Norwegian Petroleum Directorate

ANNUAL REPORT 1989

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Unofficial translation

"The objective of the Norwegian Petroleum Directorate is to promote the sound management of the Norwegian petroleum resources by the careful weighing of the environmental, safety, technological and economic aspects of the petroleum activity in a coordinated, socially-oriented evaluation."

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Report of the Directors

Offshore activities in Norway entered in 1989 their 25th year. The Norwegian Petroleum Directorate has been in existence for 17 of these years. In 1985 Norway passed its first unified petroleum legislation. In conjunction with this the regulatory supervision of offshore and related activities was delegated by the Ministry of Local Government and Labour to the Norwegian Petroleum Directorate. This move made it clear that in future Norway's supervisory activities would be based on a coordinated evaluation of resources management, safety and working environment concerns.

In a statement to the same Ministry regarding the matter of reorganisation of the maritime administration in Norway and its consequences for the Norwegian Petroleum Directorate, the Board of Directors were careful to emphasise the importance of sustaining and developing the Directorate's multi-disciplinary expertise and high level of competence.

The Board feel there is a need to underscore this feature of oil policy, because the challenges in the year behind us have demanded the full and undivided weight of the Directorate's expertise and multi-disciplinary apparatus more perhaps than in previous years. The oil industry in Norway is not long in the tooth in the traditional sense, but the need to adjust and innovate in the light of changing circumstances is nevertheless more imperative here and has greater consequences for society than in almost all other Norwegian industry. We see evidence of this in the need to manage already-proven reserves astutely, in the need to discover more oil and gas, in the operation of offshore production facilities and in the design of new technology which will support the Norwegian requirements for safety and a sound working environment; in short, the human and environmental sides of the activity.

One particular event on the Norwegian continental shelf in 1989 brings into focus all these perspectives and illustrates both the geological and technological challenges which face Norway in its future exploration for new petroleum reserves, and show simultaneously how the multi-disciplinary approach of the Norwegian Petroleum Directorate has been able to conduct more or less daily supervision of an extremely difficult drilling operation on the basis of its own, independent geological, engineering and operative assessments.

The case in point is the formidable problems encountered by Saga Petroleum in its deep well 2/4–14 early in the year when well contact and well control were both lost. This misfortune made it essential to drill the first ever relief well on the Norwegian sector of the continental shelf, at the same time as the original 2/4–14 had to be recaptured and made ready for a kill operation 4734 meters below the seabed in what has come to be known as the North Sea basement, where the Directorate has high hopes of sizeable petroleum discoveries.

The problems encountered under this drilling operation demanded considerable staff commitment by Directorate personnel for almost the whole of 1989. The Directorate found it prudent to ask all other operating companies to review the entire extent of their technical and operative experience with respect to deep wells on the shelf, with the objective of optimising safety when drilling on deep jurassic strata in the future.

An internal leakage of oil and gas in well 2/4–14 into a sandstone stratum higher up, some 800 meters below the sea bed, created an even more precarious situation and gave rise to apprehension about the long-term effects of other activities in this area of the North Sea.

The work of bringing well 2/4–14 to heel has required enormous financial and human resources, though considering the risk of a widespread environmental disaster if the well should blow, this effort and application was a natural consequence of the obligations and environmental guarantees that Norway took on at the time offshore oil exploration drilling began in 1966.

It must be remembered, too, that since 1966, 623 exploration wells have been drilled in what was originally held to be the world's toughest exploration area for oil and gas, without any mishap of this kind: 504 of the wells were drilled south of the 62nd parallel and the other 119 north of it. In 1989, 28 exploration wells were drilled, most of them in the North Sea, with only minor activity on the Mid-Norway and North-Norway shelves.

The continuing high exploration activity in the North Sea reflects two realities: firstly the North Sea still contains numerous unopened oil prospects; secondly many of these prospects are situated in the vicinity of existing production installations. This latter fact renders them time-sensitive, and the authorities have therefore held the philosophy that one should open up for exploration in them.

The first part of the 12th licensing round in 1988 therefore concerned 18 blocks, in which 23 companies sought operatorship. Many of the new production licenses were drilled up in 1989; including the 13 blocks allocated north of 62 degrees latitude, seven offshore Mid-Norway and six in the Barents Sea. Nevertheless, only in the North Sea were any new discoveries made, principally in block 1/2 under the operatorship of Phillips Petroleum Company Norway, in block 2/4 under Saga Petroleum as operator, and in block 35/9 where Norsk Hydro is the operator.

The proven in-place petroleum resources on the Norwegian continental shelf are therefore less at year end than at its beginning. Oil resources including natural gas liquids have been written down from 2000 mcm (million cubic meters) to 1969 mcm, while gas resources are now 2805 bcm (billion cubic meters) against 2825 bcm at the beginning of the year.

Exploration drilling cannot alone account for the adjustments to the resources account. Better understanding of the reservoirs, more accurate reservoir descriptions, extensive use of reservoir modelling techniques and production experience, combined with efforts directed to enhance recovery, are all essential elements in any account of the shelf's resource potential. Historically about one third of the petroleum reserves presently held by Norway accrued thanks to greater understanding and reverification of the oil and gas quantities.

The Board feel there is a need to stress the importance of this effort and the research and development which have been the focus of the enhanced recovery program (SPOR), the object of which is to squeeze more oil from the shelf, and to emphasise the necessity of continuing along these same lines.

The Norwegian Petroleum Directorate's involvement on the research side of the shelf activities is important and demonstrates that the Directorate's many-sided interests put it in a position to serve as a central supplier of premises for the further research efforts offshore, since much of the data held by the Directorate is made available to Norwegian research institutes. Again it must be emphasised how important it is that the Norwegian Petroleum Directorate, by virtue of its extended interdisciplinary integration, has an overall perspective of the research imperatives within resources and safety management.

In the practical operations on the continental shelf, too, an essential task of the Norwegian Petroleum Directorate is to bring different specialities together, thereby increasing the fund of knowledge and level of expertise which accrues to the activity. To this end the Directorate's Regional Office in Harstad held geoprofessional seminars on the Barents Sea in January and March in which oil companies were active participants and at which significant geological material was presented which may provide a basis for further exploration strategies in the area. In September a three-day conference on environmental data was convened, again looking at our northern areas.

In addition, Storting Report no. 40 (1988–89) opens up large, new areas in Barents Sea South for exploration drilling, which will promote more effective exploration activity in the area in the future.

In 1989 two exploration wells were drilled in the Barents Sea, though no oil or gas was discovered. Norske Shell drilled a well on Tromsøflaket where small amounts of oil were tested. In the region of Nkr 7 billion have been invested in exploration drilling in the Barents Sea since operations started in 1980, and there is little to indicate that the international oil industry's interest in exploration drilling there is waning. Reports of big Soviet gas discoveries and rumours of oil have very likely spurred on the general conviction that there are substantial petroleum reserves to be discovered in the region.

Interest in Svalbard has been stable for the last few years. True, the Soviet-owned Trust Arktikugol has stopped drilling operations in Vassdalen until further notice, but Norsk Hydro is planning drilling on Svalbard in 1990.

Within the field of safety and the working environment, the Norwegian Petroleum Directorate has once again spearheaded drives to achieve a more useful dialogue between the authorities and the end-users of the rules and regulations which govern offshore operations. One item on the agenda is the question of how well the internal control regulations support the working environment requirements.

The effective reach of the Working Environment Act offshore was also made the subject of an analysis by the Bull Committee, which also discussed the question of future supervision of working environment provisions. The Norwegian Petroleum Directorate was represented on the Committee and the Board consider the results of the Committee's work to be extremely pertinent to the future supervision of working environment legislation in the petroleum industry.

The working environment offshore is a steadily expanding and many-faceted commitment area, one aspect of which is the manning requirements for offshore installations. The Directorate's view, in principle, is that such questions should be resolved by and between the parties – employers and employees – themselves.

Nevertheless experience teaches us that the parties may find it difficult to reach a common understanding of what manning level to adopt in order to ensure a safe working environment and acceptable safety level.

As one consequence of this realisation the Norwegian Petroleum Directorate has instigated a research project whose purpose is to explore possible links between crew cuts and accident statistics.

The Directorate is also at pains to ensure that safety and the working environment are taken in hand from the very first phase of planning and pre-engineering of the offshore installation, and has intensified its scrutiny of the operating companies in this respect, in order to secure greater leverage during the formulation of the technical concept.

Increasing cost pressure when engineering new installations has induced the selection of simpler technical concepts. Negative operating experience with highly automated solutions has also helped load the dice in favour of simpler technology. The Norwegian Petroleum Directorate consider it important here to emphasise that there is one criterion that even a simpler solution must meet, that is that it provides a fully sound working environment and acceptable level of safety.

In 1989 the Directorate has circulated for consideration a draft regulation which would require the implementation of risk analyses as the means to fulfil the intentions in the safety and working environment requirements; and the Directorate will also be looking more closely at the technical design of the workplace offshore – ergonomics. Also chemical health hazards are under continual review in light of the steady introduction of new chemicals.

Discharge of drilling mud has proven a more intractable problem than envisaged. When new discharge restrictions are imposed to protect the *marine* environment, it is important to make sure that the *working* environment, too, is protected.

Once again in 1989, relations between the oil industry and other users of the Norwegian coast have come into the limelight. Points in question are decommissioning and removal of installations after their useful service life is over, and the effects of seismic pressure waves on fish populations.

With regard to the former question the United Nations' International Maritime Organisation has passed basic rules for removal of derelict platforms which allow other users of the sea a say.

In 1985 the Norwegian Petroleum Directorate funded an investigation which was carried out by the Maritime Research Institute to look at the effects, if any, of ordinary seismic surveys on fish. One of the conclusions of the report was that under ordinary seismic operations, serious side-effects could not be shown. It must be emphasised here that the use of dynamite is not the ordinary mode of operation and has not been employed on the Norwegian continental shelf as sound source during the time the Directorate has been in existence.

The year 1989 marked the celebration of two anniversaries for the offshore activities. One was the Ekofisk field which marked up 20 years in operation, the other Statfjord which came on stream one decade ago in November 1979. Both fields are milestones in Norwegian offshore enterprise. In the course of the year the Ekofisk barrier was deballasted into place around the Ekofisk tank to protect the operation of this major pipeline junction for many years to come, an example of how it is possible to safeguard output at the same time as the useful life of the installations was extended.

The year also witnessed the official opening of the Oseberg field and the landing facility at Sture. Landing of the Oseberg crude by pipeline to the mainland represents the fulfilment of a 20 year old commitment to land oil on the shores of Norway whenever possible.

Development of new oil fields on the Norwegian continental shelf in the years to come will more than ever before involve small and medium-size oil accumulations in fields where the oil will be expensive to produce. This circumstance, combined with unstable oil prices, will dictate simple, but flexible development concepts. Increasing understanding of oil field production characteristics will provide essential input for the planning and development of such fields especially. The drilling of horizontal wells on Gullfaks South and Troll West represents novel directional technology on the Norwegian continental shelf which there is all good reason to take note of.

In 1989 the Directorate has considered plans for test production on four separate fields in the North Sea. By performing test production it is hoped to reduce the unknowns which impair the current reserves estimates and production forecasts for these fields. The Directorate clearly sees an expanding need for this type of information and will support the quest for concepts which can provide better optimisation of field developments.

In 1989 the Directorate also considered plans for the landing of condensate from Sleipner East to Kårstø, and also the revised plan for development and operation of the Brage field. At the end of the year the plan for development and operation of Heidrun was being considered. In connection with both PDOs the fate of the gas is a central issue. The question is essentially whether to take off the gas immediately for sale under a gas sales contract, or to reinject it.

Many oil fields and prospects in the North Sea lie close to already-existing infrastructure. Many of these fields have now been explored and are ripe for development. During 1989 the Directorate studied overall coordination plans for the Statfjord, Gullfaks and Snorre area. The study shows that huge cost savings are feasible if the development of satellite fields is coordinated with existing and planned infrastructure. At year end the plans for development and operation of the satellites Statfjord North and Statfjord East were being considered by the authorities.

During the year the Directorate did a lot of work to investigate the alternative sources and transportation options for gas supplies to the markets in Scandinavia, the UK and Continental Europe. The studies show that the North Sea fields will remain the most profitable sources of gas supplies also in the future.

Stavanger, 25 January 1990
Members of the Board of Directors
of the Norwegian Petroleum Directorate

Arve Berg

Andreas Lønning — *Oddny Aleksandersen* — *Liv Hatland*

Peter J Tronslin — *Jan B M Strømme*

Arne H. Nilsen — *Elisabet Stephansen*

Fredrik Hagemann
Director General

Bjørn Bratbak
Head of Branch
Secretary of the Board

1. Duties, Directors and Administration

1.1 TERMS OF REFERENCE

The objectives and tasks of the Norwegian Petroleum Directorate are given by special instructions, amended most recently on 29 March 1979. Its tasks have since been revised by delegations which follow directly from act of parliament, regulations or delegation resolutions from a superior authority. The delegations derive from:

a) *Petroleum Act,* Act of 23 March 1985 no. 11 with regulations
b) *Working Environment Act,* Act of 9 February 1977 no. 4 with regulations
c) *Tobacco Injuries Act,* Act of 9 March 1975, section 6, 8th paragraph, and regulation given by Royal Decree of 8 July 1988
d) Regulations concerning *Safe Practices* etc for Exploration and Drilling for Natural Resources on Svalbard of 29 March 1988
e) Regulations concerning *Scientific Research* for Natural Resources on the Norwegian Continental Shelf of 31 January 1969
f) Provisional Regulations concerning *Littering and Pollution* caused by Petroleum Activities on the Norwegian Continental Shelf of 26 October 1979.

1.2 OBJECTIVES

On the basis of the above terms of reference and the Norwegian Petroleum Directorate's guiding instructions the following objective has been laid down for the Directorate:

"The objective of the Norwegian Petroleum Directorate is to promote the sound management of the Norwegian petroleum resources by the careful weighing of the environmental, safety, technological and economic aspects of the petroleum activity in a coordinated, socially-oriented evaluation."

1.3 BOARD OF DIRECTORS AND ADMINISTRATION

1.3.1 Board of Directors

The composition of the Board of Directors was up to 15 April 1989:

1. County Governor Martin Buvik, Tromsø (Chairman)
2. Group Director Andreas Lønning, Oslo (Deputy Chairman)
3. Mayor Per Sævik, Remøy
4. Managing Director Liv Hatland, Oslo
5. Director Kåre D Nielsen, Oslo
6. Trade Union Secretary for Oil, Jan B M Strømme, Drøbak
7. Head of Section Odd Raustein, Stavanger
8. Special Advisor Anna Aabø, Stavanger

Deputies:
For 1–4:
County Council Deputy Chairwoman Sylvi Enevold, Hammerfest
Editor Marit Greve, Oslo

For 5:
Managing Director Halvor Ø Vaage, Stavanger

For 6:
Department Manager Bjørn Kolby, Oslo

For 7–8:
Engineer Bjørn Kvant, Stavanger

By Royal Decree of 14 April 1989 the new Board of Directors for the period 15 April 1989 to 15 April 1991 was appointed. This new Board was made up as follows:

1. Regional Employment Director Arve Berg, Ålesund (Chairman)
2. Group Director Andreas Lønning (Deputy Chairman)
3. Managing Director Liv Hatland, Oslo
4. Consultant Oddny Aleksandersen, Tromsø
5. Trade Union Secretary for Oil, Jan B M Strømme, Drøbak
6. Managing Director Peter J Tronslin, Stavanger
7. Senior Engineer Arne H Nilsen, Stavanger
8. Head of Section Elisabet Stephansen, Stavanger

Deputies:
For 1–4:
Major Per Sævik, Remøy
County Council Chairwoman Sylvi Enevold, Hammerfest
Editor Marit Greve, Bærum

For 5:
Department Manager Bjørn Kolby, Oslo

For 6:
Negotiations Director Gunnar Flaat, Oslo

For 7–8:
Executive Officer Tor Inge Ottosen, Stavanger
Senior Engineer Susanne Larsen, Stavanger.

During the year the Board held nine meetings, seven of them in Stavanger. The November meeting was held at the Harstad Regional Office and that in

December in Bergen. In connection with the December meeting the Board visited the Oseberg field.

1.3.2 Organisation

From 1 January 1989 a new administrative unit, PETRAD, was established under the Director General. The unit will provide petroleum instruction to leaders and key individuals in the petroleum sector in developing countries. The unit has been provisionally established for a three-year period on the basis of a cooperation agreement with NORAD, the Norwegian Directorate for Development Cooperation.

From 7 August 1989 a new section was established in the Administration Branch, the Section for Document and Information Management. The section embraces the Library, Infoil, Central Files, Well Files, and Geophysical Files. The section was established as provided in the earlier plans for restructuring of the Directorate.

Following discussions and negotiations with employee representatives a reorganisation of the Resource Management Division was implemented from 1 October 1989. The Exploration Branch's Section for Production and Development Geology was wound up, its tasks and mandate being transferred partially to the Section for Reservoir Technology in the Development Branch and partially to the newly-formed Section for Production Geology in the Production Branch. The point of this change around was to provide better concordance with the principle of phase-related organisation.

1.3.3 Staff

At the end of 1989 the Norwegian Petroleum Directorate had 339 authorised positions. Four new positions were authorised during the year. Three more positions are funded by NORAD. At year end there were 367 employees in service, 12 on leave. Of Directorate employees, 37.2 per cent are women. Figure 1.3.3 shows the break down of men and women in the various position categories. One of NORAD's special advisors for oil matters in developing countries has worked in the Directorate for the entire report period.

In 1989 the Directorate considered applications for 50 vacancies and 19 new employees were taken on in permanent positions. Of the new employees eight have relocated from elsewhere, nine have joined us from other oil-related activities, and only one was newly qualified.

Employees leaving were 17 in number, representing 5 per cent of the total authorised positions (see Table 1.3.3). This is the lowest leaving statistic ever.

Codetermination

Cooperation with the staff unions has been conducted as in previous years by regular meetings between employee representatives and management.

Eight ordinary meetings were held in which various types of cases were discussed. Another eight meetings were held on an ad hoc basis in order to take up particular matters.

Among the subjects of particular interest considered were the following:

Fig. 1.3.3
Job categories as of December 1989

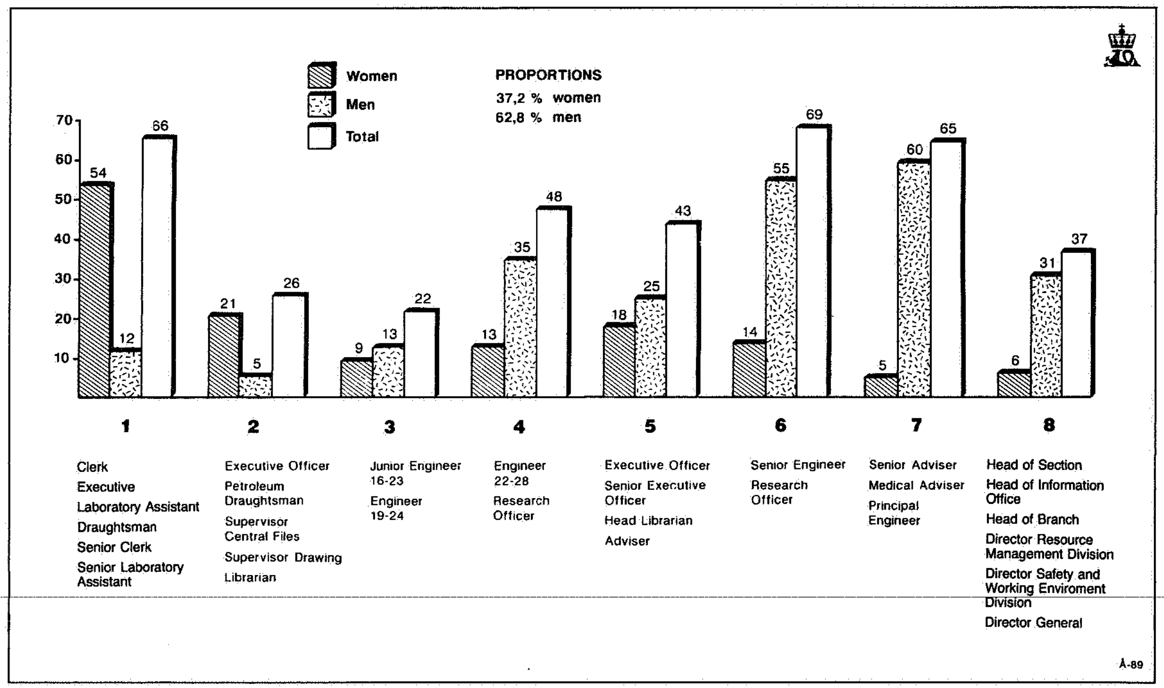


Table 1.3.3
Personnel leaving in 1989 with indication of job category

Division/ Branch	Super-visor	Special Advisor	Principal Engineer	Senior Engineer	Research Officer	Division Engineer/ Engineer	Advisor	Jr exec officer Exec officer Sr exec officer	Office Staff	Total	Decline in %
Resource	0	4	1	1	1	3	0	0	0	10	7.5
Safety	0	2	0	1	0	1	0	0	0	4	3.8
Admin	0	0	0	0	0	1	0	0	0	1	1.4
Harstad	0	0	0	0	1	0	0	0	1	2	15.4
Total	0	6	1	2	2	5	0	0	1	17	5.0

- Split up of Norwegian Petroleum Directorate
- Permanent duty rosta
- New planning system in Division for Safety and Working Environment – Reorganisation of Section for Production Geology
- Training in audit methodology in Division for Safety and Working Environment
- Program for Staff Policy
- Dedicated play school for Directorate children
- Wages for supervision leaders
- Position of economists in Resource Management Division
- Use of second Norwegian language – *nynorsk* – in Directorate
- Distribution of welfare funds
- Budget proposals.

Training
The 1989 training budget ran to Nkr 3,375,000. As in 1988 great attention was given to internal training as this provides efficient utilisation of resources. With this in mind course catalogues were printed listing the inhouse training options. Inhouse training also covers management training under a specially developed course program which will continue in 1990.

As in 1988 many staff have benefitted from on-the-job-training with the oil companies, who have once again made us most welcome and given us a training period which is extremely useful. Many Directorate employees have attended courses held by the oil companies.

Equal opportunity
The Directorate is bound by a special agreement on equal opportunity and has its own Equal Opportunity Committee. This committee is four in number, with two representatives from management and two from the staff unions. The committee has compiled several types of statistics during the period. One of the committee's tasks is the formulation of an Action Plan for Equal Opportunity, in connection with which committee members have attended a seminar on equality under the auspices of the Ministry of Consumer Affairs and Administration.

1.3.4 Budget and economy
The Directorate has employed Nkr 222,885,975 for its various tasks in 1989.

The amount was appropriated as follows:

– Operating budget	Nkr 162,849,797
– Inspection costs	7,260,314
– Geological and geophysical surveys	48,978,537
– Safety and working environment	3,797,327
Total	222,885,975

Of the operating budget payroll costs amount to Nkr 94,360,447 and hire and operation of buildings Nkr 6,048,507. The remainder, Nkr 62,440,843, covers costs of consultants, operation of weather ship, research and development projects, travel, training, computer systems operation, new investments in equipment etc.

The Norwegian Petroleum Directorate was directed to carry out certain special tasks as follows:

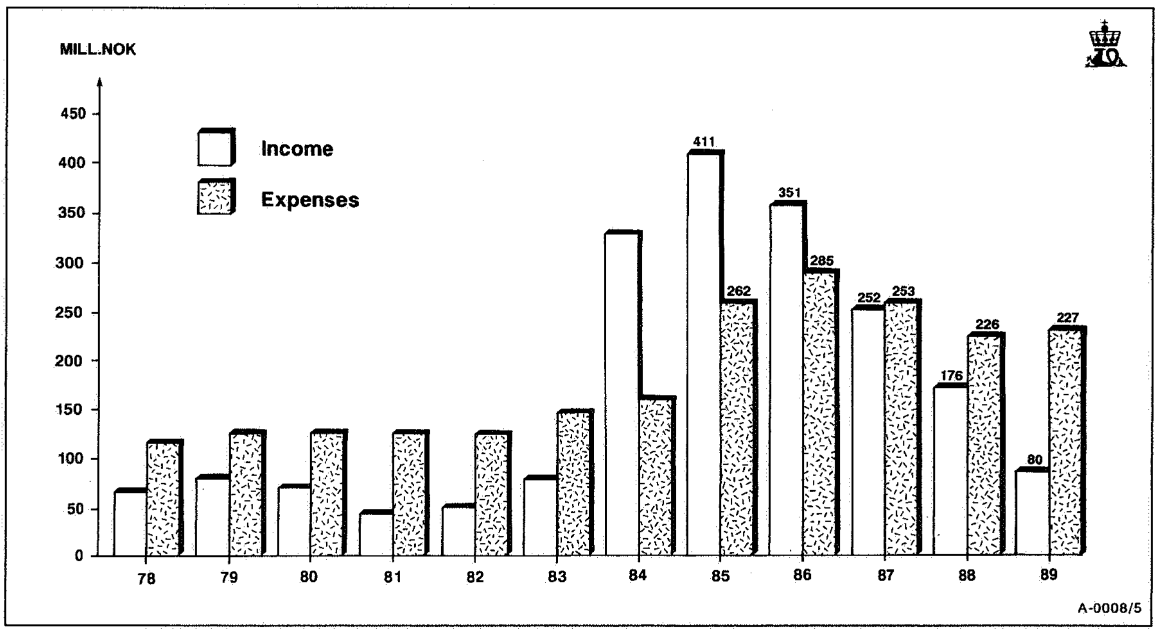
– Clearance of seabed	Nkr 4,173,046
– Research and development for enhanced oil recovery (SPOR)	16,977,974
– World Petroleum Congress 1995	55,378

The Directorate's budget situation means we have to be increasingly ruthless in our priorities. Great importance is therefore placed on the development of better management planning tools.

Revenues
In addition to the paid-up royalties on production and acreage fees (see Ch.5), the Directorate received Nkr 79,457,365 from various sources of revenue. The figures for 1989 were as follows:

– Sale of publications	Nkr 2,998,183
– Sale of released test material	864,269
– Exploration fees	960,000
– Refund of inspection outlays	22,578,574
– Sale of seismic survey results	43,124,873
– Credit interest, bank	6,064,466
– Miscellaneous	2,867,000
Total	79,457,365

Fig. 1.3.4
NPD's operating budget 1978–1989



For a diagram of the development of the Norwegian Petroleum Directorate budget and revenues from 1978 to 1989, see Figure 1.3.4.

1.3.5 Information

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

The Norwegian Petroleum Directorate Annual Report plays a central role in the Directorate's information activities. The 1988 Annual Report was presented to the press in April and an updated map of the continental shelf was issued in October.

On the Directorate's initiative a joint document was presented in May by the Norwegian Petroleum Directorate and Oil Industry Association concerning *Experiences with Contingency Information in the North Sea* to a large international conference under EC direction in Varese in Italy.

During the year 44 press releases were issued, including announcements of the termination of exploration wells, for which the Norwegian Petroleum Directorate seeks to disclose maximum information.

1.3.6 Library

Activity in the Library was again heavy despite a 15 per cent decline in the number of requests for literature and information compared with 1988. The decline was partly the result of the closure of the library for about a month in order to refurbish with new carpets and rebuild.

As in previous years almost half the total number of enquiries originated from external users in Norway and abroad. Such enquiries come from Norwegian and foreign libraries, students, research staff, oil companies and other companies in the petroleum sector.

The number of subject searches in external data bases has increased by comparison with previous years. This service is only available to Directorate employees. No new agreements with database hosts have been concluded during the year.

The Library has been an active participant in the work to publish the Oil Index abstracts list and OIL literature database. Demand for literature through the OIL service has declined from 631 orders in 1988 to 472 in 1989.

1.3.7 INFOIL secretariat

The use of the OIL and Infoil 2 databases has maintained a constant level. The number of entries made in the OIL base is higher than ever since a good number of elderly reports of high quality have been included. Binding agreements have been established with several research institutes under which their report material is input into OIL.

A committed marketing initiative for the printed Norwegian issue resulted in a marked step-up in subscriber sales.

An agreement has now been entered with the UK

Department of Energy, Royal Norwegian Council for Scientific and Industrial Research (NTNF) and Norwegian Petroleum Directorate on the one hand, and the Economic Community Administration in Brussels through the Directorate-General of Energy on the other, for a merger of the EC database of research projects in hydrocarbon technology with the Infoil 2 base.

In order to secure the Infoil 2 base long-term financial support in Norway, a five-year contract has been signed with the NTNF.

The British Petroleum Research Center in London has enlarged access to its internal research and development base from 12 to over 50 user log-ins because the base is so frequently used. Infoil 2 is a part of this BP base.

2. Activity on the Norwegian Continental Shelf

2.1 EXPLORATION AND PRODUCTION LICENCES

2.1.1 New exploration licences

As of 31 December 1989, 171 commercial exploration licences had been granted. Each licence is valid for three years.

The following licences were awarded in 1989:

Company	Licence no.
Den norske stats oljeselskap a.s (Statoil)	165
Total Marine Norsk a/s	166
Phillips Petroleum Norsk A/S	167
Elf Aquitaine Norge A/S	168
BP Norway Limited U.A	169
Enterprise Oil Norway A/S	170
Geophysical Service International Ltd	171

2.1.2 Licensing rounds and new production licences

Licensing round 12, phase B, which was announced on 1 September 1988, invited applications for three blocks in the Møre I area, two in Trøndelag II and eight key blocks in the Barents Sea. Blocks an-

Table 2.1.2.a Allocations in licensing round 12B

Licence no.	Field/Block	Share in %		Licensee (O=Operator)
154	6205/3 and	10.000		Amoco Norway A/S
	6305/12	10.000		Elf Aquitaine Norge A/S
		30.000	O	Norsk Hydro Produksjon a.s
		50.000		Den norske stats oljeselskap a.s
155	6306/10	10.000		Norsk Agip A/S
		10.000		Deminex (Norge) A/S
		30.000	O	A/S Norske Shell
		50.000		Den norske stats oljeselskap a.s
156	6406/11	10.000		Amerada Hess Norge A/S
		20.000		Mobil Development Norway A/S
		20.000	O	Saga Petroleum a.s.
		50.000		Den norske stats oljeselskap a.s
157	6406/12	15.000		BP Norway Ltd U.A
		10.000		Norske Conoco A/S
		10.000		Petrobras Norge A/S
		15.000		Phillips Petroleum Norsk A/S
		50.000	O	Den norske stats oljeselskap a.s
158	6407/8	30.000	O	BP Petroleum Ltd U.A
		10.000		Det Norske Oljeselskap A/S
		50.000		Den norske stats oljeselskap a.s
		10.000		Unocal Norge A/S.
159	6507/3	20.000		Norsk Hydro Produksjon a.s
		10.000		Saga Petroleum a.s.
		50.000	O	Den norske stats oljeselskap a.s
		20.000		Total Marine Norsk A/S
160	7228/1 and	40.000	O	Mobil Development Norway A/S
	7228/2	10.000		Phillips Petroleum Norsk A/S
		50.000		Den norske stats oljeselskap a.s
161	7228/8 and	10.000		Norske Fina A/S
	7228/9	20.000	O	Norsk Hydro Produksjon a.s
		10.000		Saga Petroleum a.s.
		10.000		A/S Norske Shell
		50.000		Den norske stats oljeselskap a.s
162	7324/10 and	10.000		Amoco Norway A/S
	7324/11	10.000		Elf Aquitaine Norge A/S
		10.000		Norsk Hydro Produksjon a.s
		20.000		Mobil Development Norway A/S
		50.000	O	Den norske stats oljeselskap a.s

nounced in previous licensing rounds were also open for applications. The application deadline was 15 November 1988.

Twenty-one companies applied for a total of 18 blocks. On 9 March 1989, 13 blocks were allocated in nine production licences, covering a total area of 5,031,263 square kilometers. Table 2.1.2.a gives details of production licences awarded in 1989 and Table 2.1.2.b shows all production licences awarded since 1965. Table 2.1.2.c shows Norwegian and foreign participation in each licensing round.

Table 2.1.2.b Production licences and acreages as of 31 December 1989

Lic. round	Allocated	Production licence no.	Blocks allocated	Blocks relinquished	Area km² allocated	Area km² relinquished	Area km² in licence
1.	01.09.65	001–021	74	54	39842.476	35363.535	4478.941
	07.12.65	022	4	4	2263.565	2263.565	0.0
	12.09.77	019 (2)	2	0	617.890	0.0	617.890
2.	23.05.69	023–031	9	1	4107.833	2233.366	1874.467
	30.05.69	032–033	2	0	746.285	376.906	369.379
	14.11.69	034–035	2	0	1024.529	564.837	459.692
	11.06.71	036	1	0	523.937	262.047	261.890
Plus	10.08.73	037	2	0	586.834	295.157	291.677
3.	01.04.75	038–040 and 042	7	4	1840.547	1389.780	450.767
	01.06.75	041	1	1	488.659	488.659	0.0
	06.08.76	043	2	0	604.558	303.217	301.341
	27.08.76	044	1	0	193.076	90.417	102.659
	03.12.76	045–046	4	2	1270.682	814.708	455.974
	07.01.77	047	2	1	368.363	304.160	64.203
	18.02.77	048	2	1	321.500	107.019	214.481
	23.12.77	049	1	1	485.802	485.802	0.0
Plus	16.06.78	050	1	0	500.509	151.962	348.547
4.	06.04.79	051–058	8	1	4007.887	2434.633	1573.254
Plus	20.08.82	079	1	0	102.167		102.167
5.	18.01.80	059–061	3	2	1108.078	998.675	109.403
	27.03.81	062–064	3	1	1099.522	499.780	599.742
	23.04.82	073–078	6	2	2311.912	1444.153	867.759
6.	21.08.81	065–072	9	1	3218.945	1362.539	1856.406
7.	10.12.82	080–084	5	5	2082.966	2082.966	0.0
Plus	08.07.83	085	3	0	1521.160	725.816	795.344
8.	09.03.84	086–100	17	0	6338.273		6338.273
9.	14.03.85	101–111	13	0	5293.053		5293.053
Plus	26.07.85	112	1		260.215		260.215
10a	23.08.85	113–120	9		3075.433		3075.433
10b	28.02.86	121–128	9		3828.258		3828.258
Plus	11.07.86	129	1		225.393		225.393
11.	10.04.87	130–142	22		7139.518		7139.518
12a	08.07.88	143–153	16		4701.021		4701.021
12b	09.03.89	154–162	13		5031.262		5031.262
			256	84	107132.128	55043.698	52088.410

Blocks relinquished includes whole and partial blocks. Plus indicates allocations made outside licensing rounds.

Tabell 2.1.2.c
Allocation rounds. Norwegian and foreign shares and operatorships as of 31 December 1989

Licensing round	Year	Number blocks	Norwegian share %	Foreign share %	Norwegian operator %	Foreign operator %
1	1965	78	9	91	0	100
2	1969 – 71	14	15	85	0	100
Statfjord	1973	2	52	48	0	100
3	1974 – 78	22	58	42	63	37
Ula (19 B)	1977	2	50	50	0	100
Gullfaks	1978	1	100	0	100	0
4	1979	8	58	42	68	32
5	1980 – 82	12	66	34	92	8
6	1981	9	64	34	50	50
Utv.t 079	1982	1	100	0	100	0
7	1982	5	60	40	80	20
Utv.t 085	1983	3	100	0	100	0
8	1984	17	60	40	60	40
9	1985	13	43	57	62	38
Utv.t 112	1985	1	67	33	0	100
10A	1985	9	64	36	67	33
10B	1986	9	65	36	56	44
Utv.t 129	1986	1	67	33	100	0
11	1987	22	59	41	62	38
12A	1988	16	57.5	42.5	37.5	62.5
12B	1989	13	64.4	35.6	66.7	33.3

2.1.3 Transfer of interests

In the course of 1989 the following interests were approved in accordance with § 61 in the Act no. 11 of 22 March 1985 regarding the Petroleum Activity:

Enterprise Oil Norway A/S has taken over Texas Eastern Norway Inc's interests in ten production licences. Following this change the ownership of these licences is as follows:

Production licence 006
Operator: Amoco Norway Oil Company

Amerada Hess Norge A/S	28.333 %
Amoco Norway Oil Company	28.333 %
Enterprise Oil Norway A/S	28.333 %
Norwegian Oil Consortium A/S & Co	15.000 %

Production licence 032
Operator: Amoco Norway Oil Company

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

Production licence 033
Operator: Amoco Norway Oil Company

Amerada Hess Norge A/S	25.000 %
Amoco Norway Oil Company	25.000 %
Enterprise Oil Norway A/S	25.000 %
Norwegian Oil Consortium A/S & Co	25.000 %

Production licence 037
Operator: Den norske stats oljeselskap a.s (Statoil)

Amerada Hess Norge A/S	1.042 %
Amoco Norway A/S	1.042 %
Norske Conoco A/S	10.000 %
Enterprise Oil Norway A/S	1.042 %
Esso Norge A/S	10.000 %
Mobil Development Norway A/S	15.000 %
Saga Petroleum a.s	1.875 %
A/S Norske Shell	10.000 %
Den norske stats oljeselskap a.s	50.000 %

Production licence 057
Operator: Saga Petroleum a.s

Amerada Hess Norge A/S	4.900 %
Deminex (Norge) A/S	24.500 %
Enterprise Oil Norway A/S	4.900 %
Saga Petroleum a.s	14.700 %
Den norske stats oljeselskap a.s	51.000 %

Production licence 128
Operator: Den norske stats oljeselskap a.s (Statoil)

Norsk Agip A/S	10.000 %
Enterprise Oil Norway A/S	10.000 %
Norsk Hydro Produksjon a.s	15.000 %
Saga Petroleum a.s	15.000 %
Den norske stats oljeselskap a.s	50.000 %

Production licence 130
Operator: Den norske stats oljeselskap a.s (Statoil)

Enterprise Oil Norway A/S	20.000 %
Petrobras Norge A/S	15.000 %
A/S Norske Shell	15.000 %
Den norske stats oljeselskap a.s	50.000 %

Production licence 134
Operator: Den norske stats oljeselskap a.s (Statoil)

Norsk Agip A/S	30.000 %
Norske Conoco A/S	10.000 %
Enterprise Oil Norway A/S	10.000 %
Den norske stats oljeselskap a.s	50.000 %

Production licence 143
Operator: Phillips Petroleum Norsk A/S

Enterprise Oil Norway A/S	15.000 %
Phillips Petroleum Norsk A/S	25.000 %
Den norske stats oljeselskap a.s	50.000 %
ØMV Norge A/S	10.000 %

Production licence 150
Operator: Norske Fina A/S

Enterprise Oil Norway A/S	10.000 %
Norske Fina A/S	30.000 %
Saga Petroleum a.s	10.000 %
Den norske stats oljeselskap a.s	50.000 %

2.1.4 Relinquishments and surrenders
Relinquishment or surrender of acreage occurred in three production licences in 1989. In two cases the entire area was relinquished. See Table 2.1.4 for details.

Table 2.1.4
Relinquishments and surrenders

Production licence	Operator	Block	Original area km²	Relinquished area km²	Area in licence km²
041	Saga	35/3	488.659	488.659	.000
058	Gulf	35/8	496.569	496.569	.000
085	Statoil/	31/3	1521.160	725.816	795.344
	Hydro/	31/5			
	Saga	31/6			

2.2 SURVEYING AND EXPLORATION DRILLING

2.2.1 Geophysical and geological surveys

Some 106,568 km of seismics were shot on the Norwegian continental shelf in 1989, see Figure 2.2.1.a. This reflects an activity level 13 per cent down on 1988.

Fig. 2.2.1.a
Seismic surveys on the Norwegian Continental Shelf 1962–89

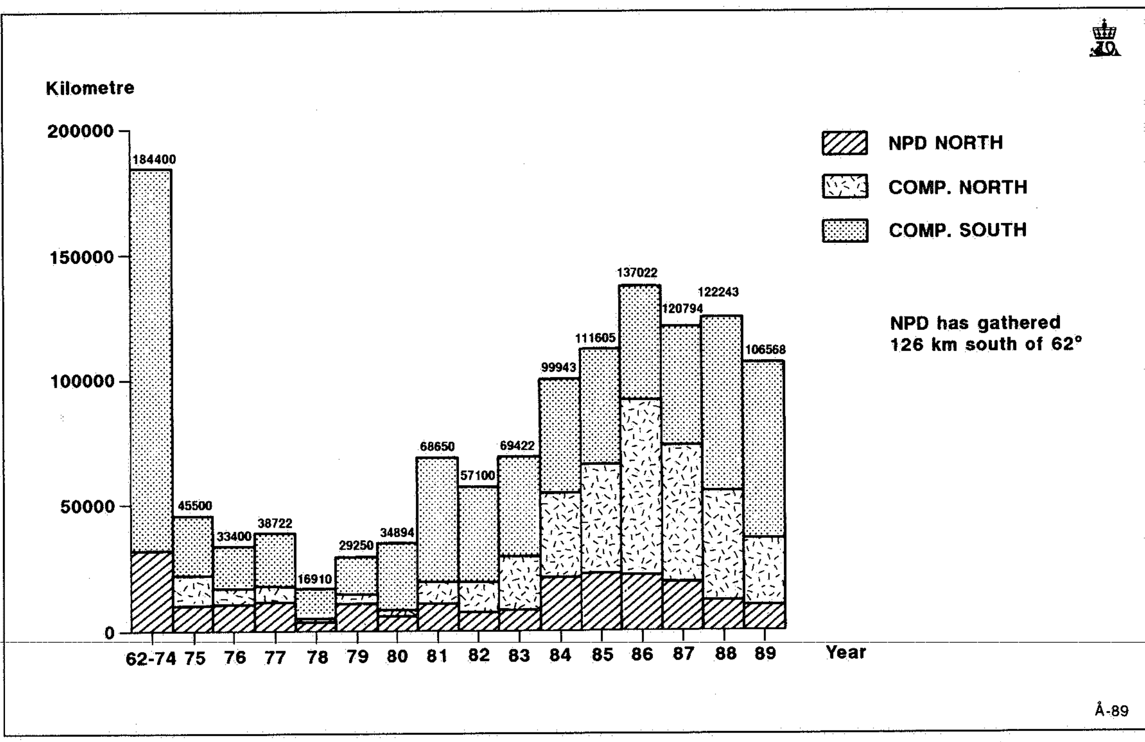


Fig. 2.2.1.b
Seismic surveys conducted by the Norwegian Petroleum Directorate

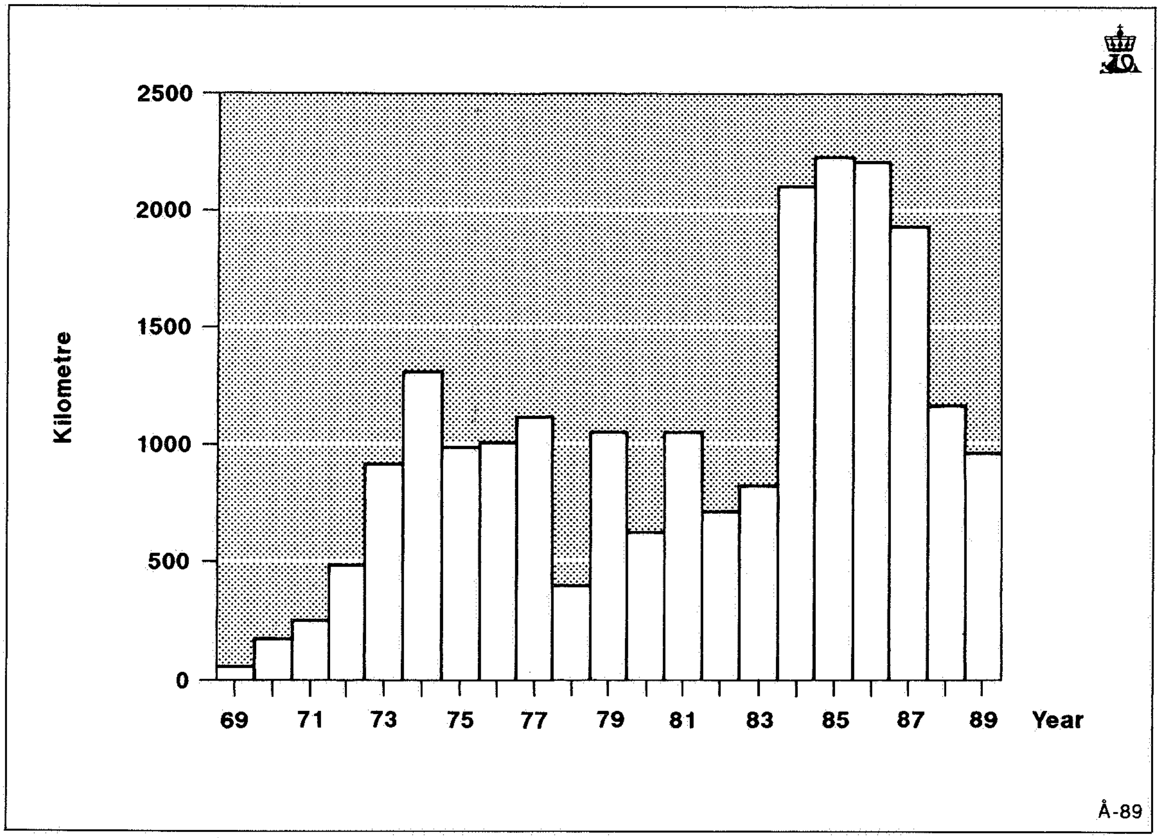
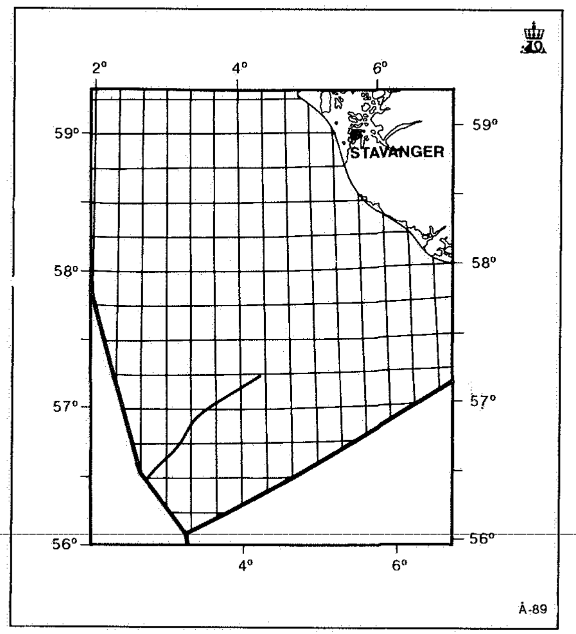


Fig. 2.2.1.c
Seismic testline in the North Sea



2.2.1.1 Directorate's geophysical surveys 1989

The Norwegian Petroleum Directorate gathered 9,625 km seismics in 1989, see Figure 2.2.1.b. Data was collected from the areas indicated in Figure 2.2.1.c, d and e.

All the Directorate's 1989 data was gathered by the vessel *Geco Gamma* with the exception of one North Sea test line which was shot by the *Seisventurer.*

North Sea

A test line 127 km in length was surveyed in the southern North Sea using SSL's Norwegian-flagged *Seisventurer.* A new type of water gun source was employed with 24 different guns at the same depth in a array enclosing a total volume of 9600 cubic inches. Data were recorded by two equally deep cables 3000 meters long and 100 meters apart. The data were processed at the SSL processing center outside London.

The purpose of the line was to test a new collection theory in connection with various geological problems in different stratigraphic levels in the southern North Sea. The line passes through several wells and the results produced were of great interest.

Fig. 2.2.1.d
Seismic surveys on Vøringplatået and offshore Lofoten

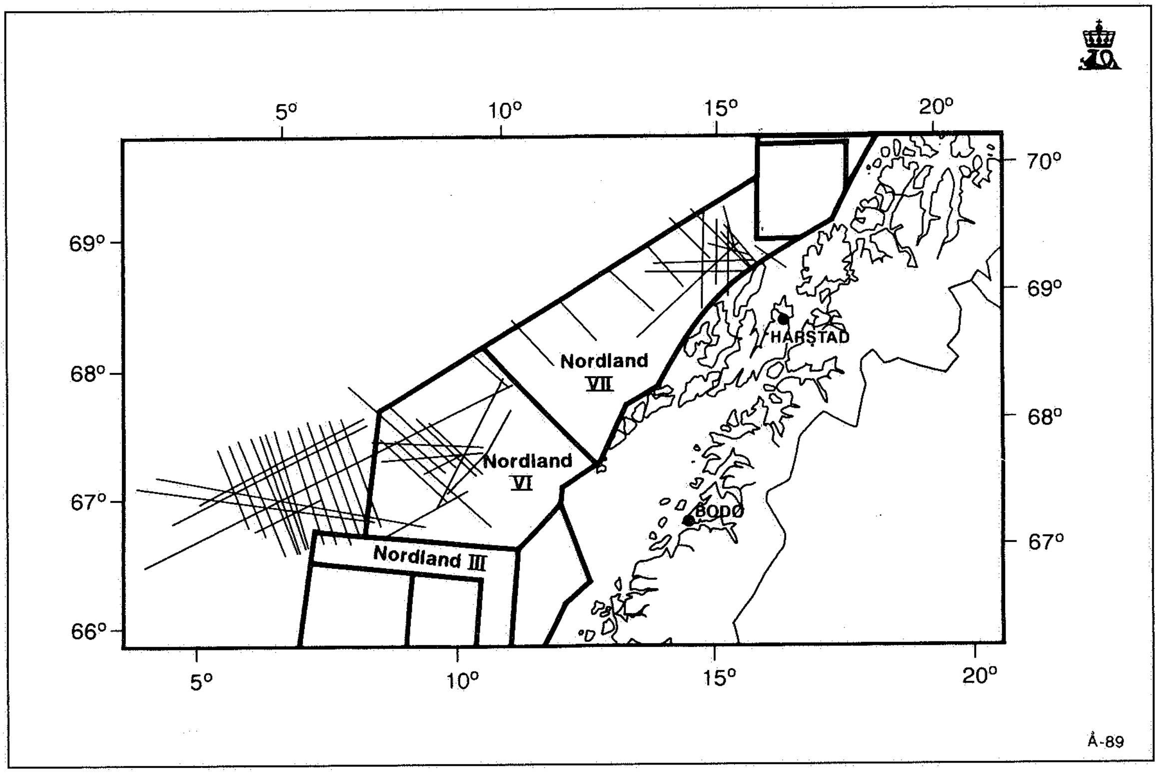
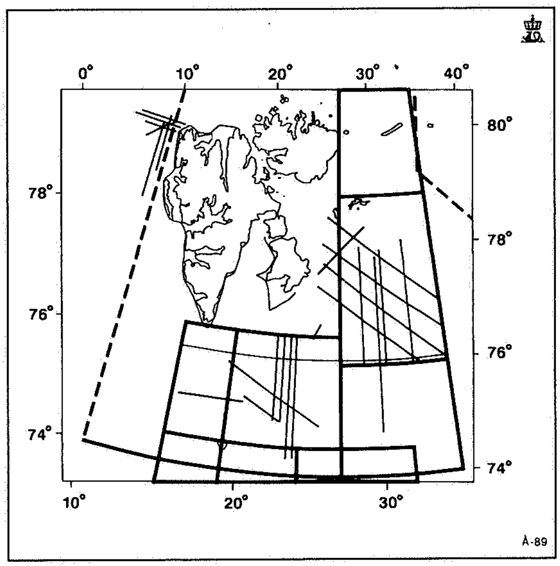


Fig. 2.2.1.e
Seismic surveys in the northern Barents Sea



Vøring Plateau

Some 2589 km seismics were collected in the Vøring Plateau. The greater part of this line was taken from the northern part of the area, 1350 km using a 3600 meter cable length. The data are being processed by Merlin Geophysical in London, while the other data shot with a 3000 meter cable are the responsibility of Western Atlas in London. It is planned to collect further data in this area during 1990.

Lofoten West

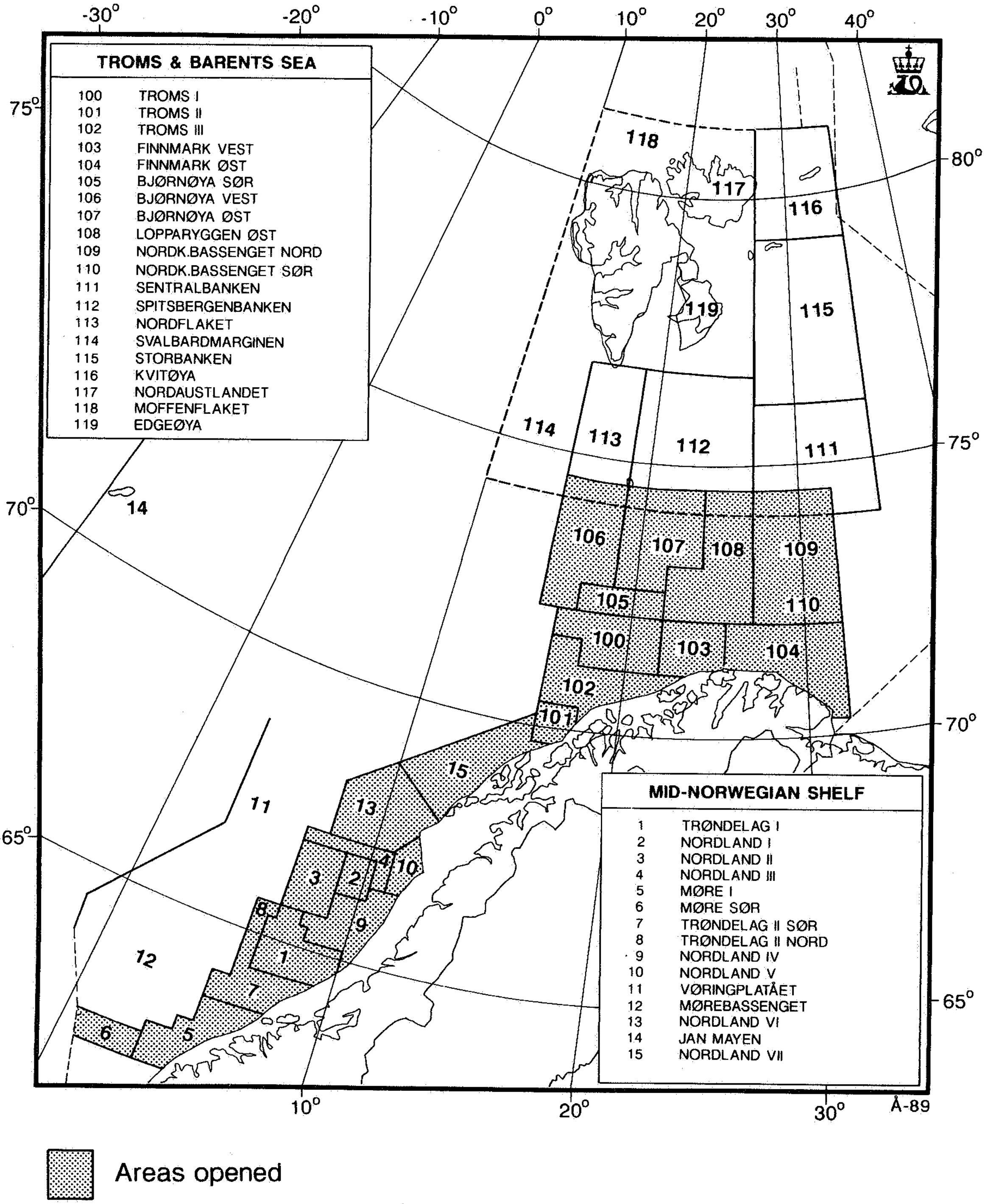
Some 1096 km seismics were collected from Nordland VI and 1086 km from Nordland VII. The data are under processing with SSL who also did the 1988 data in this area. The data quality is sometimes poor which makes the processor's task all the more difficult.

Barents Sea North

Some 4639 km regional lines were collected in the northern Barents Sea, of which 564 km in the area northwest of Spitsbergen. These data were collected using a cable, while the rest were recovered using two horizontally separated cables plus a mini-cable. The latter data were principally collected on Storbanken and Spitsbergen Bank. Some test lines were also collected on Central Graben in connection with analysis of depressions in the seafloor and studies of shallow data. Five short lines totalling 30 km were shot twice using, respectively, a point source, short shot point intervals and shallow mini-cable in addition to the normal collection parameters.

It is planned to collect data from the northern Barents Sea again next year.

Fig. 2.2.1.f
Areas which are opened for seismic surveys by companies. Area designations north of Stad



2.2.1.2 Opening-up of new exploration areas

Nordland V, VI and VII were opened up for seismic surveying from 1 July 1989.

Parts of the Vøring Plateau will be made ready for opening in the next few years. Areas north of Stad where seismological exploration is permitted are shown in Figure 2.2.1.f.

2.2.1.3 Companies' geophysical surveys

In 1989 some 96,952 km seismics were gathered on the Norwegian continental shelf under the direction of the oil companies, contractors and universities. Of the total 39,000 are three-dimensional surveys, 71,150 km were taken from the North Sea and 25,800 km from north of Stad. As the figures show, the activity level was the same as in 1988. Activity north of Stad has declined by around 15,000 km. Norwegian oil companies accounted for 31,840 and foreign for 38,990 km. Speculative surveys totalling 26,100 km were made by Geco, Geoteam, Nopec and GSI.

2.2.1.4 Sale of seismic data

In 1989 the Norwegian Petroleum Directorate recorded income from sale of seismic data packages amounting to Nkr 43.1 million (compare Nkr 130.1 million in 1988). See Table 2.2.1.4.

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

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

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

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

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

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

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

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

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

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

Nordland V
Elf, Statoil and Total.

Nordland VI
Elf, Statoil and Total.

Nordland VII
Elf, Statoil and Total.

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

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

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

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

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

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

Bear Island West
Amoco, Conoco, Elf, Enterprise, Hydro, Mobil, Saga, Shell, Statoil and Total.

Bear Island East
Agip, Amoco, Arco, BP, Conoco, Deminex, Elf, Enterprise, Esso, Fina, Hydro, Mobil, Saga, Shell, Statoil, Tenneco and Total.

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

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

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

The numbers of seismic data packages sold for each area are given in Table 2.2.1.4.

Table 2.2.1.4.
Survey of seismic data packages sold

Package		1989	Total
001	MØRE-TRØNDELAG-REGIONAL-PAKKE-1		33
002	MØRE-TRØNDELAG-REGIONAL-PAKKE-2		26
003	TAMPEN-SPUR		21
004	MØRE-SØR-84		21
005	TRØNDELAG-REGIONAL		25
006	HALTENBANKEN-VEST-84		23
007	FRØYABANKEN-84	1	26
008	MØRE-TRØNDELAG-PAKKE-2		22
009	MØRE-TRØNDELAG-PAKKE-3		28
010	TRÆNABANKEN		30
011	REG-DATA-NORDLAND-RYGGEN		20
012	NORDLAND-IV-85		9
013	REG-DATA-MIDT-N-SOKKEL		19
014	NORDLAND-II-83		21
015	NORDLAND-III-84	2	12
016	TROMS-II	2	11
017	REGIONAL-DATA-TROMS-ØST		18
018	FINNMARK-VEST-83		19
019	FINNMARK-VEST-84		20
020	NORDLAND-III-85	2	12
021	MØRE-SØR-TEST-84 #		5
022	STOREGGA-85		5
023	VØRINGPLATÅET	1	7
024	VØRING-BASSENGET-85/86		6
025	LOFOTEN-VEST-86	1	7
026	JAN-MAYEN-85		1
028	VØRING-BASSENGET-87		3
029	NORDLAND-VI-87	1	7
030	NORDLAND-VII-87	1	7
031	NORDLAND-V-87	3	3
032	NORDLAND-VI-88	4	4
033	NORDLAND-VII-88	3	3
034	NORDLAND-V-73–79	3	3
035	NORDLAND-VI-73–79	5	5
036	NORDLAND-VI-89	3	3
037	NORDLAND-VII-89	3	3
038	NORDLAND-VII-74/75	3	3
100	TROMS-HOVEDPAKKE		34
101	REG-DATA-TROMS-BAR.HAVET-73	1	21
102	TROMS-III-83/84	2	13
103	TROMS-III-85	2	10
105	TROMS-I-ØST-77		19
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		21
201	BJØRNØYA-SØR-84		21
202	BJØRNØYA-ØST-REGIONAL-84	1	18
203	BJØRNØYA-ØST-84		17
204	BJØRNØYA-TILLEGG-NORD	1	17
205	BJØRNØYA-VEST-REGIONAL-84		14
206	LOPPARYGGEN-ØST-REGIONAL-84		19
207	LOPPARYGGEN-ØST-85-SSL-DIAG		19
208	LOPPARYGGEN-ØST-85-NORD		19
209	LOPPARYGGEN-ØST-85-GECO-DIAG		19
210	LOPPARYGGEN-ØST-85-GRID		19

Package		1989	Total
211	BJØRNØYA-ØST-TEST-85 #		1
212	BJØRNØYA-VEST-86-DIAG	1	12
213	BJØRNØYA-VEST-86-HIGH	1	12
214	BJØRNØYA-VEST-86-MARGIN	2	11
215	BJØRNØYA-VEST-86-SWATH #		1
216	BJØRNØYA-VEST-87	2	11
300	BARENTSHAVET-SØR-ØST-HOVEDPAKKE		22
301	BARENTSHAVET-SØR-ØST-PAKKE-2	1	21
302	NORDKAPP-BASSENGET-85-GECO-DIAG		19
303	NORDKAPP-BASSENGET-85-NORD		18
304	NORDKAPP-BASSENGET-85-GRID		21
305	NORDKAPP-BASSENGET-86-DIAG		19
306	NORDKAPP-BASSENGET-86-SØR		20
307	NORDKAPP-BASSENGET-86-NORD		14
308	FINNMARK-ØST-86-REGIONAL	1	19
309	FINNMARK-ØST-86-DIAG	2	18
310	FINNMARK-ØST-86-GSI	1	19
312	NORDKAPP-TEST-87 #		1

2.2.1.5 Release of data and material from the shelf
In connection with the Norwegian Petroleum Directorate's monitoring of the oil activities on the Norwegian continental shelf the Directorate receives copies of well bore logs and continual, representative selections of drill cuttings and cores. Cuttings samples are recovered every 10 meters downhole and every three meters if the formation potentially contains hydrocarbons. For wet samples which should weigh at least half a kilo, the same sampling frequency is observed.

The Directorate is responsible for the publishing of data and release of material specimens for purposes of education and research. Data is released five years after the well is completed. The licensee's interpretations are not released. The Directorate's *Well Data Summary Sheets* are issued once a year and provide a survey of wells five years old in the year of publication. The series aims to show which holes have been released and what core and log materials are available from the respective holes.

Some technical data and test results are also issued as well as a composite log with lithographic specifications of each well hole to scale 1:4000.

In addition to its WDSS series the Directorate started two new publication series in 1989: *Licences, Areas, Area Coordinates, Exploration Wells* and *Borehole List, Exploration Drilling*. Both come out annually. The list of production licences contains a summary of each production licence on the Norwegian continental shelf, stating licence number, allocation date, operator, allocated area, present area, partners and units, geographical coordinate points for area, some data about each well hole drilled in the licence, and a map of each licence area with the wells plotted in. Also included are some historical details and lists and tables presenting the drilling activity. The wellbore lists are an extended version of the Directorate's previous wellbore lists. Exploration wells are sorted according to five different criteria: well number, spudding date, completion date, operator and licence number.

annually. The list of production licences contains a summary of each production licence on the Norwegian continental shelf, stating licence number, allocation date, operator, allocated area, present area, partners and units, geographical coordinate points for area, some data about each well hole drilled in the licence, and a map of each licence area with the wells plotted in. Also included are some historical details and lists and tables presenting the drilling activity. The wellbore lists are an extended version of the Directorate's previous wellbore lists. Exploration wells are sorted according to five different criteria: well number, spudding date, completion date, operator and licence number.

In the Directorate's core study room it is possible to examine the core materials, drill cuttings and wet samples, and in special cases it may be possible to be issued material from the collection in order to study and analyse it outside the confines of the Directorate. The five-year cut-off rule for release qualification also applies in this case. Figure 2.2.1.5.a shows the demand for specimens broken down by discipline: organic chemistry; biostratigraphy; and sedimentology and petrophysics.

Since 1986 the number of applications for release of material has risen sharply. The figure shows that examinations based on organic geochemistry are underrepresented in the projects the Directorate has released material for. However, this discipline accounted for the great majority of material released between 1986 and 1989.

Seismological data are released in packages covering a block at a time and are only released in the case of blocks for which there has been a production licence and for which the seismics are more than five years old. As of 31 December 1989 data from 98 such blocks had been released covering 80,158 km of profiles shot. Figure 2.2.1.5.b is a map summarising the blocks for which data have been released.

2.2.1.6 Scientific research
As of 31 December 1989 a total of 272 licences for

Fig. 2.2.1.5.a
Applications for sample material by subject

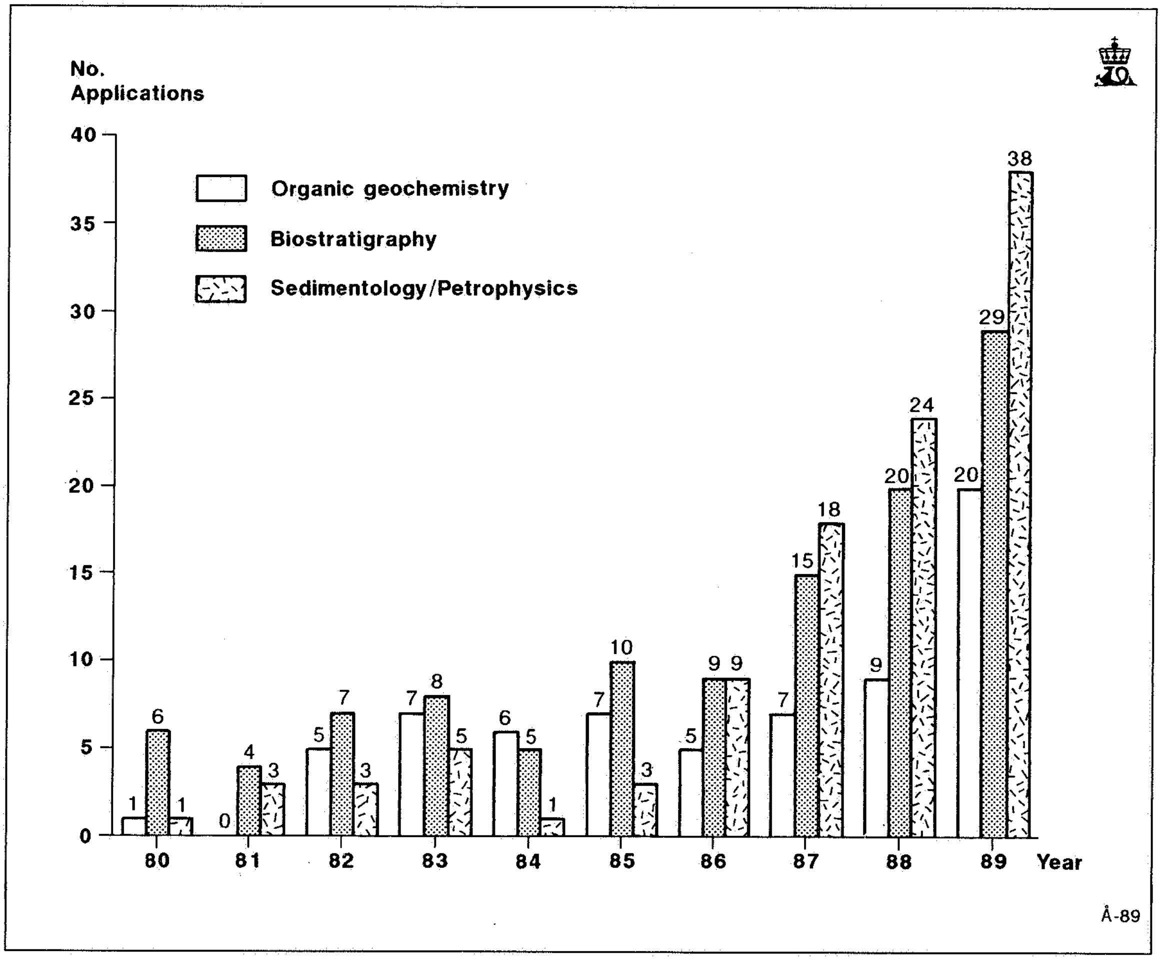
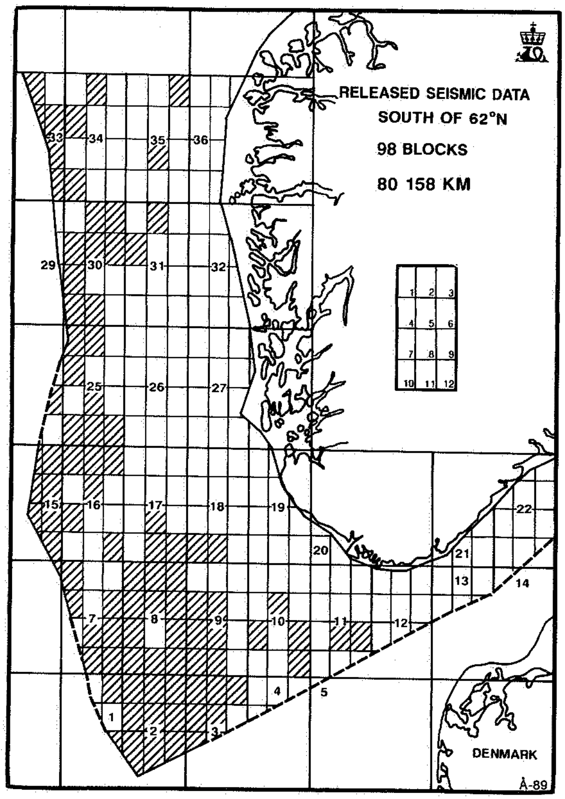


Table 2.2.1.6
Permits for scientific exploration for natural resources

Permit	Institution	Geo-physical survey	Geology	Area
256/89	Institut für Meereskunde Universität Hamburg West Germany	X	X	Skagerrak
13/89-H	Sevmorgeologia Murmansk USSR	X		Svalbard archipelago and associated sea areas
14/89-H	Universitetet i Tromsø Geologisk avdeling IBG i Tromsø	X	X	Barents Sea Norwegian Sea
15/89-H	Universitetet i Tromsø Institutt for biologi og geologi i Tromsø	X	X	Altafjord Lyngenfjord Ullsfjord
16/89-H	Universitetet i Bergen Jordskjelvstasjonen i Bergen		X	Norwegian Sea Greenland Sea

scientific research had been awarded on the Norwegian continental shelf. As Table 2.2.1.6 shows, in 1989 five such licences were awarded, one by the Norwegian Petroleum Directorate in Stavanger and the other four by the Regional Office, Harstad.

Fig. 2.2.1.5.b
Blocks in which seismic data have been released



2.2.2 Exploration drilling

There were four exploration wells being drilled at year end 1988. All were terminated in 1989. Also in 1989, 28 new exploration wells were spudded, 20 wildcats and eight appraisal wells. Another seven exploration wells were reopened in the course of the year. Twenty-four exploration wells were terminated during the year, six were suspended, and nine were still drilling at year end 1989.

A total of 626 exploration wells had been spudded on the Norwegian continental shelf by year end 1989, 449 wildcats and 177 appraisal wells. Figure 2.2.2.a shows the exploration activity on the Norwegian continental shelf.

Drilling activity in 1989 broke down with 21 wells in the North Sea, three offshore Mid-Norway and four offshore North Norway.

In all 29 exploration wells had been temporarily abandoned on the Norwegian continental shelf by year end 1989. Suspended well bores for which equipment has been installed on the seabed are as follows:

1/09–04	30/02–01	34/10–05
1/09–06 S	30/03–04	34/10–32 R
2/07–19	30/06–09	34/10–33 C
2/07–20	30/06–16	6407/07–03
2/11–06	30/06–19	6407/07–04
7/11–07 R	30/06–21	6407/09–03
15/09–17	30/06–22	6407/09–05

Fig. 2.2.2.a
Exploration drilling on the Norwegian continental shelf. Numbers of wells per year 1966–89

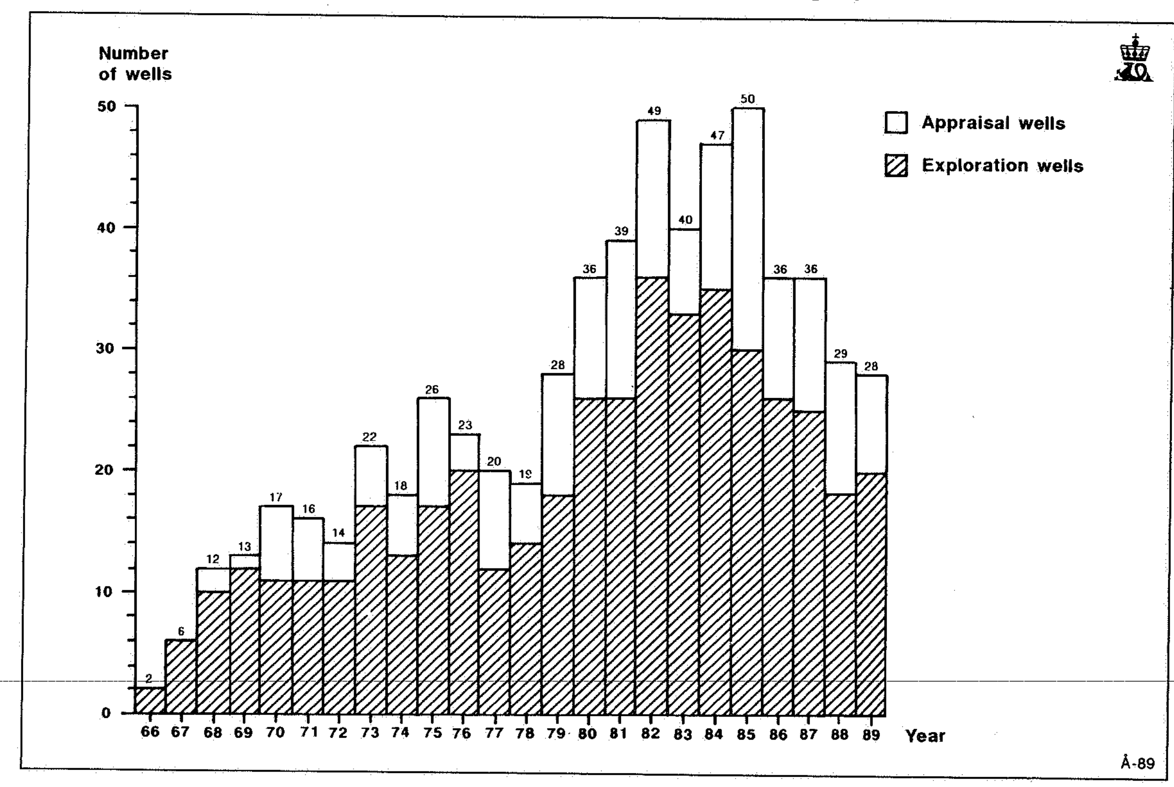
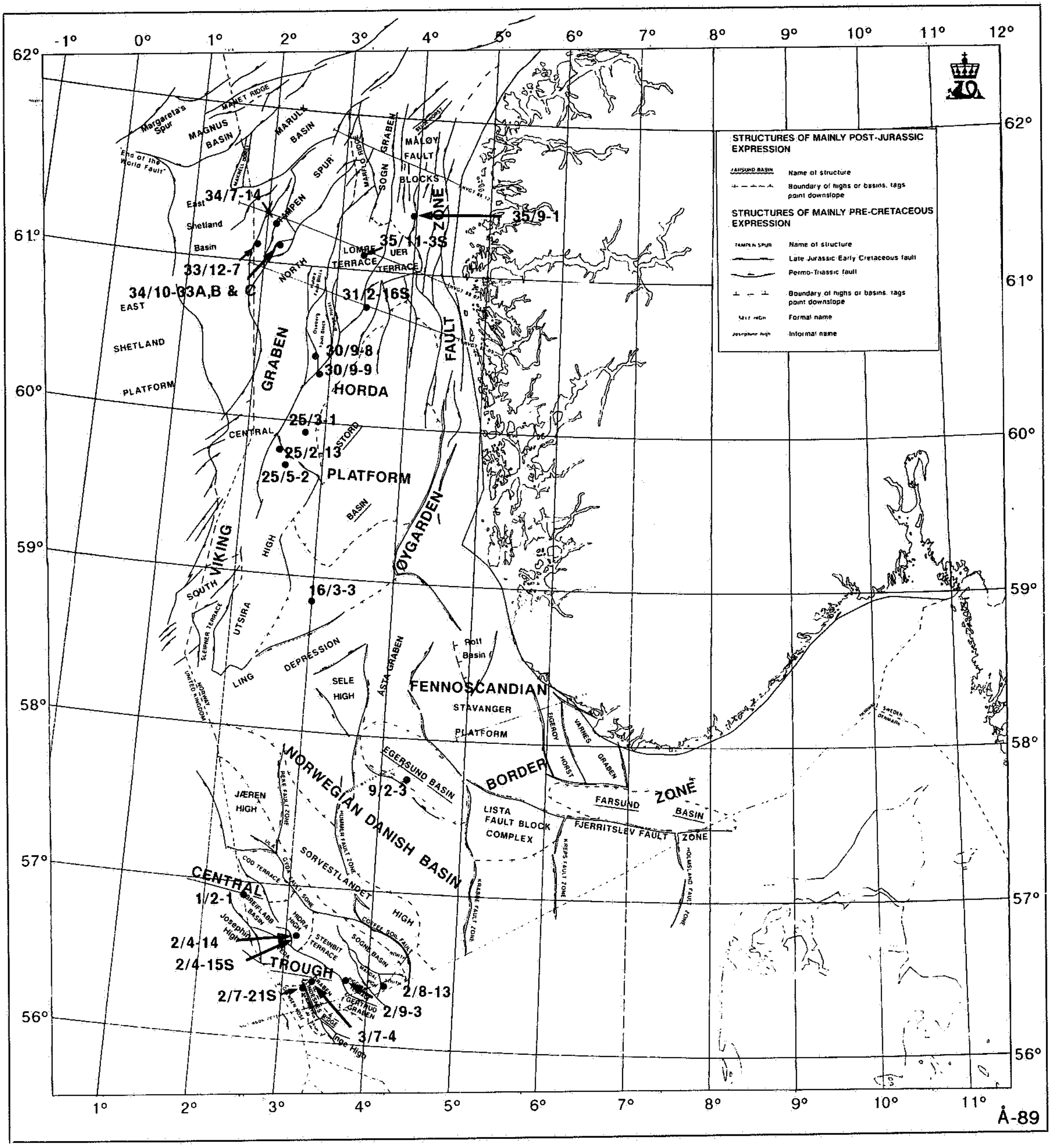


Fig. 2.2.2.b
Wells drilled in 1989 in the North Sea



25/01–07 R3	30/09–02 R	6407/09–06
25/01–08 SR3	30/09–09	6506/12–08
25/02–09	34/04–07	

Figures 2.2.2.b, c and d show the well bores spudded in the three regions of the Norwegian continental shelf (North Sea, Mid-Norway and North Norway) in relation to structural main features.

The Norwegian companies Saga, Hydro and Statoil operated 16 of the spudded bores in 1989, corresponding to 57 per cent. The remaining 12 wells were operated by Shell, Elf, Esso, Mobil, Amoco and Phillips. See Table 8.2.b for details.

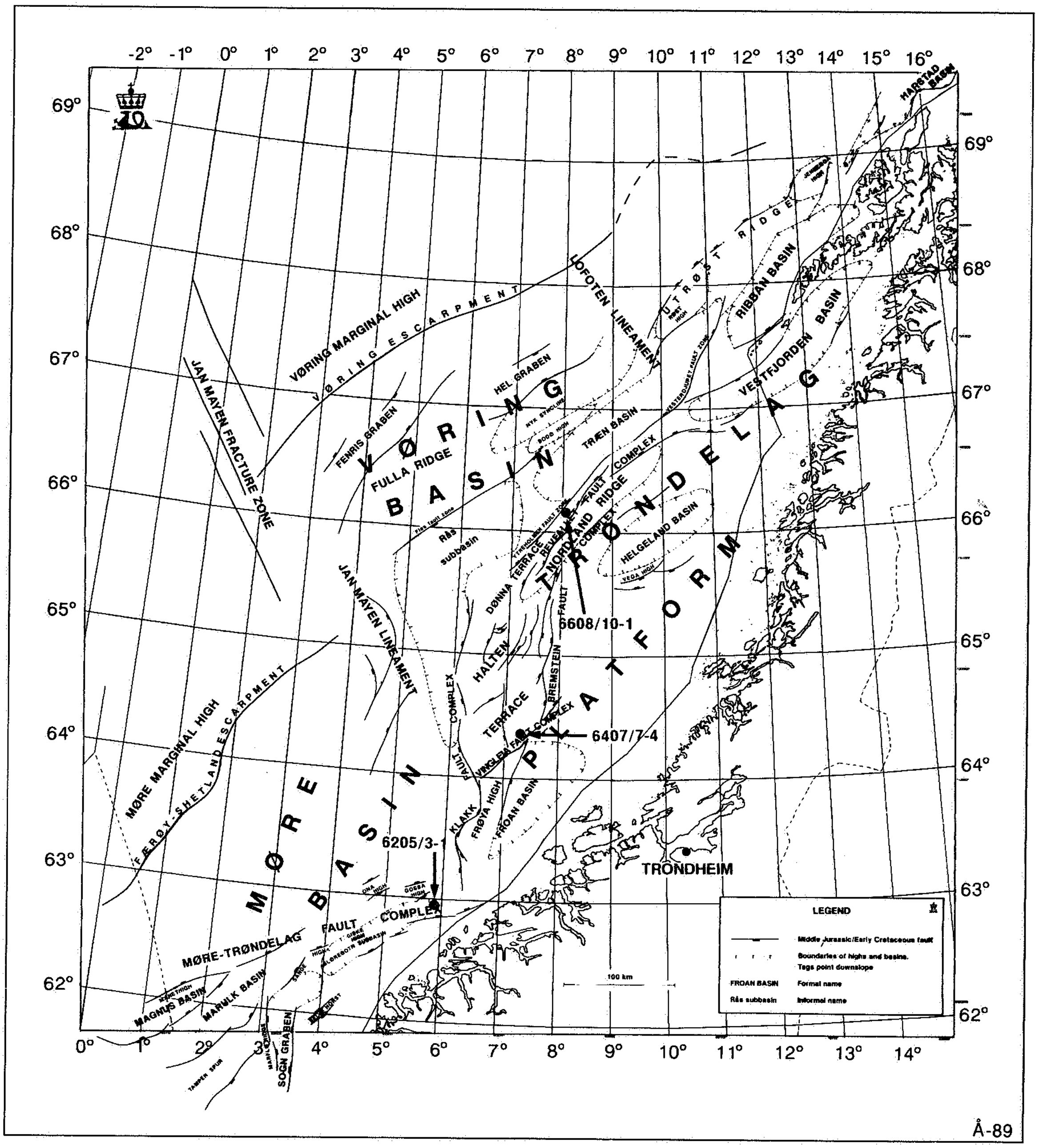
2.2.2.1 Distribution of prospect types

Exploration activity in 1989 was very largely directed to jurassic sandstone prospects. Of the 28 wells started as of 31 December 1989, 23 had jurassic strata as their main prospect. Of the five wells remaining, two were aimed at palaeocene sand, one danian chalk and two triassic sandstone as their main prospect. Some holes had secondary prospects of palaeocene, cretaceous and triassic age.

2.2.2.2 New discoveries in 1989

Twenty-eight exploration wells were started on the Norwegian continental shelf in 1989. The level of ac-

Fig. 2.2.2.c
Wells drilled in 1989 on the Mid-Norwegian shelf



tivity is therefore the same as in 1988. Twenty of the wells are classified as wildcat wells, eight as appraisal wells.

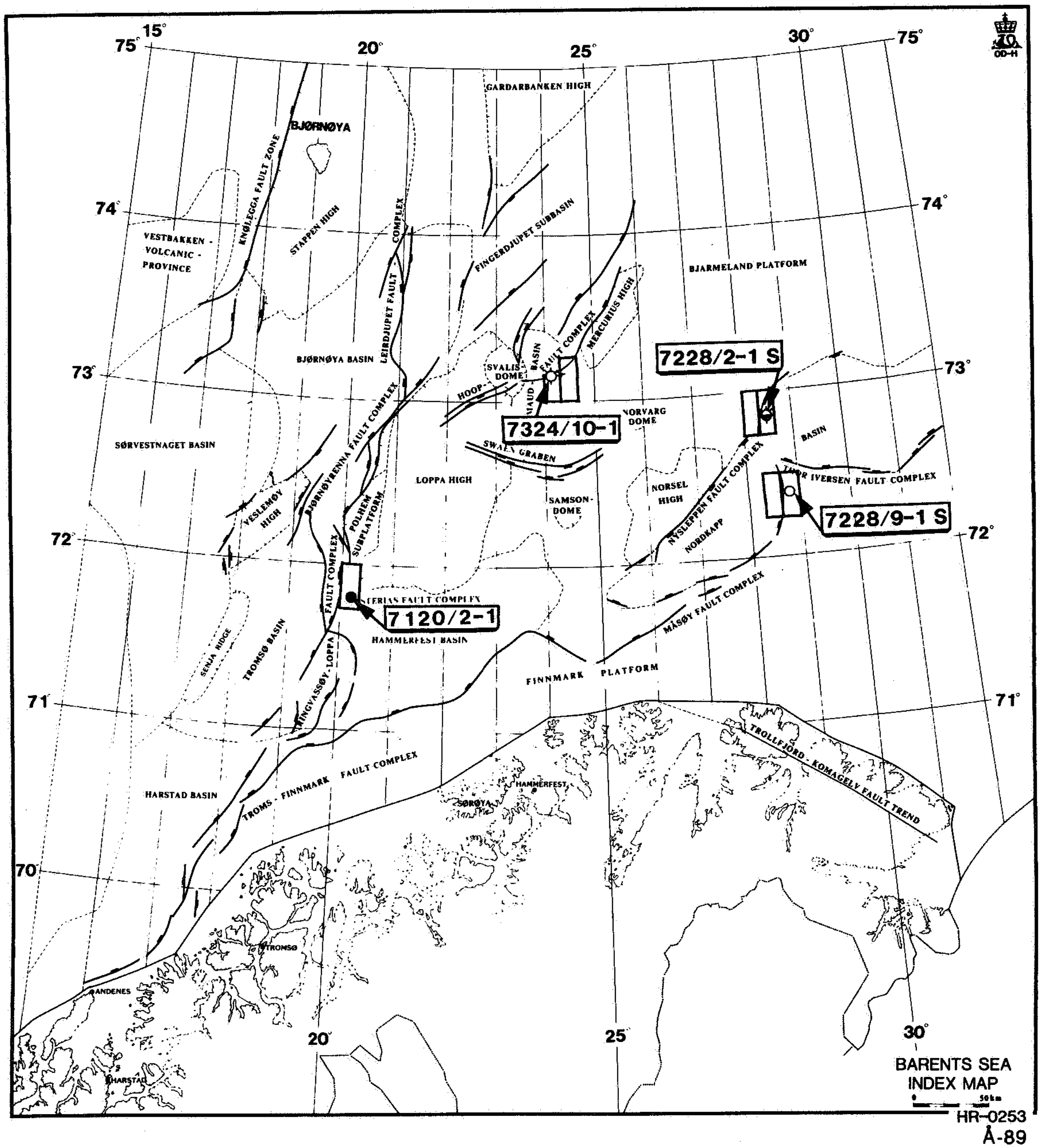
Seventeen of the 20 wildcat wells were drilled into new, previously unpenetrated structures. Sufficient traces of hydrocarbons were proven in four of the holes to classify them as discoveries, eleven were dry, and three were still working towards their prospect at year end. The last two holes, which both proved hydrocarbons, were drilled on separate parts of earlier discoveries.

As regards exploration drilling in general, activity was greatest in the North Sea with 21 holes spudded, while Mid-Norway returned the slackest level with only three new holes. Four holes were started in the Barents Sea.

Block 1/2

Phillips as operator on production licence 143 drilled well no. 1/2–1 which lies between the Cod field and Ekofisk area on the border with the UK sector. Hydrocarbons were proven in palaeocene rocks and two production tests were carried out. The highest production rate measured was 859 scm (standard cu-

Fig. 2.2.2.d
Wells drilled in 1989 in the Barents Sea



bic meters) oil a day and 57,000 scm associated gas through a 25.4 mm choke. The gas-oil ratio was 374 scm/scm and the oil density 0.81 g/cc (grams per cubic centimeter). These results are considered positive. The discovery most probably extends into the UK sector, though it is too early yet to be certain of its true size.

Block 3/7

Shell, the operator of production licence 147, block 3/7, drilled the first exploration well in the licence, well 3/7–4. The block is in the southern part of the North Sea on the border with the Danish sector. The hole was drilled to 3698 meters below sea surface and terminated in permian rock. While drilling, hydrocarbons were proven in jurassic sandstone and at year end 1989 tests of the hole were proceeding. The drilling results are considered encouraging with an eye to future discovery prospects in the area. It is possible the discovery extends into the Danish sector.

Block 30/9

On production licence 104 Hydro drilled and tested exploration well 30/9–9. The well was drilled in a separate structure south of the Oseberg field. Though oil was proven in two separate sandstone layers dating from the mid-jurassic period, no oil-water contact was proven. A production test was made of both zones. The measured peak output was 1353 scm oil a day through a 25.4 mm choke. The recorded gas-oil ratio was 157 scm/scm. Oil density was 0.821 g/cc and gas density 0.755 relative to air. The drilling results are considered positive. It is still too early to say how large the discovery is, though it will cause moderate upward readjustment of the Oseberg reserves figure.

Block 35/9

Hydro drilled well 35/9–1 on production licence 153. This licence was allocated in the 12A licensing round. Hydrocarbons were detected in sandstone of mid-jurassic age where an oil test and two gas tests were made. Maximum oil production measured was 903 scm a day through a 25.4 mm choke. The gas-oil ratio was measured at 284 scm/scm. Maximum recorded gas output 913,000 scm a day through the same size choke. The gas-condensate ratio was measured at 5107 scm/scm. Oil density was 0.815 g/cc and gas relative density 0.705. The drilling results were very encouraging, though it is still too early to put a figure on discovery size, not least because oil-water contact was not encountered.

Table 2.2.2.a
Spudded and terminated exploration wells in 1989 as of 31 December

Exploration Well	Licence/Position Prod Licence	North East	Spudded Terminated	Operator Drill rig	Well type/Completion	Water depth KBE	Total depth Geol period
2/07–14 R	221	56 29 20.30	89.06.07	Phillips	Appraisal	71 m	3690
	018	03 14 02.65	89.06.19	Ross Isle	Duster	22 m	U.Cretac.
25/01–07 R3	455	59 55 08.28	89.04.15	Elf	Appraisal	101 m	2722 m
	024	02 06 09.79	89.04.16	West Vanguard	Suspended	22 m	Cretac.
25/01–08 S3R	466	59 54 03.28	89.04.08	Elf	Appraisal	102 m	2650
	024	02 06 09.79	89.04.11	West Vanguard	Suspended	22 m	Palaeo.
7/12–07 R	583	57 06 31.92	89.05.14	BP	Appraisal	70 m	3852
	019	02 52 47.27	89.05.22	Vildkat	Oil	24 m	Jurassic
2/04–14	593	56 41 05.49	88.10.06	Saga	Exploration	68 m	4734
	146	03 08 43.06	89.01.31	Treasure Saga	Suspended	26 m	
2/04–14 R	593	56 41 05.49	89.05.08	Saga	Exploration	68 m	
	146	03 08 43.06	00.00.00	Neddrill Trigon		26 m	
2/08–12 S	595	56 23 48.80	88.11.07	Amoco	Exploration	68 m	5003
	006	03 26 15.40	89.04.27	Dyvi Stena	Hydrocarbons	25 m	Triassic
25/02–12 A	596	59 57 48.34	88.11.12	Elf	Avgrensning	115 m	3887 m
	026	02 23 40.78	89.04.06	West Vanguard	Gas/Cond.	22 m	M.Jurassic
34/10–33 A	598	61 07 33.44	88.12.16	Statoil	Appraisal	134 m	3851
	050	02 12 57.10	89.02.09	West Delta	Oil	29 m	M.Jurassic
7120/01–02	599	71 47 29.04	89.01.01	Shell	Exploration	304 m	2630
	108	20 16 42.98	89.03.28	Ross Rig	Oil	23 m	Triassic
6407/07–04	600	64 15 43.43	89.01.13	Hydro	Appraisal	328 m	3211 m
	107	07 13 25.84	89.03.28	Polar Pioneer	Suspended	23 m	L.Jurassic
33/12–07	601	61 07 35.72	89.02.22	Statoil	Exploration	140 m	3703 m
	152	01 54 32.50	89.04.27	Deepsea Bergen	Duster	23 m	L.Jurassic
2/04–15 S	602	56 40 27.25	89.01.31	Saga	Exploration	68 m	
	146	03 08 38.79	00.00.00	Treasure Saga		26 m	
35/09–01	603	61 23 00.79	89.03.31	Hydro	Exploration	361 m	2350 m
	153	03 59 03.40	89.05.08	Polar Pioneer	Suspended	23 m	Bedrock
35/09–01 R	603	61 23 07.95	89.07.03	Hydro	Exploration	361 m	2350
	153	03 59 03.72	89.07.27	Polar Pioneer	Oil/Gas	23 m	Bedrock
1/02–01	604	56 53 16.07	89.03.20	Phillips	Exploration	70 m	3576 m
	143	02 28 35.70	89.06.04	Ross Isle	Oil/Gas	24 m	Cretac.
6608/10–01	605	66 06 56.92	89.04.15	Statoil	Exploration	375 m	3437 m
	128	08 10 00.72	89.05.29	Ross Rig	Duster	24 m	U.jura
25/05–02	606	59 42 13.28	89.04.18	Elf	Appraisal	117 m	3304 m
	102	02 32 08.58	89.07.04	West Vanguard	Oil/Gas	22 m	Jurassic
2/08–13	607	56 23 22.20	89.04.29	Amoco	Exploration	68 m	1940 m
	006	03 26 15.40	89.06.22	Dyvi Stena	Duster	25 m	Permian
34/10–33 B	608	61 07 34.44	89.04.27	Statoil	Appraisal	134 m	4050 m
	050	02 12 57.10	89.07.11	Deepsea Bergen	Oil	23 m	Jurassic
7324/10–01	609	73 09 49.45	89.06.03	Statoil	Exploration	407 m	2919 m
	162	24 18 47.62	89.08.19	Ross Rig	Hydrocarbons	23 m	U.trias
2/07–21 S	610	56 20 00.05	89.06.21	Phillips	Appraisal	71 m	
	018	03 14 54.77	00.00.00	Ross Isle		22 m	
35/11–03 S	611	61 05 12.24	89.06.27	Mobil	Exploration	283 m	4040 m
	090	03 20 18.47	89.09.07	Dyvi Stena	Duster	25 m	U.Jurassic

Exploration Well	Licence/Position Prod Licence	North East	Spudded Terminated	Operator Drill rig	Well type/Completion	Water depth KBE	Total depth Geol period
16/03–03	612	58 49 44.79	89.07.24	Esso	Exploration	117 m	1566 m
	149	02 58 21.84	89.08.06	Vildkat	Duster	25 m	Cretac.
25/03–01	613	59 55 52.99	89.07.05	Elf	Exploration	136 m	3922
	151	02 46 21.34	89.09.05	West Vanguard	Duster	22 m	L.Jurassic
34/10–33 C	614	61 07 34.44	89.07.11	Statoil	Appraisal	134 m	3753 m
	050	02 12 57.10	89.08.09	Deepsea Bergen	Suspended	23 m	L/ M.Jurassic
30/09–08	615	60 25 26.10	89.07.29	Hydro	Exploration	104 m	1060 m
	104	02 47 58.38	89.08.02	Polar Pioneer	Suspended	23 m	
30/09–08 R	615	60 25 26.10	89.08.15	Hydro	Exploration	104 m	3200 m
	104	02 47 58.38	89.09.25	Polar Pioneer	Oil/Gas	23 m	L.Jurassic
7228/02–01 S	616	72 51 09.75	89.08.21	Mobil	Exploration	373 m	4300 m
	160	28 26 29.61	89.12.20	Ross Rig	Hydrocarbons	25 m	Triassic
25/02–13	617	59 47 37.69	89.09.06	Elf	Appraisal	116 m	
	112	02 27 12.52	00.00.00	West Vanguard		22 m	
2/09–03	618	56 26 03.90	89.09.15	Amoco	Exploration	66 m	4859 m
	032	03 47 49.55	89.12.14	Dyvi Stena	Hydrocarbons	25 m	Permian
3/07–04	619	56 24 15.60	89.09.20	Shell	Exploration	67 m	
	147	04 14 22.24	00.00.00	Hunter		25 m	
34/07–14	620	61 15 32.24	89.09.28	Saga	Appraisal	148 m	2653 m
	089	02 06 58.05	89.12.02	Vildkat	Oil	25 m	L.Jurassic
30/09–09	621	60 19 51.23	89.09.27	Hydro	Exploration	101 m	2809 m
	104	02 52 28.95	89.11.06	Polar Pioneer	Suspended	23 m	L.Jurassic
31/02–16 S	622	60 46 00.00	89.09.27	Hydro	Appraisal	354 m	2390 m
	054	03 25 27.55	89.12.24	Deepsea Bergen	Suspended	23 m	U.Jurassic
6205/03–01	623	62 57 08.62	89.10.24	Hydro	Exploration	157 m	
	154	05 56 38.11	00.00.00	Maersk Jutlander		22 m	
9/02–03	624	57 45 20.20	89.12.04	Statoil	Exploration	79 m	
	114	04 22 13.50	00.00.00	Vildkat		25 m	
7228/09–01 S	625	72 23 48.36	89.12.22	Hydro	Exploration	276 m	
	161	28 43 08.67	00.00.00	Ross Rig		23 m	
7/07–01	626	57 24 56.88	89.12.30	Statoil	Exploration	82 m	
	148	02 15 59.74	00.00.00	Deepsea Bergen		23 m	

KBE = Kelly Bushing Elevation, R = Reentry, X = Prospective depth not reached, S = Directionally drilled

2.2.2.3 Further details of the various drilling operations

Block 2/4

On production licence 146 Saga is busy at year end cleaning out wildcat 2/4–14 R with a view to plugging it. In January 1989 an uncontrolled kick occurred through the drill string while working over the well bore with coiled tubing. Before this operation Saga had experienced problems maintaining downhole pressure balance in the hole which extended to reservoir level at 4735 meters. The kick was stopped by activating the blow-out preventer and shearing the drill string. Drilling of a relief well 2/4–15 S started soon after this accident occurred.

At the same time as the protracted job of working over and regaining control of the well was initiated, it became clear that subterranean flow of gas and oil was taking place from the reservoir into a layer of sand at 500–800 meters depth. In December Saga succeeded in regaining control of 2/4–14 R thanks to the relief well 2/4–15 S and managed to kill the rogue well flow. The culprit well, 2/4–14 R, will be plugged when the workover is complete. As yet no decision has been taken regarding what use 2/4–15 S should be put to after 2/4–14 R is plugged.

Block 2/7

Phillips as operator of production licence 018 drilled appraisal well 2/7–21 S south of the Eldfisk field. It is not yet known how old the reservoir is or what rocks it comprises. At year end testing of the well was not yet complete.

Block 2/8

Amoco as operator of production licence 006 drilled wildcats 2/8–12 S and 2/8–13 north of the Valhall field and west of Eldfisk. The holes were terminated in rocks of triassic and permian age, respectively. Both holes proved only small amounts, or insignificant traces of hydrocarbons.

Block 2/9

On production licence 032 Amoco drilled wildcat well 2/9–3 northeast of the Valhall field. The hole was drilled down to rocks presumed to be of permian age. Slight traces of hydrocarbons were proven in jurassic sandstone. The hole was not tested.

Block 7/7

Statoil started drilling wildcat well 7/7–1 on production licence 148 on 30 December. Two prospects are due for testing, one in palaeocene sandstone and the other in triassic sandstone.

Block 16/3
On production licence 149 Esso drilled wildcat 16/3–3 east of the Balder field. The hole was drilled down to rock of cretaceous age without proving hydrocarbons.

Block 25/2
Elf as operator on production licence 026 directionally drilled well 25/2–12-A from appraisal hole 25/2–12 north of the East Frigg field. The well was drilled in a structure where 25/2–4 proved oil and gas in 1975. The well proved gas and condensate in jurassic sandstone. Technical problems drilling the well led to only one production test being run. The maximum measured production rate was around 200,000 scm gas and 102 scm condensate a day through a 5.56 mm choke. Measured condensate density was 0.81 g/cc, gas density 0.7 relative to air. These test results are encouraging.

Further south in the same block Elf drilled an appraisal well in a small oil discovery which was detected in rocks dating from the early and mid-jurassic periods by the drilling of well 25/2–5 in 1976. At year end this hole was still undergoing testing.

Block 25/3
On production licence 151 Elf drilled wildcat 25/3–1. This hole entered rock of early jurassic age. The results were disappointing as no hydrocarbons were proven.

Block 25/5
Elf as operator of production licence 102 drilled appraisal hole 25/5–2 in the southern part of the Frøy field. The well which was terminated in rock of early and mid-jurassic age proved hydrocarbons in rock of mid-jurassic period. A water test and an oil test were performed. The maximum measured production rate was 200 scm oil and 35000 scm gas a day through a 9.5 mm choke. The oil density was 0.821 g/cc. The oil-water contact on the field has now been established. The results are disappointing and mean the earlier resources estimates for the field will have to be reduced.

Block 30/9
On production licence 104 Hydro drilled wildcat 30/9–8. This well was drilled into the southern part of the Omega North structure southwest of the Oseberg field in order to obtain better information on the extent of the Omega discovery. Oil was proven in sandstone of mid-jurassic age. A production test was performed in the water zone and as a twin test in the oil zone. The maximum production rate was 405 scm oil a day through a 24.5 mm choke. The gas-oil ratio was measured to be 107 scm/scm. The oil density was 0.867 g/cc. The oil-water contact in the Omega structure is provisionally uncertain, though it is known that the results obtained will lead to an upgrading of the reserves estimated to be in place in the Oseberg area.

Block 31/2
On production licence 054 Hydro drilled the appraisal hole 31/2–16 S into the thin oil zone in the western part of the Troll field. The hole terminates in late jurassic rock and has a horizontal section of about 500 meters. The well has been reclassified as a test well, 31/2-T-1 and is now being used for test production from the thin oil zone. The well will later be incorporated in the Troll-Oseberg Gas Injection project.

Block 33/12
Statoil as operator on production licence 152 drilled exploration well 33/12–7. The well extends into rock of early jurassic age but proved no hydrocarbons. This result was a disappointment as the entry was made in an area in which a lot of oil has been proven earlier.

Block 34/7
On production licence 089 Saga drilled appraisal well 34/7–14 into rocks of early jurassic age. Oil was proven in mid-jurassic sandstone. Two oil tests produced a maximum oil production of 1170 scm a day through a 14.3 mm choke. The gas-oil ratio was shown by measurement to be 67 scm/scm. The oil density was 0.836 g/cc and the gas density 0.69 relative to air. The test results confirm the southern extent of the field and show that the reservoir has high productivity.

Block 34/10
Statoil drilled three directional wells on production licence 050 at appraisal well 34/10–33 in the northern part of the Gullfaks South field. The three wells are directionally drilled towards the northwest and were terminated in rocks dating from the early and mid-jurassic periods. All wells proved oil and gas in rocks of mid-jurassic age. Well 34/10–33-A was particularly intended to enhance the volume of data, though this purpose was partially confounded due to technical impediments. Well 34/10–33-B is the first horizontally drilled well established on the Norwegian continental shelf. Quite unexpectedly, parts of the reservoir along the horizontal portion of the hole were water-bearing. It was intended to undertake a two-month test from the oil zone in the horizontal part of the hole, but technical difficulties led to the well being plugged partially back.

Well 34/10–33-C was directionally drilled from well 34/10–33-B. The well bore was drilled at a 45 degree angle through the reservoir, then reclassified as a test well designated 34/10-T-1. Under testing the well produced an oil rate of 2990 scm a day through a 25.4 mm choke. Over a 30 day period the total production was about 60,000 scm oil of density 0.86 g/cc. The Gullfaks South field estimates remain to be updated as evaluation of the test production results was continuing at year end. The drilling operations show that the field is more complex than previously thought.

Block 35/11
On production licence 090 Mobil drilled wildcat 35/11–3. The well terminated in early jurassic rocks and proved only traces of hydrocarbons.

Block 6205/3
On behalf of production licence 154 Hydro is drilling the first well in the Møre I area. At year end the prospective reservoir had not been attained.

Block 6407/7
Hydro as operator of production licence 107 drilled appraisal well 6407/7–4 on the eastern flank of the Njord field. The well was drilled into rocks of early jurassic age and proved oil in rocks of early and mid-jurassic period. A water test and two oil tests were carried out. The maximum production rate measured was 1923 scm oil a day through a 34.1 mm choke. The gas-oil ratio was 112 scm/scm. Oil density was 0.833 g/cc. These results are positive as it is likely the oil-water contact for the field has now been established and also because oil was proven in a previously undrilled part of the Njord structure.

Block 6608/10
On behalf of production licence 128 Statoil drilled well 6608/11–1 into rocks dating from the early jurassic. No hydrocarbons were proven in the well.

Block 7120/1
Shell as operator of production licence 108 drilled wildcat 7120/12 in the south of the block. Oil was proven in rocks dating from the early cretaceous period though only small amounts of oil were produced during testing of this reservoir.

Block 7324/10
Statoil as the operator on production licence 162 drilled wildcat 7324/10–1 in the northeast of the block. Only traces of gas were proven in sandstone of triassic age. The well was not production tested.

Block 7228/2
Mobil as operator on production licence 160 drilled wildcat 7228/2–1 S on a structure in the North Cape Basin. Only traces of oil were proven in sandstone of mid-jurassic period and traces of gas in sandstone dating from the triassic. The well was not production tested.

Block 7228/9
On behalf of production licence 161 Hydro initiated drilling of exploration well 7228/9–1 S on 22 December 1989. This well is directed to a structure just east of the North Cape Basin.

2.2.2.4 Svalbard
Hydro in collaboration with Store Norske Kullkompani has shot 95 km land-based seismic lines in the Kjellstrømdalen area, inner Adventdalen. Also Polargass Prospektering KB has shot 32 km of land seismics in the area north of Kvalvågen and some marine seismics in the region of Haketangen and Kvalvågen. The Soviet company Trust Arktikugol continued drilling of the exploration well, Vassdalen 3, in Vassdalen to a total depth of 2352 in triassic rocks. Due to technical drilling problems it was decided once at this depth to sidetrack the hole from 1430 meters.

The bypass operation was concluded at 1825 meters for economic reasons. The drilling operation was terminated on 1 November 1989. No hydrocarbons were proven in the hole. Trust Arktikugol has no plans at present to drill new exploration wells for hydrocarbons on Svalbard.

Figure 2.2.2.4 shows the drilling locations on Svalbard and Table 2.2.2.4 the drilling licences awarded on Svalbard in connection with exploration for oil and gas.

2.2.2.5 Opening-up of Barents Sea South
Storting Report no. 40 (1988–89) which deals with the opening-up of the Barents Sea South area for exploration activity was considered by the Norwegian Storting on 7 June 1989. The areas which in the Report were slated for opening up for exploration activity were in the southern part of Finnmark West, Finnmark East, Troms II, Troms III and the remaining non-opened section of Barents Sea South.

The result of the Storting debate was in line with the Ministry of Petroleum and Energy's Recommendation: Troms II was not opened up for exploration drilling on this occasion. No authority was given to conduct exploration drilling north of 73 degrees in the winter period from 1 November to 1 July, nor was permission given to drill in oil-bearing strata west of an imaginary line running from North Cape to Bear Island in the period 20 March to 1 August. Figure 2.2.2.5 shows the areas affected and the time limits imposed.

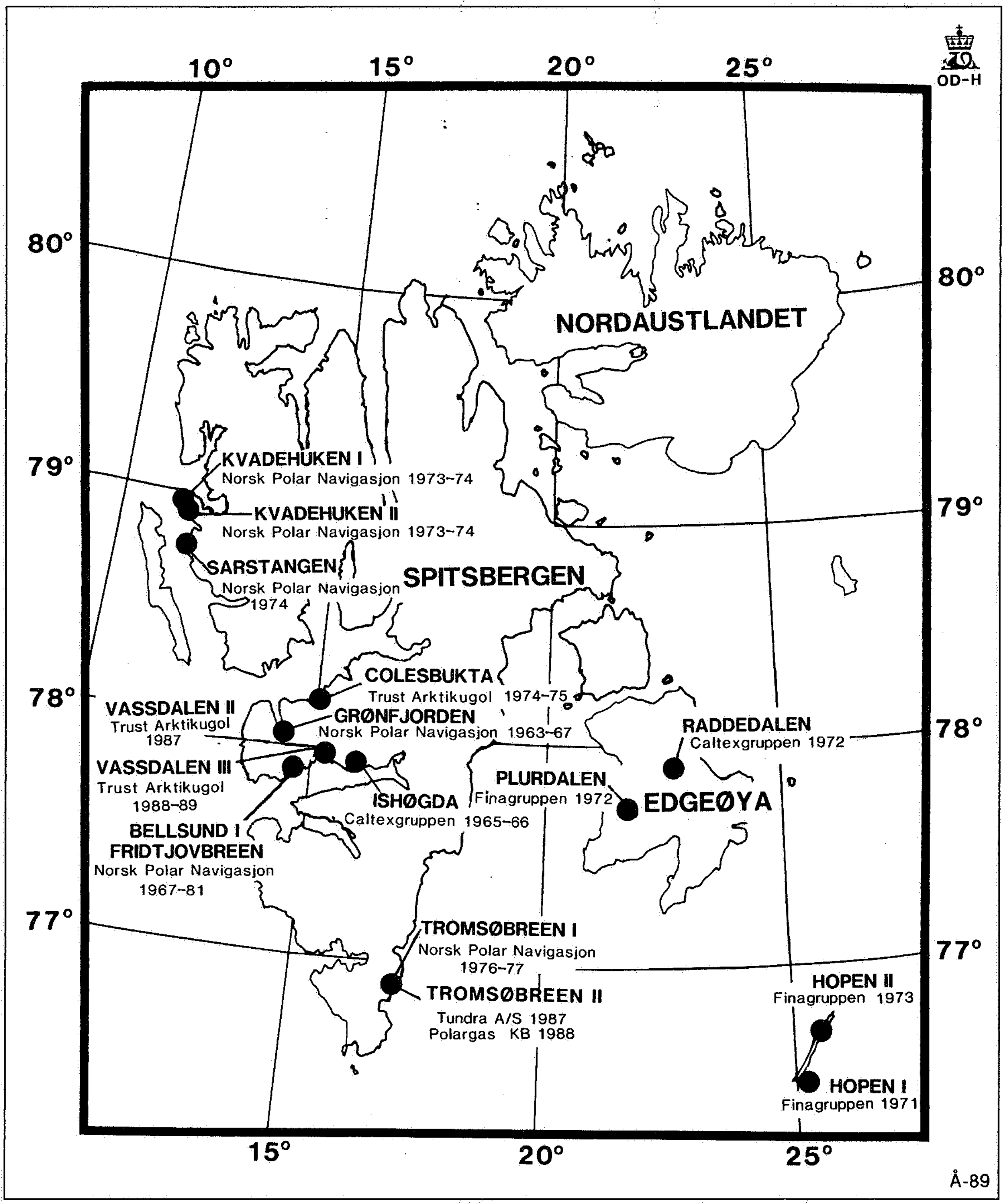
2.3 FIELDS UNDER CONSIDERATION
2.3.1 North Sea
Ekofisk area
Fields around Ula
Block 1/3 is the neighbouring block to the Gyda field in the west, with Elf as operator. A small oil discovery has been proven in the field which extends into block 2/1. There is no communication between the Gyda field and the 1/3–3 structure.

On block 2/2, the neighbour to Gyda in the east where Saga is operator, another small oil discovery has been proven. The water depth here is very moderate, 60 meters.

In block 7/8 northwest of Ula under Conoco's operatorship yet another small oil discovery has been made.

The development of these discoveries, if implemented, needs to be considered in connection with

Fig. 2.2.2.4
Well locations on Svalbard



development of the infrastructure in the immediate vicinity.

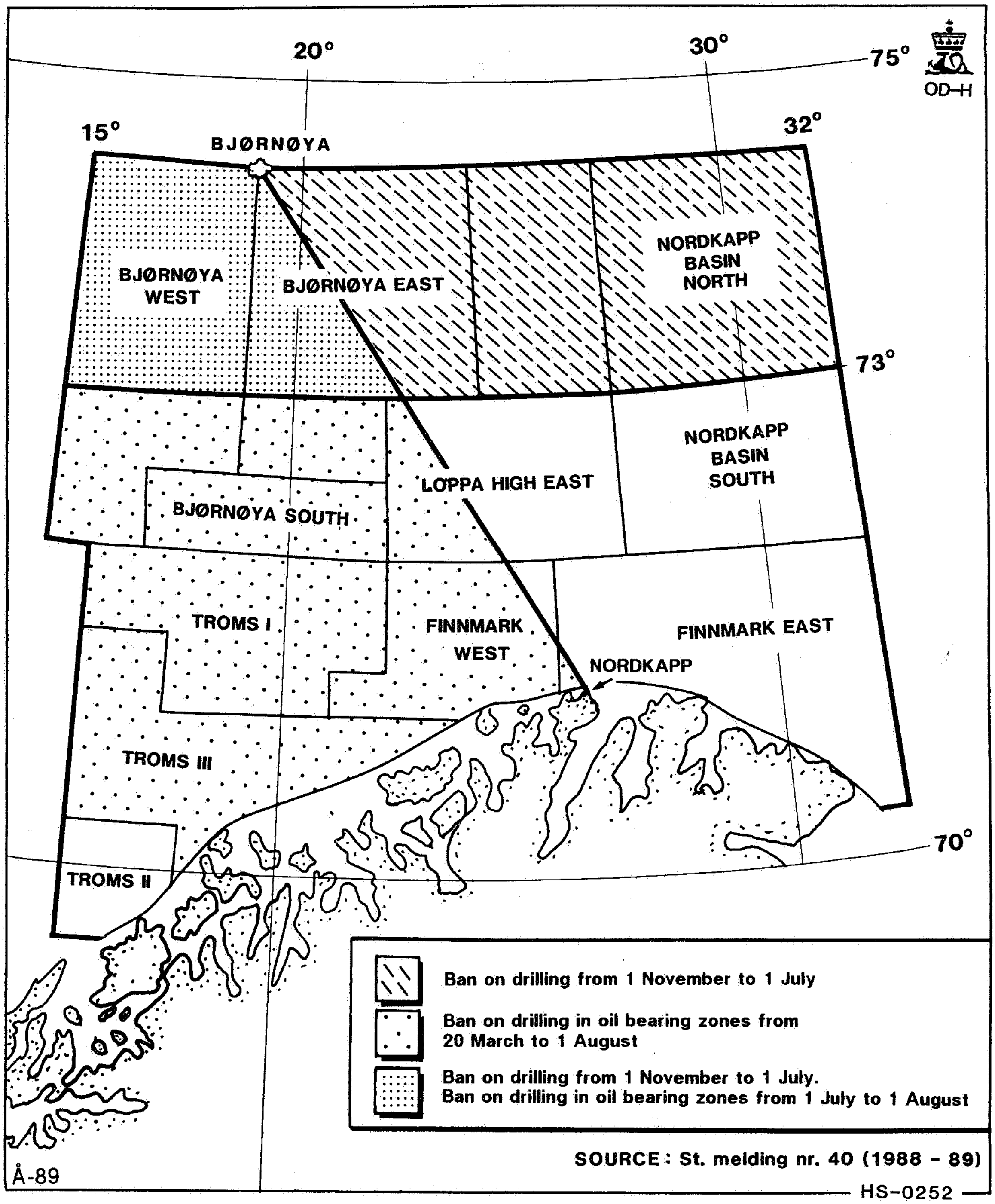
In block 7/11 between Cod and Ula, Hydro made an oil discovery with 7/11-A. In June 1989 Hydro applied for permission to run test production on the field. The Ministry of Petroleum and Energy gave its permission that August. Production is permitted for up to one and a half years from January 1990 and for up to 0.21 mcm oil. Production will be from one well, the well flow from which will be routed to the Cod installation for processing in the test separator. The oil and gas will be mixed with the Cod-produced oil and gas before transportation to the Ekofisk field for end processing.

Table 2.2.2.4
Drilling activity on Svalbard

Exploration well/ Location	Position North East	Spudded	Terminated	Days drilling	Operator Licensee	Total dybde m	KBE over MSL m*
7714/2–1							
Grønnfjorden I	77 57 34	09.06.63	05.09.63	287	Norsk Polar Navig	971.6	7.5
(Nordenskiøld Land)	14 20 36	13.06.64	26.08.64		Norsk Polar Navig		
		26.06.65	08.09.65				
		26.06.67	12.08.67				
7715/3–1							
Ishøgda I	77 50 22	01.08.65	15.03.66	277	Texaco	3304	18
(Spitsbergen)	15 58 00				Caltex-gruppen		
7714/3/1							
Bellsund I	77 47	23.08.67	02.09.67	299*)	Norsk Polar Navig	405	
(Fridtjofsbreen)	14 46	29.06.68	21.08.68		Norsk Polar Navig		
		07.07.69	16.08.69				
		10.07.74	18.09.74				
		16.07.75	20.09.75				
		22.08.80	05.09.80				
		01.07.81	10.08.81				
7625/7–1							
Hopen I	76 26 57	11.08.71	29.09.71	50	Forasol	908	9.1
(Hopen)	25 01 45				Fina-gruppen		
7722/3–1							
Raddedalen	77 54 10	02.04.72	12.07.72	100	Total	2823	84
(Edgeøya)	22 41 50				Caltex-gruppen		
7721/6–1							
Plurdalen	77 44 33	29.06.72	12.10.72	108	Fina	2351	144.6
(Edgeøya)	21 50 00				Fina-gruppen		
7811/2–1							
Kvadehuken I	78 57 03	01.09.72	10.11.72	112	Terratest a/s	479	
(Brøggerhalvøya)	11 23 33	21.04.73	19.06.73		Norsk Polar Navig		
7625/5–1							
Hopen II	76 41 15	20.06.73	20.10.73	123	Westburne Int Ltd	2840.3	314.7
(Hopen)	25 28 00				Fina-gruppen		
7811/2–2							
Kvadehuken II	78 55 32	13.08.73	19.11.73	186	Terratest a/s	394	
(Brøggerhalvøya)	11 33 11	22.03.74	16.06.74		Norsk Polar Navig		
7811/5–1							
Sarstangen	78 43 36	15.08.74	01.12.74	109	Terratest a/s	1113.5	5
(Forlandsrevet)	11 28 40				Norsk Polar Navig		
7815/10–1							
Colesbukta	78 07	13.11.74	01.12.75	373	Trust Arktikugol	3180	12
(Nordenskiøld Land)	15 02						
7617/1–1							
Tromsøbreen I	76 52 30	11.09.76	22.09.76	109	Terratest a/s	990	6.7
(Haketangen)	17 05 30	13.06.77	19.09.77		Norsk Polar Navig		
7617/1–2							
Tromsøbreen II	76 52 31	20.07.87	30.10.87		Deutag	2337	6.7
(Haketangen)	17 05 38	13.06.88	24.08.88	175	Tundra A/S		
7715/1–1							
Vassdalen II	77 49 57	22.01.85	1)		Trust Arktikugol	2481	15.13
(Van Mijenfjorden)	15 11 15						
7715/1–2							
Vassdalen III	77 49 57	30.03.88	01.11.89		Trust Arktikugol	2352	15.13
(Van Mijenfjorden)	15 11 15						

1) Drilling abandoned due to technical difficulties.
* KBE over MSL = Kelly Bushing Elevation over Mean Sea Level.

Fig. 2.2.2.5
Temporary bans on exploration in the Barents Sea South



2/7–20
Block 2/7 was allocated in 1965 as production licence 018 with Phillips as operator. Three holes have been drilled, one in 1973, one in 1988 and an appraisal well in 1989. The Directorate's estimated resources are 33 mcm recoverable oil, though the Directorate has not as yet appraised development options for the field. The operator is considering submitting his plan for development and operation in the course of 1990. The operator will probably suggest development utilising a wellhead installation to be phased in with Eldfisk.

Frigg area

Frøy

The Frøy field lies essentially in production licence 102 with parts in production licence 026. Elf is the operator. Drilling of well 25/5–1 in 1987 proved hydrocarbons in the Sleipner formation.

The Directorate's estimated recoverable reserves have not been revised this year. The operator drilled the appraisal well 25/5–2 in 1989. The Directorate will make a new evaluation of the field in 1990 in the light of the results produced by this well.

The further progress on the field will depend on the results from the ongoing exploration and evaluation of it.

Balder

Balder was proven in 1974 by exploration well 25/11–5 in sandstone dating from the palaeocene. Later, hydrocarbons were also proven in eocene sand. The field is situated in blocks 25/10 and 25/11 on production licences 001 and 028 with Esso as operator.

The Directorate estimates the recoverable reserves at 35 mcm oil. During the year the Directorate carried out a reservoir analysis of the Balder field and Esso ran an interpretation of new 3D seismology data. The results will become available early in 1990. The operator is also working on plans for test production scheduled to start in the first half of 1991. The outcome of this project will decide the subsequent progress on the field.

Oseberg area

This is one of the most prospective areas on the Norwegian continental shelf. Discoveries have been made of different sizes on Oseberg, Brage, Veslefrikk, Huldra, 30/6 Beta, 30/6 Beta Saddle, 30/6 Kappa, 30/6 Gamma North, 30/6 Omega and 30/9–06.

Oseberg itself came on stream in December 1988, see details in section 2.5.10. In addition to Oseberg the Veslefrikk and 30/6 Gamma North fields have been declared commercial.

Brage

The Brage field is situated in block 31/4 and was allocated in 1979 as production licence 055. Hydro is the operator and the plan for development and operation was submitted to the authorities in December 1987. Final approval of the plan was deferred by up to five years by Storting Proposition no. 56 (1987–88). An updated PDO was submitted to the authorities in May 1989 and is expected to be considered by the Storting in spring 1990.

Oil was proven in three formations on Brage: Statfjord, Fensfjord and Sognefjord. The Directorate has put the recoverable reserves at 46.2 mcm oil and 3.5 bcm gas.

The development plan calls for an integrated production, drilling and accommodation platform with a maximum processing capacity of 13,500 scm oil a day.

30/6 Beta and 30/6 Beta Saddle

The fields 30/6 Beta and 30/6 Beta Saddle consist of two structural elements which are separated from one another by a sealing fault. Both elements are covered by production licence 053 where Hydro is the operator. Oil has been proven in both structures in sandstone belonging to the Brent group. The operator estimates the resources in the two structures to be 19 mcm recoverable oil.

There are several alternative ways of developing the Beta area: relatively low permeability in the reservoir and the need for a large number of wells favour the use of a bottom-sitting installation rather than seafloor-completed wells. An installation is being considered with a processing system for full or partial stabilizing of the oil. If partial processing is opted for, end processing will be undertaken at the Oseberg field center.

30/9 Omega

Field 30/9 Omega is situated to the west of the Oseberg field center. Though most of the resources are in production licence 079, the structure also extends south into production licence 104. Hydro operates the field.

Oil and gas have been proven in the Ness and Tarbert formations. Estimates of the resources base are highly speculative. In 1989 an appraisal well was started on the structure but information from it will have to be analysed before it can be decided whether development is commercial.

Part of the Omega structure lies within the drainage perimeter of the Oseberg field center and could therefore be produced using wells from this installation. The other resources in Omega can be depleted either using wells on the seabed or by employing a single wellhead installation tied in to Oseberg.

Gullfaks area

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

Block 34/10 was allocated in 1978 with Statoil as operator, see history of Gullfaks in section 2.5.9. Gullfaks South lies in the middle of the block, about 9 km south of the Gullfaks field. The Beta field lies to the west of Gullfaks South and extends into 33/12. Gamma lies in the southeast corner of the block.

Gullfaks South is structurally complex: several unconnected gas-oil, gas-water and oil-water contacts have been detected. Hydrocarbons have been proven in sandstone dating from the mid and early jurassic period and triassic period.

So far nine wells have been drilled to reservoir level on Gullfaks South in addition to one on Beta and one on Gamma. Well 34/10–33 was drilled in the final quarter of 1988 on the northern part of Gullfaks South. Gas and oil were proven in sandstone of mid-jurassic age. Well 34/10–33 proved very much more oil in the Brent formation than previously suspected.

On 11 May 1989 Statoil was given permission to carry out test production from a horizontal well in Gullfaks South. The permit was valid for two months' production or 240,000 scm produced oil, whichever came first. Drilling of the horizontal bore proceeded uneventfully, but during preparations for the test such serious technical difficulties were encountered that it was decided to directionally drill and do the test in this bore instead. The new bore was drilled at 45 degrees and produced about 60,000 scm oil in a month.

Test production in the oil zone was carried out in order to obtain essential details of production conditions in the reservoir. Work is being done to evaluate the test results obtained.

The test results in combination with new 3D seismics data will form the basis for a new analysis and new reservoir simulations. The resources base in Gullfaks South is presently very tentative. The new analysis and new reservoir simulations will generate new field resources estimates.

Statoil is considering alternative development concepts for the field involving both sequential and simultaneous production of oil and gas. Coordination with either Gullfaks or Statfjord is feasible.

Block 34/8

No wells were drilled on production licence 120 in 1989. Hydro has previously made three wildcat and one appraisal well in the block. The two wildcats on what is known as the A structure proved significant quantities of oil and gas. The resources potential of the block is still believed to be relatively large and extensive activity is anticipated on the licence as the six-year period draws to a close. In 1990 one wildcat will be drilled and new seismics will be acquired for the block.

Statfjord area

Statfjord North

Statfjord North belongs under production licence 037 which embraces blocks 33/9 and 33/12. The licence was awarded in 1973. The field is 17 km north of the Statfjord C installation and was proven by well 33/9–8 in 1977. Oil was proven in two separate sandstone reservoirs: Volgian sand dating from the late jurassic period and Brent sand dating from the middle jurassic.

The operator recommends development of Statfjord North using six production and four injection wells. All wells will be completed subsea. The wellflow will be routed by pipelines to the Statfjord C platform for processing, metering and export through the Statfjord field plant. The plan for development and operation was presented to the authorities on 18 December 1989. The operator's plan assumes government approval in spring 1990 and production start-up in October 1993.

The Directorate is concerned to arrive at an optimal joint development strategy for all the satellite fields in the Statfjord, Snorre and Gullfaks area.

Statfjord East

Statfjord East is part of production licence 037 which embraces blocks 33/9 and 33/12 and production licence 089 which embraces block 34/7. The production licences were awarded in 1973 for blocks 33/9 and 33/12 and in 1984 for block 34/7. Statfjord East was proven by well 33/9–7 in 1976. Oil was proven in sandstone of the Brent group of mid-jurassic age.

The operator has recommended the development of Statfjord East using six production and four injection wells. Two of the latter are being considered for drilling from the Statfjord C platform. The remaining wells will be seafloor completions. The wellflow will be taken by pipeline to the Statfjord C platform for processing, metering and export through the plant on the Statfjord field. The plan for development and operation of Statfjord East was submitted to the authorities on 29 December 1989. The operator's plans assume government approval in spring 1990 and production start-up in spring 1994.

34/7-B

Field 34/7-B was proven in autumn 1987 and is a Brent reservoir which is split into three separate segments. The two wells drilled on the field have proven about two-thirds of the estimated reserves. It is planned to analyse the eastern segment, which has been drilled, solely by reprocessing the seismic data in 1990. The operator intends to submit his plan for development and operation in December 1990 preparatory to production start-up in 1994.

The operator's estimated recoverable reserves are 26 mcm oil.

No complete evaluation of development options has been undertaken yet, though the most probable concept is a subsea production system tied in to existing infrastructure in the vicinity.

Progress on the field will depend to some extent on the results produced by the exploration wells planned on the licence in the first half of 1990. A big discovery would very likely provoke a change in the plans and work schedule for field 34/7-B.

2.3.2 Haltenbanken

Heidrun

Eight exploration and appraisal wells have been drilled on Heidrun, a field which contains heavy oil with an overlying gas dome. The reservoir is heavily faulted and contains several reservoir formations. In order to get the most from the reservoir the gas dome should be produced after most of the oil has been recovered. The Directorate estimates the field reserves at 87 mcm recoverable oil and 43 bcm recoverable gas, while the operator puts oil reserves at

119.3 mcm. This is evidence of the not-inconsiderable uncertainty prevailing on Heidrun.

The former plans calling for early production from Heidrun were scrapped in 1989. The operator is currently planning to develop the field using a tension leg platform having a concrete flotation hull. Phasing-in of subsea wells is also called for. The operator presented his plan for development and operation to the authorities on 15 December 1989 giving production start-up in 1995.

The operator is examining several strategies for application of the gas in place in the field, among them utilisation in a petrochemicals plant onshore, injection of the gas into a close-lying water-flooded structure, or reinjection into the reservoir.

Midgard

Four exploration wells have already been drilled on the Midgard field, a structure which is divided into three parts by two transverse faults. The field contains mainly gas and the reservoir properties are good.

In one of the fault blocks a thin oil zone has been proven which may be troublesome to produce since it is situated between a large gas dome and a water zone. The Directorate assumes recoverable resources of 80 bcm gas and 15 mcm oil.

Production start-up and output will depend on the gas market. The development options being considered for the field are bottom-standing platform or floating installation. Also being considered is whether to develop parts of the field using subsea wells tied in to Heidrun.

Njord

Four exploration wells have now been drilled in 6407/7 which have all proven oil. Though the one well drilled in 6407/10 did not prove oil, it is nevertheless assumed that the field extends into block 6407/10. The fourth well proved an oil-water contact in the eastern part of Njord. The Directorate puts the field's in-place resources at 25 mcm recoverable oil and 4 bcm recoverable gas.

Smørbukk and 6506/12 Beta

A total of eight wells have been drilled in this block. The two fields contain partially gas condensate and partially oil with a relatively high gas-to-oil ratio.

During 1989 the Directorate charted the 6506/12 field on the evidence of 3D seismology data, though no new quantity evaluations were made. The Directorate estimates Smørbukk's field resources are 20 mcm recoverable oil and condensate plus 65 bcm recoverable gas. On 6506/12 Beta there are an estimated 22 mcm oil and condensate and 11 bcm gas.

Of the two discoveries in the block, 6506/12 Beta is the most mature and likely to be developed since its liquids potential is held to be greater than for Smørbukk. The Beta structure might be recoverable using gas recirculation, thereby displacing sale of the gas some years into the future.

Tyrihans

Two wells have been drilled on Tyrihans which consists of two structures, one holding gas and condensate and the other having a thin oil zone and gas dome. The resources estimates are 16 mcm recoverable oil and condensate and 40 bcm recoverable gas.

2.3.3 Troms

Approximately 250 bcm recoverable gas have been proven on Troms I (see Figure 2.3.3) in addition to which there is a thin oil zone on Snøhvit.

Snøhvit

In the last few years the Snøhvit partners have submitted studies of possible development concepts. The following concepts are considered by the licensees to be the most interesting technically and economically:

- One or two semi-submersible installations with subsea completion wells, with gas and condensate to be carried by separate pipelines to an LNG terminal onshore.
- One permanent gravity base structure of concrete (GBS-PDQ), with gas to be carried by pipeline to the LNG terminal onshore while condensate is processed, stored and offloaded on the field.
- A specially constructed production ship producing LNG on the field.

All development options with the exception of the production ship are based on an annual output of 6 bcm gas and annual sales of about 5 bcm gas.

The market analyses so far carried out show that sale of gas from Snøhvit cannot begin before 1995 at the earliest. The licensees will nevertheless continue working on market options and opportunities for alternative use of the gas.

2.4 FIELDS DECLARED COMMERCIAL

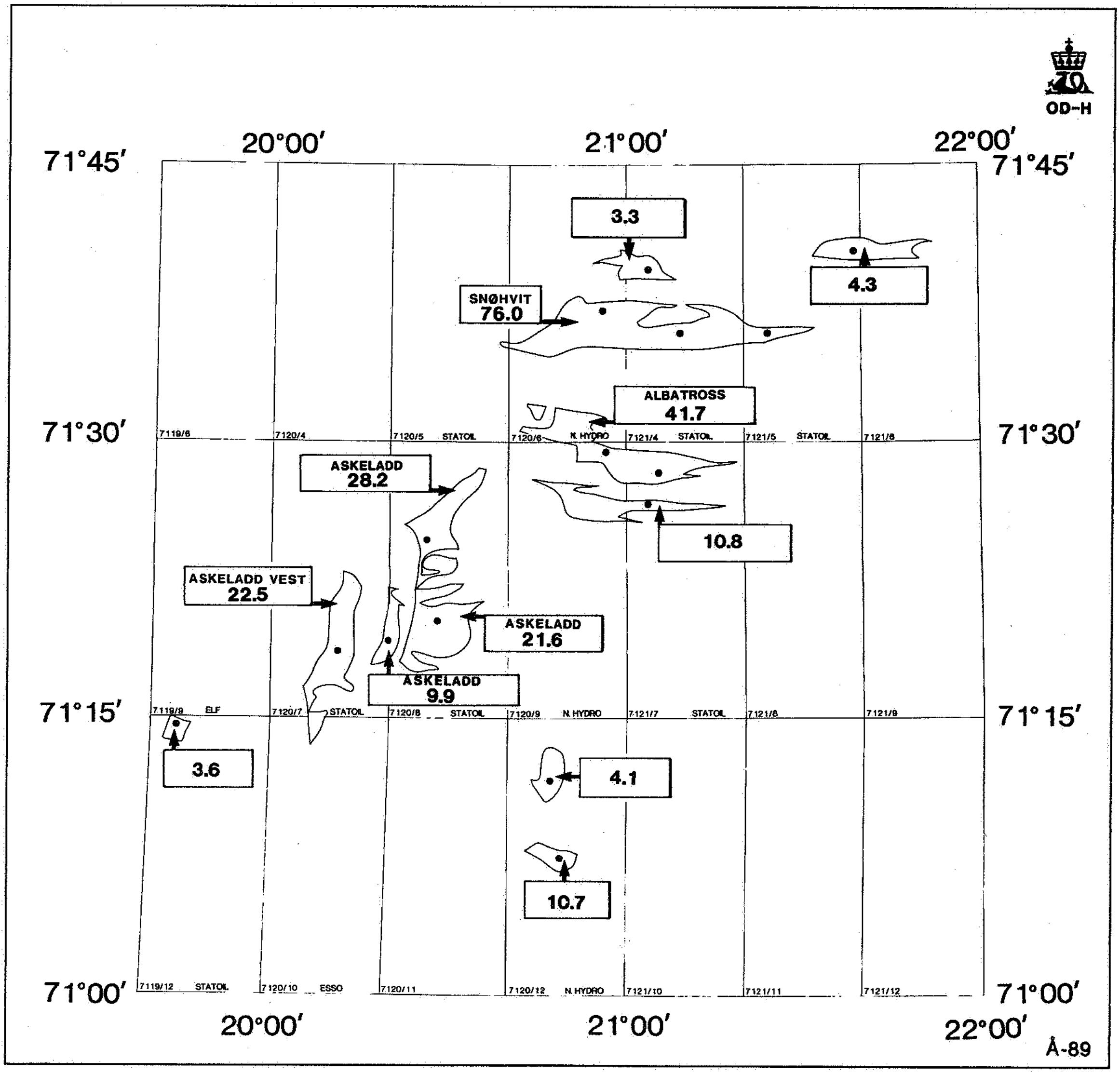
2.4.1 Hod

Licensees

Amoco Norway Company (operator)	25 %
Amerada Hess Norge A/S	25 %
Enterprise Oil Norway A/S	25 %
Norwegian Oil Consortium A/S & Co	25 %

Block 2/11, allocated in 1969 as production licence 033 with Amoco as operator, lies around 12 km south of the Valhall field. Parts of the block have since been relinquished and parts of the relinquished areas have been included in production licence 068. The Hod field comprises two small structures, West Hod and East Hod (see Figure 2.5.1.a). Five exploration and appraisal wells have been drilled on the field in all. One well on West Hod and two wells on East Hod proved and tested oil with associated gas

Fig. 2.3.3
Troms I. The resource basis. Recoverable gas indicated in 10^9Sm^3



in limestone reservoirs of late cretaceous or early tertiary age.

The partners submitted their plan for development and operation in spring 1988 and it has since been approved by the authorities.

Development
The Hod field will be developed using an unmanned wellhead installation positioned above a seafloor template with eight well slots. Five production wells are planned, though more may be needed. Oil production is driven by depressurisation.

Production
Produced quantities will be transported to Valhall in a multiphase pipeline. The operator plans to bring the field on stream in autumn 1990.

The operator estimates recoverable reserves on the field to be 4 mcm oil, 0.9 bcm gas and 0.3 mton NGL. According to the operator the estimated costs of development are in the region of 700 million 1989 kroner.

2.4.2 Gyda
The Gyda field is situated in block 2/1, about 28 km southeast of the Ula field. The field is covered by production licence 019B.

Licensees

Den norske stats oljeselskap a.s (Statoil)	50.000 %
BP Norway Limited U.A	26.625 %
Norske Conoco A/S	9.375 %
K/S A/S Pelican & Co	4.000 %
AECD	5.000 %
MOECO	5.000 %

BP operates the field which was declared commercial on 22 January 1987. The partners submitted their plan for development and operation for Gyda on 11 March 1987 and it was approved by the Storting that same spring.

Development

The plan for development of the Gyda field assumes a fixed installation for accommodation, drilling and processing of oil and gas, see Figure 2.4.2. The oil will be transported through the Ula-Ekofisk pipeline to Ekofisk and thence to Teesside. The gas will be exported in a new dedicated line directly to Ekofisk.

The drilling template has already been installed on the field and eight production wells have been drilled. The steel jacket, accommodation quarters module and cellar deck have been emplaced on the field. Tow-out and installation of the other modules was carried out in December 1989 and January 1990. Production is planned to start on 1 July 1990.

The plan calls for production using water injection as drive mechanism and assumes 19 production and 11 water injection wells.

The operator estimates in place reserves to be 31.8 mcm oil. The Directorate puts the reserves at 30.5 mcm oil and 3 bcm gas.

Using the predrilled wells it will be possible to reach plateau production right from the start. Plateau production is planned at 9500 scm oil and 1.1 mcm gas a day and will last for about two years. Thereafter production will gradually decline and is expected to cease in year 2010.

Costs

The estimated total development costs are 8.2 billion 1989 kroner. Estimated total operating costs are 12.6 billion 1989 kroner.

2.4.3 Sleipner East

Production licence 046

Licensees

Esso Exploration and Production Norway A/S	30.4 %
Norsk Hydro Produksjon a.s	10.0 %
Den norske stats oljeselskap a.s (Statoil)	49.6 %
Elf Aquitaine Norge A/S	9.0 %
Total Marine Norsk A/S	1.0 %

The production licence was allocated in 1976 and embraces blocks 15/8 and 15/9. Statoil is the operator for the Sleipner East field (see Figure 2.4.3).

Fig. 2.4.2
Installation on Gyda

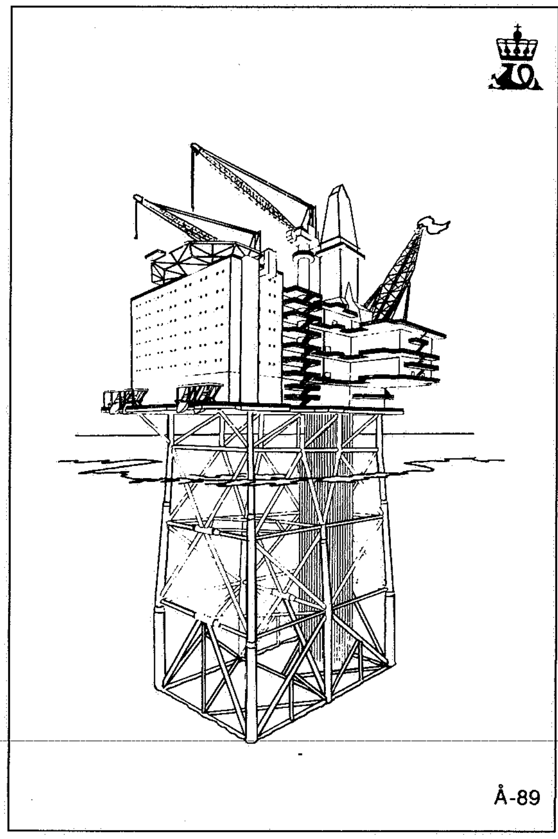
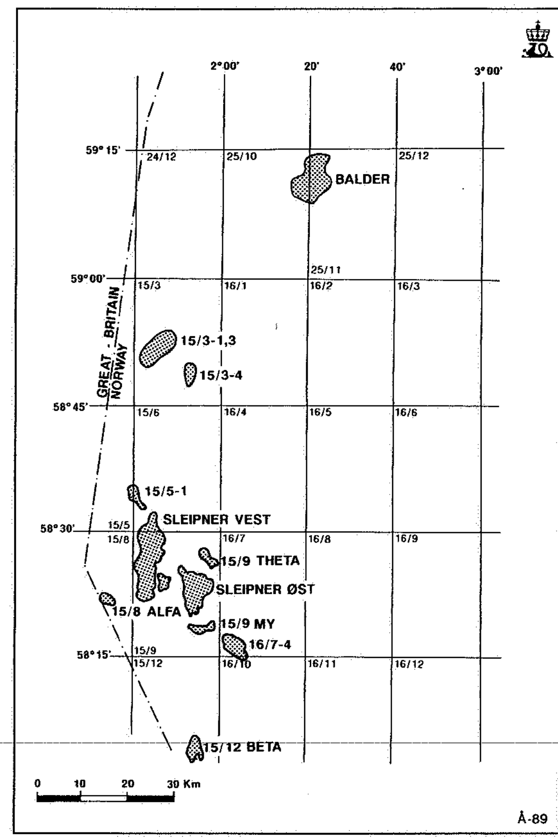


Fig. 2.4.3
The Sleipner and Balder area



The Directorate's estimated reserves in place in Sleipner East are 51 bcm gas, 19 mcm oil and 10 mton NGL.

Development

The decision to go ahead with Sleipner East development involves a fully integrated process, drilling and accommodation platform with quadripod gravity base of concrete.

Condensate will be landed to Kårstø after laying a new 508 mm pipeline from Sleipner A to Kårstø. The gas will be transported partially by pipeline to Zeebrügge in Belgium and partially through the Statpipe-Norpipe system to Emden in West Germany.

Costs

The estimated total development costs and total operating costs are 17.3 billion and 9.3 billion 1989 kroner, respectively, exclusive transportation costs.

2.4.4 30/6 Gamma North

Partner interests in production licence 053 (from 1 April 1989):

Den norske stats oljeselskap a.s (Statoil)	59.04 %
Norsk Hydro Produksjon a.s (operator)	12.25 %
Saga Petroleum a.s	7.35 %
Elf Aquitaine Norge A/S	9.33 %
Mobil Development Norway A/S	7.00 %
Total Marine Norsk A/S	4.67 %

In order to meet the demand for additional injection gas in connection with acceleration of the Oseberg Phase II development, it was decided by Royal Decree of 23 December 1988 to permit development of the Gamma North structure in block 30/6. This structure lies within production licence 053 but outside the unitised portion of the Oseberg field.

Gamma North contains gas with an underlying thin oil zone. A horizontal well will be drilled with which to produce the gas which is necessary for injection into Oseberg. The well will be completed subsea and operated from Oseberg C. Production is planned to start in October 1991.

Experience with the well will decide whether to drill a further production well on Gamma North. For further details on Gamma North, see section 2.5.10 on Oseberg.

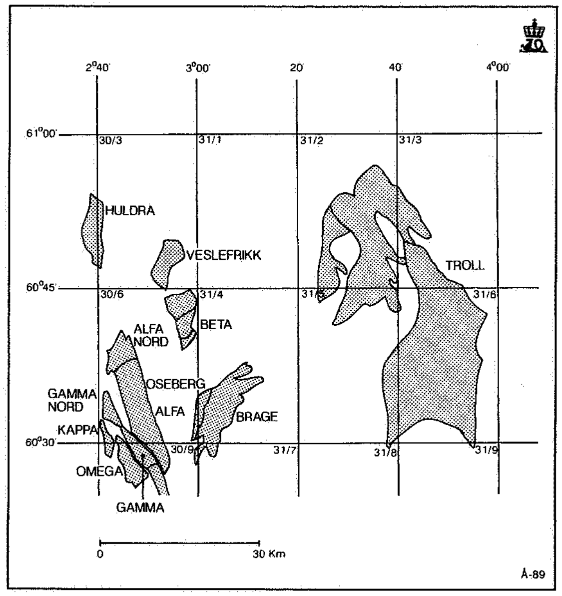
2.4.5 Troll

Production licence 054 and 085

Licensees after unitisation

Den norske stats oljeselskap a.s (Statoil)	74.576 %
A/S Norske Shell	8.288 %
Norsk Hydro Produksjon A/S	7.688 %
Saga Petroleum A/S	4.080 %
Elf Aquitaine Norge A/S	2.353 %
Conoco Norway Inc	2.015 %
Total Marine Norsk A/S	1.000 %

Fig. 2.4.5
The Oseberg and Troll area



The Troll field covers parts of blocks 31/2, 31/3, 31/5 and 31/6 (Figure 2.4.5). Allocation of 31/2 was made in 1979 while the other three blocks were allocated in 1983. Block 31/2 is production licence 054 with Shell as operator while blocks 31/3, 31/5 and 31/6 are production licence 085 with operatorship divided between Statoil, Saga and Hydro. Unitisation of the two production licences has been completed.

The reservoir is situated in three geological formations of late jurassic period. The upper formation (Sognefjord) is dominated by medium to coarse grade sandstone with good reservoir properties. This formation, the largest in the reservoir, fades into the underlying middle formation (Heather), which comprises silt and fine grade sandstone with a relatively high mica content. Flow properties are therefore not as good in Heather. The lower formation comprises sandstone of variable reservoir properties.

At the top of Troll West in block 31/2 and the top of Troll East in 31/6 and 31/3 is a gas column over 200 meters high. This gas column varies across the field and is significantly shorter in the western sections of Troll. The western part of the field, lying predominantly in block 31/2, features an oil column 22 to 27 meters tall under the gas, compared with 10 to 17 meters further east in the block. In Troll East the proven oil strata vary from zero to a few meters in thickness.

The Directorate estimates the recoverable reserves in place in Troll to be 1,288 bcm gas and 41 mcm oil. This does not include oil in those parts of the field where the column is 10 to 17 meters tall, though the prospects of recovering oil from this part of the field are still being weighed.

Shell as operator of the first gas development on Troll submitted the partners' plan for development and operation of gas phase I to the authorities in September 1986. Storting considered the PDO in December 1986. The development plan called for a platform with a concrete gravity base with initial capacity of 90 mcm gas a day once all process trains are installed. The plan will be updated by the operator and resubmitted to the authorities during 1990.

In addition to the principal gas development project a subsea production system (Troll-Oseberg Gas Injection) for gas required for injection on Oseberg from 1991 has been declared. Norsk Hydro is operator for the TOGI development.

The Troll partners are also in the process of making plans and engaging in studies in connection with Troll phase II. Both the thick and the thin Troll oil zone are being considered for development. Hydro drilled a horizontal well in the south of the thick oil zone and will carry out a long-term test using the test ship *Petrojarl I* during 1990. The test results from this well will provide a basis for the further evaluation of using horizontal wells on the field. The Directorate considers the prospects of commercial exploitation of the thick and thin oil zones promising in both cases.

Costs

The total development costs of Troll Gas phase I are estimated in the region of 23.6 billion 1989 kroner; and operating costs in the region of 900 million a year. These figures are based on the concept recommended in the PDO in 1986. Optimisation studies are in progress and an alternative concept involving shore-based processing is being considered.

2.4.6 Snorre

The Snorre field is situated in blocks 34/4 and 34/7. Block 34/4 was allocated under production licence 057 in 1979, block 34/7 under production licence 089 in 1984. Saga operates both blocks.

Licensees on production licence 057

Saga Petroleum a.s	14.70 %
Den norske stats oljeselskap a.s (Statoil)	51.00 %
Amerada Hess Norge A/S	4.90 %
Enterprise Oil Norway A/S	4.90 %
Deminex (Norge) A/S	24.50 %

Licensees on production licence 089

Saga Petroleum a.s	9.80 %
Den norske stats oljeselskap a.s (Statoil)	51.00 %
Esso Exploration and Production Norway A/S	14.70 %
Norsk Hydro Produksjon a.s	11.76 %
Elf Aquitaine Norge A/S	7.84 %
Deminex (Norge) A/S	3.92 %
Det Norske Oljeselskap A/S	0.98 %

Ownership interests after unitisation

The partners have adopted a distribution of the reserves in Snorre which puts 30 per cent in block 34/4 and 70 per cent in block 34/7. The ownership interests in the unitised Snorre field are:

Saga Petroleum a.s	11.26 %
Den norske stats oljeselskap a.s (Statoil)	51.00 %
Amerada Hess Norge A/S	1.46 %
Enterprise Oil Norway A/S	1.46 %
Deminex (Norge) A/S	10.03 %
Esso Exploration and Production Norway A/S	10.33 %
Norsk Hydro Produksjon a.s	8.27 %
Elf Aquitaine Norge A/S	5.51 %
Det Norske Oljeselskap A/S	0.69 %

Statoil has transferred 9.6 per cent of its interest in the Snorre production licence to Idemitsu Oil Exploration A/S with effect from 1 January 1990.

The plan for development and operation of the Snorre field was sent to the authorities on 1 September 1987 and received Storting approval in 1988.

Reservoir

Snorre is a large oil field: the commercially recoverable reserves according to the operator's estimate are about 120 mcm oil and 7 bcm associated gas. The Directorate estimates the reserves at 106 mcm oil and 5.7 bcm associated gas. The Directorate notes the uncertainty surrounding the Snorre field reserves. Snorre contains numerous additional reserves in the field itself and also outside the field limits (separate structures).

The oil which is heavily undersaturated is divided between two reservoirs: Statfjord and Lunde. These are well surveyed and the volumes are reasonably certain. There is some uncertainty regarding the extent of the sand formations and communication with the Lunde reservoir. This may affect reservoir performance. The depth of the reservoir is about 2,500 meters. Drilling and test operations have proven three different oil-water contacts, the deepest being in the western part of the field.

Development concept

The water depth over the field varies from 300 meters in the south to 370 meters in the north. According to plan the field will be developed in three phases: phase 1 consists of a floating tension leg platform in the south and a subsea installation in the central part of the field. Production will be driven by water injection. The oil will be separated in two stages on the Snorre platform, then transported to Statfjord for end processing. The estimated development cost for phase 1 is about 21.2 billion 1989 kroner. Phase 2 of the development involves depletion of the central and northern parts of the field and entails two development options. One is the relocation of the tension leg platform, the other to continue the development with another production unit on the seafloor.

2.4.7 Draugen

The Draugen field, situated in block 6407/9, was allocated in 1984 as production licence 093.

Licensees

Den norske stats oljeselskap a.s (Statoil)	50.00 %
A/S Norske Shell	30.0 %
BP Norway Limited U.A.	20.00 %

Shell is operator for the field. Production is scheduled to come on stream in summer 1993.

Field history

The operator declared the field commercial in September 1987 and submitted the partners' PDO to the authorities that same month. In August 1988 the operator presented an updated PDO for the field, which the Storting approved in December 1988. Draugen is the first field on Haltenbanken to be declared for development.

Reservoir

The Directorate estimates the in-place reserves on Draugen to be around 68 mcm oil and 3.0 bcm merchandisable gas. The Draugen reservoir is of excellent quality and consists of two formations: Frøya which contains the major part of the reserves, and the Haltenbank formation which contains a small part of the oil. There are several minor faults in the reservoir which may allow communication between the formations. There may also be communication in areas where the slate strata are thin. On the evidence of the test results the wells are expected to provide high delivery capacity and high injection capability.

Development concept

The field development plan assumes a fixed concrete installation with an integrated deck. Six or seven production wells are planned plus six water injection wells. Seven of the wells will be completed subsea. The installation will have ten well slots and 34 J tubes when complete. A mean plateau rate of 14,300 scm oil a day is conjectured.

Transportation

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

Alternative gas applications

The operator has considered numerous alternative uses for the associated gas. The principal plan is to reinject it into the mid-Drake horizon (water zone) for three years. It would also be possible to produce the Frøya South formation early on, making it possible to continue gas injection into this formation for a three-year period. After 1999 it is expected that a gas transportation solution or some or other use for the gas will have been found on Haltenbanken.

Costs

The total investment costs are 10.8 billion 1989 kroner, estimated. This includes gas injection plant for the mid-Drake formation. Estimated operating costs are 753 million 1989 kroner a year.

2.5 FIELDS IN PRODUCTION

2.5.1 Valhall

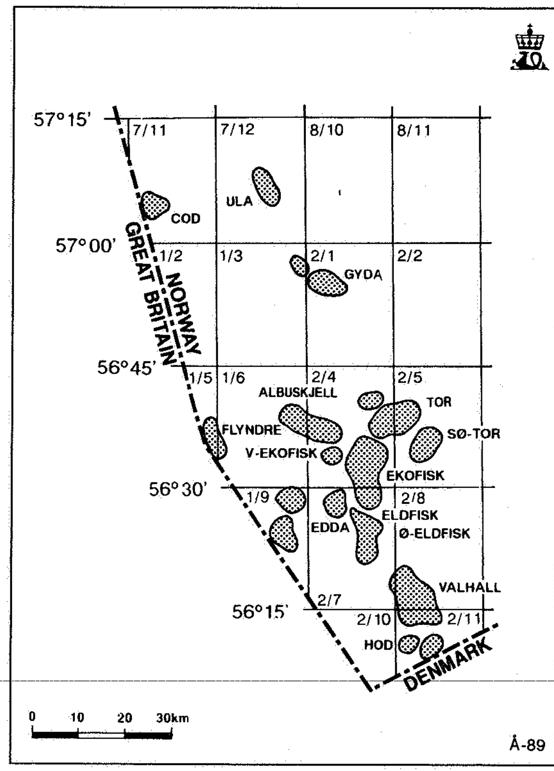
Production licence 006

Licensees

Amoco Norway Oil Company	28.33 %
Amerada Hess Norge A/S	28.33 %
Enterprise Oil Norway A/S	28.33 %
Norwegian Oil Consortium A/S & Co	15.00 %

Block 2/8 was allocated in 1965 with Amoco the operator. In 1989 Texas Eastern Norwegian Inc's interest was sold to Enterprise Oil Norway A/S. Most of the Valhall field is in block 2/8 (see Figure 2.5.1.a) though the southern part extends into block 2/11, production licence 033, in which each of the 006 partners owns 25 per cent.

Fig. 2.5.1.a
The Ekofisk area



Production

Valhall, in terms of geology and reservoir characteristics, is similar to the Ekofisk area fields, which produce from crumbled limestone which is relatively tight compared with other reservoir rocks on the Norwegian continental shelf. This gives the fields relatively low recovery, though the factor can be enhanced by employing new production techniques. In January 1990 a pilot project will be initiated whereby water in one well is injected into the Tor formation. If the results are promising a fullscale water injection project will be evaluated. Other options are also being considered. Two formations are producing on Valhall: viz Tor, which contains about two-thirds of the reserves in place, and Hod. The Ekofisk formation, though the principal one in the Ekofisk area, is not present on Valhall.

There was a great deal of uncertainty in respect of the geology on Valhall due to the gas cloud over the reservoir. This rendered the seismic records useless as a survey tool over parts of the reservoir, though following a great deal of effort on the part of operator and partners alike, it has been possible to define a reasonably serviceable geological model of the field.

Valhall came on stream in November 1982. By year end 1989 the field was producing from 23 wells. The operator seems to have succeeded with a new completion technology which avoids the problem of eroded reservoir rock migrating into the production wells.

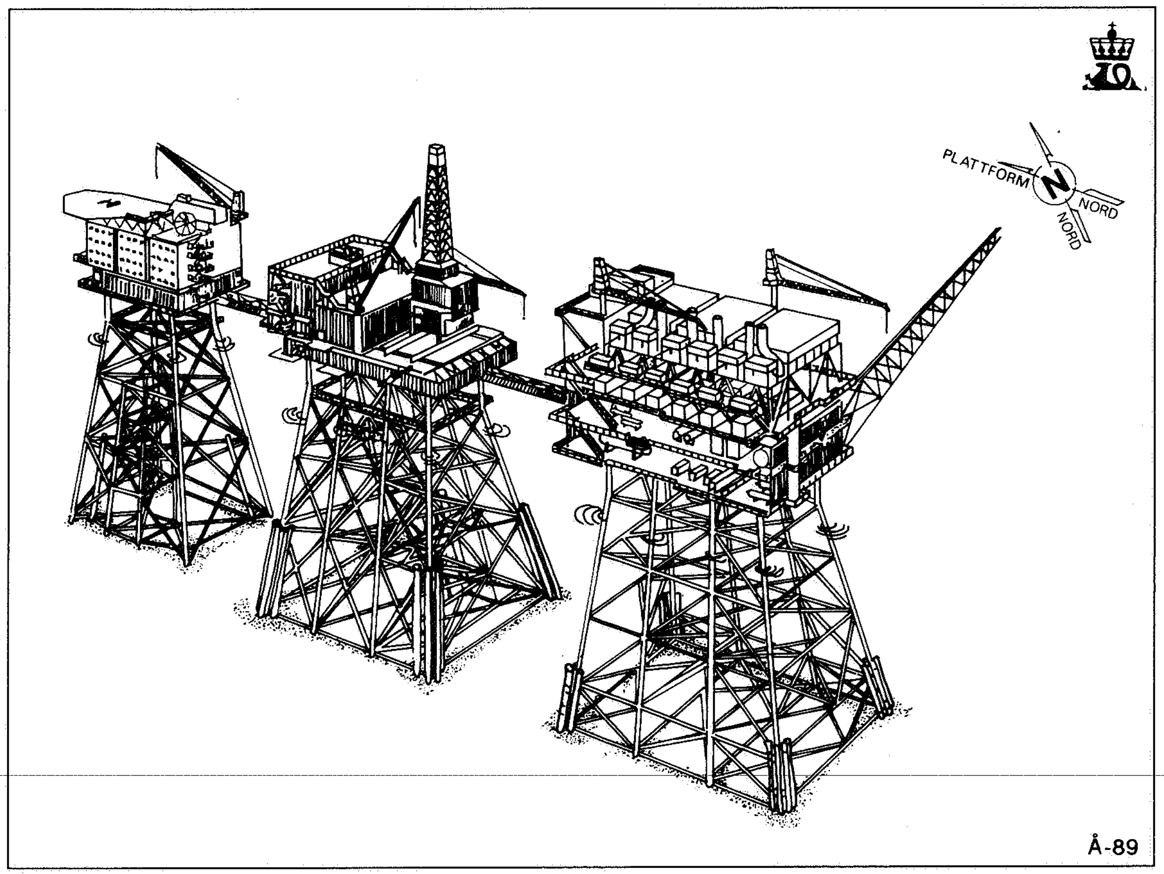
The subsidence of Valhall does not seem as much of a problem as was once feared. Several methods of measurement are being used to establish the rate of collapse. What are considered the most reliable results show a subsidence rate of about 0.18 meters a year.

Production installations

The development of Valhall comprises quarters, drilling, production and riser platforms, the three first-mentioned being on the field and connected to each other by flying gangways. See Figure 2.5.1.b for details. The riser platform – for which Phillips is the operator – is connected to the Ekofisk tank.

Oil is separated from the Valhall gas using two separation trains before being pumped to Ekofisk where it is metered and then fed into the Teesside pipeline. The gas is compressed, dried and checked for dew point on the production platform before being piped to the Ekofisk installation for metering and export through the Emden pipeline. The heavi-

Fig. 2.5.1.b
Installations on Valhall



er gas fractions, natural gas liquids (NGL), are separated on Valhall in a fractioning column and then reinjected, partly into the oil, partly into the gas.

Transportation
The oil and gas are transported in the same system as the production from the Ekofisk area.

Flaring
The reports of gas flared on the field in 1989 indicate a mean rate of 27,000 scm a day, equivalent to 1.1 per cent of gas production, and 27 per cent of the permitted maximum.

Costs
The total investments on the Valhall field up to year 2011 are expected to be roughly 11.4 billion 1989 kroner. The total operating costs to the same date have been calculated at around 17.4 billion 1989 kroner.

2.5.2 Ekofisk area
Production licence 018

Licensees

Phillips Petroleum Co Norway A/S	36,960 %
Norsk Fina A/S	30,000 %
Norsk Agip A/S	13,040 %
Norsk Hydro Produksjon A/S	6,700 %
Elf Aquitaine Norge A/S	7,594 %
Total Marine Norsk A/S	3,547 %
Den norske stats oljeselskap a.s (Statoil)	1,000 %
Eurafrep Norge A/S	0,456 %
Cofranord A/S (Norminol)	0,304 %
Coparex Norge A/S	0,399 %

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

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

The field interests are split as follows between the Ekofisk partners (Phillips Group), A/S Norske Shell, and Valhall partners (Amoco Group):

Albuskjell	
Phillips Group	50.00 %
A/S Norske Shell	50.00 %
Tor	
Phillips Group	75.3612 %
Amoco Group	24.6388 %

The Ekofisk area, operated by Phillips, consists of seven fields: Albuskjell, Cod, Edda, Ekofisk, Eldfisk, Tor and West Ekofisk. Cod was discovered in 1968 and is the only field producing from a sandstone reservoir in the Ekofisk area. The other fields in the area all produce from limestone rock. Ekofisk itself was discovered in 1969 and declared commercial almost immediately, in 1970. The other fields were found between 1969 and 1972. Ekofisk, easily the largest field in the area, has a hydrocarbon pore volume about 30 per cent larger than the Statfjord field. Eldfisk is the second in line as far as size goes. See Figure 2.5.1.a for field location.

Production
The Ekofisk area has been developed in several stages.

From June 1971 to May 1974, oil was recovered from four wells which had been completed on the seafloor on the Ekofisk field. The fields Cod, Tor and West Ekofisk were developed and tied in with the Ekofisk Center at the same time as the oil pipeline was laid to Teesside and the gas pipeline to Emden. These pipelines came on stream in October 1975 and September 1977, respectively. Before the gas line was commissioned the gas had been injected back into the Ekofisk field.

The second development stage involved the tie in of Albuskjell, Edda and Eldfisk to the Ekofisk Center.

Since December 1987 water has been injected into the Tor formation in the northern part of the Ekofisk field. The project was later expanded to include some parts of the Ekofisk formation. The operator is working on plans to further optimise the waterflood project.

Nitrogen as an injection medium has also been considered in recent years, though the prospects do not seem as encouraging now as they once did. The operator is still working on project optimisation. An obvious alternative would be to inject natural gas produced from other fields.

Such measures have the potential to substantially increase recovery from the Ekofisk field. Water flooding and gas injection would mean enhanced oil recovery; while nitrogen, if employed, would be intended to enhance gas recovery.

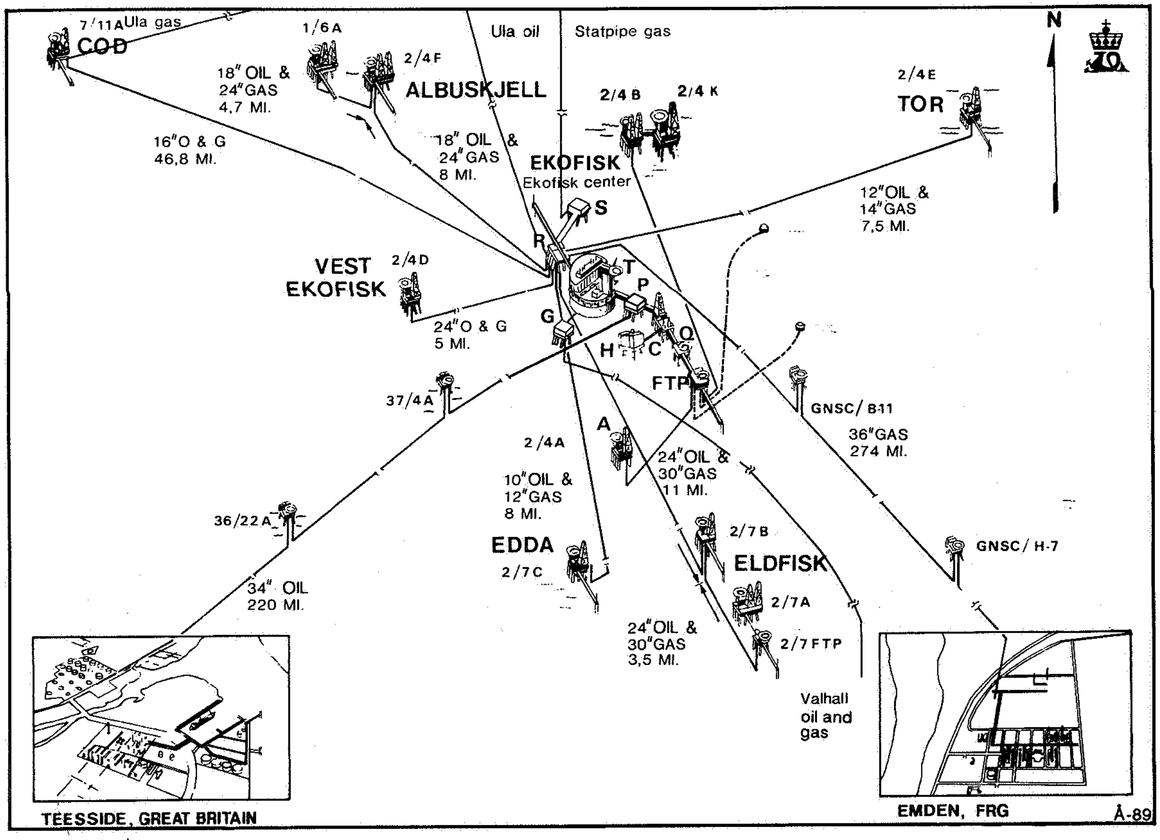
Similar measures are being considered for the second largest field in the area, Eldfisk.

On Tor, gas-lift plant has been installed with encouraging results so far. The artificial lift will help extend the commercial lifetime of the field considerably. Gas injection on Tor is less now than previously.

On Albuskjell in 1988 the operator tested the Ekofisk formation, which is very tight in this area. Further plans for testing of the formation are being prepared.

On Edda modification works have been undertaken in order to support the production from the Tommeliten field. This process will allow the Edda installation to remain operative longer than previ-

Fig. 2.5.2
Installations in the Ekofisk area



ously assumed. Figure 2.5.2 shows the Ekofisk area installations.

Subsidence

In November 1984 it was discovered that the seafloor at the Ekofisk Center had subsided. Measurements taken since show that the full depth of the subsidence was about 4.6 meters by year end 1989.

The rate of collapse from 1980 to 1986 was about 0.4 to 0.5 meters a year, though slightly less towards the end of the period. During 1987 and 1988 the measured rate of subsidence was about 0.3 meters a year. By 1989 the rate seems to be slowing down, to about 0.28 meters a year.

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

The cause of the subsidence is the compaction of the reservoir rocks, permitted by the reduction in reservoir pressure from 7200 psi originally to about 3800 psi today.

There is still some doubt about the mechanism by which the reservoir volume reduction causes subsidence and if perhaps there are also other factors contributing to the phenomenon.

The only way to prevent further compaction and other problems related to depressurisation is to limit the reduction in pressure. This can be done by injection of natural gas, nitrogen, water or some combination thereof.

Subsidence is not peculiar to the Ekofisk Center and it is reckoned there will be a need to modify installations in the north and south of the field during the 1990s.

In summer 1987 the steel platforms on Ekofisk were all jacked up to make up for the subsidence and lift them above the reach of the calculated 100 year wave. This engineering feat was impossible for the concrete Ekofisk tank, so the Phillips Group decided to construct a concrete barrier around it. Construction started in 1988 and the protective barrier was towed out to Ekofisk in two halves and mated on site in 1989.

Metering systems

Verification work has been done on some oil and gas metering systems in the Ekofisk area. In Teesside and Emden regular verifications have been made of the sales metering systems. Annual meetings are held with the German authorities. The cooperation agreement covering technical metering operations at Emden was signed by German and Norwegian authorities in 1989.

Transportation

The gas is transported by pipeline to Emden, the oil by pipeline to Teesside.

Flaring

The field gas flaring reports for 1989 record that 29,266 scm gas was flared a day, equivalent to 0.085 per cent of gas produced and 14.6 per cent of the permitted flare limit.

Costs

By year end 1989 roughly 65.7 billion 1989 kroner had been invested in the seven fields making up the Ekofisk area. The total operating costs incurred were roughly 59.3 billion 1989 kroner.

2.5.3 Tommeliten

Production licence 044

Licensees

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

Production licence 044 was allocated on 27 August 1976 and embraces block 1/9 southwest of the Ekofisk area. The field was discovered by the drilling of exploration well 1/9–1 in December 1976 and was Statoil's first discovery in the oil activity.

The plan for development and operation was approved by the Norwegian Storting in June 1986. Phase 1 of the development, comprising the Gamma structure, came on stream on 3 October 1988. A gas sales contract has been concluded with the Phillips Group for supplies up to 1 October 1991. The remaining gas remains unsold.

Production

Tommeliten comprises two structures, Alpha in the south and Gamma in the north. Both structures have proven gas and concentrate. The hydrocarbon-bearing strata are the Ekofisk and Tor formations.

There are plans to utilise the Tommeliten gas as gas lift for Edda field wells. Trials implemented so far show promising results. If successful the economic lifetime of the field will be extended.

Production installations

The Tommeliten field has been developed using subsea completion wells with full wellstream transfer to the Edda installation and tie in there.

The field is developed in several phases: Phase 1, which concerns the Gamma structure, consists of a template with six wells.

No decision has yet been made when to develop the Alpha structure: it will depend on when a sales contract for the remaining gas can be concluded.

Metering system

The existing metering system on the Edda installation has been rebuilt and upgraded to support the metering of gas, oil and condensate from both Edda and Tommeliten. The gas consumption on the installation is also recorded.

Transportation

Following the first stage separation and metering on Edda the Tommeliten gas is taken by pipeline to the Ekofisk Center for further processing, before the dry gas is compressed and exported via the Norpipe gas line to Emden.

Tommeliten condensate is transferred from Edda to the Ekofisk Center by oil pipeline together with the products (oil and gas) from Edda. After second stage processing at the Ekofisk Center, the fluids are pumped into the Ekofisk-Teesside pipeline for further stabilisation, storage and sale in Teesside.

Flaring

The volume of gas which the operator is permitted to flare off on Tommeliten is included in the aggregate volume permitted for the Ekofisk field as a whole.

Costs

The total investments in phase 1 amount to 2.7 billion 1989 kroner.

2.5.4 Ula

Production licence 019A

Licensees

BP Norway Limited U.A (operator)	57.5 %
K/S A/S Pelican & Co	5.0 %
Norske Conoco A/S	10.0 %
Den norske stats oljeselskap a.s (Statoil)	12.5 %
Svenska Petroleum Exploration A/S	15.0 %

The field, situated in block 7/12 about 70 km northwest of Ekofisk (Figure 2.5.1.a), was discovered in 1976 and declared commercial in December 1979. Though the field development plan received approval in 1980 it became clear that same year that the development would not be profitable after all. A new field development plan for a revised development concept was submitted in April 1983 and approved in January 1984. Production from Ula started in October 1986.

Production

The Ula field is a sandstone field of upper jurassic origin. It lies on the Ula Trend which is an oil province along the faulted northeast margin of the Central Graben. The field is a salt dome structure and the reservoir has excellent production properties.

However, increasing quartz cementation towards the flanks has rendered water injection difficult, leading to a substantial fall off in reservoir pressure.

The operator in 1989 upgraded the estimated reserves in place to 67 mcm oil on the evidence of results from updated reservoir studies, including new seismological interpretations and new well data. The field's assumed extent has also been upgraded and now embraces a rather larger area in the southeast.

The further development of the field is under consideration by the partners. Greater injection capacity and higher reservoir pressure are called for before the production rate can be increased.

At the end of the year the cumulative production volume was 15.7 mcm oil. By the same date some 7.3 mcm water had been injected. Simultaneously, six wells are producing and five injecting water. Water breakthrough was observed in well A-2 during the autumn. In order to avoid an increase in produced water from A-2, its nearest water injection neighbour, A-3, will be plugged and whipstocked. This will permit injection deeper into the reservoir and establish a greater separation distance from the production well.

The underlying triassic reservoir also contains oil, though drilling and analyses here have revealed poor reservoir characteristics, and no decision has been made on possible development. A strategic planning document is expected during 1990.

Production installations

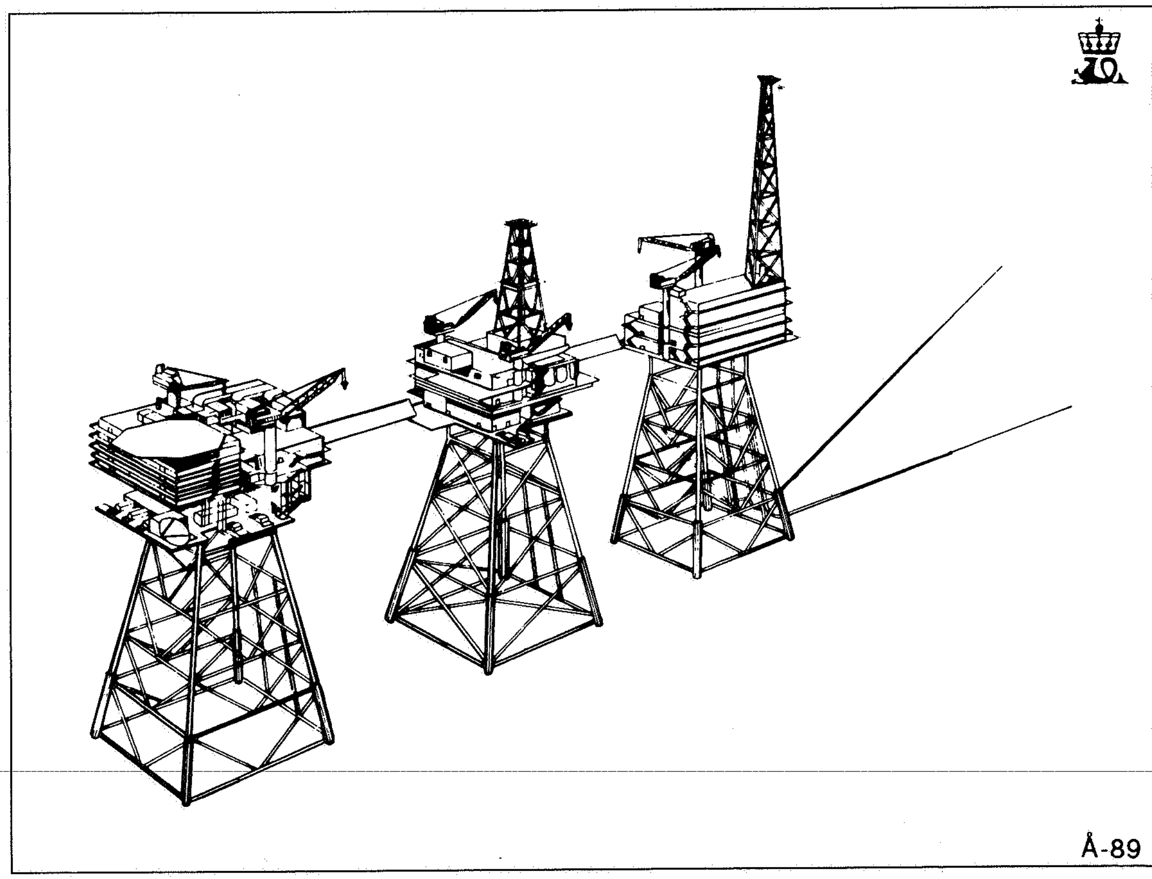
The development concept involves three conventional steel jacketed platforms for production, drilling and quarters (Figure 2.5.4). The jackets were installed in summer 1985 and offshore hookup took place from October 1985 to August-September 1986.

Current production capacity is 16,800 scm oil a day. Water injection capacity has been upgraded to 19,100 scm a day. The earlier problems met with due to deposition of asphalt in the separators have very largely abated, supposedly due to the declining pressure in the reservoir.

Transportation

The Ula crude oil is carried by pipeline via the Ekofisk Center to Teesside. Statoil is operator for the pipeline to Ekofisk, which was installed on the seabed in summer 1984, is about 70 km long and has a diameter of 508 mm. Gas from Ula is carried by a gas line via Cod to Emden. The Ula-Cod gas line was installed and tested in spring 1985.

Fig. 2.5.4
Installations on Ula



Metering system
The oil is metered for tax purposes before being exported by pipeline to Ekofisk. Similarly, fiscal metering of the Ula gas takes place before the gas is injected into the gas line via Cod to Emden. The metering systems are part of the Ekofisk hydrocarbon distribution system.

Flaring
The reported quantity of gas flared on Ula in 1989 was 20,000 scm a day, equivalent to 1.5 per cent of gas production and about 20 per cent of the permitted flare limit.

Costs
Total investments up to year end 1989 were about 9 billion 1989 kroner. Since production start-up in October 1986 roughly 1.5 billion 1989 kroner have been committed to operating costs.

2.5.5 Heimdal

Production licence 036 was allocated in 1971 and covers block 25/4, lying about 180 km west-northwest of Stavanger (Figure 2.5.6.a), where Elf is operator. On that part of the field which embraces Heimdal the Norwegian state has exercised its option, and the field ownership is now as follows:

Licensees

Den norske stats oljeselskap a.s (Statoil)	40.000 %
Marathon Petroleum Company (Norway)	23.798 %
Elf Aquitaine Norge A/S	21.514 %
Norsk Hydro Produksjon a.s	6.228 %
Total Marine Norsk A/S	4.820 %
Saga Petroleum a.s	3.471 %
Ugland Construction Company A/S	0.169 %

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

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

Production
The estimated total reserves in place in Heimdal are 36 bcm gas and 6 mcm condensate.

Production drilling on Heimdal started in April 1985. From the installation nine production wells and one observation and injection well have been drilled, though one production well had to be closed in 1987 due to leakage problems.

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

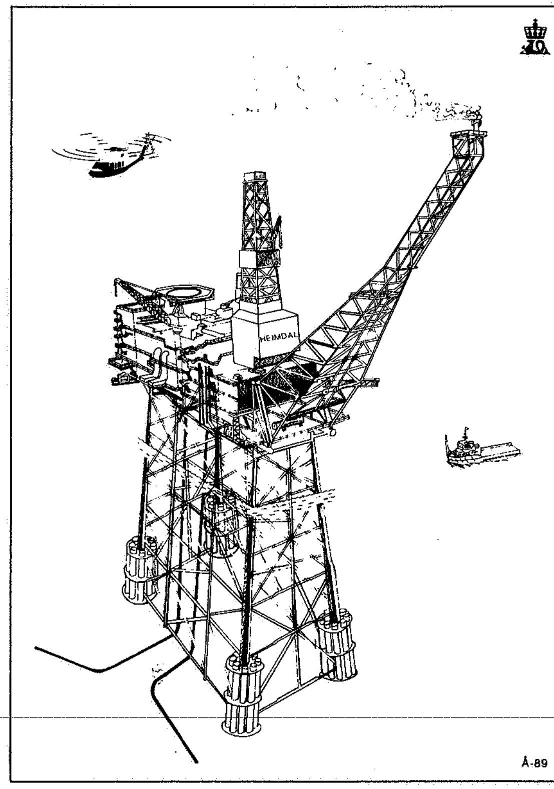
Production has reached plateau level, availability is good, and there is little occasion to flare off field gas.

Production installations
Heimdal has been developed with an integrated steel jacket structure combining drilling, production and quarters functions (Figure 2.5.5). Production start-up was in December 1985 and delivery of gas to Emden began in February 1986.

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

Transportation
The gas from the Heimdal field is transported through Statpipe, to which Heimdal is connected on riser platform 16/11 S.

Fig. 2.5.5
Installation on Heimdal



Costs

The total investments in the Heimdal field are in the region of 10.8 billion 1989 kroner. Total operating costs are expected to reach 4.6 billion 1989 kroner.

2.5.6 Frigg area

2.5.6.1 Frigg

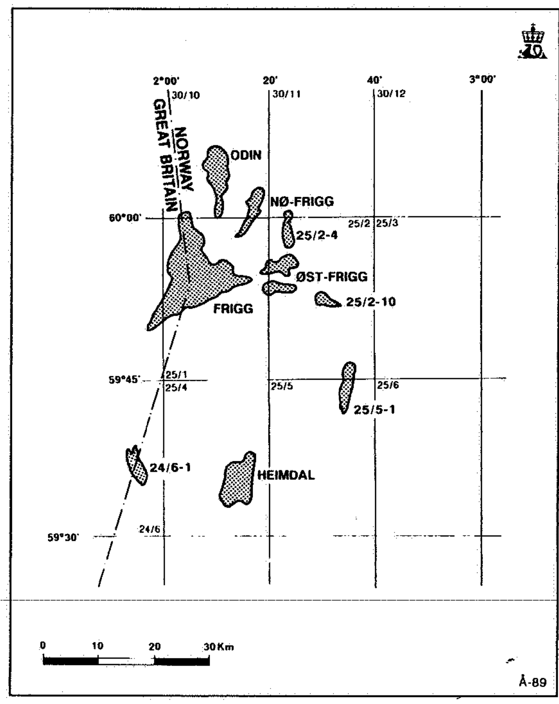
Licensees

Norwegian share (60.82 %) (production licence 024)	
Elf Aquitaine Norge A/S	25.191 %
Norsk Hydro Produksjon A/S	19.992 %
Total Marine Norsk A/S	12.596 %
Den norske stats oljeselskap a.s	3.041 %
British share (39.18 %)	
Elf Aquitaine UK Ltd	26.119 %
Total Oil Marine Ltd	13.060 %

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

The Frigg field is situated in block 25/1 and 30/10 in the Norwegian sector and block 10/1, 9/5 and 9/10 on the UK part of the continental shelf (Figure 2.5.6.a). The field has been unitised with 60.82 per cent of gas reserves in place being deemed to belong to the Norwegian partners. The remaining 39.18 per cent belong to the UK partners.

Fig. 2.5.6.a
The Frigg area



Production

The Norwegian share of the total recoverable reserves is believed to amount to 107 bcm gas.

In 1984 considerable, though uneven, water ascent was observed in parts of the field. Several wells were drilled or deepened, and considerable effort was made to clarify the situation. It transpired that the water is entering the reservoir from the southeast on account of a non-continuous slate barrier there, and flows laterally northward. This fact, coupled with the studies undertaken, caused the estimated reserves to be revised downward.

Formation water has been observed in all production wells on CDP1, and by December 1989 seven of them had been shut down. Shutdown of the CDP1 installation itself is planned during 1990. On DP2 water has been observed in four wells and production from this installation is expected to continue for another three to five years.

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

Production installations

Frigg was discovered in spring 1971 and the field declared commercial a year or so later on 25 April 1972. The field was developed in three phases, phase 1 comprising production and processing installations on the UK sector plus a quarters platform (CDP1, TP1 and QP). Production from these installations started on 13 September 1977.

Phase 2 comprises production and processing platforms (DP2 and TCP2) on the Norwegian side of the field. Production from these came on stream in summer 1978. See Figure 2.5.6.b for a map of the Frigg installations.

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

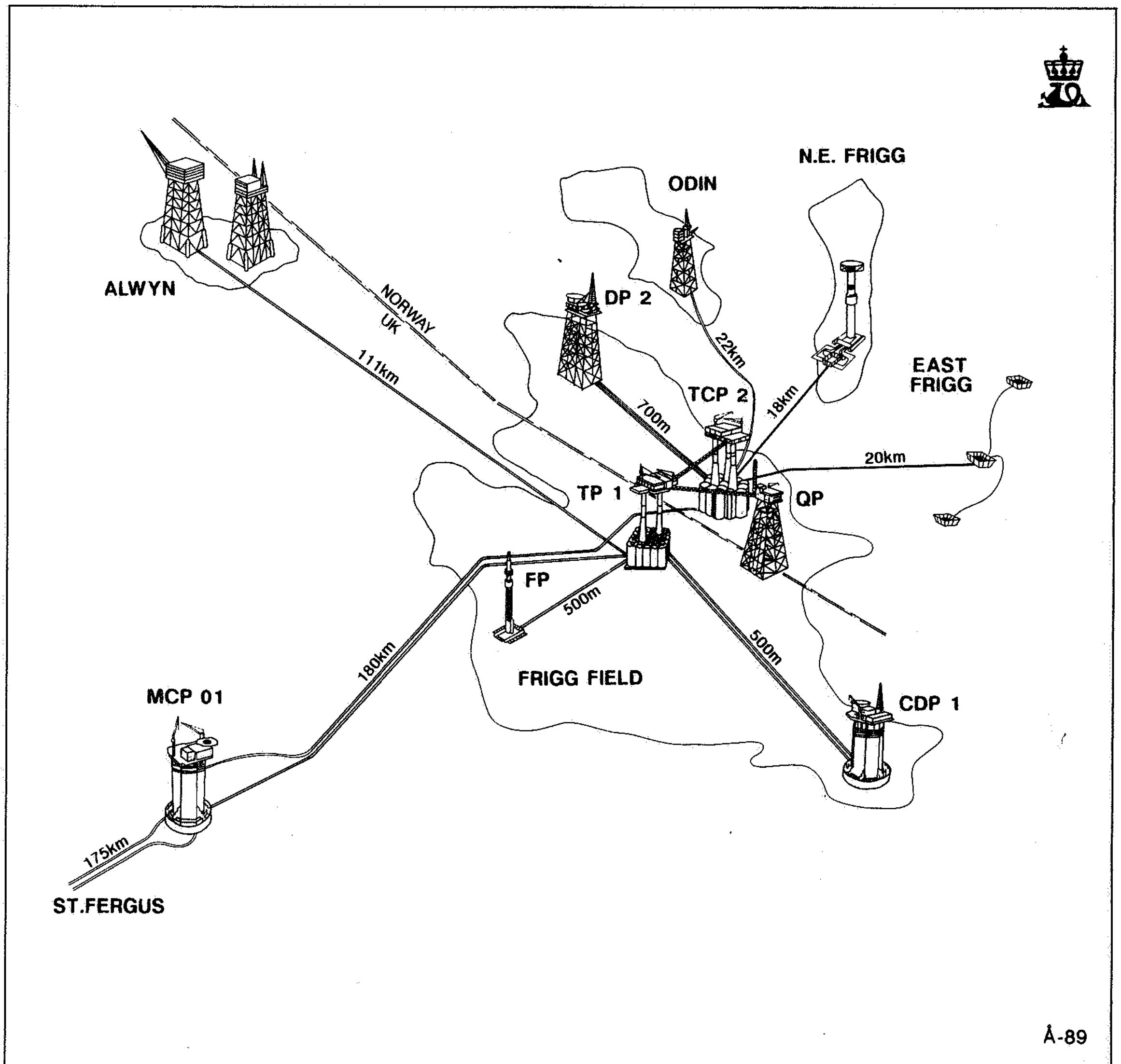
Gas from Northeast Frigg, Odin and East Frigg is processed and metered on Frigg. New modules for processing of gas and condensate from these satellite fields have been emplaced on TCP2. Export of gas from Alwyn North in the UK sector flows through TP1.

Production from CDP1 will come to an end during 1990 and the installation, complete with wells, will be secured and retired from service. As a result TP1 will be converted from a processing facility to a riser platform. TCP2 will be modified to adjust the compressor plant to the changing pressure conditions and reduced gas volumes.

Metering system Frigg area

Supervision of the metering systems on Frigg, MCP-

Fig. 2.5.6.b
Installations on the Frigg field



01, Alwyn North and St Fergus is carried out in conjunction with the UK Department of Energy. This combined supervision extends to the Norwegian fields: Northeast Frigg, East Frigg and Odin; the sum of these fields' production being deducted from the total measured quantity flowing into the St Fergus pipeline. The aim is to determine the quantity originating from the Frigg field.

Transportation
The gas is transported 355 km to St Fergus in Scotland through twin 813 mm diameter pipelines. In order to increase line capacity two compressor turbines – each of 38,000 bhp – have been installed on the compressor platform MCP-01, halfway between Frigg and Scotland. This capacity increase was necessary to make room for the Odin field gas. For the same reason the St Fergus terminal was expanded from five to six process trains. Further modifications to the terminal will allow for the increased deliveries of liquid-phase petroleum originating from the new fields.

Costs
The total investments in the Norwegian sector of the Frigg field are about 18.8 billion 1989 kroner. Investments in the transport system are additional to this figure. The estimated total operating costs over the lifetime of the field are in the region of 8.7 billion 1989 kroner.

2.5.6.2 East Frigg
Production licence 024 (block 25/1) and 026 (25/2)

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 (Statoil)	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 Produksjon a.s	17.30 %
Total Marine Norsk A/S	10.90 %
Den norske stats oljeselskap a.s (Statoil)	50.00 %

East Frigg Alpha was discovered in 1973 and East Frigg Beta the year after. Both structures extend into blocks 25/1 and 25/2 and marginally into the area previously relinquished. The reserves are split with 95.129 per cent in production licence 024 and 026, and 4.871 per cent in production licence 112. The field was declared commercial in August 1984 and the landing application considered by the Norwegian Storting on 14 December the same year. A development plan utilising four wells was approved by the partners.

The Norwegian Petroleum Directorate gave permission for production start-up in autumn 1988.

Production

The East Frigg field (Figure 2.5.6.a) consists of the two principal structures, Alpha and Beta, formerly known as East and Southeast Frigg, respectively. Production from East Frigg came on stream in August 1988 from four wells, two in each of the structures. Gas sales started on 1 October 1988. As East Frigg is a part of the same pressure system as Frigg proper, the gas is therefore sold to BGC under the existing sales agreement.

However, production on Frigg has brought about substantial reduction in pressure and inclining liquid contacts on East Frigg, plus leakage amounting to about 6.4 bcm from the Alpha structure. On the other hand the deep saddle in the western part of the Beta structure has prevented gas migration from there to Frigg. In both structures, some gas is trapped in zones already drained, and the reserve estimates have therefore been revised downward to 7.5 bcm (total); comprising 3.7 bcm in the Alpha and 3.8 bcm in the Beta structure.

It is because of these problems that a third well was entered on the Alpha structure, coming on stream in 1989.

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

Production installations

The East Frigg development is based on subsea completion technology: Two templates for the production stations and a central manifold station tying the systems together were emplaced on the seabed in summer 1987, see Figure 2.5.6.b.

These subsea production systems are remotely controlled from the Frigg control room. From the manifold a gas and service line runs to TCP2 where the gas is processed and fed into the Frigg field transportation system.

Apart from the deployment of the subsea systems, modifications also had to be made on the Frigg field before start-up in order to support receipt of the gas.

Costs

The total investment in the field was about 2.4 billion 1989 kroner. The estimated total operating costs over the lifetime of the field are 0.7 billion 1989 kroner.

2.5.6.3 Northeast Frigg

Production licence 024 (block 25/1)

Licensees

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

Production licence 030 (block 30/10)

Licensees

Esso Exploration & Production Norway Inc	100 %

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

The Northeast Frigg field lies in block 25/1 and 30/10 (Figure 2.5.6.a) and a redistribution of the gas reserves in august 1984 assigned 42 per cent and 58 per cent, respectively, to each block. Elf is the operator.

Production

The total recoverable reserves in place on Northeast Frigg are believed to be 11 bcm gas.

Sale of gas from Northeast Frigg started in October 1980 by virtue of predelivery from Frigg. Since production start-up in December 1983 Northeast Frigg has been reinstating this gas in addition to volumes delivered on behalf of Frigg and own contract volumes. In order to achieve a longer-range sales profile it was proposed to continue deliveries from Frigg after production shutdown on Northeast Frigg. However, new uncertainties regarding Frigg's own lifetime have led the partners to accelerate reinstatement from Frigg, thereby bringing Northeast Frigg sales into equilibrium with Northeast Frigg production. This balance was achieved in 1989.

Pressure measurements made before production start-up showed that the reservoir communicates with the Frigg field via the underlying aqueous zone. The field is expected to produce until 1993.

Production installations
The Northeast Frigg gas field was discovered in 1974 and the final development plan passed in 1980. The field has been developed with six wells drilled through a subsea template (Figure 2.5.6.b). In May 1986 one well had to be plugged due to gas leakage problems.

The template also supports a manifold in addition to the wellheads and valve trees the purpose of which is to gather the gas from the producing wells. The gas is led through a 406 mm diameter pipeline to the Frigg field for processing. The valve trees are controlled by separate service and control lines from the Frigg control station, an articulated columnar structure, located 150 meters from the wellheads. The control station was installed in July 1983 and is remotely controlled from Frigg itself.

Costs
The estimated total field investments are roughly 2.5 billion 1989 kroner, while total operating costs are expected to run to about 0.6 billion 1989 kroner.

2.5.6.4 Odin
Production licence 030

Licensees

Esso Exploration & Production Norway Inc	100 %

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

The Odin field lies in block 30/10 (Figure 2.5.6.a) and is operated by Esso. This gas field was proven in 1974 and the field development plan adopted in 1980.

Production
The estimated total recoverable reserves in place are 33 bcm gas.

Gas sales from Odin were initiated in October 1983 through the prior delivery arrangement with Frigg. Since production start-up in April 1984 Odin has been reinstating the predelivered volumes in addition to delivering own contract quantities.

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

In spring 1985 the operator upgraded his estimate of the in-place reserves on the basis of new well data and survey results. For the additional 12 bcm volume a contract has been signed for transportation and processing services with the Frigg Norwegian Association Group (FNA). These additional amounts will extend production by four years, viz to 1997.

Production installations
The field development concept involves a small steel jacket structure with relatively modest processing and drilling facilities and comparatively small quarters (Figure 2.5.6.b). This concept was feasible because a mobile installation was employed for two years in connection with installation work and production drilling operations.

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

Costs
The total investments in the field ran to about 3.6 billion 1989 kroner. The total operating costs over the lifetime of the field are estimated to be roughly 2.6 billion 1989 kroner.

2.5.7 Statfjord
Production licence 037

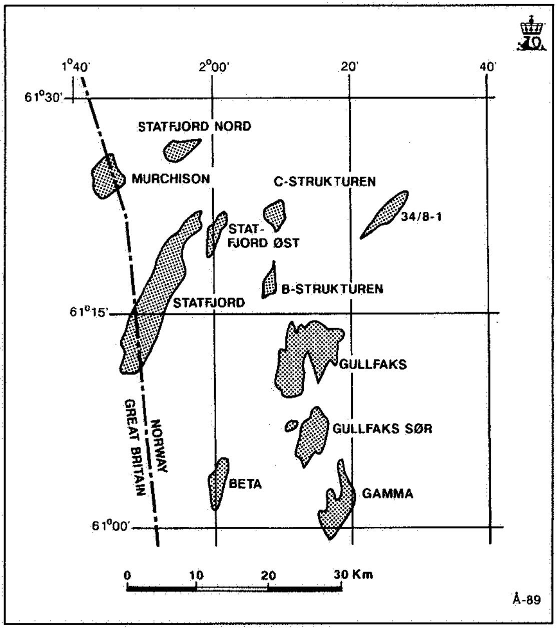
Licensees

Norwegian share (84.09322 %)	
Mobil Exploration Norway Inc	12.61400 %
Den norske stats oljeselskap a.s (Statoil)	42.04661 %
Norske Conoco A/S	8.40932 %
Esso Exploration & Production Norway A/S	8.40932 %
A/S Norske Shell	8.40932 %
Saga Petroleum a.s	1.57674 %
Amoco Norway Oil Company	0.87597 %
Amerada Hess Norge A/S	0.87597 %
Enterprise Oil Norway A/S	0.87597 %
British share (15.90678 %)	
Conoco (UK) Ltd	5.30226 %
Britoil PLC	5.30226 %
Chevron USA Inc, Gulf Oil (U.K.) Ltd	5.30226 %

Production licence 037 was allocated in 1973 and covers blocks 33/9 and 33/12 (Figure 2.5.7.a). The Statfjord field extends into the UK sector where Conoco is the operator. The field was discovered in spring 1974 and declared commercial the same year. Mobil was operator on the field until 1 January 1987 when Statoil assumed operatorship. Statfjord is Norway's largest oil field, which in November 1989 celebrated 10 years of production. So far the operator has followed the original field development plan.

The capacity utilisation figures for the Statfjord installations have passed their peak, though since

Fig. 2.5.7.a
The Gullfaks and Statfjord area



Snorre was declared for development in 1988 and will involve tie-in to the Statfjord A platform, this platform will be required from 1992 to provide greater capacity utilisation than would otherwise have been the case. Also in the case of the Statfjord C platform, the planned subsea developments of the twin satellite fields – North and East Statfjord – which assume processing on Statfjord C, have the potential to cause increased capacity utilisation from the end of 1993.

Production

Working on the assumption that the recovery factor on Statoil will be about 50 per cent for the Statfjord field as a whole, the Norwegian Petroleum Directorate has calculated that the total recoverable reserves of oil in place in the Brent group and Statfjord formation are 445.7 mcm. The comparable figure for associated dry gas is 58.6 bcm, and for NGL 18.4 mton. The recovery strategy pursued is based on maximising the production rates and recovery factor by manipulating the pressure conditions in the reservoir. This is done by injection of water in the Brent group and gas into the Statfjord reservoir. A gas cap has now developed at the top of the Statfjord reservoir which has resulted in an increase in the gas-oil ratio in all producers in this reservoir. In order to better exploit the remaining reserves in place the operator has formulated a revised production strategy for the field in so far as utilisation of the wells is concerned.

The present division of the reserves as approved by the authorities in 1979 is 15.90678 per cent on the UK side and 84.09322 per cent on the Norwegian side. Redistribution talks for the field started in 1985 and all available data up to June 1985 were drawn on at these negotiations. New redistribution talks, this time drawing on all available data up to June 1989 were initiated in summer 1989. Both redistribution talks have resulted in new provisional figures for the proper division of the reserves. However, there remains some dispute regarding interpretation on certain points, which will be submitted to neutral experts as provided by the agreement binding the partners on the UK and Norwegian sides. Though the Norwegian government has approved the experts suggested, no such approval has been forthcoming from the UK authorities. Once the experts' decision has been given, the revised figures will be submitted to the governments of both countries for ratification.

Production installations

The Statfjord field has been developed in three phases using three fully integrated platforms, Statfjord A, B and C (Figure 2.5.7.b).

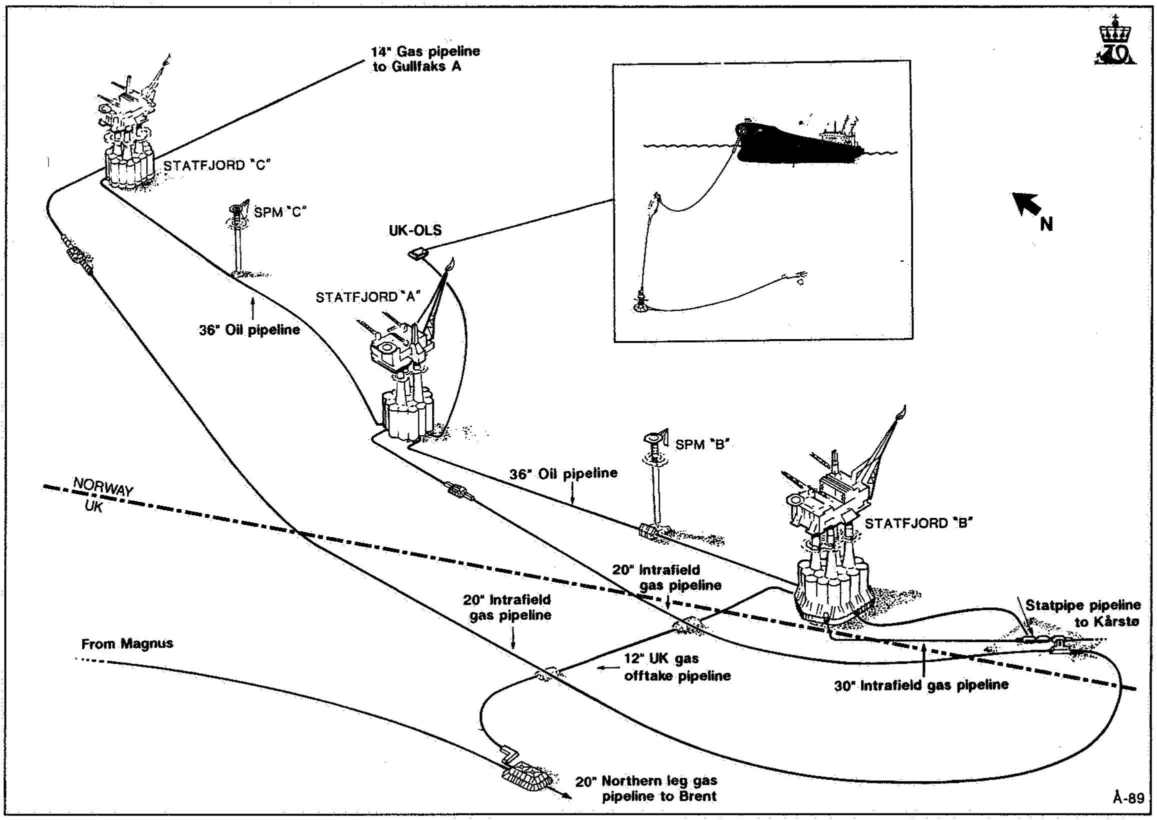
Statfjord A

The Statfjord A installation is situated near the center of the Statfjord field. It is a fully integrated platform with concrete gravity base consisting of 14 storage cells and three columns. The topsides are of steel. The production capacity is 55,000 scm a day split between two production trains. In 1988 the water treatment system capacity was upgraded in order to handle the increasing produced water volumes from the various wells. The platform started production on 24 November 1979 and has been developed with 36 wells, 22 being oil producers, 10 water injection wells and four gas injection wells. In 1986 a new type of offshore loading buoy was installed for Statfjord A after the original one had to be decommissioned and removed due to extensive mechanical malfunctioning. The new buoy has an offloading capacity of about 5000 scm an hour compared with the former buoy's approx 8000 scm an hour.

Statfjord B

The Statfjord B platform is located in the southern part of the Statfjord field. Again it is a fully integrated platform with concrete gravity base, though with 24 storage cells and four columns, and again the topsides are of steel. Production capacity is 39,800 scm a day from one production train. Here too, it has been necessary to upgrade the water treatment capacity in order to deal with the increasing water content from the various wells. Statfjord B came on stream on 5 November 1982 and has been developed with 30 wells: 20 oil producers, eight water injection wells and two gas injection wells. The original Statfjord B loading buoy also experienced mechanical problems and in 1989 it was decided to replace it with a new version similar to the Statfjord A replacement. According to plan this new offshore

Fig. 2.5.7.b
Installations on the Statfjord field



loading buoy will enter service on 15 September 1990. It will have the same capacity (8000 scm an hour) as the buoy it replaces.

Statfjord C
The Statfjord C platform, situated in the northern part of the Statfjord field, is another fully integrated installation, structurally identical to Statfjord B. Statfjord C's water treatment capacity was upgraded in 1988. The platform came on stream on 26 June 1985 and has 25 wells: 15 oil producers, eight for water injection and two gas injection wells.

Metering system
The fiscal oil and gas metering systems for Statfjord A, B and C have been operating steadily throughout 1989.

A new test sampling system was implemented in 1989.

For several years observations on Statfjord B and C have shown that there are liquids in the gas phase being measured, which tends to underestimate the gas flow. Rectification of the difficulty has been sought by physical modification of the process and chemicals injection systems.

Transportation
Statfjord gas is transported via the Statpipe pipeline. The UK takes off its part of the gas through the Northern Leg Gas Pipeline and a 12 inch line from Statfjord B. Stabilized oil is stored in storage cells before being shipped into shuttle tankers.

Flaring
The gas volume exhausted through the flare stacks on Statfjord in 1989 was 240,000 scm a day on average. This is equivalent to 1.1 per cent of gas production and represents 60 per cent of the maximum permitted flare volume. Apart from the periodic maintenance there have been certain problems with compressors and reinjection plant.

Costs
The total investments in Statfjord up to year 2010 are estimated at about 55 billion 1989 kroner. The estimated total operating costs up to the same date have been put at 55 billion 1989 kroner. These figures refer to the Norwegian share (84.09 per cent).

2.5.8 Murchison

Licensees

British share (77.8 %)	
Conoco (UK) Ltd	25.9334 %
Britoil PLC	25.9333 %
Chevron USA Inc	25.9333 %

Norwegian share (22.2 %)	
Mobil Development Norway A/S	3.3300 %
Den norske stats oljeselskap a.s (Statoil)	11.1000 %
Norske Conoco A/S	2.2200 %
Esso Exploration & Production Norway A/S	2.2200 %
A/S Norske Shell	2.2200 %
Saga Petroleum a.s	0.4162 %
Amoco Norway Oil Company	0.2313 %
Amerada Hess Norge A/S	0.2313 %
Enterprise Oil Norway A/S	0.2312 %

The Murchison field, proven in August 1975, is situated in block 211/19 in the UK sector and block 33/9 on the Norwegian sector (Figure 2.5.7.a). The Norwegian share is 22.2 per cent. The development of the Murchison field was initiated in 1976 by the UK partners. The field was declared commercial in summer 1977 and Statoil joined the declaration in summer 1978.

Production
The estimated recoverable reserves over the field as a whole are 53 mcm oil and 1.2 bcm gas. The field has been flowing at almost maximum processing capacity since 1981. 1984 was the last year of plateau production. Water breakthrough has occurred in all production wells.

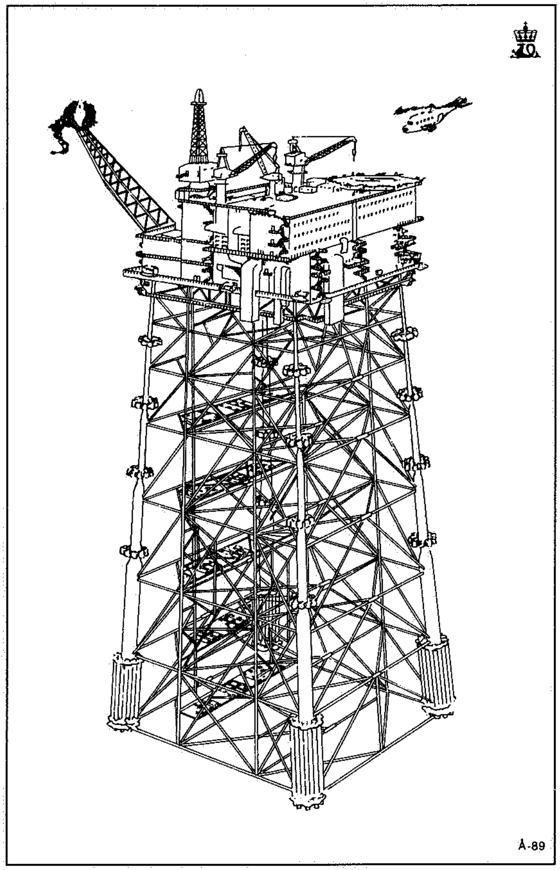
Production installations
Murchison was developed with an integrated steel jacket structure with a production capacity of 26,200 scm a day (Figure 2.5.8). The installation came on stream on 28 September 1980 and initially produced from two subsea completion wells. Present production is around 6500 scm oil a day. The installation is equipped with 27 well slots and 27 wells have been completed so far: 18 production wells and 9 water injectors. The satellite wells have now been abandoned.

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

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

Flaring
The quantity of gas reported diverted through the

Fig. 2.5.8
Installation on Murchinson



Murchison flare stack was 95,000 scm a day in 1989 (approx 22,000 scm being the Norwegian share). This is about 18 per cent of gas produced. Safety considerations on the Brent field led to shutdown of gas and oil production on Murchison for a period. In the initial restart period the gas discharge rate was increased to more than the usual amount because of malfunction in the gas injection compressor.

Costs
The predicted total investment on the Murchison field up to 1995 is roughly 3.7 billion 1989 kroner. The equivalent total operating costs are approx 1.7 billion 1989 kroner. These figures refer to the Norwegian share (22.2 per cent).

2.5.9 Gullfaks
Production licence 050 (block 34/10)

Licensees

Den norske stats oljeselskap a.s (Statoil)	85.00 %
Norsk Hydro Produksjon a.s	9.00 %
Saga Petroleum a.s	6.00 %

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

Production
Gullfaks lies in the northeasternmost part of block 34/10 and covers an area of about 200 square kilometers. Figure 2.5.7.a shows the location. Gullfaks was discovered in 1978 and the field development plans for phase 1 and 2 were approved in 1981 and 1985, respectively.

Gullfaks is a relatively shallow accumulation and has fault groups in several angled and rotated fault blocks. The reservoir rock is jurassic sandstone. The block varies in its slope and is in some places heavily eroded. The structural features in the eastern section are difficult to identify due to the poor seismic readings obtained. The complex geological makeup of the field was confirmed during the phase 1 production drilling, when several quite surprising fault patterns were turned up. However these faults are not as sealing as first supposed.

The reservoir properties in the phase 1 development have turned out to be good, particularly in the upper reaches of the Brent group. The reservoir phases 1 and 2 are segregated by a cardinal north-south fault which is believed to be sealing. Fault lines marking strata levels which have been displaced more than 100 meters vertically limit the field in the south, east and northeast.

The reserves are dispersed in the Brent group, Cook formation and Statfjord formation, though over 80 per cent are in Brent. The operator reestimated the reserves in 1989, resulting in an increase in oil in place to 230.0 mcm, 61 per cent of which are in phase 1 and 39 per cent in phase 2.

By year end 1989 the aggregate production was 28.05 mcm oil, and aggregate injection 27.04 mcm water. Phase 2 of the production came on stream in December 1989. Water is injected to maintain reservoir pressure and effectively displace the oil. Water breakthrough has already occurred in several producing wells. In order to combat this a few high-capacity injection bores are being deployed a greater distance from the producing wells. Production rates from several wells are limited by sand production from upper and lower Brent and gravel packs have been set in a few cases in the hope of reducing the problem.

Alternative recovery strategies are also being evaluated, such as gas injection, water alternating with gas (WAG) and surfactants. Pilot studies employing WAG and surfactants are undergoing consideration.

Production installations
Phase 1 comprises two installations, Gullfaks A and B, which are both Condeep type gravity base platforms with steel frame topsides. See Figure 2.5.9.

Gullfaks A stands in the southern part of the field and Gullfaks B in the northwest. The A platform is a fully integrated process, drilling and quarters platform. From Gullfaks B, which is a simpler design with only first stage separation plant, the oil is therefore transferred to Gullfaks A and C for further processing and storage.

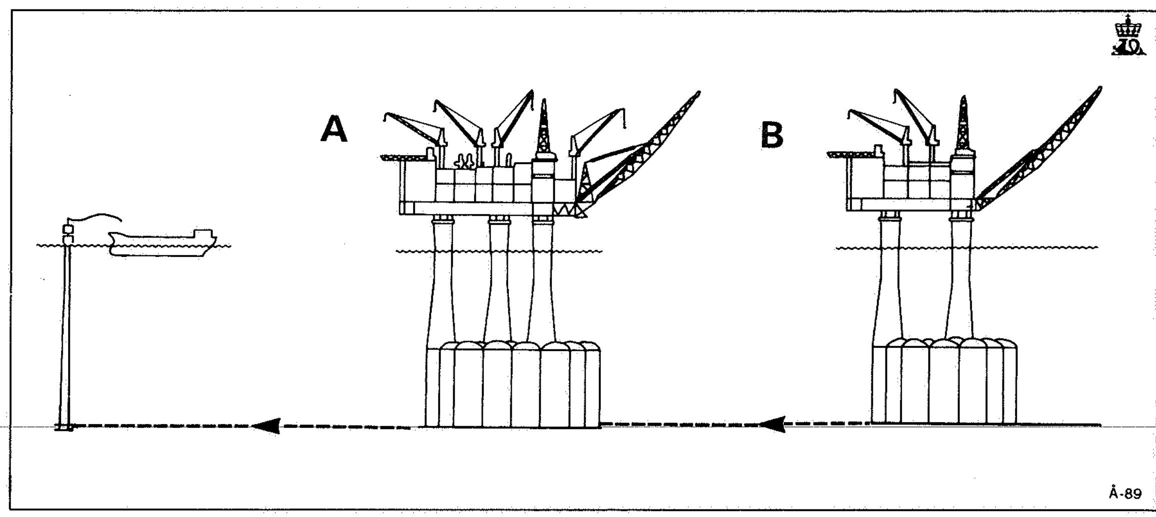
Gullfaks A entered service on 21 December 1986 and Gullfaks B on 29 February 1988.

Gullfaks C is located in the eastern part of the field and will produce the Gullfaks field's phase 2 resources. It was towed out in spring 1989. The C platform is very much a copy of Gullfaks A with fully integrated process, drilling and quarters capabilities.

Gullfaks C started production of oil transferred from Gullfaks B on 4 November 1989. Production from its own well started at about year end 1989.

The process capacity on Gullfaks A has been up-

Fig. 2.5.9
Installations on Gullfaks Phase 1



graded to 52,000 scm a day stabilized crude. By year end the unit had 16 production and seven water injection wells.

First stage separation capacity on Gullfaks B is about 30,000 scm a day. The platform will have eight production and four water injection wells by 31 December.

Both Gullfaks A and C have storage cells in which to store the killed oil. Processed gas is subject to continual fiscal metering on A and C before being exported into the Statpipe system.

Flaring

The Gullfaks gas flaring reports for 1989 show that 182,000 scm were discharged a day. This is 4.5 per cent of gas production and 60 per cent of the permitted flare limit.

Costs

At the end of the year the estimated total development costs were put at 54.7 billion 1989 kroner, of which 50.2 billion (92 per cent) had already been incurred.

2.5.10 Oseberg

Oseberg extends into two blocks: block 30/6 on production licence 053 allocated in 1979, and block 30/9 on production licence 079 which was allocated in 1982 (see Figure 2.4.3).

Partners

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

The partners in the unitised Oseberg field are as follows (from 1 April 1988):

Den norske stats oljeselskap a.s (Statoil)	65.04 %
Norsk Hydro Produksjon a.s	13.75 %
Saga Petroleum a.s	8.61 %
Elf Aquitaine Norge A/S	5.60 %
Mobil Development Norway A/S	4.20 %
Total Marine Norsk A/S	2.80 %

Production

The first discovery on Oseberg was made in 1979 which proved gas. Later evidence showed that the reservoir is an oil bearing stratum with gas cap. The commerciality declaration was submitted to the Ministry in June 1983 and the Storting dealt with the application in the spring session 1984. A revised plan for development and operation was approved in January 1988, its main revision being the accelerated development of the northern part of the field (phase 2) and an increased output from the field center in the south.

In November 1987 Hydro submitted a revised plan for development and operation of Oseberg. It is planned to upgrade the Oseberg C installation from a satellite unit to an integrated production, drilling and quarters (PDQ) platform making use of support vessel during the drilling phase. Production start-up was brought forward from 1995 to December 1990. During 1988 it became obvious that this plan was too ambitious and production start-up on Oseberg C is now set for October 1991.

In order to understand the Oseberg reservoir better, in autumn 1986 a longterm test program was initiated using the production testing vessel *Petrojarl I*. These production tests were brought to a close in spring 1988.

Ordinary production started in December 1988 from eight production wells and two gas injectors. As all 10 wells had been predrilled full production was soon attained, though teething troubles caused much of the gas to be flared off to begin with. These setbacks were gradually overcome during the year and flaring reached a normal level towards the end of 1989.

Oseberg does not contain sufficient gas to maintain pressure by gas injection. Therefore a subsea production unit, Troll-Oseberg Gas Injection, has been fabricated and installed on the Troll field with a pipeline from Troll to the Oseberg field center. The TOGI unit will supply some 25 bcm gas over a 12 year period starting in 1991. In connection with the acceleration of the Oseberg 2 development, the operator is planning to gather further injection gas from a satellite field, Gamma North, on the western flank of Oseberg. From this structure about 4 bcm gas will be injected over a six year period from start-up of the Oseberg C platform. Most of the injected gas can be recovered during the gas production phase on Oseberg which is expected to last from year 2002 to about 2020.

Chemical flooding

On account of the plans for water injection to provide the drive mechanism for the main Alpha structure reservoir, it was decided to implement a project aimed to examine the possibility of enhancing recovery by the addition of surfactants to the injection water. This project has continued despite the selection of gas injection for the Alpha enhancement, though now with the Alpha North reservoir as the target where water injection is the preferred driver.

In 1989 the project directed a lot of energy to defining the optimum surfactant system and examining what opportunities exist for running a pilot project on a limited portion of the reservoir. Though some work still remains a decision is expected in summer 1990 regarding the pilot.

Production installations

Oseberg will be developed in two phases. Phase 1 has already been developed with a field center in the south with two installations, Oseberg A which is a process and quarters platform on a gravity base, and Oseberg B which is a drilling and waterflood platform on a steel jacket. The middle portion of the field will be depleted using two subsea completion wells tied in to the field center. Production start-up on the Oseberg field center took place on 1 December 1988 where the mean crude processing capacity is about 45,000 scm a day.

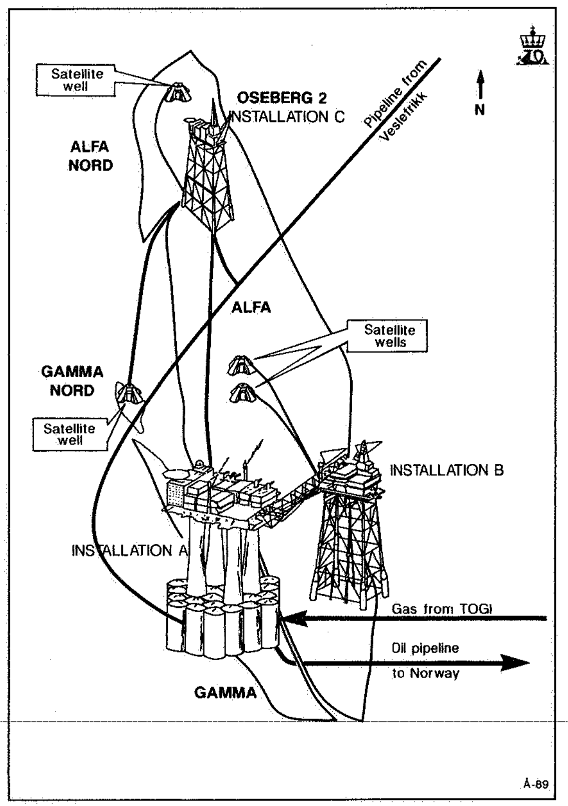
Phase 2 involves development of the northern part of the field. In the revised Oseberg plan the C installation has been upgraded from a satellite unit to an integrated production, drilling and quarters (PDQ) platform employing the services of a support vessel during the drilling phase. The date of production start has been brought forward from 1995 to October 1991. The mean crude processing capacity on Oseberg C is 14,300 scm a day.

For a diagram of the installations, see Figure 2.5.10.

Flaring

From production start-up on 1 December 1988 all associated gas was flared until February 1989, and though injection of the gas had been planned from then on, so many difficulties were encountered during the first six months that significant quantities (roughly 30 per cent) of gas had to be flared off and only about 68 per cent were injected of the total gas quantity produced. During the second six months considerable improvements were made to the processing plant enabling the mean flare rate to be reduced to about 3 per cent of total production. Of the total gas production in 1989 of 1837 mcm about 15 per cent were actually diverted to the flare stack.

Fig. 2.5.10
Existing and planned installations on Oseberg



Metering system

The oil metering system on Oseberg A and the Sture I export metering system were commissioned in December 1988 and both systems were calibrated during 1989.

The Sture II export metering system was commissioned in mid-year 1989. The Oseberg C metering station was calibrated and tested at the fabrication shop before shipment to the yard for assembly in the metering module.

The gas metering system for purchase of injection gas from Troll's TOGI system was delivered from the builder in February 1989 and is currently undergoing incorporation in the process module at the yard. The module will be installed on Oseberg A in autumn 1990.

Transport systems

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

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

- pipeline support functions on Oseberg A
- subsea pipeline
- landing point
- land pipeline
- terminal.

In the present plans the gas export from Oseberg will start in year 2002. The gas has not been sold and no decision has been made how to export it from Sture.

Costs – Oseberg

By year end 1989 some 28 billion 1989 kroner had been invested in the Oseberg field. The final total is expected to be about 37 billion 1989 kroner. The total operating budget is expected to reach about 31 billion 1989 kroner by year end 2011. These costs do not include the Oseberg Transport System (see below).

Costs – Oseberg Transport System
The total investment in OTS is about 4.3 billion 1989 kroner. Predicted operating costs are about 3.2 billion 1989 kroner up to the end of year 2000.

2.5.11 Veslefrikk
Production licence 052

Licensees

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

Veslefrikk lies in the southeast of block 30/3 which was allocated in 1979 to Statoil as operator. Four exploration wells have been drilled in the block and two in the Veslefrikk structure itself. In both holes oil was proven at two distinct levels in sandstone from the Brent and Cook formations.

The commerciality report was submitted to the partners in November 1986, and the plan for development and operation to the Ministry in February 1987. This was considered and received Storting approval as Storting Proposition no. 73 in 1986–87.

Production
Veslefrikk is a single structure with downfaulted areas on all sides. Oil is produced from two geological sandstone formations, Brent and Intra Dunlin. The operator's estimated oil production from the field is 36.4 mcm with 3 bcm associated dry gas. The drive mechanism is water injection. The first predrilled production wells also proved resources in the Statfjord and Tarbert reservoirs.

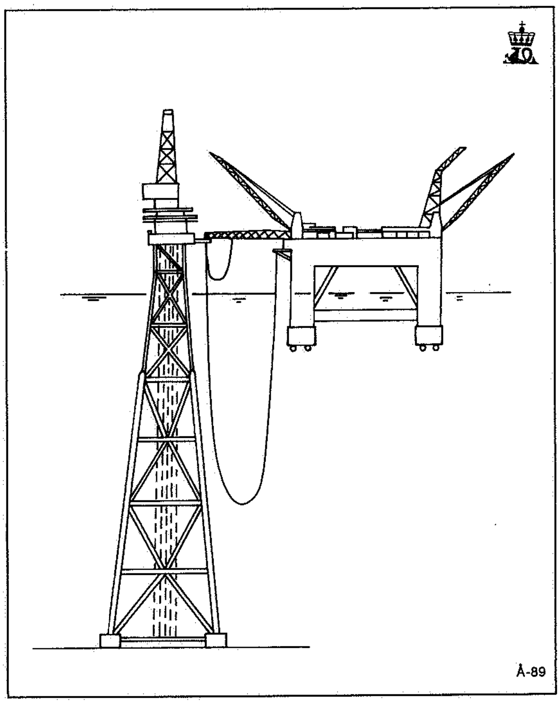
Production installations
The field has been developed with a fixed wellhead installation with a steel jacket and a semi-submersible platform containing the processing facilities and living quarters. The wellhead unit is emplaced above a template with six predrilled wells. The semi-submersible, formerly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

See Figure 2.5.11 for Veslefrikk installations.

Transport systems
An oil pipeline is connected to the Oseberg Transport System for transport of the Veslefrikk oil to the Sture terminal. Gas can be carried through the Statpipe system. The gas has not yet been sold.

Costs
The Veslefrikk development is calculated to cost about 6.9 billion 1989 kroner including well costs. This low figure and the short lead time render the field commercial even at today's oil prices. The field came on stream on 26 December 1989.

Fig. 2.5.11
Installations on Veslefrikk



Contingency preparedness
The Norwegian Petroleum Directorate is following the Veslefrikk development project very carefully as it raises new questions of a contingency nature by virtue of the concept involved: a fixed, manned wellhead installation coupled with a mobile production and quarters installation. The Directorate has been particularly concerned about the ease of access to means of escape and rescue.

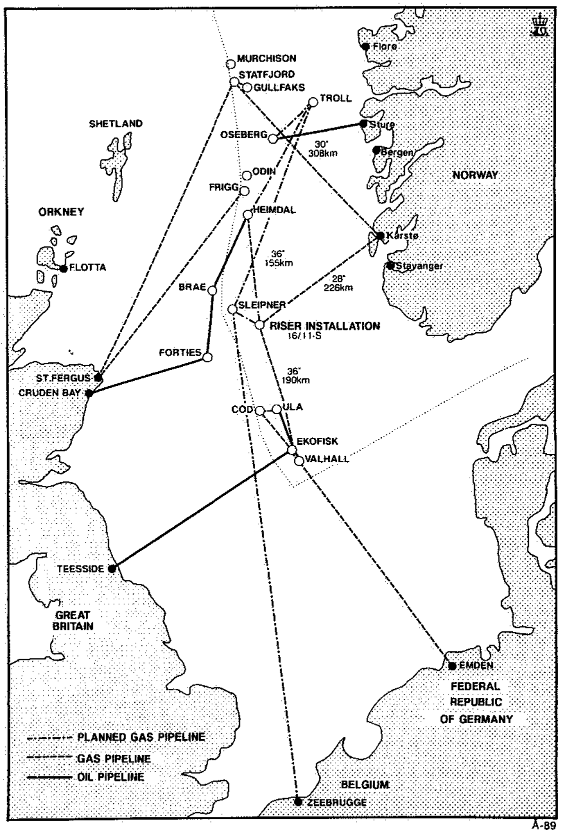
Metering system
The metering stations for oil and gas were installed and commissioned on Veslefrikk B in 1989.

2.6 TRANSPORTATION SYSTEMS FOR GAS AND OIL

2.6.1 Existing transportation systems
There are three oil pipelines and four gas pipelines which carry oil and gas from the Norwegian continental shelf to shore. There is also a condensate pipeline from Heimdal which generally carries UK oil and condensate. The UK share of gas from Statfjord is carried via the NLGP to St Fergus. See the sketch of the transport systems for oil and gas in the Norwegian sector in Figure 2.6.

The oil pipeline from the Ekofisk area, including the Ula and Valhall lines, runs to Teesside in the UK. Oil transportation from Oseberg started late in 1988 and comes to Sture. Condensate from Heimdal is taken to Cruden Bay in the UK. The Statpipe and Norpipe gas pipelines were tied together in 1986 and

Fig. 2.6
Pipelines for oil and gas from Norwegian fields in the North Sea



both lead to Emden in West Germany. Gas from Frigg is transported to St Fergus.

Gas transport systems – Statpipe

The Statpipe gas transport system involves the following partners:

Den norske stats oljeselskap a.s (Statoil)	58.25 %
Elf Aquitaine Norge A/S	10.00 %
Norsk Hydro Produksjon a.s	8.00 %
Mobil Development Norway A/S	7.00 %
Esso Exploration and Production A/S	5.00 %
A/S Norske Shell	5.00 %
Total Marine Norsk A/S	3.00 %
Saga Petroleum a.s	2.00 %
Norske Conoco A/S	1.75 %

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

- Wet gas pipeline from Statfjord to Kårstø
- Separation and fractioning plant at Kårstø, plus storage farm and loading facility
- Dry gas pipeline from Heimdal, dry gas pipeline to riser platform in block 6/11 and pipeline to riser platform at Ekofisk Center.

Kårstø

The first North Sea gas was landed to Kårstø in March 1985. The transport capacity from Statfjord to Kårstø is 8 bcm wet gas a year. The Kårstø processing plant's capacity is 5 bcm wet gas a year. The dry gas pipeline to the Ekofisk Center is capable of transporting 17 bcm a year, which is more than is required for Statfjord, Gullfaks and Heimdal, and makes it possible to tie in other fields subsequently. If an increase in the Statpipe system is required, a new compressor unit will need to be installed beside the riser platform 16/11 S. A framework contract has been signed with Norpipe A/S and the Phillips Group regarding use of the Ekofisk Center and pipeline to Emden.

The Statfjord, Heimdal and Gullfaks partners have also concluded sales agreements for the gas with buyers on the Continent.

In connection with the Kårstø facility a fiscal gas metering equipment laboratory – K-lab – has been built. This laboratory, taken into service in 1988, is owned two-thirds by Statoil and one-third by Total.

Metering system

Metering of the gas delivered from the Kårstø terminal was undertaken in compliance with current rules and standards in 1989. In the case of LPG export the propane measurements are based on a dynamic metering system, while butane and naphtha are measured using ship data.

Early in 1990 all LPG metering will be on the basis of dynamic measurements.

Gas transportation systems – Norpipe A/S

The pipeline transport system for natural gas from Ekofisk to Emden in West Germany is owned by Norpipe A/S, itself a limited company owned 50 per cent by Statoil and 50 per cent by the Phillips Group.

Emden

The Emden terminal is owned by Norsea Gas A/S, and the landing rights in the Emden area by Norsea Gas GmbH. Both these companies are owned by the Phillips Group, on whose behalf Phillips Petroleum Norsk A/S acts as operator.

Gas transportation systems – Ula

Licensees

BP Norway Limited U.A	57.5 %
K/S A/S Pelican	5.0 %
Conoco Norway Inc	10.0 %
Den norske stats oljeselskap a.s (Statoil)	12.5 %
Svenska Petroleum Exploration	15.0 %

Gas transportation systems – Frigg

The Norwegian Frigg pipeline is owned by the Norwegian Frigg partners. Their ownership interests were revised in 1988 and are now:

Elf Aquitaine Norge A/S	26.42 %
Norsk Hydro Produksjon A/S	32.87 %
Total Marine Norsk A/S	16.71 %
Den norske stats oljeselskap a.s (Statoil)	24.00 %

The operator is Total Marine UK.

The midway compressor platform MCP-01 between Frigg and St Fergus is owned 50 per cent by Norwegian interests, while the compressor plant on the installation which is designed to take care of Odin production is 100 per cent Norwegian. The total investment in the Norwegian part of the transport system was about 10.7 billion 1989 kroner.

St Fergus

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

Oil transportation systems – Norpipe A/S

The pipeline system for transportation of oil from the Ekofisk fields, Ula and Valhall to Teesside in the UK is owned by Norpipe A/S, a limited company owned 50 per cent each by Statoil and the Phillips Group.

Teesside

Ownership of the Teesside terminal facilities is split between Norpipe A/S and the Phillips Group through Norpipe Petroleum UK Ltd and Norsea Pipeline Ltd. The operator is Phillips Petroleum Company UK Ltd on behalf of Norpipe A/S and the Phillips Group. Norpipe Petroleum UK Ltd is owned 50 per cent each by Statoil and the Phillips Group. Norsea Pipeline Ltd is owned by the Phillips Group.

Oil transportation systems – Oseberg

This pipeline, of 711 mm diameter and capacity 95,000 scm a day, runs at its lowest point 350 meters below the surface.

The pipeline and the terminal facilities at Sture are owned and operated by a joint venture formed specially for the purpose called I/S Oseberg Transport Systems (OTS). The venturers are the Oseberg partners. Hydro operates the pipeline and terminal. The OTS came on stream simultaneously with the Oseberg field.

The OTS comprises the following elements:
- pipeline support functions on Oseberg A
- subsea pipeline
- landing point
- land pipeline
- terminal.

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

Oil transportation systems – Veslefrikk

The oil pipeline from Veslefrikk to Oseberg A is 37 km long and 406 mm in diameter. It connects the Veslefrikk field with the Oseberg Transportation System thereby allowing Veslefrikk crude to be exported from the Sture terminal. This export system is expected to start operation in January 1990.

In order to sell the Veslefrikk gas a 24 km pipeline of 255 mm diameter has been laid which ties in with the Statpipe system at a tee-junction east of Oseberg.

2.6.2 Planned transportation systems

Gas transport system – Zeepipe

Zeepipe is a gas pipeline for which development has already been declared and which will run from the Troll field via Sleipner to Zeebrügge in Belgium. The project will involve several phases the first of which is from Sleipner to Zeebrügge and should be completed in 1993. The Troll-Sleipner leg is planned for 1996 and Troll-Heimdal in 1998. The final decision which option to pursue for tie-in with Troll will be taken once the Troll concept has been finalised in spring 1990.

In development phase 1 the pipeline dimension will be 1016 mm and in later phases this size is the most likely alternative. The estimated maximum capacity is about 20 bcm a year.

The unmanned riser platform between Sleipner and Zeebrügge which previously formed a part of the development plan has been excluded in favour of a subsea junction, though the final decision will be made in summer 1990.

Detail engineering of the pipeline got under way in autumn 1989 at the same time as construction of the receiving terminal in Zeebrügge started. Award of the contract for laying of the Sleipner-Zeebrügge pipeline and tie-in with Norpipe has been made.

The estimated total costs of the Zeepipe project are about 15.5 billion 1989 kroner.

Condensate transport system – Sleipner East

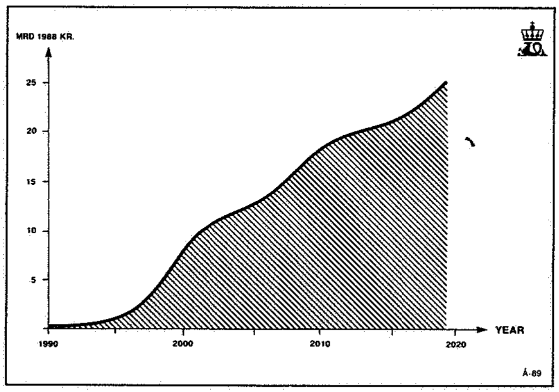
At the suggestion of the partners on production licence 046 the Norwegian Storting approved the construction of a 508 mm condensate pipeline from the Sleipner A platform to Kårstø.

The owners and operator of this pipeline system will be identical with those on Sleipner East. A letter of intent has been finalised with Statpipe for use of the transport and ancillary systems at Kårstø which also promises capacity to handle condensate from production licence 029 and 072. As yet production licence 048 has been kept outside the agreement. The final route for landing at Kårstø will be decided in 1990 and the transport system will be ready for operation on 1 October 1993.

2.7 FINAL PRODUCTION AND REMOVAL

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

Fig. 2.7.a
Estimate of accumulated removal costs of the Norwegian shelf until 2020 given all installations are removed.



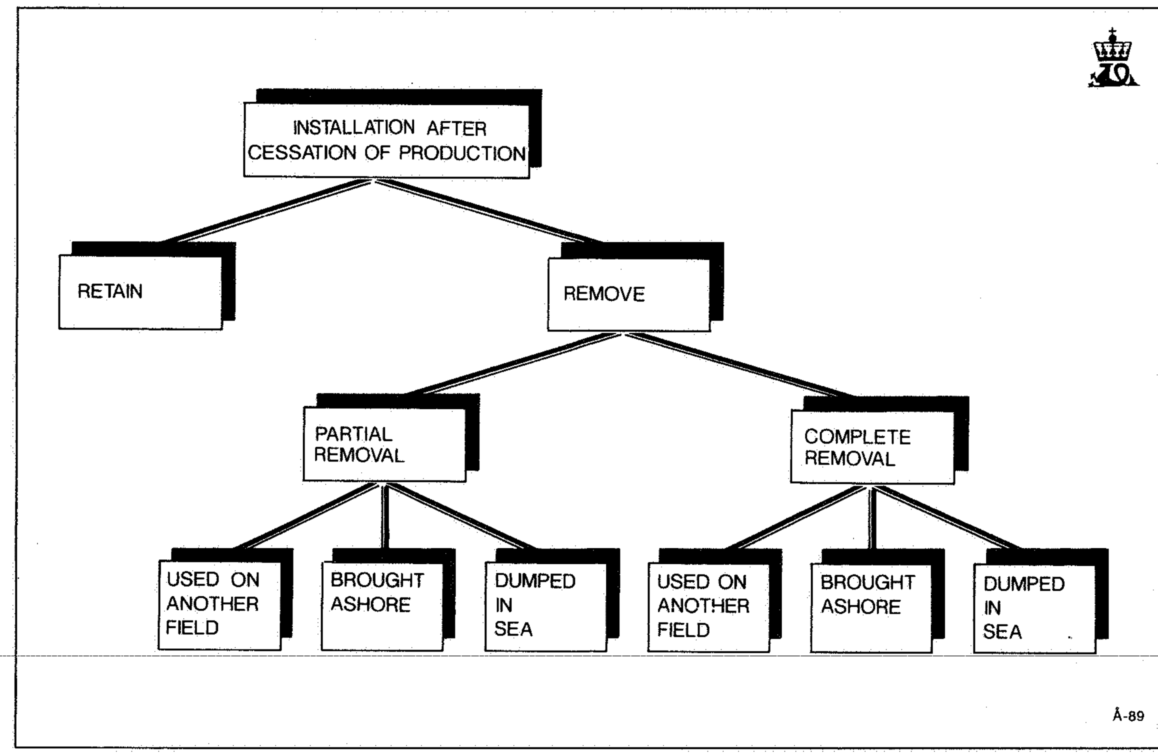
The question of how far a coastal state should be ordered to remove its installations from the continental shelf once their useful life finally terminates is of enormous importance to Norway. Removal of installations on the Norwegian continental shelf will be in almost all cases much more expensive and technically complex than in other parts of the world. At present Norway has about 50 installations already producing petroleum or under planning or construction.

The estimated cost of complete removal of all installations is roughly Nkr 38 billion, though of course this figure is highly speculative. If we just consider removal costs up to year 2020, a figure of Nkr 20 billion seems plausible (see Figure 2.7.a). Under the legislation for removal of installations the state has to bear a considerable portion of the costs thereof.

These are the main points of the IMO rules adopted:

- All installations whose use is finally over and which are at a sea depth of less than 75 meters and have a base (jacket) weighing less than 4000 tons shall be removed;
- All installations deployed after 1 January 1998 whose use is finally over and which are at a sea depth of less than 100 meters and have a base (jacket) weighing less than 4000 tons shall be removed;
- For other installations the question of removal will be determined on the basis of the individual coastal state's evaluation in each case. Said evaluation shall weigh considerations of safety at sea, other users of the sea, environmental impact and life resources, the costs and safety hazards of removal, alternative uses and other reasonable grounds to allow the installation to remain in place, wholly or in part;
- Should a coastal state determine that an installation shall be removed to below the sea surface, a

Fig. 2.7.b
Final production and removal



free height of minimum 55 meters water shall be left below the sea surface;
- Should a coastal state determine that an installation shall remain in place wholly or in part such that it protrudes from the sea surface, satisfactory maintenance shall be carried out to prevent disintegration of the installation;
- After 1 January 1998 no installations shall be emplaced which it is technically impossible to remove.

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

The removal issue is becoming especially relevant on the Norwegian continental shelf and therefore Norwegian authorities must decide many questions of technical, economic and legal content. Many such questions are likely to lend themselves to legislative or regulatory control.

3. Petroleum Resources

3.1 RESOURCES ACCOUNTING

Petroleum resources are among the non-renewable energy resources and include all technically recoverable oil and gas quantities.

Petroleum reserves are that part of the proven resources which are recoverable under given technical and economic conditions and which have been declared commercial by the licence partners.

Resources accounting implies a survey of in-place marketable petroleum quantities on the Norwegian continental shelf, and changes therein from time to time as are due to new discoveries, reappraisal of current estimates and depletion due to production.

The Norwegian Petroleum Directorate's accounting figures from 1988 to 1989 show that the depletion of oil and gas from the Norwegian continental shelf is larger than the new additions and is on balance 31 mcm oil (including NGL) and 20 bcm gas.

At the present rate of depletion of petroleum Norway has resources sufficient for 22 years of oil production and 98 years of gas production.

During 1989 four new discoveries were made: 1/2–1, 3/7–4, 30/9–9 and 35/9–1. The work of charting these discoveries is still continuing and it is therefore too early to say with any certainty how large they are. Accordingly they have been omitted from the resources status, though it seems likely they will by and large make up the net depletion reported for 1989.

The resources status on the Norwegian continental shelf is illustrated in Figure 3.1.a and the geographical distribution of the resources in Figure 3.1.b.

Fig. 3.1.a
Resource account for the Norwegian Continental Shelf

		DISCOVERED						UNDISCOVERED	
	OIL/NGL x $10^6 Sm^3$ GAS $10^9 Sm^3$	PROVED		PROBABLE		POSSIBLE		HYPOTHETICAL	SPECULATIVE
		OIL NGL	GAS	OIL NGL	GAS	OIL NGL	GAS		
PROGRESS	PRODUCING	966	365						
PROGRESS	DECIDED DEVELOPED			260	896				
PROGRESS	PLANNED DEVELOPED			261	648				
TECHNICAL ECONOMICAL CONFIDENCE	POSSIBLY DEVELOPED			308	709	148	146		
TECHNICAL ECONOMICAL CONFIDENCE	UNDER EVALUATION					17	17		
TECHNICAL ECONOMICAL CONFIDENCE	SUB. MARGINAL					9	24		
		PROD. WELLS		APPRAISAL WELLS		EXPLORATION WELLS		DEFINED PROSPECT	UNDEFINED PROSPECT
		DECREASING WELL CONTROL						DECREASING SEISMIC CONTROL	

DECREASING GEOLOGICAL CONTROL

PRODUCED	575 x $10^6 Sm^3$ oil including NGL 293 x $10^9 Sm^3$ gas

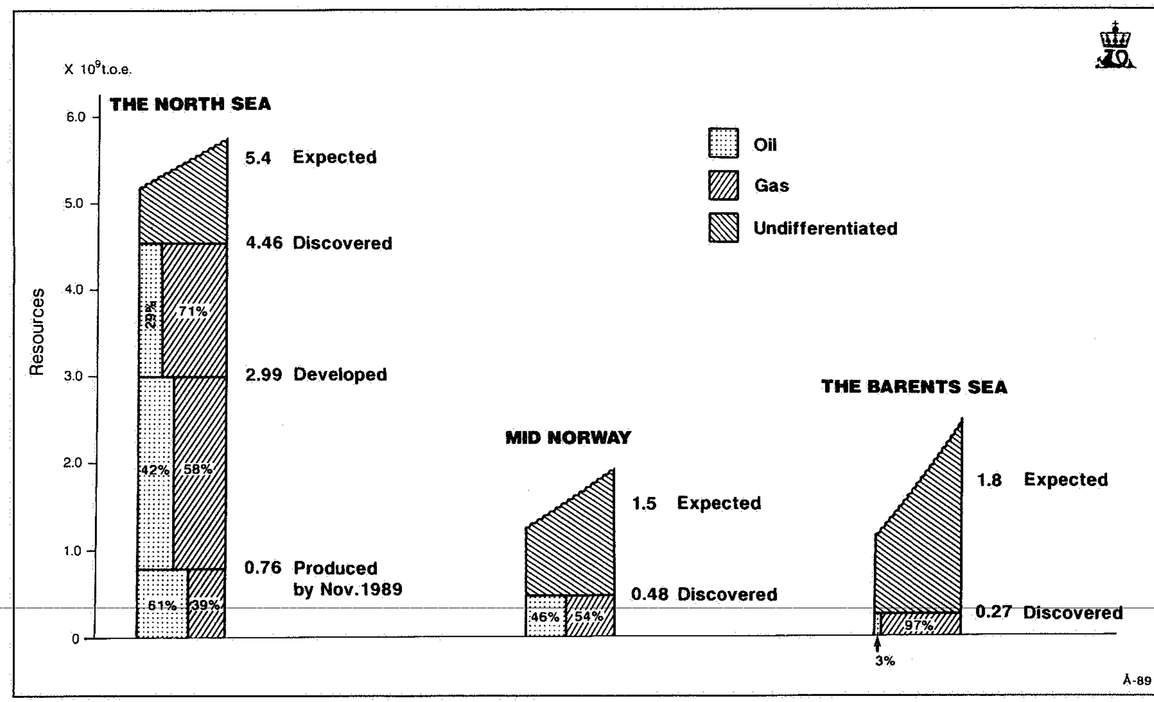
Å-89

Table 3.2
Proven petroleum resources in fields with approved development and operation plan south of Stad

	ORIGINAL AND MARKETABLE				REMAINING IN PLACE		
	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6 tonnes	TOE 10^6 tonnes	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6 tonnes
Albuskjell[1)]	10.0	22.0	1.3	32.2	3.3	8.7	0.4
Cod[1)]	2.8	7.0	0.5	10.1	0.3	1.1	
Edda[1)]	6.1	2.3	0.2	7.7	2.5	0.6	
Ekofisk	276.0	150.0	13.0	391.6	128.9	85.8	7.4
Eldfisk[1)]	75.0	58.0	4.7	126.4	34.0	42.5	2.9
Frigg[1) 2)]	0.4	107.0		107.4		5.5	
Gullfaks[1)]	230.0	16.0	2.2	215.2	204.3	14.4	2.1
Gyda	31.0	3.0	2.5	32.5	31.0	3.0	2.5
Heimdal[1)]	5.8	36.0		40.0	3.6	24.0	
Hod[1)]	4.0	0.9	0.3	4.8	4.0	0.9	0.3
Murchison[1) 3)]	12.0	0.3	0.4	11.1	2.4		
Northeast Frigg[1)]	0.1	11.0		11.1		2.3	
Odin[1)]	0.1	33.0		33.1		16.1	
Oseberg[1) 4)]	236.0	79.0	6.0	289.8	222.5	79.0	6.0
Sleipner East	19.0	51.0	10.0	80.6	19.0	51.0	10.0
Snorre	106.0	5.8	2.7	98.3	106.0	5.8	2.7
Statfjord[5)]	375.0	48.0	15.0	384.2	149.8	35.6	11.2
Tommeliten[1)]	6.4	18.4	1.0	25.3	5.5	17.2	0.9
Tor[1)]	27.0	18.0	2.0	43.4	9.6	8.5	1.0
Troll East		825.0		825.0		825.0	
Ula	67.0	4.6	3.4	65.1	52.2	3.5	2.7
Valhall[1)]	53.0	10.0	3.3	58.3	33.1	6.4	2.3
Veslefrikk[1)]	36.0	3.0	1.3	35.0	36.0	3.0	1.3
West Ekofisk[1)]	13.0	28.0	1.5	41.1	1.6	4.9	0.2
East Frigg		7.5		7.5		5.9	
30/6 Gamma North[1)]	1.3	7.1		8.2	1.3	7.1	
Sum	1593.0	1551.9	71.3	2985.0	1050.9	1257.8	53.9

1) Operator's estimate
2) Norwegian share only, i.e. 60.82 % of total
3) Norwegian share only, i.e. 22.2 % of total
4) Includes Alpha, Alpha North and Gamma structures
5) Norwegian share only, i.e. 84.09 % of total

Fig. 3.1.b
Geographical distribution of the resources on the Norwegian Continental Shelf



For the purposes of this Annual Report the resources on the Norwegian continental shelf are presented in three tables showing:

1. Reserves associated with development projects already declared, under development or in production south of Stad, Table 3.2
2. Other resources south of Stad, Table 3.3
3. Resources north of Stad, Table 3.4.

3.2 RESERVES BASE FOR APPROVED FIELDS

By year end 1989 it had been decided to go ahead with 27 development projects on the Norwegian continental shelf, the same number as one year previously. With a single exception all these development projects are located south of Stad, Draugen being the only field declared for development north of Stad.

The quantities of petroleum in place on fields which have been declared for development and operation south of Stad are presented in Table 3.2. The Draugen reserves are presented in Table 3.4.

Up to 1 November 1989 the total production was 0.76 btoe, which represents 23 per cent of discovered oil and 9 per cent of discovered gas offshore Norway.

3.3 OTHER PROVEN RESERVES SOUTH OF STAD

Table 3.3 shows the other resources discovered south of Stad. The resources in Brage, Statfjord North, Statfjord East, Sleipner West and Troll West

Table 3.3
Discovered petroleum resources south of Stad not yet declared for development

	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tonnes	TOE 10^6tonnes
Agat[1]		43.0		43.0
Balder	35.0			31.6
Brage	46.2	3.5		42.3
Frøy	11.0	3.0		12.0
Gullfaks South	45.0	88.0		127.6
Hild[1]	1.2	8.8		9.8
Huldra[1]	5.4	16.4		20.8
Sleipner satellites[2]	16.0	35.0		47.2
Sleipner West[3]	27.0	135.0	9.0	169.2
Snorre West[1]	7.0			5.7
Statfjord North	22.6	1.2		19.7
Statfjord East	19.0	2.5		18.3
SE-Tor	2.5	2.0		4.0
Troll West	41.0	463.0		499.9
1/3–3	3.3	0.1		2.8
2/7–20	33.0			27.0
2/12–1[1]	8.4			6.9
6/3 PI	0.9	1.0		1.7
7/11 A	3.0			2.5
9/2 Gamma[1]	24.0	1.0		20.9
15/3–1,3	2.0	29.0		30.6
15/3–4[1]	12.0	5.0		15.0
15/5–1	2.0	6.0		7.5
15/12 Beta[1]	16.0	1.3		14.4
16/7–4[1]	1.4	8.0		9.0
24/6–1[1]	1.8	6.0		7.5
24/9	3.0			2.4
25/2–4	4.0	12.0		15.3
30/6 Beta[1]	12.1	0.6		10.5
30/6 Beta Saddle[1]	6.9	0.4		6.0
30/6 Kappa[1]	5.0	5.0		9.1
30/9 Omega[1]	9.3	3.0		10.6
30/9–6[1]	2.7			2.2
34/7 B[1]	25.5			20.9
34/7 C[1]	4.0			3.3
34/8–1[1]	22.5	75.0		93.5
34/10 Beta[1]	8.0	22.5		29.0
34/10 Gamma	2.2	28.0		29.8
35/8–1	1.9	13.5		15.0
35/8–2	2.6	7.0		9.1
35/11–2[1]	10.3	10.9		19.4
Total	506.7	1036.7	9.0	1473.0

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

Table 3.4
Discovered petroleum resources north of Stad

		Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tonnes	TOE 10^6tonnes
Haltenbanken	Draugen	68.0	3.0		58.8
	Heidrun	87.2	42.7		114.2
	Midgard	15.0	80.0		91.6
	Mikkel[1)]	5.7	14.3		19.0
	Njord	25.0	4.0		24.5
	Smørbukk	20.0	65.0		81.4
	Trestakk[1)]	9.0			7.0
	Tyrihans	16.0	40.0		53.1
	6506/12 Beta[1)]	22.0	11.0		29.0
	Sum	267.9	260.0		478.6
Barents Sea	Albatross		41.7		41.7
	Albatross South		10.8		10.8
	Askeladd		59.7		59.7
	Snøhvit	6.5	76.0	5.7	90.7
	Snøhvit North		3.3		3.3
	7119/12 (1)		3.6		3.6
	7120/07		22.5		22.5
	7120/12		14.8		14.8
	7121/5 Beta		4.3		4.3
	7122/06-1 (1)		11.0		11.0
	7124/03-1 (1)		2.1		2.1
	Subtotal	6.5	249.8	5.7	264.5
	Total	274.4	509.8	5.7	743.1

1) Operator's estimate

have been declared commercial and amount in all to 0.75 btoe.

3.4 PROVEN RESOURCES NORTH OF STAD

To date 0.75 btoe resources have been discovered north of Stad, of which 0.48 btoe are in Haltenbanken and 0.27 btoe in the Barents Sea.

3.5 REVISION OF RESOURCES BASE SINCE LAST YEAR

3.5.1 Fields in production and approved for development

For fields in production the Norwegian Petroleum Directorate generally accepts the operator's projections of future reserves. On many fields only moderate changes were made in the forecasts compared with the figures given in the 1988 Annual Report. Fields where a substantial revision has occurred are dealt with specifically below. For changes in resources statistics from 1988 to 1989, see Table 3.5.

Albuskjell
On Albuskjell the low-permeable reservoir in the Ekofisk formation has shown itself producible, which has led to an increase in estimated oil and gas reserves of 20 per cent relative to the 1988 report.

Draugen
For Draugen an adjustment of the sales gas figure relative to recoverable gas reported in the 1988 report has been made.

Edda
Natural water drive or compaction has caused the reservoir pressure to be maintained better than anticipated, in addition to which artificial gas lift will help enhance oil production. The total increase relative to the 1988 report is 33 per cent.

Ekofisk
Pressure development on Ekofisk is still in a positive cycle as a result of water injection and compaction of the field. The oil and gas reserves estimates have been increased by 4 per cent relative to 1988.

Eldfisk
On Eldfisk it has been decided to reduce the pressure in the decade 2000 to 2010 more than was projected which will mean an increase in the total recovery of gas.

Gullfaks
New charting and better pressure response than expected have led to an upward revision of the oil and gas reserves in the field. The total increase is 9 per cent compared with last year's report.

Oseberg
On Oseberg condensate has been segregated as a separate phase. Otherwise there is no change.

Sleipner East
A new reservoir simulation has resulted in a moderate increase in oil volume.

Table 3.5
Changes in estimated resources relative to last year's Annual Report

	Annual Report 1988			Annual Report 1989		
	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tonnes	Oil 10^6Sm^3	Gas 10^9Sm^3	NGL 10^6tonnes
Fields in production and declared for development						
Albuskjell	8.1	18.3	1.2	10.0	22.0	1.3
Cod	2.8	7.1	0.	2.8	7.0	0.5
Edda	4.5	1.8	0.2	6.1	2.3	0.2
Ekofisk	266.0	143.0	13.0	276.0	150.0	13.0
Eldfisk	73.0	48.4	4.5	75.0	58.0	4.7
Frigg	0.4	105.0		0.4	107.0	
Gullfaks	210.3	14.3	2.2	230.0	16.0	2.2
Gyda	30.5	3.0	2.5	31.0	3.0	2.5
Heimdal	4.5	33.2		5.8	36.0	
Hod	4.0	0.9	0.5	4.0	0.9	0.3
Oseberg	242.0	79.0		236.0	79.0	6.0
Sleipner East	17.0	51.0	10.0	19.0	51.0	10.0
Snorre	108.0	6.6		106.0	5.8	2.7
Statfjord	374.8	48.2	14.6	375.0	48.0	15.0
Tor	26.9	17.0	1.9	27.0	18.0	2.0
Ula	52.5	3.3	5.1	67.0	4.6	3.4
Valhall	48.7	12.7	3.5	53.0	10.0	3.3
Veslefrikk	36.4	3.0		36.0	3.0	1.3
West Ekofisk	13.1	29.4	1.6	13.0	28.0	1.5
East Frigg		8.0			7.5	
30/6 Gamma North	1.4	7.5		1.3	7.1	
Other discoveries						
Draugen	68.0	4.8		68.0	3.0	
Snøhvit	6.5	91.4		6.5	76.0	5.7
30/6 Beta	20.0			12.1	0.6	
30/6 Beta Saddle	20.0			6.9	0.4	

Ula
New mapping of Ula after sinking of the oil-water contact in parts of the field led to an increase in reserves of 19 per cent relative to the 1988 report.

3.5.2 Other discoveries
Of the discoveries not yet declared for development only the resources on Snøhvit and in the 30/6 Beta area have been revised downward. Otherwise there are no changes.

Snøhvit
The Norwegian Petroleum Directorate has run a new reservoir simulation of Snøhvit which has led to a slight reduction in recovery factor and reduction of the total resources by about 6 per cent.

30/6 Beta and Beta Saddle
The Norwegian Petroleum Directorate has adopted the operator's figures for the resources statistics, though these represent only 50 per cent of the Directorate's now obsolete 1988 estimate.

4. Safety and Working Environment

4.1 INTRODUCTION

The Norwegian Petroleum Directorate has been delegated authority by the Ministry of Local Government to carry out supervisory functions in respect of some of the safety concerns of the Petroleum Act and its regulations. The same supervisory functions apply in the case of the Working Environment Act and its regulations. The nature of the delegation is to provide authority to:

- Issue regulations for the activity
- Conduct total safety evaluations
- Decide consents, directives, dispensations and approvals.

The Directorate tries to adopt a holistic approach to the implementation of its supervisory activities, and high standards of cooperation are required in the fields of safety, working environment and resource management, not only within the Directorate, but also in relations with other public institutions. The Directorate seeks to play a coordinating role relative to the other government agencies which under the Petroleum Act have an independent control responsibility in their own right. The Directorate also draws on the professional expertise of other agencies where it has no comparable skills inhouse.

During the current year the Directorate has continued to develop internal control systems which will meet the requirements for Administration-by-Objective. It was important to develop planning systems which effectively direct the application of Directorate resources towards priority input areas and which also ensure that supervisory operations are consonant with the fundamental principles staked out in the Petroleum Act.

4.2 REGULATIONS – DRAFTING AND REVISION

4.2.1 Methodical regulatory development for safety and working environment

When the new petroleum legislation with its delegated authorities and the new supervisory functions became effective in 1985 one of the key objectives was to open the door for a coherent and uniform regulatory apparatus with which to govern the oil-related activity on the Norwegian continental shelf.

Work in this vein was initiated in January 1987 when the methodical regulatory development project was set up. The work addresses form and content of the regulations and is presented in more detail in the Directorate's Annual Report for 1987.

One aspect of the work has been the formulation of a coordinated revision plan for current detail regulations which will guide revision activity up to the end of 1990.

4.2.2 Regulatory cooperation

During 1989 the Norwegian Petroleum Directorate has carried out regulatory work in line with the intentions of the revisory plan submitted to the Ministry earlier.

This work took high priority: roughly 10 per cent of the Safety Division's resources and half the Legal Branch's were mobilised for the task.

The Directorate has been careful to keep interested parties informed of progress made and the substance of the regulatory work, holding regular meetings in the established contact and reference forums as one means to this end.

At year end the regulatory project status was as follows:

Regulations issued

- *Regulations for Natural Environment Data etc,* issued 1 February 1989
- *Regulations for Manned Subsea Operations etc,* submitted to the Ministry in August 1989 and due to be issued.

Regulation drafts circulated

- *Regulations for Pipeline Systems etc*
- *Regulations for Electrical Systems etc*
- *Regulations for Performance and Application of Risk Analyses etc.*

Regulations under drafting

- *Regulations for Drilling, Drilling Technology and Data Acquisition etc*
- *Regulations for Cranes and Lifting Gear etc*
- *Regulations for Contingency Preparedness in Petroleum Activity etc*
- *Regulations for Fire and Explosion Security etc*
- *Regulations for Safety Systems etc*
- *Regulations for Process and Support Systems etc*
- *Regulations for Structural Design etc*
- *Regulations for Marking of Installations, Loads and Equipment etc.*

Guidelines issued

- *Guidelines for Steel Materials etc,* issued 1 February 1989.

4.3 SUPERVISORY DUTIES

The Norwegian Petroleum Directorate's supervisory duties during the current year were conducted according to a coherent plan which reflects the objectives adopted and priority commitment areas.

The Directorate's supervision of the operating companies is designed to affirm that they have established management and control systems with which to ensure that their activities are planned, organised and maintained in accordance with the current legislative and regulatory requirements. Said supervision is implemented in practice by investigating how the companies' management and control systems are formulated, complied with and maintained (system audits) and by getting confirmation, from spot checks, that activities and products indeed conform with the specified requirements (verification).

4.3.1 Consents and permits

When preset milestones are reached as defined in the safety regulations the Norwegian Petroleum Directorate must give its consent before certain subsequent activities can begin.

- In the current year 62 such consents and permits were given for these purposes:
- Exploratory survey (5)
- Exploration drilling (21)
- Detail engineering (2)
- Fabrication (6)
- Installation (4)
- Use of installation (12)
- Rebuild or redefinition of purpose of installation (1)
- Use of service vessel (11).

Also awarded were 64 consents and permits for production drilling, 27 for exploration drilling and 29 for shallow drilling.

4.3.2 Priority commitment areas

During the last three-year period the Norwegian Petroleum Directorate has given priority to supervisory activities associated with:

- Observance of requirements in Working Environment Act
- Early phase of field developments
- Older installations.

The work targets in the priority commitment areas are defined in the supervisory plan for the current reporting period.

4.3.2.1 Observance of requirements in WEA

During the current reporting period the Norwegian Petroleum Directorate has been particularly concerned with relations between the two parties in the offshore industry. The employers' duties to inform his employees and their delegated representatives and draw them into planning and management and control systems has been highlighted by the Directorate in supervisory functions, lectures and discussions with the parties. Employers seem only to a limited extent to ensure that the employee side receives the necessary insight and understanding of the internal control systems in the industry.

One of the primary objectives of the Working Environment Act is for both sides of industry to resolve their working environment problems jointly, helped along by supervision and consultation with the supervisory authority. For issues springing from manning cuts and restructuring of work areas and functions, it seems the objectives of the act have not been fulfilled. Indeed, this method of solving problems seems to present its own set of conflicts which often need to be submitted to the supervisory authority for decision and resolution.

The Directorate's supervisory activities reveal also that information on chemical health hazards is often poorly documented by the vendor. This may prejudice the operator's evaluation of the health risk when selecting a product, and his understanding of the necessary protective measures once the product is in use.

4.3.2.2 Early phase

Follow-up of projects in the early phase – during the pre-engineering and plan for development and operation and the detail engineering – has been a priority area during the report year. The results of this supervisory activity will first become visible when the projects are completed and the installations brought on stream. Even so it is possible on the basis of findings thus far from follow-up in the early phase to conclude that the Directorate has already achieved greater control and influence in respect of matters crucial to the working environment and safety.

The Directorate has noted a positive trend regarding the operators' formulation of specific working environment requirements for installation design and equipment during the pre-engineering phase. The results from the supervisory activities nevertheless show that some of these requirements are only marginally implemented, particularly when it comes to matching systems and equipment to the human factor.

Through its supervisory activities the Directorate has learned that greater emphasis must be put on optimisation of the time at which risk analyses are carried out relative to the progress of the project. Hopefully the outcome of this will be that the concerns for safety and the working environment will be better attended to when crucial decisions are made.

4.3.2.3 Older installations

This year too the Norwegian Petroleum Directorate has given priority to follow-up of the operators' maintenance operations on older installations. This branch of the supervisory functions has sometimes revealed major flaws in the companies' maintenance routines and on occasions a tail-back of work pending relative to the planned maintenance schedule.

In some cases the operating companies have given priority to maintenance issues in their own supervisory activities and thereby discovered serious flaws and limitations in their own maintenance systems.

It is to be welcomed that maintenance is given priority in the companies' own supervisory efforts. The result may be that the operator and the authorities will see more eye to eye on the problems in this area, thereby bringing about an upgrading of maintenance priority in the companies.

Some of the conditions originally applying to maintenance systems on older installations have since been revised. Examples are technological change, organisation and economy. Similarly the installations' working lives and useful purpose have been changed in some cases relative to the assumptions which originally dictated the engineering of the installation.

At the same time the Directorate has noted that the operating companies have gathered considerable quantities of empirical data during many years of operation and maintenance of the installations. These data may provide the operating companies with a good home base from which to analyse and document the need for change and adaption of maintenance systems in the light of the lessons learned.

It is reasonable that it may take some while to adapt the maintenance systems to the changes in conditions which have occurred. The Directorate has noted, even so, that there is a need to inspire a certain urgency in this work, if the industry is going to be ready to meet the exigencies of remote control, ageing, changing lifetimes and revised fields of operation.

4.4 REMOTE CONTROL INSTALLATIONS

Experience using remote control installations on the Norwegian continental shelf is currently limited to a few offshore loading buoys and the Northeast Frigg gas fields which are monitored from Frigg. Remote control installations may prove attractive in the future for the development of marginal fields and in connection with the remote control of existing installations. The first remote control wellhead installation is now under fabrication for use on Hod.

Remote control installations will be manned periodically in connection with inspection, maintenance and modification work. This means that the Directorate, as is the case now for continually manned installations, expects the operators when evaluating concepts, during engineering and during operation and production, to ensure an acceptable level of safety and fully sound working environment for the crews who will be on board the installation from time to time.

Evaluations of the working environment on the installations will be gauged against the standards required for maintenance, repair and modification work. Also the day and night accommodation facilities will be measured against the acceptable standard: the design of the installation, the choice of equipment and materials, its operational safety and ease of maintenance, the skills of the personnel and the organisation of work being the things it is felt ought to be considered.

The choice of transportation means also needs careful thought during the engineering phase. A concept involving transportation to an unmanned helideck will represent altered requirements so far as helideck fire and rescue aids are concerned. Sea transportation to and from the installation is another likely option. The competing modes of transportation are subject to weather constraints in different degrees. The length of forced stays on the installation due to weather factors therefore needs to be considered when designing the day and night accommodation facilities.

It will be necessary to provide fire-fighting equipment for the personnel who spend periods onboard. Evacuation options and appropriate emergency procedures must be established.

Remote control installations must also be provided with acceptable barriers to pollution of the environment.

4.5 MANNING CUTS

The petroleum installations on the Norwegian continental shelf are of variable age, design and degree of automatic control. Evaluations and analyses of crew size and composition therefore need to be based on detailed knowledge of the conditions on each installation. Manning factors can influence the risk of accident and occupational injury.

Cuts in crews might, for example, as a result of reduced manpower capacity, lead to less frequent or less thorough inspection and testing of safety-critical equipment. Manning cuts may also affect human error frequencies. Factors which lead to escalating work intensity, added stress, preference for multidisciplinary skills and greater responsibility on each person's shoulders may affect the frequency of human error.

Manning cuts mean a reduction in the number of potential victims of a major disaster. This argument, though, is of limited appeal, since every individual must, at least in principle, perceive the same level of safety, irrespective of number of crew. There must always be people present who are sufficiently qualified to assess potentially hazardous situations and who can intervene so as to reduce the hazard. Also it is important that there are sufficient and appropriately qualified personnel present to contain the consequences of a dangerous situation and to ensure safe evacuation in an emergency.

The Directorate has been following the situation closely within the frames of the present regulations and expects the operating companies to formulate crew plans for each individual installation in which the total personnel requirements, personnel qualifications and crew composition are stated. This will comprise a component of the operator's documentation that requirements for sound operations have been met. The Directorate is particularly concerned that employee input is assured in these evaluations and that the employees are furnished with the necessary information and training.

The Directorate believes in discussions between both sides on manning issues. In the case of deadlock, the Directorate assesses whether the changes proposed are sound on an overall evaluation of safety and the working environment.

The regulations and the Directorate's supervisory philosophy mean that each individual operating company is responsible for making sure that the various functions are adequately manned and that the personnel hold adequate qualifications for carrying out their tasks.

In 1989 the Directorate was particularly concerned with the following cases concerning manning cuts:

a) Phillips reduced the number of drilling crews on Ekofisk installations in 1988. In 1989 the Directorate pursued this action by verification of the work situation on the drill floor since the manning cuts. The results after verification will be reviewed again in 1990.
b) Phillips has planned to reduce manning in the radio shacks in the Ekofisk area from 24 to 12 hour watch. This will mean the shacks are only manned during the day time. The employees have brought the Directorate's decision before the Ministry of Local Government, justifying their complaint with the argument that safety is impaired by the revision. The matter is discussed more fully in section 4.8.8.
c) Statoil plans to man the radio shacks on Veslefrikk B after the same pattern and has submitted the matter to the Directorate. Further consideration of the case has been deferred until the results of internal discussions in the operating company are announced.
d) In connection with run down of activities on the Frigg field, Elf planned and implemented a number of measures to cut manning. The Directorate is watching these activities closely. In 1989 several information meetings were held between the Directorate and the operator, and between the Directorate and the company's employee representatives.
e) Phillips is planning a series of rationalisation measures on Ekofisk installations which will impact on the manning and situation of employees on several installations. The operator's plans were closely watched by the Directorate and information meetings were held during the year.

In 1989 the Directorate launched an initiative for a preliminary project to examine the correlation (if any) between crew cuts, accidents and injury. A draft project report has been prepared and is being reviewed by the Directorate with a view to continuation in 1990.

Developments on the Norwegian continental shelf suggest that the issue of crew reductions versus safety and working environment will have a prominent place in the years ahead. The Directorate's scrutiny of the operators' rationalisation plans and measures will therefore be a priority area.

4.6 EXPERIENCES WITH INTERNAL CONTROL

The continuing development away from detail control and associated detail regulations, and towards internal control and associated functional requirements, system audits and problem-oriented dialogue, means that supervisory and other activities have been performed more efficiently.

Although it is true that supervision activities have disclosed flaws in the operating companies' internal control systems at various levels, the general conclusion is that development is positive.

In November in conjunction with the employee organisations and the Rogaland Research Institute the Directorate arranged a conference entitled Internal Control for Safeguarding the Working Environment. The addresses given here will be published in a special conference report.

Hitherto the Directorate had met with considerable suspicion and dissatisfaction with the internal control scheme on the part of employees. At the conference, however, there was a positive attitude to the scheme as such, though there were still divided opinions whether it works as intended.

The areas of difficulty addressed at the conference were to do with:

a) Role of safety delegates and working environment committees in internal control system
b) Relationship between internal control regulations and Working Environment Act's requirements
c) Contractor companies and internal control
d) Internal control and training.

4.7 PERSONAL INJURIES

4.7.1 General

The Norwegian Petroleum Directorate receives reports on personal injuries in connection with the oil activities according to certain criteria. These reports are continually reviewed to see if Directorate follow-up is required. Such follow-up involves a study or investigation of the accident and may result in directives to the operating companies. In some cases the Directorate has also issued safety notices.

On the basis of empirical data gathered from the personal injury statistics for 1988 and through incidents registered in 1989 the Directorate has focused attention in particular on accidents and near-accidents in association with:

a) Work on systems which had been pressurised
b) Work on electrical systems which were not adequately disconnected from live source
c) Work on equipment which was not secured against presence of explosive gas
d) Work on systems and equipment with poor design standard which caused injury due to crushing, cuts, bumps or blows
e) Areas having poor safety planning or poor safety organisation of work.

The Directorate has ordered the operating companies to carry out job safety analyses for critical work operations as a result of incidents in these areas.

The Directorate has also entered into discussions with the industry about measures by which to reduce the continuing large numbers of accidents caused by objects and equipment in motion, falling objects, splinters, as well as falls, see Table 4.7.3.d. These injuries make up about 70 per cent of the total number. By continual assessment and analysis of personal injury statistics in 1989 the Directorate has identified the following specific areas which often recur among the causes of accidents:

a) Inappropriate position or work posture relative to tools or equipment
b) Non-use of or inadequate protective equipment
c) Equipment in poor repair or used wrongly
d) Untidy workplace, slippery surfaces etc
e) Cluttered access to equipment to be operated or maintained.

4.7.2 Near accidents

Incidents which did not result in personal injury or other material injury but which might have done so had the situation been otherwise are termed near-accidents. It is reasonable to suppose that there occur a large number of near-accidents for every accident reported. The information provided by these near-accidents constitutes a rich base from which to align the authorities' supervision priorities, and for the offshore industry's own endeavours to reduce the numbers and extent of accidents.

Since the operating companies were urged to report near-accidents, 48 such reports have come in (1989). Most of them concern falling objects, fire and near-fire, and gas leaks. Relative to the number of reported accidents the number of reported near-accidents is patently too low. The Directorate will therefore seek to improve the reporting frequency of near-accidents.

4.7.3 Personal injuries in connection with drilling and production on fixed installations

Reported injuries in connection with production of oil and gas totalled 581 in 1989, including one accident resulting in death. The figure is 56 less than in 1988, though the number of manhours worked was roughly the same.

The fatal accident was on Statfjord C. A flange gasket blew under a pressure test and the issuing liquid jet hit the casualty, who fell 28 meters from a flare stack into the sea below.

Table 4.7.3.a includes a summary of the personal injuries per 1000 man-years worked in the petroleum industry from 1976 to 1989. Since 1987 the number of hours worked a year has been cut back from 1752 to 1612. The overall injury frequency and personal injury statistics for 1988 have been adjusted for late reports and report verification.

Accidents during time-off are not included in the tabulated statistics. The number of such accidents reported in 1989 was the same as in 1988, namely 32.

Table 4.7.3.a
Injuries and deaths per 1000 man-years on production installations 1976–1989

Year	Hours worked	Hours per man-year	Man-year	Injuries and deaths	Injuries and deaths per 1000 man-years	Deaths	Deaths per 1000 man-years
1976	4876316	1852	2633	213	80.9	2	0.76
1977	8146948	1852	4399	282	64.1	2	0.45
1978	14932296	1752	8523	624	73.2	6	0.70
1979	14986608	1752	8554	575	67.2	0	0.00
1980	12237720	1752	6985	451	64.6	0	0.00
1981	15612072	1752	8911	415	46.6	0	0.00
1982	14790384	1752	8442	526	62.3	0	0.00
1983	11473848	1752	6549	334	51.0	0	0.00
1984	14643216	1752	8358	491	58.7	1	0.12
1985	15014640	1752	8570	599	69.9	1	0.12
1986	17108280	1752	9765	606	62.1	0	0.00
1987	22169458	1612	13753	832	60.5	0	0.00
1988	19878727	1612	12332	637	51.7	0	0.00
1989	19935637	1612	12367	581	47.0	1	0.08
Total	205806150		120141	7166	59.6	13	0.11

Fig. 4.7.3.a
Injuries to personnel 1979–89

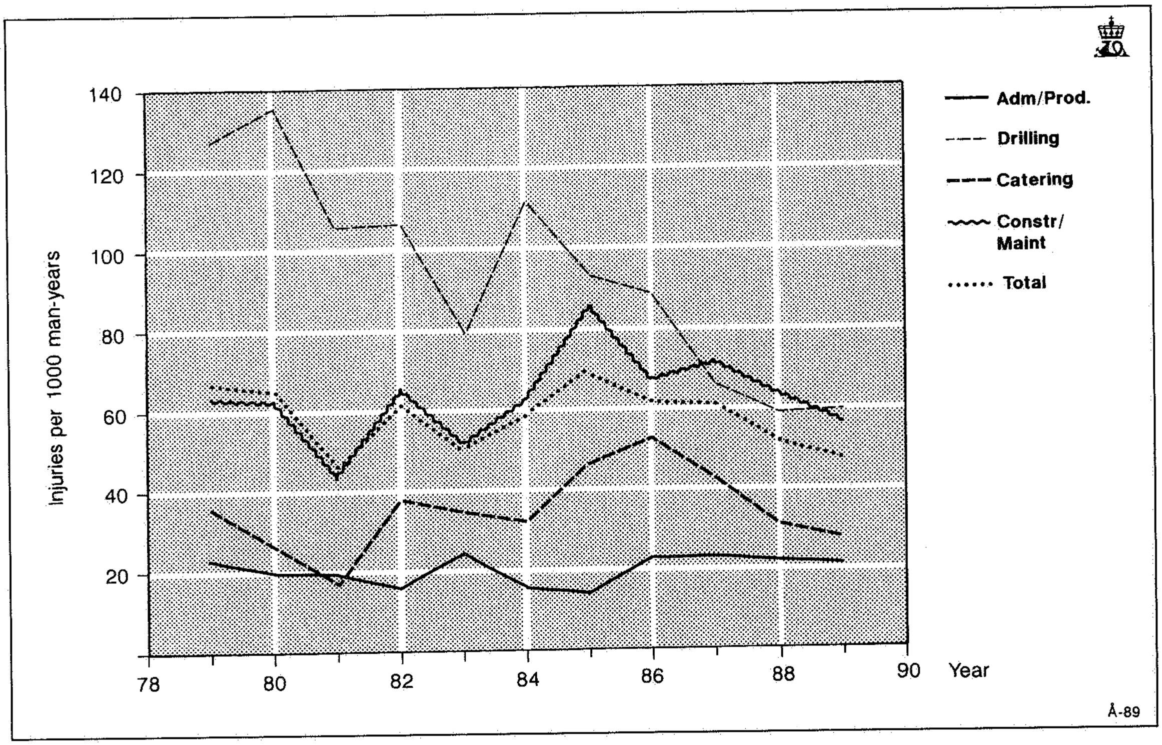


Table 4.7.3.b
Injuries per 1000 man-years by function on production installations 1979–1989

FUNCTION		1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
Administration/ Production	Man-years	1098	1174	1144	1306	1182	1614	1656	1507	2295	2440	2393
	Injuries	25	23	22	21	29	25	23	34	53	53	50
	Injuries/1000 man-yrs	22.8	19.6	19.2	16.1	24.5	15.5	13.9	22.6	23.1	21.7	20.9
Drilling	Man-years	1467	1095	1098	1289	1300	1324	1384	1371	1567	1883	2128
	Injuries	186	148	116	137	104	148	130	122	103	110	126
	Injuries/1000 man-yrs	126.8	135.2	105.6	106.3	80.0	111.8	93.9	89.0	65.7	58.4	59.2
Catering	Man-years	507	383	411	548	525	681	685	856	1167	1091	1228
	Injuries	18	10	7	21	18	22	32	45	50	33	33
	Injuries/1000 man-yrs	35.5	26.1	17.0	38.3	34.3	32.3	46.7	52.6	42.8	30.3	26.9
Construction/ Maintenance	Man-years	5482	4333	6258	5299	3542	4739	4845	6031	8724	6919	6619
	Injuries	346	270	270	347	183	296	414	405	626	441	372
	Injuries/1000 man-yrs	63.1	62.3	43.1	65.5	51.7	62.5	85.4	67.2	71.8	63.7	56.2
Total	Man-years	8554	6985	8911	8442	6549	8358	8570	9765	13753	12332	12367
	Injuries	575	451	415	526	334	491	599	606	832	637	581
	Injuries/1000 man-yrs	67.2	64.6	46.6	62.3	51.0	58.7	69.9	62.1	60.5	51.7	47.0

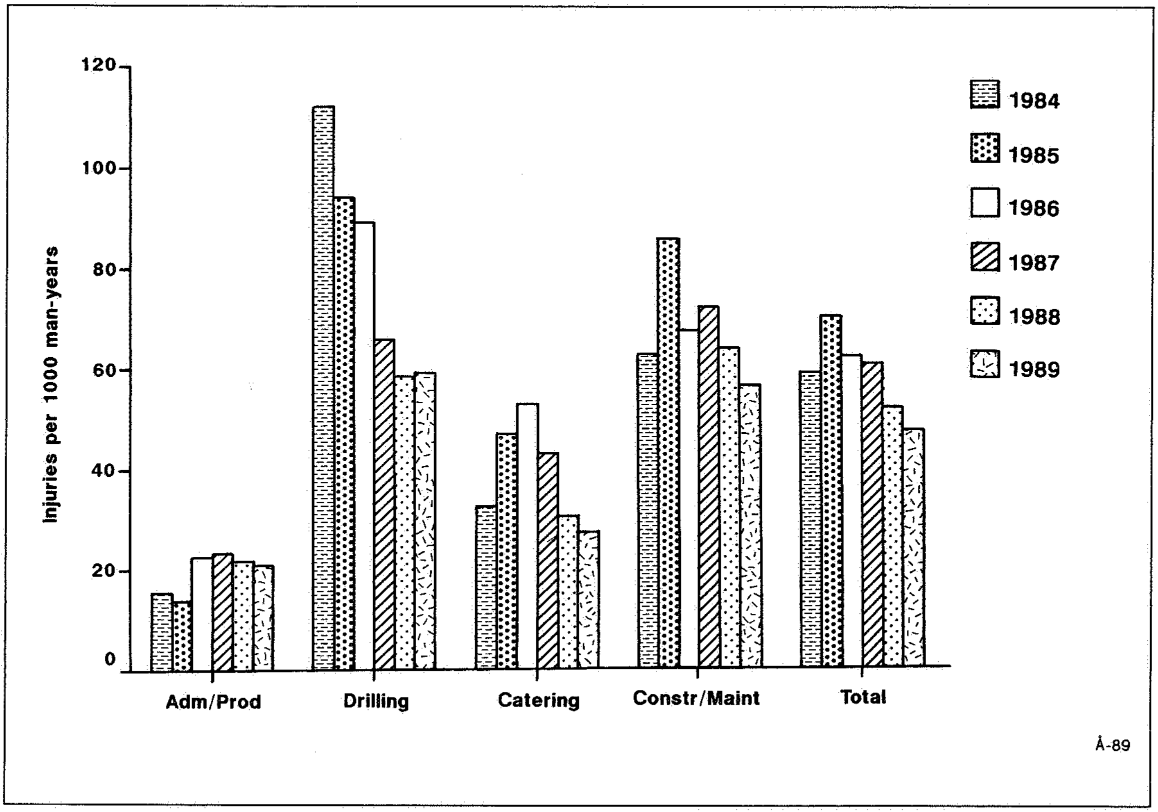
Figure 4.7.3.a shows the development of personal injuries during the period 1979–1989.

Table 4.7.3.b shows the distribution of accident frequency for the various main activities during the same period. This summary shows a reduction in accident frequency for the drilling function even though the figures for the last two years are almost identical. For the other functions the statistics cannot be taken to indicate that injury frequencies are declining. Verification of the statistics turned up a systematic error which resulted in correction of some of the 1988 figures.

Figure 4.7.3.b shows the development of the calculated injury frequency for the period 1985 to 1989 broken down by work function category.

Table 4.7.3.c shows the injury frequency and distribution of injuries and years worked for operator and contractor employees from 1986 to 1989. The

Fig. 4.7.3.b
Injuries by function (job category) 1984–89



figures tend to indicate a decline in injury frequency for contractor employees, though there remains a big gap between contractor and operator personnel. This must be viewed in the light of the different risks to which operator and contractor employees are exposed by virtue of the different work operations they perform.

Figure 4.7.3.c shows the injury frequency broken down by operator and contractor personnel and main activity functions in 1989.

Tables 4.7.3.d-g show the distribution of injury events by work group, part of body injured and contributory causes.

Table 4.7.3.h shows the distribution of personal injuries by seriousness. An injury is defined as serious here if it results (or will probably result) in permanent injury (for example amputation) or extended absence from work. The evaluation is made solely on the basis of information in the accident report and not on a medical review well after the accident.

4.7.4 Personal injuries in connection with exploration and production drilling on mobile installations

There were two fatal accidents on mobile exploration rigs in 1989: On *Vildkat* a fatality occurred during manoeuvring of a drill collar on the drill floor, when the collar shifted out of control and landed on top of the person injured.

The second fatality occurred on the *Treasure Saga* drill rig when the injured person was hit in the back by a drill string and thrown against the hydraulic pipe tongs when the brakes on the elevator holding the string failed.

Accident reporting from mobile exploration and production rigs is subject to the same criteria as for production activity. The summary only concerns personal injuries on the installations while engaging in petroleum activities. In 1989 there were 87 accident reports compared with 109 in 1988. This represents an accident frequency of 39.1 per 1000 man-years worked in 1989. 1989 is the first year for which the Directorate has received complete reports on working hours for mobile installations and it is not possible therefore to make comparisons with previous years.

Table 4.7.4.a shows the incidents distributed by occupational groups.

Table 4.7.4.b shows the incidents distributed by contributing factors.

4.7.5 Development of injury frequency

The summary for all activities on production installations shows a reduction in accident frequency in 1989 relative to 1988.

Table 4.7.3.c
Break down of injuries and man-years by operator and contractor employees

FUNCTION		1985	1986	1987	1988	1989		
Administration Production	Man-years	1575	1293	1692	1985	2099	o	(operator)
		80	213	603	454	294	c	(contractor)
	Injuries	19	34	44	47	42	o	
		4	0	9	6	8	c	
	Injuries/1000 man-yrs	12.0	26.3	26.0	23.7	20.0	o	
		49.6	0	14.9	13.2	27.2	c	
Drilling	Man-years	0	0	0	0	0	o	(operator)
		1384	1371	1567	1883	2128	c	(contractor)
	Injuries	0	0	0	0	0	o	
		130	122	103	110	126	c	
	Injuries/1000 man-yrs	0	0	0	0	0	o	
		93.9	89.0	65.7	58.4	59.2	c	
Catering	Man-years	0	39	94	209	340	o	(operator)
		685	817	1073	882	888	c	(contractor)
	Injuries	0	5	5	4	3	o	
		32	40	45	29	30	c	
	Injuries/1000 man-yrs	0	129.3	53.3	19.1	8.8	o	
		46.7	49.0	41.9	32.9	33.8	c	
Construction/ Maintenance	Man-years	1544	2063	2441	2399	2381	o	(operator)
		3301	3969	6283	4520	4237	c	(contractor)
	Injuries	61	51	49	50	69	o	
		353	354	577	391	303	c	
	Injuries/1000 man-yrs	39.5	24.7	20.1	20.8	29.0	o	
		106.9	89.2	91.8	86.5	71.5	c	
Total	Man-years	3120	3394	4227	4593	4820	o	(operator)
		5450	6370	9526	7739	7547	c	(contractor)
	Injuries	80	90	98	101	114	o	
		519	516	734	536	467	c	
	Injuries/1000 man-yrs	25.6	26.5	23.2	22.0	23.7	o	
		95.2	81.0	77.0	69.3	61.9	c	

Fig. 4.7.3.c
Injuries to personnel employed by operators and contractors 1989

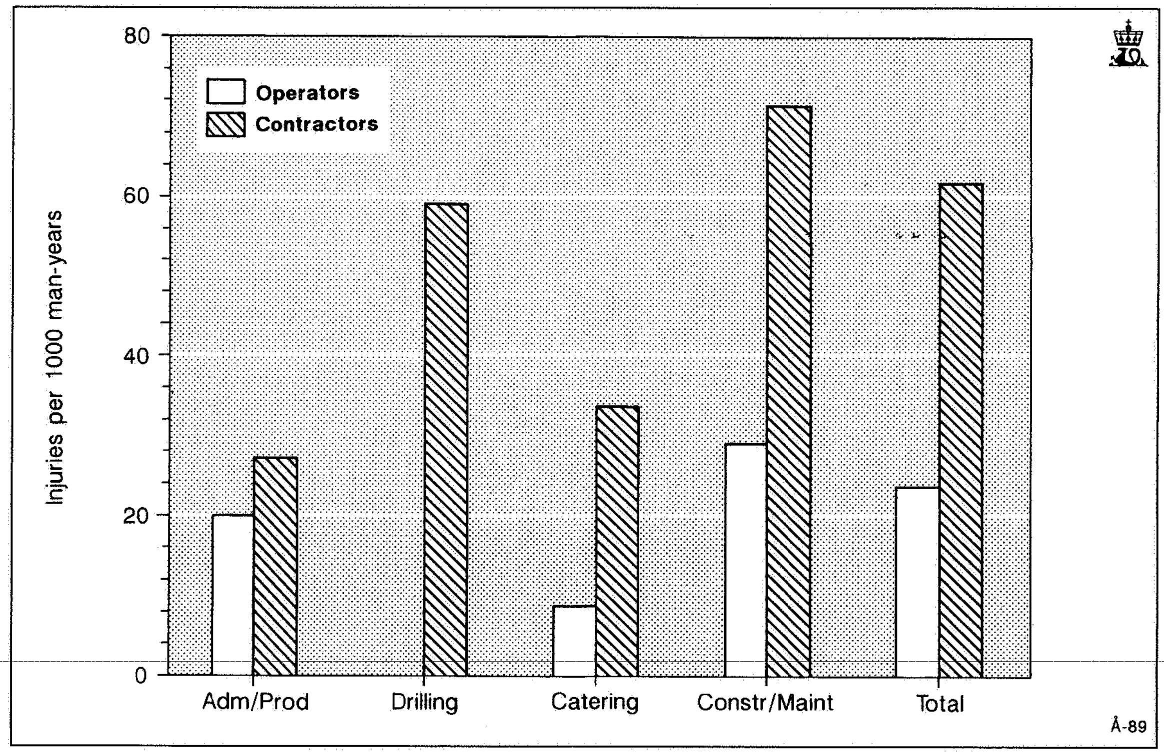


Table 4.7.3.d
Work accidents 1988–89 on production installations etc showing type of incident and occupation

Injury incident \ Occupation	Administration	Drillfloor worker	Driller	Electrician	Caterer	Assistant	Instrument technician	Crane operator	Painter, gritblaster	Mechanic, motorman	Operator	Plateworker, insulator	Pipeworker, plumber	Service technician	Scaffolder	Welder	Derrickman	Other, unspecified	Total	%	Year
Other contact with object/ machinery in motion	1	12	2	2	3	16	0	2	3	5	8	3	4	9	3	0	4	0	77	12.1	88
	1	12	6	5	4	26	3	0	2	15	0	2	7	4	9	5	5	7	113	19.4	89
Fire Explosion etc	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	88
	0	0	0	0	0	2	0	0	0	0	1	0	0	0	0	0	0	0	3	0.5	89
Fall to lower level	0	1	0	1	1	6	2	2	6	2	3	3	2	0	3	1	1	0	34	5.3	88
	0	1	0	2	2	6	1	2	4	3	2	1	1	1	0	2	0	2	30	5.2	89
Fall to same level	2	3	1	4	3	11	4	0	2	1	2	2	0	2	7	2	1	0	47	7.4	88
	2	3	1	2	2	6	0	1	2	4	3	2	2	1	2	0	0	2	35	6.0	89
Stepped on uneven surface or tripped	0	3	0	5	2	4	0	2	7	4	7	5	7	3	9	3	2	0	63	9.9	88
	2	2	1	3	3	10	3	1	0	4	2	2	6	3	2	2	1	8	55	9.5	89
Falling objects	0	8	1	0	2	1	0	0	0	7	2	3	4	0	4	2	0	0	34	5.3	88
	0	4	0	1	2	7	1	0	0	2	0	2	3	0	7	2	0	1	32	5.5	89
Other contact with object at rest	2	2	1	2	1	6	1	0	8	4	2	2	0	0	3	0	0	0	34	5.3	88
	2	1	0	2	4	8	2	0	3	3	1	4	4	3	7	6	0	3	53	9.1	89
Handling accident	2	8	1	10	11	15	3	0	6	15	11	14	8	3	10	8	1	0	126	19.8	88
	3	5	0	5	6	13	1	0	1	11	1	17	6	6	6	4	2	5	92	15.8	89
Contact with chemical or physical compound	0	3	0	1	1	5	0	0	10	1	2	3	0	0	0	0	1	0	27	4.2	88
	2	1	0	0	2	1	0	0	7	0	0	4	0	0	0	1	0	0	18	3.1	89
Muscular strain	1	2	0	6	3	8	0	0	10	4	7	7	6	2	9	4	1	1	71	11.1	88
	5	3	0	0	1	11	2	0	3	6	3	1	3	2	5	1	1	2	49	8.4	89
Splinters, splashes	1	3	0	4	3	11	0	0	25	8	4	18	11	0	2	21	2	0	113	17.7	88
	1	2	1	5	1	7	0	0	16	5	3	13	15	2	1	20	0	1	93	16.0	89
Electrical current	0	0	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0.3	88
	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0.2	89
Extreme temperature	0	0	0	0	5	0	0	0	0	0	0	0	3	0	0	1	0	0	9	1.4	88
	0	0	0	0	3	0	0	0	0	0	0	0	1	0	1	0	0	0	5	0.9	89
Other	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0.0	88
	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	0	2	0.3	89
Total	9	45	6	37	35	83	10	6	77	51	48	60	45	19	50	42	13	1	637	99.8	88
	18	34	9	26	30	97	13	4	38	53	16	48	48	22	41	44	9	31	581	99.9	89
%	1.4	7.1	0.9	5.8	5.5	13.0	1.6	0.9	12.1	8.0	7.5	9.4	7.1	3.0	7.8	6.6	2.0	0.2	99.9		88
	3.1	5.8	1.5	4.5	5.2	16.7	2.2	0.7	6.5	9.1	2.8	8.3	8.3	3.8	7.1	7.6	1.5	5.3	100		89

Table 4.7.3.e
Work accidents 1988–89 on production installations etc showing type of incident and part of body injured

Injury incident \ Injured part of body	Eye	Back	Toe, foot	Hip, leg	Stomach, chest	Arm, shoulder	Head, face	Teeth	Hand, finger	Other	Total	%	Year
Other contact with object/	1	0	9	4	0	5	14	8	36	0	77	12.1	88
machinery in motion	0	2	9	8	6	6	15	7	59	1	113	19.4	89
Fall to	0	7	5	5	4	3	6	1	3	0	34	5.3	88
lower level	0	7	3	6	1	5	5	0	3	0	30	5.2	89
Fire	0	0	0	0	0	0	0	0	0	0	0	0.0	88
Explosion etc	0	0	0	0	0	0	1	0	1	1	3	0.5	89
Fall to	0	5	5	13	3	6	6	2	6	1	47	7.4	88
same level	0	8	0	6	1	7	4	1	5	3	35	6.0	89
Stepped on uneven	0	4	48	4	2	2	0	1	1	1	63	9.9	88
surface or tripped	0	1	40	7	1	1	0	1	3	1	55	9.5	89
Falling	0	1	9	3	1	7	1	3	8	1	34	5.3	88
objects	1	1	10	4	2	0	3	4	7	0	32	5.5	89
Other contact with	0	2	1	4	2	9	6	5	5	0	34	5.3	88
objects at rest	1	3	3	11	3	0	14	5	13	0	53	9.1	89
Handling	1	0	8	2	2	4	6	16	86	1	126	19.8	88
accident	0	1	2	4	1	1	10	8	64	1	92	15.8	89
Contact with chemical or	18	0	0	0	1	1	4	0	1	2	27	4.2	88
physical compound	16	0	0	0	0	1	1	0	0	0	18	3.1	89
Muscular	0	38	1	9	8	9	0	2	4	0	71	11.1	88
strain	0	17	6	3	6	6	1	8	1	1	49	8.4	89
Splinters,	89	0	4	4	0	4	8	1	1	2	113	17.7	88
splashes	84	0	1	1	1	2	1	1	2	0	93	16.0	89
Electrical	0	0	0	0	0	0	1	0	1	0	2	0.3	88
current	0	0	0	0	0	0	0	0	1	0	1	0.2	89
Extreme	0	0	0	0	1	1	1	0	6	0	9	1.4	88
temperature	0	1	0	1	0	0	0	0	3	0	5	0.9	89
	0	0	0	0	0	0	0	0	0	0	0	0.0	88
Other	1	0	0	0	0	0	0	0	0	1	2	0.3	89
	109	57	90	48	24	51	53	39	158	8	637	99.8	88
Total	103	41	74	51	22	29	55	35	162	9	581	99.9	89
	17.1	8.9	14.1	7.5	3.8	8.0	8.3	6.1	24.8	1.3	99.9		88
%	17.7	7.1	12.7	8.8	3.8	5.0	9.5	6.0	27.9	1.5	100.0		89

Table 4.7.3.f
Work accidents 1988–89 on production installations etc showing injury incident and contributory factors

Injury incident \ Contributory factors	Chemical, physio-, biological	Cold, pressure, heat, ventilation	Materials, goods, packaging	Electrical equipment	Other mechanical equipment	Drill tongs	Hand tools, machinery, implements	Loose fittings, fixtures on structure	Lifting, transport gear	Other	Total	%	Year
Other contact with object/ machinery in motion	0	0	12	0	16	5	7	16	21	0	77	12.1	88
	0	1	10	0	18	4	27	18	35	0	113	19.4	89
Fall to lower level	0	0	3	0	0	0	0	30	1	0	34	5.3	88
	0	0	2	0	0	0	4	22	1	1	30	5.2	89
Fire Explosion etc	0	0	0	0	0	0	0	0	0	0	0	0.0	88
	1	1	0	0	0	0	1	0	0	0	3	0.5	89
Fall to same level	4	1	7	0	0	0	0	34	0	1	47	7.4	88
	0	0	3	2	1	0	2	24	3	0	35	6.0	89
Stepped on uneven surface or tripped	0	0	11	0	1	0	2	49	0	0	63	9.9	88
	0	0	10	1	0	0	4	38	2	0	55	9.5	89
Falling objects	0	0	15	0	1	1	5	6	6	0	34	5.3	88
	0	0	13	0	4	0	5	4	6	0	32	5.5	89
Other contact with object at rest	0	0	5	0	2	0	1	26	0	0	34	5.3	88
	0	0	7	0	1	0	7	35	2	1	53	9.1	89
Handling accident	0	0	25	2	1	2	74	13	9	0	126	19.8	88
	0	0	21	0	9	0	53	9	0	0	92	15.8	89
Contact with chemical or physical compound	12	0	3	0	1	0	11	0	0	0	27	4.2	88
	2	0	5	0	0	0	8	1	0	2	18	3.1	89
Muscular strain	0	1	29	1	4	1	7	20	1	7	71	11.1	88
	0	0	17	0	4	1	11	11	3	2	49	8.4	89
Splinters, splashes	15	2	16	0	5	1	67	3	0	4	113	17.7	88
	5	1	13	0	4	0	66	3	0	1	93	16.0	89
Electrical current	0	0	0	2	0	0	0	0	0	0	2	0.3	88
	0	0	0	1	0	0	0	0	0	0	1	0.2	89
Extreme temperature	3	0	1	0	2	0	3	0	0	0	9	1.4	88
	0	0	2	0	0	0	3	0	0	0	5	0.9	89
Other	0	0	0	0	0	0	0	0	0	0	0	0.0	88
	0	0	0	0	1	0	0	0	0	1	2	0.3	89
Total	34	4	127	5	33	10	177	197	38	12	637	99.8	88
	8	3	103	4	42	5	191	165	52	8	581	99.9	89
%	5.3	0.6	19.9	0.8	5.2	1.6	27.8	30.9	6.0	1.9	100.0		88
	1.4	0.5	17.7	0.7	7.2	0.9	32.9	28.4	9.0	1.4	100.1		89

Table 4.7.3.g
Work accidents 1979–89 on production installations etc showing injury incident and occupation

Injury incident \ Occupation	Administration	Drillfloor worker	Driller	Electrician	Caterer	Assistant	Instrument technician	Crane operator	Painter, gritblaster	Mechanic, motorman	Operator	Plateworker, insulator	Pipeworker, plumber	Service technician	Scaffolder	Welder	Derrickman	Other, unspecified	Total	%
Other contact with object/ machinery in motion	24	210	25	45	41	270	18	12	31	85	30	50	56	43	65	30	78	8	1121	18.5
Fall to lower level	15	22	9	35	9	89	18	10	40	38	18	26	34	16	27	32	18	3	459	7.6
Fire Explosion etc	0	0	0	2	0	7	0	0	1	2	1	1	2	0	0	1	0	0	17	0.3
Fall to same level	23	23	5	48	34	96	17	8	36	35	28	38	57	22	62	35	10	11	588	9.7
Stepped on uneven surface, tripped	19	16	3	54	24	77	16	11	36	27	30	27	50	19	47	49	13	11	529	8.7
Falling objects	7	30	8	7	6	52	4	1	6	27	4	31	33	13	40	18	5	1	293	4.8
Other contact with object at rest	11	16	3	33	24	60	18	4	44	34	12	54	38	15	49	26	6	5	452	7.5
Handling accident	12	67	7	61	71	148	21	6	36	116	34	90	94	31	64	67	23	5	953	15.8
Contact with chemical or physical compound	4	14	0	12	25	46	8	2	88	14	17	16	21	14	6	17	6	0	310	5.1
Muscular strain	11	35	5	37	16	96	4	7	35	38	24	26	54	15	58	23	16	4	504	8.3
Splinters, splashes	9	13	5	24	8	58	2	1	84	43	16	92	104	8	15	165	4	2	653	10.8
Electrical current	0	1	0	26	0	1	1	1	0	1	0	2	0	0	0	0	0	0	33	0.5
Extreme temperature	1	0	0	2	28	5	1	0	0	4	4	6	9	1	2	14	0	0	77	1.3
Fall into sea	0	0	0	0	0	0	0	0	1	0	0	0	0	0	0	0	0	1	2	0.0
Other	4	3	0	5	3	11	1	2	3	4	3	5	6	0	2	4	0	0	56	0.9
Total	140	450	70	391	289	1016	129	65	441	468	221	464	558	197	437	481	179	51	6047	99.8
%	2.3	7.4	1.2	6.5	4.8	16.8	2.1	1.1	7.3	7.7	3.7	7.7	9.2	3.3	7.2	8.0	3.0	0.8	100.1	

Table 4.7.3.h
Break down of injuries on production installations by severity

Severity	1979	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989	Total
Fatal	0	0	0	0	0	1	1	0	0	0	1	3
Serious	75	33	18	48	12	26	19	24	31	12	27	325
Minor	363	309	287	360	235	345	517	559	777	610	552	4.914
Unspecified	137	109	110	118	87	119	62	23	24	15	1	805
Total	575	451	415	526	334	491	599	606	832	637	581	6.047

Table 4.7.4.a
Work accidents in connection with exploration drilling in 1989 showing type of incident and occupation

Occupation / Injury incident	Administration	Drillfloor worker	Driller	Caterer	Assistant	Crane operator	Painter, gritblaster	Mechanic, motorman	Plateworker, insulator	Service technician	Welder	Derrickman	Total	%
Other contact with object/ machinery in motion	1	7	1	1	8	1	1	2	0	3	1	1	27	31.0
Fall to lower level	0	0	0	0	2	1	0	0	0	0	0	0	3	3.4
Fall to same level	0	3	0	0	2	0	0	0	0	1	0	0	6	6.9
Stepped on uneven surface, tripped	0	1	0	1	2	0	0	0	0	0	0	1	5	5.7
Falling objects	0	6	0	0	1	1	0	0	0	0	0	1	9	10.3
Other contact with objects at rest	0	0	0	1	2	0	0	0	1	0	0	2	6	6.9
Handling accident	0	8	1	0	0	1	0	2	0	5	0	2	19	21.8
Contact with chemical or physical compound	0	0	0	0	1	0	0	0	0	0	0	1	2	2.3
Muscular strain	0	1	0	0	1	0	0	0	0	0	0	0	2	2.3
Splinters, splashes	0	2	0	1	1	0	0	0	0	0	1	1	6	6.9
Extreme temperature	0	0	0	2	0	0	0	0	0	0	0	0	2	2.3
Total	1	28	2	6	20	4	1	4	1	9	2	9	87	99.8
%	1.1	32.2	2.3	6.9	23	4.6	1.1	4.6	1.1	10.3	2.3	10.3	99.8	

Table 4.7.4.b
Work accidents in connection with exploration drilling in 1989 showing type of incident and contributory factor

Injury incident \ Contributory factor	Chemical, physio-, biological	Materials, goods, packaging	Other mechanical equipment	Drill tongs	Hand tools, machinery, implements	Loose fittings, fixtures on structure	Cold, pressure, heat, ventilation	Lifting, transport gear	Other	Total	%
Other contact with objects/ machinery in motion	0	2	6	1	4	2	1	11	0	27	31.0
Fall to lower level	0	0	0	0	0	3	0	0	0	3	3.4
Fall to same level	0	0	0	0	1	5	0	0	0	6	6.9
Stepped on uneven surface, tripped	0	0	0	0	0	5	0	0	0	5	5.7
Falling objects	0	2	1	0	1	2	0	3	0	9	10.3
Other contact with object at rest	0	0	0	0	0	6	0	0	0	6	6.9
Handling accident	0	4	1	2	8	1	0	3	0	19	21.8
Contact with chemical or physical compound	1	1	0	0	0	0	0	0	0	2	2.3
Muscular strain	0	1	0	0	1	0	0	0	0	2	2.3
Splinters, splashes	1	2	0	0	2	0	0	0	1	6	6.9
Extreme temperature	0	0	0	0	1	0	1	0	0	2	2.3
Total	2	12	8	3	18	24	2	17	1	87	99.8
%	2.3	13.8	9.2	3.4	20.7	27.6	2.3	19.5	1.1	99.9	

Table 4.7.4.c
Injuries and deaths per 1000 man-years in connection with exploration drilling in 1989

Year	Hours worked	Hours per man-year	Man-years	Injuries and deaths	Injuries and deaths per 1000 man-years	Deaths	Deaths per 1000 man-years
1989	3584740	1612	2224	87	39.1	2	0.90

The greatest decline has been in accident frequencies for the construction and maintenance function, and the catering function. For the other functions there has been no significant change.

Overall on production installations the accident frequency is 47.0 and this has been on the decline since 1985. An almost equally low frequency was recorded in 1981, though the statistics from the early 1980s are believed to be less complete than in recent years.

Despite the inadequacies which must be supposed to exist in such a comprehensive reporting system for personal injuries and working hours, the Directorate feels that the statistical summaries provide a reasonably accurate picture of the personal injuries in the offshore industry.

Even though the materials used by the Directorate for statistics of personal injury contain elements of uncertainty, there seems to be good reason to claim that developments in recent years have been in the right direction.

4.8 WORKING ENVIRONMENT

4.8.1 Engineering of new installations

In order to permit systematic handling of working environment factors in the engineering phase it is necessary for these factors to be finalised by the operator in advance. Not all the companies are equally adept at this task. Nevertheless, the Norwegian Petroleum Directorate has formed the impression that there has been positive movement in respect of the operating companies' groundwork for specific requirements for installation design and equipment even at the engineering phase.

As regards implementation of the requirements during engineering, the follow-up of ergonomic factors is generally deficient. This means that potential trouble spots in the field "man and machine" are not identified during engineering. Ergonomic experts are drawn in only occasionally.

With this in mind the Directorate implemented the project Ergonomic Requirements and Criteria in 1989. The project is described briefly in section 6.2.

Occupational health factors such as climate (air conditioning etc), air pollution at workplace, chemical exposure and noise exposure have been followed up more systematically. This was done to ensure that the engineering concepts selected are acceptable on the basis of today's occupational health standards. Personal safety equipment is nevertheless necessary in many cases in order to safeguard employee health.

The Directorate has noted increasing awareness among the operating companies for utilisation of operative experience when engineering new installations. Such experience, when it concerns the working environment, and in particular ergonomic factors, nevertheless often does not lead to the necessary revision of the design requirements. This is true of the operating companies as much as the engineering contractors.

4.8.2 Organised safety and environmental work

During the report period the Norwegian Petroleum Directorate has carried out its watchdog and supervisory functions for the organised safety work in the offshore industry. By and large the Directorate has formed a positive impression of the way the operating companies coordinate the safety and environmental work. Safety meetings, safety delegate meetings and working environment committee meetings seem to be functioning as intended. For certain contractor employees and particularly those with short assignments, it is evident that coordination of the safety and protection work and ensuring employee input still remains a problem area.

Manning cuts on older installations and the need for the companies to rationalise has resulted in a tougher climate between the parties. The number of cases being submitted to the Directorate which have roots in the size of crews, manning cuts, employee schedules and work planning has escalated of late. Such cases often involve comparatively complex sets of problems.

In the regulations the same requirements are given for training of members of the working environment committee as for safety delegates. It is to be welcomed that the employee representatives have generally completed this training. On the other hand, very few of the employee representatives have taken the time to attend basic training in safety and working environment matters. This gives cause for concern and may mean that the participants in the working environment committees cannot communicate constructively.

In 1989 the Directorate also focused attention on the content of this training. The 40 hour courses in safety and environmental work are generally highly praised. These courses evidently fill a need and deal with matters which are pertinent to the offshore petroleum activities. On the other hand the training schemes in internal control do not seem to cover the needs of those attending, and the initiative of some educational institutions to include an account of the internal control system in the 40 hour courses is a welcome development.

The quality of the action plan and annual report for the safety and environmental work has improved. The problem here, once again, is that contractor companies with relatively short-term jobs seldom manage to draft an action plan and annual report before the work on the installation is concluded.

4.8.3 Hazardous paints

In the course of the year several operating companies have chosen to introduce new paint products for maintenance which have proven hazardous to health. The Norwegian Petroleum Directorate has noted that several paint manufacturers have provided inadequate product information on the health risk of using them; particularly in the case of spray application. This may have led the operating companies to base their paint choices on inadequate data. Even though it is the importer or manufacturer who is responsible for providing proper information on product health risks, it is evident there is a need for vigilance and a critical approach on the part of the operating companies to the information disclosed.

In those cases where the operating companies, on the basis of comprehensive product information and in compliance with the Working Environment Act's provision that products with least health risk shall be preferred, nevertheless opt for paints which represent a health hazard, then strict safety measures are required in order to avoid injurious exposure.

4.8.4 Asbestos

Construction materials in older installations often contain asbestos. Again in 1989 a major project has been ongoing to remove building materials from one of the fields, without it being determined in advance that the materials contain asbestos. This would seem to indicate that the operating companies' identification of asbestos on the installations has not always been up to scratch.

4.8.5 Quarters

4.8.5.1 Installation of Ekofisk Tank concrete barrier

In connection with installation of the concrete barrier around the Ekofisk Tank (2/4 T) in summer 1989, Phillips applied for dispensation to accommodate more than two persons per cabin for 10 weeks on the jack-up platform *West Gamma*. Phillips maintained that it was impossible to commission other flotels which could be moored with gangway communication to the field center. The alternative would be to transport several hundred employees to and from other installations. Phillips considered this a costly and risky solution. A helicopter shuttle would result in ineffective working days and fog would prevent employees from getting to work. The project was critical with respect to time and it was essential the work proceeded as planned.

The Directorate judged it possible to hire a flotel which could be positioned with gangway to the Ekofisk Center and that it would also be possible to find the necessary bunks at the Center by giving lower priority to other projects where the time element was not so critical. The Directorate therefore turned down the application for dispensation.

Phillips took the decision to the Ministry of Local Government. Before the Ministry gave its final decision, Phillips modified its application. It proved possible to hire a flotel which could support a gangway to the Center and also the accommodation needs. Mobilisation and installation of the flotel would take some time and Phillips reduced the dispensation application to maximum three weeks. The Ministry approved the application thus modified.

4.8.5.2 Older quarters

In 1980–81 Phillips made an assessment of the standard of living quarters on Ekofisk. It was decided to replace the majority of living quarters on the field.

The quarters on 2/4 B were not replaced as it was planned to construct a new installation for water injection (2/4 K) with gangway to 2/4 B. This new installation would have a new quarters with adequate capacity to take the crews of both installations.

Platform 2/4 K entered service in autumn 1987 though in the transition phase it was necessary to accommodate people in both platform quarters. In summer 1989 the quarters on 2/4 Bravo were removed to make room for new process equipment.

4.8.5.3 Quarters on H-7 and B-11

The quarters on pump platforms H-7 and B-11 are of a standard which is not up to modern requirements. Their capacity has also proven inadequate. During periods when upgrade operations or major maintenance activities are going on, Norpipe has repeatedly been forced to apply for dispensation to use temporary sleeping modules.

The Directorate has directed Norpipe to submit a plan for refurbishment of the living quarters and to find a way to expand accommodation capacity. In autumn 1989 Norpipe presented such a plan to the Directorate which involved the improvement of the quarters to an acceptable standard, plus expansion of capacity. According to plan this work will be concluded during 1990.

4.9 CONTINGENCY PREPAREDNESS

4.9.1 Alternative evacuation systems

During the year the Norwegian Petroleum Directorate has noted that a large number of rescue stockings have been ordered and commissioned as a supplement or replacement for existing evacuation means. This escape concept has been acknowledged as equal to traditional methods such as rope ladder and raft davit.

4.9.2 Contact meeting on preparedness

From February to May the Norwegian Petroleum Directorate conducted a series of meetings with all operating companies concerned.

The circumstances for the initiative were that the Directorate had formed the impression that many ongoing matters could have been expedited if the operating companies had a better idea of what the Directorate expected of them.

The major part of the meetings took up the interpretation of the Directorate's current and planned regulations in such areas as acceptance criteria, use of risk analyses, and expectations for personnel qualifications and safety and emergency preparedness training.

4.9.3 Seminar on safety zones

A seminar on the *Regulations for Safety Zones* was held in the Norwegian Petroleum Directorate in December 1989. Its purpose was to expand on the content of the regulations for the users, and to establish two-way communication for possible revision of the regulations, for example to permit the setting up of a temporary prohibition area for anchoring and fishing around subsea installations. Particular attention was given to the opportunities for setting up permanent zones.

4.9.4 Preparedness in northern areas

The limited exploration activity in this area in 1989 and experiences in conjunction with it have not caused substantial realignment of the Norwegian Petroleum Directorate's views regarding emergency preparedness here.

The incident with the Soviet cruise ship *Maxim Gorkij* 260 km west of Svalbard serves to underline the exigencies the offshore industry must be able to tackle if an accident occurs in northern waters. The *Maxim Gorkij* incident showed us that large distances, relative scarcity of neighbours compared with North Sea conditions, limited base capacities (infrastructure) and numbers of rescue helicopters still remain problems needing solution.

4.9.5 Safety training

The non-identical requirements for safety and emergency training on fixed and mobile installations caused some additional work this year.

The Norwegian Oil Industry Association's *Guidelines for 'Basic and Advanced Safety and Emergency Training* have now been revised and will be sent to the Directorate for comments. These guidelines will clearly state what requirements the operating companies undertake to meet if and when the said guidelines form the evaluation basis for consent applications.

The new guidelines will also contain a new curriculum for personnel working offshore. This curriculum has been drawn up in consultation with the employers, employees, training institutes and government authorities. Though the Norwegian Petroleum Directorate has not participated in this work it reserves the right to comment on the curriculum before it becomes effective.

4.9.6 Man-overboard preparedness

During the year several accidents occurred which have drawn attention to the quality of the man-overboard (MOB) preparedness. Time spent recovering a person who has fallen overboard and the methods of launching the MOB boat have been subject to scrutiny. A project has been carried out particularly designed to evaluate today's MOB preparedness in terms of launch method. This work concluded with a meeting in the Norwegian Petroleum Directorate in which all parties concerned were invited to present their views on the MOB preparedness of the future.

4.9.7 Objects adrift

Through the years episodes have occurred in which drifting objects (vessels, drilling rigs, structures etc) have threatened the safety of installations in the North Sea.

In 1988 the topic was taken up in the North Sea Offshore Authorities Forum (NSOAF) which appointed a working group comprising representatives from the North Sea states under the chairmanship of the Norwegian Petroleum Directorate. The group's mandate was to make an evaluation of this problematical area and if possible propose suitable measures. The group's energies were concentrated on objects which were adrift as the result of a broken towline and which were related to the offshore activity. In May 1989 the group put forward a document which set outs a series of recommendations designed to improve the situation. These recommendations were adopted by NSOAF for follow-up within the individual states' areas of authority.

In April 1989 the Norwegian Petroleum Directorate started a project which considered objects adrift which present a threat to petroleum installations on the Norwegian continental shelf. This project was supported by a referee group consisting of representatives from the shipping and offshore industries, the authorities and the professional organisations. The project enlisted the support of outside consultants. The project was concluded in November and the report will be presented to the parties concerned and others interested in the first quarter 1990.

The report gives recommendations for organisational forms and responsibility lines plus preventive measures for drifting objects.

4.9.8 Radio room manning

During 1989 the Norwegian Petroleum Directorate noted that Phillips was planning to change watch schedules for radio operators on the Ekofisk field. On certain fixed installations the radio operator's night watch will be transferred to the control room operator. In the plan this is done by minor technical modifications, schedule changes and training of the control room operators. In order to win experience with the scheme from May to November 1988 a pilot project was carried out on Eldfisk 2/7 B. This project was carried out under the observation of a referee group consisting of representatives from the employer and employees. The report from the pilot project indicated that the scheme covered the radio operators' night watch. Phillips' intention to carry through the scheme met with resistance from the employees on the grounds that it reduced the quality of the emergency preparedness, coupled with working environment reasons.

The Directorate has considered the situation relative to the current regulations. These regulations contain no requirement for 24 hour radio watch on production installations except a limited time listening watch on the emergency frequency. This can be attended to by the control room operators and other units on the field.

The Directorate considers it inappropriate to have detailed manning regulations for the various activities on the installations. The safety and working environmental measures must be tailored to the varying conditions applying on the basis of empirical observations, safety studies and consequence analyses. The Directorate sets the frameworks for responsible operation and the operating companies must stay within them. An example is the Directorate's requirement for continuous monitoring of certain types of equipment and processes, without going into detail on the number of persons required for said monitoring. The operating companies and employees must work together within the functional regulations' prescribed frameworks.

4.10 DRILLING AND WELL ACTIVITIES

4.10.1 Exploration drilling in northern areas

Exploration drilling operations in 1989 were marginally less active north of the 69th parallel than in 1988. *Ross Rig* was the only vessel working there for 305 days altogether. Three exploration wells were fully drilled and the fourth started. The drilling sequence in 1989 was again regulated by a cooperation agreement between the operating companies.

4.10.2 Experience with exploration drilling in northern areas

Since the first production licences were allocated on Tromsø Patch in 1980 and up to year end 1989, 43 exploration drilling operations had been concluded north of 69 degrees North. In 1987 permission was given for continual year-round drilling in the area.

The external environmental parameters have not affected exploration drilling operations to the extent anticipated before activities got started.

Nevertheless, there were equipment problems due to the extreme cold, especially in connection with open deck and work areas, and places unprotected from the surrounding environment.

From experience is it known that difficulties due to cold affecting drilling operations safety and physical working environment lessen markedly once the degree of enclosure starts to increase. The supply services – ships and helicopters alike – have been able to operate without notable difficulty. During anchor handling operations on the other hand, problems were experienced on supply ships in waters deeper than 400 meters. Communications between drilling rig and shorebase were generally satisfactory in operation. The weather office forecasts for the Barents Sea are held to be of poorer quality than in the North Sea and Haltenbanken. Some operating companies have therefore hired foreign meteorological contractors to try their hand at forecasting in this region.

4.10.3 Development of new technology

4.10.3.1 Blowout preventer for tophole section drilling

Poor performance of standard diverter systems when large volumes of shallow gas are encountered have promoted the development of a blowout preventer for use while drilling tophole sections (see Annual Report 1988).

In January 1989 the preventer valve was tried out on the Ullrigg research derrick in Stavanger. Initially drilling was carried out for an extended period in which the equipment was subject to heavy loads in order to verify its structural integrity. Then it was operated in different modes to verify that it is simple and functional in operation.

The test was very valuable and confirmed the performance expectations held for the valve. Some modifications were made in the light of the results observed.

After the successful land test the same prototype was tested in an exploration well being drilled by Shell. The test programme is half completed and has produced convincing results so far. The offshore programme has been structured in line with the Ullrigg trials. So far the preventer has been tested during drilling of a 430 m long 12 1/4 inch bore without any problems whatsoever. Functional testing of the blowout preventer will be carried out in connection with back plugging of the hole.

4.10.3.2 Hydraulic systems

Recently there has proven to be a considerable potential for refinement of hydraulic systems for drawworks, tophead drives and winches.

Development is possible partly due to novel technology and partly the ever increasing requirement for safer systems where the demand for operating reliability is preeminent.

The Directorate is particularly keen to emphasise the importance of the work to develop more reliable and safer braking systems, and the move towards space-saving and weight-saving designs.

4.10.3.3 Automatic drillpipe handling system

In cooperation with Statoil the Norwegian Petroleum Directorate initiated a study of automation of casing handling operations on the Troll field. This study was carried out by Smedvig IPR with the assistance of Rogaland Research Institute, Smedvig Drilling, Weatherford Norge and Wilhelm Wilhelmsen.

The motivation for the study was provided by the shallow reservoir on the Troll field, which will mean that a large part of the drilling operations will involve running casing. Also, casing operations are an area of the drilling activity in which heavy equipment represents a significant accident potential for the drilling crew.

The study shows that using known technology it is possible to reduce the accident potential by effecting relatively simple improvements. The most promising measure is to change the work routines in order to avoid crews taking up stations in hazard spots, fuller preassembly onshore before shipping out the casing pipes, and certain improvements in arrangements for stacking, hoisting and transportation during running operations.

The calculations also show that casing operations can be carried out at a speed at least equal to today's handling performance.

4.10.3.4 Subsea technology

Subsea production systems have been used for production on Tommeliten, East Frigg, Northeast Frigg and Gullfaks. Except on Gullfaks the systems chosen involve an array of wells in a template, for which divers, remote control tools and facilities are used when maintenance and intervention are called for.

These subsea systems meet the expectations for production availability and have positively influenced later subsea solutions such as Snorre, Troll-Oseberg Gas Injection (TOGI) and Statfjord.

The systems now operative are generally comparable though with varying degrees of modulisation and hydraulic-electric control systems. Use of existing fixed installations to receive the hydrocarbons has been an important consideration when deciding to develop fields on the basis of subsea production technology.

Such systems are a reliable and economic alternative to concepts which require surface wellhead installations in the case of small or satellite fields or extension of existing developments.

The focus is now on reducing cost by seeking simpler solutions, though without any sacrifice of safety or reliability.

Well intervention remains an expensive activity and work is being done to identify simpler methods which may help bring down costs. Remote control service vessels and hydraulic transport of tools through production pipes are planned on the Snorre subsea system and should lead to a reduction in the frequency of intervention and therefore costs.

The Directorate considers it important to gather experience with subsea systems because future applications will be in deeper water where the advantages relative to surface systems can be expected to be more pronounced.

4.10.4 High pressure deep wells

The procedures for drilling of deep wells at high pressure and temperature have undergone considerable revision by the Norwegian Petroleum Directorate, operating companies and drilling contractors since two serious incidents occurred:

- Arco's well 22/30-b on the UK sector which in September 1988 entered high pressure jurassic sand
- Saga's well 2/4–14 which in January 1989 struck a high pressure oil reservoir in the upper part of the jurassic.

It is essential that drilling and drilling operations under such conditions are conducted in a manner compatible with sound safety practices since similar conditions must be supposed to exist in many of the most interesting exploration areas ahead. A step-up in the activity level in such areas is therefore forecast during the latter half of the 1990s.

On the basis of the incidents mentioned above and other operational difficulties encountered while drilling deep high pressure wells the Norwegian Petroleum Directorate decided in spring 1989 to undertake a systematic review of practical experience with other wells already drilled on the Norwegian continental shelf. The statistics cover drilling operations on 32 wells. The findings of the operating companies and drilling contractors were also assembled and helped form the foundation for the report.

Based on this work the Directorate has prepared *Guidelines for Drilling of High-Pressure Wells.*

4.10.5 Problem well 2/4–14

Saga initiated drilling of high pressure well 2/4–14 on 6 October 1988 using the *Treasure Saga* drilling rig.

Having just entered the reservoir at about 4730 meters the well became unstable and the drill string stuck in the hole. While clearing the drill string with coiled tubing on 20 January 1989 an uncontrolled flow of hydrocarbons occurred and the blowout preventer on the sea floor was activated. Attempts to regain full control of the well had to be abandoned soon thereafter and the rig was shifted off station for safety reasons.

On 31 January *Treasure Saga* spudded relief well 2/4–15 some 1200 meters away from 2/4–14.

Parallel with this activity it was decided to use the jackup rig *Neddrill Trigon* and special purpose tools for direct intervention and killing of the problem well. On 1 April the necessary clearance was given for *Neddrill Trigon* to assume station above the wellhole and contact was established with the well.

Fishing for the coiled tubing proved technically and functionally difficult and took much longer than Saga had anticipated. During this work a subterranean leakage was detected in the wellhole.

Having evaluated the situation Saga chose to continue the fishing operation for the coiled tubing in the drill string while work was started to analyse the possible effects of the flow into the sand zone at 875 meters. Special monitoring of the area around the well was instituted.

The drilling of relief well 2/4–15 S went reasonably smoothly and 9 5/8 inch casing was set in June. Necessary kill tools were installed on *Treasure Saga* before breaking out of this casing.

In well 2/4–14 the fishing operation was proceeding slowly: 7 inch extension tube was set down to 4673 meters and there was about 40 meters left to drill before communication between the wells could be established.

Because of the subterranean flow regular inspections were made of the seafloor around 2/4–14 R. During one such inspection in August a small leakage was discovered, consisting of a mixture of shallow gas and reservoir gas. There were also indications that there might be leakage of hydrocarbons into higher sandstones above 875 meters, and gradual spreading of hydrocarbons in this zone.

Fishing for the coiled tubing in 2/4–14 was abandoned on 27 September 1989 after 4004 meters had been recovered. The drill string was severed at 4050 meters and the residue run out of the hole.

A new drill string with equipment to clean out the hole was run. Constrictions were met at 850–900 meters which were overcome. The cleaning string subsequently parted, with the result that most of it remained in the hole. It had by this time become clear that the 9 5/8 inch casing had parted in several places between 850 and 900 meters, and that there was therefore no opening through which the well could be negotiated with packing tools.

The original kill plan to set the packer in 2/4–14 R so as to isolate the holes in the 9 5/8 inch casing was therefore abandoned and it was decided to attempt to kill the well by pumping gravity mud down 2/4–15 S and into the bottom of 2/4–14 R without setting a packer.

Final break out from 2/4–15 S started on 11 December 1989 and communication with 2/4–14 R was established the next day. Pumping of heavy mud caused a stopping of the well flow in 2/4–14 R on 16 December. Well 2/4–15 S was plugged back in the 7 inch extension tube. By year end work was in progress to plug back 2/4–14 R.

4.10.6 High deviation drilling

The two first horizontal wellbores on the Norwegian continental shelf were drilled in 1989, the very first being by Statoil on Gullfaks South in order to carry out test production with the drill rig *Deepsea Bergen*. This well was drilled to a vertical depth of about 3400 meters. The horizontal part of the hole was 450 meters long. However, faults in the area of the horizontal section led to bore instability making lining and preparation of the hole for test production impossible. The lower part of the hole was therefore plugged and a new sidetrack drilled in order to do the test production through a 50 degree hole.

The second horizontal well was drilled by Hydro on the Troll field. The purpose was to determine if parts of the relatively thin oil layer which underlie the Troll gas are recoverable economically. Though the oil layer is thin, the hole penetrated several hundred meters of oil bearing sand as the horizontal section was positioned between the gas-oil and the water-oil contacts. Due to the long oil-bearing wellbore section it is hoped economical outputs will be feasible. A long-term test of the well will be made in 1990.

Statoil has set a new world record in lateral extension using high deviation drilling. Well C-10 on the Statfjord field was drilled to a measured depth of 6200 meters, at an angle of decline for large parts of the bore close to 75 degrees, and a lateral distance from the origin on Statfjord C of about 5000 meters. Wells of this type increase the drained radius from production installations and can in certain cases make expensive subsea wells unnecessary.

4.10.7 NPD well data base

Supervision of the safety and working environment of drilling and well operations implies technical evaluations in all phases and all types of activity. The patent need for a suitable analysis tool caused the Norwegian Petroleum Directorate to set up a data base in 1984, the object of which was that all information on well operations should be systematised, making it available and of utility to supervisory watchdog operations.

The drilling reports are punched into the data base on a daily basis and now contain information from all wells started since 1 January 1984. In all the data base covered 684 wells at year end, with about 43,000 daily status reports and about 85,000 operations.

Figure 4.10.7 shows the break down for production and exploration drilling, respectively, in 1989.

The number of enquiries received by external users of the drilling data base shows that it is also of value to the operating companies, who have access to the data they themselves reported.

4.11 NATURAL ENVIRONMENT

4.11.1 Acquisition of natural data

The acquisition of natural environment data such as information on currents, wind strengths, wave heights etc from Ekofisk, Frigg and Statfjord has continued satisfactorily. With the help of the Norwegian Meteorological Institute the Norwegian Petroleum Directorate has supervised the collection of data from these three fields. This assistance scheme has worked extremely well and contributes strongly to the good quality of supervision in this area.

In 1989 the Directorate directed that natural data shall be acquired on Draugen once this field comes on stream. This will make Draugen the fourth permanent meteorological station on the Norwegian continental shelf, the others being Ekofisk, Frigg and Statfjord.

Again in 1989 the Directorate collected natural data in the Barents Sea on the Thor Iversen Bank, Central Bank and off Bear Island. Also in 1989, data collection from the Vøring Plateau was initiated. Provisional results from Vøring indicate that the marine environment (wind and waves) is harsher than on Haltenbanken and Trænabanken where measurements have already been taken.

In 1989 the project had an overall budget of Nkr 9 million. Data have been collected on wave heights, wave directions, currents, meteorology and tides. The measurement programme was carried out with hired services from Oceanor in Trondheim.

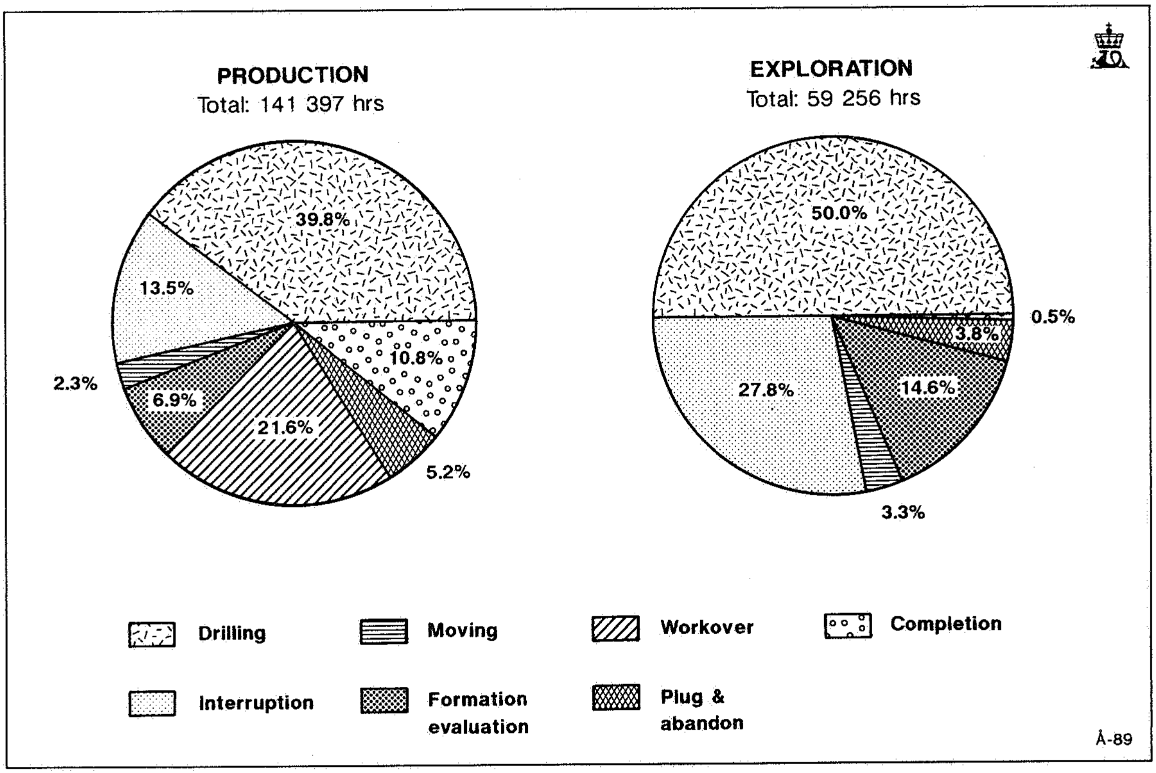
4.11.2 Barents Sea

In connection with the data acquisition done by the Norwegian Petroleum Directorate and operating companies in the Barents Sea since 1976, the Directorate organised a Natural Data Conference in Harstad in 1989 which attracted 62 participants.

The conclusions to be drawn from present knowledge of the conditions in Barents Sea South are as follows:

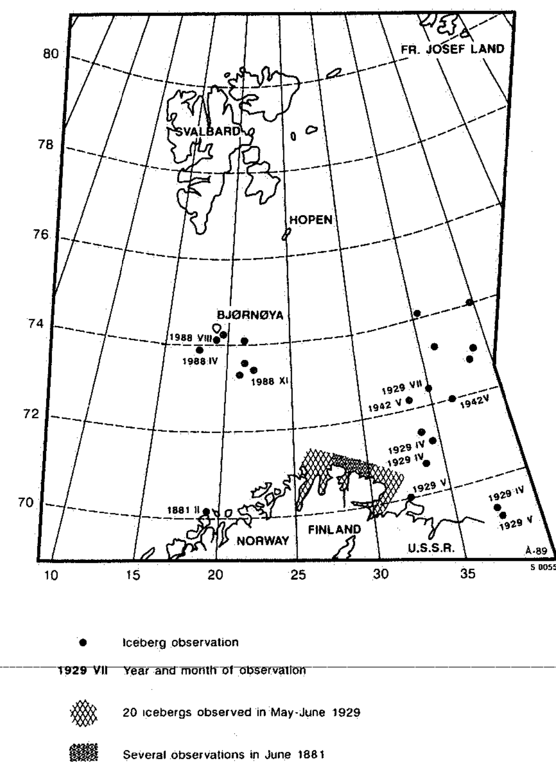
- Wind and wave conditions are comparable with those in the North Sea, though the 100 year values are lower than offshore Mid-Norway. Polar lows can cause problems for planning and execution of operations, but will not produce greater extremes of wind velocity, wave height, air temperature or icing.
- Current velocities are relatively low in the open sea though close to shore they may be moderately higher.

Fig. 4.10.7
Daily drilling report system 1989



- Water depths in the region are generally between 200 and 400 meters, as in parts of the North Sea and on Haltenbanken.
- Icing is a greater problem than further south though it is not considered to represent a dangerous additional load.
- Sea ice must be taken into consideration in the structural design of installations over most of the Barents Sea when the 100 year ice cover and 10,000 year conditions are assumed. Nevertheless, the damage potential of the sea ice will to all intents and purposes be of local nature on the installations.
- Icebergs have been observed as far south as just off the North Troms coast, see Figure 4.11.2. However, this statistic is based on unstructured observations: Reliable data on how often and how many icebergs enter the area are not available. The damage potential of a collision of an iceberg with an installation could be disastrous.
- The extreme temperature on a 100 year statistic may drop to minus 35 degrees C on Bear Island and minus 18 degrees C on Tromsø Patch. This is markedly lower than experienced further south.
- There have been few earthquake observations in the Barents Sea and structural design parameters are moderate compared with elsewhere on the Norwegian continental shelf.

Fig. 4.11.2



4.11.3 Biological monitoring close to installations in Barents Sea

In connection with the exploration activity in the Barents Sea the authorities have wanted continual measurement of the biological conditions at the installations. The aim is at all times to be in possession of updated biological data which can be used to gauge any damage to the marine environment that might result from an oil spill. It is of particular importance for evaluation of damage to fishery interests that there is information on presence or otherwise of fish larvae and, more especially, their food organisms.

Collection of samples started in August 1986 and was carried out by the crew of the contingency response vessels following training and instructions from the Ministry of Fisheries' Institute of Marine Research. The samples are collected using a plankton scoop and regularly brought to shore. They are sorted in the first instance by the Coastal Industry Center in Honningsvåg, though the Institute of Marine Research looks after subsequent processing.

4.11.4 Use of halons

Halons find very large application as fire extinguishants on installations in the offshore activity. According to studies carried out for the State Pollution Control Authority, the offshore industry is responsible for a substantial portion of the total halon discharges in Norway.

By joining the Montreal Protocol, which became effective on 1 January 1989, Norway has undertaken to stabilise consumption of halons at the 1986 level by 1992. In order to attain this goal the SPCA has drafted an action plan. This plan puts a ban on new hand extinguishers using halon, and a ban on new halon systems at a future date, and calls for the phasing out of existing systems over a longer time scale. The SPCA also seek to stop all unnecessary discharge of halons, including test release of blanketing systems to verify their serviceability.

The Norwegian Petroleum Directorate's regulations contain no specific requirements for the use of halons which means that the regulations themselves represent no hindrance to their retirement in favour of other media. In practice, however, the problems will be considerable for the operating companies since alternative extinguishants all have certain limitations compared with halons themselves. For instance there are many studies and examples where halons could be replaced by water systems – but offshore the only water source for fire-fighting is the sea, which more or less rules out water in areas containing electrical installations or electronics.

Nevertheless it does seem feasible to retain an acceptable level of safety without resorting to halon, and it is very encouraging to see that the operating companies have very often been able to find other solutions, particularly in newly engineered projects.

On existing installations the Directorate sees that it might be possible to dispense from the requirement for automatic release, provided a reliable, manual actuation system is introduced.

4.12 STRUCTURES AND PIPELINES

4.12.1 Structural steel

Through its continuing scrutiny of development projects, regulatory drafts and revisions, participation in research projects and committee work and its other activities the Norwegian Petroleum Directorate is able to follow the development of experience in the materials technology field.

The Directorate is pursuing a fixed examination programme for steels used on offshore development projects. Each steel selected is as used in the most heavily stressed parts of the structural fabric. The examination methods provide a basis for elementary evaluations of the steel's microstructure in connection with welding and fracture toughness properties in the heat-affected zone of the seam. By the end of 1989 no less than 17 steels from different offshore development projects had been examined. The test method has been developed by SINTEF (Foundation for Scientific and Industrial Research at the University of Trondheim) who also conduct the actual tests for the Directorate.

Enthusiasm for using high strength steel in structures is growing: Several development projects already started or still being engineered will employ high strength steel in some areas. What seems the most likely choice, however, is steel of up to 500 MPa in strength. It is still not completely certain how stronger steel will react, particularly in respect of fatigue loaded weld seams.

The use of forged and wrought qualities for structural members has also been stepped up in recent years: For example several steel jackets now being fabricated incorporate forged nodes. The advantages of using forgings compared with weldments is simplified fabrication and extended fatigue life.

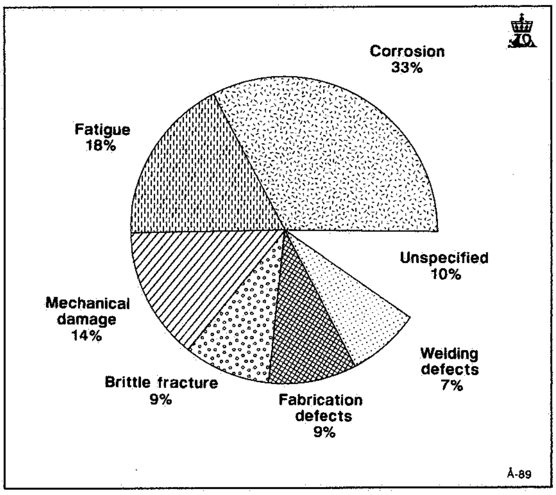
4.12.2 Corrosion and corrosion monitoring

The Norwegian Petroleum Directorate started in 1989 a study of operating companies' empirical findings in the field of corrosion in general, and the systematic analysis of monitoring results in particular.

The Directorate further wanted to hear the industry's views on the systems – or the parts of the structures – which they felt had the worst corrosion problems, and how far the companies were in a position to gauge the effects of measures which might be implemented in a bid to contain the onslaught of corrosion.

The UK company Britoil – now a part of BP – has for a 10 year period carried out registration and analysis of types of attack, and what categories of equipment are hit by damage on five different offshore installations. The indisputable conclusion is that corrosion is by far the largest cause of damage and alone accounts for no less than 33 per cent of

Fig. 4.12.2
Structural damage – classification



the total number of damage incidents. Figure 4.12.2 shows the break down of types of damage.

This study on the UK sector also investigated which types of equipment are most likely to suffer damage: the spread observed is very even for production equipment and pressure vessels (18 per cent), pumps and compressors (14 per cent), well equipment (12 per cent), drilling equipment and logging tools (12 per cent).

Particularly in the light of the age of the various installations the Directorate feels these data cannot be transferred to the Norwegian sector unmodified. Nevertheless the figures provide an indication of the probable causes of damage also on the Norwegian side.

The Directorate's study showed that the operating companies lack a straightforward, effective system with which to document the extent of corrosion damage and the cost incurred by the companies because of it.

It would seem that in its endeavours to reduce the extent of corrosion damage and thereby improve safety of personnel, the industry has little hope of being able to measure the success of its corrective measures over time.

On the basis of more general operational experience the companies point to the following problem areas in order of priority:

a) Internal corrosion in well equipment and wellstream flowpipes
b) General and galvanic corrosion in seawater and firewater system
c) Corrosion in produced water system
d) Corrosion under insulation
e) Corrosion in splash zone
f) Corrosion due to aggressive marine atmosphere.

The study also confirms that almost all operating companies have encountered considerable corrosion problems when starting up new plant. The reasons are lack of proper draining of pipes, tanks, valves etc after pressure testing, and non-application or wrong application of chemical retardants during such testing.

It was also demonstrated that corrosion in copper-nickel piping, under insulation wrappings and passive fire shielding, in equipment and fittings exposed to the sea air, in the splash zone, in the produced water system and in well equipment first becomes fully operative after the equipment has been in use for some time.

The operating companies have different practices and philosophies for controlling and eliminating corrosion problems as listed above. The methods vary from use of chemical retardant, to cathodic protection, to (for example) equipment upgrades using high alloy materials.

For corrosion monitoring purposes the companies have only experienced positive results from the use of weight loss coupons and electrical resistance probes. At the same time the importance of skilled and experienced operators and interpreters cannot be underestimated for proper interpretation of the measurement results.

The operating companies are now, in consultation with the Norwegian Petroleum Directorate, in the process of evaluating the utility of developing a new system, or perhaps adapting the existing systems and procedures, so as to be better able to structure operating experiences and make proper use of them in the work to optimise operation of the installations.

4.12.3 Pipelines and risers

The new development concepts on the Norwegian continental shelf mean an increasing measure of pipeline transportation of unprocessed and semi-processed hydrocarbons.

Hydro is in the course of laying a 48 km long 20 inch pipeline to carry unprocessed gas from the Troll field to the Oseberg field. To date this is the longest multiphase pipeline in the North Sea. In addition Shell has suggested to the Troll partners that the Troll gas should be brought to shore for processing before being redispatched to the Continent. This would mean multiphase transportation in 36 inch pipelines for distances of up to 66 km.

In the light of the demand for increased transportation capacity for gas on the Norwegian continental shelf to the Continent, Norpipe has applied for permission to augment capacity in the Norpipe line from Ekofisk to Emden beyond the rated pressure. This application will be considered in consultation with the West German and Danish authorities.

4.12.4 Plastics structures

Shell has proposed new ideas for construction of a composite protective structure for subsea completion wells. Considerable cost savings appear to be possible, allowing the government's requirement for trawlability to be met at substantially lower cost.

If it proves feasible to find a way to coordinate the activities of the operating companies which in the next few years will be installing subsea wells, there is a potential for series production in Norway which would reap further savings.

4.13 ELECTRICAL SYSTEMS

4.13.1 Electrical systems and equipment on Veslefrikk

The Veslefrikk field has been developed with a standing drilling installation and floating production installation. Under current rules the *Regulations for Electrical Facilities (FEA)* would apply to the fixed, and the *Regulations for Electrical Facilities on Ships and Marine Equipment (FEAS)* to the floating installation. A difference of this type between governing regulations on two installations connected permanently is clearly counterproductive. The operator, Statoil, therefore applied to use FEAS for the entire project. The Norwegian Petroleum Directorate was able to concur.

The electrical facilities on the fixed and floating platform are connected by two high tension cables which hang in a loop in the sea. The cables are fixed using special connectors at either end. They are also provided with shear units to enable the cables to be cut if the separation of the paired platforms becomes too wide.

4.13.2 Electrical systems and equipment on Gyda

The Norwegian Petroleum Directorate has been concerned with measures to reduce the shorting currents in the electrical systems in the North Sea. On the Gyda project this has been taken care of by increasing the electrical resistance in various parts of the systems.

4.14 GAS LEAKAGES, FIRES AND OUTBREAKS

4.14.1 Gas leakages

In all the Norwegian Petroleum Directorate has received reports of 45 gas leakages on fixed installations during the current period. In 1988 the Directorate tightened up the reporting routines for incidents and near-accidents, and in the second half of the year 24 gas leakages were reported. The tightening up of the reporting routines has provided the Directorate with better statistics on the basis of which to evaluate measures to reduce the number of gas leakages.

Figure 4.14.1.a shows the break down of reported gas leakages in order of severity. The divisions in the figure are based on the Directorate's appraisal of the course of events and what risks the gas leakage entailed. The figure illustrates that the greater part of the gas leakages are small ones which were quickly brought under control.

Table 4.14.1 shows gas leakages in the given severity categories as detected by the gas detector systems.

Figure 4.14.1b serves to illustrate the causes of the gas leakages. The causes behind a gas leakage are often several and coincidental. The figure assigns the causal factors on the basis of the Directorate's analysis of reports received. Human error is one causal subcategory in the operational error category. In turn a human error may have many underlying causal elements, such as poor preparation of

Fig. 4.14.1.a
Classification of reported gas leaks according to degree of seriousness

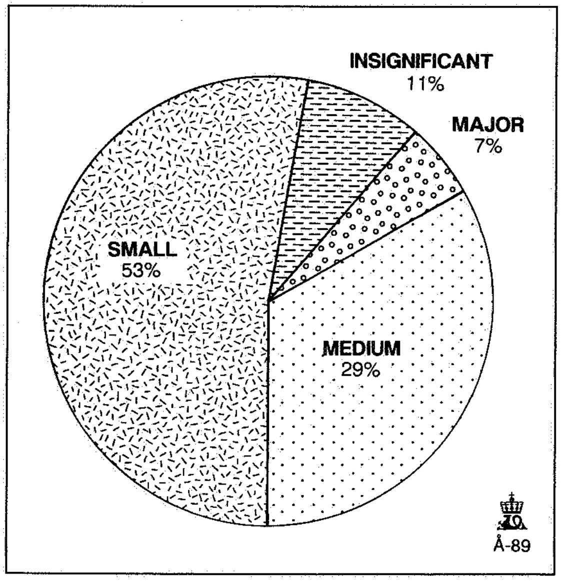
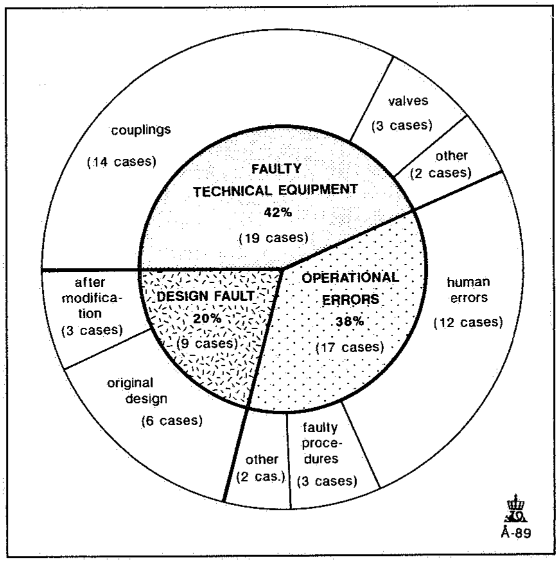


Table 4.14.1
Gas leakages detected by gas detection systems

Significance	Total number	Number detected automatically	Reading in % LEL	
			20 %	60 %
Insignificant	5	0	0	0
Minor	24	12	10	2
Medium	13	9	2	7
Major	3	2	0	2

(LEL = Lower Explosion Limit)

Fig. 4.14.1.b
45 gas leaks – classification of causal relationship



work, lack of training, lack of information, muddled lines of communication, and the stress factor.

The statistics seem to indicate that gas leakages of a more serious nature are often the result of operational error. During the current period the Norwegian Petroleum Directorate therefore directed the operating companies to evaluate alternative measures, both procedural and technical, by which to reduce the number of gas leakages.

4.14.2 Gas leakages through drain system

In 1988 a working group was formed in the Norwegian Petroleum Directorate with the object of analysing known incidents in which gas had escaped through the drain system, and putting forward proposals for procedures or regulations, or for technical proposals designed to avoid similar events.

The fruits of this work were discussed with the operating companies. In 1989 the Directorate carried the work a stage further by ordering all operators to commission studies of the drain systems on their own installations, particularly looking at identifiable problem areas and own experience. This order produced several improvements to the drain systems.

4.14.3 Fires and outbreaks

A summary of fires and fire outbreaks (near-fires) on mobile and fixed production installations reported by the operating companies in the current period is given in Table 4.14.3. The table shows the damage, number of fires, and cause of fire. The Directorate registered a total of 51 fires in 1989 compared with 35 in 1988. The increase seems to be a function of the higher activity level this year during both construction and operating phases.

4.15 DIVING

4.15.1 Diving operations

In the current period 1704 surface oriented dives, 2150 bell runs and 208,341 manhours in saturation were put in on the Norwegian continental shelf. This was an increase relative to 1988.

In addition, 15 monobaric dives in connection with pipeline operations were performed.

The total activity on the Norwegian continental shelf was split between long-term inspection and maintenance contracts on Ekofisk and the Statfjord-Gullfaks and Frigg areas, and shorter duration jobs on Valhall, Gyda and Oseberg. Construction jobs largely involved the joining of pipelines by hyperbaric welding. Operations of this type took place on Gyda (approx 75 meters depth), Oseberg (approx

Table 4.14.3
Summary of fires on mobile and fixed production installations

	Construction phase			Fixed installations Operating phase			Mobile installations Operating phase		
	A	B	C	A	B	C	A	B	C
Personal injury and material damage		1							
Personal injury and slight or no material damage					1				
No personal injury but major material damage			1	2	1				
No personal injury and minor or no material damage		2	3	12	1	10			1
Total 51		3	4	14	19	10			1

Causes of fire and fire outbreak:
A: Technical fault such as overheated bearings.
B: Welding, grinding etc defined as hot work.
C: Other.

110 meters), Veslefrikk (approx 175 meters) and Gullfaks C (approx 220 meters).

4.15.2 Accident survey for diving operations

Figure 4.15.2.a provides a summary of the number of personal injuries reported to the Norwegian Petroleum Directorate in the years 1978–89 in connection with diving operations on the Norwegian continental shelf.

Personal injuries are subdivided into categories for fatality, other injury, and decompression sickness (bends). Seven of the bends cases were during saturation diving and two during surface oriented operations. Infections and near-accidents are not included in the summary. During the current period six cases of outer ear infection were reported among divers. Eleven near-accidents were also reported.

This year it has become possible for the first time to present reports which assess the long-term effects of diving. It is concluded that several factors, among them the bends, may contribute to nerve system disorder. The reduction in numbers of bends cases over the period 1978 to 1989 is noteworthy (see Figure 4.15.2.b).

Nevertheless, during the last year or two there has been an increase in the number of cases of bends on one field, and the Directorate will be watching developments here very carefully.

4.15.3 Research in diving

In 1989 the Norwegian Petroleum Directorate launched a common research and development programme for diving technology in cooperation with Statoil and Hydro. The object of the programme is to develop the necessary expertise in diving technology to ensure that future unmanned subsea operations will be undertaken safely and cost-effectively down to 400 meters depth.

Fig. 4.15.2.a
Injuries to personnel engaged in diving activities on the Norwegian Continental Shelf 1978–89

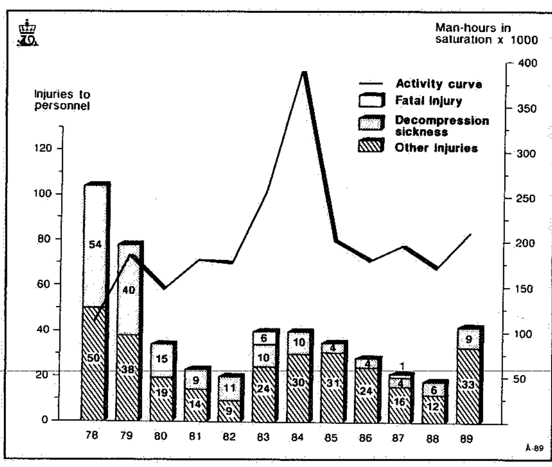
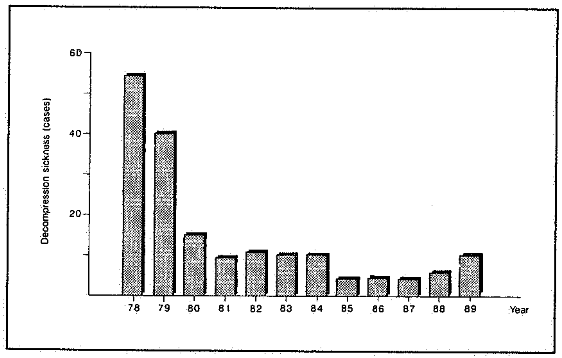


Fig. 4.15.2.b
Decompression sickness on the Norwegian Continental Shelf 1978–89



Practical implementation of its results is one of the major aims of the programme.

4.16 MECHANICAL EQUIPMENT

4.16.1 Flange leakages

Several leakages were registered which were due to failure in a flange connection. Particularly if the system contains gas under high pressure this type of fault may have serious consequences. The Norwegian Petroleum Directorate's investigations indicate that there are no universal common causes for such leakages. Suitable preventive measures must therefore be to pay even greater attention to precise alignment of piping, torquing of bolts and correct application of gasket packings. Intensified training of personnel and more frequent use of hydraulic torque wrenches may be other effective measures.

4.16.2 Novel technology

4.16.2.1 Rotary machinery

On gas compressors the development of lube oil-less shaft seals has come a long way. Packboxes of this type are now entering service on almost all new compressor units. On some less modern installations the lube oil seals have also been replaced by these novel packboxes with encouraging results. This trend cuts weight and space demands, capital expenditure and operating costs, at the same time as the risk of lube oil leakages and gas leakages is reduced.

Magnetic journals on compressors are still under development. In principle the rotor is suspended in powerful, regulated magnetic fields, allowing frictional losses to be almost completely eliminated and consigning the intricate traditional lubricator systems to a forgotten era.

Statoil has ordered the first piece of machinery on the Norwegian continental shelf with magnetic bearings – a turbo-expander for use on Sleipner.

For development of Snorre, Saga will be commissioning a new type of water injection pump. Using a newly developed twin-pole, four megawatt electric motor it has been possible to eliminate the traditional gears between motor and pump. The pump is mounted vertically so that weight, space and costs are reduced without any safety tradeoff.

4.16.2.2 Plastics flowlines

The Norwegian Petroleum Directorate has followed the work the operating companies, consulting engineers and vendors are doing in order that plastics materials may find greater application. Courses have been organised for piping design engineers and pipework fitters. The Directorate has been represented at conferences to exchange findings in the area.

The Directorate feels that the industry and the authorities today have a common, down-to-earth appreciation of where plastics can now be used without compromising safety, and of in which direction development should be steered in the future.

4.17 NPD FOLLOW-UP OF ACCIDENTS OUTSIDE NORWAY

In 1989 the Norwegian Petroleum Directorate continued its work initiated as a result of the disaster which occurred on 6 July 1988 on the UK production installation Piper Alpha. The installation was a total loss and 165 persons lost their lives.

The British Inquiry Commission is expected to conclude its work early in 1990 and the final report should be ready during the year. So far no information has come forth at the hearings which makes it necessary for the Directorate to change its strategy for follow-up of findings from this event.

All Norwegian operating companies were directed in 1988 to update their already completed safety studies in the light of the Piper Alpha findings. On installations where no such study had been done before, the operator was directed to do so. It is now apparent that the operators' revisions of their safety studies are in some cases very comprehensive and will take rather longer than first intimated. The results so far show that several installations in the Norwegian sector will need to be modified at considerable cost.

In connection with the Directorate's follow-up activities in 1989, explosion loads have been the subject of study. The operating companies of some installations in operation and under construction have carried out more detailed calculations of potential explosion loads and the probability they might occur.

At Christian Michelsen's Institute for many years relatively reliable computational models have been undergoing development. By using such models in the pre-engineering phase it is possible to optimise the concept on safety at low or no extra cost. The sizes of modules, layout of equipment and location of pressure abatement baffle panels can be tailored so that explosion pressures can be kept within acceptable limits. On existing installations these explosion calculations provide trustworthy guidance for the location and size of new pressure abatement panels and necessary reinforcements of structural elements and fire walls.

Another area to be the subject of attention is the utility of underpinning or shielding critical pipelines with pipehangers in order to prevent them crashing down like a set of dominos in the event of explosion.

In 1989 the Directorate performed several audits in order to determine how the operating companies assure the quality of safety studies. This work will continue in 1990. Provisional results show that the operators advocate risk analyses as a central decision tool for management. The Directorate has nevertheless noted some room for improvement, for example:

a) It should be possible to optimise analysis dates relative to project schedule
b) The efforts to establish in-company acceptance criteria must be intensified
c) The prior assumptions and conclusions of the risk analysis, and the recommendations of the technical experts who perform it, must be communicated more effectively to the line management and safety delegates who represent the end users of the analysis
d) The operating companies must improve their systems for verification that the assumptions upon which the analysis builds continue to hold good in the operating phase.

Generally, the investigation of accidents and inquiry commissions after major accidents and disasters will often point to such factors as unclear lines of leadership, responsibility and organisation, inappropriate or unenforced procedures, and lack of training. These factors have till now only occasionally figured in the risk analyses, though they have a profound effect on the course of disaster. The interaction of the human element, technology factors, and the organisation must come into sharper focus in risk analyses, and it is therefore essential that experts in this field are brought into the analysis teams.

Other problems identified after the Piper Alpha disaster have been followed up in the Directorate's regular supervisory activities.

The findings from Piper Alpha have also been reviewed in connection with the continuing revision of regulatory provisions.

4.18 SPECIAL PROJECTS

Thirty-five projects have been carried out in connection with safety and the working environment for which external assistance was sought. The total budget for these projects was in the region of Nkr 4 million. Section 6.2 presents each project in brief. The projects cover a wide spectrum from working environment factors to leading-edge technology.

Through projects such as these the Norwegian Petroleum Directorate can influence the offshore industry and thereby help ensure that pressing safety and working environment factors are illuminated. The projects also strengthen the Directorate's hand as an administrative body since greater expertise and knowhow is acquired.

The project funds are mostly used as relatively modest financial contributions to the individual project. By this means the Directorate can sit on the steering committees of a large number of sometimes quite extensive projects both at home and abroad.

4.19 GUIDE TO THOSE ENGAGING IN THE OFFSHORE INDUSTRY

In the Norwegian Petroleum Directorate's Safety and Working Environment Division a service group has been set up which receives and responds to and coordinates enquiries regarding the supervisory watchdog scheme and provides guidance on the technical requirements laid down in the regulations. In principle, the same guidance given to the operating companies shall be given to all others engaging in the petroleum activity, for example owners of installations, ships and equipment. The interest displayed in this service shows there is a great demand for information within the industry.

5. Petroleum Economy

5.1 EXPLORATION ACTIVITY, GOODS AND SERVICES

From 1966 exploration drilling activity steadily expanded until 1985, when no less than 50 exploration wells were started. From 1986 the decline has been very clear, with 36 exploration wells in 1986 and 1987, 29 in 1988 and 28 in the current period (1989).

Figure 5.1.a shows the costs of exploration activity since 1980. The costs include exploration drilling, general surveys, field evaluation and administration.

Below the exploration costs for 1989 are shown by goods and services category. The amounts are provisional estimates based on figures reported by the operating companies. The same figures are assumed in Figure 5.1.b which shows the percentile distribution between the various types of cost.

Exploration costs		Nkr million
Exploration drilling		3 480
of which:		
– Drilling installations	970	
– Transportation costs	420	
– Goods	680	
– Technical services	1 410	
General surveys		370
Field evaluations		670
Administration (incl acreage fees)		610
Total		5 130

Fig. 5.1.a
Exploration costs per year 1980–1989

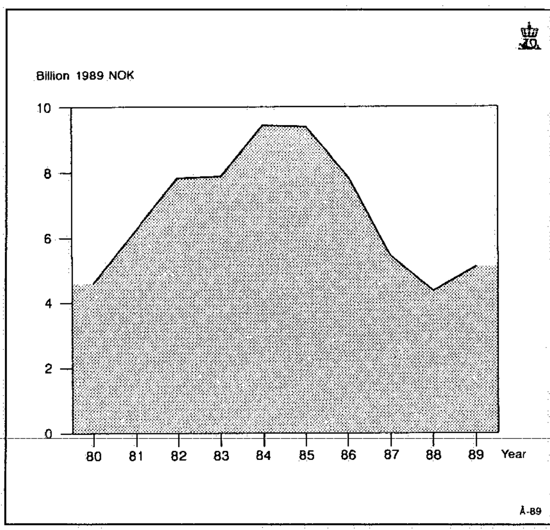


Fig. 5.1.b
Oil and gas exploration costs in 1989

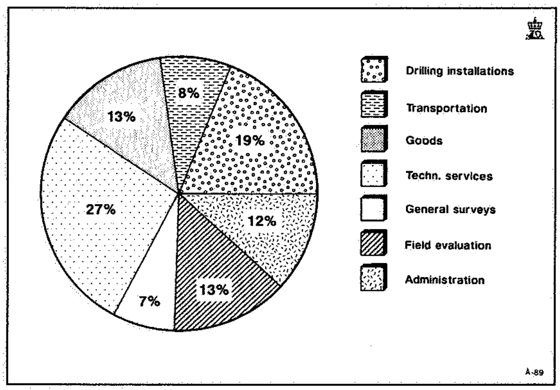
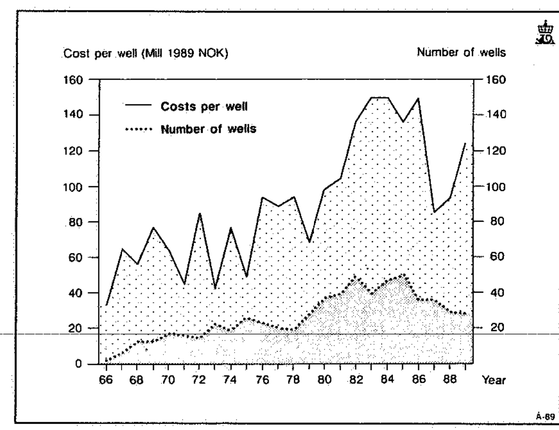


Figure 5.1.c shows the mean drilling costs per exploration (wildcat or appraisal) well.

5.2 COSTS OF DEVELOPMENT AND OPERATION ON NCS

The Norwegian Petroleum Directorate has calculated the annual costs connected with field development, including production drilling, for the period 1970–2013. These costs apply to fields in production, fields under development, and fields for which there exist approved development plans as of year end 1989. Of fields straddling the UK-Norway sector boundary, only the Norwegian part is included. The following fields and transportation systems are included in this calculation:

Fig. 5.1.c
Number of exploration wells and drilling costs per well



- Frigg (including pipeline to St Fergus)
- Albuskjell
- Ekofisk area (West Ekofisk, Cod, Edda, Eldfisk, Ekofisk)
- Northeast Frigg
- East Frigg
- Gullfaks
- Heimdal
- Murchison
- Odin
- Oseberg Transport
- Oseberg
- Statfjord
- Tommeliten
- Tor
- Ula
- Valhall
- Norpipe
- Statpipe
- Veslefrikk
- Troll-Oseberg Gas Injection
- Gyda
- Troll phase 1
- Sleipner East
- Zeepipe
- Snorre
- Hod
- Draugen
- Gamma North
- Gyda pipeline
- Ula pipeline.

Historical and adopted investments for field development and transportation facilities for petroleum are summarised in Figure 5.2.a. All amounts are converted to fixed 1989 kroner. The investments increased steadily to 1976 when they reached a temporary peak. The decline in investments in the years afterward was succeeded by a new rise from 1981 onward, with a provisional peak in 1986 when about 26.4 billion 1989 kroner were invested on the Norwegian continental shelf. Early in the 1990s investments will once again approach 30 billion 1989 kroner, though if no more fields are declared commercial, we will see a sharp decline in investment level up to the new century.

In 1989 no new field developments were adopted. In 1990 the Norwegian Parliament has several plans for development and operation it will look at. If these are approved, the downward curve of the investment level may be much gentler in the 1990s.

The annual operating costs, including pipeline operating costs, are given in Figure 5.2.b. The level of demand for goods and services for operating purposes has risen sharply and will continue to rise as more fields come on stream. The operating costs therefore appear to be the most important cost component in the future. It will be essential to try and reduce these in the years ahead.

5.3 ROYALTY

The Norwegian Petroleum Directorate has been delegated the responsibility for collection of royalty on production.

This royalty is calculated as laid down in the Petroleum Act of 22 March 1985 and its appurtenant Petroleum Regulations (Royal Decree of 14 June 1985), which both became effective on 1 July 1985. The calculation base for royalty is the value of the produced petroleum passing the production area's loading point (export flange).

In practice the calculation base for royalty will be the difference between gross sales value and costs incurred between royalty point and sales point.

On some fields the transportation costs are higher than the gross sales value of the petroleum product. This is particularly true for gas. In such cases no royalty is payable.

Royalty is not payable on petroleum produced

Fig. 5.2.a
Investments in fields and pipelines on the Norwegian Shelf 1970–2013

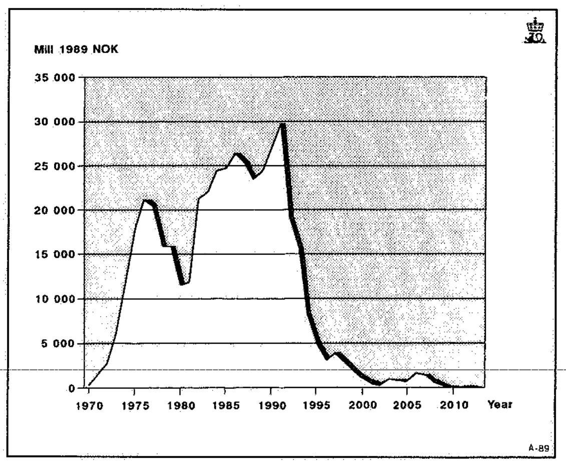
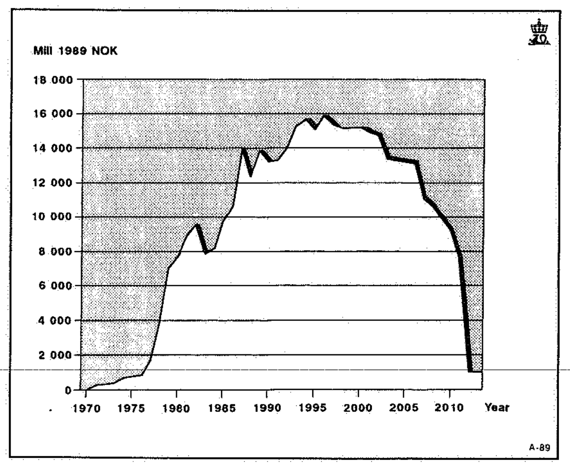


Fig. 5.2.b
Operating costs for fields and pipelines on the Norwegian Shelf 1970–2013



from accumulations for which the development plan was approved after 1 January 1986.

Interpretation and enforcement of current legislation and regulations in connection with calculation of royalty involves problems of law, economics, process technology and metering methods.

5.3.1 Total royalty

In 1989 Nkr 7,288,304,968 were paid in royalty. Table 5.3.1 shows the distribution for the various petroleum products for 1988 and 1989.

Table 5.3.1
Paid-up royalty in 1988 and 1989 (million kroner)

		1988	1989
Oil	Ekofisk/Valhall/Ula	1 029.1	1 416.8
"	Statfjord	3 321.9	4 095.5
"	Murchison	21.5	28.1
"	Heimdal	−0.3	3.2
"	Oseberg	12.9	351.0
"	Gullfaks	165.2	431.6
Gas/NGL	Ekofisk fields	415.7	448.2
"	Valhall	0.4	8.8
"	Ula	−1.2	0.0
"	Frigg, Northeast Frigg, Odin	521.4	463.6
"	Statfjord	0.0	0.0
"	Murchison	0.2	0.2
"	Heimdal	−6.0	41.3
"	Gullfaks	0.0	0.0
Total all fields		5 480.9	7 288.3

Table 5.3.2
Paid-up royalty on oil in 1989

Field/Area	1st half	2nd half	Total 1989
Ekofisk, Ula and Valhall	779 111 765	637 672 800	1 416 784 565
Statfjord	1 965 500 081	2 129 990 988	4 095 491 069
Murchison	10 758 635	17 307 976	28 066 611
Heimdal	3 203 736	−14 286	3 189 450
Oseberg	116 578 381	234 457 282	351 035 663
Gullfaks	193 407 659	238 251 697	431 659 356
Total	3 068 560 257	3 257 666 457	6 326 226 714

5.3.2 Royalty on oil

In 1989 the Norwegian Petroleum Directorate received Nkr 6,326,226,714 in royalty payments on oil from Ekofisk, Valhall, Ula, Statfjord, Murchison, Heimdal, Oseberg and Gullfaks (see Table 5.3.2). Royalty on oil is collected in kind. Sale of this royalty oil is undertaken by Statoil. Payments from Statoil to the Directorate are made on a monthly basis. Settlement is made at the norm price stipulated by the Petroleum Price Council.

Figure 5.3 shows the royalty paid up from 1973 to 1989.

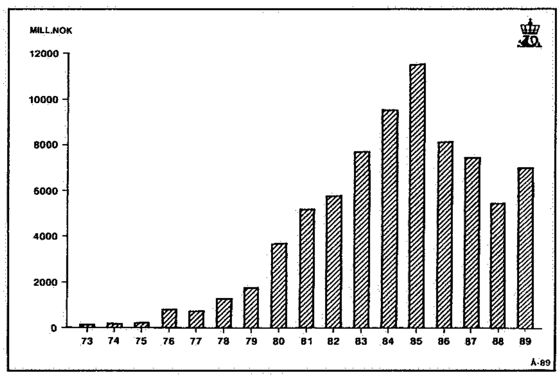
5.3.3 Royalty on gas and NGL

In 1989 the Norwegian Petroleum Directorate received Nkr 962,078,254 in royalty on gas and natural gas liquids. Table 5.3.3 shows the payments made each half year for the companies and groups of companies concerned.

The settlement of royalty is made in cash every six months with three months notice to pay.

On Statfjord, Gullfaks and Ula no royalty was

Fig. 5.3
Royalties 1973–1989



paid for gas in 1989 due to the high costs of transport.

Settlement for gas was made at contract prices which vary from group to group.

Supplies of gas to Dyno and Methanor ceased

Table 5.3.3
Paid-up royalty on gas and NGL in 1989

Field/area	1st half	2nd half	Total 1989
EKOFISK AREA			
Phillips group	164 023 732	281 030 476	445 054 208
Amoco group (Tor)	164 818	371 341	536 159
Shell (Albuskjell)	1 255 355	815 355	2 070 710
Dyno/Methanor	858 785	−287 777	571 008
Total Ekofisk area	166 302 690	281 929 395	448 232 085
FRIGG AREA			
Petronord group	188 988 579	218 823 357	407 811 936
Esso (NE-Frigg)	9 971 293	14 862 270	24 833 563
Esso (Odin)	9 503 076	21 418 713	30 921 789
Total Frigg area	208 462 948	255 104 340	463 567 288
Valhall	2 336 429	6 464 842	8 801 271
Ula	0	0	0
Statfjord	0	0	0
Murchison	10 085	218 625	228 710
Heimdal	*)−1 574 254	42 823 154	41 248 900
Gullfaks	0	0	0
Total all fields	375 537 898	586 540 356	962 078 254

*) Refund of royalty paid-up in earlier settlements

from 1 July 1984. The amounts paid and refunded to Dyno and Methanor relate to the transportation and treatment of gas already received and paid for.

5.4 ACREAGE FEES ON PRODUCTION LICENCES

In 1989 the Norwegian Petroleum Directorate collected Nkr 279,641,140 in acreage fees. Referenced to production licence year the receipts were as follows:

Award of production licence	Kroner
1965	107 490 516
1969	56 763 000
1971	5 502 000
1973	17 532 000
1975	16 921 767
1976	24 107 622
1977	7 330 833
1978	6 376 660
1979	8 093 796
1980	973 385
1981	9 430 061
1982	1 900 137
1983	2 120 363
1989	15 099 000
Total	279 641 140

The Directorate refunded Nkr 56,367,900 in acreage fees in 1989. This represents the deductible portion of the acreage fees for the royalty account settlements on production licences 006, 018, 019A, 033, 037, 050, 053 and 079.

For some of the production licences the acreage fee is deducted directly in the royalty settlement. The amount in question, Nkr 21,673,648, is taken into account in the payments of royalty.

Figure 5.4 shows paid-up acreage fees from 1973 to 1989.

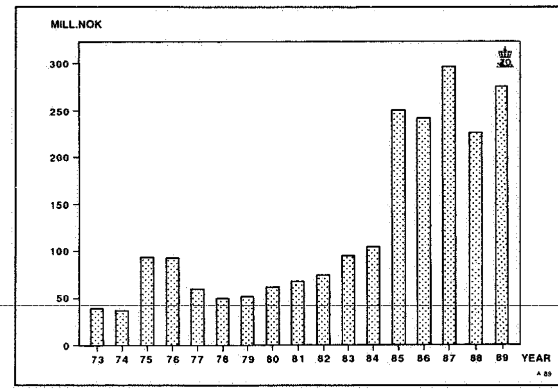
5.5 PETROLEUM MARKET

5.5.1 Crude oil market

On the doorstep to the 1990s there are several factors which affect the world's production of crude oil and the demand for oil. Among the most important is the increase in demand during the last three years. Another is that oil production outside OPEC has stagnated. This is particularly the case in the USA and Soviet Union. A third central factor is that several OPEC members are currently producing at close to capacity.

OPEC entered 1989 with a production quota of 18.5 million barrels a day. This quota was set for the

Fig. 5.4
Acreage fees 1973–1989



first half year. In June the quota for the second half was set at 19.5 million barrels a day, and in September OPEC decided to raise the fourth quarter quota to 20.5 million barrels a day.

Many of the member countries have exceeded production limits throughout 1989. The average production was 19.9 million barrels a day in the first quarter, and 21.1 in the second and third. The fourth quarter figures vary according to the source but give reason to suppose that production was about 23.5 million barrels a day. At the year's final OPEC meeting in November the countries determined to increase the total production quota to 22 million barrels a day for the first half of 1990. Figure 5.5.1.a shows the development of production in 1989.

Despite the production overruns within OPEC there was no collapse in prices during the year. Prices generally remained at a level between US$ 17 and 19 a barrel, though some exceptional notations did approach the 16 and 22 dollar marks. Figure 5.5.1.b shows the mean monthly prices on Brent Blend from October 1988 to December 1989. We see that the price recovered strongly during the first half of 1989, due largely to increasing demand for oil and stagnating oil production in non-OPEC countries.

The world-wide consumption of oil has increased markedly this last year. Most of the increase stems from countries outside the OECD. A summary by the International Energy Agency (IEA) shows that the consumption in developing countries increased by about 500,000 barrels a day in 1988 and provisional statistics show that it increased by 600,000 to 700,000 barrels a day in 1989. The greatest increase was in the Far East. Third world countries are still at a low level so far as energy consumption relative to OECD countries is concerned, and it is therefore reasonably certain that demand can only go up. However, it is worth pondering how much increase in demand these countries are in a position to finance.

Fig. 5.5.1.a
Crude oil production Jan–Dec 1989

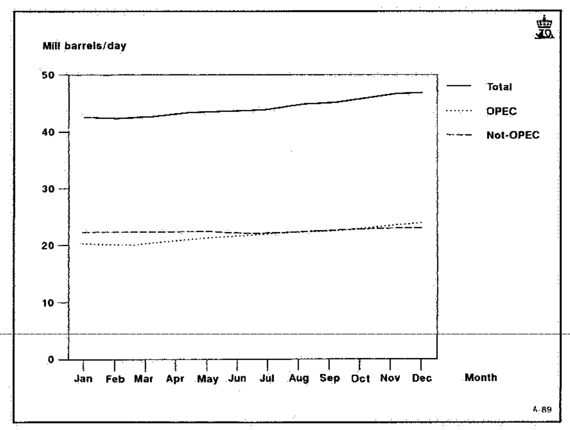
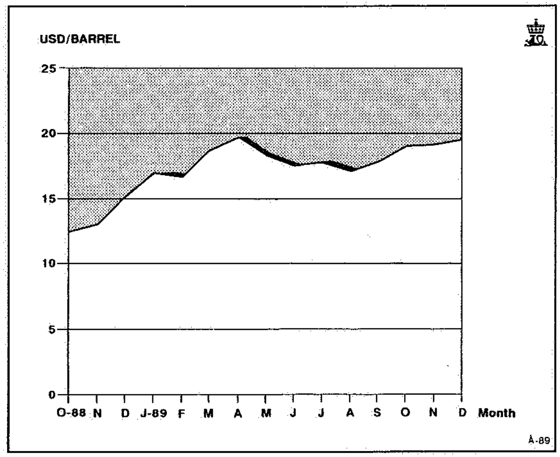


Fig. 5.5.1.b
Spot Brent blend Oct. 1988–Dec. 1989



A part of the increasing demand is also due to isolated incidents, for example operational difficulties in atomic power stations in France and Japan, low oil stocks in West Germany and later in the year, bitterly cold weather in the USA and the political thaw in Eastern Europe. Nevertheless, the experts believe that the increase in demand we have witnessed this last year is generally of a more long-term nature, caused by a very long period with relatively low oil prices.

The declining oil production in countries outside OPEC has also been of significance for the relatively high oil price in 1989. In all production from non-OPEC countries declined by about 400,000 barrels a day.

In the USA 1989 witnessed the greatest drop in oil production ever recorded. In the fourth quarter as much as 46 per cent of oil consumed was imported. The reason is that most US fields are getting very old and that the consequences of the low exploration activity levels in recent years are beginning to be felt.

The Soviet Union's oil production declined by about 2.4 per cent in 1989. Technical, bureaucratic and financial obstacles stand in the way of exploration and development of new reserves. The Soviet Union also has the considerable problem of transporting the oil to a suitable port. Also, short-term rewards have long taken priority in order to keep production going, while the long-term investments necessary to sustain production levels in the future have been ignored. It seems likely the Soviet Union will have to make some very heavy investments just to keep up today's oil production levels for the next decade.

Oil production from West European countries declined by about 3.7 per cent in 1989. The biggest cause of this decline was the gas explosion on the Cormorant A installation in the North Sea which led to the closure of the Brent pipeline system for a long period.

In the last three years Norway has limited oil production by 7.5 per cent. Despite this, oil production increased in 1989 by about 4 per cent. At the end of the year there was some political debate about our self-imposed production limit. Some argued that the production limit should be removed entirely, while others wanted to retain it. The government decided just before the new year to limit the Norwegian oil production by 5 per cent in the first half of 1990. By this means it is intended to help stabilise the oil price at a reasonably high level.

The expectations for the future which are held at year end are coloured by these factors:

- Continuing increase in oil consumption, though it is not certain how long this tendency will continue
- Increasing dependence on OPEC
- Need for major investments in key OPEC countries in order to meet increasing demand.

This adds up to an expectation of stronger price development on oil than the situation at year end 1988 gave grounds to suppose. If, however, demand should outstrip supply for a limited period, and the oil price rises sharply, it is likely price constraining processes will begin to take effect.

5.5.2 Gas market

Gas consumption in Western Europe in 1988 was 223.5 bcm. This is equivalent to a reduction in consumption of 3.6 per cent relative to 1987. Thus, the last few years' trend has been broken. The development in consumption from 1986 to 1988 was plus 2.5 per cent. The reduction in consumption from 1987 to 1988 needs to be seen in the context of the mild winter in Western Europe in 1988. Provisional figures for the first three quarters in 1989 show an increase in gas consumption of 2.6 per cent relative to the first three quarters the year before. These provisional statistics indicate that the gas consumption in Western Europe is back at the 1987 level despite the 1989 winter also being milder than usual. The consumption of natural gas is largest in the UK, followed by West Germany, Italy, the Netherlands and France. In 1987 almost 50 per cent of the gas was used in the domestic sector, a third was used for industrial purposes and 13 per cent went to power generation. Natural gas currently accounts for 15 per cent of Western Europe's total energy consumption.

The production of gas in Western Europe declined in 1988 by 6.6 per cent to 168.9 bcm. The greatest reduction in production was in the Netherlands. Norway produced 29.3 bcm gas in 1989, compared with under 30 bcm in 1988, which was also the level hitherto. Export of Norwegian gas reached 28.7 bcm in 1989, equivalent to an increase of 0.8 bcm relative to the level of the two previous years. The difference between production and export of gas is explainable since some of the gas is used as fuel, transport, flared off or injected. The major gas producing countries in Western Europe are the Netherlands, Great Britain and Norway. Apart form the Netherlands and Norway the main suppliers to European consumers are the Soviet Union and Algeria. Norwegian gas export makes up about 13 per cent of European consumption. By comparison imports from the Soviet Union and Algeria are about 18 and 11 per cent, respectively.

Of Norway's remaining proven petroleum resources, natural gas accounts for about two thirds. Of Western Europe's gas reserves, almost 50 per cent are in place on the Norwegian continental shelf. In the future supply pattern for the European market Norway is likely to grow in importance, though the Soviet Union and Algeria will remain strong competitors.

In 1989 the Gas Sales Negotiation Committee negotiated with Swedish buyers and hopes to be in a position to sign a contract for sale of Norwegian gas to Sweden in 1990. The negotiations have assumed initial deliveries late in 1995. This time span is partially related to the retirement of the first two nuclear power plants in Sweden, though now it seems more likely these plants will be phased out of service later than originally supposed. Sweden also wants to purchase gas for industrial use. Such gas could be delivered as early as 1994 if a pipeline is constructed. Both Haltenbanken and the North Sea were originally considered potential gas sources for Scandinavia, but Haltenbanken is no longer a candidate for supplies to Sweden since the partners on the Midgard production licence announced that, because of the poor commerciality of the project, they would not be continuing plans for field development based on deliveries of gas to Eastern Norway and Sweden. Also, the Swedegas negotiators have expressed the wish for at least one other supply source located south of 62 degrees. Therefore the North Sea is the only possible gas source. Negotiations are being conducted with Swedegas for sale of about 2.5 bcm a year at plateau level.

Negotiations with potential Norwegian buyers are at an early stage and there is still considerable disagreement on price. Interested buyer groups include power companies and industrial enterprises who want to generate electricity with the gas. There may also be a small market for gas for industrial purposes, such as ammonia production. The tenability of a gas market in Eastern Norway is still something about which very little is known for sure.

At present Great Britain is the largest market for Norwegian gas with a sales volume of 10.5 bcm in 1989. Norway's deliveries to the UK under existing contracts will cease in the mid-1990s. New, smaller contracts, perhaps for power generation, are presently being discussed with British buyers.

In 1989 West Germany was the next largest taker of Norwegian gas. In 1986 an agreement for sale of gas from Troll and Sleipner to German and other buyers was concluded. Deliveries under the Troll agreement will start in 1993. Two of the German gas buyers announced in December 1989 that they intend to exercise their Troll options. This means, if effected, an increase in sale of gas of about 4 bcm more than the original basic contract amount. Also it now seems that there will be a step-up in the sale of gas under the Ekofisk agreement. Buyers of Ekofisk gas include Ruhrgas in West Germany, which is also a Troll buyer. Norway's share of the German market is something less than 20 per cent at present; which means that Norway's importance as a gas supplier to West Germany will increase substantially in the 1990s.

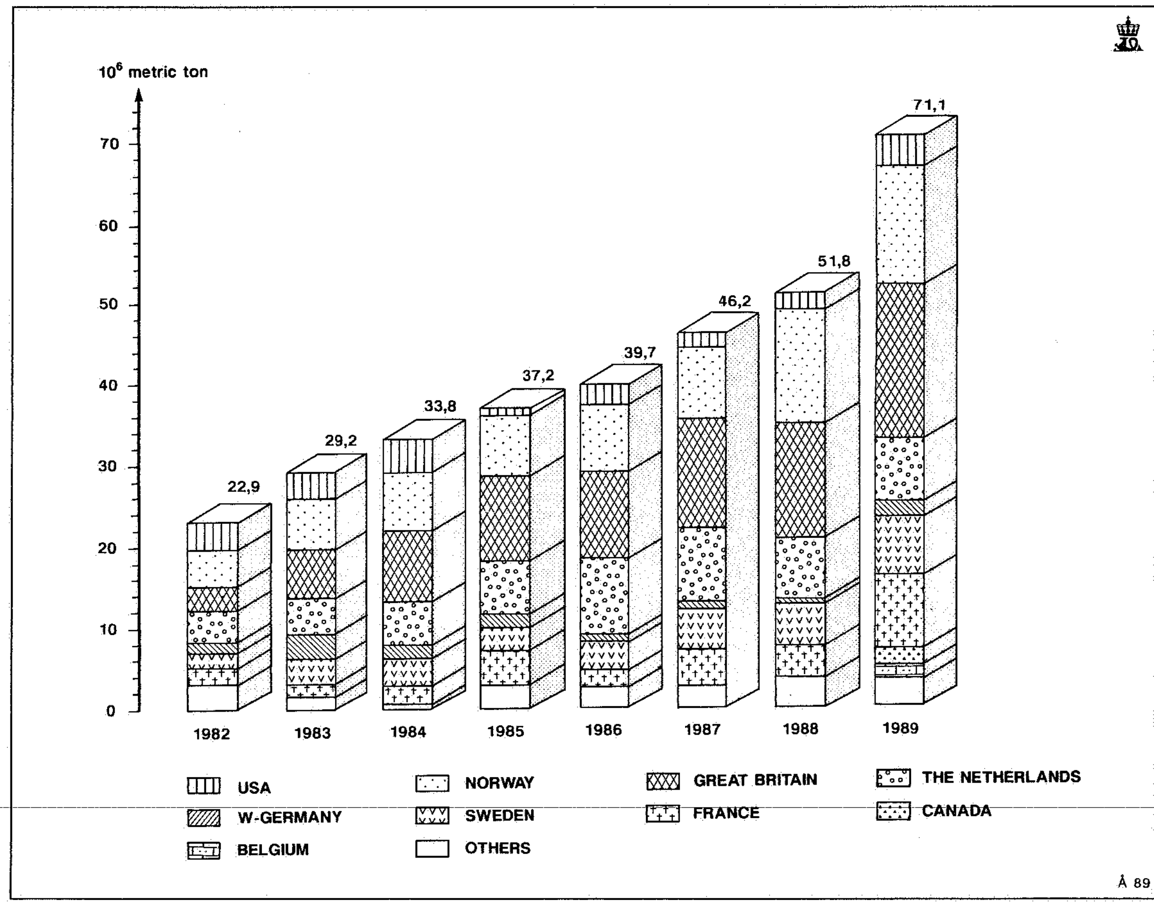
A contract has also been concluded with Spain, another of the buyers of Troll gas, for sale of additional gas. The new contract involves an advance of the initial delivery date by two years to 1993, coupled with steeper and higher escalation to plateau production.

Italy is the third largest individual market for gas in Western Europe. The Italian market is still expansive and consumed around 40 bcm gas last year. The Gas Negotiation Committee is currently negotiating for sale of Norwegian gas to Snam Italia from 1995–96. A volume of about 5 bcm is one figure mentioned in this context. The potential for this and further sales to Italy will depend in part on imports from other countries, the growth in domestic consumption and the demand for gas for electricity production. How much gas will be required for electricity production will depend apart from other factors on Italy's stand on atomic power and her desire to reduce electricity imports. On the Norwegian side there is keen interest in this market.

The positive market development in 1989 has provoked interest in a third pipeline to the Continent. As yet no decision has been made where this pipeline should make its landfall. The present Norpipe line runs from Ekofisk to Emden in West Germany and the new Zeepipe line will emanate in Belgium. Accordingly the Netherlands have been suggested as an attractive third landfall site for strategic reasons.

Although Norwegian gas is currently only sold to the European market, in the future it may be possible to sell Norwegian liquid natural gas (LNG) to

Fig. 5.5.3.a
Sale of crude oil from the Norwegian Continental Shelf



the United States market. Statoil is working in conjunction with Hydro and Saga to export LNG to the USA. The project presupposes a terminal at Kårstø and will be designed for a capacity of 2.5 bcm. The earliest startup date for modest quantities to the USA would be autumn 1994, though even this seems highly optimistic. Norway will encounter strong competition from countries such as Algeria and Nigeria in its attempts to breach the US gas market. These countries will have far lower production costs than Norway. Before it is possible to decide whether to start the project, negotiations need to be conducted on gas sale, use of the terminal, and shipping alternatives. Moreover the Kårstø project will be competing with both Haltenbanken and Snøhvit as supply source.

Methanol production has been advocated as a gas sales option for fields on the Norwegian continental shelf which have no other use for the gas. It would be particularly relevant in connection with the newly signed cooperation project between Statoil and Conoco for an analysis of the prospects of constructing and operating a methanol plant in mid-Norway taking as its feedstock the gas from the Heidrun field on Haltenbanken.

The consensus at year end 1989 was that strong growth can be expected in consumption of natural gas up to the turn of the century.

Changing environmental priorities may result in a better competitive position for gas relative to other energy carriers. In particular gas will become relatively more competitive than energy carriers which produce more pollution, for example coal and oil. It is in the power generation market that the greatest growth in gas consumption is anticipated. Also, natural gas will increase penetration on geographically new markets.

5.5.3 Sale of petroleum from NCS

In 1989 some 72 mton crude oil was sold from the Norwegian continental shelf. This represents an increase of 34.3 per cent relative to 1988. As in previous years Great Britain was the largest consumer, receiving 27.5 per cent of shipments. The Netherlands received 10 per cent, Norway 21 per cent and France 13 per cent. The Norway figure is a comparatively heavy decline: in 1988 it was 26 per cent. Figure 5.5.3.a shows crude oil sales by country for the period 1982–89. Up to 1988 Belgium and Canada were included in the "Other" category.

Sale of NGL from the Norwegian continental shelf reached 2.4 mton in 1989, the same as in 1988.

Fig. 5.5.3.b
Sales quantities of gas per country

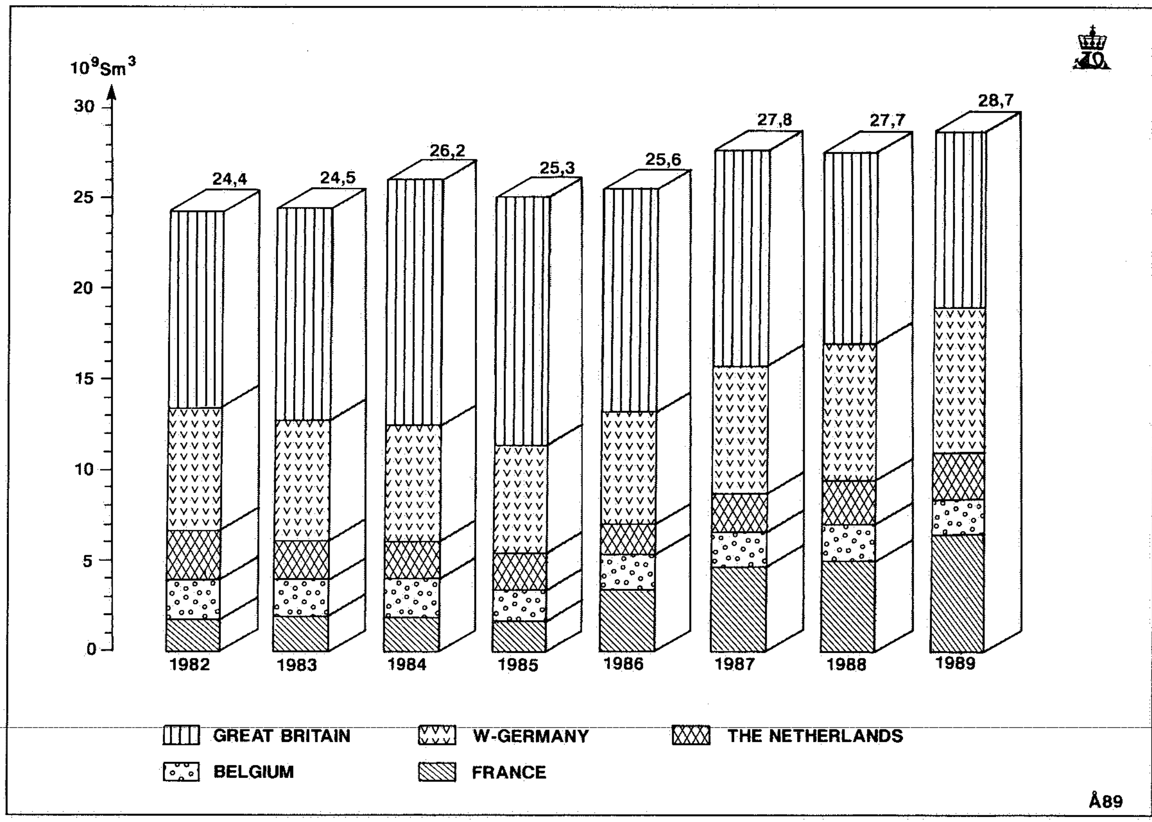


Fig. 5.5.3.c
Sales quantities of oil/NGL per licensee in 1989

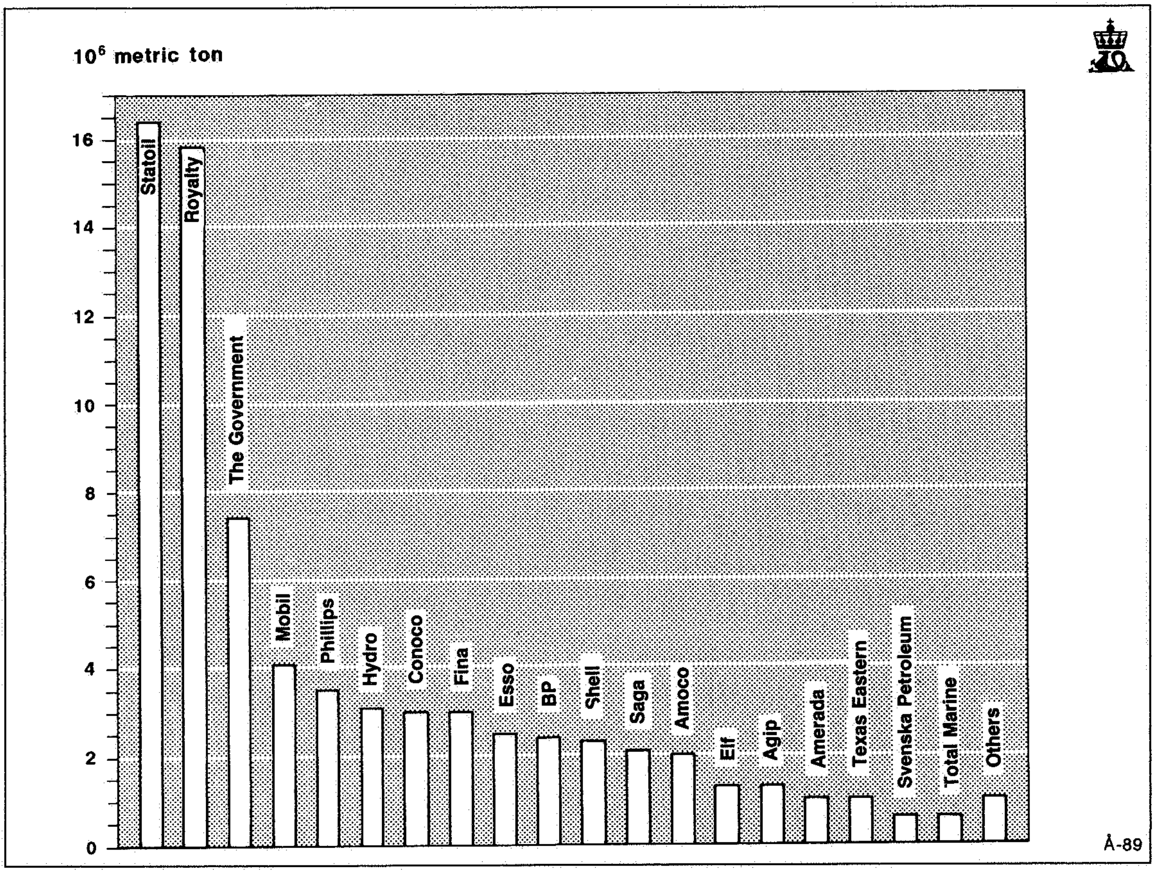
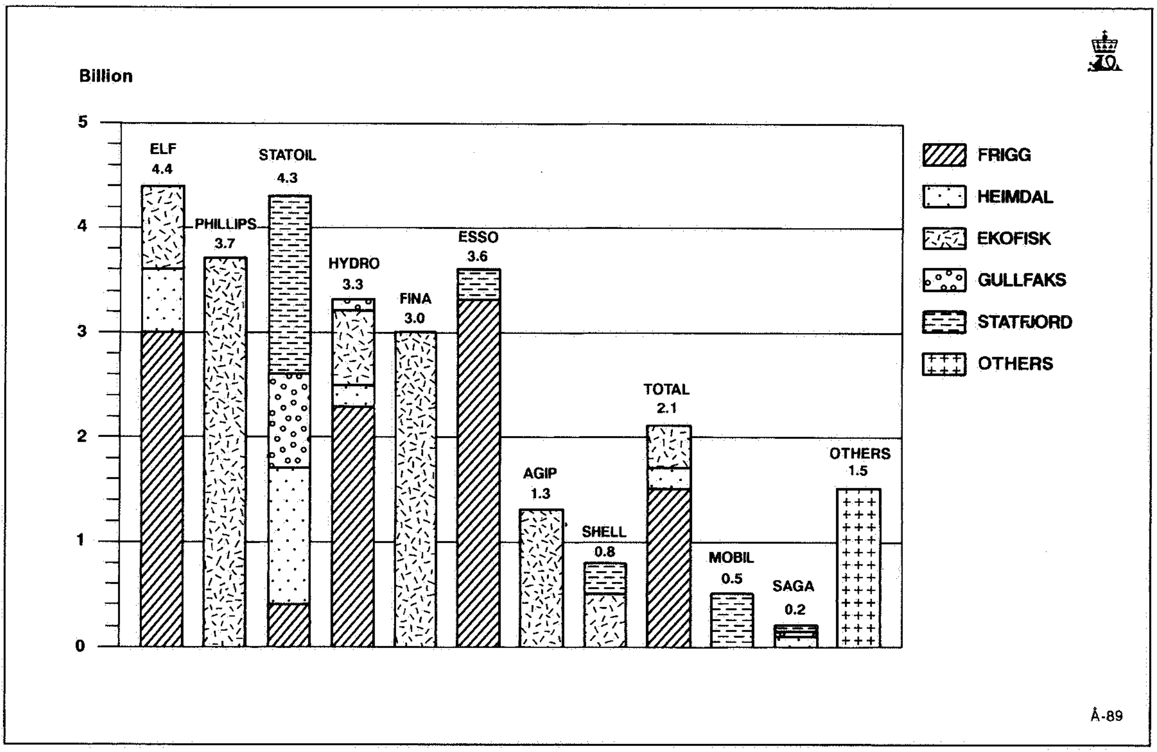


Figure 5.5.3.c shows the sale of crude oil and NGL in 1989 broken down by licensee. Norway exported 28.7 bcm gas in 1989, a moderate increase compared with 1988. Sales were as follows: 8.1 bcm to West Germany, 10.5 bcm to Great Britain, 2.5 bcm to the Netherlands, 5.3 bcm to France and 2.3 bcm to Belgium; see Figure 5.5.3.b. Figure 5.5.3.d shows the gas sale broken down by licensee.

In the column for "Other" the companies have not been named as the figures are taken from many small fields and it would be impossible to illustrate them accurately.

Fig. 5.5.3.d
Sales quantities of gas per licensee in 1989



6. Special Reports and Projects

In 1989 the Norwegian Petroleum Directorate appropriated a total of Nkr 19,877,500 for special projects. Of this amount Nkr 3,797,327 went to projects in the Safety and Working Environment Division and Nkr 16,090,173 to projects in the Resource Management Division.

Another Nkr 4,173,046 was committed to the North Sea Seabed Clearance project. Nkr 8,236,519 was made available to the Barents Sea Weather Ship project; and the enhanced recovery project SPOR received Nkr 16,977,974.

The titles of the projects and the institutions carrying them out are reviewed below.

6.1 RESOURCE MANAGEMENT DIVISION

6.1.1 Exploration Branch

PROJECT TITLE	EXECUTIVE INSTITUTION
Structural Elements in Barents Sea	NPD
Stratigraphy in North Sea	NPD
Further Development of NPD's 2D Fault Model	Rogaland Research Institute
Further Development of Monte Carlo Programme for Resource Calculation Tasks	Christian Michelsen's Institute
Bio-Stratigraphy of Tertiary Sediments on Mid-Norwegian Shelf	Institute of Energy Technology (IFE)
Well Data Summary Sheets	NPD
Construction of Geological Field Database for Reservoir Description	Norwegian Computing Center, University of Barcelona, Colorado State University
Determination of Properties of Diverse Fault Types	Rogaland Research Institute, University of Leeds
NPD's Activity in Reservoir Description linked to SPOR Recovery Enhancement Project	Rogaland Research Institute, IFE, Continental Shelf Institute (IKU)
Detailed Studies of Fluvial Reservoirs to Reduce Reservoir Unknowns	Rider French Cons, IFE
Determination of Uncertainties in Petrophysical Analyses of Wellhole Logs	Schlumberger
Further Development of Petrophysics Programme EPIC	IPEC
Study of Geological Factors of Significance for Migration Mechanisms in Gullfaks Area	University of Oslo
Method Development for Comparison of Core Samples and Log Interpretations	Rider French Cons
Method Development for Conversion of Atmospheric Core Readings to Reservoir Conditions	Geco

PROJECT TITLE	EXECUTIVE INSTITUTION
Determination of Fractal Properties in Oil and Gas Reservoirs	Fracton A/S
Study of Permian and Carboniferous Carbonates in Barents Sea	IKU
Study of Post-Caledonian Tectonics on Svalbard	University of Tromsø

Structural Elements in Barents Sea – Publication
The work to provide a nomenclature for the geological structural elements in the Barents Sea is a collaborative venture by Hydro, Saga, Statoil and the Norwegian Petroleum Directorate. The results of the work will be published and offered for sale as NPD Bulletin no 6.

Stratigraphy in North Sea – Publication
The work on stratigraphy in the North Sea is a joint project by Hydro, Saga, Statoil and the Norwegian Petroleum Directorate. The results of the work have been published and are on sale as NPD Bulletin no 5.

Further Development of NPD's 2D Fault Model
The Norwegian Petroleum Directorate has designed a computer programme which models the faults, based on interpreted seismic sections. This year's project builds on the routines and programme solutions developed by Rogaland Research last year. The programme generates important input data for the Directorate's basin modelling programme and is linked with it.

This year's work has resulted in a better match between software and work stations and evolution of a friendlier user interface.

Further Development of Monte Carlo Programme for Resource Calculation Tasks
The Norwegian Petroleum Directorate has concluded a project running over several years with Christian Michelsen's Institute and now possesses a useful tool for making resource calculations in various types of reservoir, for both discovered and undiscovered resources.

Bio-Stratigraphy of Tertiary Sediments on Mid-Norwegian Shelf
Correlation work has been done on tertiary sediments on the Vøring Plateau and Haltenbanken in order to improve understanding of the tertiary tectonic development in the area. This is important if we are to be able to determine where there are chances of finding oil and gas fields in the area.

Well Data Summary Sheets
The Norwegian Petroleum Directorate releases uninterpreted data from the continental shelf once these are more than five years old.

Uninterpreted logs and log tapes are released for sale when the wellhole is presented in the *Well Data Summary Sheets, WDSS,* the purpose of which is to show which wellholes have released status, and which core and drilling samples and which logs and tapes are available for each hole.

In addition some technical details are stated, plus wellhole history, shallow gas information and test results, and the Directorate's comparative log for each wellhole.

This year's issue is number 15 in the series and deals with the 53 wellholes drilled in 1984. Five of them were reopened.

Construction of Geological Field Database for Reservoir Description
This is a joint project carried out by Saga, Statoil, Hydro and the Norwegian Petroleum Directorate. The project involves collection of field data from reservoir analogues exposed on land and the compilation of a database for quantified data on sedimentary reservoir heterogeneities. The goal is to reduce the uncertainties in reservoir description and reservoir simulation for fields on the Norwegian continental shelf.

Determination of Properties of Diverse Fault Types
Through this project methods have been developed which make it possible to determine if a fault is sealing or not. The results will in many cases be of the utmost importance for charting fields on the Norwegian continental shelf.

NPD's Activity in Reservoir Description linked to SPOR Recovery Enhancement Project
The Norwegian Petroleum Directorate is responsible for assistance to the SPOR enhanced recovery programme in the field of reservoir description. This is accomplished through the follow-up of research projects at home and abroad. It is also essential for the Directorate's own work in reservoir description studies.

Detailed Studies of Fluvial Reservoirs to Reduce Reservoir Unknowns
The special problems associated with modelling of fluvial reservoirs and quantification of the models have been studied in detail. The results are particularly important in the case of the Ness, Statfjord and

Oseberg formations, which constitute the reservoirs on most fields in the Norwegian sector.

Determination of Uncertainties in Petrophysical Analyses of Wellhole Logs

The interpretation of wellhole logs involves considerable uncertainty in the measurement instrument and the calculation models utilised for interpretation. In 1988 the Norwegian Petroleum Directorate launched a project which would determine the margins of uncertainty in the most common measurement instruments and incorporate them systematically in a model. The project was continued in 1989 so as to include more instruments and the Directorate has also looked at the uncertainties of core readings used for log interpretation.

The results so far have been extremely useful, particularly for charting of the Smørbukk and Midgard fields off the Mid-Norwegian coast.

Further Development of Petrophysics Programme EPIC

In order to become more self-sufficient in the field of petrophysical log interpretations the Norwegian Petroleum Directorate in 1988 purchased the EPIC computer programme. This programme permits storage of crude data and results, and has been installed on the Nord computers in Stavanger and the Harstad Regional Office. In 1989 the programme was expanded to handle multiple well studies.

Study of Geological Factors of Significance for Migration Mechanisms in Gullfaks Area

This project is a continuation of the study into Porosity and Migration History in Sandstones in the Gullfaks Field.

An analysis has been made of how the reservoirs in this area have filled up with oil and gas.

The information is important so as to be able to understand the reservoir and its production characteristics. The chances of being able to correlate and extrapolate the reservoir characteristics to other areas where there is no well control have been improved.

Method Development for Comparison of Core Samples and Log Interpretations

A project has been carried out in which logs and cores are described and interpreted, correlated and evaluated in the light of geological facies attributes and interpretation. It has resulted in improvements to existing methods. The information is important in order to understand the environment during the sedimentation process and promotes better descriptions of reservoir rocks.

Method Development for Conversion of Atmospheric Core Readings to Reservoir Conditions

For purposes of petrophysical log interpretation data is employed taken from measurements made on core samples. These measurements are usually carried out under atmospheric or hydrostatic conditions which do not match those in the reservoir. Conversion of results is therefore necessary. This project has studied methods of doing this in the case of porosity, permeability and electrical readings. Core plugs from the Gullfaks and Snorre fields were used.

Determination of Fractal Properties in Oil and Gas Reservoirs

This project is a continuation of the work done in 1988. It is based on so-called fractal properties of the reservoirs. These are properties which apply equally whatever the scale of the object (over several orders of magnitude). An example is fissure patterns in drilling cores, which will often be replicated at larger scale. The effect they produce in the core can be studied, and because the fractal order is constant, the phenomenon is predictable in the larger scale of the field itself. It is therefore possible on the basis of fractal studies to make predictions about parts of the reservoir into which no wells have been drilled.

The method provides productive utilisation of core data and additional information about field behaviour during production. The information can be wielded to improve recovery from complicated reservoirs. More specifically, work is being done on complex fields such as Heidrun and Smørbukk, the results of which are employed by the Norwegian Petroleum Directorate in its follow-up activities.

Study of Permian and Carboniferous Carbonates in Barents Sea

Studies have been made into the diagenetics, sedimentology and petrophysics of permian and carboniferous carbonates in the Barents Sea. This has improved comprehension of carbonate development in the Barents Sea, which is important in connection with recommendation of new exploration areas.

Study of Post-Caledonian Tectonics on Svalbard

This project was launched in 1987 and has now been concluded. The tectonic evolution on Svalbard in post-caledonian times has been elucidated. The results are important in connection with the Norwegian Petroleum Directorate's supervisory duties on Svalbard.

6.1.2 Development Branch

PROJECT TITLE	EXECUTIVE INSTITUTION
Reservoir Studies of Statfjord North	Restek
Reservoir Follow-up Study on 7/11	READ
Simulation of Tilje and Åre on Heidrun	Restek
Ekofisk Nitrogen Injection	Restek, Rogaland Research Institute
Gas Injection Project 1989	IKU
Gas Injection in Waterflooded Structures	IPEC
Creep Effects in Sandstone	Rockmech
Log Interpretation, Midgard and Smørbukk Beta	Schlumberger
Permeability Model, Haltenbanken	Diagenesis
Test Production, General	Resek
Test Production, Balder	READ
Statistical Correlation between Relative Permeability and Mineralogy	Rogaland Research Institute
Gas Injection in Sleipner East	Restek
Reservoir Uncertainties Part I and II	IPC, READ
Value of Test Production	Christian Michelsen's Institute
New Cash Flow Model	Arthur Andersen & Co
Gas Disposal	SINTEF
Regularity and Cost Reductions	Kværner Engineering A/S
Use of Existing Plant	Novatech A/S
Materials Technology	Aker Engineering A/S
Process Technology Technology Trends	Aker Engineering A/S

Gas Injection Project 1989
The aim of this project is to elucidate the potential for application of gas on the Norwegian continental shelf to enhance oil recovery. The results of the project will be used in further studies next year in co-operation with the Norwegian oil companies.

Gas Injection in Waterflooded Structures
Gas storage has not been carried out on the Norwegian continental shelf hitherto but may be an interesting alternative on several fields. The project will search and review the relevant literature and empirical data from gas storage projects in waterflooded structures. Different approaches for information retrieval and data acquisition will be considered in order to identify potential storage reservoirs.

Log Interpretation, Midgard and Smørbukk Beta
Logs of the wells on the Midgard and Smørbukk Beta fields on Haltenbanken have been run. Particular care was taken to determine the cut-off criteria, which is a key factor in the context of resource estimation. The results are incorporated in the Norwegian Petroleum Directorate's petrophysical unknowns project.

Permeability Model, Haltenbanken
Strontium logs of 50 samples of pore salts were run on cores taken from the Smørbukk Beta field. The results of these tests will indicate if there exist any lateral barriers which might prevent vertical flow of fluids during production.

Statistical Correlation between Relative Permeability and Mineralogy
Readings were taken of relative permeability in 12 horizontal core plugs from Statfjord. The mineralogical composition was determined from thin burnished sections of the same plugs. X-ray diffraction was used to determine clay content. The results will be correlated with the comparable data already known from other fields where it has been shown that there is a statistical correlation between relative permeability and clay content.

Gas Injection in Sleipner East
It is feasible to improve recovery of condensate from Sleipner East by injection of dry gas into the field during production. This study is a simulation in which alternative injection strategies have been tried out on a model of the field. The results will be used for technical and economic analyses of a gas injection project.

Reservoir Uncertainties Part I and II
Development of North Sea fields involves considerable economic risk. A large part of this risk derives from the uncertainties in estimated reserves. In this project a review was made of sources of uncertainty in the reserves estimation process and methods of quantifying these uncertainties. Examples from the Norwegian and UK sector were reviewed.

Value of Test Production
The value of test production as a means to determine reservoir uncertainties has been evaluated. The advantage is that the development concept can be tailored to the information obtained during test production. A computer model has been developed which can estimate the value of test production.

New Cash Flow Model
In cooperation with the Ministry of Petroleum and Energy the Norwegian Petroleum Directorate has initiated efforts to develop a new cash flow model for project and corporate calculations for use in the economic analysis work. Further development and maintenance will be easier and less costly than with the old model, and the new model will also be more user-friendly.

Gas Disposal
In conjunction with the Directorate's work on source selection and transportation options for the Nordic and European gas market, wide-ranging calculations and analyses have been performed aided by an economic phase-in model (portfolio model). Considerable expert modelling assistance was required for implementation of this project.

Regularity and Cost Reductions
During times when oil prices are high it is desirable to sustain high production regularity: When prices are low the regularity requirement will be less pressing as operational shutdown will have less serious consequences on revenue.

The requirement for high production regularity means an increase in development costs. This project has looked at the relationship between production regularity and cost of development option.

Use of Existing Plant
Development concepts which make use of existing infrastructure for processing and onward transportation are ever more imperative. In this study the issues relating to development of new fields which are tied in to old installations have been examined and evaluated. The study, though general in approach, used parameters from likely tie-in areas.

Materials Technology
The Norwegian Petroleum Directorate has commissioned a study of trends in materials technology up to the new century. The study looks at alternative materials for development and operation of offshore installations. Existing materials which are expected to have new applications were highlighted as well as new materials in the process of development.

Process Technology – Technology Trends
In the context of offshore production of oil and gas, processing on the installation accounts for a significant portion of the total development costs. Pioneering ideas for design and operation of process trains may therefore be one area in which there are good chances of cutting costs. The point of the study was to identify areas and factors which might produce a more cost-optimal design of process plant and auxiliary systems on the installation.

6.1.3 Production Branch

PROJECT TITLE	EXECUTIVE INSTITUTION
LOPAP – Maintenance	Cap Gemini
ECLIPSE – Maintenance	Exploration Consultants Limited (ECL)

PROJECT TITLE	EXECUTIVE INSTITUTION
RDRS – Maintenance	Cap Gemini
BLOWOUT	Ole Vignes
WIPER and RADPACK – Maintenance	IPEC
Specific Surface Area	Rogaland Research Institute
RDRS – Further Development	Cap Gemini
Nitrogen PVT	Restek, RF
Geotechnical Support	Mervyn Jones
Gas Injection during Waterflooding	Restek
Release System	Cap Gemini
Costs of Reservoir Monitoring	Read
Wetting Analyses	Reslab
Transfer of Geological Data	Restek
PVT Package	Read
Technical and Economic Aspects of Removal	Opcon
Decommissioning and Removal of Offshore Structures	Marintec North West
Multiphase Measurement	National Engineering Laboratories
Coriolis Mass Flowmeter Research	National Engineering Laboratories
Dantest Density Measurement	Dantest
Programme Development and Maintenance of PPRS-2	Rogaland Research Institute
PPRS Well Data	Rogaland Research Institute

LOPAP – Maintenance
This is a programme for presentation of prognoses and actual production which is used for preparation of national budget reports. Cap Gemini performed maintenance and some novel adjustments to the programme during the year.

ECLIPSE – Maintenance
This is a programme package for reservoir stimulation supplied by the UK company Exploration Consultants Limited. The maintenance contract signed with ECL ensures the programme is always operative and up to date.

RDRS – Maintenance
The Reservoir Data Reporting System is a comprehensive system for transferring, quality checking, storage and retrieval of reservoir data. The contract with Cap Gemini includes maintenance and adjustments, and error correction of the programme.

BLOWOUT
This programme is used to calculate how much oil or gas (or both) can flow from an uncontrolled well. The necessary modifications and improvements have now been made to the user manual, error checking of data and more logical presentation of the calculation results.

WIPER and RADPACK – Maintenance
These programme systems were bought by the Norwegian Petroleum Directorate earlier from the UK company IPEC. Wiper is a system for interpretation of pressure build-up tests and RADPACK a partially analytical reservoir analysis system particularly suitable when reservoir data is scarce. The contract for 1989 covered maintenance of these software packages.

Specific Surface Area
The Norwegian operating companies and the Norwegian Petroleum Directorate initiated a joint project in 1989 for enhanced recovery by means of chemicals injection. Adsorption of injected chemicals is field specific and of great economic importance. Experimental measurements were made of specific surface area on core pieces and the results were correlated with adsorption levels for the chemicals concerned.

RDRS – Further Development
This Reservoir Data Reporting System programme is described above. Its further development embraced improvements to the system, enabling the data to be retrievable directly for use in other software, a feature which makes the data that much easier to use in certain other projects.

Nitrogen PVT
In this project the operator's reservoir engineering work in connection with plans for nitrogen injection in the Ekofisk field was reviewed. The review was a joint effort by Restek, the Rogaland Research Institute and the Norwegian Petroleum Directorate.

Geotechnical Support
In conjunction with the Danish Power Board the Norwegian Petroleum Directorate has taken the initiative for a limestone research project in which ten oil companies join forces for execution and financing. The Directorate holds the chair and sits on the six technical committees for the subprojects. Dr Mervyn Jones, an expert on rock mechanics, is engaged as consulting engineer for technical evaluation and participation in the limestone research projects.

Gas Injection during Waterflooding
A waterflooded reservoir will contain considerable residual oil saturation and this project was intended to provide a rough estimate of the effects of gas injection into such a reservoir. The Brent reservoir on Gullfaks was taken as the model and sectional simulation of gas injection into a waterflood area was one of the activities.

Release System
The Reservoir Data Reporting System has accumulated large quantities of reservoir data over time and it would be a good thing if external groups would also make use of it. In order to release data which is no longer confidential a system was devised for sorting the data and a reporting system was developed which allows reports to be generated with the desired data.

Costs of Reservoir Monitoring
Earlier projects have examined what types of reservoir monitoring operations have been carried out and reported for selected key fields, and evaluated their quality. This project evaluated the costs of monitoring as a function of the informative value, in the hope of raising cost-consciousness when commissioning data acquisition.

Wetting Analyses
This project included the measurement of wetting properties in cretaceous sediments from the Eldfisk field and examination of the factors which determine the wetting properties of the rock, and the effects of wetting on water absorption. The results are utilised for evaluation of enhanced recovery on Eldfisk.

Transfer of Geological Data
Serious problems were encountered in connection with transfer of oblique faults to a reservoir simulation model and the project involved correction and adjustment of the transfer protocols as well as a general examination of the necessity for and value of using oblique faults in the simulation work. Suggested improvements to the programme were also presented.

PVT Package
Pressure, volume and temperature simulation is used for quality assurance and clearance of PVT data for use in reservoir simulation. It is particularly critical in the case of condensate and volatile oils. Following an evaluation of several alternatives it was decided to purchase READ's PVT simulation programme for PC systems.

Technical and Economic Aspects of Removal
The aim of this project is to review the technical opportunities and limitations of present-day technology and examine the economic aspects of removal of offshore installations. The project also sketched out tentative requirements the authorities should make in respect of removal of offshore installations on the Norwegian continental shelf.

Decommissioning and Removal of Offshore Structures
A major research programme which examines various aspects of the removal of offshore structures was initiated by Marintech North West, UK. The programme extends over several years with participation by the UK authorities as well as the company. The Norwegian Petroleum Directorate has bought

into the programme which is scheduled for completion by the end of 1990.

Multiphase Measurement

The project group for multiphase measurement consists of a multiple client consortium in which ten operating companies participate.

The aim of the project is to develop a concept for measurement of multiphase flow based on known technology.

The work will involve three phases:

1) Fabrication and testing of equipment
2) Fabrication of prototype
3) Field testing of prototype.

So far the project is in phase 1 which is expected to be finished in 1991. Interim reports for some of the tests have been submitted.

Coriolis Mass Flowmeter Research

This is another multi-client project, again carried out by the National Engineering Laboratories in Scotland. The NEL project will test several mass flow meters which are based on registration of the coriolis effect, so as to determine how accurate such measurements are. Also interesting is information on how the instruments should be checked and maintained after use.

Instruments which make direct measurements of mass (usually volume and density are measured separately) may find increasing application in the future as the industry and the authorities acquire better knowledge and faith in the technology.

The NEL project, to be completed in 1991, will be important in this context.

Dantest Density Measurement

This project has studied how to calibrate gas density meters designed to measure density at pressures between 50 and 200 bar.

Trials have been carried out with three natural gases having methane content from 75 to 94 per cent.

Other tests have been run with synthetic gases formulated to replicate the air velocities in the three natural gases. The tests show that density measurement is possible with only 0.2 per cent uncertainty.

Programme Development and Maintenance of PPRS-2

A menu system has been developed for the database for the Petroleum Production Report System in order to give it a friendlier user interface.

Rogaland Research Institute has undertaken certain maintenance operations and adjustments to fit new fields.

PPRS Well Data

This project, also linked to the Petroleum Production Report System, is designed to prepare the well data from the PPRS database so as to be more user-friendly, faster and able to provide better plots and tables in the follow-up work for each particular well.

6.1.4 Planning Branch

PROJECT TITLE	EXECUTIVE INSTITUTION
Activity Level for Exploration	Christian Michelsen's Institute
Development of Gas Market on Iberian Peninsula	DRI, McGraw-Hill
LNG Export and Market Competition	Coopers & Lybrand
Study of Structure of European Gas Market	Fridtjof Nansen's Institute
Resource Interest and Yield Requirements	Christian Michelsen's Institute
Construction of Model for Analysis of Field Portfolios	SINTEF
Risk under Joint Use of Installations	Christian Michelsen's Institute and SikteC
World Hydrocarbon Resource Project	Cap Gemini, ECON, Colin Campbell

Activity Level for Exploration

The purpose of this project is to develop a methodology which can provide a coherent view of exploration level relative to development pace and production level. The project has stressed the concept of optimal exploration effort, the level of which is determined theoretically by modelling.

Development of Gas Market on Iberian Peninsula
In order to obtain the best possible conception of the market potential for Norwegian gas a study was commissioned in 1989 of the market on the Iberian Peninsula. This study was carried out in close cooperation with the Ministry of Petroleum and Energy.

LNG Export and Market Competition
Sale of Norwegian gas represents a bottleneck for development activities offshore Norway. Analyses of possible development scenarios will therefore be very largely guided by the assumptions which are adopted for sale of natural gas. Export of LNG is particularly interesting in the first place because this solution may apply to gas from all parts of the continental shelf, even small volumes.

The purpose of the project was twofold: First to identify the opportunities for export of Norwegian LNG, and second to identify the resources and cost frameworks for our major competitors, Nigeria and Algeria.

The project was a joint venture by the Norwegian Petroleum Directorate and Ministry of Petroleum and Energy.

Resource Rent and Yield Requirements
Reserves of oil and gas are non-renewable. This means that there is a cost to society of resource production and transport. This cost, the resource rent, reflects the cost factor implicit in the certainty that production today is at the expense of production at some future date. The purpose of the project was to illuminate how management of and return on a portfolio vary when one allows for the resource rent. Calculations of resource rent were run for Norwegian oil while making various price, market situation and discount rate assumptions.

Construction of Model for Analysis of Field Portfolios
Currently the Norwegian Petroleum Directorate uses the Portfolio Model developed by SINTEF. This model is installed on one of Statoil's IBM mainframes. The project involves the development of a corresponding model on a VAX machine with VMS operating system in the Directorate. The work of reprogramming will be concluded in 1990. The aim of the project is to save the Directorate the expense of hiring external computer power in the not too distant future. At the same time error correction and minor adjustments to the system will be easier.

Risk under Joint Use of Installations
A simplified account of the material risks was the theme of this project. By engaging a consultant with an understanding of risk analysis, a picture of the risk was obtained for "ordinary" and "disastrous" events. Given "ideal" information on the risk, a project was initiated to examine decision-making under uncertainty. The project provided material for an internal report.

World Hydrocarbon Resource Project
Information was obtained on the resources situation in a worldwide context. This information is stored in a computer tool which can extrapolate historical production figures in any of several alternative ways assuming a limited resources base. Other extrapolation options have also been explored. In addition a modest evaluation of resources potential was made.

6.1.5 SPOR Enhanced Recovery Programme

PROJECT TITLE	EXECUTIVE INSTITUTION
Water Injection (SPOR Water)	Rogaland Research Institute
Gas Injection (SPOR Gas)	Continental Shelf Institute (IKU)
Optimisation of Reservoir Data (SPOR Opt)	Institute of Energy Technology (IFE)

Again in 1989 there was much activity within the SPOR enhanced recovery programme, a government research and development programme initiated in 1985. The programme seeks through build-up of expertise, and through research and development of novel technology, to provide a foundation for enhanced oil recovery from the Norwegian continental shelf.

To date Nkr 76 million has been spent on the programme and these funds have been appropriated over the Ministry of Petroleum and Energy's budget. SPOR, a limited period research and development programme, was originally planned to last five years. In 1989 it was determined to extend the programme period to seven years, so that efforts and results can reach the level envisaged at the time SPOR was launched.

Implementation of the SPOR programme has produced tangible spinoffs for the work on enhanced oil recovery in the Norwegian Petroleum Directorate as well as the companies engaging in offshore activities in the Norwegian sector. The results from the SPOR programme also provide a basis for Norwegian participation in international cooperation such as the International Energy Agency (IEA) and bilateral cooperation, as with the USA.

6.2 SAFETY AND WORKING ENVIRONMENT DIVISION

PROJECT TITLE	EXECUTIVE INSTITUTION
Findings from Offshore Activities in Northern Areas	NPD, Aker Drilling
Membership of Welding Institute	Welding Institute
Membership of Marine Technology Directorate (MTD)	MTD
Membership of Norwegian Electro-Engineering Committee (NEK)	NEK
Trials of Tophole Blowout Preventer	Smedvig
Manned Subsea Operations International Cooperation	NPD
Consequences of Shallow Gas in Sea	Veritec
Influence of Welding on Materials Performance Offshore	Cranfield Institute of Technology
Working Environment for Divers	SINTEF
Methodological Regulatory Development	NPD
Membership of World Offshore Accident Databank (WOAD)	Veritec
Expert System for Evaluation of Corrosion Risk for Construction of Pipelines	Cranfield Institute of Technology
Acceptance Criteria for Documentation of Chemical Health Risk	Nordcal
Acceptance Criteria for Plastics Composites	Veritec
Automation of Drilling Operations	Rogaland Research Institute
Perceived Risk and Safety	NPD
Hurricane Statistics on Continental Shelf	NPD
Design Criteria for Collision Risk	SINTEF, SikteC
Design Curve for Fatigue of Cathodic Protected Structures	SINTEF
Objects Adrift	Quasar
Time Scheduling in Safety Division	Norsk Data
Explanation of High Pressure Wells	Proffshore
Status Control of Subsea Production System	Jotun Cath
Ergonomic Requirements and Criteria	Nordcal

PROJECT TITLE	EXECUTIVE INSTITUTION
Working Environment Factors and Acceptance Criteria	Nordcal
Correlation of Demanning and Accident Incidence	SikteC
Working Environment – Cooperation Strategies	Rogaland Research Institute
Technical Well Problems on Older Installations	NPD
Launch System for Man Overboard (MOB) Boat	Veritec
Maintenance Systems for Evacuation and Rescue Means	Marintek
Statistical Analysis System for Accident Data	SAS Institute
Procedures for Evaluation of Jack-up Installations	Noble Denton
Problems of Diving to Great Depths	NPD
Effect of Chlorination on Biological Activity and Corrosion of High-Alloy Steel in Seawater	SINTEF
Corrosion Rate in Crevices in High-Alloy Steel in Seawater	SINTEF

Findings from Offshore Activities in Northern Areas
This project is designed to examine and systemise the experiences won in northern areas since drilling started in 1980. The results will be used to revise the *Evaluation Criteria for Winter Drilling in Northern Areas* issued by the Norwegian Petroleum Directorate as a guideline in April 1987, and to establish the Directorate's acceptance criteria for offshore operations in the area. Special problem areas which are identified may be the subject of future R&D projects under Directorate control.

Membership of Welding Institute
The Norwegian Petroleum Directorate has been a member of the Welding Institute in Great Britain since 1981. This is the leading authority in the offshore field and is very energetic in research, training and consultancy. Membership qualifies for consultancy services, project participation and current information on the latest developments in materials technology and welding engineering.

Membership of Marine Technology Directorate (MTD)
Since 1980 the Norwegian Petroleum Directorate has been a member of the British Offshore and Underwater Engineering Group (UEG) which was a subdivision of the British Construction Industry Research and Information Association (CIRIA). The group has now joined the Marine Technology Directorate. The projects administrated by the organisation are very pertinent to the Norwegian Petroleum Directorate's work tasks in this sphere. Cooperation and availability of information have been of tremendous assistance for safety reports, regulatory drafting, and competence build-up. The Norwegian Petroleum Directorate is a member of a project concerned with Operative Inspection of Structures and Installations Underwater.

Membership of Norwegian Electro-Engineering Committee (NEK)
One reason the Norwegian Petroleum Directorate joined the NEK is to ensure that regulations in the electro-engineering field are continually under revision and keep pace with the technological development and international practices and experience. The importance of this aspect is underscored by the Norwegian efforts to meet the requirements set out in the Agreement Concerning Technical Barriers to Trade in EFTA and the EC.

The Directorate also takes part in national and international cooperation for preparation of new regulations. This work is headed by NEK.

Trials of Tophole Blowout Preventer
As a continuation of an earlier project concerned with the evaluation of new equipment and new technology for drilling the Norwegian Petroleum Directorate, in collaboration with 11 operating companies in a wide-ranging research programme, will determine the suitability of tophole blowout preventer

valves. The project also concerns design and construction of the valve.

Manned Subsea Operations – International Cooperation

This project carried on the work of standardisation: in the first place of qualification requirements, procedures and technical solutions for improvement of the total safety of implementation of underwater operations.

Consequences of Shallow Gas in Sea

This project has continued the Norwegian Petroleum Directorate's shallow gas programme. The intention is to examine whether shallow gas in the sea can be released, leading to gas concentrations on installations, thus representing a fire and explosion risk.

Influence of Welding on Materials Performance Offshore

The Norwegian Petroleum Directorate participated in this project, phase 2, which is spearheaded by England's Cranfield Institute of Technology. Phase 2 examined the weldability and similar properties of new high-strength low-alloy steels, quick-quench steels, combinations of the two, and cast and forged components.

Working Environment for Divers

This project was continued with a view to obtaining and preparing proposals or guidelines for how the key stress factors for divers in saturation can be reduced or eliminated.

Methodological Regulatory Development

This project is discussed in section 4.2.

Membership of World Offshore Accident Databank (WOAD)

The Norwegian Petroleum Directorate is a subscriber of this database which is run by Veritec a/s. The background data from the base will be of great value for the evaluation of safety and similar studies which the operating companies carry out during the various phases of a project, for making the right priorities for the Directorate's supervision duties and for regulatory revision and drafting.

Expert System for Evaluation of Corrosion Risk for Construction of Pipelines

This project is another carried out by the Cranfield Institute of Technology in the UK, financed by British oil companies, the Department of Energy and the Norwegian Petroleum Directorate. The goal is to find a practical expert system with which to evaluate the corrosion risk in pipelines, which can be used to appraise the partners' documentation of this aspect, during both the fabrication and operating phases. Through this project the Directorate also expect to enhance their own expertise in an area where the use of advanced computer techniques is expanding vigorously.

Acceptance Criteria for Documentation of Chemical Health Risk

This project examines systems and practices for development and distribution of toxicological knowledge and data on chemicals used in the offshore petroleum activity. The project results will provide a foundation for setting forth quality requirements for information on chemical health risk, which will be taken as a basis for regulatory work in this field.

Acceptance Criteria for Plastics Composites

Composite materials of plastic are by definition flammable. Nevertheless plastics composites may be used instead of the more usual metallic materials with advantages for safety and economy. The purpose of the project was to set up guidelines to describe what factors should be taken into account and what conditions must be met in order that plastics can take the place of metals without compromising the requirement for safety.

Automation of Drilling Operations

Mechanisation of drilling operations hitherto has failed to produce the desired results in terms of accident or injury reduction. A genuine decline in drilling-related accidents can only be accomplished by bringing the methods and tools of the drilling activity into line with modern technology and by organising the job better. This project aims to develop an automatic drilling rig which can form a model for the next generation of drilling units.

Perceived Risk and Safety

This project looks into the risks associated with the perception of risk, by examining whether there is a correlation between risk and accidents due to inappropriate action. The results are expected to spark off a process in the operating companies whereby appropriate measures are proposed in the areas of difficulty disclosed. The Directorate's own expertise in the field will also be augmented.

Hurricane Statistics on Continental Shelf

The Norwegian Petroleum Directorate has reviewed the storm observations from Utsira, Ingøy and Fruholmen. In the case of Utsira, weather statistics have been made continuously from 1863 to the present. A comparison of observed wave heights for the periods 1888 to 1902 and 1974 to 1987 produced the same value for the 100 year wave off the island. This would tend to indicate that only minor changes in wave regimes have occurred during the last 100 years.

Design Criteria for Collision Risk

Design criteria of this kind are only inadequately looked after in existing regulations. The goal is to devise a model which will predict the correct level of collision risk on the Norwegian continental shelf with acceptable probability.

Design Curve for Fatigue of Cathodic Protected Structures

The Norwegian Petroleum Directorate participates in a project under the direction of SINTEF and supported by the oil industry. The object is to determine the influence of cathodic corrosion protection systems on the fatigue life of welded pipeline nodes. The design curve for cathodic protected structures in the *Regulations for Structural Design of Load-Bearing Structures* etc will be revised in the light of project outcome.

Objects Adrift

Shipwrecks, manned and unmanned vessels and other structures have over the years on several occasions represented a serious risk to offshore installations. The project seeks to shed light on existing procedures, responsibility lines, and instruments of intervention by which to counter drifting objects, and to examine potential courses of action to reduce the risk.

Time Scheduling in Safety Division

A planning tool has been developed which is able to provide management with the necessary overview of planned activities and their inter-dependence. The aid will also rationalise the allocation and input of human resources to the Directorate's supervisory duties and the Safety Division's other tasks.

Explanation of High Pressure Wells

Due to the operational difficulties encountered while drilling wells at high pressure and temperature, this project will undertake a systematic review of already-drilled deep wells.

Status Control of Subsea Production System

A need is felt for criteria with which to evaluate requirements for status monitoring of subsea production systems, their associated flowlines and risers. The project is intended to produce a footing for further work designed to finalise such criteria.

Ergonomic Requirements and Criteria

The object of this project is to produce a survey of national and international standards and guidelines in the occupational health field (ergonomics). The material found will be evaluated with a view to incorporation in the operating companies' quality assurance measures for occupational health. The project may be seen as a preliminary one for formulation of suitable rules for occupational health and workplace design. The ultimate aim is to compile a sort of check list which the industry and supervisory authorities can use as reference.

Working Environment Factors and Acceptance Criteria

This project seeks to examine the applicability of GrafRisk, an analysis programme which can illustrate correlations in the working environment field. The project will also look at the modifications needed to the model in order to result in a practical decision support tool for use in the Directorate's activities in this area.

Correlation of Demanning and Accident Incidence

Reduction of workforce is a central issue of operating companies' endeavours to shrink costs, on existing and planned developments alike. Working hours and shift systems will also be of critical interest to the Directorate in connection with its supervisory function. This project seeks to reach better arrangements which are respected by the parties, in consultation with employees and employers. The project will also consider special supervision methods for Norwegian Petroleum Directorate use in this context.

Working Environment – Cooperation Strategies

This project included the implementation of a conference with participation from employee and employer representatives, research staff and the Norwegian Petroleum Directorate, in order to improve communication between the parties involved in working environment issues offshore. The conference was a continuation of the meeting activities between the Directorate, Joint Union of Oil Workers (OFS) and Norwegian Federation of Trade Unions (LO), instigated in autumn 1988. The conference produced important impulses for research activity, regulatory review and supervisory duties.

Technical Well Problems on Older Installations

This project seeks to shed light on the special difficulties encountered in the areas of barrier integrity, reliability, maintenance, inspection and redundancy in drilling and well technology which may prejudice safety on older installations. The project will be carried through in close association with Phillips and Elf as well as the engineering contractors. The Norwegian Petroleum Directorate intends to step down its own involvement in the later phases of the project.

Launch System for Man Overboard (MOB) Boat

The standard of the man overboard boat service on fixed installations is often lower than is customary on standby vessels and mobile installations. This project seeks to review the status of MOB boat standards on all producing fields, and then to define a set of desiderata for the Directorate's regulatory drafting activities and supervisory duties in this context.

Maintenance Systems for Evacuation and Rescue Means
This project starts with data acquisition from the various systems currently in use. The data will be processed and evaluated so as to provide a basis for comparison. The project aims to improve or perhaps even standardise the systems and equipment used for evacuation and rescue.

Statistical Analysis System for Accident Data
The object of this project is to produce a system interface of the SAS statistical analysis tool with the Norwegian Petroleum Directorate's database for accident registration. The project will result in significant concentration and build-up of expertise in use of SAS, which is potentially a very powerful analysis tool with applications throughout the Directorate's areas of responsibility.

Procedures for Evaluation of Jack-up Installations
Big differences have been detected between the calculation methods and evaluation philosophies of the various bodies concerned with the approval and verification of jack-up platforms. A working group with members from the operating companies, shipowners, marine architects and design engineers, classification companies and underwriters is to propose a unified method of evaluation. Standardisation will render safety level almost independent of nationality, certification class or operating company.

Problems of Diving to Great Depths
This project entails a review of medical examinations in connection with deep diving operations and the long-term effects thereof, and criteria for selection of diving personnel. The project will also keep an eye on novel technology in the deep diving sphere, most particularly the use of hydrogen as the inert component in breathing gas.

Effect of Chlorination on Biological Activity and Corrosion of High-Alloy Steel in Seawater
The Norwegian Petroleum Directorate is a partner in a project run by SINTEF which is supported by the oil industry and steel manufacturers in addition to the NTNF (Royal Norwegian Council for Scientific and Industrial Research). The project aim is to examine what chlorine level is required to prevent, or at least limit, biological activity in seawater systems. At the same time the effects of the requisite chlorination level on corrosion rates of high alloy steels in salt water environments will be investigated.

Corrosion Rate in Crevices in High-Alloy Steel in Seawater
The Norwegian Petroleum Directorate is a partner in this SINTEF project together with representatives from the oil industry and steel manufacturers. The object of the project is to investigate the development of crevice corrosion rates in the best qualities of high alloy stainless steel in salt water environments with time, and how the rates depend on material composition, method of manufacture and welding. Another object is to find out whether it is feasible to protect stainless steel effectively against crevice corrosion using cathodic protection under all conditions.

6.3 ADMINISTRATION BRANCH

PROJECT TITLE	EXECUTIVE INSTITUTION
North Sea Seabed Clearance	NPD

North Sea Seabed Clearance
The Norwegian Petroleum Directorate's seabed clearance project focused in 1989 on the area Vestrebakken, west of the Norwegian Trench, at 59 degrees North. This area was pinpointed on the advice of fishery organisations and fishery authorities. After surveying the area with side-seeking sonar, the obstacles discovered were identified more closely using a remote control underwater vehicle. The objects which were considered to represent an obstacle to rational fishery activity were then recovered using a dynamically positioned mother vessel and remote control rover.

Five wrecks were accurately charted but not raised. Various pieces of chain, wires of assorted sizes, iron benches, anchors, fishing implements and a 1300 meter long towline alone weighing 30 tons were retrieved from the seabed. In addition 14 mine anchors were recovered.

Ties with the Norwegian Hydrographic Service were further strengthened: In 1989 the NHS's hydrographic survey vessel *M/S Lance* was once again made available for sonar scans of the seabed. The clearance contract itself was awarded to Bergen Underwater Services A/S in Bergen.

The clearance project executive committee was made up of representatives from the Norwegian Petroleum Directorate, Directorate of Fisheries, Hydrographic Service, Association of Fishermen and Oil Industry Association.

7. International Cooperation

7.1 AID TO FOREIGN COUNTRIES

In 1989 the Norwegian Petroleum Directorate's activities through NORAD, the Norwegian Directorate for Development Cooperation, were channelled to Tanzania, Bangladesh, Mozambique, South Yemen and Nicaragua.

In these countries the Norwegian Petroleum Directorate has engaged in general computer processing services, processing and storage of seismic data tapes, interpretation of data, follow-up of consultants in connection with seismic processing, assistance for development of bio-stratigraphic laboratory in Tanzania, support to NORAD funded advisors in Tanzania and Mozambique, and advisory services in connection with planning of regional seismic shooting in Central America.

The Norwegian Petroleum Directorate's major commitment areas in 1989 were in the following countries:

Tanzania

Assistance to TPDC for planning and follow-up of processing of seismic data. Development of bio-stratigraphic laboratory, and reinforcement of exploration division in TPDC by active participation in evaluation of various sedimentation basins in country. Follow-up work with the filing system for geophysical and geological data has continued.

Bangladesh

As a step in the development of the Bangladesh Petroleum Institute (BPI) three geologists and geophysicists received training with the Norwegian Petroleum Directorate for short periods. The work in the Directorate was arranged so that BPI personnel were engaged in problems of interest in their home country, so that the training period would also provide valuable help to determine the petroleum potential at home.

Nicaragua

In 1989 the Norwegian Petroleum Directorate took part in the evaluation of the petroleum potential of the Pacific coast of Nicaragua by making a review of all existing data from the area. Since some data were missing, the Directorate made efforts to fill in the gaps. Reprocessing of some older seismics has therefore been initiated. The Directorate is following up the contractor's work in this respect. The Directorate also played a supportive role to Statoil for planning of a regional seismic survey of the Pacific areas of Costa Rica and Nicaragua. This survey was started late in the year.

7.2 SAFETY AND WORKING ENVIRONMENT

7.2.1 Introduction

The Directorate cooperates and has extensive contacts with international professional organisations and government agencies, either directly or through other official Norwegian bodies.

The purpose of this cooperation is as follows:

a) To help ensure that safety and the working environment at least satisfy accepted international standards
b) To secure the flow of relevant information towards expertise build-up and regulatory revision
c) To improve our understanding of and experience in international relations and influence safety and working environment issues in the right direction.

Generally the cooperation has involved taking part in inter-governmental forums in Europe and the United Nations, supplemented by direct cooperation with various kinds of national and regional technical bodies. A list of the most important cooperation partners is given below followed by further details of the areas covered:

a) EC Commission, in collaboration with Norway's Ministry of Local Government, on safety and the working environment
b) The United Nations' International Maritime Organisation, IMO, and International Labour Organisation, ILO, concerning safety at sea and the working environment, respectively, since 1979–80
c) European Diving Technology Committee, EDTC, and Association of Offshore Diving Contractors, AODC, for safety while diving, since 1983
d) Marine Technology Directorate, MTD, formerly CIRIA and UEG (see section 6.2) on inspection and maintenance of installations, since 1980
e) Welding Institute in UK on research and development of materials and welding, since 1981
f) American Petroleum Institute, API, attendance at annual conferences on petroleum subjects and standardisation, since 1979
g) National Association of Corrosion Engineers, NACE, in USA, participation at annual conferences on corrosion and surface treatment, since 1984
h) CENELEC, the *Comité Européen de Normali-*

sation Electrotechnique, concerning electro-engineering standardisation in Europe, through Norwegian Electro-Engineering Committee, NEK

i) Committee for Coordination of Joint Prospecting for Mineral Resources in Asian Offshore Areas, CCOP/ASCOPE, Norwegian Engineering Committee on Oceanic Resources, NECOR; participation in UN cooperation on safety matters for a group of East Asian countries, since 1985.

7.2.2 The European Community (EC)

Since 1982 Norway, represented by the Norwegian Petroleum Directorate, has held observer status in the EC work on safety and working environment in the offshore petroleum activity. This work comes under the EC's Safety and Health Commission for the Mining and other Extractive Industries and is implemented by the Working Party on Oil, Gas and Other Minerals Extracted by Borehole.

The Working Party considered a proposal for harmonising of safety requirements, particularly with respect to guidelines for training and occupational injury statistics. Generally emphasis was placed on exchange of findings and information. This activity under the auspices of the EC embraces subjects which were previously the business of the Northwest European cooperation.

The activities of the Working Party received higher priority and were intensified in 1989 as the political organs in the EC have determined that directives are to be produced which also cover working environment and safety in the offshore petroleum industry. Accompanying technical schedules are also planned.

Provisionally the agenda calls for submission of the Party's findings to the Commission in or about the middle of 1990.

7.2.3 International Maritime Organisation (IMO)

Jointly with the Ministry of Petroleum and Energy the Norwegian Petroleum Directorate has provided the Norwegian presence in the work aimed at formulation of international rules for removal of offshore installations from the continental shelf. The rules were adopted by the IMO General Assembly in autumn 1989.

The IMO is a special organisation in the UN system whose primary tasks are the advancement of safety at sea and measures to combat pollution at sea. Though by far the majority of IMO activities are addressed to ships and shipping operations, some have significance for the offshore petroleum industry.

The petroleum oriented aspect of IMO activities is generally found in the Safety at Sea Committee and its technical subcommittees. As a member of the Norwegian delegations the Norwegian Petroleum Directorate has participated in the deliberations of the three technical subcommittees in the fields of personnel training, diving, design of mobile installations, safety zones, and removal of offshore structures.

The IMO's general assembly adopted a resolution in 1989 concerning safety zones around offshore petroleum installations. This is of significance for standardisation of the rules concerning, for example, response to infringement of such safety zones. In the Directorate's view it is a welcome development that international guidelines have now been established in this field.

A resolution concerning criteria for removal of fixed installations was also passed in autumn 1989. This will influence activities in connection with final production and removal on the Norwegian continental shelf as well as decisions on new field development concepts.

The work to develop an IMO standard for training of maritime key personnel on mobile installations has drawn out and will not be completed until sometime in 1990.

7.2.4 CCOP/ASCOPE, NECOR

The Norwegian Petroleum Directorate is a participator in a programme for development of safety routines and methodology in resource management in the petroleum activity under the auspices of the UN system of specialist organisations. The programme is oriented towards East Asia.

CCOP/ASCOPE is the Committee for Coordination of Joint Prospecting for Mineral Resources in Asian Offshore Areas. NECOR is the Norwegian branch of ECOR, the Engineering Committee on Oceanic Resources, which is an advisory subcommittee in the UN system for exploitation of subsea resources.

7.2.5 European Diving Technology Committee (EDTC)

The Norwegian Petroleum Directorate is a member of this committee whose mandate is the exchange of findings in the diving sphere and to work for joint recommendations on technical and operational factors. There were two committee meetings in 1989.

In the second meeting the EDTC was presented with a request from the EC Commission for cooperation in the development of an overall strategy for regulation of diving in the EC. The Committee agreed to undertake such work on the understanding that employee representatives take part. Consequently each country on the Committee from now on will be represented by one public official, one medical expert, one industry spokesman and one employee representative. The work to be launched in 1990 presupposes a modest increase in Committee activity.

7.2.6 Electro-engineering standards and regulations

In the three-day period 3–5 October 1989 a meeting was held in the Norwegian Petroleum Directorate under the direction of the *Comité Européen de Normalisation Electrotechnique (CENELEC)* which took up the question of new rules for installation of electrical hardware in explosion hazard areas. According to plan the rules should be ready by the end of 1992.

7.3 INTERNATIONAL STANDARDISATION ORGANISATION (ISO)

International standards are utilised for the analysis and measurement of oil and gas, and the Norwegian Petroleum Directorate joins in the international work to revise existing standards and establish new ones in these twin areas.

In 1989 the ISO inaugurated a new technical committee with special study area Natural Gas. The Natural Gas Committee is responsible for all standardisation activity in relation to natural gas, its properties and applications, and is therefore of enormous significance for Norway as a gas supplier to Continental Europe.

National working groups have been set up in analysis and metering technology which follow up the work done in ISO standards. The Directorate is involved in this work.

From the date of realisation of the EC Inner Market on 1 January 1993 the EC will require international standards to be employed. The standardisation work in ISO is therefore of the utmost importance.

8. Statistics and Summaries

8.1 UNITS OF MEASUREMENT

The Norwegian Petroleum Directorate generally uses the *Système International d'Unités,* or SI, system of units, and this system is recommended for use by the oil companies engaged in operations on the Norwegian continental shelf. However there are many other units which have won a place in the petroleum and offshore industry by virtue of long tradition.

There are several units and expressions used to describe production statistics for oil and gas which are based on measurement units. Some of these are described below.

Quantity of oil

An exact statement of a quantity of oil, expressed as volume, must be with reference to a given set of standard conditions, or state, defined in terms of temperature and pressure. This is necessary because the volume of a given quantity of oil varies with pressure and temperature. The standard conditions in each case are the reference conditions for the measurement in question. The two most common reference conditions are a) 60 degrees Fahrenheit, 0 pounds per square inch gauge and b) 15 degrees Centigrade, 1,01325 bar.

Other pressure and temperature references are also found. Note that expressions such as "barrels at standard conditions" are ambiguous so long as the standard conditions are not identified.

The International Standardisation Organisation recommends the use of the reference state given under b) above, and this reference state was incorporated in Norwegian Standard NS 5024 in 1974. The Directorate is making efforts to get this reference state more generally accepted in the offshore industry.

An exact conversion of an oil volume under given conditions to its equivalent under other given conditions requires the use of special tables; for rough estimates only it can be assumed that the volume under conditions a) is approximately the same as under conditions b).

Common abbreviations (oil)

The Standard Cubic Meter is written SCM, scm, Sm3 or, more properly, Sm^3. Also cm is sometimes seen. For larger quantities it is useful to write mcm (million cubic meters) and bcm (billion cubic meters). Note the caution above regarding standard conditions: if the conditions are not specified, the units are ambiguous.

The traditional American unit is Barrels at Standard Conditions, the conditions usually being as under a) above (60 degrees F and 0 psig).

The conversion formula is 1 scm equals approx 6.29 barrels at standard conditions.

Quantity of gas

Even more than for oil the volume of gas will depend on the temperature and pressure conditions assumed for the measurement. Four sets of reference conditions are common: a) 60 deg F, 14.73 psi absolute; b) 60 degrees F, 14.696 psia; c) 15 degrees C, 1.01325 bar; d) 0 degrees C, 1.01325 bar. The first three are usually termed "standard conditions", while alternative d) is usually called "normal conditions".

It is not possible to convert volumes from one set of conditions to another without knowing the physical properties of the particular gas. For rough estimates it is sufficient, however, to say that conditions a), b) and c) produce nearly identical results, while alternative d) gives a volume approx 5 per cent lower for a given quantity of gas.

Common abbreviations (gas)

The abbreviations for gas are the same as given for oil above with the addition of the following: Nm3 or more properly Nm^3 indicates normal cubic meters; Scf indicates standard cubic feet. Once again the reference conditions have to be specified if the quantity is to be expressed exactly.

For conversion 1 scm is about equal to 0.95 Nm^3, or to about 35.3 Scf.

Quality indication – oil and gas

A commonly used method of indicating the composition of oil or gas is to note its specific gravity or relative density. A low value in either case means the oil or gas is made up of low molecular weight components.

Oil

a) Specific gravity 60/60°F
   This is the relative density of oil to water. Oil and water are both at 60°F temperature and atmospheric pressure at the measurement point. The quantity has no units.

b) API gravity at 60°F
   This is the specific gravity 60/60°F expressed on an expanded scale. The units are called °API and conversion is by this formula: API gravity at 60°F equals (141.5/specific gravity 60/60°F) minus 131.5.

c) Density at 15°C
Absolute density at 15°C temperature and atmospheric pressure at the measurement point.

Gas

a) Specific gravity
This is the relative density of gas compared to air. The expression is not exactly defined unless the temperature and pressure are stated. Very often, however, no reference temperature or pressure is given. For rough estimates this is not critical as the differences between the most commonly used reference states are small.

Indication of oil and gas quantities in oil equivalents

Oil and gas quantities are often expressed in tons of oil equivalent (toe) where an exact statement of the quantity or volume is not necessary. The conversion is based on the quantity of energy (thermal value) released by combustion of oil and gas. For many oils and gases the energy in one ton of oil will be very close to the energy in 1000 scm gas. As this factor is so easy to apply, and the qualitative differences between oil and gas are so very pronounced during treatment, storage, distribution and application, it would not be useful to state the conversion factor to more decimals. It is therefore usual to assume the following: 1 toe equals 1 ton oil or 1000 scm gas. A useful unit for larger volumes is therefore mtoe, for million toe.

8.2 EXPLORATION DRILLING STATISTICS

By year end 1989 a total of 626 exploration wells had been started on the Norwegian continental shelf since the first was spudded in 1966. By the same date, 681 had been terminated. Of the wells started, 449 were wildcats and 177 appraisal wells; while 29 were suspended for various reasons, including deferred testing, possible completion as production wells, or continued drilling or subsequent plugging.

The northernmost well so far on the Norwegian continental shelf is 7321/7–1 which was drilled in 1988 with Mobil as operator. The easternmost is 7228/2–1 S, again drilled by Mobil, this time in 1989; and the westernmost 6201/11–1, drilled by Statoil in 1987.

Exploration wells have been drilled by 18 different operating companies. The numbers drilled per operator are shown in Figure 8.2.a and Table 8.2.b. Figure 8.2.b shows the Norwegian operating companies' share of the drilling activities. Seasonal variations in drilling activity are shown in Figure 8.2.c.

By year end 1989 the length of hole drilled had reached 1,989,670 meters (almost 2000 km), contributed by 626 well bores. Of the total, 85,105 meters were drilled in 1989. The average total depth of the 24 exploration wells concluded in 1989 is 3316 meters.

Exploration well 30/4–1, terminated in 1979, is the

Fig. 8.2.a
Operators on the Norwegian Continental Shelf. 626 exploration wells drilled per 31.12.89

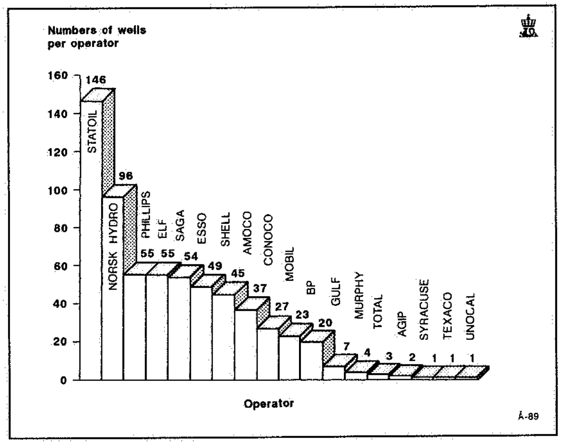


Fig. 8.2.b
Participation of Norwegian operator companies in drilling activity. Percent of operating days 1975–89

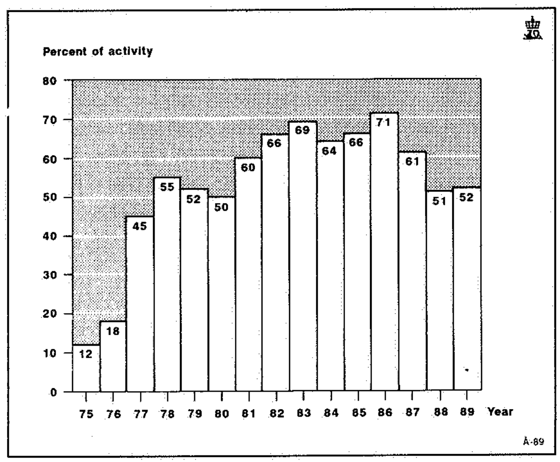


Fig. 8.2.c
Seasonal variations in exploration drilling activity 1966–89

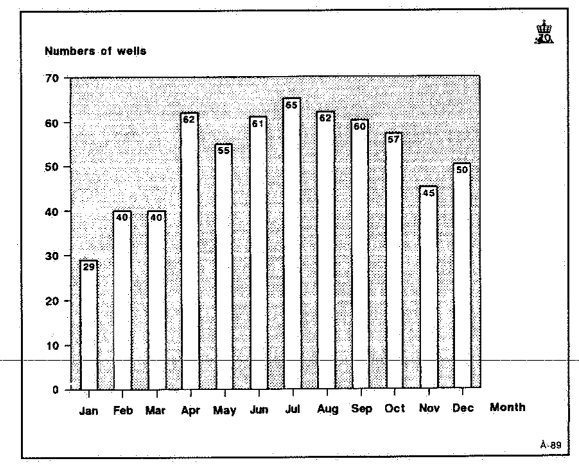


Fig. 8.2.d
Average total depth per year. Exploration drilling 1966–89

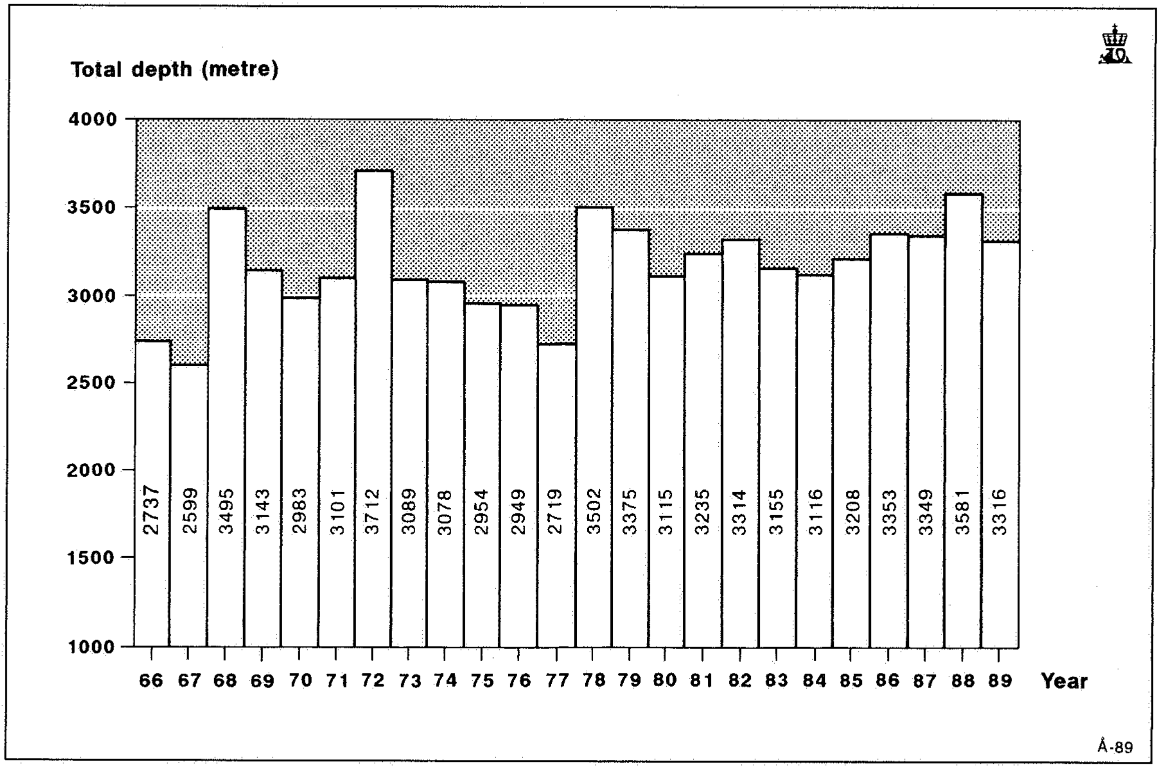
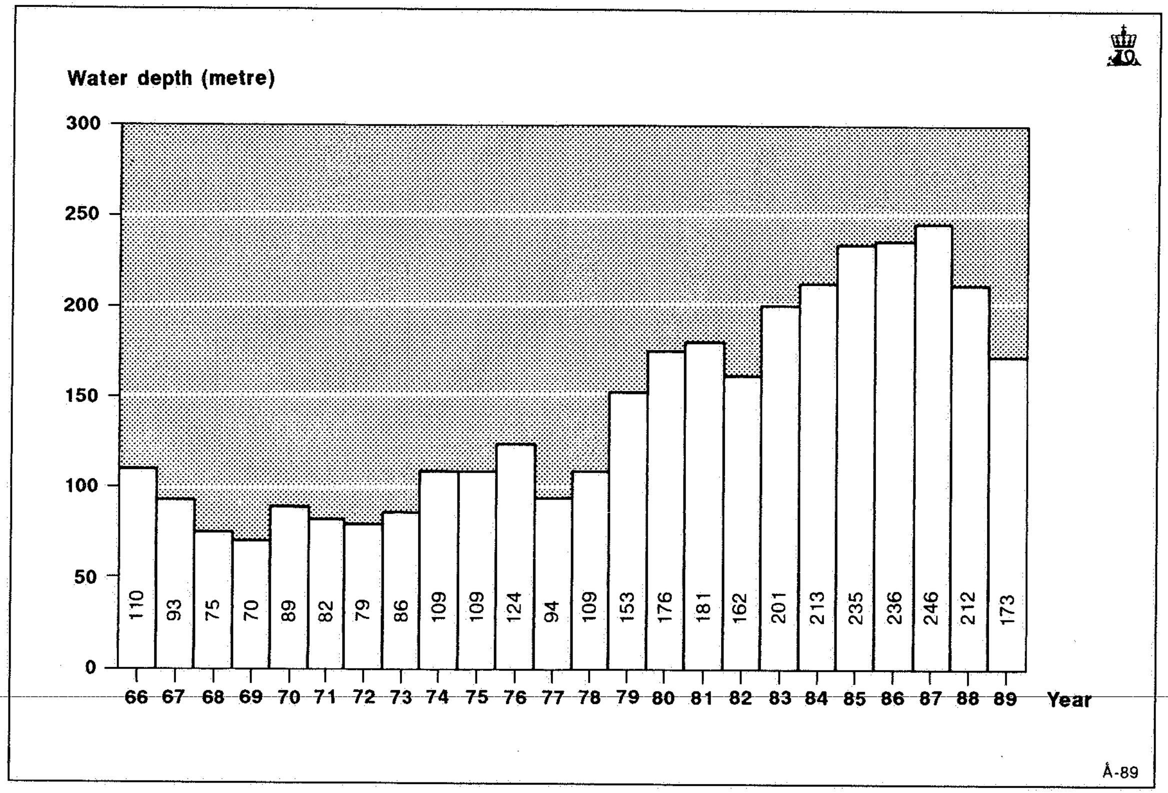


Fig. 8.2.e
Average water depth per year. Exploration wells 1966–89



Tabell 8.2.a
Wells spudded as of 31 December 1989

Year spudded	66	67	68	69	70	71	72	73	74	75	76	77	78	79	80	81	82	83	84	85	86	87	88	89	Total
Wildcat	2	6	10	12	11	11	11	17	13	17	20	12	14	18	26	26	36	33	35	30	26	25	18	20	449
Appraisal			2	1	6	5	3	5	5	9	3	8	5	10	10	13	13	7	12	20	10	11	11	8	177
Total	2	6	12	13	17	16	14	22	18	26	23	20	19	28	36	39	49	40	47	50	36	36	29	28	626
Production								1	18	24	7	34	50	36	27	16	22	23	33	47	47	48	55	66	554
Total	2	6	12	13	17	16	14	23	36	50	30	54	69	64	62	55	71	63	80	97	83	84	84	80	1180

Table 8.2.b
Exploration wells by operating company and region as of 31 December 1989

Operator	North Sea			Mid-Norway			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	50	46	96	27	4	31	18	1	19	95	51	146
Norsk Hydro	58	15	73	7	1	8	15		15	80	16	96
Phillips	39	15	54	1		1				40	15	55
Elf	37	15	52	2		2	1		1	40	15	55
Saga	34	6	40	12		12	2		2	48	6	54
Esso	28	18	46	1		1	2		2	31	18	49
Shell	24	11	35	3	5	8	2		2	29	16	45
Amoco	23	14	37							23	14	37
Conoco	16		16	3	8	11				19	8	27
Mobil	12	8	20	1		1	2		2	15	8	23
BP	10	9	19	1		1				11	9	20
Gulf	7		7							7		7
Murphy	3	1	4							3	1	4
Total	2		2				1		1	3		3
Agip	2		2							2		2
Syracuse	1		1							1		1
Texaco	1		1							1		1
Unocal	1		1							1		1
Wildcat	348			58			43			449		
Appraisal		158			18			1			177	
Exploration			506			76			44			626

W = Wildcat
A = Appraisal
E = Exploration

Table 8.2.c
Exploration wells spudded by operating company and region as of 31 December 1989

Operator	North Sea			Mid-Norway			Barents Sea			Total		
	W	A	E	W	A	E	W	A	E	W	A	E
Statoil	3	2	5	1		1	1		1	5	2	7
Norsk Hydro	3	1	4	1	1	2	1		1	5	2	7
Phillips	1	1	2							1	1	2
Elf	1	2	3							1	2	3
Saga	1	1	2							1	1	2
Esso	1		1							1		1
Shell	1		1				1		1	2		2
Amoco	2		2							2		2
Mobil	1		1				1		1	2		2
Wildcat	14			2			4			20		
Appraisal		7			1						8	
Exploration			21			3			4			28

W = Wildcat
A = Appraisal
E = Exploration

Table 8.2.d
Mean water depths and total depths

Year	Mean water depth (m)	Mean 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
1987	246	3 349
1988	212	3 581
1989	173	3 316

deepest well so far drilled on the Norwegian continental shelf. Here BP was the operator and the total depth was 5455 meters.

A summary of average total depths of exploration wells drilled between 1966 and 1989 is given in Figure 8.2.d. The average water depth in which exploration wells were drilled in 1989 was 173 meters. The greatest water depth in which a well has been drilled to date in the Norwegian sector is 475 meters: The well was 7321/7–1, drilled in 1988 with Norsk Hydro as operator. Figure 8.2.e shows the average water depths in which exploration wells were drilled from 1966 to 1989.

For the drilling operations on the Norwegian continental shelf 65 different drilling installations were employed, seven of them under two different names. Of the total, 47 were semi-submersibles, 11 jack-ups, five drilling ships and two fixed installations.

Tables 8.2.a to 8.2.e give the statistics for exploration drilling on the Norwegian continental shelf.

Table 8.2.e
Drilling rigs active on Norwegian continental shelf as of 31 December 1989

Rig name	Number of wells	Number of reentries	Type of rig
Aladdin	1		Semi-submersible
Borgny Dolphin (formerly Fernstar)	24	8	"
Borgsten Dolphin (formerly Haakon Magnus)	7		"
Bucentaur		1	Drill ship
Byford Dolphin (formerly Deepsea Driller)	15		Semi-submersible
Chris Chenery	2		"
Deepsea Bergen	20	2	"
Deepsea Driller (now Byford Dolphin)	8		"
Deepsea Saga	16	3	"
Drillmaster	5	1	"
Drillship	1		Drill ship
Dyvi Alpha	17	2	Semi-submersible
Dyvi Beta	6	1	Jack-up
Dyvi Gamma	1		"
Dyvi Delta (now West Delta)	21	1	Semi-submersible
Dyvi Stena	12		"
Endeavour	2		Jack-up
Fernstar (now Borgny Dolphin)	3		Semi-submersible
Gulftide	3		Jack-up
Glomar Biscay II (formerly Norskald)	13	1	Semi-submersible
Glomar Grand Isle	11	3	Drill ship
Glomar Moray Firth I	2		Jack-up
Haakon Magnus (now Borgsten Dolphin)	2		Semi-submersible
Henry Goodrich	2		"
Hunter (formerly Treasure Hunter)	1		"
Maersk Explorer	7		Jack-up
Maersk Jutlander	1		Semi-submersible
Neddrill Trigon	3	1	Jack-up
Neptune 7 (formerly Pentagone 81)	12		Semi-submersible
Nordraug	12		"
Norjarl	3		"
Norskald (now Glomar Biscay II)	26		"
Nortrym	32	3	"
Ocean Tide	5		Jack-up
Ocean Traveler	9		Semi-submersible
Ocean Victory	1		"

Rig name	Number of wells	Number of reentries	Type of rig
Ocean Viking	28	1	"
Ocean Voyager	2		"
Odin Drill	3		"
Orion	7		Jack-up
Le Pelerin	1		Drill ship
Pentagone 81 (now Neptune 7)	1		Semi-submersible
Pentagone 84	2	1	"
Polar Pioneer	20	2	"
Polyglomar Driller	11		"
Ross Isle	18	5	"
Ross Rig	32		"
Ross Rig (new)	8		
Saipem II	1		Drill ship
Sedco H	2		Semi-submersible
Sedco 135 F	2		"
Sedco 135 G	1		"
Sedco 703	3	1	"
Sedco 704	3		"
Sedco 707	8		Semi-submersible
Sedneth I	3		"
Transworld Rig 61	2		"
Treasure Hunter (now Hunter)	5	3	"
Treasure Saga	30	1	"
Treasure Scout	23		"
Treasure Seeker	24	5	"
Vildkat	10	1	"
Vinni	5		"
Waage Drill I	2		"
West Delta (formerly Dyvi Delta)	5		"
West Vanguard	20	4	"
West Venture	12	2	"
West Vision	1		"
Zapata Explorer	13		Jack-up
Zapata Nordic	5		"
Zapata Ugland	5	1	Semi-submersible
	624	54	
In addition two wells were drilled from fixed installations:			
Cod	1	1	
Ekofisk B	1		
	626	55	

8.3 PRODUCTION DRILLING STATISTICS

Since 1973 a total of 554 production wells have been started in the Norwegian sector of the North Sea; 318 are producers of oil, gas or condensate, 82 are water or gas injectors, four are observation and production wells and one is an observation and injection well. Of the total 142 are out of service; being either closed down, suspended for later completion for some or other reason, or, in 23 cases, having never produced. Twelve production wells were being drilled at year end 1989. A summary of production wells is given in Table 8.3.a. Figure 8.3.a shows production wells started each year during the period 1973 to 1989.

At year end production or injection was underway from 19 fields and 27 installations, three of which – on Northeast Frigg, East Frigg and Tommeliten – are subsea installations. The distribution of production wells by field is shown in Figure 8.3.b Figure 8.3.c shows production wells distributed by operating company.

By the end of the year 66 production wells had been started in 1989, seven of them drilled from mobile drilling rigs. Production wells distributed by installation are shown in Figure 8.3.d. Information on the production wells is set out in Tables 8.3.b and 8.3.c.

Fig. 8.3.a
Production drilling on the Norwegian Continental Shelf. Number of wells per year 1973–89

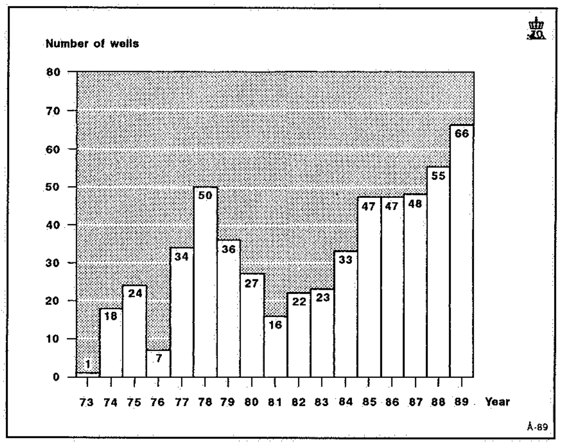


Fig. 8.3.b
Production wells per field. Total of 554 wells

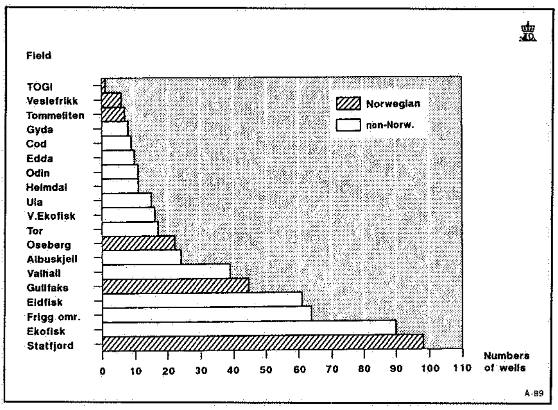


Fig. 8.3.c
Production wells by operator. Total of 554 wells

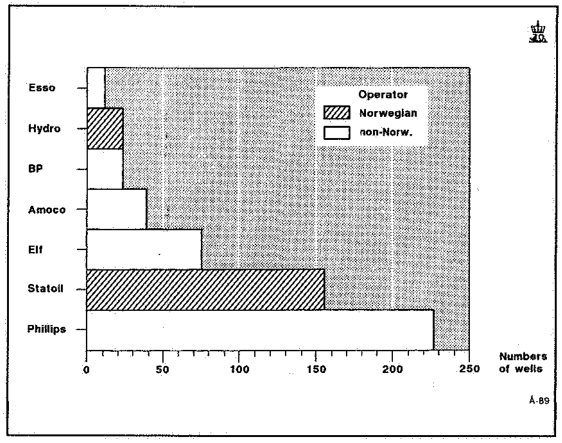


Fig. 8.3.d
Production wells drilled in 1989 by installations. Total of 66 wells

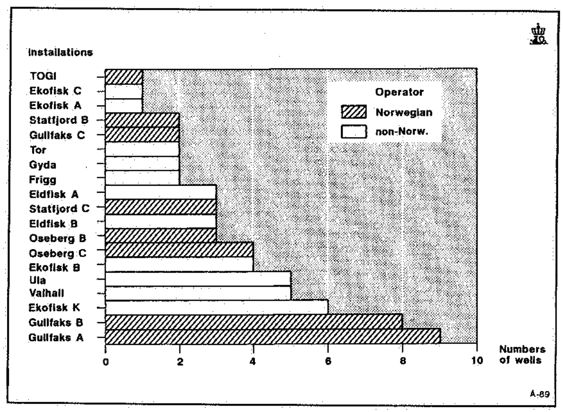


Table 8.3.a
Production drilling as of 31 December 1989

Field	Hydro-carbons	Total drilled	Spudded 1989	Producing	Injection, observation	Drilling	Suspended, plugged, completed
Albuskjell A +	cond	11		7			4
Albuskjell F +	cond	13		3			10
COD +	cond	9		5			4
Edda +	oil	10		7			3
Ekofisk A +	oil	19	1	15			4
Ekofisk B +	oil	30	4	19	1(1)*		8
Ekofisk C +	oil	18	1	9	5**	1	3
Ekofisk K +	w.inj.	23	6		18	1	4
Eldfisk A +	oil	34	3	19		1	14
Eldfisk B +	oil	27	3	20		1	7
Frigg (UK) +	gas	24		21			3
Frigg +	gas	28	2	19	(2)*		7
Gullfaks A +	oil	30	9	15	8	1	6
Gullfaks B +	oil	13	8	7	3	1	2
Gullfaks C	oil	2	2			2	
Gyda	oil	8	2				8
Heimdal +	cond	11		8	(1)***		2
N.E.Frigg +	gas	7		4			3
Odin +	gas	11		11			
Oseberg B +	oil	16	3	8	2	1	5
Oseberg C	oil	6	4			1	5
Statfjord A +	oil	38		22	14		2
Statfjord B +	oil	32	2	20	10	1	1
Statfjord C +	oil	28	3	17	10	1	
TOGI		1	1				1
Tommeliten +	cond	7		6			1
Tor +	oil	17	2	11			6
Ula +	oil	15	5	6	6(1)*		2
Valhall +	oil	39	5	24			15
W. Ekofisk +	cond.	16		9			7
Veslefrikk +	oil	6		1			5
East Frigg +	gas	5		5			
		554	66	318	82	12	142

+ Field producing/injecting
* Observation/production well/wells
** Production/injection wells depending on gas sales
*** Observation/injection well/wells

318 wells are producing (220 oil, 38 condensate and 60 gas)
86 wells are shut down or plugged
82 wells are injection wells (of which 5 injection/production)
4 wells are observation/production wells
1 well is an observation/injection well
12 wells are drilling
26 wells are suspended at total depth
1 well is suspended after 9 5/8 inch casing
3 wells are suspended after 13 3/8 inch casing
1 well is suspended after 18 5/8 inch casing
1 well is suspended after 20 inch casing
1 well is suspended with a fish in the 36 inch open hole
23 wells never produced

Table 8.3.b
Production wells spudded or terminated in 1989 as of 31 December 1989

A,B = Directionally drilled from another well. H = Subsea completion

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Field
454	7/12-A-05	88.05.15	89.02.03	BP	ULA
459	34/10-A-16	88.06.08	89.11.03	STATOIL	GULLFAKS A
461	2/07-A-13	88.06.27	89.01.31	PHILLIPS	ELDFISK A
472	2/04-K-01	89.06.18	89.08.08	PHILLIPS	EKOFISK K
478	2/08-A-07 A	88.11.07	89.01.08	AMOCO	VALHALL
484	34/10-B-05	88.10.25	89.02.15	STATOIL	GULLFAKS B
487	30/03-A-06 H	88.11.27	89.01.30	STATOIL	VESLEFRIKK
489	2/04-C-06 A	88.12.28	89.02.11	PHILLIPS	EKOFISK C
490	2/07-A-02 A	89.04.04	89.06.01	PHILLIPS	ELDFISK A
491	7/12-A-08	89.02.09	89.04.02	BP	ULA
492	2/04-K-10	88.12.11	89.01.18	PHILLIPS	EKOFISK K
493	30/06-C-10	88.12.27	89.02.22	HYDRO	OSEBERG C
494	34/10-A-20	88.12.09	89.03.09	STATOIL	GULLFAKS A
495	34/10-B-06	89.02.05	89.03.17	STATOIL	GULLFAKS B
496	34/10-A-21	89.01.15	89.03.13	STATOIL	GULLFAKS A
497	2/08-A-14 A	89.01.15	89.02.15	AMOCO	VALHALL
498	2/04-K-29	89.01.19	89.08.31	PHILLIPS	EKOFISK K
499	2/04-B-06 A	89.01.29	89.03.12	PHILLIPS	EKOFISK B
500	2/01-A-02 H	89.02.21	89.05.07	BP	GYDA
501	2/08-A-18 B	89.02.15	89.03.24	AMOCO	VALHALL
502	2/04-A-04 A	89.02.11	89.04.04	PHILLIPS	EKOFISK A
503	2/04-K-19	89.02.15	89.07.11	PHILLIPS	EKOFISK K
504	30/06-C-12	89.02.22	89.08.14	HYDRO	OSEBERG C
505	2/07-B-01 A	89.02.28	89.03.29	PHILLIPS	ELDFISK B
506	34/10-A-22	89.02.27	89.04.06	STATOIL	GULLFAKS A
507	34/10-B-07	89.03.19	89.04.26	STATOIL	GULLFAKS B
508	30/09-B-03	89.05.23	89.07.09	HYDRO	OSEBERG B
509	2/04-K-17	89.03.22	89.08.09	PHILLIPS	EKOFISK K
510	34/10-A-23	89.03.31	89.06.16	STATOIL	GULLFAKS A
511	7/12-A-13	89.04.08	89.07.02	BP	ULA
512	2/01-A-01 H	89.05.08	89.07.22	BP	GYDA
513	2/08-A-22	89.04.09	89.05.17	AMOCO	VALHALL
514	33/09-C-36	89.04.20	89.07.07	STATOIL	STATFJORD C
515	2/04-E-14 A	89.04.29	89.06.06	PHILLIPS	TOR
516	34/10-B-08	89.04.17	89.05.17	STATOIL	GULLFAKS B
517	34/10-A-24	89.06.06	89.07.24	STATOIL	GULLFAKS A
518	2/04-B-04	89.06.17	89.08.06	PHILLIPS	EKOFISK B
519	2/08-A-20 A	89.05.26	89.07.04	AMOCO	VALHALL
520	34/10-B-09	89.05.19	89.07.03	STATOIL	GULLFAKS B
521	2/07-A-07 A	89.07.10	89.09.18	PHILLIPS	ELDFISK A
522	2/04-E-11	89.06.27	89.08.27	PHILLIPS	TOR
523	2/07-B-15	89.07.04	89.10.17	PHILLIPS	ELDFISK B
524	34/10-B-10	89.06.29	89.08.21	STATOIL	GULLFAKS B
525	33/09-C-40	89.06.29	89.10.23	STATOIL	STATFJORD C
526	25/01-A-17 A	89.08.05	89.10.01	ELF	FRIGG
527	7/12-A-15	89.07.02	89.08.29	BP	ULA
528	34/10-A-25	89.07.22	89.08.26	STATOIL	GULLFAKS A
529	2/04-B-15 A	89.09.06	89.10.22	PHILLIPS	EKOFISK B
530	34/10-B-11	89.09.24	89.11.06	STATOIL	GULLFAKS B
531	30/06-C-08	89.08.15	89.10.12	HYDRO	OSEBERG C
532	2/08-A-04 A	89.09.12	89.11.07	AMOCO	VALHALL
533	34/10-B-10 A	89.08.21	89.09.24	STATOIL	GULLFAKS B
534	7/12-A-09	89.08.30	89.10.15	BP	ULA
535	30/09-B-31	89.08.15	00.00.00	HYDRO	OSEBERG B
537	34/10-A-25 A	89.08.26	89.09.24	STATOIL	GULLFAKS A
538	30/09-B-13	89.08.28	89.10.31	HYDRO	OSEBERG B
539	33/12-B-28	89.09.18	89.11.08	STATOIL	STATFJORD B
540	2/07-B-08	89.10.23	89.12.20	PHILLIPS	ELDFISK B
541	25/01-A-04 A	89.10.23	89.12.17	ELF	FRIGG
542	34/10-A-26	89.10.05	89.10.15	STATOIL	GULLFAKS A
543	33/09-C-10	89.10.18	00.00.00	STATOIL	STATFJORD C
544	34/10-C-01	89.10.01	00.00.00	STATOIL	GULLFAKS C
545	30/06-C-05	89.10.14	89.12.09	HYDRO	OSEBERG C
546	2/04-K-08	89.10.22	89.12.25	PHILLIPS	EKOFISK K
547	7/12-A-13 A	89.11.04	89.12.19	BP	ULA
548	34/10-A-16 A	89.10.19	89.11.13	STATOIL	GULLFAKS A
549	2/04-B-23 A	89.11.28	00.00.00	PHILLIPS	EKOFISK B
550	33/12-B-19	89.12.28	00.00.00	STATOIL	STATFJORD B

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Field
551	34/10-B-12	89.11.07	00.00.00	STATOIL	GULLFAKS B
552	31/05-B-06 H	89.11.19	89.12.22	HYDRO	TOGI
553	2/07-A-08 A	89.11.22	00.00.00	PHILLIPS	ELDFISK A
554	2/04-C-19	89.11.18	00.00.00	PHILLIPS	EKOFISK C
555	34/10-A-27	89.12.04	00.00.00	STATOIL	GULLFAKS A
556	30/06-C-09	89.12.11	00.00.00	HYDRO	OSEBERG C
557	34/10-C-02	89.12.31	00.00.00	STATOIL	GULLFAKS C
559	2/04-K-26	89.12.28	00.00.00	PHILLIPS	EKOFISK K

Table 8.3.c
Production wells drilled from mobile drilling rigs
H = Subsea completion

Lic. no.	Prod. well no.	Spudded	Terminated	Operator	Drilling rig
500	2/01-A-02 H	89.02.21	89.05.07	BP	VILDKAT
504	30/06-C-12	89.02.22	89.08.14	HYDRO	TRANSOCEAN 8
512	2/01-A-01 H	89.05.08	89.07.22	BP	VILDKAT
531	30/06-C-08	89.08.15	89.10.12	HYDRO	TRANSOCEAN 8
545	30/06-C-05	89.10.14	89.12.09	HYDRO	TRANSOCEAN 8
552	31/05-B-06 H	89.11.19	89.12.22	HYDRO	POLAR PIONEER
556	30/06-C-09	89.12.11	00.00.00	HYDRO	TRANSOCEAN 8

8.4 PRODUCTION OF OIL AND GAS

The total production of oil and gas on the Norwegian continental shelf was 103.6 mtoe in 1989. Production in 1988 was 85 mtoe. In Tables 8.4.a-k and Figures 8.4.a-b, production is set out in more detail.

The figures in Table 8.4.a show the Norwegian share of Statfjord, Frigg and Murchison. In the tables for oil, NGL is included for the Ekofisk area, Statfjord, Valhall, Murchison, Ula, Gullfaks and Tommeliten.

The figures for gas in Table 8.4.a indicate the quantities sold for all fields. In the figures for Statfjord, Frigg area, Heimdal and Gullfaks, the condensate is included.

Fig. 8.4.a
Oil and gas production on the Norwegian shelf 1971–1989

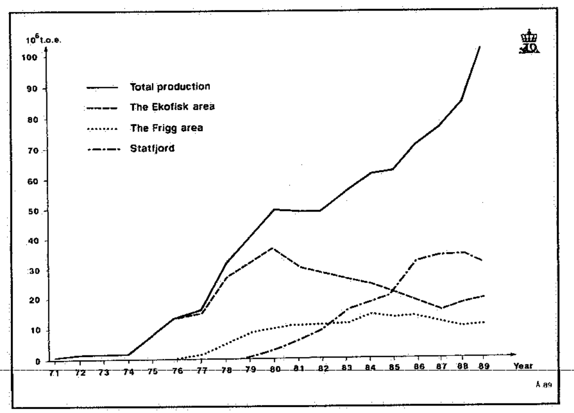


Fig. 8.4.b
Oil/NGL and gas production on the Norwegian shelf 1977–1989

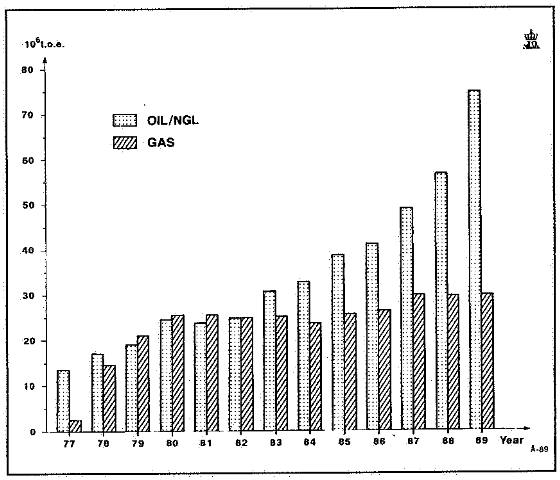


Table 8.4.a
Production in million tonnes oil equivalent (mtoe)

1989	Oil	Gas	Total
Ekofisk area	10.860	8.425	19.285
Statfjord	29.070	3.186	32.246
Frigg area	0.000	10.658	10.658
Valhall	3.686	0.842	4.528
Murchison	0.410	0.017	0.427
Heimdal	0.000	3.724	3.724
Ula	4.415	0.348	4.763
Oseberg	11.505	0.000	11.505
Gullfaks	13.672	1.088	14.760
Tommeliten	0.729	1.086	1.815
Total 1989	74.280	29.364	103.644
Total 1988	55.953	29.088	85.041

Table 8.4.b
Monthly oil and gas production on Valhall 1989

1989	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas Emden
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³
JAN	370.	76.	1.5	8.	348.	26.	69.
FEB	335.	64.	1.2	8.	313.	25.	63.
MAR	370.	66.	.7	8.	343.	30.	67.
APR	370.	75.	1.1	9.	339.	31.	66.
MAY	382.	77.	.4	9.	352.	33.	70.
JUN	301.	60.	1.1	7.	278.	25.	54.
JUL	405.	78.	.7	9.	378.	32.	70.
AUG	419.	87.	.6	8.	388.	33.	80.
SEP	400.	82.	.6	10.	369.	36.	74.
OCT	415.	85.	.6	9.	380.	37.	77.
NOV	385.	79.	.6	9.	355.	34.	71.
DEC	422.	88.	.6	8.	396.	34.	81.
YEAR TOTAL	4574.	917.	9.7	102.	4239.	376.	842.

Table 8.4.c
Monthly gas and condensate production in Frigg area 1989

1989	Gas prod	Condensate prod	Gas flared	Gas fuel	Gas St Fergus	Condensate St Fergus
	Mill Sm³	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	1142.	3.	.2	1.	1118.	5.
FEB	1053.	2.	.1	1.	1061.	5.
MAR	1100.	3.	.1	1.	1090.	4.
APR	1074.	3.	.1	1.	1065.	4.
MAY	862.	2.	.2	1.	861.	6.
JUN	653.	2.	.2	1.	655.	5.
JUL	528.	1.	.1	2.	529.	.2
AUG	664.	2.	4.6	1.	644.	3.
SEP	685.	2.	.1	1.	667.	4.
OCT	965.	3.	.1	1.	959.	3.
NOV	970.	3.	.1	1.	964.	5.
DEC	1007.	3.	.1	1.	1002.	8.
YEAR TOTAL	10703.	29.	6.0	13.	10615.	52.2

Figures are for the Norwegian share of Frigg, which is 60.82 per cent, plus 100 per cent of North East Frigg, Odin and East Frigg

Table 8.4.d
Monthly oil and gas production on Gullfaks 1989

1989	Stabilized oil prod	Gas prod	Gas flared	Gas fuel	Gas Emden	NGL/cond Kårstø
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	1214.	125.	3.	14.	92.	10.
FEB	1070.	111.	5.	13.	73.	12.
MAR	1397.	139.	3.	14.	104.	17.
APR	1399.	139.	5.	14.	98.	14.
MAY	1372.	134.	3.	14.	89.	14.
JUN	1055.	102.	9.	10.	72.	6.
JUL	1354.	131.	6.	13.	93.	20.
AUG	1371.	132.	3.	13.	98.	14.
SEP	1338.	129.	5.	13.	83.	10.
OCT	1359.	131.	4.	13.	90.	12.
NOV	1374.	134.	9.	13.	97.	10.
DEC	1186.	114.	11.	15.	70.	10.
YEAR TOTAL	15490.	1521.	66.	159.	1059.	149.

Table 8.4.e
Monthly gas and condensate production on Heimdal 1989

1989	Gas prod	Condensate prod	Gas flared	Gas fuel	Gass sold Emden	Condensate Kinneil
	Mill Sm³	1000 Sm³	1000 Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	341.	55.	57.	5.	327.	50.
FEB	317.	51.	26.	5.	302.	48.
MAR	307.	49.	0.	5.	292.	47.
APR	263.	42.	15.	5.	252.	41.
MAY	270.	43.	33.	5.	258.	41.
JUN	253.	39.	360.	4.	241.	13.
JUL	249.	39.	193.	4.	236.	29.
AUG	257.	41.	0.	5.	243.	39.
SEP	309.	50.	73.	5.	294.	43.
OCT	297.	48.	43.	5.	284.	42.
NOV	301.	49.	75.	5.	289.	40.
DEC	330.	53.	83.	5.	314.	39
YEAR TOTAL	3494.	559.	958.	58.	3332.	472.

Table 8.4.f
Monthly oil and gas production on Murchison 1989

1989	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sullom Voe	Gas St Ferg	NGL S Voe/ St Ferg
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³	Mill Sm³	1000 Sm³
JAN	62.	7.2	.5	1.3	56.	2.4	2.
FEB	53.	6.3	.4	1.2	48.	2.0	2.
MAR	52.	6.4	.4	1.2	48.	2.2	2.
APR	28.	4.0	.8	.7	26.	.8	1.
MAY	2.	.3	.2	0.	2.	0.	0.
JUN	53.	7.0	1.5	.9	47.	1.2	1.
JUL	50.	6.0	.6	1.1	45.	1.8	2.
AUG	46.	6.2	1.1	1.1	42.	1.0	1.
SEP	48.	6.0	.5	1.2	44.	1.0	1.
OCT	52.	6.3	.5	1.3	47.	1.9	1.
NOV	45.	5.6	.5	1.2	41.	1.5	1.
DEC	42.	5.9	1.2	.9	38.	.9	1.
YEAR TOTAL	533.	67.2	8.2	12.1	484.	16.7	15.

These figures are for the Norwegian share of Murchison.

Table 8.4.g
Monthly oil and gas production on Statfjord 1989

1989	Stabilized oil prod	Gas prod	Gas flared	Gas fuel	Gas Emden	NGL/cond Kårstø
	1000 Sm³	Mill Sm³	Mill Sm³	Mill Sm³	Mill Sm³	1000 Sm³
JAN	2930.	656.	11.	35.	305.	109.
FEB	2029.	459.	6.	27.	219.	125.
MAR	3130.	711.	7.	38.	290.	162.
APR	3040.	661.	6.	38.	201.	112.
MAY	2976.	649.	9.	37.	247.	140.
JUN	2578.	601.	5.	33.	282.	99.
JUL	2918.	664.	8.	35.	246.	198.
AUG	2965.	685.	7.	37.	233.	134.
SEP	2427.	527.	6.	30.	129.	72.
OCT	3100.	715.	8.	38.	253.	138.
NOV	2964.	695.	7.	38.	298.	150.
DEC	2935.	695.	7.	40.	310.	178.
YEAR TOTAL	33993.	7717.	87.	426.	3014.	1617.

Table 8.4.h
Monthly oil and gas production on Ula 1989

1989	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas sold Emden
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3	1000 Sm^3	Mill Sm^3
JAN	492.	41.	.1	4.	469.	26.	32.
FEB	394.	33.	.2	4.	369.	25.	25.
MAR	481.	40.	1.5	4.	453.	30.	30.
APR	440.	36.	.3	4.	409.	31.	29.
MAY	489.	40.	.4	4.	455.	33.	32.
JUN	373.	31.	2.2	3.	350.	25.	23.
JUL	475.	39.	1.0	4.	447.	32.	30.
AUG	469.	39.	.3	4.	439.	33.	31.
SEP	477.	39.	.2	4.	443.	36.	32.
OCT	473.	39.	.5	4.	439.	37.	30.
NOV	434.	36.	.3	4.	405.	34.	27.
DEC	399.	33.	.2	3.	377.	34.	26.
YEAR TOTAL	5398.	446.	7.2	46.	5056.	376.	348.

Table 8.4.i
Monthly oil and gas production allocated to Ekofisk fields 1989

1989	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Teesside	NGL Teesside	Gas sold Emden
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3	1000 Sm^3	Mill Sm^3
JAN	1183.	999.	.4	79.	1101.	70.	750.
FEB	1065.	896.	.5	78.	903.	70.	719.
MAR	1128.	927.	.5	76.	960.	69.	626.
APR	1136.	924.	.6	69.	962.	72.	747.
MAY	1183.	975.	1.1	78.	1013.	76.	640.
JUN	1189.	988.	1.7	74.	994.	75.	693.
JUL	1241.	1026.	.9	80.	1123.	81.	661.
AUG	1213.	1015.	.7	81.	1038.	79.	667.
SEP	982.	813.	1.0	63.	837.	53.	742.
OCT	1059.	872.	1.1	70.	902.	63.	701.
NOV	1190.	986.	1.6	78.	1012.	75.	714.
DEC	1241.	1031.	.6	78.	1105.	75.	765.
YEAR TOTAL	13811.	11453.	10.7	904.	11950.	2058.	8425.

Table 8.4.j
Monthly oil and gas production on Tommeliten 1989

1989	Unstabilized oil prod	Gas prod	Stabilized oil Teesside	NGL Teesside	Gas sold Emden
	1000 Sm^3	Mill Sm^3	1000 Sm^3	1000 Sm^3	Mill Sm^3
JAN	90.	99.	76.	14.	92.
FEB	93.	101.	78.	16.	95.
MAR	92.	108.	76.	16.	100.
APR	53.	63.	43.	9.	59.
MAY	33.	38.	28.	5.	36.
JUN	52.	66.	43.	9.	62.
JUL	96.	116.	80.	16.	109.
AUG	96.	120.	79.	17.	112.
SEP	91.	115.	74.	18.	108.
OCT	94.	121.	76.	19.	113.
NOV	80.	103.	66.	15.	96.
DEC	83.	114.	67.	16.	105.
YEAR TOTAL	953.	1166.	785.	170.	1086.

Table 8.4.k
Monthly oil and gas production on Oseberg 1989

1989	Unstabilized oil prod	Gas prod	Gas flared	Gas fuel	Stabilized oil Sture
	1000 Sm^3	Mill Sm^3	Mill Sm^3	Mill Sm^3	1000 Sm^3
JAN	727.	99.	99.	.1	727.
FEB	942.	124.	69.	2.2	942.
MAR	936.	129.	34.	4.0	936.
APR	1202.	165.	22.	6.5	1202.
MAY	1172.	160.	11.	7.8	1172.
JUN	1231.	169.	9.	8.2	1231.
JUL	1282.	176.	9.	8.0	1282.
AUG	1289.	177.	7.	8.1	1289.
SEP	1196.	163.	6.	7.8	1196.
OCT	1294.	171.	4.	9.2	1294.
NOV	1361.	186.	3.	8.2	1361.
DEC	883.	118.	3.	6.6	883.
YEAR TOTAL	13515.	1837.	277.	76.7	13515.

8.5 PUBLICATIONS BY THE NPD IN 1989

Regulations and guidelines

- *Acts, Regulations and Provisions for the Petroleum Activity 1989.* A compendium of the laws etc applying to the offshore industry issued each year and up to date on 1 January
- *Guidelines for Corrosion Protection of Installations*
- *Guidelines for Material Selection for Fabrication of Steel Structures in the Offshore Industry*

Study reports

- Three reports on *Environmental Data Collection in the Barents Sea*
- *Aids Infection in Hyperbaric Working Environment*
- *Quality Assurance and Acceptance Criteria for Documentation of Chemical Health Hazards*
- *Marine Geophysical Studies in the Northern Atlantic with Emphasis on Sedimentation, Crustal Structure and Subsidence*

Other publications

- *Well Data Summary Sheets, vol 14. Wells Finished 1983*
- *NPD Bulletin No 5. A Revised Cretaceous and Tertiary Lithostratigraphic Nomenclature for the Norwegian North Sea*
- *NPD Contribution No 27. New Datings of the Three Westernmost Wellholes in the Barents Sea. Results and Consequences for the Tertiary Rise.*
- *Norwegian Petroleum Directorate Annual Report 1988*
- *Continental Shelf Map as of 1 September 1989*
- *Licences, Areas, Area Coordinates, Exploration Wells*
- *Borehole Lists*
- *Experiences with American Information Systems for Risk Management*
- *Artworks in the NPD Building*

8.6 ORGANIZATION CHART