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Unofficial translation

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Report by the Board of Directors

The increase in the drilling activity on the Norwegian continental shelf has been substantial in 1982. The activity reached a peak during the summer months when 15 drilling rigs were operating at the same time. Altogether, 49 new exploration and appraisal wells were spudded in 1982. By the end of 1982, a total of 360 exploration and appraisal wells had been spudded on the Norwegian continental shelf.

Several encouraging new finds were made in 1982. The most important were Saga's discovery of oil on Block 34/4, Esso's gas find on Block 16/7 east of Sleipner, Statoil's gas strike on Block 30/2 and new gas finds on Tromsøflaket. It is interesting to note that finds were made in four of the five production licenses from the sixth round of concessions (relinquished acreage) where drilling was carried out. Present estimates by the Norwegian Petroleum Directorate, based on the results of this year's drilling, show proven reserves of 2.6 billion tons oil equivalent.

Production of oil and gas on the Norwegian continental shelf amounted to 48.9 million tons oil equivalent in 1982, as against 48.7 million tons oil equivalent in 1981.

In 1982, a five-day labour conflict resulted in a reduction in production on the Norwegian continental shelf of approximately 690,000 tons oil equivalent. This reduction corresponds to a gross production value of approximately NOK 830 million.

In 1982, approximately NOK 5760 million were paid in as royalties. This represents an increase of NOK 450 million compared with 1981.

The Board of Directors states with satisfaction that also for this period there were no fatal accidents.

In 1982, the Norwegian Petroleum Directorate stipulated requirements for mechanization of drilling operations, however, at the end of the report period it was too early to decide whether this action had had any positive influence on the accident statistics or not.

The Board is concerned with the efforts being made to increase the recovery factor for the reserves on the shelf. The final decision to implement the full-scale water injection project for the Ekofisk area has been postponed until the spring of 1983. Such a postponement will be justified if it simultaneously throws more light on development costs and the potential of increased production.

Two new production facilities were put into operation in 1982. The Valhall field started up on 1 September, and the Statfjord B platform started production on 5 November. The Statfjord field will gradually contribute the major part of oil production on the Norwegian continental shelf. On 20 December, the licensees in the Ula group decided to initiate the Ula project. The progress of the development projects Statfjord C, Heimdal, Gullfaks Phase I, NE Frigg, Odin and Statpipe has not tended to depart much from the plans made by the operators. The same applies to the tie-in operations on Frigg in preparation to receive gas from Odin and NE Frigg.

In this report period too, the Norwegian Petroleum Directorate has continued to integrate functional operators' internal control arrangements on production facilities. It looks as if this work is progressing well, even though some areas are not satisfactorily covered by some operators. The present state of affairs better allows the Norwegian Petroleum Directorate to depart to an ever-increasing extent from detailed controls, and concentrate its control efforts towards vital and superior areas. Notwithstanding, experience shows that the implementation of well planned control audits of the operators´ control arrangements is a very effective form of control.

In 1982, the Norwegian Petroleum Directorate took the initiative with Norwegian shipowners and operators to establish functional internal control arrangements for technical drilling facilities on mobile drilling rigs registered in Norway. This has motivated shipowners and operators to initiate the work of developing and documenting their internal control arrangements. Foreign drilling rigs are also covered by the system, as operators must ensure that there is a satisfactory internal control arrangement for all drilling rigs operating on the Norwegian continental shelf.

The Norwegian Petroleum Directorate´s seismic surveys form the basis for charting resources in the northern areas. Thus, it is vital that this exploration be maintained if we are to be in a position to evaluate the petroleum options on the shelf and propose new areas for further activity. The Norwegian Petroleum Directorate´s own processing facility, which was put into operation in 1982, represents a considerable professional strengthening of efforts related to the surveys and the processing of seismic data.

The clearing of the sea floor continued in 1982. Four million kroner were employed, and 100-125 tons of trash were collected and removed.

In previous annual reports, the Board of Directors has expressed its concern for the personnel situation at the Directorate. In 1980, certain authorizations were given to better the pay conditions of the employees. These authorizations were further extended and improved in 1982. This action, together with the general labour market situation, have resulted in an increased number of applications for vacant positions. More generous funding for further training of personnel is also a factor causing the Board to take a somewhat brighter view of the personnel situation than at previous year-ends. The Board of Directors would like to expresses its satisfaction with the Directorate´s achievement in retaining a skilful and hard-working staff during difficult years with high attrition rates.

The Board wishes to maintain a permanent watch on the personnel situation to be able to contribute to a best possible adjustment of factors involved, thus enabling work and pay conditions in the Directorate to continue to attract a competent staff.

Planning for the new building continued during the report period. The Board acknowledges with satisfaction the work executed by the Construction and Property Directorate in connection with the plans for the new building, which according to present schedules will be completed in January 1986.

During the report period, the Ministry of Petroleum and Energy continued its preparation of the new petroleum legislation. The Norwegian Petroleum Directorate commented extensively on the draft law and regulations. The terms of reference stipulated by the new legislation will also be decisive with respect to the Directorate´s executive administrative authority.

During the report period, the Norwegian Petroleum Directorate participated in the work of assessing the safety regulations for the petroleum activity. At the end of the report period, the draft was submitted to the proper authorities for a further limited hearing.

During the report period, the Government appointed two committees which are both working on vital questions related to the petroleum activity, and which may affect the future position and tasks of the Norwegian Petroleum Directorate. The Mellbye Committee has already submitted its report, and the Board expects to return to it in connection with a possible hearing statement.

The Board has noted with satisfaction the aims outlined in Storting Report No. 40 on the prospects for the petroleum activity in the coming years, from which it appears that the position of the Norwegian Petroleum Directorate will be strengthened by organizational adjustments to the activity. Further, the Board has noted that the Directorate, according to the report, will be better qualified to provide effective and critical expertise with respect to the oil companies.

The Perspective Analysis for 1982 was prepared on the request of the Ministry of Petroleum and Energy, and formed a part of the background for Storting Report No. 40. During the ten years the Norwegian Petroleum Directorate has existed, its organization has been expanded to enable it to prepare such overall surveys of future activity on the continental shelf. A network of contacts with the oil companies, research institutions and other centers has gradually been built up, so that the basis necessary to perform comparatively accurate analyses does exist. A necessary continuation of this work is the development of methods and systematization of data. The process must be a continuous one.

In this year´s analysis, we have chosen to describe the consequences of several possible paths of development and thus elucidate the possible decisions that can be made by the national authorities and the opportunities that they have to influence progress.

The consequences of various possible turns of events have been illustrated with four input variables (investment, work participation, operating costs and the need for technical personnel) and four resultant variables (oil production, gas production, total hydrocarbon production and revenues to the state).

The analysis shows that a steady level of production does not necessarily imply that the input factors (investment, work participation, operating costs and the need for technical personnel) will stay permanent. Therefore, a unilateral focusing on the level of production might produce a somewhat over-simplified picture of the petroleum activity. As control and planning parameters, the Norwegian Petroleum Directorate has chosen first of all to focus on the input factors, because control of these will affect other activity in the Norwegian community most strongly.

Besides the mapping of the petroleum resources, we are also confronting the challenge of how to work out favourable cost development patterns which will lead to a high overall recovery factor and provide satisfactory safety.

At the present time, the development of the Troll field is being planned. Of the known recoverable reserves on fields which have yet not been decided to be developed, Troll accounts for approximately 20 per cent of the oil and 45 per cent of the gas. This implies that the Troll field will undoubtedly represent a very substantial part of the development activity towards the turn of the century. The location of the field in more than 300 meters of water requires a relatively large proportion of new deep-water technology. The field covers an enormous area, with a comparatively thin oil zone below a thicker gas zone, thus complicating production. If the oil is to be extensively recovered, the energy present in the gas zone will have to be utilized, i.e. gas production in the areas where the oil is to be extracted will be heavily restricted for a period of time.

The development of gas fields also implies extensive evaluations as regards further development of the infrastructure for transportation of gas, or of whether existing systems and facilities can be employed. Assessments of the technical condition of facilities, expected useful lifetimes and availability will be crucial in this context. Utilization of existing facilities and transportation systems by tying in several fields may be technically possible as well as economically justifiable. However, this has to be weighed against the risk of production losses in the case that supplies from several fields cease to arrive due to an accident on one single installation. Therefore, the Norwegian Petroleum Directorate has recommended to the superordinate ministries that questions of risk associated with such transportation solutions should be included in the considerations before final decisions are made.

In addition to the activity related to the Troll field and other fields, the activity in the Nothern areas is expected to have great importance in the years to come. Before development can take place, it seems to be necessary to prove commercial oil reserves or considerably greater gas reserves. In this connection, the question of year-round drilling is crucial. In the evaluations which have been made, the possibility of a gradual extension of the drilling season seems to exist. Additionally, the main part of the potential reserves in Northern areas will require knowledge and technical experience of development at substantial depths. Here also, experience from the Troll field will be decisive. This again illustrates the importance of a coordinated plan for total activity on the shelf.

The dynamic character of the petroleum activity implies that the authorities also in the next few years will be confronted with complex problems and tough decisions. The Board is, therefore, concerned to obtain a place for the Norwegian Petroleum Directorate from which it may develop into a professionally strong and independent administrative body which can provide the authorities with the basic information required to make decisions.

The Board assumes that the Norwegian Petroleum Directorate's function as a professional consultative planning body will remain dominant in the immediate future, besides the fact that the Directorate's executive administrative tasks will increase at the same rate as development on the continental shelf.

All parties agree that the Norwegian Petroleum Directorate must be strengthened. However, the Board has to state that this cannot be achieved unless the Directorate is granted the funds required for realizing this aim.

1. THE DIRECTORATE'S TASKS, 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 most recently amended by resolution of the Ministry of Petroleum and Energy 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. In matters relating to the working environment, safety and preparedness, it reports to the Royal Norwegian Ministry of Local Government and Labour. 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 economic control to ensure compliance with applicable legislation, regulations, decisions, concession terms, agreements, etc. in the exploration for and exploitation of petroleum, cf. § 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 relevant Ministry.

e. To collect and process geological, geophysical and technical material relating to subsea natural reaources, 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 licenses and assist the relevant Ministry, upon request, in the processing of applications for other licenses, 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 Board of Directors and the Administration

1.2.1 The Board of Directors

During the report period, the Board consisted of:

1 Martin Buvik, County Governor, TromsØ
2 Andreas LØnning, Director, Oslo
3 BjØrg Simonsen, Mayor, Mo i Rana
4 Liv Hatland, Municipal Director, Trondheim
5 Kåre D. Nielsen, Director, Oslo
6 Ole Knapp, Secretary, Oslo
7 Øystein Kristiansen, Section Manager
8 Inge DØskeland, Section Manager

Deputies:

For 1-4: Olav Marås, Farmer, SæbØvåg
Astrid Nistad, Executive Committee Secretary
Marit Greve, Editor, Bærum

For 5: Odd Henrik Robberstad, Director, Oslo

For 6: Bjørn Kolby, Attorney-at-Law, Oslo

For 7-8: Aase Moe, Department Engineer, Stavanger
Kristen Karlsen, Section Manager, Stavanger

Deputy, Kristen Karlsen, Section Manager, resigned from his position at the Norwegian Petroleum Directorate on 30 July 1982, and consequently his duty as deputy on the Board of Directors came to an end. After the question concerning appointment of a new deputy had been discussed with the civil servants' organizations, the Ministry acceeded to the proposal by the Administration that a new deputy should not to be appointed for the remaining part of the Board of Directors' tour of duty.

During the report period, the Board held nine meetings.

In March, the Board arranged a joint meeting with Statoil's Board of Directors at which information was given about the following issues:

- the market for Norwegian gas and oil.
- capacity and structuring of competence in Statoil
- future access to qualified personnel

In the month of June, the Board made a study tour to France, including visits to:

- Elf Aquitaine
- Total
- The research centre, DEMAG, in Pau
- The gas production facilities in Lacq
- Institut Francais du Petrol
- The French Petroleum Directorate, DHYCA

In September, the Board made a tour of inspection to the Valhall field, at the same time as it was informed by the operator, Amoco Norway Oil Company, about organization and activity. The deputies also participated on this tour.

1.2.2 The Organization

In connection with the debate on the budget for 1982, establishment of a special section for assessment of fees was approved of. The section was incorporated into the Department for Legal and Economic Affairs and started operation on 1 January 1982. At the end of the report period, the section employed seven persons.

Within the Administration Department, minor organizational changes were made.

During the report period, an internal work group evaluated the need for and consequences of the establishment of departmental offices for the Norwegian Petroleum Directorate. The group's recommendation was submitted to the civil servants's organizations and has been considered by the General Management. The Board will discuss the report during the first six months of 1983.

1.2.3 Personnel

In the budget for 1982, ten new positions were established, and it was agreed that 37 contract positions should be converted into permanent positions.

At the end of the report period, the Directorate had 282 permanent authorized positions, 4 2/3 transitional positions, and 1 position salaried by the Norwegian Directorate for Development Aid (NORAD). During the year, two of the transitional positions disappeared when the holders resigned.

Eight positions were salaried through the budgets of other government agencies, either as persons with a restricted choice of occupation, or young persons in search of work. Two retired state employees are working on retirement terms, and two scholarship holders from Tanzania have for parts of the year held traineeships with the Directorate on NORAD scholarships.

The possibility of greater flexibility regarding pay questions has been improved in this report period because the Ministry of Consumer Affairs and Government Administration extended the Directorate´s authorities for granting wages and increments.

This, compared with the general labour market situation, might be one of the reasons why the number of resignations has been reduced in relation to previous years, and why there is an increased interest in applying for vacant positions. It also seems as if more applicants had experience from the oil industry.

In this report period, we reengaged three of our former employees who, following a period of service in the oil industry, applied to return to the Directorate.

At the end of the report period, 270 employees were in service. During the same period, the Directorate appointed 35 new employees. Of these, 17 moved in from other districts, including 3 foreigners. Women constitute 33 per cent of the new employees. By the end of the report period, 32 per cent of the employees were women.

Thirty-one employees resigned from their positions, cf. Table 1.2.3.a. This constitutes 11 per cent of the total number of authorized positions as against approximately 14 per cent in 1981 (39 employees) and 17 per cent in 1980 (49 employees). Table 1.2.3.b shows resignations distributed by department and type of position. A survey of positions for 1973-1983 is given in Figure 1.2.3.

TABLE 1.2.3.a. Personnel who left the NPD in 1982 with indication of new place of work.

Table 1.2.3.a

Personnel who left the Norwegian Petroleum Directorate in 1982 with indication of new place of work.

Department	Oil industry	Other private activities	Other public activities	Sundry	Education	TOTAL
Resource Management	11	0	0	0	0	11
Safety Inspection	5	0	0	0	0	5
Legal/Economic	2	1	1	0	0	4
Administration	4	0	0	4	3	11
TOTAL	22 (126)	1 (27)	1 (34)	4 (31)	3 (15)	31 (224)

The numbers in parenthesis refer to the period 1973-82.

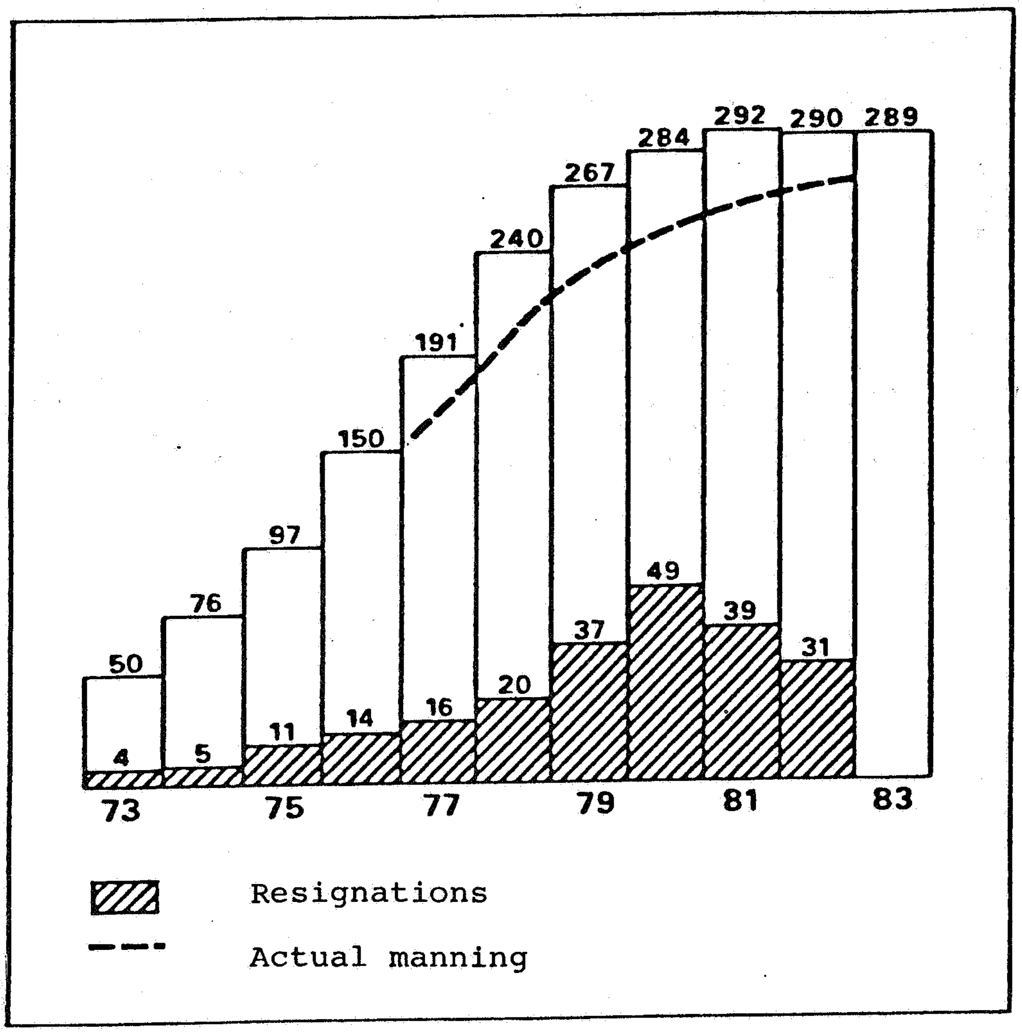
TABLE 1.2.3.b. Personnel who left the NPD in 1982 with indication of type of position.

TABLE 1.2.3.b

Personnel who left the Norwegian Petroleum Directorate in 1982 with indication of type of position.

Department	Superv.	Chief eng.	Head eng.	Geol.	Div. eng.		Lab. pers.	Office pers.	TOTAL
Resource Management	4	0	5	1	0	-	1	-	11
Safety Inspection	1	3	0	0	1	0	0	0	5
Legal/Economic	2	0	1	0	0	1	0	0	4
Administr.	0	0	0	0	0	1	0	10	11
TOTAL	7	3	6	1	1	2	1	10	31

FIGURE 1.2.3. Survey of Positions 1973-1983
Permanent + transitional positions



Codetermination

Generally, cooperation with the employee organizations took place according to the same pattern as for previous years. During the period, a total of 18 meetings were held between the management and the elected representatives of the organizations. In this period, a new form of cooperation was worked out between the general management and the organizations, in that a fixed day was set aside each month on which the general management and elected representatives met.

1.2.4 Training

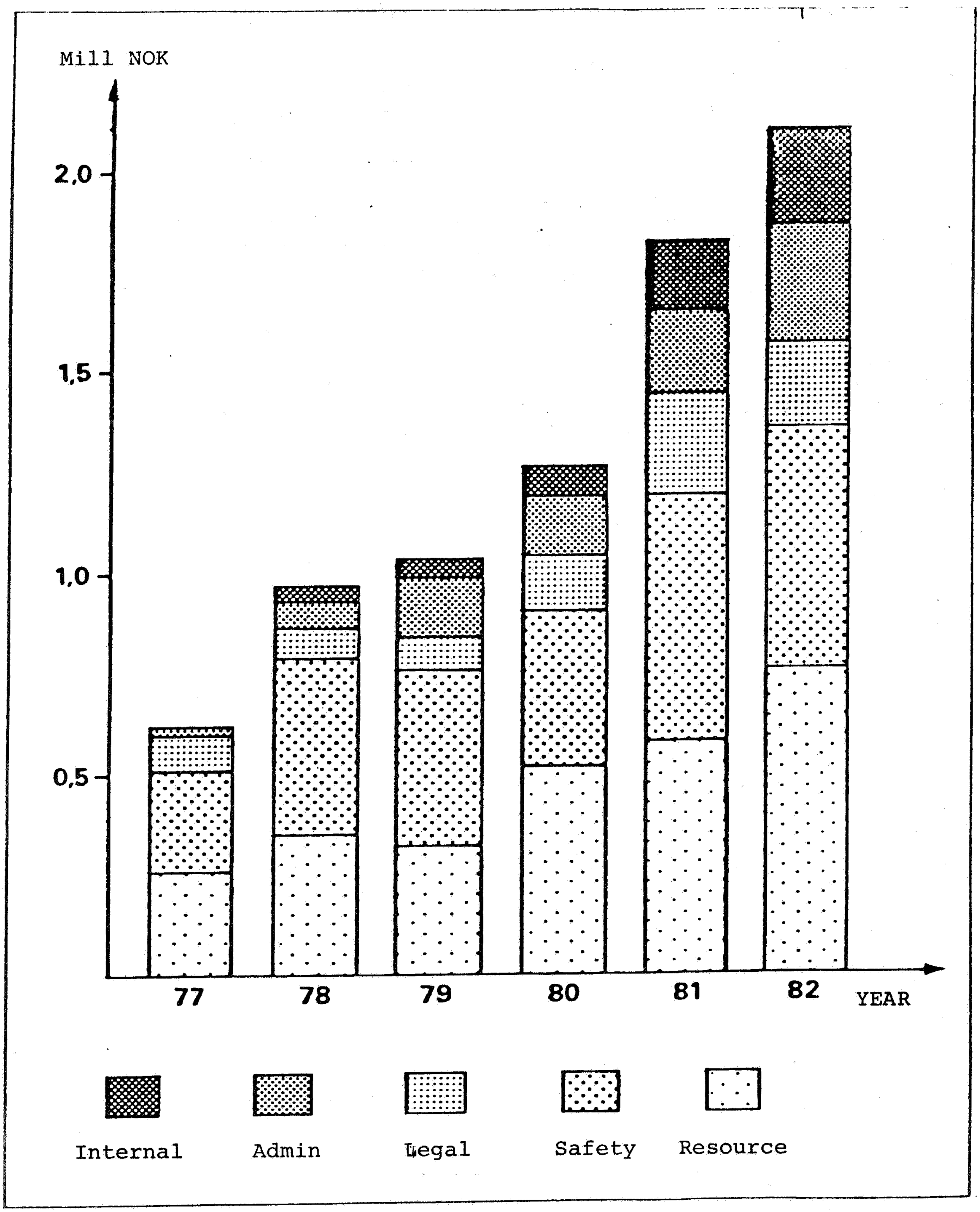
The training budget for 1982 amounted to NOK 2,156,000.- and all of it was utilized. Figure 1.2.4 shows the development and distribution of the funds for 1977-1982.

Of internal training measures, the following are listed:

- Course in quality assurance for all personnel in the Department for Safety Control.
- EDP courses
- Courses in English

Approximately 65 per cent of all training expenses were assigned for travels and stays, of which about 40 per cent involved training abroad. As in 1981, the Directorate has cooperated with the Training Courses Division of the Ministry of Consumer Affairs and Government Administration as regards courses in administrative subjects.

FIGURE 1.2.4. Development and distribution of training budget 1977–82. (Million NOK per year)
(Internal. Administration, Legal and Economic, Safety Control, Resource Management Departments)



1.2.5. Budget and Economy

In 1982, a total of NOK 126,510,000 was allocated to the various Directorate tasks. The amount was distributed as follows:

- Operating budget	NOK 68,980,000.-
- Inspection costs	NOK 15,000,000.-
- Engineering of new facilities	NOK 3,655,000.-
- Geological and geophysical surveys, etc.	NOK 32,375,000.-
- Safety and emergency preparedness research	NOK 2,500,000.-
- Clearing up the seabed	NOK 4,000,000.-
	NOK 126,510,000.-

NOK 43,326,000 from the operating budget goes to expenses and NOK 7,280,000 to the running of buildings. The remaining NOK 18,374,000 represents other expenses such as travelling, training, electronic data processing (EDP), procurements, etc., and expenses for reporting and research purposes.

Revenues

In addition to paid royalties and acreage fees (Ch. 9) the Directorate received revenues totalling NOK 48,500,000. See Table 1.2.5.

TABLE 1.2.5. NPD income development in the period 1973-1982

TABLE 1.2.5

Income development in the period 1973-81

	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982
Sale of publications	-	-	-	30	135	197	291	387	480	794
Sale of released samples	-	-	-	2	33	46	282	235	606	206
Survey fee	345	340	220	210	280	380	420	400	480	320
Insp. expenses	5 525	16 539	19 721	26 717	42 037	45 189	47 358	33 673	26 066	26 492
Sale of data packs.	-	-	-	1 300	3 170	14 847	31.275	35 304	12 947	20 633
Subletting halls	-	288	463	375	76	71	-	-	-	-
TOTAL	5 860	17 177	20 404	28 634	45 731	60 730	79 626	69 999	40 579	48 455
NDP's total budget	28 067	45 380	61 101	79 855	101 160	114 730	123 565	125 949	123 489	126 510

1.2.6. Information

Also during this report period, there has been a brisk demand for information both from Norwegian and foreign institutions, the media, enterprises, and individuals. In the course of the year, the Norwegian Petroleum Directorate was visited by a number of official delegations from other countries. Furthermore, many foreign journalists, individually or in groups, have visited the Directorate to obtain information about it and the oil activity.

The Norwegian Petroleum Directorate´s annual report is a central feature of its information activities. The 1981 annual report and the Directorate´s map of the continental shelf became available in May. In conjuction with this, representatives of the press were invited to meet with the Directorate management, who made themselves available for additional comment to the report.

The Norwegian Petroleum Directorate´s perspective analysis, submitted to the Ministry of Petroleum and Energy on 16 August 1982, was printed as a separate publication in both Norwegian and English. Great interest was registered for the perspective analysis, and a press seminar on the contents was held on 14 December 1982.

The Norwegian Petroleum Directorate participated with a its own stand at the ONS´82 oil exhibition, arranged in Stavanger in August.

The number of press releases issued in 1982 continued to rise in relation to previous years. The increase reflects the escalation of activities on the continental shelf. In the course of the year, 68 press bulletins were released.

1.2.7. The Office in Northern Norway

The Norwegian Petroleum Directorate´s district office in Harstad has been in operation since 20 June 1980. Since its establishment, the staff has consisted of a local representative and a part-time office clerk.

Within the Norwegian Petroleum Directorate´s field of work, the Harstad office has been the Directorate´s link with regional and local authorities and industry in Northern Norway. Furthermore, the office has maintained contact with the press and broadcasting, and has assisted the mass media by making information available. The district office also distributed information in the north of the country by lecturing, attending meetings, etc.

Contact with fisheries organizations is an important aspect of the office´s field of work. A study tour to Stavanger/ the North Sea was arranged for representatives of the fishing industries in Finnmark.

The office also functions as a service body for head office employees on service assignments in the North Sea.

1.2.8. Library

In 1982, the library activities were marked by a change of personnel. A new librarian and head librarian were taken on in the second half of the year. For this reason, the activity level had to be kept relatively low. New services were not initiated during the period.

The number of enquires for book loans and copy work, as well as questions of reference, remained considerable. One third of all inquires come from external users. These include Norwegian and foreign libraries, oil companies, other enterprises within the petroleum industry, and private individuals.

The library personnel also distributed information about the computer based library catalogue (ODIN) and library services to local oil companies, educational institutions, and other libraries.

1.2.9. The INFOIL secretariate

In 1982, the reference publications Olje-indeks and Oil index have, following a price increase to subscribers, provided revenues some 50 per cent in excess of those of the previous year, despite the fact that the number of subscriptions is almost the same.

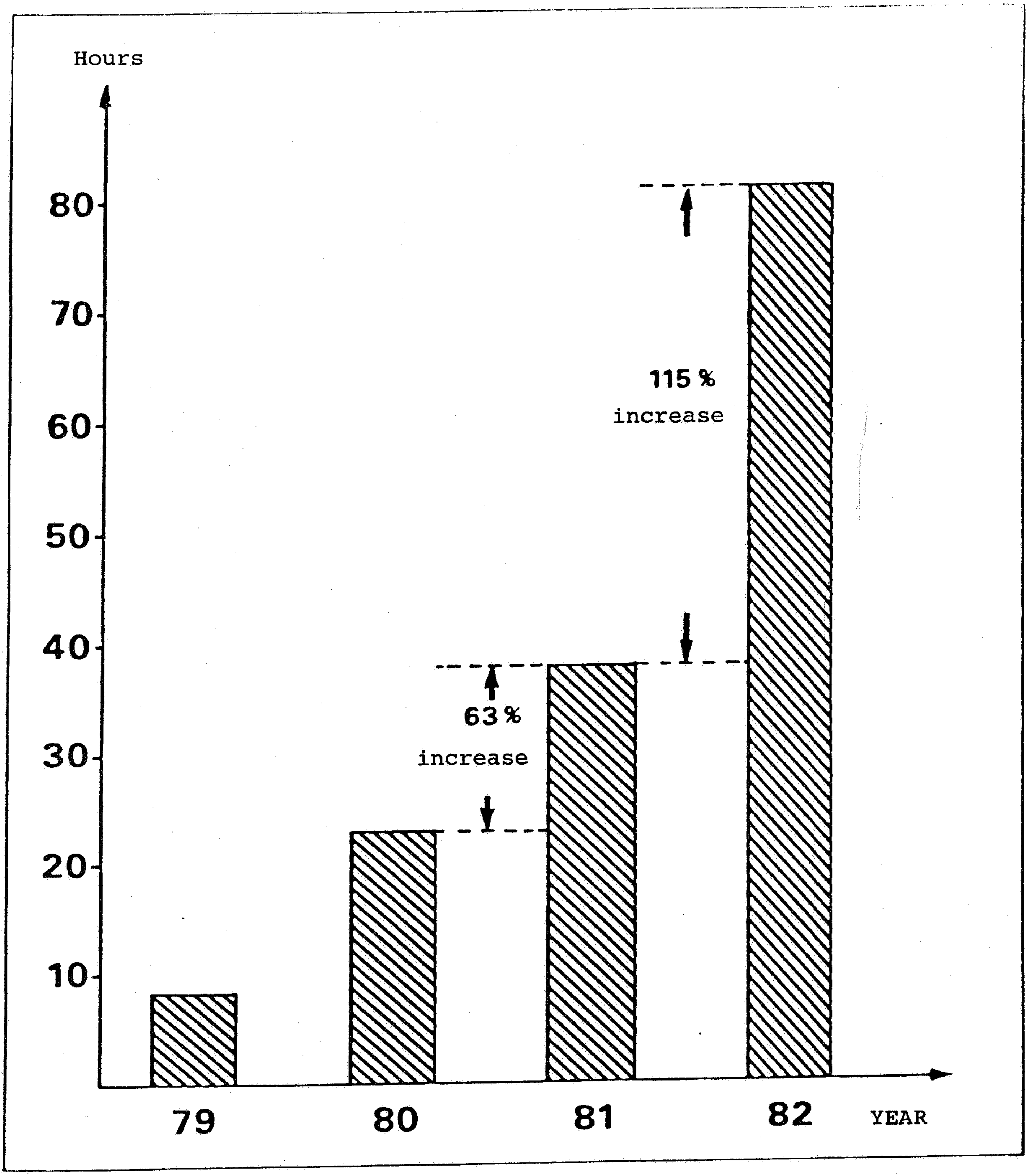
The data base OIL, which comprises the two above-mentioned reference works, showed an increase in demand of more than 100 per cent, from 40 to more than 80 hours (Figure 1.2.9).

The data base INFOIL II was made available to the public on the Nordic data network Scannet on 1 July 82, and had been used for 24 hours by the end of the year. The British Department of Energy, which participated in the funding of the data base, provided the base with information on British research projects related to offshore industries. In addition come the Norwegian project data already present in the base, which mainly originate from the Norwegian Research Council of Technology and Natural Science.

Active marketing of the two above-mentioned data bases took place through participation in a total of nine seminars, industry fairs and demonstrations in Norway and Great Britain.

The Infoil secretariate, in collaboration with the Institute of Offshore Engineering at Heriot Watt University, arranged the "Offshore Information Conference 1982" in Aberdeen with 17 Norwegian participants.

FIGURE 1.2.9. Paid up network time for OIL on Scannet 1979-82



1.2.10. Rationalization/ effectivization

In 1982 also, the Norwegian Petroleum Directorate experienced a steep growth in the utilization of electronic data processing designed to effectivize its work.

New terminals and other EDP-equipment were also taken into use.

Use of computers in the Legal and Economic Department

The department developed a model which has become a servicable tool for the execution of economic field and company analyses (the "Company Model"). The model is used, among other things, in connection with the Norwegian Petroleum Directorate's perspective analysis, to calculate the government's revenues from the oil activities.

In 1982, a data base containing capacity figures for Norwegian shipyards was developed. This information will be useful in analyses where field and development solutions are to be evaluated.

A planning model has been made available for the department by Statoil (the "Portfolio Model"). It is to be used in connection with the perspective analysis to evaluate time scheduling of fields on the basis of certain selected objective criteria such as production, investments, and labour. The model is being further adapted by the Norwegian Petroleum Directorate for its own needs.

The reporting of production figures and calculation of royalties previously meant extensive manual work. The use of EDP has reduced much of the routine involved, and has given the executive officers the chance to concentrate on more important work tasks.

Use of computers in the Safety Control Department

The Safety Control Department receives daily drilling reports from the companies regarding the progress of the wells being drilled. For the department to be able to carry out independent controls of the drilling activities more efficiently, a computer system has been developed for the registration and follow-up of the daily drilling logs. The arrangement was test run in the summer of 1982. In conjuction with this EDP-system, the department has taken modern graphic equipment into use. This is one reason why the department today can claim a clearer idea of the progress of the various wells, both those being drilled and those which are completed.

When it comes to the Directorate's own verification that requirements are complied with by the deadlines laid down, an EDP-system was developed in 1982 with the basic objective of making such verification more effective. This system was brought into test operation temporarily until the end of 1982.

When a work accident takes place on the continental shelf causing absence on the next shift or requiring medical treatment, the employer is required to send a notification of this to the Directorate. The NPD's Safety Control Department has an EDP-system in operation for recording such accidents for later print-outs, for example of statistics for use in safety work. During the report period, this system was revised. The new version builds on a more detailed classification of accidents, and has more options with respect to the statistical processing of registered data.

Use of computers in the Resource Management Department

The practical application of the Norwegian Petroleum Directorate's GEO-DATA BASE is well under way and is continually being developed. By evolving general, user-oriented programs, aids and tools are gradually being put together to enable experts, geologists, and geophysicists themselves to utilize modern computer systems in their daily work. This reduces routine manual chores, a fact which in turn will increase the productivity of the interpretation assignments in question.

The Norwegian Petroleum Directorate's production data base has been further developed, and together with graphic equipment it gives a swift and orderly display of historical data for individual fields on the continental shelf.

In 1982, the production data base was connected to the system for short-term prognoses. This provides automatic up-dating and has further removed some routine work.

Through Norsk Hydro, the Norwegian Petroleum Directorate received and took into use a new and improved model for process simulation.

Extensive computer systems have been designed to effectivize the production of perspective analyses. These systems are being further refined.

As a step in an increasingly more efficient mapping of oil and gas prospects on the continental shelf, the Norwegian Petroleum Directorate purchased in 1982 a separate computer facility for the processing of seismics. The system, complete with software, was installed in the Directorate's premises in the course of the summer and officially inaugurated by the Minister of Petroleum and Energy, Vidkunn Hveding, on 24 August 1982. The system has proved, during its six months of operation, to be an invaluable tool for controlling and improving the data quality of accumulated seismics.

Use of computers in the Administration Department

In 1982, the Directorate's Administration Department effectivized its activity, both by reorganizing and by taking into use better equipment.

By the end of 1982, electronic word processing had been adopted at ten workstations in the writing pool.

The library, Publications Office, Personnel Section, and Budget and Economy Section, have all upgraded or extended their use of computer systems.

The Directorate's EDP-based filing system EKSARD was improved also in 1982, not least with respect to arrears control.

The computer file now contains information on over 50,000 cases.

At the end of the year in 1982, efforts were also under way to introduce computer based equipment in the drawing office.

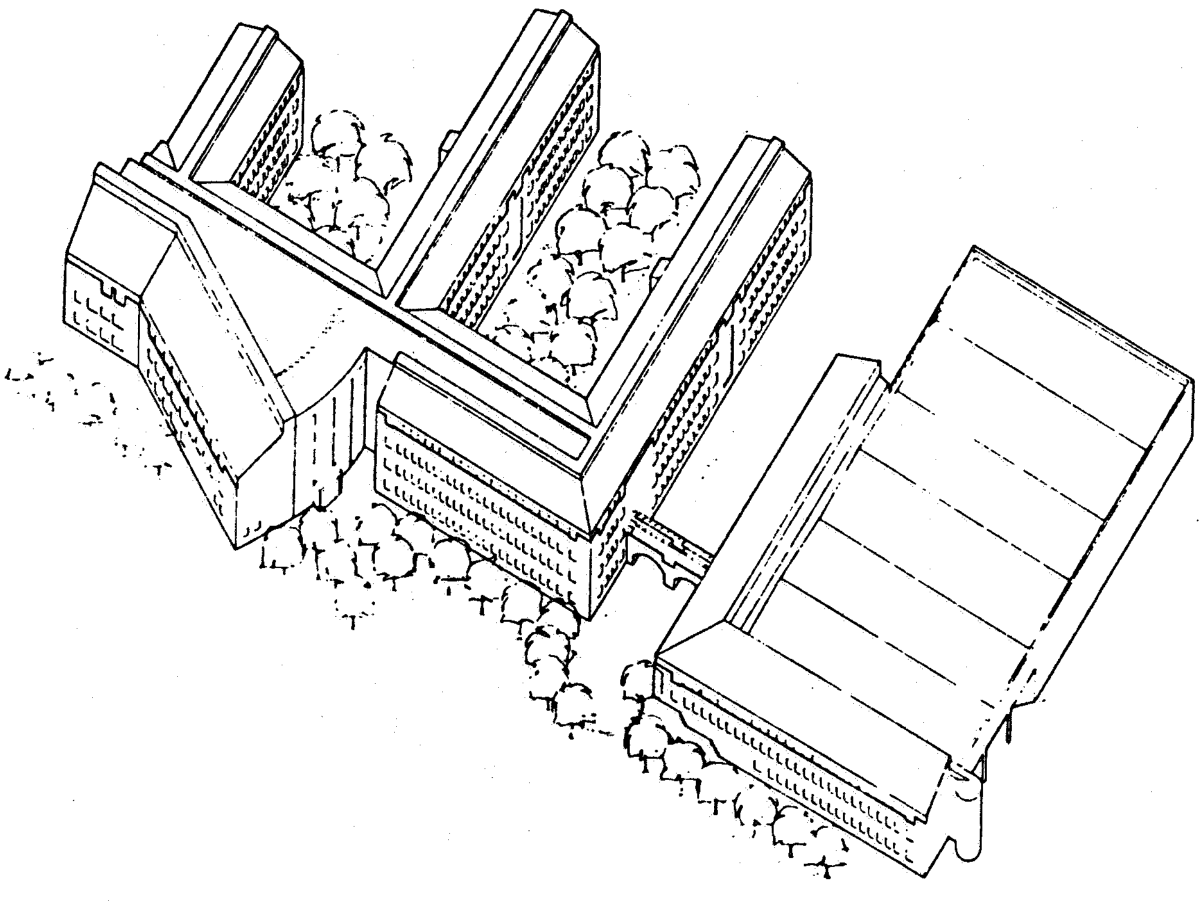
1.2.11. Premises

During this period too, we have enjoyed satisfactory office facilities, if one disregards the fact that Directorate offices are located at two different sites in Stavanger. During this report period, we have been able to expand our office space, thus covering our needs for the near future.

The preparation work for a new building in the Ullandhaug area continued under the auspices of the Construction and Property Directorate (Figure 1.2.11). The pilot project received approval in December 1982, and the Stavanger City Planning Authorities have approved the plans for building on the site.

According to the current revised time schedule, construction work is due to start in February/ March 1984. The building is planned to be completed in January 1986, with occupation by March 1986.

FIGURE 1.2.11. The Norwegian Petroleum Directorate´s new building project in the Ullandhaug area



2. ACTIVITIES ON THE NORWEGIAN CONTINENTAL SHELF

2.1. Exploration and production licences

2.1.2. Production licences

In 1982, 12 new production licences were allocated. Production Licences 073-078 make up the third division of the fifth allocation round. Production Licence 079 (part of Block 30/9) was allocated as a result of the discovery of hydrocarbons in Block 30/6. Production Licences 080-084 on Trænabanken make up the seventh allocation round and constitute a new exploration area on the Norwegian continental shelf. All the new production licences were awarded to Norwegian operators with the exception of one on Haltenbanken (BP) and one on Trænabanken (Phillips).

TABLE 2.1.2.a. Fifth round blocks (third division). Granted by Royal Decree of 23 April 1982.

Prod´n no	Field/Block	Ownership	Operator (O)/ Concession holder
73	6407/1	50.000	O/Den norske stats oljeselskap a.s
		20.000	Norsk Conoco A/S
		20.000	Amoco Norway A/S
		10.000	Norsk Hydro Produksjon a.s
74	6407/2	10.000	O/Saga Petroleum a.s
		50.000	Den norske stats oljeselskap a.s
		15.000	Norsk Agip A/S
		15.000	Arco Norge A/S
		10.000	Deminex (Norge) A/S
75	6507/10	30.000	O/BP Petr. Dev. of Norway A/S
		50.000	Den norske stats oljeselskap a.s
		10.000	Arco Norway A/S
		10.000	Union Oil Norge A/S
76	7119/7	25.000	O/Norsk Hydro Produksjon a.s
		50.000	Den norske stats oljeselskap a.s
		15.000	Elf Aquitaine Norge A/S
		10.000	A/S Norsk Shell
77	7120/7	50.000	O/Den norske stats oljeselskap a.s
		15.000	Norsk Hydro Produksjon a.s
		10.000	Phillips Petroleum Norsk A/S
		10.000	Texaco North Sea Norway A/S
		10.000	Total Marine Norsk A/S
		5.000	Saga Petroleum a.s
78	7120/9	25.000	O/Norsk Hydro Produksjon a.s
		50.000	Den norske stats oljeselskap a.s
		15.000	Elf Aquitaine Norge A/S
		10.000	A/S Norske Shell

TABLE 2.1.2.b. Allocation of Production Licence 079. Granted by Royal Decree of 20 September 1982.

Prod´n no	Field/Block	Ownership	Operator (O)/ Concession holder
73	6407/1	15.000	O/Norsk Hydro Produksjon a.s
		70.000	Den norske stats oljeselskap a.s
		10.000	Saga Petroleum a.s
		5.000	Non-allocated share

TABLE 2.1.2.c. Seventh round blocks. Granted by Royal Decree of 10 December 1982.

Prod´n no	Field/Block	Ownership	Operator (O)/ Concession holder
80	6609/5	50.000	O/Den norske stats oljeselskap a.s
		15.000	Esso Exp and Production Norway A/S
		30.000	Phillips Petroleum Norsk A/S
		5.000	Norsk Hydro Produksjon a.s
81	6609/7	30.000	O/Phillips Petroleum Norsk A/S
		20.000	Esso Exp and Production Norway A/S
		50.000	Den norske stats oljeselskap a.s
82	6609/10	10.000	O/Saga Petroleum a.s
		30.000	Esso Exp and Production Norway A/S
		10.000	Norsk Hydro Produksjon a.s
		50.000	Den norske stats oljeselskap a.s
83	6609/11	25.000	O/Norsk Hydro Produksjon a.s
		20.000	Arco Norge A/S
		5.000	Svenska Petroleum Exploration A/S
		50.000	Den norske stats oljeselskap a.s
84	6610/7	50.000	O/Den norske stats oljeselskap a.s
		25.000	Elf Aquitaine Norge A/S
		25.000	Norsk Agip A/S

TABLE 2.1.2.d. Production licences as of 31 December 1982.

Granted with effect from	Production licence no	Total area in sq km	Number of blocks
1.9.65	001-021	39 842,476	74
7.12.65	022	2 263,565	4
23.5.69	023-031	4 107,833	9
30.5.69	032-033	746,285	2
14.11.69	034-035	1 024,529	2
11.6.71	036	523,937	1
10.8.73	037	586,834	2
1.4.75	038-040,42	1 840,547	7
1.6.75	041	488,659	1
6.8.76	043	604,559	2
27.8.76	044	193,077	1
3.12.76	045-046	1 270,682	4
7.1.77	047	368,363	2
18.2.77	048	321,500	2
23.12.77	049	485,802	1
16.6.78	050	500,509	1
6.4.79	051-058	4 007,887	8
18.1.80	059-061	1 108,078	3
17.3.81	062-064	1 099,522	3
21.8.81	065-072	3 218,945	9
23.4.82	073-078	2 311,912	6
20.8.82	079	102,167	1
10.12.82	080-084	2 082,966	5
		69 100,634	150

TABLE 2.1.2.e. Licenced area as of 31 December 1982.

Production licence awarded	Original area in sq km	Relinquished area as of 31.12.82	Licenced area in sq km	Licenced area in per cent	Subdivided among number of blocks
1965	42 106,041	36 338,422	5 767,619	13,70	26
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	1 456,827	872,379	37,45	5
1976	2 068,318	924,825	1 143,493	55,29	5
1977	1 175,665	-	1 175,665	100,00	5
1978	500,509	-	500,509	100,00	1
1979	4 007,887	-	4 007,887	100,00	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
	69 100,634	42 281,303	26 819,331	38,81	92

2.1.3 Share transfers

No transfers of shares were made in 1982.

2.1.4 Relinquishments

In 1982, areas having production licences were relinquished on five production licences. These are given in Table 2.1.4.

TABLE 2.1.4. Relinquishments

Production licence	Block	Operator
005	7/3	Union
041	35/3	Saga
043	30/4	BP
044	1/9	Statoil
045	24/11 and 24/12	Statoil

Blocks 7/3, 24/11 and 24/12 were relinquished in their entirety.

Relinquishment of Production Licences 041, 043 and 045 occurred in accordance with the relinquishment rules pursuant to the Royal Decree of 8 December 1972.

Block 35/3 was relinquished 49.94 per cent, or 244,000 sq.km. The allocated area as from 1 June 1982 constituted 244,688 sq.km.

Production Licence 043 consists of two blocks, 29/6 and 30/4. The concession holders of Production Licence 043 received dispensation from the relinquishment rules. This resulted in Block 29/6 being retained in its entirety, while Block 30/4 was relinquished 59.65 per cent, or 303,216 sq.km. The total relinquishment of Production Licence 043 amounts to 50.15 per cent. The allocated area as per 6 August 1982 constituted 301,343 sq.km.

The concession holders in Block 1/9 also received dispensation from the relinquishment rules. Due to the formulation of the production licence, 46.83 per cent was relinquished. This constitutes 90,419 sq.km. The allocated area as of 27 August 1982 was 102,658 sq.km.

2.2. Surveying and exploration drilling

2.2.1 Geophysical and geological surveys

2.2.1.1 The Norwegian Petroleum Directorate´s geophysical surveys

The Norwegian Petroleum Directorate´s geophysical surveys in 1982 were concentrated in two areas. Some 3050 km were shot in an area north of the Troms area between 71o30´N and 72o00´N (Figure 2.2.1.a). This part of the survey was performed to be able to recommend to the political authorities new blocks for opening during 1983. See Figure 2.2.1.c. Further surveys are planned for 1983.

In the north-eastern part of the Barents Sea, 4050 km were shot (Figure 2.2.1.b) as a continuation of the regional network. The objective in the first place is to establish a grid of approximately 15 km. Altogether, the Norwegian Petroleum Directorate collected 7100 km seismics in 1982, and approximately 6000 km gravimetrics. In the Barents Sea, further seismic data were collected by analogue kicker. The field work was performed by GECO A/S as prime contractor, while A/S Geoteam undertook the recordings with analogue kicker. For the examination of Troms, a special navigation system was employed of Argo and Syledis type. This is an expensive system, but necessary to achieve accuracies of +/- 10 meters, which is considered essential for this type of survey.

In 1982, the Norwegian Petroleum Directorate processed the main body of the data collected in 1981. The two largest contracts were awarded to the French company Compagnie General de Geophysique (CGG) and the English company Horizon Exploration Ltd. Both companies have offices in London where all processing work took place. CGG processed a total of 5200 km and Horizon 2200 km. These two companies were chosen mainly because they can offer a good and flexible program package. The Norwegian company GECO A/S, with its processing center in Stavanger, also performed a portion of the processing work for the Norwegian Petroleum Directorate in 1982.

FIGURE 2.2.1.a Seismics shot on the Troms area.

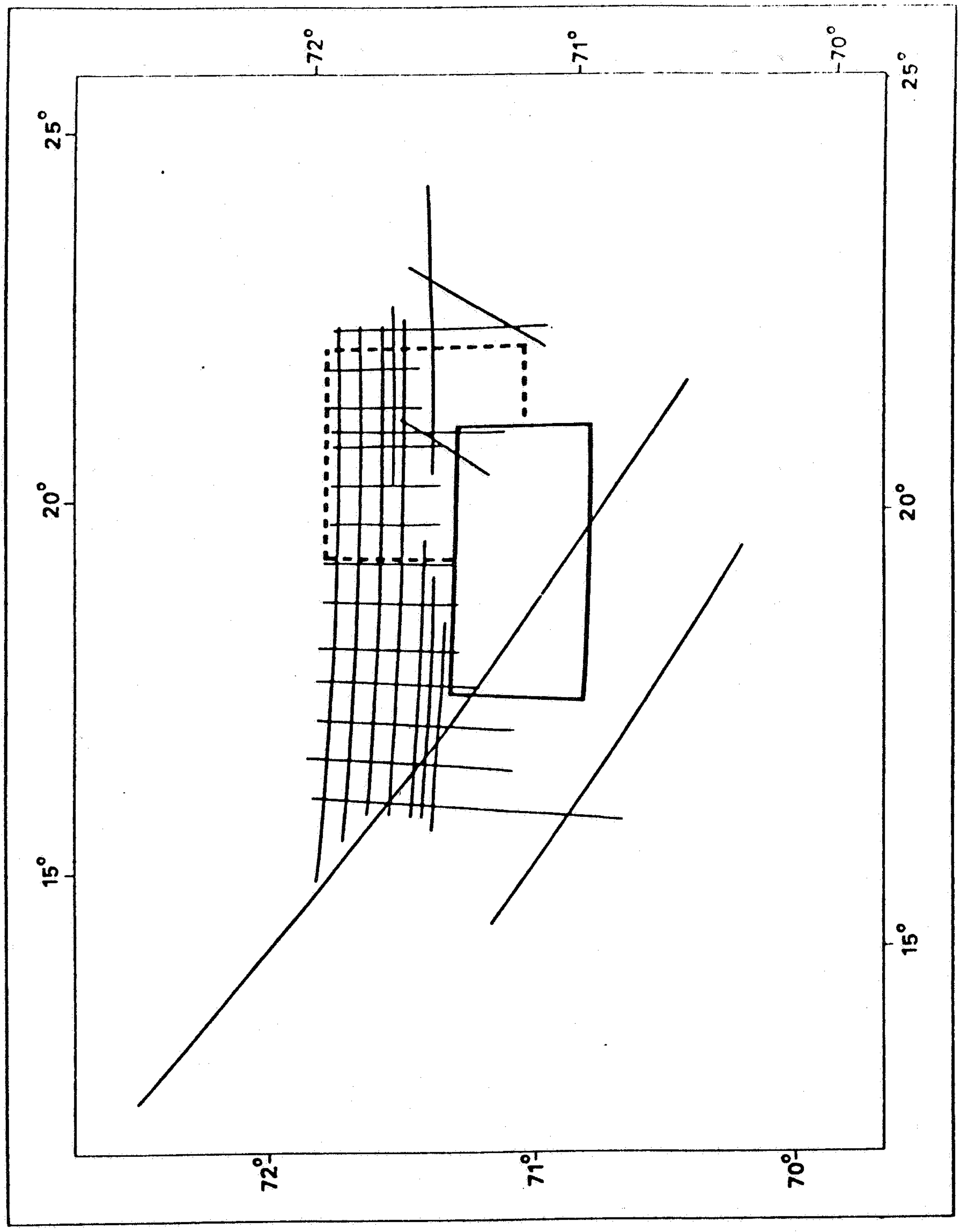
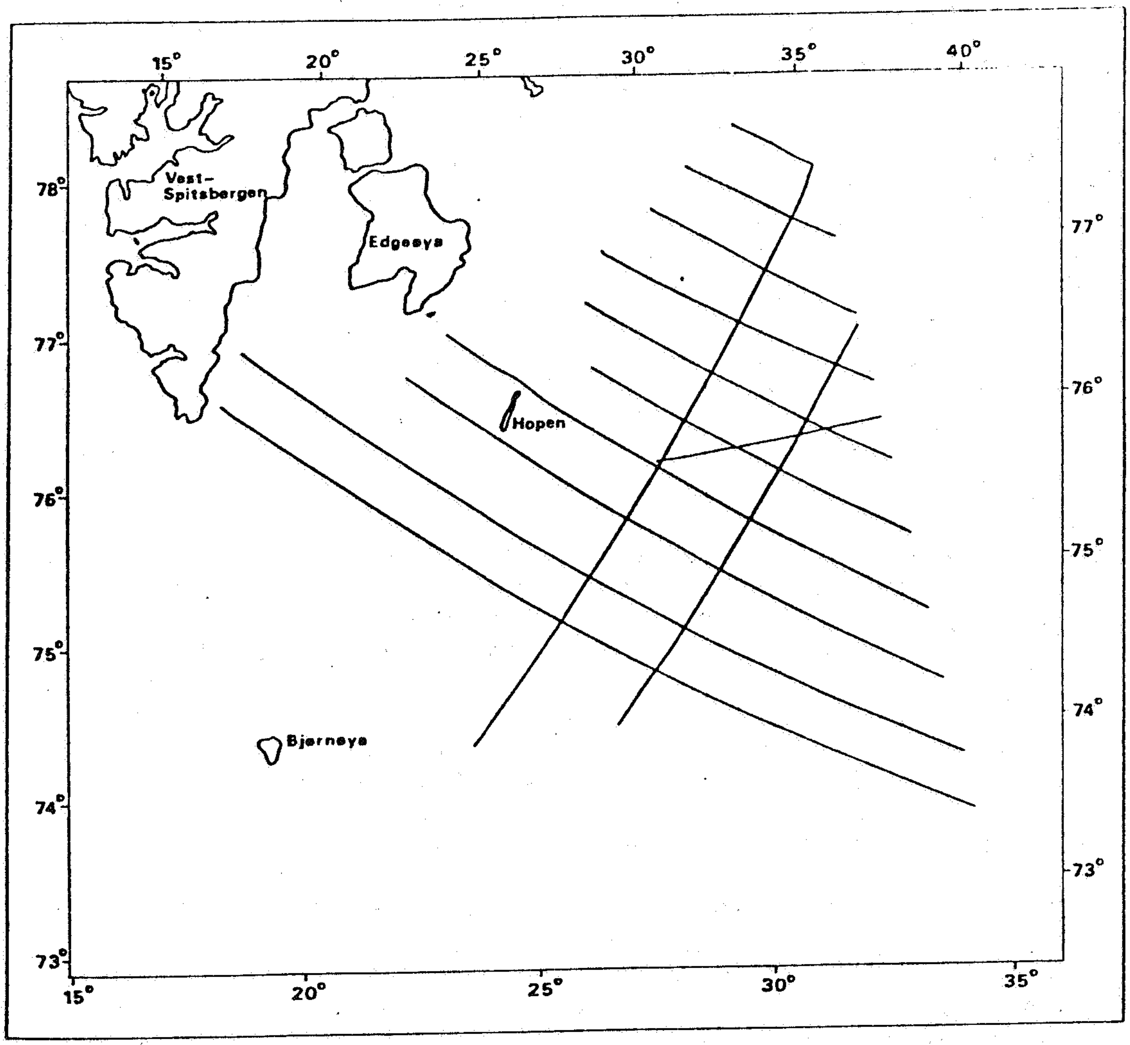


FIGURE 2.2.1.b Seismics shot in the Barents Sea.



2.2.1.2. Geophysical surveys under company direction

In 1982, a total of 50,000 km seismics was shot on the Norwegian continental shelf under the direction of the oil companies or contractors (Figure 2.2.1.c). Of these, 38,000 were shot in the North Sea and 12,000 km north of Stad in the areas of Haltenbanken, Trænabanken and Troms I (Figure 2.2.1.d).

The three Norwegian companies, Statoil, Norsk Hydro and Saga performed a total of 31,200 km, while the foreign oil companies shot 11,400 km. The remaining 7,400 km are speculative surveys performed by the contractors GECO, NOPEC and Western Geophysical. Of the seismic measurements taken in the North Sea, four 3D surveys have been performed, or detailed surveys with very high line density. This type of data is collected from limited areas on fields which have been proven and are being evaluated for development. Two of the surveys were performed by Statoil in 34/10, the Gullfaks Delta structure and in 15/9, Sleipner. The remaining two surveys were performed by Norsk Hydro on 30/7 and the Oseberg area. Interpretation of 3D data involves special problems, first and foremost due to the enormous amount of data. To be able to perform an effective interpretation of this type of data, it is necessary to find more effective work methods. One is working with data bases and interactive interpretation in computers. The Norwegian Petroleum Directorate has started work with a geophysical data base for storing data. All data collected on the Norwegian shelf are now routinely stored in the Norwegian Petroleum Directorate's data base. To ease interpretative work, charts can be plotted and posted interactively from the same data base. The Norwegian Petroleum Directorate sees a very great demand in the future for further development of EDP aids to be able to keep the huge amounts of data up to date, and perform effective work.

Three dimensional processing of seismic data, which has become more common in recent years, represents the greatest step forward in this sector for a long time. By shooting a dense network over a reservoir, this process will provide whole-volume data coverage with 3D migrated data. Two dimensional migration usually only provides correct results if shooting is performed at right angles to the structure. One of the other most important advantages is that one, during interpretation, can obtain many different 2D sections, horizontal and vertical, and zig-zag profiles between wells, etc.

During 1983, GECO will, as the first company in the world, launch the marketing of a system for interpretation of 3D data. There is no doubt that commercially available systems will be used by all companies which have 3D data to interpret.

FIGURE 2.2.1.c Geophysical surveys north of Stadt

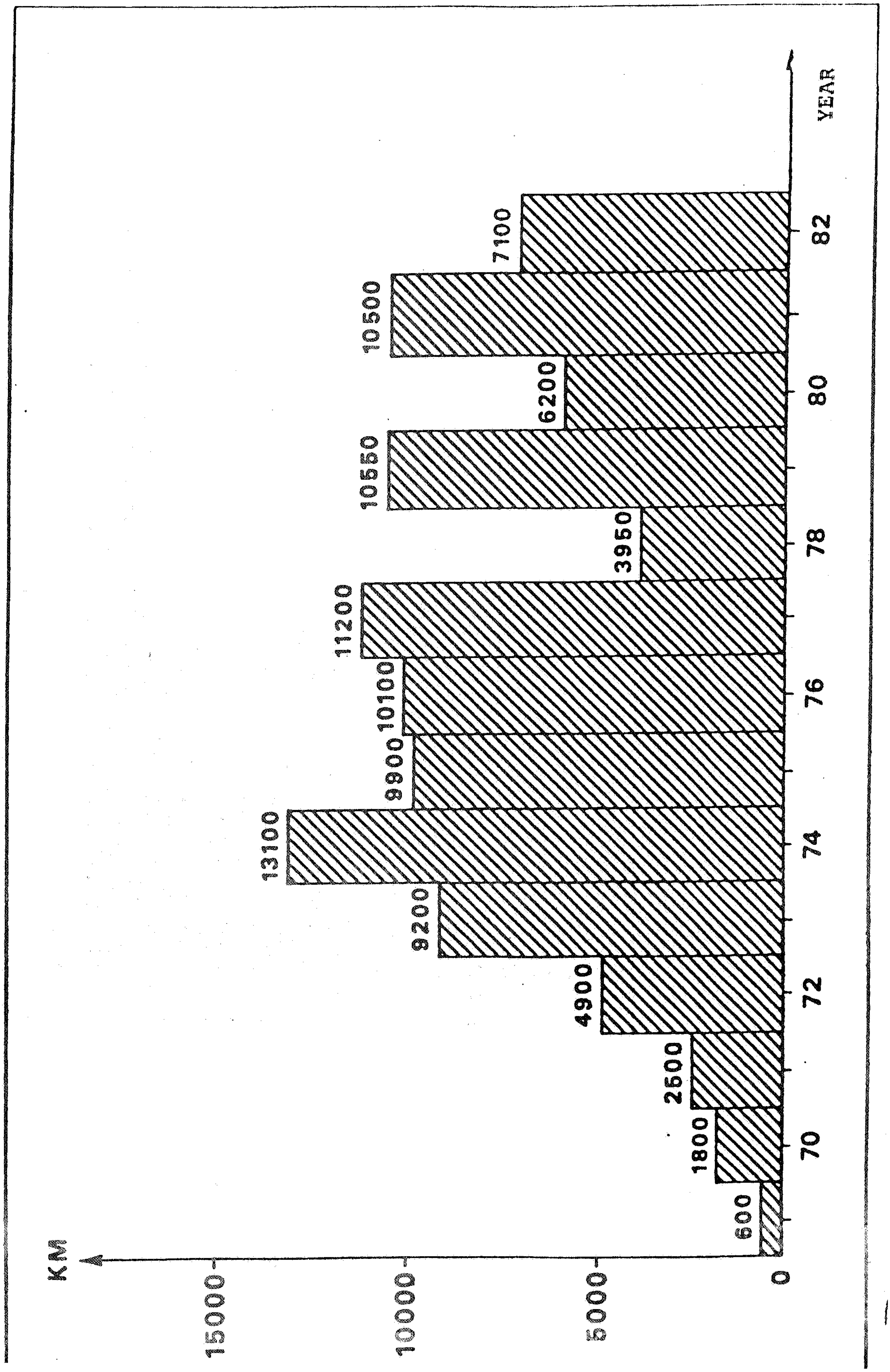
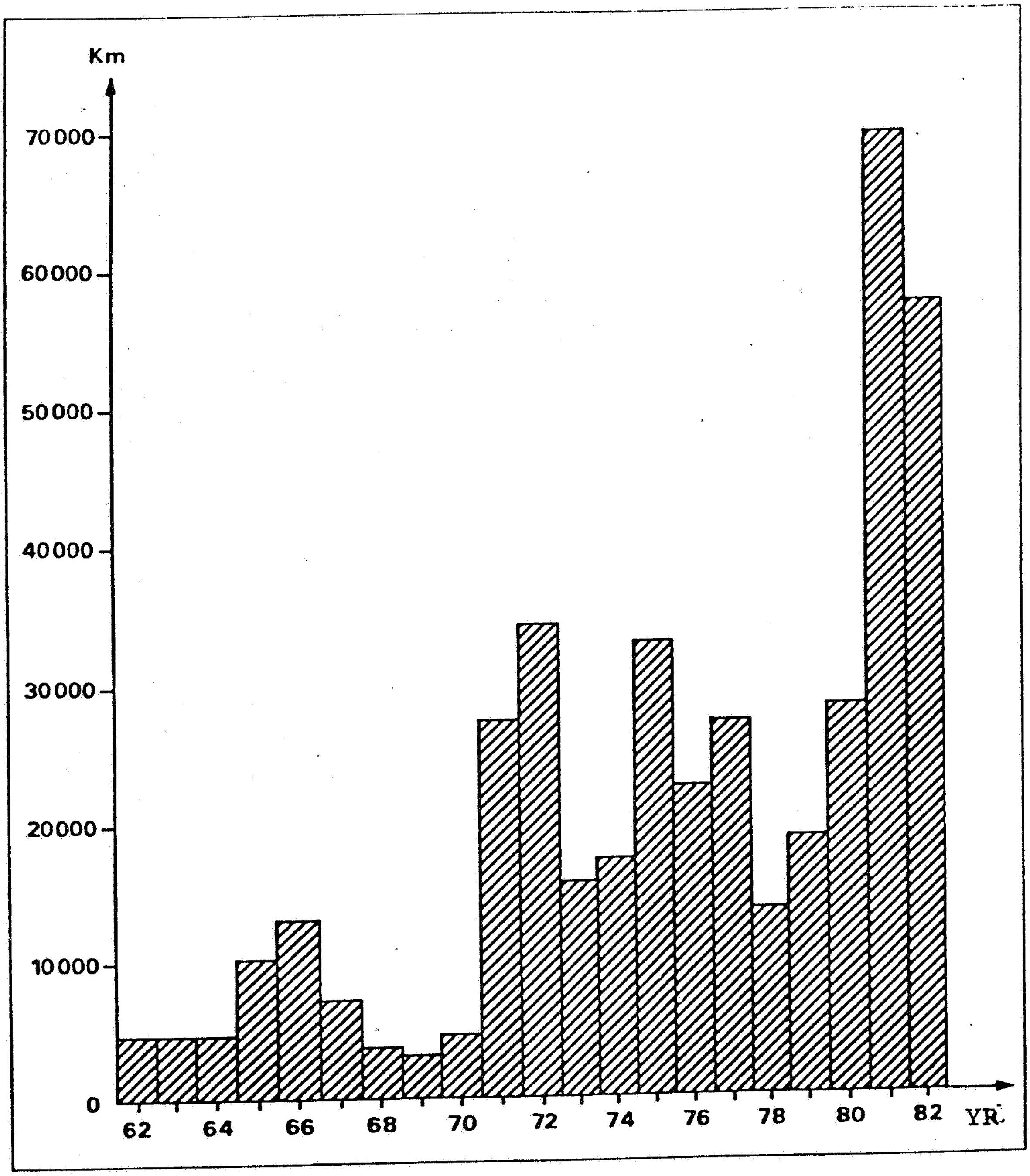


FIGURE 2.2.1.d Geophysical surveys on the whole Norwegian continental shelf (also north of 62oN).



2.2.1.3 The costs of seismic surveying

The total costs of seismic surveys for 1982 were some NOK 240 million.

2.2.1.4 Sale of seismic data

On 10 June 1982, three seismic data packages were offered:

- "Møre-shelf 62-65oN". This package consisted of 2920 km seismics at a price of NOK 1.79 million. The package was purchased by the following companies: Norsk Hydro, BP, Saga, Amoco, Elf Aquitaine and Shell.
- "Norlandsryggen". The package offers 1350 km seismics for NOK 0.51 million, and was bought by the following companies: Elf Aquitaine, Norsk Hydro, Getty, BP, Shell, Statoil, Saga, Total and Phillips.
- Regional Data, Troms East. This package consists of 725 km seismics at a price of NOK 0.16 million. The buyers were: Elf Aquitaine, Norsk Hydro, Statoil, Saga and Mobil.

Further, seismic data packages were sold which had been offered to the oil companies on previous occasions.

In all, seismic data was sold to the value of approximately NOK 24 million in 1982, which means that the state surveys have in fact been self-financing this year. The increased activity has brought with it less delay between collection, processing and sale to the companies. The capital costs have thus been greatly ameliorated in relation to conditions previously. The Norwegian Petroleum Directorate´s role as the leading collector and seller of geophysical data in non-opened areas is a highly favourable control instrument to select new areas for exploration drilling, and to ensure that the seismic surveys do not just concentrate in the most interesting areas.

2.2.1.5 Release of data

The Norwegian Petroleum Directorate can release geological material and non-interpreted data from the continental shelf which this becomes more than five years old.

Non-interpreted logs are released for sale when the well is presented in Well Data Summary Sheets published by the Directorate. All wells finished before 1978, in all 185, have now been presented in eight volumes in the series. Volume 8, to be published early in 1983, describes the following 19 wells, drilled to completion in 1977:

1/9-1	7/12-4	24/9-2	33/9-9
1/9-2	8/4-1	25/2-6	
1/9-3	9/4-4	30/7-4	
2/11-3	15/3-2	30/7-5	
7/12-3	15/6-5	30/7-6	
7/12-3S	15/9-1	30/9-8	

More extensive lithologies of the individual wells are given in the Norwegian Petroleum Directorate's series of "NPD Papers". During 1982, two volumes covering a total of 33 wells were issued. At the end of 1982, 93 wells had been published in 32 volumes (Table 2.2.1.a).

TABLE 2.2.1.a. NPD Papers.

Volume Number	Wells	Volume number	Wells
1	8/3-1	22	8/10-1
2	25/11-1	23	11/10-1
3	16/2-1	24	9/4-1,2,3
4	16/11-1	25	2/4-1,2,3,4
5	9/8-1	26	10/8-1
6	16/1-1	27	9/12-1
7	2/11-1, 2/8-1	28	25/11-2,3,4
8	16/11-1		25/10-1,2,3
9	16/6-1		25/8-1
10	7/11-1,2,3,4	29	24/4-1,2,3,4
11	16/9-1	30	2/7-1,2,3,6,7,8,9
12	17/11-1	31	7/1-1,7/8-2,7/9-1
13	2/8-2		8/1-1,8/4-1,8/9-1
14	17/4-1		8/11-1,8/12-1,9/4-4,9/10-1
15	1/3-1,2		9/11-1,10/5-1,11/9-1,
16	7/12-1		16/8-1,16/11-2,17/9-1,
17	2/3-1,2,3		17/11-2,17/12-1,17/12-1,
18	7/8-1		18/11-1
19	2/6-1	32	2/7-11,2/8-3,4,6,7,8,9
20	7/3-1		10,11
21	17/10-1		2/9-1,2/10-1,2/11-2,3/7-1

Below we give a summary of the volumes published and the wells included in the individual volume.

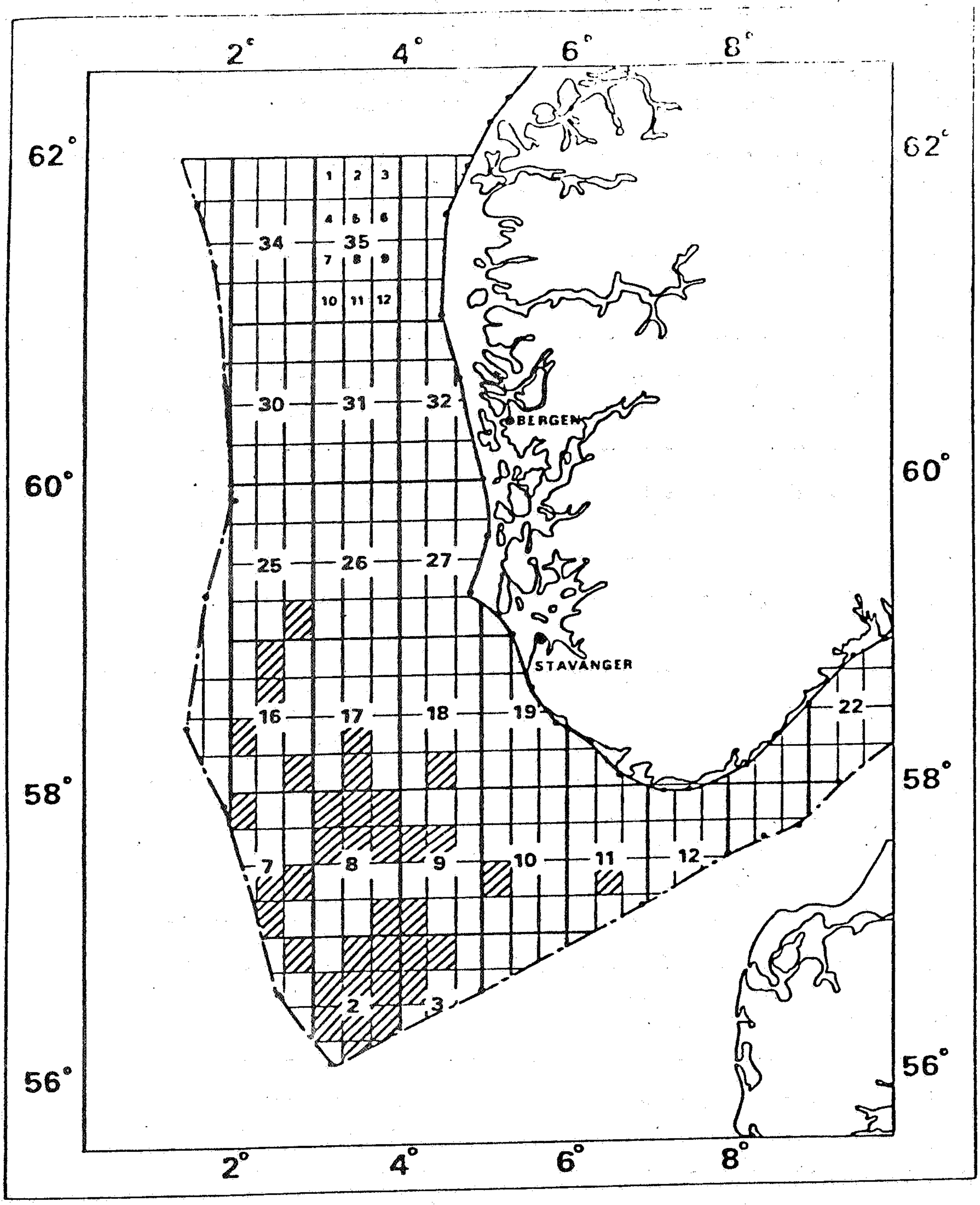
The Norwegian Petroleum Directorate has determined that this series will not be continued in its present form for the time being, which means that Volume 32 will mark the provisional end of the series. On the other hand, a new series of publications will be started, called the NPD Contributions, in which specialist articles, lectures, etc. will be issued.

Seismic data will be released in large packages for relinquished blocks. Data from only one block was released in 1982 due to capacity problems.

At the end of the year, 16,634 km seismic lines were available from 37 relinquished blocks or parts of blocks. The price was fixed to cover reproduction costs, postage and an administrative fee.

Figure 2.2.1.e provides a summary map stating the blocks for which seismic data have been released.

FIGURE 2.2.1.e. Blocks for which seismics have been released



2.2.1.6 Assignments for scientific institutions

Partly on the initiative of the research institutions and partly on the Norwegian Petroleum Directorate's own, geological and geophysical research institutions perform investigations supported economically by the Directorate. These investigations are based on the Norwegian Petroleum Directorate's work tasks and comprise an integrated part of the petroleum-orientated surveys on the continental shelf.

In 1982, nine different projects were supported by the Norwegian Petroleum Directorate with a total of NOK 549,000.

PROJECT	RESEARCH INSTITUTION
Maritime geophysical survey between 64-66oN. Fieldwork at sea.	Earthquake station University of Bergen
Survey of continental margin off Lofoten.	Earthquake station University of Bergen
Catalogue, dinoflagellate cysts	Institute of Geology University of Oslo
IGCP project 124	Institute of Geology University of Oslo
Sedimentological studies of mezozoic rocks from the Norwegian-Danish basin	Institute of Geology University of Oslo
Paleontological and sedimentalogical surveys of the jura strata layers in the northern North Sea	Institute of Geology University of Oslo
Maritime geophysical research	Institute of Geology University of Oslo
Processing of geological data from the Barents Sea	Norwegian Polar Institute
Base rock tectonics on the Norwegian continental shelf	Institute of Petroleum Technology and applied geophysics. Norwegian College of Technology, Trondheim.

2.2.1.7 Scientific research

As of 31 December 1982, a total of 155 licences for scientific research had been awarded on the Norwegian continental shelf. As seen from Table 2.2.1.b, fifteen such licences were granted for 1982. Most research stressed geology and geophysics, with some biology work.

TABLE 2.2.1.b. Licences for scientific research for natural resources.

Licence	Name	Work field Geophys	Geol	Biol	Area
141	Bedford Institute of Oceanography, Nova Scotia			x	Norwegian Sea and Greenland Sea
142	Institute for Continental Shelf Research		x		Helgeland coast
143	Ministry of Agriculture Directorate of Fisheries Research, England	x	x	x	North Sea
144	Norwegian Geological Survey	x			Trondheim Fjord
145	Norwegian Polar Institute	x			Polar Sea
146	DAFS Marine Lab., Scotland		x	x	North Sea
147	Institute of Continental Shelf Research	x	x		North Sea and Storegga off Møre
148	University of Bergen Earthquake station	x	x		North Sea
149	Institute of Geological Sciences, Marine Geophysics Unit, Scotland	x			North Sea
150	University of Tromsø, Institute of Biology and Geology	x	x		Andfjord and Indøy Deep north to Bjørn Island Trench
151	Institute for Oceanography at the University of Kiel, Federal Republic of Germany	x	x		Skagerak and northwest coast of Norway
152	Norwegian Geological Survey	x	x		Trondheim Fjord
153	Norwegian Geological Survey	x			Northern Trondheim lead Southern Helgeland coast Inner and outer Drammen Fjord
154	Norwegian Polar Institute	x	x		Hinlopenstretet and Nordaustlandet, Svalbard
155	DAFS Marine Lab., Scotland	x			North Sea

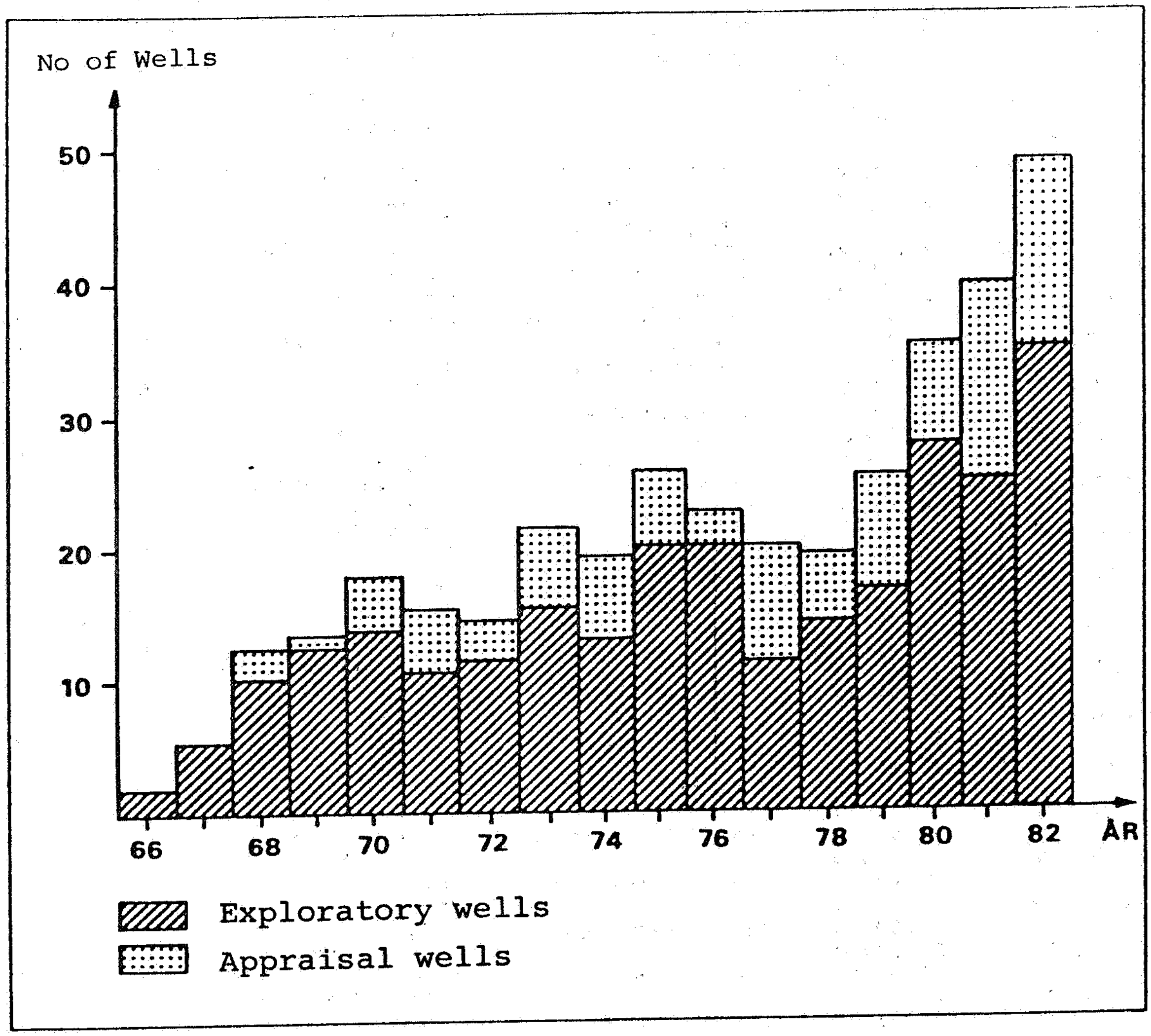
2.2.2. Exploration and appraisal drilling

At the end of the year 1981-82 there were 13 exploration and appraisal wells being drilled. All these wells were finished in 1982.

Wells 30/3-1 and 31/2-4, which had been temporarily abandoned at the previous year's end, were completed during 1982. Well 30/3-1 was extended to its total depth, while 31/2-4 was plugged permanently after having been temporarily plugged in the spring of 1981.

There was a great increase in the level of activities in 1982. During the year, 49 new wells were spudded, including 35 wildcats and 14 appraisal wells, as compared with a total of 39 in 1981 (see Figure 2.2.2.a). Thirty-seven of the spudded wells had been completed by the end of the year.

FIGURE 2.2.2.a. Drilling activity of the Norwegian Continental Shelf (number of wells spudded per year)



One well, 6407/1-1, was given up due to technical difficulties.

Wells 2/11-6, 30/2-1, 30/6-9 and 1/9-6 had been temporarily abandoned at the end of the year. As per year's end, a total of 360 exploration and appraisal wells had been spudded on the Norwegian shelf. These comprised 260 wildcats and 100 appraisal wells. Twelve wells were being drilled at year's end (Table 2.2.2.a).

TABLE 2.2.2.a. Spudded and/ or completed exploration wells (U) and delineation wells (A) in 1982. R = reentry. S = sidetrack. X = objective not reached.

Licence No	Well No	Drilling spudded/ completed	Operator Licencee	Drilling rig, land of registration	Well type	Water depth (CB)	Total depth (MSL)
215	0030/03-01 R	2.02.82	Shell	Dyvi Delta	U	138	4 394
		26.04.82	Statoil/Union	Norge	F	27	
			Hydro/Superior				
269	0030/07-08 R	23.09.81	Hydro	Treasure Seeker	U	103	4 787
		27.01.82	Stat/Petronord	Norge	F	25	
294	0024/12-02	22.06.81	Statoil	Dyvi Delta	U	119	5 068
		21.01.82	Stat/Texaco/Hydro	Norge	T	32	
298	0015/08-01	18.07.81	Statoil	Glomar Biscay II	U	112	4 275
		07.01.82	Stat/Esso/Hydro	USA	F	25	
299	0035/08-02	11.09.81	Gulf	Sedco 704	U	381	4 306
		23.05.82	Stat/Gulf/Getty	USA	F	26	
300	0034/10-13	24.08.81	Statoil	Deepsea Saga	A	214	3 366
		05.01.82	Stat/Esso/Hydro	Norge	F	25	
304	0015/03-04	03.10.81	Elf	Borgsten Dolphin	U	107	4 234
		30.03.82	Petronord	Norge	F	25	
305	0002/11-06	03.09.81	Amoco	Sedco 703	A	072	4 050
		28.02.82	Amoco/Noco gr.	USA	F	26	
306	0034/04-03	16.10.81	Saga	Dyvi Delta	U	366	4 435
		30.03.82	Stat/Saga/Amoco	Norge	T	25	
307	0029/06-01	12.10.81	BP	Sedco 707	U	124	4 807
		09.05.82	Statoil/BP	USA	F	25	
308	0015/06-06	10.04.82	Esso	Glomar Biscay II	A	105	3 735
		09.06.82	Esso	USA	F	25	
309	0015/09-12	26.11.81	Statoil	Nordraug	A	107	2 715
		23.02.82	Stat/Esso/Hydro	Norge	F	25	
309	0015/09-12 R	26.03.82	Statoil	Deepsea Saga	A	107	3 715
		27.04.82	Stat/Esso/Hydro	Norge	F	25	
310	0015/02-01	26.11.81	Hydro	Nortrym	U	109	4 575
		24.02.82	Stat/Elf/Hydro	Norge	T	25	
311	0030/06-06	09.01.82	Statoil	Deepsea Saga	A	113	3 195
		24.02.82	Stat/Petronord	Norge	T	25	
312	0034/10-14	24.12.81	Statoil	Ross Rig	A	224	2 622
		19.03.82	Stat/Hydro/Saga	Norge	F	25	
313	0035/03-05	22.12.81	Saga	West Venture	U	262	4 081
		31.03.82	Stat/BP/Saga	Norge	T	33	
314	0016/07-02	11.01.82	Esso	Glomar Biscay II	U	083	3 121
		30.03.82	Stat/Esso/Hydro	USA	F	25	
315	0034/04-04	11.09.82	Saga	Dyvi Alpha	U	344	
		.83	Stat/Saga/Amoco	Norge	F	25	
316	0007/11-05	09.02.82	Hydro	Treasure Seeker	U	080	4 453
		10.06.82	Stat/Hydro/Saga	Norge	F	25	
317	0031/04-06	28.02.82	Hydro	Nortrym	A	130	2 422
		20.04.82	Stat/Hydro/Esso	Norge	F	25	
318	0001/09-06	21.03.82	Phillips	Sedco 703	A	076	3 857
		01.12.82	Stat/Phillips	USA	F	25	
319	0015/09-13	21.03.82	Statoil	Ross Rig	A	081	3 257
		27.05.82	Stat/Esso/Hydro	Norge	F	25	
320	0002/02-01	09.04.82	Saga	Dyhi Alpha	U	059	3 978
		03.07.82	Stat/Mobil/Saga	Norge	F	25	
321	0025/02-07	01.04.82	Elf	Borgsten Dolphin	U	117	4 085
		12.07.82	Petronord	Norge	T	25	
322	0002/01-04	12.04.82	BP	Aladdin	A	060	4 500
		03.08.82	Stat/BP/Conoco	Norge	F	25	
323	7117/09-01	24.04.82	Hydro	Treasure Scout	U	256	3 177
		16.07.82	Stat/Hydro/BP	Norge	T	23	
324	7120/08-02	15.04.82	Statoil	Nordraug	U	245	2 565
		29.07.82	Stat/Esso/Hydro	Norge	F	25	
325	6507/11-02	18.04.82	Saga	West Venture	U	243	2 872
		30.05.82	Stat/Shell/Saga	Norge	T	33	
326	0031/02-07	22.04.82	Shell	Borgny Dolphin	A	338	1 635
		14.06.82	Stat/Shell/Conoco	Norge	F	25	
327	0015/09-14	01.05.82	Statoil	Deepsea Saga	U	101	3 538
		27.06.82	Stat/Esso/Hydro	Norge	T	25	
328	0030/02-01	16.05.82	Statoil	Dyvi Delta	U	125	4 213
		12.10.82	Stat/Union/Tenoco	Norge	F	30	
329	0030/06-07	20.05.82	Norsk Hydro	Nortrym	A	114	3 211
		24.08.82	Stat/Petronord	Norge	F	25	

TABLE 2.2.2.a. (Continued)

330	0015/09-15	28.05.82	Statoil	Ross Rig	U	065	[illegible]
		01.08.82	Stat/Esso/Hydro	Norge	F	25	
331	0016/07-03	11.06.82	Esso	Glomar Biscay	U	01[illegible]	3 116
		27.07.82	Stat/Esso/Hydro	USA	T	25	
232	6407/02-01	03.06.82	Saga	West Venture	U	26[illegible]	2 137
		06.08.82	Stat/Agip/Saga	Norge	T	33	
233	0030/06-08	15.06.82	Hydro	Treasure Seeker	U	121	3 575
		06.08.82	Stat/Petronord	Norge	T	25	
234	0031/02-08	16.06.82	Shell	Borgny Dolphin	U	246	3 350
		18.08.82	Stat/Shell/Conoco	Norge	T	25	
335	0015/09-16	28.06.82	Statoil	Deepsea Saga	A	085	3 095
		24.08.82	Stat/Esso/Hydro	Norge	F	25	
336	0002/02-02	04.07.82	Saga	Dyvi Alpha	A	066	3 102
		27.08.82	Stat/Mobil/Saga	Norge	F	25	
337	6507/10-01	10.07.82	BP	Sedco 707	U	297	3 669
		31.10.82	Statoil/BP	USA	T	24	
338	7120/09-01	25.07.82	Hydro	Treasure Scout	U	320	2 277
		26.09.82	Stat/Hydro/Elf	Norge	F	23	
339	0030/06-09	28.08.82	Hydro	Nortrym	U	114	3 211
		24.08.82	Stat/Petronord	Norge	F	25	
340	0016/01-03	29.07.82	Esso	Glomar Biscay	U	108	3 473
		27.09.82	Esso	USA	T	25	
341	7120/07-01	31.07.81	Statoil	Nordraug	U	236	2 617
		08.10.82	Stat/Hydro/Phillips	Norge	F	25	
342	0007/11-06	09.08.82	Hydro	Treasure Seeker	U	071	4 475
		20.10.82	Stat/Hydro/Saga	Norge	T	25	
343	0001/03-03	27.08.82	Elf	Borgsten Dolphin	U	068	4 850
			Stat/Elf/Shell	Norge		25	
344	0031/02-09	29.08.82	Shell	Borgny Dolphin	A	339	1 745
		01.10.82	Stat/Shell/Conoco	Norge	F	25	
345	0008/03-02	04.10.82	Statoil	West Vanguard	U	075	2 635
			Stat/Shell/Volvo	Norge		22	
346	0031/02-10	02.10.82	Shell	Borgny Dolphin	A	357	1 808
		31.10.82	Stat/Shell/Conoco	Norge	T	25	
347	0016/07-04	15.10.82	Esso	Glomar Biscay II	U	078	2 756
		06.12.82	Esso/Stat/Hydro	USA	F	25	
348	0030/06-10	04.10.82	Hydro	Treasure Scout	A	109	2 629
		02.12.82	Stat/Petronord	Norge		23	
349	0034/10-15	16.10.82	Statoil	Nordraug	U	164	2 375
		12.12.82	Stat/Hydro/Saga	Norge	T	25	
350	6407/01-01	19.10.82	Statoil	Dyvi Delta	U	273	0 871
		13.11.82	Stat/Hycro/Conoco/AM	Norge	X	29	
351	0030/09-01	24.10.82	Hydro	Treasure Seeker	U	105	
			Stat/Hydro/Saga/DN	Norge		25	
352	0002/06-03	09.11.82	Elf	Byford Dolphin	U	071	
			Elf/Petronord Gr.	Norge		25	
353	0002/01-05	13.11.82	BP	Sedco 707	U	066	
			Stat/BP/Conoco	USA		25	
354	0030/11-03	17.11.82	Shell	Borgny Dolphin	U	112	
			Shell	Norge		25	
355	6407/01-02	13.11.82	Statoil	Dyvi Delta	U	273	
			Stat/Hydro/Conoco/AM	Norge		29	
356	15/9-17	09.12.82	Statoil	West Vanguard	U	086	
				Norge		22	
357	34/10-16	04.12.82	Stat/Esso/Hydro	Nordraug	U	138	
				Norge		25	
358	30/6-11	20.12.82	Hydro	Nortrym	U	146	
				Norge		25	
359	7/11-7	29.12.82	Phillips/Phillipsgr.	Cod Plattform	U	075	
				Norge		42	
360	30/6-10 A	02.12.82	Hydro/Stat/Petronord	Treasure Scout	A	109	
					F	23	

As can be seen from Figure 2.2.2.a, there has been a marked increase in drilling activities from 1981 to 1982 also. This is due to several factors. One reason is that it was decided to postpone drilling on sixth-round blocks until 1982 because of high activity levels in 1981. The most important reason, however, is the high activity level on the Oseberg, Sleipner and Troll fields, which is because work is being done on the commerciality declarations for these fields. Another reason is the high frequency of finds obtained on the exploration side during the last 2-3 years. This trend, with approximately 50 per cent strike frequency, continued in 1982 too.

There has been uniformly high activity through the whole season, with a peak level during the summer months when 15 drilling rigs were in operation simultaneously.

Figure 2.2.2.b shows the geographical spread of wells drilled in the North Sea in 1982 and their location in relation to the structural main features.

Figures 2.2.2.c and 2.2.2.d show the wells on Haltenbanken and Tromsøflaket, located in relation to block division and structural highlights. Figure 2.2.2.e shows the drilling activities on Svalbard.

As is apparant from these figures, activities have been distributed over the whole shelf. But extra large efforts were made in the Sleipner area, where nine new wells were spudded, the Oseberg field, with its seven new spuddings, and the Troll field, which has seen the start of four new well holes. These comprise 40 per cent of all spuddings in 1982.

On the Haltenbanken, five new wells were started, and on the Tromsøflaket, four new wells. Together this represents approximately 20 per cent of the drilling activity.

Considerable activity was also a feature of the southern part of the North Sea, with 9 wells, or approximately 20 per cent of the total activity.

The Norwegian companies, Saga, Norsk Hydro and Statoil, had operator responsibility in 1982 for approximately two-thirds of the wells started (32), while the remaining 17 are divided among five different foreign companies. Statoil drilled 15 wells by itself, while Norsk Hydro drilled 12.

Since the start in 1966, a total of 17 different companies have been operators on the Norwegian continental shelf. Statoil has drilled the most wells (62), followed by Phillips with 51 and Esso with 44. As of now, some forty-nine different drilling vessels have operated on the Norwegian continental shelf.

FIGURE 2.2.2.b. Geographical spread of wells drilled in North Sea in 1982 in relation to structural main features

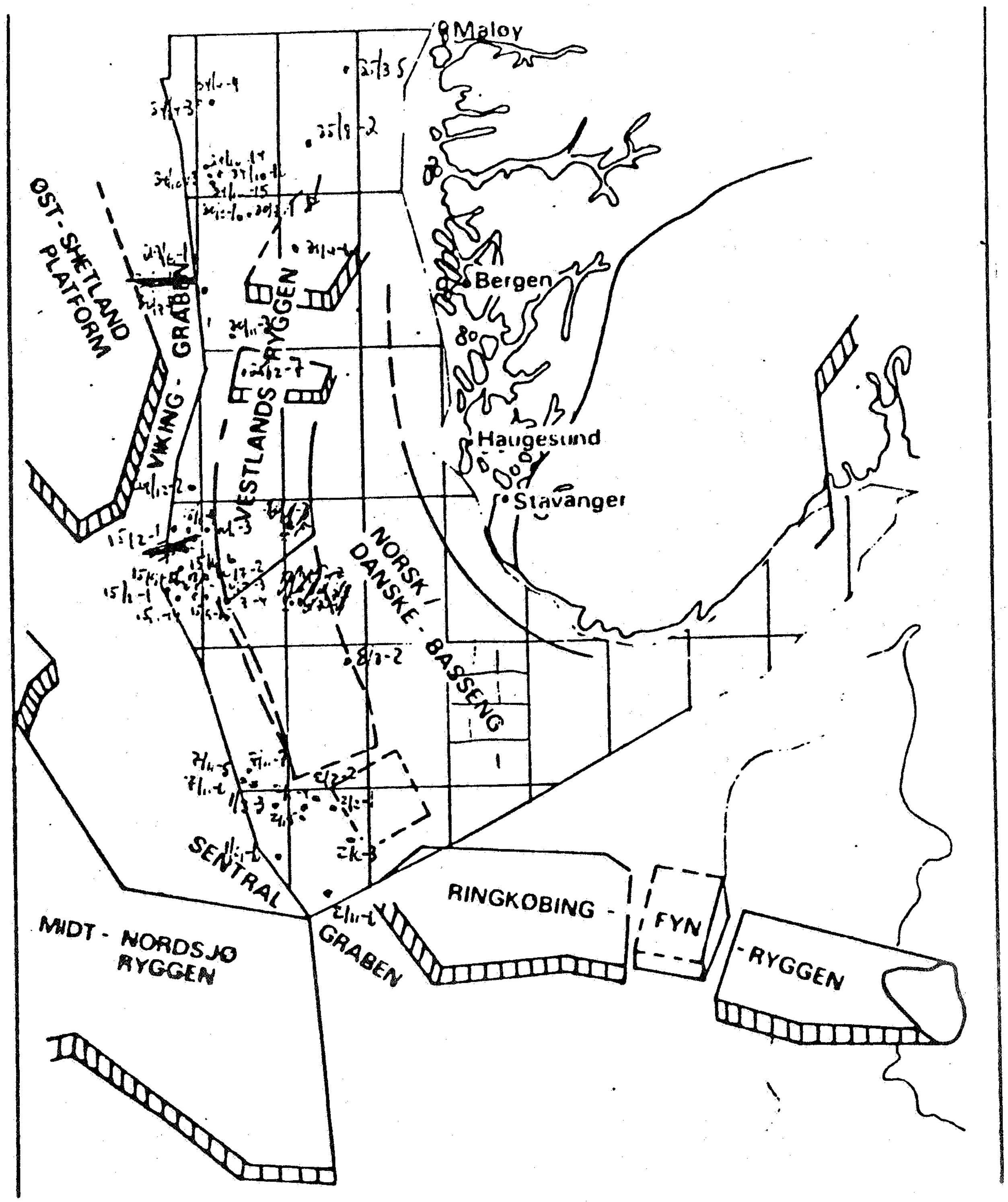


FIGURE 2.2.2.c. Wells on Haltenbanken in relation to block division and structural main features (1982)

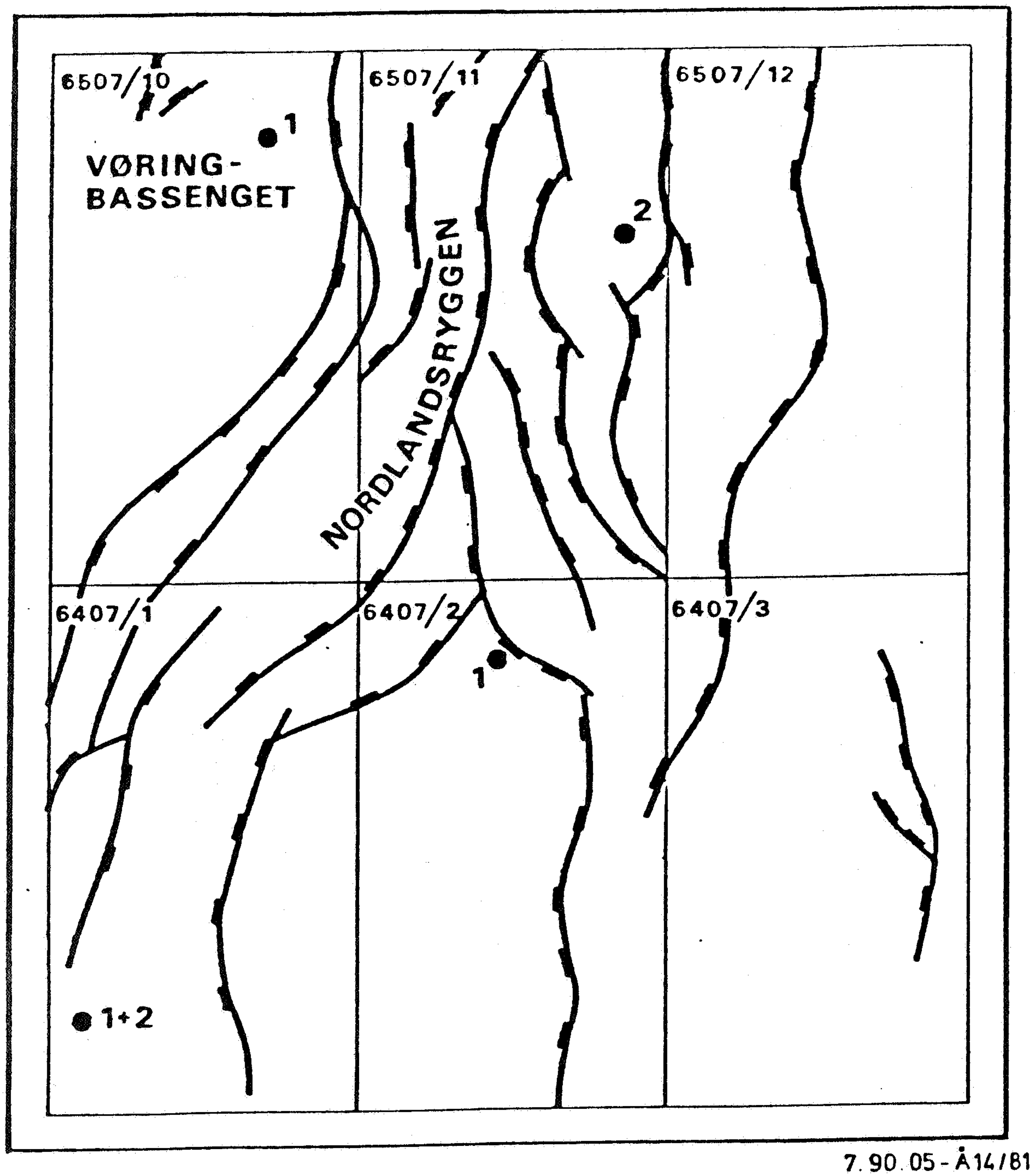
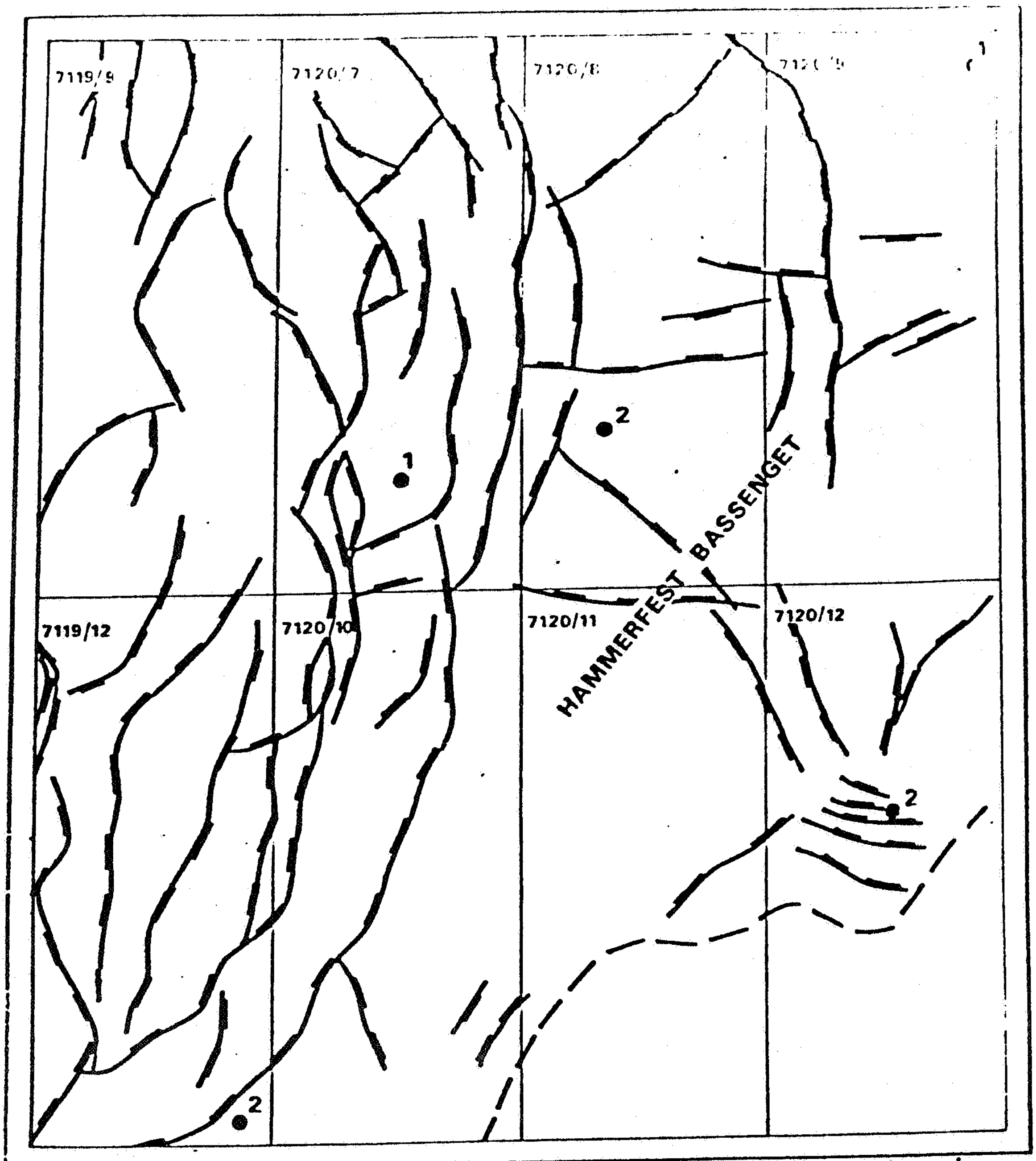


FIGURE 2.2.2.d. Wells on the easterly part of Troms I in relation to block division and structural main features (1982)



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2.2.2.1 Distribution by prospect type

In 1982 too, exploration activity has primarily been focused on jurassic sandstone reservoirs. Of all the spudded and reentered wells, 45 have had as their main objective research into different jurassic sandstone prospects. Several of these wells have also had secondary objectives at other levels.

The other five wells include two tertiary (paleocene) prospects on Sleipner, two in the triassic in 16/7-4 and 34/4-4 and one in chalk from the chalk age (Tommeliten).

All the wells being drilled at the previous year´s end which had not reached down to their primary prospect (7 wells), had jurassic primary targets.

2.2.2.2 Svalbard

No drillings have been made for oil or gas on Svalbard in 1982. On the contrary, a number of coal drillings have been made as usual. Table 2.2.2.b lists the drilling licences given on Svalbard.

FIGURE 2.2.2.2 Drillings on Svalbard

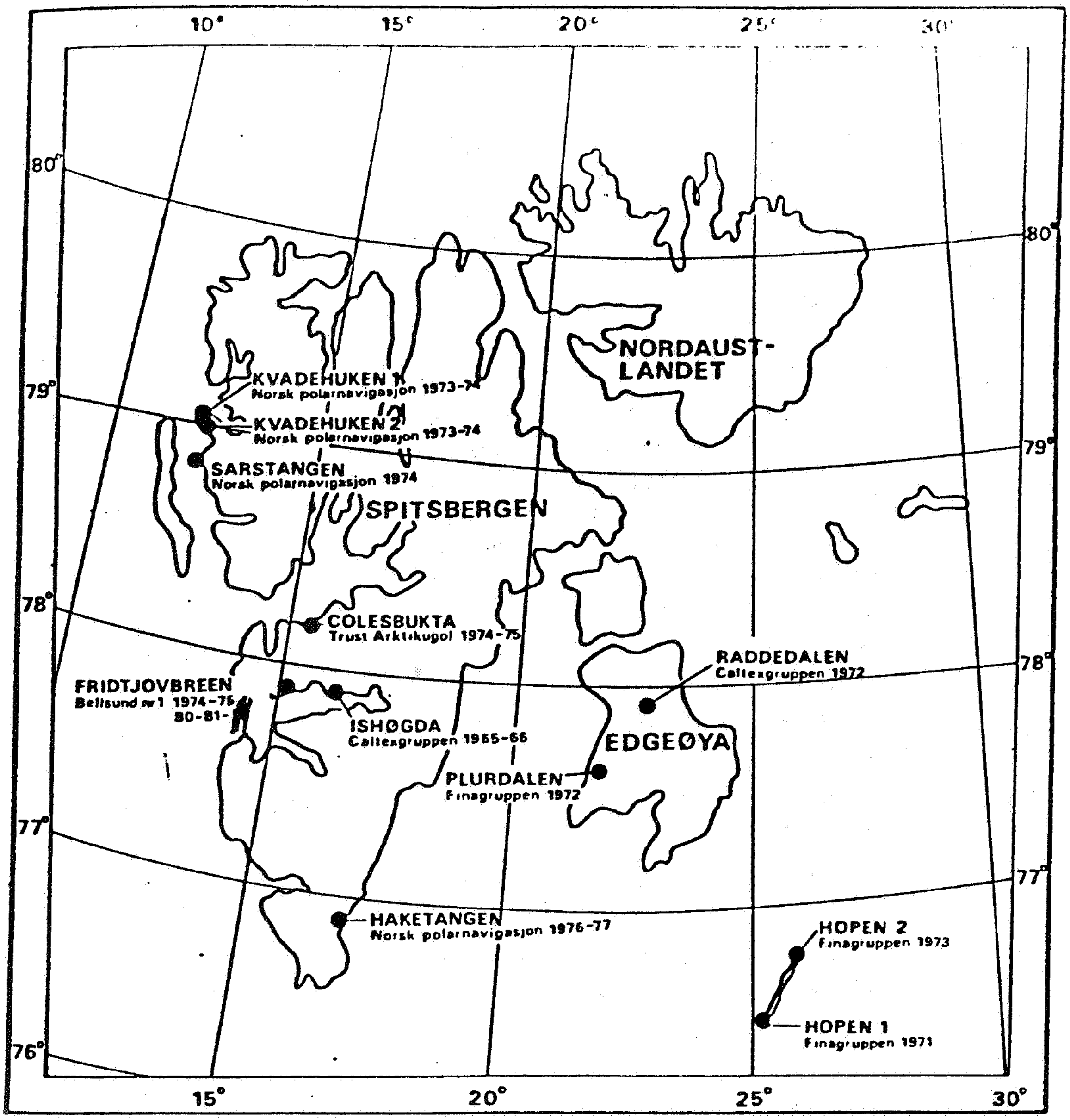

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TABLE 2.2.2.b Drilling licences awarded on Svalbard

Site	Position north east	Drilling spudded	Drilling finished	Days Drilled	Licencee
Grønnfjorden 1	77°57'34"	9.6.63	5.9.63	287	Norsk Polar Navigasjon
Spitsbergen	14°20'36"	13.6.64	26.8.64		
		26.6.65	8.9.65		
		26.6.67	12.8.67		
Ishøgda	77°50'22"	1.8.65	15.3.66	227	Caltexgruppen
Spitsbergen	15°38'00"				
Bellsund 1	77°47'	23.8.67	2.9.67	299*	Norsk Polar Navigasjon
Fridtjovsbreen	14°46'	29.6.68	21.8.68		
		7.7.69	16.8.69		
		10.7.74	18.9.74		
		16.7.75	20.9.75		
		22.8.80	5.9.80		
		1.7.81	10.8.81		
Hopen 1	76°26'55"	11.8.71	29.9.71	50	Finagruppen
	25°01'45"				
Raddedalen	77°54'30"	2.4.72	10.7.72	100	Caltexgruppen
Edgeøya	22°41'30"				
Plurdalen	77°44'33"	29.6.72	12.10.72	106	Finagruppen
Edgeøya	21°50'00"				
Kvadehuken 1	78°57'03"	21.4.73	10.8.73	112	Norsk Polar Navigasjon
Spitsbergen	11°23'33"				
Hopen 2	76°41'15"	20.6.73	20.10.73	123	Finagruppen
	25°28'00"				
Kvadehuken 2	78°55'32"	13.8.73	19.11.73	186	Norsk Polar Navigasjon
Spitsbergen	11°33'11"	22.3.74	16.6.74		
Sarstangen	78°43'36"	15.8.74	1.12.74	109	Norsk Polar Navigasjon
Spitsbergen	11°28'40"				
Haketangen	76°52'30"	11.9.76	20.9.76	109	Norsk Polar Navigasjon
Spitsbergen	17°05'30"	13.6.77	19.9.77		
Colesbukta	78°07'	13.11.74	1.12.75	373	Trust Arktikugol
Spitsbergen	15°02'				

* Drilling not finally completed

2.2.2.3 Experiences gained from this year's drilling season

1982 was a year with record exploration activity.

Despite the high activity level, there have been no problems in connection with wildcat drilling which were unable to be solved.

On Tromsøflaket in 1982, two drilling vessels were used for drilling: Treasure Scout for Norsk Hydro and Neptuno Nordraug for Statoil. Drilling started on 15 April 1982 and continued until 8 October 1982. Norsk Hydro rounded off the drilling season on 26 September 1982.

Empirical material reaped from the year's drilling season with interest for year-round drilling on Tromsøflaket was limited. A total of four wildcat wells were drilled on Tromsøflaket in 1982.

On Haltenbanken, Saga started the drilling season with the drill rig West Venture on 18 April 1982 and rounded off on 6 August 1982. Saga completed two exploration wells during this period. Later during the season, BP as the first foreign operator north of 62oN, spudded on 10 July 1982 with the rig Sedco 707. This well was completed on 31 October 1982.

Statoil began drilling from the rig Dyvi Delta on Haltenbanken on 19 October 1982. This well will be completed in the course of the spring, 1983.

Even during the first operational period, the well provided new data regarding the problems which can occur in this area. A larger number of ocean waves with long periods and moderate amplitudes was observed than has been considered usual in more southerly stretches. This will have definite operational consequences in that the drilling vessel's response to such long waves is not the same as for the more usual combinations of wave amplitude/ wave length.

In total, greater experience has been gained in operations on the Haltenbank area with regard to future year-round drilling.

Experience gained from drilling activities at depths over 300 meters clearly demonstrates that great demands will be made of both equipment and personnel.

The safety and preparedness aspects of the exploration activity in 1982 off North, Mid and South Norway were satisfactory.

2.2.2.4 Costs of exploration drilling

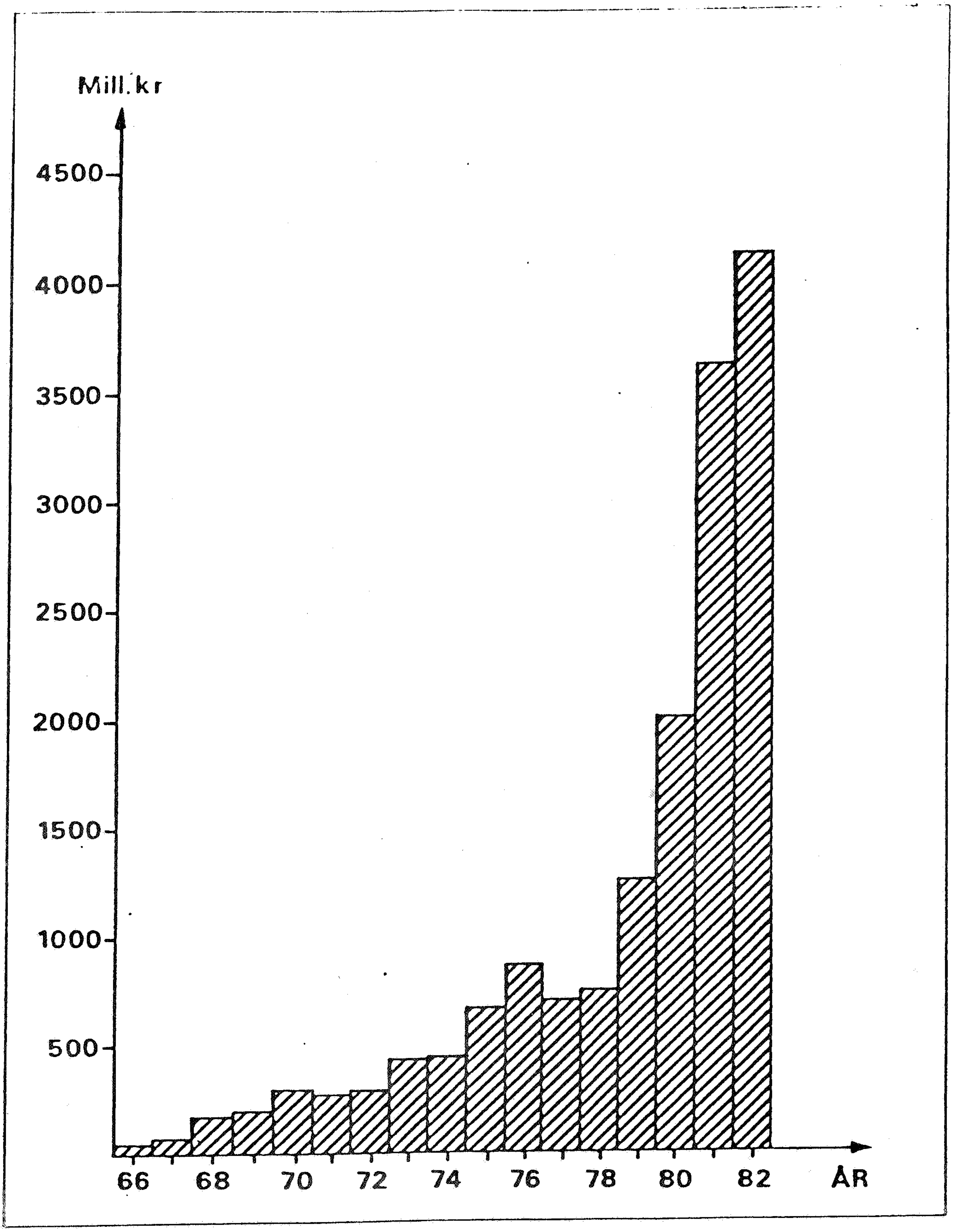
The total costs of exploration drilling will exceed NOK 4 billion in 1982. Corresponding figures for 1981 were NOK 3.6 billion. In the cost figures, the total cost of all exploration and delimitation wells spudded during the year is included. Final cost data do not yet exist for spudded drillings during the latter half of 1982. The cost estimate for 1982 is therefore a provisional one.

In terms of operational days for mobile drilling rigs, the activity in 1982 increased by about 6 per cent in relation to 1981. The total drilling activity has shown stable development in terms of value in the period from 1981 to 1982, if consideration is taken of the general rise in prices. The number of wells increased from 39 in 1981 to 49 in 1982. The mean well cost in 1982 shows a slight decline with respect to 1981.

Drilling rig rates remained more or less stable and at a high level throughout 1982.

Figure 2.2.2.f shows the costs of exploration drilling in the period 1966-1982, i.e. the period during which exploration drilling has taken place on the Norwegian continental shelf. From the figure it may be seen that the wildcat activity on the Norwegian continental shelf has constituted a market in steep growth, specially during the period 1979-1982. In current prices, the total cost of exploration drilling was NOK 16.6 billion for the period 1966-1982.

FIGURE 2.2.2.f Annual exploration drilling costs in the period 1966-1982 (NOK current)



2.2.3 Finds and fields being evaluated

2.2.3.1 Finds in 1982

A number of new finds were made in 1982. Particularly encouraging were the results of wells on relinquished areas. During the year, finds were made in four of the five blocks drilled in. Only in Block 8/3 in the Egersund Basin were no hydrocarbons found. The largest strike (gas) was presumably made by Esso in sandstone strata of jurassic/ triassic age in Block 16/7 just east of the Sleipner field. The blocks in this round of allocations (the sixth) have all been allocated previously, but have been relinquished to the state pursuant to the provisions in force, without any hydrocarbon finds having been made.

The most promising strike in 1982 was made by Saga in Block 34/4 in the northern part of the North Sea, which proved oil in sandstone strata of triassic age. Oil has previously been proven in older rock within the same structural complex. This find stretches into the neighbouring Block 34/7 in the south. Block 34/7 has not been allocated as yet.

Another promising find was made by Statoil in gas-bearing sandstone of jurassic age in Block 30/2 on a structural complex which lies on the boundary between Block 30/2 and 30/3. This reservoir is under extremely high pressure.

Further, during the year, new oil and gas reserves were proven in a new structure on the Oseberg field, gas in a new structure south of Sleipner, new finds in the 30/4-30/7 area and Block 35/8, and positive confirmation of reserves in Tommeliten and Block 2/1. There were rather more varied results with respect to the oil potential of the Troll field. As regards the areas north of 62oN, gas has been proven in two new blocks in addition to the gas reserves in 7120/8. On the Haltenbank however, no new finds were made in 1982.

At the end of 1981/82 some thirteen wildcat and appraisal wells were being drilled, of which six had achieved the reservoir level. The total number of spudded new wildcat and appraisal wells in 1982 was 49. Furthermore, one well was deepened to reservoir level (30/3-1). Forty-one of these bores had reached reservoir level by year´s end.

In all, drillings were made on 31 new prospects in 1982. Finds were made on 14 of them. This represents a find frequency of 45 per cent, which is high in the context of exploration drilling.

Tests

A total of 27 wells were tested in 1982. The best gas tests were made in the high pressure reservoirs in Blocks 30/2 and 29/6, while oil production in Well 34/4-4 was high.

2.2.3.2 Drilling on new structures

Block 1/3

The block was originally allocated to Norske Shell in 1965 on Production Licence 011. The relinquished part of the block was reallocated in the sixth round of concessions with Elf Aquitaine as operator.

Well 1/3-3 is the first drill hole on the newly allocated part of the block, and about 20 meters net hydrocarbon bearing reservoir sandstone of jurassic age was proven. The reservoir, which lies relatively deep, is probably too small to be commercially attractive. The operator is planning to test the hole.

Block 2/1

Block 2/1 was originally allocated to Gulf in 1965 on Production Licence 019. In 1971, Gulf chose to withdraw and Conoco took over as operator. In connection with this transfer, the Norwegian state secured a 12.5 per cent share. In 1977, BP took over parts of Conoco´s share, at the same time as they assumed operator responsibility. Statoil was allocated 50 per cent ownership, and the group had to perform supplementary work programs.

Two wells were drilled in the block during the year. Well 2/1-4 is an appraisal well on a relatively large and complicated structure, in which oil was proven in sandstone strata of jurassic age. The well penetrated 97 meters gross oil bearing sandstone. The highest production was measured to be 180 Sm3 daily through a 6 mm choke. This result is low compared with the best test results in the area. According to an earlier estimate, the proven recoverable reserves, on the basis of the results of this well, will increase to 18 million Sm3 oil and 2 billion Sm3 gas. It is somewhat uncertain to what extent the oil/ water contact was demonstrated. A deeper oil/ water contact would lead to further increases in the reserves estimate.

Well 2/1-5 on the south of the block was being drilled at the end of the year, but had not reached its strata objective.

Block 2/2

This block was originally allocated on Production Licence 006 in 1965 with Amoco as operator, but was relinquished in its entirety in 1974 without any drillings having been performed there. The block was reallocated in the sixth allocation round in August 1981 with Saga as the operator.

Well 2/2-1 was drilled on a structure in the southeast of the block, and oil was proven in sandstone layers dating from the jura period. The jura reservoir is of highly variable quality, and the net sand thickness is disappointing. The best amounts produced were 210 Sm3 oil and 9,700 Sm3 gas through an 11 mm choke. This is low compared with other jura reservoirs in the area.

Gas was also encountered in oligocene sandstone. This reservoir was not tested for production.

Well 2/2-2 was drilled on a structure in the northeast of the block, and the main objective, sandstone from the jura period, was water bearing. However, gas was proven in oligocene sandstone. This reservoir, though only 20 meters thick, displayed good porosity and permeability. The reservoir was tested, and produced 285,000 Sm3 gas per day through a 9.5 mm choke. This result is considered good. Well 2/3-1 in the neighbouring block tested the same sandstone formation in 1969 with corresponding results.

Block 2/6

This block was allocated to the Petronord group in the first round of concessions in 1965 on Production Licence 008, with Elf as operator.

Well 2/6-3 was drilled on a fault block in an extremely complex structure which lies to the east of the Ekofisk basin and is delimited by the Mandal height towards the northeast.

The well has not yet reached the deep-lying prospect, assumed to be of jurassic age. Well 2/6-2 has earlier shown traces of hydrocarbons in chalk rocks of jurassic age further towards the west in a lower fault block on the same structural complex.

Block 7/11

This block was allocated to the Phillips/ Petronord group in 1965 on Production Licence 018, with Phillips as operator. The part of the block which includes the Cod structure was retained. The remainder was relinquished and has now been allocated in the sixth round on Production Licence 070 with Norsk Hydro as operator.

On Production Licence 070, two wildcat wells have been drilled, namely 7/11-5 and 7/11-6.

Well 7/11-5 proved oil in sandstone of jurassic age. The reservoir quality varies and the reservoir consists of in all 24 meters net sand. Production from the reservoir under test measured 480 Sm3 oil and 143,000 Sm3 gas per day through a 13.5 mm choke.

Well 7/11-6 was water bearing.

Phillips has spudded an exploratory well, 7/11-7, which is to be directionally drilled from the Cod platform. The well hole will examine a jurassic prospect which lies under the soon dry paleocene Cod field.

Block 8/3

The block was originally allocated to Esso in the first round of concessions on Production Licence 003. The first well on the Norwegian continental shelf, 8/3-1, was drilled on this block. The well was dry however, and the block was relinquished. The whole block has since been reallocated in the sixth round with Statoil as operator, and Well 8/3-2 is the first to be drilled following the reallocation.

The well was drilled down to rocks of triassic age and the prospect, sandstone of the jura period, turned out to be water bearing.

Block 15/2

The block was allocated in the third round of allocations with Norsk Hydro as operator. Production Licence 048 includes Blocks 15/2 and 15/5, which nudge up to the British sector. The licence is now the subject of partial relinquishment, but because of the blocks' rather special shape, this is difficult with the present regulations. In the relinquishment plan, the whole of Block 15/2 is included.

Block 15/2-1 was drilled at year's end 1981-1982 and proved traces of hydrocarbons in jurassic sandstone. The reservoir was tight however, and the well was abandoned as a dry hole, without any production tests being performed.

Block 15/3

This block was allocated in the third round with Elf Aquitaine as operator.

Well 15/3-4 was drilled as an exploratory well on a relatively straightforward stratigraphic structure. Hydrocarbons were proven in four different sand layers of middle jurassic age. The thickest reservoir had 18 meters net gas bearing sandstone. The reservoir was production tested and gave 245,000 Sm3 gas and 615 Sm3 oil per day through a 16 mm choke. The carbon dioxide content was measured to be 7.4 per cent. Reserve estimates of this structure quote 12 million Sm3 oil and 5 billion Sm3 gas as recoverable.

Block 16/1

The block was allocated to Esso in 1965 in the first round of concessions. Well 16/1-3 was drilled down to bedrock and only traces of oil were recorded in a thin sandstone jura layer. This was the third dry hole in the block.

Block 24/12

The block was allocated in the third round of concessions with Statoil as operator.

Well 24/12-2 was drilled down to 5068 meters below sea level without hydrocarbons being encountered. This is the second duster on the block. The concession holders did not see any possibility of there being other structures of commercial interest and relinquished the whole licence (Blocks 24/11 and 24/12).

Block 25/2

The block was allocated in the third round of concessions with Elf as operator.

Well 25/2-7 was drilled on a fault structure right to the east of the block. Only traces of residual oil were found in rocks of jurassic age, and the well was plugged as a dry one.

Block 30/2

Block 30/2 was allocated in the fourth round of concessions with Statoil as operator.

Well 30/2-1 was drilled on a complicated structural complex which lies on the boundary between Blocks 30/2 and 30/3. Earlier, a well was drilled on this structure, 30/3-1, but only small amounts of gas were proven at the very top of the reservoir. In Well 30/2-1, gas was proven thoughout the entire 120 meter thick jura reservoir, of which 60 meters is considered to be productive.

Three different zones in the reservoir were tested. Maximum production was measured at 1.03 million Sm3 gas and 415 Sm3 condensate per day through a 19 mm choke. These test results are comparable with the best gas tests registered on the Norwegian continental shelf.

Block 30/3

This block was allocated in the fourth round with Statoil as operator.

Well 30/3-1 was spudded and temporarily abandoned in 1979. Drilling was restarted in 1982. A fairly thick sequence of potential reservoir rocks were proven, but only a thin zone at the top of the reservoir contained gas. No tests were run.

Blocks 29/6, 29/9, 30/4 and 30/7

Blocks 29/9 and 30/7 were allocated in 1974 with Norsk Hydro as operator. Blocks 29/6 and 30/4 were allocated in 1976 with BP as operator. Gas/ condensate was proven in middle jurassic sandstone in a complicated structural complex which consists of a series of fault blocks. The structure stretches into Blocks 29/6, 29/9, 30/4 and 30/7.

The reservoir rocks lie at different depths in the individual fault blocks, from 3800 to 4300 meters deep. An approximately 100 meter gas column was proven under high pressure in the best well on the field. Well 29/6 was drilled on a previously untested fault block, and the reservoir rocks were struck at a depth of a good 4200 meters. The logs indicate a gas column of over 100 meters with high water saturation throughout, low porosity and low permeability. The reservoir was tested in three zones, two of the tests producing water. The top production test was measured at 283,000 Sm3 gas and 220 Sm3 condensate per day through a 13 mm choke.

Well 30/7-8 was spudded in 1980, but temporarily abandoned due to technical problems. Drilling was restarted in September 1981 and tests performed in January 1982. A 52 meter gross gas column was proven. Only half of this is likely to be productive reservoir. During testing, 612,500 Sm3 gas and 445 Sm3 condensate were produced per day through a 13 mm choke.

Block 30/11

The block was allocated in 1969 with Shell as operator. Two wells had been drilled earlier which were dry, terminating in rocks of the upper cretaceous period.

Well 30/11-3 was still being drilled at year's end and had not reached its jurassic sandstone prospects.

Block 34/4

This block was allocated in the fourth round of concessions with Saga as operator.

Well 34/4-3 was drilled on a separate structure more or less in the middle of the block. Only traces of hydrocarbons were found in rocks of jurassic age, and the well was plugged as a dry hole.

Well 34/4-4 was drilled way to the south in the block, on a large and rather flat structure that extends into Block 34/7. The well has not yet been tested, but an approximately 170 meter oil column was proven over the oil/ water contact.

Oil was encountered in rocks of triassic age, and provisional studies indicated 105 meter net oil bearing sandstone of good porosity and permeability.

It is too early to make any prediction as to the size of the strike, as it had not been tested at the time of going to press, but the provisional concensus stamps the find as highly interesting. Well 34/4-1 has previously proven and tested oil from older reservoir rocks (middle triassic) on the same structure.

Block 35/3

The block was allocated in 1975 with Saga as operator. Four wells have been drilled on the block, of which the third well, 35/3-3, had to be abandoned at shallow depth due to technical difficulties, and was substituted by Well 35/3-4. This well bore was drilled structurally higher than 35/3-2 in the eastern part of the block. As in the case of 35/3-2, gas was proven in sandstone strata of lower cretaceous age. The reservoir is subdivided into two parts by a zone of shale. The lower part appeared not to be productive.

The geology of this block is highly complex at reservoir level. A series of thin layers of sand of different ages consititute the reservoir rocks, which in all probability cover large parts of the block.

The exploratory well, 35/3-5, was spudded in the southeast of the block at the end of 1981. No hydrocarbons were found in the lower cretaceous sandstone of the block. This indicates a limitation of the extent of the gas reservoir towards the southeast.

Block 35/8

The block was allocated in 1979 with Gulf as operator.

Well 35/8-1 was drilled in the western part of the block, on a small structure which just stretches into the neighbouring Block 35/7. Light oil/ condensate was proven in middle jurassic sandstone.

Well 35/8-2 was drilled on another structure in the southwesterly corner of the block. Hydrocarbons having the same characteristics as in 35/8-1 were proven in middle jurassic sandstone (the Brent formation). The total hydrocarbon column in the well was 60 meters deep, of which 48 meters are considered to be net gas bearing reservoir sand. The average porosity was approximately 17 per cent, with water saturation of some 25 per cent. The well was tested and produced 487,000 Sm3 gas and 330 Sm3 condensate daily through a 17.5 mm choke. This is less than in an equivalent test of Well 35/8-1, a fact which may well be due to poorer reservoir characteristics.

One structure remains undrilled on the block.

Haltenbanken

Five new wells were drilled during the year. A total of six new wells have now been drilled to full depth on Haltenbanken, and only one of them has given a strike (6507/11-1). One well had been abandoned at shallow depth and one was still being drilled at the end of the year.

Block 6407/1

This block was allocated in April 1982 with Statoil as operator. Problems arose with the setting of the 508 mm casing in Well 6407/1-1, and the well had to be abandoned and plugged at a depth of 871 meters. Well 6407/1-2 is being drilled at the same site, and will replace 6407/1-1. Drilling of 6407/1-2 continues.

Block 6407/2

The block was allocated in April 1982 with Saga as operator. The first well bore in this block proved small amounts of gas in the upper cretaceous in an interval without good reservoir properties.

Block 6507/10

This block was allocated in 1982 with BP as operator. BP drilled its first well here and proved 115 meters of good quality middle jurassic sand. The sand was water bearing.

Block 6507/11

The block was allocated in 1981 with Saga as operator.

Well 6507/11-2 was drilled on a structure in the northern part of the block, and traces of gas were encountered in sandstones of jurassic age. The quantities were so insignificant that the well may be considered to be water bearing, and no tests have been performed.

The well bore lies approximately 13 km north-northeast of the first well on the block, in which gas was proven in sandstone layers of jurassic age.

Troms I

Four new wells were drilled during the period. A total of nine new wells have been drilled on Troms I, six of them making finds.

Block 7117/9

The block was allocated in 1981 with Norsk Hydro as operator. The first well on the Senja ridge was drilled during the year. The results of this drilling provided unexpected insights into the geology of the area. Chalk deposits are much thicker than first anticipated for this well. The well did not reach its primary objective therefore, which was jurassic strata. The well was terminated at 3177 meters in the lower cretaceous, without any traces of hydrocarbons having been found.

Block 7120/7

The block was allocated in April 1982 with Statoil as operator. The first well proved gas in sandstone strata from the jurassic. A gas column of 65.5 meters over the gas/ water contact was found in a fine grained reservoir sandstone.

Top production was measured at 490,000 Sm3 gas and 19 Sm3 condensate through a 19 mm choke. This test result is good. So far, only Well 7120/8-1 has provided better production tests on Tromsøflaket.

Block 7120/9

The block was allocated in April 1982 with Norsk Hydro as operator. Norsk Hydro demonstrated gas in the first well bore on the block. The well was drilled on a structure in the north of the block. Top production was measured at 300,000 Sm3 gas and 9.5 Sm3 condensate per day through a 20.3 mm choke. The total gas column over the gas/ water contact is some 65 meters, of which 60 are considered productive. The test result was somewhat lower than results achieved in the neighbouring wells in Blocks 7120/8 and 7120/7. Gas/ water contact in the reservoir, which consists of jurassic sandstone, lies some 200 meters less deep than in the corresponding reservoir in Block 7120/8.

2.2.3.3 Fields being evaluated

Tommeliten

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

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

Recoverable reserves are provisionally estimated at 9 million Sm3 oil and 24 billion Sm3 gas. However, it is probable that the reserves base for the Tommeliten field will be adjusted upward in the light of the results from Well 1/9-6, which was drilled in 1982. The operator stepped up his estimated hydrocarbon pore volume in the Gamma structure by some 100 per cent thanks to Well 1/9-6.

The operator has recommended a total of five prime alternatives for development of the field. The final commerciality declaration is predicted to be complete in the summer of 1983. If the field is declared commercial, the operator intends to submit his landing application during that autumn.

Hod

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

The Norwegian Petroleum Directorate´s estimated recoverable reserves are 9.0 million Sm3 oil and 7.0 billion Sm3 gas.

The Hod field consists of two lesser structures. These have been examined by a total of five wells, two on West Hod and three on East Hod. The last of these wells was 2/11-6.

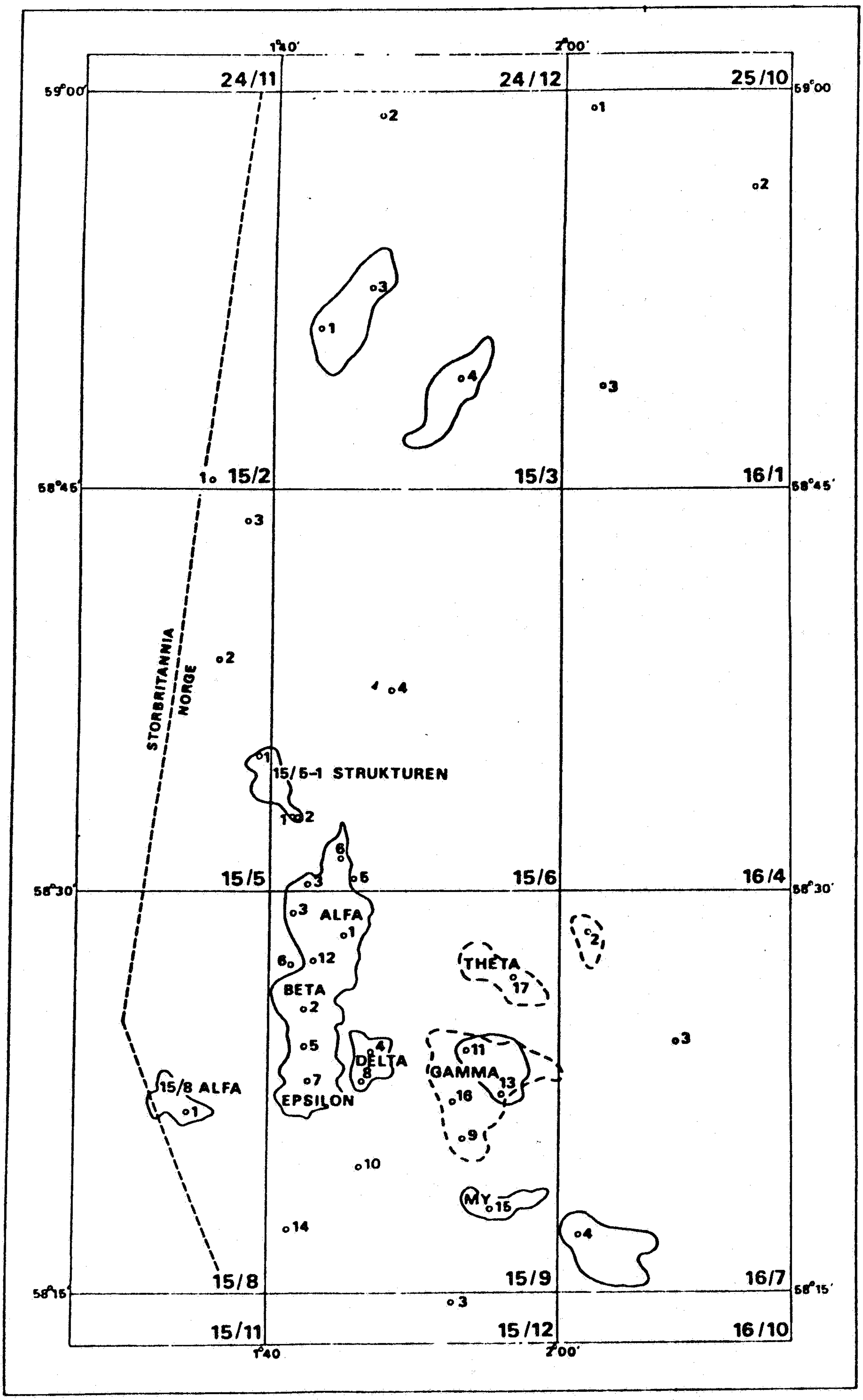
Before drilling Well 2/11-6, the field had been considered so promising that a well head template was emplaced between the two structures. Well 2/11-6 was directionally drilled from here and can be used as a production well later. The intention was to drill all production wells from this template and transfer the oil and gas through pipelines to the Valhall complex. The plans indicated further that there will be a requirement for a simple well head platform above the template.

Amoco is now working on a report on possible production from subsea completed wells. Such a solution could reduce the development costs for the Hod field. This alternative has not yet been been sufficiently worked out. If subsea completion wells without any well head platform are adopted, production can start as early as 1984, by completing Well 2/11-6 and producing from it. Production would be routed by pipeline to Valhall. Amoco considers it will require 1-2 year´s production experience from this well before a decision can be made concerning any further development of the Hod field.

The Sleipner area

The Sleipner area is made up of Blocks 15/5, 15/6, 15/8, 15/9 and 16/7 and includes a number of structures. See Figure 2.2.3.2.a.

FIGURE 2.2.3.2.a The Sleipner area.



Allocations, production licences, operator responsibilities and the number of wells drilled as per year´s end 1982, were as follows:

Block	15/5	15/6	15/8	15/9	Total
Allocation year	1977	1969	1970		
Responsible Operator	Norsk Hydro	Esso	Statoil		
Production licence	048	029	046		
Total wells	3	6	1	17	27
Drilling in 1982	0	1	0	6	7

(Including 15/9-12 which was drilled in 1981 and tested in 1982)

The first well in the area, Well 15/6-2, was drilled by Esso in 1974 on the Dagny structure.

Block 15/6

Well 15/6-6 is an appraisal well on the northeast flank of the Alfa structure, and gas was proven in middle jurassic sandstone there.

Well 15/9-14 was drilled as a wildcat on the Kappa structure, southeast in the block. All prospective strata were water bearing.

Block 15/6

Well 15/6-6 is an appraisal well between the Alfa and the Beta structures. The well proved 149 meters gross gas bearing middle jurassic sandstone.

Wells 15/9-13 and 15/9-16 are appraisal wells on the northeast and east flanks of the Gamma structure. They proved 45 meters and 56 meters respectively of gas bearing paleocene sandstone (the Heimdal formation). Well 15/9-13 also proved 27 meters gross gas bearing jurassic sandstone, a layer which had eroded away in the 15/9-16 well.

New finds in the Sleipner area

15/9-My

Well 15/9-15 is a wildcat into the My structure in the southeast of the block. Gas was proven in a reservoir assumed to be jurassic. The total gas column of the well is some 100 meters, while the net gas bearing reservoir sandstone rises 58 meters, with mean porosity 24 per cent.

15/9 Theta

Well 15/9-7 was spudded and is being drilled into the Theta structure, previously unexplored.

Block 16/7

This block was originally allocated to Esso on Production Licence 001. At that time, a dry well was drilled. The well was later relinquished in its entirety, being reallocated in the sixth round to a group comprising Statoil, Esso and Norsk Hydro, under Esso operatorship. Well 16/7-2 was drilled on a structure in the northeast of the block. Gas was proven in paleocene sand, the Heimdal formation. The major paleocene gas find in 15/9 Gamma was made in the same formation, but the total gas column in Well 16/7-2 was only 13 meters. This find was too small to be of commercial interest and was not tested. The triassic and permian prospects were water bearing.

Well 16/7-3 was drilled on a separate structure in the middle of the block, and terminated in rocks of permian age. Well 16/7-4 was drilled into a separate structure in the southwest of the block. A gas column of 118 meters was proven in sandstone from the triassic period. The find lies some 6 km to the east of 15/9 My in the same structural complex, in which gas was also proven in triassic sandstone. There is probably no direct communication between these reservoirs. The strikes are highly interesting because there have been so few finds as yet in triassic rocks on the Norwegian continental shelf. The structure is difficult to map, and it is therefore too early to predict its extent with any certainty. Provisionally, it is considered that the strike may be of Heimdal field size. Any development will have to be looked at in connection with the development of the Sleipner area.

Production tests in the Sleipner area

Well	Type	Structure	Product´n rate Sm3	Daily Sm3	Choke mm	CO2 content
15/6-6	Appraisal	Alfa	835,000	278	22.2	5 %
15/9-12	Appraisal	Alfa/Beta	807,000	236	25.4	7-9 %
15/9-13	Appraisal	Gamma	704,000	308	25.4	0.1 %
15/9-13	Appraisal	(Paleo/Jura)	786,000	336	25.4	1 %
15/9-14	Explorat´n	Kappa	Dry			
15/9-15	Explorat´n	My	510,000	200	22.2	<1 %
16/7-4	Explorat´n		475,000	250	16.7	<1 %

Reserves estimate

The reserves estimated is based on calculations performed in 1982.

Recoverable reserves on the Sleipner field, including the Alfa, Beta, Epsilon and Delta structures (cf. Figure 2.2.3.2.a), are estimated to amount to 124 billion Sm3 gas and 17 million Sm3 oil. The oil is the condensate which will separate out during production. The Sleipner field gas contains some carbon dioxide (CO2). In the estimates of the reserves in place, carbon dioxide has been deducted. On average, the carbon dioxide content is 9 per cent.

For the Gamma structure, the recoverable reserves in the Heimdal formation are estimated at 55 billion Sm3 gas and 10 million Sm3 oil (in the form of condensate separated out during production). The carbon dioxide content of the structure is minimal. Reserve estimates for the My structure, the 16/7-4 structure and the jurassic reserves on the Gamma structure have not been made as yet.

Development of the Sleipner area

The concession holders are expecting to be able to present their commerciality declaration in the course of 1983, and assume that production start will occur, at the earliest, in 1990. Statoil has performed extensive field development studies with a view to technical/ economic evaluation of a number of alternative development concepts for the Sleipner field.

The development solution which seems the most likely at the moment is based on an integrated platform on the Gamma structure, and two integrated platforms on the main Sleipner field equipped with carbon dioxide scrubbers for removing the gas. In addition, there will be a requirement for a simple development unit on the northerly part of the main field.

The choice of transportation arrangement for gas and condensate depends on the results of the sales negotiations now taking place.

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 final decision has been made as to development of the field. In 1981, six wells were drilled in the Balder area, and Well 25/10-4, spudded in 1980, was completed. No new wells were drilled in 1982.

In the autumn of 1980, the Norwegian Petroleum Directorate estimated the recoverable oil reserves to be 50 million Sm3, but information from wells drilled in 1981 lead to a reduction in this assessment to 35 x 10 Sm3. In the same period, the operator reduced the recoverable estimate from 56 to 25 x 10 Sm3.

The landing application was submitted in December 1980, but because of uncertainty in the reserves and poor project economy, the landing application was withdrawn. The operator is evaluating the field, but no final decision has been made.

Oseberg (30/6 - 30/9

Block 30/6

Block 30/6 was allocated in 1979 with Statoil as operator. In the spring of 1982, Norsk Hydro took over operator responsibility. Five structures on the block have been drilled till now: Alfa, Alfa North, Gamma, Beta and Epsilon. On the main structure (Alfa), three wells were gas bearing, one proved oil, one penetrated the gas/ water contact, and one was dry.

New wells

Well 30/6-6, which was drilled on the east flank of the Alfa structure, hit the reservoir rock below the oil/ water contact and was therefore dry.

Well 30/6-7 was drilled on a northerly extension of the Alfa structure. No previous wells have been drilled into this part of the structure. Some uncertainty attached to whether this part of the Alfa was distinct from the rest, or whether there was direct communication with the southerly main part of the structure. The provisional estimates of the results of Well 30/6-7 indicate that the parts are not in direct communication with eachother. Further detailed studies will be necessary, however, to shed light on the situation.

Oil was proven in sandstone layers of middle jurassic age (the Brent formation), and the total hydrocarbon column in the well was about 100 meters. The reservoir lies under the gas/ oil contact for the field otherwise.

Four production tests were performed. The best measurement was approximately 1000 Sm3 oil and some 120,000 Sm3 gas per day through a 12.7 mm choke. The specific gravity of the oil is about 0.855 g/cm3.

The test results from this well bore were better than the ones previously achieved from tests of the oil zone on the Alfa structure.

Well 30/6-8 was drilled on a separate structure in the southeast of the block (Epsilon). The well was dry.

Well 30/6-9 was the first bore into a structure (the Gamma) common to Blocks 30/6 and 30/9. Some 40 meters gas were proven over 120 meters oil/ condensate. The oil/ water contact was not established. The reservoir contains oil up to the shale contact in 30/6-9.

Testing of the well is taking place. Two of a total of five tests have been performed. Test 2 in the oil zone produced some 550 Sm3 oil and some 65,000 Sm3 gas per day through a 13 mm choke.

Well 30/6-10 was drilled to determine the gas/ oil contact on the Alfa structure, and hydrocarbons were proven through the whole reservoir section (118 meters). An exact gas/ oil contact could not be determined, however, and the well was plugged some way down. The well will be directionally drilled to reach further up the structure, with a view to establishing the gas/ oil contact more exactly.

Well 30/6-11 was drilled in the northwest of the block on the Delta structure. This well had not attained its prospective strata as of year´s end.

Block 30/9

Because the main (Alfa) structure in Block 20/6 stretches into Block 30/9, parts of the latter were allocated in the autumn of 1982, also with Norsk Hydro as operator.

The first bore, Well 30/9-1, way to the south on the Alfa structure, is being drilled and has attained the reservoir, but had not been tested by year´s end.

Reserve estimates

There has long been a good deal of uncertainty concerning the level of gas/ oil and water/ oil contacts on the Alfa structure, as the first wells did not penetrate them. The contacts have now been quite well defined, a fact which also provides a more certain reserve estimate. The Norwegian Petroleum Directorate has provisionally estimated the recoverable reserves in the Alfa structure, including Alfa north, to be 117 million Sm3 oil and 60 Sm3 gas.

The Directorate has not yet made any reserve estimate of the Gamma structure, but an increase in the estimate of the order of 25 per cent can be assumed. From a purely reservoir point of view, conditions are right for recovery of a large part of the oil reserves in place. Recovery will depend on the production strategy selected.

The technical reservoir properties and geology are very favourable, so that both the operator and the Norwegian Petroleum Directorate are now evaluating what can be done to increase the recovery factor above what may conventionally be obtained by water injection.

Production options

The field is expected to be declared commercial in the spring of 1983. The location of the platform and the type of platform had not been determined as of year´s end. Norsk Hydro´s prime concept is based on a combined main platform with integral drilling, treatment and living units, with two associated drilling and accomodation platforms.

The siting of the main platform is envisioned on the middle of the Alfa structure in Block 30/6, with the two other platforms located respectively in the south on the Alfa structure in Block 30/9, and in the north on the Alfa structure in Block 30/6.

For the time being, evaluations are being made of alternative platform constellations. The final decision will be made in the summer of 1983, before the development plans are presented to the Ministry of Petroleum and Energy in the autumn of 1983.

The operator is at present evaluating different transportation alternatives for the gas. Process equipment will therefore depend on whether dry or rich gas is produced. Production start is scheduled for 1990-91.

The Troll field

The Troll field extends over several blocks: 31/2, 31/3, 31/5 and 31/6. Of these, only 31/2 has been spoken for. The block was allocated in 1979 with Shell as the operator. The reservoir, which dates back to the upper jurassic period, features a number of fault blocks. The hydrocarbon bearing rocks contain both gas and oil. The oil zones in the well bores drilled are thin (from 12 to 28 meters) in relation to the gas zone and the underlying water zone.

The Norwegian Petroleum Directorate estimates the proven recoverable reserves to be 480 billion Sm3 gas and 120 million Sm3 oil. They lie primarily in Block 31/2, but also extend into Blocks 31/3 and 31/5. The predicted recoverable reserves in the undrilled parts of the field are of the order of 1100 billion Sm3 gas and 45 million Sm3 oil, but the figures are uncertain. The reserves lie mainly in Block 31/6, but also extend into Blocks 31/3 and 31/5.

In all, nine wells have been drilled on the structure, three of them in 1982. Information from the new wells has demonstrated that the reservoir is more complex than previously assumed.

Well 31/2-7 was drilled on the northwestern part of the main structure, on the same fault block as Well 31/2-5. Twenty-one meters of gas were proven on top of 28 meters of oil. The oil zone was tested, and a uniform production of about 1,100 Sm3 oil per day was registered through two chokes, each of 51 mm, during a four-day period. The oil is relatively heavy, with a specific gravity of 0.89 g/cm3.

Well 31/2-9 was drilled a little further to the north of the structure on a different fault segment. The top of the reservoir lay somewhat deeper than elsewhere in the field. Nineteen meters of gas were proven over 16 meters of oil. The well was not tested.

Well 31/2-10 was drilled on the westerly part of the Troll field, to the east of 31/2-5 (21 meter thick oil zone), i.e. closer to the fault which separates the western part from the rest of the Troll field. No hydrocarbons were found in this bore because the top of the reservoir rock (upper jurassic sand) was encountered below the oil/ water contact proven in the other wells in the vicinity.

Well 31/2-8 was drilled into a separate fault block in the north. Only residual evidence of oil was found, in jurassic sand.

The geographical location of the field is in the middle of the Norwegian Trench, with a water depth of a good 300 meters. Development would thus require new technology in a number of areas. A particular problem seems to be the transfer of petroleum from the sea bed to the production platforms. Due to the great depth of water, the technological challenges of the Troll field are enormous. This means that it is necessary to preselect just a few platform concepts for further investigation. The preselection of concepts which must be made will in turn limit the degrees of freedom available to select production strategy, as the concepts chosen may to a very large extent predetermine the ratio between oil and gas production. Before a decision on development can be taken, many technical reservoir factors and development aspects will have to be looked into.

Active reporting efforts are being made by the operator to find technical and economic solutions for production from the field. The operator intends to submit the declaration of commerciality for the field during the first half of 1983. The declaration will be based on a solution in which oil and gas are produced simultaneously from a permanent platform.

Several new wells are planned in the western part of the block in 1983. There is a chance that one of them will be directionally drilled.

Gullfaks - Phase II

The block was allocated in 1978 with Statoil as operator, see the description of Gullfaks, Phase I.

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

So far, seven wells have been drilled in the vicinity of the Delta structure which belong to Phase II of the development.

Well 34/10-14 was drilled on a separate fault block on the east side of the main fault, north of Well 34/10-9. The well proved an oil column of 60 meters over oil/ water contact in rocks of the upper jurassic. The oil/ water contact in this block is at the same depth as in the rest of the structure. The well was tested, and produced 700 Sm3 oil and 50,700 Sm3 gas per day through a 15.5 mm choke. The oil´s specific gravity is 0.875 g/cm3.

The wildcat well, 34/10-15, was drilled on a separate fault block on the southern flank of the Gullfaks field, to the east of the main fault. The reservoir zone was water bearing. The same shallow gas pocket which caused Well 34/10-10 to have to be plugged and abandoned shallow was encountered at a depth of about 425 meters in Well 34/10-15.

Well 34/10-16 is an appraisal well on the Alfa structure, and was spudded on 14 December 1982.

Reserves

Due to the complicated delimitation of the field towards the east and southeast, the reserve predictions are highly uncertain. The Norwegian Petroleum Directorate´s estimate for recoverable reserves on Delta east, Phase II, is of the order of 102 million Sm3 oil and 12 billion Sm3 gas.

Any development of the area must be submitted to the authorities as a separate matter. On the basis of today´s knowledge, it would be natural to plan for two platforms to drain the area. At present, it seems most sensible to base development on two simple production platforms which could exploit the processing equipment installed during the first phase. Production could then start up when Platform A (Phase I) has idle capacity, by Statoil´s reckoning in about 1995.

Askeladden (Block 7120/8)

The block was allocated with Statoil as operator.

The first well on the Askeladden structure, which extends over a great deal of the block, provided test results among the best attained in the North Sea. The most encouraging test of 7120/8-1 produced 1.04 million Sm3 gas and 475 Sm3 condensate through a 25 mm choke.

Well 7120/8-2 was drilled on a southerly fault block in the same structure, and lies some 8 kilometers further to the south. Gas was proven in sandstone strata of the jurassic period, and the total gas column in the well bore is 85 meters. Top production was measured to be 490,000 Sm3 gas and 15 Sm3 condensate per day through a 25 mm choke.

A larger east-west fault separates the northern and southern parts of the Askeladden structure from each other. There does not seem to be any direct communication between the two parts at reservoir level, as the gas/ water contact lies 20 meters higher in Well 7120/8-2 than in 7120/8-1.

Proven recoverable reserves on Askeladden increased following the results from the drilling of Well 7120/8-2. Subsequent reestimation of the field reduced the prediction somewhat, giving the present working estimate of reserves at 75 billion Sm3 recoverable gas.

2.2.3.4 Fields declared commercial

No fields were declared commercial during the period covered by this annual report.

2.3. Fields being planned, developed or in production

Production drilling and well maintenance

In the course of the year, 23 drilling licences were awarded for production/ injection wells. Further, well maintenance was performed on 24 wells. Production from Valhall and Statfjord B started in 1982, being followed by simultaneous drilling and production at both sites.

Well drillings on North East Frigg were completed. Preparation of these wells for production will, when the work is done, represent a new type of completion concept on the Norwegian continental shelf.

Production and injection wells

Field	1982	Total	Well maintenance
Valhall	3	4	-
Ekofisk	-	46	13
Eldfisk	1	36	3
Albuskjell	-	23	1
Tor	-	14	1
Edda	-	10	-
Cod	-	8	-
West Ekofisk	-	12	4
Frigg	-	48 +	-
North East Frigg	6	7	-
Statfjord	13	28	1
Total	23	236 +	23

\+ Twenty-four of which are on the Norwegian side.

Ekofisk	There are 39 production wells on the field, 13 on the A platform, 18 on the B platform and eight on the C platform. In addition, there are five injection wells.
Eldfisk	There are 33 production wells on the field, 23 on 2/7-A and 13 on 2/7-B.
Albuskjell	There are 19 production wells on the field, nine on 1/6-A and ten on 2/4-F.
Tor	There are 13 production wells on 2/4-E.
Edda	There are seven production wells on 2/7-C.
Cod	There are six production wells on 7/11-F.

West Ekofisk	There are ten production wells on 2/4-D.
North East Frigg	Six wells have been drilled and are planned for completion in 1983.
Statfjord A	Twenty-three wells have been drilled from the platform, 12 from the north and 11 from the southern column. Fourteen wells are in production, four are injecting gas, three inject water and two are as yet incomplete.
Statfjord B	Four wells have been drilled from the platform, three in the southern and one in the northern column. All four wells are in production.
Valhall	Three wells have been drilled from the platform.

2.3.1 Valhall

Production Licence 006
Concession holders:

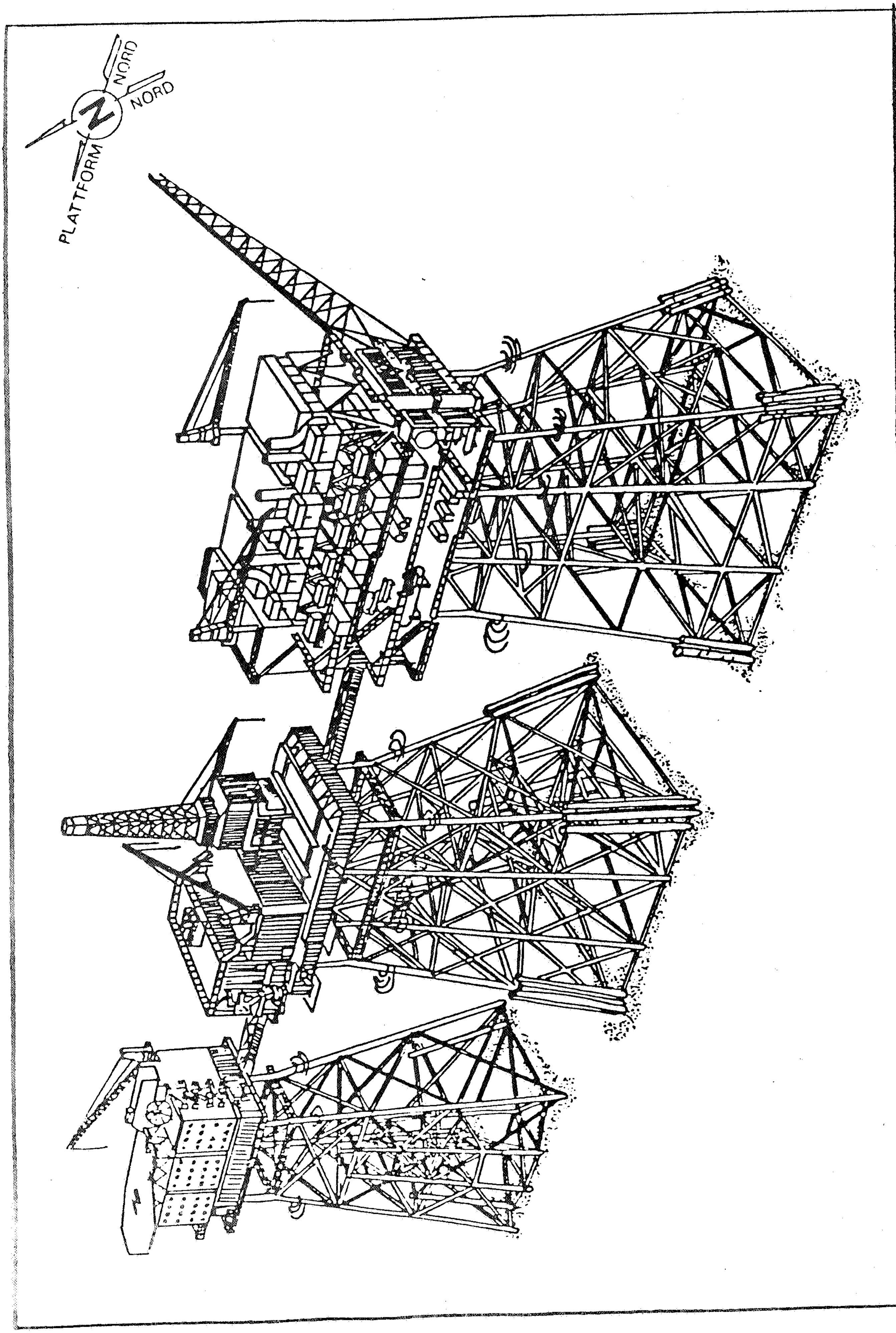
Amoco Norway Oil Company A/S	28.33 %
Amerada Petroleum Corporation of Norway	28.33 %
Texas Eastern Norway Inc	28.33 %
Norwegian Oil Consortium A/S & Co	15.00 %

Block 2/8 was allocated in 1965 with Amoco as the operator.

The Valhall field lies mainly within Block 2/8. 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. Amoco/ Noco applied for landing permission for petroleum from Valhall and Hod (Block 2/11) in the autumn of 1976. Development in the first stage (Valhall A) includes an accomodation, a drilling, a production and a riser platform. The three first named platforms are located on the Valhall field and connected by bridge links. Figure 2.3.1 shows these installations. The riser platform is coupled to the Ekofisk tank.

A royal decree to transfer operator responsibility for the Amoco/ Noco group´s Riser Platform 2/4-G on the Ekofisk field to Phillips Petroleum Company Norway was given on 17 December 1982. The resolution entered into force immediately.

FIGURE 2.3.1 Installations on Valhall



Production facilities

The crude at Valhall is removed with the help of two separation units before being pumped to the Ekofisk facility, where it is metered and forwarded via the Teesside pipeline. The gas is compressed, dried and its dew point examined on the production platform before being sent by pipeline to the Ekofisk facility, where it is metered, and dispatched via the Emden pipeline. The denser gas fractions are separated out by stabilizer on Valhall, and then injected into the oil.

As production from Valhall was less than expected, there was not sufficient gas to test the gas equipment at the facility in 1982. All gas was used or flared on the field. Amoco predicts gas sales will begin on 15 April 1983.

Recovery of reserves

Valhall is similar to the fields in the Ekofisk area as regards reservoir factors and geology.

The Norwegian Petroleum Directorate estimates that some 29 million Sm3 oil, 4 million Sm3 NGL and 26 billion Sm3 gas will be drainable from the Valhall A site by using pressure amelioration. Recovery of the resources in the Valhall field seen as a whole depends on two important factors:

- the time chosen to develop those parts of the field which cannot be reached from Valhall A, and

- the production strategy, not only for Valhall A, but also the rest of the field.

Production from Valhall A started on 1 October 1982, about one year later than the operator had originally assumed. During 1982, three production wells were tied in to the process facility. The operator expected that the mean well rate would lie at 1600 Sm3 oil per day, but this productivity has been impossible to achieve. The result has been a mean rate of about 930 Sm3 oil per day.

Metering system

The metering system for oil and gas on Valhall received approval. Operating controls of the metering system have been established.

Costs

The total costs are predicted to be some NOK 6.5 billion in current kroner, or NOK 6.9 billion in fixed 1982 kroner. (When converting from current to fixed kroner values, the total wholesale price index is used. The idea is to make it possible to compare different field developments.)

2.3.2 The Ekofisk area

Production Licence 018 (the "Phillips group")
Concession holders:

Phillips Petroleum Company Norway A/S	36.960 %
Norsk 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 concessions 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 divided between Production Licences 018 and 011, and the Tor field between Licences 018 and 006. Albuskjell lies in Blocks 1/6 and 2/4, the Tor field in Blocks 2/4 and 2/5. A reallocation was undertaken for Tor in 1982 with effect from 1 January 1983. The present subdivision is:

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 (the "Amoco group")
Concession holders:

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 %

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, the field was 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: Trial 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 line to Emden. The lines were taken into operation in October 1975 and September 1977 respectively.

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

The possibility of a fifth phase is now being evaluated. This would consist, if implemented, of a major water injection project.

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

Transport

Oil and gas from the Ekofisk area are brought ashore via pipelines to Teesside in England or Emden in West Germany, respectively.

The oil line to Teesside is 354 km long and has a diameter of 864 mm. The average flow rate through it in 1982 was 49,880 Sm3 oil per day. The gas line to Emden is 442 km long and 915 mm in diameter. During 1982, the average amount of gas transported through it per day was 37.8 million Sm3.

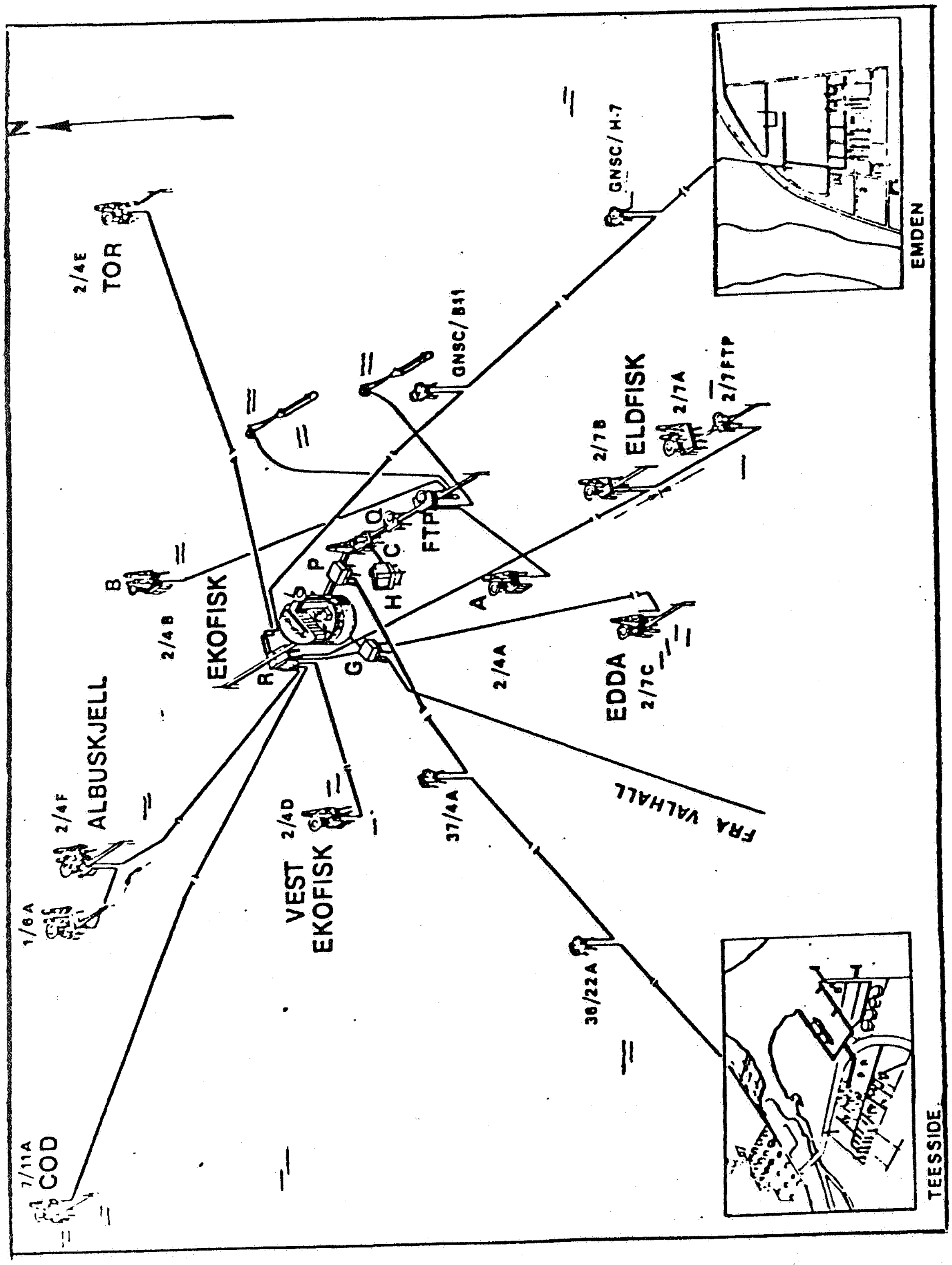
Production facilities

All seven fields in the Ekofisk area are now fully developed and in production. One major construction task in 1982 was the gas lifting system on Platform 2/4-B, which was mechanically completed in November. Otherwise, the most significant construction works have been on the maintenance side with the replacement of the living quarters. New quarters have been finished on Tor and Eldfisk A, while on Eldfisk B and West Ekofisk they are still being built. Furthermore, a contract has also been placed for Albuskjell A and Albuskjell F.

There were no scheduled maintenance close-downs in 1982. Nevertheless, the whole Ekofisk area was closed from 27-31 May because of two fires, the first on the south flare, the second on the north flare of the Ekofisk complex. From 13-18 October, the whole Ekofisk area was closed down due to a strike.

In December 1982, Phillips started using its gas lift compressor on the Ekofisk 2/4 B platform. This is an important part of the trial project for water injection. When the injected water reaches the production wells, there is not always sufficient pressure to force the mixture of oil and water to the surface. By driving gas into the production string through side valves, it is possible to lift the water and oil, with its dissolved gas, up to the surface. The compressor is rated at 0.2-0.5 million Sm3 per day, and pressurizes the gas to 190 bar. It consumes gas fuel which is now transferred by subsea pipeline from the 2/4 FTP platform. If a full scale water injection project is authorized, the compressor can be rebuilt and utilized in connection with this project.

FIGURE 2.3.2.a Installations on fields in the Ekofisk area.



Recovery of reserves

The original petroleum reserves in place on the Ekofisk field are estimated to have been 841 million Sm3 oil and 189 billion Sm3 gas. The recoverable reserves are estimated at 163 million Sm3 oil and 111 billion Sm3 gas. By injecting water into the reservoir, the Norwegian Petroleum Directorate has predicted that the recoverable oil reserves will increase by 35 million Sm3, although this would reduce the recoverable gas quantity by 6 billion Sm3.

Both the operator (Phillips) and the other concession holders made studies in 1982 of the effect of water injection into the Ekofisk field. The technical planning for a separate platform for water injection, envisioned at the 2/4 Bravo site, has been going on at full speed. A pilot project using water injection into one of the 2/4 Bravo wells, and an assessment of the results, has continued without pause. By the end of 1982, some 1.7 million cubic meters of water had been injected. The water reached the closest production well in May, following more than a year of injection. This pilot project has shown that the reservoir (Tor formation) is suited to water injection at high rates, and that the water supplants the oil in an effective way. A full assessment of the pilot project has not yet been possible. The concession holders´ present plan is to make a decision concerning the water injection project in the course of the first quarter 1983. If there is a favourable decision, the installation of the injection platform will probably take place in 1986, and water injection will be able to start in 1987.

On Cod, the plan is to examine the possibility of recovery from a deeper geological strata of jurassic age using a new well. The possibility exists here that the reserves recoverable from Cod can be increased considerably.

Flaring of gas in the Ekofisk area

The quantity of gas flared is apparant from Figure 2.3.2.b. During Phase I of the Ekofisk development from 1971 to 1974, test production was performed with a loading platform, and all gas was flared. Since 1977, the gas has been landed and sold through the Emden gas line, 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. The year 1982 has demonstrated that the flare rate is stable at about 0.4 per cent of total gas production. Figure 2.3.2.c shows gas flared as a percentage of total gas production.

The metering system

Continual inspections of the metering systems in the Ekofisk area are performed.

Inspections of the metering systems at the point of sale for the gas in Emden have taken place at monthly intervals.

Inspections of the metering systems for oil and wet gas at Teesside are performed with a view to setting up a routine inspection arrrangement.

FIGURE 2.3.2.b. Gas flared on the Ekofisk area

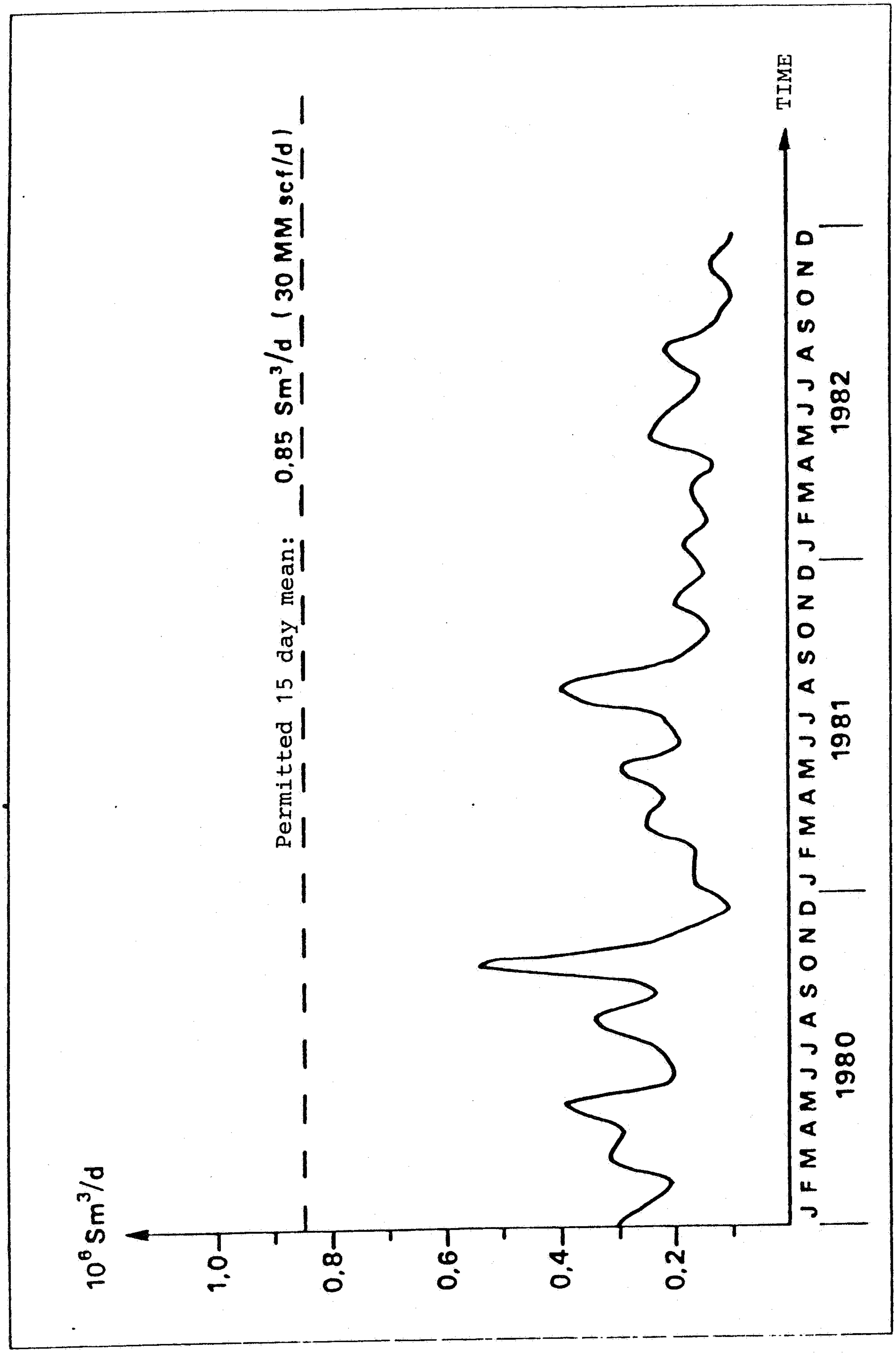
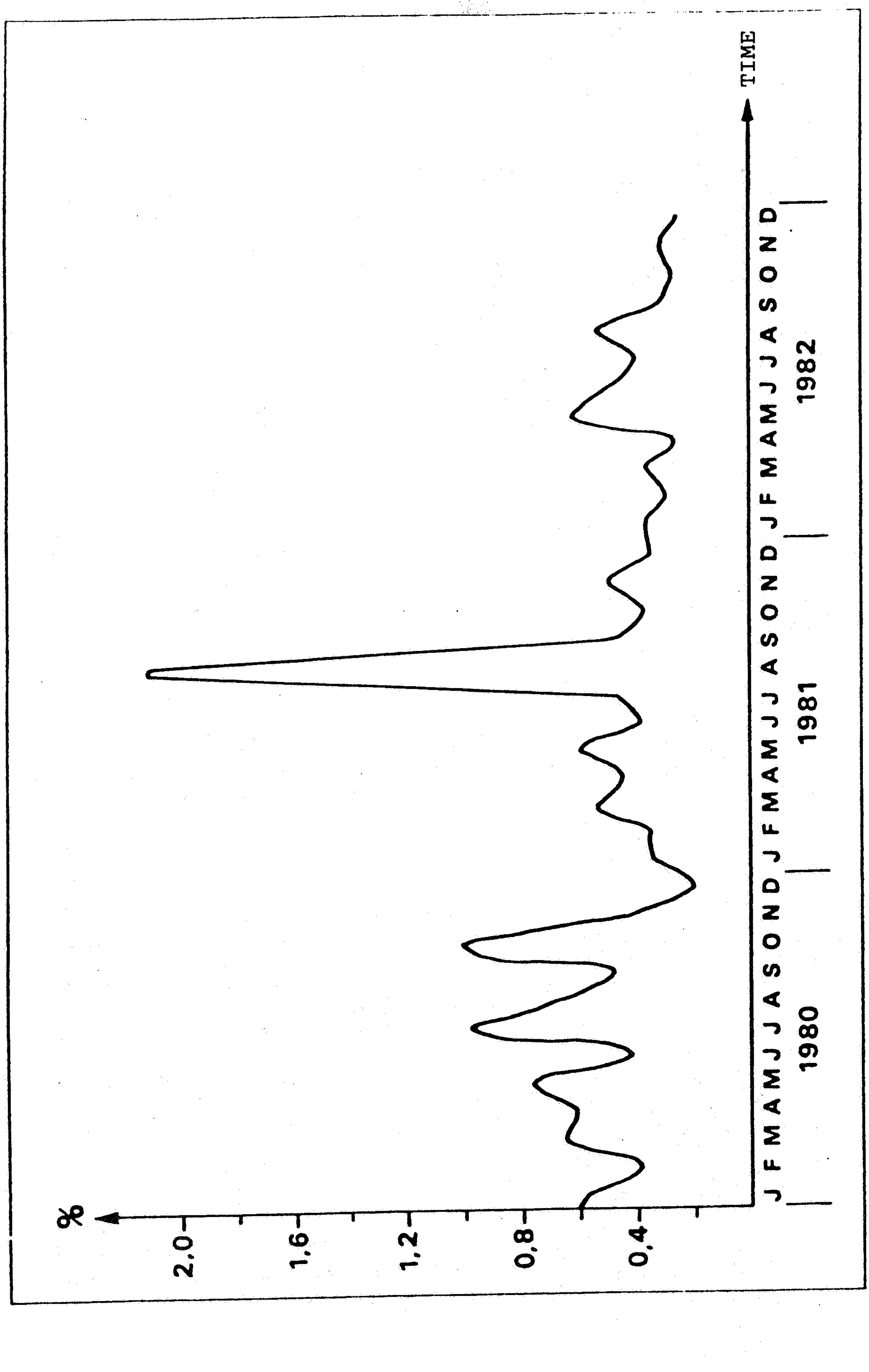


FIGURE 2.3.2.c. Gas flared on the Ekofisk area as percentage of total Ekofisk gas production



Costs

The total costs of the Ekofisk area including Tor, Albuskjell and Norpipe are predicted to amount to about NOK 33.7 billion in current kroner, or NOK 52.3 billion in fixed 1982 kroner. (For conversion, see Valhall).

Safety and the working environment

2/4 Bravo

In the late autumn it was reported that two large boat fenders had worked loose and fallen into the sea. Closer examination revealed some resulting damage to the underwater structure at different levels. Analyses of the structure were undertaken immediately to determine the importance of the damage to the safety of the structure. A repair plan is now being worked out.

The Ekofisk tank

Some mechanical damage and accidents have occurred with the gas turbines and compressors. The damage has not caused production stoppage. Mechanical maintenance and non-destructive tests continue as planned.

Because future gas from other fields can cause greater drops in temperature, the compressor housings on all pipeline compressors were replaced with steel ones which can withstand lower temperatures. All coolers in the system have also been renewed. The new coolers are made of titanium alloy.

2/4 FTP

On the production separators there is evidence of corrosion. This corrosion has no effect on safety or operations, as the pressures have now been significantly stepped down for operational reasons.

Welding shop fire on Tor 2/4 E

On 11 March 1982 a fire occurred in the welding workshop on the Tor platform. As a result of several related circumstances, gas from an oil separator tank was spread via the deck draining system and flowed into the welding shop through the floor drain. Here the gas was ignited, causing a short, but intense, fire. Of the nine persons actually inside the workshop, seven were taken to hospital with burns.

Following the fire, the operator implemented a number of measures to prevent similar accidents on its installations. The case is being investigated in the normal manner by the police.

Fire on the Ekofisk complex

Just after midnight on 27 May 1982, a fire started on the sea below the southern flare stack on the Ekofisk complex. Two fire boats took part in extinguishing it, and the fire was put out after about one hour. Shortly after, production was restarted, and a new fire occurred on the sea at about 0700 hrs by the northerly flare stack. This latter fire burned intensely with a great deal of smoke. The burning oil drifted towards the riser platform 2/4 G, and for a time things looked rather grim for this platform. The fire was brought under control after about half an hour.

There were no injuries to personnel during the fire. Mechanical damage was restricted primarily to some cables made useless. Inspections of the structure indicated that it had withstood the intense heat.

The cause of the fire seems to have been that large amounts of oil entered the pressure relief system and escaped to the sea, where ignition occurred. The source of the leak turned out to be 2/4 FTP, though it was not possible to say exactly where the oil had entered the pressure relief system.

The police are enquiring into the fire as a matter of routine, and their investigations are not yet complete.

2.3.3. Ula

Production Licence 019
Concession holders:

BP Petroleum Development of Norway A/S	57.5 %
K/S Pelican A/S	5.0 %
Norsk Conoco A/S	25.0 %
Den norske stats oljeselskap a.s	12.5 %

The field lies in Block 7/12 some 70 km northwest of Ekofisk. 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.

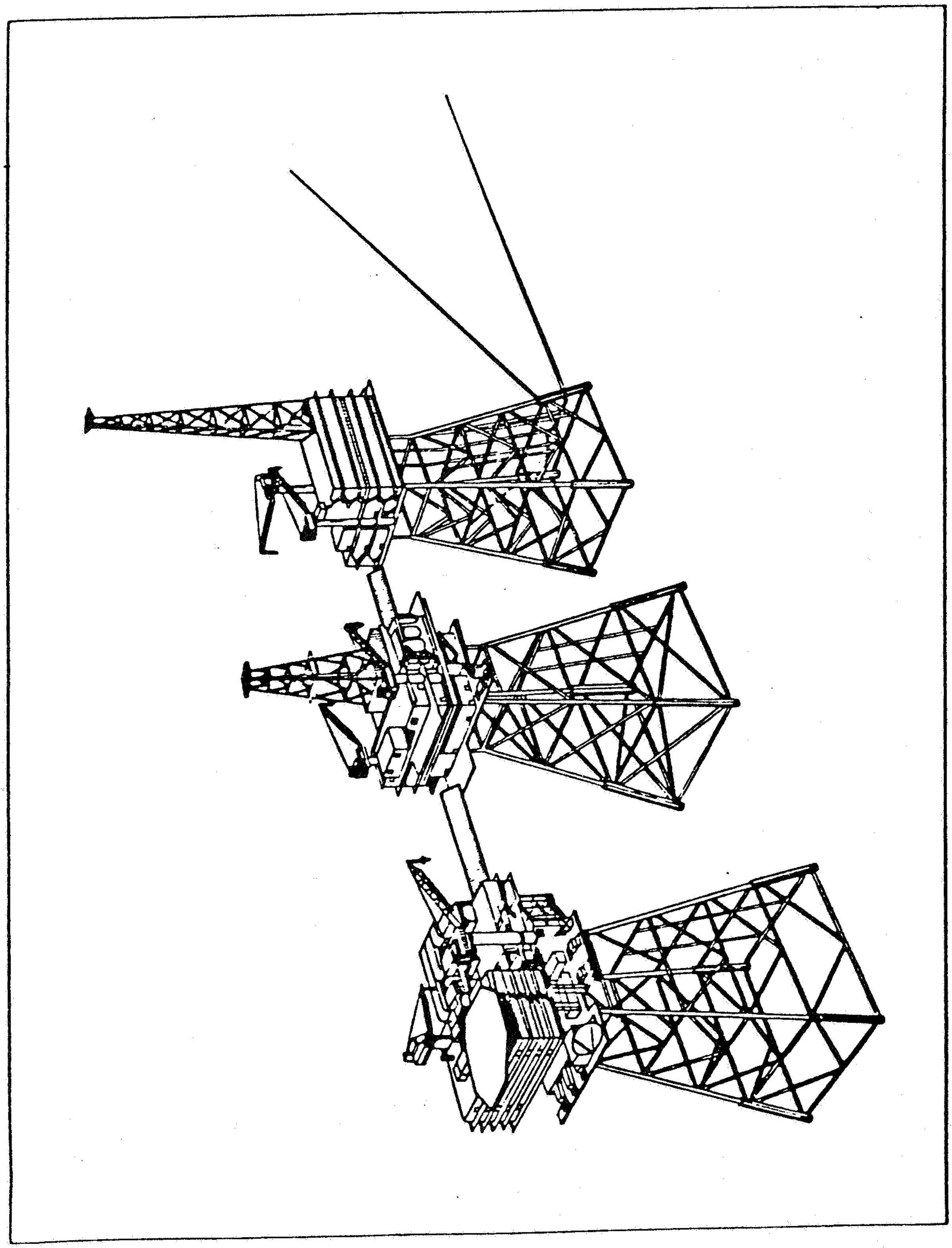
The concession holders decided in the middle of December 1982 to go ahead with the project.

Development

The Norwegian Petroleum Directorate's estimated recoverable reserves are 32 million Sm3 oil and 2 billion Sm3 gas.

The concept forming the basis of the development includes three conventional steel platforms for production, drilling and accomodation, respectively. Nine production wells and six water injection wells are planned. Drilling start is anticipated in the second half of 1986, with production start in the first half of 1987. (Figure 2.3.3).

FIGURE 2.3.3 Planned installations on Ula



Transport

At year's end, two landing alternatives were being evaluated for oil: either from a loading platform on the field, or through a pipeline to the Ekofisk center, from where the oil would be piped to Teesside.

The gas will be transported by pipeline to Cod and from there via the pipeline system to Emden.

Costs

Total costs are expected to be some NOK 9.8 billion (current value), or NOK 7.5 billion in fixed 1982 kroner.

2.3.4 Heimdal

Production Licence 036
Concession holders:

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 & Co	3.471 %
A/S Uglands Rederi	0.169 %

Production Licence 036 was allocated in 1971 and covers Block 25/4, which is situated some 215 km northwest of Stavanger. On that part of the concession which includes Heimdal, the state 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 marked altered 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.

Development

The reservoir lies some 2100 meters below sea level in paleocene sand. The total recoverable reserves are estimated at 35.6 billion Sm3 rich gas, of which 33.8 billion are dry, and 3.1 billion condensate. It has been decided to develop the Heimdal field with an integral steel platform, comprising drilling, production and accomodation functions (Figure 2.3.4). The installation work on the field will start in the summer of 1984, while production is expected to begin in mid-1986.

Transport

For gas transport, the Heimdal field will be tied in to the Statpipe system near the Sleipner field. On 6 August 1982, the concession holders submitted their landing application for condensate. The condensate will be carried by pipeline from the Heimdal field to the Brae platform in the British sector, and from there to Cruden Bay via the Brae-Forties system.

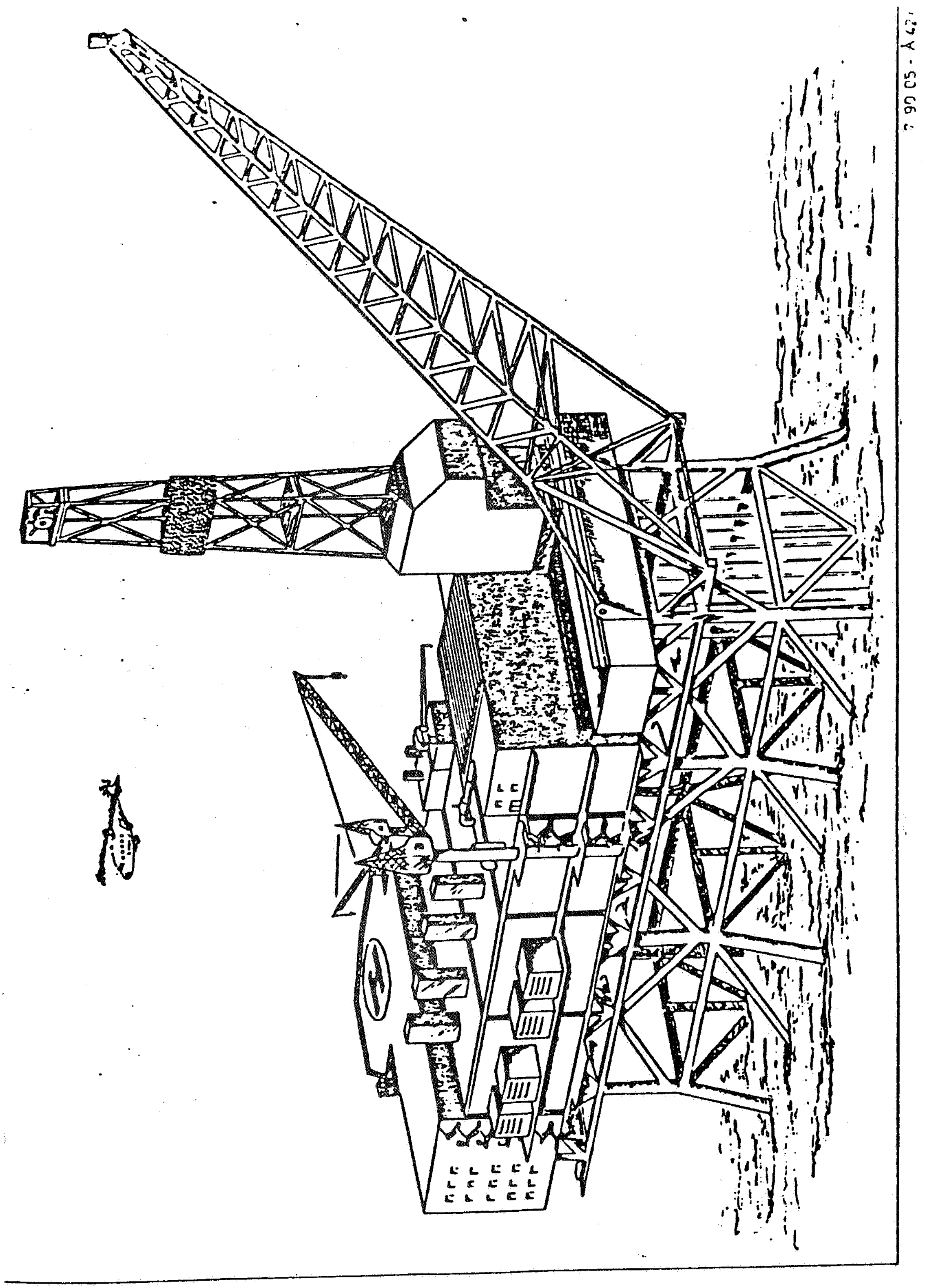
The metering system

Design controls of the metering stations for gas and condensate have started. For metering of condensate, the design controls have been performed in collaboration with the British Department of Energy.

Costs

The total costs are estimated to amount to about NOK 8.3 billion (current value), or 7.1 billion in fixed 1982 kroner.

FIGURE 2.3.4. Planned installations on Heimdal



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

2.3.5.1 Frigg

Concession holders:

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 %

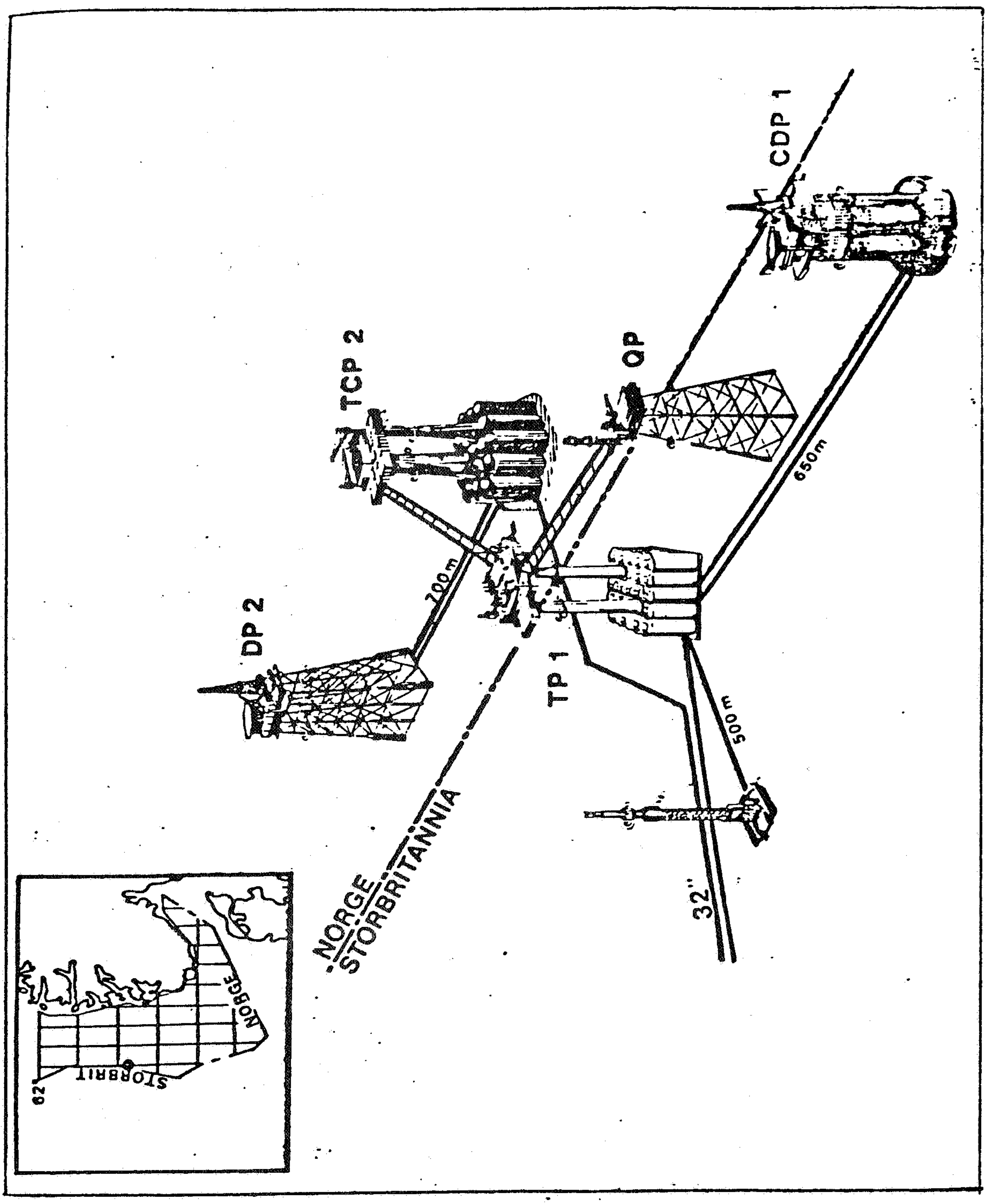
British share (39.18 %)

Elf Aquitaine UK Ltd	25.97 %
Total Oil Marine Ltd	12.98 %
BP Ltd	0.23 %

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.

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 concession holders, and the remaining 39.18 per cent to the British concessionaires. The agreement on distribution of the reserves may be renegotiated every four years, the first time on 1 January 1985, or at any time if extra reserves are proven which seem to be connected to 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.

FIGURE 2.3.5.a. (Inset) The location of the Frigg field
FIGURE 2.3.5.b. Installations on the Frigg field



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 production and treatment platforms on the British side of the field (CDP1 and TP1), and an accomodation platform (QP). Production from Phase 1 started on 13 September 1977.

Phase 2 consisted of production and treatment platforms on the Norwegian side of the field (DP2 and TCP2). Production from the Phase 2 platforms started in the summer of 1978. Figure 2.3.5.b shows 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 metered at Frigg. New modules for treatment of the gas and condensate will therefore be designed and installed on TCP2.

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 turbo-compressors are now being installed on the pump 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 is being prepared, to give six process lines rather than the present five.

Recovery of reserves

The production prospects for the Frigg field are still based on the 1977 model, which also includes the satellite fields. Nevertheless, the model is being revised and this work is expected to be completed by the start of 1983.

The oil/ water and gas/ oil contact on the Frigg field are checked several times a year. The movement in liquid contact has been somewhat uneven in 1982 too. This may indicate that the field is rather more complicated than previously assumed, with shale layers which partially prevent the oil and water form moving in the reservoir. Observation wells have been sited in some of the reservoirs where there is a good deal of shale in the sand. The shale content will make it difficult to follow the movements in liquid contact for several years to come. New measurements will be performed in 1983.

Pressure developments agree well with the model, except for the latest measurements, which have displayed higher pressure than expected in both the Frigg and Cod sand. This may perhaps be due to the extremely low summer deliveries, increased water thrust or greater amounts of gas reserves in place (not greater rock volume).

Seismic surveys have been performed to study the possible migration of gas from the satellites, North East Frigg and East Frigg, to the main field. No conclusion could be drawn regarding East Frigg. In the case of North East Frigg, there had been a definite change, but it was not possible to indicate the quantities involved. New investigations are scheduled for the summer of 1983.

Metering systems

Inspections of the metering systems on Frigg and MCP-01 were performed according to a fixed inspection arrangement in collaboration with the British Department of Energy.

Design controls and factory testing of new computers for metering systems on Frigg were performed in collaboration with the same Department of Energy.

Costs

The total costs are predicted to amount to about NOK 22.7 billion in current kroner, or 33.4 billion fixed 1982 kroner. The Norwegian share of this is 13.8 or 20.3 billion respectively. (See Valhall for conversion details).

In the case of the TCP2 extension, the costs are predicted to be some NOK 1.0 billion (current) or NOK 0.9 billion (fixed 1982 kroner).

Safety and the working environment

This year too, inspections revealed cracks in the pressure vessels on the TCP2 platform. As mentioned in the annual report for 1981, cracks were also discovered in 1979, 1980 and 1981.

The problem of cracks in the pressure vessels has now been clarified. Following pressure testing and strain gauge examinations, the operator was given permission to run some of the pressure vessels at full working pressure, while others are still working at reduced pressure.

On DP2 on the Frigg field, cracks have been noticed between the primary structure and the conductor frame some 8 meters below sea level. The cracks are being carefully watched, and different analyses of the structure have been performed to determine the importance and development of the cracks. A repair plan is being prepared.

The subsequent inspection program is the subject of discussions between the Norwegian Petroleum Directorate and the operator.

Hydrate plug in the line between TP1 and TCP2

A hydrate plug in the pipeline between TP1 and TCP2 caused displacement of the entire pipeline system. Examinations revealed that the pipe system, following pressure tests and exhaustive crack inspection, could be restarted.

2.3.5.2 North East Frigg

Production Licence 024 (Block 25/1)
Concession holders:

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)

Esso Exploration & Production Norway Inc	100 %

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

The North East Frigg field lies in Blocks 25/1 and 30/10, and the gas reserves are distributed with 60 and 40 per cent respectively on each of the blocks. Elf Aquitaine Norge A/S is the development operator.

Production facilities

The North East Frigg gas field was proven in 1974. This is a part of the same pressure system as the Frigg field. The final development plan was resolved in 1980. The field was developed with six wells completed on the seabed. These were drilled through a template placed on the bottom. In addition to the well heads and christmas trees, there is also a manifold to collect the gas from the six wells. The gas is transferred to the Frigg field for processing through a 406 mm pipeline. Each of the six valve trees will be controlled through separate service and control lines from the control station (an articulated column) located 150 meters from the well heads. The control station will be remotely controlled from the Frigg field. The station column has been built and will be hooked up with the deck and equipment module, now under construction, in 1983. The concrete base which the column will be hinged to on the seafloor has also been completely fabricated. The plan is to tow out the control station in the spring of 1983. Looked at as a whole, 63 per cent of the constructional work had been completed by year´s end.

Sales of gas from North East Frigg initiated on 1 October 1981, i.e. before any of the production wells had been drilled. This was possible because the Frigg field supplies gas on behalf of North East Frigg until this latter comes on line. Frigg will similarly supply gas on behalf of North East Frigg after production there has terminated. The "repayment" assumes an arrangement whereby North East Frigg, during its short production life, supplies gas on behalf of Frigg in addition to the North East Frigg contract amount. Thus, a more normal, long-term sales profile is achieved for the gas from North East Frigg, even though its production life is short.

The operator aims to start production on 1 January 1984.

Metering systems

The design inspection of the metering system and commissioning of the metering pipes by the manufacturer took place in collaboration with the British Department of Energy.

Costs

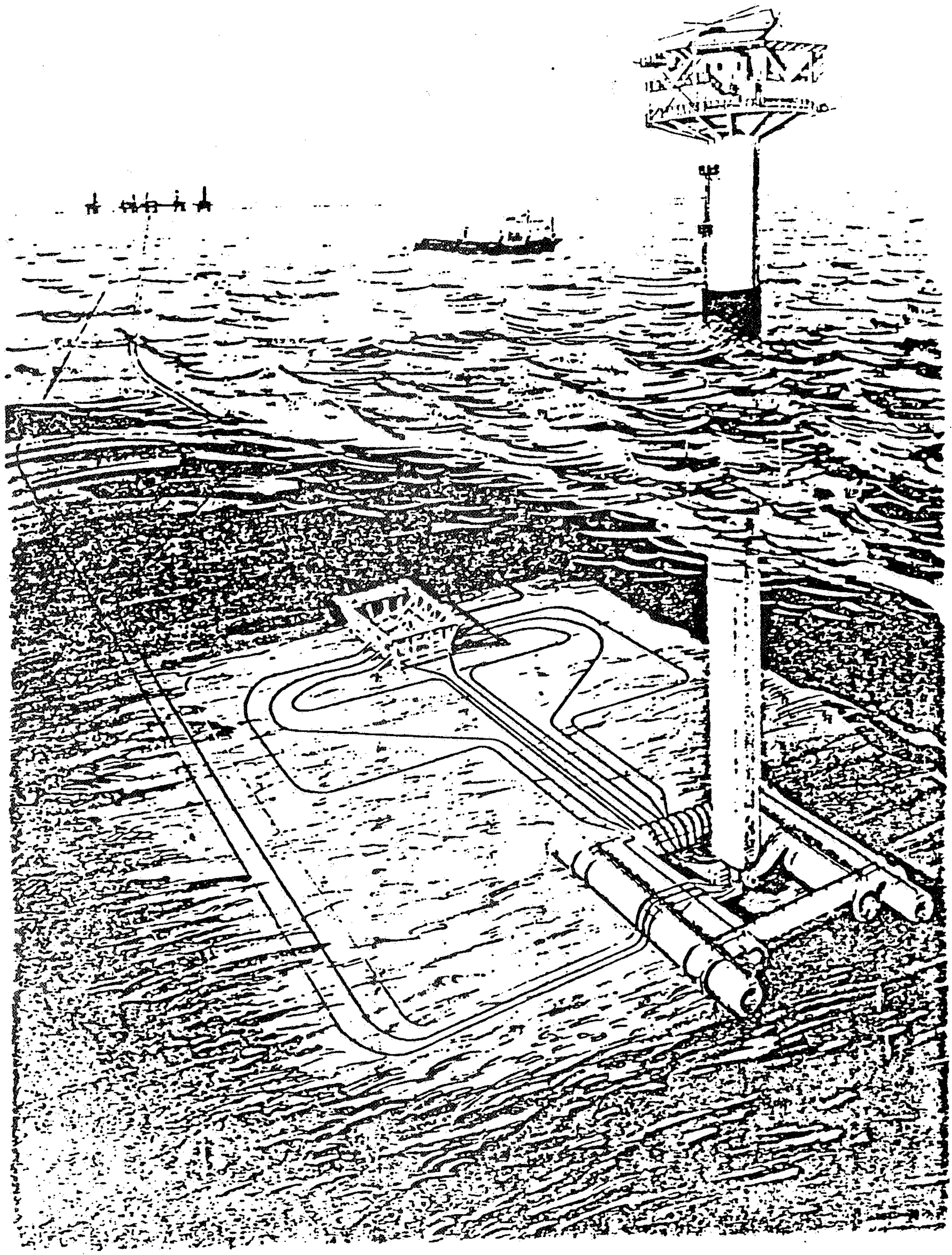
The total costs are expected to reach some NOK 2.2 billion in current kroner, or 2.1 billion in fixed 1982 kroner. (For conversion, see Valhall).

Safety and the working environment

The drilling of the production wells on North East Frigg has been performed. Preparation of these wells for production involves a completion concept entirely new for the Norwegian continental shelf. The concept is the first to employ a template with six underwater valve trees. The gas from the wells will be collected and transported through the submarine line to Frigg. Valve trees and manifold valves will be controlled remotely from the North East Frigg control station and Frigg itself.

On two of the wells, major damage has been reported. This will require extensive and costly repair work.

FIGURE 2.3.5. Production installations on North East Frigg



2.3.5.3 Odin

Production Licence 030
Concession holder

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, with development operated by Esso.

Production facilities

The Odin gas field was proven in 1974, and the development plan approved in 1980. The development option chosen consists of a steel base platform with four legs and integral deck. The drilling vessel Treasure Supporter will be rebuilt and used as a utility platform during development and production drilling.

The production platform may be equipped with treatment equipment, though only to a limited extent because the gas will be dispatched unprocessed to the Frigg field through a 508 mm line. This pipeline will have been laid and tied in to the TCP2 platform on Frigg by March 1982.

The platform will be scaled for 12 wells. It is planned to drill nine production wells, including one reserve.

The project progressed from the engineering phase to fabrication in 1982. The largest contracts for the steel base and modules had been signed by the end of 1982.

Esso envisages production start in October 1984.

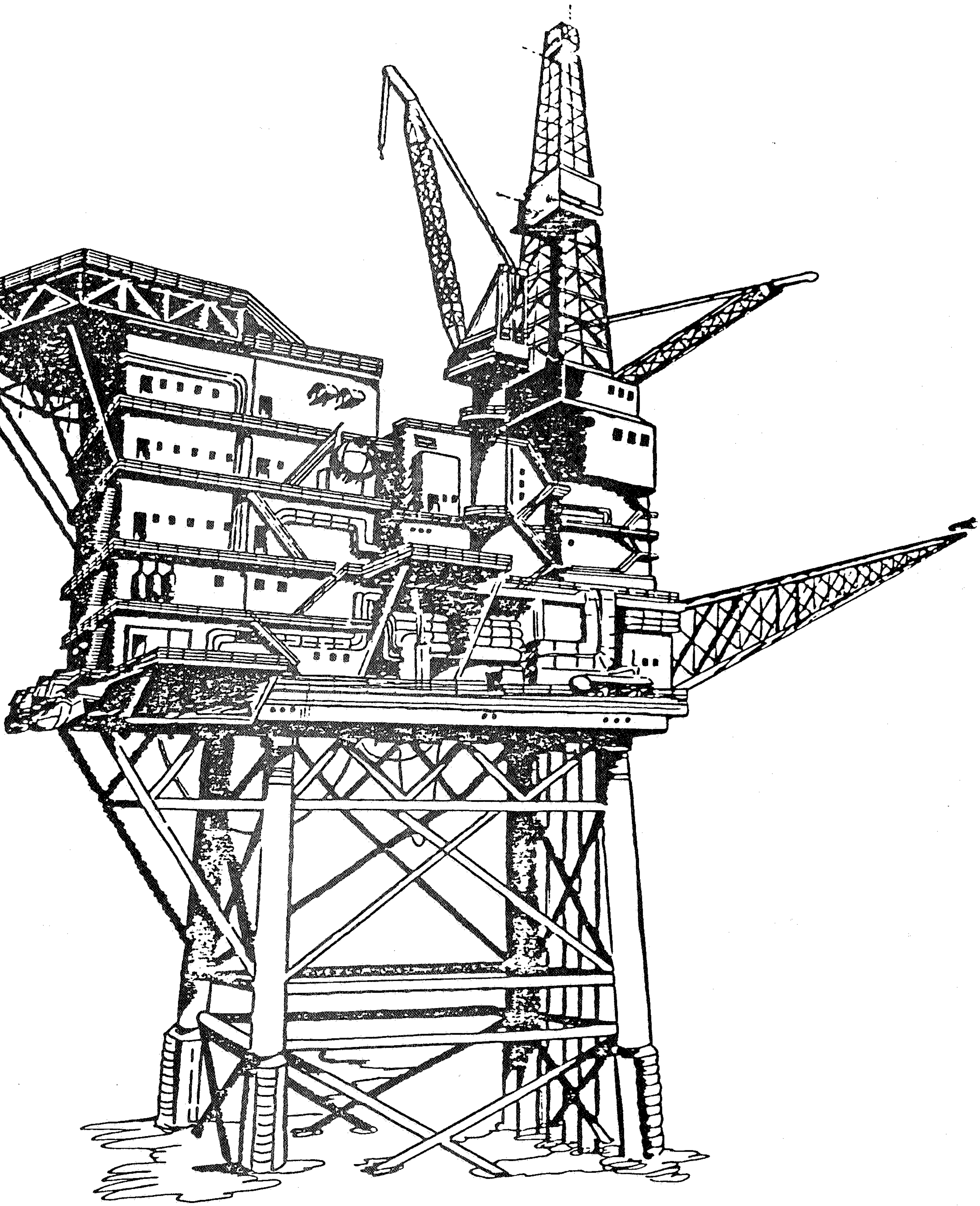
Metering systems

Design inspections of the metering systems and commissioning tests of metering pipes at the factory take place in collaboration with the British Department of Energy.

Costs

The total costs are expected to hit some NOK 3.0 billion (current value), or, in fixed-1982 values, NOK 2.7 billion. (For conversion details, see Valhall).

FIGURE 2.3.5. Installation on Odin



2.3.6. Gullfaks

Production Licence 050
Concession holders:

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 exploratory phase. Conoco has been engaged as technical assistant for the development phase.

Production facilities

The first find 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 2.3.6). Platform A will be an intergrated drilling, treatment and accomodation platform with a capacity of about 39,000 Sm3 per day. The platform will be located on the southwest part of the structure in about 135 meters of water. The platform base will be of the Condeep type with a T-shaped deck frame of steel. An articulated loading platform will be tied to the Condeep.

Platform B will be a drilling and accomodation structure with a concrete base, equipped with some process machinery. The B platform will be sited on the northwest part of the Delta East structure in about 135 meters of water.

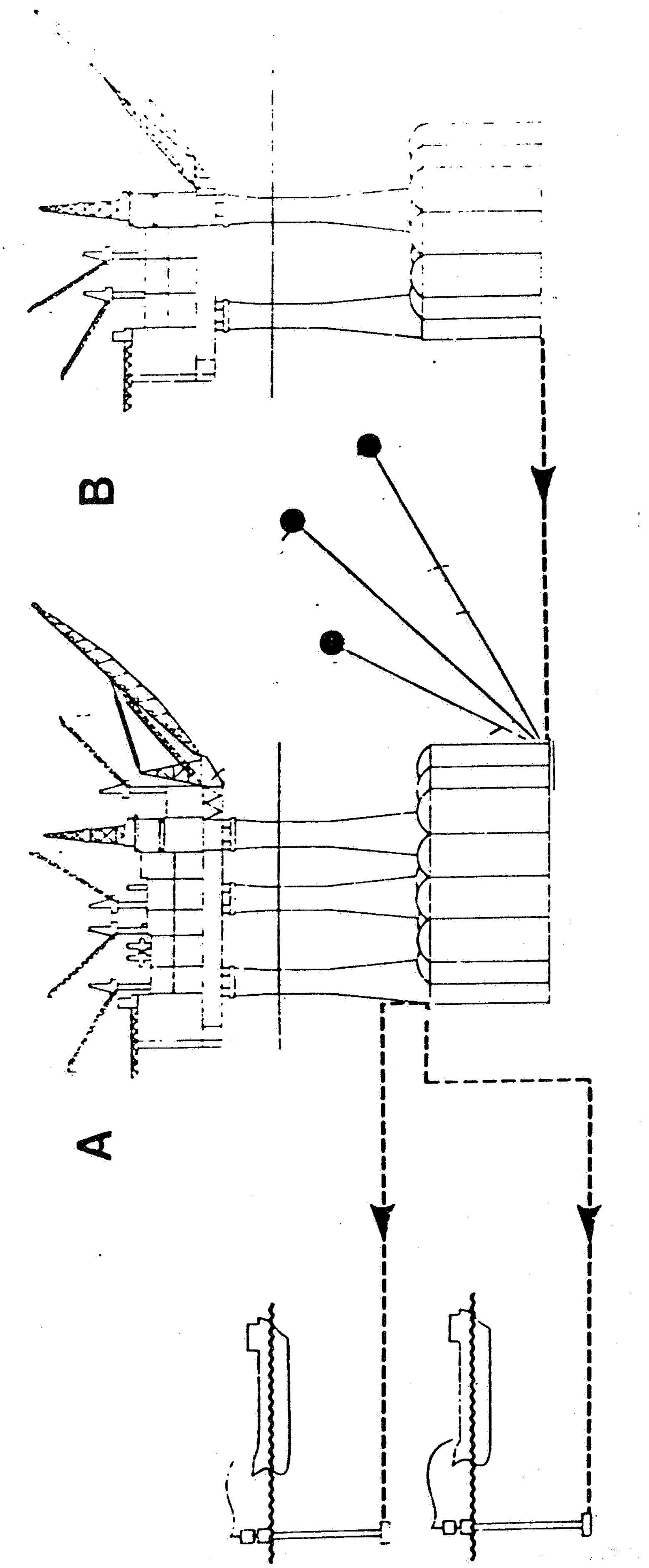
Phase I will also include a stand-by loading platform.

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

The construction of the concrete structure for the A platform will start in 1983, and the majority of the design and hook-up contracts will be assigned during 1983.

The operator expects the A platform to be ready for production by 1 July 1987, while Platform B is scheduled to come on line some two years after that.

FIGURE 2.3.6. Development of the Gullfaks field



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 2.3.7.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 from 7-20 degrees, though all point westward. In the east, the field has a more diffuse 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 complex field so far dealt with in the context of developments on the Norwegian continental shelf.

Due to the complexity of the field, the Norwegian Petroleum Directorate´s reserves estimate is very uncertain. Nevertheless, it has been found reasonable to assume a magnitude of recoverable reserves of the order of 93 million Sm3 oil and 6 billion Sm3 gas for Phase I (to the west of the main fault), and 102 million Sm3 oil and 12 billion Sm3 gas for Phase II (to the east of the main fault).

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 find in triassic strata. The reservoir rocks are rather similar to the Statfjord and Murchison ones, i.e. sandstone of high permeability and relatively high porosity. Under the oil, there usually 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. Also gas injection has been evaluated as a method of extraction. However, this would give a less favourable result than water injection, not least because the field contains so little gas that it can almost be considered to be a pure oil field.

Metering system

Design controls for the metering station for oil and gas have been instigated.

Costs

The total costs are expected to run to about NOK 39.7 billion at current kroner values, or NOK 28.9 billion in fixed 1982 values. (For conversion, the operator´s indices are used).

2.3.7 The Statfjord area

The Statfjord area includes the Statfjord field, Fields 33/9 Alfa, 33/9 Beta and 33/9 Delta.

Concession holders:

Norwegian share (84.09322 %) (Production Licence 037)

Mobil Development of Norway A/S	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 & Co	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 North Sea Inc	5.30226 %
Britoil Ltd	5.30226 %
Gulf Oil Corporation	2.65113 %
Gulf UK Offshore Investments Ltd	2.65113 %

On 10 August 1973, the concession holders on the Statfjord field were allocated Production Licence 037. This includes Blocks 33/9 and 33/12. Mobil is the operator (Figure 2.3.7.a). The only field so far resolved for development is Statfjord (Figure 2.3.7.b).

FIGURE 2.3.7.a. Location of Gullfaks in relation to Statfjord

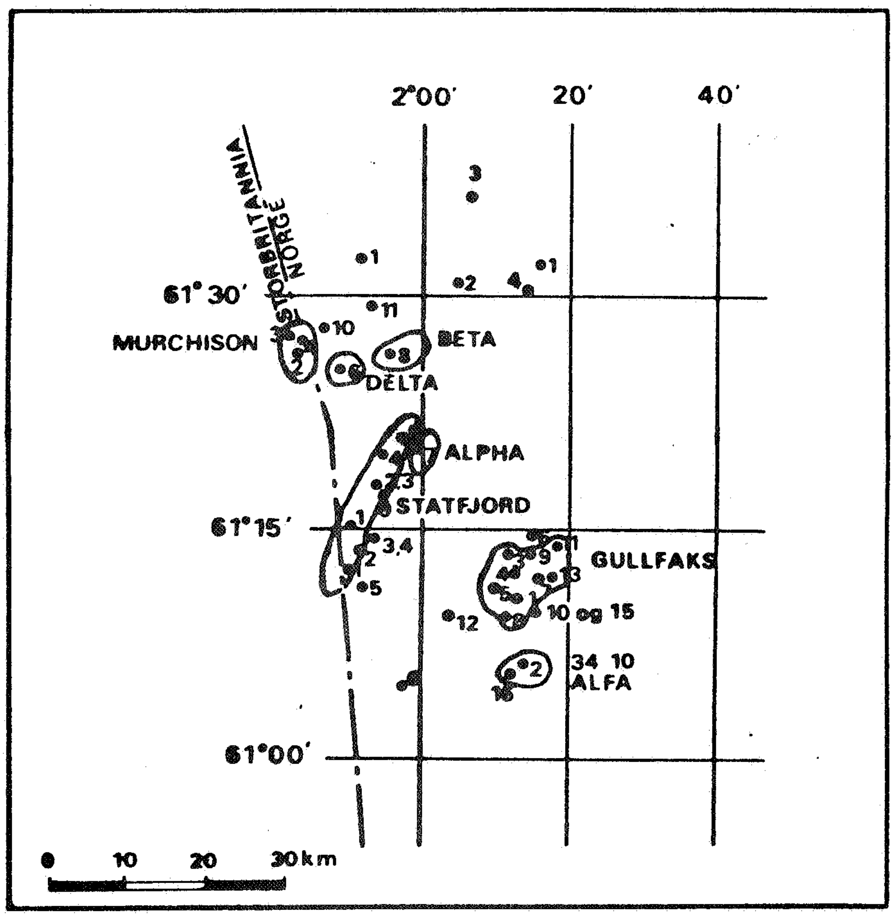
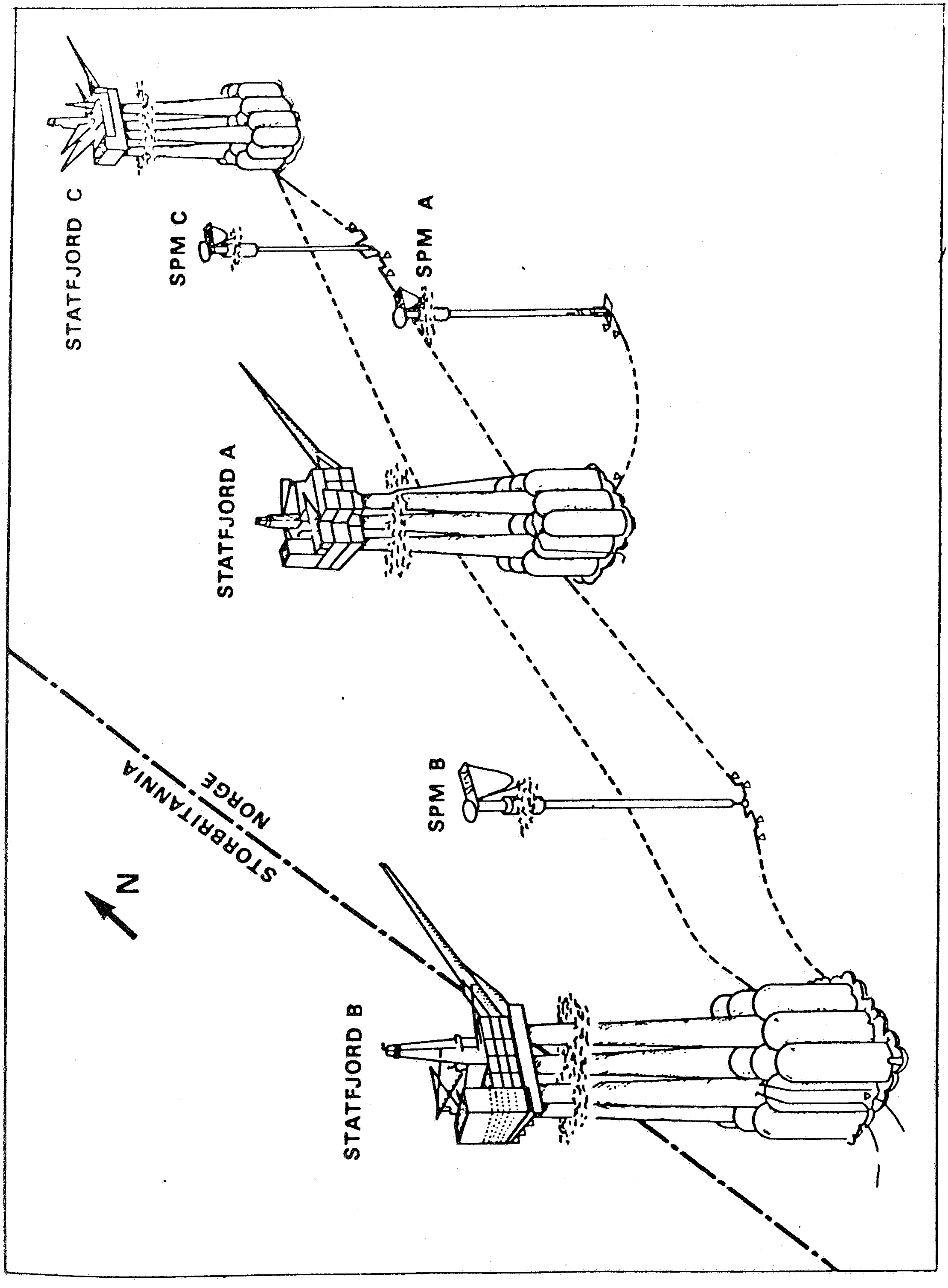


FIGURE 2.3.7.b. Existing and planned installations on the Statfjord field



The Statfjord field itself was discovered in the spring of 1974, and declared commercial the same year. Statfjord extends into Field 211 on the British side, where Conoco is the operator. The initial field development reports were submitted to the authorities in the first quarter of 1976. Since then, several development reports have been presented. It has been resolved that the field shall be developed in three phases with fully integrated platforms: A, B, and C. The Statfjord A platform is centrally located on the field, the B platform stands to the south of it, and the C will be sited to the north.

The total quantities of oil and gas in place in the field were originally estimated by the concession holders to 1033 million Sm3 and 180 billion Sm3 respectively. Later calculations performed by the Norwegian Petroleum Directorate showed 811 million Sm3 oil and 142 billion Sm3 gas. By injecting water into the Brent reservoir and gas into the Statfjord reservoir, one expects to attain a recovery factor of some 50 per cent. This means that the total recoverable amounts of oil are 405 million Sm3, including the British share. The amount of recoverable associated gas has been estimated at 48 billion Sm3 dry gas, and 15 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-proportionment at intervals of a few years, next time as of 1 January 1986. One of the two concession holding groups must request re-proportionment by 1 May 1985 if the option is to be effective.

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 rated production capacity is 47,600 Sm3 per day. The platform started production on 24 November 1979 and will undertake the operator's final drill program, consisting of 22 production and 15 injection wells. The greatest daily production so far was achieved on 17 August 1982, when 49,206 Sm3 oil were produced, exceeding the rated capacity.

Statfjord B

Statfjord B, sited as it is in the southern part of the field, consists of four columns and 24 cells, all in concrete. Its production capacity is 28,600 Sm3 per day. Production started on 5 November 1982, and the first gas injection followed on 11 December the same year. The greatest daily production of crude so far on Statfjord B is 20,000 Sm3, achieved on 28 December 1982. This date also marked the greatest combined production from the A and B platforms, namely 64,000 Sm3.

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

Statfjord C

The third and final phase of the Statfjord field development is now being completed with the construction of the Statfjord C platform. This is being built as an integrated Condeep, with four columns and 24 cells of concrete, and a deck of steel. The equipment necessary to facilitate production and storage of crude oil, together with machinery for gas injection, dehydration and water injection, will all be provided. Statfjord C will boast 42 well openings, and will make it possible to tie in nine sea-bottom completion wells. According to the progress plan, the platform will be towed onto the field in August 1984, and production start is scheduled for February 1986.

Recovery of reserves

The drilling of production and injection wells in 1982 has not provided any big surprises regarding reserves or reservoir behaviour. Well productivity is still high. The gas injection facility has started normal operation, and throughout 1982, some 92 per cent of the gas produced was returned to the Statfjord reservoir.

Water injection started in February 1982, and by year´s end 1982, water was being injected into the Brent reservoir from three wells on the Statfjord A platform.

Two of the Statfjord wells produce up to 10 per cent water. This water production has remained stable at this level the whole year, without it having been necessary to restrict oil production. From similar North Sea fields we know that water production may become a significant problem, causing oil production to be reduced.

Gas injection into the Statfjord reservoir will affect oil development favourably. Notwithstanding, there is a limit to the amount of gas that the reservoir can accomodate. The Directorate has therefore stressed that the Brent reservoir must be developed in such a way that the gas can be injected there too, if this turns out to be necessary.

The effect of injecting gas into the Statfjord field is still uncertain. If it turns out that gas drives out the oil efficiently, it would be appropriate, as far as resources are concerned, to continue injecting gas even after the gas line comes into operation.

Gas flaring in the Statfjord area

The amount of gas flared on Statfjord A in 1982 was some 0.3 million Sm3 per day (Figure 2.3.7.c). At production start in November 1979, the injection system machinery for associated gas had not been made ready, and all gas was flared. When injection started in June 1980, the operator experienced some running problems with the injection compressors, a fact which caused a high flare rate during the latter half of 1980. From 1981, it may be said that production and injection have enjoyed a relatively stable operating phase, with the result that flaring of gas now lies well below the present flaring ceiling. In 1982, some 5.5 per cent of the produced gas was flared. In the future, this quantity may be reduced further if the operator achieves greater regularity with the injection system.

At production start on Statfjord B in November 1982, the injection system was complete mechanically, and as early as mid-December the first gas could be reinjected into the reservoir. Thus, 1982 may be characterized as a starting up phase in which an average of some 1.3 million Sm3 gas were flared per day, or 72 per cent of total gas production (Figure 2.3.7.d).

FIGURE 2.3.7.c. Flaring of gas on Statfjord A

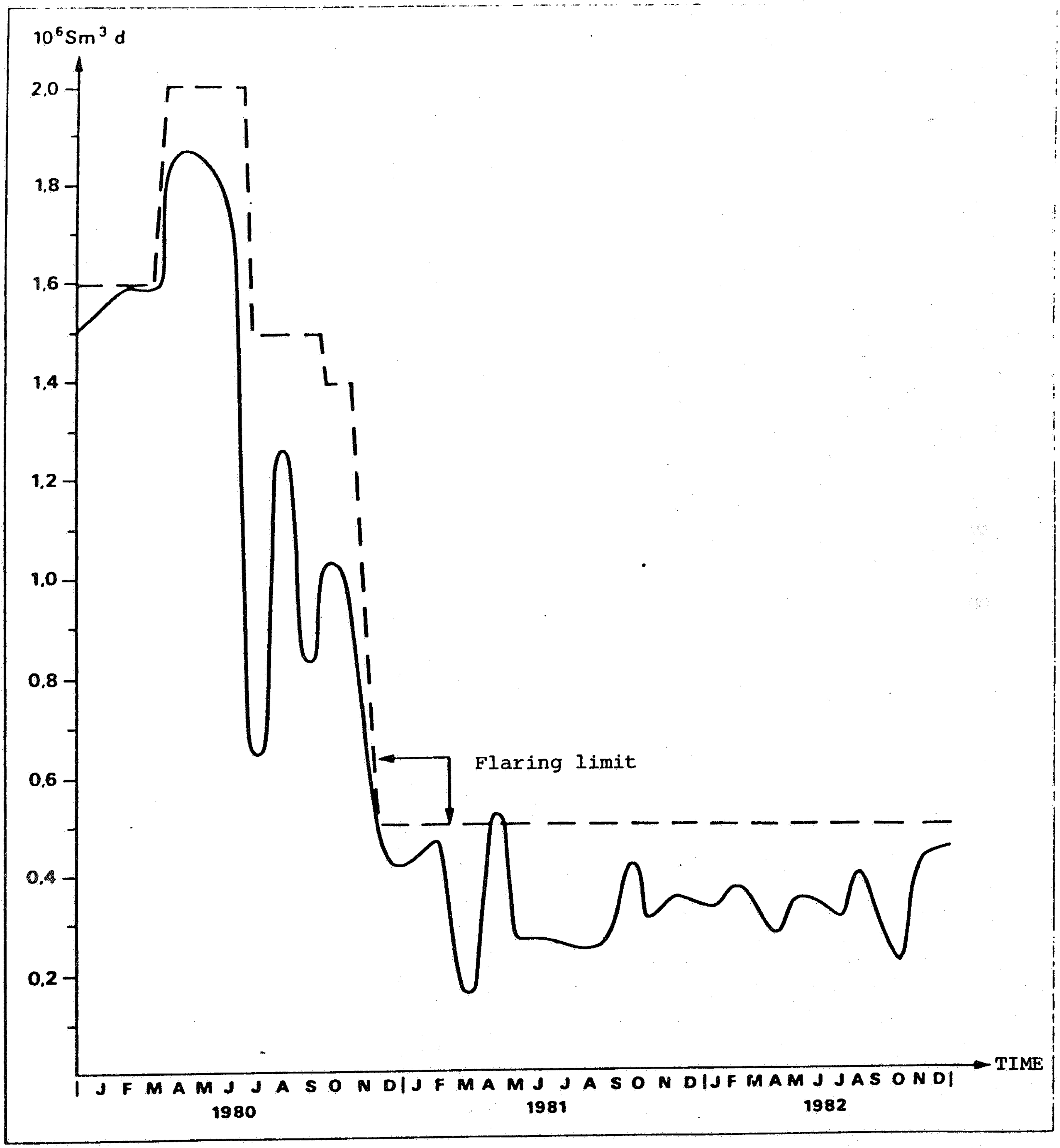
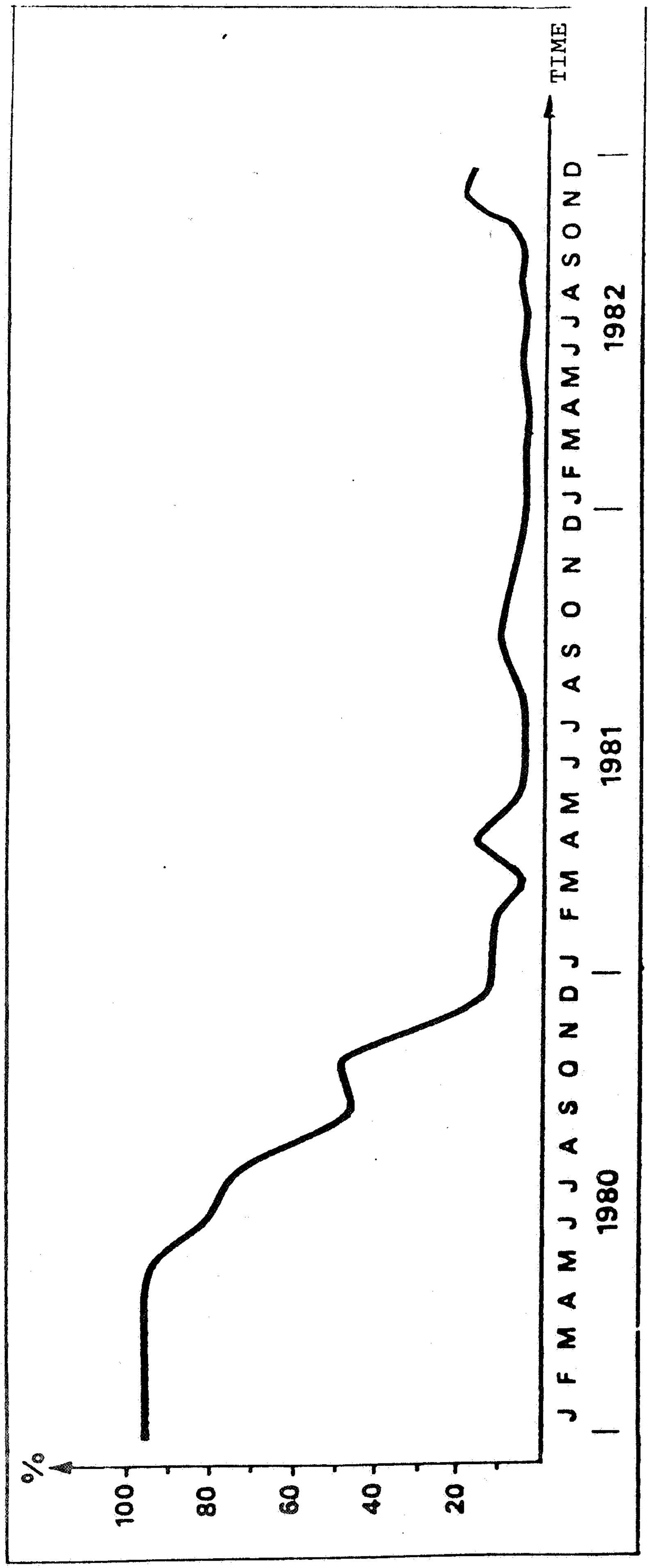


FIGURE 2.3.7.c. Flaring of gas as a percentage of total gas produced in the Statfjord area



Metering system

A permanent inspection arrangement for Statfjord A was established at the end of 1981, and for Statfjord B at the end of 1982. The metering system is subjected to fixed schedule, monthly inspections. The metering system for oil on Stafjord C has been tested at the factory and will be futher scrutinized during the start up period. Inspections of the building of the gas metering systems for Statfjord A, B and C have started. Regulation and inspection are performed in collaboration with the British Department of Energy.

Costs

The total costs are expected to run to some NOK 48.5 billion (current value), or NOK 53.5 billion (fixed 1982 kroner). The Norwegian share of this is NOK 40.8 billion, or NOK 45 billion, respectively. (For conversion, see Valhall).

Safety and the working environment

Statfjord A - water leakage in the utility shaft

On 24 September 1982, water poured into the utility shaft on Statfjord A due to a break in a 76 mm threaded coupling in the ballast system.

The water level rose to 21 meters before it became possible to equalize the pressure in the system, and later, during repair work, the water rose to the 42 meter level. At no time was there any risk of personal injury. Direct damage to material was also slight, but the accident caused complete cessation of production for six days and nights, and thus attained huge economic importance.

This accident clearly demonstrated how susceptible large, integrated platforms can be, and how difficult it is to prevent every conceivable mishap. The ballast system is subject to periodic inspection, and had been exhaustively examined 20 months before the leak arose. The operator is undertaking a new, thorough evaluation of conceivable damage due to the leakage in the shaft, what can be done to prevent damage, and what measures can be implemented to reduce the effects of any leaks arising. These investigations are being followed up by the Norwegian Petroleum Directorate.

Statfjord A - loading platform

In 1980, cracks were discovered on the inside of the buoyancy tank of the Statfjord A loading platform. The cracks, laminar tear-out flaws, developed during fabrication. Since 1980, more cracks of this type have been discovered, but most of them are believed to have been found. A special inspection program to monitor the cracks has been set up. Crack development analyses have also been performed. Repair work offshore was not recommended because fresh flaws of the same type can easily arise.

Gas transport, the Statpipe system

The pipeline company Statpipe was formed with the following concession holders:

Concession holders:

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 Norsk Shell	5 %
Total Marine Norsk A/S	3 %
Saga Petroleum a.s & Co	2 %

Statoil is the operator for Statpipe.

The transport system will include:

- a rich gas pipeline from Statfjord to Kårstø
- a separation and fractioning facility on Kårstø, including storage farm and loading facility
- pipelines from Heimdal and Kårstø to a riser platform southeast of Sleipner, and a pipeline to the riser platform on Ekofisk with the main equipment.

A framework agreement has been entered into with Norpipe A/S and the Phillips group for use of the Ekofisk center and the pipeline to Emden, and with the terminal company in Emden. The concession holders for Production Licence 050 (Block 34/10) have also recommended that the gas produced on Gullfaks should be landed through the Statpipe system.

A map of Statpipe is shown in Figure 2.3.7.e indicating pipeline lengths.

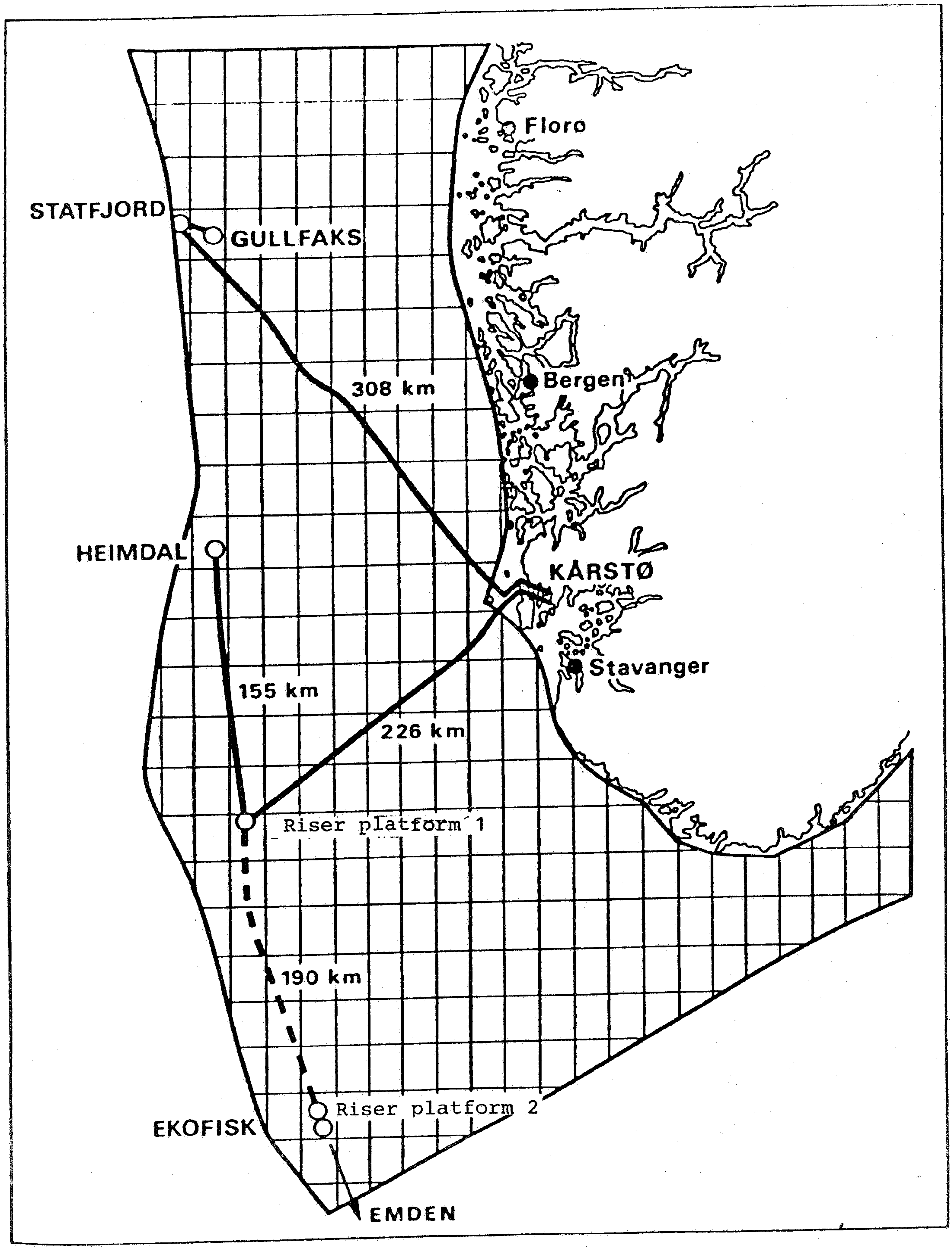
The transport capacity from Statfjord to Kårstø is 9 billion Sm3 annually, and from Kårstø to the riser platform south of Heimdal, some 7 billion Sm3 per year. The pipeline from Hiemdal to this riser platform, and the line from there to the Ekofisk riser platform, have been designed to transport maximums of 14 and 20 billion Sm3 per year, respectively. This exceeds the capacity requirement for Statfjord, Gullfaks and Heimdal, and has been so designed to accomodate possible future tying-ins from other fields.

If it is desired to increase the transport capacity of the Statpipe system, a booster platform will have to be built beside the riser platform south of Heimdal.

Costs

Total costs are expected to reach some NOK 20.3 billion at current kroner values, or NOK 17.1 billion in fixed 1982 kroner. (Conversion takes place according to the operator´s indices).

FIGURE 2.3.7.e. The Statpipe system



2.3.8 Murchison

Concession holders:

British share (83.75 %)

Conoco North Sea Inc	27.916 %
Britoil Ltd	27.916 %
Gulf Oil Corporation	13.958 %
Gulf Offshore Investment Ltd	13.958 %

Norwegian share (16.25 %) (Production Licence 037)

Mobil Development of Norway A/S	2.438 %
Den norske stats oljeselskap a.s	8.125 %
Norske Conoco A/S	1.625 %
Esso Exploration and Production Norway A/S	1.625 %
A/S Norske Shell	1.625 %
Saga Petroleum A/S & Co	0.305 %
Amoco Norway Oil Company A/S	0.169 %
Amerada Hess Norwegian Exploration A/S	0.169 %
Texas Eastern Norway Inc	0.169 %

The above concession holders 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. The Norwegian share in the block has been provisionally stipulated to 16.25 per cent of recoverable reserves, and the British to 83.75 per cent. Negotiations to adjust these proportions have continued throughout 1982, and the resulting new percentages are expected to be presented in the spring of 1983.

Development of the Murchison field was started in 1976 by the British concession holders. The 037 group declared the field commercial in the summer of 1977, and Statoil acceded to the declaration in the summer of 1978. The field has been developed with an integral steel platform with a rated production capacity of 26,200 Sm3 per day. (Figure 2.3.8).

On 28 September 1980, oil production started from the two submarine well completions at a rate of 1590 Sm3 per day.

Well drilling went very quickly on Murchison. The field has therefore produced at maximun treatment capacity since 1981. By drilling production and injection wells alternately, the water injection capacity has recently been sufficient to balance the pressure fall from oil production.

Gas injection started in one well in 1981, while one further well started injection in 1982. This was done to retain the greatest possible amount of gas produced until transport facilities exist.

The Government consented by Royal Decree of 24 September 1982 to land the Norwegian Murchison gas via FLAGS, the Far North Liquified and Associated Gas Gathering System, via St Fergus in Scotland. Consent to landing was given on the proviso that it does not hinder further efforts to reach an agreement to exchange Murchison gas for a part of the British Statfjord gas. The date for gas deliveries from Murchison has been fixed to the summer of 1983, and until then, significant amounts of gas will be flared on the field.

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

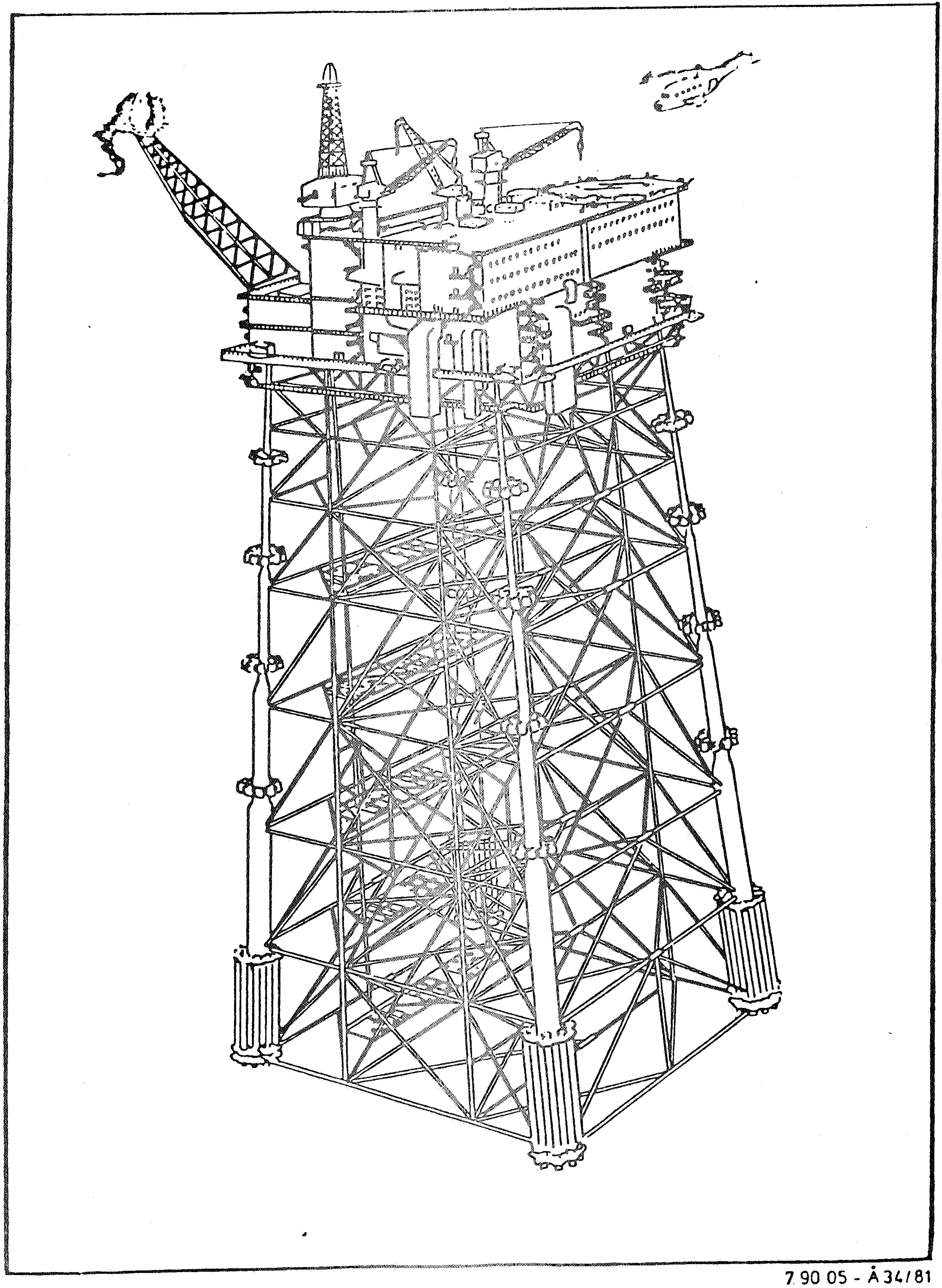
Metering system

Inspection and testing of the metering system prior to start up, including the approval of operating and maintenance procedures, was undertaken in collaboration with the British Department of Energy. Operating inspections are now performed annually in collaboration with the same department.

Costs

The total costs are expected to amount to about NOK 8.5 billion (current kroner), or NOK 9.2 billion (fixed 1982 kroner). The Norwegian share of this is respectively NOK 1.4 or 1.5 billion. (For conversion, see Valhall).

FIGURE 2.3.8. Installations on Murchison



2.4 Reserves estimates

In Tables 2.4.a and 2.4.b, a summary is given of the proven reserves in place and recoverable for:

- fields resolved for development as of 31 December 1982, fields under development and fields producing
- fields which had not been resolved for development as of 31 December 1982, including fields not considered to be independent of established facilities and fields with marked ties to activities already started.

Table 2.4.c provides a summary of the provisionally estimated amounts of NGL in fields.

Changes in the reserves estimated have occurred since last year's annual report. Notes on this follow:

Ekofisk	New reserves estimate.
Eldfisk	The production history shows that the gas/ oil ratio is developing differently from expectations. This gives greater oil production, but less gas production.
North East Frigg	Recoverable reserves have been reassessed due to new prognoses.
Gullfaks Phase II	The field will be evaluated anew in Autumn 1983/ Spring 1984.
Tor	Changes in the original amounts of oil in place are due to a miscalculation of the amount of NGL present. This makes no difference to the recoverable reserves. Minor adjustments of recoverable reserves are due to new prognoses.
Ula	A new well, 7/12-6, caused an insignificant reduction in reservoir volume. Estimation with the new reservoir parameters indicated greater reserves than the previous estimate.
Valhall A	New reserves estimates were performed for parts of the field. The rest of Valhall is being evaluated (spring 1983) and will cause further adjustment.
Askeladden	A new well, 7120/8-2, caused the estimate of what are called proven reserves to increase. A new evaluation of this has reduced the figure in relation to the perspective analysis.
Brage	New reserves estimates.
Oseberg	The gamma structure is being evaluated and will provide supplementary reserves on Oseberg.

Sleipner	New reserves estimates.
2/1	Proven reserves increased due to Well 2/1-4.
7120/7 and 7120/9	New finds in 1982.
7120/12	The reserves were altered pursuant to a fresh geophysical/ geological evaluation.

The total proven reserves recoverable as of 31 December 1982 were 1403 million Sm3 oil and 1552 Sm3 gas, or 2.7 billion tons oil equivalent. Of this, total amounts recovered were about 185 million Sm3 oil and 112 billion Sm3 gas.

Furthermore, reserves have been proven in structures which are not included in the tables, partly because the finds are too small to be economically viable, partly because their estimated reserves are far too uncertain at the present time. These reserves include Agat (35/3), Bream, Brisling, Flyndre, South East Frigg, 2/3, Oseberg Gamma, 2/2, 7/11, 15/9-My and 16/7-4.

The magnitude of these reserves lies in the region of 70 million tons oil equivalent. In addition, both Oseberg Gamma and Block 34/4 may contribute to significant increases in the proven reserves.

In addition to the proven reserves recoverable, some 1.3 billion tons oil equivalent are considered as low risk reserves. Of these, some 1.1 billion tons oil equivalent are assumed gas in Blocks 31/3, 31/5 and 31/6. Predicted total recoverable reserves in the North Sea (south of Stad) are estimated to be about 4.7 billion tons oil equivalent. In addition, there is provisional proof of 0.158 billion tons oil equivalent (158 billion Sm3 recoverable gas) north of Stad.

Figure 2.4 provides a summary of the resource potential south of Stad as of 31 December 1982. We would point out that there was an summation error in the corresponding figure for proven reserves in the 1981 annual report.

TABLE 2.4.a. Proven in place and recoverable hydrocarbons in fields declared commercial as of 31 December 1982

F i e l d	Original HC amount in place		Original HC amount recoverable		Recovered HC amounts		Remaining recoverable HC amounts	
(Oil in mill Sm3) (Gas in bill Sm3)	Oil	Gas	Oil	Gas	Oil	Gas	Oil	Gas
Albuskjell 1)	35	38	11	16	5	7	6	9
Cod 1)	8	9	2	5	2	3	<1	2
Edda 1)	14	3	3	2	3	1	<1	1
Ekofisk 1)	841	189	163	111	110	31	53	80
Eldfisk 1)	232	77	48	31	18	5	30	26
Frigg 2)		158	1	127	<1	44	1	83
NE Frigg		10		8		1		7
Gullfaks Phase I	221	20	93	6			93	6
Heimdal	3	48	3	31			3	31
Murchison 3)	19	1	9	<1	2		7	<1
Odin		30		22				22
Statfjord 1)4)	682	119	367	40	22		345	40
Tor 1)	116	25	19	11	13	5	6	6
Ula 1)	79	4	32	2			32	2
Valhall A 1)	236	58	33	26	<1		33	26
West Ekofisk 1)	60	31	12	22	10	15	2	7
Total	2549	820	796	460	185	112	611	348

1) Including NGL in the oil
2) This is the Norwegian share: 60.82 %
3) This is the Norwegian share: 16.25 %
4) This is the Norwegian share: 84.09 %

TABLE 2.4.b. Proven in place and recoverable hydrocarbons in fields <u>not</u> declared commercial as of 31 December 1982

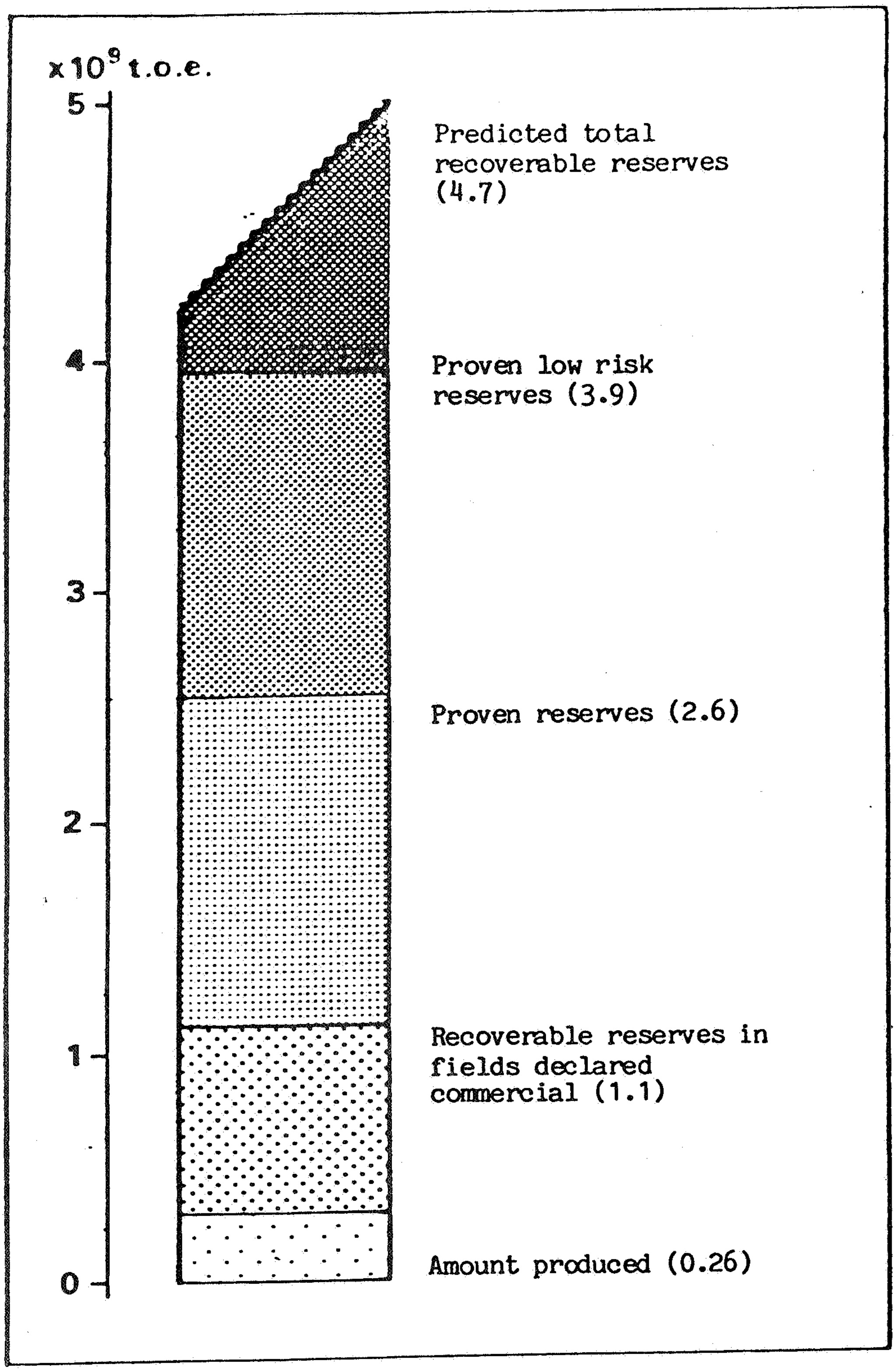
Field	In place hydrocarbon reserves		Recoverable hydrocarbon reserves	
	Oil mill Sm3	Gas bill Sm3	Oil mill Sm3	Gas bill Sm3
Askeladden		107		75
Balder	131		35	
Brage (31/4)	111	11	29	6
East Frigg		6		5
Gullfaks Phase II	254	23	102	12
Hild (30/4, 30/7)		73		51
Hod	44	11	9	7
Oseberg 1)	234	75	117	60
Sleipner 2)	51	166	17	124
Sleip. satellites:				
15/9 Gamma	30	75	10	55
15/5-1	2	6	1	4
15/8-Alfa		15		10
15/3-1,3		49	2	29
15/3-4	24	7	12	5
Tommeliten Alfa	26	19	5	11
Tommeliten Gamma	19	18	4	13
SE Tor	21	6	4	3
Troll 3)	830	690	120	480
Valhall B	126	31	25	19
2/1	60	7	18	2
24/9	11		3	
25/2-4	23	25	4	12
30/3-Beta	60	20	24	8
33/9-Alfa	37	4	18	2
33/9-Beta	78	3	39	2
34/10-Alfa	17	6	8	4
35/8		15	1	10
6507/11		19		13
7120/7		33		23
7120/9		51		36
7120/12		16		12
Total	2189	1587	607	1092

1) Constitutes the Alfa structure in Blocks 30/6 and 30/9
2) Includes Alfa, Beta, Epsilon and Delta
3) Some of the reserves exist in 31/2´s neighbouring blocks

TABLE 2.4.c. Proven recoverable NGL and sold NGL as of 1 December 1982 (million tons)

F i e l d	Originally recoverable NGL	Sold NGL	Remaining NGL
Albuskjell	1.0	0.39	0.6
Cod	0.2	0.17	0.1
Edda	0.2	0.10	0.1
Ekofisk	6.0	1.90	4.0
Eldfisk	1.9	0.47	1.4
Gullfaks Phase I	1.1		1.1
Murchison	0.4	0.04	0.3
Statfjord	13.0		13.0
Tor	1.0	0.45	0.6
Ula	0.5		0.5
Valhall A	2.0		2.0
West Ekofisk	1.0	0.49	0.5
Total	28.3	4.01	24.2

FIGURE 2.4. Predicted reserves south of Stad in billion tons oil equivalent



3. SAFETY CONTROL

The inspection programs for structures and pipelines for the year were carried out as planned, and some quite serious defects and instances of damage were discovered. Their common feature is that they were directly caused by mistakes made during the design or fabrication stage. In other words, expensive offshore repair work could have been avoided if the defects had been discovered before installation on the field.

Most elements of the inspection practice of previous years have been retained, but will gradually be rearranged into a better system. Greater emphasis will be put on systematic inspection, in tune with progress within the industry´s internal control systems, where previous inspection practice will be included as random sampling. Adjustment to the increasing level of activities on the continental shelf will take place through the development of more appropriate control procedures utilizing electronic data processing (EDP), by employing advisors, and through a very moderate increase in our own staff.

Many of the installations on the continental shelf have already begun to show signs of wear, and this makes other requirements of the operators and their inspection systems. Some main problems are the propagation of cracks and development of corrosion on equipment containing hydrocarbons under pressure, as well as the corrosion of safety systems and electrical facilities. The primary consequences are an increase in the extent of the inspection and maintenance activities, and monitoring thereof.

Power generating facilities are becoming increasingly large and complicated, and much electrical equipment is already carrying loads which are uncomfortably close to the maximum acceptable level. During the year, we have been notified of five accidents on distribution panels in which persons were injured. Two fires also occurred on such panels. Even if the requirements to electricians, work procedures and safety routines for work which takes place on or close to live installations are substantial, accidents resulting in personal injury do happen. We have been busily engaged in motivating the manufacturers of electrical panels and the users of the facilities to participate more actively in the design and construction phases of the facilities, the intention being to make the facilities as safe with regard to injuries as possible.

The work so far carried out with respect to the previous problems with down hole safety valves (DHSV) has now resulted in an improvement in quality, both of the valves themselves, and of the locks, the set procedures, and maintenance.

This has spurred on the development by the Phillips Petroleum Company Norway of EDP as a statistical and management tool for the maintenance and inspection of DHSV and other safety related devices.

As concerns safety systems, one of the most relevant subject areas is the evaluation of data based systems for control, safety and self-testing of process and auxiliary equipment. It is especially the case that, when such equipment is utilized in connection with safety and emergency systems, a very high level of quality and reliability is required. Previously, fail safe systems were used, but this method may not be applicable to modern programmable systems, whether in the context of hardware, or software.

Moreover, set-ups are often based on an ever more complete integration of previously independent systems into a main central unit with its decentralized sub-systems.

The result is that flaws in the system may be of greater consequence as regards safety, and new methods must be developed to evaluate and document quality and reliability.

Another broad subject area includes the follow-up of research, theories and criteria of fundamental significance for the spreading of gas, fires and explosions, as well as related risk and consequence analyses. These are areas in which substantial amounts are spent on the elaboration of more reliable methods for ascertaining the risks involved with the ignition of uncontrolled hydrocarbon spills and the possible consequences, thus making it possible to work out improved platform concepts.

Furthermore, attempts have been made to enforce the principle of internal control in the area of drilling technology. Operators and shipowners are now working partly to develop and partly to document their internal control systems for drilling activities. The regulations of the Norwegian Petroleum Directorate are aimed at operators and foreign shipowners on the Norwegian continental shelf. In addition, operators on the Norwegian continental shelf are required to approve the shipowners' internal control systems on technical drilling installations. If the operator finds the shipowner's internal control system to be inadequate, the operator must ensure that the matter is put right, possibly by taking his own counter-measures. The operator is also responsible for carrying out the necessary inspection audits to ensure that internal control is functioning soundly.

The drilling regulations of 23 September 1981 are now being revised in keeping with the Directorate's more precise requirements to the operator's, sub-contractor's and shipowner's internal control systems. In addition, the possible need to revise the Royal Decree of 9 July 1976 will be considered.

In connection with the technical drilling inspection, the Petroleum Directorate has also been elaborating acceptance criteria for:

1. simultaneous activities (drilling and production)
2. exploration drilling from fixed installations
3. production drilling for mobile platforms.

YEAR-ROUND DRILLING

The question of year-round drilling

The Norwegian Ministry of Petroleum and Energy feels that one superior planning objective should be to perform year-round drilling not only south, but also north of Stad. Now that two seasons have been worked, the Ministry finds it necessary to evaluate in greater detail the question of taking up year-round drilling in the individual areas. The Norwegian Ministry of Local Government and Labour has evaluated the safety-related issues in connection with a conversion to year-round drilling, and the Norwegian Ministry of Environmental Protection has undertaken similar evaluations of our oil protection preparedness and possible pollution-related consequences.

In 1981, upon an initiative from the Ministry of Local Government and Labour, a working group was appointed to undertake a more detailed examination of the safety-related prerequisites for the adoption of year-round drilling. Group members came from the Norwegian Maritime Directorate, Saga, Norsk Hydro, and Statoil, with the Norwegian Petroleum Directorate in charge. The Norwegian Institute of Ship Research provided the secretariat. The first part of the report was presented in October 1981, emphasizing the maritime environment and operational conditions. The work was continued in 1982, this time with the emphasis on a more detailed evaluation of the design and fitting-out of platforms, transportation and supply services, and preparedness in connection with winter drilling in the northernmost areas.

The report compares and evaluates the oceanographic and meteorological maritime environments as these relate to present drilling rig equipment and personnel, and lessons learned from the operation of drilling vessels in arctic conditions off Canada.

The main conclusion is that no circumstances have been found relating to the operation of technical equipment which would directly cause exploration drilling on an year-round basis in the northern areas to be significantly more difficult than in the North Sea, provided that the necessary precautions are taken with regard to equipment and operation.

The report has been sent for comment to the relevant regulatory bodies, the Norwegian Offshore Association (NOF), Norsk Hydro, Saga and Statoil. There is broad agreement on the main conclusions of the report. Nevertheless, the Norwegian Petroleum Directorate and the Norwegian Maritime Directorate assume that the operators will start the necessary planning of safety and preparedness measures to counteract the special conditions encountered when operating at low temperatures, and the possibility of more frequent bad weather spells in the north than in the North Sea.

It is considered likely that rigs working all the year round will be susceptible to ice accumulation, and will thus require de-frosting and shielding, as well as local heating to reduce exposure to the wind and the cold. With the necessary modifications, some present types of drilling vessels and platforms under construction will be able to combat the icing problem adequately. The Norwegian Maritime Directorate will also demand documentation to prove that platform design and material specifications are adequate with regard to the temperatures at which the platform can be expected to have to operate. Sea spray, icing, and atmospheric icing may cause problems of safety and/or punctuality for the supply and transportation services. Low atmospheric pressures in the Arctic, the so-called instability low pressure areas, at present impossible to forecast, are particularly prevalent in North Norway.

Under the weather conditions to be expected north of Stad in the wintertime, it will be necessary to allow for less regular helicopter and supply services than in the North Sea. This will affect preparedness plans and the size of stores onboard. However, increased requirements to minimum stores will not necessitate substantial design modifications to newer platforms.

The Civil Aviation Authority has found that it will be possible to maintain satisfactory flight regularity on Haltenbanken during the winter season, with Kristiansund N as the base. As concerns the regularity of flights to Tromsøflaket, the problem of helicopter icing is a limiting factor if Tromsø Airport is used as base. Flight safety factors, and the question of finding an alternative base so as to maintain satisfactory flight schedules, were examined by the Civil Aviation Authority and the Ministry of Transport, and the Storting has decided that the helicopter base for flights to Tromsøflaket will be located at Andenes.

The sustaining of sufficient helicopter regularity is significant, not just for the continuity of tour personnel, but also with regard to preparedness. The Ministry of Justice considers the Norwegian rescue service to be satisfactory for wintertime operations.

Based on the positive but limited experience of exploration activities in more northerly areas gained during the drilling seasons 1980, -81, and -82, and on the preliminary investigations being carried out to plan the change to year-round drilling, Statoil and Norsk Hydro feel that conversion should take place gradually. Statoil recommends that the season should be extended by stages over 2-3 years, thus facilitating operational and equipment-related adjustments in the light of the experience gained. The Ministry of Local Government and Labour believes the sound thing to do, in relation to safety, is to opt for a gradual stepping up of the activities in the North by extending the drilling season.

- The Ministry of Local Government and Labour believes that the major safety-related prerequisites have been clarified sufficiently for it to be possible to start year-round drilling on Tromsøflaket. The Ministry of Local Government and Labour finds it necessary to make a gradual conversion to year-round drilling on Tromsøflaket, probably over 2-3 years, and in the light of the experience gained.

- The Ministry of Local Government and Labour maintains its stand regarding the safety-related prerequisites which should apply for year-round operations on Haltenbanken.

- The Ministry of Local Government and Labour is of the opinion that the length of the drilling season at possible start-up on Trænabanken in 1983, must be evaluated in the light of the experience gained from a possible extended drilling season on Tromsøflaket in 1982.

The Ministry of Local Government and Labour assumes that the extent of the drilling activities north of Stad will be adjusted within the framework of a plan for the total drilling activities on the continental shelf.

INJURIES SUSTAINED DURING DRILLING OPERATIONS

The requirement that drilling operations should be mechanized was introduced in the autumn of 1981. It refers to the installation of mechanical equipment to handle the drill stem. The background material is as yet insufficient to enable a final conclusion to be reached with regard to injury frequency following the introduction of the new regulations. However, it has been noted that increased mechanization of the drilling operation has provided environmental improvements.

INTERNAL CONTROL AUDITS

Since it is the responsibility of the licensees to comply with the laws and regulations passed by the authorities by means of their own internal control systems, the Directorate's inspection activity in the design and construction phases has been geared to verifying that the quality of the internal control systems is acceptable. Verification takes place through the so-called (Internal Control) System Audits.

Three years have now passed since the first guidelines for the licensees' internal control systems were issued. Both the oil companies and the Directorate, therefore, are still in a learning phase as regards how the system should function, what requirements should be made, and how the system should be inspected.

It is important that the quality of the licensees' internal control system be verified. The Directorate does this by carrying out system audits according to a more or less fixed plan. Usually, the point of departure has been to start at the top of the internal control pyramid and to work one's way down within certain fields. The experience gained by the Directorate from this type of system audit is that the method is an efficient one for gauging the quality of an internal control system. It will therefore be utilized to a greater extent in the future, in all phases.

Regulations and guidelines

Since 1979, a substantial amount of work has been performed by the Norwegian Petroleum Directorate to prepare rules for subsea pipelines and risers. A committee was appointed, consisting of representatives from the oil companies, the universities, the classification societies and the authorities. The work is nearing completion and the rules will be issued in the spring of 1983.

The revision of the "Regulations for calculation and dimensioning of fixed load-bearing structures on the Norwegian continental shelf" has been commenced. The regulations were issued for the first time in 1977. Three things in particular prompted the revision:

- a desire to adjust the regulations to fit in with the practical implementation of the internal control philosophy,

- a desire to improve the regulations on the basis of the experience gained since they were first enacted,

- a desire to have regulations which also apply to newer platform concepts.

The revision work is expected to continue throughout 1983. In practice, the work is carried out by a general committee. This consists of representatives of research institutions, oil companies, the Ministry of Local Government and Labour, and the Norwegian Petroleum Directorate. New chapter drafts are being prepared by special, competent working groups.

The previous "Guidelines for the inspection of primary and secondary structures on production and loading facilities and subsea pipeline systems" were stipulated by the Norwegian Petroleum Directorate on 1 April 1978. These guidelines underwent revision last year on the basis of experience gained from their use in practice. Further amendments were made in respect of technological progress. One aim has been to simplify the guidelines and make them more workable.

The revised guidelines contain a more detailed specification and explanation of the inspection believed to be necessary to ensure that the requirements of the Regulations are complied with. The concept of guidelines as a method of presentation will continue, because the method has proven flexible and widely applicable.

Amendments to the Regulations for transportation of personnel to and from production facilities, etc.

Upon the invitation of the Norwegian Petroleum Directorate, operating companies and other interested bodies have written to state the issues which they would like to see amended or retained in a revised version of the regulations. The letters are being dealt with in the Directorate, and the proposed revisions will be sent for comment in 1983.

THE REGISTRATION OF ENVIRONMENTAL AND PLATFORM DATA (E- AND P-DATA)

In order to verify that platforms in the North Sea are behaving as predicted in the design phase, the Norwegian Petroleum Directorate may require the operator to carry out surveys of the platforms.

Until now, the Directorate has required suitable instrumentation to be installed on three steel base platforms (Ekofisk 2/4H, Valhall QP, and Frigg DP2), three condeep platforms (Frigg TCP2, and Statfjord A and B), and one articulated loading buoy (the Statfjord A ALP).

The type of platform data measured depends upon the type of platform; but may include readings of the sea-bottom pore pressure beneath the platform, and settling; in addition to movements and stretching at different elevations inside the platform. Environmental data are also monitored, including ocean waves, currents and winds. By comparing the environmental strains and the resultant platform behaviour, it is possible to check whether the design criteria are substantially sound.

During 1982, an analysis of Frigg TCP2 was completed, which concluded that the platform behaves pretty much as predicted in the design.

As required by the present regulations, E- and P-data projects were organized in two parts: the operator taking care of the collection of data, and the Norwegian Petroleum Directorate looking after the analysis. However, from 1 July 1982, the operator will also be responsible for the analysis.

STRUCTURES

On older structures, some marine growth has gradually accumulated. The significance of this is somewhat unclear, and it is therefore natural to attempt to increase our understanding in the future.

Because of damage to the structures by ships, etc., the Norwegian Petroleum Directorate has ordered the operating companies to determine what action can be taken to reduce the extent of the damage.

PIPELINES AND RISERS

During the autumn, approximately 13 km of uncovered pipeline belonging to the Ekofisk-Teesside transport system were buried under some 100,000 tons of gravel. Inspection, incidently, revealed an increasing degree of back filling.

Concrete shields which protect the mechanical couplings caused some trouble, because of a tendency for the sea floor to be washed away from under them. There has also been a tendency for unsupported spans to form at the ends of areas with concrete shielding. The shields will now, if necessary, be supported by sandbags.

As concerns the Ekofisk-Emden pipeline, the damage on the inlet riser to booster platform B11 was examined and analysed. After careful consideration of the available survey material, German and Norwegian authorities ordered the riser pipe to be replaced by the end of 1984. This decision must be viewed in connection with the future importance of the pipeline when it is tied in to the Statpipe transport system.

GAS PIPELINES

The requirement for emergency shut-off valves on the sea floor a given distance from a platform has become highly relevant, particularly in connection with gas lines. Previous surveys have concluded that the available valves will not meet the requirements in force. New searches must be made to find valves suitable for the purpose.

CORROSION

Routine underwater inspections have revealed that pitting has taken place in the heat affected zone (HAZ) near the nodes on several steel structures. Work has started to find the reasons for the pitting. Efforts will also be made to find better inspection methods and equipment for existing structures, and to improve corrosion protection on new structures.

Internal corrosion in production pipes and pipelines is still a problem. Work is presently being carried out, both by the companies and the Norwegian Petroleum Directorate, in order to improve the possibilities of inspection.

INSPECTION EQUIPMENT

During the year, no significant progress was made to improve equipment or methods for the internal inspection of pipelines and risers. Results with contemporary non-destructive testing (NDT) apparatus for locating internal corrosion, crack propagation, uneven pipe diameter, etc., are unreliable, and do not provide a good enough basis for an evaluation of the state of repair of the pipeline or riser. Because of the new pipeline projects and their importance to the Norwegian economy, the development of a reliable inspection instrument will receive high priority.

CRANE ACCIDENTS

In 1982, the Norwegian Petroleum Directorate received notification of some accidents in connection with offshore cranes. While no personal injury resulted, there was considerable material damage in some cases.

Crane boom toppled into the sea

During the reloading of containers from the platform onto the supply ship, the crane operator heard the sound of falling objects in the cable house behind his cab. A container had just been lowered onto the deck of the boat and released from the crane hook. While the crane operator was making the necessary checks, the crane boom fell at great speed, tearing off the boom fixtures and main hoist wire. As the boom fell it ran out the boom hoist wire and wrenched it from the drum. Great damage was done to two lifeboat stations, and to gangways and railings. One of the lifeboats was completely wrecked.

The supply boat was located outside the immediate accident area and received no damage as the crane boom and wire fell into the sea.

What triggered the accident was a fracture of the cable drum axle on the boom hoist winch. The rupture caused the drum to move out of line and disengage from the hydraulic motor. Though the crane was equipped with safety brakes which should have prevented the crane boom from falling out of control, in this instance the brakes did not work.

The Norwegian Petroleum Directorate made sure that safety measures were implemented to prevent similar accidents in the future.

The company concerned appointed a group of experts and charged them with the task of analyzing the crane type and the chain of events causing the accident, and ensuring that any modifications necessary would be carried out.

All of the company's cranes were examined, and cracks were found in the relevant areas on several of the cranes, both on quick lift, heavy lift and boom lift cable drums.

Corresponding investigations were also carried out by the other operating companies, and also on Norwegian and foreign drilling vessels.

The analysis work, and the delivery times for vital elements, made it necessary both to start making temporary repairs, and to make more long-term plans regarding the review of crane design, the selection of materials and the method of manufacture.

Load and wire fell into the sea

A similar accident happened with the same type of crane when an axle ruptured in the hydraulic motor for the quick lift winch, causing the drum to come out of mesh with the drive motor, and thus allowing the load to fall freely.

The accident happened during the loading of casing from a supply boat. The load, including the wire as it was ripped from the drum, fell into to sea without damaging the vessel or structure.

<u>Measures to be taken</u>

On the basis of these accidents, as well as previous and related accidents with other types of cranes, the Norwegian Petroleum Directorate contacted the manufacturer and Det norske Veritas (DnV) to make a review of the design criteria and the requirements to manufacture, use and maintenance of offshore cranes.

The Norwegian Petroleum Directorate did not find it necessary to amend the crane regulations because of the above accidents.

However, it may be stated that quality, in relation to design follow-up, manufacture and operation, must be improved, and that the extent and frequency of maintenance during operation must be revised.

CONTINGENCY PLANS

The work of updating the operators´ preparedness plans is a continuing process, and this was the case also in 1982. All operator plans have now been refined to an acceptable standard.

STANDARD CONTINGENCY PLANS FOR MOBILE DRILLING VESSELS

The work of standardizing the contingency plans for mobile drilling vessels continued in 1982. Some operating companies had already prepared their plans in accordance with the guidelines previously outlined by the standardization work group. Standard contingency plans will probably be taken into use on all mobile drilling platforms in the course of 1983.

RESCUE DRILLS

The operating companies carried out a number of drills during the year to test and practice their preparedness programs. The Norwegian Petroleum Directorate participated in these exercises to the extent compatible with its other commitments. Participation took the form of representation at the operating companies´ emergency centres, or on the emergency coordination teams. During the exercise "SOSEX 82", the Norwegian Petroleum Directorate´s own preparedness program was activated, and this exercise was thus more extensively represented by the Directorate.

DIVING

Diving activities on the Norwegian continental shelf have remained at about the same level in 1982 as during the previous year. The number of monobaric diving units, particularly one-man submersibles, has increased.

The oil companies' control of their own diving operations has improved significantly. Several operators now have employees with a solid knowledge of diving.

In connection with development tasks deeper than 300 meters, efforts are being made within the industry to engineer equipment and methods which will make it possible for divers to perform efficiently at such depths. The Norwegian Petroleum Directorate receives the available reports, and is often present at trial projects and when tests are performed. This information flow will ensure that the Directorate is as well qualified as possible, when the time comes to evaluate operations at great depths.

In order to facilitate development and not bind the industry and the authorities by making requirements which are too specific, the Norwegian Petroleum Directorate's current revision of the diving regulations emphasizes that requirements will be directed at function. Functional requirements focus on the aims and not the means, thus allowing for different ways of attaining the necessary safety.

In recent years, the industry has done much to increase the safety of manned submarine operations. The Directorate participates in several committees which deal with guidelines and standards in this work area. Our participation has enabled us to adjust the degree of detailing in the regulations to take account of advances made by the industry.

The Norwegian Petroleum Directorate wanted to clarify the extent to which it is possible to set up criteria for the evaluation of the state of repair of acrylic windows used in diving systems. A pilot project was carried out which concluded that criteria can be found. The main project will hopefully commence in 1983.

No requirements have been made as yet for breathing apparatus for use by divers in the North Sea. In the future, however, as dives become deeper, we consider it will be necessary to provide specific minimum requirements for such equipment. The Directorate brought this matter up for discussion once before, at a meeting with international participation in Bergen in 1981. The outcome was that British and Norwegian authorities are now in the process of completing a joint proposal for testing and approval criteria for divers' breathing equipment. The draft of the test procedures and minimum requirements for breathing equipment is expected to be presented in the first half of 1983.

The requirement that it should be possible to evacuate all divers in compression has promoted different types of rescue units.

The Norwegian Petroleum Directorate has for some time seen a need to carry out function tests on the hyperbaric rescue units which are employed on the Norwegian continental shelf. One such test was performed, and this confirmed that the regulation of the atmosphere within the rescue unit was not acceptably reliable. Demands are now being made that all rescue units in use must be tested in accordance with procedures approved by the Norwegian Petroleum Directorate. In order to obtain a better basis for evaluation of evacuation units, we have commissioned an analysis. The analysis will provide more information on the actual circumstances of underwater rescue from various types of installations, ships and platforms.

PERSONNEL QUALIFICATIONS

The Norwegian Petroleum Directorate assumes that the licensees will assess their needs for qualified personnel and the efforts necessary to man the installations in due course. This applies both in connection with the planning of field developments, and for fields which are already in operation.

JOINT INSPECTION BY THE BRITISH DEPARTMENT OF ENERGY AND THE NORWEGIAN PETROLEUM DIRECTORATE

In September, a joint survey was undertaken on Frigg, both the British and the Norwegian sides, by an inspector from the British Department of Energy and two inspectors from the Norwegian Petroleum Directorate. This turned out to be a valuable exercise in the practical work of inspection, besides providing some material for comparison of the British and the Norwegian rules and regulations.

SAFETY REPORTS

In connection with accidents, incidents, etc on fixed and mobile installations in the North Sea, the Norwegian Petroleum Directorate issues safety reports. The companies are often invited in advance to comment on and make recommendations for the circumstances in question.

These reports are intended to brief persons working on the installations of conditions in their working environment which may constitute a hazard to safety, and to give advice on preventive action. The reports are a very important part of the work to prevent bodily injury and material damage.

Safety reports are printed in large numbers and circulated to the companies. It is assumed that the reports will be made known to all employees, and that they will be processed by the company safety organizations.

CONTROL OF FOREIGN VESSELS

During a routine inspection to clarify the state of occupational hygiene on a foreign barge during welding and radiographic work for pipelaying in the North Sea, it was established that the evacuation routes from the barge in case of emergency were unacceptable. Though there were 217 men onboard, there was only one liferaft capsule, and this was rated for 14 persons.

In its explanation of what factors had prompted it to accept the barge's services, the company referred to concrete demands presented to the contractor to upgrade his contingency plans and safety procedures, and to equip the barge with survival suits and demonstrate the evacuation system.

In the opinion of the Norwegian Petroleum Directorate, these elements are part and parcel of all systematic efforts necessary for a company to satisfy itself that an activity can be carried out in accordance with the acts and regulations in force.

However, when the company in its explanation also claimed that unclear legislation entitled it to reduce safety standards, this indicates an attitude which is not in accordance with the responsibilities and duties of a licensee. The Directorate therefore found it necessary to issue the following clarification:

> The licensee's responsibility for activities relating to production, etc., has been laid down by Royal Decree of 9 July 1976, §§ 4 and 5.
>
> Emphasis is here placed on the basic principle that he who carries out the activities is responsible that work performed complies with the safety requirements in force at all times. This responsibility also includes the company's duty to conduct internal control (cf. the Guidelines for licensees' internal control, dated 15 May 1981). The principle of internal control applies to all systematic efforts which are necessary to ensure that the activities are planned, organized, carried out and maintained in accordance with requirements stipulated in, and pursuant to, legislation and regulations.
>
> Internal control shall scrutinize all parts of the organization and all phases of activity. The control shall ensure that the requirements to the quality of goods, services, organization, etc., are such as to comply with the company's requirements to safety, which must in turn fulfil the minimum requirements laid down by the authorities.
>
> We emphasize that the supervision carried out by public control agencies such as the Norwegian Petroleum Directorate, is in principle irrelevant to, and does not reduce, the company's own responsibility for performing its activities in a safe manner. The official control must in all cases be seen as a means of obtaining insight into whether the company does indeed perform its activities within the framework set up, a framework which includes the legislation, regulations, decisions, licences, agreements, and other matters applicable.

On the basis of the specification of the company's internal control system in this case, the Norwegian Petroleum Directorate would have anticipated that the use of the barge's services would have been refused because they did not meet the company's own requirements to quality in hired services, or that up-grading action would have been taken. As, despite this, the barge was in fact utilized without any modification, the Directorate considers that the company in this case had not achieved sufficient quality in its requirements to the basic systems which are directly intended to ensure employee safety.

The Royal Decree of 1976 was amended on 19 March 1982 with an extended § 5 A, which reads:

"The Ministry may lay down more detailed requirements to service vessels, pipelaying vessels or other vessels used in the activities to protect from damage installations or facilities for the production of petroleum, pipeline transportation of petroleum, or drilling for petroleum, or to protect personnel who stay on such installations or facilities."

Pending a delegational decision, and the entry into force of more detailed requirements, the Norwegian Petroleum Directorate has strongly requested the operating companies to ensure that foreign vessels, used in connection with activities regulated by the Royal Decree of 7 July 1976, do not represent a danger to equipment, facilities or personnel on such plants or facilities.

The Directorate has recommended further that the companies' control and documentation systems be designed to ensure that the necessary factors are considered when hiring services to be performed by foreign vessels.

THE WORKING GROUP "STANDBY VESSELS"

By order of the Ministry of Local Government and Labour, the Norwegian Petroleum Directorate appointed a working group in February 1982 to study the standby vessel program in conjunction with the total preparedness on the continental shelf. The reason was that NIFO, the Norwegian Industry Association for Operating Companies, wanted a broad evaluation of standby vessels and preparedness in general, before the Norwegian Maritime Directorate's new draft regulations for standby vessels came into force. The Petroleum Directorate provided the chairman and secretariat of the working group, which also included representatives from the Ministry of Local Government and Labour, the Norwegian Maritime Directorate, NIFO, the Oil Workers Joint Association (OAFS), and the Norwegian Federation of Trade Unions (LO).

Advisory assistance was provided by Det norske Veritas. Presentation of the working group's report occurred near the end of December 1982.

The working group's terms of reference were:

"The working group shall organize studies of and undertake evaluations of standby vessels as a constituent part of the total safety and preparedness:

- by analysing preparedness systems for rigs, platforms, and field installations, and evaluating methods of analysing preparedness efforts for such units;

- by considering both the positive and the negative risk contributions of the various preparedness efforts;

- by determining the cost-efficiency of the individual efforts as components of the total preparedness system."

The working group interpreted its terms of reference on the basis that standby vessels constitute but one of several elements within total safety and preparedness. The working group did not regard it as its task to evaluate in detail the arrangements which make up preventive safety measures.

In order to evaluate the standby vessel's role within total offshore preparedness, it was necessary to cover a wide range of circumstances. To do this, the working group felt it necessary to:

- prepare an outline of the acts, regulations, agreements, etc., which concern offshore preparedness on the Norwegian continental shelf, and thus arrive at an evaluation of the standby vessel's role in the total preparedness program;

- evaluate the individual evacuation and rescue systems in relation to laws and regulations, technical data, efforts in operative service, usefulness, costs, etc. The primary modes of rescue will be by helicopter and by boat.

- make use of the background data already provided in order to predict rescue efforts on the part of the primary means of rescue. The working group directed its attentions here to the subjects of evacuation and rescue, and to the serious accidents which can be expected to precipated the need for a means of evacuation and rescue. The point of departure chosen therefore, was critical events and the probability of them occurring. Data for this were assembled from previous reports and studies.

A number of reports have discussed the evacuation aspect, and the working group studied these. If the analytical method available for evacuation and rescue analysis was appropriate, it was utilized. If not, the working group had to prepare new methods of analysis for the job in hand. This entailed a substantial increase in the time spent and work required.

In order to evaluate the cost and utility of the individual means of rescue, an analysis of acceptable risk levels was made.

Further, the working group found it appropriate to use a questionnaire to collect opinions of the role of standby vessels in connection with preparedness.

The conclusions drawn and recommendations made by the working group will form part of the fabric of future regulations. Because rebuilds and new constructions will have to conform to these new regulations, a paramount consideration of the working group has been to make the time for preparation of the report as short as possible.

The scope of the work proved to be much larger than envisaged. This is why the report took longer to prepare than predicted. Its summaries and conclusions are not included here, as this would take us beyond the proper limits of the Directorate´s Annual Report.

ORGANIZED SAFETY AND ENVIRONMENTAL WORK

The organized safety and environmental work on the installations in the North Sea has been a central theme of discussions during 1982. Some groups within the industry have, among other proposals, called for a re-organization of the work, away from the present local company-based working environment committees, and towards regional oilfield-based WECs with delegates from both contractor and operator personnel sitting on the same committee.

The Directorate will look further at the organized safety and environment work in collaboration with people from the industry, to consider present and alternative solutions for this work.

In 1982, the Norwegian Petroleum Directorate began preparations for an improved and better coordinated system for reporting WEC work. It is therefore assumed that 1983 will witness the establishment of a sounder basis for evaluating the quality and intensity of activities carried out under the direction of the working environment committees.

DAMAGE AND INJURY CAUSED BY FIRE

The fires for which the Norwegian Petroleum Directorate, pursuant to the rules issued by the Attorney General, has received reports, are listed in Table 3.a. The reporting routines which have been built up are so comprehensive as to include almost every single case of fire or near-miss.

Every permanent production facility was in the operating phase in 1982; Valhall from 1 October, and Statfjord B from 5 November.

During the year, the Directorate registered a total of 31 fires, as opposed to 35 in 1981. One of the fires caused some damage, while the remainder caused little or no damage.

TABLE 3.a. Fire damage on fixed production installations

Damage or injury due to fire	Construction phase	Operating phase Cause of fire: A	B	C
Personal injuries and substantial material damage	0	0	0	0
Personal injuries, but little or no material damage	0	3	0	0
No personal injury, but substantial material damage	0	1	0	0
No personal injury and little or no material damage	2	18	7	0
Total	2	22	7	0

Cause of fire:
A - as a result of operations/ operating accident
B - construction work
C - other.

REGISTRATION OF ACCIDENTS

Reorganization of the Directorate´s reporting system for occupational injuries

The Norwegian Petroleum Directorate has for a long time been developing a report and information system which will provide the best possible picture of risks, not least in connection with technology and operation. In order for the Directorate to be able to use this information as an active means of steering efforts to prevent damage and injury, it is of paramount importance that one should clarify the links between the underlying causes and triggering mechanisms in cases where damage or injury has occurred. In connection with this, the Directorate is working out a system which will present the details more adequately.

Clarification of accidents

Occupational injuries are reported to the Directorate on the Rikstrygdeverket (National Insurance Sheme) Form 11.01 E. Each individual injury report is evaluated with regard to the quality of the information stated, and whether it is necessary to take special action. Information from the injury reports is systematized by the Directorate into a classification system and statistically processed. The statistics will be summarized regularly, and efforts will be made to apply them more energetically than previously. Work has also been done to improve the classification system as compared with previous years, in order to discern more easily, for example, any accumulation of accidents with features in common. Such cumulative effects may be symptoms of defects or failures, for example within technology or operations, and may thus represent a basis for analysing the causes.

Analysis of causes

Identification of risk areas will provide the starting point for more detailed analyses and investigations to try to determine the causes of any accident accumulation. Such analyses will include detailed studies of the information in the injury reports, as well as the companies' internal reports, and will provide an important reference mark for setting up priorities and selecting action to be taken in our efforts to prevent injury and damage.

This re-organization of the Directorate's report system has prompted us in the 1982 Annual Report to provide statistical summaries both of injury **occurrences** and injury **causes**.

THE OCCUPATIONAL INJURY STATISTICS FOR 1982

Occupational injuries are considered to include fatal accidents, injuries causing absence from work lasting into the next 12-hour shift, and injuries requiring medical treatment. By medical treatment is meant that a doctor, directly or indirectly, has participated in the treatment of the occupational injury.

These threshold criteria for the reporting of occupational injuries mean that the figures cannot be compared with corresponding figures from other activities.

Table 3.I includes an overview of occupational injuries per 1000 man years during the period 1976-1982. Injuries which occurred on the installations outside working hours are not included in the table. However, it is natural to include such injuries in a summary of the total injury situation (Tables 3.II, 3.III, 3.IV and 3.V), and here they make up 2.7 per cent of the total for 1979-1982.

The reorganization of the Directorate's registration system has caused the figures quoted in Table I to deviate slightly from those recorded in previous Annual Reports. Discrepancies are also due to the renewed examination of all 2082 injury reports from and including 1979, performed in connection with the reorganization. This date was considered appropriate, as the National Insurance Scheme's Form 11.01 E was introduced then. It was not found to be correct methodology to compare or use information about earlier injuries.

In connection with the above-mentioned reorganization of the registration system, the Directorate gathered data on working hours, subdivided according to the various activities during the period 1979-1982. These deviate somewhat from figures previously submitted to the Directorate and quoted in previous Annual Reports.

The discrepancies in the numerical material may indicate that the reports of working hours for several years are not entirely reliable. Probably they are too low. Nevertheless, the Norwegian Petroleum Directorate has chosen in Table 3.I to use the same figures as were submitted previously. This means that the statistics for the individual years must not be compared uncritically. In connection with this, the Directorate will verify the validity of the working hour data submitted by the individual companies for the years 1979-1981 with the help of material from other sources. Control audits will also be performed of the companies, in order to obtain an idea of the quality of injury reports written by company and office employees.

Table 3.II lists injury occurrences by occupation for 1981 and 1982.

Table 3.III gives injury occurrences by injured parts of the body.

Table 3.IV compares injury occurrences and the relevant external circumstances, i.e. it provides additional information about factors connected with the work situation which may have contributed towards, or may have triggered off, the incident.

Table 3.V gives a summary of the years 1979-1982 with the same parameters as Table 3.II.

General

In 1982 also, the Norwegian Petroleum Directorate enjoined the companies to report all occupational injuries which take place within company areas of responsibility. The positive development indicated by the figures for 1981 (Cf. Table 3.I), did not continue in 1982. At present the Norwegian Petroleum Directorate does not know whether the increase in injuries per 1000 man years from 1981 to 1982 is a result of systematic errors in the data, or whether the injury situation for 1982 was actually worse. The Directorate will attempt to clarify the matter as it reoganizes its accident report system.

TABLE 3.I. Injuries/ deaths per 1000 man years (1976-1982), Fixed production facilities, etc.

Year	Working hours	Hours pr. man years	Man years	Injuries	Injuries pr. man years	Deaths	Deaths per man years
1976	4 876 316	1852	2 633	213	80,9	2	0,76
1977	7 929 742	1802	4 399	282	64,1	2	0,45
1978	14 932 154	1752	8 523	624	73,2	6	0,70
1979	14 588 728	1752	8 327	578	69,4	0	0,00
1980	10 525 510	1752	6 007	450	74,9	0	0,00
1981	13 849 131	1752	7 905	422	53,4	0	0,00
1982	14 668 483	1752	8 372	547	65,3	0	0,00
Totalt	81 370 064		46 444	3 116	67,1	10	0,22

TABLE 3.II. Injury occurrence by occupation (1981-1982)

	Administration	Drillfloor worker	Driller	Electrician	Catering	Helper	Instrument technician	Crane driver	Painter Sandblaster	(Motormech. repairman	Operator	Plateworker Insulator	Plumber	Service technician	Scaffold builder	Welder	Derrickman	Unspecified	TOTAL	Per cent %	Year
Other cont. w/objects, parts of machines in motion	4	18	2	2	0	24	0	0	1	5	2	4	4	2	3	2	9	1	83	19.0	1981
	2	21	3	4	9	29	1	2	1	11	1	5	7	2	6	2	13	0	119	21.3	1982
Fires, explosions etc.	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	1	0.2	1981
	0	0	0	1	0	4	0	0	0	2	0	0	0	0	0	1	0	0	8	1.4	1982
Fall to lower level	2	1	2	1	2	5	1	1	1	1	2	2	3	2	3	4	1	0	34	7.8	1981
	2	2	1	4	0	9	1	0	5	4	0	2	4	2	5	5	2	0	47	8.4	1982
Fall to same level	3	2	1	3	2	9	1	3	0	2	3	3	7	3	6	7	0	0	55	12.6	1981
	3	2	0	9	2	13	0	1	4	3	3	2	3	5	5	6	2	0	63	11.3	1982
Stepping on uneven surface, stumbling	0	2	0	8	1	4	1	0	1	1	2	1	0	2	4	0	1	0	28	6.4	1981
	2	1	0	4	1	5	1	0	0	1	1	1	6	2	4	7	1	0	37	6.6	1982
Falling objects	2	1	0	2	0	2	1	0	1	0	0	0	1	1	1	1	0	0	13	3.0	1981
	0	2	0	3	0	11	1	0	0	2	1	3	5	1	4	1	0	0	34	6.1	1982
Other cont. w/non-moving objects	0	0	0	2	2	5	2	0	2	6	0	2	4	0	3	3	1	1	33	7.6	1981
	0	2	0	1	4	6	1	1	1	2	0	4	1	0	6	6	0	0	35	6.3	1982
Accident in conn. w/handling	1	7	1	7	0	11	1	0	0	15	3	6	6	1	6	9	5	0	79	18.1	1981
	1	4	1	5	3	12	1	2	5	12	1	6	9	2	3	7	4	0	78	14.0	1982
Contact w/ chemical physical compounds	0	1	0	0	0	3	1	0	8	1	4	1	1	1	0	0	2	0	23	5.3	1981
	0	1	0	0	0	4	0	0	9	1	1	2	1	2	1	1	0	0	28	5.0	1982
Strain on one part of the body	0	3	0	2	0	8	1	0	5	4	0	2	5	0	3	3	1	0	37	8.5	1981
	0	5	0	4	1	9	0	1	2	3	1	0	4	1	6	1	4	0	42	7.5	1982
Splinters, spray	2	1	0	0	0	3	0	0	0	1	2	4	12	0	1	7	0	0	33	7.6	1981
	1	0	0	1	0	4	0	1	2	3	0	5	8	0	1	14	1	0	39	7.0	1982
Electrical current	0	0	0	2	0	0	0	0	0	0	0	1	0	0	0	0	0	0	3	0.7	1981
	0	0	0	6	0	0	0	0	0	0	0	0	0	0	0	0	0	0	6	1.1	1982
Extreme temperature	0	0	0	0	2	0	0	0	0	0	0	1	0	1	0	0	0	0	4	0.9	1981
	0	0	0	0	4	0	0	0	0	3	1	0	3	0	0	1	0	0	12	2.2	1982
Occupational illnesses	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1981
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1982
Man over board	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1981
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1982
Other	0	0	0	2	0	0	0	0	0	3	0	1	2	0	1	0	0	0	10	2.3	1981
	1	0	0	1	1	2	0	0	0	1	0	1	0	0	0	3	0	0	10	1.8	1982
TOTAL	14	36	6	31	9	75	9	4	19	39	18	28	46	13	31	36	20	2	436		1981
	12	40	5	43	25	113	6	8	29	48	10	29	51	17	41	55	26	0	558		1982
%	3.2	8.3	1.4	7.1	2.1	17.2	2.1	0.9	4.4	8.9	4.1	6.4	10.5	3.0	7.1	8.2	4.6	0.5		100%	1981
	2.2	7.2	0.9	7.7	4.5	20.2	1.1	1.4	5.2	8.6	1.8	5.2	9.1	3.0	7.3	9.9	4.7	0.0		100%	1982

TABLE 3.III. Injury occurrence by part of body injured

Part of body injured / Accident Incident	eye	back	toe/foot	hip/leg	belly/chest	arm/shoulder	head/face	tooth	hand/finger	other	TOTAL	%	
Other contact w/ objects, part of machine in motion	0 1	1 2	15 16	5 5	2 6	6 7	3 5	2 5	48 71	1 1	83 119	19.0 21.3	'81 '82
Fire, explosion etc.	0 0	0 0	0 0	0 0	0 0	0 0	0 7	0 0	1 1	0 0	1 8	0.2 1.4	'81 '82
Fall to lower level	0 0	7 13	3 8	1 3	5 7	3 7	4 4	0 1	6 3	5 1	34 47	7.8 8.4	'81 '82
Fall to same level	0 0	7 7	14 17	6 5	3 4	5 8	7 3	1 1	10 18	2 0	55 63	12.6 11.3	'81 '82
Stepping on uneven surface, stumbling	0 0	2 0	18 28	2 3	1 2	2 1	1 0	1 1	1 1	0 1	28 37	6.4 6.6	'81 '82
Falling objects	0 0	2 0	3 8	0 7	0 1	2 2	2 6	2 1	2 8	0 1	13 34	3.0 6.1	'81 '82
Other contact w/ non-moving object	0 1	5 1	5 2	4 9	1 1	5 4	5 4	3 1	5 11	0 1	33 35	7.6 6.3	'81 '82
Accident related to handling	0 2	4 0	8 6	4 2	1 1	2 5	4 4	9 4	46 54	1 0	79 78	18.1 14.0	'81 '82
Contact with chemical/physical compound	17 25	0 0	1 0	0 0	0 0	2 0	1 2	0 0	1 0	1 1	23 28	5.3 5.0	'81 '82
Strain on one part of the body	0 0	19 28	0 2	1 1	3 3	11 6	0 0	0 0	1 2	2 0	37 42	8.5 7.5	'81 '82
Splinters, spray	30 38	0 0	0 0	0 0	0 0	1 0	0 0	0 0	2 1	0 0	33 39	7.6 7.0	'81 '82
Electrical current	0 0	0 0	0 0	0 0	0 0	0 1	0 2	0 0	2 3	1 0	3 6	0.7 1.1	'81 '82
Extreme temperatures	0 0	0 0	1 1	1 1	0 0	0 1	0 3	0 0	2 6	0 0	4 12	0.9 2.2	'81 '82
Occupational illness	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	'81 '82
Man over board	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	'81 '82
Other	3 3	0 1	0 0	0 1	1 1	1 0	0 0	0 0	1 2	4 2	10 10	2.3 1.8	'81 '82
Total	50 70	47 52	68 88	24 37	17 26	40 42	27 40	18 14	128 181	17 8	436 558		
%	11.5 12.6	10.8 9.3	15.6 15.8	5.5 6.6	3.9 4.7	9.2 7.5	6.2 7.2	4.1 2.5	29.3 32.4	3.9 1.4		100%	

TABLE 3.IV. Injury occurrence by external circumstance

	Chemical/physical, biological factor	Cooling, pressure, heat, ventilation	Materials, goods, packaging	Electrical equipment	Other machines	Drilling tongs	Hand tools, machines, implements	Non-fixed/fixed devices on building/const.	Lifting/transport device	Other	Total		
Other contact w/ objects, machine part in motion	0 0	1 4	6 20	1 0	3 6	11 10	6 15	19 34	33 29	3 1	83 119	19.0 21.3	'81 '82
Fire, explosion, etc.	0 7	0 1	0 0	0 0	0 0	0 0	1 0	0 0	0 0	0 0	1 8	0.2 1.4	'81 '82
Fall to lower levels	1 4	0 0	1 3	0 0	0 0	0 0	0 2	28 31	0 2	4 5	34 47	7.8 8.4	'81 '82
Fall to same level	1 2	0 0	1 7	1 0	0 0	0 1	1 1	45 50	0 0	6 2	55 63	12.6 11.3	'81 '82
Stepping on uneven surface, stumbling	0 0	0 0	3 4	0 0	0 0	0 0	0 1	20 27	0 0	5 5	28 37	6.4 6.6	'81 '82
Falling objects	0 0	0 0	6 14	0 0	0 1	0 0	1 6	4 11	1 1	1 1	13 34	3.0 6.1	'81 '82
Other contact w/ non-moving object	0 1	0 0	2 5	0 0	1 3	0 0	3 3	25 22	0 0	2 1	33 35	7.6 6.3	'81 '82
Accident relating to handling	0 0	0 0	14 31	0 1	8 3	0 2	43 32	6 6	4 3	4 0	79 78	18.1 14.0	'81 '82
Contact with chemical/physical compound	12 23	3 2	2 2	0 0	1 0	0 0	5 1	0 0	0 0	0 0	23 28	5.3 5.0	'81 '82
Strain on one part of the body	0 0	0 0	12 23	0 0	0 0	2 0	4 3	10 11	1 4	8 1	37 42	8.5 7.5	'81 '82
Splinters, spray	0 1	3 0	2 2	0 1	0 1	0 0	25 26	0 0	0 0	3 8	33 39	7.6 7.0	'81 '82
Electric current	0 0	0 0	0 0	3 6	0 0	0 0	0 0	0 0	0 0	0 0	3 6	0.7 1.1	'81 '82
Extreme temperatures	2 4	0 4	0 1	0 0	0 0	0 0	2 3	0 0	0 0	0 0	4 12	0.9 2.2	'81 '82
Occupational illness	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	'81 '82
Man over board	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	'81 '82
Other	0 0	0 0	1 1	0 0	0 0	0 0	0 1	0 2	0 1	9 5	10 10	2.3 1.8	'81 '82
Total	16 42	7 11	50 113	5 8	13 14	13 13	91 94	157 194	39 40	45 29	436 558		
%	3.7 7.5	1.6 2.0	11.5 20.3	1.1 1.4	3.0 2.5	3.0 2.3	20.9 16.8	36.0 34.8	8.9 7.2	10.3 5.2		100 %	

TABLE 3.V. Injury occurrence by occupation (1979-1982)

	Administration	Drillfloor worker	Driller	Electrician	Catering	Helper	Instrument technician	Crane driver	Painter Sandblaster	(Motor)mech repairman	Operator	Plateworker Insulater	Plumber	Service technician	Scaffold builder	Welder	Derrickman	Unspecified	TOTAL	Per cent %
Other cont w/objects, parts of machines in motion	12	103	8	10	11	123	7	7	4	27	5	12	22	8	21	12	47	1	440	21.4
Fires, explosions etc.	0	0	0	1	0	5	0	0	0	2	0	0	2	0	0	1	0	0	11	0.5
Fall to lower level	7	13	9	22	4	34	4	2	14	12	5	7	21	6	14	15	9	0	198	9.6
Fall to same level	9	14	4	26	10	38	7	6	8	12	12	9	23	10	18	20	5	1	232	11.3
Stepping on uneven surface, stumbling	8	7	1	25	3	28	6	1	4	8	6	9	22	4	11	18	5	0	166	8.1
Falling objects	2	5	2	5	0	18	2	0	1	3	1	3	11	2	8	5	0	0	68	3.3
Other cont w/non-moving objects	1	7	1	8	6	22	7	1	6	12	1	12	12	3	12	11	4	3	129	6.3
Accident in conn. w/handling	4	29	5	22	10	61	8	4	11	43	9	19	45	4	12	29	15	0	330	16.1
Contact w/ chemical physical compounds	0	7	0	5	3	26	1	1	24	5	8	5	7	4	2	5	2	0	105	5.1
Strain on one part of the body	1	14	3	13	5	29	1	2	10	13	3	3	24	2	14	9	9	0	155	7.6
Splinters, spray	3	4	1	2	0	16	1	1	5	6	4	12	30	0	2	39	1	0	127	6.2
Electrical current	0	0	0	15	0	1	1	0	0	1	0	1	1	0	0	0	0	0	20	1.0
Extreme temperature	0	0	0	1	9	0	0	0	0	3	3	2	4	1	0	1	0	0	24	1.2
Occupational illnesses	0	1	0	0	0	0	0	0	0	0	0	0	1	0	0	0	0	0	2	0.1
Man over board	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	4	2	6	0	1	2	5	2	4	5	0	2	4	0	0	44	2.2
TOTAL	51	207	34	159	63	407	45	26	90	152	59	98	230	44	116	169	97	5	2052	
%	2.5	10.1	1.7	7.7	3.1	19.8	2.2	1.3	4.4	7.4	2.9	4.8	11.2	2.1	5.7	8.2	4.7	0.2		100%

4. PETROLEUM ECONOMY

4.1. Costs in connection with the activities on the Norwegian continental shelf

Investments in field development and production drilling

For the period 1970-1982, the Norwegian Petroleum Directorate has calculated annual costs in connection with field development and production drilling. The costs relate to developed fields, fields being developed, and fields with approved development plans as per 31 December 1982. In addition, estimates have been made for the same items up to the year 2000. The figures are based on operator reports.

For fields extending to both sides of the border line between Norway and Great Britain, only the Norwegian share is considered. The fields listed below were included in the calculation (Norwegian share):

- The Ekofisk area (incl. Tor, Albuskjell, and the Norpipe pipeline)
- Valhall
- Ula
- Frigg (incl. pipeline) (60.82 %)
- North East Frigg
- Odin
- Statfjord (84.09 %)
- Murchison (16.25 %)
- Heimdal
- Gullfaks Phase I
- Statpipe gas landing project

All figures are in Norwegian kroner. Figure 4.1.a shows the total costs of field development, including production drilling, presented in current and fixed 1982 kroner. The reason for quoting costs from 1970 to 1982 in fixed 1982 kroner is that it is desirable to present the level of activities for the whole period in comparable figures. The Wholesale Price Index has been used for numerical material dating from before 1982. In 1982, a total of NOK 16 billion was invested in field development including production drilling and building of pipelines. The investment level will increase during 1983-84 and then quickly decrease unless new projects are started. In order to evaluate a probable development of the level of investments in the years up until 2000, reference is made to the perspective analysis prepared by the Norwegian Petroleum Directorate in 1982. The level of investments in 1983-84 is particularly high due to substantial acitivity in relation to the development of Gullfaks Phase I and Statpipe.

Figure 4.1.b shows the costs of production drilling expressed in current and fixed 1982 kroner values.

FIGURE 4.1.a. Total costs of field development including production drilling in current kroner and fixed 1982-kroner. (Billion NOK)

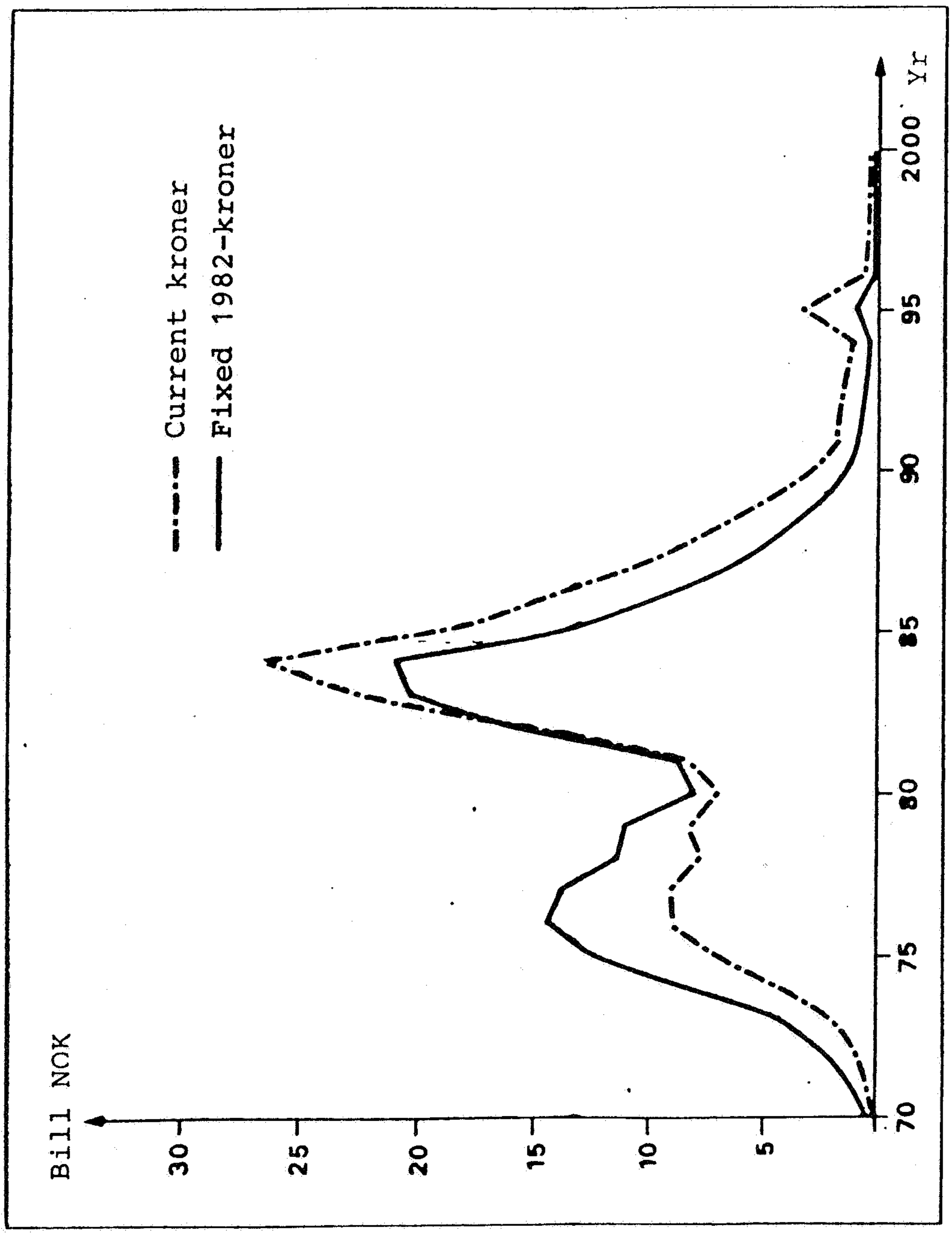
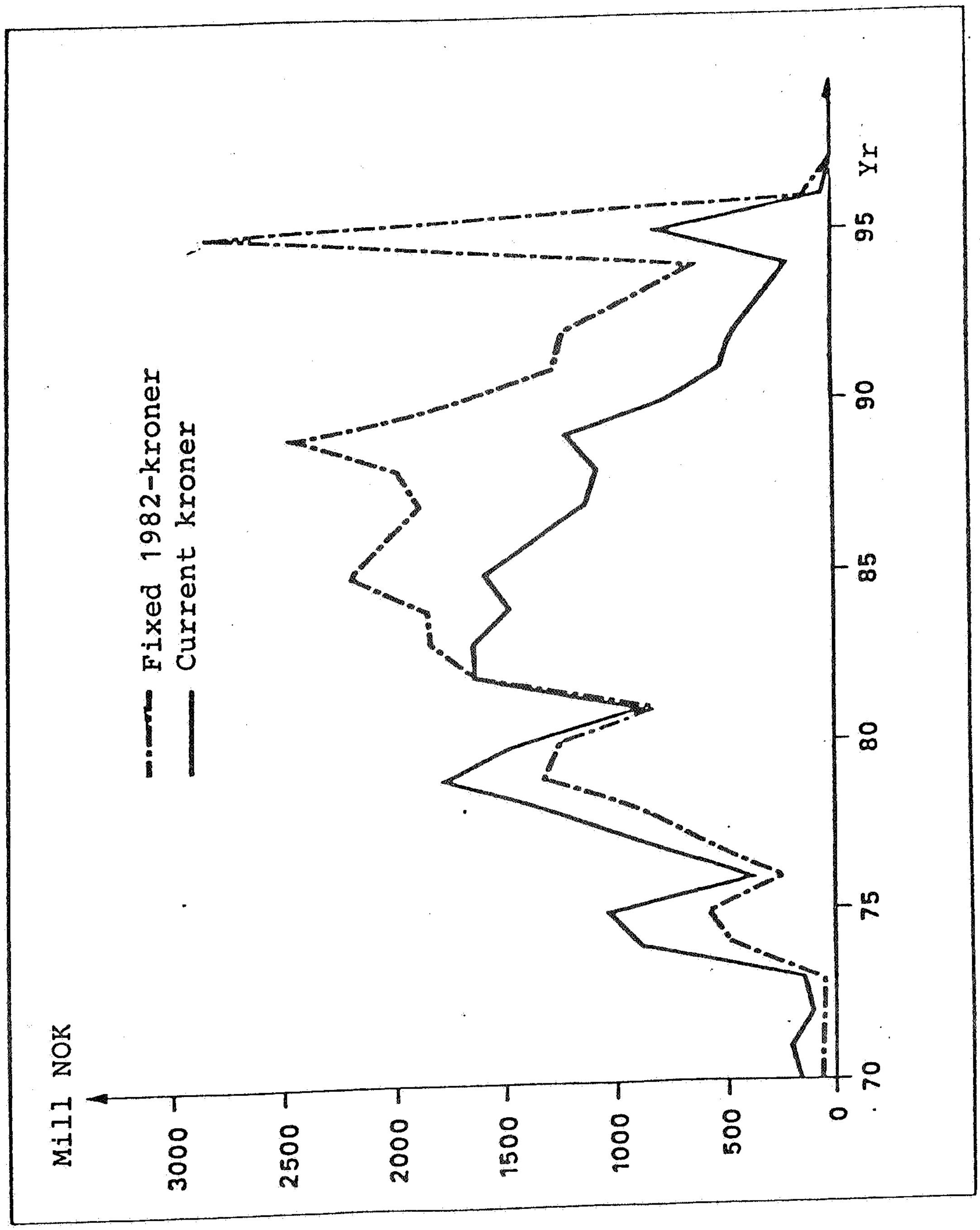


FIGURE 4.1.b. Costs of production drilling in current kroner and fixed 1982-kroner. (Billion NOK)



The Norwegian companies´ share of total field investments including production drilling and pipeline projects

Figure 4.1.c shows the Norwegian companies´ share of the total investments in developed fields, fields being developed and fields which have been decided to be developed as per 31 December 1982. The Norwegian companies´ share was 45 per cent in 1982, increasing to approximately 60 per cent in 1983-84. Statoil´s share in 1982 was about 35 per cent, and this will grow in the years 1983-84 to an average of some 50 per cent.

Costs of operations

The total costs of operation and maintenance of fields, including transportation of petroleum, amounted to about NOK 9.3 billion in 1982.

Figure 4.1.d shows the annual costs of operations for developed fields, fields being developed, and fields decided to be developed as per 31 December 1982, in current and fixed 1982 kroner values. The material of figures are based on the operators´ reports to the Norwegian Petroleum Directorate. Figures from and including 1983 are estimated costs.

FIGURE 4.1.c. Investments in fixed 1982 prices. (Billion NOK)

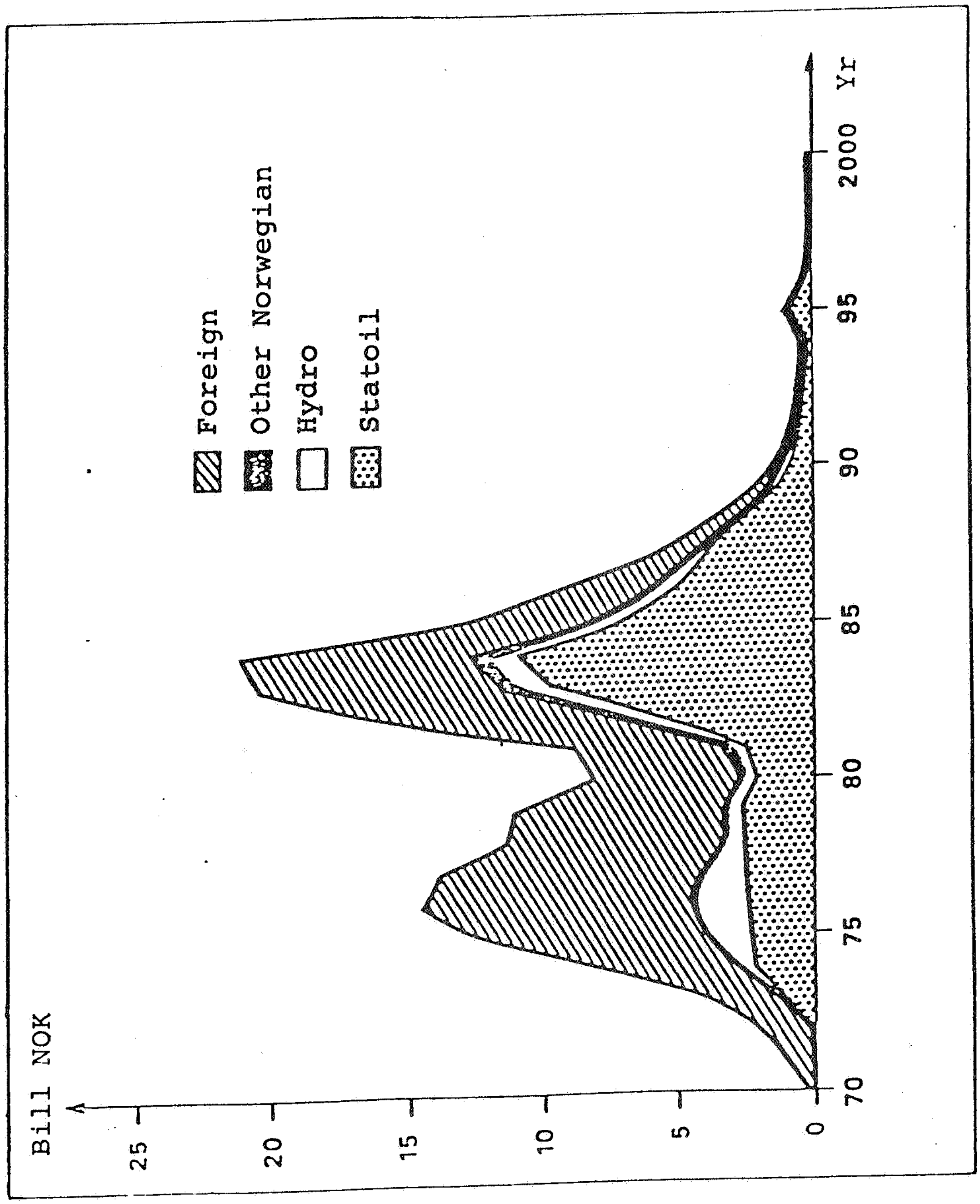
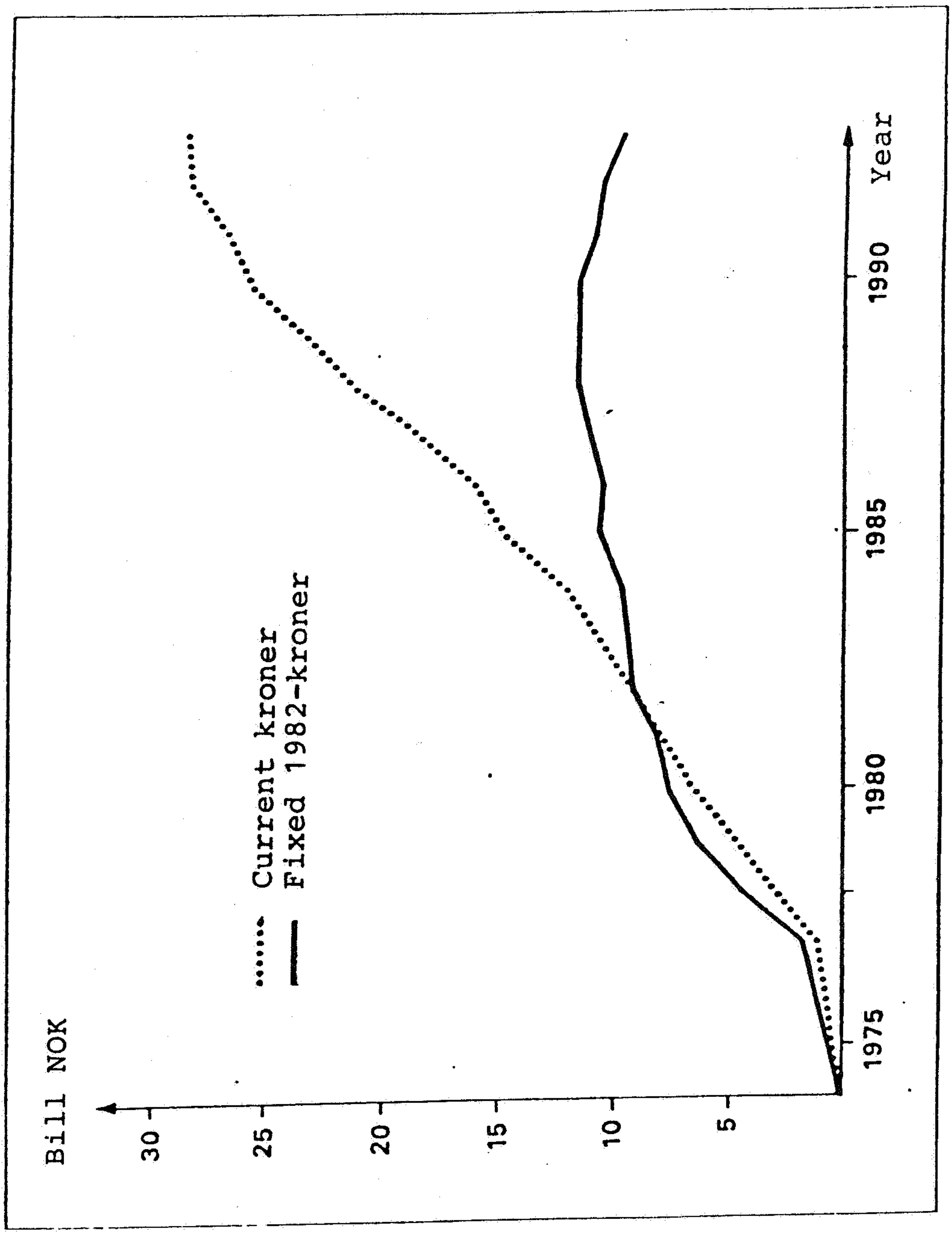


FIGURE 4.1.d. Operating costs in current kroner and fixed 1982-kroner. (Billion NOK)



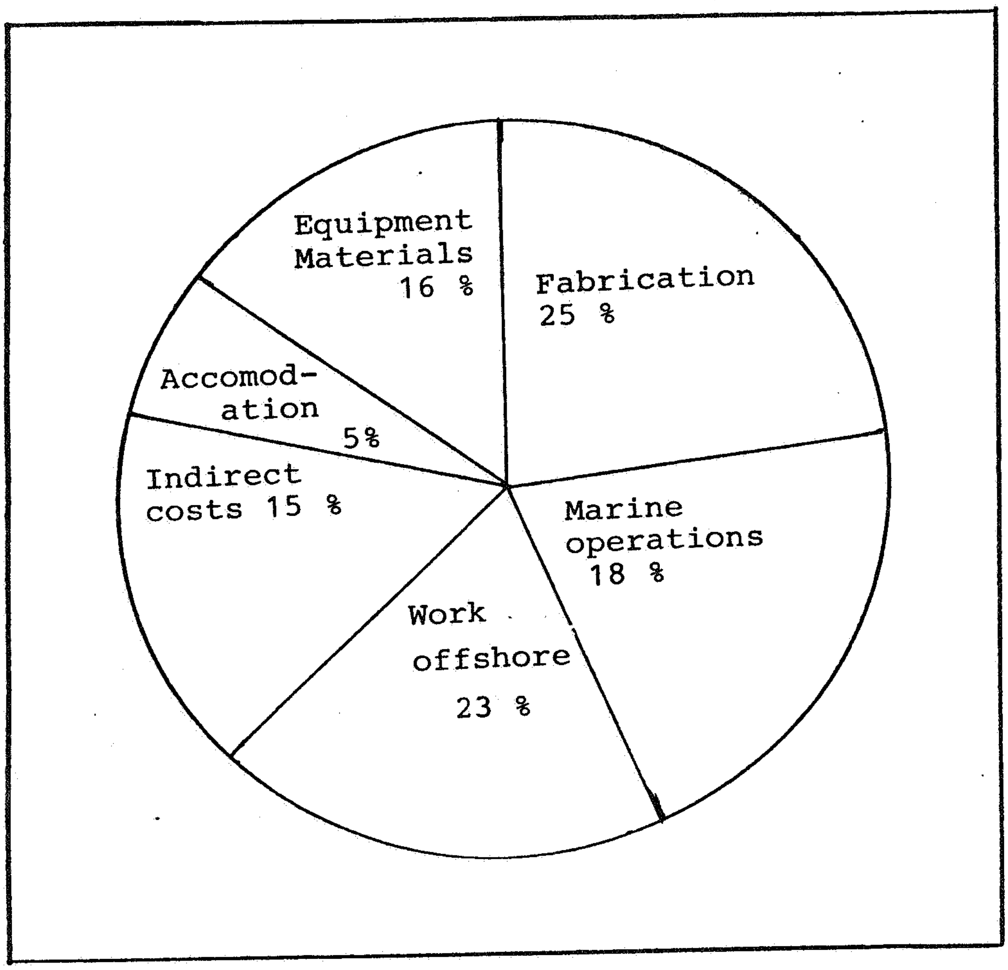
Investments broken down by some cost categories

In the following, an attempt will be made to throw some light on how total investments (excluding production drilling and pipelines) for some selected projects are broken down by cost category. The statistical basis includes the companies´ planning estimates, budgets and project reports. The selected projects represent various types of development concept, and also include modifications to platforms in regular operation. Due to differing classification routines in the operating companies, the cost categories may vary from project to project. The material presented, therefore, is not wholly consistent, a fact that should be born in mind when making comparisons. This notwithstanding, our presentation should provide a workable idea of the cost situation. All costs are quoted at current kroner value.

The Ekofisk area

The Ekofisk field has been developed in several phases. We will look a little closer at the fourth and to date final phase, which includes the development of Eldfisk, Albuskjell and Edda. These fields were developed with integrated steel platforms for drilling, accomodation, and in part also for processing. Total costs (excluding production drilling and pipelines) were a little less than $ 1300 million, or NOK 9.1 billion (NOK/$ = 7.00). The figure breaks down into its component cost categories like this:

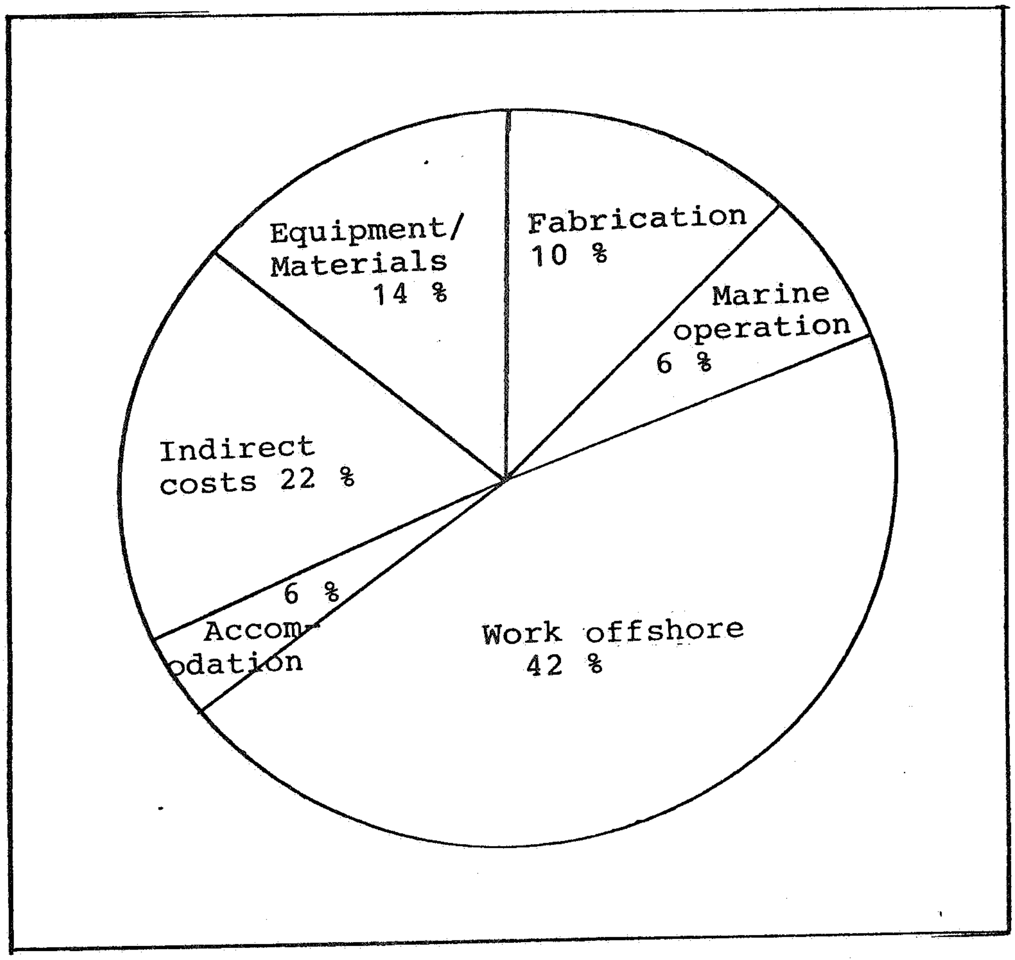
FIGURE 4.1.e. Pie chart of costs. Ekofisk area. Eldfisk, Albuskjell and Edda



The indirect costs include outlays for consumer goods, helicopter transport and supply vessels, travelling, project planning, warehouse management and inspections. The two largest indirect items are helicopter transport and supply vessels, and project planning. These two account for about 40 and 30 per cent, respectively, of the total indirect costs.

In recent years, a number of projects have been carried out on platforms in regular operation in connection with the installation of purification plants for waste water, power modules, water injection equipment, living quarters, etc. The total costs included on this chart amount to $ 320 million (NOK 2.2 billion at an exchange rate of NOK/$ = 7.00) and are distributed as follows:

FIGURE 4.1.f. Pie chart of costs. Ekofisk supplementaries



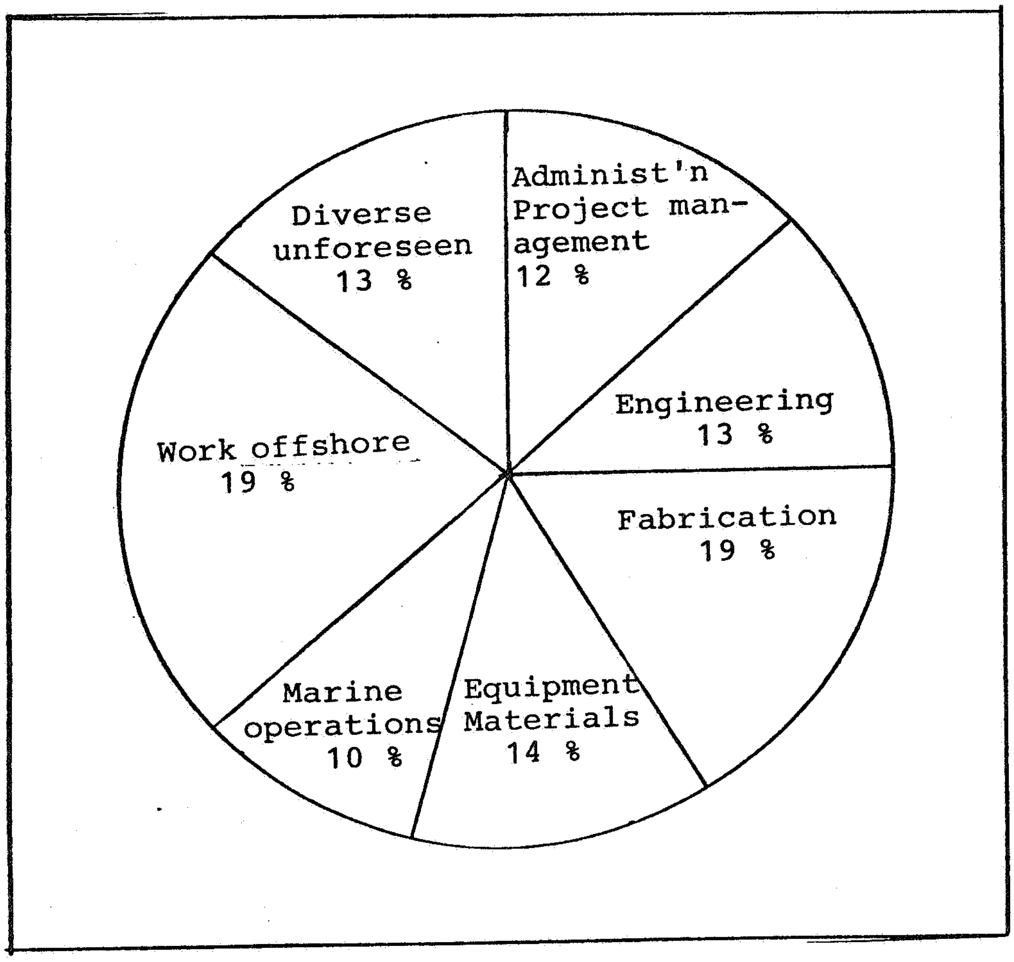
Of the indirect costs, about 45 per cent relate to project control and project planning, and about 30 per cent to helicopter transport and supply vessels.

If equipment/ materials and labour are defined as workshop related costs, their contribution here for these projects is 24 per cent, as opposed to 39 per cent for all of Phase 4. The contribution from work at sea is 42 per cent, as opposed to 23 per cent for Phase 4 in total.

Heimdal

The Heimdal field is being developed with an integrated steel platform containing drilling, production and accomodation functions. The total investments are expected to be some NOK 8 billion, thus divided:

FIGURE 4.1.g. Pie chart of costs. Heimdal



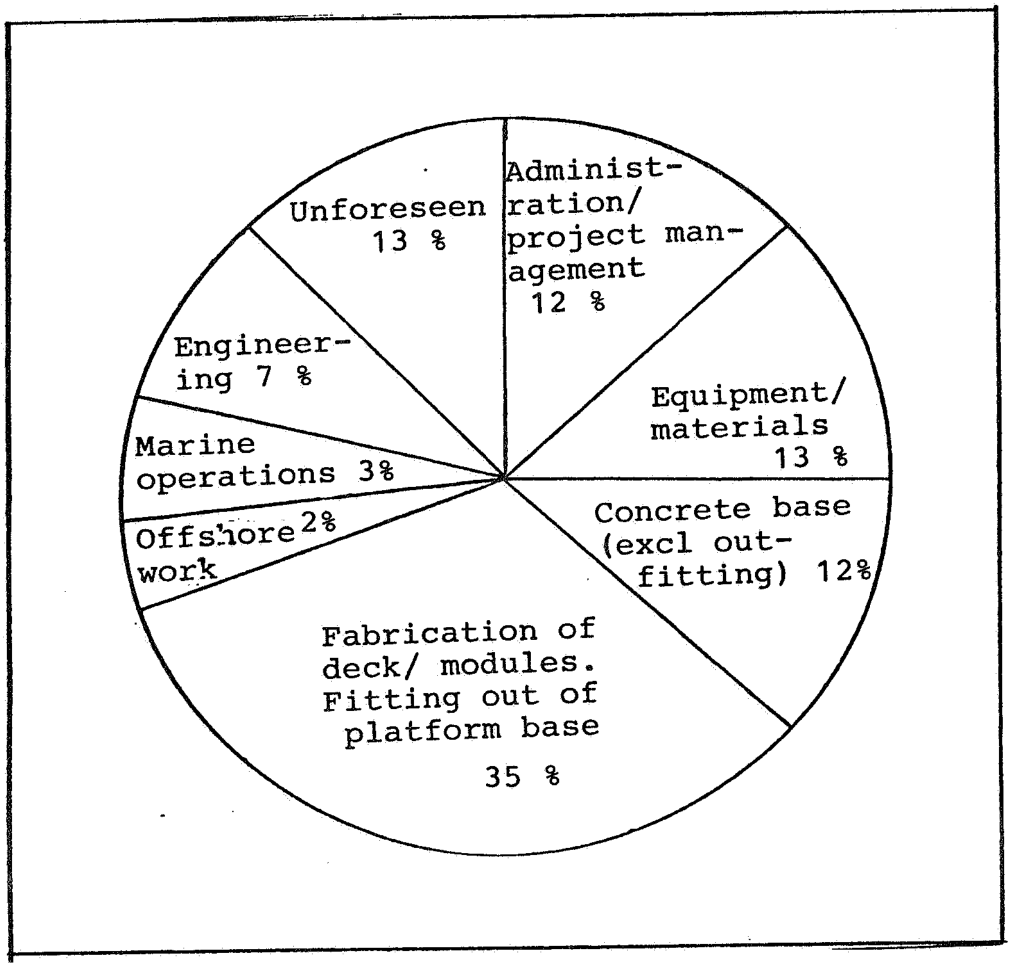
Because the development is in an early phase, the figure for sundry/ unforeseen costs is quite large. As can be seen, the workshop related costs (equipment/ materials and manufacturing) account for about 33 per cent.

Gullfaks

The Gullfaks project is also in an early phase. The platform will be an integrated drilling, accomodation and production installation with a concrete base.

Workshop and plant related work performed on land is expected to constitute slightly more than 60 per cent of the expected total cost. Construction of the concrete base has recently begun. The total investments are expected to be approximately NOK 16 billion. Total costs are composed of the following:

FIGURE 4.1.h. Pie chart of costs. Gullfaks



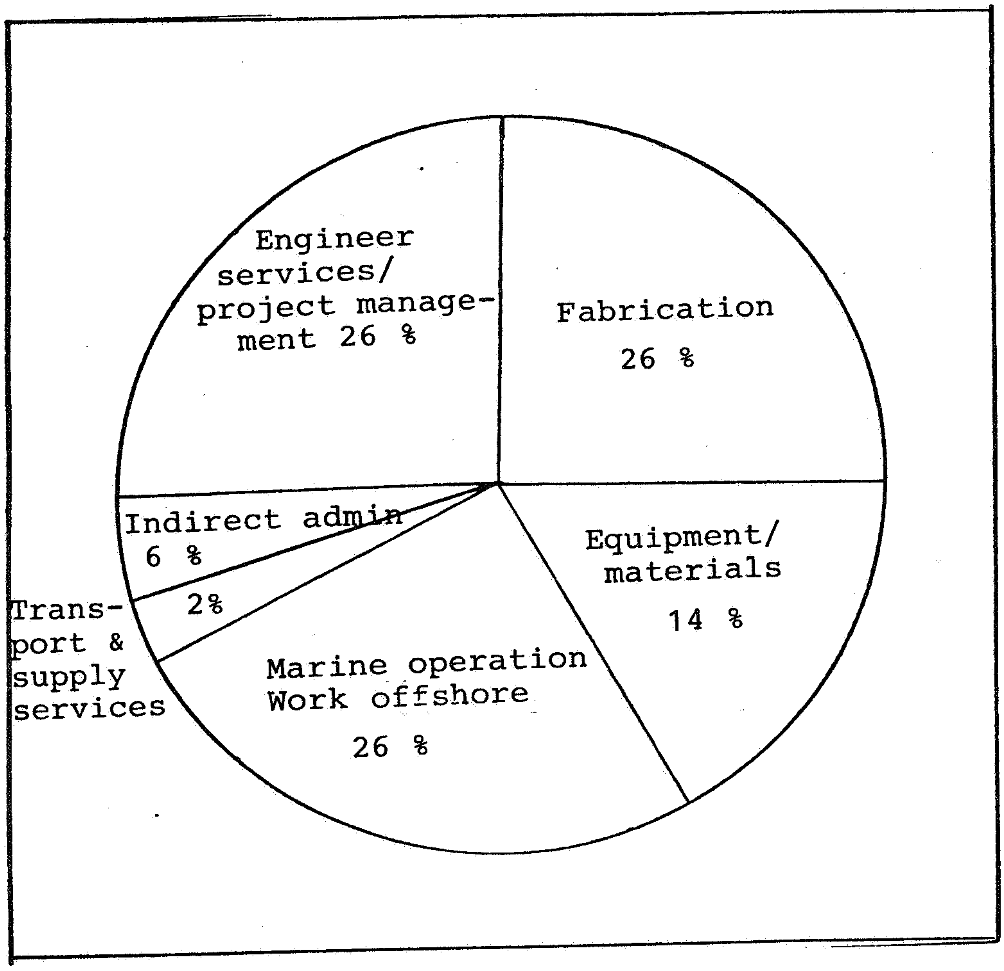
Work at sea and marine operations make a minor contribution to the total costs.

The Frigg area

The North East Frigg field is being developed with sub-sea completed wells which can be remote controlled from the Frigg field by signals to a control tower anchored near the wellheads. The tower can be manned. This is a new technical solution and is being used for the first time on the Norwegian shelf. The tower will be more or less complet by the time it is towed out to sea. The workers who are to carry out the offshore hook-up operation will typically commute from the Frigg field.

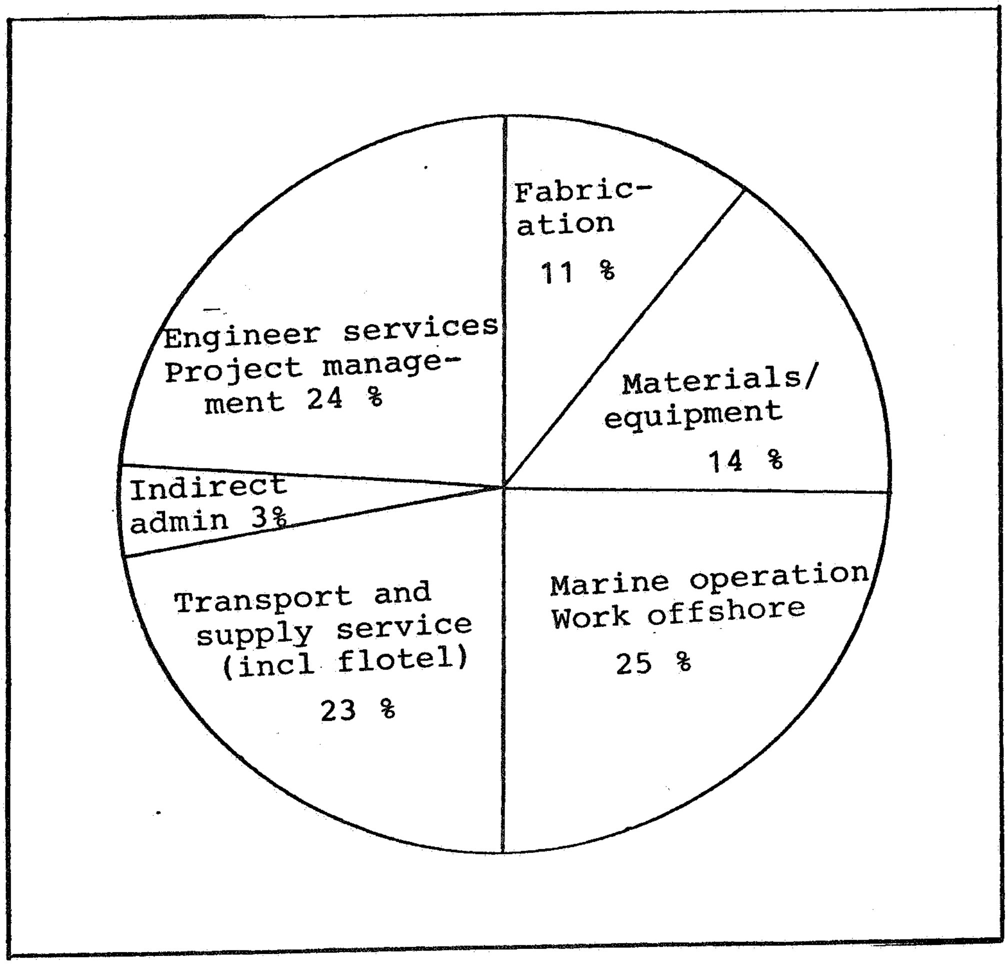
Excluding drilling costs and costs in connection with the pipeline to Frigg, the project will require about NOK 1.3 billion. The costs may be broken down into the following cost categories:

FIGURE 4.1.i. Pie chart of costs. North East Frigg



The TCP 2 platform on the Frigg field will be equipped with some new equipment in order to be able to receive and process the gas from North East Frigg and the Odin field. This project has a cost ceiling of about NOK 400 million. The breakdown looks like this:

FIGURE 4.1.j. Pie chart of costs. Upgrading of Frigg TCP 2



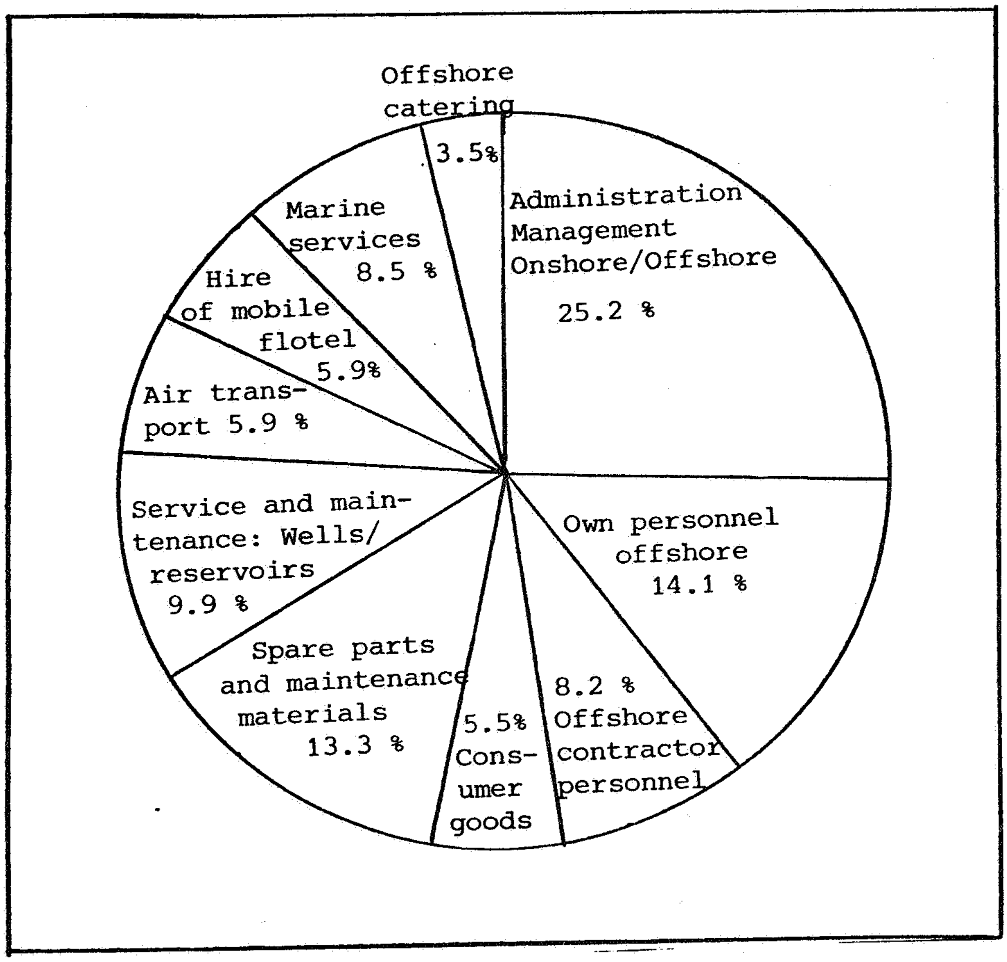
Cost of operations with some breakdowns into cost categories

The total costs of operations (excluding investment work, transport costs for petroleum, and insurance) for the fields in the Ekofisk area, Valhall, Frigg and Statfjord A and B, were budgeted at about NOK 7 billion for 1983. This figure includes the entire operating costs for the Frigg and Statfjord fields.

Figure 4.1.k. shows the relative share of the operations budget for the individual cost categories.

The budget statements by the individual operators differ, and their categorization of the costs varies somewhat. The breakdown shown here is thus somewhat empirical.

FIGURE 4.1.k. Pie chart of operating and maintenance costs



4.2 Explorational drilling, supply of goods and services

Since operations started in 1966, the market for explorational drilling expanded significantly both in volume and value. Figure 2.2.2.a shows the number of drillings started per year during the period 1966-1982. In Figure 4.2.a, the value increase of the market is presented both in current and fixed 1982 kroner. In 1966, goods and services worth NOK 65 million were supplied. Ten years later, supplies made up NOK 860 million, and reached their peak value to date of NOK 4.2 billion (current kroner) in 1982. During the period 1966-1982, the number of wells spudded annually has increased from 2 to 49.

Figure 4.2.b shows how the NOK 4.2 billion may be roughly subdivided into some groups of goods and services. Figure 4.2 shows a breakdown into hire of mobile drilling rigs, supplies of goods, services and sundry costs. Table 4.2 showns how the NOK 4.2 billion may be roughly broken down into some groups of goods and services. Figure 4.2 shows a distribution into hire of mobile drilling vessels, supply of goods, services and various costs. Table 4.2 also shows a further subdivision of the main groups into categories of goods and services.

The item, Sundry, in the main group may appear large, and it has proved difficult to specify what the item includes. It may be mentioned that a fairly large part of sundry services concerns well heads. Diving also accounts for a good deal.

The figures presented are based on the reported data from the oil companies and reflect the costs of all wells started in 1982. For drilling commenced towards the end of the year, the total cost and the cost distribution have been calculated by the Norwegian Petroleum Directorate.

FIGURE 4.2.a. Exploration costs in current kroner and fixed 1982-kroner. (Billion NOK)

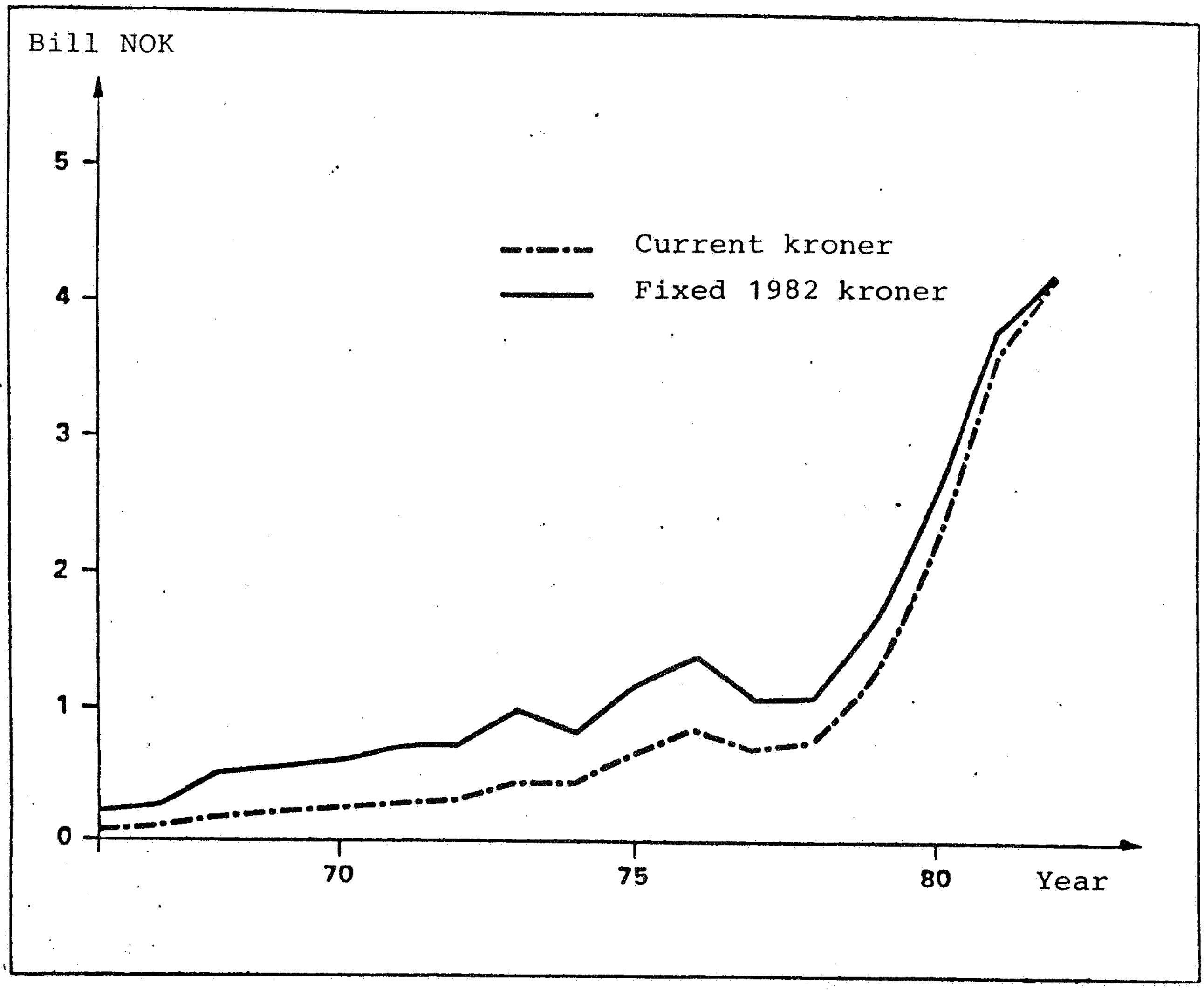
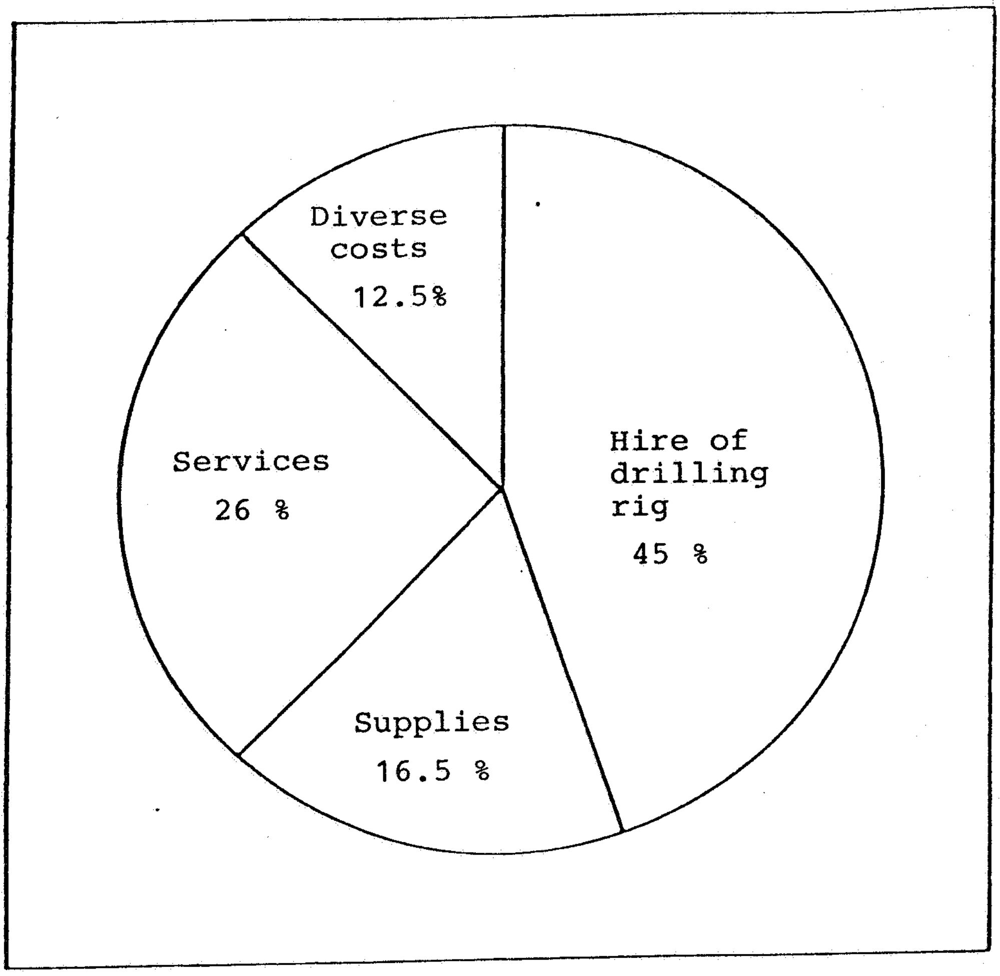


FIGURE 4.2.b. Distribution of drilling costs by cost categories. (Per cent)



It should be noted that the figures quoted contain some elements of uncertainty. However, they should provide a good indication of the contributions of the separate categories of goods and services, in relation to the total costs.

A growth is not expected in this market in the near future. The costs will probably increase in step with the general rise in prices, but the volume of the market will stabilize. Recently it has become evident that the hire charges for mobile drilling vessels have decreased substantially as compared with their usual high value. This may very well considerably influence the level of total explorational drilling costs.

TABLE 4.2. Deliveries of goods and services in 1982 to the exploration drilling market

Category		NOK million	Percentage share
Hire of drilling rig		1 890	45
Supplies of goods		695	16.5
Pipes	232		
Drilling mud	115		
Cement/Chemicals	54		
Fuel/Lubricants	149		
Drill bits	57		
Sundry supplies of goods	88		
Services		1 090	26
Supply ship/standby vessel	355		
Helicopter transportation	126		
Communication/navigation/ weather services	15		
Logging	266		
Testing	97		
Core samples	10		
Engineering studies	40		
Sundry services	181		
Sundry costs		525	12.5
Modifications to drilling rigs	97		
Maintenance and repairs	35		
Insurance	13		
Base costs	77		
Administration, etc	165		
Sundry costs	138		
		4 200	100

4.3. Royalties

Royalties are assessed on the basis of the value of the quantities of hydrocarbon produced. In 1982, royalties made up about 19.5 per cent of the total taxes and duties paid by the petroleum industry on the Norwegian continental shelf.

The Norwegian Petroleum Directorate has been given the responsibility of collecting the royalties.

The interpretation and technical implementation of the applicable acts and regulations relating to the calculation of royalties involves problems of measurement which are both legal, economic and technical.

The first provisions in this area were laid down by Royal Decree of 9 April 1965. Of the fields presently in production, the licences for Ekofisk, Frigg and Valhall were granted pursuant to these original (1965) provisions. The Royal Decree of 9 April 1965 was superceded by the Royal Decree of 8 December 1972. Of the fields presently being produced, the licences for Statfjord and Murchison were granted pursuant to this latter (1972) resolution.

Retroactive effects

In practice, most of the stipulations of the ´72 resolution have also been applied to licences granted pursuant to the ´65 resolution, even though some central provisions are applied in accordance with the wording of the ´65 version. The companies have in some instances protested against the practice followed by the authorities, as they have felt that the authorities´ application of new rules to older licences in some cases has entailed illegal retroactive effect. In one instance, a law suit was brought against the state. The case pertained to the deadlines for the payment of royalties. According to the ´72 resolution, royalty shall be paid four times a year, as opposed to the ´65 resolution which stipulates two annual payments. Judgement in this case was presented by the Oslo City Court in 1982, wherein the Plaintiff was supported. The case has been appealed by the state to a superior court.

The royalty rates. Point of reference

According to the ´65 resolution, a royalty of 10 per cent of the gross value at the production site shall be payable. One of the many problems in connection with the ´65 resolution has been to establish just what is meant by "production site", in other words, the point of reference for assessment of royalty pursuant to a correct interpretation of § 26 in the ´65 resolution.

According to the ´72 resolution, royalty shall be payable on the gross hydrocarbon value at the point of shipment from the production site. The royalty rate for oil increases by increments from 8-16 per cent depending on the quantity produced. The royalty rate for hydrocarbons other than oil is fixed at 12 1/2 per cent.

It would be natural to meter the oil or gas subject to royalty at the same place as the relevant resolution demands that royalty shall be assessed. As the price of hydrocarbons is usually determined on shore, however, there are problems connected with using the platform metering facilities as a basis for royalty assessment. This has meant that there is a general wish to meter production quantities on shore.

Cost deductions

When assessing royalty, it is the value at the production site (the ´65 resolution) or the point of shipment from the production site (the ´72 resolution) which is used as a basis. Despite this fact, the value of the hydrocarbon is usually determined at the landing site. Thus, deductions are allowable for certain costs incurred between the production site (or the point of shipment from the production site) and the landing site. The rules in force contain no explicit provisions as to which costs can be deducted.

The gross royalties for the period from the fourth quarter 1981 to the third quarter 1982 were about NOK 6.1 billion. The net paid-up royalties for the same period were about NOK 5.4 billion. This means that the authorities allowed the companies to enter some NOK 750 million, or about 12 per cent, as deductible costs in the assessment of royalties in 1982. Forty per cent of the cost deductions relate to the transport and processing of oil, while the remaining 60 per cent of the deductions in 1982 are related to the transportation and treatment of gas.

Acreage fees

One deductible cost which is common regardless of the transportation method, is the acreage fee. According to the ´72 resolution § 27, first sub-section, paid-up acreage fees shall be deducted in the settlement for production royalty.

Export duty

When landing hydrocarbons abroad, these are subject to an export duty, cf. § 1 of the Act relating to duties on exports to promote Norwegian export interests of 23 April 1956. According to this rule, a tax of 3/4 parts per thousand of the export value shall be paid in to a separate fund, the Norwegian Exports Fund. Export duty is accepted as a deductible cost in the settlement of royalty.

Insurance

The authorities have also accepted that insurance premiums for deductible installations are a deductible cost.

Deficits

When the sales price of a petroleum product, less deductible costs, indicates a deficit, the question arises of whether the deficit for the particular product may be deducted from any profits on other products.

As concerns deficits and the assessment of royalty for licences granted pursuant to the ´65 resolution, it is clear, in the opinion of the Norwegian Petroleum Directorate, that a deficit for one product may be deducted from any profit on other products. In practice this problem has arisen in connection with the assessment of production royalty from Ekofisk. In this case, deductions were allowed for deficits in connection with sales of NGL from the profits on gas.

Tariffs

In order to structure the assessment of deductible costs, tariffs have been prepared for some items. One might say that a tariff is a function listing the elements included in the calculation. Before the licensees may use the tariffs, they must be approved by the Ministry. This is a condition of the landing permissions.

A tariff will usually consist of the following elements:

O = operational costs
I = interest
D = depreciation
P = profits

As concerns the Profit element, its size depends on whether the tariff is charged to the owner interests or a third party. The member companies of the licensee group for the field from which transportation takes place will, nevertheless, often be the co-owners of the pipeline and/ or the terminal companies, though frequently in a slightly different relationship than in the licensee group. In such circumstances, the group will be charged owner's tariffs by the pipeline and terminal companies. Such owner tariffs will then be claimed as a deductible cost by the licensee, when assessing royalty.

A third party tariff is a tax paid by users, but not owners, of pipeline and/ or terminal facilities. The Profit element will here be greater than in the owner tariffs.

4.4 Petroleum markets

4.4.1 The oil market

Figure 4.4.1.a shows the average price development for Norwegian crude oil in the period 1972-1982. Nominally, the figure shows a price increase from slightly below NOK 20 per barrel in 1972 to NOK 220 per barrel in 1982. The real price curve, presented by means of the gross price index 1982=100, shows that the real price increased more than five-fold during the period 1973-1980, and that it fell by more than 25 per cent in 1981-82.

The total shipments of crude oil from Teesside, Statfjord and Murchison were 23.0 million tonnes in 1982, cf. Figure 4.4.1.b. An ever-increasing part of the Norwegian crude oil shipments is destined for refineries in Norway, in 1982 about 19 per cent. The USA is still the largest market for Norwegian crude oil, with about 23 per cent of shipments going there.

FIGURE 4.4.1.a. Price development for Norwegian crude oil (NOK per barrel, per cent in relation to fixed 1982-kroner)

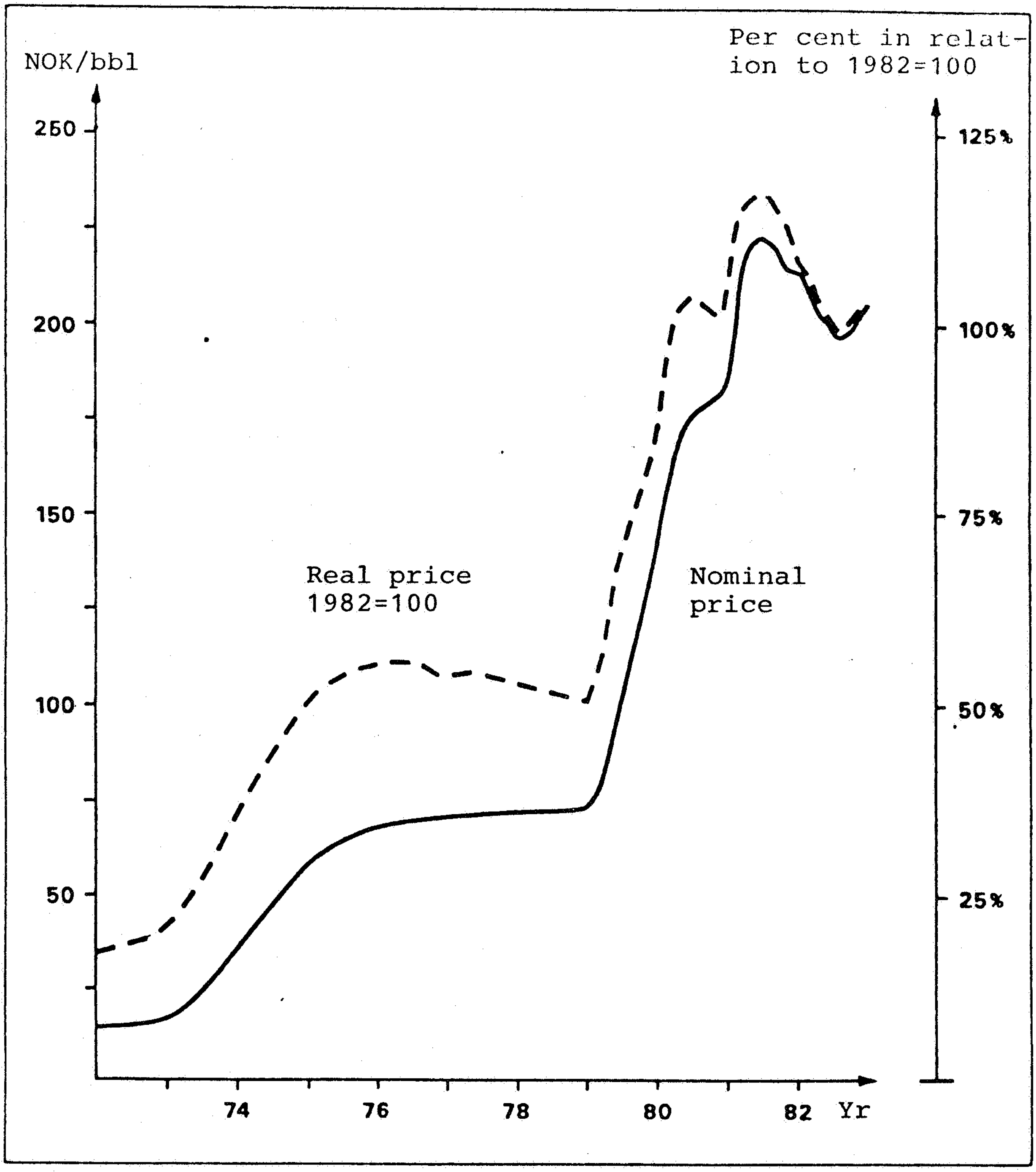
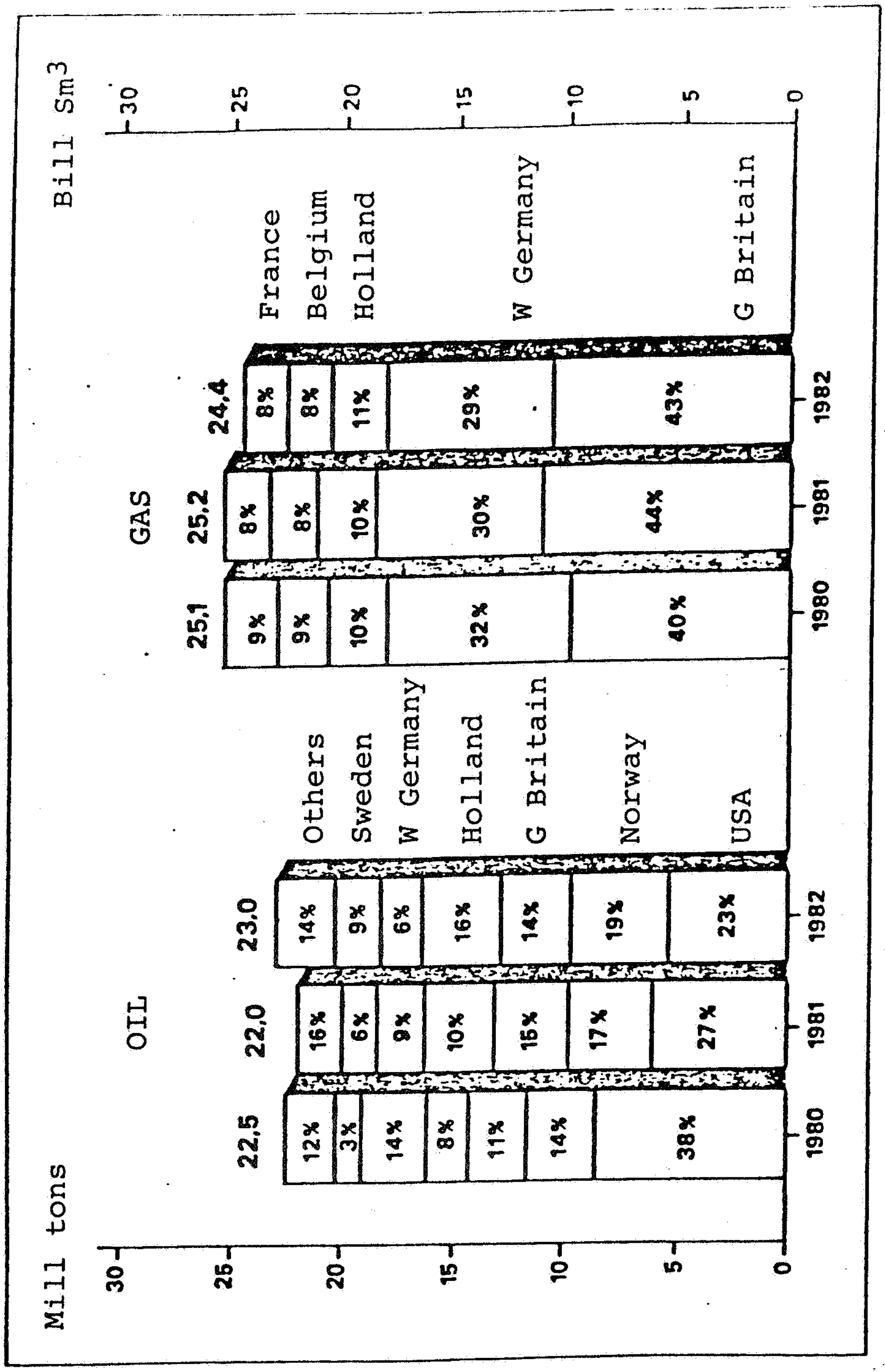
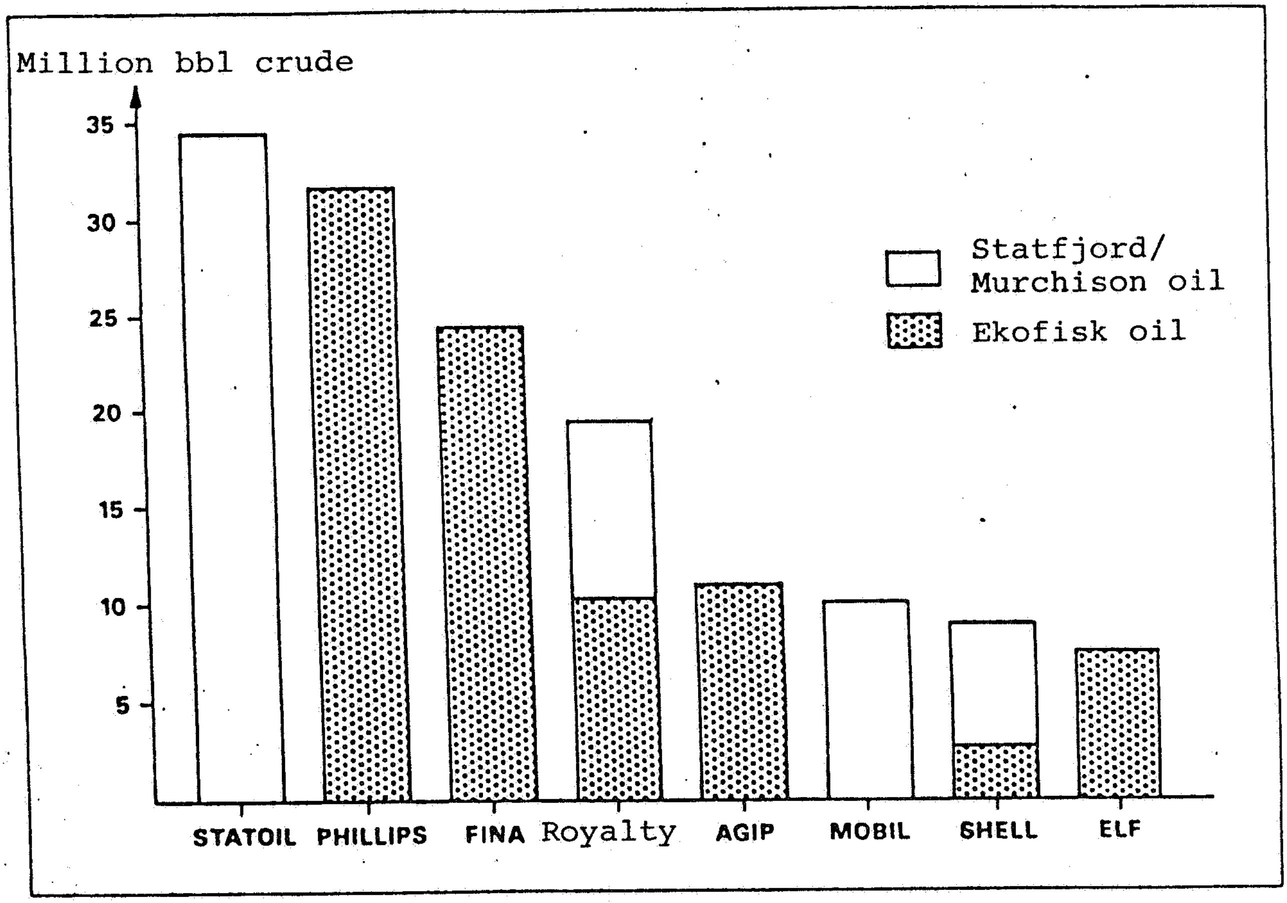


FIGURE 4.4.1.b. Sales of Norwegian crude oil and gas distributed by country (Million tons, Billion Sm3)



Statoil was the licensee on the Norwegian shelf which sold the largest quantity of self-produced crude oil in 1982, about 35 million barrels. In addition, Statoil is in charge of selling the state production royalty oil, which in 1982 amounted to about 19 million barrels. This royalty oil makes up the fourth column in Figure 4.4.1.c.

FIGURE 4.4.1.c. Crude oil sold by licensee and royalties in 1982 (Million barrels crude)



4.4.2 The gas market

The market for Norwegian dry gas is presently limited to Great Britain and the Continent, being bought by West Germany, the Netherlands, Belgium and France. The total 1982 gas exports amounted to 24.4 billion Sm3, of which 10.6 billion Sm3 went to Great Britain and 13.8 billion Sm3 to the Continent. See Figure 4.4.1.b.

Relative to the total consumption in the continental buyer countries in 1982 of 135 billion Sm3, the market share of Norwegian gas was about 10 per cent. With a total consumption in Great Britain of about 50 billion Sm3, the Norwegian share of the British gas market in 1982 was more than 21 per cent.

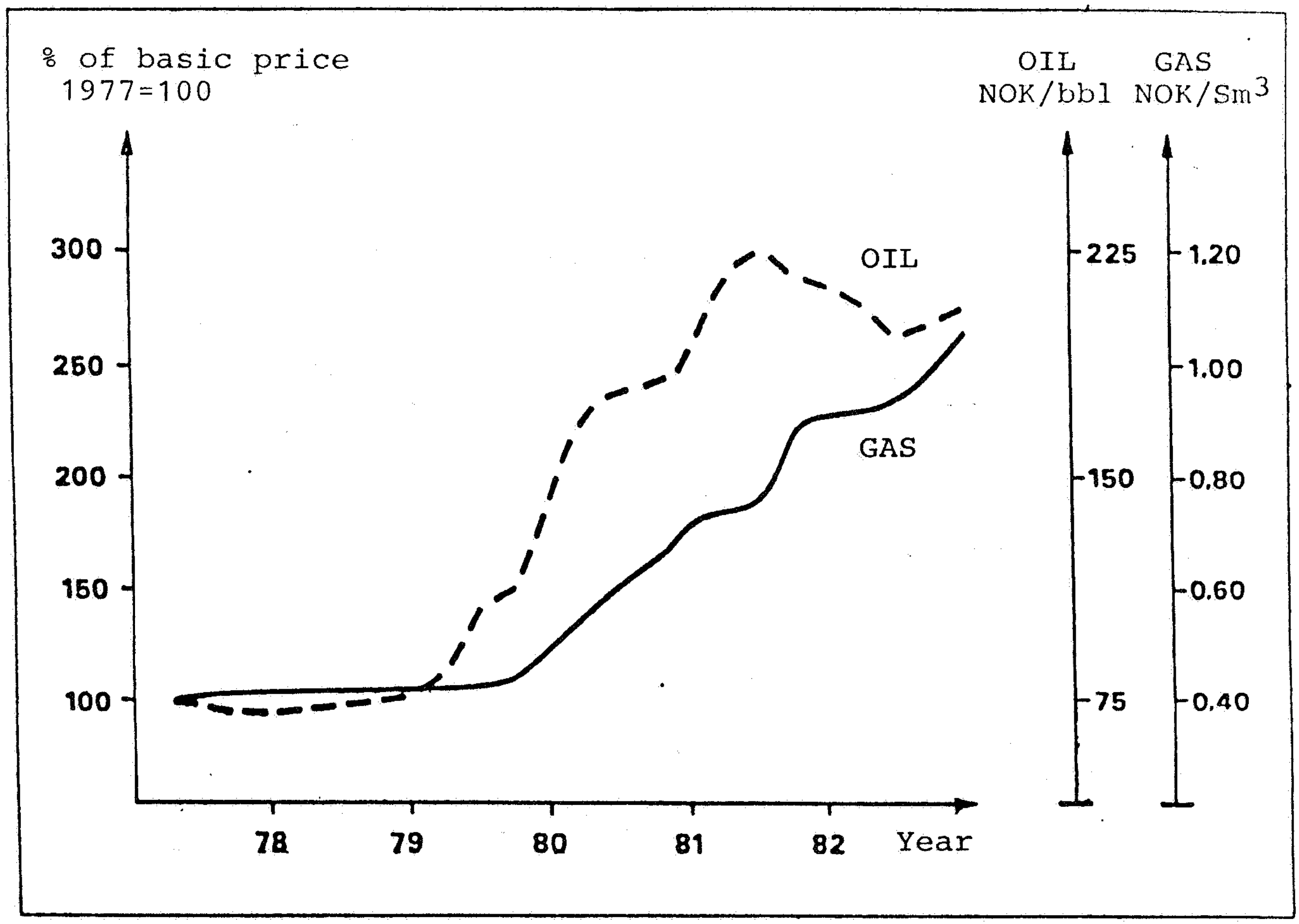
Gas deliveries from the Ekofisk area and Frigg are carried out according to long-term contracts which apply for the duration of field lifetime. The most important non-price terms in the sales contracts relate to delivery quantities, including how much gas the buyer can accept in winter as compared to the summer months.

In 1981, there occurred for the first time a reduction in the consumption of gas in Western Europe. The decrease was mainly due to the low level of economic activity in the period 1980-82, and to the fact that coal and nuclear power have replaced gas as a fuel in industry and for power stations. In the same way, comprehensive energy savings programs have reduced energy consumption as a whole.

The prices quoted in the gas contracts entered into until now have been determined by two factors, a basic price and an escalation formula. The basic price is fixed by negotiations between the buyer and seller at a level which is intended to reflect the competitive situation on the gas market, as well as the parties' demands for capital returns at the time of signing. The escalation formula is designed to tie the contract price to indexes which reflect such factors as the price development of competing oil products, the price development of crude oil, general inflation and exchange rate fluctuations.

Figure 4.4.2.a shows how the average contract price for Norwegian gas has developed in relation to the market price for Ekofisk crude oil.

FIGURE 4.4.2.a. The average price development for Norwegian gas as compared to crude oil (Per cent of norm price 1977

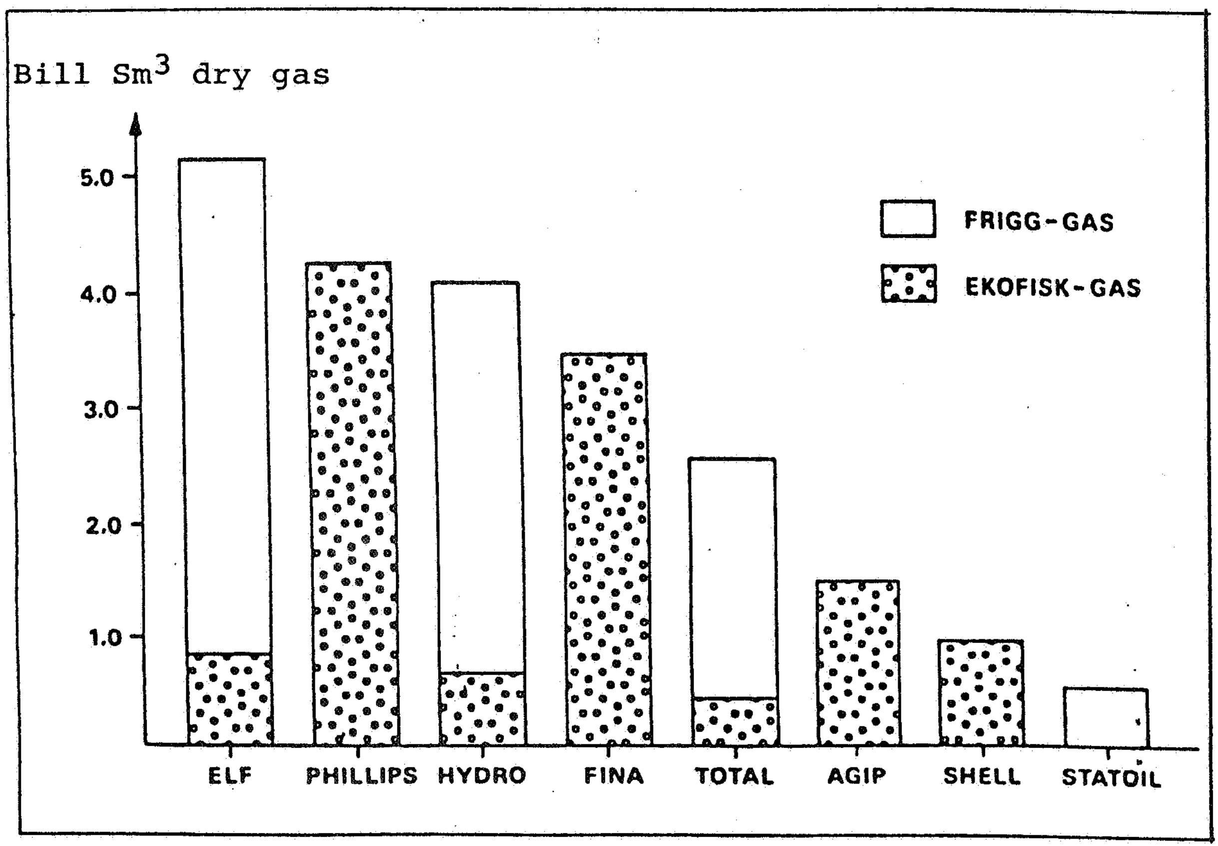


As the figure shows, the contractual provisions for price adjustment have caused a certain time lag between crude oil price movements on the one hand, and the escalation of the gas prices on the other. A reason that curves are not parallell is that the gas price is also influenced by elements other than the price of crude.

It is evident from the figure that gas has experienced a lower price increase percent-wise than crude oil, and that gas prices can increase even in periods when crude oil rates are falling. These factors indicate that in periods of unstable oil prices, the gas price may have a stabilizing effect on the total production income from the activities on the continental shelf.

Figure 4.4.2.b shows not least that Elf Aquitaine was the licensee on the Norwegian shelf which sold the largest quantity of dry gas in 1982, more than 5 billion Sm3. The same year, Norsk Hydro sold a little over 4 billion Sm3, some 3 billion Sm3 of which to British Gas, and 1 billion Sm3 to continental buyer groups.

FIGURE 4.4.2.b. Gas sold per licensee in 1982. (Billion Sm3 dry gas. Frigg and Ekofisk)



5. FUTURE ACTIVITY

5.1 Perspectives for petroleum activities on the continental shelf

In accordance with a request from the Ministry of Petroleum and Energy, the Norwegian Petroleum Directorate prepared a separate perspective analysis, entitled the Perspective Analysis 1982. The following is a summary of this analysis.

The Directorate has chosen to describe possible development paths through the four input factors: investment, labour, operating expenses and the need for technical personnel.

The results of these inputs are shown by oil production, gas production, total hydrocarbon production, and revenues to the state.

A distinction is made between activities on existing projects (Group I fields) and on projects for which there are still no approved development plans. Non-approved fields have been divided into two categories: fields with marked links with activities already started (Group II fields), and fields considered independent of established facilities (Group III fields). The proven recoverable reserves in Groups I, II and III as of 15 June 1986 amount to 1455 million Sm3 oil and 1535 billion Sm3 gas, a total of 2.7 billion tons oil equivalent. Of these amounts, 165 million Sm3 oil and 94 billion Sm3 gas have already been recovered. In addition to proven reserves there are approximately 1.3 billion tons oil equivalent in the form of low-risk, non-proven reserves. Total recoverable reserves in the North Sea are estimated to be almost 5 billion tons oil equivalent. So far 132 billion Sm3 recoverable gas has been proven north of Stad.

Group II includes some minor projects and fields with estimated weak project economy. It seems evident that some of the projects will be realized, but not all. On the basis of economic analyses and an evaluation of the operating companies´ attitudes to the projects, six field have been selected (Ekofisk water injection, Hod, Ula, Tommeliten, 33/9-Alfa, and 33/9-Beta). These represent the "mass" which will probably be developed.

Some of the Group III fields are expected to be developed independently of which other fields it may be resolved to develop (Sleipner, Oseberg, Troll and Gullfaks Phase II). However, the problem of selecting development methods for Group III fields still remains. The options may be illustrated by combining these possible solutions:

- Troll: gas or oil solution.
- Gas fields in the North: development from 1995, or from a point in time beyond the time frame for the perspective analysis (beyond the year 2000).
- Transport capacity for gas: either 32 billion Sm3 per year, or some 50 billion Sm3 per year.

Some of the other Group III fields have been treated in the same way as those in Group II. An attempt has been made to select the method of development of these fields so as to sustain, as far as possible, a uniform activity level.

An economic analysis has been undertaken of the fields covered by the Perspective Analysis. This has been performed in fixed 1982-kroner and with a basic price of NOK 1150 per Sm3 oil and NOK 1.10 per Sm3 gas.

Seventy-five per cent of the reserves considered will show a pretax profit in excess of 20 per cent. An increase in investments and operating expenses of 30 per cent, without a simultaneous real price increase on petroleum, will result in only 23 per cent of the reserves giving such high yields under otherwise similar conditions.

Furthermore, it is presumed that the final development plans for individual fields will make sufficient allowances for the technical requirements to safety and the sound exploitation of the resources. It is also presumed that idle capacity in existing production and transport facilities will be utilized to the degree this is considered desirable in the light of an overall evaluation.

A recent analysis of the availability of qualified personnel in Norway shows that one should consider increasing the Norwegian educational capacity if future demand for petroleum engineers is to be satisfied.

With the exception of a scarcity of some groups of skilled workers, welders with special certificates for instance, Norwegian engineering shops seem to have the capacity to take on a certain portion of anticipated development tasks. Heavy fluctuations in the number of orders may cause difficulty. Another possible problem area is that some workshop units may be too small to take on major assignments.

The capital supply for developments on the continental shelf in general does not seem to represent any problem.

An analysis of ten different development paths shows that a uniform production level does not necessarily require the input factors to remain constant. Thus, a unilateral focusing on production level may create a somewhat over-simplified picture of the petroleum activity. The Norwegian Petroleum Directorate has chosen to concentrate on the input factors because new development tasks will have a more immediate effect on the input side than on the result side.

By combining different sets of assumptions, we see that production can be uniformly increased from the present level of about 50 million tons oil equivalent per year to between 75 and 90 million tons oil equivalent. It is possible to choose either a high gas production or a high oil production, and still attain a total production level with minimal fluctuation. If production is to be sustained at a high level towards the end of the period, some fields will have to be developed which are as yet unproven. It is expected that this can be rectified by deliberate exploration efforts.

The input factors show somewhat greater fluctuations than production. The most obvious movement is a marked decrease in activities in the period 1986-1988. The reason is that the development tasks which were approved in 1981 (Gullfaks, Heimdal and Statpipe) will cause a peak in activities in the first half of the 1980s, and that there are few projects that can directly fill the gap when these tasks are complete.

The Directorate has considered what will happen if the gas landing capacity is not increased, and if only the most probable Group II and Group III projects actually materialize. In such a case, the investment level will fluctuate between 15 and 20 billion 1982-kroner until the early 1990s, and then drop dramatically from 1992. Similar fluctuations are also predicted by other activity indicators.

If the landing capacity for gas is increased from some 32 billion Sm3 to about 50 billion Sm3 per year from the mid-1990s, it will be possible to maintain a more uniform activity in the 1990s. There will still be a certain decrease towards the late 1990s, but this can be avoided in part by making new finds. If a new landing capability is set up in Northern Norway, we will obtain a higher level of activity in the 1990s than if a new pipeline is laid in the south.

The development of the Troll field will be of great significance to the overall activity. As an illustration of the effect that an anticipated major delay can cause, consideration has therefore been given to what will happen if the development of Troll is postponed until after the turn of the century. Even in this case, it will be possible to keep the activity level relatively uniform during most of the period. Towards the late 1990s, there will be a marked decrease in investments and the demand for labour. Any new discoveries made could alter this.

Some of the development assignments will affect opened areas, e.g. 33/9-Alfa and Troll. It is essential that the necessary block allocations take place a reasonable time before field development. Further, a key prerequisite is that exploration and appraisal drilling activities should be adapted to fit in with development strategy, thus providing the best possible reserves basis. This applies to both the southern and northern parts of the continental shelf.

The possibility of governing the direction and level of the activity is no doubt greatest through continuous planning, whereby plans are adjusted in step with changing conditions on the continental shelf and in the market. Fluctuations in the general movements of prices and costs can, for shorter periods, hamper efforts to steer events by limiting the options available in times of poor economic prospects. Under such conditions, it can be relevant to evaluate an adjustment of the framework conditions of the activity, in order to avoid undue effects of the depression.

The analysis shows that the technological and economic challenge of future assignments presupposes conscious efforts in education, research, industry and politics. Such efforts are also required to maintain the flexibility to meet fluctuations on the global market.

In conjunction with measures in the near future, the Norwegian Petroleum Directorate would like to emphasize the following points:

1. By 1984, decisions must be made on new development projects in order to avoid a decrease in the activity towards the late 1980s. Such decisions are also necessary to maintain, and possibly increase, production in the 1990s.

2. Two conditions seem to be central to an evaluation of the various development tasks. First, one ought to decide which input level is best suited to Norwegian interests and circumstances on the basis of an overall social assessment. Second, one should clarify more closely what opportunities exist for the profitable sale of Norwegian gas, and how soon and from which parts of the continental shelf sale would have to take place.

3. Moreover, the sequence and details of pending development tasks should be seen in the light of attitudes to gas exports, the selection of a concept for the first Troll field development, and the possibility of production in Northern Norway.

Consequences and necessary decisions

With the future tasks which Norwegian and foreign operating companies face, Norwegian educational capacities for a number of categories of skilled personnel may become a limiting factor, unless this situation is compensated for by imports of goods and services. For a number of specialties, however, the global market is also tight.

Norwegian operating companies will gradually come to hold a central position in future development. In addition, there are the foreign operators with established expertise. In order to exploit this expertise adequately, it is important to consider the activity level, number of operators, capacity and competence together.

It is very important to prepare the ground in research as well as business by developing expertise, if Norwegian industry is to be able to master the future tasks on the continental shelf.

Most prognoses predict that there will be an increasing demand for gas on the continent and in Great Britain from the early 1990s. These prognoses apply provided there is uniform economic growth (of some 2.0 per cent per year) and no significant change in the relative consumption of the various energy carriers from today.

It is thus important to draw up plans with a view to participating in this market. The results of the analysis show that this is possible for a number of development paths, although these to some extent are also determined by other targets, such as uniform activity and development rate.

Movements in real prices in the coming few years may cause a number of projects to have to be re-evaluated as regards development options, which in turn can cause time dislocations in the implementation of the projects. For this reason, among others, continuous planning of field activities is important, so that one can base future decisions on up-to-date predictions.

The possibilities of steering the activity on the continental shelf will be strongly increased by having an overall plan for future activity by which it is possible to see various factors in connection with each other. Such a plan will make it possible to influence decisions in the desired direction. In the long run, development activities depend on the present mapping and exploration efforts. The extent of these efforts has so far proved to give the necessary flexibility with respect to reserve quantities. It does not appear from this analysis that there is a need for any general change in these efforts. Moreover, it seems important that some gas finds in the North Sea should be studied further in the quite near future. This is in order to have the necessary flexibility to start development of these finds if the expectations of further strikes in Northern Norway are not fulfilled, or if the development of the Troll field has to be postponed for some reason or other.

It is expected that the field development plans for Sleipner, Oseberg and Troll will be presented to the authorities in the course of the next few years. How these fields will be developed will to a great extent determine the total activity level. The number of minor fields developed will primarily be determined by the price trends, available infrastructure and the companies´ willingness to invest.

6. SPECIAL REPORTS AND PROJECTS

During 1982 the Norwegian Petroleum Directorate granted a total of NOK .... for special projects. This was composed of NOK .... for projects for the Safety Control Department, NOK .... for projects for the Resource Management Department, and NOK 733,400 for the Legal and Economic Department. The project titles and research institutions are listed in Tables 6.1, 6.2 and 6.3 below.

TABLE 6.1 Project grants to the Safety Control Department

PROJECT TITLE	RESEARCH INSTITUTION
Mapping of exposure to noise for offshore personnel. Establishment of data for determination of guidelines	Norwegian State Institute of Technology (STI)
Arrangement of regional conferences under the heading of "The oilworker, his family and the community"	Three conferences held
Chemicals in the offshore activity	Joint project by several institutions
Guidelines: radiation protection offshore	The Norwegian Petroleum Directorate (NPD)
Film project: "Organized protection and environmental work on fixed installations"	Informasjonsfilm og Video A/S
Control and evaluation of acrylic windows	Nyborg Plastindustri
Guidelines for specification and operation of dynamically positioned diving vessels	Co-operation Petroleum Directorate/ British authorities
Evaluation of probability of evacuation from mobile installations in the North Sea of divers under compression	Det Norske Veritas (DnV)
Criteria for acceptance of internal control	Firma Organisation & Ledning A/B (An organization and management company)
Study tours in training and control	The Norwegian Petroleum Directorate
Purchase of special maps for the Directorate´s contingency room	The Norwegian Petroleum Directorate
Membership in The Welding Institute	The Norwegian Petroleum Directorate
Participation in the fatigue program	DnV/ SINTEF

Hydrogen induced stress corrosion cracking and hardness of welded structural and pipeline steels	The Welding Institute
Construction regulations	Collaboration: the NPD and consultants
Corrosion control of offshore pipelines II	The Norwegian Petroleum Directorate
Pitting of structures and pipelines	DnV
Corrosion control in seawater at depths down to 500 m	DnV
Membership in CIRIA - UEG	
Mooring and fender systems offshore	Norwegian College of Technology (NTH)
Sacrificial anodes: design procedures, fabrication and installation	DnV
Documentation technique	DnV
Data recording and presentation	DnV
Preparation of revised guidance on underwater inspection	CIRIA - UEG
Further development of drilling data bank	Rogaland Research Institute
Revision of drilling regulations	The Norwegian Petroleum Directorate
Demonstration of pipe handling systems	The Norwegian Petroleum Directorate
Guidelines for documentation of selectivity in alternating current (AC) systems	EU CONSULTANTS
The safeguarding of electric motors in explosion risk areas	The Norwegian Electricity Association's Research Institute (EFI)
Support for the Norwegian Electro-technical Committee (NEK) regarding Norwegian participation in International standardization work with respect to regulations for electrical installations and area classification	The Norwegian Electro-Technical Committee (NEK)
Criteria for acceptance of fire-fighting equipment on the helideck	The Norwegian Petroleum Directorate
Criteria for acceptance of gas turbines	DnV

Criteria for acceptance of subsea production systems	DnV
Develop guidelines for approval of flexible cables and pipes in hydrocarbon systems	DnV
Brittle fracture properties of wellheads and valves: evaluation of requirements	The Welding Institute
Criteria for acceptance of hydrocarbon fire walls	The Norwegian Petroleum Directorate
Registering and localizing of lightning discharges	EFI
Evaluation of operating and emergency procedures	The Norwegian Petroleum Directorate
Revision of diving regulations	The Norwegian Petroleum Directorate
Examination of the influence of node flexibility on the design of jacket structures	Underwater Engineering Group
Environmental stress on marine constructions	The Norwegian College of Technology (NTH)
Inspection techniques under water	DnV
The pitting of structures and pipelines	DnV
Corrosion control in seawater at depths down to 500 m	DnV and the Norwegian Institute for Ship Research

TABLE 6.2 Project grants to the Legal and Economic Department

PROJECT TITLE	RESEARCH INSTITUTION
The accuracy of orifice metering (Nøyaktighet ved måleblending)	Rogaland Research Institute
NEL - automatic sampling of crude oil	National Engineering Laboratory
Production Reporting System (PPRS)	Rogaland Research Institute
Production Royalties Accounting System (PABS)	Kvam Data A/ S
Further development of the Virkmod calculation model	Norconsult A/ S

Maintenance and further development of the company model	Chr Michelsens Institutt
Economic evaluation of the project portfolio on the continental shelf	SINTEF
Economic implication of pipeline reliability	Batelle Geneva Research Centres

TABLE 6.3 Project grants to the Resource Management Department

PROJECT TITLE	RESEARCH INSTITUTION
Reservoir simulation: Troll field	Franlab Consultant
Improved utilization of available energy on production installations offshore	Otter Group/ SINTEF
Acquisition and connecting of reservoir simulation models	Rogaland Research Institute
Stability of oblique and horizontal well bores	SINTEF
Pilot project for reservoir technical simulation - the Statfjord field	The Norwegian Institute for Energy Technology (Institutt for energi-teknikk)
Systems and programming projects	Chr Michelsens Institutt
Calculation of uncertainty in the production prognoses	Chr Michelsens Institutt
Possibilities for utilization of existing installations on the continental shelf	Aker Engineering
The Basement project, cores - age determination	University of Oslo
Geological analysis for Murchison and the Statfjord project	University of Oslo
Further development of database "ILGI"	Rogaland Research Institute
Petro-physical analysis, Troll field	Universities of Bergen and Oslo
Studies of reservoir rock and geo-chemical analyses	The Research Institute for the Continental Shelf
Petrographic analysis of the Ekofisk and Tor formations in the Ekofisk area	University of Aarhus, Denmark

7. INTERNATIONAL COOPERATION

7.1 Northwest European Cooperation

The third Northwest European conference on "Safety and pollution safeguards in the development of Northwest European mineral resources" was held in Oslo on 10-13 May 1982. The participating countries in the international harmonizing work are Belgium, Denmark, Eire, France, the Netherlands, Norway, Great Britain, Sweden and the German Federal Republic.

In addition, the following organizations were represented by observers at the Oslo conference:

- the International Maritime Organization
- International Labour Office
- European Community, Oil Industry
- International Exploration and Production Forum
- International Association of Classification Societies
- International Association of Drilling Contractors.

An essential purpose of the conference was to establish a voluntary system of certification of mobile drilling vessels. The conference proposed the establishment of a system that, among other things, will contribute to continued cooperation with regard to regulations aimed at harmonizing safety rules in the North Sea area.

The conference recommended that the participating countries formally adopt the proposed voluntary system of certification. Norway endorsed the system on 25 June 1982. The participating countries were informed of this by the Norwegian Maritime Directorate in a letter dated 7 July 1982. This means in effect that Norway has accepted the certifying and up-dating precedures recommended by the conference.

During the two-year period 1982-1984, Great Britain will organize the secretarial functions connected with the up-dating of the various safety standards recommended by the conference. Great Britain will also be the host country for the fourth Northwest European conference, scheduled for 1984.

7.2 The International Maritime Organization IMO

In 1982 the Norwegian Petroleum Directorate had one representative on the Norwegian delegation to the IMO's "Sub-committee on Standards of Training and Watchkeeping", 15th session. This sub-committee finalized a recommendation concerning basic safety training of personnel on mobile installations. The recommendation of the sub-committee is scheduled for hearing by the Maritime Safety Commission in June 1983.

The Petroleum Directorate was also represented in the Norwegian delegation to the IMO's "Sub-committee on Ship Design and Equipment", in connection with questions to do with the regulation and supervision of diving systems on ships, etc.

7.3 The European Economic Community EEC

The Norwegian Petroleum Directorate follows the work within the EEC concerning the harmonizing of safety requirements etc related to offshore petroleum activity. Norway has observer status at meetings and conferences etc which are arranged under the direction of the EEC entitled "Safety and Health in the Oil and Gas Extractive Industries".

7.4 Aid to foreign countries

The Norwegian Petroleum Directorate´s aid to other countries through NORAD continued during 1982 in the same pattern as during 1981. The main portion of the aid was directed to two of our major cooperating countries: Tanzania and Mocambique. In Tanzania the tasks had had to do with general assistance in connection with the surveying of the continental shelf, including the evaluation of finds and training of scholarship holders in Stavanger. In Mocambique the tasks were primarily connected with large seismic surveys, concluded during the first half of 1982, and the subsequent interpretation of these. Towards the end of the year, the Directorate was engaged in preparations for the area openings scheduled for next year.

The Petroleum Directorate has also assisted NORAD in the planning and execution of seismic surveys on the Pakistani continental shelf. Furthermore, the Directorate has carried out some evaluations in connection with proposed projects in Burma, Kenya and Guyana, to name a few.

7.5 The International Organization for Standardization ISO

The Norwegian Petroleum Directorate participates in the work of standardizing metering techniques carried out by the International Organization for Standardization ISO. International standards form the basis for metering oil and gas. To contribute to the further development of international standards, the Directorate participates in the technical committees that work with metering standards for oil and gas. Meetings were held in the technical committee for petroleum products and in the sub-committees for metering.

7.6 Jan Mayen

A boundary agreement was reached in 1981 between Norway and Iceland concerning the continental shelf south of Jan Mayen. As part of the boundary agreement, it was agreed to conduct joint surveys with Iceland in a more closely defined area. This area lies partly on the Icelandic side, though the greater part of it is on the Norwegian side. Norway has undertaken to finance the exploration costs, and the Norwegian Petroleum Directorate has been directed to take charge of executing the exploration.

It is considered necessary to shoot approximately 3000 kilometers of seismic surveys in order to define the main geological characteristics of the area. Preparations are already under way, and the actual surveys will take place during 1984.

8. SPECIAL ARTICLE

8.1 Health problems connected with diving

INTRODUCTION

The human body under water is in an alien environment where to survive for more than a few minutes it is dependent on technical supports. The technical and medical problems in diving are complicated ones, and it might be tempting to avoid the problem, for example by using small remote-controlled or manned submersibles having an internal pressure identical to that on the surface. In one of these however, the driver would be physically distant from the tasks, and thereby dependent on the technical equipment on the outside of the submersible in order to perform practical work while submerged. In practice, man is often difficult to replace satisfactorily, because of the close coordination which is possible between his senses and his manual dexterity. In the foreseeable future divers will therefore still be required if we are to recover reserves from the continental shelf.

All day long we inhale air which contains approximately 21 per cent oxygen (O_2), 79 per cent nitrogen (N_2), and lesser amounts of other gases. In the body, these gases are taken up by the body tissue at the same pressure as the atmosphere surrounding us. If a diver gradually descends into deeper water, the surrounding pressure will increase, and the pressure of his breathing gas will have to be increased correspondingly. If a diver is supplied with gas under higher pressure, however, more gas will dissolve in his body tissue. There comes a time when the body cannot absorb any more gas, and it is then said to be "saturated".

Air has following drawbacks:

1. At increasing depths, nitrogen has a gradually increasing narcotic effect, resulting in "depth drunkeness". The diver will behave less and less rationally, eventually becoming a menace to himself and others. Diving with air is therefore only permitted to depths of 50 meters.

2. With increasing depth, and depending on the combination of oxygen pressure and length of exposure, oxygen has unhealthy effects on the lungs and the central nervous system. In practical diving it is therefore necessary to reduce the amount of oxygen in the breathing gas.

3. With increasing depth, respiration becomes more difficult because the elevation of pressure increases the density of the breathing air.

An alternative composition of the breathing gas is therefore crucial in order to descend deeper. Helium is chosen as a substitute for nitrogen. Being an inert gas, helium has minor effects on the body. It is less dense and lighter than air, and therefore when compressed becomes easier to breathe than the latter. Oxygen is added in the correct proportions, thus ensuring that breathing will be safe regardless of depth. A dive to 100 meters involves a total pressure 11 times higher than that on the surface, and at this pressure it is possible to use a mixture containing only 4 per cent oxygen (96 per cent helium), and nevertheless achieve an oxygen pressure within safe limits.

DISEASES REELATED TO DIVING

Decompression sickness

When ascending through the water, the pressure around the body will decrease, thus causing the gases previously dissolved in the body tissue to escape from the body. If the diver ascends too rapidly, the gases will form bubbles in his blood vessels or body tissue. These gas bubbles are what causes decompression sickness (the bends). The mechanism can be demonstrated by opening a bottle of soda water, which contains carbon dioxide (CO_2) dissolved in the liquid. When the cork is removed, the pressure above the liquid is relieved and the gas escapes to form bubbles: the water fizzes.

To rid the body of dissolved gas, the gas must be allowed time to move from the body tissues into the lungs, and thus be exhaled. The time required depends on the depth to which the person dived, and how long he stayed there. When a diver gets the bends, the symptoms may vary from itchy skin to serious paralysis. In order to prevent the sickness, tables have been calculated showing how fast and in what manner ascent should take place, again depending on the depth and duration of the dive.

The medical consequences of having experienced the bends are not clear. There is a correlation between an aseptic bone necrosis and exposure to the bends, though the link is not clear. Most people suffering from the bends exhibit mild symptoms that are easily treated if a decompression chamber is available. The most serious cases, which affect the central nervous system, may lead to permanent disability. Complete clinical recovery is possible through speedy and correct treatment.

Saturation diving is a practical solution which reduces the number of decompression cycles a diver must go through when performing an assignment under water. A pressure chamber system is required, so constructed that the diver may remain in it for an extended period of time. The system maintains an environment in which, among other features, the correct mixtures of breathing gas and temperature are available. The chamber facility is pressurized to the pressure on the sea floor where the work is to be performed. As noted above, the tissues of a diver who remains under such a pressure will in time become saturated with the gas mixture surrounding him.

The diver is lowered from the chamber to the work site in a diving bell, puts on the necessary gear, enters the water and performs his task. While in the water, the diver is connected by an umbilical cord which provides him with breathing gas, a communications link, and heat. Having completed his work period, he returns to the chamber by means of the bell. During the entire period therefore, the diver is under the same pressure, and therefore neither decompresses nor risks getting the bends. On the Statfjord field, which lies under 150 meters of water, approximately 4.5 days are required to bring a diver in saturation back to surface pressure. The method is called saturation diving, and is used daily in the North Sea. A typical saturation period lasts from 16 to 24 days.

Barotrauma

Another problem in ascending is that the gases in the body cavities will expand, and should the gas fail to escape quickly enough through the natural body openings, a relative excess pressure will build up in the cavities and may cause injury. The phenomenon is called barotrauma. Barotrauma of the lungs (pulmonary barotrauma, or lung bursting) may cause gas bubbles to move from the aveoli to the veins, to be carried with the blood to the heart and brain, and there cause serious damage.

Aseptic bone necrosis

This is a condition that can develop in the long hollow bones of people who have been exposed to pressure. There is a connection between decompression sickness and the risk of aseptic bone necrosis, but one cannot be certain just what the connection is. A committee in England is monitoring the condition closely: In a sample of 4890 professional divers, the committee found that 207 (4.2 per cent) suffered from the necrosis. Of the 207, only three divers had suffered disabling injury to their joints. There is no complete record of the number of divers who have been forbidden to dive as a result of the complaint, but during the period 1967-1981, a major English medical center denied four divers permission to dive because of aseptic bone necrosis. Research is being conducted into the causes of the complaint, and it is hoped that preventive measures can be taken. All professional divers are closely monitored for possible aseptic bone necrosis.

The High Pressure Nervous Syndrome HPNS

This condition has been known since 1965. It does not represent a problem at the depths that have been operational in the North Sea to date. From about 180 meters and down it is possible to detect the mildest of symptoms in some divers. The syndrome usually appears as the pressure (compression) increases, and is a function of how rapidly compression builds up and the depth of the dive. In the light of what we know about the syndrome today, it should be possible to perform dives to greater depths than is common practice at present. For example, too rapid compression to great depths may trigger off the symptoms, which are felt as nausea, shivering, short spells of sleepiness (microsleep), lack of concentration, and so on.

Evaluations made by three different agencies in the world in 1982 conclude that, as of today, there is no reason to believe that the high pressure nervous syndrome causes lasting damage to the central nervous system. Continued attention will be given to the condition by broadening practical experience and dedicating research efforts.

Problems with body temperature

On dry land the human body can tolerate fairly wide variations in the surrounding temperature, not least because still air is a poor thermal conductor. When under water, however, increasing depth will cause the breathing gas to become more and more dense: Thus, the same volume of gas can carry with it larger quantities of heat. Water conducts heat well, and the diver must therefore have a means of protecting himself against heat loss. In the North Sea, the common solution is to provide diving suits through which warm water circulates. Heated water is pumped down from the surface to the diver. The general rule in practice is that, from 50 meters on down, active heating of this kind is necessary. From 150 meters, the breathing gas is assumed to have become so dense, and will therefore remove so much heat, that a heating system for the breathing gas is also required. As depths increase even further it becomes necessary, within progressively more narrow limits, to maintain the temperature, not only of the chamber, but also of the man in the water. It is suspected that a too low body temperature has been a contributing factor in several accidents, and in some cases the direct cause of death. The heating system used to maintain the divers´ body temperature has also caused injury in cases where the temperature has become too high. The most common outcome has been minor burns, but some serious accidents have also occurred.

ACCIDENTS AND ACCIDENT PREVENTION IN CONNECTION WITH DIVING

Introduction

Since 1978 the Norwegian Petroleum Directorate has been entrusted with the administrative control of diving operations on the Norwegian continental shelf in connection with the exploration and extraction of submarine natural resources.

The Petroleums Directorate´s Diving Section receives information on work-related personal injuries suffered during offshore activity in connection with diving from various sources: the National Insurance Board, diving contractors, operating companies, physicians, hospitals and the divers themselves. When the information received is inadequate and in the case of every serious accident, the Diving Section itself will gather additional data. The term "accident" is ambiguous and has numerous definitions. In the practical evaluation of an accident, three main elements must be considered:

- the reasons the incident took place
- the consequences of the incident
- the type and seriousness of the consequences.

It is customary to examine occupational injuries in the light of such factors as the exposed working population, type of activity, duration of exposure and the like. But the number of divers working in the extraction of petroleum resources in the whole of the North Sea is conservatively estimated at approximately 2000, of whom about 10 per cent are Norwegian. Consequently, the diving population is a small one. The scope of diving activities on the Norwegian continental shelf remained relatively stable during the four-year period from 1978 to 1981, with an annual average of 167,000 hours in saturation, and 1440 surface based dives. A further problem is that an examination of diving must necessarily include a number of criteria which are of little significance in other trades, modified human function for example, the alien environment, and the comprehensive technological systems necessary to protect the diver. For these reasons it is difficult to apply the statistical methods normally used for accident evaluations of large occupational groups to the diving population.

During the period 1978-1981, the Norwegian Petroleum Directorate received 224 reports dealing with divers who experienced illness or were injured, see Figures 8.1.a and 8.1.b. Of this number, 121 had to do with decompression sickness.

Decompression sickness

The health related consequences of having experienced decompression sickness (the bends) are discussed above. In order to study possible long-term effects, it is necessary to keep a record of the people who have suffered from it.

The bends is a sickness caused when the pressure surrounding a diver falls off too abruptly. Therefore, on the basis of research and practical experience, tables have been set up showing how the fall in pressure ought to be managed: the Decompression Tables. If a diver gets the bends despite the use of a decompression table, three possible reasons must be considered:

1. the decompression table is not being followed
2. the table is not adequate
3. special factors are causing the diver to suffer the bends anyway.

It is reasonable to assume that the tables were not followed in some of the cases. In others, the tables were modified on the basis of previous experience. This latter category is hard to judge because different divers have different susceptibility to the bends. Variations may even occur in the reactions of one individual diver at different times. We are aware of a number of contributing factors and are attempting to identify and counteract them.

The most effective treatment for the bends is to again subject the diver to increased pressure, and give him increased amounts of pure oxygen to breathe. The safest manner in which to achieve this is by using a pressure chamber. For dives in the North Sea to depths over 10 meters, a pressure chamber in readiness on the surface is mandatory. In the treatment of the bends, other special tables are used: the Recompression Tables. When evaluating the result of recompression treatment, the evaluation should correspond to that for decompression tables. Recompression tables are thus the subject of constant improvement, thus reflecting the evolution taking place within medical science areas.

Most cases of the bends on the Norwegian continental shelf during the period were mild and could be treated on the spot. As far as is known, none have led to lasting problems for the divers. There have not been any deaths or permanently disabling injuries. The reports received show an encouraging reduction in the number of cases of the bends.

Other injuries from accidents

Figure 8.1.a gives a breakdown of all injuries occurring during hyperbaric conditions. Decompression sickness was considered above, and of the other injuries occurring under pressure, most resulted from falls, blows etc. The most important thing in the assessment of accidents of this kind is whether they can be traced back to special aspects of the hyperbaric installation, the equipment or the procedures being followed.

One type of diving accident that requires closer examination is this: the diver is supplied the wrong gas mixture, containing too little or no oxygen. Procedures and technology have been developed to ensure that the diver receives the correct amount of oxygen all the time. A fault in the oxygen supply is therefore of enormous importance: in a matter of seconds it may kill the diver. Expressed differently, seconds may make the difference between a close call and death.

However, one detail study of such an accident found that, among the causal factors precipitating the event, there was no appreciable contribution from technical defects or mechanical failure: The main bulk of the contributions could be traced to human factors.

Conclusion

To reduce the probability of diving accidents occurring, and to limit the consequences of them if they do, must be the twin objectives of accident registration. The nature and potential seriousness of the consequences must determine the effort required and expected in the prevention of accidents. The consequences may be instantly apparent, or they may only emerge a long time after the accident. Therefore, our efforts must be constantly assessed in the light of what is known, and what new knowledge is acquired. The amount of information on the technical, medical and physiological aspects of diving is considerable, and new information and knowledge is being gathered constantly. This necessitates a solid interdiciplinary expertise for the assessment of diving mishaps. The registration of diving accidents is a useful tool in the prevention of such accidents. But the uses to which information gathered from accident registration is put must conform with real-life possibilities and realistic expectations.

During the period, the study of accidents has led to changes in the procedures of certain diving operators. In some instances, the Petroleum Directorate has issued safety bulletins to all diving operators. In the near future, new guidelines for diving will be made available, in which the experiences gained from reported accidents are taken into account. Personal qualifications are of importance for safety, and a licensing system for divers has been introduced based on qualifications.

The total number of reports shows a decline for the four-year period 1978-1981 (Figure 8.1.b). The fact that the ratio between the number of divers having suffered the bends and those struck by other accidents remained relatively constant, together with our general impression of the diving activity, gives us reason to believe that the reports submitted were correct. The drop in the aggregate number of reports per year may thus guardedly be interpreted to indicate that diving operations are safer now than they have been. Because the diving population is so small, however, a single accident affecting several divers radically upturn the statistics.

A more solid basis for the assessment of accidents would be created if international cooperation in the North Sea area could be worked out among the diving operators, the operating companies, the official regulatory bodies involved, as well as the well qualified research institutions.

FIGURE 8.1. Accidents reported which were due to or took place under increased surrounding pressure (hyperbaric conditions)

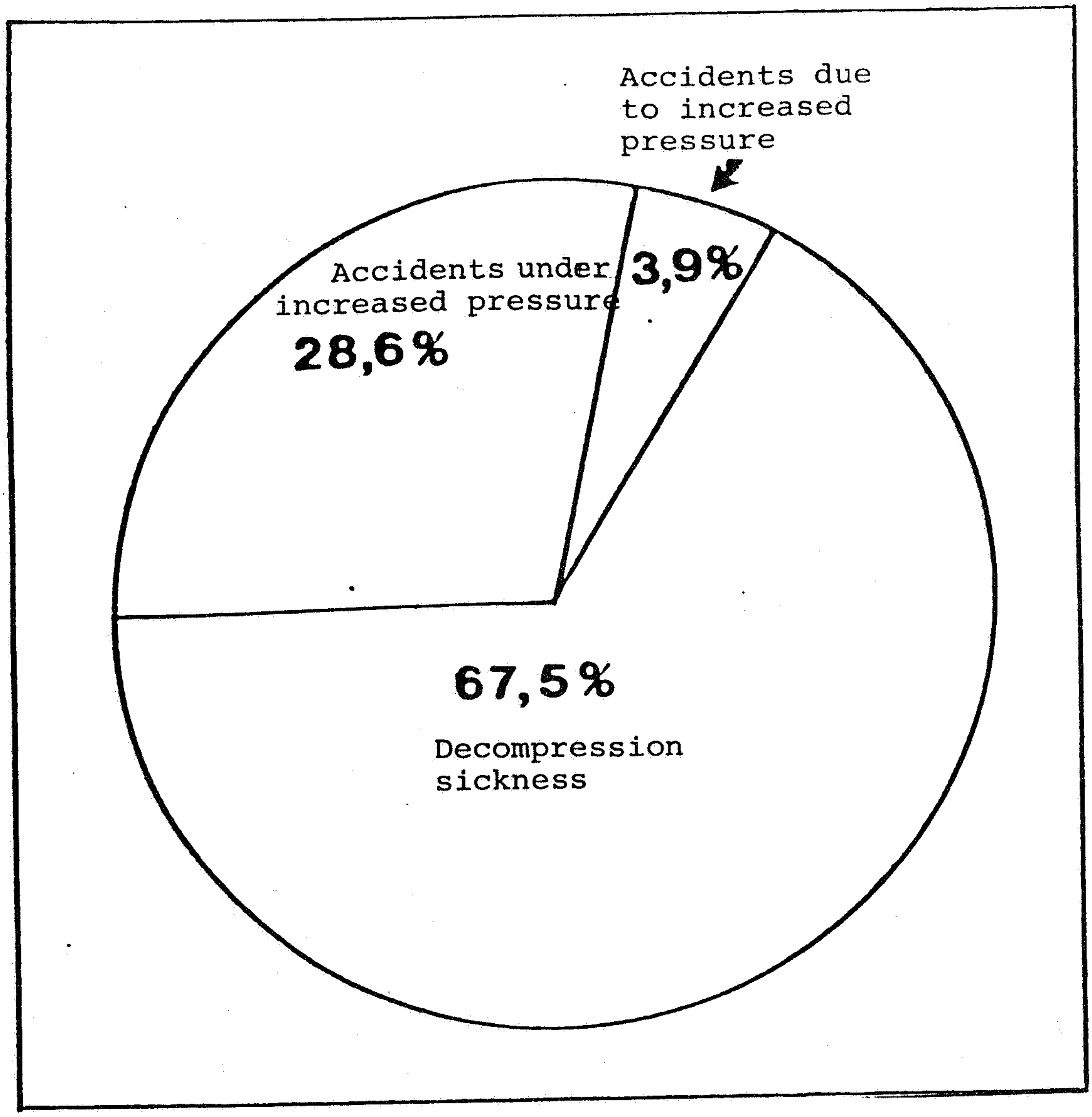
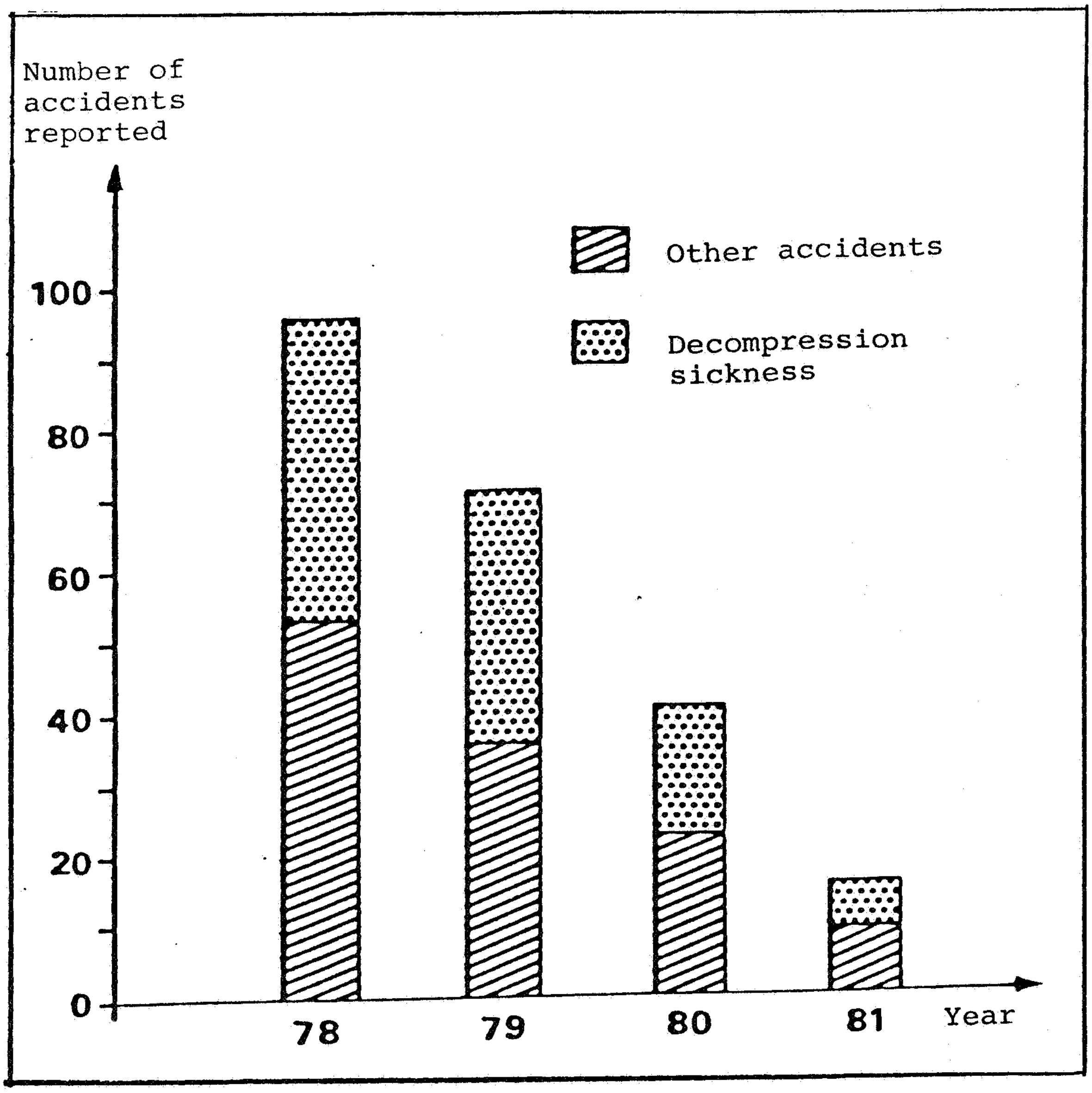


FIGURE 8.2. Total number of reports received 1978–81



9. STATISTICS AND SUMMARIES

Units of measurement

In line with common Norwegian practice for measuring units, the Norwegian Petroleum Directorate would normally use the units of the 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 traditional and practical reasons.

In Table 9.1, physical entities are tabulated along with the SI-units most often used for them. Formulas to convert from other units into the corresponding SI-unit are also given.

Furthermore, there are some concepts and abbreviations which are often used in connection with production data for oil and gas, and which are related to the measuring units. Some of these are briefly dealt with below.

Measurement - oil

An exact measurement of an oil quantity by volume (barrels or cubic meters, m3) 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 "standard state" or "reference state". The two most common reference states are a) 60oF, 0 psig and b) 15oC, 1.01325 bar.

Pressure and temperature standards other than these may also occur. One should note that expressions like "standard state", "barrels under standard conditions", etc are ambiguous unless the pressure and temperature referred to are known.

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. The Norwegian Petroleum Directorate is working to have this reference condition accepted for its own internal use and for reports from the oil companies.

Exact conversion of an oil volume from one temperature and pressure to another requires the use of special tables. For estimated values, however, the volume at 60oF, 0 psig corresponds to all intents and purposes to the volume at 15oC, 1.01325 bar

Normal units/ abbreviations:

Sm3 = 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 60oF and 0 psig.

Conversion

1 Sm3 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 refers. Four reference states are normally employed: a) (60oF, 14.73 psia), b) (60oF, 14.696 psia), c) (15oC, 1.01325 bar), d) (0oC, 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 than in state (d).

Normal abbreviations:

SCM or Sm3 = Standard cubic meter.

Nm3 = Normal cubic meter.

Scf (Scuft) = Standard cubic feet.

Temperature and pressure references must be given for the unit to be unambigious.

Conversion

1 Sm3 corresponds to approximately 0.95 Nm3
1 Sm3 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 hydrocarbon is made up of light components.

Oil:

(a) Specific Gravity 60/60oF
The relative density of oil in relation to water. Oil and water at temperature 60oF and pressure corresponding to atmospheric at the place of measurement. The figure is undenominated.

(b) API-Gravity at 60oF:
Specific Gravity 60/60oF expressed on an enlarged scale. Units are oAPI. Conversion by this formula:

$$\text{API-gravity at 60oF} = \frac{141.5}{\text{Specific Gravity 60/60oF}} - 131.5$$

(c) Density at 15oC:
Absolute density at temperature 15oC 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 at which the densities for gas and air have been measured, 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 Sm3 gas. This conversion factor is very easy to use, 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 Sm3 gas

TABLE 9.1 Some units of the SI system with conversion factors to other units. (Ref. BO R-1000, API Publ. 2563)

Size	Unit from the SI-system	Abbreviation	Conversion formula	Comments
Length	meter	m	Inches x 0.0254 Feet x 0.3048 Yards x 0.91440 Miles (US st.) x 1609.344	
Mass	Kilogrammes	kg	Pound-mass (lbs avoirdupois) x 0.45359237 Long tons x 1016.047 Short tons x 907.1847 Tonn x 1000 (permissible in the SI-syst.)	
Temperature	Kelvin	K	°Celcius + 273.15 Rankine x 5/9	
	°Celcius		(°F-32) x 5/9	
Amount of substance	Mol	Mol		Elementary units (atoms, molecules, etc.) must be stated
Area	Square meter	m^2	Acre x 4046.856 Foot x 0.09290304 Inch x 0.0006451600	
Volume	Cubic meter.	m^3	Barrel x 0.1589873 $Foot^3$ x 0.02831685 Acre ft x 1233.5 US Gallon x 0.0037854	Note! Accurate statement of volume, oil or gas includes information about pressure and temperature reference. Approximate conversion of oil and gas volume is: To Sm^3 oil:Barrels x 0.159 To Sm^3 gas:Nm^3 gas x 1.055 Scuft x 0.0283
Density	Kilogramme per cubic meter	kg/m^3	$\frac{141.5}{°API + 131.5}$ x 1000, lb/gallon x 119.83 lb/barrel x 2.8530, lb/cuft x 16.018	
Force	Newton	N	Pound-force (lbf avoirdupois) x 4.448221615260 kp x 9.806650	
Pressure	Pascal	Pa	Bar x 100000 (Bar permissible in SI-syst.)	1 Normal atmosphere=1.01325 bar 1 Techn. atmosphere=0.9806650 " $1kp/cm^2$ corresp. to 1 technical atmosph. $1kg/cm^2$ corresp. to 1 technical atmosph.
	Bar	–	mm Hg x 0.00133322 psi x 0.0689475731	
Energy	Joule	J	Calories x 4.19 (approximately) Btu x 1060 (approximately)	The calorie and Btu units must be more accurately specified for accurate conversion
Effect	Watt	W	hp x 735.499	English/American horse power is not unambiguous. Normally approx. 745 w. Watt is defined as Joule pr. second
Dynamic viscosity	Pascal-second	Pa-s	Poise x 0.1, lbm/ft - sec x 1.4882	
Chinematic viscosity	meters squared per second	m^2/s	Stoke x 10^{-4}	Defined as dynamic viscosity divided by density

See text for further description of constants.

9.2 Exploration and appraisal wells on the Norwegian continental shelf

Since exploratory activities for petroleum started in 1966 in the Norwegian sector of the North Sea, a total of 360 exploration and appraisal wells had been spudded as of 31 December 1982. Of these, 349 had been completed by the same date.

Information from these wells is presented statistically to illustrate some features of the activities.

A total of 1,131,801 meters was drilled in the wells which are included here, of which 155,299 meters in 1982.

The average penetration of the 51 wells drilled to total depth in 1982 was 3314 meters. Forty-nine wells were spudded during the year.

To drill the wells for which data are given here, 49 different drilling rigs were employed, five of them under two different names. Of these, 35 were of the semi-submersible type, nine were jack-ups, three were drill ships and two were fixed installations. In 1982, a total of 19 drilling rigs operated on the Norwegian continental shelf.

The deepest well in the Norwegian part of the North Sea is the British Petroleum operated Well 30/4-1. Drilling started here in November 1978, and was completed in March 1979 at a depth of 5430 meters.

The greatest depth of water drilled in so far is 388 meters. The well was 34/2-3, drilled in 1981 with Amoco as operator.

TABLE 9.2.a Twenty-four hour rig days on the Norwegian continental shelf in 1982

Rig name	First quarter	Second quarter	Third quarter	Fourth quarter	Total
Alladin		80	34		114
Borgny Dolphin		69	81	76	226
Borgsten Dolphin	89	91	51	92	323
Byfjord Dolphin				53	53
Cod Plattform				3	3
Deepsea Saga	86	88	55		229
Dyvi Alpha	89	83	78	92	342
Dyvi Delta	80	72	92	85	329
Glomar Biscay II	86	90	88	53	317
Nordraug	54	77	91	83	305
Nortrym	87	62	88	89	326
Ross Rig	89	91	32		212
Sedco 703	70	91	92	61	314
Sedco 704	90	51			141
Sedco 707	90	39	83	80	292
Treasure Scout		68	80	89	237
Treasure Seeker	78	87	89	90	344
West Vanguard				88	88
West Venture	90	71	37		198
Total per quarter	1,078	1,210	1,071	1,034	4,393

TABLE 9.2.b Rig months per quarter 1966–1982

Year	First quarter	Second quarter	Third quarter	Fourth quarter	Total per year
1966			2	3	5
1967	3	3	5	6	17
1968	5	11	9	8	33
1969	6	7	9	6	28
1970	5	8	16	15	44
1971	12	12	14	9	47
1972	9	13	18	13	53
1973	5	7	10	17	39
1974	19	15	8	12	54
1975	9	16	17	13	55
1976	17	8	13	8	46
1977	5	10	17	18	52
1978	10	14	14	11	49
1979	15	14	20	25	74
1980	32	29	34	35	130
1981	34	31	32	39	136
1982	36	40	36	34	146
Total per quarter	224	238	274	272	1,008

TABLE 9.2.c Wells per operator company

Statoil	62 wells
Phillips	51
Esso	44
Elf	36
Norsk Hydro	35
Amoco	32
Shell	25
Saga	18
Mobil	17
BP	14
Conoco	12
Gulf	5
Murphy	4
Texaco	2
Agip	1
Syracuse	1
Union Oil	1
Total	360 wells

TABLE 9.2.d Wells spudded in 1982

Statoil	15 wells
Norsk Hydro	12
Saga	5
Shell	5
Esso	5
Elf	3
BP	3
Phillips	1
Total	49 wells

TABLE 9.2.e Seasonal variations 1966-1982

Month	Number of wells spudded
January	17
February	20
March	18
April	35
May	28
June	38
July	42
August	41
September	30
October	34
November	26
December	31
Total	360

TABLE 9.2.f **Average water depth and total depth**

Year	Average water depth (m)	Average total depth (m)
1966	110	2737
1967	93	2599
1968	75	3495
1969	70	3143
1970	89	2983
1971	82	3101
1972	79	3712
1973	86	3089
1974	109	3078
1975	109	2954
1976	124	2949
1977	94	2719
1978	109	3502
1979	153	3375
1980	176	3115
1981	181	3235
1982	162	3314

TABLE 9.2.d **Drilling rigs that have been active on the Norwegian continental shelf**

Name	Number	Rig type
Alladin	1	Semi-submersible
Chris Chenery	2	Semi-submersible
Borgny Dolphin (prev. Fernstar)	13	Semi-submersible
Borgsten Dolphin (prev. Haakon Magnus)	6	Semi-submersible
Byfjord Dolphin (prev. Deepsea Driller)	8	Semi-submersible
Cod Plattform	1	Fixed install´n
Deepsea Driller (now Byfjord Dolphin)	8	Semi-submersible
Deepsea Saga	17	Semi-submersible
Drillmaster	6	Semi-submersible
Drillship	1	Drilling ship
Dyvi Alpha	15	Semi-submersible
Dyvi Beta	7	Jack-up
Dyvi Gamma	1	Jack-up
Dyvi Delta	4	Semi-submersible
Ekofisk B	1	Fixed install´n
Endeavour	2	Jack-up
Fernstar (now Borgny Dolphin)	3	Semi-submersible
Haakon Magnus (now Borgsten Dolphin)	2	Semi-submersible
Gulftide	3	Jack-up
Glomar Biscay II (prev. Nordskald)	13	Semi-submersible

Glomar Grand Isle	11	Drilling ship
Maersk Explorer	7	Jack-up
Neptune 7 (prev. Pentagone 81)	12	Semi-submersible
Nordraug	8	Semi-submersible
Norjarl	3	Semi-submersible
Nordskald (now Glomar Biscay)	26	Semi-submersible
Nortrym	12	Semi-submersible
Ocean Tide	5	Jack-up
Ocean Traveler	9	Semi-submersible
Ocean Victory	1	Semi-submersible
Ocean Viking	29	Semi-submersible
Ocean Voyager	2	Semi-submersible
Odin Drill	3	Semi-submersible
Orion	7	Jack-up
Pentagone 81 (now Neptune 7)	1	Semi-submersible
Pentagone 84	3	Semi-submersible
Polyglomar Driller	11	Semi-submersible
Ross Rig	28	Semi-submersible
Saipem II	1	Drilling ship
Sedco H	2	Semi-submersible
Sedco 135 F	2	Semi-submersible
Sedco 135 G	1	Semi-submersible
Sedco 703	3	Semi-submersible
Sedco 704	3	Semi-submersible
Sedco 707	6	Semi-submersible
Sedneth I	3	Semi-submersible
Transworld Rig 61	2	Semi-submersible
Treasure Scout	4	Semi-submersible
Treasure Seeker	14	Semi-submersible
Waage Drill	2	Semi-submersible
West Vanguard	2	Semi-submersible
West Venture	3	Semi-submersible
Zapata Explorer	13	Jack-up
Zapata Nordic	5	Jack-up
Total	360	

9.3 Production of oil and gas in 1982

The production of oil and gas on the Norwegian contintental shelf in 1982 was 48.9 million tons oil equivalent, compared with 48.7 million toe in 1981. In Table 9.3.a and Figures 9.3.a and 9.3.b, the production on the Norwegian continental shelf is presented in more detail.

FIGURE 9.3.a Oil and gas production on the Norwegian continental shelf in million tons oil equivalent 1974-1982

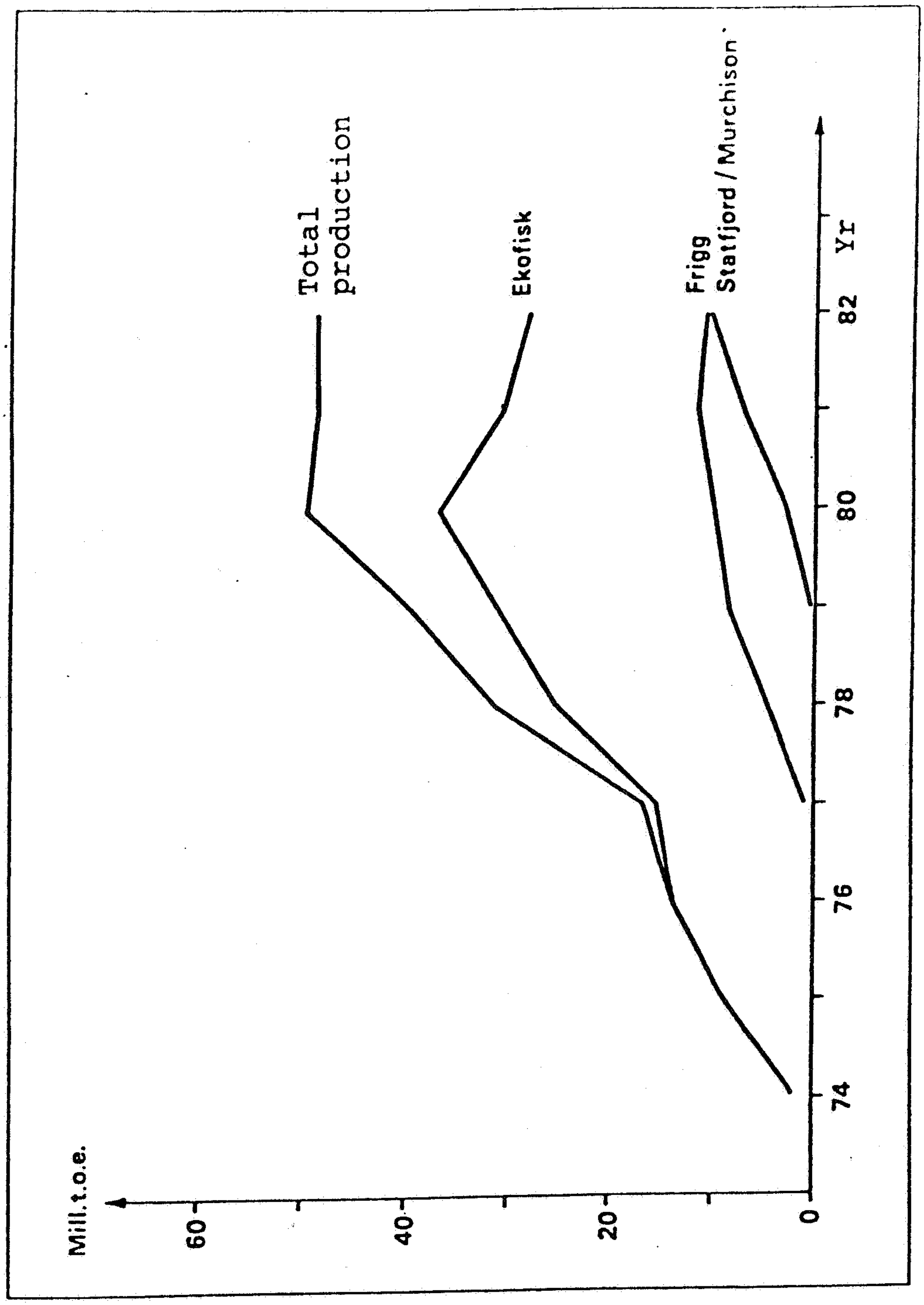


FIGURE 9.3.b Crude oil and gas production on the Norwegian continental shelf 1974-1982

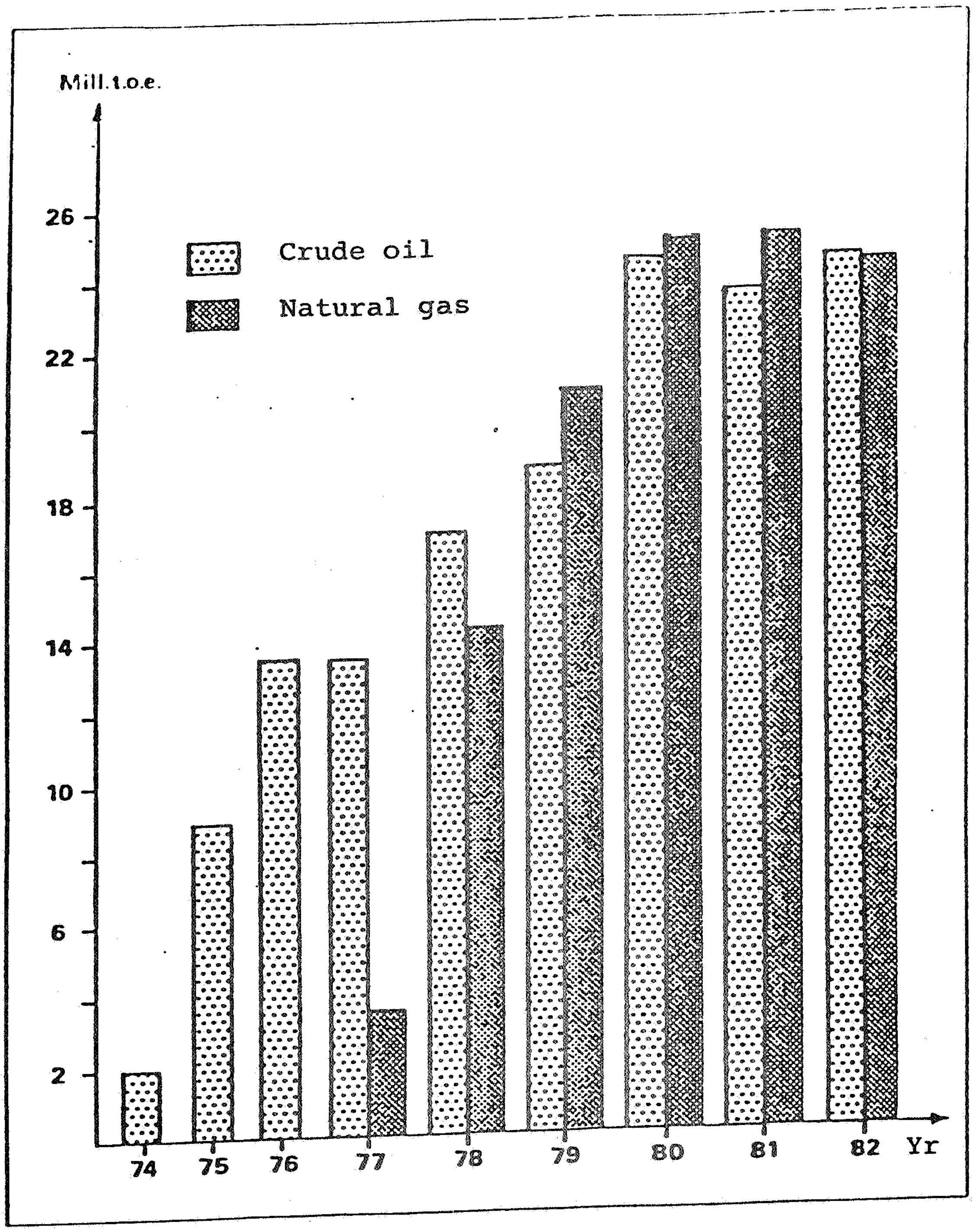


TABLE 9.3.a Production of oil and gas (in million toe)

1982	OIL	GAS	TOTAL
Ekofisk area	14 100	13 795	27 894
Statfjord	9 459	0	9 459
Frigg area	0	10 614	10 614
Valhall	0 067	0	0 067
Murchison	0 858	0	0 858
Total 1982	24 484	24 409	48 892
Total 1981	23 507	25 200	48 706

- The figures state the Norwegian shares of Statfjord, Frigg and Murchison: 84.09322 %, 60.82 % and 16.25 %.
- NGL is included in the figures for oil produced.
- The figures for gas indicate quantities sold.

TABLE 9.3.b Monthly oil and gas production from Statfjord in 1982

1982	Oil prod. stable oil 1,000 Sm3	Gas prod. mill. Sm3	Gas inj. mill. Sm3	Gas flared mill. Sm3	Gas fuel mill. Sm3
January	881	153	126	9	8
February	820	138	122	9	7
March	899	153	135	9	9
April	1 021	177	161	7	9
May	1 030	174	155	9	10
June	665	115	101	8	6
July	993	173	155	8	9
August	976	173	154	10	8
September	761	139	124	7	7
October	716	134	121	6	7
November	1 260	223	164	46	13
December	1 377	243	187	41	15
1982 total	11 397	1 994	1 716	169	109

- The figures include the Norwegian share of Statfjord: 84.09322 %

TABLE 9.3.c Monthly oil and gas production from Murchison

1982	Oil prod. stable oil 1,000 Sm3	Gas prod. mill. Sm3	Gas inj. mill. Sm3	Gas flared mill. Sm3	Gas fuel mill. Sm3	Stable oil Sullom Voe 1,000 Sm3
January	81	8	1	6	1	81
February	79	8	2	5	1	79
March	83	8	2	3	1	86
April	81	8	2	3	1	83
May	91	9	4	2	1	94
June	93	9	3	3	0	95
July	84	8	1	4	1	87
August	82	8	3	2	1	85
September	86	8	3	2	1	88
October	83	8	2	4	1	86
November	97	10	3	4	1	100
December	95	10	2	4	1	95
1982 total	1034 x)	101	28	42	8	1059 x)

- The figures give the Norwegian share of Murchison: 16.25 %

x The difference between Oil Produced and Stable Oil Sullom Voe is due to allocation factors.

TABLE 9.3.d Monthly oil and gas production on the Ekofisk field 1982

1982	Oil prod. stable oil 1,000 Sm3	Gas prod. mill. Sm3	Gas inj. mill. Sm3	Gas flared mill. Sm3	Gas fuel mill. Sm3	Stable oil Teesside 1000 Sm3	Gas sold Emden mill. Sm3
January	1 770	1 490	2	6	81	1 589	1 409
February	1 515	1 341	0	4	68	1 350	1 260
March	1 719	1 478	4	5	90	1 503	1 402
April	1 659	1 397	0	4	85	1 455	1 324
May	1 365	1 176	4	7	77	1 202	1 111
June	1 531	1 229	97	6	62	1 361	1 039
July	1 511	1 235	174	5	64	1 312	992
August	1 529	1 236	196	7	64	1 352	984
September	1 417	1 202	152	4	60	1 241	981
October	1 284	1 036	30	3	51	1 127	947
November	1 483	1 253	8	4	59	1 278	1 170
December	1 511	1 285	36	3	64	1 310	1 174
Total	18 292	15 384	703	57	826	16 079	13 795

TABLE 9.3.e Monthly gas and condensate production from the Frigg area

1982	Gas prod. mill. Sm3	Gas flared mill. Sm3	Gas fuel mill. Sm3	Gas sold St. Fergus mill. Sm3	Condensate St. Fergus ton
January	1 169	0	5	1 216	4 594
February	1 049	0	4	1 089	4 347
March	1 158	0	5	1 204	4 068
April	1 048	0	4	1 094	3 022
May	774	0	2	812	2 418
June	521	0	2	551	2 484
July	482	4	2	514	1 623
August	369	0	2	392	1 314
September	467	0	2	498	1 316
October	941	0	3	976	2 396
November	1 040	0	3	1 086	3 712
December	1 132	0	4	1 184	4 569
1982 total	10 151 x)	5	36	10 614	35 864

- The figures represent the Norwegian shares of Frigg: 60.82 %, and North East Frigg: 100 %.

x The difference between Gas Produced and Gas Sold is due to factors relating to allocation.

TABLE 9.3.f Monthly oil and gas production allocated to Valhall 1982

1982	Oil prod. incl. NGL 1,000 Sm3	Gas prod. mill. Sm3	Gas inj. mill. Sm3	Gas flared mill. Sm3	Gas fuel mill. Sm3	Stable oil Teesside 1000 Sm3	Gas sold Emden mill. Sm3
October	6	2	0	2	0	6	0
November	33	5	0	4	1	33	0
December	48	10	0	6	3	47	0
1982 total	87	18	0	13	5	85	0

9.4 Royalty

In 1982, a total of NOK 5,757,089,074 was paid in as royalty. Table 9.4.a shows how the total royalties broke down among the various petroleum products. The total royalties for 1981 and 1982 are illustrated as columns in Figure 9.4.a, while Figure 9.4.b records the royalties paid in from 1973-1982.

TABLE 9.4.a Royalties 1981-1982 (NOK)

	1981	1982
Oil Ekofisk	2 647 725 781	1 865 906 281
Oil Statfjord	1 085 598 769	1 572 124 252
Production bonus (Statfjord)		25 000 000
Oil Murchison	62 270 657	97 479 895
Gas Ekofisk	963 852 359	1 174 163 613
Gas Frigg	505 861 255	945 373 212
NGL Ekofisk	37 019 877	70 993 200
Condensate Frigg	5 968 265	5 831 606
LPG Murchison		216 965
	5 308 296 963	5 757 089 024

FIGURE 9.4.a Royalties in 1981 and 1982

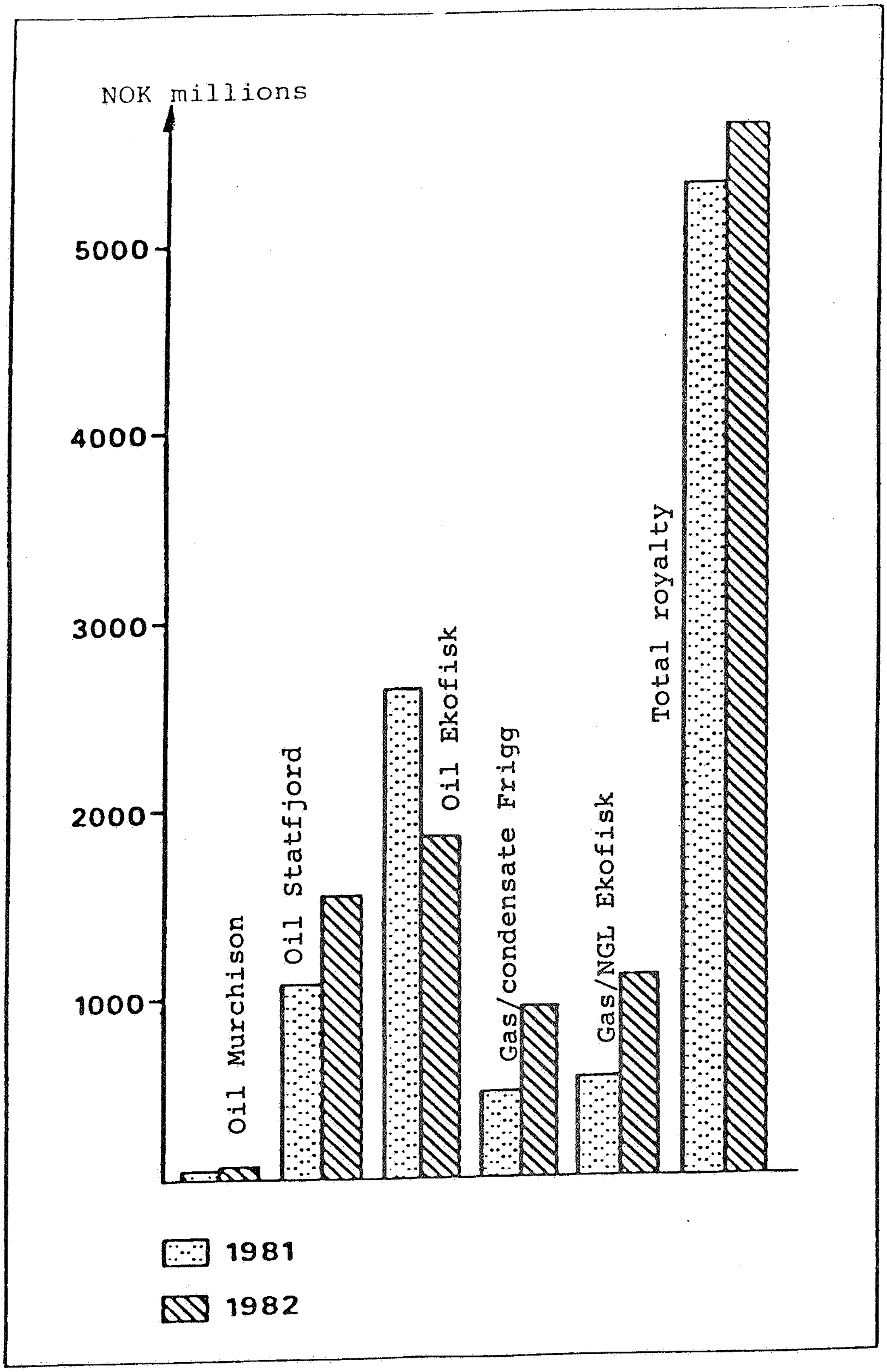
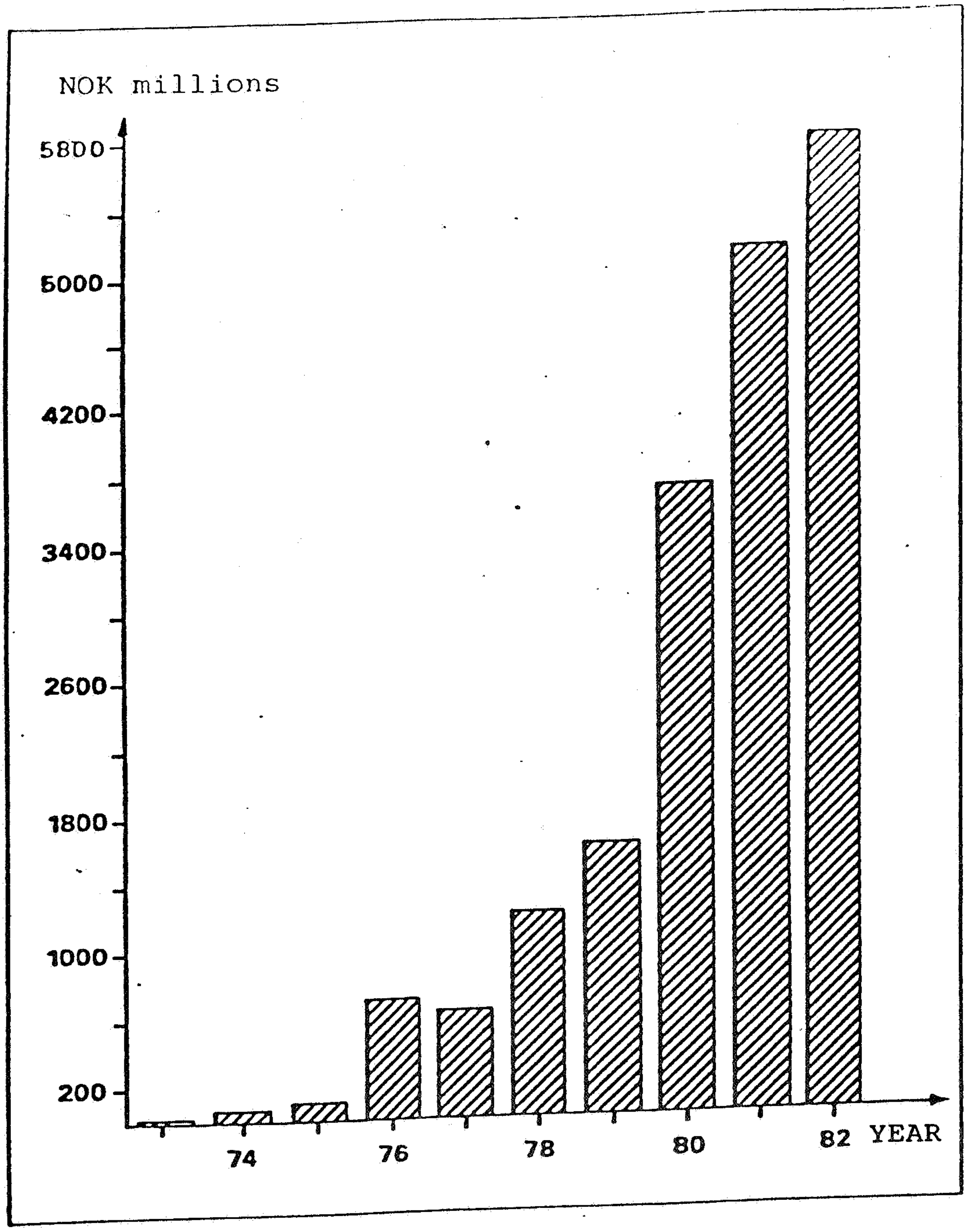


FIGURE 9.4.b Total royalties 1973-1982



Oil royalties

The Norwegian Petroleum Directorate received royalties amounting to NOK 3,535,510,428 in 1982 for crude oil from the Ekofisk area, Statfjord and Murchison.

Assessments for crude oil in 1982 were made in accordance with the price norm. Royalties were paid in quarterly as tabulated below:

Royalties on Ekofisk

1982		Royalties paid
Provisional statement 4. quarter 1981	NOK	516 030 979
Price adjustment 3. & 4. quarter 1981		39 802 473
Provisional statement 1. quarter 1982		454 889 596
Provisional statement 2. quarter 1982		548 440 162
Provisional statement 3. quarter 1982		450 616 890
Price adjustment 1. & 2. quarter 1982		64 268 873
	NOK	1 865 906 281

Royalties on Statfjord

1982		Royalties paid
Provisional statement 4. quarter 1981	NOK	358 680 098
Price adjustment 3. & 4. quarter 1981		23 380 482
Provisional statement 1. quarter 1982		422 492 515
Provisional statement 2. quarter 1982		437 098 703
Provisional statement 3. quarter 1982		430 242 072
Price adjustment 1. & 2. quarter 1982		53 008 654
	NOK	1 572 124 252

Royalties on Murchison

1982		Royalties paid
Provisional statement 4. quarter 1981	NOK	12 609 530
Price adjustment 3. & 4. quarter 1981	NOK	1 047 835-
Provisional statement 1. quarter 1982		29 564 818
Provisional statement 2. quarter 1982		28 434 565
Provisional statement 3. quarter 1982		31 369 634
Price adjustment 1. & 2. quarter 1982		3 450 817
	NOK	97 479 895

Gas royalties - Ekofisk

The Norwegian Petroleum Directorate received NOK 1,174,163,613 in royalties in 1982 for gas from the Ekofisk area. Table 9.4.b shows the receipts distributed by company/ group and quarter.

TABLE 9.4.b Royalties on gas from the Ekofisk area 1982

	4.qu.1981	1.qu.1982	2.qu.1982	3.qu.1982	TOTAL
Phillips group	108,646,326	71,227,781	67,645,955	64,454,829	311,974,891
refunded by the NPD	-4,821,514	9,538,964	8,404,226	7,907,142	30,671,846
	103,824,812	61,688,817	59,241,729	56,547,687	281,303,045
Dyno/Methanor	38,380,005	181,860,836	167,443,134	193,674,870	581,358,845
Sydvaranger/Norddeutsche Ferrowerke	55,041,633	54,218,510	---	---	109,260,143
Shell	25,218,196	27,362,990	18,305,611	15,235,894	86,122,691
Amoco/Noco	5,914,766	5,887,573	9,143,959	6,958,911	27,905,209
	228,379,412	311,018,726	254,134,433	272,417,362	1,085,949,933

Assessments of gas were made according to contract price. This was different for the various groups.

Payments from Dyno/ Methanor and Sydvaranger/ Norddeutsche Ferrowerke compensate that part of the royalty which was taken out as produced petroleum. Dyno/ Methanor have, in addition to the quarterly payments made above, also paid NOK 91,996,347 to cover the balance for the fourth quarter 1982.

In 1982, the Norwegian Petroleum Directorate refunded some NOK 34 million to Phillips Petroleum Company Norway to cover costs on Ekofisk which Phillips incurred on that part of the state royalties which was claimed in the form of produced petroleum.

Gas royalties - Frigg

In 1982, the Norwegian Petroleum Directorate received NOK 945,373,212 in royalties on gas from the Frigg area. Table 9.4.c shows the payments of royalty broken down by company and quarter.

The difference between Gas Sold and Gas Produced for Frigg is due to factors relating to allocation.

TABLE 9.4.c Royalties on gas from the Frigg area in 1982

	4.qu.1981	1.qu.1982	2.qu.1982	3.qu.1982	TOTAL
Petronord group (NE Frigg)	13,395,969	12,610,296	8,635,525	4,217,113	38,858,903
Petronord group (Frigg)	226,119,329	228,969,078	154,608,104	73,912,491	683,609,002
Petronord group (total)	239,515,298	241,579,374	163,243,629	78,129,604	722,467,905
Esso Exploration	5,622,233	5,716,657	4,413,917	---	15,752,807
	245,137,531	247,296,031	167,657,846	78,129,604	738,220,712

During the period 1977-1982, the statements for assessing royalties on the Frigg area from the Petronord group were settled according to provisional guidelines. However, an agreement has now been reached between the Norwegian Frigg group and the authorities on a division into deductible and non-deductible installations in the royalty accounts for the Frigg field pursuant to the "Ekofisk Model", which formed the basis for the 1965 production licences. For the time being, this has resulted in payments of NOK 207,152,500 on account. The Norwegian Petroleum Directorate expects that all previous settlements will be balanced in accordance with the final guidelines quite soon.

NGL royalties - Ekofisk

In 1982, the Norwegian Petroleum Directorate received NOK 70,993,200 in royalty for NGL from the Ekofisk area. Table 9.4.d shows the payments of royalties distributed by company and quarter.

TABLE 9.4.d Royalties on NGL from the Ekofisk area in 1982

	4.qu.1981	1.qu.1982	2.qu.1982	3.qu.1982	TOTAL
Shell	469,702	1,689,867	861,577	786,208	3,807,354
Amoco/ Noco group	391,584	884,821	625,384	810,523	2,712,312
Phillips group	10,379,706	15,797,502	19,852,958	18,443,368	64,473,534
	11,240,992	18,372,190	21,229,919	20,040,099	70,993,200

Royalty on NGL constitutes approximately 2 per cent of the total royalty paid on the Ekofisk area in 1982.

Condensate royalty - Frigg

In 1982, the Norwegian Petroleum Directorate received NOK 5,831,606 in royalty on condensate from the Frigg area. Table 9.4.e shows the royalty payments made by company and quarter.

TABLE 9.4.e Royalties on condensate from the Frigg field 1982

	4.qu.1981	1.qu.1982	2.qu.1982	3.qu.1982	TOTAL
Petronord group	1,757,572	2,245,211	1,328,211	500,194	5,831,606

LPG royalty - Murchison

In 1982, the Norwegian Petroleum Directorate received NOK 216,965 in royalty on LPG (propane and butane) from Murchison. Table 9.4.f shows the royalty payments made distributed by company and quarter.

TABLE 9.4.f Royalties on LPG from Murchison 1982

	2. quarter 1982	3. quarter 1982	TOTAL
Esso Exploration	63,271	101,675	164,946
Shell		52,019	52,019
	63,271	153,694	216,965

Acreage fees on areas covered by production licences

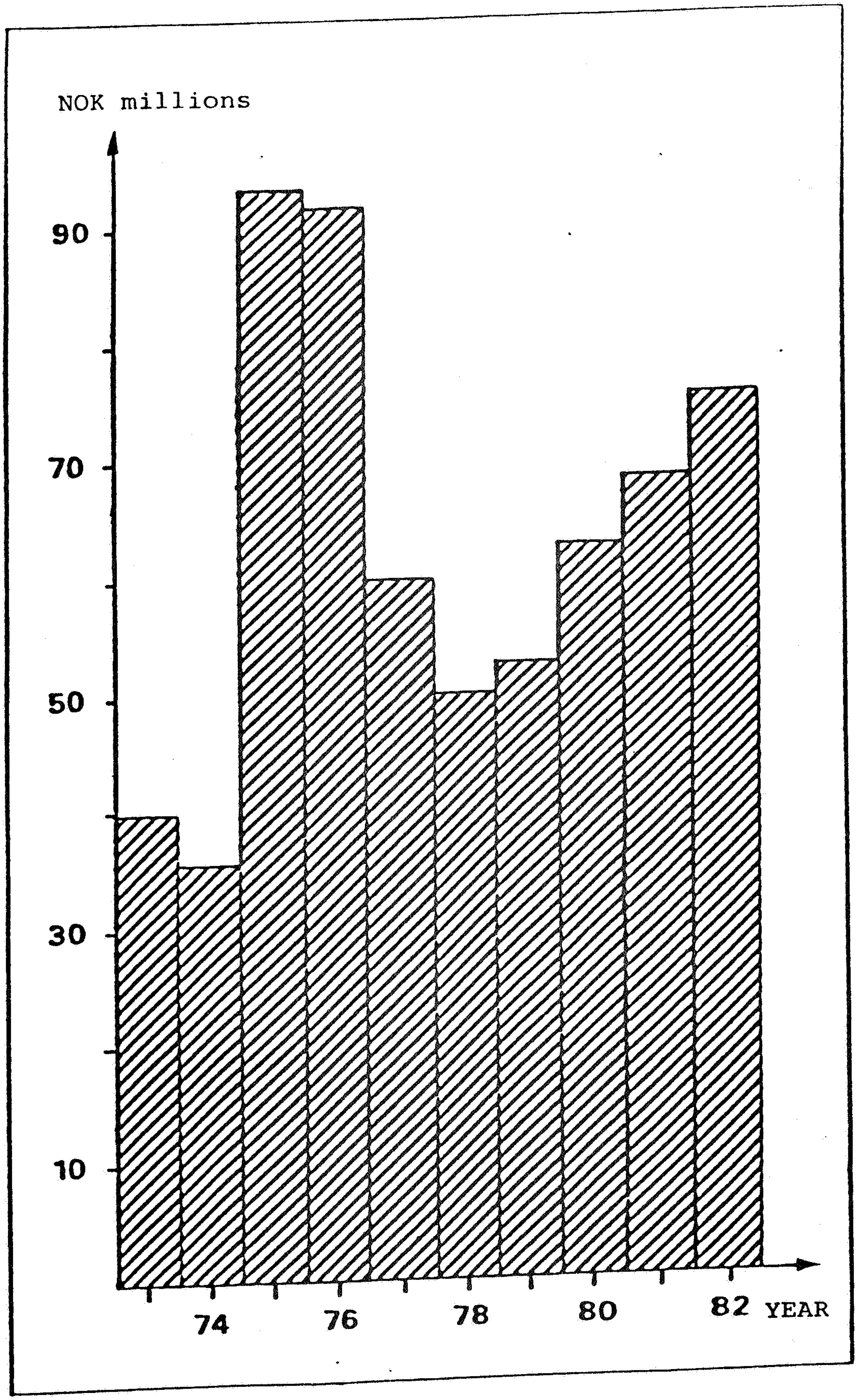
In the course of 1982, the Norwegian Petroleum Directorate collected NOK 75,913,049 in acreage fees. The amount comes from the production licences in the following fashion:

Production licences awarded in 1965:	NOK	53 633 100
Production licences awarded in 1969:		21 282 400
Production licences awarded in 1971:		1 476 492
Production licences awarded in 1973:		1 469 467
Production licences awarded in 1975:		3 120 366
Production licences awarded in 1976:		4 497 960
Production licences awarded in 1982:		2 435 250
	NOK	87 925 035
Less refunded in 1982	NOK	-12 011 986
	NOK	75 913 049

The Norwegian Petroleum Directorate refunded NOK 12,011,986 in acreage fees in 1982. This represents the deductible part of the acreage fees for Production Licences 006, 018 and 037 for the year from 1 October 1981 to 1 October 1982.

Figure 9.4.c shows the acreage fees paid from 1973-1982 in millions of kroner.

FIGURE 9.4.c Acreage fees 1973-1982 (NOK millions)



9.5 Publications by the Norwegian Petroleum Directorate in 1982

Regulations

- Regulations compendium: "Kontinentalsokkelen" ("The Continental Shelf"): An up-to-date compendium of the laws, regulations and guidelines stipulated by the Norwegian Petroleum Directorate and other regulatory agencies. Up-dated to 1 January 1983.

- Regulations relating to safety manning in the event of labour conflicts on the Norwegian Continental Shelf. Stipulated by the Norwegian Ministry of Local Government and Labour on 19 March 1982.

- Regulations relating to the collection of fees payable to the state treasury for the survey and inspection of temporary and permanent installations: Stipulated by the Ministry of Industrial Affairs on 11 November 1977 with subsequent amendments, latest 30 April 1982.

- Regulations relating to safe practices etc. in exploration and drilling for submarine petroleum resources. Stipulated by Royal Decree on 3 September 1975 with subsequent amendments, latest 19 March 1982.

- Safety regulations for production etc. of submarine petroleum resources. Stipulated by Royal Decree of 9 July 1976 with subsequent amendments, latest 19 March 1982.

- Guidelines for the inspection of the primary and secondary structures of production and shipment installations and underwater pipeline systems regulated by the Norwegian continental shelf legislation. Issued by the Norwegian Petroleum Directorate on 10 November 1982.

Research reports

- Safety shutdown system on offshore installations.

- Områdeklassifisering - Spredning av brennbare gasser og væsker. (Area classification - The spread of flammable gases and liquids)

- SSB-Programmet 1978-1981 (The SSB-Program 1978-1981) (SSB = Styringskomiteen for sokkelberedskap = the Controlling Committee for Shelf Preparedness)

Geological publications

- Well Data Summary Sheets, Vol. 7.

- NPD Paper No 31, The Norwegian-Danish Basin

Other publications

- Oljearbeideren, familien og samfunnet (The oil worker, his family and the community)
- Opprydding av havbunnen i Nordsjøen 1982 (Cleaning up the sea floor in the North Sea 1982).
- Oljedirektoratets årsberetning 1981 (the Norwegian Petroleum Directorate's Annual Report 1981)
- NPD annual report 1981 (English translation of the above annual report)
- Perspektivanalysen - 82 (Perspective analysis - 82)
- Petroleum outlook (English translation of the above perspective analysis)
- List of publications issued by the Norwegian Petroleum Directorate