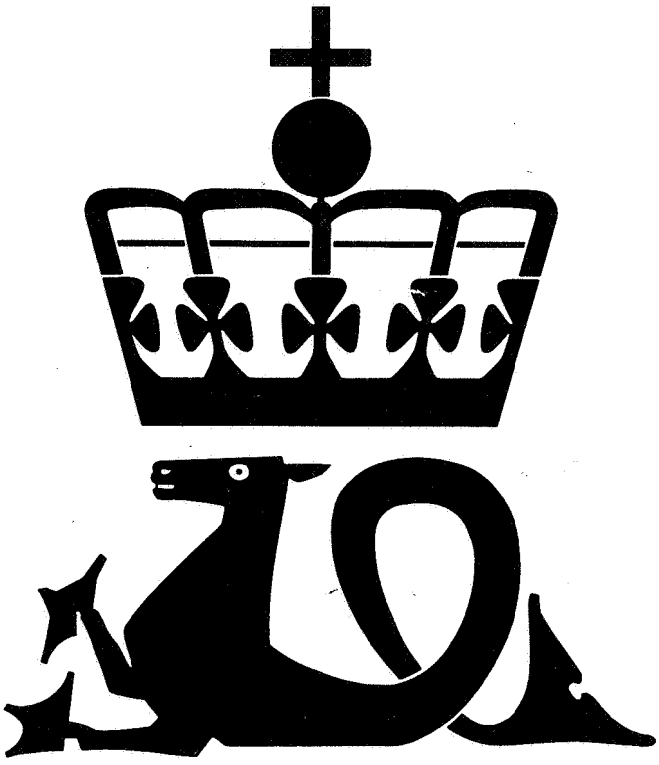

Norwegian Petroleum Directorate

ANNUAL REPORT 1985

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"The object of the Norwegian Petroleum Directorate is to actively contribute to a sound administration of the Norwegian petroleum resources through a balanced weighing of the natural, safety and economic aspects of the activity."

Contents

Report by the Board of Directors

The Norwegian Petroleum Directorate can report a slight increase in drilling activities in relation to 1984 and, with its 50 wells, 1985 has surpassed the 1982 record. Because of the major discoveries made in the Haltenbanken area during 1984, drilling activities north of Stad have increased strongly and include no less than 23 wells spudded in 1985. Sixteen of these were drilled on Haltenbanken.

Also on Haltenbanken, Statoil and Conoco have made discoveries on Blocks 6506/12 (gas/condensate) and 6507/7 (gas/oil), respectively. On Tromsøflaket no significant discoveries were made, though the results from Lopparyggen are interesting for further exploration.

Drilling activity in the North Sea has been concentrated on Oseberg, Snorre, Troll and Gullfaks and their associated areas. Statoil has made a new sizeable discovery to the south in Block 34/10.

A considerable increase occurred in activities on Svalbard in 1985 compared with previous years. Svalbards growing popularity is due primarily to the steady northward drift of research activity on the Norwegian Continental Shelf. Familiarity with the geology of Svalbard will be of paramount importance for companies planning to participate in exploration of the Barents Sea, and this fact has promoted the appreciably enhanced involvement on Svalbard.

In all some 14 large and small companies have carried out petroleum-related activities of various types on Svalbard in 1985, mainly seismic surveys and geological data collection. Only one of them however, the Soviet-owned Trust Arktikugol, has carried out any drilling for oil or gas.

In cooperation with the Ministry of Petroleum and Energy (MPE) the Norwegian Petroleum Directorate has prepared a five year plan for seismic surveys. This five year plan, running from 1985, presupposes a gradual and systematic expansion of the exploration areas in the north.

Seismic surveys in 1985 were carried out in weather conditions that were at times very favourable, and a total 22,205 kilometers of seismics were gathered on the Norwegian Continental Shelf, plus 4236 kilometers on the Jan Mayen ridge in accordance with a Norwegian-Icelandic agreement.

In connection with the updating of the five year plan and recommendations for new exploration areas where the allocation of production licences might prove interesting, the Norwegian Petroleum Directorate has since 1984 been holding annual meetings with the individual oil companies active on the shelf. The Directorate considers it highly useful to learn the first hand views of each company in connection with its total evaluation of the exploration activity.

The Norwegian Petroleum Directorate has also noted a substantial increase in the sale of its seismic packages. In 1985 the state earned approximately NOK 377 million in income from this sale, compared with NOK 301 million in 1984 and NOK 50 million in 1983.

The tenth licensing round was announced by the Ministry of Petroleum and Energy on 4 February 1985. This allocation round was divided into two phases; Phase A consisted of nine blocks or parts thereof in the North Sea, including Block 34/8; while Phase B consisted of 30 blocks within the Nordland II area. In addition, previously announced but unallocated blocks on Trøndelag I (Haltenbanken) were reannounced.

The application date for the tenth licensing round Phase A expired on 10 May 1985 with 22 companies having submitted applications. Block 34/8 was clearly the most popular prospect with 21 applicants.

The allocation of the tenth round Phase A took place on 23 August 1985. Of the nine blocks announced, eight blocks or parts thereof were allocated.

The time limit for Phase B expired on 16 August 1985 with 20 applicant companies. The applications were divided among 24 blocks, two of which were within the Trøndelag I area. The allocation of tenth round Phase B blocks was effected on 28 February 1986.

The Norwegian Petroleum Directorate's resources estimates for the Norwegian Continental Shelf were revised during 1985, partly due to new discoveries, and partly due to updates in previous estimates. For oil including natural gas liquids (NGL), resources estimates have been upgraded by 349 million Sm^3, while gas estimates have been upgraded by 160 billion Sm^3. The Norwegian Petroleum Directorate's present estimate of proven, technically recoverable reserves is 4.65 billion tons oil equivalent (toe), of which 0.43 billion have already been produced.

The Act relating to Petroleum Activities (Petroleum Act) with regulations entered into force on 1 July 1985. From this date the Norwegian Petroleum Directorate acquired a substantially larger set of work tasks and responsibilities within the supervision of safety and emergency preparedness in the petroleum activities. The Board has noted with satisfaction that during the processing of the act, the need for the coordinated management of and coordinated official responsibility for enforcement and administration of safety supervision was highlighted.

The Directorate administrates this supervisory responsibility and has the option of bringing in other public authorities having special competence by agreement with the agencies concerned. The Petroleum Act with its revised control arrangement therefore facilitates the implementation of collective, total safety evaluations of the activity.

The Board looks with continued concern however at the implementation of the Petroleum Act. Though it was intended to achieve a clear division of responsibility, it has nevertheless not created the necessary understanding of the application areas of the Petroleum Act and maritime legislation as regards mobile installations.

To establish a more unified, formalized system of coordinating the safety and environmental protection efforts on production fields in the North Sea, the Norwegian Petroleum Directorate in 1985 directed the implicated licencees to present a collected plan proposing how to accomplish this coordination responsibility. It turned out that the operating companies were willing to implement certain changes to accommodate the supervisory authorities expectations of good safety cooperation.

The extensive use of contractors within the activities creates a situation where large groups of personnel are moved from field to field at relatively short intervals. This factor will increase the need to establish unified, overriding models of safety cooperation on the Norwegian Continental Shelf. Unified solutions will also help to secure more unified administrative control practices by the supervisory authorities.

In the light of this the Norwegian Petroleum Directorate in November 1985 requested the licensees with operator responsibility on production fields on the Norwegian Continental Shelf to set up Coordinating Working Environment Committees to mirror the operators cooperational responsibility and the intentions of the Working Environment Act (WEA) regarding co-determination for all groups of personnel in the activities.

On 6 October 1985 in Well 6407/6-2 on Haltenbanken there occurred an uncontrolled gas blow-out with the "West Vanguard" drill rig, which was drilling an exploration well for Statoil. The gas caught fire and caused an explosion with subsequent conflagration. Of the 80 people onboard the rig, one lost his life. The Norwegian Petroleum Directorate has set up a special group to clarify the course of events and causal relationships, as well as evaluate possible measures in the light of the accident.

On 22 November 1985 an uncontrolled blow-out of shallow gas occurred from Well 34/10-A-2H being drilled by the "Deepsea Bergen" rig. The onset of the leak was observed at an early stage with an underwater camera and the rig was hauled off station a safe distance from the blow-out. The situation was evaluated by the operator and shipowner as not representing any particular risk to the crew or the installation, and the crew were therefore not evacuated.

On 26 June 1985 the Statfjord C platform, which will drain the northern part of the Statfjord field reservoir, started production from three wells. The start-up and initial production phase have progressed without any problems.

The operating licence for the Statpipe system was awarded in September by the authorities. In October the first quantities of dry gas were delivered from Statfjord via Kårstø to Ekofisk for further transportation in the Norpipe system.

In order to have an alternative to the development of Sleipner in case the negotiations for gas deliveries did not succeed, the Norwegian Petroleum Directorate was working as early as in 1983–84 on the advancement of the Gullfaks Phase II development. The Norwegian Petroleum Directorate remained abreast of developments by participating in licencee meetings and was in a position if required to process the development plans for Gullfaks Phase II rapidly.

On 10 February 1985 the British authorities announced they would not approve the Sleipner agreement. The Gullfaks licensees submitted their field development plan for Phase II to the authorities on 6 February. The plan was dealt with by the Norwegian Petroleum Directorate in the course of the spring of 1985, at the same time as the Directorate was carrying out an evaluation of the opportunities available for advancing and coordinating development projects, and thus limiting the deleterious long-term effects on the activity level of the loss of the Sleipner agreement. These studies showed that an advancement of Gullfaks Phase II would more than compensate in the short-term for the loss of Sleipner as regards investments. To help secure a uniform increase in production during the 1990s however, the advancement of other promising development projects, mainly oil fields, is desirable. There will be a need for new development projects from the mid 1990s.

The Norwegian Storting approved the development of Gullfaks Phase II on 7 June 1985.

The subsidence of the Ekofisk field will be a central oil policy question in 1986. In November 1984 it was discovered that the seabed at Ekofisk was sinking. Measurements carried out since then indicate

a total subsidence of approximately three meters at 1 December 1985. The subsidence rate from 1979–80 has been estimated to between 0.4 and 0.5 meters a year.

In its efforts to reduce the rate of collapse the operator has since August 1985 been reinjecting large quantities of gas. The sale of gas to the continent has for this reason had to be cut back by approximately 25 per cent.

The subsidence may have major consequences for safety, resource recovery, and economically. This means that the problems will have to be solved with input from all affected parties.

The Board considers it highly important that an acceptable solution to the subsidence problem is found during the spring of 1986.

Negotiations regarding the redistribution of the resources on the Statfjord field between Norwegian and British partners started in June 1985 and are due to terminate in 1987.

Negotiations for redistribution of the Murchison field were ongoing in 1985 and are due to terminate in 1986.

In 1985 the Norwegian Petroleum Directorate initiated the collection of environmental data from the Barents Sea with a view to future oil activities. Data are being collected that will be of decisive importance during all phases of the oil activity, both with respect to safety and economy. In addition, data will be collected to form the basis for parts of the consequence analyses than have to be carried out pursuant to the Petroleum Act before new areas can be opened for the allocation of production licences or initiation of exploration drilling. This project is being financed at present by subsidies from oil companies which have been allocated production licences north of the 62nd parallel. The Norwegian Petroleum Directorate considers it essential that the continuity of this project is assured, so that lack of knowledge of the environmental conditions does not delay a possible exploration start in these areas. It is therefore essential that the future funding of this project is entirely public, and thus independent of possible financial backing by oil companies.

State-financed clearing up operations on the seabed in 1985 have utilized methods different from previously, at the same time as the entire assignment has been seconded to a private company with subsea expertise. Experience gained from the years clearance operations has been positive and can form the template for future years.

In the autumn of 1985 the Norwegian Petroleum Directorate started work on its annual Petroleum Outlook. This time the focus will be on coordination.

During the last year great emphasis has been placed on evaluations of the Troll field. It has been considered particularly important to coordinate the two Troll production licences so that a collected plan can be submitted that presents an optimal solution for the whole area. It is assumed that such coordination of production licences will be effective fairly soon.

Two main considerations must be observed when developing a field. A strategy must be selected that facilitates reliable gas deliveries for a period, at the same time as satisfactory oil and gas recovery is achieved. Furthermore, the gas deliveries from Troll are seen as an important part of our collected gas strategy.

The four operators have made extensive efforts to evaluate a number of competing development alternatives. It is expected that the development plan, when presented, will contain a set concept for the first phase with several alternatives for later phases that are sufficiently flexible to be tailored to the overall strategy.

During 1985 the Norwegian Petroleum Directorate has carried out general area planning for the Troms area, Haltenbanken, Oseberg area and 34-area (the area around Statfjord, Gullfaks, Snorre and 34/8).

The studies show that coordination of new field developments and the exploitation of existing infrastructure can secure cost savings.

The studies are a part of the Norwegian Petroleum Directorate's groundwork for the Petroleum Outlook and its preparations for the future handling of field development plans in these areas.

Injection of gas from one field to another is a concept that has surfaced recently. The reasons for wanting to inject are to achieve greater flexibility and to increase recovery figures from the Norwegian Continental Shelf as a whole.

At present there are two fields in particular where re-routing of gas is especially interesting. In connection with the subsidence of the Ekofisk seabed, gas has to be injected to maintain the pressure in the reservoir. This process also tends to increase oil recovery from Ekofisk. However, since sales of Ekofisk gas are preset by agreement, trade-off with other gas fields may be one of several possible solutions.

Another example is the possible transfer of external gas to Oseberg. The Oseberg field itself contains too little gas to maintain full reservoir pressure. Several questions of principle arise in connection with the transfer of gas from one field to another, for example the relationship between the licensees on the respective fields. These questions are currently being actively considered in the Directorate.

During 1985 the Norwegian Petroleum Directorate has produced a report on alternative uses of gas. The objective of the analysis has been to clarify the new opportunities for gas application and link these with the development situation on the shelf. The results show that Scandinavia possesses a market potential sufficiently large to influence the development of gas fields, associated gas fields, area evaluations and investments in infrastructure on the Norwegian Continental Shelf. The Directorate in-

tends to integrate these options into the further planning of the shelf activities.

In 1985 the Norwegian Petroleum Directorate was allocated more new positions than ever before, and the number of members of staff recruited was also greater than in any previous single year. And although the number of staff leaving has increased somewhat, the percentage was about the same as in 1984. The loss has nevertheless been particularly pronounced among highly qualified personnel in the Resource Management Division, a fact that the Board views with concern.

The Norwegian Petroleum Directorate's divisional office in Harstad was established in 1980, though with few staff. Approval was given in the 1985 budget for six new positions. The resolved development of the office could thus begin. Some of our staff have already started, and the others will take up their positions during the first half of 1986.

The Board decided that an organizational study should be implemented in 1985 to determine whether there might be a need for administrative and organizational changes resulting from the entry into force of the new Petroleum Act on 1 July 1985. The Directorate engaged the services of an external consultant to carry out the work. The Directorate of Rationalization was also drawn into the task. The study has consisted apart from anything else of a clarification of the Norwegian Petroleum Directorate's work tasks in order to arrive at measures that can simplify or rationalize, and thus release resources. By the end of 1985 a working group was busy evaluating the Norwegian Petroleum Directorate's organizational structure and division of labour.

The completion of the new administration building in Stavanger has been progressing according to schedule. Moving in took place in January 1986. Thus for the first time since 1975 the main administration in Stavanger is assembled under one roof.

Stavanger, 26 February 1986

Members of the Board of Directors
of the Norwegian Petroleum Directorate

Martin Buvik

Andreas Lønning *Bjørg Simonsen* *Liv Hatland*

Kåre D. Nielsen *Ole Knapp*

Odd Raustein *Bjørn Kvant*

Fredrik Hagemann
Director

Bjørn Bratbak
Head of Department
Secretary to the Board

1 The NPD's objectives, Board of Directors and Administration

1.1 The Norwegian Petroleum 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 undertake 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 stipulated 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 have executed 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 decision 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 it is of special importance or fundamental interest.

1.2 The objective of the Norwegian Petroleum Directorate

On the basis of the above terms of reference, the following objective for the Directorate has been laid down:

"The objective of the Norwegian Petroleum Directorate is to actively contribute to a sound administration of the Norwegian petroleum resources through a balanced weighing of the natural, safety and financial aspects of the activity."

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, Director, Oslo
3 Ms Bjørg Simonsen, Mayor, Mo i Rana
4 Ms Liv Hatland, Personnel Director, Oslo
5 Mr Kåre D. Nielsen, Deputy Managing Director, Oslo
6 Mr Ole Knapp, Secretary, Oslo
7 Mr Øystein Kristiansen, Adviser, Stavanger
8 Mr Kjell G Dørum, Senior Engineer, Stavanger

The period of office of this Board expired on 31 March 1985. By Royal Decree of 12 April 1985 the above-mentioned Board members nos 1–6 were re-elected for a further period of two years until 15 April 1987. As new Board members, elected by and from among the employees, were appointed:

7 Mr Odd Raustein, Adviser, Stavanger
8 Mr Bjørn Kvant, Supervisor central files, Stavanger

Deputies:
For 1-4:
Mr Per Sævik, Manager, Rimøy
Ms Astrid Nistad, First Secretary, Gaupne
Ms Marit Greve, Editor, Bærum

For 5:
Mr Halvor Vaage, Director, Stavanger

For 6:
Mr Jan Strømme, Oil Secretary, Oslo

For 7–8:
Mr Kjell G Dørum, Senior Engineer, Stavanger
Ms Anna Aabø, Senior Engineer, Stavanger

During the report period the Board held ten meetings.

In April the Board undertook an inspection tour to Svalbard where board members visited Longyearbyen, the Sveagruva mines and Ny-Ålesund. Meetings were held with the management of Store Norske Kulkompani and a visit was paid to BP's seismic survey station on the Paula glacier.

In September the Board visited BP's main administration in London and BP's research laboratory in Sunbury.

The Board was also briefed in the contingency centre in Aberdeen and visited finally the Sullom Voe terminal in Shetland.

1.3.2 Organization

With effect from 1 January 1985 two new divisions were created at the same time as previous sub-departments were upgraded to departments. The new divisions are the Safety Control Division and the Resource Management Division.

Their heads are called the Director of Safety Control Division and Director of Resource Management Division respectively.

The newly created position of Information Manager has been occupied since 2 December 1985. From the same date public relations staff within the Administration Department were transferred to the Information Manager. At year-end the information office had four positions. The Information Manager reports directly to the Director General.

The expansion of the Harstad divisional office is outlined in Section 1.3.7 below.

A government research and development program for enhanced recovery of reserves and reservoir technology (SPOR) was initiated in 1985 with a secretariat linked to the Norwegian Petroleum Directorate.

From 1 July 1985 a provisional project group was set up to look after assignments in connection with the implementation of the new Petroleum Act. The group comprises staff members of the Safety Control Division and Legal Department. The group reports directly to the Safety Director.

Similarly, a follow-up group was set up to cover regulations within the area of authority of the Ministry of Petroleum and Energy, comprising representatives of the Resource Management Division and Legal Department.

To achieve a more workable organizational structure some of the service functions of the Administration Department were assembled into one group. The change was made effective from 8 July 1985 and will be on trial provisionally until 1 April 1986.

In connection with the entry into force on 1 July 1985 of the new Petroleum Act, in February 1985 the Directorate took the initiative for an analysis of its activities in order to be able to evaluate the administrative and organizational consequences of the passing of the Act and the regulations thereto.

The analysis, which is being carried out with the assistance of a firm of consultants, is aimed in the first phase at describing the application of Directorate resources to tasks performed by the Directorate before the Act came into force. This phase was completed on 20 March 1985 with an interim report.

The Directorate found it necessary to pursue this

work in order to determine the most rational use of its resources, including pinpointing any possible need to re-tailor its organization as a result of the new Petroleum Act. The Directorate also had reservations with respect to the Ministry of Local Government and Labour regarding whether the budget criteria that formed the basis for the 1986 State Budget would be amenable to revision as a result of the implementation of the new Act.

1.3.3 Personnel

In the budget for 1985, 30 new positions were created, six of them at the Harstad divisional office. At the end of the report period there were 319 authorized positions in the Directorate. In addition there are three positions salaried by the Directorate for Development Aid (NORAD). At year-end 1985 the Directorate employed 320 persons, see Figure 1.3.3.a. Staff members include 35.4 per cent women. Figure 1.3.3.b shows the proportions of men and women in the various job categories within the Directorate.

FIG. 1.3.3.a
Positions 1973–1985
Permanent positions and engagements

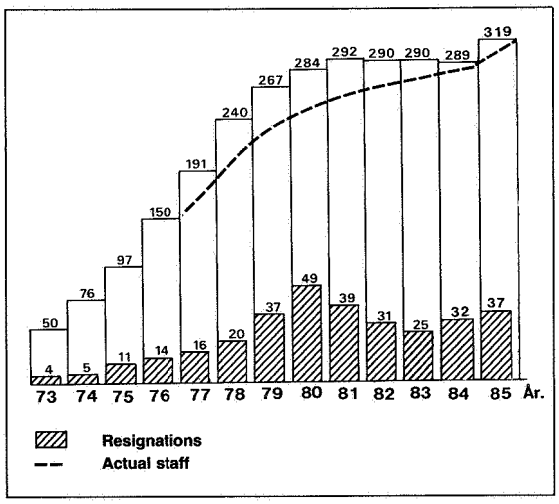
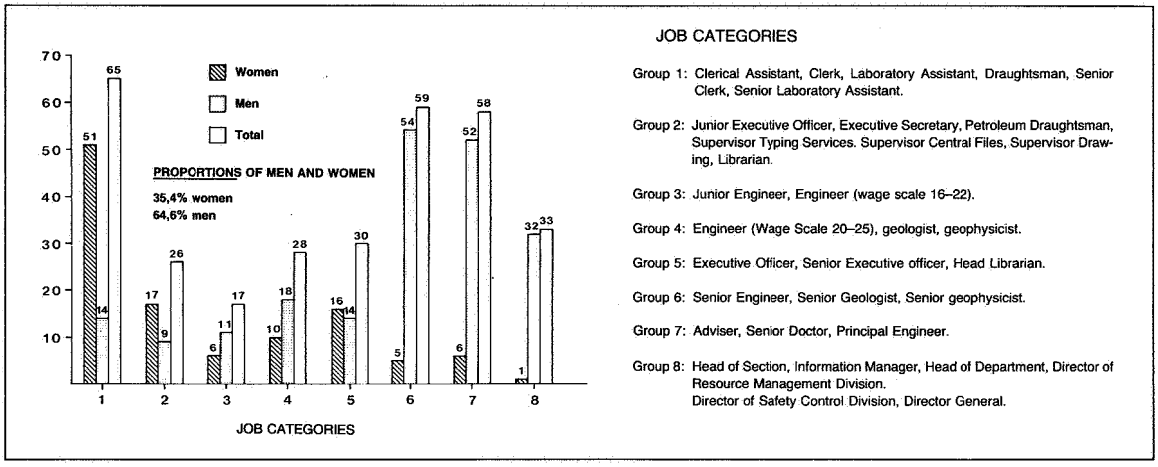


FIG. 1.3.3.b
Positions in NPD per 31. December 1985



In addition, five positions were salaried through other agencies budgets, either as occupationally disabled persons or through the youth employment scheme. One pensioned state employee has been working during parts of the period on pensioner conditions. Also working at the Directorate is one of NORADs special advisors on oil matters in developing countries. The work tasks are tied to projects in several countries, including Tanzania. Two persons doing civilian service have worked with the research data base Infoil 2.

During the report period the Directorate took on 43 new members of staff. Of the newcomers, 17 relocated to Stavanger, ten come from oil related activities and eight are newly qualified.

Thirty-seven members of staff left their positions, see Table 1.3.3.a and b. This constitutes approximately 12 per cent of the total number authorized. Among the leavers this year highly qualified personnel have been disquietingly well represented. The drain has been particularly marked in the Resource Management Division, where no less than 22 officers have left. Most of them were geo-specialists. One positive trend was that the exodus from the Safety Control Division was again small. Figure 1.3.3.c shows the personnel drain from the Norwegian Petroleum Directorate to various oil companies for the years 1973–1985.

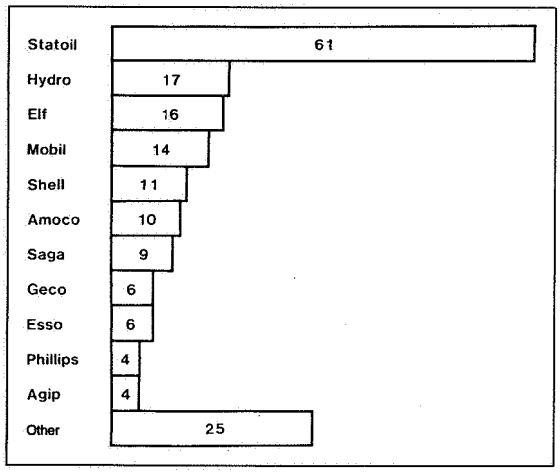
During the report period a total of 105 positions were advertised as being vacant.

The applicants can be broken down as follows:

TAB 1.3.3.a
Personnel who left NPD with indication of type of position

Division/ Department	Managers	Ad-visers	Prin.-Engin-eer	Sen-engin-eer	Senior geol./ Geol.	Engin-eer Jun. engin-eer	Jun. exec. officer Exec. officer Senior exec. officer	Office staff	Summary	Turn-over in %
Resource Management	2	4	0	5	5	5	0	1	22	18,6
Safety Control	0	3	0	1	0	0	1	1	6	6,1
Legal	0	2	1	1	0	0	1	0	5	23,8
Administration	0	0	0	0	0	0	1	3	4	5,4
Total	2	9	1	7	5	5	3	5	37	11,6

FIG 1.3.3.c
Personnel who left NPD for oil companies during the period 1973–1985



In its situation vacant advertisements for positions covered by the quota rules the Directorate has encouraged women to apply.

Equal opportunities work
As a result of a special agreement on equal opportunities an Equal Opportunities Committee was set up in the spring of 1985. This committee consists of four members, two from management and two from the staff unions.

The committee has organized a theme day on equal opportunities for Directorate managers. Moreover, the committee has taken the initiative for the preparation of a training program for women executive officers. Parts of this program were held this autumn with 14 participants.

The committee chairperson has participated in an equal opportunities conference arranged by the Ministry of Administration and Consumer Affairs.

The committee is working on an action plan for equal opportunities work within the Directorate and background material for Directorate employees.

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 dealt, among other subjects, with:

- study of NPD organization
- annual report
- budget proposals
- the Harstad divisional office, job instructions etc
- new premises
- internal organizational changes
- the new Petroleum Act
- the equal opportunities agreement
- revision of overtime guidelines
- staff interviews
- revision of staff code
- use of credit cards
- revision of local special agreement on co-determination
- announcement details for adviser position.

TAB 1.3.3.b
Personnel who left NPD in 1985 with indication of new place of work

Division/ Department	Oil-indusry	Other nongov't activity	Other gov't activity	Miscell-aneous	Education	Total
Resource Management	17	2	2	2	0	23
Safety Control	3	0	1	2	0	6
Legal	4	0	0	0	0	4
Administration	2	1	0	1	0	4
Total	26(179)	3(30)	3(46)	5(45)	0(19)	37(318)

Figures in brackets apply to the period 1973–1985.

TAB 1.3.3.c
Distribution of applicants to vacant positions

Position category	No. of vacancies announced	Total applicants		Internal applicants		External applicants		Final appointments	
		M	W	M	W	M	W	M	W
Management positions	8	38	6	14	3	24	3	5	1
Advisers	10	71	15	22	9	49	6	6	2
Technical EO's*	53	329	90	64	20	265	70	37	10
Non-technical EO's*	9	96	114	9	51	87	63	2	5
Office positions	25	43	197	20	46	23	151	2	19

*EO = Executive officer

1.3.4 Training

The training budget for the report period was NOK 2,850,000. These funds have been used in accordance with earlier practice, and large amounts have as previously been appropriated for 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.

In 1985 a number of training initiatives were taken following from the entry into force of the Petroleum Act. These training and briefing measures were carried out internally as well as externally. In January 1985 the Norwegian Petroleum Directorate took the initiative for a cooperative venture with the Ministry of Local Government and Labour to hold a seminar on internal control for the authorities concerned. The seminar was designed to coordinate the supervisory approaches of the various control authorities, and to make the supervisory methods employed by the Norwegian Petroleum Directorate better known among the other agencies. The seminar also aimed to introduce the agencies to the regulations enforced by the Norwegian Petroleum Directorate with emphasis on its control methods. This initiative also led to the Ministry of Local Government and Labour setting up a working group to review the experiences gained by the Norwegian Petroleum Directorate and others in relation to internal control, and with a view to sharing these with the other agencies that, administratively speaking, come under the wings of the Ministry of Local Government and Labour. This work is included in the so-called "modernization program" that the Ministry of Local Government and Labour is working towards.

The Norwegian Petroleum Directorate has also arranged a number of seminars relating to the Petroleum Act and the new arrangements for supervision of the petroleum activities for the benefit of the petroleum industry, shipowners, labour unions and employer associations, etc.

The entry into force of the Petroleum Act also generated a substantial requirement for information and training within the Directorate itself.

1.3.5 Budget and finance

In 1985 a total of NOK 323,205,000 was allocated to the various Directorate tasks. The amount was distributed as follows:

– Operating budget	NOK 159,505,000
– Inspection costs	NOK 9,500,000
– New premises	NOK 61,000,000
– Geological and geophysical surveys	NOK 86,700,000
– Safety and emergency preparedness research	NOK 2,000,000
– Clearing up the seabed	NOK 4,500,000
Total appropriation budget for 1985	NOK 323,205,000

NOK 70,440,000 of the operating budget was allocated to salaries and NOK 10,700,000 to the running of buildings and renting of premises. The remaining NOK 78,365,000 of the operating budget represents other expenses such as external consultancy services, operation of a weather ship, research and development projects, travelling, training, electronic data processing (EDP), investments in new equipment, etc.

Its budget situation causes the Norwegian Petroleum Directorate to be faced with an ever greater challenge regarding priorities. Efforts therefore focus on developing better planning and management systems.

Revenues and incomes

In addition to revenues in the form of royalties and acreage fees collected (Chapter 5), the Directorate received incomes totalling NOK 411,356,731.

Incomes in 1985 were distributed thus:

Sales of publications	NOK 2,453,122
Sales of released sample material	NOK 501,129
Survey fees	NOK 680,000
Refunded inspection costs	NOK 21,751,392
Refunded for environmental data collection	NOK 4,000,000
Sales of seismic survey results	NOK 377,346,130
Credit interest on bank deposits	NOK 4,048,126
Miscellaneous incomes	NOK 576,829
Total income for 1985	NOK 411,356,731

2 Activities on the Norwegian Continental Shelf

2.1 Exploration and production licences

2.1.1 New production licences

In 1985, 20 new production licences were allocated. Production licences 101–111 constitute the ninth licensing round and licenses 112-120 constitute licensing round 10A (Table 2.1.1.a).

TAB 2.1.1.a
Ninth licensing round and licensing round ten A

Prod.lic.	Field/block	Ownership %	Operator(0)/licensee
101	16/10	25,000	0 Norsk Agip A/S
102	25/5	30,000	0 Elf Aquitaine Norge A/S
103	25/7	30,000	0 Norsk Conoco A/S
104	part of 30/9	30,000	0 Norsk Hydro Produksjon a.s
105	6406/6	50,000	0 Den norske stats oljeselskap a.s
106	6407/4	50,000	0 Den norske stats oljeselskap a.s
107	6407/7	20,000	0 Norsk Hydro Produksjon a.s
108	7120/1	40,000	0 A/S Norske Shell
109	7120/2 and 7120/3	15,000	0 Norsk Hydro Produksjon a.s
110	7120/5 and 7121/5	50,000	0 Den norske stats oljeselskap a.s
111	7121/1	35,000	0 Esso Exploration and Production Norway A/S
112	part of 25/2	50,000	0 Elf Aquitaine Norge A/S
113	2/12	25,000	0 Norsk Hydro Produksjon a.s
114	9/2	50,000	0 Den norske stats oljeselskap a.s
115	9/3	30,000	0 A/S Norske Shell
116	part of 15/12	50,000	0 Den norske stats oljeselskap a.s
117	25/6	15,000	0 Saga Petroleum a.s
118	26/4	25,000	0 BP Petroleum Development of Norway A.S
119	29/3	25,000	0 Total Marine Norsk a.s
120	34/8 and part of 34/7	18,000	0 Norsk Hydro Produksjon a.s

TAB 2.1.1.b
Production licenses as of 31.12.85

Alloc. with effect from	Licensing round	Production license no	Total area sq km²	No of blocks
01.09.65	1	001-021	39 842,476	74
07.12.65	1	022	2 263,565	4
23.05.69	2	023-031	4 107,833	9
30.05.69	2	032-033	746,285	2
14.11.69	2	034-035	1 024,529	2
11.06.71	2	036	523,937	1
10.08.73	Statfjord	037	586,834	2
01.04.75	3	038-040,042	1 840,547	7
01.06.75	3	041	488,659	1
06.08.76	3	043	604,559	2
27.08.76	3	044	193,077	1
03.12.76	3	045-046	1 270,682	4
07.01.77	3	047	368,363	2
18.02.77	3	048	321,500	2
12.09.77*	1	019(2)		
23.12.77	3	049	485,802	1
16.06.78	Gullfaks	050	500,509	1
06.04.79	4	051-058	4 007,887	8
18.01.80	5	059-061	1 108,078	3
27.03.81	5	062-064	1 099,522	3
21.08.81	6	065-072	3 218,945	9
23.04.82	5	073-078	2 311,912	6
20.08.82	–	079	102,167	1
10.12.82	7	080-084	2 082,966	5
08.07.83	–	085	1 521,160	3
09.03.84	8	086-100	6 346,604	15
14.03.85	9	101-111	5 293,053	13
26.07.85	–	112	260,215	1
23.08.85	10A	113-120	3 075,435	9
			85 597,101	191

* Part of prod. lic. 019 was relinquished and reallocated 019(2) – 12.9.77

2.1.2 Exploration licences

At 31 December 1985, a total of 136 commercial exploration licences had been allocated. The following licences were awarded in 1985:

Conoco Norway Inc	Licence no. 125
Saga Petroleum a.s	126
A/S Norske Shell	127
A/S Geoteam	128
Unionoil	129
Geophysical Service Inc	130
Deminex (Norge) A/S	131
NOPEC a.s	132
Bow Valley Industries Ltd	133
CGG Norge	134
Total Marine Norsk A.S	135
Statoil	136

Licence no. 124 was awarded in 1984 but became effective only on 1 January 1985.

Licence nos. 135 and 136 were awarded in 1985 but will become effective only from 1 January 1986.

2.1.3 Transfer of licences

No licences were transferred in 1985.

2.1.4 Relinquishments

In 1985, relinquishments were made on parts of areas from five production licences. These are shown in Table 2.1.4.

TAB 2.1.1.c
Licensed area as of 31 December 1985

Prod. lic. allocated	Original area (sq km)	Relinquistred area as of 31.12.85	Area on prod. lic. in sq. km	Area on prod. lic in percent	Split on no. of blocks
1965	42 106,041	36 439,151	5 666,890	13,46	25
1969	5 878,647	3 004,025	2 874,622	48,90	13
1971	523,937	262,047	261,890	49,99	1
1973	586,834	295,157	291,677	49,70	2
1975	2 329,206	1 633,827	695,379	29,86	4
1976	2 068,318	924,825	1 143,493	55,29	5
1977	1 175,665	896,981	278,684	23,70	2
1978	500,509	–	500,509	100,00	1
1979	4 007,887	1 224,705	2 783,182	69,44	8
1980	1 108,078	–	1 108,078	100,00	3
1981	4 318,467	–	4 318,467	100,00	12
1982	4 497,045	–	4 497,045	100,00	12
1983	1 521,160	–	1 521,160	100,00	3
1984	6 346,604	–	6 346,604	100,00	15
1985	8 628,703	–	8 628,703	100,00	23
	85 597,101	44 680,718	40 916,383	47,80	129

TAB 2.1.1.d
Licensing rounds. Norwegian and foreign shares.

Round	Year	No. of bloks	Share in per cent		Operator per cent	
			Norw.	Foreign	Norw.	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	20	58	42	63	37
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	36	50	50
Prod. lic. 079	1982	1	100	0	100	0
7	1982	5	60	40	80	20
Prod. lic. 085	1983	3	100	0	100	0
8	1984	17	60	40	60	40
9	1985	13	43	57	62	38
10A	1985	10	50	50	67	33

TAB 2.1.4
Relinquishments

Production licence no.	Operator	Block	Original area sq. km	Relinquished area as of 6. april 85	Area on production license in sq. km^2
051	Statoil	30/2	504,440	252,372	252,068
052	Statoil	30/3	504,440	253,595	250,845
054	Shell	31/2	504,440	184,722	319,718
055	Hydro	31/4	508,360	287,997	220,363
057	Saga	34/4	492,619	246,019	246,600

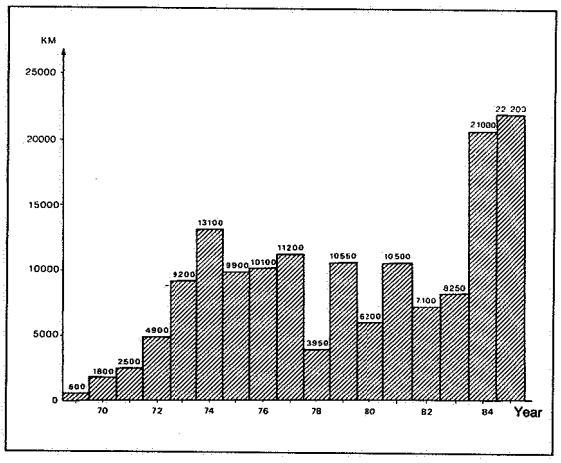
2.2 Surveys and exploration drilling

2.2.1 Geophysical and geological surveys

2.2.1.1 Opening of new exploration areas

Also in 1985, the Norwegian Petroleum Directorate surpassed the prognosis for the compilation of seismic data. This was primarily due to very favourable weather conditions as well as very few technical problems.

FIG. 2.2.1.a
Seismic surveys carried out by Norwegian Petroleum Directorate north of Stad



A total of 22,205 km of seismics were compiled (Figure 2.2.1.a), of which 4,236 km on the Jan Mayen ridge.

In the course of 1985, four new areas were made ready for further exploration, i.e. Nordland 3 (western extension), Nordland 4, Troms 3 and Loppa-ryggen East (Figure 2.2.1.b and c).

In addition, regional seismics were shot off Mid-Norway, in the North Cape basin and between Bear Island and Spitsbergen.

2.2.1.2 The Norwegian Petroleum Directorates geophysical surveys 1985

In the course of 1985, the Norwegian Petroleum Directorate collected seismics from seven areas.

Five lines totaling 1,212 km were shot on Storegga. These lines were collected by Geco with "Malene Østervold" and processed in Gecos processing center in Sandvika. These are regional lines which are processed to 12 seconds.

FIG. 2.2.1.b
Areas opened for surveys between 62°N and 68°N

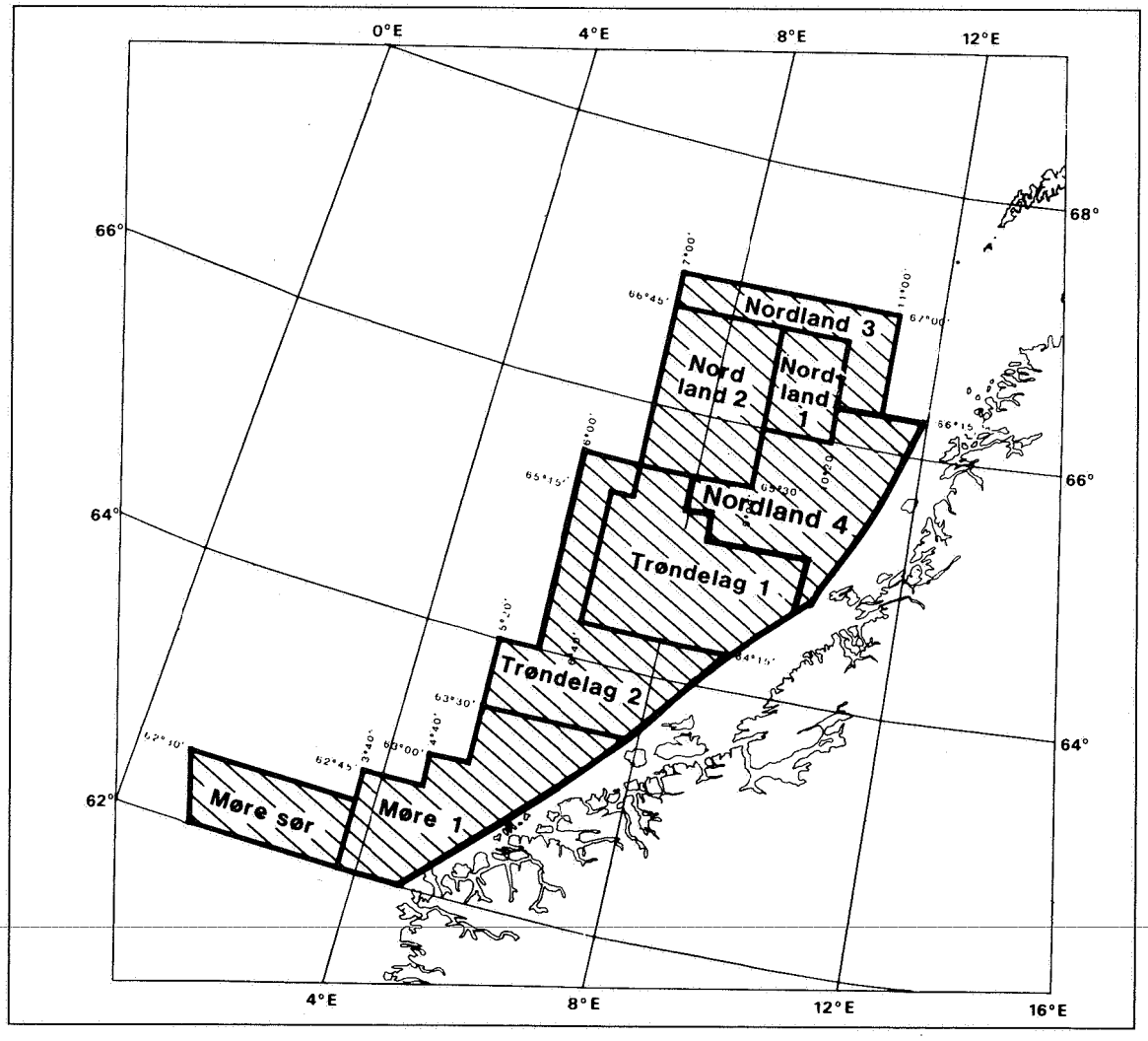
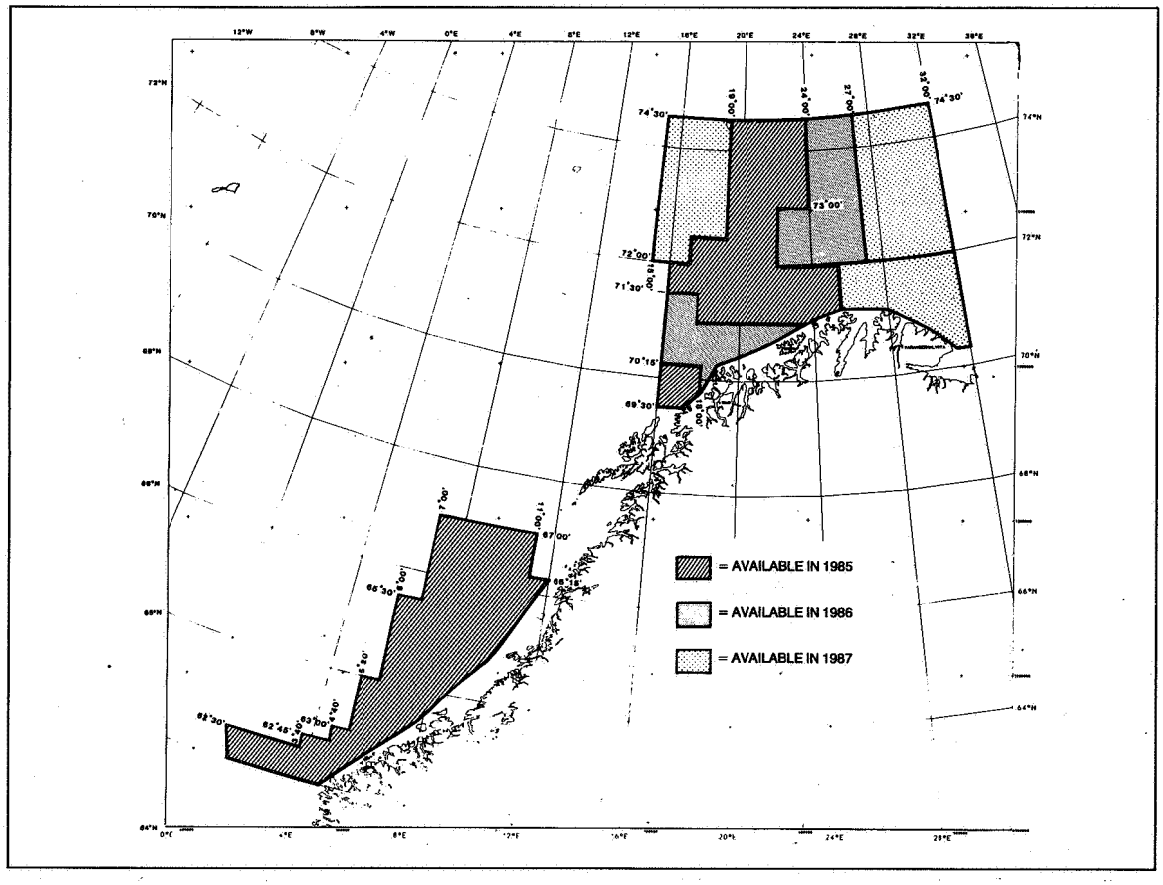


FIG. 2.2.1.c
Areas which are – or in the near future will be – available for seismic surveys by the industry



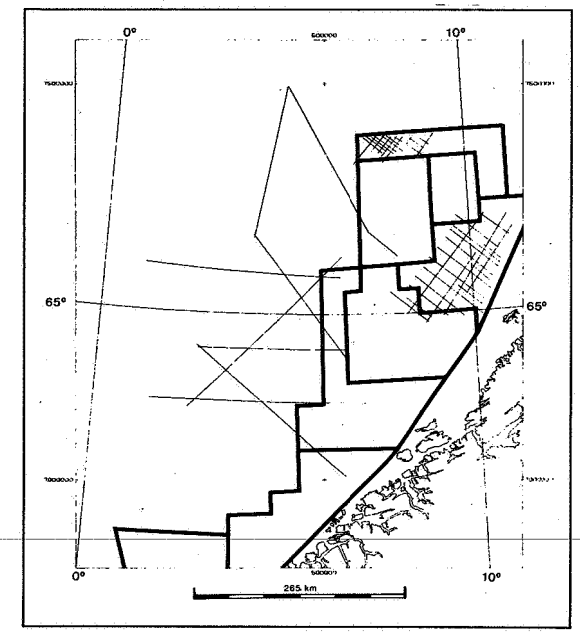
In addition, 496 km were collected on Nordland 3 in connection with a western extension of this area. These data were also gathered by Geco with "Malene Østervold" and processed with Horizon Exploration in England.

Some 1,518 km were shot on Nordland 4 by Compagnie Generale de Geophysique (CGG) with the vessel "Leon Migeaux". These data were processed with CGG in London. The area was opened on 1 July 1985 together with the western extension of Nordland 4. This means that practically the entire mid-Norwegian continental shelf within reasonable water depths has been opened for seismic surveys (Figure 2.2.1.d).

Furthermore, test data were compiled along a line on Nordland 2 by Geco with the vessel "Sea Searcher". On this line, two seismic cables at different depths were used. In connection with this test, some 606 km of regional data were collected in the area off Nordland 2.

In the Troms 3 area, 3,397 km were shot by Western Geophysical with the vessel "Western Atlantic". These data were processed by Western Geophysical in London. This means that also the Troms

FIG. 2.2.1.d
Seismic surveys on the Mid-Norwegian Shelf 1985

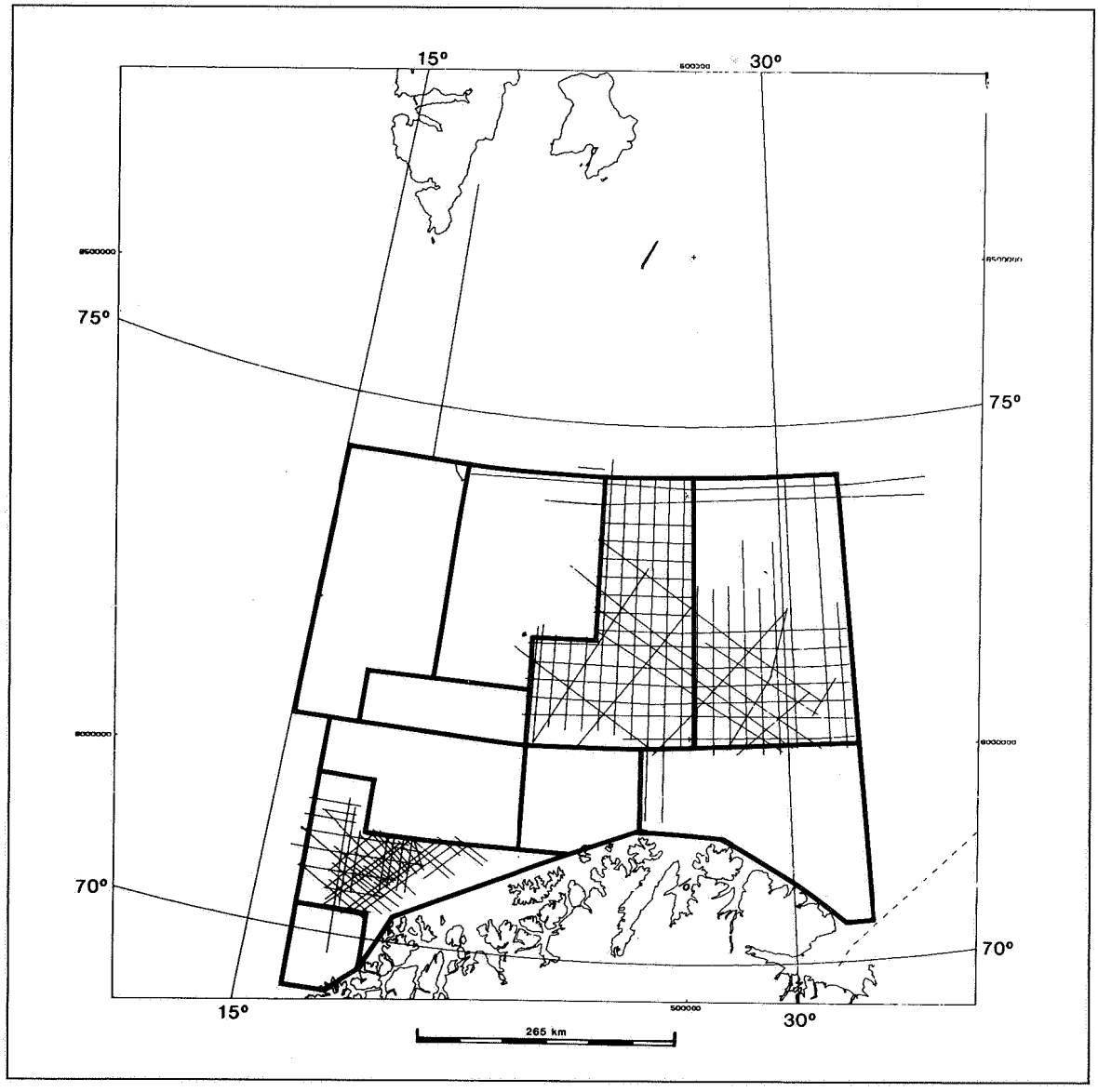


3 area may be opened for seismic surveys in the 1986 season.

However, the bulk of the data were gathered from the eastern part of the Barents Sea in the areas North Cape basin and Lopparyggen East. Here a total of 8,273 km were shot with "Malene Østervold" and 1,973 km with "Geco My". These data were processed with Seismograph Service Limited (SSL) and CGG in London and by Geophysical Service International (GSI) and Geco in Stavanger. The Lopparyggen East area is thus ready for the commencement of seismic surveys, while further surveys are planned in the North Cape basin.

Furthermore, a line of 290 km was shot between

FIG. 2.2.1.e
Seismic surveys, Troms III, Lopparyggen – øst and Nordkappbassenget

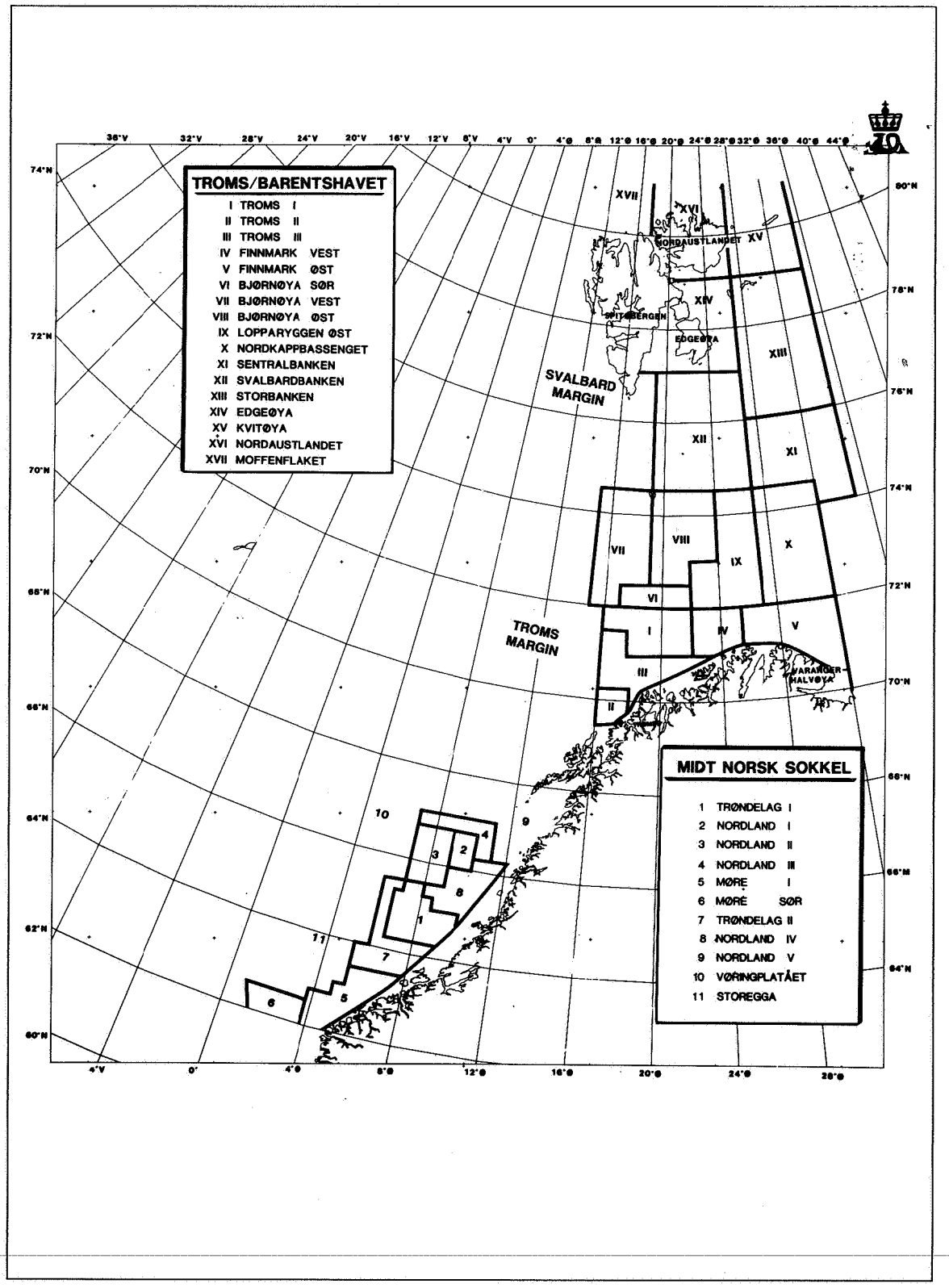


Spitsbergen and Bear Island with Geco's vessel "Sea Searcher" as well as a test line of 49 km on Troms 3 with Geoteam's vessel "Geo Scanner".

Just before the conclusion of the cruise with "Malene Østervold" in the North Cape basin, the surveys were stopped because of an event in which Soviet navy vessels were involved and which caused a substantial section of the cable to disappear. It was nevertheless possible to carry through the rest of the program with reduced cable length.

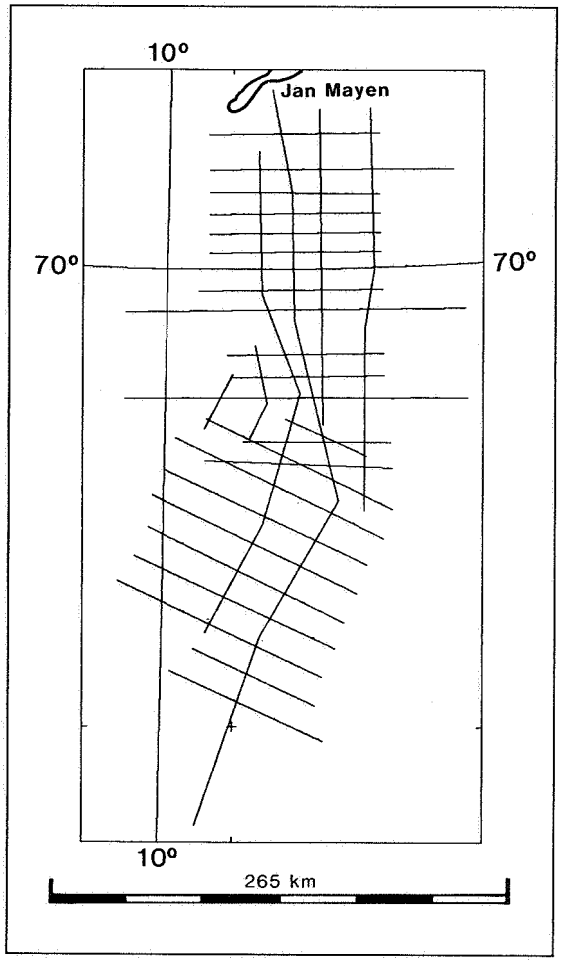
Following this survey, 4,236 km of seismics were shot on the Jan Mayen ridge with "Malene Østervold" (Figure 2.2.1.g). This area lies south of Jan Mayen and the survey is related to the border agreement between Norway and Iceland. As part of this border agreement, it has been agreed to perform

FIG. 2.2.1.f
Area designations north of Stad



joint surveys together with Iceland within a more specifically defined area. This area lies partly on the Icelandic side but primarily on the Norwegian side of the borderline. Norway has assumed the responsibility of financing the surveys and the Norwegian Petroleum Directorate has been ordered to take charge of the implementation.

FIG. 2.2.1.g
Seismic surveys, Jan Mayen, 1985



As concerns processing, the Norwegian Petroleum Directorate has completed the projects from 1984 with the companies GSI, Western, CGG, Geco, Petty Ray and Horizon.

In 1986, the Norwegian Petroleum Directorate is planning to compile some 20,000 km of seismics in the following areas:

a) Finnmark East and the North Cape basin
In the course of the 1986 season, this area will be completely covered with seismics by the Norwegian Petroleum Directorate.

b) Bear Island
This area will be completely covered in the course of 1986/87.

c) The Barents Sea, regionally
The plan is to shoot a good deal of regional lines north of 74 degrees 30 minutes.

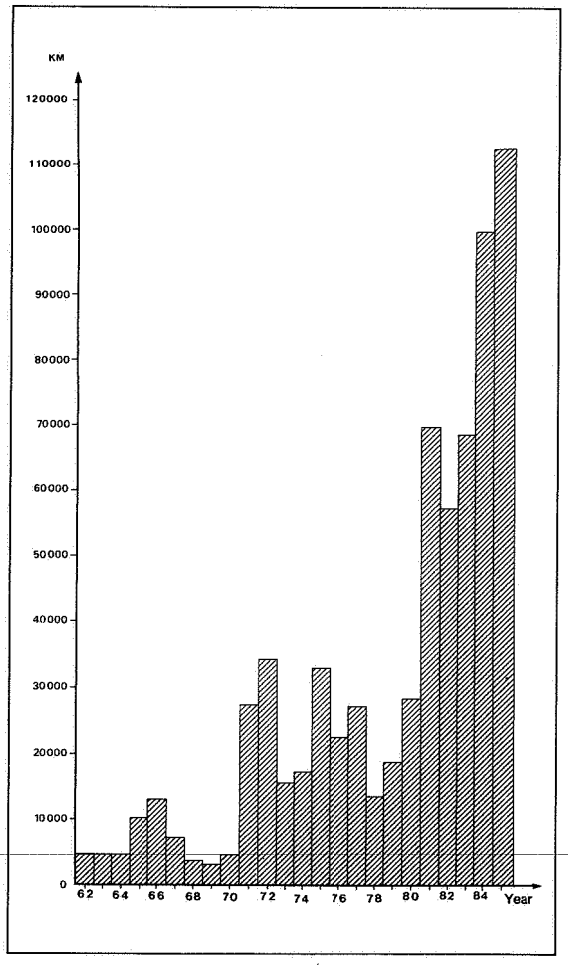
d) Mid-Norway
Some regional seismics are planned in the deep sea areas off the areas which have been opened.

2.2.1.3 Geophysical surveys administered by the companies

In 1985, a total of 89,400 km seismics were shot on the Norwegian Continental Shelf under oil company or contractor direction. Of this length, 45,700 km were shot in the North Sea, and 43,700 km north of Stad from Møre to Bear Island. Figure 2.2.1.h shows the total geophysical surveys performed on the Norwegian Continental Shelf. The main reason for the increase in the seismics activity is that large areas have been opened north of Stad.

Three dimensional surveys were performed by Statoil on Blocks 34/10 and 30/3, by Elf on Frigg, Norsk Hydro on 30/9 and Saga on 6407/2. All in all,

FIG. 2.2.1.h
Seismic surveys carried out on the whole Norwegian shelf (surveys north of Stad included)



32,500 km of 3D data were collected, of which 4,150 km north of Stad.

Esso has been the operator for a group survey on Bear Island East where 2,300 km were shot.

In addition, speculative seismics have been gathered by Geco, Western, GSI and NOPEC. A total of 15,677 km were shot north of Stad and 3,640 km south of Stad.

There was also substantial activity on Spitsbergen in 1985. Statoil shot 1,085 km, Hydro 1,000 km, Nordisk Polarinvest 1,450 km and Arctic Exploration 156 km of seismics. In addition, Horizon Exploration shot onshore seismics for BP.

The remaining part of the companies surveys are two dimensional (2D) seismics in areas on production licences and within opened areas.

2.2.1.4 Sale of seismic data

In 1985, the Norwegian Petroleum Directorate sold data packages for NOK 377 million (NOK 301 million in 1984).

The following companies have bought all of the Norwegian Petroleum Directorates seismic computer packages in the various opened areas:

MØRE SOUTH (6 packages)
Agip, Amerada, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Mobil, Occidental, Phillips, Saga, Shell, Statoil, Texas Eastern, Total.

MØRE I (5 packages)
Agip, Amerada, Amoco, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Mobil, Occidental, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern, Total, Unionoil.

TRØNDELAG II (7 packages) NORTH OF 64 DEGREES 15 MINUTES
Agip, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern, Total.

TRØNDELAG II (7 packages) SOUTH OF 64 DEGREES 15 MINUTES
Agip, Amerada, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern, Total, Unionoil.

TRØNDELAG I (1 package)
Agip, Amerada, Amoco, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Mobil, Occidental, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern, Total, Unionoil.

NORDLAND IV (8 packages)
Shell

TAB 2.2.1.4
Packages of seismic data sold in 1985 and total sale

Package no	Name	1985	Total
001	MØRE-TRØNDELAG-REG-PAKKE-1	0	30
002	MØRE-TRØNDELAG-REG-PAKKE-2	9	24
003	TAMPEN SPUR	16	19
004	MØRE-SØR-84	15	19
005	TRØNDELAG-REGIONAL	6	22
006	HALTENBANKEN-VEST-84	20	21
007	FRØYABANKEN-84	22	23
008	MØRE-TRØNDELAG-PAKKE-2	1	21
009	MØRE-TRØNDELAG-PAKKE-3	0	28
010	TRÆNABANKEN	0	30
011	REGIONAL-DATA-NORDLANDSRYGGEN	0	20
012	NORDLAND-III-85	1	1
013	REGIONAL-DATA-MIDT-NORSK-SOKKEL	8	19
014	NORDLAND-II-83	1	21
015	NORDLAND-III-84	6	6
016	TROMS-II	5	7
017	REGIONAL-DATA-TROMS-ØST	6	16
018	FINNMARK-VEST-83	10	17
019	FINNMARK-VEST-84	14	17
020	NORDLAND-III-85	1	1
021	MØRE-SØR-TEST-84	2	2
022	STOREGGA-85	1	1
023	VØRINGSPLATÅET	1	1
100	TROMS-HOVEDPAKKE	0	34
101	REGIONAL-TROMS-BARENTSHAVET-73	2	17
102	TROMS-III-83/84	5	5
105	TROMS-I-ØST-77	0	17
106	TROMS-NORD-82-PAKKE-1	1	23
107	TROMS-NORD-83-PAKKE-3	0	22
108	TROMS-NORD-82-PAKKE-2	1	15
109	TROMS-NORD-83-PAKKE-4	1	15
200	BJØRNØYA-PAKKE-1	1	20
201	BJØRNØYA-SØR-84	17	20
202	BJØRNØYA-ØST-REGIONAL-84	12	12
203	BJØRNØYA-ØST-84	11	11
204	BJØRNØYA-ØST-TILLEGG-NORD	8	8
205	BJØRNØYA-VEST-REGIONAL-84	5	5
206	LOPPARYGGEN-ØST-REGIONAL-84	6	6
300	BARENTSHAVET-SØR-ØST-HOVEDPAKKE	11	11
301	BARENTSHAVET-SØR-ØST-PAKKE-2	8	8

NORDLAND III (4 packages)
Shell

NORDLAND II (3 packages)
Agip, Amerada, Arco, BP, Britoil, Conoco, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Tenneco, Texas Eastern, Total, Unionoil.

NORDLAND I (2 packages)
Agip, Amerada, Amoco, Arco, BP, Britoil, Chevron, Conoco, Deminex, Elf, Esso, Fina, Getty, Gulf, Hispanoil, Hydro, Japan Oil, Mobil, Phillips, Saga, Shell, Statoil, Superior, Svenska Petroleum, Tenneco, Texaco, Texas Eastern, Total, Unionoil, ØMV.

TROMS II (2 packages)
Elf, Esso, Hydro, Mobil, Saga, Shell, Statoil

TROMS I (1 package)
Agip, Amerada, Conoco, Elf, Esso, Hydro, Mobil, Phillips, Saga, Shell, Statoil.

FINNMARK WEST (4 packages)
Agip, Amerada, Arco, BP, Conoco, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Tenneco, Total.

BEAR ISLAND SOUTH (4 packages)
Agip, Amerada, Arco, BP, Britoil, Conoco, Deminex, Elf, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texas Eastern, Total.

BEAR ISLAND EAST (8 packages)
BP, Conoco, Elf, Esso, Fina, Hydro, Mobil, Statoil.

2.2.1.5 Release of continental shelf data and material

In connection with the Norwegian Petroleum Directorates follow-up of the oil activities on the Norwegian Continental Shelf, the Directorate receives, apart from anything else, copies of well logs and continual, representative selections of drill cuttings and drill cores. Samples of drill cuttings are taken every 10 meters down the well hole, and each 3 meters in formations which may contain hydrocarbons. For wet samples, which shall weigh at least 0,5 kg, the same sampling frequency applies.

As regards drill cores, the Norwegian Petroleum Directorate receives complete longitudinal sections containing at least one fourth part of the core in exploration wells and half of the core in production wells.

Among its duties, the Norwegian Petroleum Directorate counts responsibility for the publication of data and release of material for educational and research purposes. Data and material are released five years after well completion. The interpretations of the operators are not released.

Well Data Summary Sheets (WDSS) are published annually, and provide a synopsis of wells that are 5 years old. The purpose of this series is to show which wells have been released, and what core and log material is available for the various wells. Furthermore, some technical data and test results are provided, and a collection log with a description of the lithography of the individual wells in the scale 1:4000.

Seismics are released in packages that cover one block, and can only be released from blocks which are, or have been, licensed, and then only if the seismics are more than 5 years old.

FIG. 2.2.1.i
Blocks where seismic data have been released

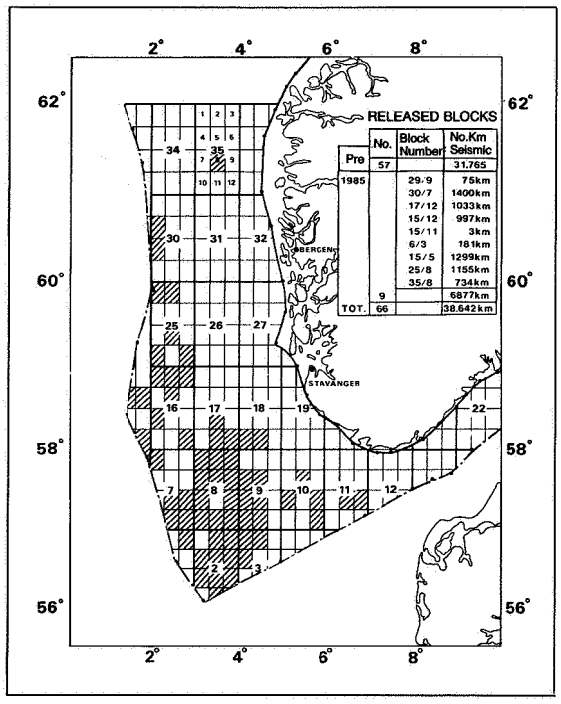


FIG. 2.2.2.a
Exploration drilling on the Norwegian Continental Shelf (Number of wells per year)

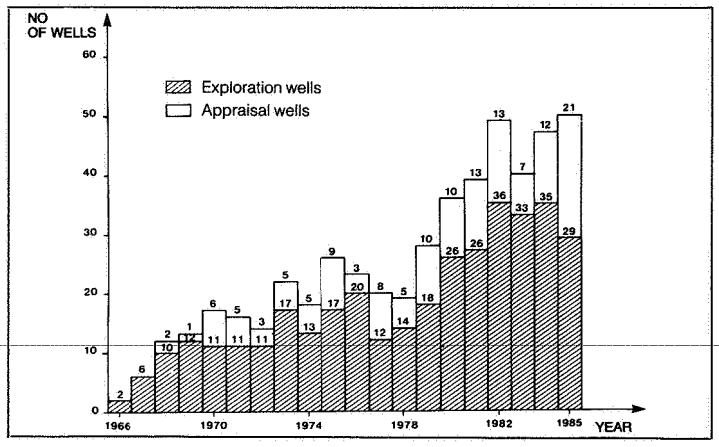
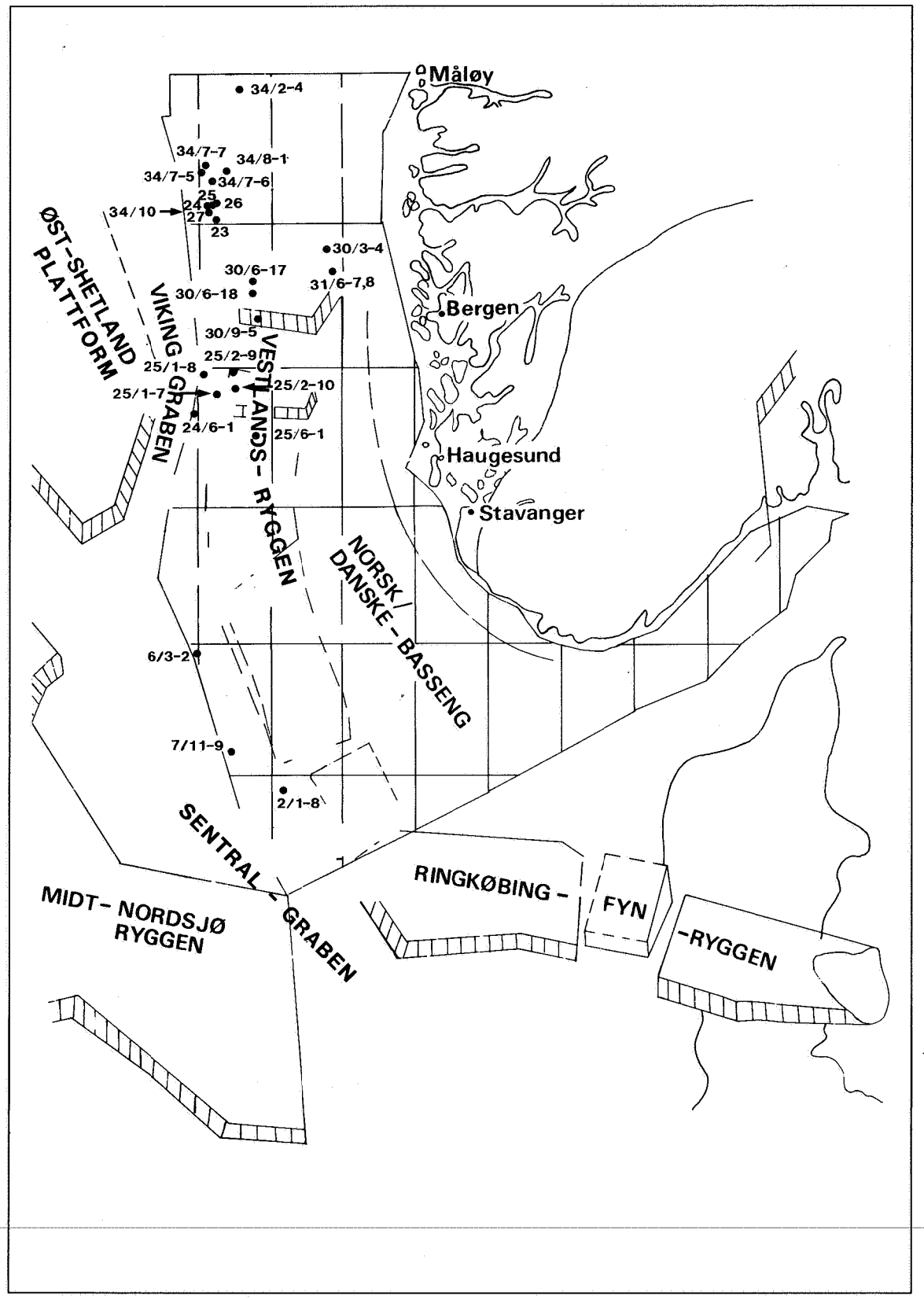


FIG. 2.2.2.b
Wells drilled in 1985 in relation to main structural elements in the North Sea



At 31 December 1985, 66 blocks had been released, nine of them in 1985. In all, 38,642 profile kilometers have been released, of which 6,877 km in 1985.

Figure 2.2.1 shows an outline map with a statement of the blocks for which data have been released.

2.2.1.6 Scientific research

As of 31 December 1985, a total of 214 licences for scientific research had been awarded on the Norwegian Continental Shelf. As seen from Table 2.2.1.a, 18 such licences were granted in 1985. Most research stressed geophysics and geology, with some biology work.

2.2.2 Exploration and appraisal drilling

At the turn of the year 1984–85 there were 12 exploration and appraisal wells being drilled. Eleven of these were finished in 1985 and one has been suspended.

In the course of 1985, 50 new wells were spudded, 29 of which were exploration wells and 21 appraisal wells. This is a new record and an increase of one well over the previous record year of 1982, and three wells more than in 1984 (Figure 2.2.2.a).

Some 43 of the spudded wells were finished during the year, 11 have been suspended and 11 wells were being drilled at years end.

At year's end, a total of 497 exploration wells had been drilled on the Norwegian shelf. A break-down of these showed 359 exploration wells and 138 appraisal wells.

Drilling activities in 1985 were relatively evenly distributed among the areas south and north of Stad with 27 wells in the south and 23 in the north.

In all, 25 wells had been temporarily abandoned on the Norwegian shelf at year's end.

Suspended wells on the Norwegian Continental Shelf with equipment located on the seabed are as follows:

TAB 2.2.1.a
License for scientific research for natural resources

Licence	Name	Field of study			Area
		Geo-plysics	Geo-logy	Bio-logy	
197	Oceaneering Norway A/S, Stavanger		X		Nordland II-området
198	British Geological Survey, Edinburgh, Skottland	X			Nordsjøen
199	Universitetet i Bergen, Jordskjelvstasjonen, Bergen	X			Hordaland, Sogn og Fjordane
200	Institutt for kontinentalsokkelundersøkelser, Trondheim	X			Barentshavet
201	Natural Environment Research Council, South Glamorgan, South Wales		X	X	Nordsjøen
202	Alfred-Wegener-Institut für Polarforschung, Bremerhaven, Forbundsrepublikken Tyskland	X		X	Grønlandshavet
203	Institutt for kontinentalsokkelundersøkelser, Trondheim	X			Barentshavet
204	Institut Francais du Pétrole, Frankrike	X			Norskehavet
205	Ocean Drilling Program, Texas, USA		X		Vøringsplatået
206	Universitetet i Tromsø, Institutt for biologi og geologi, Tromsø	X	X		Finnmarkskysten, Bjørnøyrenna
207	Institutt for Meereskunde an der Universität Kiel, Kiel, Forbundsrepublikken Tyskland	X	X	X	Vøringplatået
208	DAFS, Marine Laboratory, Aberdeen, Skottland		X	X	Nordsjøen
209	Institutt for kontinentalsokkelundersøkelser, Trondheim	X			Barentshavet
210	Institut für Meeresforschung, Bremerhaven, Forbundsrepublikken Tyskland		X	X	Nordsjøen
211	Rogalandsforskning, Stavanger		X		Barentshavet
212	Polish Academy of Sciences, Institute of Geophysics, Warszawa, Polen	X			Spitsbergenområdet
213	Institutt for kontinentalsokkelundersøkelser, Trondheim		X		Norskehavet
214	Universitetet i Bergen, Geologisk institutt Avd B, Bergen	X	X		Nordsjøen

FIG. 2.2.2.c
Wells drilled in 1985 in relation to main structural elements on Haltenbanken

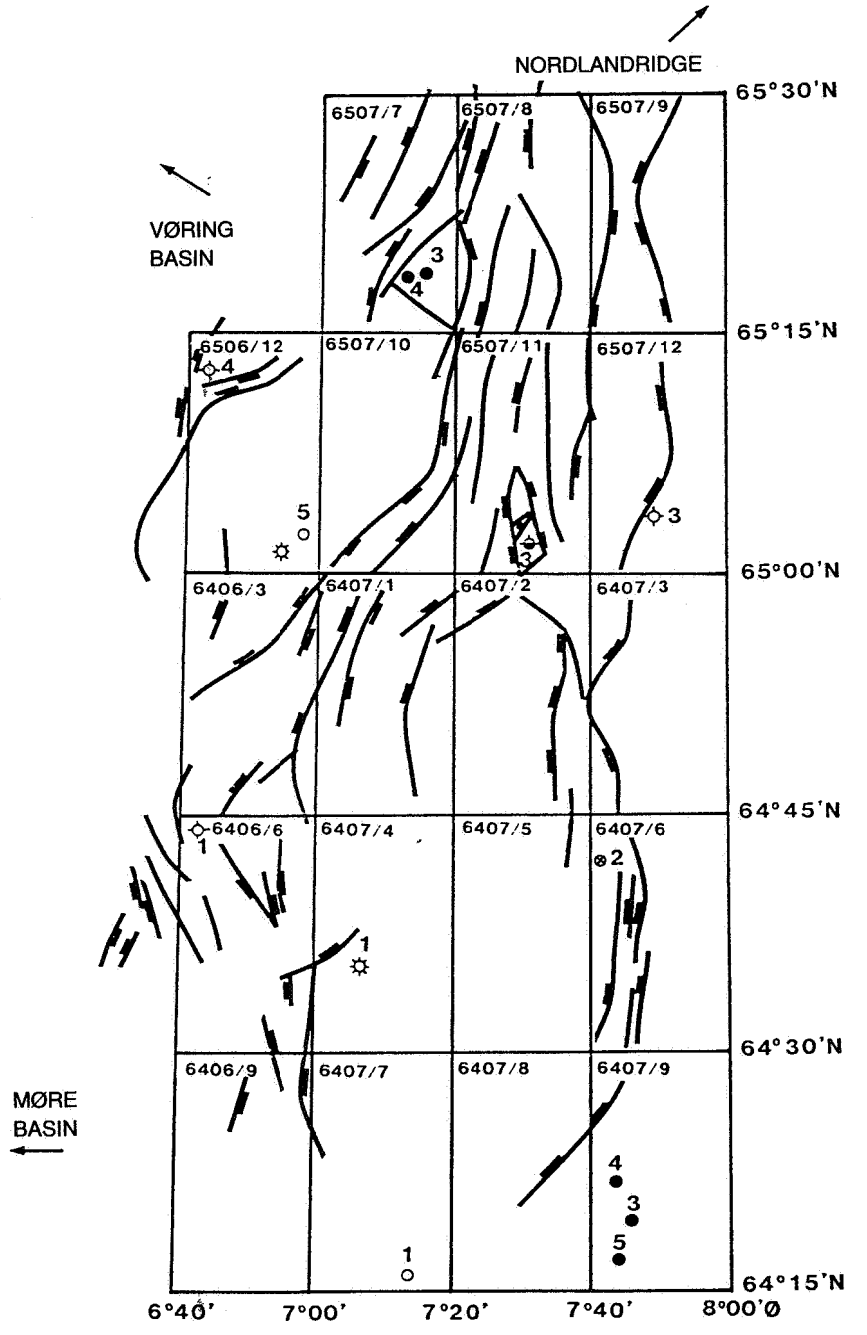
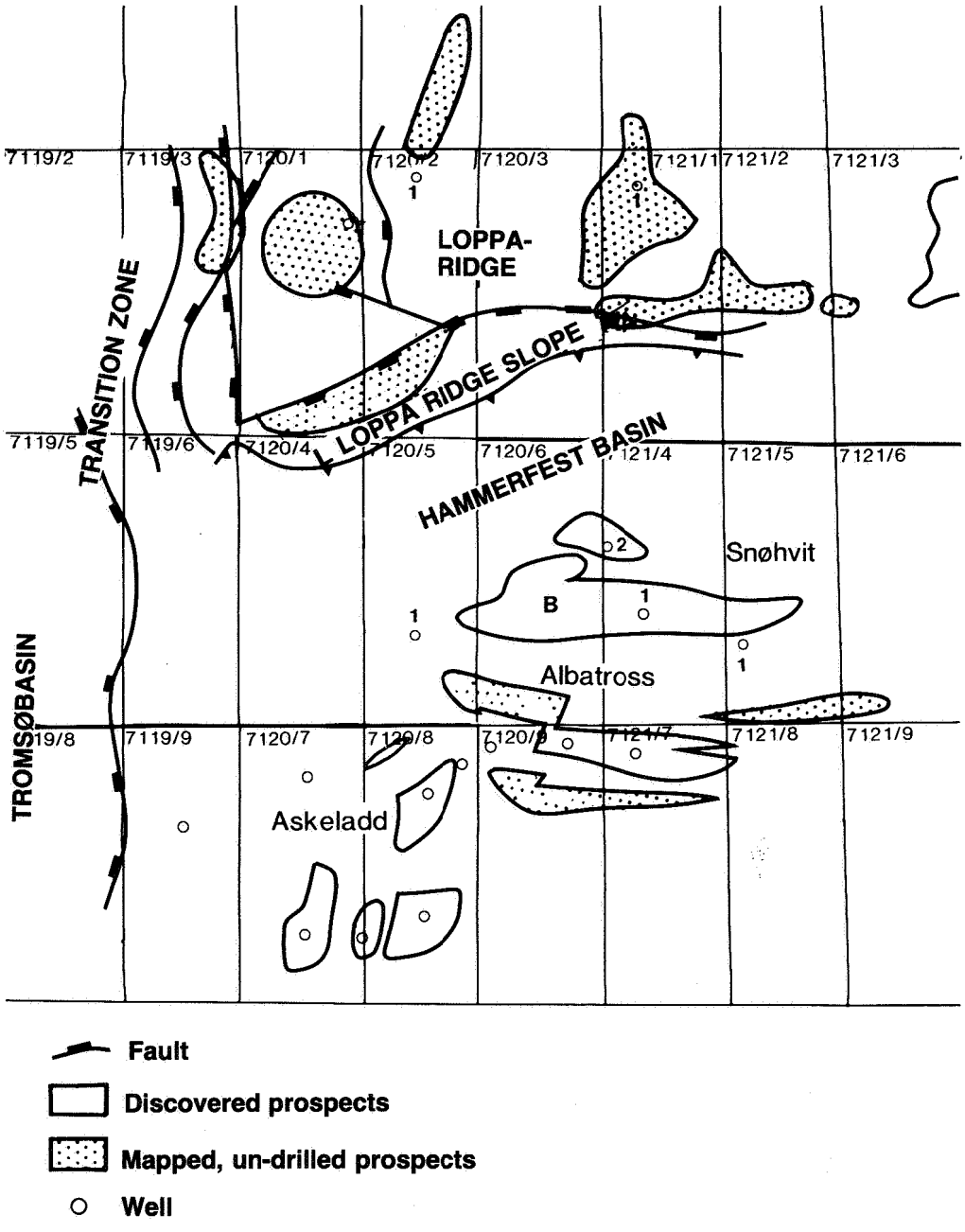


FIG. 2.2.2.d
Wells drilled in 1985 in relation to main structural elements on Tromsøflaket



1/09-01	7/12-02	30/06-13	6407/09-03
1/09-04	15/09-17	30/06-16	6407/09-05
1/09-06	25/01-08	30/09-02	7120/01-01
2/07-14	25/02-09	34/10-03	7121/01-01
2/07-19	30/02-01	34/10-05	
2/11-06 S	30/03-04	34/10-27	
7/11-08	30/06-09	6407/06-02	

Figures 2.2.2. b, c and d show the wells that have been spudded in the three areas on the Norwegian Continental Shelf (North Sea, Haltenbanken and Tromsøflaket) in relation to the structural main features.

In 1985, there was great activity on Haltenbanken. A total of 16 wells were spudded, which is about one-third of overall activities. The activity off Troms and Finnmark remained at the same level as in previous years.

In 1985, the Norwegian companies Saga, Norsk Hydro and Statoil have had operator responsibility for 34 of the wells spudded, corresponding to about 70 per cent (this is three wells below the 1984 figure). The remaining 16 are split among various foreign companies (Amoco, BP, Conoco, Elf, Esso, Shell and Total). This is evident from Table 2.2.2.a.

Since the start of all activities in 1966, a total of 18 different companies have been operators on the Norwegian Continental Shelf. Statoil has drilled the most wells (109), followed by Norsk Hydro with 68 and Phillips with 52. Sixty different drilling vessels have so far operated on the Norwegian Continental Shelf.

2.2.2.1 Distribution by prospect type

As in 1984, exploration activity in 1985 has almost exclusively been focused on Jurassic sandstone prospects (39 of the 50 spudded wells). Several of these wells have also had secondary prospects at other levels. The number of drilling operations directed at non-Jurassic prospects is nevertheless larger this year than previous years.

The other 11 wells include two in Permean/ Carbonic (Tromsøflaket), one in Triassic (34/4-6), four in Tertiary (25/1-7, 25/1-8, 25/2-9 and 25/2-10) and four in Quartiary (34/10-24 to 27). These are shallow gas drillings on Gullfaks.

Of the 12 wells which were being drilled at the turn of the year last year, nine had Jurassic strata as their primary targets. Two had Permean (1/3-5 and 2/1-7) and one (6609/5-1) had Triassic strata as their main target.

2.2.2.2 Svalbard

Increasing interest has been shown in charting Svalbards geology in recent years. So far, this activity has largely been limited to the six summer months.

In 1985, the activity level increased even more and the field season was extended. In all, 14 different companies had petroleum related activities on Svalbard this year.

The most extensive surveys were made by BP which shot seismics on the Paula Glacier. Statoil, Norsk Hydro, Nordisk Polarinvest and a Polish expedition carried out seismic surveys in the territorial waters around Spitsbergen and six different companies performed geological surveys on Svalbard.

Only one well was spudded in 1985 (Figure 2.2.2.a). In January, the Soviet company Trust Arktikugol started drilling in Vassdalen near Van Mijenfjord. This well is expected to be completed in the summer of 1986.

Table 2.2.2.b shows the 13 drilling licences that have been granted on Svalbard in connection with the drilling for oil and gas.

The activity level will probably increase even more in 1986 both as concerns the compilation of seismic data and geological field explorations. There are concrete plans for two drilling operations in 1986 to be performed by Nordisk Polarinvest and Svensk Polarenergi in collaboration with Norsk Polarnavigasjon.

In 1985, the Norwegian Petroleum Directorate made several inspection trips to Svalbard. They were made in cooperation with the Mines Supervisor for Svalbard and the Governor's office. During one of the inspection trips, 12 previous drilling locations were marked with iron rods so that they would be easy to find later.

TAB 2.2.2.a Spudded and/or completed exploration wells (U) and appraisal wells (A)
R = Reentry X = Not reached prospective depth

Well no	Licen se no	Position	Drilling spudded completed	Operator licensee	Drilling rig	Well type	Water depth KBE	Total depth (MSL)	Form. at TD	Result
6506/12-1	430	65°10'07.58"	16.08.84	Statoil	Ross Isle	U	250	4903	Jura/	Gas/cond.
		06°43'44.07"	06.02.85	Stat/Mobil/Agip			22		Trias	
2/1-7	431	56°51'49.85"	06.09.84	BP	Glomar Moray F.I.	U	68	5426	Perm	Dry well
		03°05'41.88"	06.03.85	Stat/BP/Conoco			38			
1/3-5	435	56°46'16.02"	01.10.84	Shell	Neddrill Trigon	U	71	4815	Perm	Dry well
		02°53'38.85	11.02.85	Shell			35			
34/7-3	436	61°25'54.05"	14.09.84	Saga	Vildkat	U	303	3389	Trias	Oil
		02°07'43.95"	02.01.85	Stat/Esso/Hyd/Saga			25			
6609/5-1	439	66°37'42.73"	03.11.84	Statoil	West Vanguard	U	294	3578	Trias ?	Dry well
		09°24'52.17"	05.01.85	Stat/PPCO/Esso			22			

Well No	Licen se No	Position	Drilling spudded completed	Operator Licensee	Drilling rig	Well type	Water depth KBE	Total depth (MSL)	Form at TD	Result
6/3-1	441	57°58'10.20"	02.11.84	Statoil	Deepsea Bergen	U	86	3537	Trias ?	Oil/gas/cond.
		01°55'30.38"	01.02.85	Stat/Con/Hyd/Amer			23			
30/6-16	442	60°39'31.72"	09.11.84	Norsk Hydro	Treasure Scout	U	108	3277	Trias	Oil/gas
		02°41'37.64"	21.01.85	Stat/Petronord			23			
6407/9-2	443	64°24'01.31"	18.11.84	Shell	Borgny Dolphin	A	247	1840	M. Jura	Oil
		07°48'11.26"	02.02.85	Stat/Shell/BP			25			
30/9-4	444	60°28'12.83"	22.11.84	Norsk Hydro	Treasure Seeker	U	110	4278	L. Jura	Oil/gas/cond.
		02°45'32.05"	30.03.85	Stat/Hydro/Saga			25	3552	TVD	
34/7-4	445	61°29'04.44"	18.11.84	Saga	Treasure Saga	U	319	3089	Trias	Oil
		02°08'00.26"	16.01.85	Stat/Esso/Hyd/Saga			26			
7/8-4	446	57°15'28.03"	11.12.84	Conoco	Nortrym	U	82	4375	Trias	Dry well
		02°25'46.23"	20.02.85	Stat/Con/Hydro			25			
30/2-2	447	60°49'53.89"	19.12.84	Statoil	Dyvi Delta	U	123	4141	Jura	Gas/cond
		02°39'51.65"	04.05.85	Stat/Union/Ten			30			
34/7-5	448	61°21'54.95"	17.01.85	Saga	Treasure Saga	U	244	3120	Trias	Oil
		02°01'23.67"	16.03.85	Stat/Esso/Hyd/Saga			26			
7121/4-2	449	71°39'26.09"	29.01.85	Statoil	West Vanguard	U	317	2778	Trias	Gas/cond
		21°03'45.96"	14.04.85	Stat/Total/Conoco			22			
7120/6-1	450	71°37'11.76"	02.02.85	Norsk Hydro	Treasure Scout	U	314	2797	Trias	Oil/gas
		02°55'59.72"	02.05.85	Stat/Hydro/Esso			23			
30/3-4	451	60°45'56.85"	05.02.85	Statoil	Deepsea Bergen	A	164	3264	U. Jura	Oil/gas
		02°51'30.20"	12.06.85	Statoil/Union			23			
24/6-1	452	59°36'00.25"	09.02.85	Total	Zapata Ugland	U	122	4912	U. Jura	Gas
		01°55'22.16"	25.08.85	Stat/Total/Union			25			
6506/12-2 X	453	65°01'29.85"	12.02.85	Statoil	Ross Isle	U	310	933		Abandoned
		06°53'29.41	28.02.85	Stat/Mobil/Agip			22			
6507/7-2	454	65°20'12.37"	25.02.85	Conoco	Nortrym	U	351	3237	Trias	Oil/gas
		07°18'34.52"	10.06.85	Stat/Con/Arco			25			
25/1-7	455	59°55'08.28"	09.03.85	Elf	Byford Dolphin	A	101	2694	Cret	Gas
		02°04'52.33	27.05.85	Petronord gr			25			
6506/12-3	456	65°01'31.09"	01.03.85	Statoil	Ross Isle	U	307	4338	L. Jura	Oil/gas
		06°53'27.35"	17.07.85	Stat/Mobil/Agip			22			
34/7-6	457	61°27'10.85"	17.03.85	Saga	Treasure Saga	A	307	3659	Trias	Oil
		02°08'17.26"	30.05.85	Stat/Esso/Hyd/Saga			26			
34/2-4	458	61°45'20.11"	22.03.85	Amoco	West Venture	U	391	4074	L. Jura	Dry well
		02°39'37.64"	11.06.85	Stat/Amoco gr			33			
31/6-7 X	459	60°33'19.68"	01.04.85	N. Hydro	Treasure Seeker	A	300	669		Abandoned
		03°40'39.04"	13.04.85	Stat/Hydro/Saga			25			
6506/12-4	460	65°12'46.97"	24.03.85	Statoil	Dyvi Stena	U	256	4432	L. Jura	Dry well
		06°43'30.37"	12.08.85	Stat/Mobil/Agip			25			
7120/5-1	461	71°34'51.86"	17.04.85	Statoil	West Vanguard	U	318	2678	Trias	Dry well
		20°26'12.26"	06.06.85	Stat/Hydro/Mobil			22			
31/6-8	462	60°33'21.36"	14.04.85	N. Hydro	Treasure Seeker	A	298	2113	Jura	Oil/gas
		03°40'39.07"	25.05.85	Stat/Hydro/Saga			25			
31/6-8 R	462	60°33'21.36"	22.07.85	N. Hydro	Treasure Seeker	A	298	2113	Jura	Oil/gas
		03°40'39.07"	22.09.85	Stat/Hydro/Saga			25			
6407/9-3	463	64°19'48.94"	03.05.85	Shell	Borgny Dolphin	A	279	1843	Jura	Oil
		07°46'30.91"	28.07.85	Stat/Shell/BP			25			
7120/2-1	464	71°58'57.94"	05.05.85	N. Hydro	Treasure Scout	U	387	3472		Oil
		20°28'35.09"	29.10.85	Stat/Hydro/Mobil			23			
34/10-23	465	61°01'06.35"	06.05.85	Statoil	Dyvi Delta	U	135	4735	L. Jura	Gas
		02°19'01.57"	13.10.85	Stat/Hydro/Saga			29			
25/1-8	466	59°54'03.28"	28.05.85	Elf	Byford Dolphin	A	102	2625	Paleoc.	Gas
		02°06'09.79"	25.07.85	Petronord gr			25	2545	M TVD	
30/9-5	467	60°21'31.34"	27.05.85	N. Hydro	Treasure Seeker	U	103	2955	Trias	Gas
		02°53'37.09"	19.07.85	Stat/Hydro/Saga			25			
7121/5-1	468	71°35'54.88"	07.06.85	Statoil	West Vanguard	U	336	3178	Trias	Oil/gas
		21°24'21.78"	28.09.85	Stat/Elf/Hyd/Con			22			
6507/11-3	469	65°01'59.80"	03.06.85	Saga	Treasure Saga	U	290	3224	Trias	Oil/gas
		07°30'42.34"	15.08.85	Stat/Shell/Saga			26			
25/2-9	470	59°53'10.16"	14.06.85	Elf	Nortrym	A	112	2272	Paleoc.	Gas
		02°22'15.09"	24.07.85	Petronord gr			25			
34/10-24	471	61°10'32.65"	28.06.85	Statoil	Deepsea Bergen	A	134	577	Tertiary	Gas
		02°11'28.10"	05.08.85	Stat/Hydro/Saga			23			
6407/9-4	472	64°22'14.00"	04.07.85	Shell	West Venture	A	244	1788	L. Jura	Oil
		07°43'21.84"	10.09.85	Stat/Shell/BP			32			
2/1-8	473	56°53'40.63"	28.07.85	BP	Neddrill Trigon	A	66.5	4122	Trias	Oil/gas
		03°06'55.95"	24.11.85	Stat/BP/Conoco			36.5			
6407/4-1	474	64°35'45.36"	20.07.85	Statoil	Ross Isle	U	225	4813	Trias	Cond/gas
		07°08'42.17"	14.11.85	Stat/Elf/Con/Saga			22			
6507/7-3	475	65°19'01.31"	29.07.85	Conoco	Nortrym	A	346	2825	Jura	Oil/gas
		07°17'44.79"	18.09.85	Stat/Con/Arco			25			
30/6-18	476	60°30'30.71"	01.08.85	N. Hydro	Byford Dolphin	U	108	3665	Trias	Oil/gas
		02°41'21.25"	23.11.85	Stat/Petronord			25			
34/10-25	477	61°12'11.60"	06.08.85	Statoil	Deepsea Bergen	A	143	577	Tertiary	Dry well

Well No	Licen se no	Position	Drilling spudded completed	Operator Licensee	Drilling rig	Well type	Water depth KBE	Total depth (MSL)	Form at TD	Result
		02°12'12.77"	17.08.85	Stat/Hydro/Saga			23			
30/6-17	478	60°34'15.77"	12.08.85	N. Hydro	Vildkat	U	111	589		Suspended
		02°44'59.84"	23.08.85	Stat/Petronord			24			
30/6-17 R	478	60°34'15.77"	14.11.85	N. Hydro	Treasure Hunter	U	111			
		02°44'59.84"		Stat/Petronord			25			
6406/6-1	479	64°43'48.23"	15.08.85	Statoil	Dyvi Stena	U	244	4690	L. Jura	Dry well
		06°42'14.69"	30.12.85	Stat/BP/Amerada			25			
7120/1-1	480	71°55'00.83"	16.08.85	Shell	Borgny Dolphin	U	341.5	2569		Suspended
		20°18'07.13"	24.11.85	Stat/Shell/Elf/Hydro			25			
7120/1-1 R	480	71°55'00.83"	02.12.85	Shell	Borgny Dolphin	U	341.5	2585		Suspended
		20°18'07.13"	24.12.85	Stat/Shell/Elf/Hydro			25			
6507/12-3	481	65°03'35.82"	16.08.85	Saga	Treasure Saga	U	240	2574	Jura	Dry well
		07°49'06.40"	13.09.85	Elf/Saga/Volvo			26			
6407/9-5	482	64°16'42.35"	12.09.85	Shell	West Venture	A	286	1788	L. Jura	Oil
		07°44'14.66"	13.11.85	Stat/Shell/BP			33			
34/7-7	483	61°26'54.53"	17.09.85	Saga	Treasure Saga	A	302.5	3520	Trias	Oil
		02°05'55.69"	16.12.85	Stat/Esso/Hyd/Saga			26			
6407/6-2 X	484	64°42'29.56"	04.10.85	Statoil	West Vanguard	U	221	501		Suspended
		07°40'32.59"	06.10.85	Stat/Mobil/Britoil			22			
6506/12-5	485	65°02'28.60"	17.10.85	Statoil	Dyvi Delta	A	301			
		06°58'21.93"		Stat/Hydro/Saga			29			
6407/7-1	486	64°16'31.49"	19.10.85	N. Hydro	Polar Pioneer	U	330			
		07°12'21.12"		Stat/Hydro/Shell			23			
7121/1-1	487	71°56'25.74"	10.10.85	Esso	Zapata Ugland	U	370	916		Suspenderd
		21°04'36.52"	17.11.85	Stat/Esso/Hydro			27			
34/8-1	488	61°21×53.00"	08.11.85	N. Hydro	Treasure Scout	U	325			
		02°25'57.57"		Stat/Hydro/Elf/Con			23			
34/10-26	489	61°12'59.90"	18.10.85	Statoil	Deepsea Bergen	A	219	600	Tertiary	Dry well
		02°16'23.77"	26.10.85	Stat/Hydro/Saga			23			
6507/7-4	490	65°19'11.56"	06.11.85	Conoco	Nortrym	A	345			
		07°15'44.99"		Stat/Con/Arco			25			
7/11-9	491		24.11.85	N. Hydro	Byford Dolphin	U				
				Stat/Hydro/Saga			25			
6/3-2	492	57°54'25.99"	21.11.85	Statoil	Ross Isle	U	089			
		01°59'14.19"		Stat/Con/Hydro			22			
25/6-1	493		18.12.85	Saga	Treasure Saga	U				
				Stat/Saga/Agip/Fina			26			
25/2-10	494	59°53'11.80"	02.12.85	Elf	Henry Goodrich	U	120			
		02°30'08.33"		Stat/Elf/Hydro/Total			21			
34/10-27	495	61°10'31.12"	02.12.85	Statoil	West Venture	A	134.5	450		Suspended
		02°11'23.96"	14.12.85	Stat/Hydro/Saga			32			
34/10-29	496	61°10'33.06"	27.12.85	Statoil	West Venture	A	135			
		02°11'28.76"		Stat/Hydro/Saga			32			
34/4-6	497	61°34'15.49"	31.12.85	Saga	Vinni	A				
		02°13'19.52"		Stat/Saga/Amoco			26			

2.2.3 Discoveries and fields being evaluated

2.2.3.1 New discoveries in 1985

In the course of 1985, several new interesting discoveries were made on the Norwegian Continental Shelf. The most interesting were made on Haltenbanken.

Particularly encouraging was Conoco's discovery in Block 6507/7. The find has been named Heidrun. Oil was proven in sandstone strata of Jurassic age. Four wells have been drilled in this structure, of which one is being tested. Saga drilled one well in a fault block in the Midgard field which till then had not been drilled in. Previously only gas in sandstone strata of Jurassic age had been proven in this field, but Well 6507/11-3 showed that there is also a thin layer of oil underneath the gas in parts of the field.

In Block 6407/4, Statoil made a minor gas and condensate find in sandstone strata of Jurassic age. Unfortunately the reservoir properties were variable and the reservoir showed poor production potential.

In the very southeastern part of Block 6506/12 (which also contains the Smørbukk field), Statoil made a new oil and gas discovery in sandstone strata of Jurassic age.

On Tromsøflaket, Statoil has drilled a new structure north of the Snøhvit structure. In this well (7121/4-2) gas was proven.

One well has been completed on Lopparyggen, where Norsk Hydro drilled in a Permean/Carbonic prospect. During drilling operations, traces of hydrocarbons were proven in limestone and sandstone strata of Permean/Carbonic age. However, production tests showed that there was only residual oil, and water was produced from all levels.

In the North Sea, some new minor discoveries were made. In the Oseberg area, Norsk Hydro has proven hydrocarbons in two wells. In Well 30/6-18, which was drilled in a separate structure in the fault complex southwest of the Oseberg main structure, both oil and gas were proven in sandstone strata of Jurassic age. In that part of Block 30/9 which was al-

TAB 2.2.2.b
Drilling permits on Svalbard

Well (locality)	Position North East	Spudded	Completed	Drilling time Days	Operator Licensee	Total depth metres	KB elev. over MSL metres
Grønnfjorden 1 (Nordenskiøld Land)	77°57'34" 14°20'36"	09.06.63 13.06.64 26.06.65 26.06.67	05.09.63 26.08.64 08.09.65 12.08.67	287	Norsk Polar Navigasjon	971.6	7.5
Ishøgda (van Mijenfjorden)	77°50'22" 15°58'00	01.08.65	15.03.66	277	Texaco Caltex gruppen	3304	18
Bellsund I (Fridtjovsbreen)	77°47' 14°46'	23.08.67 29.06.68 07.07.69 10.07.74 16.07.75 22.08.80 01.07.81	02.09.67 21.08.68 16.08.69 18.09.74 20.09.75 05.09.80 10.08.81	299 x)	Norsk Polar Navigasjon	405	
Hopen I (Hopen)	76°26'57" 25°01'45"	11.08.71	29.09.71	50	Forasol Fina gruppen	908	9.1
Raddedalen (Edgeøya)	77°54'10" 22°41'50"	02.04.72	12.07.72	100	Total Caltex gruppen	2823	84
Plurdalen (Edgeøya)	77°44'33" 21°50'00"	29.06.72	12.10.72	108	Fina Fina gruppen	2351	144.6
Kvadehuken I (Brøggerhalvøya)	78°57'03" 11°23'33"	01.09.72 21.04.73	10.11.72 19.06.73	112	Terratest A/S Norsk Polar Navig	479	
Hopen II (Hopen)	76°41'15" 25°28'00"	20.06.73	20.10.73	123	Westburne Int. Ltd. Fina gruppen	2840.3	314.7
Kvadehuken II (Brøggerhalvøya)	78°55'32" 11°33'11"	13.08.73 22.03.74	19.11.73 16.06.74	186	Terratest A/S Norsk Polar Navig	394	
Sarstangen (Forlandsrevet)	78°43'36" 11°28'40"	15.08.74	01.12.74	109	Terratest A/S Norsk Polar Navig	1113.5	5
Colesbukta (Nordenskiøld Land)	78°07' 15°02'	13.11.74	01.12.75	373	Trust Arktikugol	3180	12
Haketangen (Tromsøbreen)	76°52'30" 17°05'30"	11.09.76 13.06.77	22.09.76 19.09.77	109	Terratest A/S Norsk Polar Navig	990	6.7
Vassdalen II (van Mijenfjorden)	77°49'08" 15°16'00"	22.01.85		344	Trust Arktikugol	2481	
				2477 drilling days		22240.4 m drilled	

x) Drilling not finally completed

located in the ninth concession round, Norsk Hydro made a small gas discovery in sandstone strata of Jurassic age. The find was not tested for production.

South of Gullfaks South, Statoil made a gas discovery in Well 34/10-23. Attempts had previously been made to drill in the structure (34/10-20), but had to be abandoned on account of high formation pressure.

Total Marine completed drilling and testing operations of a minor gas find in Block 24/6. The Block lies on the border of the British sector. Gas was proven in Jurassic sandstone layers. Even if the discovery is relatively small, it is interesting because of its situation close to the Frigg and Heimdal fields.

At the turn of the year 1985–86, 11 exploration and appraisal wells were being drilled, of which six had reached reservoir level.

In all, 16 new structures were drilled in 1985. Discoveries were made in nine structures. This gives a discovery frequency of 56 per cent, which is high in an exploration drilling context.

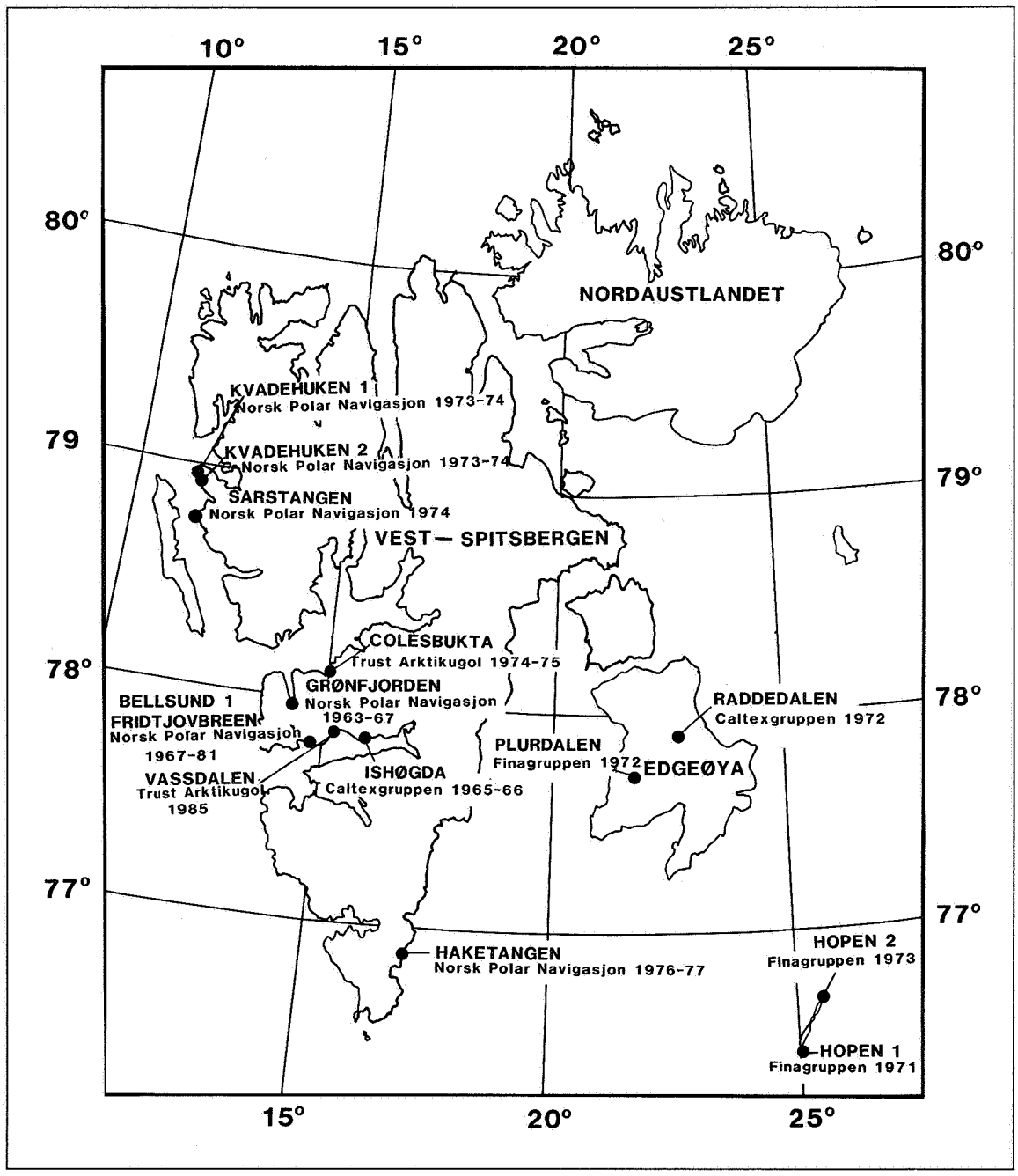
Block 24/6

The block, which is a border block towards the British sector, was allocated together with parts of Block 25/4 in 1984 with Total Marine as operator. Well 24/6-1 has been drilled in a structure up towards the borderline to the British sector. Gas discoveries have been made in sandstone strata of Middle Jurassic age. The reservoir, which has a very high pressure and high temperature, was production tested and maximum production was measured at 425,000 Sm^3 of gas and 74.7 Sm^3 of oil per 24-hour period through a 7.9 mm choke. The find is relatively small, but is believed to be interesting in consideration of its situation close to the Frigg and Heimdal fields.

Block 30/6

The block was allocated in 1979. Norsk Hydro is operator. Since the Oseberg field was discovered and declared commercial, more wells have been drilled to map the resources west and southwest of the main structure (Alfa). Well 30/6-18 was drilled in one of these complicated fault blocks (Kappa). Hydrocarbons were proven in two separate sandstone strata of Lower Jurassic age with oil and gas in the upper interval and oil in the lower interval. Maximum production from the oil zone in the upper reservoir was measured to 970 Sm^3 of oil and 195,000 Sm^3 of gas per 24-hour period through a 14.3 mm choke. It is still to early to say anything certain

FIG. 2.2.2.a
Well locations on Svalbard



about the discovery, but we are only talking about an increase of a few per cent in the estimated resources in the Oseberg area.

Block 30/9
The southern part of the block was allocated in 1985 with Norsk Hydro as operator. The northern part of the block was allocated earlier (1982) in order to obtain a rough map of the resources in the Oseberg field. Norsk Hydro has proven small quantities of gas in sandstone of Lower Jurassic age in a separate structure, distinct from the Oseberg field. The well was not tested for production.

Block 34/10
The block was allocated in 1978 with Statoil as operator. At the turn of the year 1983–84, attempts were made to drill in the Gamma structure in the south-eastern part of the block. This well never reached prospective layers on account of high pressure. In

1985, Statoil drilled 34/10-23 in the same structure, out towards the edge so that the pressure quotient would be lower. Gas was proven in sandstone strata of Middle Jurassic age. The reservoir was tested and maximum production was measured to 1,700,000 Sm^3 of gas per 24-hour period through a 22.2 mm choke. The gas-oil ratio was approximately 11,400 Sm^3/Sm^3. It is too early to say anything about the size of the reservoir before further drilling operations have been made.

In addition to 34/10-23, four wells (34/10-24 to 27) were drilled to obtain more technical data on the shallow gas resources in the Gullfaks area. A gas bearing sand layer was proven under the location of the Gullfaks A platform. One is now working on the development of technology designed to stop shallow gas from creating problems for the drilling of production wells on the field. The shallow gas resources are very small and probably of no commercial interest.

On 22 November 1985, an uncontrolled shallow gas blow-out occurred on location 34/10-A-2H with the drilling rig "Deepsea Bergen".

An initial gas leakage between the 20 and 30 inch casing was observed at an early stage with underwater cameras, and the drilling vessel was successively pulled off location to a safe distance from the gas blow-out.

The operator/ shipowner interpreted the situation as not representing any particular risk for either the crew or installation and did not therefore evacuate the crew.

The gas blow-out was due to unsuccessful cementing.

Block 6407/4

The block was allocated in 1985 with Statoil as operator. Well 64/4-1 was drilled centrally in the block. Gas was proven in sandstone strata of Middle Jurassic age. Two production tests were carried out. The lower interval produced only water and the upper produced only 35,000 Sm^3 of gas and 20 Sm^3 of condensate per 24-hour period through an 18 mm choke. The test results show that the reservoir has limited production potential.

Block 6506/12

The block was allocated in 1984 with Statoil as operator. In 1984, the large gas/ condensate field, Smørbukk, was found in the northwestern part of the block. Well 6506/12-3 was drilled in the southeastern part of the block and proved gas/condensate and oil in sandstone strata of Middle and Lower Jurassic age. An extensive production test program was carried out with tests in six zones. The highest gas production was measured to approximately 450,000 Sm^3 of gas per 24-hour period. The highest oil production was measured to 820 Sm^3 of oil per 24-hour period. Both tests were made through a 25 mm choke. The test results are favourable, but somewhat lower than those achieved on the Smørbukk field. Further drilling must be performed in order to clarify the size of the 6506/12-3 find.

Block 6507/7

The block was allocated in 1984 with Conoco as operator. Well 6507/7-2 was drilled in the eastern part of the block and proved oil and gas in Jurassic sandstones. The discovery has been named Heidrun. A large test program was performed with as many as seven production intervals. Maximum oil production was measured to 902 Sm^3 of oil and 68,000 Sm^3 of gas per 24-hour period through a 22 mm choke. The best gas production was measured to 890,000 Sm^3 of gas and 96 Sm^3 of condensate per 24-hour period through a 20 mm choke. The test shows that the reservoir potential of the Heidrun field are good.

Block 6507/11

The block was allocated in 1981 with Saga as operator. Well 6507/11-3 was drilled in a fault block centrally in the Midgard gas field. Gas was found in sandstone strata of Middle Jurassic age. The interesting thing is that there was also a thin oil zone under the gas. Three production tests were performed and maximum oil production was measured to 1,500 Sm^3 of oil per 24-hour period through a 25 mm choke. During the test, the break-through of free gas from the gas zone was observed, and the oil production was reduced to 200 Sm^3 per day in order to stop the production of free gas. Maximum gas production from the gas zone was measured to 1,730,000 Sm^3 of gas and 279 Sm^3 of condensate per 24-hour period through a 38 mm choke. The tests confirm that the reservoir potential of the Midgard field is very good. The discovery of an oil zone under the gas means that one is faced with the same problems associated with production from a thin oil zone in this field as in Troll and Snøhvit, amongst others.

Block 7121/4

The block was allocated in 1984 with Statoil as operator. Earlier the Snøhvit structure was proven in this and the neighbouring blocks (7120/6 and 7121/5). Well 7121/4-2 was drilled in a separate structure north of the Snøhvit structure. Gas was proven in sandstone of Middle Jurassic age. A production test was performed and the maximum production was measured to approximately 850,000 Sm^3 of gas and 80 Sm^3 of condensate per 24-hour period through a 25.4 mm choke. The production test shows that the reservoir potential is good, as also for the Snøhvit structure.

2.2.3.2 Fields being evaluated

Hod

Block 2/11 was allocated in 1969 with Amoco as operator.

The Norwegian Petroleum Directorate's estimated recoverable reserves are 7.0 million Sm^3 oil and 5.0 billion Sm^3 gas.

The Hod field consists of two lesser structures. These have been examined with a total of five wells, two on West Hod and three on East Hod. In 1981, a wellhead template was installed on the seabed between these two structures because at that time the field was considered to be promising. Well 2/11-6 was directionally drilled from here. Any later drilling operations of production wells will be performed from the same template.

During the last year, the operator has experienced production difficulties on Valhall because of solid particles in the well stream. The operator assumes the production from the Hod reservoir will give the same problems and that Hod therefore cannot be produced from underwater completed wells as previously intended. A development of Hod must therefore be based on production from a wellhead platform and further transportation to Valhall for final processing. The operator is planning to drill one further well on Hod in order, if possible, to prove higher resources estimates.

At present it is too early to say whether a development of the field is commercially viable.

Tommeliten

The field lies in Block 1/9, which was allocated in 1976 under Statoils operatorship.

The Tommeliten field consists of two structures, the Alfa in the south, and the Gamma structure in the north. In both structures, gas/condensate was proven.

Recoverable reserves are estimated at 6 million Sm^3 oil/condensate and 23 billion Sm^3 gas.

The operator submitted a commerciality declaration in December 1985. This is based on a field development solution with a wellhead platform installed on the Gamma structure and a platform for water removal on the Alfa structure. Non-processed well flow is transported from Gamma to Alfa, where free water is removed before further transportation to Eldfisk. On Eldfisk, the products will be processed before being transferred to Ekofisk for final processing to transport specifications. Production start is planned for 1989/90.

The operator is also evaluating other development solutions. A plan for development and operation and an application for landing is expected to be submitted for approval in the spring of 1986.

Fields around Ula

Field 2/1-North is an oil field which is situated about 25 km southeast of the Ula field. BP is operator for both these fields and the operator is working on feasibility studies for 2/1-North with connection to the Ula field. The Ula field will have idle processing capacity for oil from other fields from 1990/91. However, the gas production from 2/1-North will exceed the processing capacity of Ula as well as the capacity in the gas pipeline system Ula-Cod-Ekofisk. It seems obvious that 2/1-North must be developed, if applicable, with a separate fixed or mobile installation. Connection to Ula may involve considerable modification work or a new platform on the Ula field. The operator has indicated that a field development plan for 2/1-North can be submitted in 1986/87.

Block 1/3 is the neighbour to Block 2/1 towards the west. Elf Aquitaine is operator. A minor oil find has been proven which probably stretches into Block 2/1. There is no direct connection between the two structures.

Block 2/2 is the neighbour to Block 2/1 towards the east. Saga is operator. Also here a minor oil field has been demonstrated. The water depth is very moderate, being only 60 m. The smaller fields in Block 1/3 and 2/2 should be evaluated in connection with a possible development plan for 2/1-North.

In the neighbouring block to the Ula field towards the west, Block 7/11, an oil field has been proven. In Block 7/8 northwest of Ula, a minor oil field has also been demonstrated. These minor fields should be evaluated in connection with a possible development of the Ula field infrastructure.

The Sleipner area

The Sleipner area is made up of Blocks 15/5, 15/6, 15/8, 15/9 and 16/7. Drillings and discoveries are summarized in Figure 2.2.3.a.

Allocations, production licences and operator responsibilities are as follows:

Block	15/5	15/6	15/8 and 15/9	16/7
Allocation year	1977	1969	1970	1981
Operator	N. Hydro	Esso	Statoil	Esso
Production licence	048	029	046	072

Recoverable reserves on Sleipner West, which includes the Alfa, Beta, Epsilon and Delta structures, are estimated to amount to 135 billion Sm^3 gas, 28 million Sm^3 oil and 9 million tons NGL.

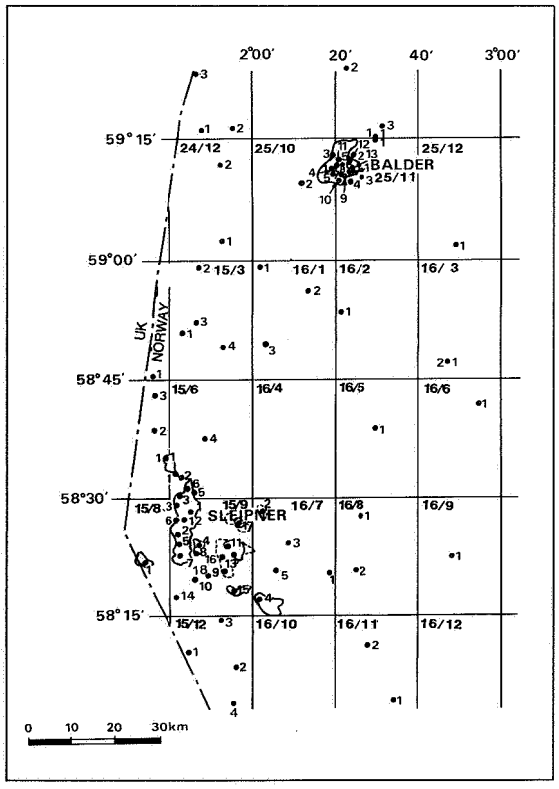
For Sleipner East the recoverable reserves in the Heimdal formation and the Jurassic and Triassic reservoir are estimated at 51 billion Sm^3 gas, 17 million Sm^3 oil and 10 million tons NGL. In place resources for 15/8 Alfa, 15/9 My and 15/9 Theta are estimated to amount to 35 billion Sm^3 gas and 16 million Sm^3 oil.

Development of the Sleipner area

The present plans presuppose the construction of a Sleipner East platform with a capacity of 16 million Sm^3 per 24-hour period.

One is currently working on plans for a larger (24 million Sm^3 per 24-hour period) Sleipner East platform for possible sale of Sleipner East gas to the

FIG. 2.2.3.a
The Sleipner and Balder area



continent. Thus, one has several development alternatives if sales agreements for the gas are concluded.

Balder

Block 25/11 was allocated in 1965 (production licence 001) with Esso as operator. Additionally, Esso acquired Blocks 25/8 and 25/10 in 1969 (production licences 027 and 028).

The field was proven in 1974 by the drilling of Well 25/11-5, in which oil was found in Paleocene sandstone. In Block 25/8, small amounts of oil were also proven in corresponding sandstone layers.

As yet, no decision has been made as to development of the field. No wells have been drilled in the block since 1981.

The recoverable oil reserves are now estimated to run to 35 million Sm^3.

The landing application was submitted in December 1980, but because of a heavy fall in the estimated reserves and consequent poor project economy, the landing application was withdrawn. The operator is evaluating the field.

The Oseberg area

The Oseberg area includes the Blocks 30/2, 30/3, 30/6, 30/9 and 31/4 (Figure 2.2.3.b). The Oseberg field itself has been resolved to be developed and is planned to be on-stream from 1989 (cf. section 2.3.6).

Resources basis

In this area, discoveries of varying sizes have been made in the fields Oseberg, Brage, Veslefrikk, Huldra, 30/6-Beta, 30/6 Kappa, 30/6-Gamma North and Block 30/9 prospect A. Discovered recoverable resources are shown in Table 2.4.3.

In addition to the discoveries, a large number of prospects have been found in the Oseberg area. This applies especially on the western edge of Oseberg and in Block 30/9 (production licences 079 and 104). The Norwegian Petroleum Directorate's estimate of anticipated recoverable resources in the prospects within production licence 104 is 35 million Sm^3 oil. In addition, some gas can be expected.

Norsk Hydro, who is operator for the bulk of the area, had relatively high exploration activity in 1985 and has planned high activity in 1986. The operator expects that the ongoing mapping and drilling activity will contribute to a clarification of the resources basis in the course of 1986 for a possible coordinated development.

Transport

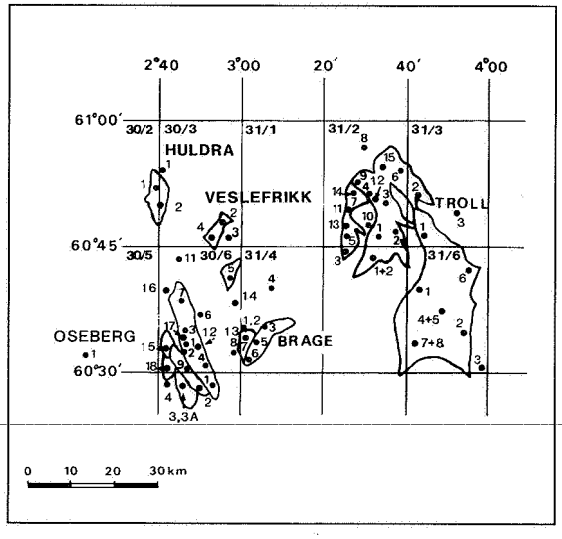
It has been resolved that the oil from Oseberg is to be landed by pipeline in Sture in Øygarden. Gas will be reinjected. The transport requirement for gas will therefore arise only after the year 2000. It is a prerequisite that Oseberg can then be connected to the transport systems for gas which are available then.

For other fields in the Oseberg area the same transport method is assumed as for Oseberg.

Development alternatives

There are basically two main alternatives for further development of the Oseberg field. One alternative is to continue the development plan for Oseberg which the field development plan involves, and to

FIG. 2.2.3.b
The Oseberg and Troll area



develop the satellite fields in accordance with this. This means that, amongst others, Veslefrikk and Brage should either be developed with their own processing capacity or that they should be suspended until Oseberg A gets idle capacity after the year 2000. The alternative is upgrading of the Oseberg C platform to a PDQ platform (processing, drilling and accommodation platform) and to develop the fields in a coordinated manner, using idle processing capacity on Oseberg.

Studies show that there may be socio-economic advantages associated with upgrading the Oseberg C platform rather than developing independent units for the fields around Oseberg.

No final decision can be made as to how the fields around Oseberg should be coordinated and developed and how large the Oseberg processing capacity should be until the resources basis in the area is better known. The operator, Norsk Hydro, is planning to submit to the authorities a revised field development plan for Oseberg in late 1986, where the concepts for the area are evaluated. The operator is planning to submit the field development plan for Brage about one year thereafter. Statoil, in the capacity of operator for Veslefrikk, intends that the field development plan for this field will be submitted at the same time as the revised field development plan for Oseberg.

Estimates show that it will not be profitable to postpone the production start for the Brage and Veslefrikk fields in anticipation of idle processing capacity on Oseberg.

By early 1986, the operator will make a final decision concerning whether the Oseberg field should be developed by means of gas or water injection. This may affect the decision concerning upgrading of the Oseberg C platform so that coordination of the area can be realized.

The authorities assume they will be able to make a decision on a coordinated development plan in connection with the treatment of the revised field development plan for Oseberg in 1986/87. It is presupposed that one can then make a decision on whether the Oseberg C platform should be upgraded to a PDQ platform.

The Troll field

The Troll field extends over parts of several blocks: 31/2, 31/3, 31/5 and 31/6 (Figure 2.2.3.b). In November 1983, the operator on Block 31/2, Norske Shell, declared that part of the Troll field lying within Block 31/2 commercial. Operator responsibility for Blocks 31/3, 31/5 and 31/6 is divided among Statoil, Saga and Norsk Hydro.

In the course of 1985, coordination (unitization) work has taken place between the two Troll production licences. This work is expected to be finished in 1986.

Parallel with the completion of this unitization work the four operators are working to come up with a recommended plan for the first development phase and find alternatives for the further development. In the course of the autumn of 1985, a joint work group tried to arrive at a development plan which will be continued up until the summer of 1986 by Shell. These efforts will produce a plan that can be submitted to the authorities towards the end of 1986.

The reservoir lies in three geological formations of upper Jurassic age (approx 140–150 million years old). The uppermost formation (Sogn) is dominated by a medium to coarse grained sandstone with good reservoir properties. Reservoir properties seem to be rather poorer in Troll East. This formation, which is the most prevalent in the reservoir, runs into the underlying middle formation (Heather) which consists of silt and fine grained sandstone with a relatively high content of mica. Its flow properties are therefore poorer than in the top formation. The bottom formation (Fens) consists of sandstone with variable reservoir properties.

On the top of Troll West in Block 31/2, and on top of Troll East in Blocks 31/6 and 31/3, there rests a gas column a good 200 meters thick. The gas column varies over the field and is significantly less in the westernmost parts of Troll. This westernmost part of the field, which lies primarily in Block 31/2, has an oil column of 22–27 meters below the gas, compared with 10–17 meters further east in the block. In Troll East, the proven oil layer varies in thickness from a few meters to zero.

To date on Blocks 31/2, 31/3, 31/5 and 31/6, fifteen, three, two and five wells have been drilled, respectively. The Norwegian Petroleum Directorate's present reserve estimate for the Troll field is 1,288 billion Sm^3 recoverable gas deposits, and 35 million Sm^3 recoverable oil deposits. The Norwegian Petroleum Directorate has for the time being ignored the oil quantities in those parts of the field that have a 10–17 meter oil zone, but the possibility of producing from this part of the field is still being evaluated.

The recovery factors for oil and gas are encumbered with some degree of uncertainty, among other things being dependent on development concept and drainage strategies.

On the basis of an overall evaluation, a start-up of gas production in Troll East will be preferred on the basis of reservoir considerations. This may give a longer stable plateau period for gas production and may possibly contribute to a somewhat higher total recovery factor for the gas. Separate oil production from the thick oil zone may provide greater flexibility. Whether this will mean increased or reduced oil recovery depends entirely on the method one finds for the most economical drainage of the area. Through the ongoing work one will seek to find answers to these questions. However, it can be clearly ascertained that a start-up in Troll East will be more

favourable than a start-up in the west with a view to possible oil production from the thin oil zone.

It is still too early to have any fixed opinions as to which development concepts will be selected. For Phase I gas a fixed platform with full processing on the field seems most likely.

The oil production concepts being evaluated are based on fixed or mobile installations, or a combination of these. Underwater wells or directionally drilled wells from a platform will then be connected to the installations.

From the southernmost oil zone, highest recovery is expected by producing oil without producing gas from the gas cap at the same time. In the northern oil province, a certain gas recovery together with the oil can increase the production volumes.

Safety, preparedness and operating accessibility
The Norwegian Petroleum Directorate has evaluated the development of the Troll field. The work has been concentrated on Troll Phase 0 and the Project Task Force (PTF). The basis for the evaluations made has been A/S Norske Shell's field development plan and the production licence projects for 1 August 1985.

In connection with oil recovery from the western part of Block 31/2, different concepts have been presented. Against this background, the Norwegian Petroleum Directorate has started report work to illucidate the requirements that have to be made for any mobile production installations on Troll West.

General
Two types of production principles are relevant:

- continuous production regardless of weather conditions
- interrupted production when certain environmental criteria are exceeded.

Several different systems can be imagined for these purposes, for example:

- conventional mooring system
- other type of chain line mooring
- tension leg mooring
- dynamic positioning
- a combination of chain line mooring and dynamic positioning.

No matter which system is selected, whether conventional mooring or dynamic positioning, the system should be subjected to an extensive safety analysis which must be incorporated into the safety analysis for the overall concept.

Continuous production regardless of weather conditions
Generally, two main requirements apply, amongst others:

- the system has to stop movements which threaten the integrity of the riser pipe/well
- in the event of system failure the remaining capacity has to be sufficient to stop movements which may threaten the integrity of the riser pipe/well.

Planned interrupted production
If, however, the platform concept is based on close-down/disconnection of the riser in the event of special weather conditions the system must

- stop movements that may threaten the integrity of the riser pipe until a controlled close-down/disconnection has been performed
- in the event of system failure there must be reserve capacity to stop movements that may threaten the integrity of the riser until a controlled close-down/disconnection has been performed.

Conventional mooring system (anchor and chain)
Continuous production
If the production is to run continuously regardless of weather conditions, it must be documented that the mooring system will keep the floater in place even if one or more of the mooring lines are put out of function.

Dragging of anchors may represent another problem area. Normally, dragging will not take place if conditions are right. But since dragging has occurred one should thoroughly consider which factors are of importance to the holding power of the anchor and how these factors affect the system.

Interrupted production
If interruptions in the operating accessibility are accepted (financially) and disconnection of the riser is accepted (with respect to safety), one can define a limit for weather conditions when production has to be closed down and disconnection performed.

If so, the mooring system must be sufficient to keep the movements within the tolerance area until such time as a controlled close-down/disconnenction of the riser has been performed.

General for conventional mooring system
Generally, the primary strength element requirement is that engineering should be in accordance with the Regulations for Load Bearing Structures so that, among other things, they should stand up to natural loads with an annual transcendence probability of 0.01 and 0.0001 and accidental loads with annual transcendence probability of 0.0001.

Furthermore, after any failure the system must still retain sufficient reserve capacity to withstand natural loads with an annual transcendence probability of 0.01.

However, in very special cases where the consequence of a failure could be serious, it may be sound practice to require a lower probability.

In practice, some chain breakages occur every

year in connection with conventional mooring systems. One should therefore analyse the conditions when using a new chain to establish to what extent the criteria during recent years concerning the calculation and fabrication of chains have improved the situation.

Furthermore, one should study the possibility of avoiding breakages which are caused by guide wheels and other equipment and thereby reduce the possibility of this type of breakage.

Tension legs
Normally the mooring lines for tension leg structures are important to the stability of the installation. Therefore the tension leg requirements will probably be independent of whether the installation is meant for continuous or interrupted operation.

For tension leg moored structures, two alternatives can be imagined:

- tension legs that are designed to last through the lifetime of the installation
- tension legs that are meant to be replaced in the course of a specified period of time.

If the tension legs are intended to be replaced regularly, this requires that the system is designed to make replacements as easy as possible. Furthermore, specifications have to be prepared stating when and in what order the braces are to be replaced. In addition, a procedure must be available that specifies how and under what conditions such replacement is to take place.

The braces should nevertheless be accessible for regular inspection, and the inspection programme should be prepared on the basis of the composition and connection of the braces, among other things.

Dynamic positioning
If the system has an annual probability of failure that is equal to or exceeds 0.0001, the remaining thruster capacity must be sufficient to keep the installation in position. In such a situation, the installation has to be able to withstand natural loads with an annual transcendence probability of 0.0001.

However, it is possible that the consequences of some forms of failure are so great that the probability of these forms of failure should be less.

In practice, one should always have a certain degree of redundancy built into the system. The degree of redundancy depends on the probability of failure of the various elements and the connections between the elements which make up the system.

Gullfaks South
Block 34/10 was allocated in 1978 with Statoil as operator, cf. the description of Gullfaks Phases I and II.

Gullfaks South lies about nine kilometers south of the Gullfaks field.

So far, three wells have been drilled in this area and the operator is planning a fourth well in the beginning of 1986.

Resources
Gullfaks South contains oil, condensate and free gas. The operator is evaluating whether to recover oil first, then gas, or whether it is possible to recover oil and gas simultaneously.

Statoils estimate of recoverable resources is 37 million Sm^3 of oil and condensate and 93 billion Sm^3 of gas for Gullfaks South.

A development of Gullfaks South has to be proposed to the authorities as a separate matter. Statoil is planning the presentation of a field development plan to the authorities in 1986.

Several platform solutions have to be evaluated, including a platform with partial processing equipment with transfer of stabilized oil to the Gullfaks field for final processing and a separate full processing platform.

The present plan for Gullfaks South involves a possibility of production start in 1993/94.

33/9 Alfa and Beta
The Alfa and Beta structures in Block 33/9 lie just east and north of the Statfjord field, respectively. It is assumed that both structures stretch into Block 34/7. So far, two wells have been drilled in the Alfa structure (33/9-7 and 34/7-5), and one well in 33/9-Beta.

Resources basis
The appraisal well in Alfa which was originally planned in 1985 has been postponed until 1986. In addition, the seismic mapping of Alfa and Beta has been postponed until 1986. The next appraisal well in Beta is planned in 1987. The operator does not expect these postponements to cause delays concerning production start in 1991 for Alfa and 1992 for Beta. In order to be able to implement optimal mapping of the structures, the operator wants unitization with the licensees of Block 34/7 as soon as possible.

The Norwegian Petroleum Directorate's estimates of recoverable resources are:

Alfa: 19 million Sm^3 of oil and 2.5 billion Sm^3 of gas
Beta: 39 million Sm^3 of oil and 2 billion Sm^3 of gas.

These estimates include probable additional resources in Block 34/7.

Development solution
In recent years, the operator has explored alternative development solutions for the Alfa and Beta structures. The solutions have been based on the exploitation of future idle processing capacity in the Statfjord area. The solution which seems to minimize development costs is the application of subsea

production templates with transmission of well streams to Statfjord C. The reservoir pressure can be maintained by means of water injection.

Snorre

The Snorre field lies in Blocks 34/4 and 34/7. Block 34/4 was allocated as production licence 057 in 1979. Block 34/7 was allocated as production licence 089 in 1984. Saga is operator for both blocks.

In 1985, two new wells were drilled and tested in the southwestern part of the Snorre field, 34/7-6 and 34/7-7. Both wells proved oil in sandstone of Lower Jurassic age. The production test results were good.

Resources basis

So far, seven wells have been drilled on the Snorre field, 34/4-1 and 4 and 34/7-1, 3, 4, 6 and 7. All wells have proven oil with associated gas, but without a gas cap. Oil has been proven in sandstone of Lower Jurassic and Triassic age. The Snorre field is structurally complex. The depth down to the reservoir is about 2,500 meters. The limits of the field towards the south are uncertain. Drilling and testing have shown that there are two separate oil zones on the Snorre field. In the western part the oil-water contact is deeper than in the eastern part.

The Norwegian Petroleum Directorate's estimate of recoverable resources is 99 million Sm^3 of oil and 27 billion Sm^3 of gas. The Norwegian Petroleum Directorate is presently working on new geological/ geophysical mapping of the field.

Development solution

The water depth varies over the field from 300 meters in the south to 370 meters in the north. The field development planning is at an early stage, and the operator is evaluating a number of concepts. The most relevant seems to be a development with two platforms, of which the first should be located in the south. One is expecting extensive use of seabed completed wells. It has not been decided what degree of processing would be most expedient for the field. For partial processing, further transport to Statfjord seems to be the most realistic alternative. Production start is expected in 1993 or 1994.

Haltenbanken

Resources basis

In 1985, drilling activities on Haltenbanken were vigorous, and several considerable gas/ condensate discoveries were made. In addition, a new oil discovery was made. Figure 2.2.3.c shows finds on Haltenbanken.

The following discoveries have been made in the area:

Tyrihans

So far, two wells have been drilled on Tyrihans. The field consists of two structures; one structure with gas/condensate and one with a thin oil column and overlying gas cap.

Midgard

So far, three wells have been drilled on the field. Midgard is a gas field with small quantities of condensate. In the last well, oil was also proven under the gas. At present, however, it is difficult to determine whether this oil is recoverable.

Draugen

A total of five wells have been drilled on the field. On the basis of these wells one seems to have a good overview of the reservoir. The reservoir is thin, from 11–40 meters, and contains light oil, but with a low gas-oil ratio. The reservoir properties are favourable.

Smørbukk and 6506/12-Beta

One well has been drilled on Smørbukk. Gas/condensate has been proven in several levels. The resources estimates at present are very uncertain, but the potential is great. How much condensate can be recovered depends on which production mechanism is used. In order to be able to give resources estimates with greater certainty, several appraisal wells are required. In the Beta structure, the second well is being drilled. The first well proved hydrocarbons in the same type of formation as on Smørbukk. Liquid samples from this well indicate light oil. The transition between heavy condensate and light oil, however, is very uncertain and further analyses are required to determine the hydrocarbon type.

Heidrun

The first well which was drilled proved two reservoir formations. The uppermost one contained gas and the lowermost gas and oil. The second well proved that both reservoir formations contain oil with a gas cap. The oil is relatively heavy. Appraisal wells will now be drilled in the structure.

The Norwegian Petroleum Directorate's resources estimates for the fields in the area appears from Table 2.4.3. In addition to what this table shows, a gas discovery was made in Block 6407/4. The resources estimates for Haltenbanken are continuously being updated as new wells are drilled.

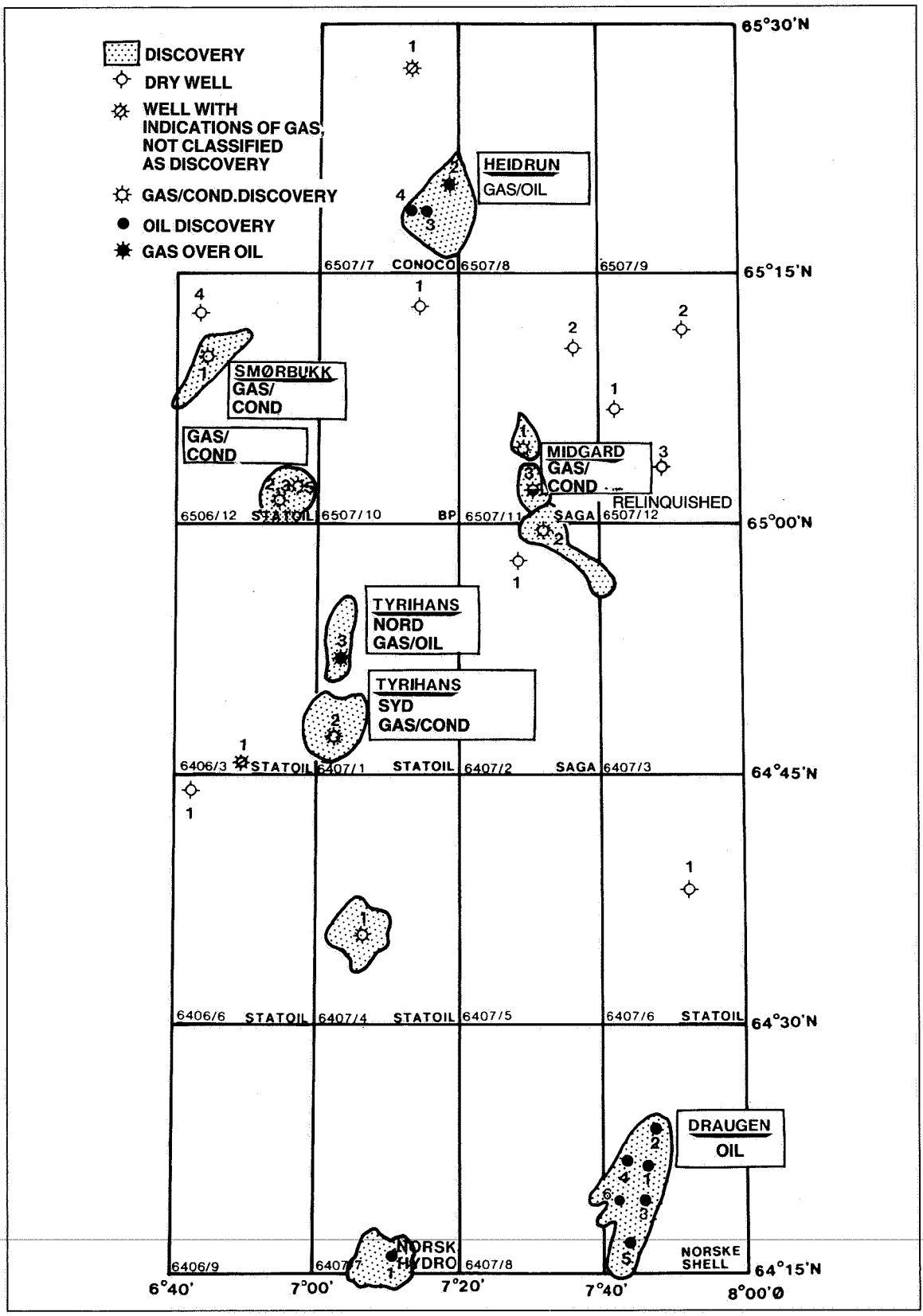
When the forthcoming drilling of prospects in connection with the ninth allocation round has been completed, it is likely that the resources potential of Haltenbanken will have been adequately elucidated.

Development plans

Activities on Haltenbanken during recent years have shown that this area has very good prospects and is highly interesting. Against the background of the resources situation on Haltenbanken and particularly in connection with the discoveries of the two oil fields Draugen and Heidrun, the relevance of developing the area has been further reinforced.

Gas production from Haltenbanken depends on the development of the gas market and is not expec-

FIG. 2.2.3.c
Haltenbanken



ted to be feasible until after the year 2000. On the basis of the evaluations which have been made, however, it may seem as if an LNG terminal will be the best solution for further gas transport.

Since Haltenbanken is an area without infrastructure one now has the opportunity to coordinate the development of production and transport facilities for the proven fields right from the start.

The operators are working on the establishment of a cooperation project which in the first instance is aiming at the establishment of a pipeline system for the transportation of oil/condensate to an onshore terminal for possible further processing and storage before further transport. In addition to forming the basis of infrastructure in the area, a joint transportation system may also contribute to simplification and savings on the field installations.

In the course of 1985, the Norwegian Petroleum Directorate performed several reservoir and technical development studies as well as area analyses on Haltenbanken. The aim was to consider the potential for Haltenbanken and how it would be possible to coordinate fields, which criteria should form the basis of coordination, and how infrastructure can best be developed so as to cater for the interests of society as well as of the companies.

In connection with the proving of the gas/ condensate fields Smørbukk and 6506/12-Beta, one has specially focused on the possibilities of just producing condensate during the first phase. At present, any production from these fields seems to require a pipeline transportation system to the shore for further processing. The Norwegian Petroleum Directorate's work has focused on the relationships between the oil and condensate fields for the various transportation options and alternative terminal facilities.

The oil fields Draugen and Heidrun, however, can be developed independently of other activity, i.e. with own transportation solutions, and in this case, buoy loading. The discussion concerning Draugen's connection to the oil transportation system will be an important point in the treatment of the Draugen field development plan and the plan for the Haltenbanken transportation system.

With satisfactory market conditions, development of Haltenbanken in accordance with a major coordinated plan for all fields in the area will reduce costs.

The activity in the various production licenses on Haltenbanken is high when considering exploration and technological development. A field development plan for Draugen is expected to be submitted towards the end of 1986, while the preliminary plans for Heidrun, Smørbukk and 6506/12-Beta are that a field development plan will be ready in the fall of 1987.

The Troms area

All discoveries in the Troms area have been made in the Hammerfest basin, consisting of the fields Askeladd, Albatross, Snøhvit and 7120/12 (Alke). In all, considerable quantities of gas have been proven. In addition, there are some prospects in which one has not yet drilled for oil or gas. Figure 2.2.3.d provides an overview of the blocks in the Troms area. In the figure, block numbers and operator have been indicated.

Drilling operations and resources

In the period since September 1984, blocks allocated in the fifth round have not been drilled in. In the blocks allocated in the eighth round, discoveries have been made in Snøhvit and Snøhvit North, Blocks 7120/6 and 7121/4 and in the eastern elongation of Albatross, 7121/7. Wells 7119/9-1 and 7120/10-1 were dry, and one does not expect that any significant resources exist in these two blocks.

Two wells have been drilled in the blocks allocated in the ninth round. Well 7121/5-1 proved gas and oil in the eastern part of the Snøhvit field, while 7120/5-1 was dry. The main prospect in Block 7120/5 therefore does not contain resources of any significance.

One well (7120/2-1) has been finished on Loppa-ryggen. The result was negative with respect to hydrocarbons, but relatively rich reservoir rock was proven. Two other wells in the same geological province, 7120/1-1 and 7121/1-1, were temporarily abandoned for the winter before striking their prospects on account of orders from the Norwegian Petroleum Directorate.

The Norwegian Petroleum Directorate's estimates of technically recoverable resources from the area appear from Table 2.4.3. The thin oil zone on Snøhvit has not been included in the table because the studies in the Norwegian Petroleum Directorate concerning development options have not yet been concluded.

Development possibilities

The Norwegian Petroleum Directorate has performed an area study for the Troms area. The conclusion of this study is that, as per today, it is not profitable for the operators to develop the area. New technology and better market conditions for LNG products may change this picture.

2.2.3.3 Fields declared commercial

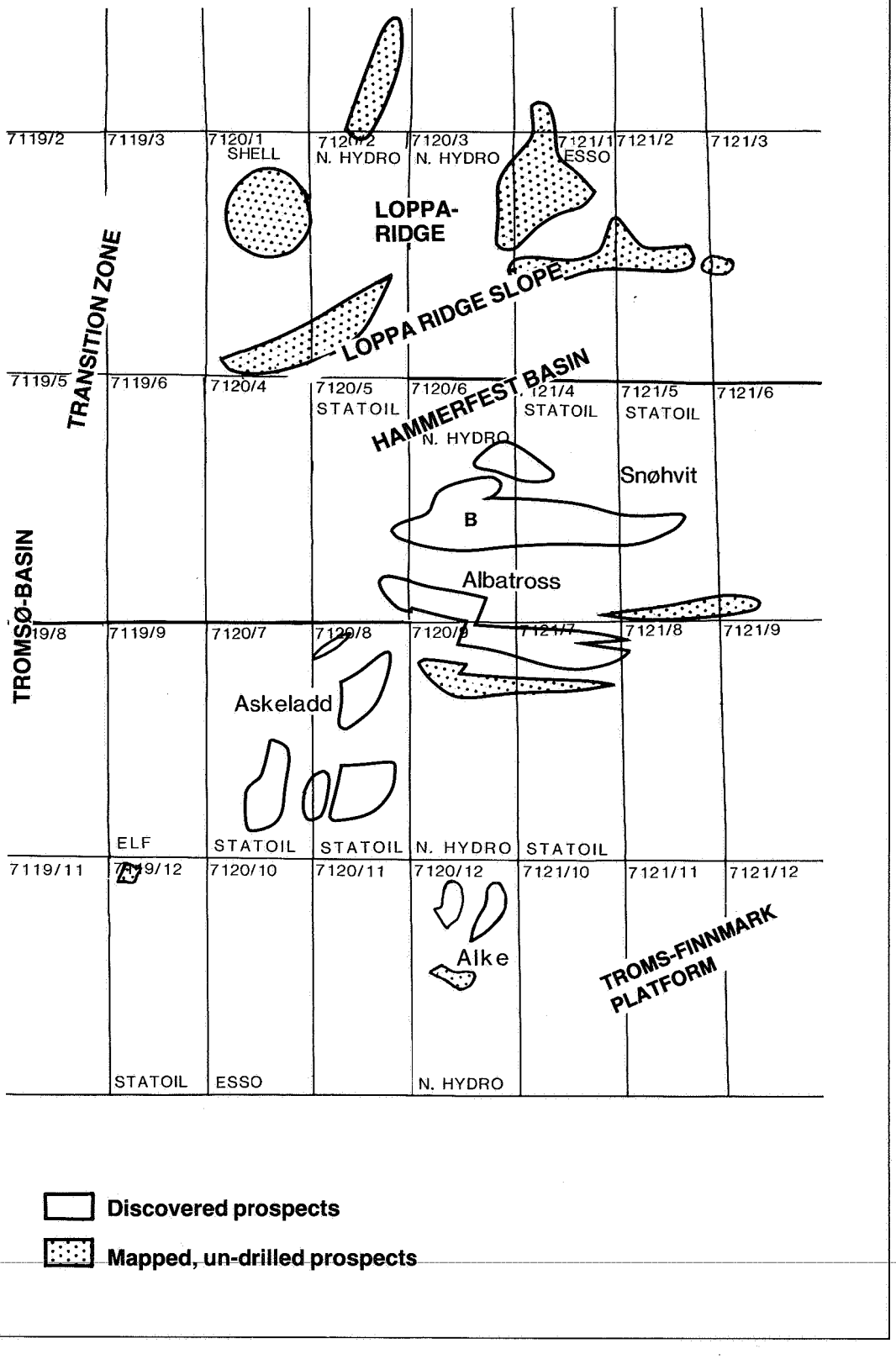
In 1985, Tommeliten was declared commercial by Statoil.

2.3 Fields being planned, developed or in production

On the Norwegian part of the continental shelf there are a number of fields which have been declared commercial and resolved to be developed or which are in production: Valhall, Albuskjell, Cod, Edda, Ekofisk, Eldfisk, Tor, West Ekofisk, Ula, Heimdal, Frigg, North East Frigg, Odin, and Statfjord.

The fields East Frigg, Oseberg and Gullfaks are

FIG. 2.3.3.d
The Troms area



being planned/developed. In the ensuing the fields are described in further detail.

2.3.1 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.

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 2.3.1.a shows these installations. The marine riser platform, which Phillips Petroleum Company Norway has the operatorship for, is connected to the Ekofisk Center 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 dewpoint 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.

Recovery of reserves

Valhall can be compared to the fields in the Ekofisk area as regards reservoir properties and geology.

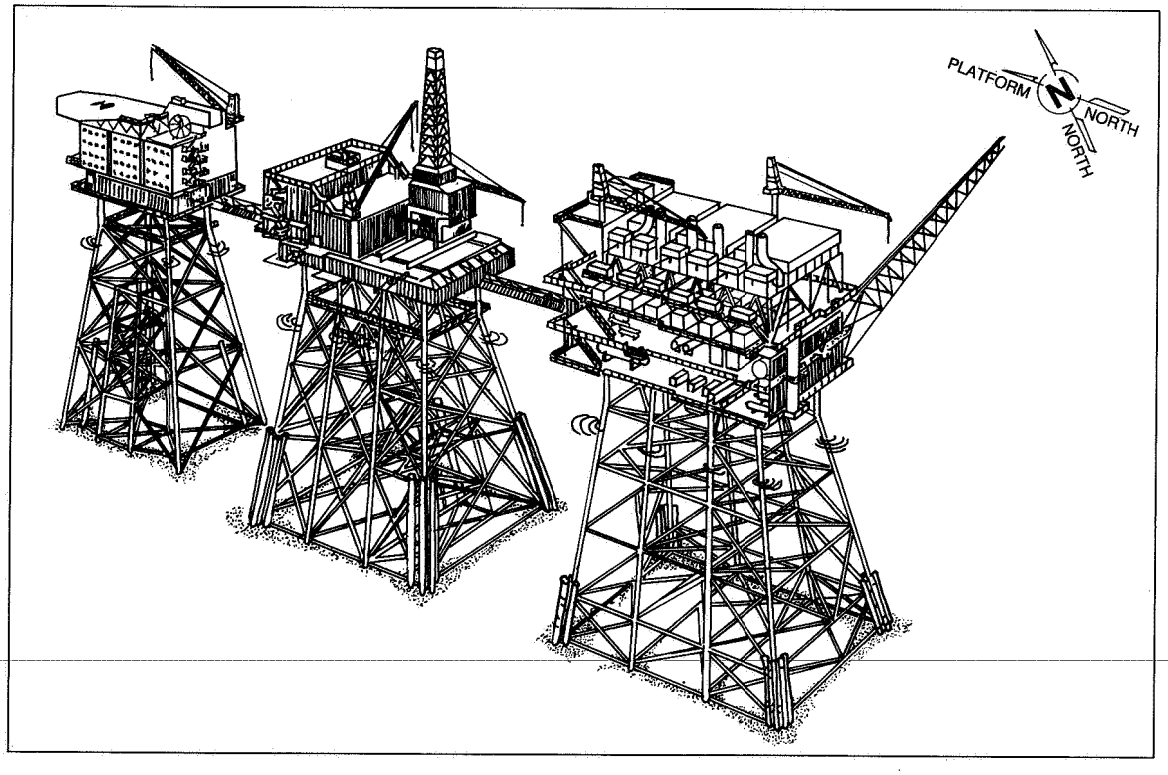
The Norwegian Petroleum Directorate estimates that some 19 million Sm^3 oil, 1.3 million tons NGL and 16 billion Sm^3 gas will be depletable from the Valhall A site by pressure amelioration.

Production from Valhall A started on 1 October 1982, and by 31 December 1985 a total of 19 wells had been tied in to the production facility.

The productivity of the wells has been substantially lower than predicted.

On the Valhall field the rock properties are highly complicated, and this has sometimes caused major difficulties in connection with production from the field, insofar as chalk particles borne by the oil flow cause the wells to clog up. During the year a great deal of work has been done to overhaul and reopen such wells.

FIG. 2.3.1.a
Installations on Valhall



Exploitation of the resources on the Valhall field depends on the time of development and the development strategy for those parts of the field that cannot be reached from Valhall A. Definite plans for further development have not been provided.

Gas flaring
The volume of gas flared in 1985 on Valhall was on average 0.10 million Sm^3 per day, corresponding to 5.9 per cent of the total gas production (Figure 2.3.1.b). The flare limit is 0.150 million Sm^3 per day. During the year there have arisen few technical process problems, thus providing high process reliability. Gas has been flared off due to compressor problems (Figure 2.3.1.b).

Costs
Total investment costs are estimated to be NOK 8.9 billion in fixed 1985-kroner.

Safety, preparedness and the working environment
Explosion and fire
On Saturday 1 June 1985 there was an explosion on the Valhall A production platform. The explosion occurred in the air inlet to a turbine. The cause was that gas under pressure from a neighbouring turbine had erronously been relieved through an atmospheric ventilation system rather than to the flare system. Because the turbine air inlet was very close to the atmospheric ventilation, gas was sucked in and ignited.

The fire was rapidly extinguished. There was no personal injury.

Underwater inspection
During the annual underwater inspection of the production platform, a puncture on a diagonal brace was detected. The damage probably arose during piling of the platform base during installation. However, the damage has been repaired.

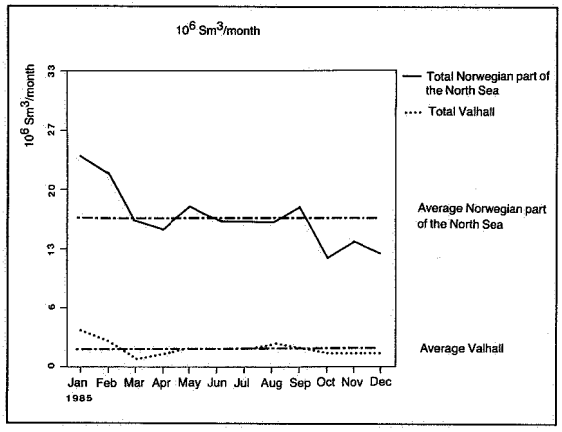
2.3.2 The Ekofisk area
Production licence 018
Licensees

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 %
Cofranord A/S	0.304 %

The above companies (the "Phillips group") hold the licences to the Ekofisk, West Ekofisk, Cod, Eldfisk and Edda fields (Figure 2.3.2.a). The two first named fields lie in Block 2/4. Cod lies in Block 7/11 and Eldfisk and Edda in Block 2/7.

Albuskjell is split between production licences

FIG. 2.3.1.b
Gas flared on Valhall



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:

Production licence 018, "Phillips group":	50 %
Production licence 011, A/S Norsk Shell:	50 %

Tor:

Production licence 018, "Phillips group":	75.3612 %
Production licence 006, "Amoco group":	24.6388 %

Production licence 006 ("Amoco group")
Licensees

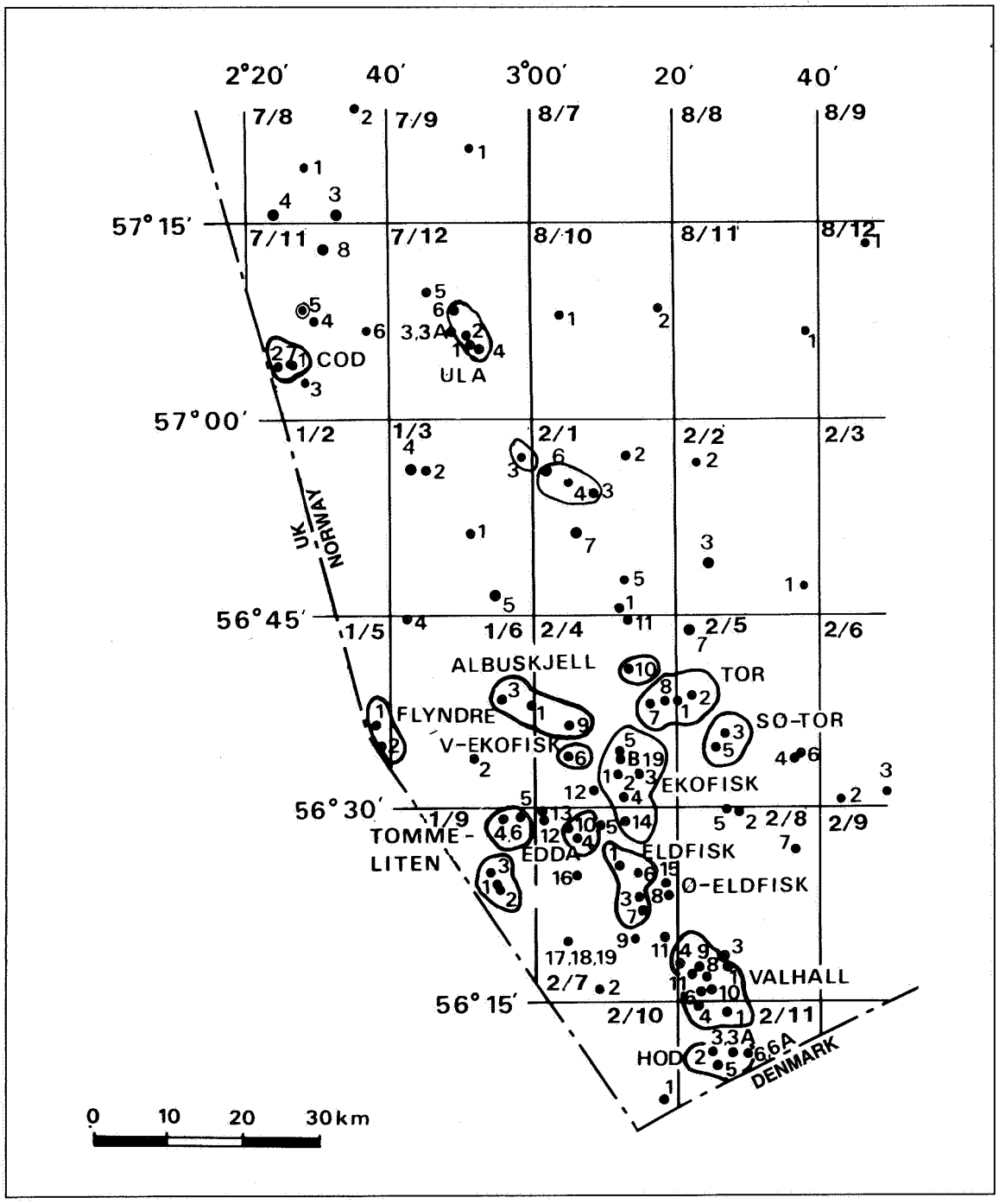
Amoco Norway Oil Company	28.33 %
Amerada Petroleum Corporation of Norway A/S	28.33 %
Texas Eastern Norway Inc	28.33 %
Norwegian Oil Consortium A/S & Co	15.00 %

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. In 1969, the Ekofisk field was found, and as early as 1970, declared commercial. In the period from 1969–72, the other fields in the area were discovered. Phillips operates all seven fields.

Development took place in four phases:

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 Center, together with the laying of an oil pipeline to Teesside and a gas pipeline to Emden. The lines were taken into oper-

FIG. 2.3.2.a
The Ekofisk area



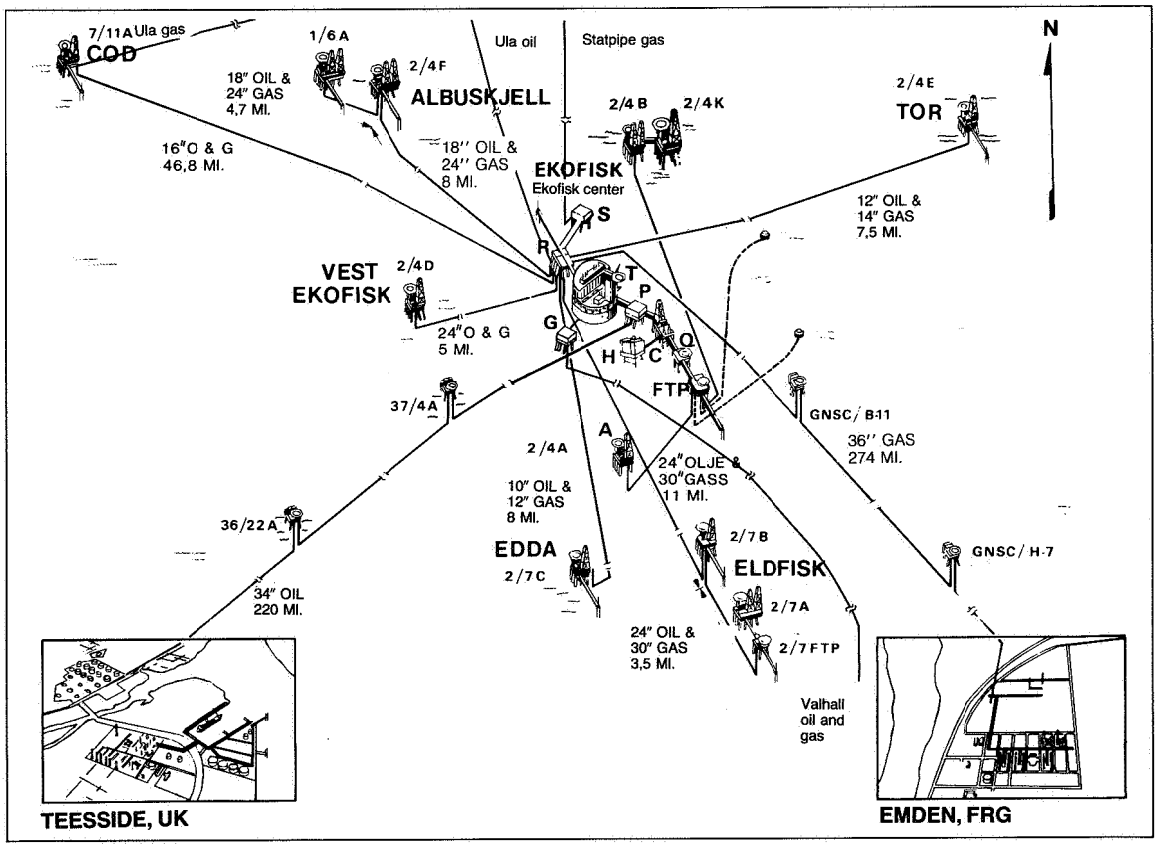
ation in October 1975 and September 1977 respectively.

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

A fifth phase, which was resolved in 1983, involves the installation of a new platform for injection of water into the Ekofisk field. This phase together with the subsidence of the Ekofisk field will be discussed below.

Figure 2.3.2.b gives a birds eye view of the installations in the Ekofisk area.

FIG. 2.3.2.b
Installations in the Ekofisk area including planned 2/4 K and connections from Ula and Statpipe



Subsidence

In November 1984, it was discovered that the seabed near the Ekofisk Center had subsided. Measurements which have been performed later indicate total subsidence as per 1 December 1985 of about three meters. The rate of subsidence from 1979/80 has been estimated at 0.4 to 0.5 meters per year.

The subsidence of the Ekofisk field is caused by petroleum being produced from the Ekofisk reservoir three kilometers under the seabed. The rock that the oil and gas are contained in is relatively porous and is compressed as pressure decreases. The pressure of the oil and gas together with the strength of the rock previously consituted a force which was sufficient to support the three kilometers of overlying rocks. When pressure is reduced, a greater part of the strain is transferred to the rock. The rock cannot withstand the strain and decreases in volume and becomes more compact. Though one earlier expected to get a reduction in reservoir volume, one did not expect this to show on the surface. It is still uncertain how the compression of the reservoir is transferred to the surface.

Several independent studies of the rock properties have been performed. They conclude that the strength falls off with increasing porosity. Mapping of reservoir porosity makes it possible to calculate the connection between the pressure development and compression in the reservoir. The Norwegian Petroleum Directorate has engaged external consultants to reveal the above mentioned connection. In addition, one will look into how the reservoir movement is transmitted to the seabed. One cannot exclude the possibility that the overlying rocks contribute to the subsidence.

In order to stop reservoir compression one has to try to maintain the pressure. This is now accomplished by the operator, through an agreement with the gas buyers, injecting about 50 per cent of the produced gas on the Ekofisk field. Thus, the gas sale to the continent has been reduced by approximately 25 per cent from the Ekofisk area.

In the long term, there are several alternative ways of sustaining the pressure in the reservoir; by injection of gas, nitrogen or water. The long term alternative will be evaluated during 1986.

The subsidence has also led to plans for modifying the platforms structurally. According to these plans, the platforms can withstand a total subsidence of 6 metres. Since the Ekofisk tank cannot be modified to stand a subsidence beyond 6 metres, this has been set as a limit.

In addition to plans for modifications, alternative structural solutions are also being evaluated. As of

today, the solution to the subsidence problem is still uncertain. Very much depends on the ongoing studies. Final conclusions from these can be expected towards the end of 1986.

Waterflood project
Water injection in the Tor formation was decided in 1983. The purpose at that time was solely to increase the recovery of hydrocarbons from the Ekofisk field. Injection of water will also increase the pressure in the reservoir. In addition, this gives a positive contribution to the efforts of reducing the subsidence. Prior to the decision of implementing the injection of water, the effect of water on the field was tried out in a laboratory test and a pilot test. During the pilot test, water was injected in a limited part of the reservoar.

A separate platform is needed for the injection of water. This platform will be placed in the northern part of the field in June 1986. Areawise, the platform will cover two thirds of the reservoir.

The drilling of wells has been started from a jack-up rig. Compared to the original plans, the drilling operations are somewhat delayed, but the water injection is expected to start as planned in the spring of 1987.

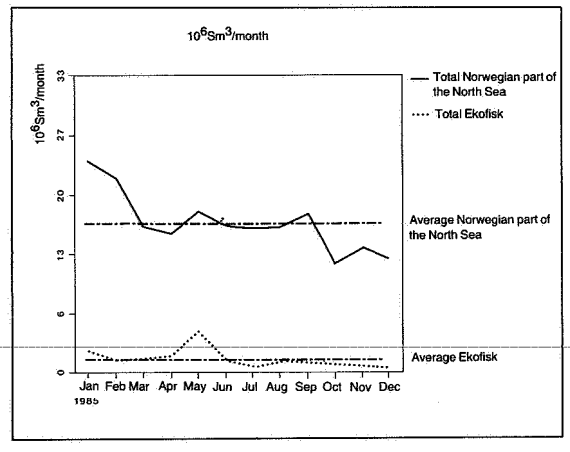
Water injection in the lower part of the Ekofisk formation is being tested. A decision on this will probably be able to be made in the first half of 1987.

Development plan
The new Platform 2/4-K is planned as an integrated steel structure whose main functions are drilling, water injection and water treatment. The platform will also have an accommodation block, flareboom and helideck. There will be a bridge connection to 2/4-B (see Figure 2.3.2.b).

The project will also require some modification of existing platforms to be implemented. These include the installation of a water separator and gas lift equipment on 2/4-B and 2/4-C. Delivery of gas to the latter will take place with the aid of an existing compressor on 2/4-C.

If it becomes necessary to have a treatment facility for sour oil (hydrogen sulphide), this will be installed on 2/4-FTP.

FIG. 2.3.2.c
Gas flared on Ekofisk



Flaring of gas in the Ekofisk area
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 field. Since the line to Emden was taken into use, the amounts of gas flared have decreased significantly. Gas flared in 1985 on the Ekofisk area was an average of 0.05 million Sm^3 per day, and corresponds to 0.14 per cent of the total gas production from the fields. During the whole year the flare limit has remained at 0.40 million Sm^3 per day. The year 1985 demonstrated that the flare rate is stable and satisfactorily low, mainly because of high processing stability. The amount of gas flared is shown in Figure 2.3.2.c.

The metering system
Inspections of the metering systems on the Ekofisk area were performed according to the stipulated shift schedule up to 1 May 1985. Since then, sporadic inspections have been performed and start-up operations were accomplished in September and October. Inspections of the metering systems at the point of sale of the gas in Emden and of the oil and wet gas in Teesside have been accomplished monthly.

Costs
The total costs on the Ekofisk area including Tor, Albuskjell, Norpipe and investments in connection with the Ekofisk waterflood project are estimated to amount to about NOK 49.4 billion in current kroner, or NOK 80.4 billion in fixed 1985 kroner.

Safety, preparedness and the working environment
The annual inspection of structures and pipelines did not reveal any serious faults.

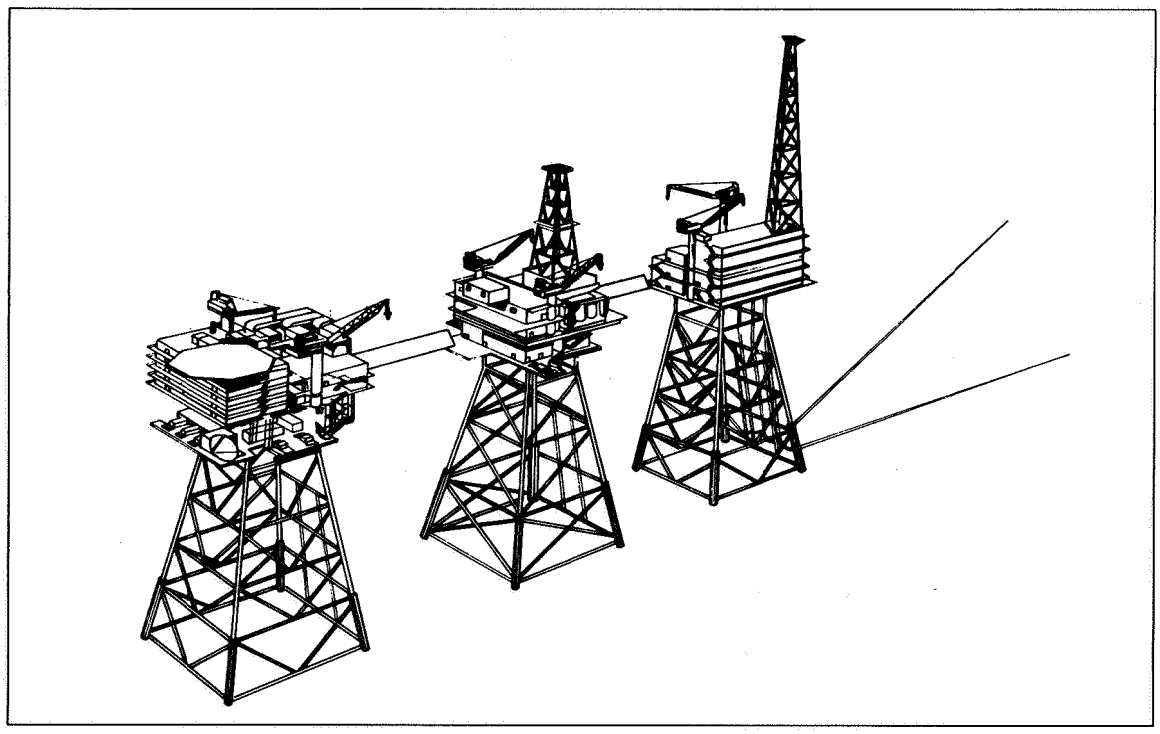
Some structural modification work was implemented on 2/4-C as a result of the subsiding seabed in the Ekofisk area. The modifications consist in rounding off some I beams in the cellar deck and cutting holes in the deck plates. These holes were then "bridged" with deck grating.

The maintenance program that was implemented to upgrade turbines and compressors to receive Statpipe gas and Ula oil has been concluded.

Turbines on 2/4-C are also being upgraded. The upgrading will consist in increasing the number of horse power and the degree of efficiency.

Changed preparedness arrangement on the Ekofisk field
In connection with the subsiding seabed on Ekofisk,

FIG. 2.3.3
Installations on Ula



the wave threat this winter made it necessary to move a lifeboat and a rescue capsule from an exposed location.

The Norwegian Petroleum Directorate has asked the operator to analyze the total emergency preparedness and describe the necessary measures to maintain and improve it. The analysis includes accessibility to means of evacuation, escape routes and bridges in the event of relevant accident and hazardous situations, as well as preparedness procedures in the event of storm forecasts.

2.3.3 Ula

Production licence 019 A

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 %

Conoco has transferred 60 per cent of its previous owner shares to Svenska Petroleum Exploration A/S.

The field lies in Block 7/12 some 70 kilometers northwest of Ekofisk (Figure 2.3.2.a). It was discovered in 1976 and declared commercial in December 1979. Statoil acceded the declaration in September 1980. BP is the operator for the production licence.

In December 1982, the licensees decided to go ahead with the project.

Development

The concept forming the basis of the development includes three conventional steel platforms (Figure 2.3.3) for production, drilling and accommodation, respectively. The steel jackets for the platforms were installed in June 1985 and the offshore hook-up work started in October 1985.

Production is planned to start from two wells in October 1986, whereas the third well will be ready for production about two months later.

Recovery of reserves

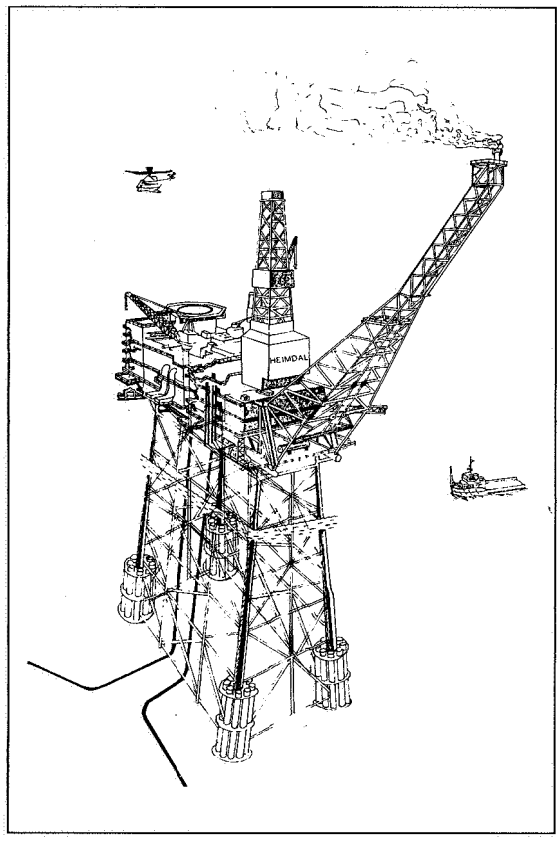
The Norwegian Petroleum Directorate's estimate of recoverable reserves is 30 million Sm^3 oil, 1.3 million tons NGL and 1.5 billion Sm^3 gas.

The field will produce with pressure support from water injection. A relatively high plateau production is planned, and the annual extraction in per cent of recoverable reserves is among the highest planned on the Norwegian Continental Shelf. Nevertheless, the Norwegian Petroleum Directorate does not expect that this will reduce the recovery factor on the field. The plan is to drain the field using nine production wells. Pressure support will be provided by six injection wells.

Transport

The licensees have agreed on the transport of oil through a pipeline via the Ekofisk Center to Teesside. Statoil is to finance and be the operator for the pipeline.

FIG. 2.3.4
Installation on Heimdal



The pipeline was installed on the seabed in the summer of 1984. Its diameter is 508 mm (20 inches) and the length approximately 70 kilometers.

The gas will be transported by pipeline to Cod and from there via the pipeline system to Emden. The steel pipes were manufactured in the summer of 1984 and coated with rust protection and a gravity collar in the autumn of 1984. The Ula-Cod pipeline was installed and tested in the spring of 1985.

Metering system
Tests of the metering system for oil and gas have been performed at the subcontractors. The metering system for oil and gas is ready to be shipped to the platform. The equipment is expected to be installed in the course of 1986.

Costs
Total investment costs are expected to be some NOK 8.5 billion in fixed 1985 kroner.

2.3.4 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	9.639 %
Bow Valley Exploration Norge A/S	8.000 %
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 licence 036 was allocated in 1971 and covers Block 25/4, which is situated some 180 kilometers west-northwest of Stavanger (Figure 2.3.5.a). On that part of the licence which includes Heimdal, Statoil has received a 40 per cent interest. Elf Aquitaine Norge A/S is the Heimdal operator.

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 prices on gas.

During 1980, the gas market picked up and Heimdal became the center of discussion regarding a landing 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 Paleocenic sand. The total recoverable reserves are estimated at 34 billion Sm^3 gas and 3 million Sm^3 oil. It has been decided to develop the Heimdal field with an integrated steel platform, comprising drilling, production and accommodation functions (Figure 2.3.4). The installation work on the field started in the summer of 1984, and production is predicted by the operator to begin in April 1986.

Production drilling started in April 1985. Two of the ten production wells that had been planned have now been drilled and completed. The same applies for one observation/ injection well.

Transport
Gas from the Heimdal field will be transported via Statpipe, and the pipeline from Heimdal will be tied in to the Statpipe system at Riser Platform 1. The 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 system.

The metering system
A system audit within volume metering of petroleum products has been implemented in addition to inspection of the performance and testing of the metering systems for gas and condensate on the Heimdal platform.

Costs
The total costs of the development are estimated to amount to about NOK 9.2 in fixed 1985 kroner.

Safety, preparedness and the working environment
Cracks were detected in nodal point connections in the flareboom on the Heimdal platform shortly after installation. These were caused by unforeseen wind loads. However, the defects have been repaired.

The work on the platform has made great progress. The accommodation quarters were taken into use early in the year and drilling operations started a bit later. Three wells have been drilled and completed. By the end of the year, production and auxiliary equipment had been installed and tested so that the main consent for use of the platform was granted in December. It is expected that gas and condensate can be delivered from April 1986.

The construction work has progressed according to plan and is somewhat ahead of the original schedule.

The Norwegian Petroleum Directorate will perform a more detailed evaluation of the permissible material loads in bolts and valves in relation to the maximum permissible gas pressure in the pipeline.

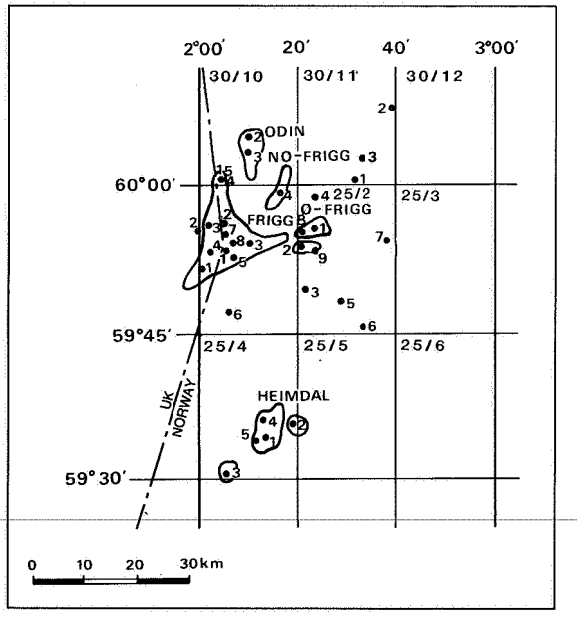
2.3.5 The Frigg area (Frigg, East Frigg, North East Frigg and Odin)

2.3.5.1 Frigg

Licensees

Norwegian share (60.82 %) (production licence 024)	
Elf Aquitaine Norge A/S	25.19 %
Norsk Hydro A/S	19.99 %
Total Marine A/S	12.60 %
Den norske stats oljeselskap a.s	3.04 %
British share (39.18 %)	
Elf Aquitaine UK Ltd	25.97 %
Total Oil Marine Ltd	12.98 %
BP Ltd	0.23 %

FIG. 2.3.5.a
The Frigg area



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 2.3.5.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 on 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. In 1982, the British group and BP agreed that 0.588 per cent of the British Frigg reserves lie in Block 9/5, which is wholly owned by BP. The BP interests in the Frigg field are looked after by Total Oil Marine.

The production system
The Frigg field was discovered in the spring of 1971 and declared commercial on 25 April 1972. The field has been developed in three phases. Phase 1 consisted of one production and one processing platform on the British side of the field and an 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 2.3.5.b depicts the Frigg installations.

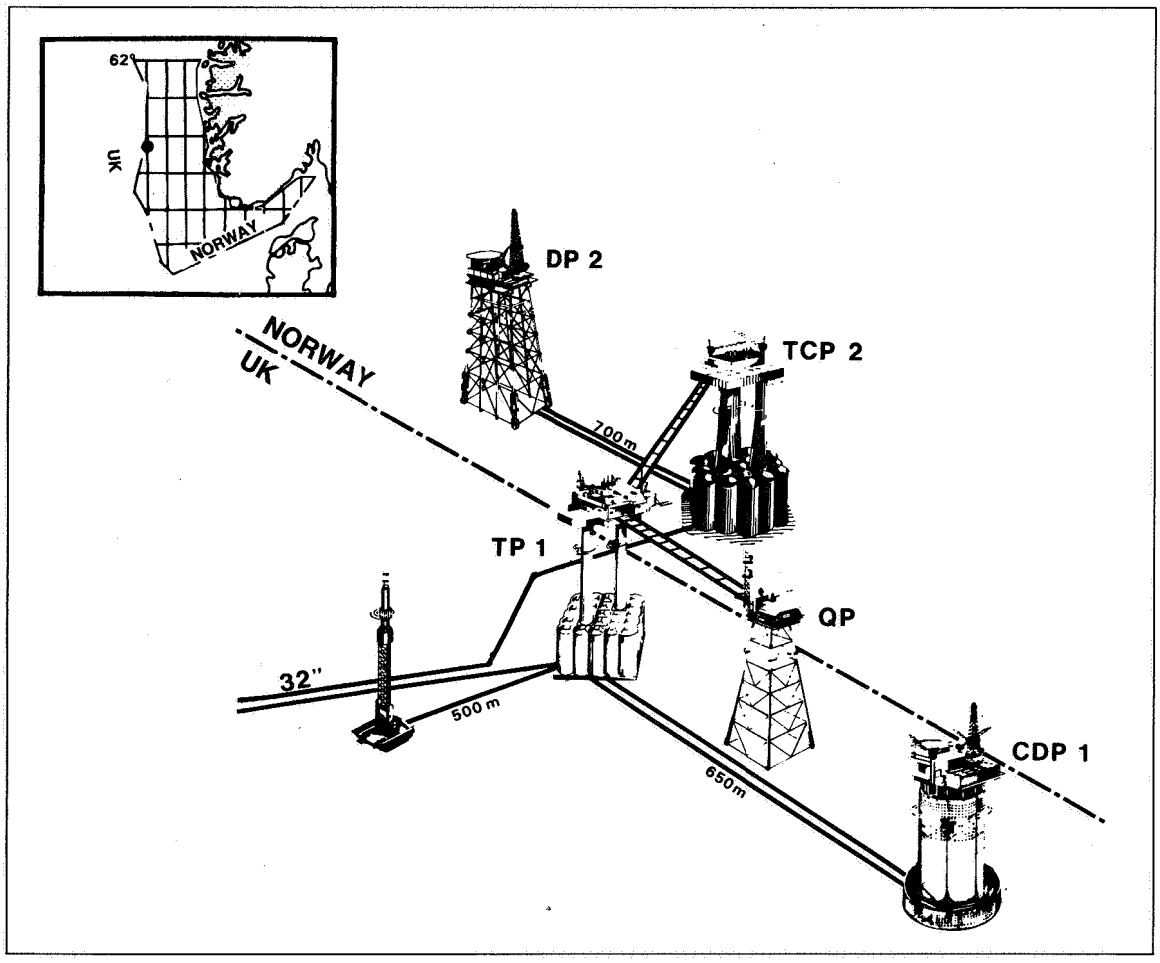
Phase 3 of the development included the installation of three turbine driven compressors of 38,000 horsepower on Platform TCP2. The booster facility is necessary to compensate for the reduced reservoir pressure. The facility started operation in the autumn of 1981.

Gas from North East Frigg and Odin will be treated and metred at Frigg. New modules for processing of the gas and condensate from these fields have been installed on TCP2. The operating licence was given on 18 November 1983.

Transport
The gas is transported to St Fergus in Scotland by two 813 mm pipelines. To increase the capacity of the transport system, two 38,000 horsepower turbocompressors have been installed on Booster Platform MCP-01, which lies midway between Frigg and Scotland. The increase in capacity is necessary to be able to transport the gas from the Odin field. For the same reason, an extension to the St Fergus terminal has been made, to provide from five to six process lines. The sale of Odin gas began in October 1983, with advance delivery from the Frigg field.

Recovery of reserves
For measurement of the liquid contacts under CPD

FIG. 2.3.5.b
Installations on Frigg



1, production well 10/1-A 12 on the British side was drilled deeper and converted to an observation well called 10/1-A25 in the summer of 1984. It revealed a water rise of about 55 meters since production start, which confirmed an uneven increase in the liquid contacts in the reservoir.

There was a need for more wells in order to improve the knowledge of the reservoir and water seep-in. In the course of 1985, five wells were drilled or made deeper, and the increase in liquid contacts for these were from about five meters to approximately 55 meters. The increase is largely determined by more or less continuous slate layers in the reservoir.

New seismics, which will be interpreted by the middle of 1986, are expected to provide valuable information. In accordance with requirements made by the British Gas Corporation, new reservoir studies were performed by an independent company which resulted in the reserves being adjusted downwards to 190.9 billion Sm^3 (Norwegian share: 116.1 billion Sm^3). As a result of this, the daily contract quantity (DCQ) was decreased from 45.5 million Sm^3 per day to 38.2 million Sm^3 per day in October 1986.

The Norwegian Petroleum Directorate's estimate of the Norwegian share is 127 billion Sm^3. Simulation studies indicate that some gas will remain in the reservoir and a possible additional development in order to produce the remaining gas is now being evaluated.

Metering system – Frigg

Inspections and processing 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 fields production is drawn from the total measured quantity into the pipeline to St Fergus. This is done to determine the Frigg field contribution.

Metering system – Alwyn

The Alwyn gas will be conducted to St Fergus via the Frigg field. The design of the metering system is

in accordance with the Norwegian Petroleum Directorate's regulations concerning fiscal quantity metering of gas, and the Norwegian Petroleum Directorate is allowed full access to the Alwyn field installations. The design and functions of the metering system have been inspected at the manufacturers in collaboration with the British Department of Energy.

Costs
The total costs (Norwegian share) for the development of Frigg, including East Frigg, are predicted to amount to about NOK 33.3 billion in fixed 1985 kroner. Included in the estimate, apart from the field installations themselves, are: the pipelines to St Fergus, compressor platform, terminal and new equipment on TCP2 to receive gas from Odin and North East Frigg.

Safety, perparedness and the working environment
The internals in one of the vessels for the compressor liquid separator (knock-out drum) have been replaced. It has been and will continue to be extensively tested before the operator decides to replace the remainder, if at all.

The drilling rig on DP2 has now been modified and, among other things, has been equipped with a new drilling derrick, "top drive" and pipe handling system.

The operator has found it necessary to modify the gas turbines onboard TCP2.

The annual inspection program did not reveal any significant faults or defects either on DP2 or TCP2. All pressure vessels are now back to normal inspection frequency.

2.3.5.2 East Frigg
Production licence 024 (Block 25/1)
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 026 (Block 25/2)
Licensees
Same as for production licence 024.

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 %

The previously relinquished part constitutes 7 per cent of the East Frigg field, and the total distribution is therefore:

Elf Aquitaine Norge A/S	40.0466 %
Norsk Hydro A/S	31.7801 %
Total Marine Norsk A/S	20.0233 %
Den norske stats oljeselskap a.s	8.1500 %

Production facilities
The East Frigg field consists of two main structures, previously called East Frigg and South East Frigg, now East Frigg Alfa and East Frigg Beta, respectively. It is part 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 Alfa 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 treated by the Storting on 14 December 1984. The development plan was presented in June 1985. A development plan with four wells has been approved by the partners. According to plan, production is to start in October 1988. Recoverable gas reserves have been estimated at 8.0 billion Sm^3 on East Frigg Alfa and 5.0 billion Sm^3 on East Frigg Beta, in all 13.0 billion Sm^3.

The sales agreement involves a production span of about 13 years. The development will be based on underwater technology.

Two identical underwater production systems remotely operated from Frigg have been planned, one on Alfa and one on Beta. A central manifold will tie the systems together and from here the gas will be transported by pipeline to TCP2. There the gas will be processed and be connected to the Frigg field transportation system.

The metering system
The Norwegian Petroleum Directorate has been orally informed of plans for the installation of Frigg of metering systems for East Frigg.

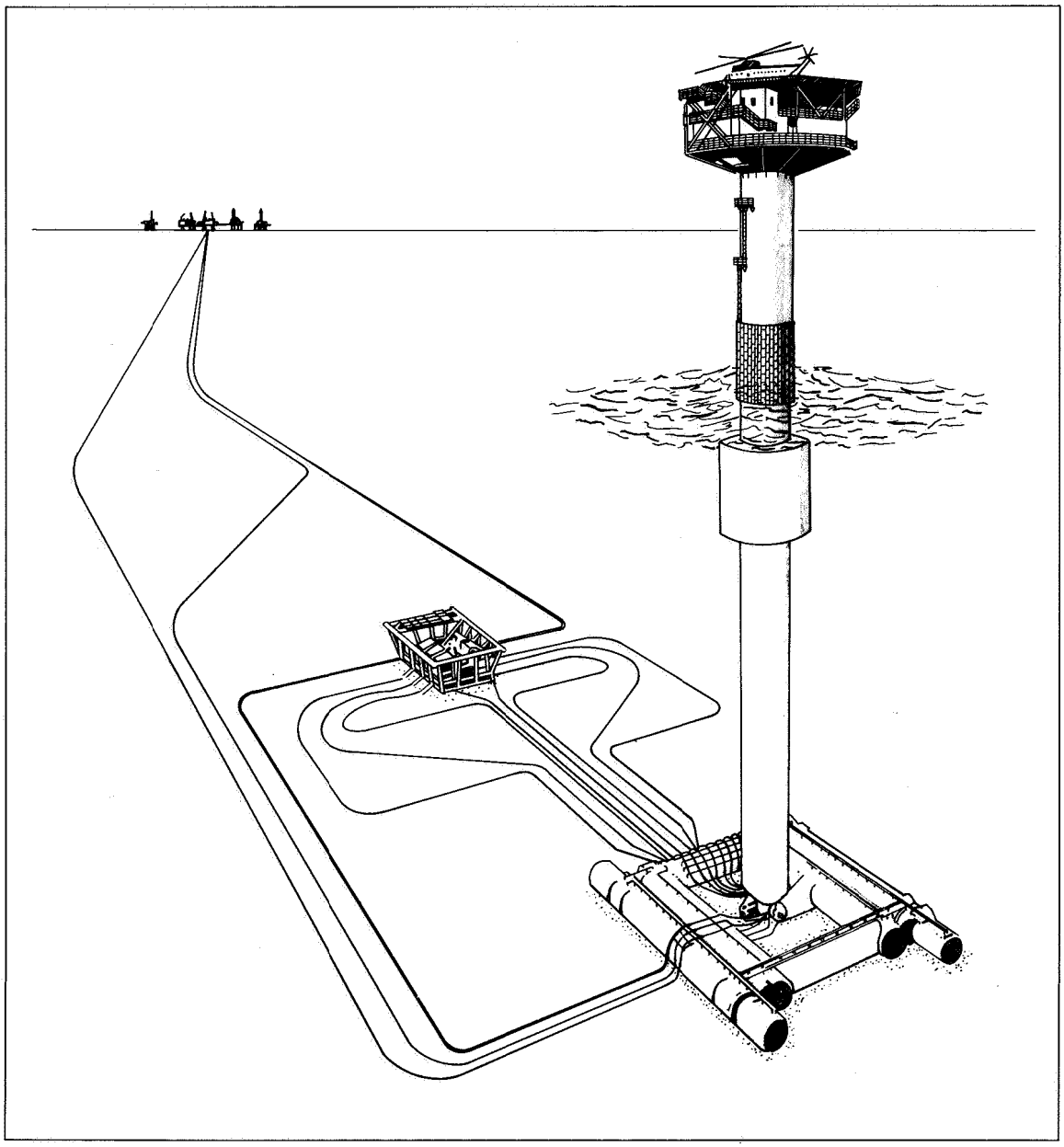
Costs
Total costs for the development are expected to be approximately NOK 2.8 billion in fixed 1985 kroner.

2.3.5.3 North East Frigg
Production licence 024 (Block 25/1)
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 030 (Block 30/10)
Licensees
Esso Exploration and Production Norway Inc 100 per cent. Statoil is entitled to 17.5 per cent of the net profits before tax.

FIG. 2.3.5.c
Installations on NE-Frigg



The North East Frigg field lies in Blocks 25/1 and 30/10 (Figure 2.3.5.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.

Production facilities

The gas field North East Frigg was proven in 1974. It is part of the same pressure system as the Frigg field. The final development plan was resolved in 1980. The field has been developed with six wells completed on the seabed (Figure 2.3.5.c). They have been drilled through a template structure located on the seabed. In addition to wellheads and Christmas trees, it is also equipped with a manifold which is to collect gas from the six wells. The gas is to be led through a 406 mm pipeline to the Frigg field for processing. Each of the six Christmas trees is controlled via separate service and inspection lines from the control station (an articulated column) located 150 meters from the wellheads. The control station was installed in July 1983 and is remotely operated from the Frigg field.

The sale of gas from North East Frigg started on 1 October 1980, i.e. before any of the production

wells had been drilled. This was possible because the Frigg field delivered gas on behalf of North East Frigg until North East Frigg came on stream. Similarly, Frigg will deliver gas on behalf of North East Frigg after production on North East Frigg has ceased. "Reimbursement" will take place through North East Frigg, in the course of its short production period, delivering gas on behalf of Frigg in addition to North East Friggs contract quantities. One thereby achieves a more normal, long-term sales profile for the North East Frigg gas, even though its production period is short.

Production started on 8 December 1983 from three wells. In the course of a one month close-down the last three wells were worked over in May/ June 1984. All six wells came on stream in the end of July after a one and a half month start-up phase with three producing wells.

Recovery of reserves
In the summer of 1984, new seismic data caused the licensees to raise the reservoir top in the northern part of the field. This gave an increase in total reserves and a greater proportion of the reserves fell to production licence 030. Recoverable reserves, however, remained at the same level as before due to a change in the recovery factor. Pressure measurements performed before production start showed that the reservoir pressure was sinking as a result of communication with the Frigg field through the saddle between the fields.

The metering system
Regular inspections and case processing in connection with the metering system that has been installed on Frigg have been performed in collaboration with the British Department of Energy.

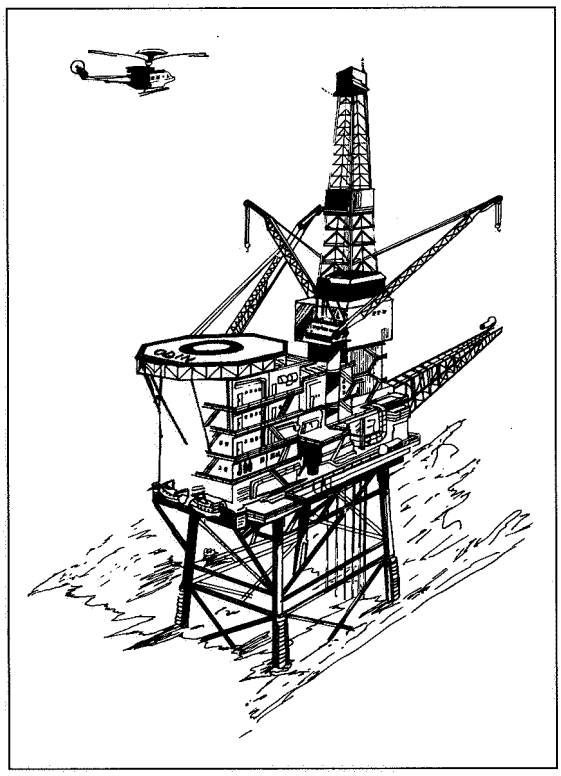
Costs
Total costs for the development are expected to run into about NOK 2.4 billion in fixed 1985 kroner.

Safety, preparedness and the working environment
Leaks in hydraulic lines
Leaks have been detected in hydraulic lines on the template for the Christmas trees. Among other things, this has caused one well to be shut down.

Annual inspection program
The inspections performed in 1985 provided satisfactory results.

The cold gas problem
Against the background of tie-in with North East Frigg and Odin as well as future connections of Alwyn and East Frigg, studies, experiments and testing have showed that cold gas may cause operational problems. The condensate problem primarily arises during the summer period when the compressors are not in use. Because of these problems,

FIG. 2.3.5.d
Installation on Odin



some modifications to the unloading and flare systems will have to be carried out on TCP2, among other things.

Fracture of actuator spindles
Two fractures on actuator spindles (of five in all) have meant that all spindles of this type and manufacture have to be replaced. Examinations have revealed material weaknesses, among other things.

Studies
The operator has performed studies concerning the lifetime of the installations QP, TP-1 and TCP2. This study concludes that the total lifetime is about 50 years (until the year 2025).

2.3.5.4 Odin
Production licence 030
Licensee
Esso Exploration & Production Norway Inc 100 %

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

The Odin field lies in Block 30/10 (Figure 2.3.5.a), with development operated by Esso.

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 jacket platform with

simplified processing and drilling equipment and relatively small accommodation quarters (Figure 2.3.5.d). This was possible because a standby 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. Before February 1985 the last four wells were drilled, completed and put into production.

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

On 1 October 1983, advance sales of gas to the British Gas Corporation were initiated, in other words, gas from Frigg was sold as if it had been produced on Odin. The "reimbursement" is now taking place insofar as Odin is supplying gas on behalf of Frigg, in addition to Odins own contract quantities.

Recovery of reserves
In the spring of 1985 the operator increased his reserve estimates for Odin on the basis of new well data and new mapping. The sale of the additional reserves depends on a satisfactory agreement being reached with the Frigg Norwegian Association (FNA) group regarding transportation and processing services. Pressure measurements prior to production start show that the reservoir pressure has fallen as a result of communication with the Frigg field across the saddle that separates Odin from Frigg.

The metering system
Regular inspections and processing of the case in connection with the metering system, which is installed on Frigg, have been performed in collaboration with the British Department of Energy.

Costs
The total costs of development are expected to be some NOK 3.10 in fixed-1985 values.

Safety, preparedness and the working environment
In 1985, the operation of the field progressed without any significant problems. All drilling equipment was dismantled on 15 April 1984 in connection with shipment to onshore locations or preservation onboard.

2.3.6 Oseberg

The Oseberg field stretches 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 2.2.3.b).

Production licence 053

Licensees

Statoil	50.00 %
Elf Aquitaine Norge A/S	13.33 %
Total Marine Norsk A/S	6.67 %
Norsk Hydro Produksjon A/S	12.50 %
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	73.50 %
Norsk Hydro Produksjon A/S	16.00 %
Saga Petroleum a.s	10.50 %

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

Ownership distribution using the sliding scale
The licencees have assumed an interim distribution 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 has been increased after the sliding scale was applied to the foreign companies only. Ownership interests in the unitized Oseberg field are as follows:

Licensees

Statoil	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 finds have shown that the reservoir is an oil bearing layer topped by a gas cap. The declaration of commerciality was presented in June 1983. The Norwegian Storting dealt with the development application in its spring session in 1984.

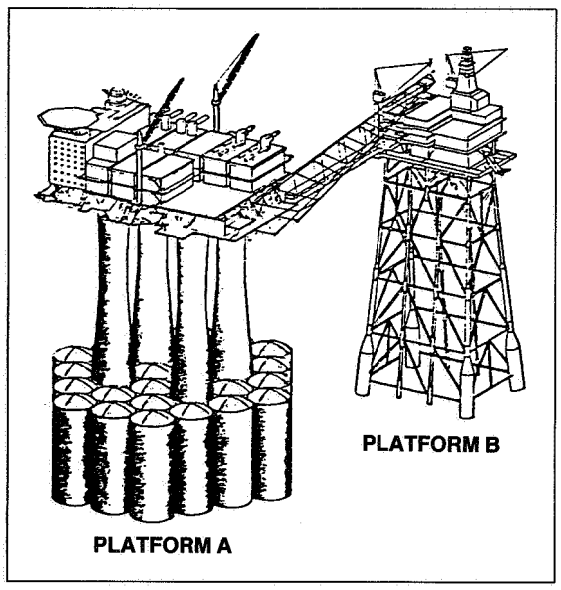
Development solution
The field has been resolved to be developed with a field center in the southern part with two platforms: Oseberg A, a processing and accommodation platform with a concrete base; and Oseberg B, a drilling and water injection platform with a steel jacket (Figure 2.3.6).

Production start has been stipulated for the first quarter of 1989.

The middle part of the field has been planned to be developed with subsea completed wells.

The northern part of the field has been planned to

FIG. 2.3.6
Planned installations on Oseberg



be developed with one single drilling and accommodation platform with equipment for partial processing. The plan is to get Oseberg C started in 1995.

Studies have been initiated with a view to these changes in the Phase II development. This will influence the platform concept on the northern flank as well as the underwater solutions. An increase in deviational drilling angle will reduce the number of subsea completed wells.

Studies have been carried out with respect to the injection of gas from other fields.

The above mentioned factors may result in changes in the field development plan that will also affect the Oseberg A platform. The proposed changes in the field development plan will increase the volume of recoverable oil.

Transport systems

A transportation line will be constructed for stabilized oil from Oseberg to a terminal at Sture in Øygarden. The pipeline is planned to have a capacity making it possible to tie in other fields in the area for the landing of oil. A participating company which is to own, build and operate the transportation system has been founded, the participants being licensees on the Oseberg field.

Gas transport will start only after the year 2000. Transportation solutions have not yet been stipulated.

Production drilling, reserves, recovery

Production drilling

Drilling of the first production wells started in the fall of 1985. Five production and five injection wells will be ready when production from the field center starts.

Reserves

The Norwegian Petroleum Directorate's reserves estimates are 172.4 million Sm^3 oil and 70.9 billion Sm^3 gas, which is slightly above what the operator is assuming. The reason for the discrepancy is that the Directorate has included the reserves in all three reservoir formations in Directorate figures, while the operator has not included them all.

Discoveries in several structures have been made on Oseberg during the spring and summer, including on the front block to the west of Oseberg. The latest discoveries have increased our expectations regarding the remainder of the front blocks, and plans exist to drill into these. For several of these potential prospects, it will be possible to tie in to Oseberg. The Oseberg field center will have idle capacity from about the year 2000.

Recovery

The upgrading of the reserves estimates has caused the Norwegian Petroleum Directorate to assume a rather longer production period than the operator. Plateau production is limited by processing capacity and will not be changed.

All gas produced in conjunction with the oil will be reinjected into one of the structures. This gas will then be produced simultaneously with the gas cap following complete depletion of the oil.

The operator is now considering changing the drive mechanism for the Alfa-Etive reservoir from water injection to gas injection. This is expected to increase the recoverable oil reserves somewhat. If so, gas for injection will have to be provided from external sources. A decision concerning the drive mechanism is expected in the spring of 1986.

In order to obtain better information for the location of the wells, the operator wants to use a production and testing ship for about 18 months from the summer of 1986. Recovered oil will be stored in the production ship and transported to the shore by tankers.

During the test period approximately 1 million Sm^3 of oil will be produced. Associated gas that is produced will have to be flared off.

Such long-term testing ships have not previously been used on the Norwegian Continental Shelf and represent a challenge to the Norwegian Petroleum Directorate both with regard to safety and resources management.

Several meetings have been held between the Norwegian Petroleum Directorate, the operator and the shipowner in order to have the ship built in such a way that it will be approved for use on the Oseberg field.

The production ship is an installation as understood by the Petroleum Act and therefore the Norwegian Petroleum Directorate can bring the necessary safety requirements to bear vis-a-vis the operator as criteria for being granted approval for use. However, the applicable detail regulations for production activities are not very well adapted to the

use of a production ship. This has raised a number of problems which have been attempted to be solved in cooperation with the operator and shipowner.

The project group has finished its evaluation of the project, and its conclusion and recommendation are available as a basis for the parties' decision.

The project group has found some points where the testing ship does not at present satisfy the Norwegian Petroleum Directorate's regulations, but expects that measures necessary to satisfy the requirements can and will be implemented.

Metering system

The specifications for the design of the oil metering system have been evaluated and commented on by the Norwegian Petroleum Directorate. Tests of parts of the metering system for oil have been performed at the sub-vendors and further part testing is being carried out.

The metering system for the loading meter station on Sture is at the planning stage.

The Norwegian Petroleum Directorate has been delegated the superior responsibility for inspection of the Sture metering systems.

Costs

Total costs, including a pipeline to Sture and a terminal, are estimated to be approximately NOK 40.8 billion in fixed 1985 kroner.

Safety, preparedness and the working environment

The Oseberg project has been driven forward under very strict deadlines. Nevertheless, it seems that all conditions with respect to safety, preparedness and the working environment have been safeguarded in a satisfactory manner. There has been good contact between the operator and the Norwegian Petroleum Directorate. The Norwegian Petroleum Directorate has been kept well informed of developments throughout the project so that comments have been taken into account at an early stage.

For Oseberg A almost all contracts have been concluded and the work is in progress at the construction sites. A few remaining contracts will be entered into in the beginning of 1986.

For the B platform all engineering contracts and one project service contract have been concluded. The contract for the base and deck frame has been allocated and the work has started.

The Norwegian Petroleum Directorate's inspection activities

The Norwegian Petroleum Directorate has implemented an extensive follow-up program concerning the operators operations in connection with the Oseberg project.

Audits have been made at all levels within the operators management and project operating organization. The purpose of the audit has been to determine a common system understanding in the organization. Special specifications and procedures have been selected that have been reviewed to check if they satisfy the Norwegian Petroleum Directorate's regulations.

A great number of audits have been performed on the contractors and sub-contractors to the operator to check if the safety requirements have been satisfied.

One sub-contractor was audited twice due to faults which were registered during the first audit. For the audit of the Oseberg B platform calculations, the Norwegian Petroleum Directorate has received assistance from the Norwegian Maritime Directorate. Furthermore, audits have also been carried out of the operator's technology and development section.

The audits and inspections that have been performed have reached the following conclusions: The operator's technical specifications essentially provide a satisfactory safety level. The technical requirements have essentially been complied with. The discrepancies pointed out by the Norwegian Petroleum Directorate have been made good. In some cases it has turned out that the fabrication sites have not had updated specifications.

The operators requirements concerning quality assurance based on the Norwegian Standards have essentially been incorporated into the work. A couple of the companies that were visited lacked an adequately documented quality assurance system.

Japanese suppliers to the project generally have a different understanding of quality assurance, but essentially cover the Norwegian Standard requirements. The interests of the operating areas have been safeguarded in the project planning.

The Oseberg transport system

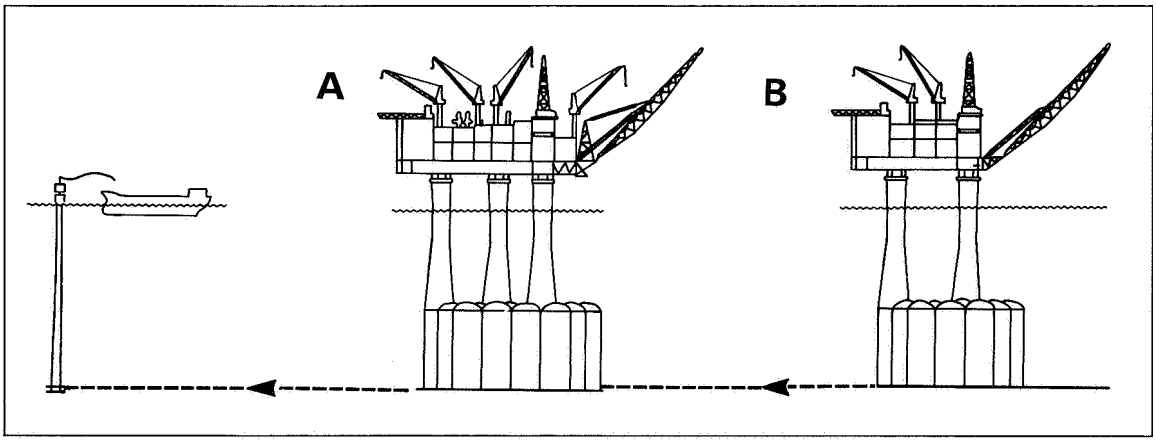
The oil in the Oseberg field has been resolved to be landed in Norway through a pipeline. A participating company with the same ownership structure as the unitized Oseberg field has been founded to be in charge of the construction and operation of the oil pipeline from the Oseberg field (platform A) in Block 30/9 to the terminal at Sture in Øygarden municipality (Figure 2.3.8.d). Norsk Hydro is the operator for the pipeline and terminal.

The ownership structure in the Oseberg transport system is as follows:

Norsk Hydro	13.75 %
Statoil	63.24 %
Saga	8.61 %
Elf	6.40 %
Total	3.20 %
Mobil	4.80 %

The Oseberg transport system will be dimensioned for the following criteria:

FIG. 2.3.7
Planned installations on Gullfaks phase 1



- To transport produced oil from the Oseberg field.
- To have the possibility of transporting produced oil from other fields connected to the Oseberg transport system.

The pipeline will have a diameter of 28 inches and a future maximum capacity of 95,000 Sm^3 per day.

The Oseberg transport system will consist of the following main elements:

- Pipeline equipment on Oseberg, platform A
- Offshore pipeline
- Landing site
- Onshore pipeline
- Terminal.

Transportation pipeline and the terminal at Sture
These projects have also been driven forward at a high pace. The engineering has largely been finished for the transportation pipeline, and the production of pipes has started.

The Oseberg transportation system is intended to transport oil from the Oseberg field from 1 April 1989.

2.3.7. Gullfaks

Production licence 050

Licensees

Den norske stats oljeselskap a.s	85 %
Norsk Hydro Production A/S	9 %
Saga Petroleum a.s	6 %

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

Production facilities

The first discovery on the block was made in 1978. On 10 June 1981, the development plan for Gullfaks Delta East was dealt with 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 will consist of two platforms (Figure 2.3.7.a). Platform A will be an integrated drilling, processing and accommodation platform with a capacity of about 39,000 Sm^3 per day. The platform will be located in the southwestern part of the structure in about 135 meters of water. The platform base will be a concrete structure with a T-shaped steel deck frame.

Platform B will be a drilling, accommodation and water injection structure with a concrete gravity base, equipped with limited processing machinery. The Gullfaks B platform will be sited in the northwestern part of the Delta East structure where the water is also about 135 metres deep.

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

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

The construction of the concrete base for the Gullfaks A platform started in 1983, and the majority of the design and hook-up contracts were assigned during the same year.

The mating of the deck and concrete structure will take place in January 1986. The construction work is essentially following the progress schedule.

The operator expects the Gullfaks A platform to be ready for production by 1 July 1987, while Gullfaks B is scheduled to come on stream by 1 December 1988 .

Recovery of reserves

The field lies in the northeastern part of Block 34/10 and covers an area about 200 square kilometers in size. The proven reserves all lie within the block. Figure 2.3.8.a shows where the field is situated in the Statfjord area.

The Delta structure is a relatively shallow-lying

field, divided by north-south faults into several upturned and rotated segments of Jurassic strata. The segments, or blocks, vary in their degree of upturn, though all point fairly consistently to the west. In the east, the field has a more uncertain structure, the area being highly segregated 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 meters. Gullfaks is definitely the most geologically complex field so far dealt with in the context of developments on the Norwegian Continental Shelf. Until new figures become available, Statoil's claims of 135 million Sm^3 oil, 8 billion Sm^3 gas and 1 million tons NGL will be used.

Oil has been proven with little dissolved gas in three Jurassic formations: Brent, Cook and Statfjord. In the eastern part of the field, there is an additional oil discovery in Triassic strata. The reservoir rocks are rather similar to Statfjord and Murchison, which is to say sandstone of high permeability and relatively high porosity. Under the oil, there exists a water zone of variable volume, which is not, however, large enough to maintain the pressure in the reservoir as oil is removed. It will therefore be necessary to inject water right from the start of production. Gas injection has also been evaluated as a method of recovery. However, this would give a less favourable result than water flooding.

Metering systems
The construction work has come so far that the metering system for oil and gas has been installed on the platform. Inspections of the metering system for gas have been carried out.

Costs
The total costs for development are expected to run to about NOK 33.7 billion in fixed 1985 kroner.

Safety, preparedness and the working environment
Auditing activity
In 1985, the Norwegian Petroleum Directorate carried out extensive audits directed at the Gullfaks development.

Audits were performed of the Gullfaks A, B and C projects at Statoil in Bergen and Forus. In the audits the following areas were focused on, among others: management and teamwork in the organization, experience build-up, development and use of new technology, personnel utilization and uniformity in documentation and organizational composition.

Gullfaks A
In the beginning of November, an event occurred on the Gullfaks A deck. Located between the deck and temporary concrete stub columns there are deformation pipes whose function it is to distribute the weight between the deck and concrete structure. On one of the legs, all of these pipes collapsed, resulting in local points on the concrete being exposed to unacceptably high loads. It was therefore decided to evacuate the deck. Subsequently the deck was jacked up again 10-15 cm by means of 160 hydraulic jacks. Steel wedges have now been placed between the stub column and the deck. No damage was observed on the deck.

Gullfaks B
The Concem accident and the wage settlement conflict at the construction site delayed the progress schedule by approximately five weeks.

Work at the construction site for deck modules and on the accommodation quarters is progressing largely according to the project work schedules. The engineering of pipelines for gas between the Gullfaks platforms and for oil between the platforms and the loading buoy has started.

Gullfaks Phase II
Gullfaks Phase II also includes the area east of the main fault between Wells 34/10-4 and -9. The water depth in this area is considerably greater than in the area embraced by Phase I.

So far, eight wells have been drilled in that area of the Delta structure which includes the Phase II development.

Appraisal Well 34/10-19 in this part of the Gullfaks field turned out to be dry.

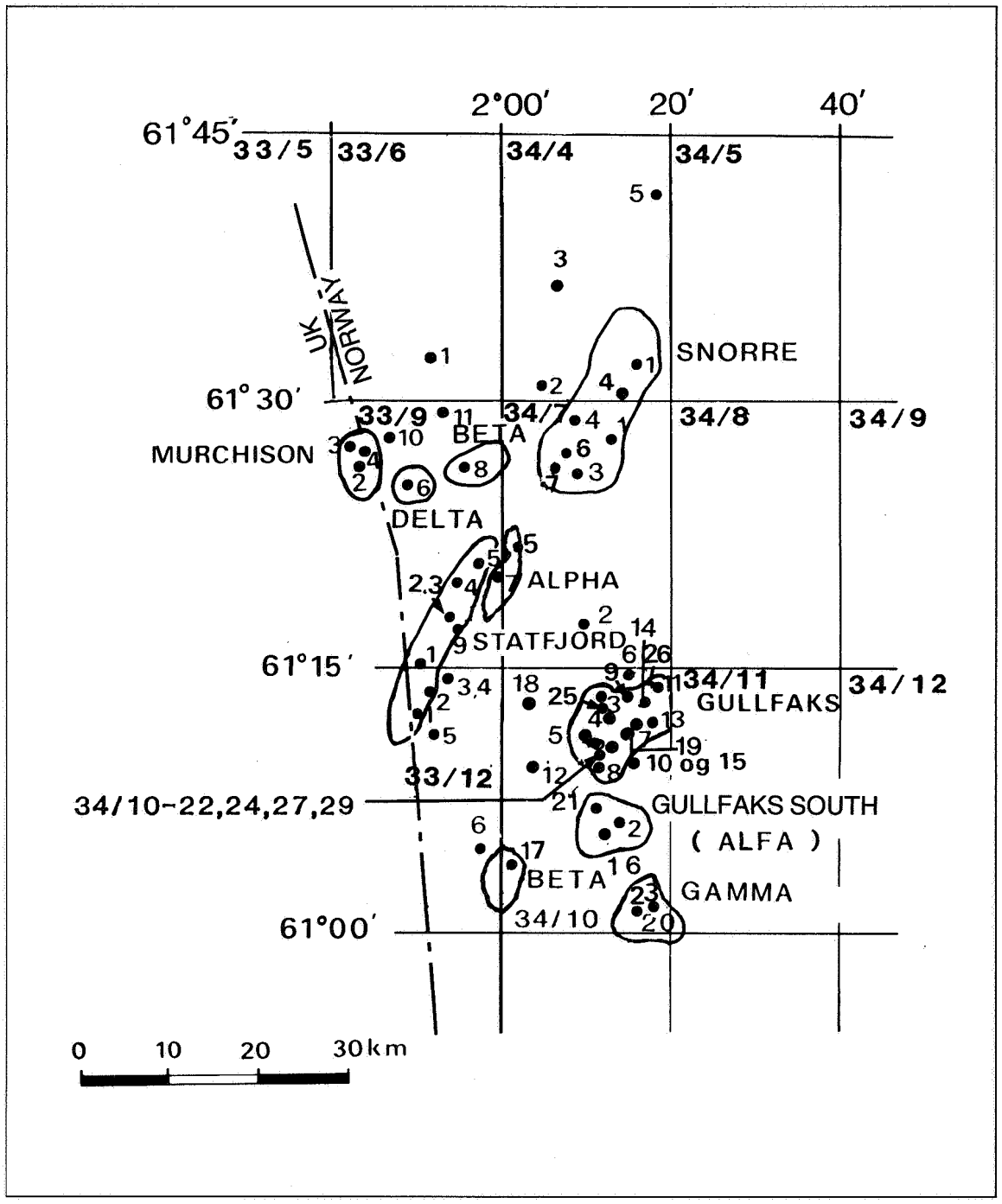
Reserves
Due to the complicated delimitation of the field towards the east and southeast, the reserves estimates are associated with great uncertainty. Statoil's estimates of recoverable reserves are in the order of 75.2 million Sm^3 of oil and 10.5 billion Sm^3 of gas for Delta East, Phase II. These estimates were calculated after drilling the Well 34/10-19.

A development of the area was approved by the Storting on 1 June 1985 (Storting Proposition no. 86 for 1984-85). Reduction of the reserves in the Phase II area resulted in the selection of a development solution with a full processing platform, a copy of the Gullfaks A platform.

The Gullfaks C platform will be located in the middle part of the field where the water depth is 220 meters. The plan is to produce all reservoirs by means of water injection, and seabed completed wells will be used to the extent this is necessary to safeguard good depletion of the reservoir.

Partially processed crude oil is planned to be transferred through a 205 mm pipeline from the Gullfaks B to the Gullfaks C platform where final processing can start in 1990. This is earlier than the planned idle available capacity on Gullfaks A. The transferred quantity will be 5.85 million Sm^3 of oil from Gullfaks B to Gullfaks C. Stabilized crude oil produced on Gullfaks C will be transported to single point loading buoy no. 2 (SPM2) through a 414 mm pipeline.

FIG. 2.3.8.a
The Gullfaks-, Statfjord- and Snorre area



The gas will be transported through the Statpipe system via a 254 mm pipeline from Gullfaks C to Gullfaks A.

2.3.8 The Statfjord field

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 Exploration A/S	0.87597 %
Texas Eastern Norway Inc	0.87597 %
British share (15.90678 %)	
Conoco (UK) Ltd	5.30226 %
Britoil Plc	5.30226 %
Gulf Oil Corporation	2.65113 %
Gulf UK Offshore Investments Ltd	2.65113 %

On 10 August 1973 the licensees on the Statfjord field were allocated production licence 037. This includes Blocks 33/9 and 33/12 (Figure 2.3.8.a).

Mobil is the operator until 1 January 1987, when Statoil will take over 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 reports were 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 2.3.8.b).

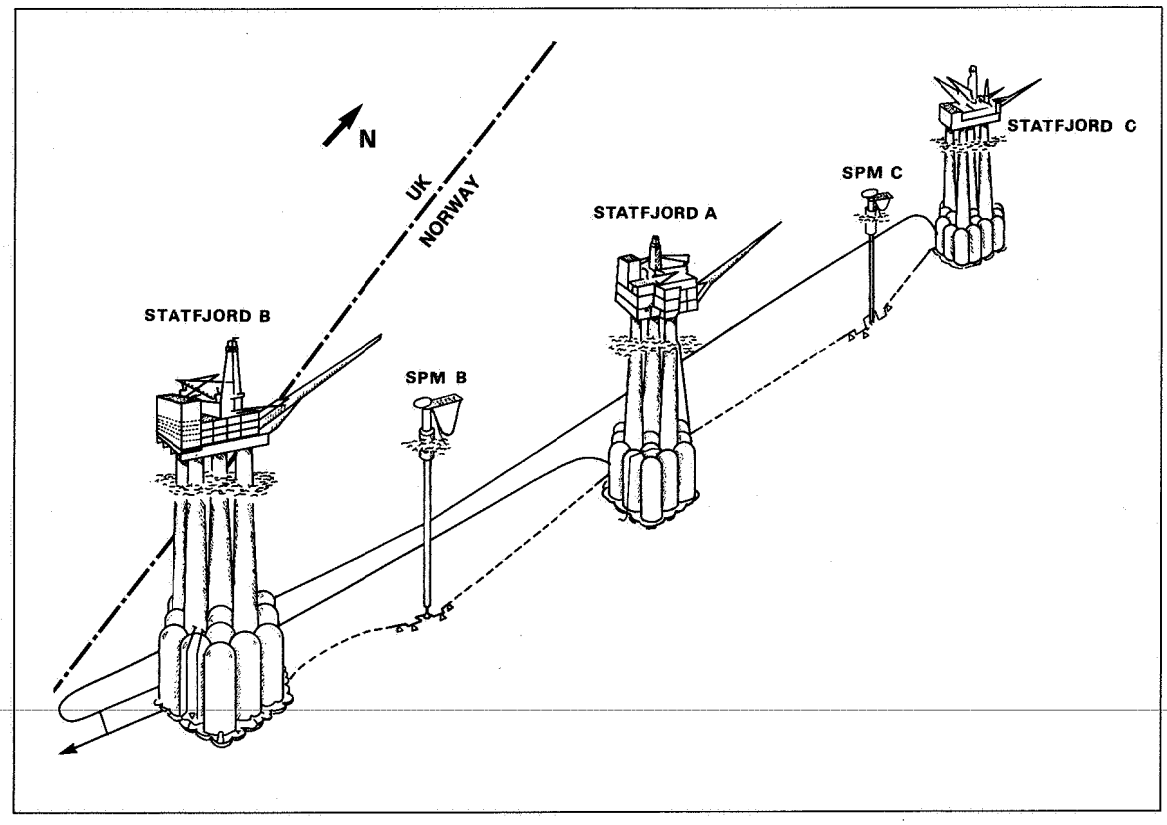
By injecting water into the Brent reservoir and gas into the Statfjord reservoir, the Norwegian Petroleum Directorate expects that a recovery factor of some 50 per cent will be attained. This means that the total recoverable amounts of oil are 342 million Sm^3. The amount of recoverable associated gas has been estimated at 41 billion Sm^3 dry gas, and 127 million tons of NGL. The proportioning 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 reserves may be the subject of re-apportionment at intervals of a few years. The licensee group is currently negotiating new apportionment figures. The negotiations are planned to be concluded in 1987.

Production facilities

Statfjord A

The Statfjord A platform is located at the center of the field, and comprises three columns and 14 cells, all of concrete. The deck is of steel. The new assumed production capacity is 54,000 Sm^3 per day. This capacity has been increased as a result of fine adjustment of the processing equipment. The average capacity utilization of the process equipment during 1985 was high. The platform started production on 24 November 1979 and, according to the operators latest drilling program, will have 21 production and

FIG. 2.3.8.b
Installations on the Statfjord field



16 injection wells. It has been decided to install a new Statfjord A loading buoy.

Statfjord B

Statfjord B, sited in the southern part of the field, consists of four columns and 24 cells, all of concrete. The deck is of steel. The platform has been built as an integrated "Condeep". Its production capacity has also increased due to fine tuning of the processing equipment. The new maximum capacity is rated at 39,800 Sm^3 per day. Production started on 5 November 1982 and capacity is now being fully exploited. The accessibility of the equipment was very high in 1985.

The drilling program, which consists in all of 31 wells, will provide 19 wells for oil production and 12 for injection.

The operator is now examining the possibility of upgrading the water processing and water injection capacity as well as an extension of the platform quarters.

Statfjord C

The third and final phase of the Statfjord field development has now been completed with the construction of the Statfjord C platform. Statfjord C is an approximate copy of Statfjord B, in other words it has also been built as an integrated Condeep, with four columns and 24 cells of concrete, and a deck of steel. As is true of the other platforms, Statfjord C has the necessary equipment to facilitate the production and storage of oil, together with machinery for gas injection, gas transport and water injection. Statfjord C has 42 well openings and in addition the possibility of a future tie-in of nine seabed completion wells.

Production start on 26 June 1985 was ahead of schedule. Start-up of the platform progressed without any significant problems and Statfjord C will reach full production capacity in the course of 1986. According to the operators drilling program, the platform will have 19 production wells and 12 injection wells. The operator is now considering upgrading the water injection capacity here also.

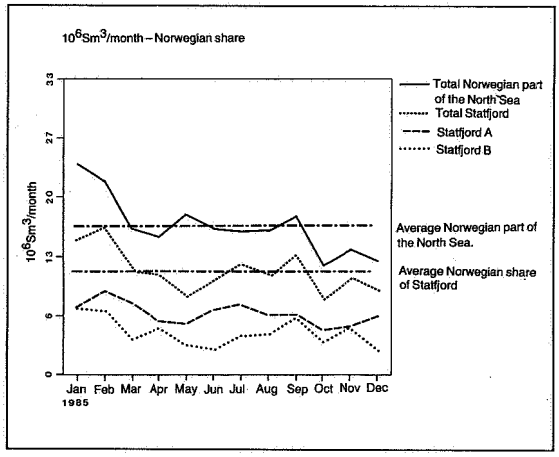
Recovery of reserves

The gas injection installations on the Statfjord A, B and C platforms have settled into normal operations. In the course of 1985, 77 per cent of the total amount of gas produced was put back into the Statfjord reservoir, and 13.5 per cent was delivered to gas sales systems.

The effect of injecting gas into the Statfjord formation is still uncertain. The operator will continue to inject gas at the same time as gas sales progress as planned.

Previous gas injection caused the reservoir pressure to approach the original reservoir pressure. After initiating gas export, the high pressure problem has now been reduced.

FIG. 2.3.8.c
Gas flared in the Statfjord area



The injection of water into the Brent formation started in 1982 on the A platform and in 1984 on the B platform. Statfjord C will start water injection in the beginning of 1986.

Though several wells produce water, it is assumed that only one of them produces water because of water penetration from injection wells. The water production is kept at a low level by means of well overhauls and re-perforations. So far, water production has not led to limitations in oil production. Water penetration is expected in several wells in 1986, but this will not affect the planned production.

Gas flaring in the Statfjord area

The amount of gas flared on Statfjord A in 1985 was about 0.27 million Sm^3 per day on average, corresponding to 3.0 per cent of the total gas production from the platform (Figure 2.3.8.c). Statfjord A has entered a stable operative phase, so that the amount of gas flared is well below the flaring limit of 0.50 million Sm^3 per day. The main reason for flaring the gas has been compressor malfunction. Further, there was some flaring after the stimulation of the gas injection wells.

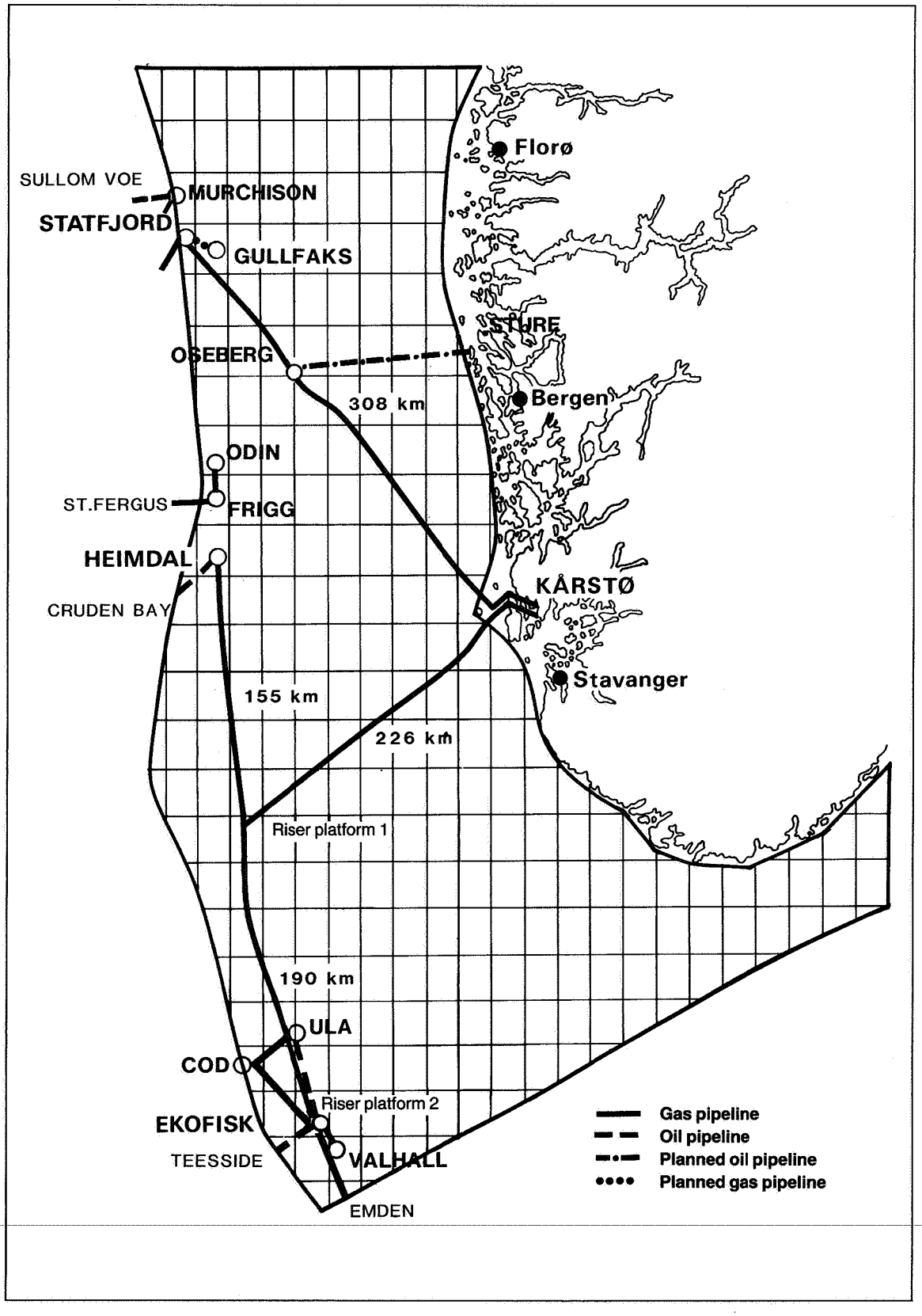
In the same period on Statfjord B, 0.19 million Sm^3 per day, corresponding to 2.7 per cent of the total gas production, was flared on average. Statfjord B is also considered to be in a stable operating phase. Gas flared remained well under the flaring limit of 0.5 million Sm^3 per day. Compressor troubles have been the main reason for flaring.

Statfjord C flared off 0.58 million Sm^3 per day on average. This corresponds to 14.4 per cent of the total gas production on Statfjord C. The high flaring rate was connected to the start-up of the production facilities and ordinary teething troubles.

Metering system

Statfjord C was put into production in July 1985. Inspection of the metering systems for oil produced

FIG. 2.3.8.d
Pipelines in the Norwegian part of the North Sea



from Statfjord A, B and C has been performed monthly.

The metering systems for gas from Statfjord A, B and C to Statpipe as well as the metering system monitoring gas to Great Britain were initiated in the fall of 1985.

Controls and inspections were performed in collaboration with the British Department of Energy.

Costs

The total investment costs for the development of Statfjord are expected to run to some NOK 61.9 billion in fixed 1985 kroner. The Norwegian share of this is approximately NOK 52 billion.

Safety, preparedness and the working environment

Evacuation

Upon approval of platform concepts for the Statfjord field, the Norwegian Petroleum Directorate ordered the operator to develop a satisfactory evacuation scheme.

In the spring of 1985, the operator field-tested the prototype of a gondola system for dry evacuation from the platform to an emergency preparedness vessel. The operator has decided to try the system and has ordered it. The first unit is expected to be installed in the middle of 1986.

Pressure tanks

In connection with the annual production shut-down, internal corrosion was detected in some pressure tanks during the inspection. The most corroded areas were repaired. After thorough evaluation it was decided to postpone the remaining repair work until the annual production shut-down in the summer of 1986.

Loading buoy

The Statfjord A loading buoy was disconnected and tugged ashore because of crack formation in the main buoyancy tank. However, extensive inspection after docking showed that the scope of the damage was significantly greater than first assumed. One has decided to install a replacement buoy which is a simplified version of the one previously installed.

The Statfjord catering project

The high degree of absence due to sickness among the catering employees which was assumed to be connected with the working environment resulted in a project being initiated to elucidate the problem, evaluate the link between strain complaints and job strain and possibly come up with some suggestions for improvements.

On the basis of the compiled data a number of concrete changes were recommended that may form the basis for improvements in the working environment of caterers and a reduction in strain-related injury complaints.

Gas transport, the Statpipe system

The gas transportation system Statpipe was formed with the following participants:

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 the operator for the construction and operation of the system.

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.

Pipelines and marine riser platforms

Emtying and drying of the pipelines was performed mainly in the early summer of 1985, with the exception of drying of the pipeline from Heimdal to platform 16/11-S which was carried out in November. The Statpipe system was pressurized and gradually made operative in the summer of 1985.

Kårstø

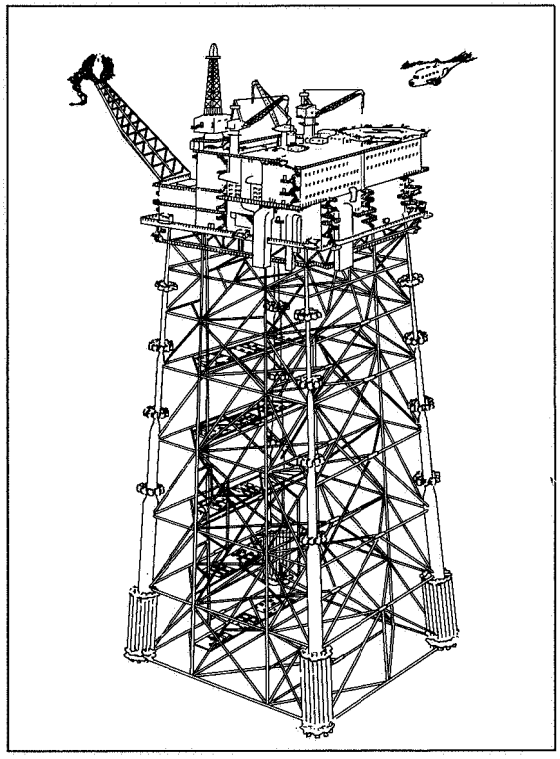
The first North Sea gas was landed at Kårstø on 25 March 1985. The first delivery of gas from the Statpipe system through the Statpipe/ Norpipe connection took place on 15 October 1985, and the first ship load of wet gas from Kårstø departed on 5 November 1985.

A sketch of the transport systems for oil and gas in the Norwegian part of the North Sea is shown in Figure 2.3.8.d.

The transport capacity from Statfjord to Kårstø is 8 billion Sm^3 of wet gas per year. The Kårstø facility has a processing capacity of 5 billion Sm^3 of wet gas per year. The dry pipeline into Ekofisk has a transport capacity of 17 billion Sm^3 per year. This exceeds the capacity requirements for Statfjord, Gullfaks and Heimdal and has been secured in order that one may later tie in other fields. If one wants to increase the transport capacity in the Statpipe system, one has to build a compressor platform 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, and with the terminal company in Emden. The licensees on Statfjord, Heimdal and Gullfaks have also entered into sales agreements for the gas with buyers on the continent.

FIG. 2.3.4.a
Installation on Murchison



Metering systems
Control of the design and check-out of the metering systems for Liquid Petroleum Gas (LPG) at Kårstø has been concluded. The LPG metering systems for gas have been delivered to Kårstø. The systems were delayed because of technical difficulties with fabrication of the pipe gauging jigs.

Costs
The estimate for the total investments including the terminal facilities amounts to NOK 20.6 billion in fixed 1985 kroner.

2.3.9 Murchison

Licensees

British share (74.94 %)	
Conoco North Sea Inc	24.98 %
Britoil Ltd	24.98 %
Gulf Oil Corporation	12.49 %
Gulf Offshore Investment Ltd	12.49 %
Norwegian share (25.06 %) (production licence 037)	
Mobil Development Norway A/S	3.75 %
Den norske stats oljeselskap a.s	12.53 %
Norske Conoco A/S	2.51 %
Esso Exploration and Production Norway A/S	2.51 %
A/S Norske Shell	2.51 %
Saga Petroleum a.s	0.47 %
Amoco Norway Oil Company A/S	0.26 %
Amerada Hess Norwegian Exploration A/S	0.26 %
Texas Eastern Norway Inc	0.26 %

The above mentioned licensees are the same as on the Statfjord field. The Murchison field was discovered in August 1975. It lies in Block 211/19 on the British side and Block 33/9 on the Norwegian (Figure 2.3.8.a). Development of the Murchison field was started in 1976 by the British licensees. The 037 group declared the field commercial in the summer of 1977, and Statoil acceded to the declaration in the summer of 1978.

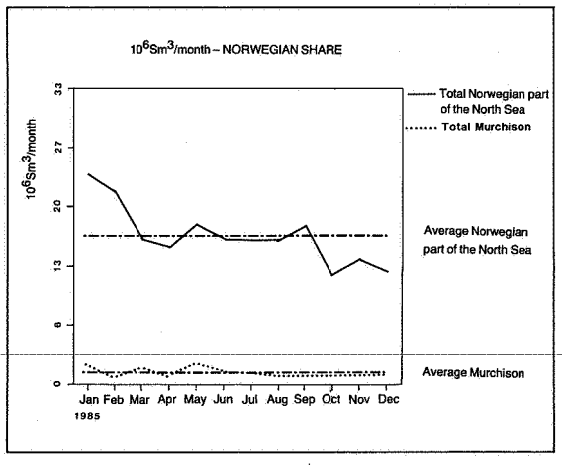
Re-distribution negotiations have now been started. These are scheduled for completion in the course of the first quarter of 1986. The recoverable reserves for the whole field are estimated to be 53 million Sm^3 oil and 2 billion Sm^3 gas.

Production facilities
The field has been developed with an integrated steel platform with a production capacity of 26,200 Sm^3 per day (Figure 2.3.9.a). On 28 September 1980, oil production started from the two seabed completion wells. The present production lies at about 14,300 Sm^3 per day.

The platform has a total of 28 well openings. So far, 26 wells have been completed as follows: 14 oil production wells, two satellite production wells, nine water injection wells and one gas injection well.

Recovery of reserves
Well drilling proceeded very quickly on Murchison. The field has therefore been producing at almost maximum processing capacity since 1981. 1984 was the last year of plateau production, and water production has risen to 30 per cent. Increased water treatment capacity is being planned. The capacity (then 7,950 Sm^3 per day) was increased to 15,900 Sm^3 per day in the course of December 1985. The

FIG. 2.3.9.b
Gas flared on Murchison



water injection capacity is also to be increased from 27,000 Sm^3 per day to 31,800 Sm^3 per day. Further increases are being planned.

By Kings Resolution of 24 September 1982, the Government consented to land the Norwegian Murchison gas via NLGP, the Northern Leg Gas Pipeline, to the Brent field on the British side, and further via FLAGS, the Far North Liquified and Associated Gas Gathering System, to St Fergus in Scotland. Gas deliveries through the NLGP started on 20 July 1983.

Oil from Murchison is forwarded by pipeline to Sullom Voe on the Shetland Isles. The fractionating facility for wet gas at Sullom Voe came into use in the spring of 1982.

Flaring of gas

On average, 0.18 million Sm^3 per day was flared in 1985, corresponding to 17 per cent of the total gas production (Figure 2.3.9.b). The reduced regularity was mainly due to problems with the gas compressors and the fact that the receiving facility was periodically out of operation.

Metering system

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

Costs

Total developmental costs are expected to amount to about NOK 33.8 billion in fixed 1985 kroner. The Norwegian share of this constitutes NOK 8.5 billion.

2.4 Petroleum resources

2.4.1 Resources accounts

Petroleum resources belong to the group of non-renewable energy resources and include all technically recoverable oil and gas quantities. Possible exploitation of these resources is decided by commercial and/or socio-economic criteria.

Petroleum resources are classified according to the certainty of the resources estimates and the certainty of commerciality (Figure 2.4.1.a). The certainty of resources estimates is determined by the degree of geological control (horizontal axis). For undiscovered resources the degree of seismic control and knowledge of geological factors will form the basis of the classification. For discovered resources the degree of well control will determine the classification. Prices and costs estimates for a re-

FIG 2.4.1.a
Classification of technically recoverable petroleum resources

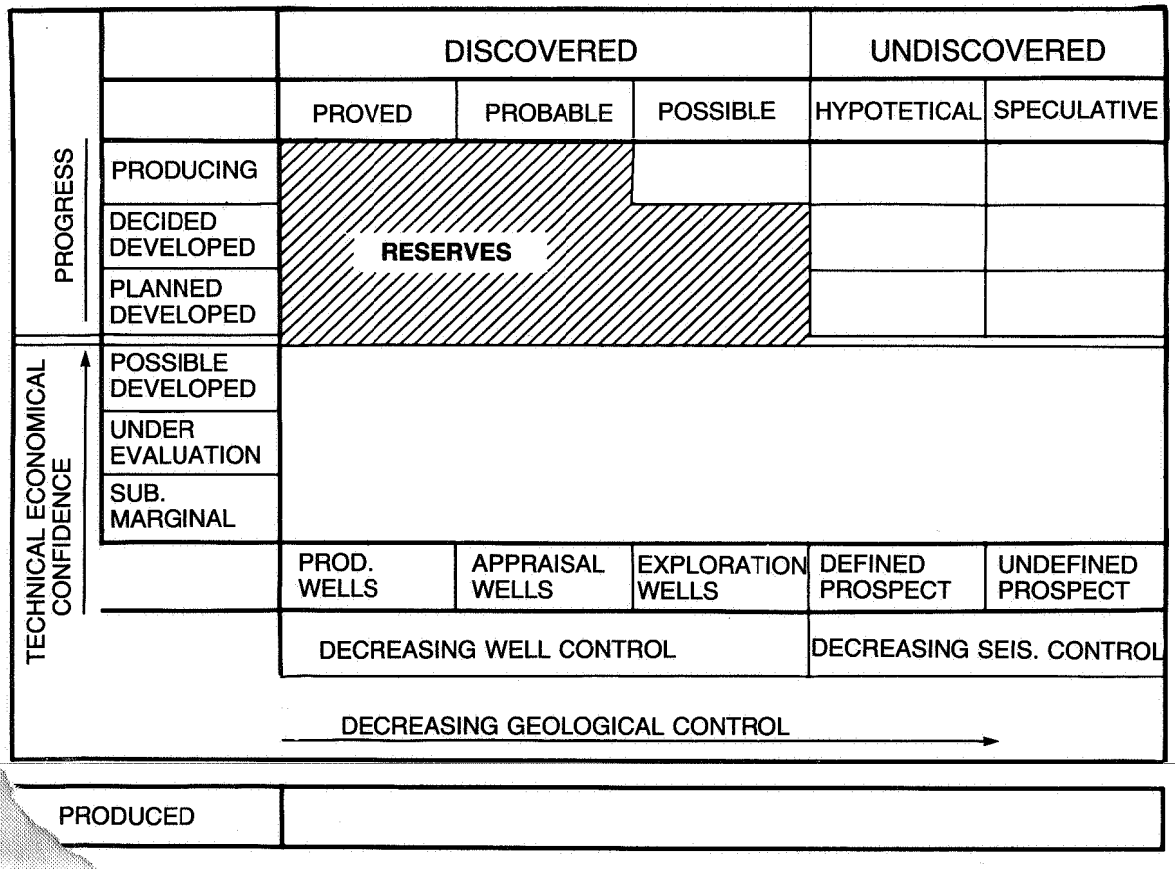


FIG 2.4.1.b
Recource account related to the Norwegian Continental Shelf

		DISCOVERED						UNDISCOVERED	
	OIL/NGL x 10^6 Sm^3 GAS 10^9Sm^3	PROVED		PROBABLE		POSSIBLE		HYPOTETI-CAL	SPECULA-TIEVE
		OIL NGL	GAS	OIL NGL	GAS	OIL NGL	GAS		
PROGRESS	PRODUCING	477	254						
PROGRESS	DECIDED DEVELOPED			423	133				
PROGRESS	PLANNED DEVELOPED			130	672				
TECHNICAL ECONOMICAL CONFIDENCE	POSSIBLE DEVELOPED			446	1310	256	324		
TECHNICAL ECONOMICAL CONFIDENCE	UNDER EVALUATION								
TECHNICAL ECONOMICAL CONFIDENCE	SUB. MARGINAL			17	41	20	24		
		PROD. WELLS		APPRAISAL WELLS		EXPLORA-TION WELLS		DEFINED PROSPECT	UNDEFINED PROSPECT
		DECREASING WELL CONTROL						DECREASING SEIS. CONTROL	
		DECREASING GEOLOGICAL CONTROL →							

TAB 2.4.2 Proven petroleum reserves in fields declared commercial

	ORIGINALLY			REMAINING		
	OIL 10^6Sm^3	GAS 10^9Sm^3	NGL 10^6 ton	OIL 10^6Sm^3	GAS 10^9 Sm^3	NGL 10^6 ton
Albuskjell[1])	7,8	16,9	1,1	2,0	6,5	0,4
Cod[1])	2,8	6,8	0,5	0,7	2,2	0,2
Edda[1])	4,4	1,9	0,2	1,3	0,3	0,1
Ekofisk	237,0	126,0	13,5	110,3	76,9	9,9
Eldfisk[1])	50,8	31,6	3,0	24,3	22,8	2,1
Frigg[2])	1,0	127,0		0,7	54,8	
Gullfaks[1])	210,3	13,7	2,1	210,3	13,7	2,1
Heimdal	3,0	34,0		3,0	34,0	
Murchison[3])	13,0	0,3	0,5	6,0	0,2	0,3
North East Frigg	0,1	8,0		0,1	4,6	
Odin	0,1	22,0		0,1	16,2	
Oseberg[4])	173,0	71,0		173,0	71,0	
Statfjord[5])	342,0	41,0	12,7	256,9	41,0	12,7
Tor[1])	19,8	13,7	1,5	4,5	5,7	0,7
Ula	29,9	1,5	1,3	29,9	1,5	1,3
Valhall A	19,4	16,2	1,3	13,1	15,2	1,0
West Ekofisk[1])	11,9	26,2	1,3	1,7	7,6	0,5
East Frigg		13,0			13,0	
Total	1126,3	570,8	39,0	837,9	387,2	31,3

1) Operator's estimate
2) This is Norwegian share: 60.82 %
3) This is Norwegian share: 25.1 %
4) Includes Alfa, Alfa North and Gamma structure
5) This is Norwegian share: 84.09 %

source quantity are included in the commerciality criteria to determine if the resource is developable (vertical axis). For resources that have been declared economically viable, the work schedule for the project will be decisive for the classification.

Petroleum reserves are those parts of the discovered resources which are recoverable under given technical and economic conditions and which the licensees have declared commercial.

The total resources accounts are shown in Figure 2.4.1.b.

For presentation in the Annual Report, resources on the Norwegian Continental Shelf have been displayed in three tables.

I Reserves associated with development projects that have been resolved to be initiated, are under development or in production (Table 2.4.2).
II Other reserves south of Stad (Table 2.4.3).
III Resources north of Stad (Table 2.4.4).

TAB 2.4.3 Proven petroleum reserves south of Stad not decided to be developed.

	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6 ton
Balder	35,0		
Brage	29,0	6,0	
Gullfaks South	37,0	93,0	
Hild		20,0	
Hod	7,2	5,4	
Huldra[1])		18,0	
Sleipner + Gamma[2])	45,0	186,0	19,0
Sleipner satellites[3])	16,0	35,0	
Snorre[4])	99,0	27,0	
SØ-Tor	4,0	3,0	
Tommeliten	6,0	23,0	
Troll West	41,0	463,0	
Troll East		825,0	
Valhall rest	14,5	12,0	
Veslefrikk	41,0	4,0	
2/1	18,0	2,0	
6/3 Pi	4,6	4,0	
7/11 A	6,5		
15/3-1,3	2,0	29,0	
15/3-4	12,0	5,0	
15/5-1	2,0	6,0	
16/7-4	1,4	9,0	
24/9	3,0		
25/2-4	4,0	12,0	
30/6 Gamma North[1])	2,3	5,0	
30/6 Kappa[1])	5,0	1,7	
30/6,Beta[1])	20,0		
30/9 Prospect A[1])	9,3	10,0	
33/9,Alfa	19,0	2,5	
33/9,Beta	39,0	2,0	
34/10 Beta	8,0	22,5	
34/4-1	3,0		
35/8	1,0	10,0	
Total	534,8	1841,1	19,0

1) Operator's estimate
2) Includes Alfa, Beta, Epsilon, Delta, Gamma tertiary and Gamma jura
3) Includes 15/8 Alfa, 15/9 My and 15/9 Theta
4) Includes Epsilon-structure in block 34/7 and 34/4

2.4.2 Resources basis for resolved fields

As of 31 December 1985, decisions had been taken to carry out 18 development projects on the Norwegian Continental Shelf. The amounts of petroleum represented by these developments are given in Table 2.4.2. All reserves figures are the Norwegian Petroleum Directorate's estimates unless specifically stated otherwise. Operating companies may have other estimates for reserves on some fields. Up until 1 November 1985, a total of 0.43 billion toe had been produced.

2.4.3 Other resources south of Stad

Table 2.4.3 shows the other resources proven south of Stad. Of these, the Sleipner Gamma, Troll West and Tommeliten fields have been declared commercial. The resources amounts in these four fields together make up 0.78 billion toe. The Norwegian Petroleum Directorate assumes that a number of the other finds too will be developed, both for reasons of size and proximity to other fields.

2.4.4 Discoveries north of Stad

Provisionally some 0.77 billion toe have been proven by drilling north of Stad. Of this quantity, 0.56 billion toe are on Haltenbanken and 0.21 billion toe off Troms. The estimates for Smørbukk, Heidrun and 6506/12 Beta are provisional and very uncertain.

2.4.5 Updates in resources estimates from last years Annual Report

Fields decided to be developed

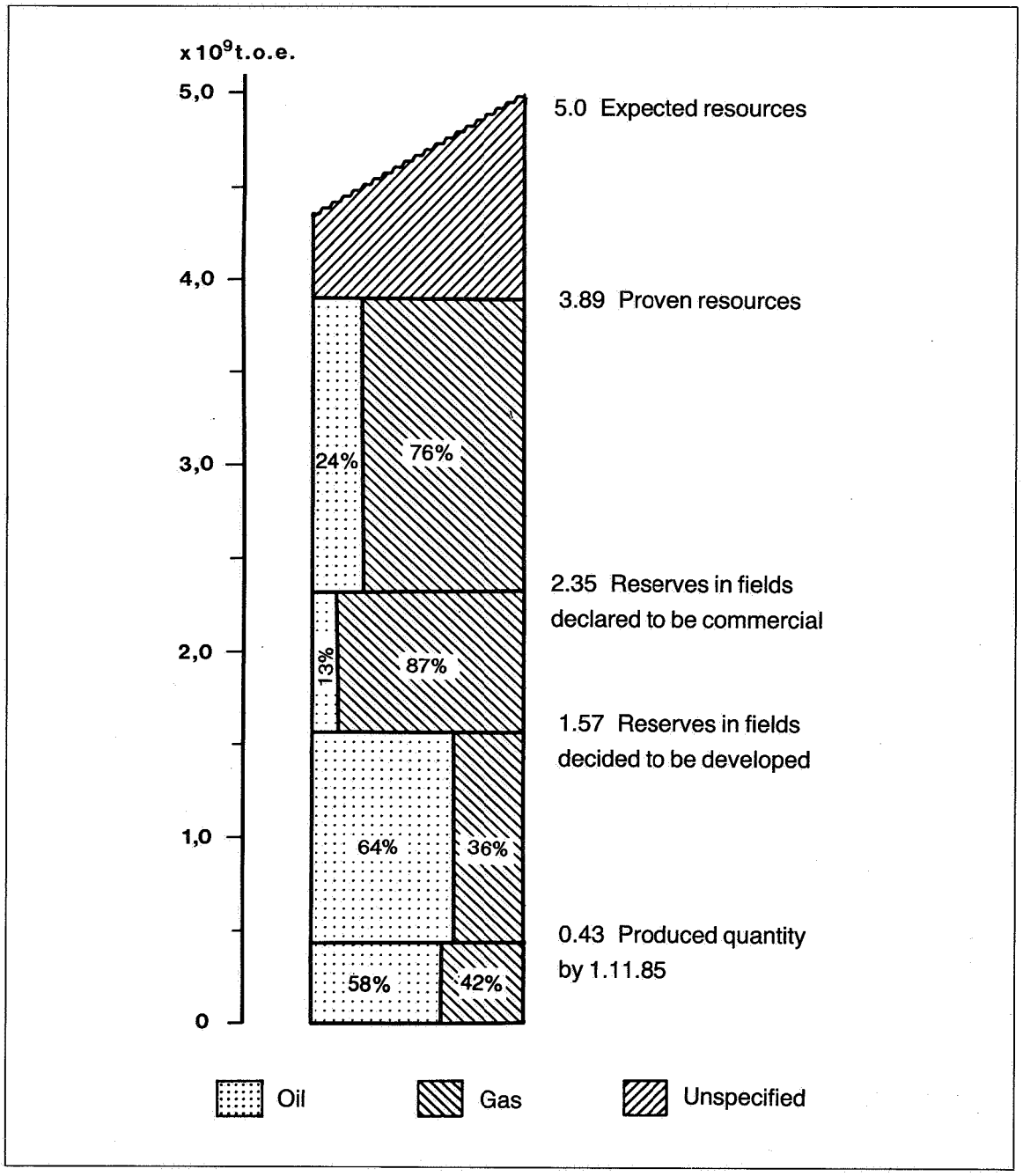
For Albuskjell, Cod, Edda, Eldfisk, Tor and West Ekofisk, the Norwegian Petroleum Directorate has not had the capacity to prepare separate production profiles. The resources figures used in the Annual

TAB 2.4.4
Discovered petroleum resources north of Stad

	Oil 10^6Sm^3	Gas 10^9Sm^3
Haltenbanken		
Draugen	39,0	
Heidrun	87,0	31,0
Midgard	22,0	103,0
Smørbukk	60,0	83,0
Tyrihans	12,0	51,0
6506/12 Beta	76,0	54,0
Total	296,0	322,0
Troms		
Albatross		34,3
Askeladd		52,0
Snøhvit		74,4
Snøhvit North		3,3
7119/12 (1)		3,6
7120/07		24,3
7120/12		14,8
Total		206,7
Total	296,0	528,7

1) Operator's estimate

FIG. 2.4.6
Expected total recoverable resources south of Stad



Report have been gathered from the operators prognoses and consistently lie somewhat higher than the 1984 estimates. For Gullfaks, Statfjord, Ula and Valhall A, minor prognosis adjustments have been made. Gullfaks includes Gullfaks Phases I and II from previous Annual Reports.

Ekofisk

The production profiles for Ekofisk have earlier been terminated in the year 2010 at the expiry of the production licence. The new production mechanisms with the injection of water and gas will prolong the production profile and cause an increase in recoverable oil resources.

Other discoveries

Sleipner satellites, 15/5-1

The Norwegian Petroleum Directorate has previously not stated condensate from several of the sa-

TAB 2.4.5 Changes in resource estimates in annual reports 84-85

	Annual Report 84			Annual Report 85		
	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6ton	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6ton
Fields decided to be developed						
Albuskjell	8,0	16,0	1,0	7,8	16,9	1,1
Cod	2,5	6,2	0,4	2,8	6,8	0,5
Edda	3,7	1,9	0,2	4,4	1,9	0,2
Ekofisk	193,0	129,0	8,0	237,0	126,0	13,5
Eldfisk	48,0	31,0	2,2	50,8	31,6	3,0
Gullfaks	210,0	17,1	1,2	210,3	13,7	2,1
Statfjord	341,0	41,0	10,5	342,0	41,0	12,7
Tor	17,0	10,0	1,0	19,8	13,7	1,5
Ula	30,0	2,0	1,3	29,9	1,5	1,3
Valhall A	19,0	16,0	1,3	19,4	16,2	1,3
West Ekofisk	11,0	21,0	1,0	11,9	26,2	1,3
Other fields						
Sleipner sat.	0,5	32,0		16,0	35,0	
Troll west	58,0	463,0		41,0	463,0	
Veslefrikk	24,0	8,0		41,0	4,0	
6/3 Pi	–	–		4,6	4,0	
7/11 A	–			6,5		
15/5-1	1,0	4,0		2,0	6,0	
30/6 Gamma North	–	–		2,3	5,0	
30/6 Kappa	–	–		5,0	1,7	
30/9 prospect A	–	–		9,3	10,0	
34/10 Beta	–	–		8,0	22,5	
Heidrun	–	–		87,0	31,0	
Smørbukk	–	–		60,0	83,0	
6506/12 Beta	–	–		76,0	54,0	
Albatross		35,0			34,3	
Askeladd		41,0			52,0	
Snøhvit		114,0			74,4	
Snøhvit North		–			3,3	
7120/12		16,0			14,8	

tellites in the Sleipner area. The condensate has been stated as oil.

Troll West
New simulations of the oil zone in Troll West indicate that the recovery factor for oil will be lower than earlier assumed.

Veslefrikk
A new well has led to a substantial increase in estimated oil resources. The resources estimate is that of the operator.

6/3-Pi
A new discovery has been proven in Well 6/3-1.

7/11 A
A discovery has been proven by Well 7/11-5 not previously mentioned in the Annual Report.

30/6 Gamma North, 30/6 Kappa, 30/9 Prospect A
These are new discoveries on the front blocks west of Oseberg that have previously not been mentioned in the Annual Report

34/10 Beta
A new discovery in the Gullfaks area.

Haltenbanken
On Haltenbanken, three major oil and condensate discoveries have been made (Heidrun, Smørbukk, 6506/12 Beta). The resources estimates for these three discoveries are provisional and very uncertain.

The Troms area
In the Troms area, remapping has been performed on Albatross, Askeladd and Snøhvit. This mapping has led to an increase in the gas resources estimates on Askeladd and a relatively heavy decline on Snøhvit. On Snøhvit North a minor gas discovery has been made.

2.4.6 Resources potential south of Stad

The Norwegian Petroleum Directorate has estimated that the expected recoverable resources potential south of Stad is about 5 billion toe (Figure 2.4.6). Until now, 3.89 billion toe have been proven by drilling. In undrilled structures a hypothetical resources potential of 1.1 billion toe has been calculated. In addition to the hypothetical resources, there may also exist some speculative resources.

3 Implementation of the Petroleum Act and reform of the Supervision of the Petroleum Activities

3.1 Introduction

The Continental Shelf Act of 21 June 1963 has been replaced by the Act relating to Petroleum Activities (the Petroleum Act) of 22 March 1985. This latter act entered into force on 1 July 1985, at which date the regulatory system developed under the auspices of the Continental Shelf Act was retired. Figure 3.1.a shows the history of the regulations.

The Act stipulates the central principles of government control of the petroleum activities. The Act is supplemented with regulations issued by Royal Decree in the constitutional spheres of the Ministry of Petroleum and Energy and Ministry of Local Government and Labour respectively. This is the case for the Regulations pursuant to the Act relating to Petroleum Activities issued by Royal Decree of 14 June 1985, the Royal Decree of 28 June 1985 concerning Regulations for Safety etc pursuant to the Act relating to Petroleum Activities, and the

FIG. 3.1.a
History of the regulations

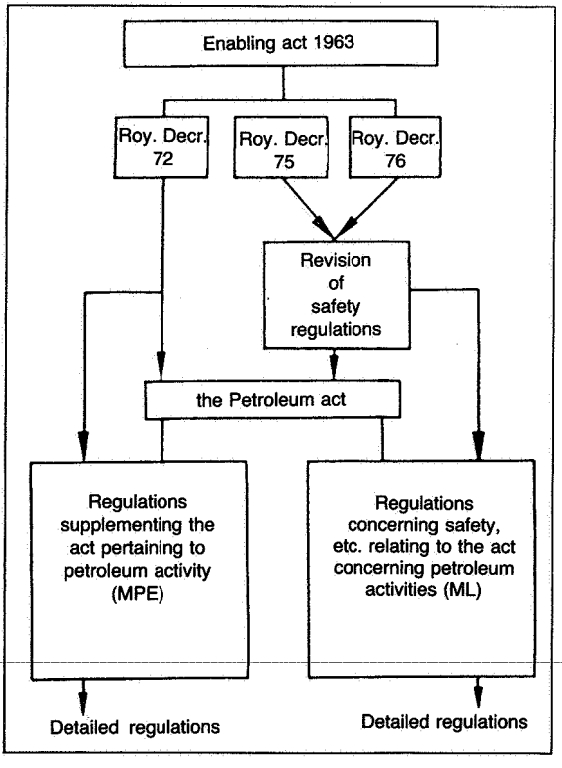
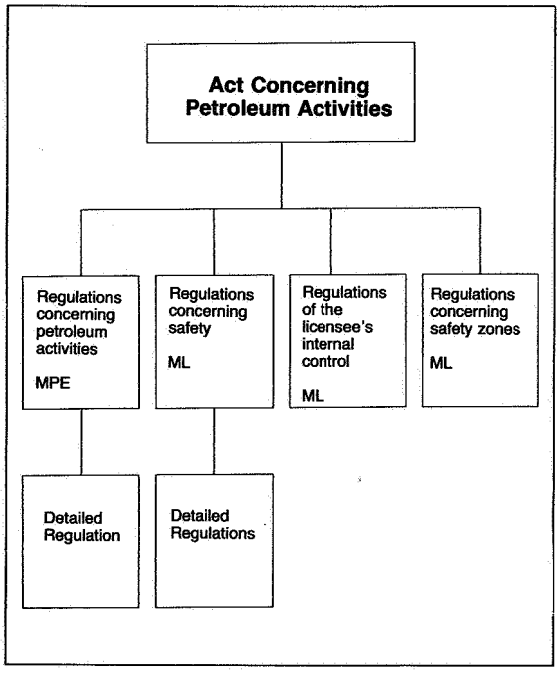


FIG. 3.1.b
The structure of the regulations pursuant to the Petroleum act



Regulations concerning the Licensees Internal Control, also issued by Royal Decree of 28 June 1985. A Regulation concerning Safety and Limitation Zones is expected to follow later.

The structure of the regulations pursuant to the Petroleum Act is illustrated in Figure 3.1.b.

The Regulations of 14 June 1985 are largely a detailed presentation of central provisions in the Petroleum Act that come under the auspices of the Ministry of Petroleum and Energy. The regulations embrace a number of provisions which were previously stipulated as criteria for approval of a production licence. The regulations also deal with several provisions coming under the area of authority of the Ministry of Local Government and Labour. In the regulations the Norwegian Petroleum Directorate is directly assigned the official responsibility pursuant to applicable provisions.

The Norwegian Petroleum Directorates earlier official responsibility has largely survived by delegation from the Ministry of Petroleum and Energy on 28 June 1985.

The Royal Decree of 31 January 1969 covering Regulations concerning Scientific Exploration for Natural Resources on the Norwegian Continental Shelf etc will continue to be authorized by the 1963 act and will come under the official responsibility of the Ministry of Petroleum and Energy. The delegation of this authority to the Norwegian Petroleum Directorate pursuant to §§ 1-15 in the regulations continues to apply.

The Royal Decree of 28 June 1985 concerning Safety etc pursuant to the Act relating to Petroleum Activities replaces Royal Decree of 9 July 1976 concerning Safety etc for Production and Royal Decree of 3 October 1975 concerning Safety etc for Exploration Drilling. The new decree has three essential aspects:

- it stipulates requirements that state when the licensee must make his application for consent to initiate (or continue) the activity, and outlines the most important requirements made of documentation
- it also stipulates requirements for sound operations in the various spheres of activity within the petroleum activity
- it provides the authority for detailed regulations.

In this way the regulations thus constitute a continuation and detailing of the main requirements of the Petroleum Act regarding sound activities, cf § 45 of the Act. The regulations moreover provide the authority for older detail regulations that remain in force following the implementation of the Petroleum Act. Pursuant to these regulations the authority was assigned to the Norwegian Petroleum Directorate by delegation from the Ministry of Local Government and Labour on 28 June 1985. This delegation allows the Norwegian Petroleum Directorate to carry out the supervision and issue the resolutions necessary to implement the regulations. The Directorate was also assigned the authority to prescribe regulations.

The Royal Decree of 28 June 1985 concerning the Licencees Internal Control is directed, unlike the Petroleum Act and Safety Regulations, solely at the licensee. This regulation makes requirements of the licensees administrative systems in order to follow up in a controlled and systematic manner the requirements made of the licensee with respect to safety, the working environment, and measures to combat pollution. These regulations therefore derive their authority from the Petroleum Act, the Act relating to Worker Protection and the Working Environment, and the Act relating to Protection against Pollution and concerning Waste.

For the Norwegian Petroleum Directorate the Petroleum Act represents a tidying up of the overriding regulatory apparatus. Nevertheless, the changes of significance for the Directorates tasks within resources management and other matters falling under the Ministry of Petroleum and Energys sphere of responsibility are few. On the other hand, resulting from the Royal Decree of 28 June 1985 concerning the Arrangement of Supervision of the Petroleum Activities, considerable changes have been made in the control arrangements, cf Section 3.2 below.

A further presupposition regarding an aspect of the control arrangement was that the Norwegian Petroleum Directorate should maintain a coordinating responsibility for tasks assigned to the Ministry of Social Affairs concerning hygienic conditions, health control etc; the Ministry of the Enviroment concerning protection from pollution; and the Ministry of Justice concerning the authorities emergency preparedness. Regarding the Norwegian Petroleum Directorates work of implementing the coordination and subscription of agreements for assistance, see the discussion in Section 3.2.

3.2 Arrangements for supervision of safety in the petroleum activities

The framework surrounding the supervision of safety in the petroleum activities on the Norwegian continental shelf has been forged by the Petroleum Act, the Safety Regulations, and the Royal Decree of 28 June 1985 concerning the Arrangement of Supervision of the Petroleum Activities. The decree opened the way for the Norwegian Petroleum Directorate to be assigned from 1 July 1985 the collected authority to carry out supervision, undertake overall safety evaluations, and prescribe the necessary regulations. This restructuring of supervision is a direct follow-up of the political presuppositions that formed the rationale for measures following the Alexander L. Kielland disaster and in connection with the Petroleum Act, where the committee highlighted the need for coordinated control and responsibility in the petroleum activity. In this connection the committee proposed a reduction in the number of inspection agencies, and advocated that the principles for enforcement and administration of the safety provisions should become effective from the same date as the act.

The responsibility for supervision that now lies with the Norwegian Petroleum Directorate implies a pensioning off of the arrangement whereby the supervisory responsibility was split under the Ministry of Local Government and Labours area of responsibility among no less than ten directorates. The Norwegian Petroleum Directorate believes the content of this reform is such that it will rationalize the supervision of the petroleum activities and provide a better utilization of the available control agencies, because:

- clear-cut boundaries have been erected regarding the government authority for administration of the supervision
- the foundation has been laid for development of a

unified set of regulations and a coordinated control methodology
- the arrangement provides the basis for overall safety evaluations, and inspection resources can be applied more cost effectively.

In order to implement in practice the Royal Decree of 28 June 1985 concerning the Arrangement of the Supervision of the Safety of the Petroleum Activities, the Norwegian Petroleum Directorate issued on 1 July 1985 detailed specifications for the arrangement of the supervision. This specification supplements and expands the principles in the decree as far as the practical application of the Petroleum Act with regulations goes. In particular the specification aims to inform the industry what detailed regulations will apply during the various phases of the activity, and link these to the individual applications for licensing consent.

From 1 July 1985 the Norwegian Petroleum Directorate implemented some changes affecting application of the consent to carry out surveys and exploration drilling. The Directorate introduced an arrangement whereby the licensees can apply for a consent that involves the use of a named installation for planned tasks within a limited geographic area, thus allowing the licensee more freedom personally to determine the scope of his application. This means that the licensee does not necessarily have to apply for "consent to use" for an installation every time he wants to drill a new well. On the other hand, a drilling permit must be obtained for each individual hole.

Use of expert assistance

In connection with the implementation of the supervision, both regarding the processing of applications and subsequent control, the Royal Decree mentioned stated that the Norwegian Petroleum Directorate could seek expert assistance from other public agencies, institutions and companies having special competence.

The concept behind this arrangement was based on the creation of binding agreements between the Norwegian Petroleum Directorate and the following agencies:

- Norwegian Telecommunications Directorate
- Civil Aviation Authority
- Directorate for Fire and Explosion Protection
- Coast Directorate
- Norwegian Meteorological Institute
- Maritime Directorate
- Norwegian Water Courses and Electricity Board (preparation of regulations).

In practice it proved substantially more time-consuming to enter into agreements for expert assistance than was presupposed by the Energy and Industry Committee and during the governments processing of the Royal Decree concerning the arrangement of the supervision. As of today agreements for assistance have been entered into with the Directorate for Fire and Explosion Protection (1 July 1985), the Norwegian Meteorological Institute (11 July 1985) and the Coast Directorate (31 July 1985). Agreements with the Telecommunications Directorate and Civil Aviation Authority are due early in 1986. No agreement on expert assistance has been entered into with the Maritime Directorate.

As a stop-gap measure the two directorates have agreed that the Maritime Directorate will assist the Norwegian Petroleum Directorate when requested in individual cases. This opportunity has been exercised by the Norwegian Petroleum Directorate.

Despite the problems relating to setting up agreements for assistance the Norwegian Petroleum Directorate nevertheless believes that this has not led to any weakening of supervision of any real consequence for safety in the petroleum activities.

Content of the agreements for assistance

The reliance on assistance treaties between administrative agencies is new in principle. Nevertheless, these agreements contain nothing more than specifications of what each agency will do pursuant to the case processing rules of the Administration Act. Generally speaking, these assistance treaties concern the provision of expert assistance by other agencies to the Norwegian Petroleum Directorate for supervision purposes.

The assistance embraces the review of the documentation submitted by the licensee in connection with his application. Also embraced, furthermore, are competent statements to the Norwegian Petroleum Directorate in connection with control audits and inspections intended to verify the submitted data in the light of the requirements of the Petroleum Act and associated regulations. The assistance also embraces participation in audits and inspections as mentioned.

The case processing rules of the Administration Act and the general principles of good administration practices are of course applicable pursuant to the Administration Act. Both the Norwegian Petroleum Directorate and agencies assisting it with its supervision have an independent responsibility to ensure that case processing requirements are satisfied. As the supervisory authority and the industrys link with the authorities, the Norwegian Petroleum Directorate has the overriding responsibility to ensure that the requirements provided by the Administration Act concerning guidance, case preparation and decision-making are observed. Agencies that provide the Norwegian Petroleum Directorate with assistance will have to communicate with the licensee, or his contractors if applicable, to be able to accomplish their duty to examine matters properly and prepare cases as prescribed by the Administration Act § 17.

The assisting agency will also be able to make verbal approaches to the licensee during the preparation of the case regarding the matters on which that agency is to make comments to the Norwegian Petroleum Directorate, for example in the case of an application. The assisting agency will be expected following conclusion of the preparations to make a written statement to the Norwegian Petroleum Directorate that will form the basis for the latters preparation of a decision. The Norwegian Petroleum Directorate itself, however, holds the decision making authority, as delegated by the Ministry of Local Government and Labour.

3.3 Introduction of the opportunity to make internal control requirements within resources management

In connection with the Norwegian Petroleum Directorate's preparatory work for implementation of the Petroleum Act, it was mentioned to the Ministry of Petroleum and Energy that the regulations in pursuance of the Act did not contain any provisions to supplement the requirement for internal control in § 58 of the Petroleum Act. Against this background the Directorate initiated work to evaluate the need for requirements that the licensee should set up an internal control system within the administrative area of the Ministry of Petroleum and Energy. Based on this work, requirements regarding the licensees internal control system were introduced in § 47 of the Royal Decree of 14 June 1985 by virtue of which the Ministry or Norwegian Petroleum Directorate was given the authority to demand that the licensee should plan and organize a control and documentation system to ensure that the requirements prescribed in the Petroleum Act and its associated regulations are indeed satisfied. It was found proper to introduce a facultative access to demand the implementation of such an internal control system.

The arrangement was considered to be particularly relevant in areas where supervision is carried out of a licensees activities, for example the metering of oil and gas, flaring of gas or collection of government revenues. The provision concerning internal control has already been introduced in the regulations for fiscal metering of oil and gas and is employed in practice for supervision. In the same provision the Norwegian Petroleum Directorate has been given the opportunity to demand that a description of the internal control system be presented by the licensee.

3.4 Supervision of technical drilling installations and equipment on mobile drilling platforms registered or intended for registration in the Norwegian Register of Shipping

In 1978 the official responsibility for supervision of technical drilling installations and equipment on mobile drilling platforms pursuant to the Act relating to Government Control of the Seaworthiness of Ships was transferred from the Ministry of Trade to the Ministry of Petroleum and Energy (now the Ministry of Local Government and Labour). The supervisory authority was delegated by resolution to the Norwegian Petroleum Directorate.

In connection with the Petroleum Act principles were drafted for the division of jurisdiction between the Ministry of Trade and the Ministry of Local Government and Labour. With this in mind the Norwegian Petroleum Directorate raised in June 1985 the question of the retrogression of the constitutional official responsibility for technical drilling installations. On the basis of the Norwegian Petroleum Directorates supervisory role pursuant to the Petroleum Act the Directorate considered that the supervision of technical drilling installations following from the flag state legislation should, in principle, be assigned to the flag state, in other words the Ministry of Trade and thereby the Maritime Directorate. However, the Norwegian Petroleum Directorate assumes that its own professional competence in the field of technical drilling installations can continue to be drawn on by the Maritime Directorate through an agreement for expert assistance between the two directorates.

The matter is presently being discussed in the Ministry of Trade and Maritime Directorate.

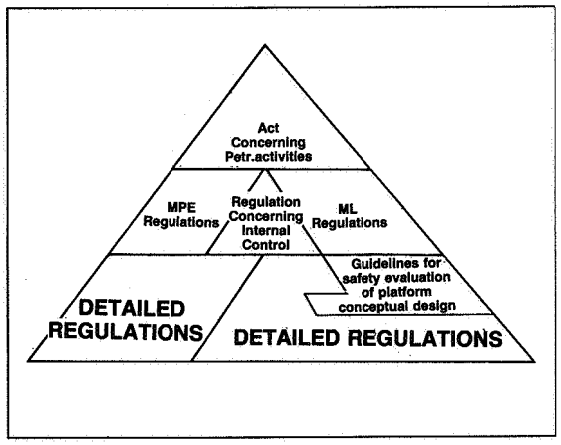
3.5 The Norwegian Petroleum Directorates work of preparing regulations pursuant to the Petroleum Act etc

Upon the entry into force of the Petroleum Act a new regulatory architecture was established. See Figure 3.5.

As illustrated by the figure, the Act itself sets the overriding requirements and frameworks. On the next level detailed and supplementary provisions in pursuance of the Act are given for the spheres of responsibility of the Ministry of Petroleum and Energy and Ministry of Local Government and Labour. A central position is held by the Regulations concerning the Licencees Internal Control, which lay down the requirements pertaining to the administrative systems that the licensee is expected to implement in order to secure, by controlled and systematic means, the fulfilment of the provisions prescribed in the Petroleum Act and the Safety Regulations. On the same level are the most important provisions relating to government management and control of the activity by means of consents. Thus the authorities have been given the opportunity to ensure by supervision that crucial decisions by the licensee remain within the bounds decreed for the petroleum activities.

The third level accommodates the detailed regulations. Detailed regulations are various in character and lack the desirable degree of mutual systematization and coordination with the overriding provisions and principles laid down by the Petroleum Act and royal decrees. The Norwegian Petroleum Directo-

FIG. 3.5
The structure of the petroleum legislation



rate has therefore assigned high priority to the work of examining the architecture of the matrix of detailed regulations with the aim of securing a unified and clear-cut level of safety in the petroleum activities, plus a more systematic and logically rigorous regulatory structure.

As a result of the need to develop a yardstick for the methodical building up of the body of regulations in the Ministry of Local Government and Labour's sphere of responsibility, a working group was created in the 1984–85 new year by the Ministry and the Norwegian Petroleum Directorate to develop the ground rules for methodic inter-structuring of the regulations. A crucial aspect of this work has been the drawing up of long-term programs for detailed regulations with a view to reviewing systematically the existing detailed regulations applying to the petroleum sector. In this connection the Directorate will be continuing its work to develop elements of a program through which the regulations can evolve, including a system for keeping records of weaknesses in the existing matrix and evolving plans for revisions of the regulations.

The Norwegian Petroleum Directorate's objective is to develop a set of regulations aimed at result-oriented, functional requirements in its regulations, supplemented by guidelines. The guiding theme behind the latter is to describe possible ways and means of satisfying the regulations. The Directorate will seek to avoid descriptive rules or requirements for specifications that can tend to hinder progress. On the other hand the Directorate will continue to resort to requirement specifications to the degree necessary.

Within these limits the Norwegian Petroleum Directorate will seek to achieve better regulatory techniques at the detailed regulation level. To follow up the Directorate's work of implementing the Petroleum Act with emphasis on its future regulatory efforts, among other aspects, a project group has been established in the Safety Control Division. This group is an inter-disciplinary assembly with participation from the Safety Control Division and Legal Section. The terms of reference of the project group are to work with questions of principle relating to the application of agreements for expert assistance, coordination of agencies having independent official responsibility, administrative coordination tasks, information measures and the review and revision of the Working Environment Act etc.

A similar cooperation was established between the Resource Management Division and Legal Department who together have created a follow-up group for regulations within the sphere of authority of the Ministry of Petroleum and Energy. This groups terms of reference are to review, interpret and prepare a specification of the Norwegian Petroleum Directorate's areas of authority and responsibility pursuant to the terms of the Petroleum Act and under the area of responsibility of the Ministry of Petroleum and Energy.

4 Supervision of safety, emergency preparedness and the working environment in the petroleum activities

4.1 Introduction

Within the sphere of safety the Petroleum Act and the restructuring of the supervision of the activity have provided the Norwegian Petroleum Directorate with a substantial challenge. The application of the new set of regulations in relation to the already existing detailed regulations has created a number of special problems. At the same time the supervisory authority of the Norwegian Petroleum Directorate has been expanded appreciably since tasks that until 1 July 1985 were the business of other directorates then came under the auspices of the Norwegian Petroleum Directorate. In this connection the Norwegian Petroleum Directorate found it proper in April 1985 to set up an ad hoc project group to carry through the implementation of the Petroleum Act, cf the discussion in Chapter 3.5.

Despite the entry into force of the Petroleum Act and associated regulations causing a number of administrative and practical questions to arise in connection with the processing of applications for consents and the associated follow-up supervision, the Norwegian Petroleum Directorate considers it has solved these satisfactorily. In the period 1 June to 31 December 1985 the Directorate issued 143 consents and licences. Of these five were consents to carry out surveys, 28 were consents to carry out exploration drilling, and 14 were consents to utilize installations. In connection with implementation of the Petroleum Act, the Norwegian Petroleum Directorate has been inclined to promote a smooth adaptation, both due to the companies need to move into line with the new law, and also the special problems caused by its entry into force in the absence of agreements for expert assistance from other government agencies.

4.2 Regulations and guidelines/ preparatory work

The Norwegian Petroleum Directorate has given high priority and will continue to do so to the work of developing a new regulatory structure. The rationale is not least to secure a unified and unambiguous level of safety in the petroleum activities, as well as to achieve a more systematic and logically coherent structure in the regulatory body.

Since in the Directorates view it will be very difficult to implement work on detailed regulations before the future overall structure has been defined, the work of preparing detail regulations has received low priority during this report period.

The Working Environment Act § 21 makes requirements regarding the employers notification of work accidents and occupationally-related illnesses that can be caused by the work or conditions at the workplace. The Norwegian Petroleum Directorate has carried on this work which started in 1984 by preparing regulations in pursuance of § 21 on the Employers Duty to Report Injuries and Accidents, and guidelines for § 22 on the Medical Practitioners Duty to Submit Reports. The guidelines to § 22 have been coordinated with the Directorate for Labour Inspection.

Preparation of Regulations concerning Safety and Limitation Zones at the installations was finalized in the spring of 1985. The draft regulations have been submitted to the Ministry of Local Government and Labour for comment. The Norwegian Petroleum Directorate assumes that the regulations will enter into force early in 1986. The regulations will elucidate major aspects of surveying, exploration drilling, development and operation in connection with subsea completed production wells, blow-out preventive measures, anchoring, emergency preparedness and reporting.

The Norwegian Petroleum Directorate's proposal for new regulations concerning manned underwater operations was circulated for comment in 1984. Based on the comments received the draft has been somewhat reworked. Revisions of a purely technical legal character in connection with the new Petroleum Act will nevertheless cause it to take some time before the new Diving Regulations can be issued.

The Norwegian Petroleum Directorate originally intended to issue a Regulation concerning Measures to Combat Noise in 1985. Because of the work load required to adapt the entire regulatory structure to the Petroleum Act however, the issue date for this regulation has been delayed. The Directorate expects though that the regulation will become available in early 1986 without any major revisions.

4.3 Diving

During the year 1936 surface-oriented dives were accomplished with 206,145 man-hours in saturation. For surface-oriented dives the figure is comparable with 1984, while the saturation hours figure is 46 per cent lower than 1984.

The Norwegian Petroleum Directorate has been heavily involved during the report period with fol-

lowing up the operators preparations for operational diving down to 300–400 meters. Planning of diving operations to these depths involves that the operators will have to be able to document that the procedures and equipment to be employed in fact functions satisfactorily. As a step in this documentation a manned dive down to 450 meters was carried out at the Norwegian Underwater Technology Centre (NUTEC) in Bergen in 1985.

On the Norwegian Continental Shelf it is primarily the Troll and Oseberg developments which will presuppose special planning of diving operations to such depths.

A working group has been established to prepare proposals for qualification requirements for personnel connected with underwater operations. Apart from participation by the Norwegian Petroleum Directorate, the group is composed of representatives of the State Diving School, Association of Offshore Contractors (AODC, Norwegian Section); Norwegian Industry Association for Oil Companies (NIFO) through its Diving Advisory Sub Committee, and the Norwegian Oil and Petrochemical Association (NOPEF).

4.4 Emergency preparedness

4.4.1 Consequences of the "Alexander L Kielland" disaster

The "Alexander L Kielland" disaster caused among other things a revision of the Standby Vessel Regulations and a reevaluation of the standby vessels role in the total emergency preparedness. In the autumn of 1983 the Directorate was assigned the task by the Ministry of Local Government and Labour of preparing Guidelines for Emergency Preparedness on the Norwegian Continental Shelf.

Following an interim report in the spring of 1984 the Ministry decided to implement a pilot project to evaluate how the authorities requirements and expectations could be best sought to be developed.

The main project will initially be implemented with the aid of funds from the Royal Norwegian Council for Scientific and Industrial Research (NTNF), though other funding will be necessary for completion.

The main project intends to:

- examine all administrative functions relating to emergency preparedness
- promote flexibility with respect to selection of operational preparedness methods, preparedness equipment, technology etc
- examine emergency preparedness communications.

Concurrently with the main project entitled "Guidelines for Emergency Preparedness" the Norwegian Petroleum Directorate will be working on the total matrix of regulations governing preparedness. Work is continuing with the project which is expected to be finished in mid-1987.

4.4.2 Summary of available emergency resources

The Sector Clubs formed by the operating companies in the North Sea basin across the national demarkation lines regulate the conditions relating to mutual assistance in the case of an emergency situation.

A summary of the resources available for emergency preparedness within each individual sector is directly accessible in a data base. The locality of fire fighting tenders, diving vessels, mobile installations and so on in the North Sea is kept up to date at all times.

The Norwegian Petroleum Directorate has access to the information stored in the data base through the Main Rescue Coordination Centre (MRCC).

The Norwegian Petroleum Directorate has pointed out to the oil companies the necessity of having such mutual agreements also north of the 62nd parallel.

4.4.3 Emergency tasks for field-based helicopters

The two Bell 212 helicopters that carry out on-field shuttle transport are integrated in the Ekofisk field preparedness plans. Rescue hoists and infra-red heat seeking equipment can be installed in a matter of minutes. When searching for persons lost at sea, such infra-red eyes are independent of weather and light conditions. The hoist operator and rescue man are included in the helicopter crew on the field.

To provide the same services the Statfjord field also has a helicopter that can be fitted with an air-sea rescue hoist. The adjacent Brent field has a similar helicopter. Agreements exist regulating mutual helicopter support in accident situations.

On the Frigg field too, a helicopter will soon be available that can be fitted with a rescue hoist.

The Norwegian Petroleum Directorate considers that such measures are of great importance to the total level of preparedness and has encouraged their development.

4.4.4 Revisions in stand-by vessel routines

On the Ekofisk field larger, more powerful standby vessels have been contracted that are also equipped to provide other functions, for example supply services and anchor handling. The new tenders also have a much improved fire fighting capacity. Since these vessels can alternate in their service assignments, their crews have a greater and more stimulating variety of work tasks.

On the Valhall field two combined supply and standby vessels alternate in service.

On Frigg and Heimdal a similar arrangement is being developed.

Studies carried out by the operator conclude that this concept provides at least as good preparedness as earlier arrangements, and the Norwegian Petroleum Directorate has approved this development.

4.4.5 Basic safety and emergency preparedness training

Following the Norwegian Petroleum Directorates directive the operating companies have, through the Norwegian Industry Association for Oil Companies (NIFO), evaluated the content of the basic safety and emergency preparedness training that all offshore personnel are bound to take.

The study has now been completed and a proposal for revisions of course subjects and content was ready in 1985. The Directorate will place decisive emphasis on this proposal in its evaluation of whether the basic safety and emergency preparedness training is to be revised.

4.4.6 Littering and pollution by the petroleum activities

The Norwegian Petroleum Directorate has noted an improvement in the companies procedures for safe handling of trash, particularly regarding internal codes and training.

The use of oil-based mud has created storage and disposal problems for reception facilities onshore. A plant is presently being constructed in Florø for the separation of mud that hopefully will improve the situation.

The companies reporting routines for bottom encumbrances and clearing up following operations are now functioning more satisfactorily.

4.4.7 New equipment on stand-by vessels

On the Frigg field a hydraulically operated net frame has been introduced that can be guided alongside a ship to fish personnel out of the sea. Casualties in a state of reduced consciousness can thus be brought onboard prostrate, thus averting further injury.

4.5 Living and office accommodation

4.5.1 Living quarters

The design and layout of living quarters have gone through substantial changes in recent years regarding the living and relaxational environment, functional design, recreation and safety. The industry has demonstrated both the willingness and creativity to come up with new solutions within the relatively strict limits set by the provisions applying in respect of space, weight, materials selection and safety.

The experience of the Norwegian Petroleum Directorate is that one of the most essential prerequisites for accommodation quarters to be satisfactory for all concerned is that one as early as possible draws lessons from experience with other concepts. Representatives of the employees can provide an important resource group in this context. The Directorate therefore expects that employees will be consulted, even where the operating company in question has no experience or its own operating organization at the time of initiating the engineering design.

The experiences drawn from development projects on the Norwegian Continental Shelf regarding the estimated and the real-life requirements for accommodations have demonstrated that living quarters are generally made too small. Extensions to living quarters on several more recent production installations are being evaluated. Experience from previous installations must be drawn on actively when planning new development projects.

Any permanent use of a flotel in connection with a production installation does not represent a fully satisfactory solution to the capacity problem, either from a safety-related or economic viewpoint. The objective must therefore be to provide living quarters on future oil installations with such large capacity that there arises no need for flotels after the start of the ordinary operating phase.

4.5.2 The office situation

In the provisional Regulations concerning Living Quarters on Production Installations etc laid down on 2 April 1979 it states in Section 2.6 that the living quarters shall be sufficiently equipped with offices, beds etc.

Notwithstanding this, the Norwegian Petroleum Directorate has noted that several concepts for the development of North Sea fields have been inadequately dimensioned regarding the necessary space for living quarters, and has therefore raised the question to what extent the companies in their planning operations have sufficiently satisfied the requirements of the regulations.

The Norwegian Petroleum Directorate's attitude is that offices for administrative functions of a practical, communications or working environment-related nature are best located in the living quarters.

This location will follow naturally from the safety and emergency preparedness philosophies that have been taken as the point of departure for the design of integrated installations. In special cases, it may be acceptable for offices to be located outside the living quarters for functional reasons. This will be the case for offices for personnel whose tasks and responsibilities are clearly related to the operation of plant and equipment.

4.6 Organized safety and working environment efforts

4.6.1 Introduction

On the basis of the discussions carried out between the employer and employee organizations regarding the organization of safety cooperation on production fields in the North Sea, the authorities found it necessary to order the operating companies to present a collected plan for the organization of the safety and working environment efforts on the fields. The plan was to contain a description of the various formalized organs that had been or would

have to be set up, their compositions, terms of reference and scope of operation, with special emphasis on how the operator would carry out his function as Principle Enterprise. Included here would be a specification of the representative participation by employees and employers alike. One precondition was that the plan should be fully discussed with all implicated employee organizations on the field.

Resulting from this order, the Norwegian Petroleum Directorate received confirmation for its view that it is possible to set up a common, overriding model to look after the operators responsibility for coordination and collation of the safety and working environment tasks on each individual field, irrespective of field size. Based on this fact, the Directorate, in consultation with the Ministry of Local Government and Labour, has informed the industry what main lines the safety cooperation is expected to be organized along in the future. This applies in particular to the setting up of a superordinate, Coordinating Working Environment Committee (WEC). The Directorate believes that the setting up of this type of Coordinating Working Environment Committee, though not necessarily an unequivocable guarantee of the quality of the safety cooperation, will nevertheless tend to promote a fairer distribution among the involved parties of their formal influence on working environment matters. These committees will have their primary function in matters that extend beyond the individual employers area of authority and responsibility, and which therefore cannot be solved there.

4.6.2 Action program for safety and protection work

The working environment legislation requires that an action program is prepared and brought into use for safety and protection work in the activity. The Norwegian Petroleum Directorate sees this as a particularly important task so as to ensure planning, quality and continuity in this area of the activity. An action program of this type will represent a crucial tool for quality assurance in safety and protection activities.

To assist in the development and implementation of such action programs within safety and working environment cooperation, a proposal for an action program has been circulated to all the operating companies. The manual was prepared by the Rogaland Research Institute in collaboration with the Norwegian Petroleum Directorate.

4.6.3 The working environment of catering staff

Since 1983 the Norwegian Petroleum Directorate has been following up the working environment of catering employees on fixed installations. The Directorate has noted positive developments, where the parties as presupposed by the Working Environment Act (WEA) have themselves pinpointed the crucial questions and demonstrated an active willingness to implement new arrangements that, in the authorities view, have brought about greater security and improved working conditions for individual employees.

4.6.4 Product control

The Working Environment Act requires that, whereever technically possible, substances and products that pose a hazard to health shall be replaced with less hazardous alternatives. The Norwegian Petroleum Directorate thus expects the operating companies to evaluate the technical and occupational hygiene qualities of the substances and products used in operations, and also assumes that requirements for such evaluation shall be incorporated in the companys quality assurance system. Such evaluations are at present not very systematic, apart from in some areas, particularly those regarding materials containing asbestos.

Occupational hygiene-related evaluations presuppose special obligations for the manufacturer and supplier. These have a duty to provide adequate documentation of the products health risk upon delivery. This documentation shall be open to verification by the Norwegian Petroleum Directorate.

Manufacturers and suppliers are further obligated to provide a complete declaration of toxic, highly toxic and carcinogenic substances and products to the Product Registry. At year-end the Product Registry had received far fewer notifications than expected and it is assumed that something like 1000 products have not yet been notified. At years end the Norwegian Petroleum Directorate therefore stepped up its inspections in collaboration with the Directorate for Labour Inspection and the State Pollution Control Authority (SFT) to ensure that the industry takes its responsibilities and obligations seriously.

4.6.5 First-aid manual

The Norwegian Petroleum Directorate has issued a First Aid Manual that deals with measures to be taken in the event of poisoning. This manual is the result of a component project that was part of an investigation program on the toxicity and health hazards attaching to chemicals used in the petroleum activities. The First Aid Manual has been prepared by the Information Centre for Poisons and is primarily intended for nurses on installations in the North Sea.

4.6.6 Lighting

Investigations on some production installations show that workplaces and outdoor and indoor areas in several cases have inadequate lighting. The same applies also for instrument illumination. The poor quality of the lighting can be caused by too low or too high (blinding) luminous intensity, the latter often combined with two few light sources. These fac-

tors act unfavourably on the working environment as well as compromizing safety and preparedness.

Even though a substantial improvement in lighting standards has taken place in recent years, the Directorate can see a major requirement to prepare Guidelines concerning Lighting on Installations. The Directorate initiated a lighting project in 1984 with this in mind. Support in this work has been received from research milieux, operating companies and lighting manufacturers. When the project is finished, the Directorate will prepare draft guidelines for lighting on installations on the Norwegian Continental Shelf.

4.7 Subsea equipment

4.7.1 Subsea production systems

The Norwegian Petroleum Directorate has continued to gather together experience from existing subsea production installations and to work on studies of several concepts now being devised by operators for application on the Norwegian Continental Shelf.

A particularly large amount of work has been done in connection with concepts that may be relevant for the Troll development.

4.7.2 Subsea barriers

To prevent the release of large quantities of gas in the case of a fracture or leak in a gas export line near a platform, subsea emergency shutoff valves have been installed on several installations.

Many companies, research institutions and oil companies have for a long time been working to develop valve trees or barriers having a very high degree of security and operating reliability. The work turns out to be time-consuming and costly. The Norwegian Petroleum Directorate has therefore take the initiative for a degree of cooperation in the development work between a number of oil companies. Participants so far include: Mobil Exploration Norway Inc, Statoil, Elf Aquitaine Norge A/S, BP Petroleum Development (Norway) Ltd, Norsk Hydro, A/S Norske Shell Exploration and Production and Saga Petroleum a.s.

4.8 Mobile production installations

The Norwegian Petroleum Directorate has worked further with requirements for separators, gas flaring systems and water separation on mobile production installations, and similarly with the operating reliability of generator sets and dynamic positioning gear.

4.9 Electrical equipment

The work of replacing old and unsuitable electrical equipment has continued also in 1985. The standard of new material seems to improve continually, though it seems that heating cable installations can cause problems on new installations too.

The Norwegian Petroleum Directorate has been working to arrive at recommendations regarding the repair of explosion proof equipment. Cooperation here is with the Norwegian Water Courses and Electricity Authority.

On a large part of the new platforms short circuit currents have reached very high levels, particularly as compared with the values typical of shore-based installations. Solutions should be sought here in collaboration with the operators so that the stress can be reduced.

4.10 Drilling activities

4.10.1 System audits

The Drilling Section has carried on the work of system audits that was initiated in 1984 and that was concentrated on the various operating companies on the Norwegian Continental Shelf.

In 1985 the work has concentrated on audits in connection with the shipowners internal control of new buildings, the procurement and installation of drilling equipment, and the operation of mobile drilling platforms flying the Norwegian flag.

4.10.2 Allocation of production licences

The selection of operator and licensee on new production licences on the Norwegian Continental Shelf constitutes an important tool to ensure that the development of safety and technology follows the intentions of the authorities.

Against this background the Drilling Section has made substantial efforts in connection with the recommendation the Directorate gave to the Ministry of Petroleum and Energy regarding the companies that should preferably be awarded operator status in the tenth licensing round parts A and B.

4.10.3 Shallow drilling

In the Safety Regulations of 28 June 1985 regarding consent to carry out surveys, it states among other things that the Ministrys consent must be obtained before surveys can be carried out that involve drilling down to below 25 meters under the seabed.

The consequence of this is that scientific, commercial and geo-technical ground surveys where drilling down to below 25 meters under the seabed takes place can only be carried out if consent has been given by the Norwegian Petroleum Directorate.

During 1985 the Norwegian Petroleum Directorate has issued 32 drilling licenses for shallow drilling in connection with consents to survey. Fifteen licences were given to research institutions for scientific surveys, and 17 to licensees in connection with geo-technical ground surveys connected with the evaluation of platform concepts.

4.10.4 Winter drilling

4.10.4.1 History and basic principles

By letter of 29 January 1985 to the Ministry of Petroleum and Energy the Ministry of Local Government and Labour expressed the view that on the ba-

sis of the experiences gained during the 1984 drilling season, it had no objections to drilling being initiated on Tromsøflaket from 1 February 1985 with a view to year-round drilling from the 1985 season.

In a letter of 16 September 1985 to the Norwegian Petroleum Directorate the Ministry of Local Government and Labour states that, based on the declaration of principle regarding safety upon which the Storting Report no. 58 (1982–83) and later statements were based, the Ministry has no further objections to year-round drilling in the areas north of Stad. The Ministry continues by noting that the Norwegian Petroleum Directorate should currently evaluate and follow up the need for special measures regarding safety, emergency preparedness and the working environment in exploration activities in the northernmost areas of the Norwegian Continental Shelf.

Against the backdrop of the applications submitted for consent to carry out exploration drilling on Tromsøflaket during the 1985–86 winter season, the Norwegian Petroleum Directorate has initiated investigative work to prepare acceptance criteria for drilling operations in colder climates, for example on Tromsøflaket, during the winter half year. To date the experiences of the operators of all-year drilling on Haltenbanken and the operators who were active on Tromsøflaket from 1 February 1985 last winter have been elucidated.

Even though this exploratory work is still in the start phase, the Norwegian Petroleum Directorate has identified considerable problem areas that tend to prevent the approval of concepts that are based on the modernization of previous generation platforms where these are not particularly well equipped for drilling in northern waters.

The Petroleum Act reflects the basic principle that the main responsibility for achieving a fully sound safety level lies with the licensee. The licensee is subject to a special duty to ensure that a total safety evaluation is carried out of the selected concept to ensure that the safety level required by the shelf legislation is indeed created, maintained and further developed. The Safety Regulations, supplemented with detailed regulations under the supervision of public authorities, take the further step of staking out the guiding framework inside which the activity must take place. In this connection the Norwegian Petroleum Directorate would like to point to a number of crucial problem areas that the operator must evaluate to ensure that his selected exploration drilling concept will achieve the safety level demanded by the legislation, for example for year-round drilling on Tromsøflaket. The Norwegian Petroleum Directorate stresses that these problem areas and evaluation criteria are not intended to provide a comprehensive check list for securing a satisfactory winterization program.

4.10.4.2 Materials and manufacturing specifications

At low temperatures the properties of steel will change. The ordinary steel qualities generally used in the ship-building industry and by its sub-contractors is not intended for temperatures below freezing point (0 degrees C). The 100 year extreme minimum temperatures that can be expected in the northernmost areas (approx minus 20 degrees C on Tromsøflaket) will represent an increased risk factor as regards failure of the platforms primary structure and its equipment for manoeuvring, anchoring up, lifesaving, cranes and lifting gear and drilling equipment. The selection of older platforms will also make the provision of necessary documentation to verify that the platform satisfies the quality requirements, for example with respect to temperature, more difficult.

4.10.4.3 Dimensioning loads

Satisfactory data are presently available describing the environmental loads (wave, wind, current, ice, snow and temperature) that can be expected when drilling year-round on Tromsøflaket. Experience to date has shown that the selection of previous generations platforms only allows of marginal winterization programs, for example to upgrade mechanization or carry out weather-shielding of equipment and systems to secure their function or to improve working conditions. Examples include:

- An increase in weather-shielding increases the weight of the installation. This weight increment comes in addition to the dimensioning ice loads and thereby reduces deck cargo capacity. Furthermore, weather-shielding may cause changes in the requirements regarding area classification.
- The increase in weather-shielding of the derrick, for example, will cause an increase in wind load, also compromizing deck cargo capacity.
- An increase in heating presupposes extra hardwear and greater fuel consumption, thus making greater demands of supply service regularity.

4.10.4.4 Requirements in special areas

Both with regard to equipment and workplaces there exist special areas where the operator has to lay down requirements for environmental and operational conditions. Experience so far has revealed substantial problems in achieving an acceptable working environment and acceptable operational and safety conditions when choosing to employ a previous generation platform.

The Norwegian Petroleum Directorate expects that an operator when applying for consent to carry out exploration drilling will, for example, have specified his requirements regarding the following factors:

- shielding, temperature and operating conditions on the drill floor
- shielding at fingerboard level
- shielding of the top of the derrick for purposes of maintenance, and to reduce the risk of falling ice blocks
- temperature in the storage area for safety valves in the event of maintenance or pressure testing
- shielding of the moon pool area
- temperature, shielding and enclosure of active work areas.
- temperature, shielding and enclosure of temporary work areas, for example test station for reservoir testing
- anchor winches
- evacuation routes and evacuation equipment
- lifeboats and launching equipment
- abort criteria for transition to survival state
- surface finishes designed to reduce ice accumulation.

The Norwegian Petroleum Directorate expects that an operator, when applying for consent to carry out exploration drilling, will submit a collected evaluation of the soundness of the concept, based on compliance with his own as well as the authorties specified requirements, as well as identifying discrepancies and stating corrective action.

4.10.4.5 Requirements of special systems
In accordance with the indication of special area requirements the Norwegian Petroleum Directorate expects that the operator will define requirements for specialist systems such as:

- pipe handling systems
- safety systems for wellhead control during drilling, logging and test phases
- control systems for the blow out preventer etc
- drilling mud system, particularly as regards the necessity to provide heating, booster lines, etc
- cementing system
- diverter system
- marine riser with slip joint, heave compensator etc
- compressed air systems
- bulk handling systems
- lifting and transportation systems
- water lines (for drilling, drinking, cooling and ballast)
- sprinkler systems (for example for flare stack)
- drainage systems
- diving systems
- fire fighting systems
- anchoring systems
- life-saving systems
- power supplies with indications of power demands, auxiliary systems, etc.

As with the area requirements the Norwegian Petroleum Directorate expects that the operator will carry out a systematic review of the chosen installation as regards the extent to which the concept complies with his own and the authorities requirements for special systems. Discrepancies must be indicated and corrective action stated.

4.10.4.6 The unified concept
To carry out drilling activities that are sound from a safety point of view a chain of interwoven activities must be planned and maintained. This is the case for example for air transportation, supply boat services, standby vessels, the drilling platform and the land-based organization. Experience so far reveals that the weak links in this chain are:

- the drilling vessel
- supply boats and anchor handling vessels
- standby vessels.

These activities are physically closely related, and the tendency at present is for the operator to evaluate these parameters collectively as a "unified concept" when selecting his preferred solutions.

Gradually as more areas are opened up for petroleum activity in areas further north and where environmental conditions are increasingly uncompromizing, the "unified concept" will become a prerequisite for operating under satisfactory safety conditions. For an operator seeking consent to carry out exploration drilling on Tromsøflaket this will mean that his application must explain:

- the operator's evaluation of and requirements relating to the regularity and scope of the supply boats and supply services to the installation chosen
- the operator's evaluation of and requirements relating to rescue and standby vessels in connection with the installation chosen
- the operator's requirements relating to his own evacuation equipment and evacuation routes in respect of regularity under severe climatic conditions
- the operator's evaluation of the emergency preparedness situation in connection with the other installations in the area
- the operator's requirements relating to environmental and damage loads
- the operator's requirements relating to operational limitations on equipment and processes due to environmental loads (for example temperature, ice, polar lows)
- the operator's requirements relating to weather forecasting and the necessary equipment and personnel onboard to support forecasting.

4.10.4.7 Conclusion
The authorities have successively extended the drilling season in the northern areas. At present all-year drilling has been allowed in the areas north of

Stad. The basis for this plan is the Ministry of Local Government and Labour's declaration of principle regarding safety:

- the control authorities' requirements for safety shall be identical for all parts of the continental shelf
- it is a prerequisite for the exploration activity in the north that it must take place under at least the same level of safety as in the North Sea
- to the extent there exist differences in climatic and technical operating conditions, measures must be implemented so as to maintain safety at a fully sound level
- in the control authorities' evaluation of safety, the dates of the drilling season are not the decisive factor.

By gradually expanding the drilling season we have assimilated greater experience of the special climatic conditions in the northerly areas.

These experiences have been used to bring about modifications to equipment and operations.

Nevertheless, the Norwegian Petroleum Directorate has the clear impression that the modifications so far carried out on existing platforms and equipment are sub-optimal solutions.

In order for an exploration drilling concept to earn the classification of being a "unified concept" and satisfy the requirements made of safety, sound economy and operating availability, new concepts must be nurtured in which environmental loads and operational requirements are laid down at the project stage, and where the final concept embraces supply services as well as standby vessels.

Our experience with one operator on the Norwegian Continental Shelf indicates till now that the "unified concept" is cost efficient and serviceable also in southerly waters.

4.10.5 Activities on Svalbard

In the past year the Norwegian Petroleum Directorate has noted an increase in matters connected with the activities on Svalbard. A dozen or so companies have carried out seismic surveys on land and offshore. The Norwegian Petroleum Directorate has been engaged in following up shallow drillings, in addition to the activities of the Soviet company Trust Arktikugol in Vassdalen.

During 1985 the Norwegian Petroleum Directorate has carried out several inspection tours to Svalbard. In connection with these trips close cooperation has been enjoyed with both the Mines Supervisor and Governor regarding the practical side of the various inspection routines.

4.10.6 Cementing

It is known that changes in permeability and strength will take place in hardened cement under high pressure and temperature. At increasing temperatures the compression strength of hardened cement can fall off drastically. A corresponding increase occurs in permeability.

The literature quotes hardening (setting) times for cement types A, B, C, D and E of approx one week following hardening at 290 degrees F and 3000 pounds per square inch pressure. After this period, strength and permeability changes will no longer occur. It is known that the addition of 30–40 per cent silicon dioxide (SiO_2) will reduce not only the loss in strength, but also the increase in permeability.

In the North Sea only G cement is employed. Tests carried out so far indicate a troubling decay in the strength of G cement that has hardened under the conditions described. If this loss in strength as a function of time continues along the same lines as have been observed till now, the result may affect well integrity. Considering this the Norwegian Petroleum Directorate has initiated a collaborative project with a North Sea operator to find out at what temperature silicon dioxide should be admixed with G cement when setting cement plugs and when cementing casing and extension pipes in production and exploration wells. The Norwegian Petroleum Directorate believes it is particularly important to clarify these matters in the light of the possible consequences a dramatic reduction in strength (and associated increase in permeability) would have on safety, reservoir economy, logistics and operating availability.

4.11 Load-bearing structures and pipelines

4.11.1 Full-scale measurements of structures

As a component of the control to determine whether load-bearing structures in the North Sea behave satisfactorily the Norwegian Petroleum Directorate has demanded instrumentation of several installations. So far three jackets, three condeep type concrete gravity bases and one loading buoy have been so equipped.

- The foundations of the platforms examined have behaved satisfactorily. Retrogression calculations on the condeeps have shown that the subsoil is stiffer than was presupposed during the engineering design phase. They therefore possess a substantially greater margin of safety against toppling over than was originally assumed. They have settled up to 30 centimeters into the soil. A pile on one of the jackets has been equipped with instruments, and here too the calculation methods produce results that are on the safe side.
- Condeep gravity base structures in water depths of 100–150 meters allow of very little dynamic movement. This was confirmed by the measurements. Measurements of structural loads show a very good fit between the measured behaviour and a retro-analysis of the consequences of the storms experienced. On one of the platforms it

was observed that the adaptor piece between the steel deck and the concrete shaft was softer than presupposed during the design phase.
- Jackets located in water from 70–100 meters deep have also very little dynamic movement. This again was confirmed by the measurements. Gangways to adjacent platforms turn out to have a major influence on the dynamic behaviour. Measurements on these jackets also revealed a good fit between the empirical results and the predicted values during storms.
- On the loading buoy, an articulated loading platform (ALP), it proved difficult to secure serviceable measurements. The buoy moves about so much that the computing facilities could not function properly.

On the basis of the measurements taken it can be stated that the calculation methods have been on the safe side for

- condeep type gravity base platforms in water depths of 100–150 meters on over-consolidated sand and mud, and
- steel jacketed platforms in water depths between 70 and 100 meters on over-consolidated sand and mud.

The Norwegian Petroleum Directorate has therefore no plans to place instruments on other such installations. For new types of structures, larger depths of water and substantially dissimilar bottom conditions however, the Norwegian Petroleum Directorate will demand such instrumentation. For installations employed for exploration drilling the Norwegian Petroleum Directorate will not be requiring instrumentation since such aspects are considered to be covered by the Maritime Directorates control.

4.11.2 Preparation of regulations

Several guidelines for the Regulations concerning the Structural Design of Load-bearing Structures Intended for Production or Exploitation of Petroleum Resources are being prepared. The scope and present status of these various guidelines is as follows:

- Guidelines for Steel Structures
  Finished. These guidelines are expected to be circulated for internal comment in the Norwegian Petroleum Directorate in January 1986.
- Guidelines for Concrete Structures
  Expected to be ready for internal comment in the Norwegian Petroleum Directorate in mid-year 1986. The work is behind schedule because of the delay in issuing revised Norwegian Standards NS 3473 and NS 3420.
- Guidelines for Mobile Structures
  Due to be ready for internal comment in the first half of 1986.
- Guidelines for Loads and Acting Loads
  Was circulated for public comment in November 1985. The guidelines are expected to be finally issued in 1986.
- Guidelines for Geo-technology
  Expected to be ready for internal comment in the Norwegian Petroleum Directorate in mid-year 1986.
- Guidelines for Corrosion.
  Have been circulated for internal comment in the Norwegian Petroleum Directorate and are now in the hands of the Ministry of Local Government and Labour to obtain consent for public circulation and comments.

Most of the guidelines are behind schedule. Some part of the delays are due to new procedures for dealing with regulations and guidelines recently laid down by the Ministry. Compared with earlier practice increased emphasis is placed on the examination of economic and administrative consequences. Moreover, the drafts have to be sent to the Ministry for approval before being sent out for public comment and before being issued.

4.11.3 Following up work on load-bearing structures

In 1985 the Norwegian Petroleum Directorate has carried out several audits of the activities pursued by licensees in connection with load-bearing structures. During the year from 1 January to 31 December 1985 a total of 36 audits lasting from 1–3 days were executed at each place. Of these four were directed solely at the licensees organization, six towards engineering planning and 26 towards fabrication sites. Fifteen of the audits were carried out in Norway and 21 abroad. At one of the audits assistance was seconded from the Meteorological Institute pursuant to our agreement for expert assistance with them, and in 16 of the audits external consultants were engaged.

Our experience with these project audits has been varied, and our follow-up of contractors is highly dependent on the way in which internal control is accomplished in each individual company. At the largest and most frequently used engineering and fabrication sites one can generally say that a sound quality assurance system has been developed. On the other hand a good number of smaller contractors and contractors who handle limited numbers of orders continue to lack an understanding of quality assurance and fail to introduce requirements that would secure the documentation of quality.

As a step in following up this work, the Norwegian Petroleum Directorate has commissioned reviews of major parts of the calculations done on load-bearing structures. One review is being performed by the Maritime Directorate and three others are being carried out by independent firms of consultants.

4.11.4 Structural steel

The evolution of structural steel for use in structures and pipelines offshore is continuing. Stricter requirements have been set chemically regarding carbon equivalent values and the content of contaminants such as sulphur and phosphor. The primary reason is to improve weldability.

At the same time steel strengths are retained by adding micro-alloy elements and by controlling the rolling operation, sometimes in combination with controlled, accelerated cooling.

In recent years more emphasis has also been placed on the fracture mechanical properties of steel, particularly in the heat affected zones (HAZ) of welds. Research and development continues to be done to clarify the properties of the various types of steel in this respect, as well as to improve the fracture mechanical test methods and calculation methods presently available.

In 1985 the Norwegian Petroleum Directorate concluded a project whereby ten different types of steel that have been employed on development projects on the Norwegian Continental Shelf have been subject to scrutiny. Using special weld simulation experiments, the micro-structures and fracture mechanical charactistics one can expect in the heat affected zones of welds have been elucidated.

Also through other research projects, committee work and the following-up of development projects that takes place, the Norwegian Petroleum Directorate is keeping abreast of developments and empirical results within materials technology.

4.11.5 Internal control

The investigation initiated in the autumn of 1983 to examine the experiences gained by operating companies and project groups concerning internal control is nearing completion. Interviews with responsible personnel within the operators and projects are in their concluding phase. A summary of the talks and the conclusions drawn is expected to be ready by the spring of 1986.

4.11.6 Pipelines

The selection of development concepts for oil or gas fields that increasingly feature subsea production systems has caused the latest pipeline technology to be brought into use.

Flexible pipelines will be employed to tie in subsea wells with the Gullfaks A platform. The plans for future development call for the utilization of this technology on other fields too.

In connection with the tying in of subsea production systems to platforms, other innovative types of pipeline technology may be relevant, for example multi-pipe bundles, new materials, floating production platforms with marine risers etc.

The Norwegian Petroleum Directorate has initiated studies of the technology of flexible pipelines and tubulars. External consultants have been recruited in addition to our own staff. Competence build-up will continue this year too.

4.12 Collection of environmental data

4.12.1 Collection of environmental data in the North Sea

As a component of the systematic elucidation of meteorological and oceanographic conditions in the North Sea, the Norwegian Petroleum Directorate has demanded the collection of such data from Ekofisk 2/4-H, Frigg QP and Statfjord A. In addition, this collection will assist the day-to-day weather forecasting service in Norway, as well as helicopter traffic and shipping in the area.

The collection operation is carried out satisfactorily where the licencee is responsible both for collection and processing of the data. All data are finally forwarded to the Environmental Data Centre in Oslo where they are available to the public.

4.12.2 Collection of environmental data in the Barents Sea by M/S "Endre Dyrøy"

In connection with the planned extensions of the exploration areas off the North Norway coast, a comprehensive data collection project in the Barents Sea was initiated under the direction of the Norwegian Petroleum Directorate. The objective of the project was to gain knowledge of the oceanographic and meteorological situation in this sea area before drilling activities are started. Furthermore, data will be collected for use in connection with the consequence analyses that must be carried out pursuant to the Petroleum Act before new areas are opened up for petroleum activity.

The Norwegian Petroleum Directorates project has been coordinated with the Oceanographic Data Acquisition Projects (ODAP) measurement activities offshore North Norway. The Directorate's project comprises two measurement stations, one on Bear Island and one on the southwestern part of the Central Bank.

The ODAP is continuing the measurements on Tromsøflaket that were done under the auspices of the Norwegian Petroleum Directorate until 31 December 1984. Additionally the ODAP has collected current data from the North Cape Bank. The ODAP has also financed current measurements at the Norwegian Petroleum Directorate's buoy station at Bear Island.

The locations of these stations are tabulated in Table 4.12.2.

The Norwegian Petroleum Directorate project is financed with the aid of funds from the ODAP. In 1985 the ODAP defrayed NOK 4 million of the total project budget of NOK 12 million.

The research ship M/S "Endre Dyrøy" was contracted and has been lying on station at 74 degrees 30 minutes north and 31 degrees 00 minutes east on the Central Bank since the end of February 1985.

The crew of the vessel is replaced every four

TAB 4.12.2 The activity within ODAP and NPD's projects

Station Position	Type measurement	Period	Responsible
Bjørnøya 73°50'N 19°52'Ø	Wave height Current (6 deep)	all year 1.1.–1.3.	NPD ODAP
Sentralbanken 74°31'N 30°55'Ø	Wave height and direction Current (6 deep) Weather observations Research ship	all year	NPD
Tromsøflaket 71°30'N 19°00'Ø	Current (6 deep)	1.1.–1.3.	ODAP
Tromsøflaket 71°45'N 20°37'Ø	Current (6 deep) Wave height Meteorology	1.1.–1.–3. hele året	ODAP
Nordkappbanken 73°02'N 26°33'Ø	Current (6 deep)	1.1.–1.3.	ODAP

weeks. Every other month the ship makes a round of all the measurement stations in connection with maintenance and care of the measuring equipment. This round trip takes about five days.

The following companies and institutions have participated in the project:

- Oceanor A/S of Trondheim, which has carried out wave and current measurements
- The Norwegian Meteorological Institute which has held the responsibility for weather measurements. These readings are taken every three hours and reported to shore.

  Additionally a newly developed automatic weather recording station has been installed. The station, which was on trial for a long period, has been functioning satisfactorily.
- The Institute for Continental Shelf Studies and Petroleum Technology (IKU) has acted as vendor to Oceanor A/S and has been responsible for the operation of the wave measurement apparatus on Central Bank.

Apart from these permanent activities the M/S Endre Dyrøy vessel has been used by several institutions. Among them ornithologists from Tromsø Museum who have been onboard in connection with the round trips. In collaboration with the Water Courses and Harbour Laboratory (VHL) an ice mast has been erected on the ship, which is used to record measurements of icing and sea spray.

It is expected that other projects and studies will be assigned to the vessel in the future.

4.13 Fire damage in 1985

The following is a summary of instances of fire damage on fixed production installations in 1985, based upon reports submitted to the Norwegian Petroleum Directorate by the operating companies:

Damage and/or injury resulting from fire	Constr. phase	Operating phase A	B	C
Personal injuries and severe material damage				
Personal injuries and minor or no material damage				
No personal injury, but severe material damage	1	3		
No personal injury and minimal or no material damage	6	11	13	4
Total fire damage incidents	7	14	13	4

A – Cause of fire: Result of operation/operating accident
B – Cause of fire: Construction work
C – Cause of fire: Other causes (lightning strike).

When repair costs exceed approx NOK 100,000 material damage is considered to be severe.

The Norwegian Petroleum Directorate registered a total of 38 fires in 1985 as against 36 in 1984. None of the fires inflicted any substantial damage on the installations.

4.14 Work accidents

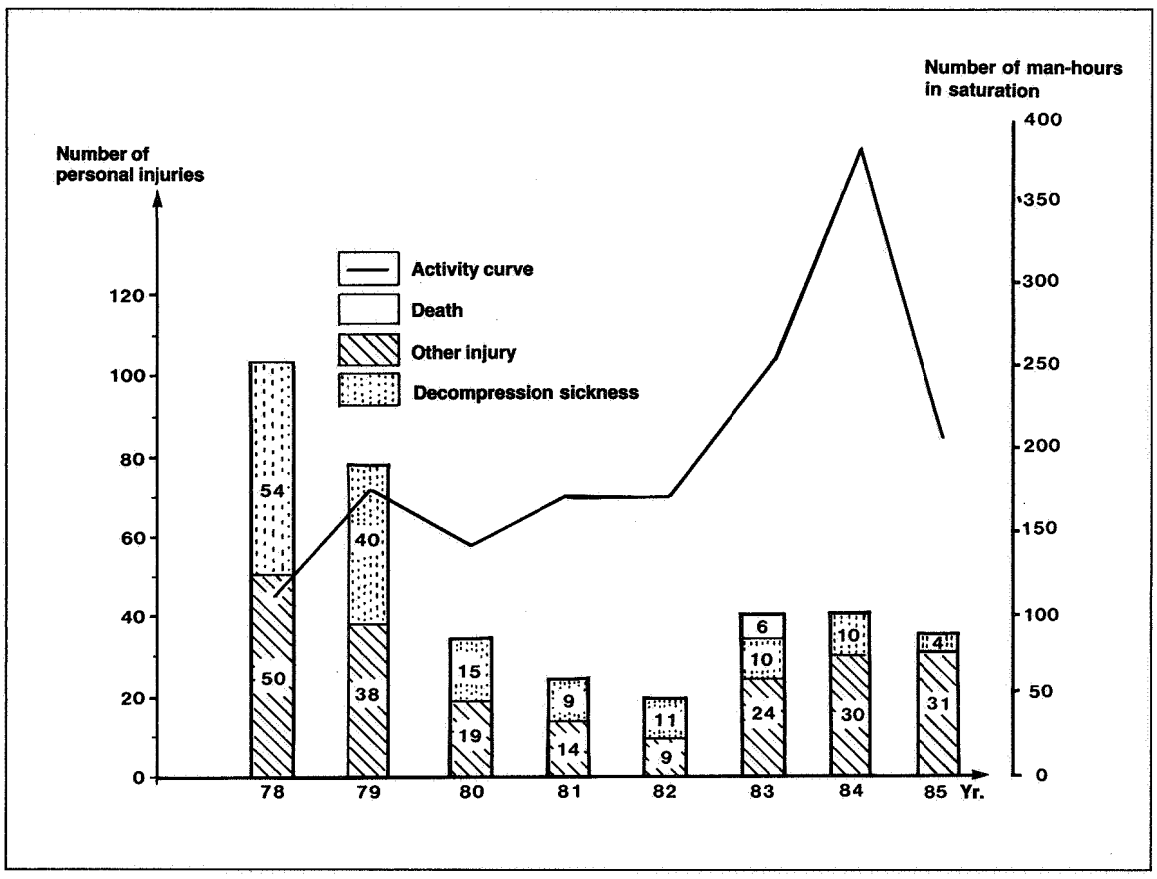
Diving

Figure 4.14.a provides a summary of the number of personal injuries reported to the Norwegian Petroleum Directorate for the years 1978–85 in connection with diving activities on the Norwegian Continental Shelf. Personal injuries are divided into the categories death, other injury and decompression sickness. The level of diving activity, measured by the number of man-hours in saturation, was in 1985 only just over half the level of previous years.

The four instances of decompression sickness were equally distributed between saturation and surface-oriented diving.

Among the 31 cases of "other injury", four were directly related to the hyperbaric environment (two baro-trauma and two ear passage infection).

FIG. 4.14.a
Total number of personal injuries in connection with diving on the Norwegian Continental Shelf –1978–85



The only case of serious personal injury resulted from a hand-operated fire extinguisher, designed for use in the chamber system, exploding in connection with discharge of the appliance outside the chamber system. A safety notice has been prepared on the basis of this occurrence.

The other injuries were in all essentials minor and without any direct connection to diving.

Accident statistics in general

The Norwegian Petroleum Directorate's personal injury statistics embrace injuries that have occurred at work on installations in connection with the production of gas and oil on the Norwegian Continental Shelf, as well as in connection with diving activities. The statistics of personal injuries are based on reported injuries that satisfy the following criteria: Death, absence from work during the succeeding 12-hour work shift, or injuries which have resulted in medical treatment. Medical treatment means treatment that is ordinarily only provided by a doctor or nurse having special authorization. Elementary first aid is not counted.

These criteria for the reporting of occupational injuries entail that the statistical material cannot be directly compared with corresponding official reports from other activities, inasmuch as continental shelf activities are subject to different and in part more stringent reporting requirements.

The number of injuries is compared with the working hours reported by the licensee for the various installations and fields each quarter. One man-labour year is equivalent to 1752 working hours in this connection.

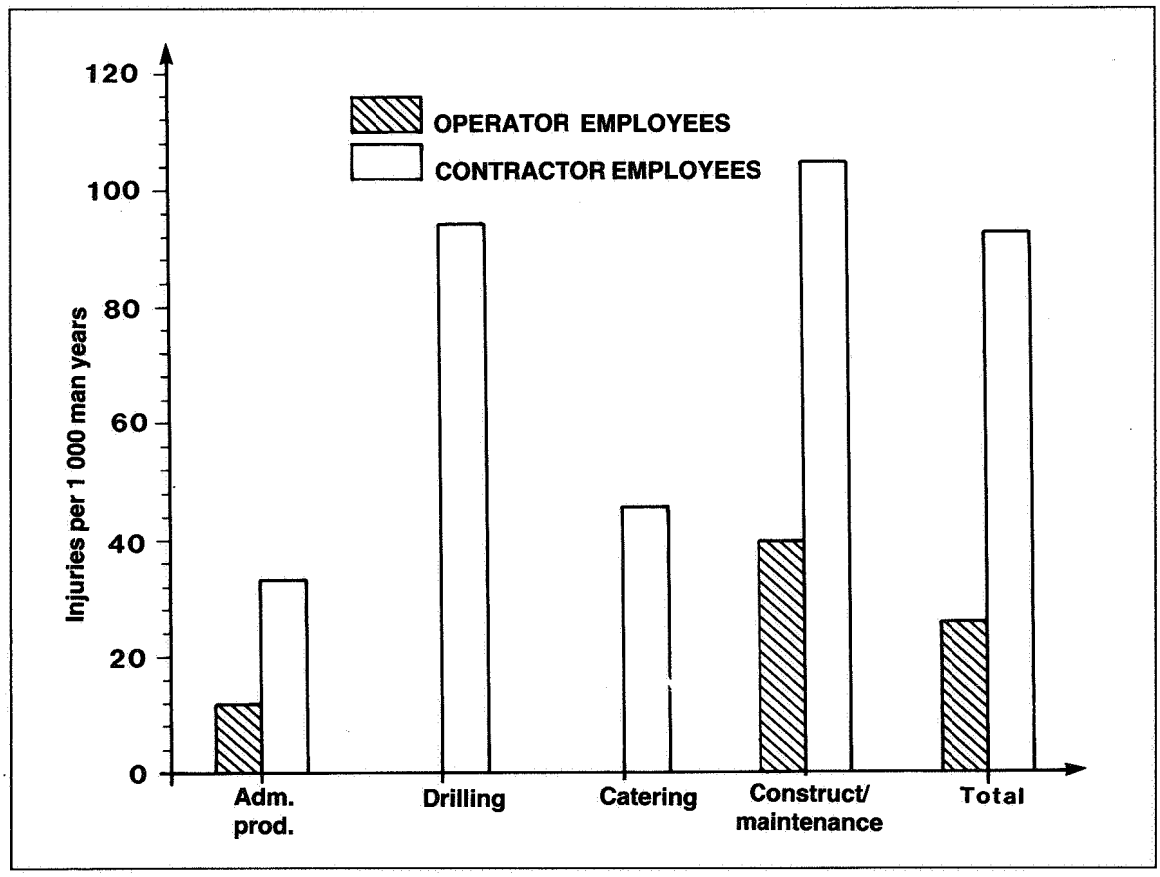
Accident statistics 1985

In 1985 a total of 591 work accidents were reported as compared with 491 the year before. At the same time the activity level increased from 8358 to 8570 man-labour years, an increase of 2.5 per cent. The figures for 1984 have been corrected for delays in incoming reports and the results of verification routines and are thus not identical with those quoted in the 1984 Annual Report.

One fatal accident occurred in 1985. This occurred on the Statfjord field when a person standing on the drill floor was hit by a part that came loose from a top-mounted drill motor. The accident is being investigated by the Stavanger Police.

Table 4.14.a. shows, among other things, a summary of injuries and deaths per 1000 man-labour years during the period 1976–85 on production in-

FIG. 4.14.b
Injury frequency 1985 operator-/contractor employees



stallations, exclusive of diving operations. The table reveals an increase in the incidence of injuries in 1985 as compared with 1984 from 58.7 to 69.0 injuries per 1000 man-labour years. The increase, which is statistically significant, implies a break with the falling trend of previous years.

Accidents occuring on installations outside working hours (leisure-time injuries) are not included in the figures in Tables 4.14.a – 4.14.f. Twenty-nine leisure-time accidents were reported in 1985.

Table 4.14.b shows how the injury frequencies are distributed in relation to the different job functions of the employees. The major differences from 1984 are in the drilling, catering, and construction and maintenance areas. Within drilling, the accident frequency fell from 111.8 to 94.0 injuries per 1000 man-labour years. No causal analysis has been made, though there is reason to believe that the reduction is connected with the purpose-directed protection work carried out and the increasing degree of automation.

The increase in accident frequency in connection with construction and maintenance tasks was appreciable, rising from 62.7 to 84.4 injuries per 1000 man-labour years. The reason is to be found in the high level of activity on fields being developed.

In 1985 contractor employees contributed 65 per cent of the total hours worked on production installations, and sustained 87 per cent of the total number of injuries. Figure 4.14.b shows the incidence of injuries for operator and contractor employees distributed by the various functions in 1985. The incidence of injuries for contractor personnel is about three and a half times higher than the incidence for operator employees. The main reasons for this difference may be that on most fields contractor personnel perform work with a relatively high risk level, for example drilling and certain types of construction and maintenance work. The highest incidence of injury continues to be within drilling.

Figure 4.14.c shows the accident distribution in the period 1979-85 by supposed degree of severity. An injury is designated severe if it has caused amputation, permanent disability or risk of disability, or when there is reason to believe that the injury will require chronic medical treatment. The classification has been made on the basis of information submitted on the work accident report forms and any other details.

Figure 4.14.d shows the accident frequency distributed by job function for 1984 and 1985.

The accident picture for 1985 shows that it is ne-

FIG. 4.14.c
Severity of injuries 1979–1985

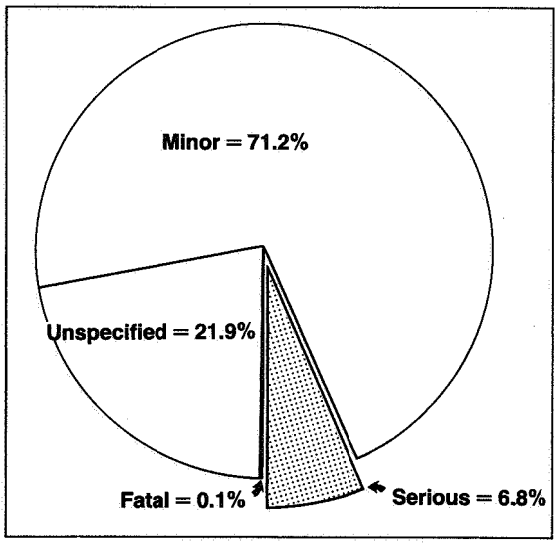
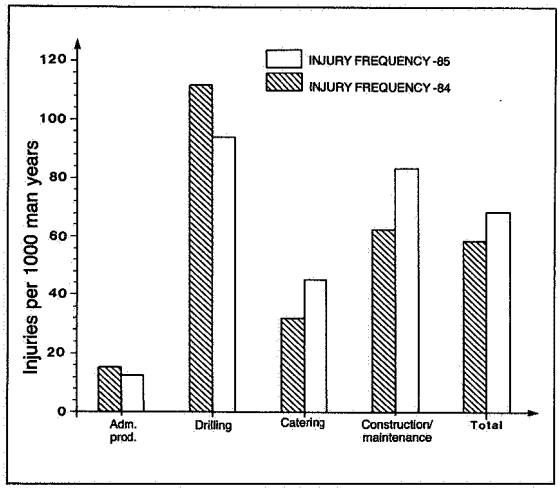


FIG. 4.14.d
Injury frequency 1984/1985



cessary for all parties to redouble their efforts to reverse the negative trend. This particularly applies for accident preventive measures. Similarly, the following up of construction and maintenance activities in the individual companies should be strengthened. There is reason to believe that better management and planning of the activity by the licensees would help to reverse this unfortunate trend. A satisfactory result also depends on contractor companies carrying out protective work actively, and on the organized safety and working environment apparatus and individual workers functioning satisfactorily. The licensees hold the responsibility for coordination of the safety and working environment work within the various activities.

The work of checking and correcting the statistical ground figures is continuing, as are efforts to improve the reporting system to eliminate sources of inaccuracy. It has been noted that several operating companies still have difficulty verifying the viability of their contractors personal injury reports. Delays in reporting also make it necessary later to adjust the statistics presented in each annual report. The Norwegian Petroleum Directorate remains convinced however that the accident statistics provide a reliable picture of the incidence of injuries on production installations on the shelf.

The Norwegian Petroleum Directorate will continue to carry out audits to verify that the reporting systems are functioning and to determine how accidents and near accidents are recorded, evaluated and followed up by the operating companies.

From and including 1986 all accidents that have occurred in activities coming under the scope of the Petroleum Act (act no. 11 of 22 March 1985) will be recorded by the Norwegian Petroleum Directorate.

TAB 4.14.a Occupational accidents/fatalities/1,000 man years (1976–85). Production installations

Year	Hours worked	Hours per man year	Man years	Number of injuries (incl. deaths)	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	7929742	1852	4399	282	64,1	2	0,45
1978	14932154	1752	8523	624	73,2	6	0,70
1979	14979074	1752	8550	575	67,3	0	0,00
1980	12238009	1752	6985	452	64,7	0	0,00
1981	15659028	1752	8938	415	46,4	0	0,00
1982	14668483	1752	8372	529	63,2	0	0,00
1983	11474696	1752	6549	334	51,0	0	0,00
1984	14643216	1752	8258	491	58,7	1	0,12
1985	15014616	1752	8570	591	69,0	1	0,11
TOTAL	126415334		71375	4506	63,1	12	0,21

TAB 4.14.b Occupational accidents per 1,000 man years, distributed on functions (1979–85). Production installations

FUNCTION		1979	1980	1981	1982	1983	1984	1985	79–85
Administration/ production	Man years	1098	1174	1144	1306	1182	1614	1656	9174
	Injuries	24	23	22	21	30	25	21	166
	Injuries per 1,000 man years	21,9	19,6	19,2	16,1	25,4	15,5	12,7	18,1
Drilling	Man years	1467	1095	1098	1289	1300	1324	1384	8957
	Injuries	178	148	115	138	100	148	130	958
	Injuries per 1,000 man years	127,5	135,1	104,8	107,0	76,9	111,8	94,0	107
Catering	Man years	507	383	411	548	525	681	685	3740
	Injuries	18	10	7	22	18	22	31	128
	Injuries per 1,000 man years	35,5	26,1	17,0	40,2	34,3	32,3	45,3	34,2
Building/ maintenance	Man years	5482	4333	6258	5299	3542	4739	4845	34428
	Injuries	346	271	271	348	186	297	409	2135
	Injuries per 1,000 man years	63,1	62,5	43,3	66,5	52,5	62,7	84,4	62,0
Total	Man years	8550	6985	8938	8372	6549	8358	8570	56322
	Injuries	575	452	415	529	334	491	591	3387
	Injuries per 1,000 man years	67,3	64,7	46,4	63,2	51,0	58,7	69,0	60,1

TAB 4.14.d Occupational accidents 1984–85. Production installations. Injury incident/injured part of the body

Injury incident \ Occupation	Administration	Drillfloor worker	Driller	Electrician	Catering	Assistant worker	Instrument technician	Crane operator	Painter/ Sandblaster	Mechanic/ Motorman	Operator	Plateworker/ insulator	Pipeworker plumber	Services technician	Scaffolder	Welder	Derrickman	Unspecified	Total	%	Year
Other contact with objects/machinery	2	24	2	7	1	29	1	1	3	10	2	7	8	9	9	2	7	0	124	25,3	-84
in motion	5	16	0	2	4	22	2	0	4	8	1	5	5	3	3	3	5	0	88	14,9	-85
Fire	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0,2	-84
Explosion etc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0,0	-85
Fall to	1	2	1	3	0	3	2	1	1	2	1	2	2	1	4	2	3	0	31	6,3	-84
lower level	1	2	1	3	1	9	3	0	6	8	3	4	1	5	0	4	4	0	55	9,3	-85
Fall to	1	1	0	1	3	8	2	0	3	3	3	2	4	2	2	1	0	2	38	7,7	-84
same level	4	1	1	8	4	14	0	1	8	3	3	8	10	3	8	7	2	1	86	14,6	-85
Stepping on uneven sur-	1	0	0	3	3	4	1	1	4	0	2	0	4	3	3	5	1	0	35	7,1	-84
face, mis-step	1	1	0	5	2	8	2	2	6	2	0	0	7	1	3	1	0	2	43	7,3	-85
Falling	0	2	1	0	1	2	1	0	2	3	0	4	3	5	5	0	3	0	32	6,5	-84
objects	2	5	1	0	0	5	0	1	0	3	0	3	7	2	4	1	0	0	34	5,8	-85
Other contact with	3	2	1	3	3	2	4	0	5	3	2	8	2	2	4	2	1	1	48	9,8	-84
objects at rest	1	1	0	6	2	0	0	0	6	1	2	7	5	2	2	0	0	0	35	5,9	-85
Handling	0	1	0	6	5	9	1	1	1	5	0	4	4	2	3	6	0	0	48	9,8	-84
accident	1	7	1	1	8	11	1	0	3	11	0	10	9	3	10	6	0	0	82	13,9	-85
Contact with chemical/	0	0	0	1	3	1	1	0	5	2	1	2	5	3	2	2	1	0	29	5,9	-84
physio-compound	1	0	0	2	6	8	1	0	15	0	0	1	5	2	1	4	1	0	47	8,0	-85
Overloading of	1	7	3	4	2	14	0	0	3	4	1	4	3	2	4	3	0	0	55	11,2	-84
part of body	1	4	1	6	0	9	0	1	4	3	1	4	4	3	4	1	0	0	46	7,8	-85
Splinters/	2	1	0	0	0	2	1	0	2	2	1	8	4	0	0	14	0	0	37	7,5	-84
splashes	0	0	0	4	0	5	0	0	10	2	2	3	10	3	2	12	1	0	54	9,1	-85
Electric	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0,4	-84
current	0	1	0	4	0	0	0	1	0	0	0	1	0	0	0	0	0	0	7	1,2	-85
Extreme	0	0	0	1	1	0	1	0	0	1	0	3	0	0	0	3	0	0	10	2,0	-84
temperature	0	0	0	0	4	2	0	0	0	0	0	0	1	0	0	1	0	0	8	1,4	-85
Fall	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0,0	-84
into sea	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0,0	-85
	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0,2	-84
Other	0	0	0	0	0	2	0	0	1	1	0	1	1	0	0	0	0	0	6	1,0	-85
	11	40	8	33	22	74	15	4	29	35	13	44	39	29	36	40	16	3	491		-84
Total	17	38	5	41	31	95	9	6	63	42	12	47	65	27	37	40	13	3	591		-85
	2,2	8,1	1,6	6,7	4,5	15,1	3,1	0,8	5,9	7,1	2,6	9,0	7,9	5,9	7,3	8,1	3,3	0,6		100	-84
%	2,9	6,4	0,8	6,9	5,2	16,1	1,5	1,0	10,7	7,1	2,0	8,0	11,0	4,6	6,3	6,8	2,2	0,5		100	-85

TAB 4.14.d Occupational accidents 1984–85. Production installations. Injury incident injured part of the body

Injured part of the body / Injury incident	Eye	Back	Toe/foot	Hip/leg	Stomach/chest	Arm/ shoulder	Head/ face	Tooth	Hand/ finger	Other	Total	%	Year
Other contact with objetcts/	1	2	12	14	3	3	13	5	71	0	124	25,3	-84
machinery in motion	0	0	9	7	3	5	12	8	44	0	88	14,9	-85
Fire	0	0	0	0	0	0	1	0	0	0	1	0,2	-84
Explosion etc	0	0	0	0	0	0	0	0	0	0	0	0,0	-85
Fall to	0	6	7	3	6	4	1	0	2	2	31	6,3	-84
lower level	0	11	6	15	7	11	1	0	3	1	55	9,3	-85
Fall to	0	8	7	6	1	5	1	0	10	0	38	7,7	-84
same level	0	15	16	12	5	14	2	3	19	0	86	14,6	-85
Stepping on uneven sur-	0	1	30	2	0	1	0	1	0	0	35	7,1	-84
face mis-step	0	2	37	4	0	0	0	0	0	0	43	7,3	-85
Falling	0	1	12	3	0	0	2	2	12	0	32	6,5	-84
objects	0	2	9	3	2	2	8	2	6	0	34	5,8	-85
Other contact with	1	2	2	9	6	3	7	3	15	0	48	9,8	-84
objects at rest	0	3	2	10	2	2	5	2	9	0	35	5,9	-85
Handling	1	2	0	0	1	1	1	5	37	0	48	9,8	-84
accidents	1	1	6	3	3	2	2	8	55	1	82	13,9	-85
Contact with chemical/	22	0	0	1	1	0	3	0	1	1	29	5,9	-84
physio compound	40	0	0	0	0	0	0	3	0	4	47	8,0	-85
Overloading of	0	39	2	0	0	9	2	0	3	0	55	11,2	-84
part of body	0	36	1	3	1	3	1	0	1	0	46	7,8	-85
Splinters,	31	0	0	2	1	0	3	0	0	0	37	7,5	-84
splashes	44	0	0	1	1	1	2	1	4	0	54	9,1	-85
Electric	0	0	0	0	0	0	1	0	1	0	2	0,4	-84
current	1	0	0	0	0	1	2	0	1	2	7	1,2	-85
Extreme	3	0	0	2	0	0	2	0	3	0	10	2,0	-84
temperature	0	0	1	0	1	2	1	0	3	0	8	1,4	-85
Fall	0	0	0	0	0	0	0	0	0	0	0	0,0	-84
into sea	0	0	0	0	0	0	0	0	0	0	0	0,0	-84
	0	0	0	1	0	0	0	0	0	0	1	0,2	-84
Other	0	0	1	0	0	1	3	0	1	0	6	1,0	-85
	59	61	72	43	19	26	37	16	155	3	491		-84
Total	86	70	88	58	25	44	39	27	146	8	591		-85
	12,0	12,4	14,7	8,8	3,9	5,3	7,5	3,3	31,6	0,6		100	-84
%	14,6	11,8	14,9	9,8	4,3	7,4	6,6	4,6	24,7	1,4		100	-85

TAB 4.14.e Occupational accidents 1984–85. Production installations. Injury incident/Contributing factor

Injury incident \ Contributing factor	Chemical/physio/ biological factors	Cold/pressure/ heat ventilation	Materials/ packaging	Electrial 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	5 5	11 11	1 0	9 10	12 7	4 11	52 28	30 16	0 0	124 88	25,3 14,9	-84 -85
Fire Explosion etc	0 0	1 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	1 0	0,2 0,0	-84 -85
Fall to lower level	0 3	0 0	2 2	0 0	0 0	0 0	0 1	28 48	1 1	0 0	31 55	6,3 9,3	-84 -85
Fall to same level	0 10	0 0	1 12	0 2	1 1	0 0	1 0	32 60	2 1	1 0	38 86	7,7 14,6	-84 -85
Stepping on uneven surface, mis-step	1 1	0 0	1 10	0 0	0 0	0 0	0 1	33 29	0 1	0 1	35 43	7,1 7,3	-84 -85
Falling objects	0 0	0 0	6 10	0 0	1 1	0 0	6 3	11 13	8 7	0 0	32 34	6,5 5,8	-84 -85
Other contact with objects at rest	0 1	1 0	6 3	2 0	3 1	1 0	1 1	32 29	2 0	0 0	48 35	9,8 5,9	-84 -85
Handling accidents	0 0	1 0	7 20	0 0	1 6	0 3	32 29	6 19	1 5	0 0	48 82	9,8 13,9	-84 -85
Contact with chemical/ physio-compound	22 28	3 6	4 0	0 1	0 0	0 0	0 12	0 0	0 0	0 0	29 47	5,9 8,0	-84 -85
Overloading of part of body	0 0	0 0	10 11	0 0	7 3	3 0	3 6	26 19	2 2	4 5	55 46	11,2 7,8	-84 -85
Splinters, splashes	1 7	2 7	9 11	0 0	6 5	0 0	16 22	0 0	0 0	3 2	37 54	7,5 9,1	-84 -85
Electric current	0 1	0 0	0 0	2 5	0 0	0 0	0 1	0 0	0 0	0 0	2 7	0,4 1,2	-84 -85
Extreme temperature	1 4	0 0	4 2	0 0	0 0	0 0	3 1	2 1	0 0	0 0	10 8	2,0 1,4	-84 -85
Fall into sea	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0,0 0,0	-84 -85
Other	0 0	0 1	0 1	0 0	0 0	0 0	0 0	1 1	0 0	0 3	1 6	0,2 1,0	-84 -85
Total	25 55	13 19	61 93	5 8	28 27	16 10	66 88	223 247	46 33	8 11	491 591		-84 -85
%	5,1 9,3	2,6 3,2	12,4 15,7	1,0 1,4	5,7 4,6	3,3 1,7	13,4 14,9	45,4 41,8	9,4 5,6	1,6 1,9		100 100	-84 -85

TAB 4.14.f Occupational accidents 1979–85. Production installations. Injury incident/Occupation

Injury incident \ Occupation	Admini-stration	Drillfloor worker	Driller	Electrician	Catering	Assistant worker	Instrument technician	Crane operator	Painter/ Sandblaster	Mechanic/ Motorman	Operator	Plateworker/ insulator	Pipeworker plumber	Services technician	Scaffolder	Welder	Derrickman	Unspecified	Total	%
Other contact with objects/machinery in motion	19	154	13	22	19	191	11	8	13	50	9	23	37	23	37	18	62	1	710	21,0
Fire Explosion etc	0	0	0	2	0	5	0	0	0	2	0	1	2	0	0	1	0	0	13	0,4
Fall to lower level	10	16	9	24	4	53	11	3	21	26	8	15	26	12	18	22	16	0	294	8,7
Fall to same level	15	15	2	32	18	59	11	6	20	20	19	24	39	15	31	27	8	5	366	10,8
Stepping on uneven surface, mis-step	13	9	0	36	10	44	9	6	17	12	8	9	31	11	18	27	9	2	271	8,0
Falling objects	7	15	5	4	1	30	3	1	3	11	1	16	20	11	18	6	4	0	156	4,6
Otdher contact with objects at rest	6	12	2	19	15	30	12	0	19	18	5	34	19	7	21	15	5	2	241	7,1
Handling accidents	3	42	6	31	28	85	12	5	17	60	14	39	61	12	29	42	17	0	503	14,9
Contact with chemical/ physio-compound	1	8	0	8	12	34	4	1	52	10	9	8	17	12	5	11	5	0	197	5,8
Overloading of part of body	5	25	4	23	8	59	1	4	16	21	9	13	34	7	25	12	12	0	278	8,2
Splinters, splashes	5	6	2	6	0	23	2	1	17	14	6	25	48	6	4	71	2	0	238	7,0
Electrical current	0	1	0	20	0	1	1	1	0	1	0	2	0	0	0	0	0	0	27	0,8
Extreme temperature	0	0	0	2	12	3	1	0	0	4	3	5	5	1	0	6	0	0	42	1,2
Fall into sea	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	1	0,0
Other	4	3	0	5	2	9	1	2	3	4	2	5	6	0	1	3	0	0	50	1,5
Total	88	306	43	234	129	626	79	38	199	253	93	219	345	117	207	261	140	10	3387	
%	2,6	9,0	1,3	6,9	3,8	18,5	2,3	1,1	5,9	7,5	2,7	6,5	10,2	3,5	6,1	7,7	4,1	0,3		100

5 Petroleum economy

5.1 Exploration drilling, deliveries of goods and services

The exploration drilling market has increased substantially both in volume and value since the beginning in 1966.

Figure 2.2.2.a shows the number of spuddings per year during 1966–1985.

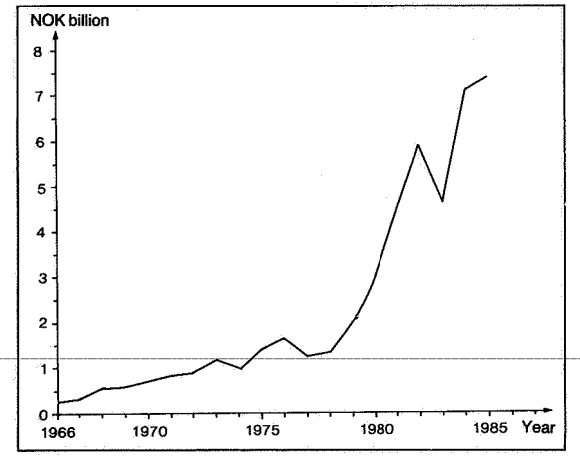
In Figure 5.1.a the value development of the market is illustrated in fixed 1985 kroner.

Table 5.1 shows the average costs per well during 1971–1985 in fixed 1985 kroner.

TAB 5.1
The average costs per well in fixed 1985 kroner

Year	Costs mill NOK
1971	53
1972	63
1973	55
1974	56
1975	54
1976	72
1977	63
1978	70
1979	72
1980	86
1981	115
1982	120
1983	117
1984	150
1985	146

FIG. 5.1.a
Yearly exploration drilling costs in fixed 1985 kroner



In 1985 the total costs for exploration ran to about NOK 7.3 billion.

Figure 5.1.b shows roughly how these costs were distributed by main categories of goods and services consumed in exploration activities. The statistics are based on reported data submitted by the operating companies.

5.2 Costs connected with activity on the Norwegian Continental Shelf

Investment in field development and production drilling

The Norwegian Petroleum Directorate has calculated the annual costs of field development including production drilling for the period 1970–1985. Costs apply to developed fields, fields under development and fields with approved development plans as of 31 December 1985. Figures are based on operator reports.

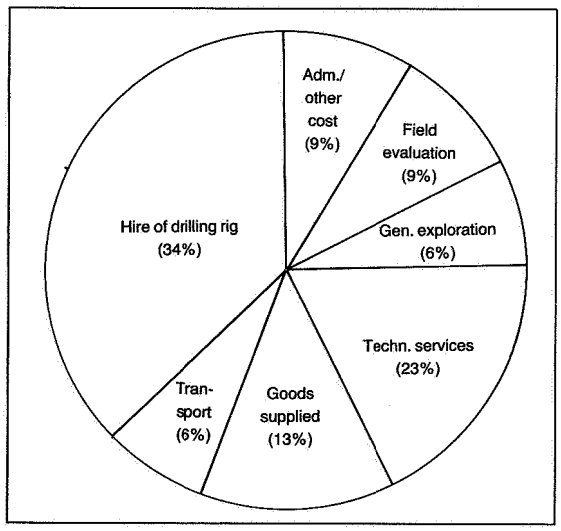
Only the Norwegian parts of fields lying on both sides of the dividing line between Norway and Great Britain are incorporated. The following fields are included in the calculations (Norwegian share):

- The Ekofisk area (including five fields and Tor, Albuskjell, the Norpipe pipeline and the water injection project)
- Valhall
- Ula
- Frigg (including pipeline) (60.82 %)
- North East Frigg
- Odin
- Statfjord (84.09 %)
- Murchison (25.06 %)
- Heimdal
- Gullfaks Phase I
- Gullfaks Phase II
- Statpipe
- Oseberg
- Oseberg transport

All figures in the summary are in fixed 1985 kroner.

Historical investments for field development, production drilling and transport facilities for petroleum are depicted in Figure 5.2.a. The investment level increased gradually up to 1976 when NOK 19.2 billion were invested. From 1976 until the present, the average annual investments have been NOK 18 billion. However, this figure hides the fact that large variations have occurred. First there was

FIG 5.1.b
Exploration expenditures in 1985



a five-year period from 1976 to 1980 in which the investment level gradually fell to NOK 10.5 billion. Subsequently we experienced five years with increasing activity until 1985, which is expected to show a new investment peak of approximately NOK 26.4 billion.

Investments in 1986 are expected to increase further to approximately NOK 27.5 billion. From then on, the investment level will fall off rapidly. New decisions to develop will probably affect the investment level early on in the four-year period and will arrive with full force in 1987–88.

Annual operating costs, including the operation of pipelines, are presented in Figure 5.2.b. The demand level for this type of goods and services has been stable since 1982, the last year during which major fields were put in operation.

The goods and services inputs for the operation and maintenance of these fields will show a long-term increase as a result of new fields being brought on stream. At present, the level is about NOK 9.3 billion. This level is expected to rise to just under NOK 13 billion in 1989. From around 1993, the effect of the closing down of the first fields will begin to show, and the operating cost levels for the declared fields are expected gradually to decrease. Nevertheless, any new fields that are declared will be able to create a recovery in demand, which will counterbalance this decrease.

Figure 5.2.c shows the total goods and services input. In 1985 the prognosis is for a total demand of about NOK 43 billion. In Figure 5.2.d the relative share of the three components: exploration costs, investments and operating costs is calculated. Following a period in which the exploration costs accounted for a relatively small part of the total market, the figure has now settled at approximately 17 per cent. The operating costs will constitute approximately 22 per cent of the total market in 1985. In 1976, by comparison, investments represented a share of 89 per cent.

5.3 Royalties

Royalties are calculated on the basis of the value of the petroleum quantities produced.

The Norwegian Petroleum Directorate is responsible for the collection of royalties.

Interpretation and implementation of existing laws and regulations regarding assessment of royalties involves legal and economic considerations, as well as metering technology questions.

The first regulations in this area were presented in the Royal Decree of 9 April 1965. Of the fields in production today, production licences for Ekofisk, Frigg, North East Frigg, Odin and Valhall were awarded in pursuance of these regulations. The Royal Decree of 9 April 1965 was superceded by Royal Decree of 8 December 1972. Of the fields in production, production licences for Statfjord and Murchison were awarded in accordance with the 1972 decree.

FIG. 5.2.a
Historical expected investments for fields decided to be developed. Fixed 1985 kroner

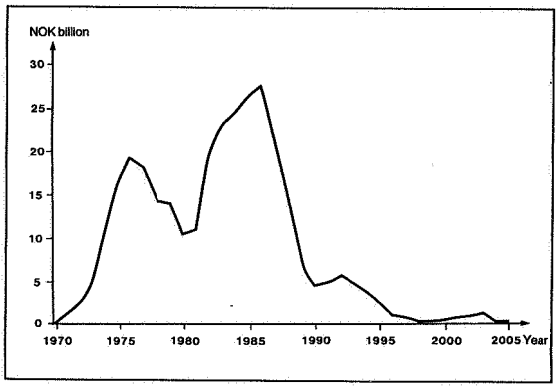
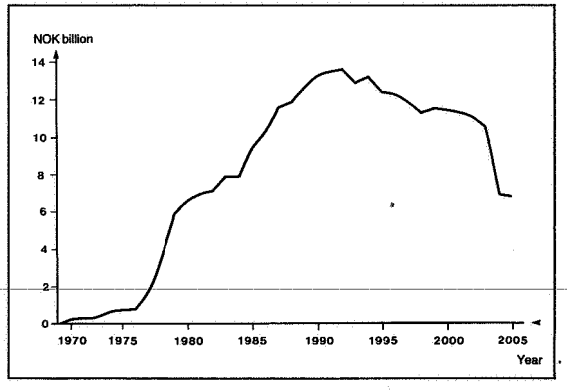


FIG. 5.2.b
Historical and expected operating costs for fields decided to be developed. Fixed 1985 kroner



The Petroleum Act with regulations entered into force on 1 July 1985. As from 1 July 1985, royalties are to be assessed and claimed in pursuance of the royalty provisions of the new laws and regulations. Final guidelines for the various production licenses are in course of preparation.

FIG. 5.2.c
Total exploration costs, investments and operating costs. Fixed 1985 kroner

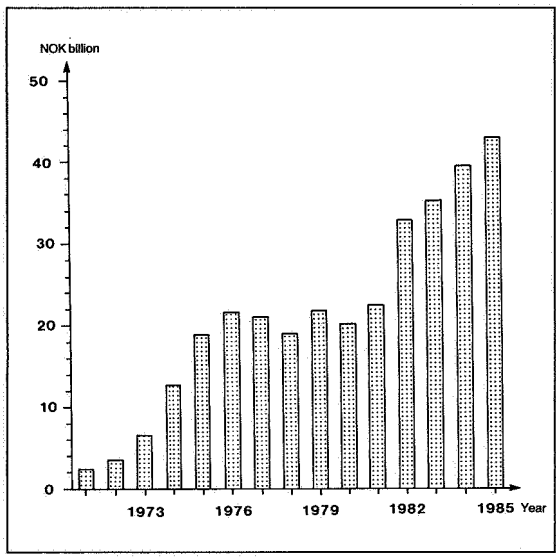
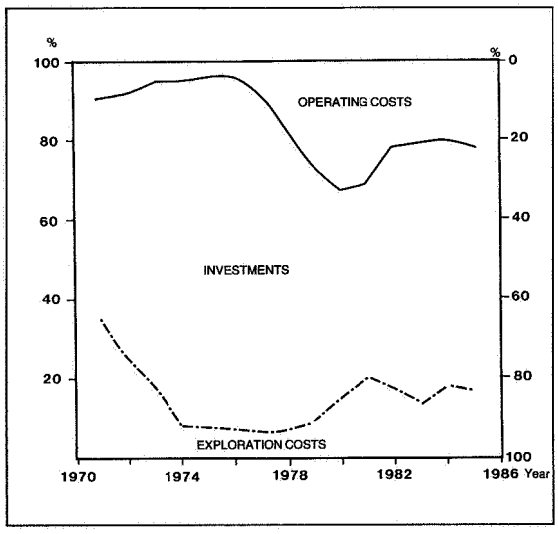


FIG. 5.2.d
Exploration costs, investments and operating costs in per cent of the total market for goods and services



5.3.1 Total royalties

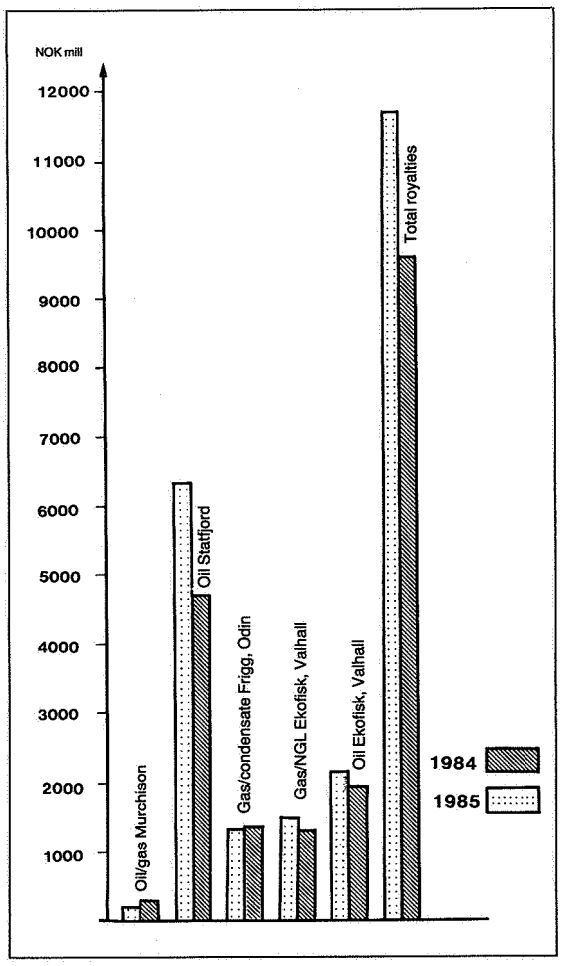
In 1985, a total of NOK 11,625,562,463 were paid in royalties.

Table 5.3.1 shows the distribution of royalties by petroleum product as paid up in 1984 and 1985.

Figure 5.3.1.a presents the royalties paid in 1984 and 1985 per field and in total.

Figure 5.3.1.b shows the paid-up royalties from 1973–1985.

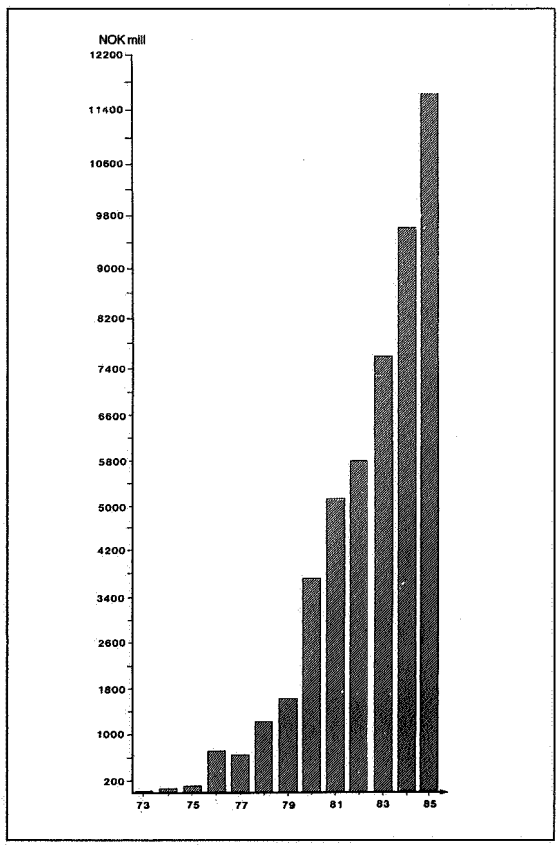
FIG. 5.3.1.a
Royalties 1984–1985



TAB 5.3.1
Royalties in 1984 and 1985 in NOK

	1984	1985
Oil Ekofisk/Valhall	1 924 617 933	2 192 617 514
Oil Statfjord	4 751 366 160	6 334 537 041
Oil Murchison	256 416 694	238 061 138
Gas Murchison	3 096 997	4 464 012
Gas Ekofisk	1 203 476 267	1 330 169 497
Gas Frigg	853 727 113	1 071 219 432
Gas NE-Frigg	53 518 568	54 221 080
Gas Odin	287 174 053	204 281 169
Gas Valhall	34 092 699	58 027 407
NGL Ekofisk/Valhall	104 609 892	113 665 599
Condensate Frigg-area	7 844 370	11 897 250
LPG and NGL Murchison	12 347 157	12 401 324
Recalculation Frigg (gas og condensate)	147 127 463	
	9 639 415 366	11 625 562 463

FIG. 5.3.1.b
Royalties 1973–1985



5.3.2 Royalties on oil

In 1985 the Norwegian Petroleum Directorate received NOK 8,765,215,693 in royalties on oil from Ekofisk, Statfjord and Murchison.

Settlements with regard to crude oil were based in 1985 on the norm price. Royalties were paid quarterly as shown in Table 5.3.2.

TAB 5.3.2
Royalties on oil production

	Ekofisk/ Valhall	Statfjord	Murchison
4. qu. 1984	582 961 131	1 621 696 307	93 912 383
1. qu. 1985	683 215 530	1 513 591 039	91 144 348
2. qu. 1985	559 251 888	1 416 522 367	36 478 050
3. qu. 1985	367 188 965	1 782 727 328	16 526 357
	2 192 617 514	6 334 537 041	238 061 138

5.3.3 Royalties on gas

In 1985 the Norwegian Petroleum Directorate collected NOK 2,722,382,597 in royalties on gas. Table 5.3.3 shows the payments of royalties by company (or group of companies) each quarter.

Gas royalties have been settled on the basis of the contract price. This is different from group to group.

The supply of gas to Dyno and Methanor ceased from 1 July 1984. The amounts refunded to Dyno and Methanor are related to the transport and handling of gas already received and paid for.

The settlement for calculation of the royalties

TAB 5.3.3
Royalties on gas production

	4. qu 84	1. qu 85	2. qu 85	3. qu 85	Total
EKOFISK-AREA					
Phillips gr.	266 389 770	357 467 274	308 599 463	329 478 859*	1 261 935 366*
Dyno/Methanor	– 232 421	– 3 159 549	– 1 105 361	– 1 243 807	– 5 741 138
Shell	16 726 430	15 399 435	13 262 912	11 264 724	56 653 501
Amoco/Noco	3 545 322	4 096 757	4 970 613	4 709 076	17 321 768
Total Ekofisk	286 429 101	373 803 917	325 727 627	344 208 852	1 330 169 497
FRIGG-AREA					
Petronord gr (Frigg)	288 854 591	336 525 970	281 502 881	164 335 990	1 071 219 432
Petronord gr. (NEF)	4 155 032	5 879 427	4 709 201	2 440 698	17 184 358
Petronord gr. (Odin)	6 677 372	4 958 662	4 505 092	5 190 621	21 331 747
Total Petronord gr	299 686 995	347 364 059	290 717 174	171 967 309	1 109 735 537
Esso NEF	7 684 697	13 816 521	11 343 023	4 192 481	37 036 722
Esso Odin	49 292 511	49 546 912	43 832 523	40 277 476	182 949 422
Total Frigg-area	356 664 203	410 727 492	345 892 720	216 437 266	1 329 721 681
VALHALL					
Amoco/Noco	12 918 837	17 080 801	17 110 761	10 917 008	58 027 407
Total Valhall	12 918 837	17 080 801	17 110 761	10 917 008	58 027 407
MURCHISON					
Stat/Mobil	1 059 644	763 547	1 568 754	1 072 067	4 464 012
Total Murchison	1 059 644	763 547	1 568 754	1 072 067	4 464 012
Total all fields	657 071 785	802 375 757	690 299 862	572 635 193	2 722 382 597

* Inclusive payments on advance per 31 December 95 of NOK 73 199 925

from the Frigg area for the Petronord group during the period 1977–1985 has been calculated according to provisional guidelines. At present, detailed rules are being prepared regarding how the deductions are to be effectuated in practice.

5.3.4 Royalty on NGL

In 1985 the amount of NOK 137,964,173 was paid up as royalty on NGL. Table 5.3.4 shows the payments by company or group each quarter.

TAB 5.3.4
Royalties on NGL production

	4. qu 84	1. qu 85	2. qu 85	3. qu 85	Total
EKOFISK-AREA					
Amoco/Noco-gr	402 659	– 58 962	415 454	403 750	1 162 901
Shell	681 017	212 441	255 831	745 425	1 894 714
Phillips-gr	23 324 117	29 178 802	27 230 754	18 975 008	98 708 681
Total Ekofisk	24 407 793	29 332 281	27 902 039	20 124 183	101 766 296
MURCHISON					
NGL (Sullom Voe + Brayf Bay)					
Stat/Mobil-gr	3 851 034	4 756 270	1 795 974	1 998 046	12 401 324
Total Murchison	3 851 034	4 756 270	1 795 974	1 998 046	12 401 324
FRIGG-AREA					
Petronord-gr	1 295 625	2 576 779	3 122 334	183 827	7 178 565
Esso	1 564 570	1 576 099	1 150 508	427 508	4 718 685
Total Frigg	2 860 195	4 152 878	4 272 842	611 335	11 897 250
VALHALL					
Amoco/Noco-gr	2 730 176	1 500 620	2 788 704	4 879 803	11 899 303
Total Valhall	2 730 176	1 500 620	2 788 704	4 879 803	11 899 303
Total all fields	33 849 200	39 742 049	36 759 559	27 613 367	137 964 173

5.3.5 Control of royalties

The Norwegian Petroleum Directorate is responsible for collection and for seeing that payment is made in accordance with the current laws and regulations. This control work is at present subject to further development with a view to improving it and adjusting it to fit the remaining control philosophy of the Directorate. This further development will be based on system audits and spot checks of the companies.

5.4 Acreage fees on licence areas

During 1985 the Norwegian Petroleum Directorate has collected NOK 249,258,074 in acreage fees. The amount is distributed by licence as follows:

Licences announced in 1965:	NOK 131,913,430
Licences announced in 1969:	NOK 56,099,164
Licences announced in 1971:	NOK 4,798,967
Licences announced in 1973:	NOK 8,010,533
Licences announced in 1975:	NOK 9,624,575
Licences announced in 1976:	NOK 7,623,600
Licences announced in 1977:	NOK 1,989,589
Licences announced in 1978:	NOK 2,989,300
Licences announced in 1979:	NOK 12,309,405
Licences announced in 1985:	NOK 13,990,511
	NOK 249,258,074

The Norwegian Petroleum Directorate had refunded NOK 30,357,258 in acreage fees as of 1 November 1985. This represents the deductible part of the acreage fees for production licences 006, 018 and 037 for the period 1 October 1983 to 1 November 1985.

Figure 5.4 shows the paid-up acreage fees for 1973–1985.

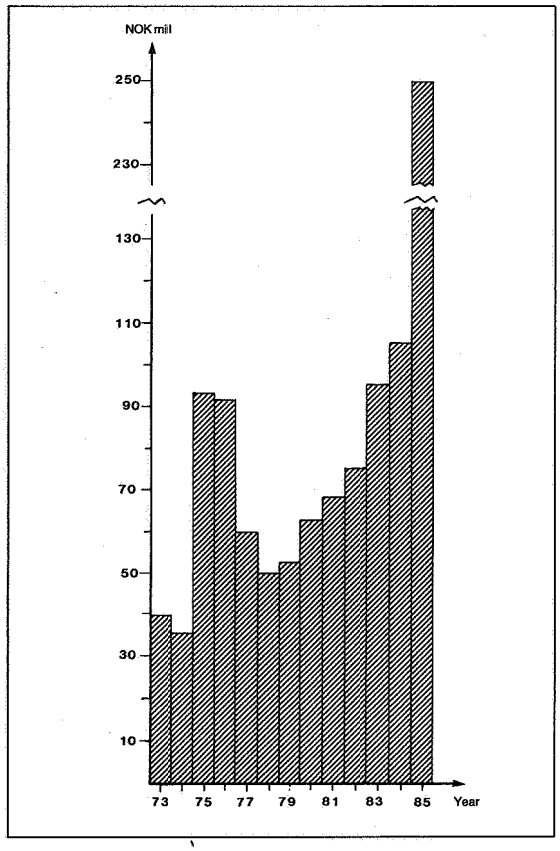
5.5 Sales of petroleum from the Norwegian Continental Shelf

5.5.1 Crude oil

5.5.1.1 Oil consumption trends

Since the beginning of the 1970s, the market for crude oil has undergone major structural changes. On the supply side, a number of countries took over the main part of the production from the giant multinationals, and some of them have coordinated their interests in the organization OPEC. Figure 5.5.1 shows how the consumption development is characterized by significant variations in demand since 1974 as a consequence of the price increase in the 1970s. The consumption is somewhat above the level of 1973, and at the same time the composition of the availability has been altered substantially by a reduction of OPEC's share. In the short run such alterations in the economic activity, together with alterations in stocks, have a direct influence on the current consumption of oil. In the long run the consumption is dependent on structural changes in the production in general, the extent of energy economization and the alternatives at hand.

FIG. 5.4
Area fees 1973–1985



5.5.1.2 Oil availability

During 1973–1985, production has moved in part from OPEC countries to countries outside OPEC. OPEC's share of the total production has fallen from 54.2 per cent in 1973 to approximately 38 per cent in 1985. The reduction in oil consumption has led to a significant over-capacity within OPEC.

Decreasing oil consumption and a consequently large production over-capacity as a result of the price increases in the 1970s led to a continuous pressure on the crude oil price. Notwithstanding, OPEC has for a long time been seeking to sustain the nominal price on long-term contracts by agreeing production quotas with its individual members.

The pressure on the crude oil rate has put OPEC solidarity sorely to the test, especially since its members, based on national interests, have different aspirations with regard to price and production policies. Recent trends tend towards an acceptance of the idea that production quotas have only limited-term effects in the absence of price adjustments. This has been highlighted by the fact that Saudi Arabia has entered into contracts at prices which are determined by the value of the products into which the crude oil is refined. Since the autumn of 1985, the goal has seemed to be to secure market shares, a trend which, in the present situation of production over-capacity, has added further pressure to the downward movement of the price level.

5.5.1.3 Sale of crude oil from the Norwegian Continental Shelf

In 1985, the total shipments from the Norwegian Continental Shelf amounted to 37.17 million tons. This represents an increase of approximately 10 per cent in relation to 1984. Great Britain still receives

FIG. 5.5.1.a
The composition of the world's oil production

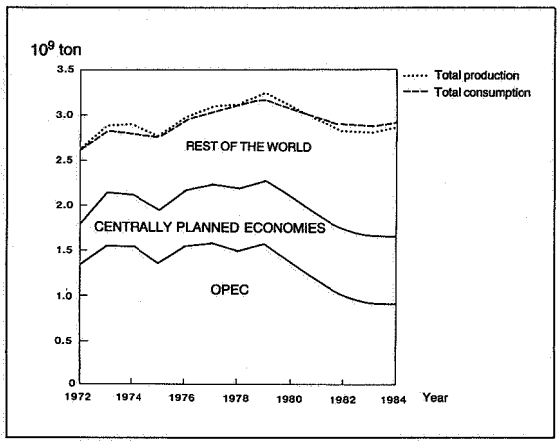
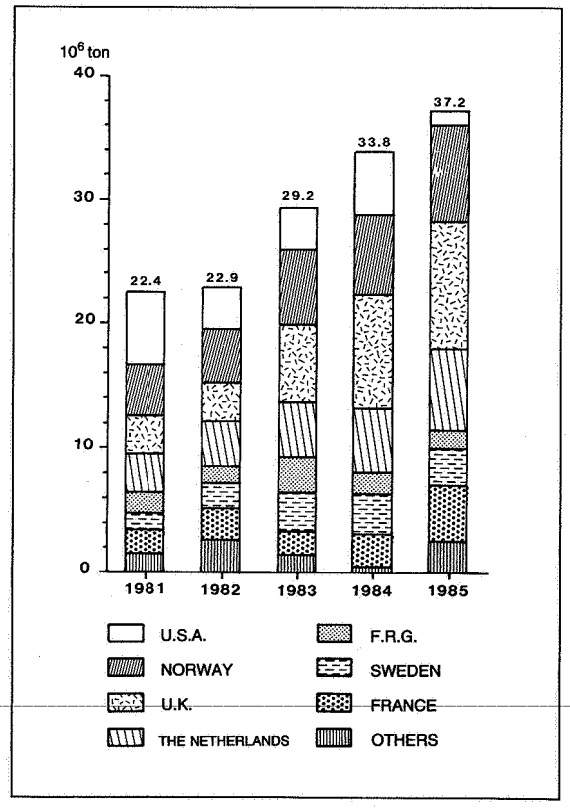


FIG. 5.5.1.b
Sale of crude oil from the Norwegian Continental Shelf



the bulk of the shipments, over 27 per cent. Norway comes next with 21 per cent. The Netherlands and France increased their shares of the shipments to 17.5 and 12.2 per cent respectively. Shipments to the USA fell significantly to approximately 3 per cent (Figure 5.5.1.b).

In 1985, the aggregate shipments of natural gas liquids (NGL) from the Norwegian Continental Shelf constituted approximately 1.43 million tons, an increase of about 11 per cent compared to 1984. The main receiver countries were Norway (54 per cent), Great Britain (16 per cent) and the Netherlands (15 per cent). In addition, 0.1 million tons of condensate were sold.

Figure 5.5.1 shows the principle oil companies sales of crude oil in 1985.

5.5.2 Gas

5.5.2.1 The gas market

As opposed to oil and with few exceptions, gas has only regional markets. This is due to the fact that gas requires an extensive and expensive transportation network, a fact which in turn has consequences for the market structure and the formulation of sales contracts. Gas can only be transported to more distant markets when refrigerated to liquid natural gas (LNG).

Great Britain, West Germany, the Netherlands, Italy and France represent the main consumers. Since 1980, there has been plenty of gas available in Europe to cover the consumption which, following a dip in 1980, recovered to 190 million toe in 1984.

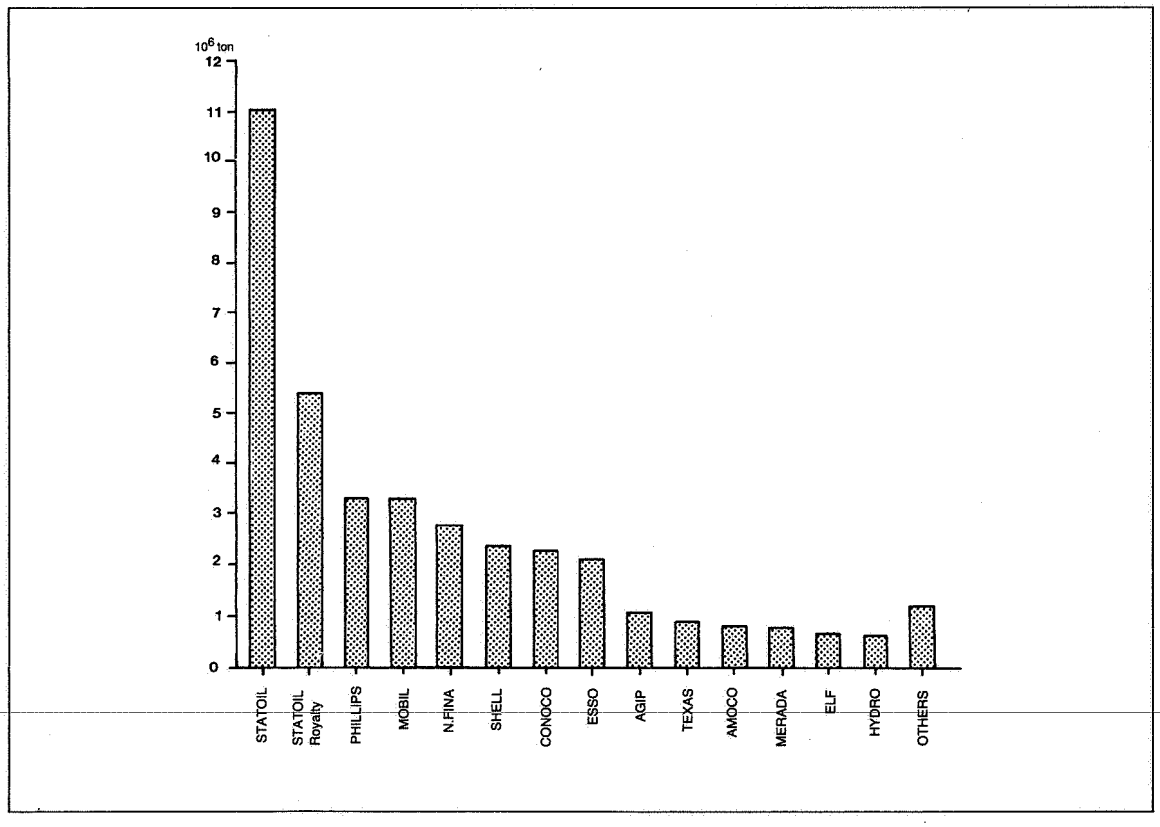
The main producers in Western Europe are represented by Great Britain which produces for its domestic market only, the Netherlands which distributes its production with approximately equal shares to the domestic market and for export, and Norway which produces for the export market only.

The international gas trade in Western Europe is still dominated by the Netherlands, which distributes its deliveries among large parts of the West European market. The Soviet Union has increased its export substantially since 1980 and exports to all major consumer countries except Great Britain and the Netherlands. Algeria exports to France and Italy in particular.

The most important markets for Norway today are Great Britain and West Germany. In both countries, there is a significant consumption of gas within housekeeping and the industrial sector. In addition, West Germany consumes appreciable quantities of gas for power generation.

As a result of the over-capacity on the supply side the increase in gas consumption is determined by

FIG. 5.5.1.c
Sales quantities of oil/NGL as per licensee in 1985



the competetive position of gas versus other energy sources. In the future, the consumption will still depend on the competitive position in the industrial sector, the housekeeping sector and the energy sector in addition to the general development of the energy consumption.

5.5.2.2 Sale of gas in 1985

In 1985, Norwegian gas was sold to Great Britain (13.66 billion Sm^3), West Germany (6.07), the Netherlands (1.84), Belgium (1.83) and France (1.95) (Figure 5.5.2.a). The total 1985 gas export amounted to 25.34 billion Sm^3. This was a decrease of 3 per cent in relation to 1984.

In 1985, the gas deliveries were still being made from the Ekofisk and Frigg area. The sale of gas from the Ekofisk area has declined by approximately 12 per cent from 1984 to 1985 as a consequence of the use of gas for injection purposes. The sale of gas from the Statfjord field began in October.

Figure 5.5.2.b shows the distribution of gas sales for the most important companies in 1984.

FIG. 5.5.2.a
Sales quantities of gas as per country

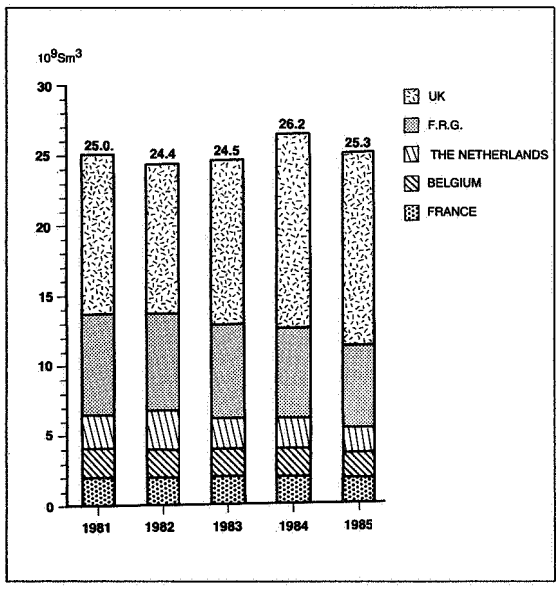
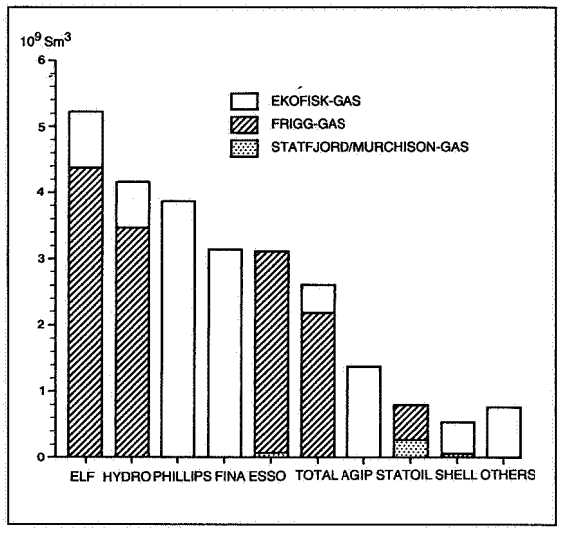


FIG. 5.5.2.b
Sales quantities of gas as per licensee in 1985



6 Special reports and projects

In 1985 the Norwegian Petroleum Directorate granted a total sum of NOK 31,388,381 for special projects. This amount is distributed on the basis of NOK 2,080,583 for Safety Control Division projects; NOK 13,070,061 for projects under the auspices of the Resource Management Division; and NOK 933,656 for organization studies and the INFOIL project under the wings of the Administration Department. In addition, the sum of NOK 4,316,048 has been granted for the North Sea seabed clearance project. The Norwegian Petroleum Directorate also administers the weather ship project in the Barents Sea, where NOK 11,668,097 was made available. The various project titles and the executive institutions are listed below. In addition, some of the projects are discussed separately.

6.1 Resource Management Division

A state-funded program for research and development within enhanced oil recovery (EOR) and reservoir technology abbreviated SPOR was initiated in 1985 and granted the sum of NOK 9.8 million that year. The intention is for the program to stretch over a five year period with a total grant of NOK 100 million during its lifetime.

A separate executive committee chaired by the Resources Director is responsible for professional and economic priorities within the program, and a secretariate located in the Norwegian Petroleum Directorate is in charge of the daily follow-up and coordination. A technical council with members from the oil industry and the education sector has been appointed as a consultative body.

During 1985, the technical content and organization of SPOR was planned, and the main areas of concentration with regard to competence build-up and research were defined. Three Norwegian research milieux have been awarded tasks within the main areas of concentration:

Main area	Project Execution agency	Planned percaentage of total means
Optimalization of reservoir data (SPOR-OPT)	Institute for Energy Technology (IFE)	20 per cent
Gas injection (SPOR-GASS)	Institute for Continental Shelf Studies (IKU)	30 per cent
Water injection (SPOR-VANN)	Rogaland Research Institute	35 per cent

Various projects within the main areas were implemented in 1985, which according to plan will continue during the program period. In addition to the sub-areas mentioned above, there will be room for special projects which do not naturally fall under any of them. The grant to SPOR for 1986 constitutes NOK 15 million.

6.1.1 Resource Exploration Department

Project title	Project execution agency
Further refinement of the resources estimation program	Institute for Energy Technology (IFE)
Calcite cementation study	IFE and Rogaland Research Institute
Software development	UNIRAS
Consultancy services in petro-physics	Schlumberger
Development of data base for resources accounts	Christian Michelsens Institute (CMI)
Bio-stratigraphy project	University of Bergen
Computer program for processing of bio-stratigraphic data	F.J. Phillips, USA

6.1.2 Resource Exploitation Department

Project title	Project execution agency
Area plan, Haltenbanken II	Norwegian Petroleum Consultants (NPC)
Area plan, Oseberg	NPC
Area plan, Troms	Kværner Engineering A/S
Area plan, the 34-area	Aker Engineering A/S
Cost estimation model	Compas Consultants
Regularity study	R. Moss Consultants
Feasibility study, Hod	Kværner Engineering A/S
Pilot study for mini-methanol plant	NPC
Nitrogen study	Kværner Engineering A/S
Company evaluation	Business Economics Institute (BI)
Enhanced Oil Recovery (EOR) production equipment	Oil Plus
Reservoir simulation, Troll Part III	Franlab
Reservoir simulation, Troll Part IV	Franlab
Selection of optimal processing pressure Troll	Kværner Engineering A/S
Separate oil production from an offshore platform	Parsons
Increased competence build-up within EOR	Institute Francaise du Petrole (IFP)
Development of software for RDRS reservoir data base	Institute for Energy Technology (IFE)
Simulation of the Statfjord field (Brent reservoir)	IFE
Haltenbank project (technical reservoir evaluation)	Franlab
Help with internal simulation of Valhall	Franlab
Routines for handling of testing and completion programs	IPEC

Area studies

In 1985, area studies for four areas on the Norwegian Continental Shelf have been carried out for the Norwegian Petroleum Directorate. These are areas on which several operating companies have been awarded different blocks, and where the Norwegian Petroleum Directorate holds that the development of the individual blocks must be considered in a larger context. The purpose has been to evaluate possible reductions of costs through the joint use of transport systems and processing plant. The studies have been carried out by external consultants as detailed in the table above. The results of the studies have been presented to the operators in "work-shops" where the operators in turn have stated their opinions of the coordination possibilities.

The studies show that joint development and operation may reap cost savings. The cooperation with consultants has provided the individual executive officer with a useful basis for an evaluation of possible field development plans for the different fields.

Cooperation on chalk reservoir research

In May 1985, a so-called chalk symposium was arranged in Stavanger. This marked the preliminary summit of a research program that has been going on for a number of years, and whose results were presented at this symposium and summarized for the participating companies and institutions.

The reason for the interest is that the limestone in the southern part of the North Sea, which stretches incidently into the Danish side as well, makes for oil reservoirs that are almost unique in a world context. Therefore, extensive research was necessary in order to elucidate the properties of this particular limestone. The Norwegian Petroleum Directorate originally played a very active role in arranging cooperation on this matter between the oil companies and the research institutions in question. The outcome was a success, and the project was sub-divided into five component units, each having its own consultative committee with members from the participating companies, and each consultative committee being subordinate to an executive committee. One of the sub-projects will continue throughout 1985, whereas the others were completed at the symposium in May.

The sub-projects have dealt with geological descriptions of the rock, the effect of water injection in core plugs, the mechanical properties of the rock in general and around production wells in particular, and well stimulation methods.

The following companies have participated in the project: Fina Exploration Norway, Norsk Agip A/S, Phillips Petroleum Company Norway, Amoco Norway Oil Company, Texas Eastern Norway, Total Marine Norsk A/S, Elf Aquitaine Norge A/S, Amerada Hess Norway Ltd, Norsk Hydro A/S, Statoil, Den Danske Energistyrelsen and the Norwegian Petroleum Directorate. The participants have partly done research under their own direction and partly employed research institutions in Norway and abroad. Expenditures amounted to approximately NOK 17 million and were distributed equally among the ten participating oil companies.

This type of cooperation by a broadly based

group of participants consisting of different licensees must be characterized as fairly unprecedented within the oil industry, and the results will undoubtedly benefit the activity on the Norwegian Continental Shelf. Since there are still tasks that remain to be solved, a possible continuation of the project will be considered in the beginning of 1986.

6.1.3 Resource Economics Department

Project title	Project execution agency
Alternative applications of gas	Asplan Analyse a.s
Further development of the portefolio model	Foundation for Scientific and Industrial Research at the University of Trondheim/SINTEF
Model system for integrated, stochastic prospect evaluation	Christian Michelsen's Institute (CMI)
Revision, maintenance and further development of MECCA	CMI
Price and market analysis for petroleum	CMI
Development of report generator for PPRS	Rogaland Research Institute

Model system for stochastic prospect evaluation
During 1985, the Norwegian Petroleum Directorate has developed a model with Christian Michelsens Institute that makes it possible to run a financial profitability and risk evaluation of prospects and fields at an early stage.

The model assimilates the geological, technical and economic data available and also takes into consideration the existing uncertainty inherent in these input factors.

The model comprises a reserves estimation model and a production and current value model.

Reserves estimation model: On the basis of existing geological and geophysical information, with the appropriate uncertainties, a resource distribution for the individual oil and gas prospects is calculated by means of simulation.

Production and current value model: Based on the distribution of resources, a new simulation is carried out. For each selection, production and cost profiles are generated for a predetermined number of development solutions, if appropriate. By means of price profiles, the current value is calculated, and the development solutions with the highest current value are selected. This is done for all selections, thus creating a current value distribution.

This current value distribution forms the basis for the profitability and risk evaluation of individual oil and gas prospects.

Alternative uses of gas
The market situation for Norwegian gas in Europe has made it necessary to strengthen the Directorate's involvement in market analyses. Market calculations will improve our opportunity to exploit time-marginal fields and associated gas, among other things, and will contribute greatly to better management of the resources on the continental shelf. Through a study of the alternative uses of gas, Asplan Analyse has surveyed new sales possibilities and has correlated these with the development situation on the continental shelf.

The main market segments which have been analysed are as follows:

- electricity production
- industrial applications
- direct distribution within ordinary energy supply.

The estimates of gas value have been based on the costs of competing products. After the costs of transport and production plants based on gas have been deducted, a payment willingness for gas refered to the platform on the continental shelf is obtained.

The greatest potential has been found within the power markets in Norway and Sweden. But there may be possibilities for Norwegian exports of gas to Denmark, West Germany and the United Kingdom too. For the continental markets, the transport costs will be significant and result in a very low value for the gas.

Methanol and ammonia are the most interesting products as regards industrial gas applications. In the longer term, both substances may be of interest on both onshore and offshore installations.

Although direct distribution of gas in Scandinavia would be very profitable, as a direct market for gas from the Norwegian Continental Shelf it is limited.

The efforts to find alternative applications of gas are coordinated by the Ministry of Petroleum and Energy.

6.2 Safety Control Division

Project title	Project execution agency
M/S "Endre Dyrøy" – research vessel	Oceanor
Further development of Drilling Data Bank	Rogaland Research Institute
Participation in the Fatigue Program	Foundation for Scientific and Industrial Research at the University of Trondheim/SINTEF
Membership – Welding Institute	Welding Institute
Membership – Ciria Ueg	Ciria Ueg
Flexible hoses, pipes and pipelines in hydrocarbon systems	Det norsk Veritas and A.S. Veritec
Support to the Norwegian Association of Electrical Engineers for participation in international standardization work for regulations for electrical installations	Norwegian Association of Electrical Engineers' Technical Committee (NEK)
Acceptance criteria – fire barriers	SINTEF
Evaluation of new equipment, new technologies within drilling and other well activities	Norwegian Petroleum Directorate (NPD)
Revision of guidelines for safety related evaluations of platform concepts	SINTEF
Technical and operational problems in connection with diving at great depths	H.V. Hempleman
Revision, guidelines, steel structures	A.S. Veritec
Illumination of production installations	EFI
Study of operational availability	A.S. Veritec
Marine Growth Data Bank – Veritec	Det norske Veritas
Statistics – personal injury preventive measures	A/S Quasar Consultants
Guidelines, shallow foundations, Institute of Geotechnology	Noteby
Evaluation of acceptance criteria for drilling equipment	Norsk Hydro
Regulations concerning collection and storage of environmental data	NPD

6.3 Legal Department

Project title	Project execution agency
Automatic sampling of crude oil, Phase 3	National Engineering Laboratory (NEL), Scotland
Density determination of natural gas under operating conditions, Phase 2	Rogaland Research Institute
Inspection requirements for orifice plates	NEL

6.4 Administration Department

Project title	Project execution agency
Clearing up North Sea seabed	Norwegian Petroleum Directorate (NPD)
Infoil II	Norwegian Centre for Informatics
Consultancy services, organizational study	IKO Management

Clearing up the North Sea seabed

The Norwegian Petroleum Directorates clearing up of the North Sea seabed took place in 1985 on a 770 square kilometer area on Viking Bank in Block 31/4 and parts of Block 30/6. The choice of area was based on recommendations by the fishermens organizations and the fishery authorities, who also suggested that methods other than trawling should be used this year. After the area had been surveyed by side scan sonar, the obstructions discovered were further identified by submersible vehicles. Dynamically positioned vessels and remotely controlled sub-

mersibles were then used to remove any objects that could be expected to obstruct efficient fishing in the vicinity.

In addition to the area stated above, 21 steel pipes weighing a total of over 30 tons were recovered from the Egersund bank during the last phase of the clearance work. Some 200 similar pipes are still lying in the same area.

The firm of Bergen Underwater Services A/S was responsible for the job which was estimated to cost NOK 4.5 million in 1985. During the planning of the clearance operation, the Norwegian Petroleum Directorate cooperated closely with the Hydrographic Survey of Norway which is using the data collected in its chart-drafting work. The executive committee for the clearance action, which consists of representatives from the Directorate of Fisheries, Norwegian Fishermens Association and Norwegian Industry Association for Oil Companies (NIFO), has concluded that the 1985 efforts were a success and that implementation should be carried out in the same way next year.

7 International Cooperation

7.1 Aid to foreign countries

In 1985, the Norwegian Petroleum Directorates engagement through NORAD was concentrated mainly in Tanzania and Mozambique. In both these countries, the Directorate was primarily involved in providing assistance in 1) general data processing, 2) storage and processing of seismic data tapes, 3) data interpretation, 4) instruction by consultancy firms (GECO and ECL) during interpretation tasks, 5) planning and management of gravimetric and/or seismic surveys (paid by NORAD) with a view to making areas ready for licence allocation and 6) instructing NORAD supported advisers in the two countries. An exploration adviser from NORAD took part in a briefing conference in the Norwegian Petroleum Directorate in 1985. Later on, the person in question was stationed in Tanzania.

A detailed survey of the "Basin Development on the East Coast of Africa and in the Western Part of the Indian Ocean" was carried out by the Norwegian Petroleum Directorate in 1985. This report forms the groundwork for the planning of future NORAD assistance within the exploration sector in the countries in this area. A previously unknown feature, the Rovuma Basin in Tanzania, was discovered as a result of this survey. Gravimetric surveys financed by NORAD in Rovuma were planned, implemented and interpreted by the Norwegian Petroleum Directorate. Seismic surveys will soon be carried out in the Rovuma Basin, and the Directorate has now finalized plans for data collection. The Directorate will also assist in the implementation of the surveys and the interpretation of the results.

Results of the same regional survey led to a decision to gather seismics in shallow waters in an area in Mozambique. These surveys, which were carried out earlier this year in the Beira Bay, led to the identification of a large structural prospect - among the largest in East Africa.

The Norwegian Petroleum Directorate has also interpreted a substantial amount of seismic data from the Tanzania-Ruvu and Selous Basins, an accomplishment that contributed to an effecient implementation of a major interpretational project carried out by GECO (and financed by NORAD).

The Norwegian Petroleum Directorate carried out a thorough evaluation of the Exploration Division of Tanzanias national oil company. This made it possible to formulate a program for improvement of work efficiency in the company. This program will be implemented with support from NORAD in 1986.

Other NORAD projects which the Directorate was involved in include:

a) India
Collection of details for the planning of NORAD assistance to the Institute of Ocean Engineering and Technology, which has been established by Indias national oil company (ONGC).

b) Nepal
Collection of details for the planning of NORAD assistance in the petroleum sector to the Nepalese government, including concrete aid in connection with ongoing licence negotiations, construction of a functional organization, establishment of follow-up routines and providing advice with regard to the overall structure of laws and regulations.

c) Seychelles
Evaluation of regional geology in order to plan NORADs future assistance, as well as storage of 14,000 kilometers of seismics.

d) Jamaica
Collection of details in order to evaluate the exploration status, as well as the planning and implementation of NORAD supported seismic surveys.

e) Angola
Collection of information in order to evaluate the possibilities of NORAD assistance within the petroleum sector.

f) Botswana
Assisting the government in formulating a proposal for an acceptable work schedule and sensible relinquishment rules in connection with the allocation of licences.

g) Bangladesh
Despite delays, this project is set to be a major undertaking for the Norwegian Petroleum Directorate in 1986. Directorate personnel will continue gathering and evaluating geological data from the area in preparation for the 1986 project.

In 1985 too, the Norwegian Petroleum Directorate has functioned as main storage location for geological data from Tanzania and Mozambique. The Directorates geophysical files have been used by Tanzania for copying and duplication of many kinds of data, including seismic data tapes, for example.

The Norwegian Petroleum Directorates drawing office and in-house print shop have been used to produce a large number of maps, figures and reports during the preparation of the individual NORAD projects.

All in all, Directorate officials in charge of the various NORAD projects have carried out work which corresponds to just above 2.9 man-years. In addition come office tasks, data storage, etc, amounting to about one man-year.

7.2 The European Diving Technology Committee EDTC

The EDTC includes members from 13 countries in Europe and each member country is, among other things, represented by a member from its national authorities. The objective of the organization is to give recommendations to member countries in matters relating to the safety of divers. The Norwegian Petroleum Directorate's representative is the chairperson of the organization for the present two-year period.

7.3 The Association of Diving Contractors AODC

In association with the Norwegian Petroleum Directorate, AODC Norge arranged a conference in Stavanger at the end of 1985. The issues dealt with by the conference were to a great extent related to diving at great depths.

7.4 CIRIA/UEG

In 1980, the Norwegian Petroleum Directorate became a member of CIRIA/ UEG of the United Kingdom. CIRIA is a research and information institute which performs a great number of significant research projects in connection with the petroleum industry. The research assignments have been very relevant for the areas of responsibility and work tasks allocated to the Safety Control Division. The professional cooperation which has been established and the fund of information that CIRIA represents have been of great help, among other things in safety reports and regulation work for the Norwegian Continental Shelf.

7.5 Regulatory cooperation with CCOP/ASCOPE/ NECOR

The Norwegian Petroleum Directorate participates in a program for the development of safety regulations under the direction of CCOP/ASCOPE/NECOR. A work seminar was held in October with the participants from Thailand, Malaysia, Indonesia, the Philippines and China.

The objective of the seminar was to give an introdution to the Norwegian philosophy regarding the development of safety regulations. In addition, plans were made for the further development work with regard to regulations in the individual participating countries.

A work schedule has now been prepared which spans over five years and which involves that the individual countries will formulate laws and regulations within the areas of highest priority. The Norwegian Petroleum Directorate will participate in this work with specialists in the individual fields in order to help bring the program to a successful close.

7.6 Welding Institute

The Norwegian Petroleum Directorate has been a member of the Welding Institute since 1981. This welding institute is a leader in the offshore area and is very active within research, education and consultancy services. Membership opens the door for consultancy assistance, project participation, and current information on the most recent findings within materials and welding technology.

7.7 The International Standardization Organization ISO

The Norwegian Petroleum Directorate participates in the work of technical measurement standardization carried out by the International Standardization Organization, ISO. International standards form the basis for the measurement of oil and gas. In order to make a contribution to the further development of international standards, the Norwegian Petroleum Directorate participates on the technical committees dealing with standards for the measurement of oil and gas. To render our national work in this area more effective, a Norwegian Measurement Technology Forum has been formed in which the Norwegian Petroleum Directorate participates. This Forum was responsible for the implementation of an international meeting of the ISOs technical committee in Stavanger (TC30/SC2). In 1985, the Norwegian Petroleum Directorate participated in a total of four meetings in this field.

8 Statistics and Summaries

8.1 Units of measurement

The Norwegian Petroleum Directorate normally utilizes 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 concepts and expressions for abbreviations occur in connection with production data for oil and gas and have connection with the units of measurement. Some of these are briefly mentioned 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 degrees F, 0 psig and b) 15 degrees C, 1.01325 bar.

Pressure and temperature standards other than these may also occur. One should note 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 (see Section 8.2). 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 degrees F, 0 psig corresponds approximately to the volume at 15 degrees C, 1.01325 bar.

Ordinary units/abbreviations

Sm^3 = standard cubic meter. 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 degrees 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 degrees F, 14.73 psia), b) (60 degrees F, 14.696 psia), c) (15 degrees C, 1.01325 bar), d) (0 degrees 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 meter
Nm^3 =	Normal cubic meter
Scf (Scuft) =	Standard cubic feet

Temperature and pressure references must be given for the unit to be unambigious.

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 degrees F
The relative density of oil in relation to water. Oil and water at temperature 60 degrees F and pressure corresponding to atmospheric at the place of measurement. The figure is undenominated.

(b) API gravity at 60 degrees F
Specific Gravity 60/60 degrees F expressed

on an enlarged scale. Units are degrees API. Conversion by this formula:

$$\text{API gravity at 60 degrees F} = \frac{141.5}{\text{Spec. Grav. 60/60 deg. F}} - 131.5$$

(c) Density at 15 degrees C
Absolute density at temperature 15 degrees 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.

Registration 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 note 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 Standard reference conditions

Here follows the Norsk Standard NS 4900 – ISO 5024, Standard Reference Conditions, prepared by the Norwegian Standardization Organization (NSF) and reproduced by agreement with the NSF:

– Petroleum, liquid and gas
– Measurement
– Standard reference conditions

The standard contains the English version of the International Standard ISO 5024-1976 and a Norwegian translation. If not otherwise agreed the Norwegian text is binding.

0) Introduction

For many years the results from measurements carried out on petroleum and petroleum products in international trade have been corrected to atmospheric pressure and 60 degrees F.

The global tendency to exclusively use the international system for units of measurement (SI) requires that pressure and temperature are stated in these units. At the same time one is trying to retain the habitual values as far as this is possible.

The hope is that the stipulation of one set of common standard reference conditions will simplify the requirements set by world trade.

1) Orientation and validity

The standard stipulates standard reference conditions for pressure and temperature for measurements carried out on both liquid and gaseous petroleum and its products.

2) Standard reference conditions

The standard reference conditions for pressure and temperature for use in connection with measurements of both liquid and gaseous petroleum and its products shall be 101.325 kPa* and 15 degrees C except for liquid hydrocarbons with a vapour pressure higher than atmospheric pressure at 15 degrees C. In this case the standard pressure should be the equilibrium pressure at 15 degrees C.

8.3 Exploration and appraisal drilling on the Norwegian continental shelf

From the start of exploration activities for petroleum in the Norwegian sector of the North Sea in 1966 until 1 January 1986, a total of 497 exploration wells were spudded on the Continental Shelf. Of these 395 were exploration holes and 138 appraisal wells. As of the same date, 461 had been concluded. Information from these wells is tabulated to illustrate some features of the activities.

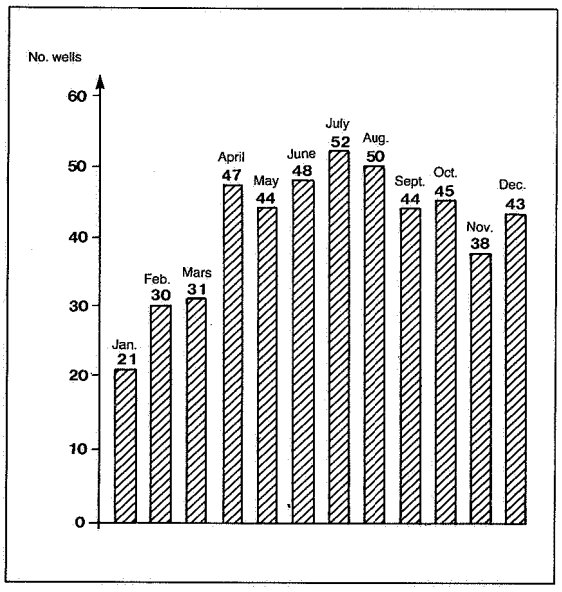
Twenty-five wells have been suspended (for reasons such as later testing, possible completion as production wells or further drilling or later plugging), and 11 are currently being drilled. The wells have been drilled by 18 different operating companies. In 1985, 50 wells were spudded, of which 29 are exploration wells and 21 appraisal wells. These were drilled by ten operating companies, of which three were Norwegian. The Norwegian companies drilled 35 wells, or 70 per cent. Furthermore, three suspended wells were re-entered in 1985 for further operations, two of which have now been concluded.

Twenty-three of the wells spudded in 1985 were drilled north of the 62nd parallel, seven on Troms and 16 on Haltenbanken.

A total of 28 blocks were drilled in, of which 13 are in the south, six in Troms and nine on Haltenbanken. During the year 43 wells were concluded, while 11 were suspended. As per 1 January 1986, a total of 1,559,526 metres had been drilled in the wells concerned, of which 143,473 metres were accomplished in 1985.

*) Note that 101,325 kPa = 1,013 25 bar - 1013,25 mbar = 1 atm.

FIG. 8.3.a
Seasonal variations in drilling activity 1966–1985



The average total depth of the 43 wells finalized in 1985 was 3208 meters, and the average water depth was 235 meters.

For drilling operations on the Norwegian Continental Shelf a total of 61 different drilling rigs were employed, five of them under two different names. Of the total, 44 are semi-submersibles, eleven are jack-ups, four are drill ships and two are fixed installations. In 1985, a total of 20 drilling vessels operated on the Norwegian Continental Shelf. Five of these started drilling on the continental shelf in the course of the year, namely "Dyvi Stena", "Henry Goodrich", "Treasure Hunter", "Vinni" and "Polar Pioneer". All five are semi-submersibles. Three drilling vessels left the continental shelf in 1985, namely "Treasure Seeker", "Glomary Moray Firth I" and "Le Pelerin". In addition, "West Vanguard" has been taken out of operation following an explosion and fire caused by a shallow gas blow-out.

The deepest bore on the Norwegian Continental Shelf is Well 30/4-1 which is operated by British Petroleum. Drilling here was initiated in November 1978 and concluded in March 1979 at a depth of 5430 metres.

The greatest depth of water drilled in so far is 391 meters for Well 34/2-4, with Amoco as operator.

TAB 8.3.a
Spudded wells

YEAR SPUDDED	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	TOTAL
EXPLORATION WELL	2	6	10	12	11	11	11	17	13	17	20	12	14	18	26	26	36	33	35	29	359
APPRAISAL WELL			2	1	6	5	3	5	5	9	3	8	5	10	10	13	13	7	12	21	138
TOTAL EXPLORATION DRILLING	2	6	12	13	17	16	14	22	18	26	23	20	19	28	36	39	49	40	47	50	497
PRODUCTION WELL								1	18	24	7	34	50	36	27	16	22	23	33	47	338
TOTAL NO OF WELLS	2	6	12	13	17	16	14	23	36	50	30	54	69	64	63	55	71	63	80	97	835

TAB 8.3.b
Monthly activity on the Norwegian shelf 1985

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
Drilled at year-end	1984/85													12 wells	
Spudded	1985	2	5	5	3	5	4	4	6	2	5	4	5	50 wells	
Re-entries	1985							1				1	1	3 wells	
In progress	1985														65 wells
Completed	1985	3	6	3	2	4	4	3	5	5	3	3	2	43 wells	
Suspended	1985	1				1	1	2	1			3	2	11 wells	
Abandoned	1985														54 wells
Drilling under progress															11 wells
Rig days: Foreign		62	59	37	30	31	30	35	56	30	53	40	30	493	12.2 %
Rig days: Norwegian		248	213	287	328	365	235	352	351	304	268	274	319	3544	87.8 %
Rig days: Total		310	272	324	358	396	265	387	407	334	321	314	319	4037	100 %

TAB 8.3.c
Rig days per rig on the Norwegian shelf

Drilling rig	1. quarter	2. quarter	3. quarter	4. quarter	Total
Borgny Dolphin	33	46	74	78	231
Byford Dolphin	23	82	86	90	281
Deepsea Bergen	8	76	48	9	220
Dyvi Delta	90	90	92	89	361
Diva Stena	8	91	88	91	278
Glomar Modray Firth I	65				65
Henry Goodrich				30	30
Neddrill Trigon	42		65	55	162
Nortrym	86	88	76	56	306
Polar Pioneer				74	74
Ross Isle	84	78	90	86	338
Treasure Hunter				48	48
Treasure Saga	90	73	89	91	343
Treasure Scout	79	76	92	83	330
Treasure Seeker	89	79	82		250
Vildkat	2		12		14
Vinni				1	1
West Vanguard	67	77	90	3	237
West Venture	10	72	88	62	232
Zapata Ugland	51	91	56	38	236
	906	1019	1128	984	4037

TAB 8.3.d
Rig days per quarter 1966–1985

Year	1. quarter	2. quarter	3. quarter	4. quarter	TOTAL per. year
1966			74	85	159
1967	90	91	168	191	540
1968	144	334	286	244	1008
1969	211	224	268	114	817
1970	64	167	424	286	941
1971	179	180	286	198	843
1972	172	363	560	372	1467
1973	142	205	309	461	1117
1974	490	462	339	367	1658
1975	267	468	523	411	1669
1976	646	451	536	323	1956
1977	225	296	532	564	1617
1978	371	436	474	342	1623
1979	464	548	653	757	2422
1980	936	892	1022	1027	3877
1981	1030	933	1000	1068	4131
1982	1081	1192	1075	1028	4376
1983	1084	920	944	952	3900
1984	943	1044	1193	1053	4233
1985	906	1019	1128	984	4037
	9445	10225	11794	10827	42391

TAB 8.3.e
Exploration wells per operator

STATOIL	110	wells
NORSK HYDRO	67	«
PHILLIPS	52	«
ESSO	47	«
ELF	44	«
SHELL	39	«
SAGA	36	«
AMOCO	33	«
CONOCO	19	«
MOBIL	18	«
BP	17	«
GULF	6	«
MURPHY	4	«
SYRACUSE	1	«
UNION	1	«
AGIP	1	«
TEXACO	1	«
TOTAL	1	«
	497	wells

TAB 8.3.f
Exploration wells spudded in 1985

STATOIL	19	wells
NORSK HYDRO	10	«
SAGA	6	«
SHELL	4	«
ELF	4	«
CONOCO	3	«
ESSO	1	«
BP	1	«
AMOCO	1	«
TOTAL	1	«
	50	wells

TAB 8.3.g
Average water depth and total depth

Year	Average water depth (m)	Average total depth (m)
1966	110	2 737
1967	93	2 599
1968	75	3 495
1969	70	3 143
1970	89	2 983
1971	82	3 101
1972	79	3 712
1973	86	3 089
1974	109	3 078
1975	109	2 954
1976	124	2 949
1977	94	2 719
1978	109	3 502
1979	153	3 375
1980	176	3 115
1981	181	3 235
1982	162	3 314
1983	201	3 155
1984	213	3 116
1985	235	3 208

TAB 8.3.h
Drilling rigs that have been operating on the Norwegian Continental shelf

Name of drilling rig	No. of wells	No. of re-entries	Type of rig
Aladdin	1		Semisubmersible
Borgny Dolphin (formerly Fernstar)	23	6	«
Borgsten Dolphin (formerly Haakon Magnus)	6		«
Byford Dolphin (formerly Deepsea Driller)	14		«
Chris Chenery	2		«
Deepsea Bergen	12	1	Semisubmersible
Deepsea Driller (now Byford Dolphin)	8		«
Deepsea Saga	17	3	«
Drillmaster	6	1	«
Drillship	1		Drillship
Dyvi Alpha	17	2	Semisubmersible
Dyvi Beta	7	1	Jack-up
Dyvi Gamma	1		«
Dyvi Delta	11	1	Semisubmersible
Dyvi Stena	2		«
Endeavour	2		Oppjekkbart
Fernstar (now Borgny Dolphin)	3		Semisubmersible
Haakon Magnus (now Borgsten Dolphin)	2		«
Gulftide	3		Jack-up
Glomar Biscay II (formerly Norskald)	12	1	Semisubmersible
Glomar Grand Isle	11	3	Drillship
Glomar Moray Firth I	2		Jack-up
Henry Goodrich	1		Semisubmersible
Maersk Explorer	7		Jack-up
Neddrill Trigon	3		«
Neptune 7 (formerly Pentagone 81)	12		Semisubmersible
Nordraug	10		«
Norjarl	3		«
Norskald (formerly Glomar Biscay II)	26		«
Nortrym	25		«
Ocean Tide	5		Jack-up
Ocean Traveler	9		Semisubmersible
Ocean Victory	1		«
Ocean Viking	29	1	«
Ocean Voyager	2		«
Odin Drill	3		«
Orion	7		Jack-up
Pelerin	1		Drillship
Pentagone 81 (formerly Neptune 7)	1		Semisubmersible
Pentagone 84	3	1	«
Polar Pioneer	1		
Polyglomar Driller	11		«
Ross Isle	10	2	«
Ross Rig	28		«
Saipem II	1		Boreskip
Sedco H	2		Halvt nedsenkbart
Sedco 135 F	2		«
Sedco 135 G	1		«
Sedco 703	3	1	«
Sedco 704	3		«
Sedco 707	6		«
Sedneth I	3		«
Transworld Rig 61	2		Semisubmersible
Treasure Hunter		1	«
Treasure Saga	16	1	«
Treasure Scout	14		«
Treasure Seeker	27	4	«
Vildkat	4		«
Vinni	1		«
Waage Drill I	2		«
West Vanguard	14		«
West Venture	10	1	«
Zapata Explorer	13		Jack-up
Zapata Nordic	5		«
Zapata Ugland	5		Semisubmersible
	497	32	

5 new drilling rigs operated in 1985:

Dyvi Stena	Semisubmersible
Henry Goodrich	«
Polar Pioneer	«
Treasure Hunter	«
Vinni	«

Tab 8.4.a
Production drilling

Field	Total drilled	Spudded 1985	Producing	Injection/ (observ.)	Drilling in progress	Suspend./ plugged/ compl.
ALBUSKJELL A	10		7			3
ALBUSKJELL F	13		7			6
COD	9	1	6		3	
EDDA	10		7			3
EKOFOSK A	15		14			1
EKOFISK B	22		17	1 (1)***	1	2
EKOFISK C	12		7	4 *		1
EKOFISK K	6	4			1	5
ELDFISK A	26	1	16			10
ELDFISK B	15		13		1	1
FRIGG (UK)	24		22			2
FRIGG	24		22	(2)***		
GULLFAKS A	3	3			1	2
HEIMDAL	11	11			1	10
N.E.FRIGG	7		6			1
ODIN	11		11			
OSEBERG	1	1			1	
STATFJORD A	37	5	20	14	1	2
STATFJORD B	25	7	16	8	1	
STATFJORD C	11	9	7	2	1	1
TOR	14		10			4
VALHALL	20	5	18		1	1
W. EKOFISK	12		9		1	2
	338	47	235	29 ** (3)***	11	60

* Wells are prod./inj. well, depending on gas sale.
** 4 wells are prod./inj. wells, depending on gas sale.
*** Wells are observator/production wells.

235 wells	producing (145 oil, 29 condensate and 61 gas)
13 wells	are shut down/plugged
29 wells	are injection wells
3 wells	are observation-/production wells
11 wells	drilling in progress (2/4-K-12, 33/9-A-26, 33/9-C-14, 33/12-B-35, 34/10-A-3H, 25/4-A-9, 2/8-A-17 (W.O.), 30/9-B-21, 2/4-B-22 (W.O.), 2/4-D-9 (W.O.) OG 2/7-B-7 (W.O.).
1 well	is shut down (10/1-A-12) and drilled deeper with English permit no and new designation (10/1-A-25).
6 hull	are susp. on TD (2/4-K-4, 2/4-K-13, 2/4-K-22 AND 34/10-A-1 H, 25/4-A-4 AND 25/4-A-6)
10 wells	are susp. after setting of 20" casing (25/4-A-1, 25/4-A-2, 25/4-A-7, 34/10-A-2 H, 25/4-A-3, 25/4-A-5, 25/4-A-8, 25/4-A-10, 25/4-A-11 and 33/9-C-14)
1 well	is susp. after setting of 30" casing (2/4-K-2)
1 well	is susp. in 30" open hole (2/4-K-3)
1 well	is susp. after 20" casing (blowout) (34/10-A-2H)
27 wells	have never produced
338 wells	

8.4 Production drilling on the Norwegian Continental Shelf

Since the drilling of production wells in the Norwegian sector of the North Sea started in 1973, a total of 338 wells have been spudded.

Information from these holes is presented in Table 8.4.a.

Of the total, 235 are production wells (oil, gas and condensate), 29 are water or gas injection holes, three are production/ observation wells and six are currently being drilled. The remaining 60 wells are either temporarily out of operation, suspended for later completion or other reasons, or in 27 cases dry.

At present, oil and gas are produced from 12 fields, using 19 production platforms and one sea bed completion (North-East Frigg). Moreover, drilling is currently being performed by the Heimdal A platform, and on the Gullfaks A field and Oseberg B field by "Deepsea Bergen" and "Vildkatt" respectively, both semi-submersible drilling vessels. At the Ekofisk field, the jack-up "Dyvi Beta" is drilling injection wells for the water injection project (Ekofisk 2/4K).

Production from the Statfjord C platform started on 26 June 1985. In the course of 1985, 47 production wells were initiated comprising 20 producers, four injection holes, six suspensions for later completion, 11 suspensions for later drilling, and six still being drilled (Table 8.4.b).

TAB 8.4.b
Production wells spudded 1985

Lic. no.	Well no.	Position north east	Spudded	Completed	Operator	Field	Comments
P 251	33/12-B-13	61°12'34.88" 01°49'50.29"	24.09.85	10.11.85	Mobil	Statfj. B	
P 294	33/9-C-21	61°17'47.70" 01°54'09.17"	09.01.85 15.04.85		16.01.85 13.05.85	Mobil	Statfj. C
P 295	2/8-A-15	56°16'41.40" 03°23'43.19"	09.01.85 15.02.85	07.02.85 18.02.85	Amoco	Valhall	
P 296	33/12-B-4		07.01.85	03.03.85	Mobil	Statfj. B	Water injection
P 297	33/9-C-33		04.01.85 16.01.85	09.01.85 18.02.85	Mobil	Statfj. C	
P 298	2/7-B-3	56°25'09.18" 03°13'06.14"	18.04.85	13.09.85	Phillips	Eldfisk B	
P 299	33/9-A-28	61°15'20.46" 01°51'13.95"	16.03.85	20.04.85	Mobil	Statfj. A	
P 300	2/8-A-16		07.02.85 18.02.85 02.03.85	15.02.85 25.02.85 13.03.85	Amoco	Valhall	
P 301	3/12-B-31		09.03.85	04.04.85	Mobil	Statfj. B	
P 302	2/8-A-17		16.03.85 12.05.85	01.05.85 19.05.85	Amoco	Valhall	
P 303	33/12-B-1		04.04.85	01.06.85	Mobil	Statfj. B	Water injection
P 304	2/8-A-18		02.05.85 27.05.85	12.05.85 02.07.85	Amoco	Valhall	
P 305	33/9-A-17		13.05.85	19.07.85	Mobil	Statfj. A	
P 306	25/4-A-6	59°34'27.24" 02°13'45.58"	02.06.85 04.07.85	06.06.85 23.08.85	Elf	Heimdal	Susp. at td (Prod/observ.)
P 307	25/4-A-1		06.06.85	09.06.85	Elf	Heimdal	20" casing is set
P 308	25/4-A-2		09.06.85	28.06.85	Elf	Heimdal	20" casing is set
P 309	25/4-A-3		28.06.85	01.07.85	Elf	Heimdal	20" casing is set
P 310	25/4-A-4		01.07.85 23.08.85	04.07.84 07.11.85	Elf	Heimdal (Inj./observ.)	Susp. at td
P 311	33/9-C-13		14.05.85	19.06.85	Mobil	Statfj. C	Gas injector
P 312	33/12-B-39		01.06.85	24.07.85	Mobil	Statfj. B	
P 313	2/8-A-19		10.07.85 25.07.85 03.09.85	16.07.85 06.08.85 04.10.85	Amoco	Valhall	
P 314	33/9-C-42		19.06.85	07.08.85	Mobil	Statfj. C	
P 315	2/4-K-22	56°33'56.62" 03°12'23.00"	01.07.85	14.10.85	Phillips	Ekofisk K	Susp. at td. (Water injector)
P 316	33/12-B-5		25.07.85	01.09.85	Mobil	Statfj. B	
P 317	33/9-A-36		21.07.85	11.09.85	Mobil	Statfj. A	Water injector
P 318	7/11-A-6	57°04'10.80" 02°26'05.04"	07.07.75	12.08.85	Phillips	Cod	This was 7/11-7
P 319	33/9-C-12		08.08.85	22.09.85	Mobil	Statfj. C	
P 320	34/10-A-1 H	61°11'04.73" 02°13'15.51"	19.08.85	17.10.85	Statoil	Gullfaks A	Susp. at td (Subsea compl.)
P 321	33/9-A-15		11.09.85	12.10.85	Mobil	Statfj. A	
P 322	33/9-C-28		22.09.85	17.10.85	Mobil	Statfj. C	
P 323	2/4-K-2		15.10.85	02.11.85	Phillips	Ekofisk K	Susp after 30" casing
P 324	30/9-B-21	60°29'36.03" 02°49'42.58"	22.09.85		N. Hydro	Oseberg	
P 325	25/4-A-8		25.11.85	27.11.85	Elf	Heimdal	20" casing is set
P 326	25/4-A-9		07.11.85 09.12.85	13.11.85	Elf	Heimdal	
P 327	25/4-A-5		13.11.85	17.11.85	Elf	Heimdal	20" casing is set
P 328	25/4-A-7		17.11.85	21.11.85	Elf	Heimdal	20" casing is set
P 329	25/4-A-10		21.11.85	23.11.85	Elf	Heimdal	20" casing is set
P 330	25/4-A-11		24.11.85	25.11.85	Elf	Heimdal	20" casing is set
P 331	33/9-A-26		15.10.85 14.12.85	29.11.85	Mobil	Statfj. A	
P 332	33/9-C-7		18.10.85	24.11.85	Mobil	Statfj. C	
P 333	34/10-A-2 H	61°10'48.04" 02°13'07.05	28.10.85		Statoil	Gullfaks A	
P 334	33/12-B-35		01.12.85		Mobil	Statfj. B	
P 335	2/4-K-3		02.11.85	23.11.85	Phillips	Ekofisk K	Suspended
P 336	2/4-K-12		23.11.85		Phillips	Ekofisk K	
P 337	33/9-C-35		24.11.85	29.11.85	Mobil	Statfj. C	20" casing is set
P 338	33/9-C-14		29.11.85		Mobil	Statfj. C	
P 339	34/10-A-3H		29.11.85		Statoil	Gullfaks A	

8.5 Production of oil and gas in 1984

Production of oil and gas on the Norwegian Continental Shelf in 1985 was 63.9 million toe. Production in 1984 was 61.4 million toe. In Tables 8.5.a to 8.5.f and Figures 8.5.a and 8.5.b, production on the Norwegian Continental Shelf is presented in more detail.

The figures show the Norwegian share of Stat-

FIG. 8.5.a
Oil and gas production on the Norwegian shelf per field and total 1971–85

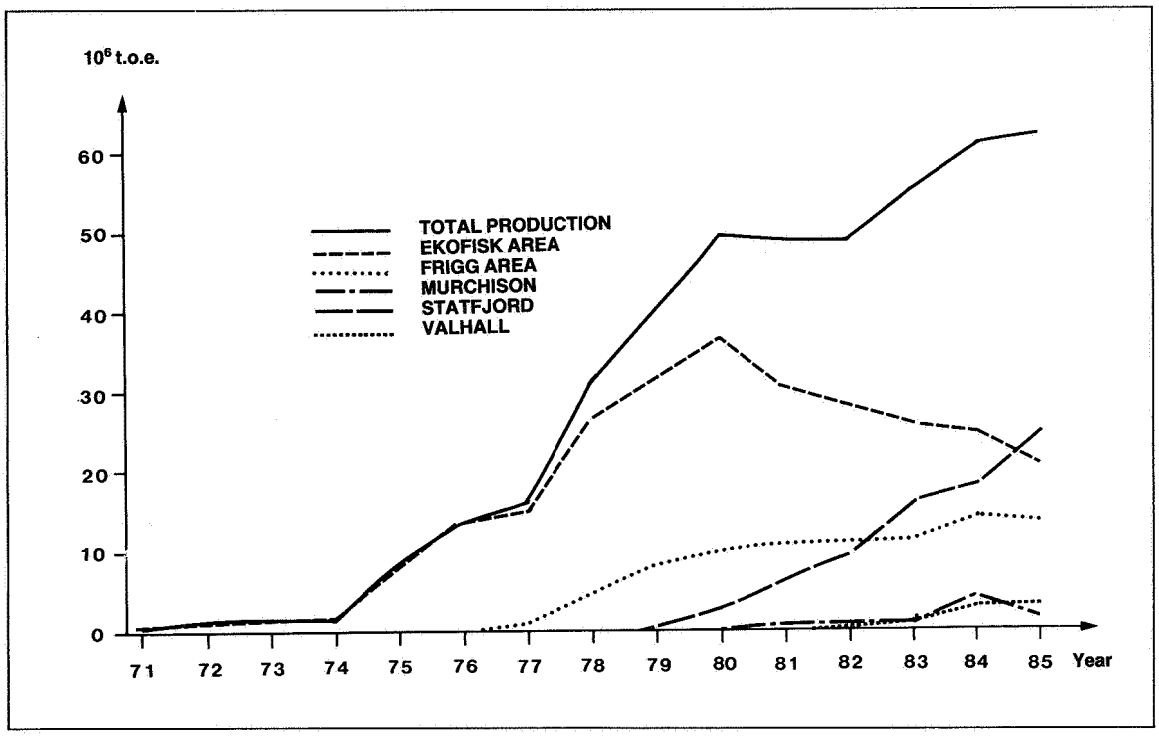
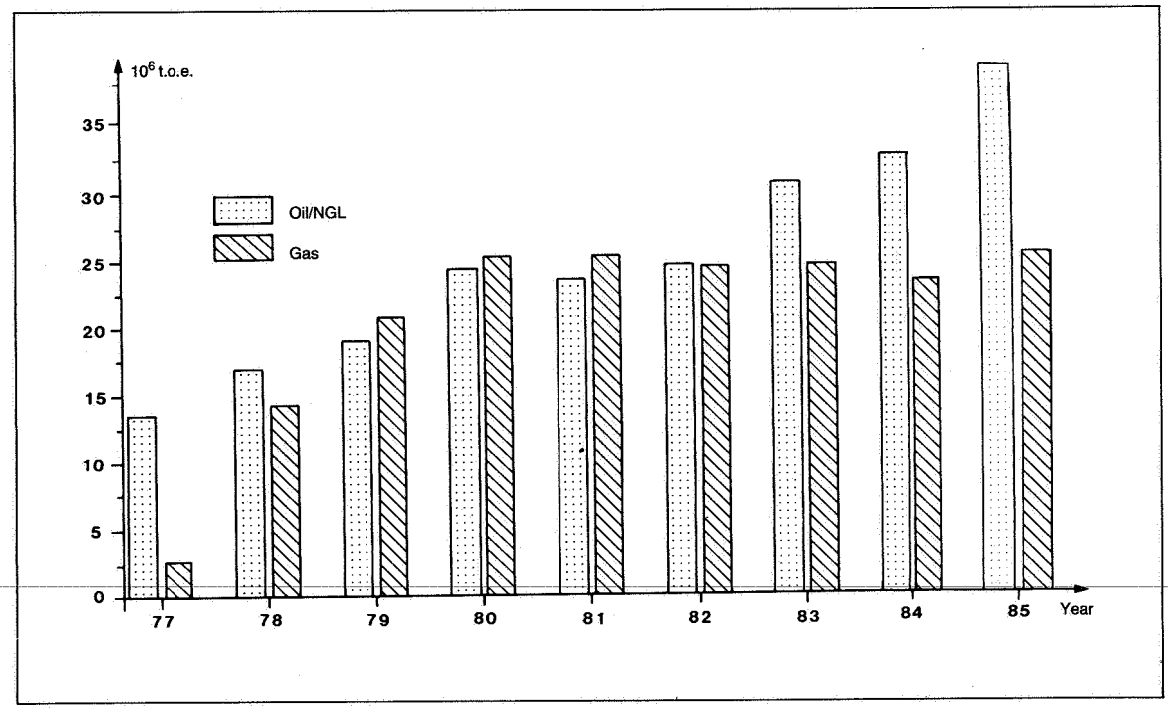


FIG. 8.5.b
Oil/NGL and gas production from the Norwegian shelf 1977–85



TAB 8.5.a
Prouction in mill t.o.e.

1985	Oil	Gas	Total
Ekofisk-area	10,410	10,847	21,257
Statfjord	24,069	0,454	24,523
Frigg-area	0	13,667	13,667
Valhall	2,480	0,468	2,948
Murchison	1,486	0,055	1,542
Total 1985	38,445	25,491	63,936
Total 1984	35,093	26,292	61,386

fjord, Frigg and Murchison. NGL for the Ekofisk area, Murchison, Valhall and Statfjord are included in the figures for oil. The figures for gas indicate the amounts sold for all fields. Condensate is included in the figures for the Frigg area.

TAB 8.5.b
Monthly oil and gas production from the Ekofisk area

1985	Prod oil incl NGL 1 000 Sm^3	Produced gas Mill Sm^3	Injected gas Mill Sm^3	Flared gas Mill Sm^3	Gas consum. (fuel) Mill Sm^3	Stable oil Teesside 1 000 Sm^3	NGL Teesside Ton	Gas sales Emden Mill Sm^3
Jan	1 253	1 264	6	2	61	1 083	83 768	1 165
Feb	1 098	1 084	0	1	53	922	86 593	1 020
Mar	1 207	1 176	1	2	59	1 021	101 178	1 100
Apr	1 163	1 124	62	2	60	996	93 235	995
May	1 172	1 131	59	5	61	994	92 808	1 008
Jun	1 069	1 026	60	2	55	906	83 464	900
Jul	1 168	1 118	141	1	60	982	94 932	913
Aug	1 115	1 076	168	1	57	941	93 651	850
Sep	1 090	1 045	267	1	61	913	93 667	714
Oct	1 126	1 082	311	1	65	948	94 949	703
Nov	1 064	1 033	260	1	62	897	92 660	704
Dec	1 088	1 053	216	1	61	913	88 846	774
Year's total	13 612	13 210	1 551	19	716	11 519	1 099 752	10 847

TAB 8.5.c
Monthly gas an condensate production from the Frigg area

1985	Produced gas Mill Sm^3	Produced condensate Sm^3	Injected gas Mill Sm^3	Flared gas Mill Sm^3	Gas consum. (fuel) Mill Sm^3	Gas sales St Fergus Mill Sm^3	Condensate St Fergus Sm^3	Condensate ton/Sm^3
Jan	1 607	2 709	0	0	2	1 531	8 187	0.8266
Feb	1 429	2 386	0	0	2	1 355	8 472	0.8262
Mar	1 559	2 693	0	0	2	1 469	13 190	0.5620
Apr	1 481	2 544	0	0	2	1 375	8 332	0.8249
May	1 279	2 580	0	0	2	1 182	7 642	0.8244
Jun	877	2 014	0	1	2	786	5 244	0.8237
Jul	668	865	0	0	2	709	3 337	0.8256
Aug	781	1 691	0	0	2	707	2 578	0.8276
Sep	843	1 946	0	0	1	774	4 376	0.8257
Oct	1 015	2 395	0	0	1	915	6 447	0.8242
Nov	1 423	2 604	0	0	2	1 348	5 530	0.8250
Dec	1 512	2 550	0	0	2	1 453	6 642	0.8231
Years total	14 475	26 977	0	1	23	13 604	79 976	

Figures show Norwegian share of Frigg 60,82%, NE-Frigg and Odin 100%.

TAB 8.5.d
Monthly oil and gas production from Murchison

1985	Prod oil Encl NGL 1 000 Sm^3	Prod gas Mill Sm^3	Injected gas Mill Sm^3	Flared gas Mill Sm^3	Gas consumed (fuel) Mill Sm^3	Stable oil Sullom Voe 1 000 Sm^3	Gas sales St Fergus Mill Sm^3	NGL Sullom Voe /St Fergus 1 000 ton
Jan	267	9	0	2	1	236	5	6
Feb	241	8	0	1	1	214	5	6
Mar	205	7	0	2	1	183	4	5
Apr	188	8	0	1	1	159	5	6
May	131	9	0	3	1	119	4	5
Jun	117	8	0	1	1	106	5	5
Jul	128	8	0	1	1	113	4	5
Aug	133	8	0	1	1	119	5	5
Sept	120	8	0	1	1	108	5	5
Oct	132	8	0	1	1	118	5	5
Nov	123	8	0	1	1	110	4	5
Des	128	8	0	1	1	113	4	5
Year's total	1 913	99	0	17	16	1 696	55	63

Figures show Norwegian share of Murchison

TAB 8.5.e
Monthly oil and gas production from Statfjord

1985	Prod oil incl NGL 1 000 Sm^3	Prod gas Mill Sm^3	Injected gas Mill Sm^3	Flared gas Mill Sm^3	Gas consumed (fuel) Mill Sm^3	Gas sales Emden Mill Sm^3
Jan	1 923	368	330	15	0	0
Feb	1 783	353	314	17	0	0
Mar	2 146	420	355	12	0	0
Apr	2 124	419	372	11	0	0
May	2 187	425	383	9	0	0
Jun	1 761	349	296	17	0	0
Jul	2 624	513	415	56	0	0
Aug	2 601	492	442	22	0	0
Sep	2 701	532	473	27	0	0
Oct	2 976	601	365	18	0	90
Nov	2 967	592	383	18	0	97
Des	2 970	589	211	13	0	268
Year's total	28 762	5 653	4 338	235	0	454

Figures are Norwegian share of Statfjord: 84,09322%

TAB 8.5.f
Monthly oil and gas production allocated Valhall

1985	Prod. oil incl NGL 1 000 Sm^3	Prod. gas Mill Sm^3	Injected gas Mill Sm^3	Flared gas Mill Sm^3	Gas consumed (fuel) Mill Sm^3	Stable oil Teesside 1 000 Sm^3	NGL Teesside 1 000 tonn	Gas sales Emden Mill Sm^3
Jan	294	63	0	4	8	276	11	49
Feb	262	53	0	2	8	239	11	42
Mar	311	61	0	1	8	284	16	51
Apr	301	59	0	1	8	275	15	49
Mai	317	52	0	2	9	288	16	50
Jun	304	59	0	1	8	276	14	47
Jul	287	55	0	1	9	259	16	43
Aug	199	37	0	2	8	179	10	26
Sep	178	34	0	2	8	162	9	23
Oct	186	36	0	1	8	169	9	25
Nov	203	38	0	1	8	185	11	28
Dec	204	38	0	1	7	183	11	29
Year's total	3 052	591	0	24	102	2 781	155	468

8.6 Publications by the Norwegian Petroleum Directorate in 1985

Regulations

- Regulations compendium: "Kontinentalsokkelen" ("The Continental Shelf"): An up-to-date compendium with parallel Norwegian and English texts of the regulations and guidelines stipulated by the Norwegian Petroleum Directorate and other regulatory agencies. Up-dated to 1 January 1985.
- Regulations concerning the Structural Design of Load-bearing Structures intended for Production or Exploitation of Petroleum Resources. Stipulated by the Norwegian Petroleum Directorate on 29 October 1984. Published in 1985. Included in Norwegian and English in the 1986 Compendium.
- Regulations concerning the Act relating to Petroleum Activity (the new Petroleum Act). Stipulated by Royal Decree on 14 June 1985. Published in 1985. Included in Norwegian and English in the 1986 Compendium.
- Regulations concerning Safety etc pursuant to the Act relating to Petroleum Activity (the new Petroleum Act). Stipulated by Royal Decree of 28 June 1985. Published in 1985. Included in Norwegian and English in the 1986 Compendium.
- Regulations concerning Worker Protection and the Working Environment etc in connection with Exploration for and Exploitation of Submarine Petroleum Reserves. Stipulated by Royal Decree of 13 September 1985. Published in 1985. Included in Norwegian and English in the 1986 Compendium.
- Regulations concerning the Licensee's Internal Control in the Petroleum Activity on the Norwegian Continental Shelf, with comments. Stipulated by the Ministry of Local Government and Labour on 28 June 1985. Published in 1985. Included in Norwegian and English in the 1986 Compendium.
- Regulations concerning the Collection of Fees Payable to the Treasury for Supervision of the Petroleum Activity. Stipulated by Royal Decree on 29 June 1984 and amended on 10 December 1985. Published in 1986. Included in Norwegian and English in the 1986 Compendium.
- Proposal for Guidelines concerning the Minimum Requirements for the Performance of Breathing Apparatus for Underwater Use and Standard Procedures for Unmanned Testing of such Breathing Apparatus. Stipulated by the Norwegian Petroleum Directorate in 1984. Published in 1984.
- Act no. 11 of 22 March 1985 relating to Petroleum Activity (new Petroleum Act). Published in 1985. Included in Norwegian and English in the 1986 Compendium.
- Temporary Regulations concerning Electrical Equipment on Installations Used for Surveys and Exploration Drilling in the Petroleum Activity. Stipulated by the Norwegian Petroleum Directorate on 26 June 1985. Published in 1985. Included in Norwegian and English in the 1986 Compendium.
- Regulations concerning the Arrangment of the Supervision of Safety etc in the Petroleum Activity on the Norwegian Continental Shelf. Stipulated by Royal Decree of 28 June 1985. Published in 1985. Included in Norwegian and English in the 1986 Compendium.
- Regulations concerning the Petroleum Register. Stipulated by the Ministry of Petroleum and Energy on 12 June 1985. Published in 1985. Included in Norwegian and English in the 1986 Compendium.

Research reports

- Rapport 9 (Report 9). Current data 1980–1983. Wave data 1981–1983. Published in 1985.
- Naturlig radioaktivitet in forbindelse med oljevirksomheten i Nordsjøen (Natural radioactivity in connection with the oil activity in the North Sea).
- Kjemikalier i petroleumsvirksomheten – Førstehjelpshåndbok (Chemicals in the Petroleum Activity – First Aid Manual).
- Flexible hoses, pipes and pipelines carrying hydrocarbons (in English).

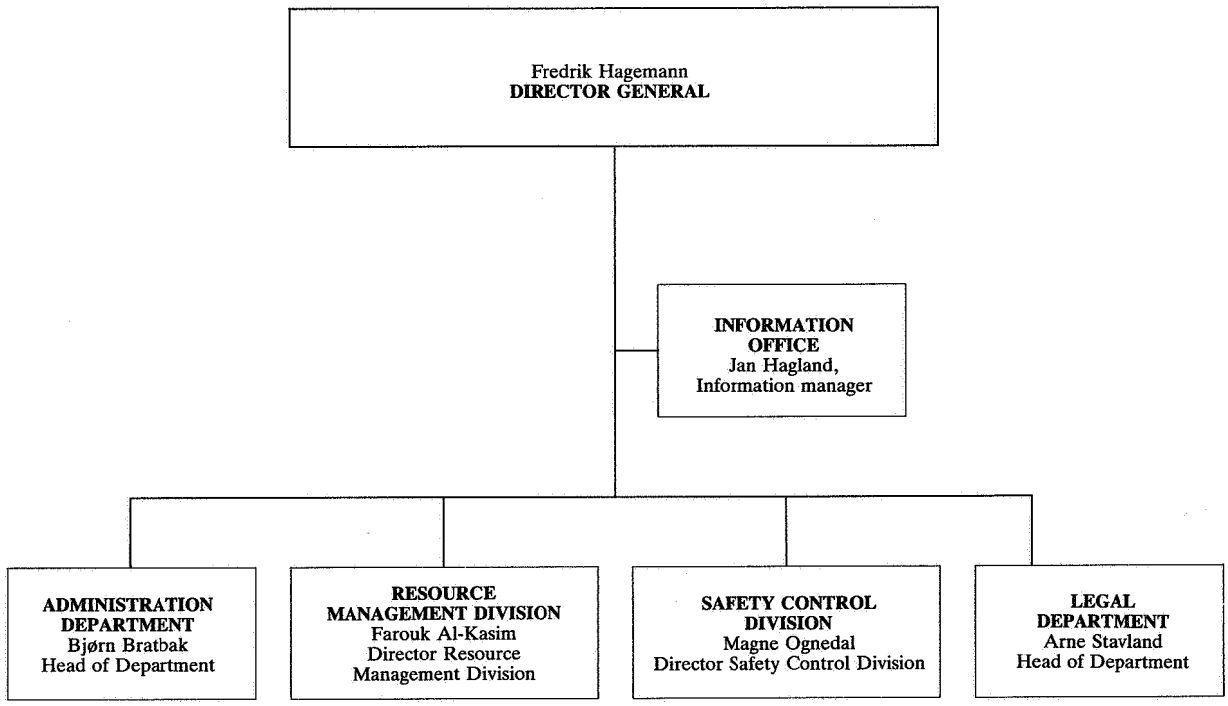
Geological publications

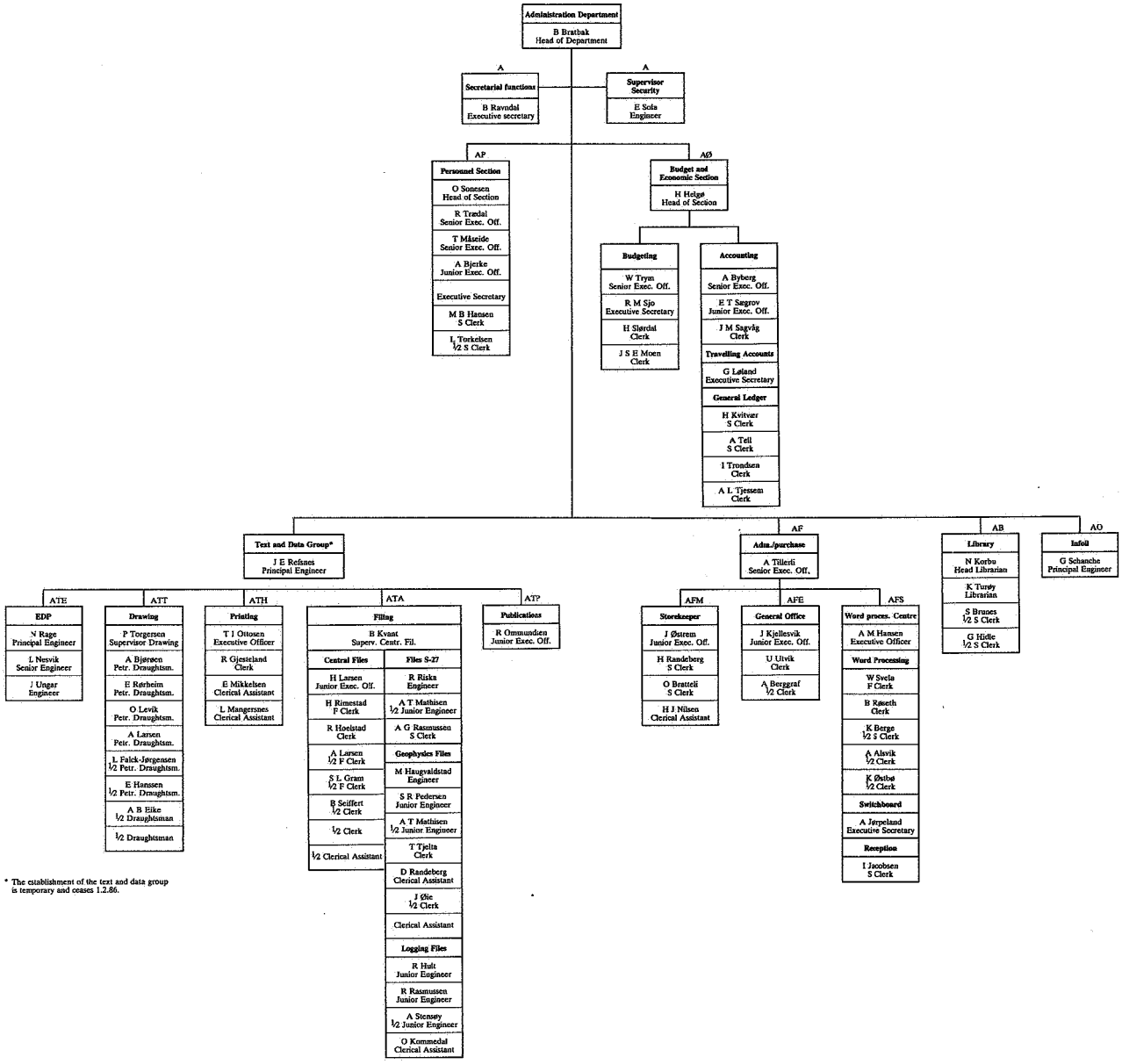
- Well Data Summary Sheets, Vol 9. Borehull fullført 1979 (Well Data Summary Sheets, Vol 9. Wells completed 1979).
- Well Data Summary Sheets, Vol 10. Borehull fullført 1979 (Well Data Summary Sheets, Vol 10. Wells completed 1979).

Other publications

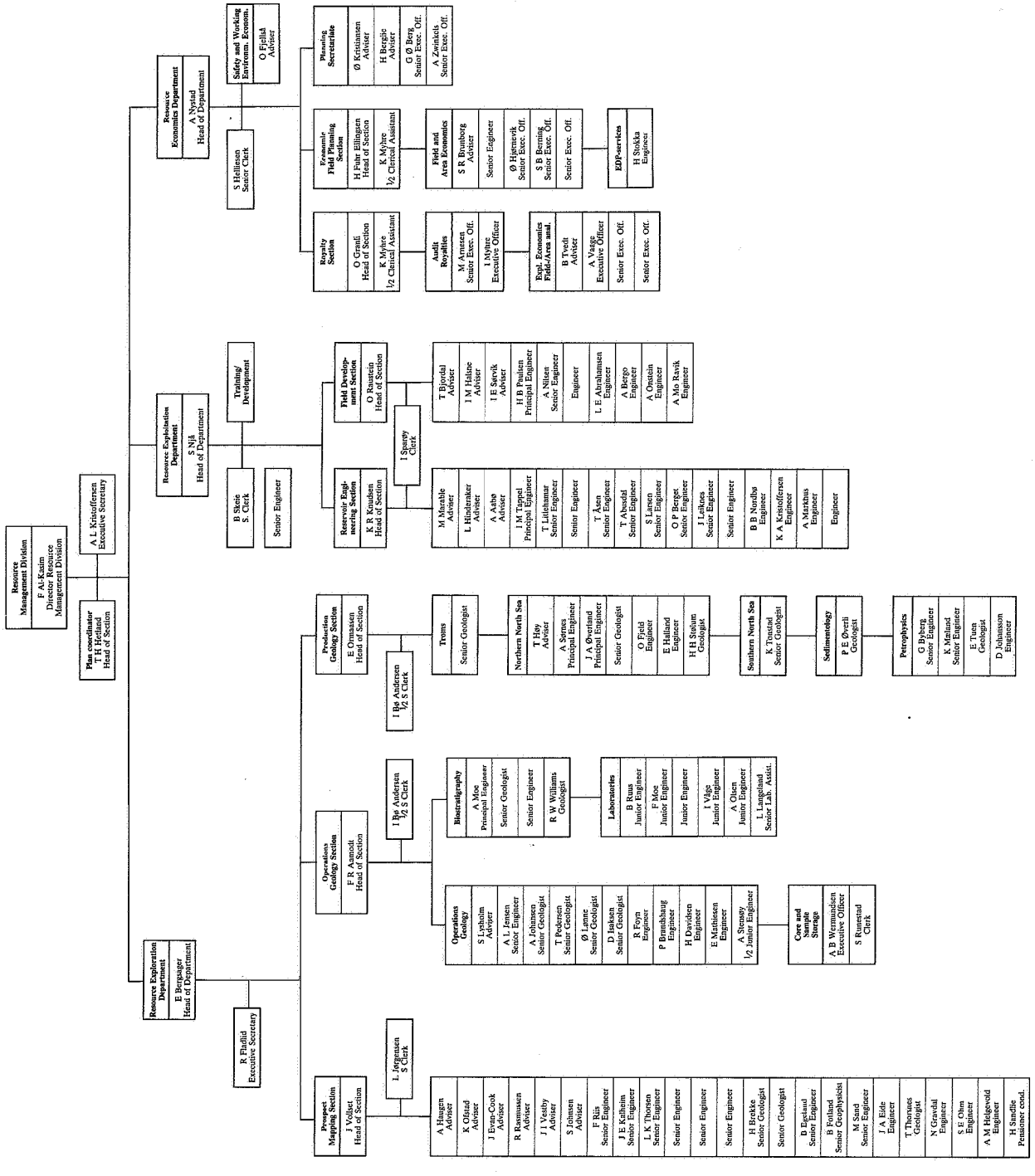
- Oljedirektoratets årsberetning 1984 (the Norwegian Petroleum Directorates Annual Report 1984) (Norwegian edition)
- NPD Annual Report 1984 (English edition of the above)
- Perspektivanalysen 1984 (the Petroleum Outlook) (Norwegian edition)
- Petroleum Outlook 1984 (English edition of the above)
- Map of the Norwegian Continental Shelf
- Map of the Western Barents Sea
- List of publications published by the Norwegian Petroleum Directorate (with details of Norwegian and English editions)
- Verne- og miljøarbeid fra handlingsprogram til praksis (Safety and environmental protection work from action program to practice).
- NPD Contribution No 22, Tectonic Development of the Western Margin of the Barents Sea and Adjacent Areas (in English).
- NPD Contribution No. 23, Character of the North Sea (in English).

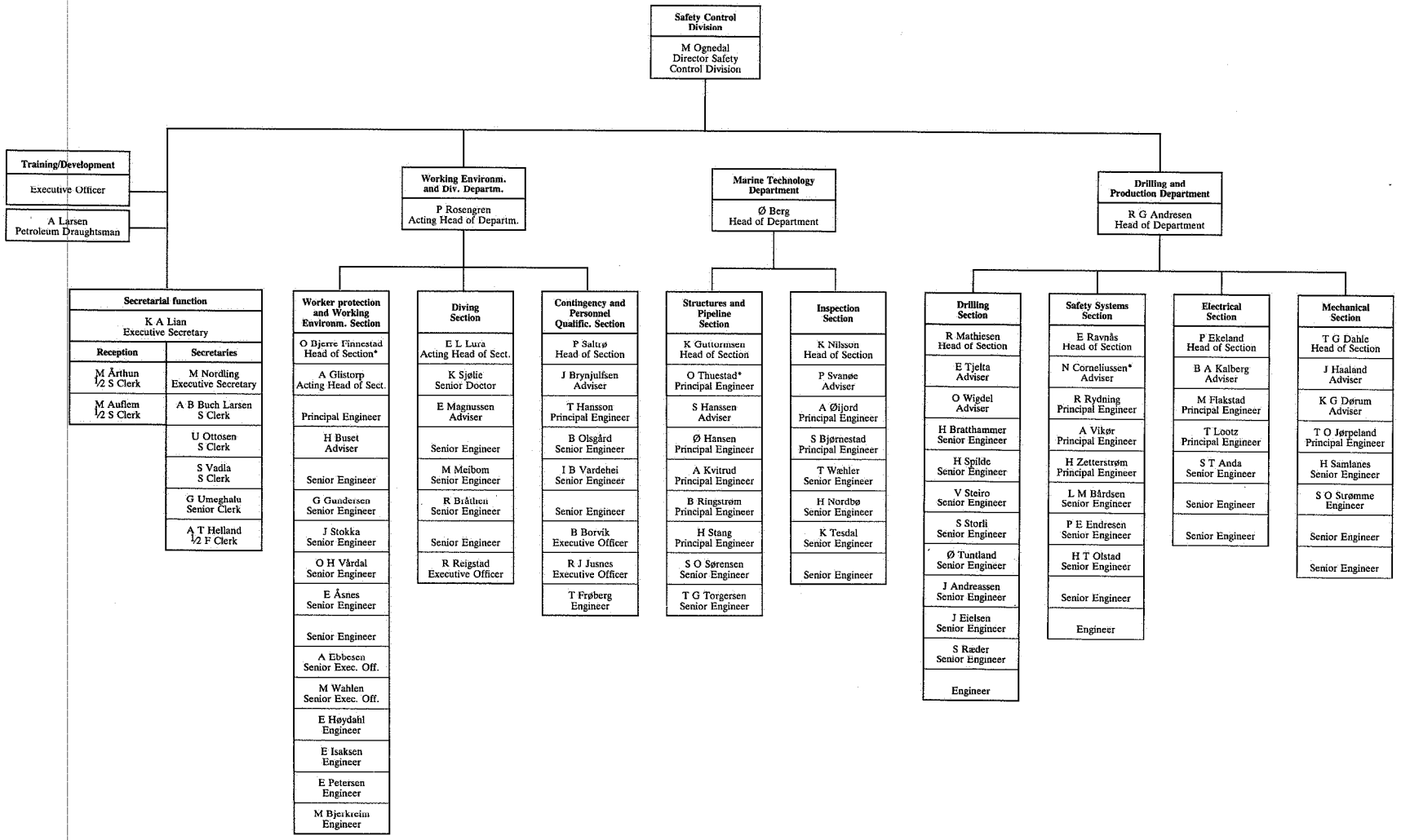
8.7 Organization chart



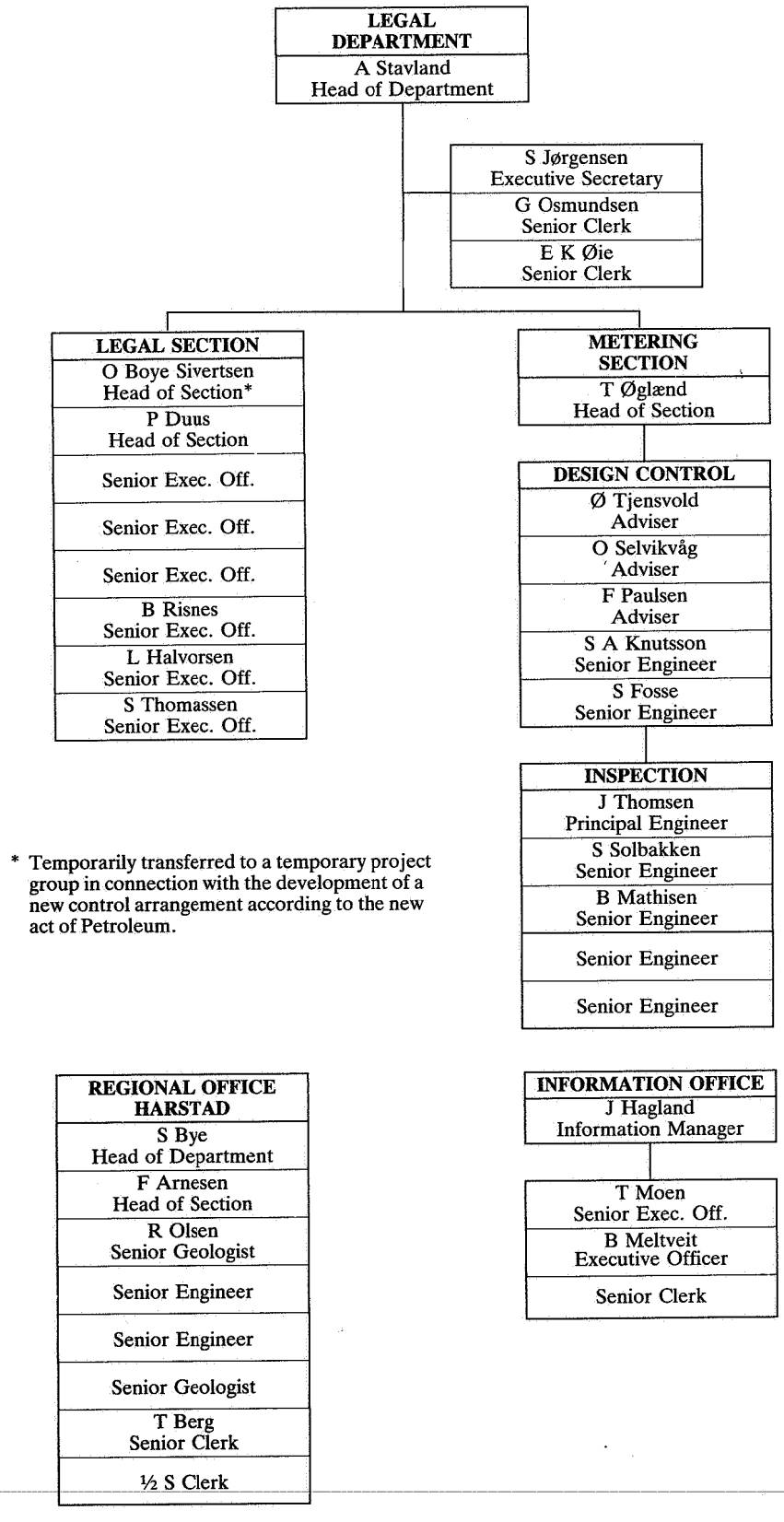


* The establishment of the text and data group is temporary and ceases 1.2.86.


Resource Management Division
F Al-Kasim
Director Resource Management Division
A L Kristoffersen
Executive Secretary
Plan coordinator
T H Hetland
Head of Section
Resource Exploration Department
E Bergsager
Head of Department
R Thefld
Executive Secretary
L Jørgensen
S Clerk
Prospect Mapping Section
J Vollset
Head of Section
A Haugen
Adviser
K Ofstad
Adviser
J Evan-Cook
Adviser
R Rasmussen
Adviser
J I Veiby
Adviser
S Johnsen
Adviser
F Riis
Senior Engineer
J E Kalheim
Senior Engineer
L K Thorsen
Senior Engineer
Senior Engineer
Senior Engineer
Senior Engineer
H Brekke
Senior Geologist
Senior Geologist
D Egelund
Senior Engineer
B Folland
Senior Geophysicist
M Sand
Senior Engineer
J A Eide
Engineer
T Thorsnes
Geologist
N Gravdal
Engineer
S E Ohm
Engineer
A M Helgesvold
Engineer
H Sandlie
Petroleum cand.
Operations Geology Section
F R Aamodt
Head of Section
I Bø Andersen
½ S Clerk
Operations Geology
S Lyshoim
Adviser
A L Jensen
Senior Engineer
A Johansen
Senior Geologist
T Pedersen
Senior Geologist
Ø Lønne
Senior Geologist
D Isaksen
Senior Geologist
R Foyn
Engineer
P Brandsburg
Engineer
H Davidsen
Engineer
E Mathiesen
Engineer
A Stensøy
½ Junior Engineer
Biostratigraphy
A Moe
Principal Engineer
Senior Geologist
Senior Engineer
R W Williams
Geologist
Laboratories
B Knus
Junior Engineer
F Moe
Junior Engineer
Junior Engineer
I Vige
Junior Engineer
Å Olsen
Junior Engineer
L Langeland
Senior Lab. Assist.
Core and Sample Storage
A B Wermundsen
Executive Officer
S Runestad
Clerk
Production Geology Section
E Ormåsen
Head of Section
I Bø Anderson
½ S Clerk
Troms
Senior Geologist
Northern North Sea
T Høy
Adviser
A Sørnes
Principal Engineer
J A Øverland
Principal Engineer
Senior Geologist
Ø Fjeld
Engineer
E Halland
Engineer
H H Stølum
Geologist
Southern North Sea
K Toustad
Senior Geologist
Sedimentology
P E Øverli
Geologist
Petrophysics
G Byberg
Senior Engineer
K Mæland
Senior Engineer
E Tuen
Geologist
D Johnsson
Engineer
Resource Exploitation Department
S Njå
Head of Department
B Skeie
S. Clerk
Senior Engineer
Training/ Development
Reservoir Engineering Section
K R Knudsen
Head of Section
Field Development Section
O Rasmussen
Head of Section
I Sparrow
Clerk
M Mæstad
Adviser
L Hinderaker
Adviser
A Aabø
Adviser
J M Tappel
Principal Engineer
T Lillehamar
Senior Engineer
Senior Engineer
T Åsen
Senior Engineer
T Abadal
Senior Engineer
S Larsen
Senior Engineer
O P Berget
Senior Engineer
J Leiknes
Senior Engineer
Senior Engineer
B B Nordby
Engineer
K A Kristoffersen
Engineer
A Markhus
Engineer
Engineer
T Bjordal
Adviser
I M Halsøe
Adviser
I E Sørvik
Adviser
H B Paulsen
Principal Engineer
A Nilsen
Senior Engineer
Engineer
L E Abrahamsen
Engineer
A Bergo
Engineer
A Onstein
Engineer
A Mo Ravik
Engineer
Resource Economics Department
A Nystad
Head of Department
S Hellesen
Senior Clerk
Safety and Working Environm. Econom.
O Fjellå
Adviser
Economic-Field Planning Section
H Futre Ellingsen
Head of Section
K Myhre
½ Clerical Assistant
Royalty Section
O Grødi
Head of Section
K Myhre
½ Clerical Assistant
Audit Royalties
M Arnesen
Senior Exec. Off.
I Myhre
Executive Officer
Expl. Economics Field/Area anal.
B Tvedt
Adviser
A Vraga
Executive Officer
Senior Exec. Off.
Senior Exec. Off.
Field and Area Economics
S R Brunberg
Adviser
Senior Engineer
Ø Hjermevik
Senior Exec. Off.
S B Berning
Senior Exec. Off.
Senior Exec. Off.
EDP-services
H Stokka
Engineer
Planning Secretariate
Ø Kristiansen
Adviser
H Bergiie
Adviser
G Ø Berg
Senior Exec. Off.
A Zwinicls
Senior Exec. Off.



* Temporarily transferred to a temporary project group in connection with the development of a new control arrangement according to the new act of Petroleum.



* Temporarily transferred to a temporary project group in connection with the development of a new control arrangement according to the new act of Petroleum.