Norwegian Petroleum Directorate

ANNUAL REPORT 1987

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Unofficial translation

«The objectives of the Norwegian Petroleum Directorate are actively to contribute to a sound administration of the Norwegian petroleum resources through a balanced evaluation of the natural, safety-related, technological and economic aspects of the activity within an overall framework.»

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Report of the Board of Directors

1987 was characterized by the difficult situation in the international oil market. The oil price fluctuated between USD 17 and 20 per barrel through most of the year. This level could be sustained since OPEC was able to limit its production sufficiently to avoid a relapse to the price level of the summer of 1986.

An oil price of USD 17–20 per barrel is still low compared with the level at the end of the 70s and the beginning of the 80s, and this affected the scope of exploration drilling in general and also on the Norwegian continental shelf in 1987. In total, 36 exploration wells were drilled, as many as the year before, but 14 less than the record year 1985. The level of activity was highest in the North Sea, with 17 exploration wells. 14 exploration wells were drilled off Mid Norway and 5 in new areas in the Barents Sea.

A number of interesting discoveries were made, particularly in the North Sea, whilst the expectations of discoveries in the Barents Sea were not fulfilled. Gas was discovered in two new blocks in the Barents Sea (7122/6 and 7124/3), but significant discoveries of oil were not made in the course of the year.

If we look at Norway's total petroleum accounts on the basis of the production in 1987, adjustment of reserve estimates of existing discoveries and the supply through new discoveries, more petroleum has been recovered through the year than the reserves that have been added. Norway thus retains oil reserves for 32 years of production and gas for 99 years production at the 1987 level.

Judging from the applications in the 11th licensing round, the interest in the northern areas of the Norwegian continental shelf is still substantial in the international oil industry. The 11th licensing round comprised a total of 13 exploration licences:

7 in the Barents Sea, 4 on Haltenbanken, 1 on Møre South and 1 in the North Sea. This round comprised three key areas in the Barents Sea. 18 companies expressed interest in Areas I and II, and 12 in Area III.

There is still great interest in Svalbard, and this must be seen in conjunction with the increased level of activity in the Barents Sea. A new well was started on Svalbard in 1987 with the drilling by Nordisk Polarinvest at Haketangen in the south–eastern part of Spitsbergen. Minor quantities of gas have so far been tested at this location. In addition, the Russian company Trust Artikogul has spudded a new well in Vassdalen, close to the former well which was terminated in the summer of 1987.

The increased activity in the North has involved the Norwegian Petroleum Directorate's staff in several ways. On the exploration side, efforts were made to keep two units operating throughout the year. This was achieved when the operating companies signed a contract to drill in a predetermined sequence with "Polar Pioneer" and "Ross Rig".

The Board of Directors is very concerned with the safety and the working environment aspects of the operations on the continental shelf. In this area, the Directorate has in particular worked with the perspectives concerning the experience with coordinating working environment committees. Furthermore, the supervision of the preservation of the working environment in all phases of the operations has been intensified. In the time to come, the Norwegian Petroleum Directorate will focus on working environment questions.

The injury rate for all activities was at about the same level in 1987 as the year before. The Board of Directors is pleased to be able to conclude that there has been a significant reduction of injuries in connection with drilling operations. Recent years' focusing on this has resulted in fewer injuries. The injury rate within the construction and maintenance activities show a significant increase compared with 1986, however. This increase is the result of a particular increase in the level of construction activities in 1987.

Because of the large distances, climatic conditions and the partial lack of infrastructure in the northern parts of the country, major attention has been given to the emergency preparedness aspects of the operations in the Barents Sea. Large distances have the effect that the drilling units in the north must rely on their own emergency preparedness resources to a greater extent than in the North Sea.

Efforts have been made to raise the emergency preparedness level through location of special search and rescue helicopters at Hammerfest, and by involving Bjørnøya in the emergency preparedness for Area II in the Barents Sea.

In addition, a basis has been laid for special legislation concerning emergency preparedness for the whole of the Norwegian continental shelf in the course of the year.

International cooperation, and participation by the Norwegian Petroleum Directorate in the work of international organizations, ensures that the work sites on the contintental shelf are in compliance with international standards for safety and working environment. The interest in Norwegian experience and our methods of regulating the operations are increasing in the international community.

The Norwegian Petroleum Directorate is also represented in the Norwegian working party which takes part in the International Maritime Organization's discussions about final production and removal of offshore installations, a question which must be faced in a few years' time on the Norwegian shelf.

Major progress has been made in 1987 as well in the development of the data base Infoil 2 into an international, electronic source of knowledge for shelf–related research projects; Canada is interested in participation and EEC's headquarters in Brussels supplies data from its research projects to the Norwegian/British Infoil 2.

The event on the Norwegian continental shelf which triggered the greatest national and international interest in 1987 was the raising of 6 platforms in the Ekofisk complex after the discovery in 1984 that the seafloor under Ekofisk was subsiding. With the help of hydraulic, computer controlled jacks, all six platforms were raised at the same time, an operation which has never before been undertaken offshore, which the operator was able to accomplish entirely according to plan.

The exploitation of the resources in the Ekofisk area has presented the Norwegian Petroleum Directorate with a number of difficult choices in 1987. The concern for optimal exploitation and national economy has had to be balanced against the existing supply obligations for gas from the Ekofisk area.

Further water injection, which has been approved, combined with possible nitrogen injection, may possibly compensate for the pressure loss caused by the present gas production. However, further contraction, deformation of wells and reduced productivity may affect the future oil production in the area in a negative way.

The Norwegian Petroleum Directorate thus considers it essential that the production strategy selected for Ekofisk will be followed very closely by the authorities, also for the years to come.

Limitation of production has been applied on the Norwegian continental shelf in 1987 too. In the view of the Norwegian Petroleum Directorate, the limitation has been followed up in a satisfactory manner by the individual operator. However, it is necessary to undertake a close examination of the production potential for the individual field, with a view to ensuring that the production limitation will not hurt the overall long–term exploitation from the fields.

Norway has imposed production limitations as a contribution to stable oil prices. Changed tax rules, a certain improvement of oil prices and a reduction of development costs through improved technology has made it economically possible to develop further fields. Within its area of expertise and responsibility, the Norwegian Petroleum Directorate has thus helped to throw light on the various aspects of an optimal sequence for the development of oil fields in the immediate future.

Should all present plans be realized, we would experience peak investments on the Norwegian continental shelf in 1991, peak production some years later in the 90s and a strong decrease in oil production some years afterwards.

The perspective analysis for 1987 highlights the uncertainty of the framework conditions for Norway's future oil income. The uncertainty in this instance supports the objectives of the Ministry of Petroleum and Energy and the Government about limiting investments on the shelf at about NOK 25 billion per year. The perspective analysis also establishes a number of criteria which may be used to clarify the fields which may be developed.

In 1987 the Norwegian Petroleum Directorate finished the consideration of the plans for the development and operation of the Gyda, Veslefrikk, Snorre and Draugen fields. The plans for Gyda and Veslefrikk were approved by the Storting in June, while it is expected that the plans for Snorre and Draugen will be discussed by the Storting early in 1988.

The Directorate has furthermore dealt with an updated plan for the development and operation of the Oseberg field. This involves accelerated installation of the platform in the northern part of the field. At the end of the report period, the plans for the development and operation of the Heidrun and Brage fields were being dealt with.

The Directorate has worked with analyses concerning the coordination of the Haltenbanken area on the basis of the establishment of joint transportation solutions and infrastructure. In the case of swift development of an oil field at Haltenbanken, the Norwegian Petroleum Directorate recommends that buoy loading be selected as a transportation system for oil. A study has been published ("Fields in Sequence") in the report period.

In its work on the Snorre development, the Norwegian Petroleum Directorate has been concerned about the uncertainty involved in the magnitude of recoverable reserves, the sensitivity to price uncertainty and the consideration for supplemental reserves in the area. The Norwegian Petroleum Directorate has requested that the licensees should by the autumn of 1988 present a plan which satisfies the requirements of the authorities concerning the exploitation of supplementary reserves in the field.

As concerns the staffing situation in the Norwegian Petroleum Directorate, the Board of Directors note with satisfaction that resignations among the employees of the Directorate are the lowest since 1976. This is a highly satisfactory development, which ensures that the expertise of the Directorate is retained.

Stavanger, 29 January 1988

Members of the Board of Directors
of the Norwegian Petroleum Directorate

Martin Buvik

Andreas Lønning *Bjørg Simonsen* *Liv Hatland*

Kåre D. Nielsen *Jan B. M. Strømme*

Odd Raustein *Anne-Lise Jensen*

Fredrik Hagemann
Director General

Bjørn Bratbak
Head of Branch
Secretary of the Board

1. The Directorate's Tasks, Board of Directors and Administration

1.1 The Directorate's terms of reference

The objectives and tasks of the Norwegian Petroleum Directorate are provided for in special instructions. These were last amended on 29 March 1979. The instructions' § 1 relating to its objectives and § 2 relating to its tasks are worded as follows:

§ 1 Objectives

The Norwegian Petroleum Directorate is located in Stavanger and reports to the Royal Norwegian Ministry of Petroleum and Energy (MPE). In matters relating to the working environment, safety and preparedness, it reports to the Royal Norwegian Ministry of Local Government and Labour (ML). The Norwegian Petroleum Directorate is authorized to determine matters relating to exploration for and exploitation of petroleum resources on the sea floor and its substrata, to the extent that these matters are not to be determined by the King, relevant Ministry or other public authority. The Norwegian Petroleum Directorate exercises this authority in Norwegian coastal waters, Norwegian sea territory, on that part of the continental shelf which is subject to Norwegian sovereignty, and in other areas where Norwegian jurisdiction follows from agreements with foreign states or from international law in general. In addition, the Norwegian Petroleum Directorate shall enforce safety regulations etc, in the areas defined by Article 1 of the Svalbard Treaty of 9 February 1920 and Section 1 of the Svalbard Act of 27 July 1925, and in the territorial waters of these areas.

§ 2 Tasks

The tasks of the Norwegian Petroleum Directorate within its area of authority are:

a. To exercise regulatory and financial control to ensure compliance with applicable legislation, regulations, decisions, licensing terms, agreements, etc in the exploration for and exploitation of petroleum, see § 1.
b. To ensure that applicable safety regulations are complied with.
c. To ensure that the exploration for and exploitation of petroleum resources does not lead to unnecessary damage or cause inconvenience to other activities.
d. To ensure that the exploration for and exploitation of petroleum resources at all times takes place in compliance with the guidelines laid down by the authorized Ministry.
e. To collect and process geological, geophysical and technical material relating to subsea natural resources, including their evaluation and the possibilities thereby available for the formulation of national petroleum policy and negotiation plans, as well as to plan and see to the performance of geological and geophysical petroleum surveys.
f. To undertake current financial control of exploration for and exploitation of petroleum resources.
g. To issue exploration licences and assist the relevant Ministry, upon request, in the processing of applications for other licences, the formulation of regulations, etc.
h. To maintain links with scientific institutions and ensure that material is made available to interested companies, scientific institutions, etc, to the extent that this is possible in view of the rules which apply concerning confidential treatment of material submitted by licencees and in general pursuant to the decision of the relevant Ministry.
i. To keep the Ministries informed at all times about the activity given in § 1, and to present the issues dealt with by the Directorate which do not come under § 2 a–h, to the Ministry in question.
j. To prepare and present for decisiön to the relevant Ministry matters of significance to plant and animal life or matters which may otherwise affect important environmental preservation interests in the areas mentioned in § 1, final sentence.
k. To present to the relevant Ministry regulations and individual decisions made concerning proper and sound exploitation of petroleum resources (conservation).
l. To act as advisory body to the Ministries in matters relating to exploration for and exploitation of subsea natural resources.

Even if a matter is subject to the authority of the Directorate pursuant to § 2 a–h, it shall be presented to the appropriate Ministry if of special importance or fundamental interest.

1.2 The Directorate's objectives

On the basis for one of the above terms of reference, the following objectives for the Directorate have been laid down:

"The objectives of the Norwegian Petroleum Directorate are actively to contribute to a sound administration of the Norwegian petroleum resources through a balanced evaluation of the natural, safety-related, technological and economic aspects of the activity within an overall social framework."

1.3 The Board of Directors and the Administration

1.3.1 The Board of Directors

At the beginning of the the report period, the Board consisted of:
1 Mr Martin Buvik, County Governor, Tromsø (Chairperson)
2 Mr Andreas Lønning, Managing Director, Oslo
3 Ms Bjørg Simonsen, Researcher ,Mo i Rana
4 Ms Liv Hatland, Managing Director, Oslo
5 Mr Kåre D. Nielsen, Director, Oslo
6 Mr Ole Knapp, Secretary, Oslo
7 Mr Odd Raustein, Section Manager, Stavanger
8 Mr Bjørn Kvant, Archives Manager, Stavanger

Deputies:

For 1–4:
Mr Per Sævik, Manager, Rimøy
Ms Marit Greve, Editor, Bærum

For 5:
Mr Halvor Ø Vaage, Managing Director, Stavanger

For 6:
Mr Jan Strømme, Oil Secretary, Oslo

For 7–8:
Mr Kjell G Dørum, Special Advisor, Stavanger
Ms Anna Aabø, Special Advisor, Stavanger

The term of office of this Board expired 15 April 1987. By Royal Decree of 10 April Directors Nos. 1–7 were reappointed for a new two–year period up to 15 April 1989. As new Director No. 8, chosen by and from among the employees, was appointed

Anne–Lise Jensen, Stavanger, Chief Engineer.

As deputies for the period up to 15 April 1989 were appointed the following:

For 1–4:
1. Mr Per Sævik, Manager, Rimøy
2. Ms Sylvi Eneyoldsen, Clerk, Hammarfest
3. Ms Marit Greve, Editor, Bærum

For 5:
Mr Halvor Ø Vaage, Managing Director, Stavanger

For 6:
Mr Jan Strømme, Oil Secretary, Oslo

For 7–8:
Ms Anna Aabø, Special Advisor, Stavanger
Bjørn Kvant, Archives Manager, Stavanger

During the report period the Board held nine meetings. In March the Board held an informal briefing and working meeting with the Ministers of Petroleum and Energy and Local Government and Labour. In August the Board visited the Directorate's regional office in Harstad.

1.3.2 Organisation

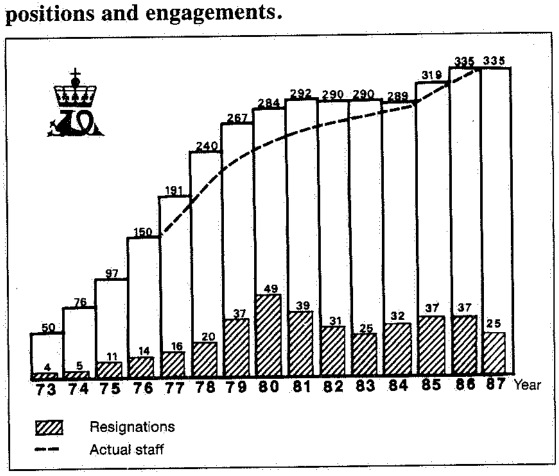
1987 has been characterised by adaptation and consolidation of the new organisational structure implemented in 1986. Internally within the organisation and in meetings between management and staff unions there has been further discussion of the details of the new structure, working methods and framework descriptions. New instructions for the branch office in Harstad have also been laid down.

1.3.3 Personnel

At the end of the report period there were 335 authorized positions in the Directorate. The Norwegian Petroleum Directorate was given no new posts in 1987. In connection with a government research program for enhanced recovery (the SPOR project) directly under the auspices of the Ministry of Petroleum and Energy, a four–year temporary position has been set up to head the project. In addition there are three positions salaried by the Directorate for Development Aid (NORAD). At year–end 1987 the Directorate employed 350 persons, see Figure 1.3.3.a. Staff members include 36.2 per cent women. Figure 1.3.3.b shows the proportions of men and women in the various job categories within the Directorate. Also working at the Directorate during the entire report period was one of NORAD's special advisors on oil matters in developing countries.

In 1987 the Directorate dealt with 59 vacancies (Table 1.3.3c) and took on 32 new members of staff. Of the newcomers, 11 have relocated to Stavanger, 9 come from oil–related activities and 4 are newly qualified.

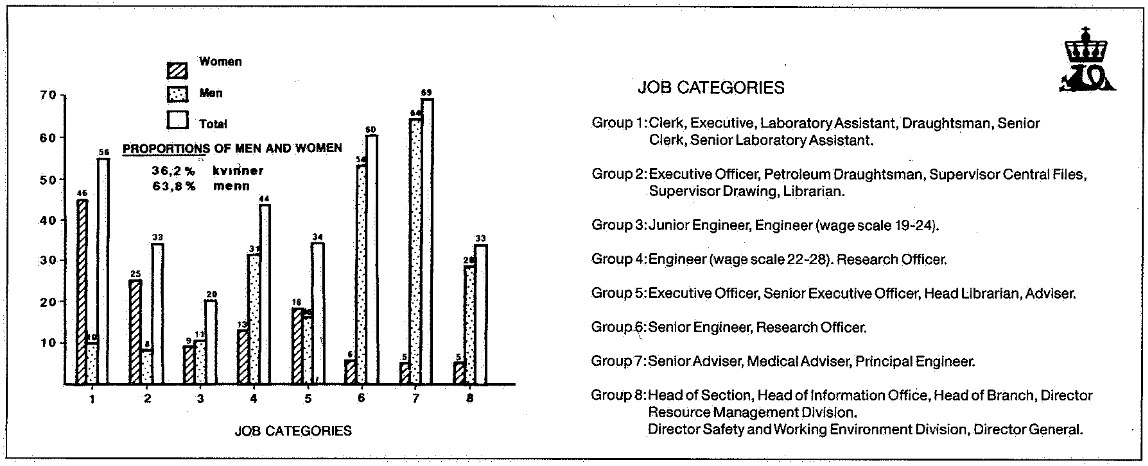
Fig 1.3.3.a
Positions 1973 - 1987. Permanent positions and engagements.



Tab 1.3.3.a
Personnel leaving the Directorate in 1987 by job category

Divison/ Branch	Managers	Senior advisers	Princ eng	Senior eng	Senior geologist/ geologists	Eng/ jnr. eng	Adviser	Jnr. exec./off exec. off/ sen. exec.	Office staff	Total	Decline in %
R-div	1	1	1	1	0	3	2	1	0	10	7,5
S-div	0	0	0	1	0	0	0	0	1	2	1,9
L branch	0	0	0	0	0	0	1	1	0	2	20,0
Adm. branch	0	0	1	0	0	2	0	1	6	10	14,3
Inf. office	0	0	0	0	0	0	0	0	1	1	25,0
Total	1	1	2	2	0	5	3	3	8	25	7,4

Fig 1.3.3.b
Position groups as of 31 December 1987.

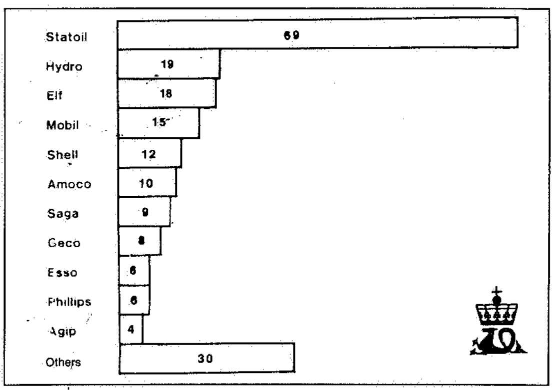


Tab 1.3.3.b
Personnel leaving the Directorate in 1987 indicating new place of work

Divison/ Branch	Oil industry	Other nongov't activity	Other gov't activity	Miscell aneous	Education	Total
Resource Management	5	3	0	1	1	10
Safety and Working Env.	0	2	0	0	0	2
Legal	1	1	0	0	0	2
Administration	0	2	3	4	1	10
Information office	0	0	1	0	0	1
Total	6 (209)	8 (43)	4 (54)	5 (56)	2 (22)	25(381)

The figures in parenthesis apply for the period of time 1973-1987

Fig 1.3.3.c Personnel leaving the Directorate for oil companies 1973 - 1987.



Twenty–five members of staff left their positions, see Table 1.3.3.a and b. This constitutes approximately 7.4 per cent of the total number of authorized positions.

The drain from the Safety and Working Environment Division has shown a sharp reduction in 1987. The drain from the Resource management Division, the Administration branch and the Legal Branch is quite like that in 1986.

Figure 1.3.3.c shows the personnel transfer from the Norwegian Petroleum Directorate to various oil companies for the years 1973–87.

Equal Opportunities Work

As a result of a special agreement on equal opportunities the Directorate possesses an Equal Opportunities Committee. This committee consists of four

Tab 1.3.3.c
Distribution of applicants among vacant positions

Position category	Number of vacancies announced	Total number applicants		Number of internal applicants		Number of external applicants		Number of applicants telcon on in cases now closed	
		M	K	M	K	M	K	M	K
Management	5	12	4	5	2	7	2	1	1
Techn. case officers	25	276	89	31	23	245	66	9	3
Non-techn. case off	18	166	142	5	17	161	125	10	9
Clerical	11	14	75	3	5	11	70	2	7
Total	59	468	310	44	47	424	263	22	20

members, two from management and two from the staff unions.

The committee checks to see that qualified women applicants have been called in to interview when vacancies occur. This initiative has been well received by the appointments authorities.

The committee has worked on an action plan for equal opportunities work within the Directorate and preparing internal background material. Information work to create acceptance and a positive attitude to equality is considered by the committee to be its most important task. The equal opportunities committee has established a "surgery" of one hour per week.

When advertising vacancies which qualify under the quota rules, women are encouraged to apply. The numbers of women applicants has increased since the change in the wording of the advertisement.

Co-determination

Cooperation with the staff unions has followed the same pattern as previously, with monthly meetings between the employee delegates and general management. During the period, 15 meetings were held which all in all considered 15 matters. The following current matters can be mentioned:

- budget proposals
- new organisational structure
- working environment study
- changes in personnel regulations
- new instructions for the Harstad office
- system for registration of hours use in Safety and Working Environment Division
- computer organisation
- guidelines for overtime work.

In line with practice in previous years, the board organized a two–way briefing with representatives of the seven staff unions.

Training

The training budget in 1987 was NOK 3,290,000. These funds have been used in accordance with earlier practice, and large amounts have as previously been allocated to travelling and overnight expenses. As in the previous report period several staff members have participated in on–the–job (OTJ) training with the oil companies. These courses are usually carefully prepared by the companies and the training periods have been well worth while for all attending.

1.3.4 Budget/finance

In all NOK 259,749,763 was granted for the Directorate's various functions in 1987. The figure can be broken down as follows:

Operating budget	NOK	141,677,830
Inspection costs	NOK	12,233,842
New-premises	NOK	1,590,663
Geological and geophysical surveys	NOK	77,548,663
Safety and emergency preparedness research	NOK	2,000,366
Cleaning up the seabed	NOK	4,698,429
Total appropriation budget for 1986	NOK	259,749,763

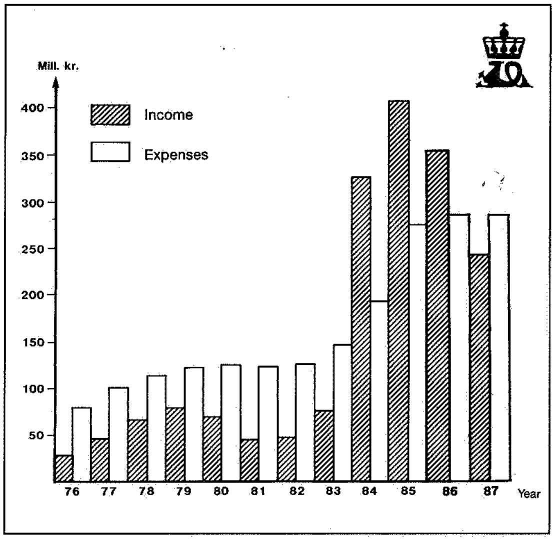
NOK 89,196,894 of the operating budget was allocated to salaries and NOK 5,352,520 to the running of buildings and renting of premises. The remaining NOK 67,128,416 of the operating budget represents other expenses such as external consultancy services, operation of a weather ship, research and development projects, travel, training, electronic data processing (EDP) operations, investment in new equipment, etc.

Its budget situation causes the Directorate to face an ever greater challenge regarding priorities. Efforts therefore focus on developing better planning and management systems. Delegation of authority is an often–used means to make more efficient use of the funds.

Revenues and income

In addition to revenues in the form of royalties and acreage fees (Chapter 5), the Directorate received income totalling NOK 252,142,765. Income in 1987 was distributed as follows:

Fig 1.3.4
NPD's operating budget 1976 - 1987.



Sales of publications	NOK	2,927,447
Sales of released sample material	NOK	662,068
Survey fees	NOK	1,340,000
Refunded inspection costs	NOK	27,579,330
Refunded for environmental data acquisition	NOK	4,500,000
Sales of seismic survey results	NOK	207,374,519
Credit interest on bank deposits	NOK	5,243,209
Miscellaneous income	NOK	2,546,192
Total income for 1986	NOK	252,172,765

The Directorate's operating budget and income development for the period 1976–87 are shown in Figure 1.3.4.

1.3.5. Information

During this report period there has been a brisk demand for information both from Norwegian and foreign institutions, the media, enterprises and individuals. In the course of the year the Directorate has entertained several official delegations from other countries. Furthermore, many foreign journalists, individually or in groups, have visited the Directorate to obtain information about us and the oil activity. For their part, Norwegian Petroleum Directorate staff have frequently participated as speakers in various fora. The Norwegian Petroleum Directorate's Annual Report is a central feature of our information activities. The 1986 Annual Report became available in June, in which connection a press conference was arranged. The Continental Shelf Map, updated to 1 September 1987, was published in October. The Directorate's analysis of perspectives, the Petroleum Outlook for 1987, entitled "Adaptation to Uncertainty" was prepared in the report oil companies and other firms within the petroleum sector.

Library staff have given tours of the library and briefings on the library's services to oil companies, public services and other libraries.

period, but published subsequently. In the report period a brochure was prepared describing how the Norwegian Petroleum Directorate can help Norwegian companies supplying goods and services to the oil industry. An internal magazine was published in two issues in the report period.

During 1987 a total of 58 press bulletins were issued, inter alia in connection with the conclusion of exploration wells, where the Norwegian Petroleum Directorate attempts to provide maximum information.

1.3.7.The library

Library activity was again considerable in 1987 with once again an increase in enquiries for literature and information from internal and external users. Fifty–four per cent of all enquiries for literature stemmed from external users, including Norwegian and foreign libraries, students, private individuals,

The library actively participates in the publication of the Norwegian Petroleum Directorate's literature reference work Olje–indeks (Oil Index) and the reference data base OIL. Enquiries about literature references in the Oil Index and OIL are still considerable.

1.3.8. The INFOIL secretariat

Use of the OIl and INFOIL data bases and the number of subscribers to the associated printed editions is at the same level as previously. There is a clear tendency for the bases to be more used in the educational system, particularly the colleges.

Considerable progress has been made in getting Canadian authorities and business partners into the project INFOIL 2 as suppliers of research project data and as users of the databases.

We have been successful in getting the EEC administration in Brussels to supply data from its collection of "European Communities Oil and Gas Technological Development Projects" to the INFOIL base.

The INFOIL database has also been sold in subscription to one of the major foreign oil companies for installation internally in the company's own computer.

A new catalogue in Norwegian and English editions, "Offshore R & D Projects 1987" ("Petroleumforskning 1987") has been generated from the INFOIL database and put on sale.

A new edition of the Norwegian vocabulary bank – the Petroleum Thesaurus – has been put on sale on the Norwegian market. This is a collaborative project between the Norwegian Petroleum Directorate and Statoil, and the technical computing work on this edition has been done at the Norwegian Term Bank at the University of Bergen.

The secretariat for the Petroleum Documentation Forum, established as a foundation 29 April 1987, has inter alia included work on articles for the foundation, preparation for board meetings, members' newsletter, computerised membership register, contact with donors and cooperation with business manager.

1.3.8 The Harstad Regional Office

In 1987 the regional office was manned by 12 whole, 2 half and 1 1/2 time posts, in all 15 persons. No personnel resources have been added to NPD–H in 1987 over and above these posts. Two persons (half–post) have been on leave as of 31 December 1987, and have been replaced by substitutes as of the same date.

The Norwegian Petroleum Directorate's Harstad regional office, NPD–H, carries out the NPD's supervisory functions north of 69° N, including Svalbard and including both resource and safety administration. In this connection NPD–H has delegated formal authority as regards issuing of consents and drilling permits. NPD–H carries out the authorities' administration responsibility under the 1971 Safety Regulations for Svalbard. A revised safety regulations for Svalbard will be introduced in 1988. NPD also has administrative responsibility for scientific study permits north of 65° N with formal powers to issue permits. The Norwegian Petroleum Directorate's informational responsibility in the three northernmost counties of Nordland, Troms and Finnmark is carried out by NPD–H. Operation of the environmental data collection project in the Barents sea is delegated to NPD–H. Assignments linked to operation of the office, such as budget, accounts, personnel management and filing are also carried out.

NPD–H has been operational in 1987 under new instructions, with formal delegations introduced 1 July 1987. Assignments include supervision of petroleum activity in the exploration phase, which in 1987 has been mainly 11th round drilling with issuing of the necesary permits amnd follow–up. This includes five § 9 consents with five drilling permits and a § 8 consent with 17 drilling permits. In addition a drilling permit has been granted for Svalbard in 1987. Two scientific study permits have been issued in 1987. The main task in 1987 has been to adapt the organisation of NPD–H to the tasks delegated to it. As the Norwegian Petroleum Directorate was given no new posts for 1987, routines and procedures for casework have received considerable attention. At the same time, coordination with the main office for consistent treatment of the operators north and south of 69° N has been one of the major assignments.

2. Activity on the Norwegian Continental Shelf

2.1 Exploration and production licences
2.1.1. New exploration licences
As of 31 December 1987, 157 commercial exploration licences had been granted. Each licence has a term of three years.
The following licences were issued in 1987:

	Licence no.
Geophysical Company of Norway A/S	146
Mobil Exploration Norway Inc	147
Norsk Hydro A/S	148
Geophysical Service Inc	149
Esso Norway a.s.	150
Saga Petroleum a.s.	151
Fina Exploration Norway	152
Institute for Continental Shelf Studies	153
Amoco Norway Oil Company	154
A/S Geoteam	155
Norsk Agip A/S	156
Amerada Hess Norge A/S	157

Licences nos. 146 and 147 were issued in 1986, but were not applicable until 1 January 1987.

2.1.2 New production licences
13 new production licences, consisting of 22 blocks, were issued in 1987. Production licences 130 to 142 make up the 11th licensing round on the Norwegian shelf. This licensing round comprises the largest area allocated since the first licensing round on the Norwegian continental shelf. Production Licences 136, 137, 139, 140 and 141 comprise the so–called key blocks in the Barents Sea. Table 2.1.2.a contains information about the production licences issued in 1987, whilst Table 2.1.2.b gives information about all production licences issued since 1965. Table 2.1.2 c shows Norwegian and foreign interests in the individual licencing rounds.

2.1.3 Interest transfers
In the course of 1987, the following transfers have been approved in accordance with Section 61 of the Act of 22 March 1985 No. 11 concerning Petrolem Activities:

Production Licence no. 052
Svenska Petroleum Exploration A/S has acquired and merged with Petroswede Norge A/S. The allocations in Production Licence No. 036 are thus:

Den norske stats oljeselskap a.s.	50.000 %
Unocal Norge A/S	20.000 %
Deminex (Norge) A/S	12.500 %
Norsk Hydro Produksjon a.s.	10.000 %
Svenska Petroleum Exploration A/S	5.000 %
Norske Deminex A/S	2.500 %

Production Licence No. 036
Elf Aquitaine A/S has acquired and merged with Bow Valley Exploration Norge A/S. The allocations in Production Licence No. 052 are thus:

Den norske stats oljeselskap a.s.	40.000 %
Marathon Petroleum Norge A/S	23.798 %
Elf Aquitaine Norge A/S	17.639 %
Norsk Hydro Produksjon A/S	6.228 %
Total Marine Norsk A/S	4.820 %
Sunningdale Norge A/S	3.875 %
Saga Petroleum a.s.	3.471 %
A/S Uglands Rederi	0.169 %

Production Licences No. 007, 008, 009, 016 and 018
Norminol A/S has acquired Cofranord A/S and renamed it Norexplor A/S. The allocations in the said production licences are thus:
Production Licence No. 007

Elf Aquitaine Norge A/S	32.376 %
Norsk Hydro Produksjon A/S	26.800 %
Norexplor A/S	1.216 %
Eurafrep Norge A/S	1.824 %
Coparex Norge A/S	1.596 %
Total Marine Norsk A/S	16.188 %
Phillips Petroleum Company Norway	14.780 %
Norsk Agip A/S	5.220 %

Production Licence No. 008

Elf Aquitaine Norge A/S	32.376 %
Norsk Hydro Produksjon A/S	13.400 %
Norexplor A/S	1.216 %
Eurafrep Norge A/S	1.824 %
Coparex Norge A/S	1.596 %
Total Marine Norsk A/S	16.188 %
Den norske stats oljeselskap a.s.	2.000 %
ØMV Norge A/S	11.400 %
Phillips Petroleum Company Norway	14.780 %
Norsk Agip A/S	5.220 %

Production Licence No. 009

Elf Aquitaine Norge A/S	32.376 %
Norsk Hydro Produksjon A/S	26.800 %
Norexplor A/S	1.216 %
Eurafrep Norge A/S	1.824 %
Coparex Norge A/S	1.596 %
Total Marine Norsk A/S	16.188 %
Phillips Petroleum Company Norway	14.780 %
Norsk Agip A/S	5.220 %

Tab 2.1.2.a
Allocations: Licencing round 11

Lic. number	Field/Block	% share		Licensee (0 denotes operator)
130	6201/11	50.000	O	Den norske stats oljeselskap a.s
		15.000		A/S Norske Shell
		15.000		Petrobras Norge A/S
		20.000		Texas Eastern Norwegian Inc
131	6406/8	20.000	O	Elf Aquitaine Norge A/S
		10.000		Svenska Petroleum Exploration A/B
		10.000		Esso Norge a.s
		10.000		Petrobras Norge A/S
		50.000		Den norske stats oljeselskap a.s
132	6407/10	20.000	O	Norsk Hydro Produksjon a.s
		10.000		Norsk Agip A/S
		10.000		Deminex (Norge) A/S
		50.000		Den norske stats oljeselskap a.s
		10.000		A/S Norske Shell
133	6408/4	50.000	O	Conoco Norway Inc
		50.000		Den norske stats oljeselskap a.s
134	6506/11	50.000	O	Den norske stats oljeselskap a.s
		30.000		Norsk Agip A/S
		10.000		Tenneco Oil Company Norsk A/S
		10.000		Texas Eastern Norwegian Inc
135	7124/3 and 7125/1	15.000	O	Saga Petroleum a.s
		5.000		Amerada Hess (Norway) Ltd
		15.000		Arco Norway Inc
		15.000		Total Marine A.S
		50.000		Den norske stats oljeselskap a.s
136	7219/9 and 7220/7	20.000	O	Norsk Hydro Produksjon a.s
		10.000		BP Petroleum Dev. of Norway A/S
		10.000		Norske Fina A/S
		10.000		Mobil Development Norway A/S
		50.000		Den norske stats oljeselskap a.s
137	7224/7 and 7224/8	50.000	O	Den norske stats oljeselskap a.s
		10.000		BP Petroleum Dev. of Norway A/S
		10.000		Norsk Hydro Produksjon a.s
		15.000		Esso Norge A/S
		5.000		Saga Petroleum a.s
		10.000		A/S Norske Shell
138	7122/6	20.000	O	Total Marine Norsk A.S
		5.000		Amerada Hess (Norway) Ltd
		10.000		Norsk Hydro Produksjon a.s
		15.000		A/S Norske Shell
		50.000		Den norske stats oljeselskap a.s
139	7226/8 and 7226/9 and 7226/11	50.000	O	Den norske stats oljeselskap a.s
		10.000		Conoco Norway Inc
		10.000		Elf Aquitaine Norge A/S
		10.000		Norske Fina A/S
		10.000		Mobil Development Norway A/S
		10.000 A/S		Norske Shell
140	7320/9 and 7321/7	35.000	O	Mobil Development Norway A/S
		15.000		Conoco Norway Inc
		50.000		Den norske stats oljeselskap a.s
141	7321/8 and 7321/9	20.000	O	Norsk Hydro Produksjon a.s
		15.000		BP Petroleum Dev. of Norway A/S
		5.000		Saga Petroleum a.s
		50.000		Den norske stats oljeselskap a.s
		10.000		Tenneco Oil Company Norsk A/S
142	29/9 and 30/7 og 30/10	40.000	O	Elf Aquitaine Norge A/S
		10.000		Saga Petroleum a.s
		50.000		Den norske stats oljeselskap a.s

Production Licence No. 016	
Phillips Petroleum Co. Norway	36.960 %
Norske Fina A/S	30.000 %
Norsk Hydro Produksjon a.s.	13.040 %
Elf Aquitaine Norge A/S	6.700 %
Total Marine Norsk A/S	8.094 %
Eurafrep Norge A/S	0.456 %
Coparex Norge A/S	0.399 %
Norexplor A/S	0.304 %

Production Licence No. 017	
Phillips Petroleum Co. Norway	36.960 %
Norske Fina A/S	30.000 %
Norsk Agip A/S	13.040 %

Tab 2.1.2.b
Production licences and areas as of 31 December 1987

Allocation round	Date	Prod licence number	Number of blocks allo-cated	Relinq-uished	Areas allocated sq km	Areas rel sq km	Areas of prod lic. sq km
1.	01.sept.1965	001-021	74	52	39842.476	35072.925	4769.551
	07.dec. 1965	022	4	3	2263.565	1984.116	279.449
	12.sept.1977	019 (2)	2	0	617.890	0.0	617.890
2.	23.may 1969	023-031	9	1	4107.833	2233.366	1874.467
	30.may 1969	032-033	2	0	746.285	376.906	369.379
	14.nov. 1969	034-035	2	0	1024.529	564.837	459.692
	11.june 1971	036	1	0	523.937	262.047	261.890
ut.	10.aug. 1973	037	2	0	586.834	295.157	291.677
3.	01.apr. 1975	038-040 and 042	7	4	1840.547	1389.779	450.768
0	1.june 1975	041	1	0	488.659	244.048	244.611
	06.aug. 1976	043	2	0	604.558	303.215	301.343
	27.aug. 1976	044	1	0	193.076	90.418	102.658
	03.dec. 1976	045-046	4	2	1270.682	531.190	739.492
	07.jan. 1977	047	2	1	368.363	304.160	64.203
	18.febr.1977	048	2	1	321.500	107.019	214.481
	23.dec. 1977	049	1	1	485.802	485.802	0.0
ut.	16.june. 1978	050	1	0	500.509	151.962	348.547
4.	06.apr. 1979	051-058	8	1	4007.887	1887.772	2120.115
ut.	20.aug. 1982	079	1	0	102.167		102.167
5.	18.jan. 1980	059-061	3	2	1108.078	998.675	109.403
	27.march 1981	062-064	3	1	1099.522	499.780	599.742
	23.apr. 1982	073-078	6	0	2311.912		2311.912
6.	21.aug. 1981	065-072	9	0	3218.945		3218.945
7.	10.dec. 1982	080-084	5	0	2082.966		2082.966
ut.	08.july 1983	085	3	0	1521.160		1521.160
8.	09.mach 1984	086-100	17	0	6346.603		6346.603
9.	14.mach 1985	101-111	13	0	5293.053		5293.053
ut.	26.july 1985	112	1		260.215		260.215
10a	23.aug. 1985	113-120	9		3075.433		3075.433
10b	28.febr. 1986	121-128	9		3828.257		3828.257
ut.	11.july 1986	129	1		225.393		225.393
11.	10.apr. 1987	130-137	11		4163.711		4163.711
	29 may 1987	138-142	11		2975.806		2975.806
			227	69	97399.820	48066.693	49333.127

ut = licences allocated outside the regular allocation rounds.

Norsk Hydro Production a.s.	6.700 %
Elf Aquitaine Norge A/S	8.094 %
Total Marine Norsk A/S	4.047 %
Eurafrep Norge A/S	0.456 %
Coparex Norge A/S	0.399 %
Norexplor A/S	0.304 %

Production Licence No. 018

Phillips Petroleum Co. Norway	36.960 %
Norske Fina A/S	30.000 %
Norsk Agip A/S	13.040 %
Norsk Hydro Production a.s.	6.700 %
Elf Aquitaine Norge A/S	8.094 %
Total Marine Norsk A/S	4.047 %
Eurafrep Norge A/S	0.456 %
Coparex Norge A/S	0.399 %
Norexplor A/S	0.304 %

Tab 2.1.2.c
Allocation rounds. Norwegian and foreign shares

Allocation rounds	Year	Number of blocks	Share % Norw.	Share % Foreign	Operatorsship % Norw.	Operatorsship % Foreign.
1	1965	78	9	91	0	100
2	1969–71	14	15	85	0	100
Statfjord	1973	2	52	48	0	100
3	1974–78	22	58	42	63	37
Ula (19 B)	1977	2	50	50	0	100
Gullfaks	1978	1	100	0	100	0
4	1979	8	58	42	68	32
5	1980–82	12	66	34	92	8
6	1981	9	64	34	50	50
Utv.t 079	1982	1	100	0	100	0
7	1982	5	60	40	80	20
Utv.t 085	1983	3	100	0	100	0
8	1984	17	60	40	60	40
9	1985	13	43	57	62	38
Utv.t 112	1985	1	67	33	0	100
10A	1985	9	64	36	67	33
10B	1986	9	65	36	56	44
Utv.t 129	1986	1	67	33	100	0
11	1987	22	59	41	62	38

2.1.4 Relinquishments

Three production licences have been relinquished in 1987. In the case of one production licence, the whole area has been relinquished. This can be seen from Table 2.1.4.

Tab 2.1.4
Relinquishments

Prod. Licence No.	Operator	Block	Original area sq. km	Relinquished area sq. km	Area of prod. licence sq.km
053	Hydro	30/6	508.360	174.408	333.952
063	Hydro	7117/9	331.606	331.606	000.000
064	Statoil	7120/8	331.606	168.174	163.432

2.1.5 Licensing rounds

The 11th licensing round was announced with a deadline for applications of 10 October 1986, and comprised 39 blocks within the areas of South Møre, Møre I, Haltenbanken, North West Troms, South Bear Island and West Finnmark. An opportunity was also provided for application for previously announced blocks north of 62° N.

In addition, five so–called key blocks in the Barents Sea (previously called "strategic blocks") were announced with a time limit for applications at 23 January 1987. A further four key blocks as well as three blocks (relinquished parts) in the North Sea were announced with a deadline for application of 8 April 1987.

In total, 21 companies applied for a total of 34 blocks.

The 12th licencing round, phase A, was announced on 13 August 1987. The round comprised 18 blocks or parts of blocks in the North Sea. The deadline for application was stipulated at 19 February 1988. On 26 November 1987, a further three North Sea blocks were announced, so that the 12th licencing round, phase A, came to comprise a total of 21 blocks.

The announcement of blocks in the North Sea was based on good prospects for making oil discoveries, proximity to existing or planned facilities, moderate exploration risks and limited water depth. If will furthermore be possible to survey structures which we have in common with Denmark and/or Great Britain.

2.2 Surveying and exploration drilling

2.2.1 Geophysical and geological surveys

A total of 120,794 km of seismics were gathered on the Norwegian continental shelf in 1987. This is somewhat less than in the 1986 record year (cf. Figure 2.2.1 a).

2.2.1.1 The Norwegian Petroleum Directorate's geophysical surveys in 1987

The Norwegian Petroleum Directorate assembled 19,289 km of seismics in the course of 1987 (Figure 2.2.1.b). Data was gathered from the areas indicated in Figure 2.2.1.c and d.

Fig 2.2.1.a
Seismic surveys on the Norwegian Continental Shelf as of 1962 - 1987.

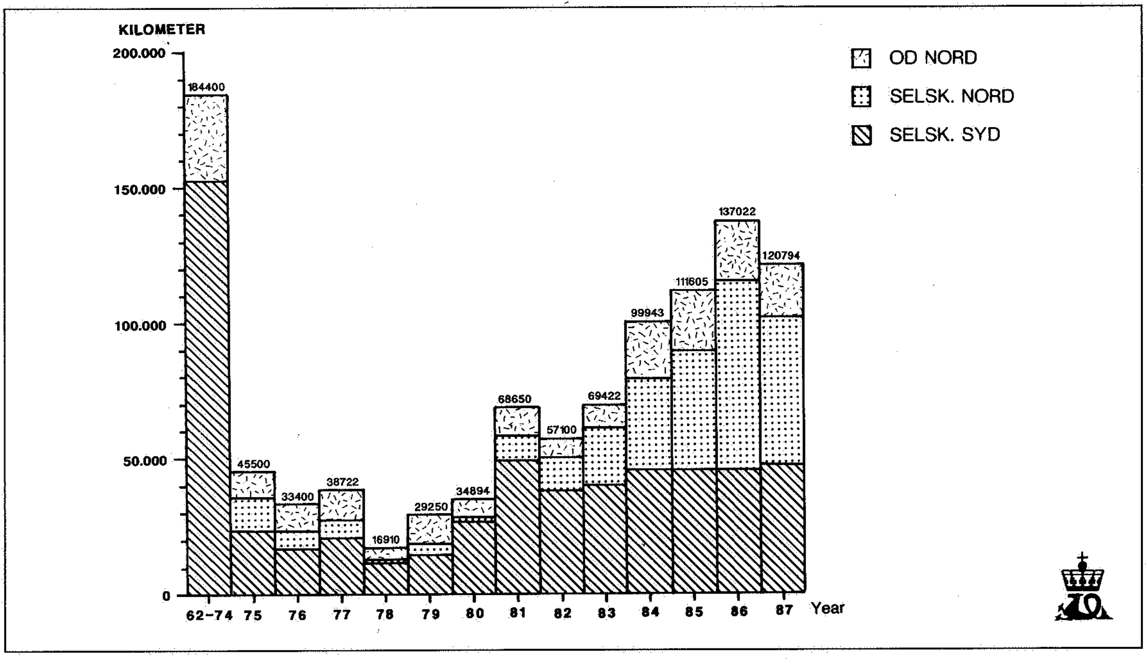


Fig 2.2.1.b
Seismic surveys north of Stad under the direction of the Norwegian Petroleum Directorate.

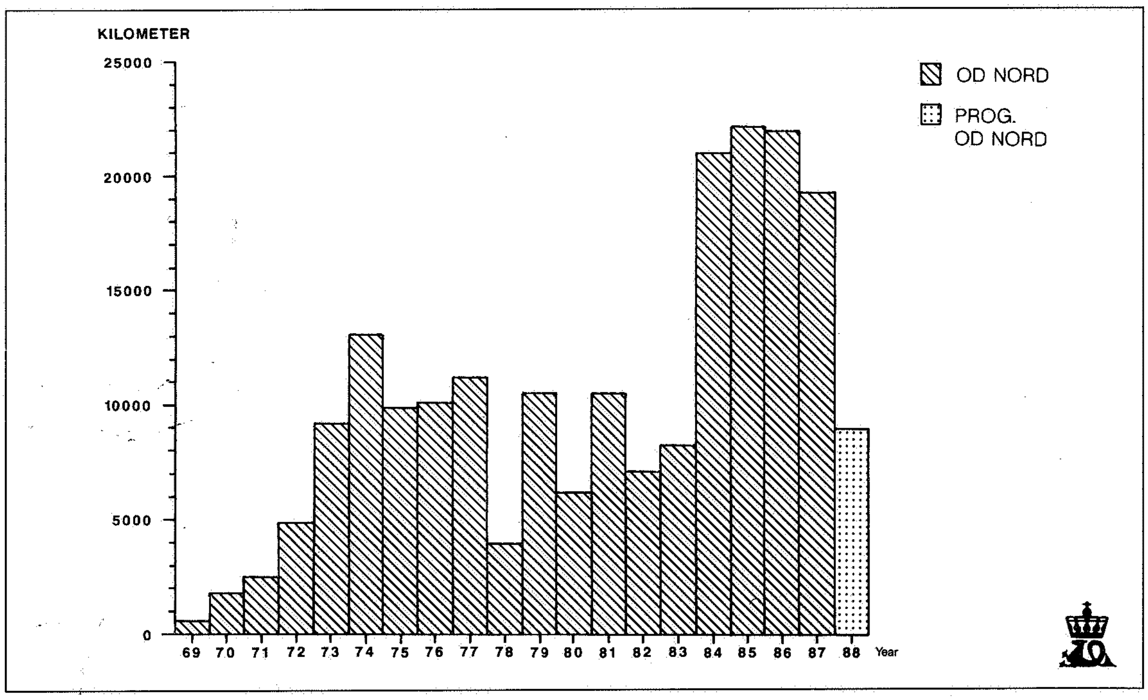
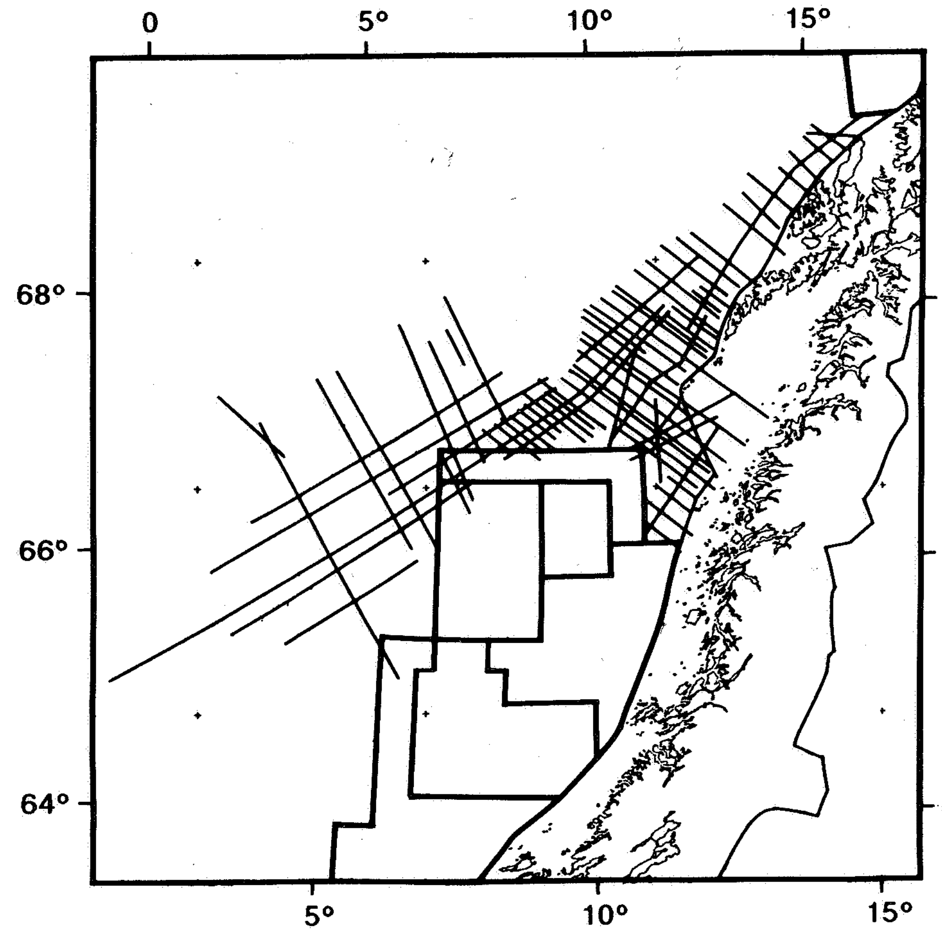


Fig 2.2.1.c
Seismic surveys on the Mid-Norwegian Shelf in 1987.



The Vøring plateau
3,416 km were assembled with "Western Challenger". This is a regional survey, and the data is to be processed in London by Western Atlas (2,721 km) and Ensign Geophysics Ltd. (695 km).

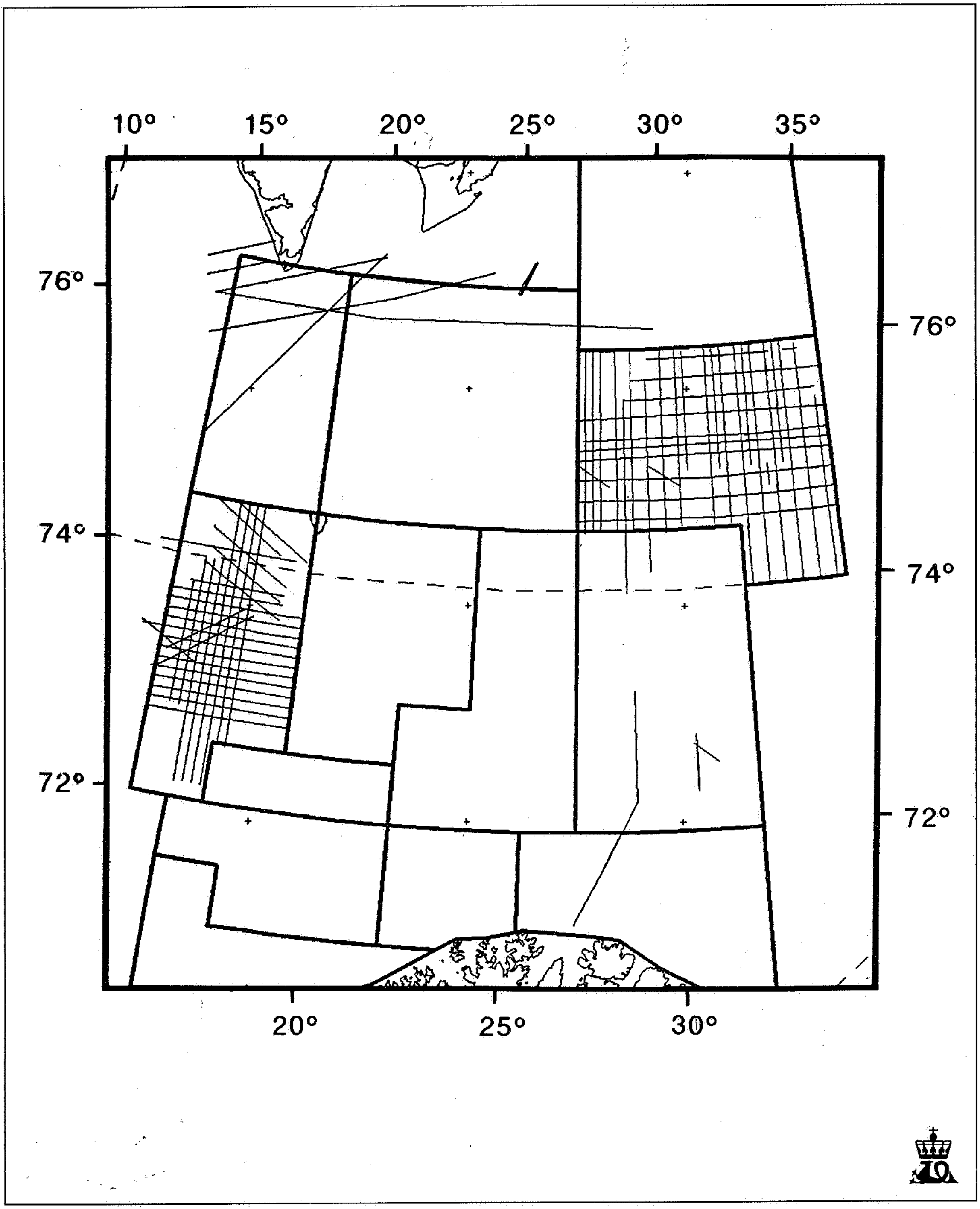
West Lofoten
3,845 km were gathered with CGG's vessel "Rig Master", and 130 km of test lines in addition. A test line was run with reduced source volume, and 4 and 8 parallel lines were gathered at the same time with the help of two-cable technology and several sources. These tests will be useful in connection with the analysis of source-generated noise and directivity studies. The data is to be processed by Geco A/S in Stavanger (2,160 km) and Ensign Geophysics Ltd. (1,815 km) in London.

West Bear Island
4,135 km were gathered with GSI's vessel "Polar Princess" and 114 with "Geco Echo". These surveys complete the Norwegian Petroleum Directorate's grid for the area. The data is to be processed by GSI in Stavanger.

Nordflaket/Spitsbergen Bank
1,365 km were gathered with GSI's vessel "Polar Princess". A line of 400 km was gathered with the help of three sources and two cables towed in a wide configuration, so that six parallel lines were gathered. The other data was gathered with a very wide "source array" (more than 100 metre) with a view to try to attain an improvement of the data quality compared with previous surveys in the area. The purpose of towing wide "source and receiver arrays" is to attain improved directivity, so that better penetration through the seafloor and better noise cancellation is attained. The disadvantage of this method is the loss of high frequencies and thus some of the minute resolution in the shallowest strata.

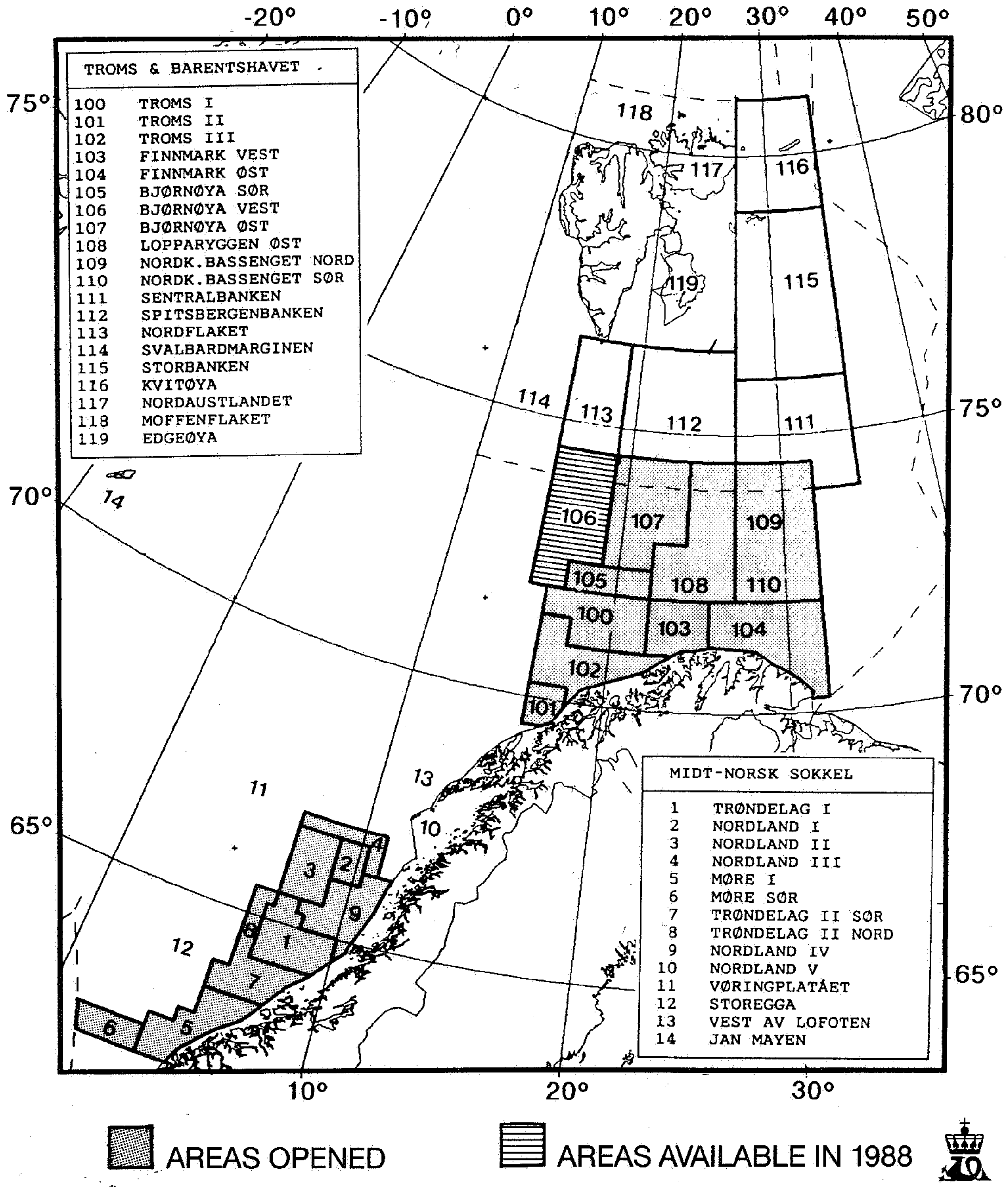
The data is to be processed by CGG in London (994 km) and Geco in Stavanger (401 km).

Fig 2.2.1.d
Seismic surveys off North Norway in 1987.



The Central Bank
4,048 km were gathered with "Geco Echo" and 1,793 km with "Geco Gamma". The "Geco Gamma" data were shot with two sources and two cables towed widely, so that four parallel lines were gathered. One of these lines were submitted to several companies for test processing, and on the basis of the result of this test processing, the processing of data was divided between CGG (2,040 km), Geco (1,892 km) and Western Atlas (1,920 km).

Fig 2.2.1.e
Areas which are-or which in a year or two will be opened for seismic survey by companies. Area designations north of Stad.



Tab 2.2.1.4.
Summary of numbers of seismic data packages sold in 1987 and cumulatively:

Pk	Name	1987	Totalt
001	MØRE-TRØNDELAG-REGIONAL-PAKKE-1		32
002	MØRE-TRØNDELAG-REGIONAL-PAKKE-2		25
003	TAMPEN-SPUR	2	21
004	MØRE-SØR-84	2	21
005	TRØNDELAG-REGIONAL	1	24
006	HALTENBANKEN-VEST-84	1	23
007	FRØYABANKEN-84	1	24
008	MØRE-TRØNDELAG-PAKKE-2	1	22
009	MØRE-TRØNDELAG-PAKKE-3		28
010	TRÆNABANKEN		30
011	REG-DATA-NORDLANDSRYGGEN		20
012	NORDLAND-IV-85	2	8
013	REG-DATA-MID-N-SOKKEL		19
014	NORDLAND-II-83		21
015	NORDLAND-III-84	2	9
016	TROMS-II	2	9
017	REGIONAL-DATA-TROMS-ØST	1	17
018	FINNMARK-VEST-83	1	18
019	FINNMARK-VEST-84	1	19
020	NORDLAND-III-85	3	9
021	MØRE-SØR-TEST-84		5
022	STOREGGA-85	1	4
023	VØRINGPLATÅET	1	4
024	VØRING-BASS.-85/86	3	3
025	LOFOTEN-VEST-86	4	4
026	JAN-MAYEN-85	1	1
100	TROMS-HOVEDPAKKE		34
101	REG-DATA-TROMS-BARENTSH.-73	2	20
102	TROMS-III-83/84	2	11
103	TROMS-III-85	3	8
105	TROMS-I-ØST-77	1	18
106	TROMS-NORD-82-PAKKE-1		23
107	TROMS-NORD-83-PAKKE-3		22
108	TROMS-NORD-82-PAKKE-2		15
109	TROMS-NORD-83-PAKKE-4		15
200	BJØRNØYA-PAKKE-1	1	21
201	BJØRNØYA-SØR-84	1	21
202	BJØRNØYA-ØST-REGIONAL-84	3	17
203	BJØRNØYA-ØST-84	3	16
204	BJØRNØYA-TILLEGG-NORD	2	15
205	BJØRNØYA-VEST-REGIONAL-84	3	10
206	LOPPARYGGEN-ØST-REGIONAL-84	3	19
207	LOPPARYGGEN-ØST-85-SSL-DIAG	3	19
208	LOPPARYGGEN-ØST-85-NORD	4	19
209	LOPPARYGGEN-ØST-85-GECO-DIAG	3	19
210	LOPPARYGGEN-ØST-85-GRID	3	19
211	BJØRNØYA-ØST-TEST-85		1
212	BJØRNØYA-VEST-86-DIAG	6	6
213	BJØRNØYA-VEST-86-HIGH	6	6
214	BJØRNØYA-VEST-86-MARGIN	5	5
300	BARENTSHAVET-SØR-ØST-HOVED	7	20
301	BARENTSHAVET-SØR-ØST-PAKKE-2	7	19
302	NORDKAPP-BASS.-85-GECO-DIAG	9	18
303	NORDKAPP-BASS.-85-NORD	9	17
304	NORDKAPP-BASS.-85-GRID	10	19
305	NORDKAPP-BASS.-86-DIAG	18	18
306	NORDKAPP-BASS.-86-SØR	18	18
307	NORDKAPP-BASS.-86-NORD	14	14
308	FINNMARK-ØST-86-REGIONAL	16	16
309	FINNMARK-ØST-86-DIAG	15	15
310	FINNMARK-ØST-86-GSI	15	15

The North Cape Basin

Several test lines were gathered from the border of the North Cape Basin with "Geco Echo". A mini cable with short groups (5 metre) and "null offset" (distance between the source and the nearest receiver), in addition to a conventional cable. Comparisons were made of different configurations, and data was also gathered with two superimposed cables with "null offset". Near field measurement over the individual guns was used for the calculation of distant field signatures. The main part of the data was processed by GSI in Stavanger, while special tests were accomplished by SERES in Trondheim, Merlin in London and Geco in Stavanger.

The purpose of the minicable and point source, in addition to the usual cable and a large "array", is to gather shallow data with high resolution in parallel with the deep data. Such shallow data may be used for detailed charting of the shallowest strata and demonstration of anomalies in the sea floor, as well as shallow gas.

At the end of the surveys, a long line (232 km) was shot through potential prospects in the North Cape Basin and towards the coast of Finnmark. This line was processed by GSI in Stavanger.

2.2.1.2 Opening–up of new exploration areas

In the course of 1987, the Norwegian Petroleum Directorate has prepared West Bear Island for opening for seismic surveys under the direction of the companies (Figure 2.2.1.e). The processing of this year's data will be finished in the spring of 1988.

2.2.1.3 Geophysical surveys by the companies

In 1987, 101,504 km of seismics were shot on the Norwegian continental shelf under the direction of oil companies, contractors or universities. Of this, 20,784 km are 3D seismics. 47,604 km were shot in the North Sea and 53,900 north of Stad.

It appears from the figures above that the activity in the North Sea increased moderately from 1986 to 1987, while the activity north of Stad was somewhat reduced.

Norwegian oil companies shot 42,643 km, foreign oil companies 30,417 km, contractors 19,272 km and scientific institutions 9,172 km of seismics in 1987. 18,072 km of wildcat seismics were gathered by GECO, NOPEC and Western, and about 1,200 km by IKU and Geoteam.

2.2.1.4 Sale of seismic data

In 1987, the Norwegian Petroleum Directorate has booked income from the sale of seismic data packages at NOK 207.4 million (NOK 313.6 million in 1986). Cf. Table 2.2.1.4.

Companies which have purchased all the seismic data packages in the various areas are:

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

Nordland I
Agip, Amerada, Amoco, Arco, BP, Britoil, Chevron, Deminex, Elf, Esso, Fina, Getty, Gulf, Hispanoil, Hydro, Japan Oil, Mobil, Phillips, Saga, Shell, Statoil, Superior, Svenska Petroleum, Tenneco, Texaco, Texas eastern, Total, Unocal and ØMV.

Nordland II
Agip, Amerada, Arco, BP, Britoil, Conoco, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Tenneco, Texas Eastern, Total and Unocal.

Nordland III
Agip, BP, Elf, Esso, Mobil, Saga, Shell, Statoil and Total.

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

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

Trøndelag II South Agip, Amerada, Amoco, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern, Total and Unocal.

Trøndelag II North
Agip, Amerada, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Mobil, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern and Total.

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

Troms I
Agip, Amerada, Conoco, Elf, Esso, Hydro, Mobil, Phillips, Saga, Shell and Statoil.

Troms
Agip, Elf, Esso, Hydro, Mobil, Saga, Shell, Statoil and Total.

Troms III
Agip, Elf, Esso, Mobil, Saga, Shell, Statoil and Total.

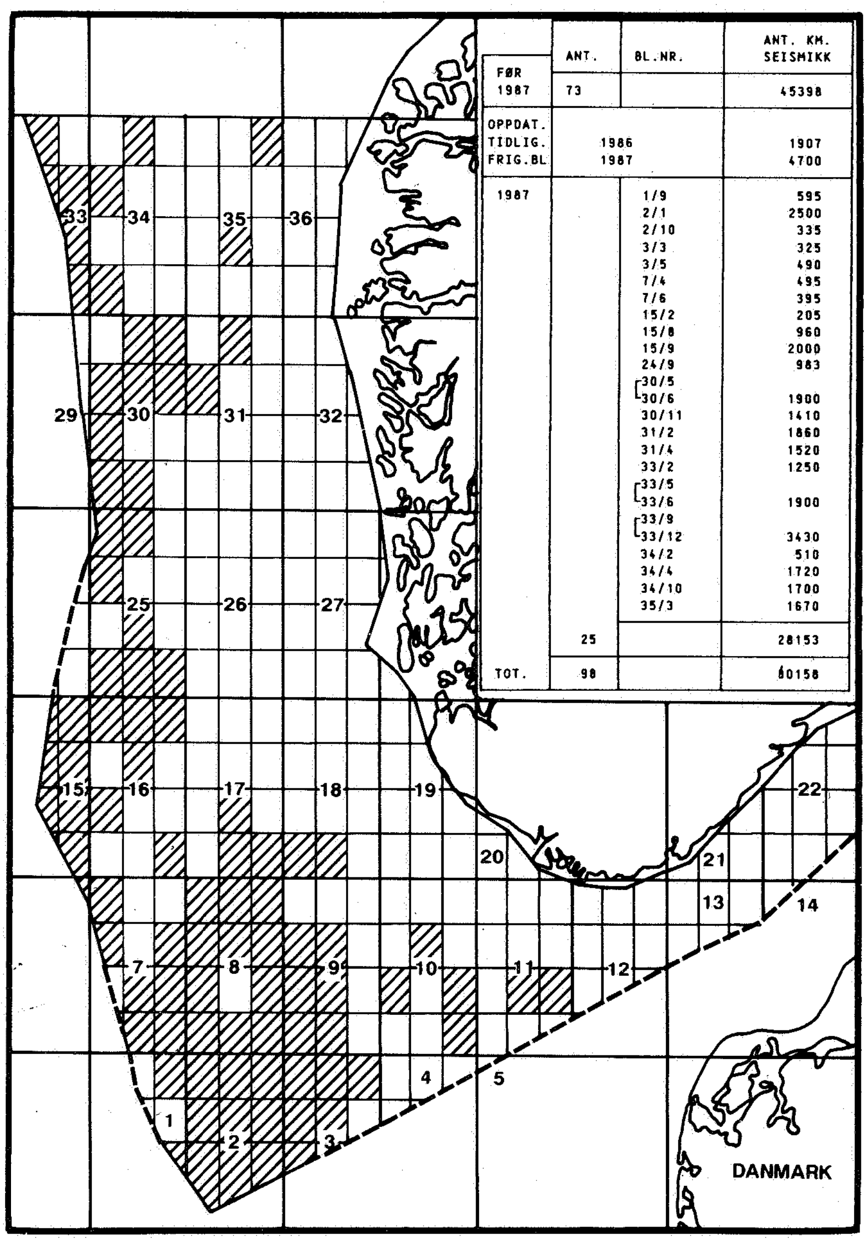
Finnmark West
Agip, Amerada, Amoco, Arco, BP, Conoco, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Tenneco and Total.

Finnmark East
Agip, Amoco, Arco, BP, Conoco, deminex, Elf, esso, Hydro, Mobil, Saga, Shell, Statoil, Texas Eastern and Total.

Bear Island South
Agip, Amerada, Amoco, Arco, BP, Britoil, Conoco, Deminex, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern and Total.

Bear Island East
Agip, Amoco, Arco, BP, Conoco, Elf, Esso, Fina,

Fig 2.2.1.f
Blocks for which seismic data has been released



	ANT.	BL.NR.	ANT. KM. SEISMIKK
FØR 1987	73		45398
OPPDAT. TIDLIG. FRIG.BL.	1986		1907
	1987		4700
1987		1/9	595
		2/1	2500
		2/10	335
		3/3	325
		3/5	490
		7/4	495
		7/6	395
		15/2	205
		15/8	960
		15/9	2000
		24/9	983
		30/5	
		30/6	1900
		30/11	1410
		31/2	1860
		31/4	1520
		33/2	1250
		33/5	
		33/6	1900
		33/9	
		33/12	3430
		34/2	510
		34/4	1720
		34/10	1700
		35/3	1670
	25		28153
TOT.	98		80158

Tab 2.2.1.a
Permits for scientific exploration for natural resources

Permit	Name	Field of work Geo-physics	Geo-logy	Bio-logy	Area
233	Institut für Meereskunde an der Universität Kiel Kiel German Federal Republic	X		X	Vøring Plateau, West and Southwest Lofoten
234	University of Oslo Geological Institute Oslo	X			Møre basin, Vøring Plateau
235	University of Bergen Earthquake Station Bergen	X			Lofoten/Vesterålen and western Barents sea
236	Norwegian Geological Survey Trondheim	X			Barents sea
237	Universität Hamburg Hamburg German Federal Republic	X			North Sea
238	Norwegian Geological Survey Trondheim		X		Sunnmøre
239	University of Tromsø Institute of Biology and Geology	X	X		Finnmark coast and south Barents sea
240	Universität Hamburg Hamburg German Federal Republic	X			Lofoten
241	Universität Hamburg Hamburg German Federal Republic	X			Norwegian Sea
242	Alfred-Wegener-Institut für Polar und Meeresforschung Bremerhaven German Federal Republick		X		Arctic Ocean
243	Norwegian Geological Survey Trondheim		X		Nordmøre and Trøndelag
244	University of Tromsø Inistitute of Biology and Geology Tromsø	X	X		Southern Barents sea Finnmark coast
245	University of Bergen Earthquake Station Bergen	X			Svalbard area
246	Norwegian Polar Research Institute Oslo Airport	X	X		Svalbard area Barent sea
247	Lapsed				
248	University of Bergen Earthquake Station Bergen	X			Coastel areas in Finnmark
249	University of Bergen Earthquake Station Bergen	X			Sognefjord
250	Universität Hamburg Hamburg German Federal Republic		X		North Sea, Skagerrak
251	University of Bergen Earthquake Station Bergen		X		Along the edge of the North Sea Basin from Arendal to Stord
1/87-H	University of Tromsø Institute of Biology and Geology Tromsø	X			Southern Barents sea Finnmark coast
2/87-H	University of Trondheim Norwegian College of Technology Institue for Petroleum Technology and Applied Geophysics Trondheim	X			Western Barents sea

Hydro, Mobil, Saga, Shell, Statoil, Tenneco and Total.

Loppa Ridge East
Agip, Amerada, Amoco, Arco, BP, Conoco, Deminex, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Tenneco, Texas Eastern and Total.

North Cape Basin North
Agip, Amoco, Arco, BP, Conoco, Elf, Esso, Hydro, Mobil, Saga, Shell, Statoil, Texas Eastern and Total.

North Cape Basin South
Agip, Amoco, Arco, BP, Conoco, Deminex, Elf, Esso, Hydro, Mobil, Petrobras, Phillips, Saga, Shell, Statoil, Texas Eastern and Total.

2.2.1.5 Release of data and material from the shelf
In connection with the Norwegian Petroleum Directorate's monitoring of oil operations on the Norwegian continental shelf, the Norwegian Petroleum Directorate receives copies of well logs and continuous, representative samples of drilling shale and cores.

Tests of drilling shale are taken every 10 metres throughout the well, and every third metre in formations which may contain hydrocarbons. As regards wet samples, which should have a weight of at least 1/2 kg, the same sampling frequency applies.

Of drilling cores, the Norwegian Petroleum Directorate receives a complete length section comprising at least one fourth of the core in exploration wells and one half of the core in production wells.

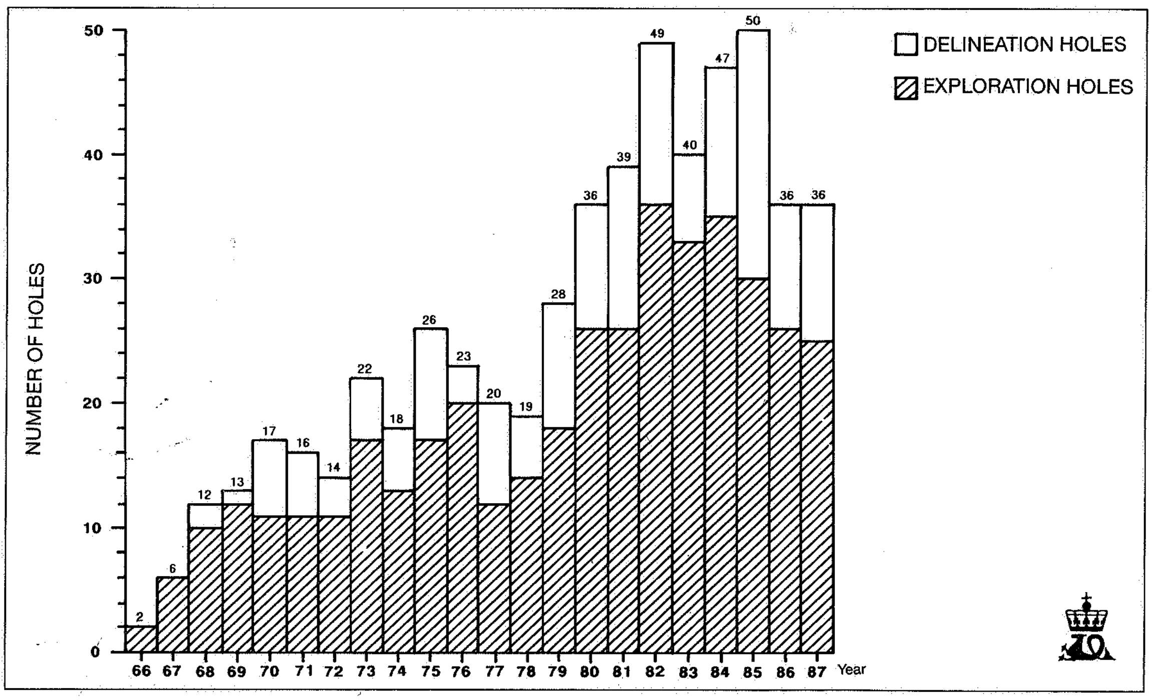
As of 31 December 1987, the Norwegian Petroleum Directorate has stored 49,187 m of core material from 535 wells, 308,715 samples of washed drilling shales from 753 wells and 305,496 wet samples from 802 wells on the Norwegian continental shelf. This includes production wells. In total, material from 1,064 wells is available.

The Norwegian Petroleum Directorate is responsible for publishing data and releasing material for educational and research purposes. Data is released 5 years after completion of the well. The licensees' interpretations are not released.

Well Data Summary Sheets (WDSS) are published annually, and summarize wells which have become more than 5 years old during the calendar year. The purpose of this series is to show which wells have been released and which core and logg material is available from the different wells. Furthermore, some technical data and test results are given, as well as a composite loss with lithological description for each well at the scale of 1:4000.

In the Norwegian Petroleum Directorate's core study room, core material, drilling shale and wet tests may be studied. In special cases, it is possible to release material for studies and analysis outside of the Directorate. The 5 year rule for release of material applies also in this instance.

Fig 2.2.2.a
Exploration drilling on the Norwegian Continental shelf per year from 1966 - 87. Number of holes.



Seismics are released in packages comprising 1 block, and may only be released from blocks which are or which have been subject to exploration licences, or after the seismics are older than 5 years.

As of 31 December 1986, 73 wells have been released, of which 7 in 1986. A total of 45,798 profile km have been released, of which 7,156 in 1986.

Figure 2.2.1.f shows a summary map with indication of blocks from which data has been released.

2.2.1.6 Scientific studies

As of 31 December 1987, a total of 252 licences for scientific surveys have been issued on the Norwegian continental shelf. As it appears from Table 2.2.1.a, 20 such licences were issued in 1987; 18 were issued by the Norwegian Petroleum Directorate in Stavanger and 2 by the Norwegian Petroleum Directorate regional office in Harstad.

From 1 July 1987, the handling of applications for and issuing of licences concerning scientific surveys for the areas north of 65°N was delegated to the Norwegian Petroleum Directorate regional office in Harstad. In the instances when such applications comprise areas both north and south of 65°N, the examination and issuance is taken care of from Stavanger. Survey nos. 1/87–H and 2/87–H have thus been issued by the Harstad office.

2.2.2 Exploration drilling

At the turn of the year 1986/87, four exploration wells were being drilled. They were all completed in 1987.

In 1987, 36 new exploration wells were initiated, divided on 25 wildcats and 11 appraisal wells. This is the same number of exploration wells as in 1986, cf.

Fig 2.2.2.b
Holes drilled in 1987 in the North Sea and Møre South.

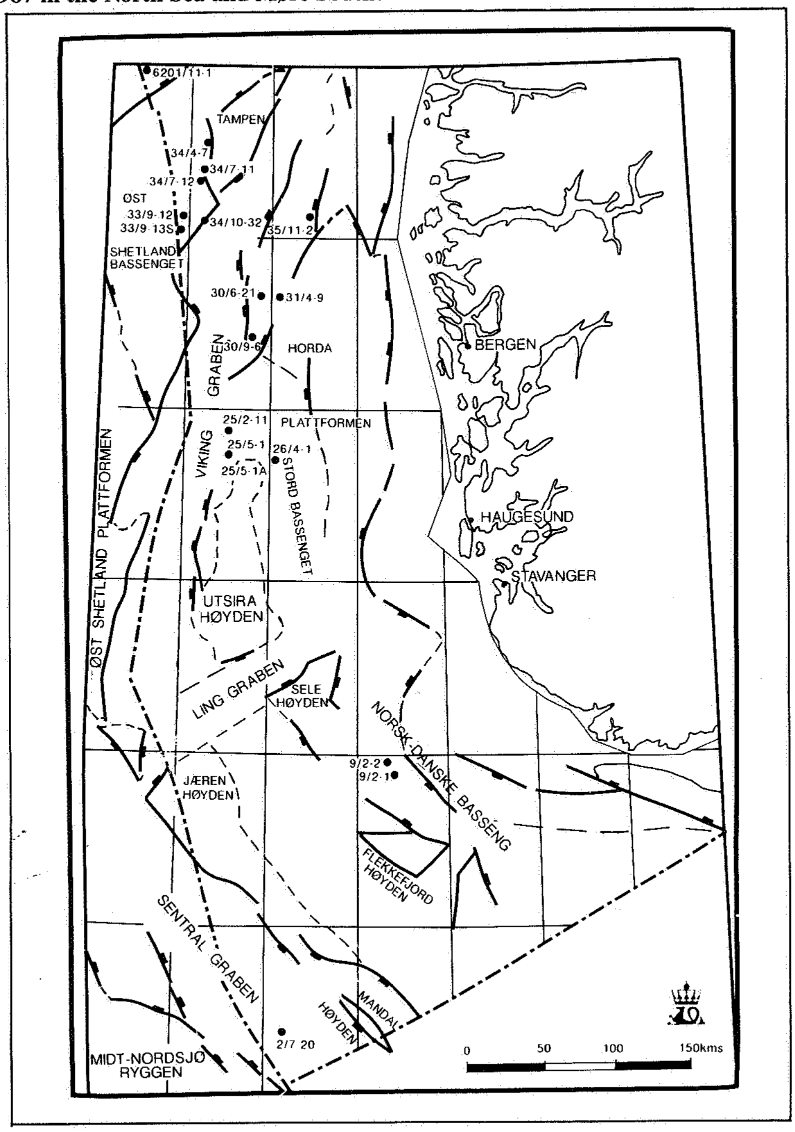


Fig 2.2.2.c
Holes drilled in 1987 outside Mid-Norway.

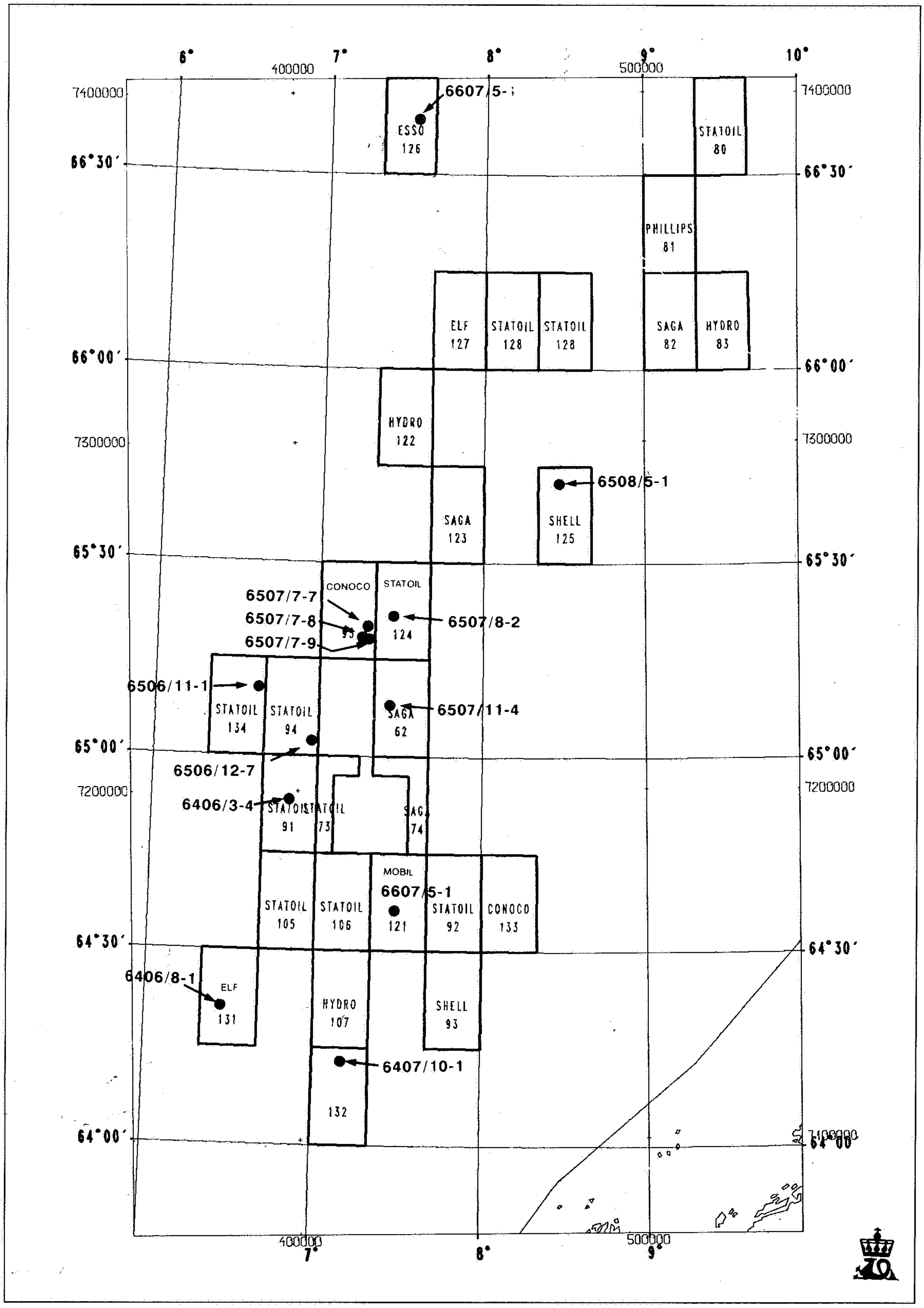
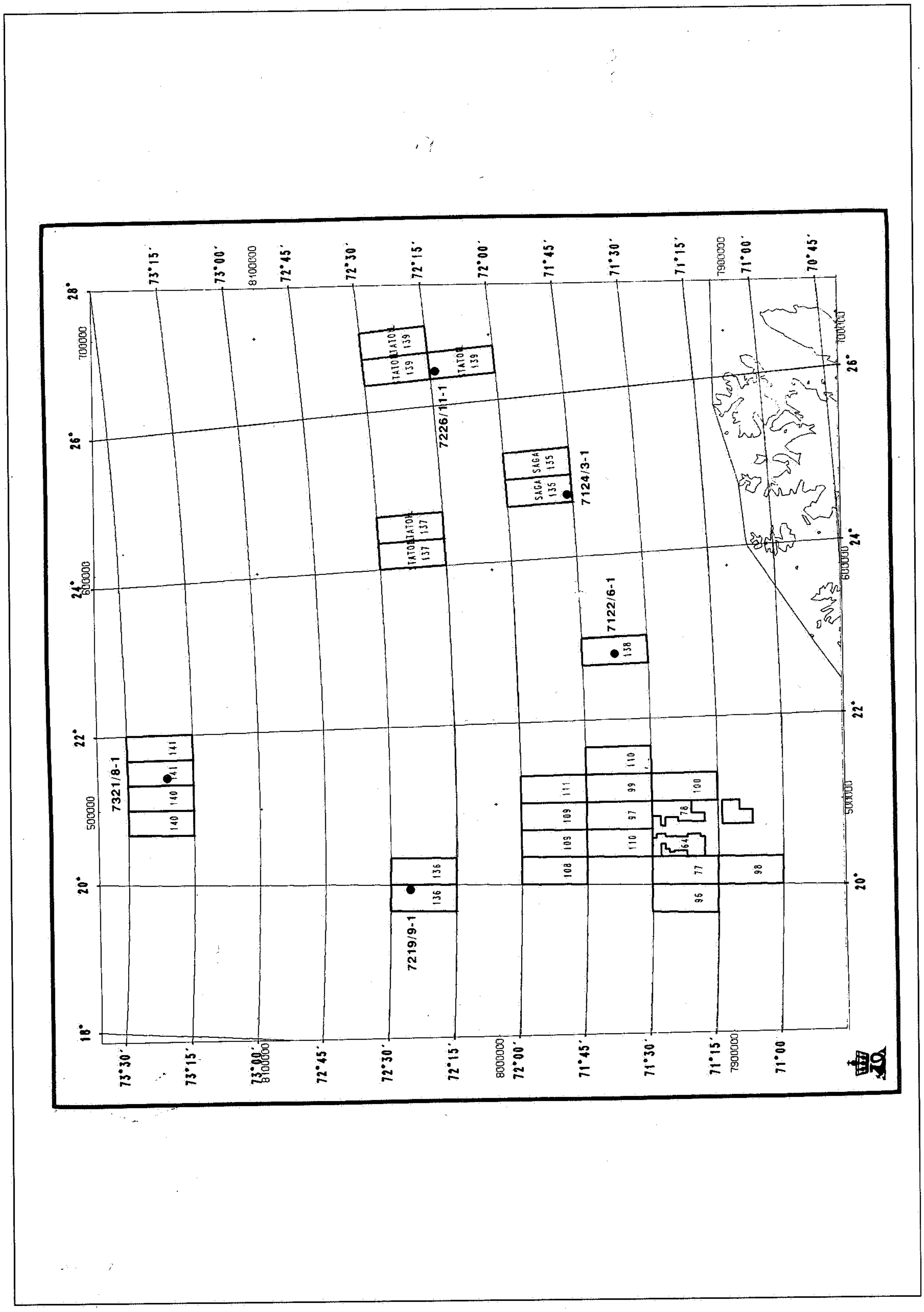


Fig 2.2.2.d
Holes drilled in 1987 in the Barents Sea.



Tab 2.2.2.a
Spudded and/or completed exploration holes (U) and appraisal holes (A) in 1987
R= Reentry x= Not reached prospective depth, s= Sidetracked

Well No	Licence No	Position North East	Dates of spudding and completion	Operator Drilling rig	Well type Completion classificat.	Water depth KBE	Total depth and Geological period
25/01-07 R	455	59 55 08.28	87.02.08	Elf	Appraisal	101	2720
	024	02 04 52.33	87.02.14	Nortrym	Suspended	25	
25/01-08 SR	466	59 54 03.28	87.02.14	Elf	Appraisal	102	2650
	024	02 06 09.79	87.02.18	Nortrym	Suspended	25	
25/02-10 SR	494	59 53 11.80	87.09.16	Elf	Exploration	120	2967
	112	02 30 08.33	87.09.22	Nortrym		0	
2/12-01	530	56 14 04.07	86.10.14	Hydro	Exploration	70	4795
	113	03 42 27.50	87.03.12	Treasure Scout	Oil/Gas	23	Perm
6407/02-03	531	64 56 01.39	86.11.07	Saga	Exploration	250	3050
	074	07 39 53.04	87.01.23	Treasure Saga	Gas/Condensate	26	Trias
6407/07-02	532	64 15 26.39	86.11.20	Hydro	Exploration	338	3320
	107	07 10 42.65	87.01.21	Polar Pioneer	Oil	23	
6407/06-03	533	64 42 31.77	86.12.15	Statoil	Exploration	222	3220
	092	07 40 09.84	87.02.17	Dyvi Delta	Oil/Gas	29	Ø.trias
31/04-09	534	60 32 02.29	87.01.23	Hydro	Appraisal	147	2480
	055	03 05 26.92	87.03.07	Polar Pioneer	Oil	23	U.jura
34/04-07	535	61 31 09.83	87.02.17	Saga	Apprailsal	354	2950
	057	02 15 15.49	87.05.12	Treasure Saga	Oil	26	Trias
25/02-11	536	59 52 27.86	87.02.20	Elf	Exploration	118	2075
	112	02 30 59.58	87.05.10	Nortrym	Oil/Gas	25	U.tertiær
30/06-21	537	60 38 34.88	87.02.20	Hydro	Appraisal	112	3100
	053	02 43 47.60	87.04.09	Vildkat	Oil/Gas	25	U.jura
9/02-01	538	57 49 58.10	87.02.21	Statoil	Exploration	98	3756
	114	04 31 27.92	87.04.28	Dyvi Delta	Oil/Gas	29	
30/09-06	539	60 23 03.77	87.03.08	Hydro	Exploration	113	3034
	104	02 49 55.59	87.04.21	Polar Pioneer	Oil/Gas	23	U.jura
34/10-32	540	61 04 33.37	87.04.09	Statoil	Exploration	136	3753
	050	02 12 43.59	87.07.13	West Vision	Suspended	34	
34/10-32 R	540	61 04 33.37	87.07.15	Statoil	Appraisal	136	3742
	050	02 12 43.59	87.08.10	Deepsea Bergen	Oil/Gas	23	Trias
6407/10-01	541	64 13 40.66	87.05.07	Hydro	Exploration	343	3347
	132	07 11 29.81	87.06.19	Polar Pioneer	Dry well	23	Trias
6508/05-01	542	65 42 51.22	87.04.22	Shell	Exploration	409	2589
	125	08 28 35.37	87.05.24	West Vanguard	Dry well	25	Trias
25/05-01	543	59 43 47.19	87.05.12	Elf	Exploration	118	3430
	102	02 34 13.46	87.08.01	Nortrym	Oil/Gas	25	Trias
6506/12-07	544	65 10 04.38	87.05.04	Statoil	Exploration	267	4840
	094	06 54 38.87	87.08.08	Dyvi Delta	Oil/Gas	29	U.jura
26/04-01	545	59 36 37.84	87.05.08	BP	Exploration	119	3690
	118	03 01 13.26	87.07.17	Treasure Scout	Dry well	23	Trias
6507/07-07 X	546	65 17 52.25	87.05.11	Conoco	Appraisal	335	1035
	095	07 18 50.65	87.06.07	Treasure Hunter	Abandoned	25	
6507/11-04	547	65 08 11.28	87.05.16	Saga	Exploration	287	3045
	062	07 26 03.45	87.06.22	Treasure Saga	Dry well	26	U.jura
7124/03-01	548	71 45 36.57	87.05.29	Saga	Exploration	273	4730
	135	24 46 49.92	87.10.20	Ross Rig	Oil/Gas	23	Karbon
6607/05-01	549	66 38 09.67	87.06.09	Esso	Exploration	366	3817
	126	07 32 21.38	87.09.11	Vinni	Dry well	26	Trias
6507/07-08	550	65 17 52.68	87.06.09	Conoco	Appraisal	32	2855
	095	07 18 49.87	87.08.02	Treasure Hunter	Oil	25	
33/09-12	551	61 19 12.04	87.06.19	Statoil	Appraisal	148	959
	037	01 59 36.42	87.08.03	Ross Isle	Oil	22	U.jura
7321/08-01	552	73 20 11.99	87.06.23	Hydro	Exploration	468	3482
	141	21 24 57.27	87.09.03	Polar Pioneer	Dry well	23	Perm
35/11-02	553	61 10 25.42	87.07.20	Mobil	Exploration	372	3677
	090	03 27 31.36	87.12.04	Treasure Scout	Gas/Condensate	23	U.jura
25/05-01 A	554	59 43 47.19	87.08.01	Elf	Appraisal	118	3432
	102	02 34 13.46	87.09.16	Nortrym	Oil	25	Jura
6507/07-09	555	65 19 32.81	87.08.04	Conoco	Appraisal	345	850
	095	07 19 04.87	87.08.08	Treasure Hunter	Dry well	25	
6201/11-01	556	62 01 52.73	87.08.13	Statoil	Exploration	381	3384
	130	01 30 50.37	87.11.06	Deepsea Bergen	Oil	23	Trias
6507/08-02	557	65 20 18.11	87.08.15	Statoil	Exploration	346	2690
	124	07 26 15.04	87.09.09	Dyvi Delta	Dry well	29	Trias
9/02-02	558	57 52 44.35	87.08.08	Statoil	Exploration	99	3577
	114	04 24 00.69	87.09.21	Ross Isle	Dry well	22	Trias

Well No	Licence No	Position North East	Dates of spudding and completion	Operator Drilling rig	Well type Completion classificat.	Water depth KBE	Total depth and Geological period
7122/06-01	559	71 38 19.32	87.09.06	Total	Exploration	401	2710
	138	22 48 42.80	87.11.11	Polar Pioneer	Gas/Condensate	23	Trias
6406/08-01	566	64 21 55.01	87.09.15	Elf	Exploration	348	
	131	06 26 48.16	00.00.00	Vinni'		27	
7226/11-01	561	72 14 18.16	87.10.22	Statoil	Exploration	238	
	139	26 28 44.78	00.00.00	Ross Rig		23	
6407/05-01	562	64 36 22.40	87.12.11	Mobil	Exploration		
	121	07 28 26.54	00.00.00	Treasure Scout		25	
6406/03-04	563	64 53 00.11	87.09.25	Statoil	Appraisal	295	4414
	091	06 50 48.55	87.12.29	Dyvi Delta	Dry well	29	U.jura
34/07-11 X	564	61 16 17.20	87.10.02	Saga	Exploration	190	887
	089	02 06 47.10	87.10.11	Treasure Saga	Abbandoned	26	
33/09-13 S	565	61 27 04.45	87.10.14	Statoil	Appraisal	291	3077
	037	01 58 03.00	87.12.24	Ross Isle	Oil	29	U.jura
2/07-20	566	56 19 58.22	87.10.15	Phillips	Exploration	71	
	018	03 14 47.62	00.00.00	Dyvi Stena		25	
34/07-12	567	61 16 17.86	87.10.11	Saga	Exploration	190	2784
	089	02 06 47.26	00.00.00	Treasure Saga		26	
7219/09-01	568	72 24 00.78	87.11.17	Hydro	Exploration	356	
	136	19 57 11.68	00.00.00	Polar Pioneer		23	
6506/11-01	569	00 00 00.00	87.12.30	Statoil	Exploration	246	
	134	00 00 00.00	00.00.00	Dyvi Delta		29	

Figure 2.2.2.a. One wildcat well and one appraisal well did not reach the prospective depths.

35 exploration wells were finished during the year, 3 were suspended and 6 were being drilled at the end of the year.

As the turn of the year 1987/88, a total of 569 exploration wells had been spudded on the Norwegian continental shelf (411 wildcat wells and 158 appraisal wells).

The drilling activity in 1987 resulted in 17 wells in the North Sea, 14 offshore Mid Norway and 5 offshore North Norway.

A total of 22 exploration wells had been temporarily abandoned on the Norwegian shelf at the end of the year.

Suspended wells on the Norwegian shelf with equipment placed on the seafloor are:

1/09–01	25/01–07 R	30/9–2 R
1/09–04	25/01–08 SR	34/10–03
1/09–06 S	30/02–01	34/10–05
2/07–14	30/02–01	6407/09–03
2/07–14	30/03–04	6407/09–05
2/11–06 S	30/06–09	6407/09–05
7/11–7 R	30/06–16	
15/09–17	30/06–19	

Figure 2.2.2.b, c and d shows the location of the wells which had been spudded in the three areas on the Norwegian shelf (North Sea, Mid Norway and North Norway).

The Norwegian companies Saga, Norsk Hydro and Statoil held operator responsibility in 1987 for 22 (61 %) of wells spudded. The remaining 14 are divided between Conoco, Shell, Elf, BP, Esso, Mobil, Phillips and Total. This appears from Table 2.2.2.a.

Since the start in 1966, 18 different companies have had operator responsibility on the Norwegian shelf. Statoil has drilled the largest number of wells, a total of 133. This is followed by Norsk Hydro, 83 wells, and Phillips, 53 wells (Table 8.2.e).

62 different mobile drilling units have so far operated on the Norwegian continental shelf (Table 8.2.h).

2.2.2.1 Classification of prospect types

The exploration activity in 1987 was mainly directed towards Jurassic sandstone prospects. Eighteeen of the 25 wildcat wells concerned Jurassic targets. The main targets for the other wells were divided between prospects of the following Ages: 2 Tertiary, 2 Cretaceous, 1 Triassic and 1 Carboniferous. One well never reached the prospect.

2.2.2.2 Svalbard

The level of exploration activity at Svalbard was somewhat lower in 1987 than in the two preceeding years. Norsk Hydro is cooperating with Store Norske Kullkompani at Svalbard. 35 km of land seismics were shot in the Adventdalen– Eskerdalen area, and 300 km marine seismics in the Tempelfjorden–Billefjorden area. In addition, geological surveying has been undertaken in the area Billefjorden–Agarfjellet.

The seismic survey vessel "Mobil Search", in cooperation with the University in Bergen, has shot deep seismics along the western and northern coasts of Svalbard. Both Norsk Hydro and Statoil plan geological fieldwork and seismic shooting in limited areas of Svalbard in 1988.

In 1987, a drilling operation was initiated at Svalbard. Nordisk Polarinvest has entered into an agreement with the licensees at Haketangen, and well no. 2 was drilled at Haketangen.

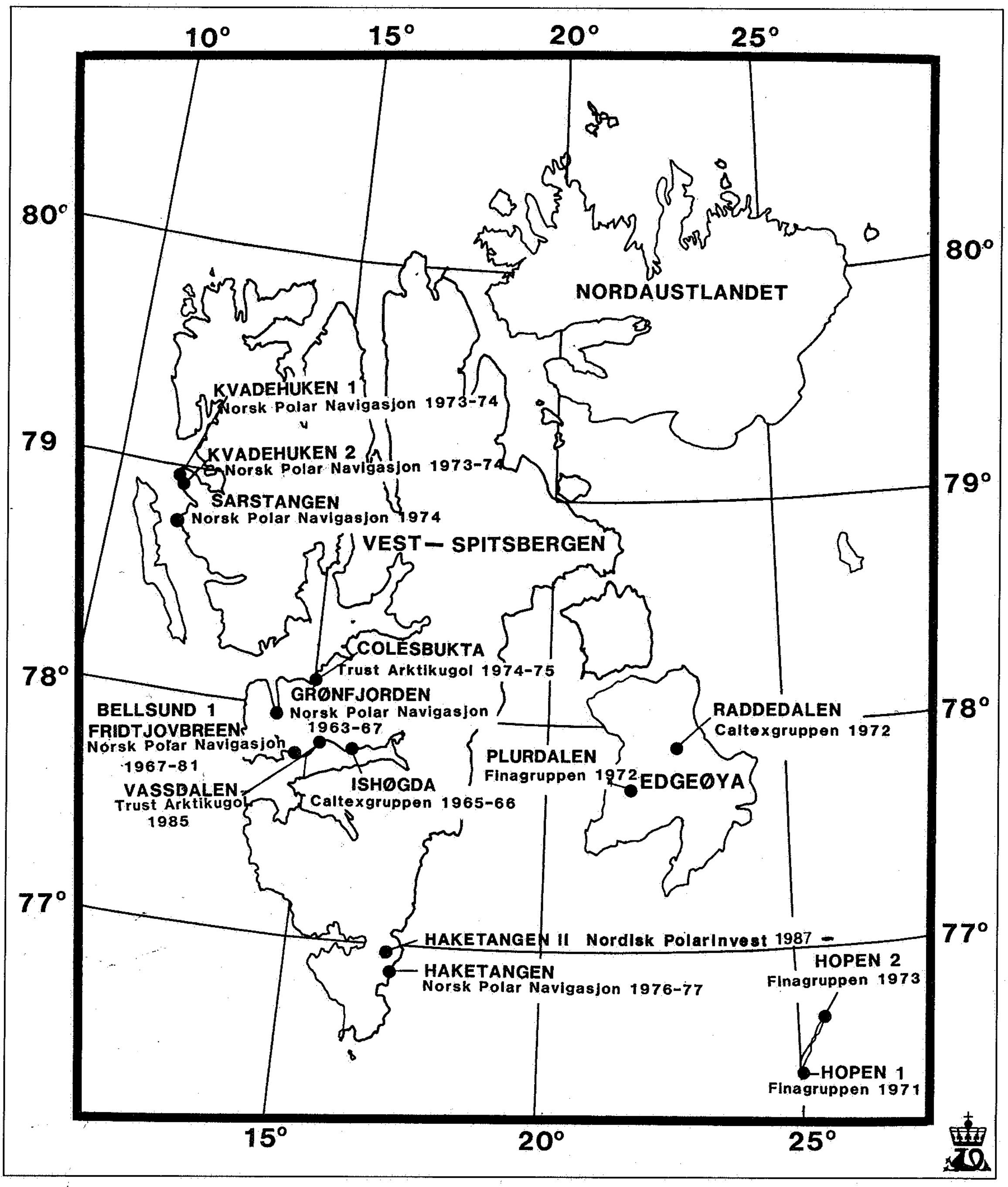
The drilling operation was started on 21 June 1987. Towards the end of October, the well was temporarily plugged back. The well had then reached a depth of 1,732 m. Three tests were made from the well, and they yielded indications of smaller quantities of gas. After demobilisation and securing of equipment, the site was abandoned for the winter. It is assumed that the operations will be restarted in April 1988.

Figure 2.2.e shows the drilling locations at Svalbard, and Table 2.2.2.b shows the drilling licences issued at Svalbard in connection with drilling for oil and gas.

2.3 Finds in 1987

Twenty–first of the 25 wildcat wells in 1987 were

Fig 2.2.2.e
Well locations on Svaldbard.



Tab 2.2.2.b
Drilling permits on Svalbard

Well (locality)	Position North easth	Spudded	Completed	Drilling time days	Operator License	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 33	21.04.73	19.06.73		Norsk Polar Navig.		
7625/5-1							
Hopen II	76 41 15	20.06.73	20.10.73	123	Westburne Int. Ltd	2840,3	314,7
(Hopen)	25 28 00				Fina gruppen		
7811/2-2							
Kvadehuken II	78 55 32	13.08.73	19.11.73	186	Terratest a/s	394	
(Brøggerhalvøya)	11 33 11	22.03.74	16.06.74		Norsk Polar Navig.		
7811/5-1							
Sarstangen	78 43 36	15.08.74	01.12.74	109	Terratest a/s	1113,5	5
(Forlandsrevet)	11 28 40				Norsk Polar Navig.		
7815/10-1							
Colesbukta	78 07	13.11.74	01.12.75	373	Trust Arktikugol	3180	12
(Nordenskiøld Land)	15 02						
7617/1-1							
Tromsøbreen I	76 52 30	11.09.76	22.09.76	109	Terratest a/s	990	6,7
(Haketangen)	17 05 30	13.06.77	19.09.77		Norsk Polar Navig.		
7617/1-2							
Tromsøbreen II	76 52 31	20.07.87			Deutag *	1732	6,7
(Haketangen)	17 05 38				Tundra A/S		
*(Deutag = Deutsche Tiefbohr-Aktiengesellschaft) (Polargas prospektering KB)							
7715/1-							
Vassdalen	77 49 08	22.01.85			Trust Arktikugol		
(Van Mijenfjorden)	15 16 00						

* Drilling not finally completed

drilled on new, previously undrilled structures. Sufficient quantities of hydrocarbons have been found for designating 10 wells as finds, while 8 were dry and 3 had not reached the prospective strata at the end of the year. The 3 last wildcat wells, which all discovered hydrocarbons, were drilled in separate parts of structures where finds had previously been made.

As concerns exploration drilling in general, the level of activity in the North Sea was high, with a certain decrease in the areas off Central Norway. The activity offshore North Norway was high in the last 6 months when all 5 wells in 1987 were being drilled (11th round blocks in new areas).

The most interesting discoveries in 1987 were made in the North Sea. With 9/2– 1 drilled in the northeast flank of the Egersund Basin, Statoil has demonstrated that source rock in the deeper parts of the basin are mature and that considerable quantities of oil have been formed. Furthermore, Elf has found oil in Block 25/5 near the Frigg and Heimdal fields, while Saga made new oil discovery in Block

34/7 between the Statfjord and Gullfaks field. Mobil has discovered gas and condensate in 35/11–2, and even if the magnitude of the discovery is still uncertain, major interest is associated with the further exploration in the area.

The westernmost well on the Norwegian shelf so far was drilled by Statoil in the 11th round Block 6201/11 at South Møre. The well, 6201/11–1, discovered oil in the Jurassic sandstone, but because of very non–porous reservoir rock, the recoverable resources are probably fairly small.

In the course of the last six months of the year, five wells were drilled on the newly allocated blocks in the Barents Sea. Two wells were drilled in the West Finnmark area. Total found gas and condensate in Block 7122/6, while Saga discovered smaller quantities of gas and oil in Block 7122/6. Norsk Hydro drilled dry wells in the areas South Bear Island (Block 7219/9), and the Key Area III (block 7321/8). At the end of the year, Statoil had discovered gas in its well in Key Area I (Block 7226/11).

Block 2/7

At the turn of the year 1987/88, Phillips was drilling well 2/7–20 at the South Eldfisk structure, where 2/7–9 discovered oil at the Jurassic level in 1974. The well had not reached prospective strata at the end of the year, but indications of oil had been found in Upper Cretaceous sandstone.

Block 2/12

Norsk Hydro's wildcat well 2/12–1 discovered oil in Middle Jurassic sandstones. The well was tested, and maximum production was 1,600 Sm^3 of oil and 220,000 Sm^3 of gas per day through a 14.3 mm choke. The magnitude of the resources has still not been determined.

Block 9/2

Statoil's well 9/2–1 was drilled on a prospect in the central part of the block, and oil was discovered in Jurassic sandstone. The well was tested, and the maximum production was 1,080 Sm^3 of oil and 26,000 Sm^3 of gas per day through a 19 mm choke. The discovery is of great interest with a view to further exploration in the area, although it is probably too small to be commercial in isolation with today's oil prices. Well 9/2–2, drilled on a structure in the north–eastern part of the block, produced water.

Block 25/2

As operator for Production Licence No. 112, Elf has drilled and tested wildcat well 25/2–11. The well was drilled on a new structure east of the Frigg field, where 25/2–10 discovered gas and oil in two strata of Oligocene and Eocene Age respectively. 25/2–11 discovered gas and oil in corresponding strata and the best test in the gas zone producted 666,000 Sm^3 og gas per year through a 25 mm choke. The result of the drilling indicates that the discovery is smaller than originally estimated.

Block 25/5

Production Licence No. 102 was allocated in the 9th licencing round with Elf as operator. Wildcat well no. 25/5–1 discovered oil in Middle Jurassic sandstones, in a structure which extends into Block 25/2. Well 25/2–6 which previously has been drilled in this structure, discovered a thin oil layer in Lower Jurassic rocks, while the main prospect, Middle Jurassic, was hit to far off on the flank and produced water. 25/5–1 has been tested, and maximum production was 658 Sm^3 of oil and 154,000 Sm^3 of gas per day through a 19 mm choke.

Appraisal well 25/5–1A was directionally drilled from 25/5–1 to provide more information about the extent of the reservoir towards the north–west. The well was not tested, but the results were very encouraging, since the resources of the structure increased considerably. The discovery is very interesting, particularly in view of the central location between Frigg and Heimdal. More wells will be necessary, however, before the extent of the discovery can be further established.

Block 30/3

Statoil has drilled a combined exploration and production well 30/3–A–1 at a central location of the Veslefrikk field. The purpose of the exploration part was to survey the lower part of the Statfjord formation, where hydrocarbons have yet to be discovered. Oil was discovered in the Statoil formation, and in testing, 300 Sm^3 of oil per day was producted through a choke of 12.7 mm. It is planned that production from the Veslefrikk field may start in 1989, and the oil discovered in the Statfjord formation may represent valuable supplementary resources in this connection.

Block 30/6

Norsk Hydro drilled wildcat well 30/6–21 in a separate fault block just north– east of the main structure on the Oseberg field. Oil was discovered in Middle Jurassic sandstone strata. The best test produced 800 Sm^3 of oil and 112,000 Sm^3 of gas per day through a choke of 19 mm. The density of the oil is 0.85 g/cm.. The drilling confirms the extent of the field to the north.

Block 30/9

Norsk Hydro drilled wildcat well 30/9–6 on a separate structure to the south of the Oseberg field. Oil was discovered in thin Middle Jurassic sandstone strata.The best test produced 186 Sm^3 of oil and 17,200 Sm^3 of gas per day through a choke of 8 mm. The density of the oil is 0.85 g/cm.. The resources proven are relatively modest, but it is assumed that the discovery may be exploited in conjunction with the development of the Oseberg field.

Block 31/4

Norsk Hydro found the oil/water contact at the eastern flank of the Brage field with appraisal well 31/4–9. The test found oil in Middle Jurassic sandstone. Maximum production was 320 Sm^3 of oil and 25,000 Sm^3 per day through a 12.7 mm choke.

Block 33/9
As operator for Production Licence No. 037, Statoil has drilled two appraisal wells in the block. Well 33/9–12 was drilled on the southern part of the East Statfjord structure, which extends into block 34/7. Oil was discovered in Middle Jurassic sandstones. The oil/water contact is at the same level as in the two previous wells on the structure. 3 tests were made, and the best test produced 1,470 Sm^3 of oil per day through a 19 mm choke. It is not expected that the new results will lead to major changes in the estimated recoverable reserves of the field, which are 19 million Sm^3 of recoverable oil.

Well 33/9–13 has been drilled in the north–eastern part of the North Statfjord structure, where oil had previously been discovered in Jurassic sandstones. Two tests were performed, and the best test produced 1,628 Sm^3 of oil per day through a 19 mm choke. The gas/oil ratio was 52 Sm^3/Sm^3. It is not expected that the results from this well will lead to major changes in the estimated resources of the field, which are 39 x $10^6 Sm^3$ of recoverable oil and $2x10^9 Sm^3$ of associated gas.

Block 34/4
As operator for Production Licence No. 057, Saga has drilled appraisal well 34/4–7 on the north–westerly part of the Snorre field. The well tested oil in Triassic sandstones. Maximum production was 1,735 Sm^3 of oil per day through a 16 mm choke. The good test results show that this part of the reservoir has good production properties.

Block 34/7
Well 34/7–12 has been drilled by Saga into a separate structure south of the Snorre field. Oil was discovered in Middle Jurassic sandstones. Three tests were performed, and the best test produced 1,490 Sm^3 of oil per day through a 12.7 mm choke. The gas/oil ratio was 65 Sm^3/Sm^3. The find is particularly interesting since it is close to existing and planned fields. Calculations show that it may be large enough to substantiate future development. However, it is necessary to undertake further surveying before the final extent of the field is established.

Block 34/10
Well 34/10 was drilled as an appraisal well on the southern part of South Gullfaks. The discovery was tested and maximum production was as much as 2,680 Sm^3 of oil per day through a 25.4 mm choke. The results from this well confirm the Norwegian Petroleum Directorate's estimate for technically recoverable reserves from South Gullfaks, $34x10^6$ Sm^3 of oil, $12x10^6$ Sm^3 condensate and $103x10^9$ Sm^3 gas.

Block 35/11
Mobil has drilled the second well on the block which was allocated in the 8th round. Gas and condensate was discovered in Middle Jurassic rocks, and the reservoir was tested in five zones. The best test produced 532,000 Sm^3 of gas and 522 Sm^3 of condensate per day through a 16 mm choke. The discovery is interesting, but more drilling will be necessary in order to evaluate its size and extent.

Block 6201/11
As operator for Production Licence No. 130, Statoil has drilled the first well in the so–called South Møre area. The well is the westernmost well ever to have been drilled on the Norwegian continental shelf. Well 6201/11–1 found oil and gas in Upper Triassic sandstones. The discovery was tested, and maximum production was 120 Sm^3 of oil and 96,000 Sm^3 of gas per day through a 16 mm choke. The reservoir properties varied widely, and several wells must be drilled in order to establish the size and importance of the discovery.

Block 6406/3
Statoil has drilled appraisal well 640/3–4 on the north–western flank of the find made by 6406/3–2. Good indications of hydrocarbons were found in 6406/3– 4, and four production tests were tried. The formations turned out to be tight, however, so that no production resulted from the reservoir. The result was disappointing, but it is still to early to tell what this means for the total recoverable reserves of the structure.

Block 6407/2
Saga drilled wildcat well 6407/2–3 in the north eastern part of the block. Gas and condensate was demonstrated in Middle Jurassic rocks in the structure which represents the extention of the Midgard field to the south east. The best test produced 1.3 Sm^3 of gas and 220 Sm^3 of condensate per day through a 38 mm choke.

Block 6407/6
As operator for Production Licence No. 092, Statoil has drilled wildcat well 6406–3 in the north westerly part of the block. Gas was discovered over a thin oil zone in the structure, probably extending into the adjacent block 6407/5. Tests of the gas and the oil zones were undertaken. The best test in the gas zone produced 1.3 x 10^6 of gas and 520 Sm^3 of condensate per day through a 38 mm choke. In the oil zone, the production was 160 Sm^3 of oil and 340,000 Sm^3 of gas per day through a 25.4 mm choke. The test results must be characterized as very good, but the total resources of the structure are probably fairly limited. The discovery has a favourable location, however, and may represent valuable supplementary resources with a view to an overall production plan for the Haltenbanken area.

Block 6407/7
With 6407/7–1, Norsk Hydro found the field which has been given the name Njord in the southernmost part of the block. The reservoir consists of several separate zones with varying reservoir properties. Exploration well 6407/7–2 was drilled on a separate part of the structure to the east of the first well, and oil was discovered in Jurassic rocks. The reservoir was tested in two zones, and maximum production was as much as 1,330 Sm^3 of oil per day through a 25.4 mm choke. The result is positive, and the Norwegian Petroleum Directorate is working on obtaining new resource estimates for the field.

Block 6407/10
Wildcat well 6407/10–1, which was drilled on a separate fault block on the south–eastern flank of the Njord field was a duster.

Block 6506/12
Wildcat well 6506/12–7 was drilled on a north–easterly extension of the Smørbukk field. As in the case of earlier wells on the Smørbukk structure, gas and condensate was discovered in Middle and Lower Jurassic sandstones. In this well, oil was in addition discovered in a subjacent sandstone reservoir of the Lower Jurassic. Four tests were performed, and the highest oil production was measured at 800 Sm^3 of oil through a 25.4 mm choke. The highest gas production was 325,000 Sm^3 of gas through a 25.4 mm choke. The test results are encouraging, particularly with a view to the good oil tests from such a deep reservoir (almost 5,000 m). However, the Smørbukk field is very complicated, with reservoir properties varying from zone to zone. There are reasons to believe that the field contains more oil than previously assumed.

Block 6507/7
Conoco has drilled a new appraisal well on the Heidrun field with positive results. Well 6507/7–8 was drilled on the south–eastern part of the field. The well found oil in Middle and Lower Jurassic sandstones. Two tests were performed. Maximum production was measured at 1,145 Sm^3 of oil and about 99,000 Sm^3 of gas per day through a 21 mm choke. The gas/oil ratio is 86 Sm^3/Sm^3. The test results are good and confirm earlier resource estimates for the field.

Block 7122/6
As operator for Production Licence No. 138, Total has drilled wildcat well 7122/6–1 on the eastern flank of the Hammerfest Basin. The well discovered gas and condensates in Triassic rocks, and two zones were tested. The best test produced 580,000 Sm^3 of gas and 75 Sm^3 of condensate per day through a 17.4 mm choke. A lot of work remains before any final opinion may be formulated about the size of the reservoir.

Block 7124/3
As operator for Production Licence No. 135, Saga has drilled wildcat well 7124/3–1. This is the easternmost well on the Norwegian continental shelf so far, and the first well in the West Finnmark area. 7124/3–1 discovered some gas over a thin oil zone in Jurassic to Triassic sandstones. The well was not production–tested, but the results are positive with a view to further exploration activity in the Barents Sea.

Block 7219/9
As operator for Production Licence No. 138, Norsk Hydro spudded the first well in the South Bear Island area in 1987. The drilling had not finished by the end of the year, but the results so far have been discouraging.

Block 7226/11
As operator for Production Licence No. 139, Statoil was in the process of drilling the first well in Key Area II at the turn of the year. Gas has been discovered. The importance of this has not yet been clarified.

Block 7321/8
As operator for Production Licence No. 141, allocated in the 11th round, Norsk Hydro has drilled the first well in Key Area III. Only traces of hydrocarbons were discovered in Jurassic rocks. The well has not been production–tested, but important information has been provided with a view to further exploration in the Barents Sea.

The Troms I area
No exploration wells were drilled in the Troms I area in the course of 1987.

2.4 Fields Under Consideration
In 1987, the operators declared the following fields commercial:
Snorre, Brage, Draugen and 30/6 Gamma north.

A number of other fields, both in the North Sea and on Haltenbanken, are considered by the operator companies as ready for development. Other fields are under evaluation in expectation of marketing possibilities, price increases, better reservoir information, progress in development technology and/or other circumstances which may result in improved profitability.

2.4.1 The North Sea
Hod
Block 2/11 was allocated in 1969 with Amoco as operator. The field is located about 12 km south of Valhall. Parts of the block have later been relinquished, and parts of the relinquished area has been made part of Production Licence No. 068.

The Hod field consists of two smaller structures. These have been explored with a total of five exploration wells; two on the western part and three on the eastern part of Hod. The exploration shows that oil is present in Cretaceous reservoirs of late Cretaceous/early Tertiary.

The Norwegian Petroleum Directorate's estimate of recoverable resources is 7 x 10^6 Sm^3 of oil and 5 x 10^9 Sm^3 of gas. The operator has a lower resource estimate. The reserve estimates are difficult because of tertiary gas destroying the quality of seismic data, and complicated oil/water interfaces. The Directorate will evaluate the resources further in connection with the consideration of the operator's plans for development and operation of the field.

The operator plans to present such a plan in the course of the spring of 1988. It will be proposed to develop the field with an unmanned wellhead platform which will be equipped with measurement equipment, a "pig launcher" and quartering facilities. Five production wells are planned, but the number may be greater. Quantities produced will be transported to Valhall as a two–phase stream. Production start–up is targetted by the operator for the summer of 1990.

Fields around Ula

Block 1/3 is adjacent to the Gyda field to the west, and Elf Aquitaine is the operator. Minor oil discoveries have been made which probably extend into block 2/1. There is no connection between the Gyda field and the 1/3–3 structure.

Block 2/2 is adjacent to Gyda eastwards, with Saga as operator. A minor oil discovery has been made here also. The water depth is very moderate, 60 m.

In the block adjacent to the Ula field to the west, 7/11, an oil find has been made, and in Block 7/8 to the north west of Ula, a minor oil discovery has also been made.

In case of development, these smaller finds should be considered jointly in connection with the development of the infrastructure at the Ula field.

West Sleipner and Sleipner area satellites

The Sleipner area comprises Blocks 15/5, 15/6, 15/8, 15/9 and 16/7.

The year of allocation, operator and production licences are as follows:

Block	15/5	15/6	15/8 and 15/9	16/7
Allocation year	1977	1969	1976	1981
Operator	N Hydro	Esso	Statoil	Esso
Production Licence	048	029	046	072

The West Sleipner field has previously been declared commercial, and recoverable reserves in the field have been estimated at 135 x 10^9 Sm^3 of gas, 27 x 10^6 Sm^3 oil and 9 x 10^6 tonnes NGL.

A total of six smaller discoveries have been made in the Sleipner area in addition to East Sleipner and West Sleipner: 15/9 Theta, 15/9 My, 15/8 South Alfa, 16/7 A and H and on a structure extending over the border between 15/5 and 15/6. Recoverable resources in the satellite fields have been estimated at 50 x 10^6 Sm^3 oil.

West Sleipner may be developed independently from Sleipner East. Alternatively, the field may be phased in after East Sleipner with a view to utilizing unused processing capacity on the East Sleipner platform.

The gas in West Sleipner contains a lot of CO_2 compared with usual specifications in sales contracts. The CO_2 content can be reduced by either mixing the gas with CO_2–lean gas from other fields, or by treating the gas in offshore or onshore CO_2 extraction plants. Onshore extraction will probably require a separate pipeline to shore for the gas. The satellite fields may probably be tied into the main platforms. Parts of the Theta reserves are in pressure communication with Sleipner East and must be exploited in connection with the production from this field.

Balder

Block 25/11 was allocated in 1965, under Production Licence No. 001, with Esso as operator. Esso was also granted Blocks 25/8 and 25/10, under Production Licence Nos. 027 and 028.

The field was discovered in 1974 with drilling of exploration well 25/11–5, where oil was discovered in Paleocene sandstones. In Block 25/8, minor quantities of oil have also been discovered in corresponding sandstone strata.

No decision has been made so far concerning the development of the field, and no drilling has been done on this field since 1981. The recoverable oil reserves have been estimated at 35 x 10^6 Sm^3.

The landing application was submitted in December of 1980, but a marked downwards adjustment of the reserves weakened the economics of the project, and the application was withdrawn. The operator company has the field under evaluation.

The Oseberg area

The Oseberg area comprises Blocks 30/2, 30/3, 30/6, 30/9 and 31/4 (Figure 2.5.9.a). The Oseberg field itself has been approved for development, and pilot production started in 1986. It is planned to have the field in operation in 1989 (cf. Chapter 2.5.9).

Discoveries of different size have been made in the fields Oseberg, Brage, Veslefrikk, Huldra, 30/6–Beta, 30/6–Kappa, 30/6–North Gamma and 30/9 Omega. Resources discovered appear from Tables 3.2 and 3.3.

In addition to the discoveries, a large number of prospects have been charted in the Oseberg area. This applies in particular to 30/9 (Production Licence No. 104). The Norwegian Petroleum Directorate's estimate of recoverable resources in the projects within Production Licence No. 104 is 35 x 10^6 Sm^3 of oil. In addition, some gas is to be expected.

It has been decided that the oil from Oseberg should be landed by pipeline at Sture in Øygarden. Gas will be reinjected during the oil production phase. A gas transportation requirement will only be present after the year 2000. It is assumed that Oseberg may be connected with the transportation systems for gas which will then be in existence. In the case of other fields in the Oseberg area, the same transportation method as in the case of Oseberg is expected.

The Oseberg field extends into two production licences: Block 30/6, Production Licence No. 053, which was allocated in 1979, and block 30/9, Production Licence No. 079, which was allocated in 1982.

In November of 1987, Norsk Hydro presented revised plans for the development and operation of the northern part of the Oseberg field; Oseberg II. The operator has estimated total recoverable oil reserves from this field at 58 x 10^6 Sm^3. In addition, some supplmental resources have been discovered in Upper Brent.

It is planned that the Oseberg II platform should be upgraded from a satellite platform to an integrated production, drilling and accommodation platform with the help of an auxiliary vessel in the drilling phase. The time for production start–up has been accelerated from 1995 to December 1990. The average production rate is estimated at 14,300 Sm^3/day.

An acceleration of Oseberg II has had the effect that the requirement for injection gas has increased past the amount which a Troll module may supply. The operator plans to obtain further injection gas from the North Gamma satellite field.

Gamma North

Gamma North is in Block 30/6, which was allocated as Production Licence No. 053 in 1979. The structure has a thin oil zone with a superjacent gas cap. The resources have been estimated by the operator at 11 x 10^6 Sm^3 of oil and x 10^9 Sm^3 of gas.

It is planned to develop the structure to cover the need for injection gas in connection with the planned acceleration of Oseberg II. The operator is evaluating the possibilities for production from horisontal wells completed at the seafloor with a view to increase the production from the oil zone. Production start–up has been planned for December 1970.

Brage

The Brage field is located in Block 31/4 which was allocated as Production Licence No. 055 in 1979. Norsk Hydro is the operator. Plans for development and production were presented to the authorities in December of 1987.

Oil has been discovered in three reservoirs: Statfjord, Fensfjord and Sognefjord. The operator has estimated recoverable reserves at 38 x 10^6 Sm^3 oil and 3 x 10^9 Sm^3 gas.

The field is planned to be developed in December of 1991, and the average production rate will be 12,100 Sm^3/d.

South Gullfaks, 34/10–Beta and 34/10–Gamma

Block 34/10 was allocated in 1978 with Statoil as operator, cf. the description of Gullfaks, Chapter 2.5.12. Gullfaks South is located in the middle of the block (about 9 km south of the Gullfaks field). Beta is located to the west of South Gullfaks and extends into 33/12. Gamma is located in the south–eastern corner of the block.

Gullfaks South is structurally difficult. Several independent gas/oil, gas/water and oil/water contacts have been observed in the field. Hydrocarbons have been discovered in sandstone of Middle and Lower Jurassic and of Triassic age. Until now, five wells have been drilled at South Gullfaks, one at Beta and one at Gamma. Well 34/10–32 was drilled in the spring and summer of 1987 on the southeastern part of the structure. Oil has been discovered and tested in Lower Jurassic sandstone. In 1987, the gathering of 3D seismics over the South Gullfaks field was initiated.

South Gullfaks contains both oil, condensate and unassociated gas. The operator evaluates both parallel oil and gas production and sequential production (first oil, later gas). The Norwegian Petroleum Directorate has not changed the reserve estimates for Gullfaks South, Beta or Gamma in 1987. The results from well 34/10–32 seems to confirm the reserve estimate of the Norwegian Petroleum Directorate.

In September of 1987, Statoil presented a feasibility study for South Gullfaks. The study shows five alternative platform concepts. It is envisaged that Gullfaks A will be used for both processing and storage of oil. Gas transportation both to Great Britain and the Continent are under evaluation. The time for presentation of a plan for development and operation is uncertain.

East Statfjord and North Statfjord

East Statfjord was previously called 33/9 Alfa, and North Statfjord was previously called 33/9 Beta. The structures are located at equal distances to the east and to the north of the Statfjord field. East Statfjord extends into Block 34/7. 3 wells have been drilled on East Statfjord. Well 33/9–12 was drilled towards the south in the summer of 1987. Hydrocarbons in Middle Jurassic sandstones were discovered and tested. The well confirmed the available resource estimates.

North Statfjord consists of two separate reservoirs, of Upper and Middle Jurassic age respectively. The lower reservoir may possibly extend into Block 34/7. Two wells have been drilled on North

Statfjord. Well 33/9–13 was drilled to the north–east of the structure in the autumn of 1987. Hydrocarbons of Middle Jurassic age were discovered and tested. The drilling of an appraisal well is planned on North Statfjord in 1988. The processing of new 3D seismic surveys covering both structures was finished in the spring of 1987.

In 1987, the Norwegian Petroleum Directorate has not changed the reserve estimate for East and North Statfjord. In 1988, the Norwegian Petroleum Directorate will work on a new evaluation of the fields.

It is envisaged that North and East Statfjord will be put into production in 1993 and 1994, respectively. In recent years, the operator has evaluated several development solutions. It is planned to develop the fields with the help of subsea installations with wellstream transfer to Statfjord C.

Snorre

The Snorre field is located in Blocks 34/4 and 34/7. Block 34/4 was allocated as Production Licence No. 057 in 1979. Block 34/7 was allocated as Production Licence No. 089 in 1984. Saga is operator for both blocks.

Plans for the development and operation of the Snorre field were submitted to the authorities on 1 September 1987. A bill for Snorre will be presented to the Storting no later than 1988.

11 exploration wells have been drilled to date on the Snorre field, 34/4–1, 4,6 and 7, and 34/7–1,3,4,6,7,9 and 10. All wells have discovered oil with associated gas, but without a gas cap.

Snorre is a large oilfield. The commercially recoverable reserves have been estimated by the operator at about 120 x 10^6 Sm^3 oil and 7 x 10^9 Sm^3 associated gas. The Norwegian Petroleum Directorate's figures are about 11 % less. The oil, which is strongly unsaturated, is divided into two reservoirs: The Statfjord reservoir and the Lunde reservoir. The reservoirs have been well surveyed, and the volumetric control is relatively good. There is uncertainty as concerns the extent of the sand units and the communication in the Lunde reservoir. This may be of importance for how it will develop during production. The depth of the reservoir is about 2,500 m. Drilling and testing has discovered three different oil/water contacts. The deepest contact is in the western part of the field.

The water depth varies over the field from 300 m in the south to 370 m in the north. It is planned for the field to be developed with one floating tension leg platform in the south and one seafloor installation in the central part of the field. The oil will be processed in two steps on the Snorre platform, and will afterwards be transported in pipelines to Statfjord for final processing.

With a view to utilizing the flexibility of the tension leg platforms, it is envisaged that the development will take place in two phases. Phase One leads to the draining of the southern and central part of the field, and has development costs of about NOK 20 billion (1987 kroner). Phase II concerns the extraction of central and northern part of the field and involved two development options. One possibility is the moving of the platform, the other is a further development with installations on the seafloor.

In working with the Snorre developent, the Norwegian Petroleum Directorate has been particularly concerned with the magnitude of the recoverable reserves, the price sensitivity of the project and additional reserves in the area. The Norwegian Petroleum Directorate has asked the licensees for the presentation by the autumn of 1988 of a plan satisfying the requirements of the authorities for the development of the supplementary reserves.

The Norwegian Petroleum Directorate is of the opinion that the project may be implemented within acceptable boundaries from the point of view of working environment and safety.

Saga has laid emphasis on a high evacuation capacity with straight escape routes through to the accommodation area. Two of these escape routes are well protected against explosion hazards.

The lifeboats will be of the free fall type. Becuase of the efficient escape routes and the lifeboat type selected, a lifeboat coverage of less than 200 % is proposed.

Based on experiences with operational problems during the cold periods in the winter of 1987, the Norwegian Petroleum Directorate has pointed out that the plans for Snorre have not sufficiently integrated design criteria with a view to counteracting such problems.

2.4.2 Haltenbanken

The activities over the last years on Haltenbanken have demonstrated that the area is prospective and interesting. Nine discoveries have been made on Haltenbanken, and the planning with a view to development has reached an advanced stage. The resource basis in the area is of the order of magnitude of 300 x 10^6 Sm^3 oil and 300 x 10^9 Sm^3 gas. Apart from Draugen, development and operation plans (DOP) have been presented in September of 1987 for Draugen, and in the case of Heidrun, the DOP was submitted to the authorities in November of 1987. These fields may be the start of the first production phase in the area, which will mainly be an oil production phase. The Norwegian Petroleum Directorate is particularly concerned with finding a use for the gas resources as early as in the first oil production phase sound from the point of view of resources and national economy. Depending on when a gas market arises, fields which mainly consist of gas resources may be phased in.

Tyrihans

Two wildcat wells have been drilled on the field, which consists of two structures, one with gas/condensate and one with a thin oil zone and a gas cap. The resources are 16 x 10^6 Sm^3 oil/condensate and 40 x 10^9 Sm^3 gas.

Midgard

A total of four exploration wells have been drilled on the Midgard field. The structure is divided in three with two transverse faults. The field mainly consists of gas, and the reservoir properties are good.

In one of the fault blocks, a thin oil zone has been discovered which it may be difficult to produce, since it is located between a large gas cap and a water zone. The field will probably be produced through pressure release. The Norwegian Petroleum Directorate has calculated recoverable reserves at 80 x 10^9 Sm^3 gas and 15 x 10^6 Sm^3 oil.

Draugen

Six exploration and appraisal wells have been drilled on the field. The reservoir has been well surveyed. It is long and narrow, with an oil column varying from 11 to about 40 m. The field contains relatively light oil with a low gas/oil ratio. The reservoir has good properties and will be produced by water injection. The Norwegian Petroleum Directorate's reserve estimate for the field is 68 x 10^6 Sm^3 oil and 4.7 x 10^9 Sm^3 gas.

Plans for the development and operation of the field were presented to the authorities in September of 1987.

It is planned that the field will be developed with a fixed concrete platform. Six–seven production wells have been planned, and six water injection wells. Because of the extent of the field, all water injection wells and two of the production wells will be subsea completion wells. Production start–up is stipulated at the summer of 1992.

The Norwegian Petroleum Directorate is of the opinion that the proposed plan may be implemented within the constraints of safety and working environment legislation.

Smørbukk and 6506/12–Beta, Block 6505/12

A total of seven wells have been drilled on the block. Two structures which both contain gas and condensate have been discovered. In 1987, one well was drilled into the Smørbukk structure. It led to the upwards adjustment of the estimate for the oil reserves.

6506/12–Beta has now been surveyed with 3D seismics. Similar surveying will be carried out in 1988 on Smørbukk.

Based on new studies, the Norwegian Petroleum Directorate's evaluation of the reserves for Smørbukk is presently at 20 x 10^6 Sm^3 condensate and 65 x 10^9 Sm^3 gas. The oil reserves discovered in 1987 have not been included in these figures. The estimate for the reserves in 6506/12–Beta has been somewhat reduced in 1987, and presently is at 22 x 10^6 Sm^3 condensate and 11 x 10^9 Sm^3 gas.

Among the two discoveries of the block, 6506/12–Beta is best surveyed and most mature for development. The time for development and the selection of development solution for the discoveries in this block will depend on the market development for gas from Haltenbanken. A phased development may also be assessed for adaptation to the gas market. As concerns the processing and transportation of gas from the Smørbrukk field, it will be natural to consider this in light of other development projects in this area.

Heidrun

The field has been surveyed with eight exploration and appraisal wells. The field contains heavy oil with a superadjacent gas cap. The reservoir is heavily faulted, and contains a number of reservoir formations. Water injection will facilitate maximum oil production. It may be possible to inject associated gas during a limited period. From the point of view of the reservoir, the gas cap should be produced after the main part of the oil has been produced. The Norwegian Petroleum Directorate's resource estimates are 113 x 10^6 Sm^3 oil and 41 x 10^9 Sm^3 gas. The Directorate will furthermore evaluate the resources more thoroughly in connection with the evaluation of the operator's plan for development and operation of the field.

This plan was presented to the authorities in November of 1987.

The operator evaluates the start–up of production from the field at a lower level from the turn of the year 1989/90. The production facility will be a rebuilt drilling unit. Such an early production phase may provide information about the reservoir which may be useful for the further planning of the main production. The development solution for the main production from the field is a tension leg platform with a concrete hull. It is planned to start main production from the field in the summer of 1992.

Block 6407/7 and 6407/10

Two exploration wells have been drilled on 6407/7, and both discovered oil. The discovery extends into block 6407/10, which was allocated in 1987. One well was drilled on this block in 1987. This well did not discover oil. The structure is heavily faulted, and several wells are necessary before the structure is sufficiently surveyed. The preliminary estimates for this resource are 25 x 10^6 Sm^3 oil and 2.5 x 10^9 Sm^3 gas.

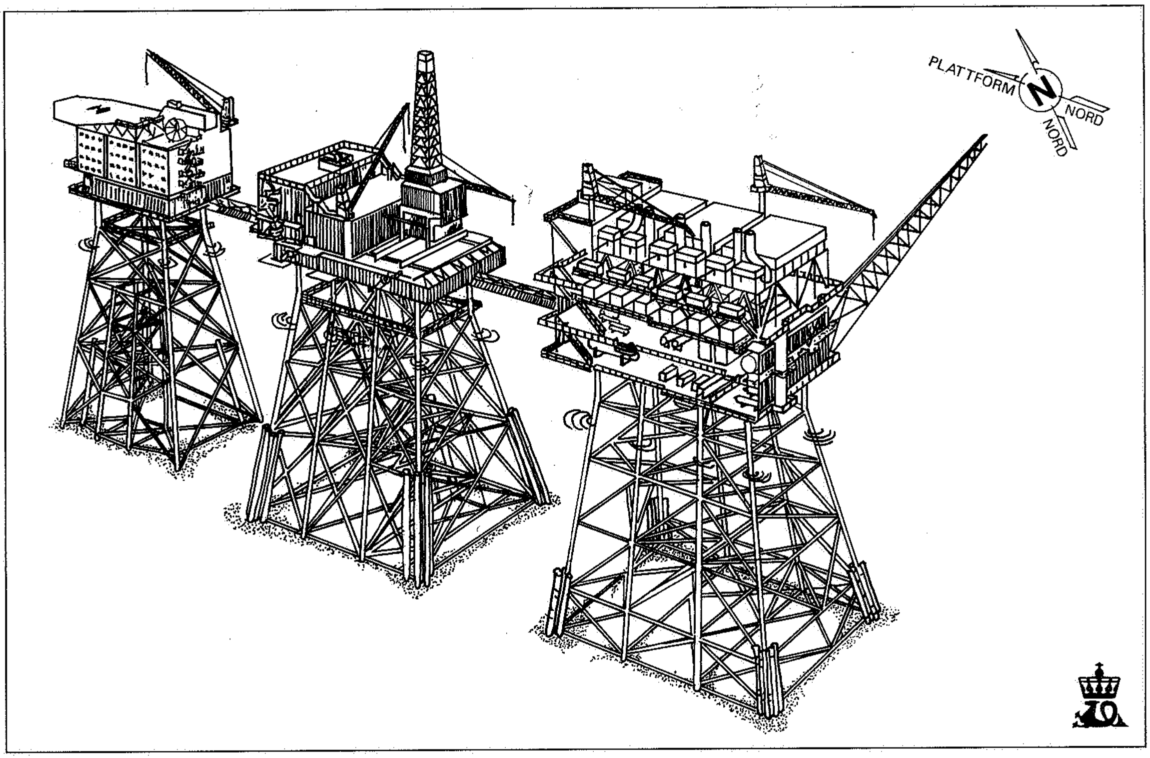
6406/3

Exploration well no. 2 in this block discovered oil saturated reservoir sandstone. In 1987, a new well was drilled into the extension of this structure. This well discovered sandstone which was tight.

2.4.3 Troms

All things considered, significant quantities of gas

Fig 2.5.1.a
Installations on Valhall.



have been discovered in the Askeladden, Albatross, Snøhvit fields and Block 7120/12 of the Hammerfest Basin in the Troms I area. No discoveries have been made in other parts of the area.

2.5 Fields being planned, developed or in production

Several fields on the Norwegian continental shelf have been declared commercial and approved for development or are in production: Valhall, Albuskjell, Cod, Edda, Ekofisk, Eldfisk, Tor, West Ekofisk, Ula, Heimdal, Frigg, North East Frigg, Odin, Gullfaks, Statfjord and Murchison are in production. The fields East Frigg, Gyda, Oseberg, Veslefrikk, Tommeliten, Troll and Sleipner East are being planned or developed. In the following the fields are described in further detail.

2.5.1 Valhall

Production Licence 006

Licensees

Amoco Norway Oil Company A/S	28.33 %
Amerada Petroleum Corporation of Norway	28.33 %
Texas Eastern Norway Inc	28.33 %
Norwegian Oil Consortium A/S & Co	15.00 %

Block 2/8 was allocated in 1965 with Amoco as the operator. The Valhall field lies mainly within Block 2/8 (Figure 2.3.2.a). The southern part of the block reaches into Block 2/11, production licence 033. In this licence, each of the companies mentioned above have a 25 per cent interest.

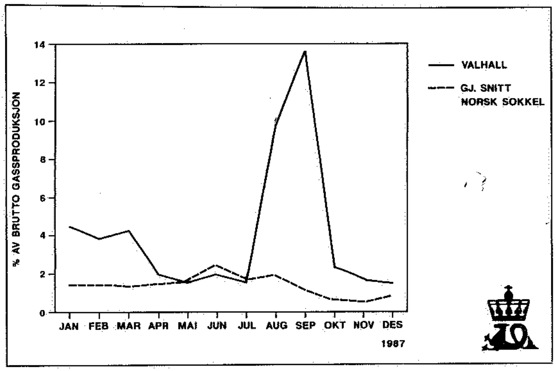
Recovery of reserves

Valhall can be compared to the fields in the Ekofisk area as regards reservoir properties and geology. The fields produce from fractured chalk which is tight in comparison with other reservoir rocks on the Norwegian shelf. This means that the field will have a long lifetime and a comparatively small degree of production. Valhall produces most from the Tor structure (2/3 of the reserves) and to a smaller extent from Hod. The Ekofisk structure, which is the most important in some of the fields in the Ekofisk area, is not present on Valhall.

Production started in November 1982 and at the end of 1987 there were 20 production wells on the field. So far production has not been up to expectations because of clogging up of the production wells by the formation rocks. The operator appears to have succeeded in getting round this problem recently, by means of a special completion technique. There has been great uncertainty about the Valhall geology on account of a cloud of gas over the reservoir that has made seismics unusable as a survey tool. After a good deal of work from the operators and other parties, a geological model for the field has been achieved, which has proved useful in the drilling of new wells.

The subsidence of Valhall was mentioned in last year's annual report, and a subsidence rate of about 20 cm/year has been measured. After more detailed investigations the Norwegian Petroleum Directorate has discovered that the subsidence potential on Val-

Fig 2.5.1.b
Gas flared on Valhall.



hall does not appear to be as severe as was feared. This means that the sort of modification used on Ekofisk is hardly likely on Valhall. Conditions linked to subsidence, as for example well deformation, loss of productivity and differential settlement, have not been studied in detail.

Production facilities

Development includes an accommodation, a drilling, a production and a marine riser pipe platform. The three first mentioned platforms are placed on the Valhall field and interlinked with bridge connections. Figure 2.5.1.a shows these installations. The marine riser platform, which Phillips Petroleum Company Norway has the operatorship for, is connected to the Ekofisk Centre Tank.

The oil is separated on Valhall using two separation units, before being pumped to the Ekofisk facility, where it is metered and led on into the Teesside pipeline. The gas is compressed, dried and its dew–point checked on the production platform before being despatched by pipeline to the Ekofisk installation, where it is metered and sent on via the Emden pipeline. Denser gas fractions of NGL are separated out on Valhall using a fractionating column, and then injected into the oil. A nitrogen generation system was begun on Valhall last summer. Injection of such gas into the export gas stream makes it easier to meet the gas specification. The system also means that the NGL injection into the export gas can be increased. A hydrozyklon plant has been tested with a view to removing oil from produced water.

Flaring of gas

The volume of gas flared in 1987 on Valhall was on average 74 x $10^3 m^3$/day, corresponding to 3.8 per cent of the total gas production (Figure 2.5.1.b). The flare limit has been 150 x $10^3 Sm^3$ a day in 1987. Gas has been flared off particulrly because of compressor problems and in connection with the closing of Ekofisk in August.

Metering systems

Inspections of the oil and gas metering systems for the Valhall production in the report period have not been carried out.

Costs

Total investment costs are about NOK 10.9 billion in fixed 1987 kroner. Total operating costs up to 2010 are estimated at about NOK 14.3 (1987) billion.

2.5.2 Tommeliten

Production Licence 044

Licensees

Den norske stats oljeselskap a.s.	70.64 %
Norske Fina A/S	20.23 %
Norske Agip A/S	9.13 %

Production Licence 044 was allocated on 27 August 1976 and includes Block 1/9, southwest of the Ekofisk area (Figure 2.5.3.a).

The field was discovered by drilling exploration well 1/9–1 in 1977. The plan for development and operation was presented and approved in the first half of 1986.

Recovery of reserves

Tommeliten consists of two structures, Alpha to the south and Gamma to the north. Gas and condensate have been proven in both structures. The hydrocarbon bearing rocks are represented by the Ekofisk and Tor formations. The Directorate estimates recoverable reserves at 16.8 x 10^9 Sm^3 gas. The preferred field development strategy involves production assisted by the reservoir's natural drive mechanism.

Development

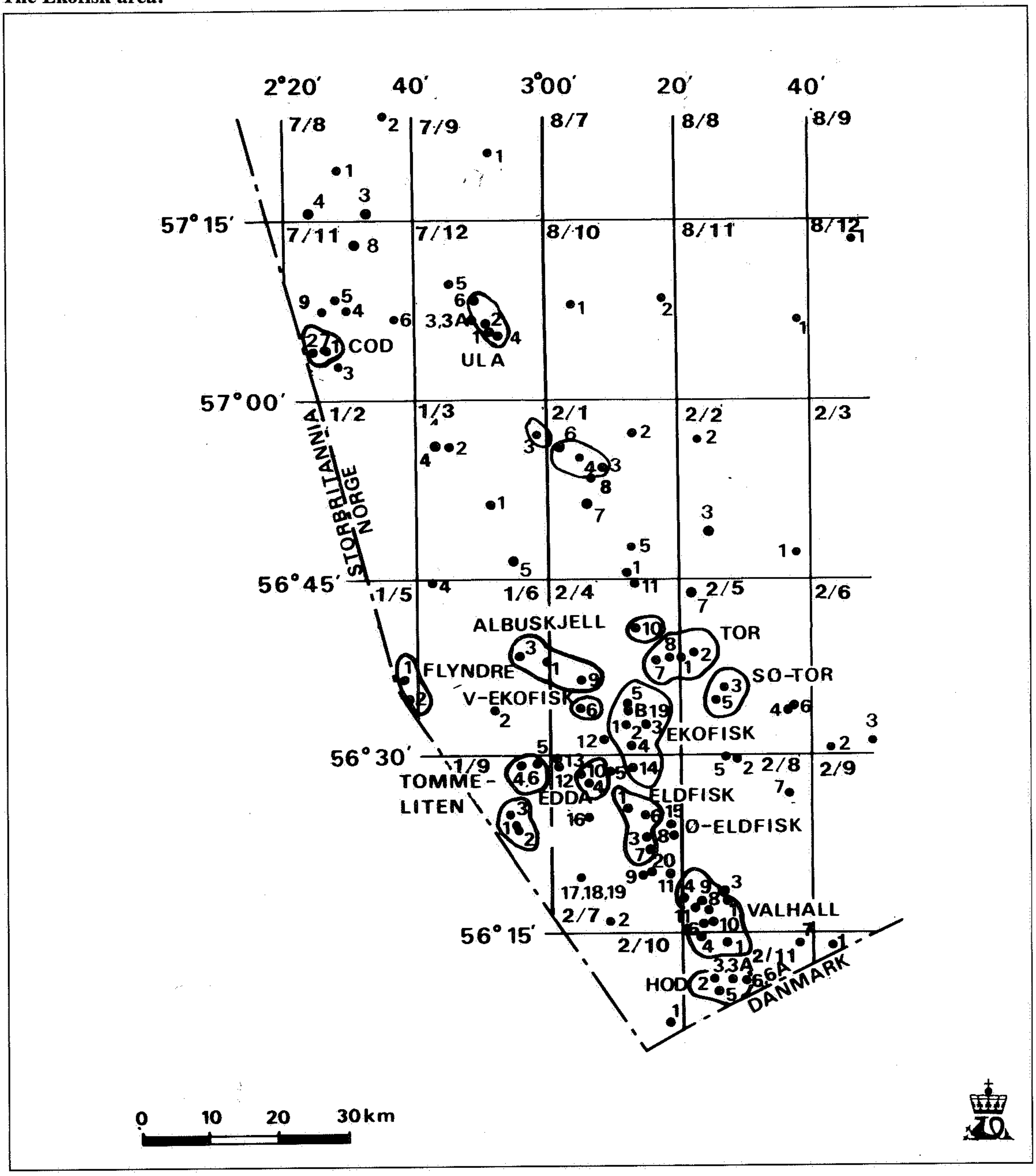
The field will be developed with subsea completion wells and full well transfer and hook up to the Edda platform. Edda will perform first stage separation, dehydration and metering, before the gas and condensate is conducted by existing pipeline for final processing at the Ekofisk Centre.

Development is planned in four phases, the first two of which will be development of the Gamma structure. The Alpha structure will be developed in phases 3 and 4. Production is planned so that a stable production plateau of 1.1 x 10^9 Sm^3. gas a year can be maintained as long as possible. The field is to start producing on 1 October 1988. Four production wells have been drilled, while the fifth is expected to be finished in the course of February 1988.

Costs

The total cost of complete development is estimated to be around NOK 4.8 billion (1987 kroner). Total operating costs are estimated at about NOK (1987) 2.2 billion.

Fig 2.5.3.a
The Ekofisk area.



2.5.3 The Ekofisk area
Production Licence 018

Licensees

Phillips Petroleum Company Norway A/S	36.960 %
Norske Fina A/S	30.000 %
Norsk Agip A/S	13.040 %
Norsk Hydro Produksjon A/S	6.700 %
Elf Aquitaine Norge A/S	8.094 %
Total Marine Norsk A/S	4.047 %
Eurafrep Norge A/S	0.456 %
Coparex Norge A/S	0.399 %
Norexplor A/S	0.304 %

The above companies (the “Phillips Group”) hold the licences to the Ekofisk, Cod, Edda, Eldfisk, Ekofisk and West Ekofisk fields. Cod is in Block 7/11, Edda and Eldfisk in Block 2/7 and Ekofisk and West Ekofisk in Block 2/4.

Albuskjell is split between production licences 018 and 011, and the Tor field between production licences 018 and 006. Albuskjell lies in Blocks 1/6 and 2/4 and the Tor field in Blocks 2/4 and 2/5. The distribution is as follows:

Albuskjell:	“Phillipsgroup”:	50 %
	A/S Norsk Shell:	50 %

Tor:	"Phillipsgroup":	75.3612 %
	"Amocogroup":	24.6388 %
	(licensees on Valhall)	

Development

Thus, the Ekofisk area consists of seven fields: Ekofisk, West Ekofisk, Cod, Tor, Eldfisk, Edda and Albuskjell. The first of these, Cod, was discovered in 1968. This is the only one producing from a sandstone reservoir in the Ekofisk area, the others in the area produce from Cretaceous rocks. In 1969, the Ekofisk field was discovered, and as early as 1970, declared commercial. In the period from 1969–72, the other fields in the area were discovered. The Ekofisk field is easily the largest in the Ekofisk area, with a hydrocarbon pore volume about 30 % greater than the Statfjord field. Eldfisk is the next biggest. Figure 2.5.3.a shows the fields in the area.

Development has taken place in four phases so far:

Phase 1: Test production on the Ekofisk field from four wells completed on the seabed. This phase lasted from June 1971 to May 1974.

Phase 2: Development of the platforms on Ekofisk.

Phase 3: Development and tying in of the fields West Ekofisk, Cod and Tor to the Ekofisk Centre, together with the laying of an oil pipeline to Teesside and a gas pipeline to Emden. The lines were taken into operation in October 1975 and September 1977 respectively. before the gas pipeline was completed, the produced gas was injected into the Ekofisk field.

Phase 4: Development and tying in of the Eldfisk, Edda and Albuskjell fields to the Ekofisk Centre.

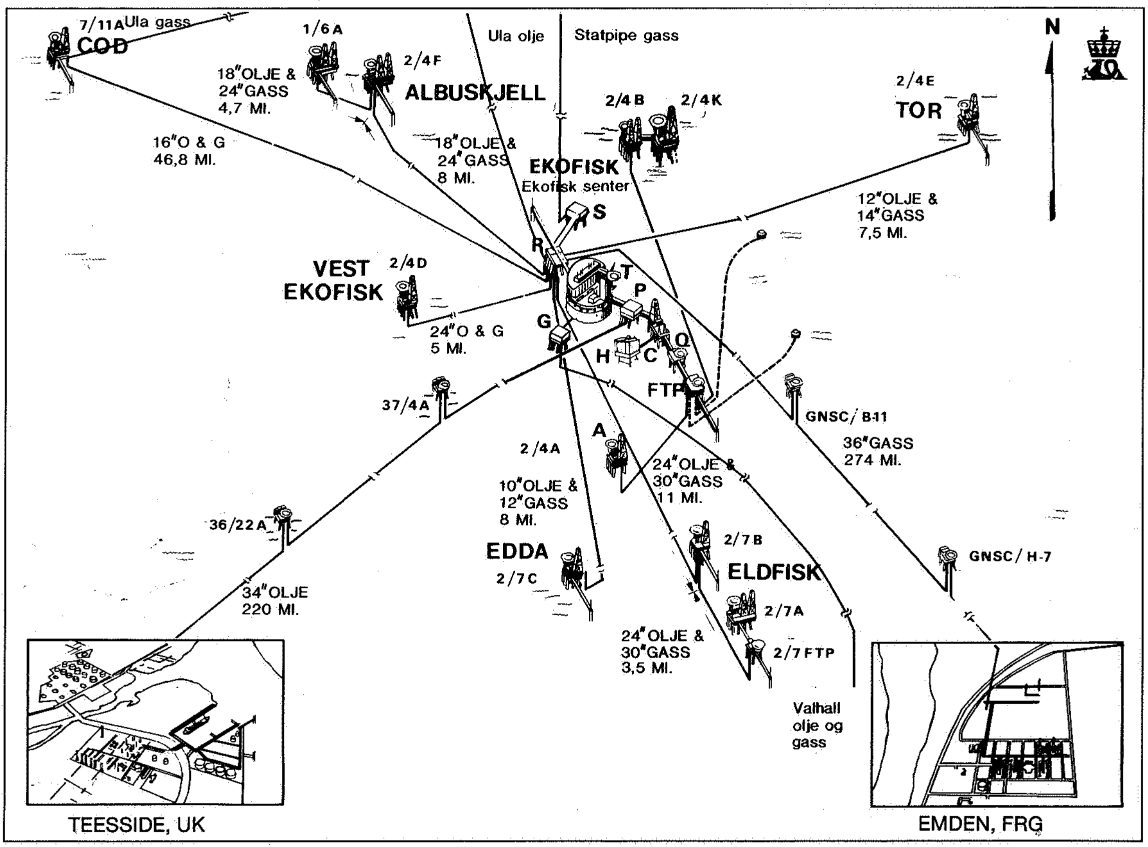
Phase 5: Water injection into the Tor formation on the Ekofisk field to increase the production of oil and gas from the field. Water injection will start in the beginning of 1988. Figure 2.5.3.b shows the installations in the Ekofisk area.

Future Plans

The recovery rate from the oil fields in the area is as low as 20 per cent. Several projects to increase the recovery rate are under consideration. The operator is presently evauluating a plan in three phases for further measures on the Ekofisk feild:

Phase 1: Water injection in the Ekofisk formation in the northern part of the field in addition to injection in the Tor formation and production from new well slots on Ekofisk centre.

Fig 2.5.3.b
Installations in the Ekofisk area.



Phase 2: Water injection from Ekofisk Centre in the Ekofisk and Tor formation, and production from new well slots in the southern part of the field.

Phase 3: Injection of nitrogen in two wells on Ekofisk Centre. The nitrogen will be generated on the exsisting process platform on Ekofisk centre.

These measures will increase the rate of recovery from the field significantly. Similar measures are under consideration for the second largest field in the area, the Eldfisk field. The two first phases will result in increased recovery of oil, while injection of nitrogen will be aimed particularly at increased recovery of gas.

Water injection project

Water injection on the Ekofisk field was at first to be restricted to the Tor formation in the northern part of the field. This limitation was imposed on the projects on the basis of results of laboratory tests. In addition to such tests, water injection was tried out on the field, and these trials yielded better results than the laboratory tests had done.

An injection test has just been completed in the Ekofisk field. The results also confirm that water injection will be beneficial in the lower part of the Ekofisk formation. The operator will therefore proceed in accordance with the above plan.

There is still a certain fear that water injection would have a negative effect on the mechanical qualities of the reservoir rock. Further studies on this will be done in 1988.

Subsidence of Ekofisk

In November 1984, it was discovered that the seabed near the Ekofisk Centre had subsided. Measurements since performed indicate the total subsidence as per 1 December 1987 to be something above four metres.

The rate of subsidence in the period 1980–86 is estimated to be 0.4 to 0.5 metres a year, with some lessening towards the end of the period. The annual rate in 1987 has been measured as about 0.3 metres.

Several measurement methods have been used to determine the rate of subsidence. In 1984/85 analyses of wave data were made. The analyses indicated only the earlier subsidence rate.For this reason the operator made a number of measurements in 1985 of the distance from the sea surface to horizontal struts in the platform base. The method was of limited accuracy, and in recent years satellites and submarine pressure probes have been employed.

Ekofisk field subsidence is the result of the oil and gas–bearing rock three kilometres under the seabed being relatively loose and being compacted as the pore pressure lessens. It was always expected that the reservoir volume would contract, but no one expected this to show on the surface. It is still uncertain how the shrinking of the reservoir accounts for the subsidence, or whether other factors are at work.

It is likely that other reservoir problems will arise due to pressure relief. The lack of stability of the wells is a growing problem on Ekofisk. Deformation of the wells may mean that larger quanities of petroleum than previously thought must be left behind in the reservoir.

The central location of Ekofisk for present and future gas transport options to the Continent makes it even more imperative that the work to understand the subsidence should continue.

The only way to prevent further subsidence and other problems related to pressure relief is to limit the fall in pressure. This can be done by injection of fluids such as natural gas, nitrogen or water, or some combination of these.

The jack–up

The platforms in the central Ekofisk complex must be modified so as to survive further subsidence. In the summer of 1987 the decks on five of the platforms were raised six metres, while the deck on the 2/4 G platform was raised 10 metres.

Detailed planning of the project began in May 1986 and included:

- hydraulic jack systems with 6.5 metres extension
- electronic control systems
- modification of the platform structures themselves.

The timetable for project design, manufacture and installation of equipment, together with the jack–up, was very tight. Periodically bad weather during the preparations led to the raising getting behind its original schedule. This had, however, no effect on the implementation of the project.

The decks of the installations were raised in the following order:

- 2/4 H
- 2/4 R
- 2/4 C, Q and FTP
- 2/4 G

The Ekofisk Centre became operational again on 4 September 1987.

The structure of the Ekofisk tank makes it difficult to undertake jack–up for permanent protection of this installation. The operator's planned solution is to protect the tank with the aid of a 105 metre high concrete wall placed around the tank itself.

Accommodation during the jack–up

The jack–up work demanded greater personnel resources than first thought, and there was soon need for extra accommodation.

The delays, the size and importance of the project, and physical limitations, meant that the accommodation was of a lower standard than required by the regulations.

There are still several accommodation units in the Ekofisk area that do not fulfill the regulations' minimum requirements. Bedrooms are not fitted with separate shower and toilet, and the accommodation is in some areas not adapted to female workers.

Preparedness

The jack–up involved comprehensive emergency preparedness measures. To meet requirements for personnel, storage and power supply, a flotel and two jack–up rigs were joined to the Centre. These, joined by gangways, provided several escape routes in line with the prearedness principles used at the Centre, namely evacuation by bridge. Extra preparedness vessels monitored the operation. In addition to strict control of who was at any given moment on the scaffolding structure beneath the platform, special look–out posts were located at strategic points, inter alia for giving the "Man Overboard!" alarm. Weather forecasting was done by the operation's own meterologist.

In addition to this, a lot of work was put in to information and educational campaigns, which were a valuable contribution to emergency preparedness.

Fires/hazards

In connection with the jack–up 15 fires were registered. None inflicted any injury or more than minor or immaterial damage.

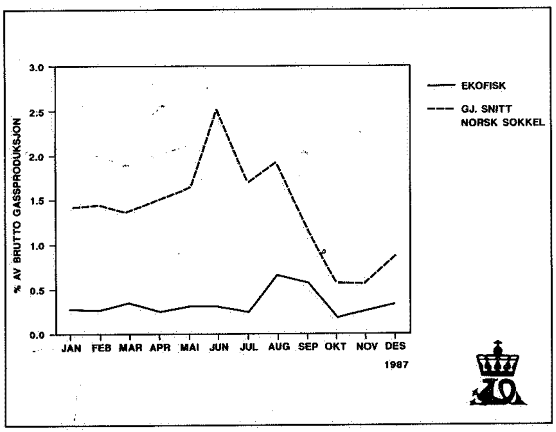
A potentially very serious accident was averted when the cutting of a supposedly pressure–less riser on processing platform 2/4 FTP was stopped before it was cut through. The near–miss is under consideration by the prosecution authorities.

Subsidence elsewhere in the area

Subsidence is not confined to Ekofisk Centre. A need for modifications of the platforms in the north and south ends of the field is foreseen for the second half of the 1990s.

The Norwegian Petroleum Directorate has in 1987 carried out a study of the potential for subsidence of the Eldfisk field. There does not so far appear to be any immediate problem with Eldfisk.

Fig 2.5.3.c
Gas flared on Ekofisk.



Other fields in the area

The operator is planning automatisation of the Albuskjell field in order to reduce the costs of operating the field. Such automatisation raises a number of questions of principle, which the authorities must decide in the course of 1988. The Norwegian Petroleum Directorate will focus inter alia on the exploitation of any supplementary reserves before the platform is automatised.

On the Tor field the installation of gas lift equipment is being prepared. This will give the field a considerably longer lifetime.

The installation on Edda can be kept going longer because the gas from Tommeliten is led to the platform.

Flaring of gas

During Phase I of the Ekofisk development from 1971 to 1974, there was test production with buoy loading, and all gas was flared. Since 1977, the gas has been landed and sold through the Emden gas pipeline, with surplus gas being injected into the Ekofisk reservoir. Gas flared in 1987 in the Ekofisk area was an average of 79 x 10^3 Sm^3 a day, corresponding to 0.3 per cent of the total gas production from the fields (see Figure 2.5.3.c). Throughout the year the flare limit stood at 400 x 10^3 Sm^3 per day. The main reason for the somewhat higher flaring in 1987 is the start–up after the August 1987 shutdown.

Pipes and pumping platforms

After long consideration the operator decided not to man 34/4–A. The installation was no longer needed on account of falling oil production on the Ekofisk field. Installation 36/22–A was unmanned in 1987. There are thus no active pumping stations in operation between Ekofisk 2/4–P and the Teesside terminal in England.

In connection with the shutdown of the Ekofisk field and the stoppage of gas transport to Emden, Norpipe found it necessary to use bedroom containers, in which more than two persons slept per room.

Use of standby vessels in association with one of the pumping platforms on the Ekofisk–Emden pipeline is under reconsideration.

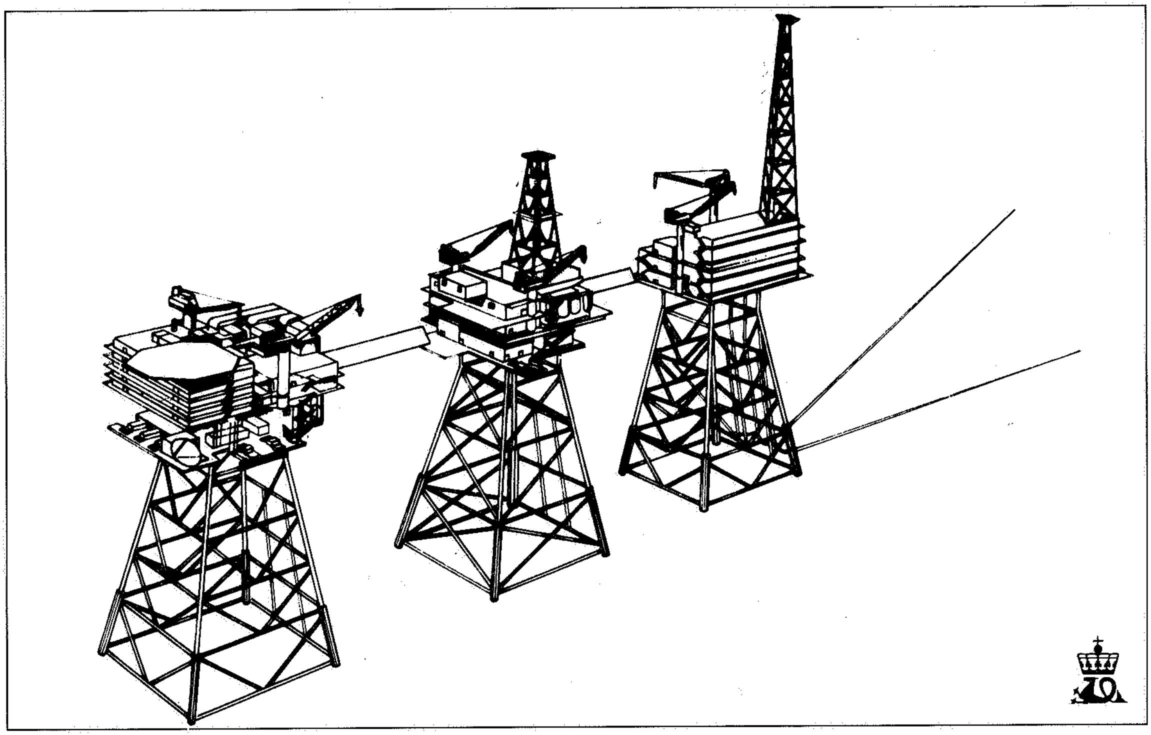
Metering systems

Inspections were conducted of certain oil and gas metering systems in the Ekofisk area.

Regular inspections were also made of sales metering stations at Teesside and Emden.

Annual meetings were held with German authorities. It was decided among other things to make a cooperation agreement on the technical measurement activity in Emden. This cooperation agreement will be signed by the authorities of both countries in the spring of 1988.

Fig 2.5.4.a
Installations on Ula.



Costs
The total costs for the seven fields constituting the Ekofisk area are estimated at about NOK 68 billion (fixed 1987 kroner). Total operating costs up to 2010 are expected to be about 126 billion 1987 kroner.

2.5.4 Ula
Production Licence 019A

Licensees

BP Petroleum Development of Norway A/S	57.5 %
A/S Pelican & Co K.S	5.0 %
Norsk Conoco A/S	10.0 %
Den norske stats oljeselskap a.s	12.5 %
Svenska Petroleum Exploration A/S	15.0 %

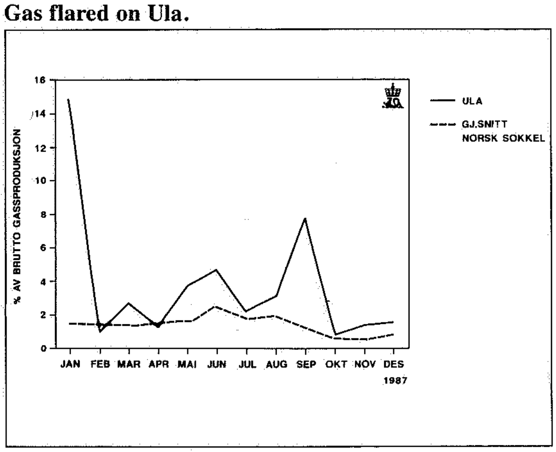
The field lies in Block 7/12 some 70 kilometers northwest of Ekofisk (Figure 2.5.3.a). It was discovered in 1976 and declared commercial in December 1979. The field development plan was approved in 1980, but the same year it became clear that the development would not be profitable. A new field development plan with a new development option was submitted in April 1983 and approved in January 1984. BP is the operator for the production licence.

Recovery of reserves
In July 1987 the operator increased his reserves estimate to 39.72 x 10^6 Sm^3 oil, that is, by 56 %. This was done on the basis of well data, production experience and new seismic interpretation. The Norwegian Petroleum Directorate's reserves estimate in the autumn of 1986 involved a minor reduction in the estimate, which now stands at 33 x 10^6 Sm^3.

Independent studies indicate that the degree of recovery is not rate–sensitive. This in addition to increased reserves and improved processing capacity, means that an increase of the plateau rate was approved.

In October 1986 production began from the first well. At the end of the year there were only four wells producing, and the low number was due to problems in the drilling phase. The first water–injection well will be ready in February 1988. One of

Fig 2.5.4.b
Gas flared on Ula.



the production wells was drilled down to the Triassic, but testing of the accumulation had to be abandoned because of high pressure. The well will be completed as a producer from the Ula formation.

Field development is planned to be finished at the end of 1989, with 9 production wells and six injection wells. Production has been kept at the level decided by the production limitation laid down by the authorities. Because of the Ekofisk jack–up, there was no production from Ula in the period 19 August to 1 September 1987.

Production facilities
The development concept involves three conventional steel platforms (Figure 2.5.4.a) for production, drilling and accommodation, respectively. The steel jackets for the platforms were installed in June 1985 and the offshore hook–up work took from October 1985 to August–September 1986. The oil pipeline to Ekofisk was laid in the summer of 1984 and the Ula–Cod gas pipeline in the spring of 1985.

In the course of the year some adjustment and modifications to the plant were necessary. The gas desiccation plant was unsatisfactory as regards dew–point, and equipment in the desiccation tower had to be upgraded. On inspection of the separators considerable quanities of asphalt deposits from the oil were found, which in time could lead to operational problems.

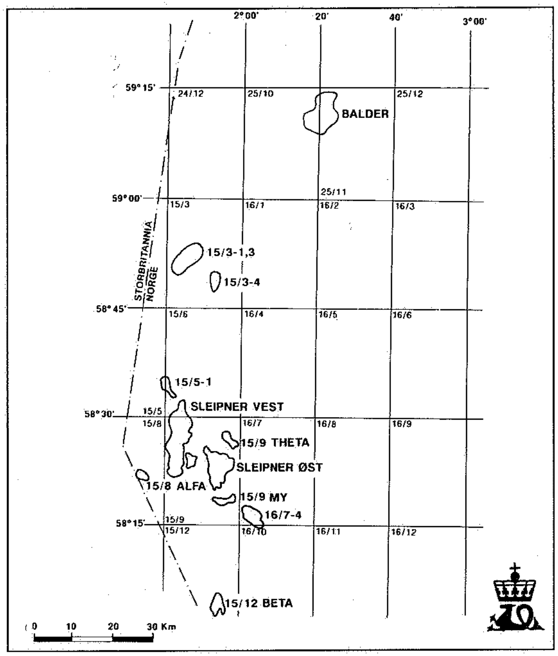
Some of the electrical equipment is located in compartments protected against penetration of gas by means of overpressure. It has proved to be difficult to have the pressure monitoring inspected satisfactorily.

Transport
Oil is carried by pipeline via the Ekofisk Centre to Teesside. Statoil is the operator for the pipeline. The pipeline to the Ekofisk Centre was installed on the seabed in the summer of 1984. Its diameter is 508 mm (20″) and its length is about 70 kilometres. The gas is transported by pipeline via Cod to Emden. The Ula–Cod pipeline was installed and tested in the summer of 1985.

Flaring of gas
The gas processing plant entered service on 28 October 1986. The flaring which has taken place after this is due first and foremost to problems with the gas drying plant up to the autumn of 1987. On average 41 x 10^3 Sm^3 per day was flared in 1987, corresponding to 3.7 % of gross gas production (see Figure 2.5.4.b). Other causes of gas flaring on Ula are problems with the MP compressor during start–up and shutdown in connection with the jack–up on Ekofisk.

Metering system
The metering system on Ula has been in operation since startup in October 1986. There has been a planned stoppage in 1987 (the Ekofisk jack–up). In 1987 the Norwegian Petroleum Directorate performed a system audit and three operational audits on the Forus operations organisation and the Ula platform and offshore measuring equipment respectively. The fiscal metering has in general been performed satisfactorily by the operator.

Fig 2.5.5.
The Sleipner and Balder area.



Costs
Total investment costs are expected to reach about NOK 8.1 billion in fixed 1987 kroner. Total operational costs are estimated at NOK 8 billion.

2.5.5 Sleipner East
Production Licence 046

Licensees

Esso Norge A/S	30.4 %
Norsk Hydro A/S	10.0 %
Den norske stats oljeselskap a.s	59.6 %

The production licence was allocated in 1976 and covers Blocks 15/8 and 15/9. Statoil is operator of Sleipner East. See Figure 2.5.5.a. Under the sliding scale provision, Statoil has increased its interest in the licence from 50 % at Esso's expense. Recoverable reserves on Sleipner East are believed to be 51 x 10^9 Sm^3 gas, 17 10^6 Sm^3 oil and 10 x 10^6 tonnes NGL.

Development
It has been decided to develop Sleipner East using a fully integrated process, drilling and accommodation platform with four-shafted concrete gravity base, plus a 508 mm diameter pipeline to Ula.

The plans call for condensate to be forwarded from there to Teesside in England through the Ula–Ekofisk–Teesside pipeline system. Gas will pass by pipeline to Zeebrügge in Belgium and through the Statpipe–Norpipe system to Emden in Germany.

Preparedness

In 1987 one inspection visit was made in connection with the Sleipner project, when deficiencies in Statoil's internal control system were uncovered.

The preparedness situation has been followed up by the Directorate via participation in the main audit and through meetings. The Directorate is satisfied with the collaboration established and its results so far.

As regards working environment, on the main audit in the spring of 1987 the Directorate found deficient practicing of working environment requirements in an early phase of the project. This area has been subject to active follow–up by the operator in the subsequent phase.

Costs

Total development costs and total operating costs are estimated at NOK 15.6 and 10.1 billion 1987 kroner respectively.

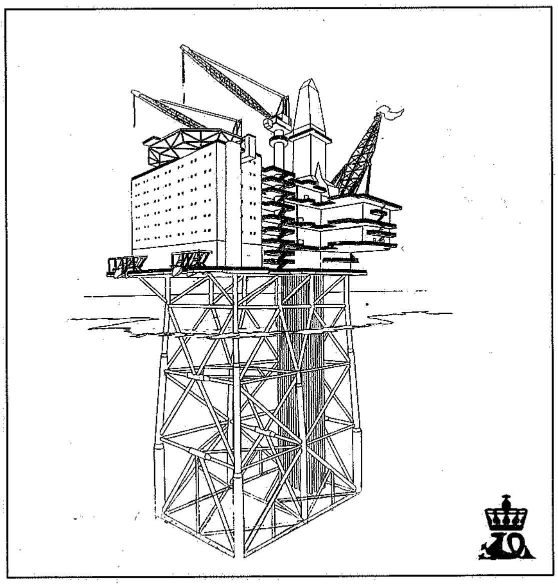
2.5.6 Gyda

The Gyda field is in Block 2/1 about 28 km southeast of Ula and is covered by Production Licence 019B.

Licensees

Den norske stats oljeselskap a.s.	50.000 %
BP Petroleum Development of Norway A/S	26.625 %
Norske Conoco A/S	19.375 %
K/S A/S Pelican & Co	4.000 %

Fig 2.5.6
Planned installation on Gyda.



BP is the operator for the field, which was declared commercial on 22 January 1987. The licensees submitted their development and operation plan on 11 March 1987, and these plans were approved by the Storting in the spring of 1987.

Development

It has been decided to develop the field with a fixed platform for accommodation, drilling and processing of oil and gas, see Figure 2.5.6. The oil is to be transported to Ekofisk via the oil pipeline from Ula to Ekofisk and on to Teesside. Gas is to be carried in a new pipeline direct to Ekofisk and used there.

The predrilling frame has been placed on the field and the first production well is being drilled. Construction of the platform will run from the second quarter of 1988 to the first quarter of 1990. The platform will be towed out and hooked up in the second quarter of 1990 and production is planned to start on 1 September 1990.

It is planned to produce the field with water injection as drive mechanism. Nineteen production wells are planned and 11 water injection wells. Eight production wells will be drilled in advance.

The operator's reserves estimate is 31.8 x 10^6 Sm^3 oil, while the Norwegian Petroleum Directorate's reserves estimate is 30.5 x 10^6 Sm^3 oil. Gas production is expected to be 5 x 10^9 Sm^3 gas.

By means of eight advance–drilled wells a plateau production can be reached from production start. Plateau production is planned at 9,500 Sm^3 oil and 1.1 x 10^9 Sm^3 gas per day, and will last for two years. Production will thereafter gradually decline, and is expected to cease in the year 2010.

Costs

Total development costs are estimated at 8.8 billion 1987 kroner, and total operating costs at about 9.3 billion 1987 kroner for the lifetime of the field.

2.5.6 Heimdal

Production Licence 036

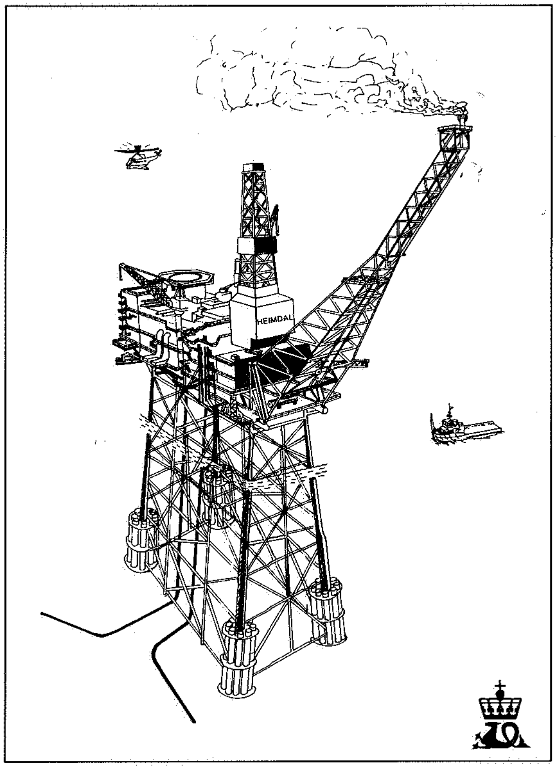
Licensees

Den norske stats oljeselskap a.s	40.000 %
Marathon Petroleum Norge A/S	23.798 %
Elf Aquitaine Norge A/S	17,639 %
Norsk Hydro Produksjon A/S	6.228 %
Total Marine Norsk A/S	4.820 %
Sunningdale Norge A/S	3.875 %
Saga Petroleum a/s	3.471 %
A/S Uglands Rederi	0.169 %

The field was discovered in 1972 by the drilling of Well 25/4–1, and was declared commercially viable in April 1974. The commerciality declaration was withdrawn in 1976 due to low gas prices.

During 1980, the gas market picked up and Heimdal became the centre of discussion for a landing

Fig 2.5.7
Installation on Heimdal.



solution for Statfjord gas. The landing application for gas to the continent was submitted in January 1981 and approved by the Norwegian Storting on 10 June 1981. The landing application for condensate was approved in January 1983.

Development
The reservoir lies some 2100 metres below sea level in Paleocene sand. The total recoverable reserves are estimated at 33 x 10^9 Sm^3 gas and 5 x 10^6 Sm^3 oil. The estimate for the oil content of the gas has been somewhat upgraded, in the light of new measurements of the gas density in the reservoir. The Heimdal field is being developed with an integrated steel platform, comprising drilling, production and accommodation functions (Figure 2.5.6). The installation work on the field started in summer 1984. Production started in December 1985 with the first deliveries to Emden in February 1986.

Production drilling on Heimdal started in April 1985. As of December 1987, eleven platform wells had been drilled, eight for production, two for observation, and one suspended.

Production
Production has proceeded without any problems worth mentioning in the last year. Daily gas sales have lain within the contractually fixed range.

During the period of severe frost in January 1987, it was found that the electrical cold protection of firewater pipes and production equipment did not live up to its performance guarantee. This state of affairs will be corrected.

Transport
Gas from the Heimdal field will be transported via Statpipe. The Heimdal line has been tied in to Statpipe at riser platform 16/11–S. Condensate will be carried by a separate pipeline to the Brae field in the British sector, and from there to Cruden Bay, Scotland, via the Brae–Forties complex.

Metering system
Fiscal measurement is carried out on Heimdal, while quality analyses are done on the mainland at Kårstø.

The metering system consists of three tubes for gas and three for condensate. The gas metering system has been inspected. Inspection of the condensate metering system has been conducted in collaboration with the UK Department of Energy.

Costs
The total development costs are estimated at about NOK 10.2 billion fixed 1987 kroner, and total operating costs are expected to be about 5.5 billion 1987 kroner for the lifetime of the field.

2.5.8 The Frigg area
2.5.8.1 Frigg
Licensees

Norwegian share (60.82 %)	
(production licence 024)	
Elf Aquitaine Norge A/S	25.19 %
Norsk Hydro Produksjon A/S	19.99 %
Total Marine Norsk A/S	12.60 %
Den norske stats oljeselskap a.s	3.04 %

Fig 2.5.8.a
The Frigg area.

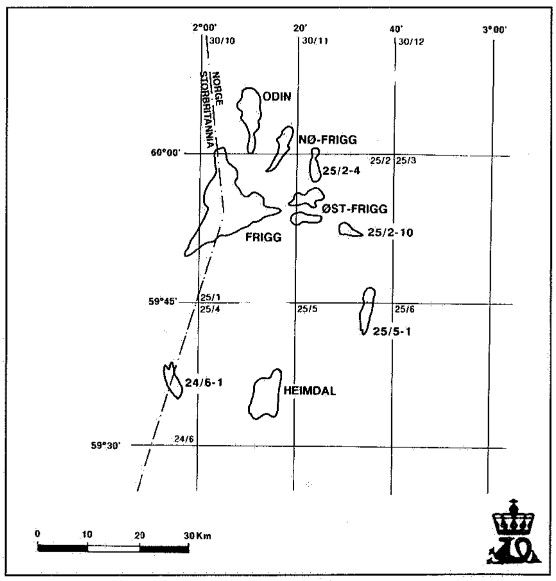
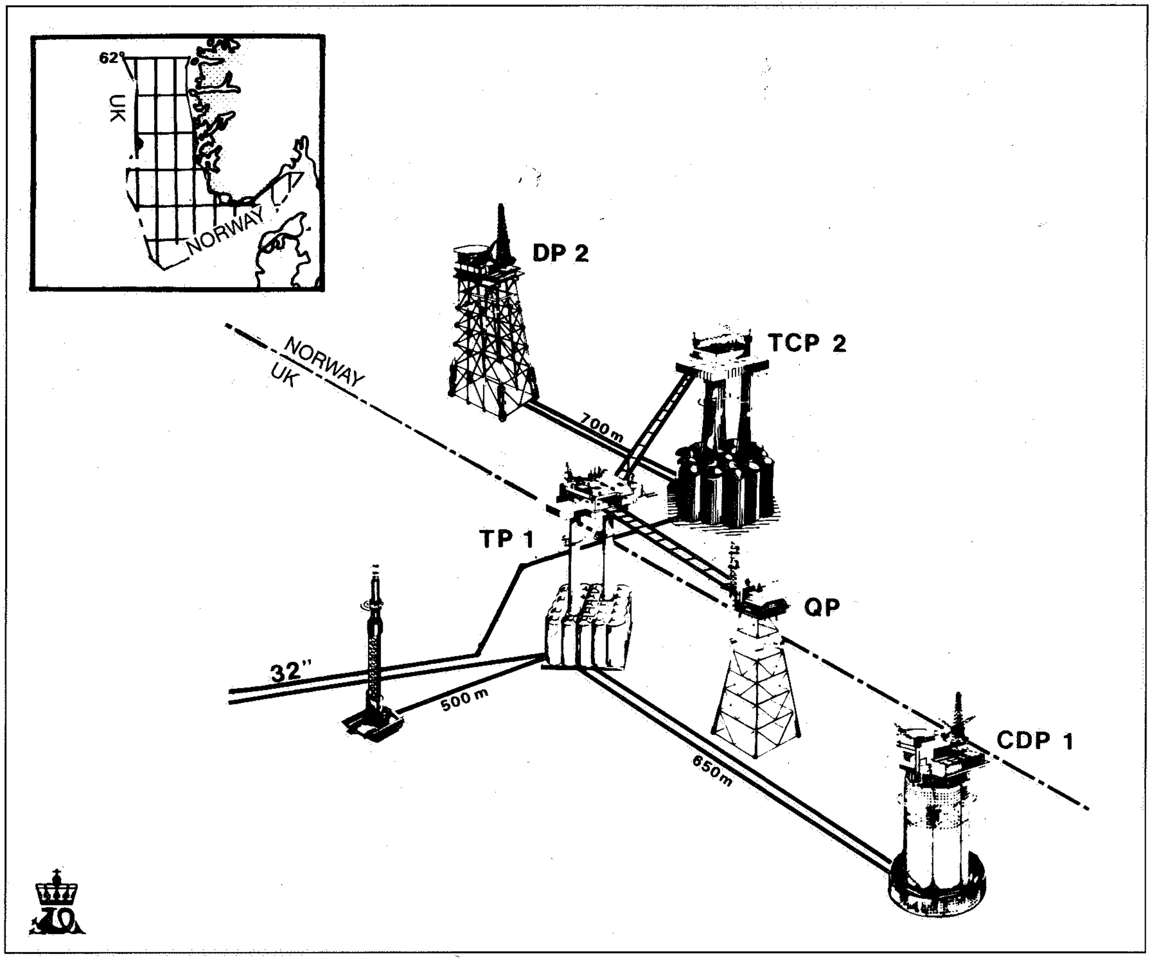


Fig 2.5.8.b
Installations on Frigg.



British share (39.18 %)	
Elf Aquitaine UK Ltd	25.97 %
Total Oil Marine Ltd	12.98 %
BP Ltd	0.23 %

Elf Aquitaine Norge A/S is the operator for the Frigg field, while Total Oil Marine Ltd is the operator for the pipeline system and St Fergus terminal in Scotland.

The Frigg field lies in Block 25/1 on the Norwegian continental shelf and Blocks 10/1 and 9/5 on the British shelf (Figure 2.5.8.a). The field has been unitized. Of the gas reserves, the agreement assumes that 60.82 per cent belong to the Norwegian licensees, and the remaining 39.18 per cent to the British licensees. The agreement governing distribution of the reserves may be renegotiated every four years, or at any time if extra reserves are proven which seem to communicate with the Frigg reservoir.

Production facilities

The Frigg field was discovered in spring 1971 and declared commercial on 25 April 1972. Frigg was developed in three phases, the first of which consisted of one production, one processing and one accommodation platform (CDP1,TP1 and QP). Production from the Phase 1 platforms started on 13 September 1977.

Phase 2 consisted of one production and one processing platform on the Norwegian side (DP2 and TCP2). Production from the Phase 2 platforms began in summer 1978. Figure 2.5.8.b depicts the Frigg installations.

Phase 3 of the development included the installation of three turbine–driven compressors, each rated at 38,000 horsepower on Platform TCP2. The booster facility is necessary to compensate for the reduced reservoir pressure. The unit started operation in autumn 1981.

Gas from North East Frigg and Odin is processed and metered at Frigg. New modules for processing of the gas and condensate from these fields have been installed on TCP2. Work is now in progress for joining East Frigg, where production will begin in October 1988, to TCP2 as well. Transport of gas from the Alwyn North field on the British side will go via TP1.

Transport

Frigg gas is transported to St Fergus in Scotland by two 813 mm diameter pipelines. To increase the capacity of the transport system, two 38,000 horsepower turbo–compressors have been installed on Booster Platform MCP–01, which stands midway between Frigg and Scotland. The increase in capacity was necessary to move the gas from the Odin field. For the same reason, the St Fergus terminal has been expanded from five to six process lines. Sale of Odin gas began in October 1983, with pre–production delivery from the Frigg field.

Recovery of reserves

In summer 1984 substantial water rise was observed in a well on the UK side, which confirmed the irregular rise in liquid contact in the reservoir and water influx. Five wells were drilled or deepened in 1985. Regular checks of the liquid contact throughout 1986 show that the water has risen 21–99 metres since production start. At present the mean rate of rise is 9–13 m/year in central parts of the field, and 17–20 m/year in the south. Water penetrates the reservoir from the south because the slate barrier is less continuous there, and flows laterally northwards. Six wells are now producing at a reduced rate to hold the water production on CDP–1 down to a reasonable level.

Production stoppage on CDP–1 on account of excess water production is expected in the course of 1989. DP2 will probably be in operation until 1991.

The operator has updated his reservoir model on the basis of new seismic interpretation, which led to a reduction of the reserves estimate.

It is being considered whether supplementary wells (directional wells from DP2 or seabed completed wells) should be drilled to produce any remaining "gas bubbles" which the existing wells have not managed to drain. On the basis of 3D seismics the operator has surveyed two deeper reservoir zones ("Deep Frigg"), where he wants to drill a wildcat well early in 1988.

Metering system – Frigg

Inspections in connection with the metering systems on Frigg, MCP–01 and in St Fergus have been performed in cooperation with the British Department of Energy. The collaboration also includes the Norwegian fields North East Frigg and Odin, as the sum of these two fields' production is deducted from the total metered quantity entering the pipeline to St Fergus. This makes it possible to determine the Frigg field's contribution.

Metering system – Alwyn

Gas from the Alwyn field on the UK side will be conducted to St Fergus via the Frigg field. The design of the metering system complies with the Directorate's regulations for fiscal quantity metering of gas, and the Directorate is allowed full access to the Alwyn field installations. The design and functions of the metering system have been inspected at the manufacturer's in collaboration with the British Department of Energy.

Costs

The total development costs are expected to reach about NOK 28.5 billion in fixed 1987 kroner, the total operating costs about 9.3 billion 1987 kroner for the lifetime of the field.

2.5.8.2 East Frigg

Production Licence 024 (Block 25/1) and 026 (Block 25/2) See Figure 2.5.8.a.

Licensees

Elf Aquitaine Norge A/S	41.42 %
Norsk Hydro A/S	32.87 %
Total Marine Norsk A/S	20.71 %
Den norske stats oljeselskap a.s	5.00 %

Production Licence 112 (previously relinquished part of Block 25/2, reallocated in 1985)

Licensees

Elf Aquitaine Norge A/S	21.80 %
Norsk Hydro A/S	17.30 %
Total Marine Norsk A/S	10.90 %
Den norske stats oljeselskap a.s	50.00 %

Production facilities

The East Frigg field consists of two main structures, previously called East Frigg and South East Frigg, now East Frigg Alpha and East Frigg Beta, respectively. They are parts of the same pressure system as the Frigg field, and the gas will be sold to British Gas Corporation within the existing sales agreement.

East Frigg Alpha was discovered in 1973 and East Frigg Beta in 1974. Both fields stretch into Blocks 25/1 and 25/2 and a little bit into the previously relinquished area.

The field was declared commercial in August 1984, and the landing application was considered by the Storting on 14 December 1984. A development plan with four wells was approved by the partners. According to plan, production is to start in October 1988. Recoverable gas reserves have been estimated at 8 x 10^9 Sm^3 on East Frigg Alpha and 5 x 10^9 Sm^3 on East Frigg Beta, in all 13 x 10^9 Sm.^{3}

There has, however, been a gas leakage on East Frigg, gas leaking over to Frigg. The reserves on East Frigg Alpha may be reduced from 8 to 4.5 x 10^9 Sm.^{3} Because of this problem the operator is considering drilling another production well. The field should have produced until 2003, but now looks like running to 1998.

Development will be based on subsea technology. Two identical underwater production systems remotely operated from Frigg have been planned, one on Alpha and one on Beta. So far the project has gone according to plan. The two seabed frames for the production stations and a central manifold to tie the systems together were placed on the seabed summer 1987. A gas and service pipeline from the manifold to TCP2, where the gas is to be produced and fed to the Frigg field transportation system, has been constructed and pressure-tested. Four wells have been fully drilled without mishap.

The individual modules and parts of the underwater systems are more or less complete, and the station control module is being tested. Trial hookup of the subsea production systems is in progress.

Costs

Total development and operating costs are expected to reach 2.0 and 1.4 billion 1987 kroner respectively.

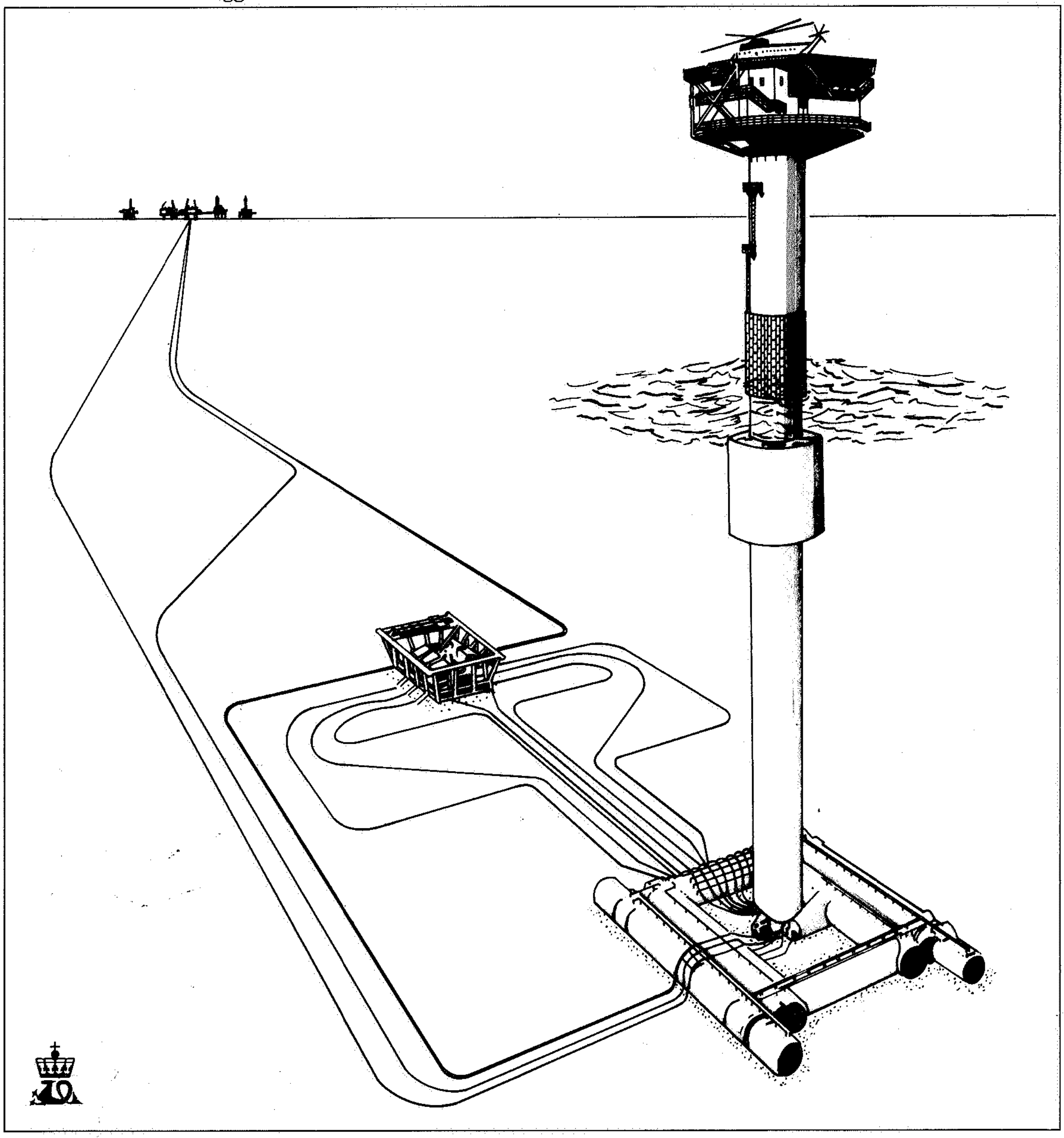
2.5.8.3 North East Frigg

Production licence 024 (Block 25/1)

Licensees

Elf Aquitaine Norge A/S	41.42 %
Norsk Hydro Produksjon A/S	23.87 %
Total Marine Norsk A/S	20.71 %
Den norske stats oljeselskap a.s	5.00 %

Fig 2.5.8.c
Installations on NE-Frigg.



Production licence 030 (Block 30/10)

Licensees

Esso Exploration and Production Norway Inc 100.00 %

Statoil is entitled to 17.7 per cent of the net profits before tax. The North East Frigg field lies in Blocks 25/1 and 30/10 (Figure 2.5.8.a) and redistribution of the gas reserves in August 1984 gave 42 per cent and 58 per cent, respectively, in each of the blocks. Elf Aquitaine Norge A/S is the operator for the development.

Recovery of reserves

The sale of gas from North East Frigg started in October 1980, by means of advance deliveries from Frigg. Since production start in December 1983, North East Frigg has reimbursed this gas, plus delivered gas on behalf of Frigg in addition to contractual quantities. In order to obtain a lengthier sales profile, sales were to continue by means of delivery from Frigg after production stop on North East Frigg. The uncertainty regarding Frigg's production life, however, has led to plans for balancing–out within 1 October 1989.

Pressure measurements made before production start showed that the reservoir pressure decreased as a result of communication with the Frigg field though the inter–field saddle. About 60 % of the field's recoverable reserves have now been tapped. Reservoir simulation shows that water break–through will occur in the first of the wells early in 1988. The low production rate maintained now so as to be able to sell gas reimbursed from Frigg is contibuting to reduction of the water coning problem in the reservoir.

Production facilities

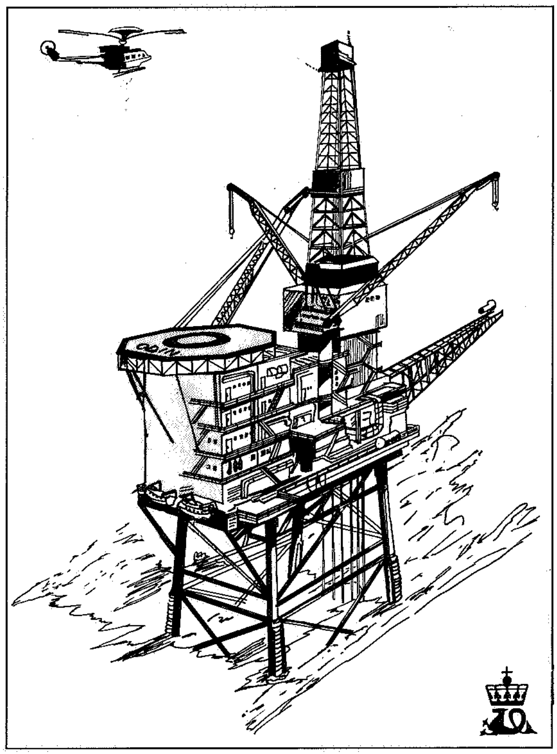
The North East Frigg gas field was proven in 1974 and the final development plan approved in 1980. The field was developed with six wells drilled through a frame structure on the seabed (Figure 2.5.8.c). In May 1986 a well had to be plugged because of leakage problems.

The frame structure has, in addition to the wellheads and valvetrees, a manifold for collecting the gas from the six wells. The gas is led through a 406 mm pipeline to the Frigg field for processing. Each of the six valvetrees is controlled via separate service and control lines from a control station (a jointed pillar) placed 150 metres from the wellheads. The control station was installed in July 1983 and is remote–controlled from the Frigg field.

Production

Production has gone without mishap or other unforeseen occurrences all year. There was total stoppage in the summer holiday and for two weeks in October/November on account of a five–year maintenance of a pressure vessel on TCP2.

Fig 2.5.8.d
Installation on Odin.



There has been a number of earthing faults on the field control station, which were put right inter alia by replacement of junction boxes.

Some insignificant underwater leakages of oil and gas have been dealt with.

Costs

Total development costs are expected to run to about NOK 2.7 billion in fixed 1987 kroner. Total operating costs are estimated at about 0.6 billion 1987 kroner.

2.5.8.4 Odin

Production licence 030

Licensee

Esso Exploration & Production Norway Inc 100 %

Statoil is entitled to 17.5 percent of the net profit before tax. The Odin field lies in Block 30/10 (Figure 2.3.7.a), with development operated by Esso.

Recovery of reserves

Gas sales from Odin began in October 1983 by means of advance delivery from Frigg. Since production start in April 1984 Odin has reimbursed this, in addition to delivery of its own contractual quantities.

Pressure measurements before production start showed pressure communication with the Frigg field via the underlying water zone. The Odin reservoir has a quicker pressure production than the other fields in the Frigg area on account of very limited water drift.

In spring 1985 the operator increased his reserve estimates for Odin on the basis of new well data and new charting. The sale of the additional reserves of 11.8 x 10^9 Sm^3 depends on a satisfactory agreement being reached with the Frigg Norwegian Association (FNA) group regarding transportation and processing services. Under current transport agreements 1993 will be the finalproduction year, but the additional reserves can support production until 1997. Odin enjoyed steady production throughout 1987.

Production facilities

The Odin gas field was proven in 1974, and the development plan approved in 1980. The field was developed with one small steel platform with simplified processing and drilling equipment and relatively small accommodation quarters (Figure 2.5.8.d).

Such a development was possible because an auxiliary vessel was used for a two-year period, for installation work as well as production drilling.

Production drilling started in December 1983, and four months later production started from two wells. Full production from seven wells started on 1 October 1984. Up to February 1985 the last four wells were drilled, completed and brought on stream.

On the Odin platform water is separated from the gas and methanol is injected for hydrate control. Subsequently the gas is dispatched by pipeline to the TCP2 platform on Frigg for further processing before delivery through the Norwegian Frigg pipeline to St Fergus.

Metering system

Inspections of the metering system, which is installed on Frigg, are conducted in collaboration with the British Department of Energy.

Costs

Total development costs were about 3.5 billion 1987 kroner. Total operating costs are calculated at about 2.6 billion 1987 kroner.

2.5.9 Oseberg

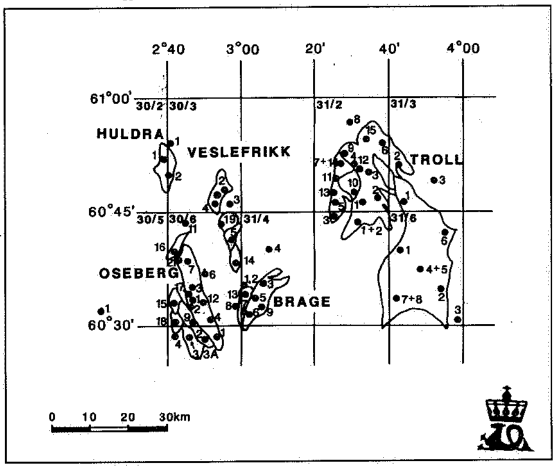
The Oseberg field extends into two production licences, Licence 053 on Block 30/6 which was allocated in 1979, and Licence 079 on Block 30/9 which was allocated in 1982 (Figure 2.5.9.a).

Production licence 053

Licensees

Den norske stats oljeselskap a.s.	50.00 %
Elf Aquitaine Norge A/S	13.33 %
Total Marine Norsk A/S	6.67 %
Norsk Hydro Produksjon A/S	12.50 %

Fig 2.5.9.a
The Oseberg and Troll area.



Mobil Exploration Norge	10.00 %
Saga Petroleum a.s	7.50 %

Statoil was operator from the start, though the operatorship was transferred to Norsk Hydro in April 1982. Elf Aquitaine Norway is the technical assistant.

Production licence 079

Licensees

Statoil	73.5 %
Norsk Hydro Produksjon A/S	16.0 %
Saga Petroleum a.s	10.5 %

Norsk Hydro is the operator with Elf Aquitaine Norway as the technical assistant.

Ownership after application of sliding scale

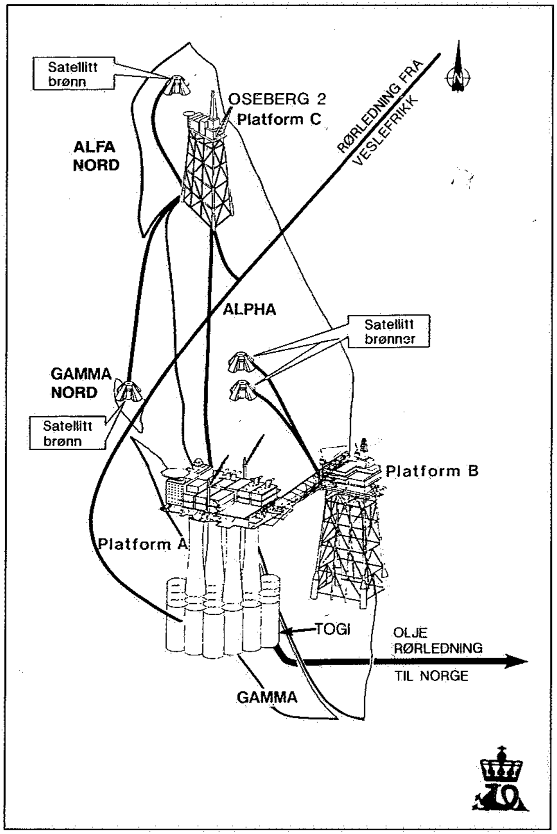
The licencees have assumed an interim breakdown of the reserves on the Oseberg field that stipulates 60 per cent in Block 30/6 and 40 per cent in Block 30/9. Statoil's share on Oseberg increased after the sliding scale was selectively applied to the foreign companies. Ownership interests in the unitized Oseberg field are as follows:

Den norske stats oljeselskap a.s.	63.24 %
Elf Aquitaine Norge A/S	6.40 %
Total Marine Norsk A/S	3.20 %
Mobil Development Norway A/S	4.80 %
Norsk Hydro Produksjon A/S	13.75 %
Saga Petroleum a.s	8.61 %

Field history

The initial discovery was made in 1979 and proved gas. Subsequent discoveries have shown that the reservoir consists of an oil-bearing layer topped by a gas cap. The declaration of commerciality was presented in June 1983. The Norwegian Storting considered the development application in the spring session of 1984. The operator's estimate for resources as of 31 December 1987 are 247 x 10^6 Sm^3 oil and 79 x 10^9 Sm^3 gas.

Fig 2.5.9.b
Planned installations on Oseberg.



Development concept
It has been decided to develop Oseberg with a field centre in the southern section comprising two platforms: Oseberg A, a processing and accommodation platform with a concrete base; and Oseberg B, a drilling and water injection platform with a steel jacket (Figure 2.5.9.b).

Production is planned to start on 1 April 1989.

Oseberg (the main field)
In the plan for development and operation approved in 1984, development was assumed to take place in the northern part of Oseberg (Oseberg II) using a single drilling and accommodation platform with equipment trains for partial processing. This platform was assumed to be ready for production in 1995.

In November 1987 Norsk Hydro submitted a revised development and operation plan for Oseberg. It is planned to upgrade the Oseberg II platform from a satellite platform to an integrated production, drilling and accommodation platform (PDQ) with use of auxiliary vessels in the drilling phase. The production start date was put forward from 1995 to December 1990.

Production from the most essential part of the Oseberg field, the so–called Alpha structure, was assumed to require water injection in the plan for development and operation. In 1986 this concept was changed. Oil in Alpha will now be recovered using gas injection as the drive mechanism. The change–over to gas injection on Alpha means that a total of roughly 15 x 10^6 Sm^3 more oil will be obtained from the field.

There is insufficient gas in Oseberg for reinjection into the Alpha structure. Injection gas must therefore be imported from another field. A subsea production unit, the Troll module, will be emplaced on the Troll field, and a pipeline from this module to the Oseberg field centre will deliver about 25 x 10^9 Sm^3 gas during the 12 year period starting in 1992. The bulk of the reinjected gas can be recovered after Oseberg oil production ceases.

In connection with the plan to accelerate Oseberg II the operator plans to fetch further injection gas from a satellite field on the west flank of Oseberg, Gamma North. Total gas volumes are about 3 x 10^9 Sm^3 over a six–year period from 1990.

Transport systems
A pipeline to transport stabilized oil from Oseberg to a terminal at Sture in Øygarden was laid in the summer of 1987. The pipeline has a diameter of 711 mm and a capacity of 95,000 Sm^3 per day. Maximum water depth is about 350 metres.

The installation, including the Sture terminal, is owned and run by a separate unit interest company called A/S Oseberg Transport System (OTS). Unit holders in the venture are the Oseberg licensees and the operator for the pipeline and terminal is Norsk Hydro. The Oseberg Transport System should be ready for opening on 1 April 1989.

The Oseberg transport system will consist of the following main components:
- pipeline equipment on Oseberg (platform A)
- seafloor pipeline
- landing site
- land pipeline
- terminal.

Gas transport will not start until after the year 2000, which is after oil production has ceased. No decision has been made yet regarding how this gas will be transported.

Production drilling/long – range testing
Production drilling
Drilling of the first production wells started in autumn 1985. It has been decided to drill eight wells before production start. This preliminary drilling program is currently being assessed and may be expanded to include an additional 1–2 wells.

Long–range testing
In order to gain a better understanding of the reservoir properties, a long running test program was initiated in autumn 1986 using "Petrojarl I", a production and test ship. The tests have continued

throughout 1987 and are expected to be finished in the spring of 1988. They have been performed in two wells divided between several reservoir zones. The first test hole is in Gamma and the other in the Alpha structure.

Experience from the tests has been good. We have obtained important information, particularly as regards the limited reservoirs in the Ness and Tarbert formations on volume, oil/water contact, productivity, rate– dependence and other reservoir behaviour during production.

Operational regularity during the tests has been very good, over 99 %. There were, however, a number of problems on hookup to the second test well that meant delays before test production could start.

The oil produced by "Petrojarl I" was carried ashore in its own tanker. The associated gas produced was flared off. It is therefore vital that the utility of a long–term test is balanced against the value of the gas gone to waste in flaring.

Accommodation

When the Oseberg A platform is emplaced on the field in June 1988 it will be capable of acccommodating about 320 people. The accommodation block represents a further imporovement in offshore living and recreational standards. Great emphasis was placed in the design on the rooms having daylight and view. In the main the living quarters are based on single rooms. The area layout and the room design has been guided by the aim of achieving optimum conditions for common activities. This new concept is not, however, more expensive than traditional designs.

During the hookup of the B platform and the later emplacement and hookup of the A platform, a flotel will be necessary. A total manning of about 1,100 persons over a short period is expected. In 1986 Norsk Hydro made an agreement with a shipowner for construction and lease of a flotel with room for 800 beds. Since the flotel represents a considerable challenge with regards to safety, preparedness and living environment, the authorities demanded various studies of the concept chosen to ensure that laws and regulations were to be obeyed.

The flotel was anchored on the Oseberg field with bridge connections to the B platform in October 1987. It represents a new generation as to size, safety, living and recreational conditions. The need for office premises for the operator and contractor employees working on the fixed platform has also been taken into account.

Experiences with the flotel in the time it has been on the field have been good.

Metering system

The oil metering system has been installed on the Oseberg A platform. The Sture I cargo metering station will be tested at the manufacturer's and despatched in February 1988.

The plans for a corresponding cargo measuring station for Sture II are in the approval phase at the operator's and are expected to be submitted to the Norwegian Petroleum Directorate in February 1988. Inspection of the metering system during loading from "Petrojarl I" to the tanker "Petroskald" has been carried out.

Costs

Total development costs for the Oseberg field centre and the accelerated Oseberg II are about NOK 38 billion in fixed 1987 kroner. Total operating costs are estimated at about 41.2 billion 1987 kroner.

2.5.10 Troll

Production Licence 054 and 085

Licensees in Production Licence 054	
Norske Conoco A/S	5.000 %
Norsk Hydro A/S Produksjon a.s.	5.000 %
Mobil Exploration Norway Inc	5.000 %
A/S Norske Shell	30.000 %
Den norske stats oljeselskap a.s	50.000 %

Licensees in Production Licence 085	
Norsk Hydro a.s.	9.000 %
Saga Petroleum a.s.	6.000 %
Den norske stats oljeselskap a.s	85.000 %

The Troll field covers parts of Blocks 31/2, 31/3, 31/5 and 31/6 (Figure 2.5.9.a). Allocation of Block 31/2 was made in 1979, while the other three blocks were allocated in July 1983. Block 31/2 belongs to production licence 054 with Norske Shell as operator. Blocks 31/3, 31/5 and 31/6 belong to production licence 085. Operatorship is here split between Statoil, Saga and Norsk Hydro. Unitization of the two production licences has been completed.

The reservoir extends through three geological formations, all Upper Jurassic. The uppermost (Sognefjord) is dominated by middle to coarse grained sandstone with good reservoir characteristics. This formation, the predominant one in the reservoir, overlies the middle (Heather) formation consisting of silt and fine grained sandstone with relatively high mica content. Flow properties in this formation are therefore poor in comparison with the overlying one. The bottom formation consists of sandstone with changeable reservoir characteristics.

At the top of Troll West in Block 31/2 and Troll East in Block 31/6 and 31/3 is a roughly 200 metre gas column. Column size varies over the field and is considerably less in western parts. The western part of Troll, largely covered by Block 31/2, has a 22–27 metre oil column underlying the gas, compared with 10–17 metres further east in the block. In Troll East the proven oil layer varies in thickness from zero to a few metres.

The resources in Troll as estimated by the Directorate include 1288 x 10^9 Sm^3 gas and 41 x 10^6 Sm^3

oil. In its estimates the Directorate has not yet included oil in those parts of the field with a 10–17 metre oil column, though the feasibility of producing from this part of the field is being considered.

Norske Shell, the operator of the first gas development on Troll, presented its plan for development and operation of gas Phase I in September 1986. The plan was considered by the Storting in December 1986. Development will consist of one concrete base platform with production capacity 19.3 x 10^9 Sm^3 gas a year. This capacity can be expanded to 22–23 x 10^9 Sm^3 a year.

In addition to the main gas development, a subsea production system (the Troll module) has been decided for injection of gas on the Oseberg field. Norsk Hydro is operator for this project. The plans call for production of about 2.2 x 10^9 Sm^3 of gas a year.

The initial oil development on the field is expected to be development of the southern part of the thick oil zone. This will involve development with a separate platform. The northern part of the thick oil zone can be produced at the same time as gas is produced from Troll West.

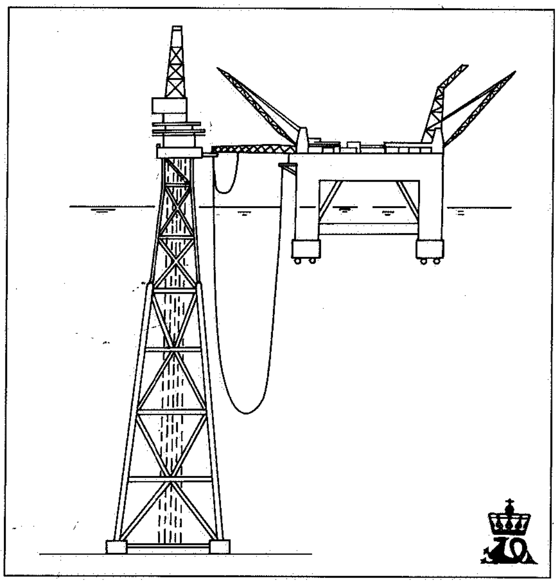
Costs

Total development costs for Troll Phase I are estimated at about 24.6 billion 1987 kroner. Total operating costs to the year 2010 are estimated at about 17.0 billion 1987 kroner.

2.5.11 Veslefrikk

Production Licence 052

Fig 2.5.11.a
Planned installations on Veslefrikk.



Licensees

Den norske stats oljeselskap a.s.	50.0 %
Unocal Norge A/S	20.0 %
Norsk Hydro Produksjon a.s.	10.0 %
Deminex (Norge) A/S	12.5 %
Norske Deminex A/S	2.5 %
Svenska Petroleum Exploration A/S	5.0 %

The field is in the south–east of Block 30/3, which was allocated in 1979 with Statoil as operator. Four wildcats have been drilled in the block and two exploration wells on the Veslefrikk structure itself. In both these wells oil was proven at two diffent levels in sandstones of the Brent and Cook formations.

The development and operation plan was submitted in February 1987. The commerciality report was submitted to the partners in November 1986. The operator has estimated the total oil recovery from the field at 36.4 x 10^6 Sm^3, and total associated gas at 3 x 10^9 Sm^3. In addition the first predrilled production wells resources in the Statfjord and Tarbert reservoirs.

A number of development alternatives have been considered for the Veslefrikk field. The recommended development solution for the field consists of a fixed wellhead platform with steel base installed over a frame with six predrilled wells.

It is planned to rebuild the semisubmersible drilling rig "West Vision" as a floating production platform, anchored and hooked up to the fixed wellhead platform.

Figure 2.5.11 shows the planned installations.

The development is estimated to cost about NOK 5.5 billion including well costs. This is a considerable cost saving in relation to the concepts previously planned for veslefrikk. The low costs and the short construction time means that the field is profitable even with today's oil prices. Given the operator's plans the field will be ready to produce in September 1989.

It is planned to connect an oil pipeline to the Oseberg field centre for transport of oil to the Sture terminal. Gas can be transported via the Statpipe system or be used for injection on Oseberg.

Preparation

The Norwegian Petroleum Directorate is following the work of this development closely, as it raises new problems on the preparedness side on account of the design of a fixed manned wellhead installation and a mobile production and accommodation installation. The Norwegian Petroleum Directorate has been particularly concerned about the accessibility of rescue and evacuation aids.

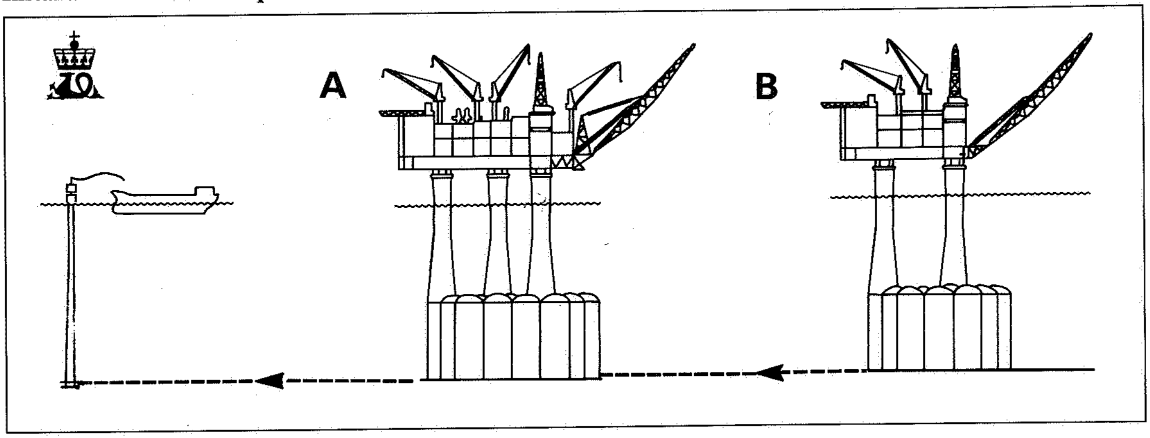
2.5.12 Gullfaks

Production licence 050

Licensees

Den norske stats oljeselskap a.s	85.0 %
Norsk Hydro Production A/S	9.0 %
Saga Petroleum a.s	6.0 %

Fig 2.5.12.a
Installations on Gullfaks phase I.



Statoil is the operator. Esso was the technical assistant during the exploration phase. Conoco has been engaged as technical assistant for the development phase.

Recovery of reserves
The field is in the north–east part of Block 34/10 and covers an area of about 200 km^2. Proven reserves are entirely within the block. Figure 2.5.12.b shows the location of the field.

The Gullfaks field is relatively shallow, divided by north–south faults into several angled and rotated segments of Jurassic strata. The segments, or blocks, vary in their degree of declination, though all point fairly consistently to the west. In the east, the structure is more uncertain, the area being highly broken by faults and in places heavily eroded. The structural details of the eastern part are more difficult to plot due to poor seismic data. The field is bounded in the south, east and northeast by faults with vertical displacements exceeding 100 metres. Gullfaks is definitely the most geologically complex field so far developed on the Norwegian continental shelf. The operator's resources estimate is 210.3 x 10^6 Sm^3 oil, 13.7 x 10^9 Sm^3 gas and 2.1 x 10^6 tonnes NGL.

Oil and a little dissolved gas has been proven in the Brent group, Cook– and Statfjordformations. In the easternmost part of the field oil has also been found in Triassic strata. The reservoir rock is quite like that found in Statfjord and Murchison, that is, sandstone with high permeability and comparatively high porosity. Under the oil there is a water zone of variable volume, which is, however, not enough to maintain pressure in the reservoir as the oil is taken out. It is therefore necessary to inject quite soon after production start. Gas injection has also been considered as a recovery method, but this gives poorer results than water injection.

Production facilities
The first discovery on the block was made in 1978. On 10 June 1981, the development plan for Gullfaks Delta East was considered by the Norwegian Storting and the Government was given authority to approve the first phase of the development, following approval of the development plan by the Norwegian Petroleum Directorate and the Ministry of Petroleum and Energy.

Phase I consists of two platforms (Figure 2.5.12.a). The Gullfaks A platform A is emplaced on the southern end of the field. It is a Condeep, with concrete base and steel deckframe.

The platform is equipped with processing equipment producing stabilised oil for storage and further transport. The gas will be separted, desiccated and compressed to the specifications for Statoil gas.

The processing capacity will cover production from separate wells in addition to partially processed oil from Gullfaks B when this begins to produce in 1988. Production capacity is 38,950 Sm^3 per day.

According to the operator's drilling programme, Gullfaks A will be equipped with in all 42 production, gas injection and water injection wells. In addition it will be possible to link in six freestanding subsea wells.

Platform B is a drilling, accommodation and water injection platform with concrete base, equipped with limited processing equipment. This platform has been emplaced on the north–west part of the Delta East structure where the ocean depth is about 135 metres.

Oil from the field will be off–loaded via field loading buoys to tankers.

Gas from the field will be transported through the Statpipe system via the Statfjord C platform.

Gullfaks Phase II
Phase II includes the area east of the main fault between exploration wells 34/10–4 and 34/10–9. The ocean depth in this area is considerably greater than in Phase I.

So far eight exploration wells have been drilled in the part of the field comprising the Phase II development.

Appraisal well 34/10–19 on this part of the Gullfaks field proved to be dry.

Resources Phase II

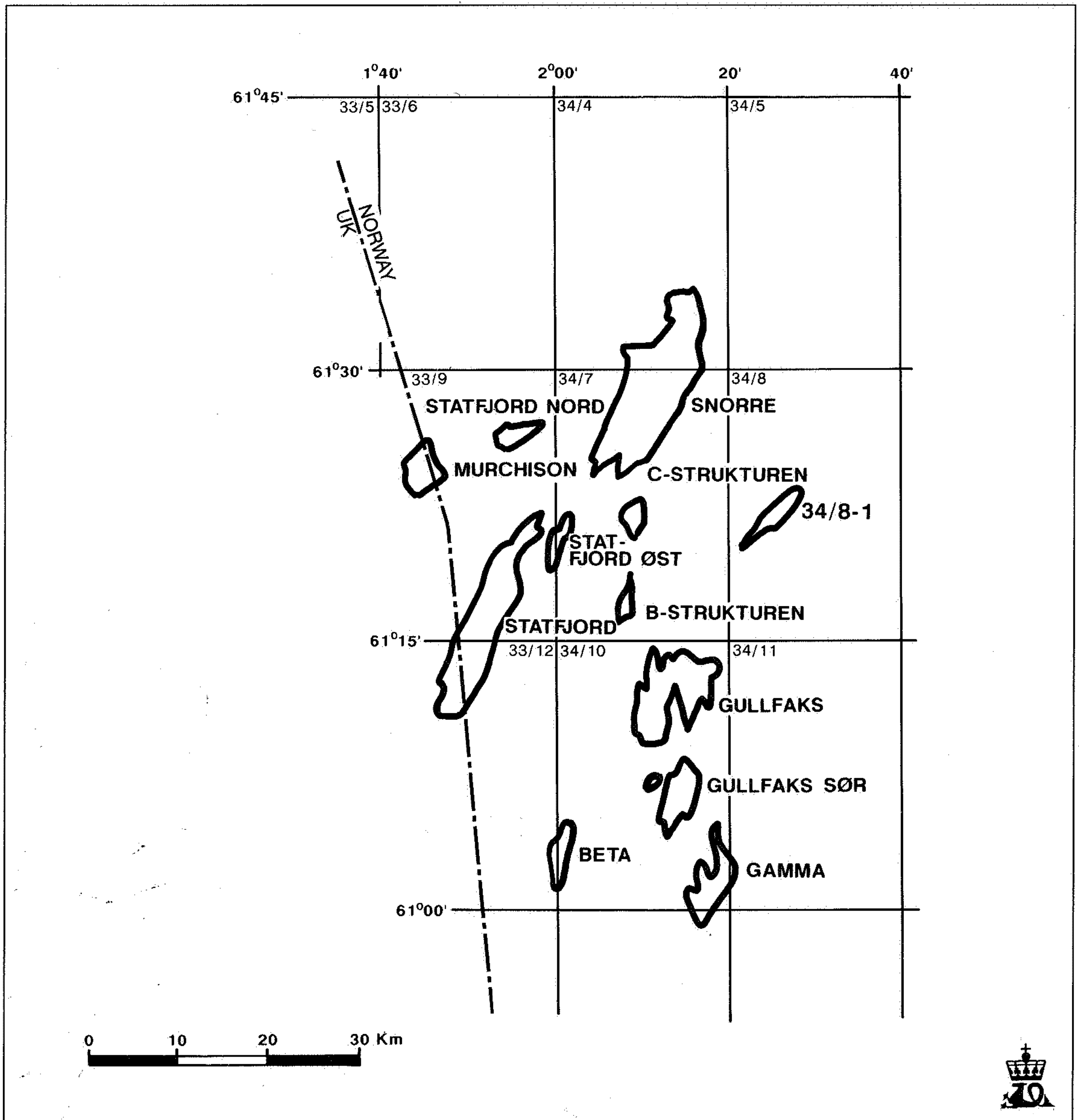
Due to the complicated field boundaries to the east and southeast, estimates of resources are very unreliable. Statoil's estimates of recoverable reserves are about 75.2 x 10^6 Sm^3 oil and 10.5 x 10^9 Sm^3 gas for Gullfaks, Phase II. These estimates were made after drilling of Well 34/10–19.

Development of the area received Storting approval on 1 June 1985. The reduction in the estimated reserves in the Phase II area led to selection of a development concept comprising a full processing platform. This will be a copy of the Gullfaks A platform.

The Gullfaks C platform will be located in the middle part of the field where the water is 220 metres deep. The plan is to produce all reservoirs using water injection, and subsea completion wells will be used to the extent necessary to ensure good depletion of the reservoir.

Partially processed crude oil is expected to be dispatched through a 205 mm pipeline from Gullfaks B to Gullfaks C, where final processing can begin in 1990. Stabilized crude oil produced on Gullfaks C

Fig 2.5.12.b
The Gullfaks-, Statfjord- and Snorre area.



will be transported to a loading buoy (single point mooring, SPM2) via a 414 mm pipeline.

The gas will pass along a 254 mm pipeline from Gullfaks C to Gullfaks A and from there into the Statpipe system.

Development

Gullfaks A

On 21 December 1986 Statoil initiated oil production by starting up three subsea completion wells on the Gullfaks A platform. In the course of 1987 four new wells have been drilled, so that at the end of the year six wells are producing and two injecting. Water injection started from one well in April.

Before the gas compression system is commissioned, the bulk of the gas will be flared off whilst parts are used to power the gas turbines.

An inspection before start-up revealed some faults in the system. These had to be righted before the Directorate could consent to the start-up.

Gullfaks B

Hookup of the deck and concrete base took place in April 1987. The platform was towed out and emplaced on the field in August. The commissioning went faster than expected, and production start is set for February/March 1988, about nine months earlier than planned.

Gullfaks C

Construction of the concrete gravity base started in January 1986 in Stavanger. Tow-out from the dry dock took place in February 1987, and the structure is expected to be finished in the first quarter 1988.

Gullfaks C will be the largest concrete platform so far built in the North Sea. Roughly 240,000 cubic metres of concrete will make up the structure.

Construction of the steel deck started at Stord in September 1986 and will take 16 months to complete.

Preparedness

Installation of the B platform has meant changes in the preparedness plans, which are now a plan for the entire field. It must be revised when the C platform is in place.

In this context the operator has tested the preparedness plan in several exercises. After minor adjustments the new plan is now in force.

Flaring

The quantity of gas flared off on Gullfaks A in 1987 was on average 419 x 10^3 Sm^3 per day (Figure 2.5.12.c). This corresponds to 40.6 % of the total gas production from Gullfaks A.

Metering systems

The metering systems for oil and gas on Gullfaks A have been in regular operation throughout the year.

The Gullfaks C systems are still at the construction site, though fully built and undergoing test.

Costs

The total development costs are expected to run to about NOK 58 billion in fixed 1987 kroner, the total operating costs to about 52.2 billion 1987 kroner.

2.5.13 Statfjord

Production licence 037

Licensees

Norwegian share (84.09322 %)	
Mobil Exploration Norway Inc	12.61400 %
Den norske stats oljeselskap a.s	42.04661 %
Norske Conoco A/S	8.40932 %
Esso Exploration and Production Norway A/S	8.40932 %
A/S Norske Shell	8.40932 %
Saga Petroleum a.s	1.57674 %
Amoco Norway Oil Company A/S	0.87597 %
Amerada Hess Norwegian	0.87597 %
Exploration A/S	0.87597 %
Texas Eastern Norway Inc	0.87597 %
British share (15.90678 %)	
Conoco (UK) Ltd	5.30226 %
Britoil Plc	5.30226 %
Chevron USA Inc/Gulf Oil (UK) Ltd	5.30226 %

Poduction licence 037 was allocated in 1973, including Blocks 33/9 and 33/12 (Figure 2.5.12.b). Mobil was operator until 1 January 1987, when Statoil assumed the operatorship. The Statfjord field itself was discovered in the spring of 1974 and declared commercial the same year. Statfjord extends onto the British side where Conoco is the operator. The initial field development report was submitted to the authorities in the spring of 1976. Since then, several development reports have been presented. The field has been developed in three phases with fully integrated platforms: Statfjord A, Statfjord B, and Statfjord C. The Statfjord A platform is centrally located on the field, the B platform stands to the south of it, and the C has been sited in the northern part of the field (Figure 2.5.13.a).

Fig 2.5.12.c

Gas flared on Gullfaks.

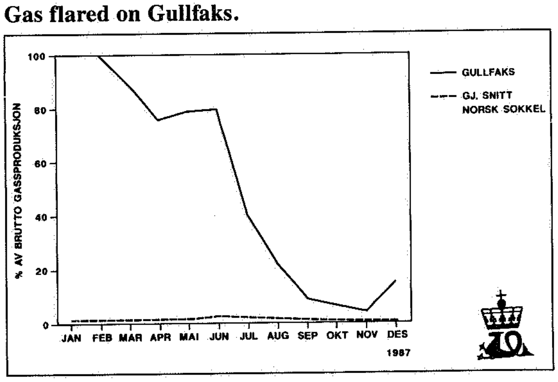
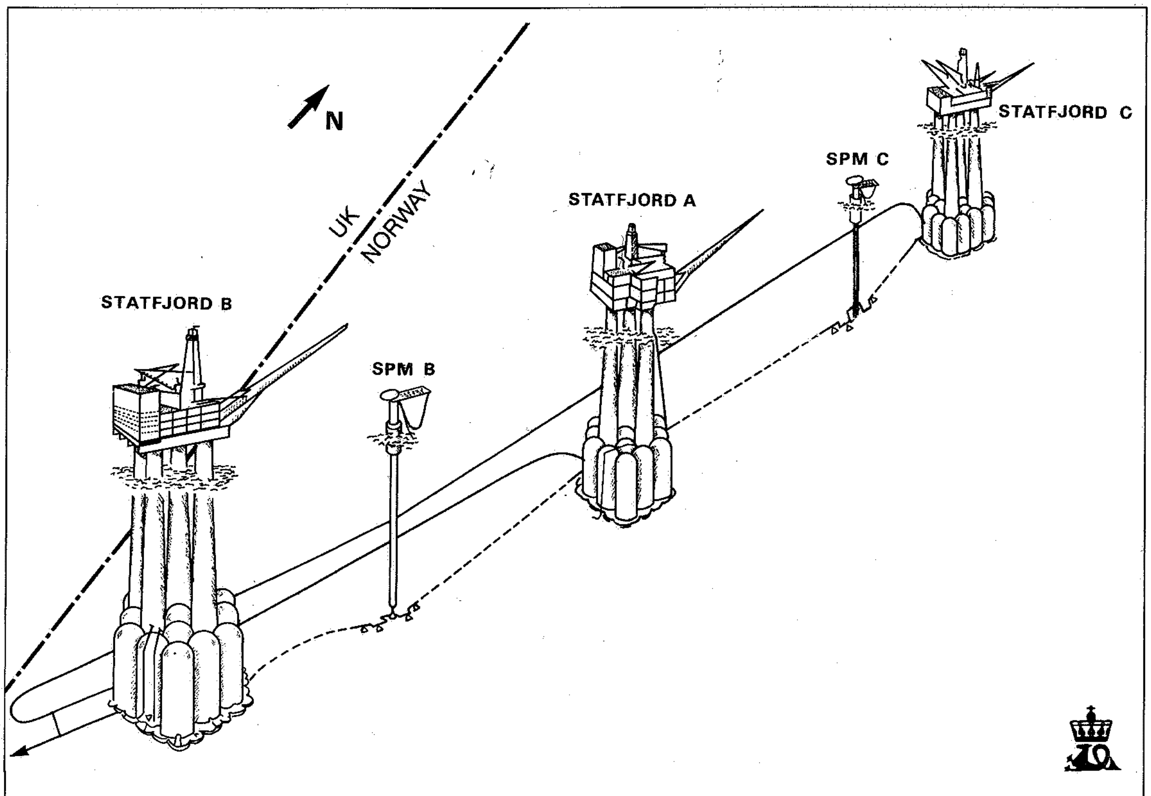


Fig 2.5.13.a
Installations on the Statfjord field.



Recovery of reserves
By injecting water into the Brent reservoir and gas into the Statfjord reservoir, the Norwegian Petroleum Directorate expects that a recovery factor of some 50 per cent will be attained. This means that the total recoverable quantities of oil in the Brent and Statfjord formations are 445.7 x 10^6 Sm^3. The amount of recoverable associated gas has been estimated at 58.6 x 10^9 Sm^3 dry gas, and 18.4 x 10^6 tons of NGL. Apportionment of the reserves in the field, as approved by the authorities in 1979, assigns 15.9068 per cent to the British side, and 84.0932 per cent to the Norwegian. The licensee groups are currently negotiating new apportionment figures. The negotiations are expected to be concluded in 1988.

Production facilities
Statfjord A
The Statfjord A platform is located at the centre of the field, and comprises shafts and 14 cells, all of concrete. The deck is of steel. Production capacity is 55,000 Sm^3 a day. Capacity increased as a result of fine–tuning of the processing equipment. The platform started production on 24 November 1979 and is equipped with 21 production wells and 15 injection wells.

Statfjord B
Statfjord B, sited in the southern part of the field, has four shafts and 24 cells, all of concrete. The deck is of steel and the platform is built as an integrated Condeep. Production capacity is 39,800 Sm^3 a day. Production started on 5 November 1982 and capacity is now being fully exploited. Availability of processing equipment in 1987 has been high. The platform is equipped with 19 production wells and 11 injection wells.

Statfjord C
Statfjord C is emplaced in the northern part of the field and like Statfjord B has four shafts and 24 concrete cells with a steel deck. Production capacity is 39,800 Sm^3 a day. Production started on 26 June 1985, and the platform has in all 31 wells, of which 19 are planned as production wells and 12 as injection wells. Operational regularity was high in 1987.

Preparedness
Development of a gondola rescue system on the Statfjord field uncovered great weaknesses in the system. Alternative systems are under consideration. Statoil is now operating Statfjord C without a flotel. The Norwegian Petroleum Directorate will continue to follow developments closely, as approval of platform solutions for the Statfjord field involved mandating the operator to develop satisfactory evaluation systems.

Preparedness situations

In the course of the year there have been two critical situations, in which partial evacuation was undertaken.

On 24 January 1987 there was a fire in the ventilation plant. This caused a certain amount of smoke in the living quarters. Firefighting and evacuation of the flotel of all personnel without assignments in the emergency organisation by and large went quickly and easily without loss or injury. The personnel check system worked satisfactorily.

A gas leakage in Well A 39 lasted about 10 minutes and involved partial evacuation. Both Statoil and the Norwegian Petroleum Directorate mobilised their preparedness organisations, and the Norwegian Petroleum Directorate maintained extra readiness throughout the subsequent work of killing the well. This lasted until 12 July 1987.

Preparedness maintenance

The Norwegian Petroleum Directorate has pointed out several deficiencies of preparedness maintenance on the Statfjord field. Most of these deficiencies have been found on Statfjord A. This will be followed up in future inspections.

Criminal charges against Statoil

On 23 February 1987 Statoil applied to the Norwegian Petroleum Directorate for permission to extend the saturation period for divers from 16 to 24 days during diving operations from "DSV Seaway Pelican" on the Statfjord field. Such consent can be given under the diving regulations, if an agreement has been made between the diving contractors and the diver's union representatives. A statement from a doctor acquainted with diving should also accompany the application.

During the Norwegian Petroleum Directorate's inspection visit on board "DSV Seaway Pelican" it was discovered that Statoil's application contained incorrect information regarding these conditions. Neither the union representatives nor diving doctor had been involved in the case. The Norwegian Petroleum Directorate therefore reported Statoil to the Stavanger Constabulary on 8 July 1987.

Loading systems

The new loading system installed in 1986 has been operational in 1987. Operational regularity has been satisfactory. Late in the year, however, it was noted that the loading line had been pinched by water pressure.

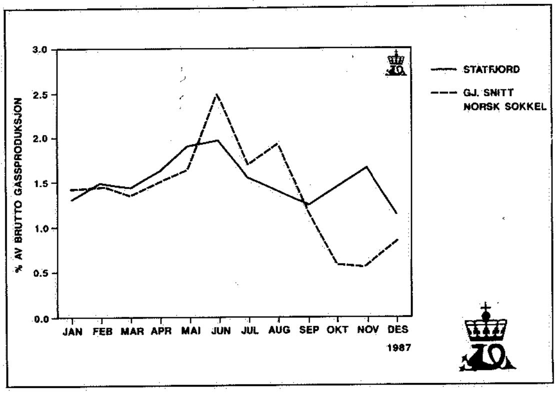
Flaring of gas

Statfjord A

The amount of gas flared on Statfjord A in 1987 was on average roughly 172 x 10^3 Sm^3 per day, corresponding to 1.9 % of total gas production from the platform.

An in parts comprehensive maintenance programme has been carried out on Statfjord A in 1987.

Fig 2.5.13.b
Gas flared in the Statfjord area.



In consequence of the gas leakage on Well A–39 in June 1987, there were certain operational disturbances and an increase in gas flaring. Despite these unforeseen disturbances, Statfjord A has been able to maintain a stable production. A good deal less than the 0.300 million Sm^3 per day given in the production licence is being flared. An important reason for this good result is the flexibility achieved through us of all three platforms.

Statfjord B

The quantity of gas flared off on Statfjord B in 1987 was on average 102 x 10^3 Sm^3 per day, corresponding to 1.3 % of the platform's total gas production. Statfjord B is in a stable operating phase, flaring well under the flare permit of 0.300 million Sm^3 per day. Compressor troubles have been the main reason for flaring.

Statfjord C

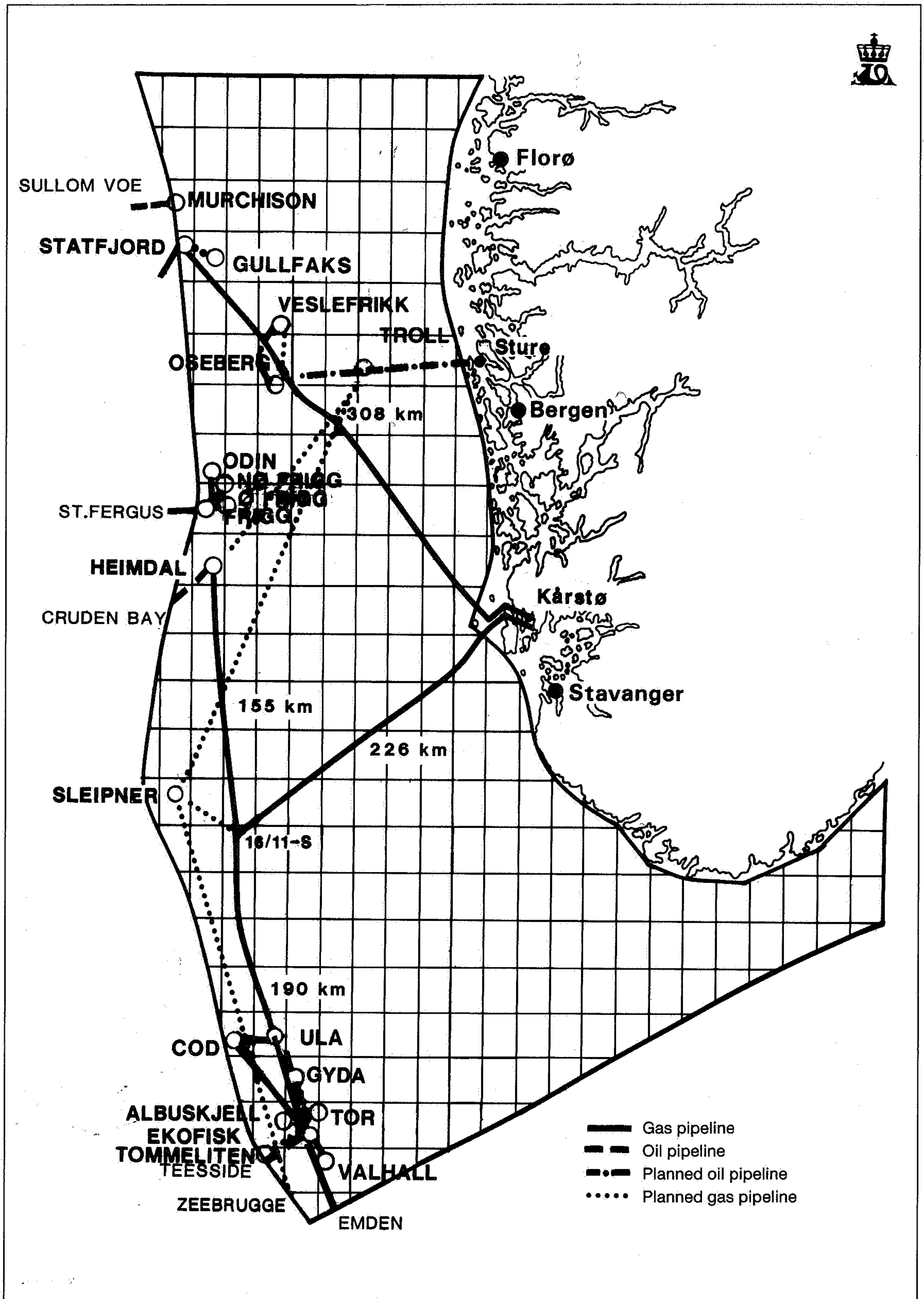
Statfjord C flared off 85 x 10^3 Sm^3 a day on average. This corresponds to 1.2 per cent of the platform's total gas production. The flare permit sets an upper gas flare limit of 0.300 million Sm^3 a day. Statfjord C has remained well below this limit, which indicates that the teething troubles have now been overcome and stable operation has been achieved. See Figure 2.5.13.b.

Metering system

The metering systems for fiscal oil metering on Statfjord A, B and C have been characterised by normal, stable operation through 1987. Some minor modification work has been carried out to replace older electronic units with newer models. On Statfjord A work has been in progress to install new sampling systems. Final start–up is scheduled for the first quarter of 1988.

The metering systems for fiscal gas measurement from the Statfjord field has, like the oil metering systems, been in normal, stable operation throughout 1987.

Fig 2.5.13.c
Pipelines in the Norwegian part of the North Sea.



While the oil side has not given technical metering problems, the gas side has encountered difficulties on account of the present high rate of production of Statfjord B and C. The problem is that hydrocarbons are quite frequently found in liquid phase in the gas measuring pipes, and they consequently measure a lower volume–to–mass ratio than that going through the metering station. An action plan to deal with this problem has been adopted.

To what extent the proposed modifications are sufficient to achive gas metering under ISO 5167 will be revealed in 1988.

Costs

The total investment costs on Statfjord up to 2010 are expected to run to about NOK 54.7 billion 1987 kroner. Total operating costs up to 2010 are estimated as being just under 60 billion 1987 kroner.

Gas transport, Statpipe

The Statpipe gas transport system was founded with the following partners:

Den norske stats oljeselskap a.s	60 %
Elf Aquitaine Norge A/S	10 %
Norsk Hydro Produksjon A/S	8 %
Mobil Development Norway A/S	7 %
Esso Exploration and Production A/S	5 %
A/S Norske Shell	5 %
Total Marine Norsk A/S	3 %
Saga Petroleum a.s	2 %

Statoil is operator for construction and operation of the pipeline. The transport system includes:

- a rich gas pipeline from Statfjord to Kårstø
- a separation and fractionating facility on Kårstø, including storage farm and loading facility
- dry gas lines from Heimdal and Kårstø to a riser platform in Block 16/11, and a pipeline to the marine riser platform at the Ekofisk Centre.

No serious problems have arisen in connection with operation of the Statpipe line. In 1987 the Gullfaks field was linked to Statpipe.

Kårstø

The first North Sea gas was landed at Kårstø on 25 March 1985. A sketch of the transport system for oil and gas in the Norwegian part of the North Sea is shown in Figure 2.5.13.c.

In connection with the shutdown of the Ekofisk field in the summer of 1987 the whole processing plant at Kårstø was overhauled and checked.

The work on the K Lab is finished, and it is expected that start–up will take place in the first quarter of 1988.The K Lab is a collaborative project between Total and Statoil. The transport capacity from Statfjord to Kårstø is 8 x 10^9 Sm^3 of wet gas per year. Kårstø has a processing capacity of 5 x 10^9 Sm^3 wet gas per year. The dry gas pipeline to the Ekofisk Centre has a transport capacity of 17 x 10^9 Sm^3 a year. This exceeds the capacity requirements for Statfjord, Gullfaks and Heimdal and has been provided to allow later tie–in of other fields. If it becomes necessary to increase transport capacity in the Statpipe system, a compressor platform will need to be erected next to the marine riser platform 16/11–S. A blanket agreement with Norpipe a/s and the Phillips group has been entered into concerning the use of the Ekofisk Centre and the pipeline to Emden.

The licensees on Statfjord, Heimdal and Gullfaks have also entered into sales agreements for the gas with buyers on the Continent.

Metering system

The dry gas metering system at Kårstø has functioned accoerding to plan in 1987. There were some operational disturbances in the LPG metering system in the second half of 1987, but these are expected to be fixed early in 1988. The LPG return gas metering system has been upgraded in 1987. A gas metering pipeline was opened for full inspection summer 1987.

2.5.14 Murchison

Licensees

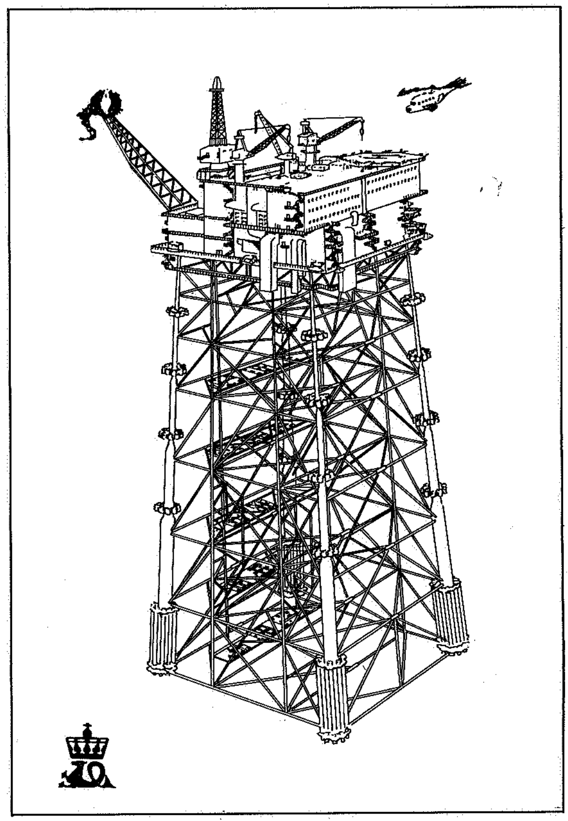
British share (77.8 %)	
Conoco North Sea Inc	25.9334 %
Britoil Ltd	25.9333 %
Chevron USA Inc	25.9333 %
Norwegian share (22.2 %)	
Mobil Exploration Norway A/S	3.3300 %
Den norske stats oljeselskap a.s	11.1000 %
Norske Conoco A/S	2.2200 %
Esso Exploration and Production Norway A/S	2.2200 %
A/S Norske Shell	2.2200 %
Saga Petroleum a.s	0.4162 %
Amoco Norway Oil Company A/S	0.2313 %
Amerada Hess Norge a.s	0.2313 %
Texas Eastern Norwegian Inc	0.2312 %

The Murchison field was proven in August 1975. It lies in Block 211/19 on the British side and Block 33/9 on the Norwegian (Figure 2.5.12.b). Development of the Murchison field was started in 1976 by the British licensees. The 037 group declared the field commercial in summer 1977, and Statoil joined the declaration in summer 1978. The division of the reserves in the field were approved by the authorities in September 1986. The Norwegian share is 22.2 %, and the recoverable reserves for the whole field are 53 x 10^6 Sm^3 oil and 1.2 x 10^9 Sm^3 gas.

Recovery of reserves

Murchison has been producing at almost maximum processing capacity since 1981. 1984 was the last year of plateau production. By Royal Decree of 24 September 1982, the Government consented to landing of Norwegian Murchison gas via the Northern Leg Gas Pipeline (NLGP) to the Brent field on

Fig 2.5.14.a
Installation on Murchison.



the UK side, and further via Far North Liquified and Associated Gas Gathering System (FLAGS) to St Fergus in Scotland. Gas deliveries through the NLGP started on 20 July 1983. Oil from Murchison is sent by pipeline to Sullom Voe on Shetland.

Production facilities

Field development uses an integrated steel platform with production capacity 26,200 Sm^3 a day (Figure 2.5.14.a). On 28 September 1980, oil production started from the two subsea completion wells. Current production is roughly 11,000 Sm^3 crude oil a day. The platform has in all 27 well slots. Twenty–seven wells have been completed, of which 18 are production wells and nine water injection. Satellite wells have now been abandoned.

Flaring of gas

In 1987 an average 0.22 x 10^3 Sm^3 gas a day was flared, corresponding to 10.8 % of total gas production (Figure 2.5.14.b). Operating regularity of the gas system in 1987 was 88 per cent. Compressor troubles and repairs to separators have affected regularity. There have also been teething troubles after stoppage/shutdown in consequence of planned maintenance on Murchison that year.

Metering system

Operating inspections are now performed annually in collaboration with the British Department of Energy.

Costs

Total investments and total operating costs are expected to be roughly NOK 3.7 and 2.3 billion 1987 kroner respectively.

2.6 Final phase/removal

The Norwegian Petroleum Directorate has set up an interdisciplinary project group with the task of looking more closely at current problems in connection with takeover and removal of installations associated with Norwegian petroleum activity.

In 1987 the group was among other things involved in international work. The IMO (International Maritime Organisation) began, in the winter of 1986, work on designing more detailed international regulations for removal of installations. At an early stage in the work in IMO the Americans demanded that 98 % of all installations be removed after use.

Norway and Great Britain have opposed the United States' demand for removal. This is due to the fact that conditions in the North Sea are special, with large and costly installations in deep water. the costs will be disproportionately greater than in other parts of the world.

During the IMO meeting of January 1987 the parties failed to reach agreement on what criteria should be applied to platform removal. It is hoped that clarification will be achieved early in 1988.

The alternatives for the installations after production has ceased are presented in Figure 2.6.

According to the Geneva Convention of 1958 (Continental Shelf Convention) as ratified by Norway, "every installation which is shut down or with is no longer in service shall be completely removed". The United Nations Convention on the Law of the Sea, 1982, has nevertheless blunted the strict removal requirements in the Geneva Convention, since it demands removal to the extent shipping, fishery interests, ocean environmental interests or other nations' rights and obligations so dictate.

Fig 2.5.14.b
Gas flared on Murchison.

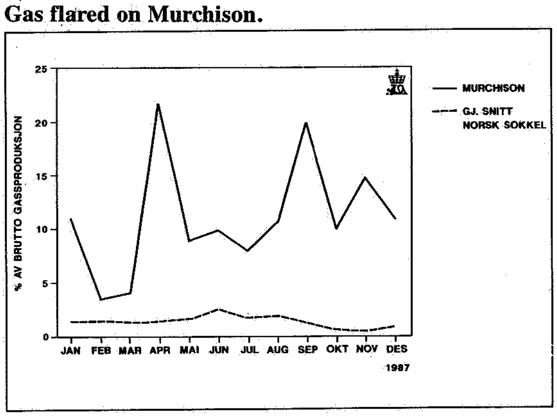
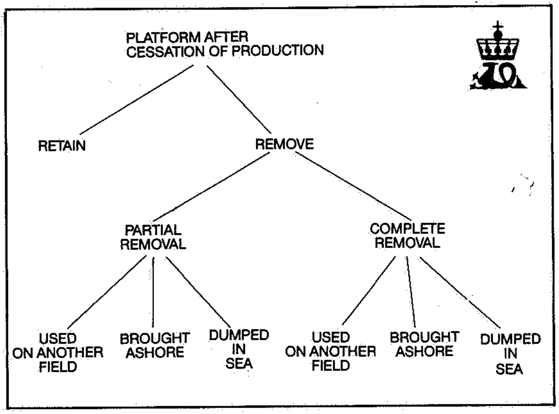


Fig 2.6
Final production and removal.



There seems now to be international agreement that the Law of the Sea Convention will be the standard by which future international law is shaped. However, Norway has not yet ratified this convention. Implementation of our international law obligations with respect to installation owners presupposes the authorization of the removal requirement in Norwegian law.

This issue is regulated in the Petroleum Act of 22 March 1985 no. 11, § 30.

When a licence expires completely or is partially relinquished or use of the installations associated with the licence ceases, the state is empowered to acquire the fixed installations and appurtenances free of charge.

The state also has two other options; instead of acquiring the installations, the Ministry can contract with the owner for temporary use of the installations; or the state can require the installation to be fully or partially removed by a given date.

World experience of platform removal has been limited to small units emplaced in shallow waters.

Technically and economically, the scope has been relatively moderate in comparison with what can be expected from removal of large units from the Norwegian shelf.

Even if it is possible from a purely technical point of view to remove even the largest structure the Norwegian shelf, the costs will be very great. It should be asked whether the costs of removal are reasonably related to its utility.

Because conditions vary greatly from field to field, the chance of devising a fixed, uniform solution does not exist. The Directorate considers that the best approach would be to lay down provisions for removal in Norwegian law compatible with the frameworks set up by international law and practice.

3. Petroleum Resources

3.1 Resource inventory

Petroleum resources belong to the group of non–renewable energy resources, and comprise all technically recoverable oil and gas quantities.

Petroleum reserves are the part of the discovered resources which may be extracted under given technical/economic conditions, and which the licensees have declared to be commercial.

The resource inventory comprises a summary of petroleum resources on the Norwegian continental shelf. Changes in the resource inventory from one year to another are caused by new discoveries, adjustment of the estimate for existing discoveries and reductions in consequence of production.

From 1986 to 1987, the Norwegian Petroleum Directorate's inventory for existing resources shows a net decrease for the first time. This decrease was at 46 x 10^6 Sm^3 oil, including NGL, and 64 x 10^9 Sm^3 gas. In addition to the production, it is the decrease in the total resource estimate for Haltenbanken which has, above all, resulted in a lower estimate for remaining resources in 1987 than in 1986.

The resource inventory for the Norwegian continental shelf is shown in Figure 3.1.a, and the resources are shown in Figure 3.1.b.

For the purpose of presentation in the annual report, the resources on the Norwegian continental shelf is shown in three tables:

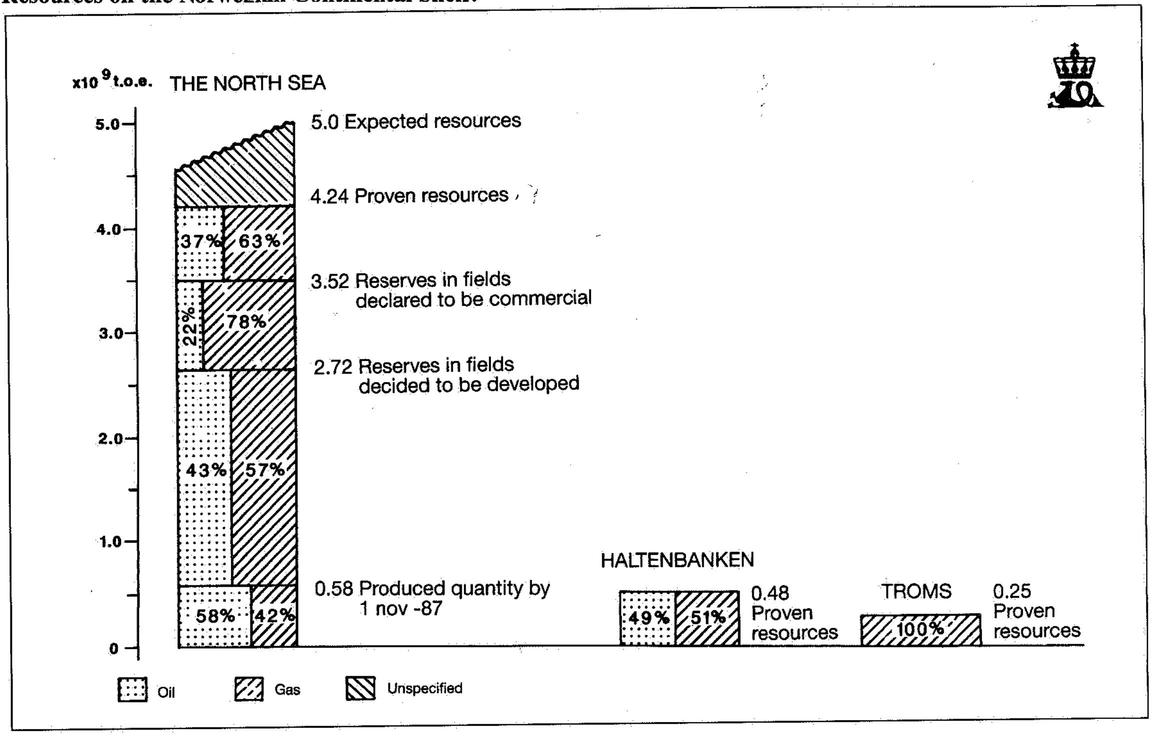
I. Reserves associated with development projects for which a development decision has been reached, or which are under development or in production (Table 3.2).
II. Other resources south of Stad (Table 3.3)
III. Resources north of Stad (Table 3.4).

Fig 3.1.a
Recource account related to the Norwegian Continental Shelf.

		DISCOVERED						UNDISCOVERED	
	OIL/NGL × 10^6 Sm^3 GAS $10^9 Sm^3$	PROVED		PROBABLE		POSSIBLE		HYPOTHETICAL	SPECULATIVE
		OIL NGL	GAS	OIL NGL	GAS	OIL NGL	GAS		
PROGRESS	PRODUCING	696	255						
	DECIDED DEVELOPED			363	992				
	PLANNED DEVELOPED			413	650				
TECHNICAL ECONOMICAL CONFIDENCE	POSSIBLE DEVELOPED			289	639	131	186		
	UNDER EVALUATION					23	31		
	SUB. MARGINAL					9	20		
		PROD. WELLS		APPRAISAL WELLS		EXPLORATION WELLS		DEFINED PROSPECT	UNDEFINED PROSPECT
		DECREASING WELL CONTROL						DECREASING SEIS. CONTROL.	
		DECREASING GEOLOGICAL CONTROL							

PRODUCED	420 X 10^6 Sm^3 oil including NGL 238 X 10^6 Sm^3 gas

Fig 3.1.b
Resources on the Norwegian Continental Shelf.



Tab 3.2
Proven petroleum reserves in fields decided to be developed

	ORIGINAL SALEABLE				REMAINING		
	OIL $10^6 Sm^3$	GAS $10^9 Sm^3$	NGL 10^6 tonn	O EKV 10^6 tonn	OIL $10^6 Sm^6$	GAS $10^9 Sm^3$	NGL 106 tonn
Albuskjell[1])	8.0	18.0	1.2	26.2	1.6	5.8	0.4
Cod[1])	2.9	7.1	0.5	9.6	0.6	1.8	0.1
Edda[1])	4.7	1.9	0.2	6.1	1.3	0.2	
Ekofisk	237.0	126.0	13.5	337.2	101.3	70.6	9.0
Eldfisk[1])	63.5	39.4	3.4	96.4	30.4	27.7	2.1
Frigg[1]) [2])	0.4	105.0		105.3			16.2
Gullfaks[1])	210.3	13.8	2.1	196.2	206.4	13.8	2.0
Gyda	30.5	3.0	2.5	32.1	30.5	3.0	2.5
Heimdal[1])	4.5	33.2		36.3	3.8	27.6	
Murchison[1]) [3])	12.0	0.3	0.4	11.1	3.4		
Nord Øst-Frigg[1])	0.1	11.0		11.1		4.8	
Odin[1])	0.1	33.3		33.4		20.7	
Oseberg[1]) [4])	247.0	79.0		299.0	245.9	79.0	
Sleipner Øst	17.0	51.0	10.0	79.1	17.0	51.0	10.0
Statfjord[5])	375.0	49.0	15.4	385.8	218.4	42.8	13.5
Tommeliten[1])	6.4	18.4	1.0	25.3	6.4	18.4	1.0
Tor[1])	24.0	14.6	1.6	36.9	7.5	5.7	0.7
Troll Øst		825.0		825.8		825.0	
Ula	33.0	1.6	1.4	31.0	27.9	1.3	1.1
Valhall[1])	41.0	11.9	2.8	49.6	28.9	9.8	2.2
Veslefrikk[1])	36.4	3.0		33.2	36.4	3.0	
Vest Ekofisk[1])	12.4	26.9	1.5	39.5	1.5	5.7	0.4
Øst Frigg		13.0		13.0		13.0	
Sum	1366.3	1485.4	57.5	2718.2	969.2	1246.9	45.0

[1]) Operator's estimate
[2]) Norwegian share: 60.82 %
[3]) Norwegian share: 22.2 %
[4]) Includes Alpha, Alpha North and the Gamma structure
[5]) Norwegian share: 84.09 %

3.2 Reserves basis for approved fields
As of 31 December 1987, decisions have been taken to go through with 23 development projects on the Norwegian continental shelf. This is an increase of two compared with 1986, and applies to Gyda and Veslefrikk. Petroleum quantities for fields decided to be developed are given in Table 3.2. The reserve figures are largely based on the operator's estimate of recoverable resources. In total, 0.58 x 10^9 t.o.e. had been produced until 1 December 1987.

3.3 Other proven reserves south of Stad
Table 3.3 shows other resources which have been discovered south of Stad. Of these, the fields Brage, Snorre, West Sleipner and West Troll have been declared commercial. The resource quantity in these 4 fields amounts to a total of 0.80 x 10^9 t.o.e.

3.4 Proven reserves north of Stad
So far, 0.72 x 10^9 t.o.e. have been discovered by

Tab 3.3
Proven petroleum resources south of Stad not yet decided to be developed.

	Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	NGL 10^6 tonn	OEKV 10^6 tonn
Agat [1])		43.0		43.0
Balder	35.0			31.6
Brage [x])	38.0	3.0		34.1
Gullfaks Sør	45.0	88.0		127.6
Hild [1])	1.2	8.8		9.8
Hod	7.2	5.4		11.5
Huldra [1])	5.4	16.4		20.8
Sleipner satellitter [2])	16.0	35.0		47.2
Sleipner Vest [3])	27.0	135.0	9.0	169.2
Snorre	108.0	6.6		96.2
Statfjord Nord	39.0	2.0		34.4
Statfjord Øst	19.0	2.5		18.3
SØ-Tor	4.0	3.0		6.3
Troll vest	41.0	463.0		499.9
1/3-3	3.3	0.1		2.8
6/3 PI	0.9	1.0		1.7
7/11 A [1])	6.5			5.3
9/2 Gamma [1])	24.0	1.0		20.9
15/3-1,3	2.0	29.0		30.6
15/3-4 [1])	12.0	5.0		15.0
15/5-1	2.0	6.0		7.5
15/12 Beta [1])	16.0	1.3		14.4
16/7-4 [1])	1.4	8.0		9.0
24/6-1 [1])	1.8	6.0		7.5
24/9	3.0			2.4
25/2-4	4.0	12.0		15.3
25/5-1 [1])	15.0	5.0		17.3
30/6 Beta [1])	20.0			17.0
30/6 Beta Sadel [1])	20.0			17.0
30/6 Gamma Nord	1.4	7.5		8.6
30/6 Kappa [1])	5.0	5.0		9.1
30/9 Omega [1])	9.3	3.0		10.6
30/9-6 [1])	2.7			2.2
34/8-1	8.0	65.0		71.6
34/10 Beta [1])	8.0	22.5		29.0
34/10 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
Total	558.8	1037.6	9.0	1518.6

[1]) Operator's estimate
[2]) Includes 15/8 Alfa, 15/9 My and 15/9 Theta
[3]) Includes Alfa, Beta, Epsilon and Delta

drilling north of Stad. Of this, 0.48 x 10^9 t.o.e.is on Haltenbanken and 0.24 x 10^9 t.o.e. is off Troms. On Haltenbanken, Draugen and Heidrun have been declared commercial.

Tab 3.4
Discovered petroleum resources north for Stad

		Oil $10^6 Sm^3$	Gas $10^9 Sm^3$	t.o.e 10^6 tonn
Haltenbanken	Draugen	68.0	4.8	60.3
	Heidrun	113.0	38.0	130.7
	Midgard	15.0	80.0	91.6
	Njord	25.0	4.0	24.5
	Smørbukk	20.0	65.0	81.4
	Tyrihans	16.0	40.0	53.1
	6406/3 Alfa 1)	9.0		7.0
	6506/12 Beta 1)	22.0	11.0	29.0
	Sum	288.0	242.8	477.6
Troms/Finnmark	Albatross		34.3	34.3
	Albatross Sør		8.2	8.2
	Askeladd		52.0	52.0
	Snøhvit		86.1	86.1
	Snøhvit Nord		3.3	3.3
	7119/12 (1)		3.6	3.6
	7120/07		24.3	24.3
	7120/12		14.8	14.8
	7121/5 Beta	5.6	.6	
	7122/06-1 (1)		11.0	11.0
	7124/03-1 (1)		2.1	2.1
	Sum		245.3	245.3
	Total	288.0	488.1	722.9

1) Operator's estimate

3.5 Changes in resource estimates from the previous annual report

3.5.1 Fields in production

In the case of fields in production, the Norwegian Petroleum Directorate mainly use the operator's forecast figures for its resource summaries. In 1987, the operators increased their estimates of the resources in most of these fields.

The largest increase was at Eldfisk, where the estimate for oil resources has been adjusted upwards by 15 %. The increase is caused by production history and a pressure development which has shown that the recovery factor will be significantly higher than assumed in 1986.

On Frigg, water has penetrated into some of the producing wells earlier than anticipated, and the estimate for gas has thus been reduced by about 17 %. The changes in resource figures from 1986 to 1987 are shown in Table 3.5.

3.5.2 Fields approved for development

As concerns fields for which a development decision has been taken, but which is still not in ordinary production, smaller forecast adjustments have been made for the fields Gyda, Tommeliten and Veslefrikk.

At Oseberg, the estimate of oil resources has been increased by almost 20 %. The reason for this increase is that the pilot drilling program and a new exploration well has yielded positive results with regards to the thickness of the reservoir and the production properties of the main reservoir. In addition, the long–term testing with "Petrojarl I" has provided positive results with a view to production from the other reservoirs at Oseberg.

3.5.3 Other finds south of Stad

Brage

New well information and new reservoir simulation has led to an increase in the estimated oil resources on Brage compared with the previous estimates of the Norwegian Petroleum Directorate. At the same time, the estimate for the gas resources has been reduced.

Hild

In this instance, the Norwegian Petroleum Directorate uses the reserve estimates of the operator (Norsk Hydro). This estimate represents a reduction by 50 % compared with the previous estimates of the Norwegian Petroleum Directorate.

Huldra

The operator has undertaken a new survey of the discovery, and has reduced the gas resources by more than 20 %.

Snorre

The Norwegian Petroleum Directorate has undertaken a technical reservoir evaluation of the recovery factor at Snorre based on the present plan for development and operation. This has led to a reduction in the estimate of economically recoverable oil resources of about 26 % compared with the technically recoverable resources reflected in the annual report for 1986.

Veslefrikk
The operator has adjusted its estimate for the gas resources to some extent because of a change in the oil/gas ratio.

1/3–3
This is a small oil discovery from 1983 which has so far not been included in the annual report.

9/2 Gamma
This is a new oil discovery from 1987.

15/12 Beta
This is an oil discovery from 1986 for which the resources have not previously been listed in the annual report.

24/6–1
In the annual report for 1987, the operator's estimate, which is slightly lower than the Norwegian Petroleum Directorate's previous estimate, is used.

25/5–1
This is a new oil and gas discovery from 1987.

30/6 North Gamma
In the annual report for 1986, the recovery factor for the thin oil zone in North Gamma has been overestimated. The recovery factor has now been reduced to a more realistic level.

Tab 3.5
Changes in resource estimate in annual reports 1986-1987

	Annual report 86			Annual report 87		
	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6 tonn	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6 tonn
Fields decided to be developed						
Albuskjell	7.8	17.1	1.2	8.0	18.0	1.2
Cod	2.7	6.6	0.5	2.9	7.1	0.5
Edda	4.2	1.8	0.2	4.7	1.9	0.2
Eldfisk	54.4	32.2	3.2	63.6	39.4	3.4
Frigg	1.0	127.0		0.4	105.0	
Gyda	30.5	6.0		30.5	3.0	2.5
Heimdal	3.1	33.8		4.5	33.2	
Murchison	11.5	0.3	0.4	12.0	0.3	0.4
Nord-øst Frigg	0.1	8.0		0.1	11.0	
Odin	0.1	22.0		0.1	33.0	
Oseberg	200.0	71.0		247.0	79.0	
Tommeliten	5.9	16.8	0.9	6.4	18.4	1.0
Tor	21.6	12.9	1.4	24.0	14.6	1.6
Valhall	38.1	14.2	5.2	41.0	11.9	2.8
Veslefrikk	36.4	4.3		36.4	3.0	
Vest Ekofisk	12.1	25.1	1.4	12.4	26.9	1.5
Other fields						
Brage	29.0	6.0		38.0	3.0	
Hild		20.0		1.2	8.8	
Huldra	4.9	21.0		5.4	16.4	
Snorre	146.0	16.0		108.0	6.6	
1/3-3	–	–		3.3	0.1	
9/2 Gamma	–	–		24.0	1.0	
15/12 Beta	–	–		16.0	1.3	
24/6-1	2.0	10.0		1.8	6.0	
25/5-1	–	–		15.0	5.0	
30/6 Gamma Nord	5.0	7.5		1.4	7.5	
30/9-6	–			2.7		
Draugen	65.0	4.5		68.0	4.8	
Heidrun	127.0	39.0		113.0	38.0	
Midgard	22.0	103.0		15.0	80.0	
Njord	25.0	2.5		25.0	4.0	
Smørbukk	60.0	83.0		20.0	65.0	
6406/3 Alfa	–			9.0		
6506/12 Beta	48.6	36.3		22.0	11.0	
7122/06-1		–			11.0	
7124/01-1		–			2.1	

30/9–6
This is a new, small oil discovery from 1987.

3.5.4 Haltenbanken
On Haltenbanken, there has been a decrease in 1987 of discovered oil and gas resources of about 20 % in total. This dramatic decrease is above all caused by disappointing drilling results from the appraisal wells in 1987.

Draugen
New surveying of the structure has resulted in a small increase in the oil and gas resources on Draugen.

Heidrun
Surveying and reservoir simulation based on new well information has led to a downwards adjustment of the estimate of resources on Heidrun.

Midgard
New surveying of Midgard has led to a reduction in the estimated resources on this field.

Njord
An adjustment has been undertaken in the gas/oil ratio, so that the estimate in the quantity of associated gas has increased slightly.

Smørbukk
New well information and new surveying of the structure has led to a significant reduction in the resource estimate.

6406/3 Alpha
This is a new discovery from the autumn of 1986 where the resource estimate has not previously been listed in the annual report.

6506/12 Beta
In view of new information from appraisal wells, the Norwegian Petroleum Directorate has evaluated the structure one more time. The resource estimate for the structure has been significantly decreased.

3.5.5 Troms/Finnmark
Two smaller discoveries have been made off Finnmark in Blocks 7122/6 and 7124/3. Otherwise, no changes have been made in the resource estimate for existing discoveries from 1986 until 1987.

4. Safety and Working Environment in the Petroleum Activity

4.1 Introduction

The work of the Norwegian Petroleum Directorate's Division for Safety and Working Environment has been characterized by consolidation of the extensive restructuring which took place in the autumn of 1986.

The supervisory activity has been accomplished in accordance with an overall plan which has formed the basis for an increase in the efficiency of the supervision in the time to come.

In the course of 1987, the division has intensified its efforts to operate more efficiently. The main structure of an integrated planning tool has been established, and a system has been developed for registration of resources employed in relation to the activities of the division, which will improve the basis for future planning. The objective is to comply with the intentions in the new principles for administration of public authorities at all times.

4.1.1 Guidance for participants in the industry

In the Division for Safety and Working Environment, a service has been established which receives and answers/coordinates requests concerning the present supervisory system and give advice about the technical aspects of the regulations. In principle, the same guidance and service which is offered to the operator companies is to be provided to all other participants in the petroleum industry, including owners of installations, vessels and equipment. The Strategy Branch is responsible for this service.

4.1.2 Evaluation of applications for concessions on the basis of safety and working environment

In connection with the Norwegian Petroleum Directorate's overall advice to the ministries in licence matters, a safety and working environment evaluation is performed of applicants for operator status. In the 11th licencing round in 1987, special emphasis was put on applicants for key blocks in Area III, since operations in northern waters make special measures necessary in relation to safety and working environment. The evaluations were based on answers by the companies to concrete questions, as well as experience with the operating companies in connection with supervision of operations.

4.1.3 R&D activities of the S Division

In connection with the organizational change in the S Division in 1986, it was decided that a separate R&D function should be established and put under the Strategic Planning Section, the Strategy Branch. This function has been active for about one year.

The main task is above all to assist the divisional management with R&D questions, an furthermore to prepare routines for control and reporting, as well as to assist those responsible for projects in the sections. The main responsibility for applications, progress and reporting concerning R&D projects rests with the different sections.

A total of 40 R&D projects have been accomplished in the course of the year, and the total project amount is NOK 4,200,000. As it appears from the listing in Chapter 6.2, the projects cover a wide range from working environment conditions to high–tech problems.

Beside the fact that the projects provide answers for specific questions, this R&D work will also lead to the development of competence among the employees.

As concerns the economic aspects of the projects, these vary from projects fully financed by the Norwegian Petroleum Directorate to very large joint projects where the Norwegian Petroleum Directorate contributes a small share. In the case of the last type of projects, it is required that the Norwegian Petroleum Directorate is allowed to participate with the same freedom of information with regard to the project as the other participants.

4.2 Legislation – work on regulations

4.2.1 Methodological regulations development in safety and working environment

At the turn of the year 1986/87, the Norwegian Petroleum Directorate inititiated a major project for systematic development of the legislation in accordance with a plan submitted to the Ministry of Labour and Local Administration. The plan contained a description of the formal scope of the further work, the status and objectives, the work on interfaces, objectives and aids (the use of data processing) in the work.

The plan further dealt with the Directorate's organization of the work and emphasized the importance of conducting the work in close cooperation with the authorities involved, the industry and the organizations of employers and employees.

Activities which will last for several years were planned, where the activities would gradually be transformed to a maintenance phase. It was furthermore planned that the work should be accomplished as three–part projects, which would be concerned with, respectively:

- examination of the content in and experiences with existing detailed regulations, as well as surveying of interfaces

  Part project I

- development of structured legislation, as well as development of an overall audit plan

  Part project II

- carry out the work on legislation in accordance with the plans adopted

  Part project III

It has been one of the assumptions for the implementation of the project that the work would be performed in close contact with other authorities, the industry and organizations for employees and employers.

This should secure, among other things:
- the desirable decree of openness/information and appreciation of the work
- expert involvement, and possible corrective actions in relation to the work being performed.

In order to take care of this aspect, a "Contact forum for development of regulations" was established at the start of the work.

Meetings have been planned at central milestones of the work so that those concerned will be aware of and will be given an opportunity to discuss conclusions/recommendations before these are sent to the Ministry of Local Government and Labour or circulated for comments in an official manner.

In the report period, the Directorate's activity has mainly been directed towards that part of the work which concerns examination, i.e. that part which is directed towards examination of existing detailed regulations and the preparation of new structures and strategy for the legislation.

Activities have furthermore been initiated in the report period which have had the objective of clarifying the need for revision of existing detailed regulations in consultation with the industry, i.a. through
- accomplishing a study of the degree of coverage between the detailed regulations laid down by the Norwegian Maritime Directorate in accordance with the seaworthiness legislation and shelf legislation requirements for installations to be used by the petroleum acivity,
- evaluating the suitability of the Norwegian Petroleum Directorate's construction regulations in respect of mobile installations with hull shapes, and, in view to the above, to propose possible recommendations for necessary adjustments.

4.2.2 Regulations work

In expectation of a new structure of the legislation, the work of revising the detailed regulations has been postponed, with some exceptions. The reason for this is that the Directorate's freedom of action should not be restricted.

Work was nevertheless initiated for regulations within the areas of drilling, well technology and data gathering, subsea pipeline and riser, manned subsea operations. As well as development of guidelines in accordance with the Norwegian Petroleum Directorate's construction regulations.

This work was initiated/carried on, partly to "test" in practice the proposals/thoughts drawn up in the legislation project. Furthermore, there is a need for development of new rules within these areas.

In addition, the Norwegian Petroleum Directorate has developed as a short–term measure draft regulations which will have the effect that detailed regulations which are applicable to mobile installations engaged in "exploration drilling" will in the main also be applicable to "production drilling".

The Norwegian Petroleum Directorate has published the following guidelines:
- Guidelines for loads and the effect of loads (2 January 1987)
- Guidelines for corrosion protection of installations (22 December 1987)

In addition the following guidelines are under preparation:
- Guidelines for steel materials have been submitted for public comments with a time limit at 31 December 1987.
- Guidelines for steel structures are expected to be reado for public hearing in 1988.
- Guidelines for concrete structures have been submitted for inhouse comments. It is expected that they will be ready for public hearing in the summer of 1988.
- Guidelines for floating structures will be ready for inhouse hearing in the spring of 1988 and public hearing at the turn of the year 1988/89.
- Guidelines for foundations have been submitted for public comments with a time limit of 31 December 1987.

4.3 Supervisory activities

The Norwegian Petroleum Directorate's supervision shall inspire and contribute to secure that those taking part in petroleum operations comply with the regulations in a complete manner through the internal safety control principles, thus contributing to maintain the Norwegian Petroleum Directorate's safety objectives in relation to safety and working environment in an optimum manner.

The Norwegian Petroleum Directorate makes sure that the operator has a control system which ensures that the operations are planned, organized and maintained in accordance with the requirements of laws and regulations. This is undertaken by the study of how the control systems are followed up and maintained (system audit) and through spot checks to confirm that activities and products are in accordance with specified requirements (verification).

At a number of milestones defined in the safety regulations, approval from the Norwegian Petroleum Directorate is necessary in order to initiate petroleum activities.

In 1987, 95 consents and part consents were given, broken down as follows:

- 10 consents for exploration, with 96 associated drilling permits
- 26 consents for exploration drilling, with 36 associated drilling permits
- 6 consents for detailed planning
- 3 consents for fabrication
- 12 consents for emplacement
- 26 consents for use
- 3 consents for rebuilding or change of use
- 9 consents for the use of service vessels.

In addition to this, 49 permits have been given for production drilling as well as one drilling permit on Svalbard.

1987 was the first year in which the Norwegian Petroleum Directorate had an overall supervision plan for the Norwegian continental shelf and Svalbard, which also included contributory agencies and cooperation with coordinating agencies in the supervisory activity.

The areas given most attention in this plan were:

- Compliance with the intentions of the Working Environment Act.
- Older installations
- Early phase

11 major system audits were accomplished, involving 9 different operators, and a number of smaller audits and verifications. In the case of two of the major system audits, persons from the Health & Safety Executive Accident Prevention Advisory Unit, Great Britain, and from the Canada–Newfoundland Offshore Petroleum Board, Canada, took part.

These activities have confirmed a generally positive development as regards the appreciation of and compliance with the internal safety control duty on the part of the operator companies. As concerns the control systems for maintenance of the duties in accordance with the Working Environment Act, a good deal of work remains.

On the part of some operators, there are still certain weaknesses in regards to the maintenance systems. Otherwise, the internal safety control duty in connection with the technical aspects seems to be well taken care of.

In 1987, a supervision plan for 1988 has also been planned, which make greater requirements of systems and objectives in some of the supervisory activities and for the plan as a whole.

4.4 Working environment

4.4.1 System audits

Operating phase

In 1987, the Norwegian Petroleum Directorate has given priority to audits directed at the companies' maintenance of the working environment on older installations.

The audit has uncovered that there is still a lack of system as regards surveying and supervising the working environment. The Norwegian Petroleum Directorate has registered that there is a need to clarify the areas of work and responsibility between the operator and contractor within this area.

Design phase

In 1987, the Norwegian Petroleum Directorate has undertaken system audits directed at the companies' design of installations for offshore petroleum activities. The way in which the companies take care of the working environment aspects in this phase will be further focussed on in 1988. The background for this is that the Directorate would like to ensure that these circumstances are taken care of in a satisfactory manner, since the basis for a good working environment on the installations is mainly laid in the design phase.

The audits have been directed towards the companies' quality assurance systems. These have been examined also with a view to how the working environment aspects have been taken care of.

A central question is the acceptance criteria which the operator companies have established as reference values and a basis for their control (supervision).

When the operator companies shall evaluate whether circumstances have been taken care of and are in accordance with their own requirements, and when possible deviations should be indicated, it is a condition that reference values be established. It may be difficult to quantify some working environment requirements, but it can still be done better than as registered by the Norwegian Petroleum Directorate's audits in 1987.

In the case of such circumstances which it is difficult to quantify, attitudes, united (common) understanding and objectives are very important as instruments of management.

The Norwegian Petroleum Directorate's experience is that the working environment must in the main be considered as an operating responsibility. A satisfactory system for transfer of experience from operations to project has not been established. The companies have only to a limited extent specified working environment requirements and implemented these in their quality assurance systems at the start of any project. Likewise, the Norwegian Petroleum Directorate notes that the project groups only to a limied extent have or involve professional expertise in the working environment at an early date in the project. As the internal safety control system shall also comprise the working environment, these aspects should be better taken care of by the companies.

The Directorate notes as a positive factor that some companies are presently in the process of preparing or have prepared technical specifications related to the working environment aspects which will be used in the design phase.

The Directorate's expectation in relation to the follow–up of the companies of the working environment in the individual phases of the project is that the quality of these systems should be secured in an equally systematic, planned and efficient manner as is the case for the technical and safety aspects. It is thus assumed that the principles and control elements which are applicable to quality assurance are also utilized to secure the quality of the working environment.

4.4.2 Approval and consent provisions

The Norwegian Petroleum Directorate will still put major emphasis on preventive safety and working environment. It is thus of major importance that this is taken care of in an early phase of development and production plans (DPP), and in later documentation in connection with applications for consents. In this connection, it is important that the Norwegian Petroleum Directorate clarifies to the extent necessary vis–à–vis the industry which requirements it expects to have satisfied. The Norwegian Petroleum Directorate has therefore began work in this area.

4.4.3 Coordinating working environment committees

In the course of 1987, instructions have been given to all operator companies with responsibility within the scope of the Working Environment Act (WEA) to the effect that coordinating working environment committes (C–WEC) should be established. This C–WEC shall coordinate the worker protection and working environment work on the field and should consist of representatives of both the operator company and the contractor(s).

There has been a discussion in relation to the interface between the C–WEC and the working environment committees of the individual companies, and about the role of the C–WEC in the ongoing work of securing a fully sound working environment. This discussion has not been concluded.

4.4.4 Living quarters

During the last years, the general standard of the living quarters on the Norwegian continental shelf has been substantially improved. Single rooms, more rest rooms for smokers and non–smokers and leisure rooms for both quiet and "noisy" activities have become more usual.

In 1987, the Norwegian Petroleum Directorate has undertaken audits directed towards the operator companies' own evaluation of the older living quarters. The audits have signalled expectations to the effect that upgrading will be necessary if the requirements of the Working Environment Act in the direction of keeping up with the development shall be complied with. Attention has been given to the companies' internal safety control and plans related to the living quarters for the future.

4.4.5 Natural ventilation

The legislation establishes requirements for ventilation with a view to avoiding gas concentrations which might represent danger of explosion and/or poisoning.

On offshore installations, natural ventilation is used to a large extent. Measurements made on a major platform show that the ventilation quantity is in accordance with calculations and satisfy the requirements of the legislation. The requirements are here established on the basis of unfavourable operating conditions, i.e. hot weather and little wind. In the case of increasing wind, the ventilation will be better, but then environmental problems may arise because of the large quantities of air giving a feeling of draughtiness and chill.

Several operator companies are presently looking at the possibility of optimizing natural ventilation. Efforts are made to find methods of providing sufficient ventilation at the same time that draught and coldness will not damage the working environment. These projects will probably continue with increased intensity in the years to come.

4.4.6 Methanol deicing

During the very cold weather in January of 1987, methanol was used for de–icing purposes on walkways, which led to methanol poisoning in one instance. Even if everything went well on this occasion, methanol is too hazardous a substance to be used in this manner. There are other methods of efficient de–icing, and inter alia hot air blowers will be used.

4.4.7 Noise

Many work sites on the installations have noise which may damage the hearing, and which requires the use of hearing protection. In the case of the Statfjord field, a better picture has been gained in recent years as concerns the extent to which lack of hearing protection leads to damage to employees' hearing. Other fields are now following with such surveys.

The examination of hearing of those employed by the operator at the Statfjord field in the period 1982–87 showed that about 1/3 had a previous hearing injury at the time of employment. In the course of this 5 year period, 5 % of the persons examined developed a permanent changes in the hearing which is assumed to have been caused by the effect of noise during work at Statfjord. The use of hearing protection is thus not sufficient to prevent long–term effects.

Efforts should above all be made to solve the noise problems in connection with the design of the installations. In view of the noise level presently experienced on offshore installations, the Norwegian Petroleum Directorate wants to emphasize the importance of making use of proper hearing protection.

4.4.8 Organizational conditions for contracted personnel

Traditionally, hired personnel performs tasks which the operator companies feels that they do not have the expertise to deal with themselves, or tasks limited in time and scope. As examples of contracted personnel, one may mention maintenance workers, drilling personnel and catering employees.

Contracted personnel have traditionally had lower status than operator personnel, and this has to some extent characterized the working conditions which they have worked under.

In the development of new and improved technology, it is advantageous that personnel with practical user experience from similar operating conditions are involved in the planning and design phase. When special work operations shall to a significant extent be performed by people that are not employed by the operator companies, this will become difficult in practice. In order to compensate for this, the contracting company should be used as consultants within their areas of expertise.

Technical improvements or design changes require time for the planning and implementation. Personnel employed for a shorter period only will frequently be less involved in problems which may conceivably only be solved after they have left the platform.

The employer has independent responsibility for ensuring that the employees enjoy a good working environment. Desire for change should be reported through the line management. In the case of contracted personnel, the employer is not part of the operator's line organization, and this may reduce the possibilities of affecting the working environment through the employer.

Two Norwegian operator companies employ their own catering personnel and use these actively in the planning and design of new living quarters. It seems that this has a positive effect on their work situation and the quality of the new living quarters.

4.5 Emergency preparedness

4.5.1 Guidelines for emergency preparedness

The work of the "Guidelines for emergency preparedness" project was finished in the autumn of 1987. The result is presently available in the form of a report which will be the basic documentation for future preparedness legislation in the petroleum activity on the Norwegian continental shelf.

4.5.2 Early project phase

Through auditing of projects in the early phase, the Norwegian Petroleum Directorate has found that the understanding of the concept of emergency preparedness varies between the different operator companies. Understanding and the view of the concept of emergency preparedness also vary internally within the companies.

This leads to differential integration of the emergency preparedness aspect in the design phase, which may again affect the quality of the final project. With a view to harmonizing the understanding of the concept, it is necessary to make efforts for good contact with the oil companies on a professional basis, as well as through the inspection activity. It is possible that the emergency preparedness problems should be raised as early as possible in the project with a view to attain optimal concepts from the point of view of safety and economy in design, operation and organization.

4.5.3 The Norwegian Petroleum Directorate's emergency preparedness

The Norwegian Petroleum Directorate has its own emergency preparedness centre which may be activated during exercises or in situations of crisis/accident. The centre comprises rooms and equipment for:

- Information, conferences, operation handling and services (telex, telefax, datalogs, etc.) Logs etc. may be transferred to a large screen in a separate meeting room in connection with a press centre, for instance. The communications include direct lines to the operator companies and the main rescue centres.

Through the direct line to the Main Rescue Centre at Sola, the log of the rescue centre may be observed on a screen terminal. This arrangement has turned out to be very useful.

In the commissioning phase, there were some problems with the communications. After improvement of these conditions, the emergency preparedness centre has functioned satisfactorily and in accordance with the assumptions.

4.6 Drilling and well technology

4.6.1 Shallow gas problems

On the basis of the surveying of the distribution and magnitude of shallow gas, as well as the serious accidents in recent years when gas is encountered during drilling, the Norwegian Petroleum Directorate wished to gather the oil industry for a summary of experiences and knowledge within this area.

On the 27th and 28th of August, 1987, the Norwegian Petroleum Directorate thus arranged a seminar, at which the dangers and problems caused by shallow gas were highlighted.

Representatives from operator companies, drilling contractors, service companies, research institutions and others, together with representatives of the relevant authorities, took part. The participation was limited by the Norwegian Petroleum Directorate to 180 persons.

A special compendium has been issued which sums up the seminar.

4.6.2 Exploration drilling in the northern areas

General

The Norwegian Petroleum Directorate has followed closely the exploration drilling in the Barents Sea which got underway in 1987. In this connection, the Norwegian Petroleum Directorate guidelines "Evaluation criteria for exploration drilling in the northern areas" have been used as a basis.

As part of the follow–up of the operations for the part of the 11th licensing round which comprised the key blocks in Area III, a questionnaire was prepared for the applicants for operator status, with special emphasis on emergency preparedness conditions. The answers given have been very useful in the work of preparing the recommendation for the ministry.

Coordination of drilling activities

It is a general view shared by all operator companies which have drilled blocks allocated in the 11th licensing round in 1987 that coordination of drilling activities in the Barents Sea has obvious advantages. A coordination of services and supplies, such as the supply base, helicopters, supply and service vessels and doctors on call is practical and may lead to savings from the point of view of national economy. The use of two drilling units in the 11th round in 1987 probably also represented savings from the point of view of national economy, and also meant that the emergency preparedness level for both drilling operations increased in the large area of the Barents Sea.

The coordination requires extensive cooperation between the operators which involved increased contact and increased exchange of information.

In connection with the invitation to participate in the 11th licensing round, the Ministry of Petroleum and Energy established in a letter of 27 March 1987 conditions to the effect that the drilling activities should be coordinated.

- an even drilling activity level should be maintained through the year
- the drilling activity must be coordinated in accordance with a drilling sequence laid down by the Ministry of Petroleum and Energy
- continual year–around drilling must take place within the scope of a reasonable commercial cost
- the licence agreement shall be applicable.

Futhermore, pressure was put on the parties involved to ensure that the practical aspects of the agreement in connection with the drilling operation should be finished by 1 May 1987.

Statoil, Norsk Hydro and Saga, which received one production licence each on 10 April 1987, were given a central role in the preparation of this agreement about coordination of the drilling activities.

In the Norwegian Petroleum Directorate, a process was initiated to establish what was possible in accordance with the legislation. It was concluded that as long as the principle that each individual operator is still responsible for its own operations is applicable, there were no formal problems.

The installations selected were "Polar Pioneer" and "Ross Rig", on contract with Norsk Hydro and Statoil, respectively. As of 31 December, the following wells had been completed or had been initiated on blocks allocated in the 11th licensing round:

Company	Block No.	Production Licence	Drilling unit
Norsk Hydro	7321/8–1	141	"Polar Pioneer"
	7219/9–1	136	"Polar Pioneer"
Total	7122/6–1	138	"Polar Pioneer"
Saga	7124/3–1	135	"Ross Rig"
Statoil	7226/11–1	139	"Ross Rig"

The drilling operations have been conducted without appreciable problems. In addition, the weather conditions as of 31 December 1987 had been particularly good, compared with what could be expected in this area at this time of the year.

Support functions

Two helicopters were stationed at Hammerfest with a view to ensure the transportation of personnel to and from the installations. The operators have an agreement with the helicopter company to the effect that one helicopter will be available for search and rescue operations within a short time limit. The necessary equipment and personnel for this is stationed at the helicopter base.

In this connection, a certain upgrading has taken place in these helicopters in that they have been equipped with extra fuel tanks prolonging the period of operation considerably.

An agreement has been made with the helicopter company to the effect that a certain number of hours shall be used each month for seach an rescue training, where this has taken place in conjunction with the two installations.

Experience from the supervision activities
The Norwegian Petroleum Directorate has given the standby vessels particular emphasis, as they are of significant importance for the emergency preparedness of the unit. Certain differences have been registered as concerns the requirements of the various operators for standby vessels for operation in the Barents Sea.

As concerns other emergency preparedness circumstances, the Norwegian Petroleum Directorate has focused in particular on safety training beyond the basic for the personnel of the unit in the exercise of the supervision. In this instance, some operators have given effect to NIFO's guidelines for advanced safety training.

The Norwegian Petroleum Directorate has otherwise focussed on some equipment details in the supervision, which have all been considered as being of importance for the safety of the installation.

Feedback from the operator companies
After the completion of each well, the different operators have been asked to provide an evaluation of the experience gained on the emergency preparedness side. This will initially be practiced through the two year period. The experience indicates that there are few problems beyond those which have been experienced in areas further to the south.

The SOSEX–87 exercise in the Barents Sea
This exercise was arranged in the beginning of September and simulated a blow–out followed by major pollution from the mobile facility "Polar Pioneer". Useful experience was gained, among other things, Bear Island was used as a landing site for helicopters during the exercise.

The Norwegian Petroleum Directorate has raised with the Ministry of Local Government and Labour the question of the need for using Bear Island as an alternative landing site for helicopters in the petroleum activity. It would be of major importance to clarify this with a view to present and future activity in the Barents Sea.

Other circumstances
A possible extended cooperation with the USSR as concerns the rescue services in the Barents Sea associated with the petroleum activity is under consideration.

Arctic drilling on land
In view of the possibilities for a certain increase in the activities on Svalbard, the Norwegian Petroleum Directorate has carried out a study project concerning Arctic land drilling in 1987. The purpose of the project was to gain experience within drilling operations/drilling technology in relation to the use of land rigs in the Arctic.

The project was twofold, where phase 1 clarified the available rig concept in Germany, which was considered as representative for potential European concepts planned for use on Svalbard. Phase 2 clarified the experience within specific problem areas for drilling in the Arctic with permafrost and extreme climatic conditions. This part of the project was sited in Canada and Alaska.

The experience from the project will be used to evaluate possible rig concepts, as well as to contribute to form the basis for the evaluation of the Norwegian Petroleum Directorate of equipment and procedures for the use on Svalbard.

4.7 Load–bearing structures and pipelines
In 1987, work has been done on a description of the application of legislation on older installations on the shelf. Further comments have also been prepared in relation to "Regulations for loadbearing structures" and "Guidelines for loads and the effect of loads" with a view to arrive at a unified basis for interpretation of the regulations.

4.7.1 Guidelines for loads and load effects
In 1987, the Norwegian Petroleum Directorate has laid down new guidelines for the stipulation of loads and the effect of loads on offshore structures. Different types of loads have been examined, and recommendations have been issued for how the loads should be stipulated. Guidelines have also been given for the value of important loads.

4.7.2 Comparison of requirements for structural strength for semisubmersible, mobile and jack–up installations and vessels
In connection with the surveying of interfaces between the regulations of the Norwegian Petroleum Directorate and the rules of Det norske Veritas (DnV), a working party was established in June of 1986 with a view to identify the differences between the Norwegian Petroleum Directorate's Regulations for load–carrying structures and DnV's rules for mobile installations and ships. The working party consisted of representatives from the Norwegian Petroleum Directorate and DnV.

The comparison was finished in June of 1987 with the following main conclusions:
- DnV's rules for semisubmersible, mobile installations are in the main in accordance with the strength requirements in the Norwegian Petroleum Directorate's Regulations for load–bearing structures.
- However, DnV's rules for ships are not in line with the strength requirements in the Norwegian Petroleum Directorate' Regulations for load–bearing structures.

With a view to evaluating the differences between the Norwegian Petroleum Directorate Regulations for load–bearing structures and DnV's Rules for ships, a study project was initiated. The work comprised three main areas:

- Wave loads
- Hull breaking strength
- Guidelines concerning the application of the Norwegian Petroleum Directorate's regulations for load–carrying structures on production installations with a hull design.

The work has been performed by DnV, while the steering committee for the project has consisted of representatives from the Norwegian Petroleum Directorate, the Norwegian Shipowners Association, Det norske Veritas and the Central Institute for Industrial Research (SINTEF).

It is expected that the project will be finished in the beginning of 1988.

4.7.3 Risk assessment of buoyancy loss (RABL)

The RABL research program for semi–submersible platforms was initiated early in 1986, after a pilot project phase in 1985.

The program was finished in the last part of 1987. Since then, the program has been expanded to also include semi–submersible installations used in connection with drilling and for accommodations.

The program has been supported financially by Norwegian and British authorities, as well as the oil companies. RABL has developed a procedure for analyses with a view to identify accident situations which may cause loss of buoyancy. The principal procedure has been developed in accordance with the Norwegian Petroleum Directorate's principles for the safety evaluation of the structural design concepts of the installations.

Studies have been made with a view to demonstrate the use of this method. These studies are the basis for conclusions and recommendations in connection with the loss of buoyancy in the design of floating installations.

The collision risk is the most obvious factor in the safety evaluation of floating installations. This is so, regardless of the use of the installations. Errors with the ballast systems and major fires in the structure follow as the most relevant types of risk.

4.7.4 Collection of natural data

Gathering of natural data (current, wind, waves, etc.) from Ekofisk, Frigg and Statfjord has functioned satisfactorily in 1987.

With the help of the Norwegian Institute of Meteorology (DNMI), audits have been undertaken with the collection of data from all three fields. By using DNMI, the Directorate has attained greater professional expertise in the audits. The system under which assistance has been provided has functioned very satisfactorily.

In 1987, the Norwegian Petroleum Directorate has given instructions about the gathering of meteorological data during exploration drilling in the Barents Sea. The notification service for the Barents Sea is less reliable than in the North Sea. The Directorate has therefore also given instructions about the gathering of meteorological data. In the case of drilling in Area III, the Directorate has laid down regulations for the winter of 1987/88 concerning the notification of possible ice berg movements.

In addition, the Norwegian Petroleum Directorate has been engaged in the gathering of natural data from the Barents Sea in cooperation with the Oceanographic Data Acquisition Project (ODAP). The project is financed with the help of ODAP. In 1987, ODAP has paid NOK 4.5 million of the total budget of the project of NOK 14 million. The project of the Norwegian Petroleum Directorate has consisted of two waveheight/current direction measurement stations and three current measurement stations.

The research vessel M/S "Endre Dyrøy" has been hired from Georg Lokøy, Brattholmen. The vessel has lain at Sentralbanken at a position of 74° 30'N, 31° 00' E, when it has not been used by different geographical institutions. The vessel has changed its crew every fourth week, and in connection with this the vessel makes a round trip to all measurement stations for maintenance and servicing. On this round trip, tests of the water at different depths have also been taken.

An automatic weather station has been installed on the vessel. This registers meteorological data which is transferred automatically by satellite to DNMI at Blindern, which makes use of the data for weather reports.

The following companies and institutions have activities onboard the vessel:

- Oceanor A/S, Trondheim, has undertaken wave and current measurement.
- DNMI has been responsible for the meteorological measurements undertaken every third hour and reported to shore.
- The crew of "Endre Dyrøy" has operated the vessel and assisted with the various tasks on board.
- The oceanographic institute has taken water samples and undertaken plankton trawling and pelagic trawling.
- Tromsø Museum has undertaken the counting of birds.
- The Polar Institute has taken observations concerning the movement pattern for feeding purposes of Brünnichs guillemot. The Polar Institute has also been given help to trawl for rigs located under the ice for current measurement, which it has been difficult to recover.

For 1988, the project will change in character, as the charterparty for M/S "Endre Dyrøy" will expire on 30 April 1988. The last 8 months of the year, maintenance and examination of the buoys will be undertaken once a month by vessels on short–term contracts.

In 1986–87, the Norwegian Petroleum Directorate has undertaken an evaluation of the wave conditions in the Ekofisk area. In 1985, the operator undertook an analysis of the period 1955–84. The

Norwegian Petroleum Directorate established a committee with both internal and external members with the task of evaluating the data and analysis that were present and to give recommendations about the size of the one hundred year wave.The work was finished in 1987, and the conclusions varied from 22.5 m to 25 m. In the design phase for Ekofisk, 23.8 m was used, and the Norwegian Petroleum Directorate found it natural for this size to be used as a basis in the future as well.

4.7.5 Earthquakes

In 1987, the Norwegian Petroleum Directorate has participated in a larger study with a view to improve the mapping of earthquake activity on the Norwegian continental shelf. In view of known earthquakes and the knowledge about local ground conditions, it has been possible to prepare a statistical analysis for the occurrence of earthquakes. This then forms the basis for specifying a hundred year earthquake in the same manner as a hundred year wave. The most exposed areas seem to be located off Sogn and Helgeland. From the middle of the 1970s, installations on the shelf have been dimensioned for earthquake loads.

4.7.6 Full-scale measurements

From 1976, measurements have been undertaken of the effect of natural loads for seven production installations on the Norwegian shelf. All measurements and analyses have been finished. In 1987, all reports prepared for the Norwegian Petroleum Directorate were made subject to freedom of information. The data from the collection projects will be stored for the Norwegian Petroleum Directorate by SINTEF.

4.7.7 Telemetric surveillance of installations

The exploitation of petroleum resources at larger depths makes the use of traditional surveillance and inspection methods more difficult because of increased risks. Lower oil prices, as well as the need for development of marginal fields have accelerated the process of arriving at new methods and technical solutions which are adapted to the new environment, and which function without the use of divers and which have a high quality at a competitive price. Plans have been laid by Norwegian operator companies to make use of the new technology, and it is reasonable to believe that others will follow suit.

In 1987, the Norwegian Petroleum Directorate engaged in studies and research activities in this area in Norway and abroad. The change to telemetric surveillance will require incresed efforts both on the technical side and later within the regulations for the years to come.

4.7.8 Data bank for damage to structures and pipelines

Since 1984, the Norwegian Petroleum Directorate has undertaken systematic registration of damage to structures and pipelines based on the operator's reporting of inspection having been performed. The data bank is presently manually operated, but will require continual updating of performed inspection/damage reporting. It is intended that this should take place through the transfer of standardised formats from the operator companies to the Norwegian Petroleum Directorate.

It is anticipated that the data bank will provide information about injury statistics and trend analyses and that it will identify the scope and possible deviations in the operating companies' inspection activity.

4.7.9 Tension leg structures (TLP)

In 1987, some work was done by the Norwegian Petroleum Directorate in connection with questions associated with tension leg structures. An internal computer program has been developed which calculates the movements in a tension leg structure, as well as tension and fatigue in the tension legs.

4.7.10 Corrosion and corrosion control

The follow up of development projects, the experience from fields in operation as well as participation in research projects and working parties makes the Norwegian Petroleum Directorate able to keep abreast of the development in the corrosion technical area.

The Directorate has participated actively in working parties which have developed international standards within this discipline. This has happened through participation in the organizations NACE (National Association of Corrosion Engineers) and CCEJV (Corrosion Control Engineering Joint Venture between the Institution of Corrosion Science & Technology and NACE).

In recent years, weight saving has become a primary objective for new installations. This has led to new concepts in the field of corrosion protection. Advanced coating systems on the primary structure, in combination with cathodic protection, are about to become the standard. This reduces the necessary anode weight considerably, and provide a better overall protection system.

Sea water injection has been taken in use to an increasing extent for the purpose of increasing oil production. One result is that the quantity of water produced increases on older installations with injection plants. This water is corrosive and will strengthen the need for chemical treatment and examination of the state of processing equipment and pipelines.

4.7.11 Structural steel

Through the followup of development projects, legislative work, participation in research projects and committee work, the Norwegian Petroleum Directorate is following development and experiences within the area of material technology.

In newer development projects, the industry has changed to the use of microalloyed low carbon steel and controlled rolled steel plate in load–carrying structures.

Interest in making use of high tensile strength steel in structures is increasing. Several development projects which have recently been initiated or which are in the design phase will/may make use of this material.

The interest in the use of casted nodes seems to have increased in recent years. The advantage of using these compared with welded structures is that the fabrication is simplified and that lower tension concentrations are achieved in the hollow fillet welds of the node, so that the fatigue life increases.

In 1987, the Norwegian Petroleum Directorate presented for public consultation draft "Guidelines for material selection and fabrication of steel structures". The consultation comments show that there is a high degree of interest on the part of operator companies, engineering companies and other companies and institutions in these regulations.

The Norwegian Petroleum Directorate has previously decided to implement examination of steel which is used for development projects on the shelf. Steel is used for the most exposed parts of the load–bearing structures. Through welding simulation techniques, a picture may be obtained of the micro structure of the steel and the breaking tensile strength properties in the heat–affected zone of the weld. In 1987, steel from one development project has been examined. In total, steel from 15 different projects has been examined to date. In 1987, an article was published in the American publication "Welding Journal", dealing with the examination of 10 of these steel samples. The publication is the organ of the reputable American Welding Society. At the end of the year, the article and the examination described were awarded the American Welding Society's prize. The article was prepared by SINTEF, in consultation with the Norwegian Petroleum Directorate.

4.7.12 Internal control

As a follow–up of previous investigations concerning internal safety control and quality assurance on the part of the operator companies and for special projects, the Norwegian Petroleum Directorate initiated a similar study in the autumn of 1986 within the contractor industry with a view to surveying the experience of the industry in connection with the requirements concerning quality assurance. Experience from about 60 companies has now been collected and are under processing, and it is expected that this will be presented early in 1988.

4.8 Electrical plant and safety systems

4.8.1 Electrical plant and equipment

Supervision of the licesees' internal safety control systems and some problem areas have been given particular attention, including:

- In order to control and possibly reduce short circuit loads in electrical installations, the Norwegian Petroleum Directorate is now asking the companies to present their views on the dimensioning and operation of main generators, large motors and transformers before the reactance is established and the design cannot be changed. Among other things, this has resulted in the design of new facilities with other voltage levels than before, both in the case of high tension and low tension facilities, such as 660 V. Furthermore, it is proposed to use frequency regulators for large motors and equipment to limit the current in switchboard installations.

With a view to contributing to increased transfer of experience and to focus on special problem areas, a number of pictures have been taken of completed installations, and parts of this collection have been presented at courses and to people arranging courses, as well as to the operating companies, consultants and suppliers. Significant improvements have later been observed, including:

- The suppliers have developed equipment adapted to the requirements of the regulations, such as special equipment for heating cable installations and grounding arrangements for switchboards and boxes.
- In maintaining and upgrading old electrical installations, suitable materials and good installation practices have been selected.

One problem area which may require special attention and efforts is artificial ventilation and rooms with overpressure.

4.8.2 Programmable electronic systems for emergency shut–down and securing of processing and for fire and gas detection systems

The regulations presently in use have not been developed around programmable, electronic systems (PES). In the regulations for production and auxiliary systems, some functional requirements have been defined. In addition, there are some international codes and standards, but so far, they do not seem to be satisfactory for the systems mentioned above. Some work on regulations has been done in this area, i.a. in Great Britain, and it seems as if this is going in the right direction.

The development in the North Sea has been a change–over from simple circuit breakers, initially to simple and easily laid out programmable electronic emergency shut–down systems, and next to increasing complexity and size. In addition, integrated systems have been established for the different safety functions. This has not always been equally succesfull.

As the development goes very quickly in this area, it turns out that systems are quickly taken out of production, in spite of good customer experience. This has the effect that few or no similar installations are in operation, and the supplier's customer support will thus not be as good as it should be.

On the basis of experience from the simple facilities through larger, complex integrated systems, the trend has now turned for the new project. These will have more simple electronic systems which it is easy to grasp and program.

4.8.3 Seabed control systems

In case of large distances between surface and subsea installations, the short–down time for the safety valves may become unreasonably long.

It is important that the shut–down period be clearly defined at the design stage depending on the safety and environmental pollution aspects.

In recent times, there has been a certain "weakening" of the principle that valves of importance to the safety shall return to a safe position in case of possible errors ("fail–safe"). In the view of the Norwegian Petroleum Directorate, the "fail–safe" principle should be maintained for all parts of the safety system, also for the transfer of signals and power.

The Norwegian Petroleum Directorate has so far accepted joint systems for the transfer of signals for the control and safety systems. It is important that this is taken sufficiently into account in the design of the systems, so that this does not affect the safety.

4.8.4 Use of plastic materials

Through recent years, the Norwegian Petroleum Directorate has met with an increasingly stronger pressure from the operator companies and the suppliers regarding the acceptance of the utilization of plastic pipes on installations in the petroleum activity. The regulations of the Norwegian Petroleum Directorate requires that non–combustible materials should be as far as possible be used. It is nevertheless clear that pipes of plastic composite materials may have a number of advantages compared with steel or other metallic materials, such as:

- low installation and maintenance costs
- low weight
- good resistance to most types of chemicals.

With today's low oil prices and the efforts of the companies to keep the development and maintenance costs at a low level, the use of plastic materials becomes of still greater more interest.

In the view of the Norwegian Petroleum Directorate, there are several disadvantages to plastic materials:

- they are combustible
- the develop smoke in case of a fire
- the impact strength is low
- there are quality control problems
- there is a lack of knowledge about the materials.

Within some of these problem areas, major efforts have been made over the last year.

The Norwegian Petroleum Directorate has accepted the use of plastic composites to a limited extent. The purpose is to gather experience with these new materials within areas where technical failure or wrong application will not have any consequences in terms of safety. As the experience will increase, the Norwegian Petroleum Directorate will be able to evaluate whether it will be sound to increase the use.

4.8.5 Acceptance criteria for hydrocarbon fire barriers

In 1987, the Norwegian Petroleum Directorate completed the project "Acceptance criteria for hydrocarbon fire barriers". The project has been implemented in close contact with SINTEF and the Norwegian Laboratory for Fire Technology.

As a result of the work, a new fire curve has been prepared which is used in the case of simulation of hydrocarbon fires, and a test specification.

This work has also received contributions from a fire laboratory in England, so that the test procedure for the hydrocarbon fire separation is presently the same in England and Norway.

The work was presented at an international conference ("New Technology to reduce Fire Losses and Costs") as well as being introduced to international cooperation in ISO/TC92/SC2 – "Fire Resistance".

The hydrocarbon curve has been integrated into the revised edition of the international ISO 834 standard.

4.8.6 Fires

The following fires on production installations have been reported by the operator companies in 1987:

	Constr	Operating	phase	
	phase	"A"	"B"	"C"
1. Injury to persons and major physical damage				
2. Injury to persons and minor or no physical damage				
3. No injury to persons, but major physical damage				
4. No injury to persons, and minor or no physical damage		17	23	3
In total	0	17	23	3

"A" cause of fire: Caused by operations/operating work
"B" cause of fire: Construction work
"C" cause of fire: Other causes

The Norwegian Petroleum Directorate has registered a total of 43 fires in 1987, as against 22 in 1986. The change is associated with a high level of activity in connection with the jack–up of the Ekofisk installations.

4.9 Diving

In the course of 1987, 2367 bounce dives have been registered and 195,885 man–hours in saturation. The activity level was about 8 % higher than in 1986.

On 30 March 1987, a diver lost his life during diving at the Oseberg field. The diver was on his way to the bell at the work site at a depth of 110 meters. When it was clear that the diver had difficulties, the back–up diver went out of the bell and found the diver on the seafloor, unconscious and without the diving helmet. The incident is presently being investigated by the prosecuting authorities and the Norwegian Petroleum Directorate. In this connection, a weakness has been uncovered in the technical device which should ensure that the diver's helmet remains in place during subsea work.

On 26 December 1987, a fire occurred in the engine room of "Safe Regalia". The fire had the effect that five of the six available thrusters which keep the vessel in position fell out. In the course of this incident, communication with two divers in the welding habitat at the seafloor (at 137 m) was disrupted for short periods. When the situation was brought under control, communication was reestablished, and another diving vessel, "Sta Dive", was solicited for assisting in the rescue of the two divers that remained on the seabed. The divers were quickly brought up to the diving vessel "Sta Dive".

Twenty–one cases of infection in the external meatus have been reported with divers in 1987. This represents an increase compared with the number of ear infections which have been reported in recent years. In this connection, the Norwegian Petroleum Directorate has engaged the research institution SINTEF to describe preventive measures against infection of the external meatus. It is envisaged that the final report will be distributed to the diving industry.

The work of preparing regulations for manned subsea operations (to replace the present temporary regulations for diving) has been given high priority. It is envisaged that these will be submitted for comments in the first half of 1988.

In the report period, the Norwegian Petroleum Directorate has been involved in the follow–up of qualification requirements for personnel associated with subsea operations, and the draft has now been completed for qualification requirements for the majority of the personnel associated with diving operations.

The "working environment for divers" project

In connection with the "Working environment for divers" project, two new part projects have been initiated in 1987. One intends to clarify possible measures against noise injury to divers in water. The other part project intends to clarify possible preventive measures against contamination hazards in hyperbaric environments.

Problems associated with diving at greater depths

In 1986, the Norwegian Petroleum Directorate established, upon an initiative from the Ministry of Local Government and Labour, a working group to evaluate the problems areas/limitations in connection with diving at greater depths than 180 m. The group has finished its work, and the recommendation has been published.

4.10 Production plant and mechanical equipment

Cranes

In 1987, errors were registered on the electronic control system for several cranes on one installation. This caused, among other things, uncontrolled crane operations having the effect that the boom was operated at full lowering speed towards the cradle. This control system has been in use on offshore cranes for a number of years, and has proved to be very safe from an operating point of view. In case of interruption of cables or erroneous voltage input, however, errors in the controls could be caused. In this connection, improvements have been made to the control system which will take care of safety in case of interruption of cables or erroneous voltage input.

Mobile production installations

In 1987, the Norwegian Petroleum Directorate dealt with several plans for development of operations which comprise the use of mobile production installations, which is a new concept on the Norwegian continental shelf. The floating production facility "Petrojarl I" on the Oseberg field has been in operation throughout the period, and the experience from the operations is positive.

Subsea production installations

There are presently two subsea production installations in operation on the Norwegian continental shelf, (North East Frigg and Gullfaks A), and several others are under development (East Frigg, Oseberg, TOGI, Tommeliten and a number in the design phase).

Operating regularity for North East Frigg and Gullfaks A has been very satisfactory in 1986, and without serious problems. With the relatively high level of activities in the subsea production area, increasing expertise is being developed by the operators, the engineering companies and the workshop industry, but the lack of personnel with wide experience is still a limitation. In general, it is the impression of the Norwegian Petroleum Directorate that the mechanical equipment available for subsea completion and production is presently satisfactory, while the development of equipment for remote control, particularly over longer distances, is holding the development back.

Two–phase or multi–phase flow is an area where the basis for reliable calculation of flow conditions under all operating conditions is still lacking and where it is strongly desirable to develop an improved theoretical basis and calculating tools. The Norwegian Petroleum Directorate's follow–up of the TOGI project in 1987 confirms that the uncertainty in flow calculations is still a limiting factor for the conceptual optimalization and cost reduction.

4.11 Injuries

4.11.1 Background information

The Norwegian Petroleum Directorate's statistical summaries of personal injury covers injury to persons caused during work on installations on the Norwegian continental shelf in connection with exploration drilling and production of oil and gas. The summary is based on reported personal injuries which satisfy the criteria of absence into the next 12 hour shift or injury which has caused medical attention.

These criteria for reporting of personal injuries have the effect that the statistical material is not directly comparable with similar official reports from other industries, as the petroleum industry is subject to other and, to some extent, more stringent reporting requirements.

The number of injuries on the production installations are compared with the number of hours which the licensees have reported from the individual installations and fields for each quarter. One man–year has been defined for these purposes as 1752 hours work.

The Norwegian Petroleum Directorate undertakes regular inspection and correction of the basic statistical material because of incomplete and delayed reporting from the companies. The reporting of occupational accidents and working hours has been followed closely. As concerns the follow–up of the reporting from the exploration activity, this will be given priority in future.

Personal injuries in diving have a different classification and are registered as deaths, other casualties and pressure drop injury.

4.11.2 Summary of injuries in diving

Figure 4.11.a provides a summary of the number of personal injuries which have been reported to the Norwegian Petroleum Directorate in the years 1978–87 in connection with diving activities on the Norwegian continental shelf. Personal injuries have been divided into the categories of deaths, other casualties and pressure drop injury.

Reported near accidents and other incidents related to illness have not been included in the summary.

4.11.3 Summary of injuries for the production operations

815 incidents of personal injury have been reported in connection with the production of oil and gas in 1987, none of which have caused loss of lives. This is 209 more than the year before, i.e. an increase of 34.5 %. At the same time, 12,775 man–years were reported, an increase of about 30.8 %. This increase is caused mainly by the activity at Ekofisk in connection with the jack–up operations last summer.

The injury rate varies considerably from operator to operator. This is caused by the major differences in activity levels, the type of installations and the different phases of the field development.

The tables

Table 4.11.a shows a summary of personal injury cases per 1000 man–years in the period 1976–87 in the production operations. The table shows an increase in the injury rate in 1987 compared with 1986 from 62.0 to 63.7 cases of injury per 1000 man–years. Because of the uncertainty of the statistical basis, this change is not significant.

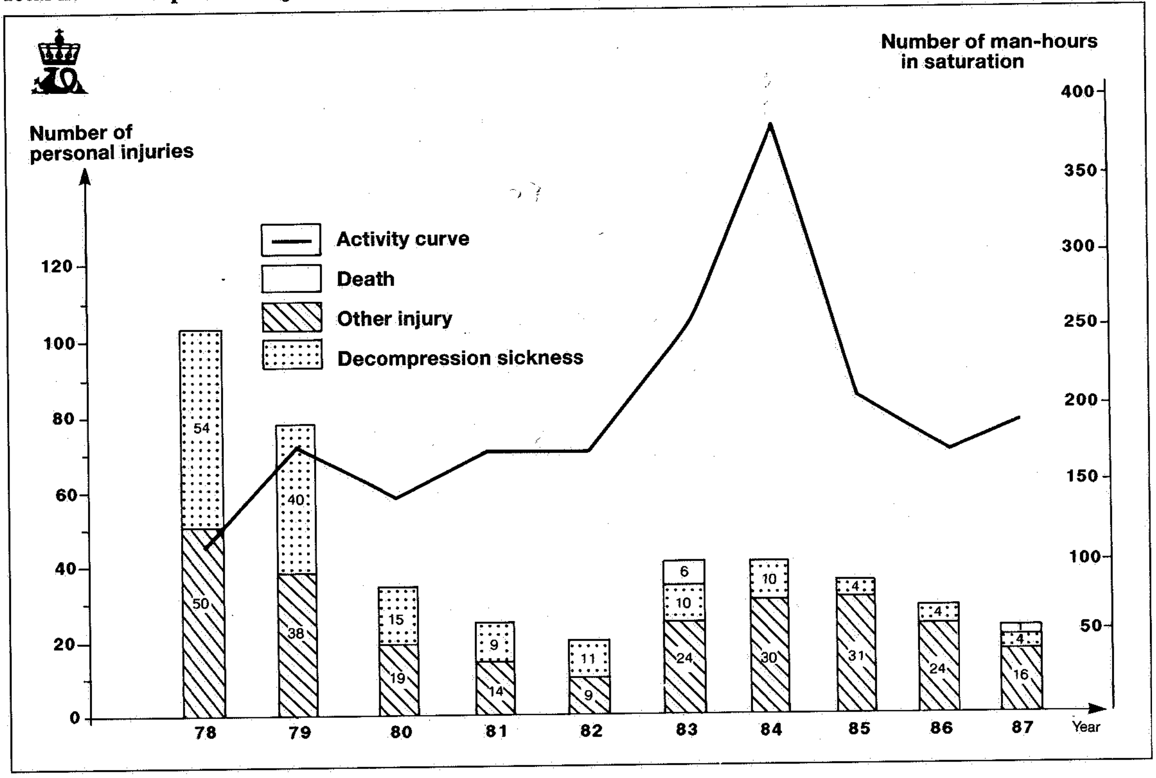
Injury that have occurred on the installations outside of working hours (leisure time injuries) have not been included in the tables. In 1987, 23 leisure time injuries were reported, against 29 the year before.

Table 4.11 shows the distribution of the injury rate for the different functions. The most marked change compared with 1986 has occurred within the area of drilling, where the injury rate has been reduced from 89.0 to 66.5. Injury in connection with squeezing has been significantly reduced. Drilling accounts for 12.1 % of the quantity of work performed at the production installations and 12.5 % of the casualties. This reduction is particularly positive in view of the high injury risk which the drilling operation represents. The frequency per 1000 man–years for serious personal injuries in connection with drilling and well maintenance has been reduced from 5.1 (in 1985 and 1986) to 1.3.

The decrease must be ascribed to the major effort which has been undertaken in recent years by the companies, the R&D environments and the authorities with a view to preventing injury through training/motivation and the introduction of better equipment which removes the personnel from the exposed area. Analyses have shown, however, that special position categories within the drilling and well personnel are exposed to an injury rate which is significantly higher than average.

As concerns the construction and maintenance operations, which amounted to about 60 % of the activity level in both 1986 and 1987, the injury rate shows a marked increase from 67.0 to 75.9. For the first time, the injury rate for these activities is higher than for the activities associated with drilling. As this is not a very homogenous group, there are position categories which have a significantly higher injury rate than average values. This particularly applies to personnel involved in heavier welding and construction work. Construction and maintenance operations are jointly responsible for 62.8 % of the work done and 74.8 % of the injuries. Similar figures from the year before were 61.7 and 66.7 respectively. Stepping wrongly, injury because of handling of tools and materials as well as splints and

Fig 4.11.a
Total number of personal injuries in connection with diving on the Norwegian Continental Shelf – 1978 - 87.



bursts from welding and grinding equipment are responsible for as much as 45 % of these injuries. Similar figures for 1986 were 33 %, i.e. a relative increase of 12 % for a type of accidents for which it would have been more natural to expect a decrease, even with another activity picture.

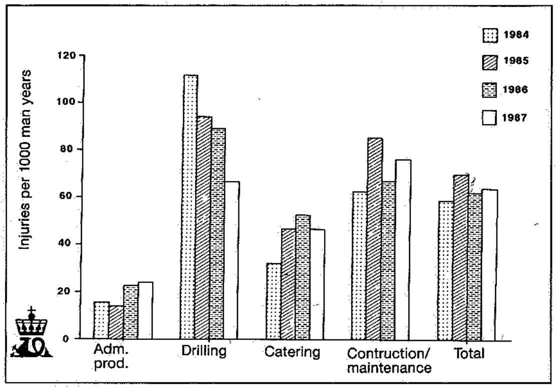
As regards the catering and administration/production activities, there are small changes compared to the year before.

Table 4.11.c shows the distribution of injuries and man–years for the years 1986 and 1987 between the employees of the operator companies and the contractors in the various work areas. In 1987, the contractor companies contributed with 69.5 % of the total work efforts of the production installations on the Norwegian continental shelf, against 65 the year before. 88.5 % of the injuries in 1987 took place within this group, against 85 % the year before. The

Tab 4.11.a
Occupational accidents/fatalities/1,000 man years (1976-87). Production installations

Year	Hours worked	Hours per man year	Man years	Number of injuries (incl dead)	Number of injuries per 1.000 man years	Number of deaths	Number of deaths per 1.000 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	452	64.7	0	0.00
1981	15612072	1752	8911	415	46.6	0	0.00
1982	14790384	1752	8442	529	62.7	0	0.00
1983	11473848	1752	6549	334	51.0	0	0.00
1984	14643216	1752	8358	491	58.8	1	0.12
1985	15014640	1752	8570	598	69.8	1	0.12
1986	17108280	1752	9765	605	62.0	0	0.00
1987	22341489	1752	12775	815	63.8	0	0.00
Total	166163817	1752	94842	5933	62.6	12	0.13

Fig 4.11.b
Injury frequency 1984 - 87.



injury rate for contractor employees were at 81.1, compared with 80.8 in 1986. The most significant reason for this uneven distribution is that drilling and most of the construction and maintenance work is performed by contractor companies.

Table 4.11.d–g shows the distribution of injury within the different groups. For the sake of comparison, the 1986 figures have been listed in tables d–f.

Table 4.11.h shows the distribution of injury according to the degree of seriousness in the period 1979 to 1987. The frequency of serious accidents is at 0.06, and 0.78 for the less serious. An injury is defined as serious if it causes the loss of a limb (or parts thereof), lasting injury or if the injury will cause long–term absence from work. The classification has been made on the basis of information given in the injury form, and possible supplementary information.

The figures

Figure 4.11.b shows the distribution of the injury frequency within the four main categories in the period 1984–1987.

4.11.4 Injury summary for exploration drilling and pipelaying operations.

This is the first time that the Directorate has published a summary of occupational accidents on installations involved in exploration drilling or pipelaying. The reporting of injuries is done in the same way as for the production installations. The summary for the exploration activity only comprises the injuries which have occurred when the installations were in a drilling or pipelaying position on the Norwegian continental shelf. The injury rate for the different main activities have not been computed as the Directorate has not had sufficient information about the quantity of work involved.

The tables

Tables 4.11.i and j show the distribution of incidents causing injury within the various position categories in 1987.

Conclusion

The injury rate for all activities in 1987 are about at the same level as in the year before. However, there has been a significant decrease in injuries associated with drilling operations, a development which started in 1985.

The injury rate within the construction and maintenance actitities shows a significant increase compared with 1986. This development is associated with the implementation of a particular amount of construction work leading to the use of mechanical hand tools and movement of the work in 1987. The injuries have particularly affected the eyes, hand/fingers and feet which in all represent 59 % of the total number of injuries.

The injury rates for the years from 1979 to 1987 shows major variations and an average of 60.7. If the figures alone are used as a basis for the evaluation of the development of the safety, there is no improvement when everything is taken into account. In view of the audits which have been undertaken and the considerable efforts which have been made for the establishment of reliable procedures for the reporting of injury and number of hours worked, the Directorate is nevertheless of the opinion that in real terms, there has been a significant improvement of the working environment and safety standard on the production installations.

In spite of the limitations and weaknesses which must be taken into account for such a comprehensive reporting system as described in this instance, the Directorate is of the opinion that the statistical summaries provide a reasonably accurate picture of personal injuries within the petroleum industry on the continental shelf.

Tab 4.11.b
Occupational accidents per 1000 man years, distributed on functions (1979-87). Production installations

FUNCTION		1979	1980	1981	1982	1983	1984	1985	1986	1987
Administration/ production	Man years	1098	1174	1144	1306	1182	1614	1656	1507	2124
	Injuries	25	23	22	21	29	25	23	34	51
	Injuries/1000 man years	22.8	19.6	19.2	16.1	24.5	15.5	13.9	22.6	24.0
Drilling	Man years	1467	1095	1098	1289	1300	1324	1384	1371	1550
	Injuries	186	148	116	137	104	148	130	122	103
	Injuries/1000 man years	126.8	135.2	105.6	106.3	80.0	111.8	93.9	89.0	66.5
Catering	Man years	507	383	411	548	525	681	685	856	1074
	Injuries	18	10	7	22	18	22	32	45	50
	Injuries/1000 man years	35.5	26.1	17.0	40.1	34.3	32.3	46.7	52.6	46.6
Building/ maintenance	Man years	5482	4333	6258	5299	3542	4739	4845	6031	8027
	Injuries	346	270	270	348	183	296	413	404	611
	Injuries/1000 Man years	63.1	62.3	43.1	65.7	51.7	62.5	85.2	67.0	76.1
Total	Man years	8554	6985	8911	8442	6549	8358	8570	9765	12775
	Injuries	575	451	415	528	334	491	598	605	815
	Injuries/1000 Man years	67.2	64.6	46.6	62.5	51.0	58.7	69.8	62.0	63.8

Tab 4.11.c
Occupational injuries among Operator (O) and Contractor (C) employees.

FUNCTION		1985	1986	1987		
Administration/ production	Man years	1575	1293	1569	o	(operator)
		80	213	555	c	(contractor)
	Injuries	19	34	42	o	
		4	0	9	c	
	Injuries/1000 Man years	12.0	26.3	26.8	o	
		49.8	0	16.2	c	
Drilling	Man years	0	0	0	o	(operator)
		1384	1371	1550	c	(contractor)
	Injuries	0	0	0	o	
		130	122	103	c	
	Injuries/1000 Man years	0	0	0	o	
		93.9	89.0	66.5	c	
Catering	Man years	0	39	86	o	(operator)
		685	817	987	c	(contractor)
	Injuries	0	5	5	o	
		32	40	45	c	
	Injuries/1000 Man years	0	129.3	58.1	o	
		46.7	49.0	45.6	c	
Building maintenance	Man years	1544	2063	2246	o	(operator)
		3301	3969	5781	c	(contractor)
	Injuries	61	51	46	o	
		352	353	565	c	
	Injuries/1000 Man years	39.5	24.7	20.5	o	
		106.6	88.9	97.7	c	
Total	Man years	3120	3394	3902	o	(operator)
		5450	6370	8873	c	(contractor)
	Injuries	80	90	94	o	
		518	515	721	c	
	Injuries/1000 Man years	25.6	26.5	24.1	o	
		95.0	80.8	81.3	c	

Occupational accidents 1986-87. Production installations. Injury incident/occupation

Injury incident / Occupation	Admin. stration	Drillfloor worker	Driller	Electrician	Catering	Assistent worker	Instrument tenchnicien	Crane operator	Painter/ Sandblaster	Mechanic/ Motorman	Operator	Plateworker isolator	Pipeworker Plummer	Service-technicien	Scaffolder	Welder	Derrickman	Unspecified	Total	%	Year
Other contact with objects/machinery in motion	3	24	2	9	10	20	2	1	6	6	7	13	3	4	5	0	5	0	120	19.8	86
	1	8	2	7	4	17	2	1	7	7	5	9	5	3	11	7	2	0	98	12.0	87
Fire Explosion etc.	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	86
	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1	0.1	87
Fall to lower level	1	3	0	3	0	17	4	1	6	1	3	4	1	1	2	4	1	1	53	8.8	86
	4	1	0	5	2	6	0	2	3	4	2	3	4	2	4	3	0	0	45	5.5	87
Fall to same level	2	2	1	3	5	8	2	1	6	8	3	5	9	3	7	2	0	2	69	11.4	86
	2	0	0	6	6	12	0	0	6	2	1	5	7	1	15	3	1	2	69	8.5	87
Stepping on uneven surface, mas-step	2	0	1	3	1	9	1	0	3	3	5	5	2	2	3	2	0	0	42	6.9	86
	2	2	1	6	8	10	3	2	9	4	8	6	4	1	15	15	1	1	98	12.0	87
Falling objects	0	3	1	1	1	5	0	0	2	2	1	3	3	1	6	4	0	0	33	5.5	86
	0	0	1	1	0	9	0	0	1	5	0	7	3	1	5	4	1	0	38	4.7	87
Other contact with objects at rest	1	1	0	2	3	4	2	2	9	3	2	6	4	1	6	1	1	0	48	7.9	86
	0	0	0	8	1	11	1	2	5	6	2	8	11	4	10	4	0	0	73	9.0	87
Handling acidents	1	4	0	5	10	12	3	0	8	10	2	6	6	4	5	1	3	0	80	13.2	86
	3	8	0	9	16	23	1	1	4	19	6	14	13	6	14	11	0	0	148	18.2	87
Contact with chemical/ phyaic-compound	0	0	0	1	4	4	0	0	13	1	2	1	1	1	1	1	0	0	30	5.0	86
	1	2	0	1	6	2	3	1	6	2	4	0	3	1	0	4	0	0	36	4.4	87
Overloading of part of body	0	1	0	4	2	7	1	0	5	3	2	1	1	1	4	3	0	1	37	6.1	86
	0	4	1	3	2	10	0	2	1	4	3	3	10	3	15	3	2	0	65	8.0	87
Splinters, splashes	2	2	2	4	2	6	0	0	15	8	2	7	15	0	2	13	0	0	80	13.2	86
	0	0	0	5	2	11	0	0	11	7	1	30	13	0	5	40	0	1	126	15.5	87
Electric current	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	86
	0	0	0	3	0	0	0	0	0	0	0	0	0	0	0	0	0	0	3	0.4	87
Exstreme temperature	0	0	0	0	6	1	0	0	0	0	0	0	1	0	1	3	0	0	12	2.0	86
	1	0	0	0	3	1	0	0	0	0	1	1	0	0	0	4	0	0	11	1.3	87
Fall into sea	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0.2	86
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	87
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	86
	0	0	0	0	1	2	0	0	0	0	1	0	0	0	0	0	0	0	4	0.5	87
Total	12	40	7	35	44	93	15	5	73	46	29	51	46	18	42	34	10	5	605	100	86
	14	25	5	54	51	114	10	11	54	59	34	86	73	22	94	98	7	4	815	100	87
%	2.0	6.6	1.2	5.8	7.3	15.4	2.5	0.8	12.1	7.6	4.8	8.4	7.6	3.0	6.9	5.6	1.7	0.8	100		86
	1.7	3.1	0.6	6.6	6.3	14.0	1.2	1.3	6.6	7.2	4.2	10.6	9.0	2.7	11.5	12.	0.9	0.5	100		87

Tab 4.11.e

Occupational accidents 1986-87. Production installations. Injury incident/Injured part of the body

Injury incident \ Injured part of the body	Eye	Back	Toe/foot	Hip/leg	Stomach/chest	Arm/ shoulder	Head/ face	Tooth	Hand/ finger	Other	Total	%	Year
Other contact with objects/	2	2	11	5	3	9	7	6	75	0	120	19.8	86
machinery in motion	3	0	17	10	2	7	13	6	40	0	98	12.0	87
Fall to	0	0	0	0	0	0	0	0	0	0	0	0.0	86
lower level	0	0	0	0	0	0	1	0	0	0	1	0.1	87
Fire	0	10	7	8	9	4	8	0	7	0	53	8.8	86
Explosion etc.	0	9	3	4	2	10	10	0	3	4	45	5.5	87
Fall to	12	8	16	7	10	5	3	8	0	69	11.4	86	
same level	0	16	8	10	2	8	4	1	20	0	69	8.5	87
Stepping on uneven	0	2	25	9	1	2	0	0	3	0	42	6.9	86
surface, move-step	0	9	66	13	2	3	2	0	3	0	98	12.0	87
Falling	0	0	12	3	0	0	5	1	11	1	33	5.5	86
objects	1	0	11	1	0	3	6	0	16	0	38	4.7	87
Other contact with	1	4	2	6	8	3	10	2	12	0	48	7.9	86
objects at rest	0	4	4	10	7	9	18	8	13	0	73	9.0	87
Handling	6	1	4	5	1	2	2	6	52	1	80	13.2	86
accidents	4	0	7	9	2	3	8	9	106	0	148	18.2	87
Contact with chemic	25	0	0	0	0	0	0	0	0	5	30	5.0	86
physo compound	27	0	0	0	3	0	3	0	0	3	36	4.4	87
Overloading of	0	25	3	0	1	6	0	0	2	0	37	6.1	86
part of body	0	32	4	6	5	11	0	1	6	0	65	8.0	87
Splinters,	71	0	1	1	0	0	6	0	1	0	80	13.2	86
splashes	114	0	0	0	0	2	7	0	2	1	126	15.5	87
Electric	0	0	0	0	0	0	0	0	0	0	0	0.0	86
current	0	0	0	0	0	0	2	0	1	0	3	0.4	87
Exstreme	0	0	4	1	1	2	2	0	2	0	12	2.0	86
temperature	0	0	3	2	1	2	2	0	1	0	11	1.387	
Fall	1	0	0	0	0	0	0	0	0	0	1	0.2	86
into sea	0	0	0	0	0	0	0	0	0	0	0	0.0	87
	0	0	0	0	0	0	0	0	0	0	0	0.0	86
Other	0	0	1	0	0	0	1	2	0	0	4	0.5	87
	106	56	77	54	31	38	45	18	173	7	605	100	86
Total	149	70	124	65	26	58	77	27	211	8	815	100	87
	17.5	9.3	12.7	8.9	5.1	6.3	7.4	3.0	28.6	1.2	100		86
%	18.3	8.6	15.2	8.0	3.2	7.1	9.5	3.3	25.9	1.0	100		87

Tab 4.11.f
Occupationel accidents 1986-87. Production installations. Injury incident/Contributing factor.

Contributing factor \ Injury incident	Chemical/ physio/bio- logical factors	Cold pres- sure/heat ventilation	Materials/ packaging	Electrical equipment	Other machinery	Drill strings	Handtools/ machines/ implements	Loose/fixed fittings on structure	Lifting transp. gear	Other	Total	%	Year
Other contact with objects/ machinery in motion	0 0	0 0	12 20	1 1	18 11	10 6	17 6	41 31	21 23	0 0	120 98	19.9 12.0	86 87
Fall to lower level	0 0	0 0	0 0	0 0	0 0	0 0	0 1	0 0	0 0	0 0	0 1	0.0 0.1	86 87
Fire Explosion etc.	0 0	0 0	4 1	0 0	0 1	0 0	3 0	42 41	4 2	0 0	53 45	8.8 5.5	86 87
Fall to same level	2 0	0 0	2 11	1 0	1 0	0 0	3 2	55 52	4 2	0 2	68 69	11.3 8.5	86 87
Stepping on uneven sur- face, mis-step	0 0	0 0	5 11	0 0	2 0	0 0	1 1	31 86	2 0	1 0	42 98	7.0 12.0	86 87
Falling objects	0 0	0 0	10 19	2 0	2 2	0 0	2 5	15 9	2 3	0 0	33 38	5.5 4.7	86 87
Other contact with objects at rest	1 0	0 1	8 4	1 0	0 2	0 0	1 1	35 61	2 3	0 1	48 73	7.9 9.0	86 87
Handling acidents	1 1	0 0	23 38	1 0	1 6	1 3	46 86	6 9	1 5	0 0	80 148	13.2 18.2	86 87
Contact with chemical/ physio-compound	27 24	0 2	0 0	0 0	0 0	0 0	3 10	0 0	0 0	0 0	30 36	5.0 4.4	86 87
Overloading of part of body	0 0	0 0	15 18	0 1	2 6	0 1	5 9	14 20	0 8	1 2	37 65	6.1 8.0	86 87
Splinters, splashes	10 5	2 1	18 21	0 1	3 0	0 0	37 93	3 0	0 0	7 5	80 126	13.2 15.5	86 87
Electric current	0 0	0 0	0 0	0 3	0 0	0 0	0 0	0 0	0 0	0 0	0 3	0.0 0.4	86 87
Extreme temperature	1 0	0 1	10 7	0 0	0 0	0 0	0 3	1 0	0 0	0 0	12 11	2.0 1.3	86 87
Fall into sea	0 0	0 0	0 0	0 0	0 0	0 0	0 0	1 0	0 0	0 0	1 0	0.2 0.0	86 87
Other	0 0	0 0	0 2	0 0	0 0	0 0	0 0	0 0	0 0	0 2	0 4	0.0 0.5	86 87
Total	42 30	2 5	107 152	6 6	29 28	11 10	118 217	244 309	36 46	9 12	604 815	100 100	86 87
%	7.0 3.7	0.3 0.6	17.7 18.7	1.0 0.7	4.8 3.4	1.8 1.2	19.5 26.6	40.4 37.9	6.0 5.6	1.5 1.5	100 100		86 87

Occupational accidents 1979-87. Production installations. Injury incident/Occupation.

Injury incident \ Occupation	Admini-stration	Drillfloor worker	Driller	Electrician	Catering	Assistent worker	Instrument technician	Crane operator	Painter/ Sandblaster	Mechanic/ Motormen	Operator	Plateworker insulator	Pipeworker plumber	Services technician	Scaffolder	Welder	Derrrickman	Unspesified		
Other contact with objects/machinery in motion	22	186	17	38	34	228	15	10	26	63	22	45	45	30	53	25	69	1	929	19.3
Fall to lower level	0	0	0	2	0	5	0	0	1	2	0	1	2	0	0	1	0	0	14	0.3
Fire Explosion etc.	15	20	9	32	6	77	15	6	30	32	13	22	31	15	24	29	17	1	394	8.2
Fall to same level	19	17	3	42	29	79	13	7	32	30	23	34	55	19	53	32	9	9	505	10.5
Stepping on uneven surface, mis-step	17	11	2	45	19	63	13	8	29	19	21	20	37	13	36	44	10	3	410	8.5
Falling objects	7	18	7	6	2	44	3	1	6	18	2	26	26	13	29	14	5	0	227	4.7
Other contact with objects at rest	7	13	2	29	19	45	15	4	33	27	9	48	34	12	38	20	6	2	363	7.5
Handling accident	7	54	6	45	54	120	17	6	29	89	22	59	80	22	48	54	20	0	732	15.2
Contact with chemical/ physio-compound	2	10	0	10	22	40	8	2	71	13	15	9	21	14	6	16	5	0	264	5.5
Overloading of part of body	5	30	5	30	12	76	2	6	22	28	14	17	45	11	44	18	14	1	380	7.9
Splinters splashes	7	8	4	15	4	40	2	1	43	29	9	62	76	6	11	123	2	1	443	9.2
Electrical current	0	1	0	23	0	1	1	1	0	1	0	2	0	0	0	0	0	0	30	0.6
Extreme temperature	1	0	0	2	20	5	1	0	0	4	4	6	5	1	1	13	0	0	63	1.3
Fall into sea	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0.0
Other	4	3	0	5	3	11	1	2	3	4	3	5	6	0	1	3	0	0	54	1.1
Total	113	371	55	324	224	834	106	54	325	359	157	356	463	156	344	392	157	19	4809	100
%	2.3	7.7	1.1	6.7	4.7	17.3	2.2	1.1	6.8	7.5	3.3	7.4	9.6	3.2	7.2	8.2	3.3	0.4	100	

Tab 4.11.h
Distribution of injuries after degree of severity. Production installations.

	1979	1980	1981	1982	1983	1984	1985	1986	1987	TOTAL
Serious	0.13	0.07	0.04	0.09	0.04	0.05	0.03	0.04	0.04	0.06
Minor	0.63	0.69	0.69	0.68	0.70	0.70	0.86	0.92	0.93	0.78
Unspec.	0.24	0.24	0.27	0.22	0.26	0.24	0.10	0.04	0.03	0.16
Fatal	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00	0.00
Total	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00	1.00

Tab 4.11.i
Accidents at work 1987 in connection with exploration drilling. Injury incident/Occupation

Injury incident \ Occupation	Admini-stration	Drillfloor worker	Driller	Electricien	Catering	Assistent worker	Crane Operator	Mechanic/ Motorman	Operator	Plateworker/ instructor	Services/ mechanics	Scafloder	Total
Other contact with objects/machinery in motion	0	17	5	0	2	10	1	0	3	0	5	43	33.7
Fire Explosion etc.	0	0	0	0	0	0	0	0	0	1	0	1	0.1
Fall to lower level	0	0	0	0	0	4	0	1	1	0	3	9	7.1
Fall to same level	1	2	0	2	1	2	1	0	0	0	0	9	7.1
Stepping on uneven surface, mis-step	1	3	0	0	0	1	0	1	0	0	1	7	5.5
Falling objects	0	4	2	0	0	4	0	1	0	0	1	12	9.4
Other contact with objects at rest	0	0	0	2	0	0	0	1	0	0	0	3	2.4
Handling incident	1	15	2	0	1	4	0	0	2	3	1	29	22.7
Contact with chemical physio comp.	0	0	0	0	1	0	0	0	0	0	1	2	1.6
Overloading of part of body	0	0	0	0	0	3	0	1	0	0	0	4	3.1
Splinters, splashes	0	0	1	0	0	2	1	3	0	1	1	9	7.1
Total	3	41	10	4	5	30	3	8	6	5	13	128	100
%	2.3	32.1	7.8	3.1	3.9	23.4	2.3	6.3	4.7	3.9	10.2	100	

5. Petroleum Economy

5.1 Exploration drilling, supply of goods and services
Since 1966 exploratory drilling has risen relatively evenly up to 1985, in which year in all 50 new exploratory wells were begun. Activity in 1987 was at the same level as in 1986, with in all 36 holes. Total costs, however, fell from 1986 to 1987. Reduced hire rates on the rig market were an important reason for the costs reduction.

In Figure 5.1.a the value of the market is shown in 1987 kroner. In this year total exploration costs were nearly NOK 5 billion.

The table below shows the 1987 costs divided by main groups of goods and services used in exploration. The numerical material is based on data reported by the operator companies, and costs are in millions of kroner.

– Drilling vessels	881
– Transport	273
– Goods	605
– Services	1,043
– General surveys	467
– Field evaluations	1,028
– Administration	662
Total	4,959

Fig 5.1.a
Yearly exploration drilling costs in fixed 1987 kroner.

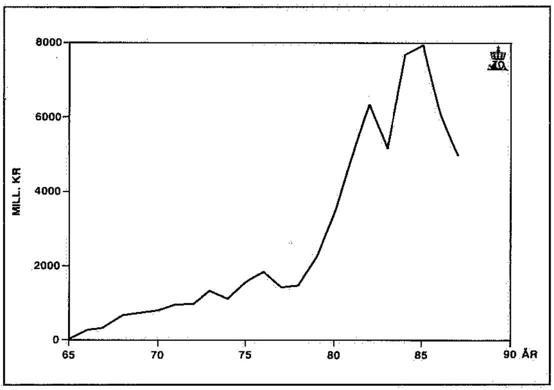


Fig 5.1.b
Exploration expenditure oil and gas 1987.

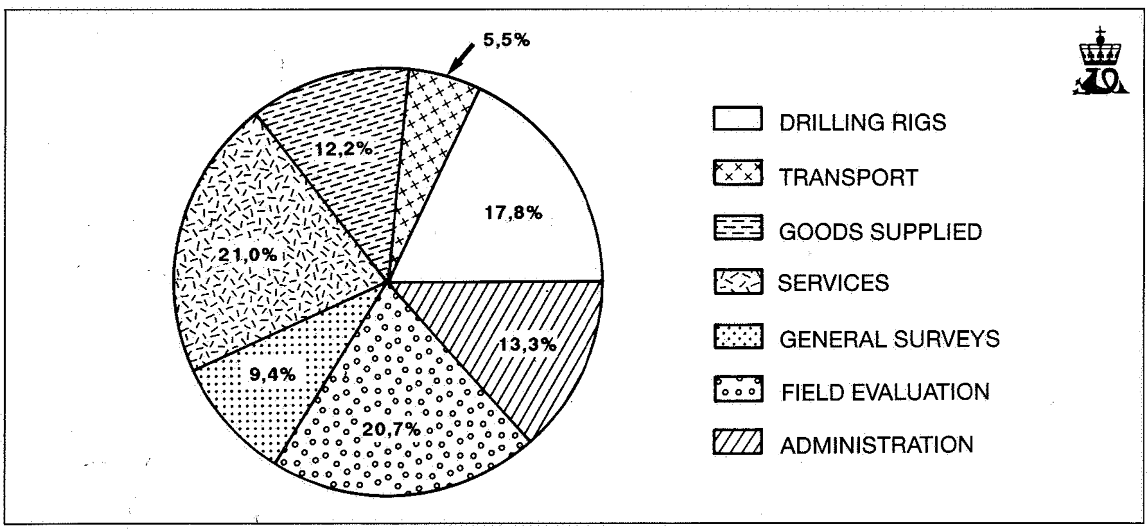


Fig 5.1.c
Number of wells and average costs per well.

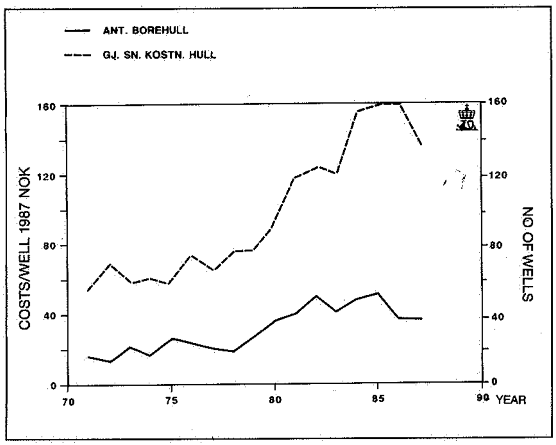


Figure 5.1.b shows the costs of exploration for oil and gas in 1987 divided by goods and services groups.

Figure 5.1.c shows a nearly continuous rise in average costs per well up to 1986. Average costs per well were, however, lower in 1987 than in 1986. Calculation of average costs takes account of costs of general surveys, administration and field development studies. If we look at exploration costs in isolation, that is, the sum of the items drilling vessels, transport, goods and services (NOK 2,802 million), the average costs per well would be about NOK 78 million.

5.2 Costs connected with development and operation on the Norwegian continental shelf

The Norwegian Petroleum Directorate has calculated the annual costs associated with development of fields, including production drilling, for the period 1970–87. The cost figures apply to fields in production, fields under development and fields for which there are approved development plans as of 31 December 1987. The figures are based on the operators' reports.

For fields on both sides of the sector line between Norway and Great Britain, only the Norwegian share is included. The following fields and transport systems are included in the calculation:

- Ekofisk (including 7 fields)
- Valhall
- Heimdal
- Ula
- Frigg
- North–east Frigg
- Odin
- Statfjord (84.09 %)
- Murchison (22.2 %)
- Gullfaks
- Norpipe
- Statpipe
- Ula Pipeline
- East Frigg
- Gyda
- Tommeliten
- Sleipner East
- Troll Phase 1
- Troll Module
- Oseberg
- Veslefrikk
- Oseberg Transport System
- Zeepipe
- Troll/Sleipner Transport System

All figures are recalculated in 1987 kroner.

Past and approved investments for field development, production drilling and transport plant for petroleum can be seen from Figure 5.2.a. Investments increased steadily until 1976, when they amounted to about NOK 21.3 billion in 1987 values. The decline in investment in subsequent years was replaced by a new rise from 1981 on, and in 1987 investments on the Norwegian shelf totalled NOK (1987) 24.5 billion.

The figure also shows that if no further field developments are approved, investment will oscillate around a falling trend in the years to come and dip as low as about NOK (1987) 2 billion per year as early as 1996.

Several fields are, however, awaiting development decisions, and the probability of new fields being discovered is high. The investment level may be considerably higher in the 1990s than it is today, and under no circumstances is likely to fall below NOK (1987) 10 billion per year before the end of the 1990s.

In 1987 the Norwegian Petroleum Directorate reported on a number of questions in connection with the so–called "field queue" debate, cf the Directorate's perspective analysis for 1987.

Figure 5.2.b shows two investment paths that can be realised if all the fields that were part of the field queue debate in 1987 are developed at once. The

Fig 5.2.a
Historical and expected investment for fields decided to be developed.

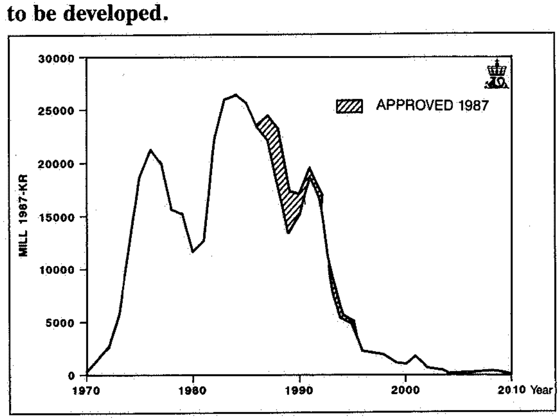
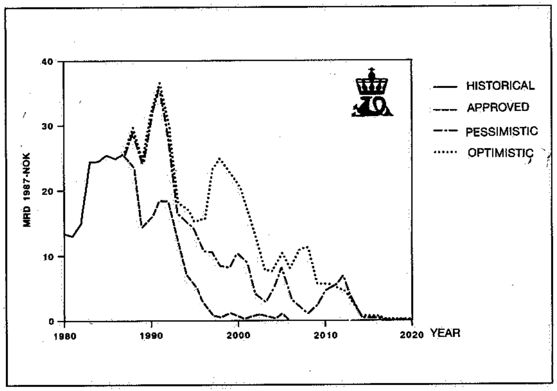


Fig 5.2.b
Course of investment – No investment ceiling 1987 - 2020.



upper path rests on relatively optimistic assumptions as to number and quality of finds and gas sales opportunities. The lower path rests on relatively pessimistic estimates for the same variables.

It is apparent from Figure 5.2.b that early development will result in a very high investment peak early in the 1990s, in the best case (on the NPD's assumptions) a decline from a level of about NOK (1987) billion per year from the year 2000 on, and in the worse case a fall to below NOK (1987) 10 billion per year as early as the mid–nineties. Early development will therefore make it difficult to maintain a reasonably high activity level on the shelf far into the future, even if we meet with favourable developments in oil discoveries and gas marketing.

Figure 5.2.c shows two investment paths that can be realised if an investment ceiling of NOK (1987) 25 billion per year is introduced. The assumptions for the upper and lower paths are identical with those for the upper and lower paths in Figure 5.2.b respectively.

It is apparent from Figure 5.2.c that introduction of an investment ceiling will result in steadier investment activity through the 1990s, give us more time to make new finds and at all events postpone the fall

Fig 5.2.c
Course of investment – Investment Ceiling NOK 25 billion 1987 - 2020.

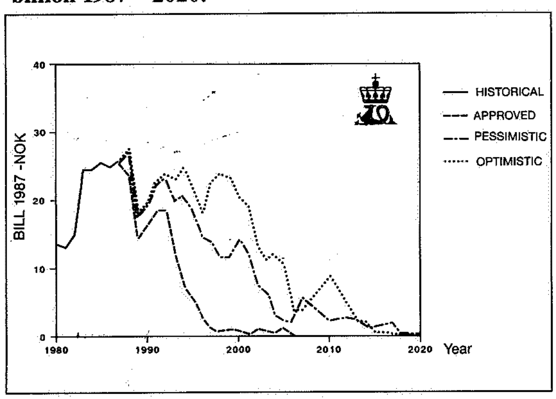
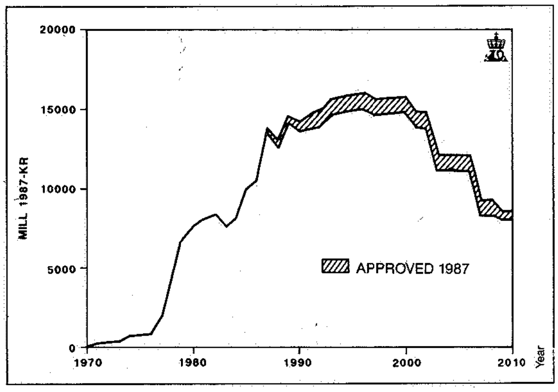


Fig 5.2.d
Historical and expencted operating costs for fields decided to be developed.



in investment opportunities to below NOK (1987) 10 million per year.

Annual operating costs, including pipelines, can be seen from Figure 5.2.d. The level of demand for goods and services for operational purposes has risen steadily, and will continue to rise as more fields come into production. Operating costs will thereby be ever more important to take account of in assessments of the effects of growth in the petroleum sector on the rest of the Norwegian economy.

5.3 Royalties

Royalties are calculated according to the provisions of the Petroleum Activities Act. The calculation base for royalty is the value of the produced petroleum quantities at the outshipment point of the individual production area.

The Norwegian Petroleum Directorate is responsible for collection of royalties.

Interpretation and practice of the applicable acts and regulations for calculation of royalties involve legal, financial, process technological and measurement problems.

The first provisions for royalty were promulgated in Royal Decree of 9 April 1965. Of the fields in production today, the production licences for the Ekofisk fields, Frigg, N.E. Frigg, Odin, Valhall, Ula and Heimdal were allocated under these provisions.

Royal Decree of 8 December 1972 later replaced the Decree of 9 April 1965. Of fields in production, the production licences for Statfjord, Murchison, Gullfaks and Oseberg (test production) were allocated under the 1972 Decree.

The Petroleum Activities Act with Regulations came into force on 1 July 1985 and replaces the above–mentioned Decrees. The Act applies to all previously allocated licences, but with certain transitional provisions for the fields whose licences were issued under the older system.

Tab 5.3.1
Rovalties in 1986 and 1987 in mill. NOK

		1986	1987
OIL	EKOFISK/VALHALL/ULA	1002.8	1190.8
"	STATFJORD	4827.1	4832.6
"	MURCHISON	86.7	14.5
"	HEIMDAL	9.9	-12.1
"	OSEBERG	0.0	33.0
"	GULLFAKS	0.0	82.5
GAS	EKOFISK	831.2	513.0
"	VALHALL	27.5	9.6
"	ULA	0.0	0.0
"	STATFJORD	0.0	0.0
"	MURCHISON	4.1	0.0
"	FRIGG	1048.2	673.6
"	NØ-FRIGG	53.0	57.8
"	ODIN	136.6	50.0
"	HEIMDAL	30.3	27.6
"	GULLFAKS	0.0	0.0
NGL	EKOFISK	74.0	32.3
"	VALHALL	7.7	5.1
"	ULA	0.0	0.0
"	STATFJORD	18.9	7.1
"	GULLFAKS	0.0	0.0
LPG/NGL MURCH.		4.9	-0.3
KOND. FRIGG-AREA.		7.2	3.6
NGL HEIMDAL		0.0	0.2
		8170.2	7521.1

Tab 5.3.2
Royalties on oil

Area/Field	4.QU.1986	1.QU.1987	2.QU.1987
Ekofisk,Ula and Valhall	246 835 518	293 602 228	245 840 385
Statfjord	916 461 845	934 777 960	1 153 782 782
Murchison	7 485 469	375 981	8 688 745
Heimdal	4 363 424	4 726 298	30 862 125
Oseberg	14 014 018	12 467 424	12 494 040
Gullfaks	0	30 799 700	73 548 882
Total	1 189 160 274	1 275 997 629	1 463 492 709

Tab 5.3.2
Royalties on oil

Area/Field	3.QU.1987	* 4.QU.1987	** SDØE	SUM
Ekofisk,Ula and Valhall	218 712 940	185 798 836		1 190 789 907
Statfjord 1	079 622 088	747 948 938		4 832 593 613
Murchison	-709 270	-543 107		14 545 856
Heimdal ***	2 610 531	2 916 216	4 133 692	-12 111 964
Oseberg	10 854 756	1 635 135	-18 415 656	33 049 717
Gullfaks	104 972 927	96 280 215	-223 089 258	82 512 466
Total	1 416 063 972	1 034 036 233	-237 371 222	6 141 379 595

* Excluding December 1987

** Correction for royality not paid on direct State financial involvement. The Ministry of Petroleum and Energy decided in December 1987 that royalty is not to be calculated on the State share.

*** Refundable transport costs for the State's royalty oil exceeds the gross value of the oil.

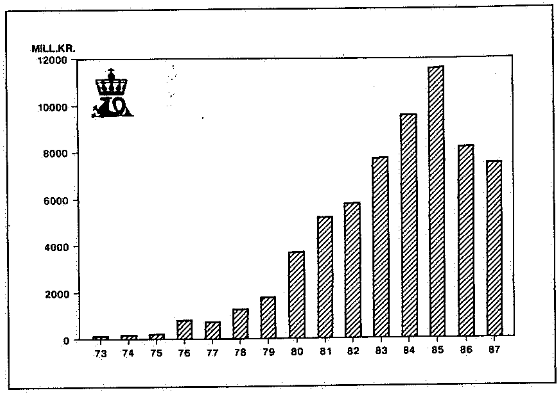
A number of companies allocated production licences under the 1965 Decree have now brought suit against the State, demanding that the rules of the 1965 Decree on calculation point be used as the basis for their payment of royalties, and claiming that the "production site" given as the calculation point in the 1965 Decree must be interpreted as being the wellhead. The Petroleum Act gives the outshipment point of the production area as the calculation point, and for most fields this will mean greater royalty payments than if the wellhead were used.

In Odelsting Proposition No. 64 (1986–87), a Bill to Amend the Petroleum Act, it is proposed that royalty not be paid on petroleum produced from accumulations whose development plan was approved after 1 January 1986.

If the proposed amendment is approved, future collection of royalty will be limited to the fields in production before now and also East Frigg (planned production start October 1988).

On 23 December 1987 the Ministry of Petroleum and Energy decided that royalty is not to be calculated on the state's direct financial involvement. This is relevant to the fields Gullfaks, Heimdal, Oseberg and East Frigg.

Fig 5.3.1.a
Royalties 1973 - 1987.



5.3.1 Total royalties.
In 1987 NOK 7,521,094,614 was paid in royalties, see Table 5.3.1.
Figure 5.3.1.a shows paid royalties 1973–1987.

5.3.2 Royalties on oil.
In 1987 the Norwegian Petroleum Directorate received NOK 6,141,379,595 in royalties on oil from Murchison, Ekofisk, Valhall, Ula, Statfjord, Heimdal, Oseberg and Gullfaks, see Table 5.3.2.

Tab 5.3.3.
Royalties on gas production

	4. qu.1986	1. qu.1987	2. qu.1987	3. qu.1987	Total
EKOFISK-AREA					
Phillipsgr.	131164208*	143695623	130551527	101376396**	506787754
Dyno/Methanor	-692474	-1135136	-342762	-989555	-3159927
Shell (Albuskjell)	2760556	61593	1333102	942845	5098096
Amoco/Noco-gr. (Tor)	2279003	1203579	820310	0	4302892
Total Ekofisk	135511293	143825659	132362177	101329686	513028815
FRIGG-AREA					
Petronord-gr. (Frigg)	203844538	243187007	127483707	98786879	673567966
Petronord-gr. (NØF)	13025869	13934780	6527468	4341209	37829326
Petronord-gr. (Odin)	2520180	2407343	2509925	1501378	8938826
Total Petronord-gr.	219390587	259529130	136521100	104895301	720336118
Esso NEF	6707936	8619211	3419963	1233914	19981024
Esso Odin	15210073	10668517	12755638	2445585	41079813
Total Frigg-area	241308596	278816858	152696701	108574800	781396955
VALHALL					
Amoco/Noco-gr.	3757053	3306621	2539314	0	9602988
MURCHISON					
Statoil/Mobil-gr.	37381	0	0	0	37381
HEIMDAL					
Heimdal-gr.-	9532723	8204948	6947893	2900611	27586175
STATFJORD					
Statoil/Mobil-gr.-	0	0	0	0	0
ULA					
BP a.o.	0	0	0	0	0
GULLFAKS					
Statoil,Saga,Hydro			6	0	0
Total all fields	390147046	434154086	294546085	212805097	1331652314

* Excluding advanced payment in 3.qu. NOK 62 360 000
** Including advanced payment for 4.qu. NOK 41 360 000

Royalty for oil was taken in the form of oil. Sale of the State's royalties oil is conducted by Statoil. From 1987 payment from Statoil to the Norwegian Petroleum Directorate is monthly, as opposed to quarterly before. Calculation is on the basis partly of norm prices fixed by the Petroleum Price Council and partly of calculation prices laid down by the Ministry of Petroleum and Energy (Gullfaks and Oseberg).

Paid royalty for oil in 1986 included the third quarter of 1985 to the third quarter of 1986, whereas paid royalty for oil in 1987 included the fourth quarter of 1986 to the fourth quarter of 1987 inclusive (except December, which is due in January 1988).

5.3.3 Royalties on gas.
In 1987 the Norwegian Petroleum Directorate received NOK 1,331,652,314 in royalty on gas. Table 5.3.3 shows payment by quarter and company/group. On Ula, Statfjord and Gullfaks no royalty on gas was paid. This is due to deductions for transport costs, which in all quarters is greater than gross royalty.

Calculation for gas has been undertaken on the basis of the contract price, which varies from group to group.

Deliveries of gas from Dyno/Methanor ceased from 1 July 1984. Sums refunded to Dyno/Methanor are related to transport and treatment of already received and paid gas.

5.3.4 Royalties on NGL.
In 1987 NOK 48,062,705 was paid in royalties for NGL. Table 5.3.4 shows the payment of royalties divided quarterly by company/group. The reason for there being no payments for certain fields in one or more quarters is that the transport deductions are larger than the gross royalty.

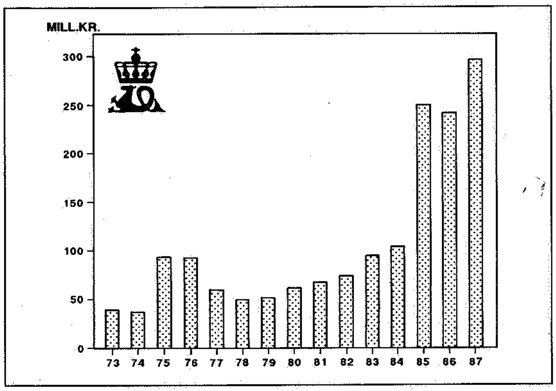
5.4 Acreage fee on production licences.
In 1987 the Norwegian Petroleum Directorate has collected NOK 297,795,036 in acreage fees. The sum is divided between production licences as follows:

Production licences issued in 1965:	NOK 111,111,315
Production licences issued in 1969:	NOK 56,805,000
Production licences issued in 1971:	NOK 5,502,000
Production licences issued in 1973:	NOK 15,769,600
Production licences issued in 1975:	NOK 26,667,746
Production licences issued in 1976:	NOK 22,054,429
Production licences issued in 1977:	NOK 3,750,908
Production licences issued in 1978:	NOK 5,998,473
Production licences issued in 1979:	NOK 18,795,520
Production licences issued in 1980:	NOK 621,748
Production licences issued in 1981:	NOK 9,259,747
Production licences issued in 1987:	NOK 21,458,550
	NOK 297,795,036

Tabell 5.3.4.
Royalties on NGL production

	4. qu.1986	1. qu.1987	2. qu.1987	3. qu.1987	Total
EKOFISK-AREA					
Phillips-gr.	13093769	6663843	9082561	2826397	31666570
Shell (Albuskjell)	0	0	34572	279524	314096
Amoco/Noco-gr. (Tor)	172506	127805	7537	6856	314704
Total Ekofisk	13266275	6791648	9124670	3112777	32295370
FRIGG-AREA					
Petronord-gr.	651073	1003869	671478	431211	2491796
Esso	768	656784	213454	231438	1102444
Total Frigg-area	651841	1660653	884932	396814	3594240
VALHALL					
Amoco/Noco-gr.	2261871	1665584	1206040	8733	7688019
MURCHISON					
Statoil/Mobil-gr.	66504	5611	23413	-394088	-298560
STATFJORD					
I Statoil/Mobil-gr.	6535551	531276	29951	0	7096778
HEIMDAL					
Elf a.o.	42257	97085	43207	50100	232649
ULA					
BP a.o.	0	0	0	0	0
GULLFAKS					
Statoil,Saga,Hydro				0	0
Total all fields	22824299	10751857	11312213	3174336	50608496

Fig 5.4
Acreage fees 1973 - 1987.



The Norwegian Petroleum Directorate has refunded NOK 54,753,865 in acreage fees as of 1 November 1987. This represents the tax–deductible part of the acreage fee in the royalty settlement for Production Licences 006, 018, 019a, 033, 037, 050 and 053 in the period 1 November 1986 to 1 November 1987.

For individual production licences the acreage fee will be deducted direct in the royalty settlement. This sum is not included in the NOK 54,753,865. Figure 5.4 shows paid acreage fee, 1973–87.

5.5. The petroleum market.

5.5.1 The crude oil market.

The price of oil in American dollars swung comparatively little in 1987, see Figure 5.5.1.a. In this way the 1987 price development was very different from 1986, when OPEC and market forces between them brought the price of oil from Brent in the North Sea down from 26 dollars the barrel in the beginning of January to about 9 dollars the barrel at the end of July. A combination of official prices within OPEC and quota regulation of production would seem to take the credit for the price statistics of 1987.

The price fall in 1986 was triggered by Saudi Arabia's decision of autumn 1985 to go over from pricing its oil in line with OPEC's day–to–day official prices, to pricing it in accordance with oil product prices applicable at any given time. In the autumn of 1986 OPEC decided to stop the new system and go back to official prices.

In December 1986 OPEC decided to resume quota regulation of its members' production. The production ceiling was to be 15.8 million barrels per day through the first half of 1987, 16.6 million in the third quarter and 18.3 million in the fourth quarter. Regulation was supposed to make it possible to introduce an official reference price of 18 dollars the barrel on 1 February.

It took a while for the market to believe in OPEC's will and ability to carry through its price stabilisation programme. Many predicted that the price rise round the end of the year would lead to the collapse of the organisation's solidarity and lead to exceeding of quotas and price falls. The oil companies were sitting on large stocks and could wait for the new official prices before signing contracts. Prices sank relatively fast in February, but there were no reports of significant overproduction among the OPEC members, and the market picked up again and went into a relatively stable period.

Over the summer the prices rose. The oil companies had run their stocks down, and at the beginning of June were sitting on less oil than at any time since early in the 1970s. Demand for OPEC oil, especially in the USA, rose sharply. This increased demand overshadowed the fact that some OPEC countries were now overproducing in relation to their quotas.

In the beginning of July OPEC held its biannual conference. The participants found that there was no basis for raising the production ceiling to 18.3 million barrels per day on 1 October, and decided to let the 16.6 million barrel limit run through the rest of the year. This was well received by the market; OPEC's declared goals and methods were considered realistic, the fear of collapse of solidarity abated and prices rose. After the OPEC meeting Brent Blend was sold for over 20 dollars the barrel.

Early in the autumn various forces made themselves felt in the market. The level of tension in and

Fig 5.5.1.a
Spot market price for Brent oil in 1987.

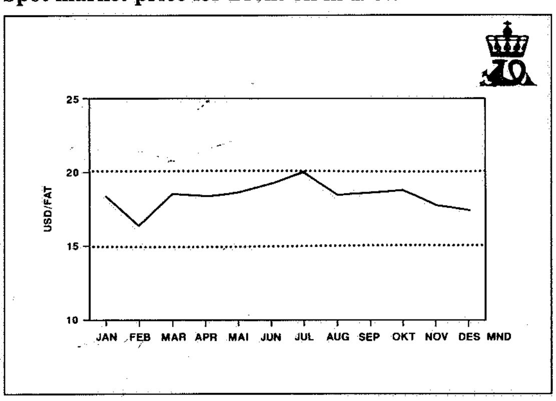
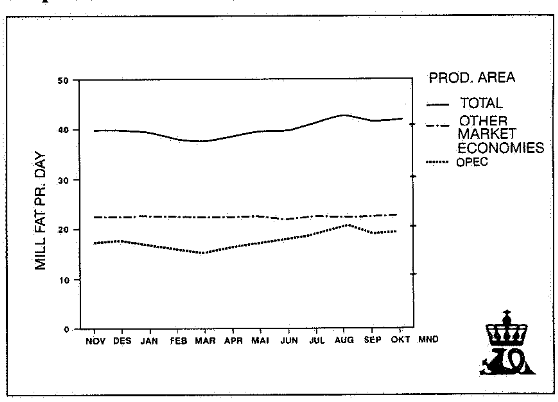


Fig 5.5.1.b
Oil production November 1986 - October 1987.



around the Persian Gulf rose, leading to rapid stockpiling and pushing prices up. On the other hand, product prices had not risen together with crude, and the refineries had to operate with smaller profit margins. At the same time there arose rumours (later confirmed, see Figure 5.5.1.b) of rising overproduction within OPEC. These factors affected prices negatively.

The market reaction to new attacks on tankers in the Gulf became, however, steadily weaker, and the effects of supply and demand development on prices became correspondingly stronger over the autumn. In some parts of September the OPEC countries were producing more than 20 million barrels a day. Stockpiling continued, now more with a view to the winter season than of fear of cessation of Middle Eastern supplies. This kept prices up. But the feeling that OPEC would have great problems defending the reference price of 18 dollars the barrel spread.

At the end of October many thought that the war was on the way into a new phase. At the same time the OPEC countries' production sank somewhat, and prices rose a little. The upswing was, however, not of long duration. The world outside the state economies had increased its oil stocks by on average about 2.4 million barrels per day in the third quarter, and the market seemed to be standing before a veritable deluge of oil. In this situation USA's boycott of oil from Iran was effective.

In December OPEC's oil ministers met to determine a reference price and a production ceiling for the first half of 1988. The members had discussed whether they ought to raise the reference price to for example 20 dollars the barrel and keep the production ceiling down, or keep the 18 dollar price and instead permit a somewhat higher production, but developments in the market before the meeting indicated that neither was defensible. The result of the meeting was an extension of the agreement of July 1987. The market was nervous, and Brent Blend went under 16 dollars a barrel for a couple of days in September.

We cannot reckon on any stable oil price development over the next few years. The gap between OPEC's production capacity and sales potential means that the organisation's production behaviour, that is, the member states' choice of degree of capacity utilisation, will be the decisive driving force in the market for a long time yet. Economic and political tensions in OPEC generally and between the Middle East producers in particular makes the pattern of behaviour difficult to predict.

Growth in oil production in the rest of the world, and the growth of oil demand, will affect price developments in the years to come.

Overall, production in the rest of the world changed little between 1986 and 1987. According to provisional estimates the non–OPEC and non–state–economy world produced on average 22.5 million barrels a day, and the state–economy countries on average 15.5 million barrels per day, that is, together on average 38.0 million barrels. Corresponding figures for 1986 are 22.7, 15.4 and 38.1 million barrels per day respectively. On a country basis, however, there were changes. American and British production went down by 4.6 and 3.0 per cent respectively, while the Soviet Union's, Mexico's and Norway's increased by 1.5, 4.5 and 16.0 per cent respectively.

In the short run oil production in the non–OPEC world is probably not very sensitive to fluctuations in the price of oil. The 1986 price fall led to shutting–down of some production in especially high–cost areas, but had less effect than expected. Any new price collapses need not have more serious short–term consequences for production in the rest of the world. The oil companies will probably continue to exploit the bulk of their existing capacity at full blast, almost irrespective of what happens to prices.

There is therefore a narrower band of production development prognoses than price development prognoses for 1988. The oil price prognoses were just as divergent at the end of 1987 as the beginning.

The 1986 price fall had clear consequences for the level of exploration and development activity in several of the world's oil provinces. In USA, where there is a number of small oil companies operating with high costs, the number of drilling rigs in operation sank by 62 per cent between December 1985 and October 1986. Thirty oil companies, together sitting on about two–thirds of USA's proven recoverable oil reserves, reported a decline in their reserves of five per cent in 1986. The level of activity picked up again in the second half of 1987, but no more than that the number of rigs in operation was 40 per cent lower at the end of 1987 than at the end of 1985.

As regards Western Europe, the number of drilling rigs in operation sank 44 per cent between the end of 1985 and the end of 1986. Here, too, there was an upswing in the summer of 1987, and in October the number lay 35 per cent over the peak reached at the end of 1985.

At the end of 1987 the estimates of the world's total proven recoverable reserves were adjusted, from under 700 billion barrels to 887 billion. The upward adjustment of as much as 27 per cent is first and foremost due to several countries reporting new estimates based on new surveys for their respective reserves. All these countries are OPEC countries. The reserves estimates are uncertain, and the OPEC countries' new figures may be set too high because of expectations that future production quotas will be based on the member countries' reserves. It is, however, clear that the countries round the Persian Gulf have oil for many more years' production at present levels than any other oil–producing country, so that in the longer term OPEC looks like dominating the market once more.

5.5.2 The gas market.

The gas trade demands a comprehensive and costly infrastructure. There is therefore no integrated world market for gas, only a number of regional markets. The European market is characterised by a few major actors, and a few, large and long–term contracts, and the almost complete lack of sales oppportunities besides these contracts.

After many years of high growth, Western Europe's gas consumption went into a stagnant phase in 1980, see Figure 5.5.2.a. The change is due largely to the oil price jump of 1979–80: declining growth in the world economy on the one hand, and energy conservation on the other, resulted in a decline of consumption. Price developments led in turn to substitution away from hydrocarbons in general.

European gas consumption picked up again from 196.5 x 10^9 Sm^3 in 1983 to 216.3 x 10^9 Sm^3 in 1986. The international economic reverse was succeeded by a new boom, and price developments made gas more competitive in certain markets. Whether the upswing would continue would not be clear until the Spring of 1988.

Prognoses for growth in Western European gas consumption diverge. Many believe that the gas industry will not succeeed in increasing its share of the West European energy market to any degree from today's level of about 15.5 per cent, and that this market will grow by only one per cent or so up to the year 2000, so that Western Europe will will demand 255–260 x 10^9 Sm^3 in 2000.

In the autumn of 1987, however, two well–known consultant groups produced studies that wound up with expectations of a market of almost 300 billion Sm. around the year 2000.

In the summer of 1987 Statoil signed an agreement with Austria for the supply of about 1 x 10^9 Sm^3 gas from Troll. Statoil was also successful in its

Fig 5.5.2.a
Western European gas consumption 1974 - 1986.

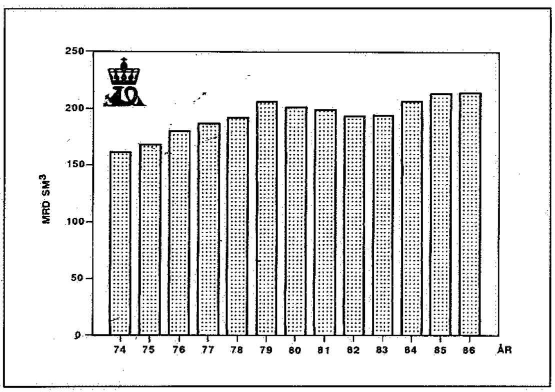
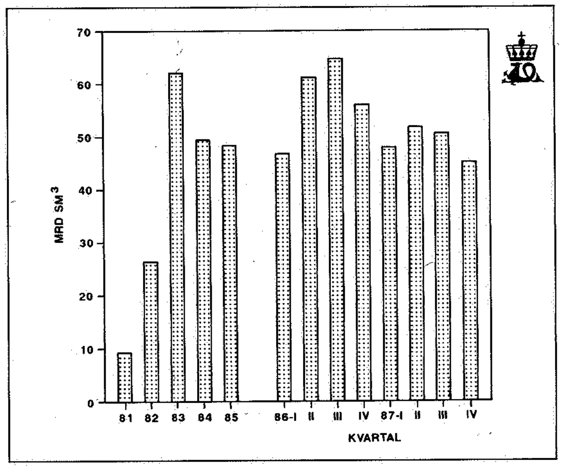


Fig 5.5.2.b
Gas surplus in the US. Average figures 1981-85. Real figures 1986-87.



negotiations with Spain for supplies of about 1 x 10^9 Sm^3 per year from 1996. Marketing vis–à–vis Italy has not so far produced any contracts.

Norway's gas deliveries to Great Britain will, under existing contracts, come to an end in a few years, and throughout 1987 it was unclear whether the British wanted a new agreement running already from the early 1990s, or whether they were going to wait. The British Gas Corporation has signalled interest in a contract, but certain oil companies claim that there is enough gas under the British shelf for many years' production, and that a new import agrement will hinder the exploitation of these resources.

There is great interest at the moment in the growth potential of the Scandinavian market. The discussion of Norway's future gas needs was in 1987 linked primarily to the questions of how much power we will need in the coming years and where the first gas power station(s) should be sited. Both Western, Central and Eastern Norway are likely areas for gas power station development. Choice of time and place for the first development will among other things affect the potential for development of Haltenbanken.

The Swedish gas market is still small, but is thought to have considerable growth potential. A decisive factor for the rate of growth will be if and when the run–down of nuclear power begins.

Norway wants future deliveries of Norwegian gas to both Sweden and Denmark. Late in 1987, however, we were reminded that competition for the Swedish market will be hard. There is now an intention agreement between Sweden and the Soviet Union for supply of about 0.5 x 10^9 Sm^3 Soviet gas per year. The gas is to be transported via Germany and Denmark, but if larger volumes are later in question, there is a possibility of laying pipelines under the Baltic.

The potential for development of the gas fields off North Norway has been coupled to the possibility of LNG deliveries to the American market. As far as we can see, this will not materialise until around the year 2000. The American market is a large one, but since 1981 has suffered from excess supply, see Figure 5.5.2.b. Conditions are unlikely to change in the near future. American energy authorities reckon, however, that the USA – which in 1986 imported 21.5 x 10^9 Sm^3 gas – will around the end of the century have to purchase between 60 and 100 x 10^9 Sm^3 from abroad. Since Canada and Mexico will scarcely be able to meet all of this demand, increased import of LNG will be a prospect.

5.5.3 Sale of petroleum from the Norwegian continental shelf.

In 1987 46.21 x 10^6 tons crude oil were sold from the Norwegian continental shelf. This represents an increase of 16.3 per cent in relation to 1986. Last year as in 1986 Great Britain was the largest recipient, with 29.6 per cent of the shipments. The Netherlands took 19.9 per cent and Norway 18.5 per cent.

Figure 5.5.3.a shows sales of crude oil divided by countries in the period 1981–87.

Fig 5.5.3.a
Sale of crude oil from the Norwegian Continental Shelf.

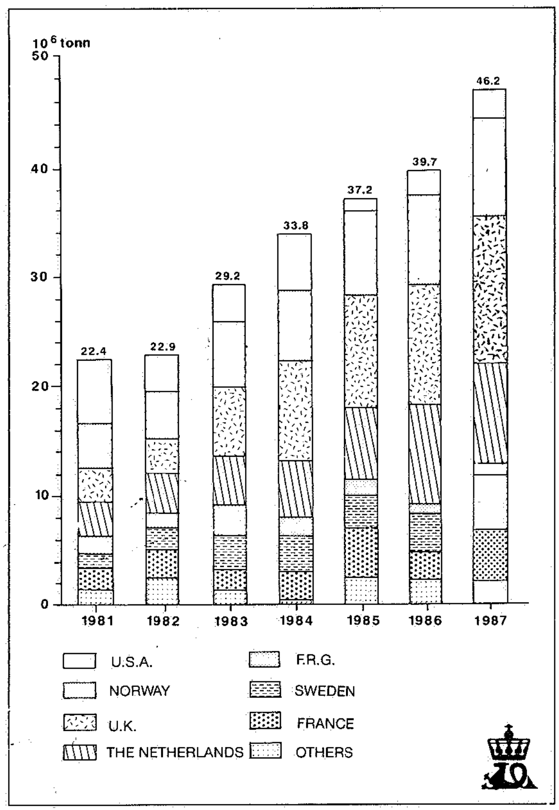
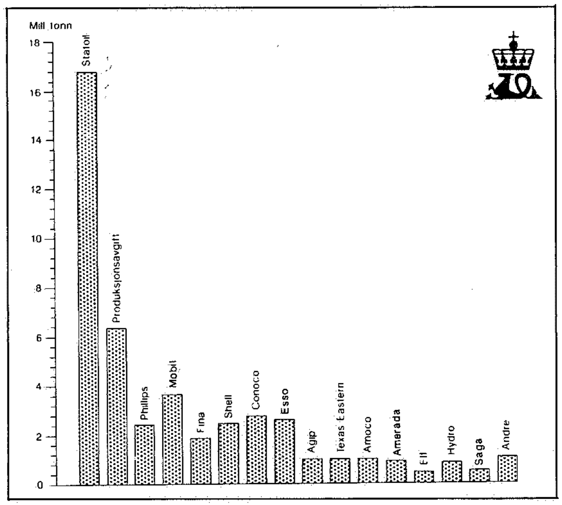


Fig 5.5.3.b
Sales quantites of oil/NGL as per licensee in 1987.



In 1987 sales of NGL from the Norwegian shelf reached 1.93 x 10^6 tons, an increase of 3.2 per cent in relation to 1986.

Fig 5.5.3.c
Sales quantites of gas as per country.

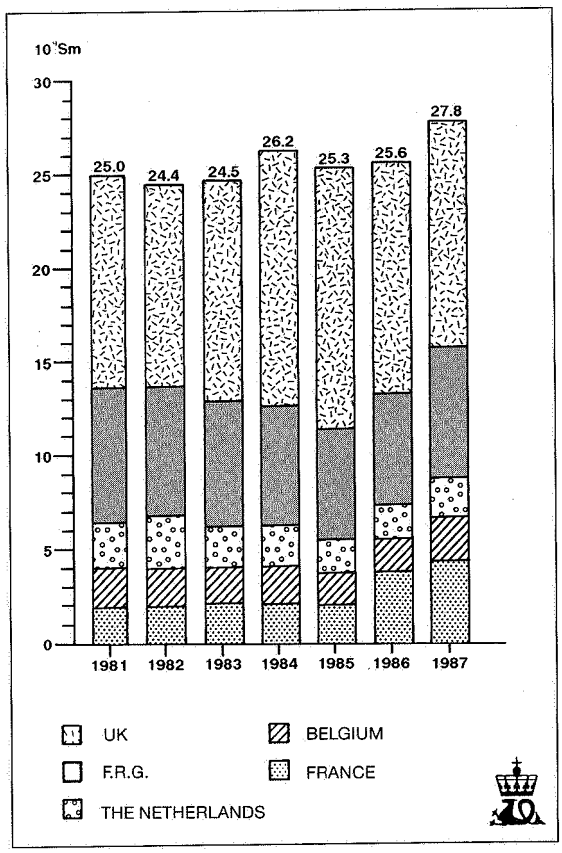


Fig 5.5.3.b
Sales quantities of gas as per licensee in 1987.

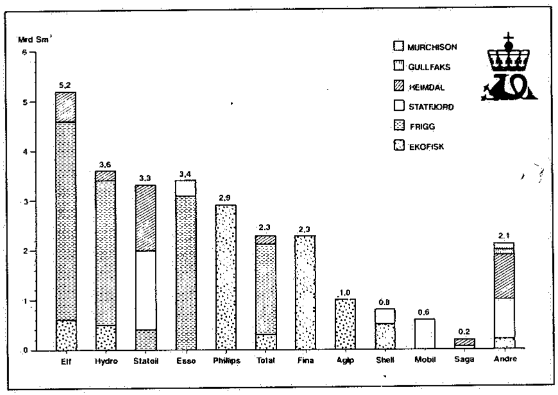


Figure 5.5.3.b shows sales of crude oil and NGL in 1987 divided by licensees.

In 1987 as 1986 0.2 x 10^6 tons of condensate were shipped.

In 1987 Norway exported 27.8 x 10^9 Sm^3 gas, that is to say, 8.8 per cent more than in 1986. 12.04 x 10^9 Sm^3 were sold to Great Britain, 6.99 x 10^9 Sm^3 to West Germany, 4.73 x 10^9 Sm^3 to France, 2.09 x 10^9 Sm^3 to the Netherlands and 1.95 x 10^9 Sm^3 to Belgium, see Figure 5.5.3.c.

Figure 5.5.3.d shows gas sales in 1987 divided by licensees.

6. Special Reports and Projects

In 1987 the Norwegian Petroleum Directorate granted in all NOK 17,630,625 for special projects. This is divided between NOK 4,214,367 for projects of the Safety and Working Environment Division and NOK 14,434,254 for the Resource Management Division, of which NOK 508,000 was granted to the universities.

NOK 4,698,429 was also granted for the North Sea seabed clearance project.

The weather ship project in the Barents Sea, administered by the Norwegian Petroleum Directorate, received NOK 13,876,006.

Some of the project titles with implementing institutions are listed below. In addition, some of the projects are discussed separately.

6.1 Resource Management Division.
In 1987, too, there was a high level of activity within the SPOR program, a State–funded research and development program begun in 1985. Through building up of expertise, research and development of new technology, SPOR aims at laying the groundwork for enhanced oil recovery.

The program is to run over five years, and has a financial framework of NOK 100 million, granted from the budget of the Ministry of Petroleum and Energy.

A report is in preparation with a view to further research and development work after SPOR comes to an end in 1989.

6.1.1 Exploration Branch

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Study of the Brent Group on the Norwegian shelf	University of Bergen
Diagenetic survey of Statfjord and Gullfaks	University of Oslo
Purchase and development of petrophysical software	IPEC
Geological studies of the Cretaceous fields	IPEC
Diagenetic studies on Albuskjell	IFE
Calcite cementation in the reservoirs	IFE and Rogaland Research Institute (RRI)
Geological/petrophysical studies of the Aldra formation on Haltenbanken	Hartland–White and Read
Sealing faults, Heidrun	ARK geophysics and Dr. R.F. Knipe
Geostatistics, reservoir heterogeneity	Norwegian Calculation Centre
Marine geological and micropaleontological surveys in the Barents Sea	University of Tromsø
Biostratigraphy in the Triadic Dia structure	University of Utrecht
Lithostratigraphic nomenclature – North Sea	NPD and the Norwegian operator companies
Fault modelling	RRI
Basin modelling	RRI
Prospect evaluation	CMI/NRS
Interactive velocity analysis	GECO
Velocity data base	GECO
Grav/Mag modelling	GECO

Study of the Brent Group.
The University of Bergen has carried out a study of the Brent group on the Norwegian shelf, work which has given increased understanding of the group's extent, reservoir characteristics and continuity.

Diagenetic survey of Statfjord and Gullfaks.
The University of Oslo is under way with a project for the Norwegian Petroleum Directorate concerning diagenetic surveys of the Statfjord formation on Statfjord and Gullfaks. This includes isotope surveys, datings, mineral stability analyses and formation water analyses.

Purchase and development of petrophysical software.
In the course of 1986 and 1987 the Norwegian Petroleum Directorate has evaluated a number of petrophysical EDP programs. A decision was made to procure IPEC's software. The Norwegian Petroleum Directorate has carried out about 20 well interpretations on this new EPIC system.

Geological studies of the Cretaceous fields.
A number of core descriptions and reservoir analyses from wells on fields in the Ekofisk area have been done. This will increase our geophysical understanding of the reservoir. Studies will aid understanding of communication between wells on the field.

Diagenetic studies on Albuskjell.
With the aid of isotope analyses we have attempted correlations within the reservoir. This study will aid understanding of communication between wells on the field.

Calcite cementation in the reservoirs.
Analyses have been done of calcite–cemented zones on Haltenbanken and Brage. This is important to the understanding of the incidence and significance of such impermeable zones in a reservoir.

Geological/petrophysical studies of the Aldra formation on Haltenbanken.
Petrophysical interpretation of wells from the Smørbukk area has been carried out. Emphasis has been placed on porosity and water saturation determinations so as to compare with test results. Petrological analyses of core material have also been performed for purposes of comparison with petrophysical analyses. The aim of the project is to improve the methods of proving oilbearing zones.

Sealing faults, Heidrun.
The project aims to yield better knowledge of sealed faults, their type and incidence. This knowledge is of great importance for oil and gas production.

Geostatistics, reservoir heterogeneity.
The intention is to enhance understanding of reservoir description of heterogeneous reservoirs. Modelling will be done and a geological expertise base will be built up.

Marine geological and micropaleontological surveys in the Barents Sea.
In order to improve knowledge of the youngest sedimentary deposits in the Barents Sea, the University of Tromsø in 1987 carried out studies of Late Cenozoic sediments in this area.

Biostratigraphy in the Dia structure.
In order to enhance expertise in Triassic palynostratigraphy, detailed palynological studies of materials from the shallow drillings on the Dia structure have been carried out in collaboration with the University of Utrecht, Holland.

Lithostratigraphic nomenclature.
The lithostratigraphic nomenclature published in 1977 by Degan & Scull has gradually become obsolete. A working group, consisting of representatives of the Norwegian Petroleum Directorate and the Norwegian operator companies, has therefore revised the lithostratigraphic nomenclature south of 62° N for Cretaceous and Tertiary.

Fault modelling.
By means of digitalised seismic sections the program can do strata peeling of faulted horizons and compute tensile factors important to maturation simulation of source rocks. The program will also be able to model the geometry of listric faults and reconstruct the pre–fault geology. Possible interpretations can thereby be tested.

Basin modelling.
The aim of this project is to develop a program that can be part of the Norwegian Petroleum Directorate's internal program package in connection with estimation of hydrocarbon formation and basin development. This year the model has been further developed with a view to calculating erosion activity. This makes the program more useful in the Barents Sea.

Prospect evaluation.
Prospect evaluation has been started in order better to estimate volumes of hydrocarbons, type of hydrocarbons and the probability of oil and gas. This kind of estimating is required in connection with opening up of new areas and blocks for licence allocation.

Interactive velocity analysis.
In connection with seismic processing a program module has been developed for interactive velocity analysis. This facilitates an optimum determination of processing parameters.

Development of velocity data base.
For determination of velocity fields in the geological structures based on seismic "stacking" velocities and well logs, the program system Hast–Prog is to be integrated with the Norwegian Petroleum Directorate's database system. This will yield optimum parameters for depth conversion of geological time charts for volume calculations.

Gravimetric/magnetic modelling.
New software has been developed for modelling of geological structures based on GRAV/MAG data. The aim is to yield the best possible description of the development of geological structures.

6.1.2 Development Branch

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Oil Development on Troll	Smedvig IPR A/S
Technology development/cost reductions	Novatech A/S
Capacity assessment for gas transport	R.M. Parsons Co. Ltd.
Reservoir monitoring	IPEC
Field–related EOR studies	Rogaland Research Institute, Institute Français du Petrole
Reservoir technology studies in the Oseberg area	Restek, Reslab A/S, RRI
Investment strategy under uncertainty/value of flexibility	CMI
Choice between terminal and buoy–loaded oil on Haltenbanken	Petroleum Economics Ltd.

Oil Development on Troll.
In 1986 the licensees concluded that commercial development of the oil province in Troll West required reduction in costs. This project aims to assess the potential of a low–cost solution for Troll oil, and the conclusion is that a development can enjoy good economics. The results will be discussed with the licensees in 1988.

Technology development/cost reductions.
The work of assessing potential for cost reductions in future field developments was continued in 1987. Efforts have been particularly concentrated on analysis of the connections between technical concept and choice of strategy for project implementation. There may be potential for considerable cost savings in optimum adaptation.

Capacity assessment for gas transport.
In connection with the decision on start–up year for Zeepipe, a study has been made of the real capacity in existing landing systems and the potential for capacity extension and their consequences. On the basis of this study, among other things, the Norwegian Petroleum Directorate agrees with the licensees' choice of 1993 as start–up year.

Reservoir monitoring.
Thirteen North Sea fields have been studied, and it has been shown how understanding of the fields has changed over time. Statfjord has received the most detailed treatment. Recommendations are made as to what data should be collected in an early phase.

Field–related EOR studies.
Subprojects illuminate the potential for enhanced oil recovery in the Heidrun, Draugen and Smørbukk fields.

Reservoir technology studies in the Oseberg area.
Subprojects deal with various reservoir technology problems in connection with the Directorate's consideration of the Plan for Development and Operation of Oseberg North and Brage.

Investment strategy under uncertainty/value of flexibility.
The value of being able to stop, delay or change investment decisions for proposed development plans and fixed platform concepts on Snorre has been assessed.

Choice between terminal and buoy–loaded oil on Haltenbanken.
The project was designed to undertake independent assessment of the price differential between buoy–loaded and terminal–loaded oil in connection with Haltenbanken field plans for development and operation.

6.1.3 Production Branch

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Further density measurements	Dantest, Denmark
Allocation of well production	Moore, Barret & Redwood, UK
Densimeter error	Rogaland Research Institute
Technical and economic aspects of removal	Opcon
Kick rates	Vignes
New reservoir monitoring technology	Read
Formation water, analysis procedures and reporting	Aquateam

Further density measurements
In collaboration with the K–Lab (Statoil/Total) the NPD has supervised a laboratory test at Dantest in Copenhagen. The object of the project is to determine a calibration procedure for densimeters which will reduce the uncertainty of test measurements when using the instrument with gases at high pressure. It is this uncertainty which lies behind the erroneous Emden readings, which in turn forced the seller to deliver compensatory gas volume to the buyer. Project completion is scheduled for spring 1988.

Technical and economic aspects of removal of installations offshore Norway
This project is intended to assess the technical alternatives and constraints inherent in today's technology, as well as look at the economics of removal of concrete installations. More specifically, the project focused on the following:
- Identification of parameters needing consideration when fully or partially removing concrete installations
- Examination of likely removal methods
- Assessment of costs of alternative removal operations.

Continuation of the project is planned in which the focus will be on measures needing to be implemented on platforms which will remain in place after decommissioning. This project is included in the work the Norwegian Petroleum Directorate program's "Final Phase Group" is conducting.

New reservoir monitoring technology
This project is designed to elucidate the status of reservoir monitoring technology and gather information on the latest market innovations. The institute in charge will also serve as consultant for processing of the statistics received from service contractors and oil companies.

Formation water – analysis procedures and reporting
This is part two of the formation water project launched in 1986, which principally dealt with procedures for sampling, handling and storing formation water samples.

Part two emphasizes standardization of analysis programs and procedures intended to assure compatible and reliable results, and a minimum batch range of analyses on all samples. Report procedures for water analysis have also been formulated. The project results will be incorporated in the rules governing sampling and analysis of formation water.

Several laboratories and Norwegian oil companies have contributed experiential ballast.

6.1.4 Planning Branch

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Phase–in of development projects under uncertainty	SINTEF
Oil and gas price trends	CMI
Market potential for Norwegian LNG in the US	ECON
The Swedish gas market	Asplan Analyse A/S
The taxation system and price uncertainties	CMI
Delivery patterns relating to offshore activity	Novatech A/S
Requirements of the petroleum sector for higher educated labour 1987–2000	Asplan Stavanger A/S

Phase–in of development projects under uncertainty
Planning of operations on the Norwegian continental shelf must take account of many uncertainty factors which require careful consideration of the planning concept, attention to goal formulation, and realizing that decisions in practice will follow upon one another in time. This project was designed to create a decision tool of assistance in such planning – a model that, instead of generating a set of decisions for the entire timespan of the plan, says what decisions should be made later in the light of information not available now, but available then. Development of the model may be termed dynamic programming using stochastic state variables. The work will continue in 1988 aimed at improving the universality, flexibility and ease–of–use of the tool.

Oil and gas price trends
The Norwegian Petroleum Directorate assisted in 1984–85 in the development of the PRIMO oil market model, a system–dynamic particularly attuned to oil's status as a crude commodity, the price of which, like other commodity rates, has fluctuated violently. Last year's project attempted to extend the model in the light of recent studies of the substitution potential of oil and other energy–bearers in various regional markets, and generate consistent prognoses for both oil and gas price trends. A subreport will examine the commercial risks of the Troll contract based on various gas price scenaria.

Taxation system and price uncertainty
The system of petroleum taxation divides both revenue and risk between the licensees and the state. The aim of this project was to calculate the sensitivity of the cash flow under the new price revision system, and examine the effects of changing tax parameters on the economy of various development projects. The methods employed are sensitivity and expectation variance analysis.

Delivery patterns relating to offshore activity
The aim of this study was to assess what demand for main components future development paths may bring. The project took care to make this assessment on the basis of expected technological advance and cost development.

One result of the study was that we can expect a change–over from today's traditional modules to large modules and integrated decks. Floating platform bases may corner a significant share of the base market from now on at the expense of fixed platform bases of concrete or steel.

Requirements of the petroleum sector for labour with higher education 1987– 2000
This study was intended to examine whether supply of well–educated labour might represent a bottle–neck to the industry in the future.

Several prognoses for future demand were therefore prepared in the various subsectors, which were then collated with estimates of appropriate available labour.

The results showed a growth in demand for educated personnel during the next few years, followed by a recession. Demand growth varied for the different development paths and personnel categories. The Ministry of Petroleum and Energy has received a report on the results.

6.2. Safety and Working Environment Division

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
Support of NEK and Norwegian participation in SFS inter– national standardization work	Norwegian Electrotechnical Committee
Member of CIRIA–UEG (SFM)	CIRIA–UEG
Member of Welding Institute (SFM)	Welding Institute
Guidelines for Regulations for Load–bearing Structures (SFM)	Norwegian Petroleum Directorate
Regulations for Subsea Pipe–line Systems (SFM)	Norwegian Petroleum Directorate
Systematic development of regulations (SS)	Norwegian Petroleum Directorate
Flexible flowlines (SFM)	Veritas/Varitec
Winterization of drilling operations (SFB)	SINTEF
Acceptance criteria for G–cement (SFB)	Norsk Hydro
Deep diving (SFU)	Norwegian Petroleum Directorate
International cooperation for standardization of diving (SFU)	Norwegian Petroleum Directorate
Working environment for divers (SFU)	Norwegian Petroleum Directorate
Acceptance criteria for fire barriers (SFS)	SINTEF
Effects of mineral oil (SFA)	Trondheim Regional Hospital
Organization of health and safety service for petroleum operations (SFA)	FAHS, Bergen
Drilling–related personal injury (SFA)	Rogaland Research Institute
Toxicological aspects of environmental pollution in hyper- baric systems (SFA)	NUTEC
Cold stress effects on physical and psychological work ca- pacity (SFA)	NUTEC
Acceptance criteria for drilling mud and analysis methods (SFA)	SINTEF
Installation removal after decommissioning (SFM)	Veritec
Assessment of new equipment and new technology for drilling and well–related activities (SFB)	Norwegian Petroleum Directotrate
Guidelines for Emergency Preparedness (SFC)	Scandpower a/s
Influence of welding (SFM)	Cranfield Institute
Well data bank (SFB)	Rogaland Research Institute
Fiber optics (SFS)	Veritas/SINTEF
Computerized security and control systems	Norwegian Petroleum Directorate
Acceptance criteria for old installations and structures (SFM)	Aas Jacobsen, SINTEF, Veritas
Comparison of regulations: NPD versus Veritas (SFM)	NPD/Veritas
New design criteria for cathodic protection (SFM)	Veritas
Corrosion problems of seawater injection	Norwegian Petroleum Directorate
Acceptance criteria for riserless drilling (SFB)	Piotech, Trondheim
Criteria for production stream makeup (SFB)	Rogaland Research Institute
Worldwide Offshore Accident Databank (WOAD) (SSP)	Veritas
Total safety assessments (SSP)	Siktec a/s
Instrumental surveillance of offshore installations (SFM)	Norwegian Petroleum Directorate
Experience and reaction of oil–related industry and ven- dors to operators' internal control and quality assurance practices	Norwegian Petroleum Directorate
Toughness requirements for offshore structures in North Sea (SFM)	IRO, Holland
Effect of corrosion inhibitor on hydrogen penetration in steel (SFM)	Rogaland Research Institute
Use of downhole blowout preventer for drilling top hole sections (SFB)	Smedvig IPR
Use of reotrope fluid as barrier(SFB)	Petreco, Trondheim

Acceptance criteria for working environment conditions

The aim of this project is to develop acceptance criteria by which to guide implementation by the Safety Division of its administrative responsibility for working environment matters in petroleum operations. Material will be prepared to guide officers in their consideration of consents and audits, and in information initiatives directed to the industry and research circles. Professional expertise from the universities of Bergen and Trondheim has been engaged to assist with this task.

The project was completed in 1987 with six subprojects.

Winterization of mobile installations

This is a collaborative project between several technical sections in the Safety Division. The project leads toward formulation of acceptance criteria for winter season drilling in the far north. Canadian authorities have been contacted, as have operators with experience of Arctic drilling. The acceptance criteria will apply to equipment, operations and structural design alike. SINTEF has acted as outside expert.

The project was started in 1986 and terminated in 1987.

Guidelines for emergency preparedness

This project aims to develop a contingency model, specification and guidelines which take care of all necessary contingency functions, and permit flexible, straightforward choice of method and hardware. The functional requirements of the model must also be measurable and compatible with the principle of internal control.

This project is split into two subprojects:

– Subproject 1: Guidelines and requirements for functions, systematics and assessments of contingency systems.
– Subproject 2: Guidelines and requirements for emergency communications.

Both subprojects were started in 1986 and completed about 1987. The budget ceiling is about NOK 2.3 million.

Scandpower A/S has been engaged as project consultant.

Continuation of project on flexible flowlines for hydrocarbon systems

This project was started in 1984 (Phase I) and continued in 1985–86 (Phase II). The object is to supply the NPD with professional skills in the field, a new one on the Norwegian continental shelf, enabling the Directorate to design regulations and guidelines for consideration of development concepts embracing flexible flowline technology.

There is still little available data from operation of flexible flowlines. This, coupled with the inability to inspect by conventional methods, constitutes the biggest hurdle to assessing their use.

More recently plans incorporating the use of flexible risers on mobile production installations have been submitted to the Directorate. Empirical data from such risers is very limited. Examples of the problems encountered are the dependence of lifetime on load, and mechanics of fault incidence.

In 1986 the project concentrated on assessing empirical data from the operating phase and flexible risers. The project was concluded in 1987.

Veritas and Veritec have been the project's consultants.

6.3 The Administration Branch

PROJECT TITLE	PROJECT IMPLEMENTATION AGENCY
North Sea seabed clearance	Norwegian Petroleum Directorate
Infoil 2	Norwegian Petroleum Directorate with Norwegian Informatics Center

Seabed clearance

The Norwegian Petroleum Directorate's clearance of the seabed in 1987 concentrated on a 910 square kilometer area southwest of the Egersund Bank, the "English Klondyke". The area was chosen on the recommendation of fishery organizations and fishery authorities. Following survey using lateral sonar, fixes were singled out for identification by a submersible. Dynamically positioned vessels with submersible support were then commissioned to raise the objects considered most likely to hamper efficient fishing in the area. The objects recovered were largely derived from shipping and fishery operations. It transpired that the area contained less rubbish than had been assumed before the clearance operation.

Clearance operations also revealed the wreck of a German U–boat lying in 74 meters of water, sunk by Allied aircraft in summer 1944. Three other wrecks were discovered, two of them fishing vessels.

The wrecks were not raised by the NPD, though their exact positions were marked off on the Norwegian Hydrographic Service's fishery charts. This office incidently will receive all sonar and related bottom data gathered during the clearance operation.

Following completion of the clean–up of this area, the remaining budget was employed continuing the work already initiated of retreiving piping from the Egersund Bank. There seem to be about 300 large dimension steel tubulars, very likely a deck cargo lost overboard in rough seas. These tubulars were located during the official clearance operation in 1985, when 21 were recovered. In 1986 a further 55 were removed, and the year after 127.

Bergen Underwater Services A/S was contracted to conduct operations, budgeted to NOK 4.8 million. The Clearance Steering Committee, consisting of representatives from the NPD, Fishery Directorate, Hydrographic Office, Norwegian Union of Fishermen and Norwegian Industry Association for Oil Companies (NIFO) concluded that this year's action was a success.

These official clearance operations continue to command the keen attention of fishermen and media.

Infoil 2: Norwegian–UK database of offshore–related research projects

Work on the Infoil 2 database concentrated in 1987 on strengthening contacts – in meetings and talks – with Canadian officials through COGLA, the Canada Oil and Gas Lands Administration in Ottawa. The hope is to assemble a binding cooperation for input of project data from officially funded Canadian petroleum–related research projects. Our links with NLDC, the Newfoundland and Labrador Development Corporation, have also been more closely forged since the NLCS has emerged as a potential venture partner for NLDC if a database is set up in St Johns.

The EEC administration has also been pursuaded to supply data in their collection of "European Community Oil and Gas Technological Development Projects" to Infoil.

One international oil company has taken out a subscription with the Infoil base for installation in–house in London.

Catalogues of projects are issued in English and Norwegian and are for sale, the former being entitled Offshore R&D Projects 1987. The catalogues contain 681 project entries.

Another part of the project is the Petroleum Thesaurus (Norwegian terminology for use when searching through petroleum–related informational databases), sixth edition, fully updated. This work has been done by Statoil and the NPD jointly, with the Norwegian Terminology Bank at the University of Bergen.

7. International Cooperation

7.1 Aid to foreign countries

In 1987 the Norwegian Petroleum Directorate's involvement in the Norwegian Development Aid (NORAD) programs was concentrated primarily on Tanzania, the Seychelles and to a lesser extent in Mozambique. In these countries the Directorate was primarily concerned with (1) general data processing, (2) processing and storage of seismic data tapes, (3) data interpretation, (4) guidance of consultants brought in to conduct interpretational and seismic reprocessing work, (5) help in establishing core data stores, building up of a biostratigraphic laboratory (Tanzania) and (7) guidance to NORAD-supported consultants in Mozambique and Tanzania.

In the report period a continuous evaluation was made of the petroleum potential in the southern part of Bangladesh with a view to a greater involvement from the Norwegian side.

The Norwegian Petroleum Directorate has also played an active role in steering and working groups led by the Ministry of Development Aid, which has considered the need for a petroleum training facility for middle management in developing countries. The Norwegian Petroleum Directorate has accepted the administrative responsibility for a secretariat to guide this training activity for a trial period of three years.

Other NORAD projects in which the Norwegian Petroleum Directorate has been involved include:

(a) INDIA
Assistance in planning NORAD aid to the "Institute of Ocean Engineering and Technology" run by the Indian state oil company, ONGC.

(b) CENTRAL AMERICA
Assessment of possible projects within the petroleum sector in Costa Rica and Nicaragua with a view to possible assistance to the region.

7.2 Safety and Working Environment

7.2.1 Introduction

The Safety Division has had a comprehensive collaboration with international professional institutions and political/technical organs either directly or indirectly through other Norwegian authorities.

The object of this collaboration is:

- to contribute to ensuring that safety and working environment conditions in the petroleum activity as a minimum requirement satisfy recognised international standards.
- to ensure access to relevant information for expertise development and legislation development.
- to contribute our insight and experience to the outside world and exert a positive influence on safety and working environment.

In the main collaboration has consisted of participation in international authority cooperation in Europe and in UN contexts, plus more direct cooperation with various types of international and regional professional bodies. The most important partners hitherto have been:

- The Common Market Commission, in collaboration with the Ministry of Local Government and Labour on safety and working environment.
- Safety and Pollution Standards in the Development of North-West European Offshore Mineral Resources, from 1973.
- The UN organisations IMO and ILO on respectively maritime safety and working environment, from 1979/80.
- EDTC and AODC on diving safety, from 1983.
- CIRIA/UEG (UK) on inspection and maintenance of installations, from 1980.
- Welding Institute (UK), on research and development of materials and welding, from 1981.
- API (USA), participation in annual conferences on petroleum subjects and standardisation, from 1979.
- NACE (USA), participation in annual conferences on corrosion and surface treatment, from 1984.
- CENELEC, collaboration on electrical technology standardisation in Europe via the Norwegian Electrotechnology Committee (NEK).
- CCOP/ASCOPE/NECOR, participation in UN cooperation on safety questions for a group of East Asian countries, from 1985.

Further description of the institutions and the content of the cooperation is to be found also in previous annual reports of the Norwegian Petroleum Directorate.

It is particularly within the fields of diving, drilling, production, electronics, materials and operational inspection that the S Division has enjoyed considerable professional collaboration with foreign bodies. Also within other of the S Division's areas of responsibility, however, there has been considerable international contact, with exchange and transfer of experience and discussion of problems.

7.2.2 European Economic Community EEC

From 1982 Norway has had observer status in the organised EEC conference activity with the main emphasis on "Safety and Health in the Oil and Gas Extraction Industries". The Norwegian Petroleum Directorate has taken part in Norwegian delegations to meetings and has in particular followed the work of harmonising of safety requirements etc related to petroleum activity at sea, where experience has been discussed and exchanged with regard to industrial injury statistics, training requirements etc. This EEC-directed activity also includes a number of matters previously dealt with by the North-West European Cooperation.

In 1987 the Ministry of Local Government and Labour started formal cooperation with the EEC Safety and Health at Work Commission. The cooperation embraces exchange of experience with a view to harmonisation of provisions in regulations and standards. The Norwegian Petroleum Directorate participates as an observer in the annual meetings, the last being in April 1987 in Luxembourg, but can also raise questions of interest as a part of the ongoing collaboration within the agreement (Letter of Exchange) between the Ministry and the Commission.

In the EEC's new system for regulations harmonisation, which came into force in 1987, a formalised cooperation with the Common Market countries is included, and this looks likely to come to embrace the petroleum sector. This formal partnership with the EEC Commission through the Ministry of Local Government and Labour will therefore be of significance for the Norwegian Petroleum Directorate's own regulations development.

7.2.3 Northwest European collaboration

In March 1973 a conference was arranged in London on the topic "Safety and Pollution Standards in the Development of North-West European Offshore Mineral Resources" between the countries that were more or less directly affected by the North Sea oil activity: Belgium, Denmark, Eire, France, the Netherlands, Norway, Great Britain, Sweden and West Germany.

This was the beginning of permanent organised collaboration between the above-mentioned countries with regard to safety and pollution problems in the petroleum industry. So far five conferences have been arranged, in 1973, 1978, 1982, 1984 and 1986, the 1982 conference being held in Oslo. Several working parties have been set up, which have worked at length on central questions and reported to the conference. The Legal Department and the Safety Division of the Norwegian Petroleum Directorate have been represented in the Norwegian delegation.

The objectives of the conference have been:

- mutual exchange of information
- harmonisation of technical standards
- collaboration with relevant technical organisations.

During the fifth conference held in Copenhagen in 1986, it was decided to look at the working methods of the conferences. A working party was established of participants from the authorities in the North Sea countries meeting 10-11 September 1987, at Clausthal-Zellerfeld in West Germany.

The working party has put forward a number of proposals as to how collaboration between the North Sea countries can proceed for the future. These proposals will be dealt with formally at a meeting between representatives from the continental shelf authorities of the North Sea countries in May-June 1988 in Bonn, West Germany.

7.2.4 International Maritime Organization IMO

The IMO is a special agency in the UN system whose primary task is to work for better safety and against pollution at sea. The main thrust of IMO's activities is directed at vessels and shipping, but some of its activities are also of relevance to the offshore petroleum activities.

The petroleum-related part of the IMO's business is transacted mainly in the Maritime Safety Committee and its technical subcommittees. As a member of the Norwegian delegation to the IMO, the Norwegian Petroleum Directorate has taken part in the committee work of three of the subcommittees in the fields of personnel training, diving, construction of mobile installations and removal of fixed installations.

In 1987 the Norwegian Petroleum Directorate participated in the subcommittees Ship Design and Equipment, in the work on revision of the IMO standard for mobile drilling installations and Safety of Navigation, in which removal of fixed installations has been discussed.

The Norwegian Petroleum Directorate also participates in the work of developing an IMO standard for training of key maritime personnel on mobile installations in the Standards of Training and Watchkeeping subcommittee. The last meeting was in 1986 and the next will be in 1988.

In the winter of 1986 the IMO started work on detailed formulation of international regulations for removal of offshore installations.

The background for this is the Law of the sea Convention's Article 60, subsection 3, which requires that the question of removal of installations be subject to discretionary consideration by the coastal states, in which regard is to be paid among other things to the question of to what extent an installation is a nuisance to shipping, fishing, the environment etc. Article 60 subsection 3 also gives "the competent international organisation" powers to issue more detailed international removal regulations. IMO is generally recognised as being that organisation.

The work is carried out in the Safety of Navigation subcommittee, which has established its own group for the job. The Norwegian Petroleum Directorate is represented in the Norwegian delegation.

In the light of the "Ocean Ranger" accident the IMO in 1986 began work on international qualification standards for key personnel on mobile installations involved with the offshore oil industry. The work is being done in the Training and Watchkeeping Subcommittee, which has established a separate working party for this function. In 1987 the work continued on the international level in order to prepare Norwegian participation in IMO's subcommittee in January 1988.

7.2.5 CCOP/ASCOPE/NECOR

The Petroleum Directorate participates in a program of development of safety regulations for petroleum activity under the auspices of the United Nations' system of agencies. This particular program is directed at East Asian countries (Thailand, Malaysia, Indonesia, the Philippines and China) and is administered by CCOP/ASCOPE/NECOR.

NECOR is the Norwegian subdivision of ECOR, the Engineering Committee on Oceanic Resources, the UN advisory subcommittee for exploitation of subsea resources. Norwegian authorities contributed roughly one million kroner to the program in 1987.

A work program extending over five years from 1985 was set up in which individual countries develop laws and regulations in the areas of highest priority. The Petroleum Directorate will take part in this activity using specialists in the individual fields so as to assist the implementation of the program.

7.2.6 European Diving Technology Committee EDTC

The Norwegian Petroleum Directorate has worked actively in this group, in which most European nations participate. The objectives of the organization are to make recommendations to member countries in questions regarding diver safety. Work is done to improve harmonization and standardization designed to improve safety of diving operations.

7.2.7 CIRIA/UEG

The Construction Industry Research and Information Association (CIRIA) in the UK is an industry association or assembly of consultants, contractors, companies in the construction industry and public authorities. The Association's aims are to further research, propagate information and advise members and the construction industry in general.

The Association has three subgroups that administer concrete projects:

- Administration Group
- Business Development Group
- Construction Group
- Offshore and Underwater Engineering Group (UEG).

Since 1980 the Norwegian Petroleum Directorate has been a member of the UEG subgroup. Projects administered by the UEG are very relevant for the responsibilities and assignments of the Safety Division. The technical collaboration established and the source of information represented by the CIRIA has been of great help for safety reports and regulations work. The Safety Division is at present a member of a project for operational inspection of structures and installations under water.

7.2.8 Welding Institute

The Norwegian Petroleum Directorate has been a member of the Welding Institute since 1981. The WI is the leading institute in the offshore field and is very active in research, training and consultancy services. Membership provides consultancy assistance, project participation and updated information on the most recent materials and welding technology.

7.3 ISO – the International Standardisation Organisation

The Norwegian Petroleum Directorate is participating in the work of standardization of technical measurement performed by the ISO. International standards apply for metering of oil and gas. To assist the further development of international standards, the Directorate sits on the technical committees working with oil and gas measurement.

In order to make Norwegian work in this area more efficient, a national measurement technology forum has been set up in which the Directorate participates.

8. Statistics and Summaries

8.1 Units of measurement

The Norwegian Petroleum Directorate normally utilizes the International System of Units, or SI system. This system is also recommended for use by the oil companies operating on the continental shelf. However, other units than those whose use is allowed in the SI system have a very strong position in the petroleum industry for historical reasons.

Some terms and abbreviations occur in connection with production data for oil and gas and are connected with the units of measurement. Some of these are mentioned briefly below.

Measurement – oil

An exact measurement of an oil quantity by volume must refer to a more closely defined measuring state characterized by pressure and temperature. This is necessary because the volume of an oil quantity varies with its pressure and temperature. The pressure and temperature which the measured oil volume refers to is normally its "reference state". The two most common reference states are a) 60° F, 0 psig and b) 15° C, 1.01325 bar.

Pressure and temperature standards other than these may also occur. It should be noted that expressions like "standard state", "barrels at standard conditions", etc are ambiguous unless the pressure and temperature referred to are defined.

Reference condition b) is recommended for use by the International Standardization Organization, ISO. Moreover, this reference condition was introduced as a Norsk Standard in 1979, NS 5024. The Norwegian Petroleum Directorate is working to have this reference condition established in the petroleum industry.

Exact conversion of an oil volume from one condition to another requires the use of special tables. For estimated values, however, the volume at 60° F, 0 psig corresponds approximately to the volume at 15° C, 1.01325 bar.

Ordinary units/abbreviations

Sm^3 = standard cubic metre. Temperature and pressure references must be given for the unit to have an unambiguous meaning.

Barrels at standard conditions = Traditional american unit reference condition normally 60° F and 0 psig.

Conversion

1 Sm^3 corresponds to approx 6.29 barrels at standard conditions.

Measurement – gas

To an even greater extent than for oil volumes, the numerical value of a gas volume will depend on the pressure and temperature to which it is referred. Four reference states are normally employed: a) (60° F, 14.73 psia), b) (60° F, 14.696 psia), c) (15° C, 1.01325 bar), d) (0° C, 1.01325 bar). Reference states a), b) and c) are usually termed "standard conditions", d) "normal conditions".

A volume cannot be converted exactly from one state to another without knowing the physical properties of the gas. For estimates, however, the volume of the same quantity of gas can be assumed to be approximately equal in states a), b) and c), and the volume of this quantity is 5 per cent less in state d).

Common abbreviations

SCM or Sm^3 =	Standard cubic metre
Nm^3 =	Normal cubic metre
Scf (Scuft) =	Standard cubic foot

Temperature and pressure references must be given for the unit to be unambiguous.

Conversion

1 Sm^3 corresponds to approximately 0.95 Nm^3

1 Sm^3 corresponds to approximately 35.3 Scf.

Quality measurement – oil and gas

Density or relative density is often used to describe the composition of an oil or gas. A low density value indicates that the oil or gas is made up of light components.

Oil

a) "Specific gravity" 60/60°F

The relative density of oil in relation to water. Oil and water at temperature 60° F and pressure corresponding to atmospheric at the place of measurement. The figure is undenominated.

b) "API gravity" at 60°F

Specific Gravity 60/60° F expressed on an enlarged scale. Units are ° API. Conversion by this formula:

$$\text{API gravity at } 60°\text{F} = \frac{141.5}{\text{Spec. Grav. } 60/60°\text{F}} - 131.5$$

c) Density at 15° C
Absolute density at temperature 15° C and pressure corresponding to atmospheric at the place of measurement.

Gas

a) "Specific gravity"
The relative density of gas in relation to air. The content of this concept is not exactly defined unless the temperature and pressure are given. Very often however, no temperature or pressure references are given for specific gravity. For rough calculations this is not very important, as the differences between the values which may be measured/calculated for the most often used reference states are very small.

Expression of oil and gas in oil equivalents

Oil and gas are often measured in tons oil equivalent in contexts where an exact registration of amount or quality is not required. Conversion is based on the amount of energy liberated in the combustion of the oil or gas. In many cases, the amount of energy in a ton of oil will be close to the amount of energy in 1000 Sm^3 gas. This conversion factor is very easy to employ, at the same time as the difference in quality between oil and gas is so large –during processing, storage, distribution and application –that it would not be correct to express the conversion factor more accurately. Normal practice is therefore that:
1 ton oil equivalent (toe) corresponds to 1 ton oil or 1000 Sm^3 gas.

8.2 Exploration drilling on the Norwegian continental shelf in 1986

From the start of exploration activities for petroleum in the Norwegian sector of the North Sea in 1966, a total of 569 exploration wells were drilled on the Norwegian continental shelf. Of these 411 were exploration wells and 158 appraisal wells. As of 31 December 1987, 541 had been concluded. Twenty–two wells were suspended for different reasons (typical reasons being suspension for later testing, possible completion as a production well or later extension or plugging), and six are being drilled. The wells were drilled by 18 different operating companies.

Thirty–six wells were spudded in 1987, 25 for exploration and 11 for appraisal purposes. They were drilled by 11 operating companies, three of them Norwegian. The Norwegian companies drilled 22 wells, or 61 per cent.

Work was also restarted in 1987 on four suspended exploration wells, all of which were completed.

Seventeen of the wells spudded in 1987 were drilled in the North Sea, 14 in off Central Norway and 5 off North Norway.

Drilling took place in 30 blocks, 13 in the North Sea, 12 off Central Norway and five off North Norway. Thirty–five exploration wells were completed and three suspended during the year. Two exploration wells failed to reach prospective depths.

As of 31 December 1987 some 1,793,179 metres had been drilled in the 569 exploration wells, including 109,882 metres in 1987. Total mean depth of the 35 wells completed in 1987 was 3,349 metres. Mean water depth was 246 metres.

For drilling on the Norwegian continental shelf, 63 different drilling platforms have been used, five of them under two different names. Forty–five were semi–submersibles, 11 jack–ups, five drillships and two fixed installations. One of these, the semisubmersible "West Vision" came onto the Shelf in the course of the year.

The deepest bore on the Norwegian continental shelf is Well 30/4–1 for which BP is operator.Drilling started in November 1978 and terminated in March 1979. The greatest water depth so far drilled in is 468 metres by Norsk Hydro as operator for exploration well 7321/8–1, drilled in 1987.

Since 1978 and excluding 1982 a relatively gradual increase in water depth has occurred for drilling operations, from an average 94 metres in 1977 to 246 metres in 1987 (Figure 8.2.d). Two of the reasons for this are that the bulk of major discoveries in shallow water were made before 1977 and that new technology has enabled operators to produce from and drill at greater depths. Drill depth has changed very little.

Figure 8.2.a shows seasonal variations in drilling activity. Figure 8.2.b shows boreholes divided by operators on the Norwegian continental shelf. Figure 8.2.c. shows Norwegian operator companies' share of the drilling activity. Tables 8.2.a and 8.2.e present exploration drilling statistics.

Fig 8.2.a
Seasonal variations in drilling activity 1966 - 1987.

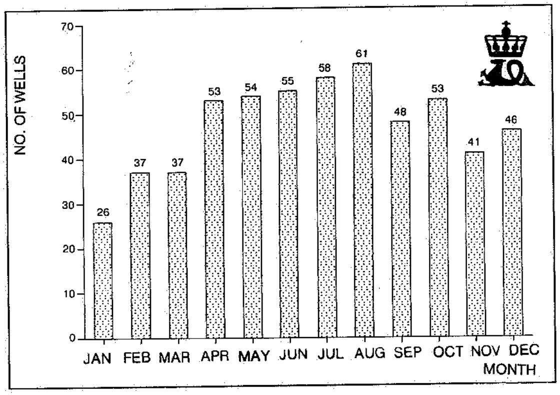


Fig 8.2.b
Operations on the Norwegian Continental Shelf. 569 explorations wells were drilled as of 31 December 1987.

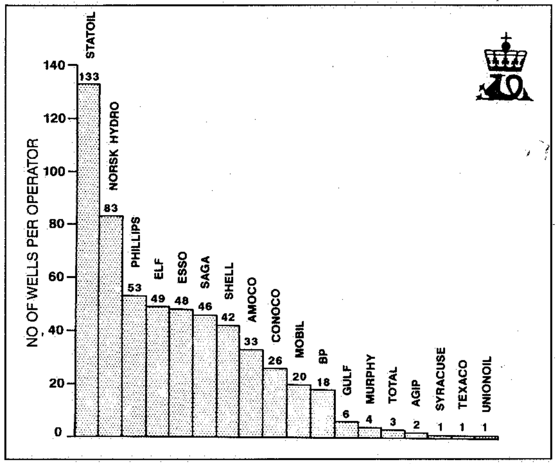


Fig 8.2.d
Average water depth per year. 1966 - 1987 (569 holes).

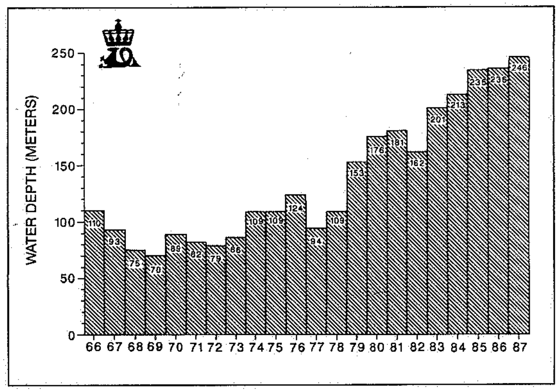
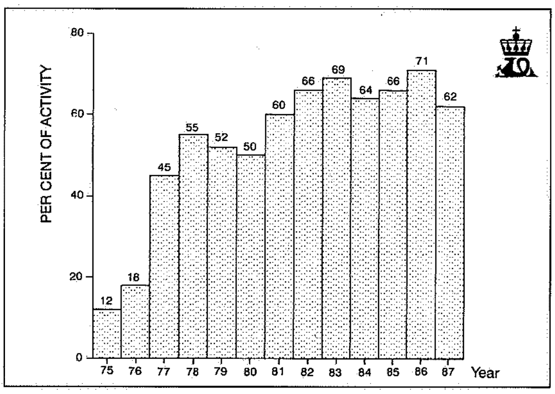


Fig 8.2.c
Participation by Norwegian Operating Companies in drilling activity. Per cent of operating days. 1975 - 1987.



Tab 8.2.a
Holes spudded per year

Year spudded	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	Total
Exploration	2	6	10	12	11	11	11	17	13	17	20	12	14	18	26	26	36	33	35	30	26	25	411
Appraisal	2	1	6	5	3	5	5	9	3	8	5	10	10	13	13	7	12	20	10	11	158		
Sum	2	6	12	13	17	16	14	22	18	26	23	20	19	28	36	39	49	40	47	50	36	36	569
Production	1	18	24	7	34	50	36	27	16	22	23	33	47	46	48	432							
Total	2	6	12	13	17	16	14	23	36	50	30	54	69	64	63	55	71	63	80	97	82	84	1001

Tab 8.2.b
Wells divided by operator.

Statoil	133	wells
Norsk Hydro	83	”
Phillips	53	”
Elf	49	”
Esso	48	”
Saga	46	”
Shell	42	”
Amoco	33	”
Conoco	26	”
Mobil	20	”
BP	18	”
Gulf	6	”
Murphy	4	”
Total	3	”
Agip	2	”
Syracuse	1	”
Texaco	1	”
Union	1	”
	569	wells

Tab 8.2.d
Average water depth and total depth

Year	Average water depth (m)	Average total depth (m)
1966	110	2737
1967	93	2599
1968	75	3495
1969	70	3143
1970	89	2983
1971	82	3101
1972	79	3712
1973	86	3089
1974	109	3078
1975	109	2954
1976	124	2949
1977	94	2719
1978	109	3502
1979	153	3375
1980	176	3115
1981	181	3235
1982	162	3314
1983	201	3155
1984	213	3116
1985	235	3208
1986	236	3353
1987	246	3349

Tab. 8.2.c
Exploration wells spudded in 1987

Statoil	11	wells
Norsk Hydro	6	”
Saga	5	”
Elf	4”	
Conoco	3	”
Mobil	2	”
Shell	1	”
Total	1	”
Esso	1	”
Phillips	1	”
BP	1	”
	36	wells

Tab 8.2.a
Drilling rigs that have been operating on the Norwegian Continental shelf

Name of drilling rig	No of wells	No of reentries	Type of rig
Aladdin	1		Semi-submersible
Borgny Dolphin (prev. Fernstar)	25	7	”
Borgsten Dolphin (prev. Haakon Magnus)	6		”
Bucentaur		1	Drillship
Byford Dolphin (prev. Deepsea Driller)	15		Semi-submersible
Chris Chenery 2		”	
Deepsea Bergen	13	2	”
Deepsea Driller (now Byford Dolphin)	8		”
Deepsea Saga	17	3	”
Drillmaster	6	1	”
Drillship	1		Drillship
Dyvi Alpha	17	2	Semi-submersible
Dyvi Beta	7	1	Jack-up
Dyvi Gamma	1		”
Dyvi Delta	20	1	Semi-submersible
Dyvi Stena	7		”
Endeavour	2		Jack-up
Fernstar (now Borgny Dolphin)	3		Semi-submersible
Gulftide	3		Jack-up
Glomar Biscay II (prev. Norskald)	12	1	Semi-submersible
Glomar Grand Isle	11	3	Drillship
Glomar Moray Firth I	2		Jack-up
Haakon Magnus (now Borgsten Dolphin)	2		Semi-submersible
Henry Goodrich	2		”
Maersk Explorer	7		Jack-up
Neddrill Trigon	3		”

Neptune 7 (prev. Pentagone 81)	12		Semi-submersible
Nordraug	10		"
Norjarl	3		"
Norskald (now Glomar Biscay II)	26		"
Nortrym	33	3	"
Ocean Tide	5		Jack-up
Ocean Traveler	9		Semi-submersible
Ocean Victory	1		"
Ocean Viking	29	1	"
Ocean Voyager	2		"
Odin Drill	3		"
Orion	7		Jack-up
Pelerin	1		Drillship
Pentagone 81 (now Neptune 7)	1		Semi-submersible
Pentagone 84	3	1	"
Polar Pioneer	11		"
Polyglomar Driller	11		"
Ross Isle	16	3	"
Ross Rig	30		"
Saipem II	1		Drillship
Sedco H	2		Semi-submersible
Sedco 135 F	2		"
Sedco 135 g	1		"
Sedco 703	3	1	"
Sedco 704	3		"
Sedco 707	6		Semi-submersible
Sedneth I	3		"
Transworld Rig	61	2	"
Treasure Hunter	5	3	"
Treasure Saga	25	1	"
Treasure Scout	21		"
Treasure Seeker	27	4	"
Vildkat	5		"
Vinni	2		"
Waage Drill I	2		"
West Vanguard	16		"
West Venture	11	2	"
West Vision	1		"
Zapata Explorer	13		Jack-up
Zapata Nordic	5		"
Zapata Ugland	5	1	Semi-submersible
	567	42	
In addition two holes were drilled from fixed installations.			
Cod Plattform	1	1	
Ekofisk B	1		
	569	43	

8.3 Production drilling on the Norwegian continental shelf

Since drilling of production wells began in the Norwegian sector of the North Sea in 1973, 432 wells in all have been spudded. Information on these production wells is set up in Table 8.3.a. Of these wells, 277 are production (oil, gas and condensate), 36 are water or gas injection, four are observation/production wells, one is a observation/injection well, 79 are temporarily out of commission, suspended for completion later or for other reasons and 23 are dry. Twelve production wells were being drilled at the end of the year.

As of 1 January 1988 15 fields are producing, with 23 production platforms and one seabottom completion (North–East Frigg). No new fields came on stream in 1987. Production drilling began on Gyda, Gullfaks B, Veslefrikk and east Frigg in the course of 1987. In all 48 production wells were begun in the year, as shown in Table 8.3.b.

Tab 8.3.a
Production drilling

FIELD	TOTAL DRILLED	SPUDDED 1987	PRODU-CING	INJEC-TION/ (OBSERV.)	DRILLING IN PROGRESS	SUSPEND./ PLUGGED/ COMPL.
ALBUSKJELL A +	11		8			3
ALBUSKJELL F +	13		7			6
COD +	9		6			3
EDDA +	10		6			4
EKOFISK A +	17	2	13		1	3
EKOFISK B +	24	1	19	(1)*		4
EKOFISK C +	13		8	4**		1
EKOFISK K +	11	4		2	9	
ELDFISK A +	29	1	19		1	9
ELDFISK B +	21	3	14		1	6
FRIGG (UK) +	24		22			2
FRIGG + 26	2	21		(3)*		2
GULLFAKS A +	14	8	6	2	1	5
GULLFAKS B	1	1			1	
GYDA	1	1			1	
HEIMDAL +	11		8	(1)***		2
N.E.FRIGG +	7		6			1
ODIN +	11		11			
OSEBERG	11	2	1		10	
STATFJORD A +	38		21	13	2	2
STATFJORD B +	29		19	10		
STATFJORD C +	24	4	16	7		1
TOMMELITEN	6	4			1	5
TOR +	14		10			4
ULA +	6	3	4		1	1
VALHALL +	29	3	20			9
V. EKOFISK +	14	1	12			2
VESLEFRIKK	4	4				4
EAST FRIGG	4	4				4
	432	48	277	32 (4)* 4** (1)***	12	102

* Wellsa are prod.§inj. wells, depending on gas sale.
** 4 wells are prod./inj. wells, depending on gas sale.
*** Wells are observation-/production wells
**** Well is observation-/injection well

277 wells producing (176 oil, 41 condensate and 60 gas)
39 " are shut down/plugged
36 " are injection wells (whereof 4 inj./prod.)
4 " are observation-/production wells
1 " are observation-/production wells
12 " drilling in progress (1/9-A-5 H, 2/1-A-8 H, 2/4-A-1 A, 2/4-K-4, 2/4-K-20, 2/7-A-8, 2/7-B-2, 7/12-A-3, 33/9-A-19, 33/9-A-23, 34/10-A-13 og 34/10-B-1
1 " is shut down (10/1-A-12) and drilled deeper with English permit No and new designation (10/1-A-25).
31 " is susp. at td (1/9-A-1 AH, 1/9-A-2 H, 1/9-A-3 H, 1/9-A-4 H, 2/4-D-8, 2/4-K-9, 2/4-K-12, 2/4-K-13, 2/4-K-22, 2/4-K-28, 2/4-K-30, 7/12-A-7, 25/2-A-1, 25/2-A-2, 25/2-B-1, 25/2-B-2, 30/3-A-1, 30/3-A-2, 30/9-B-20, 30/9-B-21, 30/9-B-23, 30/9-B-24, 30/9-B-25 30/9-B-26, 30/9-B-27, 30/9-B-29, 30/9-B-50 H, 34/10-A-6, 34/10-A-7 og 34/10-A-9 H, 34/10-A-12
2 " is susp. after setting of 9 5/8 casing (30/3-A-3 and 30/9-B-19)
1 " is susp. after setting of 13 3/8 casing (2/4-K-23)
2 " is susp. after setting of 20 casing (25/4-A-1 and 33/9-C-1)
2 " is susp. after setting of 30 casing (2/4-K-2 and 30/3-A-4)
1 " is susp. 10" open (2/4-K-3)
23 " have never produced

432

Tab 8.3.b.
Production wells spudded 1987

Lic. No.	Well No.	Spudded	Completed	Operator	Field	Comments
P 385	7/12-A-18	11.01.87	19.04.87	BP	Ula	
P 387	1/9-A-3 H	04.01.87	19.02.87	Statoil	Tommeliten	Susp. at TD
P 388	2/8-A-13 A	14.01.87	25.02.87	Amoco	Valhall	Plugged
P 389	2/8-A-15 A	10.02.87	18.03.87	Amoco	Valhall	
P 390	34/10-A-6	10.02.87	09.03.87	Statoil	Gullfaks A	Susp. at TD
P 391	1/9-A-4 H	21.02.87	05.05.87	Statoil	Tommeliten	Susp. at TD
P 392	7/12-A-7	18.04.87	14.11.87	BP	Ula	Susp. at TD
P 393	33/9-C-30	18.03.87	20.05.87	Statoil	Statfjord C	
P 394	34/10-A-7	09.03.87	08.04.87	Statoil	Gullfaks A	Susp. at TD
P 396	2/4-D-11 A	06.04.87	15.06.87	Phillips V.	Ekofisk	
P 397	34/10-A-9 H	22.03.87	30.05.87	Statoil	Gullfaks A	Susp. at TD
P 398	34/10-A-8	09.04.87	06.06.87	Statoil	Gullfaks A	
P 399	1/9-A-1 A H	05.04.87	06.05.87	Statoil	Tommeliten	Plugged
P 400	2/7-B-10 B	11.03.87	17.06.87	Phillips	Eldfisk B	
P 401	2/4-A-15 A	10.04.87	02.07.87	Phillips	Ekofisk A	
P 402	30/9-B-19	11.04.87	20.05.87	N. Hydro	Oseberg	Susp. 9 5/8
P 403	2/8-A-13 B	16.05.87	08.06.87	Amoco	Valhall	
P 404	30/9-B-50 H	25.05.87	27.06.87	N. Hydro	Oseberg	Susp. at TD
P 405	34/10-A-10	07.06.87	03.08.87	Statoil	Gullfaks A	
P 406	2/4-B-20 A	20.06.87	21.10.87	Phillips	Ekofisk B	
P 407	25/2-B-1	12.07.87	10.08.87	Elf	Øst Frigg	Susp. at TD
P 408	30/3-A-1	15.07.87	23.09.87	Statoil	Veslefrikk	Susp. at TD
P 409	25/2-B-2	12.08.87	08.09.87	Elf	Øst Frigg	Susp. at TD
P 410	2/4-K-30	24.07.87	26.12.87	Phillips	Ekofisk K	Susp. at TD
P 411	33/9-C-26	30.07.87	28.08.87	Statoil	Statfjord	
P 412	2/7-B-14 A	23.07.87	01.10.87	Phillips	Eldfisk B	
P 413	34/10-A-11	05.08.87	20.10.87	Statoil	Gullfaks A	Water injection
P 414	25/1-A-3 A	05.09.87	28.09.87	Elf	Frigg	Obs./prod.
P 415	25/1-A-22 A	06.10.87	01.11.87	Elf	Frigg	Obs./prod.
P 416	33/9-C-6	29.08.87	01.11.87	Statoil	Statfjord C	
P 417	25/2-A-1	02.10.87	04.12.87	Elf	Øst Frigg	Susp. at TD
P 418	25/2-A-2	09.09.87	30.12.87	Elf	Øst Frigg	Susp. at TD
P 419	2/4-K-28	07.09.87	17.11.87	Phillips	Ekofisk K	Susp.
P 420	2/4-K-20	16.09.87		Phillips	Ekofisk K	
P 421	30/3-A-2	25.09.87	18.11.87	Statoil	Veslefrikk	Susp. at TD
P 422	2/4-A-1 A	07.11.87		Phillips	Ekofisk A	
P 423	2/7-A-8	27.10.87		Phillips	Eldfisk A	
P 424	7/12-A-3	15.11.87		BP	Ula	
P 425	34/10-A-12	25.10.87	22.12.87	Statoil	Gullfaks A	Susp. at TD
P 426	33/9-C-1	03.11.87	08.11.87	Statoil	Statfjord C	Susp. 20"
P 427	30/3-A-3	18.11.87	19.12.87	Statoil	Veslefrikk	Susp. 9 5/8"
P 428	2/4-K-9	17.11.87	30.11.87	Phillips	Ekofisk K	Susp. at TD
P 430	2/1-A-8 H	18.11.87		BP	Gyda	
P 431	2/7-B-2	20.11.87		Phillips	Eldfisk B	
P 432	34/10-B-1	23.11.87		Statoil	Gullfaks B	
P 433	1/9-A-5 H	31.12.87		Statoil	Tommeliten	
P 434	30/03-A-4	19.12.87	21.12.87	Statoil	Veslefrikk	Susp. 30"
P 435	34/10-A-13	23.12.87		Statoil	Gullfaks A	

Fig 8.4.a
Oil and gas production on the Norwegian shelf per field and total 1971 - 1987.

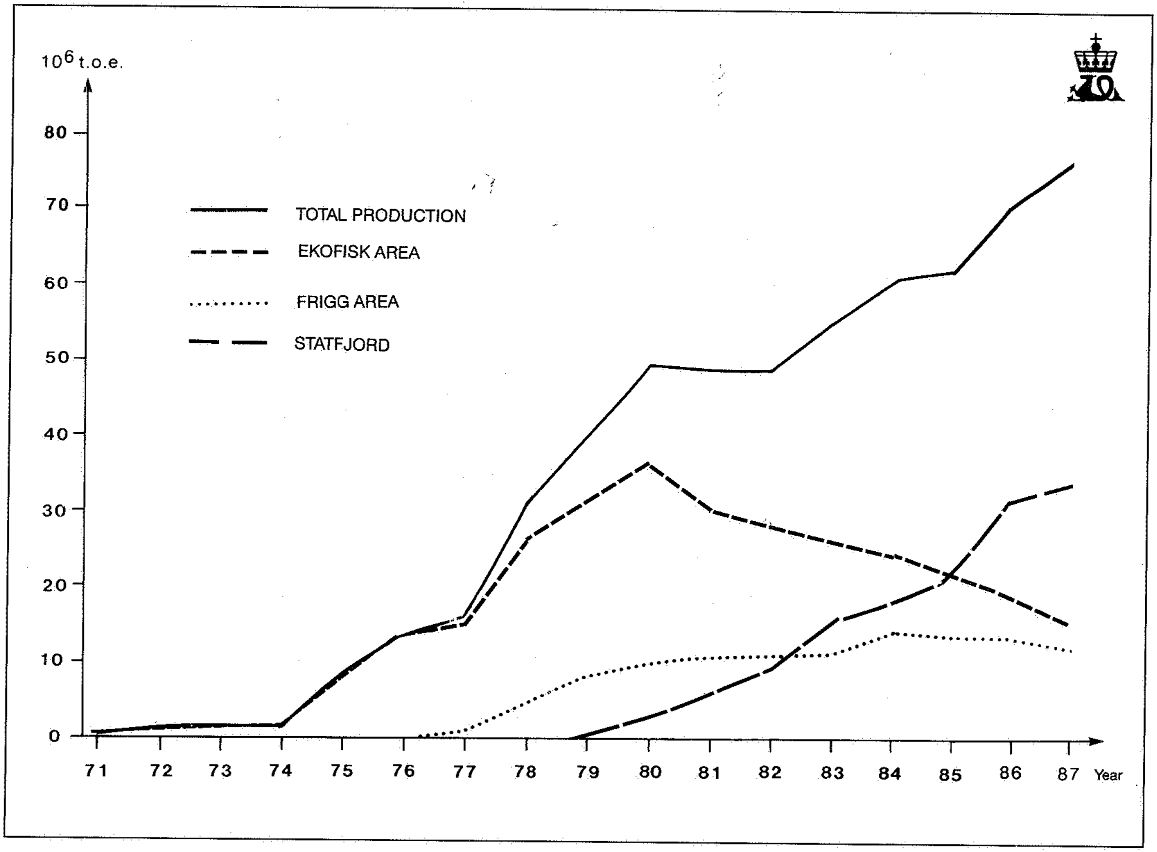
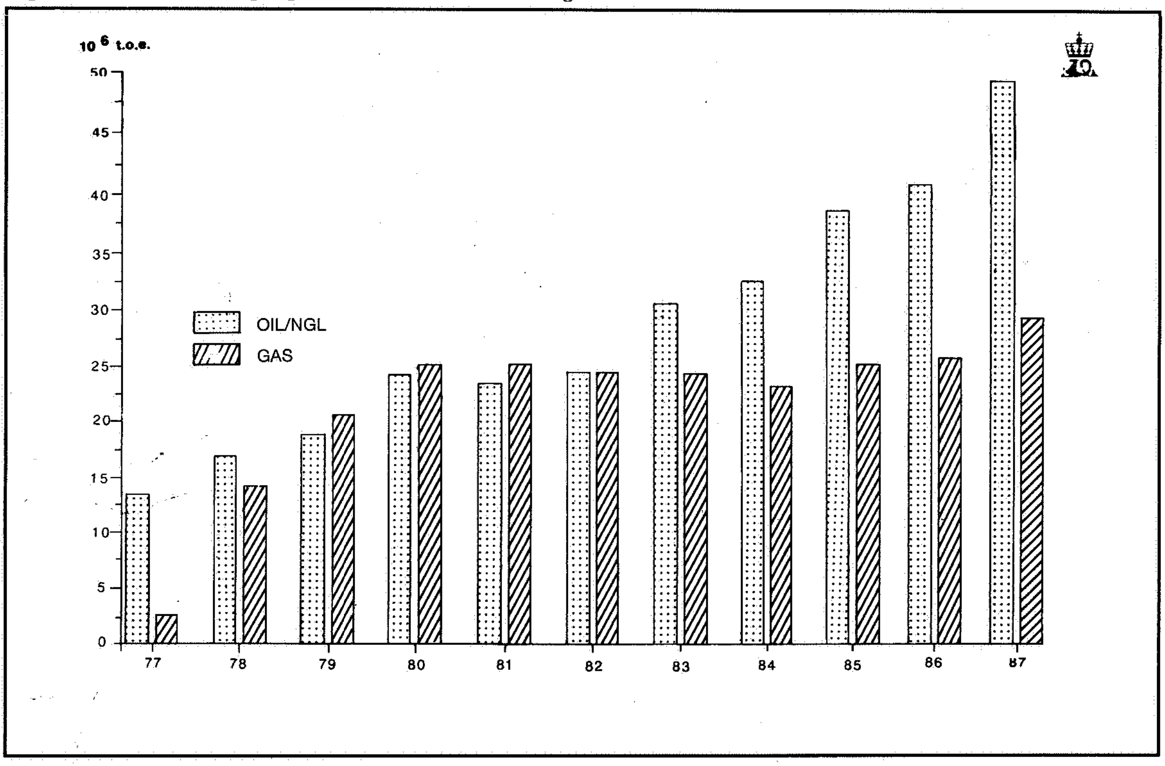


Fig 8.4.b Oil/NGL and gas production from the Norwegian shelf 1977 - 1987.



Tab 8.4.a
Production in mill t.o.e.

1987	OIL	GAS	TOTAL
EKOFISK-AREA	7.495	7.900	15.395
STATFJORD	30.013	3.423	33.436
FRIGG-AREA	0.000	12.423	12.423
VALHALL	3.020	0.622	3.642
MURCHISON	0.297	0.024	0.321
HEIMDAL	0.000	3.958	3.960
ULA	3.958	0.320	4.278
OSEBERG	0.692	0.000	0.692
GULLFAKS	3.550	0.125	3.675
TOTAL 1987	49.025	27.795	77.820
TOTAL 1986	42.293	25.653	67.946

The figures show the Norwegian share of Statfjord, Frigg and Murchison. NGL is included in the figures for oil, condensate in the gas figures.

Tab 8.4.b
Monthly oil and gas production from the Ekofisk-area

1987	Prod Oil Incl. NGL	Produced Gas	Injected Gas	Flared Gas	Gas Consum Fuel	Stable Oil Teesside	NGL Teesside	Gas Sales Emden
	1000 Sm³	Mill. Sm³	Mill. Sm³	Mill. Sm³	Mill. Sm³	1000 Sm³	Tonn	Mill. Sm³
JAN	934.	902.	81.	1.	57.	793.	70087.	765.
FEB	847.	797.	129.	1.	55.	721.	63320.	617.
MAR	879.	861.	126.	1.	65.	745.	66090.	678.
APR	918.	849.	152.	0.	57.	776.	69554.	640.
MAY	863.	801.	82.	1.	63.	727.	66044.	666.
JUN	782.	733.	5.	1.	50.	661.	59314.	677.
JUL	909.	823.	123.	1.	60.	790.	66017.	641.
AUG	237.	222.	5.	1.	16.	204.	18750.	203.
SEP	801.	689.	113.	3.	55.	694.	54997.	524.
OCT	922.	906.	0.	0.	49.	803.	60693.	852.
NOV	834.	857.	0.	1.	45.	679.	65374.	807.
DEC	818.	884.	0.	1.	49.	656.	67476.	831.
Year's total	9743.	9324.	816.	11.	622.	8250.	727716.	7900.

Tab 8.4.c
Monthly gas and condensate production from the Frigg-area

1987	Gas produced Mill. Sm³	Condensate produced Sm³	Gas injected Mill. Sm³	Gas flared Mill. Sm³	Gas fuel Mill. Sm³	Gas sold St.Fergus Mill. Sm³	Condensate St.Fergus Sm³	Condensate Tonn/Sm³
JAN	1396.	3147.	0.	0.	3.	1365.	7265.	0.8243
FEB	1289.	3139.	0.	0.	2.	1222.	4840.	0.8251
MAR	1372.	3284.	0.	0.	3.	1365.	4990.	0.8242
APR	1093.	869.	0.	0.	2.	1092.	6431.	0.8225
MAY	1028.	2792.	0.	0.	2.	1031.	5452.	0.8233
JUN	797.	713.	0.	0.	1.	793.	4360.	0.8225
JUL	602.	638.	0.	0.	2.	590.	337.	0.8227
AUG	779.	2141.	0.	0.	2.	750.	2105.	0.8239
SEP	886.	1876.	0.	0.	2.	888.	4188.	0.8250
OCT	940.	1689.	0.	0.	2.	937.	4711.	0.8240
NOV	1199.	2013.	0.	0.	2.	1196.	4566.	0.8273
DEC	1146.	2479.	0.	0.	2.	1149.	5843.	0.8239
Year's total	12526.	24778.	0.	1.	25.	12378.	55086.	

Figures are Norwegian share of Frigg, 60.82%. NE Frigg and Odin 100%.

Tab 8.4.d
Monthly oil and gas production from Gullfaks

	Prod of oil incl. NGL 1000 Sm³	Prod. gas MILL. Sm³	Flared gas MILL. Sm³	Gas consumed fuel MILL. Sm³	GAS Emden MILL. Sm³	NGL Kårstø TONN
JAN	150.219	13.659	13.659	0.000	0.000	0
FEB	184.039	16.978	16.978	0.000	0.000	0
MAR	248.309	23.170	20.583	2.745	0.000	0
APR	256.650	23.467	17.732	6.085	0.000	0
MAY	300.604	27.901	21.980	6.283	0.000	0
JUN	323.002	30.008	23.856	6.288	0.000	0
JUL	410.311	38.347	15.553	8.310	11.969	287
AUG	493.816	46.663	10.294	9.231	23.113	734
SEP	523.228	49.386	4.309	10.171	30.298	2263
OCT	517.043	48.682	3.021	10.005	27.143	1531
NOV	400.157	37.703	1.593	9.879	20.084	400
DEC	212.613	20.726	3.150	7.620	8.914	1114
Year's total	4019.990	376.689	152.707	76.618	121.521	6329

Tab 8.4.e
Monthly gas and condensate production from Heimdal

1987	Gas prod Mill. Sm³	Condensate produced Sm³	Flared gas Mill. Sm³	Gas consumed Mill. Sm³	GAS Emden Mill. Sm³	Condensate Kinneil Sm³
JAN	331.	52120.	0.	6.	316.	46478.
FEB	301.	47557.	1.	5.	285.	44329.
MAR	334.	52620.	1.	6.	316.	52567.
APR	328.	51684.	0.	6.	311.	50557.
MAY	335.	52993.	0.	6.	329.	52002.
JUN	320.	50267.	4.	5.	297.	17325.
JUL	329.	51551.	0.	6.	313.	50075.
AUG	132.	20719.	1.	2.	123.	21214.
SEP	315.	49714.	0.	5.	299.	42643.
OCT	320.	50937.	0.	5.	303.	50051.
NOV	336.	53942.	0.	5.	318.	49016.
DEC	332.	53446.	0.	5.	315.	48397.
Year's total	3711.	587550.	8.	63.	3525.	524654.

Tab 8.4.f
Monthly oil and gas production from Murchison

1987	Prod oil Unstabilized 1000 Sm³	Prod gas MILL Sm³	Injected gas MILL Sm³	Flared gas MILL Sm³	Gas consumed fuel MILL Sm³	Stable oil Sullom Voe 1000 Sm³	Gas St FergusS MILL Sm³	NGL VOE/St Fergus 1000 TONN
JAN	33	4	0	1	1	29	2	1
FEB	31	4	0	0	1	28	2	1
MAR	34	4	0	0	1	30	2	1
APR	22	3	0	1	0	20	1	1
MAY	35	4	0	1	1	31	2	1
JUN	33	4	0	1	1	29	2	1
JUL	37	4	0	1	1	29	2	2
AUG	36	4	0	1	1	32	2	1
SEP	32	4	0	1	1	30	1	1
OCT	31	4	0	1	1	30	2	0
NOV	30	4	0	1	1	28	2	0
DEC	29	4	0	1	1	28	2	0
Year's total	383	46	0	8	10	344	24	12

FIGURES SHOW NORWEGIAN SHARE OF MURCHISON

Tab 8.4.g
Monthly oil and gas production from Statfjord

1987	Prod oil Incl NGL 1000 Sm³	Prod gas MILL. Sm³	Inj. gas MILL. Sm³	Flared gas MILL. Sm³	Gas consumed fuel MILL. Sm³	Gas sales Emden MILL. Sm³
JAN	3336.	652.	259.	9.	38.	284.
FEB	2674.	539.	185.	8.	32.	260.
MAR	3011.	637.	259.	9.	36.	276.
APR	3004.	634.	231.	10.	35.	293.
MAY	3090.	663.	275.	13.	37.	276.
JUN	2386.	501.	151.	10.	29.	263.
JUL	2801.	581.	215.	9.	33.	285.
AUG	2725.	570.	387.	8.	34.	112.
SEP	2917.	592.	239.	7.	36.	289.
OCT	3112.	652.	237.	10.	39.	331.
NOV	3008.	636.	219.	10.	38.	322.
DEC	3076.	673.	174.	8.	37.	391.
Year's total	34958.	7331.	2832.	110.	425.	3382.

Figures are Norwegian share of Statfjord : 84,09322 %

Tab 8.4.h
Monthly oil and gas production from Ula

1987	Unstabilized oil 1000 Sm³	Prod gas MILL. Sm³	Flared gas MILL. Sm³	Gas consumed fuel MILL Sm³	Stable oil Teesside 1000 Sm³	NGL Teesside 1000 TONN	GAS Emden MILL SM³
JAN	461.	39.	6.	3.	439.	18.	28.
FEB	412.	35.	0.	3.	393.	16.	28.
MAR	370.	32.	1.	3.	350.	16.	24.
APR	454.	39.	0.	3.	430.	18.	31.
MAY	465.	40.	1.	3.	446.	18.	30.
JUN	304.	26.	1.	3.	287.	12.	19.
JUL	479.	40.	1.	3.	452.	20.	32.
AUG	134.	11.	0.	1.	128.	6.	9.
SEP	414.	35.	3.	3.	391.	17.	26.
OCT	487.	41.	0.	3.	458.	21.	34.
NOV	448.	38.	1.	3.	421.	20.	30.
DEC	409.	35.	1.	3.	387.	17.	28.
Year's total	4836.	410.	15.	34.	4581.	200.	320.

Tab 8.4.i
Monthly oil and gas production allocated Valhall

1987	Prod oil incl. NGL 1000 Sm³	Prod gas MILL. Sm³	Inj. gas MILL. Sm³	Flared gas MILL. Sm³	Gas consumed fuel MILL. Sm³	Stabilized Oil Teesside 1000 Sm³	NGL Teesside 1000 TONN	GAS Emden MILL. Sm³
JAN	316	57	0	2	8	288	14	46
FEB	304	56	0	2	7	278	14	46
MAR	331	62	0	2	9	302	15	50
APR	310	57	0	1	8	287	15	47
MAY	332	60	0	1	9	304	14	51
JUN	324	76	0	1	7	298	13	53
JUL	357	68	0	1	8	327	15	59
AUG	99	19	0	1	1	92	4	16
SEP	355	67	0	9	7	330	13	51
OCT	368	61	0	1	8	336	15	71
NOV	351	60	0	1	8	321	15	69
DEC	334	66	0	1	8	310	13	57
Year's total	3788	716	0	26	93	3478	166	621

8.4 Production of oil and gas in 1986

Production of oil and gas on the Norwegian continental shelf in 1987 was 77.8 x 10^6 toe. Production in 1986 was 67.9 x 10^6 toe.

In Tables 8.4.a –8.4.i and Figures 8.4.a and b, production on the Norwegian continental shelf is presented in more detail.

The data in Table 8.4.a show the Norwegian share of Statfjord, Frigg and Murchison. NGL for the Ekofisk area, Murchison, Valhall and Statfjord are included in the figures for oil.

The figures for gas in Table 8.4.a indicate the amounts sold for all fields. Condensate is included in the figures for the Frigg area.

8.5 Publications by the Norwegian Petroleum Directorate in 1986

Regulations

- Regulations compendium: "Regelverksamling for petroleums–virksomheten 1987" (Acts, regulations and provisions for the petroleum activity 1986): up–to– date compendium in two volumes with parallel Norwegian and English texts of the regulations and guidelines laid down by the Norwegian Petroleum Directorate and other regulatory agencies. Updated to 1 January 1987.
- Regulations on safety zones.
- Guidelines for determination of loads and load effects.

Research reports

- Petroleum Research 1987. Research projects from the British/Norwegian database INFOIL 2.
- Rfb. Documentation for preparedness work in the petroleum activity on the Norwegian continental shelf.

Other publications

Well Data Summary Sheets, vol. 12. Boreholes completed in 1981.

Oljedirektoratets årsberetning 1986 (Norwegian Petroleum Directorate Annual Report 1986) (Norwegian edition)

NPD Annual Report 1986 (English edition of the above)

Map of the Norwegian continental shelf

Clearance of the seabed 1986

Clearance of the seabed 1987

Licences, Areas, Area Coordinates, Boreholes.

Geophysical Data packages available from the Norwegian Petroleum Directorate

Released tapes from the Norwegian Petroleum Directorate, complete to 1981.

Future Activity

Shallow gas Seminar – August 27–28 1987

Fields in sequence on Haltenbanken

How the Norwegian Petroleum Directorate can help Norwegian companies supplying goods and services to the Shelf.

8.6 Organization chart