Norwegian Petroleum Directorate

ANNUAL REPORT 1986

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Unofficial translation

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

Contents

Report by the Board of Directors

1986 was principally characterized by the heavy fall in the price of oil and the subsequent decline in exploration drilling on the Norwegian Continental Shelf. In all 36 wells were drilled compared with 50 the year before. One has to go all the way back to 1980 to find a similarly low level of exploration activity in Norway. One highlight of 1986 was the conclusion of the gas sales negotiations for the Troll and Sleipner East fields.

Despite the cuts in exploration activity, several interesting discoveries were made during the year. Again Haltenbanken proves to be the most interesting exploration area on the Norwegian Continental Shelf. The most promising discoveries were made by Norsk Hydro in Block 6407/7 and Statoil in Block 6406/3.

In the North Sea too, interesting discoveries have been made, including in the vicinity of the Oseberg and Statfjord fields and in the Stord basin. It is still too early to predict whether the reserves are large enough to justify development.

The new discoveries in 1986 and updating of earlier estimates of resources constituted grounds for upwards adjustment of the Directorates estimate of Norwegian continental resources upward. For oil, including NGL, the estimates have been increaseed by 256 million standard cubic meters (Sm^3) while estimates of gas reserves have been increased by 142 billion Sm^3. The Directorates total estimate of technically recoverable resources is thus 4.99 billion tons oil equivalent (toe), of which 0.5 billion have already been produced.

The proven petroleum resources in Norway are equivalent to about 120 years of production of gas and about 35 years of production of oil at todays recovery rates. Exploitation of this gas must therefore be the backbone of our petroleum activity in the future. The agreement reached in 1986 for sale of gas from Sleipner East and Troll is a very encouraging development in this respect. The volumes sold will enable us to maintain the present production level of gas.

The flexibility incorporated into the gas sales agreement and the infrastructure which will result from development of Troll and Sleipner East will substantially enhance our chances of making further sales of Norwegian gas. In addition, the substitution potential of associated gas from oil fields secures a basis for sound exploitation of the total gas resources on the Norwegian shelf.

In 1986 the Directorate did considerable work to examine the problems of alternative use of gas. A report which lists the most likely solutions is now being prepared in conjunction with industry and Norwegian research institutions.

As far as future activity on the Norwegian shelf is concerned, development of the oil price will be the deciding factor. Development of the oil price this last year has revealed the unstable state of the market. The price level can fluctuate considerably over short periods. Even though the expectations of price development in the long term are positive, the probability that the price will remain low for extended periods cannot be ignored.

On the basis of our known petroleum resources, there is a large probability that future development activity will be lower than in recent years. The reason is principally the limited number of developable fields available, and the impossibility of maintaining the high level of activity by means of gas field development. Due to the market limitations for gas the best alternative will be to strike a balance between oil and gas production on the continental shelf.

Oil field development should be scheduled for periods in which gas-based activity is low. In this way, development of oil discoveries will enable us to maintain a minimum of activity in Norway. The uncertainties in the future oil price also indicate that oil production should not be increased substantially in the short term.

Several of the Haltenbanken fields are among the closest to development. Preparations here have reached an interesting phase. The operators Plan for Development and Operation of the Draugen and Heidrun fields is expected from Shell and Conoco respectively in 1987. In this connection the Directorate believes a joint transport system for oil and gas from Haltenbanken may provide a good alternative from a socio-economic point of view.

Development on Haltenbanken seems most likely also to provide examples of new technology forced into existence by the lower price of oil, which also makes fresh demands of profitability in the industry.

One instrument for maintaining activity levels is the reduction of the cost level. The Directorate therefore launched a project in 1986 to elucidate the costs savings potential of future field developments. The project also seeks to determine whether the regulations force prices up. The results show that considerable potential exists for costs savings on future field developments in relation to the most recently realized projects. This can be achieved by optimization of known technology, application of new technology and selection of new concepts. There are several examples of this in the present plans for the Tommeliten and Veslefrikk fields.

The Directorate has discussed the provisional results of the studies with representatives of the oil companies, engineering contractors, building yards, shipping companies and research institutions at a seminar in the Directorate in November. The project will be continued in 1987.

The new price and market situation has made it necessary for the Directorate to examine what exploration strategies should be preferred for the various areas on the shelf, both as regards activity level and geographical area.

The studies show that no obvious major prospects now remain uncharted in the North Sea with a high probability of finding oil, though it makes economic sense to sustain some level of activity so as to be able to prove satellite fields around producing or soon-to-be-producing fields. Off mid-Norway it may make economic sense to make discoveries that may be of significance for the regional solution on Haltenbanken. Off the Møre coast too, economically interesting prospects exist. In the northern areas, the Directorate's calculations show that major oil discoveries may be economically interesting. A strategy must therefore be charted to find the geological provinces with high oil potential, though as cheaply as possible.

Allocation of blocks in Phase B of the tenth licensing round was made on 28 February 1986, and of the 24 blocks for which 20 companies had applied, nine were allocated.

In addition the relinquished acreage on Block 25/1 was allocated to Norsk Hydro in summer 1986 outside the allocation round. The eleventh round was announced with application deadline 10 October 1986 and embraces 39 blocks on Møre South, Møre I, Haltenbanken, Troms Northwest, Bear Island South and Finnmark West.

Twenty-one companies, including Statoil, applied for production licences on a total of 22 blocks. Twenty of these blocks were in the current area, and two in areas previously opened. By far the greatest interest was shown in Haltenbanken, Bear Island South and Finnmark West.

Exploration drilling in the northern reaches has so far led to several gas discoveries with only small amounts of oil. With todays price and market situation we depend on major oil discoveries in the north if development is to be viable. Larger areas have therefore been opened with the announcement of the eleventh round blocks. In addition, a new instrument of oil policy has been introduced in the form of so-called strategic blocks.

In consultation with the Directorate and following a round of comments by the companies, the Ministry of Petroleum and Energy selected three areas in the Barents Sea where announcement of strategic blocks was appropriate. These were selected in order to facilitate as quickly as possible the location of commercial discoveries in the Barents Sea. Wells will therefore be drilled into the most interesting structures in the areas.

Five blocks in two different areas were announced in December 1986, and the application date set at January 1987.

The marked increase in interest in Svalbard in 1985 continued in 1986. There seems to be a clear connection between this and the expansion of research activity northward. It is very important for companies wanting to participate in exploration in the Barents Sea to understand the geology of Svalbard, and this has triggered the increase in activity there. Several companies conducted seismic surveys on Svalbard in 1986, both onshore and off. The companies have also shown interest in obtaining acreage for oil and gas exploration, though only one company, the Soviet Trust Arktikogul, drilled for oil or gas on Svalbard this year.

The Directorate's seismic surveys on the Norwegian Continental Shelf in 1986 were conducted in favourable weather. A total of 21,979 kilometers of seismics was logged.

This year too, the Directorate has made considerable sales of seismic packages. In 1986 sales reached NOK 313 million, though this is a reduction from the 1985 figure of NOK 377 million.

Acquisition of environmental data in the Barents Sea as started by the Directorate in 1985 continued in 1986 with satisfactory results. Data acquisition in connection with consequence analyses as required by the Petroleum Act has also started. This project is considered a crucial foundation upon which to plan activity in this region, and its implementation must therefore be safeguarded.

The subsidence trouble at Ekofisk was a key focus of attention in 1986. In November 1984 it was established that the seabed under the Ekofisk center had sunk. Measurements taken later estimate the total subsidence at 1 December 1986 to be about 3.8 meters.

The subsidence rate has been estimated to be about 40 centimeters a year. Due to the subsidence, the decks on the central platforms on Ekofisk will be raised six meters. This work will be carried out in summer 1987. In 1986 the operator conducted planning operations and preparatory work for the project. Both the operator and the Directorate worked in 1986 on plans for future measures to safeguard the installations in the longer term if subsidence continues in the years ahead.

By letter of 24 November 1986 the Directorate was informed that similar subsidence is occuring on Valhall.

The Directorate has asked all operating companies on the Norwegian shelf to examine the subsidence potential of fields in production, or scheduled for development, and, if necessary, set up reference points making it possible to monitor any subsidence if and when it occurs.

In connection with final production and removal of installations from the Norwegian shelf the Directorate has set up an inter-disciplinary project group whose task it is to look more closely at the problems that will arise. This work has been initiated for several reasons:

- In a few years the question of a date on which to end production from several fields will have to be addressed. By the turn of the century several individual fields in or near Ekofisk and Frigg with its satellites will have stopped producing.
- Several of the installations presently on fields approaching the end of their producing life are conceivable alternatives for other offshore fields. The alternatives are either to let the old and new fields share the installations, or allow the new field to completely take over the existing installations.
- The question of what will happen after the installation has finished its useful service life will be discussed in several international fora during the next few years. This forces Norway to decide on its stance in such fora.

In pursuance of the Act relating to Petroleum Activity which entered into force on 1 July 1985 the Directorate received additional responsibilities and work tasks connected with supervision of safety and the working environment in the petroleum activity.

The Directorate has concluded agreements for assistance with its supervisory activities with the Telecom administration, Coast Directorate, Meteorological Institute, Directorate for Fire and Explosion Protection and Civil Aviation Administration. Work to achieve an agreement for supervisory assistance with the Maritime Directorate is continuing.

The Norwegian Petroleum Directorate undertakes certain coordinating tasks vis-á-vis the State Pollution Control Authority and Health Directorate with respect to their control responsibilities in the oil activity. Coordinating instructions have been prepared by the respective ministries for these aspects of the work.

The Directorate has assigned high priority to review of the regulations under its direction and the formulation of a new regulatory structure subordinate to the legislation governing safety and the working environment.

In 1986 the Directorate, through its work with its own organizational structure, has facilitated the accomplishment of this priority work.

The Safety Regulations and Working Environment Act lay down clear obligations on the industry to develop and introduce a technological standard compatible with the technological and social advances in society. The basic means to secure this must be incorporated into planning and fabrication. This year therefore the Directorate has supported the work of encouraging the industry to make suitable design requirements. Moreover, organization and facilitation of working environment factors in the operating phase has found a central place in the Directorate's supervisory activity.

One result of this has been that all operating companies on the Norwegian shelf have complied with the Directorate's request to set up coordinating working environment committees to coordinate the safety and environmental protection work.

Working environment questions also have a central place in the international context. In April 1986 for example, a preparatory meeting was held in the Directorate under the direction of the Ministry of Local Government and Labour between Norwegian authorities and representatives of the Commission of the European Communities (CEC), in which formalized cooperation between the CEC and Norway in the safety and working environment field was discussed.

The ILO's Petroleum Committee held its tenth session in Geneva from 9–17 April 1986. Twenty-three countries attended with tripartite delegations. The Norwegian Petroleum Directorate was represented in the Norwegian delegation together with representatives of the government and both sides of industry. Several problems relating to safety and working environment in the petroleum industry were thoroughly considered. Matters relating to diving and subsea operations were particularly highlighted.

The organizational efforts started in 1985 brought about extensive changes in the Directorate's internal structure and working methods.

The board of directors would like to express its satisfaction with the diligence shown by managers and staff of the Directorate in arriving at an organizational model which is better in tune with the tasks which will face us in the years ahead.

In 1986 the Directorate was given 16 new positions, five of which were assigned to the regional office in Harstad, which now has 13.5 positions. Due to the state of the labour market, there were more applications for jobs with the Directorate than previously. 1986 saw a wastage rate of 11 per cent, which is about the same level as in the previous five years.

The Directorate's regional office in Harstad was opened in 1980. Build-up of the office was authorized in the 1985 budget year. In 1986 responsibility for resources and safety on allocated production licences on Tromsøflaket was delegated. Further delegation of responsibilities is planned in 1987.

The Directorate moved into its new premises at Ullandhaug, OD-Huset (NPD House) in January 1986. On 20 May 1986 the official opening of the new building was attended by a large number of guests from central and local authorities. OD-Huset has proven to be both functional and pleasant, and our employees have settled down comfortably in their new surroundings.

Stavanger, 19 January 1987

Members of the Board of Directors
of the Norwegian Petroleum Directorate

Martin Buvik

Martin Buvik

Andreas Lønning Bjørg Simonsen Liv Hatland

Andreas Lønning *Bjørg Simonsen* *Liv Hatland*

Kåre Nielsen Ole Knapp

Kåre D. Nielsen *Ole Knapp*

Odd Raustein Bjørn Kvant

Odd Raustein *Bjørn Kvant*

Fredrik Hagemann Bjørn Bratbak

Fredrik Hagemann
Director General

Bjørn Bratbak
Head of Branch
Secretary to the Board

The Directorate's Tasks, Board of Directors and Administration

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

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

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

a. To undertake regulatory and financial control to ensure compliance with applicable legislation, regulations, decisions, licensing terms, agreements, etc in the exploration for and exploitation of petroleum, see § 1.
b. To ensure that applicable safety regulations are complied with.
c. To ensure that the exploration for and exploitation of petroleum resources does not lead to unnecessary damage or cause inconvenience to other activities.
d. To ensure that the exploration for and exploitation of petroleum resources at all times takes place in compliance with the guidelines laid down by the authorized Ministry.
e. To collect and process geological, geophysical and technical material relating to subsea natural resources, including their evaluation and the possibilities thereby available for the formulation of national petroleum policy and negotiation plans, as well as to plan and see to the performance of geological and geophysical petroleum surveys.
f. To undertake current financial control of exploration for and exploitation of petroleum resources.
g. To issue exploration licences and assist the relevant Ministry, upon request, in the processing of applications for other licences, the formulation of regulations, etc.
h. To maintain links with scientific institutions and ensure that material is made available to interested companies, scientific institutions, etc, to the extent that this is possible in view of the rules which apply concerning confidential treatment of material submitted by licencees and in general pursuant to the decision of the relevant Ministry.
i. To keep the Ministries informed at all times about the activity given in § 1, and to present the issues dealt with by the Directorate which do not come under § 2 a-h, to the Ministry in question.
j. To prepare and present for 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 of special importance or fundamental interest.

1.2 The Directorate's objectives

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

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

1.3 The Board of Directors and the Administration

1.3.1 The Board of Directors

At the beginning of the the report period, the Board consisted of:

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

Deputies:

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

First Secretary Astrid Nistad was appointed as Deputy Minister at the Ministry of Petroleum and Energy on 15 May 1986. From this date she was relieved of her official duties as deputy board member.

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

For 6:
Mr Jan Strømme, Oil Secretary, Oslo

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

During the report period the Board held nine meetings.

In October 1986 the board of directors undertook a study trip to Exxon, USA where the following were visited:

- Exxon Production Research at Houston
- Exxons training center at Friedenswood
- Exxon USAs Offshore District Administration in New Orleans
- Lena Guyed Tower in the Gulf of Mexico.

1.3.2 Organization

During 1986 the Directorate has undergone restructuring to better adapt its organization to tasks in connection with the new Petroleum Act which became effective from 1 July 1985 and to secure product-oriented and efficient activity. The primary structure of the Directorate with two divisions, legal branch and administration branch plus Head of information office has not been departed from.

THE SAFETY AND WORKING ENVIRONMENT DIVISION

This division now has three branches:

The *Supervisory Activities Branch* is responsible for supervision tasks of the division in accordance with shelf legislation.

The *Technical and Working Environment Branch* is responsible for technical assessments, professional development, build-up of expertise and revision of regulations. The number of sections was cut from nine to six.

The *Strategy Branch* has a double responsibility. The first is to attend to the divisions common internal functions, the second to assist the divisional management with strategic advice and elucidation.

RESOURCE MANAGEMENT DIVISION

A key feature of the restructuring of this division is the change-over from discipline-oriented to phase-oriented departments, plus the establishment of a Planning branch and a section in the Development branch.

The *Exploration Branch* corresponds to previous Exploration Department.

The *Development Branch* looks after resource management tasks in connection with development.

The *Production Branch* attends to the divisions tasks in connection with fields in operation.

The *Planning Branch* is charged with the divisions overall work of planning and reporting plus common administrative functions.

LEGAL BRANCH

The Measurement Section has been transferred to the Resource Management Division. The Legal Branch has set up a new position on its staff below the Head of Branch with general responsibility for the branch's work on strategy and regulatory development.

ADMINISTRATION BRANCH

This attends to the same functions as previously.

Two new sections have been suggested, one to handle information science and document processing, the other computer operations.

INFORMATION OFFICE

No change from previously.

DIRECTOR GENERAL
With effect from 1 September 1986 a secretariat immediately subordinate to the Director General was set up.

Three sets of meetings have also been set up for the Director General's benefit:
- Operating forum for dealing with matters of more general nature. Largely replaces the earlier post meetings.
- Coordination forum for dealing with matters requiring coordination between the organizational units.
- Planning forum for dealing with the Directorate's overriding plans and objectives and strategic questions.

1.3.3 Personnel
In the budget for 1986, 16 new positions were created, six of them at the regional office Harstad. At the end of the report period there were 335 authorized positions in the Directorate. In addition in connection with a government research program for enhanced recovery (the SPOR project) directly under the auspices of the Ministry of Petroleum and Energy, a four-year temporary position has been set up to head the project. In addition there are three positions salaried by the Directorate for Development Aid (NORAD). At year-end 1985 the Directorate employed 331 persons, see Figure 1.3.3.a. Staff members include 36.3 per cent women. Figure 1.3.3.b shows the proportions of men and women in the various job categories within the Directorate.

Also working at the Directorate during the entire report period was one of NORAD's special advisors on oil matters in developing countries.

In 1986 the Directorate dealt with 96 vacancies (tab 1.3.3.c) and took on 57 new members of staff. Of the newcomers, 19 have relocated to Stavanger, 12 come from oil related activities and 11 are newly qualified.

Thirty-seven members of staff left their positions, see Table 1.3.3.a and b. This constitutes approximately 11 per cent of the total number of authorized positions.

This year too, highly qualified personnel have predominated in the leaving statistics. Though the loss from the Safety and Working Environment Division has been growing, the drain from the Resource Management Division was substantially lower this year than in 1985.

Figure 1.3.3.c shows the personnel drain from the Norwegian Petroleum Directorate to various oil companies for the years 1973–86.

FIG. 1.3.3.a
Positions 1973–1986
Permanent positions and engagements

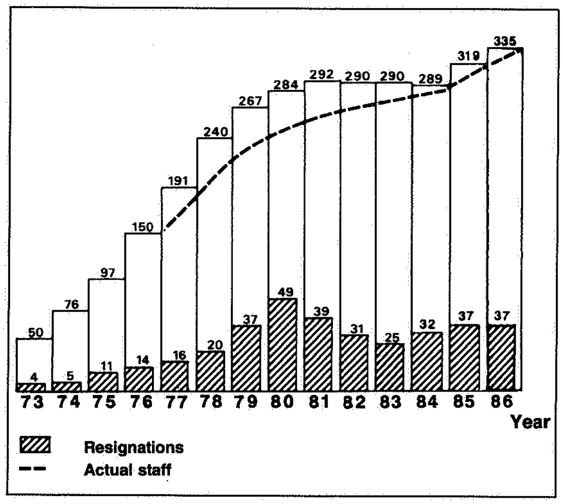


FIG 1.3.3.b
Position groups as of 31 December 1986

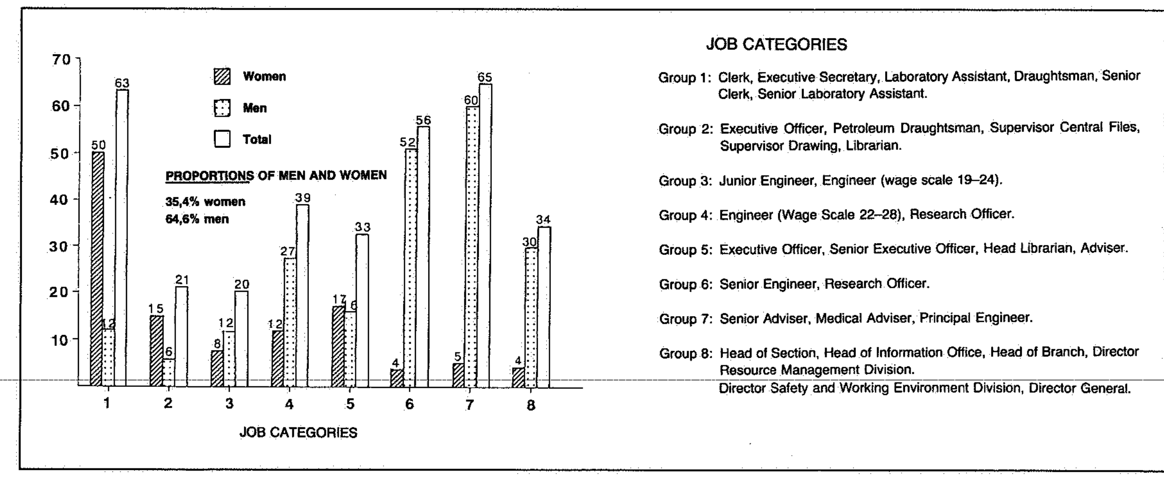
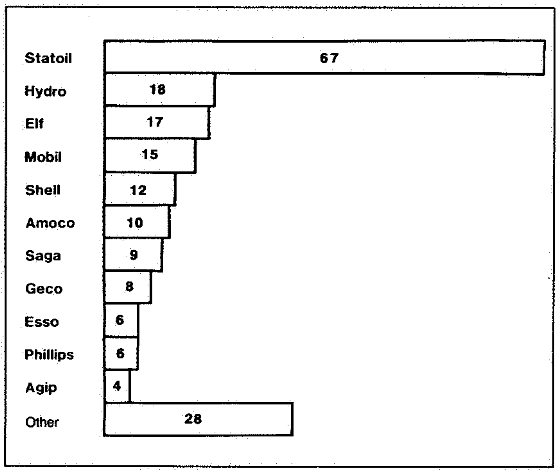


Table 1.3.3.a
Personnel leaving the Directorate in 1986 indicating type of position

Division/ Branch	Managers	Senior advisers	Princ eng	Senior eng	Senior geologists / Geologist	Engineers / jr engs	jr exec. off/ exec. off.	Office staff	Total	Decline in %
Resource Management	2	2	1	3	2	0	1	1	12	9,9
Safety and Working Environment	0	0	1	7	0	0	2	4	14	13,5
Legal	0	1	1	0	0	0	0	0	2	9,1
Administration	0	0	0	0	0	0	3	6	9	12,5
Total	2	3	3	10	2	0	6	11	37	11,0

FIG. 1.3.3.c
Personnel leaving the Directorate for oil companies 1973–1986



Equal opportunities work
As a result of a special agreement on equal opportunities the Directorate possesses an Equal Opportunities Committee. This committee consists of four members, two from management and two from the staff unions.

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

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

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

Co-determination
Cooperation with the staff unions has followed the same pattern as previously, with monthly meetings between the employee delegates and general management. During the period, 15 meetings were held which all in all considered 84 matters. The following current matters can be mentioned:
- budget proposals
- service functions of the Administration Branch
- internal control, working environment
- job rotation
- Directorate organizational structure and work method
- safety routines in OD-huset (NPD House).
- day care center.

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

Training
The training budget for the report period was NOK 2,950,000. These funds have been used in accordance with earlier practice, and large amounts have as previously been spent on travel expenses. As in the previous report period several staff members have participated in on-the-job (OTJ) training with the oil companies. These courses are usually carefully prepared by the companies and the training periods have been well worth while for all attending.

In 1986 several inhouse courses were held using

TAB 1.3.3.b
Personnel leaving the Directorate in 1986 indicating new place of work

Division/ Branch	Oil industry	Other nongov't activity	Other gov't activity	Miscell-aneous	Education	Total
Resource Management	7	3	1	0	1	12
Safety and Working Environment	9	2	1	2	0	14
Legal	2	0	0	0	0	2
Administration	6	0	2	4	0	9
Total	24 (203)	5 (35)	4 (50)	6 (51)	1 (20)	37 (356)

Figures in brackets are totals for the period 1973–86

Table 1.3.3.c
Distribution of applicants among vacant positions

Position category	Number of vacancies announced	Total number of applicants		Number of internal applicants		Number of external applicants		Number of applicants taken on in cases now closed	
		M	W	M	W	M	W	M	W
Management	8	46	8	10	4	36	1	7	3
Technical case officers	47	496	163	74	27	422	136	36	22
Non-technical case officers	17	141	105	9	10	132	95	8	9
Clerical	24	36	255	5	21	31	234	3	21

staff members as instructors. The Directorate has furnished a special training room for the purpose and this has made instruction decidedly more rational.

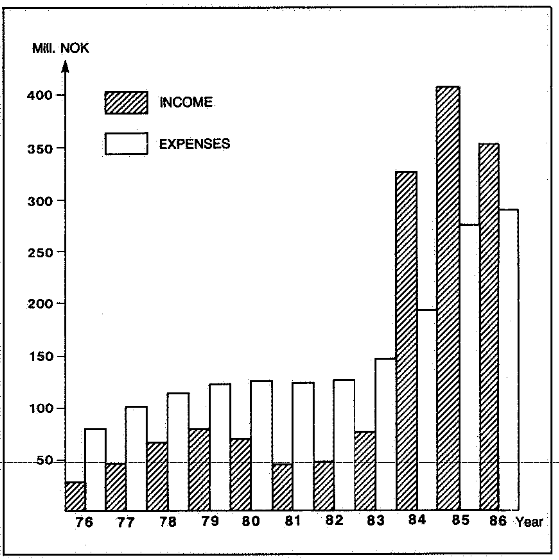
1.3.4. Budget and finance

In 1985 a total of NOK 285,504,000 was allocated to the various Directorate tasks. The amount was distributed as follows:

– Operating budget	NOK 148,929,000
– Inspection costs	NOK 9,700,000
– New premises	NOK 10,400,000
– Geological and geophysical surveys	NOK 109,750,000
– Safety and emergency preparedness research	NOK 2,000,000
– Cleaning up the seabed	NOK 4,725,000
Total appropriation budget for 1986	NOK 285,504,000

NOK 79,124,000 of the operating budget was allocated to salaries and NOK 6,250,000 to the running of buildings and renting of premises. The remaining NOK 63,555,000 of the operating budget represents

FIG. 1.3.4
NPD's operating budget 1976–1986



other expenses such as external consultancy services, operation of a weather ship, research and development projects, travel, training, electronic data processing (EDP) operations, investments in new equipment, etc.

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

Revenues and income

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

Income in 1986 was distributed as follows:

Sales of publications	NOK 3,242,010
Sales of released sample material	NOK 14,547
Survey fees	NOK 760,000
Refunded inspection costs	NOK 26,686,285
Refunded for environmental data acquisition	NOK 4,500,000
Sales of seismic survey results	NOK 313,609,825
Credit interest on bank deposits	NOK 2,813,640
Miscellaneous income	NOK 64,860
Total income for 1986	NOK 351,691,167

The Directorate's operating budget and income development for the period 1976–86 are shown in Figure 1.3.4.

1.3.5. Information

During this report period there has been a brisk demand for information both from Norwegian and foreign institutions, the media, enterprises, and individuals. In the course of the year the Directorate has entertained several official delegations from other countries. Furthermore, many foreign journalists, individually or in groups, have visited the Directorate to obtain information about the Directorate and the oil activity. For their part, Norwegian Petroleum Directorate staff have frequently participated as speakers in various fora.

With respect to the media the Head of information office's job as press spokeman has meant that the Directorate has been able to service the media more effectively than hitherto, at the same time as Directorate management has been relieved of such duties.

The Norwegian Petroleum Directorate's Annual Report is a central feature of our information activities. The 1985 Annual Report and the Directorate's updated map of the continental shelf became available in May. Simultaneously, the Directorate's analysis of perspectives, the Petroleum Outlook for 1986, was published. In conjuction with this event, representatives of the press were invited to meet with the Directorate's senior management. Information was also given to the press regarding the conclusion of the years clearing-up operations on the North Sea seabed. In November the Directorate organized a press seminar in connection with the release of the report "Future Activity Level".

During 1986 a total of 74 press bulletins were issued. Most of these were released in conjunction with the conclusion of wells drilled, for which the Directorate seeks to provide maximum information.

The Directorate participated with its own stand at the Offshore Northern Seas (ONS 86) exhibition which was held in Stavanger in August.

A memorandum on strategy for further development of the Directorate's information activities was considered by the board of directors.

1.3.6. Regional office Harstad

The Directorate's regional office in Harstad (OD-H) was allocated seven new positions for 1986, including the appointment of a permanent director of division and half position transferred from the office in Stavanger. As of 31 December 1986 13 persons were employed in addition to the one unfilled authorized position in the Safety Management Section.

In 1986 the regional office was delegated the supervisory responsibility within resources and safety administration for allocated production licences on Tromsøflaket. Further delegation of responsibility will occur in 1987. Harstad attends to the Directorate's interests in North Norway for liaison with regional and local government and industry.

The regional office Harstad has adjusted to the Directorate's reorganization in 1986 and in 1987 will prepare routines and procedures for the new organization. The temporary instructions from 1985 for Harstad will be adapted to the new organization, in addition to the delegation carried out and planned regarding expertise and activity level.

1.3.7. The library

Library activity was again considerable in 1986 with many inquiries for literature and information from internal and external users. The library registered a steady increase in the number of applications to borrow books, make copies and examine references compared with previous years. For the first time, applications from external users exceeded those from the Directorate itself. Over 51 per cent of all inquiries for literature stemmed from external users, including Norwegian and foreign libraries, students, private individuals, oil companies and other firms within the petroleum sector.

The most important event of the year must be the relocation to new library premises in the new block at Ullandhaug where the library is situated in well-lit, attractive location with plenty of space. The new library is on the first floor of the open zone in the building and is entered from the reception area. This is very practical for external users.

Library staff have given tours round the new library and briefings on library services to oil companies, government agencies and other libraries.

The library actively participates in the publication of the Norwegian Petroleum Directorate's literature reference work Olje-indeks (Oil Index) and the reference data base OIL.

Inquiries about literature references in the Oil Index and OIL are still increasing. The number of literature searches from national and international data bases has grown markedly from last years. No fixed contacts have been established with data base suppliers during the report year.

1.3.8. The INFOIL secretariat

External users have made use of the OIL data base for over 50 hours in 1986, an increase of over 18 per cent compared with the previous year. Considerable effort has been made to improve literature coverage, not least in collaboration with the library, and the form of presentation of offprints.

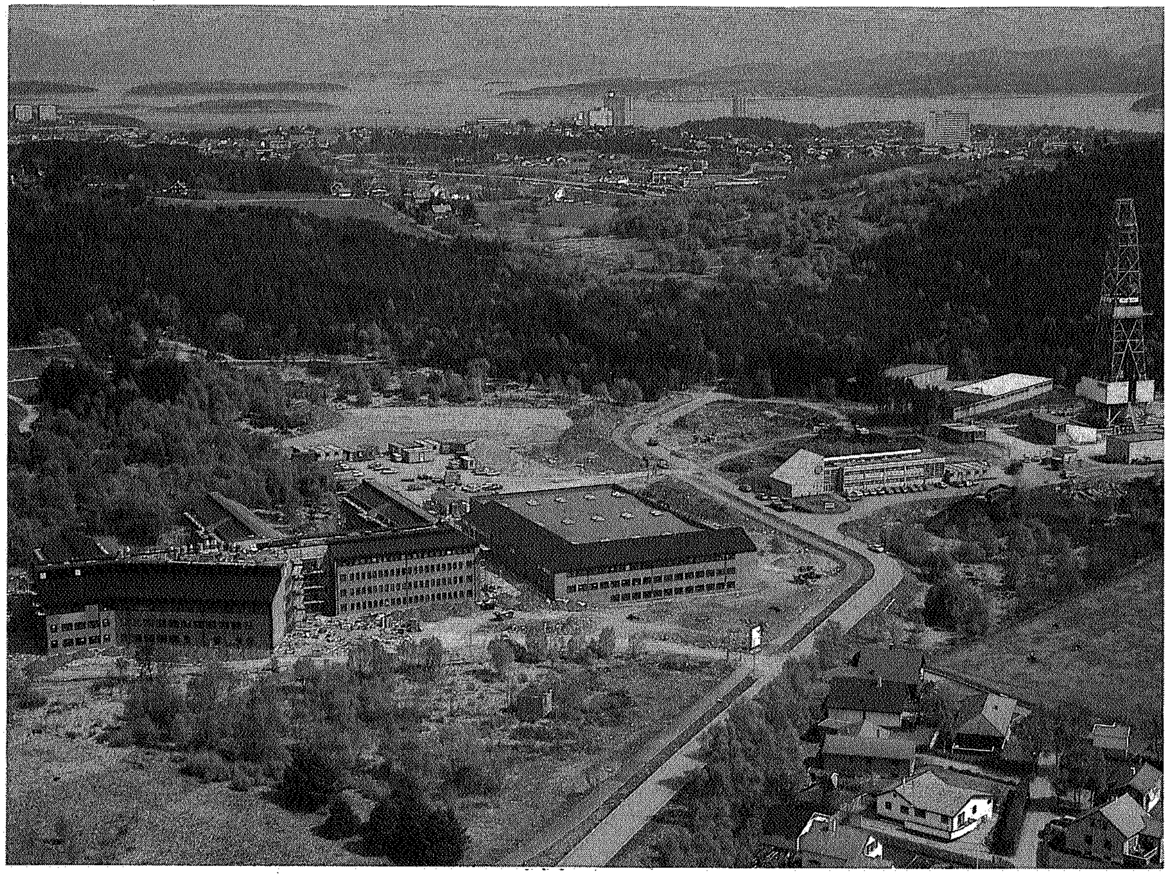
Use of the Infoil 2 data base remains constant, while project data has been input from several sources, including the USA.

A new, updated version of "Norwegian Petroleum Directorate Projects" has been generated from a special data base.

The secretariat service for the planned foundation known as the "Forum for Petroleum Documentation" has embraced work on articles of association and participation in the arrangement of the "Offshore Information Conference – 86" in Edinburgh in collaboration with the Institute of Offshore Engineering at Herriot-Watt University.

The Infoil secretariat has participated in the working group for a project Statoil has financed for the Norwegian Term Bank at the University of Bergen. The project is intended to input a hierarchic structure for the Norwegian vocabulary in the Petroleum Thesaurus.

The increase in activity has been possible because the secretariat has obtained one more permanent position.



The new NDP building in the Ullandhaug area was officially opened 20 May 1986.

Brynhild Meltveit, NPD's first employee unveiled the commemorative plaque at the opening ceremony 20 May 1986.

NPD's regional office in Harstad's new office at Verkstedveien 1.

Activity on the Norwegian Continental Shelf

2.1 Exploration and production licences

2.1.1 New exploration licences

As of 31 December 1986, a total of 147 commercial exploration licences had been allocated. Each licence is valid for three years. The following licences were awarded in 1986:

BP Petroleum Development (Norway) Ltd	Licence no. 137
Elf Aquitaine Norge A/S	138
Esso Norge a.s.	139
Amoco Exploration of Norway A/S	140
Phillips Petroleum Company Norway	141
Institute for Continental Shelf Studies	142
Fina Exploration Norway	143
Maersk Olje og Gas A/S	144
Britoil	145
Geophysical Company of Norway A/S	146
Mobil Exploration Norway Inc	147

Licences no. 135 and 136 were awarded in 1985 but became effective only on 1 January 1986.

Licences no. 146 and 147 were awarded in 1986 but will become effective only from 1 January 1987.

2.1.2 New production licences

In 1986 nine new production licences were allocated. Production licences no. 121–128 comprise allocation round 10 B, while licence 129 falls outside the allocation round. See Table 2.1.1.a.

Table 2.1.2.a
Allocations: allocation round 10B and production licence 129

Prod. lic. number	Field/Block	% share		Licensee (O denotes operator)
121	6407/5	20.000	O	Mobil Development Norway A/S
		10.000		Britoil Norge A/S
		20.000		Norsk Hydro Produksjon a.s
		50.000		Den norske stats oljeselskap a.s
122	6507/2	20.000	O	Norsk Hydro Produksjon a.s
		10.000		Amerada Hess Norw. Expl. A/S
		10.000		Esso Norge a.s
		10.000		Mobil Development Norway A/S
		50.000		Den norske stats oljeselskap a.s
123	6507/6	15.000	O	Saga Petroleum a.s
		15.000		BP Petroleum Dev. of Norway A.S
		10.000		Elf Aquitaine Norge A/S
		50.000		Den norske stats oljeselskap a.s
		10.000		Total Marine Norsk A/S
124	6507/8	50.000	O	Den norske stats oljeselskap a.s
		10.000		Arco Norge A/S
		15.000		Norske Conoco A/S
		5.000		Det norske oljeselskap a.s
		10.000		Norsk Hydro Produksjon a.s
		10.000		Tenneco Oil Company Norsk A/S
125	6508/5	35.000	O	A/S Norske Shell
		15.000		Norsk Occidental A/S
		50.000		Den norske stats oljeselskap a.s
126	6607/5	35.000	O	Esso Norge a.s
		15.000		Mobil Development Norway A/S
		50.000		Den norske stats oljeselskap a.s
127	6607/12	35.000	O	Elf Aquitaine Norge A/S
		15.000		Norske Fina a/s
		50.000		Den norske stats oljeselskap a.s
128	6608/10 and 6608/11	50.000	O	Den norske stats oljeselskap a.s
		10.000		Norsk Agip A/S
		15.000		Norsk Hydro Produksjon a.s
		15.000		Saga Petroleum a.s
		10.000		Texas Eastern Norway A/S
129	25/1	17.300	O	Norsk Hydro Produksjon a.s
		21.800		Elf Aquitaine Norge A/S
		50.000		Den norske stats oljeselskap a.s
		10.900		Total Marine Norsk A.S

Table 2.1.2.b
Production licences and areas as of 31 December 1986

Allocation round	Date	Prod. licence number	Number of blocks allo-cated	relin-quished	Area allocated sq.km	Area rel. sq.km	Area of prod.lic. sq.km
1.	01.Sept.1965	001–021	74	52	39842.476	35072.925	4769.551
	07.Dec. 1965	022	4	3	2263.565	1984.116	279.449
	12.Sept.1977	019 (2)	2	0	617.890	0.0	617.890
2.	23.May 1969	023–031	9	1	4107.833	2072.282	2035.551
	30.May 1969	032–033	2	0	746.285	376.906	369.379
	14.Nov. 1969	034–035	2	0	1024.529	564.837	459.692
	11.June 1971	036	1	0	523.937	262.047	261.890
ut.	10.Aug. 1973	037	2	0	586.834	295.157	291.677
3.	01.Apr. 1975	038–040 og 052	7	4	1840.547	1389.779	450.768
	01.June 1975	041	1	0	488.659	244.048	244.611
	06.Aug. 1976	043	2	0	604.558	303.215	301.343
	27.Aug. 1976	044	1	0	193.076	90.418	102.658
	03.Dec. 1976	045–046	4	2	1270.682	531.190	739.492
	07.Jan. 1977	047	2	1	368.363	304.160	64.203
	18.Febr.1977	048	2	1	321.500	107.019	214.481
	23.Dec. 1977	049	1	1	485.802	485.802	0.0
ut.	16. June 1978	050	1	0	500.509	151.962	348.547
4.	06.Apr. 1979	051–058	8	1	4007.887	1713.364	2294.523
ut.	20.Aug. 1982	079	1	0	102.167		102.167
5.	18.Jan. 1980	059–061	3	2	1108.078	998.675	109.403
	27.Mar. 1981	062–064	3	0	1099.522		1099.522
	23.Apr. 1982	073–078	6	0	2311.912		2311.912
6.	21.Aug. 1981	065–072	9	0	3218.945		3218.945
7.	10.Dec. 1982	080–084	5	0	2082.966		2082.966
ut.	08.July 1983	085	3	0	1521.160		1521.160
8.	09.Mar. 1984	086–100	17	0	6346.603		6346.603
9.	14.Mar. 1985	101–111	13	0	5293.053		5293.053
ut.	26.July 1985	112	1		260.215		260.215
10a	23.Aug. 1985	113–120	9		3075.435		3075.435
10b	28.Febr.1986	121–128	9		3828.257		3828.257
ut.	11.July 1986	129	1		224.329		224.329
			205	68	90267.574	46947.902	43319.672

* whole blocks or parts of blocks
** number of discoveries as of 31 December 1986
ut. licences allocated outside the regular allocation rounds

2.1.3 Transfer of licences and participations

In 1986 the following units were transferred as authorized in § 48 of Royal Decree of 8 December 1972.

Production licence 052
Norske Deminex A/S and Petroswede Norge A/S have each taken over 2.5 per cent from Petro Canada Exploration A/S, and Deminex (Norge) A/S and Svenska Petroleum Exploration A/S have taken over 7.5 and 2.5 per cent from Unocal Norge A/S.

The resulting distribution for production licence 052 is:

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

Production licence 054
Mobil Development Norway A/S has acquired five per cent from Superior Oil (Norge) A/S.

The resulting distribution for production licence 054 is:

Den norske stats oljeselskap a.s	50.000 %
A/S Norske Shell	35.000 %
Norsk Hydro A/S	5.000 %
Norske Conoco A/S	5.000 %
Mobil Development Norway A/S	5.000 %

2.1.4 Relinquishments

Relinquishments were made on four production licences in 1986. On three of these, the entire acreage was relinquished. See Table 2.1.4.

2.1.5 Allocation rounds

Blocks were allocated in the tenth round, phase B on 28 February 1986. Twenty companies applied for a total of 24 blocks, nine of which were allocated.

In addition the relinquished part of Block 25/1 was allocated to Norsk Hydro on 11 July outside the allocation round.

The eleventh round was announced with application date 10 October 1986 and embraced 39 blocks on Møre South, Møre I, Haltenbanken, Troms Northwest, Bear Island South and Finnmark West.

Twenty-one companies applied for 22 blocks.

By far the greatest interest was shown in Haltenbanken, Bear Island South and Finnmark West. See Table 2.1.2.c.

Table 2.1.2.c
Allocation rounds. Norwegian and foreign shares

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

Table 2.1.4
Relinquishments

Prod. licence No.	Operator	Block	Original area sq.km	Relinquished area sq.km	Area of prod. licence sq.km
050	Statoil	34/10	500.509	151.962	348.547
056	Amoco	34/2	488.659	488.659	.000
059	Saga	6407/12	436.310	436.310	.000
060	Statoil	7119/12	335.884	335.884	.000
061	N.Hydro	7120/12	335.884	225.481	109.403

2.2 Surveys and exploration drilling

2.2.1 Geophysical and geological surveys

In all 137,022 kilometers of seismics were compiled on the Norwegian Continental Shelf in 1986, a new record. See Figure 2.2.1.a.

2.2.1.1 The Directorates' geophysical surveys 1986

The Directorate gathered 21,979 kilometers of seismics during 1986. Data were collected from the areas shown in Figure 2.2.1.b – e.

FIG. 2.2.1.a
Seismic surveys on the Norwegian Continental Shelf as of 1962–1986 1 January 1987..

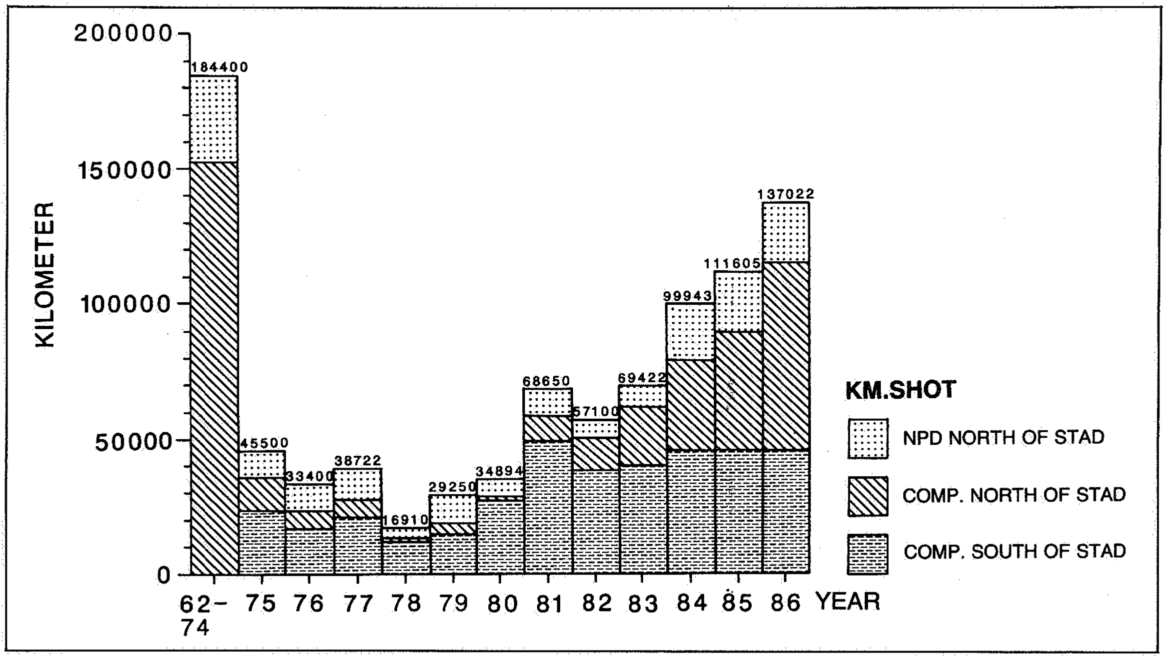
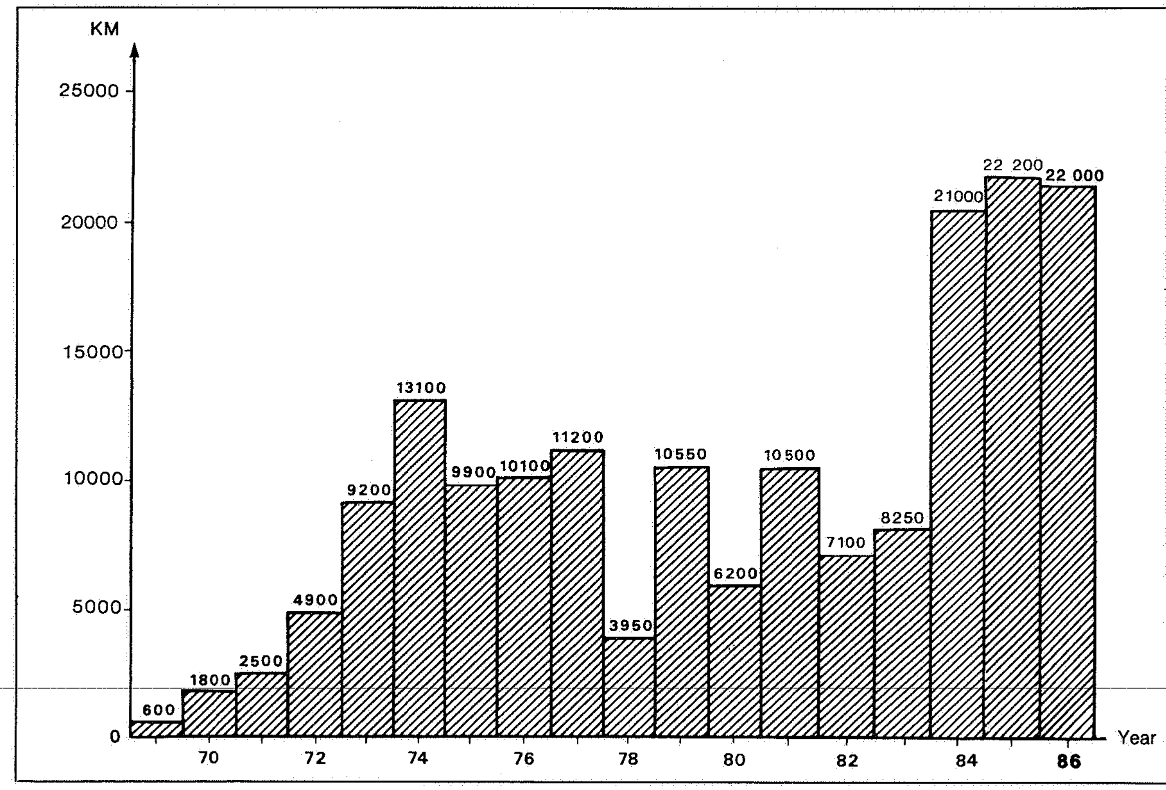


FIG. 2.2.1.b
Seismic surveys north of Stad under the direction of the Norwegian Petroleum Directorate.



Finnmark East
The Geco vessel "Geco Echo" and Geophysical Service International (GSI)s vessel "Polar Prince" collected 3421 and 2676 km seismics, respectively. Seismograph Service Ltd (SSL) is processing 2676 km data from the former in London, while Geco Stavanger is processing the remaining 765 km. The "Polar Prince" data are being processed by GSI in Bedford.

North Cape Basin
Gecos "Geco Echo" and "Geco Gamma" shot 3045 and 340 km seismics respectively, and the SSL vessel "Seismariner" shot 1607 km. GSI Stavanger is processing 2438 km of the "Geco Echo" data, while Geco Stavanger is processing 607 km. CGG in London is processing the "Geco Gamma" and "Seismariner" data.

Finnmark East and North Cape Basin were opened up for company-directed seismic surveys on 1 January 1987.

Bear Island West
Gecos "Geco Echo" and Compagnie Générale de Geophysique (CGG)'s "Rig Master" collected 3790 and 1881 km seismics, respectively. In addition one 101 km test line was shot by "Geco Gamma".

This test line was shot using two parallel sources (flip-flop) and two parallel cables 100 meters apart, thereby collecting four parallel lines 25 meters apart.

The "Rig Master" data and 1218 km of the "Geco Echo" data are being processed by Merlin in London, while the remaining 2575 km of "Geco Echo" data are being processed by Petty-Ray in London.

Northern Barents Sea
Geco's vessels "Geco Gamma" and "Sea Searcher" collected 1039 and 778 km seismics. Part of the "Sea Searcher" data were collected using two vertical cables. This technique allowed the cables to lie lower than usual, enabling data to be acquired in weather

FIG. 2.2.1.c
Seismic surveys on the Mid-Norwegian Shelf in 1986.

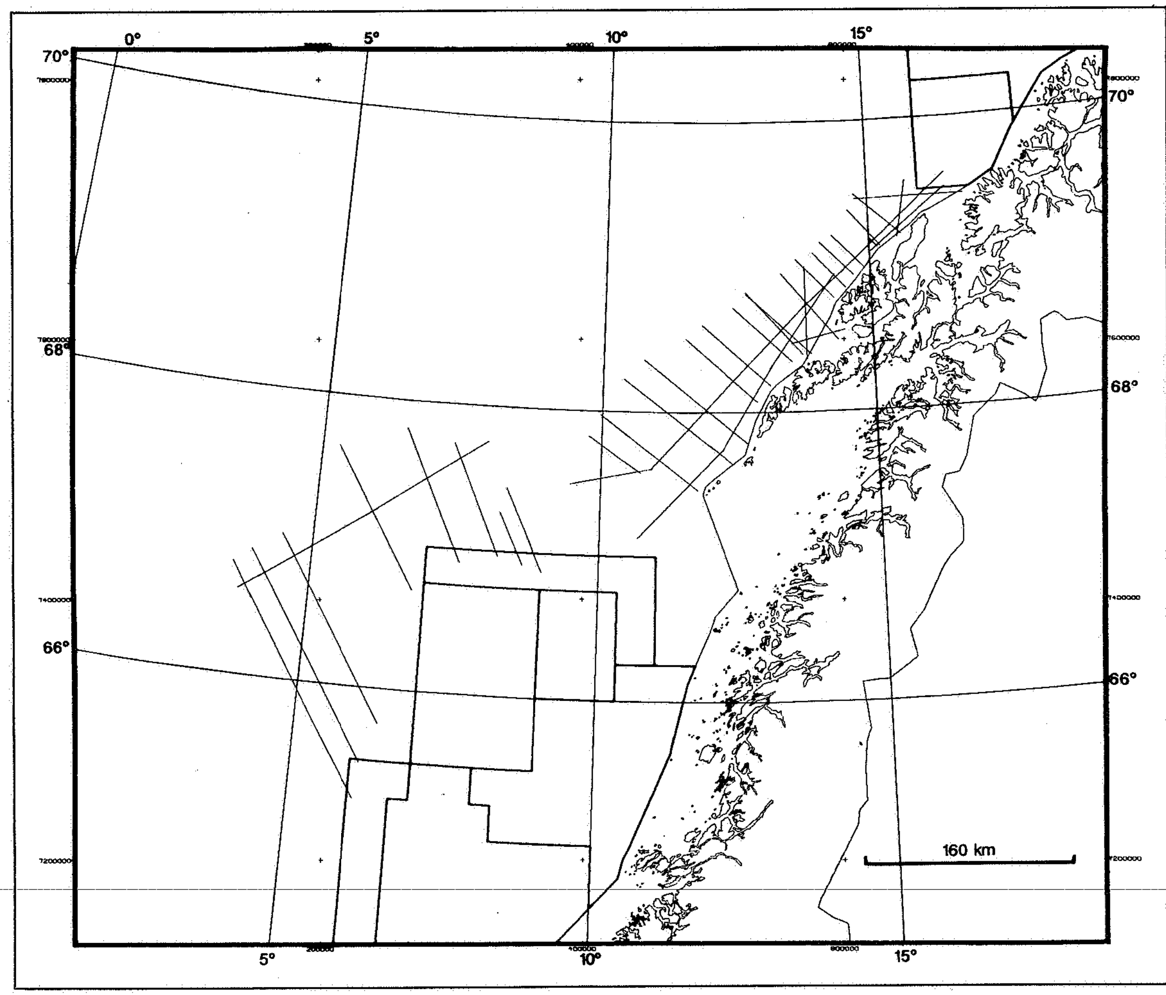
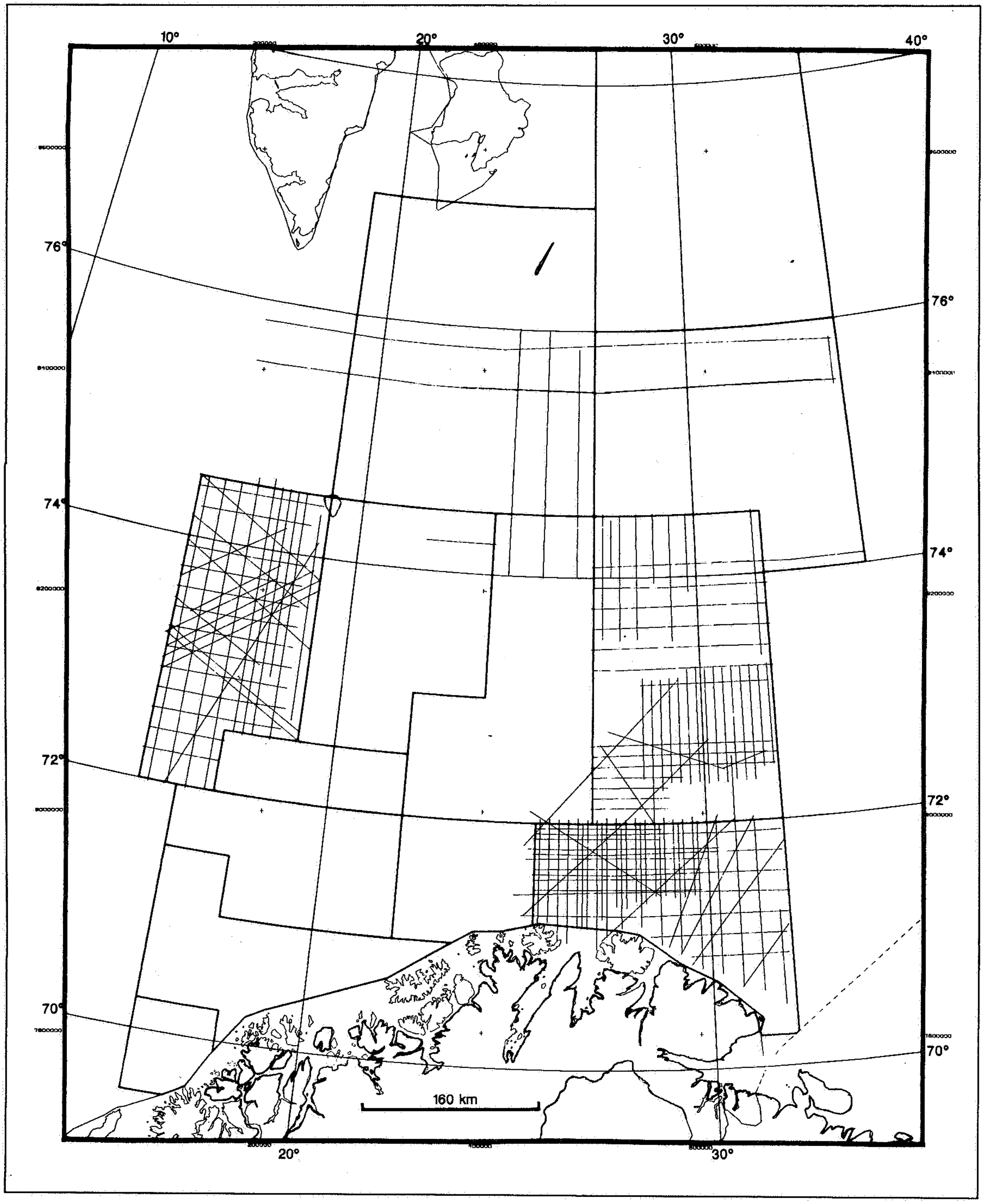


FIG. 2.2.1.d
Seismic surveys offshore North Norway in 1986.



conditions that would otherwise have been prohibitive. One line was shot in a gale.

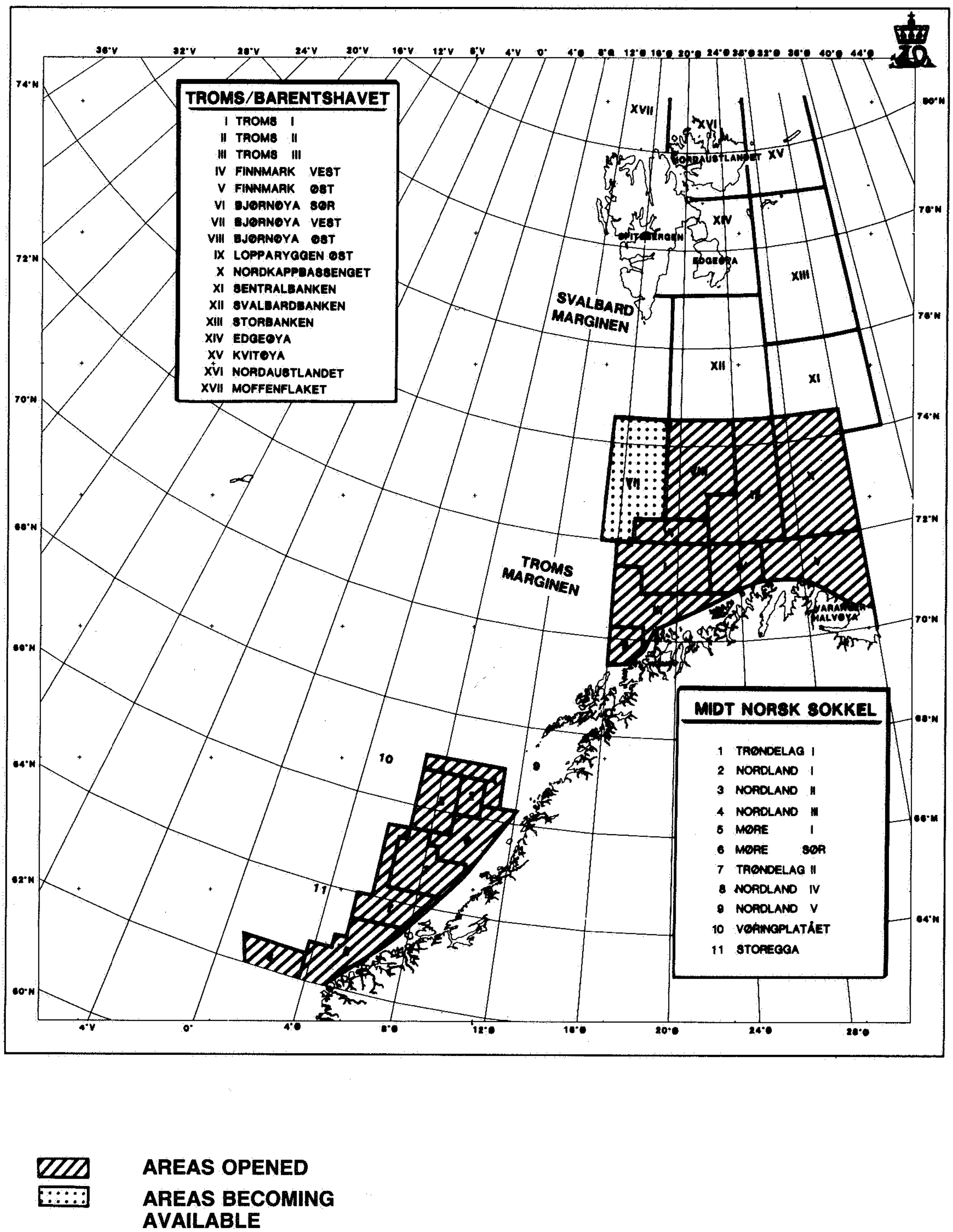
CGG is processing 539 km of the "Geco Gamma" data, the rest being done by GSI in Stavanger.

Bear Island East – test lines

A flip-flop test line of 55 km by 4 was shot from GSIs vessel "Polar Princess" with two cables 150 metres apart. This line is being processed at GSI in Bedford.

CGG has shot and processed a 63 km long test line at the same location from the vessel "Odys Echo". This line was shot with water cannon.

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



Lofoten West

The Western vessel "Western Reliance" collected 1827 km seismics and Gecos "Geco Gamma" 138 km. These data are being processed by CGG in London.

Vøring Plateau

"Western Reliance" collected 1218 km which are undergoing processing by Horizon in London.

Processing of roughly 606 km of Vøring Plateau seismics dating from 1985 is also being done by Horizon in London.

Geco Stavanger has processed three test lines from 1985 which were collected by "Sea Searcher" using vertical cables.

Geco Sandvika has been occupied throughout 1986 with the processing of 4236 km seismics collected from the Jan Mayen Ridge in 1985.

2.2.1.2 Opening of new exploration areas

In 1986 two new areas were prepared for seismics under company direction. These are the North Cape Basin and Finnmark East, as shown in Figure 2.2.1.e.

2.2.1.3 Plans for 1987

In 1987 the Directorate plans to collect almost 20,000 km seismics in the following areas, see Figure 2.2.1.c:

- Bear Island West, approx 3000 km, after which the area will be ready to be opened up
- Northern Barents Sea, 6–8000 km
- Mid-Norway, Lofoten West, 6–8000 km.

In addition plans call for various test lines designed to try out new collection and processing methods.

2.2.1.4 Geophysical surveys under direction of companies

In 1986, a total of 115,043 km seismics were shot on the Norwegian Continental Shelf under oil company or contractor direction. Of this length, 45,508 km were shot in the North Sea, and 69,535 km north of Stad. Figure 2.2.1.a shows all the geophysical surveys performed on the Norwegian Continental Shelf. It is apparent from the figures above that the activity level in the North Sea was stable from 1985–86. The increase in the north is due to the opening up of new areas in the Barents Sea, including the strategic blocks, coupled with the collection of three-dimensional seismics in connection with charting of interesting discoveries on Haltenbanken.

Norwegian companies collected roughly 39,000 km seismics, while foreign companies accounted for roughly 35,000 km. The remainder were so-called "speculative surveys" done by the consultants NOPEC, Geco and GSI.

The main bulk of speculative surveys in the northern areas was concentrated around the so-called strategic blocks.

In all 34,146 km three-dimensional seismics were shot in 1986, which is slightly in excess of 1985.

Collection of three-dimensional data was greatly rationalized by the frequent use of twin cables for collection.

2.2.1.5 Sale of seismic data

In 1986 the Directorate sold seismic data packages to the value of NOK 313.6 million (compared with NOK 377 million in 1985). See Table 2.2.1.5.

The decrease is because sales dried up in the third quarter when the authorities hinted that the pack-

Table 2.2.1.5
Summary of numbers of seismic data packages sold in 1986 and cumulatively

Package No	Name	1986	Total
001	MØRE-TRØNDELAG-REG-PAKKE-1	2	32
002	MØRE-TRØNDELAG-REG-PAKKE-2	1	25
003	TAMPEN SPUR		19
004	MØRE-SØR-84		19
005	TRØNDELAG-REGIONAL	1	23
006	HALTENBANKEN-VEST-84	1	22
007	FRØYABANKEN-84		23
008	MØRE-TRØNDELAG-PAKKE-2		21
009	MØRE-TRØNDELAG-PAKKE-3		28
010	TRÆNABANKEN		30
011	REGIONAL-DATA-NORDLANDSRYGGEN		20
012	NORDLAND-IV-85	4	5
013	REGIONAL-DATA-MIDT-NORSK-SOKKEL		19
014	NORDLAND-II-83		21
015	NORDLAND-III-84	1	7
016	TROMS-II		7
017	REGIONAL-DATA-TROMS-ØST		16
018	FINNMARK-VEST-83		17
019	FINNMARK-VEST-84	1	18
020	NORDLAND-III-85	4	6
021	MØRE-SØR-TEST-84	3	5
022	STOREGGA-85	2	3
023	VØRINGPLATTÅET	2	3
100	TROMS-HOVEDPAKKE		34
101	REGIONEL-TROMS-BARENTSHAVET-73		19
102	TROMS-III-83/84	3	8
103	TROMS-III-85	3	3
105	TROMS-I-ØST-77		17
106	TROMS-NORD-82-PAKKE-1		23
107	TROMS-NORD-83-PAKKE-3		22
108	TROMS-NORD-82-PAKKE-2		15
109	TROMS-NORD-83-PAKKE-4		15
200	BJØRNØYA-PAKKE-1		20
201	BJØRNØYA-SØR-84		20
202	BJØRNØYA-ØST-REGIONAL-84		12
203	BJØRNØYA-ØST-84		11
204	BJØRNØYA-ØST-TILLEGG-NORD	3	11
205	BJØRNØYA-VEST-REGIONAL-84	2	7
206	LOPPARYGGEN-ØST-REGIONAL-84	7	13
207	LOPPARYGGEN-ØST-85-SSL-DIAG.	13	13
208	LOPPARYGGEN-ØST-85-NORD	12	12
209	LOPPARYGGEN-ØST-85-GECO-DIAG	12	12
210	LOPPARYGGEN-ØST-85-GRID	14	14
300	BARENTSHAVET-SØR-ØST-HOVEDPAKKE	1	12
301	BARENTSHAVET-SØR-ØST-PAKKE-2		8
302	NORDKAPPBASSENGET-85-GECO-DIAG	7	7
303	NORDKAPPBASSENGET-85-NORD	7	7
304	NORDKAPPBASSENGET-85-GRID	7	7

age prices would be cut from 40 to 15 per cent of cost as of 1 January 1987. Partial recoupment of this can be expected from increased sales after that date.

The following companies bought all the Directorates seismic data packages for the opened-up areas noted.

Trøndelag I (1)
Agip, Amerada, Amoco, Arco, BP, Britoil, Conoco, Deminex, DNO, Elf, Esso, Fina, Hydro, Mobil, Occidental, Petrobras, Phillips, Saga, Shell, Statoil, Svenska Petroleum, Tenneco, Texaco, Texas Eastern, Total, Union and ØMV.

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

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

Nordland III
Elf, Esso, Mobil, Saga, Shell and Statoil.

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

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

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

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

Nordland IV
Elf, Mobil, Saga, Shell and Statoil.

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

Troms II
Elf, Esso, Hydro, Mobil, Saga, Shell and Statoil.

Troms III
Mobil, Saga and Statoil.

Finnmark West
Agip, Amerada, Arco, BP, Conoco, Elf, Esso, Fina, Hyd, Mbil, Phillips, Saga, Shell, Statoil, Tenneco and Total.

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

Bear Island East
Statoil and Total.

Loppa Ridge East
Amerada, BP, Esso, Fina, Hydro, Mobil, Phillips, Saga, Shell, Statoil, Texas Eastern and Total.

2.2.1.6 Release of shelf data and material

In connection with its follow-up of the oil activity on the Norwegian shelf the Norwegian Petroleum Directorate receives copies of well logs and continual, representative samples of drill cuttings and cores.

Samples of drill cuttings are taken every ten meters downhole and every three meters in formations which may contain hydrocarbons. The same sampling frequency applies for wet samples, for which a minimum weight of half a kilo applies.

The Directorate receives complete longitudinal cuts of well cores containing at least one quarter of the core from exploration wells, and half the core in production wells.

As of 31 December 1986 the Directorate has stored 44,256 meters of well core from 480 wells, 291,222 samples of washed drill cuttings from 662 wells and 296,382 wet samples from 743 wells on the Norwegian shelf. This includes production wells.

In addition comes material from 62 foreign wells, mainly in the UK sector of the North Sea, though also including samples from Svalbard, Andøya, Hopen, Tanzania and Mozambique.

Release

The Norwegian Petroleum Directorate is responsible for publishing data and releasing materials for educational and research purposes. Data is released five years after completion of the well. Licensees interpretations are not released.

Well Data Summary Sheets (WDSS) are published annually and provide a summary of wells which become five years old in the calendar year. The purpose of the series is to show which wells have been released, and what core and logs are available for the various wells. Also released are technical data and test results, plus cumulative logs containing lithologies of each well on a 1:4000 scale.

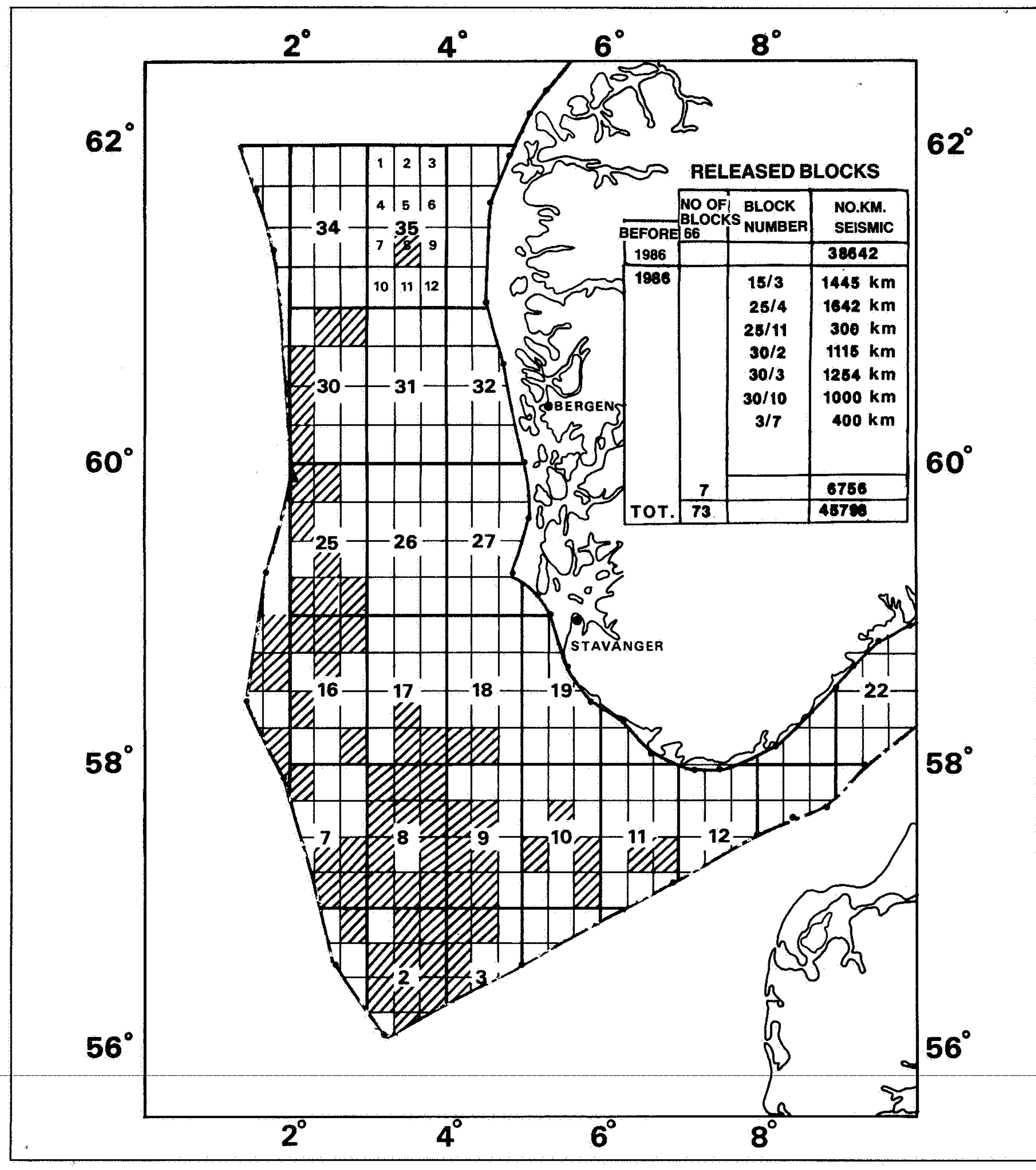
The Directorate's core study room is provided for study of core materials, drill cuttings and wet samples, and in special cases materials may be taken out for study and analysis outside the building. Here, too, the five year release rule applies.

Seismics are released in packages covering individual blocks and only become available for blocks where a production licence has been awarded and when the seismics are over five years of age.

As of 31 December 1986, data from 73 blocks had been released, seven of these being in 1986. In total 45,798 km of profiles have been released, of which 7,156 in 1986.

Figure 2.2.1.f gives a summary map of the blocks for which data have been released.

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



	NO OF BLOCKS	BLOCK NUMBER	NO.KM. SEISMIC
BEFORE 1986	66		38642
1986		15/3	1445 km
		25/4	1642 km
		25/11	300 km
		30/2	1115 km
		30/3	1254 km
		30/10	1000 km
		3/7	400 km
	7		6756
TOT.	73		45798

Table 2.2.1.a
Licenses for scientific surveys to find natural resources

Licence	Name of holder	Field of work Geo-physics	Geo-logy	Bio-logy	Area
215	Universitetet i Bergen Geologisk institutt Avd B Bergen		x		Nordsjøen
216	Universitetet i Bergen Jordskjelvstasjonen Bergen	x			Nordsjøen
217	Universität Hamburg Hamburg Forbundsrepublikken i Tyskland		x		Nordsjøen
218	Institutt for kontinental- sokkelundersøkelser Trondheim	x			Barentshavet
219	Natural Environment Research Council South Glamorgan South Wales		x		Spitsbergen
220	Institutt für Meereskunde an der Universität Kiel Kiel Forbundsrepublikken Tyskland			x	Nordsjøen
221	Institut für Meereskunde an der Universtität Kiel Kiel Forbundsrepublikken Tyskland	x		x	Vøringplatået Vest og sydvest Lofoten
222	Norges geologiske under- søkelse 7001 Trondheim	x			Nord-Trøndelag Sør-Trøndelag Møre og Romsdal
223	Institutt for kontinental- sokkelundersøkelser Trondheim		x		Nordkappbassenget
224	Institutt für Meereskunde Universität Hamburg Hamburg Forbundsrepublikken Tyskland		x	x	Norskehavet
225	Universitetet i Tromsø Institutt for biologi og Geologi, Tromsø	x	x		Finnmarkskysten Barentshavet
226	Institut Francais du Pètrole Rueil Malmaison, Frankrike	x			Norskehavet Barentshavet
227	Universität Hamburg Hamburg Forbundsrepublikken Tyskland	x			Norskehavet
228	Universitetet i Oslo Institutt for geologi Oslo	x			Midt-norsk konti- nentalsokkel- margin/Jan Mayen-ryggen
229	Universitetet i Bergen Jordskjelvstasjonen Bergen	x			Vest Spitsbergen
230	Universitetet i Bergen Jordskjelvstasjonen Bergen	x			Kystnære områder mellom Sogne- fjorden og Trond- heimsfjorden
231	Universitetet i Bergen Jordskjelvstasjonen Bergen	x			Kystnære områder mellom Trøndelag og Rogaland
232	Universitetet i Oslo Institutt for geologi Oslo	x			Skagerrak Ytre Oslofjord

2.2.1.7 Scientific research

As of 31 December 1986 a total of 232 permits for scientific studies on the Norwegian shelf had been awarded. Table 2.2.1.a shows that 18 such permits were given in 1986. Most studies are concerned with geophysics, some with geology and a few with biology.

2.2.2 Exploration and appraisal drilling

At the end of 1985 eleven exploration wells were being drilled. Nine of these were completed in 1986, the other two being suspended.

In the year 36 new exploration wells were spudded, including 26 exploration and 10 appraisal wells. See Figure 2.2.2.a.

This represents a sizeable decrease from 1985 when 50 exploration wells were drilled. The decrease first became noticable in August 1986 see Table 2.2.2.a.

During the year 46 exploration wells were completed, four were suspended and four were still drilling at year-end.

At year-end a total of 533 exploration wells had been drilled on the Norwegian shelf. Of these, 386 were for exploration and 147 for appraisal purposes.

FIG. 2.2.2.a
Exploration drilling on the Norwegian Continental Shelf per year from 1966–86. Number of wells

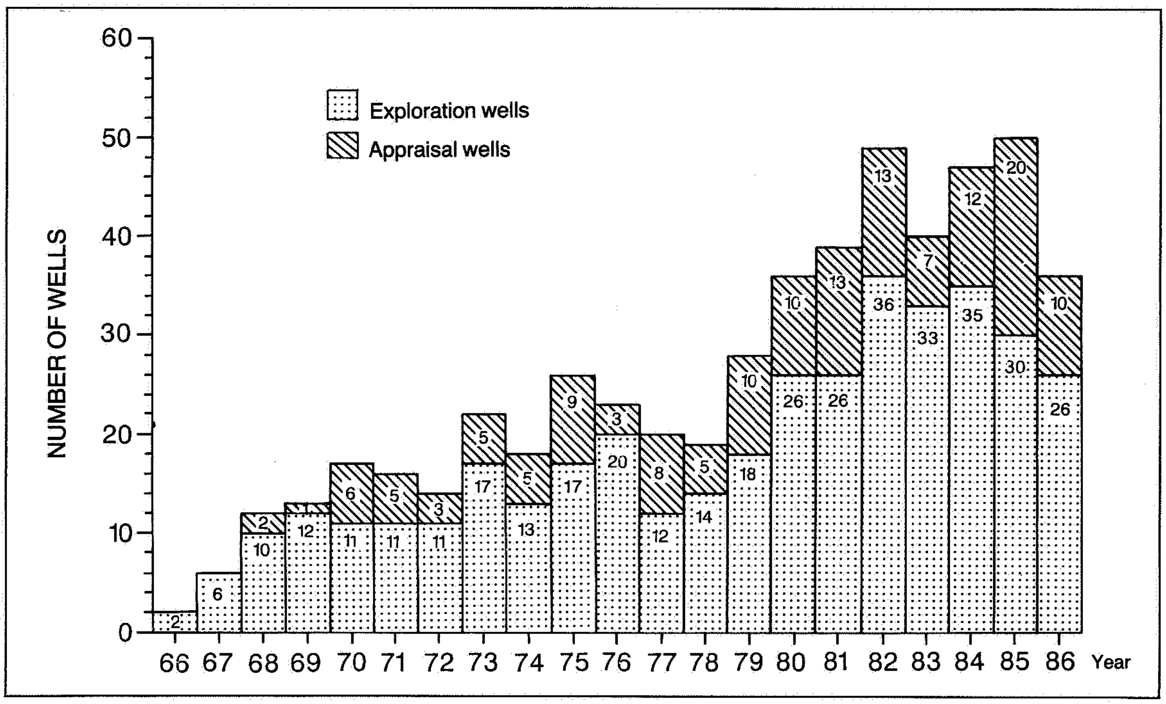


Table 2.2.2.a
Exploration drilling August–September 1985–86

Year	Drilling rigs in activity at the first of each month					Rig days per month				
	Aug	Sept	Oct	Nov	Dec	Aug	Sept	Oct	Nov	Dec
1985	12	12	10	10	9	407	334	321	314	349
1986	12	9	5	4	4	262	206	148	134	119

Drilling activity was split between 19 wells south and 17 north of Stad.

A total of 25 exploration wells had been temporarily abandonned on the Norwegian shelf at the end of the year.

Wells suspended with equipment emplaced on the seabed include:

1/09–01	25/02–09	34/10-A-1 H	1/09–04	25/02–10	34/10-A-2AH
			1/09–06	30/02–01	34/10-A-3 H
			2/07–14	30/03–04	34/10-A-4 H
			2/07–19	30/06–09	6407/09–03
			2/11–06 S	30/06–19	6407/09–05
			15/09–17	30/09-T-1	6407/09–06
			25/01–07	34/10–03	
			25/01–08	34/10–05	

FIG. 2.2.2.b
Wells drilled in 1986 in relation to structural main features of the North Sea.

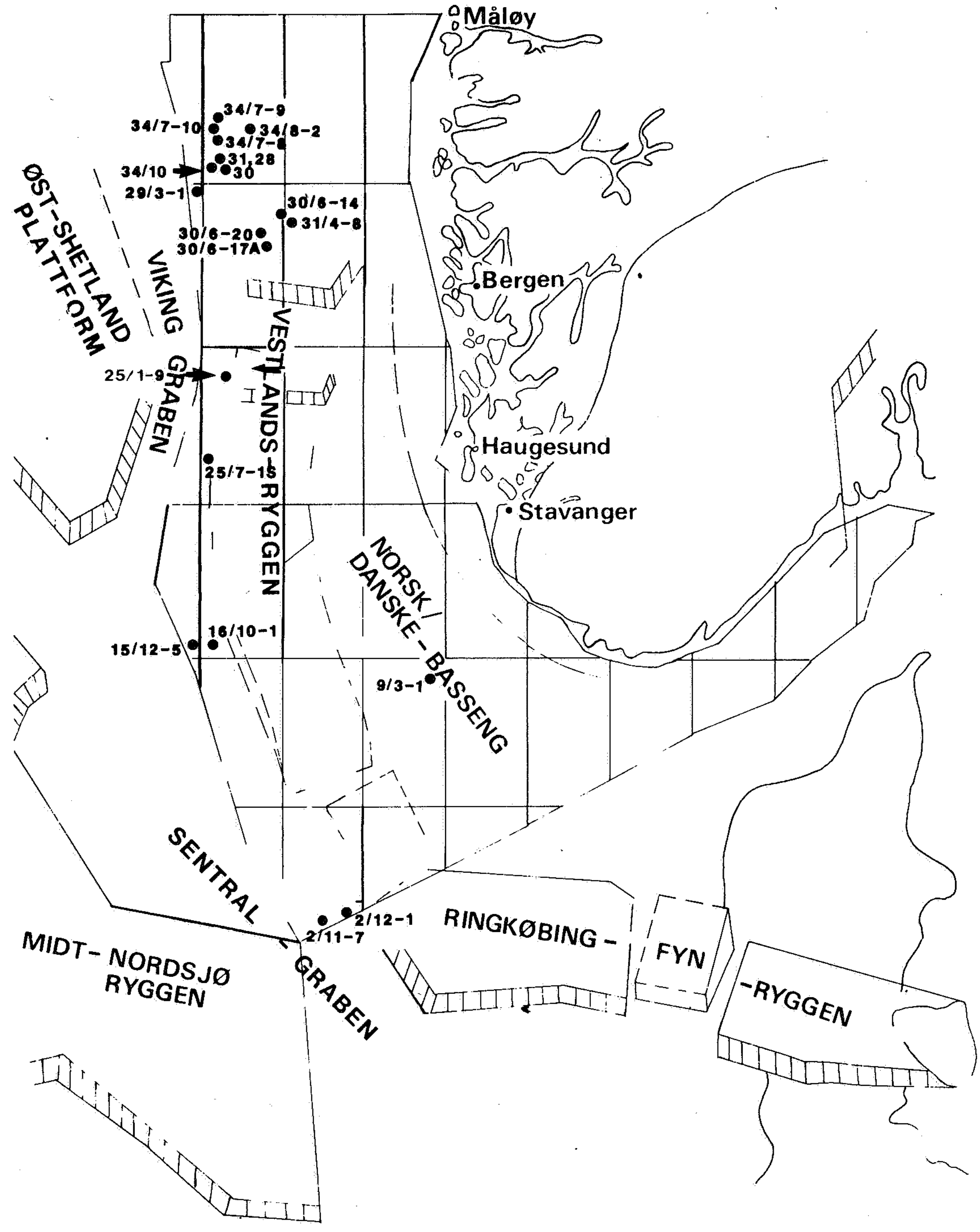


Fig. 2.2.2.c
Location chart for Mid-Norway

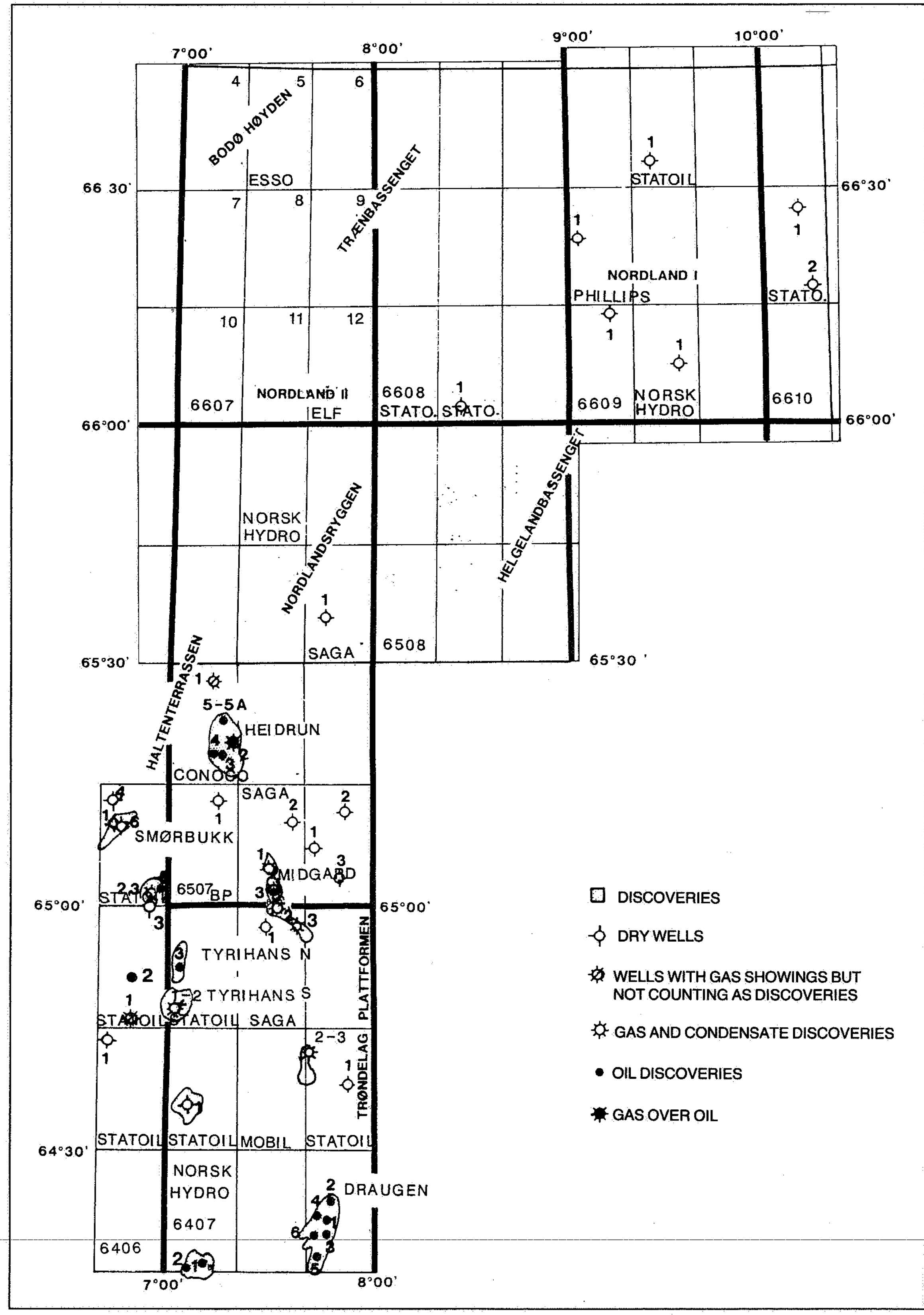
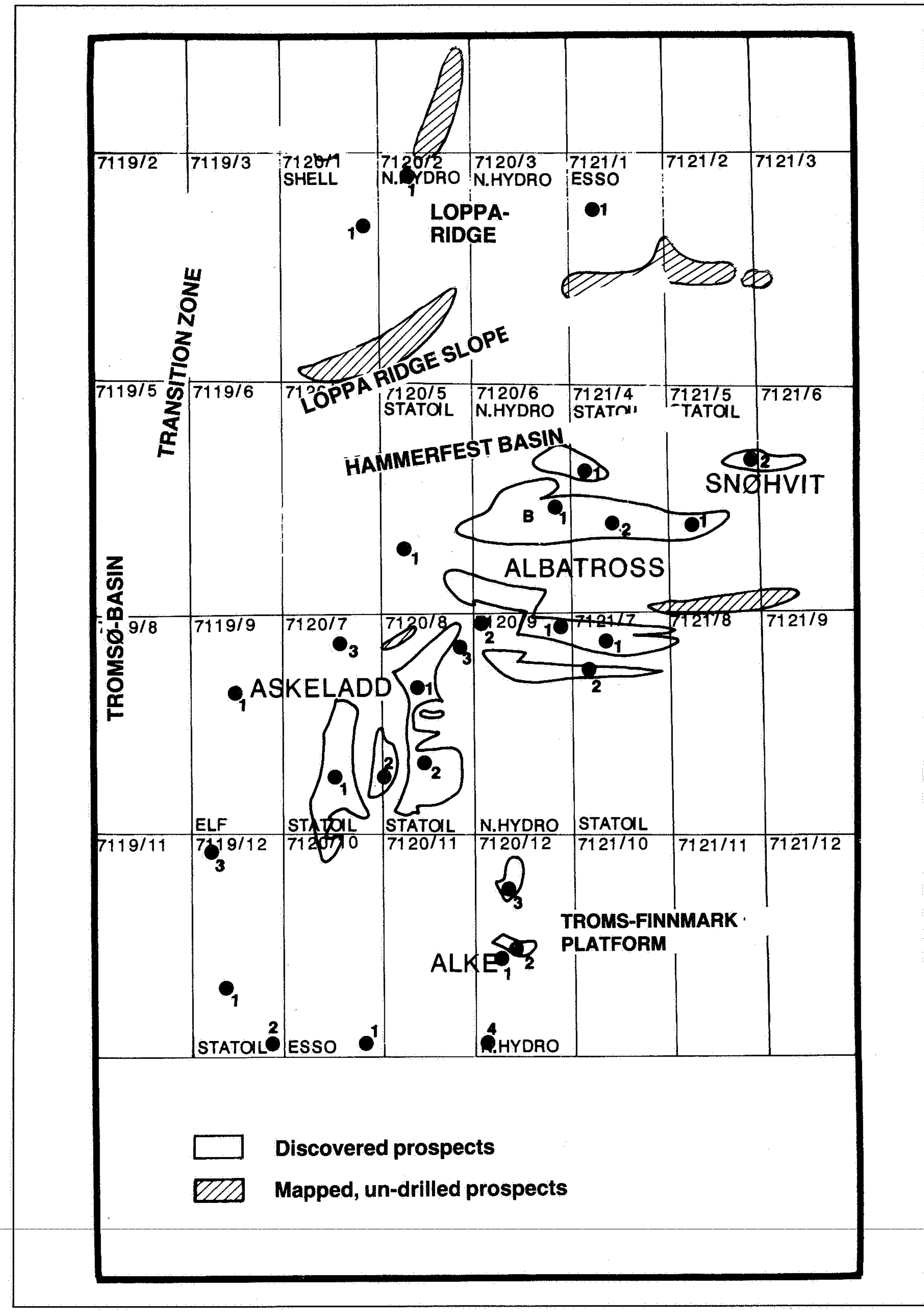


FIG. 2.2.2.d
Wells drilled in 1986 in relation to main structural elements on Tromsøflaket.



Tab 2.2.2.b
Spudded and/or completed exploration wells (U) and appraisal wells (A) in 1986.
R = Reentry, X = Not reached prospective depth, S = Sidetracked

Well No	Licence No	Position North East	Dates of spudding and completion	Operator Drilling rig	Well type Competition-classification	Water depth KBE	Total depth and Geological period
30/06–13 R	366	60 33 14.59	86.09.08	Hydro	Appraisal	105	2725
	053	02 49 21.76	86.09.11	Treasure Hunter	Oil/gas	25	Upper Jur.
30/09–02 R	370	60 27 53.00	86.06.01	Hydro	Exploration	104	2830
	079	02 49 13.03	86.07.07	Treasure Hunter	Susp. for test m/PTS	25	Upper Jura.
30/06–17 R	478	60 34 15.77	85.11.14	Hydro	Exploration	111	2650
	053	02 44 59.84	86.02.04	Treasure Hunter	Oil	25	Jurassic
7120/01–01 R2	480	71 55 00.83	86.03.18	Shell	Exploration	342	4003
	108	20 18 07.13	86.07.21	Borgny Dolphin	Dry well	25	Permian
6407/06–02 R	484	64 42 29.56	86.05.08	Statoil	Exploration	221	523
	092	07 40 32.58	86.05.20	Ross Isle	Abandoned after blowout	22	
6407/06–02 R2 X	484	64 42 29.56	86.06.13	Statoil	Exploration	221	523
	092	07 40 32.59	86.06.24	Bucentaur	Abandoned	2	
6506/12–05	485	65 02 28.60	85.10.17	Statoil	Appraisal	301	4588
	094	06 58 21.93	86.03.27	Dyvi Delta	Oil	29	Lower Jura.
6407/07–01 S	486	64 16 31.49	85.10.19	Hydro	Exploration	330	3950
	107	07 12 21.12	86.04.07	Polar Pioneer	Oil/gas	23	Triassic
7121/01–01 R	487	71 56 25.74	86.03.19	Esso	Exploration	370	5000
	111	21 04 36.52	86.08.23	Zapata Ugland	Dry well	25	Carboniferous ?
34/08–01	488	61 21 53.50	85.11.08	Hydro	Exploration	324	3610
	120	02 25 57.57	86.03.08	Treasure Scout	Oil/gas	23	Triassic
6507/07–04	490	65 19 11.56	85.11.06	Conoco	Appraisal	345	2850
	095	07 15 44.99	86.01.13	Nortrym	Oil/gas	25	Jurassic
7/11–09	491	57 12 11.79	85.11.26	Hydro	Exploration	91	4272
	070	02 24 50.18	86.03.09	Byford Dolphin	Dry well	25	Triassic
6/03–02	492	57 54 25.99	85.11.21	Statoil	Exploration	89	4091
	086	01 59 14.19	86.03.10	Ross Isle	Dry well	22	Permian
25/06–01	493	59 31 32.04	85.12.18	Saga	Exploration	120	2281
	117	02 48 02.07	86.02.03	Treasure Saga	Oil/gas	26	Bedrock
25/02–10 S	494	59 53 11.80	85.12.02	Elf	Exploration	120	2967
	112	02 30 08.33	86.03.19	Henry Goodrich	Suspended	21	
34/10–27 R	495	61 10 31.12	86.01.27	Statoil	Appraisal	135	450
	050	02 11 23.96	86.01.31	West Venture	Gas	32	
34/10–29	496	61 10 33.06	85.12.27	Statoil	Appraisal	135	405
	050	02 11 28.76	86.01.26	West Venture	Gas	32	
34/04–06	497	61 34 15.49	85.12.31	Saga	Appraisal	374	3282
	057	02 13 19.52	86.03.26	Vinni	Oil	26	Triassic
34/10–28 X	498	61 06 31.99	86.01.02	Statoil	Appraisal	133	521
	050	02 15 23.72	86.01.16	Dyvi Stena	Abandoned	25	
6407/09–06	499	64 19 58.07	86.01.02	Shell	Appraisal	297	1800
	093	07 44 23.70	86.03.13	Borgny Dolphin	Susp. Oil	25	Lower Jurassic
6507/07–05	500	65 21 30.27	86.01.16	Conoco	Appraisal	332	2660
	095	07 17 35.08	86.03.06	Nortrym	Oil/gas	25	Lower Jurassic
34/10–30	501	61 06 31.07	86.01.16	Statoil	Appraisal	133	3785
	050	02 15 23.92	86.05.10	Dyvi Stena	Oil/gas	25	Triassic
34/10–31	502	61 10 32.40	86.02.01	Statoil	Appraisal	132	420
	050	02 11 15.46	86.04.10	West Venture	Gas	32	
34/07–08	503	61 22 25.93	86.02.05	Saga	Exploration	133	2766
	089	02 08 33.37	86.04.11	Treasure Saga	Oil	26	Triassic
30/06–17 A	504	60 34 15.77	86.02.04	Hydro	Exploration	111	3677
	053	02 44 59.84	86.03.18	Treasure Hunter	Gas	25	Lower Jurassic
6507/07–05 A	505	65 21 30.27	86.03.06	Conoco	Appraisal	332	2673
	095	07 17 35.08	86.04.05	Nortrym	Oil/gas	25	Lower Jurassic
30/06–20	506	60 37 20.52	86.03.10	Hydro	Exploration	111	3042
	053	02 42 18.52	86.04.13	Treasure Scout	Dry well	23	Lower Jurassic
15/12–05	507	58 04 53.36	86.03.12	Statoil	Exploration	84	3105
	038	01 54 54.24	86.05.04	Ross Isle	Oil	22	Triassic
31/04–08	508	60 31 22.82	86.03.21	Hydro	Appraisal	124	2570
	055	03 00 09.59	86.05.11	Treasure Hunter	Oil/gas	25	Triassic
6506/12–06	509	65 09 57.60	86.03.31	Statoil	Appraisal	276	4741
	094	06 46 43.19	86.08.02	Dyvi Delta	Gas/Condensate	29	Lower Jurassic
34/07–09	510	61 29 11.99	86.04.13	Saga	Appraisal	304	3214
	089	02 11 43.60	86.06.12	Treasure Saga	Oil	26	Triassic
30/06–19	511	60 42 58.03	86.04.09	Hydro	Exploration	136	3304
	053	02 54 54.18	86.06.21	Polar Pioneer	Susp. oil/gas	23	Lower Jurassic
25/07–01 S	512	59 18 35.23	86.04.14	Conoco	Exploration	127	3592
	103	02 16 05.37	86.07.19	Nortrym	Dry well	25	Bedrock
2/11–07	513	56 14 06.09	86.04.16	Hydro	Exploration	73	5042
	068	03 37 38.84	86.09.06	Treasure Scout	Dry well	23	Upper Jur.
29/03–01	514	60 57 50.24	86.05.20	Total	Exploration	131	4427
	119	01 56 13.25	86.09.15	Byford Dolphin	Oil/gas	25	Upper Jur.

Well No	Licence No.	Position North East	Dates of spudding and completion	Operator Drilling rig	Well type Completion classification	Water depth KBE	Total depth and geological period
16/10–01	515	58 03 23.68	86.05.25	Agip	Exploration	84	3151
	101	02 03 14.05	86.07.14	Dyvi Stena	Dry well	25	Permian
7121/05–02	516	71 40 20.79	86.05.05	Statoil	Exploration	328	2543
	110	21 39 24.42	86.07.06	Ross Isle	Oil/gas	22	Triassic
6507/06–01	517	65 36 37.59	86.06.15	Saga	Exploration	419	4040
	123	07 43 43.04	86.08.23	Treasure Saga	Dry well	26	Triassic
6507/02–01	518	65 54 02.48	86.06.24	Hydro	Exploration	390	4477
	122	07 26 16.43	86.09.29	Polar Pioneer	Dry well	23	Triassic
6406/03–02	519	64 51 45.78	86.06.28	Statoil	Exploration	300	4527
	091	06 49 51.87	86.11.22	West Vanguard	Oil/gas	22	Upper.triassic
7121/07–02	520	71 26 37.91	86.07.07	Statoil	Exploration	343	2156
	100	21 03 21.42	86.08.12	Ross Isle	Gas	22	Triassic
6607/12–01	521	66 12 54.15	86.07.19	Elf	Exploration	391	3521
	127	07 44 26.72	86.10.01	Henry Goodrich	Dry well	21	
34/08–02	522	61 22 10.51	86.10.04	Hydro	Exploration	378	3240
	120	02 31 36.09	86.11.17	Polar Pioneer	Dry well	23	Triassic
6608/11–01	523	66 01 04.02	86.07.19	Statoil	Exploration	382	1620
	128	08 23 38.10	86.08.13	Dyvi Stena	Dry well	25	Triassic
6507/07–06	524	65 21 30.03	86.07.23	Conoco	Appraisal	351	2525
	095	07 19 10.35	86.09.06	Nortrym	Oil/gas	25	Lower Jurassic
9/03–01	525	57 49 45.19	86.07.29	Shell	Exploration	124	1971
	115	04 45 58.38	86.09.04	Borgny Dolphin	Dry well	25	Triassic
6406/03–03	526	64 59 49.19	86.08.04	Statoil	Exploration	303	4416
	091	06 53 27.90	86.10.26	Dyvi Delta	Dry well	29	Lower Jurassic
34/07–10	527	61 25 02.64	86.08.26	Saga	Exploration	300	3000
	089	02 07 36.23	86.10.29	Treasure Saga	Oil	26	Triassic
25/01–09	528	59 50 13.34	86.09.09	Hydro	Exploration	112	2807
	129	02 13 30.24	86.10.11	Treasure Scout	Dry well	23	Lower Cretaceous
6507/08–01	529	65 18 35.20	86.10.28	Statoil	Exploration	342	2600
	124	07 20 52.80	86.12.09	Dyvi Delta	Oil/gas	29	Lower Jurassic
2/12–01	530	56 14 04.07	86.10.14	Hydro	Exploration	70	
	113	03 42 27.50	00.00.00	Treasure Scout	23		
6407/02–03	531	64 56 01.39	86.11.07	Saga	Exploration	250	
	074	07 39 53.04	00.00.00	Treasure Saga	26		
6407/07–02	532	00 00 00.00	86.11.20	Hydro	Exploration	338	
	107	00 00 00.00	00.00.00	Polar Pioneer	23		
6407/06–03	533	00 00 00.00	86.12.15	Statoil	Exploration	222	
	092	00 00 00.00	00.00.00	Dyvi Delta	29		

Figures 2.2.2.b – d show the wells spudded in the three continental shelf areas (North Sea, Mid-Norway and North Norway) in relation to structural main features.

There was great activity of Mid-Norway in 1986. Fifteen exploration wells were spudded, comprising roughly 42 per cent of total activity. Activity off North Norway was low with only two exploration wells.

Norwegian companies Saga, Norsk Hydro and Statoil were responsible in 1986 as operators of 27 of the spudded wells, or 75 per cent. The remaining nine wells were operated by Conoco, Shell, Agip, Elf and Total. See Table 2.2.2.b.

Since petroleum activity started in 1966, 18 different companies have held operatorships on the Norwegian Continental Shelf. Of these, Statoil has operated the greatest number of wells with 122, followed by Norsk Hydro with 77 and Phillips with 52. See Table 8.3.e.

Sixty-one different mobile drilling installations have so far seen service on the Norwegian shelf. See Table 8.3.h.

2.2.2.1 Distribution by prospect type

To an even greater extent than previously exploration activity in 1986 concentrated on Jurassic sandstone prospects. Thirty-three of the 36 exploration wells spudded were directed to such prospects.

The other three exploration wells were targeted at the Eocene or Palaeocene (Well 25/1–9), Cretaceous (6607/12–1) and Quaternary (34/10–27). Several wells also had secondary prospects.

Of the eleven exploration wells being drilled at the end of 1985, eight were primarily aimed at Jurassic strata. One was directed to the Triassic (34/4–6), one to the Eocene (25/2–10) and one, a shallow gas well on Gullfaks, aimed at a Quaternary main prospect (34/10–29).

2.2.2.2 Svalbard

Again in 1986 there was considerable oil and gas exploration activity on Svalbard. This was also the case for charting and seismics activity on land and sea.

Among the more active participants were BP, Statoil, Arctic Development Corporation (ADC) and Trust Arktikugol.

BP has expanded its activity compared with 1985 and in 1986 shot seismics on the majority of glaciers on Kapp Heer Land. Statoil conducted seismic surveys at Grimfjellet in the South Spitsbergen National Park. The ADC also shot some seismics in Berzelius Valley.

The Russian company Trust Arktikugol is at present drilling a well which is expected to be completed in summer 1987. Because of technical difficulties this well has taken considerably longer than planned.

In addition to land-based exploration, several companies have collected seismics in the fjords and sea areas off Svalbard. Geco has conducted the majority of jobs in Storfjorden, Van Mijenfjorden, Van Keulenfjorden and Isfjorden. Some work was also done along the western and northern coasts of Svalbard.

Oil acreage has been allocated to two companies, Norsk Polarnavigasjon and Nordisk Polarinvest (NPI). These plots are located in Van Mijenfjorden and on the northern side of the fjord.

Figure 2.2.2.e shows the sites of wells on Svalbard and Table 2.2.2.c the 13 drilling licences awarded there for oil and gas drilling.

The activity level on Svalbard is expected to stabilize or fall slightly in 1987. Statoil and Store Norske in collaboration with Norsk Hydro and Norsk Polarnavigasjon in collaboration with Svensk Polar Energi have definite plans to shoot land-based seismics in 1987, and Nordisk Polarinvest in collaboration with other companies has planned a well at Haketangen in 1987.

The Directorate made several tours of inspection to Svalbard in 1986. These were carried out in collaboration with the Mines Superintendant and Governor's office.

2.2.3 Discoveries and fields being evaluated

2.2.3.1 New discoveries in 1986

Despite the low oil prices and reduced exploration activity, several new, promising discoveries were made in 1986. Haltenbanken again showed itself to be the most fruitful exploration area on the Norwegian shelf with discoveries in two new structures.

The most promising strike was made by Norsk Hydro in Block 6407/7, the runner-up by Statoil in Block 6406/3. There was great interest, too, in the tenth round blocks in the North Sea, particularly in connection with the Stord Basin and Egersund Basin, where there is considerable uncertainty regarding the maturity of the source rock. In Block 25/6 Saga discovered small quantities of hydrocarbons, proving the presence of mature source rock in the Stord Basin. It is still uncertain whether these have managed to generate sufficient hydrocarbons for there to be a chance of making larger discoveries in other structures. On the Egersund Basin one dry well has been drilled so far in Block 9/3.

Statoil made a new oil discovery on Block 15/12 in the same structural complex as the 15/12–4 strike in 1984. The discovery warrants further attention, particulary concerning oil in associated structures to the southeast and east.

In the Oseberg area Norsk Hydro has made yet another discovery on a separate structure in the northwest of the block immediately to the north of the Beta South structure. A long-term test will be run of this discovery using the production and test ship "Petrojarl I".

Block 2/12

Norsk Hydro proved oil at high pressure in Jurassic rock close to the dividing line with Denmark. Exploration well 2/12–1 which entered the same structural complex as the Gert-1 discovery had not been tested by the end of the report period.

Block 15/12

This block was allocated in 1975 and partially relinquished in 1981. Exploration well 15/12–5 was drilled in a northeastern segment of a structure proven by 15/12–4. The latter was not tested since the strike was only a very thin oil zone right on the southwestern flank of the structure. Well 15/12–5 proved oil in a Jurassic sandstone reservoir. The size of the resources has not yet been determined.

Block 25/2

Exploration well 25/2–10 entered a previously relinquished part of Block 25/2. The area was reallocated as production licence 112 to operator Elf. Well 25/2–10 entered a new structure east of the Frigg field. The exploration well proved gas and oil in two strata dating from the Oligocene and Eocene, respectively. Technical troubles prevented testing for hydrocarbons, and new wells will be drilled for this purpose. Tests so far, however, (RFT) indicate that the oil is too viscous to produce.

Block 25/6

Exploration well 25/6–1 entered the eastern side of the Utsira Heights to test the hydrocarbon potential in the Stord Basin. Even though light oil was proven in mid-Jurassic sandstone, the resources are insignificant. The well was tested and maximum production measured as 300 Sm^3 oil and 39,000 Sm^3 gas a day through an 8 mm choke.

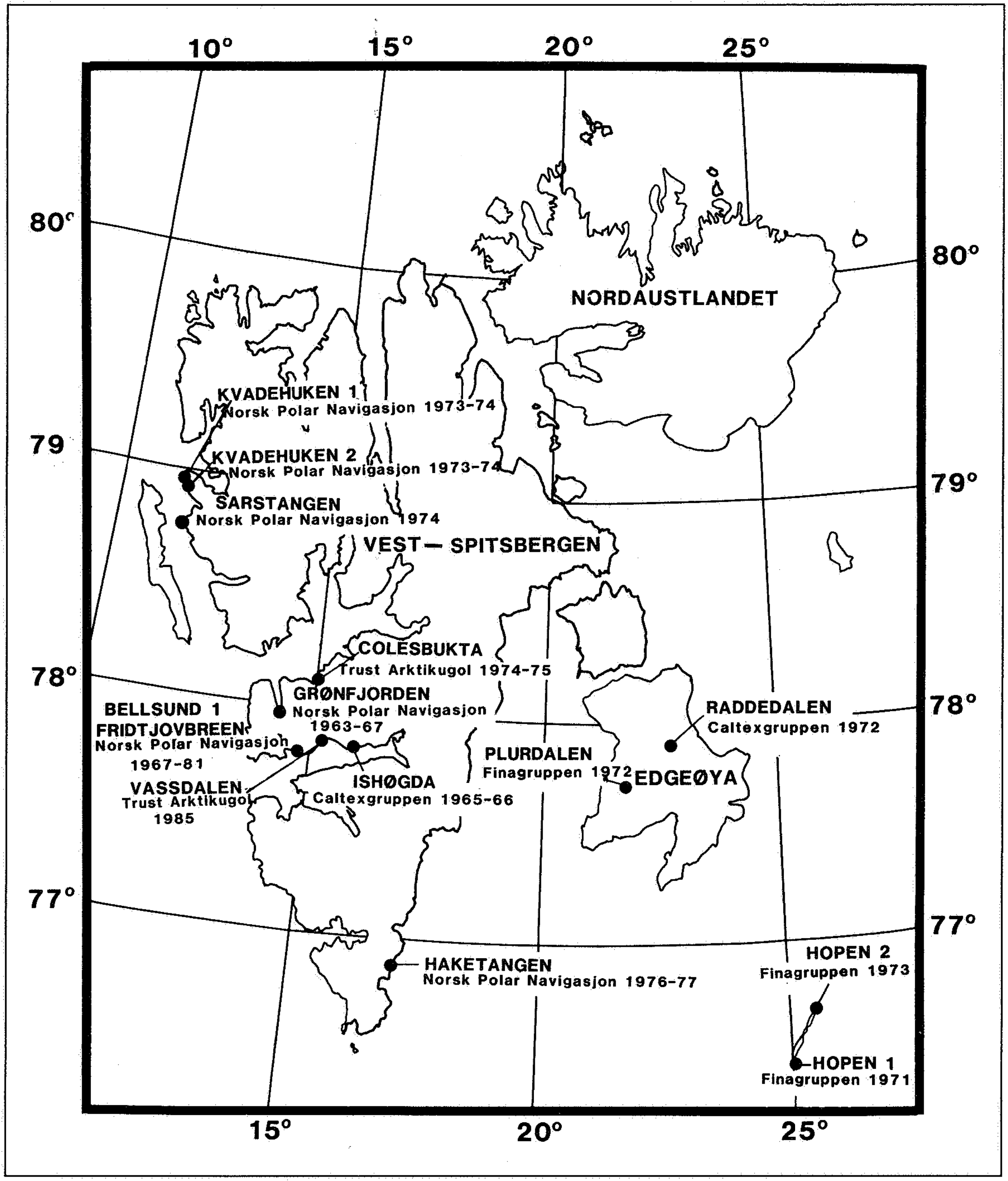
Block 29/3

Total as operator for production licence 119 drilled exploration well 29/3–1 on a block on the dividing line of the UK sector slightly south of Brent (Great Britain) and Gullfaks. Gas and oil was proven in mid-Jurassic sandstone. The well was tested and yielded maximum production of 667 Sm^3 gas plus 540,000 Sm^3 oil a day.

Block 30/6

Exploration well 30/6–17 was drilled west of the Oseberg field's Alpha structure to prove oil and gas in the Statfjord formation. However, the well was

FIG. 2.2.2.e
Well locations on Svalbard



mislocated and encountered oil-bearing strata of the mid-Jurassic (Cook formation), while the Statfjord formation was water bearing. The oil zone was tested and produced 570 Sm^3 oil and 80,000 Sm^3 gas a day through a 17.5 mm choke. The operator decided to directionally drill the well to hit the planned target. Exploration well 30/6–17A proved only gas at a higher level of the Cook formation. This was not tested.

Exploration well 30/6–19 entered a separate fault block north of the Beta structure in the northeast of Block 30/6. Oil was proven in sandstone strata dating from the mid-Jurassic. The best test was very encouraging with 1320 Sm^3 oil and 71,380 Sm^3 gas a day through a 23.7 mm choke. Oil density was 0.83 g/cm^3.

Tab 2.2.2.c
Drilling permits on Svalbard

Well (locality)	Position North East	Spudded	Completed	Drilling time Days	Operator Licensee	Total depth metres	KB elev. over MSL metres
Grønnfjorden I	77 57 34	09.06.63	05.09.63	287	Norsk Polar Navig.	971,6	7,5
(Nordenskiøld Land)	14 20 36	13.06.64	26.08.64		Norsk Polar Navig.		
		26.06.65	08.09.65				
		26.06.67	12.08.67				
Ishøgda I	77 50 22	01.08.65	15.03.66	277	Texaco	3304	18
(Spitsbergen)	15 58 00				Caltex gruppen		
Bellsund I	77 47	23.08.67	02.09.67	299*)	Norsk Polar Navig.	405	
(Fridtjofsbreen)	14 46	29.06.68	21.08.68		Norsk Polar Navig.		
		07.07.69	16.08.69				
		10.07.74	18.09.74				
		16.07.75	20.09.75				
		22.08.80	05.09.80				
		01.07.81	10.08.81				
Hopen I	76 26 57	11.08.71	29.09.71	50	Forasol	908	9,1
(Hopen)	25 01 45				Fina gruppen		
Raddedalen	77 54 10	02.04.72	12.07.72	100	Total	2823	84
(Edgeøya)	22 41 50				Caltex gruppen		
Plurdalen	77 44 33	29.06.72	12.10.72	108	Fina	2351	144,6
(Edgeøya)	21 50 00				Fina gruppen		
Kvadehuken I	78 57 03	01.09.72	10.11.72	112	Terratest a/s	479	
(Brøggerhalvøya)	11 23 33	21.04.73	19.06.73		Norsk Polar Navig.		
Hopen II	76 41 15	20.06.73	20.10.73	123	Westburne Int. Ltd	2840,3	314,7
(Hopen)	25 28 00				Fina gruppen		
Kvadehuken II	78 55 32	13.08.73	19.11.73	186	Terratest a/s	394	
(Brøggerhalvøya)	11 33 11	22.03.74	16.06.74		Norsk Polar Navig.		
Sarstangen	78 43 36	15.08.74	01.12.74	109	Terratest a/s	1113,5	5
(Forlandsrevet)	11.28.40				Norsk Polar Navig.		
Colesbukta	78 07	13.11.74	01.12.75	373	Trust Arktikugol	3180	12
(Nordenskiøld Land)	15 02						
Haketangen	76 52 30	11.09.76	22.09.76	109	Terratest a/s	990	6,7
(Tromsøbreen)	17 05 30	13.06.77	19.09.77		Norsk Polar Navig.		
Vassdalen	77 49 08	22.01.85			Trust Arktikugol		
(Van Mijenfjorden)	15 16 00						

*) Drilling not finally completed

Block 31/4

Norsk Hydro drilled well 31/4–8 as an appraisal well on the western flank of the Brage structure, thereby proving oil in Lower Jurassic sandstone. Maximum production was 983 Sm^3 oil and 27,000 Sm^3 gas a day through a 17.5 mm choke. The Brage field consists of reservoirs on several levels, and this well confirmed the presence of oil also in the lowermost reservoir. The result was positive and the Directorate's work to update the resources estimate for Brage is expected to be ready early in 1987. Provisional estimates indicate larger resources than previously estimated.

Block 34/4 and 34/7

Saga, as operator of production licences 057 and 089, kept up a high activity level throughout the entire period. Well 34/4–6 is an appraisal bore in the north of the Snorre field. The top reservoir came in deeper than expected with the result that the resources estimate for this field will have to be reduced slightly. Maximum production was 1180 Sm^3 oil a day through a 12.7 mm choke.

Exploration well 34/7–8 entered a separate structure centrally placed in the block, just to the south of the Snorre field. Oil was proven in Upper and Lower Jurassic sandstone. Three tests were conducted, the best of them producing 1300 Sm^3 oil a day through a 17.5 mm choke.

Well 34/7–9 is an appraisal well in the center of Snorre which proved oil in Upper and Lower Jurassic sandstone. Maximum production from the upper reservoir was 1400 Sm^3 oil a day through a 16.9 mm choke.

Well 34/7–10 was an exploration well in the southeastern flank of Snorre. Oil was proven in sandstone dating from the mid-Jurassic. The good test results confirm that this part of the structure possesses fine production characteristics. Maximum production was 970 Sm^3 a day through a 12.5 mm choke. The product had a gas-to-oil ratio of 36 Sm^3 per Sm^3.

Block 34/8

This was the most popular block in the tenth round of licensing. Exploration well 34/8–1 was drilled with great expectations. Even though the well proved gas and oil in mid-Jurassic sandstone, the result was disappointing. The discovery contains mainly gas over a thin oil-bearer, but is relatively small. Even though some minor structures remain, the potential resources estimated in the block were heavily reduced after 34/8–2 was found to be dry.

Block 34/10

Well 34/10–30 was drilled as an appraisal well on the northeast flank of Gullfaks South. This well proved oil and gas in Lower Jurassic and Triassic rock. The very promising aspect of this well was its considerably lower oil-water contact than previously shown for the structure. This opens up the possibility of additional resources in the east. The discovery was tested and maximum production in the oil zone was 1300 Sm^3 oil and 130,000 Sm^3 gas a day through a 17.5 mm choke. Maximum production in the gas zone was 1.2 million Sm^3 gas and 370 Sm^3 oil a day through a 19 mm choke. As a result of this well, the estimate of technically recoverable resources on Gullfaks South was upped from 37 million Sm^3 oil and 93 billion Sm^3 gas to 43 million Sm^3 oil and 103 billion Sm^3 gas.

Block 6406/3

As one dry well had previously been drilled in the block expectations were not great when exploration well 6406/3–2 entered the Alpha structure. Nevertheless, the well proved oil in mid-Jurassic rock. It is still too early to say how large the Alpha resouces might be, though the discovery undoubtably yields valuable additional resources in connection with other near-by discoveries. The results of 6406/3–2 also open the way for new prospects to the northwest of the block. Tests of the discovery gave a presentable 650 Sm^3 oil and 130,000 Sm^3 gas a day through a 50.8 mm choke.

Block 6407/7

Norsk Hydro operated exploration well 6407/7–1 made a substantial discovery in the very south of the block, roughly 20 km west of the Draugen field. This reservoir consists of several separate zones with varied reservoir properties. Well 6407/7–1 was tested in five zones and yielded good maximum production: 740 Sm^3 oil and 147,000 Sm^3 gas a day through a 13 mm choke. Oil density was 0.83 g/cm^3, which is identical with crude oil from Draugen.

Block 6407/9

Shell as operator of production licence 093 drilled appraisal well 6407/9–6 in the western part of the Draugen field. As expected, light oil was proven in Upper Jurassic sandstone. Maximum production was measured at 1017 Sm^3 oil a day through a 22.2 mm choke. The gas-to-oil ratio was 20 Sm^3 per Sm^3.

Block 6506/12

Appraisal well 6506/12–5 on Smørbukk South proved oil and gas in mid-Jurassic sandstone strata. Considerable quantities of oil were also proven in Upper Cretaceous sandstone. The best reservoir test (mid-Jurassic) produced 200 Sm^3 oil and 55,000 Sm^3 gas through a 19 mm choke. A test of the Upper Cretaceous produced a very encouraging 610 Sm^3 oil and 98,000 gas through a 16 mm choke. Well 6406/3–3 which entered the southern flank of the structure was dry, and thus provides a measure of the reservoir boundary in this direction. The Directorate is working on a resources estimate for the structure.

Block 6507/7

Conoco drilled four new appraisal wells into the Heidrun structure with positive outcome. Well 6507/7–4 entered the southwestern part of the field and proved oil in mid and Lower Jurassic sandstone. Three tests were run. Maximum production was 1034 Sm^3 oil and roughly 91,000 Sm^3 gas a day through a 60 mm choke. The gas-to-oil ratio was 88 Sm^3 per Sm^3.

Wells 6507/7–5 and 6507/7–5A entered two separate fault blocks in the northwestern part of Heidrun. Oil was proven in mid-Jurassic sandstone in both wells. Although Well 6507/7–5 was tested, 6507/7–5A could not be due to technical troubles. Maximum production measured was 954 Sm^3 oil and roughly 85,000 Sm^3 gas a day through a 36 mm choke.

Block 6507/8

Statoil as operator of production licence 124 drilled exploration well 6507/8–1 in the east flank of Heidrun. This well proved gas and oil in Mid- and Lower Jurassic rock. Maximum production measured was 1017 Sm^3 oil and roughly 45,000 Sm^3 gas a day through a 19 mm choke.

Block 7121/5

Well 7121/5–2 is an exploration well in a separate structure northeast of the Snøhvit structure, in which oil and gas were proven in Jurassic sandstone. This exploration well also proved oil and gas in Jurassic sandstone, though no tests were run due to relatively high concentration of hydrogen sulphide (H_2S). The well is the furthest east on Tromsøflaket.

Block 7121/7

Well 7121/7–2 is an exploration well in a separate structure south of the Albatross structure. Gas was proven in mid-Jurassic rock. The test conducted produced a maximum 510,000 Sm^3 gas a day through a 16 mm choke.

2.2.3.2 Fields being evaluated

Hod

Block 2/11 was allocated in 1969 with Amoco as operator. The field is situated roughly 12 km south of Valhall.

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

The Hod field consists of two lesser structures. These have been investigated with a total of five wells, two on West Hod and three on East Hod. In

1981 a wellhead template was installed on the seabed between these two structures because at that time the field was considered to be promising. Well 2/11–6 was directionally drilled from the template. Later drilling of production wells, if any, will be performed through the same template.

Operator Amoco is experiencing production difficulties on Valhall due to solids in the well flow, and it is expected that production from Hod may be fraught with the same difficulties. If so, the field will be difficult to produce from seabed completion wells as originally planned.

Development of Hod will have to be accomplished with a wellhead platform, with further transport of the product flow to Valhall for final processing.

Before a plan for development and operation can be submitted the operator considers another exploration well should be drilled in order to prove additional reserves, if possible. The operator's estimated reserves are lower than the Directorate's.

Fields around Ula

The Gyda field, 2/1 North, is an oil field situated about 25 km southeast of the Ula field. BP as operator for both these fields presented its declaration of commerciality for Gyda on 21 October 1986. The licensees have joined the commerciality declaration.

BP intends to develop Gyda with a fixed accommodation, drilling and process platform. Ocean depth is 66 meters.

Several transport alternatives are being looked into, among them buoy loading of crude oil. Alternatively, one can imagine the oil being conducted by pipeline from Ula via Ekofisk to Teesside. Rich gas is transported in a new line to Ekofisk for further treatment.

The Directorate's resources estimate for Gyda is 30.5 million Sm³ oil and 6 billion Sm³ gas.

The plan for development and operation is expected in February or March 1987. Production can start in 1991 according to plan.

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

Block 2/2 is the neighbour to Block 2/1 towards the east, where Saga is operator. Also here a minor oil field has been proven. The water depth is very moderate, being only 60 meters.

The smaller fields in Blocks 1/3 and 2/2 should be evaluated in connection with a possible development plan for Gyda.

In Block 7/11, the westerly neighbour to the Ula field, an oil field has been proven. In Block 7/8 northwest of Ula, a minor oil field has also been demonstrated.

Any development of these minor fields should be evaluated in connection with development of the Ula field infrastructure.

Sleipner West and satellites in Sleipner area

The Sleipner area is made up of Blocks 15/5, 15/6, 15/8, 15/9 and 16/7.

Allocations, production licences and operators are as follows:

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

Sleipner West has already been declared commercial, and recoverable reserves there are estimated at 135 billion Sm³ gas, 27 million Sm³ oil and 9 million tonnes NGL.

In all six small discoveries have been made in and around Sleipner in addition to Sleipner East and Sleipner West. These are 15/9 Theta, 15/9 My, 15/8 Alpha S, 16/7 A and H, and in one structure that extends across the boundary between 15/5 and 15/6.

Recoverable reserves in these satellites are estimated at 50 billion Sm³ gas and 19 million Sm³ oil.

Development

Sleipner West can be developed with two platforms independently of Sleipner East. Alternatively the field can be phased in after Sleipner East, making use of idle processing capacity on the Sleipner East platform.

Sleipner West gas contains a good deal of carbon dioxide (CO_2) compared with the usual specifications in sales contracts. The carbon dioxide content can be reduced either by mixing the gas with gas from other fields containing relatively little carbon dioxide, or by passing the gas through a carbon dioxide scrubber offshore or on land. A land-based scrubber is likely to require a dedicated gas pipeline.

Development of the field depends on buyers for the gas being found.

The satellite fields can probably be tied in to the main platform.

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 exploration 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 strata.

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

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

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

Oseberg area

The Oseberg area includes the Blocks 30/2, 30/3, 30/6, 30/9 and 31/4 (Figure 2.2.8.b). The Oseberg field itself has been resolved to be developed and pilot production started in 1986. The field is planned to be on stream from 1989 (cf. Section 2.3.8).

Resources basis

In this area, discoveries of varying sizes have been made in the fields Oseberg, Brage, Veslefrikk, Huldra, 30/6 Beta, 30/6 Kappa, 30/6 Gamma North and 30/9 Omega. Discovered recoverable resources are shown in Tables 3.2 and 3.3.

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

Transport

It has been decided that oil from Oseberg is to be landed by pipeline at Sture in Øygarden. Gas will be reinjected in the oil production phase. The need to transport gas will therefore not arise until after the year 2000. It is presumed that Oseberg can be tied in to the transport systems for gas then available.

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

Development alternatives

There are basically two main alternatives for further development of the Oseberg field. One is to continue the development of Oseberg as outlined in the field development plan, which involves a drilling, living quarters and water injection (DQW) platform in the northernmost part of the field and start-up in the mid-1990s. The other is to develop the northern part of the field with a separate process platform and start-up in the early 1990s.

A production, drilling and living quarters (PDQ) platform at Oseberg North would enable the operator to make use of processing plant on Oseberg to treat crude oil from neighbouring fields starting in the latter half of the 1990s.

Norsk Hydro intends to present its plan for development and operation for Brage at the end of 1987. This will probably be based on a simple PDQ platform using support vessels in the building period.

During 1986 a well was drilled on 30/6 Beta. This exploration well led to substantial positive revision of the estimated reserves. However, much work remains before this part of the Oseberg area can be said to be adequately charted, and no hard and fast development plans for the field exist.

The west flank satellites of Oseberg will be produced from subsea wells when processing capacity becomes available on Oseberg.

Veslefrikk

This field lies to the southeast in Block 30/3 which was allocated in 1979 with Statoil as operator.

Four exploration wells have been drilled on the block, two of them entering the Veslefrikk structure proper. In both these wells oil was proven at two different levels in Brent and Cook formation sandstone.

According to the operator the plan for development and operation will be presented in February 1987. The declaration of commerciality was presented to the partners in November 1986.

The operator has estimated the total oil recovery from the field to be 36.4 million Sm^3. In addition comes 4.3 billion Sm^3 of associated gas.

Several development alternatives have been considered for Veslefrikk. The recommended development concept consists of a fixed wellhead platform with steel jacket to be installed over a template with six predrilled wells.

The plan calls for conversion of the semi-submersible drilling rig "West Vision" to a floating production platform to be anchored up and connected to the fixed wellhead platform.

Development cost estimates are about NOK 5.5 billion including well costs. This is substantially less than earlier concepts planned for Veslefrikk.

The low costs and short building time render the field profitable even at todays oil prices.

If the plan for development is approved in spring 1987, the operator expects the field to come on stream as early as summer 1988.

An oil pipeline will be connected to the Oseberg field center to carry oil to the terminal at Sture. Gas can be conducted by pipeline through the Statpipe system or injected at Oseberg.

Gullfaks South and 34/10 Beta and Gamma

Block 34/10 was allocated in 1978 with Statoil as operator, see the description of Gullfaks in Section 2.3.10.

Gullfaks South lies in the middle of the block about nine kilometers south of the Gullfaks field. Beta lies in the southwest and Gamma in the southeast of the block.

Gullfaks South is structurally complex. Several independent gas-oil, gas-water and oil-water contacts have been observed on the field. Hydrocarbons have been proven in mid and Lower Jurassic and Triassic sandstone.

So far four wells have been drilled in Gullfaks South plus one each in Beta and Gamma. Well 34/

10–30 was drilled in the spring of 1986 on the eastern part of Gullfaks South. Gas and oil was proven in Lower Jurassic sandstone, and oil in Triassic sandstone. No oil-water contact was proven in the Triassic.

Statoil is planning a new well on Gullfaks South in the spring of 1987.

Resources

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

The Directorate has made the following estimate of discovered resources:

Gullfaks South	45 million Sm^3 oil and condensate
	88 billion Sm^3 gas
34/10 Beta	8 million Sm^3 oil and condensate
	22 billion Sm^3 gas
34/10 Gamma	2 million Sm^3 oil and condensate
	28 billion Sm^3 gas

Development of Gullfaks South has to be laid before the authorities as a separate matter. Statoil is planning to present the plan for development and operation in the autumn of 1987, though the timetable is uncertain.

Several platform solutions are being considered, including a platform with partial processing equipment which transfers stabilized oil to the Gullfaks field for final processing, or a separate full process platform.

The present plans for Gullfaks South involve a possibility of production start in 1992.

33/9 Alpha and Beta

The Alpha and Beta structures in Block 33/9 lie just east and north of the Statfjord field, respectively. The Alpha structure extends into Block 34/7, as seems also to be the case for the Beta. So far, two wells have been drilled in Alpha (33/9–7 and 34/7–5), and one well in Beta (33/9–8).

Resources basis

The Directorate's estimates of recoverable resources are:

Alpha 19 million Sm^3 of oil and 2.5 billion Sm^3 of gas

Beta 39 million Sm^3 of oil and 2 billion Sm^3 of gas.

Development concept

Production start is planned in 1993 from Alpha and 1994 from Beta. In recent years the operator has explored alternative development solutions. The solutions have been based on the exploitation of future idle processing capacity on Statfjord C. Reservoir pressure can be sustained by means of water injection.

Snorre

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

Three exploration wells were drilled and tested on Snorre in 1987. Well 34/4–6, an appraisal well in the north of the structure, proved oil in Triassic sandstone. Well 34/7–9 was an appraisal well that entered the center of the structure just south of the boundary line with Block 34/4. This well proved oil in Lower Jurassic sandstone. Production tests were good.

Exploration well 34/7–8 entered a small, standalone structure south of Snorre (the C structure). Oil was proven in Upper and Lower Jurassic sandstone. The oil-water contact here is at a shallower level than on Snorre, showing that the oil reservoirs on Snorre and the C structure do not communicate. The quantity of resources in the C structure is small.

Resources basis

To date ten exploration wells have been drilled on the Snorre field, 34/4–1, 4 and 6 and 34/7–1, 3, 4, 6, 7, 9 and 10. All wells have proven oil with associated gas, but without a gas cap. Oil has been proven in sandstone of Lower Jurassic and Triassic age. The Snorre field is structurally complex. Total depth of the reservoir is roughly 2500 meters. Drilling and testing have revealed three different oil-water contacts, the deepest being in the western part of the field. The Directorate's estimated recoverable resources are 146 million Sm^3 oil and 16 billion Sm^3 gas.

Development concept

The water depth varies over the field from 300 meters in the south to 370 meters in the north. The operator has examined a number of concepts for field development, which is likely to start in the southern part of the field. There are two alternative concepts for production from the northern part of the field: either relocating a tension leg platform, or development involving subsea completion wells. No decision has been made as yet regarding the optimum degree of processing for the field. If partial processing is chosen, further transport to Statfjord seems most realistic. Production is planned to start in 1992.

HALTENBANKEN

Tyrihans

Two exploration wells have been drilled on the field which comprises two structures, one with gas and condensate, the other with a thin oil zone and gas cap. The resources are estimated at 15.7 million Sm^3 oil and condensate, and 40 billion Sm^3 gas.

Midgard

In all four exploration wells were drilled in the Midgard field. This structure is divided into three by crossing faults. Midgard consists primarily of gas and has good reservoir properties.

A thin oil zone has been proven in one fault block which may be difficult to recover since it lies between a large gas cap and water zone.

The field can probably be produced using pressure relief.

The Directorate estimates the recoverable resources at 103 billion Sm^3 gas and 22 million Sm^3 oil.

Draugen
Six exploration wells have been drilled on Draugen. The well-charted reservoir is long and thin, with an oil column varying from 11–40 meters containing light oil with low oil-to-gas ratio. Reservoir characteristics are very good. The plan is to produce the reservoir using water injection. So far, nothing definite has been decided regarding utilization of the associated gas. Based on new surveys and technical reservoir studies the Directorate upgraded the resources estimate for the field to 64 million Sm^3 oil and 4 billion Sm^3 gas.

Smørbukk and 6506/12 Beta
One new exploration well was drilled in each structure in 1986. The structures are complex and contain several isolated reservoir formations. The reservoir fluid is close to its critical point. The Beta well provided highly unexpected results and it will be necessary to shoot three-dimensional seismics and drill at least one more exploration well to forecast the reserves in this structure. The Smørbukk well proceeded as expected. Analyses of the reservoir fluid and characteristics have shown that the structure ought probably to be produced by pressure relief. The Directorate has made no new assessment of its resources estimate for the structure based on production by pressure relief. Such studies are planned in 1987.

The Directorate's estimated resources in Smørbukk are therefore too high. They stand at 60 million Sm^3 condensate and 83 billion Sm^3 gas. Estimates for the Beta structure were revised before the results from this years well came in, and these will most probably reduce the estimates even further. Plans call for the estimates to be updated in 1987. The estimated reserves stand at the moment at 48 million Sm^3 oil and condensate and 36 billion Sm^3 gas.

Heidrun
To date six exploration wells have entered the Heidrun structure, one of them in Block 6507/8. The structure consists of two reservoir formations exhibiting heavy faulting. The reservoirs contain heavy oil with a gas cap. Water injection will be the major production mechanism for the field. The Directorate has reassessed the field and are in the process of rounding off technical studies of the reservoir. The estimated reserves have accordingly been upgraded from 1985 and now stand at 127 million Sm^3 oil and 40 billion Sm^3 gas.

The operator submitted his declaration of commerciality on 1 December 1986.

6407/7
The second exploration well is being drilled on this structure. The first one proved oil. The structure is heavily faulted and it is too early yet to make a reliable estimate of the resources in the structure as a whole. The resources quoted in Table 3.4.4 are based on the first exploration well.

6406/3
The second exploration well in this block struck reservoir sandstone flooded with oil. The structure is long and flat and may possess great potential. More wells will have to be drilled to ascertain its full extent, so the Directorate has not carried out any new assessment following the drilling of the new well.

Development plans
This last year's activity on Haltenbanken has shown that the area is promising. Nine discoveries have been made, and development planning has progressed a long way. The estimated resources in the area are roughly 300 million Sm^3 oil and condensate, and 300 billion Sm^3 gas. In the case of Draugen, the plan for development and operation is scheduled for autumn 1987. For Heidrun the operator is planning to submit his plan for development and operation at the end of 1987. These fields may make up the first phase of production in the area, a phase largely committed to oil production. However, the Directorate is very concerned to exploit the gas accumulations in a way that makes sense in terms of resources and socio-economics, and to do this right from the early oil production phase. Depending on the date of finding a gas market, fields containing primarily gas will be able to be phased in.

Area appreciation
The Haltenbanken area is a new oil and gas province with no existing infrastructure. This provides us with a unique opportunity to plan the development and transport from the area on a rational basis. For a long time the Directorate has studied the benefits of coordination, particularly on the transport side where advantages seem to be attainable. To grasp these advantages, extensive coordination between the authorities and operating companies is essential.

TROMS AREA
All discoveries in the Troms area have been made in the Hammerfest Basin. Considerable quantities of gas have been proven in the Askeladd, Albatross, Snøhvit and Block 7120/12 fields. Som additional undrilled prospects still remain.

Drilling and resources
Drilling activity on Troms has been low in 1986. Two new exploration wells were made in the Hammerfest Basin, where Well 7121/7-2 proved gas in a prospect south of Albatross, and 7121/5-2 proved

gas in a thin oil zone in a tiny prospect northeast of Snøhvit.

Two exploration wells on Loppa Ridge, 7120/1–1 and 7121/1–1 were entered and drilled to completion. The results were negative as far as hydrocarbons are concerned, though relatively rich rocks were proven.

Estimates of discovered resources off North Norway stand at 0.23 billion tonnes oil equivalent (toe), not including the thin oil zone in the Hammerfest Basin.

The Directorate has carried out an area study of Troms, while the various field operators have conducted their own feasibility studies for development. Economic calculations show that it would be unprofitable to develop the Troms area at present.

New technology and higher prices for LNG products may change this state of affairs.

2.2.3.3 Fields declared commercial

The following fields were declared commercial by the operator: Sleipner East, Gyda, Heidrun and Veslefrikk.

2.3 Fields being planned, developed or in production

2.3.1 Valhall

On the Norwegian part of the continental shelf a dozen or so fields have been declared commercial and approved for development or are in production: Valhall, Albuskjell, Cod, Edda, Ekofisk, Eldfisk, Tor, West Ekofisk, Ula, Heimdal, Frigg, North East Frigg, Odin, and Statfjord.

The fields East Frigg, Oseberg, Tommeliten, Gullfaks, Troll and Sleipner East are being planned or developed. In the following the fields are described in further detail.

2.3.1 Valhall

Production licence 006

Licensees

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

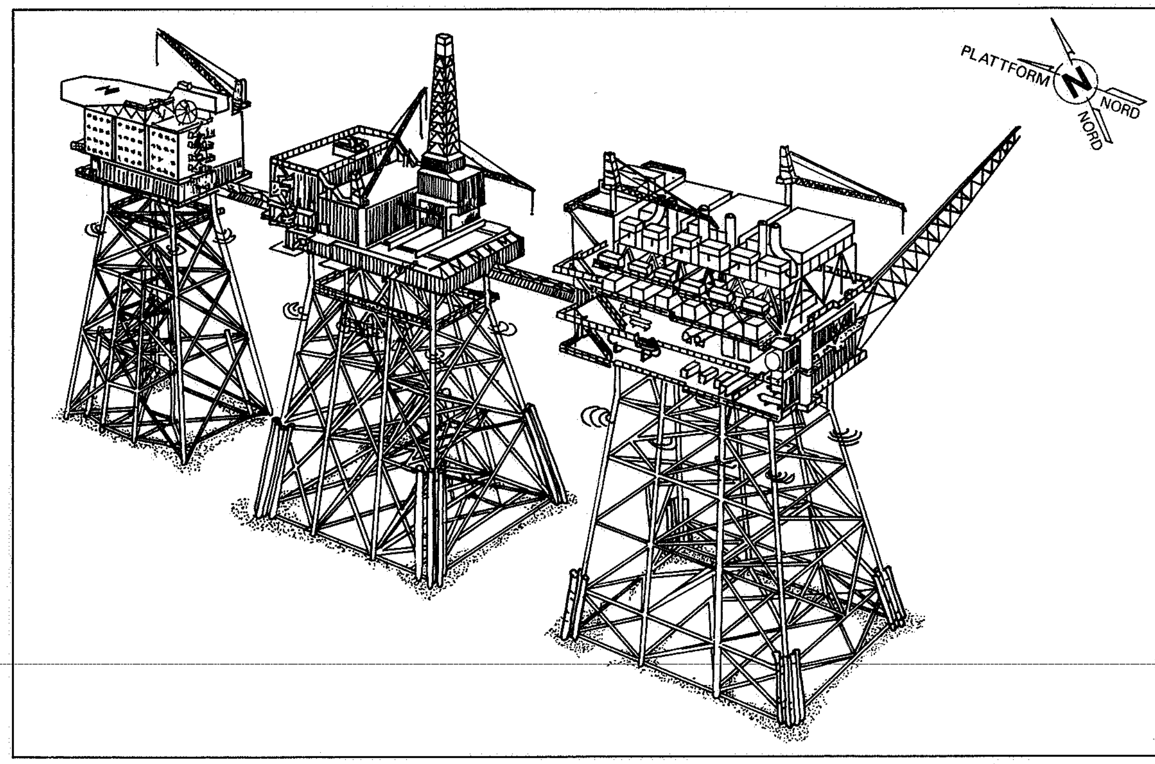
Block 2/8 was allocated in 1965 with Amoco as the operator.

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

Production facilities

Development includes an accommodation, a drilling, a production and a marine riser pipe platform. The three first mentioned platforms are placed on the Valhall field and interlinked with bridge connections. Figure 2.3.1.a shows these installations. The

FIG. 2.3.1.a
Installations on Valhall



marine riser platform, which Phillips Petroleum Company Norway has the operatorship for, is connected to the Ekofisk Center Tank.

The oil is separated on Valhall using two separation units, before being pumped to the Ekofisk facility, where it is metered and led on into the Teesside pipeline. The gas is compressed, dried and its dewpoint checked on the production platform before being despatched by pipeline to the Ekofisk installation, where it is metered and sent on via the Emden pipeline. Denser gas fractions of NGL are separated out on Valhall using a fractionating column, and then injected into the oil.

Recovery of reserves

Valhall can be compared to the fields in the Ekofisk area as regards reservoir properties and geology. Production started in November 1982. As of 31 December 1986, no less than 19 production wells were available at the platform.

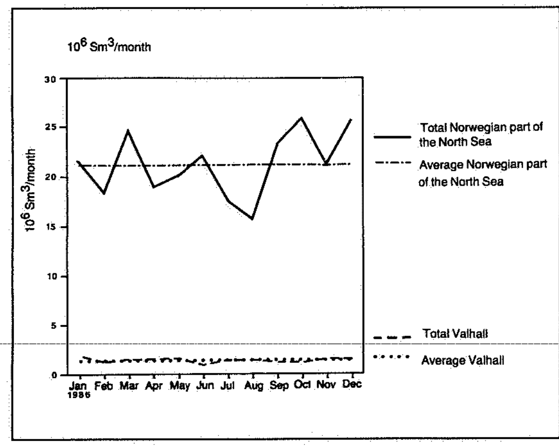
There have been great difficulties relating to the mechanical properties of the Valhall field rocks, resulting first and foremost in clogging up of the production wells by the formation. This has meant that Valhall has never produced as much oil a day as originally planned.

In addition to the difficulties of maintaining field production, it has now been established that the field is subsiding. Based on two measurements six months apart, roughly 30 centimeters of subsidence has been proven. The cause is a reduction in pore pressure in the reservoir. The chance of there occurring further subsidence and associated difficulties will be elucidated in 1987.

Flaring of gas

The volume of gas flared in 1986 on Valhall was on average 0.045 million Sm³ a day, corresponding to 3.3 per cent of the total gas production (Figure 2.3.1.b). The flare limit is 0.150 million Sm³ a day. During the year there arose few technical process problems, thus providing high process reliability. Gas has generally been flared off due to compressor problems.

FIG. 2.3.1.b
Gas flared on Valhall



Costs

Total investment costs are predicted to reach about NOK 9.1 billion in fixed 1986 kroner.

Metering systems

Metering systems for oil and gas have been installed on the 2/4-G platform. Inspections have been conducted of these systems.

Maintenance

The Valhall field has recently acquired a new, computerized maintenance system which seems to be functioning satisfactorily. Replacement of inappropriate equipment has continued.

2.3.2 Tommeliten

Production licence 044

Licensees

Den norske stats oljeselskap	50.000 %
Phillips Petroleum Company Norway	28.870 %
Norske Fina A/S	15.000 %
Norsk Agip A/S	9.130 %

Production licence 044 was allocated on 27 August 1976 and includes Block 1/9, southwest of the Ekofisk area (Figure 2.3.3.a).

The field was discovered by drilling exploration well 1/9–1 in 1977. The plan for development and operation was presented and approved in the first half of 1986. Phillips Petroleum Company Norway is not participating in the development, which leaves the following as licensees on Tommeliten:

Den norske stats oljeselskap	70.640 %
Norske Fina A/S	20.230 %
Norsk Agip A/S	9.130 %

Development

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

Development is planned in four phases, the first two of which will be development of the Gamma structure. The Alpha structure will be developed in the last two phases.

The plans call for development with 14 wells, seven on each structure. The four phases will run successively in time to maintain the stable production plateau of 1.1 billion Sm³ gas a year as long as possible.

Production will start from four wells in mid-1988 (Phase 1). The start date for Phase 2 and further field development will depend on the sales opportunities for the gas.

Production drilling on the field started on 22 September 1986, drilling of the second production well being in progress at year-end.

Recovery of reserves
Tommeliten consists of two structures, Alpha to the south and Gamma to the north. Gas and condensate have been proven in both structures. The hydrocarbon bearing rocks are represented by the Ekofisk and Tor formations, with Tor being the best reservoir rock. The best production characteristics, however, are held by the Gamma structure.

The Directorate estimates recoverable reserves at 16.8 billion Sm^3 gas. The preferred field development strategy involves production assisted by the reservoirs natural drive mechanism.

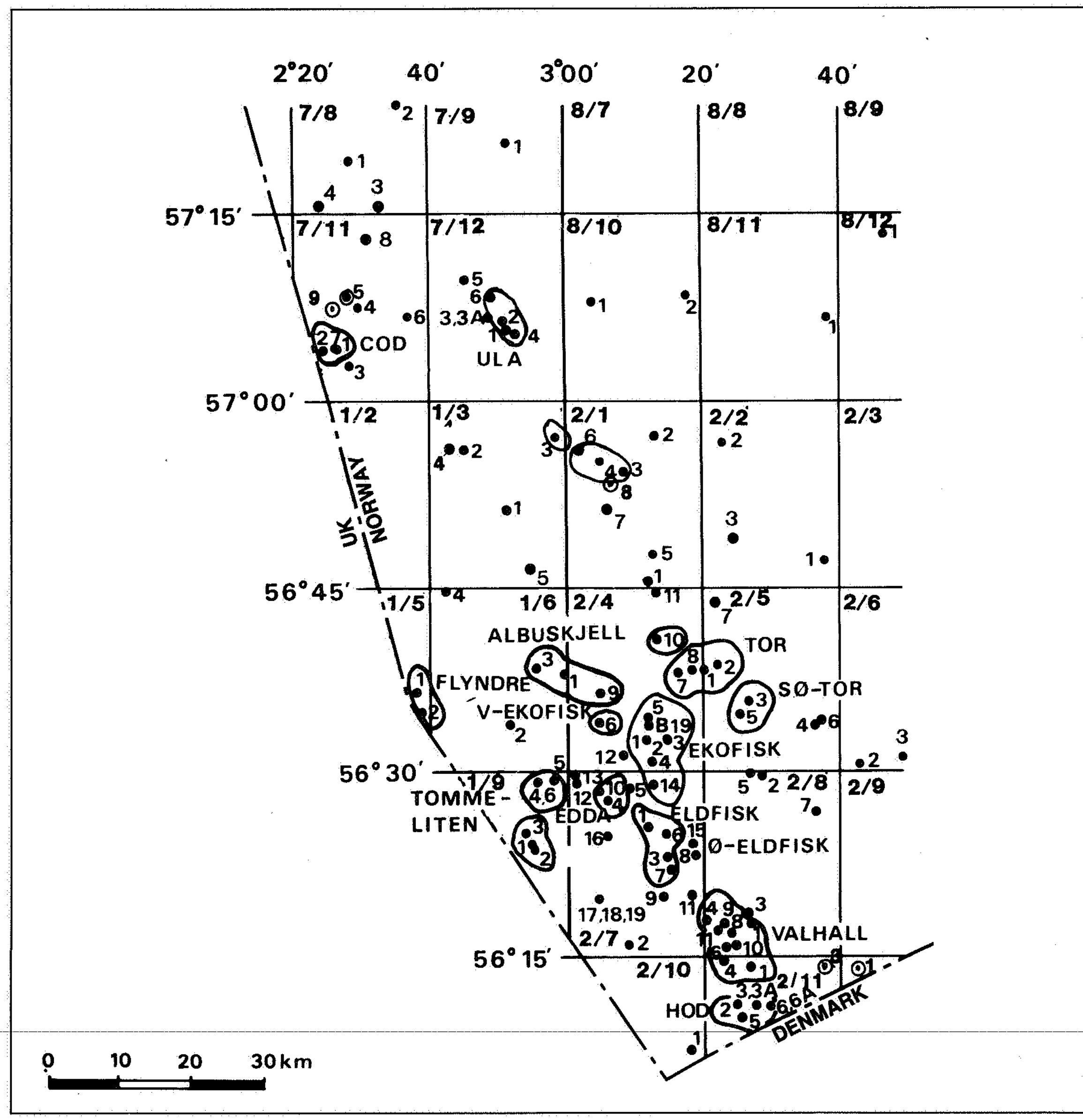
Costs
The total cost of complete development is estimated to be rather less than NOK 5 billion (1986 kroner).

2.3.3 The Ekofisk area
Production licence 018

Licensees

Phillips Petroleum Company Norway A/S	36.960 %
Norske Fina A/S	30.000 %
Norsk Agip A/S	13.040 %

FIG. 2.3.3.a
The Ekofisk area



Norsk Hydro Produksjon A/S	6.700 %
Elf Aquitaine Norge A/S	8.094 %
Total Marine Norsk A/S	4.047 %
Eurafrep Norge A/S	0.456 %
Coparex Norge A/S	0.399 %
Cofranord A/S	0.304 %

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

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

Albuskjell:

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

Tor:

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

Production licence 006; ("Amoco group")
Licensees

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

Thus, the Ekofisk area consists of seven fields: Ekofisk, West Ekofisk, Cod, Tor, Eldfisk, Edda and Albuskjell. The first of these, Cod, was discovered in 1968. In 1969, the Ekofisk field was discovered, and as early as 1970, declared commercial. In the period from 1969–72, the other fields in the area were discovered. Phillips operates all seven fields.

Development took place in four phases:

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

Phase 2: Development of the platforms on Ekofisk.

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

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

Phase 5: Installation of new platform for the Ekofisk waterflood project.

Phase 5 and the subsidence of the Ekofisk field will be discussed below.

Figure 2.3.2.b gives a bird's eye view of the installations in the Ekofisk area.

Subsidence of Ekofisk

In November 1984, it was discovered that the seabed near the Ekofisk Center had subsided. Measurements since performed indicate the total subsidence as per 1 December 1985 of about 3.8 meters. The rate of subsidence in the period 1980–86 is estimated to be 0.4 to 0.5 meters a year, with some lessening towards the end of the period.

Ekofisk field subsidence is the result of petroleum being produced from the Ekofisk reservoir three kilometers under the seabed. The rock that the oil and gas are contained in is relatively porous and is compressed as pressure decreases. The pressure of the oil and gas together with the strength of the rock previously constituted a force which was sufficient to support the three kilometers of overlying rocks. When pressure is reduced, a greater part of the strain is transferred to the rock. The rock cannot withstand the strain and decreases in volume and becomes more compact. Although it was long realized that the reservoir volume would contract, no one expected this to show on the surface. It is still uncertain how the shrinking of the reservoir accounts for the subsidence, or whether other factors are at work.

Several independent studies of the rock properties have been performed. They conclude that the strength falls off with increasing porosity. Some variables which might affect subsidence have not yet been studied. In 1986 the Directorate was occupied with its own studies of subsidence, and has carefully followed the operators own work through its own experts and outside consultants.

Additional to the subsidence it is likely that other reservoir problems will arise due to pressure relief. The lack of stability of the wells is a growing problem on Ekofisk. Studies carried out by the operator indicate that pressure relief is a major cause of well deformation. Because the rock is becoming more compact, it is feared that changes in flow properties may occur in the rock that will mean that greater volumes of petroleum than calculated will have to be left in the reservoir as the field approaches the end of its useful life.

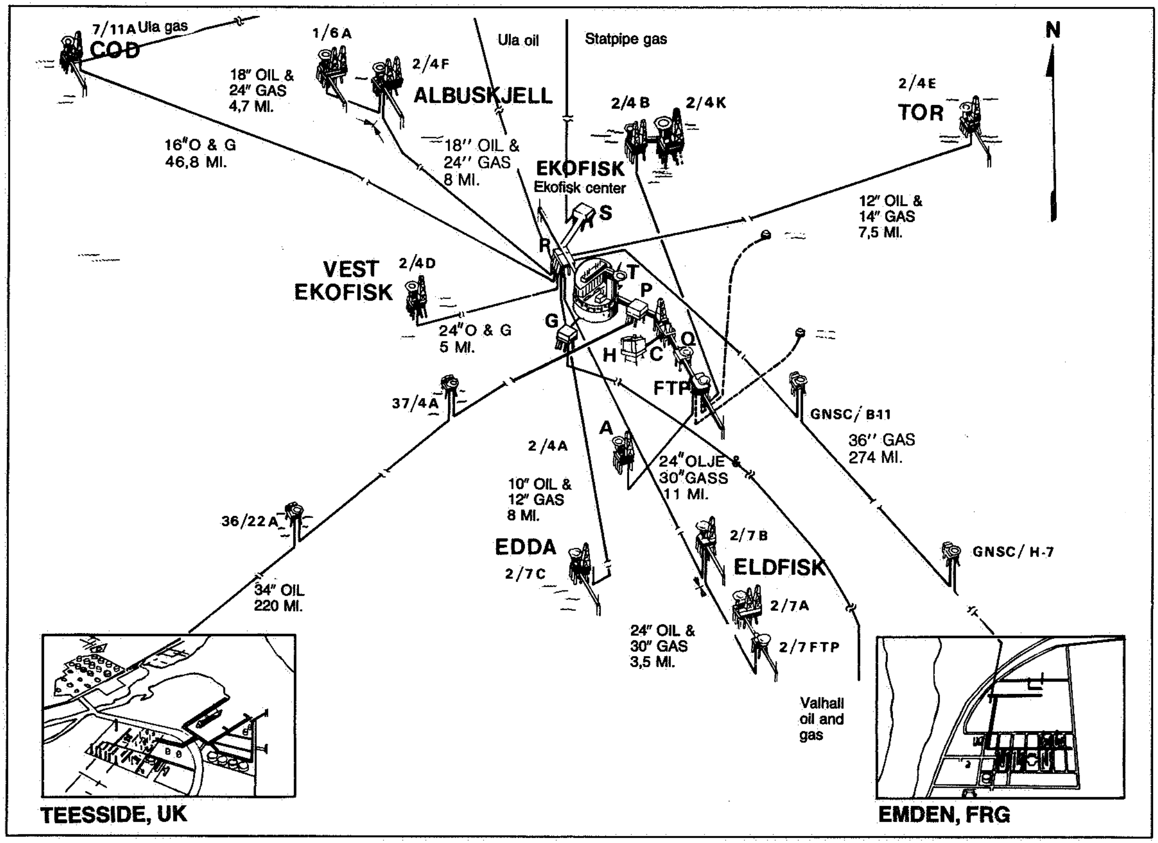
The only way to prevent further subsidence and other problems related to pressure relief is to limit the fall in pressure. This can be done by injection of fluids such as natural gas, nitrogen or water, or some combination of these. The operator is looking further into the potential of injecting gas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

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

The subsidence has led to a need to modify the platforms in the central Ekofisk complex so as to survive further subsidence. Plans are therefore afoot to jack up the platform decks in summer 1987 and build an additional six meters on to their legs.

In 1986 the operator carried out the last part of an

FIG. 2.3.3.b
Installations in the Ekofisk area including planned 2/4 K and connections from Ula and Statpipe



extensive analysis of wave conditions in and around Ekofisk. The last part of this analysis has now been completed, and the Directorate expects to compete its assessment of the analysis by early 1987.

Both the operator and the Directorate have been working to plan future measures when and if subsidence continues in the years ahead.

Waterflood project

Water injection into the Tor formation was decided on in 1983. The intention at that time was to increase the quantities of hydrocarbons recovered from the Ekofisk field. Injection of water will increase the reservoir pressure, which will also help reduce subsidence. Before the decision to start water injection, the effect of water on the field was assessed by means of a laboratory test and pilot project. The pilor project involved injection of water into a limited section of the reservoir.

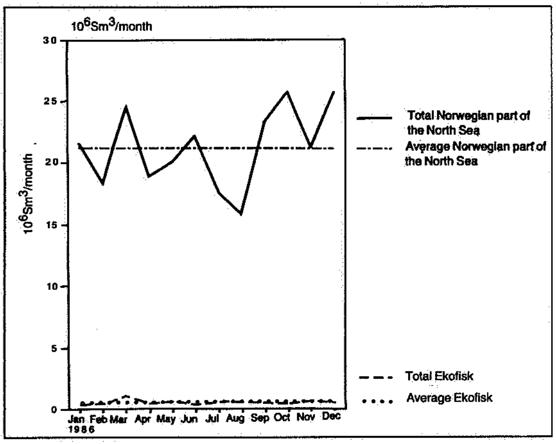
Water injection requires its own platform, and this is now being installed on the field. The platform is expected to reach into about two thirds of the area of the reservoir. So far water injection has been limited to one of the field formations, which means that only one third of field reserves will be affected by water injection to begin with. Injection is expected to start in August 1987. By installing a new drilling derrick in addition to the present one on the K platform, the operator hopes to meet his earlier schedule for injection.

Water injection into the lower part of the Ekofisk formation is being tried out. Serious problems have been encountered with wells for this project, so a possible decision to include the Ekofisk formation in the waterflood project on Ekofisk will not be made until the end of 1987. The question of possible expansion of the project to cover the entire field area may also be a subject of discussion in 1987.

Flaring of gas

During Phase I of the Ekofisk development from 1971 to 1974, there was test production with buoy loading, and all gas was flared. Since 1977, the gas has been landed and sold through the Emden gas pipeline, with surplus gas being injected into the Ekofisk reservoir. Gas flared in 1986 in the Ekofisk area was an average of 0.02 million Sm^3 a day, corresponding to 0.06 per cent of the total gas production from the fields. Throughout year the flare limit stood at 0.40 million Sm^3 per day. The amount of gas flared is shown in Figure 2.3.2.c.

FIG. 2.3.3.c
Gas flared on Ekofisk



Metering system
Inspections were conducted of oil and gas metering systems in the Ekofisk area. Regular inspections were also make of sales metering stations at Teesside and Emden. In Emden, a meeting was held with German authorities to establish more formal cooperation between Norwegian and German authorities.

Costs
The total costs in the Ekofisk area including Tor, Albuskjell, Norpipe and investments in connection with the Ekofisk waterflood project are estimated at about NOK 82.3 billion (fixed 1986 kroner).

Preparedness
Activity at the Ekofisk Center has encreased the need for personnel so much that there is no longer 200 per cent excess space in the lifeboats. The operator has analysed the situation and reported the results to the Directorate.

The relatively generous access to bridges as escape routes has led the Directorate to waive the 200 per cent lifeboat capacity requirement.

The Directorate will examine the general aspects of the matter more closely when the regulations come up for review.

In connection with the installation of the 2/4-K waterflood platform, the operator asked permission to use a large crane vessel to provide accommodation for a total of 750 people. The Directorate carried through a major verification of an earlier evacuation study prepared by the operator and found that, in this case, it would be safe to house so many people on the installation.

Maintenance
The operator has pursued ordinary maintenance programs for mechanical equipment. One of the 2/4-T compressors required a major program of maintenance due to iron oxide and rust dust from the Statpipe line. One turbine on 2/4-B suffered ingress of water in the oil, causing a major turbine overhaul in England.

Processing
Water injection from 2/4-B was resumed following a break of two and a half years. The gas dessicator on 2/4-T was closed down and made inoperable. The gas dessicator on 2/4-FTP was removed from the platform.

On 7/11 Cod and 2/4-T modifications to the piping for receipt of gas and oil from Ula were carried out. Modifications of the gas pipeline to one of the 2/4-T coolers were made, plus installation of a new cooler.

Preparations to utilize waste gas have been made. Major replacements of electrical equipment were carried out to improve plant quality.

2.3.4 Ula
Production licence 019 A

Licensees

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

The field lies in Block 7/12 some 70 kilometers northwest of Ekofisk (Figure 2.3.3.a). It was discovered in 1976 and declared commercial in December 1979. BP is the operator for the production licence.

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

Production facilities
The development concept involves three conventional steel platforms (Figure 2.3.4.a) for production, drilling and accommodation, respectively. The steel jackets for the platforms were installed in June 1985 and the offshore hook-up work took from October 1985 to August-September 1986.

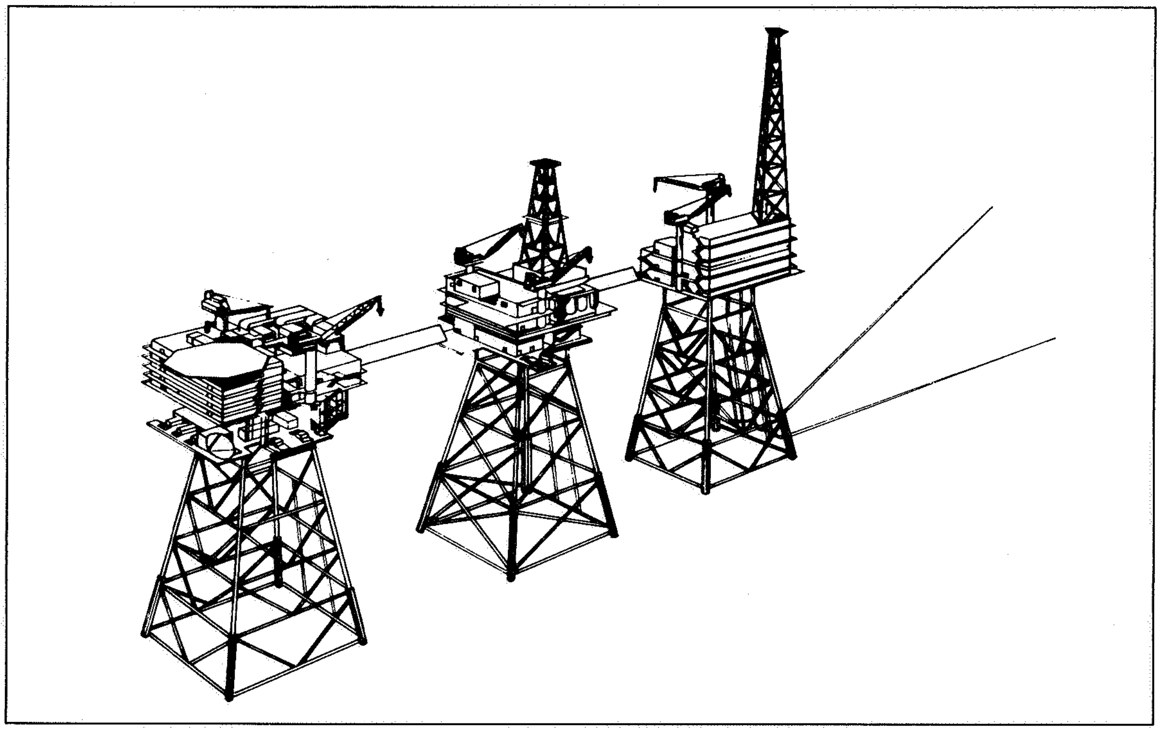
Production from the first well started on 6 October 1986. At year-end three production wells had been drilled, with an average production in December of 13,900 Sm^3 a day. On some days the rated day capacity of 15,900 Sm^3 was utilized to the full.

Deposits have accumulated on the blowout preventers causing unexpected difficulties. No other problems of note have been encountered.

Recovery of reserves
The Directorate's estimate of recoverable reserves is 30 million Sm^3 oil, though the operator believes the figure should be somewhat lower (25 million Sm^3). In its final form the field will have nine production wells and six water injection wells. Start of water injection is planned for September 1987.

Although production plans call for a relatively high plateau level, this is not expected to reduce the recovery factor of the field.

FIG. 2.3.4.a
Installations on Ula



Transport

The licensees have agreed to conduct oil by pipeline via the Ekofisk center to Teesside. Statoil will operate the pipeline.

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

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

Metering system

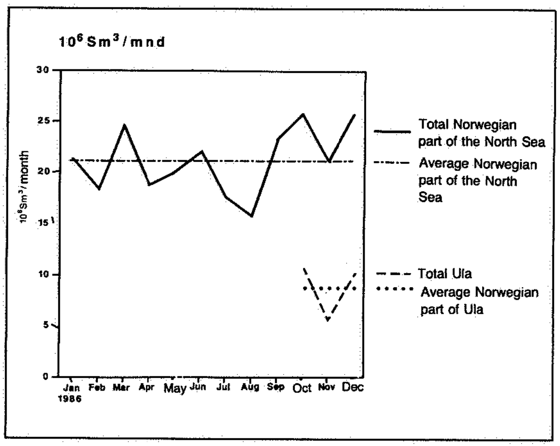
Tests of the metering system for oil and gas have been performed at the subcontractors. Metering system for oil and gas is ready to be shipped to the platform. The equipment was installed and inspected in spring 1985.

Flaring of gas

The gas processing plant entered service on 28 October 1986, before which the gas was flared off. Since production start 26 million Sm^3 gas have been flared on the field, corresponding to about 0.03 million Sm^3 a day (Figure 2.3.4.b).

During the entire period 34 per cent of gas production has been flared off, most of it before gas exportation started on 31 October 1986, though subsequent problems with a dessicator also caused some flaring.

FIG. 2.3.4.b
Gas flared on Ula



Metering system

The Ula field oil and gas metering systems were installed in February 1986. They were commissioned on the production platform by the vendor.

Fiscal metering is carried out on Ula, while verifications can be performed using a separate metering system on the Ekofisk R platform.

The Ula metering system consists of three metering tubes for oil and three for gas. Their capacity is about 25,000 Sm³ oil a day.

Costs

Total investment costs are expected to reach about NOK 8.7 billion in fixed 1986 kroner.

Preparedness

The Ula field installations consist of three steel jacket platforms strung in a line and connected by gangways. The drilling platform is in the middle, with the production and accommodation platforms on each wing.

Acceptance of the inter-platform bridge as the primary evacuation route has now been given. There are no lifeboats or liferafts on the Ula drilling platform, but two lifeboats on the production platform and six on the accommodation platform.

2.3.5 Sleipner East

Production licence 046

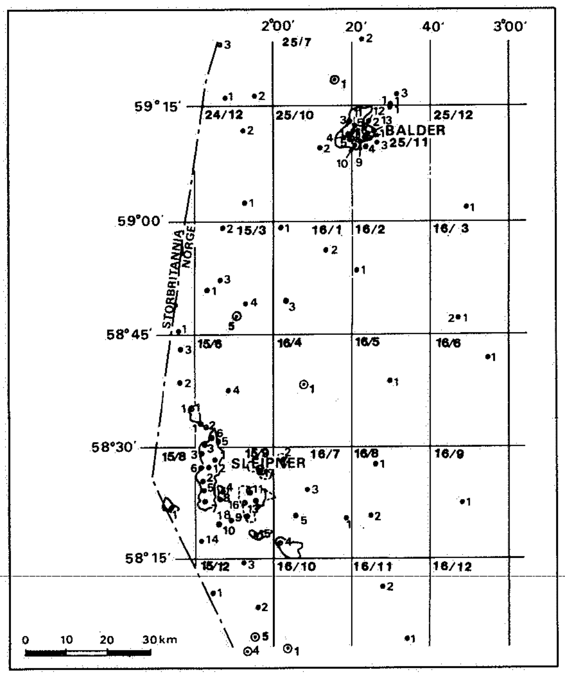
Licensees

Esso Norge A/S	40.000 %
Norsk Hydro A/S	10.000 %
Den norske stats oljeselskap a.s	50.000 %

Production licence 046 was allocated in 1976 and covers Blocks 15/8 and 15/9. Statoil is operator of Sleipner East. See Figure 2.3.5.a.

The plan for development and operation of Sleipner East was considered by the Storting on 15 December 1986. Sleipner East gas has been sold to the

FIG. 2.3.5
Sleipner and Balder area



Continent in the Troll-Sleipner gas agreement. Production start is scheduled for 1993.

Recoverable reserves on Sleipner East are believed to be 51 billion Sm³ gas, 17 million Sm³ oil and 10 million tonnes NGL.

Development

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

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

2.3.6 Heimdal

Production licence 036

Licensees

Den norske stats oljeselskap a.s	40.000 %
Marathon Petroleum Norge A/S	23.798 %
Elf Aquitaine Norge A/S	9.639 %
Bow Valley Exploration Norge A/S	8.000 %
Norsk Hydro Produksjon A/S	6.228 %
Total Marine Norsk A/S	4.820 %
Sunningdale Norge A/S	3.875 %
Saga Petroleum a/s	3.471 %
A/S Uglands Rederi	0.169 %

Production licence 036 was allocated in 1971 and covers Block 25/4, which is situated some 180 kilometers west-northwest of Stavanger (Figure 2.3.7.a). On that part of the licence which includes Heimdal, Statoil has 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 gas prices.

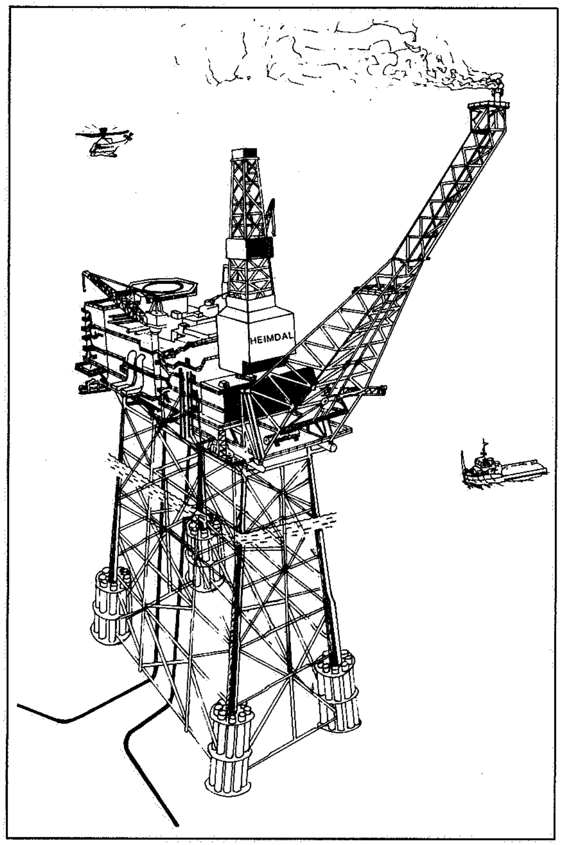
During 1980, the gas market picked up and Heimdal became the center of discussion for a landing solution for Statfjord gas. The landing application for gas to the continent was submitted in January 1981 and approved by the Norwegian Storting on 10 June 1981. The landing application for condensate was approved in January 1983.

Development

The reservoir lies some 2100 metres below sea level in Paleocenic sand. The total recoverable reserves are estimated at 34 billion Sm³ gas and 3 million Sm³ oil. It has been decided to develop the Heimdal field with an integrated steel platform, comprising drilling, production and accommodation functions (Figure 2.3.6). The installation work on the field started in summer 1984. Production started in December 1985 with the first deliveries to Emden in February 1986.

Production drilling on Heimdal started in April

FIG. 2.3.6
Installation on Heimdal



1985. As of December 1986, eleven wells had been drilled, nine for production, one for observation, and one suspended.

Transport

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

Metering system

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

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

Costs

The total costs are estimated at about NOK 9.4 billion fixed 1986 kroner.

Preparedness

On 21 August 1986 a Heimdal free-fall lifeboat fell out of its davits. The NPD was contacted and a working group called in consisting of representatives from the operator, davit manufacturer and lifeboat manufacturer. This group reviewed the accident and presented an interim report, on the basis of which it was decided to rehang all the lifeboats in conventional davits.

In consultation with the lifeboat manufacturer the operator has since arrived at a solution devised to ensure that accidents of this type cannot occur with the lifeboat hanging in free-fall position.

On 27 November 1986 the trawl of a fishing boat snagged the seabed just outside the Heimdal (HMP1) safety zone. The trawl was slightly damaged. Pressure and volume measurements of the condensate pipeline did not reveal any damage to it.

On 8 December 1986 a fire occurred in an oil pump on HMP1 (standby pump C in the hot oil system).

The contingency procedure to extinguish the fire was followed to the letter and the fire brought under control very quickly. Radio telephones used by the smoke divers proved to have serious limitations when the sprinkler triggered.

The probable cause of the fire was an oil leak in the insulation around the pump.

Production facilities

The drilling and completion phase ended on 3 June 1986. This was earlier than planned due to cancellation of one well.

Permission was given for Heimdal to operate early in the year and production soon reached its normal capacity. Start-up proceeded as planned with no major surprises.

Production has continued with no notable difficulties, though at a lower level than foreseen.

Maintenance

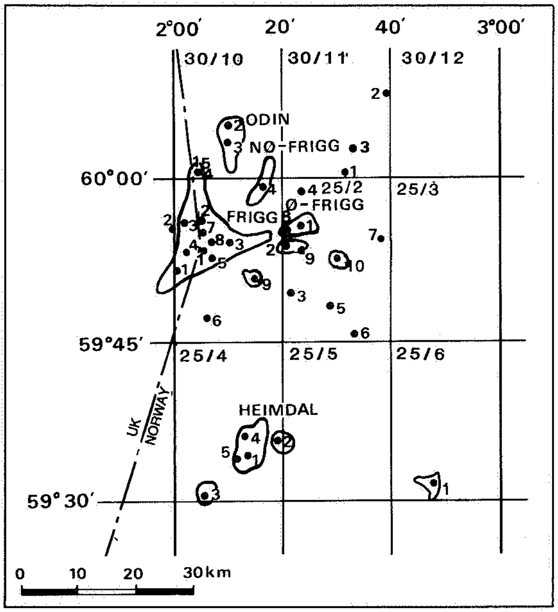
The annual production shut-down was made in June. One of the objectives this time was to modify the monoethylene glycol system.

2.3.7 The Frigg area
2.3.5.1 Frigg
Licensees

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

Elf Aquitaine Norge A/S is the operator for the

FIG. 2.3.7.a
The Frigg area



Frigg field, while Total Oil Marine Ltd is the operator for the pipeline system and St Fergus terminal in Scotland.

The Frigg field lies in Block 25/1 on the Norwegian Continental Shelf and Blocks 10/1 and 9/5 on the British shelf (Figure 2.3.7.a). The field has been unitized. Of the gas reserves, the agreement assumes that 60.82 per cent belong to the Norwegian licensees, and the remaining 39.18 per cent to the British licensees. The agreement governing distribution of the reserves may be renegotiated every four years, or at any time if extra reserves are proven which seem to communicate with the Frigg reservoir. 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, whose interests in the Frigg field are looked after by Total Oil Marine.

Production facilities

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

Phase 2 consisted of one production and one processing platform on the Norwegian side (DP2 and TCP2). Production from the Phase 2 platforms began in summer 1978. Figure 2.3.7.b depicts the Frigg installations.

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

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

Transport

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

Recovery of reserves

In summer 1984 substantial water rise was observed in a well on the UK side, which confirmed the irregular rise in liquid contact in the reservoir and water influx. Five wells were drilled or deepened in 1985. Regular checks of the liquid contact throughout 1986 show that the water has risen 19–67 meters since production start. At present the mean rate of rise is 10 meters a year. The rise is largely determined by more or less continuous slate barriers in the reservoir.

A provisional update of the field model made by the operator estimates rather smaller reserves. The final update will be available in spring 1987, based on three dimensional seismic interpretations. A decision will then be made whether additional wells are needed to produce any residual gas in the reservoir.

The Directorate estimates the Norwegian share of Frigg reserves at 127 billion Sm^3.

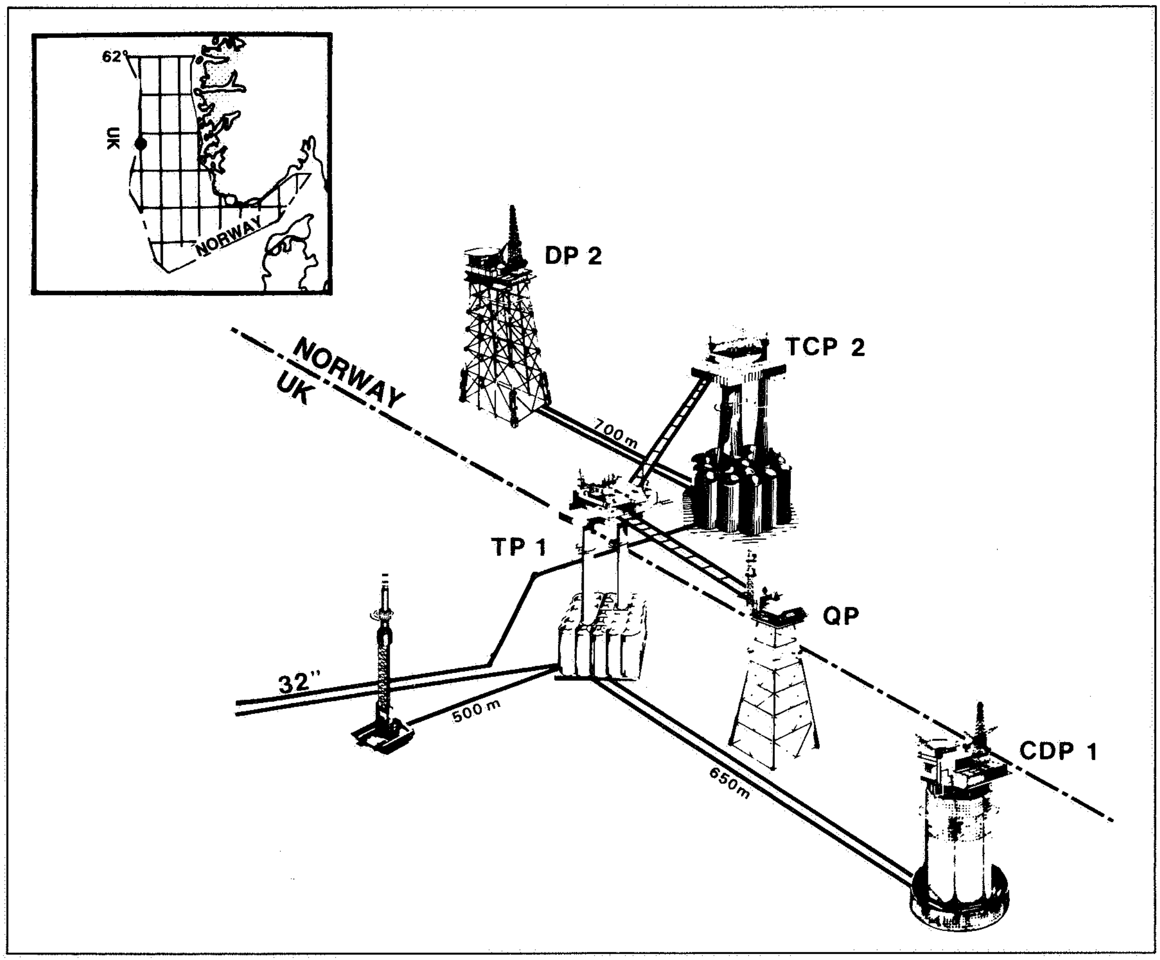
Metering system – Frigg

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

Metering system – Alwyn

Gas from the Alwyn field on the UK side will be conducted to St Fergus via the Frigg field. The design of the metering system complies with the Directorates regulations for fiscal quantity metering of gas, and the Directorate is allowed full access to the

FIG. 2.3.7.b
Installations on Frigg



Alwyn field installations. The design and functions of the metering system have been inspected at the manufacturers in collaboration with the British Department of Energy.

Costs
The total costs are expected to reach about NOK 34.1 billion in fixed 1986 kroner.

Maintenance
Frigg installations are showing their age with the result that maintenance and repair costs are increasing. The operator discovered a leak due to corrosion in a heat exchanger. Repair work included replacing the internal tube bundle. Five fire pumps were replaced due to corrosion damage, and four others are due for replacement.

2.3.7.2 East Frigg
Production licence 024 (Block 25/1) and 026 (Block 25/2) (Figure 2.3.7.a).

Licensees

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

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

Licensees

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

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

Gas Corporation within the existing sales agreement.

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

The field was declared commercial in August 1984, and the landing application was considered by the Storting on 14 December 1984. A development plan with four wells was approved by the partners. According to plan, production is to start in October 1988. Recoverable gas reserves have been estimated at 8.0 billion Sm^3 on East Frigg Alpha and 5.0 billion Sm^3 on East Frigg Beta, in all 13.0 billion Sm^3.

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

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

Metering system
The Directorate has considered the plans for a metering system for East Frigg. The system will be installed on Frigg itself.

Costs
Total costs are expected to reach roughly NOK 34.1 billion in fixed 1986 kroner.

Engineering design
The engineering design phase has ended. Progress among the various equipment contractors is going according to schedule and is being carefully followed, since equipment must be ready for installation in summer 1987.

2.3.7.3 North East Frigg

Production licence 024 (Block 25/1)

Licensees

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

Production licence 030 (Block 30/10)

Licensees

Esso Exploration and Production Norway Inc	100.00 %

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

The North East Frigg field lies in Blocks 25/1 and 30/10 (Figure 2.3.7.a) and redistribution of the gas reserves in August 1984 gave 42 per cent and 58 per cent, respectively, in each of the blocks. Elf Aquitaine Norge A/S is the operator for the development.

Production facilities
The gas field North East Frigg was proven in 1974. It is part of the same pressure system as the Frigg field. The final development plan was resolved in 1980. The field has been developed with six wells completed on the seabed (Figure 2.3.7.c) and drilled through a template structure located on the seabed. In addition to wellheads and Christmas trees, the template is also fitted with a manifold designed to collect gas from the six wells. The gas is led through a 406 mm pipeline to the Frigg field for processing. Each of the six Christmas trees is controlled via separate service and control lines from the control station (an articulated column) anchored 150 meters from the wellheads. The control station was installed in July 1983 and is remotely operated from the Frigg field.

The sale of gas from North East Frigg started on 1 October 1980, which was even before any of the production wells had been drilled. This was possible because the Frigg field delivered gas on behalf of North East Frigg until the latter came on stream. Similarly, Frigg will deliver gas on behalf of North East Frigg after production on the latter has ceased. "Reimbursement" will be achieved by allowing North East Frigg, in the course of its short production life to deliver gas on behalf of Frigg in addition to North East Friggs contract quantities. A more traditional, long-term sales profile for North East Frigg gas is thereby attained despite its short production life.

Recovery of reserves
Pressure measurements made before production start showed that the reservoir pressure decreased as a result of communication with the Frigg field though the inter-field saddle.

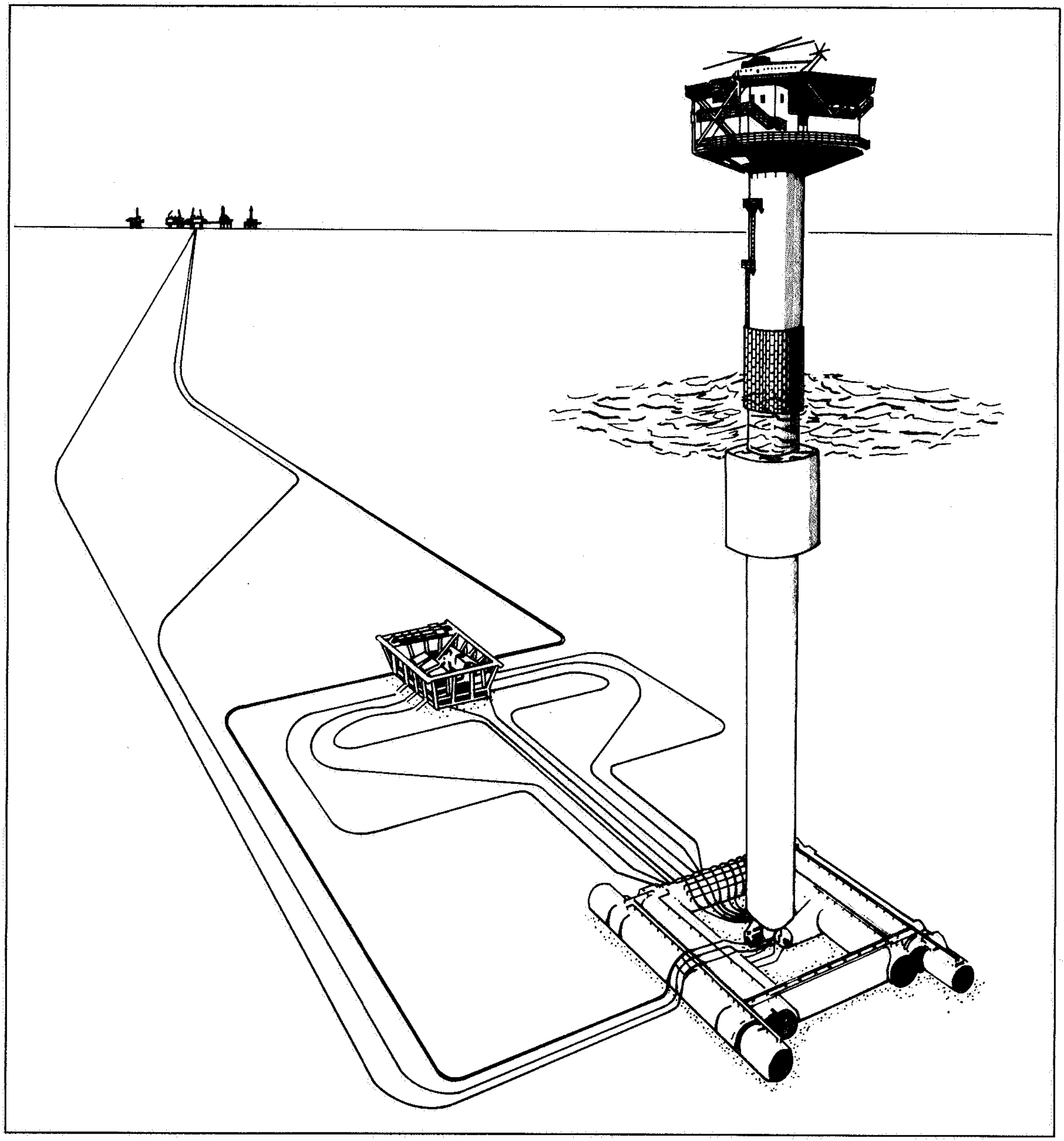
About half the fields recoverable reserves have now been tapped. All individual wells were tested in autumn 1986 and field productivity is considered stable. Reservoir simulation shows that water break-through will occur in autumn 1987, after which water production will limit the gas rate.

In 1987 the operator will conduct studies to determine the optimal method of intervention with subsea completion wells.

Metering system
Regular inspections and paperwork in connection with the metering system installed on Frigg have been performed in collaboration with the British Department of Energy.

Costs
Total costs for the development are expected to run into about NOK 3.2 billion in fixed 1986 kroner.

FIG. 2.3.7.c
Installations on NE-Frigg



Production facilities
Well 25/1-B-4 was plugged on 22 May 1986 because of leakage around the well pipe. Production is continuing from five wells.

Leaks were also discovered from the hydraulic control lines to the subsea production units. The leaks were caused in part by intergranular and galvanic corrosion resulting from a mixture of material qualities and lack of cathodic protection. The lines to five wells have been replaced.

Inspection with a remotely operated subsea vessel (ROV) of the methanol line and electrical power lines between TP-1 and North East Frigg revealed about five meters of damage to the lines. A fishing trawl is assumed to have caused the damage.

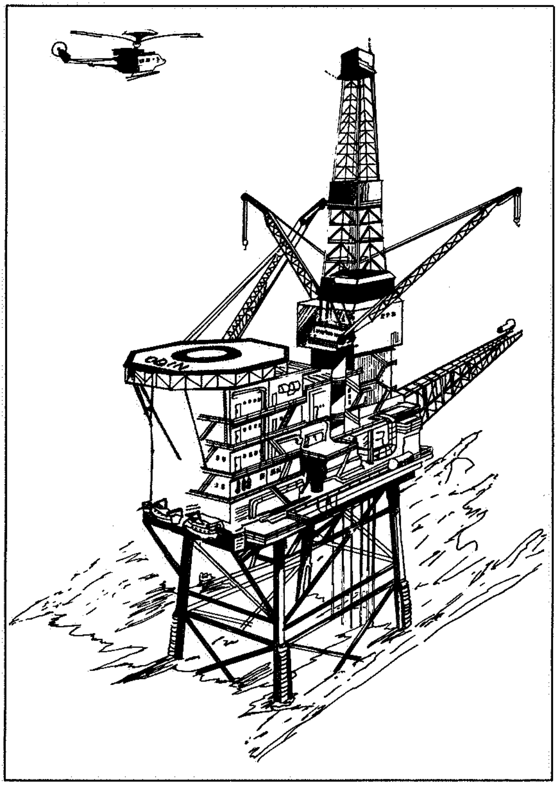
2.3.7.4 Odin
Production licence 030

Licensee
Esso Exploration & Production Norway Inc 100 %

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

The Odin field lies in Block 30/10 (Figure 2.3.7.a), with development operated by Esso.

FIG. 2.3.7.d
Installation on Odin



Production facilities

The Odin gas field was proven in 1974, and the development plan approved in 1980. The field was developed with one small steel jacket platform with simplified processing and drilling equipment and relatively small accommodation quarters (Figure 2.3.7.d). This was possible because an auxilliary vessel was used for a two-year period, for installation work as well as production drilling.

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

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

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

Recovery of reserves

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

Metering system

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

2.3.8 Oseberg

The Oseberg field extends into two production licences, Licence 053 on Block 30/6 which was allocated in 1979, and Licence 079 on Block 30/9 which was allocated in 1982 (Figure 2.3.8.a).

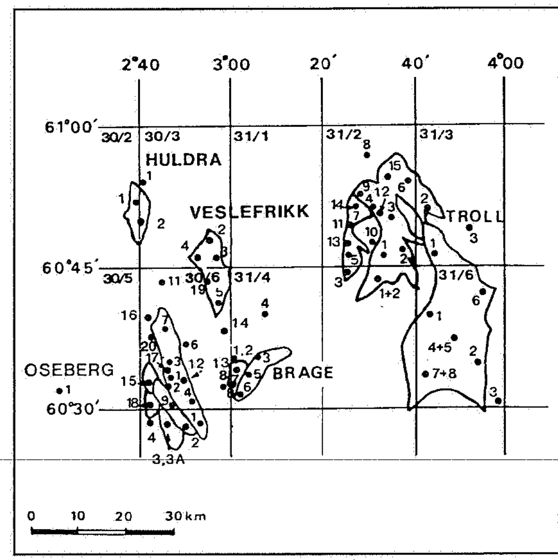
Production licence 053

Licensees

Statoil	50.00 %
Elf Aquitaine Norge A/S	13.33 %
Total Marine Norsk A/S	6.67 %
Norsk Hydro Produksjon A/S	12.50 %
Mobil Exploration Norge	10.00 %
Saga Petroleum a.s	7.50 %

Statoil was operator from the start, though the operatorship was transferred to Norsk Hydro in

FIG. 2.3.8.a
Oseberg and Troll area



April 1982. Elf Aquitaine Norway is the technical assistant.

Production licence 079

Licensees

Statoil	73.50 %
Norsk Hydro Produksjon A/S	16.00 %
Saga Petroleum a.s	10.50 %

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

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

Licensees

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

Field history
The initial discovery was made in 1979 and proved gas. Subsequent discoveries have shown that the reservoir consists of an oil-bearing layer topped by a gas cap. The declaration of commerciality was presented in June 1983. The Norwegian Storting considered the development application in the spring session of 1984.

Development concept
It has been decided to develop Oseberg with a field center in the southern section comprising two platforms: Oseberg A, a processing and accommodation platform with a concrete base; and Oseberg B, a drilling and water injection platform with a steel jacket (Figure 2.3.8.b).

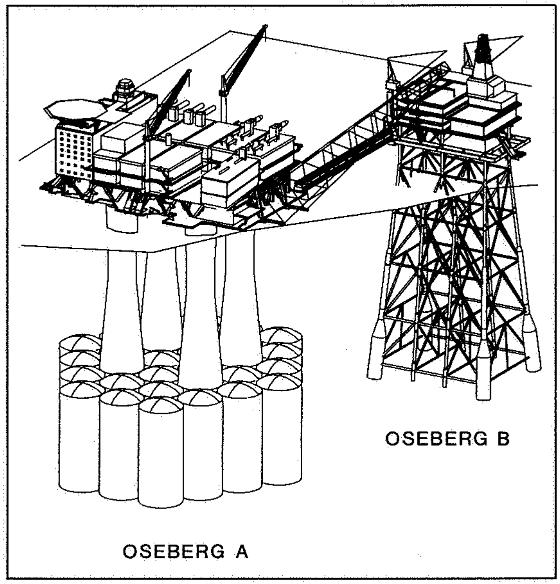
Production is planned to start on 1 April 1989.

The middle section of the field is planned to be developed with subsea completed wells.

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

Production from the most essential part of the Oseberg field, the so-called Alpha structure, was assumed to require water injection in the plan for development and operation. In 1986 this concept was changed. Oil in Alpha will now be recovered using gas injection as the power source. The change-over

FIG. 2.3.8.b
Planned installations on Oseberg



to gas injection on Alpha means that a total of roughly 15 billion Sm^3 more oil will be obtained from the field.

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

The operator is considering proposing changes in the Oseberg Phase II development plans. The changes call for development of the northern part of the field with a platform fitted with equipment to fully stabilize the oil. A platform of this type could be erected faster than the original Phase II field development concept, since it would not then be necessary to await idle production capacity at the field center.

The plan to accelerate Phase II coupled with possible upward adjustment of process capacity at the field center may enable plateau production from Oseberg to increase from an average 35,500 to over 47,700 Sm^3 a day.

Norsk Hydro is planning to submit an updated plan for development and operation of Oseberg in 1987 where a stand will be taken regarding development of the northern section of the Oseberg field.

Transport systems
A pipeline is being constructed to transport stabilized oil from Oseberg to a terminal at Sture in Øygarden. The pipeline is owned and operated by a se-

parate venture called the I/S Oseberg Transport System (OTS).

Unit holders in the venture are the Oseberg licensees. The pipeline has a capacity of 95,000 Sm^3 a day. If the Sture terminal is upgraded, the facility will be capable of transporting oil from other fields in the area in addition to crude from Oseberg. The pipeline will be 711 mm in diameter. Norsk Hydro will operate both the pipeline and terminal.

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

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

Production drilling

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

Recovery of reserves

In the years prior to the end of the century all gas produced from Oseberg will be reinjected into the Etive formation in the Gamma structure. The production profile will be greatly affected by the decision taken with regard to development of the northern part of the field.

In order to gain a better understanding of the reservoir properties, a long running test program was initiated in autumn 1986 using "Petrojarl I", a production and test ship. The tests are planned to last 18 months. Plans call for testing of two wells, one in Gamma and one in Alpha. These wells will be tested in several formations. Experience so far with the first well has been encouraging.

"Petrojarl I" has been on station at Oseberg since September 1986. Operating regularity has been excellent, over 90 per cent, and apart from some minor events the ship has functioned satisfactorily.

The oil produced by "Petrojarl I" is landed by special tankship. Associated gas produced is flared off.

Metering system

The metering system has undergone testing and has left the manufacturer. The Sture cargo metering station plans are at the approval stage with the operator, and are expected to be sent to the Directorate at year-end 1986–87.

The metering system has been tested on the production and test vessel "Petrojarl I". Inspection has also been made of the metering system during offloading of "Petrojarl I" to the tanker "Petroskald".

Costs

Total costs are expected to run to roughly NOK 41.8 billion in fixed 1986 kroner.

Preparedness

The contract between Golar-Nor and Norsk Hydro regarding use of PTS "Petrojarl I" on the Oseberg field was the first application of this technology in Norwegian petroleum activity. It meant that the Directorate had to apply the rules in a new way. During the consideration of permits for PTS "Petrojarl I" several interpretational obscurities were cleared up.

On Oseberg Norsk Hydro has contracted to use a flotell with up to 800 beds. This is significantly more than the previous accepted number.

In connection with this a letter was sent to the operators on the Norwegian shelf concerning the requirements in the Petroleum Act regarding effective contingency preparedness. The letter explained in detail how the Directorate intends to administrate the Regulations concerning Rescue Equipment on Fixed Installations etc.

Transport line and terminal at Sture

These projects are pushing ahead at high speed. Engineering design for the pipeline is complete; the pipes were manufactured in Japan and are now in Scotland to receive a protective coat and concrete gravity collar.

Preparatory pipelaying work is in progress. The over two kilometer long tunnel for landing at Øygarden has been excavated, and sealing walls in the tunnel outlet are being erected. The tunnel enters the sea 80 meters below the surface.

Since the pipeline crosses important fishing grounds where bottom trawls and similar are employed, a new type of field joint formwork is being tried out on about 30 km of the pipeline at the Oseberg end.

Fishery interests have claimed that field joint formwork (a sheath fitted around the pipe where lengths are welded together) and rough-finished concrete surfacing are the two culprits responsible for damaging fishing implements.

The Directorate is very pleased that Norsk Hydro is conducting this experiment to determine whether such measures may combat the problems claimed by fishermen in connection with bottom trawling across pipelines. The issue is particularly important in the case of pipelines now at the planning stage.

The Oseberg transport system will be ready to move oil from Oseberg from 1 April 1989.

Troll-Oseberg gas injection TOGI

In order to optimize production from the Oseberg reservoir gas will be injected. The gas will be supplied from a subsea production module on the Troll field 55 kilometers from Oseberg.

The subsea production module will supply unprocessed gas and will be controlled from Oseberg. The Directorate has taken on consultants to assess project safety.

2.3.9 Troll

Production licence 054

Licensees

Conoco Norway Inc	5.000 %
Norsk Hydro A/S	5.000 %
Mobil Exploration Norway Inc	5.000 %
A/S Norske Shell	35.000 %
Den norske stats oljeselskap a.s	50.000 %

Production licence 085

Licensees

Norsk Hydro	9.000 %
Saga Petroleum A/S	6.000 %
Den norske stats oljeselskap a.s	85.000 %

The Troll field covers parts of Blocks 31/2, 31/3, 31/5 and 31/6 (Figure 2.3.8.a). Allocation of Block 31/2 was made in 1979, while the other three blocks were allocated in July 1983. Block 31/2 belongs to production licence 054 with Norske Shell as operator. Blocks 31/3, 31/5 and 31/6 belong to production licence 085. Operatorship is here split between Statoil, Saga and Norsk Hydro. Unitization of the two production licences has been completed.

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

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

The resources in Troll as estimated by the Directorate include 1288 billion Sm^3 gas and 41 million Sm^3 oil. In its estimates the Directorate has not yet included oil in those parts of the field with a 10–17 meter oil column, though the feasibility of producing from this part of the field is being considered.

Norske Shell, the operator of the first gas development on Troll, presented its plan for development and operation of gas Phase I in September 1986. The plan was considered by the Storting in December 1986.

Development will consist of one concrete base platform with production capacity 19.3 billion Sm^3 gas a year. This capacity can be expanded to 22–23 billion Sm^3 a year.

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

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

Zeepipe

In autumn 1986 it was decided in principle to set up a new gas transport system to deliver Troll and Sleipner gas. The pipeline will terminate in Zeebrügge in Belgium. Further studies will be made to determine system design, necessary capacity and starting year. The earliest date at which Zeepipe will be needed is 1993, though if Norpipe has suitable idle capacity, this date can be postponed.

2.3.10 Gullfaks

Production licence 050

Licensees

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

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

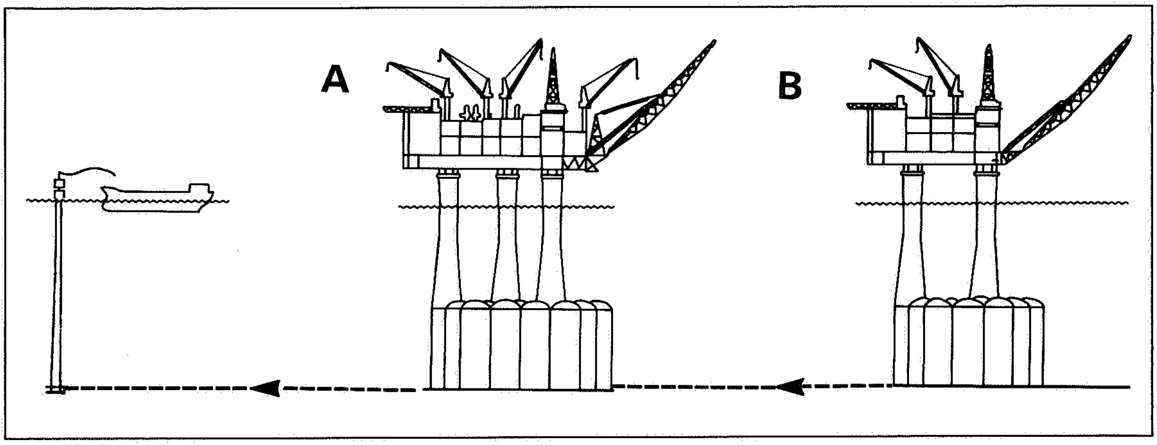
Production facilities

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

Phase I will consist of two platforms (Figure 2.3.10). Platform A is an integrated drilling, processing and accommodation platform with a capacity of about 39,000 Sm^3 a day. The platform is located in the southwestern part of the structure in about 135 meters of water. The platform is a gravity base concrete structure with a T-shaped steel deck frame.

Platform B will be a drilling, accommodation and water injection structure with a concrete gravity base, equipped with limited processing machinery.

FIG. 2.3.10
Planned installations on Gullfaks phase 1



The Gullfaks B platform will be sited in the northwestern part of the Delta East structure where the water is also about 135 metres deep.

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

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

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

Construction of Gullfaks A progressed generally according to plan and the unit was ready for operation in December 1986.

In December the operator initiated production from three of the four subsea completion wells drilled and hooked up to the platform. Commissioning of these wells has been faster than expected, and production started about six months before schedule.

The first 2–3 months will be committed to reservoir tests to try and unravel the fault pattern, which seems to be extremely complex.

Gullfaks B is scheduled to come on stream on 1 December 1988 .

Recovery of reserves

The field lies in the northeastern part of Block 34/10 and covers an area of about 200 square kilometers. The proven reserves all lie within the block. Figure 2.3.11 shows the location of the field.

The Delta structure is a relatively shallow, divided by north-south faults into several angled and rotated segments of Jurassic strata. The segments, or blocks, vary in their degree of declination, though all point fairly consistently to the west. In the east, the structure is more uncertain, the area being highly broken by faults and in places heavily eroded. The structural details of the eastern part are more difficult to plot due to poor seismic data. The field is bounded in the south, east and northeast by faults with vertical displacements exceeding 100 meters. Gullfaks is definitely the most geologically complex field so far developed on the Norwegian Continental Shelf. Until the Directorate has presented it's estimate, Statoils claim of 135 million Sm^3 oil, 8 billion Sm^3 gas and 1 million tons NGL will be used.

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

Gullfaks Phase II

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

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

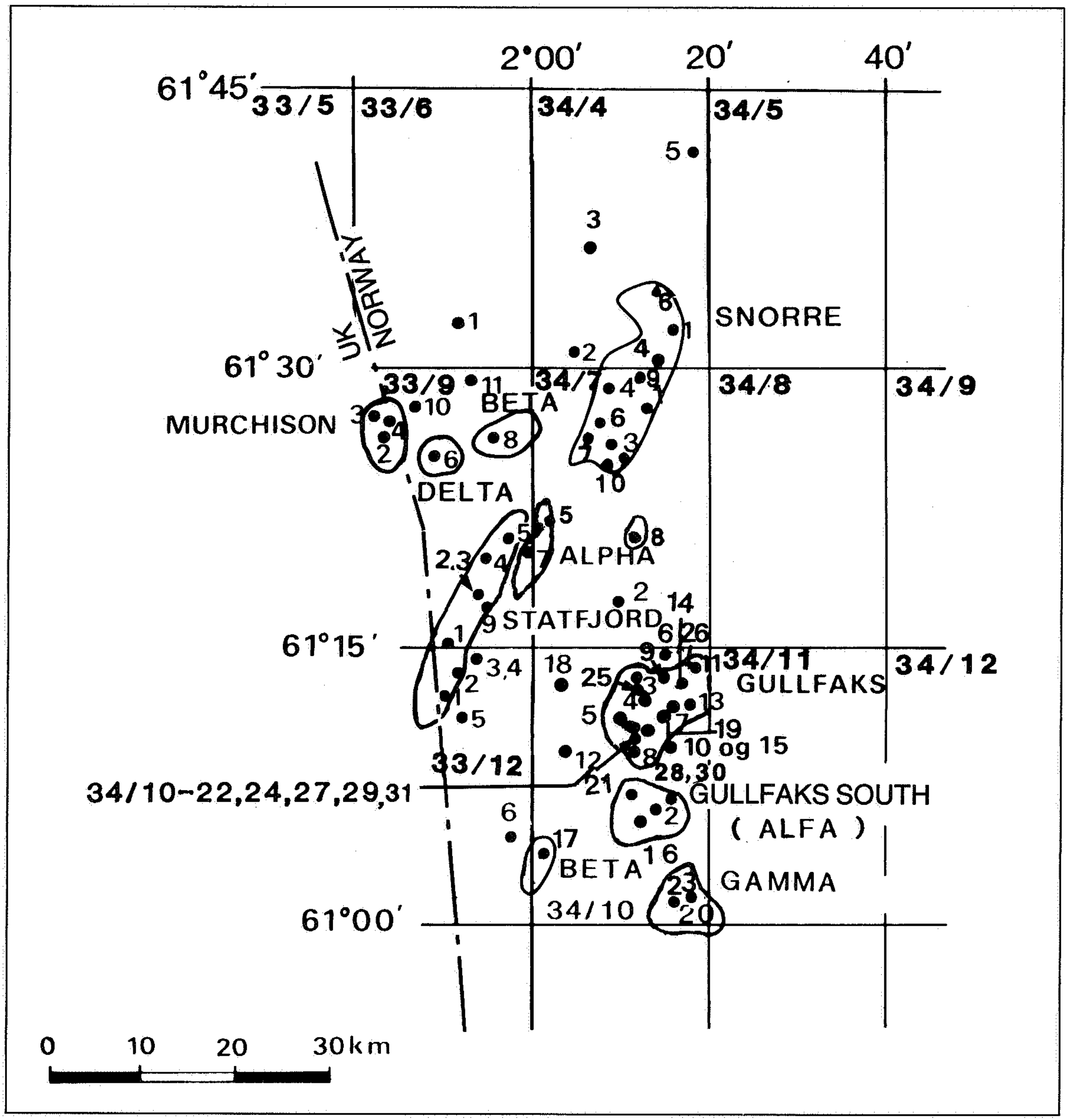
Appraisal well 34/10–19 on this part of the Gullfaks field proved to be dry.

Recovery of reserves

Thanks to the complicated field boundaries to the east and southeast, estimates of resouces are very unreliable. Statoils estimates of recoverable reserves are about 75.2 million Sm^3 oil and 10.5 billion Sm^3 gas for Delta East, Phase II. These estimates were made after drilling of Well 34/10–19.

Development of the area received Storting appro-

FIG. 2.3.11.a
The Gullfaks-, Statfjord- and Snorre area



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

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

Partially processed crude oil is expected to be dispatched through a 205 mm pipeline from Gullfaks B to Gullfaks C, where final processing can begin in 1990. Stabilized crude oil produced on Gullfaks C will be transported to a loading buoy (single point mooring, SPM2) via a 414 mm pipeline.

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

Development of Gullfaks A, B and C
Gullfaks A
On 21 December Statoil initiated oil production by starting up three subsea completion wells on the Gullfaks A platform.

Hydrocarbons from these three wells are conducted through flexible flowlines along the seabed and up through the drilling shafts to the processing area.

Before the gas compression system is commissioned in spring 1987 the bulk of the gas will be flared off whilst parts are used to power the gas turbines.

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

Gullfaks B

Construction of the concrete gravity base of this platform was completed in 1986 and mechanical outfitting is now taking place.

Construction of the steel deck and installation of modules is being done and mating of deck to base is planned in April 1987.

Gullfaks C

Construction of the concrete gravity base started in January 1986 in Stavanger. Tow-out from the dry dock will take place in February 1987, and the structure will be finally slip-formed by the first quarter 1988.

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

The steel deck has been being fabricated at Stord since September 1986 and will take 16 months to complete.

Metering systems

The metering systems for oil and gas on Gullfaks A have been installed. The Gullfaks C systems are still at the construction site, though fully built and undergoing test.

Costs

The total costs are expected to run to about NOK 35 billion in fixed 1986 kroner.

2.3.11 Statfjord

Production licence 037.

Licensees

Norwegian share (84.09322 %)	
Mobil Exploration Norway Inc	12.61400 %
Den norske stats oljeselskap a.s	42.04661 %
Norske Conoco A/S	8.40932 %
Esso Exploration and Production Norway A/S	8.40932 %
A/S Norske Shell	8.40932 %
Saga Petroleum a.s	1.57674 %
Amoco Norway Oil Company A/S	0.87597 %
Amerada Hess Norwegian Exploration A/S	0.87597 %
Texas Eastern Norway Inc	0.87597 %
British share (15.90678 %)	
Conoco (UK) Ltd	5.30226 %
Britoil Plc	5.30226 %
Gulf Oil Corporation	2.65113 %
Gulf UK Offshore Investments Ltd	2.65113 %

On 10 August 1973 the licensees on the Statfjord field were allocated production licence 037. This includes Blocks 33/9 and 33/12 (Figure 2.3.11.a).

Mobil is operator until 1 January 1987, when Statoil will assume operatorship.

The Statfjord field itself was discovered in the spring of 1974 and declared commercial the same year. Statfjord extends onto the British side where Conoco is the operator. The initial field development report was submitted to the authorities in the spring of 1976. Since then, several development reports have been presented. The field has been developed in three phases with fully integrated platforms: Statfjord A, Statfjord B, and Statfjord C. The Statfjord A platform is centrally located on the field, the B platform stands to the south of it, and the C has been sited in the northern part of the field (Figure 2.3.11.b).

Recovery of reserves

By injecting water into the Brent reservoir and gas into the Statfjord reservoir, the Norwegian Petroleum Directorate expects to attain a recovery factor of some 50 per cent. This means that the total recoverable amounts of oil in the Brent and Statfjord formations are 445.7 million Sm^3. The amount of recoverable associated gas has been estimated at 58.6 billion Sm^3 dry gas, and 18.4 million tons of NGL.

Apportionment of the reserves in the field, as approved by the authorities in 1979, assigns 15.9068 per cent to the British side, and 84.0932 per cent to the Norwegian. The licensee groups are currently negotiating new apportionment figures. The negotiations are expected to be concluded in 1987.

Production facilities

Statfjord A

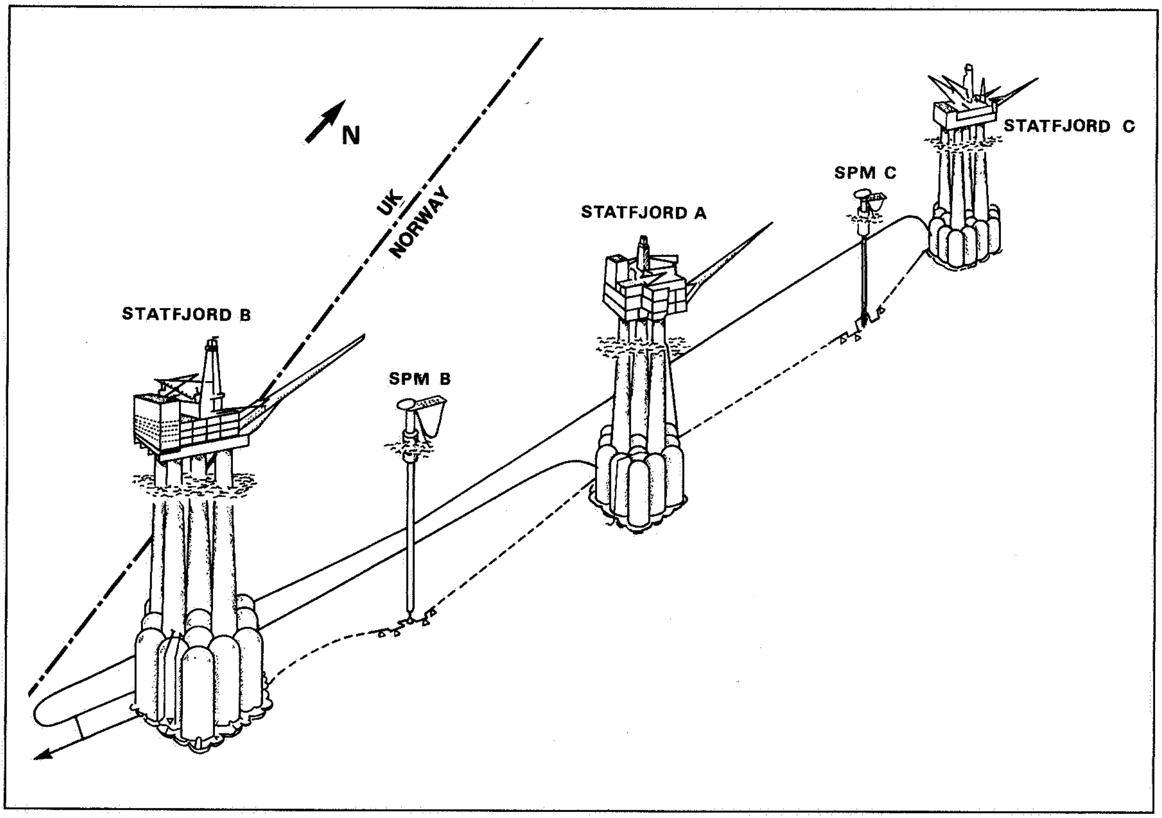
The Statfjord A platform is located at the center of the field, and comprises three columns and 14 cells, all of concrete. The deck is of steel. New assumed production capacity is 55,000 Sm^3 a day. Capacity increased as a result of fine-tuning of the processing equipment. The average capacity utilization of the process equipment during 1986 was high. The platform started production on 24 November 1979.

The operators well program is now complete and consists of 22 production and 14 injection wells. Earlier plans for two observation wells have been postponed until further notice.

Statfjord B

Statfjord B, sited in the southern part of the field, has four columns and 24 cells, all of concrete. The deck is of steel. Statfjord B production capacity has also increased due to fine-tuning of the process

FIG.2.3.11.b
Installations on the Statfjord field



trains. The new maximum capacity is rated at 39,800 Sm^3 a day. Production started on 5 November 1982 and capacity is now being fully exploited.

The drilling program, which consists in all of 30 wells, will provide 19 wells for oil production and 11 for injection. One injection well remains of this well program, though this has been delayed until further notice. Water treatment and water injection capacity was expanded in autumn 1986.

The operator is looking into the chances of enlarging the Statfjord B accommodation quarters.

Statfjord C

Statfjord C is an approximate copy of Statfjord B. Like its two sisters, it has the necessary equipment to produce and store oil, together with machinery for gas injection, gas transport and water injection. Statfjord C has 42 well slots and in addition the potential for future tie-in of nine subsea completion wells. Production capacity is 39,800 Sm^3 a day. Production started on 26 June 1985 ahead of schedule.

According to the operators well program, the platform will have 19 production wells and 12 injection wells. So far 11 of the former and seven of the latter have been drilled.

Flaring of gas from Statfjord A, B and C

The amount of gas flared on Statfjord A in 1986 was roughly 0.189 million Sm^3 a day on average, corresponding to 2.1 per cent of the total gas production from the platform. Statfjord A has entered a stable operating phase, so that the amount of gas flared is well below the flaring limit of 0.400 million Sm^3 a day. The main reason for flaring the gas has been compressor malfunction. Further, there was some resulting from stimulation of the gas injection wells.

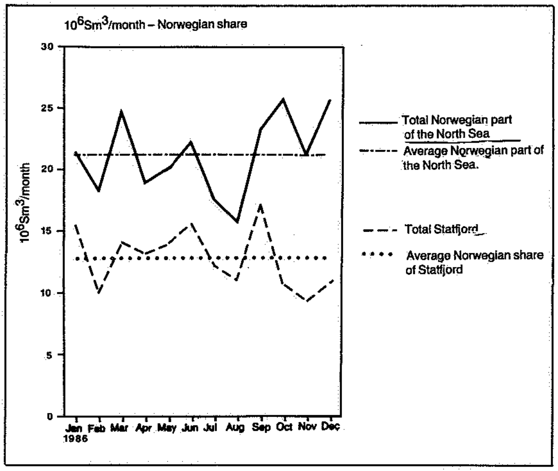
In the same period on Statfjord B, an average 0.100 million Sm^3 a day, corresponding to 1.4 per cent of total gas production, was flared. Statfjord B is also considered to be in a stable operating phase. Gas flared remained well under the flaring limit of 0.400 million Sm^3 a day. Compressor troubles have been the main reason for flaring.

Statfjord C flared off 0.130 million Sm^3 a day on average. This corresponds to 2.3 per cent of the platforms total gas production. The flare permit sets an upper gas flare limit of 0.400 million Sm^3 a day. Statfjord C has remained well below this limit, which indicates that the teething troubles have now been overcome and stable operation has been achieved. See Figure 2.3.11.c.

Metering system

The metering systems for oil on Statfjord A, B and C worked as intended in 1986. The metering systems on the A platform were upgraded during the

FIG. 2.3.11.c
Gas flared in the Statfjord area



summer maintenance shut-down. Some work remains, however, before the A systems are as high quality as on the B and C platforms.

The gas metering systems for Statpipe on Statfjord A, B and C and the system metering gas for export to Great Britain (Statfjords UK offtake) have been operating regularly in 1986.

The metering system on Statfjord C was not much used since technical reservoir considerations dictated preference of Statfjord A gas, followed by Statfjord B, and with Statfjord C only third choice.

The Directorate carried out regular inspection of the oil and gas metering systems on Statfjord, in part in collaboration with the British Department of Energy.

Costs

The total investment costs for the development of Statfjord are expected to run to about NOK 63.4 billion in fixed 1986 kroner. The Norwegian share of this is approximately NOK 53 billion.

Preparedness

Development of a gondola rescue system on the Statfjord field continued in 1986. However, field trials uncovered some points of difficulty, delaying operational start-up of the system until the new year. The Directorate sees this system as an important contribution to the fields total preparedness, and will follow developments carefully.

Production

Production from the Statfjord field has been good, with almost the only interruptions being the scheduled shutdowns. On Statfjord A major refurbishments were made to the ventilation system, thereby bringing area classifications and overpressure fans into compliance with current regulations.

Loading system

To replace the wrecked Statfjord A loading buoy, a system developed by Norwegian manufacturers was selected. The key feature of this system is its simplicity and the replacement of the traditional loading buoy with a flexible tube running from the seabed to the tankship. The new system has been installed and will begin operation in the first quarter 1987.

Maintenance

Corrosion damage made it necessary to replace parts of the ballast water piping system at the bottom of the utility shaft on Statfjord A in summer 1986. Pipes of titanium alloy were chosen to replace the damaged concrete-jacketed steel pipes. Complications arose due to the limited workspace and the strict conditions under which titanium must be welded.

Gas transport, Statpipe

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

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

Statoil is operator for construction and operation of the pipeline.

The transport system includes:

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

No serious problems have arisen in connection with operation of the Statpipe line.

The inspection in summer 1986 revealed some mines close to the pipeline. These were towed away from the line and destroyed. The mines presumably arrived in the area in connection with trawling operations.

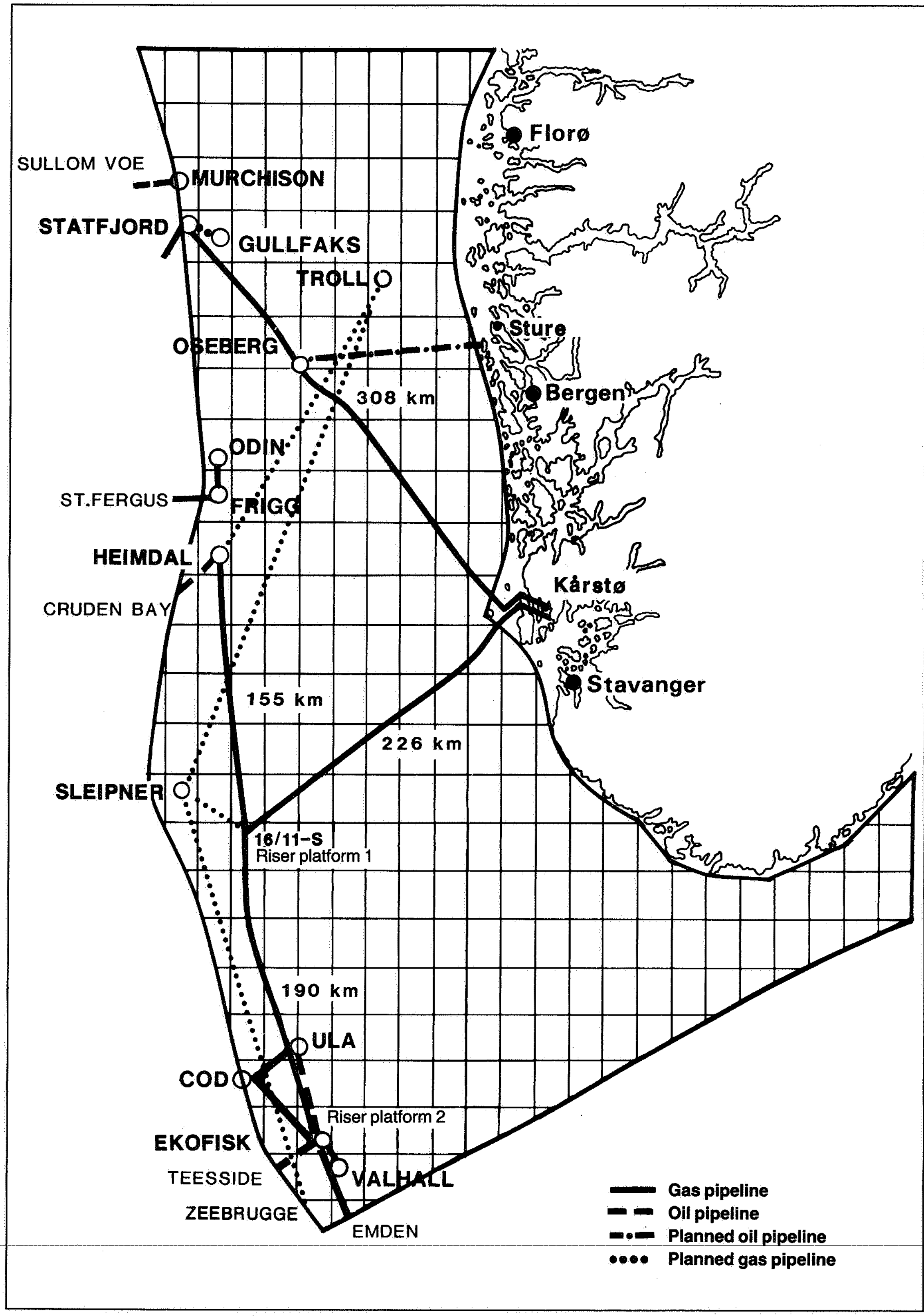
The pipeline from 16/11-S to 2/4-S was inspected internally in June 1986. British Gas Corporation equipment was employed with satisfactory results. No thinning of the pipeline walls was observed at any point in the pipeline.

Kårstø

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

A sketch of the transport systems for oil and gas in the Norwegian part of the North Sea is shown in Figure 2.3.11.d.

FIG. 2.3.11.d
Pipelines in the Norwegian part of the North Sea



The transport capacity from Statfjord to Kårstø is eight billion Sm^3 of wet gas per year. Kårstø has a processing capacity of five billion Sm^3 wet gas per year. The dry pipeline to the Ekofisk Center has a transport capacity of 17 billion Sm^3 a year. This exceeds the capacity requirements for Statfjord, Gullfaks and Heimdal and has been provided to allow later tie-in of other fields. If it becomes necessary to increase transport capacity in the Statpipe system, a compressor platform will need to be erected next to the marine riser platform 16/11-S.

A blanket agreement with Norpipe a/s and the Phillips group has been entered into concerning the use of the Ekofisk Centre and the pipeline to Emden. The licensees on Statfjord, Heimdal and Gullfaks have also entered into sales agreements for the gas with buyers on the Continent.

Metering system

The LPG and dry gas metering systems at Kårstø have been operational since November 1985. The systems have functioned largely according to requirements. Some minor improvements to the LPG metering system are planned in 1987. The Directorate has inspected the metering systems regularly.

2.3.12 Murchison

Licensees

British share (77.8 %)	
Conoco North Sea Inc	25.93 %
Britoil Ltd	25.93 %
Chevron USA Inc	25.93 %

Norwegian share (25.06 %) (production licence 037)	
Mobil Development Norway A/S	3.33 %
Den norske stats oljeselskap a.s	11.10 %
Norske Conoco A/S	2.22 %
Esso Exploration and Production Norway A/S	2.22 %
A/S Norske Shell	2.22 %
Saga Petroleum a.s	0.42 %
Amoco Norway Oil Company A/S	0.23 %
Amerada Hess Norwegian Exploration A/S	0.23 %
Texas Eastern Norway Inc	0.23 %

The above mentioned licensees are the same as on the Statfjord field. The Murchison field was proven in August 1975. It lies in Block 211/19 on the British side and Block 33/9 on the Norwegian (Figure 2.3.11.a). Development of the Murchison field was started in 1976 by the British licensees. The 037 group declared the field commercial in summer 1977, and Statoil joined the declaration in summer 1978.

Re-distribution negotiations were completed in 1986 and the new figures apply from September 1986. The Norwegian share was reduced from 25.1 to 22.2 per cent. Recoverable reserves for the whole field are estimated to be 53 million Sm^3 oil and 1.2 billion Sm^3 gas.

Production facilities

Field development uses an integrated steel platform with production capacity 26,200 Sm^3 a day (Figure 2.3.12.a). On 28 September 1980, oil production started from the two subsea completion wells. Current production is roughly 12,200 Sm^3 crude oil a day.

The platform has a total of 28 well slots. So far, 27 wells have been completed, including 18 oil production wells and nine water injection wells.

Recovery of reserves

Murchison has been producing at almost maximum processing capacity since 1981. 1984 was the last year of plateau production, and water production has risen to 30 per cent. Increased water treatment capacity is planned. Capacity (then 7,950 Sm^3 a day) was increased to 15,900 Sm^3 a day in the course of December 1985. Water injection capacity will also be increased from 27,000 to 31,800 Sm^3 a day. Further increases are being planned.

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

FIG. 2.3.12.a
Installation on Murchison

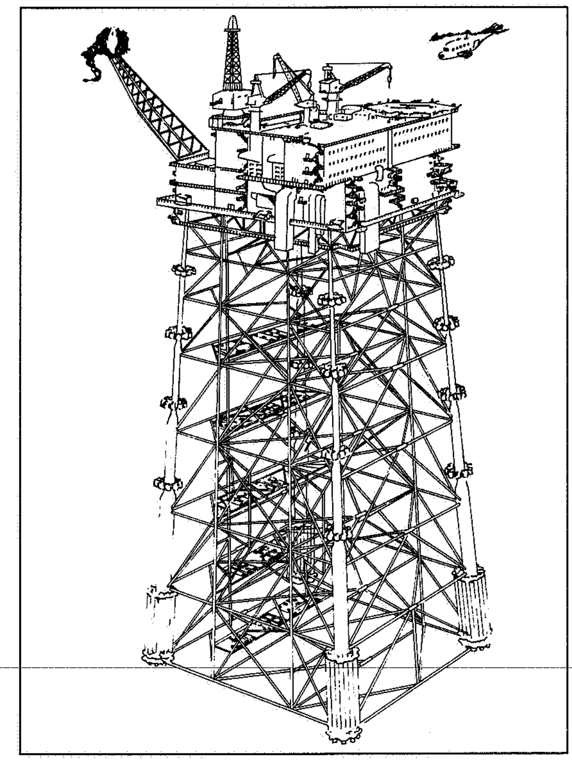
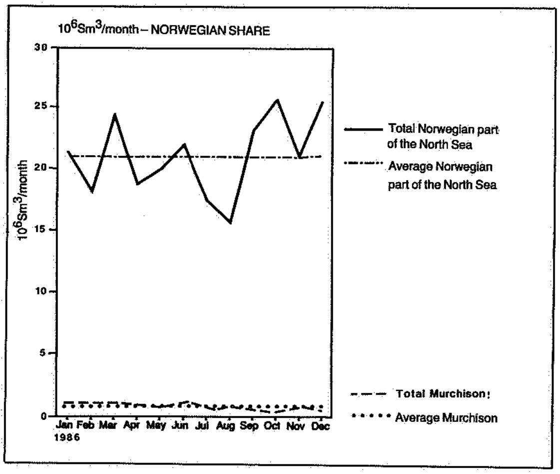


FIG. 2.3.12.b
Gas flared on Murchison



Oil from Murchison is forwarded by pipeline to Sullom Voe on the Shetland Isles.

Flaring of gas
In 1986 an average 0.093 million Sm^3 gas a day was flared, corresponding to 9 per cent of total gas production (Figure 2.3.12.b). Operating regularity of the gas system in 1986 was 91 per cent. Of the factors contributing to the final figure, mention can be made of compressor troubles and some separator repairs.

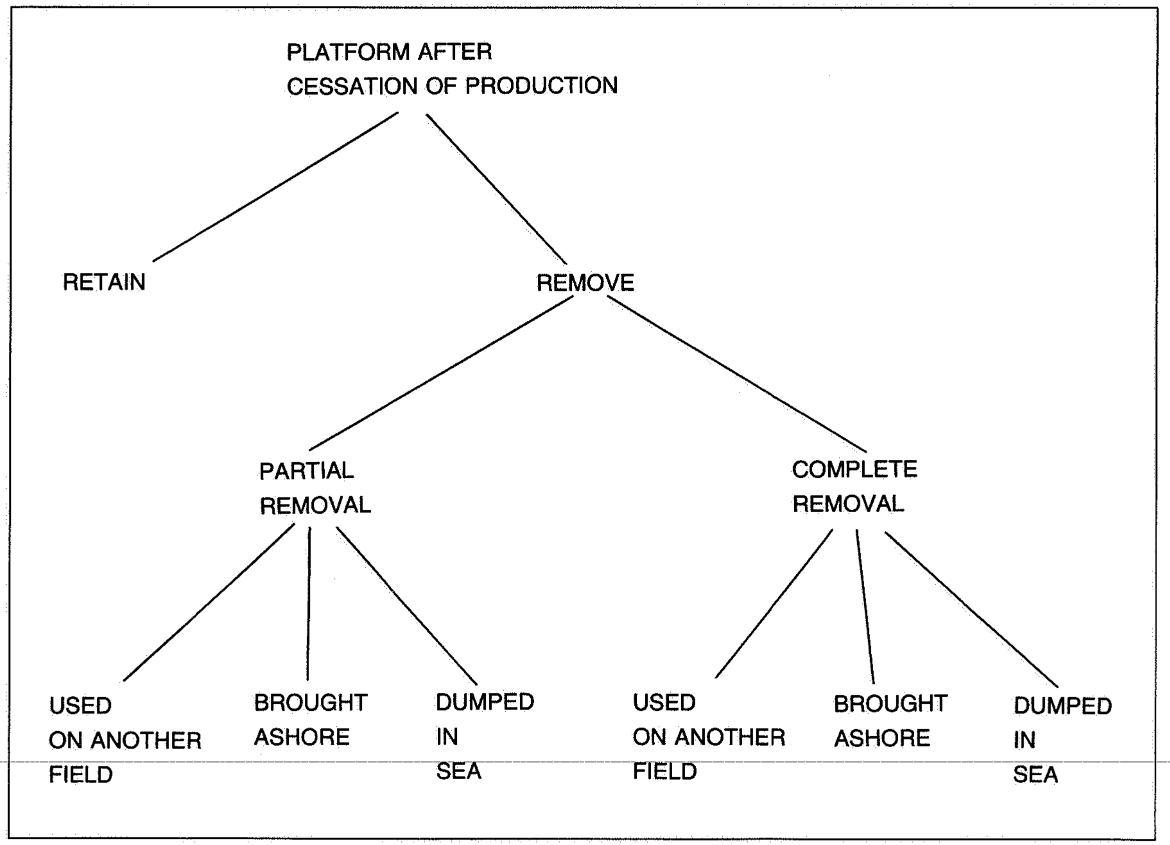
Metering system
Operating inspections are now performed annually in collaboration with the British Department of Energy.

Costs
Total costs are expected to be roughly NOK 34.6 billion in fixed 1986 kroner.

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

There are three reasons for focusing on this problem complex:
- In a few years the question of production shutdown date will have to be addressed for several fields off Norway. Before the turn of the century several individual Ekofisk and Frigg fields and satellites will have stopped producing.

FIG. 2.4
Final production and removal



- Several installations on fields approaching final production date might be serviceable on other offshore fields, either through concurrent use of the installations by old and new fields, or through complete acquisition of the installation by the new field.
- The problem of what to do with installations no longer in service will be discussed in several international fora in the next few years. This will force us to discuss what attitude Norway should adopt.

The alternative fates of the installations after production shutdown are demonstrated in Figure 2.4.

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

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

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

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

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

The country in the world with most experience of installation removal is the USA. In the Gulf of Mexico 350 structures have been removed to date. However, these were relatively small units in shallow water. The scope of the operations technically and costwise has been relatively moderate compared with what we can expect when removing giant structures on the Norwegian Continental Shelf.

Although purely technical considerations allow removal of even the largest structures off Norway, the costs of doing so will be enormous. The question whether the costs of removal bear a reasonable relationship to the value of the operation has to be asked.

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

3. Petroleum Resources

3.1 Resources accounting
Petroleum resources belong to the group of non-renewable energy resources and involve all technically recoverable oil and gas volumes. Exploitation of these volumes is dictated by commercial and socio-economic conditions.

Petroleum resources are classified according to the reliability of resources estimates and of certainty of commerciality (Figure 3.1.a). Resources estimate reliability is decided by the degree of geological control (horizontal axis). The classification of undiscovered resources will be based on the degree of seismic control and geological knowledge. Classification of discovered resources will be subject to the degree of well control. For the purpose of deciding whether a resource may be developed (vertical axis), its price and cost estimates are included in the commerciality criteria. As for resources which are declared commercial, the classification will be decided by the project progress.

Petroleum reserves represent the proportion of proven resources which are recoverable on given technical and economic premises and which have been declared commercial by the licensees.

The resources accounts of the Norwegian Continental Shelf are presented in Figure 3.1.b and the resources are shown in Figure 3.1.c.

For the purpose of presentation, the resources on the Norwegian Continental Shelf are displayed in three tables.

- Reserves attached to development projects with approved implementation which are being developed or which are in production (Table 3.2).
- Other resources south of Stad (Table 3.3).
- Resources north of Stad (Table 3.4).

Fig 3.1.a
Classification of technically recoverable petroleum resources

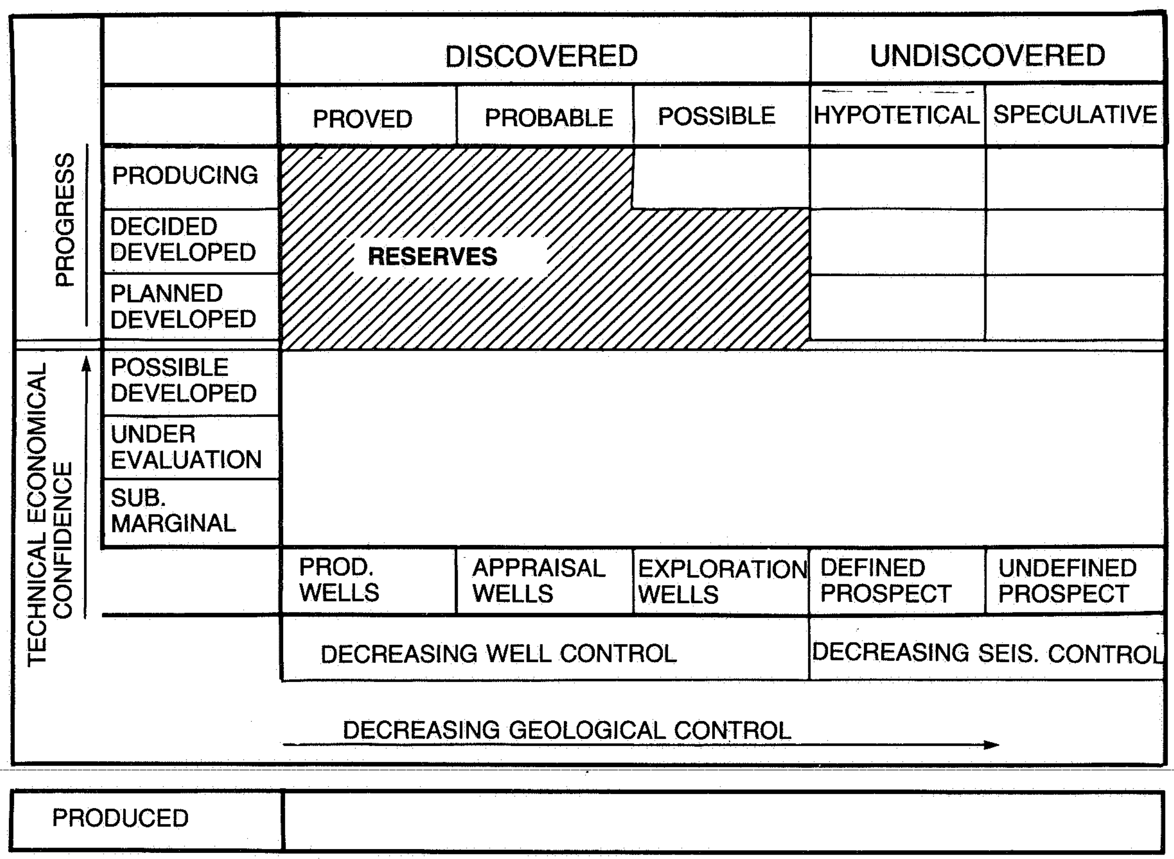


Fig 3.1.b
Recource account related to the Norwegian Continental Shelf

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

DECREASING GEOLOGICAL CONTROL →

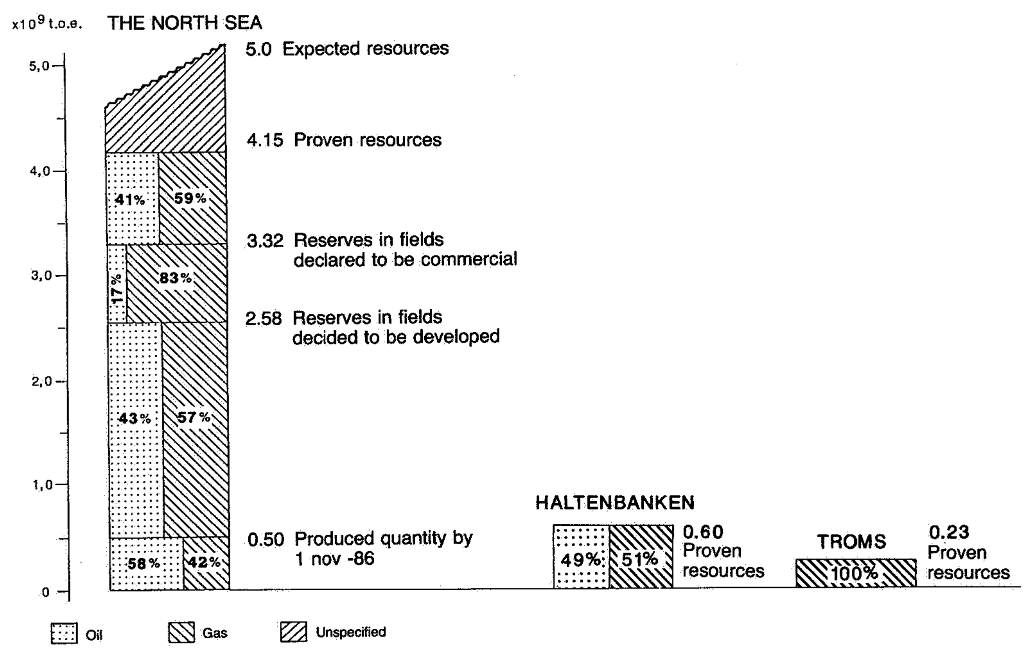
PRODUCED	358 X 10^6 Sm^3 oil including NGL 209 x 10^9 Sm^3 gas

Tab 3.2
Proven petroleum reserves in fields declared commercial

	ORIGINALLY Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6ton	REMAINING Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6ton
Albuskjell[1])	7,8	17,1	1,2	1,6	5,7	0,4
Cod[1])	2,7	6,6	0,5	0,4	1,6	0,1
Edda[1])	4,2	1,8	0,2	0,9	0,2	
Ekofisk	237,0	126,0	13,5	105,4	74,1	9,4
Eldfisk[1])	54,4	32,2	3,2	24,5	21,9	2,1
Frigg[2])	1,0	127,0		0,6	45,0	
Gullfaks[1])	210,3	13,7	2,1	210,3	13,7	2,1
Heimdal	3,1	33,8		3,0	32,4	
Murchison[3])	11,5	0,3	0,4	3,1	0,1	0,1
North-øst Frigg	0,1	8,0			3,8	
Odin	0,1	22,0			13,5	
Oseberg[4])	200,0	71,0		200,0	71,0	
Sleipner East	17,0	51,0	10,0	17,0	51,0	10,0
Statfjord[5])	375,0	49,0	15,4	254,0	46,0	14,5
Tommeliten	5,9	16,8	0,9	5,9	16,8	0,9
Tor[1])	21,6	12,9	1,4	5,6	4,4	0,5
Troll East		825,0			825,0	
Ula	33,0	1,6	1,4	32,8	1,6	1,4
Valhall[1])	38,1	14,2	5,2	29,3	12,7	4,7
Vest Ekofisk[1])	12,1	25,1	1,4	1,5	5,1	0,4
East Frigg		13,0			13,0	
Sum	1234,9	1468,1	56,8	895,9	1258,6	46,6

1) Operator's estimate
2) This is Norwegian share: 60,82 %
3) This is Norwegian share: 22,2 %
4) Includes Alfa, Alfa North and Gamma structure
5) This is Norwegian share: 84.09 %

FIG. 3.1.c
Resources on the Norwegian Continental Shelf



3.2 Resources base for resolved fields
As of 31 December 1986, a total of 21 development projects had been approved on the Norwegian Continental Shelf, three more than in 1985. The increase includes Tommeliten, Sleipner East and Troll East. The petroleum volumes of fields for which development is approved are given in Table 3.2. The reserves figures are based partly on calculations by the Norwegian Petroleum Directorate and partly on the operator's estimate of recoverable reserves. Production up to 1 November 1986 totals 0.50 billion toe.

3.3 Other proven resources south of Stad
Table 3.3 shows the other resources discovered south of Stad. Of these, Sleipner East, Troll West, Gyda and Veslefrikk have been declared commercial, and the resources volume of these four fields totals 0.73 billion toe.

Furthermore, the Norwegian Petroleum Directorate expects that a number of the other discoveries will be developed too, in the light of their sizes and locations relative to other fields.

3.4 Proven discoveries north of Stad
So far, 0.83 billion toe have been discovered by drilling north of Stad. Of this, 0.60 billion toe were found on Haltenbanken and 0.23 billion off Troms. In December 1986 Heidrun was declared commercial by its operator. The preliminary estimates for Smørbukk 6506/12 and 6407/7–1 are very uncertain, and the resources estimate for Smørbukk has not been adjusted following the drilling of the last exploration well. It is expected, however, that it will be reduced.

3.5 Updating of resources estimates from 1985 annual report

3.5.1 Fields for which development has been decided
For the fields Albuskjell, Cod, Edda, Tor and West Ekofisk the Norwegian Petroleum Directorate has not had the capacity to make its own production profiles. The resources figures applied in this annual report are thus taken from the operators prognoses and show relatively small variations compared to last years prognoses and last years operator forecasts. For Heimdal, the Directorate has made a few, minor prognosis adjustments. The Norwegian share of Murchison has been reduced from 25.1 to 22.2 per cent.

Oseberg
New well information from the pre-drilling programme and the decision to perform external gas in-

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

	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6ton
Agat¹)		43,0	
Balder	35,0		
Brage	29,0	6,0	
Gullfaks Sør	45,0	88,0	
Gyda	30,5	6,0	
Hild		20,0	
Hod	7,2	5,4	
Huldra¹)	4,9	21,0	
Sleipner satelitter²)	16,0	35,0	
Sleipner Vest³)	27,0	135,0	9,0
Snorre	146,0	16,0	
SØ Tor	4,0	3,0	
Troll Vest	41,0	463,0	
Veslefrikk¹)	36,4	4,3	
6/3 PI	0,9	1,0	
7/11 A¹)	6,5		
15/3–1,3	2,0	29,0	
15/3–4¹)	12,0	5,0	
15/5–1	2,0	6,0	
16/7–4¹)	1,4	9,0	
24/6–1	2,0	10,0	
24/9	3,0		
25/2–4	4,0	12,0	
30/6 Beta¹)	20,0		
30/6 Beta Sadel¹)	20,0		
30/6 Gamma North	5,0	7,5	
30/6 Kappa¹)	5,0	5,0	
30/9 Omega¹)	9,3	3,0	
33/9 Alfa	19,0	2,5	
33/9 Beta	39,0	2,0	
34/8–1	8,0	65,0	
34/10 Beta¹)	8,0	22,5	
34/10 Gamma	2,2	28,0	
34/4–1	3,0		
35/8–1	1,9	13,5	
35/8–2	2,6	7,0	
Total	598,8	1037,7	9,0

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

jection have caused an approx 15 per cent increase in the Oseberg oil estimates.

Sleipner East
Sleipner East includes the 15/9 Gamma structure as discussed in previous annual reports. Although resources estimates from the structure have not previously been presented separately, as opposed to as part of Sleipner, the decision to develop Sleipner East has made it necessary to separate the structure for report purposes from the rest of Sleipner.

Valhall
Valhall includes both Valhall A and Valhall Other discussed in previous annual reports. The resources figure is based on the operator's prognoses for the entire field. The figures for oil and NGL have gone up somewhat, whereas gas has been halved compared with last year's estimates from the Norwegian Petroleum Directorate. The Directorate has not had the capacity to verify whether the operators gas-to-oil ratio is realistic.

Tab 3.4
Discovered petroleum resources north of Stad

	Oil 10^6Sm^3	Gas 10^9Sm^3
Haltenbanken		
Draugen	65,0	4,5
Heidrun	127,0	39,0
Midgard	22,0	103,0
Smørbukk	60,0	83,0
Tyrihans	16,0	40,0
6407/7–1	25,0	2,5
6506/12 Beta	48,6	36,3
Total	363,6	308,3
Troms		
Albatross		34,3
Albatross Sør		8,2
Askeladd		52,0
Snøhvit		86,1
Snøhvit Nord		3,3
7119/12 (1)		3,6
7120/07		24,3
7120/12		14,8
7121/5 Beta		5,6
Total		232,2
Total	363,6	540,5

1) Operator's estimate

Statfjord
The Norwegian Petroleum Directorate is working on an upward adjustment of the Statfjord resources estimate. A preliminary estimate shows an approx 10 per cent increase in oil compared to the annual report of 1985.

Tommeliten
The resources estimates for the two Tommeliten structures have been adjusted by the Norwegian Petroleum Directorate as part of a plan for development and operation of Tommeliten. This has resulted in a minor reduction in gas estimates.

3.5.2 Other discoveries
Agat
Agat is a gas discovery west of Måløy not previously incorporated in the annual report.

Gullfaks South
New well data and appraisals have altered the gas-to-oil ratio in favour of oil.

Gyda
The Norwegian Petroleum Directorate has carried out a new appraisal, thereby increasing the recovery factor from 30 per cent to 40 per cent.

Huldra
The discovery has undergone new appraisal by the operator, generating a new resources estimate as presented in the annual report.

Sleipner West
As a result of the decision to develop Sleipner East (Gamma structure), it was natural to separate these resources from the rest of Sleipner. The Sleipner West resources basis remains unchanged compared to the 1985 annual report.

Snorre
The Norwegian Petroleum Directorate has performed a new appraisal of Snorre. The new calculations show a significantly increased estimate for oil, though the gas estimate is halved.

Veslefrikk
The operator has adjusted the resources estimate downward as a result of new appraisals.

6/3 Pi
The Norwegian Petroleum Directorate's appraisal of the discovery has resulted in a considerably lower resources estimate than the operator's estimate as presented in the 1985 annual report.

24/6–1
This is a relatively small gas and oil discovery made in August 1985. The discovery has not been presented in the Norwegian Petroleum Directorate's report before.

30/6 Beta saddle
This is a new discovery proven by exploration well 30/6–19 which was a compulsory well in connection with the postponed relinquishment on Block 30/6. Although the resources estimate was uncertain, the result from 30/6–19 is encouraging.

30/6 Gamma North, Kappa and 30/9 Omega
The operator has carried out a new three-dimensional seismic interpretation of the structures, resulting in a few changes in the resources estimate compared to 1985.

34/8–1
This is a new gas and oil discovery.

35/8–1
This discovery has been appraised by the Norwegian Petroleum Directorate, and the resources basis has risen somewhat.

35/8–2
The discovery was proven in 1982, and its resources estimate has previously not been included in the annual report.

3.5.3 Haltenbanken

Draugen
New well information and new appraisal of the Draugen structure have led to an increase in the resources estimate. The resources calculation now includes the entire structure and not just the southern part as stated in 1985.

Heidrun
New well information and new appraisal have led to a significant increase in the Heidrun resources estimate.

6407/7–1
This is a new discovery for which preliminary resources estimates are very uncertain.

6506/12 Beta
On the basis of new well information, the Norwegian Petroleum Directorate has carried out new appraisal of the structure, resulting in a considerable reduction in last years resources estimate.

3.5.4 Troms area

Snøhvit
New appraisal has been carried out on Snøhvit, as a result of which gas reserves have been upgraded by roughly 15 per cent. So far, it is uncertain whether or not the oil on Snøhvit can be produced, and it has therefore not been included in the resources summary of recoverable petroleum volumes.

Albatross South and 7121/5 Beta
New discoveries are made in Albatross South and 7121/5 Beta. Resources estimates are preliminary.

3.6 Resources potential south of Stad

The Norwegian Petroleum Directorate has estimated the anticipated recoverable resources potential south of Stad at approx 5 billion toe. So far, approx 4.15 billion toe have been discovered by drilling. In undrilled structures, a hypothetical resources potential of 0.8 billion toe have been calculated. Some speculative resources may exist in addition to the hypothetical resources.

Tab 3.5
Changes in resource estimate in annual reports 1985–1986

	Annual report 85			Annual Report 86		
	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6ton	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6ton
Fields decided to be developed						
Albuskjell	7,8	16,9	1,1	7,8	17,1	1,2
Cod	2,8	6,8	0,5	2,7	6,6	0,5
Edda	4,4	1,9	0,2	4,2	1,8	0,2
Eldfisk	50,8	31,6	3,0	54,4	32,2	3,2
Heimdal	3,0	34,0		3,1	33,8	
Murchison	13,0	0,3	0,5	11,5	0,3	0,4
Oseberg	173,0	71,0		200,0	71,0	
Sleipner East	–	–		17,0	51,0	10,0
Statfjord	342,0	41,0	12,7	375,0	49,0	15,4
Tommeliten	6,0	23,0		5,9	16,8	0,9
Tor	19,8	13,7	1,5	21,6	12,9	1,4
Ula	29,9	1,5	1,3	33,0	1,6	1,4
Valhall	3,9	28,2	1,3	38,1	14,2	5,2
Vest Ekofisk	11,9	26,2	1,3	12,1	25,1	1,4
Other fields						
Agat		–			43,0	
Gullfaks Sør	37,0	93,0		45,0	88,0	
Gyda	18,0	2,0		30,5	6,0	
Huldra		18,0		4,9	21,0	
Sleipner Vest	–	–	–	27,0	135,0	9,0
Snorre	99,0	27,0		146,0	16,0	
Veslefrikk	41,0	4,0		36,4	4,3	
6/3 Pi	4,6	4,0		0,9	1,0	
24/6–1	–	–		2,0	10,0	
30/6 Beta Sadel	–	–		20,0		
30/6 Gamma North	2,3	5,0		5,0	7,5	
30/6 Kappa	5,0	1,7		5,0	5,0	
30/9 Omega	9,3	10,0		9,3	3,0	
34/8–1	–	–		8,0	65,0	
35/8–1	1,0	10,0		1,9	13,5	
35/8–2	–	–		2,6	7,0	
Draugen	39			65,0	4,5	
Heidrun	87,0	31,0		127,0	39,0	
6407/7–1	–	–		25,0	2,5	
6506/12 Beta	76,0	54,0		48,6	36,3	
Albatross Sør	–	–			8,2	
Snøhvit		74,4			86,1	
7121/5 Beta	–	–			5,6	

4. Safety and Working Environment in the Petroleum Activity

4.1 Introduction

The Petroleum Act of 22 March 1985 established an independent legal basis for petroleum-related safety work. The subsequent restructuring of supervision of the activity has substantially broadened the Norwegian Petroleum Directorate's supervisory responsibilities and given the Safety and Working Environment Division particularly challenging tasks. The changes, however, also provide better opportunities for devising an overall safety strategy for activity on the Norwegian Continental Shelf. Essential components of this strategy are development of more uniform regulatory structure, and implementation of more consistent follow-up of regulatory provisions.

The new challenge and broadened responsibility make greater claims on organizational efficiency. Organizational adaptation and greater employee motivation are recognized tools to achieve this. Organizational change has been a high priority task in the Safety and Working Environment Division in 1986, resulting in wide-reaching restructuring which became effective on 1 October 1986. This structure is intended to be more functional and goal-oriented.

The main objective of the new organizational structure is to rationalize activity within the area of responsibility of the Safety and Working Environment Division by splitting the division according to its three principal functions:
- planning, coordination and management of supervisory activity
- securing necessary technical expertise within divisional areas of responsibility
- strategic planning and appraisal.

The Supervisory Activities Branch has six Heads of supervisory activities each responsible for supervision of given operating companies. Supervision is intended to ensure that licensees attend to their obligations according to government regulations, and the department has been delegated the requisite authority to decide issues in this connection. The Technical and Working Environment Branch and assisting agencies make the necessary expertise available to the supervision activity. The branch has eight staff members.

The Technical and Working Environment Branch is the Safety and Working Environment Division's technical knowhow base and is responsible for providing adequate expertise to the division. The branch is also responsible for technical regulatory work, professional assessment of supervision matters and participation in the conduct of supervisiory acitivity. The department has 75 members of staff.

The Strategy Branch is 22 strong and also attends to some common administrative functions in the Safety and Working Environment Division. However, its primary function is general advice and assessment within the divisions entire area of responsibility, strategic regulatory development and coordination and management of certain inter-disciplinary activities.

As far as industry and other government agencies are concerned the effects of the organizational changes will largely be visible as new contact persons in the Safety and Working Environment Division, and, to a lesser extent, different communications routines. In time greater coherence and more efficient supervision is expected from the Safety and Working Environment Division, coupled with better service to everyone in its area of responsibility.

4.2 Methodical development of regulations governing safety and the working environment

In its annual report for 1984 and 1985 the Norwegian Petroleum Directorate highlighted various problems relating to the safety and working environment regulations it is set to administrate.

The work of devising strategies for further development of the overall conditions covering safety and the working environment and administration of supervision are closely linked to how well the regulations fit the problems at hand, both technical and managemental.

The Norwegian Petroleum Directorate feels that work on these questions requires some preparation, including organizational revision. In its restructuring efforts the Directorate therefore devised an organization suited to the task.

4.2.1 Formal basis for regulatory work

The formal basis for the Norwegian Petroleum Directorate's efforts to revise regulations concerning safety and working environment supervision in the petroleum activity is to be found in:
- frameworks laid down in general legislation, plus regulations and instructions laid down by the Ministry of Local Government and Labour
- Royal Decree of 28 June 1985 concerning the arrangement of safety etc in the petroleum activity
- the Ministry of Local Government and Labour's delegation of 28 June 1985 where the Petroleum Directorate is delegated powers inter alia to:

- lay down regulations for the activity
- make overall safety assessments
- make decisions in licensing, injunction, non-conformance and approval matters

- the Ministry of Local Government and Labours letter of 28 June 1986 concerning preparation of an action plan for revision of the detailed regulations.

Through these instruments the Norwegian Petroleum Directorate has been given adequate formal authority under which to plan regulations and follow-up of petroleum acitivity in the areas coming under Ministry of Local Government and Labour responsibility.

4.2.2 Status of the Norwegian Petroleum Directorate's regulatory work and features of present detailed regulations.

By its decision of 28 June 1985 the Ministry of Local Government and Labour delegated to the Norwegian Petroleum Directorate responsibility (previously held by the Ministry) for detailed regulations laid down pursuant to:

- Royal Decree of 3 October 1975 concerning safety regulations etc for exploration and drilling etc
- Royal Decree of 9 July 1976 concerning safety regulations for production etc.

The above-mentioned detailed regulations – prepared by different agencies – express different supervisory philosophies. Each agency has prepared detailed regulations based on its own regulatory traditions, producing a result that lacks coordination with the central preconditions of the overriding legislation. In some cases there is also lack of agreement between the delegated regulatory authority and its exercise to embrace the entire supervision area for which the agency is responsible. There are other examples of agencies which have prepared detailed regulations for which authority is given in part in shelf and in part in other legislation. Another feature is that the areas of application of the Petroleum Act and Working Environment Act are inconsistent.

It should be emphasized, however, that the Petroleum Act with the new inspection arrangement has not brought about changes in the present situation with regard to detailed regulations through:

- changes in technical or actual areas of application
- changes in technical content of regulations.

In this respect the situation, seen from the point of view of the user, remains unchanged.

The new aspect is that a single agency – the Norwegian Petroleum Directorate – now holds responsibility for the entire set of detailed regulations, with all the potential this gives for simplification, restructuring and updating.

4.2.3 Future activity

The present position of the oil industry and the special technological challenges facing it offshore Norway mean that the industry has actively to seek new solutions.

Even though the Norwegian Petroleum Directorate believes that the regulations by and large provide sufficient flexibility in the choice of development strategy and concept, todays detailed regulations mainly concentrate on traditional and known technological solutions, leaving the regulations inadequately suited for promotion of innovation or new ideas.

This situation, together with the complex, heterogeneous nature of the existing regulations, which does not facilitate rational supervision of safety and working environment, makes great demands of the authorities.

Among other consequences, there is an urgent need for extensive review of the existing detailed regulations in order to assess and examine the following:

- future shape and structure of the regulations
- safety level
- flexibility
- functional capability and opportunity to choose cost-effective solutions
- relationship between various actors, including the operator, contractors, shipping industry, employee and employer organizations.

These priorities are mirrored in the Norwegian Petroleum Directorate's new organizational model, which facilitates planned development and maintenance of regulations (regulatory strategy).

By letter to the Ministry of Local Government and Labour of 6 November 1986 the Norwegian Petroleum Directorate announced a plan for methodical revision of the regulations. The plan describes the formal framework of further work, status and objectives, evaluation of boundary lines, instruments and work aids (computerization).

The plan also discusses the Norwegian Petroleum Directorate's organization of the work and emphasized the importance of proceeding in conjunction with the implicated authorities, industry, employees and employers. Timetables have been suggested for subprojects designed to designate boundary lines etc (subproject I), architecture of new regulatory structure (subproject II) and implementation of regulatory revision in 1986–87 (subproject III).

When carrying out its plan the Norwegian Petroleum Directorate will be particularly careful to secure contact with the authorities, industry and employee organizations, and will set up contact bodies to secure the necessary openness, experience exchange and swapping of opinions with the implicated parties.

4.2.4 Regulatory revision and preparation

Until the development of a new regulatory structure subordinate to the overall regulations, work of revising the detailed regulations has been postponed to avoid limiting the Norwegian Petroleum Directorate's freedom to select a new regulatory structure and scheme of regulatory revision. Consequently no regulations or guidelines were laid down in 1986. One exception is the drafting of guidelines to be laid down in pursuance of the Norwegian Petroleum Directorate's regulations concerning load-bearing structures. See Section 4.7.1.

4.3 Supervisory activity

At the same time as the Petroleum Act entered into force on 1 July 1985 the Norwegian Petroleum Directorate's supervisory responsibility was substantially expanded since supervisory tasks formerly under the auspices of other agencies were now assigned to the Directorate.

The subsequent reorganization of the Safety and Working Environment Division was intended to strengthen and rationalize supervision by splitting the division by function into three branches, as outlined in Section 4.1. In this way better lines of communication were established between the operating companies and the authority, and conditions are now better suited to planning and implementation of supervisory activity and build-up of the divisions professional expertise.

The Supervisory Activities Branch plans, coordinates and leads implementation of supervision. The Techical and Working Environment Branch provides technical resources for implementation of audits and inspections. The Supervisory Activities Branch has also a close cooperation with the Legal Branch and the Resource Management Division on supervision matters.

One important element of the Norwegian Petroleum Directorate's supervision of safety and the working environment is the consents given to operating companies to start new activity.

In 1986 the Norwegian Petroleum Directorate considered 110 concents. Broken down, these include:
- 4 consents for surveys
- 32 consents for exploration drilling
- 8 consents for detail engineering
- 5 consents for fabrication
- 10 consents for installation work
- 27 consents for use
- 5 consents for rebuilding or change of use
- 5 consents for removal or relocation
- 14 consents for use of service vessels.

Introduction of a scheme whereby assisting agencies help out with the supervision was one prerequisite for structural revision of petroleum-related supervisory activity. The scheme is founded on binding agreements between the agency in question and the Norwegian Petroleum Directorate. As of 31 December 1986 agreements have been concluded with:
- Norwegian Telecom Authority
- Fire and Explosion Protection Directorate
- Norwegian Meteorological Institute
- Coast Directorate.

Work is continuing to set up an assistance agreement with the Maritime Directorate.

The Norwegian Petroleum Directorate has also been assigned responsibility for the coordination of agencies with independent responsibilities in the petroleum activity. Coordination instructions have been set up between the Norwegian Petroleum Directorate and the:
- Health Directorate
- National Pollution Control Authority (SFT).

4.4 Working environment

4.4.1 System audits

In 1986 the Norwegian Petroleum Directorate implemented system audits based on the Working Environment Act. The audits revealed that the companies have not sufficiently developed and employed quality assurance systems which secure working environmental conditions. According to the Internal Control Regulations the working environment must be subject to continual scrutiny and appraisal. Moreover, lines of responsibility, authority and communication must be clearly defined and understood. The audits showed that matters of this kind are not being well enough attended to by the companies.

4.4.2 Organized safety and environmental work

According to the Working Environment Act an action program for safety and working environment initiatives must be prepared for an activity. Preparation of this action program is the duty of the employer. The work is most often done at present by the Working Environment Committee (WEC). In support of this work, the Norwegian Petroleum Directorate has cooperated with the Rogaland Research Institute in the publication of a handbook discussing preparation of the action program. The Directorate noted a positive change in the companies attention to their action programs in 1986. Programs have been set up with better defined content than hitherto, with specification of action, budget, deadline and person responsible.

Since 1983 the Norwegian Petroleum Directorate has actively cooperated with the industry to set up WECs in which both contractor employees and operator employees are represented. In the course of 1986 all but two operating companies have set up coordinating WEC's and these two are in the process of doing so.

4.4.3 Living quarters

The standard of new living quarters is steadily improving and the industry is showing a will to devise new, modern accommodation for personnel. One aspect of these efforts is the emphasis put on lessons learned from earlier projects.

Nevertheless, experience shows that living quarters are generally too small for actual accommodation and office needs. The new concepts do not take sufficient account of this weakness.

The oldest installations have living quarters of lower standard than is presently required in the

"Provisional regulations for living quarters". The useful lives of several such installations may be extended by using them for new projects. One condition made for the "Licence for major rebuilding or change of use" for Edda in connection with development of the Tommeliten field was that the living quarters in their present form were given a limited life to 1991.

4.4.4 Flotels

Following the "Alexander L. Kielland" accident the upper limit for the number of people allowed to stay on a flotell was set at 500. This limit was based on safety assessments and discretion regarding the chances of evacuating a large number of people efficiently.

In recent years flotels have been built which, according to safety analysis, have much higher safety standards than older flotels. One operator applied in 1986 to use "DB 102" as a flotel for up to 750 people. Careful review of the safety and working environment aspects of the vessel convinced the Directorate that consent could be given.

The safety aspects were reviewed by several firms of consultants, and smaller consequences of an accident involving major damage were shown for this flotel than for others.

Other studies were also run to determine what effect the concentration of so many employees has on living conditions. Results of these studies show that well-organized environmental work can compensate for the negative sides of housing such a large number of workers.

4.4.5 Reports of occupational illness

In collaboration with the Directorate for Labour Inspection the Norwegian Petroleum Directorate has been preparing a guide to § 22 of the Working Environment Act concerning the "Doctors duty to report". This section provides that a doctor must report all illness that might have arisen as a consequence of conditions at the workplace to the Labour Inspection or to the Norwegian Petroleum Directorate, depending on whether the workplace in onshore or off. Such reports are intended to assist the authorities uncover problem areas in the industry.

4.4.6 Mercury exposure

Urine analyses from personnel working with mercury show that occupational hygiene has improved in recent years. Instances of exposure requiring ventilation are now very rare. In collaboration with the Institute of Occupational Hygiene the Norwegian Petroleum Directorate has arranged for less frequent urine sampling of people working with mercury offshore then was formerly required. The Norwegian Petroleum Directorate's objective here, as before, is to change over to mercury-free instrumentation. As long as mercury remains in use, however, the Directorate looks positively on alternative control arrangements which are better able to prevent overexposure of employees.

4.4.7 Radioactive deposits on production equipment

When oil or gas is recovered, water is often produced too. This water contains salts that may be radioactive. Some salts dissolved in the water precipitate out and form deposits on the insides of the process trains. Even though radioactivity in the deposits is much lower than in isotopes used for well-logging and radiography, the radioactivity is such that care must be taken when handling equipment containing such deposits. The Statfjord and Ekofisk operators in recent years have made extensive studies of the extent of the deposits and implemented procedures for safe handling of equipment contaminated with radioactive scale. The radioactivity in the deposits has shown a tendency to increase in recent years. In future water injection projects the scope of the deposition is expected to increase substantially.

4.4.8 Cold stress

In connection with all-year drilling in the northernmost areas an analysis must be made of the special precautions necessary to safeguard employees from excessive climatic stress. Stress here has been focussed on insulation properties of clothes such as coveralls, gloves and face masks. Organization of this work is also important to ensure that the windchill factor of cold and wind is kept above reasonable limits. The industry has carried out a research project and lay down procedures intended to identify problem areas and secure measures to prevent unacceptable chilling. This work will continue in 1987.

4.5 Contingency preparedness

4.5.1 Regulations

The Norwegian Petroleum Directorate through its administratrion and enforcement of the "Regulation concerning Rescue Equipment on Fixed Installations for Production of Petroleum etc" has determined that the regulation is not adequately functional or suited to cover all areas and activities where it is applied. Reference is made to § 46 of the Petroleum Act which lays down requirements for effective preparedness based on a total assessment of contingency issues to reach an optimal solution.

The Norwegian Petroleum Directorate intends to revise the current regulations in order better to meet the requirements made when the Petroleum Act was passed. Revision will be accomplished by drafting a Regulation for Preparedness in the Petroleum Activity.

At present the Norwegian Petroleum Directorate considers it unwise to alter the current detailed regulations. To accommodate the lessons learned from the Directorate's administration and enforcement of the current detailed regulations, the Directorate has sent a special letter to the operators outlining the preparedness issues it will emphasize.

4.5.2 Unified preparedness concept

It is essential that the operating companies make a thorough analysis of needs before selecting a preparedness concept. Some companies have assigned more weight to this than others, and have in time hired suitable and well-equipped contingency vessels as component parts of their total preparedness.

In the future the Norwegian Petroleum Directorate will assess the operating companies criteria for selection of preparedness concept. Necessary manning of contingency vessels beyond the Maritime Directorate's skeleton requirements must be carefully considered by the operators. The numbers of extra personnel will depend not least on the degree of automation on the vessel and availability of rescue appliances. The Petroleum Act lays down requirements additional to the maritime legislation regarding the vessels contingency effectiveness.

4.5.3 Operations in northern waters

All-year-round drilling in the northern parts of the Norwegian Continental Shelf requires special preparedness measures too. This fact has been the subject of special scrutiny and the Norwegian Petroleum Directorate will present evaluation criteria for preparedness in the far north.

4.5.4 Alternative evacuation systems

Throughout the year the Norwegian Petroleum Directorate has carefully followed the development of alternative evacuation systems. The impression is that this discipline showed little development during the period, with the exception of a system presently being tested on Statfjord.

The Norwegian Petroleum Directorate considers the development of alternative evacuation systems as an essential supplementary improvement in the total preparedness of the offshore oil industry.

4.5.5 Safety and preparedness training

In 1984 the Norwegian Petroleum Directorate asked the operating companies to prepare proposals for revision of basic safety and preparedness training. In 1986 the Directorate received one such proposal for consideration from the Norwegian Industry Association for Oil Companies (NIFO). The proposal is being assessed in connection with NIFOs recommendation for advanced preparedness training.

4.6 Drilling

4.6.1 The "West Vanguard" blowout

In conjunction with the uncontrolled blowout of gas on the "West Vanguard" mobile drilling rig on 6 October 1985 from Well 6407/6–2 on Haltenbanken, the Norwegian Petroleum Directorate set up an internal working group with the following terms of reference:

- to elucidate the course of events and chain of causes
- to assess whether the operators internal guidelines, procedures, well program, contingency plan and Norwegian Petroleum Directorate's regulations were followed.
- to assess the need to implement measures or react
- to ensure that relevant operating and contractor companies are familiarized with the lessons learned in connection with the accident.

The group's work and conclusions are summed up in the "Norwegian Petroleum Directorate's Report on the West Vanguard Accident" which was nearing completion within the Directorate at the end of 1986.

The well was shut off and back-plugged by drill vessel "Bucentaur" in mid-June 1986. "West Vanguard" needed extensive shipyard repairs.

4.6.2 Shallow gas problems

Introduction

Based on several near accidents on the Norwegian Continental Shelf in connection with kickback of shallow gas up the well bore, the Directorate has reassessed its view of the problems associated with shallow gas. A central feature of this reassessment has been the appraisal of alternatives to the present diverter pipe system.

The technical solutions presently chosen to deal with shallow gas problems on mobile installations have severe limitations. Even though a system based on a marine riser from the wellhead and a diverter pipe at the surface has constituted accepted industry practice, experience has shown that such systems may fail due to plug formation, bore washout, pipe wear or valve malfunction. Reports have also been received of displacement of the slipjoint, causing the packer in the diverter pipe system to move out of position. Accordingly the Norwegian Petroleum Directorate has assessed concepts involving riser-less well control for drilling of 30 inch opening tubing.

Drilling with mud and a diverter tube system will reduce the probability of a blowout when drilling tophole sections. If gas starts to flow in, the gas in the annular space will reduce mud weight with subsequent risk of aggravated gas inflow. One assumes that the greater part of the mud will be forced out of a 18 5/8 inch marine riser by a gas flow of six million standard cubic feet (SCF) a day, even if a pump rate of 1000 gallons per minute (GPM) is maintained. The riser and well might become completely empty of mud, and gas inflow might approach the flow potential of the formation.

A serious objection to drilling without a riser is the theory that the drill rig will loose buoyancy due to gas in the sea, thereby encountering stability problems. More recent technical studies seem to indicate that loss of buoyancy resulting from a shallow gas blowout is of little significance at the likely well rates and typical well depths. For example, calculations show that for a 24,000 ton semi-submersible drill rig in 200 meters of water, a blowout rate of 30 million SCF a day will only reduce the freeboard by about one meter. It should be noted, however, that these calculations assume symmetrically centered blowout beneath the rig.

Shifting of the rig to a new location when drilling without a return line in such a situation will take longer than it takes to engage a surface diverter system. Assuming that the mobile rig is anchored up with sufficient tension in the anchor cables to move the rig without gunning the winches, however, it may be assumed that this time difference will be marginal.

Subsea diverter system

An interesting alternative to drilling without a return line is to employ a subsea diverter system with annular preventer and eight inch dump valve located below the lower marine riser package (LMRP). If shallow gas is encountered, the annular preventer is closed and gas diverted though the dump valve into the sea. After the blowout communication with the well is intact.

Before reliable conclusions can be drawn regarding riser-less well control when drilling out of the 30 inch openers, further studies should be performed of buoyancy loss resulting from gas in the sea. Particular attention should be directed to platform stability as a function of how centrally placed the gas flow is in relation to the rig, considering for example gas flow under one pontoon of a semi-submersible drill rig. Another technique worth considering is "logging while drilling" (LWD).

Logging while drilling (LWD)

The Norwegian Petroleum Directorate has undertaken a review of the companies experience with use of instruments to conduct logging while drilling (LWD) of upper well sections.

Companies are of the opinion that drilling of pilot holes (12 1/4 or 17 1/2 inch) with LWD tools will raise safety levels in comparison with conventional drilling and electrical cable logging. The reasoning is as follows.

When using LWD instrumentation more reliable proof of shallow gas can be obtained when drilling through shallow sand formations than is possible with conventional methods. In conjunction with conventional gas measurement in the returning drill mud, the gas zone can be proven shortly after penetration of the zone and before the planned total depth of the well section is reached. Immediate containment of the gas zone will reduce the risk of gas starting to flow because of inadequate mud weight, or careless tripping out of the string or other operational disturbance.

By logging the formation immediately above the drillbit, log quality will generally be better than with conventional drilling, since leaching and mud filtrate have not yet corrupted the formation materially.

Logging with LWD instruments will ensure good directional control since the units generally monitor direction during drilling.

In areas where the geology is known and well site surveys show no accumulations of shallow gas, the Norwegian Petroleum Directorate has noted growing interest among the operators in opening a 26 inch well section in one operation using LWD. In the Directorate's view, the operational and safety consequences of this concept can be summarized as follows:

Even though the probability of a shallow gas blowout is small, direct drilling of 26 inch well sections may constitute a substantially greater risk due to larger bore volume and flow surface, for example by comparison with a 12 1/2 inch or smaller pilot bore.

The makeup of the drill string needed to drill, log and open hole is less directionally stable than the makeup presently used to drill a pilot bore. Nevertheless, the difference is not sufficient to cause serious difficulty.

When a well section is drilled and opened in one operation the drillbit will be at the bottom of the hole. Any inflow of formation fluid will thus be circulated out of the well. When drilling a 12 1/4 inch pilot, it will not always be possible to reach far enough into the well effectively to circulate out formation fluid when opening out to 26 inch.

Experience so far shows that pressure in shallow gas formations is seldom excessively high, and that formation fluid can thus enter the wellhole, for example as a result of swabbing. In such cases a well opened by underreamer to 26 inch will not draw in formation fluid in the same way as a drillbit in a pilot.

Activity will generally progress faster if drilling, logging and hole opening is conducted as a single operation. The bore is therefore exposed for a shorter time, reducing the risk of corruption. Of course, this presupposes high equipment reliability and good stocks of materials for different operational conditions.

One-step drilling of 26 inch hole proceeds by experience slower than drilling of the pilot, and the lower wellrate promotes better LWD resolution. If on the other hand we look at the total time consumed to drill a 26 inch section, then drilling of a pilot followed by hole opening will take longer than one-step drilling of the same well section. The latter will therefore make better sense economically.

The Directorate feels that drilling of pilot bores utilizing LWD in the drill string will increase safety relative to conventional electrical logging.

Even though direct opening of 26 inch holes with LWD instrumentation may detect shallow gas earlier and produce better log resolution than a pilot hole, the consequences of a gas blowout through the 26 inch hole will be much more severe than an uncontrolled kick through a 12 1/4 inch or smaller pilot.

The Directorate feels, therefore, that a pilot hole drilled with LWD instrumentation followed by hole opening to 26 inches is preferable from a safety point of view.

It should be noted that this assessment assumes a traditional gas diverter system. The conclusion may be different if other gas diverter concepts are employed, for example riser-less drilling.

Other factors worthy of careful consideration when selecting a diverter system for drilling tophole are:
- ocean currents
- wind conditions
- ocean depth
- diverter reliability
- drilling platform.

Economics

Estimates show that considerable time is saved by drilling a 30 inch conductor without return line and directly opening 26 inch section with full bore drillbit and no pilot. An example of the time savings to be expected for a Troll well is four per cent if drilling proceeds as indicated.

4.6.3 Shallow drilling

In the Safety Regulations of 28 June 1985 concerning consent to conduct surveys, one requirement is that the Ministry's permission must be obtained if surveys that involve drilling to depths below 25 meters under the seabed are to be conducted.

In 1986 the Norwegian Petroleum Directorate awarded 27 drilling permits in connection with exploration licences. Sixteen of these were awarded to research institutions in connection with scientific investigations, and 11 to licensees for geotechnical bottom surveys related to appraisal of platform concepts.

4.6.4 Simultaneous drilling and production (SDP)

Introduction

Simultaneous drilling and production has developed into an accepted method of recovery of oil and gas in the North Sea. Norwegian field developments based on simultaneous activities have largely been justified on the grounds of huge economic investment in construction, installation, development and operation of oil and gas installations offshore. On marginal fields, simultaneous operations may be essential to project viability.

Another crucial point has been the necessity of being able to appraise reservoir conditions at an early date, not least so as to be in a position to assess the efficiency of drive mechanisms of significance for the selection of production and injection wells.

The alternative to simultaneous operations is sequential phases of construction, installation, hookup, drilling and production.

According to the Norwegian Petroleum Directorate regulations, simultaneous operations are prohibited unless special permission has been given by the Directorate. The rationale for the restriction has been the fear that interaction of simultaneous activities will increase the risks involved due to:
- greater probability of and consequences of personal injury since more people are exposed
- greater probability of major disasters, for example drilling into a producing well
- probability of a higher activity level demanding more of management, control and coordination.

Based on the experience and material available to the Norwegian Petroleum Directorate during consideration of permits awarded earlier, it has been found useful to express the Directorate's attitude to simultaneous operations on one and the same installation as follows.

The Norwegian Petroleum Directorate considers that parallel activities will, under certain conditions, be able to be conducted within acceptable safety limits. This applies particularly to simultaneous drilling and production.

Planning

One prerequisite for simultaneous drilling and production within acceptable safety limits is that both activities are assessed as one within the framework of the total development concept. For integrated platform concepts in particular one prerequisite will be that an assessment of and an opinion on simultaneous operations is available from the licensee at the earliest possible stage of field development, in other words, in connection with submission of the plan for development and operation. The plan must provide a detailed explanation of the aspects of platform design resulting from the desire to conduct simultaneous operations.

Double barrier concept

The decisive factor for simultaneous operations from a drilling or well activity point of view is the double barrier philosophy. This means that parallel activities can only continue if each well operation can be conducted with at least two tested safety barriers in the direction of flow. If a well operation during simultaneous operations cannot maintain two barriers, all simultaneously occurring operations affecting that wells safety must cease until the failed barrier has been reinstated.

Test methods and test times must be documented for each barrier. The barriers must be specified.

Examples of barriers for a drilling operation are drill mud (with adequate density to control formation pressure), blow out preventers and cemented, pressure-tested casing.

All parallel activities must, as mentioned, cease immediately a required barrier fails. Examples of failure may include:
- uncontrolled inflow of formation fluid (well kick)
- loss of circulation during drilling or setting casing
- release of hydrocarbons to atmosphere due to

leaks in well control equipment, for example Christmas tree.

These examples are taken at random. The important thing is that the responsible operator must consider, based on his procedures and knowledge of the process, whether a barrier is failing or has failed. For example, a down hole safety valve (DHSV) which is fail-safe and in confirmed position will not normally be considered a failed barrier if, upon failure, it shuts properly.

Protective production barrier

Three operations are normally considered particularly critical when assessing the integrity of a production well:

- directional drilling in vicinity of a producing well
- skidding (relocation) of derrick
- lifting operations above producing well.

Producing wells must be protected from damage from wells being drilled, which requires that safety zones be set up round both the producer and the well being drilled.

Having defined a safe minimum separation, measurement of each new well in relation to its previous neighbours is necessary. If the planned direction of a well encroaches upon the safe minimum distance from a completed, perforated well, the latter must be closed in according to the double barrier concept. The accepted method is for the well to be closed in at the surface and below the lowest point at which interaction can occur, either using a down hole safety valve or, if necessary, by setting a plug.

When setting or removing a blowout preventer or when skidding the derrick from one well to another, there is some probability that the preventer and other equipment may drop and damage valve trees on production units, flow lines or manifolds. The Norwegian Petroleum Directorate accepts that only wells within a more closely defined radius need to be shut down under such operations. When preventers are shielded by trolley during skidding, the requirement for production shutdown of neighbouring wells will normally be waived.

When heavy loads are lifted over a production area, there will always be some risk of damage to the production installation as well as its preventer systems. Therefore all wells in the vicinity where falling objects might damage the barriers must be shut down. The Norwegian Petroleum Directorate assumes that detailed procedures will be prepared describing the method of doing this and the responsibility areas of personnel participating in such heavy lifts.

In addition to the fundamental philosophy that simultaneous drilling and production can only be conducted when at least two tested barriers are in operation for each activity, development has shown that special conditions must be regulated by supplementary requirements.

Gas in well area

All simultaneous operations must cease if the gas level in the drilling area exceeds a given threshhold. In practice, Norwegian Continental Shelf requirements call for an alarm to sound at 20 per cent of the lower explosion limit (LEL) followed by automatic shutdown of the well at 60 per cent LEL.

Hot work

No welding, grinding, flame cutting or other high energy work must take place in the wellhead, blowout preventer or drillfloor area during simultaneous operations.

Penetration of reservoir

Higher risk is expected when drilling through potential production zones. Unless the operator can document due consideration of the risk and appropriate installation design, the Norwegian Petroleum Directorate will expect restrictions to be placed on the number of simultaneous operations during penetration of producing zones. Operations during this phase should preferably be limited to drilling and production.

Due to the added risk of uncontrolled wellkick when drilling through such zones, restrictions must also be considered on the use of the flare stack for non-drilling-related hydrocarbons, as well as other potential souces of ignition.

Testing

Tests of the emergency shutdown (ESD) systems must be coordinated according to fixed procedures to counteract reduction in vital ESD functions during simultaneous operations. Bad coordination might, for example, cause situations where it is impossible quickly to close the down hole safety valve and surface preventers. More stringent control of work operations will be called for if parallel activities are to proceed during ESD tests.

Work on pressurized wells

When working on wells under pressure, no other simultaneous operations should take place. Preparation of service operations (snubbing), for example operation of hydraulic overhaul units, may nevertheless take place at the same time as simultaneous operations as long as the well is not pressurized at the surface.

Safety meetings

Safety meetings for personnel should be held before carrying out any operation that may be critical, for example an operation involving well safety or containment. In particular, safety meetings should be held before drilling out the last set casing prior to production casing.

4.6.5 Well barriers and marine riser margin when drilling from mobile installation

In the assessment of the operator's well program the marine riser margin requirement is enforced in conjunction with the double barrier doctrine.

The marine riser margin is a "hydrostatic reserve in the form of additional mud weight intended to compensate loss of hydraulic pressure if the mud column in the riser (to the rotary kelly bushing, RKB) is suddenly replaced by sea water (to sea level)".

At large depths the riser margin may make a substantial contribution to hydrostatic pressure over and above the hydrostatic safety margins, for example, the trip margin.

The riser margin should not be considered in isolation; the viability of other barriers must also be taken into account. As far as barrier requirements are concerned, appraisal of the following is important:
- availability of barrier
- consequences of barrier failure.

By way of example, barrier availability may depend on:
- season of year
- location
- drilling installation and equipment
- drilling operation
- well properties
- well fluid properties
- personnel
- procedures.

When drilling from an installation capable of operating within wide weather limits which seldom experiences weather conditions requiring disconnection of the riser, availability of the mud barrier will usually be high.

Loss of mud barrier may occur in connection with:
- faulty equipment (for example, causing involuntary disconnection of riser)
- errors in handling (for example, causing involuntary disconnection of riser)
- outside causes (for example, collision or risk of collision with another vessel).

The probability of such events is considered low.

Any requirement for a riser margin in deep seas may introduce operational difficulties such as abnormal friction (differential sticking) or formation cracking. In such cases the riser margin will be more of a risk factor than a safety factor.

The consequences of failure in the main barrier (drill mud) will depend on the availability of the blowout preventer and pressure conditions in the well.

Compensatory measures when drilling without a riser margin may therefore include:
- special requirements (for example, weather windows) when drilling through hydrocarbon-bearing zones
- operational limitations requiring disconnection of marine riser under given heave conditions
- mud reserve with necessary mud density or properties, to be pumped down before disconnecting drillstring in bad weather
- simulated disconnection of marine riser in order to verify well properties.

4.7 Load-bearing structures and pipelines

4.7.1 Regulation revision and preparation

The following regulations and guidelines are presently undergoing drafting or revision:
- Research work in connection with the planned "Regulations for Environmental Data" is being done. These will replace the "Regulations for Instrumentation and Processing of E(nvironmental) and P(latform) Data" from 1978.
- The Guidelines for Loads are now complete and have been submitted to the Ministry of Local Government and Labour before promulgation.
- The Guidelines for Corrosion Protection were circulated for official comments in 1986. Consideration of the comments is continuing and the guidelines are expected to be ready for promulgation in spring 1987.
- The Guidelines for Steel Structures have been circulating in the Norwegian Petroleum Directorate to receive internal comments. Some redrafting remains before public comments are invited, hopefully in summer 1987.
- The Guidelines for Concrete Structures were circulated for internal comment in 1986. Public comments are expected to be invited in spring 1987.
- The Guidelines for Mobile Installations will be ready for internal comment in spring 1987 and public comment at year-end 1987.
- The Guidelines for Foundations were circulated for internal comments in 1986. Public comments will be invited in spring 1987.
- Exploratory work is being done on future Regulations for Pipelines, with associated guidelines.

All guidelines are somewhat behind schedule in relation to the plans set up when work started.

4.7.2 Guidelines concerning inspection of primary and secondary structures for mobile installations

The Norwegian Petroleum Directorate's current "Guidelines concerning Inspections of Primary and Secondary Structures for Production and Shipment Facilities and Subsea Pipelines" does not meet the Directorate's objectives for inspection of mobile installations.

Work has therefore been initiated on new guidelines for inspection of load-bearing structures on mobile installations. Collaboration has started with the industry and classification agencies in connection with the work.

4.7.3 Use of mobile installations for production of petroleum resources

Due to the fall in oil and gas prices, the licensee's desire to gain an early understanding of reservoir particulars, development of marginal fields and greater ocean depths on announced blocks, interest in utilization of mobile installations for production of petroleum accumulations on the Norwegian Continental Shelf has recently increased very greatly.

The first mobile production installation entered service on the Oseberg field in October 1986.

Basically, the strength of a mobile installation for production activities should comply with the Norwegian Petroleum Directorate's regulations for load-bearing structures.

The design, construction and operating regulations of the Maritime Directorate, classification houses and foreign authorities for mobile installations are in many respects not in accordance with the Norwegian Petroleum Directorate's regulations for load-bearing structures.

The Norwegian Petroleum Directorate has assigned high priority to the work of charting the regulatory differences and collaborates with the Maritime Directorate, industry and classification agencies in this task. The work will continue in 1987.

4.7.4 Acquisition of environmental data

Acquistion of environmental data (current, wind, waves etc) from Ekofisk, Frigg and Statfjord went well in 1986.

Since the signing of the assistance agreement between the Norwegian Petroleum Directorate and the Norwegian Meteorological Institute (DNMI) on 1 July 1985, inspections of data acquisition from all three fields have been conducted. By calling on DNMI assistance, the Norwegian Petroleum Directorate has achieved greater professional authority for its inspections. The assistance scheme may be said to work very satisfactorily.

Acquisition of data from production installations and foreign-registered mobile drill rigs in 1986 continued by order of the Norwegian Petroleum Directorate. Acquisition of data from Norwegian-registered drill rigs continued by order of the Maritime Directorate.

In spring 1986 the Norwegian Petroleum Directorate undertook an assessment of wave conditions in the Ekofisk area. This assessment was based on an analysis made by the licensee in autumn 1985. During 1986 the operator continued work on the analysis, and has indicated that the 100 year wave height in the area may be less than the 26 meters assumed in previous years. The analysis is expected to be complete in January 1987 and will be carefully examined by the Directorate.

Mid-Norway seems to be the continental shelf area where the highest waves can be expected.

Computer software to calculate wave statistics was developed in the Norwegian Petroleum Directorate in 1986.

4.7.5 Full-scale measurement

From 1976 measurements of the behaviour of seven production installations on the Norwegian Continental Shelf have been carried out. All measurements have now ceased, the last analyses being done in 1986. Data from Frigg TCP2, Statfjord A-ALP and Valhall QP were published in 1986.

4.7.6 Acquisition of environmental data in Barents Sea with research vessel M/S "Endre Dyrøy"

In conjunction with the planned expansion of exploration areas off the North Norway coast, an extensive data acquisition project was started under the Norwegian Petroleum Directorate direction in the Barents Sea. The aim of the project was to obtain knowledge of the oceanographic and meteorological conditions in this sea area before drilling activity gets started. Also, data will be collected for use in connection with consequence analyses which, according to the Petroleum Act, must be carried out before new areas can be opened up to petroleum activity.

The Norwegian Petroleum Directorate's project is coordinated with the measurement activity of the Oceanographic Data Acquistion Project (ODAP) off North Norway. The Directorate's project consists of two measurement stations, one at Bear Island and one on the southwestern part of Central Bank.

The ODAP will continue the monitoring on Tromsøflaket which the Norwegian Petroleum Directorate conducted up to 31 December 1984. The ODAP has also collected current data from North Cape Bank, as well as sponsoring current measurements at the Directorate's buoy stations off Bear Island.

The location of these measurement stations is shown in Table 4.7.6. The Norwegian Petroleum Directorate's project is financed with the aid of ODAP funds. In 1986 ODAP supplied NOK 4.5 million of the project budget of NOK 13 million.

The research ship M/S "Endre Dyrøy" was hired from Georg Lokøy, Brattholmen. This vessel has remained on station at Central Bank in position 74: 30 N and 31:00 E since the end of February 1985.

The ship changes crew every four weeks. Every other month the vessel makes a round of all monitoring stations in connection with maintenance and inspection of the measuring instruments. This round takes roughly five days.

In addition a newly developed automatic weather station has been installed and tested over a long period of time. This station was further modified this year by fitting extra transducers. Among other variables the unit now monitors true wind speed and direction, even when the boat is under way.

Data from the weather stations are transmitted automatically via satellite to the Norwegian Meteo-

Tabell 4.7.6
The activity within ODAP and NPD's project:

Station Position	Type measurement	Period	Responsible
Bjørnøya 73°50'N 19°52'Ø	Wave height	all year	NPD
Sentralbanken 74°31'N 30°55'Ø	Wave height and direction. Current (6 deep) Weather observation Research vessel	all year	NPD
Tromsøflaket 71°45'N 20°37'Ø	Wave height Meteorology	all year	ODAP

rological Institute (DNMI), Oslo. This happens 9–15 times a day. The Institute uses the data for forecasting purposes.

The following companies and institutions have participated in the project:

- Oceanor A/S, Trondheim carried out wave and current measurements.
- The Norwegian Meteorological Institute bore responsibility for meteorological measurements. These are taken every three hours and reported to shore.
- The Institute for Continental Shelf Studies and Petroleum Technology (IKU) was subcontracted by Oceanor A/S and looked after operation of the wave monitor on Central Bank.

Apart from the fixed activities, the vessel was used by several institutions. Among others, ornithologists from Tromsø Museum have been on board in connection with the inspection rounds. In collaboration with the Water Courses and Harbour Laboratory (VHL) an ice mast was erected on the ship which among other things monitors icing and sea spray.

In late autumn 1986 it became clear that the ship will be even more heavily occupied in 1987 in connection with consequence analyses, particularly in connection with the program being devised by the Ministry of Petroleum and Energy.

4.7.7 Structural steel

By following up on development projects, participation in research projects and committee work, the Norwegian Petroleum Directorate is keeping abreast of developments and experience in the field of materials technology.

In recent years industry has been increasingly moving towards use of micro-alloy low carbon steel and controlled, rolled steel in structures and pipelines. Strict requirements for chemical composition and content of impurities such as sulphur and phosphor have led to improvement in the fracture toughness of the steel and its welding properties.

High strength, case hardened steel has also just about entered service in connection with load-bearing structures. Considering the challenges confronting developers offshore Norway, including greater ocean depths and a requirement for lighter constructions, high strength steel also seems to have a bright future in as far as quantities employed are concerned.

In 1985 the Norwegian Petroleum Directorate concluded a project in which ten different types of steel employed in developments offshore were examined. By simulating welding operations, the micro-structure and fracture toughness of the steels were mimicked in areas equivalent to the heat affected zone (HAZ) when welding.

In 1986 it was decided to continue this investigation with structural steels employed in new and future development projects. This brought in a further four types of steel for analysis in 1986.

4.7.8 Corrosion and corrosion control

In the years ahead we are facing new, major challenges in field developments on the Norwegian Continental Shelf. Oil production from greater sea depths and at lower temperatures, plus requirements for lower development costs dictate improvements in corrosion protection methods.

For pipelines from subsea installations to platforms, new coating concepts are being developed. These involve thermal and corrosion protective layers in combination with cathodic protection. Thermal insulation helps prevent hydrate formation in the flowline.

Seawater injection finds ever greater application in the efforts to enhance recovery. This increases the need for chemical treatment and surveillance of process trains with regard to corrosion, precipitation and sulphate-reducing bacteria (SRB) activity. Research and development is continuing in order to optimize chemical additives and improve their corrosion properties.

On the most recent platforms there are systems to control the galvanic protection potential of the structure. These systems monitor individual sacrificial anodes. Surveillance of this type expands our experiential base in the cathodic protection of offshore installations.

Studies conducted on Tromsøflaket and the Troll field have indicated that the present current density criteria for design of cathodic protection may not be applicable to new fields.

By participating actively in research projects and following up development projects, the Norwegian Petroleum Directorate intends to follow developments in corrosion technology carefully.

4.7.9 Instrumental surveillance of installations on the Norwegian Continental Shelf

Recovery of petroleum reserves in deep water confounds traditional monitoring methods due to the greater risk. The low price of oil has accelerated the process of evolving monitoring methods suited to the new environment, which work without diver intervention and provide high quality at low cost. Norwegian operators are planning to utilize this new technology, and it seems reasonable to suppose that others will follow.

In 1986 the Norwegian Petroleum Directorate took an interest in studies and research activity in this field at home and abroad. The change-over to instrumental inspection will demand greater effort both on the technical side and in our regulatory revision in the years ahead.

4.7.10 Internal control

A study of the experiences of the operating companies and project groups with internal control initiated in 1983 was rounded off early in 1986. Feedback from about 60 individuals in leading positions showed that about 85 per cent took a positive view of the structure, scope and application of the Norwegian Petroleum Directorate's guidelines.

As far as implementation of internal control and quality assurance goes, 10 per cent were positive, while about 33 per cent found that implementation had not caused particular problems. Over 40 per cent noted that lack of support by top management, both of the basic organization and project organization, hampered implementation due to limited funds for in-house training and motivation to prepare adequate control systems and procedures. This led to wide variation in the requirements made of industry from project to project and operator to operator.

In autumn 1986 a similar study was therefore set up to determine how industry meets this situation and the problems it causes. The results of this survey are expected during 1987.

4.8 Diving and production systems

During 1986 divers performed 2049 surface oriented dives and logged 182,573 manhours in saturation. Surface oriented activity thus lay at about the same level as in 1985. Saturation diving, on the other hand, declined by roughly 11 per cent compared with last year.

During the 1986 report period the Norwegian Petroleum Directorate was still occupied with follow-up of the operator's preliminary work for operational dives down to 300–400 meters. This follow-up has been particularly oriented to technical equipment and procedures. One step in the preliminary work was three manned dives down to 360 meters at the Norwegian Underwater Technology Center (NUTEC) in Bergen. These diving operations were planned and carried out in connection with development of the Oseberg field.

The Directorate took part in a working group whose job it was to propose qualification requirements for personnel associated with manned diving operations. At the conclusion of its work, the group handed over its final report to the Directorate. The conclusions in the report will form the basis of a standard for specified personnel categories.

The Directorate is also taking part in a working group with the task of proposing chamber parameters for diving systems. This working group is broadly composed of representatives of the diving industry.

The need for diving operations below 200 meters is starting to arise. In this connection it is important to illuminate all aspects of such dives if at all possible. The Directorate has therefore set up a working group whose mandate includes these points:

- to consider to what depths it is sound practice to conduct diving operations
- to propose areas, if any, to which more research and development should be directed
- to reconsider the present guidelines for deep dives.

4.9 Safety systems and electrical equipment

4.9.1 Electrical equipment

As far as electrical equipment is concerned, the Norwegian Petroleum Directorate applies regulations prepared by the Norwegian Water Courses and Electricity Authority (NVE) which are intended for ships and mainland installations (buildings and production plant). New regulations for ships entered into force on 1 September 1986. Regulations for mainland installations are being revised and are expected to be promulgated in 1987. They will be brought into harmony with the new international standards issued by the IEC. The Directorate thinks it best in the long term to arrive at a single regulations covering electrical installations within its area of responsibility.

The Norwegian Petroleum Directorate participated in the preparation of draft guidelines for repair of explosion-proof equipment.

The Directorate's participation in the efforts to reduce the power of short-circuits on new platforms continued in 1986.

4.9.2 Fiber optics

The techniques of fiber optic signal transmission seem to be winning acceptance in the oil activity. The method has many advantages compared with electrical transmission:

- immunity to electromagnetic noise
- electrically insulating
- better signal quality
- no sparks, particularly critical in explosion hazard areas
- enormous transmission capacity.

The Directorate will watch developments in this area carefully.

4.9.3 Fire damage in 1986

Below is a survey of fires on fixed production installations in 1986 as reported by the operating companies. In all the Norwegian Petroleum Directorate recorded 22 fires in 1986, as compared with 38 in 1985.

	Constr. phase	Operating phase "A"	"B"	"C"
1. Personal injury and major material damage	Nil		Nil	
2. Personal injury and small or no material damage				
3. No personal injury, but major material damage				
4. No personal injury, small or no material damage	3	13	6	
Total number of fires	3	13	6	

"A" Caused by operations or operational work
"B" Caused by building work
"C" Caused by other causes

4.10 Drilling data bank DDRS

In April 1984 the drilling data bank (Daily Drilling Report System) entered service. The system is intended to collect daily drilling reports from the companies. At the end of 1986 DDRS held information from roughly 270 wells on the Norwegian Continental Shelf. Reports are sent either by manual keying of data over a telephone connection to the Norwegian Petroleum Directorate computer, or directly. Direct reporting involves retreiving the data from the companys private system before dispatching in to the Directorate's mainframe. The advantages of direct reporting are innumerable, including time savings, better data quality, and avoidance of manual duplication, first to a private system, then to the Directorate.

Several tools have been devised in connection with the DDRS for further processing of the reports. Among them is a modern graphic analysis tool for estimated and real pressure conditions in the well or formation and the planned and final direction.

Plans include improved structuring of information connected with faults or problems arising from use of drilling equipment. Some changes will also be made in formats and displays used for manual keying of data. The possibility of allowing licensees to retreive data from the DDRS is also being weighed.

4.11 Work accidents

4.11.1 Background information

The Norwegian Petroleum Directorate's statistical summary of personal injuries includes injuries occuring at work on installations in connection with production of oil and gas on the Norwegian Continental Shelf, and in connection with diving activities. The statistics are based on reported personal injuries which fit the prescribed criteria, in other words, work absence into the next 12 hours shift, or injury resulting in medical treatment.

These reporting criteria for work accidents mean that the figures cannot be directly compared with similar official statistics from other activities. This is because offshore activity is subject to different, often stricter reporting rules.

The number of injuries is collated with the number of working hours reported by the licensee from each installation and field each quarter. A man-year in this context is equivalent to 1752 manhours. It has proven difficult to provide the Directorate with a systematic and reliable summary of the amount of work done on individual fields and installations.

The Norwegian Petroleum Directorate conducts regular revision and correction of the statistical basis. The annual retrospective audit of the operating companies shows that the industry is still making heavy weather of reporting personal injury to the Directorate. Delayed and incomplete reports also make it necessary to adjust the injury figures each year. The potential sources of error noted here must be considered in the further analysis of the numerical material. Despite these sources of error, though, the Directorate considers that the statistical summaries provide a reasonably correct idea of the state of injuries on production installations on the continental shelf.

4.11.2 Accident statistics for diving activity

Figure 4.11 provides a summary of the number of personal injuries reported to the Norwegian Petroleum Directorate in the years 1978–86 in connection with diving activity on the Norwegian Continental Shelf. Personal injuries are broken down into deaths, other injuries and decompression sickness. Diving activity, indicated by the number of hours in saturation, in 1986 remained at about the same level as in 1985.

The four instances of decompression sickness included two from surface dives and two from helium-oxygen (HeO_2) dives. One instance affected two divers, making the number of divers treated in 1986 five.

Among the 24 cases of other injury, six were related to hyperbaric habitat (four burns and two ear infections).

Ten episodes were characterized as near accidents. The remaining injuries were very largely sustained without any direct links to diving.

4.11.3 Accident statistics apart from diving

The Norwegian Petroleum Directorate recorded 598 reports of personal injury in 1986, the same as last year. At the same time, activity increased from 8570 to 9723 reported man-years, or 13.4 per cent. This increase was largely due to activity on Gullfaks and the Ekofisk field. The injury frequency varies considerably from operator to operator. One reason is the wide range of activity levels, installation types and different development phases.

No personal injuries resulted in fatality in 1986.

Tables of accident statistics

Table 4.11 includes a summary of personal injuries per 1000 man-years in the period 1976–86 on production installations, excluding diving activity. The figures show a decline in accident frequency per 1000 man-years from 69.8 in 1985 to 61.2 in 1986. The decline is statistically significant.

Injuries occuring on installations outside working hours (recreational injuries) are not included in Tables 4.11.a-f. In 1986 reports were received of 29 recreational injuries, the same as last year.

Table 4.11.b shows the breakdown of injury frequency by function. The most pronounced change in relation to 1986 was in the construction and maintenance work category, where injury frequency fell from 85.2 to 66.3 per 1000 man-years. This work category accounts for 62 per cent of the gross work done on the installations, and about 67 per cent of injuries. It is difficult to pinpoint any direct causal link to explain this. As for the result, the Directorate believes the improvement may in part be due to increased safety and environmental efforts among contractor companies.

It is also worth noting that the work category of drilling, which traditionally has returned the highest injury frequency and accounts for roughly 20 per cent of the work load, reduced its figure from 94.0 to 89.0 injuries per 1000 man-years. There is reason to believe that the declining tendency in recent years is the fruit of goal-oriented safety efforts and increased mechanization.

Table 4.11.c shows the breakdown of injuries and man-years between operator and contractor employees in the various work categories for 1985 and 1986.

In 1986 contractors contributed 65 per cent of the total work effort on production installations offshore, the same as in 1985. Eighty-five per cent of personal injuries in 1986 were sustained by this group, a decline of two per cent from last year. The injury frequency was 80.2 in 1986, compared with 95.0 in 1985, while for operator employees the frequency remained constant at 25.6. The primary reason for this bias is that drilling and the bulk of construction and maintenance work – which is relatively high risk – is done by contractors. The decline in injury frequency in contractor companies is considerable.

Tables 4.11.d-g provide a summary of injury distribution in terms of several variables. For purposes of comparison, the figures for 1985 are included in Tables 4.11.d-f.

Figures illustrating accident statistics

Figure 4.11.b presents the breakdown of injuries according to presumed seriousness from 1979–86. A personal injury is considered serious if it results in amputation, permanent injury or is likely to require long-term medical attention. Classification is made on the basis of details reported on the accident report form, plus any additional data.

Figure 4.11.c shows injury frequency broken down by job function for 1984–86.

Conclusion

The Norwegian Petroleum Directorate feels that the decline in injury frequency from 1985 to 1986 is considerable. The percentage decline is largest in the fields of construction and maintenance and drilling, where the majority of contractor employees belong. Even though no thorough analysis of the causes behind this has been made as yet, there is reason to believe that the positive development is largely the fruit of markedly improved quality of safety and environmental work by the contractors, plus better control and planning of individual operators activities. There is still room for improvement in as far as coordination and effectivization of safety and environmental work in individual operators activities is concerned. The Directorate has noted, however, increased commitment and conscientiousness in the industry regarding the importance of watching over the working environment and conducting planned, active safety and environmental work. Let the 1986 figures provide encouragement, but remember at the same time that they commit all parties to redouble their efforts to safeguard life and health in the petroleum activity.

Fig. 4.11.a
Total number of personal injuries in connection with diving on the Norwegian Continental Shelf – 1978–86

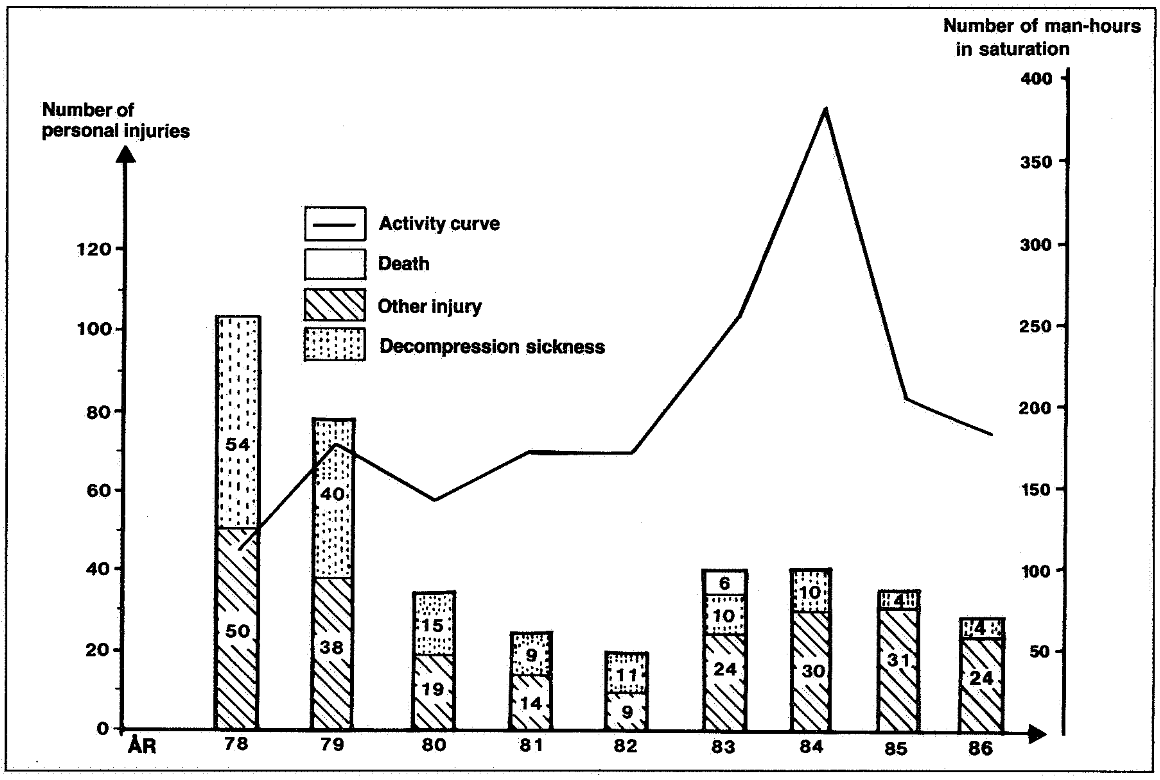


Fig. 4.11.b
Severity of injuries 1979–86

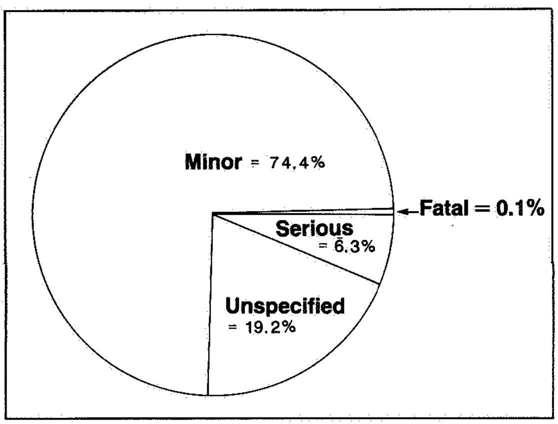
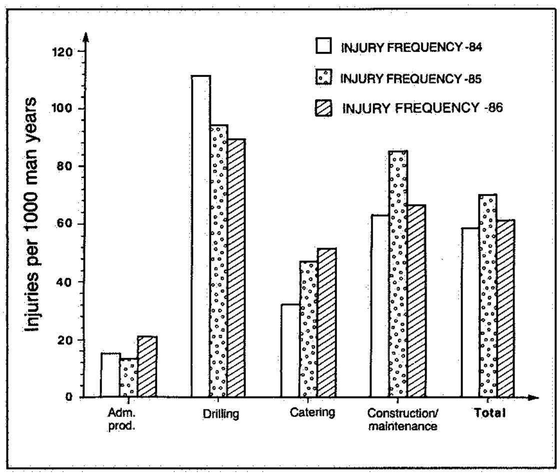


Fig. 4.11.c
Injury frequency 1984–86



TAB 4.11.a Occupational accidents/fatalities/1,000 man years (1976–86). Production installations

Year	Hours worked	Hours per man year	Man years	Number of injuries (incl. deaths)	Number of injuries per 1,000 man years	Number of deaths	Number of deaths per 1,000 man years
1976	4876316	1852	2633	213	80.9	2	0.76
1977	8146948	1852	4399	282	64.1	2	0.45
1978	14932296	1752	8523	624	73.2	6	0.70
1979	14986608	1752	8554	575	67.2	0	0.00
1980	12237720	1752	6985	452	64.7	0	0.00
1981	15612072	1752	8911	415	46.6	0	0.00
1982	14790384	1752	8442	529	62.7	0	0.00
1983	11473848	1752	6549	334	51.0	0	0.00
1984	14643216	1752	8358	491	58.8	1	0.12
1985	15014640	1752	8570	598	69.8	1	0.12
1986	17108280	1752	9765	598	61.2	0	0.00
Total	143822328		81689	5111	62.5	12	0.15

TAB 4.11.b

Occupational accidents per 1000 man years, distributed on functions (1979–86). Production installations.

FUNCTION		1979	1980	1981	1982	1983	1984	1985	1986	79–86
Administration/ production	Man years	1098	1174	1144	1306	1182	1614	1656	1507	10681
	Injuries	25	23	22	21	29	25	23	32	200
	Injuries/1000 man years	22.8	19.6	19.2	16.1	24.5	15.5	13.9	21.2	18.7
Drilling	Man years	1467	1095	1098	1289	1300	1324	1384	1371	10328
	Injuries	186	148	116	137	104	148	130	122	1091
	Injuries/1000 man years	126.8	135.2	105.6	106.3	80.0	111.8	93.9	89.0	105.6
Catering	Man years	507	383	411	548	525	681	685	856	4596
	Injuries	18	10	7	22	18	22	32	44	173
	Injuries/1000 man years	35.5	26.1	17.0	40.1	34.3	32.3	46.7	51.4	37.6
Building/ maintenance	Man years	5482	4333	6258	5299	3542	4739	4845	6031	40529
	Injuries	346	270	270	348	183	296	413	400	2526
	Injuries/1000 man years	63.1	62.3	43.1	65.7	51.7	62.5	85.2	66.3	62.3
Total	Man years	8554	6985	8911	8442	6549	8358	8570	9765	66134
	Injuries	575.0	451.0	415.0	528.0	334.0	491.0	598.0	598.0	3990.0
	Injuries/1000 man years	67.2	64.6	46.6	62.5	51.0	58.7	69.8	61.2	60.3

TAB 4.11.c
Occupational injuries among Operator (O) and Contractor (C) employees

FUNCTION		1985	1986		
Administration/ production	Man years	1575	1293	o	(operator)
		80	213	c	(contractor)
	Injuries	19	32	o	
		4	0	c	
	Injuries/1000 man years	12.0	24.7	o	
		49.8	0	c	
Drilling	Man years	0	0	o	(operator)
		1384	1371	c	(contractor)
	Injuries	0	0	o	
		130	122	c	
	Injuries/1000 man years	0	0	o	
		93.9	89.0	c	
Catering	Man years	0	39	o	(operator)
		685	817	c	(contractor)
	Injuries	0	4	o	
		32	40	c	
	Injuries/1000 man years	0	103.4	o	
		46.7	49.0	c	
Building/ maintenance	Man years	1544	2063	o	(operator)
		3301	3969	c	(contractor)
	Injuries	61	51	o	
		352	349	c	
	Injuries/1000 man years	39.5	24.7	o	
		106.6	87.9	c	
Total	Man years	3120	3394	o	(operator)
		5450	6370	c	(contractor)
	Injuries	80	87	o	
		518	511	c	
	Injuries/1000 man years	25.6	25.6	o	
		95.0	80.2	c	

TAB. 4.11.d

Occupational accidents 1985–86. Production installations. Injury incident/injured part of the body

Injury incident / Occupation	Admini-stration	Drillfloor worker	Driller	Electrician	Catering	Assistant worker	Instrument technician	Crane operator	Painter/ Sandblaster	Mechanic/ Motorman	Operator	Plateworker/ insulator	Pipeworker plumber	Services technician	Scaffolder	Welder	Derrickman	Unspecified	Total	%	Year
Other contact with objects/machinery in motion	5	16	0	2	5	22	2	0	4	8	2	5	5	3	3	3	5	0	90	15.1	85
	3	24	2	9	10	20	2	1	6	6	7	13	3	4	5	0	5	0	120	20.1	86
Fall to lower level	1	2	1	3	1	10	3	0	6	9	3	4	1	5	0	4	4	0	57	9.5	85
	1	3	0	3	0	17	4	1	6	1	3	4	1	1	2	4	1	1	52	8.9	86
Fall to same level	4	1	1	9	4	14	0	1	8	3	3	8	10	3	8	7	2	1	87	14.5	85
	1	3	2	4	5	7	2	1	6	8	1	5	7	3	7	2	0	2	66	11.0	86
Stepping on uneven surface, mis-step	1	1	0	5	2	8	2	2	6	2	0	0	7	1	3	1	0	2	43	7.2	85
	2	0	1	3	1	8	1	0	3	3	5	3	2	2	3	2	0	0	41	6.9	86
Falling objects	2	5	1	0	0	5	0	1	0	3	0	3	7	2	4	1	0	0	34	5.7	85
	0	3	1	1	1	5	0	0	2	2	1	3	3	1	6	4	0	0	33	5.5	86
Other contact with objects at rest	1	1	0	6	2	0	0	0	6	1	2	7	5	2	3	0	0	0	36	6.0	85
	1	1	0	2	3	4	2	2	9	3	2	6	4	1	6	1	1	0	48	8.0	86
Handling accident	1	7	1	1	8	11	2	0	3	11	0	10	9	3	10	6	0	0	83	13.9	85
	1	4	0	5	9	12	3	0	8	10	2	6	5	4	5	1	3	0	78	13.0	86
Contact with chemical/ physio-compound	1	0	0	2	6	8	1	0	15	0	0	1	5	2	1	4	1	0	47	7.9	85
	0	0	0	1	4	3	0	0	12	1	2	1	1	1	1	1	0	1	29	4.8	86
Overloading of part of body	1	4	1	6	0	9	0	1	4	3	1	4	4	3	4	1	0	0	46	7.7	85
	0	1	0	4	2	7	1	0	5	4	2	1	1	0	4	3	0	2	37	6.2	86
Splinters/ splashes	0	0	0	4	0	5	0	0	10	2	2	3	10	3	2	12	1	0	54	9.0	85
	2	2	2	4	2	6	0	0	15	8	2	7	15	0	2	13	0	0	80	13.4	86
Electric current	0	1	0	4	0	0	0	1	0	0	0	1	0	0	0	0	0	0	7	1.21	85
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	86
Extreme temperature	0	0	0	0	4	2	0	0	0	0	0	0	1	0	0	1	0	0	8	1.3	85
	0	0	0	0	6	1	0	0	0	0	0	0	1	0	1	3	0	0	12	2.0	86
Fall into sea	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	85
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0.2	86
Other	0	0	0	0	0	2	0	0	1	1	0	1	1	0	0	0	0	0	6	1.0	85
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	86
Total	17	38	5	42	32	96	10	6	63	43	13	47	65	27	38	40	13	3	598	100	85
	11	41	8	36	43	90	15	5	72	46	27	51	43	17	42	34	10	7	598	100	86
%	2.8	6.4	0.8	7.0	5.4	16.1	1.7	1.0	10.5	7.2	2.2	7.9	10.9	4.5	6.4	6.7	2.2	0.5	100		85
	1.8	6.9	1.3	6.0	7.2	15.1	2.5	0.8	12.0	7.7	4.5	8.5	7.2	2.8	7.0	5.7	1.7	1.2	100		86

TAB. 4.11.e

Occupational accidents 1985–86. Production installations. Injury incident injured part of the body

Injury incident \ Injured part of the body	Eye	Back	Toe/foot	Hip/leg	Stomach/chest	Arm/ shoulder	Head/ face	Tooth	Hand/ finger	Other	Total	%	Year
Other contact with objetcts/ machinery in motion	0 2	0 2	9 11	7 5	3 3	6 9	12 7	8 6	45 75	0 0	90 120	15.1 20.1	85 86
Fall to lower level	0 0	12 10	6 7	15 8	7 9	12 4	1 8	0 0	3 7	1 0	57 53	9.5 8.9	85 86
Fall to same level	0 0	15 11	16 7	12 16	6 6	14 10	2 5	3 3	19 8	0 0	87 66	14.5 11.0	85 86
Stepping on uneven surface mis-step	0 0	2 1	37 24	4 10	0 1	0 2	0 0	0 0	0 3	0 0	43 41	7.2 6.9	85 86
Falling objects	0 0	2 0	9 12	3 3	2 0	2 0	8 5	2 1	6 11	0 1	34 33	5.7 5.5	85 86
Other contact with objects at rest	0 1	3 4	2 2	10 6	2 8	2 3	6 10	2 2	9 12	0 0	36 48	6.0 8.0	85 86
Handling accidents	1 6	1 1	6 4	3 5	3 1	2 2	2 2	8 6	56 50	1 1	83 78	13.9 13.0	85 86
Contact with chemical/ physio compound	40 25	0 0	0 0	0 0	0 0	0 0	3 0	0 0	0 0	4 4	47 29	7.9 4.9	85 86
Overloading of part of body	0 0	36 25	1 3	3 0	1 1	3 6	1 0	0 0	1 2	0 0	46 37	7.7 6.2	85 86
Splinters, splashes	44 71	0 0	0 1	1 1	1 0	1 0	2 6	1 0	4 1	0 0	54 80	9.0 13.4	85 86
Electric current	1 0	0 0	0 0	0 0	0 0	1 0	2 0	0 0	1 0	2 0	7 0	1.2 0.0	85 86
Extreme temperature	0 0	0 0	1 4	0 1	1 1	2 2	1 2	0 0	3 2	0 0	8 12	1.3 2.0	85 86
Fall into sea	0 1	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 0	0 1	0.0 0.1	85 86
Other	0 0	0 0	1 0	0 0	0 0	1 0	3 0	0 0	1 0	0 0	6 0	1.0 0.0	85 86
Total	86 106	71 54	88 75	58 55	26 30	46 38	43 45	24 18	148 171	8 6	598 598	100 100	85 86
%	14.3 17.7	11.8 9.0	14.7 12.5	9.7 9.2	4.3 5.0	7.6 6.3	7.1 7.5	4.0 3.0	24.7 28.6	1.3 1.0	100 100		85 86

TAB 4.11.f

Occupational accidents 1985–86. Production installations. Injury incident/Contributing factor

Injury incident \ Contributing factor	Chemical/physio/ biological factors	Cold/pressure/ heat ventilation	Materials/ packaging	Electrial equipment	Other machinery	Drill strings	Handtools/machines/ implements	Loose/fixed fittings on structure	Lifting/ transp. gear	Other	Total	%	Year
Other contact with objects/ machinery in motion	0	5	11	0	11	7	11	29	16	0	90	15.1	85
	0	0	12	1	18	10	17	41	21	0	120	20.1	86
Fall to lower level	3	0	2	0	0	0	1	50	1	0	57	9.5	85
	0	0	4	0	0	0	3	42	4	0	53	8.9	86
Fall to same level	10	0	12	2	1	0	0	61	1	0	87	14.5	85
	2	0	2	1	1	0	2	54	4	0	66	11.0	86
Stepping on uneven surface, mis-step	1	0	10	0	0	0	1	29	1	1	43	7.2	85
	0	0	5	0	2	0	1	30	2	1	41	6.9	86
Falling objects	0	0	10	0	1	0	3	13	7	0	34	5.7	85
	0	0	10	2	2	0	2	15	2	0	33	5.5	86
Other contact with objects at rest	1	0	3	0	1	0	1	30	0	0	36	6.0	85
	1	0	8	1	0	0	1	35	2	0	48	8.0	86
Handling accidents	0	0	20	0	6	3	30	19	5	0	83	13.9	85
	0	0	23	1	1	1	45	6	1	0	78	13.0	86
Contact with chemical/ physio-compound	28	6	0	1	0	0	12	0	0	0	47	7.9	85
	26	0	0	0	0	0	3	0	0	0	29	4.8	86
Overloading of part of body	0	0	11	0	3	0	6	19	2	5	46	7.7	85
	0	0	15	0	2	0	5	14	0	1	37	6.2	86
Splinters, splashes	7	7	11	0	5	0	22	0	0	2	54	9.0	85
	10	2	18	0	3	0	37	3	0	7	80	13.4	86
Electric current	1	0	0	5	0	0	1	0	0	0	7	1.2	85
	0	0	0	0	0	0	0	0	0	0	0	0.0	86
Extreme temperature	4	0	2	0	0	0	1	1	0	0	8	1.3	85
	1	0	10	0	0	0	0	1	0	0	12	2.0	86
Fall into sea	0	0	0	0	0	0	0	0	0	0	0	0.0	85
	0	0	0	0	0	0	0	1	0	0	1	0.2	86
Other	0	1	1	0	0	0	0	1	0	3	6	1.0	
	0	0	0	0	0	0	0	0	0	0	0	0.0	86
Total	55	19	93	8	28	10	89	252	33	11	598	100	85
	40	2	107	6	29	11	116	242	36	9	598	100	86
%	9.2	3.2	15.6	1.3	4.7	1.7	14.9	42.1	5.5	1.8	100		85
	6.7	0.3	17.9	1.0	4.8	1.8	19.4	40.5	6.0	1.5	100		86

TAB 4.11.g
Occupational accidents 1979–86. Production installations. Injury incident/Occupation

Injury incident \ Occupation	Admini-stration	Drillfloor worker	Driller	Electrician	Catering	Assistant worker	Instrument technician	Crane operator	Painter/ Sandblaster	Mechanic/ Motorman	Operator	Plateworker/ insulator	Pipeworker plumber	Services technician	Scaffolder	Welder	Derrickman	Unspecified	Total	%
Other contact with objects/machinery in motion	22	178	15	31	30	211	13	9	19	56	17	36	40	27	42	18	67	1	832	20.9
Fire Explosion etc	0	0	0	2	0	5	0	0	0	2	0	1	2	0	0	1	0	0	13	0.3
Fall to lower level	11	19	9	27	4	71	15	4	27	28	11	19	27	13	20	26	17	1	349	8.7
Fall to same level	16	18	4	37	23	66	13	7	26	28	20	29	46	18	38	29	8	7	433	10.9
Stepping on uneven sur-face, mis-step	15	9	1	39	11	52	10	6	20	15	13	14	33	12	21	29	9	2	311	7,8
Falling objects	7	18	6	5	2	35	3	1	5	13	2	19	23	12	24	10	4	0	189	4.7
Otdher contact with objects at rest	7	13	2	21	18	34	14	2	27	21	7	40	23	8	28	16	6	2	289	7.2
Handling accidents	4	46	6	36	37	97	16	5	25	70	16	45	66	16	34	43	20	0	582	14.6
Contact with chemical/ physio-compound	1	8	0	9	16	37	5	1	64	11	11	9	18	13	6	12	5	1	227	5.7
Overloading of part of body	5	26	4	27	10	66	2	4	21	25	11	14	35	7	29	15	12	2	315	7.9
Splinters, splashes	7	8	4	10	2	29	2	1	32	22	8	32	63	6	6	83	2	0	317	7.9
Electrical current	0	1	0	20	0	1	1	1	0	1	0	2	0	0	0	0	0	0	27	0.7
Extreme temperature	0	0	0	2	18	4	1	0	0	4	3	5	6	1	1	9	0	0	54	1.5
Fall into sea	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	2	0.1
Other	4	3	0	5	2	9	1	2	3	4	2	5	6	0	1	3	0	0	50	1.3
Total	99	347	51	271	173	717	96	43	270	300	121	270	388	133	250	294	150	17	3990	
%	2.5	8.7	1.3	6.8	4.3	18.0	2.4	1.1	6.8	7.5	3.0	6.8	9.7	3.3	6.3	7.4	3.8	0.4		100

5. Petroleum Economy

5.1 Exploration drilling, deliveries of goods and services

Since the start of exploration drilling in 1966, exploration activity has increased considerably in both volume and value.

Figure 5.1.a shows the development of the market by value, in 1986 kroner.

TAB 5.1
Number of wells and costs per well in fixed 1986 kroner.

Year	Number of wells	Cost per well
1971	16	54
1972	13	69
1973	21	58
1974	17	60
1975	26	57
1976	23	74
1977	20	65
1978	18	75
1979	27	76
1980	35	90
1981	39	118
1982	49	123
1983	40	120
1984	47	154
1985	50	149
1986	36	160

Table 5.1 shows the number of wells and the average costs per well for the period 1971–86 in 1986 kroner.

In 1986 total exploration costs were somewhat over NOK 5.7 billion (Figure 5.1.b).

Below are shown costs for 1986, roughly divided into main categories of goods and services involved

FIG. 5.1.a
Yearly exploration drilling costs in fixed 1986 kroner

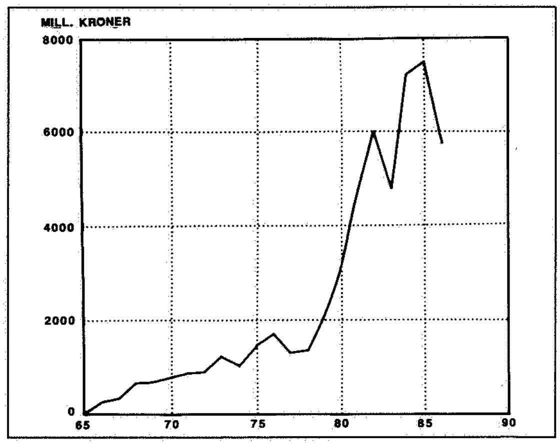
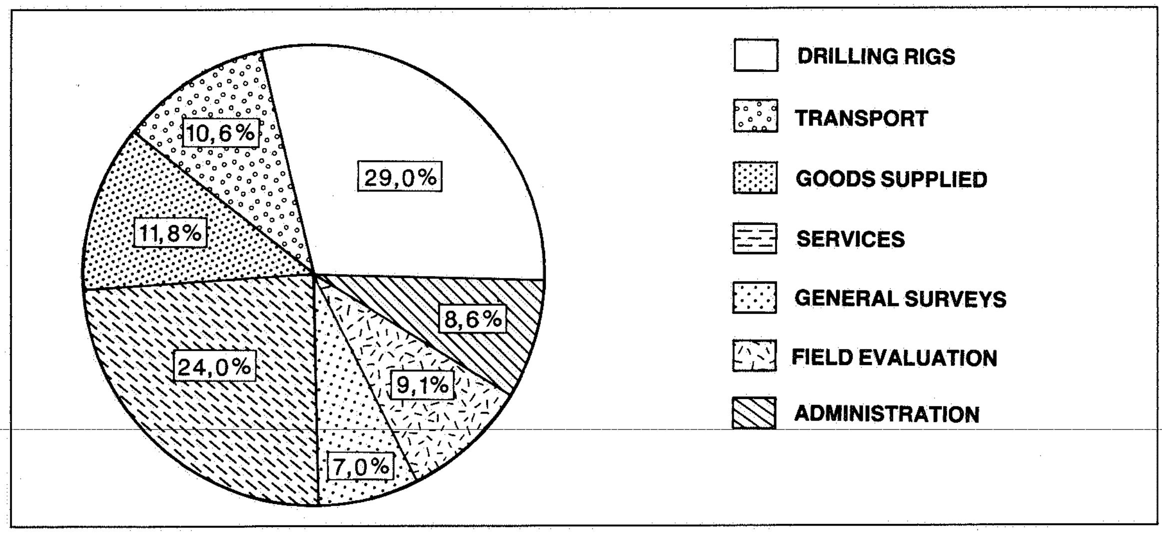


FIG. 5.1.b
Exploration expenditure in 1986



in exploration activity. The numerical material is based on data reported by the operator companies, and costs are in NOK million.

– Drilling rigs	1,666
– Transport	612
– Goods	676
– Services	1,377
– General surveys	401
– Field evaluation	521
– Administration	495
Total	5,748

5.2 Costs of activity on Norwegian Continental Shelf Investments in field development and production drilling

The Norwegian Petroleum Directorate has for the period 1970–86 calculated the annual costs associated with field development, including production drilling. These costs apply to developed fields, fields under development and fields with approved development plans as of 31 December 1986. Figures are based on the operators reports.

For fields lying on both sides of the sector line between Norway and Great Britain only the Norwegian share is included. The following fields are included in the calculation (Norwegian share):

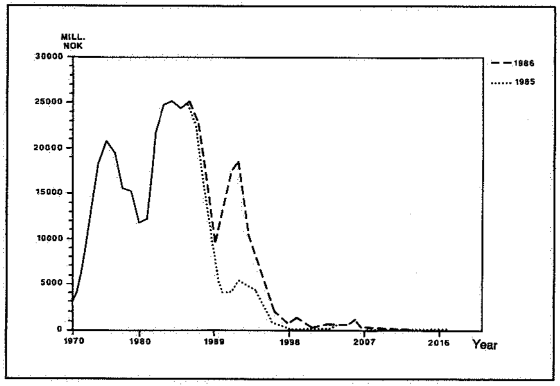
- the Ekofisk area (including five fields plus Tor, Albuskjell, the Norpipe line and the Ekofisk waterflood project)
- Valhall
- Ula
- Frigg (60.82 %)
- North-East Frigg
- Odin
- Statfjord (84.09 %)
- Murchison
- Heimdal
- Gullfaks Phase I
- Gullfaks Phase II
- Statpipe
- Oseberg
- Oseberg Transport
- Tommeliten
- Troll
- Sleipner
- Zeepipe.

In this account all figures are recalculated in 1986 kroner.

Past and expected investment in field development, production drilling and transport systems for petroleum is shown in Figure 5.2.a. The level of investment built up gradually to 1976, when NOK 20.6 billion had been invested. Investments in 1986 reached NOK 25,1 billion. The level of investment thus exhibited large variations from 1976 to the present.

Investment levels are expected to fall in the period between 1986 and 1989, after which the investment in newly approved fields will have a positive effect in the next few years. These fields are Troll, Sleipner, Tommeliten and the Zeepipe transport system. Figure 5.2.a shows the effect on the level of investment caused by the new fields as the difference between the figures for 1985 and 1986.

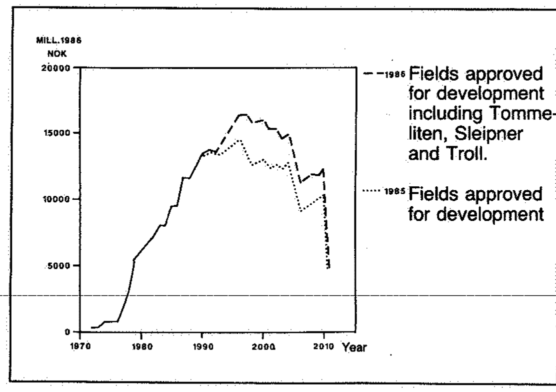
FIG. 5.2.a
Historical and expected investment for fields decided to be developed. Fixed 1986 kroner



Annual operating costs, including operation of pipelines, are shown in Figure 5.2.b. Up to the present the level of demand for this type of goods and services has been steadily increasing on account of the fields which in the course of time come on stream. The goods and services input for operation and maintenance will continue to rise over time as the approved fields come into production in the next few years. At present operating costs are running at about NOK 10 billion per year. A peak of around NOK 16.5 billion has been calculated for 1997.

If we compare this years calculations of expected operating costs with last years, we see that the effects of the shutdown of the first fields will not make themselves felt before 1997, as opposed to the earlier forecast of 1993: that is, the level of demand will remain stable until after the year 2000.

FIG. 5.2.b
Historical and expected operating costs for fields decided to be developed. Fixed 1986 kroner.



5.3 Royalties

Royalties are calculated on the basis of the value of petroleum produced.

The Norwegian Petroleum Directorate has been allocated the responsibility for collecting royalties.

Interpretation and practice of current laws and regulations in connection with calculation of royalties embraces legal, financial, process and metering problems.

The first regulations in this area were made by Royal Decree of 9 April 1965. Of the fields in production today, Ekofisk, Frigg, North-East Frigg, Odin, Valhall, Ula and Heimdal were granted their production licences under these provisions. Royal Decree of 9 April 1965 was replaced by that of 8 December 1972, under which production licences were granted for Statfjord and Murchison.

The new Petroleum Act with regulations came into force on 1 July 1985. From this date royalties are to be collected under the provisions of the new legislation.

The 1965 and 1972 decrees created many problems of interpretation with regard to the royalties calculation point. It was hoped that the Petroleum Act would solve such problems.

It has been found, however, that the definition of the royalties reference point in the Petroleum Act creates obscurities too.

For example, all licensees engaged in production have appealed the Directorate's decision on the royalties calculation point, as they consider that the new regulations cannot apply to licences granted under older decrees. By Royal Decree of 19 December 1986 the Ministry of Petroleum and Energy resolved these complaints. The Ministry upheld the Directorate's previous decision. Suit has also been brought against the State regarding royalty deadlines.

5.3.1 Total royalties

In 1986 NOK 8,168,955,149 was paid in royalties.

Table 5.3.1 shows the royalties paid in 1985 and 1986 divided between various petroleum products. The reduction in royalties paid between 1985 and 1986 is due to the recent fall in oil and gas prices.

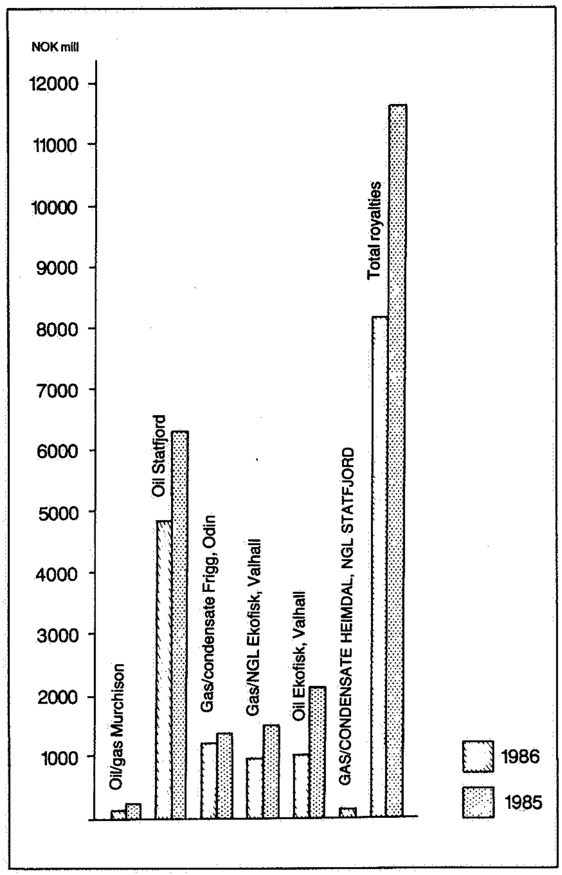
Figure 5.3.1.a shows the royalties paid in 1985 and 1986 by fields and in total.

Figure 5.3.1.b shows royalties paid in 1973–1986.

TAB 5.3.1
Royalties in 1985 and 1986 in NOK

	1985	1986
Oil Ekofisk/Valhall	2 192 617 514	1 001 639 570
Oil Statfjord	6 334 537 041	4 827 100 261
Oil Murchison	238 061 138	86 677 367
Gas Murchison	4 464 012	4 131 011
Gas Ekofisk	1 330 169 497	831 173 831
Gas Frigg	1 071 219 432	1 048 216 288
Gas NØ-Frigg	54 221 080	53 008 707
Gas Odin	204 281 169	136 588 810
Gas Valhall	58 027 407	27 472 961
Gas Heimdal		30 264 081
NGL Ekofisk/Valhall	113 665 599	81 713 942
Condensate Frigg-area	11 897 250	7 238 184
Cond. Heimdal, Statoil		9 907 626
LPG and NGL Murchison	12 401 324	4 935 685
NGL Statfjord		18 886 825
	11 625 562 463	8 168 955 149

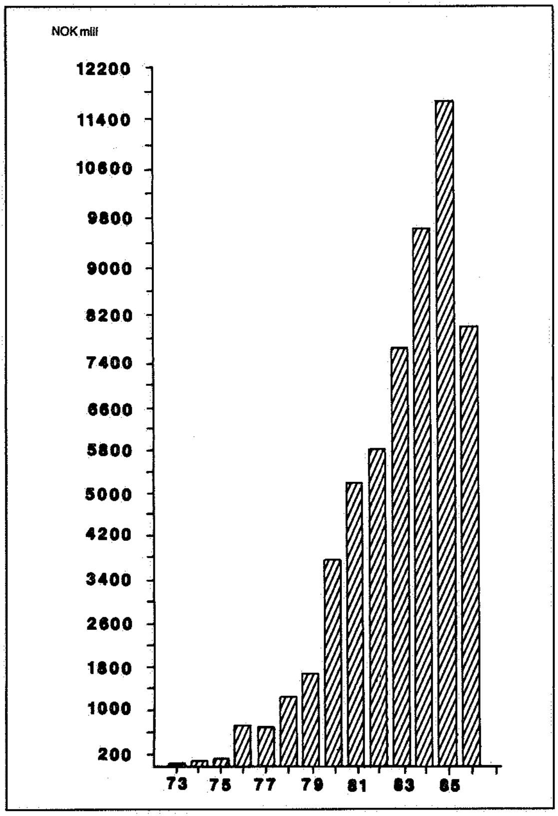
FIG. 5.3.1.a
Royalties 1985–1986



TAB. 5.3.2
Royalties on oil

	Ekofisk/Valhall	Statfjord	Murchison	Total
4. qu. 1985	439 779 352	2 152 461 214	58 082 049	2 650 322 615
1. qu. 1986	236 500 379	1 151 423 936	7 533 719	1 395 458 034
2. qu. 1986	170 874 356	593 702 909	13 856 999	778 434 264
3. qu. 1986	154 485 483	929 512 202	7 204 600	1 091 202 285
	1 001 639 570	4 827 100 261	86 677 367	5 915 417 198

FIG. 5.3.1.b
Royalties 1973–1986



5.3.2 Royalties on oil

In 1986 the Norwegian Petroleum Directorate received NOK 5,915,417,198 in royalties for oil from Murchison, Ekofisk and Statfjord.

Calculation for crude oil has been performed according to norm prices. Royalty has been paid quarterly as shown in Table 5.3.2.

5.3.3 Royalties on gas

In 1986 the Norwegian Petroleum Directorate received NOK 2,130,855,689 in royalties for gas. Table 5.3.3 shows payments divided quarterly by company or group. On the Statfjord field royalties have not been paid on gas because the cost deductions were larger than gross royalties in all quarters.

Calculation for gas has been performed according to contract price, which varies from group to group.

Deliveries of gas to Dyno/ Methanor ceased as of 1 July 1984. The sums refunded to Dyno/ Methanor are related to transport and treatment of gas already received and paid for.

5.3.4 Royalties on NGL

In 1986 NOK 122,682,262 was received in royalties for NGL. Table 5.3.4 shows payment of royalties divided quarterly between company/ group. The reason for there being no payment from the Statfjord field in the second quarter of 1986 is that deductions for cost were greater than gross royalty.

TAB 5.3.3
Royalties on gas production

	4. qu.1985	1. qu.1986	2. qu.1986	3. qu.1986	Total
EKOFISK-AREA					
Phillipsgr.	157 446 598*	239 909 596	153 436 082	241 954 059**	792 746 335
Dyno/Methanor	-362 046	-1 659 222	-26 192	-546 132***	-2 593 592
Shell	10 794 593	4 917 933	2 046 273	9 345 448	27 104 247
Amoco/Noco-gr.	4 304 188	3 922 776	2 342 668	3 347 209	13 916 841
Total Ekofisk	172 183 333	247 091 083	157 798 831	254 100 584	831 173 831
FRIGG-AREA					
Petronord-gr. (Frigg)	290 548 886	379 500 676	196 726 131	181 440 595	1 048 216 288
Petronord-gr. (NØF)	4 927 635	7 156 163	2 140 020	3 701 466	17 925 284
Petronord-gr. (Odin)	6 057 481	5 981 454	3 098 329	2 496 764	17 634 028
Total Petronord-gr.	301 534 002	392 638 293	201 964 480	187 638 825	1 083 775 600
Esso NØF	12 401 688	11 606 584	5 259 366	5 815 785	35 083 423
Esso Odin	55 811 673	36 655 970	16 395 690	10 091 449	118 954 782
Total Frigg-area	369 747 363	440 900 847	223 619 536	203 546 059	1 237 813 805
VALHALL					
Amoco/Noco-gr.	9 610 704	11 291 118	2 797 414	3 773 725	27 472 961
Total Valhall	9 610 704	11 291 118	2 797 414	3 773 725	27 472 961
MURCHISON					
Statoil/Mobil-gr.	1 488 414	1 582 041	967 289	93 267	4 131 011
Total Murchison	1 488 414	1 582 041	967 289	93 267	4 131 011
HEIMDAL					
Heimdal-gr.	0	0	18 049 884	12 214 197	30 264 081
Total Heimdal	0	0	18 049 884	12 214 197	30 264 081
Total all fields	553 029 814	700 865 089	403 232 954	473 727 832	2 130 855 689

* Excluding advanced payment in 3.qu. NOK 73 199 925,-.
** Including advanced payment for 4.qu. 1986 NOK 62 360 000,-.
*** Including advanced payment for 4.qu. 1986 NOK -354 168,-

5.3.5 Control of royalties

The Norwegian Petroleum Directorate has been given the task of collecting royalties and checking that payment is made according to regulations. Work is being done on further development of procedures to tighten control and increase conformity to the Directorates general supervision philosophy. This upgrading is based on system audit and spot checks of the companies.

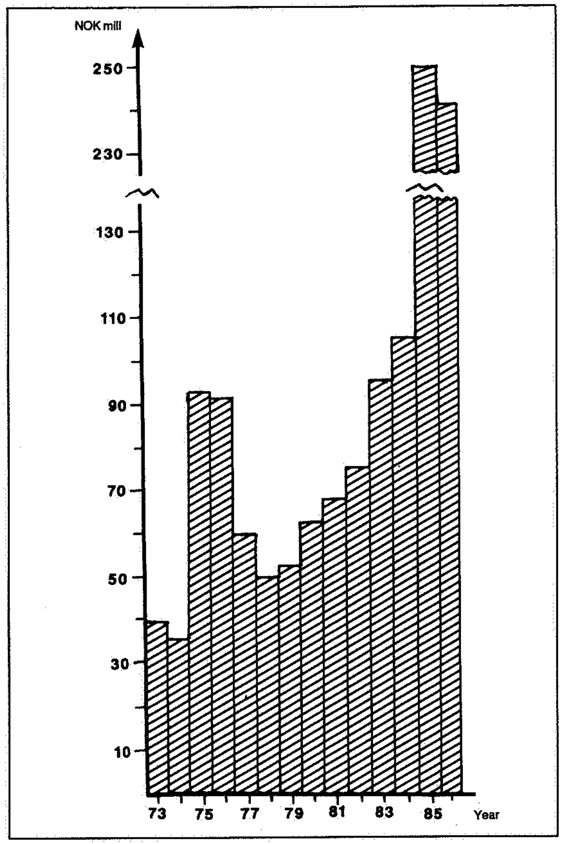
5.4 Acreage fees on licence areas

In the course of 1986 the Norwegian Petroleum Directorate collected NOK 242,839,770 in acreage fees, divided between the production licences as follows:

Production licences granted in 1965:	NOK 114,003,295
Production licences granted in 1969:	NOK 56,805,000
Production licences granted in 1971:	NOK 5,502,000
Production licences granted in 1973:	NOK 9,785,358
Production licences granted in 1975:	NOK 14,616,000
Production licences granted in 1976:	NOK 11,704,377
Production licences granted in 1977:	NOK 2,504,000
Production licences granted in 1978:	NOK 2,617,500
Production licences granted in 1979:	NOK 12,543,380
Production licences granted in 1980:	NOK 599,500
Production licences granted in 1986:	NOK 12,159,360
	NOK 242,839,770

As of 1 November 1986 the Norwegian Petroleum Directorate had refunded NOK 44,699,500 in acreage fees. This represents the deductible part of the acreage for production licences 006, 033, 018 and 037 in the period 1 November 1985 to 1 November 1986. Figure 5.4 shows paid-up acreage fees 1973–1986.

FIG. 5.4
Acreage 1973–1986



5.5 Petroleum market
5.5.1 Crude oil market
5.5.1.1 Oil market development

From January to July crude oil prices on the spot market fell from USD 28 to under USD 9 per barrel. The cause was that in the autumn of 1985 Saudi Arabia revised its market strategy. It found itself unable to continue as a swing-producer dedicated to stabilising oil prices, and gave recovery of lost market shares highest priority. With this in mind the countrys authorities introduced among other things so-called netback agreements in their sales contracts. These meant that the value of the contracts was tied to the value of the products the crude oil was refined to. The principle reduces the price risk for the sellers and guarantees sales for the producers.

The reorganisation led to powerful growth in Saudi Arabia's and other OPEC countries' oil production, to a stop in the signing of contracts based on normal prices and to the dramatic fall in the spot prices.

The price fall was probably deeper than the OPEC countries had reckoned with, and after a while the organisation came under strong pressure to return to the old system.

In August the organisation adopted a new production quota system, and the oil price rose by about USD 5 per barrel. The quota principle was confirmed at OPECs December meeting: a production ceiling of 15.8 million barrels per day was fixed, to apply during the first half of 1987, and thereafter rising to 16.6 million barrels in the third quarter and to 18.3 million in the fourth quarter. A system of norm prices was also fixed around a reference price of USD 18 per barrel.

A factor that had made effective price stabilisation difficult is oil stockpiling in transit, which grew powerfully in the autumn of 1986. Around 25 per

TAB 5.3.4
Royalties on NGL production

	4. qu.1985	1. qu.1986	2. qu.1986	3. qu.1986	Total
EKOFISK-AREA					
Phillips-gr.	29 021 269	15 572 254	11 870 933	14 193 942	70 658 398
Shell	1 401 156	194 007	968 220	95 081	2 658 464
Amoco/Noco-gr.	357 700	175 524	98 492	77 345	709 061
Total Ekofisk	30 780 125	15 941 785	12 937 645	14 366 368	74 025 923
FRIGG-AREA					
Petronord-gr.	1 505 636	1 747 009	4 335 739	–3 350 532	4 237 852
Esso	1 997 954	751 139	255 198	–3 959	3 000 332
Total Frigg-area	3 503 590	24 98 148	4 590 937	–3 354 491	7 238 184
VALHALL					
Amoco/Noco-gr.	3 428 768	–160 225	1 536 859	2 882 617	7 688 019
Total Valhall	3 428 768	–160 225	1 536 859	2 882 617	7 688 019
MURCHISON					
Statoil/Mobil-gr.	2 835 489	1 129 459	778 835	191 902	4 935 685
Total Murchison	2 835 489	1 129 459	778 835	191 902	4 935 685
STATFJORD					
Statoil/Mobil-gr.	319 703	15 229 315	0	3 337 807	18 886 825
Total Statfjord	319 703	15 229 315	0	3 337 807	18 886 825
HEIMDAL					
Heimdal-gr.,Statoil	0	0	4 792 070	5 115 556	9 907 626
Total Heimdal	0	0	4 792 070	5 115 556	9 907 626
Total all field	40 867 675	34 638 482	24 636 346	22 539 759	122 682 262

cent of the primary stores on land of oil and oil products constitute so-called strategic reserves. There are in addition secondary product stores further down the distribution lines. Oil companies stockpiles can be functionally divided into operationally necessary, officially required and variable storage. Size of the variable stores is determined by the companies price expectations and the costs of storage. The picture is complicated by there being up to 1,200 million barrels in tankers en route from the production site to the market, and considerable quantities of oil in supertankers hove-to at important shipment harbours. Total land-based stores in the OECD countries rose from 418 million tons in July to about 450 million tons in October 1986.

In this situation, expectations of OPECs production policy are of decisive significance. The suspicion that solidarity within the organisation will once more break down may lead to emptying of stores and a fall in prices. The belief that solidarity will last may lead the actors to opt for continued major storage and perhaps further increases in order to gain from the rise in value and avoid problems should OPEC decide on further production cut-backs.

It is said that some OPEC countries have already exceeded their new quotas and also continue to sell oil on a netback basis, but so far breaches of the agreement have been so minor that spot prices have not sunk significantly below normal prices. At the same time several major oil companies have agreed to sign long-term fixed-price contracts with Saudi Arabia. There are, however, different opinions in the market as to the probability that todays prices will last the spring and summer.

Most observers expect moderate economic growth in the OECD countries in the years to come. OECD itself is operating with a 1987 growth prognosis for the whole area of 2.75 per cent.

Demand will probably develop differently in different countries and within different sectors. The growth in overall demand expected by most observers, however, will lead to higher energy consumption. The effect is dependent inter alia on to what extent the oil price fall is passed on to the consumer.

Total energy consumption within OECD has since 1979 fallen by two million barrels of oil per day. The decline has, however, flattened out.

Progress in energy-saving measures is affected by changes in the oil price in isolation, the subsequent changes in the prices of other energy sources, and the price expectations created.

The rise in the price of energy in the 1970s led to a more efficient use of energy sources. Falling oil prices may lead to stabilisation of, or new upswing in, consumption of energy per produced unit. This result is again dependent on how much the oil price fall is passed on to comsumers of oil products and other energy sources. From December 1985 to October 1985 these prices fell in the richest industrial nations by on average 33 per cent. The price fall in local currency the consumers enjoyed was thus on average half as large as the fall in the dollar price of crude between January and July 1986.

The opportunities for substitution of one energy source with another vary from sector to sector and with the difference between prices of the individual energy sources. The potential in the OECD area for replacement of oil will with todays prices be limited to about one million barrels per day in the next few years.

Figure 5.5.1.a shows how crude oil production is divided between countries up to the middle of 1986. OPECs share of total world production sank from 48 per cent in 1979 to 32 per cent in 1984. The organization has as described above later taken steps to reverse this trend.

Producer's short-term decisions, that is, whether they choose to shut down or continue to operate fields once begun, depend in the main on whether the price of oil covers the operating costs per produced unit. The price fall has not made many producers shut down fields.

Producer's long-term decisions, that is, whether they choose to develop new fields or to wait, are dependent on, among other things, the relationship between expected oil price and the sum of development and operating costs per produced unit.

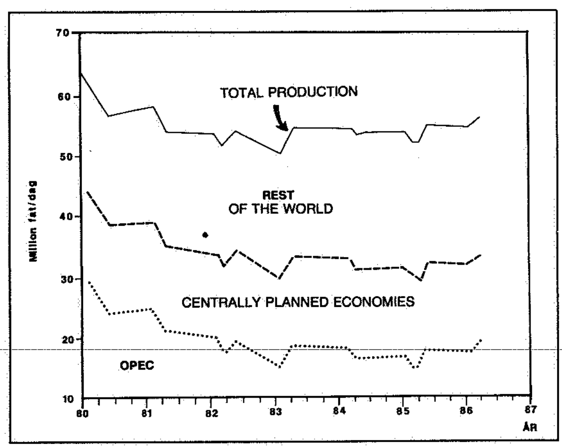
The difference between individual OPEC members and the other producers long-term costs are great. Non-OPEC producers exploration and development costs per barrel have fallen considerably. Many of them, however, operate with costs too high to enable them to withstand new and lasting price falls.

5.5.1.2 Sale of crude oil from the Norwegian Continental Shelf

In 1986 total shipments from the Norwegian Continental Shelf lay at 39,720,000 tons. This represents an increase of about seven per cent in relation to 1985. Great Britain is still the largest recipient with 27 per cent of the shipments, followed by the Netherlands with 24 per cent and Norway with 21 per cent.

Total shipments of NGL from the Norwegian Continental Shelf were 1,870,000 tons in 1986, an increase of about 31 per cent over 1985.

FIG. 5.5.1.a
The composition of the world's oil production



Statfjord wet gas goes to Kårstø, and from November 1985 there have been several shipments of NGL from this terminal. The largest recipients were Norway (31 %), followed by Britain (25 %) and the Netherlands (13 %). See Figure 5.5.1.b and c.

5.5.2 Gas market

5.5.2.1 Gas market development

In contrast to oil, gas has with few exceptions only regional markets. This is due to the fact that gas requires a widespread and costly transport network, which in turn affects the structure of the market and the shape of sales contracts. Only in its refrigerated form of NGL is it possible to transport gas to distant markets.

After 1980 there has been a rich supply of gas in Western Europe in order to meet a demand which, following a decline after 1980, rose to 190 million toe in 1984. Consumption is greatest in Britain, West Germany, the Netherlands, Italy and France.

The largest producers in Western Europe are Great Britain, producing for the home market alone; the Netherlands, dividing production about equally betwen home and export; and Norway, producing for export only.

The international gas trade in Western Europe is

FIG. 5.5.1.b
Sale of crude oil from the Norwegian Continental Shelf

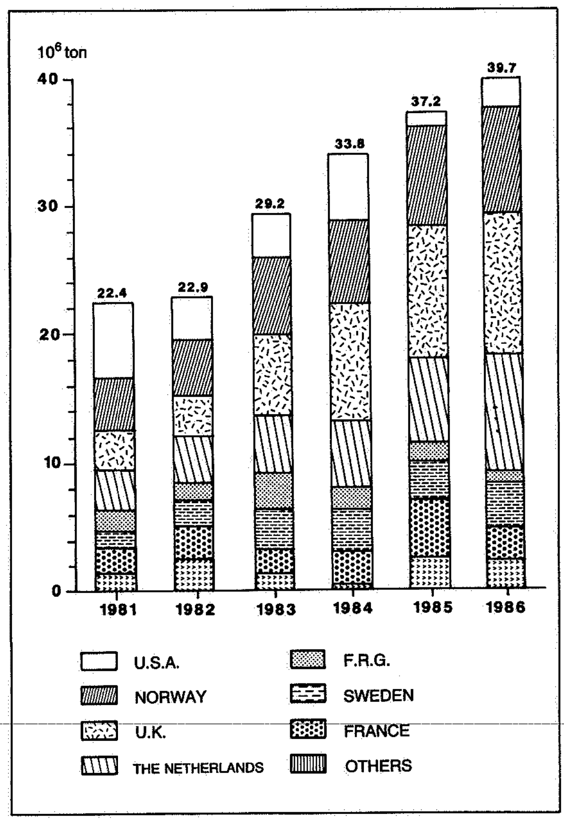
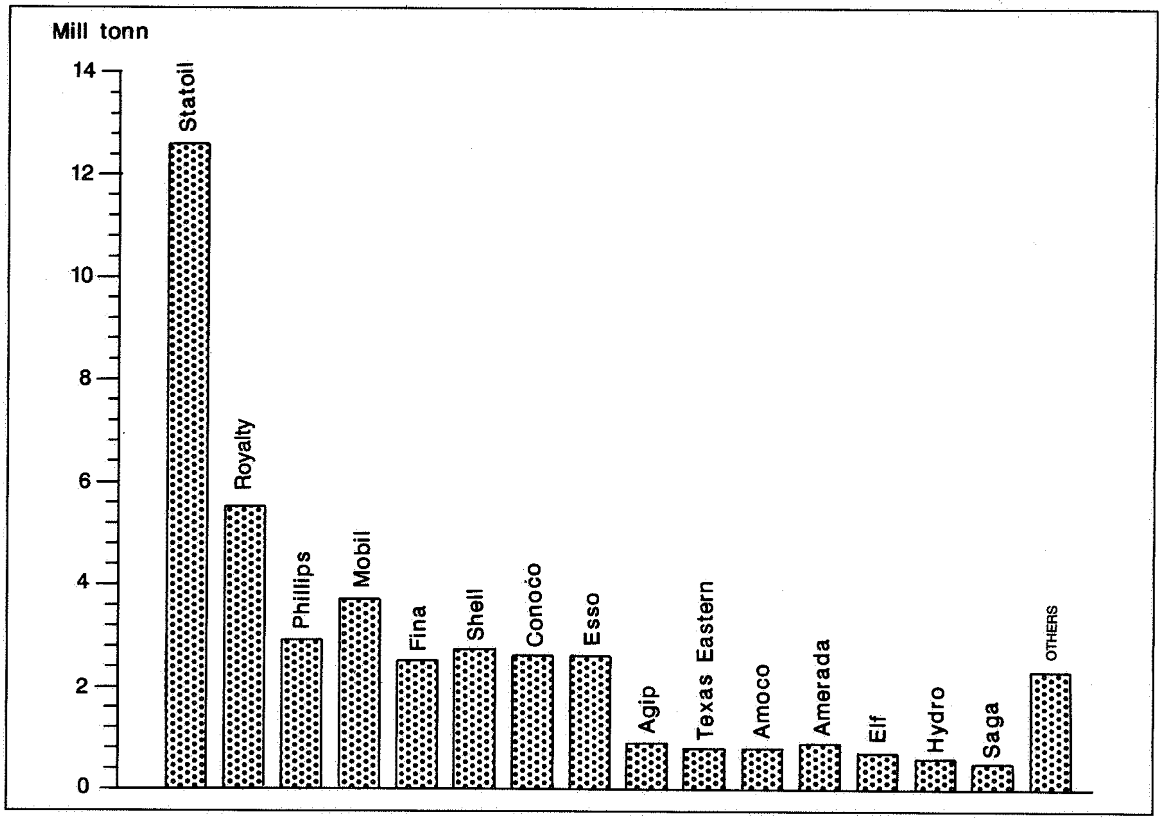


FIG. 5.5.1.c
Sales quantities of oil/NGL as per licensee in 1986



still dominated by the Netherlands, which distributes its supplies to large sectors of the Western European market. Russia has increased its exports to all major consumers except Britain and the Netherlands. Algeria exports mostly to France and Italy.

Norway's most important markets today are Britain and West Germany. In both countries the consumption of gas is significant in the domestic and industrial sectors. West Germany also uses a considerable amount of gas for electricity generation.

FIG. 5.5.2.a
Sales quantities of gas as per country

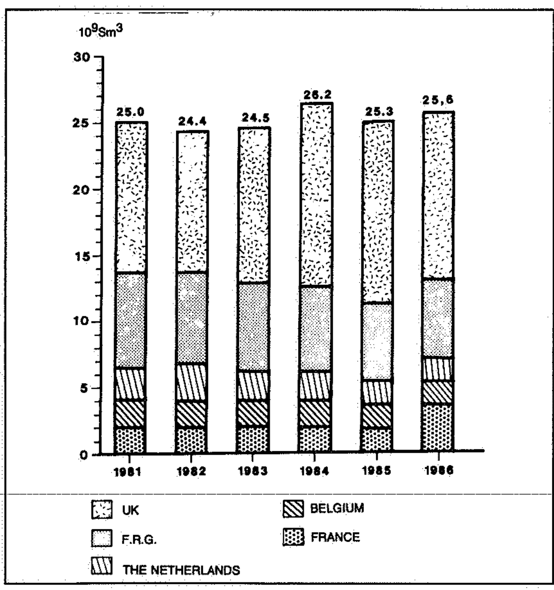
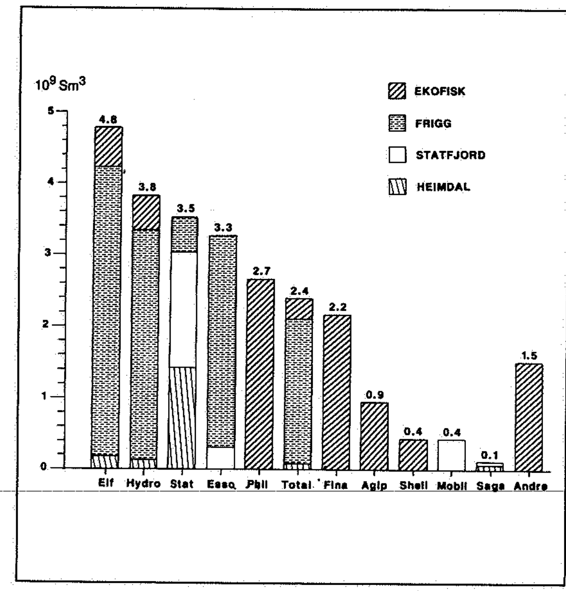


FIG. 5.5.2.b
Sales quantities of gas as per licensee in 1986



Sweden may be a new market for Norwegian gas. Even now Sweden is importing gas from Denmark for use in industry and homes in Southern Sweden. Overcapacity in supply means that growth in gas consumption is determined by its competitive position vis-a-vis other energy sources.

Future growth of gas consumption will depend on the development of energy consumption in general, competitive conditions in the industrial sector and the authorities attitude both to nuclear power and the question of maintaining the coal industry. The growth in consumption will thus largely depend on political decisions.

5.5.2.2 Sale of gas from the Norwegian Continental Shelf

In 1986 12,750,000,000 Sm^3 gas was sold to Great Britain, 5,980,000,000 to West Germany, 1,750,000,000 to the Netherlands, 1,650,000,000 to Belgium and 3,430,000,000 to France.

Total gas exports were 25,560,000,000 Sm^3, an increase of less than one per cent in relation to 1985 (Figure 5.5.2.a and b).

In March 1986 sales of gas from the Heimdal field began.

6. Special Reports and Projects

In 1986 the Norwegian Petroleum Directorate granted a total sum of NOK 18,425,495 for special projects. This amount is distributed on the basis of NOK 3,180,331 for Safety and Working Environment Division projects; NOK 15,245,176 for projects under the auspices of the Resource Management Division of which NOK 594,722 was granted to the universities.

In addition, the sum of NOK 4,613,080 has been granted for the North Sea seabed clearance project.

The Norwegian Petroleum Directorate also administers the weather ship project in the Barents Sea, where NOK 13,101,650 was made available.

The various project titles and the executive institutions are listed below. In addition, some of the projects are discussed separately.

6.1 Resource Management Division

The SPOR programme – a state-funded R&D programme initiated in 1985 – was characterized by a great deal of activity in 1986. Through building-up of expertise, research and development of new technology, SPOR aims at providing a basis for enhanced oil recovery.

The intention is for the program to stretch over a five year period with a total grant of NOK 100 million during its lifetime.

6.1.1 Exploration Branch

PROJECT TITLE	PROJECT EXECUTION AGENCY
Foraminifera stratigraphy of Carboniferous/Permian carbonates (Loppa Ridge/Tromsøflaket)	British Museum and Norwegian Petroleum Directorate
Software development/basin modelling	Rogaland Research Institute
Sales of well logs on magnetic tapes	Stavanger Data a.s
Study of Brent Group on Norwegian shelf	University of Bergen
Diagenetic survey of Statfjord and Gullfaks	University of Oslo

Foraminifera stratigraphy

In connection with the exploration activity on Lopparyggen and drilling in Permian and Carboniferous rock, the Norwegian Petroleum Directorate has surveyed the possibilities of using micro-fossils for dating such rocks.

Software development

The purpose of this project has been to develop programs to be included in the Norwegian Petroleum Directorate's internal program package in connection with hydrocarbon formation and basin development.

Well logs on magnetic tape

All released well logs are now ready for sale on magnetic tape.

Study of Brent group

In 1985 S.L. Røe of the University of Bergen initiated a project on behalf of the Norwegian Petroleum Directorate. The project involves a study of the Brent group on the Norwegian Continental Shelf and includes core descriptions from Blocks 30/6 and 30/4 and a regional synthesis.

Diagenetic survey of Statfjord and Gullfaks

P. Aagaard and H. Dypvik of the University of Oslo are presently carrying out a project for the Norwegian Petroleum Directorate concerning diagenetic surveys of the Statfjord formation in the Statfjord and Gullfaks fields. The surveys involve isotope studies and dating as well as mineral stability and formation water chemistry.

6.1.2 Production Branch

PROJECT TITLE	PROJECT EXECUTION AGENCY
Well test analyses, West Ekofisk	IPEC
Standardization of sampling and analyses of formation water	READ
Recovery from fractured reservoirs mechanisms and models	Rogaland Research Institute
Finite element analysis. Ekofisk subsidence	UCL
Nitrogen injection on Ekofisk	Institute for Continental Shelf Studies (IKU)
Evaluation of Ekofisk well tests	Smedvik IPR
Draugen reservoir study	IPEC
PVT characteristics for simulated Ekofisk	Rogaland Research Institute
Relative permeabilities for use in Ekofisk simulation	Rogaland Research Institute
Automatic sampling, Phase 4	National Engineering Laboratory (NEL)
Densitometers, analysis of experimental data	Rogaland Research Institute
VOS project	Dantest, Denmark
Fabrication requirements for orifice plates	NEL
Metering pipes for gas meter stations	NEL
Calculations of flow coefficient	Norwegian Petroleum Directorate
Continuation of PPRS-2	Rogaland Research Institute

6.1.3 Development Branch

PROJECT TITLE	PROJECT EXECUTION AGENCY
Relative permeability	FRANLAB
Assistance, use of RADPAC on Snorre	IPEC
Heidrun reservoir study	IPEC
Reservoir study for Oseberg area	READ
Development of thin oil zone	Institute for Continental Shelf Studies (IKU)
Horizontal well study	Norwegian Institute of Technology (NTH)
Literature search, thin oil zone	READ
Reservoir monitoring sub sea wells	SSI
Evaluation of tariff systems	CMI/SAF
Reduced costs in future development	Novatech

Evaluation of tariff systems
Discussion regarding principles for fixing of rates and organisation of transport services is of increasing importance in connection with the Haltenbanken development.

As of yet, no development has been initiated in this area, thus providing the authorities with a unique opportunity to organise a transport system which will contribute to a socio-economically favourable development of the area.

The Christian Michelsen Institute and the Centre for Applied Research at the Norwegian Institute of Technology have been involved in illuminating the problems tied to a social economic fixing of the transport service price and the consequences of different ways of organising such transport systems.

The work is not yet terminated and will continue in 1987.

Reduced costs in future development
A future high activity level within Norwegian oil industry is dependent on a cost level sufficiently low to make the activity profitable despite fluctuating oil prices. Reduced development and operating costs will contribute significantly in this connection.

In 1986, the Norwegian Petroleum Directorate therefore carried out a project with a view to making future field developments more economical. The essential features of the technological development assuming high and low oil price paths have also been evaluated, and the report covers the period up to around year 2000.

The main object of the report has been to identify the areas where cost-cutting is feasible. Where possible, rough economies estimates have also been set up, and in cases where such estimates are difficult, qualitative assessments have been made.

The report shows the cost-intensive elements of todays development concepts and how the individual functions and subconcepts – drilling, processing, accommodation, production platform, floating production unit, seabed installation, pipelines etc –

constitute subelements of a total field development system. This has been done so as to provide a basis for comparing part-concept costs.

There are several courses to follow, each of which may serve to reduce costs, either on its own or in combination with others. The following areas have been evaluated in the studies:

- Development of less costly and optimal concepts based on known and tested technology.
- Development of new, potentially more economical technology.
- Preparation of project implementation methods.
- Changes in regulations imposing unnecessarily cost-intensive elements.

In addition, development of new technology opening up the door to new markets may serve to improve project economics.

The report covers mainly the first three of the above courses.

The total cost reducing potential in connection with development of a field is estimated at 20–30 per cent above the amounts capitalised during the past field developments.

6.1.4 Planning Branch

PROJECT TITLE	PROJECT EXECUTION AGENCY
Risk administration in development projects	SINTEF
Optional assessment of development projects	SAF
Choice of gas contract flexibility in the light of development costs and buyer's adaption to uncertainty	CMI

Value assessment of option availability for development projects

In conventional project analyses, using discounted cash flows, no attention is paid to the financial value of option or the possibility of making decisions at a later point of time when new information has been obtained. This study is the Norwegian Petroleum Directorate's first survey of the validity of option price theory for analysis of development projects.

Risk administration in development projects

The project evaluates methods of handling financial uncertainty and risk for both individual projects and project portefolios.

Gas contract and development cost flexibility

The project was carried out in connection with the consideration of development plans for Sleipner and Troll. The purpose was to analyse the value to Norwegian gas producers of being able to offer different degrees of flexibility in gas deliveries in relation to the costs involved.

The analysis involved flexibility in connection with installations on individual fields, flexibility in connection with tie-ins of fields and flexibility in connection with transport and possible storage functions.

6.2 Safety and Working Environment Division

PROJECT TITLE	PROJECT EXECUTION AGENCY
M/S "Endre Dyrøy" – research vessel	Oceanor
Further development of drilling data bank	Rogaland Research Institute
Membership – Welding Institute	Welding Institute
Membership – CIRIA/UEG	CIRIA/UEG
Flexible hoses and pipes	Veritas/Veritec
Support for NEK for participation in international standardization work for regulations	Norwegian Association of Electrical Engineers' Technical Committees (NEK)
Acceptance criteria for fire barriers	SINTEF
Evaluation of new technologies and equipment within drilling and other well activities	Norwegian Petroleum Directorate
Problems in connection with diving at great depths	Norwegian Petroleum Directorate
Study of operational availability	SINTEF
Study of pipeline system reliability	Aprotech
Marine growth data bank	Veritec
Acceptance criteria for working environment conditions	Universitites of Bergen and Trondheim, Quasar Consultants
Working environment of divers	Norwegian Petroleum Directorate
Evaluation of acceptance criteria for drilling equipment	Petreco
Regulations concerning acquisition and storage of environmental data	Norwegian Petroleum Directorate
Guidelines for regulations concerning load-bearing structures	Norwegian Petroleum Directorate
Contingency guidelines	Scandpower A/S
Development of regulatory structure	Norwegian Petroleum Directorate
Influence of welding on materials	Cranfield Institute
Fiber-optics – safety aspects	Veritas/SINTEF
Winterization	SINTEF
Problems in connection with final production and removal	Veritec

Acceptance criteria for working environment conditions
The purpose of this project is to develop acceptance criteria on which the Safety and Working Environment Division will base its attendance to the administrative responsibility for working environment conditions in the petroleum activity. Special material will be developed on which to base all case handling in connection with approvals, implementation of revisions and information to industry and R&D teams. Experts from the Universities of Bergen and Trondheim have been engaged in this work.

Winterization of mobile installations
This project is a joint venture by several technical sections of the Safety and Working Environment Division, and the purpose is to prepare acceptance criteria for winter drilling in northern areas. The sections have been in contact with Canadian authorities and operators who are experienced in Arctic drilling. The acceptance criteria will apply to equipment and operators as well as the installation design. SINTEF is providing outside expert assistance.

Preparedness guidelines
The aim of the project is to develop a preparedness model, description and guidelines which will attend to all requisite preparedness functions and promote flexibility and simplicity with regard to choice of methods and equipment. Furthermore, the functional requirements for the model for it to be auditable in accordance with the internal control principle.

The project is divided into two subprojects:

Subproject 1:
Guidelines and requirements for functions, systematics and appraisals of preparedness systems.

Subproject 2:
Guidelines and requirements for preparedness communication.

Both part-projects were started in 1986. The project is expected to be completed in mid-1987, and the economic limit is estimated at NOK 2.3 million.

Scandpower A/S is involved as project consultant.

Continuation of project for flexible hoses, pipes and pipelines in hydrocarbon systems
The project was initiated in 1984 (Phase I) and continued in 1985 and 1986 (Phase III). Its aim is to provide the Norwegian Petroleum Directorate with technical know-how within the area of flexible flowlines, a new technology on the Norwegian Continental Shelf, with a view to preparing regulations

and guidelines plus and consideration of development concepts.

As yet there is little information available on the operation of flexible pipe systems. Combined with the fact that inspection cannot be done by means of conventional methods, this represents the biggest problem in considering the use of flexible hoses, pipes and pipelines.

Lately, the Norwegian Petroleum Directorate has been receiving plans concerning use of flexible risers in connection with floating production installations. Experience from the use of such risers, however, is very limited. The relation between load/ lifetime and error mechanisms may serve as an example of problems associated with such use.

The 1986 project has concentrated on evalulation of experience obtained from the operating phase and flexible risers.

On several occassions meetings have been held with operating companies that have a great deal of experience within the use of flexible pipelines and risers.

Det norske Veritas and Veritec are used as project consultants.

6.3 Administration Branch

PROJECT TITLE	PROJECT EXECUTION AGENCY
Cleaning up North Sea seabed	Norwegian Petroleum Directorate
Infoil 2	Norwegian Centre for Informatics

Cleaning up the North Sea seabed

In 1986, the Norwegian Petroleum Directorate's cleaning up of the North Sea seabed took place on 840 square kilometres of Viking Bank in Block 30/3 and parts of Blocks 30/2 and 30/1. The choice of area was based on recommendations by the fishermens organizations and the fishery authorities. After the area had been surveyed by side scan sonar, the obstructions discovered were further identified by a remotely controlled submersible vehicle. A dynamically positioned vessel and a remotely controlled submersible were then used to remove any objects that could be expected to obstruct efficient fishing in the vicinity.

The clean-up action also revealed a wrecked German submarine at 190 metres depth, sunk by British destroyers in autumn 1939. Furthermore, a wrecked fishing vessel and a 12 metre long whale skeleton were discovered.

Although the wrecks will not be removed by the Norwegian Petroleum Directorate, their accurate positions will be marked on the Hydrographic Survey of Norways fishery maps. Moreover, all sonar and seabed data collected during the clearance action will be submitted to the Hydrographic Survey of Norway.

After the completion of the planned Viking Bank clearance, the remaining share of the 1986 grants was used to continue the clearance of pipes from the Egersund Bank. These include some 200 large steel pipes, probably part of a deck cargo lost in bad weather. The pipes were discovered during the state-financed clean-up last year. Twenty-one pipes were then removed, and 55 pipes were cleared this year.

The firm of Bergen Underwater Services A/S was responsible for the job which had a cost limit of NOK 4.7 million in 1986. The clean-up action executive committee, which consists of representatives from the Directorate of Fisheries, Norwegian Fishermens Association and Norwegian Industry Association for Oil Companies (NIFO), concluded that the 1986 efforts were a success and that the action should be repeated in the same way next year.

Infoil 2 – Anglo-Norwegian data base for offshore-related research projects

The work on the data base Infoil 2 has in 1986 mainly concentrated on:

- arranging data for production of a new edition of a printed data base catalogue,
- contact with NLDC – Newfoundland and Labrador Development Corporation – of St. Johns, Newfoundland, and COGLA – Canada Oil and Gas Lands Administration – of Ottawa, Ontario, concerning Canadian input of project data to the base and marketing of the on-line service in Canada.

The new catalogue will be ready for printing in the beginning of 1987 and contain:

From Norway	332 project entries
From Great Britain	242 project entries
From the USA	104 project entries
From the Far East	3 project entries
In all	681 project entries

In comparison, the 1984 catalogue contained 522 project entries.

506 new project entries were included in 1986, so that by the end of the year the data base contained information on a total of 1825 projects.

836 of these come from Great Britain, 882 from Norway, 104 from the USA and three from the Far East.

In 1986, the data base was accessed for 14.5 hours by external on-line users in all the Nordic countries, England, Scotland and France.

The contact with Canada has resulted in meetings, testing of the Norwegian software POLYDOC at NDLC and negotiations with both NLDC and COGLA.

A final answer from NDLC will be given on 1 April 1987, while negotiations with COGLA will continue in 1987.

7. International Cooperation

7.1 Aid to foreign countries
In 1986 the Norwegian Petroleum Directorate's involvement in the Norwegian Development Aid (NORAD) programs was concentrated primarily on Tanzania, Mozambique and to a lesser extent the Seychelles. In these countries the Directorate was primarily occupied with general data processing, processing and storage of seismic data tapes, data interpretation, guidance of consultants brought in to conduct interpretational and seismic reprocessing work, assistance with establishing an archives system (Tanzania) and, finally, guidance to NORAD-supported consultants in Mozambique and Tanzania.

A detailed survey of "Basin Development in Southern Africa" was completed by the Norwegian Petroleum Directorate in the report period. The Directorate used this survey, in conjunction with a 1986 study of "Basin Development on Africas East Coast and the Western Indian Ocean", when presenting a study at a seminar organized by the "Southern Africa Development Cooperation Conference" (SADCC) in Arusha, Tanzania in November 1986. This study, which looked at the entire area in southern Africa was a key submission in a conference in which the other studies covered specific areas or countries and thereby provided a reference framework whereby to assess the areas potential.

The Norwegian Petroleum Directorate also looked at the petroleum potential in the southern parts of Bangladesh.

Other NORAD projects in which the Norwegian Petroleum Directorate has been involved include:

a. India
Assistance in planning NORAD aid to the "Institute of Ocean Engineering and Technology" run by the Indian state oil company, ONGC.

b. Botswana
Assistance with geological appraisal of basins to lay the foundations for negotiations with oil companies applying for exploration licences in that country.

c. Peoples Republic of South Yemen
Preliminary study trip to look at research activity and assess the countrys future aid requirements.

The Norwegian Petroleum Directorate also posted a divisional engineer to Tanzanias state oil company, TPDC. In recent years the Directorate has provided the principal storage space for geological data from Tanzania. The data bank was transferred to Tanzania in 1986.

7.2 European Diving Technology Committee EDTC
The Norwegian Petroleum Directorate has worked actively in this group, in which most European nations participate. The objectives of the organization are to make recommendations to member countries in questions regarding diver safety. Work is done to improve harmonization and standardization designed to improve safety of diving operations. The Directorates representative held the office of chairman for the two-year period 1985–86.

7.3 Association of Offshore Diving Contractors AODC
AODC Norway took part in three working groups which the Norwegian Petroleum Directorate took the initiative to set up. One of the working groups has completed its task which resulted in a standard for qualification requirements for diving supervisors.

7.4 Joint exercise "Bright Eye"
Total emergency preparedness in the North Sea includes the rescue services of several countries. In order continually to improve preparedness and cooperation, "Bright Eye" exercises are held annually, involving several nations. These exercises also cover scenarios embracing petroleum installations.

The exercises provide a good basis for appraisal of the operating companies tailoring of their contingency arrangements to assist others. The Norwegian Petroleum Directorate follows the exercises carefully.

7.5 International organizations CIRIA/UEG
Since 1980 the Norwegian Petroleum Directorate has been a member of CIRIA/UEG, UK. This is a research and information institution carrying out a long series of important research projects in connection with the oil activity. The projects have been very relevant to the areas of responsiblity and tasks of the Directorate's Safety and Working Environment Division. The professional cooperation established and information source it represents makes CIRIA very useful, for example in safety appraisals and regulatory revision on the Norwegian Continental Shelf.

7.6 Welding Institute

The Norwegian Petroleum Directorate has been a member of the Welding Institute since 1981. The WI is the leading institute in the offshore field and is very active in research, training and consultancy services. Membership provides consultancy assistance, project participation and updated information on the most recent materials and welding technology.

7.7 CCOP/ASCOPE/NECOR

The Norwegian Petroleum Directorate participates in a program of development of safety regulations for petroleum activity under the auspices of the United Nations system of agencies. This particular program is directed at East Asian countries (Thailand, Malaysia, Indonesia, the Philippines and China) and is administered by CCOP/ASCOPE/NECOR.

NECOR is the Norwegian subdivision of ECOR, the Engineering Committee on Oceanic Resources, the UN advisory subcommittee for exploitation of subsea resources. Norwegian authorities contributed roughly one million kroner to the program in 1986.

A work program extending over five years from 1985 was set up in which individual countries develop laws and regulations in the areas of highest priority. The Norwegian Petroleum Directorate will take part in this activity using specialists in the individual fields so as to assist the implementation of the program.

Participating countries have to varying degrees begun this work, and assistance from NECOR has so far been limited to courses and seminars within safety-related fields.

7.8 European Economic Community EEC

The Norwegian Petroleum Directorate keeps abreast of the work done in the EEC regarding harmonization of safety requirements as these relate to petroleum activity offshore. Norway has observer status at meetings arranged by the Community under the heading "Safety and Health in the Oil and Gas Extractive Industries".

In 1986 the Directorate was consulted in connection with contacts between the Ministry of Local Government and Labour and the EEC Commission regarding closer cooperation in working environment and safety matters.

7.9 International Labour Organization ILO

The ILO's Petroleum Committee held its tenth session in Geneva on 9–17 April 1986. Twenty-three countries took part with tripartite delegations. The Norwegian Petroleum Directorate was represented in the Norwegian delegation together with representatives of the government and both sides of industry. Several problems concerning safety and working environment efforts in the petroleum industry were thoroughly discussed. Issues particularly relating to diving and subsea operations were highlighted.

7.10 Northwest European collaboration

The fifth Northwest European conference on "Safety and Pollution Safeguards in the Development of North-West European Mineral Resources" was held in Copenhagen on 3–5 November 1986. Countries participating were Belgium, Denmark, Eire, France, the Netherlands, Norway, Great Britain, Sweden and West Germany. Several international organizations attended the Copenhagen conference as observers.

The conference was a continuation of the London conference of 1984. In addition to reviewing the material presented to the conference, the question of future mode of operation was discussed. It was decided to set up a working group to look into the matter and make proposals for change in the modus operandi as necessary. The working groups report will be discussed in separate meetings where West Germany will provide the secretariat and organize the practical details. The Netherlands undertook to provide the secretariat and chairmanship for the work following from the decisions made in the West German meeting.

7.11 International Maritime Organization IMO

In the light of the "Ocean Ranger" accident the IMO in 1986 took up the issue of international qualification requirements for key figures on mobile installations engaged in in petroleum activity offshore. This work is done in the "Sub-Committee on Training and Watchkeeping" which has set up an ad hoc group for the purpose. The Norwegian Petroleum Directorate is represented in the Norwegian delegation. Norway was given chairmanship of the working group, which is expected to conclude its work in 1988.

7.12 International Standardization Organization ISO

The Norwegian Petroleum Directorate is participating in the work of standardization of technical measurement performed by the ISO. International standards apply for metering of oil and gas. To assist the further development of international standards, the Directorate sits on the technical committees working with oil and gas measurement.

In order to make Norwegian work in this area more efficient, a national measurement technology forum has been set up in which the Directorate participates. This forum was responsible for organization of an international meeting of the ISO technical committee in Stavanger (TC28). The Norwegian Petroleum Directorate participated in national meetings as well as international meetings of TC30/SC2 and TC28/SC2.

8. Statistics and Summaries

8.1 Units of measurement

The Norwegian Petroleum Directorate normally utilizes the International System of Units, or SI system. This system is also recommended for use by the oil companies operating on the continental shelf. However, other units than those whose use is allowed in the SI system have a very strong position in the petroleum industry for historical reasons.

Some concepts and abbreviations occur in connection with production data for oil and gas and are connected with the units of measurement. Some of these are mentioned briefly below.

Measurement – oil

An exact measurement of an oil quantity by volume must refer to a more closely defined measuring state characterized by pressure and temperature. This is necessary because the volume of an oil quantity varies with its pressure and temperature. The pressure and temperature which the measured oil volume refers to is normally its "reference state". The two most common reference states are a) 60 degrees F, 0 psig and b) 15 degrees C, 1.01325 bar.

Pressure and temperature standards other than these may also occur. It should be noted that expressions like "standard state", "barrels at standard conditions", etc are ambiguous unless the pressure and temperature referred to are defined.

Reference condition b) is recommended for use by the International Standardization Organization, ISO. Moreover, this reference condition was introduced as a Norsk Standard in 1979, NS 5024 (see Section 8.2). The Norwegian Petroleum Directorate is working to have this reference condition established in the petroleum industry.

Exact conversion of an oil volume from one condition to another requires the use of special tables. For estimated values, however, the volume at 60 degrees F, 0 psig corresponds approximately to the volume at 15 degrees C, 1.01325 bar.

Ordinary units/abbreviations

Sm^3 = standard cubic meter. Temperature and pressure references must be given for the unit to have an unambiguous meaning.

Barrels at standard conditions = Traditional American unit. Reference condition normally 60 degrees F and 0 psig.

Conversion

1 Sm^3 corresponds to approx 6.29 barrels at standard conditions.

Measurement – gas

To an even greater extent than for oil volumes, the numerical value of a gas volume will depend on the pressure and temperature to which it is referred. Four reference states are normally employed: a) (60 degrees F, 14.73 psia), b) (60 degrees F, 14.696 psia), c) (15 degrees C, 1.01325 bar), d) (0 degrees C, 1.01325 bar). Reference states a), b) and c) are usually termed "standard conditions", d) "normal conditions".

A volume cannot be converted exactly from one state to another without knowing the physical properties of the gas. For estimates, however, the volume of the same quantity of gas can be assumed to be approximately equal in states a), b) and c), and the volume of this quantity is 5 per cent less in state d).

Common abbreviations

SCM or Sm^3 =	Standard cubic meter
Nm^3 =	Normal cubic meter
Scf (Scuft) =	Standard cubic feet

Temperature and pressure references must be given for the unit to be unambiguous.

Conversion

1 Sm^3 corresponds to approximately 0.95 Nm^3

1 Sm^3 corresponds to approximately 35.3 Scf.

Quality measurement – oil and gas

Density or relative density is often used to describe the composition of an oil or gas. A low density value indicates that the oil or gas is made up of light components.

Oil

a) Specific gravity 60/60 degrees F
The relative density of oil in relation to water. Oil and water at temperature 60 degrees F and pressure corresponding to atmospheric at the place of measurement. The figure is undenominated.

b) API gravity at 60 degrees F
Specific Gravity 60/60 degrees F expressed on an enlarged scale. Units are degrees API. Conversion by this formula:

$$\text{API-Gravity at } 60^{\circ}\text{F} = \frac{141.5}{\text{Spesific Gravity } 60/60^{\circ}\text{F}} - 131.5$$

c) Density at 15 degrees C
Absolute density at temperature 15 degrees C and pressure corresponding to atmospheric at the place of measurement.

Gas

a. Specific gravity
The relative density of gas in relation to air. The content of this concept is not exactly defined unless the temperature and pressure are given. Very often however, no temperature or pressure references are given for specific gravity. For rough calculations this is not very important, as the differences between the values which may be measured/calculated for the most often used reference states are very small.

Registration of oil and gas in oil equivalents

Oil and gas are often measured in tons oil equivalent in contexts where an exact registration of amount or quality is not required. Conversion is based on the amount of energy liberated in the combustion of the oil or gas. In many cases, the amount of energy in a ton of oil will be close to the amount of energy in 1000 Sm^3 gas. This conversion factor is very easy to employ, at the same time as the difference in quality between oil and gas is so large – during processing, storage, distribution and application – that it would not be correct to express the conversion factor more accurately. Normal practice is therefore that:

1 ton oil equivalent (toe) corresponds to 1 ton oil or 1000 Sm^3 gas

8.2 Standard reference conditions

These figures are taken from Norsk Standard NS 4900 – ISO 5024, Standard Reference Conditions, prepared by the Norwegian Standardization Organization (NSF) and reproduced by agreement with the NSF:

- Petroleum, liquid and gas
- Measurement
- Standard reference conditions

The standard contains the English version of the International Standard ISO 5024–1976 and a Norwegian translation. If not otherwise agreed the Norwegian text is binding.

Introduction

For many years the results from measurements carried out on petroleum and petroleum products in international trade have been corrected to atmospheric pressure and 60 degrees F.

The global tendency to exclusive use of the international system for units of measurement (SI) requires that pressure and temperature are stated in these units. At the same time one is trying to retain the habitual values as far as this is possible.

The hope is that the creation of one set of common standard reference conditions will simplify the demands of world trade.

Introduction and validity

The standard stipulates standard reference conditions for pressure and temperature for measurements carried out on both liquid and gaseous petroleum and its products.

Standard reference conditions

The standard reference conditions for pressure and temperature for use in connection with measurements of both liquid and gaseous petroleum and its products shall be 101.325 kPa*) and 15 degrees C except for liquid hydrocarbons with a vapour pressure higher than atmospheric pressure at 15 degrees C. In this case the standard pressure should be the equilibrium pressure at 15 degrees C.

8.3 Exploration and appraisal drilling on the Norwegian Continental Shelf in 1986

From the start of exploration activities for petroleum in the Norwegian sector of the North Sea in 1966 until 1 January 1987, a total of 533 exploration wells were drilled on the Norwegian Continental Shelf. Of these 385 were exploration wells and 147 appraisal wells. As of the same date, 504 had been concluded. Twenty-five wells were suspended for different reasons (typical reasons being suspension for later testing, possible completion as a production well or later extension or plugging), and four are being drilled. The wells were drilled by 18 different operating companies.

Thirty-six wells were spudded in 1986, 26 for exploration and 10 for appraisal purposes. They were drilled by eight operating companies, three of them Norwegian. The Norwegian companies drilled 27 wells, or 75 per cent.

Work was also restarted in 1986 on seven suspended exploration wells, all of which were completed.

Seventeen of the wells spudded in 1986 were drilled north of Stad, two in Troms and 15 off mid-Norway.

Drilling took place in 27 blocks, 13 in the south, two in Troms and 12 off mid-Norway. Forty-six exploration wells were completed and four suspended during the year.

As of 31 December 1986 some 1,683,297 meters of exploration wells had been drilled, including 123,771 meters in 1986.

Average total depth of the wells completed in

*) Note that 101,325 kPa = 1.01325 bar = 1013.25 mbar = 1 atm.

1986 was 3353 meters. Average water depth was 236 meters.

For drilling on the Norwegian Continental Shelf, 62 different drilling platforms have been used, five of them under more than one name. Forty-four were semi-submersibles, 11 jack-ups, five drillships and two fixed installations. During 1986 some 15 drilling vessels took part in exploration activity. One of these, the drillship "Bucentaur", arrived on the shelf during the year and was used solely to plug a wellbore.

Ten drilling vessels were taken out of exploration drilling offshore in 1986. The largest decline occurred from August, when 12 vessels were active, until November, when only four vessels continued in operation.

FIG. 8.3.a
Seasonal variations in drilling activity 1966–1986

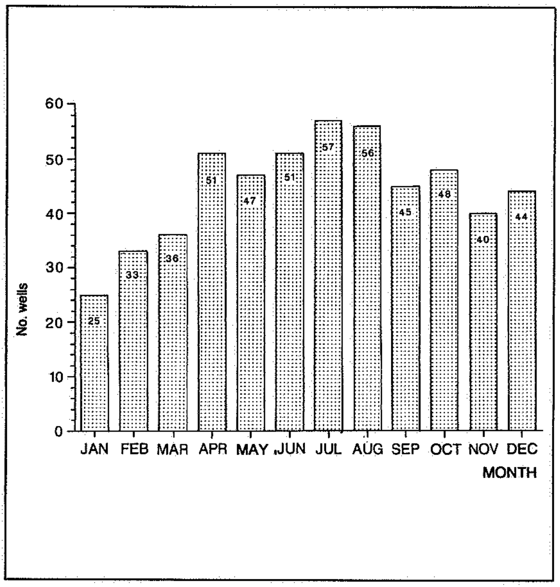
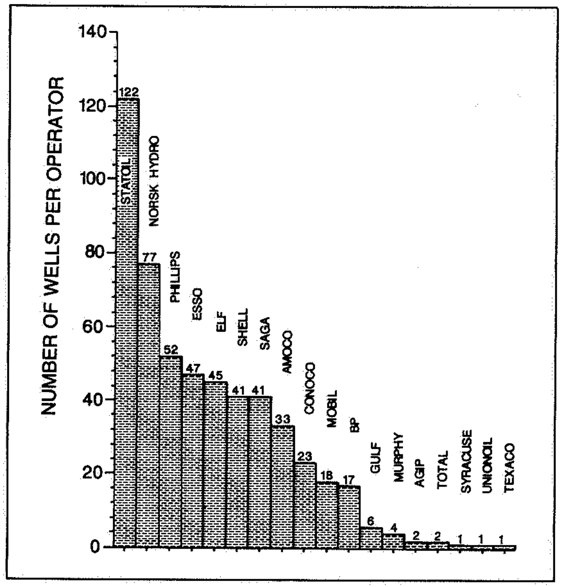


FIG. 8.3.b
Operators on the Norwegian Continental Shelf. 533 exploration wells were drilled as of 31 December 1986



TAB 8.3.a
Spudded wells

YEAR SPUDDED	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	Total
EXPLORATION WELL	2	6	10	12	11	11	11	17	13	17	20	12	14	18	26	26	36	33	35	30	26	386
APPRAISAL WELL			2	1	6	5	3	5	5	9	3	8	5	10	10	13	13	7	12	20	10	147
TOTAL EXPLORATION DRILLING	2	6	12	13	17	16	14	22	18	26	23	20	19	28	36	39	49	40	47	50	36	533
PRODUCTION WELL								1	18	24	7	34	50	36	27	16	22	23	33	47	46	384
TOTAL NO OF WELLS	2	6	12	13	17	16	14	23	36	50	30	54	69	64	63	55	71	63	80	97	82	917

TAB 8.3.b
Monthly activity on the Norwegian shelf 1986

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec		
Drilled at year-end	1985/86														11 wells
Spudded	1986	4	3	5	4	3	3	5	2	1	3	2	1	36 wells	
Re-entries	1986	1		2		1	2			1				7 wells	
In progress	1986														54 wells
Completed	1986	4	2	7	5	3	3	4	5	6	4	2	1	46 wells	
Suspended	1986			2		1		1						4 wells	
Adandoned	1986														50 wells
Drilling under progress															4 wells
Rig days: Foreign		31	28	31	30	31	30	43	62	59	1			346	10.5 %
Rig days: Norwegian		369	336	335	268	237	282	301	262	147	147	134	119	2937	89.5 %
Rig days: Total		400	364	366	298	268	312	344	324	206	148	134	119	3283	100 %

FIG. 8.3.c

Participation by Norwegian operating companies in drilling activity. Percent of operating days. 1975–1986.

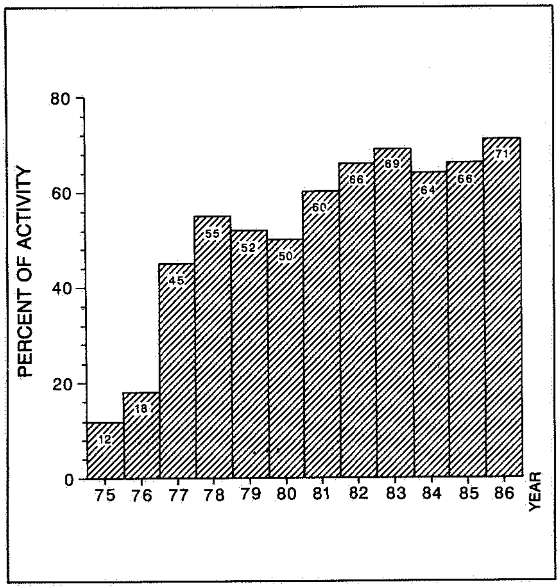
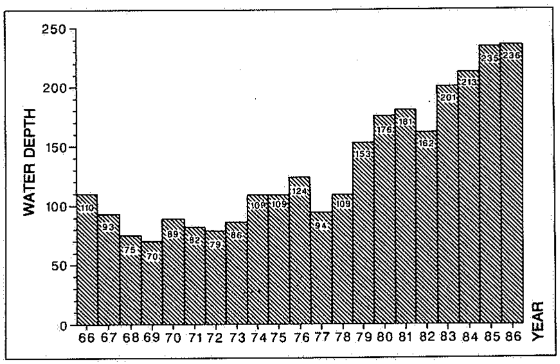


FIG 8.3.d

Average water depth 1966–1986



The deepest bore on the Norwegian Continental Shelf is Well 30/4–1 for which BP is operator. Drilling started in November 1978 and terminated in March 1979.

The greatest water depth so far drilled in is 391 meters by Amoco as operator for exploration well 34/2–4.

Since 1978 and excluding 1982 a relatively gradual increase in water depth has occurred for drilling operations, from an average 94 meters in 1977 to 236 meters in 1986 (Figure 8.3.d). Part of the reason for this is that the majority of major discoveries in shallow water were made before 1977 and that new technology has enabled operators to produce from and drill at greater depths. Drill depth has changed very little.

TAB 8.3.c

Rig days per rig on the Norwegian shelf

Drilling rig	1. quarter	2. quarter	3. quarter	4. quarter	Total
Borgny Dolphin	85	91	59		235
Bucentaur		13			13
Byford Dolphin	68	42	77		187
Dyvi Delta	87	91	91	86	355
Dyvi Stena	90	77	39		206
Henry Goodrich	78		73	1	152
Nortrym	89	83	65		237
Polar Pioneer	90	88	91	87	356
Ross Isle	89	71	42		202
Treasure Hunter	89	41	11		141
Treasure Saga	89	88	90	84	351
Treasure Scout	89	89	90	90	358
Vinni	85				85
West Vanguard		3	92	53	148
West Venture	90	10			100
Zapata Ugland	12	91	54		157
	1130	878	874	401	3283

TAB 8.3.d

Rig days per quarter 1966 – 1986

Year	1. quarter	2. quarter	3. quarter	4. quarter	TOTAL per. year
1966			74	85	159
1967	90	91	168	191	540
1968	144	334	286	244	1008
1969	211	224	268	114	817
1970	64	167	424	286	941
1971	179	180	286	198	843
1972	172	363	560	372	1467
1973	142	205	309	461	1117
1974	490	462	339	367	1658
1975	267	468	523	411	1669
1976	646	451	536	423	2056
1977	225	296	532	564	1617
1978	371	436	485	342	1634
1979	464	548	653	757	2422
1980	936	892	1022	1027	3877
1981	1030	933	1000	1068	4131
1982	1081	1192	1075	1028	4376
1983	1084	920	944	952	3900
1984	943	1044	1193	1053	4233
1985	906	1019	1128	984	4037
1986	1130	878	874	401	3283
	10575	11103	12679	11328	45685

TAB 8.3.e

Exploration wells per operator

Statoil	122	wells
Norsk Hydro	77	«
Phillips	52	«
Esso	47	«
Elf	45	«
Saga	41	«
Shell	41	«
Amoco	33	«
Conoco	23	«
Mobil	18	«
BP	17	«
Gulf	6	«
Murphy	4	«
Total	2	«
Agip	2	«
Syracuse	1	«
Texaco	1	«
Union	1	«
	533	wells

TAB 8.3.f
Exploration wells spudded in 1986

Statoil	12	wells
Norsk Hydro	10	«
Saga	5	«
Conoco	4	«
Shell	2	«
Agip	1	«
Elf	1	«
Total	1	«
	36	wells

TAB 8.3.g
Average water depth and total depth

Year	Average water depth (m)	Average total depth (m)
1966	110	2 737
1967	93	2 599
1968	75	3 495
1969	70	3 143
1970	89	2 983
1971	82	3 101
1972	79	3 712
1973	86	3 089
1974	109	3 078
1975	109	2 954
1976	124	2 949
1977	94	2 719
1978	109	3 502
1979	153	3 375
1980	176	3 115
1981	181	3 235
1982	162	3 314
1983	201	3 155
1984	213	3 116
1985	235	3 208
1986	236	3 353

TAB. 8.3.h
Drilling rigs that have been operating on the Norwegian Continental Shelf

Name of drilling rig	No. of wells	No. of re-entries	Type of rig
Aladdin	1		Semi submersible
Borgny Dolphin (før Fernstar)	25	7	«
Borgsten Dolphin (før Haakon Magnus)	6		«
Bucentaur		1	Drillship
Byford Dolphin (før Deepsea Driller)	15		Semi submersible
Chris Chenery	2		«
Deepsea Bergen	12	1	«
Deepsea Driller (nå Byford Dolphin)	8		«
Deepsea Saga	17	3	«
Drillmaster	6	1	«
Drillship	1		Drillship
Dyvi Alpha	17	2	Semi submersible
Dyvi Beta	7	1	Jack-up
Dyvi Gamma	1		«
Dyvi Delta	15	1	Semi submersible
Dyvi Stena	6		«
Endeavour	2		Jack-up
Fernstar (nå Borgny Dolphin)	3		Semi submersible
Gulftide	3		Jack-up
Glomar Biscay II (før Norskald)	12	1	Semi submersible
Glomar Grand Isle	11	3	Drillship
Glomar Moray Firth I	2		Jack-up
Haakon Magnus (nå Borgsten Dolphin)	2		Semi submersible
Henry Goodrich	2		«
Maersk Explorer	7		Jack-up
Neddrill Trigon	3		«
Neptune 7 (før Pentagone 81)	12		Semi submersible
Northraug	10		«
Norjarl	3		«
Norskald (nå Glomar Biscay II)	26		«
Nortrym	29		«
Ocean Tide	5		Jack-up
Ocean Traveler	9		Semi submersible
Ocean Victory	1		«
Ocean Viking	29	1	«
Ocean Voyager	2		«
Odin Drill	3		«
Orion	7		Jack-up
Pelerin	1		Drillship
Pentagone 81 (nå Neptune 7)	1		Semi submersible
Pentagone 84	3	1	«
Polar Pioneer	5		«
Polyglomar Driller	11		«
Ross Isle	13	3	«
Ross Rig	28		«
Saipem II	1		Drillship
Sedco H	2		Semi submersible
Sedco 135 F	2		«
Sedco 135 g	1		«
Sedco 703	3	1	«
Sedco 704	3		«
Sedco 707	6		Semi submersible
Sedneth I	3		«
Transworld Rig 61	2		«
Treasure Hunter	2	3	«
Treasure Saga	21	1	«
Treasure Scout	18		«
Treasure Seeker	27	4	«
Vildkat	4		«
Vinni	1		«
Waage Drill I	2		«
West Vanguard	15		«
West Venture	11	2	«
Zapata Explorer	13		Jack-up
Zapata Northic	5		«
Zapata Ugland	5	1	Semi submersible
	531	38	
Two wells were also drilled from fixed installations			
Cod Platform	1	1	
Ekofisk B	1		
	533	39	

8.4 Production drilling on the Norwegian Continental Shelf

Since drilling of production wells began in the Norwegian sector of the North Sea in 1973, 384 production wells in all have been spudded.

Information on these production wells is set up in Table 8.4.a.

Tab 8.4.a
Production drilling

Field	Total drilled	Spudded 1985	Producing	Injection/ (observ.)	Drilling in progress	Suspend./ plugged/ compl.
Albuskjell A	11	1	8			3
Albuskjell F	13		7			6
Cod	9		6			3
Edda	10		6			4
Ekofisk A	15		13		1	1
Ekofisk B	23	1	17	1 (1)***	1	3
Ekofisk C	13	1	7	4 * (1)****		1
Ekofisk K	7	1				7
Eldfisk A	28	2	19			9
Eldfisk B	18	3	13		1	4
Frigg (UK)	24		22			2
Frigg	24		22	(2)***		
Gullfaks A	6	3	3		1	2
Heimdal	11		9	(1)****		1
NØ Frigg	7		6			1
Odin	11		11			
Oseberg	9	8			1	8
Statfjord A	38	1	22	14		2
Statfjord B	29	4	19	10		
Statfjord C	20	9	10	7	1	2
Tommeliten	2	2			1	1
Tor	14		10			4
Ula	3	3	2		1	
Valhall	26	6	19		1	6
V. Ekofisk	13	1	11		1	1
	384	46	262	36 ** (3)*** (2)****	10	71

* Wells are prod./inj. wells, depending on gas sale.
** 4 wells are prod./inj. wells, depending on gas sale.
*** Wells are observation-/production wells
**** Well is observation-/injection well

262 wells	producing (160 oil, 38 condensate and 64 gas)
22 wells	are shut down/plugged
36 wells	are injection wells
3 wells	are observation-/production wells
2 wells	are observation-/injection wells
10 wells	drilling in progress (2/8-A-16 A, 2/4-A-12, 34/10-A-5 H, 7/12-A-2, 2/4-B-10 A, 2/4-D-3, 30/9-B-26, 1/9-A-2 h, 2/7-B-18 A and 33/9-C-31)
1 well	is shut down (10/1-A-12) and drilled deeper with English permit No and new designation (10/1-A-25).
16 wells	is susp. of td (2/4-K-4, 2/4-K-13, 2/4-K-22, 34/10-A-3H, 30/9-B-21, 30/9-B-29, 2/4-K-12, 2/8-A-11 S2, 30/9-B-25, 30/9-B-23, 30/9-B-49 H, 30/9-B-20, 34/10-A-3 H, 30/9-B-24, 30/9-B-27 and 1/9-A-1 H.
1 well	is susp. after setting of 13 3/8Z casing (2/4-K-23(
3 wells	is susp. after setting of 20" casing (25/4-A-1, 33/9-C-4 and 5)
1 well	is susp. after setting of 30" casing (2/4-K-2)
1 well	is susp. in 30" open hole (2/4-K-3)
26 wells	have never produced
384 wells	

Of these wells, 262 are production (oil, gas and condensate), 36 are water or gas injection, 3 are observation/ production, 2 are observation/ injection wells, 45 are temporarily out of commission, suspended for completion later or for other reasons and 26 are dry. Ten production wells were being drilled at the end of the year.

As of 1 January 1987 15 fields are producing, with 21 production platforms and one seabottom completion (North-East Frigg).

Three new fields have come on stream in 1986; the Heimdal field with production start 9 February 1986, the Ula field, which started drilling 9 July 1986 and came on stream 6 October 1986, and the Gullfaks field, which began producing from seabottom completed wells 22 and 23 December 1986.

On the Oseberg field test production began 22 September 1986 from test well 30/9-T-1 and production/ test ship "Petrojarl I". The aim of this production was to obtain reservoir data. This is the first time a production/ test ship and this kind of test production have been used on the Norwegian shelf.

Production drilling on the Tommeliten field was begun 22 September 1986 with the drillship "Ross Isle". The boreholes on the field are to be seabottom-completed. At the turn of the year three drillships were engaged in production drilling.

On the Gullfaks field "Deepsea Bergen" is dril-

TAB 8.4.b
Production wells spudded 1986

Lic. No.	Well No.	Spudded	Completed	Operator	Field	Comments
P 234	33/12-B-20	16.06.86	13.07.86	Mobil	Statfj. B	
P 324	30/9-B-21	22.09.85	13.01.86	N.Hydro	Oseberg	Susp. at TD
P 326	25/4-A-9	07.11.85	13.11.85	Elf	Heimdal	
		09.12.85	03.01.86			
P 327	25/4-A-5	13.11.85	17.11.85	Elf	Heimdal	
		03.01.86	27.01.86			
P 328	25/4-A-7	17.11.85	21.11.85	Elf	Heimdal	
		16.02.86	10.03.86			
P 329	25/4-A-10	21.11.85	23.11.85	Elf	Heimdal	
		11.03.86	06.04.86			
P 330	25/4-A-11	24.11.85	25.11.85	Elf	Heimdal	
		27.01.86	16.02.86			
P 331	33/9-A-26	15.10.85	29.11.85	Mobil	Statfj. A	
		14.12.85	15.01.86			
		27.01.86	29.01.86			
P 333	34/10-A-2 H	28.10.85	26.11.85	Statoil	Gullfaks A	Plugged
		11.05.86?	15.07.86			
P 334	33/12-B-35	01.12.85	12.01.86	Mobil	Statfj. B	
P 336	2/4-K-12	23.11.85	04.03.86	Phillips	Ekofisk K	
P 337	33/9-C-35	24.11.85	29.11.85	Mobil	Statfj. C	Water injection
		11.02.86	21.03.86			
P 338	33/9-C-14	29.11.85	22.01.86	Mobil	Statfj. C	Water injection
P 339	34/10-A-3 H	28.11.85	30.01.86	Statoil	Gullfaks A	
P 340	33/9-A-40	01.02.86	01.06.86	Mobil	Statfj. A	
P 341	30/9-B-29	13.01.86	18.03.86	N.Hydro	Oseberg	Susp. at TD
P 342	33/12-B-14	13.01.86	04.03.86	Mobil	Statfj. B	Water injection
P 343	34/10-A-4 H	31.01.86	02.05.86	Statoil	Gullfaks A	
P 344	2/8-A-21	07.02.86	21.03.86	Amoco	Valhall	
P 345	2/4-K-23	04.03.86	31.03.86	Phillips	Ekofisk K	Susp.after 13 3/8
P 346	1/6-A-7	19.02.86	28.06.86	Phillips	Albuskjell	
P 347	33/12-B-22	04.03.86	29.04.86	Mobil	Statfj. B	
P 348	30/9-B-27	18.03.86	19.05.86	N.Hydro	Oseberg	Susp. at TD
P 349	33/9-C-16	23.03.86	07.05.86	Mobil	Statfj. C	
P 350	33/12-B-6	30.04.86	03.06.86	Mobil	Statfj. B	
P 351	2/8-A-16 A	04.04.86	17.06.86	Amoco	Valhall	
P 352	34/10-A-2 AH	10.05.86	28.07.86	Statoil	Gullfaks A	
P 353	33/9-C-32	08.05.86	08.07.86	Mobil	Statfj.c	
P 354	30/9-B-25	19.05.86	08.07.86	N.Hydro	Oseberg	Susp. at TD
P 355	33/9-C-9	08.06.86	08.07.86	Mobil	Statfj.C	Water injection
P 356	2/8-A-11 A	19.06.86	19.06.86	Amoco	Valhall	
P 357	2/4-C-11	16.06.86	15.10.86	Phillips	Ekofisk	
P 358	30/9-B-49 H	09.07.86	07.09.86	N.Hydro	Oseberg	Testing
P 359	30/9-B-20	09.07.86	26.08.86	N.Hydro	Oseberg	Susp. at TD
P 360	2/8-A-18 A	13.08.86	05.10.86	Amoco	Valhall	
P 361	33/9-C-37	08.07.86	16.08.86	Mobil	Statfj.C	
P 363	2/7-B-5 A	06.07.86	22.08.86	Phillips	Eldfisk B	
P 364	2/7-B-18 A	01.12.86		Phillips	Eldfisk B	Drilling
P 365	7/12-A-10	09.07.86	04.10.86	BP	Ula	
P 366	33/9-C-19	15.08.86	05.10.86	Mobil	Statfj.C	Water injection
P 367	2/7-A-23 A	18.08.86	26.08.86	Phillips	Eldfisk A	
P 368	30/9-B-23	29.08.86	13.11.86	N.Hydro	Oseberg	Susp. at TD
P 369	2/7-A-17	02.09.86	10.11.86	Phillips	Eldfisk A	
P 370	1/9-A-1 H	22.09.86	24.11.86	Statoil	Tommeliten	Susp.
P 371	2/8-A-21 A	07.10.86	06.12.86	Amoco	Valhall	Water injection
P 372	33/9-C-25	06.10.86	22.11.86	Mobil	Statfj.C	
P 373	2/7-B-10 A	27.08.86	27.10.86	Phillips	Eldfisk B	
P 374	30/9-B-24	14.11.86	20.12.86	N.Hydro	Oseberg	Susp. at TD
P 375	7/12-A-2	29.10.86		BP	Ula	Drilling
P 376	2/4-D-3	13.11.86		Phillips	V.Ekofisk	Drilling
P 377	33/9-C-4	14.11.86	20.11.86	Mobil	Statfj.C	20" casing is set
P 378	2/8-A-3 A	11.11.86	20.11.86	Amoco	Valhall	
P 379	33/9-C-5	20.11.86	25.11.86	Mobil	Statfj.c	20" casing is set
P 380	1/9-A-2-H	19.11.86		Statoil	Tommeliten	Drilling
P 381	33/9-C-31	26.11.86		Mobil	Statfj.C	Drilling
P 382	34/10-A-5 H	04.12.86		Statoil	Gullfaks	Drilling
P 383	7/12-A-6	05.10.86	28.10.86	BP	Ula	
P 384	2/4-B-10 A	17.12.86		Phillips	Ekofisk B	Drilling
P 386	30/9-B-26	21.12.86		N.Hydro	Oseberg	Drilling

TAB. 8.4.c
Drilling rig days for production drilling by mobile installations 1986

Rig name	1. qu	2. qu	3. qu	4. qu	Total for year
Deepsea Bergen	90	84	88	77	339
Dyvi Beta	91				91
Ross Isle			9	91	100
Treasure Hunter			61		61
Vildkat	73	92	92	92	349
	254	176	250	260	940

ling seabed-completed wells to be connected to the Gullfaks A platform, and on the Oseberg field "Vildkat" is engaged in pre-drilling of production wells for the Oseberg B platform. All three drilling platforms are semi-submersible.

As of 31 December 46 production wells have been spudded in 1986. Twenty-eight are producing, 6 are water injection and 12 are suspended for later completion.

8.5 Production of oil and gas

Production of oil and gas on the Norwegian Continental Shelf in 1986 was 67.9 million toe. Production in 1985 was 63.9 million toe. In Tables 8.5.a-f and Figures 8.5.a and b, production on the Norwegian Continental Shelf is presented in more detail.

The data in Table 8.5.a show the Norwegian share of Statfjord, Frigg and Murchison. NGL for the Ekofisk area, Murchison, Valhall and Statfjord are included in the figures for oil. The figures for gas in Table 8.5.a indicate the amounts sold for all fields. Condensate is included in the figures for the Frigg area.

TAB 8.5.a
Production in mill t.o.e.

1986	Oil	Gas	Total
Ekofisk-area	8 660	7 303	15 963
Statfjord	29 393	2 724	32 117
Frigg-area	000	12 795	12 795
Valhall	2 258	430	2 687
Murchison	969	52	1 021
Heimdal	000	2 311	2 311
Ula	726	38	764
Oseberg	252	0	252
Gullfaks	35	0	35
Total 1986	42 283	25 653	67 946
Total 1985	38 445	25 491	63 936

FIG. 8.5.a
Oil and gas production on the Norwegian shelf per field and total 1971–1986

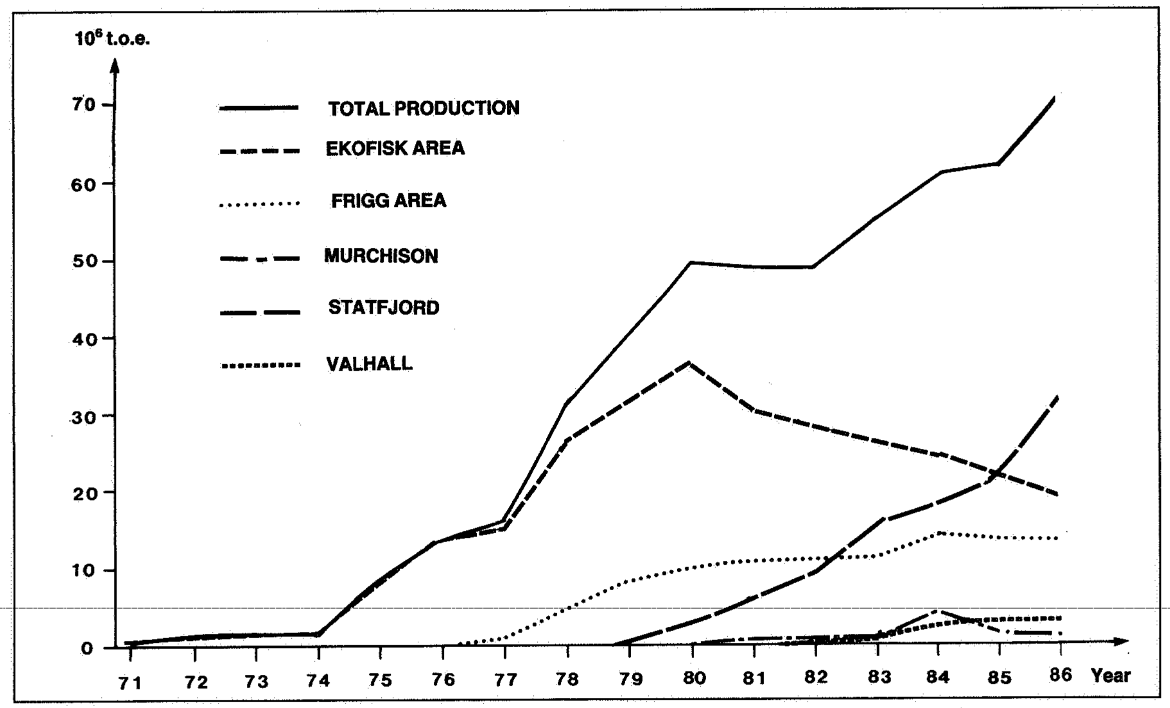
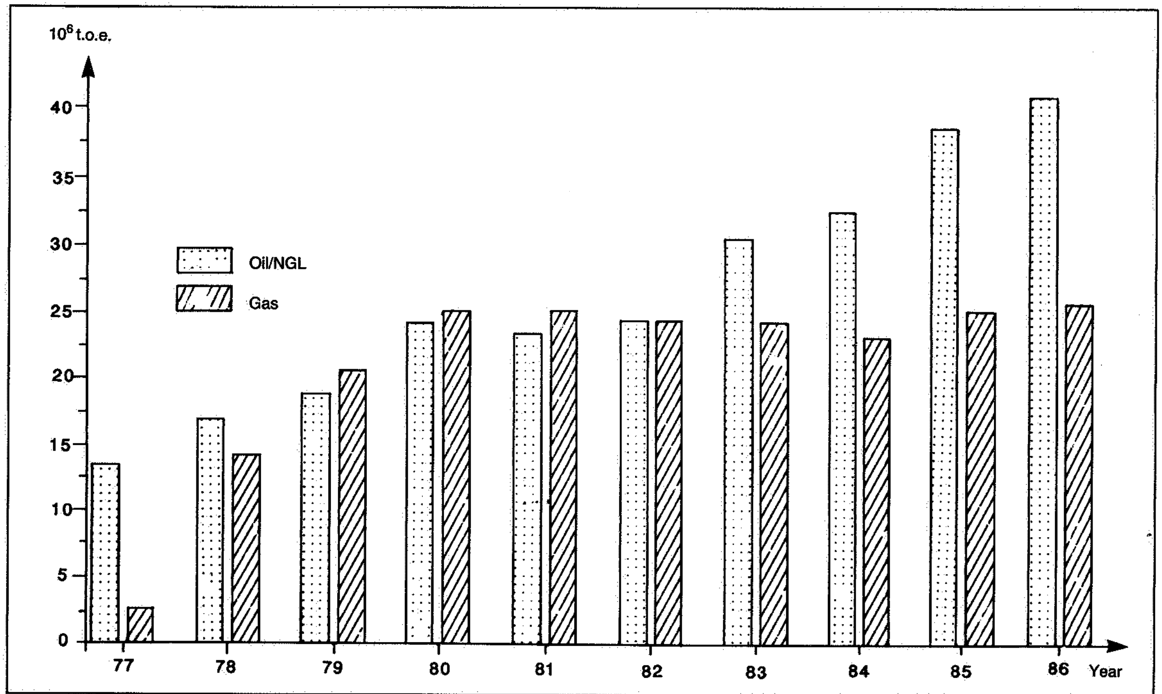


FIG. 8.5.b
Oil/NGL and gas production from the Norwegian shelf 1977–86



TAB 8.5.b
Monthly oil and gas production from the Ekofisk area

1986	Prod oil incl NGL 1 000 Sm^3	Produced gas Mill Sm^3	Injected gas Mill Sm^3	Flared gas Mill Sm^3	Gas consum. (fuel) Mill Sm^3	Stable oil Teesside 1 000 Sm^3	NGL Teesside Ton	Gas sales Emden Mill Sm^3
Jan	1 068	1 059	260	0	66	894	89 165	735
Feb	954	928	201	0	59	802	78 012	675
Mar	1 016	993	146	1	63	854	82 452	743
Apr	331	302	0	0	21	284	24 927	205
May	1 126	1 022	0	1	74	962	82 048	624
Jun	1 047	1 012	0	0	69	890	85 228	581
Jul	1 043	1 049	0	1	72	878	83 902	588
Aug	983	978	0	0	65	829	81 592	621
Sep	921	917	311	0	62	787	68 628	553
Oct	925	950	215	0	60	810	56 291	683
Nov	901	870	181	1	57	765	67 678	636
Dec	949	907	188	1	60	806	75 662	659
Year's total	11 264	10 988	1 502	6	727	9 561	875 585	7 303

TAB 8.5.c
Monthly gas and condensate production from the Frigg area

1986	Gas prod Mill Sm^3	Kondensat produsert Sm^3	Gas inj Mill Sm^3	Gas brent Mill Sm^3	Gas brensel Mill Sm^3	Gas solgt St.Fergus Mill Sm^3	Kondensat St.Fergus Sm^3	Kondensat Ton/Sm^3
Jan	1 546	2 639	0	0	2	1 476	6 075	0.8260
Feb	1 401	2 552	0	0	2	1 335	7 145	0.8263
Mar	1 527	2 567	0	0	2	1 472	9 053	0.8266
Apr	947	905	0	0	2	751	2 409	0.8268
Mai	1 041	2 386	0	0	2	1 001	5 002	0.8261
Jun	804	1 457	0	0	2	807	4 051	0.8261
Jul	848	1 716	0	0	2	796	– 701	0.8247
Aug	892	2 089	0	0	2	793	3 268	0.8256
Sep	884	1 968	0	1	2	850	5 647	0.8243
Okt	1 170	2 437	0	0	2	1 122	7 541	0.8247
Nov	1 202	2 409	0	0	2	1 151	5 728	0.8245
Des	1 190	2 340	0	0	2	1 147	6 132	0.8254
Year's total	13 452	25 466	0	2	25	12 701	61 550	

TAB 8.5.d
Monthly oil and gas production from Murchison

1986	Prod oil Encl NGL 1 000 Sm³	Prod gas Mill Sm³	Injected gas Mill Sm³	Flared gas Mill Sm³	Gas consumed (fuel) Mill Sm³	Stable oil Sullom Voe 1 000 Sm³	Gas sales St Fergus Mill Sm³	NGL Sullom Voe /St Fergus 1 000 ton
Jan	129	8	0	1	1	115	5	5
Feb	114	8	0	1	1	103	5	5
Mar	114	8	0	1	1	101	5	5
Apr	120	8	0	1	1	106	6	5
May	112	8	0	1	1	100	5	5
Jun	103	8	0	1	1	93	4	3
Jul	104	8	0	1	1	92	5	5
Aug	72	5	0	1	1	64	3	3
Sept	35	2	0	0	1	30	1	1
Oct	34	2	0	0	1	29	1	1
Nov	32	2	0	0	1	29	1	1
Des	34	2	0	0	1	30	1	1
Year's total	1003	71	0	7	17	892	41	38

Figures show Norwegian share of Murchison

TAB 8.5.e
Monthly oil and gas production from Statfjord

1986	Prod oil incl NGL 1 000 Sm³	Prod gas Mill Sm³	Injected gas Mill Sm³	Flared gas Mill Sm³	Gas consumed (fuel) Mill Sm³	Gas sales Emden Mill Sm³
Jan	2 944	587	176	13	32	298
Feb	2 715	531	177	8	30	267
Mar	3 002	595	227	12	34	257
Apr	995	194	73	11	12	79
May	2 518	481	144	12	28	237
Jun	2 882	564	178	13	32	288
Jul	3 233	638	257	10	35	278
Aug	3 296	630	295	9	37	233
Sep	2 885	553	224	15	31	237
Oct	3 234	640	238	9	35	282
Nov	3 254	634	254	8	36	268
Des	3 323	645	252	9	37	286
Year's total	34 281	6 693	2 497	129	379	3 010

Figures are Norwegian share of Statfjord: 84,09322%

TAB 8.5.f
Monthly oil and gas production allocated Valhall

1986	Prod. oil incl NGL 1 000 Sm³	Prod. gas Mill Sm³	Injected gas Mill Sm³	Flared gas Mill Sm³	Gas consumed (fuel) Mill Sm³	Stable oil Teesside 1 000 Sm³	NGL Teesside 1 000 tonn	Gas sales Emden Mill Sm³
Jan	229	44	0	2	9	208	12	33
Feb	224	42	0	1	8	203	11	33
Mar	238	45	0	2	9	216	12	35
Apr	68	13	0	2	2	63	3	9
Mai	239	46	0	2	9	217	12	35
Jun	242	47	0	1	9	218	13	37
Jul	242	46	0	1	9	220	12	36
Aug	248	46	0	1	9	225	12	36
Sep	256	48	0	1	8	232	12	38
Oct	271	41	0	1	8	247	13	50
Nov	257	37	0	2	8	244	12	37
Dec	271	41	0	2	9	247	13	51
Year's total	2 784	496	0	17	99	2 538	137	430

8.6 Publications by the Norwegian Petroleum Directorate in 1986

Regulations

- Regulations compendium: "Regelverksamling for petroleums-virksomheten 1986" (Acts, regulations and provisions for the petroleum activity 1986): up-to-date compendium in two volumes with parallel Norwegian and English texts of the regulations and guidelines laid down by the Norwegian Petroleum Directorate and other regulatory agencies. Updated to 1 January 1987.
- Supplementary description of the regulatory supervision etc, within the petroleum activities.

Research reports

- Report 10. Current data 1984. Wave data 1984. (English)
- Safety evaluation decompression tables. (English)
- Flexible hoses, pipes and pipelines carrying hydrocarbons. Report 2. (English).

Geological publications

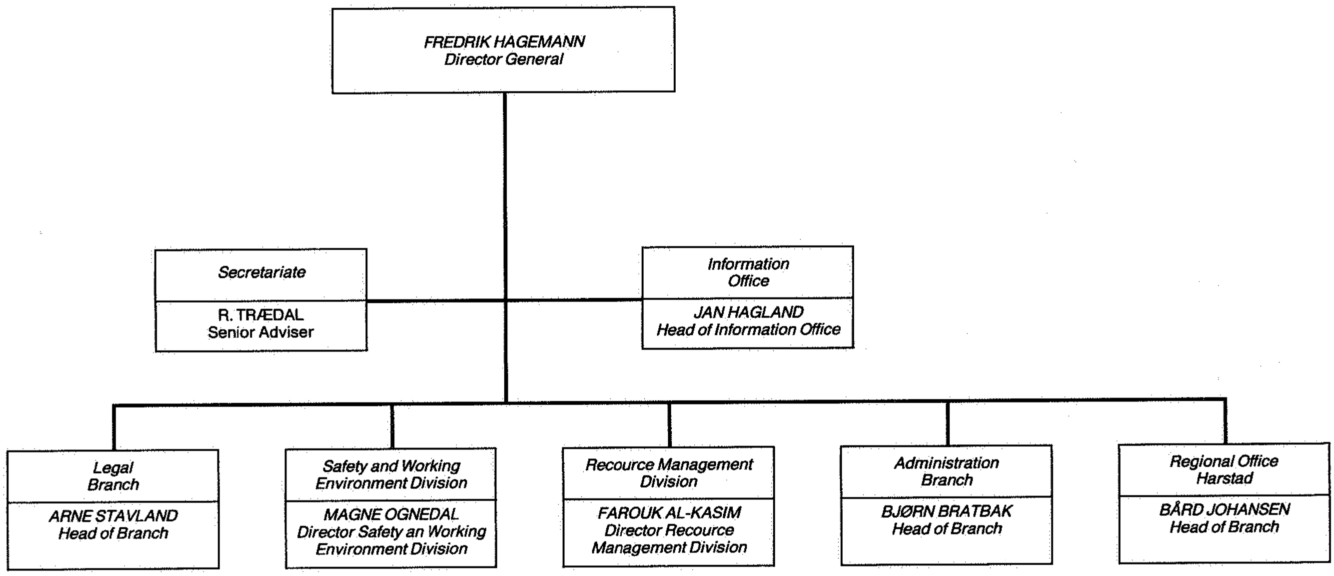
- Well Data Summary Sheets, Vol 11. Borehull fullført 1980 (Well Data Summary Sheets, Vol 11. Wells completed 1980).

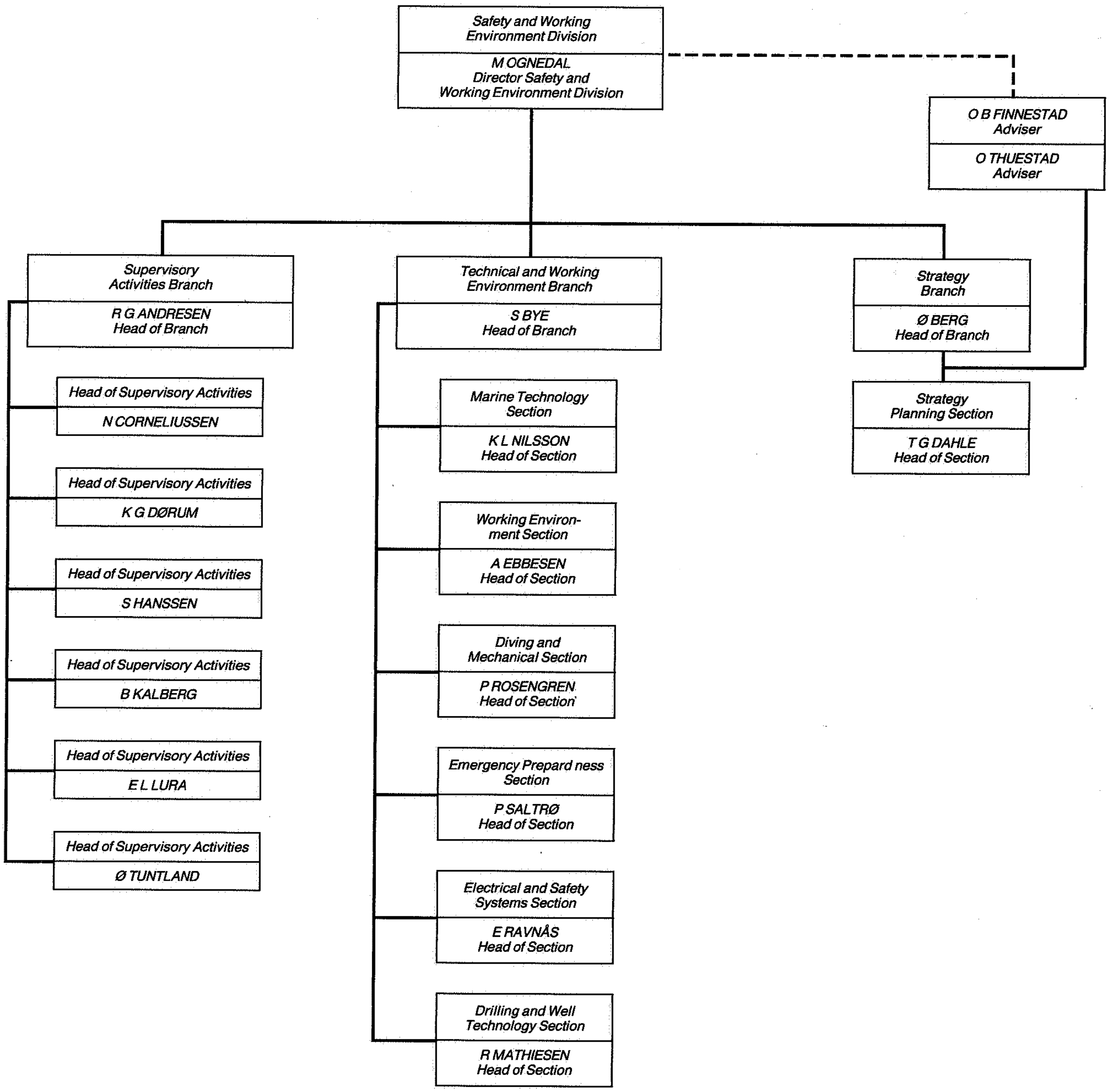
Other publications

- Oljedirektoratets årsberetning 1985 (Norwegian Petroleum Directorate Annual Report 1985) (Norwegian edition)
- NPD Annual Report 1985 (English edition of the above)
- Perspektivanalysen 1985 (Petroleum Outlook) (Norwegian edition)
- Map of the Norwegian Continental Shelf
- Collection of overheads relating to the Petroleum Act
- Handbook for Action Program for Safety and Working Environment Efforts (in Norwegian)
- The Norwegian Petroleum Directorate's projects. Survey of projects carried out by the Norwegian Petroleum Directorate or receiving Directorate support in 1986.

8.7 Organization charts

Charts showing the organization of the Norwegian Petroleum Directorate are included in the figures section below.

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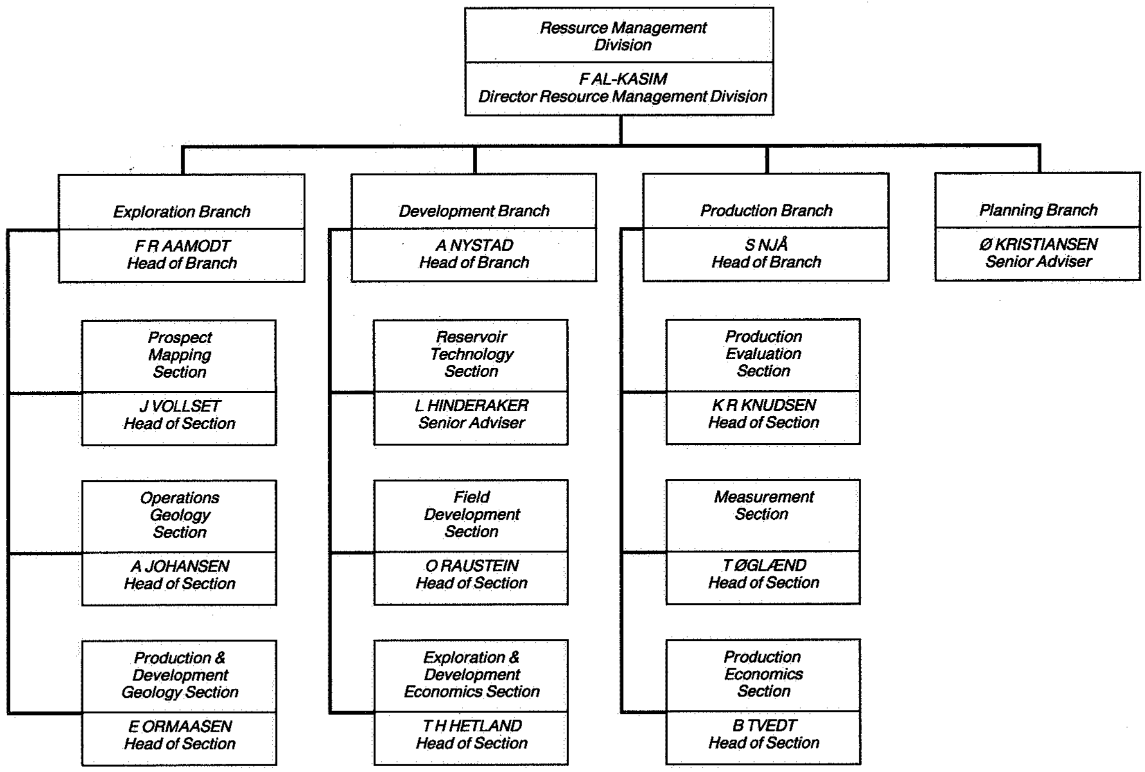
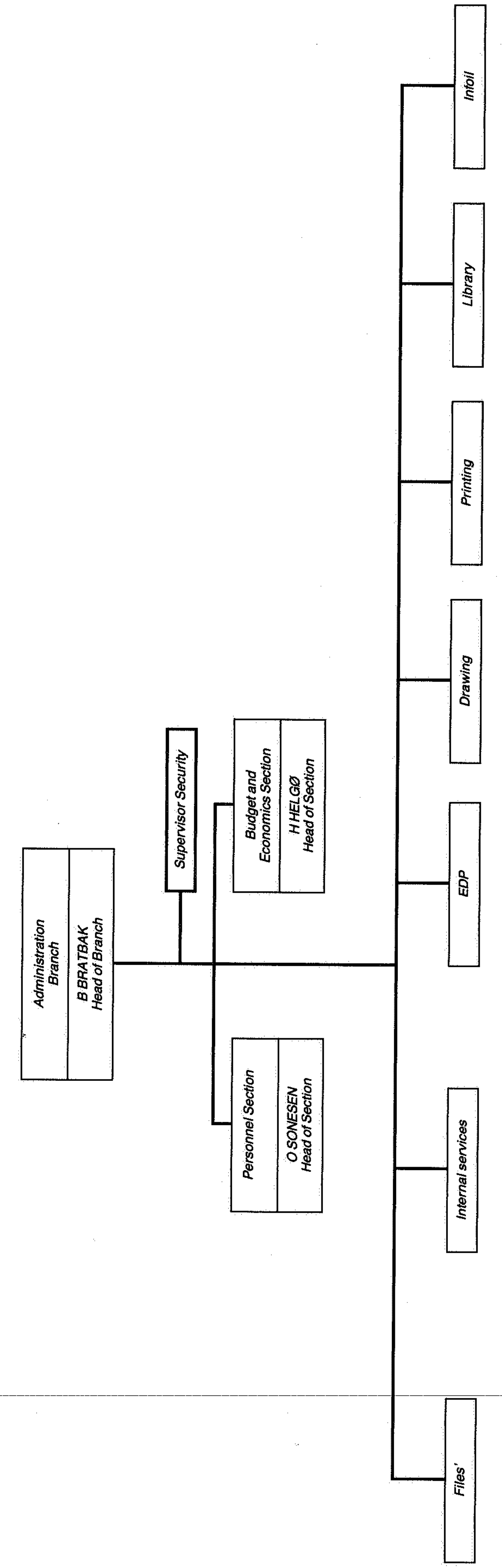
M OGNEDAL Director Safety and Working Environment Division
O B FINNESTAD Adviser
O THUESTAD Adviser
Supervisory Activities Branch
R G ANDRESEN Head of Branch
Technical and Working Environment Branch
S BYE Head of Branch
Strategy Branch
Ø BERG Head of Branch
Head of Supervisory Activities
N CORNELIUSSEN
Head of Supervisory Activities
K G DØRUM
Head of Supervisory Activities
S HANSSEN
Head of Supervisory Activities
B KALBERG
Head of Supervisory Activities
E L LURA
Head of Supervisory Activities
Ø TUNTLAND
Marine Technology Section
K L NILSSON Head of Section
Working Environ- ment Section
A EBBESEN Head of Section
Diving and Mechanical Section
P ROSENGREN Head of Section
Emergency Prepard ness Section
P SALTRØ Head of Section
Electrical and Safety Systems Section
E RAVNÅS Head of Section
Drilling and Well Technology Section
R MATHIESEN Head of Section
Strategy Planning Section
T G DAHLE Head of Section


Ressurce Management Division
F AL-KASIM
Director Resource Management Division
Exploration Branch
F R AAMODT
Head of Branch
Development Branch
A NYSTAD
Head of Branch
Production Branch
S NJÅ
Head of Branch
Planning Branch
Ø KRISTIANSEN
Senior Adviser
Prospect Mapping Section
J VOLLSET
Head of Section
Operations Geology Section
A JOHANSEN
Head of Section
Production & Development Geology Section
E ORMAASEN
Head of Section
Reservoir Technology Section
L HINDERAKER
Senior Adviser
Field Development Section
O RAUSTEIN
Head of Section
Exploration & Development Economics Section
T H HETLAND
Head of Section
Production Evaluation Section
K R KNUDSEN
Head of Section
Measurement Section
T ØGLÆND
Head of Section
Production Economics Section
B TVEDT
Head of Section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Supervisor Security
Budget and Economics Section
H HELGØ Head of Section
Personnel Section
O SONESEN Head of Section
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EDP
Drawing
Printing
Library
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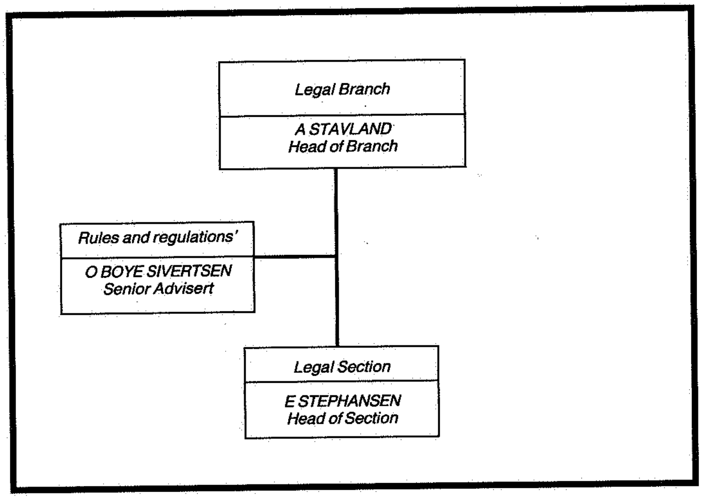
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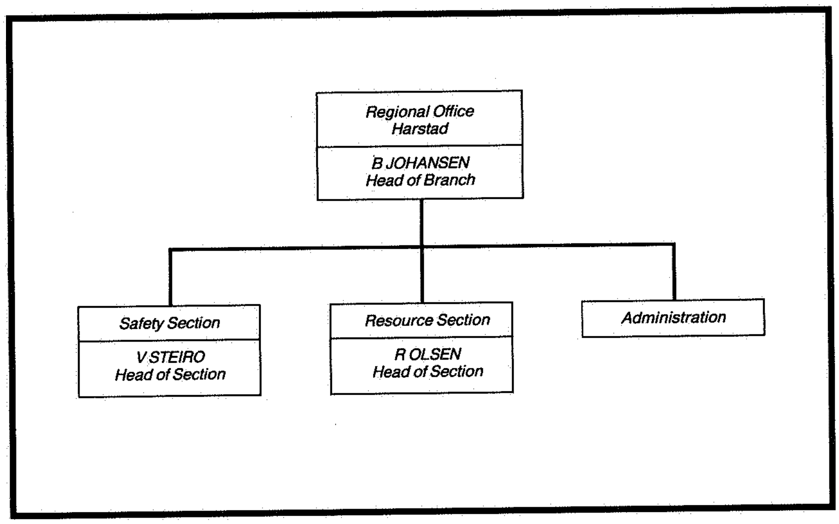
Senior Advisert
Legal Section
E STEPHANSEN
Head of Section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Harstad
B JOHANSEN
Head of Branch
Safety Section
V STEIRO
Head of Section
Resource Section
R OLSEN
Head of Section
Administration