Norwegian Petroleum Directorate

ANNUAL REPORT 1992

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Director General's Statement

1992 was another positive year for the offshore community on the Norwegian continental shelf. New discoveries were made which place the Norwegian shelf among the most attractive exploration provinces in the world. It is also with great satisfaction that we can state that no fatal injuries were incurred, nor were there any serious environmental accidents or major damage to material assets.

Drilling activity was heavier than ever before. No less than 129 wells were spudded, 86 of them development and 43 exploration wells. This is 18 more than in 1991, the former record year. The upswing is due to increased production drilling, the number of exploration wells declining slightly from 47 in 1991 to 43 in 1992.

Exploration also produced many encouraging results in 1992. The discovery rate remains high, and nine new discoveries were confirmed under test. Hydrocarbons were also proven in three other wells which had not been tested by year end. Almost all the discoveries were located in the North Sea, but the areas further north also provided new discoveries.

Among the particularly encouraging discoveries are the new oil discovery in the Snorre region, a new oil and gas discovery north of Troll (35/11), oil in block 7/7 in the southern North Sea, and the discovery of oil and gas in a new part of the Norwegian Sea.

Though it is not clear just how much petroleum resources these discoveries represent, provisional evaluations indicate that they are unlikely to make up for the amount depleted during the year.

With today's knowledge of discovered petroleum resources and assuming today's production levels are sustained, Norway has sufficient oil to produce for about another 20 years, and sufficient gas for about 100 years of gas production.

If the resources which one expects to discover in the course of time are added to the above figures, the production spans involved are about twice as long.

It is important to note that further exploration for oil and gas on the Norwegian continental shelf presupposes increasingly sound data quality. This realisation has already produced additional efforts to gather seismic data, and most seismics nowadays are three-dimensional in order to tackle the added geological complexity of the exploration process.

In the course of the year the Directorate considered the plans for development and operation (PDO) for the following fields: Frøy, Troll phase 2, Sleipner Vest, Heimdal Jura, and Mime. The plans for construction and operation (PCO) of Frostpipe and Zeepipe phase 2A were also considered.

So as to be in a position to review future field developments in a larger context, the Directorate has prepared area studies for the northern and southern North Sea. These studies also aim to secure the optimal utilisation of existing infrastructure.

At the beginning of the year the Directorate launched a programme of methodical regulations development in the resource management field. This work, called the MR project, continues similar regulatory development in the safety and working environment field and is being conducted jointly with the Ministry of Industry and Energy. This project aims to provide an efficient and manageable means of drafting and structuring the general conditions for the offshore industry.

Another issue which was central in the Directorate's work in 1992 was the distribution of gas sales volumes from the various source fields. The Directorate presented its recommendations to the Ministry in connection with the allocation of the 30 per cent option in the Troll gas sales agreement and the Electrabel contract in Belgium.

During the year the Directorate undertook calculations of Norway's total petroleum capital. Apart from providing a picture of the long-term development trends on the Norwegian continental shelf, the calculations are also relied on for the Government's long-range programme and the carbon dioxide emission prognoses.

The State's Direct Economic Engagement (SDØE) in the offshore activities is now very considerable. In 1992, the Directorate undertook a study designed to elucidate the exposure of this involvement and outline alternative solutions for the future.

Oil and gas production in 1992 was up 10 per cent compared to 1991. According to the data reported by the oil companies in 1992, the estimated reserves have increased by about 180 million standard cubic metres of oil. The increase is largely the result of improved understanding of the reservoir conditions and the improvement of technology capable of enhancing the recovery factor, for example by deploying horizontal and long-range wells.

The steadfast efforts by the companies and the authorities over the past decade to develop methods and technologies to enhance recovery seem now to be paying dividends. However, enormous potential still remains.

The Directorate's own estimate of the technical potential of enhanced recovery is 600 million cubic metres. The Directorate's long-range objective is to increase the expected production from fields already producing or approved for development by 400 million cubic metres by year 2000, compared to the 1991 estimated reserves.

In order to achieve this target, close cooperation between the industry and the government authorities is essential, both in terms of routine operation and in terms of forward-looking plans embracing research and development.

A research programme known as RUTH (reservoir exploitation using advanced technology) was initiated in 1992 with the principal purpose of facilitating enhanced recovery from Norwegian offshore fields. We are very pleased with the great interest evidenced by the oil companies in this project through their desire to participate. So far, this has resulted in very productive relations between the Royal Norwegian Council for Scientific and Industrial Research (NTNF), the Directorate, and the companies. The Directorate has been appointed leader and administrative coordinator for the programme.

Petroleum activities on the Norwegian continental shelf have produced huge volumes of data in the almost 30 years they have been going on. Most of this has been furnished to the Directorate in the form of reports, status reports, background material submitted with licence applications, magnetic tapes, and geological samples. In 1992, the Directorate recognised in practice the substantial value that good management of this material represents and established a special Data Management Department in the Resource Management Division. The mandate of this new department is to increase the efficiency and quality of technical work done inhouse and facilitate and place on offer useful information held by the Directorate for the benefit of external research and commercial establishments within the oil companies and engineering consultants.

The Directorate reached a milestone in its regulatory work with the completion of the new set of safety regulations issued under the Petroleum Act. The Directorate has thus acquired a modern and serviceable tool with which to conduct its supervisory activities. The reactions of the affected parties show that the new regulations meet the industry's requirement for a consistent set of rules which endorse the principles underlying the supervisory arrangement in the petroleum activities. The task of drafting similar rules for application of the Working Environment Act to offshore activities has already started. In this work too, the Directorate will encourage active participation by the parties affected.

Supervision of the manner in which operators address their responsibilities in the safety and working environment sphere was largely conducted according to plan. One central principle in the planning of supervision is that the accumulated fund of experience with each company is used to guide our priorities, enabling us to focus our scrutiny where it is most needed. In addition supervisory activities towards the same field of activity in different operating companies have been performed, which makes the exchange of experience between them possible, at the same time as it enables the Directorate to compare operators with each other on a meaningful basis.

The general conclusion one can draw from our supervisory activities is that the activities are generally carried out in conformity with sound safety and working environment principles. Nonetheless, many inadequacies in control systems intended to ensure the companies' systematic conformance with rules and regulations were identified. The supervisory arrangement established for the petroleum industry is built on the assumption that such systems are in place and working properly. It is in the interests of both the industry and the supervisory authority that these systems work and evolve. In addition to pure supervision, the Directorate has therefore made a great point of getting information about the supervisory arrangement and the regulatory principles out to the users.

It is essential that the industry is thoroughly familiar with the requirements embodied in the Working Environment Act regarding employee codetermination in the challenges facing us in the future.

The challenges associated with operation and maintenance of offshore installations have continued to increase in scope and complexity. The greatest challenge so far is the Ekofisk field centre, and to ensure that potential problems do not develop into real problems the Directorate ordered the licensees to identify the problem areas and immediately take steps to secure sound operation. The Directorate further ordered the licensees to develop a plan for a long-term solution which addresses the issues of safe and lasting processing and transportation. The continued subsidence of the field only heightens the challenge.

Concern for the external environment is one of the Directorate's spheres of responsibility which is largely addressed by preventive measures and action to contain or stop acute pollution. These are integral aspects of the regulatory work, Directorate supervision, and other duties. In 1992, the Directorate reviewed its own activities particularly directed at protection against environmental damages. These include supervision of company planning and execution of measures to meet environmental requirements, evaluation of corporate environmental expertise in connection with licence award, and reviews of the effects of the various environmental measures. The Directorate also advises the Ministry of Local Government and Labour and the Ministry of Industry and Energy in their involvement with the industry to reduce operational discharges of hazardous substances into water and the atmosphere, and implements the requisite measures.

PETRAD, the International Programme for Petroleum Management and Administration, completed its three-year pilot period at the beginning of the year. This programme was performed by the Directorate on behalf of NORAD, the Norwegian Directorate for Development Cooperation, and in cooperation with the affected institutions and individuals in Norway and abroad. A working party headed by the Ministry of Foreign Affairs and the heads of Norad and the Directorate found that the programme had justified its existence and should be extended. They recommend that Norad and the Directorate establish a foundation as soon as possible in order to assist developing countries and countries in Eastern Europe and the former Soviet Union with the work of strengthening petroleum management and administration by competence-building initiatives.

On 14 June 1972, the Norwegian Parliament, Stortinget, resolved to establish the Norwegian Petroleum Directorate. In the 20 years that have passed, the importance of a strong and independent Petroleum Directorate has been demonstrated many times. Throughout these years the organisational structure and professional expertise of the Norwegian Petroleum Directorate have been enhanced to the stage where the Directorate now stands forth as a petroleum administrator of high competence and high integrity.

Stavanger, 10.3.1993

Fredrik Hagemann

Fredrik Hagemann
Director General

1. Duties and Administration

1.1 TERMS OF REFERENCE
The objectives and duties of the Norwegian Petroleum Directorate are given in special instructions, as last amended on 1 October 1992. Furthermore, the Directorate has been assigned duties by delegations. Delegations ensue directly from acts/regulations or from separate decisions of delegation from superior authority. The delegations apply to parts of:

a) *Petroleum Act*, of 23 March 1985 no. 11, embracing
   - *Petroleum Regulations*, by Royal Decree of 14 June 1985
   - *Safety Regulations*, by Royal Decree of 28 June 1985
   - *Internal Control Regulations*, by Royal Decree of 28 June 1985
   - *Safety Zone Regulations*, by Royal Decree of 9 October 1987
   - *Anchoring and Fishing Prohibition Regulations*, by Royal Decree for each specific field (see 1993 compendium of Acts, Regulations and Provisions for the petroleum activity)

b) *Working Environment Act*, of 4 February 1977 no. 4, embracing
   - *Working Environment Regulations*, by Royal Decree of 27 November 1992
   - (See also WER section 5 with comments)

c) *Carbon Dioxide Tax Act*, of 21 December 1990, no. 72

d) *Tobacco Injuries Act*, of 9 March 1973, no. 14, embracing
   - *Tobacco Injuries Regulations*, by Royal Decree of 8 July 1988

e) *Svalbard Act*, of 17 July 1925, no. 11, embracing
   - Regulations for *Safe Practices* for Exploration and Exploration Drilling for Petroleum Deposits on Svalbard etc, by Royal Decree of 25 March 1988

f) Act relating to *Scientific Research* for, Exploration for and Exploitation of Subsea Natural Resources Other than Petroleum Resources, of 21 June 1963 no. 12, embracing
   - Regulations for *Scientific Research* for Natural Resources on the Norwegian Continental Shelf etc, by Royal Decree of 31 January 1969
   - Regulations for the *Government Action Control Group* in the event of Pollution Accidents etc, by Royal Decree of 19 November 1982

g) Provisional Regulations for *Littering and Pollution* caused by Petroleum Activities on the Norwegian Continental Shelf, by Royal Decree of 26 October 1979.

1.2 OBJECTIVE
The overall objective of the Norwegian Petroleum Directorate is to promote the sound management of the Norwegian petroleum resources having a balanced regard for the safety, environmental, technological and economic aspects of the petroleum activity in the context of society as a whole.

1.3 DIRECTORS AND ADMINISTRATION
1.3.1 Board of Directors
By Royal Decree of 3 April 1992 it was resolved to abolish the Board of Directors of the Norwegian Petroleum Directorate as of 15 April 1992, the day on which the tenure of the directors was due to expire. The functions of the directors have now been assumed by the Director General.

1.3.2 Organisation
The changes announced in the Resource Management Division from 1 January 1992 were effected from that date. The new Data Management Department was established with the transfer of geophysical and well data archives from their former home in the Administration Department.

The Exploration Department sections were divided by geographical region into the Exploration Section Southern area, Exploration Section Northern area. The former Production Evaluation Section and Production Geology Section were combined into a single Production Evaluation Section.

The former Planning Department was wound up and a new Planning Coordinator function and Project Director post were established in the Resource Director's staff.

1.3.3 Staff
At the end of the period the Directorate had 339 authorised positions. Three more positions are funded by NORAD, the Norwegian Directorate for Development Cooperation. No new positions were authorised in 1992. At year end there were 350 members of staff in service and 14 on leave.

In the year the Directorate took on 25 new members of staff in permanent positions, of whom six come from oil-related activities, five from the public sector, eight from private enterprise, and six of whom were newly qualified.

Staff leaving were 23 in number, representing 6.8 per cent of the total authorised positions.

The Directorate is bound by a specific agreement on equality and has its own Equal Opportunity Committee on which representatives of both sides sit. Each year an Equal Opportunity Action Plan is drawn up. In 1992, much of the Committee's work was devoted to ensuring that equality issues are addressed and visualised in the Directorate's internal governing documents.

1.3.4 Budget and economy

The Directorate employed Nkr 231,881,331 for its various duties in 1992.

The amount was appropriated as follows:

– Operating budget	Nkr 173,393,111
– Supervision costs	8,552,850
– Geological and geophysical surveys	43,485,108
– Projects conc safety and working environment	6,450,262
Total	231,881,331

Of the operating budget, payroll costs account for Nkr 109,315,663; lease and operation of buildings Nkr 6,807,530. The remainder, Nkr 50,593,470, covers costs of consultants, operation of a weather ship, external assistance, travel, training, computer systems operation, new investments in equipment, etc.

The Directorate was required to carry out the following specific task:

– Clearance of seabed	Nkr 4,503,062

Revenues

In addition to production royalties, area fees and carbon dioxide tax totalling Nkr 10,661,119,397, the Directorate received Nkr 92,428,212 from various other sources of revenue as follows:

– Sale of publications	Nkr 4,575,924
– Sale of released test material	2,611,617
– Exploration fees	1,800,000â
– Reimbursed inspection outlays	33,488,224
– Sale of seismic survey results	37,002,192
– Credit interest, bank	7,745,553
– Miscellaneous	13,782
– Reimbursed for unemployment schemes	368,848
– Reimbursed from other agencies	4,822,072
Total	92,428,212

1.3.5 Information

During the report period great interest was shown in the Directorate's information services on the part of Norwegian and foreign institutions, the media, companies and individuals. One confirmation of this is the visits by foreign media representatives, individually or in groups, in order to familiarise themselves with the Directorate and the petroleum activity. For their part, Directorate staff have been energetic as visiting lecturers in various forums.

The *Norwegian Petroleum Directorate Annual Report* plays a central role in the Directorate's information activities. The 1991 Annual Report was presented to the press in April.

The Directorate's internal newspaper *Oss Direkte* was published in four issues in 1992, as planned.

There were 67 press releases issued in 1992, the majority in connection with the completion of exploration wells.

1.3.6 Document and data records management

Requirement specifications have been prepared for new software for the archives and library system; and work to procure the new systems has commenced. An Office Manual has been prepared and issued to all staff which is intended to simplify and streamline the production of documents and their storage, retrieval and distribution. At the same time increased utilisation of existing software and equipment for office support is anticipated.

Improvements have been made to the remote archives making it easier for users to access the materials contained therein and simplifying the process of document submission to the National Archives.

Again in 1992, assistance was furnished to Namibia for the development of archival functions in Namcor. Suitable PC based solutions were developed and put in place and standard user instructions were prepared.

Library utilisation expanded significantly in 1992 and the number of enquiries exceeded all previous periods. Much work was done to secure all the standards referred to in the Directorate's compilation of *Acts, Regulations and Provisions* for the petroleum activity. Fairly late in the year the library was able to introduce CD-ROM storage systems and one hopes to build on the present collection of reference works and Norwegian and international standards based on this medium.

The online use of the Oil, Infoil and Sesame data bases by Norwegian users was much increased due to active marketing. The two latter bases are also accessible via the German Scientific and Technical Network (STN) host system in Karlsruhe. Online access via the National Computing Centre was discontinued at year end, this service being offered now in a CD-ROM version, or online via Karlsruhe.

1.3.7 Internal control and working environment audit

The Directorate has established an internal control system to look after requirements ensuing from the Working Environment Act.

This internal control is described in a separate document which, with other documentation, forms the basis for implementation of the Directorate's internal quality audits. The Directorate conducted two such audits in 1992 based on the *Internal Control Regulations* of 22 March 1991, which entered into force 1 January 1992.

2. Resource Management on the Norwegian shelf

2.1 INTRODUCTION

The objective of the Norwegian Petroleum Directorate is to contribute actively to the sound management of the petroleum resources on the Norwegian continental shelf. The objective can only be achieved if the Directorate at all times has a general overview of the petroleum resources and evaluates alternative ways for proper exploration, development and recovery of these resources. Such an overview and evaluations underlie our advisory function vis-a-vis the central authorities with respect to prudent management of the petroleum resources.

The formal basis for the Directorate's resources management duties is as follows:

- Act of 22 March 1985 no. 11 pertaining to *Petroleum Activities* (Petroleum Act)
- Act of 21 December 1990 no. 72 relating to *Carbon Dioxide Tax* in the Petroleum Activities
- Act of 21 June 1963 no. 12 relating to *Scientific Research* and Exploration for and Exploitation of Subsea Natural Resources Other than Petroleum Resources.

The resources management activity on the Norwegian continental shelf was again high in 1992, within exploration, development, and operation. The resources division was reorganised in 1992 to increase efficiency. The background for this move was the perceived demands regarding the requirements of the Ministry of Industry and Energy, technological trends on the continental shelf, and the needs of the industry in the final decade of the century. One chose to retain the structure of phase-specific departments for exploration, development and operation. This ensures efficient, product-oriented handling vis-a-vis the Ministry and the industry. However, changes were made in the section structure within the phase departments in order to achieve professional synergies. It was decided to close the planning department and establish a new department for resource data management, the idea being to enhance the efficiency of the resource division's overall work involving databases and to prepare resource data and information in a systematic and coordinated manner for the Directorate's inhouse users, the industry, and other external clients.

Furthermore, two staff positions were established for the resources director: one planning coordinator and one project director.

2.2 DEVELOPMENT OF REGULATIONS

At the end of 1991 and beginning of 1992, the Directorate was involved in methodic development of rules and regulations in the field of resources management (the MR project). This project is a continuation of corresponding development of rules and regulations in the field safety and the working environment, see chapter 3, and is carried out in collaboration with the Ministry of Industry and Energy.

The object of the project is to efficiently and purposefully consider development and structuring of the framework conditions governing the petroleum activity, by, among other things:

- ensuring controlled and combined development of rules and regulations in the field of resources management, including evaluating the potential for simplification of the rules and regulations,
- considering the potential for simplifying, systematising and unifying management practice in certain areas,
- contributing to a greater opportunity for systematic and consistent use of means for public control so as to allow the industry a sufficient degree of predictability,
- clarifying interfaces between the Directorate and other administrative bodies.

The project is divided into the following four phases:

1. Clarification of framework conditions, including available documentation of circumstances which may be significant for the authorities' function in the field of resources management and further clarification of potential for improvement
2. Development of necessary strategies in order to further develop future rules and regulations
3. Preparation of an overall plan for changes in the framework conditions
4. Plan implementation.

2.2.1 Status of resources management project

The clarification phase in the Directorate was completed with a partial report in autumn 1992. Based on this work, clarification in the then Ministry of Petroleum and Energy, now the Ministry of Industry and Energy, was initiated in autumn 1992. These clarification duties are expected to be finalised in the first quarter of 1993.

As part of phase 2 of the project, various research work has been initiated internally in the Directorate on the basis of the findings. Further project progress will be implemented in cooperation with the Ministry.

The plan is that the implementation of the regulations development project in the field of resources management will take place with industry input.

The possibility of using and developing the Directorate's internal database for rules and regulations, REGAL, in the field of resources management is being considered.

2.3 EXPLORATION AND PRODUCTION LICENCES

2.3.1 New exploration licences

As of 31 December 1992, 201 commercial exploration licences had been granted. Each licence is valid for three years.

The following licences were awarded in 1992:

Company	Licence no.
Enterprise Oil Norwegian A/S	194
Den norske stats oljeselskap a.s	195
Phillips Petroleum Company Norway	196
Elf Petroleum Norge A/S	197
Simon-Robertson	198
Halliburton Geophysical Service Int. Ltd	199
BP Norway Limited U.A	200
Total Norge A.S	201

2.3.2 Scientific exploration licences

As of 31 December 1992, a total of 296 licences had been granted for scientific exploration on the Norwegian continental shelf. As Table 2.3.2 shows, eleven such licences were granted in 1992, all of them issued by the Directorate in Stavanger.

2.3.3 New production licences

Effective 11 September, parts of blocks 31/9 and 32/4 were allocated in production licence 085B. This allocation falls outside any normal licensing round and is considered to be supplemental acreage to the Troll field.

Table 2.3.3.a shows production licences awarded in 1992.

Table 2.3.3.b shows production licences and acreages, Table 2.3.3.c licensing rounds, and Figure 2.3.3 exploration wells drilled in each licensing round.

Table 2.3.2
Permits for scientific exploration for natural resources

Permit	Institution	Subject Geophysics	Geology	Biology	Area
260/92	Institut für Meereskunde Universität Hamburg Germany	X	X	X	Norwegian Sea Barents Sea Greenland Sea
261/92	Institut für Meereskunde Universität Hamburg Germany	X	X		Norwegian Sea Greenland Sea
262/92	Universitetet i Tromsø	X	X		Coast of Finnmark and south-western Barents Sea
263/92	Norsk Polarinstitutt		X		Areas in Barents Sea and around Svalbard
264/92	Universitetet i Bergen	X			Vøring Basin with adjacent areas
265/92	Universitetet i Tromsø	X	X		Fjord areas in Troms
266/92	Universitetet i Tromsø	X	X		Fjord areas in south Troms, Tana fjord, Finnmark
267/92	Institut für Meereskunde an der Universität Kiel Germany			X	Vøring Plateau Lofot Basin
268/92	Universitetet i Tromsø	X	X		Fjord areas in Troms
269/92	Universitetet i Tromsø	X	X		Western Barents Sea and north-eastern Norwegian Sea
270/92	Universitetet i Tromsø	X	X		Fjord areas in Troms

Table 2.3.3.a
Allocation: Production license 085B

License no.	Field/block	Share	Licensee
085B	31/9, 32/4	2.000	Elf Petroleum Norge A/S
		9.000	Norsk Hydro Produksjon a.s (operator)
		6.000	Saga Petroleum a.s. (operator)
		82.000	Den norske stats oljeselskap a.s (operator)
		1.000	Total Norge A.S

Table 2.3.3.b
Production licenses and acreages as of 31.12.1992

Lic. round	Allocated	Prod. lic. no.	No. of blocks* allo-cated	re-linquished	Area allocated km²	Area relinquished km²	Area in license km²
1.	01.09.65	001-021	74	58	39842.476	35946.840	3895.636
	07.12.65	022	4	4	2263.565	2263.565	0.000
	12.09.77	019	2		617.891	0.000	617.891
2.	23.05.69	023-031	9	1	4107.833	2233.346	1874.487
	30.05.69	032-033	2		746.285	376.906	369.379
	14.11.69	034-035	2		1024.529	564.837	459.692
	11.06.71	036	1		523.937	262.047	261.890
plus	10.08.73	037	2		586.834	295.157	291.677
3.	01.04.75	038-040 and 042	7	5	1840.547	1389.780	450.767
	01.06.75	041	1	1	488.659	488.659	0.000
	06.08.76	043	2		604.558	555.553	49.005
	27.08.76	044	1		193.076	90.417	102.659
	03.12.76	045-046	4	2	1270.682	814.708	455.974
	07.01.77	047	2	1	368.363	304.160	64.203
	18.02.77	048	2	1	321.500	107.019	214.481
	23.12.77	049	1	1	485.802	485.802	0.000
plus	16.06.78	050	1		500.509	151.962	348.547
4.	06.04.79	051-058	8	2	4007.887	2434.633	1573.254
5.	18.01.80	059-061	3	2	1108.078	998.675	109.403
	27.03.81	062-064	3	1	1099.522	867.542	231.981
	23.04.82	073-078	6	2	2311.912	1751.343	560.569
6.	21.08.81	065-07	9	3	3218.945	2149.358	1069.587
plus	20.08.82	079	1		102.167	102.167	
7.	10.12.82	080-084	5	5	2082.966	2082.966	0.000
ur.	08.07.83	085	3		1521.160	725.816	795.344
plus	11.09.92	085B	2		27.166	27.166	
8.	09.03.84	086-100	17	2	6338.273	2947.470	3389.803
9.	01.03.85	101-111	13		5293.054	2620.534	2672.520
plus	26.07.85	112	1		260.215	129.958	130.257
10a	23.08.85	113-120	9	2	3075.433	1985.871	1089.562
10b	28.02.86	121-128	9	3	3828.258	1489.782	2338.476
plus	11.07.86	129	1		225.393	119.417	105.976
11.	10.04.87	130-137	11	4	4163.711	1521.799	2641.912
	29.05.87	138-142	11	4	2975.807	1188.588	1787.219
12a	08.07.88	143-153	16		4701.021		4701.019
12b	09.03.89	154-162	13	2	5031.262	602.952	4428.310
13	01.03.91	163-184	36		12076.88		12076.889
plus	13.09.91	185	1		25.535		25.535
			295	107	119261.720	69948.534	49313.186

* whole and partial blocks plus = allocations made outside licensing rounds

2.3.4 Transfer of interests
In the course of 1992, the following transfers of interests were approved in accordance with Section 61 of the Petroleum Act, no. 11 of 22 March 1985:

Elf Petroleum Norge A/S has taken over the interests of Sunningdale Oil Norge A/S in production licence 036, which also includes the Heimdal field. The transfer was made effective from 1 January 1989.

Table 2.3.3.c
Licensing rounds. Norwegian and foreign shares as of 31.12.1992

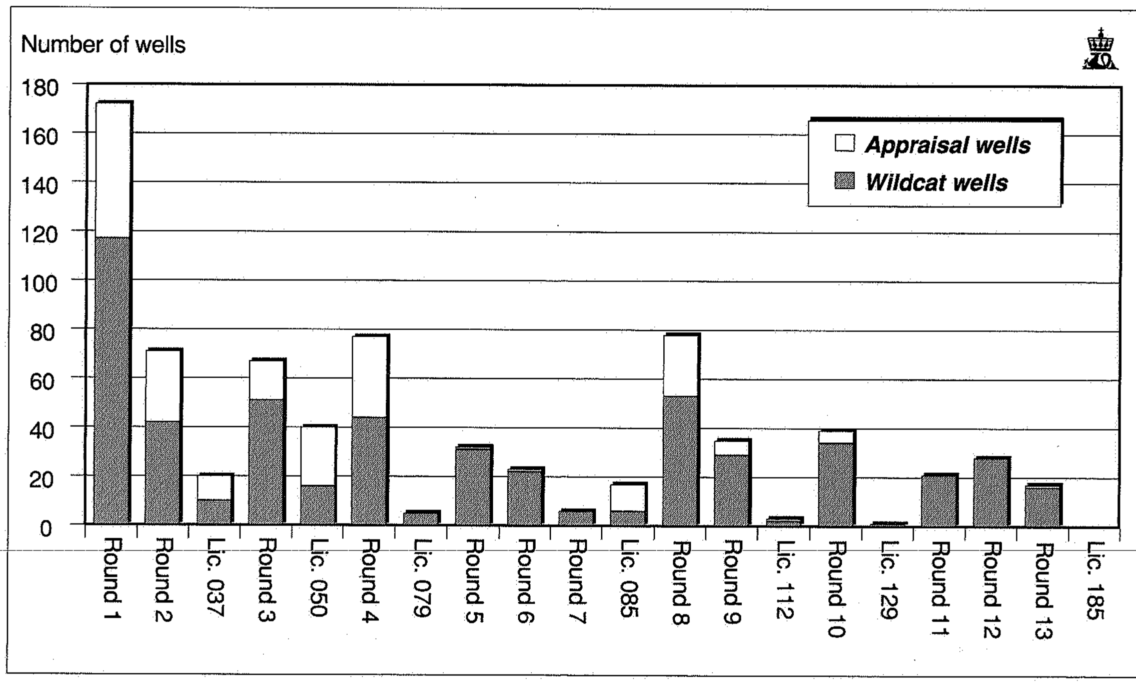
Licensing round	Year	Number of blocks	Share % Norwegian	Share % foreign	Operator % Norwegian	Operator % foreign
1	1965	78	8	91	0	100
2	1969-1971	14	15	85	0	100
Statfjord	1973	2	52	48	0	100
3	1974-1978	22	58	42	63	37
Ula (19B)	1977	2	50	50	0	100
Gullfaks	1978	1	100	0	100	0
4	1979	8	58	42	68	32
5	1980-1982	12	66	34	92	8
6	1981	9	64	36	50	50
Prod. lic. 079	1982	1	100	0	100	0
7	1982	5	60	40	80	20
Prod. lic. 085	1983	3	100	0	100	0
Prod. lic. 085B	1992	2	97	3	100	0
8	1984	17	60	40	60	40
9	1985	13	43	57	62	38
Prod. lic. 112	1985	1	67	33	0	100
10A	1985	9	64	36	67	33
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	3	100	0

Production licence 036
Operator: Elf Petroleum Norge A/S

Elf Petroleum Norge A/S has taken over 7.381 per cent from Sunningdale Oil Norge A/S. The distribution in the production licence after this is as follows:

Elf Petroleum Norge A/S	33.702 %
Norsk Hydro Produksjon a.s	6.920 %
Marathon Petroleum Norge A/S	46.904 %
Saga Petroleum a.s	6.611 %
Total Norge A/S	5.541 %
Ugland Construction Company A/S	0.322 %

Fig. 2.3.3
Exploration wells drilled in each licensing round



Production licence 036 (Heimdal)
Operator: Elf Petroleum Norge A/S

Elf Petroleum Norge A/S has taken over 3.875 per cent from Sunningdale Oil Norge A/S. The distribution in the production licence after this is as follows:

Elf Petroleum Norge A/S	21.514 %
Norsk Hydro Produksjon a.s	6.228 %
Marathon Petroleum Norge A/S	23.798 %
Saga Petroleum a.s	3.471 %
Den norske stats oljeselskap a.s	40.000 %
Total Norge A/S	4.821 %
Ugland Construction Company A/S	0.169 %

The company Norwegian Oil Consortium A/S & Co (NOCO A/S & Co) was dissolved effective 25 February 1992 and struck off the records of the Registrar of Companies on the same date. All of the company's rights were taken over by Elf Petroleum Norge A/S from the same day. The change affects shares in three production licences.

Production licence 006
Operator: Amoco Norway Oil Company

Elf Petroleum Norge A/S has taken over 15.00 per cent from NOCO A/S & Co. The distribution in the production licence after this is as follows:

Amerada Hess Norge A/S	28.333 %
Amoco Norway Oil Company	28.333 %
Elf Petroleum Norge A/S	15.000 %
Enterprise Oil Norwegian A/S	28.333 %

Production licence 032
Operator: Amoco Norway Oil Company

Elf Petroleum Norge A/S has taken over 15.00 per cent from NOCO A/S & Co. The distribution in the production licence after this is as fo follows:

Amerada Hess Norge A/S	25.000 %
Amoco Norway Oil Company	25.000 %
Elf Petroleum Norge A/S	15.000 %
Enterprise Oil Norwegian A/S	25.000 %
Svenska Petroleum Exploration A/S	10.000 %

Production licence 033
Operator: Amoco Norway Oil Company

Elf Petroleum Norge A/S has taken over 25.00 per cent from NOCO A/S & Co. The distribution in the production licence after this is as follows:

Amerada Hess Norge A/S	25.000 %
Amoco Norway Oil Company	25.000 %
Elf Petroleum Norge A/S	25.000 %
Enterprise Oil Norwegian A/S	25.000 %

Production licence 101
Operator: Norsk Agip A/S

Effective from 1 March 1992, Norsk Agip A/S has taken over Norske Fina A/S's share in the production licence. The distribution in the production licence after this is as follows:

Norsk Agip A/S	45.000 %
Deminex (Norge) A/S	5.000 %
Den norske stats oljeselskap a.s	50.000 %

Production licence 008
Operator: Elf Petroleum Norge A/S

Effective 26 March 1992, Total Norge A/S has taken over a share of 11.284 per cent from Norsk Hydro Produksjon a.s. The distribution in the production licence after this is as follows:

Norsk Agip A/S	5.220 %
Elf Petroleum Norge A/S	32.376 %
Elf Rep Norge A/S	1.824 %
Elf Rex Norge A/S	2.712 %
Norsk Hydro Produksjon a.s	12.400 %
Norminol A/S	1.216 %
Phillips Petroleum Company Norway	14.780 %
Den norske stats oljeselskap a.s	2.000 %
Total Norge A.S	27.472 %

A merger of the company Elf Rep Norge A/S with Elf Rex Norge A/S, formally completed on 15 July 1992, led to changes in four production licences.

Production licence 008
Operator: Elf Petroleum Norge A/S
The distribution in the production licence after this is as follows:

Norsk Agip A/S	5.220 %
Elf Petroleum Norge A/S	32.376 %
Elf Rex Norge A/S	4.536 %
Norsk Hydro Produksjon a.s	12.400 %
Norminol A/S	1.216 %
Phillips Petroleum Company Norway	14.780 %
Den norske stats oljeselskap a.s	2.000 %
Total Norge A.S	27.472 %

Production licence 009
Operator: Elf Petroleum Norge A/S

The distribution in the production licence after this is as follows:

Norsk Agip A/S	5.220 %
Elf Petroleum Norge A/S	32.376 %
Elf Rex Norge A/S	3.420 %
Norsk Hydro Produksjon a.s	26.800 %
Norminol A/S	1.216 %
Phillips Petroleum Company Norway	14.780 %
Total Norge A.S	16.188 %

Production licence 016
Operator: Phillips Petroleum Company Norway

The distribution in the production licence after this is as follows:

Norsk Agip A/S	13.040 %
Elf Petroleum Norge A/S	8.094 %
Elf Rex Norge A/S	0.885 %
Norske Fina A/S	30.000 %
Norsk Hydro Produksjon a.s	6.700 %
Norminol A/S	0.304 %
Phillips Petroleum Company Norway	36.960 %
Total Norge A.S	4.047 %

Production licence 018
Operator: Phillips Petroleum Company Norway

The distribution in the production licence after this is as follows:

Norsk Agip A/S	13.040 %
Elf Petroleum Norge A/S	7.594 %
Elf Rex Norge A/S	0.885 %
Norske Fina A/S	30.000 %
Norsk Hydro Produksjon a.s	6.700 %
Norminol A/S	0.304 %
Phillips Petroleum Company Norway	36.960 %
Den norske stats oljeselskap a.s	1.000 %
Total Norge A.S	3.547 %

Production licence 024
Operator: Elf Petroleum Norge A/S

Effective 20 August 1992, Elf Petroleum Norge A/S transferred a 15.000 per cent share to Den norske stats oljeselskap a.s. The distribution in the production licence after this is as follows:

Elf Petroleum Norge A/S	26.420 %
Norsk Hydro Produksjon a.s	32.870 %
Den norske stats oljeselskap a.s	20.000 %
Total Norge A/S	20.710 %

2.3.5 Relinquishments and surrenders
Relinquishment or surrender of acreage occurred in 16 production licences in 1992. In four cases the entire area was relinquished. See Table 2.3.5 for details. The originally allocated and present acreages are shown in Figure 2.3.5.

2.4 SURVEYING AND EXPLORATION DRILLING

2.4.1 Geophysical and geological surveys

Some 390,796 kilometres of seismics were shot on the Norwegian continental shelf in 1992. The number of kilometres refers to the total «line kilometres». This means there was an increase in seismic activity compared to the record year 1991. Figure 2.4.1.a shows the development in recent years with respect to the number of line kilometres.

2.4.1.1 Directorate's geophysical surveys
The Directorate commissioned 6668 kilometres of seismic lines in 1992, see Figure 2.4.1.1.a. Data were collected from the areas indicated in Figures 2.4.1.1.b and c.

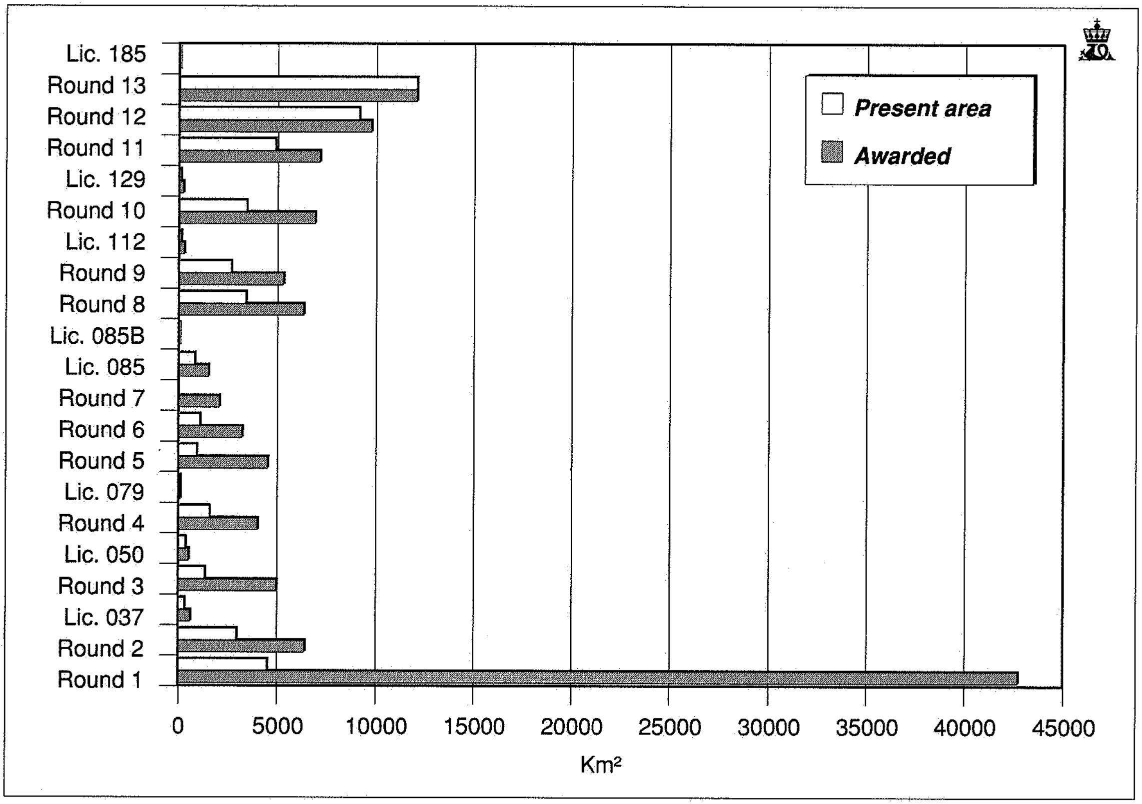
Norwegian Sea
A total of 3455 kilometres of seismics were shot in the Vøring basin II and the Møre basin. Also this year the data were compiled using the vessel *Master Odin*. Due to the great water depth and sediment thickness a relatively long cable (3600 metres) and deep registration (10 seconds) were used. Parts of the programme had to be reduced as a result of heavy fishing activity in the area. Also this year the data will be processed by Ensign and Digicon.

Nordland 2
Approximately 30 kilometres of test line was surveyed in an area where there were many problems in

Table 2.3.5
Relinquishments

Prod. lic.	Operator	Block	Original area km^2	Relinquished area km^2	Area in license km^2
065	Elf	1/3	365.661	182.973	182.688
068	Hydro	2/8, 11	219.314	219.314	0.000
078	Hydro	7120/9	331.606	261.165	70.441
088	Total	24/6, 25/4	401.128	304.077	97.051
101	Agip	16/10	546.986	312.160	234.826
108	Shell	7120/1	323.030	162.409	160.621
109	Hydro	7120/2, 3	646.061	354.279	291.782
114	Statoil	9/2	550.790	405.489	145.301
116	Statoil	15/12	188.465	94.707	93.758
117	Saga	25/6	523.937	415.417	108.520
121	Mobil	6407/5	444.465	221.907	222.558
123	Saga	6507/6	428.120	428.120	0.000
126	Saga	6607/5	411.636	411.636	0.000
129	Hydro	25/1	225.393	119.417	105.976
131	Elf	6406/8	448.529	448.529	0.000
133	Conoco	6408/4	444.465	444.465	0.000

Fig. 2.3.5
Allocated and present areas in each licensing round



the data. The line was shot three times using different compilation configurations:

- Two parallel cables, about 2400 metres long and 100 metres apart horizontally at a depth of ten metres
- One long cable of 4800 metres at a depth of ten metres
- One long sloping cable of 4800 metres at a depth of 6-60 metres.

The data were compiled by Geco-Prakla's vessel *Akademik Shatskiy*, while processing was performed by Ensign.

Barents Sea
The Directorate compiled 3124 kilometres of seismics in the northern Barents Sea using *Akademik Shatskiy*, with 1703 kilometres on Nordflaket and 1421 kilometres on Spitsbergen bank. Two cables with a horizontal separation of approximately 100 metres were used, in addition to a 500 metre long mini-cable at a depth of 2-4 metres for shallow data. The data are being processed by Geco-Prakla in Stavanger, Harstad and Holwood.

Processing
The Directorate has concluded the processing of the data compiled in the course of 1991. Some reconditioning of older data has also been performed. This applies especially to data in connection with the sale of data packages from the northern Barents Sea.

Gravimetric and magnetic data
Gravimetric and magnetic data are often compiled in connection with seismic surveys, though only in the Norwegian Sea.

Integrated gravimetric and magnetic maps have been produced by Amarok a.s in Oslo. These maps are available to companies which have purchased the Directorate's data packages in the area.

The gravimetric maps for the Barents Sea are corrected as new data come in. The 1992 data are being processed by Amarok a.s.

2.4.1.2 Opening of new exploration areas
The Vøring basin II and Møre basin have been prepared to be opened up for seismic surveys, see Figure 2.4.1.2. The Directorate has thus completed its compilation of seismic data in the Norwegian Sea.

In 1992, the Directorate offered two new regional data packages for sale from the northern Barents

Fig. 2.4.1.a
Seismic surveys on the Norwegian continental shelf 1962–1992

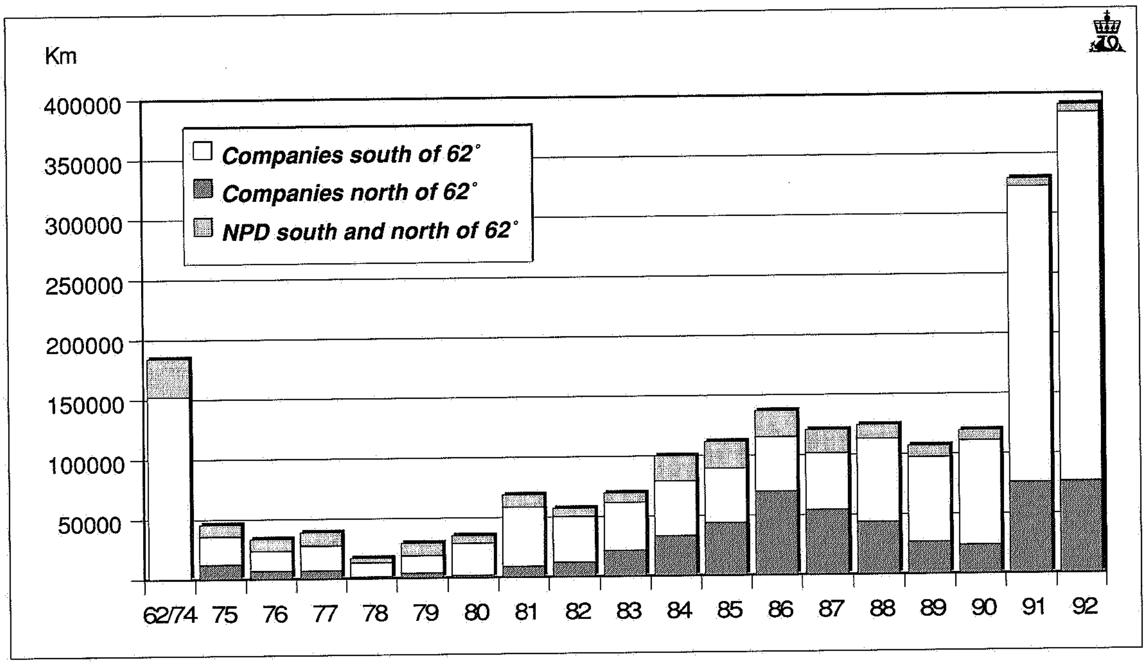


Fig. 2.4.1.1.a
Seismic surveys conducted by the Norwegian Petroleum Directorate

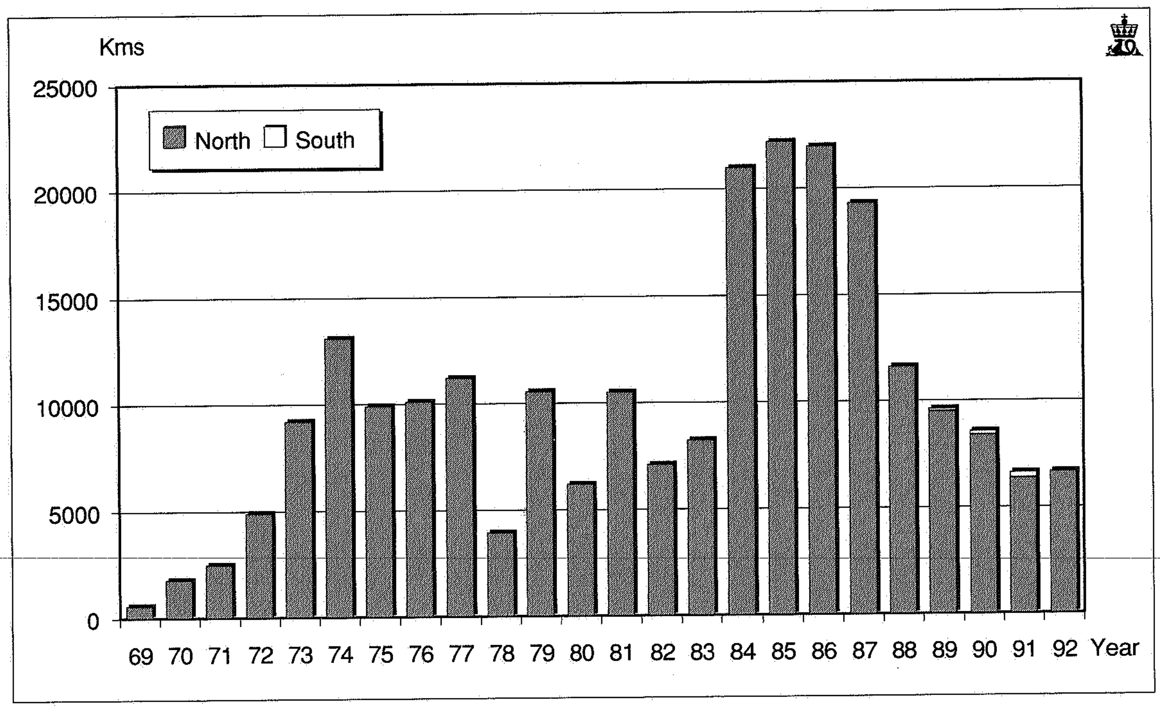


Fig. 2.4.1.1.b
Geophysical surveys in the Norwegian Sea

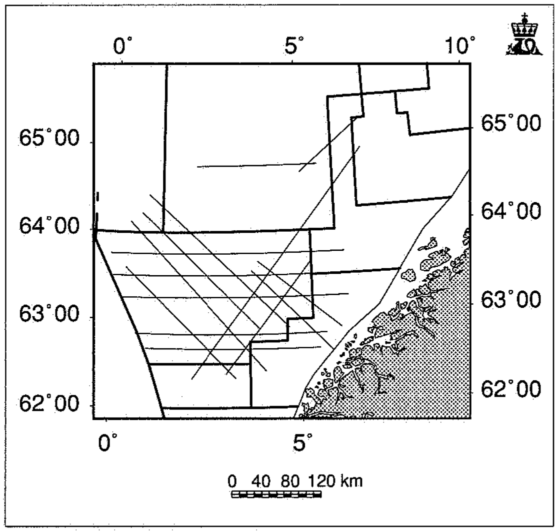
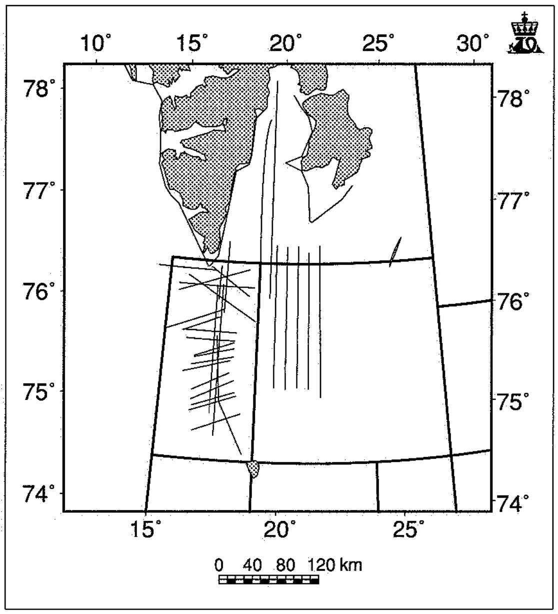


Fig. 2.4.1.1.c
Geophysical surveys in the Barents Sea



Sea. However, this area has not been opened up for seismic surveys by the companies.

2.4.1.3 Companies' geophysical surveys
In 1992, some 384,128 kilometres of seismics were shot on the Norwegian continental shelf under the direction of the oil companies and seismic survey operators. Of the total, 328,470 kilometres are three-dimensional surveys. All told, some 307,904 kilometres were taken in the North Sea and 76,224 kilometres in the Norwegian Sea and the Barents Sea. As the figures show, the activity level increased by some 60,000 kilometres compared to 1991. The activity in the Norwegian Sea and the Barents Sea maintained the same level as in 1991. Norwegian oil companies shot some 208,069 kilometres of seismics, which is an increase of 100,367 kilometres from the year before. Foreign companies shot 128,301 kilometres, or 33,092 kilometres less than in 1991. A total of 47,754 kilometres of commercial seismics were shot by Geco, Geoteam, HGS, and Nopec, which is a decrease of 5,085 kilometres compared to the previous year.

2.4.1.4 Sale of seismic data
In 1992, the Directorate recorded income from the sale of seismic data packages amounting to Nkr 37.0 million (compare Nkr 50.6 million in 1991). See Table 2.4.1.4.

Companies having purchased all of the Directorate's seismic data packages for the individual regions are listed below:

Møre Sør
Agip, Amerada, Amoco, BP, Britoil, Conoco, Deminex, DNO, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Occidental, Pelican, Petrobras, Phillips, Saga, Shell, Statoil, and Total.

Møre I
Agip, Amerada, Amoco, BP, Britoil, Conoco, Deminex, DNO, Elf, Enterprise, Esso, Fina, Hydro, Idemitsu, Mobil, Neste, Occidental, Pelican, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Total, and Unocal.

Trøndelag I
Agip, Amerada, Amoco, BP, Britoil, Conoco, Deminex, DNO, Elf, Enterprise, Esso, Fina, Hydro, Idemitsu, Mobil, Neste, Occidental, Pelican, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Total, and Unocal.

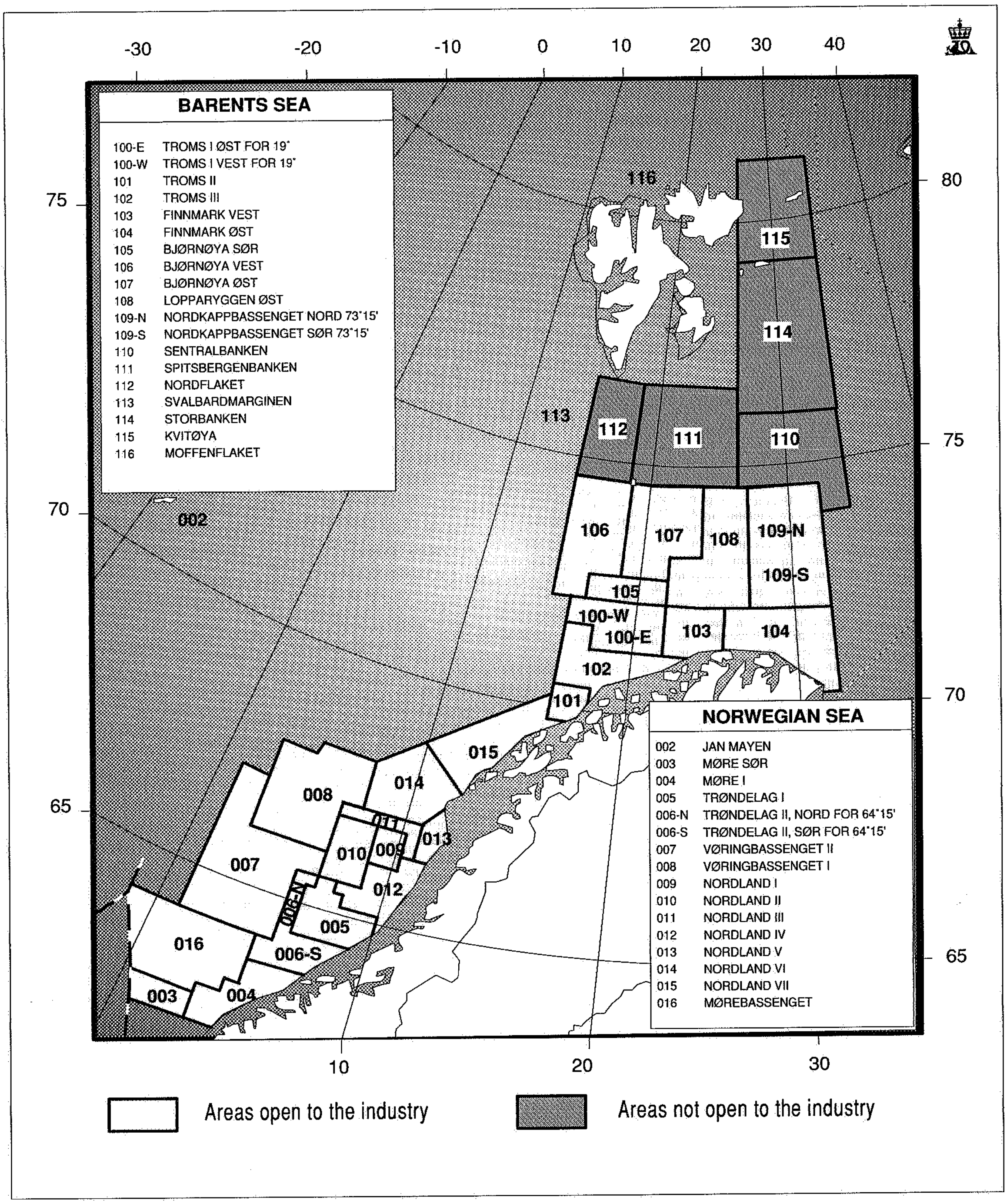
Trøndelag II, north of 64°15'
Agip, Amoco, BP, Britoil, Conoco, Deminex, DNO, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, and Total.

Trøndelag II, south of 64°15'
Agip, Amerada, Amoco, BP, Britoil, Conoco, Deminex, DNO, Elf, Enterprise, Esso, Fina, Hydro, Idemitsu, Mobil, Neste, Occidental, Pelican, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Total, and Unocal.

Vøring basin I
BP, Hydro, Phillips, Saga, Statoil, and Total.

Nordland I
Agip, Amerada, Amoco, BP, Britoil, Chevron, Conoco, Deminex, Elf, Enterprise, Esso, Fina, Getty, Gulf, Hispanoil, Hydro, Japan Oil, Mobil, Neste,

Fig. 2.4.1.2
Area status for seismic acquisition in the Norwegian Sea and in the Barents Sea



Phillips, Saga, Shell, Statoil, Superior, Svenska Petroleum, Tenneco, Texaco, Total, Unocal, and ØMV.

Nordland II
Agip, Amerada, Amoco, BP, Britoil, Conoco, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Total, and Unocal.

Nordland III
Agip, Amerada, Amoco, BP, Conoco, Elf, Enterprise, Esso, Hydro, Mobil, Saga, Shell, Statoil, and Total.

Nordland IV
Agip, BP, Elf, Esso, Hydro, Mobil, Phillips, Saga, Shell, Statoil, and Total.

Nordland V
BP, Conoco, Elf, Hydro, Mobil, Phillips, Saga, Shell, Statoil, and Total.

Nordland VI
Amoco, BP, Conoco, Elf, Enterprise, Esso, Hydro, Mobil, Saga, Shell, Statoil, and Total.

Nordland VII
Amoco, BP, Conoco, Elf, Enterprise, Esso, Hydro, Mobil, Saga, Shell, Statoil, and Total.

Troms I, east of 19°E
Agip, Amerada, Amoco, BP, Conoco, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Phillips, Saga, Shell, Statoil, and Total.

Troms I, west of 19°E
Agip, Amerada, BP, Conoco, Elf, Enterprise, Esso, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Tenneco, and Total.

Troms II
Agip, Conoco, Elf, Enterprise, Esso, Hydro, Mobil, Phillips, Saga, Shell, Statoil, and Total.

Troms III
Agip, Amerada, BP, Conoco, Elf, Enterprise, Esso, Fina, Hydro, Idemitsu, Mobil, Neste, Phillips, Saga, Shell, Statoil, and Total.

Finnmark Vest
Agip, Amerada, Amoco, BP, Conoco, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Phillips, Saga, Shell, Statoil, Tenneco, and Total.

Table 2.4.1.4
Survey of sold seismic data packages

Package		1992	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		23
007	FRØYABANKEN-84		27
008	MØRE-TRØNDELAG-PAKKE-2 #)		22
009	MØRE-TRØNDELAG-PAKKE-3 #)		28
010	TRÆNABANKEN		30
011	REG-DATA-NORDLAND-RYGGEN	1	22
012	NORDLAND-IV-85	2	11
013	REG-DATA-MIDT-N-SOKKEL	1	21
014	NORDLAND-II-83	1	23
015	NORDLAND-III-84	1	14
016	TROMS-II		12
017	REGIONAL-DATA-TROMS-ØST		18
018	FINNMARK-VEST-83		19
019	FINNMARK-VEST-84		20
020	NORDLAND-III-85	1	14
021	MØRE-SØR-TEST-84 #)		5
022	STOREGGA-85	1	6
023	VØRINGPLATÅET	1	12
024	VØRING-BASSENGET-85/86	2	11
025	LOFOTEN-VEST-86	2	12
026	JAN-MAYEN-85		1
028	VØRING-BASSENGET-87	2	11
029	NORDLAND-VI-87	1	12
030	NORDLAND-VII-87	1	12
031	NORDLAND-V-87	1	10
032	NORDLAND-VI-88	2	12
033	NORDLAND-VII-88	2	13
034	NORDLAND-V-73–79	1	10
035	NORDLAND-VI-73–79	1	12

Package		1992	Total
036	NORDLAND-VI-89	2	12
037	NORDLAND-VII-89	2	12
038	NORDLAND-VII-74/75	2	12
039	NORDSJØEN-SØR-TEST-89 #)		1
040	VØRING-BASSENGET-88	1	8
041	VØRING-BASSENGET-MERLIN-89	1	8
042	VØRING-BASSENGET-WESTERN-89	1	8
043	MØRE-BASSENGET-88	1	5
044	TYPEPROFILER-BARENTSHAVET #)		2
045	VØRINGBASSENGET-I-90	5	7
046	STOREGGA-90	1	2
047	VIKINGGRABEN-SØR-TEST-91 #)	1	1
048	VIKINGBANKEN-TEST-91 #)	3	3
100	TROMS-HOVEDPAKKE		35
101	REG-DATA-TROMS-BAR.HAVET-73		22
102	TROMS-III-83/84		17
103	TROMS-III-85		17
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
312	NORDKAPP-TEST-87 #)		1
400	BARENTSHAVET NORDVEST REGIONAL	1	1
500	BARENTSHAVET NORDØST REGIONAL	1	1

Finnmark Øst
Agip, Amerada, Amoco, BP, Conoco, Deminex, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Phillips, Saga, Shell, Statoil, and Total.

Bjørnøya Sør
Agip, Amerada, Amoco, BP, Britoil, Conoco, Deminex, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, and Total.

Bjørnøya Vest
Amoco, Conoco, Deminex, Elf, Enterprise, Hydro, Mobil, Saga, Shell, Statoil, and Total.

Bjørnøya Øst
Agip, Amoco, BP, Conoco, Deminex, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Saga, Shell, Statoil, Tenneco, and Total.

Lopparyggen Øst
Agip, Amerada, Amoco, BP, Conoco, Deminex, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Phillips, Saga, Shell, Statoil, Tenneco, and Total.

Nordkapp basin, north of 73°15' N
Agip, Amoco, BP, Conoco, Elf, Enterprise, Esso, Hydro, Mobil, Neste, Saga, Shell, Statoil, and Total.

Nordkapp basin, south of 73°15'N
Agip, Amerada, Amoco, BP, Conoco, Deminex, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Neste, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, and Total.

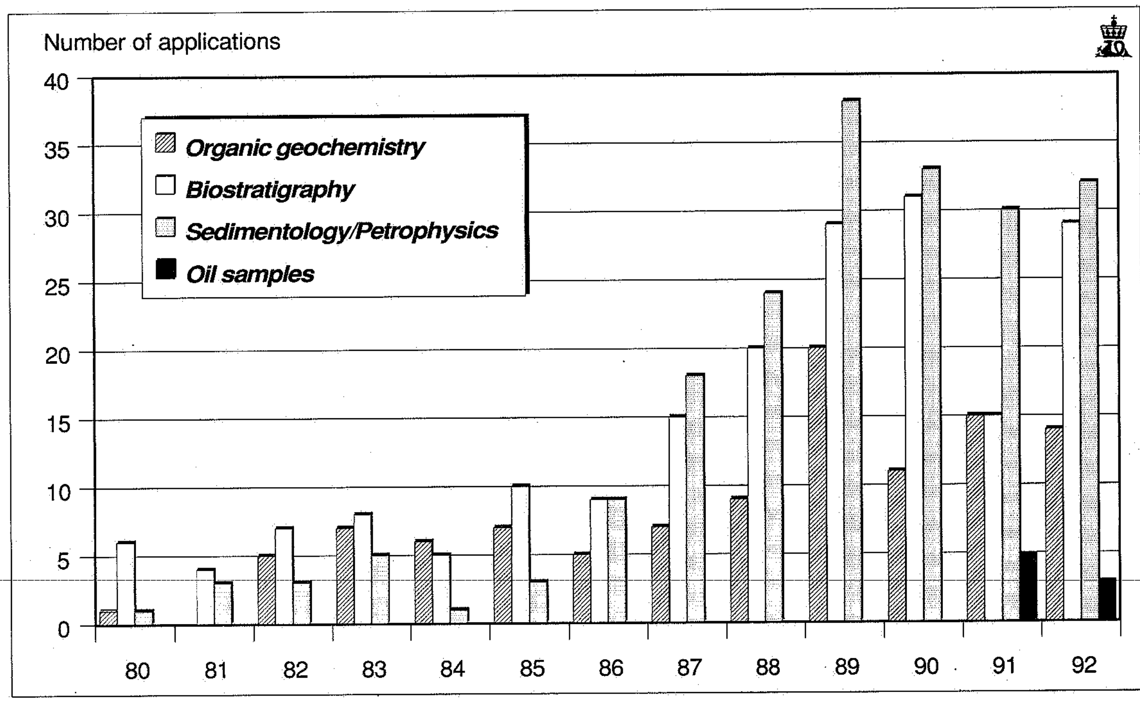
2.4.1.5 Release of data and material from the continental shelf
In connection with resources supervision of the petroleum activities offshore Norway, the Directorate is supplied with copies of borehole logs and continuous, representative samples of drill cuttings and cores. Cuttings samples are recovered every ten metres downhole and every three metres if the formation potentially contains hydrocarbons. For wet samples, which should weigh at least half a kilo, the same sampling frequency is observed. The Directorate receives a complete longitudinal section of core samples including minimum a quarter of cores in exploration wells and minimum half in production wells.

As of 31 December 1992, the Directorate had stocks totalling 77,175 metres of core material from 847 wells, 362,667 samples of washed cuttings from 975 wells, and 420,648 wet samples from 1188 wells. This includes material from foreign wells, mainly from the UK sector of the North Sea, but also including Svalbard, Andøya, Hopen, Tanzania, and Mozambique.

The Directorate is responsible for the publishing of data and release of material specimens for purposes of education and research. Data are released five years after well completion. The licensees' interpretations are not released.

The Directorate's *Well Data Summary Sheets* are issued once a year and provide a survey of wells five years old in the year of publication. In order to catch up with a backlog from 1991, two WDSS were published in 1992. The series aims to show which exploration wells have been released and what core and

Fig. 2.4.1.5
Applications for sample material by subject



log materials are available from the various wells. Some technical data and test results are also issued as well as a composite log with lithology specifications of each well to scale 1:4000.

In addition to its WDSS summaries, the Directorate issues two publication series: *Licences, Areas, Area Coordinates, Exploration Wells* and *Borehole List, Exploration Drilling*, which also provide information on released material. Both are published annually.

The list of production licences contains a summary of each production licence on the Norwegian continental shelf, stating licence number, allocation date, operator, allocated acreage, present acreage, partners and units, geographical coordinates for area, some data about wells drilled in the production licence, and a map of each licence area with the exploration wells plotted in. Also included are some historical details and tables presenting the drilling activity. The borehole list is an extended version of the Directorate's previous borehole list. Exploration wells are sorted according to five different criteria: well number, spudding date, completion date, operator, and production licence number. Information of this type is also available on diskette from the Directorate.

In the Directorate's core study room it is possible

Table 2.4.1.5 Released seismic data

No	Package name	Length (km)	Area	No	Package name	Length (km)	Area
1 A	NH-8007	BL. 7/11	231,328	46 A	G-81	BL. 35/8,9	519,484
2 A	SG-8048	BL. 7/11	689,619	47 A	GU-82	BL. 35/8	681,716
3 A	NH-8302	BL. 7/11	350,404	48 A	GU-81	BL. 35/8	376,311
4 A	NHCN-82	BL. 7/8,11	1400,587	49 A	ST-8313	BL. 34/10	276,587
5 A	SH-82	BL. 2/5	872,699	50 A	ST-8112	BL. 30/2,3	368,311
6 A	SG-8052	BL. 2/2	541,722	51 A	ST-8111	BL. 30/6,9	347,830
7 A	BP80-019	BL. 2/1,7/12	985,315	52 A	G-8101	BL. 35/8&9	848,026
8 A	EL-8180	BL. 2/6,2/9	1023,510	53 A	BP81–043	BL. 29/6,30/4	1375,896
9 A	ST-501	BL. 33/2	696,000	54 A	NH-8502–3D	BL. 30/9	22431,769
10 A	ST-502	BL. 33/3	1182,771	55 A	NS-79	SYD 62°N	3710,355
11 A	ST-503	BL. 33/5,6	1307,000	56 A	NS-78	SYD 62°N	4638,521
12 A	NH-754	BL. 33/5	174,000	57 A	PGE-82	BL. 2/7,10	700,213
13 A	NAG-80	BL. 33/6	498,000	58 A	NH-8201	BL. 2/8,11	1103,320
14 A	ANO-77	BL. 34/2	195,921	59 A	PGO-2/10–77	BL. 2/10	204,562
15 A	ANO-77–1	FELT 30,31	357,787	60 A	ANO-78–2	BL. 2/6,8&3/4	1540,000
16 A	ANO-77–2	BL. 24/6	9,000	61 A	ANO-78–3	VALHAL/HOD	363,927
17 A	ANO-79	BL. 34/2	923,155	62 A	ANO-79–1	BL. 2/5	90,834
18 A	ANO-80	BL. 34/2	72,566	63 A	PGE-80	BL. 2/4,7	716,189
19 A	SA-530	BL. 35/3	1229,439	64 A	PSL-84-2	BL. 2/7	235,360
20 A	SAG-78	BL. 35/3	186,660	65 A	ANO-83	VALHALL	393,692
21 A	SG-8130	BL. 35/3	783,153	66 A	ST-8421	BL. 2/9,12	592,346
22 A	GULF-79–2	BL. 35/8,9	1000,323	67 A	NS-76	SYD 62°N	3569,609
23 A	GULF-80–1	BL. 35/8	1396,503	68 A	ANO-80-1	BL. 2/5,8	199,091
24 A	ANO-74	BL. 36/1	1515,589	69 A	CSSC-78-4	BL. 2/2	93,062
25 A	SG-8252	BL. 2/2,3	1115,433	70 A	ST-404	BL. 1/9	454,590
26 A	PSL-84–1	BL. 8/10	562,258	71 A	EL-8201	BL. 3/7	592,000
27 A	ST-8007	FELT 31	395,000	72 A	SH-72	BL. 1/9	83,507
27 A	SH-8007	FELT 31,32	2495,000	73 A	EL-8186	BL. 1/3	1743,788
28 A	TO-8513	BL. 29/3	25,287	74 A	PG-2/7–73	BL. 2/7	115,142
29 A	TO-8510	BL. 29/3	261,665	75 A	EL-8083	BL. 3/7	124,002
30 A	SG-85	BL. 34/4	27,474	76 A	GULF-79	BL. 2/2,3	420,961
31 A	NH-8504	BL. 30/6	421,850	77 A	ST-809	BL. 1/9,2/7	28,406
32 A	MN-85	BL. 35/11	587,980	78 A	PGE-80-GE	BL. 2/4	25,995
33 A	NH-8502	BL. 30/9	1269,787	79 A	ST-8013–81	BL. 1/9	121,976
34 A	NH-8503	BL. 29/3,33/12	24,073	80 A	CSSC-78–2	BL. 2/2,3	62,829
35 A	NH-8202	FELT 31,32	2072,594	81 A	ANO-78–1	BL. 2/2,5	793,394
36 A	SG-8127	FELT 35,36	813,636	82 A	EL-980	BL. 2/6	356,736
37 A	SG-8133	BL. 34/11	350,377	83 A	PSL-84–3	BL. 2/4	440,268
38 A	SG-8425	BL. 31/2,3	275,184	84 A	EL-686	BL. 2/6	207,568
39 A	NH-8104	FELT 32,36	1921,288	85 A	PG-2/4–73	BL. 2/4	101,000
40 A	ST-8109	FELT 35,36	1318,896	86 A	ANO-76	BL. 2/4,5	251,148
41 A	81–007	FELT 31	339,599	87 A	ST-601	BL. 1/5	110,379
42 A	EL-8307	BL. 34/8	2372,612	87 A	ST-602	BL. 1/2	406,030
43 A	ST-8006	BL. 30/2,3,6	1948,741	87 A	ST-603	BL. 7/11	419,115
44 A	BP-85	BL. 16/8	423,043	88 A	N2–70	BL. 2/1	226,399
45 A	ST-8116	FELT 31,32	2194,671	89 A	SH-79–1	BL. 1/3,2/1	598,979

No	Package name	Length (km)	Area
90 A	PGE-79	BL. 2/4,5	120,029
91 A	A-79	BL. 1/6,2/4	344,734
92 A	ANO-80–2	BL. 3/4	117,580
93 A	SH-74–1	FELT 1	437,325
94 A	EL-8186–82	BL. 1/3	158,842
95 A	CSSC-78–3	BL. 3/4	52,681
96 A	CN2–73	BL. 2/1	639,479
97 A	CN2–76	BL. 2/1	430,723
98 A	SSL-7172	56–58°N	3274,995
99 A	CN2–77	BL. 2/2	357,822
100 A	SH-79–3	BL. 2/2	86,895
101 A	UN-80	BL. 2/2	153,508
102 A	C3–74	BL. 3/2	173,007
103 A	EL-8086	BL. 2/1,2,4,5	191,406
104 A	CN7–76	BL. 7/12	1124,482
105 A	C3–71	BL. 3/2	47,294
106 A	N7–71	BL. 7/9,12	202,283
107 A	MOB-79	FELT 10	177,163
108 A	CN7–73	BL. 7/12	478,447
109 A	PG-8/10–73	BL. 8/8,10,11	180,508
110 A	MOB-81–2	BL. 8/12	103,075
111 A	PW-8303	BL. 1/2	132,028
112 A	SH-72–5	BL. 3/5,8	54,340
113 A	A-80	ALBUSKJELL	76,730
114 A	ST-805	57–62°N	2682,502
115 A	NERC-83	FELT 8,9	135,554
116 A	ANO-81	HOD	248,398
117 A	EL-8084	BL. 1/3,7/	140,533
118 A	TO-8401	BL. 25/4,24/6	168,103
119 A	TO-8605	BL. 30/10	563,399
120 A	ST-8410	BL. 8/3	592,514
121 A	ST-8629	FELT 12	1033,074
122 A	SH-84–1	FELT 25–31	957,388
123 A	SG-8603	BL. 25/6	1406,246
124 A	NH-8603	BL. 25/1	338,168
125 A	EL-8603	BL. 25/2	139,030
126 A	BN16–86	BL. 15/6	331,105
127 A	ST-8516	BL. 31/11	570,020
128 A	ST-8502	BL. 15/12	505,055
129 A	SBP-85	BL. 26/4	565,747
130 A	NA-85	BL. 16/10	460,576
131 A	M85–16	BL. 15/2,3	20,000
132 A	EL-8504	BL. 25/4	962,803
133 A	EL-8503	BL. 25/2,5	1654,389
134 A	BP-85–1	BL. 34/8	293,181
135 A	PSL-84	BL. 16/11	612,945
136 A	ST-8315	BL. 16/10	699,141
137 A	SH-83–2	BL. 30/11	252,862
138 A	EL-8302	BL. 16/6	529,731
139 A	E-83	BL. 16/7	454,945
140 A	ST-8215	BL. 15/9	99,800
141 A	NH-8204	BL. 15/5	154,004
142 A	ST-8004	BL. 15/6,9,12	293,107
143 A	ST-8107-GE	FELT 17	2109,984
144 A	ST-8104	BL. 15/8	50,779
145 A	SH-81	BL. 30/11	577,033
146 A	P-1712–81	BL. 17/12	207,143
147 A	EL-8183	BL. 18/10	575,958
148 A	NH-8611	BL. 16/4	230,606
149 A	ST-8602	FELT 16,25,26	519,839
150 A	EL-8602	BL. 30/10	110,000

No	Package name	Length (km)	Area
151 A	TO-8506	BL. 24/6,25/4	265,000
152 A	BVI-85	BL. 15/2	302,479
153 A	NH-8408	BL. 16/10	477,000
154 A	EL-8303	BL. 25/4	559,219
155 A	ST-8202	FELT 26,27	259,170
156 A	ST-8201	FELT 26,27	5200,253
157 A	ST-8108	FELT 7	1566,000
158 A	SH-82–2	BL. 30/11	353,459
159 A	ST-8122	BL. 15/9,16/47	1020,340
160 A	E-82	BL. 16/7	308,573
161 A	EL-8206	BL. 15/3	1539,390
162 A	MOB-81–3	BL. 17/3,4,11	511,656
163 A	ST-8209	BL. 15/8	389,000
164 A	NH-8006	BL. 15/2	470,649
165 A	ST-8236	BL. 15/12	49,494
166 A	SH-82–1	BL. 31/2	69,438
167 A	CN-8525	BL. 25/7	1157,936
168 A	ST-508	BL. 15/5	289,799
169 A	NH-753	BL. 15/5	633,000
170 A	ST-8114	BL. 30/6,9	31,448
171 A	NH-8406	BL. 30/9	109,613
172 A	ST-507	BL. 15/2	245,119
173 A	EL-580	BL. 15/3	1120,380
174 A	ST-8107-WE	FELT 16,17	937,803
175 A	ST-8118	BL. 8/3	356,812
176 A	ST-8619	BL. 8/3	78,531
177 A	SH-74–2	BL. 17/11	450,270
178 A	PSE-78–1	BL. 17/12	381,374
179 A	SB-81	STORDBASIN	2314,596
180 A	CSSC-75–1	BL. 17/8,18/7	814,439
181 A	ST-8009	BL. 35/10,12	407,589
1 B	SH-84	BL. 6407/9	1238,985
2 B	CN-8502	HALTENBANKEN	1002,000
3 B	NH-8102	TRÆNABANKEN	4699,883
4 B	BP-83	HALTENBANKEN	923,962
5 B	SG-8158	BL. 6507/11,12	236,813
6 B	SG-8258	BL. 6507/11,12	436,561
7 B	SG-8271	BL. 6407/2	638,185
8 B	ST-8110	TRØNDELAG WEST	280,384
9 B	ST-8306	HALTENBANKEN	325,840
10 B	EL-8204	TRÆNABANKEN	2934,451
11 B	ST-8217	TRÆNABANKEN	464,058
12 B	ST-8407	BL. 6609/5	422,139
13 B	EL-8502	NORDLAND 2	652,803
14 B	PW-83	BL. 6609/7	1056,637
15 B	SG-8445	BL. 6507/12	93,613
16 B	SG-8458	BL. 6507/11	162,952
17 B	SG-8558	BL. 6507/11	144,511
18 B	SG-8558–1	BL. 6507/11	92,074
19 B	SG-8658	BL. 6507/11	173,572
20 B	ST-8002	BL. 6507/7,8,9	214,532
21 B	ST-8102	BL. 6507/7,8,9	893,371
22 B	ST-8616	BL. 6407/4	202,161
23 B	ST-8634	BL. 6406/6	240,648
24 B	MN-84–3	BL. 6407/7	647,282
25 B	NH-8411	FRØYABANKEN	289,429
26 B	ST-8403	HALTENBANKEN	926,372
27 B	MN-85–1	NORDLAND 2	574,398
28 B	SH-85–1	HALTEN WEST	558,463
29 B	NH-8609	BL. 6407/7	171,704
30 B	SH-86–2	BL. 6407/9	154,269

to examine the core materials, drill cuttings and wet samples, and in special cases permission may be granted to remove sediment samples and oil samples for study and analysis outside the confines of the Directorate. The five-year rule for release applies here also. In 1992, the Directorate introduced a fee for use of the core study room.

In 1991, the routines for release of geological samples were amended in connection with applications for such release. Applications for release of material are now considered three times a year, with application deadlines on 1 April, 1 August, and 1 December.

Figure 2.4.1.5 shows the demand for specimens broken down by discipline: organic geo-chemistry; biostratigraphy; sedimentology; petrophysics and oil samples.

As of 31 December 1992, the Directorate had released a total of 168,468,242 line kilometres of seismics in 219 data packages. The released seismics included 189 packages in the North Sea and 30 packages in the Norwegian Sea. Table 2.4.1.5 shows a list of released seismic data.

A list of the released surveys is found in *Released Seismic Surveys*, Volumes A and B.

Volume A contains seismic survey packages for the North Sea, while Volume B contains packages for the Norwegian Sea.

2.4.2 Exploration drilling

Of the 12 exploration wells being drilled at year end 1991, one was a reentry well. In 1992, 43 new exploration wells were spudded, of which 29 were wildcats and 14 appraisal wells. Drilling activity in 1992 comprised 35 exploration wells in the North Sea, 21 wildcats and 14 appraisal wells; five wildcats in the Norwegian Sea; and three wildcats in the Barents Sea. In addition, two suspended exploration wells were reentered for further operations.

Of the eight wells being drilled at the end of 1992, one was a reentry well.

As of 31 December 1992, a total of 752 exploration wells had been spudded on the Norwegian continental shelf, 535 of them wildcats and 217 appraisal wells. See Figure 2.4.2.a.

In 1992, 47 exploration wells were completed on the Norwegian continental shelf, 34 of which were wildcats and 13 appraisal wells. The geographical distribution of the wells is as follows: 24 wildcats and 13 appraisal wells in the North Sea; six wildcats in the Norwegian Sea; and four wildcats in the Barents Sea.

The operators for the completed drilling operations were as follows: Hydro 15, Statoil nine, Saga six, Phillips three, Mobile three, BP three, Elf two, Esso two, Shell two, and Amoco and Conoco one each.

As of 31 December 1992, 745 exploration wells had been completed on the Norwegian continental shelf, comprising 531 wildcats and 214 appraisal wells. Table 2.4.2 gives a list of exploration wells started or completed in 1992.

In all, 50 exploration wells had been temporarily abandoned on the Norwegian continental shelf at the end of the year.

Suspended exploration wells on the Norwegian continental shelf for which equipment has been installed on the seabed are as follows:

2/01-09 A	25/04-06S	31/02-18A
2/04-15S	25/05-04	31/05-04AR
2/04-17	25/11-16	34/04-07
2/07-20R	30/02-01	34/07-16R
2/07-21SR	30/03-04	34/07-19
2/07-23S	30/06-19a	34/08-04S
2/07-25S	30/06-21	34/08-08
2/07-26S	30/06-22	34/10-34
2/07-27A	30/06-23	6407/07-02R
2/12-02S	30/09-07	6407/07-03
7/11-10SR	30/09-08R	6407/07-04
7/12-08	30/09-09	6407/09-03
7/12-09	30/09-10	6407/09-05
15/12-06S	30/09-12A	6407/09-06
15/12-09S	30/09-13S	6407/09-08
25/02-13	31/02-16SR	6506/12-08
	31/02-17B	6507/08-04

Figures 2.4.2.b, c and d show the exploration wells spudded in the three provinces of the Norwegian continental shelf (North Sea, Norwegian Sea and Barents Sea).

The Norwegian companies Saga, Norsk Hydro and Statoil operated 29 of the spudded wells, corresponding to 67.4 per cent. The remaining 14 wells were operated by Elf, Conoco, BP, Phillips, Esso, Mobil, and Shell. See Table 7.2.c for details.

2.4.2.1 Distribution of prospect types

Exploration activity in 1992 was very largely targeted at Jurassic sandstone prospects. Of the 43 exploration wells spudded, 36 had Jurassic strata as their main prospect. Of the other main prospects, five were in Palaeocene, two in Triassic, and one in Tertiary strata. Of the secondary prospects, 16 were in Jurassic, two in Palaeocene, one in Triassic, and one in Tertiary strata.

2.4.2.2 New discoveries in 1992

Of the exploration wells terminated in 1992, nine were confirmed through testing. In addition, hydrocarbons were proven in 1/6-6, 34/7-8R and 25/11-16, though no production test had been conducted by year end.

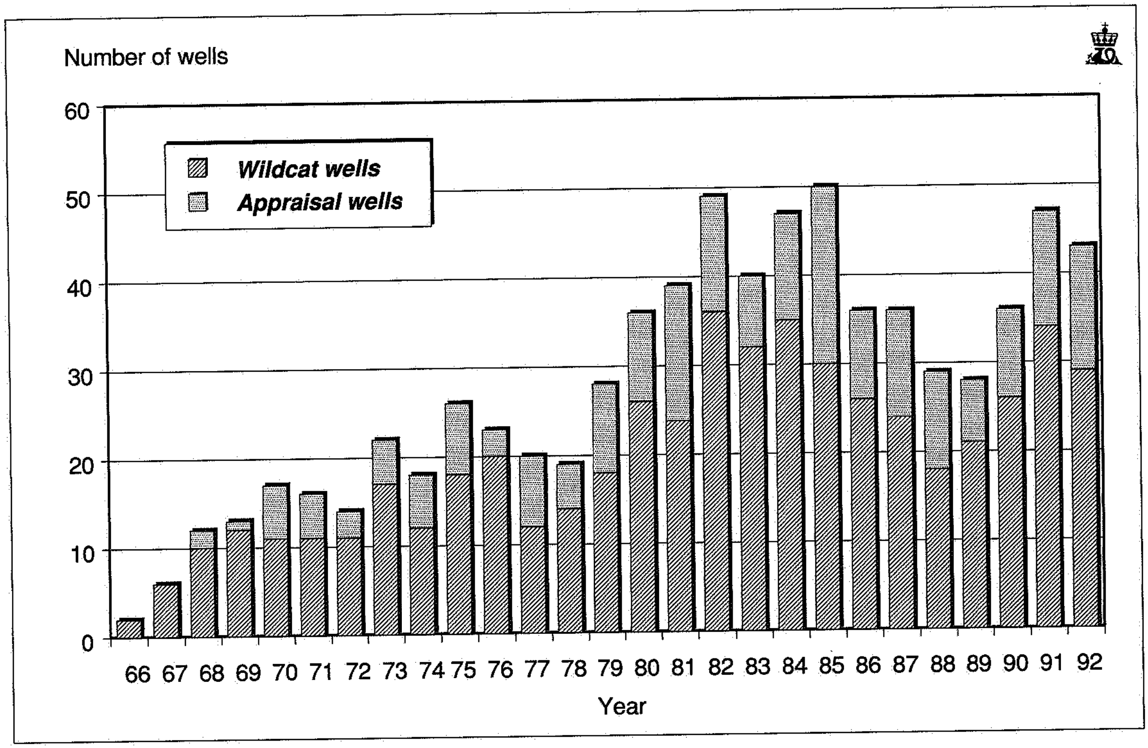
Exploration well	Operator	Hydrocarbons
2/2-5	Saga	Oil
2/4-17	Phillips	Oil and gas
7/7-2	Statoil	Oil
30/10-6	Elf	Gas
34/7-21	Saga	Oil
35/11-7	Mobil	Oil and gas
6507/2-2	Hydro	Gas
6608/10-2	Statoil	Oil
7316/5-1	Hydro	Gas

Table 2.4.2
Spudded and terminated exploration wells in 1992
R = reentry, X = junked due to technical problems, S = side drilled, A, B, C = side drilled new well

Exploration well	Lic. no. Prod. lic. no.	Position north east	Drilling Spudded Terminated	Operator Drill rig	Well type Completion classification	Water depth (in metres) KBE in metres	Total depth (in metres) Geol period
2/04–17	689	56 41 02.60	91.07.21	Phillips	Wildcat	68	5258
	018	03 13 45.20	92.02.29	Mærsk Guardian	Susp. Gas/Condensate	43	
35/10–01	692	61 07 02.05	91.08.01	Statoil	Wildcat	362	3986
	173	03 13 34.87	92.01.16	Deepsea Bergen	Dry hole	23	E. Jurassic
2/05–09	697	56 32 07.18	91.09.10	Amoco	Wildcat	69	5460
	006	03 33 13.06	92.01.18	West Vanguard	Dry hole	22	L. Jurassic
6507/02–02	702	65 55 01.69	91.10.21	Hydro	Wildcat	384	3958
	122	07 30 54.56	92.03.16	Polar Pioneer	Oil/Gas	23	E. Jurassic
6608/10–02	701	66 00 49.35	91.10.28	Statoil	Wildcat	374	3678
	128	08 04 26.48	92.01.29	Ross Rig	Oil/Gas/Condensate	23	Triassic
2/02–05	705	56 50 05.80	91.11.07	Saga	Wildcat	63	4082
	066	03 27 22.90	92.02.19	Treasure Saga	Oil	26	Permian
2/01–10	703	56 57 53.61	91.11.09	BP	Wildcat	66	4525
	164	03 01 19.70	92.01.14	Ross Isle	Dry hole	23	Triassic
2/07–27 S	707	56 19 59.81	91.11.09	Phillips	Appraisal	71	4801
	018	03 14 53.77	92.06.17	West Delta	Susp. Oil/Gas	29	Pre-jura
7122/04–01	706	71 44 50.47	91.11.13	Esso	Wildcat	343	3015
	178	22 05 06.39	92.01.13	Arcade Frontier	Gas shows	25	Triassic
35/11–04 R	642	61 01 59.93	91.11.16	Mobil	Wildcat	355	3127
	090	03 32 53.58	92.01.27	Sovereign Explorer	Oil/Gas	25	E. Jurassic
3/07–05	708	56 28 47.00	91.12.06	Shell	Wildcat	67	3666
	147	04 18 17.60	92.02.08	Dyvi Stena	Dry hole	25	
31/02–17 S	709	60 52 57.08	91.12.28	Hydro	Appraisal	340	2220
	054	03 27 05.79	92.01.20	Transocean 8	Oil/Gas	24	L. Jurassic
30/10–06	712	60 09 13.65	92.01.13	Elf	Wildcat	91	5250
	142	02 12 37.38	92.11.09	West Alpha	Gas	18	M. Jurassic
2/01–09 A	713	56 51 37.77	92.01.18	BP	Appraisal	66	4379
	019	03 05 04.77	92.03.08	Ross Isle	Suspended	23	Jurassic
7/07–02	710	57 29 04.16	92.01.20	Statoil	Wildcat	82	3430
	148	02 18 17.59	92.04.25	Deepsea Bergen	Oil	23	
31/02–17 A	716	60 52 57.08	92.01.20	Hydro	Appraisal	340	1924
	054	03 27 05.79	92.01.31	Transocean 8	Oil/Gas	24	
35/11–06	714	61 11 45.82	92.01.30	Mobil	Appraisal	370	3995
	090	03 27 55.46	92.04.20	Sovereign Explorer	Oil/Gas shows	26	E. Jurassic
31/02–17 B	719	60 52 57.08	92.02.01	Hydro	Appraisal	340	1838
	054	03 27 05.79	92.02.14	Transocean 8	Suspended	23	
34/10–35	715	61 04 16.17	92.02.05	Statoil	Wildcat	135	4310
	050	02 19 16.77	92.06.30	Ross Rig	Oil/Gas	23	
1/06–06	718	56 36 41.13	92.02.10	Shell	Wildcat	70	5567
	011	02 57 18.19	00.00.00	Dyvi Stena		25	
34/08–04 A	711	61 19 29.58	92.02.18	Hydro	Appraisal	309	3567
	120	02 25 18.67	92.05.27	Transocean 8	Suspended	23	
35/12–01	720	61 11 04.06	92.02.27	Saga	Wildcat	351	3020
	174	03 57 45.41	92.04.24	Treasure Saga	Dry hole	26	Basement
2/07–28	719	56 22 52.16	92.03.08	Phillips	Appraisal	71	3893
	018	03 14 19.29	92.08.07	Mærsk Guardian	Shows	43	Permian
1/06–07	724	56 33 20.01	92.03.16	Conoco	Wildcat	70	4995
	144	02 54 11.18	92.07.13	West Vanguard	Shows	21	L. Jurassic
34/08–07	725	61 19 09.07	92.03.21	Hydro	Wildcat	334	5460
	120	02 33 32.15	92.07.16	Polar Pioneer	Suspended	23	Triassic
6407/08–01	726	64 23 29.16	92.03.27	BP	Wildcat	284	4650
	158	07 21 26.14	92.06.07	Ross Isle	Dry hole	23	Jurassic
33/09–15	727	61 24 24.67	92.04.23	Mobil	Wildcat	252	3011
	172	01 57 15.78	92.06.08	Sovereign Explorer	Shows	27	
25/06–02	729	59 33 39.83	92.04.26	Saga	Wildcat		2392
	117	02 49 13.44	92.05.29	Treasure Saga	Dry hole	26	

Exploration well	Lic. no. Prod. lic. no.	Position north east	Drilling Spudded Terminated	Operator Drill rig	Well type Completion classification	Water depth (in metres) KBE in metres	Total depth (in metres) Geol period
34/10–36	723	61 06 48.49	92.04.28	Statoil	Wildcat	136	3640
	050	02 10 35.15	92.07.13	Deepsea Bergen	Oil/Gas	23	E.Jurassic
30/03–05 S	728	60 46 57.82	92.05.01	Statoil	Wildcat	175	4724
	052	02 53 52.70	92.07.17	Veslefrikk A	Reclass. as oil prod.	56	E. Jurassic
6407/10–03	721	64 06 11.66	92.05.29	Hydro	Wildcat	324	2973
	132	07 18 11.43	92.06.27	Transocean 8	Dry hole	23	
2/04–16 R X	680	56 40 37.23	92.06.04	Saga	Wildcat	68	4996
	146	03 09 02.07	92.07.15	Treasure Saga	Junked	26	
30/02–03	731	60 50 49.05	92.06.11	Statoil	Appraisal	123	4325
	051	02 39 19.68	92.10.05	Ross Isle	Gas/Condensate	23	E. Jurassic
10/07–01	735	57 28 23.30	92.06.28	Esso	Wildcat	87	1890
	165	05 03 33.21	92.07.30	Arcade Frontier	Dry hole	25	
25/11–16	733	59 07 06.55	92.06.29	Hydro	Wildcat	120	1945
	169	02 23 06.20	92.07.24	Vildkat Explorer	Suspended	25	Cretaceous
34/08–08	730	61 22 46.19	92.06.30	Hydro	Appraisal	341	3625
	120	02 28 43.81	92.08.24	Transocean 8	Suspended	23	
6506/11–03	734	65 13 58.44	92.07.08	Statoil	Wildcat	326	4350
	134	06 22 26.89	92.10.01	Ross Rig	Shows	23	Jurassic
15/12–09 S	732	58 04 40.17	92.07.17	Statoil	Appraisal	84	3848
	038	01 53 25.54	92.10.08	Deepsea Bergen	Susp. Oil/Gas	23	Triassic
34/07–20	736	61 26 39.65	92.07.18	Saga	Wildcat	295	3178
	089	02 01 49.98	92.08.27	Treasure Saga	Shows	26	Triassic
7316/05–01	740	73 31 12.78	92.07.21	Hydro	Wildcat	454	4027
	184	16 25 55.87	92.10.05	Polar Pioneer	Gas	23	
35/11–07	737	61 01 59.74	92.07.23	Mobil	Wildcat	356	2895
	090	03 35 26.23	92.09.29	West Delta	Oil/Gas	29	E. Jurassic
25/08–04	738	59 15 31.31	92.07.25	Hydro	Wildcat	128	1891
	169	02 36 42.97	92.08.11	Vildkat Explorer	Shows	25	Paleocene
6407/09–08	739	64 23 07.69	92.08.14	Shell	Wildcat	230	2126
	093	07 57 37.47	92.09.22	West Vanguard	Susp. dry hole	22	E. Jurassic
30/10–07	742	60 11 28.14	92.09.08	Elf	Wildcat	106	2612
	142	02 07 27.27	92.10.17	Mærsk Jutlander	Dry hole	18	Cret.?
31/02–18	741	60 54 10.49	92.09.15	Hydro	Appraisal	364	1711
	054	03 34 41.79	92.10.07	Treasure Saga	Plugged Oil/Gas	25	Jurassic
7219/08–01 S	744	72 22 28.32	92.10.05	Saga	Wildcat	370	
	182	19 23 40.24	92.12.26	Ross Rig		23	
31/02–18 A	743	60 54 10.49	92.10.07	Hydro	Wildcat	364	2005
	054	03 34 41.79	92.10.17	Treasure Saga	Susp. shows	26	Jurassic
7122/02–01	745	71 57 40.28	92.10.07	Hydro	Wildcat	363	2120
	179	22 38 40.10	92.11.11	Polar Pioneer	Dry hole	23	
34/07–21	747	61 17 36.84	92.10.19	Saga	Wildcat	192	3015
	089	02 04 21.14	92.12.11	Treasure Saga	Plugged	26	
34/08–09 S	746	61 18 50.53	92.10.25	Hydro	Appraisal	300	
	120	02 23 17.89	92.12.26	West Delta		29	
6610/03–01	748	66 55 29.70	92.10.29	Statoil	Wildcat	309	
	177	10 54 06.28	00.00.00	Deepsea Bergen		23	
25/02–15	722	59 48 53.54	92.11.14	Elf	Wildcat	120	
	112	02 30 06.20	00.00.00	West Alpha		23	
15/09–19 S	749	58 26 25.26	92.11.18	Statoil	Wildcat		
	046	01 53 29.07	00.00.00	Treasure Prospect		22	
34/08–07 R	725	61 19 09.07	92.11.19	Hydro	Wildcat	334	5460
	120	02 33 32.15	00.00.00	Polar Pioneer		23	
33/09–16	750	61 23 28.91	92.11.28	Mobil	Appraisal		
	172	01 57 02.51	00.00.00	Ross Isle		22	
31/05–05	751	60 41 49.6	92.12.30	Hydro	Appraisal		
	085	03 29 08.9	00.00.00	West Delta			
34/07–21 A	752	61 17 36.84	92.12.11	Saga	Appraisal	192	
	089	02 04 21.14	00.00.00	Treasure Saga		26	

Fig. 2.4.2.a
Exploration drilling on the Norwegian continental shelf. Number of wells per year 1966–1992



Block 2/2
Saga Petroleum as operator of production licence 066 drilled wildcat 2/2-5. The well was drilled to a total depth of 4056 metres below sea level and terminated in Zechstein rock.

Oil was proven in thin, Late Jurassic sandstone strata. One production test was run which flowed with a maximum production rate of 600 scm a day through a 7.9 mm choke. The observed gas-to-oil ratio (GOR) was 44 scm/scm, while oil density was 0.85 g/cc.

Block 2/4
Phillips Petroleum as operator of production licence 018 drilled and tested the 2/4-17 wildcat.

The well was drilled to a depth of 5212 metres below sea level and two production tests were run. The first, and deepest, test produced 890 scm water a day from an interval of unknown age. The second test, which was performed in Jurassic rock, produced 774 scm of condensate per day and 849,618 scm of gas per day through a 15.9 mm choke at a wellhead pressure of 408 bar. Oil density was 0.799 g/cc, while gas density was 0.735 relative to air. The results of the drilling operation and test are positive and interesting with a view to further exploration activity in the area.

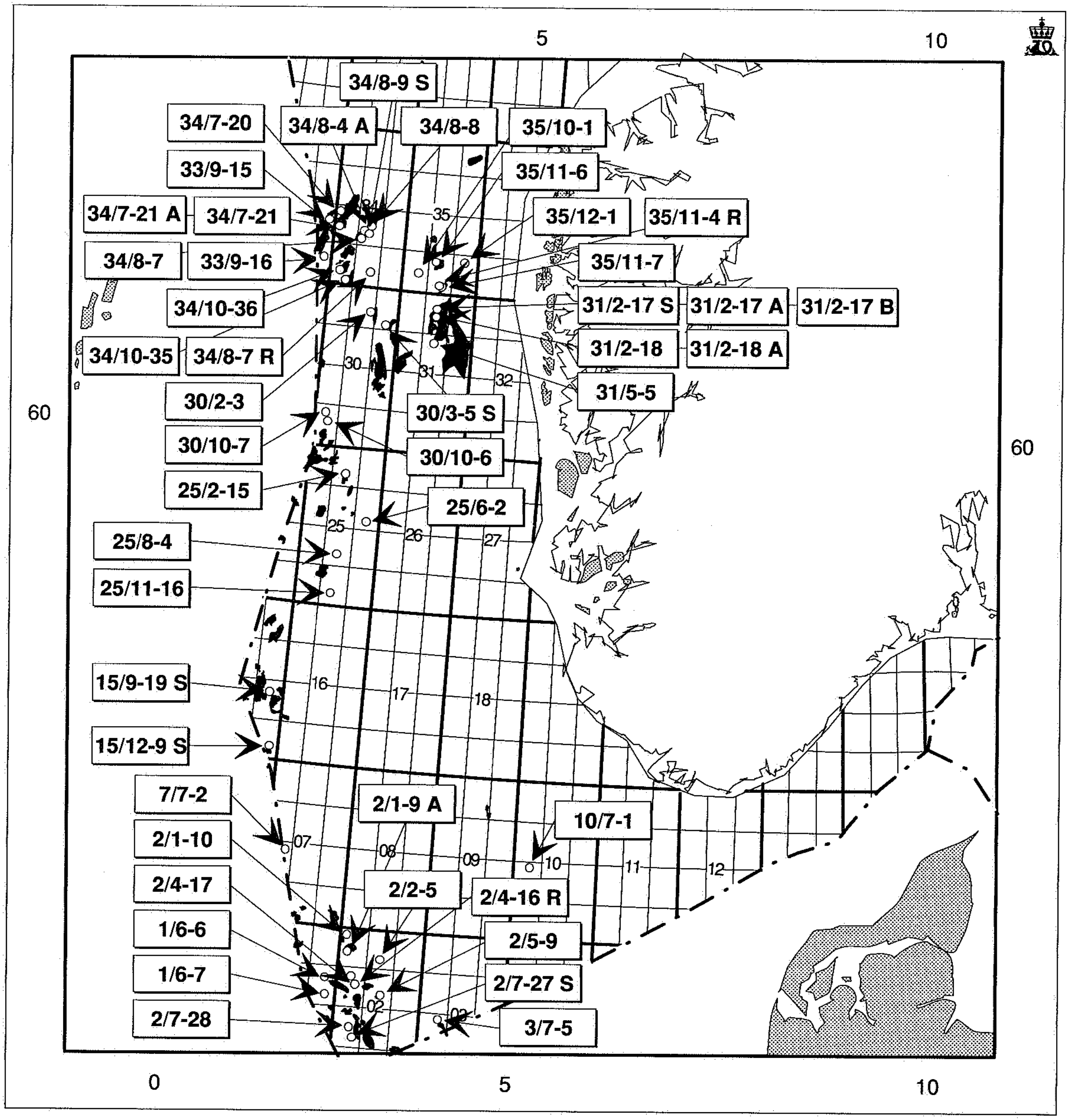
Block 7/7
Statoil as operator of production licence 148 drilled the 7/7-2 wildcat. The well was drilled to a depth of 3407 metres below sea level and terminated in Permian rock. Oil was proven in Jurassic rock. Two production tests were run, giving a maximum production rate of 788 scm oil per day through a 9.5 mm choke. Drilling and test results are considered interesting with a view to further exploration activity in the area.

Block 30/10
Elf Petroleum Norge A/S as operator of production licence 142 drilled the 30/10-6 wildcat just north of the Odin field. The well, which was drilled in a structure centrally in block 30/10, reached a total depth of 5232 metres below sea level and was terminated in Middle Jurassic rock. Hydrocarbons were proven in Middle Jurassic sandstone and four production tests were run. The highest measured production rate was 96,000 scm of gas a day through an 8 mm choke. Test results were disappointing, indicating poor reservoir quality.

Block 34/7
Saga Petroleum, as operator of production licence 089, drilled wildcat 34/7-21 and proved oil bearing strata roughly 35 metres thick in Upper Jurassic sandstone. The well was production tested and showed a maximum flow rate of 900 scm oil a day through a 12.7 mm choke. Oil density was 0.839 g/cc, while the gas-to-oil ratio was 128 scm/scm. In addition, two thin oil bearing sand strata were proven, approximately five metres over and 30 metres under the main strata, respectively. The well was terminated 2989 metres below sea level in Early Jurassic rock.

The results are considered both interesting and

Fig. 2.4.2.b
Exploration wells drilled in the North Sea in 1992



encouraging. More work can be expected to explore the possibilities of striking hydrocarbons using an Upper Jurassic exploration model. A sidetracking drilling operation in 34/7-21A was in progress at the end of the year.

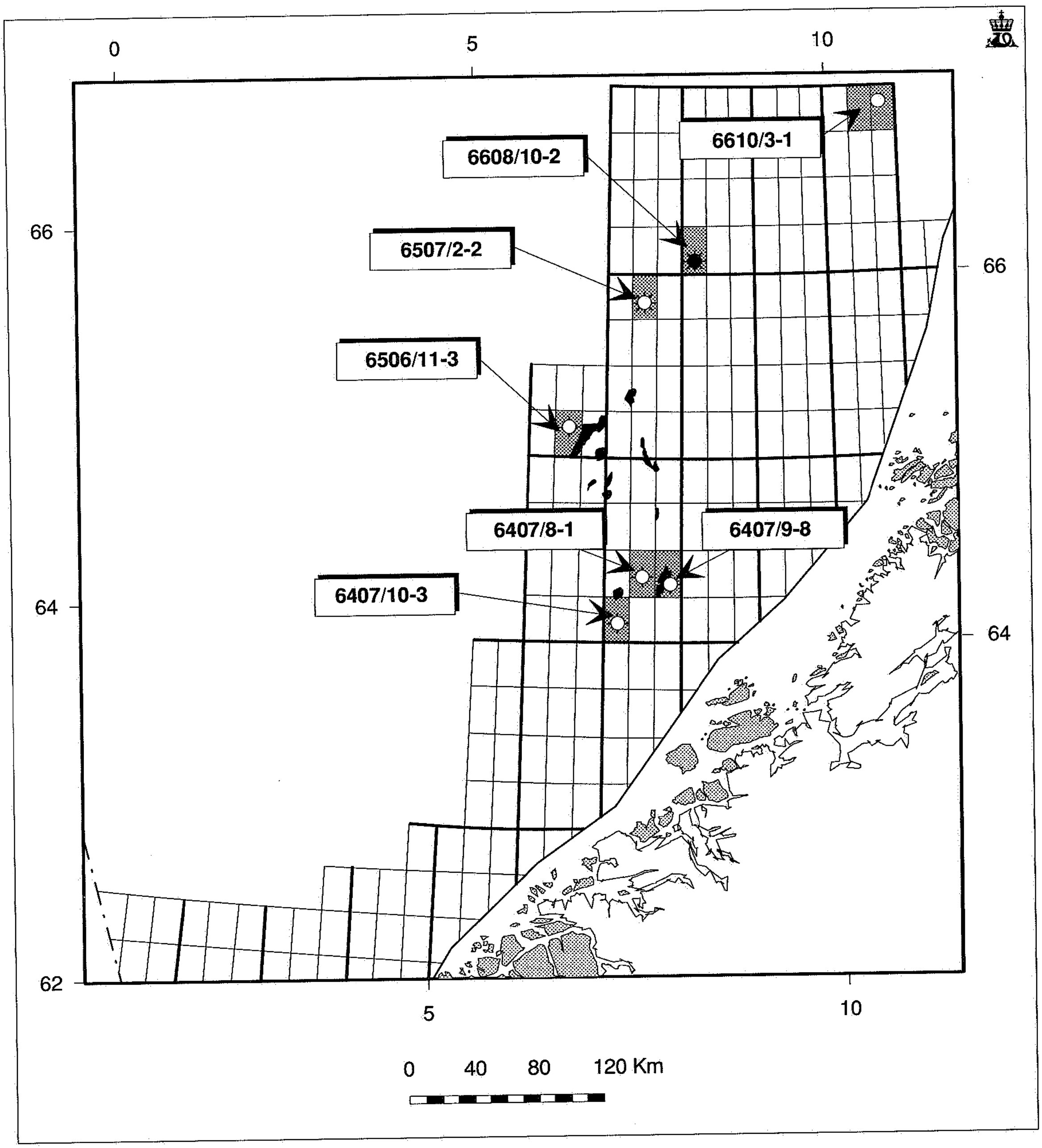
Block 35/11

Mobil as operator of production licence 090 drilled the 35/11-7 wildcat just east of 35/11-4, where oil and gas were proven in 1991. Well 35/11-7 was drilled to a depth of 2866 metres below sea level and terminated in Early Jurassic rock. Oil and gas were proven in Middle and Late Jurassic rock. Two production tests were performed, giving a maximum production rate of 1252 scm oil and 52,100 scm gas through a 37 mm choke. Oil density was measured at 0.854 g/cc, while gas density was 0.681 relative to air. These drilling results are encouraging considering the proximity to the discovery in 35/11-4 and with a view to further exploration in the area.

Block 6507/2

Norsk Hydro as operator of production licence 122 drilled the 6507/2-2 wildcat in the same structure as

Fig. 2.4.2.c
Exploration wells drilled in the Norwegian Sea in 1992

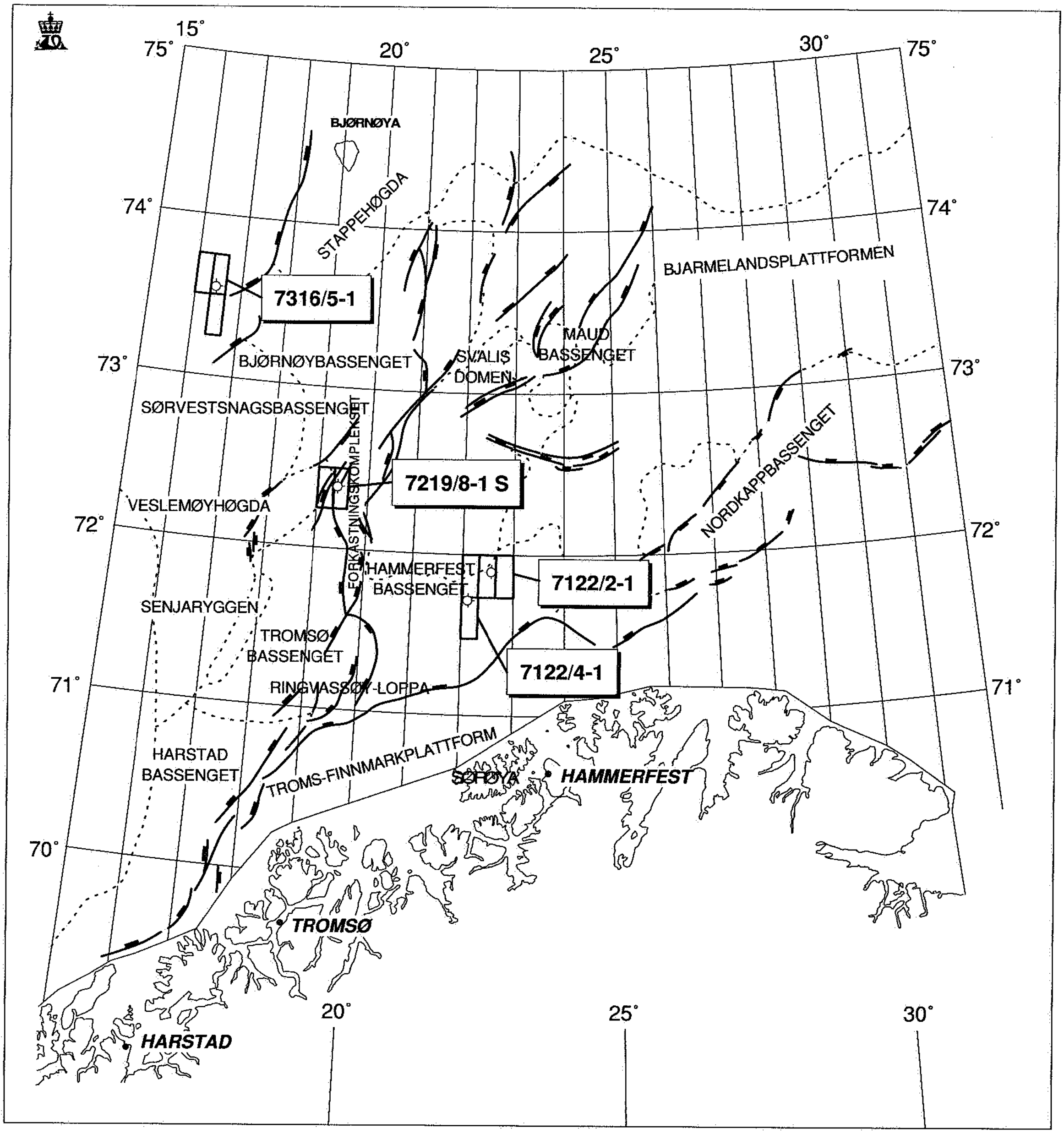


6507/2-1, which was dry but located higher up in the structure. The well was drilled to a depth of 3935 metres below sea level and terminated in Early Jurassic rock. Gas and condensate were proven in Cretaceous sandstone, while the Jurassic strata were found to be dry. Two production tests were performed, the better of them giving 130 scm condensate and 670,000 scm gas a day through a 25 mm choke. The gas-to-condensate ratio was 5200 scm/scm; while gas density relative to air was 0.64; and condensate density was 0.789 g/cc. The results from this drilling operation were encouraging with a view to further potential in Cretaceous sands in this area. It is also possible that there are heavier hydrocarbons further down the flank in this structure.

Block 6608/10

Statoil as operator of production licence 128 completed the drilling of the 6608/10-2 wildcat. It was drilled in the southwestern corner of block 6608/10. The primary objective was to explore a Jurassic sand structure. The well was drilled to a depth of 3655 metres below sea level and terminated in Triassic or Jurassic rock. Gas, condensate and oil were proven in Jurassic rock.

Fig. 2.4.2.d
Exploration wells drilled in the Barents Sea in 1992



Three production tests were performed, the best of which gave 1165 scm oil a day through a 50 mm choke. The gas-to-oil ratio was 99 scm/scm, while oil density was measured at 0.85 g/cc. This discovery is very encouraging seen in isolation and with a view to further exploration in the area. An appraisal well will be drilled in the northern part of the structure early in 1993.

Block 7316/5
Norsk Hydro as operator of production licence 184 drilled the 7316/5-1 wildcat in a Tertiary prospect in the Bjørnøya Vest area. To date, this is the most northerly well on the Norwegian continental shelf, and it was drilled in 450 metres of water. The well terminated in Cretaceous rock 4004 metres below sea level.

Gas was proven in Tertiary sandstone. One production test was run, giving a highest production rate of 563,000 scm a day through a 25.4 mm choke. The results of the drilling operation, the first in this area, are considered encouraging since they prove the presence of good, gas bearing reservoir rock.

2.4.2.3 Further details of other drilling operations

Block 1/6

Conoco as operator of production licence 144 drilled the 1/6-7 wildcat in the Central Graben, southwest of the Albuskjell field. The well was drilled to a total depth of 4902 metres below sea level and terminated in Late Jurassic rock. Only traces of hydrocarbons were proven in Late Cretaceous and Late Jurassic rock. No production tests were performed.

Shell as operator of production licence 011 drilled the 1/6-6 wildcat in a structure just south of the Albuskjell field. The purpose of the drilling operation was to test the hydrocarbon potential in Jurassic sandstone. The well was drilled to a depth of 5542 metres below sea level and terminated in rocks probably of Jurassic age. So far, this is the deepest well ever drilled on the Norwegian continental shelf. At the end of the year Shell was preparing for production testing of the well.

Block 2/1

BP Norway Ltd as operator of production licence 164 drilled wildcat 2/1-10. The well was drilled to 4502 metres below sea level and terminated in Triassic rock. No hydrocarbons were proven in this well.

Appraisal well on the Gyda field, block 2/1

BP Norway Ltd as operator of production licence 019B drilled appraisal well 2/1-9A. This well was sidetracked from well 2/1-9, which tested high GOR oil in the southeastern reaches of the Gyda field. Well 2/1-9A was drilled to a total depth of 4356 metres below sea level and terminated in Jurassic rock.

The objective of clarifying the reservoir productivity and hydrocarbon type was achieved without having to test the well. The drilling results led to an increase in proven resources.

Block 2/4

Saga Petroleum as operator of production licence 146 drilled the 2/4-16R wildcat. Well 2/4-16 was plugged temporarily in 1991 after regaining control of the well after a gas kick. The purpose of reentering 2/4-16 was to deepen it to test a possible Triassic reservoir. When the well had been drilled to 4938 metres below sea level there was a new kick into the well necessitating shutdown. When the situation had stabilised drilling continued to 4948 metres below sea level, at which point there was a new, uncontrolled kick of hydrocarbons into the well, which was then abandoned for safety reasons.

Block 2/5

Amoco as operator of production licence 006 drilled the 2/5-9 wildcat. The well was drilled to 5423 metres below sea level and terminated in Upper Jurassic rock. It was a dry hole.

Block 2/7

Phillips Petroleum as operator of production licence 018 drilled appraisal well 2/7-28. The purpose of the drilling operation was to test the hydrocarbon potential in Late Jurassic sandstones under the Eldfisk field, which produces oil and gas from Cretaceous rock. The well was drilled to 3852 metres below sea level and terminated in Permian rock. Only traces of oil were proven.

Appraisal well on the Embla field, block 2/7

Phillips Petroleum as operator of production licence 018 sidetracked appraisal well 2/7-27S. The well was drilled to 4423 metres below sea level where it terminated in Pre-Jurassic rock. One production test was carried out, during which the well produced 1494 scm oil and 400,909 scm gas per day through a 15.9 mm choke. The gas-to-oil ratio was 268 scm/scm. Oil density was 0.80 g/cc, and gas density was 0.80 lative to air. The results of drilrilling and testing have not altered the resource basis for the field.

Block 3/7

A/S Norske Shell as operator of production licence 147 drilled wildcat 3/7-5. The well was drilled to a depth of 3641 metres below sea level and terminated in Zechstein rock. No hydrocarbons were proven in the well.

Block 10/7

Esso Norge A.S as operator of production licence 165 drilled the 10/7-1 wildcat. The well was drilled in a structure in the northwestern part of the block, the purpose being to test the hydrocarbon potential in Jurassic sandstone. The well was drilled to a total depth of 1865 metres below sea level and terminated in Late Permian rock. No hydrocarbons were proven in the well.

Block 15/9

Statoil as operator of production licence 046 is in the process of sidetracking the 15/9-19S wildcat into a structure just north of Sleipner Øst. The well is being sidetracked to the west from the seabed template on the Loke field. The purpose of this well is to test the hydrocarbon potential in Tertiary and Jurassic sandstone. At the end of the year the well had not reached reservoir level.

Block 15/12

Statoil as operator of production licence 038 sidetracked the 15/12-9S appraisal well in 15/12 Beta. The well was drilled to a depth of 3190 metres below sea level and terminated in Triassic rock. Oil was proven in Late Jurassic sandstone strata. Two production tests were carried out, and peak production was measured to 1530 scm oil a day through a 20 mm choke. The well was plugged temporarily with a view to reuse as a producer if 15/12 Beta is developed. New and important information about the reservoir geology was obtained in this drilling operation.

Block 25/2

Elf Petroleum Norge A/S as operator of production licences 026 and 112 is drilling wildcat 25/2-15 in a structure just north of the 25/2-5 discovery. The purpose of this well is to test the hydrocarbon potential in Jurassic sandstone. At the end of the year the well had not reached reservoir level.

Block 25/6
Saga Petroleum as operator of production licence 117 drilled the 25/6-2 wildcat. In the first well drilled in this production licence a minor oil discovery was made in Middle Jurassic sandstone. Well 25/6-2 was drilled about four kilometres north-northeast of this discovery in order to test potential hydrocarbon traps in Tertiary and Jurassic layers. The well was drilled to a depth of 2366 metres below sea level and terminated in Jurassic rock. The drilling results were disappointing as no hydrocarbons were proven.

Block 25/8
Norsk Hydro as operator of production licence 169, blocks 25/11 and 25/8, drilled the 25/8-4 wildcat in a structure northeast of Balder. The well was drilled to a depth of 1866 metres below sea level and terminated in Cretaceous rock. Oil was struck in some thin Palaeocene sandstone strata. The main reservoir, the Heimdal formation, came in deeper than forecast and was an aquifer. The well was plugged permanently without a production test.

Block 25/11
Norsk Hydro as operator of production licence 169, blocks 25/11 and 25/8, drilled the 25/11-16 wildcat in a structure south of Balder and the 25/11-15 discovery. The well was drilled to 1920 metres below sea level and terminated in Cretaceous rock. Oil was proven in Palaeocene sandstone. The well was temporarily plugged and production tests will not be run until a later date.

Block 30/2
Statoil as operator of the Huldra field drilled the 30/2-3 appraisal well. This, the fourth well in the field, was drilled to a vertical depth of 4300 metres below sea level and terminated in Early Jurassic rock. Gas/condensate was proven in Middle Jurassic sandstone strata. A total of three production tests were carried out, and peak production was measured at 1 mcm gas a day through a 19.05 mm choke. It is still too early to tell whether this drilling operation will lead to any changes in the resource estimate for Huldra.

Block 30/3
Statoil as operator of production licence 052 drilled the 30/3-5S wildcat in a structure southeast of the Veslefrikk field. The well was terminated in Early Jurassic rock at a depth of 3283 metres below sea level. Oil was struck in Early and Middle Jurassic sandstone strata. The well has now been completed as a producer and has been tied in with Veslefrikk for production.

Block 30/10
Elf Petroleum Norge A/S as operator of production licence 142 drilled the 30/10-7 wildcat. The well was drilled to a total depth of 2589 metres below sea level and terminated in Cretaceous rock. No hydrocarbons were found in the well.

Block 31/2
Norsk Hydro as operator of the Troll oil development drilled appraisal wells 31/2-17S, 31/2-17A, 31/2-17B and 31/2-18, and the 31/2-18A wildcat. Well 31/2-17S was sidetracked to a depth of 2197 metres below sea level (1682 metres vertical depth) and terminated in Late Jurassic rock. Two directional boreholes were made as 31/2-17A and 31/2-17B, respectively, to achieve horizontal well angle. At the same time the well path was turned 200 degrees. The purpose of this drilling operation was, on the one hand, to obtain information on the reservoir strata in this part of the field, and on the other, to test the technical drilling problems associated with dual-level drilling. The wells struck oil and gas, but they were not production tested. Well 31/2-18 was drilled to 1685 metres below sea level, while 31/2-18A, which was drilled from 31/2-18, was drilled to a depth of 1979 metres below sea level. Both wells were terminated in Jurassic rock.

Well 31/2-18 confirmed oil and gas in sandstone strata in the Sognefjord formation. In addition, traces of oil were found in 31/2-18A in the Krossfjord formation. No production tests were made of the wells.

Block 31/5
Norsk Hydro as operator of the Troll oil field development drilled appraisal well 31/5-5. At the end of the year the drilling operation was still not completed.

Block 33/9
Mobil as operator of production licence 172 drilled the 33/9-15 wildcat to test the potential for hydrocarbon bearing strata in Upper Jurassic sandstone. A major sandstone level was proven, but hydrocarbons were indicated only in the first four metres of the sand strata, and the well was therefore not tested. The well was drilled to Middle Jurassic rock at a depth of 2988 metres below sea level.

Appraisal well 33/9-16 in the same production licence was being drilled at the end of the year.

Block 34/7
Saga Petroleum as operator of production licence 089 drilled the 34/7-20 wildcat with a view to finding hydrocarbon bearing sand strata in Upper Jurassic rock. The well proved a four metre thick sand layer with only traces of oil. Pressure measurements from the Statfjord formation deeper down the borehole indicate that the western part of the Snorre field may contain more oil than previously assumed. The well was drilled down to Triassic rock and terminated 3151 metres below sea level.

Block 34/8

Norsk Hydro as operator of production licence 120 drilled wildcat 34/8-7 in a deep prospect east of the Visund structure. The well was drilled to a total depth of 5418 metres below sea level and terminated in Triassic rock.

Gas was proven in Middle and Early Jurassic sandstone. The reservoir rock has low porosity. Well 34/8-7R was a reentry for production testing, which was ongoing at the end of the year.

Three appraisal wells were drilled in the same production licence in the Visund structure. Well 34/8-4A was drilled down to Triassic rock to a vertical depth of 3290 metres below sea level and proved oil in Early Jurassic sandstone and gas in Late Triassic rock. Five production tests were performed, giving a peak flow rate of 1250 scm oil a day and 307,000 scm gas a day. This was an encouraging result which led to an increase in the resource estimate for oil in Visund.

Appraisal well 34/8-9S was drilled in order to further delineate these enhanced oil resources. It was drilled to a vertical depth of 3351 metres below sea level and terminated in Triassic rock. The well showed indications of hydrocarbons in a sand body whose age is uncertain (Middle or Early Jurassic). However, the expected main reservoir was water bearing. This was a disappointment and shows that the Visund structure is more complex than previously assumed. No tests were made of this well.

Appraisal well 34/8-8 was drilled centrally in the main structure in Visund. The prospect was Triassic rock and the borehole terminated 3600 metres below sea level. Oil was proven in Middle Jurassic sandstone, a result which confirms that the hydrocarbon contact in this area is almost identical with the contact in the northern part of Visund. The well has not yet been production tested, but testing is expected to take place early in 1993.

Block 34/10

Statoil as operator of production licence 050 drilled two exploration wells. Well 34/10-35 was drilled to delineate the 34/10 Gamma discovery in the southeastern part of the block. Early Jurassic rocks were struck at a shallower level than expected, which reinforces the impression of structural complexity in the area. This drilling operation confirms the existence of hydrocarbons also in this part of the structure as gas was proven in Middle and Early Jurassic sandstone.

Three production tests were carried out, and the peak production rate measured was about 1 mcm gas a day through a 15.8 mm choke. The well was terminated 4286 metres below sea level in Early Jurassic rock. The 34/10-36 wildcat was drilled primarily to clarify whether there are hydrocarbon bearing strata in Upper Jurassic sandstone around the western flank of Gullfaks Sør. These hopes were dashed, however, as the potential reservoir level consisted of shale. However, oil was proven in Middle Jurassic sandstone. This confirms the principal features in our understanding of the Gullfaks Sør field and did not produce any significant changes in the reserves estimate for the field. A production test was carried out, giving a maximum flow rate of 915 scm oil a day and 177,000 scm gas a day through a 15.8 mm choke. The well was terminated in Early Jurassic rock at a depth of 3617 metres below sea level.

Block 35/11

Mobil as operator of production licence 090 drilled the 35/11-6 appraisal well in order to delineate a discovery made in 1987 in the northern part of the block. The well was drilled to 3961.5 metres below sea level and terminated in Early Jurassic rock. Only traces of oil and gas were proven. The result was disappointing and will probably lead to a reduction in the resource estimate for the discovery made by wildcat 35/11-2.

Block 35/12

Saga Petroleum as operator of production licence 174 drilled the 35/12-1 wildcat. It was drilled to a total depth of 2994 metres below sea level and terminated in bedrock. The results from this drilling operation were disappointing as no hydrocarbons were proven. The well nevertheless represents important information with a view to further exploration in the area.

Block 6407/8

BP Norway Ltd as operator of production licence 158 drilled the 6407/8-1 wildcat in the middle of the block situated between the Njord field to the west and Draugen to the east. The prospect was assumed to be Upper Jurassic sandstone. The well was drilled to a total depth of 4627 metres below sea level and terminated in Upper Jurassic rock. Only weak traces of hydrocarbons were proven in some thin Cretaceous and Upper Jurassic sandstone strata and therefore the well was not tested.

Block 6407/9

A/S Norske Shell as operator of production licence 093 drilled the 6407/9-8 wildcat directly east of the Draugen field. The well was drilled to a total depth of 2101 metres below sea level and terminated in Lower Jurassic rock. No hydrocarbons were found during the drilling operation.

Block 6407/10

Norsk Hydro as operator of production licence 132 drilled the 6407/10-3 wildcat south of the Njord field. The location of the well was chosen to examine a prospect in Jurassic and Triassic strata and to obtain general stratigraphic information about a rise called Frøyahøgda. The well was drilled to a total depth of 2950 metres below sea level and terminated in bedrock. Only traces of hydrocarbons were found in sandstone strata and therefore the well was not tested.

Block 6506/11

Statoil as operator of production licence 134 drilled wildcat 6506/11-3 in the northwestern part of the block. The location of the well was chosen primarily to examine several Cretaceous prospects, but also to explore Jurassic sandstone. The well was drilled to a total depth of 4327 metres below sea level and terminated in Jurassic rock. Only small quantities of hydrocarbons were proven in Cretaceous sandstone and the well was therefore not tested.

Block 6610/3

Statoil as operator of production licence 177 is drilling wildcat 6610/3-1. This is the first wildcat in the Nordland III area. At the end of the year the well had still not been completed.

Block 7122/2

Norsk Hydro as operator of production licence 179 drilled the 7122/2-1 wildcat in a Cretaceous prospect on the northern flank of the Hammerfest basin. The well was terminated in Middle Jurassic rock 2097 metres below sea level. No hydrocarbons were found. The Directorate nevertheless considers the result to be positive because rich sandstone strata with good reservoir properties were found in the Lower Cretaceous.

Block 7122/4

Esso Norge as operator of production licence 178 drilled the 7122/4-1 wildcat in a Middle Jurassic prospect in the northeastern part of the Hammerfest basin. The well was terminated in Triassic rock 2992 metres below sea level. Only traces of hydrocarbons were found, and the well was not production tested.

Block 7219/8

Saga Petroleum as operator of production licence 182 drilled the 7219/8-1S wildcat in a Cretaceous or Jurassic prospect in the Bjørnøya Sør area. The well was terminated in Middle Jurassic rock at 4381 metres vertical depth below sea level (4588 metres measured depth). No hydrocarbons were proven.

2.4.2.4 Svalbard

There was no drilling for hydrocarbons on the Svalbard islands in 1992. Statoil shot 185.4 kilometres of seismics in the vicinity of Agardh-Nordmannsfonna. Table 2.4.2.4 and Figure 2.4.2.4 show boreholes on Svalbard.

2.4.2.5 Jan Mayen

The Jan Mayen ridge is a bathymetric ridge extending southward from the Jan Mayen island toward Iceland. This ridge is believed to represent a continental crust fragment which potentially contains both Mesozoic and Cenozoic rocks.

The Directorate, in collaboration with the Icelandic energy authorities, *Orkustofnun*, carried out three different seismic surveys in this area. The Jan Mayen-79 and Jan Mayen-85 surveys are both major

Table 2.4.2.4
Drilling activity on Svalbard

Exploration well/ location	Position north east	Spudded	Terminated	Days drilling	Operator Licensee	Total depth metres	KB elev. over msl metres
7714/2-1							
Grønnfjorden I	77 57 34	09.06.63	05.09.63	287	Norsk Polar Navig	971.6	7.5
(Nordenskiøld Land)	14 20 36	13.06.64	26.08.64		Norsk Polar Navig		
		26.06.65	08.09.65				
		26.06.67	12.08.67				
7715/3-1							
Ishøgda I	77 50 22	01.08.65	15.03.66	277	Texaco	3304	18
(Spitsbergen)	15 58 00				Caltex-gruppen		
7714/3/1							
Bellsund I	77 47	23.08.67	02.09.67	299*)	Norsk Polar Navig	405	
(Fridtjofsbreen)	14 46	29.06.68	21.08.68		Norsk Polar Navig		
		07.07.69	16.08.69				
		10.07.74	18.09.74				
		16.07.75	20.09.75				
		22.08.80	05.09.80				
		01.07.81	10.08.81				
7625/7-1							
Hopen I	76 26 57	11.08.71	29.09.71	50	Forasol	908	9.1
(Hopen)	25 01 45				Fina-gruppen		
7722/3-1							
Raddedalen	77 54 10	02.04.72	12.07.72	100	Total	2823	84
(Edgeøya)	22 41 50				Caltex-gruppen		
7721/6-1							
Plurdalen	77 44 33	29.06.72	12.10.72	108	Fina	2351	144.6
(Edgeøya)	21 50 00				Fina-gruppen		
7811/2-1							
Kvadehuken I	78 57 03	01.09.72	10.11.72	112	Terratest a/s	479	
(Brøggerhalvøya)	11 23 23	21.04.73	19.06.73		Norsk Polar Navig		

Exploration well/ location	Position north east	Spudded	Terminated	Days drilling	Operator Licensee	Total depth metres	KB elev. over msl metres
7625/5-1 Hopen II (Hopen)	76 41 15 25 28 00	20.06.73	20.10.73	123	Westburne Int Ltd Fina-gruppen	2840.3	314.7
7811/2-2 Kvadehuken II (Brøggerhalvøya)	78 55 32 11 33 11	18.08.73 22.03.74	19.11.73 16.06.74	186	Terratest a/s Norsk Polar Navig	394	
7811/5-1 Sarstangen (Forlandsrevet)	78 43 36 11 28 40	15.08.74	01.12.74	109	Terratest a/s Norsk Polar Navig	1113.5	5
7815/10-1 Colesbukta (Nordenskiøld Land)	78 07 15 02	13.11.74	01.12.75	373	Trust Arktikugol	3180	12
7617/1-1 Tromsøbreen I (Haketangen)	76 52 30 17 05 30	11.09.76 13.06.77	22.09.76 19.09.77	109	Terratest a/s Norsk Polar Navig	990	6.7
7617/1-2 Tromsøbreen II (Haketangen)	76 52 31 17 05 38	20.07.87 13.06.88	30.10.87 24.08.88	175	Deutag Tundra A/S	2337	6.7
7715/1-1 Vassdalen II (Van Mijenfjorden)	77 49 57 15 11 15	22.01.85	1)		Trust Arktikugol	2481	15.13
7715/1-2 Vassdalen II (Van Mijenfjorden)	77 49 57 15 11 15	30.03.88	01.11.89		Trust Arktikugol	2352	15.13
7816/12-1 Reindalspasset-I (Spitsbergen)	78 03 28 16 56 31	17.01.91	18.04.91		Norsk Hydro	2315	182.5

1) Drilling abandoned due to technical problems. *) Drilling not concluded.

regional surveys made available to the industry in 1987. In 1992, the Jan Mayen-88 survey was offered to the industry together with regional lines extending from Jan Mayen towards Vøring I and Troms I, respectively. The Jan Mayen-88 survey covers an area which must be regarded as interesting even though its hydrocarbon potential is uncertain and more surveys have to be carried out for proper evaluation.

2.5 DISCOVERIES UNDER EVALUATION AND FIELDS PLANNED DEVELOPED

2.5.1 Ekofisk area

This is the area on the Norwegian continental shelf which has been in production for the longest period of time, see Figure 2.7.4.a. The fields in production are primarily Cretaceous, while the exploration activity is focused on sandstone prospects. A number of small discoveries have been made in the area and the plan is to produce them as satellites to existing installations.

Mjølner

Mjølner lies in block 2/12 in production licence 113, allocated in 1985, with Norsk Hydro as operator. The field straddles the borderline between the Norwegian and Danish continental shelves. The A segment, from which production is planned to take place, lies, according to the Norwegian operator, 100 per cent within the Norwegian sector. The reserves in the segment are estimated by Norsk Hydro to be 1.5 mcm oil and 0.7 bcm gas.

Norsk Hydro, in cooperation with the operator in the Danish sector, will reinterpret the three-dimensional seismics in order to evaluate whether the A segment is sealed off from that part of the reservoir which extends into the Danish sector.

The commerciality declaration was submitted in June 1992. A possible development concept is a wellhead installation without permanent manning and a production well and pipeline to existing installations for further processing.

Trym

The Trym field was proven by the drilling of the 3/7-4 wildcat and lies in production licence 147, which was allocated in 1988 and where Shell is operator. The discovery straddles the borderline between the Danish and Norwegian sectors. According to Shell's estimates, recoverable resources are 10-14 bcm gas and 2.0 – 2.6 mcm condensate. Of the total, 60 per cent is in the Norwegian sector. The reservoir is divided into three segments, two of which are located in the Norwegian sector.

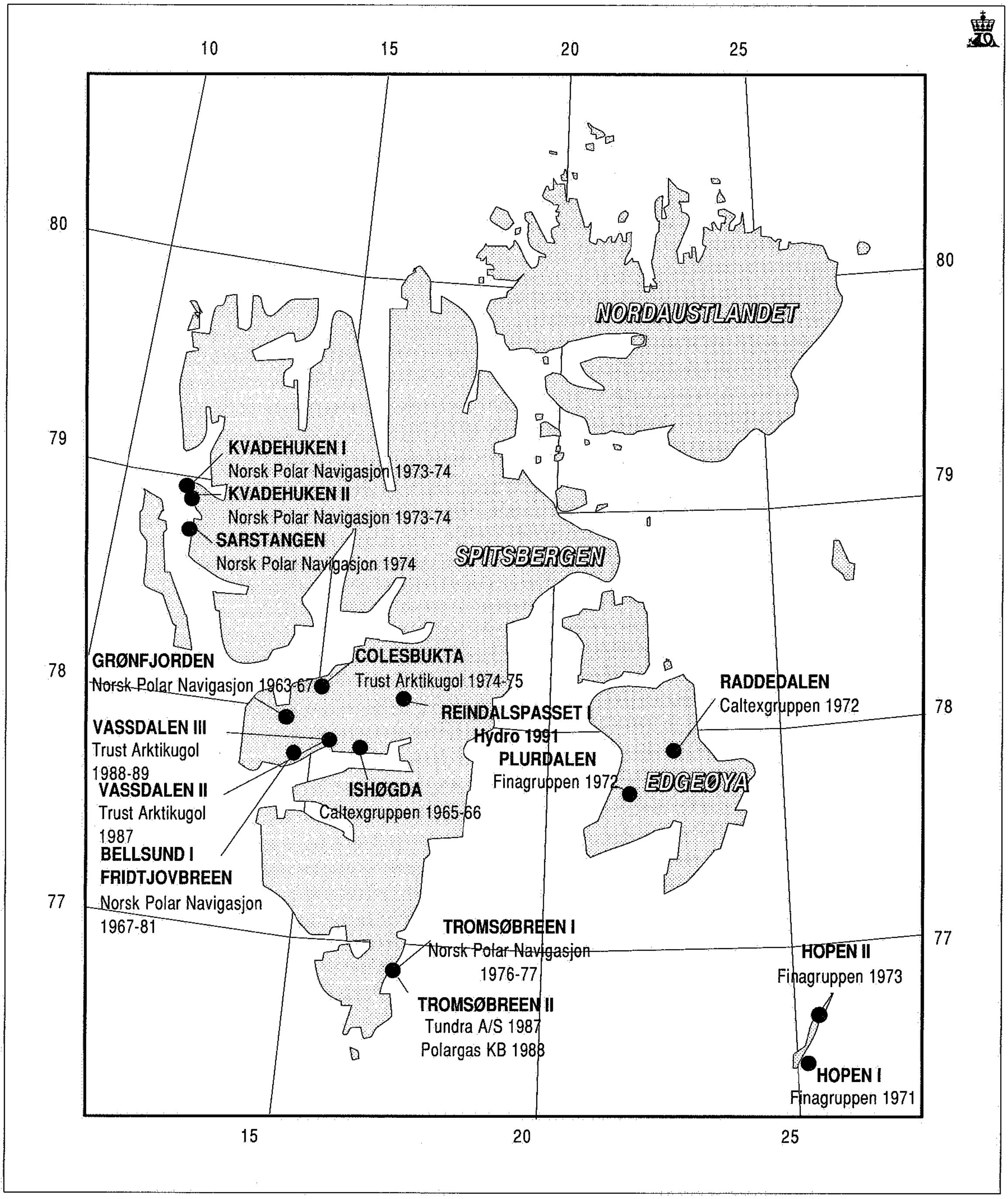
2/5-3 Sørøst-Tor

This field is located in block 2/5 in production licence 006, allocated in 1965, where Amoco is operator. The Directorate estimates the recoverable oil resources to be 2.5 mcm and the gas resources to be 2 bcm.

9/2-1 Gamma

This discovery is located in block 9/2 on production licence 114, which was allocated in 1985 with Statoil as operator. The discovery lies in the Egersund basin

Fig. 2.4.2.4
Well locations on Svalbard



and was proven by well 9/2-1. There is no existing infrastructure in the area. The operator's estimate of recoverable resources is 3.7 mcm oil. A possible development concept may be to use a jackup rig with direct buoy loading to tankers. The partners hope to declare the field commercial in spring 1993 and submit a plan for development and operation to the authorities later in the year. On this basis, production may start in 1995.

2.5.2 Sleipner and Balder area

In addition to Sleipner Øst, Loke, Sleipner Vest and 15/12 Beta discussed below, the Sleipner area consists of a number of other discoveries and prospects, see Figure 2.5.2.

15/12 Beta

This discovery is located in block 15/12, allocated in production licence 038 in 1974, where Statoil is operator. The operator estimates the recoverable resources to be between 15 and 20 mcm oil. The licensees are evaluating various development concepts at the same time as the geological data are being processed further. The preliminary plans are to start production in 1996-97.

Other discoveries and prospects
Two discoveries have been made in block 15/3: a gas-condensate discovery 15/3-1,3 in 1974; and a gas-oil discovery 15/3-4 in 1984. The Directorate's estimates for recoverable resources in 15/3-1,3 are 10.5 bcm gas and 5.2 mcm oil. Both discoveries are still in the early phase. In a structure in block 15/5 which extends across the border to the UK sector, a discovery has been made on the UK side. The discovery was first assumed to extend into the Norwegian sector, but exploration drilling in 1991 gave a negative result on the Norwegian side. Norsk Hydro as operator has therefore provisionally suspended all field development work except for further geological studies.

Balder
Balder was proven in 1974 by exploration well 25/11-5. The field is situated in blocks 25/10 and 25/11 in production licences 001 and 028 where Esso is the operator. Esso owns 100 per cent of production licence 001.

The Directorate estimates the recoverable reserves at 32.2 mcm oil. The Balder discovery contains relatively viscous oil. Hydrocarbons have been proven in Lower Eocene and Palaeocene sandstone in four different sand entities. The reservoir sandstone is relatively poorly consolidated but the reservoir parameters are otherwise good.

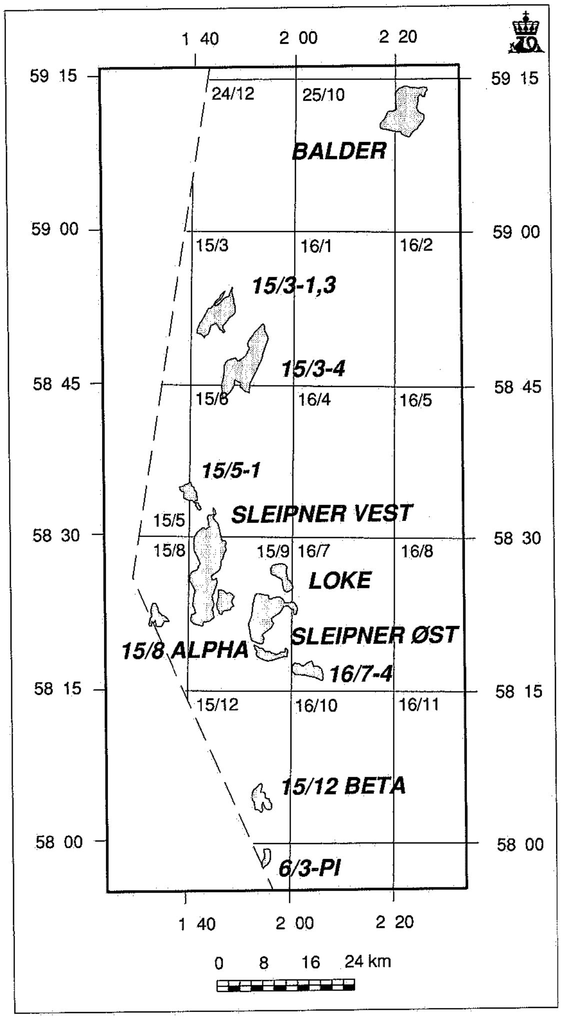
Long-term testing was carried out in summer 1991 using the production ship *Petrojarl I*, giving a production of 128,500 scm oil. The well gave valuable geological and technical production information. The operator has still not determined further progress for Balder. The Directorate will evaluate the Balder discovery in conjunction with the neighbouring discovery in 25/11-15.

2.5.3 Frigg area
This is an area where gas fields have been in production since 1977, see Figure 2.7.8.a. Recently, several small discoveries have been made in the area and the plan is to tie them into the existing infrastructure. Oil has also been found in the area. Two development plans were approved last year, for Frøy and Heimdal Jurassic. The most relevant of the planned developments are Skirne, Peik and Byggve.

Skirne
This field is situated in block 25/5 in production licence 102 allocated in 1985 with Elf as operator. The field was proven by well 25/5-3 in the Brent group in 1990. The operator's reserves estimates are 5.0 bcm gas and 0.7 mcm condensate. The Directorate's estimates are about half of the operator's.

Three-dimensional seismics were shot over the field in 1992 and new maps will be available in 1993. A probable development concept is a subsea installation with transfer of the well flow to Frøy and thence to Frigg. A plan for development and operation may be submitted in the fourth quarter of 1993. This may allow for production start-up in late 1997. However, field development depends on sale of the gas.

Fig. 2.5.2
The Sleipner and Balder area



Byggve
This field is situated in block 25/5 in production licence 102 allocated in 1985 and operated by Elf. The field was proven by well 25/5-4 in the Brent group in 1991. The operator's reserves estimates are 3.4 bcm gas and 0.7 mcm condensate, while the Directorate's estimates are somewhat lower.

No water contact has been proven in the discovery well, and further mapping of the field is necessary. An appraisal well will be drilled in 1994 based on the results of three-dimensional seismics shot over the field in 1992. The drilling results will form the basis for a plan for development and operation in 1994.

Production is planned to start in late 1997, provided the gas is sold. The assumed development concept is a subsea installation with transfer of the well flow to Frøy, before forwarding the flow to Frigg. It may be possible to achieve synergies with a development of Skirne.

Peik

Peik was proven by well 24/6-1 in 1985. The field is situated in production licence 088 allocated in 1984 with Total as operator. In 1987, the 9/15-1 wildcat in the UK sector proved hydrocarbons.

The operator's reserves estimate is 9.6 bcm gas and 3.0 mcm condensate, of which about 60 per cent is in the Norwegian sector.

Three-dimensional seismics were shot over the structure in 1992, and new maps will be available in the first six months of 1993.

The operator is planning development using a wellhead installation with minimum manning and transfer of the well flow to Frigg for processing. A plan for development and operation may be submitted in the fourth quarter of 1993, but any development is contingent on gas sale.

Hild

Hild is situated in production licences 040 and 043 operated by Norsk Hydro and Total Norge, respectively; see Figure 2.6.9.a. The gas discovery was proven by well 30/7-6 in 1977. On 1 January 1991, Total took over BP's interest and operatorship in production licence 043. Production licence 040 in blocks 29/9 and 30/7 was allocated in 1975. Production licence 043 was allocated in 1976 covering blocks 29/6 and 30/4. If the field is developed unitisation talks must be conducted between the production licences.

In 1991, three-dimensional seismics were shot in the area, the interpretation of which is still proceeding. Based on the results, the partners are planning to drill a test well in 1994.

The most probable development concept, as it seems at the present, is a subsea installation with transfer of the well flow to Frigg. The plan for development and operation can be submitted in 1995, which would mean production start-up in 1998.

25/2-5

This discovery is located in block 25/2 in production licence 026, which was allocated in 1969 with Elf as operator. Well 25/2-5 proved oil in 1976. At present there are no concrete plans to develop the field, but drilling results from 25/2-15, which are expected to be available in the first quarter of 1993, may change this. If the latter turns out to be dry the application for test production may be postponed until 1994.

Vale

This discovery is located in block 25/4 in production licence 036 which was allocated in 1981 with Elf as operator. Gas, rich in condensate, was proven in summer 1991. The partners are currently working towards a commerciality declaration, and the plan for development and operation may be submitted in 1994. The most probable development concept is a subsea installation with tie-in to either Frigg or Heimdal.

2.5.4 Oseberg and Troll area

Oseberg area

Several oil and gas fields in this area are in production and being developed. In addition, a number of discoveries have been made in the area which are planned to be produced as satellites to existing facilities, see Figure 2.6.9.a.

Oseberg Øst

Oseberg Øst is located about 28 kilometres northeast of the Oseberg field centre and comprises two structures divided by a sealing fault. Both structures are situated in production licence 053 operated by Norsk Hydro. Oil has been proven in several formations in the Brent group. The reservoirs are complicated, with several different oil-water contacts and relatively low permeability. The reserves are estimated by the Directorate at 19 mcm oil and 1.0 bcm gas.

The field was declared commercial in June 1991, based on a development with partial processing on the field and transfer of oil and gas to the Oseberg field centre for further processing. The partners plan to maintain pressure by means of water injection. The submission of the plan for development and operation has been postponed from autumn 1991 to the end of 1994 because Oseberg is sustaining its plateau rate of production longer than first anticipated.

Huldra

Huldra is a gas field located northwest of Veslefrikk. The bulk of the field lies in block 30/2 in production licence 051, although the field also extends into production licence 052 in block 30/3. Statoil operates both production licences.

The field was declared commercial in summer 1991 and unitisation talks are currently ongoing between the two production licences.

Gas has been proven in the Brent group, and Statoil's reserve estimates have varied between 17 and 22 bcm gas and between 4.5 and 5.6 mcm condensate. A new appraisal well was drilled in the field in 1992, but the task of mapping has not yet been completed. The operator is contemplating a field development using a wellhead installation tied in to existing processing facilities in the area. In 1993, the operator will continue mapping the field and proceed with technical studies.

The plan for development and operation may be submitted to the authorities in the middle of 1994, and the field could come on stream in 1998.

30/9-3 Omega Nord

This discovery is situated to the southwest of the Oseberg field centre, mainly in production licence

079. Oil has been proven in the Ness formation and oil and gas have been proven in the Tarbert formation. The reservoirs may be reached with wells from the Oseberg field centre and the plan is to produce from there. However, such a development concept depends on free or new well slots at the Oseberg field centre. So far, no decision has been made concerning details of the field development. The Directorate's estimates of recoverable resources are 16.6 mcm oil and 8.0 bcm gas.

Other discoveries under evaluation

The three discoveries making up Oseberg Vest are located west of the Oseberg field centre, mainly in production licence 053, and comprise 30/6-C-27H Lower Statfjord, 30/6-18 Kappa, and 30/6-17R Alpha Cook.

Well 30/6-C-27H was drilled as a pilot hole in the Lower Statfjord reservoir in connection with the horizontal production well for 30/6 Gamma Nord. An appraisal well has been planned to determine the gas-oil contact in autumn 1993. The operator's planned development concept is an extension of the existing production well. So far, no development plans have been made for the two other fields.

The six fields making up Oseberg Sør are located south of the Oseberg field centre and comprise 30/9-10 Omega Sør, 30/9-13S G-Øst, 30/9-4 B-Nord, 30/9-7 B-Sør, 30/9-9 J-Vest, and 30/9-6C.

Well 30/9-4 B-Nord lies in production licence 079, while the other five discoveries are located in production licence 104. Exploitation of these discoveries probably requires a common installation for partial treatment and transportation of oil and gas to the Oseberg field centre. Due to the extended plateau production on Oseberg, a development plan can be submitted at the end of 1994 at the earliest.

2.5.5 Gullfaks, Statfjord and Snorre area

This is a high activity area where several fields are in operation, in the process of being developed or under evaluation, see Figure 2.7.11.a. The area is very prospective and a number of interesting discoveries have been made.

Gullfaks Sør, 34/10 Beta and 34/10 Gamma

Block 34/10 was allocated in 1978 with Statoil as operator; see history of Gullfaks in section 2.5.11.

Gullfaks Sør lies in the middle of the block, about nine kilometres south of the Gullfaks field. The Beta field lies to the west of Gullfaks Sør and extends into 33/12. Gamma lies in the southeastern corner of the block. Gullfaks Sør is structurally complex: several unconnected gas-oil, gas-water and oil-water contacts have been detected. Hydrocarbons have been proven in Jurassic and Triassic sandstone.

So far, nine wells have been drilled to reservoir level on Gullfaks Sør in addition to one on Beta and one on Gamma. In 1992, one well was drilled on Gullfaks Sør and one on Gamma. Together with new three-dimensional seismics the test results form the basis for remapping and new resources estimates, such estimates being highly speculative as far as Gullfaks Sør is concerned. The Directorate has carried out its own mapping of Gullfaks Sør. The Directorate's resource estimates are 25.6 mcm oil and 56.1 bcm gas.

The plan is to prepare a commerciality declaration for both the oil and gas phases of Gullfaks Sør in 1993. Further work in the production licence will include an evaluation of coordination with other fields and discoveries in the area. Up to two wells may be drilled in the area in 1993.

Vigdis

The Vigdis field is situated in block 34/7 and comes under production licence 089. Vigdis comprises several discoveries and structures for which Saga Petroleum is the field operator.

In 1991, well 34/7-19 proved hydrocarbons in Middle Jurassic reservoirs and two production tests were carried out. No appraisal wells were drilled in Vigdis in 1992. The operator estimates the reserves at 27.1 mcm oil and 1.9 bcm gas. There is also potential for subsidiary resources in surrounding structures.

The water depth in the area is 230 to 300 metres. The operator's recommendation is to develop Vigdis with subsea wells tied up to Snorre TLP and Gullfaks.

The operator submitted a commerciality declaration on 29 December 1992, while the plan for development and operation is expected to be submitted to the authorities in 1993. Based on the development concepts examined by the partners, production may commence in 1996 at the earliest.

Visund

The Visund discoveries lie in block 34/8, which is in production licence 120 allocated in 1985 and operated by Norsk Hydro. The first discovery was made in the Brent group by well 34/8-1 in 1986. Well 34/8-3 followed in 1988 and proved hydrocarbons in a Brent segment further north. In 1991, three wells were drilled in the production licence, two of which were in connection with existing discoveries.

In 1992, three wells were drilled in the structure. Well 34/8-4A proved oil in the Statfjord formation, while well 34/8-8 will test reservoirs in the Brent group in 1993. Three-dimensional seismics have been shot over the entire structure. Two more wells may be drilled in 1993.

Visund has proven resources in the Brent group, and in the Amundsen, Statfjord and Lunde formations. The operator's estimates of recoverable resources are 16.2 mcm oil and 47.6 bcm gas.

The water depth in the area is 310-380 metres. The preliminary plans involve field development using a floating installation. The gas will probably be processed on the installation and transferred to an existing transportation system. The oil can either be exported via offshore loading buoys or transferred to an existing process centre in the vicinity. Production start-up is expected in autumn 1998.

2.5.6 Fields and discoveries in the Norwegian Sea

Haltenbanken can be characterised as a petroleum province which has been fairly exhaustively explored. All told, ten fields and discoveries have been proven, see Figure 2.5.6. There are good chances of making further discoveries in the area.

Trestakk

Trestakk is an oil discovery in block 6406/3. Statoil operates the production licence, which was allocated in 1984. The operator estimates recoverable resources to be 4.8 mcm oil. According to plan, produced gas will be reinjected into the reservoir to enhance oil recovery. It is assumed that the reservoir can be drained by means of three horizontal production wells.

Tyrihans

Tyrihans lies in blocks 6406/3 and 6407/1 and consists of two structures: Tyrihans and Tyrihans Nord, which probably have pressure communication through a common aquifer. Statoil is the operator. Tyrihans is classed as a gas-condensate structure, while Tyrihans Nord contains an oil zone with an overlying gas cap. The magnitude of the oil zone in Tyrihans Nord is uncertain since no oil-water contact has been proven. The operator's estimates for recoverable resources are 9.6 mcm oil-condensate and 26.5 bcm gas.

Njord

Njord is an oil discovery in blocks 6407/7 and 6407/10, where Norsk Hydro operates production licences 107 and 132, allocated in 1985 and 1987, respectively. A total of seven exploration wells have been drilled in the two blocks, four of which proved oil. The structure features a complex fault pattern which will probably have a major impact on oil recovery. The Directorate's estimates of recoverable resources are 35 mcm oil and 7.2 bcm marketable gas. The licensees are working towards submitting a plan for development and operation in 1994.

Midgard

The Midgard field is situated in blocks 6507/11 and 6407/2 under production licences 062 and 074, with Saga as operator. The field was discovered in 1981 by the drilling of well 6507/11-1 and was declared commercial by the operator in autumn 1991.

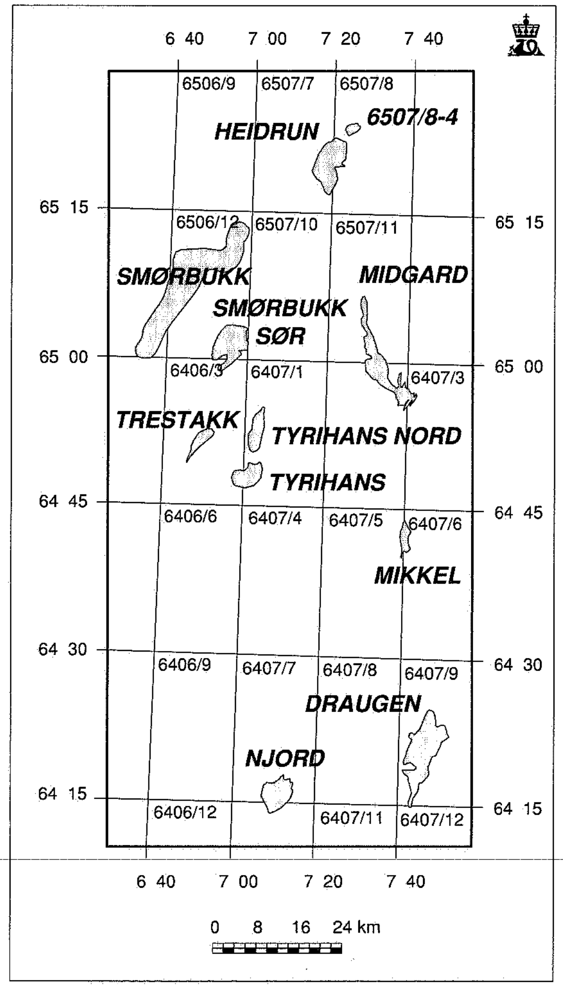
All in all, seven exploration wells have been drilled in the area, four of which were drilled in the structure, which is split into four structural segments. The field is mainly a gas field with some condensate and a thin oil zone. Reservoir properties are good, and the Directorate's reserves estimates are 87 bcm gas, 1.3 mcm oil, and 13 million tonnes NGL.

Field development is planned using a fixed, gravity base platform with integrated deck. It is planned to produce the reservoir by using depressurisation as the driving force. Development is based on a total of twelve production wells for gas, and two horizontal oil producers. The plateau production rate will correspond to dry gas sales of 8 bcm per annum. The operator assumes that the gas will be processed on the field and transported to the market via a dry gas pipeline.

Smørbukk

The bulk of this discovery lies in block 6506/12 in production licence 094 allocated in 1984. The southern part lies in block 6506/11 in production licence 134 allocated in 1987. Statoil operates both licences. The discovery contains gas, condensate and oil with a relatively high gas-to-oil ratio. It is located about 200 kilometres from relevant onshore tie-in points, in 250 metres of water. A total of eight wells have been drilled in block 6506/12. One wildcat has also been drilled in the southern part of the Smørbukk structure, in block 6506/11. The Directorate's resources estimates are 20 mcm recoverable oil and condensate and 65 bcm recoverable gas. Gas production from Smørbukk must be seen in conjunction with a general gas transport solution for Haltenbanken.

Fig. 2.5.6
Fields and discoveries in the Norwegian Sea



The licensees are now considering joint development of Smørbukk and Smørbukk Sør.

Smørbukk Sør
This field, situated in the southern part of block 6506/12, was proven in 1985 by the wildcat 6506/12-3, and later confirmed by two appraisal wells. The field lies about ten kilometres from Smørbukk in 300 metres of water. The Directorate's reserves estimates for Smørbukk Sør are 31 mcm oil and condensate and 24 bcm gas. Statoil is the operator.

The field was declared commercial in January 1992 and the licensees then hoped to submit a plan for development and operation in June 1992. Submission of the plan was later postponed indefinitely due to unsatisfactory profitability.

6507/8-4
This discovery, covered by production licence 124 under Statoil's operatorship, is situated about four kilometres northeast of the Heidrun field. In August 1990, the discovery well, 6507/8-4, proved oil with an overlying gas cap in the Åre formation. The operator's estimates of recoverable resources are 12 mcm oil and 2.5 bcm gas.

2.5.7 Barents Sea
About 250 bcm recoverable gas has been proven in the Troms I and Finnmark Vest area, see Figure 2.5.7. In addition, there is a thin oil zone on Snøhvit. In 1992, the Directorate reevaluated the resources base for the Snøhvit discovery.

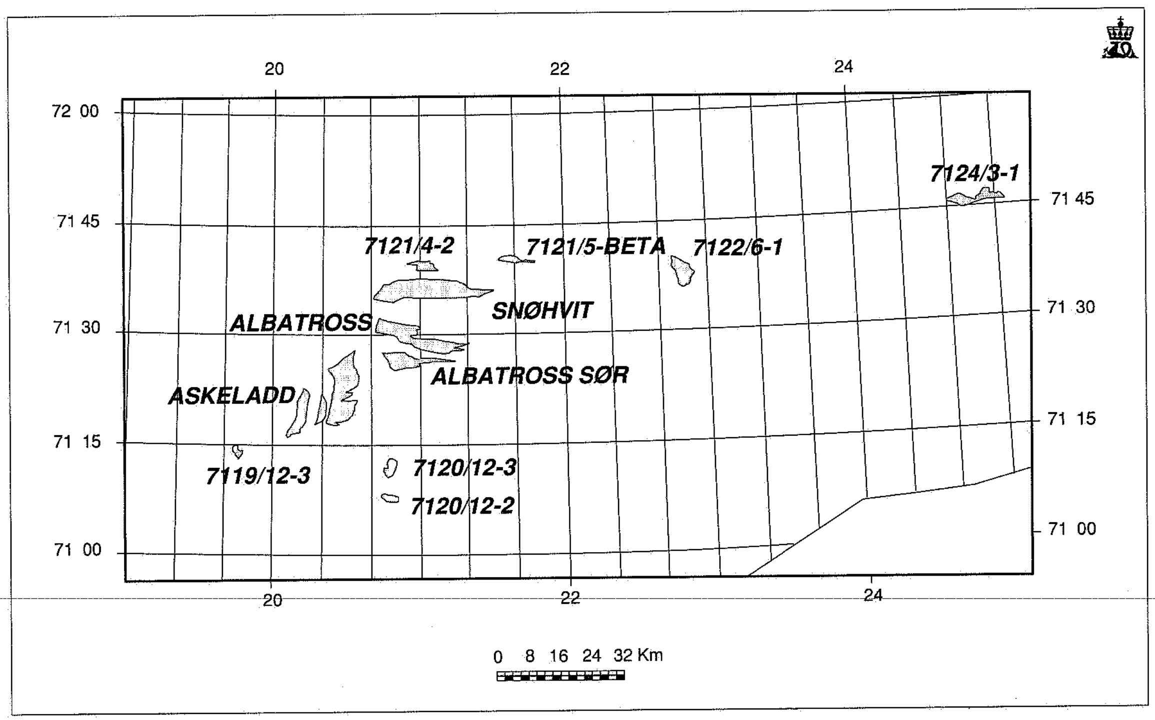
Snøhvit
Snøhvit lies in the following blocks and production licences: 7120/6 – 097; 7121/4 – 099; 7121/5 and 7120/5 – 110. Norsk Hydro is the operator of production licence 097, whereas Statoil is the operator of production licences 099 and 110. Production licences 097 and 099 were allocated in 1984, while production licence 110 was allocated in 1985. There is no existing infrastructure in the area.

The operator's estimates for recoverable resources are 105 bcm gas and 11.1 million tonnes NGL, while the Directorate's estimates for the same resources are 83 bcm gas, 6.7 mcm oil and 9.2 million tonnes NGL. The resources estimates are currently under review.

Pipeline transportation of the gas has been found uneconomic due to the long distance to potential gas markets. Thus, any field development must include a facility whereby the gas can be cooled to LNG. This will require additional investments compared to a traditional development of a gas field. In the last few years the development studies have therefore concentrated on finding simple and inexpensive solutions that are commercially sound. The following concepts are considered the most interesting:

- Subsea production system, with well flow to be carried directly to an LNG terminal onshore. When the reservoir pressure depletes, the subsea unit must be connected to a floating booster installation to pump the gas to shore.
- Semi-submersible platform with production from

Fig. 2.5.7
The Barents Sea



subsea completion wells. The gas is processed on the platform before transportation to an LNG terminal onshore.

A satisfactory sales contract for gas is decisive for any development of Snøhvit and the other gas fields on Troms I. The most interesting buyer seems to be Enel, Italy. Sales negotiations are currently being conducted, which, together with further technological studies, will determine whether the Troms fields can be developed.

In addition to gas the Snøhvit field also contains thin oil zones. The narrowness of the zones and the average to poor reservoir characteristics render the oil difficult to recover. The operator considers integrated oil and gas production to be feasible if the concept involving full processing on the field is chosen.

2.6 FIELDS APPROVED DEVELOPED

2.6.1 Embla

Embla lies in block 2/7 and was allocated under production licence 018 in 1965, see Figure 2.7.4.a.

Licensees

Phillips Petroleum Company Norway (operator)	36.9600 %
Norske Fina A/S	30.0000 %
Norsk Agip A/S	13.0400 %
Elf Petroleum Norge A/S	7.5940 %
Elf Rex Norge A/S	0.8550 %
Norsk Hydro Produksjon a.s	6.7000 %
Total Norge A/S	3.5470 %
Den norske stats oljeselskap a.s (Statoil)	1.0000 %
Norminol A/S	0.3040 %

Field history

The first well was drilled in 1974 and proved hydrocarbons in what was initially held to be Jurassic rock but which later turned out to be older. High reservoir pressure led to postponement of any further exploration. The discovery was not confirmed until 1988 by a new exploration well. Once it was ascertained that the reservoir was pre-Jurassic, a new exploration model could be developed for the southern part of the North Sea. The plan for development and operation of Embla was submitted in 1990 and approved in December of the same year. In addition to the discovery well, a total of five combined appraisal and production wells have been drilled, one of which was dry and had to be abandoned for technical reasons.

Reservoir

Great drilling depths and high reservoir pressures have led to some technical difficulties during the pre-drilling programme. At the same time, complex geology has brought surprises during development of the field. For this reason the operator has elected to reduce the reserves base to 5.6 mcm oil, 2.1 bcm gas, and 0.2 million tonnes NGL. There is still a great deal of uncertainty about field geology and reservoir characteristics.

Development concept

The original plan was to develop Embla in several stages, phase 1 including a wellhead installation with slots for up to 18 wells. Due to the imponderables of the geology and reservoir conditions, further plans for development will be evaluated as soon as production experience from the pre-drilled development wells is available. Planned production start-up is February 1993. An updated plan for development and operation is to be submitted within twelve months after production start-up.

Transportation

After processing on Eldfisk FTP, both the oil and gas will be carried to Ekofisk. From here they will be exported to Teesside and Emden, respectively.

Costs

The estimated investment costs for phase 1 run to about 2.3 billion 1992 kroner, with the estimated annual operating costs amounting to 38 million 1992 kroner.

2.6.2 Sleipner Øst

Production licence 046

Licensees

Den norske stats oljeselskap a.s (Statoil)	49.6000 %
Esso Norge a.s	30.4000 %
Norsk Hydro Produksjon a.s	10.0000 %
Elf Petroleum Norge A/S	9.0000 %
Total Norge A/S	1.0000 %

The production licence was allocated in 1976 and embraces blocks 15/8 and 15/9, see Figure 2.5.2. Statoil is the operator for the Sleipner Øst field.

The Directorate's estimated reserves in place in Sleipner Øst are 50 bcm gas, 19 mcm oil and 11.3 million tonnes NGL. It has been decided to inject gas from Sleipner Vest into Sleipner Øst, which may increase the recovery of condensate from Sleipner Øst by at least 10 mcm.

Development concept

The Sleipner Øst partners have resolved to develop the field with a fully integrated process, drilling and accommodation platform with quadripod concrete gravity base.

Condensate will be landed to Kårstø after laying a new 508 mm diameter pipeline from Sleipner A to Kårstø. The gas will be transported partially by pipeline to Zeebrügge in Belgium and partially through the Statpipe-Norpipe system to Emden in Germany. Sleipner Øst is planned to be ready for production start-up on 1 October 1993.

After the concrete gravity base for the Sleipner A installation sank in the Gandsfjord in August 1991, the licensees have extensively revised the plans for development of Sleipner Øst with a view to meeting the field's gas sales obligations under the Troll gas sales agreements. The two most important changes in the development concept are a new riser installation and a new subsea production system in order to drain the northern part of the Sleipner Øst field. Delivery obligations are safeguarded through contracts with other gas suppliers on the Norwegian continental shelf.

Costs
The estimated total development costs are about 21 billion kroner, inclusive a condensate pipeline from the Sleipner A installation to Kårstø. The total operating costs are an estimated 8.4 billion 1992 kroner, exclusive transportation costs. The stated development costs take into account the insurance sum paid after the loss of the concrete gravity base and accrued additional costs in this connection.

2.6.3 Loke
Production licence 046

The licensees and allocation year are the same as for Sleipner Øst. Development of Loke was approved in 1991. Two reservoir strata have been proven, Heimdal and Triassic, corresponding to the reservoir strata in Sleipner Øst. The Heimdal reservoir in Loke has pressure communication with the Heimdal reservoir in Sleipner Øst. Production of Sleipner Øst will therefore influence the pressure in Loke. Development of Loke will therefore stop large volumes of hydrocarbons from being trapped in the aquifer between Loke and Sleipner Øst. A new geological interpretation has reduced the operator's reserves estimate for the Heimdal reservoir to 0.81 bcm gas, 0.42 mcm oil, and 0.19 million tonnes NGL. For the Triassic reservoir, which has not yet been declared, the reserves estimates are 5.1 bcm gas and 2.0 mcm oil.

Development concept
Loke will be produced by means of a subsea production system with transfer of the well flow to the Sleipner A installation. Thus Loke will be drained with just one well. The exploration well that has been drilled from the Loke subsea template to the Theta Vest prospect will be converted into a production well if a discovery is made in Theta Vest. The gas is planned to be sold under the Troll gas sales agreement in the same way as the gas from Sleipner Øst. According to plan, Loke will be ready for production at the same time as Sleipner Øst.

Costs
The estimated investment costs are about 0.7 billion 1992 kroner. The total operating costs are estimated at 32 million 1992 kroner over the lifetime of the field.

2.6.4 Sleipner Vest
Production licences 046 and 029

Licensees

Den norske stats oljeselskap a.s (Statoil)	52.6000 %
Esso Norge a.s	28.0000 %
Norsk Hydro Produksjon a.s	9.4000 %
Elf Petroleum Norge A/S	9.0000 %
Total Norge A/S	1.0000 %

Sleipner Vest lies in blocks 15/6, 15/9 and 15/8, allocated in 1969 and 1976. Unitisation negotiations are currently being conducted between the respective production licences 046 (15/9 and 15/8) and 029 (15/6). Statoil is operator of production licence 046 and Esso of production licence 029. The Directorate estimates the field's reserves to be 135 bcm gas (including carbon dioxide), 27 mcm oil and 9 million tonnes NGL. The Sleipner Vest gas contains up to 9 per cent carbon dioxide. The plan for development and operation was submitted in December 1991 and the field was approved for development in December 1992.

Development concept
The first phase of the development concept consists of a wellhead installation, Sleipner B, and an installation for processing and carbon dioxide removal, Sleipner T. Sleipner B will be located in the southern part of the Sleipner Vest field, with transfer of the well flow to the Sleipner T installation located next to Sleipner A. Further development of the northern reaches of Sleipner Vest will, according to plan, be performed using subsea templates or wellhead installations with transfer of the well flow to Sleipner B.

Again, according to plan, Sleipner Vest should be ready for production in April 1997, when the gas will be injected into Sleipner Øst in order to increase the production of oil and NGL from the latter. Sleipner Vest has been awarded the gas sale in connection with the 1991 contracts when the buyers exercise their 30 per cent options under the Troll gas sales agreement.

Costs
The estimated total development costs are 13.7 billion 1992 kroner for the first phase of the development and 18.9 billion 1992 kroner for development of the entire field. The total operating costs are estimated at 22.2 billion 1992 kroner.

2.6.5 Heimdal Jurassic
Heimdal Jurassic is located in block 25/4, beneath the main Heimdal reservoir. Production licence 036 was allocated in 1971 with Elf as operator.

Licensees

Elf Petroleum Norge A/S	21.5140 %
Den norske stats oljeselskap a.s (Statoil)	40.0000 %
Marathon Petroleum Norge A/S	23.7980 %
Norsk Hydro Produksjon a.s	6.2280 %
Total Norge A/S	4.8200 %
Saga Petroleum a.s	3.4710 %
Ugland Construction Company A/S	0.1690 %

Field history
This field was proven with the same well as the main reservoir on Heimdal, 25/4-1 in 1972, and is located beneath the main reservoir. Gas and condensate have been found in the Brent group and Statfjord formation. The reserves estimate is 1.76 bcm gas and 0.44 mcm condensate. The plan for development and operation was approved in October 1992.

Development concept
The field will be drained using one production well drilled from the Heimdal installation. Treatment will be carried out using existing facilities on Heimdal, where only minor modifications will be necessary. The gas will be transported in the existing Heimdal transport system to the Continent. No final decision has been made with respect to transportation of the condensate, which may either be sent through the existing transport system to Great Britain, or through a new pipeline to Frigg and thence via Frostpipe.

Costs
The estimated total development costs are 173 million 1992 kroner for the well and modifications. A new condensate pipeline, if built, will cost between 200 and 260 million 1992 kroner in addition.

2.6.6 Frøy
Frøy is located in blocks 25/2 and 25/5 in production licences 026 and 102.

Licensees

Elf Petroleum Norge A/S (operator)	24.7573 %
Den norske stats oljeselskap a.s (Statoil)	53.9600 %
Total Norge A/S	15.2346 %
Norsk Hydro Produksjon a.s	6.0481 %

Field history
Development licences 026 and 102 were allocated in 1969 and 1985, respectively. Elf operates both licences. The field was proven in 1987 by well 25/5-1 and declared commercial in November 1990. The plan for development and operation of Frøy was approved in May 1992.

Reservoir
Frøy is an oil field and the operator's reserves estimates are 15.7 mcm oil and 3.2 bcm gas. The Directorate's estimates are somewhat lower than those of the operator.

Development concept
The field is to be developed using a wellhead platform with single-stage separation. Oil and gas will be transported in separate flowlines to Frigg for further processing. Onward transportation will take place in the existing transport system for gas to Great Britain and in a new oil pipeline, Frostpipe, to Oseberg. The field will be drained with five production wells and four water injection wells.

Costs
The estimated investment costs are 4.1 billion 1992 kroner, while the total operating costs have been estimated at 4.8 billion kroner exclusive of tariffs.

2.6.7 Lille-Frigg
Lille-Frigg is situated in block 25/2 covered by production licence 026, see Figure 2.7.8.a.

Licensees

Elf Petroleum Norge A/S (operator)	41.4200 %
Norsk Hydro Produksjon a.s	32.8700 %
Total Norge A/S	20.7100 %
Den norske stats oljeselskap a.s (Statoil)	5.0000 %

Field history
The production licence was allocated in 1969 with Elf as operator. The 25/2-4 wildcat proved hydrocarbons in 1975. The work of producing a commerciality declaration started after the drilling of well 25/2-12 in 1988. The plan for development and operation was submitted in February 1991 but was not approved. An updated plan was approved in September 1991.

Reservoir
Lille-Frigg is a combined gas-condensate field. The reservoir lies in the Brent group in a fault block which is an extension of the Heimdal ridge. The operator's estimates for recoverable reserves are 7 bcm gas and 2.7 million tonnes NGL.

Development concept
Lille-Frigg will be developed using a subsea installation remotely controlled from Frigg. Development is based on three production wells with depressurisation as the drive mechanism. It will be possible to tie in two extra wells. The untreated wellflow will be transferred under high pressure directly to Frigg for treatment. Gas will be forwarded to St Fergus in the existing pipeline. Stabilised condensate will be transported in a new pipeline, Frostpipe, to Oseberg. Production start-up was scheduled for 1 October 1993, but will be delayed until December 1993.

Costs
The estimated investment costs are 2.6 billion 1992 kroner and the total operating costs 1.6 billion 1992 kroner exclusive of tariffs.

2.6.8 Brage
The bulk of the Brage field is situated in block 31/4 and was allocated in 1979 as production licence 055, see Figure 2.6.9.a. The field also extends into block 30/6, production licence 053, and into the northern part of block 31/7. In 1991, this section of block 31/7 was allocated to the licensees of production licence 055 as production licence 185. Unitisation negotiations were conducted between production licences 055 and 053 in 1992, but no agreement was reached.

Licensees in production licences 055 and 185

Den norske stats oljeselskap a.s (Statoil)	56.0000 %
Esso Norge a.s	17.6000 %
Norsk Hydro Produksjon a.s	13.2000 %
Neste Petroleum a.s	13.2000 %

Norsk Hydro is the operator for the field and the plan for development and operation was approved by the Storting in spring 1990. Oil has been proven, providing the basis for development of two formations on Brage: Statfjord and Fensfjord. In the Sognefjord formation minor quantities of oil and gas have been proven, but the reservoir has not yet been incorporated in the development plans. The authorities ordered the operator to drill an appraisal well in the northeastern part of the field in connection with the approval of the plan for development and operation. This well must be drilled maximum three years after production start and will provide more information on the resources in the Sognefjord reservoir and parts of the Fensfjord reservoir outside the drainage area of the installation.

The State's interest was increased by 5 per cent through the exercising of the sliding scale. The interest though offered for sale has not yet been sold.

The Directorate has put the reserves at 46.2 mcm oil, 1.7 bcm gas, and 1.0 million tonnes NGL; whereas the operator's estimates are 38.5 mcm oil and 1.7 bcm gas.

Development concept

The field will be developed with an integrated production, drilling and quarters installation on a steel jacket. Production start-up is scheduled for November 1993, and the plateau production of 13,000 scm oil a day is expected to be reached in the course of the first year. Six production wells are to be predrilled, five of which have been completed. Pre-drilling started in December 1991.

The oil will be transported by pipeline to Oseberg and from there through the Oseberg line to Sture. A gas pipeline is to be tied into the Statpipe line.

Costs

The estimated total development costs are 10.5 billion 1992 kroner, and the total operating costs 7.7 billion 1992 kroner.

2.6.9 Troll

The rights associated with Troll were allocated in 1979 under production licence 054 (block 31/2) and in 1983 under production licence 085 (blocks 31/3, 31/5 and 31/6).

Troll was proven in 1979 when the operator on block 31/2, A/S Norske Shell, drilled the 31/2-1 exploration well in Troll Vest.

In November 1983, A/S Norske Shell declared that part of the Troll field which lies inside the block commercial. The licensees acceded to the commerciality declaration in December 1984. At that time 15 wells had been drilled in the block to delineate its extension.

The gas resources in Troll Øst were proven by the drilling of well 31/6-1. Subsequent drilling formed the basis for unitisation of the field between the licensees in production licences 054 and 085 in 1986.

The present rights in the Troll field are distributed as follows:

Troll Unit licensees

Den norske stats oljeselskap a.s (Statoil)	4.57600 %
A/S Norske Shell	8.28800 %
Norsk Hydro Produksjon A/S	7.68800 %
Saga Petroleum A/S	4.08000 %
Elf Petroleum Norge A/S	2.35344 %
Norske Conoco A/S	2.01456 %
Total Norge A/S	1.0000 %

The Troll field covers parts of blocks 31/2, 31/3, 31/5 and 31/6, see Figure 2.6.9.a. Development will take place in the following phases:

- TOGI: Troll-Oseberg gas injection
- Troll I: Development of gas reserves in Troll Øst
- Troll II: Development of oil reserves in Troll Vest
- Troll III: Development of gas reserves in Troll Vest.

No decision has been reached regarding the development of Troll III.

Reservoir

The reservoir is situated in three geological formations of Late Jurassic age. The upper formation, Sognefjord, is dominated by medium to coarse grade sandstone with good reservoir characteristics. Sognefjord contains the bulk of the gas and oil in the field. Underneath Sognefjord lies the Heather formation, which has inferior reservoir properties, and the Fensfjord formation with variable reservoir characteristics.

At the top of Troll Øst and Troll Vest is a gas column over 200 metres high. The western part of the field (Troll Vest oil province), lying predominantly in block 31/2, features an oil column 22 to 26 metres thick, compared to 11 to 13 metres in the Troll Vest gas province. In Troll Øst the proven oil strata vary from zero to four metres in thickness.

Troll phase I: Development of gas reserves in Troll Øst

Shell is the development operator for Troll phase I, but it has been agreed that Statoil will take over the operatorship when the field comes on stream.

Led by the operator, A/S Norske Shell, the licensees submitted their plan for development and operation of the gas reserves in Troll Øst (Troll phase 1) to the authorities in September 1986. The Storting considered and approved the PDO in December 1986. The plan called for a fully integrated platform with initial processing capacity of 21.3 bcm gas a year. The operator was asked to submit a revised plan with a more detailed description of the installation and processing equipment. A revised plan was submitted by the licensees in May 1990 and approved by the authorities in December the same year.

This new development plan for Troll phase I involves drainage of the gas reserves in Troll Øst from a fixed, concrete wellhead installation. The platform location is about 80 kilometres northwest of Bergen in 303 metres of water. The wellflow from up to 40 wells will be transferred from the installation via two multiphase pipelines to the landing site at Kollsnes in the Øygarden local district. Condensate will be separated from the gas in the onshore processing facility and will either be transported by pipeline to the existing terminal at Sture or to a new terminal and shipping facility at Ljøsneset. The licensees will decide on a condensate shipping site early in 1993 (simultaneously with the submission of the plans for landing of oil from Troll phase II). The dry gas will be compressed and exported from the onshore terminal to the Continent through new pipelines. When completed in 1996, the facility will have a capacity of 23.7 bcm gas a year. Figure 2.6.9.b shows planned installation for Troll phase I.

Some of the gas from the field has been sold under the Troll gas sales agreements (TGSA) finalised in 1986 with buyers in Germany, the Netherlands, Belgium, France, and Austria. Since 1986, further gas sales agreements have been negotiated with other buyers, where Troll, or other fields, will supply the gas. Under the agreements the initial gas will be delivered from Sleipner from 1 October 1993 pending production start-up of the Troll field in 1996.

Total investment costs for Troll phase I have been estimated at 32 billion 1992 kroner, with estimated annual operating costs of 850 million 1992 kroner, rising to 1180 million 1992 kroner.

Troll phase II: Development of oil reserves in Troll Vest

Troll phase II involves development of the 22-26 metre thick oil column in the Troll Vest oil province. Norsk Hydro operates both the development and operating phases.

The plan for development and operation of Troll phase II was submitted to the authorities in December 1991 and approved by the Storting in May 1992. In connection with the approval of Troll phase II it was decided that Statoil will be the operator for further planning, development and operation of the residual gas in the Troll field. Norsk Hydro, though subject to Statoil's overall coordination, will be the operator for any development, or for modification and operation of the Troll phase II installation, if this is also used to treat part of the residual gas in the Troll field.

The original plan for drainage of Troll Vest oil reserves recommended oil production from 17 horizontal wells. A concrete floater was recommended for processing and storage of the oil before export, after studies had been made of concepts using floaters, fixed installations, and ships. An installation capable of handling both oil and subsequent gas production from Troll Vest was also considered by the licensees.

The planned plateau production is 25,000 scm oil a day, corresponding to about 157,000 barrels a day. Between 5 and 6 million scm gas a day can be exported to the Troll phase I installation for forwarding to Kollsnes together with gas and condensate from Troll phase I.

The licensees decided to carry out gas injection through a separate injection well in the southern part of the reservoir in the Troll Vest oil province in the course of 1992. This will increase the recovery rate for oil and is considered by the Directorate to be an improved production strategy for the southern part of the oil province. In addition, it was decided to increase the number of production wells in the Troll Oil province north from five to six. According to present plans, Troll II will therefore be developed with 18 oil producers and one gas injector, covered by a total of four subsea stations, which in turn are tied in to the installation. In addition, the installation will have capacity for hook-up of another five subsea stations from the Troll Vest gas province. Norsk Hydro, which operates Troll phase II, will drill appraisal wells in order to clarify the potential for production from the oil column in the Troll Vest gas province.

When the Storting approved the development of Troll phase II in May 1992, the transport solution for the oil from the field had not been clarified. The plans were based on storage of up to 100,000 scm oil in the base of the concrete floater with offshore buoy loading of the oil for export by tankers, at the same time as landing to an onshore terminal was still being considered. In autumn 1992, the licensees decided to land the oil through a 406 mm pipeline to Mongstad. A plan for construction and operation of the pipeline to shore is expected to the submitted early in 1993.

Total investment costs for Troll phase II have been estimated at some 18 billion 1992 kroner, including a pipeline to Mongstad and expansion of the terminal plant. Annual operating costs for the field installations have been estimated at 370 million 1992 kroner in the first year of operation, rising to 500 million 1992 kroner.

Troll phase III: Development of gas reserves in Troll Vest

Any future development of the gas reserves in the Troll Vest gas province will constitute phase III of the Troll field development. Various development concepts, dates of production start-up, and coordination concepts with other infrastructure on the Troll field are being examined.

It has been decided that Statoil will be the operator for further planning, development and operation of the residual gas in the Troll field.

Statoil (and to some extent Shell), on behalf of the Troll group, in 1992 examined possible development concepts for the gas reserves in Troll Vest, the aim being to establish development concepts covering re-

Fig. 2.6.9.a
The Oseberg and Troll area

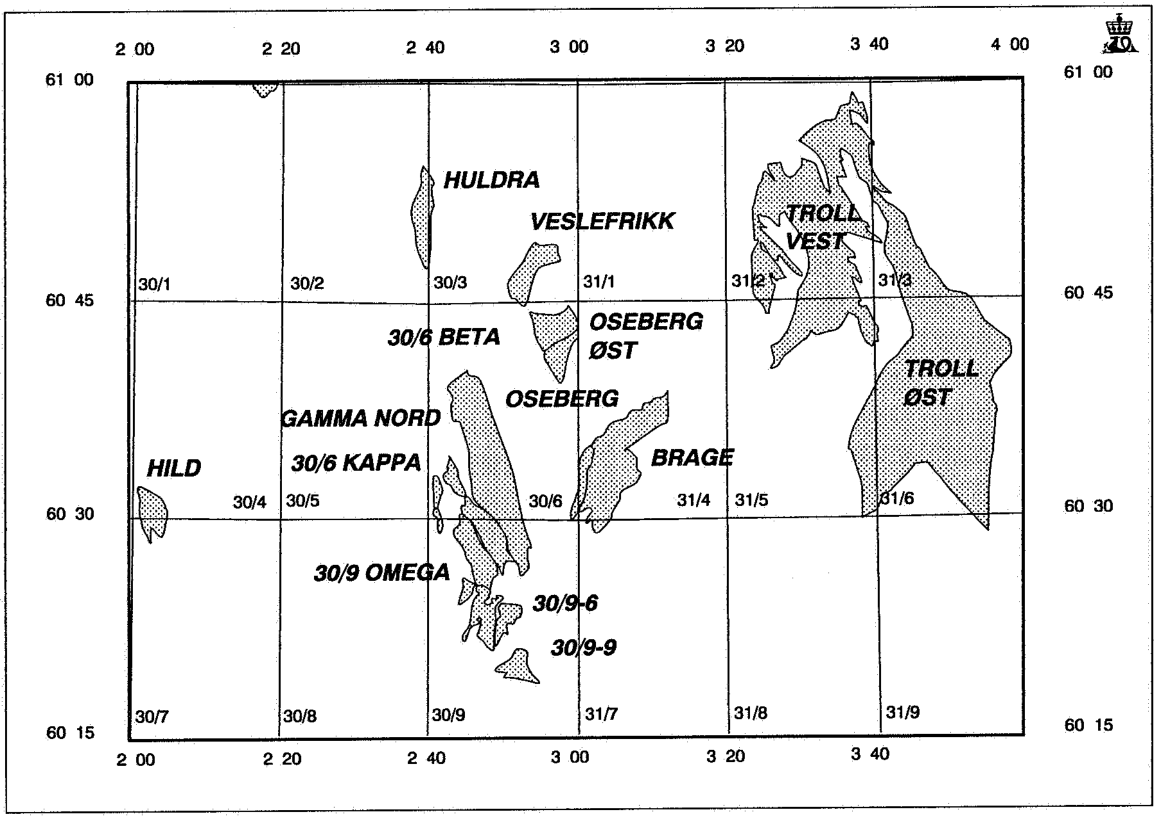
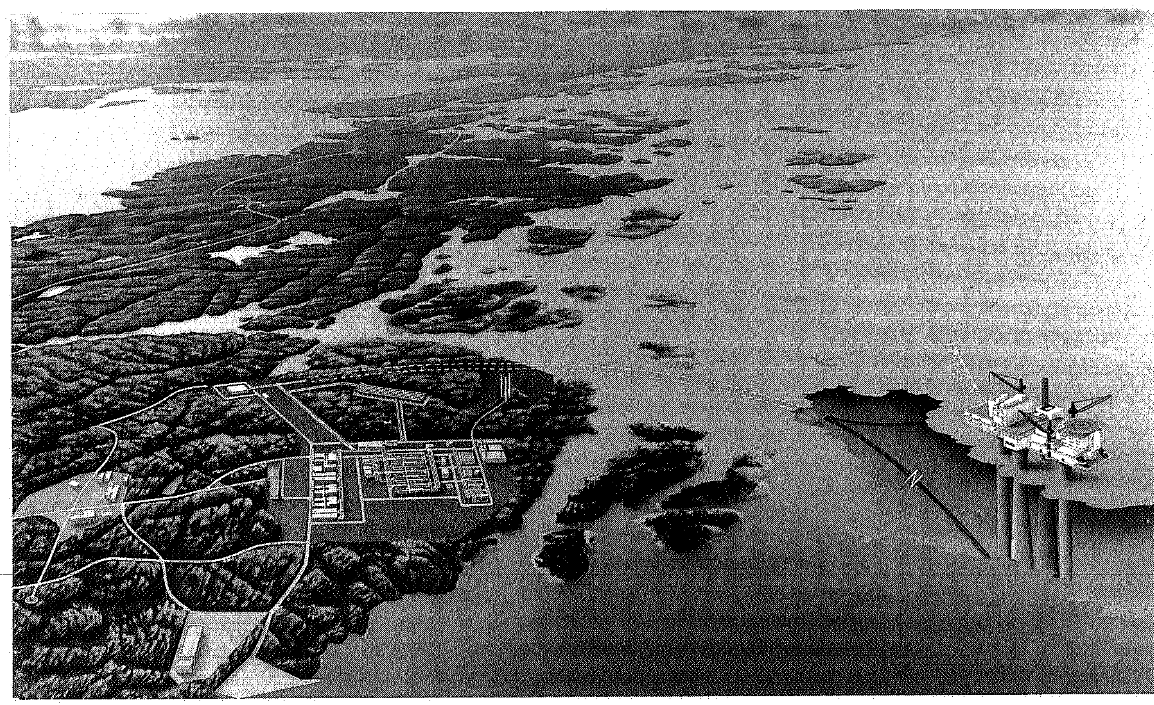


Fig. 2.6.9.b
Planned installation on Troll phase I



levant gas sales scenarios with a view to providing qualified background information for gas sales promotion.

The table below shows the Directorate's reserves estimate for Troll Vest. The Directorate has started remapping of Troll Vest, and this is expected to be completed in 1993.

RESERVES	Oil mcm	Gas bcm
Troll phase I (Troll Øst)	–	825
Troll phase II (Troll Vest oil province)	64	–
Troll phase III (Troll Vest gas province)	30-40	463

The operator's estimates for gas reserves coincide with those of the Directorate.

No decision has been made concerning recovery of the oil reserves in the Troll Vest gas province.

TOGI

In addition to the principal gas development project in Troll Øst (Troll phase I), a subsea production system (Troll Oseberg Gas Injection, TOGI) has been built. The TOGI template is located in Troll Øst, controlled from the Oseberg field centre, and supplies gas for injection in the Oseberg field. TOGI production and the Troll Øst gas supplies started in February 1991. By the end of 1992, about 10 mcm gas a day were being supplied to Oseberg.

Norsk Hydro is operator for the development and operation of TOGI.

TOGI investments are in the region of 3.1 billion 1992 kroner, while total operating costs up to 1999 inclusive are an estimated 1.1 billion 1992 kroner.

2.6.10 Tordis

Tordis is situated in block 34/7 and comes under production licence 089, see Figure 2.7.11.a.

Licensees

Production licence 089 was allocated in 1984 with Saga as operator. The sliding scale has been exercised in the production licence, giving the following distribution:

Den norske stats oljeselskap a.s (Statoil)	55.4000 %
Esso Norge a.s	10.5000 %
Idemitsu Oil Exploration a.s	9.6000 %
Norsk Hydro Produksjon a.s	8.4000 %
Saga Petroleum a.s (operator)	7.0000 %
Elf Petroleum Norge A/S	5.6000 %
Deminex (Norge) A/S	2.8000 %
DNO Olje A/S	0.7000 %

Field history

Tordis was proven by the drilling of the 34/7-12 wildcat in 1987. An appraisal well, 34/7-14, was drilled on the field in autumn 1989. Based on these two wells the field was declared commercial, and the plan for development and operation was approved by the Storting in May 1991.

Reservoir

The Directorate estimates the recoverable resources to be 18.8 mcm oil, 1.2 bcm gas and 0.5 million tonnes NGL. These estimates are almost identical to those of the operator. The drive mechanism for the field is pressure maintenance by means of water injection. The oil is undersaturated and is found in the two reservoirs Upper and Lower Brent.

Development concept

The plan is to develop the field with subsea completion wells: five producers and two water injectors. The well flow will be phased in with Gullfaks C for processing, metering and forwarding. According to the operator's plans, production will start in autumn 1994. The gas will be sold under the Troll gas sales agreement.

Costs

Total investments are estimated at some 3.7 billion 1992 kroner, including wells and modification costs on Gullfaks C. The estimated total operating costs are 1.65 billion 1992 kroner.

2.6.11 Statfjord Øst

Statfjord Øst is situated in production licences 037 and 089, see Figure 2.7.11.a. Production licence 037 covers blocks 33/9 and 33/12 and was allocated in 1973, while production licence 089 covers block 34/7 and was allocated in 1984.

The sliding scale has been exercised in the production licence, giving the following licensees in the unitised field:

Licensees after unitisation

Den norske stats oljeselskap a.s (Statoil)	52.7000 %
Esso Norge a.s	10.2500 %
Mobil Development Norway A/S	7.5000 %
Norske Conoco A/S	5.0000 %
A/S Norske Shell	5.0000 %
Idemitsu Oil Exploration (Norsk) a.s	4.8000 %
Saga Petroleum a.s	4.4400 %
Norsk Hydro Produksjon A/S	4.2000 %
Elf Petroleum Norge A/S	2.8000 %
Deminex (Norge) A/S	1.4000 %
Amerada Hess Norge a.s	0.5200 %
Amoco Norway A/S	0.5200 %
Enterprise Oil Norwegian A/S	0.5200 %
DNO Olje A/S	0.3500 %

Field history

The plan for development and operation of Statfjord Øst was approved by the King in Council on 9 November 1990. Statoil operates the field. A unitisation agreement for Statfjord Øst was signed in June 1991 which splits the reserves with 50 per cent to each of the two production licences. On 19 November 1991, the Ministry of Petroleum and Energy approved a coordination agreement for Statfjord Øst, which means that Statfjord Nord and Statfjord Øst will have a common project organisation and use the same equipment on Statfjord C. According to plan, production from Statfjord Øst will start in the fourth quarter of 1994 and last until the year 2007.

Reservoir
According to Statoil's estimates the oil reserves are approximately 19.4 mcm. The Directorate's estimates for oil reserves in Statfjord Øst are 13.4 mcm, which is about 30 per cent lower than Statoil's estimates. Differences in geological model account for most of the discrepancy.

Development concept
The field will be developed with subsea installations connected to the Statfjord C platform. The subsea installations will consist of three templates: two for production and one for water injection. The well flow, which comprises oil, gas and water, will be carried in two pipelines to Statfjord C for processing, storage and onward transportation. The plan is to drain the fields using six production wells and four water injection wells. A scheme has been approved for conversion of two water injection wells drilled from Statfjord C into subsea completion wells, which constitutes a change in the plan for development and operation of the field.

Costs
The estimated investment costs for Statfjord Øst are 3.5 billion 1992 kroner. In the production phase the annual operating costs for Statfjord Øst have been estimated at 89 million 1992 kroner. The work to modify the Statfjord C platform is believed now to be more extensive than first supposed, although it is not yet clear how large the overruns will be.

2.6.12 Statfjord Nord
Statfjord Nord is situated in block 33/9 covered by production licence 037 and was allocated in 1973, see Figure 2.7.11.a. The partners in the licence are given below.

Licensees in production licence 037

Den norske stats oljeselskap a.s (Statoil) (operator)	50.0000 %
Mobil Development Norway A/S	15.0000 %
A/S Norske Shell	10.0000 %
Esso Norge a.s	10.0000 %
Norske Conoco A/S	10.0000 %
Saga Petroleum a.s	1.8750 %
Amerada Hess Norge A/S	1.0420 %
Amoco Norway Oil Company	1.0420 %
Enterprise Oil Norwegian A/S	1.0420 %

Field history
The plan for development and operation of Statfjord Nord was approved by the King in Council on 9 November 1990. Statoil operates the field. According to plan, production from Statfjord Nord will start in the second quarter of 1994 and last until the year 2009. A coordination agreement exists between Statfjord Nord and Statfjord Øst.

Reservoir
According to Statoil's estimates, there are 27.7 mcm oil reserves in place. The Directorate's estimate for the oil reserves in Statfjord Nord is about 31 mcm. This estimate assumes that eight production wells will be drilled and that oil production is not terminated until the year 2014. Any decision to drill two extra wells will be deferred until after production start-up.

Development concept
The field will be developed with subsea installations connected to the Statfjord C platform. The subsea installations will consist of three templates: two for production and one for water injection. The well flow, which comprises oil, gas and water, will be carried in two pipelines to Statfjord C for processing, storage and onward transportation. The plan is to drain the fields using six production wells and four water injection wells. Statfjord Nord and Statfjord Øst will use the same equipment at Statfjord C.

Costs
Investment costs for Statfjord Nord run to 3.7 billion 1992 kroner. In the production phase the annual operating costs for Statfjord Nord have been estimated at 90 million 1992 kroner. The operating costs given by the operator are associated with some measure of uncertainty since the strategies for maintenance and compilation of data have not been finalised. The modification work on the Statfjord C platform is believed to be more extensive than originally assumed, and the additional work on Statfjord C may mean postponement of the date for production start-up.

2.6.13 Draugen
The Draugen field, situated in block 6407/9, was allocated in 1984 as production licence 093; see Figure 2.5.6.

Licensees

Den norske stats oljeselskap a.s (Statoil)	65.0000 %
A/S Norske Shell	21.0000 %
BP Norway Limited U.A	14.0000 %

Shell operates the field, where production is scheduled to come on stream in autumn 1993.

Field history
The operator declared the field commercial in September 1987 and submitted the partners' plan for development and operation to the authorities that same month. In August 1988, the operator presented an updated PDO for the field, which the Storting

approved in December 1988. Draugen is the first field on Haltenbanken to be approved for development.

Reservoir

The Directorate estimates the in-place reserves on Draugen to be 68 mcm oil and 3 bcm gas. The Draugen reservoir is of excellent quality and consists of two formations: Rogn which contains the major part of the reserves, and Garn. There are several minor faults in the reservoir which may allow communication between the formations. There may also be communication in areas where the intervening shale strata are thin. On the evidence of the test results the wells are expected to provide high delivery capacity.

Development concept

The field development plan assumes a fixed concrete gravity base with integral topsides. Six or seven production wells are planned, plus six water injection wells and one gas injection well. Nine of the wells will have subsea completion. The installation will have ten well slots and a total of 34 J tubes when complete. An average plateau rate of 14,300 scm oil a day is conjectured.

Transportation

It is proposed to export the crude via a floating loading platform, FLP, with compliant moorings. The gas will be reinjected until a use has been found for it.

Gas application

The operator has considered numerous alternative uses for the associated gas. The principal option in the plan for development and operation was to inject it into the Ile formation (aquifer) for three years. Further, it was planned to produce the Rogn Sør formation early on, enabling the partners to continue gas injection into this formation for a three-year period. After the year 2000, it is expected that a gas transportation solution or some other use for the gas will have been found on Haltenbanken.

Following interpretation of new three-dimensional seismics in 1992, it was discovered that the intended location in the Ile formation was unacceptable for gas storage due to a lack of structural closure. In the third quarter of 1992, an exploration well was drilled about ten kilometres east of the main field, one of the purposes being to clarify the feasibility of gas storage in the so-called »Husmus» structure. The well did not prove any hydrocarbons, but potential structures were identified for gas storage in the Garn, Ile and Tilje formations. The operator will submit a revised plan for gas application in the first quarter of 1993.

Costs

Total estimated investment and operating costs over the lifetime of the field are 12.7 billion and 13 billion 1992 kroner, respectively.

2.4.14 Heidrun

Heidrun is situated in blocks 6507/7 and 6507/8 (see Figure 2.5.6), the former being allocated in 1984 under production licence 095, and the latter in 1986 under production licence 124.

Licensees after unitisation

Den norske stats oljeselskap a.s (Statoil)	75.0000 %
Norske Conoco A/S (operator)	18.1250 %
Neste Petroleum a.s	5.0000 %
Norsk Hydro Produksjon a.s	1.2500 %
Norminol A/S	0.6250 %

Statoil will take over the Heidrun operatorship from Conoco during the operating phase. Production start-up is scheduled for autumn 1995.

Field history

Heidrun was discovered in 1985 and declared commercial in December 1986. The plan for production and operation of the field was submitted in November 1987, including early production. The plan was approved but the partners discontinued their efforts to implement it, and the operator submitted a revised plan in December 1989. This plan was approved by the Storting in May 1991. However, the decision about what to do with the associated gas was postponed. In November 1991, the Government presented a proposition recommending landing of the associated gas for methanol production, a solution which was approved by the Storting in February 1992.

Reservoir

The field contains oil with an overlying gas cap. The reservoir is faulted and consists of several geological formations. For optimal resource exploitation the gas cap should be produced after the bulk of the oil. The reserves estimates for Heidrun have given rise to much uncertainty, the Directorate's estimates being 87 mcm oil and 38 bcm gas, while the operator's estimates are 119 mcm oil and 45 bcm gas. The variations in reserves estimates are primarily due to differences in geological models.

Development concept

Heidrun will be developed using a concrete tension leg platform installed over a subsea template with 56 well slots. According to the plan, 35 production wells, 11 water injection wells and two gas injection wells will be drilled. Six of the water injection wells will have subsea completion. The projected production capacity for oil is 35,000 scm a day; while maximum treatment capacity for water and gas will be 24,700 cubic metres and 4,7 mcm a day, respectively. Oil will be exported by means of a new concept based on direct shipboard loading (DSL), which is tanker transport without the use of offshore oil storage.

Costs

The estimated total investment and operating costs over the lifetime of the field are 29 billion and 22 billion 1992 kroner, respectively. The investment estimate includes operations related costs. The estimated development costs are 26 billion 1992 kroner.

Gas application

Associated gas will be reinjected into the reservoir in the period 1995-96 and subsequently landed to Tjeldbergodden for methanol production from the fourth quarter of 1996. Production of the gas cap is not an issue until the end of the oil production period.

2.7 FIELDS IN PRODUCTION

2.7.1 Hod

Production licence 033

Licensees

Amoco Norway Oil Company	25.0000 %
Amerada Hess Norge A/S	25.0000 %
Enterprise Oil Norwegian A/S	25.0000 %
Elf Petroleum Norge A/S	25.0000 %

Hod lies in block 2/11 and was allocated in 1969 as production licence 033 with Amoco as operator. The field is located about 12 kilometres south of the Valhall field. Parts of the block have later been relinquished, and parts of the relinquished acreage have been included in production licence 068. The Hod field consists of two separate structures: Vest-Hod and Øst-Hod. See Figure 2.7.4.a.

The plan for development and operation of the Hod field was approved by the Storting in June 1988, and production from the field started in October 1990.

Production

The Hod field is a Cretaceous field in the Central Graben producing from several formations. The production takes place from two wells in Vest-Hod and from three wells in Øst-Hod. About 95 per cent of the product comes from Øst-Hod. The recovery factor for oil is 17 per cent. Primary recovery is by means of pressure relief. Further potential for increased recovery is being evaluated.

Production installations

Development features an unmanned production installation, where oil and gas are separated by means of a separation unit and metered before being piped to Valhall for further processing.

Transportation

Oil and gas are transported in a single pipeline to Valhall and from there through the existing transportation systems to Emden and Teesside.

Metering system

Oil and gas are metered to fiscal standard at Hod. The metering system is part of the Valhall-Hod system for the distribution of hydrocarbons.

Costs

The total investments in the Hod field from 1988 to 2005, inclusive, are estimated at 0.9 billion 1992 kroner. The total operating costs, including carbon dioxide tax and tariffs, are estimated to be 1.7 billion 1992 kroner.

2.7.2 Valhall

Production licences 006 and 033

Licensees

Amoco Norway Oil Company	28.0937 %
Amerada Hess Norge A/S	28.0937 %
Enterprise Oil Norwegian A/S	28.0937 %
Elf Petroleum Norge A/S	15.7187 %

Block 2/8 was allocated in 1965 with Amoco as operator. In 1989, Texas Eastern Norwegian Inc's interest was sold to Enterprise Oil Norwegian A/S. Norwegian Oil Consortium A/S & Co was sold to Elf in 1991. Valhall is located primarily in block 2/8, which contains 92.8 per cent of the reserves (production licence 006). The remaining 7.2 per cent of the reserves lie in block 2/11 (production licence 033), in which each partner owns 25 per cent. The plan for development and operation was approved by the Storting in 1977, and production started in autumn 1982.

Production

Valhall produces from fragmented limestone. The recovery factor at present is 23.5 per cent.

In summer 1990, a pilot project was initiated whereby water was injected into the Tor formation from a well on the field. The intention was to test the effect on drainage of water injection. Water break-through occurred in one of the adjacent wells after injection of some 600,000 cubic metres of water. The results so far have been positive both with regard to injectivity and the drainage effect. So far, there have been no indications of water break-through in other producers. The pilot project will probably continue until the middle of 1994.

The Ministry of Petroleum and Energy in 1991 ordered the operator to perform an extended study of the Valhall field, the purpose of which is to evaluate feasible measures to increase field recovery, including both gas and water injection. It is expected that this study will be completed in 1993.

Production installations

The development of Valhall comprises quarters, drilling, production and riser platforms, the three first-mentioned being on the field and connected to each other by flying gangways, see Figure 2.7.2. The riser platform – for which Phillips is the operator – is connected to the Ekofisk tank.

Oil is separated from the Valhall gas using two separation trains. The gas is compressed, dried and checked for dew point. The heavier gas fractions, natural gas liquids (NGL), are separated on Valhall in a fractioning column and then reinjected, mainly into the oil.

Transportation
Oil including NGL is transported by pipeline to Ekofisk for forwarding to Teesside, while gas is carried in a separate pipeline to Ekofisk for forwarding to Emden.

Metering system
Oil and gas are fiscally metered on the riser platform 2/4-G. The fiscal metering systems are part of the Ekofisk system for hydrocarbon distribution.

Costs
The total investment costs on the Valhall field from August 1977 to year 2011, inclusive, are expected to be 20.4 billion 1992 kroner, while the total operating costs have been calculated at 16.5 billion 1992 kroner.

2.7.3 Tommeliten
Production licence 044

Licensees

Den norske stats oljeselskap a.s (Statoil)	70.6400 %
Norske Fina A/S	20.2300 %
Norsk Agip A/S	9.1300 %

Production licence 044 was allocated on 27 August 1976 and embraces block 1/9 southwest of the Ekofisk area. The field was discovered in December 1976 and was Statoil's first offshore petroleum discovery. The plan for development and operation of Tommeliten was approved by the Norwegian Storting in June 1986. Production started on 3 October 1988.

Production
Tommeliten comprises two structures: Alpha in the south and Gamma in the north.

Phase 1 of the development comprised the Gamma structure. Gas from Tommeliten is processed on the Edda installation. A portion of the gas is used as gas lift for wells on Edda and thus extends the economic duty cycle of the Edda field. A revised plan for development and operation of Tommeliten, which also includes development of the Alpha structure, will probably be submitted in 1993.

Production installations
The Gamma structure has been developed using subsea completion wells. The entire production is transported to Edda for processing.

Transportation
Following the first stage separation on Edda, the Tommeliten gas is taken by pipeline to the Ekofisk

Fig. 2.7.2
Installations on Valhall

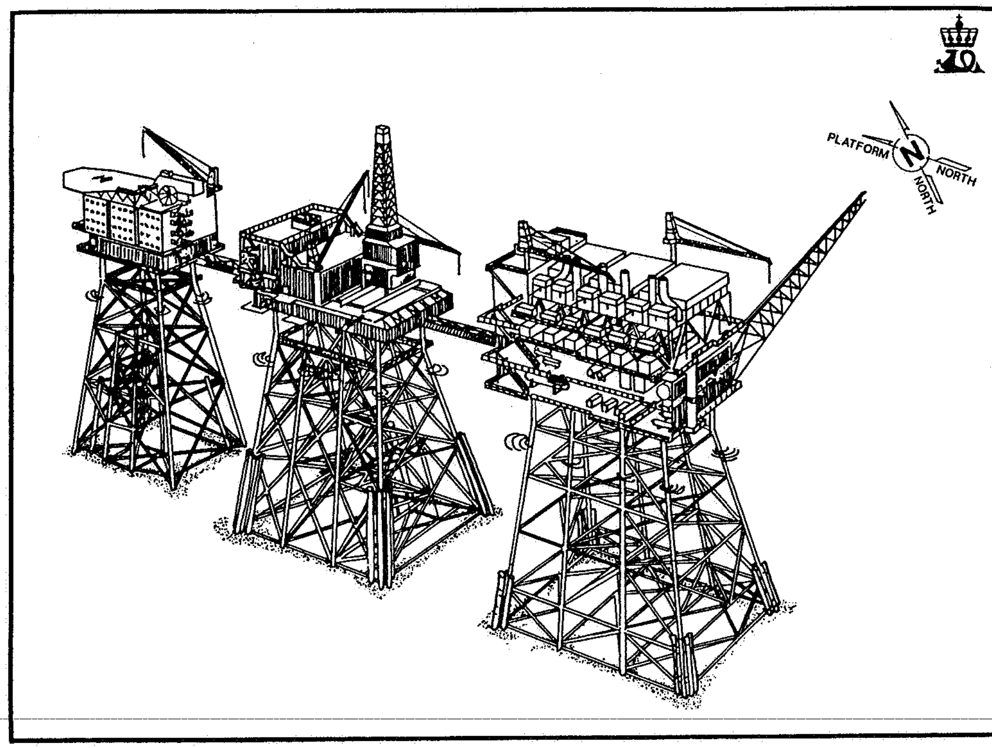
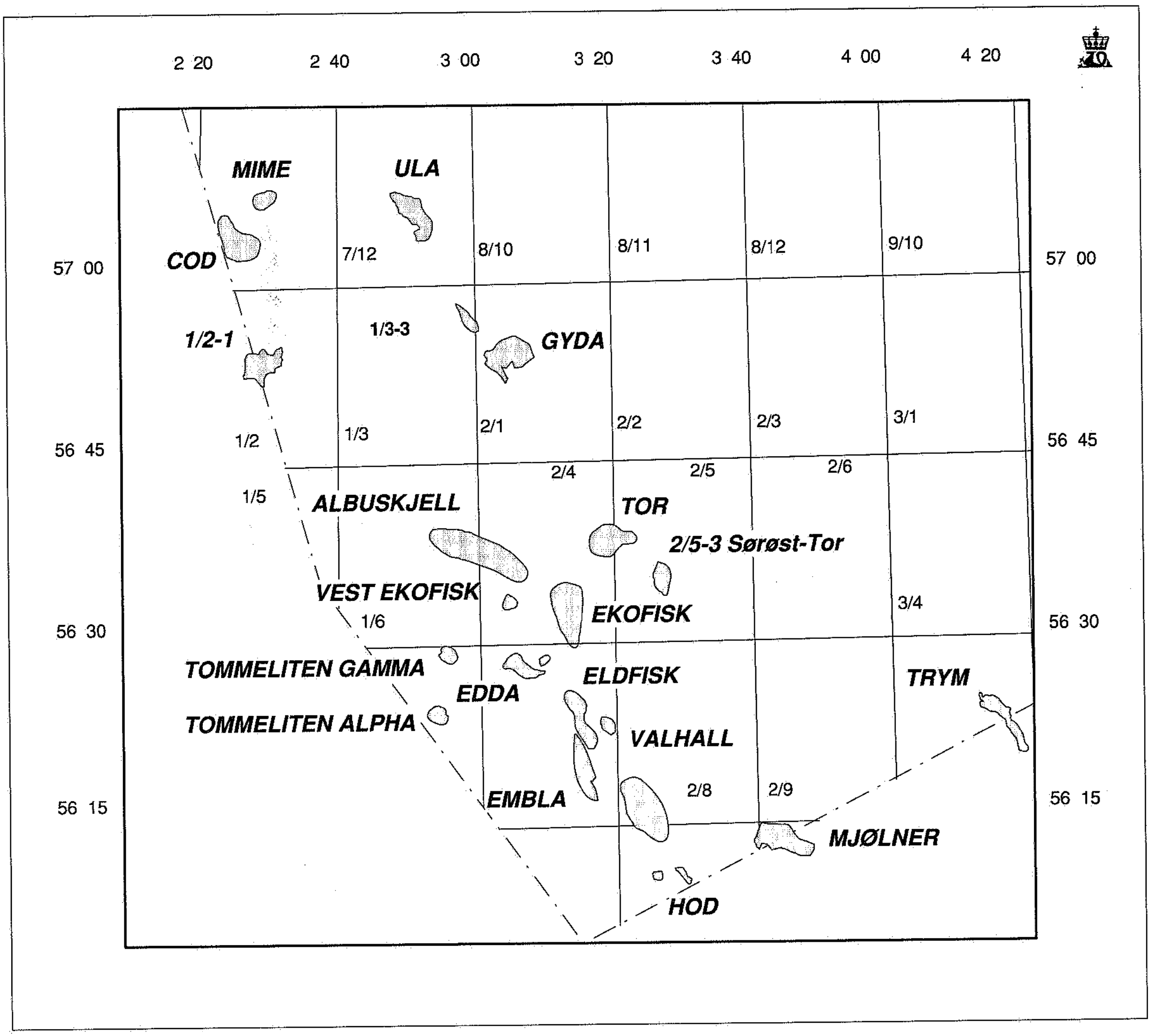


Fig. 2.7.4.a
The Ekofisk area



field centre for further drying, while the dry gas is included in Phillips's system for delivery of gas to Emden.

Tommeliten crude is transported from Edda to the Ekofisk field centre and thence by pipeline to Teesside.

Metering system

The existing metering systems have been rebuilt and upgraded to support the separate metering of oil and gas from both the Edda and Tommeliten fields on Edda.

Costs

The total investments in the Tommeliten field up to and including the year 2006 are expected to reach about 4.8 billion 1992 kroner. This figure includes development of the Alpha structure. The total operating costs up to the same date are expected to be about 1.8 billion 1992 kroner.

2.7.4 Ekofisk area

Production licence 018

Licensees

Phillips Petroleum Company Norway	36.9600 %
Norsk Fina A/S	30.0000 %
Norsk Agip A/S	13.0400 %
Elf Petroleum Norge A/S	7.5940 %
Norsk Hydro Produksjon a.s	6.7000 %
Total Norge A/S	3.5470 %
Den norske stats oljeselskap a.s (Statoil)	1.0000 %
Elf Rex Norge A/S	0.8550 %
Norminol	0.3040 %

This group, called the Phillips Group, owns the rights to the Cod, Edda, Eldfisk, Ekofisk and Vest Ekofisk fields. Cod lies in block 7/11, Edda and Eldfisk in block 2/7, and Ekofisk and Vest Ekofisk in block 2/4.

The Albuskjell field is split between production licences 018 and 011; the Tor field between production licences 018 and 006. Albuskjell lies in blocks 1/6 and 2/4; Tor in blocks 2/4 and 2/5.

The field interests are split as follows:

Albuskjell	
Phillips Group	50.0000 %
A/S Norske Shell	50.0000 %
Tor	
Phillips Group	75.3612 %
Amoco Group (Valhall licensees)	24.6388 %

The Ekofisk area, operated by Phillips, consists of seven fields in production: Albuskjell, Cod, Edda, Ekofisk, Eldfisk, Tor and Vest Ekofisk. Cod was discovered in 1968 and is the only field producing from a sandstone reservoir in the Ekofisk area. The other fields in the area all produce from limestone. Ekofisk itself was discovered in 1969 and declared commercial the year after. The other fields in the area were discovered between 1969 and 1972. Ekofisk, easily the largest field in the area, has a hydrocarbon pore volume about 30 per cent larger than the Statfjord field. Eldfisk is the second in line as far as size goes. See Figure 2.7.4.a for field locations.

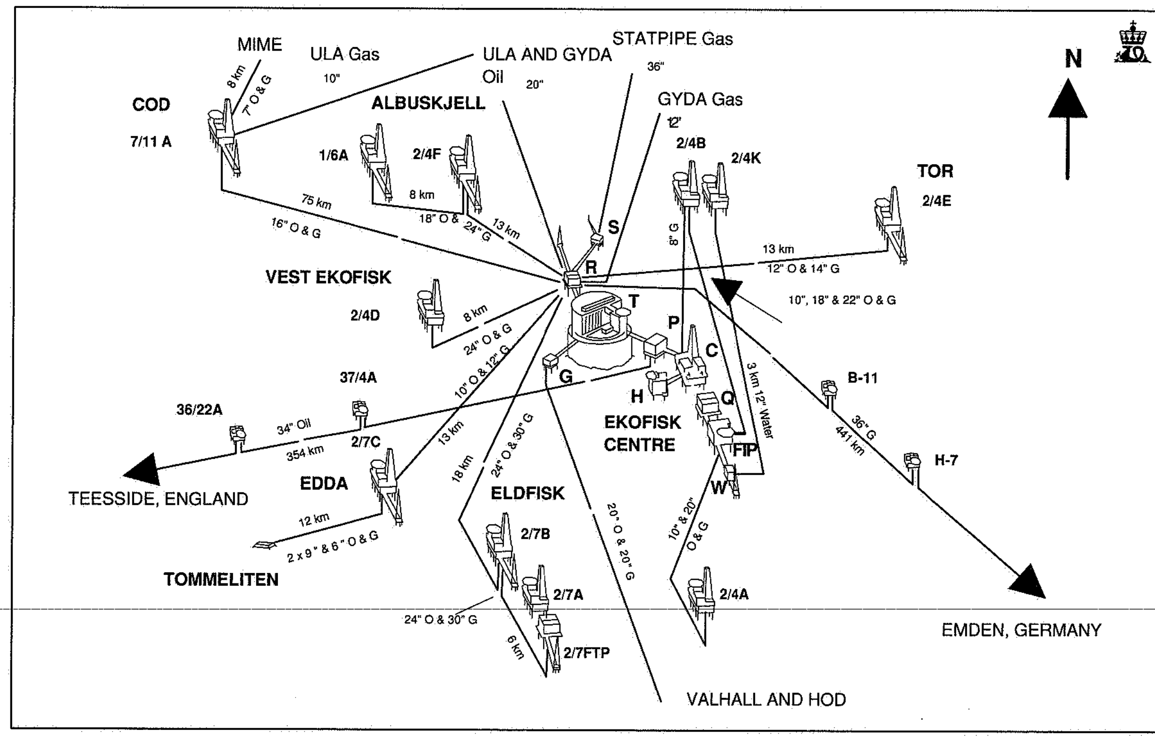
Production

The Ekofisk area has been developed in several stages. From June 1971 to May 1974, oil was recovered from four wells which had been completed on the seafloor on the Ekofisk field. The fields Cod, Tor and Vest Ekofisk were developed and tied in with the Ekofisk field centre at the same time as the oil pipeline was laid to Teesside and the gas pipeline to Emden. These pipelines came on stream in October 1975 and September 1977, respectively. Before the gas line was commissioned the gas had been re-injected into the Ekofisk field. The second development stage involved the tie-in of Albuskjell, Edda and Eldfisk to the Ekofisk field centre. The fields, which are produced by means of depressurisation, have a relatively low oil recovery factor of about 30 per cent. The recovery factor can be increased by injecting water or gas into the reservoirs. In addition, greater use of horizontal wells both as producers and injectors can contribute to increased recovery. In 1991, the Ministry of Petroleum and Energy ordered the operator to perform extended field studies of Ekofisk, Eldfisk and Tor. The purpose of these studies was to evaluate the feasibility of optimising recovery from the fields.

On the Ekofisk field, where water flooding has been performed on a field scale since 1987, the recovery factor will probably increase to over 30 per cent. In 1991, the water injection equipment was upgraded to an injection capacity of about 80 000 m^3 of water a day. This upgrade permitted injection of water into the Tor formation and the lower part of the Ekofisk formation across the entire field. The operator is currently evaluating the future production strategy for the rest of the Ekofisk formation.

On Eldfisk, the second largest field in the area, the operator is also considering increasing the recovery

Fig. 2.7.4.b
Installations in the Ekofisk area



by means of water flooding or gas injection. To this end a pilot project was performed in 1991 in which limited volumes of water were injected into a single well with positive results.

On the Tor field, water injection started from a single well in 1992. The operator is evaluating the additional potential for water flooding or gas injection. The first horizontal well spudded on the Tor field in 1991 has now come on stream. The drilling of further horizontal wells in the area is being considered. Figure 2.7.4.b shows the installations in the Ekofisk area.

Subsidence

In November 1984 it was observed that the seabed beneath the Ekofisk field centre had subsided. Since then, measurements have shown that the total depth of the subsidence was 5.58 metres as of 15 December 1992.

The rate of collapse from 1980 to 1986 was about 0.4 to 0.5 metres a year, although slightly less towards the end of the period. During 1987 and 1988, the observed rate of subsidence was about 0.3 metres a year. In 1992, the rate of subsidence increased compared to what was expected.

Several monitoring methods have been used to estimate the rate of subsidence. In 1984-85, analyses were made of wave data, though these could only indicate the previous subsidence rate. This prompted the operator in 1985 to take many measurements of the distance from the sea surface to certain horizontal braces in the platform steel jackets. This method was of limited precision. Nowadays the subsidence is measured using pressure sensitive detectors on the seabed in addition to regular satellite passes.

The cause of the subsidence is the compaction of the reservoir rocks. There is still some doubt about the mechanism by which the reservoir volume reduction takes place and causes subsidence.

The only way to prevent further subsidence and other problems related to compaction of the reservoir seems to be to limit the net reservoir recovery. This can be done by injection of gas and/or water.

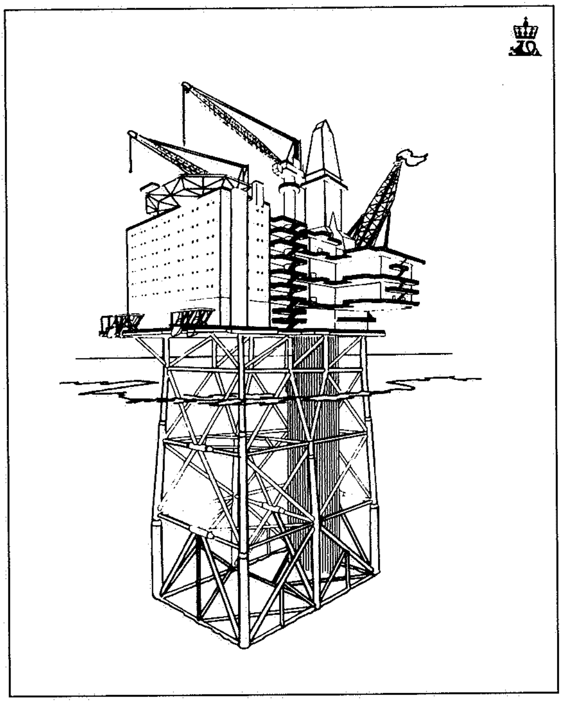
Subsidence is not peculiar to the Ekofisk field centre and it is reckoned there will be a need to modify installations in the northern and southern parts of the field in the course of 1994.

In summer 1987, the steel platforms at the Ekofisk field centre were all jacked up due to the subsidence. This was done to lift them out of reach of the waves (100 year wave). It was not technically feasible to use this method to protect the Ekofisk tank. In order to give it the same protection the Phillips group decided to build a concrete barrier around it. Construction started in 1988 and the protective barrier was towed out to Ekofisk in two halves and mated on site in 1989.

Transportation

The gas is transported by pipeline to Emden. The capacity is fully exploited. The oil, containing the NGL fraction, is transported by pipeline to Teesside. Here the transport capacity is augmented by boosting the operating pressure. As a further measure, anti-friction chemicals are added, giving a total current transportation capacity of over 95000 Sm^3 a day.

Fig. 2.7.5
Installation on Gyda



Metering systems

Total oil and gas deliveries to the Teesside and Emden pipelines from the area are metered and analysed on the Ekofisk tank. In addition, oil and gas production are metered on the individual satellite platforms before being transferred by pipeline to the Ekofisk field centre. The exceptions are Vest Ekofisk and Ekofisk itself, which are metered on the Ekofisk tank. All metering systems are in accordance with the fiscal standard and are part of the operator's system for hydrocarbon distribution. Modernisation work is currently being undertaken in Teesside, Emden and the Ekofisk area.

Costs

Total investment costs on the seven fields making up the Ekofisk area up to and including the year 2011 are expected to run to some 95 billion 1992 kroner.

2.7.5 Gyda

Production licence 019B

Licensees

Den norske stats oljeselskap a.s (Statoil)	50.0000 %
BP Norway Limited U.A (operator)	26.6250 %
Norske Conoco A/S	9.3750 %
Norske AEDC Ltd	5.0000 %
Norske MOECO Ltd	5.0000 %
K/S A/S Pelican & Co	4.0000 %

The Gyda field is located in block 2/1, about 28 kilometres southeast of Ula, along the so-called Ula Trend; see Figure 2.7.4.a. The field was proven in 1980 by exploration well 2/1-3, and by 1985 three appraisal wells had also been drilled in the structure.

The Gyda field was declared commercial on 22 January 1987. The partners submitted their plan for development and operation on 11 March 1987, and the plan received Storting approval in spring 1987. Gyda came on stream on 21 June 1990.

Production

The reservoir from which production takes place consists of Upper Jurassic sandstone. The estimates for recoverable oil and gas are 32.0 mcm and 4.3 bcm, respectively; and 1.9 million tonnes is NGL.

The field is produced using water injection as the drive mechanism. There are plans for 17 production wells and eight injection wells, although the number can be increased if necessary. All in all there are 32 available slots.

At the end of 1992, the field had production from ten wells and injection in six. Water production was less than expected and only one well has been shut down. Oil production in 1992 was therefore higher than forecast.

The field has turned out to be more complicated than first assumed. Partly sealing faults divide the field into provinces which pose a challenge to draining strategy.

An exploration well with a single sidetrack proved hydrocarbons in a structure south of Gyda. This structure is called Gyda-Sør and a plan for development and operation is currently being prepared.

In 1992, the water injection capacity was upgraded from 12,240 to 24,480 scm a day. Current production capacity is 11,000 scm oil and 1.6 mcm gas a day. Production is now at plateau level where it is expected to remain for two more years, after which time it will gradually decline and probably be terminated in the year 2012.

Production installations

The development concept for the field comprises a combined drilling, quarters and processing installation on a steel jacket, see Figure 2.7.5. The installation was prefabricated in large assemblies which were generally finally inspected and tested in the yard before being towed offshore in winter 1989-90. The high degree of completion before tow-out cut costs and reduced the manhours spent on offshore hook-up operations.

Transportation

Gyda crude is transported to Ekofisk via the Ula-Ekofisk oil pipeline and thence to Teesside, whereas the gas is transported in a separate pipeline to Ekofisk and from there to Emden.

Metering system

Oil and gas production is metered to fiscal standard before being piped to Ekofisk. The metering systems are included in the Ekofisk system for distribution of hydrocarbons.

Costs

Total investments up to 2012 amount to 8.8 billion 1992 kroner, whereas total operating costs come to 11.2 billion 1992 kroner.

2.7.6 Ula

Production licence 019A

Licensees

BP Norway Limited U.A (operator)	57.5000 %
Svenska Petroleum Exploration A/S	15.0000 %
Den norske stats oljeselskap a.s (Statoil)	12.5000 %
Norske Conoco A/S	10.0000 %
K/S A/S Pelican & Co	5.0000 %

The Ula field, situated in block 7/12, see Figure 2.7.4.a, was discovered in 1976 and declared commercial in December 1979. Although the field development plan received approval in 1980, it became clear that same year that the development would not be profitable after all. A new field development plan was therefore submitted for a revised development concept in April 1983 and approved in January 1984. Production from Ula started in October 1986.

Production

The Ula field is an Upper Jurassic sandstone sediment. It lies on the Ula Trend which is an oil province along the faulted northeast margin of the Central Graben. The field is a salt dome structure with a reservoir having excellent production characteristics.

In 1992, production from the Ula field declined relative to the plateau level due to water break-through in four wells, two of which have been shut down. Nine wells were in production and six injected water. Production will decline gradually until 2007.

In 1992, the Ministry of Petroleum and Energy ordered the operator to start work on an extended field study (UFS). This study will provide the basis for a decision regarding measures to enhance recovery.

In the underlying Triassic reservoir, recoverable volumes of oil have been proven only in the northern part of the block. Oil-water contact is uncertain, and the estimate for oil in place is in the region of 15 mcm, but a low recovery factor can be expected due to poor reservoir properties.

Production installations

The development concept involves three conventional steel jacketed platforms for production, drilling and quarters; see Figure 2.7.6. The jackets were installed in summer 1985 and offshore hookup took place from October 1985 to August-September 1986.

Since 1991, the production capacity has been upgraded from 15,900 to 21,700 scm oil a day. The water injection capacity was increased from 28,600 to 30,900 cubic metres a day in 1992.

Transportation
The Ula crude is carried by pipeline via the Ekofisk field centre to Teesside. Statoil is operator for the link to Ekofisk, which was installed on the seabed in summer 1984. The Ekofisk link is about 70 kilometres long and has a diameter of 508 mm. The Ula gas is carried by a gas line via Cod to Emden. The Ula-Cod link was installed and commissioned in spring 1985.

Metering system
The oil and gas production is metered to fiscal standard before being exported by pipeline to Ekofisk. The metering systems are part of the Ekofisk hydrocarbon distribution system.

Costs
The estimated total investments up to year end 2007 are about 12.1 billion 1992 kroner, while the total operating costs up to the same date are expected to be 11.1 billion 1992 kroner.

2.7.7 Heimdal
Production licence 036 was allocated in 1971 and covers block 25/4, lying about 180 kilometres west-northwest of Stavanger, see Figure 2.7.8.a, where Elf is operator. On that part of the field which embraces Heimdal, the State has exercised its option.

Licensees

Den norske stats oljeselskap a.s (Statoil)	40.0000 %
Marathon Petroleum Company (Norway)	23.7980 %
Elf Petroleum Norge A/S	21.5140 %
Norsk Hydro Produksjon a.s	6.2280 %
Total Norge A/S	4.8200 %
Saga Petroleum a.s	3.4710 %
Ugland Construction Company A/S	0.1690 %

The field was proven in 1972 by the drilling of exploration well 25/4-1 and declared commercial in April 1974. The declaration was withdrawn in 1976 due to the low gas price.

In 1980, the gas market swung around and Heimdal became the key element in the debate about a landing option for the Statfjord gas. The application to land the gas on the Continent was submitted in January 1981 and received Storting approval on 10 June 1981. The landing application for condensate was approved in January 1983.

Production
The estimated total reserves in place in Heimdal are 35.6 bcm gas and 4.26 million tonnes NGL.

Production drilling on Heimdal started in April 1985. From the installation, ten wells » nine producers and one observation and injection well » have

Fig. 2.7.6
Installations on Ula

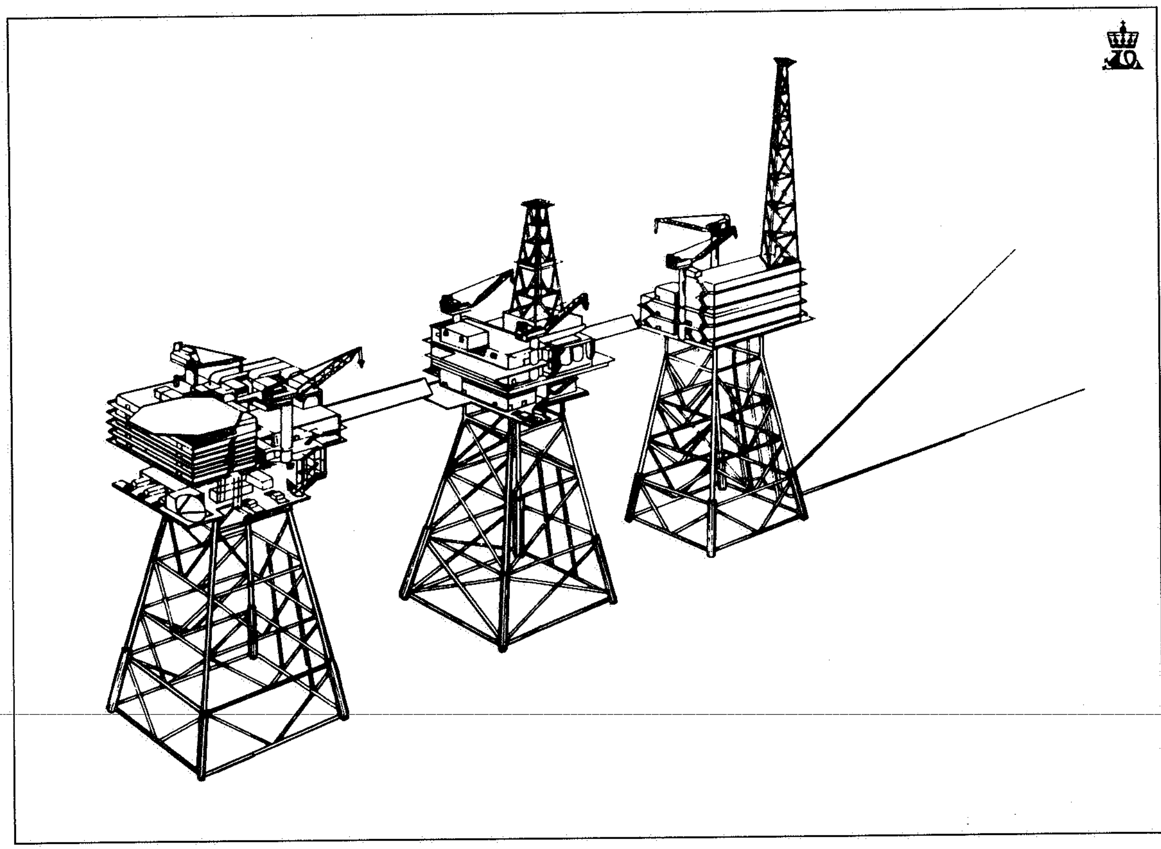
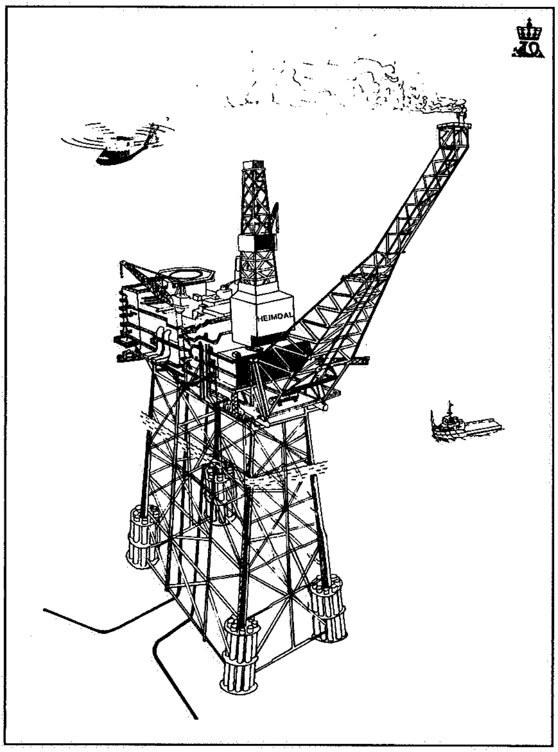


Fig. 2.7.7
Installation on Heimdal



been drilled, although one producer had to be shut down in 1987 due to leakage problems.

Production so far has not met with any serious setbacks, though because of the powerful water drive in the field, pressure development and water ascent are both carefully monitored.

Production has reached plateau level, availability is good, and there is little occasion to flare off field gas.

Production installations
Heimdal has been developed with an integrated steel jacket structure combining drilling, production and quarters functions; see Figure 2.7.7. Production start-up was in December 1985 and delivery of gas to Emden began in February 1986.

Transportation
The gas from the Heimdal field is transported through Statpipe, and the pipeline from Heimdal is tied in with the Statpipe system at the 16/11-S riser platform.

Metering system
The Norwegian Petroleum Directorate inspects the metering systems for gas and condensate. In the case of the condensate system, the inspection is done in collaboration with the British Department of Trade and Industry, as the condensate is transported via the Forties gathering system from the Brae field in the UK sector to Cruden Bay in Scotland. The condensate travels in a dedicated pipeline from Heimdal to Brae.

Costs
The total investments in the Heimdal field are in the region of 13.1 billion 1992 kroner. The total operating costs over the lifetime of the field are expected to reach 5.6 billion 1992 kroner.

2.7.8 Frigg area

2.7.8.1 Frigg
Production license 024

Licensees

Norwegian share (60.8200 %)	
Elf Petroleum Norge A/S	25.1910 %
Norsk Hydro Produksjon A/S	19.9920 %
Total Norge A/S	12.5960 %
Den norske stats oljeselskap a.s (Statoil)	3.0410 %
British share (39.1800 %)	
Elf Exploration UK Ltd	26.1190 %
Total Oil Marine Ltd	13.0600 %

Elf Petroleum Norge A/S is the operator of the Frigg field and Total Oil Marine Ltd the operator of the pipeline system and St Fergus terminal in Scotland.

The Frigg field is situated in blocks 25/1 and 30/10 in the Norwegian sector and blocks 10/1, 9/5 and 9/10 in the UK sector; see Figure 2.7.8.a. The field has been unitised with 60.82 per cent of gas reserves in place being deemed to belong to the Norwegian partners.

Frigg was proven in spring 1971 and declared commercial on 25 April 1972.

Production
The Norwegian share of the total recoverable reserves is believed to be 110 bcm gas.

In 1984 considerable, though uneven, water ascent was observed in the reservoir. Several wells were drilled or deepened, and a lot of effort was made to clarify the situation. It transpired that the water is entering the reservoir from the southeast on account of discontinuous shale barriers there, and flows laterally northward. This realisation, coupled with certain other studies, caused the estimated reserves to be scaled down.

North of the DP2 installation is an undrained zone into which an additional well has been drilled so as to produce the remaining gas. Another well has been drilled from DP2 into that part of the reservoir which is situated under CDP1 in order to deplete this part of the remaining gas once CDP1 has shut down.

Production installations
The field was developed in three phases, phase 1 comprising production and processing installations

in the UK sector and a quarters platform (CDP1, TP1 and QP). Production from phase 1 started on 13 September 1977.

Phase 2 comprises production and processing platforms (DP2 and TCP2) in the Norwegian part of the field. Production from phase 2 started in summer 1978. See Figure 2.7.8.b for a map of the Frigg installations.

Phase 3 of the Frigg development comprises the installation of three turbine driven compressors on TCP2, which are necessary to compensate for the falling reservoir pressure. Commissioning of the compressor plant was accomplished in autumn 1981.

Gas from Nordøst-Frigg, Odin and Øst-Frigg is processed and metered on Frigg. New modules for processing of gas and condensate from these satellite fields have been emplaced on TCP2. Export of gas from Alwyn North in the UK sector flows through TP1.

TP1 has been converted from a processing facility to a riser platform. TCP2 has been modified to adapt the compressor plant to changed pressure conditions and reduced gas volumes. In addition, one of three process trains on TCP2 has been decommissioned.

Transportation

The gas is transported 355 kilometres to St Fergus in Scotland through twin 813 mm diameter pipelines. In order to increase line capacity, two compressor turbines, each rated at 38,000 bhp, were installed on the compressor platform MCP-01 in 1983, halfway between Frigg and Scotland in a capacity upgrade that was necessary to make room for the Odin field gas. Now, because the requirement for transportation capacity is reduced, the compressors have been retired.

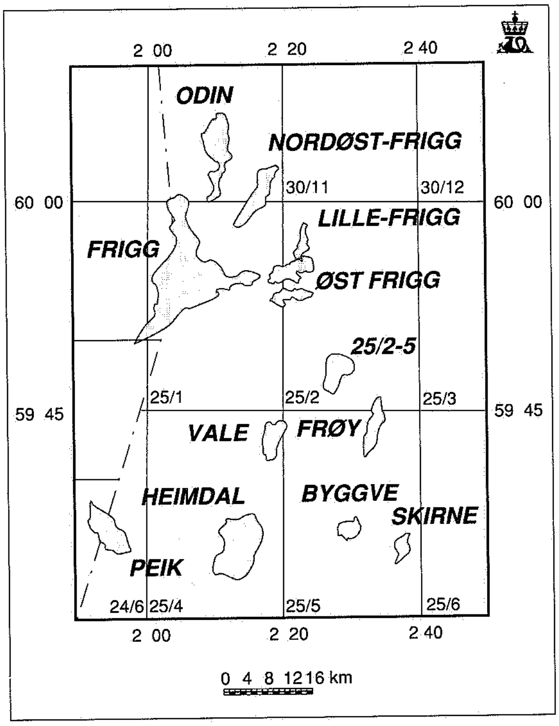
Metering system – Frigg area

Supervision of the metering systems on Frigg, Alwyn North and St Fergus is carried out in conjunction with the UK Department of Trade and Industry. This combined supervision extends to the Norwegian fields: Nordøst-Frigg, Øst-Frigg and Odin; the sum of these fields' production being deducted from the total measured quantity flowing into the St Fergus pipeline. The aim is to determine the quantity originating from the Frigg field.

Costs

The estimated total investments in the Norwegian sector of the Frigg field are about 23.5 billion 1992 kroner over the lifetime of the field. Investments in the transportation system come on top of this figure. The estimated total operating costs over the lifetime of the field are in the region of 11.1 billion 1992 kroner.

Fig. 2.7.8.a
The Frigg area



Licensees

Elf Petroleum Norge A/S	41.4200 %
Norsk Hydro Produksjon a.s	32.8700 %
Total Norge A/S	20.7100 %
Den norske stats oljeselskap a.s (Statoil)	5.0000 %

Production licence 112 (previously relinquished part of block 25/2, re-allocated in 1985):

Licensees

Den norske stats oljeselskap a.s (Statoil)	50.0000 %
Elf Petroleum Norge A/S	21.8000 %
Norsk Hydro Produksjon a.s	17.3000 %
Total Norge A/S	10.9000 %

Elf Petroleum Norge A/S operates the Øst-Frigg field. Øst-Frigg Alpha was discovered in 1973 and Øst-Frigg Beta the year after. Both structures extend into blocks 25/1 and 25/2 and marginally into the area previously relinquished. The reserves are split with 95.129 per cent in production licences 024 and 026, and 4.871 per cent in production licence 112. The field was declared commercial in August 1984 and the landing application considered by the Norwegian Storting on 14 December the same year. Production commenced in August 1988 and the sale of gas on 1 October 1988.

2.7.8.2 Øst-Frigg

Production licence 024 (block 25/1) and production licence 026 (block 25/2), see Figure 2.7.8.a:

Production

The Øst-Frigg field consists of the two principal structures, Alpha and Beta, formerly known as Øst-

Frigg and Sørøst-Frigg, respectively. They are part of the same pressure system as the Frigg field, and the gas is therefore sold to the British Gas Corporation (BGC) under the existing sales agreement.

The recoverable gas reserves were originally estimated at 8 bcm in Alpha and 5 bcm in Beta, or 13 bcm in all. However, production on Frigg has brought about substantial reduction in pressure and receding liquid contacts on Øst-Frigg, plus gas leakage amounting to about 6.4 bcm from the Alpha structure. On the other hand the deep saddle in the western part of the Beta structure has prevented gas migration from there to Frigg. In both structures, some gas is trapped in zones already drained, and the reserve estimates have therefore been revised downward to 8.2 bcm (total); with 5.1 bcm in Alpha and 3.1 bcm in Beta. It is because of these problems that a third well was drilled on the Alpha structure, coming on stream in 1989.

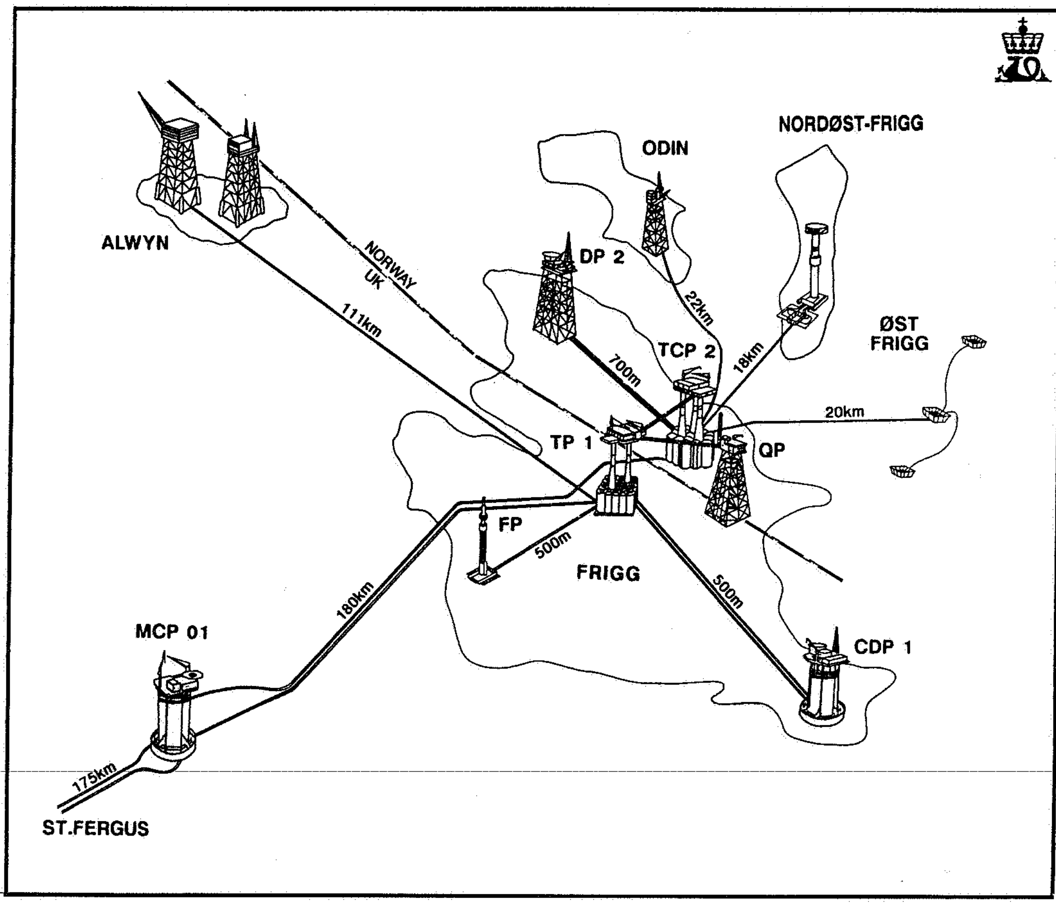
The forecast final year of production is now 1994, compared with the year 2002 originally planned. The reason is not just the decline in estimated reserves, but also the greater rate of production on the field.

Production installations
The Øst-Frigg development is based on subsea completion technology: Two templates for the production stations and a central manifold station tying the systems together were emplaced on the seabed in summer 1987. These subsea production systems are remotely controlled from the Frigg control room. From the manifold a gas and service line runs to TCP2 where the gas is processed and fed into the Frigg field transportation system. In connection with this development, modifications also had to be made on the Frigg field before start-up in order to support receipt of the gas.

Costs
The estimated total investments in the field are about 2.7 billion 1992 kroner. The estimated total operating costs over the lifetime of the field are 0.6 billion 1992 kroner.

2.7.8.3 Nordøst-Frigg
Production licence 024 (block 25/1)

Fig. 2.7.8.b
Installations in the Frigg area



Licensees

Elf Petroleum Norge A/S	41.4200 %
Norsk Hydro Produksjon a.s	32.8700 %
Total Norge A/S	20.7100 %
Den norske stats oljeselskap a.s (Statoil)	5.0000 %

Production licence 030 (block 30/10)

Licensees

Esso Norge a.s	100 %

Statoil is entitled to 17.5 per cent of the net profit before tax.

The Nordøst-Frigg field lies in blocks 25/1 and 30/10, see Figure 2.7.8.a, where a redistribution of the gas reserves in August 1984 assigned 42 per cent to the former and 58 per cent to the latter. Elf Petroleum Norge A/S operates the field.

The gas field Nordøst-Frigg was proven in 1974 and the final development plan was approved in 1980.

Production

The total recoverable reserves in place on Nordøst-Frigg are believed to be 11.8 bcm gas.

Sale of gas from Nordøst-Frigg started on 1 October 1980 by virtue of pre-delivery from Frigg. Since production started up in December 1983, Nordøst-Frigg has been reinstating this gas in addition to volumes delivered on behalf of Frigg and own contract volumes. In order to achieve a longer-range sales profile it was proposed to continue deliveries from Frigg after production shutdown on Nordøst-Frigg.

Pressure measurements made before production start-up showed that the reservoir communicates with the Frigg field via the underlying aquifer. Although the field is expected to cease production in spring 1993, sales will continue until 30 September 1993.

Production installations

The field has been developed with six wells drilled through a subsea template; see Figure 2.7.8.b. The template also supports a manifold in addition to the wellheads and valve trees which gather the gas from the six wells. The gas is led through a 406 mm diameter pipeline to the Frigg field for processing. Each of the valve trees is controlled by discrete service and control lines from the Frigg control station, an articulated column structure located 150 metres from the wellheads. The control station was installed in July 1983 and is remotely controlled from Frigg itself. The plan for removal of the Nordøst-Frigg installation was submitted to the authorities on 30 August 1991.

Costs

The estimated total field investments are roughly 3.1 billion 1992 kroner, while the total operating costs are expected to run to about 0.7 billion 1992 kroner.

2.7.8.4 Odin

Production licence 030

Licensees

Esso Norge a.s	100 %

Statoil is entitled to 17.5 per cent of net profit before tax. The Odin field lies in block 30/10, see Figure 2.7.8.a, and is operated by Esso. This gas field was proven in 1974 and the field development plan approved in 1980.

Production

The estimated total recoverable reserves in place are 29.3 bcm gas. Gas sales from Odin were initiated on 1 October 1983 through the pre-delivery arrangement with Frigg. Since production start-up in April 1984, Odin has been reinstating the pre-delivered volumes in addition to delivering its own contract quantities.

Pressure readings taken before production start-up showed that the Odin field communicates with Frigg through the underlying aquifer. The Odin reservoir is losing pressure faster than the other Frigg area fields due to its very limited aqua-drive.

In spring 1990, the operator detected water penetration in the field's southernmost well. It was expected that water penetration would occur in this well first, but it happened rather earlier than anticipated. New studies show that both the remaining reserves and the lifetime of the field will be somewhat curtailed.

Production installations

The field development concept involves a small steel jacket structure with relatively modest processing and drilling facilities and comparatively small quarters; see Figure 2.7.8.b. This concept was feasible because a standby vessel was employed for two years in connection with installation work and production drilling operations.

The Odin facilities separate the water from the gas and inject methanol for hydrate control purposes. The gas is then sent by pipeline to the TCP2 platform on Frigg for further processing before delivery through the Norwegian pipeline to St Fergus.

Costs

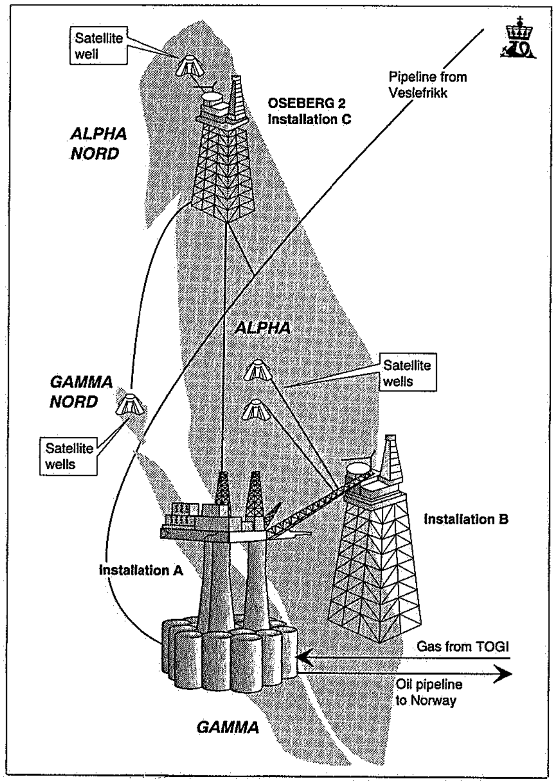
The estimated total investments in the field are about 4.4 billion 1992 kroner. The total operating costs over the lifetime of the field are estimated to be about 3.0 billion 1992 kroner.

2.7.9 Oseberg area

2.7.9.1 Oseberg

The Oseberg field extends into two blocks: block 30/6 in production licence 053 allocated in 1979, and block 30/9 in production licence 079 which was allocated in 1982. See Figure 2.6.9.a.

Fig. 2.7.9
Installations on Oseberg



Licensees

Those parts of the production licences which cover Oseberg have been unitised over the two licences. The partners have assumed a provisional apportionment of the reserves with 60 per cent in block 30/6 and 40 per cent in block 30/9. Statoil's equity in Oseberg increased relative to the foreign partners when the sliding scale was exercised. The latest increase was on 1 April 1988 in connection with approval of the revised plan for development and operation.

The partners in the unitised Oseberg field are as follows:

Den norske stats oljeselskap a.s (Statoil)	65.0400 %
Norsk Hydro Produksjon a.s	13.7500 %
Saga Petroleum a.s	8.6100 %
Elf Petroleum Norge A/S	5.6000 %
Mobil Development Norway A/S	4.2000 %
Total Norge A/S	2.8000 %

Production

The first discovery on Oseberg was made in 1979 which proved gas. Later evidence showed that the reservoir is an oil bearing stratum with a gas cap. The field consists of several reservoirs in the Brent group in multiple structures. The main reservoirs are found in the Oseberg formation in the Alpha and Gamma structures. The development application was considered by the Storting in the spring session of 1984.

The original plan was to inject water in the reservoir in the Alpha structure and reinject the associated gas in the reservoir in Gamma. Following new studies this was changed in 1986 to gas injection in both structures. In order to obtain enough gas for efficient gas injection with pressure maintenance it was at the same time decided to buy gas from Troll and go ahead with the TOGI (Troll Oseberg Gas Injection) development with a pipeline from Troll to the Oseberg field centre. Gas production from TOGI started in February 1989 and the facility will deliver some 25 bcm gas over a 12-year period. In connection with the accelerated development of Oseberg C the operator is taking additional injection gas from a satellite field on the western flank of Oseberg, Gamma Nord (see section 2.7.9.2).

In order to gain better insight into the Oseberg reservoir and how it behaves under production, a long-term testing programme was initiated in autumn 1986 using a production testing vessel. The programme lasted until spring 1988.

Ordinary production started to flow from the Oseberg field centre in December 1988 through a total of eight pre-drilled production wells, assisted by two gas injectors. As all eight wells had been pre-drilled, full production was soon reached. Oseberg C started production in September 1991 and also quickly reached full production due to the pre-drilled wells. Increased reserves in the northern part of the field occasioned the laying of a multiphase flowline from the C platform to the field centre. This line will result in optimal production and improved exploitation of the processing capacity at the field centre.

The estimated total oil recovery from the field is about 277 mcm. This gives a mean recovery factor close to 54 per cent. Although the original plans did not call for horizontal wells, several such wells have been drilled during the last year with successful results and more are being planned. This fact, coupled with generally positive production experience, is the main reason why the anticipated recovery factor has increased compared to the year before. Even though the factor is already relatively high, there are good opportunities for increasing oil production from the field even further.

As a preliminary conclusion of the project which has been ongoing for several years in order to examine the possibility of increasing production by adding surfactants (tensides) to the injection water in those parts of the reservoir which are to be recovered by means of water injection, a well test was carried out in summer 1992 using trace materials to determine the residual oil saturation around the well after water injection and after surfactant injection. The results have not been fully interpreted yet, but preliminary results indicate that the test was successful and that injection of surfactants led to reduced residual oil saturation.

According to plan, the gas in the field will be produced and sold in a gas production phase from 2003 to about 2021.

Production installations

The Oseberg field was developed in two phases. Phase 1 was developed with a field centre in the south comprising two installations, Oseberg A which is a process and quarters platform on a gravity base, and Oseberg B which is a drilling and waterflood platform on a steel jacket. The middle portion of the field will be depleted using two subsea completion wells tied in to the field centre. Production start-up occurred on 1 December 1988 on the Oseberg field centre, which has a mean crude processing capacity of about 55,000 scm a day.

Phase 2 involves development of the northern part of the field. In the revised Oseberg plan the C installation has been upgraded from a satellite unit to an integrated production, drilling and quarters (PDQ) platform employing the services of a support vessel during the drilling phase. Production start for Oseberg C was 2 September 1991. The mean crude processing capacity is some 20,000 scm a day.

For a diagram of the installations, see Figure 2.7.9.

Transportation

A pipeline for transportation of stabilised oil from Oseberg to Sture, north of Bergen, was laid in summer 1987. This 711 mm diameter line has a capacity of 95,000 scm oil a day. The greatest water depth the line reaches is about 350 metres.

The plant including the Sture terminal is owned and operated by a joint venture, I/S Oseberg Transport System (OTS), whose partners are identical with the Oseberg partners. The pipeline operator is Hydro, which also operates the terminal. The OTS entered service when Oseberg came on stream and comprises the following main elements:

- Pipeline support functions on Oseberg
- Subsea pipeline
- Landing point
- Onshore pipeline
- Terminal.

In the present plans the gas export from Oseberg will commence in year 2003. The gas has not been sold and no decision has been made how to transport it.

Metering system

The oil metering system on Oseberg A and the Sture 1 export metering station were commissioned in December 1988. The Sture 2 export metering system has been in operation since mid-year 1989.

The gas metering system for injection gas purchased from Troll's TOGI system was tested in December 1990 and commissioned by the time of production start-up in early 1991.

The metering system for Oseberg C entered service at the time of production start-up in September 1991.

Costs

By year end 1992, some 40.6 billion 1992 kroner had been invested in the Oseberg field. The final total is expected to be about 49.1 billion 1992 kroner. The total operating budget is expected to reach about 32.2 billion 1992 kroner by year end 2010. These costs do not include the Oseberg Transport System (see below).

Costs for Oseberg Transport System

The total investment in OTS is about 4.8 billion 1992 kroner. Predicted operating costs are about 3.7 billion 1992 kroner up to the end of year 2000.

2.7.9.2 Gamma Nord

Production licence 053

Licensees

Den norske stats oljeselskap a.s (Statoil)	59.4000 %
Norsk Hydro Produksjon a.s	12.2500 %
Elf Petroleum Norge A/S	9.3330 %
Saga Petroleum A/S	7.3500 %
Mobil Development Norway A/S	7.0000 %
Total Norge A/S	4.6670 %

Gamma Nord is situated in block 30/6 which was allocated in 1979. The field is included in the revised development plan for the northern part of the Oseberg field.

Production

The Gamma Nord structure is situated west of the Oseberg field and is an inclined fault block whose hydrocarbon bearing strata are part of the Statfjord formation. A layer of rich, coal bearing shale divides the Statfjord formation into an upper and a lower reservoir zone. Gas was first proven, with a thin oil zone in the upper part of Statfjord. A horizontal well was selected in order to recover as much of the oil as possible before depleting the gas. While drilling this well, oil was also proven in the lower part of the reservoir. The producer is a subsea completion well tied in to Oseberg C. The field came on stream in October 1991, and oil production from the horizontal well has proceeded much better than anticipated. All gas produced is injected into the Oseberg field.

Total oil production is estimated at about 0.92 mcm; while gas production is about 6.20 bcm.

In order to examine whether it is possible to produce oil from the lower reservoir also, an appraisal well will be drilled in 1993. Based on the results of this drilling operation it will be decided how best to implement any such production from the lower level.

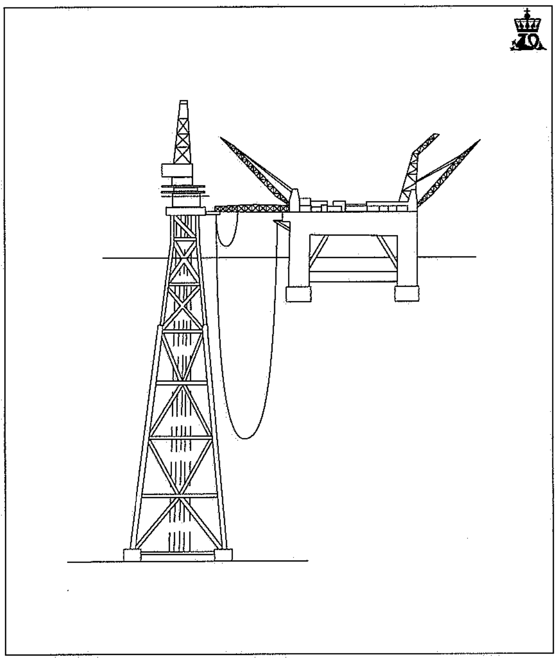
Metering system

The oil and gas metering system entered service simultaneously with production start-up in the middle of October 1991. A simplified metering system is used.

2.7.10 Veslefrikk

Production licence 052

Fig. 2.7.10
Installations on Veslefrikk



Licensees

Den norske stats oljeselskap a.s (Statoil)	55.0000 %
Total Norge A.S	18.0000 %
Deminex (Norge) A/S	11.2500 %
Norsk Hydro Produksjon a.s	9.0000 %
Norske Deminex A/S	4.5000 %
Svenska Petroleum Exploration A/S	2.2500 %

Veslefrikk lies in the southeast of block 30/3, allocated in 1979 with Statoil as operator. Four exploration wells have been drilled in the block and two in the Veslefrikk structure itself. In 1992, another exploration well was drilled in an additional prospect (G prospect) along the southeastern flank of the structure.

The commerciality declaration was submitted to the partners in November 1986; whereas the plan for development and operation was submitted in February 1987 and approved by the Storting in April 1987. An updated reservoir management report, written after pre-drilling of six development wells, was submitted in September 1989. The field started production on 26 December 1989. After 13 development wells had been drilled, yet another revised plan for reservoir management was prepared in February 1992.

Production

The Veslefrikk field makes up the highest part of a slightly arched structure with downfaulted areas on all sides. Commercially recoverable reserves are found in two levels, in the Brent group and Intra Dunlin Sand (IDS). There are also resources in a deeper reservoir, in the Statfjord formation, for which one expects to submit a plan for development and operation in 1993. This reservoir has a gas cap and a higher associated gas content than the resources in Brent and IDS. Additional resources were proven in Brent and IDS in the G area, a downfaulted segment along the southeastern flank of the field, by the drilling of exploration well 30/3-5 in June 1992.

Effective February 1992, the reserves were upgraded by about 20 per cent compared to the estimate at the time of production start-up. The upgrade is due to greater rock volume, since the reservoirs in several fields have come in higher than anticipated. Moreover, the recovery factor has increased as the production history indicates better lateral communication over faults than originally projected. The official reserves are now 43.8 mcm oil and 3.5 bcm gas (36.4 mcm and 3.1 bcm, respectively, at the time of production start-up). In addition, there is potential for a further increase in reserves as the resources in the G area, plus resources in isolated pressure regimes in Upper Brent, were not included in the latest calculations.

Production from the field is by means of water injection. However, delayed start-up of water injection and problems of availability have resulted in somewhat lower than anticipated production since February 1991. Enhanced injection capacity and plans to upgrade show signs of giving positive pressure development and stable production. Water alternating gas (WAG) injection can materially boost production. Studies so far indicate that start-up in 1996 will give the best result. However, the effect of WAG is highly sensitive to the pressure conditions in the reservoir.

Production installations

The field has been developed with a fixed wellhead installation on a steel jacket and a semi-submersible platform containing the processing facilities and living quarters. The wellhead unit is emplaced above a template with six pre-drilled wells. The semi-submersible, formerly the *West Vision* drilling rig, is moored and hooked up to the fixed wellhead unit.

The Veslefrikk production facilities have returned 95 per cent availability. Water injection was initiated in spring 1991.

See Figure 2.7.10 for Veslefrikk installations.

Transportation

An oil pipeline is connected to the Oseberg Transport System for transportation to the Sture terminal. Gas is carried through the Statpipe system. The gas has not yet been sold, although an interim agreement has been struck with Heimdal for intermediate storage of produced gas from Veslefrikk.

Metering system

The metering of oil and gas delivered from Veslefrikk was satisfactory in 1992.

Costs

The estimated total investment and operating costs over the lifetime of the field are 9.4 billion and 11.9 billion 1992 kroner, respectively.

2.7.11 Gullfaks

Production licence 050

Licensees

Den norske stats oljeselskap a.s (Statoil)	85.0000 %
Norsk Hydro Produksjon a.s	9.0000 %
Saga Petroleum a.s	6.0000 %

Gullfaks lies in the northeastern part of block 34/10 and covers an area of about 200 square kilometres. Figure 2.7.11.a shows the location. Gullfaks was discovered in 1978. Due to the phased development concept, separate field development plans for phase 1 and 2 were approved in 1981 and 1985, respectively. The phase 1 development embraces the A and B installations, while the C installation represents phase 2. Production from the field started to flow in December 1986.

Production

Gullfaks is a relatively shallow accumulation having fault groups in several angled and rotated fault blocks. The reservoir rock is Jurassic sandstone. The blocks vary in slope and are in some places heavily eroded. The structural features in the eastern section are difficult to identify due to the poor seismic readings obtained. The complex geological makeup of the field was confirmed during the production drilling, when several quite surprising fault patterns turned up. However, these faults are not as sealing as first supposed.

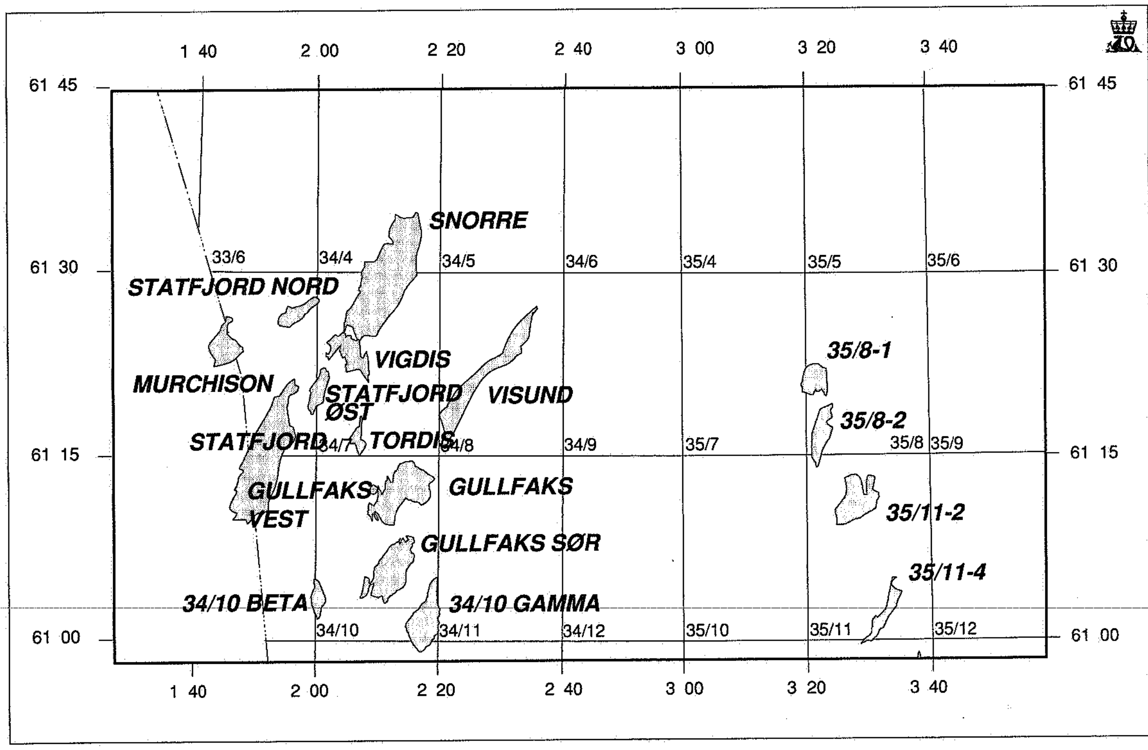
The reservoir phases 1 and 2 are segregated by a north-south fault. A certain degree of communication has been proven in the northern part. Fault lines more than 1000 metres apart limit the field in the south, east and northeast.

The reserves are dispersed in the Brent group, Cook formation and Statfjord formation. The total recoverable volume of oil is 230 mcm, 61 per cent of which is in phase 1 and 39 per cent in phase 2. Phase 2 production started in December 1989.

In 1992, production from the Gullfaks field exceeded the forecasts, the increase being mainly due to the fact that the increase in water cut will come later than was simulated. Other reasons for the high production are more wells, horizontal wells (the first horizontal well on the field, 34/10-A-34A, came on stream in November 1991), high regularity, successful intervention, and active follow-up of well control criteria. Problems with water and sand production are still a limiting factor. Anticipated production in 1993 is 23 mcm oil as against the expected 24 mcm oil in 1992. Production will then gradually be stepped down until 2006.

The drive mechanism in the field is primarily pressure maintenance by means of water injection, alt-

Fig. 2.7.11.a
The Gullfaks, Statfjord and Snorre area



hough alternative methods of increasing the recovery factor are also being considered and tested. Pilot studies employing WAG (water alternating gas) injection were tried, which seemed to give an additional oil recovery of at least 0.1 mcm, plus some acceleration benefits. A well test with surfactant injection as well as the drilling of horizontal wells started in 1991. The injection of thin gel is also considered a plausible recovery strategy on Gullfaks, a strategy which according to plan will be tested in the beginning of 1993. New well completion and stimulation methods have been tested with encouraging results.

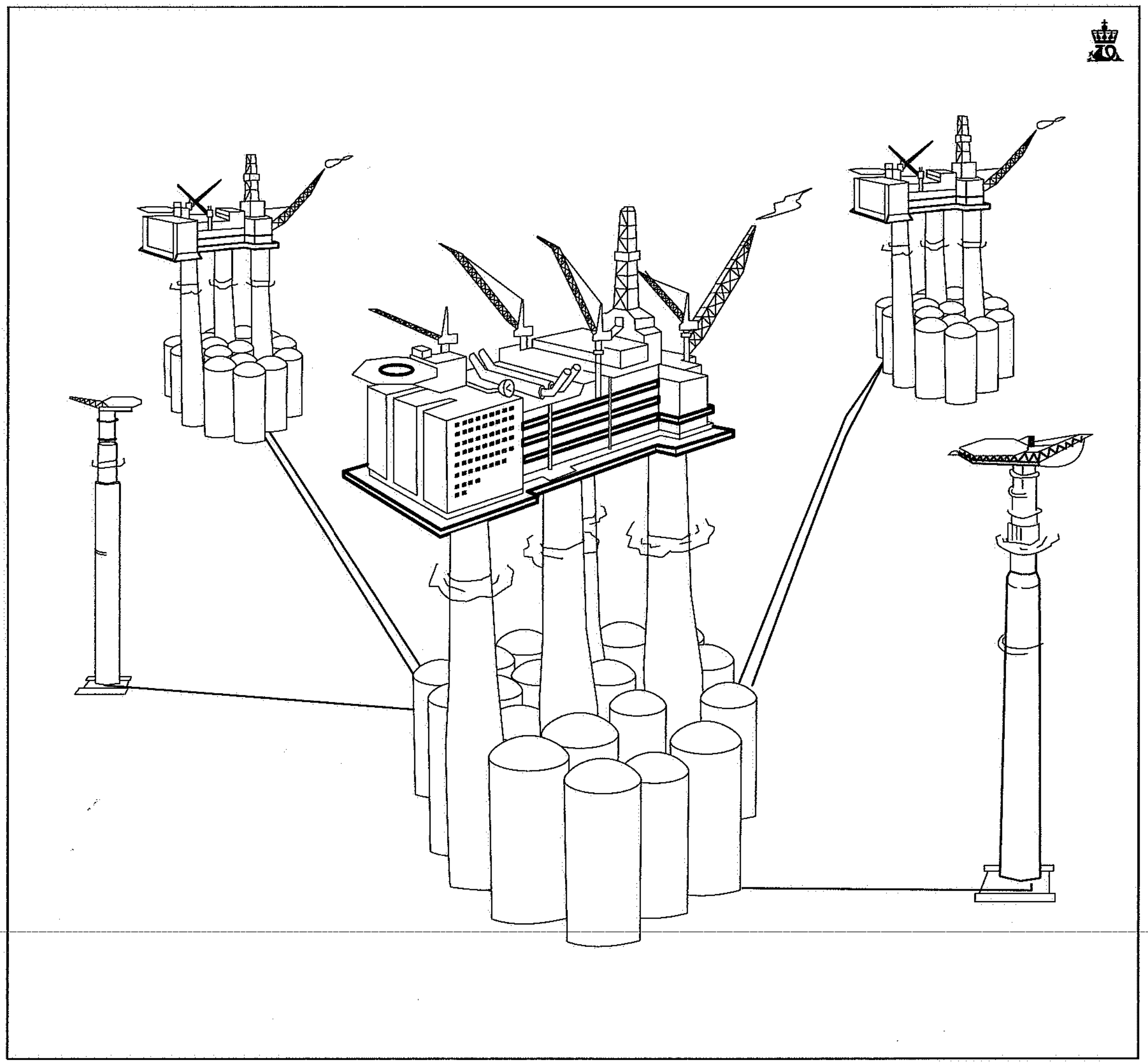
Production installations

Phase 1 comprises two installations, Gullfaks A and B, which are both Condeep type gravity base platforms with steel frame topsides. See Figure 2.7.11.b. The C installation in phase 2 is essentially a copy of Gullfaks A. All three are fully integrated process, drilling and quarters platforms, although Gullfaks B has a simplified process train with only first-stage separation.

Gullfaks A is located in the southern part of the field where production commenced on 21 December 1986. The process capacity is 52,000 scm oil and 35,000 cubic metres of water a day. Gullfaks A water injection capacity is 75,000 cubic metres a day. At year end the platform counted 27 production wells and nine water injection wells, six of which were completed subsea.

Gullfaks B is located in the northwestern part of the field and came on stream on 29 February 1988. Its process capacity is 30,000 scm oil and 30,000 cubic metres of water a day. Oil from Gullfaks B is transferred to Gullfaks A and C for further processing and storage. A separate water injection system was installed on Gullfaks B in 1991 with a capacity of 30,000 cubic metres a day. In addition, injection

Fig. 2.7.11.b
Installations on Gullfaks



water can be transferred from Gullfaks A. At year end, 16 production wells and eight water injection wells had been linked up to Gullfaks B.

Gullfaks C is located in the eastern part of the field and will produce the Gullfaks field's phase 2 reserves. Operations started with oil transferred from Gullfaks B on 4 November 1989. Production from its own well started around year end 1989. Process capacity on the installation is 50,000 scm oil and 30,000 cubic metres of water a day, and up to 60,000 cubic metres of water can be injected on a daily basis. At year end the installation had ten production wells and three water injection wells.

Gullfaks Vest

Gullfaks Vest is an oil field located in block 34/10. The field was proven by exploration well 34/10-34 in summer 1991.

Production from this field will be by means of two horizontal production wells with natural water drive. Gullfaks Vest contains recoverable oil reserves of 3.3 mcm which will be recovered over a 12-year period. The plan is to drill the two horizontal wells from Gullfaks B.

Metering system and transportation

Both Gullfaks A and C have storage cells in which to store the stabilised oil, which is metered and exported via loading buoy to tankers. Processed gas is subject to continual fiscal metering on A and C before being exported into the Statpipe system.

Costs

The estimated total investment costs and operating costs over the lifetime of the field are 67.7 billion and 47.3 billion 1992 kroner, respectively (excluding Gullfaks Vest). The investments in Gullfaks Vest have been estimated at 200 million and the operating costs at 50 million 1992 kroner.

2.7.12 Statfjord

Production licence 037

Licensees

Norwegian share (85.23869 %)

Mobil Development Norway A/S	12.785804 %
Den norske stats oljeselskap a.s (Statoil)	42.619345 %
Norske Conoco A/S	8.523869 %
Esso Norge A/S	8.523869 %
A/S Norske Shell	8.523869 %
Saga Petroleum a.s	1.598225 %
Amoco Norway A/S	0.887903 %
Amerada Hess Norge A/S	0.887903 %
Enterprise Oil Norwegian A/S	0.887903 %

British share (14.76131 %)

Conoco North Sea Inc	4.920437 %
BP Petroleum Development Ltd	4.920437 %
Chevron UK Ltd	4.920437 %

Production licence 037 was allocated in 1973 and covers blocks 33/9 and 33/12; see Figure 2.7.11.a. The Statfjord field extends into the UK sector. The field was discovered in spring 1974 and declared commercial the same year. Mobil was operator on the field until 1 January 1987 when Statoil assumed operatorship. Statfjord is Norway's largest oil field.

The Statfjord field partners have now concluded the protracted process of redistributing the field between Norway and the UK. An independent expert approved by both parties was appointed to redistribute the resources. The final expert decision on redistribution of the field was available in August 1991, resulting in an increase in the Norwegian share by 1.4547 per cent to 85.23869 per cent. The new distribution was effective from 1 September 1991, and the corresponding relinquishment of oil volumes from the UK sector will take place for 24 months from that date.

Production

The total recoverable reserves of oil were upgraded in 1992 to an estimated 565 mcm, the comparable figure for associated dry gas being 60.0 bcm, and for NGL 18.6 million tonnes, extracted from the gas at Kårstø. The recovery strategy pursued is based on maximising the production rates and recovery factor by manipulating the pressure conditions in the reservoirs. This is achieved by injection of water in the Brent group and gas into the upper part of the Statfjord reservoir. A gas cap has now developed at the top of the Statfjord reservoir, which has resulted in an increase in the gas-to-oil ratio in many producers in this reservoir. In the lower part of the Statfjord reservoir the operator is now preparing for water injection.

In order to better exploit the remaining reserves in place the operator has formulated a revised production strategy for the field. The strategy involves more wells than originally planned, plus extensive re-use of the wells in several reservoir zones. Using horizontal and long-range high-deviation bores is also part of the strategy.

Horizontal wells have been drilled in both the Brent and Statfjord reservoirs, and long-range high-deviation wells or horizontal wells have been drilled into the geologically more complex eastern and northern parts of the field.

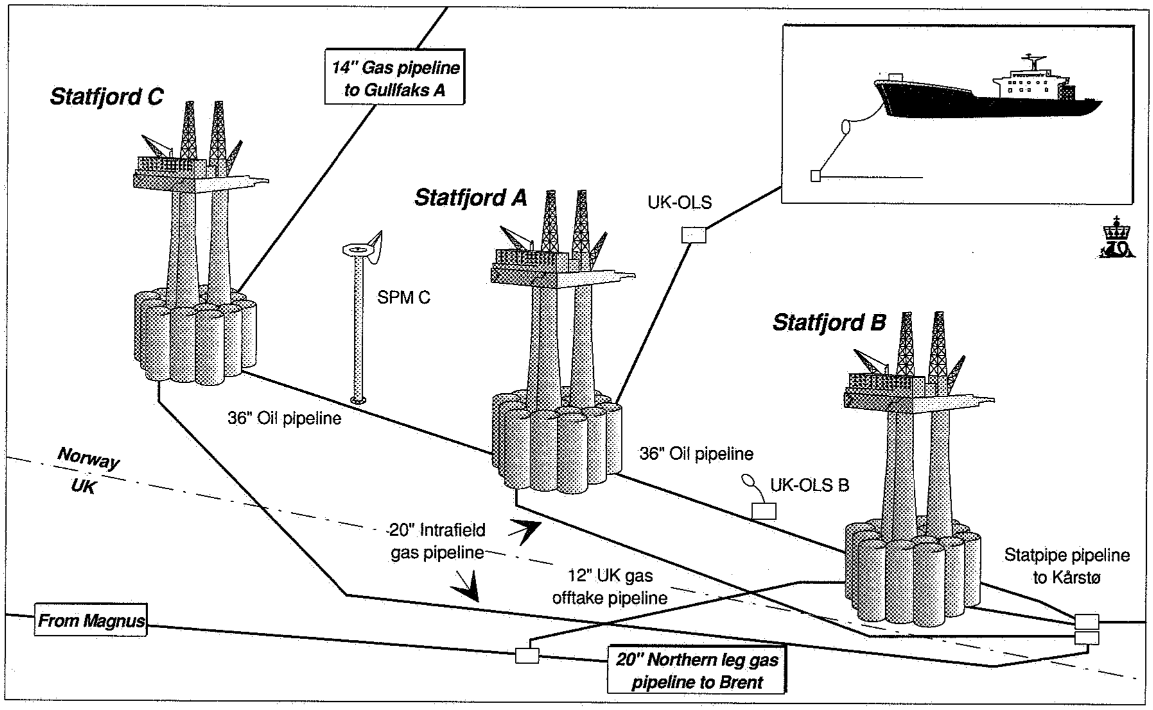
Studies were performed in 1992 to examine how reservoir exploitation can be improved. Furthermore, a plan for exploitation of the Dunlin reservoir is under preparation. This reservoir has a limited volume of resources compared to the Brent and Statfjord reservoirs.

A study programme into advanced oil recovery methods is in progress and may culminate in a pilot project on the field.

Production installations

The Statfjord field has been developed in three phases using three fully integrated platforms, Statfjord A, B and C. See Figure 2.7.12.

Fig. 2.7.12
Installations on the Statfjord field



Statfjord A

The Statfjord A installation is situated near the centre of the Statfjord field. It is a fully integrated platform with concrete gravity base consisting of 14 storage cells and three columns. The topsides are of steel. The crude oil processing capacity is currently 59,000 scm a day split between two production trains. The water treatment capacity is in the region of 24,000 scm. It was upgraded with the increasing need. The platform started production on 24 November 1979 and has been developed with 24 producers, ten water injection wells and four gas injection wells. Oil is loaded via one of the three offshore loading systems on the field.

The Snorre field came on stream on 3 August 1992. Snorre production is received at Statfjord A following second stage separation at Snorre TLP. This means that Statfjord A is now producing close to its maximum processing capacity. In 1992, Statfjord A had an average own oil production of about 35,400 scm a day.

Statfjord B

The Statfjord B platform is located in the southern part of the Statfjord field. Again it is a fully integrated platform with concrete gravity base, this time combining 24 storage cells and four columns. Again, too, the topsides are of steel. Production capacity is 40,000 scm a day from one production train. The Statfjord B water treatment capacity is currently being upgraded to 26,000 scm a day. Statfjord B came on stream on 5 November 1982 and has been developed with 23 producers, eight water injection wells and two gas injection wells. After ten years of production, Statfjord B had produced 12 mcm oil. Oil production in 1992 reached an all time high. This was achieved by using a test separator as a production separator. In 1992, Statfjord B had an average oil production of some 36,400 scm a day.

Statfjord C

The Statfjord C platform, situated in the northern part of the Statfjord field, is another fully integrated installation, structurally identical to Statfjord B. The production capacity is 43,500 scm through a single production train. Statfjord C's water treatment capacity will be upgraded in the same way as for Statfjord B. The platform came on stream on 26 June 1985 and has 24 producers, eight water injection wells and two gas injection wells. The work of preparing Statfjord C to receive production from the Statfjord satellites is ongoing. The anticipated date for production start-up for the satellites is some time in 1994. Statfjord C produced on average about 39,200 scm of oil a day in 1992.

Transportation

Statfjord gas is transported via the Statpipe pipeline and sold in Emden, while NGL is extracted at Kårstø and sold there. The UK takes off its part of the gas through the Northern Leg Gas Pipeline from Statfjord B to Shell's terminal in St Fergus in Scotland where the gas is sold.

Stabilised oil is stored in storage cells on each installation before being shipped into shuttle tankers via one of the three offshore loading systems on the field.

Metering system
Oil and gas are metered to fiscal standard on each of the three platforms. After Snorre started producing, Statfjord A's production is determined as the difference between the total quantity metered at Statfjord A less the quantity metered at Snorre.

Costs
The total investments in Statfjord up to year 2010 are estimated at about 70.9 billion 1992 kroner. The estimated total operating costs up to the same date have been put at 78.1 billion 1992 kroner. These figures refer to the Norwegian share.

2.7.13 Murchison
Production licence 037

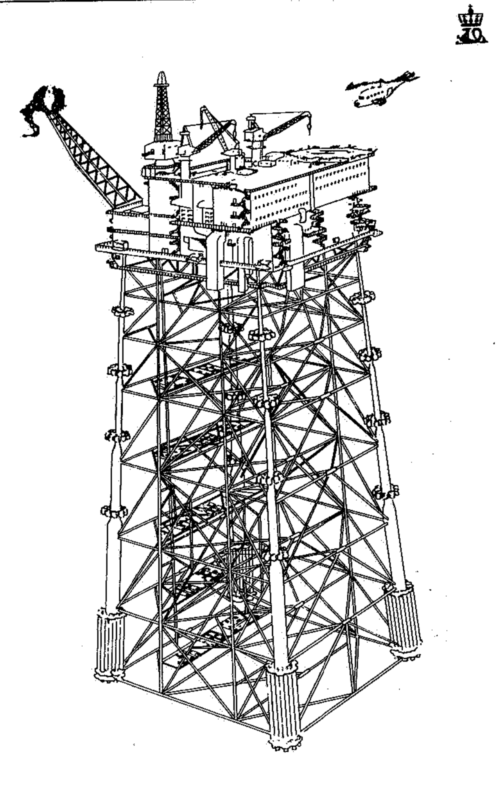
Licensees

British share (77.8 %)	
Conoco (UK) Ltd	25.9334 %
Oryx UK Energy Company	25.9333 %
Chevron UK Ltd	25.9333 %
Norwegian share (22.2 %)	
Den norske stats oljeselskap a.s (Statoil)	11.1000 %
Mobil Exploration Norway Inc	3.3300 %
Norske Conoco A/S	2.2200 %
Esso Norge a.s	2.2200 %
A/S Norske Shell	2.2200 %
Saga Petroleum a.s	0.4162 %
Amoco Norway Oil Company	0.2313 %
Amerada Hess Norge A/S	0.2313 %
Enterprise Oil Norwegian A/S	0.2312 %

Conoco (UK) Ltd operates the Murchison field. It was proven in August 1975 and is situated in block 211/19 in the UK sector and block 33/9 in the Norwegian sector; see Figure 2.7.11.a. The Norwegian share is 22.2 per cent. The development of the Murchison field was initiated in 1976 by the UK partners. In 1979, the British and Norwegian partners entered into an agreement for joint exploitation of the Murchison field. Production started in 1980.

Production
The estimated recoverable reserves for the field as a whole are 57 mcm oil and 1.2 bcm gas in the Brent group. The field has been flowing at almost maximum fluid processing capacity since 1981, and the water treatment capacity has been upgraded several times. 1984 was the last year of plateau production. Water break-through has occurred in all of the original production wells, with a high cut of water. According to a plan prepared in 1987 several new wells have been drilled in recent years, including long-range high-deviation wells towards the flanks of the field. Studies have also been made into re-use of existing wells in various reservoir zones. These measures help improve production.

Fig. 2.7.13
Installation on Murchison



Production installations
Murchison was developed with an integrated steel jacket structure with a production capacity of 26,200 scm oil a day; see Figure 2.7.13. The installation came on stream on 28 September 1980 and initially produced from two subsea completion wells. Present production is around 5000 scm oil a day.

Transportation
The Norwegian government by Royal Decree of 24 September 1982 gave the go-ahead for landing of the Norwegian part of the Murchison gas via the Northern Leg Gas Pipeline to the Brent field in the UK sector, and thence to St Fergus in Scotland through the Far North Liquified and Associated Gas Gathering System, FLAGS. Gas deliveries started flowing through the NLGP on 20 July 1983. The Murchison crude oil is carried by pipeline to Sullom Voe in the Shetland Isles.

Metering system
Inspection of the metering system operation is carried out each year jointly with the UK Department of Trade and Industry.

Costs
The predicted total investment in the Murchison field up to year 2001 is roughly 4.7 billion 1992 kroner. The equivalent total operating costs are estimated at roughly 2.8 billion 1992 kroner. These figures refer to the Norwegian share (22.2 per cent).

2.7.14 Snorre
Production licences 057 and 089

Licensees
The Snorre field is situated in blocks 34/4 and 34/7, with Saga as operator. Block 34/4 was allocated under production licence 057 in 1979; block 34/7 under production licence 089 in 1984. The partners have adopted a distribution of the reserves in Snorre which puts 30 per cent in block 34/4 and 70 per cent in block 34/7. The ownership interests in the unitised Snorre field are:

Den norske stats oljeselskap a.s (Statoil)	41.4000 %
Saga Petroleum a.s	11.2559 %
Esso Norge a.s	10.3323 %
Deminex (Norge) A/S	10.0348 %
Idemitsu Oil Exploration (Norsk) A/S	9.6000 %
Norsk Hydro Produksjon a.s	8.2658 %
Elf Petroleum Norge A/S	5.5106 %
Amerada Hess Norge A/S	1.4559 %
Enterprise Oil Norwegian A/S	1.4559 %
DNO Olje A/S	0.6888 %

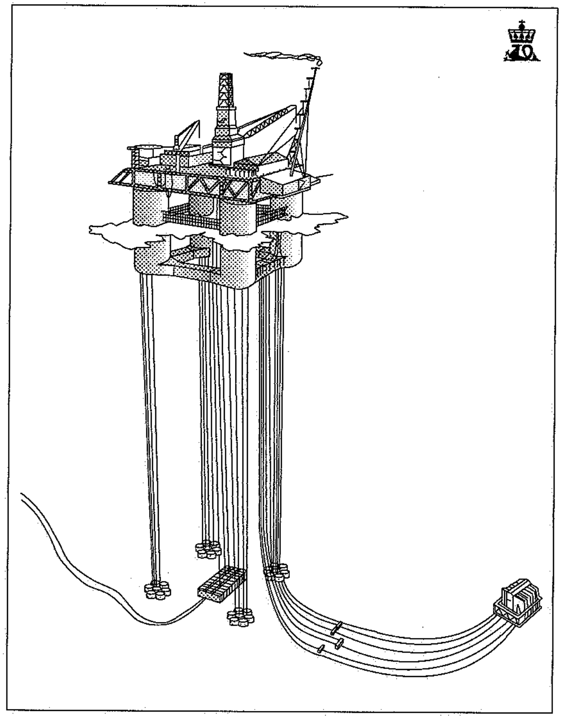
The plan for development and operation of Snorre was adopted by the Storting in 1988. Pre-drilling of wells started in autumn 1990 and the field came on stream on 3 August 1992.

Production
The Snorre field consists of several large fault segments which are generally not believed to be in communication with each other. The reservoir rocks are fluvial sandstones in the Statfjord formation (Lower Jurassic) and the Lunde formation (Upper Triassic). Both in the Lunde and Statfjord formations the rich reservoir intervals are believed to represent continuous channel belts, where the extent and overall geometry are believed to be well understood. The thinner reservoir intervals are generally believed to represent smaller channel belts and individual channels, and here the uncertainties of extent and geometry are much greater.

After the plan for development and operation had been submitted the reserves in Snorre were adjusted from 119 mcm oil and 7.5 bcm gas to 130 mcm oil and 6.7 bcm gas. This upward adjustment of the oil reserves is mainly due to the updated geological model and reservoir model based on reprocessed seismics and data from the pre-drilled wells. In addition, increased production of oil amounting to 3 mcm a year has been forecast due to the inclusion of the WAG (water alternating gas injection) pilot project. The reserves are probably even greater as the extension of exploration well 34/7-20 gave clear indications that the oil-water contact in one of the fault segments lies much deeper than anticipated. Long-term testing of additional resources in the Lunde formation in autumn 1993 may also lead to an upgrade of the reserves.

The field is produced by means of water injection. In addition, WAG injection is being considered. Among other things, this depends on the results of the WAG pilot project which according to plan will be initiated in autumn 1994. The greatest uncertainty factor in the Snorre field is the communication conditions in the reservoir. The uncertainty is most felt in connection with the smaller channel belts and individual channels where the extent and geometry are hard to predict.

Fig. 2.7.14
Snorre



Production installations
The water depth over the field varies from 300 metres in the south to 370 metres in the north. In the plan the field will be developed in two phases. Phase 1 comprises a floating tension leg platform in the south and a subsea installation in the central part of the field, see Figure 2.7.14. The oil will be separated in two stages on the Snorre platform, which was commissioned on 3 August 1992.

The subsea installation is ready for production in January 1993. Following initial processing at Snorre, the oil is transported to Statfjord A for further processing. Phase 2 of the development involves depletion of the central and northern parts of the field and entails two development options. One is the relocation of the tension leg platform, the other to continue the development with production units on the seafloor. The oil processing capacity on the Snorre platform is 30,000 scm a day. Production has increased rapidly from the start-up date to an average of roughly 17,000 scm a day.

Transportation
Snorre crude will be sold via a loading system on Statfjord A, while the gas will be sold through the Statpipe system via Statfjord A.

Metering system
Oil and gas are metered to fiscal standard on the Snorre platform.

Costs
According to the operator's reports, the total development costs for phases 1 and 2 run to some 38 billion 1992 kroner. This estimate assumes further development with production facilities on the seabed. The corresponding operating costs for this concept have been reported to be about 17 billion 1992 kroner up to 2011. The figures for phase 1 alone (provided phase 2 is realised) are 25 billion 1992 kroner (for investments) and 11 billion 1992 kroner (for operation). Especially the phase 2 figures are very speculative.

2.7.15 Mime
Production licence 070

Licensees

Den norske stats oljeselskap a.s (Statoil)	51.0000 %
Norsk Hydro Produksjon A/S (operator)	24.5000 %
Saga Petroleum a.s	9.8000 %
Norske Conoco A/S	7.3500 %
Mobil Exploration Norway Inc	7.3500 %

Mime is a small oil field seven kilometres north of Cod, in block 7/11 allocated in 1987. Hydro discovered the field in 1982 and has conducted test production since October 1990. Further operation of the field was approved by the authorities on 6 November 1992.

Production
The reservoir consists of Upper Jurassic sandstone in the Ula formation. The operator's reserves estimates are 0.7 mcm oil and 0.2 bcm gas.

Mime is produced from one well, located centrally in the structure. Based on the Directorate's geological understanding of the field this well has a less than optimal location and low productivity. In order to increase production the operator will install equipment designed to lower the receiving pressure at Mime on the Cod platform. Other than this, no further work is planned on Mime. Total production depends on the lifetime of the Cod platform.

Production installations
Production is by means of a subsea completion well with transfer of the well flow to the Cod installation. The well stream from Mime uses the Cod test separator for metering.

Transportation
The oil and gas from Mime are mixed with gas and condensate from the Cod production and transferred to the Ekofisk field for final processing and allocation. The oil is forwarded to Teesside, whereas the gas is used at the Ekofisk field centre.

Costs
The estimated total investment costs for the Mime development are 417 million 1992 kroner, not including the installation of a new compressor at Cod. The annual operating costs are estimated at 10 million 1992 kroner.

2.8 TRANSPORTATION SYSTEMS FOR OIL AND GAS

2.8.1 Existing transportation systems

There are three oil pipelines and four gas pipelines which carry oil and gas from the Norwegian continental shelf to shore. See the sketch of the transport systems for oil and gas in the Norwegian sector of the North Sea in Figure 2.8.

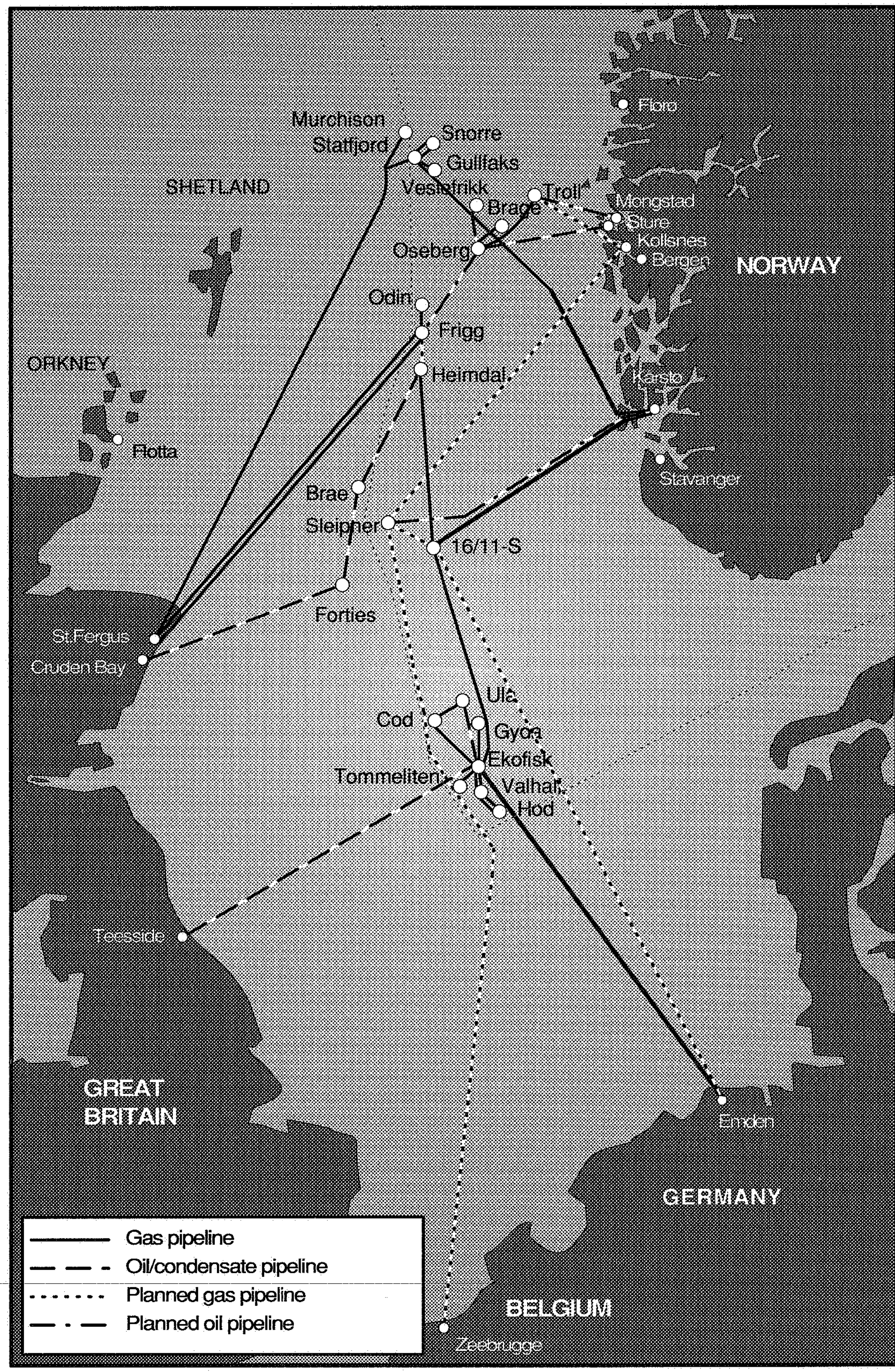
The UK share of gas from Statfjord is carried via the NLGP to Shell's terminal in St Fergus. The oil pipeline from the Ekofisk area, including the Ula and Valhall lines, runs to Teesside in the UK. Oil transportation from Oseberg comes to Sture at Øygarden. Condensate from Heimdal is taken via the British Brae and Forties systems to the BP operated Kinneil terminal near Edinburgh. This pipeline mainly transports British oil and condensate. The Statpipe and Norpipe gas pipelines were tied together in 1985 and both lead to Emden in Germany. Gas from Frigg is transported to Total's terminal at St Fergus in Scotland.

Gas transportation systems – Statpipe
The Statpipe gas transportation system has the following partners:

Partners

Den norske stats oljeselskap a.s (Statoil)	58.2500 %
Elf Petroleum Norge A/S	10.0000 %
Norsk Hydro Produksjon a.s	8.0000 %
Mobil Development Norway A/S	7.0000 %
Esso Norge a.s	5.0000 %
A/S Norske Shell	5.0000 %
Total Norge A/S	3.0000 %

Fig. 2.8
Pipelines for oil and gas from Norwegian fields in the North Sea



Saga Petroleum a.s	2.0000 %
Norske Conoco A/S	1.7500 %

Statoil was responsible for construction and is the operator of the system which comprises:

- Wet gas pipeline from Statfjord to Kårstø
- Separation and fractioning plant at Kårstø, plus storage farm and loading facility
- Dry gas pipeline from Heimdal; dry gas pipeline from Kårstø to riser platform in block 16/11; and pipeline to the 2/4-S riser platform at the Ekofisk field centre.

After production start-up the Gullfaks, Veslefrikk and Snorre fields were tied in to the Statpipe system upstream of the Kårstø facility.

Kårstø

The first North Sea gas was landed to Kårstø in March 1985. Delivery of dry gas from the terminal started in October 1985. The transport capacity from Statfjord to Kårstø is 25 mcm a day. This capacity will be fully exploited in 1995–96.

In order to process and forward this volume of gas the Kårstø facility is being modified, among other things by laying a bypass line from the wet gas side to the dry gas side of the plant. The gas transport compressors at Kårstø are being upgraded in order to handle the changed transportation requirements associated with the tie-in of Statpipe and Zeepipe.

In connection with the Sleipner development a new facility for treatment of the condensate has been built at the Kårstø terminal. Propane and butane will be separated from the condensate and subsequently stored in common tanks with similar products from Statpipe before being sold. Condensate is a new sales product from the Kårstø terminal.

Metering system

Metering of the gas delivered from the Kårstø terminal was undertaken in compliance with the current rules for gas metering.

Propane, butane and naphtha measurements are based on a dynamic metering system. A new loading quay with a dynamic metering station is being erected for Sleipner condensate. In addition, it will also be possible to load the other products currently shipped from the terminal from this quay.

Gas transportation systems – Norpipe

The pipeline transportation system for natural gas from the Ekofisk field centre to Emden in Germany is owned by Norpipe A/S. Gas from the Ekofisk area, Statpipe, Valhall, Hod, Ula and Gyda is delivered to Norpipe. Norpipe A/S is a limited company owned 50 per cent by Statoil and 50 per cent by the Phillips Group.

Phillips Petroleum Company Norway operates the pipeline.

Emden

The owner of the facilities at the Emden terminal is Norsea Gas A/S. Norsea Gas GmGH owns the site for the facilities. Both these companies are owned by the Phillips Group, on whose behalf Phillips Petroleum Norsk A/S acts as operator.

The metering station in Emden will be modernised in 1993.

Etzel gas terminal

Partners

Den norske stats oljeselskap a.s (Statoil)	67.0000 %
Norsk Hydro Produksjon a.s	8.0000 %
A/S Norske Shell	8.0000 %
Esso Norge a.s	8.0000 %
Saga Petroleum a.s	4.0000 %
Elf Petroleum Norge A/S	2.2985 %
Norske Conoco A/S	1.7015 %
Total Norge A/S	1.0000 %

Under the Troll gas sales agreement the sellers have covenanted to deliver gas for up to 14 days in the event of a shutdown for »non-technical reasons». In addition to ensuring this requirement can be met, the terminal's storage capacity will offer operational advantages with respect to delivery availability, gas quality equalisation, and deliveries that can be upheld during inspection and maintenance shutdowns. Quantities to and from the terminal will be measured by a new fiscal metering station operated by Phillips in Emden. The terminal will be ready for gas filling at the beginning of 1993 and will be operative in autumn 1993.

Gas transportation systems – Frigg

The Norwegian Frigg pipeline is owned by the Norwegian Frigg partners. Their ownership interests are:

Norsk Hydro Produksjon a.s	32.8700 %
Elf Petroleum Norge A/S	26.4200 %
Den norske stats oljeselskap a.s (Statoil)	24.0000 %
Total Norge A/S (operator)	16.7100 %

The compressor platform MCP-01, midway between Frigg and St Fergus, is owned 50 per cent by Norwegian interests. The compressors have now been decommissioned and the installation is unmanned. Some UK fields are connected to the Norwegian Frigg pipeline via MCP-01. As long as the installations were manned, their volumes were determined by metering on MCP-01. Following the removal of all manpower the volumes from the British fields are metered on the individual installations.

St Fergus

This terminal is owned by the Norwegian Frigg partners and UK Frigg partners (Elf UK 66 2/3 and Total UK 33 1/3 per cent). The various processing modules on the terminal are owned either by one partner group or by both. Total Oil Marine UK is the operator.

Oil transportation systems – Norpipe A/S
The pipeline system for transportation of oil from the Ekofisk field centre to Teesside in the UK is owned by Norpipe A/S. Oil from the Ekofisk area, Valhall, Hod, Ula, and Gyda is delivered to Norpipe. Norpipe A/S is a limited company owned 50 per cent each by Statoil and the Phillips Group. Phillips Petroleum Company Norway operates the pipeline.

Teesside
Ownership of the Teesside terminal facilities is split between Norpipe A/S and the Phillips Group through Norpipe Petroleum UK Ltd and Norsea Pipeline Ltd. The operator is Phillips Petroleum Company UK Ltd.

Oil transportation systems – Oseberg
The pipeline and the terminal facilities at Sture are owned and operated by a joint venture formed for the purpose and called I/S Oseberg Transport System. The venturers are the Oseberg partners. Hydro operates the pipeline and terminal. The OTS came on stream simultaneously with the Oseberg field. Veslefrikk was subsequently linked up to the OTS.

The Oseberg Transport System comprises the following main elements:

- Pipeline support functions on Oseberg A
- Subsea pipeline
- Onshore pipeline
- Terminal.

The pipeline, of 711 mm diameter and capacity 111,000 scm a day (currently being upgraded to this level), lies in water depths of up to 350 metres.

The OTS entered service in December 1988 and the first export oil cargo was shipped from Sture on 20 December 1988.

2.8.2 Projected transportation systems
Zeepipe

Partners

Den norske stats oljeselskap a.s (Statoil)	70.0000 %
Norsk Hydro Produksjon a.s	8.0000 %
A/S Norske Shell	7.0000 %
Esso Norge a.s	6.0000 %
Elf Petroleum Norge A/S	3.2985 %
Saga Petroleum a.s	3.0000 %
Norske Conoco A/S	1.7015 %
Total Norge A/S	1.0000 %

Zeepipe is a gas transportation system which will carry gas from Kollsnes in Øygarden to the Continent. Phase 1 of the project has been approved, which includes a 966.4 mm diameter, 800 kilometre long pipeline from Sleipner to Zeebrügge in Belgium and a 725 mm diameter, 40 kilometre long pipeline from Sleipner to the 16/11-S riser platform. Phase 1, including the terminal in Zeebrügge, is under construction and will be ready to transport gas in 1993. Capacity without compression will be 13 bcm gas a year.

Development of phase IIA has also been resolved and involves a 300 kilometre long pipeline of diameter 966.4 mm from Kollsnes to Sleipner.

Phase IIB studies are currently being performed. A plan for construction and operation in phase IIB is expected to be submitted in 1993. This phase will include a pipeline to carry gas from Kollsnes to Frigg or Heimdal or to the 16/11-S riser platform. The size and route for phase IIB have not yet been decided.

Costs
The estimated total development costs are 10.5 billion 1992 kroner for Zeepipe phase I and 3.9 billion 1992 kroner for Zeepipe phase IIA.

Europipe

Partners

Den norske stats oljeselskap a.s (Statoil)	70.0000 %
Norsk Hydro Produksjon a.s	8.0000 %
A/S Norske Shell	7.0000 %
Esso Norge a.s	6.0000 %
Saga Petroleum a.s	3.0000 %
Elf Petroleum Norge A/S	3.2985 %
Total Norge A/S	1.0000 %
Norske Conoco A/S	1.7015 %

The general plan for the building of a third pipeline to the Continent was approved by the Ministry of Petroleum and Energy. Statoil's plans are to build a 966.4 mm diameter pipeline running about 600 kilometres from a new riser platform 16/11-E (near 16/11-S) to Emden in Germany. The system will be able to accommodate compression facilities about half way between 16/11-E and Emden. Without compression the capacity will be 12 bcm gas a year. With compression the capacity can be upgraded to about 18 bcm gas a year. Problems associated with approval of the landing site in Germany have led to delays for parts of the facility. It is nevertheless expected that the pipeline system will be operational from autumn 1995.

Costs
Total development costs have been estimated at 12.8 billion 1992 kroner.

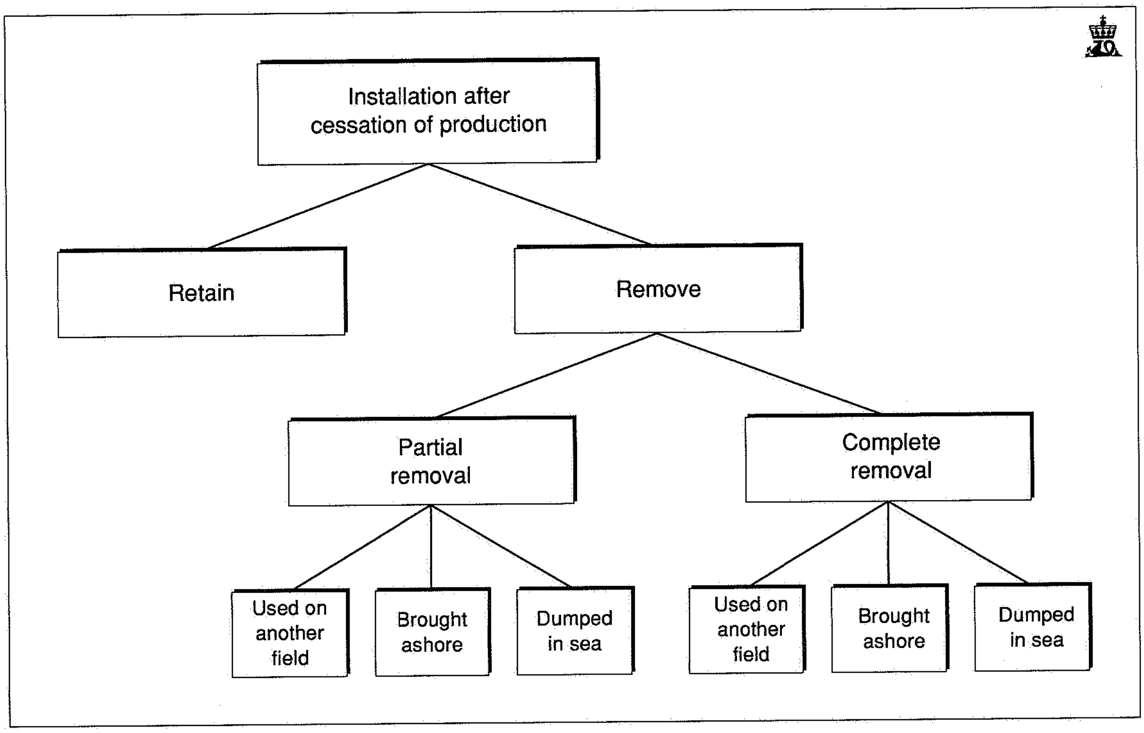
Frostpipe

Partners

Den norske stats oljeselskap a.s (Statoil)	50.0000 %
Elf Petroleum Norge A/S	22.0000 %
Total Norge A.S	14.2500 %
Norsk Hydro Produksjon a.s	13.7500 %

Development
Frostpipe is a pipeline 80 kilometres in length and 406 mm in diameter for transportation of stabilised

Fig. 2.9
Final production and removal



crude and condensate from Frigg to Oseberg with a capacity of 16,000 scm a day. The plan for construction and operation was approved by the King in Council in April 1992.

Costs
Total investment costs for the pipeline are 0.7 billion 1992 kroner, while total operating costs are 0.4 billion 1992 kroner, exclusive of tariffs.

2.9 DECOMMISSIONING AND REMOVAL
The International Maritime Organization (IMO) in autumn 1989 resolved international guidelines for removal of installations on the continental shelf.

The question of if and when a coastal state should be ordered to remove its installations from the continental shelf once their useful life expires is of enormous importance to Norway. Removal of the installations on the Norwegian continental shelf will inevitably be in almost all cases much more expensive and technically complex than in other parts of the world. At present, Norway has about 70 installations already producing petroleum or under planning or construction. Several possible solutions exist for disused installations, see Figure 2.9.

The estimated cost of complete removal of all installations is roughly Nkr 50 billion, although of course this figure is highly speculative. Under the legislation for removal of installations the State has to bear a considerable portion of the costs of removal.

These are the main points in the IMO rules as adopted:

- All installations whose use is finally over and which are at a sea depth of less than 75 metres and have a base (jacket) weighing less than 4000 tonnes shall be removed;
- All installations deployed after 1 January 1998 whose use is finally over and which are at a sea depth of less than 100 metres and have a base (jacket) weighing less than 4000 tonnes shall be removed;
- For other installations the question of removal will be determined on the basis of the individual coastal state's evaluation in each case. Said evaluation shall weigh considerations of safety at sea, other users of the sea, environmental impact and living resources, the costs and safety hazards of removal, alternative uses and other reasonable grounds to allow the installation to remain in place, wholly or in part;
- Should a coastal state determine that an installation shall be removed to below the sea surface, a free height of minimum 55 metres of water shall be left below the sea surface;
- Should a coastal state determine that an installation shall remain in place wholly or in part such that it protrudes from the sea surface, satisfactory maintenance shall be carried out to prevent disintegration of the installation;

– After 1 January 1998 no installations shall be emplaced which it is technically impossible to remove.

The IMO's international guidelines for removal of installations highlight the need to draft further national rules of law addressing the removal question in Norway. It must be emphasised that the IMO rules should be considered more like guidelines – they will not be legally binding on the states involved. On the other hand, the rules will have considerable moral force and it would be politically difficult to ignore them.

The removal issue is becoming especially relevant on the Norwegian continental shelf. In this connection the Petroleum Act Committee has been requested to study and develop a national set of rules for decommissioning and removal of installations on the Norwegian continental shelf.

2.10. PETROLEUM RESOURCES

2.10.1 Resources accounting

Petroleum resources are non-renewable energy resources comprising all technically recoverable oil and gas quantities.

Resources accounts are summaries of the original marketable petroleum quantities on the Norwegian continental shelf and the amounts remaining to date. Changes in the accounts from one year to the next result from new discoveries, adjustments to estimates for existing discoveries, and reductions due to production.

In 1991, the Directorate introduced a new system of classifying resources. The new system is published in NPD Contribution no. 31 for 1991 and distinguishes between discovered and undiscovered resources, as shown in Figure 2.10.1.a.

Discovered resources include fields and discoveries. Fields includes resources and reserves in fields in production, approved for development, or planned for development. Petroleum reserves are that portion of the proven resources which are recoverable under given technical and economic conditions, and which the licensees have declared commercial. Additional resources are the subsidiary quantities that can be produced using various enhanced recovery techniques not included in approved plans.

Discoveries are proven and tested resources in separate structures or separate stratigraphic levels. This category includes recent discoveries, discoveries being evaluated, and discoveries which under present conditions are not considered commercial. A discovery or field has only one discovery well. This means that wildcats which prove resources which are included, or will be included, in the resources figure for an existing discovery or field are not reckoned as new discoveries. The year of discovery is the year in which the well undergoes production testing.

The undiscovered resources include predicted resources in surveyed, undrilled structures; and predicted resources in areas where exploration models have been defined, but no prospects identified.

Fig. 2.10.1.a
Resource account for the Norwegian continental shelf

			OIL $10^6 Sm^3$ Most likely	GAS $10^9 Sm^3$ Most likely	NGL 10^6 tonnes Most likely	T.O.E. Most likely
Discovered resources	Fields producing (originally)	Current plan	1863	678	72	2305
		Improved recovery	478			397
	Fields decided developed	Current plan	398	1078	44	1452
		Improved recovery	110			91
	Fields planned developed	Current plan	94	611	24	712
		Improved recovery				
	Discoveries under evaluation		466	764		1162
	Fields and discoveries total		3409	3132	140	6119
Undiscovered resources			1480	2410		3670

	Oil	Gas	NGL	T.O.E.
Sold per: *31/12-92*	879	375	28	1134

Reserves Resources

Undiscovered resources

In 1992, the Directorate reanalysed the undiscovered petroleum resources on the Norwegian continental shelf (see Figure 2.10.4.d and section 2.10.4). The new resources estimates replace those published in the Directorate's last edition of the *Petroleum Outlook* in 1988. A new feature compared to that Outlook is that one has ceased splitting the undiscovered resources into hypothetical and speculative resources. Estimates of the undiscovered resources are based on 44 defined regional exploration models which between them cover the entire Norwegian continental shelf. The estimated statistical expectation for the undiscovered resources in 1992 is some 3670 million toe, while the corresponding estimate in 1988 was 3570 million toe. If we compare this with the addition in resources in the form of new discoveries during this period, which are in the order of 285 million toe, it means an increase in the statistical expectation of proving undiscovered resources on the Norwegian continental shelf of about 385 million toe since 1988. This figure corresponds to somewhat less than 12 per cent.

Discoveries made in 1992

Nine new discoveries were made in 1992. These were 2/2-5, 2/4-17, 7/7-2, 30/10-6, 34/7-21, 35/11-7, 6507/2-2, 6608/10-2, and 7316/5-1. Hydrocarbons were also encountered in 1/6-6, 34/8-7R, and 25/11-16, though these wells had not been tested at the end of the year. The work of evaluating the discoveries is ongoing.

Of the year's discoveries, 7/7-2, 6507/2-2, and 6608/10-2 have been evaluated and are included in the resources accounts. The growth in resources attributable to these new discoveries is 46.8 mcm oil and 4.6 bcm gas.

The six discoveries which have still not been evaluated are expected to make a contribution to the resources in the order of 20-70 million toe.

Past discoveries newly recorded

In addition to this year's discoveries already mentioned, the following past discoveries are now included in the resources accounts: Vale, 25/6-1, 25/8-1, 30/9-13S, and 6506/11-2. The growth in resources attributable to these past discoveries newly recorded is 27.7 mcm oil and 9.0 bcm gas.

Adjustment of resources estimate for existing fields and discoveries

For fields in production, approved for development and planned for development, and existing discoveries, the present resources accounts show that, relative to the *Annual Report 1991*, oil resources have increased by 148.4 mcm and gas resources by 30.7 bcm. Natural Gas Liquids decreased by 2.3 billion tonnes. For details of revisions, see Table 2.10.2.2.

Production

Lifting of petroleum on the Norwegian continental shelf amounted to 123.5 mcm oil, 25.8 bcm gas, and 3.0 million tonnes NGL in 1992.

Resources status

The Directorate's accounts for 1991 and 1992 show that the additions of oil and gas are greater than the depletion. The increase in oil was 98.8 mcm, whereas gas increased by 18.6 bcm. NGL was reduced by 4.7 million tonnes.

At the present rate of depletion of petroleum, Norway has proven resources sufficient for 20 years of oil production and 115 years of gas production. Enhanced oil recovery has then been taken into account, see Section 2.10.3.

Change in resources 1991-92	Oil mcm	Gas bcm	NGL mton
Discoveries entered in 1992	46.8	4.6	
Past discoveries now recorded	27.7	9	
Adjustments for fields and discoveries	148.4	30.7	−2.3
Production	−124.1	−25.7	−2.4
Sum change	98.8	18.6	−4.7

The resources accounts for the Norwegian continental shelf are illustrated in Figure 2.10.1.a and the geographical distribution of the resources in Figure 2.10.1.b.

For the purposes of presentation the resources on the Norwegian continental shelf are set out in four tables showing:

1. Reserves in fields in production, Table 2.10.1.a
2. Reserves in fields approved for development, Table 2.10.1.b
3. Reserves in fields planned for development, Table 2.10.1.c
4. Resources in discoveries being evaluated, Table 2.10.1.d-e.

Reserves in fields in production or approved for development

By year end, 39 development projects had been approved on the Norwegian continental shelf, four more than one year previously. The four newcomers are Frøy, Mime, Sleipner Vest, and Troll Vest oil. As yet, only Draugen and Heidrun have been adopted north of Stad (see Table 2.10.1.a and 2.10.1.b).

Up to end-92, total production was 1134 mtoe. This is 25 per cent of discovered oil and 12 per cent of discovered gas on the Norwegian continental shelf. Enhanced oil recovery has then been taken into account.

Reserves in fields planned for development

By year end there were 12 fields which had been declared commercial and therefore are classified as fields, see Table 2.10.1.c. The amount of petroleum in these fields is 0.7 btoe.

Resources in discoveries being evaluated

Table 2.10.1.d is a summary of discoveries being evaluated south of Stad. The quantities here amount to 0.61 btoe in all. Resources in discoveries being evaluated north of Stad amount to 0.55 btoe; of which 0.29 btoe is in the Norwegian Sea and 0.26 btoe in the Barents Sea. See Table 2.10.1.e.

2.10.2 Revisions since last year

2.10.2.1 Fields in production, approved and planned for development

For fields in production the Directorate generally accepts the operator's projections of future reserves. On many fields only moderate changes were made in the forecasts compared to the figures given in the 1991 Annual Report. Fields where a substantial revision has occurred are dealt with specifically below. For changes in resources statistics from 1991 to 1992, see Table 2.10.2.

Embla

The operator has made a downward adjustment of the reserves following a re-interpretation. The Directorate is currently performing its own evaluation of Embla. New reserve figures will be available in spring 1993.

Fig. 2.10.1.b
Geographical distribution of resources on the Norwegian continental shelf

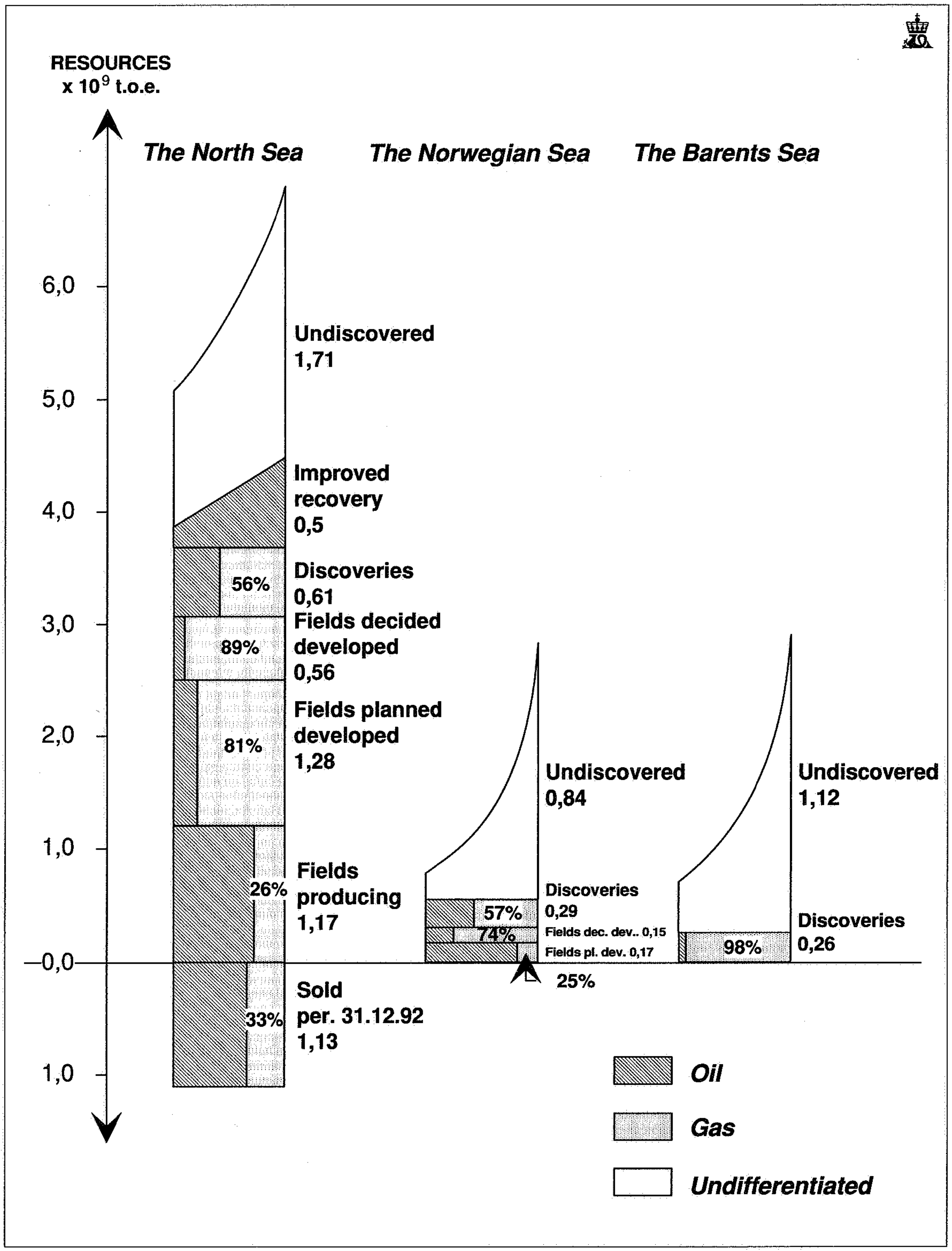


Table 2.10.1.a
Petroleum reserves in fields in production

	Initial produceable reserves				Remaining produceable reserves		
	Oil 10^6 Sm^3	GAS 10^9 Sm^3	NGL mton	mtoe	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL mton
Albuskjell[1]	9.0	20.0	1.3	28.4	2.0	5.8	0.4
Cod[1]	2.9	7.4	0.5	10.1	0.2	0.9	
Edda[1]	5.0	2.1	0.2	6.5	0.9	0.3	
Ekofisk[1]	360.0	151.0	14.4	467.8	186.5	69.9	7.2
Eldfisk[1]	79.0	56.5	4.7	125.2	27.9	35.7	2.3
Frigg[1,2]		110.0	0.4	110.4		2.3	
Gullfaks[1]	230.0	16.0	1.8	213.3	142.0	10.1	1.2
Gyda	32.0	4.2	1.9	32.3	23.7	3.1	1.4
Heimdal[1]		35.6	4.2	39.8		12.8	1.4
Hod[1]	6.7	1.3	0.3	7.2	3.7	0.8	0.2
Mime[1]	0.7	0.2		0.8	0.4	0.1	
Murchison[1,3]	12.7	0.3	0.4	11.3	1.7		
Nord Øst-Frigg[1]		11.8	0.1	11.9		0.3	
Odin[1]		29.3	0.2	29.5		4.1	
Oseberg[1,4]	277.0	81.0	11.6	328.1	197.3	81.0	11.6
Snorre[1]	130.0	6.7	3.3	117.9	128.4	6.7	3.2
Statfjord[1,5]	486.0	52.0	15.4	470.8	149.7	30.3	8.8
Tommeliten Gamma[1]	3.6	8.5	0.6	12.1	1.0	3.7	0.2
Tor[1]	25.7	14.3	1.5	36.8	7.0	4.2	0.4
Ula[1]	69.0	4.3	2.8	63.7	33.8	1.9	1.2
Valhall[1]	76.0	19.0	3.6	84.2	43.4	12.6	2.1
Veslefrikk[1]	43.8	3.5	1.4	41.3	33.4	3.5	1.0
Vest Ekofisk[1]	12.7	28.6	1.5	40.3	0.9	4.0	0.2
Øst Frigg		8.2		8.2		2.2	
30/6 Gamma Nord[1]	0.9	6.2	0.4	7.4	0.5	6.2	0.4
Sum	1862.7	678.0	72.5	2305.3	984.4	302.5	43.2

Table 2.10.1.b
Petroleum reserves in fields approved developed

		Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL mton	mtoe
North Sea	Brage	46.2	1.7	1.0	41.5
	Embla[1]	5.6	2.1	0.2	6.9
	Frøy	14.0	3.0		14.5
	Lille-Frigg[1]		7.0	2.7	9.7
	Loke[1,6]	4.1	8.0		11.1
	Sleipner Vest[8]	27.0	135.0	9.0	164.5
	Sleipner Øst	19.0	50.0	11.3	75.7
	Statfjord Nord	31.0	2.5		27.9
	Statfjord Øst	13.4	2.0		13.1
	Tordis	18.8	1.2	0.5	17.1
	Troll Øst[8]		825.0	19.2	844.2
	Troll Vest olje	64.0			57.2
	Sum	243.1	1037.5	43.9	1283.4
Norwegian Sea	Draugen	68.0	3.0		58.8
	Heidrun	87.3	37.8		109.4
	Sum	155.3	40.8		168.2
	Total	398.4	1078.3	43.9	1451.6

Troll Vest test production in thick and thin oil zone, which is 1,2 mcm, is not included in the account.

Ekofisk
Reserves estimates were increased due to a new historical approach to the reservoir simulation model. Increased water injection is the primary reason for the boost in reserves.

Frøy
The recovery factor has been upgraded, resulting in an upward adjustment of the recoverable reserves.

Oseberg
An updated geological model, use of horizontal wells, and positive production experience have all led to an upward adjustment of the reserves.

Snorre
The reserves upgrade is due to an updated simulation model and new drilling plan for phase 1, among other things.

Table 2.10.1.c
Petroleum reserves in fields planned developed

		Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL mton	mtoe
North Sea	Byggve	0.6	2.6		3.1
	Gullfaks Vest[1)]	3.3			2.7
	Huldra[1)]	4.5	17.0		20.7
	Mjølner[1)]	1.5	0.7		1.9
	Oseberg Øst	19.0	1.0		16.5
	Peik[1)9)]	1.8	6.0		7.5
	Skirne	0.3	2.3		2.5
	Tommeliten Alpha	3.5	7.8	0.5	11.2
	Troll Vest gass[7)]		463.0	10.8	473.8
	Vigdis[1)]	27.1			22.2
	Sum	61.6	500.4	11.3	562.1
Norwegian Sea	Midgard	1.3	87.0	13.0	101.0
	Smørbukk Sør	31.0	24.0		49.7
	Sum	32.3	111.0	13.0	150.7
	Total	93.9	611.4	24.3	712.8

1) Operator's estimate
2) Norwegian share only, i.e. 60.82 % of total
3) Norwegian share only, e.e. 22,2 % of total
4) Includes Alpha, Alpha Nord and Gamma structure
5) Norwegian share only, i.e. 85,24 % of total
6) Resource figure includes the reservoirs in Heimdal formation and Trias. Only Heimdal reservoir is approved developed.
7) Condensate incl. in NGL.
8) Includes Alpha, Beta, Epsilon and Delta.
9) Norwegian share of proven resources: 60 % (not unitised)

Table 2.10.1.d
Petroleum resources in discoveries south of Stad under evaluation

	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL mton	mtoe
Agat[1)]		43.0		43.0
Balder[1)]	32.2			29.3
Gullfaks Sør[1)]	25.6	56.1		78.6
Hild[1)]	1.9	12.1		13.6
SØ-Tor	2.5	2.0		4.0
Trym[2)]	2.1	8.7		10.4
Vale	3.1	2.3		4.8
Visund[1)]	16.2	47.6		60.9
1/2–1[2)]	3.0			2.4
1/3–3	3.3	0.1		2.8
1/3–6	1.2	2.8		3.7
6/3–1 PI	0.9	1.0		1.7
7/7–2[1)]	16.0	0.5		14.6
7/8–3[1)]	6.2			5.4
9/2 Gamma[1)]	3.7			3.1
15/3–1.3[1)]	5.2	10.5		14.7
15/3–4[1)]	2.2	1.3		3.1
15/5–1	2.0	6.0		7.5
15/8–1 Alpha	5.0	11.0		14.8
15/9–15 My	5.0	11.0		14.8
15/12 Beta[1)]	16.0	1.3		14.4
15/12–8[1)]	0.6	1.3		1.7
16/7–4[1)]	1.4	8.0		9.1
25/2–5[1)]	5.3	1.9		6.2
25/6–1[1)]	4.1	0.9		4.3
25/8–1[1)]	7.0			5.9
25/11–15	60.0	1.8		58.8
30/6–18 Kappa[1)]	1.0	3.6		4.4
30/9–3 Omega	16.6	8.0		21.6
30/9–6[1)]	2.7			2.2
30/9–9[1)]	5.2			4.3
30/9–10[1)]	3.2			2.8
30/9–13 S[1)]	7.2	2.2		8.3
34/10–17 Beta[1)]	8.0	22.5		29.0
34/10–23 Gamma	2.2	28.0		29.8
35/8–1	1.9	13.5		15.0
35/8–2	2.6	7.0		9.1
35/9–1 R[1)]	5.0	11.0		15.6
35/11–2	5.4	5.6		10.0
35/11–4 R	18.0	10.8		25.6
	310.7	343.4		611.3

1) Operator's estimate 2) Norwegian share

Table 2.10.1.e
Petroleum resources in discoveries in the Norwegian Sea and in the Barents Sea under evaluation

		Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL mton	mtoe
	Njord	35.0	7.2		36.0
Norwegian	Mikkel[1)]	3.8	18.0		21.1
Sea	Smørbukk[1)]	37.0	95.0		125.3
	Trestakk[1)]	4.8			3.9
	Tyrihans Sør[1)]	5.1	11.5		15.5
	Tyrihans Nord[1)]	4.5	15.0		18.9
	6506/11-2[1)]	6.3	3.6		8.8
	6507/2-2[1)]	0.5	2.6		3.0
	6507/3-1[1)]	1.1	7.1		7.9
	6507/8-4[1)]	19.8	2.4		20.4
	6608/10-2[1)]	30.3	1.5		27.3
	Sum	148.2	163.9		288.1
	Albatross		41.7		41.7
	Albatross Sør		10.8		10.8
	Askeladd		59.7		59.7
Barents	Snøhvit	6.7	83.0		88.5
Sea	Snøhvit Nord		3.3		3.3
	7119/12-3[1)]		3.6		3.6
	7120/07-1		22.5		22.5
	7120/12-2		10.7		10.7
	7120/12-3		4.1		4.1
	7121/5-2 Beta		4.3		4.3
	7122/06-1[1)]		11.0		11.0
	7124/03-1[1)]		2.1		2.1
	Sum	6.7	256.8		262.3
	Total	154.9	420.7		550.4

1) Operator's estimate

Statfjord
The operator has upgraded the reserves on the basis of present reservoir behaviour, an extensive well programme, and updated reservoir simulations.

Valhall
The increase in recoverable reserves is due to updating of the reservoir model.

Veslefrikk
The reserves have increased due to positive drilling operations which have proven larger than assumed *in situ* resources. Furthermore, the recovery factor has been upgraded on the basis of new reservoir simulations and more production wells.

2.10.2.2 Discoveries
The changes in resources estimates from 1991 to 1992 are reported in Table 2.10.2. Discoveries for which a major change was made are discussed specifically.

Balder
Previous estimates were based on the Directorate's almost ten year old estimate. The Directorate has now elected to use the operator's new resources estimates.

Mikkel
New geological mapping and reservoir evaluation following the drilling of well 6407/6-4 have led to an increase in the resources estimate.

Smørbukk
The new resources estimate is based on new geological mapping and reservoir simulation following the drilling of appraisal well 6506/11-2. In addition, a new oil and gas discovery was made in Cretaceous rock during the drilling of this well.

Trestakk
Remapping and new reservoir simulations have brought about a reduction in the recoverable resources.

Tyrihans
Previous resources estimates were based on the Directorate's mapping from 1985 but the operator's estimates are used now. Note, too, that Tyrihans has been divided into Tyrihans and Tyrihans Nord.

9/2 Gamma
The resources figure has been downgraded in tune with the operator's new estimates.

Table 2.10.2
Changes in estimated resources annual reports 1991–1992

	Annual Report 1991			Annual Report 1992		
	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL mton	Oil 10^6 Sm^3	Gas 10^9 Sm^3	NGL mton
Fields in production						
Albuskjell	10.0	22.0	1.5	9.0	20.0	1.3
Cod	2.8	7.0	0.5	2.9	7.4	0.5
Edda	5.2	2.1	0.2	5.0	2.1	0.2
Ekofisk	330.0	151.0	15.0	360.0	151.0	14.4
Eldfisk	77.0	59.0	5.3	79.0	56.5	4.7
Gullfaks	230.0	16.5	1.9	230.0	16.0	1.8
Heimdal		35.6	4.1	0.0	35.6	4.2
Hod	5.7	1.2	0.4	6.7	1.3	0.3
Mime	0.9	0.2		0.7	0.2	
Murchison	12.0	0.3	0.4	12.7	0.3	0.4
Odin	0.2	29.3			29.3	0.2
Oseberg	226.0	70.0	3.0	277.0	81.0	11.6
Snorre	106.0	6.7	3.2	130.0	6.7	3.3
Statfjord	453.0	51.6	15.9	486.0	52.0	15.4
Tommeliten Gamma	7.5	16.5	1.0	7.1	16.3	1.1
Tor	27.2	15.9	1.8	25.7	14.3	1.5
Ula	69.2	4.7	3.5	69.9	4.3	2.8
Valhall	68.8	17.7	4.1	76.0	19.0	3.6
Veslefrikk	36.0	3.0	1.3	43.8	3.5	1.3
Vest Ekofisk	13.3	28.9	1.7	12.7	28.6	1.5
30/6 Gamma Nord	1.3	7.1		0.9	6.2	0.4
Fields approved developed						
Embla	9.2	3.4	0.5	5.6	2.1	0.2
Frøy	12.5	2.7		14.0	3.0	
Sleipner Øst	19.9	51.0	10.3	19.0	50.0	11.3
Fields under evaluation						
Gullfaks Vest	3.0			3.3		
Mjølner	1.7			1.5	0.7	
Discoveries						
Balder	35.0			32.2		
Gullfaks Sør	25.6	56.1	3.0	25.6	56.1	
Mikkel	5.7	14.3		3.8	18.0	
Smørbukk	20.0	65.0		37.0	95.0	
Snøhvit	6.5	76.0	5.7	6.7	83.0	
Trestakk	9.0			4.8	0.0	
Tyrihans	16.0	40.0		9.6	26.5	
Vale				3.1	2.3	
7/7–2				16.0	0.5	
9/2 Gamma	6.4			3.7		
25/6–1				4.1	0.9	
25/8–1				7.0	0.0	
30/9–13 S				7.2	2.2	
6506/11–2				6.3	3.6	
6507/2–2				0.5	2.6	
6608/10–2				30.3	1.5	

2.10.2.3 Name changes in 1992

Present name	Previous name
Gullfaks Vest	34/10-34
Tommeliten Alpha and Tommeliten Gamma	Tommeliten
Tyrihans and Tyrihans Nord	Tyrihans
Vale	25/4-6S

2.10.3 Enhanced recovery

The potential of increasing production both in the short and long term relative to existing plans is subject to annual consideration by the licensees and the authorities. Increases relative to the original plans have been substantial for most fields in production.

For fields that were in production ten years ago or which had been resolved for development at that time, the increase has been in the region of 30 per cent.

In 1992, upgrading of the plans for future production has led to an increase in the reserves for oil fields of 177 mcm attributable to enhanced recovery. Such increase has been greatest in sandstone reservoirs with a total of 119 mcm, whereas limestone fields have shown an increase of 58 mcm. The average recovery factor has now been calculated at 36 per cent.

In order to focus on the technical possibilities of increasing recovery the Directorate, in collaboration with the oil companies, has been mapping the potential for enhanced recovery for several years. For fields in production or resolved for development the estimated potential is 588 mcm, corresponding to 488 mtoe.

2.10.4 Undiscovered resources on the Norwegian continental shelf

Introduction

The greatest uncertainty factor in the resources accounts is the estimate of undiscovered resources on the Norwegian continental shelf. At the same time, reliable estimates are a prerequisite for making plans beyond the known horizon for resources already discovered. Ideally, such an estimate should also include an analysis of the geographical distribution of the resources and the breakdown of oil and gas, and last but not least, an analysis of the uncertainty of the estimate. This kind of analysis of undiscovered resources forms the basis of the authorities' choice of exploration strategy and the planning of other activities relative to the chosen exploration activity.

One has sought to incorporate these factors in the new analysis of undiscovered resources. As was the case in the Directorate's 1988 Petroleum Outlook, the new estimates are based on an analysis of the various geological exploration models. Since the 1988 Outlook, this methodology has been continued and substantially extended as far as degree of detail and supporting documentation go.

A difference from the 1988 Outlook is that the Directorate has now ceased distinguishing between the two categories of undiscovered resources: «speculative» and «hypothetical». Now there is only one category, namely «undiscovered resources», which includes resources in mapped prospects (previously «hypothetical») and unmapped resources (previously «speculative»). The reason for this change is to make it easier to treat the resources estimates for the various exploration models as statistical units.

Methodology

The resources estimates have been arrived at through a so-called exploration model analysis of the entire Norwegian continental shelf. This analysis method is briefly described in the ensuing.

When mapping prospects for drilling one makes certain assumptions regarding the prospects' properties in terms of reservoir rock, trap mechanism, and source rock, which means that one has made a model of the type of prospect one is looking for in advance. This is called an exploration model. An exploration model is defined by a specific set of critical geological parameters which *have to* be present if one is to find recoverable quantities of hydrocarbons. All prospects and discoveries within the same exploration model are characterised precisely by the model's specific set of critical geological parameters, and can therefore be distinguished from prospects and discoveries belonging to other exploration models.

An exploration model is geographically limited to the areas where the critical geological parameters coincide. In its definition and description of the exploration models on the Norwegian continental shelf, the Directorate's point of departure is to use as much as possible of its database of maps, seismic data, well data, onshore geological knowledge, and regional geological knowledge. Based on this systematised knowledge it was possible to define the various models and their geographical demarcations. In the analysis the exploration model concept has been used at a general level to limit the number of models to a workable figure and to avoid splitting up into too many models in areas where the data hardly justify such detail. Therefore the basis for the models is uncertain.

The defined exploration models on the Norwegian continental shelf can in principle be divided into two risk groups:

1. Confirmed exploration models; i.e. those models which through drilling results have proved to work according to the definition;
2. Unconfirmed exploration models; i.e. those models which have yet to be confirmed through drilling.

Generally, the probability of making a discovery will be smaller for prospects in unconfirmed models than for prospects in confirmed models. However, if an unconfirmed model proves to be valid (be confirmed), this may at once increase the probability of making a discovery for the entire area covered by the model. On the other hand, if an unconfirmed model proves invalid, its contribution to the total resources estimate will be erased, and the resources potential for the area will need to be downgraded. Thus it is uncertain whether an unconfirmed model will bring success. It is particularly important to be aware of this fact in new, relatively unknown areas, as a significant portion of the exploration models in such regions will be unconfirmed and will represent large geographical areas.

The reservoir rocks in the various exploration models are always associated with a particular stratigraphic level. Figures 2.10.4.a, 2.10.4.b and 2.10.4.c show which stratigraphic reservoir levels the Directorate has defined exploration models for on the Norwegian continental shelf. It is important to be aware of the fact that the number of exploration models is higher than the number of stratigraphic reservoir levels since several models may have the same reservoir level but still be different with respect to trap mechanism and/or source rock.

The estimates presented have been produced by calculating the expected resources within each exploration model and then adding all the models up to give the total resources. All calculations are made using the statistical calculation programme FASPUM developed by RA Crovelli of the United States Geological Survey.

Results

The Directorate's analysis has shown that the statistical expectation for the undiscovered resources on

Fig. 2.10.4.a
Reservoir levels in the North Sea

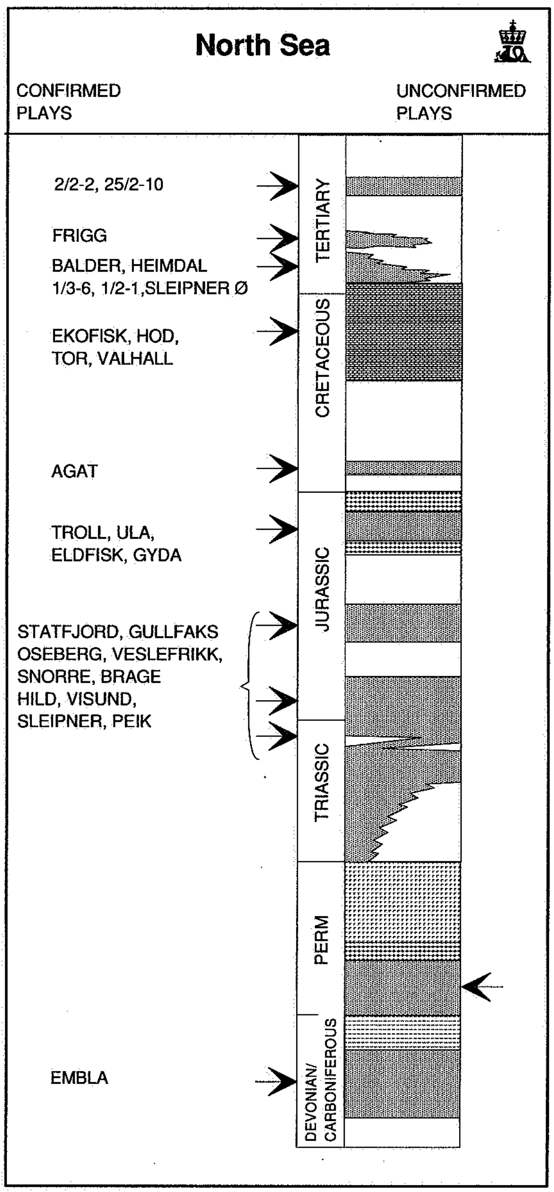
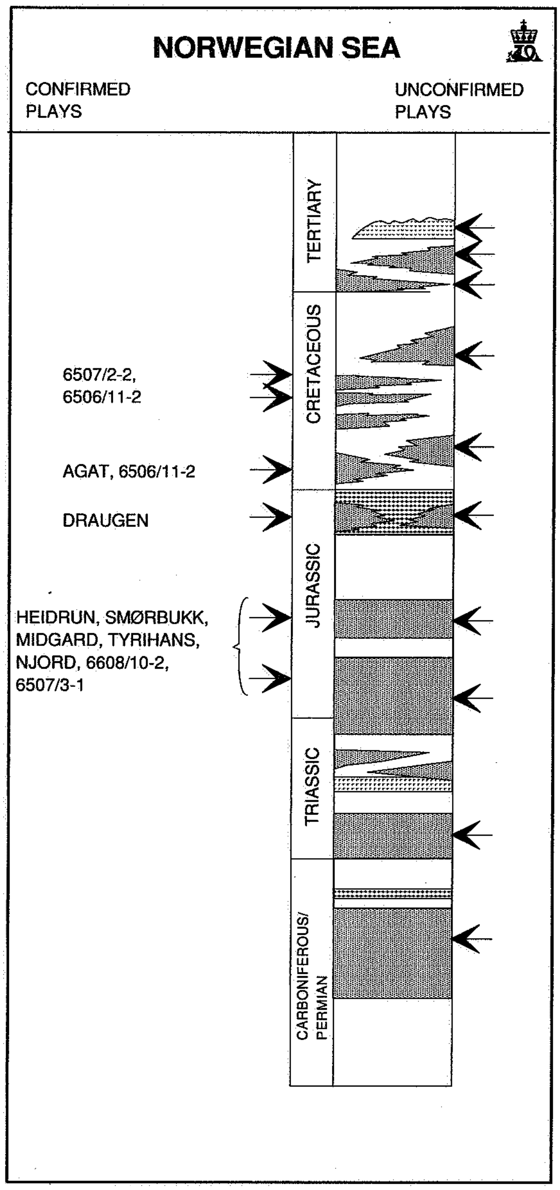


Fig. 2.10.4.b
Reservoir levels in the Norwegian Sea



the Norwegian continental shelf is distributed on the three main provinces as follows:

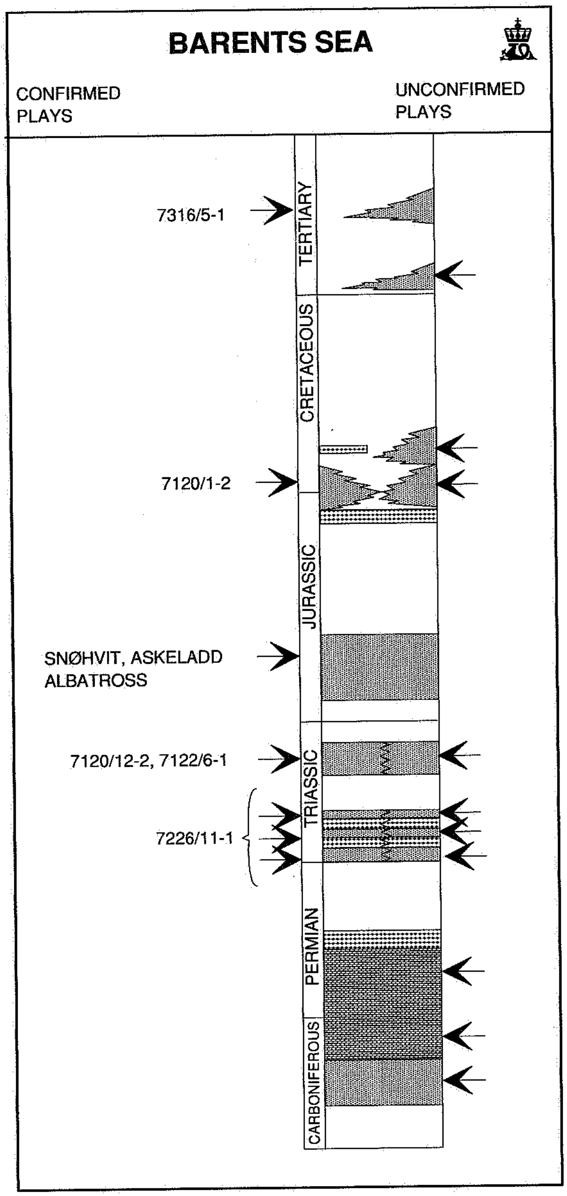
- North Sea: 0.75 btoe oil and 0.96 btoe gas
- Norwegian Sea (defined as the continental shelf between 62°N and 69° 30'N): 0.32 btoe oil and 0.52 btoe gas
- Barents Sea: 0.19 btoe oil and 0.93 btoe gas.

The total for the Norwegian continental shelf is therefore 1.26 btoe oil and 2.41 btoe gas.

These estimates are also presented in Figure 2.10.4.d (gas estimates include associated gas). Table 2.10.4.a. shows how these resources are distributed on the most important stratigraphic levels in line with the distribution in Figures 2.10.4.a, 2.10.4.b and 2.10.4.c. More than 75 per cent of all recoverable hydrocarbon resources already proven are found in Jurassic reservoir rocks. Table 2.10.4.a shows that the Jurassic level is expected to be the main level also in the future, while the Tertiary and pre-Triassic levels appear to be important additional levels. The Cretaceous and Triassic levels also have resource potential, although expectations here are somewhat lower. As far as the Cretaceous level is concerned, this is due in part to the high risk of these models, especially in the immature exploration areas north of Stad. See further comments under the discussion on uncertainty and unconfirmed models.

Of the total undiscovered resources, about 47 per

Fig. 2.10.4.c
Reservoir levels in the Barents Sea



cent are in the North Sea, 23 per cent in the Norwegian Sea, and 30 per cent in the Barents Sea. These figures show that the North Sea distinguishes itself with a considerable undiscovered oil potential. As shown by Figure 2.10.4.a, in the North Sea nearly all exploration models have been tested and exploration is largely confined to confirmed models. At present it appears that only exploration models at the Permian level remain to be confirmed or disproved. Table 2.10.4.a shows that the Jurassic and Tertiary levels are expected to contain most of the undiscovered resources in the North Sea. Note that the upper part of the Triassic level is included in the Jurassic models due to the stratigraphic continuity of the reservoir rocks.

In the Norwegian Sea there is an even distribution between confirmed and unconfirmed exploration models; see Figure 2.10.4.b. The confirmed models cover the well-known Jurassic models with their giant discoveries, as well as the Cretaceous models which in recent years have turned out to be successful along the Nordland ridge. The Agat discovery off Måløy shows that the Cretaceous level can also be an interesting model along the coast of Møre. However, seismic mapping of the Cretaceous models is very difficult, and one of the challenges is to develop the methods so as to provide more precise mapping of prospects. The unconfirmed exploration models in the Norwegian Sea are largely found in the areas which have not yet been opened, i.e. the deep basin areas in the west (Vøring and Møre basins) and the eastern platform areas close to the coast. It is expected that the Cretaceous and Tertiary levels will contain interesting models in the western basin areas, while potential in the east will be linked to the older strata. Estimates show that the two most important levels in the Norwegian Sea can be expected to be the Jurassic and Cretaceous levels also in the future. See Table 2.10.4.a.

In the Barents Sea, see Figure 2.10.4.c, a good deal of unconfirmed exploration models remain to be tested, and much of the anticipation vis-a-vis the potential in the Barents Sea is linked to them. The greatest expectations concern the models at the pre-Triassic level. Even though they are generally unconfirmed, statistical expectations are higher in this level than in the Jurassic or Upper Triassic levels where the largest discoveries have been made so far. Thus, the biggest challenge in the Barents Sea will be to explore the unconfirmed models or even develop new ones.

Uncertainty of estimates

In Figure 2.10.4.d the estimates for the undiscovered resources are shown. The uncertainty distribution is also shown. The P5 and P95 probabilities are a measure of this distribution. It can be seen that the distribution of the estimates is much wider in the Norwegian Sea and the Barents Sea than in the North Sea, which means that the uncertainty is greatest in the two northern provinces. The reason why this is so is that these provinces include areas with quite large, unconfirmed models in addition to the confirmed exploration models. These unconfirmed models have a generally high risk but also a high upside potential. Thus, these types of models have a rather special status since, depending on their success, they may give rise to a considerable upward or downward adjustment of the resources potential in their exploration areas. Due to the large upside potential it will be important to initiate exploration activity in areas with large, unconfirmed exploration models even if the statistical expectation is moderate. This is precisely the case for the large, unconfirmed exploration models in the Møre and Vøring basins in the Norwegian Sea and major parts of the Barents Sea. A

Fig. 2.10.4.d
Undiscovered resources on the Norwegian continental shelf 1992

	OIL (mill. t.o.e.)			GAS (mill. t.o.e.)		
	P95	Exp.	P05	P95	Exp.	P05
North Sea	475	750	1100	660	960	1320
Norwegian Sea	110	320	685	75	520	1550
Barents Sea	30	190	615	380	930	2000
NORWEGIAN SHELF	750	1260	1980	1310	2410	4020

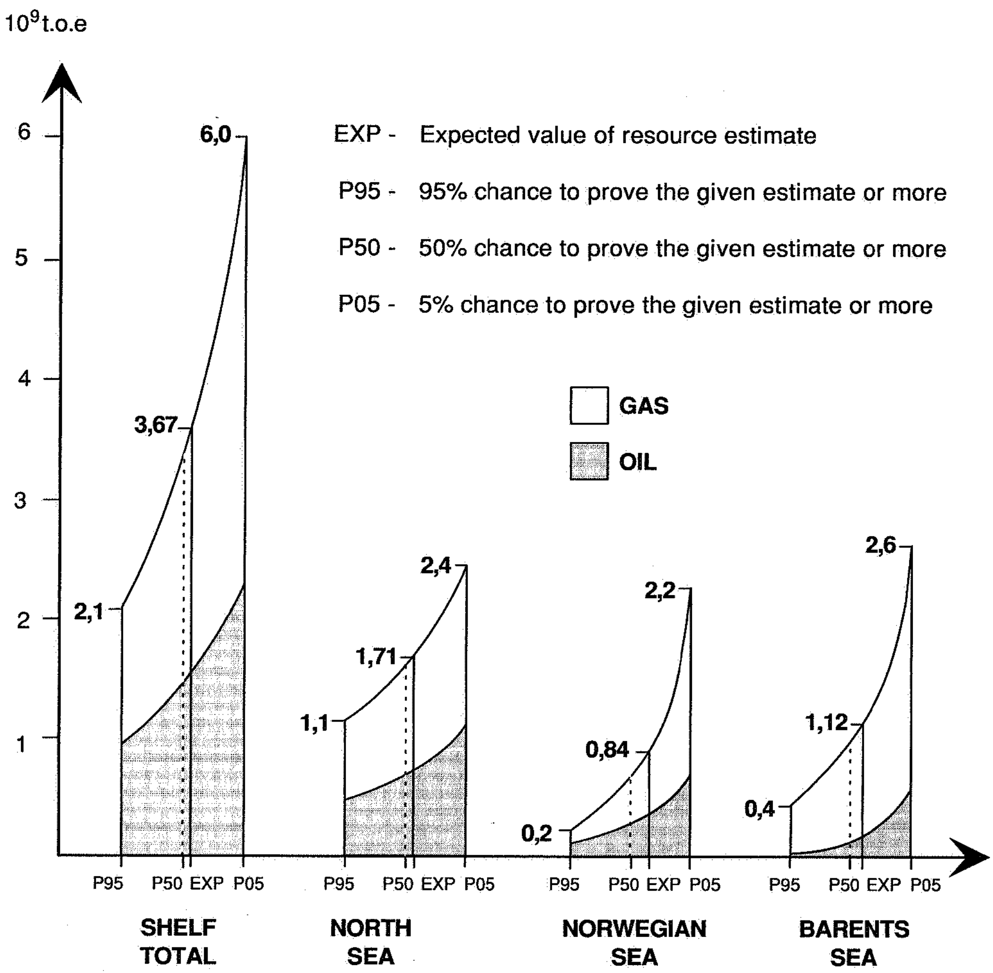


Table 2.10.4.a
Distribution of undiscovered resources on stratigraphic levels (statistical expectation 10^6 toe)

	PRE-TRIASSIC		TRIASSIC		JURASSIC		CRETACEOUS		TERTIARY		TOTAL (rounded)	
	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
NORTH SEA	40	110			555	710	20	10	135	130	750	960
NORWEGIAN SEA	3	2	3	4	245	285	60	140	10	90	320	520
BARENTS SEA	115	465	15	90	50	365	0,1	1	10	11	190	930
TOTAL *(rounded)*	160	580	20	90	850	1360	80	150	155	230	1260	2410

clarification of the uncertainty represented by these models will provide the basis for a future adjustment of the resources estimates in these areas.

The exploration activity in the North Sea has been going on for almost 30 years, and the North Sea must now be considered a relatively mature exploration area. This means that the exploration activity is primarily taking place in well known and confirmed exploration models in this part of the continental shelf. Therefore, North Sea estimates are more precise and have a far narrower distribution bandwidth than estimates for the two northern provinces.

Changes in estimates since 1988

When making comparisons between the new estimates and those given in the Directorate's Petroleum Outlook for 1988, we also have to take into account the new discoveries made in the period 1988 to 1992. Since 1988, 21 new discoveries have been made on the Norwegian continental shelf, with some 170 mtoe oil and 65 mtoe gas. In addition, ten discoveries have been made which are either of very limited magnitude or not sufficiently evaluated. These ten discoveries represent something in the order of 25-100 mtoe oil and gas, with an assumed resource volume of about 50 mtoe. The resources figures for the new discoveries have been stipulated on the basis of proven reserves. All told, this constitutes an addition in new discoveries of 285 mtoe since 1988.

The estimate for the statistical expectation in undiscovered resources in 1992 is about 3670 mtoe, while the corresponding estimate in 1988 was 3570 mtoe. Compared with the resources growth in new discoveries during the period, this means an upward adjustment of about 385 mtoe in the statistical expectation for the undiscovered resources on the Norwegian continental shelf. That corresponds to an increase of just under 12 per cent for the continental shelf as a whole and is not much different from the 1988 estimate.

The biggest change in the numbers is accounted for by the geographical distribution of the resources, where the North Sea has been heavily upgraded by some 100 per cent, while the Norwegian Sea and the Barents Sea have been downgraded by 10 per cent and 30 per cent, respectively. The figures also include an upward adjustment of the total undiscovered *oil* resources by some 40 per cent.

2.11. PETROLEUM ECONOMY

2.11.1 Exploration activity, goods and services

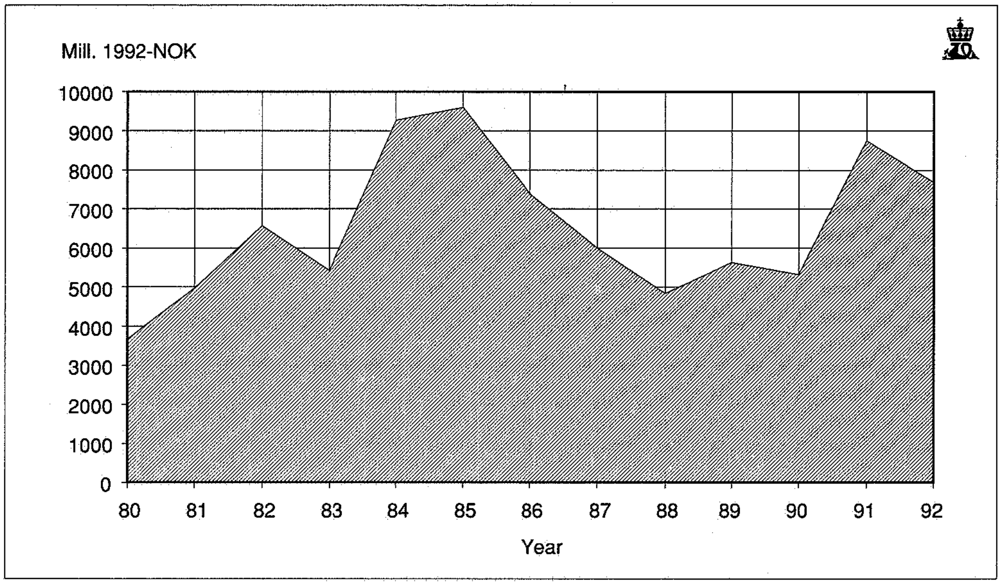
The exploration drilling activities increased relatively steadily between 1966 and 1985, when 50 new exploration wells were commenced. 1992 saw the commencement of 43 new exploration wells, a small reduction relative to 1991. In all, 29 wildcats and 14 appraisal wells were spudded, while the corresponding figures for 1991 were 34 and 13, respectively. On average for the period 1966 to 1992, the number of spudded wildcat wells and appraisal wells has been 20 and eight, respectively, which means the activity level is still high.

Figure 2.11.1.a shows the costs of exploration from 1980 onwards. These costs include exploration drilling, general surveys, field evaluation and administration. According to figures reported to the Directorate, total exploration costs for the period 1980 to 1992 were equivalent to about 78 billion 1992 kroner.

Shown below are the exploration costs for 1992 broken down by goods and services. The amounts are based on data reported by the operating companies. The same statistics produced the chart in Figure 2.11.1.b, which shows the percentage breakdown between the different expenditure types.

Exploration costs		Nkr million
Exploration drilling		5 150
of which:		
– Drilling installations	1846	
– Transportation costs	569	
– Goods	616	
– Technical services	2119	
General surveys		1 006
Field evaluations		363
Administration (incl acreage fees)		1 160
Total		7 679

Fig. 2.11.1.a
Exploration costs per year 1980–1992



Expenses in connection with field evaluations have been greatly reduced compared to 1991, while the general survey expenses are somewhat higher. General surveys include, among other things, the compilation of seismic data. Expenses associated with the compilation of seismic data have shown a considerable increase relative to figures from a few years back. Annual expenses in the period 1980-89 were over Nkr 500 million, whereas the estimated total expenses in 1992 were just under Nkr 1.2 billion.

Figure 2.11.1.c shows the mean drilling costs per exploration well. Exploration wells are wildcats and appraisal wells. Drilling costs in 1992 were roughly Nkr 5,150 million, broken down as follows (approximate figures): drilling installations 36 per cent, transportation 11 per cent, goods 12 per cent, and technical services 41 per cent.

Figure 2.11.1.d shows the mean drilling costs per day and per metre in the years 1980 to 1992.

2.11.2 Costs of development and operation on the Norwegian continental shelf

The Directorate has calculated annual costs in connection with the development of offshore fields, including production drilling, for the period 1970-2015. The costs include fields in production, fields for which the development plans had been approved at 31 December 1992, and pipeline systems. Where fields straddle the sector dividing line between Norway and the UK, only the Norwegian parts have been included. The following fields and transport systems are included in the calculations:

- Albuskjell
- Brage
- Draugen
- Ekofisk area (Cod, Edda, Ekofisk, Eldfisk, Vest-Ekofisk, Embla)
- Europipe
- Etzel Gas Store
- Frigg (including Frigg Transport)
- Frostpipe
- Frøy
- Gullfaks
- Gyda
- Haltenpipe
- Heidrun
- Heimdal
- Heimdal Jurassic
- Hod
- Lille Frigg
- Loke
- Mime
- Murchison
- Norpipe
- Nordøst Frigg
- Odin

Fig. 2.11.1.b
Oil and gas exploration costs in 1992

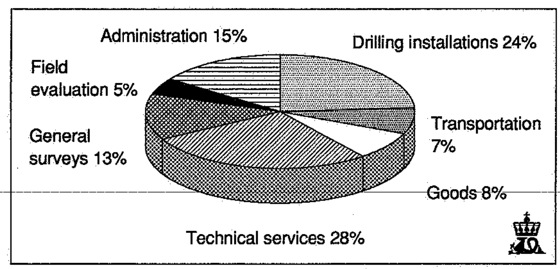


Fig. 2.11.1.c
Drilling costs per well

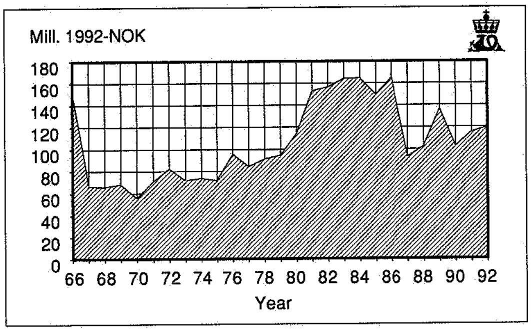


Fig. 2.11.1.d
Exploration costs 1980–1992

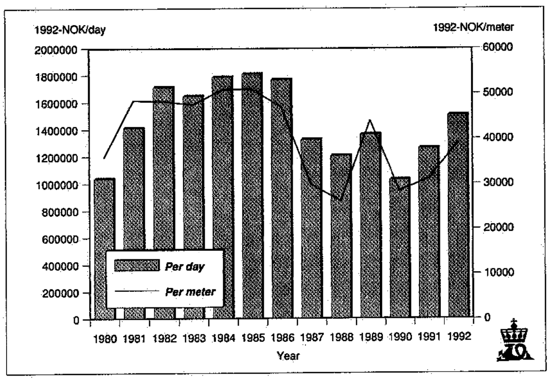
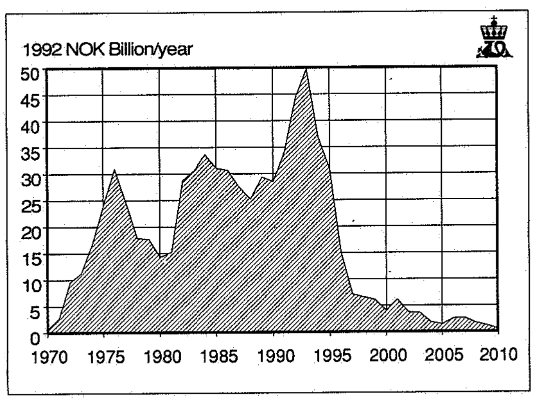
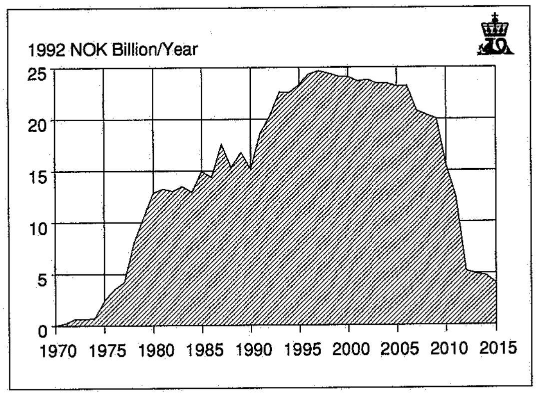


Fig. 2.11.2.a
Investments in fields and pipelines in operation and approved for development on the Norwegian shelf 1970–2010



– Oseberg
– Oseberg Transport
– Sleipner Øst
– Sleipner Vest
– Snorre

Fig. 2.11.2.b
Operating costs for fields and pipelines in operation and approved for development on the Norwegian shelf 1970–2015



– Statfjord
– Statfjord Øst
– Statfjord Nord
– Statpipe
– Tommeliten Gamma
– Tor
– Tordis
– Troll phase 1
– Troll phase 2
– Troll-Oseberg Gas Injection
– Ula
– Ula Transport
– Valhall
– Veslefrikk
– Zeepipe IIa
– Øst Frigg
– 30/6 Gamma Nord.

Historical and approved investments for field developments and transport systems for petroleum are shown in Figure 2.11.2.a. All amounts are given in fixed 1992 kroner. Investments increased steadily until 1976 when they reached a provisional high, then slowed in the years thereafter until a new increase occurred from 1981 on. A temporary peak was reached in 1984, when 33.6 billion 1992-value kroner was invested on the Norwegian continental shelf. Taking new decisions into account, the investment level will approach 50 billion 1992 kroner in the first half of the present decade before falling off rapidly up to the year 2000.

In 1992 the following fields and pipeline systems were approved for development:

– Europipe
– Frostpipe
– Frøy
– Haltenpipe
– Heimdal Jurassic
– Mime
– Sleipner Vest
– Troll phase 2
– Zeepipe phase IIA.

Fig. 2.11.3.a
Estimated total production on the Norwegian shelf 1992–2000 (Mill. t.o.e.)
Other fields include fields approved for development, fields under evaluation and EOR.

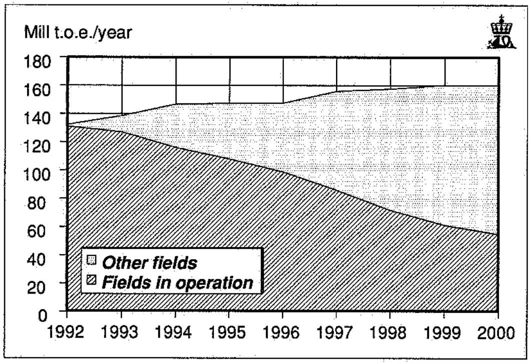


Fig. 2.11.3.c
Estimated total operating costs for fields and pipelines on the Norwegian shelf 1992–2000.
Other fields include fields approved for development, fields under evaluation and EOR

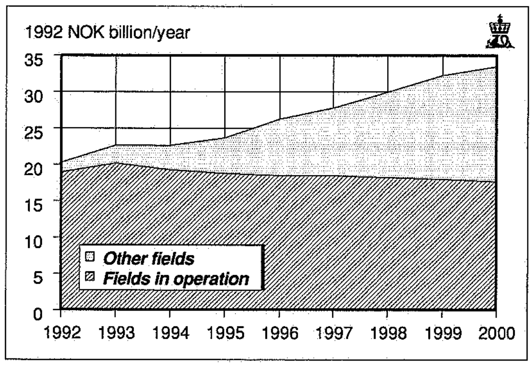


Fig. 2.11.3.b
Estimated total investments fields in operation and pipelines on the Norwegian shelf 1992–2000.
Other fields include fields approved developed, fields under evaluation and EOR

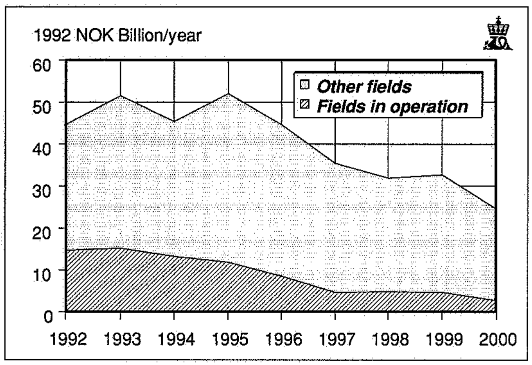
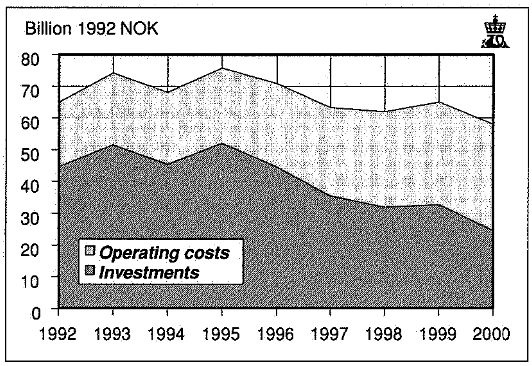


Fig. 2.11.3.d
Estimated total operating costs and investments for fields and pipelines in operation on the Norwegian shelf 1992–2000



During 1993, it is expected that several plans for development and operation will be considered. If these are approved the investment curve will show a much gentler drop than outlined above.

The annual operating costs, including pipeline operating costs, are shown in Figure 2.11.2.b. The level of demand for goods and services for operations has increased considerably, and will continue to increase for some years as more fields come on stream. Operating costs therefore appear to be the most serious cost component henceforth, and it will be essential to seek to reduce such costs from now on.

2.11.3 Activity level up to the year 2000

The Directorate has evaluated the overall activity level on the Norwegian continental shelf up to the year 2000. Evaluations in this chapter are based partly on the operators' figures for fields in operation and fields resolved for development, and partly on the Directorate's own assumptions for fields under evaluation and enhanced recovery from existing fields relative to the present plans. Figures are regarded as estimates for future development.

The total petroleum production is shown in Figure 2.11.3.a, which shows that production is expected to increase modestly up to a level of some 160 mtoe in the year 2000. This increase in production is due to the fact that several fields adopted for development and under evaluation are coming on stream. In addition, one is expecting enhanced recovery from existing fields.

The total investment level in the period 1992-2000 is shown in Figure 2.11.3.b. The level of investments is assumed to climb slightly in the next few years and then drop to about 25 billion 1992 kroner in the year 2000. Fields in operation are expected to have a low investment level throughout the period. Investments in fields approved for development and under evaluation, along with assumptions for investments in connection with enhanced recovery from existing fields, give the anticipated investment level up to the year 2000.

Figure 2.11.3.c shows costs in connection with the operation of fields and pipelines on the Norwegian continental shelf up to the year 2000. Operating costs, and production, are expected to increase evenly in the period as a whole. In 2000, the overall offshore demand for goods and services for operations is expected to be in the region of 33 billion 1992 kroner. Operating costs for fields in operation are assumed to be stable in the period. The increase is due to the fact that fields approved for development or under evaluation will come on stream, coupled with operating costs in connection with enhanced recovery from existing fields.

Total operating costs and investments for fields and pipelines on the Norwegian continental shelf are expected to maintain a stable level of some 65 billion 1992 kroner in the period 1992-2000, as illustrated in Figure 2.11.3.d.

The estimates up to the end of the century can only be speculative. Future oil prices are a key determinant which may have a significant impact on long-term development.

2.11.4 State's direct economic engagement

The State's direct economic engagement in the petroleum activity, SDØE, was established with effect from 1985 such that cash flows linked to most of Statoil's stakes were divided in two, with one part to Statoil and the other to the State (SDØE).

SDØE participates in 121 production licences of a total of 185. At present, the SDØE is represented with considerable volumes in the exploration, development and operating phases.

SDØE as the largest investor on the Norwegian continental shelf has secured for the State a high share in present and future reserves in the petroleum activity. Thus, this scheme has fulfilled the partial objective identified in 1985: to secure for the State the greatest possible share of future revenues from the recovery of hydrocarbons.

The total average percentage of State participation is broken down by field categories as shown in Table 2.11.4.

Overall investment and operating costs on the Norwegian continental shelf for the period 1992-2002 have been estimated at Nkr 500 billion (non-discounted fixed 1992 kroner). This includes investments and operating costs for fields planned and approved for development and fields in operation, excluding tariffs and carbon dioxide tax.

The SDØE's net share of these investment and operating costs constitutes some Nkr 165 billion. See Figure 2.11.4 for the breakdown over time.

For a few more years the SDØE will continue to make big investments, resulting in a build-up of real capital in the petroleum sector. The yield from these investments depends among other things on the future development of prices as well as the escalation of costs on the fields concerned and any fluctuations in production.

2.11.5 The role of petroleum in the Norwegian economy

Below is a brief survey of the importance of the resources managed by the Directorate in the Norwegian economy. The figures are taken from the Central Bureau of Statistics.

Fig. 2.11.4
SDEE: Capital investments and operating costs for fields in production under development and under planning (ex. CO_2-tax and tariffs)

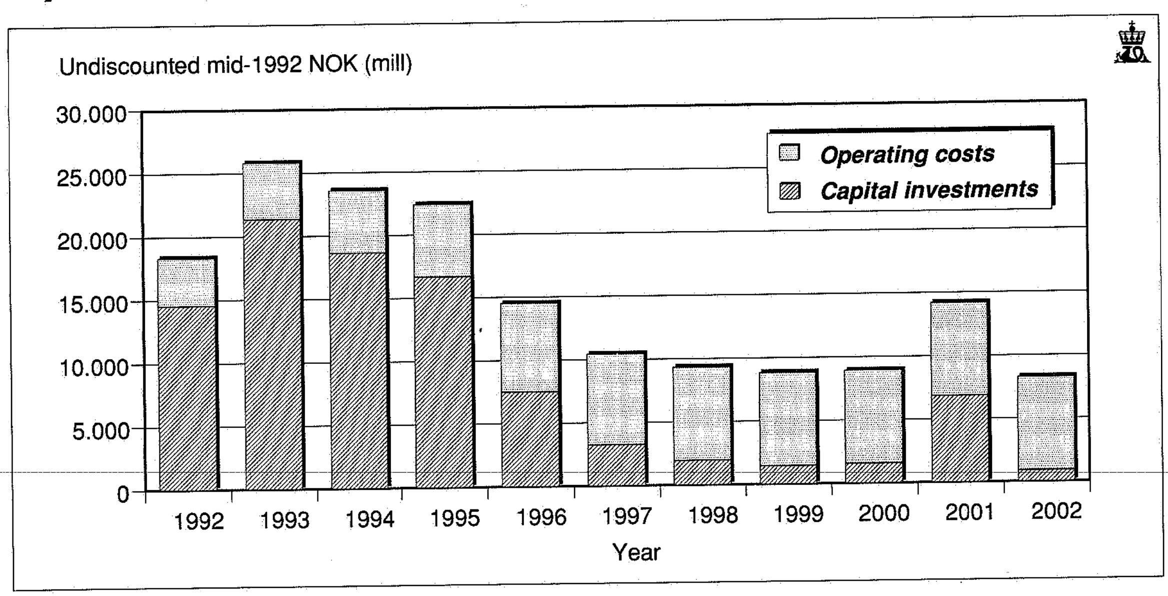


Table 2.11.5.

	1975	1980	1985	1988	1989	1990	1991	1992
The petroleum sector's share of GNP[1].	3 %	16 %	19 %	9 %	13%	15%	14%[4]	14%[4]
The petroleum sector's share of total exports[2].	6 %	33 %	38 %	24 %	29 %	31 %	32 %	35%[4]
The State's revenues derived from petroleum activities[3]. (Bill. 1992–NOK)	0.7	42.6	67.0	13.7	15.3	28.6	30.5	23.6[4]

Source: Central Bureau of Statistics

1) Includes production of crude oil and natural gas, drilling and operation of pipelines.
2) Includes export of crude oil, natural gas and pipeline transportation services.
3) Includes ordinary corporate tax, special tax, area fees and royalties.
4) Preliminary figures/estimates.

Gross national product

The petroleum sector makes a significant contribution to the overall economy in Norway today. In 1975, the value added in the petroleum sector constituted some 3 per cent of the GNP. In 1985, its share had increased to 19 per cent, then dropping back due to the fall in oil prices in 1985-86. More recently, the share has been in the region of 14 per cent. The development of the petroleum sector's contribution to Norway's Gross National Product is shown in Table 2.11.5.

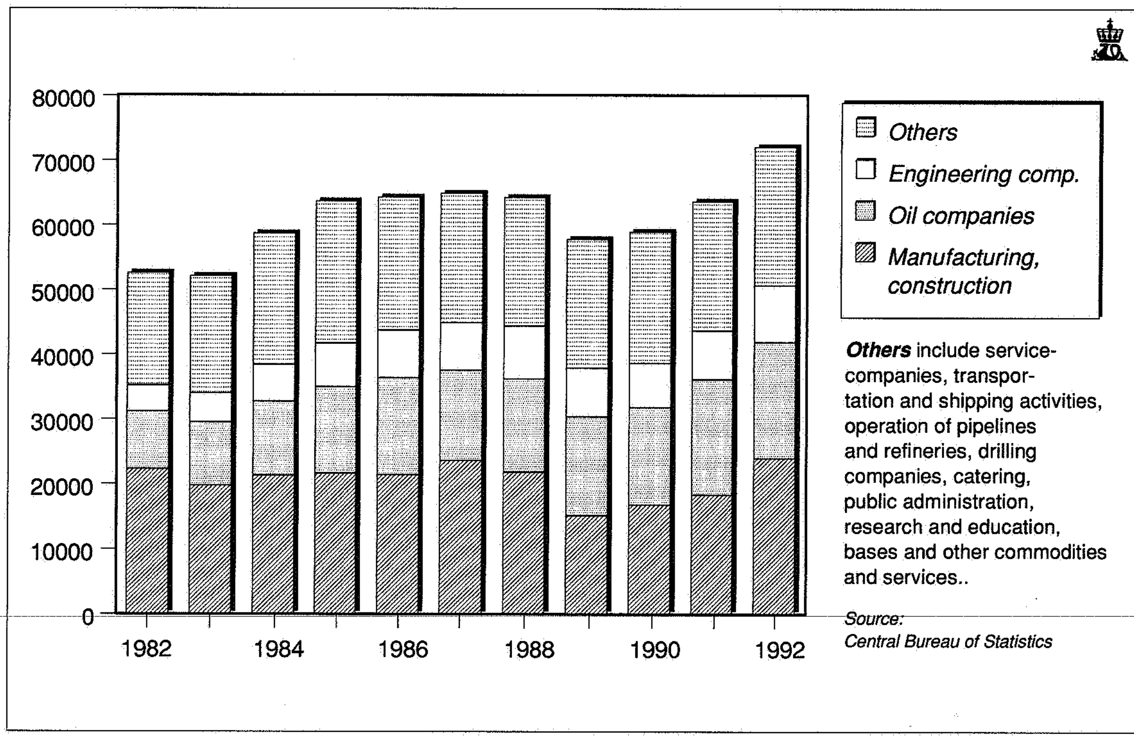
Foreign economy

The petroleum sector also earns a relatively large portion of Norway's export revenues, with an increase in export share from approximately 6 per cent in 1975 to 38 per cent in 1985, after which time it fell to about 24 per cent in 1988. In recent years there has again been a slight upturn in the contribution from the petroleum sector, see Table 2.11.5 for details.

State's tax revenues

The State's total tax revenues from the petroleum activity comprise corporate wealth and income tax,

Fig. 2.11.5
Employees in the petroleum industry, by type of establishment



special tax, royalty, and acreage fees. Tax revenues reached a preliminary high of Nkr 67 billion in 1985, before dropping to just under Nkr 14 billion in 1988. In the course of the last few years there has been a new increase in the State's tax revenues. In 1991, tax revenues from the petroleum activity were Nkr 30.5 billion, or some 19 per cent of the State's total revenues from direct and indirect taxes. All calculations are in 1992 kroner. The development in tax revenues is shown in Table 2.11.5.

Employment

The activity level on the Norwegian continental shelf involves employment both onshore and offshore. In 1992, some 72,000 people were employed as a result of the petroleum activity in Norway. Of these, about 24,000 had direct employment in the production of oil and gas, and 19,500 worked offshore in 1992. Figure 2.11.5 shows employment as a result of the petroleum activity, broken down by type of company. Some 33 per cent of employees in the petroleum sector work in industry, building and construction; 25 per cent in the oil companies; and 12 per cent in engineering consulting firms. The remaining 30 per cent work in the service industry, transportation, ship and rig owning companies, drilling contractors, catering, landing and refining facility operation, public administration, and research and training.

2.11.6 Petroleum market

2.11.6.1 Crude oil market

Global oil production slipped by about 0.2 per cent from 1991 to 1992 to about 60 million barrels a day. The decline was particularly obvious in the USA and the former Soviet Union. Production in the USA fell by 280,000 barrels a day, whereas the decline in production from the former Soviet Union was 1.4 billion barrels a day. In Western Europe production increased by 5 per cent to an average of 4.49 million barrels a day, primarily due to the rise in Norway's production. OPEC production rose by 1 million barrels a day in 1992, largely due to higher production from Kuwait and Iraq. Kuwait is expected to increase its production further in 1993, while Iraq's production will still be limited in accordance with the UN restrictions.

Norwegian oil production accounted for about 3.5 per cent of world crude in 1992, compared to about 3.1 per cent in 1991. Norway's output of oil also surpassed that of the United Kingdom, whose production did not materially change from 1991.

In 1992, there was an increase in estimated oil reserves in most parts of the world. Statistics show an overall increase in reserves of 0.6 per cent from 1991 to 1992. Based on these estimates the largest future oil producing areas will be OPEC and the Middle East. Production ran at about 2 per cent of reserves. Due to a minor decrease in output, the ratio of proven reserves to production changed slightly relative to 1991. Global oil reserves are equivalent to 46 years of production at the 1992 level.

At the beginning of 1992 the price of oil was approximately US$ 18 per barrel. OPEC decided at the February 1992 meeting to fix production quotas at 23 million barrels a day in the second quarter, which was higher than anticipated by the market and consequently the price of oil dropped to US$ 17 per barrel in March. From the end of May crude oil prices rose to US$ 21 per barrel due to higher demand and greater activity in the market and maintained this level to the end of September. The average price of crude up to the month of October was over US$ 19 per barrel, equivalent to Nkr 119.

2.11.6.2 Natural gas market

Today all Norwegian export of gas goes to Western Europe. In 1992, Norway exported gas to the UK, Germany, the Netherlands, Belgium, and France. The UK was the largest client up to 1990 but Germany has now taken over this role and will probably maintain this position in future. Figure 2.11.6.3.c shows the distribution of gas sales to the various countries buying Norwegian gas. In connection with the Troll agreements Norway has also entered into contracts for delivery of gas to Spain and Austria.

In 1992, Norwegian exports amounted to 25.7 bcm, an increase of 0.6 bcm over the year before. This constitutes about 9 per cent of gas consumption in Western Europe. According to plan, Norway's gas sales will rise steeply from autumn 1993 when deliveries under the Troll agreements commence.

In 1991, the other buyers confirmed their intention to exercise the so-called 30 per cent options in the Troll agreement. In 1992, the Dutch company Gasunie confirmed its intention to exercise the so-called 50 per cent option, increasing Norway's annual sales under the Troll agreements by about 1 bcm to about 34 bcm (from 2005 onward). If the rest of the buyers exercise their 50 per cent options, the aggregate annual sales under these agreements will come to a maximum of 40.8 bcm. The buyers have until 1 July 1995 to exercise the remainder of the 50 per cent options.

Significant parts of the gas sold under the Troll agreements had not been nominated to the various fields when the period started. In June 1992, the Ministry of Petroleum and Energy allocated the volumes (except Gasunie's 50 per cent option) to Troll and Sleipner Vest. These fields, together with Sleipner Øst and some associated gas, will deliver gas under the contracts so far signed.

Negotiations relating to adjustments in gas prices were conducted under the sales contracts in 1992 and these negotiations will continue in 1993.

In addition to the above contracts, contracts were signed with National Power in Great Britain in 1991 for 2.2 bcm a year, and with Distrigaz/ Electrabel in Belgium in January 1993 for 1.8 bcm a year. None of these contracts had been approved by the authorities in the respective buyer countries in January 1993, nor had it been decided which fields would source the supplies under them.

At year end, negotiations and talks were being conducted with prospective buyers in a number of countries, including countries in Eastern Europe. Sales to Scandinavian countries, however, are less probable in the short term. The same applies to the sale of LNG. For one field an agreement was entered into in 1992 for the sale of excess gas in the summer months. This represents a departure from the traditional long-term nature of gas sales contracts on the Norwegian continental shelf. In general, we must anticipate a different gas market in future than we were used to in the 1980s.

In Norway, too, there is a market for gas. In February 1992, the Storting approved the plans whereby Heidrun will deliver 0.7 bcm gas a year to a methanol plan at Tjeldbergodden (from 1996 onward). First in line, however, is North Rogaland, where a contract has been signed for annual deliveries of 0.02 bcm gas to the Gasnor distribution company. Today, the most important takers in the Norwegian gas market are on the continental shelf. The biggest buyer is Oseberg, with a demand of some 3.5 bcm a year (from Troll). Oseberg uses the gas for enhanced oil recovery. Ekofisk takes about 2 bcm gas a year for fuel and other purposes. In Sleipner Øst considerable quantities of gas will be injected (up to 6.5 bcm a year) using gas from Sleipner Vest, the purpose of which is to boost the production of condensate. On other fields, too, gas is used for fuel and in some cases for enhanced recovery. Most of the injected gas can be produced again at a later date and sold.

2.11.6.3 Sale of petroleum from the Norwegian continental shelf

In 1992, total sales of crude oil from the Norwegian continental shelf amounted to 124.1 million tonnes. This was an increase of 27.0 per cent compared to 1991. Norway was the largest recipient with 22.4 per cent of the shipments; Britain received 22.3 per cent, the Netherlands 11.9 per cent, Germany 9.4 per cent, and Sweden 6.8 per cent.

In 1991, Norway took 20.7 per cent of the total, so a small percentage increase was recorded in 1992.

Figure 2.11.6.3.a shows the sale of crude oil by country for the period 1982-92.

Up to 1988, both Belgium and Canada were reported under the heading «Others». The sale of Natural Gas Liquids from the Norwegian continental shelf reached 2.4 million tonnes in 1992, or 0.1 million tonnes more than in 1991. Figure 2.11.6.3.b shows the sale of crude oil and NGL in 1992 by licensee.

Norway exported 25.7 bcm gas in 1992, an increase of 2.0 per cent compared to 1991. A total of 8.8 bcm was sold to Germany, 5.7 bcm to the UK, 5.8 bcm to France, 2.8 bcm to the Netherlands, and 2.6 bcm to Belgium, as charted in Figure 2.11.6.3.c. Figure 2.11.6.3.d shows the gas sale by licensee for 1992. The column «Others» contains figures for several small fields.

Fig. 2.11.6.3.a
Sale of crude oil from the Norwegian continental shelf

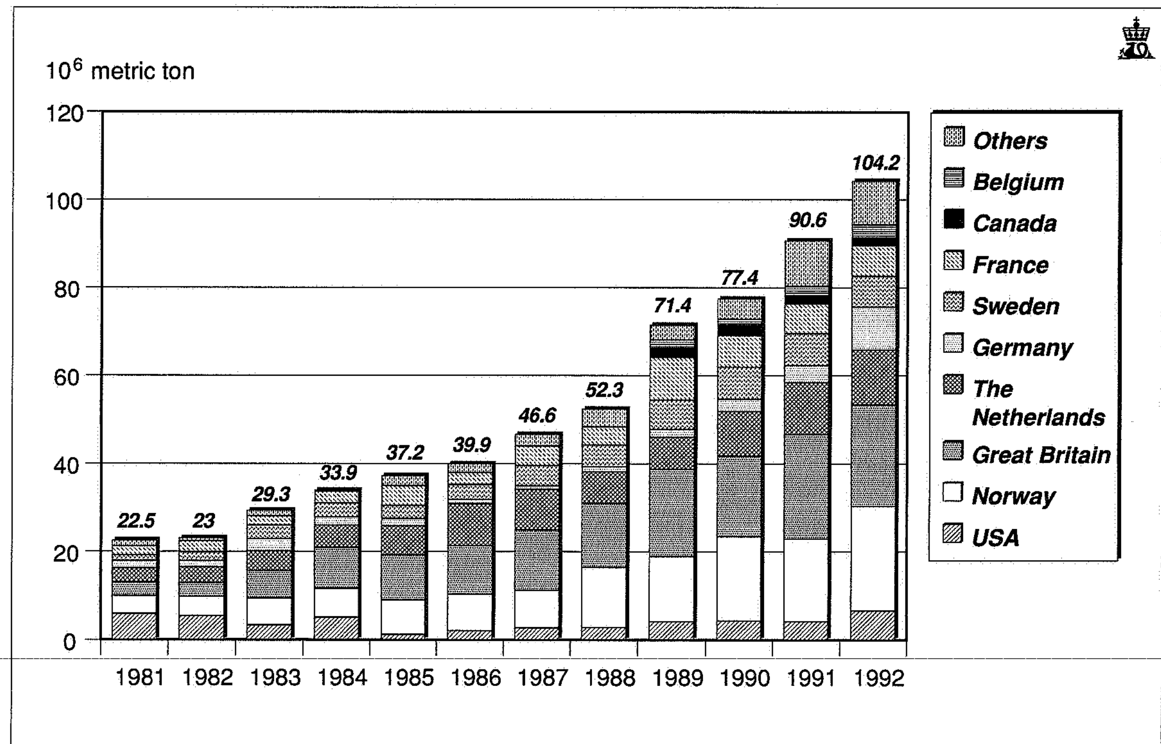


Fig. 2.11.6.3.b
Sales quantities of oil/NGL per licensee in 1991

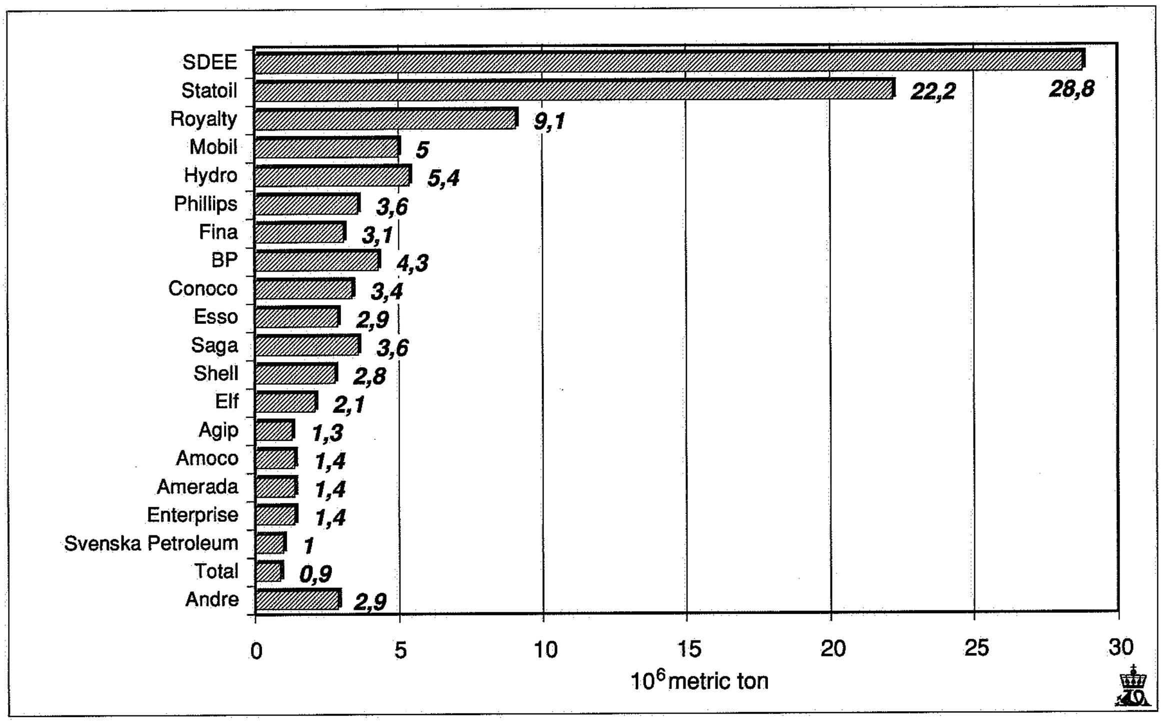


Fig. 2.11.6.3.c
Sales quantities of gas per country

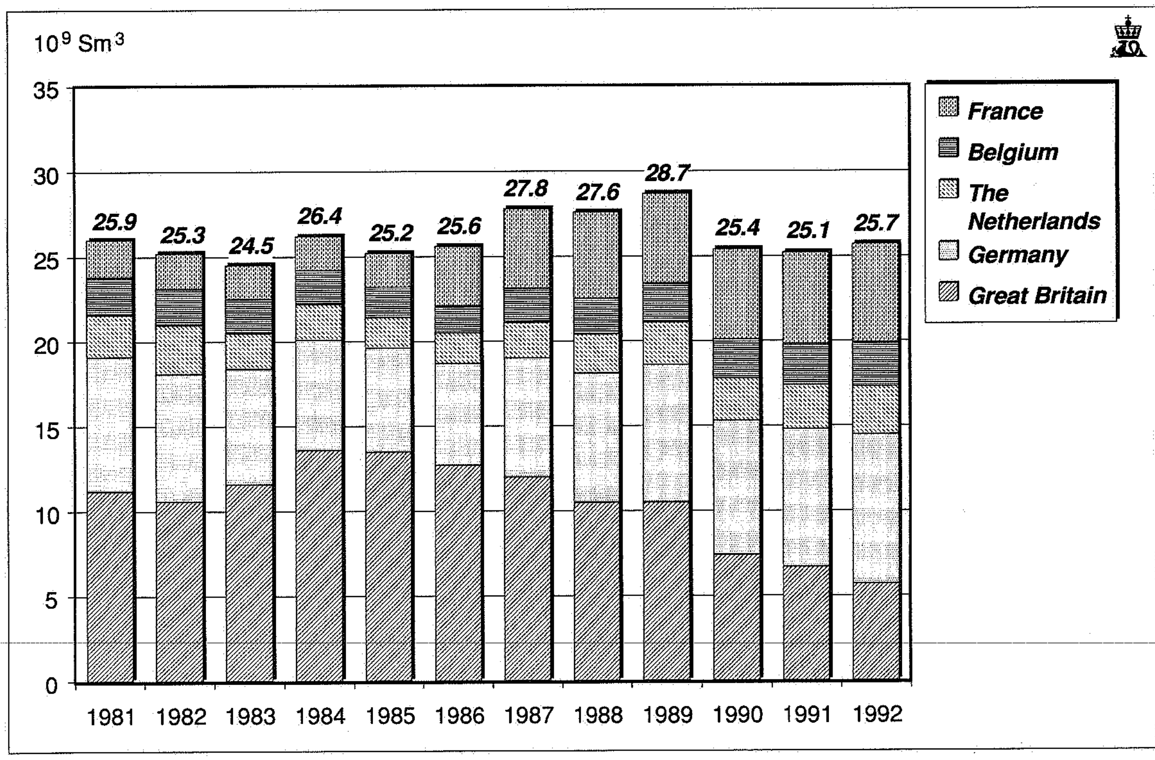
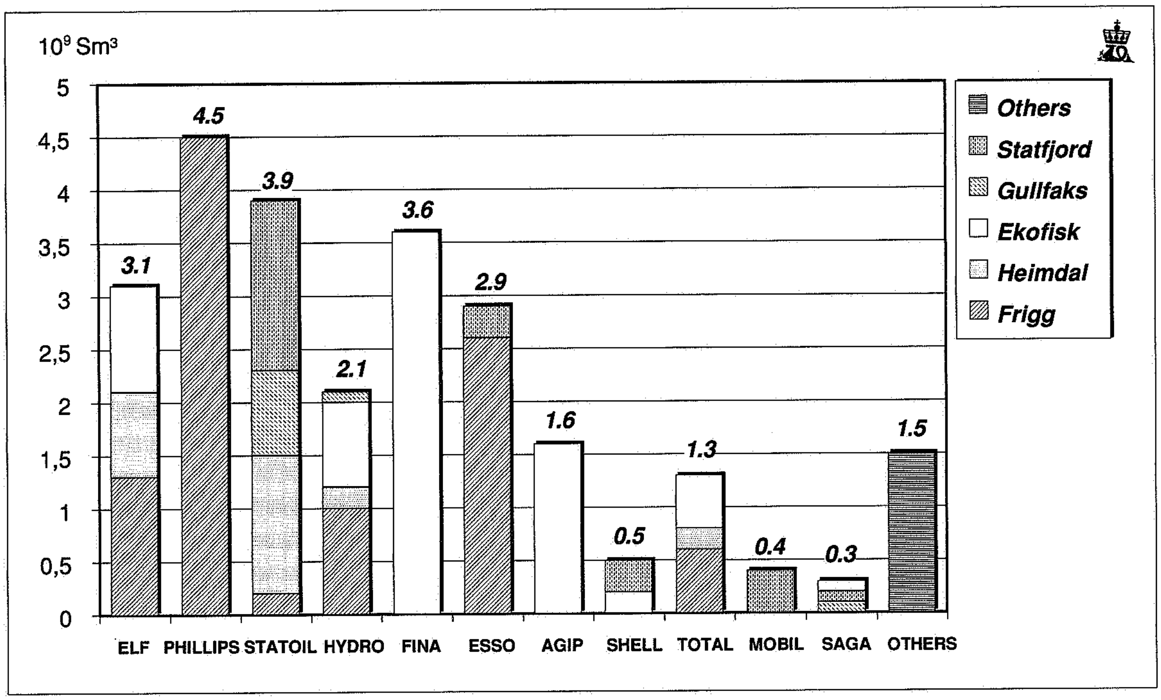


Fig. 2.11.6.3.d
Sales quantities of gas per licensee in 1992



2.11.7 Royalty

The Directorate has been delegated the responsibility for collection of royalty from petroleum production.

Production royalty is calculated as specified in the Petroleum Act, which came into effect from 1 July 1985. The formula for calculating the royalty is the value of petroleum production passing each field's loading point. In practice the formula for the calculation is the difference between the gross sales value and the costs incurred between the taxation point and the point of sale.

The interpretation and enforcement of the current rules and regulations for royalty calculation involve problems of a legal, economic, processing and measurement nature.

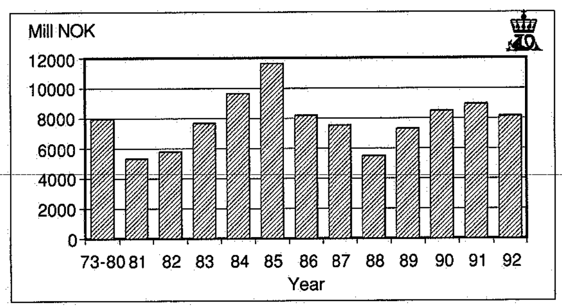
For some fields the cost of transportation is higher than the gross sales value for the specific petroleum product. This applies especially to gas. Under such circumstances the petroleum production has no value at the taxation point, and no royalty is charged.

A case is currently before the courts concerning setting of the tax bases for oil and gas. The Statfjord licensees, except Statoil, have claimed that the tax base for gas royalty, which is negative due to low gas rates and high transportation costs, should be deductible from the tax base for oil, which is positive. The Norwegian State contests this view. The Oslo City Court in judgment of 26 April 1991 held for the State, hence separate calculations must be made for oil and gas royalty. The licensees have appealed this decision, however, and the Supreme Court will examine the matter directly in 1993. The amounts at issue are very substantial.

According to Odelsting Proposition no. 64 for 1986-87, Act regarding certain revisions to the Petroleum Act, it was decided that royalties would not be charged for production from areas for which the development plans were approved after 1 January 1986.

From 1 January 1992 the royalty rate for gas was set to zero, confer Royal Decree of 27 March 1992 and Crown Prince Regent Decree of 22 May 1992. This means that from now on, royalty will only be levied on oil.

Fig. 2.11.7
Royalties paid 1973–1992



2.11.7.1 Total royalty

The total of royalties collected by the Directorate from licensees on the Norwegian continental shelf in 1992 was Nkr 8,129,205,421. Table 2.11.7.1 shows

Table 2.11.7.1
Paid-up royalty in 1991 and 1992 (mill Nkr)

		1991	1992
OIL	EKOFISK, ULA AND VALHALL	1 790.9	1 695.6
«	STATFJORD	4 866.9	4 356.6
«	MURCHISON	29.1	23.7
«	HEIMDAL	9.9	4.1
«	OSEBERG	692.0	964.6
«	GULLFAKS	660.6	738.2
GAS/NGL	EKOFISK-FIELDS	471.6	205.5
«	VALHALL	23.3	13.0
«	ULA	0.2	0.0
«	FRIGG, NØ-FRIGG, ODIN	329.8	132.5
«	STATFJORD	0.0	–31.1
«	MURCHISON	1.3	0.7
«	HEIMDAL	64.6	25.8
«	GULLFAKS	0.0	0.0
TOTAL		8 940.2	8 129.2

Table 2.11.7.2
Paid-up royalty on oil, 1992

Area/field	1st half	2nd half	Total 1992
EKOFISK, ULA AND VALHALL	824 334 963	871 234 858	1 695 569 821
STATFJORD	2 227 067 926	2 129 547 034	4 356 614 960
MURCHISON	16 256 253	7 406 509	23 662 762
HEIMDAL	3 922 360	213 932	4 136 292
OSEBERG	410 181 563	554 420 284	964 601 847
GULLFAKS	353 745 195	384 481 687	738 227 062
TOTAL	3 835 508 260	3 947 304 484	7 782 812 744

the breakdown for the various petroleum products for 1991 and 1992.

Figure 2.11.7 shows royalty receipts for the period 1973-92.

2.11.7.2 Royalty on oil

In 1992, royalty of Nkr 7,782,812,744 was collected on oil production from the Ekofisk, Valhall, Ula, Statfjord, Murchison, Heimdal, Oseberg, and Gullfaks fields; see Table 2.11.7.2. Royalty for oil is taken out in kind. The sale of the State's royalty oil is the responsibility of Statoil, and payment for the sale is made from Statoil to the Directorate on a monthly basis. Settlement is at the nominal rate fixed from time to time by the Petroleum Price Council.

2.11.7.3 Royalty on gas and NGL

The royalty collected for gas and NGL in 1992 amounted to Nkr 346,392,677. Table 2.11.7.3 shows the receipts on a half-yearly basis by company and partner group.

The settlement, which is in cash, is on a six-monthly basis, with a three-monthly term for payment. As the royalty on gas was set to zero effective 1 January 1992, receipts for gas in 1992 will all stem from the second half of 1991.

No gas royalty was paid for the Statfjord and Gullfaks fields for 1992, due to the high transport costs.

The settlement for gas is related to gas contract prices, which vary for the different groups.

The delivery of gas to Dyno-Methanor was discontinued from 1 July 1984. The receipts from Dyno-Methanor relate to the transportation and processing of gas already received and paid for.

2.11.8 Area fees in production licences

The Directorate collected Nkr 702,879,529 in 1992 in area fees. With reference to licence year the receipts were as follows:

Licence awarded	Kroner
1965	94,773,000
1969	56,767,820
1971	5,502,000
1973	35,478,000
1975	85,809,822
1976	73,872,000
1977	48,751,836
1978	20,019,213
1979	106,297,191
1980	8,803,899
1981	40,643,217
1982	23,317,771
1983	21,353,824
1984	27,607,419
1985	38,828,597
1986	14,945,056
1992	,108,864
Total	702,879,529

Table 2.11.7.3
Paid-up royalty on gas and NGL in 1992

	1st half	2nd half	Total 1992
EKOFISK AREA			
Phillips-group	171 622 842	19 220 716	190 843 558
Amoco-gr. (Tor)	436 622	110 092	546 714
Shell (Albuskj.)	13 014 872	0	13 014 872
Dyno/Methanor	579 822	553 089	1 132 911
Total Ekofisk area	185 654 158	19 883 897	205 538 055
FRIGG AREA			
Petronord-group	103 956 690	−562 081	103 394 609
Esso (NØ-Frigg)	4 437 600	0	4 437 600
Esso (Odin)	24 642 196	5 495	24 647 691
Total Frigg area	133 036 486	−556 586	132 479 900
VALHALL	10 910 678	2 112 784	13 023 462
ULA	0	0	0
STATFJORD	0	*)−31 134 122	−31 134 122
MURCHISON	385 805	290 367	676 172
HEIMDAL	24 053 776	1 755 434	25 809 210
GULLFAKS	0	0	0
TOTAL ALL FIELDS	354 040 903	−7 648 226	346 392 677

*) Replayed for excess paid-up royalty in earlier periods.

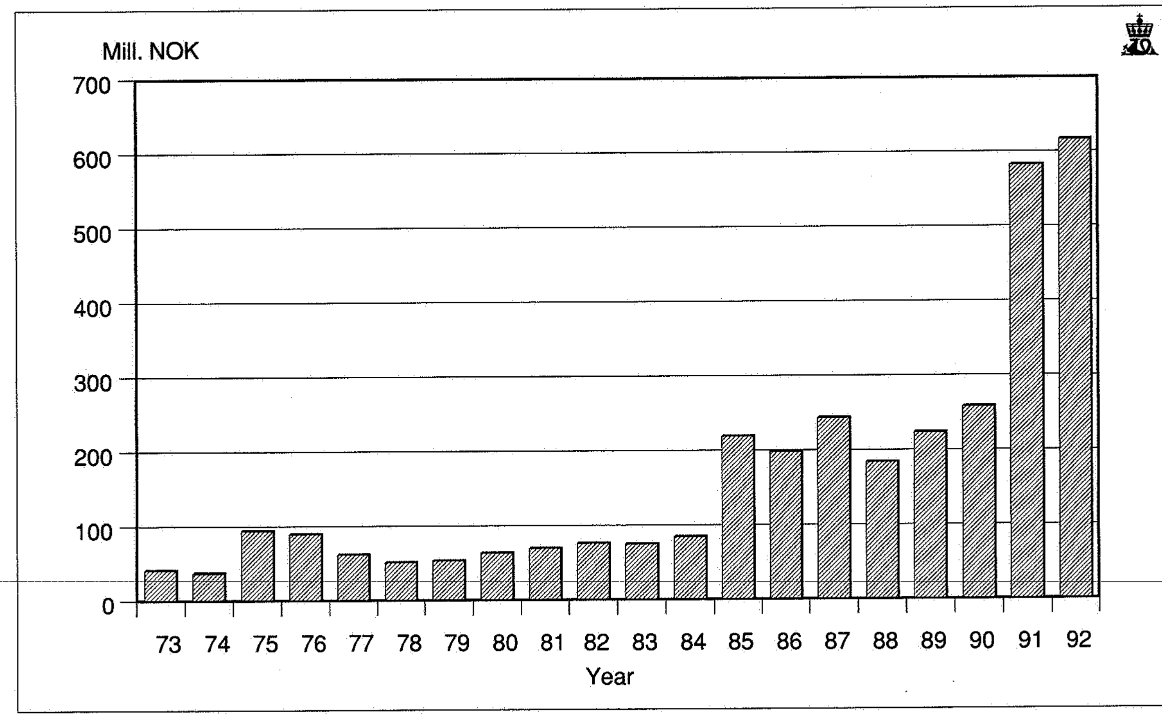
The Directorate refunded Nkr 86,912,003 in area fees in 1992.

This represents the deductible portion of the area fees in the royalty settlement for production licences 006, 018, 019A, 033, 037, 050, 053, and 079.

The area fees for some of the production licences are deducted directly in the royalty settlement. For 1992, the deduction was Nkr 13,701,940, as is reflected in the royalty receipts, which are reported net.

Figure 2.11.8 shows the area fee receipts for the years 1973-92.

Fig. 2.11.8
Area fees 1973–1991



2.11.9 Carbon dioxide tax

The new Act no. 72 relating to *Carbon Dioxide Tax* in the Petroleum Activities, passed by the Storting on 21 December 1990, became effective on 1 January 1991. The Directorate was given the responsibility of collecting the carbon dioxide tax and passing the resolutions necessary to enforce the law. The tax is calculated on petroleum flared and natural gas released to the atmosphere from platforms, installations and plants used in connection with production or transportation of petroleum. This tax is also levied on Norwegian petroleum transport systems which cross the continental shelf. Where fields straddle a sector boundary, the carbon dioxide tax is only calculated on the Norwegian share.

In 1991, the carbon dioxide tax was Nkr 0.60 per standard cubic metre of gas and per litre of diesel oil, while the comparable figure in 1992 was Nkr 0.80 for gas and diesel. The tax, payable on a six month basis with three months to pay, is levied on field and installation operators. Table 2.11.9 is a list of the total tax receipts broken down by field and transport system for the second half of 1991 and the first half of 1992. The receipts in 1992 were Nkr 1,915,946,450.

Table 2.11.9

Paid-up Carbon Dioxide tax for 2nd half 1991 and 1st half 1992

Paid-up Carbon Dioxide tax for 2nd half 1991 and 1st half 1992		
Field:	2nd half 1991	1st half 1992
BALDER	3 056 954	0
EKOFISK	250 451 337	343 490 978
FRIGG	15 016 675	21 164 364
GULLFAKS	113 773 040	148 489 878
GYDA	12 683 657	15 886 498
HEIMDAL	14 139 883	19 831 396
HOD	6 604 172	7 625 285
MIME	670 258	910 804
MURCHISON	7 087 102	10 597 330
ODIN	1 971 909	3 275 883
OSEBERG	89 136 000	126 873 570
STATFJORD	150 351 028	202 826 578
ULA	24 138 140	32 698 430
VALHALL	21 952 056	27 487 425
VESLEFRIKK	21 397 980	29 566 469
Transport systems:		
FRIGG TRANSPORT	757 837	1 501 629
NORPIPE	72 408 068	114 182 912
STATPIPE	1 575 661	2 365 264
Total	807 171 757	1 108 774 693

3. Safety and Working Environment in the Petroleum Activity

3.1 INTRODUCTION

The formal authorities underpinning the Norwegian Petroleum Directorate's supervisory and regulatory duties in safety and the working environment in 1992 were as follows:

a) Frameworks given in governing legislation:
 - *Petroleum Act*, of 22 March 1985 no. 11
 - *Working Environment Act*, of 4 February 1977 no. 4
 - *Svalbard Act*, of 17 July 1925 no. 11
 - *Scientific Research Act*, of 21 June 1963 no. 12, relating to non-petroleum resources
 - *Tobacco Injuries Act*, of 9 March 1973 no. 14.

b) Regulations and instructions given by the Ministry of Local Government:
 - Regulatory supervisory activities with the safety etc in the Petroleum Activities etc, by Royal Decree of 28 June 1985
 - Authority of 28 June 1985 whereby the Directorate is delegated certain powers, including to:
   - Stipulate regulations for the activity
   - Conduct overall safety evaluations
   - Decide consents, orders, exemptions and approvals.

The Directorate's supervisory duties are based on close cooperation on safety, the working environment and resource management, both inside the organisation and externally with other government agencies and institutions. The Directorate plays a coordinating role relative to the other government agencies which under the Petroleum Act exercise an autonomous supervisory responsibility in their own right; and draws on the professional expertise of other agencies in areas where the Directorate has no inhouse expertise.

The Royal Decree of 27 November 1992 determined that the Working Environment Act would apply from 1 January 1993 to mobile units engaging in petroleum activities and manned subsea operations from vessels or installations. The Ministry of Local Government resolved to vest the supervisory authority in the Directorate. Thus, the working environment sphere has also been provided with a coordinated, unified supervisory regime, embodied in the *Safety Supervision Regulations* enacted by Royal Decree of 28 June 1985. The challenge to the Directorate lies in the added supervision duties the decision entails, the development of detailed regulations in the field, and the resolution of general delimitation issues, etc. In our drawing up of the supervisory plans for 1993 we have therefore been obliged to enact strict priorities so as to ensure that adequate resources are committed to the new tasks.

The scope of the offshore petroleum activities continued to widen in 1992, and once again it was imperative to focus on sharpening our organisational efficiency and thus maintain a prudent level of supervision, even though no new positions have been authorised since 1987.

3.2 REGULATORY DEVELOPMENT

The latest of the Directorate's new *Technology Regulations* entered into force in the first half of 1992. The work had been continuing unabated since 1987 and has covered both the form and the content of the regulations. The new unified regulations conform to the frameworks established in the governing rules, not least when it comes to reflecting the principles of a supervisory regime based on internal control by the companies. Previous Annual Reports have looked at the objectives and frames underlying the regulatory drafting and revision work. The Directorate has formed the distinct impression that the new rules are perceived by all parties as being both modern and serviceable.

When the last of the new regulations came into force, the Directorate ordered each operator to undertake a systematic review of its activities to identify and, if necessary, take controlled action to correct any deviation from the regulations. This identification, combined with the new regulations, will provide one of the Directorate's reference points for future supervision activity.

The Directorate joined with the Norwegian Maritime Directorate and Det norske Veritas in 1988 in a review of the continental shelf and flag-state regulations to identify areas of overlap and parallelism (similarity study). The review aimed to find areas where the two sets of regulations made similar, dissimilar or contrary provisions and to clarify the areas of contact between the various government agencies in these areas. The review also sought to highlight the role played by maritime certificates as documentation of compliance with shelf requirements.

In connection with the entry into force of the new Technology Regulations in 1991-92, the authorities commissioned a new study. This work will be continued by the Directorate for as long as the industry finds it useful.

3.2.1 Regulatory status

The following regulations and explanatory guidelines were stipulated in 1992:
- Regulations for *Drilling, Well Activities and Geological Data Collection* etc

- Regulations for *Explosion and Fire Protection* etc
- Regulations for *Safety and Communications Systems* etc
- Regulations for *Marking of Installations* etc
- Regulations for *Lifting Appliances and Lifting Gear* etc
- Regulations for *Emergency Preparedness* etc
- Regulations for *Process and Auxiliary Facilities* etc
- Regulations for *Loadbearing Structures* etc.

3.2.2 Regulations under Working Environment Act

The *Technology Regulations* are issued under the authority of the safety legislation. The main reasons for choosing this authority are as follows:

- Most of the existing detailed regulations were technology oriented
- The safety concept in the safety legislation is more fully defined than in the Working Environment Act (WEA), in that safety of the environment and economic values is built in
- The safety legislation has a wider scope than the WEA and therefore offers a more useful starting point for enforcement in the petroleum activity as a whole.

The choice of the safety regulations as the preferred authority meant, however, that key working environment aspects are not covered by the new technology regulations.

In the 1991 Annual Report the Directorate explained in detail the work initiated to identify needs and, as necessary, propose frameworks for working environment matters in the petroleum activity.

Both the elucidation work and the fund of experience built up from supervisory duties indicate that there is no need to devise new requirements for the working environment, but that there is a need to highlight those already in existence, for example by referring to existing standards and other national rules and passing resolutions which can create precedent. Supervisory experience also points to the necessity of enacting requirements for a systematic approach to working environment issues in the various phases of a development project.

It is necessary, too, to regulate, or at least elucidate, certain factors in the working environment field in light of the pending European Economic Area (EEA) agreement.

Accordingly the Directorate suggested to the Ministry of Local Government that regulations should be developed which collectively deal with working environment matters in the offshore petroleum industry. It was further suggested that specific requirements and standards for working environment matters should, wherever possible, be coordinated with corresponding rules for mainland activity. The regulations propose to cover requirements relating to: planning, the specification of requirements, implementation and verification of the working environment; and the integral assimilation of a procedure for systematic observance of these requirements in any development project.

In 1992, the Ministry gave the Directorate the go-ahead for the initiation of the work to develop a draft detailed regulation. The plan is that this draft will be circulated to the consultative bodies in 1993 after initial presentation to the implicated parties and government agencies.

The regulations will be issued under the authority of and as an elaboration of the Working Environment Act of 1977 and the Royal Decree of 27 November 1992 providing Regulations for Worker Protection and the Working Environment in the Petroleum Activity.

3.3 SUPERVISORY DUTIES

The Directorate's supervisory duties in safety and the working environment during the year were generally conducted according to a plan which reflects the objectives adopted and the priority commitment areas. However, the safety aspects of Ekofisk 2/4-T (the Ekofisk tank) generated considerable activity which made some re-ranking of priorities necessary.

Again in 1992, several across-board supervisory activities were performed, by which is meant that several operators were scrutinised in the same fields. As a supplement to the operator-specific supervision, across-board audits have proved a valuable tool for transferring experience and building competence. Supervisory audits of this type also allow the Directorate to compare the companies against a common baseline when it comes to meeting the safety and working environment requirements.

3.3.1 Consents awarded

The year saw the award of 118 consents, compared to 111 in 1991. These were as follows (1991 in brackets):

- Exploratory survey 8 (9)
- Exploration drilling 36 (40)
- Detail engineering 13 (8)
- Fabrication 15 (10)
- Installation 10 (6)
- Use of installation 16 (20)
- Rebuild or redefinition of purpose of installation 6 (8)
- Use of service vessel 14 (10).

3.3.2 Priority commitment areas

In 1992, the Directorate gave priority to supervisory activities associated with:

- Major modifications and tie-ins with existing installations
- Operator systems for maintenance management
- High-pressure wells and drilling operations in environmentally sensitive areas
- Implementation of new regulations
- Operator facilitation of working environment for contractor personnel.

3.3.2.1 Major modifications and tie-ins with existing installations

Supervision of several operators was performed where the focus was on major modification works and new field development tie-ins to existing installations. The aim of the supervision was to illuminate the operator's management of each project in terms of meeting regulatory requirements. Great variations were revealed between the various operators regarding clarity of responsibility allocation, coordination, communication, and documentation of this type of project activity.

The task also covered audit of operators' compliance with internal company requirements and government requirements regarding ergonomic control room design. The audits showed that certain operators to a limited extent have embarked on systematic assessment, effectuation and follow-up of ergonomic factors in general; or control room design in particular.

3.3.2.2 Operator systems for maintenance management

Previous years' supervision has revealed weaknesses in the operators' management of maintenance activities, and the subject was therefore continued as a commitment area in 1992. The year's audits show that maintenance is becoming recognised as a key field of endeavour. The results so far show that systematic maintenance measures offer good returns over time, both in terms of safety and economic operation.

It transpires that many of the problems associated with maintenance in the operating phase are rooted in decisions about technical solutions in early project phases. The Directorate therefore decided to include audits of a specific project in this supervision area. The results confirm that, by prevailing on the project organisation to facilitate efficient maintenance, benefits can be obtained in the form of greater cost-effectiveness of maintenance procedures in the operating phase.

In addition to the system audits and verifications associated with maintenance management, the year also saw the convening of status meetings and technical seminars to examine the topic and pursue previous years' supervisory findings.

The industry is faced with major challenges in mastering the safety consequences of aging equipment and the increasing propensity for and severity of mechanical failure. Mastering this challenge requires the establishment of suitable administrative management systems, clear lines of responsibility, proper expertise, and implementation of the necessary measures to maintain the overall technical standard at sound levels.

3.3.2.3 High-pressure wells and drilling operations in environmentally sensitive areas

During the year there were eight wells in the high-pressure, high-temperature category. The problems typically encountered when drilling such wells were also sometimes encountered in 1992. The supervisory work done showed that although the actual drilling operations were performed in a sound manner, there is still room for improvement in the planning phase and in documentation to ensure that future such wells are also drilled soundly.

Supervision of a drilling operation in an area of the far north which is held to be environmentally sensitive was also performed. It showed that the operator in his planning and implementation had taken into account the sensitivity of the environment in the area in question. Nonetheless, the Directorate considers that further effort must be made in future activities of the kind before the requirements and expectations of the authorities are fully satisfied.

3.3.2.4 Implementation of new regulations

Supervision under this commitment area was principally directed to studying how much of the *Emergency Preparedness Regulations* have been implemented by the various licensees. Attention was particularly given to:

- Competence requirements
- Establishing preparedness
- Rescue and evacuation requirements
- Maintenance of emergency systems
- Preparedness control.

The audits showed that the companies differ in how far they have progressed with effectuation of these regulations. Departments within any given company were also liable to show differences in progress.

3.3.2.5 Operator facilitation of working environment for contractor personnel

Supervision under this commitment area continued where the 1991 activities left off. The audits revealed several breaches of working hours regulations for well service personnel, largely deriving from the definition of who should be classed as leading personnel, and the Directorate therefore chose to focus on this issue. The operating companies are required to classify the positions and functions they consider leading or particularly independent. The classifications invoked indicate that the companies vary greatly in the criteria they apply, and the issue will be examined further in 1993.

The draft regulation for systematic follow-up of the working environment in the petroleum activity provides that employees may be classed as leading or particularly independent if:

- The employee must assess and decide whether or not his input is required
- The employee can control his own working hours.

Under the proposed regulations employees in offshore well service companies will only occasionally be classed as leading personnel. This will promote greater uniformity in the industry and improve the wo-rking conditions of employees in such service companies.

3.3.2.6 Employee codetermination

This, though not a commitment area *per se*, was an integral part of much of the work performed in 1992. It included the review and evaluation of operator systems for meeting the Working Environment Act's requirements for employee participation. The work was included as an element in the system audits carried out in many problem areas in many operating companies.

The results of the evaluation are set forth in the summaries of each supervisory activity, and in some cases elicited orders to the operator to take steps to address the requirements in a better way. By and large, however, the Directorate has formed the impression that employees on fixed installations have a say in almost all issues, but there are still challenges in connection with ongoing changes in manning.

3.3.3 Ekofisk tank

This key processing and transport installation on the Ekofisk field has for many years attracted considerable attention from the Directorate, in part because studies carried out by the operator, Phillips, have revealed significant safety deficiencies. Ekofisk 2/4-T, the Ekofisk tank, fails to meet the operator's own risk acceptance criteria and the measures once projected to improve matters are only partially in place.

As a result of the increasing age of the installation, the need for maintenance and modification work is increasing greatly: as time goes on the backlog of planned maintenance activities is growing longer.

The continuous subsidence of the field will steadily heighten the risk. The Directorate has concluded that continuing modifications to 2/4-T will be inadequate to compensate for the negative build-up of risk on the installation, and believes that safe operation will no longer be feasible after some years.

The Directorate therefore sent to the licensees notification of order to immediately initiate plans for the permanent cessation of all petroleum processing and transport on 2/4-T. On account of the considerable economic consequences of such a decision, special measures were put in place to ensure that all aspects of the matter were adequately illuminated before the final decision. One such measure entailed meeting with each individual licensee.

On the basis of the reply from the licensees and meetings with them, the Directorate ascertained that they largely shared the Directorate's assessment of the risks involved. Nor did the licensees object to the view that continued modification of the technical systems will not be sufficient to ensure safe operation of 2/4-T in the long run.

The final order contains the following elements:

Interim measures

Until the present processing and transport activities on 2/4-T finally cease, the licensees must, without unreasonable delay, implement suitable risk-containing measures to meet the authorities' requirements and the operator's own risk acceptance criteria.

Plan for long-term solution

No later than 1 July 1993, the licensees must present to the Directorate a binding plan setting out a long-term solution which meets the requirements for safe processing and transport activities for the Ekofisk fields and third-party users.

Shutdown due to subsidence

Should the subsidence lead to the result that the 100-year wave would overwash the concrete barrier around the Ekofisk tank, then the licensees must shut down all processing and transport operations unless it can be proven that the installation meets the requirements of rules relating to safety regarding such impact.

3.4 INTERNAL CONTROL EXPERIENCE

In 1992, supervisory activities targeted the operating companies, focusing on the quality assurance units' responsibilities and duties and the interaction of the quality units with the company line organisations. The initial audit examined the requirements of the *Internal Control Regulations* in respect of organisation of the internal control system.

Audits showed there to be great variation between the companies regarding how they organise their internal control activities and how they describe and develop their control systems under the said regulations. The audits also revealed inadequacies in the document management systems of certain operators, and ambiguous division of responsibilities between the quality unit and the company line managers.

In the light of the findings so far, the Directorate intends to give priority to these matters again in 1993.

3.5 INTER-DEPARTEMENTAL COOPERATION

Under the Royal Decree of 28 June 1985 setting out the *Supervision of Safety Regulations* the Directorate, in supervising the safety and working environment in the petroleum activities, is expected to draw on the competence of other government agencies in fields where the Directorate has none. In cases where the other agency has an autonomous supervisory authority of its own, the Directorate's role is to coordinate.

Cooperation with such agencies has been very largely satisfactory and the arrangement ensures efficient and unified supervision of the activities.

3.6 FOLLOW-UP SYSTEM FOR ACCIDENTS AND WORK-RELATED DISEASES

Recognising the need to upgrade its systems for registration, reporting, evaluation and follow-up of accidents, the Directorate initiated work to achieve this end in 1991. The work continued in 1992. The Rogaland Research Institute was commissioned to perform and completed an external study of the industry's needs in the same area.

3.7 PERSONAL INJURIES

3.7.1 General

The Directorate receives reports and notices about personal injuries and fatalities in connection with offshore activities on fixed and mobile installations on the Norwegian continental shelf. These reports generally belong to one of two categories: Notices or Reports.

Notices

In case of fatality or serious personal injury the Directorate is notified immediately. Notices trigger an assessment process and are followed up by the Directorate. Follow-up is usually by on-scene inquiry in cooperation with the Police or monitoring of the company's own accident investigations.

Reports

Subsidiarily to and separately from notices of serious injuries and fatalities, the Directorate also receives reports of personal injury resulting in lost-time in the following 12-hour shift or requiring medical treatment. The reports follow a fixed format and serve as the basis for statistics such as those disclosed in this Annual Report. Although reporting is the employer's responsibility, operators are required to maintain familiarity with events on their installations. The raw statistics registered in the Directorate are compared each year with oil company figures, enabling both parties to check and correct any under-reporting or registration errors. The injury frequencies are based on comparisons of the injuries reported and the working hours reported each quarter from each particular installation and field.

While it is to be expected that such a comprehensive reporting programme sometimes turns up erroneous data, the Directorate feels that relatively stable reporting practices have evolved within most operating companies. The injury frequencies vary a great deal from one operator to the next, and the statistical summaries presented in this Annual Report should provide a reasonably accurate picture of the injury situation in Norway's offshore industry.

3.7.2 Causes of personal injury

In the light of the causal accounts given on the standard reporting forms for injuries in 1992, the Directorate intends to focus on the following hazardous conditions and actions:

- Unsuitable work posture for tools and equipment used
- Inadequate personal protection equipment or non-use of required protection
- Misuse of tools and equipment
- Air-borne particulate matter
- Cluttered access and poor workplace design
- Slippery, uneven surfaces.

The most common types of accident in 1992 were:

- Crushing injuries and wounds caused by objects in motion or equipment handling, hands and fingers being most at risk
- Eye injuries caused by splinters and splashes in the absence of protective goggles, largely associated with welding and grinding work or use of high-pressure jets
- Sprains and muscular stress injuries from use of tools and equipment or slipping on slippery or uneven surface
- Dental injuries caused by careless handling of hand tools.

3.7.3 Personal injuries on fixed installations

The total personal injury frequency declined slightly in 1992 compared to 1991. The Directorate has recorded 571 personal injuries in connection with drilling for and production of oil and gas on fixed installations on the Norwegian continental shelf in 1992, none of them fatal. Injuries which occurred outside working hours offshore (in off-duty periods) are not included in the statistics. In 1992 there were 28 off-duty injuries, compared to 26 in 1991. Off-duty injuries are generally sprains, over half of them sustained in connection with sporting activities.

One new installation was emplaced on the Norwegian continental shelf in the year, a tension leg platform on Snorre, which accounts for about 4.3 per cent of all hours worked offshore. The increase in manhours was offset by the completion of the Oseberg C installation work. On most of the other fixed installations, there was little change in the number of hours worked. Overall there was an insignificant decrease in offshore manhours in 1992 compared to 1991.

Tables and figures – fixed installations

Table 3.7.3.a provides a summary of the personal injuries per 1000 man-years worked in production from 1976 to 1992 including the drill ship *Petrojarl 1* (not 1992).

The overall injury frequency in 1992 is equivalent to 25.7 injuries per million hours worked. The reported injury frequency for 1991 has been corrected for 14 injuries notified in late reports.

Figure 3.7.3.a shows the development of personal injury frequency during the period 1979-92 for the various main activities. The most salient difference since 1991 is in drilling and well operations which traditionally constitute the most risk-intensive activity. Here the injury frequency has fallen from 65.7 to 48.3 injuries per 1000 years worked. This activity has also produced the most striking long-term reduction in injury frequency.

Catering, which accounts for the smallest volume of work with only 10 per cent of total hours, was

Table 3.7.3.a
Injuries and deaths per 1000 man-years on production installations 1976-92.

Year	Hours worked	Hours per man-year	Man-years	Injuries and deaths	Injuries and deaths per 1000 man-years	Deaths	Deaths per 1000 man-years
1976	4876316	1852	2633	213	80,9	2	0,76
1977	8146948	1852	4399	282	64,1	2	0,45
1978	14932296	1752	8523	624	73,2	6	0,70
1979	14986608	1752	8554	575	67,2	0	0,00
1980	12237720	1752	6985	451	64,6	0	0,00
1981	15612072	1752	8911	415	46,6	0	0,00
1982	14790384	1752	8442	526	62,3	0	0,00
1983	11473848	1752	6549	334	51,0	0	0,00
1984	14643216	1752	8358	491	58,7	1	0,12
1985	15014640	1752	8570	599	69,9	1	0,12
1986	17108280	1752	9765	606	62,1	0	0,00
1987	22169458	1612	13753	832	60,5	0	0,00
1988	19878727	1612	12332	637	51,7	0	0,00
1989	19935637	1612	12367	596	48,2	1	0,08
1990	19852093	1612	12315	568	46,1	1	0,08
1991	22263572	1612	13811	588	42,6	0	0,00
1992	22203641	1612	13774	571	41,5	0	0,00
Total	270125456		160041	8908	55,7	14	0,10

responsible for 8.6 per cent of all injuries in 1992 compared to 7.5 per cent in 1991. The injuries reported were mostly cuts and bruises caused by equipment handling. Catering injury statistics have fluctuated considerably in recent years and were slightly greater in 1992 than the year before.

Construction and maintenance accounted for 52.4 per cent of the work performed, down from 53.5 per cent in 1991, and 59.7 per cent of the injuries suffered in 1992, up from 56.1 per cent in 1991. Thus the injury frequency for this group also increased from 1991. The typical injuries were bruises and impacts

Fig. 3.7.3.a
Injuries to personnel 1979–92. Drilling and Production – fixed installations.

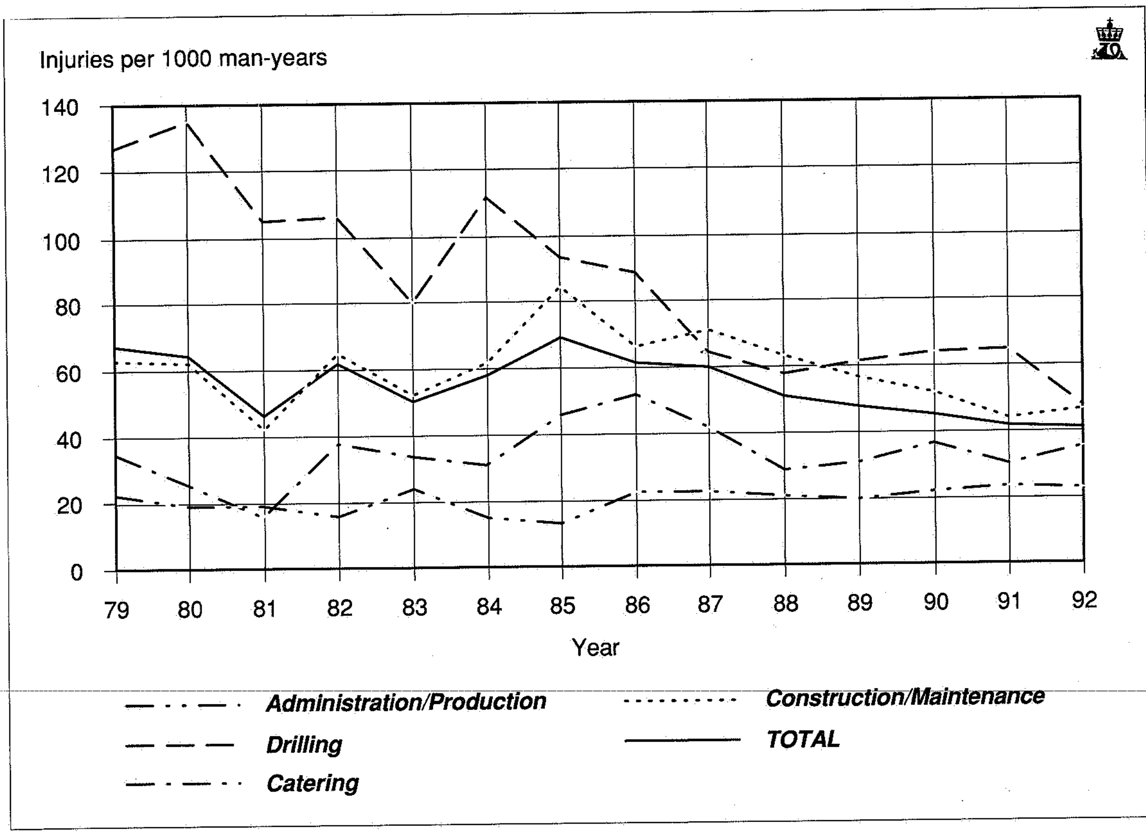


Fig. 3.7.3.b
Injuries to personnel employed by operators and contractors – 1992. Drilling and Production – fixed installations.

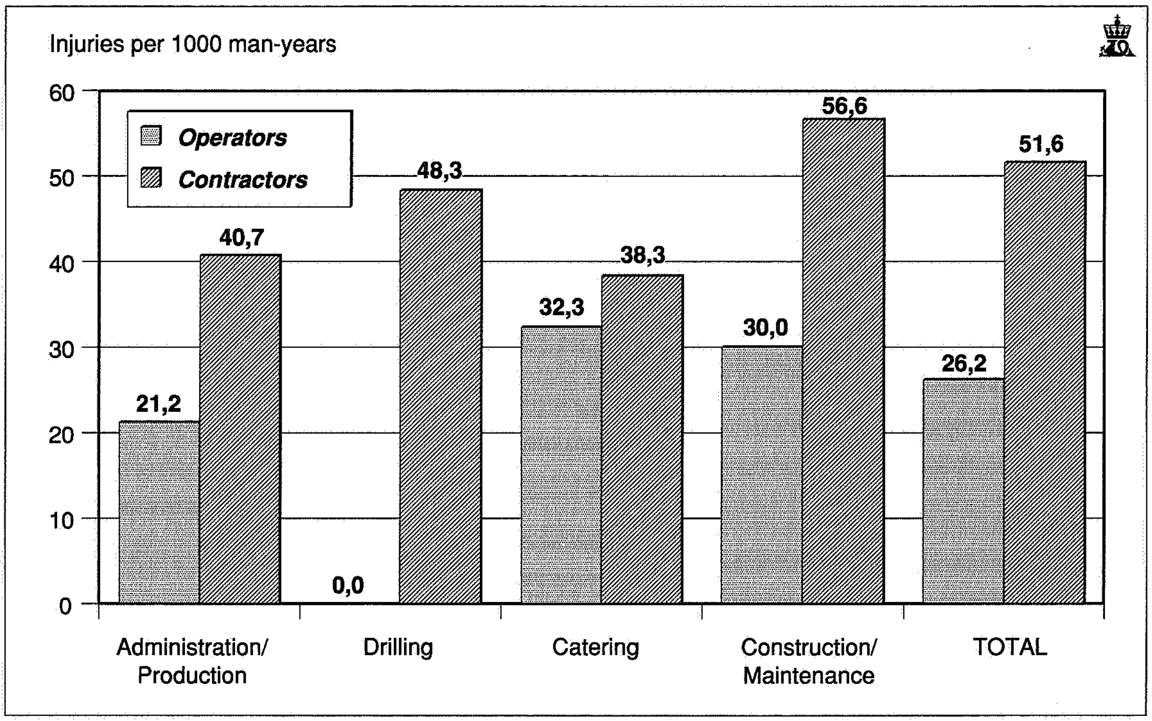


Table 3.7.3.b
Injuries per 1000 man-years by function on production installations 1985-1992

FUNCTION		1985	1986	1987	1988	1989	1990	1991	1992	
Admini-stration/ Production	Man-years	1575	1293	1692	1985	2099	2259	2366	2499	Operator
		80	213	603	454	294	500	424	369	Contractor
	Injuries	19	34	44	47	43	49	53	53	o
		4	0	9	6	6	12	14	15	e
	Injuries/	12,1	26,3	26,0	23,7	20,5	21,7	22,4	21,2	o
	1000 man-years	50,0	0,0	14,9	13,2	20,4	24,0	33,0	40,7	e
Drilling Well operations	Man-years	0	0	0	0	0	0	0	0	o (operator)
		1384	1371	1567	1883	2128	2027	2239	2340	e (contractor)
	Injuries	0	0	0	0	0	0	0	0	o
		130	122	103	110	131	132	147	113	e
	Injuries/	0,0	0,0	0,0	0,0	0,0	0,0	0,0	0,0	o
	1000 man-years	93,9	89,0	65,7	58,4	61,6	65,1	65,7	48,3	e
Catering	Man-years	0	39	94	209	340	396	447	464	o (operator)
		685	817	1073	882	888	868	953	887	e (contractor)
	Injuries	0	5	5	4	3	13	13	15	o
		32	40	45	29	36	34	31	34	e
	Injuries/	0,0	128,2	53,2	19,1	8,8	32,8	29,1	32,3	o
	1000 man-years	46,7	49,0	41,9	32,9	40,5	39,2	32,5	38,3	e
Construction/ Maintenance	Man-years	1544	2063	2441	2399	2381	2364	2482	2538	o (operator)
		3301	3969	6283	4520	4237	3901	4900	4679	e (contractor)
	Injuries	61	51	49	50	70	61	65	76	o
		353	354	577	391	307	267	265	265	e
	Injuries/	39,5	24,7	20,1	20,8	29,4	25,8	26,2	30,0	o
	1000 man-years	106,9	89,2	91,8	86,5	72,5	68,4	54,1	56,6	e
TOTAL	Man-years	3119	3395	4227	4593	4820	5019	5295	5499	o (operator)
		5450	6370	9526	7739	7547	7296	8516	8275	e (contractor)
	Injuries	80	90	98	101	116	123	131	144	o
		519	516	734	536	480	445	457	427	e
	Injuries/	25,6	26,5	23,2	22,0	24,1	24,5	24,7	26,2	o
	1000 man-years	95,2	81,0	77,1	69,3	63,6	61,0	53,7	51,6	e

to the hands and head, plus eye injuries caused by splinters and splashing in the absence of required safety equipment.

The injury statistics for the administration and production function remain stable.

Table 3.7.3.b shows the distribution of injuries for operator and contractor employees for 1992 in each of the main activities.

Table 3.7.3.b shows the distribution of injuries and years worked for operator and contractor employees from 1985 to 1992. In 1992, contractors contributed 60.1 per cent of the total hours worked on fixed installations, against 61.7 per cent the year before; and 74.8 per cent of injuries, against 77.7 per cent in 1991. The mismatch of share of manhours and share of accidents therefore continued to decline for contractors and operators as a group. The frequency for operator employees increased, however, while that for contractor employees declined.

Table 3.7.3.c is a cross-reference to the distribution of accident types in each particular professional category. The figures are cumulative for the period 1979-1992.

3.7.4 Personal injuries on mobile units

In the reporting period, 17 mobile units were in action on the Norwegian continental shelf compared to 19 in 1991. According to the Directorate's records there were 138 personal injuries in connection with exploration and development drilling, a decrease of 21 from 1991, although the hours worked fell slightly more expressed as a percentage. Overall the injury frequency has declined. There were no fatal accidents on mobile units in 1992. One off-duty injury was reported, the same as in 1991.

Table 3.7.3.c
Work accidents 1979-92 on production installations, showing type of incident and occupation

Occupation / Injury incident	Administration	Drillfloor worker	Driller	Electrician	Caterer	Assistant	Instrument technician	Crane operator	Painter gritblaster	Mechanic, motorman	Operator	Plateworker insulator	Pipeworker plumber	Service technician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Other contact with object/machinery in motion	35	266	33	61	65	339	25	17	41	119	40	71	72	59	88	45	88	3	1467	18,8
Fire Explosion etc	0	1	0	3	0	7	0	0	1	5	2	2	4	0	0	3	0	0	28	0,4
Fall to lower level	15	26	12	43	16	101	20	13	49	45	26	34	37	20	32	33	19	3	544	7,0
Fall at same level	33	25	6	54	54	116	21	9	38	37	32	42	59	28	67	42	12	8	683	8,8
Stepping on uneven surface or tripped	27	19	6	61	35	98	20	15	48	37	44	34	58	27	58	52	14	8	661	8,5
Falling objects	9	41	9	10	11	75	5	1	15	31	5	37	35	20	56	24	5	2	391	5,0
Other contact with object at rest	20	19	5	50	34	79	25	6	60	51	22	67	46	22	61	39	12	4	622	8,0
Handling accident	21	83	8	76	100	185	27	12	49	142	42	108	110	43	81	82	28	3	1200	15,4
Contact with chemical or physical compound	6	16	0	15	33	66	10	2	95	21	23	22	25	18	8	26	8	0	394	5,1
Muscular strain	25	43	7	43	31	117	11	10	40	52	37	33	61	23	70	26	18	4	651	8,4
Splinters, splashes	16	26	6	30	15	88	5	1	118	59	27	128	141	17	25	238	5	3	948	12,2
Electrical current	0	2	0	28	0	1	1	1	0	1	0	2	0	0	0	1	0	0	37	0,5
Extreme temperature	1	0	0	4	41	5	1	0	1	5	7	7	9	1	4	16	0	1	103	1,3
Fall into sea	0	0	0	0	0	1	0	0	1	0	0	0	0	0	0	1	0	1	4	0,1
Total	4	3	0	5	3	11	1	2	3	4	3	5	6	0	2	4	0	0	56	0,7
Total	212	570	92	483	438	1289	172	89	559	609	310	592	663	278	552	632	209	40	7789	100
%	2,7	7,3	1,2	6,2	5,6	16,5	2,2	1,1	7,2	7,8	4,0	7,6	8,5	3,6	7,1	8,1	2,7	0,5	100,0	

Table 3.7.4.a
Injuries and deaths per 1000 man-years in connection with drilling from mobile units in 1989–92

Year	Hours worked	Hours per man-year	Man-years	Injuries incl. deaths	Injuries per 1000 man-years	Deaths	Deaths per 1000 man-years
1989	3584740	1612	2224	87	39.1	2	0.90
1990	4328907	1612	2685	139	51.8	1	0.37
1991	4878152	1612	3026	159	52.5	0	0.00
1992	4385045	1612	2720	138	50.7	0	0.00
Total	17176844		10656	523	49.1	3	0.28

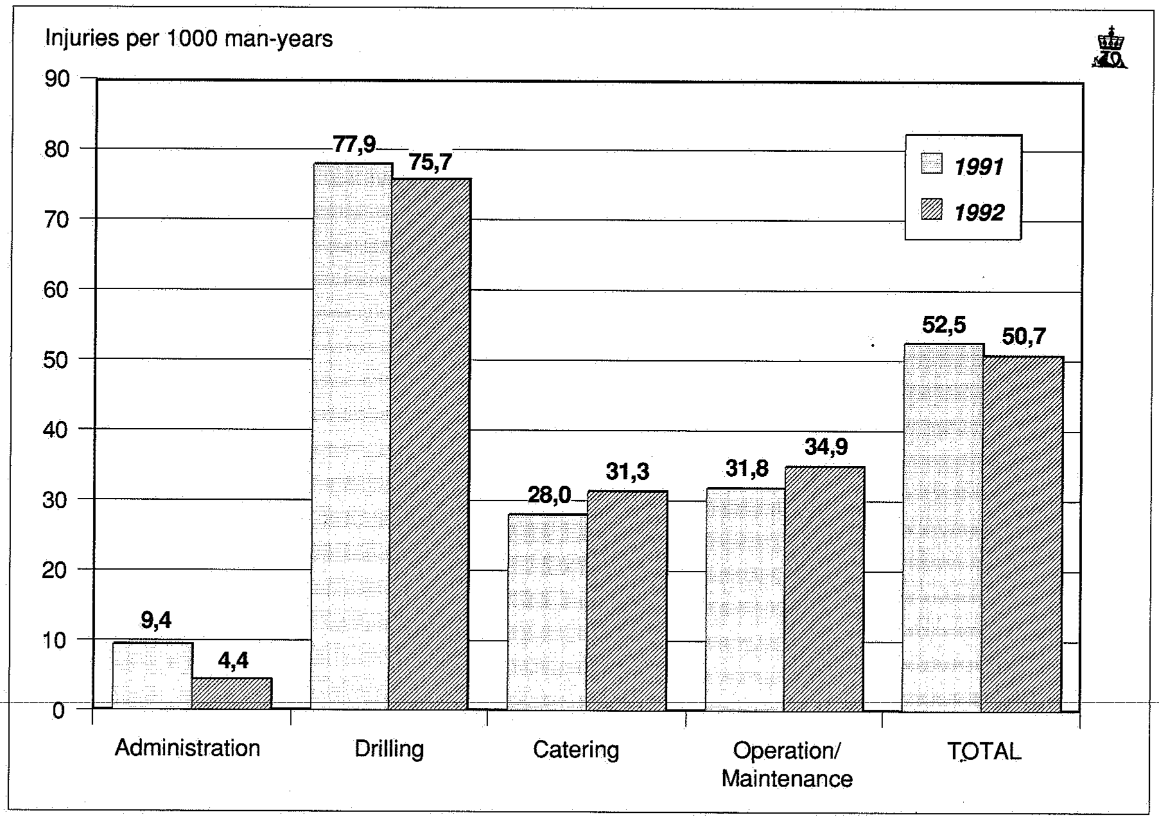
Accident reporting for mobile units is subject to the same criteria as for fixed installations. The Directorate has noted a relatively wider discrepancy between the reports submitted to the Directorate and the summaries compiled by the operators for mobile units than for fixed installations. Also, it has been harder to achieve the same degree of retrospective reporting of incidents, since the units tend to work for different clients, be laid up, or cease operations in Norwegian waters. All these factors render it difficult to achieve as accurate figures for working hours on mobile units. In the past few years the Directorate has therefore been at pains to verify the figures. The working hours reported by the operators have been collated with the rig days registered by the Directorate and adjusted in talks with the operators, thus producing a reasonably accurate estimate of the number of personnel on the units. The Directorate feels therefore that the latest years' figures offer a reasonably accurate picture of the situation on the mobile units.

Tables and figures – mobile units

Table 3.7.4.a presents a summary of personal injuries per 1000 man-years from 1989 to 1992 on mobile units. The injury frequency in 1992 is slightly down on 1991 and is equivalent to 31.5 injuries per million manhours. The figures for 1991 were not revised in retrospect.

Figure 3.7.4.a shows the comparative injury frequency for each main activity on mobile units the past two years. Drilling and well activities make up

Fig. 3.7.4.a
Injuries to personnel 1991–92. Mobile drilling units.



52 per cent of the hours worked, but 77.5 per cent of the injuries. The injury rate is therefore relatively high compared to similar activities on fixed installations. The absolutely predominant type of injury in drilling and well operations is bruises and impact injuries in connection with lifting operations and handling of equipment on the drill floor. In 10 per cent of cases the mechanical roughneck is involved in the causal chain, and in 40 per cent of cases somebody's hand has been pinched.

The catering function and the operations and maintenance function both showed an increase in injury frequency, though this fact is overshadowed by the relatively large number of injuries in drilling and well activities.

In the administration function the injury frequency was halved, though the statistical significance of this fact is limited – there being only two incidents in 1992 and five in 1991.

A comparison of operator personnel and contractor personnel on mobile units indicates that the former account for only 8.7 per cent of manhours worked, and this mainly in administration. One operator employee was injured in 1992, compared to none in 1991.

Table 3.7.4.b is a matrix of the types of accident in each professional category, showing cumulative values from 1989 to 1992.

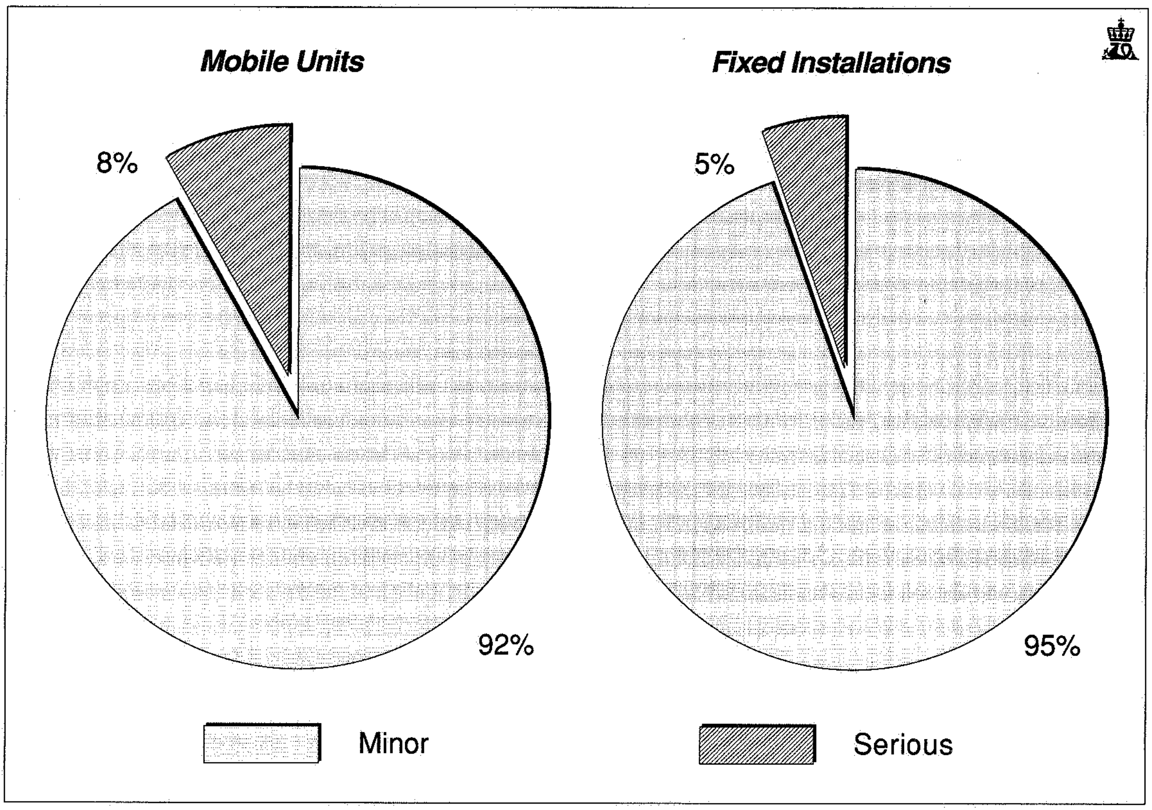
3.7.5 Summary

There was a marked decline in the injury frequency in the drilling and well activities function in 1992. Even if this level is not sustained, it may nevertheless indicate a reversal of the slowly rising trend of recent years. In 1991, the construction and maintenance function had the second lowest injury frequency ever after a striking four-year decline. Despite a fairly marked increase in 1992, the level is still lower than the average for the past ten years. Catering is responsible for relatively few manhours and few injuries, the injury frequency remaining between 30 and 40

Table 3.7.4.b Work accidents in connection with drilling from mobile units in 1989-92 showing type of incident and occupation

Injury incident / Occupation	Administration	Drillfloor worker	Driller	Electrician	Caterer	Assistant	Crane operator	Painter, gritblaster	Mechanic, motorman	Operator	Plateworker, insulator	Plumber	Service technician	Scaffolder	Welder	Derrickman	Other, unspecified	TOTAL	%
Other contact with object/machinery in motion	1	62	9	0	3	54	4	1	4	4	0	0	18	0	3	12	1	176	33,7
Fire Explosion etc	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	1	0,2
Fall to lower level	0	3	2	0	2	6	2	0	2	0	1	0	5	0	1	2	0	26	5,0
Fall at same level	0	7	0	1	1	5	1	0	0	0	0	0	3	0	0	1	0	19	3,6
Stepped on uneven surface or tripped	2	10	5	1	3	12	1	0	3	0	0	1	6	0	0	4	1	49	9,4
Falling objects	0	16	2	0	1	8	1	0	0	0	0	0	2	1	0	2	0	33	6,3
Other contact with objects at rest	0	9	4	1	5	7	0	0	2	1	1	0	3	0	1	3	0	37	7,1
Handling accident	3	33	3	1	5	6	2	0	6	0	1	0	10	0	2	6	1	79	15,1
Contact with chemical or physical compound	1	5	1	1	1	2	0	0	0	0	0	1	1	1	2	3	0	19	3,6
Muscular strain	4	13	2	0	2	9	1	0	0	1	0	0	5	0	0	3	0	40	7,6
Splinters, splashes	0	11	1	1	1	6	0	1	4	0	0	0	2	0	5	5	1	38	7,3
Electrical current	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	1	0,2
Extreme temperature	0	1	0	0	4	0	0	0	0	0	0	0	0	0	0	0	0	5	1,0
Total	11	170	29	6	28	116	12	2	21	6	3	2	56	2	14	41	4	523	100
%	2,1	32,5	5,5	1,1	5,4	22,2	2,3	0,4	4,0	1,1	0,6	0,4	10,7	0,4	2,7	7,8	0,8	100,0	

Fig. 3.7.5.a
Injuries by severity 1992



per 1000 years worked for the past five years. Administration and production have returned stable injury statistics since 1986 with a slight rise in the past two years.

On mobile units it may be that reporting and registration have become more consistent. The statistics here are thinner than for fixed installations, and they are much more uncertain. The injury frequency for the last three years was over 50 injuries per 1000 years worked.

In terms of the severity of the personal injuries suffered, it seems that on mobile units there are relatively more serious accidents than on the fixed installations. An injury is defined as serious if in all probability it will result, or has resulted, in permanent injury (such as amputation) or extended absence from work. The classification is not based on a medical evaluation in retrospect, but on the information reported in the accident report. The percentages are given in Figure 3.7.5.a.

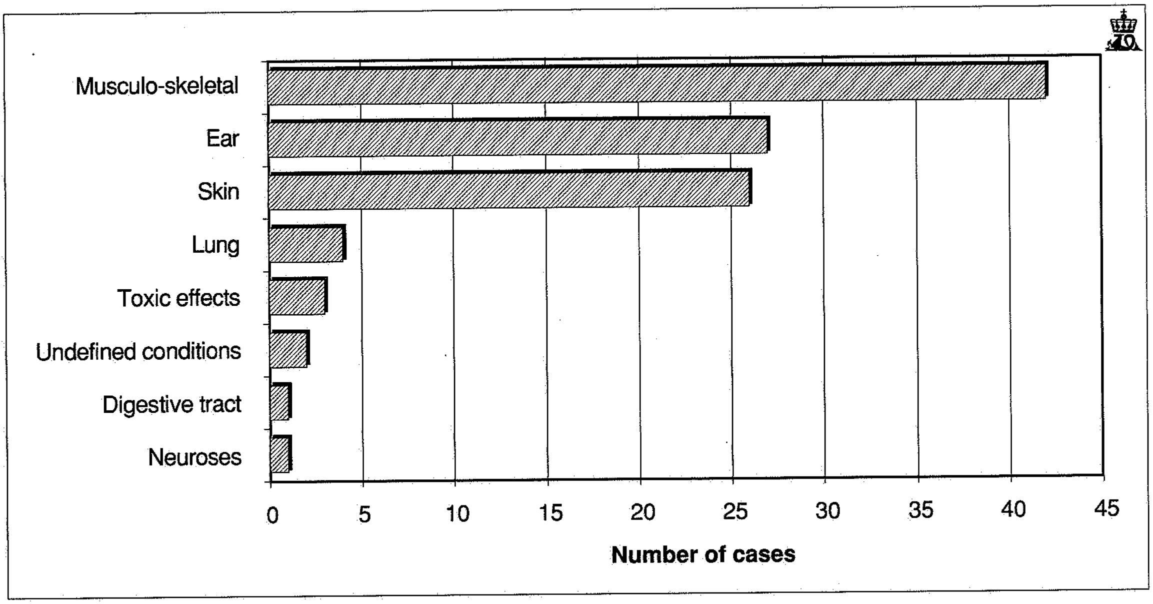
Despite the limitations of such a comprehensive reporting system, the Directorate believes that these statistical summaries provide a reasonable picture of the situation in the petroleum industry. Although the reduction in injury frequency on fixed installations was not as marked in 1992 as in previous years, the Directorate is encouraged that the promising trend of recent years does not seem to have reversed.

3.8 WORK-RELATED DISEASES

In addition to the reports and notices of personal injury in connection with the petroleum activity, the Directorate also requires notice of diseases that may be the result of occupational factors. The Directorate observed that this requirement in the Working Environment Act was not being pursued by the industry and therefore sent a letter in May 1992 to companies in which the medical officer's and employer's notification duty regarding work-related diseases was pointed out. The letter stresses that medical officers are required to send in notice under section 22 of the WEA, and set out the Directorate's expectation that the industry would follow up cases of work-related diseases.

This announcement, and other contacts with the companies on the subject, are the likely reason for the considerable increase in the number of reported cases compared to previous years. The majority of the reports come from a few companies, and many of the largest companies have not submitted any reports whatsoever. This tends to indicate that there is considerable under-reporting of work-related diseases. The Directorate will audit the companies' follow-up of these types of diseases and their reports to the authorities. The matter will also be examined from the perspective of the new *Working Environment Regulations.*

Fig. 3.8
Distribution of work-related diseases on diagnosis groups 1992



The Directorate has established a special database to bring the incoming work-related disease reports into order. This base records the patient's present and former employer, type of work, work factors supposed to have triggered the symptoms, and the diagnosis.

Figure 3.8 shows the distribution of reported work-related diseases in 1992 by diagnostic group. The main emphasis is on muscular and skeletal complaints (connective tissue), usually called muscular strain injuries. Typical causes are repetitive, monotonous movement and uncomfortable posture. Other factors are pace of work and static work.

Another major group is ear diseases, including noise-induced hearing loss, often caused by chronic exposure in the present or former work.

The third major group is skin disease. This is eczema due to exposure to various chemicals. The group is dominated by employees with hand eczema after contact with oil-based drilling mud. Other cases may be due to contact with other organic substances, epoxy, certain inorganic compounds, or certain metals.

Lung diseases include diagnoses grouped as asthma and bronchitis due to atmospheric irritants, while toxic effects refer to a range of symptoms following exposure to hazardous gases in the working atmosphere. Illnesses in the digestive tract and nervous disorders are believed to stem from psychosocial conditions at work.

In the future the Directorate will seek to expand the database already in place, and has contacted the Danish Labour Inspection which will assist in the task. The empirical material collected in the base of work-related diseases will be relayed to the industry.

3.9 WORKING ENVIRONMENT

3.9.1 Job-safety planning

Through its offshore accident reporting system and analyses of the incoming data the Directorate has noted a number of serious work accidents in which inadequate safety planning of the work was a major contributory factor to the event. Accordingly the operators were ordered to develop a structure for the implementation of job-safety analysis in connection with work on systems and equipment with a high risk factor. At the same time guidelines were issued for job-safety analyses.

The use of such analyses as a component of job-preparation means, generally, that the work must be examined and broken down into subtasks in the order of execution. The analysis should be done jointly by those responsible for actually performing the work, those responsible for the area in which the work will be done, and those responsible for the system being worked on. At each job step potential hazards are identified, which are then eliminated using safety and protection measures. Another feature is the specification of emergency preparedness measures to minimise potential damage if an accident nevertheless occurs.

The Directorate has since registered certain serious accidents despite the procedure of running such an analysis. It turns out that they were due to not following up the guidelines in two important respects:

1) The analysis was not done by the personnel who performed the work associated with the accident
2) The work was not split into job steps identifying the relevant safety, protection and emergency preparedness measures.

3.9.2 Compliance with working hour provisions

The Directorate has noted a positive trend in connection with compliance with the working hour provisions for well service contractors in 1992. The order issued in December 1991, requiring them to keep records of working hours for all personnel in the well service field seems to have had a positive effect. Not nearly as many breaches of the working hour provisions were uncovered for well service contractors in 1992 as the year before.

Nonetheless, the Directorate was forced to settle certain disputes regarding classification of personnel in leading and particularly independent positions.

3.9.3 Ergonomic assessment of control room

Supervisory activities looking into the ergonomic assessment of control rooms of three operators were performed in 1992. The supervision focused on control rooms for process monitoring, drilling, and diving operations.

In these activities the Directorate has spotlighted the operator's systems for following up ergonomic factors during engineering and construction of control rooms, as well as systems to identify and follow up ergonomic factors in control rooms already in service. It is evident that, in general, few ergonomic requirements are specified for equipment design in control rooms aimed at optimising the man-machine interface.

In connection with selection of control room concept, the Directorate notes that little systematic job or task analysis is performed in the engineering phase. The Directorate discerns a need for the increasing use of personnel with ergonomic expertise in the engineering phase so as to address ergonomic issues. Concrete problem areas revealed in the supervision include the following:

- Few requirements are specified for design of control room equipment to optimise the man-machine interface
- Inappropriate design of terminal workplaces
- Noise levels exceeding threshold limits
- Inadequate lighting
- Substandard indoor climate and cramped space.

One positive note is that the companies are now, more than before, using physical mock-ups of their designs to test the location of equipment and instruments. This, combined with increased involvement of personnel with practical experience from control room work, has led to improved solutions.

3.9.4 Accommodation

On the Ekofisk complex there remains a need to accommodate more people than there are quarters for on the fixed installations. In the first half of the year the operator, Phillips, used a flotel and a jack-up quarters platform with total capacity in the region of 690 beds. In the second half the flotel was succeeded by a jack-up quarters platform giving a total capacity of roughly 560 beds. Both jack-ups have been hired on long-term contracts and are expected to remain at Ekofisk until 1994.

Norsk Hydro has announced that it wishes to utilise the same accommodation concept at Troll Vest as for Brage.

Conoco has awarded the building contract for the living quarters for the Heidrun installation, and the Directorate has permitted a flexible cabin arrangement allowing the quarters to service a peak workforce of 350 persons and a regular crew of about 220.

3.9.5 Emergency quarters

On marginal field developments, enquiries are often made for consent to use sporadically manned installations. These do not have quarters units, but so-called emergency quarters are installed for the use of visitors and as overnight accommodation when departure from the installation is inadvisable. One such emergency quarter is in use on Hod. The Embla installation has been fitted with an emergency quarter and the plans are to develop Frøy with a similar arrangement. Also certain loading buoys have small quarters units. On existing installations remote control and demanning are being considered as ways to extend lifetimes, in which case the existing quarters will be partially closed and partially used as emergency accommodation.

3.10 CONTINGENCY PREPAREDNESS

3.10.1 Connection between risk analysis and emergency preparedness analysis

The Directorate, Norske Shell, Phillips, Norsk Hydro and Conoco in 1992 funded a project to examine the *Connection between Risk Analysis and Emergency Preparedness Analysis*, aimed at clarifying the link between the requirements in the *Risk Analysis Regulations* for formulation of acceptance criteria for risk, and the specific emergency preparedness requirements in the *Emergency Preparedness Regulations*; as well as describing methods and approaches that can be used to look after the Risk Analysis Regulations' requirements for risk-reducing measures and the Emergency Preparedness Regulations' requirements for doing emergency preparedness analyses.

The project concluded with a presentation at the Directorate of the challenges implicit in the regulations regarding the choice of risk-reducing measures, and the role of risk and emergency preparedness analyses in safety management in a development project. The presentation was therefore an important contribution to the work of effectuating the Analysis Regulations and the Emergency Preparedness Regulations in the industry.

3.10.2 Safety zones

The *Safety Zones Regulations* determine that a safety zone shall be enforced around and above all installations used for drilling, production, exploitation and transportation of petroleum, except pipelines, cables and subsea installations. Around and above subsea installations the Ministry may provide that there shall be a safety zone, or a zone in which anchoring and fishing are prohibited.

The safety rules, on the other hand, require such installations to be so designed that they will operate safely and stand up to the strains that can be expected, and that they will cause no damage to fishing gear. The rules state, further, that wherever possible one should seek to remove or reduce the individual risks that the activity entails, and that the petroleum activity must interfere as little as possible with other activities.

Based in part on technological advances, the Directorate can see a general increase in development concepts relying on the use of subsea production installations. Considerable expense has been taken to make sure that subsea installations are trawlable and able to withstand the impact involved. Nevertheless, the operators often apply to establish a safety zone or anchoring and fishing prohibition zone around such installations.

The arguments in these applications are based on the wish to further limit the risk that nonetheless remains after all risk-reducing measures have been put in place – as is consonant with the safety philosophy underlying the petroleum industry. The authorities' view, however, is usually that such a safety zone or prohibition zone would affect or seriously interfere with other activities in the region.

In general the Directorate feels that technological advance has come so far that it is possible to build installations that will withstand the likely impacts, thereby allowing safety to be kept at a sound level without the establishment of safety zones or prohibition of other activities.

In the development of marginal fields where the allowable minimum return from an investment is decisive in deciding whether or not to develop, the Directorate cannot dismiss the possibility that the demand for over-trawlability may be a significant deciding factor.

3.10.3 Concept for helicopter operations on the Norwegian continental shelf

According to the *Safety Regulations* the »licensee shall have a transport system for personnel and freight to allow the emplacement and use of the installation to proceed in a sound manner». The steady increase in the scope of helicopter traffic to and from the offshore installations means a greater need for formalisation of air traffic control for helicopter flights over the North Sea if the safety of such operations is to be maintained within safe limits.

The air traffic authorities, and the helicopter companies and the operators, have expressed concern about these matters. In consultation with the Civil Aviation Authority, the Directorate decided that air traffic services should be established on key installations in the North Sea.

In 1990, the Directorate therefore resolved to set up a helicopter flight information service (HFIS) for the Ekofisk and Gullfaks areas. This resolution was the formalisation of a service which had been operating for several years and embraced equipment, training and certification of air traffic control personnel on the installations.

In 1991, it was determined, on the basis of experience and studies in the interim, to revise the 1990 concept. Toward the end of 1991 a working group was therefore set up with representation from the Civil Aviation Authority, Norwegian Petroleum Directorate, Oil Industry Association, Norwegian Pilots Association, Norwegian Oil and Petrochemical Workers Union, and Oil Workers Joint Organisation.

The terms of reference of this group were to:

- Evaluate factors of relevance concerning the establishment and operation of air traffic services and units
- Prepare guidelines for use of relevant air space and establishment of and division of responsibility in connection with navigation, communications, and surveillance systems
- Review and, if necessary, adjust spheres of responsibility and routines between supervisory authorities, helicopter companies, and operators regarding helidecks and helideck services
- Elucidate significance of evolution and changes in European aviation on helicopter activities on Norwegian continental shelf.

The main objective of the new concept is to pave the way for efforts by the authorities, helicopter companies, and operators to improve the safety of helicopter flights for the oil industry. The concept will be the starting point for development and enhancement of helicopter operations until the year 2000.

The *Concept for Helicopter Operations on the Norwegian Continental Shelf* project was completed in December 1992 and will be circulated to consultative bodies early in the new year.

3.11 DRILLING OPERATIONS

3.11.1 High-deviation drilling

In recent years the number of high-angle wells has been steadily increasing. Since 1984 a total of 125 wells have been drilled with a maximum angle exceeding 60 degrees, no less than 61 of them in the last two years. In 1992, the number of such wells was 32.

As Table 3.11.1 shows, there has been a striking trend towards ever higher maximum wellbore angles. The driving force behind the trend is the economic advantage of reaching areas further away from the installation without the expense of subsea completion wells, and the steadily improving technology which makes the advantage attainable.

At the centre of the technological improvement is the improvement in equipment and methods for measurement while drilling, coupled with technical advances in navigable directional drilling systems allowing the optimal well path to be obtained fast and with precision. Significant research in rock mechanics, hole clearance and cementing in connection with high deviation drilling also produced positive spinoffs.

An important property of horizontal or near-horizontal wells is the capacity to penetrate the target reservoir section for a much greater length than conventional vertical wells. This enables each well to reach high production levels even from thin reservoir sections and despite factors that might otherwise reduce the rate, such as gas and water coning, or poor formation rock permeability.

A good example of success in achieving a high well flow from a thin oil zone where gas coning is a problem is one of Norsk Hydro's wells on the Troll field, where an oil zone about 12 metres thick has been penetrated for a distance of about 800 metres.

Table 3.11.1
Number of wells with maximum deviation 60° – 90°

Year/ <	60°–65°	65°–70°	70°–75°	75°–80°	80°–90°
1984	2				
1985	3	4			
1986	4	4			
1987	7				
1988	4	1	1	1	
1989	13	1		1	2
1990	8	4	1		3
1991	8	5	5	2	9
1992	9	4	3	3	13

3.11.2 Gas lift

The innate ability of a reservoir to produce oil to the surface depends in part on the pressure conditions downhole. Some way into the lifetime of the field the pressure alone will be inadequate to lift the oil to the production installation and the production rate will sink. At that stage artificial lift may be called for. One mode of attack is to inject gas into one or more points way down in the production tubing. The gas will rise to the surface with the oil, reducing its density and the weight of the liquid column, and thus increasing production.

On Ekofisk, Norway's oldest oil field, Phillips initiated gas lift as early as 1985. Several of the Ekofisk wells now produce with the aid of gas-lift and the number will increase. Gas-lift is also planned on other fields in production and similar fields under development.

The gas employed is usually hydrocarbons produced with the oil. In terms of safety the gas therefore represents an added risk since the annulus between the casing and the production tubing is charged with flammable gas under high pressure. This makes it necessary to take additional safety precautions to prevent the lift gas from escaping and causing a fire and explosion hazard on the installation. In the new *Drilling Regulations*, a requirement has therefore been included that, when upgrading already completed wells, an extra annulus barrier element must be installed to minimise the risk of such loss of gas.

3.11.3 Well maintenance and intervention

The scope of operations associated with the completion of new wells and recompletion of existing ones has grown considerably in recent years, in part since the wells are becoming older. One of the effects is corrosion of the production string which leads in turn to heavy increases in the number of service operations requiring to be conducted on each well.

The use of hydraulic well overhauling equipment has also grown steadily, and has proven an extremely useful tool for this type of workover. At the same time a reduction in the scope of traditional wireline interventions has been noted. Part of the reason is that increasing numbers of wells are completed at high deviation where the necessary gravitation is not available to pull the wireline tool down the hole. As a direct consequence the use of coiled tubing methods has escalated in recent years. There has also been a considerable rise in the development of new service equipment which opens for new service fields.

The new technology and the use of new methods often provide new potential for safety enhancement, though experience teaches us that new types of risk may also obtain. The Directorate therefore keeps a close watch and will examine very closely the operators' activities to ensure that the new technology and new methods are brought into service in a controlled manner in terms of health, safety and the working environment.

3.11.4 High-pressure wells

The Directorate's supervision of companies which have put down wells at high pressure and high temperature was a commitment area again in 1992. Experience shows that it still remains to improve several points both as regards planning and implementation.

In no previous year have so many wells of this type been drilled. In fact, eight such wells were drilled in 1992, and at one point no less than seven of them were in progress at the same time.

Drilling activities have generally proceeded without major upset except in one case where there were certain operational problems. The most typical problems in such wells continue to be in connection with the high temperatures and high pressures encountered.

It must be admitted that these wells are still fraught with difficulty and a higher level of risk. In the future it will therefore be necessary to emphasise the follow-up of such activities both through augmented supervision audits and work and by close monitoring of the drilling activity and through the projects and meetings held in the field.

The drilling of high pressure, high temperature wells is also fairly prevalent in the Danish and UK sectors. Accordingly the Directorate has taken the initiative for inter-authority cooperation in the three countries. The aim is to establish an experience exchange scheme at the same time as one tries to coordinate activities, thereby further improving safety for this type of drilling operation.

3.11.5 Temporary abandonment

Whenever an exploration well is considered a potential production well if the field is developed, or the licensee for whatever other reason wishes to keep his reentry option open, then the wellhead must be abandoned when the rig goes off station.

The former drilling regulations contained a requirement that such wells should be provided with a marker buoy and abandonment could be made without protecting the wellhead. The new *Drilling Regulations* has changed this rule, and now a special protective enclosure which will stand up to trawl impact must be emplaced over the wellhead.

By year end 1992, there were 50 such temporary abandonments in the Norwegian sector, 29 with a protective enclosure, and the remainder marked, albeit temporarily, with a buoy.

3.11.6 Daily drilling report system, DDRS

In 1992, much effort went into the Directorate's Daily Drilling Report System database. In addition to daily operation of the database certain system changes were made aimed at improving the base in the light of user experience since the base was established in 1984. The Directorate now uses the base systematically for the analysis and processing of raw data in order to rank supervision priorities for drilling and well activities. The commitment to dissemination of base information to the industry has also increased.

Figures 3.11.6.a and b show the activity levels and time spent on exploration and development drilling, respectively, in 1992.

3.12 NATURAL ENVIRONMENT DATA

The acquisition of natural environment data such as information on currents, wind strengths, wave heights from Ekofisk, Frigg, Statfjord and the mobile units *Deepsea Bergen*, *Ross Rig* and *Polar Pioneer* proceeded apace in 1991. With the help of the Norwegian Meteorological Institute the Directorate supervised the collection of data from these installations. This assistance scheme worked extremely well and is a powerful contributory factor to the good quality of supervision in this field.

In 1992, further efforts were made to initiate environmental data acquisition from Draugen and Heidrun once the installations are in place. All told, this will mean six monitoring stations off the Norwegian coast.

3.13 STRUCTURES AND PIPELINES

3.13.1 Subsidence on Ekofisk

The gradual subsidence of the seabed around the Ekofisk field centre and Vest Ekofisk has been continuing since the late 1970s. The causes are a combination of weak reservoir rock and depressurisation of

Fig. 3.11.6.a
DDRS: Daily drilling report system 1992
Main operation: Exploration drilling

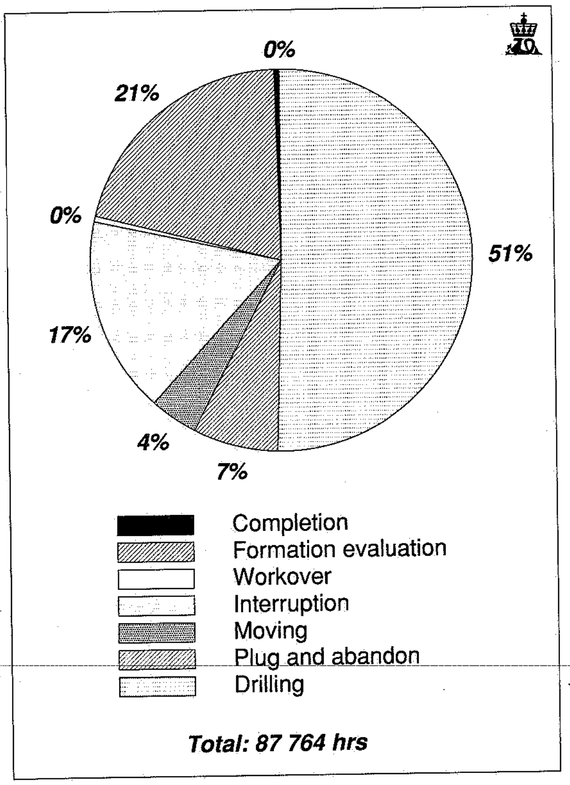
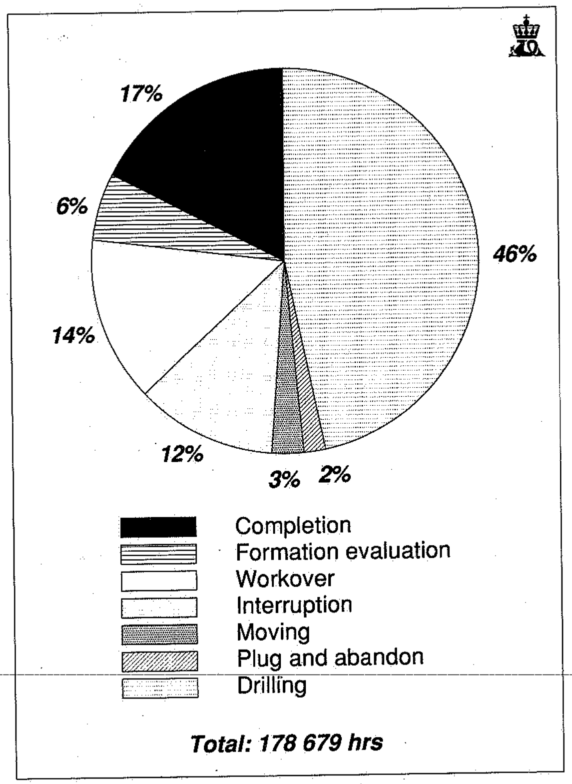


Fig. 3.11.6.b
DDRS: Daily drilling report system 1992
Main operation: Development drilling



the reservoir, the latter being the result of depletion of the oil and gas.

During the first half of the 1980s the subsidence rate at the Ekofisk field centre was about 0.5 metres a year. Towards the end of the decade it had slowed to about half, but increased again to 0.35 metres a year from 1990 to 1992. The total subsidence of the Ekofisk field centre is 5.6 metres to date.

At 2/4 A and B and Vest Ekofisk 2/4 D the subsidence is slightly less, the totals to date being 2.8, 3.2 and 2.7 metres, respectively; while the rate of subsidence is roughly the same as before, about 0.15 to 0.20 metres a year.

The Eldfisk installations have also sunk somewhat, though the rate is very slow. The total to date is about 0.5 metres.

It was anticipated that subsidence rates would slacken off as the reservoir collapsed. The increase in rate for the Ekofisk field centre over the past three years tends to indicate that there are other causes at work. An explanation that would provide a reasonable prediction of events to come has yet to be found.

The subsidence means that the clearance of the deck structures above a 100-year wave is less than intended. Installations at the field centre were therefore jacked up in 1987 to maintain the necessary clearance. For the 2/4 A, B and D installations, Phillips is considering what measures to take to compensate for the lower safety margin. For the time being special procedures have been implemented to shut down production if extreme weather conditions are forecast.

Strenuous efforts have been made in measurement and analysis to obtain the best possible picture of the subsidence. Phillips is also working on increasing the volume of water flooded into the reservoir, which hopefully will slow subsidence as much as possible.

3.13.2 Ringing and springing effects

Under model tank testing of the Heidrun concrete hull it became apparent that large waves may induce a form of vibration in the structures over and above those already known and estimated.

Depending on the height and weight of the structure, it will have a specific resonance frequency. If a concrete shaft is impacted by waves of this frequency, resonance effects may result, causing additional strain on the structure. Now it appears that this frequency can also be generated by several waves in combination, an effect that depends on wave height, frequency and shape, as well as shaft dimensions. The effect, called ringing, allows waves to climb higher up the structure than estimated in the assumptions underlying the design. Though the phenomenon is not unknown, it was not considered significant for structures the size of the Heidrun hull.

The discovery that the effect is significant caused much activity in connection with design of the Heidrun, Troll A and Draugen installations in 1992. A review was also undertaken of existing structures to assess the significance of ringing on them. Research has also been initiated in order to describe and find ways of predicting the effect.

Springing is a related phenomenon known from wave impact on ship hulls. In simple terms it is an elastic spring effect whereby the structure vibrates when impacted by a load of a certain frequency. While ringing is a sporadic phenomenon limited to specific circumstances, springing is a more general strain that may last for long periods. Springing is therefore primarily a source of loads that may induce fatigue failure, though it also adds to the maximum load in any given situation. Figure 3.13.2 shows ringing and springing against a time scale.

The twin effects will arise in structures having a natural period shorter than the wave period (about 15 seconds). In practice this means all bottom-standing structures and all tension-leg structures. Semi-submersible units have fundamental periods longer than about 18 seconds and will not be affected.

The effects of springing are largely accessible using modern analytical methods. On the other hand ringing is not readily susceptible to known calculation models. Assessments must therefore to a large extent rely on wave tank trials.

A major research project to be executed by SINTEF and Det norske Veritas has been initiated aiming to improve the predictability of ringing and, if possible, develop numerical methods for estimating its value. The project is financed jointly by several oil companies, the installation builder Norwegian Contractors, and the Directorate.

Increasing deck clearance

The wave tank trials with models of the Snorre installation showed that wave crests will climb higher up the shafts than originally thought. It was therefore decided to raise the deck. The same happened in the Heidrun wave trials in Trondheim in June 1992, and again it was decided to raise the deck. In these cases the wave heights between the shafts are augmented by the sympathetic movements of the shafts under wave action. A similar effect was observed on Draugen, though Draugen is a mono-tower construction. Observations showed that the waves will climb significantly further up the tower than originally supposed and the designers decided to lift the deck by a similar amount.

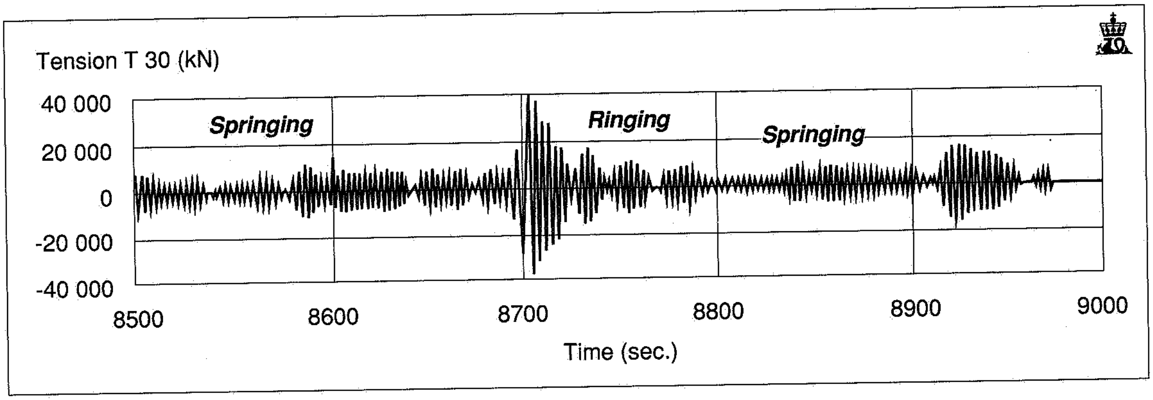
Installations in engineering or fabrication phase

For the Heidrun installation the ringing effect was found early enough in the project to engineer the results into the design and the matter has thus been adequately dealt with.

For Draugen the realisation came later in the project and the operator, Shell, being unable to prove that the tower as a whole is strong enough to withstand the added load, has resolved to compensate by operational measures, principally the lowering of water ballast levels in the tower in rough weather.

On Troll the ringing effect was demonstrated in

Fig. 3.13.2
Time series plot of ringing and springing



the wave tank and the data are still undergoing analysis. Until further notice an additional load of 10 per cent has been incorporated in all calculations on which the installation now under construction are based.

All other structures now at the detail engineering stage or in fabrication have such long natural periods that ringing and springing effects can be discounted.

Existing installations

Measurements made on the large installations at Frigg TCP2, Statfjord A and Statfjord B under storm conditions show that the maximum wave loads are greater than predicted in the original calculations, which tends to support the ringing effect theory. Since the loads were originally estimated on a very conservative basis, the effect is nonetheless of no significance for safety on these installations.

On Oseberg A, Norsk Hydro has noticed the effects of the phenomena, though they are small and believed to be insignificant. Statoil, similarly, has observed effects on its gravity base structures, which again are considered negligible.

Measurements made on the steel jacket structures of Valhall QP, Ekofisk 2/4-H, Oseberg B and Frigg DP2 by the respective operators concluded that ringing effects may be present, but are negligible.

Saga reviewed the wave trials for the Snorre tension-leg platform and observed a ringing effect, though at a low level and considerably lower than for Heidrun.

Operators employing jack-ups have been asked to assess any effects of ringing on them. Only a few such installations are in service in the Norwegian sector.

On the Statfjord C offshore loading buoy, severe short-duration loads were detected in wave tank trials in 1985. They may be evidence of ringing, though this is not yet clear. Statoil is reassessing its loading buoys in light of this finding. Elf is similarly reassessing the field control station at Nordøst-Frigg.

Laboratory trials of the Kallstø tunnel detected ringing effects from breaking waves. Statoil is investigating the matter further.

3.13.3 Collisions

One collision was reported in 1992 between a vessel and an installation, namely a tanker which collided with the Statfjord C offshore loading buoy.

In the last decade, 14 collisions have been reported of vessels with installations. The average rate is thus about two per 100 years of operation. The many reports of minor damage to installations may signify the occurrence of collisions that were not reported. As four of the registered collisions were of tankers with loading buoys, there appears to be no difference in collision frequency between large and small vessels.

The Directorate's *Guidelines for Loads and Load Effects*, issued in 1992, suggest installation designs to allow for collisions with vessels which regularly enter the safety zone.

3.13.4 Transportation pipelines for oil and gas

It is now clear that several new transportation pipelines will be constructed in the next few years to land petroleum in Norway. By year end 1992 there were three such lines to the Norwegian mainland: Statpipe carrying gas to Kallstø, Oseberg Transport System carrying oil to Sture, and a line carrying condensate from Sleipner to Kallstø (operational from autumn 1993).

The developments approved so far are twin 915 mm (36 inch) lines from the Troll A platform to Øygarden north of Bergen, Zeepipe phase II A, a 1020 mm (40 inch) line from Øygarden to Sleipner A, and a 405 mm (16 inch) line between Heidrun and Tjeldbergodden. Under evaluation is a line between Troll Vest and Mongstad, for which the final decision is expected early in 1993. The Europipe line will land in the vicinity of Emden in Germany.

To date no lines larger than 760 mm (30 inch) diameter have crossed the Norwegian Trench. The lines from Troll A and the Zeepipe phase II A line therefore pose a serious challenge, as they involve the laying of wide-diameter lines at depths down to 360 metres. For the lines planned to cross or run parallel with the West Norway fjords, the seabed topography is a real challenge. The seabed varies greatly over short distances and in places the bottom is composed of rocky outcrops separated by sedimentary ooze in the intervening valleys.

In some places the pipelines may therefore have to cross relatively long spans. Long spans are liable on account of vibration caused by product flow to induce fatigue and fracture, leading to line severance. It is therefore necessary to prepare the seabed before laying the line. One method is to construct support points which divide the span into smaller lengths and prevent fatigue effects.

The nature and topography of the seabed may require large quantities of gravel to be positioned under support points. The laying operation itself is also tricky in such conditions and several alternatives to the conventional techniques are being assessed.

Europipe will cross environmentally sensitive wetlands as it enters Germany. Various solutions have been examined to cross this area and for parts of the distance a telescopic method is being studied. This involves the driving of large-diameter pipe through the soil, after which the pipeline is fed through.

3.13.5 Flexible flowlines and loading hoses

The trend in Norwegian field development nowadays is increasingly towards concepts for satellite fields and associated satellite wells. There is reason to believe that these will increasingly utilise flexible flowlines and hoses. In general, operating experience with these systems on the Norwegian continental shelf has been positive, though certain incidents and experiences have led to corrective action being taken.

In one case a flexible flowline to carry hydrocarbons from a fixed wellhead installation to a floating production platform was replaced due to leakage between the various lamina making up the flowline.

In another case damage to the coating on the loading hoses from two underwater buoys caused them to be replaced. One of the replacements was a larger dimension, increasing loading capacity.

Another flowline was twisted during installation and later broke while on stream. There was also one case of rupture due to bulging of the line through the protective stone layer covering it.

3.13.6 International standardisation

A committee was set up under the auspices of the Norwegian Building Standards Council in 1990 with the task of revising Norwegian Standard NS 3479 for structural loads. The Directorate was represented on the committee. After the committee started its work, work also started on a European Community standard concerning the same subject matter, from which time therefore the Norwegian committee has become a consultative body for the EC standard.

In 1991, the Norwegian Engineering Standards Association (NVS) set up Norwegian reference committees for a new ISO standard concerning Offshore Structures, Pipeline Transportation Systems for the Petroleum and Natural Gas Industries, and Line Pipe. The Directorate was represented on the committee and working parties charged with formulating parts of these standards in 1992.

3.13.7 Pipeline and structural damage reports, CODAM

The CODAM, for COrrosion DAMage, database covers damage and non-conformance of pipeline systems and structures. Standard reporting forms have been designed, and operators can choose between reporting in writing or employing a specified diskette transfer format, depending on report volume. The Directorate hopes this will simplify the reporting routines. The Directorate is also concerned that operators and the industry as a whole should draw benefit from the systematic experiential data that the database can provide.

The demand for data at home and abroad was relatively high in 1992.

Work is continuing to include damage and nonconformance dating from pre-1982. This work requires a great deal of time as damage documentation from the early days of activity on the Norwegian continental shelf is inadequate.

3.13.8 Erosion

In 1992, the Directorate undertook a review of all available inspection reports about seabed erosion caused by the legs of steel jackets. None of them reported erosion exceeding the rates assumed in the design process.

The conclusions of the report are:

- Erosion commences when the jacket is installed but reaches a limit after a few years
- There is little erosion around installations engaging in drilling since cuttings are dumped on the seabed, which counteracts erosion
- Erosion stops once a fairly erosion resistant layer is reached, for example one containing shell
- In areas of major subsidence the hollows in the seabed have been filling with sand over the past few years, causing a build-up rather than erosion of sand around the legs.

A similar study of pipeline systems close to the Ekofisk field centre is in progress, intended to examine how unsupported spans in the region correlate with subsidence and prevailing erosion or sedimentation.

3.14 GAS LEAKS, FIRES AND OUTBREAKS

3.14.1 Gas leaks

During the year, 106 gas leaks were reported on fixed and mobile installations. This is much more than in 1991, when the number was 55.

The Directorate has made it clear to the operators that large differences often occur in their reporting criteria for gas leaks. It is reasonable to suppose that improved reporting routines have added to the number of gas leaks reported.

As Table 3.14.1 shows, in 1992 some 82 small gas leaks were reported, compared to 36 in 1991. The figures can be interpreted to support the theory that reporting has improved. The table also shows that medium and large gas leaks also increased slightly compared to 1991. This is taken to indicate a negative trend which the Directorate has decided to implement measures to combat.

The table also shows the proportion of gas leaks detected by gas detector systems.

Figure 3.14.1.a breaks down the reported gas leakages by severity. The divisions in the figure are based on the Directorate's appraisal of the course of events and the risks the gas leak entailed. The figure shows that most of the leaks were small.

Figure 3.14.1.b serves to illustrate the causes of the gas leakages. The causes behind a gas leak are often several and coincidental. The figure assigns the causal factors on the basis of what the Directorate considers the most significant causes.

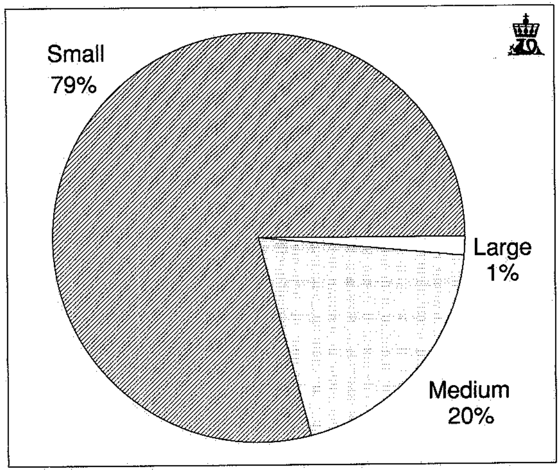
Human error is one causal subcategory in the operational error category. In turn a human error may have many underlying causal elements, such as lack of training and lack of information. The factors are illustrated in Figure 3.14.1.b, which shows, among other things, that faulty installation and faulty use of connectors and valves is a prominent cause of gas leaks.

3.14.2 Fires and outbreaks

The Directorate registered 52 fires in 1992, the same number as in 1991. As in 1991, fires in connection with welding operations account for most of the occurrences.

Table 3.14.2 summarises the scope and causes of fires and outbreaks reported to the Directorate in 1992. It will be seen that three of the reported fires are classified as major fires (class C). The Directorate notes that the fire statistics reveal an increasing tendency (see categories). Here, too, the Directorate is planning specific action.

Fig. 3.14.1.a
Classification of reported gas leaks by degree of seriousness



3.14.3 Explosion and fire on Ekofisk tank

On 25 May 1992, there was an explosion and subsequent fire in a gas compressor turbine on Ekofisk 2/4-T, the Ekofisk tank.

Prior to the incident the turbine had experienced capacity shortfalls for several days. To correct this a series of washing operations were conducted on the turbine compressor stage. During washing it is customary to disconnect the flame monitors as they are likely to trip in such circumstances. By mistake the disconnection was not reinstated after the wash operation. In all probability combustion in the turbine ceased, most likely due to the wrong mix of fuel and air. The control system interpreted the falling revolutions as a signal to increase fuel supply and filled the turbine with gas. This was then sparked by contact with hot surfaces outside the combustion chamber, causing the explosion and accompanying fire.

The air inlet, exhaust outlet and turbine casing were all severely damaged. Nobody was present at the time of the explosion and nobody was injured in the fire. Since the incident Phillips has instituted important changes in the operating and maintenance procedures for turbines.

Table 3.14.1
Gas leakages detected by gas detection systems

Severity	Total number	Number detected automatically	Reading in % LEL	
			20%	60%
Minor	82	17	14	3
Medium	21	12	2	10
Major	3	2	0	2

(LEL = Lower explosion limit)

Fig. 3.14.1.b
Gas leaks – classification of causal relationship

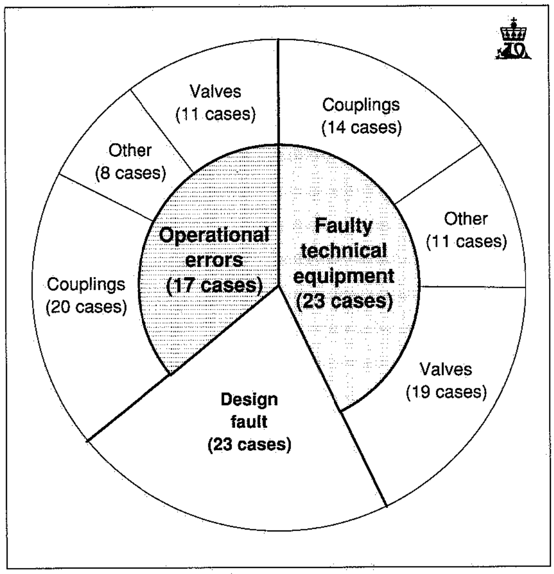


Table 3.14.2
Summary of fires on fixed and mobile production installations

	Fixed installations			Mobile installations		
	S	M	L	S	M	L
Welding	13	4	1	1		
Spontaneous ignition	6	3	1	1		
Electrical short circuiting	6	3			1	
Other causes	7	3	1	1		
Total	32	13	3	3	1	

S = Small, M = Medium, L = Large

3.14.4 Fire on Frigg TCP-2

On 10 November 1992, there occurred a fire in a concrete shaft on the Frigg TCP-2 installation. A controlled methanol leak was ignited by welding sparks despite being covered and diluted with water. The fire, though small and limited in area, was difficult to get to and extinguish. Nobody was injured and only minor material damage was sustained. The Directorate in its review of the incident nevertheless identified several circumstances which gave cause for discussion with the operator.

3.15 DIVING

3.15.1 Diving operations

In the current period, 2252 surface oriented dives, 1404 bell runs (in saturation), and 177,211 manhours in saturation were put in on the Norwegian continental shelf. This was about the same level of activity in saturation as in 1991, though the number of surface oriented dives increased. The mean bell run time for saturation diving was 5.9 hours and the mean saturation period 12.3 days. The mean immersion time for surface oriented divers was 1.8 hours. The dives were carried out from 12 different tenders and installations, as shown in Figure 3.15.1. No monobaric dives were performed in the Norwegian sector in 1992.

Diving operations were generally under inspection, maintenance and structural contracts for fields operated by Elf, Esso, Norsk Hydro, Phillips, Saga and Statoil. Heavy diving activity was also required in connection with laying the Zeepipe. Diving in connection with construction work was generally to hook up flowlines and risers and give assistance with the emplacement of various structures.

3.15.2 Diving accident survey

Figures 3.15.2.a and b provide a summary of the events reported to the Directorate from 1985 to 1992 in connection with diving operations. The events are broken down into the following categories: incident, accident, and fatality. Previous years' figures have been corrected where necessary for late reports.

In 1992, for the first time in Norway's offshore history, no cases of decompression sickness were reported in connection with diving of any sort. Table 3.15.2 shows how accidents involving personal injury were divided between the various injury categories.

It emerges that there was an increase in accidents involving personal injury in saturation. The increase is due to the increase in outer ear inflammation and the incidence of other disease and injury (influenza, common cold, diarrhoea, etc).

Table 3.15.2
Accidents related to type of injury

Type of injury	Saturation diving	Surface oriented diving
Outer ear infection	25	2
Thermal injury		
Decomp. sickness		
Wounds	2	
Pain in muscle/joint	5	
Cold injury		
Fracture	1	
Infection	7	
Hypoxia/Anexia		
Unconsciousness		
Barotraume – comp.	1	2
Barotraume – decomp.	1	
Other illness/injury	12	2
Total	54	6

Fig. 3.15.1
Diving operations in 1992

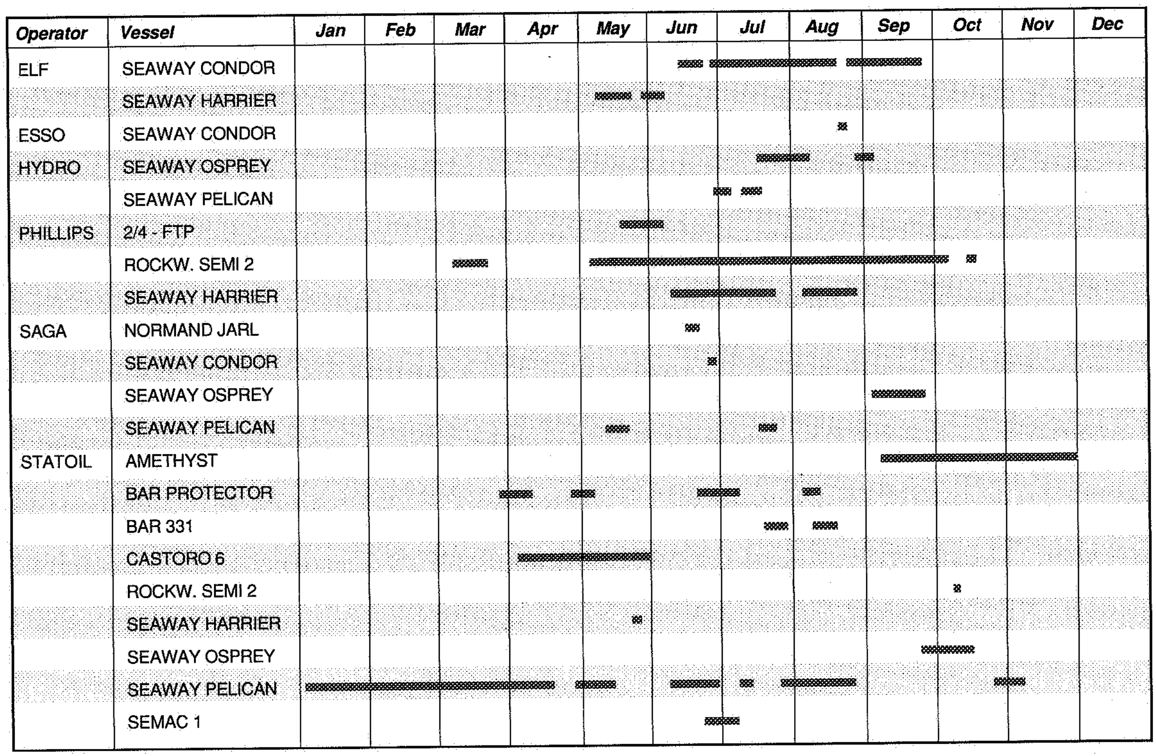


Fig. 3.15.2.a
Incidents in saturation diving

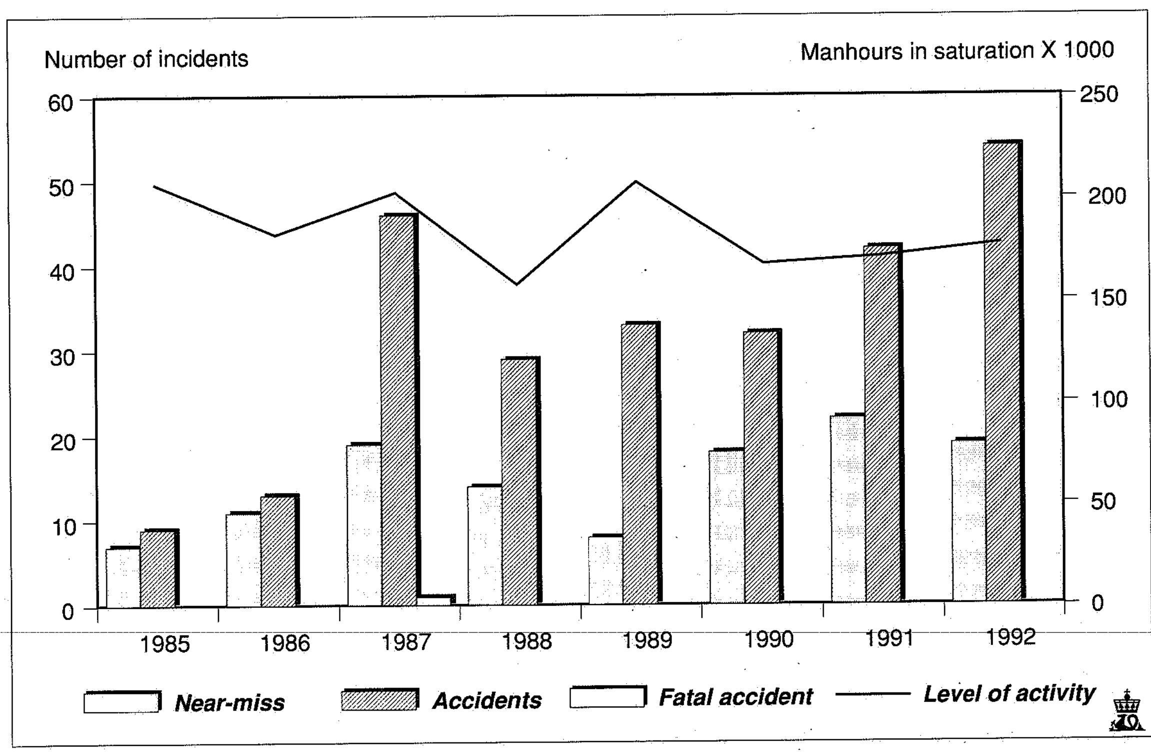
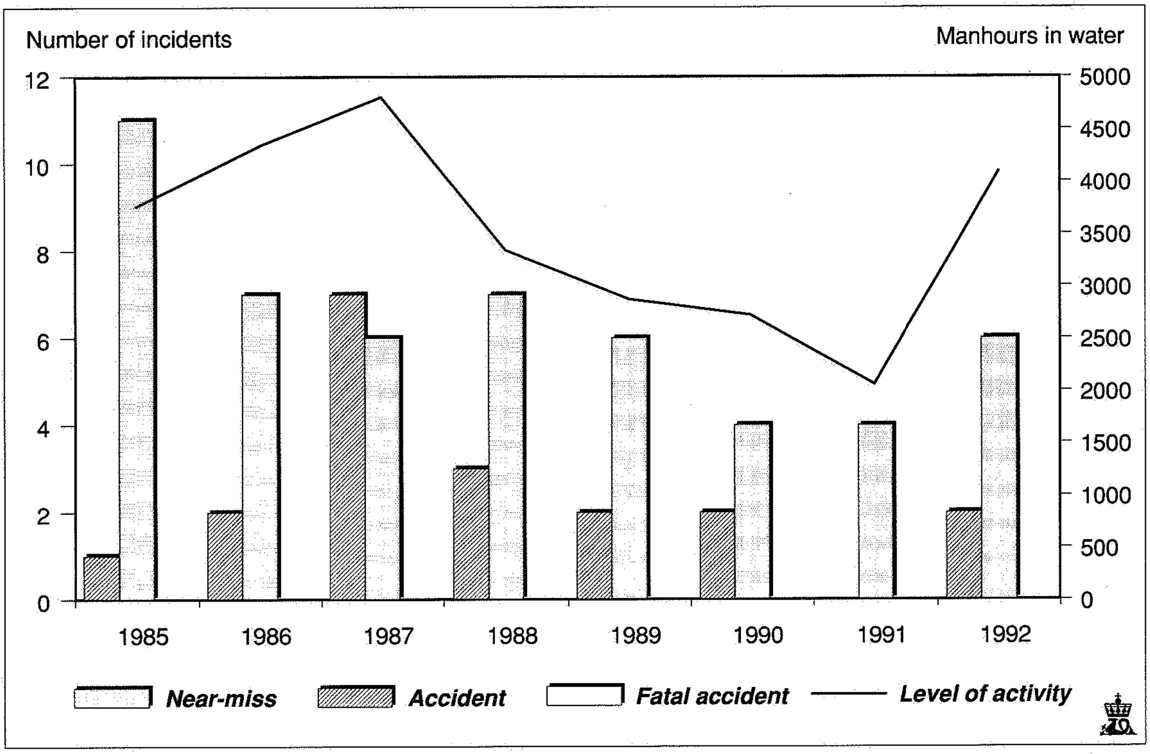


Fig. 3.15.2.b
Incidents in surface oriented diving



3.15.3 Diving research

In 1989, the Directorate joined with Statoil and Norsk Hydro in launching a joint *Programme for Research and Development in Diving Technology and Diving Medicine* (FUDT). In 1990, Saga joined the programme; and other oil companies have contributed in certain fields, either on an independent basis or through the Norwegian Oil Industry Association.

The Directorate is very pleased that the oil companies can work together to reach common solutions to pressing offshore diving issues.

In 1992, the Directorate provided an observer to the steering committee for the HADES project, a research programme to study decompression financed by Phillips. The project, started in 1990, is planned to finish in 1995.

3.16 SAFETY ECONOMY

The Directorate clearly sees a broad potential for improved profitability over time from maintaining and developing a sound level of safety in the petroleum activities; and notes that increasingly the participants in the offshore industry are including in their official strategy the idea that it pays to invest in safety.

The Directorate is following up with additional resources to look at the connection between safety and economy. Much of the effort goes to developing regulations, where economic consequence analyses are performed in accordance with the requirements in the overall frameworks for such work.

In the supervisory activities in 1992 in particular the matters concerning the safety related aspects related to the Ekofisk tank have undergone extensive economic analyses.

4. Environmental Measures in the Petroleum Activity

4.1 INTRODUCTION

In recent years there has occurred a marked increase in the focus on environmental issues. These issues are therefore playing a more central role in energy policy design. In the petroleum activity, strong efforts must be made to prevent environmental damage due to the activity, and to contain the effects of the damage, should it occur. The costs involved can be expected to increase and may amount to substantial sums. It is therefore important that the industry in particular, and society as a whole, should address the issue carefully and resolutely.

In pursuance of basic requirements for prudent activity the Directorate is implementing a series of actions which seek to reduce the regular emissions and discharges to the atmosphere and sea, as well as implementing actions of a preventive nature.

Security against damage to the environment is defined in the general frameworks as a function of the safety concept. Safety aspects of the environmental requirements are generally addressed as an integral part of safety activity, as discussed in chapter 3 on safety and the working environment. The Directorate's principal duties in environmental protection are thus in the field of preventive measures, and specific environmental measures designed to prevent and contain pollution damage.

The main components of this work are the stipulation of regulations and other constraints for the activity, supervisory activity, reports, specific projects, joint efforts with other authorities, and information services. These duties in sum make up a substantial part of the Directorate's total use of resources.

In 1992, the Directorate undertook an analysis of its activities in the environmental field in order to obtain a sound basis on which to manage its total engagement in this sector. The analysis provides the basis for this review of the Directorate's work in 1992 of significance for environmental protection.

4.2 FRAMEWORK AND CONDITIONS FOR ENVIRONMENTAL MEASURES

In 1992, the Directorate implemented activities in many areas relating to the establishment of framework of significance for protection of the external environment. Among other measures the Directorate:

- Participated in consequence analyses (AKUP) before new areas of the continental shelf are opened for exploration drilling or production licence allocation
- Introduced work to evaluate environmental expertise of potential applicants in fourteenth licensing round
- Participated with Ministry of Petroleum and Energy in discussions with operating companies regarding consequence analyses in connection with approval of plans for development and operation (PDO) and plans for construction and operation (PCO)
- Followed up criteria and framework established for the environment in Storting Propositions and other government papers in connection with consideration of development matters and consent applications
- Participated in work of Petroleum Law Committee on Norwegian and international rules for removal of installations from continental shelf
- Implemented evaluation of effect and design of ongoing and planned measures to reduce marine discharges and atmospheric emissions from the petroleum industry.

In 1992, the Directorate was occupied with regulatory development on several fronts of significance for the protection of the environment. The *Emergency Preparedness Regulations* were developed in cooperation with the State Pollution Control Authority (SFT) and stipulated by both agencies on 1 May 1992. Regulatory work is also taking place in connection with the health and environmental risk of chemicals, this time in cooperation with the State Pollution Control Authority and Labour Inspection.

4.3 SUPERVISORY DUTIES

Very much of the Directorate's supervision of the operating companies was performed as an integral part of our supervision of safety and the working environment. This supervision targets the companies' internal control mechanisms, which are intended to be a systematic means of ensuring that company operations during all phases are planned and executed in conformity with the government's requirements and the companies' self-imposed objectives and acceptance criteria.

In 1992, one of the areas spotlighted was operators' precautionary measures while drilling in sensitive environmental areas. Special focus was put on their development of acceptance criteria, the implementation and use of risk analyses, and the implementation of risk-reducing measures.

4.4 CARBON DIOXIDE TAX

Since 1 January 1991, the Directorate has been assigned responsibility on behalf of the Ministry of Finance for enforcement of the *Carbon Dioxide Tax Act* on the Norwegian continental shelf. Apart from managing the actual collection operation, the Directorate also supervises the metering systems for fuel and flare gas. For this purpose, draft *Regulations for Fuel and Flare Gas Metering for Carbon Dioxide Tax Assessment in the Petroleum Activities* have been prepared, which were circulated to external bodies for their comments in December 1992.

The Directorate also considers complaints and other judicial problems in connection with the new Act. It must also consider the ongoing effects of the tax. This latter work is organised into annual meetings with the operating companies and analyses of the statistics reported by them.

In 1992, the tax rate was 0.80 kroner per standard cubic metre of gas or litre of petroleum (diesel) consumed. In the first half of the year, Nkr 1109 million was collected from the tax, compared to Nkr 810 million in the first half of 1991. The increase was mainly due to the escalation of the tax from 0.60 kroner in 1991.

4.5 REPORTS AND EVALUATIONS

In 1992, the Directorate completed and contributed to many reports and evaluations, in part as documentation for the various ministries' work to set the limits of environmental constraints in terms of the energy policy, and in part as documentation for its own activities. Among the reports the following subjects were examined:

- Development of a scheme for reporting atmospheric emissions from the petroleum activity. This scheme was devised in collaboration with the State Pollution Control Authority (SFT). For the first time the operators reported their prognoses for atmospheric emissions due to fuel, flaring, cold venting, offshore buoy loading, diesel and halon gases to the Directorate in connection with the parliamentary budget debate and review.
- Development of own emission prognoses for carbon dioxide (CO_2), volatile organic carbon (VOC) and nitrogen oxides (NO_x) from the petroleum activity. The environmental prognoses are crucial tools when selecting measures which would enable us to monitor national and international environmental obligations. Our environmental accounts and prognoses will also provide the basis for the Norwegian position in negotiations on reduction or stabilisation of climatic (greenhouse) gas emissions.
- Participation in the Oil Industry Association's environment programme. The Directorate joined with the State Pollution Control Authority as observers of the programme. The Directorate also supplied statistical data for many of the studies. The programme embraces much interesting research on emissions and marine discharges from the petroleum activity, and the current studies will be completed during the first half of 1993.
- Clarification of types and sources of emission and discharge as well as opportunities to reduce them and the costs of doing so. In 1992, the Directorate carried out a study to examine the feasibility of reducing nitrogen oxide emission from the petroleum activity. One key aspect of this study was the elucidation and evaluation of existing and future technology for nitrogen oxide reduction and its cost.
- Follow-up of research programme into effects of seismic surveys on fish.
- Evaluation of possible climatic changes and their effects on the weather of significance for the petroleum activity.

4.6 TECHNOLOGY DEVELOPMENT

A broad range of research and technology development is carried out with the purpose of increasing the energy efficiency of existing and planned installations for offshore use. The energy-efficient equipment and methods available often stem from technologies which have other, added advantages, among them good reliability, ease of maintenance, and sound overall economy. The Directorate is therefore energetic in following up these developments and the decision processes in the operating companies relating to selection of technical solutions and hardware.

In 1990, the Directorate issued *Regulations for the Implementation and Use of Risk Analyses*. A key principle embodied therein was the operating companies' duty to set safety targets and acceptance criteria for risk. In 1992, the Directorate continued to monitor industry activities in connection with the development of acceptance criteria for environmental risk.

The Petroleum Act and the regulations derived from it set requirements, not only for technical solutions and activities, but also for the continuous development of safety and technology to keep up with advances made and the heightened standards elsewhere in society. This is something the Directorate keeps watch on in many areas. In 1992 attention was focused on:

- Measures to reduce emission of volatile organic carbon gases in offshore loading buoy operations
- Development of improved cleansing methods for produced water
- Development of burner to reduce nitrogen oxide emissions
- Development and use of new types of drilling mud, and work to obviate or at least minimise use of oil-based drilling mud
- Evaluation of various handling and disposal methods for oily cuttings
- Development of more efficient drainage systems
- Development of new fire-fighting agents as halons are phased out
- Work in connection with reduction of need for gas flaring during production operations and in connection with well testing
- Incineration of waste on installations
- Marking of containers and other storage options to ensure safe storage and transport of environmental hazard substances to shore
- Perpetrator's reporting duty in case of scrap on the seabed

- Surveys, inspections and clearance of the seabed
- Use and handling of biocides, heavy metals and low activity isotopes
- Development of methods for separation of heavy metals from produced water
- Composition of sacrificial anodes for corrosion protection.

In connection with the cleansing of produced water, the Directorate has examined the water treatment capacity on selected installations and evaluated it against the quantity of water produced. On many installations the operators have taken steps to upgrade the water treatment capacity due to increasing water cut. The volume of water produced in 1992 was 22.9 million cubic metres, up 31.7 per cent from 1991. Both the absolute volume of the water produced and its oil content vary from field to field. The total quantity of water produced on the Norwegian continental shelf will increase substantially in the coming years, so that treatment systems and capacities will have to meet strict requirements if discharge limits are to be met.

4.7 OTHER ENVIRONMENTAL ACTIVITY

The Directorate takes part in a range of national and international forums of significance for the protection of the environment. These activities allow us to influence their work and bring our opinions to bear. Another benefit is the competence they bring to the Directorate, enabling us to better attend to our responsibility in the field. The following are worthy of note:

- Governmental Action Control Group (AKU)
- Paris Commission's Working Party for Protection from Oil Pollution
- International Maritime Organization (IMO)
- The North Sea Offshore Authorities Forum (NSOAF)
- Environmental Northern Seas (ENS)
- Standardisation organisations CEN and ISO.

In 1992, the Directorate was a member of the technical committee of the NTNF research programme MUST, a programme for environment-friendly and profitable development of small petroleum fields. The programme itself will last for a five-year period starting 1993 and has an overall cost budget of Nkr 111 million.

The Directorate also administers and operates the scrap recovery programme for the North Sea which in 1992 had an operating budget of Nkr 4.5 million.

4.8 COOPERATION WITH THE STATE POLLUTION CONTROL AUTHORITY

As provided in the assumptions underlying the supervisory regime for the petroleum activities, the Directorate coordinates the practical implementation of supervision efforts by both the Directorate and the State Pollution Control Authority (SFT) under their respective mandates, namely the Pollution Control Act and the Petroleum Act, including coordination of duties in connection with the issue of consents and discharge permits. The Directorate undertakes the supervision of the operators' systematic efforts to meet the requirements in the Regulations for *Licensee's Internal Control*, the Regulations for *Implementation and Use of Risk Analyses* and the Regulations for *Emergency Preparedness*, which have been prepared by both agencies.

In its coordination role the Directorate must evaluate the cost and safety aspects of actions contemplated by the pollution control authorities insofar as they may be of significance for the petroleum activity.

Also, the Directorate must, in cooperation with the State Pollution Control Authority, prevail on the industry to engage in environmental experience exchange programmes. The aim is to help the incubation of solutions which are at the same time effective and economic.

The Directorate also assisted the State Pollution Control Authority in the staging of pollution control exercises.

5. Special Reports and Projects

In 1992, the Norwegian Petroleum Directorate appropriated a total of Nkr 19,745,363 for special projects. Of this amount, Nkr 6,450,262 was budgeted for projects in the Safety and Working Environment Division and Nkr 12,174,752 for projects in the Resource Management Division.

Another Nkr 4,503,062 was committed to the North Sea Seabed Clearance project. Nkr 4,120,458 was made available for collection of meteorological and oceanographic data in the Barents Sea, under the auspices of the Directorate; while the PROFIT programme administered an additional Nkr 21,325,404 in the year.

The titles of the projects and the various institutions carrying them out are reviewed below.

5.1 RESOURCE MANAGEMENT DIVISION

5.1.1 Exploration Department

PROJECT TITLE	EXECUTIVE INSTITUTION
Continued Development of Resource Database	Opheim Data A/S
Three-Dimensional Acquisition Parameters	Seismograph Service Inc
Database for Sealing Faults	Geo-Recon A/S
External Biostratigraphic Dating	Continental Shelf and Petroleum Technology Institute (IKU Petroleumsforskning a.s), K. Perch-Nilsen, Institute of Energy Technology (IFE), CB Magneto
Isotope Analyses of Early Permian Reef Carbonates in Barents Sea and on Bear Island	Institute of Energy Technology (IFE)
Field Work on King Charles Land, Svalbard	University of Oslo, Statoil, Norsk Hydro, Norwegian Petroleum Directorate (NPD)
Geochemical Assays	University of Oslo, University of Nottingham
Correlation of Metal-in-Oil Studies with Source Rock	Rogaland Research Institute (RF)
Laboratory Studies of Formation and Primary Migration of Hydrocarbons	IFP
Laboratory Studies of Secondary Migration	Continental Shelf and Petroleum Technology Institute (IKU Petroleumsforskning a.s)
Selected Projects on Late Tertiary Land Rise and Erosion	
– Svalbard Traverse and Ponam Project	Norwegian Polar Research Institute
– Miocene and Pliocene Sedimentation and Paleoecology on Vøring Plateau	University of Bergen
– Paleogeography and Land Rise	University of Bergen

Continued Development of Resource Database
The keeping of resource accounts is one of the Exploration Department's most important duties. The latest version of these computer-based accounts is called PROFF. This project aimed to improve the reporting facilities in the base and interface it with other databases of interest.

Three-Dimensional Collection Parameters
One of most important geophysical tools in the offshore industry is three-dimensional seismic survey. This project, conducted jointly with Statoil, aimed to optimise 3D data collection methods so as to ensure adequate data quality without excessive cost.

Database for Sealing Faults
The properties of sealing faults are crucial in any evaluation of a prospect, discovery or field. The ordered compilation of relevant data will help improve our understanding of these geological features. The project is run jointly by Statoil, Norsk Hydro, Saga and the Directorate.

External Biostratigraphic Dating
This project dates specimens using dating methods which are outside the competence of the Directorate, such as magneto-stratigraphy and strontium isotope analysis.

Isotope Analyses of Early Permian Reef Carbonates in Barents Sea and on Bear Island
Isotope studies have been performed on Early Permian reef sediments to elucidate the digeneous history of the sediments. The tests were run on core specimens from the Barents Sea and materials collected by the Directorate on Bear Island.

Field Work on King Charles Land, Svalbard
In August 1992, the Directorate conducted ten days of scientific field work on King Charles Land, an island group off Svalbard, with researchers from the Directorate, University of Oslo, Statoil, Norsk Hydro, and Saga Petroleum. The objective was to improve our understanding of the islands' geology and extrapolate the findings into the realm of marine seismics.

The expedition carried out a very wide range of geological field work covering sedimentology, macro palaeontology, structural geology and vulcanology.

Four hundred specimens were recovered from the Late Triassic to Early Cretaceous on Kings Island and Swedish Island, the main islands in the group.

Extensive post-analysis has been initiated in which the Norwegian oil establishment and various research centres are cooperating. The results will be published.

Geochemical Assays
This project covers a complete geochemical assay of the geological specimens recovered by the King Charles Land expedition; and the cores from borehole 6607/5-2 directly west of Sandnessjøen on a rise called Bodøhøgda in the Norwegian Sea.

Correlation of Metal-in-Oil Studies with Source Rock
The metal content of oils and shales from wells on Haltenbanken was analysed to study whether it is feasible to use such analyses in an attempt to correlate different crude compositions and crudes with particular source rocks. This is a supplement to the other geochemical correlation methods.

Laboratory Studies of Formation and Primary Migration of Hydrocarbons
By employing a pressure cell designed to study how hydrocarbons are formed and how they migrate from the source rock, tests were made to study the influence of pressure, temperature and time on the process. Also the type and saturation of the organic substrate was measured. The study is conducted jointly with Statoil.

Laboratory Studies of Secondary Migration
Using a test rig an experimental study has been performed of the quantification of migration rates and oil saturation under secondary migration of oil in an aquifer. Studies were also made of the way the secondary migration depends on pore size and perviousness of the rock. This study is a joint project in conjunction with Statoil.

Selected Projects on Late Tertiary Land Rise and Erosion

- **Svalbard Traverse and Ponam Project:** The Directorate takes part in this project which is a collaboration between several Norwegian and foreign research institutes. Its purpose is to study the Late Cenozoic development in the North Atlantic. The Norwegian contribution should aid our understanding of the mechanisms behind land rise and erosion in the Barents Sea.
- **Miocene and Pliocene Sedimentation and Paleoecology on Vøring Plateau:** This project aims to document the changing temperature in the Norwegian Sea for the past 6-10 million years in order to determine how the cooling process in the northern hemisphere took place and its effect on erosion and sedimentation rates.
- **Paleogeography and Land Rise:** Certain sediments and chemical deposits have been studied in a selection of caves in Nordland county. By correlating the sediments with those on the continental shelf it was possible to glean some information about the rates of land rise of the Norwegian mainland in earlier times.

5.1.2 Planning and Field Development Department

PROJECT TITLE	EXECUTIVE INSTITUTION
Seismic Interpretation of 15/12 Beta	Badly Earth Sciences Ltd
WAG Injection Heidrun	Intera
Field Simulation Sleipner Øst	Petec a.s
Petrophysical Interpretation of Embla and Visund	Petec a.s
PVT Analysis of Gas-Condensate Field	Scientific Software Intercom (SSI)
Reservoir Management Sleipner Vest	Petec a.s
Computer Tools for Dipmeter Interpretation	Z&S Consult
Eastern European Gas Market	Fridjof Nansen Foundation
Development of Gas Price Model	SNF
Process Simulation Programme	HYPROTECH
Simulation Model of Pipeline Network Flow	Scientific Software Intercom (SSI)
Further Development of INVERS Cost Database	Cap Computas

Seismic Interpretation of 15/12 Beta
A seismic interpretation of 15/12 Beta and the immediate area was carried out. The main purpose was to map the resources in the area. The findings will be used in reservoir technology tasks to follow, and in the evaluation of development plans for 15/12.

WAG Injection Heidrun
Intera reviewed the critical reservoir parameters for water-alternating-gas injection for the Fangst group on Heidrun. A sector model of the field was used to assess the potential for enhanced recovery using WAG in Fangst. The main aim was to identify the critical reservoir parameters by analysing WAG on Heidrun and quantifying the enhanced recovery potential.

Field Simulation Sleipner Øst
A new simulation model based on new mapping of Sleipner Øst has been developed to further assess gas injection in the field. Earlier studies showed that detailed modelling of the reservoir is essential. The aim was to analyse various injection strategies on the field based on the new reservoir model. The findings will be used in gas location studies and field development follow-up of Sleipner Øst.

Petrophysical Interpretation of Embla and Visund
Petec undertook a log interpretation of the wells on the Embla and Visund fields. The study also mapped permeability. The findings will be incorporated in the Directorate's field mapping.

PVT Analysis of Gas-Condensate Fields
Scientific Software Intercom (SSI) reviewed the procedures for selection of gas-condensate samples and analysis methods employed. The study aimed to ensure that the selected samples for pressure, volumetric and temperature testing from such fields are as representative of the reservoir fluids as possible. The consultant particularly assessed the samples from Sleipner Øst.

Reservoir Management Sleipner Vest
A review was made of the reservoir data from Sleipner Vest in order to determine how the uncertainties in reservoir specifications can be revealed using suitable reservoir management. The consultant submitted proposals for a data acquisition programme. The study aimed to prepare a data acquisition strategy from future production wells on the field.

Computer Tools for Dipmeter Interpretation
The Directorate has purchased an application programme called Incline-2 in order to analyse dipmeter logs. The programme offers interpretation of structural geology logs.

Eastern European Gas Market
This project aimed to compile information relating to the developments in Eastern Europe as they may affect Norwegian exports of natural gas. Political and economic factors of potential relevance to the gas market were one of the subjects of the inquiry.

Development of Gas Price Model
SNF has developed a model which takes into account the correlation of gas price and gas demand. The model will provide a basis for continued gas planning on the Norwegian continental shelf using the gas portfolio model.

Process Simulation Programme
In 1992, the Directorate purchased a computer application called HYSIM for the purpose of evaluating different treatment processes when developing new accumulations in the North Sea.

Simulation Model of Pipeline Network Flow
In connection with the evaluation of new gas sales contracts the Directorate has purchased TG Net, a computer programme which offers simulation by means of models of future gas sales via existing and projected pipeline networks.

Further Development of INVERS Cost Database
In 1992, the Directorate continued its work on an analysis tool for the INVERSE cost database. One of the uses of the computer tool is in connection with evaluation of cost estimates for new prospects.

5.1.3 Production and Operation Department

PROJECT TITLE	EXECUTIVE INSTITUTION
Chalk Research	NPD
Reservoir Studies of Eldfisk	Petec a.s
Reservoir Simulation of Ekofisk	Rogaland Research Institute (RF), Petec a.s
Enhanced Recovery from Sandstone Fields	Intera, Scandpower, Continental Shelf and Petroleum Technology Institute (IKU Petroleumsforskning a.s), Rogaland Research Institute (RF)
Seismic Interpretation of Ekofisk Area	Petrolet A/S
Core Analyses for Tor Field	Res Lab A/S
Laegerdorf	Geo-Recon A/S
SAFARI Data Acquisition	NPD, Saga, Statoil, Norsk Hydro. Consultants: Norwegian Computer Centre, University of Bergen, Geo-Recon A/S, University of Liverpool
International Standardisation Work	NPD
Water Flooding and Reservoir Souring	Capcis Manchester
Flowmeter for Oil, Gas and Water	Christian Michelsen Institute (CMI)
Ultrasound Fluid Flowmeters	Christian Michelsen Institute (CMI)
Multiphase Measurement	National Engineering Laboratories (NEL)
Coriolis Mass Flowmeter Project	National Engineering Laboratories (NEL)
Computer Subsystems for Fiscal Metering Systems	Simrad Albatross
Online Gas Chromatography	NPD
Reduction of Nitrogen Oxide Emissions from Petroleum Activity	R.M Parsons Ltd
Environmental Constraints on Petroleum Activity in Other Countries	DnV Technica

Chalk Research
The Norwegian Petroleum Directorate joined with the Danish Energy Agency to initiate this chalk research programme, which eleven oil companies are financing and implementing jointly. The programme aims to improve our understanding of chalk fields and use this understanding to improve recovery. The project chair was held by the Ministry of Energy in 1992. The Directorate was represented in the six technical committees and steering committee.

Reservoir Studies of Eldfisk
This project was a continuation of the 1991 project. Reservoir simulations of the northern structure in the field were performed, and different recovery mechanisms, such as gas injection and water flooding, were simulated. The results indicate that there are good opportunities for enhancing recovery from the field.

Reservoir Simulation of Ekofisk
In connection with the development and historical adaptation of the Ekofisk field simulation model, Petec a.s and Rogaland Research Institute were engaged as consultants. The simulation model will be used in the work of evaluating production strategies in connection with the review of the extended field study (UFS) for the field.

Enhanced Recovery from Sandstone Fields
The purpose of this project was to illuminate the potential for enhanced recovery from certain sandstone fields. Water-alternating-gas injection was examined for Gyda, Ula and Statfjord; and various enhanced recovery models for Cook phase II and Gullfaks were studied.

Seismic Interpretation of Ekofisk Area
This project embraced interpretation of three-dimensional seismic observations from fields in the Ekofisk area, with particular emphasis on fault patterns. Petrolet A/S carried out the project which terminated in 1992.

Core Analyses for Tor Field
Res Lab A/S undertook special core analyses in the period of Tor field cores on behalf of the Directorate. The purpose was to improve the underlying data (imbibition, capillary pressure, wetting properties and relative permeability measurements).

Laegerdorf
This cooperation project between the Directorate and eight interested companies was launched in 1990 and concluded in 1992. Consultants Geo-Recon A/S implemented the project, which sought to compile a three-dimensional fracture database using data collected from the Laegerdorf chalk quarry in Germany. The project aimed to provide a better understanding and description of fracture geometry in the chalk fields in the North Sea.

SAFARI Data Acquisition
This is a cooperation project involving Saga, Statoil, Norsk Hydro and the Directorate. The project covers collection of quantitative, geological data from sediments which are uncovered on land and which are analogous to sediments in the North Sea reservoirs. The project is compiling a database of quantified information on sedimentary and tectonic reservoir heterogeneities. The ambition is to reduce the uncertainties in reservoir descriptions and reservoir simulations for fields in the Norwegian sector.

International Standardisation Work
This project is concerned with participation in the work of the International Standardisation Organisation (ISO) for measurement and analysis of oil and gas. The work is of great significance in connection with the coming of the European Community's Internal Market, since the European CEN standards used in the EC are largely based on ISO standards.

Water Flooding and Reservoir Souring
This is a joint project by Norwegian and British oil companies and authorities. Execution of the project is done by Capcis at the University of Manchester and aims to explore possible measures to reduce or prevent reservoir souring in water flooded reservoirs. The project is also building up a database to help predict souring of specific wells. The project, which started in 1991, will be completed in 1993.

Flowmeter for Oil, Gas and Water
This project performs development trials for a measuring instrument able to measure water, oil and gas flow rates simultaneously. The project is run on a multiclient basis with participation by BP, Saga, Elf and the Directorate.

Ultrasound Fluid Flowmeters
Three different ultrasonic detectors are being tested in Norsk Hydro's Porsgrunn laboratory and Christian Michelsen Institute (CMI) to determine how accurate they are and how much influence minute quantities of gas and water in the fluids will have on instrumental accuracy and utility. This is a multiclient project in which Statoil, Saga, Norsk Hydro and the Directorate take part.

Multiphase Measurement
The project group for multiphase measurement consists of a multiple client consortium in which eight operating companies participate with the Directorate. The mandate was to develop a concept for measurement of multiphase flow based on known technology.

The work involved three phases:

1) Design and testing of equipment
2) Fabrication of prototype
3) Field testing of prototype.

After many of the sub-components had been duly tested with variable results it proved impossible to put a workable prototype together. NEL, the National Engineering Laboratories in Scotland, wished to continue the project but lack of support from the sponsors forced the project to close.

Coriolis Mass Flowmeter Project
This project continued where a previous project, combining the forces of Statoil, Total, Phillips, the Directorate, Kodak and the UK authorities, left off. It tested metering devices from many instrument suppliers which exploit the coriolis effect. The instruments were carefully screened for accuracy, installation effects, maintenance routines, etc.

Computer Subsystems for Fiscal Metering Systems
Phillips is building a new metering computer for Ekofisk 2/4-T, the Ekofisk tank. The system relies on new, complex technology, and the Directorate has signed a contract with Simrad Albatross to monitor the computer subsystem in the test phase.

Online Gas Chromatography
The aim of this project was to examine the experience of the various users in terms of technical solution chosen, analysis accuracy, and operating reliability of online gas chromatography systems. Various user groups in Norway and abroad were contacted.

The project acquired relevance when operating companies and equipment vendors started evaluation projects aiming to qualify GC instruments for fiscal metering.

Reduction of Nitrogen Oxide Emissions from Petroleum Activity
This project was carried out to determine the potential for reduced NO_x emissions from the offshore petroleum activities in Norway. A key aspect of the study was the survey of existing and upcoming technology for reducing such emissions, combined with an assessment of the utility of the various technologies and the costs of putting them into service.

Environmental Constraints on Petroleum Activity in Other Countries
This study identified the offshore-related environmental problems which representative countries in the various geographical regions have to face and the various environmental constraints that have been enacted as a consequence. The details obtained were analysed critically and the economic cost of the regulation relative to the environmental benefit obtained was assessed.

5.1.4 Data Management Department

PROJECT TITLE	EXECUTIVE INSTITUTION
Consulting Services for Release	Proffshore, Allservice, TK-Service
Petrophysical Quality Control	Petec a.s
Wet Sample Handling	Geco-Prakla
Well Data Summary Sheets	NPD
Maintenance and Hire of Computer Programmes	Various, see below
Further Development and Procurement of Computer Programmes	Various, see below

Consulting Services for Release
This project covers a range of activities associated with the reprocessing and preparation of materials for release. A consultant was engaged to run a check and correct the database for well trajectories and well identities. External contractors were also employed to help with copying and printing of catalogues and the various publications compiled.

Petrophysical Quality Control
To perform some of the preliminaries in connection with the overall improvement in log data quality from Norwegian exploration wells the services of external consultants were employed. The primary task in 1992 was to write detailed requirement specifications which will be used in the implementation of the main project in 1993.

Wet Sample Handling
In the year, many complimentary wet samples were received from Statoil from wells for which the Directorate's backup stocks for scientific analysis were running low. External consultants were used to pack and mark the samples in the prescribed manner so that storage and retrieval can proceed efficiently.

Well Data Summary Sheets
The Directorate's Well Data Summary Sheets, an annual publication listing released well data from the continental shelf, were behind schedule for some years. With the release in 1992 of volumes 16 and 17 and the preparation of material for volume 18, due for publication in January 1993, the series is now back on schedule. It details all exploration wells more than five years old.

Maintenance and Hire of Computer Programmes
To ensure that the Directorate's computer programmes are always operational and ready to perform technical and administrative duties for the Resource Management Division, maintenance contracts have been signed with the following firms: OIS Contracting, Andersen Consulting, Geodata A/S, IPEC, Intera, Calcep, Cap Computas, Sintef, Rogaland Research Institute, Current Software, and Geomatic.

Further Development and Procurement of Computer Programmes
So as to increase the availability of effective, modern applications, programmes have been purchased or developed from the following firms: Opheim Data, InfoPass, Geomatic, and ISI A/S.

Some of these firms also assist with the conversion of certain of the Directorate's older format systems from SIBAS to the UNIX platform.

5.1.5 RUTH Programme

PROJECT TITLE	EXECUTIVE INSTITUTION
Use of Surfactants	Rogaland Research Institute (RF)
Use of Polymers and Gels	Rogaland Research Institute (RF)
Microbial Methods	Rogaland Research Institute (RF)
Combined Gas and Water Injection	Continental Shelf and Petroleum Technology Institute (IKU Petroleumsforskning a.s)
Use of Foam	Rogaland Research Institute (RF), Continental Shelf and Petroleum Technology Institute (IKU Petroleumsforskning a.s)
Gas Flooding	Continental Shelf and Petroleum Technology Institute (IKU Petroleumsforskning a.s)

RUTH, the research programme for *Reservoir Utilisation Using Advanced Technological Help*, was launched in 1992 and will last for four years, ending in 1995. The programme aims in the first place to contribute to the enhanced recovery of oil, but also to enhance the Norwegian research establishment. The overall budget is approximately Nkr 110 million, of which the State, through the Royal Norwegian Council for Scientific and Industrial Research (NTNF), will provide Nkr 60 million. The balance comes from the oil companies. At year end there were 17 corporate sponsors.

RUTH is organised into six sub-programmes as shown in the table above, representing the six recovery methods which may help enhance recovery from Norway's offshore fields. Rogaland Research Institute and IKU Petroleumforskning a.s have been nominated to have main responsibility for the sub-programmes, though links have been forged with many other research centres. Each sub-programme contains multiple sub-projects.

In 1992, roughly Nkr 20 million was spent on the programme. The first of the scheduled technical seminars was held in the Directorate in December and assembled approximately 120 participants from six countries.

RUTH is an NTNF programme headed by the Directorate. Fuller details are presented in a special brochure.

5.1.6 PROFIT
The *Programme for Research into Field Oriented Improved Recovery Technology* was launched in 1990. In it the Directorate takes part on an equal footing with 13 oil companies to finance and manage the agenda. The research is largely undertaken at Norwegian institutes.

Profit has a maximum budget of Nkr 90 million. Two projects have been initiated so far, with a budget of Nkr 68 million for the five-year period 1990-94. They examine:

- Reservoir specification
- Near-well flow.

Research for roughly Nkr 18 million was performed in 1992. The results of the first two years of research were presented at a seminar held in the Directorate in February 1992. The Directorate administers the programme. A special brochure provides further details.

5.2 SAFETY AND WORKING ENVIRONMENT DIVISION

PROJECT TITLE	EXECUTIVE INSTITUTION
Membership of Welding Institute	Welding Institute (WI)
Membership of Marine Technology Directorate	Marine Technology Directorate (MTD)
Membership of Norwegian Electrical Engineering Committee	Norwegian Electrical Engineering Committee (NEK)
Petroleum Operations North of 74°30'N	NPD
Manned Underwater Operations, International Cooperation	NPD
Working Environment for Divers	Foundation for Scientific and Industrial Research at University of Trondheim (SINTEF)
Jack-up Site Assessment Procedures	Noble Denton Associates (NDA)
Worldwide Offshore Accident Databank, WOAD	Det norske Veritas (DnV)
Hydrostatic and Dynamic Pressure Modelling for High-Pressure, High-Temperature Deep Wells	Rogaland Research Institute
Gas Safety Programme	Christian Michelsen Institute (CMI)
Technical and Operational Aspects of Manned Underwater Operations	Oceaneering
Internal Control in companies in Norway	Sintef
Design Curves for Fatigue of Cathodic Protected Structures	Sintef
Maintenance of Formula PS Planning Tool	Norsk Data
Kick Tests with Horizontal Wells	Rogaland Research Institute (RF)
Maintenance Management	Sintef
Ductility of High-Strength Concrete	Sintef
Qualification of Welding Joints	Sintef
High-Strength Concrete, Phase 3	Sintef
Corrosion and Erosion in Piping for Process and Auxiliary Systems	Sintef
Data Communications, Implementation of a New Concept	Info Pass Software
Accident Reporting	Rogaland Research Institute (RF)
Revision of DnV's Offshore Standard RPB 401	Det norske Veritas (DnV)

PROJECT TITLE	EXECUTIVE INSTITUTION
Utilisation Factor for Permissible Stress in High-Strength Pipe Materials	Sintef
Safety and Environmental Aspects of Gas Release	Thule Engineering
Reliability Design Codes for Offshore Pipeline Systems	Sintef
Understanding Pressures and Temperatures during drilling under Extreme Conditions	Rogaland Research Institute (RF)
Drilling in Deep Water	Rogaland Consultants
Working Hours Arrangements Offshore	Rogaland Research Institute (RF)
Connection between Risk Analysis and Preparedness Analysis	DnV Technica
Programme for Research and Development in Diving Technology and Diving Medicine (FUDT)	Sintef, through Norwegian Underwater Technology Centre (Nutec)
Technical Fire Characteristics of Surface Materials	Sintef, through Norwegian Building Research Laboratory (NBL)
Smoke Protection in Living Quarters	Partner Consult
Project for Multiphase Research (PROFF)	Norwegian Institute of Technology (NTH), Sintef, and others
Use of Coiled Tubing Techniques	Smedvig IPR
High Strength Steel in Offshore Engineering	Cranfield Institute of Technology
Evaluation of Opportunities using New Computer Technology	NPD
Ekofisk Fields in a Long-term Perspective	Sintef
Evaluation of Standard for Breathing Apparatus for Divers	Nutec

Membership of Welding Institute
The Directorate has been a member of the Welding Institute in Great Britain since 1981. WI is the leading authority in the offshore field and is very energetic in research, training and consultancy. Membership qualifies for consultancy services, project participation and current information on the latest developments in materials technology and welding engineering.

Membership of Marine Technology Directorate
Since 1980, the Norwegian Petroleum Directorate has been a member of the British Offshore and Underwater Engineering Group (UEG), formerly a subdivision of the British Construction Industry Research and Information Association (CIRIA). The group has now joined the Marine Technology Directorate (MTD). The projects administrated by the organisation are very pertinent to the Norwegian Petroleum Directorate's duties in this sphere. Cooperation and availability of information have been of tremendous assistance for safety reports, regulatory drafting, and competence building. The Norwegian Petroleum Directorate is a member of a project concerned with operative inspection of structures and installations underwater.

Membership of Norwegian Electrical Engineering Committee
The Directorate's membership of the Norwegian Electrical Engineering Committee (NEK) is designed to ensure that regulations in the electrical enginee-

ring field are continually under revision and keep pace with technological advance, international practices, and experience. The importance of these factors is underscored by Norway's effort to meet the prescriptions of the Agreement on Technical Barriers to Trade in EFTA and the EC.

The Directorate also takes part in national and international cooperation for preparation of new regulations. This work is headed by NEK.

Petroleum Operations North of 74°30'N

This project started by looking at the risk of encountering drift ice at selected positions in the Barents Sea. Also, the distance to the ice edge and the length of ice-free periods was analysed. In an earlier phase the project studied the collision risk and probable size of icebergs in the area. In 1992, the project evaluated the supervision options available and looked at possible subsidiary audit measures.

Manned Underwater Operations, International Cooperation

This project aims to continue and expand the established international cooperation in the fields of: safety and the working environment; standardisation of regulatory requirements; and guidelines for and enhancements to technical systems for manned underwater operations. The project, which has been continuing for several years and has produced invaluable results, is of great significance for current and future underwater operations.

Working Environment for Divers

Former projects under the auspices of the Directorate, using only modest resources, produced valuable results of considerable practical importance in relation to the working environment for divers. In 1992, the project developed guidelines for ergonomic aspects of the bell control room and in this regard particularly concentrated on the man-machine interface in the control room.

Jack-Up Site Assessment Procedure

Noble Denton Associates (NDA) have identified major discrepancies in the calculation methods (use of parameters) and philosophies of the various companies and institutions for assessing jack-up rigs. In this project the overall target is to arrive at international procedures for this sort of assessment which are acceptable to all concerned. International standards should introduce greater predictability for the industry and the authorities. The project agenda has hitherto been concerned with compiling and evaluating background materials.

Worldwide Offshore Accident Databank, WOAD

This project is an annual subscription to the WOAD database, which is a systematic directory of accidents from petroleum operations worldwide. The root base is managed by Veritec, which compiles and updates data on accident events on a current basis.

Hydrostatic and Dynamic Pressure Modelling for High-Pressure, High-Temperature Deep Wells

This project is a continuation of the examination of deep wells started in 1989. Based on thermodynamic data (pressure, volume and temperature) and HPHT rheology data for the various well fluids, an exact model will be developed to calculate downhole pressure on the basis of well tightness and rheology. Work in 1992 concentrated on acceptable safety constraints for exploration and production drilling.

Gas Safety Programme

Christian Michelsen Institute (CMI) in Bergen has studied explosion risks in offshore modules. The work continued in 1992 with the support of certain oil companies and government agencies. The work has three parts:

- Experimental test programme
- Improvement of FLACS computer programme for simulation of blast pressure (flame acceleration)
- Application of safety technology.

The project will last three years and has a budget framework of Nkr 30 million.

Technical and Operational Aspects of Manned Underwater Operations

From experience we know that there are still technical and operational aspects of manned underwater operations which could be improved. The project highlights problems in emergency systems for divers. Other highlights are emergency diving bell battery capacity, emergency training for diving personnel, and depth monitoring of divers.

Internal Control in companies in Norway

So far the Internal Control project has achieved the following:

- Determined if internal control has had a generally positive effect, and identified any difficulties it has encountered
- Offered documentation of solutions to problems in selected companies
- Referred good and bad experiences back to the companies
- Developed evaluation tools to enable companies to evaluate their inhouse introduction of internal control
- Provided substance for supervisory agencies' follow-up of implementation and enforcement of internal quality control systems in the industry.

The project is a major collaborative effort with the Confederation of Industry (NHO) and NTNF.

Design Curves for Fatigue of Cathodic Protected Structures

The Directorate is one of the participants in a Sintef project backed by the oil industry. The objective is to determine the effects of cathodic protection on the fatigue lifetime of welded tubular nodes. The design curve for cathodic protected structures in the Directorate's *Regulations for Loadbearing Structures* will if necessary be reviewed in the light of the project results.

Maintenance of Formula PS Planning Tool
A computer-based planning tool has been developed which will provide management with the necessary overview of planned activities and their interdependence. The tool will also rationalise the allocation and utilisation of human resources for the Directorate's supervisory and other duties. Maintenance of the programme was assisted by outside expertise.

Kick Tests with Horizontal Wells
The numbers of horizontal wells drilled in Norwegian waters are expected to grow, and one difficulty with such bores is how to deal with a gas kick. This project staged a full-scale test which produced answers to many of the issues that were raised in connection with well behaviour during a well kick and methods of detecting and tackling such eventualities.

Maintenance Management
Proper maintenance is crucial to safety. The increasing age of many installations in the North Sea is bringing the problem ever closer.

The Directorate's supervision shows that there sometimes exist serious defects in the maintenance systems of some operators. They also show that the petroleum industry is not a leader when it comes to utilising new maintenance technology, compared for example with land-based industry where maintenance is a prerequisite for safe operation and sound economy.

The need to improve the management of maintenance has led us to look at new types of maintenance technology and identify the most critical equipment in service with the operators.

The Directorate's objective for this project is to develop the competence required in the maintenance discipline, principles of cost-effective engineering, and furtherance and implementation of maintenance systems. The project aims also to contribute technical expertise for regulatory drafting, enabling the Directorate's requirements and expectations for maintenance management to be duly amplified.

Ductility of High-Strength Concrete
This project helped develop high-strength, high-ductility concrete for applications in structures which may experience particular stresses, such as impact, pressure shock, earthquake, heat and cold. The development of specifications for design and structural shaping of high-strength concrete exposed to particular stresses was also examined. The following were involved with the Directorate: NTNF, Norwegian Contractors, Norske Shell and the Norwegian Army Construction Service.

Qualification of Welding Joints
This project developed new standards for fabrication specifications, qualification routines and quality control of welded seams. The project also collated requirements which the authorities (the Directorate) and clients (the operating companies) prescribe on materials technology and welding technology grounds.

The new European standards for welding procedures, mechanical testing of weld seams, and accreditation of workshops and welders were incorporated by reference. The project helps continue the standardisation work in welding and materials technology already started.

The Norwegian Welding Technology Association and Sintef took the initiative for the project which, besides NTNF and the Directorate, attracted input from shipyards and workshops, engineering consultants, and offshore operators.

High-Strength Concrete, Phase 3
This project is a continuation of the preliminary project in 1986, phase 1 in 1986-88, and phase 2 in 1989-90. In 1992, the project compared the data obtained in phases 1 and 2 with high-quality data available from other parts of the world. The project also included additional experiments.

The results of phases 1 and 2 comprised a major part of the documentation which underlies the new Norwegian Standard NS 3473 for concrete. This standard is currently considered the most advanced standard for high-strength concrete in the world.

The project was carried out by Sintef's FCB section in Trondheim and attracted considerable support from the industry. The 1992 budget was Nkr 7.1 million.

Corrosion and Erosion in Piping for Process and Auxiliary Systems
This project developed a summary of internal and external corrosion and erosion problems in piping systems. The need to develop better corrosion protection was also examined. The project will examine such issues as when and where corrosion and erosion arise, and how the associated problems can best be handled. The project lasted two years and provided valuable information on the mechanisms of corrosion and erosion in piping systems.

Data Communications, Implementation of a New Concept
In an earlier preliminary project various alternatives were examined for upgrading the Directorate's data communications for data reporting from the oil companies. This project examined the implementation of new communications software. Consultants augmented our inhouse expertise.

Accident Reporting
This project was implemented after an internal preliminary project in order to identify a more consistent system for operator reporting of various types of

accident and hazard situations to the Directorate. Rogaland Research Institute carried out the project jointly with internal expertise.

Revision of DnV's Offshore Standard RPB 401
This joint work by many operators and the Directorate and Det norske Veritas reviewed and corrected the standards for cathodic protection designated Veritas RPB 401. Experience from ten years of operation has been incorporated in the revised edition. The Directorate's guidelines for cathodic protection build on the DnV standard.

Utilisation Factor for Permissible Stress in High-Strength Pipe Materials
The Directorate's *Regulations for Pipeline Systems* set out the maximum utilisation factor for permissible stress in rigid steel pipes. The factors as currently listed are for carbon steel. In recent years pipelines on the Norwegian continental shelf have started using high alloy duplex steels, which behave differently under tension. In this project Sintef evaluated and recommended criteria for utilisation factors when using high metallurgy steels. The results will be implemented in the Pipeline Regulations.

Safety and Environmental Aspects of Gas Release
The sharpened focus on harmful ecological effects caused by offshore emissions may represent a conflict between safety concerns and environmental targets. The operators are examining various alternatives for reducing the emissions. In connection with this work it is necessary to elucidate the safety and environmental aspects of the various options. This will provide a sound foundation for the Directorate's evaluation of solutions proposed. The project examined safety, environmental, and economic aspects of the various solutions. The Directorate's consultant for the project was Thule Engineering.

Reliability Design Codes for Offshore Pipeline Systems
In designing pipelines some of the concerns are wall thickness, stress during installation and residual strain, and the stability of the line on the seabed. The criteria set out in today's standards entail a safety margin which in some cases is too conservative, leading to inconsistent safety. Factors affecting the safety margin are water depth, bottom topography and stability to erosion, medium transported, and any accident loads that might arise.

The project developed proposals for a design method based on reliability. This means that one starts from certain limiting values for the various irregularities that might arise. The project was carried out under Sintef.

Understanding Pressures and Temperatures during drilling under Extreme Conditions
The drilling of high pressure wells involves particular operational and safety problems. For one thing the kick frequency is significantly greater. This project will advance our understanding of the problems involved, allowing safety to be improved while drilling into high pressure areas.

The work is divided into four phases. In phase 1, field measurements were taken of relevant high pressure wells in which water based and oil based drilling mud had both been used. In phase 2, tests were run on ten different drilling muds in the laboratory and a databank was compiled. Phase 1 and 2 will be continued and phase 3 and 4 will commence in 1993.

The project, carried out by Rogaland Research Institute, has participation from six oil companies, NTNF, the UK Health and Safety Executive, and the Directorate. The project results will help further the Directorate's *Guidelines for Drilling of Deep High Pressure Wells* in several key respects.

Drilling in Deep Water
During the present decade, blocks on the continental shelf can be expected to be awarded in deep water (1000 to 2000 metres). Drilling at such extreme depths approaches the limits of what is feasible using the known art. Before such awards can be made, the problems of this type of drilling must be elucidated so that operational constraints can be drawn up in advance.

This project gives an account of the problems envisaged in deep water drilling. The prevailing climatic and geological conditions on the parts of the Norwegian continental shelf in question are also considered. The Directorate's consultant for the project was Rogaland Consultants.

Working Hours Arrangements Offshore
The aim of this project was to define the consequences of alternative working hour arrangements for offshore personnel. Rogaland Research Institute identified the rotation schemes actually employed and reviewed the research already carried out in the field and its main conclusions. Based on this review the project will assess whether a wider HSE project, making a deeper analysis of the consequences of alternative working hours arrangements for health, safety, and the working environment, should be undertaken.

Connection between Risk Analysis and Preparedness Analysis
The criteria in the *Risk Analysis Regulations* and the *Emergency Preparedness Regulations* are very similar for Risk Analysis and Emergency Preparedness Analysis, respectively. They also make similar demands regarding preparation of risk acceptance criteria and preparation of specific requirements for preparedness. The Risk Analysis Regulations demand that risk-reducing measures should wherever possible take priority over consequence-reducing measures. The Emergency Preparedness Analysis aims to determine the most suitable measures to meet the activity's specific preparedness requirements.

This project examined the links between the acceptance criteria for risk and the specific requirements for preparedness. The project also described in depth methods that can be applied to meet the demands in the two regulations. Further, the project provides important impetus for training, both in the industry and in the Directorate, and will promote a better understanding of the intentions of the Emergency Preparedness Regulations in the establishments which perform risk analyses. The Directorate's consultant for the project was DnV Technica.

Programme for Research and Development in Diving Technology and Diving Medicine (FUDT)
The Directorate participates jointly with Statoil, Norsk Hydro and Saga in this diving technology and medicine programme. The project's main aim is to develop the necessary expertise in diving technology to ensure that future underwater operations can be executed safely and cost-effectively. The total annual expenditure budget for the project is about Nkr 15 million, and both the volume of resources committed and the organisation of the project indicate that considerable advances will be made by project completion.

Technical Fire Characteristics of Surface Materials
Following the conflagration on the car ferry, *Scandinavian Star*, tests were made of the plastic laminate sheeting erected on walls and ceilings, which were of purported non-flammable material. The tests showed that the surface material considerably aided the spread of fire and heat build-up, and that the combustion gases contained significant amounts of toxic gases.

The sheeting had been certified and approved under internationally recognised standards. Accordingly, Sintef, through the Norwegian Building Research Laboratory (NBL), tested surface coverings for use in offshore living quarters under comparable conditions. The Directorate accepts documented compliance with recognised standards as sufficient documentation of technical fire characteristics and therefore joined the project to clarify the problems in this context.

Smoke Protection in Living Quarters
The lessons of the Piper Alpha disaster on the UK shelf indicate that air quality protection in living quarters during an external fire has not been adequate. Partner Consult used this project to examine existing ventilation conditions in case of fire, and evaluated the need for solutions that would secure acceptable air quality during a fire.

Project for Multiphase Research (PROFF)
This project is carried out by Sintef through the Norwegian Institute of Technology (NTH), Veritec, the University of Oslo, and others, for the development of knowhow and methodologies for multiphase transportation over medium and long distances. The project is split into sub-projects to examine multiphase flow technology, streaming effects, material selection, and equipment. The project is steered via NTNF and enjoys substantial support from the operating companies and other industry. The 1992 budget was Nkr 16.6 million. The project aims to develop reliable methods for predicting the effects of shut-downs and start-ups on flow patterns, corrosion and erosion, hydrate formation and wax formation.

Use of Coiled Tubing Techniques
Use of coiled tubing is increasing and it is essential to keep up to date on developments of equipment, systems and use. This project concentrated on topside equipment, coiled tubing, relevant strength calculations, equipment rigging, pressure testing and barrier issues.

High Strength Steel in Offshore Engineering
This project was carried out at the Cranfield Institute of Technology in the UK and is a major collaborative venture with participation by many countries. On a broad basis the project has studied the properties of modern high strength steels in practical applications in the offshore environment. Even the very latest high strength steels, such as Japanese titanium dioxide steel and European fast cooled steel were examined. Modern high strength steels have a higher ratio of yield point to strength, enabling them to be used closer to the ultimate strength. The project studied steels with yield points from 500 MPa and up; while the Directorate's current guidelines cover steels of up to that strength.

One of the factors studied was the effects of sulphate reducing bacteria (SRB) on high strength steels; another the properties of weld metals used to join such steels.

Evaluation of Opportunities using New Computer Technology
The Directorate's computer strategy involves moving away from terminal workstations to powerful PCs. This change-over eases access to information on other inhouse machines and allows information to be presented more suitably. The project helps build up our competence in available computer technology with a view to looking after our internal needs for computerised information systems, which we rely on for regulatory revision and drafting, supervision and supervisory audits, and data used in connection with safety and working environment concerns. The project aims to render existing information more easily accessible and to optimise the use of administrative data processing in case handling with the aid of integrated, readily available applications.

Ekofisk Fields in a Long-term Perspective
The Directorate feels the need for assistance in its evaluation of long-range unified plans for the Ekofisk fields. This project particularly addressed the 2/4-T (Ekofisk tank) installation, which is a key node for Norwegian oil and gas exports. The project is raising a report that will form part of the back-

ground for the authorities's requirements and criteria when the long-term solution is selected, specifically:

- Risk acceptance criteria reflecting the nodal function of the installation in the export context
- Operating regularity requirements compatible with the interests of the operator, third-party users, and the Norwegian state.

Sintef organised the implementation of the project in 1992.

Evaluation of Standard for Breathing Apparatus for Divers
The International Association of Offshore Diving Contractors (AODC) issued in autumn 1992 a draft for an expanded industry standard for evaluation of breathing apparatus for divers. The British authorities were positive to the draft. AODC is planning to propose that the standard be adopted and issued as the European Community's standard under the EC Directive for Personal Protective Equipment. The Directorate hopes to become involved in the work and to influence the final outcome, and commissioned Nutec to make an in-depth review of the draft to make sure that it meets the Directorate's requirements for breathing apparatus, and propose any additional matters that should be incorporated or addressed more fully in the new standard.

5.3 ADMINISTRATION DEPARTMENT

PROJECT TITLE	EXECUTIVE INSTITUTION
North Sea Seabed Clearance	NPD

North Sea Seabed Clearance
The Directorate's seabed clearance project concentrated in 1992 on the Tampen area and parts of the Snorre field, directly west of Florø. The area, covering 1202 square kilometres, was chosen on the advice of fishery organisations and fishery authorities. Exploration drilling has been proceeding in the area since 1978. The Compensation Board for Loss of Fishing Gear has heard several compensation suits for gear lost or damaged during fishing operations in the area.

Wires of various sizes, fishing implements and assorted chains were recovered from the seabed with a total weight of about 100 tons.

Again in 1992, the Norwegian Hydrographic Service's survey vessel, *M/S Lance*, was used to chart the bottom by sonar. The clearance contract was awarded to Stolt-Nielsen Seaway A/S, of Haugesund.

The clearance project executive committee was made up of representatives from the Norwegian Petroleum Directorate, Directorate of Fisheries, Norwegian Hydrographic Service, Association of Fishermen, and Oil Industry Association.

6. International Cooperation

6.1 BILATERAL COOPERATION

The Norwegian Petroleum Directorate engages in bilateral cooperation with the authorities of other nations in connection with the follow-up of treaties governing safety and resource management.

Agreements have been signed with the respective authorities regarding procedures for supervision of pipelines in respect of safety and the working environment. With the countries in which oil and gas are landed from the Norwegian continental shelf, agreements are in place for the performance of metering inspections.

The Directorate has also established general bilateral cooperation with authorities in certain other countries in order to promote experience transfer and exchange in the safety and resource management field. Such arrangements are in force in particular between Norway and the offshore authorities for the United Kingdom and Danish continental shelves.

6.1.1 North Sea Offshore Authorities Forum (NSOAF)

In the field of safety management the Directorate participates in the North Sea Offshore Authorities Forum (NSOAF) in which all North Sea basin countries are represented.

This Forum established two working groups in May 1992 in which the Directorate is represented. One of them will consider whether a NSOAF plan should be drawn up to encourage mutual acceptance of other member authorities' methods of documenting compliance with their national regulatory demands. An example is the «Safety Case», which is specific to each mobile unit. This group has a Norwegian chairman.

The other, under a Danish chairman, will seek to harmonise safety training requirements in the respective North Sea countries.

6.2 AID TO FOREIGN COUNTRIES

6.2.1 Aid through NORAD

The Directorate's association with NORAD, the Norwegian Directorate for Development Cooperation, started as long ago as 1975 in connection with an enquiry by Tanzania regarding Norwegian technical assistance to evaluate a gas discovery on the island of Songo Songo. This cooperation evolved to embrace all sorts of professional assistance in the petroleum sector in countries where Norway, through Norad, has development programmes. To ensure flexibility and efficiency in the relations between beneficiary and Norway, and between the Norwegian institutions, a cooperation agreement was signed in 1986 between the Directorate and Norad in which the professional and administrative guidelines were established. One key element of the agreement is that the Directorate can provide assistance over the whole range of its professional competence. For beneficiaries it is particularly significant that the Directorate is proficient in its field and commercially unbiased. The annual scope of the assistance was for a long time four man-years, though in 1992 this was reduced to three.

Up to the present the Directorate has rendered assistance to about 20 different countries. This assistance has covered almost all administrative spheres of activity of the Directorate, though the general trend has been to focus on activities related to the exploration for petroleum. Everything from considered advice on the general organisation of exploration efforts and result monitoring regimes, to pure technical assistance with acquisition, storage, interpretation, evaluation and sale of geophysical and geological data, has been covered. More and more assistance has been given in projects associated with development of petroleum accumulations and transportation of the volumes recovered, and projects to do with safe operations. The trend is likely to continue for many years to come.

Some of the Directorate's assistance is with the training of personnel in certain limited disciplines. Training of this kind is directed to a single country and is given both in the cooperating institution in close association with Directorate experts who stay there for short periods, and in the Directorate in Norway where personnel from the cooperating institution learn job-related skills. Although the Directorate does not arrange set courses for this type of training, special arrangements are worked out for the particular situation in hand and to meet special needs. Training of administrative personnel of a more general kind is provided by Petrad through its courses and seminars.

In 1992, the Directorate engaged in development cooperation with Tanzania, Namibia, Yemen, Bangladesh, Nicaragua, and Costa Rica. Assistance was also given to the Committee for Coordination of Joint Prospecting for Mineral Resources in Asian Offshore Areas (CCOP), an organisation covering 11 countries in Southeast Asia, and the Economic and Social Commission for Asia and the Pacific (ESCAP), the latter in conjunction with CCOP.

The Directorate's duties in 1992 included overseeing consultants for such services as: seismic data acquisition, processing and reprocessing; seismic interpretation and computer systems maintenance;

transfer and storage of seismic data; development and implementation of archival systems and routines and the training of archive personnel; advice in connection with resource evaluation; evaluation and advice in connection with preparing regulations for onshore and offshore petroleum activities; and general guidance in connection with the execution of projects.

The Directorate concentrated its commitments in 1992 on the following countries:

a) Bangladesh
The Directorate works in conjunction with the Bangladesh Petroleum Institute (BPI) on the development of the institute to become a professional advisory body to the Ministry of Energy and Mineral Resources. These duties comprised assistance with the operation and maintenance of hardware, and the development of training schemes in the use of the seismic processing systems and their implementation. To expedite this the Directorate engaged an assistant for a two-year period from summer 1991 in Bangladesh. The Directorate also headed the closure of a contract with a hardware systems maintenance and repair firm. It also acted as advisor for the reprocessing of seismic data, and the mapping and appraisal of a gas field.

b) Namibia
The Directorate collaborates with the National Petroleum Corporation of Namibia (NAMCOR), many of its duties being connected with the planning and realisation of a records management system for administrative data, and the training of personnel to use it. The Directorate was also the technical advisor for acquisition of aero-magnetic data, reprocessing of seismic data, acquisition and processing of seismic data, and negotiations with and follow-up of performance by contractors.

The Directorate attended the Safety Seminar in Windhoek concerning the drafting of laws and regulations for the petroleum activity. The Directorate also played host to a delegation from Namibia including representatives from the Ministry of Mines and Energy (MME) and NAMCOR.

c) Nicaragua
The Directorate works in collaboration with the Nicaraguan national energy office, *Instituto Nicaraguense de Energia* (INE), to carry out a campaign for petroleum exploration on the Nicaraguan continental shelf. This work is performed by Geco-Prakla and is followed up by the Directorate on behalf of INE. The task of compiling data packages for the campaign is also overseen by the Directorate.

d) Tanzania
The Directorate works together with the Tanzania Petroleum Development Corporation (TPDC) and in 1992 concentrated its efforts on the reformatting of seismic data stored by Rockall Ltd in Tananger, Norway, into a more serviceable format for permanent conversion and storage at TPDC in Tanzania. The Directorate has assisted with and followed up the reprocessing of older seismics from the Rufiji area. Once reprocessed these data were interpreted by TPDC personnel during a long stay at the Directorate in connection with control of the reformatted data. The Directorate also assisted with the interpretation, reconditioning and presentation of the data. The Directorate was also involved in connection with the evaluation of Norway's assistance to the petroleum sector in Tanzania by Nopec, a company on contract to Norad.

e) Yemen
Early in the year the Directorate concluded its Yemen project concerning the training of personnel (carried out in 1991) and the evaluation of environmental and safety-related issues in connection with oil operations. The results of the evaluation were reported to the Ministry of Oil and Mineral Resources. The project was carried out jointly by the Directorate and Norway's State Pollution Control Authority (SFT).

f) Costa Rica
The Directorate collaborated with Recope (*Refinadora Costaricense de Petroleo S.A*), Costa Rica's national oil company, in connection with that country's plans to reorganise its oil industry. A delegation from Recope and the Ministry of Planning visited the Directorate for the purpose. A joint regional geological mapping programme by Costa Rica and Nicaragua, coordinated by Recope, was followed up by INE (the Nicaraguan national energy office, see above) and the Directorate.

g) Asian offshore prospecting (CCOP)
The Directorate acts as the technical advisor to the Committee for Coordination of Joint Prospecting for Mineral Resources in Asian Offshore Areas (CCOP, see above) in connection with Norad's support of a sub-project involving petroleum resources evaluation in the region. Directorate personnel took part in a workshop in exploration model analysis in Pukhet in Thailand. The Directorate also attended a seminar on the removal of disused offshore installations in Djakarta, Indonesia. This seminar was organised jointly by CCOP and the Economic and Social Commission for Asia and the Pacific (ESCAP).

6.2.2 Aid through PETRAD
From 1 January 1989 until 31 December 1992, the Directorate undertook a test project for Norad aimed at examining the feasibility of setting up a training scheme in Norway for petroleum administration and management executives. The target group is executives in petroleum administration and the national oil companies in the developing countries.

The project, called the *International Programme for Petroleum Management and Administration* (PE-

TRAD), was the direct responsibility of the Director General of the Directorate.

Based on information regarding the need for executive training in the petroleum sector in Africa, Asia and Latin America, Petrad organised 33 courses and seminars, lasting from one day to eight weeks. Training was given in Africa, Asia and Norway. No less than 1250 executives from 42 countries attended the seminars. The budget for the period was Nkr 27 million.

For the development and implementation of the project, Petrad sought to draw on all aspects of Norwegian competence in the petroleum sector. Some 32 representatives of Norwegian institutions took turns as resource persons and lecturers. Petrad also engaged a score or so lecturers from developing countries as well as many experts from a long list of international organisations.

The programme sought to cover a broad spectrum of management and administration of petroleum activities, both upstream and downstream, and training was organised in four categories:

- The role of petroleum in sustainable development
- Petroleum resource management and administration
- Safety and environmental management and administration
- Management and administration of import, marketing, distribution and use of petroleum products.

In the light of its experience with these courses and seminars Petrad was able to develop two eight-week instruction programmes:

- Petroleum policy and management
- Management of petroleum operations.

These programmes were developed with the aid of 50 experts from Norwegian teaching environments, consultants and operating companies.

The courses were first offered between 9 September and 1 November 1991, attracting 40 participants from 19 countries, among them Norway. The courses were then repeated from 4 May to 26 June 1992, attracting 40 participants from 20 countries. The courses were in great demand and participants came from high levels in their respective national oil companies and government departments.

Of the other activities in 1992, two key seminars must be mentioned.

The first: *Securing Petroleum Supplies in Eastern Africa* was held in Tanzania from 7 to 11 September. Here questions impacting on the efficiency of procurement, transport, refining, distribution, marketing and substitution by natural gas in the region supplied via Dar es Salaam and Mombasa ports were discussed. Key figures from Tanzania, Kenya, Zambia, Uganda, Rwanda and Malawi attended accompanied by observers and contributors from Angola, Canada, Denmark, Norway, England and the World Bank.

All inefficiencies in the supplies of petroleum, which in some African countries commands 40-60 per cent of export revenues, are of crucial significance, even in terms of the aid received by these countries. The seminar was an effective means of identifying efficiency measures and putting them on the agenda.

The second, organised by Petrad in Moscow on 30 November and 1 December, was a seminar on petroleum industry framework. The seminar marked the opening of the Norwegian-Russian Forum for Energy and the Environment established by the ministers of energy for the two neighbouring countries. Forty-four leading figures from central administration, production units and research institutes took part.

The demand for Petrad courses and seminars is increasingly marked as they become known. They also provide a basis for more efficient and productive industrial cooperation.

6.3 SAFETY AND THE WORKING ENVIRONMENT

The Directorate cooperates and enjoys extensive contacts with international professional organisations and political and technical bodies, both directly and indirectly through other Norwegian agencies.

The purpose of this cooperation is as follows:

a) To help ensure that safety and the working environment in the petroleum activity at least meet the accepted international standards
b) To secure the supply of relevant information for competence building and regulatory development
c) To contribute insights and experience in international forums to promote the positive development of safety and working environment issues.

Generally the cooperation has involved taking part in inter-governmental forums in Europe and the United Nations, supplemented by direct cooperation with various kinds of international and regional professional bodies. A list of the most important partners in 1992 is given below followed by further details of the areas covered:

a) The North Sea Offshore Authorities Forum (NSOAF), with representation from all North Sea basin countries
b) The EC Commission, in collaboration with Norway's Ministry of Local Government, on safety and the working environment
c) The United Nations' International Maritime Organisation (IMO) and the International Labour Organisation (ILO), concerning safety at sea and the working environment, respectively
d) The European Diving Technology Committee (EDTC) and the Association of Offshore Diving Contractors (AODC), on diving safety
e) The Marine Technology Directorate (MTD) in the United Kingdom, on inspection and maintenance of installations

f) The Welding Institute (WI) in the United Kingdom, on research and development of materials and welding
g) The American Petroleum Institute (API), for attendance at annual conferences on technical petroleum topics and standardisation
h) The National Association of Corrosion Engineers (NACE) in USA, for participation at annual conferences on corrosion and surface treatment
i) *Comité Européen de Normalisation Electrotechnique* (CENELEC), concerning electrical engineering standardisation in Europe, through the Norwegian Electrical Engineering Committee (NEK).

6.3.1 The EC Commission
Since 1982 Norway, represented by the Norwegian Petroleum Directorate, has held observer status in the EC proceedings on safety and the working environment in the offshore petroleum activity. This work comes under the EC's Safety and Health Commission for the Mining and other Extractive Industries and is implemented by the Working Party on Oil, Gas and Other Minerals Extracted by Borehole.

The activities of the Working Party received higher priority in 1990 as a result of the decision on the part of the EC to prepare directives which also cover the working environment and safety in the offshore petroleum industry. Technical appendices were also prepared.

The year after, the draft directive was considered in the European Parliament, whose comments were considered by the EC Safety and Health Commission for the Mining and Extractive Industries, and a new consultative document was circulated in the EC. The directive was adopted in autumn 1992 and will become effective in the new year 1993-94.

6.3.2 Electro-engineering standards and regulations
The Norwegian Petroleum Directorate is a member of the following committees:

a) CENELEC, Working Group 12, Regulations for Installation of Explosion-proof Materials
b) NEK, Standards Committee (NK) 18, Shipboard Installations
c) NEK, Standards Committee (NK) 31, Electrical Equipment for Areas with Explosion Risk
d) International Electrotechnical Commission (IEC), Technical Committee 18, Electrical Installations of Ships and of Mobile and Fixed Offshore Units. The Directorate's participant acts as secretary to the European part of Working Group 18, which, together with a North-American group, will prepare new IEC publications for mobile and fixed installations.

6.3.3 Lectures
In 1992, as previously, the Directorate was engaged to lecture and chair meetings at a number of courses and conferences concerning issues relating to health, safety and the working environment, in Norway and abroad. This activity is considered an essential factor in the mutual exchange of information and influence, not least in the light of the increasingly international flavour of regulations and other codes and provisions.

6.3.4 International Labour Organisation (ILO)
Since autumn 1990, the Directorate has had a member of staff seconded to the International Labour Organisation secretariat in Geneva working on a project to examine the role of the Labour Inspection in the petroleum producing industry. This engagement runs until summer 1993. The Directorate has also assisted with funding of the project.

6.4 INTERNATIONAL STANDARDS
International standards are utilised for the analysis and measurement of oil and gas, and the Directorate participates in the international work to revise existing standards and establish new ones in these technical areas.

With the establishment of the EC Internal Market in 1993, there will be a stronger emphasis on standardisation requirements. CEN, the European Standardisation Organisation, will build on existing ISO standards where suitable ones exist. ISO is the International Standardisation Organisation.

Norwegian working groups have been set up to review ISO's activities, not least in the field of oil and gas metering. The Norwegian Engineering Industry Standardisation Centre (NVS) organises this work and provides the secretariat function. The Directorate is actively involved in the working groups.

6.5 INFOIL/SESAME DATABASE
The Directorate works jointly with the Royal Norwegian Council for Scientific and Industrial Research (NTNF) in Norway and the Health and Safety Executive in the UK on the Infoil and Sesame research databases, for which the Directorate has editorial responsibility. The databases contain information on current and completed research projects in the petroleum industry. Since 1990, there has also been cooperation with the EC through the *Directorate Generale XVII*, which has permitted the database to include European Community research projects in hydrocarbon technology. This cooperation with the EC qualified the base to a place on the EC stand at the Offshore Northern Seas exhibition, ONS-92. The base is available on diskette or CD-ROM; via the Scientific and Technical Network (STN) host system in Karlsruhe; and via Eurobases, the EC's central computing facility, in Brussels. Activity on the database increased substantially in 1992.

7. Statistics and Summaries

7.1 UNITS OF MEASUREMENT FOR OIL AND GAS

Oil and gas are often measured in volumetric units valid under defined ISO standard conditions (temperature 15 degrees Celsius, pressure 1.01325 bar). Oil volumes are stated in million standard cubic metres, for convenience abbreviated in this report to mcm (10^6 Sm^3); and gas volumes in billion standard cubic metres, for convenience abbreviated in this report to bcm (10^9 Sm^3). Standard cubic meter is abbreviated scm.

Oil and gas volumes are also often stated in tonnes oil equivalents (toe) if exact quantities are not required. This unit is useful when aggregating and comparing gas and oil volumes. The abbreviations mtoe and btoe are used here for convenience to denote million and billion toe, respectively.

The conversion of oil and gas quantities to toe is based on the energy released on combustion of the oil or gas. For a large variety of naturally occurring oil and gas compositions on the Norwegian continental shelf the energy in one tonne of oil is the same as that in 1000 scm gas. This gives rise to the following simple formulae:

- 1 tonne oil equals 1 toe oil
- 1000 scm gas equals 1 toe gas.

The density of oil varies between 0.8 and 0.9 grams per cubic centimetre (g/cc, g/cm^3, depending on its composition. For oils of unknown composition the density is usually assumed to be 0.85 g/cc. By this measure, 1 scm oil is equal to 0.85 toe.

7.2 EXPLORATION DRILLING STATISTICS

By year end 1992, a total of 752 exploration wells had been started on the Norwegian continental shelf since the first was spudded in 1966. Of this number, 535 were wildcats and 217 appraisal wells.

By the same date, 695 exploration wells had been terminated, while 50 were suspended for various reasons. The reasons include deferred testing, possible completion as production wells, continued drilling, or subsequent plugging.

The most northerly exploration well to date on the Norwegian continental shelf is 7316/5-1, which was drilled in 1992 under Hydro as operator. The furthest east is 7228/6-1, drilled by Conoco in 1991; and the westernmost 6201/11-2, drilled by Statoil in 1991.

Exploration wells have been drilled by 19 different operating companies. The regional numbers drilled per operator are shown in Figure 7.2.a.

Estimates of the number of days of operation per company in 1992 are shown in Figure 7.2.b. Figure 7.2.c depicts the Norwegian operating companies' share of drilling operations.

By year end 1992, the total length of exploration hole had reached 2,428,213 metres. Of the total, 140,651 metres were drilled in 1992.

The average total depth of the exploration wells reaching their prospective total depth in 1992 was 3560 metres.

Exploration well 1/6-6, drilled to prospective total depth in 1992, is the deepest exploration well to date on the Norwegian side. Here, Shell was the operator and the total vertical depth was 5567 metres relative to the Kelly bushing (5542 metres below mean sea level).

The longest borehole so far is 2/12-2-S, sidetracked by Norsk Hydro in 1990. The length of the well is 5757 metres, but as it was drilled at an angle it did not reach as deep below the sea surface as 1/6-1.

The average water depth for exploration wells drilled in 1992 was 225 metres. The greatest water depth in which a well has been drilled to date in the Norwegian sector is 523 metres: The well, 6607/5-2, was drilled in 1991 with Esso as operator.

Figure 7.2.d shows the average water depths in which exploration wells were drilled from 1966 to 1992.

For the drilling operations to date on the Norwegian continental shelf, 73 different drilling rigs have been employed, nine of them under two different names. Of the total, 54 were semi-submersibles, 11 jack-ups, five drill ships, and three fixed installations. In 1992, there were 16 different drilling rigs in action on Norway's offshore provinces.

Tables 7.2.a-e present the statistics for exploration drilling on the Norwegian continental shelf.

Table 7.2.a
Wells spudded per year 1966–1992

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	Total
Wildcat	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	535
Appraisal			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	217
Exploration	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	752
Development								1	18	24	7	34	50	36	27	16	22	23	33	47	47	48	55	66	60	64	86	764
Total	2	6	12	13	17	16	14	23	36	50	30	54	69	64	62	55	71	63	80	97	83	84	84	94	96	111	129	1516

Table 7.2.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	61	48	109	36	4	40	18	1	19	115	53	168
Norsk Hydro	72	33	105	11	02	13	18		18	101	35	136
Saga	43	10	53	14		14	3		3	60	10	70
Elf	44	17	61	2	2	1		1	47	17	64	
Phillips	41	20	61	1		1			42	20	62	
Esso	29	19	48	2		2	4		4	34	20	54
Shell	26	11	37	5	5	10	2		2	33	16	49
Amoco	25	14	39							25	14	39
Conoco	19		19	3	8	11	1		1	23	8	31
Mobil	17	9	26	2		2	2		2	21	9	30
BP	12	14	26	2		2				14	14	28
Gulf	7		7							7		7
Murphy	3	1	4							3	1	4
Total	2		2				1		1	3		3
Agip	3		3							3		3
Fina	1		1							1		1
Syracuse	1		1							1		1
Texaco	1		1							1		1
Unocal	1		1							1		1
Wildcat	407			78			50			535		
Appraisal		197			19			1			217	
Exploration			604			97			51			752

W = Wildcat
A = Appraisal
E = Exploration

Table 7.2.c
Exploration wells spudded in 1992 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	5	2	7	2		2				7	2	9
Norsk Hydro	4	7	11	1		2	2		2	7	7	14
Phillips		1	1								1	1
Elf	3		3							3		3
Saga	4	1	5				1		1	5	1	6
Esso	1		1							1		1
Shell	1		1	1		1				2		2
Conoco	1		1							1		1
Mobil	2	2	4	1		1				2	2	4
BP		1	1	1		1				1	1	2
Wildcat	21			5			3			29		
Appraisal		14									14	
Exploration			35			5			3			43

W = Wildcat
A = Appraisal
E = Exploration

Table 7.2.d
Average water depth and drilling depth

Year	Average water depth (m)	Average total depth (m)	Year	Average water depth (m)	Average total depth (m)
1966	94	3 015	1980	170	3 209
1967	100	2 682	1981	164	3 243
1968	81	3 303	1982	163	3 457
1969	74	3 276	1983	192	3 287
1970	92	2 860	1984	212	3 247
1971	79	3 187	1985	224	3 367
1972	78	3 742	1986	234	3 248
1973	85	3 075	1987	236	3 383
1974	106	3 163	1988	248	3 598
1975	106	3 173	1989	188	3 331
1976	108	3 314	1990	156	3 619
1977	104	3 450	1991	194	3 639
1978	110	3 432	1992	225	3 560
1979	157	3 444			

Table 7.2.e
Drilling rigs active on Norwegian continental shelf as of 31 December 1992

Rig name	Number of wells	Number of reentries	Type of rig
Aladdin	1		Semi-submersible
Arcade Frontier (formerly Norjarl)	6		«
Borgny Dolphin (formerly Fernstar)	27	8	»
Borgsten Dolphin (formerly Haakon Magnus)	9		«
Bucentaur		1	Drill ship
Byford Dolphin (formerly Deepsea Driller)	27		Semi-submersible
Chris Chenery	2		«
Deepsea Bergen	32	3	«
Deepsea Saga	16	3	«
Drillmaster	5	1	«
Drillship	1		Drill ship
Dyvi Beta	6	1	Jack-up
Dyvi Gamma	1		«
Dyvi Stena	20	1	Semi-submersible
Endeavour	2		Jack-up
Glomar Biscay II (formerly Norskald)	39	1	Semi-submersible
Glomar Grand Isle	11	3	Drill ship
Glomar Moray Firth I	2		Jack-up
Gulftide	3		«
Henry Goodrich	2		«
Hunter (formerly Treasure Hunter)	6	3	Semi-submersible
Kolskaya		1	«
Le Pelerin	1		Drill ship
Mærsk Explorer	7		Jack-up
Mærsk Guardian	2		«
Mærsk Jutlander	4	1	Semi-submersible
Neddrill Trigon	3	1	Jack-up
Neptune 7 (formerly Pentagone 81)	13		Semi-submersible
Nordraug	12		«
Nortrym	32	3	«
Ocean Tide	5		Jack-up
Ocean Traveller	9		Semi-submersible
Ocean Victory	1		«
Ocean Viking	28	1	«
Ocean Voyager	2		«
Odin Drill	3		«
Orion	7		Jack-up
Pentagone 84	2	1	Semi-submersible
Polar Pioneer	26	3	«
Polyglomar Driller	11		«
Ross Isle	29	7	«
Ross Rig	30		«
Ross Rig (new)	19	3	«
Saipem II	1		Drill ship
Scarabeo	1		Semi-submersible
Sedco 135 G	3		«
Sedco 703	3	1	Semi-submersible
Sedco 704	3		«
Sedco 707	8		«
Sedco H	2		«
Sedneth I	3		«
Sovereign Explorer	3	1	«
Transocean 8	15	2	«
Transworld Rig 61	2		«
Treasure Prospect	1		«
Treasure Saga	43	4	«
Treasure Scout	23		«
Treasure Seeker	24	5	«
Vildkat Explorer	23	4	«
Vinni	5		«
Waage Drill I	2		«
West Alpha (formerly Dyvi Alpha)	22	2	«
West Delta (formerly Dyvi Delta)	34	2	«
West Vanguard	27	6	«
West Venture	12	2	«
West Vision	1		«
Yatzy	1		«
Zapata Explorer	13		Jack-up
Zapata Nordic	5		«
Zapata Ugland	5	1	Semi-submersible
	749	76	
In addition three wells have been drilled from fixed installations			
Cod platform	1	1	
Ekofisk B	1		
Veslefrikk A	1		
	752	77	

Fig. 7.2.a
Regional spread of exploration wells per operator

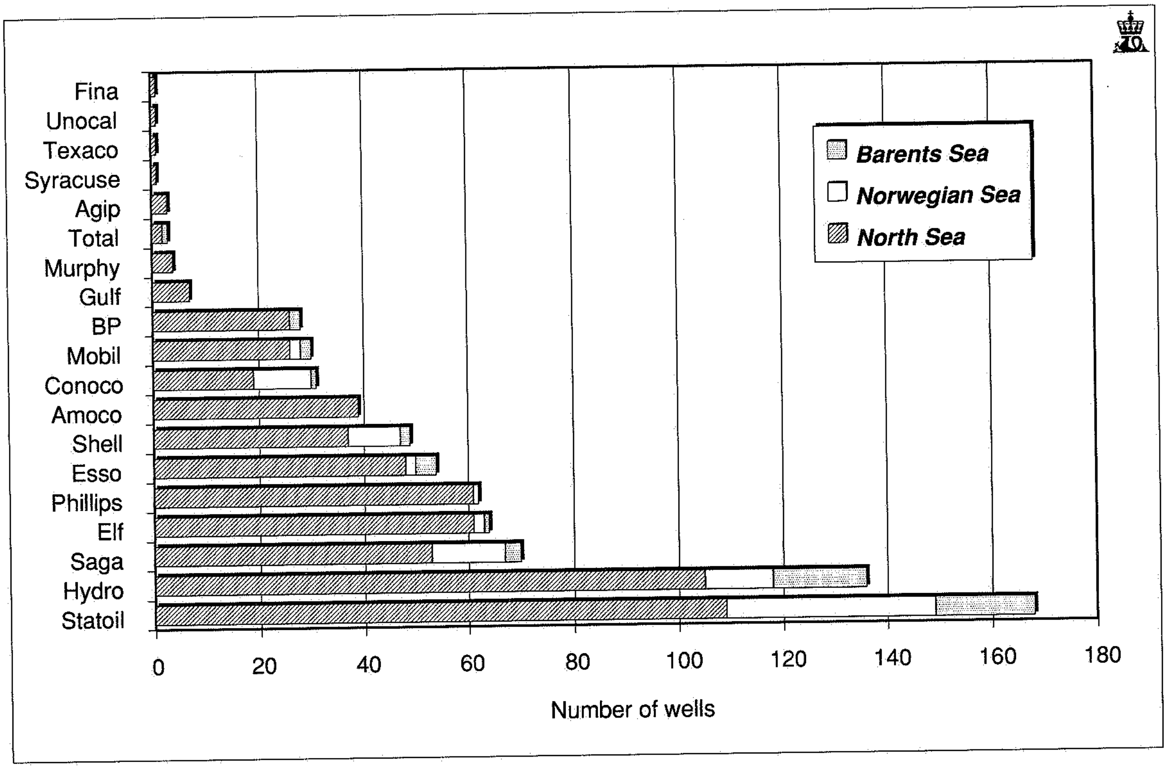


Fig. 7.2.b
Rigdays per operator in 1992

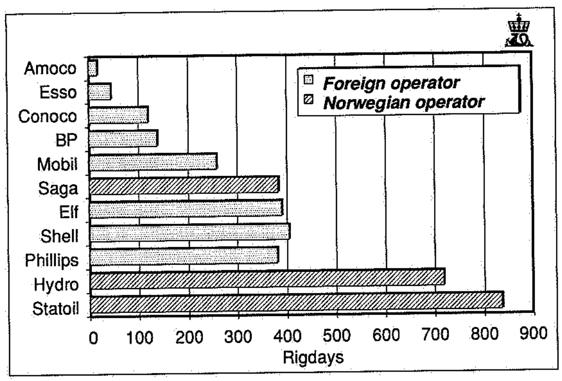
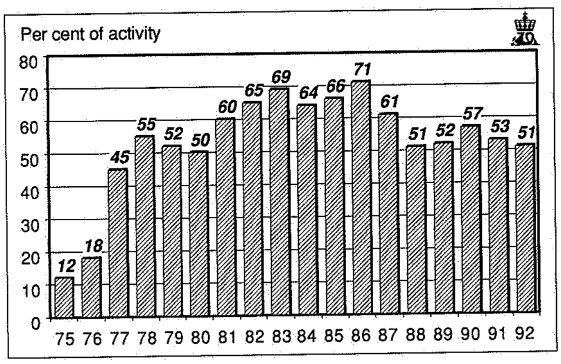


Fig. 7.2.c
Participation of Norwegian operators in exploration drilling activity



7.3 DEVELOPMENT DRILLING STATISTICS

Since 1973, a total of 764 development wells have been commenced in the Norwegian sector of the North Sea; of which 383 are producers of oil, gas or condensate; 115 are water or gas injectors; and one is an observation and production well. Of the total, 247 are out of service; being either suspended for later completion, or closed down for some other reason. Eighteen development wells were being drilled at year end 1992.

Full details of development wells are given in Table 7.3.a. Figure 7.3.a shows development wells started each year during the period 1973 to 1992.

At year end, production or injection was underway from 23 fields and 34 installations. Four of the latter are subsea installations: namely Nordøst-Frigg, Øst-Frigg, TOGI and Tommeliten.

The distribution of development wells by field is shown in Figure 7.3.b; while Figure 7.3.c shows the wells broken down by operating company.

The first development wells on Lille-Frigg, Loke and Heidrun were spudded in 1992 by the semi-submersible drilling units *Mærsk Jutlander*, *Treasure Prospect* and *Transocean 8*, respectively.

A new development drilling milestone was passed on 16 November 1992, when Conoco started drilling

Fig. 7.2.d
Average waterdepth for exploration wells 1966–1992

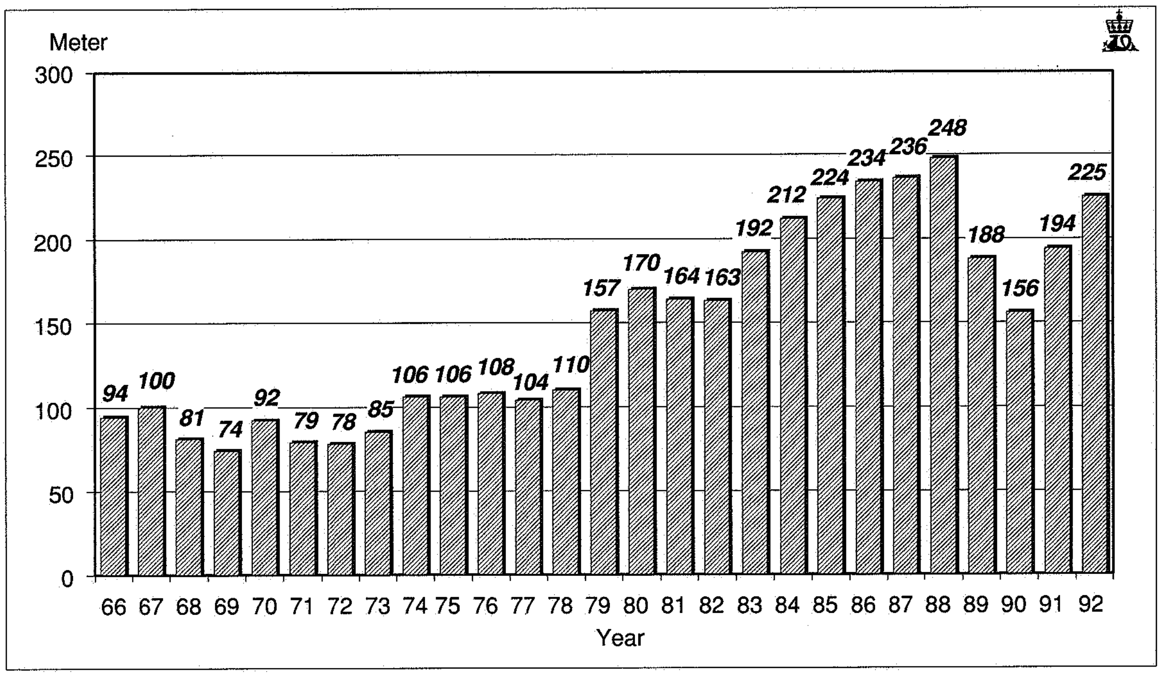


Fig. 7.3.a
Development wells on the Norwegian continental shelf 1973–1992

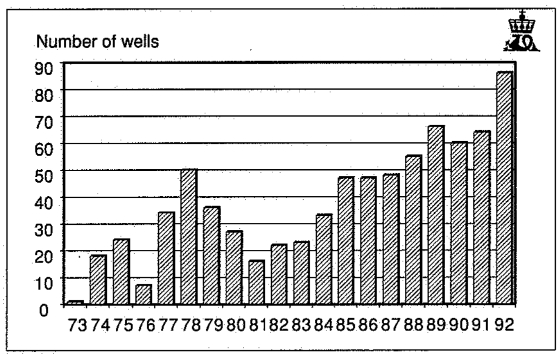


Fig. 7.3.b
Development wells per field

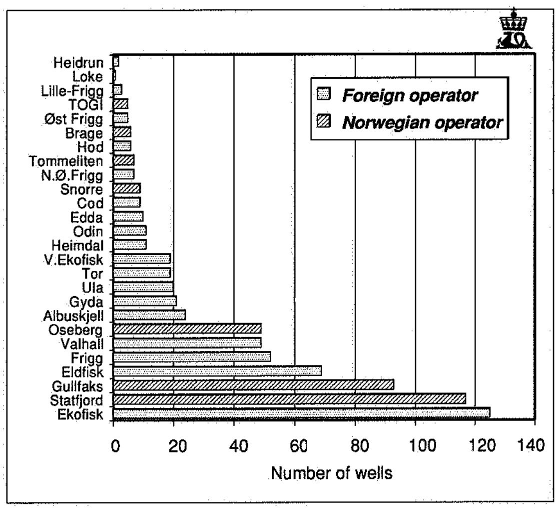


Fig. 7.3.c
Development wells per operator

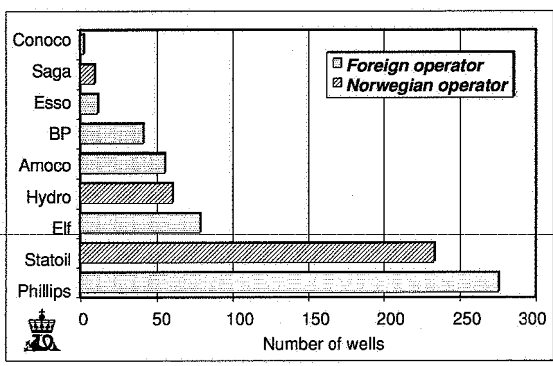


Fig. 7.3.d
Development wells drilled 1992 by installations

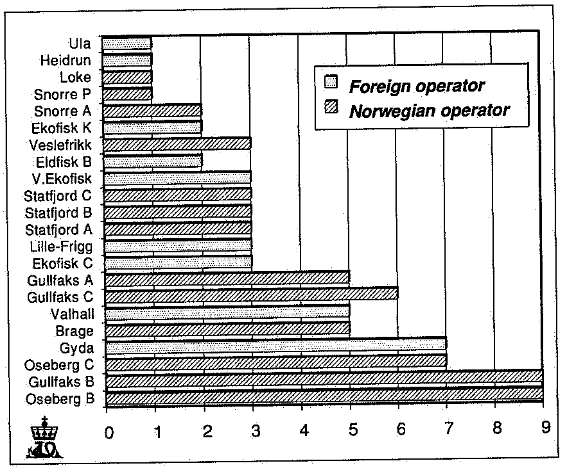


Fig. 7.3.e
Development wells by mobile installations

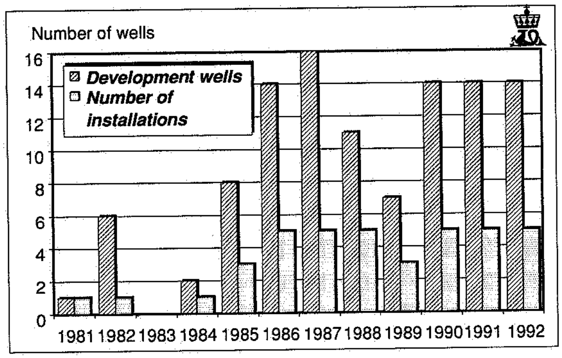


Table 7.3.a Development drilling as of 31 December 1992

Field	Hydro-carbon	Total drilled	Spudded 1992	Producing	Injection/ (observation)	Drilling	Plugged/ Shut-down/ Suspended
ALBUSKJELL A +	cond	11		7			4
ALBUSKJELL F	cond	13					13
BRAGE	oil	6	5			1	5
COD +	cond	9		3			6
EDDA +	oil	10		7			3
EKOFISK A +	oil	27	1	21		1	5
EKOFISK B +	oil	35		21	1*		13
EKOFISK C +	oil	27	3	17	6**		4
EKOFISK K +	w.inj.	28	2		26		2
EKOFISK W +	w.inj.	8			8		
ELDFISK A +	oil	38		23			15
ELDFISK B +	oil	31	2	20		1	10
FRIGG (UK)	gas	24					24
FRIGG +	gas	28		9			19
GULLFAKS A +	oil	47	5	26	9	1	11
GULLFAKS B +	oil	30	9	16	8	1	5
GULLFAKS C +	oil	16	6	9	3	1	3
GYDA +	oil	21	7	11	5	1	4
HEIDRUN	oil	2	2			1	1
HEIMDAL +	cond	11		7			4
HOD +	oil	6		5			1
LILLE-FRIGG	gas	3	3			1	2
LOKE	gas	1	1				1
N.Ø.FRIGG +	gas	7		2			5
ODIN +	gas	11		9			2
OSEBERG B +	oil	33	9	15	7	1	10
OSEBERG C +	oil	16	7	7	4	1	4
SNORRE A	oil	2	2			1	1
SNORRE P	oil	7	1	6		1	
STATFJORD A +	oil	45	3	24	11	1	9
STATFJORD B +	oil	37	3	23	9		5
STATFJORD C +	oil	35	3	21	8	1	5
TOGI +	gas	5		5			
TOMMELITEN +	cond	7		6			1
TOR +	oil	19		12			7
ULA +	oil	20	1	9	6	1	4
VALHALL +	oil	49	5	22		1	26
V. EKOFISK +	cond	19	3	6			13
VESLEFRIKK +	oil	15	3	9	5	1	
ØST FRIGG +	gas	5		5			
		764	86	383	110	18	247
					(1)* 5**		

\+ Field producing/injecting
* Observation/production well(s)
** Prod./inj. wells depending on gas sales

383 wells are producing (324 oil, 29 condensate and 30 gas)
217 wells are shut down/plugged
115 wells are injection wells (of which 5 inj./prod.)
1 well is an observation-/production well
18 well are under drilling (2/1-A-24 A, 2/4-A-13 A, 2/7-B-2 A, 2/8-A-29, 7/12-A-14 A, 25/2-C-2 H, 30/3-A-15, 30/6-C-4, 30/9-B-32, 31/4-A-4, 33/9-A-23 A, 33/9-C-2, 34/7-A-4 H, 34/7-P-25, 34/10-A-39 A, 34/10-B-26, 34/10-C-15 A, 6507/7-A-52)

21 well are suspended at total depth: (2/1-A-14 A, 2/4-D-1 A, 2/4-D-13 A, 2/7-A-7 A, 25/2-C-1 AH, 30/6-C-15 A, 30/9-B-18 A, 30/9-B-32, 31/4-A-1, 31/4-A-2, 31/4-A-3, 31/4-A-5, 31/4-A-6, 33/9-A-10, 33/12-B-2 A, 34/7-P-28, 34/10-A-38, 34/10-A-39, 34/10-B-22 A, 34/10-C-14, 6507/7-A-20)
2 well is susp. at 9 5/8": (33/12-B-2 A, 34/10-C-9)
3 wells are susp. at 13 3/8": (2/7-A-15, 2/7-A-22, 30/9-B-42)
3 well are susp. at 20": (25/4-A-1, 33/12-B-29, 34/10-C-14)
1 well is suspended with a fish in the 36" open hole: (2/4-K-3)

Table 7.3.b
Development wells spudded or terminated in 1992

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Field/installation
463	30/09-B-04	92.06.27	92.08.04	HYDRO	OSEBERG B
616	2/04-K-16	90.12.26	92.01.17	PHILLIPS	EKOFISK K
627	2/04-K-25	92.04.26	92.07.18	PHILLIPS	EKOFISK K
653	2/04-E-06 A	91.11.14	92.05.01	PHILLIPS	TOR
660	33/09-A-24	91.08.14	92.03.11	STATOIL	STATFJORD A
663	2/07-B-03 A	91.09.28	92.01.06	PHILLIPS	ELDFISK B
665	33/12-B-02	91.08.17	92.02.07	STATOIL	STATFJORD B
667	34/10-C-09	91.08.19	92.01.17	STATOIL	GULLFAKS C
673	30/09-B-46	91.10.16	92.01.30	HYDRO	OSEBERG B
676	2/01-A-16	91.10.26	92.01.09	BP	GYDA
677	34/10-B-19	91.11.22	92.01.07	STATOIL	GULLFAKS B
678	34/10-C-10	91.10.22	92.03.27	STATOIL	GULLFAKS C
679	34/10-A-35	91.11.17	92.01.21	STATOIL	GULLFAKS A
681	2/07-B-07 A	92.02.01	92.04.09	PHILLIPS	ELDFISK B
682	33/09-C-27	91.11.27	92.04.05	STATOIL	STATFJORD C
683	31/04-A-01	91.12.30	92.01.31	HYDRO	VILDKAT EXPLORER
684	2/04-C-20	92.01.11	92.03.15	PHILLIPS	EKOFISK C
685	30/06-C-14	92.01.01	92.03.23	HYDRO	OSEBERG C
686	2/08-A-05 A	92.01.03	92.01.31	AMOCO	VALHALL
687	2/04-D-07 A	92.05.11	92.06.29	PHILLIPS	EKOFISK D
688	30/09-B-38	92.02.16	92.05.05	HYDRO	OSEBERG B
689	34/07-P-13	91.12.29	92.03.06	SAGA	SCARABEO 5
690	2/04-K-18	92.01.17	92.04.26	PHILLIPS	EKOFISK K
691	2/01-A-19	92.01.10	92.04.09	BP	GYDA
692	34/10-A-36	92.01.22	92.06.26	STATOIL	GULLFAKS A
693	34/10-B-20	92.01.08	92.02.28	STATOIL	GULLFAKS B
694	34/10-C-11	92.01.18	92.03.05	STATOIL	GULLFAKS C
695	30/03-A-13	92.01.29	92.04.28	STATOIL	VESLEFRIKK A
696	2/04-C-21	92.03.16	92.05.14	PHILLIPS	EKOFISK C
697	25/02-C-01 H	92.02.25	92.06.24	ELF	MÆRSK JUTLANDER
698	31/04-A-02	92.01.31	92.04.15	HYDRO	VILDKAT EXPLORER
699	2/08-A-26	92.02.01	92.04.01	AMOCO	VALHALL
700	33/12-B-11	92.02.27	92.06.18	STATOIL	STATFJORD B
701	30/06-C-25	92.03.24	92.05.04	HYDRO	OSEBERG C
702	34/10-B-21	92.02.28	92.04.17	STATOIL	GULLFAKS B
703	33/09-A-35	92.03.24	92.08.27	STATOIL	STATFJORD A
704	33/09-C-20	92.03.02	92.05.04	STATOIL	STATFJORD C
705	34/07-P-34	92.03.06	92.04.01	SAGA	SCARABEO 5
706	34/10-C-12	92.03.27	92.05.17	STATOIL	GULLFAKS C
707	2/01-A-27	92.04.23	92.06.23	BP	GYDA
708	34/10-B-19 A	92.04.17	92.05.13	STATOIL	GULLFAKS B
709	34/10-A-37	92.07.01	92.09.10	STATOIL	GULLFAKS A
710	31/04-A-03	92.04.17	92.05.24	HYDRO	VILDKAT EXPLORER
711	2/08-A-14 B	92.05.09	92.07.16	AMOCO	VALHALL
712	30/09-B-01	92.05.05	92.06.01	HYDRO	OSEBERG B
713	30/06-C-03	92.05.04	92.06.01	HYDRO	OSEBERG C
714	34/10-B-22	92.05.14	92.06.12	STATOIL	GULLFAKS B
715	2/04-C-14 A	92.07.07	92.09.23	PHILLIPS	EKOFISK C
716	34/10-C-13	92.05.17	92.06.28	STATOIL	GULLFAKS C
717	31/04-A-05	92.05.25	92.06.27	HYDRO	VILDKAT EXPLORER
718	33/09-C-24	92.05.30	92.10.13	STATOIL	STATFJORD C
719	30/09-B-01 A	92.06.01	92.07.09	HYDRO	OSEBERG B
720	30/06-C-01	92.06.01	92.09.14	HYDRO	OSEBERG C
721	25/02-C-01 A H	92.06.26	92.09.05	ELF	MÆRSK JUTLANDER
722	2/01-A-15	92.06.24	92.08.02	BP	GYDA
723	34/10-B-23	92.06.13	92.09.10	STATOIL	GULLFAKS B
724	34/10-B-22 A	92.06.21	92.07.15	STATOIL	GULLFAKS B
725	2/04-D-13 A	92.07.23	92.09.20	PHILLIPS	EKOFISK D
726	30/09-B-18	92.07.10	92.09.26	HYDRO	OSEBERG B
727	2/08-A-28	92.07.26	92.10.06	AMOCO	VALHALL
728	2/07-B-02 A	92.11.01		PHILLIPS	ELDFISK B
729	34/10-A-38	92.09.10	92.11.16	STATOIL	GULLFAKS A
730	30/06-C-15	92.09.19	92.10.17	HYDRO	OSEBERG C
731	33/09-A-10	92.09.04	92.11.17	STATOIL	STATFJORD A
732	2/01-A-26	92.08.03	92.09.18	BP	GYDA
~~733~~	~~34/10-C-14~~	~~92.08.11~~	~~92.11.13~~	~~STATOIL~~	~~GULLFAKS C~~
734	31/04-A-06	92.08.15	92.11.20	HYDRO	VILDKAT EXPLORER
735	30/03-A-14	92.08.15	92.08.21	STATOIL	VESLEFRIKK A
736	33/12-B-02 A	92.09.09	92.11.22	STATOIL	STATFJORD B
737	34/07-A-04 H	92.09.01		SAGA	SCARABEO 5
738	34/10-B-24	92.09.10	92.11.20	STATOIL	GULLFAKS B

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Field/installation
739	2/04-D-01 A	92.10.12	92.11.27	PHILLIPS	EKOFISK D
740	2/01-A-24	92.09.18	92.11.14	BP	GYDA
741	30/09-B-18 A	92.09.27	92.11.02	HYDRO	OSEBERG B
742	2/08-A-29	92.10.24		AMOCO	VALHALL
743	15/09-C-02 H	92.10.12	92.11.18	STATOIL	TREASURE PROSPEC
744	34/07-A-05 H	92.10.15	92.10.18	SAGA	SCARABEO 5
745	30/06-C-15 A	92.10.17	92.11.19	HYDRO	OSEBERG C
746	6507/07-A-20	92.11.16	92.12.17	CONOCO	TRANSOCEAN 8
747	34/10-A-39	92.11.16		STATOIL	GULLFAKS A
748	25/02-C-02 H	92.10.19		ELF	MÆRSK JUTLANDER
749	30/09-B-05	92.11.02	92.11.18	HYDRO	OSEBERG B
750	33/09-C-02	92.10.29		STATOIL	STATFJORD C
751	34/10-C-15	92.11.13	92.12.03	STATOIL	GULLFAKS C
752	30/09-B-32	92.11.20		HYDRO	OSEBERG B
753	34/10-B-25	92.11.21	92.12.05	STATOIL	GULLFAKS B
754	30/06-C-04	92.11.20		HYDRO	OSEBERG C
755	31/04-A-04	92.11.20		HYDRO	VILDKAT EXPLORER
756	2/01-A-14	92.11.16	92.12.19	BP	GYDA
757	33/12-B-29	92.11.29	92.12.13	STATOIL	STATFJORD B
758	33/09-A-23 A	92.12.23		STATOIL	STATFJORD A
759	30/03-A-15	92.12.02		STATOIL	VESLEFRIKK A
761	2/04-A-13 A	92.12.27		PHILLIPS	EKOFISK A
762	34/10-C-15 A	92.12.03		STATOIL	GULLFAKS C
763	6507/07-A-52	92.12.18		CONOCO	TRANSOCEAN 8
765	7/12-A-14	92.12.08		BP	ULA
768	2/01-A-24 A	92.12.25		BP	GYDA
772	34/10-B-26	92.12.14		STATOIL	GULLFAKS B

Table 7.3.c
Production wells drilled from mobile drilling units

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Drilling unit
743	15/09-C-02 H	92.10.12	92.11.18	STATOIL	TREASURE PROSPEC
697	25/02-C-01 H	92.02.25	92.06.24	ELF	MÆRSK JUTLANDER
721	25/02-C-01 A H	92.06.26	92.09.05	ELF	MÆRSK JUTLANDER
748	25/02-C-02 H	92.10.19		ELF	MÆRSK JUTLANDER
698	31/04-A-02	92.01.31	92.04.15	HYDRO	VILDKAT EXPLORER
710	31/04-A-03	92.04.17	92.05.24	HYDRO	VILDKAT EXPLORER
755	31/04-A-04	92.11.20		HYDRO	VILDKAT EXPLORER
717	31/04-A-05	92.05.25	92.06.27	HYDRO	VILDKAT EXPLORER
734	31/04-A-06	92.08.15	92.11.20	HYDRO	VILDKAT EXPLORER
737	34/07-A-04 H	92.09.01		SAGA	SCARABEO 5
744	34/07-A-05 H	92.10.15	92.10.18	SAGA	SCARABEO 5
705	34/07-P-34	92.03.06	92.04.01	SAGA	SCARABEO 5
746	6507/07-A-20	92.11.16	92.12.17	CONOCO	TRANSOCEAN 8
763	6507/07-A-52	92.12.18		CONOCO	TRANSOCEAN 8

the first development well north of 62°N, in Norwegian Sea.

Well 6507/7-A-20 is the first borehole on the Heidrun field.

By year end 1992, 86 development wells had been spudded in 16 fields, 14 being drilled by mobile units. Development wells broken down by installation are shown in Figure 7.3.d. Further details of development wells are compiled in Tables 7.3.a-c. Figure 7.3.e is a summary of the development wells drilled from mobile units.

7.4 PRODUCTION OF OIL AND GAS

The total production of crude oil and natural gas on the Norwegian continental shelf was 132.7 mtoe in 1992. Production in 1991 was 118.8 mtoe. Tables 7.4.a-r, which look at each producing field in turn, and Figures 7.4.a-b, which give period summaries, set out production in more detail.

The data in Table 7.4.a summarise the Norwegian shares in Statfjord, Frigg, and Murchison. In the tables for oil, NGL is included for the Ekofisk area,

Table 7.4.a
Production in million tonnes oil equivalents (mtoe)

1992	Oil	Gas	Total
Ekofisk area	10.985	8.686	19.671
Frigg area	0.000	5.563	5.563
Gamma Nord	0.267	0.000	0.267
Gullfaks	21.992	1.850	23.842
Gyda	3.146	0.479	3.625
Heimdal	0.000	3.914	3.914
Hod	1.099	0.250	1.349
Mime	0.104	0.028	0.132
Murchison	0.396	0.003	0.399
Oseberg	21.789	0.000	21.789
Snorre	1.335	0.009	1.344
Statfjord	31.522	3.131	34.653
Togi	0.053	0.000	0.053
Tommeliten	0.419	1.171	1.590
Ula	6.282	0.457	6.739
Valhall	3.446	0.928	4.374
Veslefrikk	3.463	0.011	3.474
Total 1992	106.250	26.480	132.730
Total 1991	93.124	25.639	118.763
Total 1990	81.446	26.118	107.564
Total 1989	74.280	29.364	103.644
Total 1988	56.001	29.023	85.024
Total 1987	49.016	28.797	77.813
Total 1986	42.052	26.561	68.613
Total 1985	38.479	26.276	64.755

Fig. 7.4.a
Oil and gas production on the Norwegian shelf 1971–1992

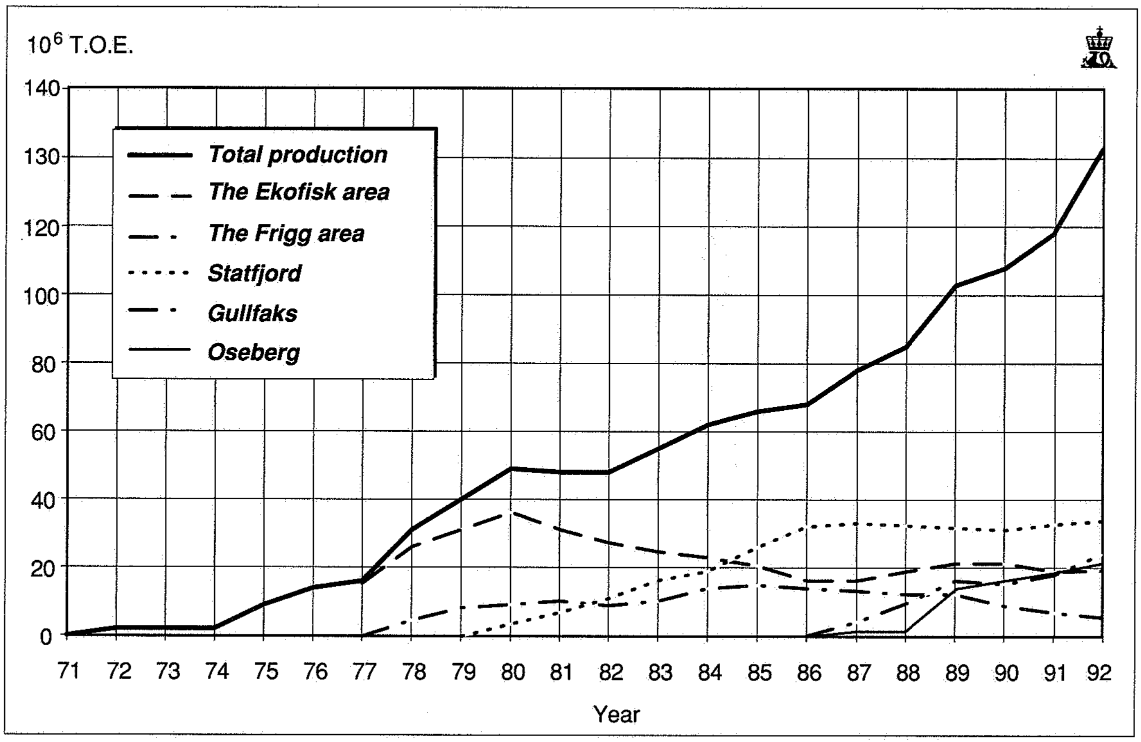


Fig. 7.4.b
Oil and gas production on the Norwegian shelf 1977–1992

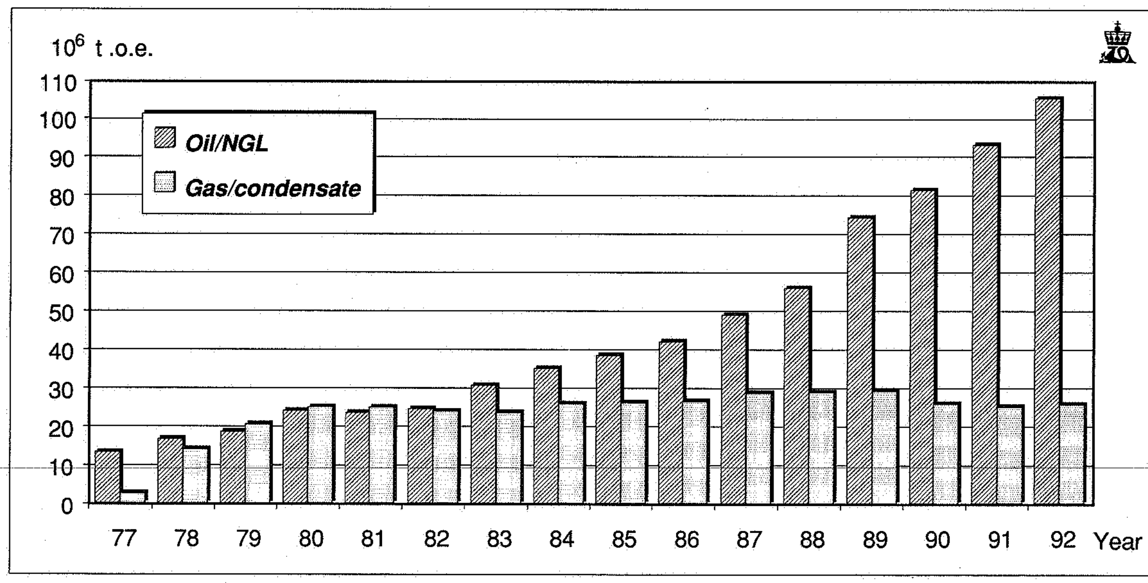


Table 7.4.b
Monthly oil and gas production allocated to Ekofisk fields

1992	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³
JAN	1246.	977.	.5	93.	1105.	128.	778.
FEB	1111.	886.	4.3	87.	1013.	115.	724.
MAR	1154.	902.	2.4	89.	1041.	114.	748.
APR	1201.	970.	.9	92.	1074.	129.	801.
MAY	1045.	829.	2.2	82.	938.	107.	655.
JUN	1255.	939.	2.1	96.	1106.	123.	711.
JUL	1167.	922.	2.4	97.	1108.	122.	664.
AUG	1201.	925.	2.6	97.	1080.	126.	690.
SEP	1124.	856.	1.1	90.	1011.	114.	688.
OCT	1125.	908.	1.0	98.	1043.	87.	754.
NOV	1088.	852.	1.3	93.	989.	97.	718.
DEC	1140.	889.	.7	98.	1039.	113.	755.
YEAR TOTAL	13857.	10855.	21.6	1112.	12547.	1375.	8686.

Table 7.4.c
Monthly gas and condensate production from the Frigg area

1992	Gas prod	Condensate prod	Gas flared	Gas fuel	Gas St Fergus	Condensate St Fergus
	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	609.	2.	28.	9.	601.	6.
FEB	597.	2.	19.	7.	592.	3.
MAR	606.	2.	25.	7.	600.	5.
APR	516.	2.	23.	6.	504.	3.
MAY	385.	1.	15.	6.	376.	3.
JUN	497.	2.	100.	9.	498.	2.
JUL	433.	2.	106.	9.	428.	3.
AUG	422.	1.	93.	7.	415.	5.
SEP	403.	1.	46.	6.	394.	1.
OCT	317.	1.	79.	6.	324.	4.
NOV	348.	1.	155.	4.	337.	5.
DEC	466.	1.	63.	7.	459.	3.
YEAR TOTAL	5599.	18.	751.	83.	5528.	43.

Figures are for the Norwegian share of Frigg 60.82 %, NØ-Frigg, Odin and Øst-Frigg 100 %.

Table 7.4.d
Monthly oil and gas production from Gamma Nord

1992	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sture
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	41.	17.	.2	.0	39.
FEB	29.	13.	.1	.0	28.
MAR	33.	30.	.3	.3	32.
APR	33.	40.	.2	.2	30.
MAY	32.	51.	.3	.1	29.
JUN	29.	53	.3	.1	25.
JUL	27.	61.	.4	.2	23.
AUG	24.	49.	.2	.0	21.
SEP	22.	48.	.1	.0	19.
OCT	22.	44.	.1	.0	19.
NOV	25.	62.	.1	.0	24.
DEC	28.	71.	.1	.0	26.
YEAR TOTAL	345.	539.	2.5	.9	315.

Table 7.4.e
Monthly oil and gas production from Gullfaks

1992	Stabilized oil prod	Gas prod	Gas flared	Gas fuel	NGL/cond Kårstø	Gas Emden
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3	Mill Sm^3
JAN	2143.	220.	6.	26.	20.	155.
FEB	1940.	202.	4.	24.	24.	115.
MAR	2066.	214.	6.	25.	23.	129.
APR	1996.	216.	4.	25.	32.	153.
MAY	2124.	234.	10.	26.	32.	166.
JUN	1614.	173	6.	19.	25.	128.
JUL	2059.	217.	7.	25.	29.	152.
AUG	2114.	225.	15.	26.	24.	143.
SEP	2059.	217.	11.	26.	13.	140.
OCT	2217.	239.	3.	27.	33.	180.
NOV	2272.	248.	3.	26.	32.	174.
DEC	2423.	268.	5.	28.	49.	164.
YEAR TOTAL	25027.	2673.	80.	303.	336.	1799.

Table 7.4.f
Monthly oil and gas production from Gyda

1992	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3	1000 Sm^3	Mill Sm^3
JAN	159.	22.	1.0	2.	148.	16.	18.
FEB	328.	47.	.5	2.	303.	35.	40.
MAR	345.	50.	.6	3.	322.	36.	42.
APR	361.	52.	.2	3.	335.	39.	45.
MAY	281.	41.	.2	2.	261.	30.	35.
JUN	330.	47.	.6	3.	307.	34.	39.
JUL	337.	48.	.2	3.	313.	35.	41.
AUG	337.	48.	.1	3.	314.	36.	41.
SEP	328.	48.	.8	3.	306.	34.	41.
OCT	357.	54.	.2	3.	333.	34.	48.
NOV	342.	52.	.2	3.	317.	34.	45.
DEC	353.	53.	.1	4.	329.	36.	44.
YEAR TOTAL	3858.	562.	4.7	34.	3588.	399.	479.

Table 7.4.g
Monthly gas and condensate production from Heimdal

1992	Gas prod	Condensate prod	Gas flared	Gas fuel	Gas sold Emden	Condensate Kinneil
	Mill Sm^3	1000 Sm^3	1000 Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3
JAN	310.	50.	107.	4.	326.	46.
FEB	287.	47.	70.	4.	293.	46.
MAR	295.	48.	16.	4.	311.	44.
APR	246.	40.	61.	4.	264.	36.
MAY	265.	43.	60.	4.	286.	39.
JUN	250.	41.	27.	4.	265.	37.
JUL	242.	39.	7.	4.	257.	40.
AUG	285.	46.	40.	4.	303.	44.
SEP	250.	41.	101.	4.	266.	37.
OCT	279.	45.	6.	4.	313.	42.
NOV	254.	41.	21.	4.	309.	38.
DEC	288.	47.	14.	4.	317.	43.
YEAR TOTAL	3251.	528.	531.	48.	3510.	491.

Table 7.4.h
Monthly oil and gas production from Hod

1992	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³
JAN	131.	19.	.1	1.	126.	6.	18.
FEB	115.	17.	.1	1.	109.	7.	17.
MAR	111.	21.	.1	2.	107.	6.	19.
APR	121.	23.	.1	2.	116.	7.	22.
MAY	100.	19.	.1	1.	95.	6.	18.
JUN	121.	5.	.3	2.	115.	7.	18.
JUL	121.	11.	.1	2.	115.	7.	24.
AUG	117.	17.	.3	2.	111.	7.	25.
SEP	108.	5.	.4	2.	102.	6.	19.
OCT	110.	25.	.1	2.	105.	6.	25.
NOV	97.	21.	.5	1.	91.	6.	22.
DEC	99.	24.	.1	2.	95.	5.	23.
YEAR TOTAL	1351.	205.	2.3	19.	1288.	77.	250.

Table 7.4.i
Monthly oil and gas production from Mime

1992	Unstabilized oil prod	Gas prod	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm³	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³
JAN	13.	3.	13.	1.	3.
FEB	12.	2.	11.	1.	3.
MAR	10.	2.	10.	1.	2.
APR	9.	2.	8.	1.	2.
MAY	10.	2.	9.	1.	2.
JUN	11.	2.	11.	1.	2.
JUL	11.	2.	11.	1.	2.
AUG	11.	2.	11.	1.	2.
SEP	10.	2.	10.	1.	2.
OCT	11.	2.	11.	1.	2.
NOV	10.	2.	10.	1.	2.
DEC	9.	2.	9.	1.	2.
YEAR TOTAL	127.	25.	124.	12.	26.

Table 7.4.j
Monthly oil and gas production from Murchison

1992	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sullom Voe	NGL S.Voe/St.Fer	Gas St.Fergus
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³
JAN	55.	7.	1.2	1.1	51.	2.	0.0
FEB	54.	7.	1.2	1.0	49.	2.	.4
MAR	33.	4.	.5	.7	30.	1.	.3
APR	54.	7.	.9	1.1	49.	2.	.4
MAY	52.	7.	.5	1.3	47.	2.	.5
JUN	43.	6.	.5	1.3	40.	1.	0.0
JUL	37.	5.	.2	1.2	35.	1.	.3
AUG	34.	5.	.8	.9	31.	1.	.2
SEP	35.	5.	.4	1.1	32.	1.	.2
OCT	39.	5.	.3	1.3	36.	1.	.3
NOV	37.	5.	.3	1.2	35.	0.	.3
DEC	37.	5.	.1	1.3	34.	1.	.3
YEAR TOTAL	510.	68.	6.9	13.5	469.	15.	3.2

These figures are for the Norwegian share of Murchison.

Table 7.4.k
Monthly oil and gas production from Oseberg

1992	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sture
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3
JAN	2214.	333.	2.	17.	2202.
FEB	1426.	197.	8.	9.	1416.
MAR	2170.	287.	13.	7.	2162.
APR	2193.	298.	1.	17.	2184.
MAY	2268.	308.	1.	16.	2265.
JUN	2192.	299.	2.	15.	2183.
JUL	2253.	295.	5.	15.	2248.
AUG	2252.	294.	2.	18.	2248.
SEP	2208.	292.	2.	17.	2204.
OCT	2240.	303.	4.	17.	2232.
NOV	2174.	295.	5.	17.	2167.
DEC	2287.	306.	1.	20.	2280.
YEAR TOTAL	25877.	3507.	46.	185.	25791.

Table 7.4.l
Monthly oil and gas production from Snorre

1992	Stabilized oil prod	Gas prod	Gas flared	Gas fuel	NGL/condensate Kårstø
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3
JAN					
FEB					
MAR					
APR					
MAY					
JUN					
JUL					
AUG	78.	9.	7.	0.0	3.
SEP	223.	25.	12.	0.0	6.
OCT	317.	32.	5.	0.0	15.
NOV	479.	45.	1.	3.	22.
DEC	472.	44.	2.	3.	41.
YEAR TOTAL	1569.	155.	27.	6.	87.

Table 7.4.m
Monthly oil and gas production from Statfjord

1992	Stabilized oil prod	Gas prod	Gas flared	Gas fuel	NGL/cond Kårstø	Gas Emden
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3	Mill Sm^3
JAN	3454.	707.	9.	38.	95.	286.
FEB	3243.	677.	7.	35.	148.	270.
MAR	3314.	700.	6.	37.	128.	266.
APR	3291.	704.	6.	36.	144.	234.
MAY	2527.	511.	6.	27.	115.	219.
JUN	3225.	686.	7.	35.	125.	235.
JUL	3199.	693.	5.	36.	117.	215.
AUG	2639.	579.	9.	29.	145.	266.
SEP	2665.	564.	8.	30.	68.	225.
OCT	3256.	694.	5.	37.	140.	265.
NOV	2994.	630.	5.	34.	128.	240.
DEC	3184.	647.	5.	37.	179.	259.
YEAR TOTAL	36991.	7792.	78.	411.	1532.	2980.

These figures are for the Norwegian share of Statfjord.
The figures for oil include quantities repayed in connection with redistribution per September 1991.

Table 7.4.n
Monthly oil and gas production from Tommeliten

1992	Unstabilized oil prod	Gas prod	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm³	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³
JAN	59.	118.	44.	12.	109.
FEB	51.	107.	38.	11.	98.
MAR	55.	113.	42.	11.	105.
APR	54.	110.	41.	11.	102.
MAY	41.	89.	31.	9.	82.
JUN	33.	69.	24.	7.	64.
JUL	55.	114.	40.	12.	106.
AUG	54.	117.	39.	12.	108.
SEP	48.	103.	35.	11.	95.
OCT	40.	93.	31.	7.	86.
NOV	48.	111.	35.	10.	104.
DEC	52.	121.	37.	12.	111.
YEAR TOTAL	590.	1265.	437.	125.	1170.

Table 7.4.o
Monthly oil and gas production from Togi

1992	Gas prod	Condensate prod	Gas flared	Gas fuel	Stabilized oil Sture
	Mill Sm³	1000 Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	337.	6.	1.0	4.	5.
FEB	191.	3.	.0	3.	3.
MAR	372.	6.	.4	9.	5.
APR	386.	7.	.0	5.	6.
MAY	315.	6.	.0	5.	5.
JUN	246.	5.	.0	4.	4.
JUL	363.	6.	.1	5.	6.
AUG	402.	7.	.0	5.	7.
SEP	377.	7.	.1	4.	6.
OCT	360.	6.	.1	4.	6.
NOV	290.	6.	.0	4.	5.
DEC	284.	6.	.2	3.	5.
YEAR TOTAL	3923.	71.	1.9	55.	63.

Table 7.4.p
Monthly oil and gas production from Ula

1992	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³
JAN	703.	54.	1.3	6.	672.	50.	41.
FEB	653.	50.	.6	6.	622.	46.	38.
MAR	707.	54.	.9	6.	679.	50.	41.
APR	687.	53.	.4	6.	656.	51.	40.
MAY	539.	42.	.4	5.	516.	39.	31.
JUN	671.	53.	1.1	5.	639.	48.	39.
JUL	676.	54.	.5	6.	646.	47.	41.
AUG	642.	52.	.6	6.	615.	45.	39.
SEP	587.	47.	.9	5.	561.	41.	36.
OCT	579.	47.	1.1	5.	557.	34.	37.
NOV	580.	46.	.9	5.	557.	39.	36.
DEC	620.	50.	.6	6.	596.	41.	37.
YEAR TOTAL	7644.	602.	9.4	67.	7316.	531.	456.

Table 7.4.q
Monthly oil and gas production from Valhall

1992	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3	1000 Sm^3	Mill Sm^3
JAN	383.	84.	.3	6.	367.	22.	80.
FEB	322.	74.	.4	5.	307.	18.	69.
MAR	341.	74.	.3	5.	327.	19.	71.
APR	317.	72.	.4	5.	304.	17.	69.
MAY	291.	64.	.4	4.	280.	15.	61.
JUN	381.	86.	1.2	5.	365.	21.	81.
JUL	368.	85.	.4	5.	351.	20.	82.
AUG	368.	88.	.9	5.	353.	20.	84.
SEP	343.	86.	1.1	5.	327.	18.	82.
OCT	357.	85.	.3	5.	342.	18.	81.
NOV	364.	86.	1.7	5.	348.	19.	81.
DEC	395.	90.	.3	5.	376.	21.	87.
YEAR TOTAL	4231.	973.	7.5	62.	4046.	228.	928.

Table 7.4.r
Monthly oil and gas production from Veslefrikk

1992	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	NGL/cond Kårstø	Stabilized oil Sture
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3	1000 Sm^3
JAN	339.	37.	1.	3.	13.	343.
FEB	254.	24.	2.	3.	17.	257.
MAR	355.	38.	1.	4.	19.	356.
APR	343.	41.	2.	3.	25.	346.
MAY	356.	42.	2.	4.	23.	357.
JUN	341.	39.	1.	3.	22.	341.
JUL	334.	37.	1.	4.	21.	334.
AUG	341.	42.	1.	4.	22.	342.
SEP	248.	27.	2.	3.	10.	250.
OCT	343.	42.	2.	4.	22.	342.
NOV	338.	41.	1.	4.	21.	338.
DEC	346.	42.	1.	4.	30.	348.
YEAR TOTAL	3938.	452.	17.	43.	245.	3954.

Statfjord, Valhall, Murchison, Ula, Gullfaks, Tommeliten, Hod, Mime, Veslefrikk, Gyda and Snorre.

The data for gas in Table 7.4.a indicate the volumes sold in all fields. For the fields Statfjord, Frigg area, Heimdal and Gullfaks, condensate is included.

7.5 NPD PUBLICATIONS IN 1992

Acts, regulations and guidelines

- *Acts, Regulations and Provisions* for the Petroleum Activity 1992. A compilation of the acts etc applying to the offshore industry issued each year and up to date on 1 January 1992. Published in two volumes. English and Norwegian text.
- Supplement to *Acts, Regulations and Provisions* for the Petroleum Activity 1992. New compilation of *Technology Regulations* and guidelines. English and Norwegian text.
- Regulations for *Drilling, Well Activities and Geological Data Collection* in the Petroleum Activities, with Guidelines. English and Norwegian text.
- Regulations for *Lifting Appliances and Lifting Gear* in the Petroleum Activities, with Guidelines. English and Norwegian text.
- Regulations for *Loadbearing Structures* in the Petroleum Activities, with Guidelines. English and Norwegian text.
- Regulations for *Marking of Installations* in the Petroleum Activities, with Guidelines. English and Norwegian text.
- Regulations for *Emergency Preparedness* in the Petroleum Activities, with Guidelines. English and Norwegian text.
- Regulations for *Process and Auxiliary Facilities* in the Petroleum Activities, with Guidelines. English and Norwegian text.
- Regulations concerning *Safety and Communications Systems* on Installations in the Petroleum Activities, with Guidelines. English and Norwegian text.
- Regulations for *Explosion and Fire Protection* on

Installations in the Petroleum Activities, with Guidelines. English and Norwegian text.
- *Grenseflater til sokkellovgivningen.* Common Borders with the Continental Shelf Legislation. Norwegian text.
- *Likhetsstudien 1992.* Similarity Study (of the continental shelf and flag-state regulations to identify areas of overlap and parallelism). Norwegian text.

Studies and reports
- Project report: *Forholdet mellom risiko- og beredskapsanalyse.* Connection between Risk Analysis and Emergency Preparedness Analysis. Norwegian text.

Other publications
- *Well Data Summary Sheets.* Volume 16, Wells completed 1985. English text.
- *Well Data Summary Sheets.* Volume 17, Wells completed 1986. English text.
- NPD Contribution no. 32. *En biostratigrafisk og seismostratigrafisk analyse av tertiære sedimenter i nordlige deler av Norskerenna, med hovedvekt på øvre pliocene viftavsetninger.* A biostratigraphic and seismostratigraphic analysis of Tertiary sediments in northern parts of Norwegian Trench, with main emphasis on Upper Pliocene fantail sediments.
- NPD Contribution no. 33. *Identification for Wells.* English and Norwegian text.
- *Oljedirektoratets årsberetning 1991.* NPD Annual Report 1991. Norwegian text.
- *NPD Annual Report 1991.* English text.
- *The Norwegian Continental Shelf.* Two-way offshore time map of the unconformity at the base of the Upper Jurassic (north of 69°N) and the unconformity at the base of the Cretaceous (south of 69°N), including the main geological trends onshore.
- *Licences, Areas, Area Coordinates, Exploration Wells.* English text.
- *Borehole List.* English text.
- *Borehole List – Exploration Drilling.* English text.
- *Opprydding av havbunnen i Nordsjøen 1991.* North Sea Seabed Clearance 1991. Norwegian text.
- *Report from the Dive Database – DSYS.* English and Norwegian text.
- *Oljedirektoratet – Spesifikke krav til beredskap.* NPD – Specific requirements for emergency preparedness. Norwegian text.
- *Released Seismic Surveys.* A survey of released seismic packages. English text.
- *Russisk-engelsk-norsk petroleumsteknisk ordliste.* Russian-English-Norwegian Petroleum Technology Glossary. Norwegian text.
- *Safety and Working Environment in the Offshore Petroleum Industry.* A guide to the understanding of the safety regime. English text.
- *Well Data Published by NPD.* An overview of well data from released wells which can be ordered from the NPD. English text.

7.6 ORGANISATION CHART