "Changes in Resource Estimates".

The total, original recoverable reserves in fields approved for development are 5320 million Sm^3 o.e., divided between 3348 million Sm^3 o.e. oil/NGL and 1972 billion Sm^3 gas. This is shown in Table 1.1.c. In addition, resources totaling 1078 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 389 million Sm^3 o.e. oil/NGL and 689 billion Sm^3 gas (including Troll III (Troll Vest gas)) (Table 1.1.c and Table 7.5.d).

Up to 31 December 1996, a total of 1555 million Sm^3 o.e. oil/NGL and 492 billion Sm^3 o.e. gas has been produced. This constitutes 36% of the registered, discovered oil and 14% of the registered, discovered gas. The registered additional resources and resources from the measures for increased recovery are included, but not the resources in Class MT.

Resources in discoveries in the late planning stages
At the end of the year, there were 23 discoveries in the late planning stages (Table 7.5.e). 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 for these discoveries constitute a total of 563 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.f 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 12 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. In this context, Troll III (Troll Vest gas) is considered to be a discovery in this category.

The resource volume constitutes a total of 486 million Sm^3 o.e. If we disregard Troll III, the resources amount to 98 million Sm^3 o.e.

Resources in discoveries which may be developed over the long term
A total of 55 discoveries have been identified in this category (Table 7.5.g) 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 610 million Sm^3 o.e., whereof 326 million Sm^3 o.e. are located in the North Sea, 52 million Sm^3 are located in the Norwegian Sea and 232 million Sm^3 o.e. are located in the Barents Sea.

Resources in discoveries where development is very uncertain
The Norwegian Petroleum Directorate's resource accounts show 32 discoveries for which profitable development is not expected without significant changes in technology or price (Table 7.5.h). 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 65 million Sm^3 o.e. may be produced from these discoveries.

Resources in discoveries where evaluation is not complete
Five of the discoveries in 1996 as well as one of the discoveries in 1995 have not yet been completely evaluated (Table 7.5.i.) The preliminary estimates for these discoveries total 27 million Sm^3 o.e.

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

Changes in resource estimates since the previous annual report
A number of reevaluations have been made of the resource and reserves estimates during 1996. The total changes are shown in Table 1.1.b. Table 7.5.j in chapter 7.5 shows all the changes from 1995 to 1996. The most important changes are discussed under:

Fields in production

Frøy
The reserves in Frøy have been reduced based on the performance of a new survey and development of a new geological model on the basis of the information in the production wells.

Heidrun
The Heidrun reserves have been increased after the development of a new geological model. In addition, the recovery from the lower portion of the Tilje formation and the Åre formation is now based on pressure support from water injection.

Snorre
The reserves in Snorre have been reduced as a consequence of the fact that the resources in Snorre phase 2 are now registered under resource class 3 in the Norwegian Petroleum Directorate's new system for classification of resources. In last year's annual report, the resources in phase 2, which has not yet been approved by the authorities, were included in the reserves. Recoverable oil resources in Snorre phase 2 are estimated to be 40.1 million Sm^3. Seen in total for Snorre, therefore, the oil resources have been increased by 20 million Sm^3 compared with the previous annual report. The increase is due to a new reservoir model and optimization of the recovery strategy. See also the description of the field in chapter 1.4.24.

Statfjord Nord
The reserves estimate has been increased based on results from a new reservoir model and an extended production period.

Statfjord Øst
The reserves estimate has been increased based on results from a new reservoir model and an extended production period.

Troll I (Troll Øst)
The gas reserves have been adjusted upwards after the operator's new survey and resource calculation. Liquid which was previously identified as NGL is now reported as oil, as it is sold as oil from Stura.

Troll II (Troll Oil)
The reserves in Troll II include all developed and approved reserves in the former "Troll Vest oil phase II and II B". That is to say that the development of "well group I", which was approved by the authorities in 1996, is included, while the parts of the development of the oil resources which are not yet approved are included in resource class 3 in Table 7.5.d. In addition, some of the changes are due to experiences with production so far and new reservoir studies.

Valhall
Reduced oil reserves in 1996 are due to the inclusion of the operator's alternative production strategies in 1995. The oil which may possibly be recovered with the aid of these measures is placed in resource class 3 in 1996, resources in the late planning stage, and is included in Table 7.5.d.

Fields which have been approved for development

Balder
The reserves in Balder have been reduced somewhat in that parts of the resources which were previously included in the field are now classified as non-proven resources, that is, prospects in resource class TP.

Gullfaks Sør
New resource estimates in connection with the PDO and process simulation have led to changes in the liquid volumes. The gas resources, which have not been approved for development, have been moved to resource class 4 and are included in Table 7.5.d.

Njord
The change in the reserves estimate is mainly due to the fact that the gas resources, which have not been approved for development, are registered in resource classes 4 and 5. Therefore, they are not a part of the reserves, but are included in Table 7.5.d. Reference is also made to the description of the field in chapter 1.4.25.

Norne
The change in oil reserves is due to the fact that the Norwegian Petroleum Directorate now uses the operator's estimate of the reserves. The change in gas stems from the fact that the gas resources, which have not been approved for development, are now registered under resource class 3 and are included in Table 7.5.d. See also the description of the field in chapter 1.4.29.

Oseberg Øst
The reserves estimates have been adjusted in connection with the development of the PDO.

Rimfaks
The gas resources and accompanying condensate volumes have been moved to resource class 4 and are included in Table 7.5.d.

Varg
The reserves estimates have been adjusted in connection with the development of the PDO.

Visund
The gas resources and accompanying condensate volumes have been moved to resource class 4 and are included in Table 7.5.d.

Åsgard
The increase in the oil reserves is due to an updating of reservoir models and fluid descriptions as well as an optimization of the production strategy. The reduction in gas is due to the fact that the gas resources-in-place have been reduced as a consequence of information from new wells.

Discoveries in the late planning stages

25/8-5 S, 25/8-8 S, 25/7-3 (Jotun)
The resource estimates have been adjusted in connection with the preparation of the PDO.

25/11-15 Hermod
The Norwegian Petroleum Directorate has gone over to using the operator's figures for in-place and recoverable oil. The operator previously had a lower figure for recoverable oil, but has now carried out comprehensive work in order to optimize recovery in connection with preparations for the PDO.

34/11-1
The changes are a consequence of preliminary upward adjustments after well 34/11-3.

35/11-4 R Fram
This discovery is in an active exploration phase. It is likely that a development will include several nearby discoveries, and this year's estimate includes the resources in the 35/

11-7 discovery and the 35/11-8 S discovery. New exploration drilling is planned in connection with these discoveries in 1997.

6407/1-2 Tyrihans
The increase in the oil resources from 1995 to 1996 is due to the fact that condensate from Tyrihans Sør was not included in 1995, and also that more comprehensive reservoir studies and simulations have been conducted.

Discoveries in the early planning stages

35/9-1 R Gjøa
This discovery is in an active exploration phase. It is likely that a development will include several nearby discoveries, and this year's estimate includes the resources in the 36/7-1 discovery. Additional exploration drilling is planned in connection with these discoveries in 1997.

Discoveries which may be developed over the long term

7120/7-1 Askeladd Vest
7120/7-2 Askeladd Sentral
7120/8-1 Askeladd
7121/4-1 Snøhvit
7121/7-2 Albatross Sør
The gas resources in these discoveries have been reduced because the operator is considering a subsea development with multi-phase transportation in pipelines to land as the most realistic development concept. This gives a somewhat lower degree of recovery.

Name changes made in 1996
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 always remain the same.

The name changes made in 1996 are as follows:

Present name	Previous designation
Balder	25/11-1 Balder
Gullfaks Sør	34/10-2 Gullfaks Sør
Gullveig	34/10-37
Oseberg Øst	30/6-5 Oseberg Øst
Rimfaks	34/10-17 Rimfaks
Varg	15/12-4 Varg
Visund	34/8-1 Visund
Åsgard	6507/11-1 Midgard et.al.*
35/9-1 R Gjøa	35/9-1 R
35/11-4 R Fram	35/11-4 R
6407/1-2 Tyrihans	6407/1-2 Tyrihans Sør et.al..**
7120/7-1 Askeladd Vest	7120/7-1

* The Åsgard field comprises the three discoveries, 6507/1-11 Midgard, 6506/11-1 Smørbukk and 6506/11-3 Smørbukk Sør.

** In its reporting to the Norwegian Petroleum Directorate, the operator of 6407/1-2 Tyrihans Sør and 6407/1-3 Tyrihans Nord has merged the two discoveries together. Therefore, they are reported together under the name 6407/1-2 Tyrihans this year.

1.2 PRODUCTION PROGNOSES

Oil prognosis for fields in production and for fields which have been approved for development
Several of the producing oil fields on the Norwegian shelf are now in or are approaching the decline phase. This gives an increased degree of uncertainty related to the short-term production from these fields. Around the year 2005, it is expected that all fields in operation and approved for development as of 31 December 1996 will be in the decline phase. Over the long term, the greatest uncertainty for these fields will therefore be related to the rate of decline. More recovery from the fields at plateau can lead to a greater rate of decline. Additional resources on the fields, a better rate of recovery than expected, improved resource utilization as well as phase-in of satellite fields are factors which could reduce the decline in production, increase recovery and thereby also extend field lifetime.

In the year 1999, production from fields in production and approved for development as of 31 December 1996 is evaluated to be between 175 and 225 million Sm^3 with an expectancy of 200 million Sm^3. In 2010, it is expected that production from the same fields will be reduced to between 25 and 55 million Sm^3, with an expectancy of 40 million Sm^3.

During the period from 1997-2000, approximately 90% of the production on the Norwegian shelf will come from fields which are in production or approved for development as of December 1996 (Figure 1.2.a). The uncertainty related to production from these fields will therefore have the greatest significance over the short term. Over the longer term (2001-2010), fields in production and fields approved for development will make up about 50% of the expected production, while discoveries which are expected to be developed are estimated to account for 15%. The uncertainty here is primarily linked to the size of the recoverable resources. Over the short term, however, uncertainty related to the timing of production start for discoveries is also a significant factor.

Making prognoses of production from deposits which are not yet discovered is based on a number of assumptions and suppositions which are, evaluated separately, extremely uncertain. The most important uncertainties in the prognoses are related to the size of future discoveries and the start-up date, as well as the frequency of new developments. Future oil price and development of technology will be important factors in the continued exploration and development activities on the Norwegian shelf. Improved resource utilization from fields in production and production from undiscovered resources is estimated to be 35% of the expected production during the period from 2001 to 2010.
Figure 1.2.b shows the expected total oil production with

Figure 1.2.a
Future oil production

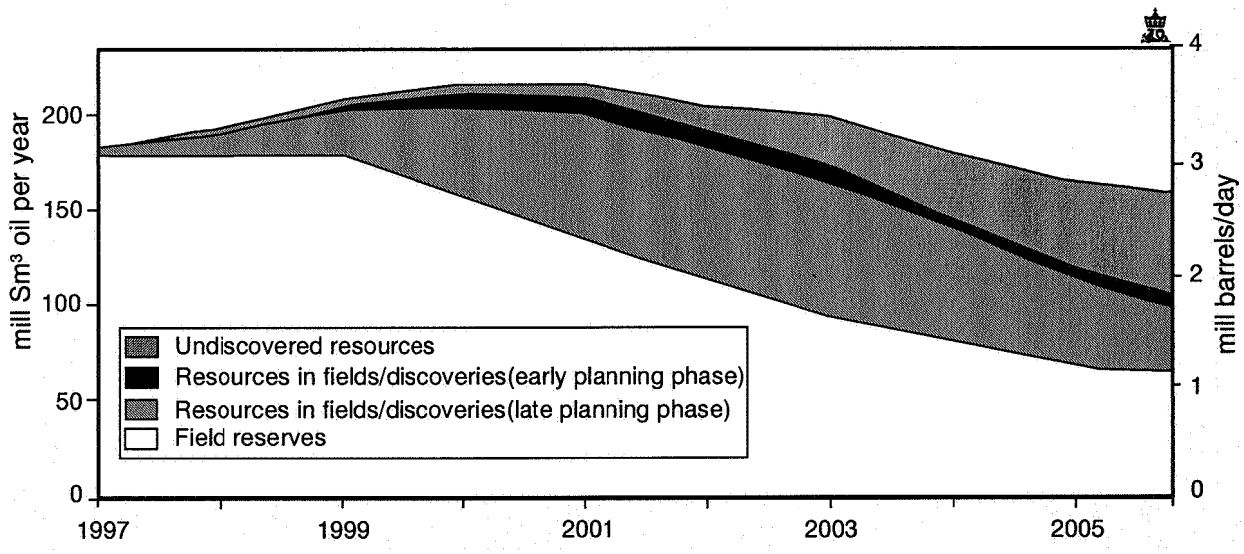
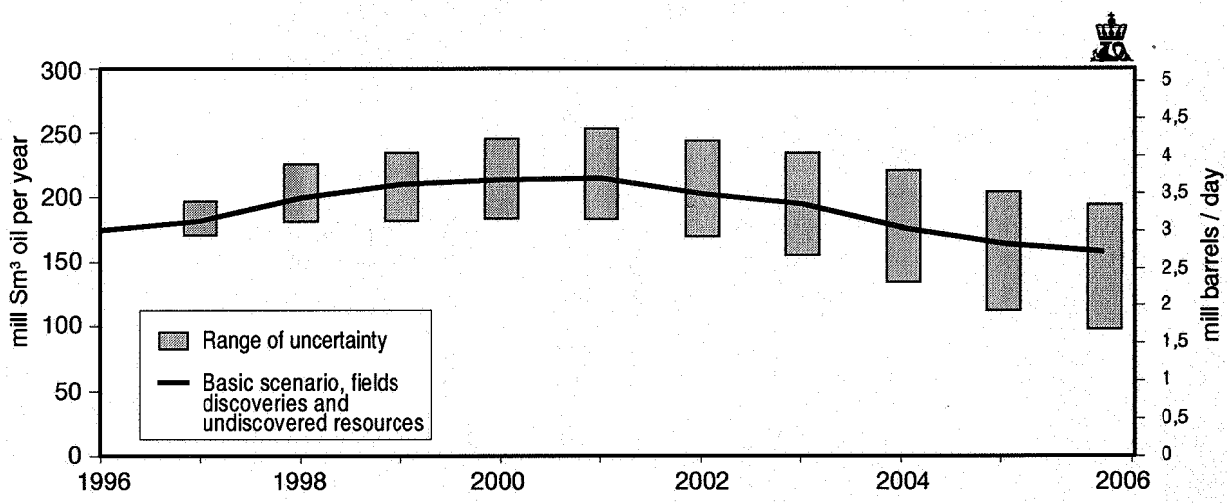


Fig. 1.2.b
Basic scenario for oil production on the Norwegian shelf - with range of uncertainty



areas of uncertainty (prediction interval). In the evaluation of uncertainty in future oil production, only uncertainty in oil production for individual years is evaluated, no low and high prognoses are given. The highest level of Norwegian oil production is expected in the year 2001 with roughly 215 million Sm^3. The uncertainty related to this estimate is, however, great. The uncertainty area in the year 2001 is estimated to 70 million Sm^3. In 2010, production is expected to be about 100 million Sm^3 with a span of uncertainty from 55 to 150 million Sm^3.

1.3 FIELDS WHERE PRODUCTION HAS CEASED

1.3.1 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 1996-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. Disposition of the pipeline to Cod will be determined in light of the ongoing clarification program for pipelines.

1.3.2 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:	11,8 billion Sm^3 gas 0,1 million NGL tonnes
Total investments (firm 1996-NOK):	approx. NOK 3,4 billion
Accrued disposal costs:	approx. NOK 70 million
Disposal costs 1997:	approx. NOK 80 million

Disposal

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

The subsea installation will be brought to land in 1997. Disposition of the pipeline to Frigg will be determined in light of the ongoing clarification program for pipelines.

1.3.3 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:	26,6 billion Sm^3 gas
Total investments (firm 1996-NOK):	approx. NOK 4.7 billion
Estimated disposal cost:	NOK 220 million

Disposal

The installations on the Odin field will be brought to land for scrapping and recycling. The deck was brought to land in autumn 1996. The structure will be removed in early 1997. Disposition of the pipeline to Frigg will be determined in light of ongoing clarification program for pipelines.

1.4 FIELDS IN PRODUCTION AND FIELDS APPROVED FOR DEVELOPMENT

1.4.1 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:	8,7 million Sm^3 oil 2,2 billion Sm^3 gas 0,3 million NGL tonnes
Total investments (firm 1996-NOK):	NOK 1,4 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance	NOK 50 million

Production

The Hod field is the southernmost chalk field in the Norwegian part of the North Sea, and produces from reservoir zones in the Ekofisk, Tor and Hod formations. The field is produced with the aid of depressurization, with six wells producing, whereof four are horizontal. In 1994, a structure in the north was drilled (the Hod Saddle area) and oil was found. Further surveys in this area led to the drilling of a new well in 1995 which also revealed oil. Both wells have been put into production.

Development

The development features an unmanned production installation. 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. From Valhall, oil and gas are transported in the existing transportation systems to Emden and Teesside. 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.

1.4.2 VALHALL

Production licenses: 006 and 033	**Blocks:** 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:	115,4 million Sm^3 oil 32,1 billion Sm^3 gas 4,8 million NGL tonnes

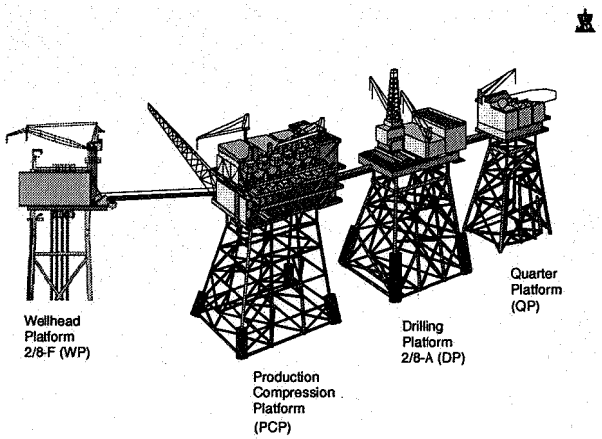
Total investments (firm 1996-NOK):	NOK 20,4 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 645 million

Production

The Valhall field produces from reservoir zones 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 have lead to subsidence of the seabed estimated at about 3 meters at the end of 1996. At the end of 1996, 31 production wells were producing on the field.

In order to increase the recovery rate of the oil, the operator is considering the possibility of carrying out 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 1.4.2
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 platform was installed with room for 19 wells. The four installations are connected to each other by gangways. Figure 1.4.2 shows these installations. The riser installation 2/4 G, for which Phillips Petroleum is the operator, is connected to the Ekofisk Center.

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 fractioning column 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 necessary changes in the transportation and metering systems for petroleum from the Valhall and Hod fields. In this connection, the operator submitted a new plan for installation and operation (PIO) of the Valhall gas export system to the authorities in the autumn of 1996.

1.4.3 TOMMELITEN GAMMA

Production license: 044	**Block:** 1/9
Operator: Den norske stats oljeselskap a.s	
Licensees:	
Den norske stats oljeselskap a.s (SDFI 42,38000 %)	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:	3,79 million Sm^3 oil 9,25 billion Sm^3 gas 0,5 million tonnes NGL
Total investments (firm 1996-NOK):	NOK 3 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 18 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. The field is a gas/condensate field which is produced through depressurization.

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 drying, and finally, transportation through Norpipe to Emden. Some of the gas is used for gas lift on Edda and in this way helps to extend the economic lifetime of the Edda field. Oil and NGL are transferred from Edda to the Ekofisk Center and then on to Teesside. Production from Tommeliten Gamma is in its final phase and the plan is to shut down the field in 1998.

1.4.4 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	7,59400 %	Amerada Hess Norge AS	8,73760 %
	Elf Rex Norge AS	0,85500 %	Elf Petroleum Norge AS	11,20500 %
	Fina Production Licences AS	30,00000 %	Elf Rex Norge AS	0,74070 %
	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 1.4.4.b.

Production license 018B comprises the portion of Albuskjell which lies in block 1/6. Albuskjell was previously split between production licenses 018 and 011.

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 the part of production license 006 which contains the Tor field, 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.

Figure 1.4.4.a
Installations in the Ekofisk area

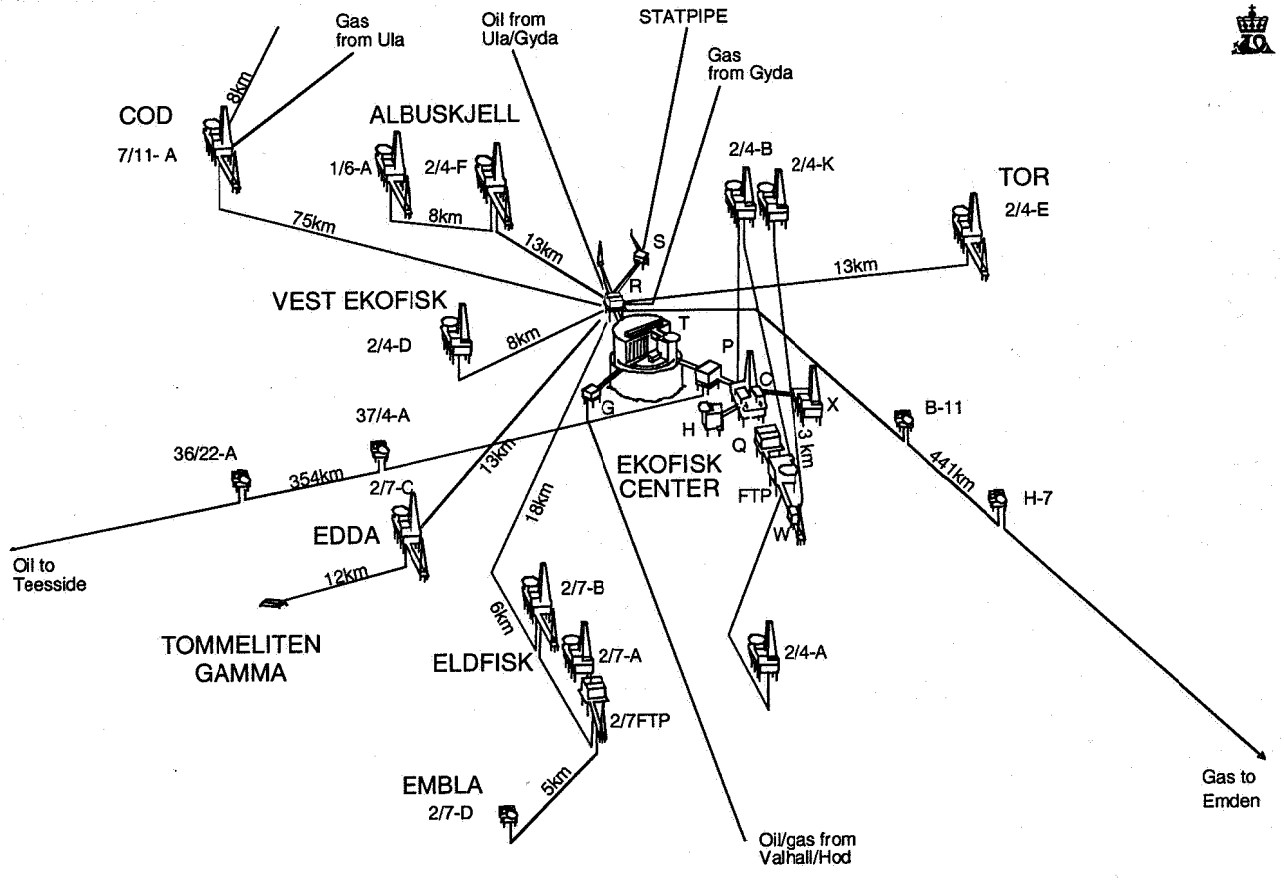
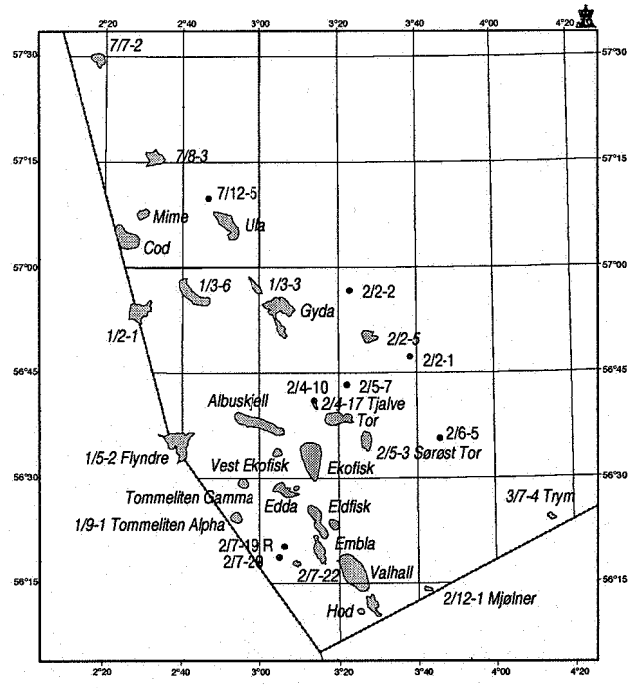


Figure 1.4.4.b
Fields and discoveries in the Ekofisk area



Production from Ekofisk started in June 1971, and during 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, a plan for development and operation of Ekofisk II was presented to the authorities and approved by the Storting in December 1994. Ekofisk II will be in production from the autumn of 1998. According to current plans for Ekofisk II, Cod, Albuskjell, Edda and Vest Ekofisk will cease production and shut down their installations while Eldfisk, Tor and Embla will be connected to the new field center (see Figure 1.4.4.a)

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:	8,3 million Sm^3 oil 6,0 billion Sm^3 gas 0,6 million tonnes NGL
Total investments (firm 1996-NOK):	NOK 2,35 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 30 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.

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 2016.

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:	81,3 million Sm^3 oil 58,7 billion Sm^3 gas 4,6 million tonnes NGL
Total investments (firm 1996-NOK):	NOK 24 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 570 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 only drive mechanism. Over 70% of the Eldfisk reserves have now been produced. Drilling of many horizontal wells on Eldfisk in recent years has given increased production from the field. In 1996, a two-path horizontal well was also put into production. Additional increase of the recovery factor with the aid of full-field water injection is being considered.

Development

Eldfisk B is a combined drilling, wellhead and process installation while Eldfisk A is a wellhead installation and a process installation connected with a bridge. The drilling installation 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 connected 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 2016.

Edda

Production license: 018	**Block:** 2/7
Operator: Phillips Petroleum Co. Norway	
Discovery well: 2/7-4	Year: 1972
Development approved: 1975	Prod.start: 1979
Recoverable reserves:	4,9 million Sm^3 oil 2,1 billion Sm^3 gas 0,2 million tonnes NGL
Total investments (firm 1996-NOK):	NOK 5,8 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 107 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, and has somewhat poorer reservoir properties than the other chalk fields in the area. The field 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 platform and oil/gas is transported to the Ekofisk Center. The plan is to shut down the field before Ekofisk II is completed in 1998.

Ekofisk

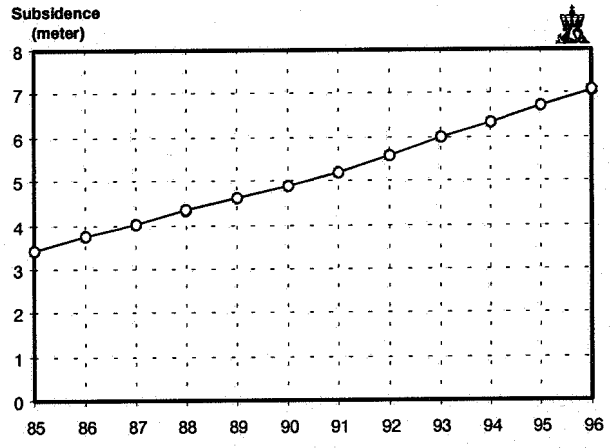
Production license: 018	**Block:** 2/4
Operator: Phillips Petroleum Co. Norway	
Discovery well: 2/4-2	Year: 1969
Development approved: 1970	Prod.start: 1971
Recoverable reserves:	404 million Sm^3 oil 150,4 billion Sm^3 gas 15,2 million tonnes NGL
Total investments (firm 1996-NOK):	Ekofisk I: NOK 50 billion Ekofisk II: NOK 17 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 1 900 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 nearly 25 years of production, a little over half of the field reserves have been produced. All the fields in the Ekofisk area were originally developed with depressurization as the drive mechanism, but for Ekofisk, limited gas injection and comprehensive water injection has contributed to a considerable increase in the rate of recovery of oil, from the original approximately 18% to 40%. 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 130,000 m^3 of water is distributed in the reservoir through 36 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. A trial project with alternating water/gas injection was implemented in 1996 in order to evaluate the possibility of further increasing oil recovery from the field.

The subsidence of the seabed in the Ekofisk area causes problems for the older installations. Satellite measurements show a total subsidence as of December 1996 of 7.1 meters at Ekofisk H. Figure 1.4.4.c shows the measured subsidence values at 2/4-H during the period 1985-1996. The subsidence rate in 1996 was approximately 38 cm per year. In order to limit the subsidence and well problems related to compaction in the reservoir, the depletion of oil and gas from the field during recent years has been balanced with injection of corresponding or larger volumes of water and gas. So far this has not resulted in any noticeable decrease in the subsidence.

Figure 1.4.4.c
Subsidence at Ekofisk Complex



Development

Figure 1.4.4.b shows the installations in the Ekofisk area. In all there are around 25 different installations connected to the fields in the area. 2/4-K and 2/4-W are water injection installations for Ekofisk. Oil and gas are routed from the fields 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 over 95,000 Sm^3 per day. Sales metering of oil, NGL and natural gas is carried out at the terminals in Teesside and Emden. Total oil and gas deliveries to the Teesside and Emden pipelines from the area are metered and analyzed at the Ekofisk tank. In addition, the oil and gas production is metered at the individual satellite installations prior to pipeline transpor-

tation to the Ekofisk Center, with the exception of production from the Vest Ekofisk and Ekofisk fields which is metered at the Ekofisk tank. All metering systems comply with fiscal standards and are incorporated in the operator's system for hydrocarbon distribution.

In August 1996, a new drilling and wellhead installation for 50 wells, 2/4-X, was placed on the field. The first new production wells are being drilled now. In 1998, a new process and transportation installation will be installed. Both installations will be scaled to withstand a further 12 meters of subsidence of the seabed. Several of the old installations will be shut down and parts of these will be removed in the years to come.

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 1996-NOK):	NOK 2,5 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 42 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, and the field is now in its final stages.

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 by the time Ekofisk II is completed in 1998.

Albuskjell

Production license: 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 1996-NOK):	NOK 8 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 127 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 drive mechanism, and the field is now in its final stages.

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 by October 1998.

Tor

Production licenses: 018 and 006	**Blocks:** 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:	25,5 million Sm^3 oil 11,4 billion Sm^3 gas 1,2 million tonnes NGL
Total investments (firm 1996-NOK):	NOK 6,1 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 162 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. Nearly 4500 m^3 water is injected daily in two wells on the field. The water injection equipment will be upgraded in 1997 and the water injection is expected to last throughout the lifetime of the field.

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 2011.

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 1996-NOK):	NOK 3,3 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 78 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.

Development
Cod is developed with a manned wellhead installation with equipment for water separation. Gas and oil are sent in a common pipeline to the Ekofisk Center. Gas from the Ula field is transported to Cod for further transportation on to Ekofisk. Cod will be shut down before Ekofisk II is completed in 1998.

1.4.5 GYDA SØR AND GYDA

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 AS		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		30,0 mill Sm^3 oil 3,7 billion Sm^3 gas 1,6 million tonnes NGL
Gyda Sør		2,1 million Sm^3 oil 1,1 billion Sm^3 gas 0,3 million tonnes NGL
Total investments (firm 1996-NOK):		
Gyda og Gyda Sør		NOK 9,3 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:		
Gyda og Gyda Sør		NOK 351 million

Production - Gyda
The reservoir is made up of Upper Jurassic sandstone. Gyda is produced using water injection as the drive mechanism. At end-1996, 13 wells were producing, while 10 wells were used for water injection.

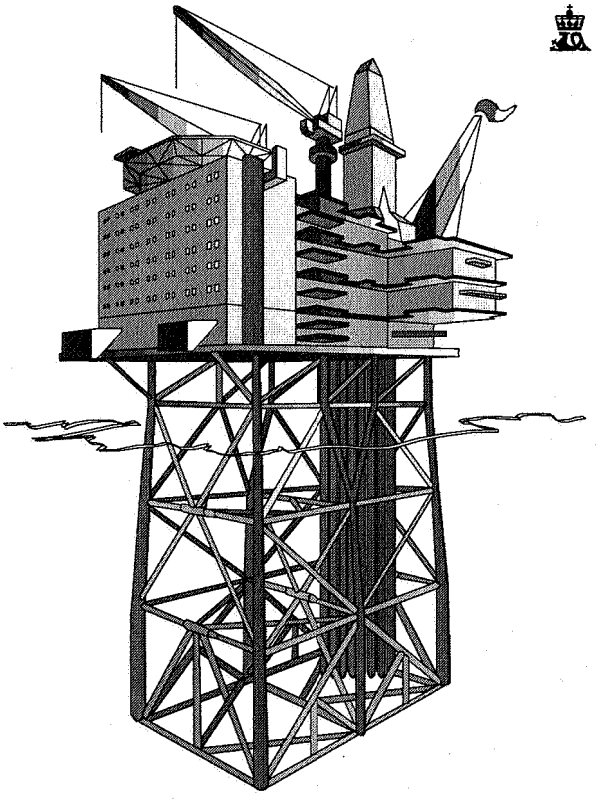
Development - Gyda
The development solution for the field consists of a combined drilling, living quarters and processing installation with a steel jacket, see Figure 1.4.5. Production capacity is currently 14,300 Sm^3 oil per day and 1.8 million Sm^3 gas per day. Water injection capacity is 24,500 m^3 per day.

The oil is transported to Ekofisk via the oil pipeline from Ula, and then on to Teesside. The gas is transported 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 a long-range well 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.

Development - Gyda Sør
The production well from the Gyda installation to Gyda Sør has a horizontal range of approximately 5,700 meters. The wellstream is treated in existing facilities on Gyda.

Figure 1.4.5
Installation on Gyda

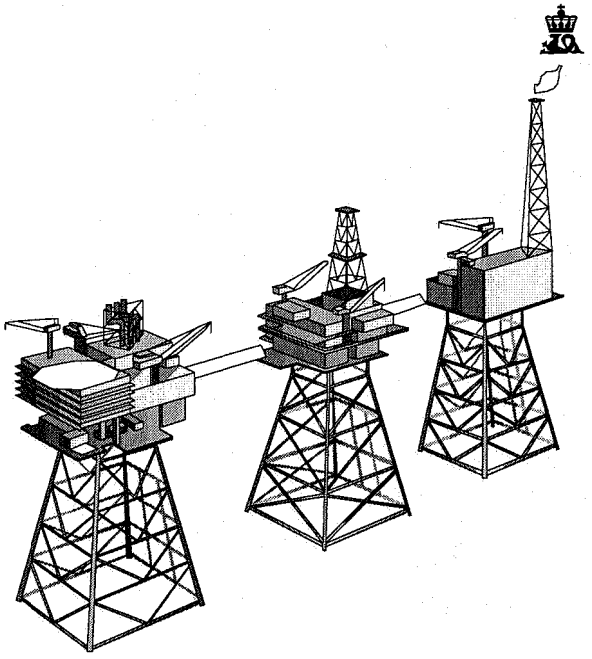


1.4.6 ULA

Production license:	019A	**Block:** 7/12
Operator: BP Petroleum Dev. of Norway AS		
Licensees:		
BP Petroleum Dev. of Norway AS		57,50000 %
Svenska Petroleum Exploration AS		15,00000 %
Den norske stats oljeselskap a.s		12,50000 %
Norske Conoco A/S		10,00000 %
AS Pelican		5,00000 %
Discovery well:	7/12-2	Year: 1976
Development approved:	1980	Prod.start: 1986
Recoverable reserves:		69,2 mill Sm^3 oil 3,6 billion Sm^3 gas 2,6 million tonnes NGL

Total investments (firm 1996-NOK):	NOK 13,3 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 392 million

Figure 1.4.6
Installations on Ula



Production
The reservoir consists of Jurassic sandstone and is produced using water injection as the drive mechanism. The water front is advancing from the north and east towards the central parts of the field, and production now has a high and increasing amount of water. At the end of 1996, there were 8 wells producing while 7 wells were used for water injection.

The operator plans to implement WAG (alternating water/gas injection) on Ula during 1997.

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.

Development
The development concept consists of three steel installations for production, drilling and living quarters respectively, see Figure 1.4.6. Production capacity is currently 24,000 Sm^3 oil per day and 1.6 million Sm^3 gas per day. Water injection capacity is 32,000 m^3 per day. The capacity for treatment of produced water is approximately 19,000 m^3 per day. All produced water on Ula is reinjected.

The oil is transported by pipeline via Ekofisk to Teeside. Statoil is the operator of the pipeline. 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 transport to Ekofisk. The metering systems are included in the Ekofisk system for distribution of hydrocarbons.

1.4.7 YME

Production licenses:	114 and 114B	**Blocks:**	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:			8,7 million Sm^3 oil
Total investments (firm 1996-NOK):			NOK 1,5 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:			NOK 595 million

Production
Development of the Yme field will be carried out in several phases.

The main reservoir on Yme is in the Gamma Vest structure which is covered under Phase I. Here oil is found in the Sandnes formation, which is from the Middle to Late Jurassic Age. The reservoir will for the most part be produced by depressurization, but limited water injection and the use of downhole pumps is also planned.

Phase II entails draining the resources in an adjacent structure (Beta Øst) as well as extended production from Gamma Vest. The plan for development and operation of Phase II was approved in the autumn of 1995. Yme Beta Øst is produced with two subsea-completed wells. Depressurization with gas lift has been chosen as the drive mechanism. Production from Beta Øst will lead to an extended production period from Yme Gamma Vest and thereby increased recovery from this reservoir.

Phase III comprises the plan for development and operation of Yme Gamma Sørøst which was submitted to the authorities in December 1996. The plan covers completion of and production from well 9/2-6 S, where the operator made a discovery in October 1996. The discovery was made in the first of several prospects which may be included in Phase III. The operator plans to drain 9/2-6 S Yme Gamma Sørøst using depressurization.

At the end of 1996 there were five 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.

Development concept
The field development concept consists of a jack-up installation and a storage tanker with buoy loading to shuttle tankers. 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 Sm^3 per day (0.25 million Sm^3 per month) with the possibility of upgrading. The gas treatment capacity is 800,000 Sm^3 gas per day, whereof 400,000 Sm^3 gas per day may be recirculated for gas lift.

1.4.8 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:	1994
Development approved:	1996	Prod.start:	1998
Recoverable reserves:			10,7 million Sm^3 oil
Total investments (firm 1996-NOK):			NOK 3,1 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:			NOK 220 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. In the autumn of 1996, a well was drilled (15/12-10 S) on the northern part of the field which discovered oil in sand with extremely poor reservoir quality.

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 wells will be drilled with a jack-up drilling installation. The production capacity is 9000 Sm^3 oil per day.

1.4.9 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:			41,5 billion Sm^3 gas 27,3 million tonnes NGL
Total investments (firm 1996-NOK):			NOK 24,1 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:			NOK 550 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 Sm^3 gas 1,5 million tonnes NGL
Total investments (firm 1996-NOK):			NOK 0,66 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:			NOK 3 million

Sleipner Vest

Production licenses:	046 and 029	**Blocks:**	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:			129,4 billion Sm^3 gas 33,7 million tonnes NGL
Total investments (firm 1996-NOK):			NOK 17,5 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:			NOK 680 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:			2,1 billion Sm^3 gas 0,9 million tonnes NGL
Total investments (firm 1996-NOK):			NOK 0,22 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:			NOK 133 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 amount 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. In 1996, the gas-condensate ratio in the production wells has risen less than expected so that the production of condensate has been somewhat higher than the prognosis.

Loke contains gas/condensate in reservoirs of the Tertiary and Triassic Age. The Tertiary reservoir in Loke is in pressure communication with the Tertiary reservoir in Sleipner Øst. The Tertiary reservoir in Loke is drained with one well, which will subsequently be extended for production from the Triassic reservoir.

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 % 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 plans to drill one or two of the gas production wells in order to obtain more information.

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.

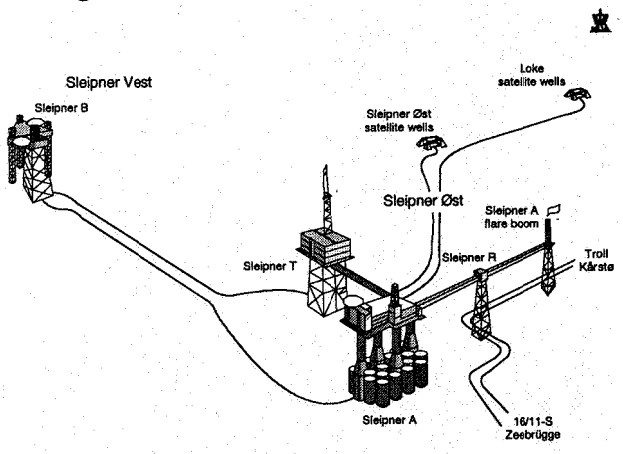
The first phase of the development of Sleipner Vest includes a wellhead installation, Sleipner B, and an installation for processing and removal of CO_2, Sleipner T. Sleipner B is located in the southern part of Sleipner Vest with wellstream transfer to Sleipner T, which has a gangway connection with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

The production facilities in the Sleipner area are shown in Figure 1.4.9.

As of December 1996, 14 wells were producing on Sleipner A, and gas is injected in five wells. In addition, there is a well for injection of CO_2 which is separated from the Sleipner Vest gas. On Sleipner B, six gas-producers are in operation.

An agreement has been signed concerning sales and injection cooperation among the Sleipner fields. Sleipner Vest has been allocated gas sales in connection with the

Figure 1.4.9
Existing installations in the Sleipner area



contracts which were signed in 1991 in connection with the exercise of the 30% options under the Troll gas sales agreement. The gas is transported via pipeline both to Zeebrügge in Belgium and through Statpipe/Norpipe and the Europipe system to Emden in Germany. The licensees plan to apply for new gas allocation for the fields in the Sleipner area in 1997.

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

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

1.4.10 BALDER

Production licenses: 001 and 028	**Blocks:** 25/11 and 25/10
Operator: Esso Exploration and Production Norway A/S	
Licensees: Esso Exploration and Production Norway A/S	100 %
Discovery well: 25/11-1	Year: 1967
Development approved: 1996	Prod.start: 1997
Recoverable reserves:	27,2 million Sm^3 oil 0,8 billion Sm^3 gas
Total investments (firm 1996-NOK):	NOK 5,073 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 350 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 longer than anticipated and production start is now expected in the summer of 1997.

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 Statpipe, and the plan is now to inject gas for a period of time while the final solution is resolved.

Five production wells and a gas injector have been pre-drilled and 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).

1.4.11 HEIMDAL

Production license: 036 **Block:** 25/4

Operator: Elf Petroleum Norge AS

Licensees:

Den norske stats oljeselskap a.s. (Statoil) (SDFI 20 %)	40,00000 %
Marathon Petroleum Norge AS	23,79800 %
Elf Petroleum Norge AS	21,51400 %
Norsk Hydro Produksjon AS	6,22800 %
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: 6,6 million Sm^3 oil, 40,5 billion Sm^3 gas

Total investments (firm 1996-NOK): NOK 14,4 billion

Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance: NOK 305 million

Production

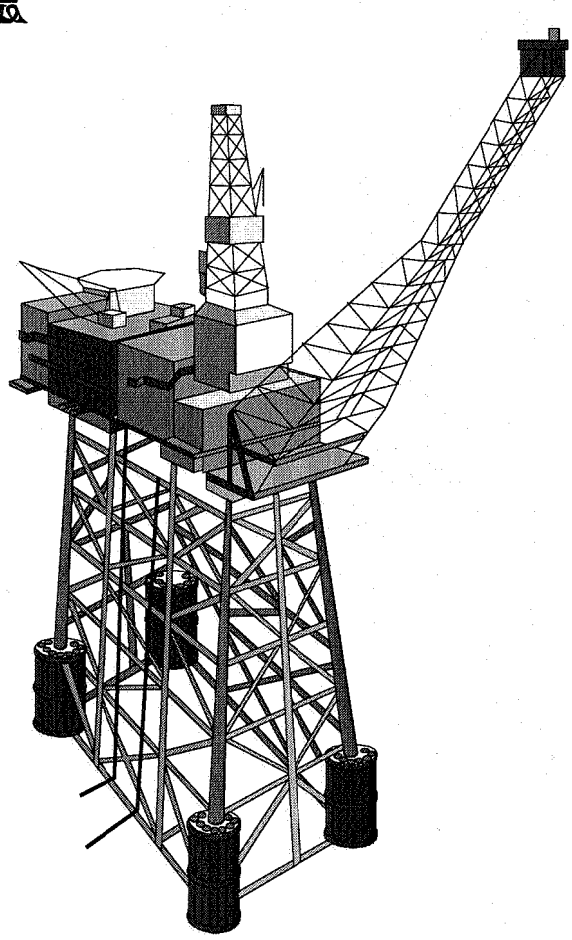
The field produces from the Heimdal formation, which consists of Paleocene sand. Ten wells have been drilled from the installation on the field, nine production wells and one observation well. Because of the powerful water drive in the field, pressure development and water ascent are both carefully monitored.

Development

The Heimdal field has been developed with an integrated steel jacket structure with combined drilling, production and living quarters functions, see Figure 1.4.11. 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 in to the Statpipe system at the Draupner riser platform. 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.

Figure 1.4.11
Installation on Heimdal



1.4.12 FRIGG AREA

Frøy

Production licenses: 026 and 102 **Blocks: 25/2 and 25/5**

Operator: Elf Petroleum Norge AS

Licensees:

Den norske stats oljeselskap a.s (Statoil) (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:		11,1 million Sm^3 oil	
		2,3 billion Sm^3 gas	
		0,2 million tonnes NGL	
Total investments (firm 1996-NOK):		NOK 5,7 billion	
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:		NOK 137 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, whereof 6 are production wells. Some of these have not been operative in periods due to problems in connection with water production. The operator has reduced the 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 expenses and the risk of unprofitable operations.

Development

The field was developed by means of a wellhead installation. Oil and gas are transferred in separate pipelines to Frigg for further processing and metering. Capacity studies have shown that it is possible to treat up to 7000 Sm^3 oil per day. The field is well-controlled and has produced 4-6000 Sm^3 per day in 1996. 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 1.4.12.a shows an overview of the fields and discoveries in the Frigg area.

Øst Frigg

Production licenses:		**Blocks:**	
024, 026 and 112		**25/1 and 25/2**	
Operator: Elf Petroleum Norge AS			
Licensees:			
Elf Petroleum Norge AS		37,22500 %	
Norsk Hydro AS		32,11200 %	
Total Norge AS		20,23200 %	
Den norsk stats oljeselskap a.s (Statoil) (SDFI 1,4613 %)		10,43100 %	
Discovery well 25/2-1		Year:	1973
Development approved:	1984	Prod.start:	1988
Recoverable reserves:		9,5 billion Sm^3 gas	
Total investments (firm 1996-NOK):		NOK 2,9 billion	
Operating costs 1996 incl. CO_2 tax, excluding 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 has 5 production wells, whereof one has been permanently shut down. 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:			
Elf Petroleum Norge A/S		41,42000 %	
Den norske stats oljeselskap a.s (Statoil)		5,00000 %	
Total Norge A/S		20,71000 %	
Norsk Hydro Produksjon a.s		32,87000 %	
Discovery well:	25/2-4	Year:	1975
Development approved:	1991	Prod.start:	1994
Recoverable reserves:		1,6 million Sm^3 oil	
		3,5 billion Sm^3 gas	
Total investments (firm 1996-NOK):		NOK 4,1 billion	
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:		NOK 40 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. During extended periods last year, only one well was producing 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 been cut in half over the last two years 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 wellstream is transferred under high pressure directly to Frigg for processing. The gas is further transported via pipeline to St. Fergus. Stabilized condensate is transported via Frostpipe 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 norsk stats oljeselskap a.s (Statoil)	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:	
0,4 million tonnes NGL (Norwegian share)	
111,9 billion Sm^3 gas (Norwegian share)	
Total investments (firm 1996-NOK):	approx. NOK 26 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 415 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 1996. All of these have reduced production potential due to water influx in the wells. 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 2000. 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 1 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 1 started in 1977.

Phase 2 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 1.4.12.b shows the installations in the Frigg area.

Phase 3 of the development comprises the installation of three turbine-driven compressors on TCP2. The compressor system is necessary 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 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 platform. TCP2 has been modified to adapt the compressor facilities to altered pressure conditions and reduced gas volumes.

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.

Figure 1.4.12.a
Fields and discoveries in the Frigg area

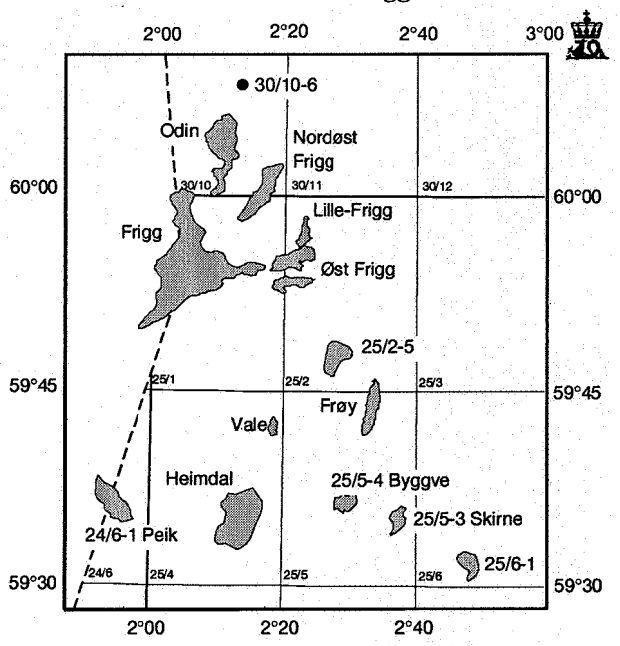
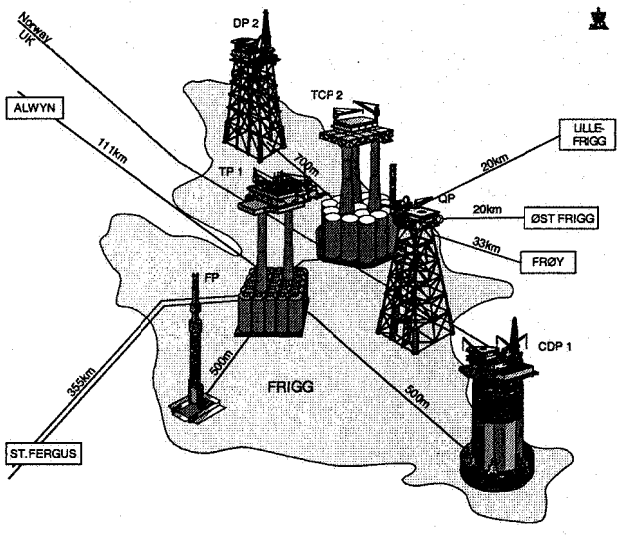


Figure 1.4.12.b
Installations in the Frigg area



1.4.13 OSEBERG AREA

Oseberg Vest

Production license:	**053**	**Block:**	**30/6**
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s (Statoil) (SDFI 45,400 %)			59,40000 %
Norsk Hydro Produksjon AS			12,25000 %
Saga Petroleum ASA			7,35000 %
Elf Petroleum Norge AS			9,33300 %
Mobil Development Norway AS			7,00000 %
Total Norge AS			4,66700 %
Discovery well:	30/6-15	Year:	1984
Dev. approved: Phase I	1988	Prod.start:	1991
Recoverable reserves:	1,8 million Sm^3 oil 7,5 billion Sm^3 gas 0,2 million tonnes NGL		
Total investments (firm 1996-NOK):			NOK 980 million
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:			NOK 17 million

The licensees in Oseberg Vest and Oseberg are working on an agreement where the objective is that Oseberg Vest will be included in the unitized Oseberg field. Figure 1.4.13.b shows an overview of the fields and discoveries in the Oseberg and Troll areas.

Production

Oseberg Vest, which comprises 30/6-15 Gamma Nord, 30/6-18 Kappa and 30/6-17 A (Alpha Cook), is included in the amended development plan for the northern part of the Oseberg field. The Oseberg Vest structure lies to the west

Figure 1.4.13.a
Installations on Oseberg

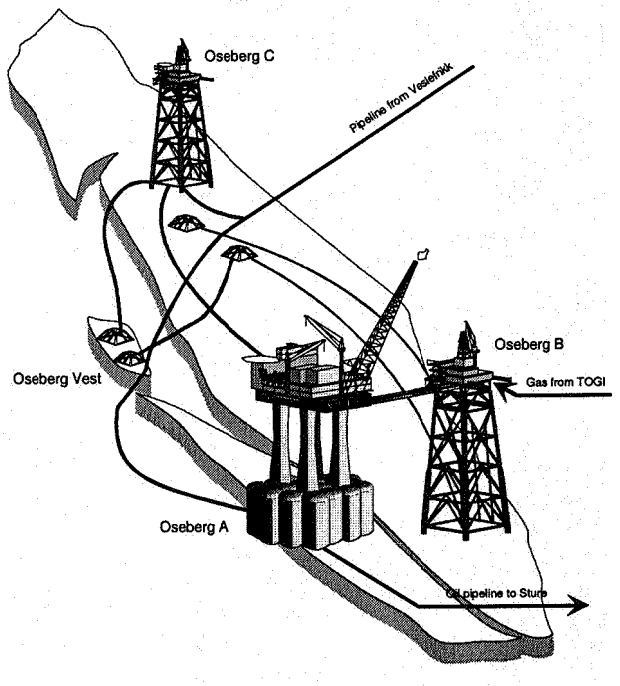
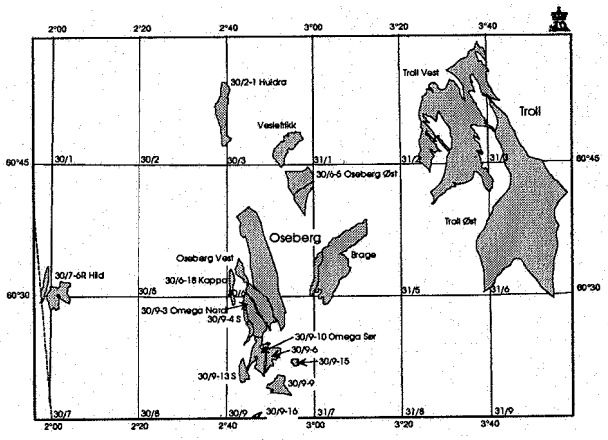


Figure 1.4.13.b
Fields and discoveries in the Oseberg and Troll area



of the Oseberg field. It is an angled fault block where the hydrocarbon-bearing zones are found in the Statfjord formation. A layer of rich, coal-bearing shale divides the Statfjord formation into an upper and a lower reservoir zone. Gas was proven first with a thin oil zone in the upper part of Statfjord. In order to produce as much of the oil as possible before the gas is depleted, a horizontal production well was chosen. In connection with the drilling of this well, oil was also discovered in the lower part of the reservoir. The production well is a subsea completed well linked to Oseberg C.

Development

Well no. 2 on Oseberg was completed in 1996. The flow from this well is led to Oseberg B. Further processing and simplified fiscal metering is carried out on Oseberg A. All gas which is produced is injected into the Oseberg field.

The Oseberg field

Production licenses:	**053 and 079**	**Blocks:**	**30/6, 30/9**
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s (Statoil) (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:		Prod.start:	1988
Phase I	1984		
Phase II	1988		
Phase III	1996		
Recoverable reserves:			319,3 million Sm^3 oil 88,9 billion Sm^3 gas 6,0 million tonnes NGL
Total investments (firm 1996-NOK):			NOK 52 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:			NOK 1150 million

Production

The first discovery showed gas in 1979, while subsequent drilling showed 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

The Oseberg field was developed in two phases, see Figure 1.4.13.a. Phase 1 was 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 in to the field center. Average oil processing capacity is about 55,000 Sm^3 per day.

Phase 2 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. The licensees plan to apply for expanded gas allocation for Oseberg in 1997.

Oseberg A and Oseberg C are equipped with metering stations for fiscal metering of stabilized oil prior to pipeline transport to Stura. Purchase of 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.

Oseberg Øst

Production license:	**053**	**Block:**	**30/6**
Operator:	Norsk Hydro Produksjon AS		
Licensees			
Den norske stats oljeselskap a.s (Statoil) (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 1,4 billion Sm^3 gas
Total investments (firm 1996-NOK):			NOK 3,7 billion
Anticipated operating costs at plateau incl. CO_2 tax, excl. tariffs and insurance			NOK 200 million

Production

The field (see Figure 1.4.13.b) consists of two structures which are separated by a sealed fault. Four wells have been drilled on the field. 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 intent 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 m^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.

1.4.14 BRAGE

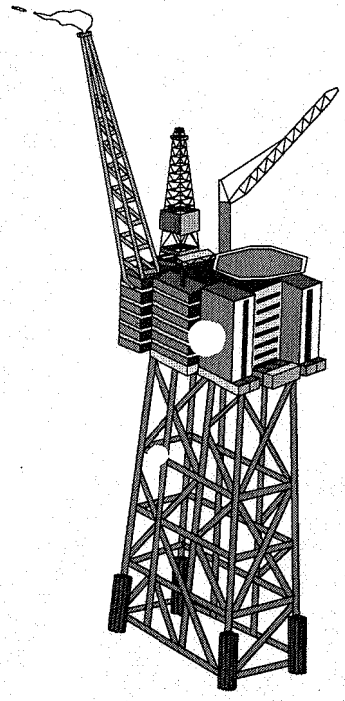
Production licenses:		**Blocks:**	
053, 055 and 185		**30/6, 31/4, 31/7**	
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap a.s (Statoil) (SDFI 34,2567 %)			46,95680 %
Norsk Hydro Produksjon AS			22,41820 %
Esso Expl and Prod Norway A/S			16,34340 %
Neste Petroleum AS			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
Dev. approved: Phase I	1990	Prod.start:	1993
Recoverable reserves:			46,6 million Sm^3 oil 1,4 billion Sm^3 gas 0,5 million tonnes NGL
Total investments (firm 1996-NOK):			NOK 10,5 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:			NOK 455 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 is planned in the summer of 1997. 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 1.4.14. 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 1.4.14
Installation on Brage



1.4.15 VESLEFRIKK

Production license:	**052**	**Block:**	**30/6**

Operator: Den norske stats oljeselskap a.s (Statoil)

Licensees:	
Den norske stats oljeselskap a.s (Statoil) (SDFI 37 %)	55,00000 %
Total Norge AS	18,00000 %
Deminex Norge AS	11,25000 %
Norsk Hydro Produksjon AS	9,00000 %
Svenska Petroleum Exploration AS	4,50000 %
Norske Deminex AS	2,25000 %

Discovery well:	30/3-2	Year:	1980
Development approved:	1987	Prod.start:	1989

Recoverable reserves: 54,4 million Sm^3 oil
2,6 billion Sm^3 gas
1,0 million tonnes NGL

Total investments (firm 1996-NOK):	NOK 10,2 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:	NOK 506 million

The field is located southeast in block 30/3, see Figure 1.4.13.b.

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. It has been decided to use WAG injection in the main field.

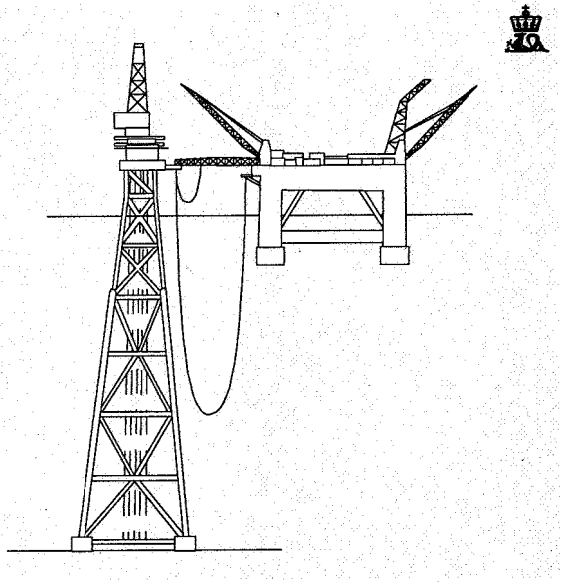
Production start from the Statfjord formation is planned for 1997. The plan is to drain the reservoir with a horizontal producer, and the recovery will be increased by recirculating the gas in a horizontal injector. The Statfjord formation has a gas cap and a higher content of associated gas than the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

A small discovery was made during the drilling of well 30/3-7 S in 1995. Testing will take place 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 1.4.15. 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 transportation system for transport to the Stura 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 1.4.15
Installation on Veslefrikk



1.4.16 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 a.s			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:			113.9 million Sm^3 oil 854.8 billion Sm^3 gas
Total investments (firm 1996-NOK):			NOK 61.784 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance			NOK 1784 million

Structurally, the Troll field lies on the northwestern part of the Horda platform. The field mainly 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 sandstones, mainly 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 occurred in several phases. The Troll field was unitized in 1986.

TOGI

The subsea system Troll Oseberg Gas Injection (TOGI) is controlled from the Oseberg Field Center and takes care of production and delivery of 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 1996, TOGI had delivered approximately 17 billion Sm^3 gas to Oseberg. In all, the agreement comprises delivery of 25 billion Sm^3 gas over an 11-year period. 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 East

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. Drilling of production wells started in September 1995. By the end of 1996, 15 out of a total of 39 gas producers had been drilled from the Troll A installation. Testing and cleaning of wells commenced in February 1996.

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 is sold. The pressure development will be very dependent on future gas allocations to Troll. The oil production from Troll Vest gas province will have consequences for the gas strategy on the field. Work is in progress to find an optimal production strategy for oil and gas on the Troll field.

Development

The gas reserves in Troll Øst are produced from Troll A, which is a permanent wellhead installation with concrete substructure. The wellstream is mixed with gas from the oil production in Troll Vest prior to transfer via two multiphase 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 transportation to the market. The condensate will be flow-metered through 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 gas capacity of approx. 89 million Sm^3 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 western part of the field, with a 22-26 meter oil column under a small gas cap. Production started in September 1995 from seven predrilled wells, and the plateau rate of 30,000 Sm^3 oil per day was quickly achieved. Up to the end of 1996, 14 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 (well clusters) 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 production of gas from both Troll Øst and Troll Vest. The development will take place in stages, as it is important to acquire some production experience from the area before a decision is made as to further oil development of the entire gas province.

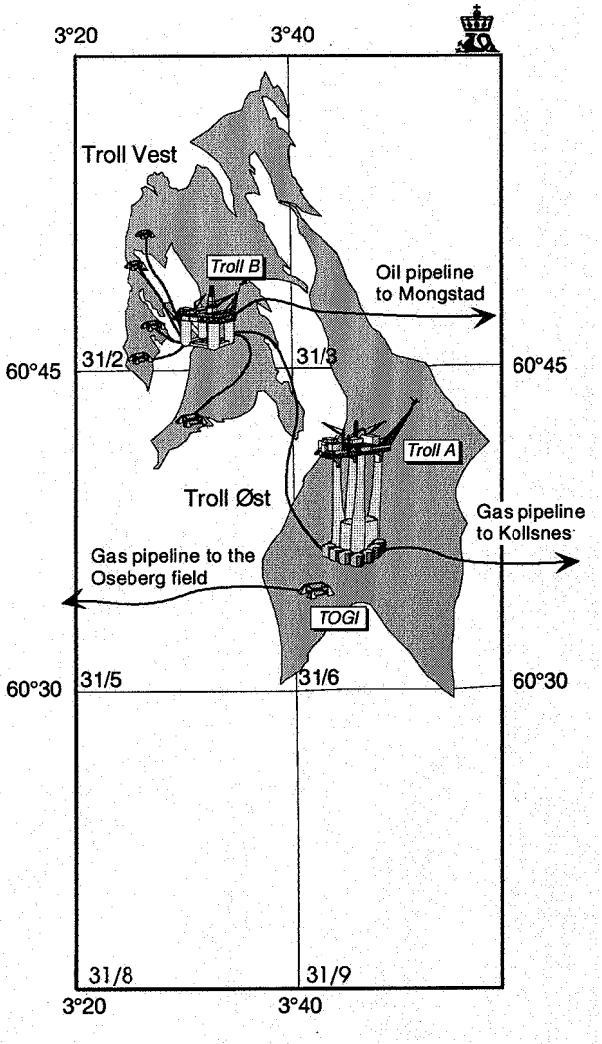
The plans for development and operation of the first two subsea installations in the southern part of the Troll Vest gas province (the H cluster and well group I) were approved by the authorities in May 1994 and October 1996 respectively. Production from the H cluster started in November 1995 and experience so far is better than expected. At the end of the year, four wells were producing. Planned production start-up for well group I is October 1997. In all, these two developments will include 12 horizontal production wells.

A continued plan for development and operation of the oil in Troll Vest gas province was submitted to the authorities in the autumn of 1996. The development plan includes nine subsea installations (well groups) with a total of 50 horizontal production wells, whereof several multi-path 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. Planned production start for this development is July 1998 for Troll B and September 1999 for Troll C.

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. The well clusters are connected to the riser foundation on the installation via two parallel pipelines. A total of nine well clusters will be connected to Troll B. Necessary modifications must be carried out on the installation before production lines from the new well areas in the gas province can be connected. With small modifications on the Troll B installation, so far it has been possible to increase the production level gradually from 30,000 to 40,000 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 1.4.16.

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 land, 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.

Fig. 1.4.16
The Troll field



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. Already determined and future recovery of the oil resources is time-critical in relation to production of gas from Troll. It is uncertain when major gas production from Troll Vest should start. The gas production from Troll Vest should be limited somewhat during the first years due to consideration for the oil production. Later, this can be increased gradually so that the gas production from east and west may be concluded at about the same time. Decisions concerning further development of the oil resources in Troll Vest in 1996/1997, as well as the Troll field's total commitments and physical delivery capability for gas, seen in context with gas supply solutions for the Norwegian shelf, will provide indications for the final timing of decisions regarding development of Troll Phase III.

1.4.17 GULLFAKS AREA

Rimfaks

Production licenses:	050 and 050B	**Blocks:**	34/10 and 33/12
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 a.s			6.00000 %
Discovery well:	34/10-17	Year:	1973
Development approved:		Prod.start:	1998
Phase I	1996		
Phase II			
Recoverable reserves:			18.9 million Sm^3 oil/condensate
Total investments (firm 1996-NOK): (Phase I)			NOK 2.76 billion
Anticipated operating costs at plateau incl. CO_2 tax, excluding tariffs and insurance			NOK 122 million

Production

Rimfaks, which lies approx. 15 kilometers southwest of Gullfaks, (see Figure 1.4.17.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 portion 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 Brent reservoir contains an oil column of about 40 meters in addition to a large gas cap with high condensate content. The Statfjord reservoir has an oil column.

The plan for development and operation of Phase 1, which comprises the liquid phase, was approved in 1996 together with Gullfaks Sør and Gullveig. Phase 2, 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. The processing of the wellstream will take place on Gullfaks A. Production start is planned for 1998. The field is expected to produce 13,500 Sm^3 per day oil/ condensate which will be stored on Gullfaks A and shipped. The gas from the field will be reinjected on the field and the initial plan is for gas injection capacity of 7.5 million Sm^3 per day. Rimfaks also receives gas from Gullfaks Sør for injection.

Gullveig

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:	34/10-37	Year:	1995
Development approved:		Prod.start:	1998
Phase I	1996		
Phase II			
Recoverable reserves:			2.1 million Sm^3 oil/condensate
Total investments (firm 1996-NOK): (Phase I)			NOK 0.39 billion
Anticipated operating costs at plateau incl. CO_2 tax, excluding tariffs and insurance			NOK 10 million

Production

The plan is to produce Gullveig 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. Processing of the wellstream will take place on Gullfaks A.

Gullfaks Sør

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:	34/10-2	Year:	1979
Development approved:		Prod.start:	1998
Phase I	1996		
Phase II			
Recoverable reserves:			20.7 million Sm^3 oil/condensate 2.1 billion Sm^3 gas
Total investments (firm 1996-NOK): (Phase I)			NOK 3.37 billion
Anticipated operating costs at plateau incl. CO_2 tax, excluding tariffs and insurance			NOK 95 million

Production

Gullfaks Sør lies 9 km to the south of Gullfaks, see Figure 1.4.17.a, and contains oil and gas in sandstone from the Jurassic and Triassic Ages.

The Brent reservoir contains both gas and oil, and several independent gas/oil and oil/water contacts have been observed. The Statfjord reserve has a thicker oil zone than Brent with a small gas cap. Ten wells have been drilled to reservoir level on Gullfaks Sør.

The plan for development and operation for Phase 1, which comprises the liquid phase, was approved in 1996 together with Rimfaks and Gullveig. Phase 2, which consists of the gas phase, is not covered under this plan. The licensees plan to seek gas allocation in 1997.

Development

The plan is to develop the field using gas injection and the development concept includes 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 is planned for 1998. The field is expected to produce 13,000 Sm^3 per day oil/ condensate which will be stored on Gullfaks and shipped. The gas will be reinjected in the field and in Rimfaks. The initial gas injection capacity is planned to be 2.7 million Sm^3 per day.

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	December 1986	
Phase II	1985		
Gullfaks Vest	1993		
Lunde formation	1995		
Recoverable reserves: **Gullfaks**		307.7 million Sm^3 oil 23.0 billion Sm^3 gas 2.4 million tonnes NGL	
Rec. reserves: **Gullfaks Vest**		3.1 million Sm^3 oil	
Total investments (firm 1996-NOK):			
Gullfaks		NOK 73.9 billion	
Gullfaks Vest		NOK 0.2 billion	
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance		NOK 2129 million	

Production

The Gullfaks field (see Figure 1.4.17.a) contains oil in sandstone from the Jurassic and Triassic Ages. The reservoir lies relatively shallow, and is made up of several angled and rotated fault blocks. The blocks have variable slope degrees and parts of the area are heavily eroded. The field is complicated to develop, inter alia because of many faults.

The reservoirs in Phase 1 and 2 are separated by a north-south fault. Some communication across the faults 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 Lunde formation is located to the east of and under the other reservoirs.

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 90. Future sidetracks are planned from several of the existing production wells.

Based on the basis reserves, the last production years for Gullfaks A, B and C are 2011, 2006 and 2007, 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 in block 34/10, to the northwest of Gullfaks, see Figure 1.4.17.a. Production is based on natural water drive.

Development

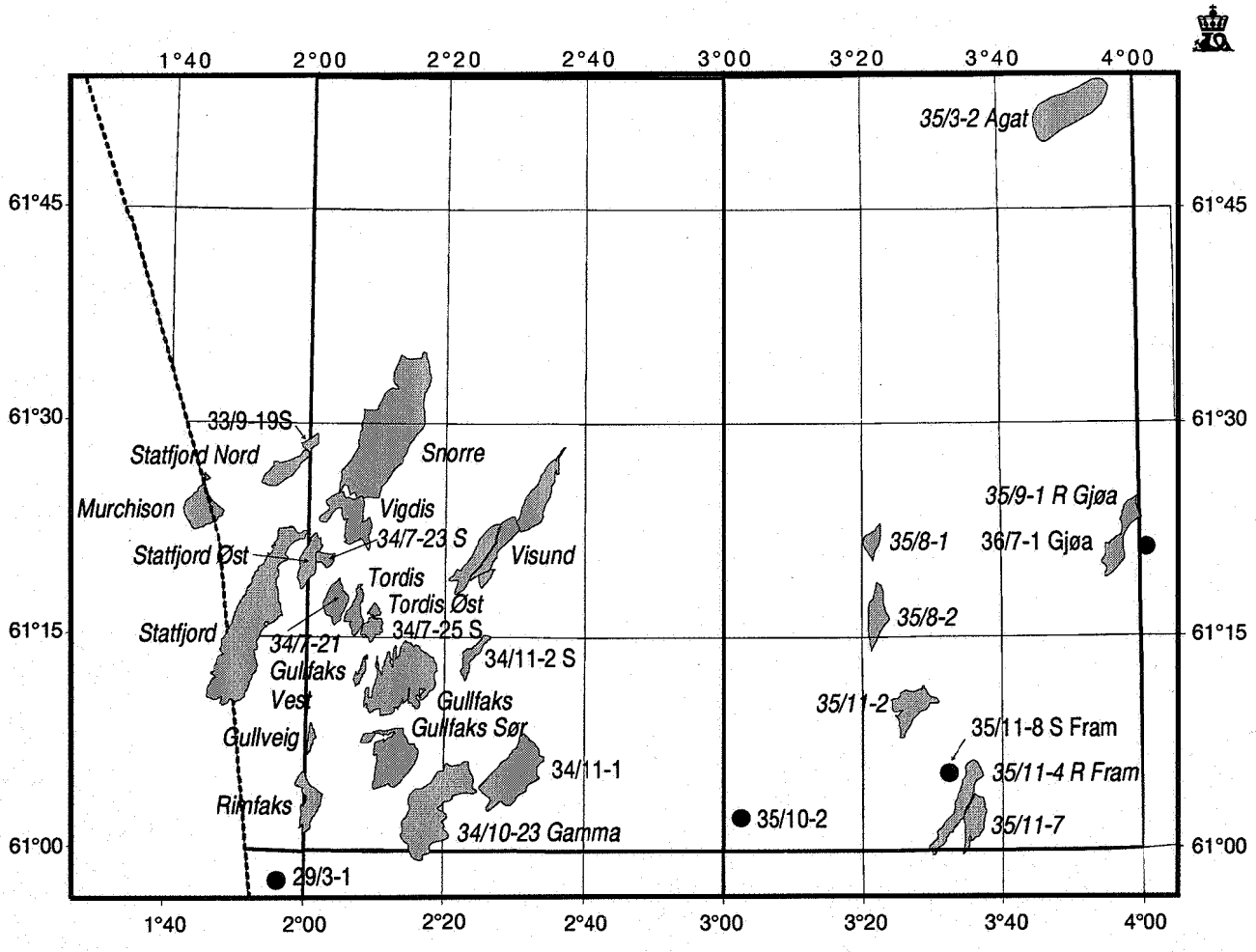
The A and B installations are both Condeep-type concrete gravity base structures with steel frame topside, see Figure 1.4.17.b. The C installation is basically built as a copy of Gullfaks A. All three are fully-integrated process, drilling and living quarters installations, while Gullfaks B has a simplified process facility with only first stage separation.

Gullfaks A, which is placed on the southwestern part of the field, started production in December 1986. Processing 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 located 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. In addition, water can be transferred from Gullfaks A for injection.

Gullfaks C was placed on the eastern part of the field for production from the reserves in Phase 2. 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.

Fig. 1.4.17.a
Fields and discoveries in the Gullfaks, Statfjord and Snorre area



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 B. 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 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.

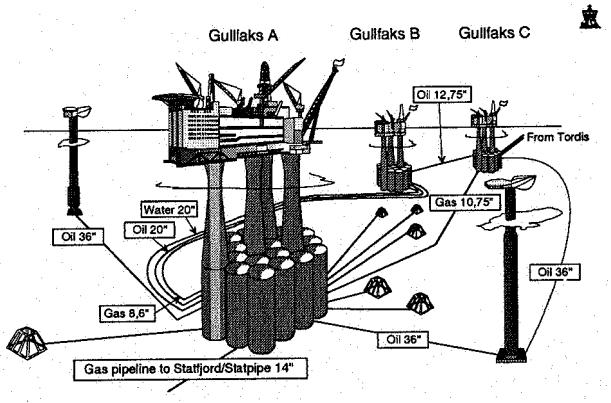
Gullfaks as infrastructure

In addition to Gullfaks Vest, the installations 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 in to Gullfaks C. In 1994, it was decided that completely processed oil from Vigdis (via Snorre) should be delivered to Gullfaks A for storage and loading to tankers. A similar agreement for Visund was made in December 1995.

A plan for the development and operation of the oil resources in Gullfaks Sør, Rimfaks and Gullveig was submitted in December 1995. According to the plan, these discoveries will be tied in to Gullfaks A. In 1995, the Gullfaks licensees, production license 050, were awarded previously relinquished areas of block 34/10. There are also other discoveries which may be candidates for development in connection with Gullfaks. The Gullfaks installations can also be used for new discoveries in this area.

Fig. 1.4.17.b
Installations on Gullfaks



1.4.18 STATFJORD AREA

Statfjord

Production license:	037 **Blocks:** 33/9 and 33/12
Operator:	Den norske stats oljeselskap a.s [1]
Licensees:	
Norwegian part (85.46869 %)	
Den norske stats oljeselskap a.s	42.734348 %
Mobil Development Norway AS	12.820304 %
Norske Conoco A/S	9.437169 %
Esso Expl. & Prod. Norway A/S	8.546869 %
A/S Norske Shell	8.546869 %
Saga Petroleum a.s.	1.602534 %
Amerada Hess Norge AS	0.890300 %
Enterprise Oil Norwegian AS	0.890300 %
British part (14.53131 %)	
Conoco North Sea Inc.	4.843769 %
BP Petroleum Development Ltd.	4.843769 %
Chevron U.K. Ltd.	4.843769 %
Discovery well:	33/12-1 Year: 1974
Development approved:	1976 Prod.start: 1979
Recoverable reserves:[2]	535.0 million Sm^3 oil 53.9 billion Sm^3 gas 15.1 million tonnes NGL
Total investments (firm 1996-NOK):	NOK 78.919 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance	NOK 2282 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. A smaller portion of the field extends onto the British continental shelf. The reservoirs on the Statfjord field consist of sandstone from the Brent group, the Cook formation and the Statfjord formation.

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, the operator will evaluate whether the production strategy in lower Brent should be changed.

The Statfjord formation has been produced with the aid of pressure support from gas injection. In lower Statfjord, the operator has now concluded upflank gas injection, 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 reservoirs with upflank water 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 utilization 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 1.4.18. 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 now roughly 67,000 Sm^3 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 oil 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 24,000 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 corresponding 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.

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 a.s.			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:			29.8 million Sm^3 oil 3.6 billion Sm^3 gas 0.7 million tonnes NGL
Total investments (firm 1996-NOK):			NOK 3.608 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance			NOK 58 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 by pressure maintenance assisted by water injection. A total of six production wells and three injection wells are planned. 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 1.4.18. 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.

Statfjord Øst is limited by agreements to a maximum delivery of 10,600 Sm^3 per day to Statfjord C. The water injection capacity is approx. 18,300 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.

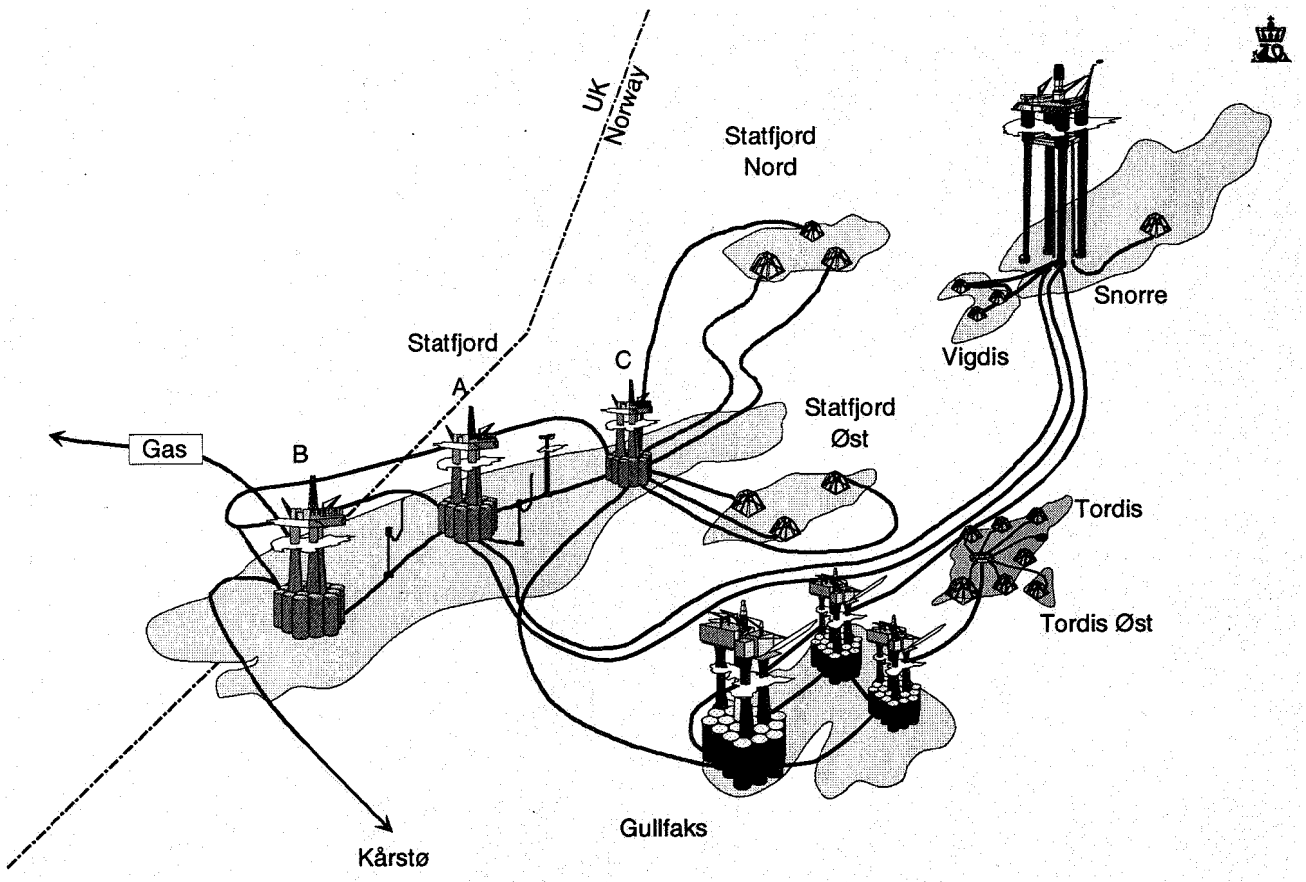
Statfjord Nord

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:			40.9 million Sm^3 oil 2.5 billion Sm^3 gas 0.5 million tonnes NGL
Total investments (firm 1996-NOK):			NOK 4.121 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance:			NOK 116 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. A total of seven production wells and three injection wells are planned. The primary drilling program will be completed in 1997.

Fig. 1.4.18
Installations and infrastructure in the Statfjord, Gullfaks and Snorre area



Development

The field is developed with subsea installations connected to the Statfjord C installation. The subsea installations consist of three templates, whereof two are for production and one for water injection, see Figure 1.4.18. The well-stream 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.

Production from the Statfjord satellites is governed by an agreement which ensures a throughput rate up to 25,000 Sm^3 per day. Since Statfjord Øst is limited to a maximum delivery of 10,600 Sm^3 per day, this means that Statfjord Nord can deliver up to 14,400 Sm^3 per day. The water injection capacity is approx. 15,000 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.

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.

1.4.19 TORDIS

Production license:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Licensees:			
Den norske stats oljeselskap (SDFI 51 %)			55.40000 %
Esso Expl. & Prod. Norway A/S			10.50000 %
Idemitsu Petroleum Norge A/S			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:		28.9 million Sm^3 oil 2.3 billion Sm^3 gas 0.7 million tonnes NGL	
Total investments (firm 1996-NOK):		NOK 4.271 billion	
Operating costs at plateau incl. CO_2 tax, excluding tariffs and insurance:		NOK 86 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 two injection wells are planned. Drilling of the injection wells has, however, been postponed for the time being as the reservoir has more natural pressure support from the water zone than expected.

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 1.4.18.

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 and analyzed, and are further treated 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.

1.4.20 TORDIS ØST

Production license:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Licensees:			
Den norske stats oljeselskap (SDFI 51 %)			55.40000 %
Esso Expl. & Prod. Norway A/S			10.50000 %
Idemitsu Petroleum Norge A/S			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:	34/7-22	Year:	1993
Development approved:	1995	Prod.start:	1997
Recoverable reserves:		5.6 million Sm^3 oil 0.4 billion Sm^3 gas 0.1 million tonnes NGL	
Total investments (firm 1996-NOK):		NOK 0.526 billion	
Operating costs at plateau incl. CO_2 tax, excluding tariffs and insurance		NOK 14 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 a production well and a water injection well. The decision on 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.

Development

The field will be developed by means of a new four-well subsea template which will be tied in to 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 tanker loading. 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 1997. 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.

1.4.21 VISUND

Production license:	120	**Blocks:**	34/8 and parts of 34/7
Operator:	Norsk Hydro Produksjon AS		
Licensees:			
Den norske stats oljeselskap (SDFI 4.96 %)			65.00000 %
Norsk Hydro Produksjon AS			12.60000 %
Elf Petroleum Norge AS			9.10000 %
Norske Conoco AS			9.10000 %
Saga Petroleum ASA			4.20000 %
Discovery well:	34/8-1	Year:	1986
Development approved:		Prod.start:	1998
Phase I	1996		
Phase II			
Recoverable reserves:		48.5 million Sm^3 oil	
Total investments (firm 1996-NOK):		NOK 7.75 billion	
Anticipated operating costs at plateau incl. CO_2 tax, excl. tariffs and insurance		NOK 475 million	

Production

The Visund field lies about 22 kilometers to the northeast of Gullfaks, see Figure 1.4.17.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 is complex, inter alia due to many faults and liquid systems.

The planned drive mechanism in the oil phase (Phase 1) is pressure maintenance through water injection and gas injection. The drilling of 23 wells is planned in Phase 1. The licensees plan to seek gas allocation in 1997. All gas will be reinjected until a gas sale 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. 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 m^3 per day. Drilling and well maintenance will be carried out from the installation. Planned production start-up is mid-1998.

1.4.22 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:		33.9 million Sm^3 oil 2.4 billion Sm^3 gas	
Total investments (firm 1996-NOK):		NOK 4.675 billion	
Operating costs at plateau incl. CO_2 tax, excl. tariffs and insurance		NOK 197 million	

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 decided to be developed, 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 potential production from the Vigdis Øst segment will be decided when the results from a new appraisal well are available.

The plan is to produce the field 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, whereof 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.

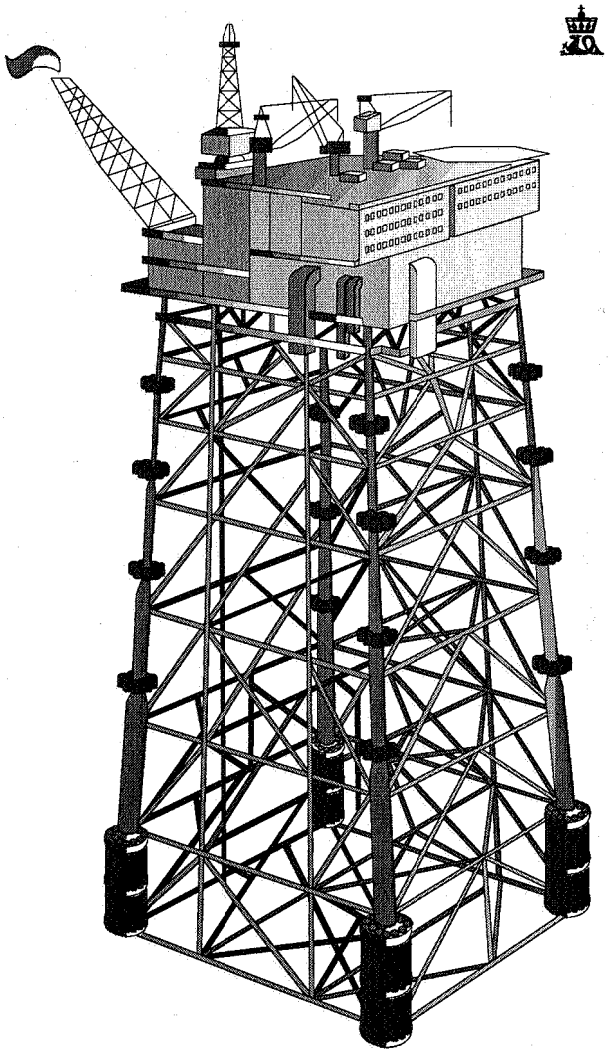
Snorre TLP will also deliver injection water to Vigdis. The capacity for water injection is estimated to be approx. 22,000 m^3 per day.

1.4.23 MURCHISON

Production license:	037	**Block:**	33/9
Operator:	Oryx UK Energy Company [1]		
Licensees:			
Norwegian part (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 A/S			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 part (77.8 %) [3]			
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]		12.8 million Sm^3 oil 0.4 billion Sm^3 gas 0.4 million tonnes NGL	
Total investments (firm 1996-NOK):		NOK 5.074 billion	
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance		NOK 81 million	

[1] Oryx took over as operator of the field on 9 January 1995.
[2] Norwegian share (22.2 %).
[3] In 1996, Chevron UK Ltd. sold its shares on Murchison to Oryx UK Energy Company and Ranger Oil UK Ltd.

Fig.1.4.23
Installation on Murchison



Production

The Murchison reservoir consists of sandstones belonging to the Brent group. The field has produced at nearly maximum fluid 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, ruined 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.

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 1.4.23.

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.

1.4.24 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:		Prod.start:	1992
Snorre Phase I	1988		
Snorre - amended plan [1]	1994		
Recoverable reserves: [2]	169.1 million Sm^3 oil 5.0 billion Sm^3 gas 2.3 million tonnes NGL		
Total investments (firm 1996-NOK): [3]	NOK 29.63 billion		
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance	NOK 814 million		

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

2) Recoverable reserves include only reserves in Snorre Phase 1 and Lunde L02-L05. Recoverable oil resources in Snorre Phase 2 are estimated to be 40.1 million Sm^3

3) Includes Snorre Phase 1 and Snorre - amended plan

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 produce the field with water injection as the drive mechanism. Based on inter alia a pilot project in 1994 with WAG (water alternating gas injection) in the Statfjord formation, a decision was made

to amend 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.

Production strategy for the northernmost fault blocks (Snorre Phase 2) is under evaluation. Based on good results from WAG in the southern areas, the operator is considering WAG as a production strategy also in the northern parts of the Snorre field.

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 1.4.24. 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.

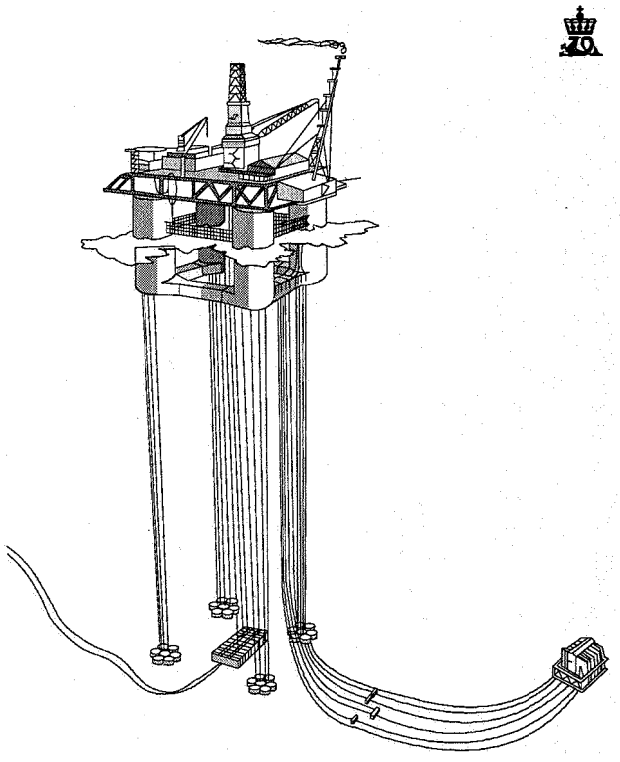
The increased reserves basis and increased need for gas injection have necessitated the upgrading of the process facilities on Snorre. Among other things, the capacity for oil processing and gas injection will be increased to 39,000 Sm^3 and 5 million Sm^3 per day, respectively. This upgrade will be completed by 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 Vigdis volumes 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. Several development solutions are being evaluated. Subsea installations connected to Snorre TLP or another installation in the area, final processing on Snorre TLP, and a separate development with a production ship are potential development alternatives. A decision regarding development concept for Phase II is expected in 1997.

Fig. 1.4.24
Installation on Snorre



1.4.25 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:		Prod.start:	
Phase I	1995		October 1997
Recoverable reserves:			37.5 million Sm^3 oil
Total investments (firm 1996-NOK):			NOK 6.556 billion
Anticipated operating costs at plateau incl. CO_2 tax, excl. tariffs and insurance			NOK 470 million

Production

The field consists of sandstones from the Early and Middle Jurassic Age and are 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 drainage mechanism for the oil-bearing eastern segment. The injection gas will mainly come from the oil production. Production experience may, however, lead to alternative drainage 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. Two wells were pre-drilled in 1996.

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.

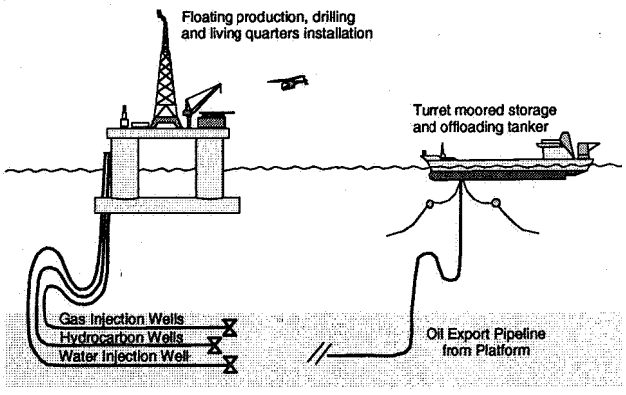
Development

The Njord production installation will consist of a catenary moored, semi-submersible production, drilling and living quarters installation, Figure 1.4.25. The installation will be placed directly over the field's subsea wells, which will be connected to the installation via flexible risers. Fabrication of the installation started in June 1995. Plateau production will be approximately 11,000 Sm^3 oil per day. Water treatment and water injection capacity will each be 2,500 m^3 per day, with potential for upgrading. The gas treatment and gas injection capacities will amount to 10 million Sm^3 per day.

Stabilized oil will be transferred to a storage ship 2.5 kilometers from the installation for storage and loading onto shuttle tankers. Fabrication of the storage ship started in 1996, and fabrication of the subsea systems in 1995 and 1996.

The oil metering station will be 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.

Fig. 1.4.25
Planned installations on Njord



1.4.26 DRAUGEN

Production license:	093	**Block:**	6407/9
Operator:	A/S Norske Shell		
Licensees:			
Den norske stats oljeselskap a.s (SDFI 57.88 %)			73.00000 %
A/S Norske Shell			16.20000 %
BP Petroleum Dev. of Norway AS			10.80000 %
Discovery well:	6407/9-1	Year:	1984
Development approved:		Prod.start:	1993
Phase I	1988		
Recoverable reserves:		94.5 million Sm^3 oil	
Total investments (firm 1996-NOK):		NOK 16,116 billion	
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance		NOK 736 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 at the end of the field's lifetime.

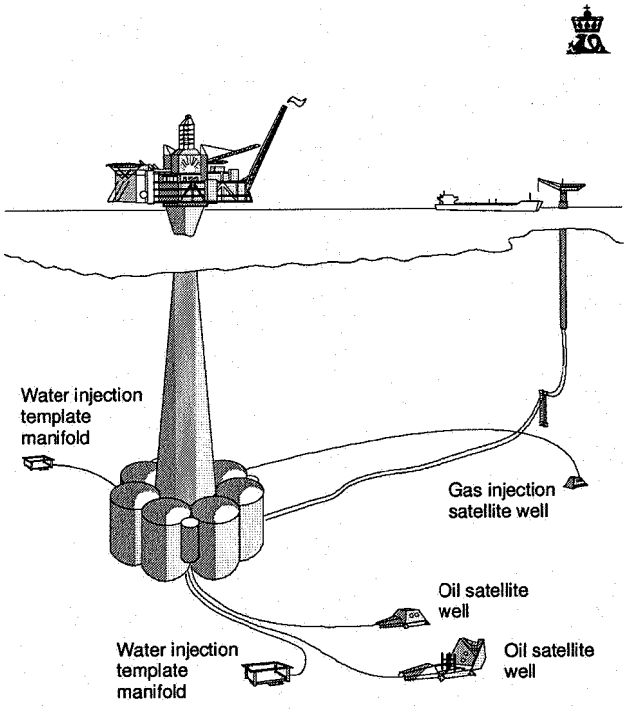
The field produces from five wells on the installation and two subsea-completed wells. Pressure support for oil production is ensured by five subsea-completed water injection wells. Associated gas is injected via a gas injection well in a nearby water-bearing structure. The operator is considering commercial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

Development

The field is developed with a concrete installation resting on the seabed with integrated topsides, see Figure 1.4.26. The installation has ten well slots and a total of 34 conductor casings. Production capacity was upgraded in 1996 from 24,600 Sm^3 per day to 28,600 Sm^3 per day. However, production in 1996 has been below maximum capacity as full upgrading of the water injection capacity to 37,200 m^3 per day has been postponed until the first quarter of 1997. 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 lies well over 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.

Fig. 1.4.26
Installations on Draugen



1.4.27 ÅSGARD

Production licenses: 094, 134, 062 and 074	**Blocks:** 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 %)	60.50000 %
Norsk Agip AS	7.90000 %
Total Norge AS	7.65000 %
Mobil Development Norway AS	7.35000 %
Neste Petroleum AS	7.00000 %
Saga Petroleum ASA	7.00000 %
Norsk Hydro Produksjon AS	2.60000 %
Discovery well: 6507/11-1 Midgard	Year: 1981
6506/12-1 Smørbukk	1984
6506/12-3 Smørbukk Sør	1985
Development approved: 1996	Prod.start:
Phase I	Phase I: 1 October 1998
Phase II	Phase II: 1 October 2000
Recoverable reserves:	132.3 million Sm^3 oil 191 billion Sm^3 gas 24 million tonnes NGL
Total investments (firm 1996-NOK):	NOK 30.7 billion
Anticipated operating costs at plateau incl. CO_2 tax, excl. tariffs and insurance	NOK 1750 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 between 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 made 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, whereof 22 are producers and 16 are gas injectors. Drilling of new wells in 1996 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 an 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, whereof seven are producers and three are injectors. Subsequent optimization of the production strategy has resulted in changes to this figure. 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.

The first pre-drilled production well was started in 1996.

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. A well will be drilled in 1997 to determine the size of this zone. Production of the oil zone will be evaluated in light of the results from this well.

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 production start on 1 October 1998, and a gas export phase with delivery of gas from 1 October 2000. Åsgard will deliver 6.3 billion Sm^3 gas in the year 2000, 8.9 billion Sm^3 per year in the years 2001-2006 and 10.8 billion Sm^3 per year from 2007.

Åsgard will be developed with subsea-completed wells connected to a semi-submersible installation for gas and condensate treatment, and a production and storage ship for oil. 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.

Total field investments for Åsgard are estimated to be NOK 30.7 billion.

1.4.28 HEIDRUN

Production licenses:		**Blocks:**
095 and 124		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 13.2 billion Sm^3 gas
Total investments (firm 1996-NOK):		NOK 32.215 billion
Operating costs 1996 incl. CO_2 tax, excluding tariffs and insurance		NOK 693 million

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 1996, ten oil producing wells were in operation, eight wells accounted for water injection and one for gas injection. The plan is to drill a total of 41 production wells, ten water injection wells and two gas injection wells. As a part of the optimization of the production strategy, an increase in the number of wells is being considered.

Export of 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. The licensees plan to seek gas allocation in 1997.

Development

The field has been developed with a floating tension leg platform of concrete, installed over a subsea template with 56 well slots. In the second quarter of 1996, production capacity was adjusted upwards from 35,000 to 40,000 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.

1.4.29 NORNE

Production license: 128	**Blocks:** 6608/10 and 6608/11
Operator:	Den norske stats oljeselskap a.s
Licensees:	
Den norske stats oljeselskap (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	July 1997
Recoverable reserves:	72.4 million Sm^3 oil
Total investments (firm 1996-NOK):	NOK 8.038 billion
Anticipated operating costs at plateau incl. CO_2 tax, excl. tariffs and insurance	NOK 488 million

Production

The reservoir consists of sandstone from the Early and Middle Jurassic Ages, and the plan is to produce Norne using 14 production wells, five water injection wells and two gas injection wells. The production strategy is water injection, but in the early phase, the associated gas will also be injected into the reservoir. The licensees plan to apply for gas allocation in 1997.

Development

Field development is by means of a subsea well system linked to a combined production and storage ship. The subsea system consists of five well templates with four wells each and the possibility of tie-in to satellite wells. In 1996 it was decided to upgrade the production capacity for oil from 27,500 to 35,000 Sm^3 per day. The water treatment capacity will be 20,000 m^3 per day and the water injection capacity will be 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 will amount to 6.7 million Sm^3 per day. However, 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 on the aft of 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.

1.5 DISCOVERIES IN THE LATE PLANNING STAGES

1.5.1 2/12-1 MJØLNER

Production license: 113	**Block:** 2/12
Operator:	Amerada Hess Norge AS
Discovery well: 2/12-1	Year: 1987
Earliest production start:	Year: 1999
Recoverable reserves:	3.5 million Sm^3 oil
	0.6 billion Sm^3 gas
Total investments (firm 1996-NOK):	NOK 0.552 billion

The discovery lies near the dividing line between the Norwegian and Danish shelves. Mjølner lies in a complex faulted area between Fedagrabenen in the west and Gertrudgrabenen 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 pressure is highest in a reservoir on the Norwegian shelf.

In 1995, work was begun with a view towards further development of the discovery. The declaration of commerciality was presented in June 1992.

In 1995, Amerada Hess Norge took over Norsk Hydro's share in the production license, as well as operatorship.

1.5.2 15/9-19 SR

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:	6.1 million Sm^3 oil
	1.0 billion Sm^3 gas
Total investments (firm 1996-NOK):	NOK 1.8 billion

This oil discovery was made in 1993 in rocks from the Jurassic/Triassic Age on the Theta Vest structure just north of Sleipner Øst. A wellhead installation and tie-in to Sleipner A are potential development solutions. Coordination with a potential recoverable oil zone in Sleipner Vest and with oil discoveries in block 15/5 (production license 048) may also be of interest.

1.5.3 25/11-15 HERMOD

Production license: 169	**Block:** 25/11
Operator:	Norsk Hydro Produksjon AS
Production license: 001	**Block:** 25/11
Operator:	Esso Exploration and Production Norway A/S
Discovery well: 25/11-15	Year: 1991
Earliest production start:	Year: 2000
Recoverable reserves:	84.5 million Sm^3 oil
Total investments (firm 1996-NOK):	NOK 8 billion

The Hermod discovery is located about 7 kilometers east of Balder. The largest portion of the field 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 plan is to choose a production strategy in the spring of 1997. If gas injection is chosen, there will be a need for import of gas. Various development concepts are being evaluated, and the licensees also plan to choose a concept in the spring. The intent is to submit the plan for development and operation towards the end of 1997.

There are several discoveries/prospects surrounding the Hermod discovery and 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 Hermod discovery to the north. Total recoverable oil including these structures is 84.5 million Sm^3 oil.

1.5.4 25/8-5 S, 25/8-8 S AND 25/7-3 (JOTUN)

Production license:	027P	**Block:**	25/8
Operator:	Esso Exploration and Production Norway A/S		
Production license:	103	**Block:**	25/7
Operator:	Norske Conoco AS		
Discovery well:	25/8-5 S	Year:	1994
	25/8-8 S		1995
	25/7-3		1995
Earliest production start:		Year:	1999
Recoverable reserves:			30.7 million Sm^3 oil
Total investments (firm 1996-NOK):			NOK 5.9 billion

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. Work towards the objective of submitting a plan for development and operation has been in progress in 1996 and a draft was submitted to the authorities at the end of the year. Water injection, possibly in combination with natural water drive is the planned production strategy.

A wellhead installation and production ship have been outlined as the development concept.

1.5.5 OSEBERG SØR

Production licenses:	079, 104 and 171	**Blocks:**	30/6, 30/9 and 30/12
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	30/9-3	Year:	1984
Development approved:		Prod.start:	2000
Recoverable reserves:			53.5 million Sm^3 oil
			11.4 billion Sm^3 gas
Total investments (firm 1996-NOK):			NOK 7.6 billion

Ten potential reservoir structures lie within the area which the operator defines as Oseberg Sør. Seven of these are included in the basis estimates for Oseberg Sør. Hydro is the operator, and the area is unitized. The unitization agreements are awaiting approval by the authorities.

The licensees have sent a plan for development and operation to the authorities for approval. The plan entails developing the field with an installation with living quarters, drilling module and first stage separation of oil and gas. Final processing will take place at the Oseberg Field Center. The oil will be transported in the Oseberg transportation system to Stura. A part of 30/9-3 Omega Nord may be reached with wells from the Oseberg Field Center, and will be produced from there.

1.5.6 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:			7.9 million Sm^3 oil
			22.3 billion Sm^3 gas
Total investments (firm 1996-NOK):			NOK 2.5 billion

Huldra is a gas discovery which lies to the northwest of Veslefrikk, Figure 1.4.13.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 in connection with a potential development.

The gas could be drained by 6 production wells. The Huldra discovery can deliver gas from 2000 (1999).

Several development concepts with connection to several existing production facilities in the area are being evaluated. The field was declared commercial in the summer of 1991.

The licensees plan to seek gas allocation for Huldra in 1997.

1.5.7 34/11-1

Production license:	193	**Block:**	34/11
Operator:	Den norske stats oljeselskap a.s		
Discovery well:	34/11-1	Year:	1994
Earliest production start:		Year:	2000
Recoverable reserves:			20.0 million Sm³ oil
			50.0 billion Sm³ gas
Total investments (firm 1996-NOK):			NOK 4 billion

The 34/11-1 discovery lies about 17 kilometers southeast of the Gullfaks field, see Figure 1.4.17.a. Gas/condensate has been proven in sandstone in the Brent group (Middle Jurassic). Structurally, the reservoir is a rotated fault block. Two exploration wells on the structure have shown gas/condensate. The licensees plan to apply for gas allocation in 1997.

A wellhead installation which will be tied in to existing production facilities in the area is being evaluated as an interesting development concept.

1.5.8 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:			7.1 million Sm³ oil
			0.7 billion Sm³ gas
Total investments (firm 1996-NOK):			NOK 0.355 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. Development of a reservoir model in 1997 will form the basis for production strategy. 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 a plan for development and operation to the authorities during 1997.

1.5.9 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:		Year:	1999
Recoverable reserves:			10.2 million Sm³ oil
			1.3 billion Sm³ gas
Total investments (firm 1996-NOK):			NOK 0.792 billion

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 start sometime during 1997.

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 plans to drill an appraisal well in the area in 1997. Results from this well and the test production from the 34/7-21 discovery will be decisive factors in the selection of development concept.

1.5.10 34/7-23 S

Production license:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Licensees:			
Den norske stats oljeselskap a.s			
(Statoil) (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:	2000

Recoverable reserves:	3.6 million Sm³ oil 0.4 billion Sm³ gas
Total investments (firm 1996-NOK):	NOK 0.513 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 in 1997. Results from this well and the planned production test of the 34/7-21 discovery will be crucial factors for the selection of a development concept.

1.5.11 33/9-19 S

Production license:	037	**Block:**	33/9
Operator:	Den norske stats oljeselskap a.s		
Production license:	089	**Block:**	34/7
Operator:	Saga Petroleum ASA		
Discovery well:	33/9-19 S	Year:	1996
Earliest production start:		Year:	1998
Recoverable reserves:			11.0 million Sm³ oil 0.8 billion Sm³ gas
Total investments (firm 1996-NOK):			NOK 0.645 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. There is uncertainty connected with the geological model and volume estimates for the discovery. 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.

Several development alternatives are under evaluation. Phase-in towards Statfjord Nord, Snorre or Vigdis are potential development concepts. A plan for development and operations could be submitted to the authorities during 1997.

1.5.12 35/11-4 R FRAM

Production license:	090	**Block:**	35/11
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	35/11-2	Year:	1987
Earliest production start:		Year:	2001
Recoverable reserves:			26.6 million Sm³ oil 19.9 billion Sm³ gas
Total investments (firm 1996-NOK):			NOK 7.9 billion

Production license 090 in block 35/11 was awarded in 1984. In August 1995, the operator responsibility was transferred from Mobil Development Norway A/S to Norsk Hydro Produksjon AS. So far, eight wells have been drilled, whereof four proved hydrocarbons. Gas/condensate was proven in the B structure in 1987. During the period from 1990-1996, oil and gas were proven in F Øst, C Vest and the H structure. The hydrocarbons occur in several reservoir strata in Jurassic sandstones.

Evaluation of potential development concepts is in progress. A decision concerning the choice of concept is expected in October 1997, and submission of a development plan to the authorities in December 1997. Drilling of one or two wells is planned during the coming year.

1.5.13 6406/2-1

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:	1995
Development approved		Prod. start:	
Phase I			Year 2000 at the earliest
Phase II			
Recoverable reserves:			26 million Sm³ oil 84 billion Sm³ gas 11 million tonnes NGL
Total investments (firm 1996-NOK):			NOK 5.87 billion

Well 6406/2-1 in production license 199 was drilled in 1994 and proved gas and oil in sandstones of the Jurassic Age. The reservoir formations Garn, Ile, Tofte and Tilje are located at depths down to 5892 m/MD. In 1996, an appraisal well, 6406/2-2, was drilled which proved new resources. The operator assumes production through depressurization and recoverable resources are estimated to be 84 billion Sm³ gas, 26 million Sm³ oil and 11 tonnes NGL.

The licensees plan to apply for gas allocation in 1997. Both independent developments and unitized solutions with other fields are being considered. A tension leg installation or production ship would appear to be the most likely independent solution.

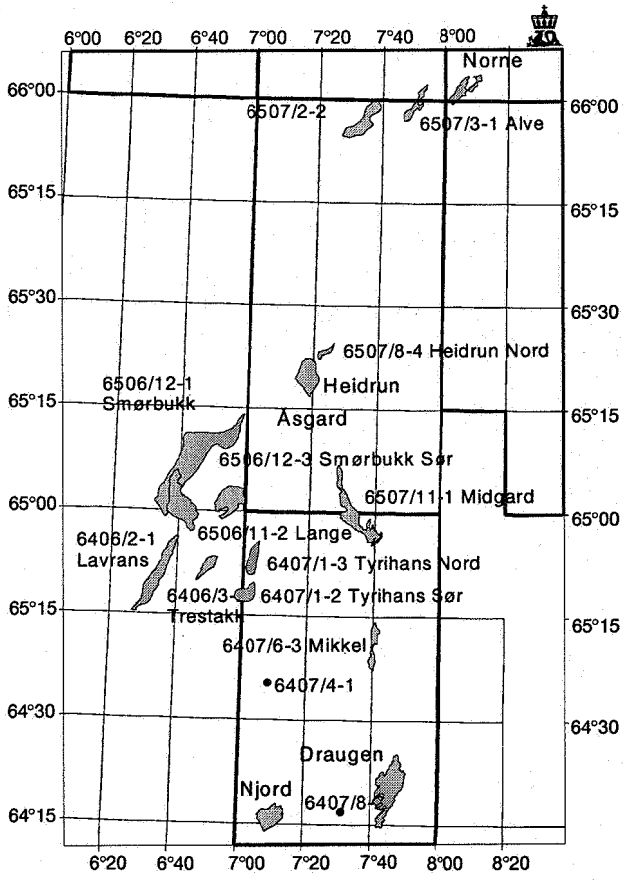
1.5.14 6406/3-2 TRESTAKK

Production license:	091	**Block:**	6406/3
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
Development approved	Prod. start:	Year 2000 at the earliest
Recoverable reserves:		4.8 million Sm³ oil
Total investments (firm 1996-NOK):		NOK 755 billion

Trestakk is an oil discovery which was proven in 1986 in production license 091 (see Figure 1.5.14). Recoverable resources are estimated to be 4.8 million Sm³ oil if associated gas is reinjected. This is based on an evaluation of Trestakk as a satellite of Tyrihans, 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.

Fig. 1.5.14
Fields and discoveries in the Norwegian Sea



1.5.15 6407/1-2 TYRIHANS

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	Year:	1984
	Prod. start:		Year 2000 at the earliest
Recoverable reserves:			16 million Sm³ oil 25 billion Sm³ gas 6 million tonnes NGL
Total investments (firm 1996-NOK):			NOK 4.75 billion

Tyrihans Sør was proven in 1983 and Tyrihans Nord 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. Recoverable resources are estimated to be 16 million Sm³ oil/condensate, 25 billion Sm³ gas and 6 million tonnes NGL.

The licensees plan to seek gas allocation in 1997. 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.

1.6 FIELDS IN THE EARLY PLANNING STAGES

1.6.1 1/3-3

Production license:	065	**Block:**	1/3
Operator:	Elf Petroleum Norge AS		
Discovery well:	1/3-3	Year:	1983
Recoverable reserves:			4.3 million Sm³ oil

This is a small oil discovery made in the Ula formation from the Late Jurassic Age.

It is assumed that the discovery will be developed with two horizontal wells. There are no plans for development at the time being.

1.6.2 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 0.2 million tonnes NGL		
Total investments (firm 1996-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. Development is not anticipated before the year 2007 as a consequence of future limitations in process capacity on Ekofisk II.

1.6.3 15/5-1 DAGNY

Production license:	048	**Block:**	15/5
Operator:	Norsk Hydro Produksjon AS		
Production license:	029	**Block:**	15/6
Operator:	Esso Exploration and Production Norway A/S		
Discovery well:	15/5-1	Year:	1978
Earliest production start:		Year:	2002
Recoverable reserves:	5.9 billion Sm^3 gas 1.3 million tonnes NGL		

This is a gas/condensate discovery in the Hugin formation. Norsk Hydro was the operator for production license 048 in 1996, however, towards the end of the year an agreement was signed regarding transfer of the operatorship to Statoil. As the discovery extends into block 15/6, it must be unitized with the licensees in production license 029. The most likely development concept is a subsea solution with tie-in to nearby infrastructure. The plan is to send an application for gas allocation from 2002 in 1997.

1.6.4 15/5-2

Production license:	048	**Block:**	15/5
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	15/5-2	Year:	1978
Earliest production start:		Year:	2001
Recoverable reserves:	2.9 billion Sm^3 gas 0.1 million tonnes NGL		

This is a small gas/condensate discovery in the Skagerrak formation in the B structure in block 15/5. Development as a satellite to Sleipner A is being considered.

1.6.5 15/5-5

Production license:	048	**Block:**	15/5
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	15/5-5	Year:	1995
Earliest production start:		Year:	2000
Recoverable reserves:	11.4 million Sm^3 oil		

This is an oil discovery in the Heimdal formation on the G structure in block 15/5. Various development concepts are being evaluated and unitization with other discoveries in the area is also a possibility.

1.6.6 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:	1.7 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 the Jotun development are being considered. Production start depends on the timing of available capacity on Jotun.

1.6.7 30/7-2

Production license:	040	**Block:**	30/7
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	30/7-2	Year:	1975
Recoverable reserves:	1.5 million Sm^3 oil 0.4 billion Sm^3 gas		

This is a small oil and gas discovery in the Frigg formation from the Eocene Age.

1.6.8 30/8-1 S

Production licenses:	190 and 034	**Blocks:**	30/8 and 30/5
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	30/8-1 S	Year:	1995
Recoverable reserves:	20 billion Sm^3 gas		

This is a gas/condensate discovery made in a rotated fault block just west of the Oseberg field. The reservoir belongs to the Brent group of the Middle Jurassic Age.

An appraisal well (30/5-2) drilled on the northern part of the structure in 1996 showed that the discovery extends into block 30/5 (production license 034) where Shell is the sole licensee.

Ongoing evaluation work indicates that the discovery may contain approx. 50 million Sm^3 o.e.

1.6.9 35/9-1 R GJØA

Production license:	153	**Blocks:**	35/9 and 36/7
Operator:	Norsk Hydro Produksjon AS		
Discovery well:	35/9-1	Year:	1989
Earliest production start:		Year:	2001
Recoverable reserves:			16.3 million Sm^3 oil 26.4 billion Sm^3 gas

So far, three wells have been drilled, all of which have proven hydrocarbons in various segments of the A structure. The discoveries have been made in several reservoir layers in Upper and Middle Jurassic sandstone. Field development studies are in progress.

1.6.10 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:		Year:	1999
Recoverable reserves:			3.4 million Sm^3 oil 0.5 billion Sm^3 gas
Total investments (firm 1996-NOK):			NOK 945 million

The discovery lies in a fault block with sandstones from the Sub-Jurassic Age (the Åre formation).
Development as a satellite to Heidrun is being considered.

1.7 EXPLORATION ACTIVITY

1.7.1 GEOPHYSICAL SURVEYS

A total of 835,961 km of seismic data were acquired on the Norwegian Shelf in 1996. The number of kilometers refers to cmp-line kilometers.

In the North Sea, a total of 346,793 km seismic data were acquired, in addition to 481,860 kilometers seismic data in the Norwegian Sea and 7,308 kilometers seismic data in the Barents Sea.

The Norwegian Petroleum Directorate gathered a total of 6,669 kilometers, while oil companies and seismic contractor companies gathered a total of 829,292 kilometers. Of this total, Norwegian oil companies acquired 491,690 kilometers and foreign oil companies acquired 218,268 kilometers. The contractor companies (Geco-Prakla, PGS Exploration, Norex, Nopec, Geoteam, CGG Norge and Western) acquired 118,334 kilometers of seismic data for their own accounts.

Of the total seismic data acquired, 3D seismic accounts for 805,963 kilometers. Never before has there been such a high level of collection activity on the Norwegian shelf, nor has this much 3D seismic ever been gathered. The large increase is due to both a general increase in the use of 3D seismic in the exploration phase and commitments related to the work programs in connection with the 15th licensing round. Figure 1.7.1 provides an overview of recent years' development with regard to the number of cmp-line kilometers.

1.7.2 EXPLORATION DRILLING

At the turn of the year 1995/1996, drilling of seven exploration wells was in progress, two of these were re-opened wells.

30 new exploration wells were spudded in 1996, of which 21 were wildcats and 9 were appraisal wells. Drilling activities in 1996 comprised 19 wildcat and 5 appraisal wells in the North Sea and two wildcat and four appraisal wells in the Norwegian Sea. In addition, two temporarily abandoned exploration wells were re-entered for further work, both in the Norwegian Sea.

At the turn of the year 1996/1997, eight exploration wells were in progress, one of these was a re-entered well.

As of 31 December 1996, a total of 866 exploration wells had been spudded on the Norwegian continental shelf: 617 wildcat wells and 249 appraisal wells, see Table 7.3.a.

In 1996, 31 exploration wells were completed or temporarily abandoned after having reached the planned depth on the Norwegian shelf. Three of these were re-entries, whereof 2 were re-opened for further operations while the third, 6610/03-1 R 2, was permanently plugged. The wells consisted of 23 wildcat wells and 8 appraisal wells. The geographical distribution of the wells is as follows: 20 wildcat and 3 appraisal wells in the North Sea, and three wildcat and five appraisal wells in the Norwegian Sea.

The operators for the wells completed or temporarily abandoned in 1996 were as follows: Statoil 13, Hydro 7, Saga 4, BP 2, Amoco, Shell, Agip, Esso and Phillips with 1 each.

A wildcat well is the first well drilled to explore 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 discovered petroleum deposits. 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. 73 exploration wells on the Norwegian shelf have been reclassified, 69 of these from wildcat to appraisal wells and four from appraisal to wildcat wells.

Fig. 1.7.1
Seismic surveys on the Norwegian continental shelf 1962-1996

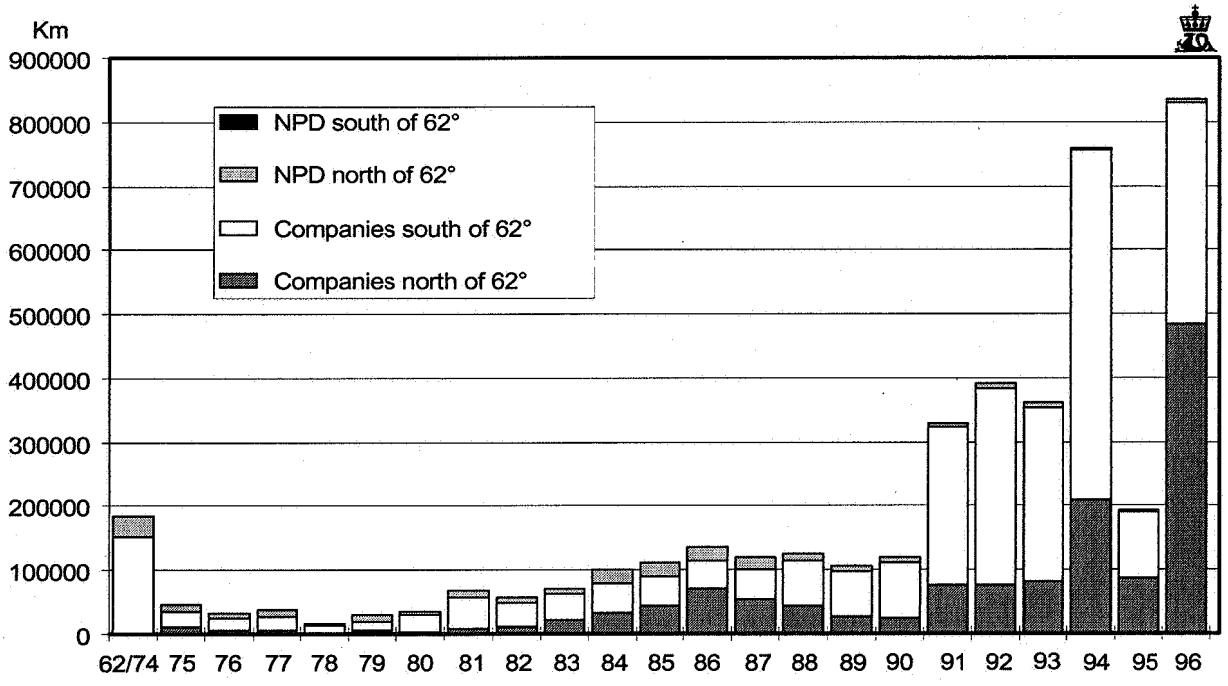
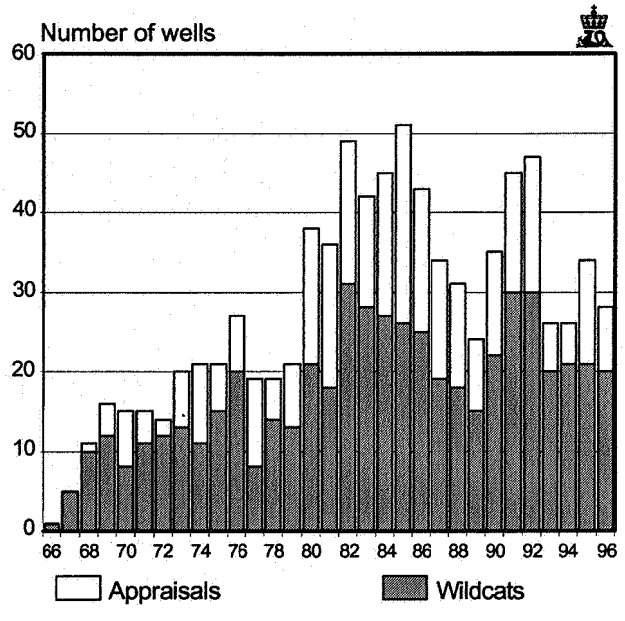


Fig. 1.7.2
Exploration wells completed per year after re-classification



As of 31 December 1996, 859 exploration wells were completed or temporarily abandoned on the Norwegian shelf. After reclassification, these comprise 545 wildcat and 314 appraisal wells, see Figure 1.7.2.

Table 7.3.f provides an overview of spudded and/or completed exploration wells in 1996.

As of year-end, a total of 47 exploration wells have been temporarily abandoned on the Norwegian continental shelf. The suspended exploration wells on the Norwegian shelf with equipment remaining on the seabed are:

2/1-9 A	25/5-4	31/2-18 A
2/4-15 S	25/8-5 S	31/5-4 AR
2/4-17	25/8-6	31/5-5
2/7-23 S	25/11-16	34/4-7
2/7-25 S	25/11-19 S	34/8-4 A
2/10-2	25/11-21 S	34/10-34
2/12-2 S	30/2-1	34/10-37 A
7/12-8	30/3-4	34/11-2 S
7/12-9	30/8-1 SR	6406/2-2
9/2-6 S	30/9-7	6407/7-2 R
15/9-19 SR	30/9-8 R	6407/7-4
15/12-6 S	30/9-9	6506/11-4 S
15/12-9 S	30/9-10	6506/11-5 S
15/12-10 S	30/9-12 A	6506/12-8
25/2-13	30/9-13 S	6507/8-4
25/4-6 S	31/2-16 SR	

The Norwegian companies Statoil, Hydro and Saga have been the operators of 22 of the spudded wells in 1996, representing 73.3%. The remaining 8 wells were divided among Shell, Esso, Phillips, Amoco, Mobil, BP and Agip. This is illustrated in Table 7.3.c.

1.7.3 EXPLORATION TARGETS

For the most part, exploration activity in 1996 has continued to target Jurassic sandstone prospects. Of the 30 exploration wells spudded, 25 had Jurassic as the main

prospect, one had the Triassic, one had the Cretaceous, and three had the Tertiary. Many of the spudded wells had several exploration targets. In addition to the main prospect, secondary prospects were also the subject of investigation. Secondary prospects were divided among 12 in the Jurassic, three in the Cretaceous, four in the Tertiary and one in the Paleozoic.

1.7.4 NEW DISCOVERIES IN 1996

Ten discoveries have been made, whereof five have been confirmed through formation testing. All of the new discoveries have been made in the North Sea, see Table 1.7.4. A more detailed description of the various discoveries may be found in Section 1.7.5.

1.7.5 DETAILED DESCRIPTION OF DRILLING IN 1996

Southern part of the North Sea

Four exploration wells were completed in the southern part of the North Sea in 1996 (Table 1.7.5.a). All of the four exploration wells are wildcat wells. One of the wells, 9/2-6 S, has been temporarily abandoned. In addition, wildcat wells (1/3-8 and 2/6-5) have been spudded, but not completed as of the end of the year. Two discoveries of hydrocarbons were made in the area in 1996.

Well 2/6-5, which was drilled east of the Ekofisk field, struck oil in rocks from the Cretaceous Age. Formation testing of the well gave 8 Sm^3 oil per day. The disappointing result is assumed to be a consequence of poor reservoir properties in the rock.

Well 9/2-6 S, which was drilled to the southeast of the Yme field, struck oil in rocks from the Middle Jurassic Age. This is a relatively small discovery and no formation testing of the well was performed.

The Sleipner / Balder area

Six exploration wells were completed in this area in 1996 (Table 1.7.5.b). Five were wildcat wells and one was an appraisal well. Two of the wells, 15/12-10 S and 25/11-21 A, have been temporarily abandoned. Two oil discoveries were made in the area in 1996. None of the discoveries were formation tested.

Well 15/12-10 S was drilled on a segment north of the Varg field. Preliminary results indicate oil saturation in low permeability sand from the Late Jurassic Age.

Well 24/12-3 S is the first well drilled on a production license awarded in the 15th licensing round. It was drilled to the west of the Balder field and proved oil in reservoir rocks from the Paleocene Age.

Appraisal well 25/11-21 A was drilled on the 25/11-15 Hermod discovery. It was drilled horizontally from 25/11-21 S. Test production was carried out from the reservoir level in the Heimdal formation. The test production lasted for two months, and a total of 77,000 Sm^3 oil was produced.

The Oseberg and Troll area

Nine exploration wells were completed in the Oseberg and Troll area in 1996 (Table 1.7.5.c). Eight of these were wildcat wells and one was an appraisal well. Four new discoveries were made in the area. In addition, two wildcat wells (30/11-5 and 35/4-1) have been spudded, but not completed as of year-end. One of the wells, 30/8-1 SR, has been temporarily abandoned.

Table 1.7.4
New discoveries in 1996

Exploration well	Operator	Hydro-carbon type	Reservoir level	Forma-Tion tested	Production rate (per day)	Choke	Size of discovery (recoverable)
2/6-5	Saga	oil	Cretaceous	yes	8 Sm^3 oil	11,1 mm	2 mill Sm^3 o.e.
9/2-6 S	Statoil	oil	Middle Jurassic	no			2 mill Sm^3 o.e.
15/12-10 S	Saga	oil	Late Jurassic	no			3 mill Sm^3 o.e.
24/12-3 S	Statoil	oil	Paleocene	no			5 mill Sm^3 oil
33/9-19 S	Statoil	oil	Middle Jurassic	no			11,0 mill Sm^3 oil + 0,8 bill Sm^3 gas
34/7-25 S	Saga	gas/ oil	Late Jurassic	yes	1 050 Sm^3 oil 106 000 Sm^3 gas	15,9 mm	7,1 mill Sm^3 oil + 0,7 bill Sm^3 gas
34/11-2 S	Statoil	gas/cond	Middle Jurassic	yes	175 000 Sm^3 gas 85 Sm^3 cond 125 000 Sm^3 gas 125 Sm^3 cond	12.7 mm 14,3 mm	9 mill Sm^3 o.e.
35/10-2	Statoil	gas	Middle Jurassic	no			8 mill Sm^3 o.e.
35/11-8 S [1]	Norsk Hydro	gas/ oil	Late Jurassic	yes	700 Sm^3 oil 77 000 Sm^3 gas	19,05 mm	approx. 20 mill Sm^3 o.e.
36/7-1 [2]	Norsk Hydro	gas/ oil	Late Jurassic	yes	1 025 Sm^3 oil 171 175 Sm^3 gas	25,4 mm	approx. 15 mill Sm^3 o.e.

[1] included in 35/11-4 R Fram
[2] included in 35/9-1 R Gjøa

Table 1.7.5.a
Exploration wells drilled in the southern North Sea

Exploration well	Well classification	Production licence	Operator	Total vertical depth (MSL)	Total depth (age)	Status
1/3-8	wildcat	011	Norske Shell Amoco Norge*			
2/6-5	wildcat	008	Saga			oil
2/8-15	wildcat	006	Amoco Norge	3 725	Late Cretaceous	dry
3/7-6	wildcat	147	Norske Shell	4 097	Late Jurassic	dry
7/12-12 S	wildcat	019 A	BP Norge	4 010	Triassic	dry
9/2-6 S	wildcat	114	Statoil	3 600	Middle Jurassic	oil

*) Drilling operator

Table 1.7.5.b
Exploration wells drilled in the Sleipner and Balder area

Exploration well	Well classification	Production licence	Operator	Total vertical depth (MSL)	Total depth (age)	Status
15/12-10 S	wildcat	038	Saga	3 078	Triassic	oil
16/10-3	wildcat	101	Norsk Agip	2 810	Triassic	dry
24/12-3 S	wildcat	204	Statoil	2 726	Cretaceous	oil
25/10-6 S	wildcat	168	Statoil	4 280	Middle Jurassic	dry
25/10-7 S	wildcat	028 P	Esso Norge	2 557	Cretaceous	dry
25/11-21 A	appraisal	169	Norsk Hydro	1 775	Tertiary	oil

Table 1.7.5.c
Exploration wells drilled in the Oseberg and Troll area

Exploration well	Well classification	Production licence	Operator	Total depth (MSL)	Total depth (age)	Status
30/5-2	appraisal	034	Norske Shell Norsk Hydro*	4 052	Early Jurassic	gas/cond/ oil
30/8-1 SR	wildcat	190	Norsk Hydro	4 741	Early Jurassic	gas/cond
30/8-2	wildcat	190	Norsk Hydro	2 383	Cretaceous	dry
30/11-5	wildcat	035	Norske Shell			
31/2-19 S	wildcat	191	Norsk Hydro	3 647	Jurassic	dry
32/4-1	wildcat	205	Phillips Petroleum	3 162	Basement	dry
35/4-1	wildcat	194	Norsk Hydro			
35/10-2	wildcat	173	Statoil	4 652	Early Jurassic	gas
35/11-8 S	wildcat	090	Norsk Hydro	3 598	Early Jurassic	gas/oil
36/4-1	wildcat	196	BP Norge	2 716	Basement	dry
36/7-1	wildcat	153	Norsk Hydro	2 819	Basement	gas/oil

*) Drilling operator

Well 30/8-1 SR was drilled just to the west of the Oseberg field. It was first spudded in November 1994, and was temporarily abandoned in February 1995 out of consideration for the environmental and fishery interests in the area. Gas/condensate had then been proven in rocks from the Middle Jurassic Age (the Brent group). The well was re-entered in November 1995. Gas/condensate was also proven at a deeper stratigraphic level (the Statfjord formation) from the Early Jurassic Age. The lowest reservoir was formation tested, but the test was not successful. The uppermost reservoir has not been formation tested.

An appraisal well, 30/5-2, was drilled in order to delimit the gas/condensate discovery which was made in well 30/8-1 S. This was a cooperative project between the licensees in production license 034 (block 30/5) and production license 190 (block 30/8). The results were positive and show that the discovery extends into block 30/5.

Well 35/10-2 was drilled northwest of the Troll field. The well struck gas in sandstone strata from the Middle Jurassic Age. This is probably a relatively small gas discovery, and it has not been production tested.

Hydrocarbons were proven in 35/11-8 S and 36/7-1, both north of the Troll field. Well 35/11-8 S proved oil and gas in rocks from the Late Jurassic Age. Two tests

Fig. 1.7.5.a
Exploration wells drilled in the southern North Sea

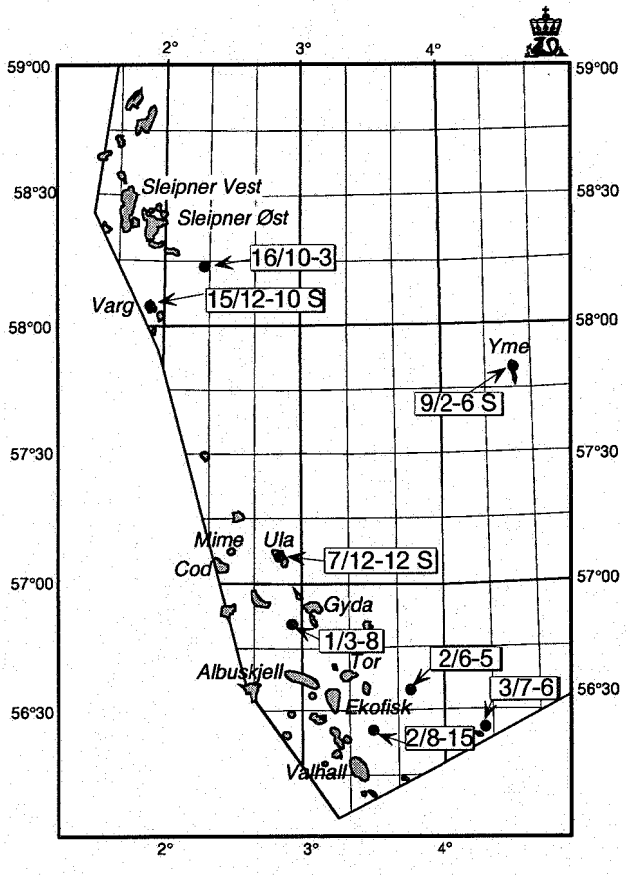
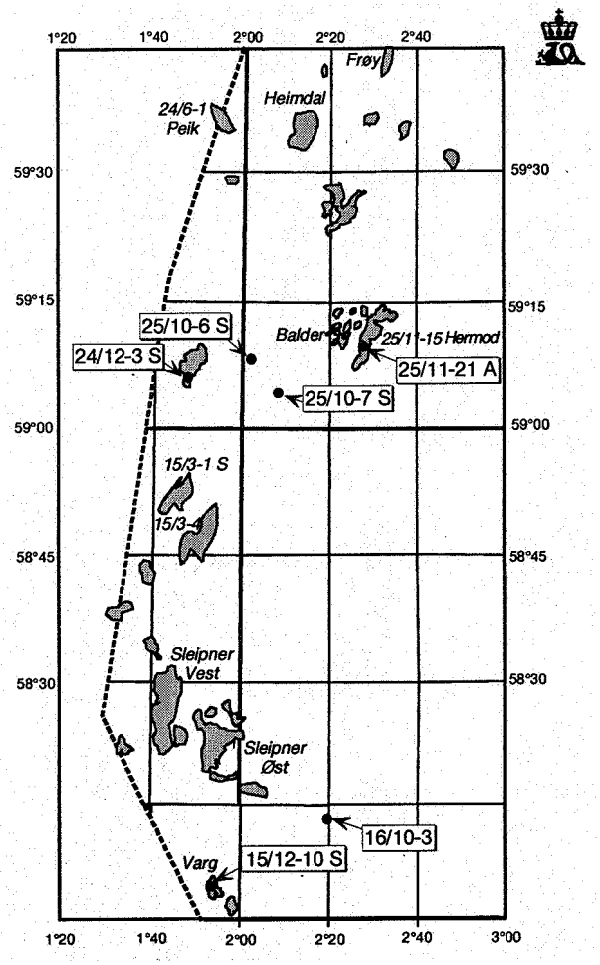


Fig. 1.7.5.b
Exploration wells drilled in the Sleipner and Balder area



were performed in the oil zone with a maximum flow rate of 700 Sm^3 oil per day and a gas/oil ratio of 110 Sm^3/Sm^3 through a 19.05 mm choke. Well 36/7-1 was drilled between Troll and the 35/3-2 Agat discovery. The well struck oil and gas in rocks from the Late Jurassic Age. A formation test has been performed in the oil zone, with a maximum flow rate of 1025 Sm^3 oil per day and a gas/oil ratio of 167 Sm^3/Sm^3 through a 25.4 mm choke.

The Gullfaks, Statfjord and Snorre area

Four exploration wells were completed in this area in 1996 (Table 1.7.5.d). Three of these were wildcat wells and one was an appraisal well. Discoveries were made in all of the wildcat wells. In addition, one wildcat well (33/6-2) and one appraisal well (34/11-3) were spudded, but not completed as of the end of the year.

Well 34/7-25 S was drilled to the southeast of the Tordis field. It proved gas/oil in Upper Jurassic sandstones. The well was tested and production was metered at 1050 Sm^3 oil per day and 106,000 Sm^3 gas per day through a 15.9 mm choke. The gas/oil ratio is 101 Sm^3/Sm^3. This confirms that the reservoir properties are good.

Well 34/11-2 S was drilled east of the Gullfaks field. It proved gas/condensate in sandstones from the Middle Jurassic Age. Two production tests were carried out. The lower gave a maximum flow of 125,000 Sm^3 gas and 125 Sm^3 condensate per day through a choke of 14.3 mm. The gas/oil ratio was 1000 Sm^3/Sm^3. The highest level tested gave a maximum flow of 175,000 Sm^3 gas and 85 Sm^3 condensate through a 12.7 mm choke. The gas/oil ratio was 2060 Sm^3/Sm^3.

Wildcat well 33/9-19 S and sidetrack well 33/9-19 A were drilled on the northeastern extension of the Statfjord Nord structure. The structure, which extends into block 34/7, production license 089, was drilled in cooperation between the two production licenses. 33/9-19 S proved oil in sandstone from the Middle Jurassic Age.

The Norwegian Sea

Eight exploration wells were completed north of 62° latitude in 1996 (Table 1.7.5.e).

Three of the wells were wildcat wells. In addition, one wildcat well (6406/2-3) was spudded and one appraisal well (6505/12-11 SR) was re-opened for testing. These were not completed as of year-end. No new discoveries of hydrocarbons were made in the area in 1996. (The discovery well 6406/2-1 R is registered as a discovery in 1995). Four of the appraisal wells, (6406/2-2, 6506/11-

Fig. 1.7.5.c
Exploration wells drilled in the Oseberg and Troll area

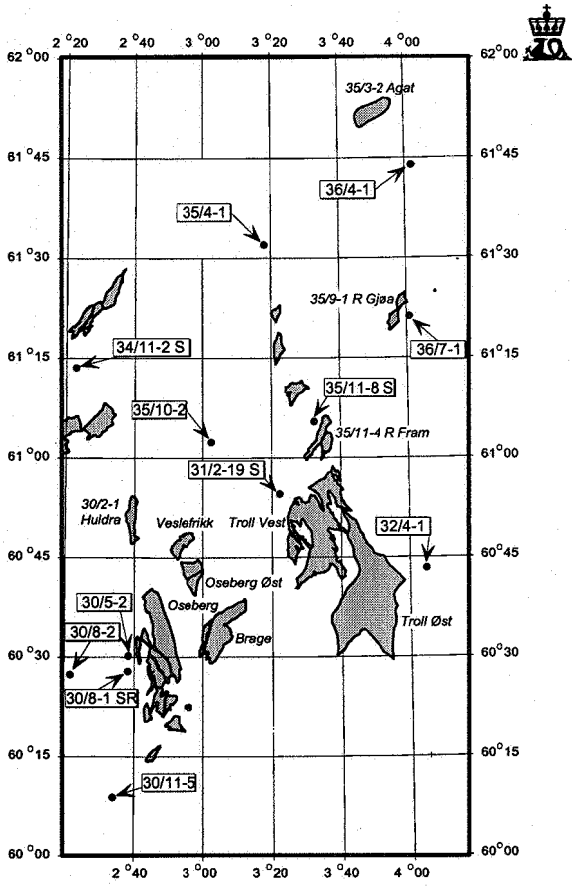


Fig. 1.7.5.d
Exploration wells drilled in the Gullfaks, Statfjord and Snorre area

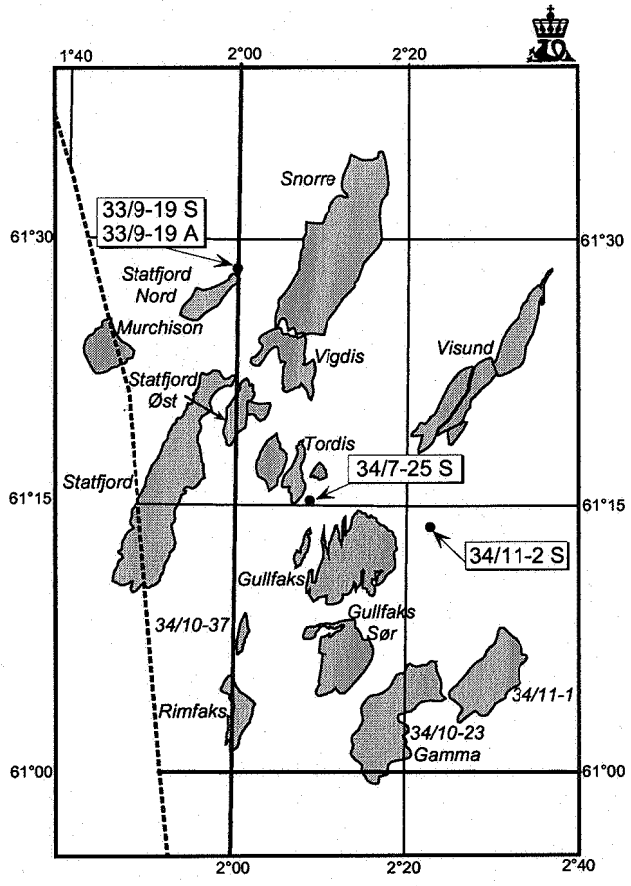


Table 1.7.5.d
Exploration wells in the Gullfaks, Statfjord and Snorre area

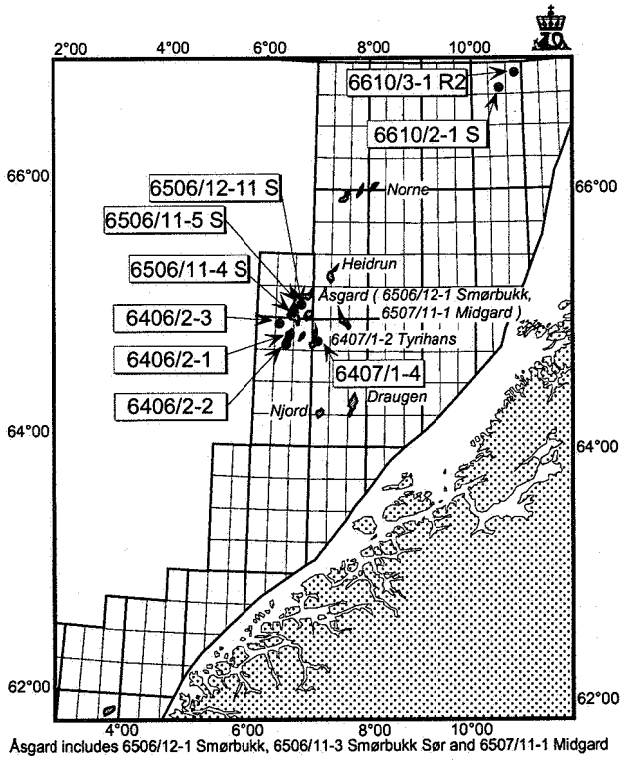
Exploration well	Well classification	Production licence	Operator	Total depth (MSL)	Total depth (age)	Status us
33/6-2	wildcat	206	Mobil			
33/9-19 S	wildcat	037	Statoil	3 037	Early Jurassic	oil
33/9-19 A	appraisal	037	Statoil	3 032	Early Jurassic	oil
34/7-25 S	wildcat	089	Saga	2 573	Early Jurassic	gas/oil
34/11-2 S	wildcat	193	Statoil	4 742	Early Jurassic	gas/cond
34/11-3	appraisal	193	Statoil			

Table 1.7.5.e
Exploration wells drilled in the Norwegian Sea

Exploration well	Well classification	Production licence	Operator	Total depth (MSL)	Total depth (age)	Status
6406/2-1 R	wildcat	199	Saga	5 790*	Early Jurassic	gas/cond
6406/2-2	appraisal	199	Saga	5 327	Early Jurassic	gas/cond
6406/2-3	wildcat	199	Saga			
6407/1-4	appraisal	073	Statoil	3 805	Middle Jurassic	oil
6506/11-4 S	appraisal	Åsgard unit	Statoil	5 088	Early Jurassic	gas/oil
6506/11-5 S	appraisal	Åsgard unit	Statoil	4 768	Early Jurassic	
6506/12-11 S	appraisal	Åsgard unit	Statoil	5 246	Early Jurassic	oil
6506/12-11 SR	appraisal	Drilling completed earlier, opened for testing in 1996				
6610/2-1 S	wildcat	177	Statoil	2 558	Triassic	dry
6610/3-1 R2	wildcat	(permanently plugged)				

* Deepest well on the shelf so far

Fig. 1.7.5.e
Exploration wells drilled in the Norwegian Sea



Åsgard includes 6506/12-1 Smørbukk, 6506/11-3 Smørbukk Sør and 6507/11-1 Midgard

4 S, 6506/11-5 S, 6506/12-11 S) have been temporarily abandoned and plugged.

Appraisal well 6406/2-2 was drilled south on the same structure where a major discovery was made previously with well 6406/2-1 R. Gas and condensate were proven at several levels as in the discovery well 6406/2-1 R. Two of the reservoir levels were production tested. From the best zone, 1,037,000 Sm^3 gas and 575 Sm^3 condensate per day were produced through a choke of 27 mm. The results from 6406/2-2 are positive and show that the discovery is larger than previously assumed. A new estimate is approx. 125 million Sm^3 of recoverable oil equivalents.

The appraisal wells 6506/11-4 S, 6506/11-5 S and 6506/12-11 S were all drilled downflank on the Smørbukk discovery and showed gas and condensate at several levels. They provided valuable information with a view towards further development of the Åsgard field. These wells will subsequently be converted to injection and production wells.

The appraisal well 6407/1-4 on the Tyrihans Nord discovery proved gas and oil. A production test in the oil zone gave 250 Sm^3 oil per day through a choke of 12.7 mm. The gas/oil ratio is 120 Sm^3/Sm^3.

The Barents Sea
No wells were drilled in 1996.

Svalbard
No exploration drilling has been conducted on Svalbard in 1996.

1.8 TRANSPORTATION SYSTEMS FOR OIL AND GAS

1.8.1 EXISTING TRANSPORTATION SYSTEMS

The various transportation systems for gas and oil/condensate from the Norwegian continental shelf are shown in Figure 1.8.1. Some of the transportation systems are British where the Norwegian share of the transported volumes 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	58.2500 %
Elf Petroleum Norge AS	10.0000 %
Norsk Hydro Produksjon AS	8.0000 %
Mobil Development Norway AS	7.0000 %
Esso Exploration & Production Norway A/S	5.0000 %
A/S Norske Shell	5.0000 %
Norske Conoco A/S	2.7500 %
Saga Petroleum ASA	2.0000 %
Total Norge AS	2.0000 %

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

- a rich gas pipeline from Statfjord to Kårstø
- separation and fractionating plant at Kårstø, plus storage and loading facility
- dry gas pipeline from Heimdal, dry gas pipeline from Kårstø to riser platform in block 16/11 (Draupner), and a pipeline from this installation to the 2/4-S riser platform at the Ekofisk Center.

After production start, the Gullfaks, Veslefrikk, Snorre and Brage fields were connected to the Statpipe system upstream of the Kårstø facilities. 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. Transport capacity from Statfjord to Kårstø is 25 million Sm^3 per day. This capacity will be fully utilized through the end of 1997.

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 Kår-

stø, 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 58.9 million Sm^3 per day.

Norpipe Gas

Ownership structure:

Phillips Petroleum Company Norway	15.89000 %
Fina Production Licenses 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 %

Norsea Gas A/S, Emden

Ownership structure:

Phillips Petroleum Company Norway	36.96000 %
Fina Production Licenses AS	30.00000 %
Norsk Agip AS	13.04000 %
Elf Petroleum Norge AS	7.09600 %
Norsk Hydro Produksjon AS	6.70000 %
Total Norge AS	3.04700 %
Den norske stats oljeselskap a.s	2.00000 %
Elf Rex AS	0.85500 %
Norminol AS	0.30400 %

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 (operator)	16.71000 %

The pipeline is 50% Norwegian-owned. 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 Exploration & Production 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, will be put into operation in 1997.

Statoil is the operator.

Europipe

Ownership structure
(same as for Zeepipe)

This pipeline goes from Draupner (16/11E) to Emden in Germany and is about 600 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 814 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:

SDFI	60.00000 %
Den norske stats oljeselskap a.s	9.71000 %
Norsk Hydro Produksjon AS	6.47000 %
Saga Petroleum ASA	5.18000 %
Esso Exploration & Production Norway A/S	3.88000 %
Mobil Development Norway AS	3.88000 %
Total Norge AS	2.91000 %
Elf Petroleum Norge AS	2.14000 %
Norsk Agip AS	1.94000 %
A/S Norske Shell	1.29000 %
Neste Petroleum AS	1.29000 %

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

Haltenpipe
A 245 kilometer long 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 will be put into operation in early 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 in to 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 Norway 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 (OTS). 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)

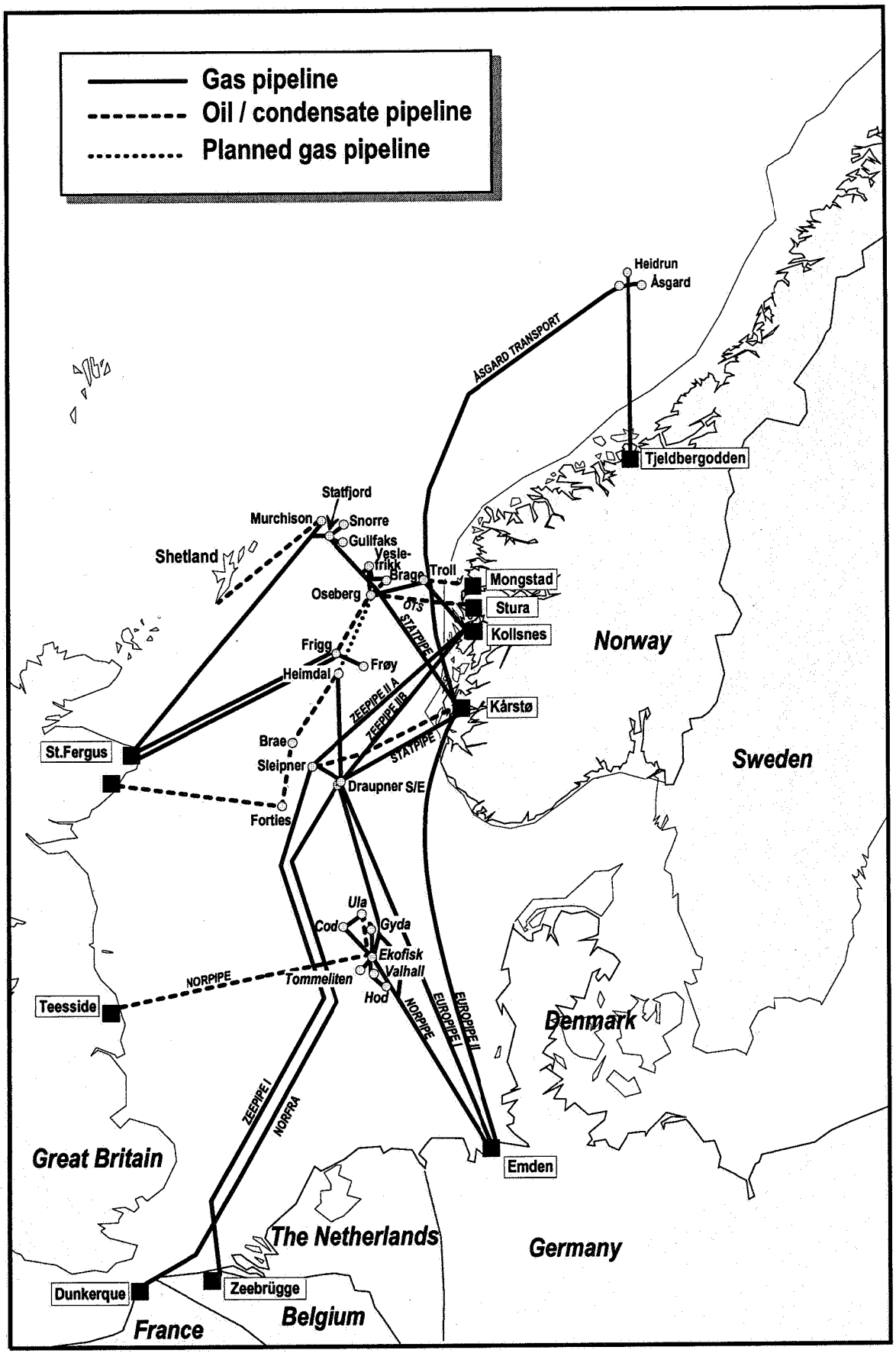
Ownership structure:

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.

Fig. 1.8.1
Transportation systems for oil and gas from Norwegian fields



Frostpipe

Ownership structure:	
Den norske stats oljeselskap a.s	50.00000 %
Elf Petroleum Norge AS (operator)	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.

1.8.2 PROJECTED TRANSPORTATION SYSTEMS

Åsgard Transport

Åsgard Transport will be a 745 kilometer long 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	60.50000 %
SDFI	46.95000 %
Saga Petroleum ASA	9.00000 %
Norsk Agip AS	7.90000 %
Total Norge AS	7.65000 %
Mobil Development Norway A/S	7.35000 %
Neste Petroleum AS	5.00000 %
Norsk Hydro Produksjon AS	2.60000 %

Europipe II

Europipe II will be a 653 kilometer long 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:	
SDFI	60.00000 %
Den norske stats oljeselskap a.s	0.01000 %
Norsk Hydro Produksjon AS	4.72000 %
Saga Petroleum ASA	10.63000 %
Esso Expl. and Prod. Norway A/S	7.68000 %
Mobil Development Norway AS	1.18000 %
Total Norge AS	5.90000 %
Elf Petroleum Norge AS	0.00600 %
Norsk Agip AS	2.36000 %
A/S Norske Shell	1.18000 %
Neste Petroleum AS	3.66000 %
Norske Conoco A/S	66.00000 %

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

1.9 PETROLEUM ECONOMY

The petroleum sector is in continuous growth and development. The sector 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. For 1996, this share has increased to 16%, which is largely a consequence of the high oil prices. The share is expected to be somewhat reduced in 1997 and 1998.

The petroleum sector also accounts for a large and increasing share of total exports from Norway. In recent years the share has been about 33%, while it rose to 39% in 1996. It is expected that the share will be somewhat reduced in the next few years.

The activity level on the Norwegian shelf leads to employment both offshore and on land. Nearly 73,000 people were employed in petroleum-related activities in Norway in 1996.

The petroleum activities create large revenues for the licensees and the state. The net cash flow from the activities (total revenues from sale of petroleum products less total costs connected with these activities) amounted to approx. NOK 100 billion in 1996. The state's share of the net cash flow (taxes, fees, net cash flow from the state's direct financial involvement, dividend from Statoil) is estimated to be over NOK 70 billion in 1996.

Estimates for future cash flow may vary significantly due to the uncertainty connected with production and price development for oil and gas. In pure calculation/technical terms, this may be illustrated using simple sensitivity analyses. Figure 1.9.a shows that the future cash flow will be extremely sensitive to changes in oil production and a lasting change in the price of oil.

It is evident that the activity within the petroleum sector in the years to come will transition from development-related tasks to tasks connected with operation of fields and pipelines. Figure 1.9.b shows the distribution of costs for exploration, operation and investments during the period from 1990 - 2006.

Fig.1.9.a
Net cash flow estimates, the Norwegian shelf 1997 - 2006

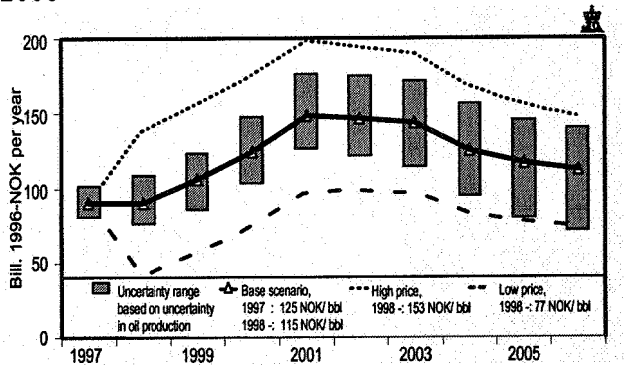
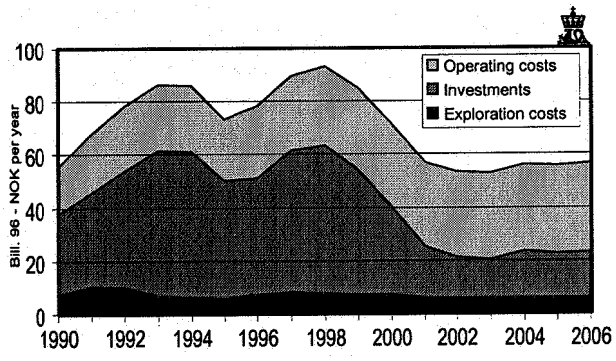


Fig. 1.9.b
Total costs Norwegian shelf 1990-2006

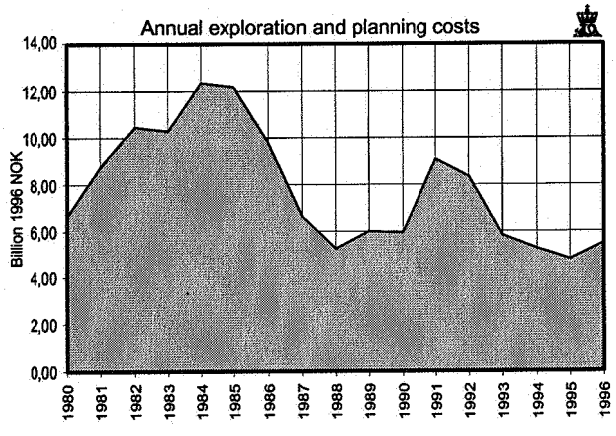


1.9.1 EXPLORATION AND PLANNING ACTIVITIES

In 1996, 30 exploration wells were spudded, while the number of exploration wells in 1995 was 36. 21 wildcat wells and 9 appraisal wells were spudded in 1996. Corresponding figures for 1995 were 22 and 14. On average over the period from 1966-1996, the number of spudded wildcat and appraisal wells has been 20 and 8, respectively.

Figure 1.9.1.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 the Norwegian Petroleum Directorate's reported figures, the total exploration costs in the years 1980-1996 amount to approximately 132 billion 1996-NOK.

Fig. 1.9.1.a
Annual exploration and planning costs



Exploration and planning costs for 1996 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 1.9.1.b, which shows the percentage distribution of the costs.

Exploration and planning costs	Million NOK
Exploration drilling	2721
General surveys	1207
Field evaluations	432
Administration [1]	1096
Total	**5456**

[1] Administration costs include area fees.

In 1996, the share of exploration costs related to exploration drilling was 50%, while the corresponding figure for 1995 is 45%. The share of costs related to general surveys is 22% in 1996 compared with 14% in 1995. General surveys include inter alia collection of seismic data.

Fig. 1.9.1.b
Percentage distribution of the costs

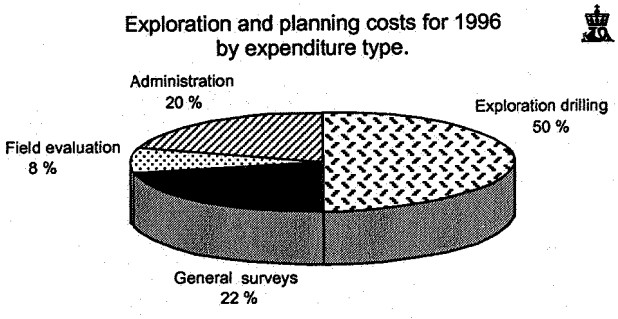


Figure 1.9.1.c shows the average drilling expenses per exploration well, that is, wildcat and appraisal wells. In 1996, drilling was carried out at a cost of around NOK 2.7 billion, and the cost per well is estimated to be about NOK 91 billion. This is an increase compared with 1995 when drilling was carried out for about NOK 2.1 billion, which constituted approx. NOK 61 million per well.

Fig. 1.9.1.c
Average drilling cost per exploration well

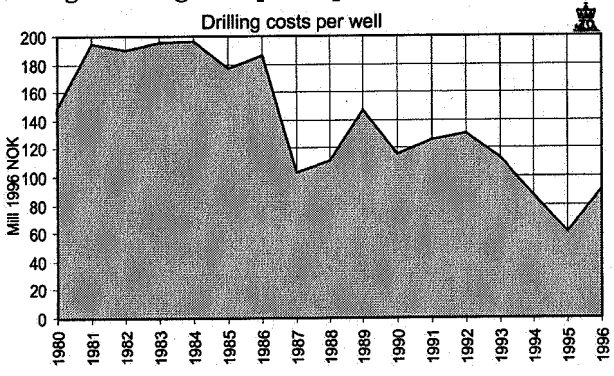
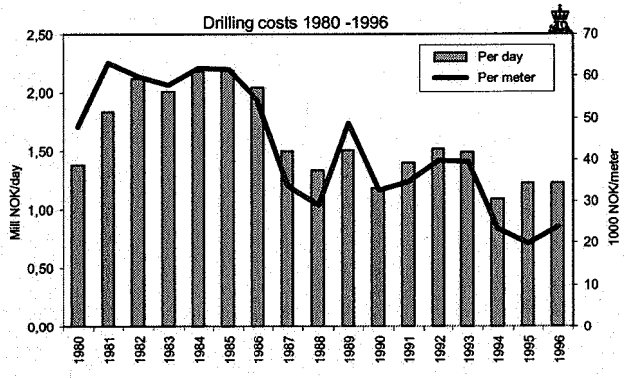


Figure 1.9.1.d shows the average drilling costs per day and per meter drilled in the years 1980-1996.

Fig. 1.9.1.d
Average drilling costs per day and per meter drilled in the years 1980 - 1996



1.9.2 ACTIVITY LEVEL TOWARDS YEAR 2006

The Norwegian Petroleum Directorate has taken a closer look at the expected total activity level on the Norwegian shelf towards the year 2006. Estimates of the total petroleum production may increase towards a level of about 290 million Sm^3 o.e. in the year 2001, and will thereafter be reduced somewhat. There is some uncertainty connected to the expected production in the future. In particular, the future development of oil and gas prices will have a significant effect on the long-term development of production.

Estimates of the total investment level in the period 1970-2006 are shown in Figure 1.9.2.a. The investment level reached a peak in 1993 and 1994 with investments of about 55 billion 1996-NOK each year. In the following years, the investment level sank somewhat, but is expected to reach approximately the same size in 1998. After this, it is expected that the investments will fall to under NOK 20 billion from 2001. Investments related to resources which are currently in the planning phase as well as undiscovered resources account for the majority of the expected investment level towards 2006. There is great uncertainty connected with the estimates for investment costs, particularly for undiscovered resources. Changes in future oil and gas prices will affect the estimate of future investment levels.

Figure 1.9.2.b shows the estimated development in total operating costs on the Norwegian shelf towards the year 2006. Operating costs include CO_2 taxes and insurance. There is great uncertainty connected with the estimates for operating costs, particularly for undiscovered resources. Improved resource exploitation, a greater degree of coordination of operations-related tasks, common use of infrastructure and development of new cost-efficient technology are important challenges in order to reduce operating costs on the Norwegian shelf. This could extend the economic lifetime of fields.

Figure 1.9.2.c shows the expected development in operating costs per produced unit for fields in operation. Many of the fields which are in production now are producing at plateau level so that the activities are in a period with relatively low operating costs per produced unit. As the production from the fields gradually enters the decline phase, the operating costs per produced unit will increase.

Fig. 1.9.2.a
Investments in fields, discoveries and pipelines on the Norwegian continental shelf 1970 - 2006

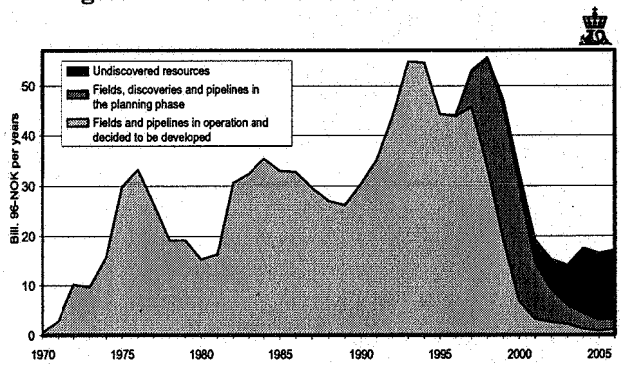


Fig. 1.9.2.b
Operating costs for fields, discoveries and pipelines on the Norwegian shelf 1970-2006

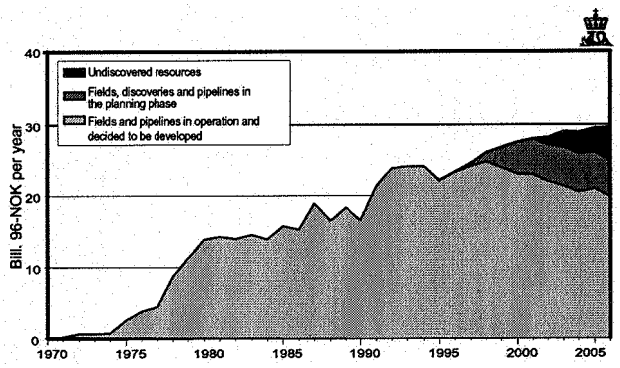
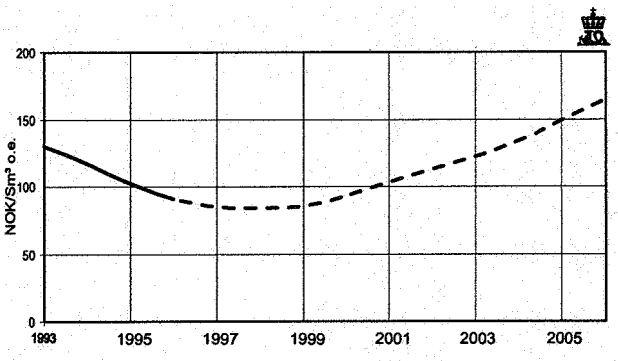


Fig. 1.9.2.c
Operating costs per produced unit for fields in production



1.9.3 THE STATE'S DIRECT FINANCIAL INTEREST

The State's Direct Financial Interest (SDFI) in the petroleum activities was established with effect from 1985.

Historically, the main principal has been that the cash flows linked to the total state participation in production licenses was split into a share for Statoil (20%) and an SDFI share (30%). However, this principle has been changed somewhat in recent years. In the 15th licensing round there were also blocks awarded without SDFI participation. Statoil is responsible for the operational and financial administration of the state's direct shares.

SDFI is the largest investor on the Norwegian shelf, and represents a considerable volume in the exploration, development and operations phases.

Total investment costs on the Norwegian continental shelf for the period from 1996-2001 are estimated at NOK 152 billion (non-discounted firm 1996-NOK). This includes investments in fields in production and fields approved for development as well as pipelines in operation and approved for development. SDFI's share is about 41%.

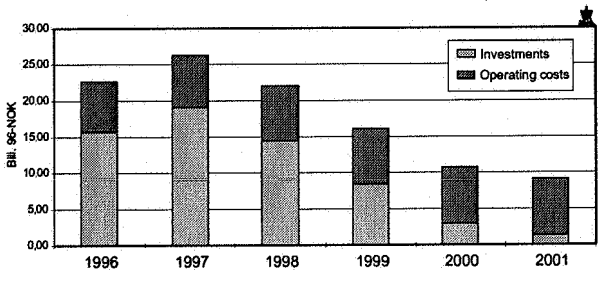
The total operating costs during the period are estimated to be NOK 142 billion. These costs comprise operating costs incurred and CO_2 taxes, but not tariffs. SDFI's total share of these investment and operating costs constitutes about NOK 107 billion. SDFI's share is about 32%. Distribution over time is illustrated in Figure 1.9.3.

Of the total anticipated production, SDFI is expected to account for about 49% of both oil (including condensate) and gas production for the same period.

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.

One of the main objectives of the licensing and taxation systems is to distribute costs and revenues between private licensees (companies) and the state. Through SDFI and framework conditions such as taxes, fees, carrying and use of a sliding scale favoring SDFI, the state has collected a maximum share of the net current value of the fields.

Fig. 1.9.3
SDFI : Net costs



1.9.4 CRUDE OIL MARKET

Global oil production in 1996 (excluding NGL) is estimated to be about 63.4 million barrels per day (Source: Oil and Gas Journal (OGJ) December 1996). This corresponds to just under 3.7 billion Sm^3 per year, and means an increase of 2.5% from 1995 to 1996. Production from the OPEC countries increased by 2.8%, or a little more than average. In Eastern Europe and the former Soviet Union, production declined by a little more than 1%. Other regions, including the North Sea, showed an overall increase in production.

In 1996, Norwegian oil production accounted for a scant 5% of global production. Norway's production increased according to OGJ by about 11% in 1996, and also in 1996 was 17% higher than British production, which increased by a scant 3%. The Norwegian Petroleum Directorate's own figures show a somewhat larger increase for Norwegian oil production (+12.1%). OPEC's market share was just over 40%.

According to OGJ, the global proven oil reserves at the end of 1996 were 162 billion Sm^3, up more than 1 billion from 1995. This constitutes 44 years of production at 1996 level. The growth largely took place in OPEC, where Iran and Iraq in particular increased their resource estimates. The estimates for resources outside of OPEC are basically unchanged, with the greatest increase for Norway, and an overall reduction for other non-OPEC countries. Based on the resource estimates, the largest oil-producing areas in the future will be OPEC and the Middle East.

At the beginning of 1996, the price of Brent Blend oil was about 17-18 dollars (USD) per barrel. The oil price then rose markedly from February to mid-April. Low reserves combined with cold weather contributed to an explanation of the increase. The oil price continued to rise through the autumn. This resulted in an average norm price for Norwegian-produced oil of a scant 21 USD per barrel, or just over NOK 135 per barrel. As a comparison, the price for Norwegian-produced oil in 1995 was an average of approx. NOK 108 per barrel (about 17 USD).

1.9.5 NATURAL GAS MARKET

Today, all Norwegian export of gas goes to Western Europe. In 1996, Norway exported gas to the United Kingdom, Germany, the Netherlands, Belgium, France, Spain and Austria. Figure 1.9.6.c shows the distribution of gas sales to the various buyer countries.

In 1996, export from Norway constituted 38.1 billion Sm^3 (41.5 MJ/Sm^3), an increase of about 10.5 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.

Organization of Norwegian gas sales

In recent years, the sale of Norwegian gas has been coordinated by a joint Gas Negotiation Committee (GFU) under the leadership of Statoil, and with representatives from Norsk Hydro and Saga. Other companies have also been involved in the negotiations for certain gas sales contracts. The GFU negotiates contracts with purchasers of Norwegian gas. The licensees in a production license do, however, have the opportunity to sell gas on their own. 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, has an advisory role towards the Ministry of Industry and Energy in questions related to development and management of gas fields and transportation systems for gas. The Ministry of Industry 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. The Troll agreements consist of basic gas deliveries of 23.7 billion Sm^3 per year, as well as the 30% and 50% options which gave the buyers the right, but not the obligation, to receive deliveries in excess of the basic volumes. After the exercise of these options, these sales constitute 40.8 billion Sm^3 per year at plateau.

Newer commitments

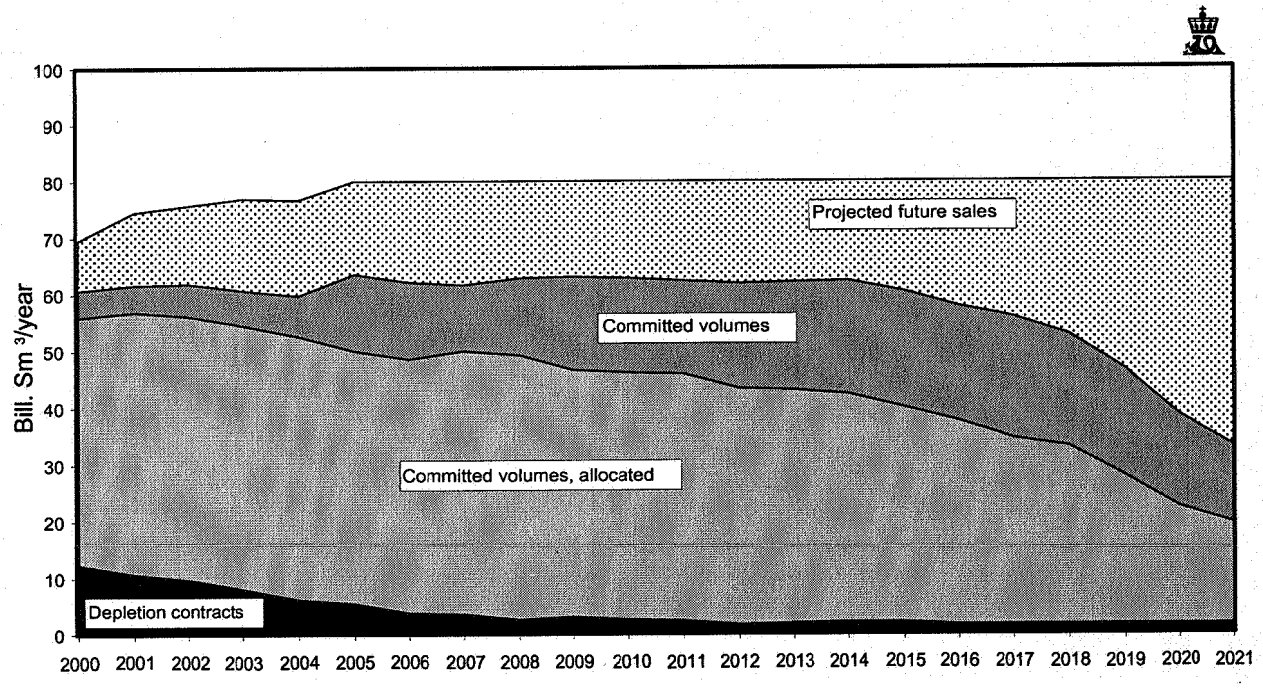
In 1992, the Electrabel contract (Belgium) was signed. In 1993, two new contracts were signed for the sale of additional volumes to Ruhrgas and VNG (Germany). In 1994, contracts were signed with MEEG (Germany) and GdF (France). In 1995, a contract was signed with GdF (France) for the sale of additional volumes.

In all, these five contracts constitute 14.7 billion Sm^3 per year at plateau. New sales to the United Kingdom have also been negotiated, but these are dependent on agreement with the British authorities.

New sales

During 1996, negotiations and discussions have been conducted with possible buyers in a number of countries.

Fig. 1.9.5
Committed and projected future gas sales.



A contract with the Italian company SNAM for 6 billion Sm^3 gas annually with the possibility of increasing to 8 billion Sm^3, and a contract for 3 billion Sm^3 per year with the Czech company, Transgas, may be imminent.

Sale of Norwegian gas to the Scandinavian market has not yet been economically interesting. The same applies to sale of Liquified Natural Gas (LNG).

There is a potential that Norway's total gas sales over the long term may reach 80 billion Sm^3 per year. Figure 1.9.5 shows committed and potential new sales. Committed volumes are divided between field contracts, allocated volumes and non-allocated volumes. The Ministry of Industry 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 Industry 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 and other purposes. 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 1996, a total of 15.9 billion Sm^3 gas was used for injection and 2.8 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 is also 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.

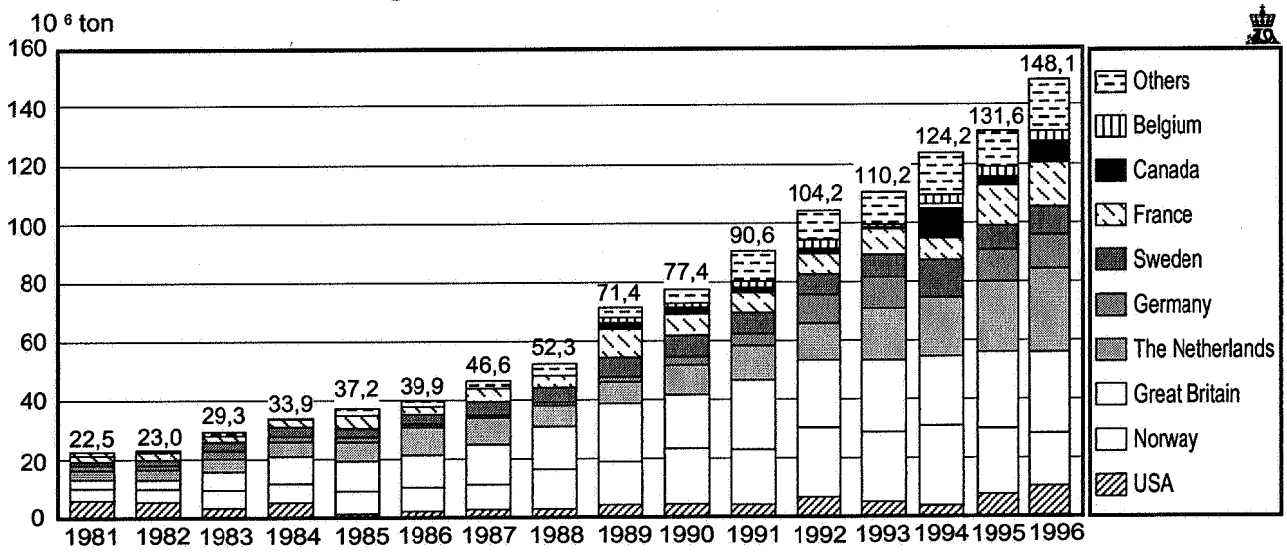
In 1994, Statkraft, Statoil and Norsk Hydro set up a joint company, Naturkraft. In 1996, Naturkraft has received a concession for development and operation of two gas power plants. The power plans will be established at Kårstø and Kollsnes. Total consumption of gas in the gas power plants will be 0.9 billion Sm^3 gas per year.

1.9.6 SALE OF PETROLEUM FROM THE NORWEGIAN CONTINENTAL SHELF

In 1996, 148.1 billion tonnes of crude oil was sold from the Norwegian continental shelf. This represents an increase of 12.5% compared with 1995. The Netherlands was the largest recipient with 28.4% of the shipments, the United Kingdom received 27.2%, Norway 18.1%, France 15.4% and Germany 11.7%. In 1996, Norway received 22.4%, a decline compared with 1995. Figure 1.9.6.a shows crude oil sales distributed by country in the period 1981-1996.

Up to 1988, Belgium and Canada are included in the group "others". Sale of NGL (including condensate) from the Norwegian continental shelf in 1996 reached 7.1 mil-

Fig. 1.9.6.a
Sale of crude oil from the Norwegian continental shelf



lion tonnes. This is 0.6 million tonnes more than in 1995. Figure 1.9.6.b shows the sale of crude oil and NGL in 1996 distributed by licensees.

Norway exported 38.1 billion Sm^3 gas in 1996. This is an increase of 38% compared with 1995. 14.6 billion Sm^3 was sold to Germany, 1.7 billion Sm^3 to the United Kingdom, 10.6 billion Sm^3 to France, 4.3 billion Sm^3 to the Netherlands, 5.1 billion Sm^3 to Belgium, 1.4 billion Sm^3 to Spain and 0.3 billion Sm^3 to Austria, see Figure 1.9.6.c. Figure 1.9.6.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.

Fig. 1.9.6.b
Sales quantities of oil/NGL (excl. condensate) per licensee in 1996

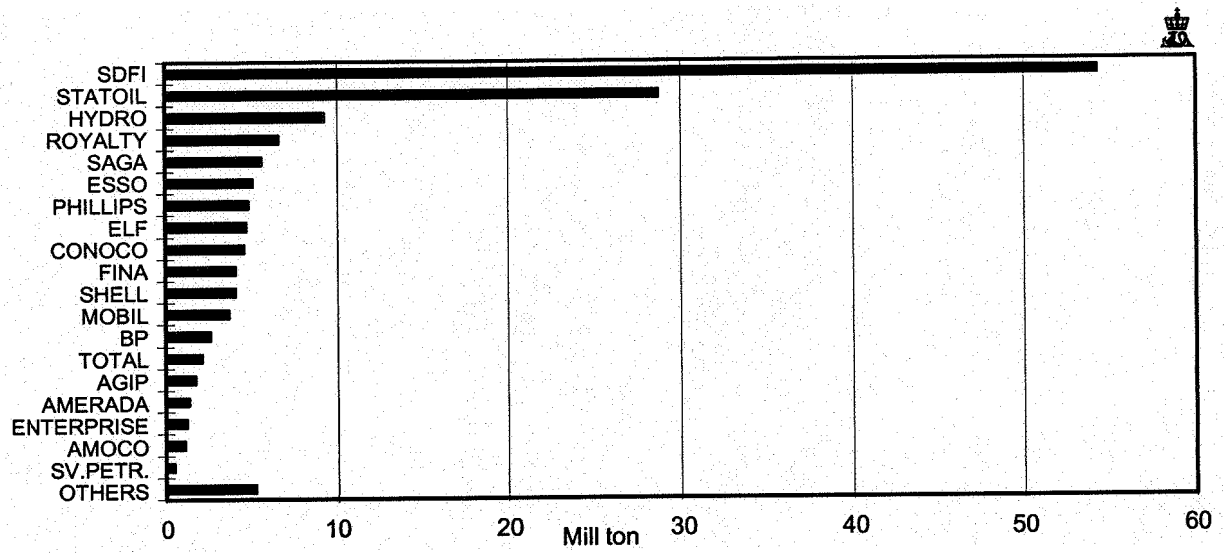


Fig. 1.9.6.c
Sales quantities of gas per country

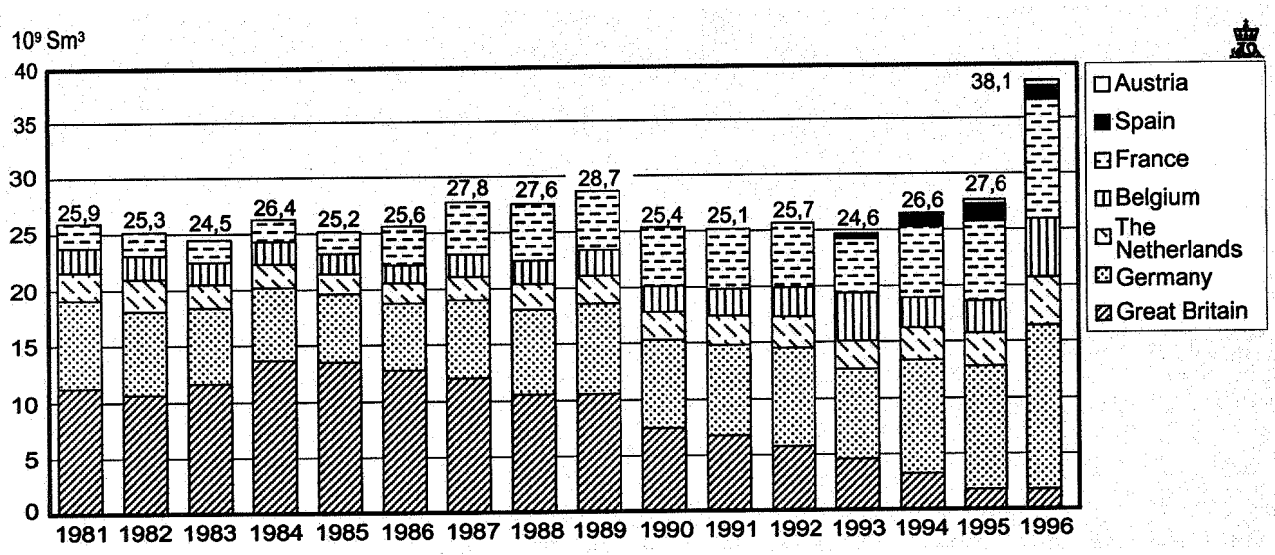
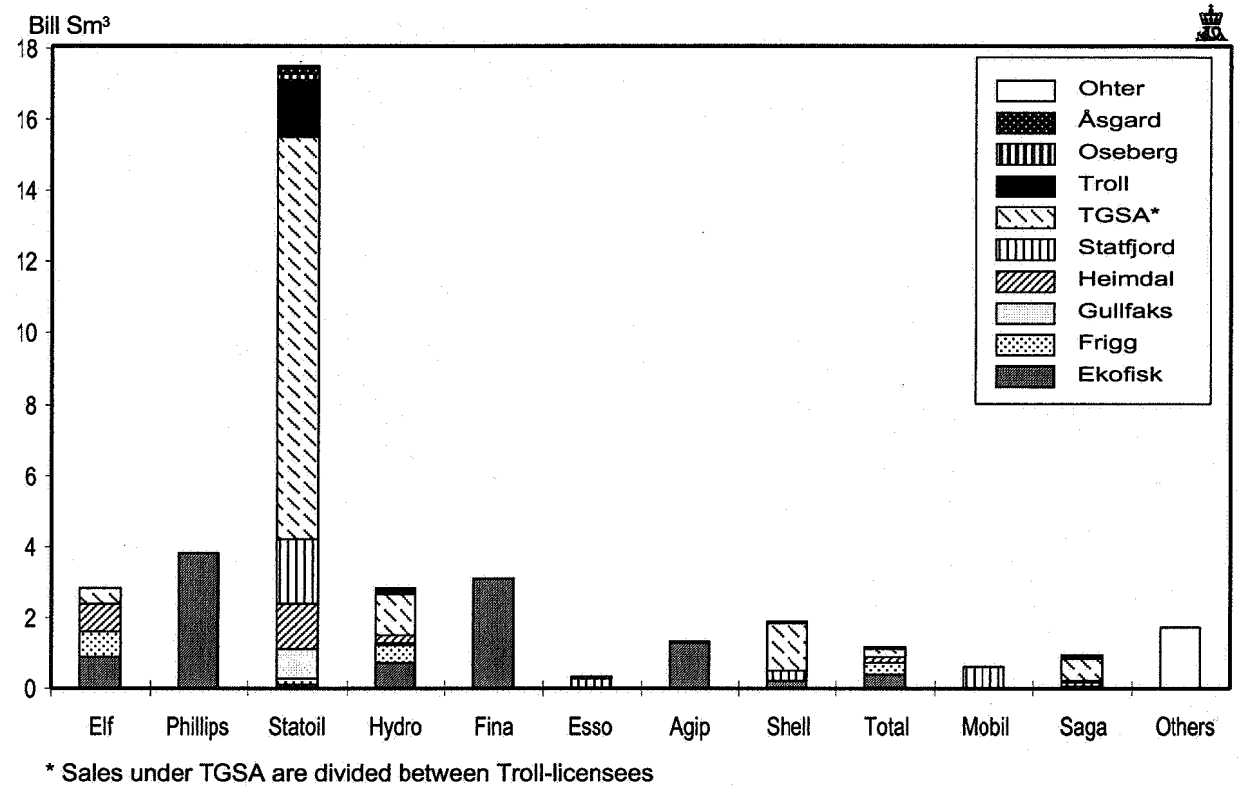


Fig. 1.9.6.d
Sales quantities of gas per licensee in 1996



* Sales under TGSA are divided between Troll-licensees

1.9.7 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.

In Odelsting. Proposition No. 64 (1986-87), the Act regarding amendments to the Petroleum Act, it was provided that royalties would not be charged for production from deposits for which the development plans were approved after 1 January 1986.

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

From 1 January 1992, the royalty rate for gas was set to nil, cf. Royal Decree of 27 March 1992 and The Crown Prince Regent's Decree of 22 May 1992. 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.

Table 1.9.7.a
Royalty paid in 1994 and 1995 (mill NOK)

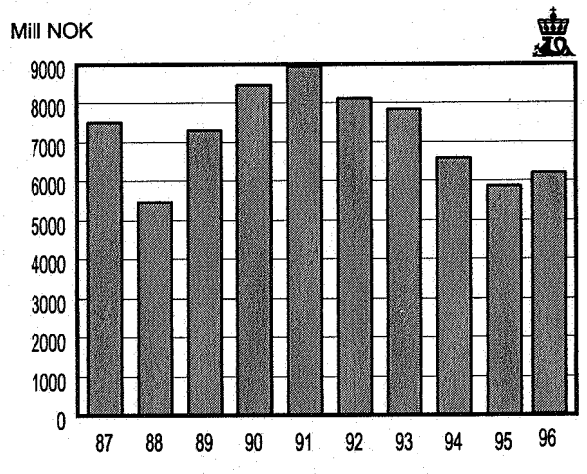
Product	Field/area	1995	1996
Oil	Ekofisk area, Ula and Valhall	1 500,4	1 766,8
"	Statfjord	2 610,5	2 457,6
"	Murchison	8,3	13,2
"	Heimdal	*-7,8	6,2
"	Oseberg	934,9	1 164,9
"	Gullfaks	807,7	864,7
NGL	Ekofisk area	22,2	21,5
"	Valhall	4,8	4,3
"	Ula	2,9	1,9
"	Murchison	1,0	0,1
"	Heimdal	**-0,8	0,1
TOTAL		5 884,1	6 301,3

* Refund of transportation costs for royalty oil for previous years
** Repaid production royalties for gas for previous years

Total royalty

In 1996, licensees on the Norwegian continental shelf paid royalties totaling NOK 6,301,343,399 to the Norwegian Petroleum Directorate. Table 1.9.7.a shows the breakdown for the various petroleum products for 1995 and 1996. Figure 1.9.7 shows paid royalties from 1987-1996.

Fig. 1.9.7
Royalties paid 1987-1996



Royalty on oil

In 1996, NOK 6,273,398,061 was paid in royalties for oil from the Ekofisk area, Ula, Valhall, Statfjord, Murchison, Heimdal, Oseberg and Gullfaks, see Table 1.9.7.b. The royalty on oil is usually taken out as oil, but the Ministry of Industry 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. In spite of the fact that the received quantity of royalty oil has been reduced by more than 14% in 1996 due to lower production from those fields where there is a royalty, the royalty has nevertheless increased by 7.2% as a consequence of significantly higher oil prices in 1996 than in 1995.

Table 1.9.7.b
Royalty paid on oil (NOK)

Field/area	1st half	2nd half	Total 1996
Ekofisk area, Ula and Valhall	791 717 859	975 048 942	1 766 766 801
Statfjord	1 249 839 752	1 207 802 191	2 457 641 943
Murchison	4 897 026	8 322 780	13 219 806
Heimdal	0	6 240 267	6 240 267
Oseberg	490 664 951	674 198 113	1 164 863 064
Gullfaks	427 532 440	437 133 740	864 666 180
TOTAL	2 964 652 028	3 308 746 033	6 273 398 061

Table 1.9.7.c
Royalty paid on NGL (NOK)

Field/area	1st half	2nd half	Total 1996
Ekofisk area			
Phillips group	11 044 130	10 177 433	21 221 563
Amoco group (Tor)	15 401	67 345	82 746
Dyno/Methanor	171 685		171 685
Total	**11 231 216**	**10 244 778**	**21 475 994**
Valhall	1 633 579	2 719 636	4 353 215
Ula	1 237 842	664 835	1 902 677
Murchison	26 892	40 387	67 279
Heimdal		146 173	146 173
Total all fields	**14 129 529**	**13 815 809**	**27 945 338**

Royalty on NGL

In 1996, NOK 27,945,338 has been paid in royalties on NGL. Table 1.9.7.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 a reduction in the paid royalty on NGL from 1995 to 1996 of more than 7%.

1.9.8 AREA FEES ON PRODUCTION LICENSES

In 1996, the Norwegian Petroleum Directorate collected NOK 1,258,005,634 in area fees. The amount is broken down among production licenses as shown in Table 1.9.8.

The Norwegian Petroleum Directorate has refunded NOK 98,751,176 in area fees in 1996. 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 1.9.8.a shows the net area fee receipts for 1973-1996. For 1996, there was an increase of over NOK 600 million compared with 1995. The reason for this is that production licenses awarded according to the 1972 resolution and the Petroleum Act paid their area fees for 1996 on 2 January 1996 and for 1997 on 31 December 1996.

Production royalties and area fees in 1996 amounted to 33% of total taxes and fees paid from the petroleum activities. The proportion of the fees has varied over time. The highest proportion was in 1989 with 53%. Figure 1.9.8.b shows the total taxes and fees paid from 1980 to 1996.

Table 1.9.8
Area fees in production licenses

Production license awarded	NOK
1965	59 286 556
1969	48 563 066
1971	4 899 904
1973	70 956 000
1975	57 591 000
1976	147 744 000
1977	41 652 000
1978	84 807 000
1979	244 560 864
1981	135 465 897
1982	46 922 250
1983	71 153 589
1984	77 653 168
1985	83 442 780
1986	20 005 236
1987	9 443 096
1988	24 372 601
1989	8 897 210
1991	9 390 287
1992	439 028
1995	10 760 102
Total	**1 258 005 634**

1.9.9 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 1995 and 1996, the CO_2 tax was fixed at NOK 0.83 and 0.85 per Sm^3 gas and NOK 0.83 and 0.85 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 1.9.9 shows the total tax paid in 1996. 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 2,787,225,474 was paid in 1996.

Fig. 1.9.8.a
Area fees 1973-1996

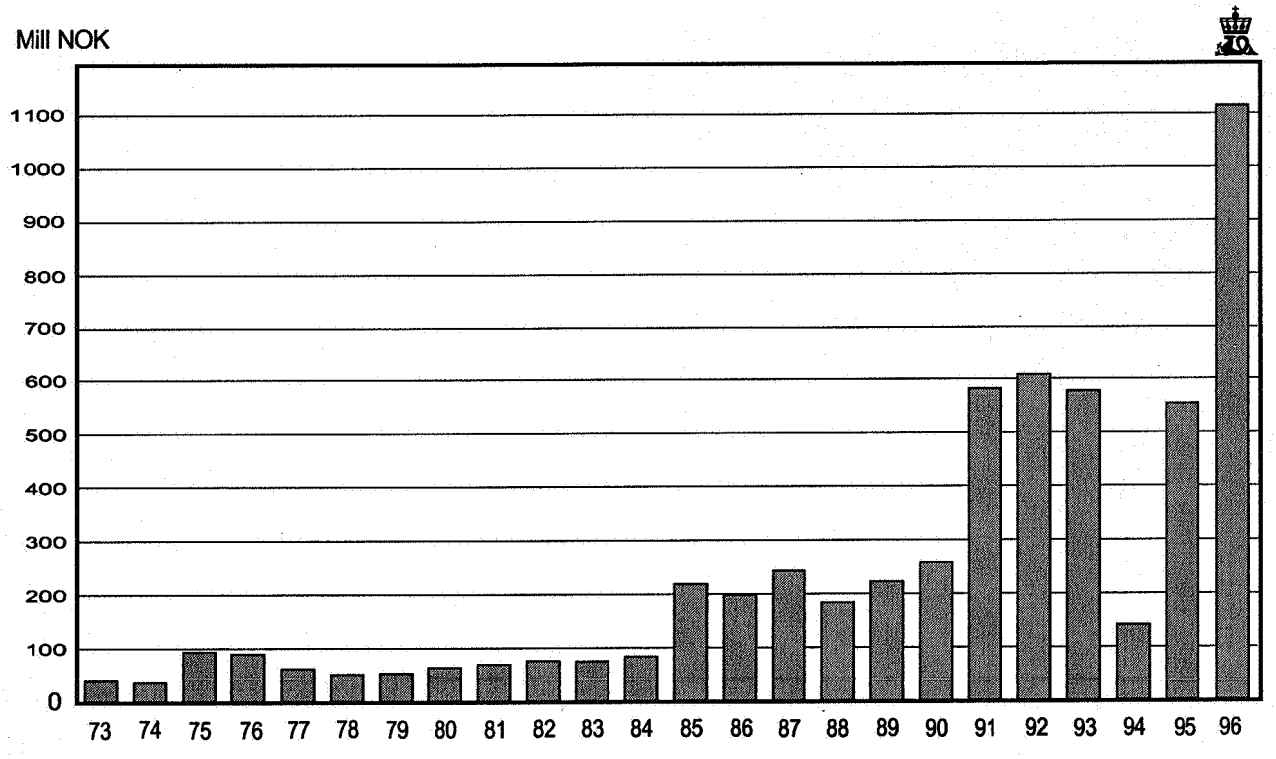


Fig. 1.9.8.b
Total taxes and royalties

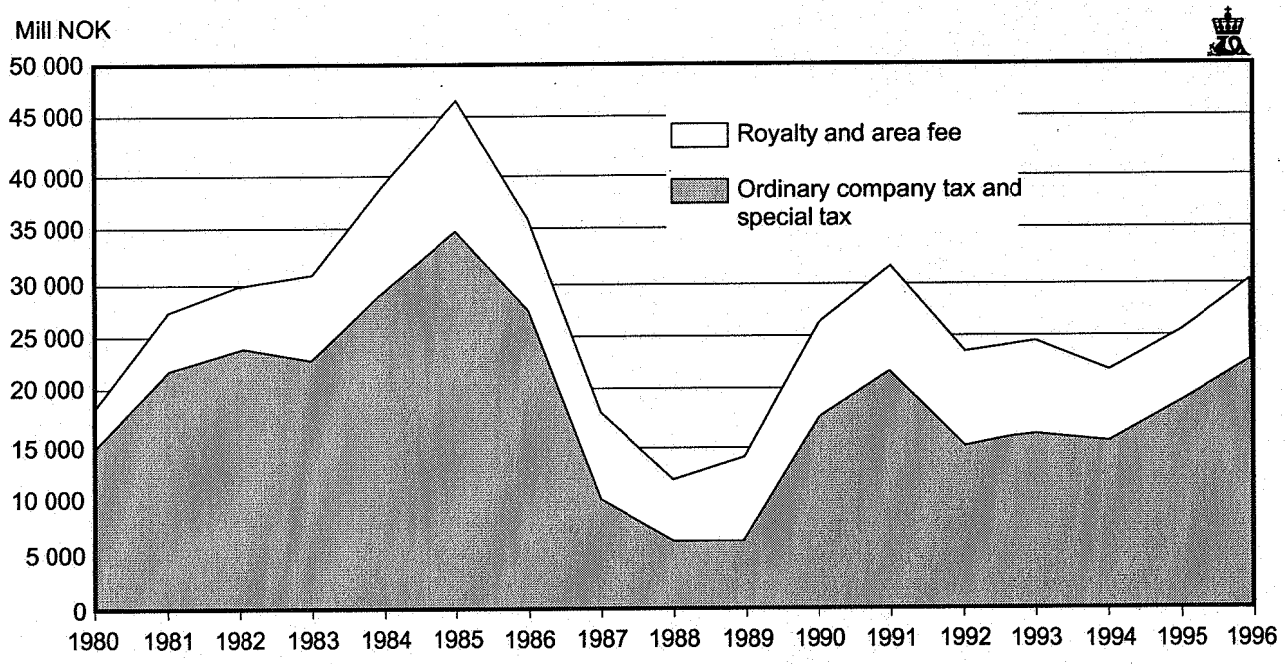


Table 1.9.9
CO_2 -tax for the 1st and 2nd half 1996 (NOK)

Field:	1st half	2nd half	Total 1996
Ekofisk area	361 601 016	363 984 714	725 585 730
Frigg area	19 673 063	16 264 241	35 937 304
Gullfaks A+B+C	164 375 997	163 736 950	328 112 947
Yme		19 092 737	19 092 737
Gyda	19 755 632	18 259 430	38 015 062
Heimdal	18 834 322	25 603 001	44 437 323
Hod	76 692	72 165	148 857
Murchison	7 815 174	9 734 643	17 549 817
Odin	29 382	110 840	140 222
Oseberg A+B+C	137 139 240	144 970 050	282 109 290
Brage	30 147 260	34 047 600	64 194 860
Sleipner	57 132 610	51 379 604	108 512 214
Statfjord A+B+C	227 099 559	218 149 628	445 249 187
Ula	26 862 837	25 769 661	52 632 498
Valhall	36 910 237	38 626 651	75 536 888
Veslefrikk	28 507 097	27 458 520	55 965 617
Snorre	43 507 999	48 314 379	91 822 378
Draugen	25 845 564	27 453 959	53 299 523
Troll A		24 004 238	24 004 238
Troll B	24 992 130	37 060 000	62 052 130
Heidrun	64 937 382	63 087 145	128 024 527
Transport systems:			
Norpipe	49 305 367	75 005 458	124 310 825
Statpipe	7 536 293	2 955 007	10 491 300
Total	**1 352 084 853**	**1 435 140 621**	**2 787 225 474**

2. Safety and working environment administration

The Norwegian Petroleum Directorate's performance of its administrative duties in connection with safety and the working environment is based on close cooperation in the areas of safety, working environment and resource administration, both internally within the Directorate as well as externally in relation to other authorities and institutions. 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 internal control. 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. Conclusions from the supervision are directed at areas of improvement in the companies' control systems.

The system-oriented supervision consists of systems audits which are supported by verifications. The systems audits have the objective of determining whether the control systems have been established and whether they function as expected. The objective of the verifications is to evaluate the effect of the control systems by examining the actual standard of safety and the working environment in the activities. The Norwegian Petroleum Directorate's supervisory activities come in addition to the industry's own audit and inspection activities which are carried out to ensure that the activities are always in compliance with the requirements of the authorities and of the industry itself.

2.1 ESTABLISHMENT OF FRAMEWORK

General

The Norwegian Petroleum Directorate has once again carried out an annual updating of the regulations in 1996. The updating has included incorporation of relevant portions of the EEA Agreement regarding the electrical area as well as minor adjustments or clarifications in the other regulations. The Directorate has maintained a strong commitment with regard to follow-up of ongoing standardization work which is of significance for the petroleum activities, as well as follow-up of the EEA Agreement.

Overarching regulations

In 1996, the Norwegian Petroleum Directorate has assisted the Ministry of Local Government and Labour in its work to revise the departmental regulations under the Petroleum Act. In this connection, at the end of the year the Norwegian Petroleum Directorate has submitted to the Ministry proposals for new regulations in the following areas for circulation to interested parties for comment:

- safety in the petroleum activities,
- control of own activities in order to comply with the authorities' requirements in the petroleum activities (internal control),
- reimbursement of expenses in connection with supervision of the petroleum activities.

The proposals have been harmonized with the new Petroleum Act and incorporate users' experiences as well as relevant NORSOK recommendations.

New regulatory structure for safety and the working environment in the petroleum activities

The Norwegian Petroleum Directorate has submitted a proposal to the Ministry of Local Government and Labour concerning a new regulatory structure for the regulations relating to safety and the working environment in the petroleum activities.

The proposal entails the development of four new thematic regulations within the areas of control, documentation, technology and operation. These four regulations will inter alia incorporate the 14 prevailing thematic regulations for the area of safety and working environment. Furthermore, the proposal means that the new regulations will be developed with the objective of being in force at the turn of the year 1999/2000.

The goal of the regulatory reform is not to intensify the technical requirements for the activities, but it will continue the prevailing regulation within the framework of a new regulatory structure. In the opinion of the Directorate, such a restructuring will make the regulations more accessible and will provide the supervisory authorities with more comprehensive and efficient control instruments. Furthermore, the objective is to make arrangements for a greater degree of utilization of recognized industry standards, as well as to improve the predictability in connection with application of the regulations vis-à-vis mobile units.

The proposal must be viewed in context with the work which has been implemented in order to evaluate whether all or parts of the Norwegian Petroleum Directorate's technical guidelines may be incorporated in existing or new industry standards.

The proposal which has been submitted to the Ministry has been discussed on a general basis with employee and trade organizations in meetings in the external forum for regulatory development (ERR). The members of ERR have given their general support to the ideas which lie behind the proposal for a new regulatory structure.

Furthermore, the proposal for a new regulatory structure must also be viewed in light of the opportunities the reorganization will create with regard to:

- further simplification of overall Shelf regulations,
- the goal to further develop the regulations within the

areas of control and use, while the more technical-professional regulation will to a greater degree be carried out by standardization organizations in organization cooperation between the industry and the authorities,
- being able to place additional focus on the development of, and to work more intensively on areas which currently are not sufficiently or comprehensively regulated or coordinated in the overall Shelf regulations,
- better organization for interdisciplinary and coordinated processing under the established supervision system for activities on the Shelf,
- better adaptation of the regulatory structure to the structure in the EEA regulations so as to also better prepare for incorporation of the EEA Agreement and any subsequent additions to the Agreement in the overall Shelf regulations.

There is general agreement between the Norwegian Petroleum Directorate and the parties represented in ERR that the extra use of resources which must be expected over the short term as a consequence of the development and implementation of the new regulations will be more than offset by the efficiency gains which will be achieved over the long term. The industry has thus given its support to the continued work.

NORSOK standards

In Chapter 5.1, an account is given of NORSOK's proposal regarding incorporation of all or parts of the material content of the Norwegian Petroleum Directorate's technical guidelines in its standards.

2.2 SUPERVISORY ACTIVITIES

The supervision of safety and working environment in the petroleum activities was essentially carried out in accordance with the designated priority commitment areas for 1996.

Supervisory activities are carried out by means of audits and verifications specifically aimed at the individual operating company, with a point of departure which includes the Directorate's overall experience with each individual company.

Part of the supervision is, however, carried out as universal supervisory activities, which means that the supervision is aimed at several operating companies within the same problem area. This type of supervision provides a good basis for assessing the general situation within the respective areas.

Factors which influence the development of the Directorate's supervision plan include:

- signals from the Ministry of Local Government and Labour,
- the operators' activity plans,
- initiatives from coordinated and supporting agencies,
- new and changed regulations,
- experience with the operating companies, accidents and incidents,
- development trends within technology and organization.

The expenses for supervision aimed at the individual operating company are invoiced to the individual company according to fees which are stipulated by regulation. 60,000 man-hours of fee-related work were performed in 1996. The volume of the supervision work has been more or less constant over several years, in spite of the fact that the overall activity on the shelf is steadily increasing. Nevertheless, through the implementation of efficiency measures, the Norwegian Petroleum Directorate has been able to maintain proper supervision of the activities.

2.2.1 CONSENTS

The consent system is one of the tools the Norwegian Petroleum Directorate uses to supervise the operating companies to see that they are in control of central decision elements of their activities. The application for consent to commence an activity implies a commitment by the operating company to provide status with regard to regulatory requirements for the control systems in general, and the relevant activity in particular.

The Norwegian Petroleum Directorate's consent to commence the activity applied for is a formalized expression of the Directorate's confidence in the operator's ability to carry out the activity in accordance with the authorities' requirements.

A total of 115 consents were granted in 1996, compared with 105 the previous year. The consents granted in 1996 were divided among the following consent categories (1995 figures in parentheses):

2	(4)	consents for exploratory survey
24	(21)	consents for exploration drilling
9	(8)	consents for detail engineering
11	(12)	consents for fabrication
16	(16)	consents for installation
27	(21)	consents for use
8	(10)	consents for rebuilding or changes in operation
4	(1)	consent for removal of installation
14	(12)	consent for use of service vessel

All applications for consent have been granted after the Norwegian Petroleum Directorate's review. In some cases, the applications for consent were turned down because of lack of information regarding circumstances which had significance for the Directorate's consideration of the application. In these cases, the Directorate was nevertheless able to give its consent after the operator submitted a new application or provided the necessary additional information. In some cases, this has led to delays in the process, which could cause problems for the progress of the projects.

2.2.2 PRIORITY COMMITMENT AREAS

In 1996, the Norwegian Petroleum Directorate gave priority to supervisory activities associated with the following commitment areas:

- New development projects
- Older installations
- The industry's control and achievement of goals within safety and working environment

New development projects

The Norwegian Petroleum Directorate believes it is important to give priority to supervision of the operating companies' control over their own activities in the earliest stages of the development projects when decisions are made which have crucial importance for safety and working environment in the operations phase. The authorities want to stimulate innovation both within technology and organization and, among other things, have attempted to accomplish this through the formulation of the regulations. Development solutions which are previously untried on the Norwegian shelf may, however, entail new challenges related to safety and working environment, and therefore, the Norwegian Petroleum Directorate gives priority to supervision of the operators' evaluations and decision-making processes related to such developments.

Therefore, supervision under this commitment area has largely been aimed at the development projects Varg (Saga), Åsgard A and B (Statoil) and Balder (Esso). All of these developments are mobile production units with hulls, with the exception of Åsgard B, which is developed with a semi-submersible mobile production unit. The development projects have been in different project phases and have had different work schedules, so the supervision has encompassed both planning and fabrication.

The mobile production unit which is to be used on Balder, however, was built on "speculation", that is to say, the unit was planned and fabrication begun before the owner entered into a contract with the operator for use of the unit. For this reason, supervision was not carried out in the planning phase nor in the early stages of fabrication. After Esso assumed responsibility for the unit, however, several supervision activities have been directed towards the project.

In addition to the supervision carried out, status meetings and other meetings have been held with the projects. In the status meetings, the Norwegian Petroleum Directorate has emphasized a focus on safety and working environment. In connection with the review of the Plan for Development and Operation (PDO), the Directorate has identified potential deviations from the regulations and has focused on the operator's handling of these in the status meetings.

In general, the Norwegian Petroleum Directorate has registered that all of the projects have made satisfactory arrangements for use of previous operational experience and employee participation, inter alia through the safety delegate function and the working environment committees.

A common feature of all of these development projects is that the operating companies have set ambitious goals for themselves with regard to implementation time and economy. On the whole, it is the Norwegian Petroleum Directorate's impression that the companies follow up circumstances which the Directorate points out through their own supervisory activities, and that these are corrected within the stipulated deadlines. In addition, the companies demonstrate that the results of the Directorate's supervision are used actively in the transfer of experience between the companies in order to avoid repetition of mistakes. After an initiative by the Norwegian Petroleum Directorate, meetings for transfer of experience between the companies have been held.

The biggest problems have been related to the Balder project. Modification work on the unit necessitated by deficiencies both in relation to the regulations and to the operator's own requirements have led to a delay of production start-up.

Older installations

An increasing number of installations are now in or approaching the end of their production phase. In this phase, the operating companies will seek to reduce operating costs, in order to be able to extend production and thereby improve resource exploitation. At the same time, this often means that both the installation and equipment are used beyond the originally planned lifetime. Therefore, Norwegian Petroleum Directorate gives priority to supervision to ensure that the licensees' decisions are carried out in such a way as to maintain proper safety and working environment during this phase.

Supervision under this commitment area has included Phillips, with particular focus on the Ekofisk 2/4 T, C and FTP installations, Statoil (Statfjord A) and Elf (Frigg TCP-2 and DP-2).

Experience from this supervision is varied. In some areas, the Norwegian Petroleum Directorate has noted that a positive development has occurred with regard to improvement of systems for control of maintenance activities. In other areas, however, discrepancies have been registered in relation to the companies' own requirements for maintenance, and that measures which have been implemented on the basis of previous supervision by the Directorate have not resulted in the expected effect. In relation to one company, blameworthy circumstances were found which, among other things, are connected with lack of follow-up, e.g., with regard to handling of alarm signals concerning overpressure which shall guard against penetration of gas into the control room, etc. Several directives have been issued to the company in this connection. The company has also been informed that stronger measures may be necessary if efficient compliance with the directives is not ensured.

Moreover, the Norwegian Petroleum Directorate has taken the initiative for a meeting between the involved operating companies in order to facilitate improved transfer of experience concerning problems related to aging and maintenance control.

The industry's control and achievement of goals within safety and working environment

The Norwegian Petroleum Directorate's exercise of the administration tasks within safety and working environment are based on an assumption that the operating companies will conduct their activities so as to ensure systematic compliance with regulatory requirements (internal control). In 1996, the Directorate has given priority to supervisory activities with a view towards influencing the industry to set concrete and ambitious goals and to implement measures in special areas which are important for safety and the working environment.

Thus, system audits have been carried out under this commitment area against selected operating companies, in which the operators' goals and steps in order to achieve these were reviewed in the areas of personal injuries, work-related diseases and falling objects.

In addition to this, supervision has been carried out of all operating companies aimed at the operators' own supervision activities. This has included evaluations of which priorities the companies have used as a basis for planning and implementation of their supervision, as well as by reviewing the companies' internal supervision reports in order to assess focus, scope and results of the supervision. In several cases, the Norwegian Petroleum Directorate has chosen to participate in the operators' own supervision in individual areas as a part of the basis for taking a stand as to the operators' exercise of supervision activities.

The work in this commitment area has also consisted of continuous evaluations of undesirable incidents and supervision results against the goals for safety and working environment which the individual operator has defined for its activities, as well as how the operators themselves evaluate and follow up these results.

The Norwegian Petroleum Directorate makes positive note that this type of supervision often seems to have entailed an increased commitment by management, which has contributed to concrete improvements with regard to organization, execution, reporting and follow up of the companies' supervision activities. Several companies have stated that the Directorate's follow up of the operators' own supervision is perceived as being constructive and useful.

The Norwegian Petroleum Directorate has also registered that issues such as goals for safety and the working environment, goal management and internal supervision have been given more attention in some license meetings and in the licensees' follow up of the operator. In some cases, the partners have participated actively in the operators' own supervision.

Furthermore, the supervision has given the Norwegian Petroleum Directorate better insight into the operators' ongoing follow-up of their own goal achievement and the way in which major deviations are followed up, for example, through information/ motivation campaigns or own supervision activities.

2.3 CONSENT SYSTEM FOR MOBILE UNITS IN PETROLEUM ACTIVITIES

The use of mobile units in petroleum activities will increase significantly in the years to come. Traditionally, mobile units have mostly been used for the drilling of exploration wells, but increasingly also for the drilling of production wells. Development trends in petroleum activities for the future clearly indicate significant use of mobile units, also in the production phase. This type of solution is particularly suited to development of small fields with short production lifetimes, but also other factors, such as deep water, can make the use of mobile units for production purposes interesting.

The shipping industry has particularly maintained that the Norwegian Petroleum Directorate's regulations and methods of supervision do not provide the desired degree of predictability with regard to the use of mobile units in petroleum activities on the Norwegian continental shelf. It was on this basis, among others, that the Business Legislation Committee in 1992 appointed a work group which was given a mandate to:

- evaluate and form an opinion as to whether the applicable safety regulations (including manning and qualifications rules) for mobile units and adjoining areas in the petroleum activities should be changed and, if necessary, make proposals for how the regulations should be changed

- evaluate and form an opinion as to whether today's system of administration and supervision of the regulations should be changed and, if necessary, propose changes

In the report submitted by the work group in 1993, the group recommends under the last part of the mandate, inter alia, that:

- a system of consent for use of mobile units on the Norwegian shelf be established

Furthermore, the work group recommends that the administrative responsibility for flag state legislation regarding safety, manning, etc. for mobile units in petroleum activities should be transferred from the Ministry of Foreign Affairs to the Ministry of Local Government and Labour, and that the latter be granted the authority to instruct the Norwegian Maritime Directorate and the Norwegian Petroleum Directorate, with regard to rules relating to safety, manning, etc. for mobile units in petroleum activities. The recommendations have been submitted to the ministries for consideration.

In 1996, the Norwegian Petroleum Directorate has continued internal work related to clarification of principle and administrative consequences for the Directorate if the

work group's recommendations are implemented, with the objective of being able to follow-up such a decision with rapid and efficient action for implementation on the part of the Norwegian Petroleum Directorate. Options are being kept open in the internal clarification work for several solution models which could satisfy the intentions of the work group's recommendations.

2.4 PERSONAL INJURIES

2.4.1 INTRODUCTION

The Norwegian Petroleum Directorate receives continuous reports regarding personal injuries in connection with petroleum activities on fixed and mobile units. 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 steps 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.

Report

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 personal 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 with background in 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 1996, this review led to retrospective reporting of approx. 14% of the total number of personal injuries included in this account. The control also led to 100 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, 14 injuries were reported in 1996 which occurred in 1995. 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.

2.4.2 FATAL ACCIDENTS

No accidents with fatal outcome occurred within the Norwegian Petroleum Directorate's area of authority in the petroleum activities in 1996. Unfortunately, however, three fatal accidents occurred on board vessels in connection with petroleum-related activities.

One person was killed during work on the deck of the standby vessel "Normand Mjolne" during preparations for a lifting operation between the vessel and the "Polycrown" flotel. The accident occurred while the vessel was in the process of backing up to the flotel. The victim was to receive a mail bag which was being lowered by crane from the flotel. There were two containers on the deck, whereof one had been freed for an imminent lifting operation. A strong wave which broke over the deck washed the loose container across the deck so that the man was crushed between the two containers and died from the injuries he suffered.

On the anchor-handling vessel "Far Minara", one person was killed while the vessel was pulling up an anchor buoy for a pipelaying vessel. The hoist got hung up in the deck plates astern. A seaman stationed in the area reported this, but due to inertia in the system, the winch did not stop immediately. This caused the hook to loosen and swing forward with great force, striking the victim in the head.

One person was killed on the pipelaying vessel LB 200. The weather was such that the vessel was rolling a bit. A pipe which was placed in the wrong location loosened and rolled towards a person engaged in grinding work on another pipe. The person was crushed between the two pipelines, and subsequently died of the injuries suffered.

These accidents are added to several fatal accidents during the last two to three years occurring on vessels which carry out tasks on the fringes of the petroleum activities. Activities onboard vessels are governed by maritime regulations, therefore, these accidents are not included in the statistical material for the petroleum activities. As the accidents have occurred in connection with activities connected with petroleum activities, the Norwegian Petroleum Directorate will nevertheless address these issues so as to ensure that measures are implemented to prevent such accidents. Among other things, the Norwegian Petroleum Directorate has initiated cooperation with the Norwegian Maritime Directorate in order to evaluate potential joint steps. Furthermore, cooperation has been initiated with the

Norwegian Shipowners' Association, the Norwegian Oil Industry Association and certain operating companies regarding this problem.

2.4.3 PERSONAL INJURIES ON FIXED INSTALLATIONS

In 1996, the Norwegian Petroleum Directorate registered 552 personal injuries on fixed installations, compared with 590 in 1995. Compared with the fact that the total number of work hours was reduced by 3.5%, this means that the total injury frequency is somewhat reduced. Furthermore, the operating companies' summaries show that approximately 25% of the injuries in 1996 resulted in absence, while the remainder only required basic medical treatment. For the previous year, the proportion of injuries causing absence was approximately 30%. This could indicate that fewer serious injuries occur, and that there has been an increase in the reporting of less serious injuries. 37 injuries during off-duty time have been reported in 1996, compared with 32 in 1995. These are mainly injuries connected with exercise activities.

Tables and figures - fixed installations

Table 2.4.3.a shows a summary of personal injuries per million man-hours on fixed installations for the period from 1987-1996. The figures also include mobile units which have a permanent gangway connection to fixed installations which are involved in production activities and which are thereby regarded as being fixed. For statistics from the period prior to 1987, the Norwegian Petroleum Directorate refers to previous annual reports. The tables have also been changed so that the injury frequency is now reported as injuries per million hours, and not per 1000 man-years, as before. Nor must the injury frequency be confused with various forms of injuries causing absence as it is based on injuries which are subject to the Norwegian Petroleum Directorate's reporting requirement, i.e., both injuries causing absence and injuries requiring medical treatment.

Figure 2.4.3a shows the development of personal injury frequency in injuries per million man-hours for the various main activities over the last ten years. Drilling and construction/maintenance have experienced a small reduction, while in the areas of administration/production and catering there has been a minor increase in the injury frequency over the last year.

The largest percentage increase in injury frequency on fixed installations from 1995 to 1996 may be found in the group of contractors employed in catering, while the injury frequency is still higher for operator-employed workers. The injuries in the area of catering are mostly related to cut and bruising injuries to the hands in connection with handling of kitchen equipment as well as some soft-tissue injuries to the feet and legs due to coming in contact with objects through dropping or kicking. Three serious injuries also occurred within catering caused by slippery floors, which resulted in one fracture and two concussions. Catering contributes approx. 9.8% of the total number of hours worked on fixed installations. In 1996, catering accounted for 8.5% of the injuries, with an injury frequency of 22.8 injuries per million man-hours, compared with 22.0 the previous year.

Table 2.4.3.a
Injuries/fatalities per million hours worked on fixed installation (1987-1996)

Year	Hours worked	Number of injuries/fatalities	Injuries and fatalities per million hours worked	Fatalities
1987	22.169.458	831	37,5	0
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	552	26,1	0
Total/average	216.284.082	6147	28,4	6

There has been a relatively large reduction in man-hours, approximately 16% within construction and maintenance during the last year. For contractor employees, the reduction in man-hours has been as much as 24%. Thereby, construction and maintenance accounts for 37.1% of the man-hours in 1996 compared with 42.6% in 1995. The proportion of injuries has also been reduced from 50.2% to 44.7% in 1996. Consequently, the total injury frequency for construction and maintenance activities has declined somewhat, in spite of a fairly significant increase in the injury frequency for the contractor employee group. The percentage of serious injuries within construction and maintenance has been cut in half. The most common types of injuries in this group are scrapes, cuts and crushing injuries. The hands are the most vulnerable body parts. There has also been a relative increase in the frequency of eye injuries among this personnel group.

Drilling and well operations accounted for approx. 22% of the total amount of work and approx. 26% of the injuries in 1996, roughly the same as in 1995. The injury frequency was 31.0 injuries per million hours, which is the second lowest recorded by the Directorate for this category. The majority of the injuries in 1996 have been cuts and crushing injuries in connection with handling of tools and equipment. 50% of all the injuries and all of the serious injuries to personnel within drilling and well operations occurred on the drill floor.

The administrative/production function has the lowest injury frequency, 17.2 injuries per million man-hours. This is a slight increase compared with 1995. Here too, accidents in connection with handling of tools are the most frequently occurring incidents. In addition, there are relatively many incidents where the injured person has bumped into objects such as pipes, scaffolding, and the like, which may be due to the fact that this group of personnel moves relatively often in areas where access is difficult.

Figure 2.4.3.b shows the injury frequency divided by operator employees and contractor employees in the main activity categories for 1996.

Figure 2.4.3.a
Personal injury frequency on fixed installations (1979-1996)

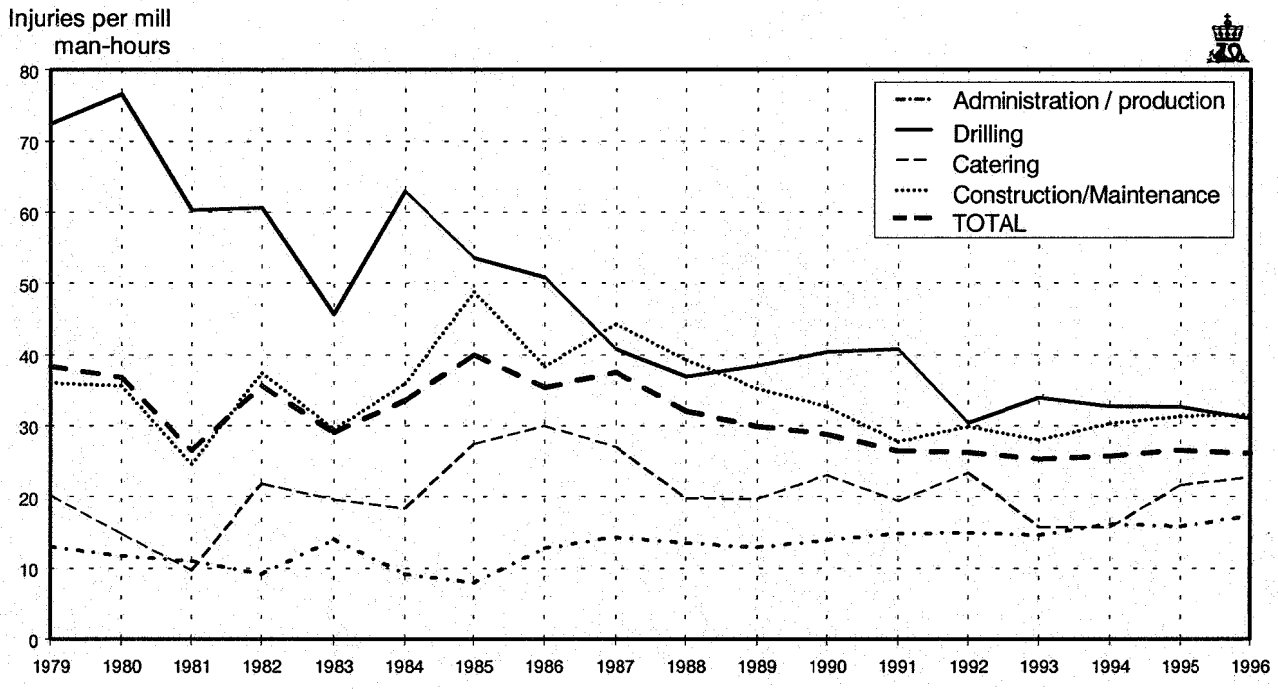


Figure 2.4.3.b
Personal injury frequency by operators and contractors - 1996 on fixed installations

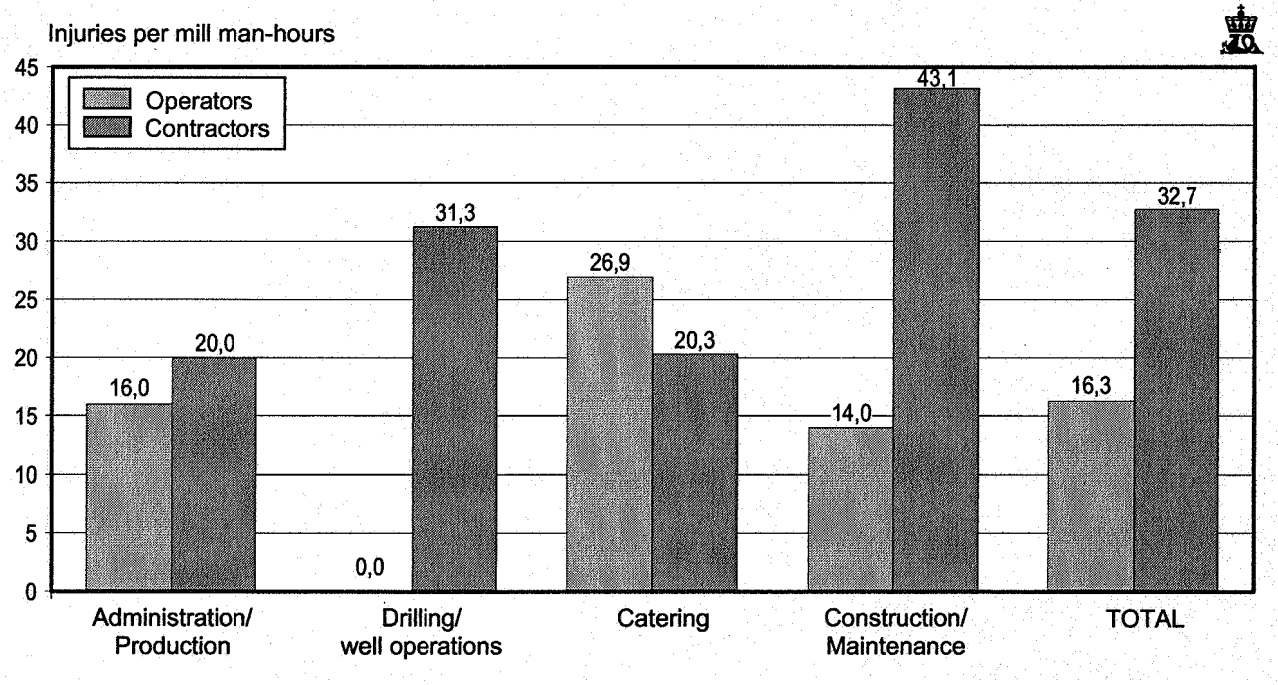


Table 2.4.3.b
Distribution of injuries and man-years on operator and contractor employees on fixed installations (1987- 1996)

FUNCTION		1987	1988	1989	1990	1991	1992	1993	1994	1995	1996	
Administrat./	Man-years	2.727.504	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	Operator
Production		972.036	731.848	473.928	806.000	683.488	594.828	776.984	754.416	1.065.532	2.053.363	Contractor
	Injuries	44	47	44	50	53	54	59	76	72	72	o
		9	6	6	12	14	15	14	15	20	41	c
	Injury frequ.	16,1	14,7	13,0	13,7	13,9	13,4	14,0	15,6	15,2	16,0	o
		9,3	8,2	12,7	14,9	20,5	25,2	18,0	19,9	18,8	20,0	c
Drilling	Man-years	0	0	0	0	0	0	0	0	0	0	(operator)
		2.526.004	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	(contractor)
	Injuries	0	0	0	0	0	0	0	0	0	0	o
		103	112	132	132	147	115	142	140	152	146	c
	Injury frequ.	0	0	0	0	0	0	0	0	0	0,0	o
		40,8	36,9	38,5	40,4	40,7	30,5	34,0	32,8	32,5	31,3	c
Catering	Man-years	151.528	336.908	548.080	638.352	720.564	747.968	802.776	731.848	707.668	779.369	(operator)
		1.729.676	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	(contractor)
	Injuries	5	4	3	13	13	17	12	10	19	21	o
		46	31	36	34	31	34	25	23	26	26	c
	Injury frequ.	33,0	11,9	5,5	20,4	18,0	22,7	14,9	13,7	26,8	26,9	o
		26,6	21,8	25,1	24,3	20,2	23,8	16,2	17,0	18,8	20,3	c
Construction/	Man-years	3.934.892	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	(operator)
Maintenance		10.128.196	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	(contractor)
	Injuries	49	51	70	63	65	80	39	48	45	44	o
		575	387	306	267	266	268	351	242	246	203	c
	Injury frequ.	12,5	13,2	18,2	16,5	16,3	19,6	9,0	15,0	14,3	14,0	o
		56,8	53,1	44,8	42,5	33,7	35,5	36,7	38,0	39,8	43,1	c
TOTAL	Man-years	6.813.924	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	(operator)
		15.355.912	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	(contractor)
	Injuries	98	102	117	126	131	151	110	134	136	137	o
		733	536	480	445	458	432	532	420	444	416	c
	Injury frequ.	14,4	13,8	15,1	15,6	15,4	17,0	11,8	15,2	15,8	16,3	o
		47,7	43,0	39,5	37,8	33,4	32,4	33,1	33,0	33,4	32,7	c

Table 2.4.3.b shows the distribution of injuries, man-hours and injury frequency per million man-hours for operator and contractor employees during the last ten years. Contractors account for approximately 60% of the total hours worked on fixed installations, while 75% of the injuries are suffered by this group.

Table 2.4.3.c shows the distribution of accident types in the various occupational categories. The table shows 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.

Figure 2.4.4
Personal injury frequency on mobile installations 1991 -1996

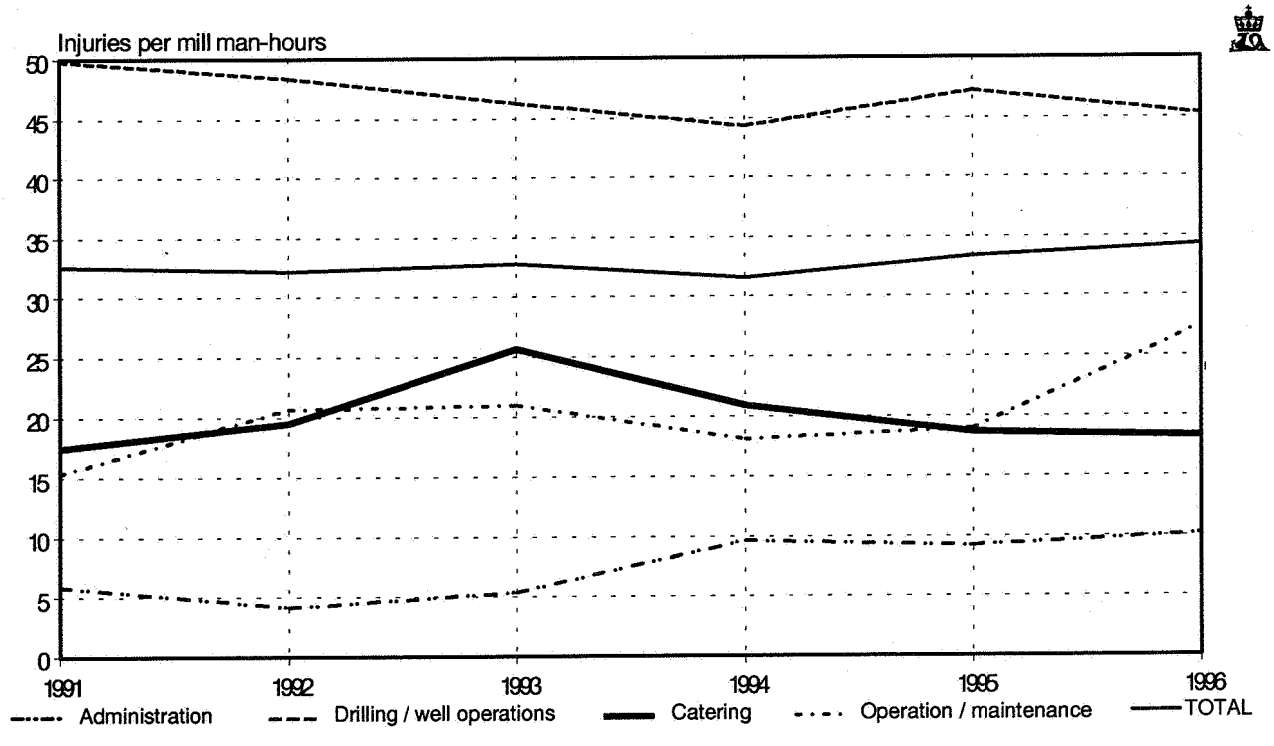


Table 2.4.3.c
Work accidents 1991-1995 and 1996 on fixed installations. Injury incident / occupation.

Occupation / Injury incident	YEAR	Administration	Drill floor worker (roughneck)	Driller	Electrician	Caterer	Assistant	Instrument technician	Cook	Crane operator	Painter / Grit blaster	Mechanic / Motorman	Operator	Plateworker / Insulator	Pipeworker / Plumber	Servicetechnician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Contact with objects or machinery in motion	1991-95	22	86	17	22	24	118	7	9	8	17	51	24	21	29	28	36	24	14	2	559	18,9%
	1996	1	10	2	3	8	7	1	1	1	2	8	4	2	6	4	4	4			68	12,3%
Fire Explosion	1991-95		1				1					3		2	2			1			10	0,3%
	1996																				0	0,0%
Fall to lower level	1991-95	5	8	2	12	4	26	2	1	5	16	11	15	8	7	13	8	4	1		148	5,0%
	1996	1	3			3	3			1	1	4	1			3		1			21	3,8%
Fall at same level	1991-95	6	8	1	6	17	19	4	3	4	6	10	9	6	7	7	8	8	1	1	131	4,4%
	1996	1	3			5		1	1	2	2	4	1	1		3	2	1			27	4,9%
Missteps tripping	1991-95	15	16	6	18	11	35	7	1	6	12	23	16	11	12	17	15	11	2	1	235	7,9%
	1996	3	1		2	2	7	1		1	1	4	3	2	2	4	3			1	37	6,7%
Falling objects	1991-95	3	15	2	7	7	30	3	3		12	11	3	8	2	13	20	13	1	1	154	5,2%
	1996	1	3	2	2	3	3	1	1	2		5	1	3	2	4	1	3			37	6,7%
Contact with objects at rest	1991-95	15	8	4	33	12	33	15	2	4	19	34	28	26	20	12	30	19	9	1	324	11,0%
	1996	6	1		9	2	5	4	1	3	2	8	4	2	1	5	6	2			61	11,0%
Handling accidents	1991-95	11	23	6	30	27	45	12	24	13	21	62	13	34	34	26	27	32	10		450	15,2%
	1996	9	14	3	16	10	16	1	4	2	6	23	9	7	11	5	7	13	2		158	28,6%
Contact with chemical or physical compound	1991-95	2	5		7	11	18	2	1	2	17	10	15	4	6	9	4	11	2	1	127	4,3%
	1996		1			1	1			1	1	4	4			2		1			16	2,9%
Muscular strain	1991-95	19	15	5	10	15	28	11	8	5	9	34	23	11	16	11	21	6	3	1	251	8,5%
	1996	4	3		4	2	4	1		1	1	6	4	1	1	3	3	1	1		40	7,2%
Splinter and splashes	1991-95	9	21	4	17	10	42	3	3	4	76	40	17	45	60	12	13	135	5	1	517	17,5%
	1996	4	1		3	2	10				10	8		8	12	3	7	14	1		83	15,0%
Electrical current	1991-95				2												1				3	0,1%
	1996																				0	0,0%
Extreme Temperature	1991-95	1			5	9	1		7	1	1	5	4	2	4		2	5		1	48	1,6%
	1996												1		1						2	0,4%
Other	1991-95																				0	0,0%
	1996	1			1	1															3	0,5%
TOTAL	1991-95	108	206	47	169	147	396	66	62	52	206	294	167	178	199	148	185	269	48	10	2957	100,0%
	1996	31	40	7	40	39	56	10	8	14	26	74	32	26	36	36	33	40	4	1	553	100,0%
%	1991-95	3,7%	7,0%	1,6%	5,7%	5,0%	13,4%	2,2%	2,1%	1,8%	7,0%	9,9%	5,6%	6,0%	6,7%	5,0%	6,3%	9,1%	1,6%	0,3%	100,0%	
	1996	5,6%	7,2%	1,3%	7,2%	7,1%	10,1%	1,8%	1,4%	2,5%	4,7%	13,4%	5,8%	4,7%	6,5%	6,5%	6,0%	7,2%	0,7%	0,2%	100,0%	

2.4.4 PERSONAL INJURIES ON MOBILE UNITS

There has been a considerably higher level of activity with mobile units in 1996 than in 1995, as the number of man-hours has increased by approximately 77%. 171 personal injuries were registered in 1996 compared with 94 in 1995, which gives an injury frequency for mobile units which is somewhat higher than in 1995. No fatal accidents occurred on mobile units in 1996, and the percentage of serious accidents is about the same as in 1995. The Directorate has registered seven off-duty injuries in 1996, compared with three in 1995.

Reporting from mobile units shall be carried out according to the same criteria as for fixed installations. The Norwegian Petroleum Directorate continues to note variable knowledge with regard to the reporting criteria for mobile units. It has also proven to be difficult to achieve the same degree of accuracy in figures for hours worked on mobile units as for the fixed installations. The operators' reporting of hours worked is compared with rig-days registered in the Directorate and adjusted in consultation with the operating companies. The Norwegian Petroleum Directorate therefore believes that the figures for recent years provide a reasonably correct picture of the conditions on mobile units.

Tables and figures - mobile units

Table 2.4.4 shows inter alia a summary of personal injuries

Table 2.4.4.a
Injuries/fatalities per million hours worked on mobile installation (1989-1996)

Year	Hours worked	Number of injuries/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	171	34,3	0
Total/average	27712537	874	31,5	5

per million man-hours for mobile units during the last ten years.

Figure 2.4.4 shows the injury frequency for the main activities on mobile units over the past six years. Drilling and well activities account for about 56% of the amount of work, and about 74% of the injuries. This led to a reduction in the injury frequency of approximately 3 injuries per million man-hours. The predominant types of injuries within drilling and well operations on mobile units continue to be cuts and bruises in connection with lifting operations and handling of equipment on the drill floor. Nearly 60% of the reported injuries to personnel related to drilling and well operations have occurred on the drill floor. The hands are most vulnerable body parts, while there has been a reduction in injuries to the feet and legs compared to 1995.

Within the areas of maintenance and operation on mobile units, there has been a marked increase in injury frequency, however, the total number of injuries in this category is nevertheless only 29. These relate mainly to crushing injuries and eye injuries caused by splinters and splatters. Both types of injuries occur often in connection with incorrect use of hand tools combined with deficient safety equipment. The changes in the injury frequency for catering and administration on mobile units from 1995 to 1996 are small, and the number of injuries within these activities is low, totaling only 15 in 1996.

On mobile units, operator employees account for only about 7% of the hours worked, and this is substantially work of an administrative nature. No injuries to operator employees were reported in connection with work on mobile units in 1996.

Table 2.4.4.b shows a cross-reference of the distribution of the various types of accidents in the various occupational categories. The table shows figures for 1996 compared with accumulated figures for the five previous years.

2.4.5 SUMMARY

The total injury frequency appears to have stabilized at a level of a little more than 25 injuries per million man-hours.

Table 2.4.4.b
Work accidents 1991-95 and 1996 on mobile installations. Injury incident / occupation

Occupation / Injury incident	YEAR	Administration	Drill floor worker (roughneck)	Driller	Electrician	Caterer	Assistant	Cook	Crane operator	Painter / Grit blaster	Mechanic / Motorman	Operator	Plateworker / Insulator	Pipeworker / Plumber	Servicetechnician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Contact with objects or machinery in motion	1991-95	3	84	15	1	2	57		2		8	3			18		3	15	3	214	33,3%
	1996	1	14	2	1		7				2	3			1		1	2		34	19,9%
Fire Explosion	1991-95						1													1	0,2%
	1996																			0	0,0%
Fall to lower level	1991-95	3	5	1	1	1	7				1		1		3		5	3		31	4,8%
	1996	1	2	2			2				2				1			1		11	6,4%
Fall at same level	1991-95	3	4	1	1	1	8	1	3		2				5			1		30	4,7%
	1996		1	1			2										2	1		7	4,1%
Missteps tripping	1991-95	4	13	5			6	2	3		1			1	11			8		54	8,4%
	1996		3		1		3		1						1	1				10	5,8%
Falling objects	1991-95		14	3		1	8	1	3		2				6	1	2	2		43	6,7%
	1996	1	2						1								2			6	3,5%
Contact with objects at rest	1991-95	2	6	3	2	2	5	2			1	1			7		2	6		39	6,1%
	1996	2	6	1	1		1		1					1	3					16	9,4%
Handling accidents	1991-95	4	39	3	1	5	11	8	1		6				8		3	7		96	15,0%
	1996	1	14	4	1	2	6	2			5	1		2	1	1	2	1	1	44	25,7%
Contact with chemical or physical compound	1991-95	2	6		1	1	2				1			1	2	1		2		19	3,0%
	1996					1					3				4					8	4,7%
Muscular strain	1991-95	3	18	5	2	2	10		2		1				11			8		62	9,7%
	1996	1	8	1			3		2		1	1			3			2		22	12,9%
Splinter and splashes	1991-95	3	10	1	3		7	1	1	1	4				2		7	3		43	6,7%
	1996				1	1	1	1		1	2	1	1		1		3			13	7,6%
Electrical current	1991-95																	1		1	0,2%
	1996																			0	0,0%
Extreme Temperature	1991-95		1			2		2			1			1			1			8	1,2%
	1996																			0	0,0%
Other	1991-95			1																1	0,2%
	1996																			0	0,0%
TOTAL	1991-95	27	200	38	12	17	122	17	15	1	28	4	1	3	73	2	23	56	3	642	100,0%
	1996	7	50	11	5	4	25	3	5	1	15	6	1	3	15	2	10	7	1	171	100,0%
%	1991-95	4,2%	31,2%	5,9%	1,9%	2,6%	19,0%	2,6%	2,3%	0,2%	4,4%	0,6%	0,2%	0,5%	11,4%	0,3%	3,6%	8,7%	0,5%	100,0%	
	1996	4,1%	29,2%	6,4%	2,9%	2,3%	14,6%	1,8%	2,9%	0,6%	8,8%	3,5%	0,6%	1,8%	8,8%	1,2%	5,8%	4,1%	0,6%	100,0%	

The largest actual increase in injury frequency from 1995 to 1996 has taken place within operations and maintenance activities on mobile units. There has also been a relatively large increase in the injury frequency for contractor employees within maintenance and construction on fixed installations. The Norwegian Petroleum Directorate does not regard the development as being cause for concern, among other things because it appears that the percentage of serious injuries has been reduced compared to less serious injuries requiring simple medical treatment.

There were no fatal accidents in 1996 on fixed installations and mobile units in operation on the Norwegian continental shelf. There were, however, three tragic fatal accidents on vessels in connection with petroleum activities. The Norwegian Petroleum Directorate is concerned about this development, and wants to take a closer look at how the Directorate can contribute to preventing any such additional fatal accidents.

The description of the incidents and the reasons for these as stated on the accident reports show that the number of accidents in connection with handling of tools and equipment has increased from about 19% in 1995 to about 27% in 1996. The most common causal factors are incorrect use of tools and equipment combined with unfortunate location in relation to tools and equipment which are used in the work. This often appears to be combined with insufficient safeguards and inattention. Injuries caused by stumbling, slipping, eye injuries resulting from splinters and splatters and injuries caused by moveable objects and machine parts account for a smaller percentage in 1996 compared with 1995.

The accident scenario is very similar to the previous year. Bruising and cut injuries to the hands and fingers continue to be the most common type of injury. The most vulnerable occupational groups are drill floor workers, roustabouts and mechanics, which each account for approximately 12% of the total number of injuries.

The Norwegian Petroleum Directorate is well satisfied with the cooperation with the operating companies in connection with the review of injury reports for 1996. It has been proven that this review is valuable for both parties and contributes to a constructive dialogue regarding the reporting system. This helps to create a common understanding of the reporting routines and criteria. There is still varying knowledge within the industry, and we have in particular seen that some projects and new organizational units do not have adequate knowledge of the routines for reporting to the authorities.

2.4.6 INJURY SUMMARY FOR DIVING ACTIVITIES

Figures 2.4.6.a and 2.4.6.b present a summary of the number of incidents reported to the Norwegian Petroleum Directorate for the years 1985-1996 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

Figure 2.4.6.a
Incidents in saturation diving

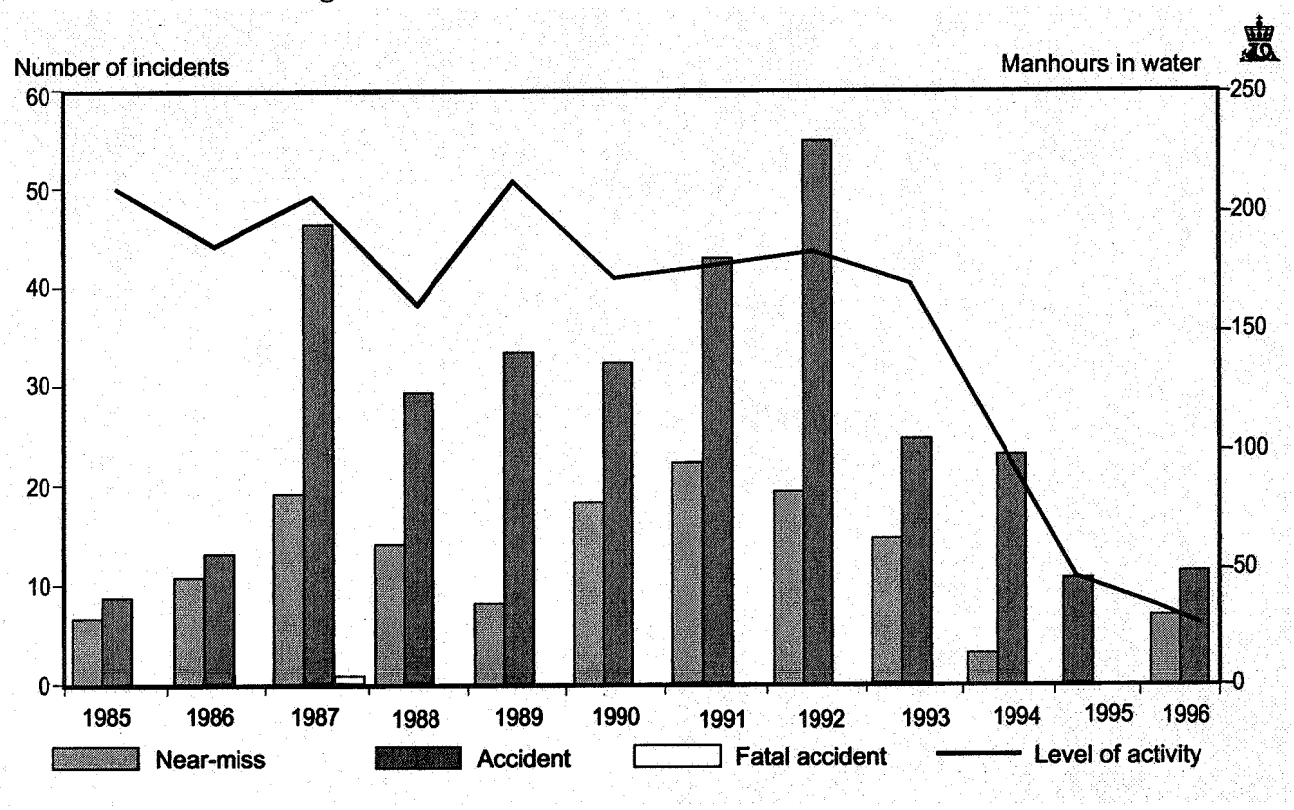
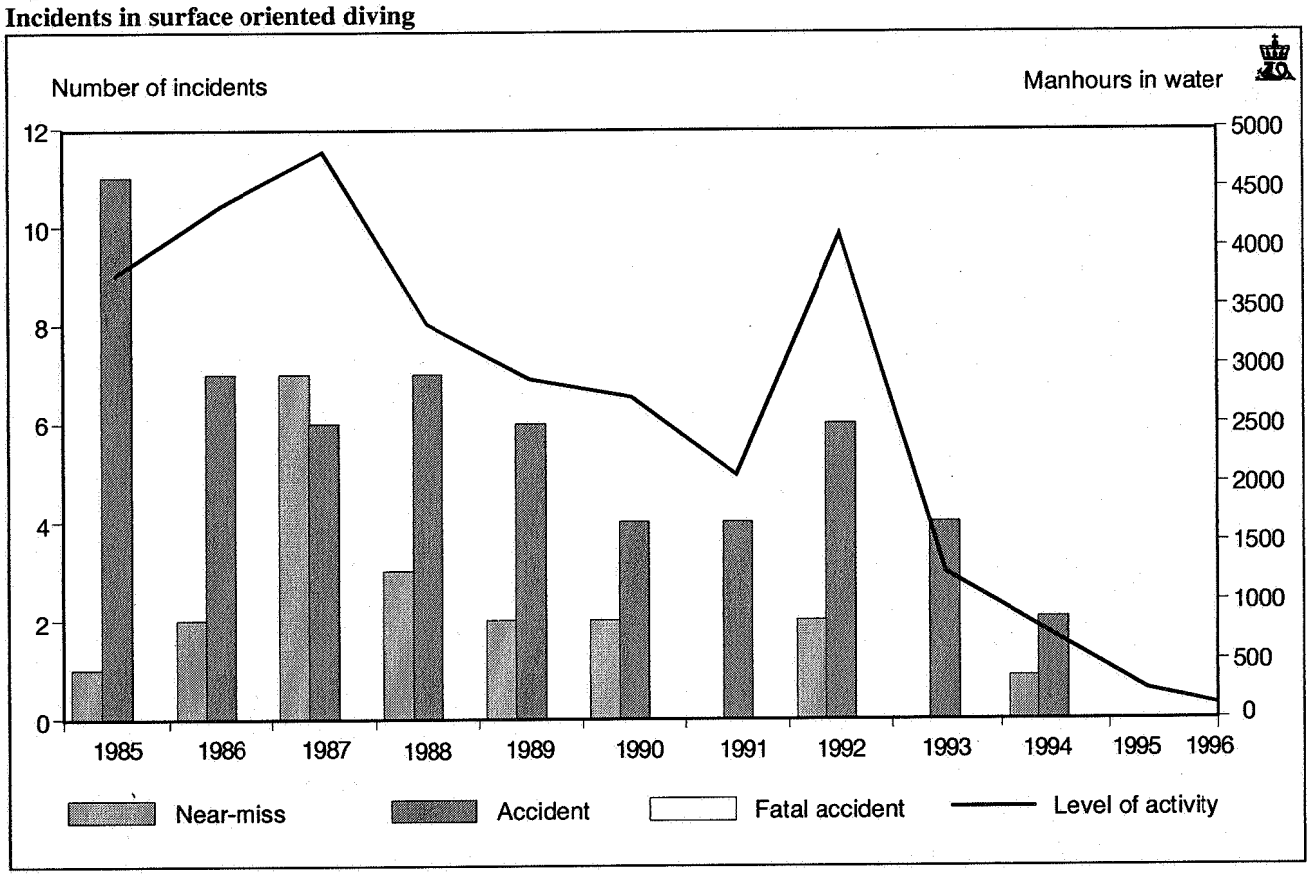


Figure 2.4.6.b
Incidents in surface oriented diving



form of personal injury. Infections, such as inflammation of the external auditory canal, are consequently also registered as accidents.

Figure 2.4.6.a shows that the number of accidents entailing personal injury related to saturation diving is basically unchanged in 1996 compared with 1995. Inflammation of the external auditory canal is the predominant type of accident. This may be related to a presumed improvement in reporting.

As for the two previous years, no cases of decompression sickness or other serious accidents in connection with diving related to the petroleum activities were reported in 1996.

2.5 WORK-RELATED DISEASES

The requirements of the Working Environment Act regarding notification of disease that can be attributed to work is being followed up by the operating companies and contractors more and more actively. In 1996, the Norwegian Petroleum Directorate has also exercised supervision of the companies' compliance with the notification requirement.

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.

697 notifications regarding work-related disease were received in 1996, an increase of 51% from 1995, giving a notification frequency of 4.3 incidents per 100 man-years. A large part of this increase relates to incidents of noise-induced hearing loss. Another contributing factor to the increase is an exchange of notifications with the Directorate of Labour Inspection in the 7th District for employees who work both onshore and offshore.

If hearing injuries caused by noise (236 incidents) are excluded, the frequency of other diseases is 2.9 incidents per 100 man-years. This is significantly higher than the figure which has been reported for onshore industrial operations. Nevertheless, the Norwegian Petroleum Directorate expects that there may still be a degree of under-reporting, since it is still receiving relatively few notifications from certain companies with many employees.

Figure 2.5.a shows the diagnosis group distribution of work-related diseases registered during the period 1993-1996, in accordance with the ICD classification. These statistics exclude cases of noise-related loss of hearing.

The picture is as previously dominated by skeleto-muscular disorders (including disorders of the connective tissues) which are normally referred to as repetitive-strain injuries: back disorders, tendinitis and various forms of muscular pain. Since the total number of notifications has gone up, this means that the percentage of repetitive-strain

Figure 2.5.a. Distribution of work-related diseases on diagnosis groups 1994 - 1996

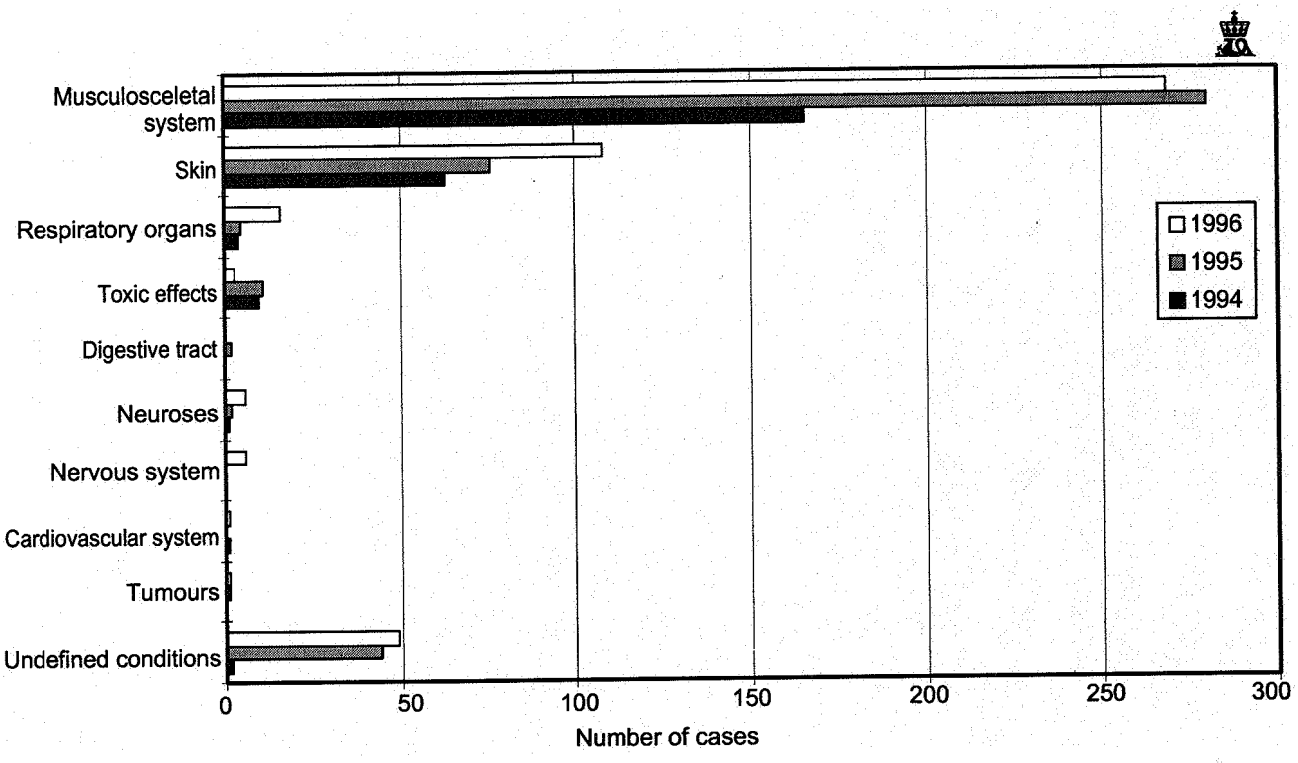
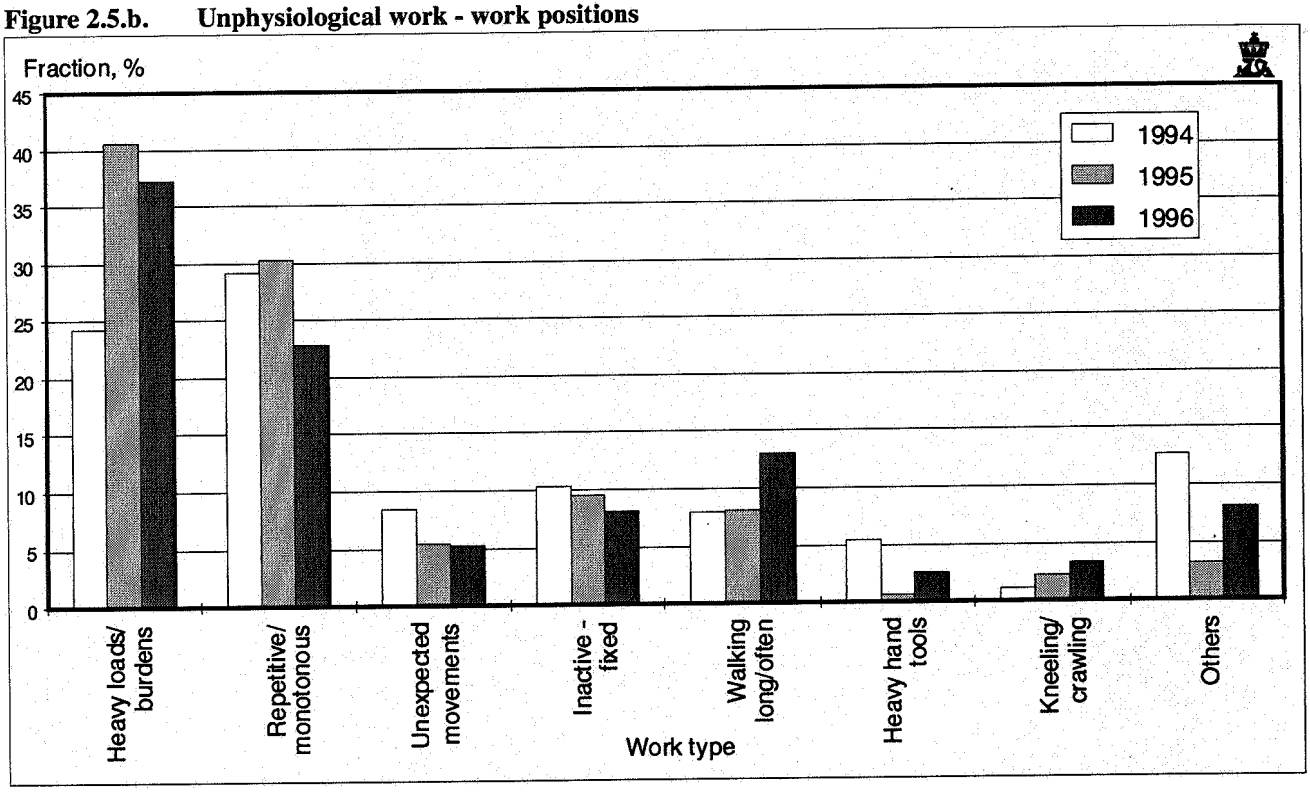


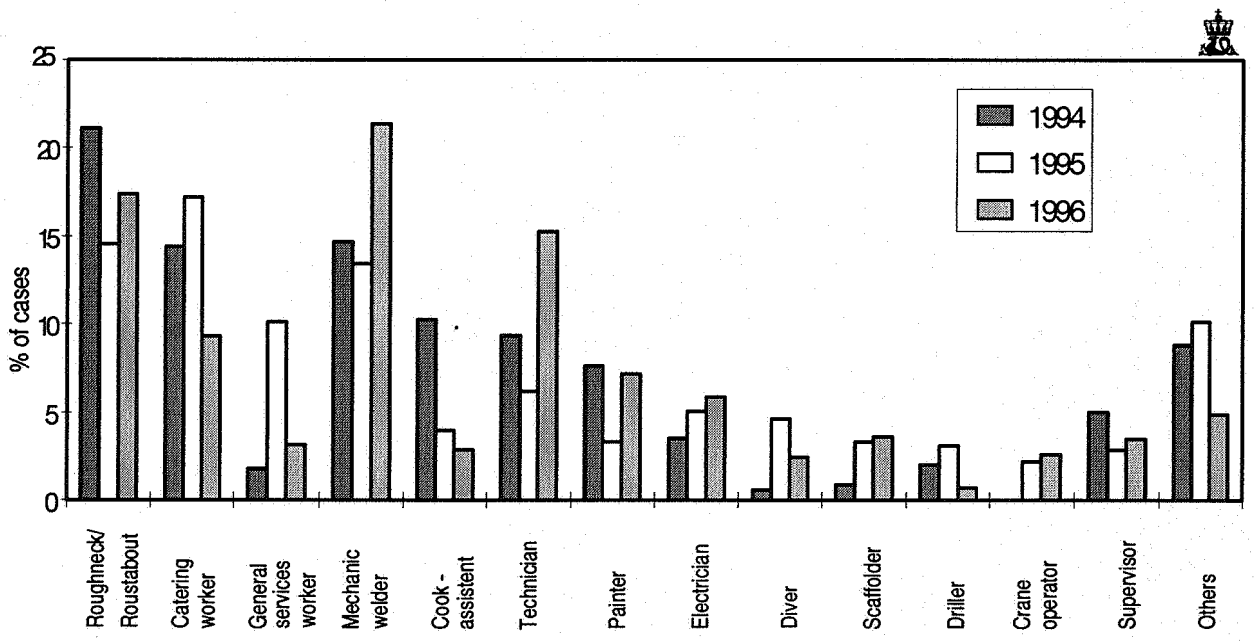
Figure 2.5.b. Unphysiological work - work positions



injuries is reduced compared to the previous year. The exposures given as cause of these repetitive-strain injuries are summarized in Figure 2.5.b. This diagram includes data from 1994 to 1996, which are the years for which the current coding system for repetitive-strain injuries has been employed.

The diagram shows that handling of heavy loads and heavy lifting have been cited as the most important causes of disorders of the skeleto-muscular system in 1996, and that this share was basically unchanged compared with 1995. Another important cause of this kind of disorder was repetitive, monotonous work. Both these exposure categories are cited as causes of inter alia tendinitis and muscle pain. The proportion of cases of degenerative

Figure 2.5.c
Distribution of work - related diseases on occupations



changes in knees and hips attributed to extensive walking on hard surfaces is relatively high, and has increased compared with the previous year. This may be related to a general aging of the workforce on the shelf. Sudden movements and inactive/stationary work have often resulted in back problems (lumbago/sciatica).

Another large diagnosis group is skin conditions, and the number of incidents in this group increased in 1996 compared with 1995. This group is dominated by workers who have developed eczema on their hands after having been in contact with oil-based drilling mud. Some cases can also be attributed to other organic compounds, including epoxy, while other incidents in this group are presumed to be caused by inorganic compounds such as various metals and well chemicals. Some eczema cases among the catering staff have been attributed to contact with detergents and other chemicals used by this employee category. A high and increasing incidence of skin conditions indicates that preventive efforts in this area are important.

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. The diagnoses grouped as toxic effects refer to a range of different symptoms occurring after exposure to chemicals.

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 resulting from two-shift work in the form of so-called swing shifts. In the group of mental diseases there are cases of neuroses caused by psychological stress in the working environment.

In 1996, three incidents of disease caused by the effect of asbestos in previous employment relationships were registered. One case of cancer of the lung membrane is included in this group.

The various position categories which were exposed to work-related diseases are shown in Figure 2.5.c. Since there were 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. This group, however, is responsible for more than 29% of the number of man-years and the number of cases is therefore considerably lower than may be expected. The share of reports for the catering staff group was lower than in 1995, and was approximately equivalent to the number of man-years for this group. There was a clear increase in 1996 of reported incidents in the construction and maintenance group. This group was responsible for 34% of the total man-years, but accounted for 52% of the reported incidents of disease. This development will be followed closely in the supervision activities.

2.6 WORKING ENVIRONMENT

2.6.1 PLANNING OF NEW INSTALLATIONS

In 1996, the Norwegian Petroleum Directorate has carried out a number of supervisory activities in order to investigate how the industry relates to the *Regulations relating to systematic follow-up of the working environment* in connection with the planning and fabrication of new installations. Particular emphasis has been placed on how the participants use their control systems to ensure that requirements related to the working environment are followed up in all phases of the projects.

NORSOK's working environment specification has been implemented in 1996 as the basis for requirements for new development projects. The specification represents an elaboration and concretization of the project-relevant requirements in the regulations. The Norwegian Petroleum Directorate has noted that there is often some confusion surrounding the status of this specification in the projects' required documentation. It is not always apparent whether the document constitutes a rule or only guidelines, whether all or only parts of the specification should be perceived as rules, and reservations are made with regard to individual provisions without subjecting this to a variance analysis. The Norwegian Petroleum Directorate has also noted that the transmission of the requirements to contractors and subcontractors is not always complete and consistent. Nevertheless, it is clear that the NORSOK standard, together with the *Regulations relating to systematic follow-up of the working environment,* have contributed to a significant improvement in the companies' specification of requirements concerning the working environment.

In connection with the planning of new installations, working environment-related analyses, studies and evaluations shall be carried out, partly to specify functional requirements, and partly to ensure that requirement goals are met. The Norwegian Petroleum Directorate has experienced that the companies increasingly make use of resources to perform such studies, but have registered several weaknesses in the companies' method of approach with regard to

- identification of problem areas, critical equipment, purchasing packages and processes
- definition of the need for studies and their scope
- clarity and amplification in the description of the studies, responsibility and need for expertise
- awareness concerning proper phase-in of studies
- clarification of how recommendations made in studies shall be handled
- evaluation of contractors' ability to implement studies

In order to achieve the best possible utility effect from studies related to the working environment, it is necessary for the companies to actively and critically assess the need for and the scope of studies in relation to issues connected with the selection of development concept and technical solutions.

The implementation of working environment-related analyses, studies and follow-up of working environment factors connected with design and delivery requires personnel with both general knowledge and special expertise in the area of working environment. This expertise may be found in the operating companies and in major design companies, however, the capacity is not sufficient. The Norwegian Petroleum Directorate is also concerned about the expertise in the supplier industry, and particularly among the foreign participants, who have less tradition in this area. The concern is intensified by the fact that new implementation models and contract strategies involve a considerable increase in the scope of work on the part of contractors. The operating companies have a special responsibility in this situation to ensure that contractors have access to both systems and expertise. Independent consultants are used to an increasing degree in connection with performance of studies. In this context, the Norwegian Petroleum Directorate has seen that the transferal of results to the project organization, coordination and follow-up of the recommendations have not always been adequate.

2.6.2 IMPLEMENTATION OF REGULATIONS RELATING TO SYSTEMATIC FOLLOW-UP OF THE WORKING ENVIRONMENT ON MOBILE UNITS

On the whole, good systems have been established for implementation of *Regulations relating to systematic follow-up of the working environment* on mobile units in the petroleum activities. The industry is well aware of the requirement in the regulations, goals and a program for following up the working environment have been developed. The Norwegian Shipowners' Association and the Employers' Association for ships and offshore installations have prepared guidelines for systematic follow-up of the working environment in the petroleum activities. These guidelines are normally incorporated in the companies' specific requirements relating to working environment on mobile units. However, the guidelines are somewhat weak as regards ergonomics, so that the companies should supplement their requirement specifications with specific ergonomics requirements which are adapted to the individual installation.

The companies' survey of the working environment on the individual installation takes place pursuant to established procedures and uncovers weaknesses and areas where improvements are needed based on the companies' specific requirements for working environment. On many installations, prioritization of measures is now underway after completion of the survey. The Norwegian Petroleum Directorate wishes to emphasize that it is important to balance the resources used for the survey with the resources which are set aside for the follow-up measures. So far, the resources have largely been used on the survey. The greatest challenges relating to the working environment aspect are in the areas of noise, ergonomics, chemicals as well as organization of the work, including employee participation.

Deficiencies have been revealed in connection with the companies' systems for variance procedures relating to working environment factors. The Norwegian Petroleum Directorate has received applications for consent which have not described any deviations from the working environment regulations, while the Directorate's supervision has revealed significant deviations. Through supervision aimed at mobile units, the Directorate has registered that the results of the survey activity have not been dealt with in the company's system for treatment of variances.

Compliance with the work hour provisions is good on the individual mobile units in the petroleum activities.

It appears that joint local working environment committees on mobile units are beginning to function according to the intentions. There has been some confusion and unfortunate organization of the joint local working environment committees on the individual installation, however, this is beginning to improve.

Chemicals

Over a period of several years, the Norwegian Petroleum Directorate has registered that occupational-health data sheets for hazardous chemicals have not been of adequate quality, and there are examples of unfortunate consequences related to this. The operating companies have each individually employed considerable resources on quality assurance of data sheets as well as to set up data bases in order to obtain an overview concerning the use of chemicals. The utility value of this work measured in reduction of risk does not seem to be in proportion with the efforts which have been expended. In the guidelines for *Regulations relating to systematic follow-up of the working environment*, the Norwegian Petroleum Directorate has pointed out the need for industry cooperation with regard to quality assurance of occupational-health data sheets. It seems clear that there is a great potential both for raising quality and increased efficiency in this area.

In 1996 the Norwegian Oil Industry Association established an approval system for data sheets. The system means that the operating companies place demands on the suppliers to deliver occupational-health data sheets which have been quality controlled by an organization which can document adequate expertise and systems. The scheme will be introduced in 1997, and the Norwegian Petroleum Directorate expects that the scheme will entail an improvement of the quality of the data sheets, which can make them more suitable as a basis for evaluation in connection with the selection of chemicals. The approval system can also contribute to providing a better foundation for risk assessments and preventive measures. The Norwegian Petroleum Directorate recognizes this need, and desires more intensive emphasis on risk-based efforts in the chemicals area.

Noise

Noise is a significant working environment problem in the operation of installations in the petroleum activities. During the course of the year, the Norwegian Petroleum Directorate has arranged a seminar on this subject with broad participation from the industry. The central regulations relating to noise have been elaborated in a letter to the industry.

The *Regulations relating to systematic follow-up of the working environment* demand a minimization of exposure to noise, both with a point of departure in the hazardous effects of noise with regard to hearing, and other unfortunate effects of significance for health and safety. The regulations' demand for development of specific requirements for the working environment means that noise level requirements must be developed on an area to area basis both in connection with the planning of new installations and in connection with modifications and operations of existing installations. The companies' requirements for existing installations do not necessarily have to be the same as for the design of new installations.

In connection with the planning of new installations, any violations of the area noise levels by more than 3 dBA will require an application to the Norwegian Petroleum Directorate for an exemption from the requirement. The Directorate takes a restrictive position with regard to granting exemptions from the regulations if the opportunities for cost-efficient combating of noise have not been utilized during the planning. Experience shows that the costs in connection with measures to combat noise are significantly higher if the work must be done as modifications at a later point in time.

The *Regulations relating to systematic follow-up of the working environment* require that no one shall be exposed to noise which can damage hearing. This is primarily meant to be achieved through technical measures, and secondarily with organizational measures. In other words, a noise problem should ideally not be solved through the use of personal protective equipment, such as ear protection. Nevertheless, the Norwegian Petroleum Directorate is aware that, in some areas, it will be necessary to rely on the use of ear protection so as to fulfill the requirement that no employee shall be exposed to noise levels which are hazardous to their hearing. This applies particularly to existing installations. In connection with planning of new installations, the possibility of finding good physical technical/economical solutions will be much better. Based on the relatively large scope of reported incidents of hearing loss due to noise, the Norwegian Petroleum Directorate has emphasized the importance of regular maintenance of personal safety equipment, and that ear protection should be used continuously during stays in areas with high levels of noise.

The Norwegian Petroleum Directorate assumes that the companies will conduct a comprehensive prioritization with regard to technical noise abatement measures on the basis of a survey of the noise level in the various areas on the installation compared with the companies' specific requirements for noise levels, supplemented with measurements of noise exposure for persons who to a great extent work in areas with hazardous noise levels. Extensive activity is currently underway in the companies in this area, both on mobile units and fixed installations.

Safe preparation of work

Strict requirements are placed on safe planning of work on the installations. The companies' procedures for work permits/safety clearance and safe preparation of the work (safe-job-analysis) are key elements in this work, and the work is generally good. Nevertheless, based on the importance of good safety planning of the work, the Norwegian Petroleum Directorate has focused particularly on the practice of safe-job-analysis, with the goal of

contributing to a further improvement of the quality of procedures and practice.

The *Regulations relating to systematic follow-up of the working environment* require that guidelines be developed for when and how safe-job-analysis shall be performed, and that the employees who will participate in the imminent work shall participate in the implementation of the analysis. The Norwegian Petroleum Directorate has experienced that there may be a need for more detail in the companies' procedures and a more unified understanding of the term safe-job-analysis, particularly as relates to jobs where adequate procedures/routines have already been established. The Directorate has pointed out that the analysis should describe dangers, possible consequences and protective measures for each individual step in the work process. Somewhat variable practice has been registered in the industry with regard to stating risk in the form of probability and consequence as a part of the safe-job-analysis. The Directorate has emphasized that the most important element must be to make the safe-job-analysis a user-friendly tool which is used to make the individual aware of possible risk factors and safety measures related to the planned work, without necessarily quantifying the risk.

The Norwegian Petroleum Directorate has stressed the fact that there should be a permanent system where the safe-job-analysis is reviewed at a meeting of all involved parties before the work is commenced. If the work extends over several shifts, such a meeting should be held for each shift.

The Norwegian Petroleum Directorate has also recommended that the safe-job-analysis be subjected to a system of limited retention in a similar manner as for work permits/safety clearances. With regard to re-use of analyses, the Directorate has emphasized that this must assume a new review in order to ensure that consideration has been given to possible changes in the preconditions.

Jet water washing ("water jetting")

During recent years, several accidents have occurred in connection with the use of water jetting equipment, i.e., equipment used for jet water washing or ultra jet water washing. The Norwegian Petroleum Directorate has obtained information from the companies regarding the scope of such work, risk factors and preventive measures.

The information which has been gathered indicates that water jetting is used more and more often. This applies particularly to so-called "ultra water jetting" to replace sand-blasting. The injuries reported are of a serious nature, and significant safety and working environment problems are connected with the use of this equipment. Only a few operating companies have made certain that a detailed evaluation of safety and working environment factors has been conducted.

On the part of the Directorate, it has been stressed that safety and working environment requirements must be placed on the equipment itself and its use. There is a need to conduct more detailed evaluations of the actual equipment and related personal safety equipment, in order to arrive at improvements with a view towards safer and better working environment conditions.

Extraordinary accommodation

As a general rule, the regulations for the petroleum industry require that there be as many beds in the living quarters on the installation as there are persons living there, i.e., that the same bed cannot be used both at night by a person who normally works the day shift, and again during the daytime by a different person who works the night shift. Thus, the general rule is that so-called "hot bedding" is not allowed.

Recently, the Norwegian Petroleum Directorate has received an increasing number of applications for exemption from the regulations for such extraordinary accommodations. In those cases where such applications have been granted, the most important conditions have been that such accommodations are only used to a limited extent in difficult situations where time is of the essence, that only single-occupancy cabins are used for such accommodations, and that extra catering staff are mobilized.

In the special situations which have been considered, the realistic alternative has often been accommodation on another installation, with helicopter transportation to and from each shift. Many people regard such helicopter "shuttling" as a less satisfactory solution than "hot-bedding" in single-occupancy cabins, both from a welfare and a safety point of view.

Labor disputes

There have been four labor disputes on the continental shelf in 1996. These disputes have been somewhat difficult to handle, also on the part of the Norwegian Petroleum Directorate.

Among other things, the Norwegian Petroleum Directorate has evaluated the safety conditions in connection with temporary shutdown of drilling operations, inter alia in connection with the regulatory requirements that there must always be two testable barriers, which may be accommodated in several ways. There have been extensive discussions concerning the time necessary to stop the operations in a proper way and establish safety manning in connection with a labor dispute.

Cases have also been discussed concerning who shall participate in the safety manning in connection with a labor dispute. The fact that there are often relatively few employees who are affected by a walkout has in some instances led to difficulty in handling the cases. Questions have been posed as to whether it may be prudent from a safety point of view to continue operations even though some employees are in dispute. The Norwegian Petroleum Directorate's consideration of these cases has been based on concrete evaluations in each specific case.

2.7 PREPAREDNESS

The Action Committee for the State (AKU) was dissolved effective 15 February 1996. AKU was replaced by two cooperation agreements; between the State Pollution Control

Authority and the Norwegian Petroleum Directorate, and between the State Pollution Control Authority, the Norwegian Maritime Directorate and the Coast Directorate.

The coordination agreement between the Norwegian Petroleum Directorate and the State Pollution Control Authority assumes that an annual joint exercise shall be held between the two agencies. The exercise shall ensure that the two agencies are able to safeguard the state's responsibility and tasks in a coordinated and efficient manner in connection with hazardous and accident situations which affect both agencies. The exercise has been designated MYNDEX, and was conducted both in 1995 and 1996.

2.8 DRILLING

2.8.1 OVERVIEW OF DRILLING AND WELL ACTIVITIES

In 1996 a total of 30 exploration wells were spudded on the Norwegian shelf, which is a decline of six compared with 1995.

Geographically speaking, the exploration wells were distributed with 24 in the North Sea and 6 in the Norwegian Sea. No new exploration wells were spudded in the Barents Sea in 1996.

With regard to production drilling, a total of 141 wells were drilled in 1996, compared with 109 in 1995. 57 of these wells were drilled from mobile units.

2.8.2 INCIDENTS INVOLVING LOSS OF WELL CONTROL

There are often small margins between controlled well operations and loss of well control. In 1996, two incidents occurred which necessitated shutdown of the well and implementation of emergency procedures in order to regain control. In both incidents, however, it was possible to regain control over the wells without injury to personnel, the environment or equipment.

Each year, both operating companies and contractors expend significant resources on preparing personnel and installations to handle critical well control situations. Equipment is subjected to thorough maintenance and control, while personnel undergo regular training and exercise in the area of well control.

The two incidents have shown that there is room for improvement, both with regard to equipment and training of personnel. On the equipment side, it is important that the shear ram when activated, cuts and closes as expected. In addition, better control must be achieved with regard to where this closes in relation to the pipe joints. In one of the incidents, the shear ram was activated at a pipe joint and thus could not cut the string.

The incidents have also revealed defects with regard to understanding of the well control problems. It is important that the operators, the contractors, the well control schools and the authorities maintain close contact in order to ensure that the training is appropriate, relevant and adequate.

2.8.3 DRILLING IN DEEP WATERS

In 1996, the Norwegian Petroleum Directorate prioritized work to identify and address the special technical challenges such activities represent. The work forms the basis for ensuring that the regulations are adequate for exploration and production activities in deep waters, as well as to strengthen the Directorate's expertise in connection with supervision of the companies' activities in deep waters. Through this work, the Directorate has also wanted to stimulate the operating companies to get involved in the problems in advance, so that the activities can be carried out in a prudent and cost-efficient manner.

Drilling in deep waters entails operational problems due to the large distance between the surface installation and the actual well hole, which complicates hydraulic communication and control of the equipment on the seafloor and in the well. The great depths also create problems in relation to most available exploration units due to the need for increased load capacity for larger quantities of risers and drilling fluids, as well as for the installation's ability to maintain its position.

Hydratization is a phenomenon which will present special challenges in deep waters. Hydrates are chemical compounds formed by water in hydrocarbon gas under high pressure, appearing as an ice-like substance. The hydrates can clog the riser, and otherwise cause functional problems for equipment in the well. Naturally formed hydrates may also be found in the upper layers of the seafloor, which may affect the development of local slides which can entail danger of damage to the well and associated equipment.

Particularly on the Vøring plateau where production licenses were awarded in the 15th Licensing Round, there are also fast-moving currents and complicated current conditions. This implies inter alia increased loads on anchoring systems and risers.

In terms of preparedness, special consideration must be given to the fact that the deep water areas on the Norwegian shelf are also situated farther from land than has been the case up to now. The above-mentioned challenges, including increased load capacity, mean that as of today there are only a limited number of suitable drilling installations available. This is a factor which must be evaluated, keeping in mind a potential need for drilling of relief wells if a well control problem should arise.

A number of the challenges which have been identified with regard to drilling activities will also be relevant in the production phase.

Within the problem areas identified, in 1996 the Norwegian Petroleum Directorate has carried out a number of activities in order to develop knowledge and experience in order to be able to manage the administration tasks in connection with petroleum activities in deep waters.

Among other things, the Directorate has conducted a

series of meetings with the operators to discuss the selection of areas and relevant problems, as well as method/ cooperation projects so as to ensure a coordinated joint follow-up. So far, the companies have taken a positive view of the Norwegian Petroleum Directorate's efforts to begin a dialogue at an early point in time in relation to activities in deep waters.

2.9 NATURAL ENVIRONMENT DATA

With the aid of the Norwegian Meteorological Institute, the Norwegian Petroleum Directorate supervises the collection of natural environment data (currents, waves, wind, etc.) on selected installations on the Norwegian continental shelf. The assistance arrangement has functioned in a highly satisfactory manner and contributes to the efficient supervision of this activity.

In 1996, natural environment data has been collected from the following installations: Ekofisk, Yme, Sleipner, Frigg, Gullfaks, Draugen, Heidrun, Transocean Arctic, Deepsea Bergen and Polar Pioneer.

The collection of natural environment data from the Yme field began in 1996. Preparations have also been made for the gathering of natural environment data from Norne when production starts on this field in 1997.

In 1996, the Norwegian Petroleum Directorate has also collected natural environment data on the Vøring Plateau, off Vesterålen and on Tromsøflaket. Data has been gathered on wave height, wave direction, current and weather conditions. The measurement program has been carried out by the Trondheim company, Oceanor. These measurements have now gone on for 20 years, with a cost framework of NOK 3.1 million in 1996.

2.10 STRUCTURES AND PIPELINES

2.10.1 COLLISIONS

Three collisions between vessels and installations were reported in 1996. All of the collisions may be regarded as minor, and the damage was slight.

During the last 16 years, a total of 36 collisions between structures and vessels were reported. This gives a frequency of about 3 collisions per 100 years and installation. The incidents are more or less evenly distributed throughout this period, and there is no clear trend towards increase in the number of collisions, even though the number of installations has increased substantially during the period.

Only two collisions have been caused by an unauthorized vessel, that is to say, vessels that have not been cleared to maneuver within the security zone around the installation. There have been no reports in 1996 of drifting objects that have represented any immediate danger of collision with installations.

In 1994 a collaborative project was begun by British and Dutch authorities to compare and standardize the calculation of collision risks. The work was continued in 1996 and will also continue in 1997. Experiences with collisions on the Norwegian shelf are largely the same as on the British side, although the frequency and number are somewhat lower. What is unique about the Norwegian material is a higher incidence of collision between tank loading ships and loading buoys. The reason for these collisions is linked with the use of dynamic positioning systems.

2.10.2 DEEP WATER STRUCTURES

Current conditions

Measurements taken on the Vøring Plateau show high current speeds from the surface and all the way down to the seafloor at a depth of 1500 meters. However, investigations have only been performed at a few target locations, and additional measurements are needed in order to create a basis for calculation of loads on structures, anchor systems and risers.

The greatest current speeds measured on the Vøring Plateau are high and may be compared with current speeds in the Troll area. In addition to the mechanical strains on installations and equipment, high current speeds may also affect the precision of the operations and thus demand special measures in order to compensate for this. Furthermore, strong currents increase the danger of collisions between installations and vessels.

Positioning systems

The positioning system is of great importance for holding an installation in place so that the operations may be carried out in a prudent manner, without damage to risers and other equipment. The Norwegian Petroleum Directorate is currently carrying out an assessment of the reliability of such systems for deep water locations. A satellite system is available as a reference for positioning on the Vøring Plateau. In addition, a system may be used which is based on acoustic signals from the seafloor. The accuracy of this system depends on the water depth, changes in salinity and water temperature, and the uncertainties connected with this method generally increase with increasing water depths. The use of Loran C as a reference system may also be an option, and a number of tests using this system have been carried out in 1996. Furthermore, work has commenced using a Russian satellite system as reference, and tests using this system have begun. In 1996, the Norwegian Petroleum Directorate has participated in a development project with the objective of improving the reliability of systems for dynamic positioning.

2.11 LIFTING GEAR

Several serious undesirable incidents occurred in connection with crane operations also in 1996. Some of the incidents involved relatively serious personal injuries, while several incidents were extremely hazardous. The Norwegian Petroleum Directorate regards insufficient organization and planning of lifting operations, as well as

deficient maintenance as being the causes of the incidents. By their very nature, lifting operations on installations in the petroleum activities represent a potential for danger.

During recent years, several fatal accidents and other serious accidents have occurred on board supply vessels in connection with lifting operations between installation and vessel. The activities on such vessels are covered under maritime regulations and the safety of personnel on board is not covered under the regulations administered by the Norwegian Petroleum Directorate. Nevertheless, the Directorate is concerned about the development and therefore, in 1996, entered into a cooperation with the Norwegian Maritime Directorate concerning supervision aimed at the companies' planning and routines for crane operations between installation and vessel. This cooperation will continue in 1997.

2.12 HYDROCARBON LEAKS, FIRES AND NEAR-FIRES

2.12.1 HYDROCARBON LEAKS

The Norwegian Petroleum Directorate has received reports of 156 hydrocarbon leaks in 1996 compared with 120 in 1995. Four of the reported hydrocarbon leaks were considered to be major (serious), based on an evaluation including the quantity of the emission, danger potential and causal relation. Table 2.12.1 shows the distribution of gas leaks according to degree of severity and method of detection. Two of the leaks were caused by operational errors, while two occurred as a result of failure of components. A person suffered minor injuries in one of the incidents.

Figure 2.12.1.a illustrates areas on the installation where the gas leaks occurred, while Figure 2.12.1.b shows the main types of faults which caused the leaks.

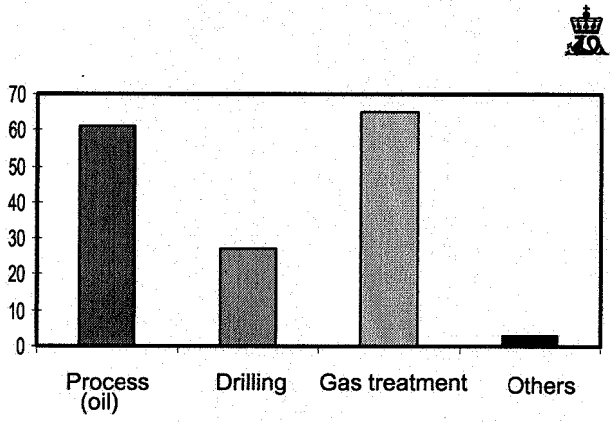
Seen in relation to the number of installations in operation and produced petroleum, the Directorate believes that there has been a positive development during previous years in the number and severity of reported leaks. Most of the operating companies now use a common database and thereby a common template for reporting of hydrocarbon leaks. This can stimulate the willingness to report and thereby explain some of the increase in reported leaks. Nevertheless, it seems reasonable to assume that the increase in 1996 indicates a real negative development of the danger scenario.

Therefore, 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.

Table 2.12.1
Distribution of gas leaks according to degree of severity and method of detection

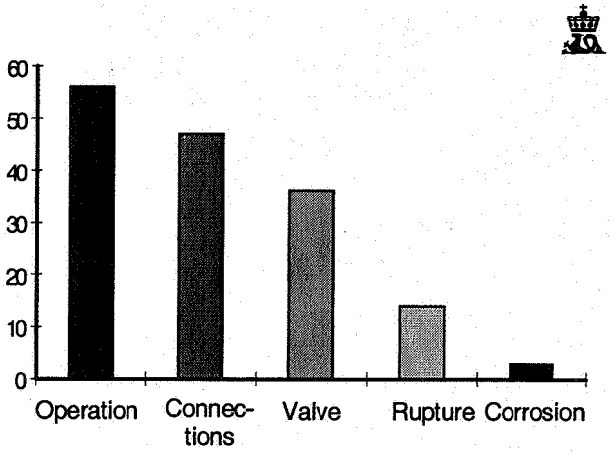
Severity	Number of leaks	Number of automatically detected	Number of manually detected
Major	4	2	2
Middle	32	22	10
Minor	120	33	87
Total	**156**	**57**	**99**

Fig. 2.12.1.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 2.12.1.b
Main group of faults resulting in gas leaks



Operation: Procedural faults, faulty operation
Connections: Flanges, seals, fittings

2.12.2 FIRES AND NEAR-FIRES

The Norwegian Petroleum Directorate has registered 19 fires and near-fires in 1996, compared with 18 in 1995. High surface temperatures (such as exhaust outlets from combustion engines) and electrical defects were the most frequent causes of ignition.

Table 2.12.2 provides an overview of the extent and causes of fires and near-fires reported to the Norwegian Petroleum Directorate in 1996. The number and distribution according to severity are at a reasonable level, nevertheless, the causes indicate that it would be possible to further reduce this number through goal-oriented efforts.

Table 2.12.2
Causes and extent of fires reported in 1996

Cause	Extent		
	Minor	Medium	Major
Welding	1		
Hot surfaces, overheating	7	3	1
Electrical	5		
Other	2		
Total	**15**	**3**	**1**

Fire on Statfjord C

This fire, which was categorized as major, occurred on Statfjord C on 31 January 1996. A missing blind flange on a transmission line led to oil, for use in drilling operations, spilling over the deck and down the outside of the installation. The discharge was probably ignited by non-insulated mounting brackets on an exhaust pipe from a generator turbine. The fire led to damage to electrical installations, air intake to the generator turbine and to deck and wall plates. The fire was extinguished by the preparedness vessel in about 25 minutes. Fire fighting equipment was not available in the relevant area as, during the construction of the installation, it was considered to be highly unlikely that a fire could occur in this area.

2.13 DIVING

2.13.1 DIVING ACTIVITIES

During 1996, 47 surface-oriented dives and 201 bell runs totaling 28,662 man-hours in saturation were carried out on the Norwegian shelf and in connection with Norwegian pipelines in foreign sectors under Norwegian jurisdiction. This is approximately one-third of the number of surface-oriented dives and saturation dives in 1995.

The average length of bell dives for saturation diving was 6.4 hours in 1996, which is approximately the same as in 1995. The average saturation period was 12.4 days, a reduction of 3.1 days from the previous year. The average time in the water for surface-oriented diving was 1.6 hours, which is about the same as in 1995. The diving operations have been conducted from five different vessels and installations.

Diving activities have been divided among inspection, maintenance and construction activities on fields where Elf, Hydro, Phillips and Statoil 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.

2.13.2 DIVER TRAINING

The National Divers' School (Statens dykkerskole) has trained 12 saturation divers in 1996. In addition, the Norwegian Professional Divers' School (Norsk yrkesdykkerskole) and the National Divers' School have trained a total of 66 divers who have been issued Grade 1 certificates.

2.13.3 RESEARCH AND DEVELOPMENT

In 1996, the Norwegian Petroleum Directorate has continued its participation as a member of the Board and Project Management 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 1996, the annual diving seminar was held as a joint seminar for both open sea diving and diving in sheltered waters.

Development work aimed at meeting the authorities' requirements with regard to spare gas supply has been ongoing for several years. These requirements became effective on 1 January 1996. Equipment for spare gas supply has been subjected to operational adaptation and use during 1996.

3. Environmental measures in the petroleum activities

3.1 CONSIDERATION FOR THE ENVIRONMENT

Environmental issues have gradually attained a central position in the formulation of petroleum and energy policy, and consideration for the environment is an integral part of the Norwegian Petroleum Directorate's total efforts towards sound management of the Norwegian petroleum resources. The Norwegian Petroleum Directorate's efforts are particularly directed towards preventive measures designed to avoid and limit damage due to pollution.

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 with the protection of the environment, information work and cooperation with other authorities, particularly the State Pollution Control Authority (SFT).

3.2 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 shall be carried out in a responsible manner which safeguards the safety of personnel, the environment and economic 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 ability to produce and maintain self-sufficiency.

The regulations regarding internal control, risk analysis and preparedness have authority in both of the central acts mentioned above, and are managed 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 procedures for organization of the supervision.

3.3 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-related 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 internal control, 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 vulnerable 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 can better safeguard the consideration for environmental vulnerability 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, 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, and the Directorate evaluates whether the tax contributes to reducing CO_2 emissions in an efficient manner. In 1996, the tax rate has been 85 øre per Sm^3 natural gas burned and cold vented and 85 øre per liter diesel consumed.

The total CO_2 emissions from taxable activities were 7.9 million tons in 1996. This is an increase of 0.5 million tons compared with 1995, however, the CO_2 emissions per produced unit have decreased. This is illustrated in Figure 3.3.a. Figure 3.3.b shows how the emissions are divided by source.

Figure 3.3.a
Emissions of CO_2 per produced unit

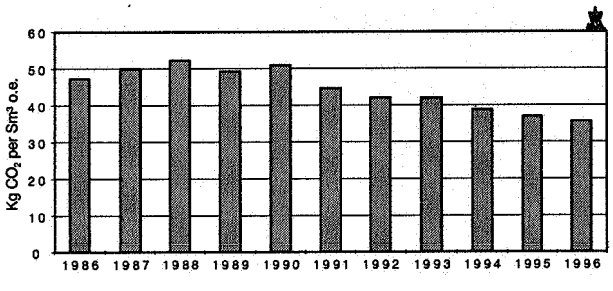
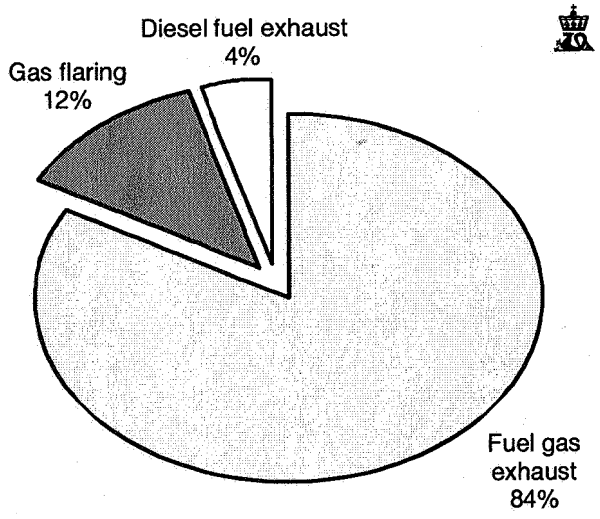


Figure 3.3.b
CO_2 - emission sources



3.4 THE EXTERNAL ENVIRONMENT

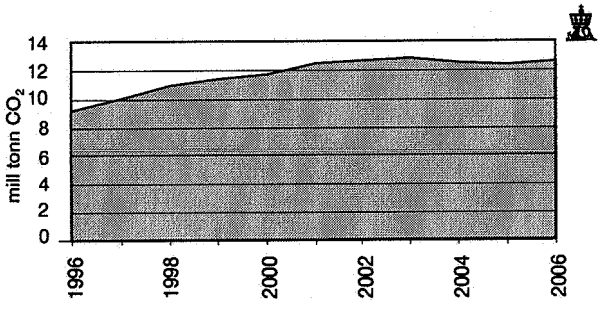
When the Norwegian Petroleum Directorate evaluates consequence analyses, plans for development and operation and applications for consent, great emphasis is placed on the ability to make use of technology which reduces the volume of emissions.

Within the Norwegian Petroleum Directorate's sphere of responsibility, the Directorate follows up the environment-related conditions which are evident from Storting documents. In 1996, the Norwegian Petroleum Directorate has inter alia worked on a study which examines costs in connection with supplying the 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), and will be concluded during spring of 1997.

As a component in the authorities' work with national action plans for reduction of volatile organic compounds (NMVOC), the Norwegian Petroleum Directorate has carried out evaluations of measures in the petroleum activities.

The Norwegian Petroleum Directorate has also developed prognoses for emissions of CO_2 (see Figure 3.4),

Figure 3.4
Prognosis for CO_2 emissions from the petroleum activities



nitrogen oxides and NMVOC. The prognoses are an important basis from which to evaluate means so that national and international commitments may be met.

In the MILJØSOK work, the Norwegian Petroleum Directorate has been represented by an observer in the management group, and similarly in one of the working groups, technical and economic action alternatives. The Norwegian Petroleum Directorate has also contributed supporting material for this work.

3.5 TECHNOLOGY DEVELOPMENT

The Petroleum Act with regulations requires that safety and technology be developed further in concurrence with the general development of technology and society at large. In 1996, the Norwegian Petroleum Directorate has given priority to following up these areas, among others:

- research, development and use of more energy efficient technology for oil and gas production,
- reduced need for burning of gas in connection with production,
- development of technology in order to reduce emission of NO_x from combustion,
- use and handling of heavy metals, materials with low level radiation and biocides,
- mapping and reduction of emissions to the air and sea in connection with formation testing

In addition, the Norwegian Petroleum Directorate works towards influencing the industry to systematize the transfer of experience in environmental issues, in order to develop efficient and environmentally-friendly solutions which at the same time provide the best possible economy.

3.6 DISPOSAL OF INSTALLATIONS WHICH ARE NO LONGER IN SERVICE

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 under the Oslo and Paris convention (OSPAR) and the London convention. The Norwegian Petroleum Directorate is a key contributor of terms in this work.

As of today, it is mainly the guidelines of the International Maritime Organization (IMO) which provide guidance in connection with disposition of installations which are no longer in service. Two key conditions in these guidelines are:

- All installations which are located at a depth of less than 75 meters and have a supporting structure which weighs more than 4,000 tons shall be removed (the water depth increases 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 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 disposition plans for the individual fields. The plan for disposition of Mime has been considered in 1996. A similar plan for Odin has received final processing.

3.7 CLEAN-UP OF THE SEABED

During 1996, the Norwegian Petroleum Directorate's clean-up of the seabed took place in a 1000 m^2 area between Patchbank and the Utsira ridge west of Karmøy. The area is the site of intensive fishing activity, and was selected on the basis of recommendations from fishermens' organizations and the fishery authorities. The compensation board for loss of fishing equipment has considered several cases concerning loss and damage to fishing equipment in these waters.

Various chains, wires of various dimensions, an iron structure and fishing gear for a total weight of approx. 25 tons was removed from the seabed. The exact position of six wrecks were determined, but the wrecks were not raised.

The work was carried out by Stolt Comex Seaway A/S, Haugesund, with the vessel M/V Bergen Viking. The selection of the contractor took place after announcement through the EEA system.

The management committee for the clean-up action has consisted of representatives from the Norwegian Petroleum Directorate, the Directorate of Fisheries, the Hydrographic Survey of Norway, the Norwegian Fisherman's Association and the Norwegian Oil Industry Association.

4. International cooperation

4.1 COOPERATION WITH NORAD

In 1996, the Norwegian Petroleum Directorate's NORAD assistance, which amounted to 5.25 man-years, was financed by NORAD. The majority of the assistance has been directed towards the following cooperating countries: Angola, Namibia, Tanzania, South Africa, Mozambique, Eritrea, India, Bangladesh and Nicaragua. The Norwegian Petroleum Directorate has also continued its cooperation with the Coordinating Committee for Coastal and Offshore Geoscience Programmes in East and Southeast Asia (CCOP).

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. We assume that all main projects will be governed by such agreements during the course of next year.

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 main developing countries and activities:

Angola

The Norwegian Petroleum Directorate has assisted in the organization of several delegation visits in Norway, including in connection with the visit by the Angolian Minister of Energy. Planning of future assistance concerning regulatory development in the fields of safety and resource management and general institutional support have accounted for the main activity in 1996. MINPET (Ministry) is the natural main cooperation partner. Sonangol, which currently performs several authority functions, also participates in the planning of future assistance activities.

Namibia

The Norwegian Petroleum Directorate has assisted in the formulation of regulations, follow-up of drilling operations and assistance in connection with establishment of core storage and files. Development of the Kudu gas field and continuing oil exploration are main challenges. NAMCOR is the main cooperation partner (state oil company).

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 and establishment of framework conditions for marketing of natural gas in South Africa are important areas for potential future Norwegian assistance.

Mozambique

The Norwegian Petroleum Directorate has assisted in the formulation of legislation, resource, pipeline and safety regulations, treaty negotiations with South Africa, follow-up of drilling operations, data security and general institutional support. The main cooperation partners are DNCH (Directorate) and ENH (state oil company).

Development of the Pande gas field and build-up of gas-based industry or large-scale export to South Africa and further resource mapping is the main challenge for the cooperation institutions in Mozambique. An increasing number of international companies have shown interest in exploration for oil and development of gas resources.

Tanzania

The assistance has included negotiation support concerning development of the Songo-Songo gas field, assistance concerning planning for use of gas and assistance concerning data management. TPDC is the main cooperation partner (state oil company).

Eritrea

The Norwegian Petroleum Directorate has provided assistance concerning establishment of framework conditions, resource planning, promotion, data storage and seismic surveying. The Ministry of Energy and Mineral Resources is the main cooperation partner.

India

The Norwegian Petroleum Directorate has provided assistance concerning the Directorate's entire sphere of responsibility with transfer of experience to a comparable agency, DGH, which is being developed. Storage of large quantities of data, resource evaluation, development planning and implementation of safety audits are areas of focus for the assistance.

Bangladesh

The Norwegian Petroleum Directorate has provided assistance in connection with the establishment of a new management model for the petroleum sector with establishment of a new "Hydrocarbon Unit" in the Ministry of Oil and Energy in Dhaka. The Norwegian Petroleum Directorate has also participated in development of a study regarding administrative routines for exercise of resource and safety management and has contributed to a PETRAD seminar on the same topics.

Bangladesh Petroleum Institute was the main cooperation partner in the program, which has now been concluded.

Vietnam

The Norwegian Petroleum Directorate has provided 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. In December 1996, a geo-professional expert from the Norwegian Petroleum Directorate joined CCOP's secretariat in Bangkok as a consultant for a period of 2-3 years.

Nicaragua

The Norwegian Petroleum Directorate has provided assistance concerning promotion, mapping of the resource potential and securing of data. INE is the main cooperation partner (office answers to the Ministry of Energy).

In addition, administrative tasks have been performed in connection with the above-mentioned projects and general assistance to NORAD, inter alia in connection with evaluation and planning of new projects.

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 arrangement of two eight-week courses each year addressing "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 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 1996, 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 45 participants from 28 nations.

In addition, the Norwegian Petroleum Directorate contributed to the implementation of PETRAD's 6-week course "Management of Petroleum Development and Operations", arranged for 18 managers from the "Oil & Natural Gas Corporation of India" (ONGC).

The Norwegian Petroleum Directorate has also contributed to the implementation of seminars in India, Namibia, Russia, Kazakhstan, Bangladesh and Papua New Guinea.

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 increased oil recovery, development of small fields and unitization. The Danes have particular problems related to limestone fields. It has therefore been valuable to acquire first hand information on their experiences. Data management is another area where it has been very useful to exchange experience. Close cooperation is envisaged also in this connection.

During the year, two meetings were conducted with the Danish authorities. The first meeting was held in Copenhagen on 4-5 September and the second was held in Stavanger on 29 November.

In addition to the exchange of information regarding the status in the respective areas, a number of issues related to the structures which extend beyond national boundaries were discussed during the meeting in Copenhagen. In addition, the Danish government's energy plan was

presented. A visit was also made to Skåne to view a sandstone fracture where the geology is representative of some of the geology found on the Norwegian shelf. Efforts within research and development in order to achieve better exploitation of oil and gas deposits is a continuous theme. Petroleum legislation and the resource situation in Skagerrak-southern North Sea was the main theme of the meeting in Stavanger.

This year's meeting with the British authorities was held in London 25-26 November. The main topic this time was exploration, development and production as well as environmental conditions. The British presented their experiences, while we contributed inter alia with information regarding the MILJØSOK cooperation.

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 geo-technical, exploration technology and data management issues and 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 considerable, 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 1996, the foundation was laid for a cooperation agreement with France, which is expected to be concluded and signed during the first half of 1997. 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.

4.4 COOPERATION WITHIN SAFETY AND WORKING ENVIRONMENT

The Norwegian Petroleum Directorate cooperates extensively with international professional institutions and government agencies within the area of safety and management of working environment, 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 by 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 1996 have been:

- NSOAF - North Sea Offshore Authorities Forum,
- the EU Commission, in cooperation with the Ministry of Local Government and Labour, on safety and the working environment,
- the United Nations' International Maritime Organisation (IMO) and International Labour Organisation (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).

BORIS - development of safety regulations for offshore petroleum activities in Russia

The BORIS project (Bilateral Cooperation on Development of Russian Regulations concerning Industrial Safety) started in 1995. This is a cooperation project between the Russian Gosgortekhnadzor (Supervisory Directorate), which is

responsible for the supervision of safety in most sectors of Russian industry, and the Norwegian Petroleum Directorate. The project will run over a period of three years. The Norwegian part of the project is financed by the Ministry of Foreign Affairs.

In the BORIS project, the Norwegian Petroleum Directorate assists the Gosgortekhnadzor in the preparation and planning of development of safety regulations for the offshore Russian petroleum industry. No such regulations currently exist. Based on its own experiences in the development of regulations, the Norwegian Petroleum Directorate provides advice and guidance with regard to the charting and analysis of factors which will steer the development of regulations. The reforms now being carried out in Russia, including the transition from a centrally directed to a market economy, contribute to making the task of developing relevant regulations adapted to the Russian petroleum industry of the future a complicated one. In 1996, the project has carried out activities with a view towards formulating a suitable supervision system and developing overarching safety regulations.

The nature of the project demands the building of a climate of trust and good communication between the participants in the Russian and Norwegian parts of the project. To assist in these efforts, the Norwegian Petroleum Directorate has employed two project team members whose qualifications include mastery of the Russian language. This has had a positive effect on the cooperation atmosphere.

The Norwegian value of the project is primarily the fact that by contributing to the development of effective safety regulations for petroleum activities in the Russian sector of the north, the danger of major catastrophes or accidents occurring in or near Norwegian coastal or ocean areas is reduced. In addition, the project also provides a practical means of strengthening cooperative relations between Norway and Russia, which can also provide interesting opportunities for Norwegian industry as a whole.

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 a 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).

During the course of 1994-95, the Borehole Committee's work was particularly concentrated on a draft SHCMOEI report on the Piper Alpha catastrophe on the British sector in 1988, as well as a report on personal injury statistics for offshore petroleum activities. Work on the reports was concluded in the Borehole Committee in February 1996 and the reports were submitted to SHCMOEI. The reports were processed and accepted by SHCMOEI in March 1996.

In February 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 will probably agree to the arrangement of a working conference under the direction of EU during 1997 to discuss common recognition of instruction/training certificates.

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.

Standardization within structures and pipelines

In 1991, the former Norwegian Workshops' Standardization

Association (NVS) established Norwegian reference committees for new ISO standards for "Offshore structures", "Pipeline Transportation System for the Petroleum and Natural Gas Industries" and "Line Pipe". The Norwegian Petroleum Directorate has been represented both in national committees and as the Norwegian representative in connection with international work.

ISO 13636 - part 1 regarding *"Offshore structures"* was released in December 1995. Work on part 2 concerning steel structures is in progress with the objective of release in the year 2000. The Norwegian Petroleum Directorate participates in the work in two working groups on marine environment and corrosion protection. Work on part 3 concerning concrete structures is also in progress, with release planned in the year 2001. This will largely build on the Norwegian standards NS 3420 and NS 3473. The Norwegian Petroleum Directorate's representative is also the chairperson of a panel on control of the condition of concrete structures. The work on part 4 concerning mobile units started in1995. Here, the Norwegian Petroleum Directorate is represented on a panel on anchoring and dynamic positioning. The plan is to complete this standard in 2002.

Lecture activities

Also in 1996, the Norwegian Petroleum Directorate's staff members have 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 and the like.

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 have requested the Norwegian Petroleum Directorate's assistance in the work to develop such a management model.

5. Projects

5.1 NORSOK - INTSOK - MILJØSOK

NORSOK

In previous annual reports, the Norwegian Petroleum Directorate has provided information regarding the background for and the content of the ongoing NORSOK work, and has simultaneously clarified the Norwegian Petroleum Directorate's role and participation in this work. In its annual reports, the Directorate has also provided an account of how future work would formally relate to NORSOK's various recommendations.

During the period covered by the annual report, the Norwegian Petroleum Directorate has followed up the work in NORSOK through its participation in NORSOK's management group, and has assisted the Ministry of Local Government and Labour and the Ministry of Industry and Energy in the work to develop and complete the new Petroleum Act as well as revision of the accompanying regulations. In this context, the Norwegian Petroleum Directorate has also evaluated relevant NORSOK recommendations and, where the Directorate has found these recommendations to be relevant, it has proposed their incorporation in the new regulations.

Development of verification model

NORSOK sub-report No. 4 on "Documentation and Information Technology" discusses the use of classification methodology as a basis for verification of "offshore structures".

In the spring of 1996, an initiative was taken by the NORSOK secretariat for more detailed discussion of the use of classification systems in connection with verification, i.e., testing and documentation that the specified requirements have been fulfilled.

The mandate for the work was to describe a cost efficient verification model geared for the future for use on offshore installations, with a point of departure in classification and offshore experience.

With the clear point of departure that the supervision system in the petroleum activities is initially based on the licensees' obligation to carry out internal control, and that verification systems cannot be established which disturb this duty or the hierarchy of responsibility which applies for the activities in general, the Norwegian Petroleum Directorate has participated in the work through its representation in the initiative group and underlying work group.

At the time this annual report was prepared, no final report on the work was available.

NORSOK standards

In its annual report for 1995, the Norwegian Petroleum Directorate provided information concerning a proposal from NORSOK to incorporate all or parts of the material content of the Norwegian Petroleum Directorate's technical guidelines in its standards. The idea was that the Directorate could then withdraw these guidelines and instead take part in the work towards further development of these NORSOK standards, and also refer to these standards as recognized norms in its regulations.

After having discussed this on a principle basis with the other trade parties, the Norwegian Petroleum Directorate took a positive position to the proposal, with the condition that the NORSOK standards would have to be given a permanent basis in authority, must be subjected to formal procedures for updating and further development, as well as that the established standard for safety and the working environment in the petroleum activities must be continued. In addition, the Norwegian Petroleum Directorate stated the condition that the updated or new standards must be completed before the Norwegian Petroleum Directorate decides what to do with its own guidelines.

After these conditions had been met in a satisfactory manner, in cooperation with the designated NTS/NORSOK Standardization Group, the Norwegian Petroleum Directorate's guidelines have been reviewed with a view towards identifying the areas where such a transfer could be appropriate. The work has not been completed.

INTSOK

For many years, the Norwegian Petroleum Directorate has cooperated with a number of different countries with a view towards assistance in issues related to the management of petroleum resources. Many of the countries have significant petroleum resources, and are therefore interesting in an INTSOK context.

The network and the expertise which the Norwegian Petroleum Directorate has developed here has been conveyed to INTSOK through the Directorate's active participation in the management committee and various working groups.

MILJØSOK

In 1995, the Ministry of Industry and Energy took the initiative to establish MILJØSOK, modeled on NORSOK, so as 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 cabinet on 13 December 1996. The main objective for the management group has been *to contribute to the further development of an efficient environmental strategy which will lead the Norwegian shelf to the forefront with regard to cost-efficient and environmentally-friendly petroleum activities, and at the same time promote an improved comprehensive understanding for this strategy both nationally and internationally. Furthermore, to stimulate the development of a more efficient cooperation between the industry and the authorities which will result in more cost-efficient means to achieve optimal environmental effects and competition efficiency within the petroleum industry.*

The report provides a comprehensive environmental status and description of the environmental challenges for

Norwegian petroleum activities, a review of technical/economic action alternatives on the shelf and an evaluation of the means used in climatic and environmental policy. A number of ambitions and goals are set which the management group believes that that industry and the authorities should be able to realize through a mutually binding cooperation. Furthermore, proposals have been made for new means in order to achieve the goals.

At the beginning of 1997, the Norwegian Petroleum Directorate has commenced work on follow-up of the MILJØSOK report in cooperation with the Ministry of Petroleum and Energy and other concerned authorities.

5.2 PROJECTS WITHIN RESOURCE MANAGEMENT

5.2.1 INDUSTRY COOPERATION

FORCE

FORCE (*"FOrum for Reservoir Characterization and reservoir Engineering"*) is a cooperation forum on problems related to increased oil recovery. FORCE started in 1995 and has 18 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.

The main goal of FORCE is to contribute to increasing oil recovery on the Norwegian continental shelf. The potential for increased oil recovery is large and time-critical. FORCE provides the companies with a forum in which to discuss critical 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 increased oil recovery.

In 1996, two "Problem Defining Workshops" were arranged. The topics discussed included seismic monitoring, analog field data, sand control, permanent downhole tools, prediction and quantification of residual oil saturations as well as geo-professional and reservoir technology research related to production from the chalk fields. The conclusions from the latter are followed up by oil companies who have previously been involved in the chalk research program "Joint Chalk Research". These companies are working for the initiation of a new research program.

A total of 10 projects have been initiated in 1996 through FORCE with financial support from the FORCE members. The projects are carried out by both Norwegian and foreign universities, institutions, consultants and service companies.

FORCE has arranged 4 seminars during 1996 with the following themes: *Geo-guidance during drilling, WAG injection, Chlorite and Production of gas/condensate.* The quality of the seminars has been high and has contributed to better understanding of the challenges in the various areas. Experts from the FORCE members, from service companies as well as from research institutions and universities have contributed presentations.

FIND

In 1996, the Norwegian Petroleum Directorate took the initiative to establish FIND, a cooperation forum for exploration technology. FIND is organized with a board consisting of representatives from 20 oil companies as well as the Norwegian Petroleum Directorate. The Norwegian Petroleum Directorate has the secretariat.

The objective of FIND is to create a forum where the members can focus on cooperation with regard to planning and implementation of technology-related projects with significance for future exploration on the Norwegian shelf.

After an initiative from the Norwegian Petroleum Directorate, two projects have been commenced:

The "Super grid" project has the objective of establishing a joint coordinate system for handling of digital seismic data. This will make it possible to connect the various 3D seismic surveys together, which will facilitate the access and improve the opportunities to exploit the large quantities of data which have been collected during recent years.

The "Evaluation of Well Results" project has the goal of charting the critical success factors for exploration in various areas on the Norwegian shelf. The first phase consists of an evaluation of approx. 170 appraisal wells drilled during the period from 1990 to 1996.

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 13 oil companies as well as the Norwegian Petroleum Directorate. In addition, four contractor companies have also agreed to load their own seismic data into the data base.

IBM EPAC in Stavanger has developed the software which is in use. New versions which handle new types of data will be launched in 1997 and 1998.

The data base and the network which the DISKOS members are connected to is operated by PetroData A/S. During 1996, large quantities of seismic data and data from boreholes (exploration wells) were loaded, in all more than four terrabytes. The Norwegian Petroleum Directorate delivers quality-controlled administrative data to the data base on a weekly basis. These data describe production licenses, blocks, fields, seismic navigation, well locations, pipelines, etc.

The cooperation in the DISKOS group is headed by the Norwegian Petroleum Directorate. Data access will be 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. The costs for development and operation will be divided among the users of the system.

5.2.2 RESEARCH AND DEVELOPMENT COOPERATION

"Joint chalk research"
Phase IV of this research program was completed in the autumn of 1996 and concluded with a symposium. The program started in 1982 after an initiative by Norwegian and Danish authorities. The goal has been to improve knowledge of reservoir behavior and to increase recovery from the chalk fields in the North Sea. During the period from 1982 to 1996, approx. NOK 60 million has been spent on the program.

Phase IV has been carried out as a cooperative effort between the Norwegian Petroleum Directorate, the Danish Energy Agency, seven oil companies and research institutions in Norway and Denmark. This phase has targeted the following topics in particular:

- Characterization of chalk rocks and fractures
- Mechanical properties of chalk rocks
- Effects of water injection

In one of the seven projects in this phase, an overview of the results of the three preceding phases in the program was prepared, including results from other chalk research performed during the past ten years. This was completed in 1995 and the information was published in book form by Rogaland Research. The program results which have been achieved have inter alia been crucial for handling of compacting in the reservoir and subsidence of the seabed, and for an optimal utilization of water injection.

The program has been administered by Amoco, and the steering committee is headed alternately by the Danish Energy Agency and the Norwegian Petroleum Directorate.

In the autumn of 1996, an initiative was taken within FORCE with a view towards continuing this research.

RUTH
The research program RUTH (Reservoir Utilization through advanced Technological Help) was concluded with a seminar in the Norwegian Petroleum Directorate on 6-7 May 1996. The program yielded important research results and development of methodology within methods for increased recovery of oil, and was actively involved in pilot projects on the fields for the use of foam and WAG (alternating water/gas injection).

The program was discussed in more detail in the 1995 annual report. At the conclusion of the program, a book was published which provides a summary from each of the program's 32 projects. This book is sold by the Norwegian Petroleum Directorate.

5.2.3 OTHER PROJECTS

THE NORWEGIAN PETROLEUM DIRECTORATE'S GEOPHYSICAL SURVEYS IN 1996
The Norwegian Petroleum Directorate acquired a total of 6,669 km 2D seismic during 1996.

Coastal areas - In order to study coastal sedimentary basins and the most important landlineaments' marine extension, shallow seismic surveys were made of the stretch from Karmøy - Kristiansund. 1,190 boat-kilometers of seismic data were collected (Figure 5.2.3.a). At the same time, registration of data from a small air gun was conducted to enable study of the geology just under the seabed in order to find suitable ground drilling locations and to register any neo-tectonic movements.

The Norwegian Sea and the southern Barents Sea - Seismic data was collected in the Vøring Basin and over Bjørnøyavifta in order to chart the extent of sedimentary rocks on the Atlantic Ocean margin (Figure 5.2.3.b). In these areas, a total of 3,980 boat-kilometers of seismic data were collected with a 4,800 meter long cable.

The northern Barents Sea - Little ice in the area around Kong Karls Land made it possible to collect 1,499 boat-kilometers of seismic (Figure 5.2.3.c). Simultaneously with the investigations in the Norwegian Sea and the southern and northern Barents Sea, data was registered from a small air gun. This type of seismic provides valuable information concerning conditions on the seabed and about the rocks just under the seabed.

Figure 5.2.3.a Shallow seismic surveys offshore Karmøy - Kristiansund

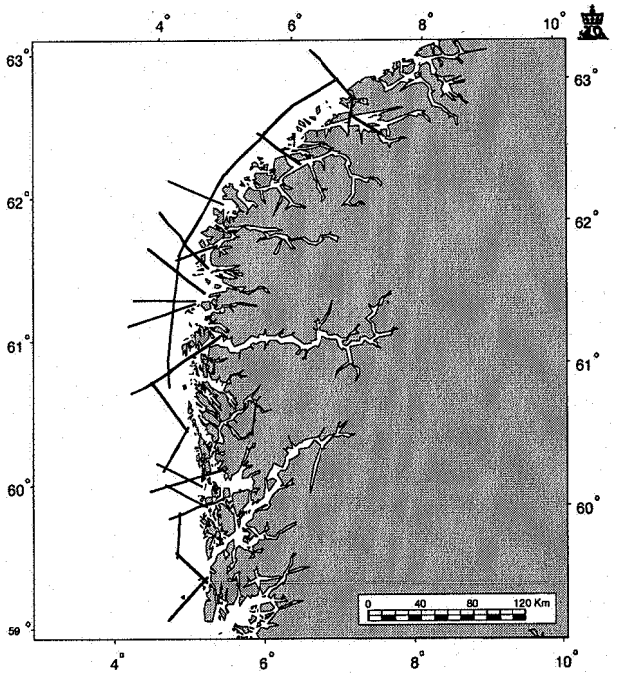


Figure 5.2.3.b
Seismic surveys in the Norwegian and Southern Barents Seas

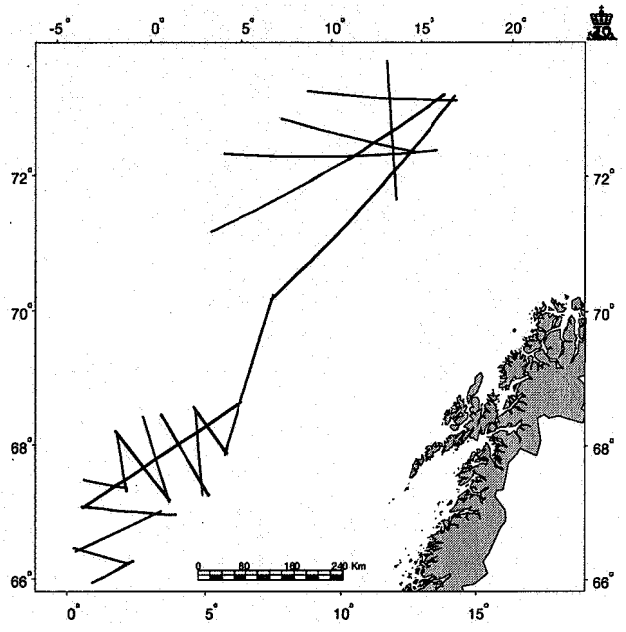
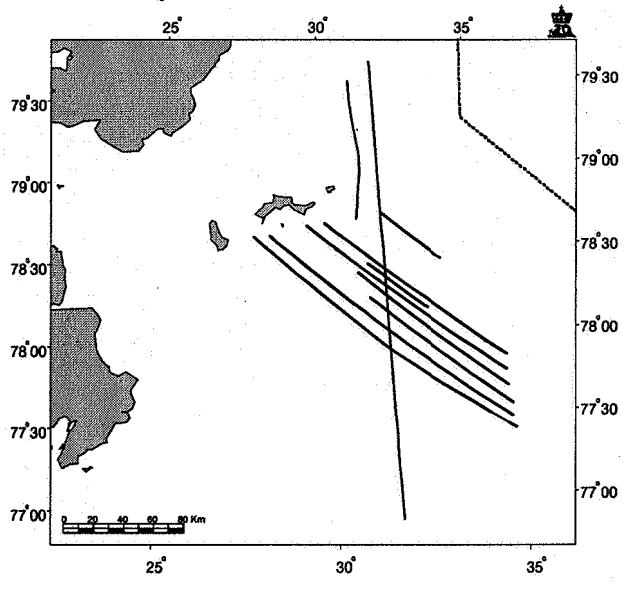


Figure 5.2.3.c
Seismic surveys in the northern Barents Sea



Gravimetric data - At the same time as the marine seismic surveys, approximately 7,100 km of gravimetric data were acquired. The data are incorporated in regional studies and are a valuable support for seismic data in the surveying of relatively unexplored areas.

In connection with the ongoing processing of the Norwegian Petroleum Directorate's gravimetric data, a gravimetric map of the northern Barents Sea has been produced.

Varying seismic data quality and geological structural complexity in certain provinces make it difficult to arrive at a clear seismic interpretation of structural main characteristics. Therefore, it is important to correlate seismic with observed and modeled gravimetric and magnetic data. The Norwegian Petroleum Directorate has achieved an increased understanding of the geological structural elements in this area, which contributes significantly to the mapping of the northern Barents Sea. The Norwegian Petroleum Directorate's geologists and geophysicists are working with the external consultant, Amarok a.s.

RESEARCH COOPERATION ON 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. There are currently nine participating countries, and the cooperation mainly consists of a commitment to a certain extent of research in specific areas and the exchange of results. As for Norway, for the period from 1992 to 1995, this cooperation has been taken care of through the state research program RUTH, which has been led by the Norwegian Petroleum Directorate.

The Norwegian Petroleum Directorate has been represented on the international management committee for this IEA cooperation.

NEWSLETTER

Four issues of the newsletter have been published in 1996. From its start in 1994, the newsletter originally focused on issues related to improved oil recovery, but the content has now been expanded to cover relevant news within the entire professional 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.

SAMBA

The SAMBA project has been started in order to improve the information systems (IS) in the Petroleum Resource Management Division. The project was started in early 1996, and will be continued in 1997.

The main objective of the project is to simplify storage, searching and interpretation of data for the individual employee. Particular emphasis is placed on integrating data which is of common interest to several professional areas in the division.

This is done by using an interdisciplinary data model based on the POSC standard and a more uniform user interface in connection with use of the geographic information system (GIS) and MS-Windows. The SAMBA project will make use of experiences from the DISKOS project in several key areas.

The project is divided into three phases. Phase 1, which included a review of all the information needs, was carried out during the first half of 1996. Phase 2 consists of preparing an information system for the most central informa-

tion carriers, and was started in the autumn of 1996. Phase 3 of the project will entail optimization of the data flow between the various EDP tools in the division.

DINIUM-ALPHA

Dinium-Alpha is a data base for microplankton species which includes chronostratigraphic spread, morphology and photomicrography.

The objective of the project is to give Petrobank users access to released biostratigraphic raw data. The data base shall contain uninterpreted biostratigraphic data from exploration and production wells on the Norwegian shelf. The basis data is gathered from external biostratigraphic reports and internal studies carried out at the Norwegian Petroleum Directorate's laboratory. The project is conducted in cooperation with BV edbkonsulent.

Dinium-Alpha is a Windows 95/NT-based data base application which, based on searchable morphological and stratigraphic criteria, retrieves chronostratigraphic spread, morphological criteria and digital photomicrography of microplankton species. Several hundred morphological criteria have been produced on a user-friendly interface. Dinium-Alpha's area of application is adapted to both individual and multi-user environments in order to function as a consistent, morphological/chronostratigraphic platform.

The Norwegian Petroleum Directorate has developed and aims at offering Dinium-Alpha for sale during the autumn of 1997. The sales package will include a data base module which includes Mesozoic and Cenozoic microplankton species, chronostratigraphic spread in the North Sea, the Norwegian Sea and the Barents Sea, as well as photographic documentation consisting of about 2000 digital electron and light microscope pictures. Dinium-Alpha can be connected with DinoSys, which is produced by the LPP Foundation at the University of Utrecht. Once connected, the user can access original descriptions and an additional 8000 pictures of all microplankton species through morphological and/or chronostratigraphic searches.

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 will be made available to the industry in 1997. This has been a cooperative effort by the Norwegian Petroleum Directorate, Saga, Norsk Hydro and Statoil.

5.3 PROJECTS IN THE AREAS OF SAFETY AND WORKING ENVIRONMENT

5.3.1 MANAGEMENT SYSTEMS

Management of joint operating and modification activities

The project is a continuation of a project which was started in 1995, and which has the goal of identifying risk factors in connection with all operating and modification activities. In 1996, a statistical processing of numerical material has been carried out which shows that there is a connection between modification work/activity level and the number of major fires and gas leaks on the installations. In addition, information has been gathered regarding the operators' methods and techniques for planning and coordination of joint operating and modification activities, and work is in progress on a model for interpretation of the connections.

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 1996, the Norwegian Petroleum Directorate has carried out a project in cooperation with Det norske Veritas and Stavanger College which has 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 will be incorporated in the Directorate's basis for supervision of the operators' activities within the area of risk analysis.

Management tools for supervision in the operations phase

In 1996, the Norwegian Petroleum Directorate has carried out a project with SINTEF as partner which has had the goal of strengthening the Directorate's expertise in the area of maintenance. The work has provided increased insight into strategies, methods, planning and organization of modern maintenance. The project has also charted and illuminated the most relevant standards in the area. The experiences from the project will be incorporated as a part of the basis for planning and implementation of the Norwegian Petroleum Directorate's supervision of the operators' management of maintenance activities in the future.

5.3.2 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 Confederation of Norwegian Business and Industry and the Ministry of Local Government and Labour.

The background for the project is the recognition of the fact that a number of physical, chemical and psycho-social 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.

Work is in progress to identify persons who have, or have had, their workplace on the Norwegian continental shelf. 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.

Handling of radioactive deposits

Water which is produced together with oil and gas acquires an increasing content of various radioactive substances as the reservoir is emptied. Some of these substances are deposited in the production equipment on the installations. Removal of such deposits is normally carried out on the installations, but some of the equipment components are sent to the supplier of the equipment for cleaning. The project has resulted in knowledge regarding the current practice with regard to removal of such deposits both on the installations and on land. Surveys have been made of the quantity of radioactive material which is handled through such work, and an evaluation has been performed of the health consequences such handling may have.

The project has been carried out by the Norwegian Radiation Protection Authority with financial support from the Norwegian Petroleum Directorate.

5.3.3 DRILLING AND WELL TECHNOLOGY

Well maintenance - status and trends

The project has continued work from earlier phases, and has in 1996 focused on establishing an overview of status and trends for equipment and operations related to so-called underbalanced wells. Experiences have been evaluated against the requirements in the drilling regulations, with regard to how these cover underbalanced operations. It has been noted that the current requirements are not relevant/adequate for today's or future drilling and well operations. The conclusions from the project will be incorporated as a part of the foundation for the upcoming review of the regulations.

Well control in deep waters

The Norwegian Petroleum Directorate participates, 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 waters.

The results from the project, which is expected to last through 1997, will have great significance for the Directorate's expertise in this area, and will be incorporated in the basis for continued development of the regulations for planning and carrying out supervision of operators who conduct activities in deep waters.

5.3.4 PREPAREDNESS

Efficiency of rescue and evacuation means

The goal of the project is to develop an overall description of strengths and weaknesses in connection with various rescue and evacuation means, as well as frameworks for their application. In 1996 information has been gathered and systematized, and areas for concentration of efforts have been identified for continued work in the project in 1997. The project will be led by a broad-based group under the leadership of the Norwegian Petroleum Directorate.

5.3.5 FIRE AND EXPLOSION SAFETY

Gas safety program

Since 1990, the Norwegian Petroleum Directorate has provided support to and participated in the professional reference group for a comprehensive research program on gas explosions carried out at the Christian Michelsens Institute. The program has now been concluded. In 1996, the project has developed a new version of FLACS, which is a simulation program for calculation of explosion pressure. On the whole, the program has provided a significant contribution to the understanding of the progress of gas explosions, which has in turn provided significant contributions to the work to reduce the consequences of a gas explosion through design and construction of modules, location of equipment, etc.

Technological development in safety systems

The development within electronics and signal processing is proceeding at a great pace, and the Norwegian Petroleum Directorate is concerned with maintaining the expertise necessary in order to evaluate constant new solutions in relation to the regulatory requirements for functionality with regard to reliability of the safety systems. The project, which

was carried out at SINTEF, has performed an evaluation of relevant solutions for signal transmission and processing, and has inter alia revealed several potential problems in connection with reliability and integrity for relevant conditions and situations. A review and evaluation of relevant standards in this area has also been performed. The project is expected to be continued in 1997.

5.3.6 PROCESS FACILITIES

Process technology - framework conditions for construction and operation
The project has first and foremost had the objective of raising the Directorate's expertise with a view towards the supervision of the operating companies' activities related to planning and operation of process facilities, particularly in connection with the need for upgrading of the process facility's capacity during the operations phase as a consequence of a changed production profile. In addition to the technical aspects in connection with production equipment, etc., external frameworks such as reservoir conditions, emission requirements and transportation solutions have also been examined. SEVU has been responsible for carrying out the project.

Production capacity for process facilities
Det norske Veritas, on assignment from the Norwegian Petroleum Directorate, has prepared a report which explains the various standards which the industry uses as a basis in connection with design and construction of process facilities. An attempt has been made to illuminate what margins the standards incorporate, particularly keeping in mind potential increases in capacity. The report discusses several relevant issues in connection with the upgrading of such facilities, with regard to changes in capacity, composition and changed parameters such as pressure and temperature. The Norwegian Petroleum Directorate will use the report in connection with supervision of the operating companies' qualification of plans for upgrading of process facilities.

Reduction of flanged connectors in process facilities
This project is a continuation of work begun in 1992 with the objective of achieving optimum function conditions for conventional flanged connectors, first and foremost to contribute to a reduction in the number of unintentional hydrocarbon leaks. The goal of the project is to prepare proposals for improvement, both with regard to calculations as well as practical work on flanged connectors. In 1996, the project has addressed a status for application of so-called compact flanges. Det norske Veritas has done the work, which has included a review of relevant codes and standards, gathering of user experiences, as well as evaluation of areas where compact flanges are particularly well-suited.

5.3.7 DIVING

Technical and operational aspects of manned underwater operations
Experience has shown that there still are technical and operational aspects of underwater operations which can be improved. The project has previously addressed problem areas such as battery capacity for diving bells in emergency situations, emergency training of diving personnel, depth monitoring of divers, decompression tables for surface-oriented diving, loss of bodily fluids (dehydration), air bell diving and so-called "Flipper" diving (diving from smaller, open boats operating from a mother vessel). With assistance from SINTEF, a comparison of the regulations for manned underwater operations in the North Sea countries has been carried out in 1996.

5.3.8 STRUCTURES AND PIPELINES

Lightweight construction concrete
The Norwegian Petroleum Directorate participates in a joint industry project which has the goal of finding new areas of application for lightweight concrete, motivated by the technical and economic potential a weight reduction in concrete could create. The project also examines the durability of lightweight concrete, and is carried out inter alia using experiments connected with Norwegian bridge projects where lightweight concrete has been used. The project will continue in 1997 and, among other things, is expected to provide important contributions to development of criteria for cathodic protection and covering of reinforcements.

Reliability-based design methods for pipelines
In 1996, the Norwegian Petroleum Directorate participated in the final phase of a project which was started in 1992 with the participation of Snamprogetti, Sintef and Veritec. The objective of the project has been to lay a foundation for an optimal construction of pipelines by arriving at a calculation method which could take into consideration the different factors in connection with the individual pipelines better than current methods. Factors which are significant are, e.g., water depth, character of the surface of the seabed, mediums to be transported and external loads. The Norwegian Petroleum Directorate will, among other things, use the experience from the project as a basis for further development of regulatory requirements for pipelines.

Reliability of corroded pipelines
The Norwegian Petroleum Directorate has participated in a project carried out by Det norske Veritas Industri which has had the goal of finding suitable methods for calculating residual strength in corroded pipelines, mainly based on analytical methods. Simultaneously, a project has been carried out in the U.K. which has included a materials testing program. In 1997, a new project is planned which is to

link the experiences from the two countries' projects with a view towards developing common guidelines for calculations in this area.

Corrosion in pipelines
The Norwegian Petroleum Directorate has participated in a comprehensive industrial project which since 1994 has worked on developing a calculation model which can provide a reliable safety assessment when corrosion attacks are discovered in transportation pipelines. Earlier, the project has conducted a large number of full-scale blasting tests, as well as scaled tests with simulated corrosion damage. In 1996, the work has included systematizing of data and experiences from the tests and development of a new calculation model. The experiences from the project will be used as a basis for a potential revision of the Norwegian Petroleum Directorate's regulations in this area.

Mechanical couplings 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. Through the project, the Norwegian Petroleum Directorate has illuminated which evaluations should be carried out in order to be able 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.

Evaluation of new pipeline code
Det norske Veritas has prepared a new pipeline code, DnV96, which is to replace Norwegian operating companies' own specifications within the field of pipeline technology. Thus, the code will be a key element in connection with a number of the upcoming development projects. Therefore, in 1996 the Norwegian Petroleum Directorate has carried out a project in order to evaluate the code against the corresponding regulatory requirements. The conclusions from the project will be discussed with DnV during 1997, with a view towards use of the code by the companies within the framework of the regulatory requirements in this area.

5.3.9 INTERNAL MATTERS

Internal information network
The Norwegian Petroleum Directorate has begun use of Internet technology for internal exchange of information ("intranett"). In 1996, a pilot project was started in connection with the supervision of safety and the working environment ("tilsynsnett"). The supervision network ("tilsynsnett") shall contain information of significance for the planning and implementation of the Norwegian Petroleum Directorate's supervision towards the operating companies. The supervision network will be used by Directorate officials, and will only be available internally.

The objectives of the supervision network are to
- provide a systematic overview of problem areas on various installations
- develop a good foundation for internal communication and cooperation
- create a good foundation for prioritization between various problem areas

An internal editing group has been established to work on information structure, technical development and updating of the supervision network. In 1996, data concerning one selected operating company has been entered into the supervision network. As experience is gained in the use of the system, the supervision network can be expanded to cover all the operating companies with associated installations on the Norwegian shelf.

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 in direct pursuance of acts/regulations or by individual administrative decisions by a superior authority. Delegation applies to parts of:

a) The Petroleum Act, of 23 March 1985 No. 11, including
   - the Petroleum Regulations, Royal Decree of 14 June 1985
   - the Safety Regulations, Royal Decree of 28 June 1985
   - the Internal Control Regulations, Royal Decree of 28 June 1985
   - the Safety Zone Regulations, Royal Decree of 9 October 1987

b) The Working Environment Act, of 4 February 1977 No. 4,

Including:
   - the Working Environment Regulations, Royal Decree of 27 November 1992

c) The CO_2 Act, of 21 December 1990, No. 72

d) The Tobacco Act, of 9 March 1973, No. 14

e) The Svalbard Act, of 17 July 1925, No. 11,

Including:
   - Regulations concerning safe practices in scientific research and exploration for petroleum deposits on Svalbard, Royal Decree of 25 March 1988

f) Act relating to scientific research and exploration for and exploitation of subsea natural resources other than petroleum resources, of 21 June 1963 No. 12,

Including:
   - Regulations relating to scientific research for natural resources on the Norwegian continental shelf, etc., Royal Decree of 31 January 1969

g) Provisional regulations concerning littering and pollution caused by petroleum activities on the Norwegian continental shelf, Royal Decree of 26 October 1979

6.2 ORGANIZATIONAL CHANGES

A reorganization was carried out in the Division for Petroleum Resource Management with effect from 10 June. The three sections: Section for Reservoir Evaluation Southern North Sea (RDS), Section for Reservoir Evaluation Northern North Sea (RDN) and the Section for Reservoir Evaluation Norwegian Sea/Barents Sea/Troll (RDH), were merged into two: the Reservoir Evaluation Section Southern area (RDS) and the Reservoir Evaluation Section Northern area (RDN).

It was subsequently decided that a new unit should be established as from 1 January 1997, the Forecasting and Resource Assessment Department, as well as a unit for the division's international work.

Otherwise, no significant organizational changes have taken place in the Norwegian Petroleum Directorate in 1996.

6.3 STAFF

At the end of the reporting period the Norwegian Petroleum Directorate had 354 authorized positions. In addition, six positions are funded by NORAD (the Norwegian Directorate for Development Cooperation), two by the Ministry of Foreign Affairs, three by the Employment Service Division and four are contract assignments. The Directorate received no new positions in 1996. At the end of 1996 there were 368 staff members in service. 16 staff members are on leave.

Seven new staff members were hired in permanent positions. Of these, three come from the oil industry or oil-related activities, three from other private industry, and one from the public sector.

19 staff members have left their positions, representing 5.4% of the total authorized positions.

6.4 PREMISES

An extension of the building of 3000 m^2 (gross area) is under construction. Among other things, this will provide additional and more appropriate work rooms and meeting rooms. The work commenced in June and will be finished in July 1997.

6.5 BUDGET/ECONOMY

Expenses

A total of NOK 272,825,939 was spent on the Norwegian Petroleum Directorate's operations in 1996.

The amount was appropriated as follows:

Operating budget	NOK	216 553 553,-
Supervision costs	"	9 729 326,-
Geological and geophysical surveys	"	43 278 052,-
Projects related to safety and working environment	"	3 265 008,-
Total	NOK	272 825 939,-

Of the operating budget, payroll costs account for NOK 131,061,374, lease and operation of buildings NOK 28,195,654, consultancy assistance to the Division for petroleum resource management NOK 7,240,585, consultancy assistance to the Division for safety and working environment NOK 3,705,807 and collection of meteorological and oceanographic data in the Barents Sea NOK 2,711,304.

The remainder covers expenses related to travel, training, electronic data processing (EDP) operations, new investments in equipment, modifications and expansions, etc.

In addition to its regular operations, the Norwegian Petroleum Directorate is responsible for:

Clean-up of the seabed	NOK	4 600 650,-
Administration of research program	"	1 384 640,-
Contribution to the PETRAD foundation	"	1 000 000,-
Project cooperation vis-à-vis Eastern Europe	"	1 656 265,-

Revenues

In addition to paid production royalties, area fees and carbon dioxide taxes totaling NOK 10,247,823,329, the Directorate received NOK 90,613,399 in revenues.

The breakdown of revenues was as follows:

Exploration fees	NOK	1 440 000,-
Commission fees	"	1 377 792,-
Reimbursed supervision costs	"	59 587 093,-
Sale of publications	"	5 431 312,-
Kindergarten fees	"	2 675 556,-
Canteen sales	"	960 230,-
Reimbursed for job schemes	"	528 030,-
Reimbursed from National Insurance Administration	"	1 357 796,-
Reimbursed from other government agencies	"	4 833 531,-
Sale of seismic survey data	"	4 818 497,-
Income from cooperation projects	"	5 962 353,-
Credit interest, bank	"	1 523 714,-
Miscellaneous income	"	117 495,-
Total	NOK	90 613 399,-

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 in two editions in 1996.

47 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 in 1996.

6.7 INTERNET

The Norwegian Petroleum Directorate's home page on Internet provides information concerning the Directorate's sphere of responsibility. Press releases are entered continuously. The address is *http://www.npd.no*, and the page is available in both Norwegian and English formats.

6.8 PUBLICATIONS RELEASED IN 1996

Acts, regulations and guidelines

- Compilation of Acts, regulations and provisions for the petroleum activities in 1996.
  An updated compendium of the statutory framework of acts, regulations and guidelines applicable to the Norwegian continental shelf. Issued 1 April 1996.
- CD edition of the regulatory compendium. Issued 11 July 1996.
- Act relating to petroleum activities
- Regulations to Act relating to petroleum activities
- Regulations relating to safety, etc., to the Act relating to petroleum activities
- Regulations relating to worker protection and working environment
- Regulations relating to drilling and well activities and geological data collection in the petroleum activities, with guidelines
- Regulations relating to lifting appliances and lifting gear in the petroleum activities, with guidelines
- Regulations relating load-bearing structures in the petroleum activities, with guidelines
- Regulations relating to marking of installations in the petroleum activities, with guidelines
- Regulations relating to the licensees' internal control
- Regulations relating to electrical installations in the petroleum activities, with guidelines
- Regulations relating to the collection of environmental data, with guidelines
- Regulations relating to pipeline systems in the petroleum activities, with guidelines
- Regulations relating to emergency preparedness in the petroleum activities, with guidelines
- Regulations relating to process and auxiliary facilities in the petroleum activities, with guidelines
- Regulations relating to safety and communication systems on installations in the petroleum activities, with guidelines
- Regulations relating to explosion and fire protection of installations in the petroleum activities, with guidelines
- Regulations relating to systematic follow-up of the working environment in the petroleum activities, with guidelines
- Regulations relating to safety delegate and working environment committee
- Interfaces in legislation applicable to the Norwegian continental shelf (Norwegian and English versions)

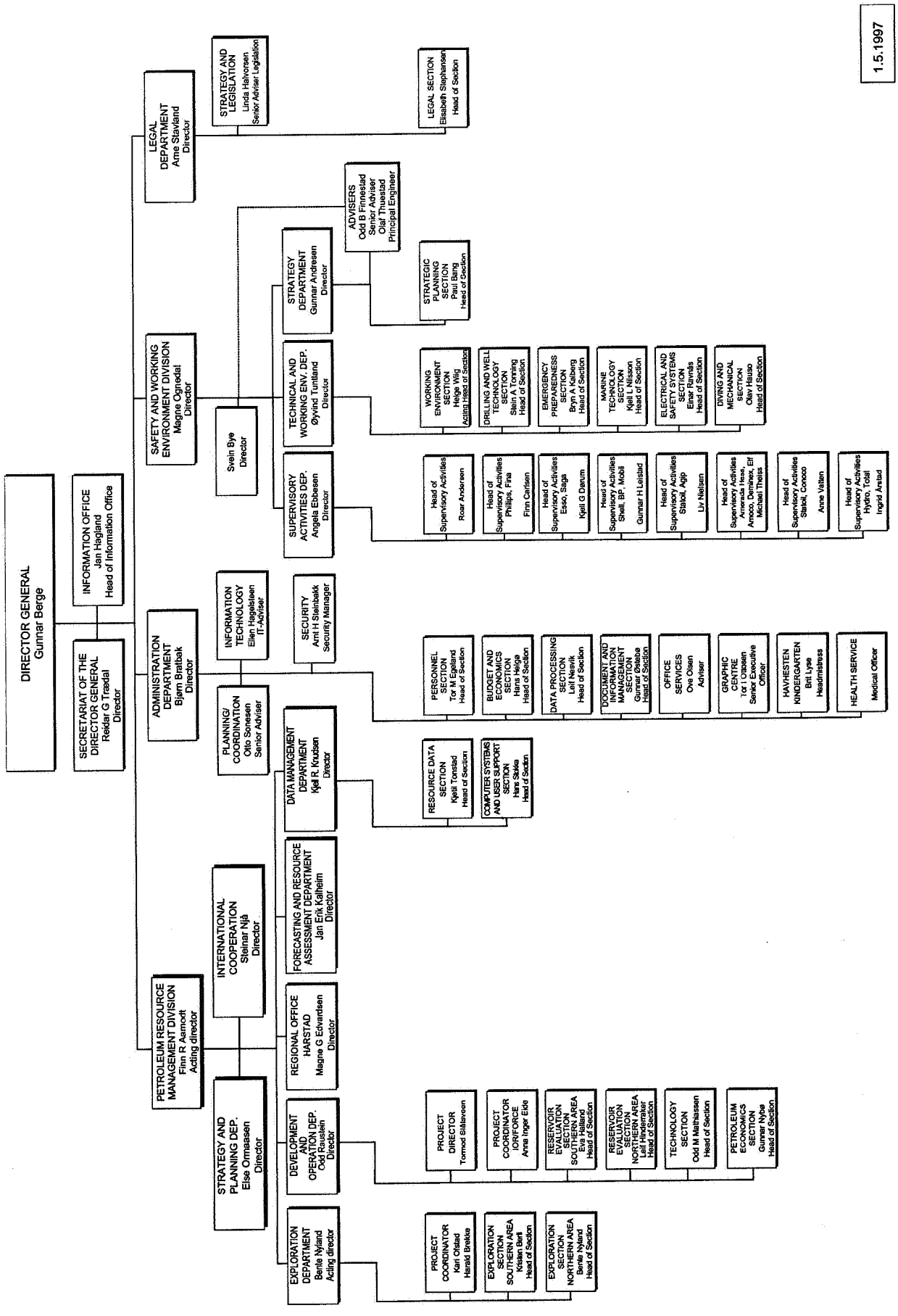
Studies - Reports

- Diving from light boats
- Description and classification of chalks
- Technical report - Qualification and use of compact flanges on the Norwegian continental shelf

Other publications

- List of publications issued by the Norwegian Petroleum Directorate
- Well Data Summary Sheets, Vol. 21
- Well Data Summary Sheets, Vol. 22
- Norwegian Petroleum Directorate Annual Report 1995 (Norwegian and English versions)
- Licenses, Areas, Area-coordinates, Exploration Wells
- Borehole list
- Borehole list - Exploration Drilling
- Development Wells
- Clean-up of the seabed in the North Sea 1995
- Report from diving data base - DSYS 1995
- Well Data published by Norwegian Petroleum Directorate
- RUTH - A Norwegian research program on improved oil recovery
- Geology and petroleum resources in the Barents Sea (Norwegian and English versions)

6.9 ORGANIZATION CHART



7. Statistics and summaries

7.1 EXPLORATION LICENSES AND PRODUCTION LICENSES

7.1.1 NEW EXPLORATION LICENSES

As of 31 December 1996, a total of 241 exploration licenses have been awarded. These licenses are valid for three years. The following licenses were awarded in 1996:

Company	License No.
Esso Exploration and Production Norway AS	228
Mobil Exploration Norway Inc.	229
Geophysical Company of Norway A/S	230
Institutt for kontinentalsokkelundersøkelser, the Sintef Group	231
Norsk Agip AS	232
Norsk Hydro Produksjon AS	233
CGG Norge	234
Amoco Norway Oil Company	235
Saga Petroleum ASA	236
Fina Production Licenses AS	237
Amerada Norge AS	238
R&R Geo Tech AS	239
Robertson Research International Limited	240
Petroleum Geo-Services AS	241

7.1.2 SCIENTIFIC EXPLORATION

As of 31 December 1996, a total of 299 licenses for scientific exploration have been awarded on the Norwegian continental shelf. License 291/96 has been recalled. As illustrated in Table 7.1.2, nine such licenses have been awarded in 1996.

7.1.3 NEW PRODUCTION LICENSES

The 15th licensing round was awarded on 2 February 1996. The award consisted of 18 production licenses and covers 47 blocks or parts of blocks; four production licenses with 13 blocks in the North Sea and 14 production licenses with 34 blocks in the Norwegian Sea.

Nine companies were awarded operatorships. Statoil and Hydro each received three, Saga, Mobil, BP, Shell and Amoco received two each, and Phillips and Esso each received one operatorship, see Table 7.1.3.a. An overview of licensing rounds with production licenses, allocated area, relinquished and current area is shown 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	
292/96	University of Tromsø		X		Andfjorden and Malangsdjupet
293/96	University of Bergen			Seismic gravimetric magnetic	Vøring and Møre Margin
294/96	Aarhus University			Seismic gravimetric magnetic	Skagerrak
295/96	University of Bergen			Multichannel reflection seismic	North Sea
296/96	Institutt für Meereskunde			Seismic	North Sea
297/96	University of Bergen	X		Marine geological	Southwestern Barents Sea Northeastern Norwegian Sea and Tanafjorden
298/96	University of Tromsø	X		Marine geological	North of Svalbard
299/96	University of Bergen			Marine gravimetric	Norwegian part of Skagerrak
300/96	University of Bergen			Multichannel reflection seismic	Norwegian Trench

Table 7.1.3.a
Awards in the 15th licensing round

Prod.lic.	Field/block	% Share	SDFI		Licensee (O=operator)
203	24/6	35,000		O	Norsk Hydro Produksjon AS
	25/4	20,000			Norske Conoco A/S
	25/7	15,000			Amoco Norway AS
		30,000	(30,000)		Den norske stats oljeselskap a.s
204	24/9	65,000	(30,000)	O	Den norske stats oljeselskap a.s
	24/11	20,000			Amerada Hess Norge AS
	24/12	15,000			Enterprise Oil Norwegian AS
205	32/1	30,000		O	Phillips Petroleum Norsk AS
	32/2	20,000			Norsk Hydro Produksjon AS
	32/4	20,000			Total Norge AS
	32/5	30,000	(30,000)		Den norske stats oljeselskap a.s
206	33/5	75,000		O	Mobil Development Norway AS
	33/6	25,000			Saga Petroleum ASA
	34/4				
207	6302/4	35,000		O	Esso Expl. & Prod. Norway A/S
	6302/5	55,000	(30,000)		Den norske stats oljeselskap a.s
	6302/7	10,000			Saga Petroleum ASA
	6302/8				
208	6304/9	45,000		O	BP Petr. Dev. of Norway AS
	6305/7	25,000			A/S Norske Shell
		30,000	(30,000)		Den norske stats oljeselskap a.s
209	6305/1	25,000		O	Norsk Hydro Produksjon AS
	6305/2	15,000			A/S Norske Shell
	6305/4	10,000			Esso Expl. & Prod. Norway A/S
	6305/5	50,000	(35,000)		Den norske stats oljeselskap a.s
210	6404/3	30,000		O	A/S Norske Shell
	6405/1	20,000			Norsk Hydro Produksjon AS
	6504/9	50,000	(30,000)		Den norske stats oljeselskap a.s
	6504/12				
	6505/7				
	6505/10				
211	6506/6	30,000		O	Mobil Development Norway AS
	6507/4	20,000			Norsk Agip AS
		20,000			Elf Petroleum Norge AS
		30,000	(30,000)		Den norske stats oljeselskap a.s
212	6507/5	30,000		O	Amoco Norway AS
	6507/6	25,000			Enterprise Oil Norwegian AS
		15,000			Mobil Development Norway AS
		30,000	(30,000)		Den norske stats oljeselskap a.s
213	6508/1	25,000		O	Saga Petroleum ASA
		55,000	(30,000)		Den norske stats oljeselskap a.s
		20,000			Phillips Petroleum Norsk AS
214	6510/1	30,000		O	A/S Norske Shell
	6510/2	20,000			Mobil Development Norway AS
		20,000			Elf Petroleum Norge AS
		30,000	(30,000)		Den Norske stats oljeselskap a.s
215	6604/2	25,000		O	Saga Petroleum ASA
	6604/3	20,000			Norsk Hydro Produksjon AS
	6704/12	15,000			Norsk Conoco A/S
	6705/10	10,000			Mobil Development Norway AS
		30,000	(30,000)		Den norske stats oljeselskap a.s
216	6610/1	30,000		O	Amoco Norway AS
		25,000			Total Norge AS
		15,000			Enterprise Oil Norwegian AS
		30,000	(30,000)		Den norske stats oljesekap a.s
217	6706/11	65,000	(30,000)	O	Den norske stats oljeselskap a.s
	6706/12	20,000			BP Petr. Dev. Of Norway AS
		15,000			Norske Conoco A/S
218	6706/12	25,000		O	BP Petr. Dev. Of Norway AS
	6707/10	50,000	(35,000)		Den norske stats oljeselskap a.s
		15,000			Esso Expl. & Prod. Norway A/S
		10,000			Saga Petroleum ASA
219	6710/6	45,000		O	Norsk Hydro Produksjon AS
		40,000			Norsk Agip AS
		15,000			Fina Production Licences AS
220	6710/10	70,000	(30,000)	O	Den norske stats oljeselskap a.s
		15,000			Amerada Hess Norge AS
		15,000			Amoco Norway AS

Table 7.1.3.b
Production licenses and acreages as of 31 December 1996

Lic. round	Awarded date	Production license no	Number of blocks* Awarded	Blocks relinquished	Area km² awarded	Area km² relinquished	Area km² in licenses
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		617,891
2.	23.5.1969	023-031	9	2	4107,833	2682,948	1521,707
	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	1603,469	237,078
	1.6.1975	041	1	1	488,659	488,659	
	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	

Lic. round	Awarded date	Production license no	Number of blocks* Awarded	Blocks relinquished	Area km² awarded	Area km² relinquished	Area km² in licenses
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	867,542	231,980
	23.4.1982	073-078	6	2	2311,912	1849,470	462,442
6.	21.8.1981	065-072	9	3	3218,945	2149,358	1069,587
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	4348,802	1989,471
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	2319,444	755,989
or.	11.8.1995	114B	1		11,059		11,059
10b	28.2.1986	121-128	9	3	3828,258	2856,693	971,565
or.	11.7.1986	129-129	1	1	225,393	225,393	
11.	10.4.1987	130-137	11	9	4163,711	3655,233	508,478
	29.5.1987	138-142	11	7	2975,807	2370,757	605,050
12a	8.7.1988	143-153	16	2	4701,019	1715,827	2985,192
12b	9.3.1989	154-162	13	7	5031,262	3253,553	1777,709
13.	1.3.1991	163-184	36	8	12076,889	3942,282	8134,607
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
			376	138	147389,385	88385,192	59004,193

* 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
Gullfaks (050)	1978	1	100	0	100	0
Prod.lic. 050B	1995	1	100	0	100	0
4	1979	8	58	42	68	32
5	1980	12	66	34	92	8

Licens. round	Year	Number of blocks	Share % Norwegian	Share % Foreign	Operator % Norwegian	Operator % Foreign
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

7.1.4 TRANSFER OF INTERESTS AND CHANGES IN OPERATOR

Transfer of interests
During 1996, 47 transfers of interest have been approved under Section 61 of the Act of 22 March 1985 No. 11 relating to petroleum activities. These are shown in Table 7.1.4.

Changes in operator
Eight changes in operator were approved in 1996:

Production license 054
Operator: Den norske stats oljeselskap a.s. took over the operatorship from A/S Norske Shell on 19 June 1996.

Production license 069
Operator: Saga Petroleum ASA took over the operatorship from Norske Conoco A/S on 26 August 1996.

Production license 115
Operator: Den norske stats oljeselskap a.s. took over the operatorship from Total Norge AS on 4 July 1996.

Production license 122
Operator: Norsk Agip AS took over the operatorship from Norsk Hydro Produksjon AS on 1 January 1996.

Production license 143
Operator: BP Petroleum Development of Norway AS took over the operatorship from Phillips Petroleum Norsk AS on 1 January 1996.

Production license 145
Operator: Phillips Petroleum Norsk AS took over the operatorship from BP Petroleum Development of Norway AS on 1 January 1996.

Production license 181
Operator: Den norske stats oljeselskap a.s took over the operatorship from Norsk Conoco A/S on 26 August 1996.

Production license 197
Operator: Amerada Hess Norge AS took over the operatorship from Norsk Conoco A/S on 1 June 1996.

Utvinningstillatelse 197
Operatør: Amerada Hess Norge AS overtok operatøransvaret fra Norsk Conoco A/S 1. june 1996.

Table 7.1.4
Transfer of interests

Area: N=North Sea, M=Norwegian Sea, B=Barents Sea

Prod. lic.	From:	To:	Share	Date:	Area:
019	Conoco Norway Inc	Norske Conoco A/S	10,00000 %	96.03.02	N
019B	Conoco Norway Inc	Norske Conoco A/S	9,37500 %	96.03.02	N
032	Svenska Petroleum Expl. AS	Amerada Hess Norge AS	10,00000 %	96.04.01	N
044	Phillips Petroleum Norsk AS	Den norske stats oljeselskap a.s	21,88000 %	96.12.03	N
044	Phillips Petroleum Norsk AS	Norsk Agip AS	3,99000 %	96.12.03	N
052	Norsk Hydro Produksjon AS	Petro-Canada Norge AS	9,00000 %	96.12.13	N
064	Phillips Petroleum Norsk AS	Den norske stats oljeselskap a.s	5,00000 %	96.02.29	B
066	Saga Petroleum ASA	BP Petr. Dev. of Norway AS	5,00000 %	96.07.31	N
069	Norske Conoco A/S	Saga Petroleum ASA	25,00000 %	96.08.26	N
077	Phillips Petroleum Norsk AS	Den norske stats oljeselskap a.s	10,00000 %	96.02.29	B
077	Texaco Exloration Norway AS	Den norske stats oljeselskap a.s	10,00000 %	96.04.25	B
086	Norske Conoco A/S	Den norske stats oljeselskap a.s	30,00000 %	96.08.12	N
091	Mobil Development Norway AS	Saga Petroleum ASA	12,00000 %	96.04.16	M
104	Norsk Agip AS	Norsk Hydro Produksjon AS	5,00000 %	96.07.23	N
104	Norsk Hydro Produksjon AS	Norske Conoco AS	6,00000 %	96.01.01	N
107	Norsk Hydro Produksjon AS	Petro-Canada Norge AS	7,50000 %	96.12.13	M
109	Norske Conoco A/S	Norsk Hydro Produksjon AS	3,05500 %	96.01.01	B
109	Norske Conoco A/S	Den norske stats oljeselskap a.s	6,94500 %	96.01.01	B
115	Norske Conoco A/S	Den norske stats oljeselskap a.s	15,00000 %	96.07.04	N
115	Saga Petroleum ASA	Den norske stats oljeselskap a.s	5,00000 %	96.07.04	N
115	Total Norge AS	Den norske stats oljeselskap a.s	30,00000 %	96.07.04	N
116	Norske Conoco A/S	Den norske stats oljeselskap a.s	30,00000 %	96.08.12	N
122	Norsk Hydro Produksjon AS	Norsk Agip AS	20,00000 %	96.07.23	M
128	Norsk Hydro Produksjon AS	Norsk Agip AS	1,50000 %	96.07.23	M
132	Norsk Hydro Produksjon AS	Petro-Canada Norge AS	7,50000 %	96.12.13	M
138	Norsk Hydro Produksjon AS	Total Norge AS	5,00000 %	96.01.01	B
138	Norsk Hydro Produksjon AS	Amerada Hess Norge AS	5,00000 %	96.01.01	B
143	Phillips Petroleum Norsk AS	BP Petr. Dev. of Norway AS	15,00000 %	96.01.01	N
145	BP Petr. Dev of Norway AS	Phillips Petr. Norsk AS	30,00000 %	96.01.01	N
145	Den norske stats oljeselskap a.s	Phillips Petr. Norsk AS	10,00000 %	96.09.09	N
146	Den norske stats oljeselskap a.s	Phillips Petr. Norsk AS	20,00000 %	96.09.09	N
152	Saga Petroleum ASA	Mobil Dev.Norway AS	10,00000 %	96.04.16	N
156	Mobil Development Norway AS	Saga Petroleum ASA	20,00000 %	96.04.16	M
158	Total Norge AS	A/S Norske Shell	10,00000 %	96.02.19	M
166	A/S Norske Shell	Den norske stats oljeselskap a.s	10,00000 %	96.02.27	N
169	Norske Conoco A/S	Norsk Hydro Produksjon AS	10,00000 %	96.01.01	N
171	Saga Petroleum ASA	Mobil Dev. Norway AS	10,00000 %	96.04.16	N
174	Esso Expl. & Prod. Norway A/S	Saga Petroleum ASA	10,00000 %	96.06.07	N
174	Mobil Development Norway AS	Saga Petroleum ASA	10,00000 %	96.04.16	N
174	Saga Petroleum ASA	Norske Conoco A/S	20,00000 %	96.08.26	N
177	BP Petr. Dev. of Norway AS	Saga Petroleum ASA	10,00000 %	96.01.01	M
181	Norske Conoco A/S	Elf Petroleum Norge AS	4,17000 %	96.08.26	B
181	Norske Conoco A/S	Den norske stats oljeselskap a.s	20,83000 %	96.08.26	B
189	Phillips Petroleum Norsk AS	Den norske stats oljeselskap a.s	15,00000 %	96.09.09	N
197	Norske Conoco A/S	Amerada Hess Norge AS	25,00000 %	96.06.01	M
197	Den norske stats oljeselskap a.s	Amerada Hess Norge AS	15,00000 %	96.06.01	M
197	Amoco Norway AS	Amerada Hess Norge AS	15,00000 %	96.06.01	M

7.1.5 RELINQUISHMENTS AND SURRENDERS

There have been 6 relinquishments/surrenders of production licenses in 1996. In one 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 km²	Relinquished area km² in 1996	Area in prod.lic. km²
024	Elf	25/1	446,965	96,822	124,750
036	Elf	25/4	523,937	67,524	197,366
108	Shell	7120/1	323,030	80,078	0,0
112	Elf	25/2	260,150	39,979	10,394
122	Hydro	6507/2	424,012	109,096	102,926
128	Statoil	6608/10, 6608/11	839,790	424,031	415,759

7.1.6 LICENSEES IN ACTIVE PRODUCTION LICENSES

Table 7.1.6
Licensees in active production licenses as of 31 December 1996

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	28,333000	
	11/09/01	2/8	O	Amoco Norway Oil Company	28,333000	
		3/4		Elf Petroleum Norge AS	15,000000	
				Enterprise Oil Norwegian AS	28,333000	
008	65/09/01	2/6		Amerada Hess Norge AS	50,000000	
	11/09/01	18/10	O	Saga Petroleum ASA	50,000000	
009	65/09/01	9/5	O	Elf Petroleum Norge AS	65,612000	
	11/09/01			Elf Rex Norge AS	3,420000	
				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	50,000000	
		1/6				
		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	7,594000	
		2/7		Elf Rex Norge AS	0,855000	
		7/11		Fina Production Licences 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	
018 B	95/08/25	1/6		Den norske stats oljeselskap a.s	1,000000	
	98/12/31			Elf Petroleum Norge AS	7,594000	
				Elf Rex Norge AS	0,855000	
				Fina Production Licences 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 Development of Norway AS	57,500000	
				Norske Conoco A/S	10,000000	
				Den norske stats oljeselskap a.s	12,500000	
				Svenska Petroleum Exploration AS	15,000000	
019 B	77/09/12	2/1		AS Pelican	4,000000	
	11/09/01	7/12	O	BP Petroleum Development of Norway AS	26,625000	
		7/12		Norske Conoco A/S	9,375000	
				Den norske stats oljeselskap a.s	50,000000	(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	O	Elf Petroleum Norge AS	53,200000	
	15/05/23			Norsk Hydro Produksjon AS	10,000000	
				Total Norge AS	36,800000	

Prod. lic.	Awarded	Blocks		Licensees	Share %	SDFI %
026	69/05/23	25/2		Den norske stats oljeselskap a.s	5,000000	(1,461)
	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 Licences 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	O	Elf Petroleum Norge AS	33,702000	
	21/07/11			Marathon Petroleum Norge AS	46,904000	
				Norsk Hydro Produksjon AS	6,920000	
				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	
044	76/08/27	1/9	O	Den norske stats oljeselskap a.s	71,880000	(30,000)
	12/08/27			Fina Production Licences 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		BP Petroleum Development of Norway AS	10,900000	
	13/02/18			Den norske stats oljeselskap a.s	50,000000	(30,000)
				Elf Petroleum Norge AS	21,800000	
			O	Norsk Hydro Produksjon AS	17,300000	
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)

Prod. lic.	Awarded	Blocks		Licensees	Share %	SDFI %
	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	51,000000	(31,400)
	15/04/06			Norske Conoco A/S	24,500000	
				Total Norge AS	24,500000	
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	
				Svenska 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 AS	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)
	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		BP Petroleum Development of Norway AS	8,333000	
				Den norske stats oljeselskap a.s	40,000000	(30,000)
			O	Elf Petroleum Norge AS	16,667000	
				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 Development 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 Oil Company	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	

Prod. lic.	Awarded	Blocks		Licensees	Share %	SDFI %
074	82/04/23	6407/ 2	O	Den norske stats oljeselskap a.s	65,000000	(31,400)
	18/04/23			Mobil Development Norway AS	7,000000	
				Neste Petroleum AS	10,500000	
				Norsk Agip AS	10,500000	
				Saga Petroleum ASA	7,000000	
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	
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 AS	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		BP Petroleum Development of Norway AS	2,000000	
	20/03/09		O	Den norske stats oljeselskap a.s	50,000000	(30,000)
				Mobil Development Norway AS	40,000000	
				Saga Petroleum ASA	8,000000	
093	84/03/09	6407/9	O	A/S Norske Shell	16,200000	
	24/03/09			BP Petroleum Development of Norway AS	10,800000	
				Den norske stats oljeselskap a.s	73,000000	(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	

Prod. lic.	Awarded	Blocks		Licensees	Share %	SDFI %
				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	
				Svenska 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	
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 Licences 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	100,000000	(30,000)
	21/08/23					
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 Licences AS	15,000000	
			O	Saga Petroleum ASA	25,000000	
120	85/08/23	34/7		Den norske stats oljeselskap a.s	50,000000	(28,000)
	23/08/23	34/8		Elf Petroleum Norge AS	13,000000	
			O	Norsk Hydro Produksjon AS	18,000000	
				Norske Conoco A/S	13,000000	
				Saga Petroleum ASA	6,000000	
121	86/02/28	6407/5		BP Petroleum Development of Norway AS	2,000000	
	22/02/28		O	Den norske stats oljeselskap a.s	50,000000	(40,000)
				Mobil Development Norway AS	20,000000	
				Norsk Hydro Produksjon AS	20,000000	
				Saga Petroleum ASA	8,000000	
122	86/02/28	6507/2		Amerada Hess Norge AS	20,000000	
	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	

Prod. lic.	Awarded	Blocks		Licensees	Share %	SDFI %
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 Licences 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)
	97/04/10			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		Den norske stats oljeselskap a.s	50,000000	(30,000)
	97/05/29	30/7	O	Elf Petroleum Norge AS	40,000000	
		30/10		Saga Petroleum ASA	10,000000	
143	88/07/08	1/2		Amoco Norway AS	10,000000	
	97/07/08			Den norske stats oljeselskap a.s	50,000000	(30,000)
				Enterprise Oil Norwegian AS	15,000000	
			O	BP Petroleum Development of Norway AS	15,000000	
				Phillips Petroleum Norsk AS	10,000000	
144	88/07/08	1/5		BP Petroleum Development of Norway AS	25,000000	
	97/07/08	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	
	97/07/08			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	
	97/07/08	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	
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 Licences AS	10,000000	
				Saga Petroleum ASA	10,000000	
152	88/07/08	33/12		BP Petroleum Development of Norway AS	30,000000	
	25/07/08		O	Den norske stats oljeselskap a.s	50,000000	(30,000)
				Idemitsu Petroleum Norge AS	10,000000	
				Saga Petroleum ASA	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	
	97/03/03			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)
	97/03/03			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 Development of Norway AS	40,000000	
	97/03/03			Den norske stats oljeselskap a.s	50,000000	(30,000)
				A/S Norske Shell	10,000000	

Prod. lic.	Awarded	Blocks		Licensees	Share %	SDFI %
159	89/03/03	6507/ 3	O	Den norske stats oljeselskap a.s	50,000000	(20,000)
	97/03/03			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	
	97/03/01	2/10		Den norske stats oljeselskap a.s	50,000000	(35,000)
				Norsk Agip AS	10,000000	
			O	Saga Petroleum ASA	30,000000	
164	91/03/01	2/1	O	BP Petroleum Development of Norway AS	30,000000	
	97/03/01	7/12		Den norske stats oljeselskap a.s	50,000000	(30,000)
		7/12		Norske Conoco A/S	10,000000	
		8/10		Svenska Petroleum Exploration AS	10,000000	
166	91/03/01	15/6	O	Deminex Norge AS	30,000000	
	98/03/01			Den norske stats oljeselskap a.s	70,000000	(30,000)
167	91/03/01	16/1		Amoco Norway AS	10,000000	
	97/03/01		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	
	97/03/01		O	Den norske stats oljeselskap a.s	65,000000	(20,000)
				Fina Production Licences AS	15,000000	
169	91/03/01	25/8		Den norske stats oljeselskap a.s	50,000000	(35,000)
	97/03/01	25/11		Esso Expl. & Prod. Norway A/S	10,000000	
			O	Norsk Hydro Produksjon AS	40,000000	
170	91/03/01	30/6		Den norske stats oljeselskap a.s	50,000000	(35,000)
	97/12/31		O	Norsk Hydro Produksjon AS	30,000000	
				Total Norge AS	20,000000	
171	91/03/01	30/12		Den norske stats oljeselskap a.s	50,000000	(35,000)
	97/03/01		O	Norsk Hydro Produksjon AS	30,000000	
				Mobil Development Norway AS	20,000000	
				Saga Petroleum ASA	20,000000	
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)
	97/03/01			Elf Petroleum Norge AS	15,000000	
				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)
	97/03/01		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)
	98/03/01	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	
	97/03/01	6407/12		Den norske stats oljeselskap a.s	50,000000	(35,000)
				Fina Production Licences AS	10,000000	
				Norsk Hydro Produksjon AS	10,000000	
177	91/03/01	6610/2		BP Petroleum Development of Norway AS	20,000000	
	97/03/01	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	
	97/03/01	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)
	97/03/01	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	O	Amoco Norway AS	25,000000	
	99/09/10	7/11		Den norske stats oljeselskap a.s	50,000000	(40,000)
				Saga Petroleum ASA	10,000000	

Prod. lic.	Awarded	Blocks		Licensees	Share %	SDFI %
				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	55,000000	(40,000)
		15/3		Norsk Hydro Produksjon AS	20,000000	
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	60,000000	(50,000)
	99/09/10			Enterprise Oil Norwegian AS	15,000000	
			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	55,000000	(35,000)
	99/09/10		O	Mobil Development Norway AS	25,000000	
				Norske Conoco A/S	20,000000	
193	93/09/10	34/11		BP Petroleum Development of Norway AS	15,000000	
	99/09/10		O	Den norske stats oljeselskap a.s	65,000000	(40,000)
				Norsk Hydro Produksjon AS	20,000000	
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 Development of Norway AS	25,000000	
	99/09/10			Den norske stats oljeselskap a.s	45,000000	(35,000)
				Norsk Hydro Produksjon AS	15,000000	
				Norske Conoco A/S	15,000000	
196	93/09/10	35/6	O	BP Petroleum Development of Norway AS	25,000000	
	99/09/10	36/4		Den norske stats oljeselskap a.s	45,000000	(25,000)
				Idemitsu Petroleum Norge AS	10,000000	
				Norsk Hydro Produksjon AS	20,000000	
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	40,000000	(25,000)
	99/09/10	7019/1		Enterprise Oil Norwegian AS	20,000000	
				Neste Petroleum AS	10,000000	
			O	Norsk Agip AS	30,000000	
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	

Prod. lic.	Awarded	Blocks		Licensees	Share %	SDFI %
	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				
208	96/02/02	6304/9	O	BP Petroleum Development 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 Development of Norway AS	20,000000	
				Norske Conoco A/S	15,000000	
218	96/02/02	6706/12	O	BP Petroleum Development 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 Licences 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	

7.2 SALE AND RELEASE OF DATA

7.2.1 REPORTING OF MATERIAL FROM THE SHELF

In connection with the Norwegian Petroleum Directorate's supervision 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 1996, the Norwegian Petroleum Directorate has stocked 96,826 meters of core material from 1,085 wells, 407,163 samples of washed cuttings from 1,128 wells and 488,145 wet samples from 1,404 wells. In addition, there are oil and condensate samples

from 306 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 1996 the Norwegian Petroleum Directorate received 4,871 meters of cores, 9,790 samples of washed cuttings, 7,131 wet samples and 47 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. Some types of data can also be delivered in digital format on diskette or magnetic tape.

The Norwegian Petroleum Directorate has experienced a growing demand for released data as more data types with improved quality are made available.

The Norwegian Petroleum Directorate received 88 orders for a total of 1,291 logs from 266 wells during 1996. 51 orders were for film/hard copies, 32 were orders for digital logs on magnetic tape, 4 orders were for digital core analyses and one order was a request for digital guidance data. This is an increase of about 95% compared with 1995.

The reason that the number of orders for well logs did not increase even more compared with 1995 is that the Norwegian Petroleum Directorate's quality-controlled edition of digital logs from the «High Quality Log Data project» (HQLD) was obtained as early as 1995, and is therefore accessible for most oil companies for all exploration wells drilled before 1991.

The Data Management Department has delivered 58 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 Norwegian Petroleum Directorate's Publications List. In addition, several special collections have been made to order.

In the Norwegian Petroleum Directorate's core study room it is possible to examine core materials, drill cuttings and wet samples from released wells. 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. 34 applications have been considered in 1996. Twelve of these were for organic geochemistry studies, thirteen for biostratigraphy, six for sedimentology/petrophysical and four for oil-condensate samples. A total of 108 kg of sample material and 156 ml of oil was released.

In 1996, the Norwegian Petroleum Directorate's two core study rooms were used by 36 different companies/institutions for examination of cores and/or geological sampling. The core study rooms have been used by external guests on 115 days, in addition to 155 days of use by employees of the Norwegian Petroleum Directorate.

As of 31 December 1996, the Norwegian Petroleum Directorate has edited data packages on paper/film for release of data from 343 seismic surveys shot by companies. The surveys comprise 291,336 line kilometers of seismic. The surveys are divided among 302 surveys in the North Sea and 41 in the Norwegian Sea. 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.

Eight orders for company seismic were received and filled by the Norwegian Petroleum Directorate in 1996. The large decline in requests for such data is due to the fact that the industry wants data in interpretation station format, which was not available from the Norwegian Petroleum Directorate. However, such data will be available through the DISKOS project in 1997.

Only 5 data packages with NPD seismic were sold in 1996.

Table 7.2.2
Survey of seismic data packages (NPD-seismic)

Package No	Name	1996	Total
001	Møre-Trøndelag-Regional-Pk-1		34
002	Møre-Trøndelag-Regional-Pk-2		27
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-Pakke-2 #)		22
009	Møre-Trøndelag-Pakke-3 #)		28
010	Trænabanken		30
011	Reg-Data-Nordland-Ryggen		22
012	Nordland-IV-85		13
013	Reg-Data-Midt-N-Sokkel		21

Package No	Name	1996	Total
014	Nordland-II-83		23
015	Nordland-III-84		17
016	Troms-II		13
017	Regionel-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	Vøring-Bassenget-85/86		15
025	Lofoten-Vest-86		17
026	Jan-Mayen-85		1
027	Jan-Mayen-79/85		
028	Vøring-Bassenget-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	Vøring-Bassenget-88		15
041	Vøring-Bassenget-Merlin-89		15
042	Vøring-Bassenget-WesternN-89		15
043	Møre-Bassenget-88	1	12
044	Typeprofiler-Barentshavet #)		2
045	Vøringsbassenget-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	1	13
053	Jan-Mayen-88		1
054	Vøringbassenget-II-92		13
055	Mørebassenget-Ensign-92	1	13
056	Mørebassenget-Digicon-92		13
057	Vestfjorden	1	5
058	Vestfjorden-77/78	1	5
100	Troms-Hovedpakke		35
101	Reg-Data-Troms-Bar.havet-73		22
102	Troms-III-83/84		17
103	Troms-III-85		17
104	Troms-1976-Slag #)		
105	Troms-I-Øst-77		20
106	Troms-Nord-82-Pakke-1		24
107	Troms-Nord-83-Pakke-3		23
108	Troms-Nord-82-Pakke-2		17
109	Troms-Nord-83-Pakke-4		17
200	Bjørnøya-Pakke-1		21
201	Bjørnøya-Sør-84		21
202	Bjørnøya-Øst-Regional-84		18
203	Bjørnøya-Øst-84		17
204	Bjørnøya-Tillegg-Nord		17
205	Bjørnøya-Vest-Regional-84		15
206	Lopparyggen-Øst-Regional-84		19
207	Lopparyggen-Øst-85-SSL-Diag		19
208	Lopparyggen-Øst-85-Nord		19
209	Lopparyggen-Øst-85-Geco-Diag		19
210	Lopparyggen-Øst-85-Grid		19
211	Bjørnøya-Øst-Test-85 #)		1
212	Bjørnøya-Vest-86-Diag		13
213	Bjørnøya-Vest-86-High		13
214	Bjørnøya-Vest-86-Margin		12
215	Bjørnøya-Vest-86-Swath #)		1
216	Bjørnøya-Vest-87		13
300	Barentshavet-Sør-Øst-Hovedpk.		22
301	Barentshavet-Sør-Øst-Pakke-2		21
302	Nordkapp-Bass-85-Geco-Diag		20
303	Nordkapp-Bassenget-85-Nord		20
304	Nordkapp-Bassenget-85-Grid		21
305	Nordkapp-Bassenget-86-Diag		20
306	Nordkapp-Bassenget-86-Sør		21
307	Nordkapp-Bassenget-86-Nord		14
308	Finnmark-Øst-86-Regional		19
309	Finnmark-Øst-86-Diag		18
310	Finnmark-Øst-86-GSI		19
311	Nordkapp-Finnmark-87 #)		
312	Nordkapp-Test-87 #)		1
400	Barentshavet Nordvest Regional		2
500	Barentshavet Nordøst Regional		2

#) not compulsory

7.3 EXPLORATION DRILLING STATISTICS

As of 31 December 1996, a total of 866 exploration wells had been spudded on the Norwegian continental shelf since drilling commenced in 1966. Of these, 617 were wildcats and 249 were appraisal wells.

812 exploration wells have been completed and 47 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.

Fig. 7.3.a
Regional spread of exploration wells per operator

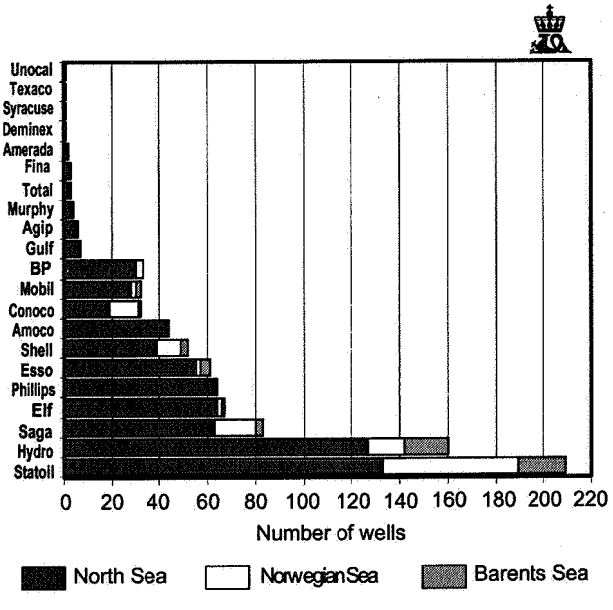


Fig. 7.3.b
Rig days per operator

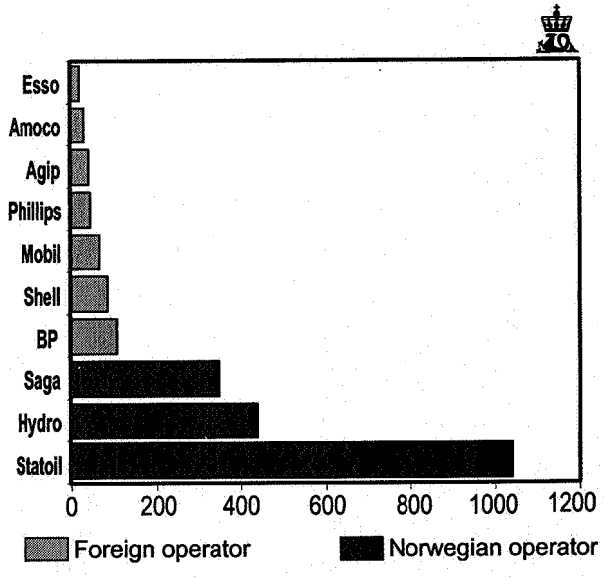
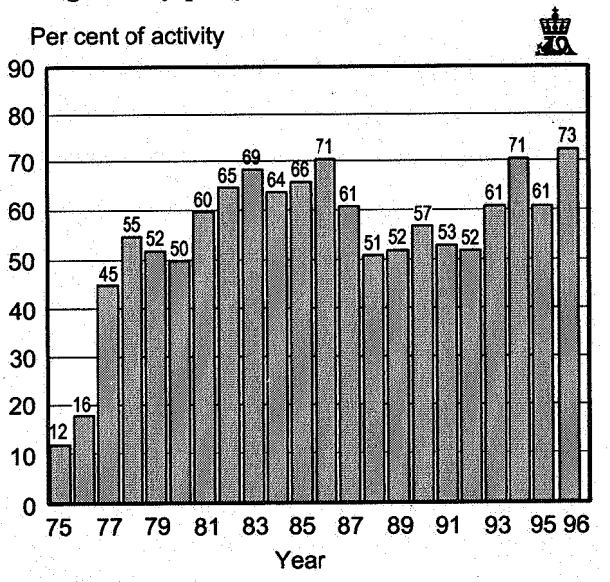


Fig. 7.3.c
Participation of Norwegian operators in exploration drilling activity per year



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 1996 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 1996, 2,805,766 meters have been drilled during exploration drilling, whereof 113,327 meters in 1996.

Average total depth for exploration wells which reached total depth in 1996 is 3,982 meters.

Exploration well 6406/2-1 R drilled in 1995, is the deepest well ever drilled on the Norwegian shelf. Saga was the operator, and the total depth of this well was 5,892 meters RKB (5,870 MSL).

The longest ever 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 average water depth for exploration wells drilled in 1996 was 221 meters.

The deepest water ever drilled in on the Norwegian shelf is 523 meters. This was exploration well 6607/5-2 drilled in 1991 with Esso as operator.

Table 7.3.d shows the average water depth for exploration wells drilled during the period 1966-1996.

81 different drilling rigs have been utilized for drilling on the Norwegian continental shelf, 13 of these under 2 different names. Of these, 53 have been semi-submersibles, 17 jack-ups, 5 drilling ships and 6 permanent installations.

During 1996, 12 different drilling rigs have been active in exploration drilling on the Norwegian shelf.

Tables 7.3.a to 7.3.f contain statistics on exploration drilling on the Norwegian continental shelf.

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	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	472
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	221
Norwegian Sea																																
Wildcats															1	2	5	7	6	10	10	10	5	2	7	8	5	4	5	3	2	92
Appraisals																			1	6	5	4	1	1	1			2		3	4	28
Barents Sea																																
Wildcats															2	3	4	5	7	7	2	5	4	4	1	3	3	2				52
Appraisals																		1														1
Exploration total																																
Wildscats	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	616
Appraisals			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	250
Exploraton 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	866
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	1239
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	2105

Table 7.3.b
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	77	56	133	44	12	56	19	1	20	140	69	209
Hydro	86	41	127	13	2	15	18		18	117	43	160
Phillips	43	20	63	1		1				44	20	64
Elf	46	18	64	2		2	1		1	49	18	67
Saga	51	12	63	16	1	17	3		3	70	13	83
Esso	31	24	55	2		2	4		4	37	24	61
Shell	28	11	39	5	5	10	3		3	36	16	52
Amoco	31	13	44							31	13	44
Conoco	19		19	4	8	12	1		1	24	8	32
Mobil	19	9	28	2		2	2		2	23	9	32
BP	16	14	30	3		3				19	14	33
Gulf	7		7							7		7
Murphy	3	1	4							3	1	4
Total	2		2				1		1	3		3
Agip	6		6							6		6
Deminex	1		1							1		1
Syracuse	1		1							1		1
Texaco	1		1							1		1
Unocal	1		1							1		1
Fina	2	1	3							2	1	3
Amerada	2		2							2		2
Wildcats	473			92			52			617		
Appraisals		220			28			1			249	
Exploration wells			693			120			53			866

W = wildcats A = appraisals E = exploration wells

Table 7.3.c
Exploration wells spudded in 1996 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	4	3	7	1	4	5				5	7	12
Hydro	4	2	6							4	2	6
Phillips	1		1							1		1
Elf												
Saga	3		3	1		1				4		4
Esso	1		1							1		1
Shell	2		2							2		2
Amoco	1		1							1		1
Conoco												
Mobil	1		1							1		1
BP	1		1							1		1

Gulf												
Murphy												
Total												
Agip	1		1						1		1	
Deminex												
Syracuse												
Texaco												
Unocal												
Fina												
Amerada												
Wildcats	19		2						21			
Appraisals	5		4						9			
Explorations wells	24		6						30			

W = wildcats A = appraisals 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
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

Table 7.3.e
Drilling rigs active on the Norwegian continental shelf as of 31 December 1996

Rig name	Number of wells	Number of re-entries	Type of rig
Aladdin	1		Semi-submersible
Arcade Frontier (was Norjarl)	7		"
Borgny Dolphin (was Fernstar)	27	8	"
Borgsten Dolphin (was Haakon Magnus)	9		"
Bucentaur		1	Drill ship
Byford Dolphin (was Deepsea Driller)	30	1	Semi-submersible
Chris Chenery	2		"
Deepsea Bergen	53	3	"
Deepsea Saga	16	3	"
Deepsea Trym	2		"
Drillmaster	5	1	"
Drillship	1		Drill ship
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	Drill ship
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		Drill ship
Mærsk Explorer	7		Jack-up
Mærsk Gallant	2		"
Mærsk Giant	2		"
Mærsk Guardian	4	1	"
Mærsk Jutlander	7	1	Semi-submersible
Neddrill Trigon	3	1	Jack-up
Neptune 7 (was Pentagone 81)	13		Semi-submersible
Nordraug	12		"
Nortrym	32	3	"
Ocean Tide	5		Jack-up
Ocean Traveler	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		Drill ship
Scarabeo 5	1		Semi-submersible
Sedco 135 G	3		"
Sedco 703	3	1	"
Sedco 704	3		"
Sedco 707	8		"
Sedco H	2		"
Sedneth I	3		"

Rig name	Number of wells	Number of re-entries	Type of rig
Sovereign Explorer	3	1	"
Stene Dee (was Dyvi Stena)	23	1	"
Transocean 8	16	2	"
Transocean Arctic (was Ross Rig (ny))	31	3	"
Transocean Nordic	2		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	"
Transworld Rig 61	2		"
Treasure Saga	56	6	"
Treasure Scout	23		"
Treasure Seeker	24	5	"
Vinni	5		"
Waage Drill I	2		"
West Alpha (was Dyvi Alpha)	22	2	"
West Delta (was Dyvi Delta)	37	5	"
West Epsilon	1		Jack-up
West Vanguard	37	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
	858	98	
In addition 8 wells have been drilled from fixed installations:			
Cod platform	1	1	
Ekofisk B	1		
Gullfaks B	1		
Sleipner A	1		
Ula A	1		
Veslefrikk A	3		
	866	98	

Table 7.3.f
Spudded and/or completed exploration wells in 1996
R=re-entry, X=junked due to technical problems, S=side drilled, A/B/C=sidetracked new wells

Well		Reg.no Prod.lic number	Position north south	Spudded Completed	Operator Drilling installation	Well classification Completion status	Water depth KBE	Total depth (m) Geological period
1/03-08		855	56 52 07.1	96.12.12	Amoco	Wildcat	70	0
		011	02 53 20.6	00.00.00	Trans. Nordic		40	
2/06-05		866	56 35 36.54	96.11.17	Saga	Wildcat	69	0
		008	03 45 42.67	00.00.00	Deepsea Bergen		23	
2/08-15		834	56 25 05.14	95.11.27	Amoco	Wildcat	70	3754
		006	03 28 58.96	96.01.09	Vildkat Explorer	Dry hole	25	
3/07-06		862	56 25 49.44	96.10.02	Shell	Wildcat	64	4120
		147	04 18 02.98	96.11.30	Mærsk Jutlander	Shows	23	L.Jurassic
7/12-12	S	833	57 06 41.19	95.11.14	BP	Wildcat	70	6079
		019	02 50 50.73	96.03.17	Ula platform	Dry hole	57	Jurassic
9/02-06	S	854	57 49 07.47	96.08.19	Statoil	Wildcat	93	5205
		114	04 31 10.95	96.12.13	Mærsk Giant	Suspended	42	
15/12-10	S	860	58 04 40.48	96.10.02	Saga	Wildcat	84	3550
		038	01 53 25.56	96.11.04	Deepsea Bergen	Suspended. Oil	23	Triassic

Well		Reg.no Prod.lic number	Position north south	Spudded Completed	Operator Drilling installation	Well classification Completion status	Water depth KBE	Total depth (m) Geological period
16/10-03		856	58 13 18.54	96.10.22	Agip	Wildcat	75	2850
		101	02 19 34.30	96.12.01	Trans. Nordic	Dry hole	39	Triassic
24/12-03	S	847	59 05 57.53	96.06.27	Statoil	Wildcat	116	3058
		204	01 47 23.33	96.07.29	Deepsea Trym	Oil discovery	25	Cretaceous
25/10-06	S	836	59 08 08.69	95.12.26	Statoil	Wildcat	117	4706
		168	02 01 37.54	96.03.22	Deepsea Bergen	Shows	23	M.Jurassic
25/10-07	S	840	59 04 57.64	96.05.20	Esso	Wildcat	116	2617
		028 P	02 08 23.75	96.06.08	Vildkat Explorer	Dry hole	25	Cretaceous
25/11-21	A	845	59 09 43.43	96.05.12	Hydro	Appraisal	122	3006
		169	02 27 53.07	96.10.01	Treasure Saga	Suspended	26	
30/05-02		861	60 30 16.30	96.10.04	Hydro	Appraisal	92	4078
		034	02 38 12.71	96.12.21	Treasure Saga		26	
30/08-01	SR	797	60 27 46.93	95.11.18	Hydro	Wildcat	96	5149
		190	02 38 06.53	96.03.01	Treasure Saga	Suspended.Gas/cond.	26	
30/08-02		835	60 27 24.51	95.12.15	Hydro	Wildcat	100	2405
		190	02 21 47.92	96.01.14	West Vanguard	Shows	22	
30/11-05		868	60 08 50.3	96.12.05	Shell	Wildcat	104	0
		035	02 33 59.6	00.00.00	Mærsk Jutlander		23	
31/02-19	S	844	60 54 37.50	96.05.08	Hydro	Wildcat	344	4114
		191	03 22 17.32	96.07.13	West Vanguard	Dry hole	22	
32/04-01		863	60 43 21.58	96.10.21	Phillips	Wildcat	310	3186
		205	04 04 36.44	96.12.04	Transocean 8	Dry hole	23	Basement
33/06-02		864	61 32 15.8	96.10.28	Mobil	Wildcat	317	0
		206	01 56 32.8	00.00.00	Byford Dolphin		22	
33/09-19	S	848	61 28 33.56	96.06.29	Statoil	Wildcat	304	3197
		037	01 59 50.60	96.07.23	Trans.. Wildcat	Oil discovery	25	E.Jurassic
33/09-19	A	857	61 28 33.56	96.07.23	Statoil	Appraisal	304	3514
		037	01 59 50.60	96.08.09	Trans.. Wildcat	Oil	25	
34/07-25	S	852	61 15 09.24	96.07.31	Saga	Wildcat	189	3235
		089	02 08 41.14	96.09.14	Deepsea Bergen	Oil/gas discovery	23	E.Jurassic
34/11-02	S	838	61 13 33.24	96.01.16	Statoil	Wildcat	261	4742
		193	02 22 56.81	96.05.17	Vildkat Explorer	Suspended.Gas/cond.	25	E.Jurassic
34/11-03		853	61 05 45.25	96.08.01	Statoil	Appraisal	207	0
		193	02 31 06.51	00.00.00	Deepsea Trym		25	
35/04-01		870	61 32 00.6	96.12.23	Hydro	Wildcat	378	0
		194	03 18 08.2	00.00.00	Treasure Saga		26	
35/10-02		843	61 02 22.67	96.04.16	Statoil	Wildcat	373	4677
		173	03 02 30.60	96.08.22	Trans.. Artic	Gas discovery	24	E.Jurassic
35/11-08	S	841	61 05 25.53	96.03.03	Hydro	Wildcat	361	3624
		090	03 32 14.85	96.05.11	Treasure Saga	Oil/gas discovery	26	
36/04-01		850	61 43 56.60	96.09.03	BP	Wildcat	260	2717
		196	04 02 01.29	96.10.02	Mærsk Jutlander	Dry hole	23	
36/07-01		842	61 21 13.49	96.03.31	Hydro	Wildcat	358	2841
		153	04 00 57.22	96.05.07	West Vanguard	Oil/gas discovery	22	
6406/02-01	R	798	64 52 15.19	95.08.21	Saga	Wildcat	278	5892
		199	06 36 21.35	96.01.07	Ross Isle	Gas/cond. discovery	22	
6406/02-02		825	64 49 46.35	95.12.12	Saga	Appraisal	272	5367
		199	06 34 15.43	96.03.27	Ross Rig	Suspended.Gas/cond.	24	E.Jurassic
6406/02-03		851	64 58 40.69	96.08.24	Saga	Wildcat	371	0
		199	06 24 37.67	00.00.00	Trans.. Artic		24	
6407/01-04		846	64 51 46.05	96.06.06	Statoil	Appraisal	286	3805
		073	07 01 21.25	96.08.23	Byford Dolphin	Oil	24	M.Jurassic
6506/11-04	S	839	65 01 46.17	96.02.11	Statoil	Appraisal	304	5110
		134	06 36 04.74	96.06.06	Trans.. Searcher	Suspended.Oil/gas	22	
6506/11-05	S	859	65 05 17.62	96.09.10	Statoil	Appraisal	288	4790
		134	06 39 43.86	96.11.10	Trans.. Searcher	Suspended		
6506/12-11	S	849	65 05 07.20	96.06.08	Statoil	Appraisal	289	5268
		094	06 40 54.75	96.09.07	Trans.. Searcher	Susp. Oil	22	
6506/12-11	SR	849	65 05 07.20	96.11.12	Statoil	Appraisal	289	0
		094	06 40 54.75	00.00.00	Trans.. Searcher		22	
6610/02-01	S	858	66 48 48.73	96.08.27	Statoil	Wildcat	406	2673
		177	10 30 26.70	96.09.28	Byford Dolphin	Dry hole	24	Triassic
6610/03-01	R2	748	66 55 29.70	96.10.01	Statoil	Wildcat	309	4200
		177	10 54 06.28	96.10.07	Byford Dolphin	Shows	24	Triassic

7.4 DEVELOPMENT DRILLING STATISTICS

Since 1973, 1,239 development wells have been spudded on the Norwegian continental shelf; 1,197 of these in the North Sea, and 42 in the Norwegian Sea where drilling started in 1992. 933 are production wells, 229 are water or gas injection wells and 77 are observation wells. 451 are currently out of service, temporarily abandoned for later completion, or shut down for other reasons.

The wells have been drilled from 75 permanent installations (stationary, floating or subsea templates).

Drilling was in progress on 19 development wells as of 31 December 1996. Figure 7.4.a shows development wells commenced per year during the period 1973-1996.

Fig. 7.4.a
Development wells on the Norwegian continental shelf 1973-1996

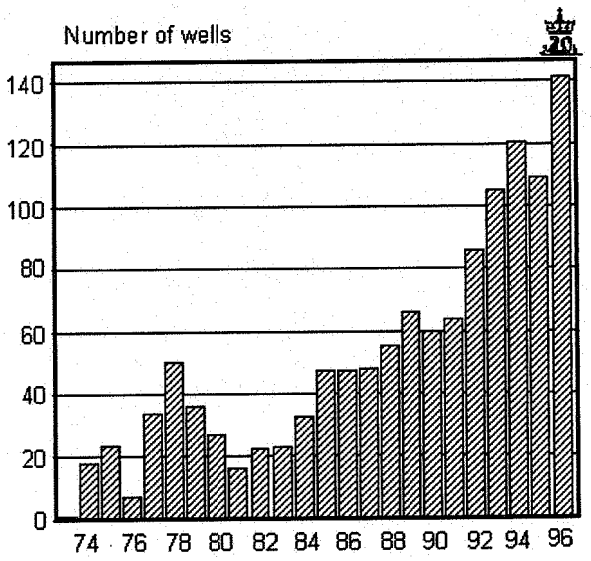


Fig. 7.4.b
Development wells per field

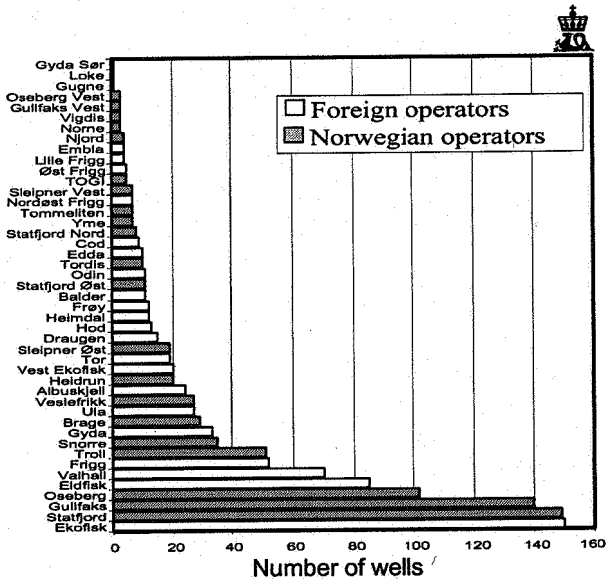


Fig. 7.4.c
Development wells per operator

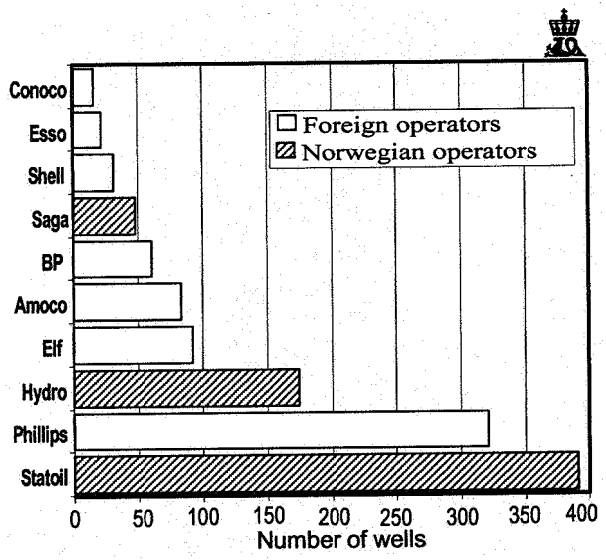


Fig. 7.4.d
Development drilling by mobile installations

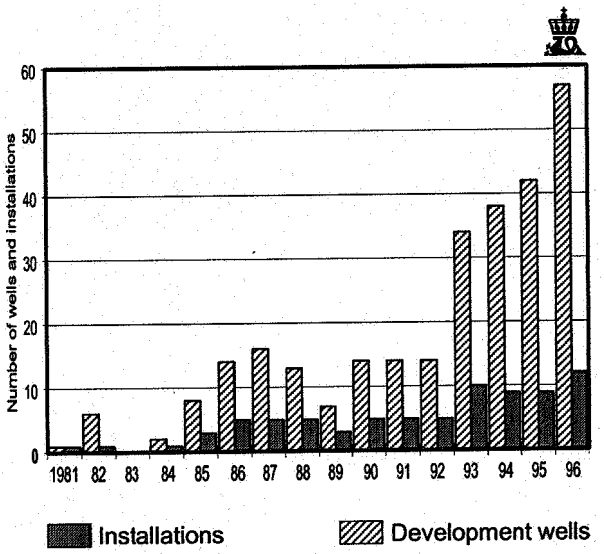
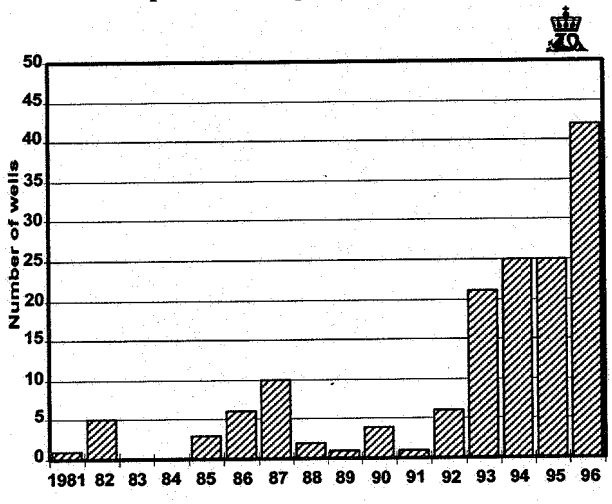


Fig. 7.4.e
Sub-sea completed wells per year



As of 31 December 1996, production or injection is carried out from 65 installations divided among 38 fields.

Three new fields have started producing in 1996: Gungne, Sleipner Vest and Yme.

Three fields have terminated production: Nordøst Frigg, Odin and Mime. In addition, the F platform on Albuskjell has been shut down.

Development wells divided by the various fields are shown in Figure 7.4.b. Figure 7.4.c shows development wells divided by operating companies.

Drilling of the first development wells on the Balder, Njord and Norne fields was commenced in 1996.

In 1996, 141 development wells were spudded on 24 fields. 57 of the wells were drilled from 12 different mobile units, see Figure 7.4.d.

The number of subsea-completed wells has shown a strong increase over the last 5 years. This increase was particularly marked from 1995 to 1996 when the number of subsea-completed wells went up from 25 to 42, see Figure 7.4.e. This means that the percentage of subsea-completed wells drilled per year has increased from 7% in 1992 to 30% in 1996.

Information on development wells is set out in Tables 7.4.a, 7.4.b and 7.4.c.

Table 7.4.a Development drilling

	Drilled	Drilled	Producing					Closed/
Field	total	1996	Oil	Cond.	Gas	Inject	Drilling	susp.
Albuskjell A	11			6				5
Albuskjell F	13							13
Balder A, B, C, D	11	11					1	10
Brage	29	7	14			7	1	7
Cod	9			3				6
Draugen A	10		7			1		2
Draugen B	3					3		
Draugen C	2					2		
Edda	10		6					4
Ekofisk A	35		22					13
Ekofisk B	40		22					18
Ekofisk C	33		22					11
Ekofisk K	31					30		1
Ekofisk W	8					8		
Ekofisk X	3	3					2	1
Eldfisk A	45	3	25					20
Eldfisk B	40	3	16				1	23
Embla	4		4					
Frigg (UK)	24							24
Frigg	28				13			15
Frøy	12		6			4		2
Gullfaks A	58	4	31			8	1	18
Gullfaks B	42	3	21			9		12
Gullfaks C	40	7	27			8		5
Gullfaks Vest	3		1					2
Gugne	1				1			
Gyda	33	3	12			9		12
Gyda Sør	1		1					
Heidrun A	14	4	10			3	1	
Heidrun B	3					3		
Heidrun C	3					3		
Heimdal	12			8				4
Hod	13		6					7
Lille-Frigg	4		1					3
Loke	1				1			
Njord	4	4					1	3
Norne B, C, D	3	3					1	2
N-Ø Frigg	7							7
Odin	11							11
Oseberg B	55	7	25			10		20
Oseberg C	47	8	16			7	1	23

Field	Drilled total	Drilled 1996	Producing Oil	Cond.	Gas	Inject	Drilling	Closed/ susp.
Gullfaks Vest	3		1					2
Gungne	1				1			
Gyda	33	3	12			9		12
Gyda Sør	1		1					
Heidrun A	14	4	10			3	1	
Heidrun B	3					3		
Heidrun C	3					3		
Heimdal	12			8				4
Hod	13		6					7
Lille-Frigg	4		1					3
Loke	1				1			
Njord	4	4					1	3
Norne B, C, D	3	3					1	2
Nordøst Frigg	7							7
Odin	11							11
Oseberg B	55	7	25			10		20
Oseberg C	47	8	16			7	1	23
Oseberg Vest	3	1	2					1
Sleipner A	17	2			12	3		2
Sleipner D	2					2		
Sleipner Vest	7	4			6		1	
Snorre A	11	1	7			3		1
Snorre P	24	3	13			8		3
Statfjord A	56	3	24			11	1	20
Statfjord B	50	4	30			11		9
Statfjord C	42	3	26			12	1	3
Statfjord G	1	1					1	
Statfjord Nord	8	1	5			2	1	
Statfjord Øst	11	3		6		3		2
TOGI	5				5			
Tommeliten	7			6				1
Tor	19		11			2		6
Tordis	10	2	5					5
Troll A	19	16			15		1	3
Troll B	1					1		
Troll D,E,F,G,H	31	11	23				1	7
Ula	27	1	8			7		12
Valhall A	64	2	27				1	36
Valhall F	6	3	3				1	2
V. Ekofisk	20			4				16
Veslefrikk	27	2	13			9		5
Vigdis	3	2						3
Yme A, B	7	6						7
Øst Frigg A	3		1					2
Øst Frigg B	2		1					1
	1239	**141**	**494**	**33**	**53**	**189**	**19**	**451**

Table 7.4.b
Development wells spudded and/or completed in 1996
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-12	1156	56 54 17.61	96.05.08	BP	Water inj	6024 m
	019 B	03 05 06.49	96.08.07	Gyda	Susp. at TD	
2/01-A-14 A	1137	56 54 17.43	96.03.15	BP	Oil prod	4747 m
	019 B	03 05 06.61	96.05.08	Gyda	Oil	
2/01-A-25	1119	56 54 17.19	96.01.22	BP	Oil prod	5370 m
	019 B	03 05 06.38	96.03.12	Gyda	Susp. at TD	
2/01-A-28	1034	56 54 17.36	95.10.30	BP	Oil prod	4633 m
	019 B	03 05 06.07	96.01.19	Gyda	Oil	
2/04-K-03	335	56 33 55.98	85.11.02	Phillips	Water inj	6585 m
	018	03 12 23.11	96.02.10	Dyvi Beta	Water inj	
2/04-X-08	1230	56 32 50.96	96.12.13	Phillips	Oil prod	m
	018	03 13 08.41	00.00.00	Mærsk Gallant		
2/04-X-38	1219	56 32 51.79	96.10.26	Phillips	Cutting inj	3074 m
	018	03 13 08.70	96.12.07	Ekofisk X	Susp. at TD	
2/04-X-46	1235	56 32 51.98	96.12.08	Phillips	Oil prod	m
	018	03 13 08.75	00.00.00	Ekofisk X		
2/07-A-09 A	628	56 22 36.41	96.08.08	Phillips	Oil prod	5355 m
	018	03 15 57.67	96.09.27	Mærsk Gallant	Susp. at TD	
2/07-A-12 A	1155	60 22 36.48	96.05.26	Phillips	Oil prod	5386 m
	018	03 15 57.60	96.07.23	Mærsk Gallant	Oil	
2/07-A-14 A	1203	56 22 36.59	96.10.13	Phillips	Oil prod	4872 m
	018	03 15 57.71	96.12.01	Mærsk Gallant	Susp. at TD	
2/07-A-15	111	56 22 36.55	78.06.07	Phillips	Oil prod	5614 m
	018	03 15 57.56	96.05.09	Eldfisk B	Oil	
2/07-B-01 B	1212	56 25 08.94	96.12.08	Phillips	Oil prod	m
	018	03 13 06.46	00.00.00	Eldfisk B		
2/07-B-17 A	1151	56 25 09.21	96.06.13	Phillips	Oil prod	5621 m
	018	03 13 06.25	96.09.01	Eldfisk B	Plugged	
2/07-B-17 B	1183	56 25 09.21	96.09.02	Phillips	Oil prod	5621 m
	018	03 13 06.25	96.09.28	Eldfisk B	Susp. at TD	
2/08-A-03 B	1233	56 16 41.08	96.11.29	Amoco	Oil prod	m
	006	03 23 44.30	00.00.00	Valhall		
2/08-A-26 A	1138	56 16 41.02	96.03.18	Amoco	Oil prod	4389 m
	006	03 23 44.20	96.05.02	Valhall	Oil	
2/08-F-01	1093	56 16 35.69	95.12.11	Amoco	Oil prod	5012 m
	006	03 23 47.14	96.05.28	Mærsk Guardian	Susp. at TD	
2/08-F-02	1094	56 16 35.65	95.12.08	Amoco	Observation	4807 m
	006	03 23 46.96	96.03.11	Mærsk Guardian	Plugged	
2/08-F-02 A	1132	56 16 35.65	96.03.12	Amoco	Oil prod	5355 m
	006	03 23 46.96	96.07.08	Mærsk Guardian	Susp. at TD	
2/08-F-03	1095	56 16 35.70	95.12.13	Amoco	Oil prod	5226 m
	006	03 23 47.03	96.10.14	Mærsk Guardian	Susp. at TD	
2/08-F-04	1096	56 16 35.67	96.06.09	Amoco	Oil prod	4918 m
	006	03 23 47.25	96.12.05	Mærsk Guardian	Susp. at TD	
2/08-F-06	1211	56 16 35.57	96.12.06	Amoco	Oil prod	m
	006	03 23 46.96	00.00.00	Mærsk Guardian		
7/12-A-07 A	1163	57 06 41.45	96.10.11	BP	Observation	4089 m
	019	02 50 50.50	96.10.23	Ula	Susp. at TD	
9/02-A-01	1074	57 49 07.48	96.02.01	Statoil	Oil prod	4435 m
	114	04 31 10.74	96.03.08	Mærsk Giant	Susp. at TD	
9/02-A-02	1238	57 49 07.54	96.12.14	Statoil	Oil prod	m
	114	04 31 10.87	96.12.30	Mærsk Giant	Susp. at 13 3/8"	
9/02-A-04	1167	57 49 07.53	96.06.09	Statoil	Oil prod	4845 m
	114	04 31 11.21	96.11.25	Mærsk Giant	Susp. at TD	

Well	Reg.no Lic.no	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
9/02-A-05	1013	57 49 07.48	95.03.08	Statoil	Water/Gas inj	3510 m
	114	04 31 10.74	96.03.21	Mærsk Giant	Susp. at TD	
9/02-A-08	1141	57 49 07.53	96.03.25	Statoil	Oil prod	4637 m
	114	04 31 11.21	96.06.06	Mærsk Giant	Susp. at TD	
9/02-B-01 H	1109	57 45 15.30	96.04.07	Statoil	Oil prod	3355 m
	114	04 21 21.16	96.05.08	Deepsea Bergen	Susp. at TD	
9/02-B-02 H	1139	57 45 15.30	96.03.25	Statoil	Oil prod	3438 m
	114	04 21 21.80	96.07.28	Deepsea Bergen	Susp. at TD	
15/09-A-02	1063	58 22 02.69	95.08.29	Statoil	Gas prod	8529 m
	046	01 54 29.70	96.03.04	Sleipner A	Gas	
15/09-A-16	1126	58 22 02.70	96.03.13	Statoil	Gas inj	3752 m
	046	01 54 30.25	96.04.16	Sleipner A	Susp. at TD	
15/09-A-23	993	58 22 02.05	96.09.25	Statoil	Gas inj	5590 m
	046	01 54 32.06	96.11.22	Sleipner A	Susp. at TD	
15/09-B-05	1100	58 25 04.57	95.11.26	Statoil	Gas prod	4800 m
	046	01 43 04.00	96.08.04	West Epsilon	Susp. at TD	
15/09-B-06	1111	58 25 04.61	96.02.05	Statoil	Gas prod	4540 m
	046	01 43 04.14	96.07.22	West Epsilon	Susp. at TD	
15/09-B-07	1136	58 25 04.66	96.03.27	Statoil	Gas prod	5732 m
	046	01 43 04.29	96.08.28	West Epsilon	Susp. at TD	
15/09-B-13	1154	58 25 04.42	96.08.30	Statoil	Gas prod	6235 m
	046	01 43 04.17	96.12.27	West Epsilon	Susp. at TD	
15/09-B-14	1086	58 25 04.46	95.10.23	Statoil	Gas prod	3888 m
	046	01 43 04.31	96.07.07	West Epsilon	Susp. at TD	
15/09-B-24	1244	58 25 04.40	96.12.30	Statoil	Gas prod	m
	046	01 43 04.77	00.00.00	West Epsilon		
25/05-A-10	1103	59 44 03.51	95.11.28	Elf	Water inj	m
	102	02 33 28.30	96.02.25	Mærsk Gallant		
25/11-A-04 H	1227	59 11 28.37	96.11.16	Esso	Observation	2324 m
	001	02 21 34.86	96.12.04	West Alpha	Plugged	
25/11-A-04 A H	1236	59 11 28.37	96.12.04	Esso	Oil prod	2115 m
	001	02 21 34.86	96.12.10	West Alpha	Susp. at TD	
25/11-A-05 H	1202	59 11 30.25	96.09.27	Esso	Observation	2502 m
	001	02 21 33.88	96.11.03	West Alpha	Plugged	
25/11-A-05 A H	1221	59 11 30.25	96.11.04	Esso	Oil prod	2460 m
	001	02 21 33.88	96.11.15	West Alpha	Susp. at TD	
25/11-A-06 H	1210	59 11 23.39	96.10.07	Esso	Oil prod	m
	001	02 21 37.38	96.10.17	West Alpha	Susp. at 9 5/8"	
25/11-A-08 H	1237	59 11 29.83	96.12.11	Esso	Water prod	m
	001	02 21 32.62	96.12.15	West Alpha	Susp. at 13 3/8"	
25/11-B-07 H	1245	59 10 40.45	96.12.17	Esso	Observation	m
	001	02 22 46.46	00.00.00	West Alpha		
25/11-C-03 H	1194	59 11 00.62	96.08.29	Esso	Observation	2118 m
	001	02 24 32.58	96.09.20	West Alpha	Plugged	
25/11-D-01 H	1162	59 12 01.03	96.05.25	Esso	Gas inj	2525 m
	001	02 24 37.02	96.07.30	West Alpha	Susp. at TD	
25/11-D-02 H	1189	59 11 59.60	96.08.02	Esso	Observation	2330 m
	001	02 24 33.19	96.08.13	West Alpha	Plugged	
25/11-D-02 A H	1193	59 11 59.60	96.08.13	Esso	Oil prod	2140 m
	001	02 24 33.19	96.08.24	West Alpha	Susp. at TD	
30/03-A-07 A	1102	60 46 57.92	95.12.20	Statoil	Observation	3810 m
	052	02 53 52.06	96.01.04	Veslefrikk A	Plugged	
30/03-A-07 B	1118	60 46 57.92	96.02.02	Statoil	Oil prod	5333 m
	052	02 53 52.06	96.02.28	Veslefrikk A	Susp. at TD	
30/03-A-17 A	1131	60 46 58.08	96.02.29	Statoil	Water inj	3897 m
	052	02 53 52.16	96.04.10	Veslefrikk A	Water inj	
30/06-B-51 A H	1110	60 31 59.58	96.01.23	Hydro	Oil prod	4606 m
	053	02 44 23.91	96.08.11	West Vanguard	Susp. at TD	
30/06-C-07 A	1105	60 36 29.42	96.08.06	Hydro	Observation	m
	053	02 46 33.72	96.09.01	Oseberg C	Susp. at 9 5/8"	
30/06-C-07 B	1196	60 36 29.42	96.11.06	Hydro	Oil prod	5175 m
	053	02 46 33.72	96.12.18	Oseberg C	Susp. at TD	

Well	Reg.no Lic.no	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
30/06-C-07 C	1196	60 36 29.42	96.12.18	Hydro	Oil prod	m
	053	02 46 33.72	00.00.00	Oseberg C		
30/06-C-10 C	1161	60 36 29.42	96.05.20	Hydro	Oil prod	5256 m
	053	02 46 33.60	96.09.25	Oseberg C	Susp. at TD	
30/06-C-12 A	1112	60 36 29.42	96.01.22	Hydro	Observation	m
	053	02 46 33.60	96.02.13	Oseberg C	Plugged	
30/06-C-12 B	1127	60 36 29.42	96.02.13	Hydro	Oil prod	5266 m
	053	02 46 33.60	96.03.05	Oseberg C	Oil	
30/06-C-12 C	1134	60 36 29.42	96.03.05	Hydro	Oil prod	4739 m
	053	02 46 33.60	96.04.27	Oseberg C	Susp. at TD	
30/06-C-13	1204	60 36 29.49	96.09.26	Hydro	Observation	4700 m
	053	02 46 33.13	96.10.24	Oseberg C	Plugged	
30/09-B-10	1184	60 29 36.36	96.09.23	Hydro	Observation	4635 m
	079	02 49 42.85	96.10.28	Oseberg B	Plugged	
30/09-B-10 A	1220	60 29 36.36	96.10.28	Hydro	Oil prod	5482 m
	079	02 49 42.85	96.12.05	Oseberg B	Susp. at TD	
30/09-B-14	1142	60 29 36.24	96.04.24	Hydro	Observation	4223 m
	079	02 49 42.55	96.05.18	Oseberg B	Plugged	
30/09-B-14 A	1164	60 29 36.24	96.05.18	Hydro	Oil prod	5796 m
	079	02 49 42.55	96.07.03	Oseberg B	Oil	
30/09-B-16 A	1175	60 29 36.27	96.07.08	Hydro	Oil prod	5734 m
	079	02 49 42.89	96.09.17	Oseberg B	Susp. at TD	
30/09-B-36	1117	60 29 36.05	96.01.23	Hydro	Observation	m
	079	02 49 43.33	96.02.26	Oseberg B	Plugged	
30/09-B-36 A	1128	60 29 36.05	96.02.26	Hydro	Oil prod	6044 m
	079	02 49 43.33	96.04.23	Oseberg B	Oil	
31/02-D-02 H	1108	60 51 30.48	95.12.19	Hydro	Oil prod	4602 m
	054	03 26 43.53	96.01.28	Polar Pioneer	Oil	
31/02-D-07 H	1133	60 51 21.02	96.03.06	Hydro	Oil prod	3900 m
	054	03 26 34.19	96.04.07	Polar Pioneer	Oil	
31/02-E-05 H	1122	60 47 52.42	96.01.29	Hydro	Observation	m
	054	03 26 34.66	96.02.09	Polar Pioneer	Plugged	
31/02-E-05 A H	1124	60 47 52.42	96.02.09	Hydro	Oil prod	2991 m
	054	03 26 34.66	96.03.02	Polar Pioneer	Oil	
31/02-E-06 A H	1248	60 47 51.30	96.12.31	Hydro	Observasjon	m
	054	03 26 43.10	00.00.00	Polar Pioneer		
31/02-F-01 H	1188	60 46 36.40	96.08.25	Hydro	Observation	3970 m
	054	03 26 09.20	96.10.13	Polar Pioneer	Plugged	
31/02-G-01 H	1209	60 45 04.72	96.10.14	Hydro	Observation	1860 m
	054	03 26 11.19	96.10.23	Polar Pioneer	Plugged	
31/02-G-01 A H	1217	60 45 04.72	96.10.23	Hydro	Oil prod	4070 m
	054	03 26 11.19	96.11.21	Polar Pioneer	Susp. at TD	
31/04-A-09	1174	60 32 33.00	96.06.25	Hydro	Oil prod	6602 m
	055	03 02 50.35	96.10.06	Brage	Susp. at TD	
31/04-A-15	1143	60 32 33.00	96.05.10	Hydro	Oil prod	4397 m
	055	03 02 50.69	96.06.25	Brage	Oil	
31/04-A-16	1240	60 32 33.34	96.12.16	Hydro	Water/gas inj	m
	055	03 02 51.03	00.00.00	Brage		
31/04-A-17	1121	60 32 33.42	96.02.02	Hydro	Observation	3985 m
	055	03 02 51.03	96.04.03	Brage	Plugged	
31/04-A-17 A	1129	60 32 33.42	96.04.04	Hydro	Water inj	5541 m
	055	03 02 51.03	96.05.09	Brage	Water inj	
31/04-A-24	1224	60 32 32.92	96.11.12	Hydro	Water prod	1107 m
	055	03 02 50.86	96.11.22	Brage	Susp. at TD	
31/04-A-29	1225	60 32 33.09	96.11.23	Hydro	Water prod	1095 m
	055	03 02 50.69	96.12.01	Brage	Susp. at TD	
31/04-A-40	1091	60 32 33.47	95.11.06	Hydro	Oil prod	5822 m
	055	03 02 50.46	96.01.11	Brage	Oil	
31/05-H-01 H	1146	60 42 57.98	96.04.14	Hydro	Observation	2400 m
	085	03 30 39.37	96.04.30	Polar Pioneer	Plugged	

Well		Reg.no Lic.no	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
31/05-H-02	H	1234	60 43 49.39	96.11.26	Hydro	Oil prod	4260 m
		085	03 30 46.79	96.12.30	Polar Pioneer	Susp. at TD	
31/05-H-04	H	1168	60 42 55.16	96.06.28	Hydro	Oil prod	3938 m
		085	03 30 26.53	96.08.06	Polar Pioneer	Susp. at TD	
31/06-A-02		1185	60 38 44.90	96.09.07	Shell	Gas prod	1642 m
		085	03 43 35.08	96.10.14	Troll A	Susp. at TD	
31/06-A-03		1186	60 38 44.83	96.09.01	Shell	Gas prod	1647 m
		085	03 43 35.08	96.10.05	Troll A	Susp. at TD	
31/06-A-06		1067	60 38 44.90	96.03.29	Shell	Gas prod	1592 m
		085	03 43 35.23	96.06.15	Troll A	Susp. at TD	
31/06-A-10		1145	60 38 44.98	96.04.10	Shell	Gas prod	1579 m
		085	03 45 35.38	96.06.06	Troll A	Susp. at TD	
31/06-A-12		1159	60 38 44.83	96.05.04	Shell	Gas prod	m
		085	03 45 35.38	96.05.20	Troll A	Susp. at 10 3/4"	
31/06-A-16		1153	60 38 44.83	96.04.20	Shell	Gas prod	1602 m
		085	03 45 35.53	96.05.28	Troll A	Susp. at TD	
31/06-A-17		1187	60 38 44.75	96.08.17	Shell	Gas prod	1611 m
		085	03 45 35.53	96.10.25	Troll A	Susp. at TD	
31/06-A-25		1214	60 38 43.77	96.11.08	Statoil	Gas prod	m
		085	03 45 35.23	00.00.00	Troll A		
31/06-A-26		1215	60 38 43.69	96.11.19	Statoil	Gas prod	1605 m
		085	03 45 35.23	96.12.29	Troll A	Susp. at TD	
31/06-A-27		1170	60 38 43.62	96.06.16	Shell	Gas prod	m
		085	03 45 35.23	96.08.16	Troll A	Susp. at 10 3/4"	
31/06-A-29		1171	60 38 43.77	96.07.06	Shell	Gas prod	1599 m
		085	03 45 35.38	96.07.27	Troll A	Susp. at TD	
31/06-A-30		1071	60 38 43.69	96.01.28	Shell	Gas prod	1600 m
		085	03 43 35.38	96.03.28	Troll A	Susp. at TD	
31/06-A-31		1172	60 38 43.62	96.06.26	Shell	Gas prod	1604 m
		085	03 45 35.38	96.08.07	Troll A	Susp. at TD	
31/06-A-34		1213	60 38 43.77	96.10.28	Statoil	Gas prod	m
		085	03 45 35.53	96.11.07	Troll A	Susp. at TD	
31/06-A-35		1072	60 38 43.69	96.02.21	Shell	Gas prod	1616 m
		085	03 43 35.53	96.03.18	Troll A	Susp. at TD	
31/06-A-36		1216	60 38 43.62	96.11.30	Shell	Gas prod	1612 m
		085	03 45 35.53	96.12.20	Troll A	Susp. at TD	
33/09-A-16	A	1150	61 15 20.46	96.05.06	Statoil	Oil prod	5487 m
		037	01 51 13.95	96.07.11	Statfjord A	Susp. at TD	
33/09-A-34	A	1179	61 15 19.77	96.07.24	Statoil	Oil prod	5255 m
		037	01 51 14.39	96.11.11	Statfjord A	Susp. at TD	
33/09-A-35	A	1079	61 15 20.46	95.10.26	Statoil	Oil prod	5719 m
		037	01 51 13.95	96.01.15	Statfjord A	Oil	
33/09-A-40	A	1199	61 15 19.72	96.11.25	Statoil	Oil prod	m
		037	01 51 13.87	00.00.00	Statfjord A		
33/09-C-01	A	1135	61 17 47.69	96.03.09	Statoil	Water inj	5190 m
		037	01 54 11.09	96.04.21	Statfjord C	Susp. at TD	
33/09-C-17		1114	61 17 47.91	96.01.20	Statoil	Oil prod	3280 m
		037	01 54 11.19	96.02.16	Statfjord C	Oil	
33/09-C-29		1207	61 17 46.83	96.10.13	Statoil	Oil prod	m
		037	01 54 10.41	00.00.00	Statfjord C		
33/09-C-41		1092	61 17 46.68	95.11.14	Statoil	Oil prod	4438 m
		037	01 54 09.95	96.01.17	Statfjord C	Oil	
33/09-E-03	H	1106	61 26 03.40	95.12.22	Statoil	Oil prod	4378 m
		037	01 55 31.04	96.03.14	Treasure Prospect	Oil	
33/09-E-04	H	1197	61 26 02.01	96.09.25	Statoil	Oil prod	m
		037	01 53 30.21	00.00.00	Treasure Prospect		
33/09-G-03	H	1229	61 21 56.57	96.12.09	Statoil	Oil prod	m
		037	01 56 05.94	00.00.00	Transocean 8		
33/09-L-02	H	1166	61 19 46.02	96.07.04	Statoil	Oil prod	2853 m
		037	01 59 11.05	96.08.12	Treasure Prospect	Susp. at TD	

Well	Reg.no Lic.no	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
33/09-M-04 H	1125	61 20 27.97	96.03.25	Statoil	Oil prod	3632 m
	037	01 59 59.27	96.04.18	Treasure Prospect	Plugged	
33/09-M-04 A H	1152	61 20 27.97	96.04.18	Statoil	Oil prod	3160 m
	037	01 59 59.27	96.05.21	Treasure Prospect	Oil	
33/12-B-02 B	1107	61 12 25.25	96.02.08	Statoil	Oil prod	5114 m
	037	01 49 52.41	96.04.26	Statfjord B	Oil	
33/12-B-06 A	1169	61 12 25.18	96.06.28	Statoil	Oil prod	3435 m
	037	01 49 52.34	96.07.08	Statfjord B	Oil	
33/12-B-23 A	1180	61 12 24.10	96.07.15	Statoil	Oil prod	4500 m
	037	01 49 51.19	96.09.19	Statfjord B	Oil	
33/12-B-41 A	1158	61 12 24.88	96.05.19	Statoil	Oil prod	4610 m
	037	01 49 50.29	96.06.06	Statfjord B	Oil	
34/07-A-17 H	1182	61 29 21.19	96.08.08	Saga	Oil prod	4301 m
	089	02 13 34.65	96.11.14	Scarabeo 5	Susp. at TD	
34/07-C-01 H	1113	61 22 49.91	96.01.17	Saga	Oil prod	4431 m
	089	02 06 11.80	96.12.30	Scarabeo 5	Susp. at TD	
34/07-C-02 H	1090	61 22 49.91	95.11.26	Saga	Oil prod	3220 m
	089	02 06 11.80	96.12.04	Scarabeo 5	Susp. at TD	
34/07-C-03 H	1123	61 22 49.49	96.01.23	Saga	Oil prod	4716 m
	089	02 06 11.82	00.00.00	Scarabeo 5		
34/07-I-03 A H	1144	61 16 34.23	96.04.25	Saga	Oil prod	2636 m
	089	02 07 01.68	96.07.02	Scarabeo 5	Plugged	
34/07-I-03 B H	1178	61 16 34.23	96.07.02	Saga	Oil prod	2312 m
	089	02 07 01.68	96.07.18	Scarabeo 5	Oil	
34/07-P-09	1116	61 26 56.95	96.02.01	Saga	Oil prod	4994 m
	089	02 08 37.37	96.06.16	Snorre P	Oil	
34/07-P-22	1190	61 26 57.47	96.08.18	Saga	Water inj	5869 m
	089	02 08 36.81	96.11.27	Snorre P	Susp. at TD	
34/07-P-32	1104	61 26 58.11	95.12.06	Saga	Water inj	4923 m
	089	02 08 36.53	96.02.01	Snorre P	Water inj	
34/07-P-39	1165	61 26 57.99	96.06.18	Saga	Oil prod	4560 m
	089	02 08 37.07	96.08.12	Snorre P	Oil	
34/10-A-06 A	1148	61 10 33.64	96.04.25	Statoil	Oil prod	3526 m
	050	02 11 23.09	96.06.01	Gullfaks A	Oil	
34/10-A-07 A	1228	61 10 34.77	96.12.01	Statoil	Oil prod	m
	050	02 11 21.80	00.00.00	Gullfaks A		
34/10-A-17 A	1099	61 10 33.93	95.12.01	Statoil	Water inj	3246 m
	050	02 11 23.14	96.01.12	Gullfaks A	Water inj	
34/10-A-44	1120	61 10 34.91	96.01.31	Statoil	Oil prod	4130 m
	050	02 11 21.63	96.04.18	Gullfaks A	Susp. at TD	
34/10-A-45	1192	61 10 34.73	96.08.23	Statoil	Oil prod	3214 m
	050	02 11 21.65	96.09.30	Gullfaks A	Susp. at TD	
34/10-B-05 A	1176	61 12 11.13	96.08.09	Statoil	Oil prod	4014 m
	050	02 12 05.24	96.12.21	Gullfaks B	Susp. at TD	
34/10-B-36 A	1206	61 12 10.01	96.10.04	Statoil	Water inj	2664 m
	050	02 12 06.22	96.11.19	Gullfaks B	Susp. at TD	
34/10-B-37	1198	61 12 10.04	96.09.15	Statoil	Oil prod	m
	050	02 12 05.99	96.10.03	Gullfaks B	Susp. at 13 3/8"	
34/10-C-20 A	1149	61 12 53.39	96.04.20	Statoil	Oil prod	4712 m
	050	02 16 28.06	96.05.24	Gullfaks A	Oil	
34/10-C-31	1101	61 12 54.62	95.11.27	Statoil	Water inj	4381 m
	050	02 16 26.59	96.01.17	Gullfaks C	Water inj	
34/10-C-32	1115	61 12 53.43	96.01.23	Statoil	Oil prod	5100 m
	050	02 16 28.21	96.03.17	Gullfaks C	Oil	
34/10-C-33	1140	61 12 54.90	96.03.18	Statoil	Oil prod	2295 m
	050	02 16 26.25	96.04.04	Gullfaks C	Oil	
34/10-C-34	1157	61 12 54.87	96.05.06	Statoil	Observation	4553 m
	050	02 16 24.48	96.06.20	Gullfaks C	Plugged	
34/10-C-34 A	1173	61 12 54.87	96.06.20	Statoil	Oil prod	4460 m
	050	02 16 24.46	96.08.11	Gullfaks C	Oil	

Well	Reg.no Lic.no	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
34/10-C-34 A	1173	61 12 54.87	96.06.20	Statoil	Oil prod	4460 m
	050	02 16 24.46	96.08.11	Gullfaks C	Oil	
34/10-C-35	1181	61 12 53.38	96.08.11	Statoil	Oil prod	m
	050	02 16 27.69	96.11.10	Gullfaks C	Susp. at 13 3/8"	
34/10-C-36	1205	61 12 54.77	96.10.05	Statoil	Observation	m
	050	02 16 26.79	96.10.12	Gullfaks C	Susp. at 20"	
6407/07-A-08 H	1231	64 16 15.25	96.11.27	Hydro	Gas inj	m
	107	07 12 08.68	00.00.00	West Vanguard		
6407/07-A-14 H	1191	64 16 16.38	96.08.16	Hydro	Observation	m
	107	07 12 06.40	96.09.20	West Vanguard	Susp. at 18 5/8"	
6407/07-A-15 H	1201	64 16 16.53	96.09.21	Hydro	Observation	4122 m
	107	07 12 05.58	96.11.02	West Vanguard	Plugged	
6407/07-A-15 AH	1218	60 16 16.53	96.11.02	Hydro	Oil prod	4150 m
	107	07 12 05.58	96.11.27	West Vanguard	Susp. at TD	
6507/07-A-09	1147	65 19 32.85	96.04.24	Statoil	Oil prod	3985 m
	095	07 19 02.31	96.07.04	Heidrun	Oil	
6507/07-A-25	1177	65 19 32.64	96.07.04	Statoil	Water inj	4926 m
	095	07 19 02.45	96.11.16	Heidrun	Susp. at TD	
6507/07-A-46	1223	65 19 32.58	96.11.17	Statoil	Oil prod	m
	095	07 19 04.00	00.00.00	Heidrun		
6507/07-A-51	1130	65 19 32.40	96.03.08	Statoil	Water inj	4145 m
	095	07 19 03.24	96.04.23	Heidrun	Water inj.	
6608/10-B-02 H	1239	66 00 55.04	96.12.13	Statoil	Oil prod	m
	128	08 03 17.00	00.00.00	Trans. Wildcat		
6608/10-C-04 H	1226	66 00 52.20	96.11.18	Statoil	Gas inj	2900 m
	128	08 03 21.72	96.12.11	Trans. Wildcat	Susp. at TD	
6608/10-D-01 H	1208	66 00 49.30	96.09.28	Statoil	Oil prod	3500 m
	128	08 03 28.89	96.11.18	Trans. Wildcat	Susp. at TD	

Table 7.4.c
Development wells drilled from mobile units 1996
H=sub-sea completed, A/B/C=sidetracked new well, X=junked well

Well	Reg.no License	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
2/04-X-08	1230	56 32 50.96	96.12.13	Phillips	Oil producer	m
	018	03 13 08.41	00.00.00	Mærsk Gallant		
2/07-A-09 A	628	56 22 36.41	96.08.08	Phillips	Oil producer	5355 m
	018	03 15 57.67	96.09.27	Mærsk Gallant	Susp at TD	
2/07-A-12 A	1155	60 22 36.48	96.05.26	Phillips	Oil producer	5386 m
	018	03 15 57.60	96.07.23	Mærsk Gallant	Oil	
2/07-A-14 A	1203	56 22 36.59	96.10.13	Phillips	Oil producer	4872 m
	018	03 15 57.71	96.12.01	Mærsk Gallant	Susp at TD	
2/08-F-02 A	1132	56 16 35.65	96.03.12	Amoco	Oil producer	5355 m
	006	03 23 46.96	96.07.08	Mærsk Guardian	Susp at TD	
2/08-F-04	1096	56 16 35.67	96.06.09	Amoco	Oil producer	4918 m
	006	03 23 47.25	96.12.05	Mærsk Guardian	Susp at TD	
2/08-F-06	1211	56 16 35.57	96.12.06	Amoco	Oil producer	m
	006	03 23 46.96	00.00.00	Mærsk Guardian		
9/02-A-01	1074	57 49 07.48	96.02.01	Statoil	Oil producer	4435 m
	114	04 31 10.74	96.03.08	Mærsk Giant	Susp at TD	
9/02-A-02	1238	57 49 07.54	96.12.14	Statoil	Oil prod	m
	114	04 31 10.87	96.12.30	Mærsk Giant	Susp. at 13 3/8"	
9/02-A-04	1167	57 49 07.53	96.06.09	Statoil	Oil producer	4845 m
	114	04 31 11.21	96.11.25	Mærsk Giant	Susp at TD	
9/02-A-08	1141	57 49 07.53	96.03.25	Statoil	Oil producer	4637 m
	114	04 31 11.21	96.06.06	Mærsk Giant	Susp at TD	
9/02-B-01 H	1109	57 45 15.30	96.04.07	Statoil	Oil producer	3355 m
	114	04 21 21.16	96.05.08	Deepsea Bergen	Susp at TD	
9/02-B-02 H	1139	57 45 15.30	96.03.25	Statoil	Oil producer	3438 m
	114	04 21 21.80	96.07.28	Deepsea Bergen	Susp. at TD	

Well			Reg.no License	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
15/09-B-06			1111	58 25 04.61	96.02.05	Statoil	Gas producer	4540 m
			046	01 43 04.14	96.07.22	West Epsilon	Susp at TD	
15/09-B-07			1136	58 25 04.66	96.03.27	Statoil	Gas producer	5732 m
			046	01 43 04.29	96.08.28	West Epsilon	Susp at TD	
15/09-B-13			1154	58 25 04.42	96.08.30	Statoil	Gas producer	6235 m
			046	01 43 04.17	96.12.27	West Epsilon	Susp. at TD	
15/09-B-24			1244	58 25 04.40	96.12.30	Statoil	Gas prod	m
			046	01 43 04.77	00.00.00	West Epsilon		
25/11-A-04		H	1227	59 11 28.37	96.11.16	Esso	Observation	2324 m
			001	02 21 34.86	96.12.04	West Alpha	Plugged	
25/11-A-04	A	H	1236	59 11 28.37	96.12.04	Esso	Oil producer	2115 m
			001	02 21 34.86	96.12.10	West Alpha	Susp at TD	
25/11-A-05		H	1202	59 11 30.25	96.09.27	Esso	Observation	2502 m
			001	02 21 33.88	96.11.03	West Alpha	Plugged	
25/11-A-05	A	H	1221	59 11 30.25	96.11.04	Esso	Oil producer	2460 m
			001	02 21 33.88	96.11.15	West Alpha	Susp at TD	
25/11-A-06		H	1210	59 11 23.39	96.10.07	Esso	Oil producer	m
			001	02 21 37.38	96.10.17	West Alpha	Susp at 9 5/8"	
25/11-A-08		H	1237	59 11 29.83	96.12.11	Esso	Water producer	m
			001	02 21 32.62	96.12.15	West Alpha	Susp. at 13 3/8"	
25/11-B-07		H	1245	59 10 40.45	96.12.17	Esso	Observation	m
			001	02 22 46.46	00.00.00	West Alpha		
25/11-C-03		H	1194	59 11 00.62	96.08.29	Esso	Observation	2118 m
			001	02 24 32.58	96.09.20	West Alpha	Plugged	
25/11-D-01		H	1162	59 12 01.03	96.05.25	Esso	Gas injector	2525 m
			001	02 24 37.02	96.07.30	West Alpha	Susp at TD	
25/11-D-02		H	1189	59 11 59.60	96.08.02	Esso	Observation	2330 m
			001	02 24 33.19	96.08.13	West Alpha	Plugged	
25/11-D-02	A	H	1193	59 11 59.60	96.08.13	Esso	Oil producer	2140 m
			001	02 24 33.19	96.08.24	West Alpha	Susp at TD	
30/06-B-51	A	H	1110	60 31 59.58	96.01.23	Hydro	Oil producer	4606 m
			053	02 44 23.91	96.08.11	West Vanguard	Susp at TD	
31/02-D-07		H	1133	60 51 21.02	96.03.06	Hydro	Oil producer	3900 m
			054	03 26 34.19	96.04.07	Polar Pioneer	Oil	
31/02-E-06	A	H	1248	60 47 51.30	96.12.31	Hydro	Observation	m
			054	03 26 43.10	00.00.00	Polar Pioneer		
31/02-E-05		H	1122	60 47 52.42	96.01.29	Hydro	Observation	m
			054	03 26 34.66	96.02.09	Polar Pioneer	Plugged	
31/02-E-05	A	H	1124	60 47 52.42	96.02.09	Hydro	Oil producer	2991 m
			054	03 26 34.66	96.03.02	Polar Pioneer	Oil	
31/02-F-01		H	1188	60 46 36.40	96.08.25	Hydro	Observation	3970 m
			054	03 26 09.20	96.10.13	Polar Pioneer	Plugged	
31/02-G-01		H	1209	60 45 04.72	96.10.14	Hydro	Observation	1860 m
			054	03 26 11.19	96.10.23	Polar Pioneer	Plugged	
31/02-G-01	A	H	1217	60 45 04.72	96.10.23	Hydro	Oil producer	4070 m
			054	03 26 11.19	96.11.21	Polar Pioneer	Susp at TD	
31/05-H-01		H	1146	60 42 57.98	96.04.14	Hydro	Observation	2400 m
			085	03 30 39.37	96.04.30	Polar Pioneer	Plugged	
31/05-H-01	A	H	1160	60 42 57.98	96.04.30	Hydro	Oil producer	4771 m
			085	03 30 39.37	96.06.01	Polar Pioneer	Susp at TD	
31/05-H-02		H	1234	60 43 49.39	96.11.26	Hydro	Oil producer	4260 m
			085	03 30 46.79	96.12.30	Polar Pioneer	Susp. at td	
31/05-H-04		H	1168	60 42 55.16	96.06.28	Hydro	Oil producer	3938 m
			085	03 30 26.53	96.08.06	Polar Pioneer	Susp at TD	
33/09-E-04		H	1197	61 26 02.01	96.09.25	Statoil	Oil producer	m
			037	01 53 30.21	00.00.00	Treasure Prospect		
33/09-G-03		H	1229	61 21 56.57	96.12.09	Statoil	Oil producer	m
			037	01 56 05.94	00.00.00	Transocean 8		
33/09-L-02		H	1166	61 19 46.02	96.07.04	Statoil	Oil producer	2853 m
			037	01 59 11.05	96.08.12	Treasure Prospect	Susp at TD	
33/09-M-04		H	1125	61 20 27.97	96.03.25	Statoil	Oil producer	3632 m
			037	01 59 59.27	96.04.18	Treasure Prospect	Plugged	
33/09-M-04	A	H	1152	61 20 27.97	96.04.18	Statoil	Oil producer	3160 m
			037	01 59 59.27	96.05.21	Treasure Prospect	Oil	
34/07-A-17		H	1182	61 29 21.19	96.08.08	Saga	Oil producer	4301 m
			089	02 13 34.65	96.11.14	Scarabeo 5	Susp at TD	

Well			Reg.no License	Position	Spudded Completed	Operator Installation	Classification Status	TD (RKB)
34/07-C-01		H	1113	61 22 49.91	96.01.17	Saga	Oil producer	4431 m
			089	02 06 11.80	96.12.30	Scarabeo 5	Susp at TD	
34/07-C-03		H	1123	61 22 49.49	96.01.23	Saga	Oil producer	4716 m
			089	02 06 11.82	00.00.00	Scarabeo 5		
34/07-I-03	A	H	1144	61 16 34.23	96.04.25	Saga	Oil producer	2636 m
			089	02 07 01.68	96.07.02	Scarabeo 5	Plugged	
34/07-I-03	B	H	1178	61 16 34.23	96.07.02	Saga	Oil producer	2312 m
			089	02 07 01.68	96.07.18	Scarabeo 5	Oil	
6407/07-A-08		H	1231	64 16 15.25	96.11.27	Hydro	Gas injector	m
			107	07 12 08.68	00.00.00	West Vanguard		
6407/07-A-14		H	1191	64 16 16.38	96.08.16	Hydro	Observation	m
			107	07 12 06.40	96.09.20	West Vanguard	Susp. at 18 5/8"	
6407/07-A-15		H	1201	64 16 16.53	96.09.21	Hydro	Observation	4122 m
			107	07 12 05.58	96.11.02	West Vanguard	Plugged	
6407/07-A-15	A	H	1218	60 16 16.53	96.11.02	Hydro	Oil producer	4150 m
			107	07 12 05.58	96.11.27	West Vanguard	Susp at TD	
6608/10-B-02		H	1239	66 00 55.04	96.12.13	Statoil	Oil prod	m
			128	08 03 17.00	00.00.00	Trans. Wildcat		
6608/10-C-04		H	1226	66 00 52.20	96.11.18	Statoil	Gas injector	2900 m
			128	08 03 21.72	96.12.11	Trans. Wildcat	Susp. at TD	
6608/10-D-01		H	1208	66 00 49.30	96.09.28	Statoil	Oil producer	3500 m
			128	08 03 28.89	96.11.18	Trans. Wildcat	Susp at TD	

7.5 RESOURCES IN DISCOVERIES AND FIELDS ON THE NORWEGIAN CONTINENTAL SHELF

Table 7.5.a
Original petroleum reserves in fields having ceased production

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	Total 10^6 Sm^3 o.e.
Mime	0,4	0,1		0,5
Nordøst Frigg		11,8	0,1	11,9
Odin		26,6		26,6
Total	**0,4**	**38,5**	**0,1**	**39,0**

Discoveries that in 1996 are reported jointly as part of another field/discovery

Discovery	Reported as
35/9-1 R	
36/7-1	35/9-1 R Gjøa
35/11-4 R	
35/11-7	
35/11-8 S	35/11-4 R Fram
6407/1-2 Tyrihans Sør	
6407/1-3 Tyrihans Nord	6407/1-2 Tyrihans
6506/12-1 Smørbukk	
6506/12-3 Smørbukk Sør	
650//11-1 Midgard	Åsgard

In addition, 30/6-18 Kappa, is part of Oseberg Vest

Table 7.5.b
Petroleum reserves in fields in production

	ORIGINAL RECOVERABLE				REMAINING			
	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3
North Sea:								
Albuskjell	7,4	16,1	1,0	24,8	0,1	0,9	0,0	1,0
Brage	46,6	1,4	0,5	48,7	27,6	0,6	0,2	28,4
Cod	2,9	7,4	0,5	11,0	0,1	0,3	0,0	0,4
Edda	4,9	2,1	0,2	7,3	0,2	0,2		0,4
Ekofisk	404,0	150,4	15,2	574,2	185,4	49,5	6,4	243,2
Eldfisk	81,3	58,7	4,6	146,0	20,5	31,0	1,8	53,8
Embla	8,3	6,0	0,6	15,1	3,9	4,6	0,5	9,1
Frigg[1)]		111,9	0,4	112,4		0,8	0,0	0,8
Frøy	11,0	2,3	0,2	13,6	8,4	1,8	0,2	10,4
Gullfaks	307,7	23,0	2,4	333,8	108,3	9,4	1,0	119,0
Gullfaks Vest	3,1			3,1	1,6			1,6

	ORIGINAL RECOVERABLE				REMAINING			
	Oil	**Gas**	**NGL**	**O.E.**	**Oil**	**Gas**	**NGL**	**O.E.**
	10^6 Sm^3	10^9 Sm^3	10^6 tons	10^6 Sm^3	10^6 Sm^3	10^9 Sm^3	10^6 tons	10^6 Sm^3
Gungne[2]		2,1	0,9	3,3		2,1	0,8	3,2
Gyda[3]	30,0	3,7	1,6	35,8	7,7	0,6	0,4	8,8
Gyda Sør[3]	2,1	1,1	0,3	3,6	2,1	1,1	0,3	3,6
Heimdal	6,6	40,5		47,1	1,2	2,9		4,1
Hod	8,7	2,2	0,3	11,3	3,2	1,1	0,1	4,5
Lille-Frigg	1,6	3,5		5,1	0,5	1,7		2,2
Loke[2]		3,5	1,5	5,5		3,5	1,5	5,5
Murchison[4]	12,8	0,4	0,4	13,7	0,9	0,1	0,1	1,1
Oseberg	319,3	88,9	6,0	416,0	124,5	88,9	6,0	221,2
Oseberg Vest	1,8	7,5	0,2	9,6	0,7	7,5	0,2	8,5
Sleipner Vest[2]		129,4	33,7	173,2		129,4	33,2	172,6
Sleipner Øst[2]		41,5	27,3	77,0		23,9	16,7	45,6
Snorre[5]	169,1	5,0	2,3	177,1	127,9	3,1	0,9	132,2
Statfjord[6]	535,0	53,9	15,1	608,5	86,2	19,9	5,5	113,3
Statfjord Nord	40,9	2,5	0,5	44,1	35,0	2,1	0,4	37,6
Statfjord Øst	29,8	3,6	0,7	34,3	22,6	3,2	0,6	26,6
Tommeliten Gamma	3,8	9,2	0,5	13,7	0,1	0,5	0,0	0,6
Tor	25,5	11,4	1,2	38,5	5,4	1,0	0,1	6,6
Tordis	28,9	2,3	0,7	32,1	18,7	1,6	0,5	20,9
Troll I (Troll Øst)	19,9	834,9		854,8	19,4	829,5		849,0
Troll II (Troll Oil)	94,0	19,9	0,4	114,4	76,9	19,8	0,4	97,2
Ula	69,2	3,6	2,6	76,2	14,7	0,1	0,4	15,3
Valhall	115,4	32,1	4,8	153,7	68,6	22,6	3,0	95,1
Veslefrikk	54,4	2,6	1,0	58,3	27,2	1,4	0,1	28,7
Vest Ekofisk	12,1	26,9	1,4	40,8	0,0	1,2	0,0	1,3
Yme	8,7			8,7	7,5			7,5
Øst Frigg		9,5		9,5		0,4	0,0	0,3
Sum	2466,8	1721,0	129,0	4355,5	1007,3	1268,1	81,4	2381,2
Norwegian Sea:								
Draugen	94,5			94,5	75,1			75,1
Heidrun	155,0	13,2		168,2	141,8	13,2		155,0
Sum	249,5	13,2		262,7	216,9	13,2		230,1
Total	**2716,3**	**1734,2**	**129,0**	**4618,2**	**1224,2**	**1281,3**	**81,4**	**2611,3**

The estimates comprise all resources that are approved for development (resource class 1-2) for the individual fields. Resources that can be produced following measures for improved recovery and additional resources are included in table 7.5.d.

[1] Norwegian share only: 60,82%

[2] The combined production from Sleipner Øst and Loke is measured as one. The production is subtracted from Sleipner Øst.

[3] The combined production from Gyda and Gyda Sør is measured as one. The production is subtracted from Gyda.

[4] Norwegian share only: 22,2%

[5] See comments on reserve estimate on Snorre in chapter 1.4.24.

[6] Norwegian share only: 85,46869%

Table 7.5.c
Petroleum reserves in fields with approved development plan

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3
North Sea:				
Balder	27,2	0,8		28,0
Gullfaks Sør	20,7	2,1		22,8
Gullveig	2,1			2,1
Oseberg Øst	23,5	1,4		24,9
Rimfaks	18,9			18,9
Tordis Øst	5,6	0,4	0,1	6,1
Varg	10,7			10,7
Vigdis	33,9	2,4		36,3
Visund	48,5			48,5
Sum	191,1	7,1	0,1	198,3
Norwegian Sea:				
Njord	37,5			37,5
Norne	72,4			72,4
Åsgard	132,3	191,0	24,0	354,5
Sum	242,2	191,0	24,0	464,4
Total	**433,3**	**198,1**	**24,1**	**662,7**

The estimates comprise all resources that are approved for development (resource class 2) for the individual fields. Resources that can be produced following measures for improved recovery and additional resources are included in table 7.5.d. Changes following the Norwegian Petroleum Directorates new resource classification system are described in chapter 1.1.

Table 7.5.d
Resources that can be produced following measures for improved recovery and additional resources in fields

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3
Class 3	248,4	136,6	5,6	392,3
Class 4	68,3	148,8	19,3	242,2
Class 5	25,0	23,2	0,8	49,2
Class 6	4,2	0,9		5,1
Sum classes 3-6 in fields	**345,9**	**309,5**	**25,7**	**688,8**

Table 7.5.e
Petroleum resources in discoveries in late planning phase

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3
North Sea:				
2/12-1 Mjølner	3,5	0,6		4,1
15/9-19 SR	6,1	1,0		7,1
25/7-3	2,0			2,0
25/8-5 S	20,7			20,7
25/8-8 S	8,0			8,0
25/11-15 Hermod[1)]	84,5			84,5
30/2-1 Huldra	7,9	22,3		30,2
30/9-3 Omega Nord	16,8	9,7		26,5
30/9-5 S	1,5	0,4		1,9
30/9-6	2,9	0,7		3,6
30/9-9	1,4	0,4		1,8

	Oil 10^6 Sm³	Gas 10^9 Sm³	NGL 10^6 tonn	O.E. 10^6 Sm³
30/9-10 Omega Sør	16,0	2,0		18,0
30/9-13 S	9,9	9,2		19,1
30/9-16 K	4,1	1,4		5,5
33/9-19 S*	11,0	0,8		11,8
34/7-21	10,2	1,3		11,5
34/7-23 S	3,6	0,4		4,0
34/7-25 S*	7,1	0,7		7,8
34/11-1	20,0	50,0		70,0
35/11-4 R Fram	26,6	19,9		46,5
Sum	263,8	120,9		384,7
Norwegian Sea:				
6406/2-1 Lavrans	26,0	84,0	11,0	124,3
6406/3-2 Trestakk	4,8			4,8
6407/1-2 Tyrihans	16,0	25,0	6,0	48,8
Sum	46,8	109,0	17,0	177,9
Total	**310,6**	**229,9**	**17,4**	**562,6**

The estimates comprise the total resources booked in resource classes 3-6 for the individual discoveries.
* Discoveries in 1996
[1] See comments on resource estimates for 25/11-15 Hermod i chapter 1.5.3.

Table 7.5.f
Petroleum resources in discoveries in early planning phase

	Oil 10^6 Sm³	Gas 10^9 Sm³	NGL 10^6 tonn	O.E. 10^6 Sm³
North Sea:				
1/3-3	4,3			4,3
2/4-17 Tjalve	1,2	2,2	0,2	3,6
15/5-1 Dagny		5,9	1,3	7,6
15/5-2		2,9	0,1	3,0
15/5-5	11,4			11,4
15/9-20 S		0,2		0,2
25/5-5	1,7			1,7
30/7-2	1,5	0,4		1,9
30/8-1 S		20,0		20,0
35/9-1 R Gjøa	13,6	26,4		40,0
Sum	33,7	58,0	1,6	93,7
Norwegian Sea:				
6507/8-4 Heidrun Nord	3,4	0,5		3,9
Sum	3,4	0,5		3,9
Total ex. Troll III	37,1	58,5	1,6	97,6
Troll III (Troll Vest Gas)	9,3	379,0		388,3
Total	**46,4**	**437,5**	**1,6**	**485,9**

The estimates comprise the total resources booked in resource classes 4-6 for the individual discoveries.

Table 7.5.g
Petroleum resources in discoveries that may be developed in the long term

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3
North Sea:				
1/2-1	0,1			0,1
1/3-6	1,5	0,9	0,1	2,5
1/5-2 Flyndre	5,1	1,6		6,7
1/9-1 Tommeliten Alpha	3,2	3,5	0,3	7,1
2/2-1	0,4	1,1		1,5
2/2-5	0,9			0,9
2/5-3 Sørøst Tor	0,9	0,3		1,2
2/7-22		0,6		0,6
2/7-29	3,0			3,0
3/7-4 Trym		2,9	0,5	3,6
6/3-1 PI	0,8	0,4		1,2
15/3-1 S	4,0	14,6	1,8	20,9
15/3-4	2,2	1,1		3,3
15/8-1 Alpha		4,1	1,3	5,8
15/12-8			1,0	1,3
16/7-2	0,5	1,8	0,3	2,7
16/7-4	0,9	8,0	0,5	9,6
18/10-1	1,2			1,2
24/6-1 Peik	3,0	9,1		12,1
24/9-3	3,0			3,0
24/9-5	0,7			0,7
24/9-6	3,1			3,1
24/12-3 S*	5,0			5,0
25/2-5 Lille Frøy	1,5	1,6	0,2	3,4
25/4-6 S Vale	3,5	4,0		7,5
25/5-3 Skirne		5,1	0,4	5,6
25/5-4 Byggve		3,9	0,5	4,6
25/6-1	1,2			1,2
30/7-6 R Hild	13,1	33,4		46,5
30/9-4 S	1,3	0,9		2,2
30/9-15	0,5	0,4		0,9
34/4-5	2,0			2,0
34/7-18	1,7			1,7
34/10-23 Gamma	6,0	69,0		75,0
35/3-2 Agat		43,0		43,0
35/8-1	1,9	13,5		15,4
35/8-2	2,6	7,0		9,6
35/11-2	1,5	4,9	2,6	9,8
Sum	77,6	236,6	9,5	326,6
Norwegian Sea:				
6407/6-3 Mikkel		17,1	3,4	21,5
6407/8-2	0,4	1,4		1,8
6506/11-2 Lange	7,9	4,6		12,5

* Discoveries in 1996

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3
The Barents Sea:				
7120/7-1 Askeladd Vest		10,0		10,0
7120/7-2 Askeladd Sentral		8,0		8,0
7120/8-1 Askeladd		40,0		40,0
7120/9-1 Albatross		39,1	1,6	41,2
7120/12-2		10,7		10,7
7120/12-3		4,1		4,1
7121/4-1 Snøhvit	6,7	78,0	9,2	96,7
7121/4-2 Snøhvit Nord		3,5		3,5
7121/5-2 Beta	3,0	0,5		3,5
7121/7-2 Albatross Sør		3,0		3,0
7122/6-1	3,2	5,7		8,9
7124/3-1		2,1		2,1
Sum	12,9	204,7	10,8	231,6
Total	**98,8**	**480,6**	**23,7**	**610,3**

Table 7.5.h
Petroleum resources in discoveries where development is very uncertain

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3
North Sea:				
1/3-1				
2/2-2		0,9		0,9
2/3-1				
2/4-10	2,4			2,4
2/4-11				
2/5-4				
2/5-7	2,9			2,9
2/7-2				
2/7-19 R	2,0			2,0
7/7-2	2,4	0,1		2,5
7/8-3	3,6	0,2		3,8
7/12-5	1,1			1,1
17/3-1				
17/12-1 Bream	1,0			1,0
17/12-2 Brisling	0,2			0,2
25/7-2	1,0	1,0		2,0
25/8-1				
29/3-1	0,6	1,0		1,6
30/6-14				
30/6-16				
30/6-17 R				
30/10-6		1,0		1,0
33/9-6				
34/8-7 R				
34/10-40 S		0,6		0,6
Sum	17,2	4,8		22,0

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3
Norwegian Sea:				
6201/11-1	1,0	0,3		1,3
6204/11-1		10,3	0,4	10,8
6407/4-1				
Sum	1,0	10,6	0,4	12,1
Barents Sea:				
7119/12-3		4,1		4,1
7128/4-1	0,9	0,1		1,0
7226/11-1	0,6	24,0		24,6
7316/5-1		1,2		1,2
Sum	1,5	29,4		30,9
Total	**19,7**	**44,8**	**0,4**	**65,0**

The resources estimates are very uncertain.

Table 7.5.i
Preliminary estimates for petroleum resources in discoveries not yet evaluated

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	O.E. 10^6 Sm^3
North Sea:				
2/6-5*	2,0			2,0
9/2-6 S*	2,0			2,0
15/12-10 S*	3,0			3,0
30/3-7 S	3,0			3,0
34/11-2 S*		9,0		9,0
35/10-2*		8,0		8,0
Total	**10,0**	**17,0**		**27,0**

* Discoveries in 1996

Table 7.5.j
Change in reserve/resource estimates, annual reports 1995-1996

	Annual report 1996			Annual report 1995			Changes 1995 to 1996		
	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL 10^6 tons
Fields in production									
Brage	46,6	1,4	0,5	46,2	1,9	0,8	0,4	-0,5	-0,3
Cod	2,9	7,4	0,5	2,9	7,4	0,5	0,0		0,0
Edda	4,9	2,1	0,2	4,9	2,1	0,2	0,0		
Ekofisk	404,0	150,4	15,2	404,0	157,4	15,0		-7,0	0,3
Eldfisk	81,3	58,7	4,6	79,2	58,3	4,7	2,1	0,4	-0,1
Embla	8,3	6,0	0,6	7,3	4,8	0,5	1,0	1,2	0,1
Frigg		111,9	0,4		111,5	0,4		0,4	
Frøy	11,0	2,3	0,2	15,8	3,2	0,2	-4,8	-0,9	0,0
Gullfaks	307,7	23,0	2,4	308,7	21,9	2,5	-1,0	1,1	-0,1
Gullfaks Vest	3,1			2,9	0,3		0,2	-0,3	
Gyda	30,0	3,7	1,6	30,6	3,9	1,7	-0,6	-0,2	-0,1
Gyda Sør	2,1	1,1	0,3	1,5	0,9	0,2	0,6	0,2	0,1
Heidrun	155,0	13,2		133,0	12,5		22,0	0,7	
Heimdal	6,6	40,5		6,8	40,6		-0,2	-0,1	
Hod	8,7	2,2	0,3	9,3	2,3	0,3	-0,6	0,0	
Lille-Frigg	1,6	3,5		1,7	4,2	0,0	-0,1	-0,7	0,0
Loke		3,5	1,5		3,4	1,4		0,1	0,1
Murchison	12,8	0,4	0,4	12,5	0,4	0,4	0,3		0,0
Oseberg	319,3	88,9	6,0	325,0	90,9		-5,7	-2,0	6,0
Oseberg Vest	1,8	7,5	0,2	2,0	7,5		-0,2		0,2

	Annual report 1996			Annual report 1995			Changes 1995 to 1996		
	Oil	Gas	NGL	Oil	Gas	NGL	Oil	Gas	NGL
	10^6 Sm³	10^9 Sm³	10^6 tons	10^6 Sm³	10^9 Sm³	10^6 tons	10^6 Sm³	10^9 Sm³	10^6 tons
Fields in production									
Oseberg Vest	1,8	7,5	0,2	2,0	7,5		-0,2		0,2
Sleipner Vest		129,4	33,7		126,9	33,7		2,5	
Sleipner Øst		41,5	27,3		41,0	26,0		0,5	1,3
Snorre	169,1	5,0	2,3	189,2	10,1	5,5	-20,1	-5,1	-3,2
Statfjord	535,0	53,9	15,1	538,0	57,0	15,0	-3,0	-3,1	0,1
Statfjord Nord	40,9	2,5	0,5	27,6	1,9	0,4	13,3	0,6	0,1
Statfjord Øst	29,8	3,6	0,7	24,7	3,0	0,7	5,1	0,6	
Tommeliten Gamma	3,8	9,2	0,5	3,8	9,5	0,6	0,0	-0,3	-0,1
Tor	25,5	11,4	1,2	25,0	11,3	1,2	0,5	0,1	
Tordis	28,9	2,3	0,7	29,6	2,0	0,7	-0,7	0,3	0,0
Troll I (Troll Øst)	19,9	834,9			825,0	20,0	19,9	9,9	-20,0
Troll II (Troll oil)	94,0	19,9	0,4	71,0	19,3		23,0	0,6	0,4
Ula	69,2	3,6	2,6	69,1	3,6	2,6	0,1		
Valhall	115,4	32,1	4,8	130,9	32,0	5,1	-15,5	0,1	-0,3
Veslefrikk	54,4	2,6	1,0	54,4	2,7	1,0		-0,1	
Vest Ekofisk	12,1	26,9	1,4	12,2	27,0	1,5	-0,1	-0,1	-0,1
Yme	8,7			10,5			-1,8		
Øst Frigg		9,5			9,3	0,1		0,2	-0,1
Fields with approved dev. plan									
Balder	27,2	0,8		39,3			-12,1	0,8	
Gullfaks Sør	20,7	2,1		20,1	62,5	17,8	0,6	-60,4	-17,8
Gullveig	2,1			2,1	0,7			-0,7	
Njord	37,5			37,5	14,0			-14,0	
Norne	72,4			76,2	15,6		-3,8	-15,6	
Oseberg Øst	23,5	1,4		19,0	1,0		4,5	0,4	
Rimfaks	18,9			20,3	17,0		-1,4	-17,0	
Tordis Øst	5,6	0,4	0,1	5,4	0,5	0,5	0,2	-0,1	-0,4
Varg	10,7			9,8			0,9		
Visund	48,5			48,4	56,4	2,1	0,1	-56,4	-2,1
Åsgard	132,3	191,0	24,0	77,0	232,0	34,3	55,3	-41,0	-10,3
Discoveries in late planning phase									
15/9-19 SR	6,1	1,0		4,8	0,8		1,3	0,2	
2/12-1 Mjølner	3,5	0,6		1,5	0,7		2,0	-0,1	
25/11-15 Hermod	84,5			60,0	0,9		24,5	-0,9	
25/8-5 S	20,7			24,0	5,0		-3,3	-5,0	
30/9-10 Omega Sør	16,0	2,0		12,5	1,8		3,5	0,3	
30/9-13 S	9,9	9,2		8,1	3,2		1,8	6,0	
30/9-16 K	4,1	1,4		3,8	1,2		0,3	0,2	
30/9-3 Omega Nord	16,8	9,7		14,2	10,7		2,6	-1,0	
30/9-5 S	1,5	0,4					1,5	0,4	
30/9-6	2,9	0,7		2,0	0,9		0,9	-0,2	
30/9-9	1,4	0,4		1,6	0,6		-0,2	-0,2	
34/11-1	20,0	50,0			45,0	14,3	20,0	5,0	-14,3
34/7-21	10,2	1,3		11,0			-0,8	1,3	
34/7-23 S	3,6	0,4		3,9			-0,3	0,4	
35/11-4 R Fram (incl. 35/11-7 and -8 S*)	26,6	19,9		18,0	12,6		8,6	7,3	
6406/3-2 Trestakk	4,8			4,8	1,2		0,0	-1,2	
6407/1-2 Tyrihans (Nord + Sør)	16,0	25,0	6,0	2,5	27,5	5,3	13,5	-2,5	0,7
Discoveries in early planning phase									
Troll III (Troll Vest gas)	9,3	379,0			407,0	11,0	9,3	-28,0	-11,0
1/3-3	4,3			1,2	0,3		3,1	-0,3	
2/4-17 Tjalve	1,2	2,2	0,2	0,9	2,4		0,3	-0,2	0,2
15/5-1 Dagny		5,9	1,3		5,8	2,0		0,1	-0,7
35/9-1 R Gjøa (incl. 36/7-1-discovery*)	13,6	26,4		5,0	11,5		8,6	14,9	
Discoveries that may be dev. in the long term									
1/2-1	0,1			2,9	0,4		-2,8	-0,4	
1/3-6	1,5	0,9	0,1	3,3	5,8		-1,8	-4,9	0,1
2/5-3 Sørøst Tor	0,9	0,3		0,8	0,3		0,1		

	Annual report 1996			Annual report 1995			Changes 1995 to 1996		
	Oil 10^6 Sm³	Gas 10^9 Sm³	NGL 10^6 tons	Oil 10^6 Sm³	Gas 10^9 Sm³	NGL 10^6 tons	Oil 10^6 Sm³	Gas 10^9 Sm³	NGL 10^6 tons
15/3-4	2,2	1,1		2,2	1,3		0,0	-0,2	
15/8-1 Alpha		4,1	1,3		4,1	0,9			0,5
16/7-2	0,5	1,8	0,3		1,8		0,5		0,3
16/7-4	0,9	8,0	0,5	1,4	8,0		-0,5		0,5
24/6-1 Peik	3,0	9,1			9,1	3,0	3,0		-3,0
24/9-6	3,1			4,0			-0,9		
25/2-5 Lille Frøy	1,5	1,6	0,2	1,2	1,5	0,3	0,3	0,1	-0,1
25/4-6 S Vale	3,5	4,0		3,4	2,5		0,1	1,5	
25/5-4 Byggve		3,9	0,5	0,6	3,1	0,0	-0,6	0,8	0,5
25/5-3 Skirne		5,1	0,4		5,2	0,4		-0,1	
25/6-1	1,2			2,0			-0,8		
30/7-6 R Hild	13,1	33,4		7,7	33,2		5,4	0,2	
30/9-15	0,5	0,4		2,8			-2,3	0,4	
30/9-4 S (incl. 30/9-7-discovery)	1,3	0,9		1,6	1,5		-0,3	-0,6	
6407/6-3 Mikkel		17,1	3,4	1,0	17,4	2,6	-1,0	-0,3	0,8
6506/11-2 Lange	7,9	4,6			2,0	3,4	7,9	2,6	-3,4
6507/2-2		7,7			6,8			0,9	
6507/3-1 Alve		8,5		2,9	10,5	1,0	-2,9	-2,0	-1,0
6507/8-4	3,4	0,5		3,2	1,8		0,2	-1,3	
7120/7-1 Askeladd Vest		10,0			15,1			-5,1	
7120/7-2 Askeladd sentral		8,0			10,4			-2,4	
7120/8-1 Askeladd		40,0			55,7			-15,7	
7120/9-1 Albatross		39,1	1,6		38,0			1,1	1,6
7121/4-1 Snøhvit	6,7	78,0	9,2	6,7	83,0	9,2	0,0	-5,0	0,0
7121/5-2 Beta	3,0	0,5		3,1	0,5		-0,1		
7121/7-2 Albatross Sør		3,0			5,8			-2,8	
7122/6-1	3,2	5,7		3,2	3,7			2,0	
Misc. adjustments									
Changes in the booking of resources on Troll							-74,0	-68,0	
Classes 3-6 on fields							345,9	309,5	25,7
Improved resource utilization in 1995							-267,0		
Minor adjustments in discoveries not mentioned in last year's annual report							-8,5	18,1	11,2
* New discoveries reported as part of other discoveries							-20,0	-14,0	
Total changes in fields and discoveries							**155,0**	**1,0**	**-36,0**

7.6 UNITS OF MEASUREMENT FOR OIL AND GAS

1 000	Sm³ gas equals:	1 Sm³ o.e.
1	Sm³ oil equals:	1 Sm³ o.e.
1	tonnes NGL equals:	1,3 Sm³ o.e.

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 (10^6 Sm³) and gas volumes in billion standard cubic meters (10^9 Sm³).

Conversion from volume units to oil equivalents for oil and gas volumes is used for the purpose of totaling 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 *Sm³ oil equivalents* (Sm³ o.e.). Consequently, when adding up or comparing oil and gas volumes we will use the conversion formula above.

Conversion from the NGL unit of weight to Sm³ 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 from tonnes NGL/condensate to Sm³ o.e. This is based on the quantity of energy in 1 tonne of an average NGL/condensate mixture from the Norwegian shelf being equal to the quantity of energy in 1.3 Sm³ of oil.

7.7 PRODUCTION OF OIL AND GAS

Production of oil and gas on the Norwegian continental shelf amounted to 222.1 million Sm^3 o.e. in 1996. Production in 1995 was 192.9 million Sm^3 o.e. Table 7.7.a and Figures 7.7.a and 7.7.b describe the production in greater detail. For the Statfjord, Frigg and Murchison fields, Table 7.7.a shows the Norwegian share of the production.

Figure 7.7.a
Oil and gas production on the Norwegian shelf 1971-1996

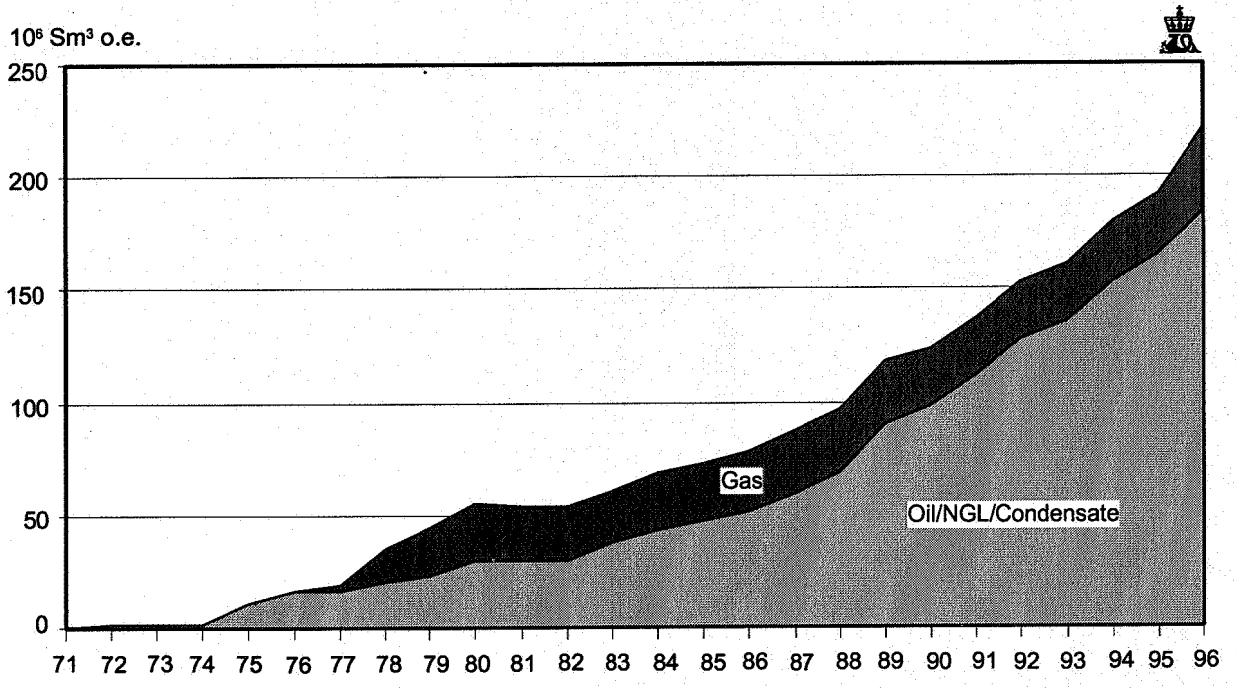


Table 7.7
Production in million Sm^3 oil equivalents

	PRODUCTION ⇨			CONSUMPTION ⇨		MARKETABLE PRODUCTS ⇨		
1996	**Oil**	**Gas**	**Cond.**	**Gas Flared**	**Gas Fuel**	**Oil/NGL**	**Gas/cond.**	**Total**
Brage	6,441	0,648		0,019	0,055	6,528	0,357	6,885
Draugen	8,444	0,457		0,013	0,044	8,444		8,444
Ekofisk area	17,513	9,460		0,011	0,943	17,203	7,568	24,771
Embla	1,061	0,383				1,045	0,355	1,400
Frigg area	1,899	1,906	0,557	0,010	0,034	2,060	1,921	3,981
Gullfaks	25,025	2,999		0,061	0,275	25,131	1,813	26,944
Gullfaks Vest	0,420	0,047				0,420		0,420
Gyda (incl. Gyda Sør)	4,051	1,089		0,002	0,038	3,354	0,608	3,962
Heidrun	12,190	1,421		0,038	0,105	12,263		12,263
Heimdal		4,673	0,731		0,059	0,635	4,569	5,204
Hod	0,590	0,129		0,001	0,010	0,582	0,120	0,702
Murchison	0,264	0,055		0,006	0,015	0,240	0,006	0,246
Oseberg	29,082	5,912		0,021	0,277	28,974		28,974
Oseberg Vest	0,159	0,310		0,001	0,005	0,154		0,154
Sleipner area		8,689	6,617	0,007	0,142	1,928	11,227	13,155
Snorre	11,440	1,207		0,030	0,079	11,873	0,660	12,533
Statfjord	21,609	7,131		0,090	0,420	22,487	3,426	25,913
Statfjord Nord	3,307	0,230				3,401	0,347	3,748

	PRODUCTION ⇨			CONSUMPTION ⇨		MARKETABLE PRODUCTS ⇨		
1996	Oil	Gas	Cond.	Gas Flared	Gas Fuel	Oil/NGL	Gas/cond.	Total
Statfjord Øst	3,356	0,478				3,419	0,233	3,652
Tommeliten Gamma	0,303	0,855				0,241	0,788	1,029
Tordis	4,504	0,455		0,007	0,033	4,626	0,381	5,007
Troll area	13,204	8,430	0,194	0,041	0,109	13,324	5,507	18,831
Ula	2,806	0,250		0,002	0,055	2,820	0,165	2,985
Valhall	4,241	0,553		0,006	0,070	4,187	0,880	5,067
Veslefrikk	4,092	0,553		0,007	0,051	4,230	0,447	4,677
Yme	1,283	0,059		0,053	0,000	1,195		1,195
Sum 1996	177,283	59,454	8,400	0,428	2,817	180,762	41,379	222,141
Sum 1995	158,235	47,192	6,975	0,409	2,640	161,682	31,192	192,874
Sum 1994	147,674	45,392	4,588	0,364	2,630	150,775	29,492	180,267
Sum 1993	133,770	41,576	1,280	0,340	2,544	135,241	25,562	160,803
Sum 1992	125,936	42,444	0,573	0,309	2,449	127,036	26,167	153,203
Sum 1991	110,513	39,717	0,563	0,356	2,257	111,547	25,302	136,849
Sum 1990	96,844	37,065	0,521	0,556	2,132	97,673	25,767	123,440
Sum 1989	88,266	39,320	0,547	0,474	2,013	89,038	29,010	118,048
Sum 1988	66,882	36,302	0,588	0,336	1,818	67,774	28,581	96,355
Sum 1987	58,538	34,499	0,577	0,434	1,443	59,524	28,399	87,923
Sum 1986	50,579	33,924	0,355	0,258	1,311	51,160	26,331	77,491
Sum 1985	47,339	34,102	0,030	0,304	1,190	46,665	26,259	72,924

Figure 7.7.b
Oil and gas production on the Norwegian shelf 1977-1996