OIL AND GAS PRODUCTION IN DENMARK

98

Energistyrelsen
MILJØ- OG ENERGIMINISTERIET

PREFACE

The international oil industry was affected by the drop in oil prices in 1998. Nevertheless, the Danish area generally experienced favourable development in exploration, development and production.

The outcome of the Fifth Licensing Round - 17 new licences and the most comprehensive work programme since the first licensing round - bode well for the future. As a result of the new licences, at least DKK 1.7 billion will be spent on exploration in Danish territory in the next six years.

At end-1998, two major development projects were in progress in the Siri and South Arne Fields. Production from the Statoil group's Siri Field commenced in March 1999, and the Amerada Hess group is expected to start up production from the South Arne Field in mid-1999.

Moreover, the development of existing fields has yielded positive results. For instance, new wells drilled in the "old" Gorm and Dan Fields contributed to record-high oil production in 1998.

In light of the plunge in oil prices, this year's report contains a special section entitled *Fluctuations in the Oil Price*, which describes the historical development in the price of oil and the factors determining the price.

Copenhagen, May 1999

Ib Larsen
Director

CONVERSION FACTORS

In the oil industry, two different systems of units are frequently used: SI units and the so-called oil field units. The SI units are based on international definitions, whereas the use of oil field units may vary from one country to another, being defined by tradition.

The abbreviations used for oil field units are those recommended by the SPE (Society of Petroleum Engineers). The density of oil is often expressed in API gravity or degrees API: °API. The conversion factors are shown in the formulae below.

Quantities of oil and natural gas may be indicated by volume or energy content. As gas, and, to some extent, oil are compressible, the volume of a specific amount varies according to pressure and temperature. Therefore, measurements of volume are only unambiguous if the pressure and temperature are indicated. In addition, the composition, and thus the calorific value per volumetric unit, of crude oil and natural gas vary from field to field and with time. Therefore the conversion factors for t and GJ are dependent on time. For crude oil, the lower calorific value is indicated, whereas the upper calorific value is indicated for natural gas.

The SI prefixes k (kilo), M (mega), G (giga), T (tera) and P (peta) stand for 10^3, 10^6, 10^9, 10^{12} and 10^{15}, respectively. A somewhat special prefix is used for oil field units: M (roman numeral 1,000). Thus, the abbreviated form of one million stock tank barrels is 1 MMstb, and the abbreviation used for one billion standard cubic feet is 1 MMMscf or 1 Bscf. In certain contexts, the unit t.o.e. (tonnes oil equivalent) is used. The international definition of 1 t.o.e. is 10 Gcal.

Reference pressure and temperature for the above mentioned units:

		TEMP.	PRESSURE
Crude Oil	m^3 (st)	15°C	101.325 kPa
	stb	60°F	14.73 psia[ii]
Natural Gas	m^3 (st)	15°C	101.325 kPa
	Nm^3	0°C	101.325 kPa
	scf	60°F	14.73 psia

	FROM	TO	MULTIPLY BY
Crude Oil	m^3 (st)	stb	6.292955*
	m^3 (st)	GJ	36.3
	m^3 (st)	tonne	0.855[i]
	tonne	GJ	42.62[i]
Natural Gas	Nm^3	scf	37.2396
	Nm^3	GJ	0.0393
	Nm^3	kmol	0.0446158
	m^3 (st)	scf	35.3014
	m^3 (st)	GJ	0.0373
	m^3 (st)	kmol	0.0422932
Units of Volume			
	m^3	bbl	6.28981
	m^3	ft^3	35.1467
	gallon	in^3	231*
	bbl	gallon	42*
Energy	t.o.e.	GJ	41.868*
	GJ	Btu	947817

	FROM	TO	CONVERSION
Density	°API	kg/m^3	141364.33/(°API+131.5)
	°API	γ[iii]	141.5/ (°API+131.5)

*) Exact value.

i) 1997 value.

ii) The reference pressure used in Denmark and in US Federal Leases and in a few states in the USA is 14.73 psia.

iii) γ: Density, relative to water.

1. EXPLORATION

The awarding of 17 new licences in the Fifth Licensing Round in 1998 created a basis for high exploration activity in the years to come. Thus, exploration activity can be maintained at its current level when the exploratory commitments under the licences granted in the Fourth Licensing Round have been fulfilled.

The filing of three new applications for licences under the *Open Door* procedure shows that the more favourable licensing conditions make it attractive for the oil companies to explore areas further removed from the known oil and gas fields.

The keen interest oil companies have shown in exploration of the Danish area means that the current number of licences for exploration and production of oil and gas has exceeded 40, the highest number ever.

FIFTH LICENSING ROUND

On 15 June 1998, the Minister for Environment and Energy, Svend Auken, awarded 17 new licences for exploration and production of hydrocarbons as a successful conclusion of the Fifth Licensing Round.

The round was opened in September 1997, and the time limit for submitting applications expired on 27 January 1998. All unlicensed areas west of 6°15' East longi-

Fig.1.1 Seismic Surveys in 1998

tude, totalling about 15,000 km², were offered for licensing in the round. Geologically speaking, the areas offered are situated both in the Central Graben, from which the total current Danish production of hydrocarbons derives, and further towards the east in the Norwegian-Danish Basin and on the Ringkøbing-Fyn High.

The conditions for submitting applications and the terms applicable to the licences granted in the Fifth Licensing Round were virtually unchanged compared to the fourth licensing round in 1994-95. However, in order to facilitate the selection of applicants with equal qualifications, the Danish Energy Agency invited the oil companies to submit a supplementary offer for state participation on the basis of a sliding scale. The sliding scale determines the percentage increase of state participation in relation to the amount of production, if commercial oil and gas discoveries are made at a later date.

Upon the expiry of the application period, the Danish Energy Agency had received 19 applications, the highest figure since 1984, when a much larger area was offered for licensing in Denmark's first licensing round. In the Fifth Licensing Round, an equal number of applications was submitted for areas in the Central Graben and for the areas east of the Central Graben. The oil discovery made in the Siri structure by the Statoil group in 1995 has contributed to the great interest shown in the areas east of the Central Graben.

Although applicants were competing for several attractive areas, it proved possible to accommodate the desires of 17 of the applicant groups. In one case, supplementary offers for sliding scale participation had to be invited in order to determine which group was to be awarded a licence for the area.

As a result of the new licences, agreements have been made representing total investments of about DKK 1.7 billion in exploration over the next six years. Thus, the oil companies are to drill 13 unconditional and eight conditional exploration wells, as well as to carry out 3D seismic surveys covering a total area of about 3,500 km².

The groups of companies holding the licences granted in the Fifth Licensing Round include a number of oil companies which are new to the Danish area, in addition to companies already active in exploration and production. Appendix A gives an outline of all the companies holding the new licences, while the location of the areas comprised by the individual licences appears from the maps at the back of the report.

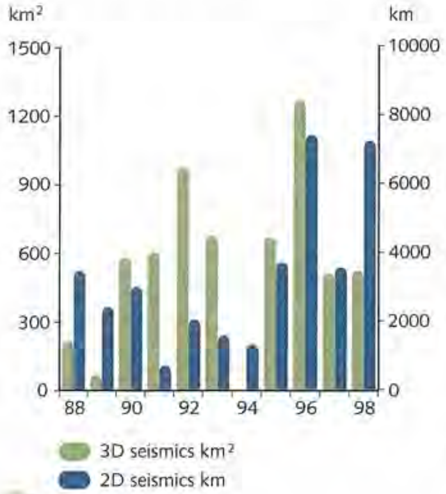
OPEN DOOR

In 1998, the Danish Energy Agency received another three applications for licences under the Open Door procedure. These applications were submitted by Agip Denmark BV, Anschutz Overseas Corporation and the Amerada Hess group.

Under the Open Door procedure, applications are invited for all open areas east of 6°15' East longitude every year in the period from 2 January through 30 September. According to the licence terms, Dansk Olie- og Gasproduktion A/S is to have a 20% share of all licences in the Open Door area.

Agip and Anschutz have submitted applications for areas in the North Sea due east of the areas for which applications were invited in the Fifth Licensing Round. The Amerada Hess group, composed of the companies Courage Energy Inc.,

Fig. 1.2 Annual Seismic Surveying Activities



Emerald Energy Plc., Amerada Hess A/S and Odin Energi ApS, has applied for areas on the Djursland peninsula (Jutland), in the Kattegat and North Zealand.

At the beginning of 1999, the Minister for Environment and Energy granted the applications from Agip and Anschutz. Agip, which already holds a share of three licences in Danish territory, was awarded licence no. 1/99 on 15 February 1999. The licence granted to Anschutz, a new company in Danish territory, was issued on 20 March 1999 as licence no. 3/99.

On 20 March 1999, Gustavson Associates, who submitted an application back in 1997, was granted a licence for an area in the eastern part of the North Sea, due south of the Norwegian border. Their licence is designated no. 2/99.

The application submitted by the Amerada Hess group was still being discussed by the group and the Danish Energy Agency at the beginning of 1999.

The location of the new licence areas appears from the map at the back of the report.

At the end of 1998, the Danish Energy Agency evaluated the Open Door procedure, which has now been operative for two years since its introduction in May 1997. The conclusion was that the procedure works as intended, and has motivated the oil companies to resume exploration, also in the areas where no oil or gas discoveries have been made as yet. The Minister for Environment and Energy has therefore decided to uphold the procedure in its present form.

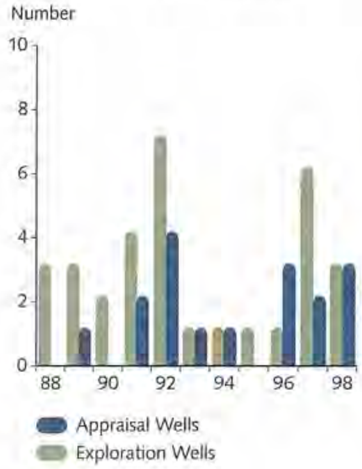
EXPLORATION ACTIVITY

Exploratory Surveys

In the Open Door area, seismic surveys were continued under the new licences from 1997. Mærsk Olie og Gas AS, which initiated a 2D seismic survey in the Horn Graben in 1997, brought its survey to a conclusion at the beginning of 1998. Norsk Agip A/S was responsible for the performance of the first 3D seismic survey in the Open Door area in 1998. The 3D surveys give a more detailed picture of the structures in the subsoil than 2D surveys.

In 1998, Amerada Hess A/S and Mærsk Olie og Gas AS carried out the first seismic surveys under the licences granted in the Fifth Licensing Round. Thus, Mærsk initiated a survey on the Ringkøbing-Fyn High only one-and-a-half months after the signing of the new licences.

Fig. 1.3 Exploration and Appraisal Wells



In the Central Graben, Danop i-s conducted a new 3D seismic survey of the Amalie gas field. Even though 3D seismic data were acquired in this area in 1992, it has proved necessary to procure new data in order to map the gas deposit situated in Middle Jurassic sandstone at a depth of about 5 km.

The coverage of the above-mentioned seismic programmes is shown in Fig. 1.1. Appendix B contains further information about the seismic surveys.

As appears from Fig. 1.2, the amount of 2D seismic data acquired in 1998 almost doubled the figure for 1997, while the acquisition of 3D data was unchanged from 1997.

The Danish Energy Agency anticipates a high level of exploratory surveying in 1999. In February 1999, the new licensees from the Fifth Licensing Round initiated 3D seismic surveys, which are expected to continue throughout most of 1999.

Wells

In 1998, the wells drilled included three exploration wells and three combined production/appraisal wells in the producing fields; see Figs. 1.3 and 1.4.

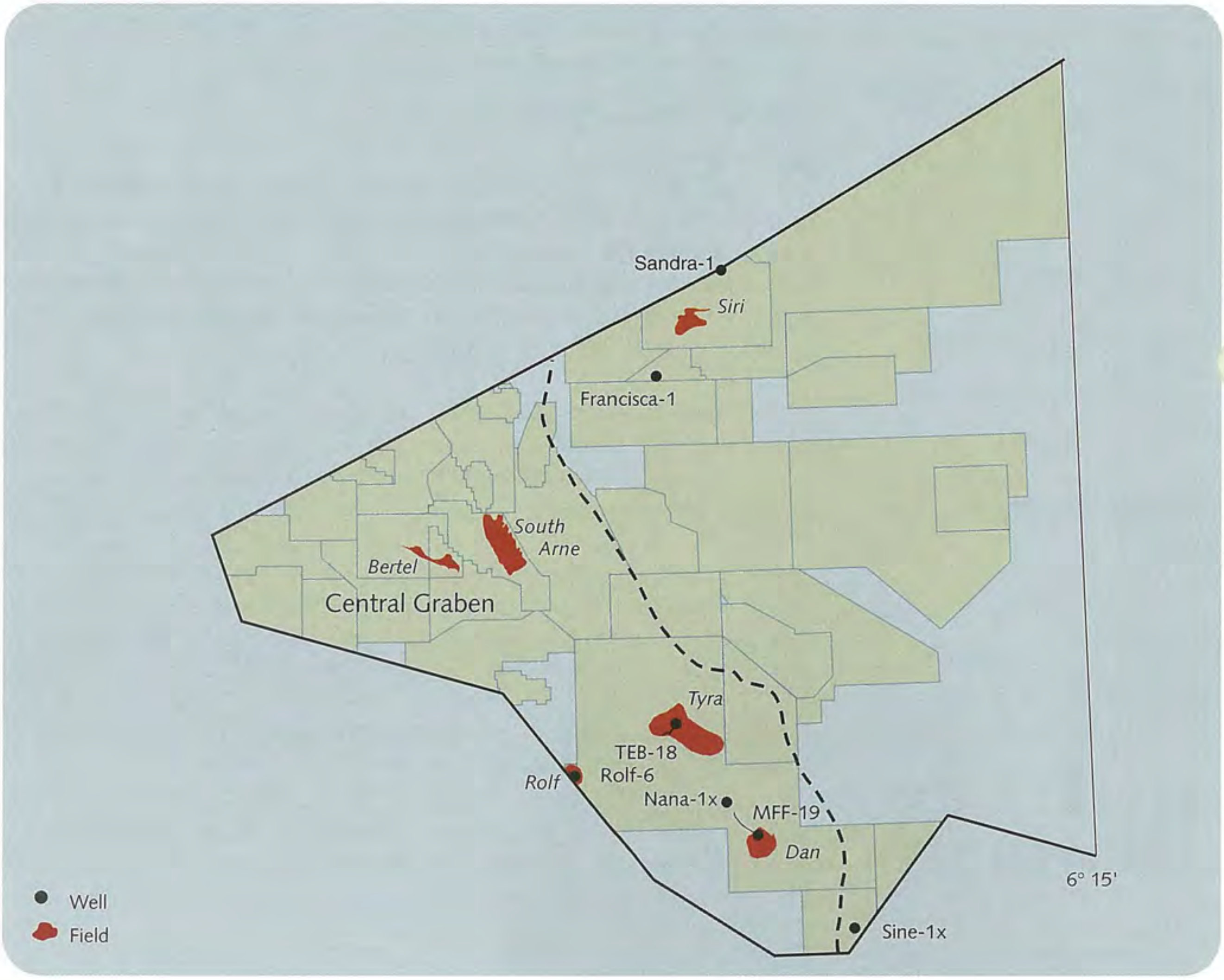
Sandra-1 (5605/13-2)

Under licence 6/95, the Statoil group drilled a new exploration well in June-July 1998 about 12 km northeast of the Siri Field, where an oil discovery was made in Palaeocene sandstone in 1995. The well penetrated Tertiary layers and terminated in the uppermost part of the chalk. The Sandra-1 well encountered the expected sandstone reservoir, which however did not contain any hydrocarbons.

Francisca-1 (5604/24-1)

In July-August 1998, Danop i-s drilled an exploration well under licence 2/90. The well was drilled close to the border between the areas comprised by licences 2/90 and 3/95, and was thus a joint venture undertaken by the two groups holding the licences, which are composed of the same oil companies.

Fig.1.4 Outline Map



Francisca-1 terminated in early Tertiary layers. A minor gas discovery was made in a sandstone formation. However, the licensees consider that there is no basis for subjecting the discovery to further appraisal.

Sine-1x (5505/22-2)
In August-September 1998, Mærsk Olie og Gas AS drilled the exploration well Sine-1x on the Ringkøbing-Fyn High southeast of the Contiguous Area. The well was located in the area comprised by licence 7/95, but was drilled in cooperation between the holders of licences 7/95 and 17/98, A.P. Møller's Sole Concession and licensees in German territory. Mærsk, Shell and Texaco carry on exploration under all the above-mentioned licences. Sine-1x terminated in the crystalline basement, but no hydrocarbons were encountered in the layers penetrated.

MFF-19 (5505/17-16)
In the Dan Field, Mærsk Olie og Gas AS has set a new record for the length of horizontal wells with the well drilled in the northwestern flank of the field. From the Dan F platform, the well was drilled about 7,650 m towards the northwest in order to appraise the extent of a reservoir zone in the chalk, where previous wells have shown good oil saturations.

MFF-19 showed good production properties and has now begun producing. With a horizontal length of just over 6.1 km, the well set a record for horizontal wells. At the beginning of 1999, Mærsk began drilling an exploration well, Nana-1x, about 1,100 m northwest of the terminal point of the horizontal well.

Rolf-6 (5504/14-2)
In March-May 1998, Mærsk Olie og Gas AS drilled a horizontal well, Rolf-6, in the Rolf Field in order to evaluate the production potential in the northwestern part of the field. However, the well did not meet expectations, and is now used as an observation well.

TEB-18 (5504/12-8)
In November 1998, Mærsk Olie og Gas AS began drilling the TEB-18 well in order to appraise the Danian oil zone at the southern flank of the Tyra Field. At the beginning of 1999, Mærsk was in the process of completing the well in order to start up production.

AMENDED LICENCES

Extended Licence Terms

Licences 7/89, 8/89 and 10/89
At the beginning of 1998, the Danish Energy Agency extended the terms of the three licences remaining from the Third Licensing Round. The term of all three licences was extended by two years until 20 December 1999.

Amerada Hess A/S is the operator under licence 7/89, which comprises the South Arne Field, expected to be brought on stream in July 1999. The licensee has previously drilled two exploration wells, Baron-2 and Rigs-1, and acquired 3D seismic data. Further exploration will now show whether more discoveries can be made in the area.

Under licence 8/89, for which Danop i-s is the operator, the licensee has previously drilled an exploration well, Bertel-1, and acquired 3D seismic data. The drilling

Fig.1.5 Stratigraphic Column

System	Series	Stage	m. years
Tertiary	Palaeocene	Danian	65
Cretaceous	Upper	Maastrichtian	
	Lower	Aptian Barremian	146
Jurassic	Upper		
	Middle		
	Lower		208
Triassic	Upper		
	Middle		
	Lower		245
Permian	Upper	Zechstein	
	Lower		290
Carboniferous			363

of the well resulted in the discovery of the Bertel oil accumulation, which was declared commercial in 1997.

The oil companies' evaluation of data from the licence area has shown that there is potential for further exploration.

Data collected under licence 10/89, for which Mærsk Olie og Gas AS is the operator, combined with the results of the Rita-1x exploration well previously drilled and 3D seismic data, have shown that there is also a basis for continuing exploration under this licence.

Licences 2/90 and 3/95

A two-year extension of licences 2/90 and 3/95 was granted in 1998. The term of these licences, covering an area south of the Statoil group's Siri accumulation, has thus been extended until 3 July 2000. Danop i-s is operator for both licences. In 1997, the licensees drilled the Frida-1 exploration well. The background for the extension was the Danop group's plans for further exploration, and in this connection, Danop drilled the above-mentioned Francisca-1 exploration well in the summer of 1998.

Licence 3/90

In July 1998, the term of licence 3/90 was extended by two years until 13 July 2000. With Mærsk Olie og Gas AS as the operator, the DUC companies and Dansk Olie- og Gasproduktion A/S are continuing their investigations in order to determine whether oil is likely to be encountered in this area, which borders on the Freja Field (the former Gert Field).

Transfer of Licence Shares

A 20% share of licence 4/95 has been transferred to Enterprise Oil Denmark Ltd. from Wintershall AG. The transfer took effect on 1 April 1998.

In the summer of 1998, Statoil Efterforskning og Produktion A/S withdrew from licences 2/90 and 3/95. Later in 1998, the composition of the groups was changed on two separate occasions, so that Denerco Oil A/S now has the largest shares, just under 60% and 50%, respectively, of the two licences. These changes were made with retroactive effect from 1 January 1998, and have thus affected the distribution of the costs associated with the Francisca-1 exploration well, which the two licence groups drilled in cooperation in the summer of 1998.

LD Energi A/S, which reduced its shares of licences 2/90 and 3/95 in connection with the above-mentioned transfers, has taken over a 25% share of licence 16/98 from Denerco Oil A/S. Licence 16/98 comprises an area adjacent to the areas covered by the other two licences. The transfer was made with retroactive effect from 15 June 1998, when licence 16/98 was granted to Denerco Oil and Dansk Olie- og Gasproduktion as a result of the Fifth Licensing Round.

At the beginning of 1999, a 20% share of licence 11/98 was transferred to Veba Oil Denmark GmbH, effective 1 January 1999. Veba Oil did not previously have a share of this licence. In addition, with effect from 15 June 1998, Dansk Olie- og Gasproduktion A/S took over a 5% share, bringing its licence share up to a total of 25%. Amerada Hess A/S and Denerco Oil A/S have reduced their licence shares.

The composition of all existing licence groups appears from Appendix A.

RELEASED WELL DATA

Generally, data collected under licences granted in pursuance of the Danish Subsoil Act are protected by a five-year confidentiality clause. However, the confidentiality period is limited to two years for licences which expire or are relinquished. In 1998, data regarding the following exploration wells were released:

Well	Well no.	Operator
Rita-1x	5603/27-05	Mærsk Olie og Gas AS
Alma-2x	5505/17-11	Mærsk Olie og Gas AS
Tabita-1	5604/26-3	Statoil Efterforskning og Produktion A/S

A list of all exploration and appraisal wells drilled in the past ten years is available on the Danish Energy Agency's homepage, www.ens.dk.

All information about released well data, seismic surveying data, etc. collected in connection with exploration and production activities, is provided by the Geological Survey of Denmark and Greenland.

2. DEVELOPMENT AND PRODUCTION

In 1998, Danish oil and gas production came from 13 fields: the oil fields of Dan, Gorm, Skjold, Rolf, Kraka, Dagmar, Regnar, Valdemar, Svend and Lulita, and the Tyra, Roar and Harald gas fields. The Svend, Harald and Lulita Fields are situated in the northern part of the Central Graben, while all other fields are situated in the Contiguous Area in the southern region of the Central Graben. On behalf of the operator, Mærsk Olie og Gas AS is in charge of recovery from all 13 fields. Dansk Undergrunds Consortium (DUC) and the Statoil group handle recovery from the Lulita Field, while the other fields are operated by DUC alone.

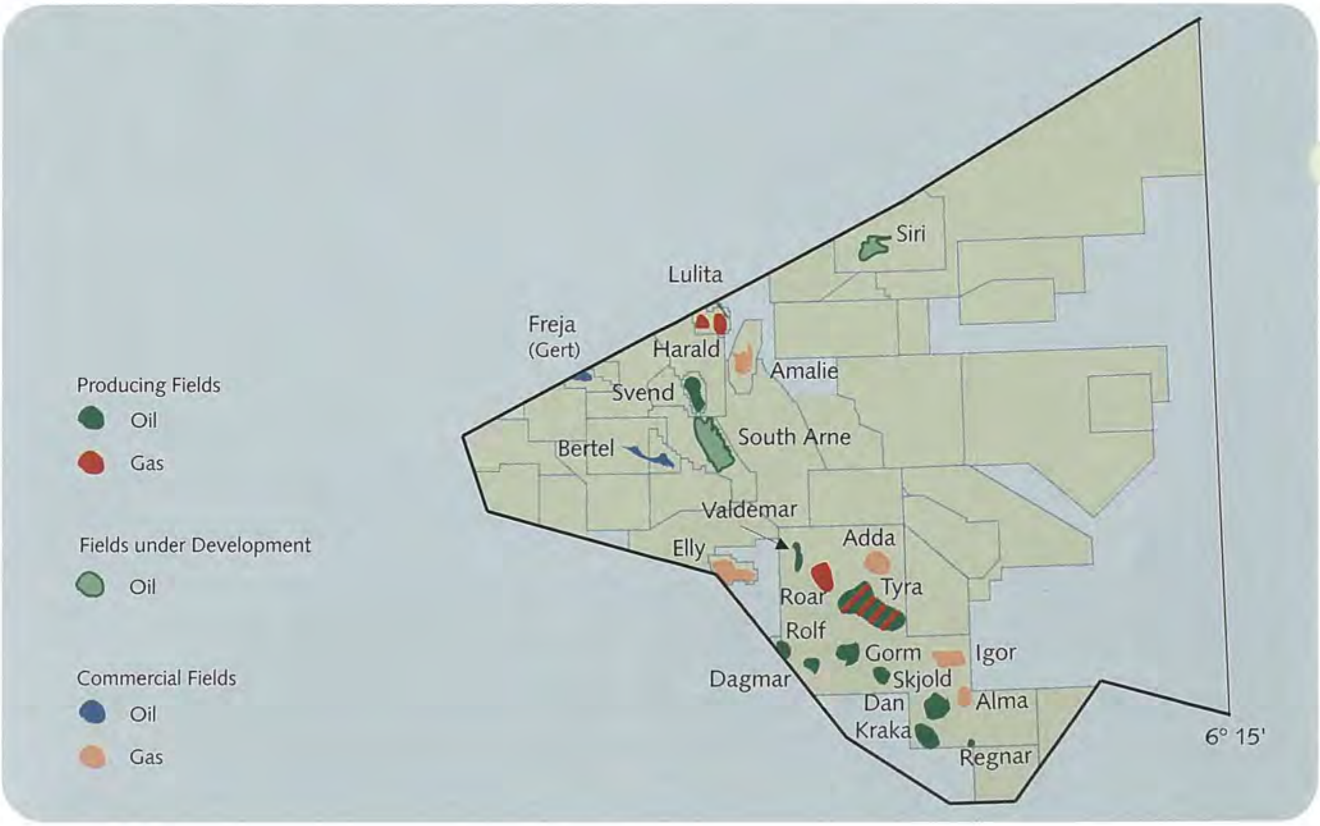
Fig. 2.1 is a map showing the location of the Danish producing fields and new field developments.

1998 DEVELOPMENT PROJECTS

The type of development projects carried out in the North Sea in 1998 differed from those undertaken in previous years.

Where the majority of development projects were previously implemented in fields where Mærsk Olie og Gas AS is the operator, the 1998 development projects concentrated on the Siri and South Arne Fields, for which Statoil and Amerada Hess are the operators. A development project was also carried out at the Harald Centre in connection with commencing production from the Lulita Field, for which DUC and the Statoil group hold the licence, with Mærsk Olie og Gas AS as the operator. In addition, the level of drilling activity remains high in the fields for which Mærsk Olie og Gas AS is the operator.

Fig. 2.1 Danish Fields in the North Sea



The Lulita Field is situated a little to the north of the Harald Field. Production from the field, which is Middle Jurassic sandstone, was commenced in June 1998.

The Siri Field is an oil accumulation in Tertiary sandstone, about 25 km east of the Central Graben. The Siri Field development in 1998 provided for the installation of a combined platform housing wells, processing facilities and accommodation. The platform and oil storage tank were shipped out to the field for installation in November 1998. The platform is placed on an oil storage tank situated on the sea bed. Production will take place from six horizontal oil wells and three injection wells for co-injecting water and gas, and in 1998 one well of each type was drilled. The field was brought on stream in March 1999.

In the South Arne Field, the platform is expected to be installed in the first half of 1999. South Arne is a chalk field situated in the northern part of the Central Graben due south of the Svend Field. Production is expected to commence from this field in 1999. The Siri and South Arne field developments are discussed in more detail towards the end of this section.

In December 1998, the Danish Energy Agency received an application for further development of the Skjold Field, consisting of drilling another seven wells. The drilling operations have been scheduled for 1999. The application was approved in February 1999.

In 1998, 23 new horizontal or highly deviated production and injection wells were drilled in connection with developing Danish fields in the North Sea. The increase in the number of wells drilled in 1998 as compared to 1997 is mainly attributable to the numerous wells drilled in the Dan Field.

The wells contributing to Danish production in 1998 totalled 227. The number of horizontal wells in operation in 1998 totalled 127: 95 production wells and 31 water-injection wells. In the Tyra Field, five wells were alternately used for production and injection in 1998. In calculating the above figures, these five wells were classified as production wells.

In 1998, DONG laid a new gas pipeline in the North Sea for transporting gas from the South Arne Field via the Harald Field to the gas processing facilities at Nybro. At the same time, the capacity of DONG's oil pipeline from the Gorm Field to shore has been expanded to 270,000 barrels per day.

SUCCESSFUL PRODUCTION OF OIL CONTAINING WAX

As previously mentioned, the Lulita Field was brought on stream in June 1998. The oil produced from the Lulita Field has a large content of wax. Experience shows that this causes problems in the processing and transportation systems, and the startup of production from this field was therefore a technical challenge.

The production from the Lulita wells is separated into liquids (unstabilized oil with water) and gas on the Harald platform. The liquids are conveyed to Tyra East through a 16" pipeline together with the liquid production from Harald and the total production of hydrocarbons from Svend. After processing to meet the sales specifications, gas from the Lulita Field is transported together with gas from Harald through a 24" pipeline to Tyra.

The high content of wax in the crude oil from Lulita means that under certain operating conditions, primarily in the case of cooling below a critical temperature, the oil may solidify during transportation through the pipeline to Tyra. For instance, if the oil from Lulita is cooled down to sea temperature, the oil will harden into solid wax. If the fall in temperature occurs en route in the Harald-Tyra pipeline, a "wax candle" may theoretically be formed along the whole length of the pipeline. In practice, subsequently removing solidified crude oil from the pipeline will not be feasible. The operator, Mærsk Olie og Gas AS, has conducted laboratory tests to find a suitable additive, an inhibitor, that will reduce the risk of wax precipitation.

Another method for reducing the risk of wax precipitation is to "dilute" the Lulita oil with the liquids produced at Harald. Mærsk Olie og Gas AS has performed a number of tests to ascertain the degree of dilution required.

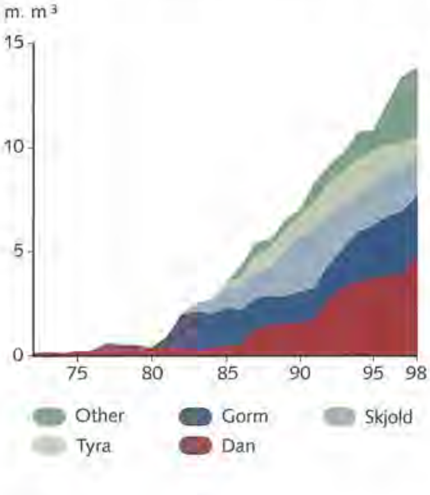
Moreover, in connection with starting up production from the Lulita Field, the amount of water produced together with the oil proved to be much larger than originally foreseen. This fact, combined with the increase in the production of water from Svend with a relatively high barium content, may result in scaling, i.e. the precipitation of barium sulphate in the 16" pipeline between Svend and Tyra. To prevent this, a scale inhibitor is added to the water produced from Lulita.

As another safeguard to prevent the 16" pipeline from becoming clogged in connection with the transportation of liquids from the three fields, a chemical is being added which reduces the friction of the liquid against the pipe wall, thus reducing the pressure drop in the pipeline.

Finally, it is necessary to clean the inside of the 16" pipeline at one- to three-week intervals with a special "cleaning pig" in order to avoid the depositing of wax in the pipeline.

As appears from the above, the operator, Mærsk Olie og Gas AS, has introduced various measures to reduce the risk associated with producing oil from the Lulita Field. In fact, no major problems have been encountered in connection with processing or transporting the oil produced. Nor did a short-term shutdown of the pipeline in mid-October 1998 give rise to any problems upon the resumption of production. Launching the production of waxy oil must be deemed a technical success.

Fig. 2.2 Distribution of Oil Production by Field



OIL PRODUCTION CONTINUES TO RISE

In 1998, Danish oil production yet again exceeded the production figures recorded in previous years, while gas production declined in relation to 1997. The increase in oil production can be attributed mainly to the new, highly productive oil wells drilled in the Dan and Gorm Fields in 1998.

Fig. 2.2 shows the development of Danish oil production in the period from 1972 to 1998, distributed by field.

Total oil production in 1998 amounted to 13.83 million m³, equal to 11.81 million tonnes. This means that the 1998 oil production figure was 3% higher than the figure for 1997.

Fig. 2.3 Production of Oil and Natural Gas

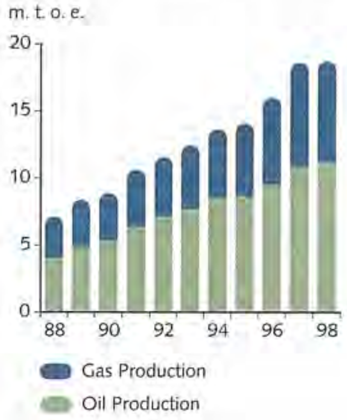
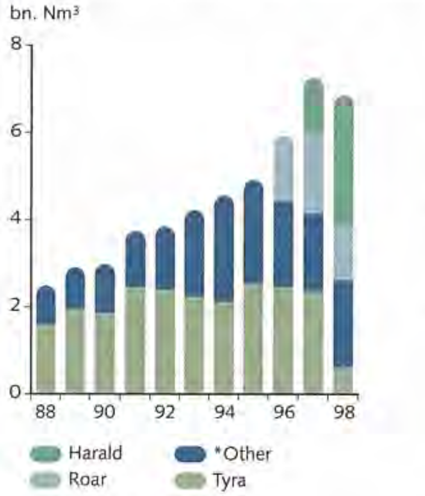
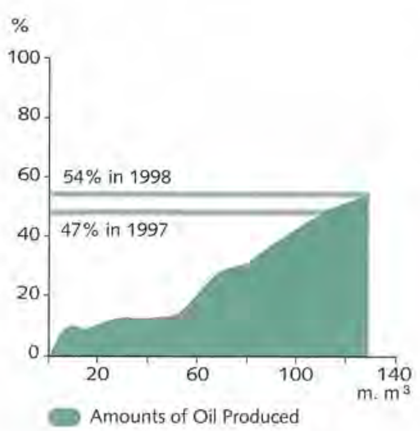


Fig. 2.4 Natural Gas Supplies Broken down by Field



** Dan, Gorm, Skjold, Rolf, Kraka, Regnar, Valdemar, Svend and Lulita*

Fig. 2.5 Development in Water Production



Gross gas production amounted to 10.28 billion Nm^3 in 1998, of which 2.93 billion Nm^3 was reinjected into the Gorm and Tyra Fields. Thus, net gas production amounted to 7.35 billion Nm^3 in 1998. More than 99% of the total amounts of injected gas was reinjected in the Tyra Field to enhance the recovery of liquid hydrocarbons from the Tyra Field. Net gas production in 1998 was 4% lower than the previous year.

Gas production from the Tyra, Roar and Harald Fields accounted for 0.73, 1.46 and 2.74 billion Nm^3, respectively, of total net gas production, while the balance constituted associated gas produced with oil in the other fields.

Gas supplies to Dansk Naturgas A/S amounted to 6.63 billion Nm^3. The difference between the net gas produced and the amount of gas sold (6.9% of the net gas) was either utilized or flared on the platforms. Three-fourths was used for energy supplies to the platforms, while the remainder was flared without being utilized. The gas is flared for safety and technical reasons exclusively.

Fig. 2.3 shows the development of Danish oil and gas production in the period from 1988 to 1998. Gas production comprises gas supplied to Dansk Naturgas A/S and gas used for energy supplies to the platforms.

Fig. 2.4 shows the development in gas supplies to Dansk Naturgas A/S in the period 1988 to 1998, broken down into the Tyra Field, the Roar Field and the Harald Field, and a combined figure for associated gas produced from the other Danish fields.

Appendix D contains an overview of Danish oil and gas production in the period from 1972 to 1998. It also includes an outline of the development in natural gas sales from the startup of the gas project in 1984 until 1998, broken down by field. Finally, this appendix sets out the monthly production figures for oil and condensate for the individual fields in 1998.

AMOUNTS OF WATER PRODUCED AND INJECTED

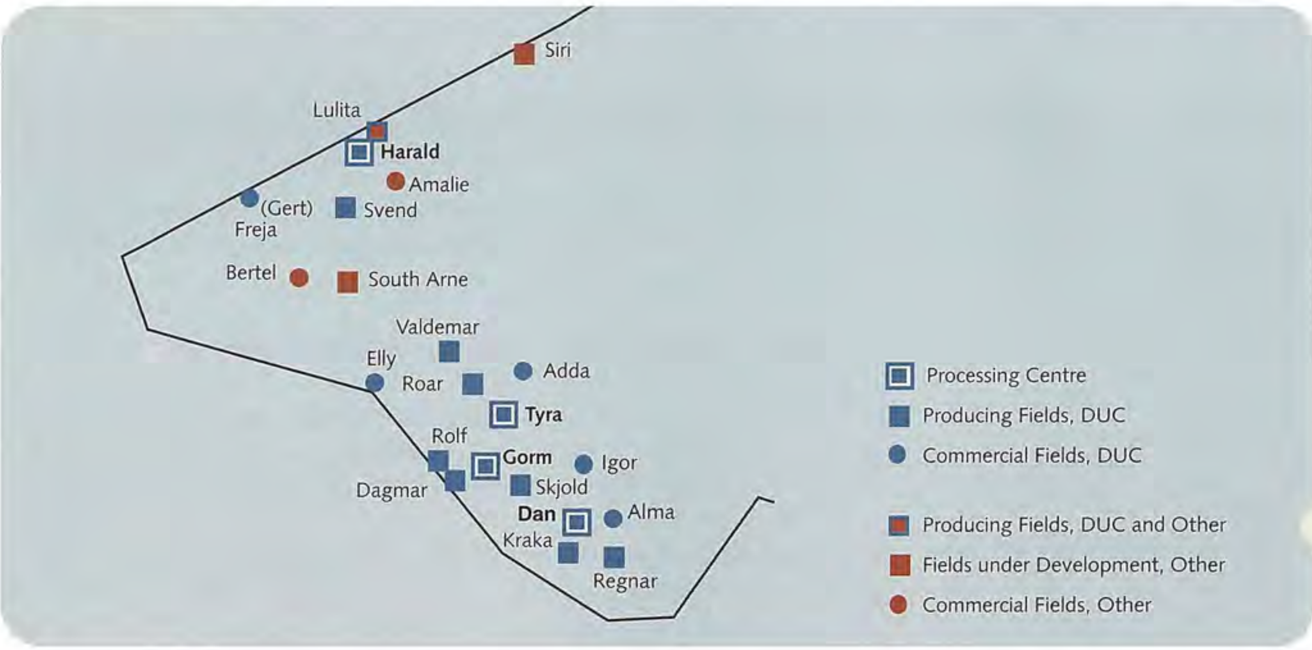
In 1998, Danish fields produced 14.16 million m^3 of water together with the oil produced, a 17% increase compared to 1997.

The share of water production relative to the total production of liquids continues to climb moderately for most Danish oil fields. For the Dan, Gorm and Skjold Fields, water accounted for 38%, 53% and 67%, respectively, of all liquids produced in 1998.

Fig. 2.5 shows the development in the ratio of water produced to total liquids produced, relative to cumulative oil production from producing chalk fields. The figures calculated at 1 January 1999 show that, after the production of almost 130 million m^3 of oil, the share of water produced has gone up to 54%. This means that every cubic metre of oil extracted from the reservoirs is now accompanied by a slightly larger amount of water.

Water is still injected into the Dan, Gorm and Skjold Fields in order to improve oil recovery. In total, 26.23 million m^3 of water was injected into these three fields in 1998. This represents an 11% increase compared to 1997. In order to lessen the impact on the marine environment, an increasing amount of the water produced from the Gorm, Skjold and Dan Fields is reinjected into the reservoirs.

Fig. 2.6 Danish Oil and Gas Fields



Appendix D shows figures for the amounts of water produced, as well as the amounts of gas and water injected into the reservoirs.

PRODUCING FIELDS

The producing Danish oil and gas fields are grouped round four processing centres: the Dan, Gorm, Tyra and Harald Centres. The following description of Danish oil and gas fields is based on this grouping of fields and focuses mainly on developments in 1998. More details are also given about the Siri and South Arne Fields.

Fig. 2.6 contains an outline map showing the locations of the four centres, and existing and planned production facilities appear from Fig. 2.9.

Appendix E provides an outline - with supplementary data - of producing fields, including the most important key figures. Appendix C contains various information about new field developments, i.e. the Siri and South Arne Fields, as well as the fields for which development plans have been approved.

THE DAN CENTRE

This centre comprises the Dan Field and the Kraka and Regnar satellite fields. The Igor and Alma Fields, as yet undeveloped, are also to be hooked up to Dan as satellites.

After processing at the Dan F complex, oil and gas are transported to shore through the Gorm and Tyra Centres, respectively. Total oil production from the Dan Centre amounted to 5.12 million m^3 in 1998. Fig. 2.8 illustrates the development in oil production from the fields at the Dan Centre.

Total net gas production from the fields at the Dan Centre amounted to 1.45 billion Nm^3 in 1998, of which 1.26 billion Nm^3 was transported to shore via the Tyra Centre. The rest of the gas was used as fuel or flared without being utilized.

The Dan Field

Dan is an oil field with a gas cap, and is the largest accumulation of oil demonstrated to date in the Danish subsoil. The field was brought on stream already in 1972, and was thus the first Danish producing field. Water injection was introduced in 1989.

The most recent development plan from 1995 provides for a major expansion of the production facilities, including the Dan FF wellhead and processing platform, which was installed in 1997 and put into full operation in 1998.

In 1998, an additional 12 horizontal wells were drilled in the field, so the 1995 development plan is close to being implemented. The only work outstanding is the completion of two production wells in the southern part of the B-block. The wells drilled appear from Fig. 2.7.

For three of the wells drilled in 1998, well slots from older, deviated wells were reused. The older wells were abandoned because, with only one producing zone in the reservoir, they were no longer economically viable compared to the new horizontal wells, which extract oil from up to 15 to 20 producing zones.

The length of an existing horizontal well from 1988 was doubled, being extended by about 1,200 metres, which illustrates the technological advances made in drilling and completion technology in merely ten years.

Fig. 2.7 Wells Drilled in the Dan Field in 1998

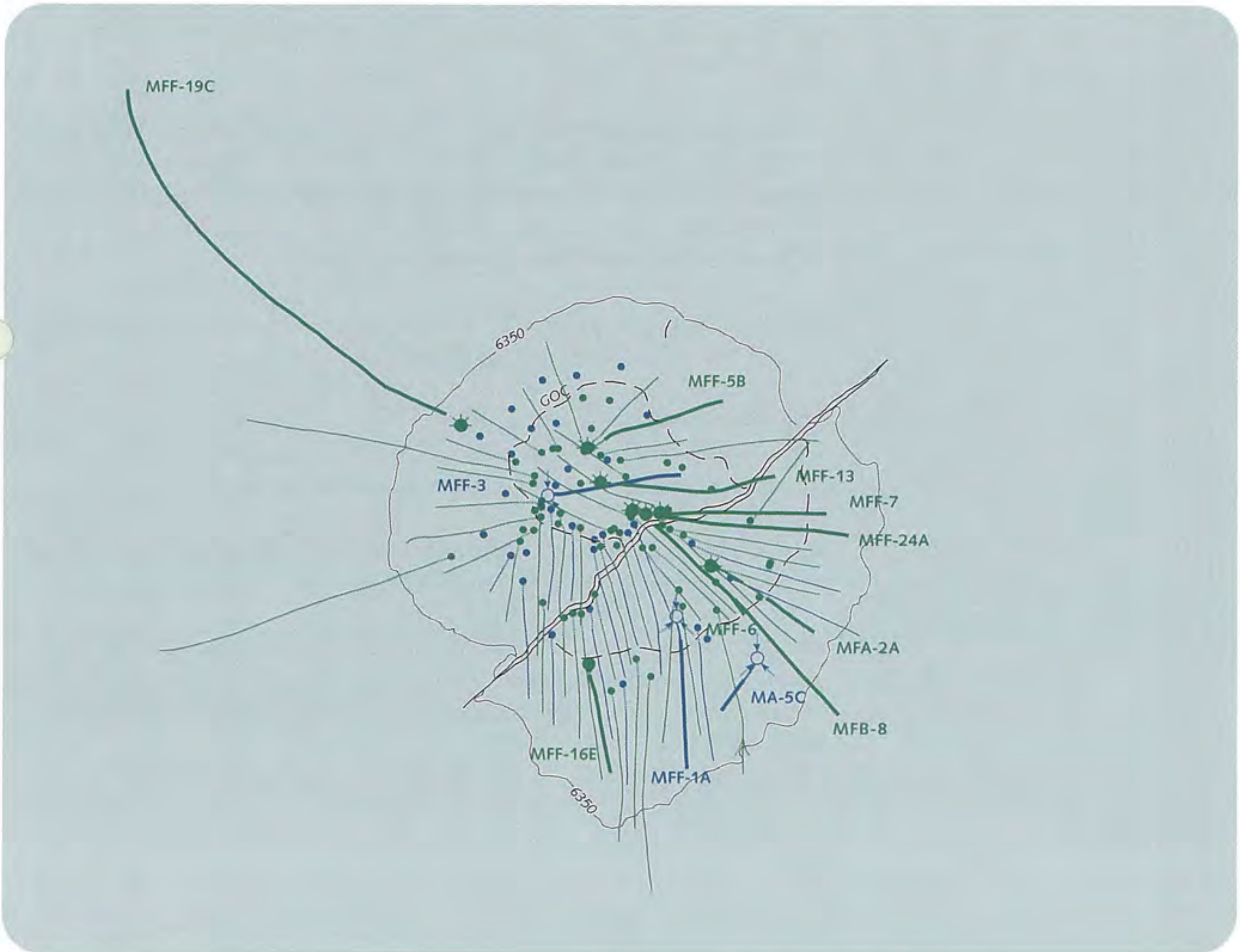
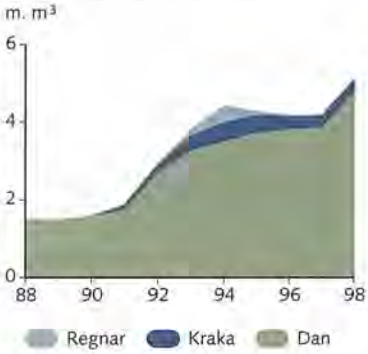


Fig. 2.8 Oil Production from the Fields at the Dan Centre



Of the 12 wells, three are directly designed for water injection, having from three to five injection points. Due to the injection pressure, the water induces a controlled fracture in the chalk, so that the water is distributed over a much larger area than that penetrated by the well.

Production has been initiated from the remaining nine wells. Large sections of two of these wells were drilled for appraisal purposes.

The MFF-16E well drilled in Danian layers in the southern part of the B-block is to investigate whether the induced producing fractures and the water injected from the wells in the Maastrichtian chalk contribute to draining and stabilizing pressure, respectively, in the overlying Danian chalk.

The MFF-19C well has been drilled in a northwesterly direction beyond existing well control in the A-block. Where the MFF-4B well drilled in 1997 set a new North Sea record for horizontal wells, Mærsk Olie og Gas AS has now succeeded in setting a world record with a horizontal well of 6,117 m, measured from the point where the deviation of the well from the perpendicular exceeds 86 degrees. By means of LWD (logging while drilling) and biostratigraphic analyses, the well was targeted at the high-porous zones in the upper section of the Maastrichtian chalk.

Satisfactory oil saturations have been ascertained along the entire horizontal section of the well. At the beginning of 1999, production from the MFF-19C well set a record for the Dan Field, bringing total production from the Dan Field up to more than 100,000 barrels a day.

In 1998, production from the Dan Field exceeded the 1997 production figure by 24%, due mainly to the drilling and hooking up of new production wells. The amounts injected in 1998 exceeded the previous year's figures by about one-third as a result of the new injection wells drilled and the increase in injection capacity following the commissioning of the Dan FF platform.

Tests are currently being carried out in the field to assess the consequences for the reservoir of reinjecting the water produced.

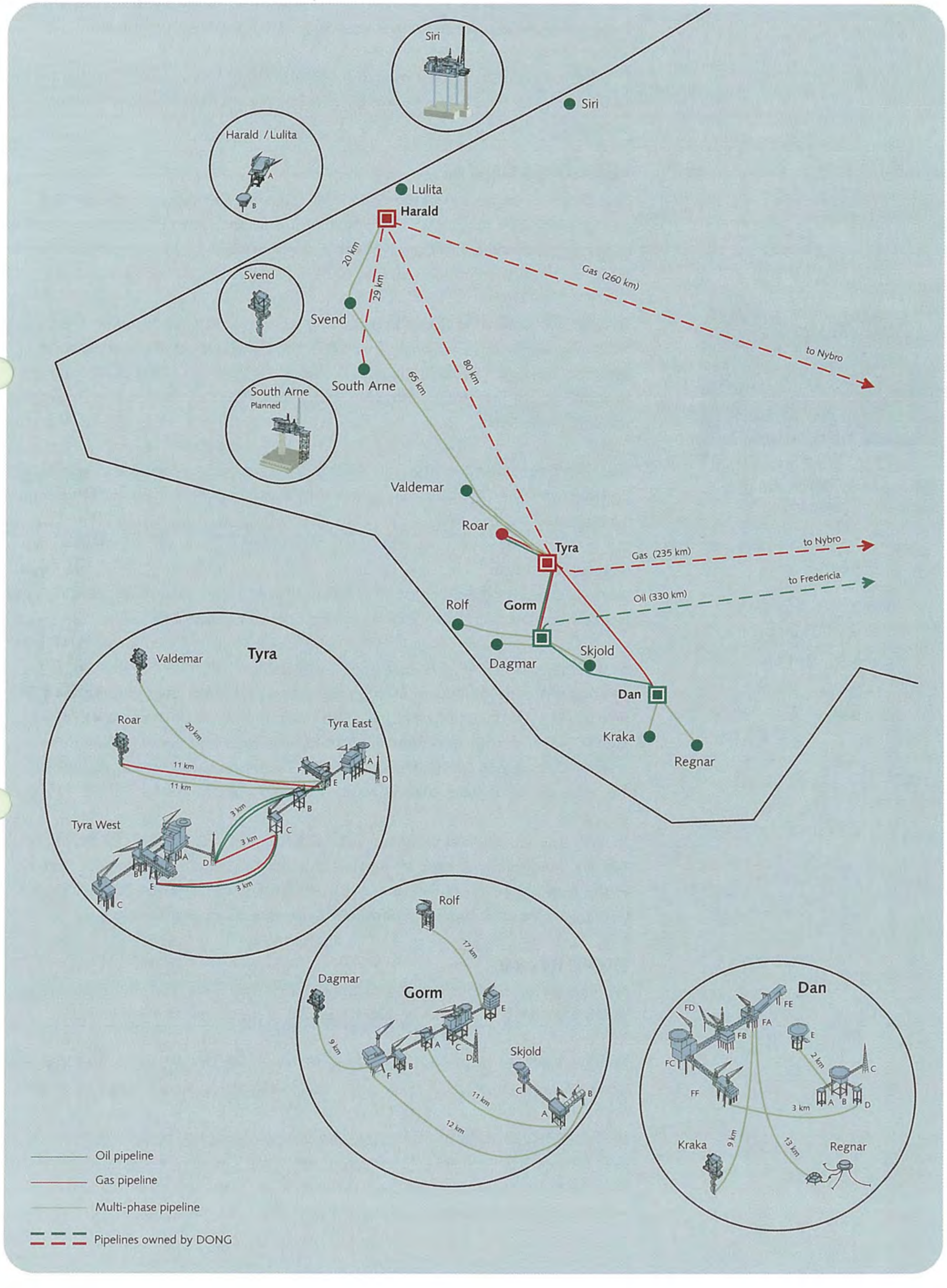
The Kraka Field

Kraka is a minor oil field with a gas cap, which is located approx. 7 km southwest of the Dan Field. Production from the field was initiated in 1991.

In April 1998, the utilization of lift gas in the Kraka wells was introduced. The gas is conveyed to the Kraka Field from Dan FF.

In 1998, Kraka produced 0.31 million m^3 of oil, which corresponds to the 1997 production figure. The utilization of lift gas was expected to enhance production, but an increase in the water produced from 0.29 to 0.35 million m^3 curbed the expected increase.

Fig. 2.9 Production Facilities in the North Sea 1998



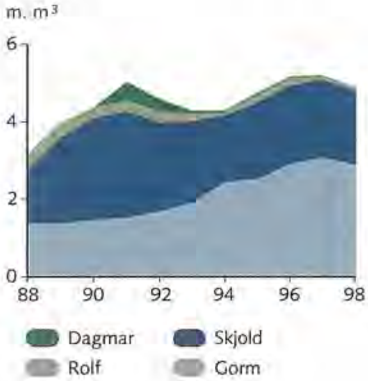
The Regnar Field

The Regnar Field is a minor oil field situated approx. 13 km southeast of the Dan Field. The field was brought on stream in 1993 from a subsea installation.

In 1998, oil production amounted to 0.04 million m³, a 33% increase compared to 1997, when the field was closed in for the first part of the year due to technical problems.

THE GORM CENTRE

Fig. 2.10 Oil Production from the Fields at the Gorm Centre



This Centre is composed of the Gorm Field and the satellite fields, Skjold, Rolf and Dagmar. The pipeline to shore emanates from the Gorm Centre, conveying oil and condensate from the Danish fields in the North Sea to the west coast of Jutland, and from there to the terminal facilities near Fredericia on the east coast.

In 1998, oil production from the fields at the Gorm Centre totalled 4.86 million m³, which is a slight decrease relative to 1997. The development in oil production from the individual fields in the period 1988-1998 is shown in Fig. 2.10. It appears from this figure that production, particularly from the Gorm and Skjold Fields, was substantial in 1998.

Total net gas production from the fields at the Gorm Centre amounted to 0.76 billion Nm³ in 1998, of which 0.54 billion Nm³ was transported to shore through the Tyra Centre.

The Gorm Field

Gorm is a major oil field situated 27 km northwest of the Dan Field. The field was brought on stream in 1981, and water injection was initiated in 1989.

In the autumn of 1998, a further two oil production wells were drilled in the B-block of the field. Both wells encountered areas drained insignificantly as a result of the production to date, and they have higher production rates than anticipated. Two old wells have been converted into water-injection wells, and one well used for water injection since 1993 has been opened up to oil production. The conversion of more wells is planned to take place in 1999.

In 1998, the Gorm Field produced 2.86 million m³ of oil and 0.76 billion Nm³ of net gas. Production showed an upward trend in the autumn of 1998, due mainly to the commissioning of the two new wells. In January 1999, the field set a production record with a daily production figure of just under 69,000 barrels.

The Skjold Field

Skjold is an oil field located 10 km southeast of the Gorm Field. Production was initiated in 1982, and in 1986, water injection in the reservoir commenced.

In 1998, the field produced 1.90 million m³ of oil, which is about 5% less than the year before, and the water content of total production went up from 64% to 67%.

In October 1998, a further development plan providing for the drilling of seven new wells in the field was submitted for approval. The new wells are to be drilled in those parts of the reservoir least drained of oil. Thus, it is expected that the water content of production can be reduced and the capacity of the pipeline to the processing facilities at the Gorm complex can be better utilized. One of the wells is to be used as a water injector to improve the distribution of water injected into the reservoir.

In 1998, the amount of water injected exceeded the estimate. About 20% of the water injected is water produced from the Gorm and Skjold Fields. The reinjection of produced water is closely monitored to determine whether there is any impact on the reservoir.

The Rolf Field

Rolf is a minor oil field situated 15 km west of the Gorm Field. In 1986, the field came on stream.

Based on a revised, geological model, a new horizontal well was drilled in the northern flank of the field in 1998. Unfortunately, the results did not lead to confirmation of the model; therefore, the well is now used exclusively as an observation well.

In 1998, 0.09 million m^3 of oil was produced from the field.

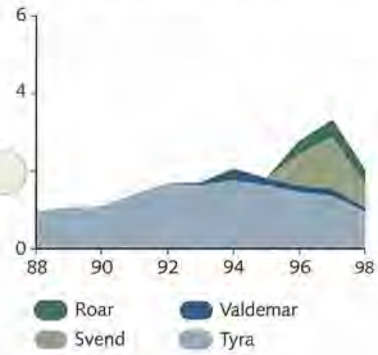
The Dagmar Field

Dagmar is a minor oil field situated 10 km west of the Gorm Field. The field was brought on stream in 1991.

Oil production in 1998 was a mere 0.01 million m^3.

THE TYRA CENTRE

Fig. 2.11 Oil Production from the Fields at the Tyra Centre



In 1998, production from the Tyra Centre derived from the Tyra Field and the satellite fields, Valdemar, Roar and Svend. Subsequently, the small satellite installations, Adda, Elly and Tyra Southeast, are expected to be hooked up to the Tyra Centre.

The gas produced is transported from Tyra East through the gas pipeline to Nybro on the west coast of Jutland, while the oil produced is conveyed to the Gorm Field for export ashore.

Fig. 2.11 shows the development in oil production at the Tyra Centre over the past ten years. Total oil production from the fields connected to the Tyra Centre constituted 2.00 million m^3 in 1998.

Total net gas production from the fields at the Tyra Centre amounted to 2.42 billion Nm^3 in 1998, of which 2.06 billion Nm^3 was transported to shore.

The Tyra Field

Tyra comprises a large gas cap overlying a thin black oil zone. Next to the Dan Field, the oil zone is the largest oil accumulation discovered in Danish territory. Production commenced in 1984, and since 1987, part of the gas produced has been reinjected into the reservoir to increase the production of condensate.

At the end of 1998, about 52 million barrels (8.27 million m^3) of oil had been extracted from the oil zone, the bulk from the oil rim of the field.

In 1997, the gas-injection project was expanded to comprise Tyra East, in which connection seven existing production wells were converted. In 1998, another two existing production wells were converted into gas-injection wells.

To further improve the injection pattern and enhance capacity, a horizontal side-track was drilled from an ordinary deviated well in 1998. The drilling operations were carried out without the use of a jack-up drilling rig. All equipment was placed on the existing wellhead platforms, and the actual drilling operations were carried out by using the coiled tubing technique. The coiled tubing is unwound from a large coil, hence the name, and lowered into the well. This drilling technique proved a great success, with a horizontal section of almost 1,000 m being drilled, but in the final phase, problems were encountered, and it was impossible to install the injection completion as planned.

In the winter of 1998/99, a combined gas production/oil appraisal well was drilled in the southern flank of the field. Whereas the existing oil production wells terminate in Maastrichtian layers, this well confirmed the presence of an oil rim in Danian chalk only previously penetrated by the distal part of two horizontal gas production wells. Production from this well starts in 1999.

Facilities for the utilization of lift gas were completed in 1998, and in a number of oil wells were gaslift installed.

In 1998, 0.73 billion Nm^3 of net gas was recovered from the Tyra Field, which is about 70% less than in 1997. Total oil production in 1998 declined by 25% compared to the year before. The amounts of water produced in 1998 were slightly below the 1997 level. The decline in production is mainly attributable to the commissioning of the Harald gas field.

The Valdemar Field

The Valdemar oil field is located approx. 20 km northwest of the Tyra Field. Since 1993, production has taken place from the so-called North Jens area in the Valdemar Field.

Valdemar is a large oil accumulation by Danish standards. However, the reservoir consists of very tight chalk, which makes recovery very difficult.

The Valdemar Field produced 0.10 million m^3 of oil in 1998. Production from the field continues to be difficult because parts of the formation are brought to the surface with the oil produced, and the production string and casings collapse.

The Roar Field

Roar is a minor gas accumulation situated 10 km northwest of the Tyra Field. The Roar Field was brought on stream in 1996.

In 1998, gas and condensate production rates declined by about 25% compared to 1997. The main reason for the fall in production is increasing water cut.

The Svend Field

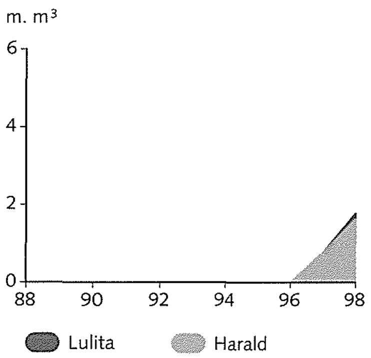
The Svend oil field is situated 60 km northwest of the Tyra Field. Production was commenced in 1996.

The Svend Field produced 0.64 million m³ of oil in 1998, a 50% reduction in relation to 1997. In the course of 1998, the water content of production increased considerably. One well was shut down for more than five months for this reason. However, production has been resumed from the well, with a much lower water content.

When the two existing production wells were drilled, they did not penetrate the whole length of the reservoir. The second section of the northern well will be drilled in the first quarter of 1999, and the results, combined with additional production experience and a reinterpretation of existing seismic data, will form the basis for evaluating the potential for further development of the field.

THE HARALD CENTRE

Fig. 2.12 Oil Production from the Fields at the Harald Centre



The Harald and Lulita Fields are the only fields connected to the Harald Centre to date. An 80 km gas pipeline connects the Harald Centre with Tyra East. Condensate is conveyed to Tyra via the Svend Field. Fig. 2.6 shows the location of the Harald Centre. The amount of condensate produced from the centre totalled 1.85 million m³ in 1998, while total net gas production amounted to 2.81 billion Nm³.

The Harald Field

The Harald gas field is situated close to the Norwegian border, about 80 km north of the Tyra Field. Production commenced at end-March 1997.

The field consists of two independent reservoirs, West Lulu and Lulu. West Lulu is a Middle Jurassic sandstone reservoir, while Lulu is a Danian chalk reservoir.

Both reservoirs contain gas with a fairly high content of condensate. This means that for every m³ of gas produced, almost three times as much condensate is produced as in the Tyra Field.

West Lulu was the first sandstone reservoir from which production was initiated in Denmark. Production takes place from two wells, which started producing in June 1997 and March 1998, respectively. It is planned to drill one more well at West Lulu.

At Lulu, there is one producing well, to be supplemented by another well in 1999.

In 1998, 2.74 billion Nm³ of net gas and 1.64 million m³ of condensate were produced.

The Lulita Field

The Lulita Field is an oil accumulation extending from the Harald Field towards the Norwegian border. The field is covered by licences 7/86 and 1/90, which belong to the Statoil group, as well as A.P. Møller's Sole Concession.

Mærsk Olie og Gas AS is the operator on behalf of DUC and the Statoil group, and the Lulita Field is the first field in Danish territory which has been unitisered.

The Lulita accumulation is a structural fault trap in sandstone layers forming part of the Middle Jurassic Bryne Formation.

The Lulita Field development is based on production from two wells by natural depletion. Production takes place from the Harald A platform, which can now handle production from Lulita as a result of minor modifications and extensions. The field was brought on stream in June 1998.

As previously mentioned, the crude oil from the Lulita Field has a very high content of wax. The oil is in a liquid state under the pressure and temperature conditions existing in the reservoir, but if the pressure and temperature drop too much, the oil will solidify. Owing to a number of measures introduced to counteract this problem, transporting the oil through the pipelines has not given rise to any major difficulty.

In 1998, 0.15 million m^3 of oil was produced from the field. The amount of water produced is much larger than originally foreseen, which means that the amount of oil produced diminished.

THE SIRI FIELD

The Siri Field is an oil accumulation in Tertiary sandstone. Siri is situated about 25 km east of the Central Graben, where all commercial oil and gas discoveries have been made to date. Statoil Efterforskning og Produktion A/S is operator for the field, with Danop as co-operator.

The field development consists of a combined platform housing wells, processing facilities and accommodation. The platform is placed on an oil storage tank placed on the sea bed. The oil produced is loaded on board tankers by means of buoy loading facilities.

Production from the field will take place from six horizontal oil wells. In order to enhance recovery, the gas will be reinjected together with water through three deviated wells. The co-injection of gas and water is a novel technique, also in an international context. One advantage of co-injection is that the injection pressure at the surface is much lower than when gas is injected alone, thus requiring less energy.

The platform was installed in the field in November 1998. Production commenced in March 1999, initially from one well, and the remaining wells are expected to be drilled in the course of 1999.

THE SOUTH ARNE FIELD

The South Arne Field is an oil accumulation with a relatively high content of gas in Danian and Maastrichtian chalk. The field is situated in the northern part of the Central Graben, about 10 km south of the Svend Field. Amerada Hess A/S is the operator for the field.

A development and production plan for the field was approved by the Danish Energy Agency in August 1997. The field is currently being developed, and production is planned to commence in 1999.

The field development is based on a combined wellhead, processing and accommodation platform. The oil produced will be stored in a tank installed on the sea bed. From here, the oil will be loaded on board tankers by means of buoy loading facilities, while the gas produced will be exported to shore via a new pipeline emanating from the South Arne Field.

It is planned to carry out the development project in three phases. The first phase of the development will consist of drilling up to 12 horizontal wells, of which four were drilled in 1998. Studies conducted in the course of 1998 have shown that there is great potential for improving recovery from the field by means of water injection. The second phase of the development project therefore provides for the possible use of water injection in the field. The third phase is based on a possible further development of the field through the drilling of more wells and the start-up of production from structures and formations not comprised by phase 1.

NATURAL GAS STORAGE FACILITIES

Dansk Naturgas A/S has two natural gas storage facilities at its disposal, one at Lille Torup near Viborg in Jutland, and one at Stenlille on Zealand.

At the turn of the year 1998/99, the Lille Torup and Stenlille storage facilities provided an extraction capacity of 420 million Nm^3 and 350 million Nm^3, respectively, totalling 770 million Nm^3.

Dansk Naturgas A/S operates on the basis of two goals for natural gas supplies - a short-term goal, which concerns any interruptions in DUC's supplies on very cold winter days, and a long-term goal, which concerns accidents involving a suspension of the supply of gas through the existing 30" pipeline from Tyra to shore for up to 30 days.

With the above-mentioned total extraction capacity of 770 million Nm^3 and an agreement made with DUC for the supply of gas from Tyra via Harald and from there through the new 24" pipeline to shore, Dansk Naturgas A/S is able to meet its long-term goal.

As far as the short-term goal is concerned, Dansk Naturgas A/S needs to increase the rate at which gas can be extracted from the storage facilities. In this connection, the company plans to establish a new withdrawal processing train to upgrade the extraction capacity of the Stenlille facility in 1999.

3. RESERVES

Fig. 3.1 Oil Reserves and Recovery Factor

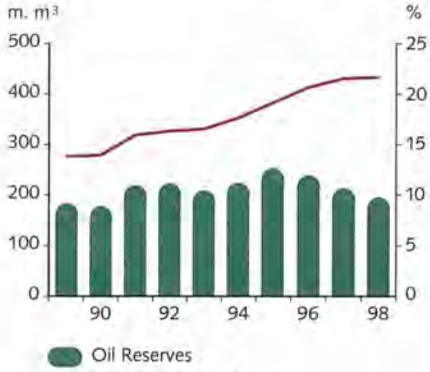


Fig. 3.2 Oil Reserves Broken down by the Geological Age of the Reservoirs

An assessment of Danish oil and gas reserves is made annually by the Danish Energy Agency.

The assessment made by the Danish Energy Agency at 1 January 1999 shows a decline in oil and gas reserves of 8% and 10%, respectively, in relation to the assessment at 1 January 1998. The decline in reserves is mainly attributable to the depletion caused by production in 1998. Moreover, the reserves of several fields have been reassessed, including fields in the *possible recovery* category.

Oil reserves have been estimated at 195 million m^3. Compared to last year's assessment, total expected oil recovery has been written down by 4 million m^3. Production in 1998, which exceeded production in 1997 by 0.4 million m^3, amounted to 13.8 million m^3. Thus, the decline in oil reserves totals about 18 million m^3.

In the past ten years, oil reserves have been estimated at 200 million m^3, thus remaining fairly constant; see Fig. 3.1. This means that, on average, reserves have increased at the same rate as production, even though production has doubled over the same period. The increase in reserves is chiefly attributable to further field developments, including the drilling of horizontal wells and the use of water injection, as well as new discoveries made.

The reserves attributable to the further field developments mentioned above can also be illustrated by the increase in the overall recovery factor, the ratio of ultimate recovery to total oil in place, from 14% to 22%, i.e. an increase of approx. 50% in the course of ten years.

Oil reserves can be put into perspective by calculating the ratio of reserves to the previous year's production. Such a calculation results in a so-called *R(reserves)/P(production)* ratio, which is an indicator of the number of years for which oil production is estimated to be sustained. Based on the new assessment of reserves, the R/P ratio is 14, meaning that oil production is estimated to be sustainable at the 1998 level for the next 14 years.

The development in the R/P ratio is described in more detail in the section on the twenty-year production forecast.

ASSESSMENT OF RESERVES

The reserves reflect the amounts of oil and gas that can be recovered by means of known technology under the prevailing economic conditions. The figures indicated for oil reserves include the contribution from condensate recovery. The method used by the Danish Energy Agency in calculating the reserves and preparing the production forecasts is described in Appendix H.

Fig. 3.2 shows the oil reserves broken down by the geological age of the reservoirs.

The bulk of the reserves are located in chalk from the Cretaceous and early Palaeocene periods. Thus, chalk layers account for about 83% of the reserves, attributable mainly to Danian and Maastrichtian reservoirs.

Table 3.1 Production and Reserves at 1 January 1999

	OIL, million m³				GAS, billion Nm³			
	Ultimate Recovery				Ultimate Recovery			
	Produced	Reserves			Produced	Reserves		
		Low	Exp.	High		Low	Exp.	High
Ongoing and Approved Recovery:								
Dan	38	37	64	93	14	5	10	15
Kraka	3	0	2	3	1	0	1	2
Regnar	1	0	0	0	0	0	0	0
Igor	-	0	0	0	-	1	2	3
Alma	-	0	1	1	-	1	1	2
Gorm	34	3	15	29	4	1	2	4
Skjold	27	6	15	25	2	0	1	2
Rolf	4	0	1	1	0	0	0	0
Dagmar	1	0	0	0	0	0	0	0
Tyra	17	2	6	10	29	35	47	60
Valdemar	1	0	1	1	0	0	1	1
Roar	1	1	2	3	5	6	9	13
Svend	3	1	4	7	0	0	0	1
Adda	-	0	1	1	-	0	0	1
Elly	-	0	1	1	-	2	5	7
Harald	2	4	5	7	4	14	18	23
Lulita	0	0	0	1	0	0	0	1
Siri	-	5	8	12	-	-	-	-
South Arne	-	8	14	28	-	3	6	11
Subtotal	**131**		**140**		**60**		**104**	
Planned Recovery:								
Freja	-	1	2	3	-	0	0	0
Amalie	-	1	2	3	-	1	3	5
Bertel	-	1	1	2	-	0	0	0
Subtotal			**5**				**3**	
Possible Recovery:								
Prod.Fields	-	10	20	30	-	4	7	11
Other Fields	-	12	23	35	-	0	0	0
Discoveries	-	3	7	17	-	2	9	17
Subtotal			**51**				**16**	
Total	**131**		**195**		**60**		**123**	
January 1998	117		213		53		137	

The contribution to reserves from Danian reservoirs is included in the Cretaceous category.

Production has been carried on from chalk reservoirs since 1972, whereas recovery from deeper and older Jurassic sandstone reservoirs was not initiated until 1997 in the Harald Field. The future production from Jurassic reservoirs is expected to account for about 10% of total reserves.

In March 1999, production was commenced from the Siri Field, where oil is extracted from a Tertiary sandstone reservoir of late Palaeocene age. The recovery from this type of reservoir is foreseen to account for about 6% of total reserves.

Only 1% of the reserves are located in sandstone from the Triassic period, and Bertel is the only field in this category.

Fig. 3.3 Oil Recovery, m. m³

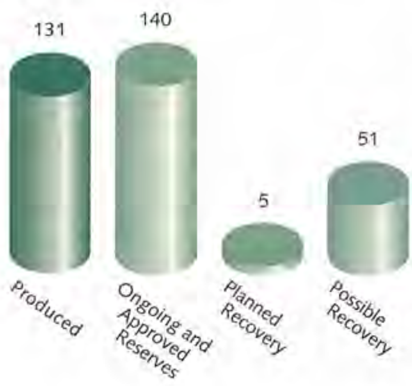
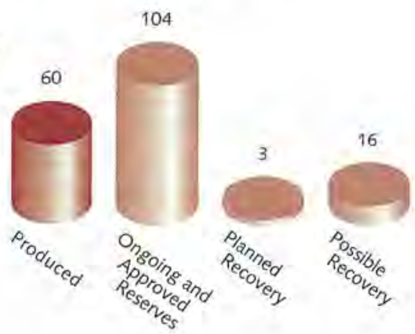


Fig. 3.4 Gas Recovery, bn. Nm³



However, the present distribution of reserves must be expected to change, as the exploration activity initiated under the licences granted in the Fifth Licensing Round is primarily targeted at Tertiary and Jurassic sandstone prospects.

Table 3.1 shows the Danish Energy Agency's assessment of oil and gas recovery, broken down by field and category.

A low, expected and high estimate of reserves is given for each individual field, in order to illustrate the uncertainty attached to the assessment. In assessing Denmark's total reserves, it is not realistic to assume that either a high or a low figure will prove accurate for all fields. Therefore, for a large number of fields, the total assessment of reserves should be based on the expected value.

It appears from Fig. 3.3 that the expected amount of oil reserves ranges from 145 to 195 million m³. The reserves assessed for planned and possible recovery, respectively, reflect the increasing uncertainty as to whether such reserves can be exploited commercially.

Likewise, Fig. 3.4 illustrates that the expected amount of gas reserves ranges from 107 to 123 billion Nm³. Gas production figures represent the net production, i.e. produced gas less reinjected gas. It should be noted that the amounts of gas stated deviate from the amounts which can be marketed as natural gas. The difference (10-15%) represents the amounts consumed or flared on the platforms.

There have been several revisions of the Danish Energy Agency's assessment of reserves compared to the assessment made in January 1998. These revisions are attributable to well results, more production experience and new reservoir models resulting from improved knowledge of the fields.

The areas where significant revisions have been made are described below.

Ongoing and Appoved Recovery

The reserves of the Gorm Field have been written up due to the drilling of another two wells in 1998.

The amount of reserves for the Skjold Field has been raised following the approval of a further development project for the field, providing for the drilling of seven more wells.

Table 3.2 Oil Production Forecast, million m³

	1999	2000	2001	2002	2003
	Ongoing and Approved:				
Dan	5.6	5.3	5.2	4.7	4.3
Kraka	0.4	0.3	0.2	0.2	0.1
Regnar	0.0	0.0	0.0	0.0	0.0
Igor	-	-	0.0	0.0	0.0
Alma	-	-	-	-	0.1
Gorm	3.1	2.4	1.6	1.3	1.1
Skjold	1.9	1.9	1.6	1.4	1.3
Rolf	0.1	0.1	0.1	0.1	0.1
Dagmar	0.0	0.0	0.0	0.0	0.0
Tyra	0.9	0.7	0.7	0.8	0.6
Valdemar	0.1	0.1	0.2	0.1	0.1
Roar	0.4	0.5	0.4	0.3	0.2
Svend	0.9	0.7	0.3	0.2	0.2
Adda	-	-	0.5	0.1	0.0
Elly	-	-	0.2	0.2	0.1
Harald	1.5	1.2	0.8	0.7	0.5
Lulita	0.2	0.0	0.0	0.0	0.0
Siri	1.8	2.2	1.4	0.9	0.6
South Arne	1.1	2.6	2.5	1.9	1.4
Total	**17.8**	**18.0**	**15.7**	**12.8**	**10.8**
Planned	**-**	**-**	**-**	**-**	**0.3**
Expected	**17.8**	**18.0**	**15.7**	**12.8**	**11.0**

In the Svend Field, reserves have been reassessed on the basis of production experience and further drilling operations initiated in the field at the beginning of 1999.

The Lulita reserves have been written down on the basis of production experience.

Planned Recovery

Freja is the name of the former Gert Field.

Possible Recovery

The Danish Energy Agency has reviewed a number of options for enhancing recovery with the use of known technology, i.e. technology which is used today under conditions comparable to those prevailing in the North Sea.

Based on reservoir calculations and general estimates of investments, operating costs and oil price developments, it is assessed that the recoverable reserves can be augmented considerably by implementing additional water-injection projects in a number of fields. Moreover, the potential of some of these fields has been reassessed.

The drilling of horizontal wells is considered to further increase the production potential of the Kraka and Rolf Fields, as well as the oil zone in the Tyra Field. Reserves in the Siri Field have also been included in this category. A further delineation to be made in connection with the development of this field will show whether expectations for the reserves in the northern part of the field can be confirmed.

Finally, a number of discoveries that are under evaluation are included in this category, which also includes discoveries that are considered to be marginal based on current technology and prices.

The total amount of oil that is recoverable with the use of known technology corresponds to only approx. 22% of the hydrocarbons in place in Danish territory.

In fields like Dan, Gorm and Skjold, where the production conditions are favourable, an average recovery factor of 34% of the oil in place is expected, based on the assumption that known methods are used, including water and gas injection.

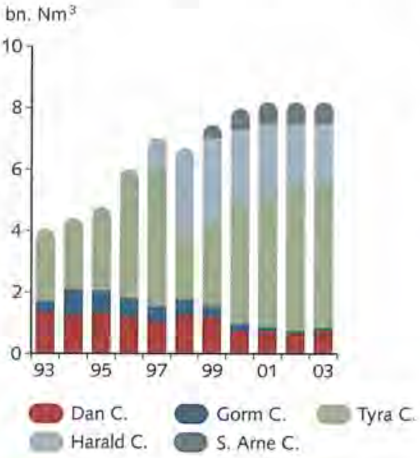
The total oil reserves also include contributions from the relatively large accumulations in the Tyra and Valdemar Fields, where the recovery factors are fairly low due to the difficult production conditions.

PRODUCTION FORECASTS

Based on the assessment of reserves, the Danish Energy Agency prepares production forecasts for the recovery of oil and natural gas in Denmark.

The present five-year forecast shows the Danish Energy Agency's expectations for production until the year 2003. In addition, the twenty-year forecast shows the Danish Energy Agency's assessment of the production potential for oil and natural gas in the longer term.

Fig. 3.5 Natural Gas Sales Broken down by Processing Centre



Five-Year Production Forecast

The five-year forecast uses the same categorization as the assessment of reserves, and includes only the categories *ongoing*, *approved*, and *planned recovery*.

Fields are incorporated into the production forecast from the time production startup is approved or from the earliest date on which production can be commenced.

As appears from Table 3.2, oil production is expected to reach approx. 17.8 million m^3 in 1999, and is then anticipated to increase to 18.0 million m^3 in 2000, equal to about 310,000 barrels per day. After that time, production is expected to decline.

It is assumed in the forecast that oil production will not be subject to any restrictions in terms of capacity or transportation. In the course of 1998, the design capacity of DORAS' oil pipeline facilities has been expanded to 270,000 barrels per day. However, for a few days in 1999, it was possible to transport more than 290,000 barrels per day.

The oil produced in the new Siri and South Arne Fields will be loaded on board tankers by means of buoy loading facilities, but, nevertheless, the transportation capacity earmarked for the remaining fields will marginally exceed the capacity of the oil pipeline for a short period of time. However, this should be viewed in light of the uncertainty surrounding the exact capacity of the pipeline and the production forecasts for the fields.

In relation to the forecast in the Danish Energy Agency's 1997 Report on Oil and Gas Production in Denmark, expected production figures have been written up, except for 1999, for which year a writedown has been made. The revisions to the production forecast are dealt with below.

For the Dan and Gorm Fields, expected production figures for 1999 have been written up due to the new, productive wells.

Production estimates for the Skjold Fields have been adjusted upwards for the years to come, due to the drilling of additional wells.

The Roar condensate production estimate has been written up, as another well is expected to be drilled in the field.

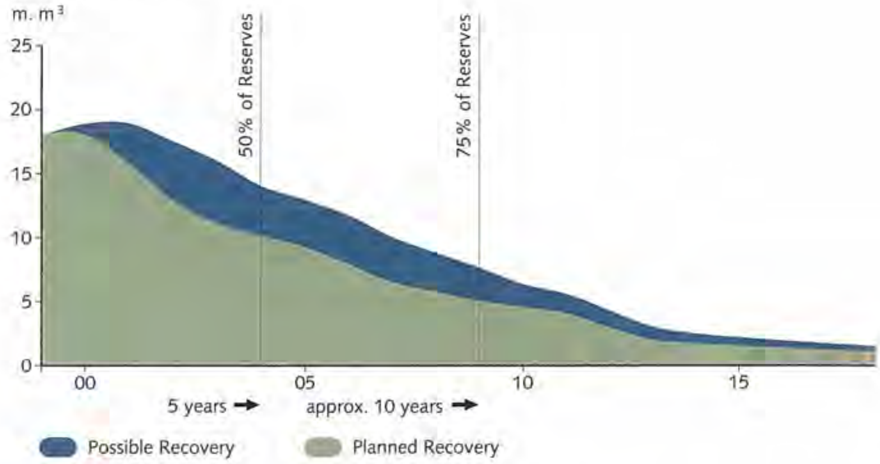
The expected production figure for the Svend Field has been reassessed, in part due to the high water content of production, and in part due to drilling activities in the field at the beginning of 1999.

The Harald condensate production estimate has been adjusted as a result of changes in the gas production forecast.

The Lulita production forecast has been revised based on production experience.

For Siri and South Arne, the 1999 production estimates have been revised, because the wells in these fields are no longer expected to be completed in accordance with the approved field development plans.

Fig. 3.6 Oil Production Forecast



The expectations for production from the remaining fields are largely unchanged in relation to last year's report.

The *planned recovery* category comprises the future development of the Freja Field.

Expected production of natural gas is shown in Fig. 3.5, broken down by processing centre.

Twenty-Year Production Forecast

The twenty-year forecast has been prepared according to the same method as the five-year forecast, and thus uses the same categorization as the assessment of reserves. However, unlike the five-year forecast, the *possible recovery* category is also included.

In preparing the forecast up to the year 2018, it has been assumed that the course of production will be planned exclusively on the basis of the technical potential of the fields, without taking legal and operational constraints into account.

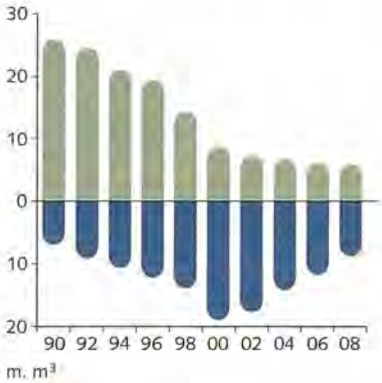
Fig. 3.6 illustrates two oil production scenarios. The curve illustrating planned recovery is simply a continuation of the curve shown in Table 3.2, while the second curve also includes *possible recovery*.

Within the category *possible recovery*, the production potential is based on the Danish Energy Agency's assessment of possibilities for initiating further production not based on development plans submitted.

The Danish Energy Agency estimates that the increased use of water injection in certain fields represents further oil production potential, and moreover, that a potential for enhancing recovery from the oil zone in the Tyra Field as well as from the Kraka, Rolf and Siri Fields exists.

It appears from Fig. 3.6 that annual oil production for the planned and possible recovery categories will increase to 18 million m^3 and 19 million m^3 in the years around 2000, after which production is expected to decline.

Fig. 3.7 Oil Production and R/P Ratio



If the assumptions underlying the forecasts prove correct, and if no new discoveries are made, 50% and 75% of Danish oil reserves will have been recovered in five years and roughly ten years, respectively.

As mentioned previously, the R/P ratio for oil of 14 has been calculated on the basis of the new assessment of reserves. Over the past ten years, the R/P ratio has dropped from 30 to approx. 15; see Fig. 3.7. The decreasing R/P ratio is mainly due to growth in production, as the production figure has more than doubled in the past ten years.

If the assumptions underlying the forecasts prove correct, the R/P ratio will have declined to 7 and 6, respectively, in five and ten years. The downward trend in the production estimate means that the development in the R/P ratio will stabilize in the longer term.

Although the forecast covers a period of 20 years, it is only possible to predict the development for a few years ahead. For instance, the Siri Field was discovered in December 1995, and a mere three years later, the field was developed and brought on stream. Thus, the methods used in making the forecasts imply that production must be expected to decline after a short number of years.

The downward plunge of oil production can hopefully be curbed as a result of new discoveries made in connection with the exploration activity initiated in the Fifth Licensing Round, as well as by advances in technological research and development.

As opposed to the production of oil, which can always be sold at the current market price, the production of natural gas requires that long-term sales contracts have been concluded.

Since the start of gas sales in 1984, Danish natural gas has been supplied under gas sales contracts concluded between DUC and Dansk Naturgas A/S. The present gas sales contracts do not stipulate a fixed total volume, but rather a fixed annual volume that will be supplied for as long as DUC considers it technically and financially feasible to carry on production at this level.

In 1997, a contract was concluded between the Amerada Hess group and Dansk Naturgas A/S for the sale of gas from the South Arne Field, and, in 1998, a provisional contract was concluded between the Statoil group and Dansk Naturgas A/S for the sale of the Statoil group's share of the gas produced from the Lulita Field.

The Danish Energy Agency's forecast for the planned course of production is based on the contracts with DUC providing for a maximum gas production plateau of 7.5 billion Nm³ a year and total gas supplies of approx. 130 billion Nm³ until the year 2012. In addition, the planned course of production for the South Arne Field accounts for 5.5 billion Nm³.

4. RESEARCH

The Government's involvement in oil and gas research is based on a desire to sustain a high degree of self-sufficiency for as long as possible, in an environmentally appropriate manner.

To help fulfil this objective, the Government coordinates research initiatives with public and private corporations.

State-subsidized research related to oil and natural gas is conducted under the Energy Research Programme (ERP) and under the auspices of the EU and the Nordic Council of Ministers.

In terms of their administration, objectives and publications of results, the individual research programmes are described in greater detail below.

RESEARCH PROGRAMMES

Energy Research Programme (ERP)

Support for research and development in the area of energy is granted under the Energy Research Programme. The Danish Energy Agency, which administers the programme, determines the overall strategy for and priority given to the areas covered by the programme, in cooperation with the *Advisory Energy Research Committee*. The annual applications for ERP funds far exceed the funds available. Committees of experts within the respective areas of research, including the *Oil and Natural Gas Research Committee,* assist the Danish Energy Agency in selecting the projects to be funded and in following up the progress of the selected research projects.

In the past four years, the action plan *Research and Development in the Area of Oil and Natural Gas,* published in March 1994, has served as the general basis for prioritizing the numerous ERP applications. This action plan will now be replaced by an updated plan covering the period 2000 to 2003.

The principal criterion for funding is the importance of the projects to society and their relevance in terms of fulfilling the energy-policy objectives set. The projects funded are divided into the following areas of research: exploration, recovery methods, equipment and installations, as well as arctic oil and gas issues. In granting funding to projects, the ERP attaches weight to how well a project ties in with previous ERP projects carried out and with international research projects.

In recent years, the Danish Energy Agency has funded oil and natural gas research projects with an average amount of about DKK 17 million per year. The subsidized companies, universities and research institutes have covered about 50% of project costs with own funds, which means that about DKK 34 million has gone into initiating energy research projects every year.

The oil and natural gas research programme primarily focuses on projects that contribute significantly to gaining access to further Danish oil and natural gas reserves through new exploration and production methods, as well as new technology.

As a main rule, the results of research projects and the new knowledge accumulated under the programme are to be available to the public. The final reports for all ERP projects completed are kept at Risø's library, which lends them out. In addition, Risø's library maintains a database (Nordic Energy Index, NEI) containing information about all ERP projects initiated and completed since 1981.

Information about the research programme can be obtained from the Danish Energy Agency and on its homepage, www.ens.dk. Information about ongoing and completed ERP projects can be found at the Internet address www.risoe.dk/nei.

EU Research and Development Programmes

The fifth EU framework programme for research, technological development and demonstration was adopted on 25 January 1999. The programme covers the period from 1998 to 2002. The total budget for the first activity under the fifth framework programme, which deals with the central programme areas, runs into EUR 10,843 billion, and consists of four thematic programmes. The fourth thematic programme has been divided into two subprogrammes, the environment and energy, which are considered independent, with their own budgets and committees. Funding in the amount of EUR 1,042 billion (DKK 7.7 billion) has been granted for the energy subprogramme.

The subjects dealt with under the energy subprogramme are cleaner technologies and renewable energy, accounting for about 46% of the total budgeted costs, and economic and efficient forms of energy (concentrating on the rational use of energy and hydrocarbon activities), accounting for the remaining 54%.

The draft energy work programme dealing with hydrocarbon activities is aimed at promoting more efficient exploration, recovery and production techniques. The objective is to make the identification of exploitable resources in the EU more efficient and to optimize recovery, while minimizing costs and the environmental impact by means of developing techniques that are globally competitive.

Specifically, techniques are sought to develop deep-water fields and fields difficult to access, including marginal fields and fields in the arctic area. The development of more efficient offshore production and subsea facilities is also desired. Production facilities are to be developed so that they can be removed in an expedient and environmentally friendly way, thus ensuring complete recycling.

The results of research projects and knowledge accumulated through participation in EU programmes must generally be available to the public. Information about completed projects can be obtained at Risø's library, while information about the programme sections relevant to energy and the respective deadlines for applications is available on the homepage www.cordis.lu/fp5/src/programmes, from the Danish Energy Agency's research division, from Energicenter Danmark and Euro-Center.

The Nordic Council of Ministers

On 1 January 1999, a new four-year research programme began. This programme places more emphasis than before on energy savings, renewable energy and cooperation with the local community.

The funding of petroleum technology research will be phased out over a two-year period, the aim being for this research to continue within another framework, based on financial support from the industries concerned.

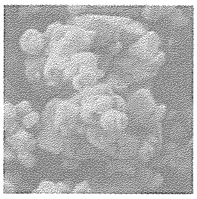
Further information about the programme is available on the homepage www.nordisk.energiforskning.org.

ENERGY RESEARCH IN 1998

Energy Research Programme 1999 (ERP 99)

In 1998, applications for ERP 99 were considered. Funding in the amount of DKK 60 million for 26 projects was applied for within the area of oil and natural gas. The total budgeted costs of these projects amounted to DKK 98 million. The selection made among the numerous applications resulted in funding for seven energy projects, totalling DKK 18.2 million. The implementation of these projects provides for research with total budgeted costs of DKK 38.9 million, including self-financing by the research institutes and industrial contributions. The funding of DKK 18.2 million granted for these projects equals approx. 47% of the total budgeted costs on average.

The criteria for selecting projects and their priority appear from the action plan *Research and Development in the Area of Oil and Natural Gas,* which covers the period 1995-99, as well as the material concerning *Call for Project Proposals for the 1999 Energy Research Programme.*



The projects funded under ERP 99 appear from Appendix G. The research topics of the individual projects are described in more detail below, and their numbering matches the project reference numbers stated in Appendix G.

Of the projects funded, one project concerns exploration, two concern recovery methods, two concern equipment and installations and two concern arctic conditions.

Exploration:

The objective of the project *Palaeozoic sedimentary deposits and basement structures in the Danish area* (0003) is to map the basement under the sediment basins, and thus to identify areas where subsidence may positively contribute to the formation and accumulation of oil and gas. Reflection seismic sections integrated with gravimetric, magnetic and refraction seismic data are analyzed to identify structures beneath the "conventional acoustic basement". This project falls within the scope of the research area selected for exploration of untested formations and traps within the Danish continental shelf.

Recovery Methods:

Priority – *Improved recovery from Lower Cretaceous Chalk reservoirs* (0009) - aims to stimulate interest in exploration and enhance the recovery of oil and gas from Lower Cretaceous chalk reservoirs of Barremian and Aptian age. This project is intended to improve understanding of the special properties of such reservoirs, whose poor quality and lack of formation stability make recovery difficult. ERP funding has been granted for the remaining two years of the scheduled five-year programme period. The Priority Project, which has special significance for energy-policy aims, falls within the special priority areas of the action plan.

The aim of the project *On the significance of three-phase displacement mechanisms for recovery efficiency in connection with the planning and optimization of WAG/CGW injection* (0011) is to investigate three-phase flow properties (oil, gas and water) by setting up micromodels and through mathematical network modelling. The purpose is to achieve three-phase relative permeability data at macroscale level that reflect the conditions at microscale level. This project follows up a project previously funded under ERP 94.

Equipment and Installations:
One project, *Free span burial instrumentation pig – phase A* (0013), is aimed at devising a method for checking pipelines internally for free spans, to determine the thickness of the pipeline covering and to check whether the external concrete coating is intact. This project is a further development of projects previously funded under ERP 91 and ERP 95, and a continuation of a Thermie 92 project.

Another project, *Improved design basis for offshore flexible pipes* (0014), may impact on the use of flexible piping to transport oil and gas containing corrosive components. The aim of the project is to determine, through measurements and modelling, whether methane, carbon dioxide and hydrogen sulphide are able to permeate the internal lining of a flexible pipe to the steel reinforcement, where they may cause corrosion.

Arctic Conditions:
The purpose of one project, *Mapping and evaluation of the Nuussuaq Basin* (0024), is to collect and interpret new seismic data, thus improving understanding of the structural composition of the Nuussuaq Basin, and to stimulate interest in commercial exploration of the area. This project is a continuation of two projects previously financed under ERP 95 and ERP 96.

The other project, *An integrated study of the stratigraphy and hydrocarbon prospectivity of Palaeozoic sediments offshore southwestern Greenland* (0025), is aimed at mapping Palaeozoic sediments offshore southwestern Greenland through a sequential stratigraphic study.

Both projects involve investigations of unlicensed areas.

ERP Projects completed in 1998
In 1998, 16 projects funded in whole or in part under the oil and natural gas programme were completed. The distribution of these projects on the areas covered by the action plan appears from the Table 4.1. In addition, the table shows the year in which the projects were granted funds under the ERP programme.

Table. 4.1 ERP Funding

	Exploration	Recovery Methods	Equipm. & Install.	Arctic Cond.
ERP-94	1	1		2
ERP-95	2	2	3	
ERP-96	1	3		1
Total	4	6	3	3

Appendix G indicates the project title and participating institutions/businesses for all projects completed in 1998.

Exploration:
Three of the four exploration projects have led to the discovery of good and mature source rock material in Middle and Upper Jurassic layers in the area comprised by the Central Graben. Source rock was found in Upper Jurassic layers in the Feda and Gertrud Graben and in the Heno Plateau. Investigation of Middle Jurassic sections has improved our knowledge of the source rock potential and its regional variation in the Central Graben. These projects also dealt with migration paths from Jurassic source rock up to the Cretaceous and Lower Tertiary chalk fields in the Central Graben, and the amounts of hydrocarbons formed were estimated. In addition, optical and geochemical data were used and correlated to borehole logs to identify sequential stratigraphic surfaces for the purpose of developing better geological models.

Finally, a fourth project studied the Jurassic succession in the Gertrud Graben, using advanced seismic data correlated to well data. This study shows with a high degree of probability that the sand deposits penetrated by the Jeppe-1 well can also be found in the central part of the Gertrud Graben, thus constituting an interesting exploration objective.

The results of the projects carried out are likely to have stimulated the oil companies' interest in applying for exploration licences in the Fifth Licensing Round.

Fig. 4.1 ERP 99 Funding Broken down by Area of Research

Recovery Methods:
Six projects have been carried out under the heading Recovery Methods.

One project involved utilizing micromodels with varying pore geometrics and porous network structure to make experimental studies of transport mechanisms at microscale level. The results of the project make it possible to upscale displacement processes from microscale level.

Another project shows how to obtain a geophysical and geostatic reservoir characterization as a basis for a subsequent reservoir simulation. As part of this project, the 3D seismic inversion method was employed to establish the acoustic impedance and porosity of the Dan Field; the result has proved useful in planning further field developments and production from the field.

Two projects address the potential use of various physical methods in studying saturation profiles and displacement processes in porous cores.

Under one of these projects, four methods were tested: gamma transmission, NMR, CT scanning and electric impedance. The applicability of the individual method was subsequently investigated by comparing it with the other methods. The NMR method and CT scanning proved to be the best methods for determining the distribution of saturations in porous cores.

Moreover, under a fourth project, attempts were made to obtain two-dimensional saturation images of a cross section of a core, by measuring the transmission through the cylindrical core with parallel gamma rays, and by measuring gamma quanta in scattered radiation. This method has not yet been developed for practical application in the oil industry.

As the result of a fifth project, a new method has been developed to determine saturation functions, capillary pressure and relative permeability in chalk samples. This method utilizes the so-called "end-effect" in displacement tests on samples with high capillary pressure. It seems to be faster than any other method.

Finally, a sixth project deals with the upscaling of detailed small-scale geological models into reservoir simulation models for subsequent use in calculating and predicting the production from Danish chalk fields.

Equipment and Installations:
One project under this heading concerns the formation of wax, which may be a major problem in the production of oil and its subsequent transportation. Wax is precipitated when oil with a large paraffin content cools. Under this project, improved equipment and methods were developed for calculating wax precipitation at high pressures.

The aim of another project was to determine the risk of both internal and external corrosion, as well as the formation of cracks in natural gas transmission pipelines. The soil corrosiveness and the corrosion rate due to sulphide and sulphate reduction were determined at various locations in Denmark. Equipment for corrosion testing of soil was developed and manufactured. Further, the risk of hydrogen brittleness developing was investigated.

Fig. 4.2 Project Areas in Greenland

Under a third project, a tracer method for measuring the multi-phase flow of gas/oil/water in horizontal production pipelines was developed. This method is based on marking each of the three flows with a different radioactive tracer. The method has been tested in the North Sea with good results.

Arctic Conditions:
Three arctic projects concerning Greenland have been completed.

One project has provided new information on sedimentology and biostratigraphy in the southeastern part of the Wandel Sea Basin in northeastern Greenland, including new information on the area's hydrocarbon potential.

Two other projects involved further investigations of the hydrocarbon potential in the Nuussuaq area in western Greenland.

One of these projects was intended to improve insight into the subsidence and uplift history. Because the late uplift history is of major importance to the occurrence of mature source rock in the area, the project has contributed to evaluating the exploration potential. The above mentioned locations are shown on Fig. 4.2.

The other project deals with delimiting prospective reserves in the Nuussuaq Basin by means of geophysical investigations. This has rendered the presence of source rock, reservoirs and seal beds in the area likely, and all the geological conditions required for the presence of major hydrocarbon accumulations in the area have been confirmed.

EU Research and development Programmes
As stated above, funds of DKK 7.7 billion have been allocated to energy research under the fifth EU framework programme, which covers the period 1998-2002. The active interaction between public- and private-sector energy research gives Danish research a good chance of continuing to hold its own in the competition for European research funds.

The Nordic Energy Research Programme
In 1998, the Nordic Energy Research Programme allocated funds to senior researchers and student researchers, who are participating in inter-Nordic research cooperation at Nordic universities. The following topics related to hydrocarbons are given priority: petroleum fluids, oil technology and petrophysics (upstream operations), as well as catalytic processes, separation processes and reactive distillation (downstream operations).

The Energy Research Programme (ERP) finances the Danish participation in this cooperation. In 1998, grants were awarded for one PhD scholarship and 15 senior researchers (including six Danish) in the area of petroleum technology.

More Participants in the Joint Chalk Research

In 1997, it was decided to continue the cooperation on *Joint Chalk Research* by extending the programme with a fifth phase. The new phase is scheduled to run for a period of two years until the year 2000, and has an overall budget of about DKK 17 million.

The subjects of research in the new phase can be given the following headings: geology, rock mechanics and recovery processes. The research topics are discussed in more detail in the Danish Energy Agency's report *Oil and Gas Production in Denmark 1997*.

When the contract for this joint research programme was signed in 1997, nine oil companies, seven Norwegian and two Danish, had joined the programme. In 1998, another German oil company, RWE-DEA, and a Dutch oil company, Veba Oil Nederland B.V., became participants. The background for these companies' interest is that RWE-DEA is a licensee and Veba Oil Nederland B.V. is the operator of a new chalk oil field situated on the Dutch continental shelf close to the Danish sector.

The public authorities, which were behind this Joint Chalk Research Programme at the beginning of the 1980s, are pleased to see the oil companies today cooperating on research of their own accord, thus jointly addressing the problems associated with improving the recovery of oil and gas from the tight chalk reservoirs in the North Sea.

The Danish companies/research institutes involved in this research programme are the Geological Survey of Denmark and Greenland, COWIconsult AS, the Danish Geotechnical Institute and the Technical University of Denmark. Danish research will account for about one third of the total funds allocated to this programme.

5. FLUCTUATIONS IN THE OIL PRICE

At the end of 1997, the international crude oil price plummeted. The fall in the oil price continued throughout 1998, bottoming out in December with a price of less than USD 10 per barrel, the lowest since July 1986. The average crude oil price (as quoted for Brent oil) for 1998 was USD 12.8 per barrel.

At first glance, the development in the crude oil price over the past 30 years presents a very confused picture; see Fig. 5.1. The precipitous increases and decreases in price are the most conspicuous. What is the explanation? Below, a brief description is given of the various factors determining the evolution of oil prices.

DEVELOPMENT IN THE CRUDE OIL PRICE

The price of crude oil is determined by the development in the total supply and overall demand for crude oil on the world market.

The Organization of Petroleum Exporting Countries, OPEC, has greatly influenced the formation of oil prices. OPEC was established in 1960, and its present members are Iran, Iraq, Kuwait, Qatar, Saudi Arabia, the United Arab Emirates, Algeria, Libya, Nigeria, Indonesia and Venezuela.

Until 1973, the international price of crude oil reflected the actual costs associated with exploration and production. The price was just high enough to make it pay to produce the most expensive barrel of oil necessary for meeting overall demand.

The steep price increases of 1973 and 1979 were spurred by political conflicts in the Middle East. During these crises, the OPEC countries reduced the supply of crude oil on the world market, forcing up prices dramatically. Prices did not subsequently fall to the level prevailing before the oil crises because the OPEC countries began using quotas to control prices. Since then, this quota scheme has been the OPEC countries' most important tool for controlling prices on the world market. The aim of this scheme is to fix the quotas so low that the limited supply results in a higher price, since the actual price fixing is left to the market.

Since introducing the quota scheme, OPEC has felt the repercussions of high oil prices. Firstly, the consumption of crude oil is declining because the consumer countries have introduced energy conserving measures, established renewable

Fig. 5.1 Development in the Oil Price from 1972-98 (as quoted for Brent oil)

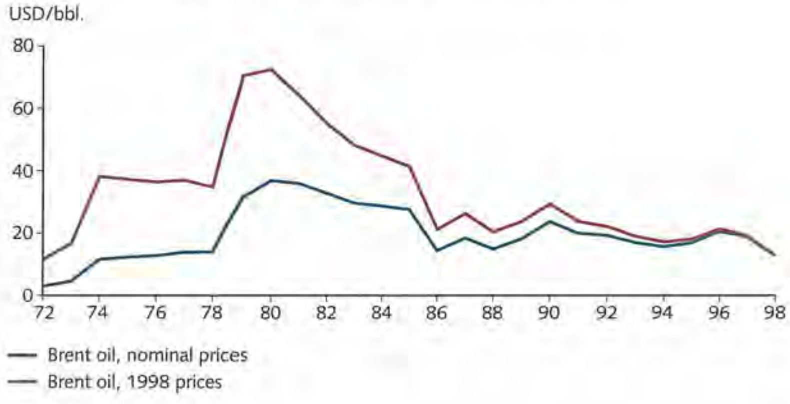
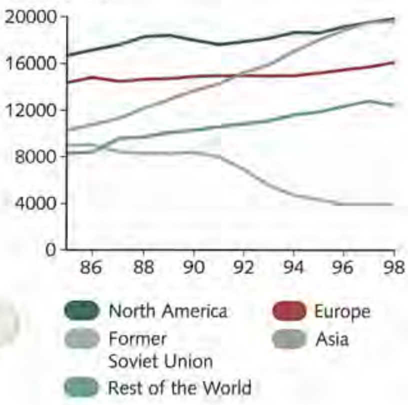


Fig. 5.2 Breakdown of Oil Production by Region

Fig. 5.3 Demand for Crude Oil on the World Market



energy facilities and developed alternative fuels. Secondly, the high prices mean that it pays to increase production substantially in the countries not comprised by the quota scheme. Consequently, the OPEC countries' market share shrank from more than 50% at the beginning of the 1970s to about one third in the course of the 1980s. To bolster the price level, OPEC has regularly been forced to reduce its quotas, in order to compensate for the growth in supply from countries outside OPEC.

In the course of the 1980s, this development created conflict among the OPEC countries, which had difficulty in deciding on the distribution of cutbacks. To protect their oil revenues, several OPEC countries failed to observe the quotas agreed upon.

Precisely this situation, combined with subdued growth in demand from consumer countries, caused the market to collapse in the summer of 1986. An excess production of about 2 million barrels per day sent prices plunging to below USD 10 per barrel.

OPEC soon regained control of the market by immediately limiting supply. Subsequently, Saudi Arabia forced through measures aimed at stabilizing the price level at about USD 19 per barrel, which was considerably lower than at the beginning of the 1980s. This means that the OPEC countries have gradually retrieved their market shares. In the 1990s, the OPEC countries' production accounted for about 40% of world market production. Fig. 5.2 shows a breakdown of the production of crude oil by region in recent years.

Since the collapse of crude oil prices in the mid-1980s, the average price has hovered around USD 18 per barrel, except for the high prices prevailing during the Kuwait crisis in 1990-91.

Nevertheless, the OPEC countries' control of the market has diminished in the intervening period, because nearly all OPEC countries now exceed their quotas.

In 1998, the market collapsed again. The drop in the oil price in 1986 and 1998 reveals a characteristic feature of the oil market, viz. that a slight excess production can lead to a nosedive in prices.

WHAT HAPPENED IN 1998?

As in 1986, the drop in the oil price in 1998 was caused by a number of coinciding factors relating to both demand and supply on the world market.

What happened to demand?

As appears from Fig. 5.3, Asia plays an increasingly important role in the global demand for crude oil. After experiencing rapid economic growth for a number of years, Asia has accounted for a larger share of the demand for crude oil than Europe in recent years. Today, the Asian countries' demand largely represents the same volume as the combined demand of the USA and Canada. However in the wake of the economic crisis in Asia, which set in in mid-1997, the demand for crude oil from the Asian market stagnated in 1998.

The demand for crude oil in the former Soviet Union has declined dramatically since the Union disintegrated. In the Western world, the demand for crude oil has remained fairly constant for the past ten years.

During the same period, the supply of crude oil on the world market has climbed slowly. It is therefore not surprising that the economic crisis in Asia had a major impact on the crude oil price in 1998. Precisely the growth in Asian economies in recent years has caused the world market to expect a growth in demand for crude oil.

At the same time, the low crude oil price has not increased demand from the rest of the world. There are several reasons why falling oil prices are not matched by a corresponding hike in oil demand. In most countries, oil forms part of the total supply of energy. Therefore, the consumption of oil is ruled by a number of technical and environmental factors which mean that consumption reacts slowly to changed prices.

The International Energy Agency, IEA, voiced the opinion at the beginning of 1999 (Oil Market Report, January 1999) that it is unrealistic to expect substantial increases in world market oil prices, unless the Asian economy recovers.

What happened to supply?
The decline in demand from the Asian countries has not yet caused the world market to adapt its production of crude oil correspondingly.

Like demand, the supply of crude oil reacts slowly to price changes.

Perhaps this can best be illustrated by contemplating a minor, fictitious field in the North Sea. If an oil price of USD 12 per barrel is required in order for production from the field to be economically viable, it could easily be assumed that operations in the field would be discontinued if the price dropped below USD 10 per barrel. However, when discontinuing the operation of a field, only the actual operating costs, i.e. USD 5 per barrel, are saved. The remaining costs typically consist of interest and repayments on loans, which have to be paid regardless of whether the field is shut-in or not. As long as the crude oil price is higher than the actual operating costs, it will pay to carry on production. Thus, it will frequently be most worthwhile to continue producing oil, even in periods when prices are very low.

As opposed to most other commodities, crude oil is difficult to store, as the storage capacity is limited. Oil has to be sold fairly quickly after being produced. Therefore, it is usually not possible to inflate prices artificially by storing the oil temporarily in storage facilities.

As OPEC - and other oil-producing countries - have failed to adapt the supply of crude oil to the stagnating demand through quotas, the consequence is the heavy fall in prices witnessed throughout 1998.

Despite meeting several times throughout the year to address the problem, the OPEC countries have only managed to agree on minor reductions in the supply.

Since April 1998, the aim of the OPEC countries was to reduce production by 2.2 million barrels per day on average for the rest of 1998 (Monthly Oil Report, January 1999). However, only about 70% of this target was met, because some OPEC countries produced beyond the quotas agreed upon internally. At the same time, the daily production from Iraq went up by about 1 million barrels in 1998 compared to 1997. In total, the OPEC countries, including Iraq, have thus succeeded in reducing the supply of crude oil by about 0.5 million barrels per day.

However, the OPEC countries' total production figure is never known with certainty, as they presumably carry on unofficial production and trade to circumvent the predetermined quotas and thus secure additional export earnings.

In addition, several oil-producing countries outside OPEC, including Norway, Mexico and Russia, have cut production by 0.5 million barrels of crude oil combined.

In the opinion of the IEA (Monthly Oil Report, December 1998), a further 1-2 million barrel reduction per day is required if crude oil prices are to begin climbing in earnest. These figures should be viewed on the basis of a total global daily production of crude oil of about 75 million barrels in 1998.

FUTURE DEVELOPMENT?

It has always been difficult to make predictions about the development in the crude oil price. A mere two years ago, no-one would have foreseen the dramatic fall in the oil price experienced in 1998. It is just as difficult to anticipate developments in the years to come.

However, if the low oil price prevails for several years to come, this will probably mean that the OPEC countries will recapture their lost market shares in the longer term. Today, the OPEC countries in the Middle East control about 60% of global oil reserves. These reserves are easily accessible and are therefore producible at a far lower cost than in the rest of the world. A prolonged period with low crude oil prices will presumably make developing new fields economically viable only in the Middle East. Production from the rest of the world will therefore decline in the long term.

Other factors also come into play. When the Asian economies recover, the demand from this part of the world will grow again and thus force up the crude oil price. In fact, the low oil price may prove an advantage for the Asian countries, as most of them are dependent on oil imports.

At the same time, the market is waiting for the large oil-producing countries, in particular the OPEC countries, to make the necessary cuts in production. Considering the OPEC countries' dependence on their income from crude oil exports, they must be expected to reach agreement, sooner or later, on the fairly moderate measures, required to raise the crude oil price to, say, USD 20 per barrel.

6. ECONOMY

The Danish economy benefits from the oil and gas production activities in the North Sea. In 1998, Denmark was self-sufficient in energy for the second consecutive year. The production of oil and natural gas in the North Sea is the driving force behind this result. Oil and gas production also has a positive impact on the Danish balance of payments and secures revenue for the state.

CRUDE OIL PRICES AND DOLLAR EXCHANGE RATE 1998

The value of the Danish oil and gas production is contingent on the development in the international crude oil price, and thus the fluctuations in the dollar exchange rate.

1998 was characterized by very low oil prices. The fall in the oil price that set in towards the end of 1997 continued throughout 1998. From a price of USD 15.1 per barrel in January, the crude oil price (as quoted for Brent oil) dropped to less than USD 10 per barrel in December. Thus, the average crude oil price for 1998 ended at USD 12.8 per barrel. This was a precipitous fall compared to 1997, when the average oil price was USD 19.1 per barrel. The low prices are due mainly to lower demand from the Asian countries, in the wake of the financial crisis. Moreover, the OPEC countries did not succeed in controlling prices by making agreements on restrictions in the supply. The section on *Fluctuations in the Oil Price* contains a more thorough analysis of the development in the crude oil price.

The average USD exchange rate was DKK 6.70 in 1998. This is a slight increase compared to 1997, when the USD exchange rate averaged DKK 6.61. In terms of Danish kroner, this increase compensates somewhat for the sharp drop in the crude oil price.

SALES VALUE OF OIL AND GAS PRODUCTION

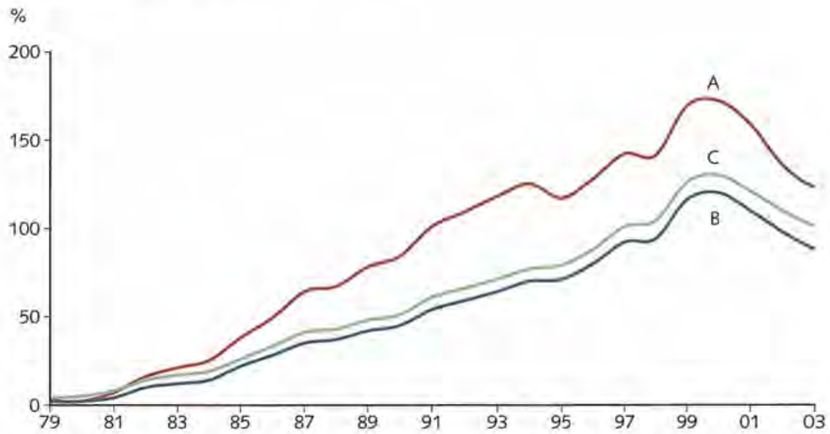
The low oil price in 1998 impacted on the total value of Danish oil and gas production. The aggregate value of the DUC companies' production in 1998 declined by 22% to about DKK 10.9 billion, relative to DKK 13.9 billion in 1997.

In 1997, the total sales value of Danish oil production amounted to DKK 10.3 billion, compared to DKK 3.6 billion for Danish gas production. The preliminary figures for 1998 show that the production of oil generated proceeds for the DUC companies of about DKK 7.6 billion, while the sales value of their gas production is estimated at DKK 3.3 billion.

The Lulita Field came on stream in 1998. The income from production in this field is shared equally by the DUC companies and the Statoil group; see Appendix E. Lulita is the first field from which companies other than the DUC companies have been able to derive earnings from oil and gas production in the North Sea. In 1998, the Statoil group's share of income from the Lulita Field amounted to about DKK 41 million.

The cumulative value of the oil and gas produced in the Danish part of the North Sea since 1972 amounted to about DKK 165 billion in 1998 prices.

Fig. 6.1 Degrees of Self-Sufficiency



In the years to come, the development in the value of production will depend on the amounts produced, the trend in product prices and the dollar exchange rate. Based on the known amount of reserves, the Danish Energy Agency estimates that oil production will peak in the years 1999-2000, and then start declining if no new development initiatives are taken. Until the year 2001, gas production is expected to climb, after which it is assumed to remain constant for a number of years. How the oil price will develop is very difficult to predict, so the development in the sales value of oil production in future years is subject to great uncertainty.

DEGREES OF SELF-SUFFICIENCY

In 1997, Denmark became self-sufficient in energy for the first time. The combined Danish production of crude oil, natural gas and renewable energy exceeded total Danish energy consumption by 1%. The preliminary figures for 1998 indicate that total energy production exceeded total energy consumption by 4%.

The development in the degrees of self-sufficiency in the past 20 years and the expected development for the next five years is illustrated by the three curves in Fig. 6.1. Curve A shows the production of oil and natural gas relative to domestic oil and gas consumption. Curve B shows the production of oil and natural gas relative to total domestic energy consumption. Curve C shows the development in total domestic energy production relative to total domestic energy consumption, i.e. the degree of self-sufficiency for the Danish economy as a whole.

Table 6.1 Degrees of Self-Sufficiency

	1999	2000	2001	2002	2003
Production (PJ)					
Crude Oil	649	655	573	467	392
Gas	311	341	350	350	349
Renewable Energy	82	84	92	101	103
Energy Consumption (PJ)*					
Total	825	831	836	835	838
Degrees of Self-Sufficiency (%)					
A	168	172	159	136	123
B	116	120	110	98	88
C	126	130	121	110	101

** Including fuel consumption offshore. The projection was made in spring 1996*

A. Oil and gas production vs domestic oil and gas consumption.
B. Oil and gas production vs total domestic energy consumption.
C. Total energy production vs total domestic energy consumption.

The rise in oil and gas production has made Denmark increasingly self-sufficient in these energy products. The efforts to channel supplies into more types of fuel have also contributed to making Denmark self-sufficient in oil and natural gas from 1991 (A). In 1998, total oil and gas production amounted to 94% of total Danish energy consumption (B), and from 1999, the production from the North Sea is expected to exceed Denmark's total energy consumption.

The Danish Energy Agency estimates that the current situation, where Danish energy production exceeds consumption (C), will be upheld at least until end-2003; see Table 6.1. Like oil production, the degree of self-sufficiency will peak in the year 2000.

IMPACT OF PRODUCTION ON THE ECONOMY

The oil and gas activities in the North Sea have a positive impact on the Danish economy. Our own production of oil and natural gas has a beneficial effect on the balance of payments and the revenue generated for the state.

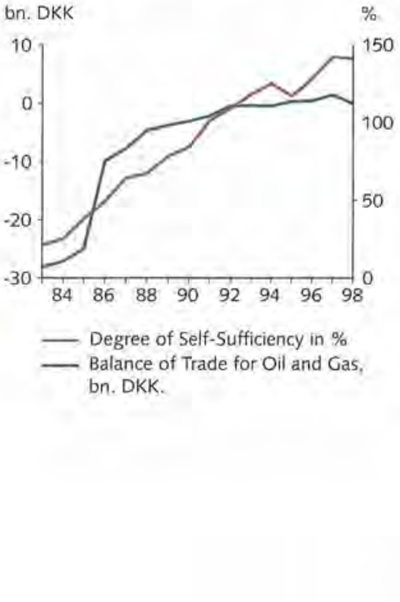
Economic Assumptions

Two oil price scenarios have been used in making the calculations in this section. Both scenarios operate with a crude oil price of USD 11 per barrel in 1999 and USD 13 per barrel in 2000. After that, the two scenarios differ in that one assumes continuously increasing prices until 2005, after which the price will remain constant at USD 22 per barrel, while the other operates with a constant price of USD 13 per barrel from 2000 and onwards. In both scenarios, the price of natural gas is assumed to parallel the development of the price of crude oil.

These projections cannot be considered crude oil price forecasts. One of the main purposes of operating with two different price scenarios is to show how sensitive financial projections are to fluctuations in crude oil prices.

Both scenarios are based on a dollar exchange rate of DKK 6.40 per USD for the whole period covered by the projection.

Fig. 6.2 The Balance of Trade for Oil and Gas and Degree of Self-Sufficiency, 1998 Prices



The Balance of Trade for Oil and Natural Gas

The trade in oil products and natural gas accounts for an increasing share of Denmark's trade with other countries. The financial impact of this trade can be illustrated by the balance of trade for oil and natural gas, which reflects the difference between total exports and imports.

The balance of trade shows the same trend as the degrees of self-sufficiency. If a large portion of a country's energy demand is covered by its own production, the country will also have a high degree of self-sufficiency. The balance of trade improves due to diminishing energy imports. Thus, in periods with stable prices, the degrees of self-sufficiency will develop on a par with the balance of trade for oil and natural gas. Fig. 6.2 illustrates the development in the balance of trade and the degree of self-sufficiency in oil and natural gas (A).

As opposed to the degree of self-sufficiency, the trend in the balance of trade does not depend merely on the size of energy production relative to consumption. The composition of the products traded and the development in oil product prices are also highly significant to the balance of trade.

Until the mid-1980s, Danish trade with foreign countries was appreciably affected by the net import of oil. In 1985, the net import of oil products contributed to the deficit on Denmark's overall balance of trade with an amount of about DKK 18 billion. By way of comparison, Denmark had a deficit of about DKK 8 billion on its overall foreign trade balance. Throughout the 1990s, the increasing production of oil and natural gas eliminated the large deficits. Since 1992, the annual deficit on the balance of trade for oil and natural gas has been less than DKK 1 billion. In 1995 and 1996, the balance of trade showed a surplus of the same size, and in 1997, the surplus on the balance of trade for oil and natural gas was at a record high, viz. DKK 1.4 billion.

The preliminary figures for 1998 indicate a surplus of about DKK 1 billion. The export of natural gas to Sweden and Germany contributes with a surplus of about DKK 1.8 billion, while the trade in oil products will yield a deficit of about DKK 0.8 billion. The reason that the trade in oil products yields a deficit even though Denmark is self-sufficient in oil is that Denmark imports fairly many expensive products, such as aviation petrol for jet engines, whereas the income from exports generally derives from cheaper products, including fuel oil. However, there was still a surplus on the trade in petrol, a relatively expensive product, in 1998. The closedown of a refinery at Stigsnæs on the west coast of Zealand in April 1997 also meant that the share of exports accounted for by fairly expensive refined products diminished.

Effect on the Balance of Payments

The production of oil and natural gas improves the Danish balance of payments. Part of the production is exported, and the share of production used in Denmark replaces the energy imports otherwise required.

Based on the above assumptions as to crude oil prices and the dollar exchange rate, the Danish Energy Agency has made an estimate of the extent to which oil and gas activities in the Danish part of the North Sea will affect the balance of payments in the years to come. It should be emphasized that the estimates are based on models incorporating standard assumptions. For one thing, it is necessary to make assumptions about the import share of future investments and operating costs. Despite the uncertainty surrounding such calculations, there is no doubt that Danish oil and natural gas production has an extremely favourable effect on the balance of payments on current account.

The socio-economic production value illustrated by Table 6.2 shows the value of direct export revenue and the savings on import costs. When the import share of investments and operating costs is subtracted, the effect on the balance of goods and services results. The direct effect on the balance of payments on current account can then be calculated by deducting interest and dividends transferred abroad.

Table 6.2 Effect of Oil/Gas Activities on the Balance of Payments, DKK billion, 1998 Prices, Constant Prices

	1999	2000	2001	2002	2003
Socio-Economic Production Value	11.0	13.1	12.0	10.5	9.5
Import Share	4.3	2.9	1.7	1.7	1.3
Balance of Goods and Services	6.8	10.2	10.3	8.8	8.2
Transfer of Interest and Dividends	2.8	2.8	2.5	2.4	2.1
Balance of Payments Current Account	4.0	7.4	7.7	6.5	6.1
Increasing Real Oil Prices	4.0	7.4	8.9	8.5	8.8

The Danish Energy Agency estimates that the effect of the Danish oil and gas activities in the North Sea on the balance of payments on current account represented a value of about DKK 3 billion in 1998. In the report for 1997, the Danish Energy Agency estimated that the effect on the balance of payments would constitute about DKK 6 billion in 1998. The estimate made at the time was based on a crude oil price of USD 19 per barrel. This emphasizes how sensitive the result is to fluctuations in the oil price.

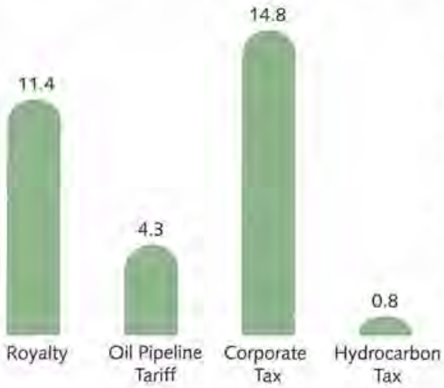
According to the new estimates made, the impact on the balance of payments will grow until 2001 due to rising production and declining investments. In these estimates, the price of crude oil is assumed to increase from USD 11 to 13 per barrel from 1999 to 2000, which affects the results in both price scenarios.

Not surprisingly, the impact on the balance of payments is larger when using the highest oil price scenario. This illustrates that the Danish production of oil and natural gas has greater significance in periods of climbing oil prices.

State Revenue

All companies producing oil and natural gas in the Danish part of the North Sea are liable to pay corporate tax and hydrocarbon tax, as well as a 5% profit element that is payable for the use of the Gorm Field-Fredericia oil pipeline owned by Dansk Olierør A/S, DORAS.

Fig. 6.3 Total State Revenue from Oil/Gas Production, 1972-1998, DKK billion, 1998 Prices



However, the oil companies may apply for an exemption from the obligation to connect their production facilities to the pipeline and to pay the 5% profit element to DORAS. If the oil is transported by tanker instead, the companies are to pay a 5% compensatory fee to the state.

Under A.P. Møller's Sole Concession and licences issued before 1989, royalty is payable. No royalty is payable under licences granted after 1989.

At end-1998, the accumulated state revenue from oil and gas production amounted to about DKK 31 billion in 1998 prices. Fig. 6.3 shows the total state revenue from these taxes.

Corporate tax and hydrocarbon tax are collected by the Danish Ministry of Taxation, Central Customs and Tax Administration, while the collection of royalty, the oil pipeline tariff and the 5% compensatory fee is handled by the Danish Energy Agency. Moreover, the Danish Energy Agency supervises the metering of the amounts of oil and natural gas produced on which the assessment of state revenue is based.

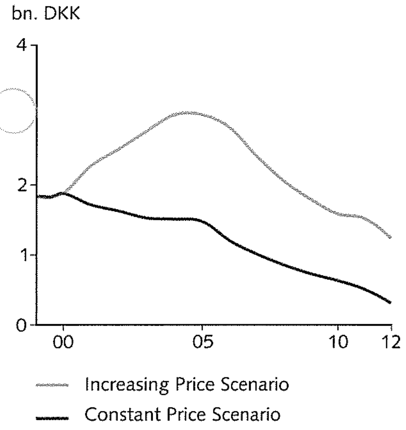
The low oil prices in 1998 made an impact on total state revenue from oil and gas production. The preliminary figures indicate that state revenue dropped by about DKK 0.5 billion compared to 1997; see Table 6.3. For the next five-year period, the Danish Energy Agency estimates that, based on the price scenarios used and the expected development in production, total state revenue will range between DKK 1.5 and DKK 2.8 billion; see Table 6.4. The future corporate tax projections are subject to additional uncertainty, as the calculations are highly sensitive to the assumptions regarding the oil companies' financing.

Table 6.3 State Revenue over the Past Five Years, DKK million, Nominal Prices

	1994	1995	1996	1997	1998*)
Hydrocarbon Tax	0	0	0	0	0
Corporate Tax	1,106	1,043	1,408	1,743	1,599
Royalty	670	663	944	1,097	861
Oil Pipeline Tariff	281	271	393	444	310
Total	**2,057**	**1,977**	**2,745**	**3,284**	**2,770**

Assessed amounts **) Estimate*

Fig. 6.4 Taxes and Duties, DKK billion, 1999-2012, 1998 Prices



As expected, Fig. 6.4 shows that in the somewhat longer term, tax revenue will decline in step with the expected downward trend in production.

This outlook may well change. The fact that the Minister for Environment and Energy awarded 17 new licences in the Fifth Licensing Round in the summer of 1998 ensured that a large area of the Danish subsoil will be subjected to thorough exploration. This improves the chances of the licensees making new commercial discoveries.

As the DUC companies are no longer the only companies producing oil and natural gas from the North Sea, in the years to come the Danish state will also receive tax payments from two different Statoil groups (the Lulita Field and the Siri Field) and from the Amerada Hess group (the South Arne Field). Appendix A shows the composition of these groups. As a licensee, the state-owned company, Dansk Olie og Gas produktion A/S, will share the production proceeds from the three new fields.

Corporate tax

Although production from the North Sea was commenced in 1972, the DUC companies did not become liable to pay corporate tax until the beginning of the 1980s. This fact illustrates that operations in the oil and gas sector require major investments that are not recouped for many years. Fig. 6.3 shows that at end-1998, state revenue from corporate tax payments totalled approx. DKK 14.8 billion in 1998 prices. With effect from 1 January 1999, the corporate tax rate was reduced to 32%.

Hydrocarbon tax

Hydrocarbon tax was introduced by a Parliamentary Act in 1982. The objective of the Act was to levy a special tax on high profits, particularly during periods with high oil prices. In addition, the Act provides an incentive for the oil and gas producing companies to reinvest their profits in further exploration and development activities. Hydrocarbon tax only became payable for a few years during the first half of the 1980s, with total hydrocarbon tax payments amounting to approx. DKK 0.8 billion in 1998 prices. In light of the investments foreseen and the expected development in crude oil prices for the next few years, it must be considered unlikely that hydrocarbon tax can be levied.

The oil pipeline tariff

DORAS owns the existing oil pipeline from the Gorm Field to Fredericia.
The users of the oil pipeline are obliged to pay the costs associated with the establishment and operation of the pipeline, as well as a profit element of 5% of the value of the crude oil transported. DORAS pays an annual tax to the state, below referred to as the oil pipeline tariff, since 1992 constituting 95% of the income from the 5% profit element.

In 1998, the pipeline tariff payments made by DORAS amounted to DKK 310 million, a 30% decline compared to 1997. Up to and including 1998, the pipeline tariff payments yielded revenue for the Danish state of about DKK 4.3 billion in 1998 prices.

5% compensatory fee

The Danish Oil Pipeline Act was amended in June 1997. The amendment stipulated that any parties granted an exemption from the obligation regarding connection to and transportation through the oil pipeline are required to pay a fee to the Danish state amounting to 5% of the value of the crude oil and condensate comprised by the exemption. Thus, the payment of such a fee was stipulated as a condition for exempting the Siri and South Arne Fields from this obligation.

Table 6.4 Expected State Revenue from Oil and Gas Production, DKK billion, 1998 Prices*

	1999	2000	2001	2002	2003
Hydrocarbon Tax	0.0	0.0	0.0	0.0	0.0
	(0.0)	(0.0)	(0.0)	(0.0)	(0.0)
Corporate Tax	0.9	0.8	0.7	0.8	0.7
	(0.9)	(0.8)	(1.1)	(1.4)	(1.6)
Royalty	0.6	0.7	0.6	0.6	0.5
	(0.6)	(0.7)	(0.8)	(0.8)	(0.8)
Oil Pipeline Tariff**	0.4	0.4	0.4	0.3	0.3
	(0.4)	(0.4)	(0.4)	(0.4)	(0.4)
Total	**1.9**	**1.9**	**1.7**	**1.7**	**1.5**
	(1.9)	(1.9)	(2.3)	(2.6)	(2.8)

* *Assessed amounts* *( ) Based on increasing oil prices* ***) Including 5% compensatory fee*

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Royalty

The royalty payable under A.P. Møller's Sole Concession of 8 July 1962 amounts to 8.5% of the total value produced, after deducting the cost of transporting the oil. The deductible transportation costs also include the 5% profit element. The royalty payable for any one year is based on the preceding year's production. In June 1998, the DUC companies made royalty payments of about DKK 1,097 million on production in 1997. Based on the 1998 production figure, the Danish Energy Agency expects that royalty payments of about DKK 860 million will be made in June 1999.

The Statoil group also pays royalty on its share of production from the Lulita Field. The percentage of royalty payable depends on the total value produced. In 1998, total royalty payments of about DKK 1.3 million were made.

Since 1972, a total amount of about DKK 11.4 billion in 1998 prices has been paid by way of royalty on the oil and natural gas produced from the North Sea.

THE FINANCES OF THE LICENSEES

Companies carrying on oil and gas production activities run a great risk in the exploratory phase. Exploration for commercial oil and gas accumulations involves exorbitant costs, and it is uncertain whether the investments made will yield any return. On the other hand, if discoveries are made, the production phase offers large earnings potential, even though it also involves major construction and operating costs.

Fig. 6.5 Total Costs of all Licensees 1963-1998, DKK billion, 1998 Prices

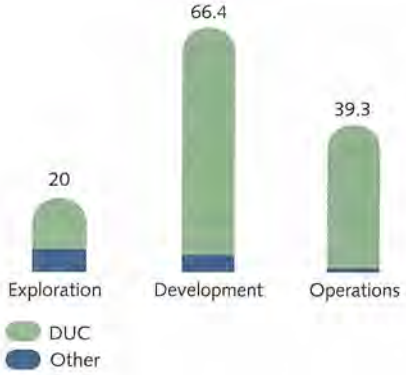


Fig. 6.5 and Appendix F show the total exploration, development and operating costs attributable to the licensees operating in the Danish part of the North Sea.

Costs of Exploration

Total exploration costs in 1998 have been preliminarily estimated at DKK 325 million. The three exploration wells, Francisca-1, Sandra-1 and Sine-1x, account for about DKK 100 million, while seismic surveys account for another DKK 100 million. The remaining DKK 125 million relates to other types of geological investigations and analyses, as well as administration. Total exploration costs for 1998 fall short of the 1997 figure, which was about DKK 520 million. This decline is attributable to six exploration wells being drilled in 1997, as opposed to three in 1998.

The terms of the licences awarded in the Fifth Licensing Round imposed unconditional work programmes worth about DKK 1.7 billion on the licensees, and at least 13 exploration wells are to be drilled over a six-year period. The work programmes to be performed in the Fifth Licensing Round are thus of the same scope as those stipulated in the Fifth Licensing Round in 1984.

It is planned to carry out 3D seismic surveys under a great many of the licences granted in the Fifth Licensing Round in 1999. The Danish Energy Agency expects two to three exploration wells to be drilled in 1999, with total exploration costs running into about DKK 600 million.

Table 6.5 Investments in Development Projects, DKK million, Nominal Prices

	1994	1995	1996	1997	1998*
Dan	412	526	1,708	1,272	1,090
Kraka	175	3	1	99	120
Regnar	1	-	-	-	-
Gorm	516	632	336	73	170
Rolf	0	0	0	1	95
Skjold	556	266	35	1	14
Tyra	1,158	1,450	731	236	170
Valdemar	106	1	80	1	-
Roar	25	289	72	2	-
Svend	55	200	164	0	13
Adda	-	-	-	144	70
Harald	149	810	1,079	486	100
Lulita	-	-	11	81	133
Siri	-	-	-	760	1,415
South Arne	-	-	-	592	1,890
Not allocated	-14	-12	40	75	28
Total	**3,140**	**4,166**	**4,257**	**3,824**	**5,308**

*)Estimate

In the years to come, the Danish Energy Agency expects an increase in exploration activity in step with the progress of the work to be performed under the licences from the Fifth Licensing Round. In addition, more exploration activity will result from the new licences continuously issued under the Open Door procedure and from existing licences.

Since 1963, the licensees have incurred aggregate exploration costs of about DKK 20 billion in 1998 prices, of which the DUC companies account for about DKK 13.4 billion. For a more detailed review of exploration activity in the Danish sector in 1998, see the section on *Exploration*.

Costs of Development

The present and future producing companies in the North Sea made total investments of about DKK 5.3 billion in 1998, the highest level since 1983 in terms of 1998 prices.

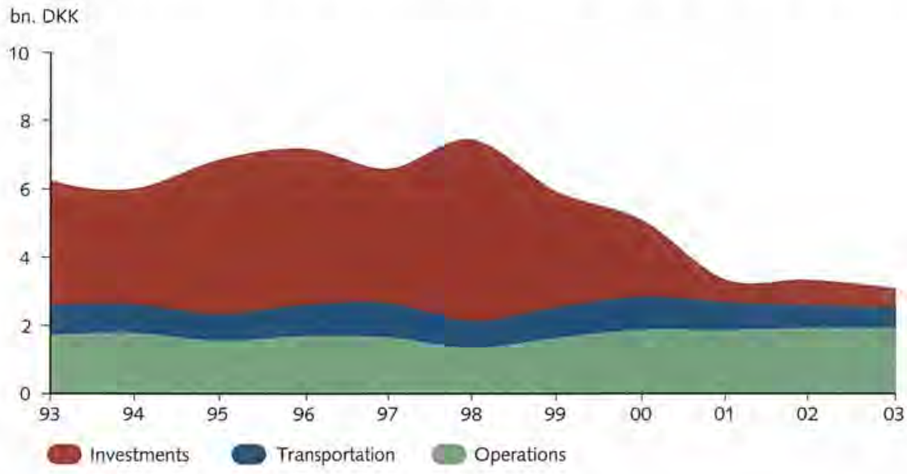
The completion of the most recent development project in the Dan Field accounted for the largest share of the DUC companies' investments. The largest investments made by the Statoil group and the Amerada Hess group related to the construction of platforms for the Siri and South Arne Fields; see Table 6.5. Based on the information currently available, the investment level is assumed to fall in subsequent years, as appears from Table 6.6. However, the Danish Energy Agency considers that there is additional potential for further development of a number of fields, which may also affect the investment level in the years to come.

The companies producing oil and natural gas in the North Sea incurred total investment costs of about DKK 66.4 billion in 1998 prices. DUC accounts for by far the largest share, viz. about DKK 61.6 billion in 1998 prices.

Table 6.6 Investments in Development Projects, DKK billion, 1998 Prices

	1999	2000	2001	2002	2003
Ongoing and Approved					
Dan	0.1	-	-	-	-
Alma	-	-	-	0.4	0.2
Igor	-	0.3	-	-	-
Skjold	0.6	0.1	-	-	-
Tyra	0.2	0.5	1.2	-	-
Roar	0.1	-	-	-	-
Valdemar	-	0.1	-	-	-
Svend	0.1	-	-	-	-
Adda	-	0.1	-	-	-
Elly	0.2	0.4	-	-	-
Harald	0.1	0.2	0.2	-	-
South Arne	1.4	0.5	0.5	-	-
Siri	0.7	-	-	-	-
Total	**3.4**	**2.2**	**1.9**	**0.4**	**0.2**
Planned	-	-	-	0.3	0.4
Expected	**3.4**	**2.2**	**1.9**	**0.7**	**0.6**

Fig. 6.6 Investments in Fields, as well as Operating and Oil Transportation Costs, DKK billion, 1998 Prices



Moreover, in 1998, DONG established a new gas pipeline for transporting gas from the South Arne Field. This pipeline emanates from the South Arne production facilities, conveying the gas produced to DONG's gas facilities at Nybro via DUC's Harald Field. The approximate cost of the new gas pipeline is DKK 2 billion.

Costs of Operations and Transportation

For a number of years, annual operating and administration costs have hovered around DKK 1.5 billion. Preliminary figures for 1998 indicate that the DUC companies cut these costs by about DKK 2-300 million last year. However, in connection with the startup of a number of new fields, the Danish Energy Agency expects that operating and administration costs will climb again in the next few years.

The total costs of transporting the crude oil produced consist of the operating costs as well as the capital cost of the oil pipeline. To this must be added the 5% profit element based on the value of the crude oil transported. In 1999, the final instalments on the loans financing the initial investment in the oil pipeline will be paid, thus reducing future payments towards the capital cost.

The oil produced in the Siri Field, which began producing in March 1999, and the South Arne Field, where production is expected to commence in the summer of 1999, will be loaded on board tankers via buoy loading facilities for transport to shore. As the Statoil and Amerada Hess groups have been granted an exemption from the obligation to use DORAS' oil pipeline, they are to pay a compensatory fee to the state, amounting to 5% of the value of the oil produced.

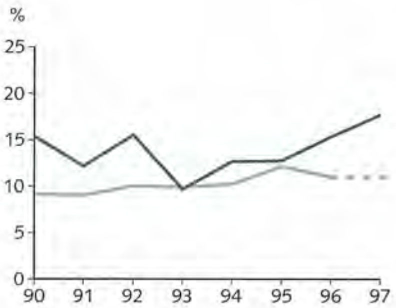
As appears from Fig. 6.6, the Danish Energy Agency does not expect any major fluctuations in transportation costs in the next few years.

The operating, administration and transportation costs incurred by the DUC companies totalled about DKK 39 billion in 1998 prices, while the total costs incurred by other licensees amounted to about DKK 0.3 billion in 1998 prices.

Financial Results of the DUC Companies

The DUC companies' pretax results have shown an upward trend for a number of years; see Table 6.7. They recorded a record-high result of DKK 6.6 billion in 1997, attributable mainly to increasing production and the higher dollar exchange

Fig. 6.7 Rates of Return (after Tax) for the DUC Companies and Other Danish Industries, 1990-1997



rate. The financial results recorded by the DUC companies for 1998 had not been published at the time this report went to press.

Fig. 6.7 shows the DUC companies' rate of return (a ratio reflecting the return on the capital invested) for the past few years, relative to the average rate of return for all other Danish industries. Generally, the DUC companies' rate of return is higher. For the period 1990-96, the average rate of return recorded by the DUC companies was 13%, compared to 10% for other industries.

The higher rate of return in the 1990s may be considered a kind of risk premium for companies engaged in oil and gas production.

Table 6.7 Pretax Results of the DUC Companies, DKK million, Nominal Prices

	1993	1994	1995	1996	1997
Income	8,741	8,723	8,615	11,632	14,048
Operating Costs*)	2,299	2,209	1,988	2,164	2,545
Interest Exp.	297	314	337	419	475
Exc.-Rate Adj.	-408	632	472	-491	-1,074
Gross Income	5,737	6,833	6,762	8,558	9,954
Depreciation	2,386	2,716	2,554	2,850	3,309
Pretax Result	**3,351**	**4,117**	**4,208**	**5,708**	**6,645**

*) *Incl. transportation costs and exploration costs charged to expense*

7. HEALTH, SAFETY AND THE ENVIRONMENT

The Danish Energy Agency supervises health, safety and environmental matters in connection with the exploration and production of oil and natural gas in the Danish part of the North Sea.

The Danish Maritime Authority handles certain aspects of safety supervision, especially such matters as concern the maritime equipment, design, strength, buoyancy and layout of mobile offshore installations, and matters concerning life-saving equipment, etc.

The Danish Environmental Protection Agency handles the environmental aspects of the supervision relating to emergency preparedness in case of pollution of the sea from offshore operations, and monitors discharges into the sea of substances and materials from offshore installations.

FIXED OFFSHORE INSTALLATIONS

1998 was characterized by the work involved in establishing the new offshore installations at the Siri and South Arne Fields. As regards the development of the Siri Field, the facilities were installed at the field, including the subsea oil storage facilities on the seabed, complete with oil loading facilities, and the platform housing production facilities and accommodation for the personnel operating the field. In the South Arne Field, a pipeline has been installed on the sea bed as part of the offshore oil loading facilities in the field. In addition, a gas pipeline has been laid from the South Arne Field, which conveys the gas produced to the west coast of Jutland via DUC's Harald facilities.

Minor new construction works included the modification and expansion of the Harald Field facilities required to phase in the Lulita Field.

In connection with these and other projects, in 1998 the Danish Energy Agency considered and issued a considerable number of permits for new construction projects, and issued a number of permits for offshore installation works and the subsequent commissioning of such new installations.

As in its previous approval work, the Danish Energy Agency has focused especially on the environmental and safety aspects of the individual installations, which are documented in the operator's environmental and safety assessments and safety management systems. The Danish Energy Agency has also continued its efforts to ensure a satisfactory working environment on the North Sea installations.

The Danish Energy Agency's Inspections

In 1998, the Danish Energy Agency paid inspection visits to selected, fixed offshore production installations in the North Sea, as part of its supervision of health and safety as well as fiscal metering systems.

MOBILE OFFSHORE INSTALLATIONS

The Danish Energy Agency's supervision is based on evaluating the physical and organizational layout of the installations before permitting them to be used in the Danish sector. Moreover, compliance with the relevant Danish regulations and licence terms is monitored through random checks made on the installations working in the sector.

Thus, for mobile installations operating in the Danish sector for prolonged periods, supervisory work consists mainly of monitoring compliance with conditions previously set. However, when such mobile installations are moved to new locations, the new location must be sure to present no safety hazards resulting from untoward interaction with other installations.

In connection with issuing permits for the use of installations not previously brought into agreement with Danish rules and regulations, major problems may arise because international regulations focus primarily on the most significant safety aspects, such as the buoyancy of the installations, their power supply and life-saving equipment, while they place less emphasis on accommodation facilities and the layout of industrial workplaces. Therefore, compliance with Danish regulations may require major alterations to the installations. In such cases, the public authorities will consider, taking into account the duration of the operations, and the general health and safety conditions on board the installation, whether the activities contemplated can be implemented under satisfactory conditions in another way.

In 1998, Dansk Naturgas A/S established a new gas pipeline connecting the fields in the North Sea to shore. The pipeline was installed by the pipe-laying barge *Castoro Sei.* The accommodation and working areas underwent major improvements before the pipe-laying barge was permitted to operate in the Danish sector. At the same time, restrictions limiting the number of persons allowed on board were agreed upon in order to curb the number of departures from Danish rules and regulations, which allow a maximum of two persons per cabin.

Statoil began installing Europipe II, a pipeline traversing the Danish sector, in 1998. The installation of this pipeline has been planned for a number of years, and the plan provided for the use of the newly built pipe-laying barge *Solitaire*. While the barge was being built, ALLSEAS, the company operating *Solitaire,* held regular discussions with the Danish Energy Agency, thus ensuring compliance with Danish rules and regulations from the initial stage of construction. Consequently, the Danish Energy Agency did not hesitate to grant permission for the use of *Solitaire*.

However, unforeseen difficulties arose during the running-in of *Solitaire,* and the barge was unable to complete the installation of Europipe II in the Danish sector within the time limit set. Therefore, as a relief measure, the Danish Energy Agency approved the use of *Castoro Sei* to lay the remaining part of Europipe II in the Danish sector.

Mærsk Olie og Gas AS employed the drilling rigs *Mærsk Endeavour, Mærsk Exerter, Noble Byron Welliver* and *Transocean Shelf Explorer* throughout 1998. Under the supervision of Danop and the operator, Amerada Hess, the drilling rig *Kolskaya* drilled production wells in the South Arne Field for the whole of 1998. Likewise, since mid-1998 the drilling rig *Noble George Sauvageau* has been performing drilling operations for Statoil in connection with the development of the Siri Field. Finally, the drilling rig *Glomar Adriatic VI* drilled two exploration wells for Danop and Statoil, respectively. The permission to use *Glomar Adriatic VI* was granted after a major expansion and enhancement of the accommodation facilities had been completed and the working environment at exposed workstations had been improved.

In addition to the above-mentioned drilling rigs and pipe-laying barges, several other vessels were employed in field developments and pipe-laying operations in 1998. They were typically employed for a few days only and required no major alterations in order to be permitted for use in the Danish sector.

NOTIFICATION OF INDUSTRIAL INJURIES

As previously, the statistics on industrial injuries on fixed and mobile offshore installations fall into two categories: statistics of work-related accidents reported and statistics of presumed or recognized work-induced conditions reported.

Work-Related Accidents

All industrial injuries sustained offshore must be reported to the Danish Energy Agency. Thus, a work-related accident must be reported if the injured person is unfit for work for one day or more in addition to the day of the accident.

In 1998, the Danish Energy Agency received 31 reports on accidents offshore, broken down as 17 accidents on fixed offshore installations, and 14 on mobile offshore installations. The reports on accidents occurring on board fixed offshore installations comprise accidents sustained in connection with the operation and maintenance of existing installations, during the construction of new installations and the expansion of existing installations. In addition, accidents reported for flotels are attributed to fixed offshore installations. Mobile offshore installations comprise drilling rigs, pipe-laying barges and crane barges.

None of the 17 accidents reported for fixed offshore installations occurred on board flotels, while the 14 accidents reported for mobile offshore installations break down as 12 on drilling rigs and two on pipe-laying barges.

None of the accidents reported were fatal or involved serious personal injury.

Nearly half of the 17 accidents on fixed offshore installations are attributable to tripping and falling incidents on board the installations, while the rest can be attributed to transporting goods, heavy lifting operations, colliding with various objects, chemicals, inexpedient working postures and a few other causes.

For the vast majority of these accidents, the reported period of incapacity for work was estimated at more than 14 days, while a few reports put the estimated period of incapacity at between four and 14 days. In a few cases, the persons injured were expected to be unfit for work for more than five weeks.

According to the reports, about half of the 12 accidents on drilling rigs occurred during work on drill floors and in derricks. The majority of these accidents occurred in connection with the manual handling of the drill string and other equipment.

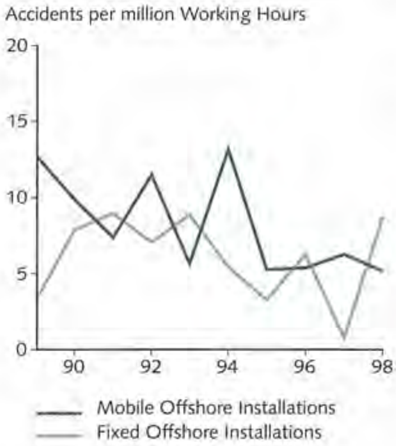
The rest of the accidents relate to contact with machinery and equipment in other areas of the platform, poor working postures and tripping and falling incidents on board the platform.

In most cases, the persons injured were expected to be unfit for work for more than two weeks, while the expected period of unfitness for work exceeded five weeks in one case.

Table 7.1 Accident Frequency on Offshore Installations

Year	Fixed Installations	Mobile Installations
1989	3.4	12.7
1990	7.9	9.9
1991	9,0	7.4
1992	7.1	11.5
1993	8.9	5.7
1994	5.5	13.5
1995	3.3	5.3
1996	6.3	5.4
1997	0.8	6.3
1998	8.8	5.9

Fig. 7.1 Accident Frequency on Offshore Installations



The two accidents on pipe-laying barges occurred during work with machinery and equipment, and both reports indicated an expected period of incapacity for work of more than two weeks.

Accident Frequency

When the work-related accidents reported for fixed offshore installations are related to the number of hours worked (1.94 million hrs.), it yields an accident frequency of 8.8 per million working hours.

Likewise, when the work-related accidents on mobile offshore installations, excluding flotels, reported in 1998 are related to the number of hours worked on these installations (2.68 million hrs.), it yields an accident frequency of 5.2 per million working hours.

The number of working hours is calculated on the basis of information received from the companies and the person-on-board lists, based on an average workday of 13 hours.

Table 7.1 and Fig. 7.1 show the accident frequency for each year in the period from 1989 to 1998 for fixed offshore installations, including flotels, and for mobile offshore installations.

By way of comparison, the average accident frequency for Danish onshore industries is 46.2 per million working hours (the Danish Employers' Confederation, Industrial Accidents 1997).

Fig. 7.2 Number of Working Hours on Offshore Installations

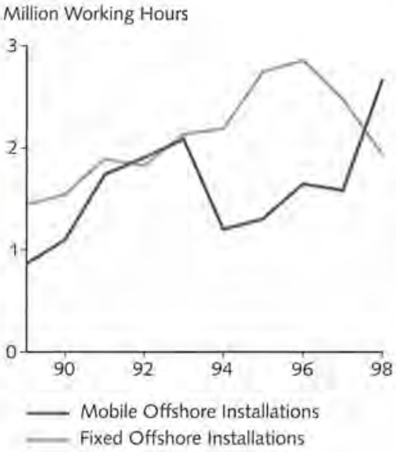


Fig. 7.2 shows the number of hours worked on fixed and mobile offshore installations in the Danish sector of the North Sea. The number of hours worked on mobile offshore installations in 1998 increased compared to previous years, due to the major construction works carried out in connection with installing new gas pipelines in the Danish sector, as well as the drilling and installation works associated with new field developments.

Work-Induced Conditions

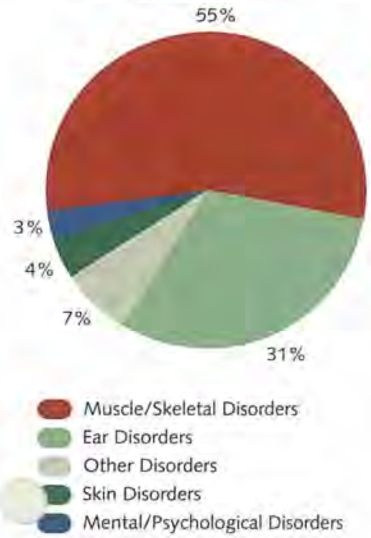
If a doctor suspects or ascertains that a condition has been induced by work on offshore installations, the Danish Energy Agency must be notified. The number of such notifications remains very low. Since 1993, the Danish Energy Agency has been notified of 29 presumed or recognized work-induced conditions, of which 12 were notified in 1998.

Fig. 7.3 shows the distribution of these 29 conditions on main diagnostic groups. Notifications have been received for both fixed and mobile offshore installations, but the vast majority relate to fixed offshore installations. The National Board of Industrial Injuries has also been notified of a number of the conditions reported for the purpose of recognizing them as industrial injuries.

CO_2 EMISSIONS RELATING TO ACTIVITIES IN THE NORTH SEA

The Danish Energy Agency was a member of the working group set up by the Danish Ministry of Taxation. This working group made an investigation as part of the Danish Government's latest austerity programme aimed at determining the potential for cutting CO_2 emissions from the oil and gas production activities in the North Sea.

Fig. 7.3 Work-Induced Conditions Reported, 1993-1998



It appears from the report prepared by the working group that CO_2 emissions from the activities on the fixed installations in the North Sea in 1997 were 1.6 million tonnes, accounting for about 2.75 per cent of total Danish CO_2 emissions. Due to the rising consumption of energy, attributable to the increasing age of the fields, among other factors, emissions are expected to increase to about 2.3 millions tonnes of CO_2, equivalent to about 4 per cent of total Danish CO_2 emissions.

The CO_2 emitted during the production of oil and gas is not subject to the CO_2 tax imposed on emissions from the majority of onshore industries.

However, these CO_2 emissions are regulated differently. Thus, all oil and gas production facilities must be approved prior to installation. Energy consumption and CO_2 emissions are also considered in this connection. In addition, the installations are currently monitored and production activities are regulated to reduce the flaring of gas.

Therefore, the potential for further cutting CO_2 emissions is already limited. Only the most cost-intensive options for reducing CO_2 emissions remain. It is estimated that the average cost of reducing CO_2 emissions will range from DKK 2,500 to 8,000 per tonne of CO_2 nearly ten times the level otherwise accepted in households, which bear the largest costs. Therefore, the level of CO_2 emitted from oil and gas production activities in the North Sea cannot be reduced at reasonable cost. Imposing a CO_2 tax at the ordinary rate applicable to onshore industries would have only a marginal effect on offshore emissions.

Likewise, the state revenue from introducing a CO_2 tax on energy consumption related to the production of oil and gas in the North Sea would be marginal. To this comes that, ultimately, the Danish state would presumably have to bear a large share of the resulting tax load, as the agreements made between Dansk Naturgas A/S and DUC would quite likely result in the fair share of the tax having to be paid by Dansk Naturgas A/S.

Therefore, if a CO_2 tax on the production of oil and gas were to be channelled back to the industry, along the line of other green taxes, the net result for the state would be a loss of revenue. Only if a departure were made from the principle of channelling back the tax, would the state achieve an equilibrium or limited revenue.

Finally, a CO_2 tax or similar cost-increasing schemes would contribute to reducing the total amount of oil and gas reserves recovered from Danish territory.

On the basis of the above, the report concludes that no benefit would result, either for the environment or in terms of state revenue, that would warrant subjecting offshore oil and gas production activities to the CO_2 tax.

ASSESSMENT OF EFFECTS ON THE ENVIRONMENT

As a result of the amendments to the Danish Subsoil Act enacted in 1995, the EU Council Directive on the Effects of Certain Private and Public Projects on the Environment was implemented with effect for the offshore industry, as the amendments created a legal basis for requiring environmental impact assessments for offshore projects. Thus, prior to the launching of the projects defined in the Subsoil Act, provided that the relevant projects are assumed to have a significant impact on the environment, an assessment of the effects on the environment must be made, accompanied by the necessary measures to ensure that the party seeking approval of such a project submits the information required for making the assessment. The environmental impact assessment must have been carried out before any approvals are granted under the Subsoil Act. No general rules were prepared for the submission of environmental impact assessments in connection with the amendment of the Subsoil Act.

In 1997, the EU Council Directive underwent certain changes, which do not affect the tenor of the Directive. The changes appear from Council Directive 1997/11/EC, and must be implemented in 1999. The amendments made to the Subsoil Act in 1995 authorized the Minister for Environment and Energy to lay down more detailed regulations as to which projects are to be comprised by the Act and which minimum information and investigations are required to make an environmental impact assessment. In addition, the Minister may lay down regulations regarding the notification and consultation of the public as well as the authorities and organizations concerned.

The changes following from the Directive have already been put to use for projects in the Danish part of the North Sea, as the companies in charge of developing the Siri and South Arne Fields have made environmental impact assessments for both field developments according to the rules laid down in the amended Directive. These environmental impact assessments were prepared in close cooperation between the energy and environmental authorities and the oil companies, and a reference group was set up, composed of representatives of the Danish Energy Agency, the National Forest and Nature Agency and the Danish Environmental Protection Agency, which monitored the work and offered advice to the companies.

Likewise, a reference group was appointed in connection with Dansk Naturgas A/S' preparation of an environmental impact assessment for the gas pipeline connecting the South Arne Field with the west coast of Jutland. As the gas pipeline was to continue over land, the reference group also cooperated with the authorities in Ribe County.

The amendments to the Danish Continental Shelf Act introduced in 1997 also included a provision aimed at implementing the above-mentioned Council Directive, so that projects for the installation of pipelines to transport hydrocarbons across the Danish continental shelf and to transport hydrocarbons over the continental shelf to the Danish coast can be subjected to an environmental impact assessment.

On this basis, the environmental effects of establishing Europipe II were assessed, the first environmental impact assessment made for a pipeline transporting hydrocarbons in transit across the Danish continental shelf.

New Notification Procedure

According to the new procedure for giving the public an opportunity to express an opinion, the Danish Energy Agency must insert a notice in three national newspapers, announcing that an environmental impact assessment has been made for the development of a specific field, and that the environmental impact assessment will be made available to the public at five of Denmark's largest libraries for the following two-month period. In addition, a non-technical summary can be obtained from the Danish Energy Agency.

INTERNATIONAL COOPERATION

As part of the international cooperation on health and safety on offshore installations in the North Sea, the Danish Energy Agency held meetings with the supervisory authorities of the relevant countries in 1998.

The Danish Energy Agency also participated in cooperation within the North Sea Offshore Authorities Forum (NSOAF) on safety training and issues concerning mobile offshore installations.

NSOAF completed the pilot project initiated in 1997 for the purpose of clarifying the potential advantages of having the public authorities jointly supervise the owners of mobile offshore installations and their facilities. The results of this project, which was aimed towards the drilling contractor Noble Drilling, which has activities in the Netherlands, UK, Norway and Denmark, were positive, both from the authorities' and industry's point of view. Consequently, at their annual meeting in April 1998, the member states of NSOAF decided to launch a new, joint supervisory project, this time focusing on maintenance systems on drilling rigs. This project is expected to be completed in the summer of 1999.

As far as safety training is concerned, there is every indication that the North Sea countries will agree on reciprocal recognition of their basic safety training. The parties involved in this work include the international association of operators, E&P Forum, and the International Association of Drilling Contractors, IADC.

The Danish Energy Agency also continued its work under the auspices of the Safety and Health Commission for the Mining and Other Extractive Industries under the EU Commission (SHCMOEI).

In cooperation with the Danish Environmental Protection Agency, the Danish Energy Agency dealt with environmental issues through its participation in the Paris/Oslo Commission's Offshore Forum (GOP) and as a member of the Commission's working group on Sea-Based Activities (SEBA).

LICENCES IN DENMARK

Licence	Sole Concession of 8 July 1962
Operator	Mærsk Olie og Gas AS
Licence granted	8 July 1962
Blocks	Area (km²)
5504/7, 8, 11, 12, 15, 16	
5505/13, 17, 18	
(The Contiguous Area)	1934.0
5504/5, 6 (Elly)	64.0
5603/27, 28 (Freja former Gert)	44.8
5504/10, 14 (Rolf)	8.4
5604/25 (Svend)	48.0
5604/21, 22 (Harald)	55.7

Company	Share (%)
Shell Olie- og Gasudvinding Danmark BV	46.000
A.P. Møller (Concessionaires)	39.000
Texaco Denmark Inc.	15.000

Licence	7/86 (the Amalie share)
Operator	Danop, Amerada Hess is co-operator
Licence granted	24 June 1986 (2nd Round)
Blocks	5604/22, 26
Area (km²)	106.8

Company	Share (%
Amerada Hess Energi A/S	42.758
Dansk Olie- og Gasproduktion A/S	25.317
Denerco Oil A/S	20.731
LD Energi A/S	11.194

Licence	7/86 (the Lulita share)
Operator	Danop, Statoil is co-operator
Licence granted	24 June 1986 (2nd Round)
Block	5604/22
Area (km²)	2.6

Company	Share (%)
Statoil Efterforskning og Produktion A/S	37.642
Dansk Olie- og Gasproduktion A/S	27.184
Denerco Oil A/S	24.260
LD Energi A/S	10.914

Licence	7/89
Operator	Amerada Hess
Licence granted	20 December 1989 (3rd Round)
Blocks	5504/2; 5604/25, 29, 30
Area (km²)	261.6

Company	Share (%)
Amerada Hess A/S	65.690
Dansk Olie- og Gasproduktion A/S	25.000
Denerco Oil A/S	7.500
Danoil Exploration A/S	1.810

Licence	7/89 (the South Arne share)
Operator	Amerada Hess
Licence granted	20 December 1989 (3rd Round)
Blocks	5604/29, 30
Area (km²)	93.3

Company	Share (%)
Amerada Hess A/S	57.479
Dansk Olie- og Gasproduktion A/S	34.375
Denerco Oil A/S	6.563
Danoil Exploration A/S	1.584

Licence	8/89
Operator	Danop, Amerada Hess is co-operator
Licence granted	20 December 1989 (3rd Round)
Blocks	5603/32; 5604/29
Area (km²)	234.0

Company	Share (%)
Amerada Hess A/S	63.263
Dansk Olie- og Gasproduktion A/S	23.624
Denerco Oil A/S	10.564
Danoil Exploration A/S	2.549

Licence	10/89
Operator	Mærsk Olie og Gas AS
Licence granted	20 December 1989 (3rd Round)
Blocks	5603/27, 31
Area (km²)	186.8

Company	Share (%)
A.P. Møller	26.667
Shell Olie- og Gasudvinding Danmark BV	26.667
Texaco Denmark Inc.	26.667
Dansk Olie- og Gasproduktion A/S	20.000

Licence	1/90
Operator	Danop, Statoil is technical assistant
Licence granted	3 July 1990
Block	5604/18
Area (km²)	1.2

Company	Share (%)
Statoil Efterforskning og Produktion A/S	37.642
Dansk Olie- og Gasproduktion A/S	27.184
Denerco Oil A/S	24.260
LD Energi A/S	10.914

Licence	2/90
Operator	Danop
Licence granted	3 July 1990
Blocks	5604/23, 24
Area (km²)	430.5

Company	Share (%)
Denerco Oil A/S	58.500
Amerada Hess Energi A/S	19.000
LD Energi A/S	12.500
Dansk Olie- og Gasproduktion A/S	10.000

Licence	3/90
Operator	Mærsk Olie og Gas AS
Licence granted	13 July 1990
Block	5603/28
Area (km²)	29.6

Company	Share (%)
Shell Olie- og Gasudvinding A/S	36.800
A.P. Møller	31.200
Dansk Olie- og Gasproduktion A/S	20.000
Texaco Denmark Inc.	12.000

Licence	1/95
Operator	Amerada Hess, Danop is co-operator
Licence granted	15 May 1995 (4th Round)
Blocks	5503/2, 3; 5603/30, 31
Area (km²)	187.8

Company	Share (%)
Amerada Hess A/S	40.000
Premier Oil BV	20.000
Denerco Oil A/S	20.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	2/95
Operator	Danop, Amerada Hess is co-operator
Licence granted	15 May 1995 (4th Round)
Blocks	5503/3, 4; 5603/31; 5604/29
Area (km²)	331.1

Company	Share (%)
Amerada Hess A/S	63.263
Dansk Olie- og Gasproduktion A/S	23.624
Denerco Oil A/S	10.564
Danoil Exploration A/S	2.549

Licence	3/95
Operator	Danop
Licence granted	15 May 1995 (4th Round)
Blocks	5604/19, 20; 5605/21
Area (km²)	178.7

Company	Share (%)
Denerco Oil A/S	48.500
Dansk Olie- og Gasproduktion A/S	20.000
Amerada Hess Energi A/S	19.000
LD Energi A/S	12.500

Licence	4/95
Operator	Danop
Licence granted	15 May 1995 (4th Round)
Blocks	5604/20; 5605/4, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17; 5606/1, 5, 9
Area (km²)	2170.2

Company	Share (%)
Mobil Erdgas-Erdöl GmbH	27.500
RWE-DEA AG	20.000
Enterprise Oil Denmark Ltd.	20.000
Dansk Olie- og Gasproduktion A/S	20.000
EWE AG	12.500

Licence	5/95
Operator	Phillips
Licence granted	15 May 1995 (4th Round)
Blocks	5603/30, 31
Area (km²)	233.2

Company	Share (%)
Phillips Petroleum International Corporation Denmark	35.000
Amerada Hess Efterforskning A/S	20.000
Dansk Olie- og Gasproduktion A/S	20.000
Pelican A/S Danmark	15.000
Denerco Oil A/S	5.000
Premier Oil BV	5.000

Licence	6/95
Operator	Statoil, Danop is co-operator
Licence granted	15 May 1995 (4th Round)
Blocks	5604/16, 20; 5605/13, 17
Area (km²)	414.1

Company	Share (%)
Statoil Efterforskning og Produktion A/S	40.000
Enterprise Oil Denmark Ltd.	20.000
Dansk Olie- og Gasproduktion A/S	20.000
Phillips Petroleum Int. Corp. Denmark	12.500
Denerco Oil A/S	7.500

Licence	7/95
Operator	Mærsk Olie og Gas AS
Licence granted	15 May 1995 (4th Round)
Block	5505/22
Area (km²)	195.9

Company	Share (%)
A.P. Møller	26.667
Shell Olie- og Gasudvinding Danmark BV	26.667
Texaco Denmark Inc.	26.667
Dansk Olie- og Gasproduktion A/S	20.000

Licence	8/95
Operator	Mærsk Olie og Gas AS
Licence granted	15 May 1995 (4th Round)
Blocks	5504/3, 4
Area (km²)	326.0

Company	Share (%)
Shell Olie- og Gasudvinding Danmark BV	36.800
A.P. Møller	31.200
Dansk Olie- og Gasproduktion A/S	20.00
Texaco Denmark Inc.	12.000

Licence	9/95
Operator	Mærsk Olie og Gas AS
Licence granted	15 May 1995 (4th Round)
Blocks	5604/21, 22, 25, 26
Area (km²)	218.5

Company	Share (%)
Shell Olie- og Gasudvinding Danmark BV	36.800
A.P. Møller	31.200
Dansk Olie- og Gasproduktion A/S	20.000
Texaco Denmark Inc.	12.000

Licence	1/97
Operator	Norsk Agip A/S
Licence granted	15 September 1997 (Open Door)
Blocks	5606/14, 18
Area (km²)	428.6

Company	Share (%)
Agip Denmark B.V.	80.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	2/97
Operator	Amerada Hess
Licence granted	15 September 1997 (Open Door)
Blocks	5606/27, 28, 30, 31, 32; 5506/2, 3, 4, 6, 7
Area (km²)	1709.4

Company	Share (%)
Amerada Hess A/S	30.000
Enterprise Oil Denmark Ltd.	30.000
Denerco Oil A/S	20.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	3/97
Operator	Amerada Hess
Licence granted	15 September 1997 (Open Door)
Blocks	5606/19, 22, 23, 26, 27
Area (km²)	969.1

Company	Share (%)
Amerada Hess A/S	48.000
Denerco Oil A/S	32.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	4/97
Operator	Mærsk Olie og Gas AS
Licence granted	15 September 1997 (Open Door)
Blocks	5506/4, 8, 12, 16, 20, 24; 5507/ 1, 2, 5, 6, 9, 10, 13, 14, 17, 18, 21, 22, 25, 26
Area (km²)	3335.7

Company	Share (%)
A.P. Møller	40.000
Shell Olie- og Gasudvinding Danmark BV	40.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	5/97
Operator	Odin Energi ApS
Licence granted	15 September 1997 (Open Door)
Blocks	5512/2; 5612/30
Area (km²)	406.8

Company	Share (%)
Odin Energi ApS	80.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	1/98
Operator	CLAM
Licence granted	15 June 1998 (5th Round)
Blocks	5505/1, 5, 6
Area (km²)	285.5

Company	Share (%)
CLAM Petroleum Danske B.V.	80.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	2/98
Operator	CLAM
Licence granted	15 June 1998 (5th Round)
Blocks	5605/18, 19, 22, 23
Area (km²)	231.9

Company	Share (%)
CLAM Petroleum Danske B.V.	80.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	3/98
Operator	Marathon
Licence granted	15 June 1998 (5th Round)
Blocks	5605/28; 5605/32
Area (km²)	216.4

Company	Share (%)
Marathon Petroleum Denmark, Ltd	80.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	4/98
Operator	Phillips
Licence granted	15 June 1998 (5th Round)
Blocks	5604/26, 27, 30, 31; 5504/2, 3
Area (km²)	604.4

Company	Share (%)
Phillips Petroleum International Corporation Denmark	30.000
Saga Petroleum Danmark AS	25.000
Veba Oil Denmark GmbH	25.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	5/98
Operator	Phillips
Licence granted	15 June 1998 (5th Round)
Blocks	5603/24, 28; 5604/21, 25
Area (km²)	232.6

Company	Share (%)
Phillips Petroleum International Corporation Denmark	30.000
Saga Petroleum Danmark AS	25.000
Veba Oil Denmark GmbH	25.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	6/98
Operator	Phillips
Licence granted	15 June 1998 (5th Round)
Blocks	5504/1, 2; 5604/29
Area (km²)	213.8

Company	Share (%)
Phillips Petroleum International Corporation Denmark	30.000
Saga Petroleum Danmark AS	25.000
Veba Oil Denmark GmbH	25.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	7/98
Operator	Enterprise, Danop is co-operator
Licence granted	15 June 1998 (5th Round)
Blocks	5505/1, 2, 3, 6, 7, 10
Area (km²)	583.4

Company	Share (%)
Enterprise Oil Denmark	60.000
Denerco Oil A/S	20.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	8/98
Operator	Kerr-McGee
Licence granted	15 June 1998 (5th Round)
Blocks	5605/18, 19
Area (km²)	359.1

Company	Share (%)
Kerr-McGee Denmark Ltd	40.000
ARCO Denmark Limited	40.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	9/98
Operator	Agip
Licence granted	15 June 1998 (5th Round)
Blocks	5604/28, 32; 5605/25, 29
Area (km²)	721.2

Company	Share (%)
Agip Denmark B.V.	80.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	10/98
Operator	Agip
Licence granted	15 June 1998 (5th Round)
Blocks	5503/3, 7
Area (km²)	169.5

Company	Share (%)
Agip Denmark B.V.	80.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	11/98
Operator	Amerada Hess
Licence granted	15 June 1998 (5th Round)
Blocks	5503/8; 5504/1, 2, 5, 6
Area (km²)	352.8

Company	Share (%)
Amerada Hess A/S	42.000
Dansk Olie- og Gasproduktion A/S	25.000
Veba Oil Denmark GmbH	20.000
Denerco Oil A/S	13.00

Licence	12/98
Operator	Amerada Hess
Licence granted	15 June 1998 (5th Round)
Blocks	5604/27, 28, 31, 32
Area (km²)	276.2

Company	Share (%)
Amerada Hess A/S	50.000
Denerco Oil A/S	30.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	13/98
Operator	EDC (Europe) Ltd.
Licence granted	15 June 1998 (5th Round)
Blocks	5505/5, 9
Area (km²)	328.0

Company	Share (%)
EDC (Denmark)	80.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	14/98
Operator	Mærsk Olie og Gas AS
Licence granted	15 June 1998 (5th Round)
Blocks	5505/3,4; 5605/26, 27, 28, 30, 31, 32; 5606/25
Area (km²)	1355.9

Company	Share (%)
A.P. Møller	26.667
Shell Olie- og Gasudvinding Danmark B.V.	26.667
Texaco Denmark Inc.	26.667
Dansk Olie- og Gasproduktion A/S	20.00

Licence	15/98
Operator	Mærsk Olie og Gas AS
Licence granted	15 June 1998 (5th Round)
Block	5604/25
Area (km²)	70.5

Company	Share (%)
Shell Olie- og Gasudvinding Danmark B.V.	36.800
A.P. Møller	31.200
Dansk Olie- og Gasproduktion A/S	20.000
Texaco Denmark Inc.	12.000

Licence	16/98
Operator	Danop
Licence granted	15 June 1998 (5th Round)
Blocks	5604/15, 18, 19, 20
Area (km²)	194.1

Company	Share (%)
Denerco Oil A/S	55.000
LD Energi A/S	25.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	17/98
Operator	Mærsk Olie og Gas AS
Licence granted	15 June 1998 (5th Round)
Blocks	5505/19, 23
Area (km²)	146.1

Company	Share (%)
Shell Olie- og Gasudvinding Danmark B.V.	36.800
A.P. Møller	31.200
Dansk Olie- og Gasproduktion A/S	20.000
Texaco Denmark Inc.	12.000

Licence	1/99
Operator	Agip
Licence granted	15 February 1999 (Open Door)
Blocks	5506/4, 7, 8, 10, 11, 12, 14, 15, 16, 18, 19, 22, 23
Area (km²)	1792.1

Company	Share (%)
Agip Denmark B.V.	80.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	2/99
Operator	Gustavson
Licence granted	20 March 1999 (Open Door)
Blocks	5707/16,19,20,22,23,24,26,27,30,31
Area (km²)	1329.3

Company	Share (%)
Gustavson Associates	80.000
Dansk Olie- og Gasproduktion A/S	20.000

Licence	3/99
Operator	Anschutz
Licence granted	20 March 1999 (Open Door)
Blocks	5606/10, 11, 12, 15, 16, 20, 24; 5607/9, 13, 17, 21, 25, 29
Area (km²)	2791.2

Company	Share (%)
Anschutz Overseas Corporation	80.000
Dansk Olie- og Gasproduktion A/S	20.000

Please note that the figures showing the licensees shares has been rounded off. The list will be updated on the Danish Energy Agency's homepage www.ens.dk. Reference is made to the maps of the Danish licence area at the back of the report.

EXPLORATORY SURVEYS 1998

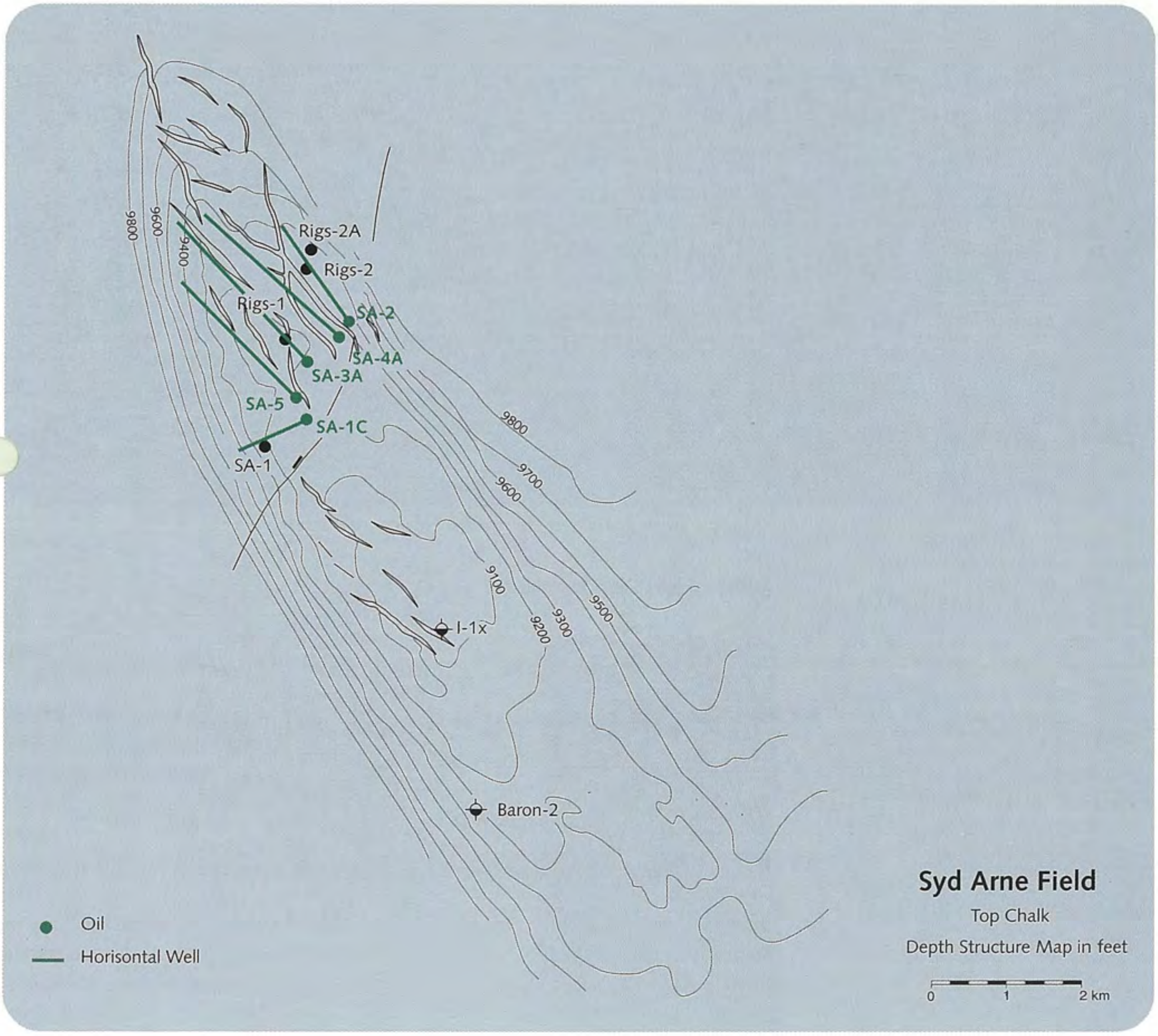
Survey Licence	Operator Contractor	Type	Initiated Completed	Area Block	Acquired in 1998
HG97 4/97	Mærsk Olie og Gas AS Fugro-Geoteam A/S	Offshore 2D	16-11-1997 17-04-1998	HG 5506, 5507, 5606, 5607	2,505 km
RE98 14/98	Mærsk Olie og Gas AS Schlumb. Geco-Prakla	Offshore 2D	27-07-1998 09-10-1998	RFH 5504, 5505, 5506, 5604, 5605, 5606	3,686 km
AH98 12/98	Amerada Hess A/S Fugro-Geoteam A/S	Offshore 2D	07-09-1998 23-09-1998	CG, RFH 5504, 5604	980 km
G98 Spec.	TGS Nopec TGS Nopec	Offshore 2D	01-11-1998 18-11-1998	RFH 5506	14 km
DN9801 7/86	Danop i-s Schlumb. Geco-Prakla	Offshore 3D	17-07-1998 13-08-1998	CG 5604	184 km^2
AG9801 1/97	Norsk Agip A/S Fugro-Geoteam A/S	Offshore 2D/3D	13-09-1998 26-11-1998	RFH, NDB 5605, 5606	81 km +347 km^2

CG=Central Graben, HG=Horn Graben, NDB=Norwegian-Danish Basin, RFH=Ringkøbing-Fyn High

NEW FIELDS

New Field Developments

Field name	South Arne
Location:	Blocks 5604/29 and 30
Licence:	7/89
Operator:	Amerada Hess A/S, Danop is co-operator
Discovered:	1969
Dev. plan approved:	1997
Year on stream:	1999
Water depth:	60 m
Reservoir depth:	2,800 m
Reservoir rock:	Chalk
Geological age:	Lower Tertiary and Upper Cretaceous (L.Cret.)
Type of hydrocarbons:	Oil

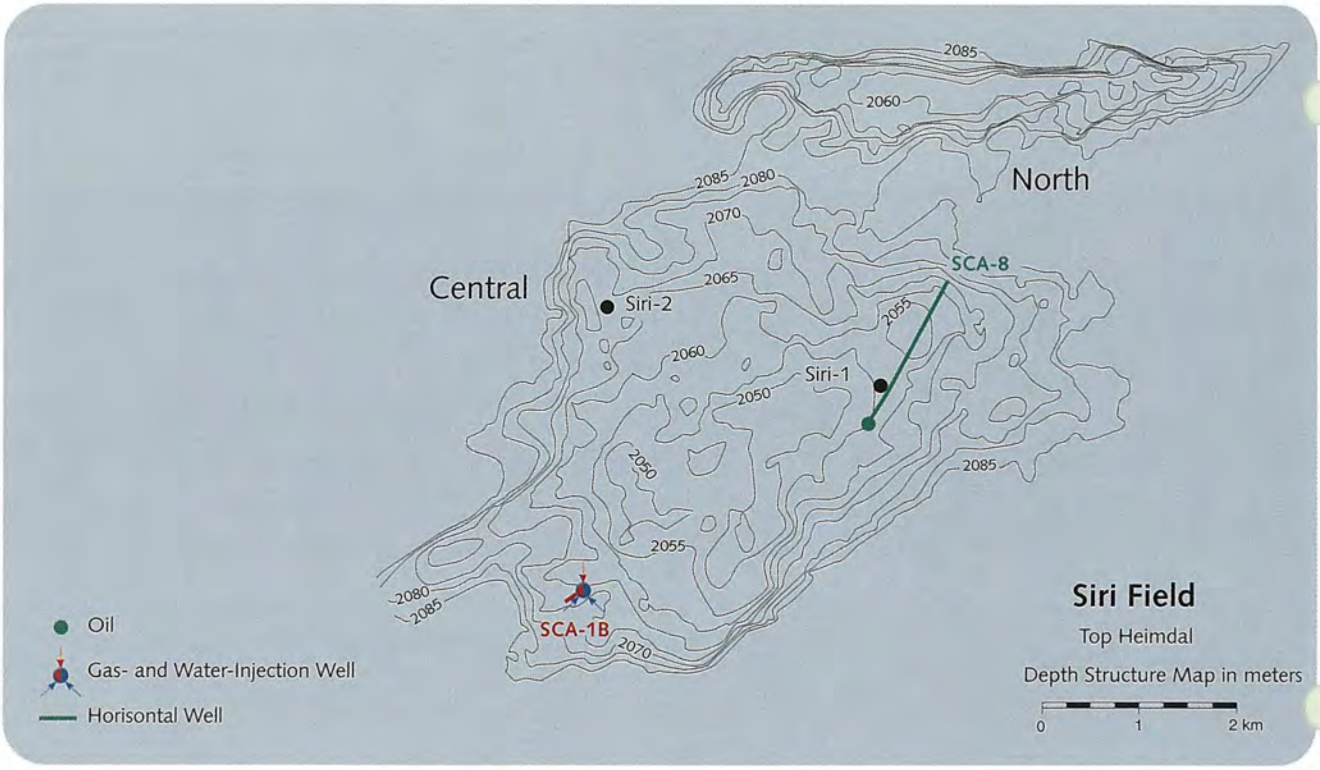


Syd Arne Field

Top Chalk

Depth Structure Map in feet

Field name	Siri
Location:	Block 5604/20
Licence:	6/95
Operator:	Statoil, Danop is co-operator
Discovered:	1995
Year on stream:	March 1999
Water depth:	60 m
Reservoir depth:	2,060 m
Reservoir rock:	Sandstone
Geological age:	Palaeozoic
Type of hydrocarbons:	Oil



Future Field Developments

Field name	Adda
Location	Block 5504/8
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1977
Dev. plan approved:	1990
Year on stream:	2001
Water depth:	38 m
Reservoir depth:	2,200 m and 2,300 m
Reservoir rock:	Carbornates
Geological age:	Upper and Lower Cretaceous
Type of hydrocarbons:	Oil/gas

Field name	Igor
Location:	Block 5505/13
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1968
Dev. plan approved:	1990
Year on stream:	2001
Water depth:	50 m
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Type of hydrocarbons:	Gas

Field name	Elly
Location:	Block 5504/6
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1984
Dev. plan approved:	1995
Year on stream:	2001
Water depth:	40 m
Reservoir depth:	3,200 m and 4,000 m
Reservoir rock:	Chalk and Sandstone
Geological age:	Upper Cretaceous and Jurassic
Type of hydrocarbons:	Gas

Field name	Freja (former Gert)
Location:	Block 5603/27 og 28
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1984
Water depth:	70 m
Reservoir depth:	4,900 m
Reservoir rock:	Sandstone
Geological age:	Upper Jurassic
Type of hydrocarbons:	Oil

Field name	Alma
Location:	Block 5505/17
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1990
Dev. plan approved:	1995
Year on stream:	2003
Water depth:	43 m
Reservoir depth:	3,600 m
Reservoir rock:	Sandstone
Geological age:	Middle Jurassic
Type of hydrocarbons:	Gas

AMOUNTS PRODUCED AND INJECTED

Danish Oil Production 1972-1998, million m³

Year	Dan	Gorm	Skjold	Tyra	Rolf	Kraka	Dagmar	Regnar	Valdemar	Roar	Svend	Harald	Lulita	Total
1972-80*	2.68	-	-	-	-	-	-	-	-	-	-	-	-	2.68
1981	0.34	0.53	-	-	-	-	-	-	-	-	-	-	-	0.88
1982	0.31	1.64	0.02	-	-	-	-	-	-	-	-	-	-	1.97
1983	0.27	1.84	0.40	-	-	-	-	-	-	-	-	-	-	2.52
1984	0.36	1.62	0.65	0.07	-	-	-	-	-	-	-	-	-	2.71
1985	0.45	1.80	0.85	0.35	-	-	-	-	-	-	-	-	-	3.46
1986	0.47	1.72	1.07	0.57	0.47	-	-	-	-	-	-	-	-	4.29
1987	1.23	1.50	1.21	0.84	0.63	-	-	-	-	-	-	-	-	5.42
1988	1.50	1.35	1.37	0.95	0.40	-	-	-	-	-	-	-	-	5.57
1989	1.47	1.35	2.21	1.05	0.39	-	-	-	-	-	-	-	-	6.48
1990	1.58	1.44	2.63	1.08	0.27	-	-	-	-	-	-	-	-	7.00
1991	1.72	1.50	2.73	1.39	0.29	0.14	0.47	-	-	-	-	-	-	8.26
1992	2.70	1.66	2.28	1.67	0.30	0.21	0.31	-	-	-	-	-	-	9.12
1993	3.26	1.89	2.10	1.64	0.18	0.39	0.07	0.15	0.05	-	-	-	-	9.72
1994	3.50	2.42	1.72	1.75	0.09	0.49	0.03	0.43	0.30	-	-	-	-	10.73
1995	3.71	2.49	1.98	1.63	0.22	0.47	0.03	0.09	0.17	0.00	0.00	-	-	10.79
1996	3.80	2.88	2.02	1.45	0.22	0.34	0.02	0.04	0.16	0.32	0.84	0.00	-	12.09
1997	3.86	3.05	2.01	1.26	0.10	0.31	0.02	0.03	0.16	0.43	1.36	0.79	-	13.37
1998	4.77	2.86	1.90	0.93	0.09	0.31	0.01	0.04	0.10	0.33	0.64	1.70	0.15	13.83
Total	**38.00**	**33.55**	**27.17**	**16.63**	**3.65**	**2.67**	**0.97**	**0.77**	**0.94**	**1.08**	**2.83**	**2.49**	**0.15**	**130.86**

**The annual production figures for the years 1972 to 1980 are available on the Danish Energy Agency's homepage www.ens.dk.*
Amounts produced from the Lulita Field are shared between DUC and the Statoil Group, cf. Appendix E. All other production belongs to DUC.

Monthly Oil Production 1998, thousand m³

Field	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	1998
Dan	385	346	397	388	404	410	406	405	396	406	404	420	4,768
Gorm	241	218	238	229	224	205	211	229	248	270	274	278	2,865
Skjold	158	175	180	172	159	152	164	144	123	136	183	150	1,896
Tyra	97	77	89	84	72	71	62	61	65	82	83	90	931
Rolf	8	8	8	8	8	8	7	7	7	8	7	6	92
Kraka	21	10	16	8	37	30	30	28	30	34	34	36	314
Dagmar	1	1	1	1	1	1	1	1	1	1	1	1	13
Regnar	4	4	1	4	4	4	4	3	3	3	3	3	43
Valdemar	8	6	9	8	8	8	8	8	8	7	7	8	95
Roar	36	24	27	28	14	24	22	26	29	33	31	34	327
Svend	104	61	62	48	45	38	45	49	42	48	49	44	635
Harald	161	151	157	127	142	131	144	137	148	139	125	110	1,703
Lulita	-	-	-	-	-	14	15	16	21	28	26	26	145
Total	**1,224**	**1,082**	**1,184**	**1,137**	**1,119**	**1,097**	**1,118**	**1,115**	**1,120**	**1,194**	**1,227**	**1,208**	**13,826**

Amounts produced from the Lulita Field are shared between DUC and the Statoil Group, cf. Appendix E. All other production belongs to DUC.
The most recent monthly production figures are available on the Danish Energy Agency's homepage www.ens.dk.

Danish Gas Production (net*) 1972-1998, billion Nm³

Year	Dan	Gorm	Skjold	Tyra	Rolf	Kraka	Dagmar	Regnar	Valdemar	Roar	Svend	Harald	Lulita	Total
1972-80**	0.78	-	-	-	-	-	-	-	-	-	-	-	-	0.78*
1981	0.08	0.05	-	-	-	-	-	-	-	-	-	-	-	0.13
1982	0.08	0.05	0.00	-	-	-	-	-	-	-	-	-	-	0.14
1983	0.08	0.03	0.04	-	-	-	-	-	-	-	-	-	-	0.14
1984	0.13	-0.04	0.06	0.26	-	-	-	-	-	-	-	-	-	0.41
1985	0.21	-0.09	0.07	1.11	-	-	-	-	-	-	-	-	-	1.31
1986	0.24	0.11	0.10	1.63	0.02	-	-	-	-	-	-	-	-	2.10
1987	0.44	0.02	0.10	2.02	0.03	-	-	-	-	-	-	-	-	2.60
1988	0.60	0.12	0.11	1.77	0.02	-	-	-	-	-	-	-	-	2.62
1989	0.71	0.00	0.19	2.11	0.02	-	-	-	-	-	-	-	-	3.02
1990	0.80	0.03	0.22	2.02	0.01	-	-	-	-	-	-	-	-	3.08
1991	0.88	0.11	0.23	2.61	0.01	0.06	0.07	-	-	-	-	-	-	3.96
1992	1.06	0.13	0.21	2.57	0.01	0.09	0.05	-	-	-	-	-	-	4.12
1993	1.34	0.36	0.19	2.40	0.01	0.13	0.01	0.01	0.03	-	-	-	-	4.47
1994	1.26	0.85	0.19	2.28	0.00	0.12	0.01	0.03	0.10	-	-	-	-	4.83
1995	1.33	0.73	0.19	2.71	0.01	0.13	0.01	0.01	0.05	0.00	0.00	-	-	5.16
1996	1.25	0.65	0.16	2.62	0.01	0.09	0.00	0.00	0.06	1.33	0.08	0.00	-	6.25
1997	1.12	0.55	0.19	2.45	0.00	0.08	0.00	0.00	0.09	1.96	0.15	1.09	-	7.69
1998	1.34	0.61	0.15	0.73	0.00	0.11	0.00	0.00	0.05	1.46	0.08	2.74	0.07	7.35
Total	**13.72**	**4.26**	**2.40**	**29.29**	**0.15**	**0.80**	**0.15**	**0.05**	**0.38**	**4.75**	**0.32**	**3.83**	**0.07**	**60.10**

**Reinjected gas has been deducted.*
***The annual production figures for the years 1972 to 1980 are available on the Danish Energy Agency's homepage www.ens.dk.*
Amounts produced from the Lulita Field are shared between DUC and the Statoil Group, cf. Appendix E. All other production belongs to DUC.

Natural Gas Supplies from Danish Fields 1984-1998, billion Nm³

Year	Dan	Gorm	Skjold	Tyra	Rolf	Kraka	Dagmar	Regnar	Valdemar	Roar	Svend	Harald	Lulita	Total
1984	0.01	0.02	<0.01	0.19	-	-	-	-	-	-	-	-	-	0.22
1985	0.05	<0.01	<0.01	1.02	-	-	-	-	-	-	-	-	-	1.06
1986	0.21	0.12	0.01	1.46	<0.01	-	-	-	-	-	-	-	-	1.80
1987	0.38	0.02	<0.01	1.90	<0.01	-	-	-	-	-	-	-	-	2.30
1988	0.53	0.10	0.01	1.63	<0.01	-	-	-	-	-	-	-	-	2.27
1989	0.64	0.06	0.01	1.98	<0.01	-	-	-	-	-	-	-	-	2.69
1990	0.74	0.10	0.03	1.89	<0.01	-	-	-	-	-	-	-	-	2.75
1991	0.77	0.17	0.05	2.48	<0.01	0.05	-	-	-	-	-	-	-	3.51
1992	0.93	0.15	0.04	2.43	<0.01	0.08	-	-	-	-	-	-	-	3.63
1993	1.23	0.30	0.08	2.26	<0.01	0.12	-	0.01	0.02	-	-	-	-	4.01
1994	1.13	0.72	0.15	2.15	<0.01	0.10	-	0.02	0.06	-	-	-	-	4.33
1995	1.21	0.60	0.15	2.57	0.01	0.12	-	0.01	0.04	-	-	-	-	4.70
1996	1.12	0.49	0.12	2.48	0.01	0.09	-	<0.01	0.05	1.26	0.08	-	-	5.71
1997	0.98	0.37	0.13	2.32	<0.01	0.07	-	<0.01	0.08	1.86	0.14	1.01	-	6.96
1998	1.17	0.43	0.10	0.65	<0.01	0.09	-	<0.01	0.05	1.29	0.07	2.71	0.07	6.63
Total	**11.1**	**3.63**	**0.87**	**27.4**	**0.03**	**0.71**	**-**	**0.09**	**0.30**	**4.41**	**0.29**	**3.72**	**0.07**	**52.26**

Water Production from Danish Fields 1972-1998, million m³

Year	Dan	Gorm	Skjold	Tyra	Rolf	Kraka	Dagmar	Regnar	Valdemar	Roar	Svend	Harald	Lulita	Total
1972-80	0.12	-	-	-	-	-	-	-	-	-	-	-	-	0.12
1981	0.02	0.09	-	-	-	-	-	-	-	-	-	-	-	0.12
1982	0.02	0.20	0.00	-	-	-	-	-	-	-	-	-	-	0.22
1983	0.02	0.31	0.00	-	-	-	-	-	-	-	-	-	-	0.33
1984	0.02	0.32	0.00	0.00	-	-	-	-	-	-	-	-	-	0.34
1985	0.03	0.38	0.00	0.00	-	-	-	-	-	-	-	-	-	0.41
1986	0.04	0.48	0.00	0.06	0.00	-	-	-	-	-	-	-	-	0.58
1987	0.07	0.50	0.00	0.16	0.06	-	-	-	-	-	-	-	-	0.80
1988	0.10	0.54	0.00	0.12	0.13	-	-	-	-	-	-	-	-	0.89
1989	0.12	0.49	0.01	0.18	0.22	-	-	-	-	-	-	-	-	1.02
1990	0.16	0.52	0.00	0.25	0.25	-	-	-	-	-	-	-	-	1.17
1991	0.28	0.52	0.02	0.39	0.20	0.05	0.02	-	-	-	-	-	-	1.47
1992	0.51	0.58	0.34	0.67	0.35	0.13	0.21	-	-	-	-	-	-	2.79
1993	0.78	0.56	0.82	1.00	0.26	0.20	0.39	0.00	0.00	-	-	-	-	4.02
1994	1.12	0.82	0.89	1.29	0.16	0.19	0.37	0.24	0.02	-	-	-	-	5.10
1995	1.27	0.95	1.34	1.75	0.44	0.25	0.46	0.40	0.02	0.00	0.00	-	-	6.88
1996	1.54	1.92	2.68	2.16	0.49	0.27	0.51	0.30	0.03	0.01	0.00	0.00	-	9.92
1997	1.85	2.91	3.63	2.22	0.39	0.29	0.41	0.16	0.06	0.10	0.06	0.00	-	12.07
1998	2.98	3.18	3.94	2.07	0.41	0.35	0.34	0.41	0.05	0.15	0.27	0.00	0.00	14.16
Total	**11.05**	**15.27**	**13.67**	**12.34**	**3.36**	**1.72**	**2.71**	**1.51**	**0.19**	**0.26**	**0.34**	**0.00**	**0.00**	**62.42**

Water Injection in Danish Fields, million m³

Year	Dan	Gorm	Skjold	Total
1986	-	-	0.63	0.63
1987	-	-	1.04	1.04
1988	-	-	1.38	1.38
1989	0.08	0.36	2.90	3.34
1990	0.18	0.89	3.38	4.45
1991	0.18	1.01	3.24	4.43
1992	0.86	1.60	2.79	5.25
1993	1.53	2.14	2.84	6.51
1994	3.81	4.61	3.51	11.93
1995	5.88	5.75	3.99	15.62
1996	8.24	8.11	5.71	22.07
1997	8.65	8.64	6.32	23.62
1998	11.56	8.38	6.29	26.23
Total	**40.99**	**41.50**	**44.01**	**126.50**

Gas Injection in Danish Fields, billion Nm³

Year	Gorm	Tyra	Total
1981	0.03	-	0.03
1982	0.22	-	0.22
1983	0.40	-	0.40
1984	0.55	-	0.55
1985	0.73	-	0.73
1986	0.67	-	0.67
1987	0.86	0.63	1.50
1988	0.86	1.59	2.45
1989	0.89	1.41	2.30
1990	0.78	1.28	2.06
1991	0.74	1.07	1.80
1992	0.71	1.37	2.08
1993	0.42	1.45	1.87
1994	0.07	1.37	1.44
1995	0.03	1.13	1.16
1996	0.03	1.22	1.25
1997	0.06	1.78	1.84
1998	0.02	2.91	2.93
Total	**8.06**	**17.21**	**25.28**

PRODUCING FIELDS

THE DAN CENTRE

Field name	Dan
Prospect:	Abby
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1971
Year on stream:	1972
Producing wells:	52 (46 horizontal)
Water-injection wells:	39 (21 horizontal)
Water depth:	40 m
Acreage:	20 km²
Reservoir depth:	1,850 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 99:	
Oil:	64.6 million m³
Gas::	10.3 billion Nm³
Cum. production at 1 Jan. 99:	
Oil:	38.00 million m³
Gas:	13.72 billion Nm³
Water:	11.05 million m³
Cum. injection at 1 Jan. 99:	
Water:	40.99 million m³
Production in 98:	
Oil:	4.77 million m³
Gas:	1.34 billion Nm³
Water:	2.98 million m³
Injection in 98:	
Water:	11.56 million m³
Tot. investments at 1 Jan. 99:	
98 prices	DKK 18.1 billion

REVIEW OF GEOLOGY

Dan is an anticlinal structure partly induced through salt tectonics of the Zechstein/Triassic. A major fault divides the field into two reservoir blocks, which, in turn, are intersected by a number of minor faults. The chalk reservoir has high porosity, although low permeability. There is a gas cap in the field.

PRODUCTION STRATEGY

Recovery from the field is based on the simultaneous production of oil and injection of water. Water injection was initiated in 1989. The most recent development plan from 1995 provides for the introduction of high-rate water injection. The high pressure involved causes the injected water to fracture the chalk, ensuring the rapid distribution of water throughout the reservoir. Injecting large amounts of water quickly stabilizes and builds up the reservoir pressure in the oil zone. The recovery of oil is optimized by flooding the largest possible reservoir volume with as much water as possible.

PRODUCTION FACILITIES

The Dan field installations comprise six wellhead platforms (DA, DD, DE, DFA, DFB and DFE), two processing/accommodation platforms (DB and DFC) and two gas flare stacks (DC and DFD), as well as a combined wellhead and processing platform (DFF).

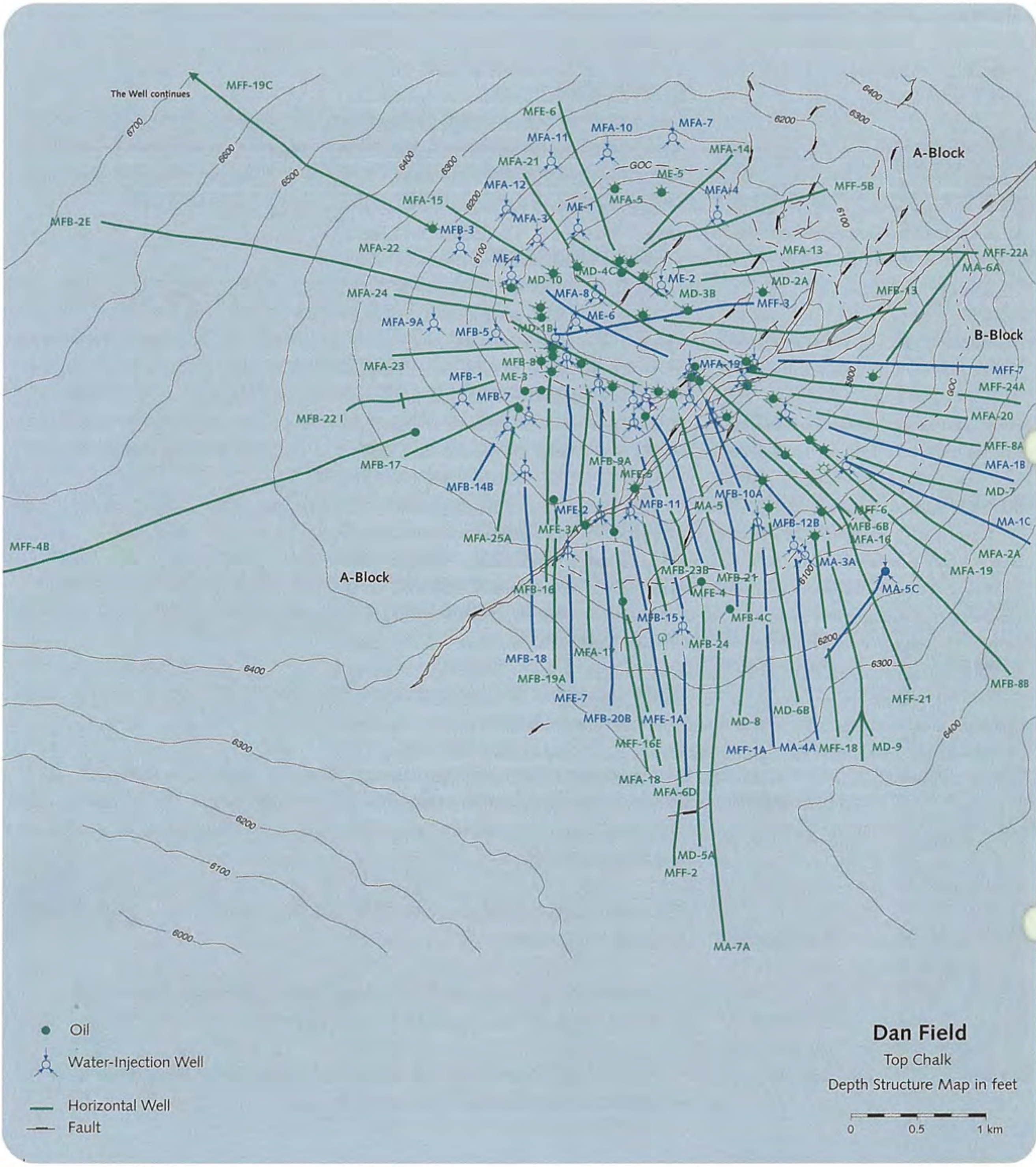
At the Dan Field, there are receiving facilities for the production from the Kraka and Regnar satellite fields.

The processing facilities on the DFC platform and on the new DFF platform handle production from the Dan, Kraka and Regnar Fields. The processing facilities include an oil stabilization plant and a gas dehydration plant, as well as gas compression facilities.

The water-injection capacity at the Dan Field is about 20 million m³ per year (360,000 bbls per day).

After final processing, the oil is transported to shore via the booster platform, Gorm E. The gas is pre-processed and transported to Tyra East for final processing.

In the Dan Field, there are accommodation facilities for 86 persons on the DFC platform and five persons on the DB platform.


The Well continues
MFF-19C
A-Block
B-Block
A-Block
MFB-2E
MFF-4B
MFB-17
MFB-22 I
MFA-23
MFA-24
MFA-22
MFA-15
MFA-9A
MFB-3
MFE-6
MFA-11
MFA-10
MFA-7
MFA-21
MFA-12
MFA-14
MFA-3
ME-1
ME-5
MFA-5
MFA-4
MFF-5B
ME-4
MD-10
MD-4C
ME-2
MD-3B
MFA-13
MD-2A
MFF-3
MFA-8
ME-6
MD-1B
MFB-5
MFB-8
MFB-1
ME-3
MFB-7
MFB-13
MFF-22A
MA-6A
MFA-19
MFF-7
MFF-24A
MFA-20
MFF-8A
MFA-1B
MD-7
MA-1C
MFA-2A
MFA-19
MFB-14B
MFA-25A
MFB-9A
MFF-5
MFE-2
MFE-3A
MFB-11
MA-5
MFB-10A
MFB-12B
MFF-6
MFB-6B
MFA-16
MA-3A
MA-5C
MFB-23B
MFB-21
MFE-4
MFB-16
MFB-15
MFB-4C
MFB-24
MFB-18
MFB-19A
MFA-17
MFE-7
MFB-20B
MFE-1A
MFF-16E
MFA-18
MFA-6D
MD-8
MD-6B
MFF-1A
MA-4A
MFF-18
MD-9
MFF-21
MFB-8B
MD-5A
MFF-2
MA-7A
GOC
6700
6600
6500
6400
6300
6200
6100
6000
5900
Oil
Water-Injection Well
Horizontal Well
Fault
Dan Field
Top Chalk
Depth Structure Map in feet
0
0.5
1 km

THE DAN CENTRE

Field name:	Kraka
Prospect:	Anne
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1966
Year on stream:	1991
Producing wells:	7 (all horizontal)
Water depth:	45 m
Acreage:	20 km²
Reservoir depth:	1,800 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 99:	
Oil:	1.8 million m³
Gas:	0.8 billion Nm³
Cum. production at 1 Jan. 99:	
Oil:	2.67 million m³
Gas:	0.80 billion Nm³
Water:	1.72 million m³
Production in 98:	
Oil:	0.31 million m³
Gas:	0.11 billion Nm³
Water:	0.35 million m³
Tot. investments at 1 Jan. 99:	
98 prices	DKK 1.2 billion

REVIEW OF GEOLOGY

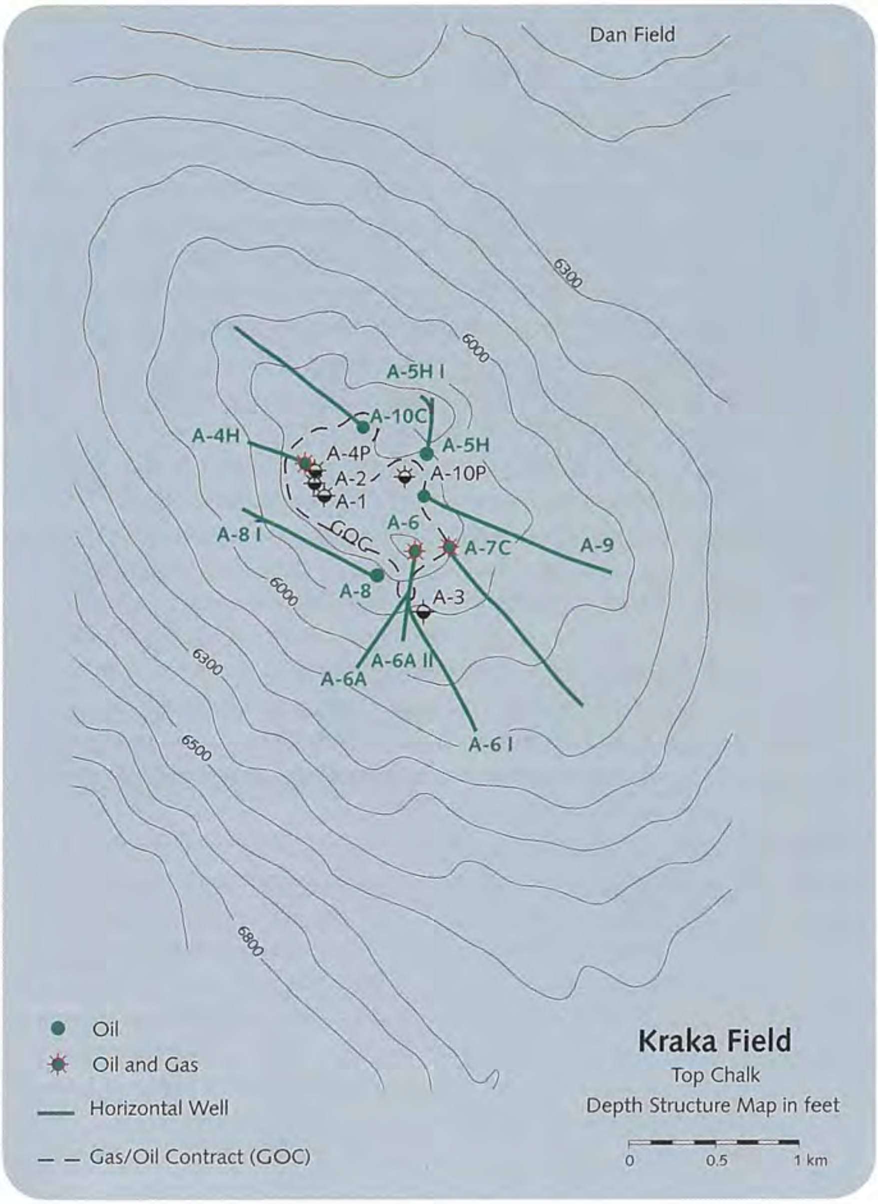
Kraka is an anticlinal structure induced through Zechstein salt tectonics, which to a certain degree has caused fracturing in the chalk. The chalk reservoir has high porosity, although low permeability. The thin oil pay zone is further characterized by high water saturations. There is a minor gas cap in the reservoir.

PRODUCTION STRATEGY

Production from the field is based on primary recovery, meaning no secondary recovery techniques are used, either in the form of gas or water injection. Attempts are currently being made to optimize production so as to liberate as much oil and gas, and as little water, as possible from the tight chalk formation.

PRODUCTION FACILITIES

Kraka is a satellite development to the Dan Field, with an unmanned production platform of the STAR type hosting seven wells. The produced oil and gas are transported to the Dan FC platform for processing and export ashore. In April 1998, the utilization of lift gas in the Kraka wells was initiated. The gas is imported from the Dan FF platform.



THE DAN CENTRE

Field name:	Regnar
Prospect:	Nils
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1979
Year on stream:	1993
Producing wells:	1
Water depth:	45 m
Acreage:	8 km²
Reservoir depth:	1,700 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Upper Cretaceous and Zechstein
Reserves at 1 Jan. 99:	
Oil:	0.1 million m³
Gas:	0.0 billion Nm³
Cum. production at 1 Jan. 99:	
Oil:	0.77 million m³
Gas:	0.05 billion Nm³
Water:	1.51 million m³
Production in 98:	
Oil:	0.04 million m³
Gas:	0.00 billion Nm³
Water:	0.41 million m³
Tot. investments at 1 Jan. 99:	
98 prices	DKK 0.2 billion

REVIEW OF GEOLOGY

The Regnar Field is an anticlinal structure, induced through Zechstein salt tectonics. The structure is heavily fractured, resulting in favourable reservoir conductivity (compare Skjold, Rolf, Dagmar and Svend).

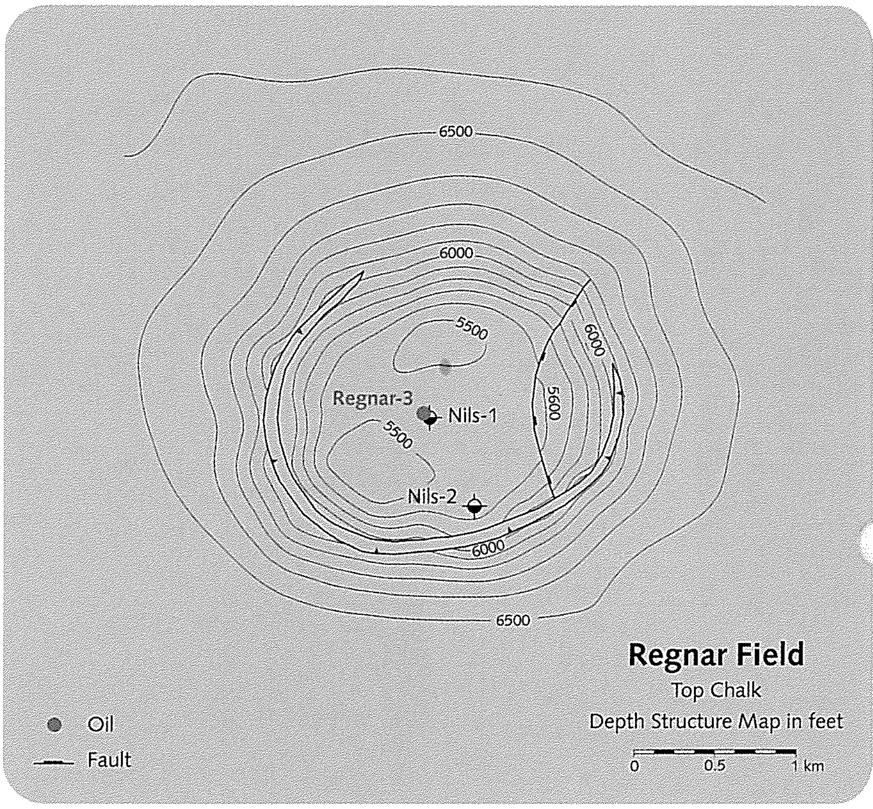
PRODUCTION STRATEGY

Production in the Regnar Field is carried on from a vertical well drilled in the crest of the structure. The oil is forced towards the production well by water flowing in from the water zone. The production strategy is to displace and produce as much of the oil as possible from the tight part of the formation, the matrix.

PRODUCTION FACILITIES

The Regnar Field has been developed as a satellite to the Dan Field. Production takes place in a subsea-completed well. The hydrocarbons produced are conveyed by pipeline in multi-phase flow to Dan FC for processing and export ashore.

The well is remotely monitored and controlled from the Dan FC platform.



THE GORM CENTRE

Field name:	Gorm
Prospect:	Vern
Location:	Blocks 5504/15 and 16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1971
Year on stream:	1981
Producing wells:	32 (10 horizontal)
Gas-injection wells:	2
Water-injection wells:	14 (9 horizontal)
Water depth:	39 m
Acreage:	12 km²
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 99:	
Oil:	15.3 million m³
Gas:	2.0 billion Nm³
Cum. production at 1 Jan. 99:	
Oil:	33.55 million m³
Net gas:	4.26 billion Nm³
Water:	15.27 million m³
Cum. injection at 1 Jan. 99:	
Gas:	8.06 billion Nm³
Water:	41.50 million m³
Production in 98:	
Oil:	2.86 million m³
Net gas:	0.61 billion Nm³
Water:	3.18 million m³
Injection in 98:	
Gas:	0.02 billion Nm³
Water:	8.38 million m³
Tot. investments at 1 Jan. 99:	
98 prices	DKK 9.5 billion

REVIEW OF GEOLOGY

Gorm is an anticlinal structure partly due to Zechstein salt tectonics. A major fault extending north-south divides the field into two reservoir blocks. The western reservoir block is intersected by numerous, minor faults.

PRODUCTION STRATEGY

In 1989, water injection was initiated in the reservoir. Oil production from the field is based on extending the use of water injection to the whole field. In the western reservoir block, oil is recovered from the mid-flank areas of the reservoir, with simultaneous water injection in the flanks. In a later phase, recovery will be moved towards the crest of the structure, while water injection will be initiated in the areas where oil was produced previously. In the eastern reservoir block, oil is recovered from the mid-flank areas of the reservoir, with simultaneous water injection in the water zone under the reservoir. The recovery of oil is optimized by flooding the largest possible reservoir volume with as much water as possible.

If gas exports to Tyra are interrupted, the gas is injected into the Gorm Field.

PRODUCTION FACILITIES

The Gorm Field consists of two wellhead platforms (Gorm A and Gorm B), one processing/accommodation platform (Gorm C), one gas flare stack (Gorm D), one riser/booster platform (Gorm E), owned by Dansk Olierør A/S, and one combined wellhead/processing/booster platform (Gorm F).

Gorm receives production from the satellite fields, Skjold, Rolf and Dagmar. The Gorm Field installations supply the Skjold Field with injection water and lift gas and the Rolf Field with lift gas. Most of the gas produced is sent to Tyra East. The stabilized oil from the processing facilities at the Dan, Tyra and Gorm Centres is transported ashore via the booster platform Gorm E.

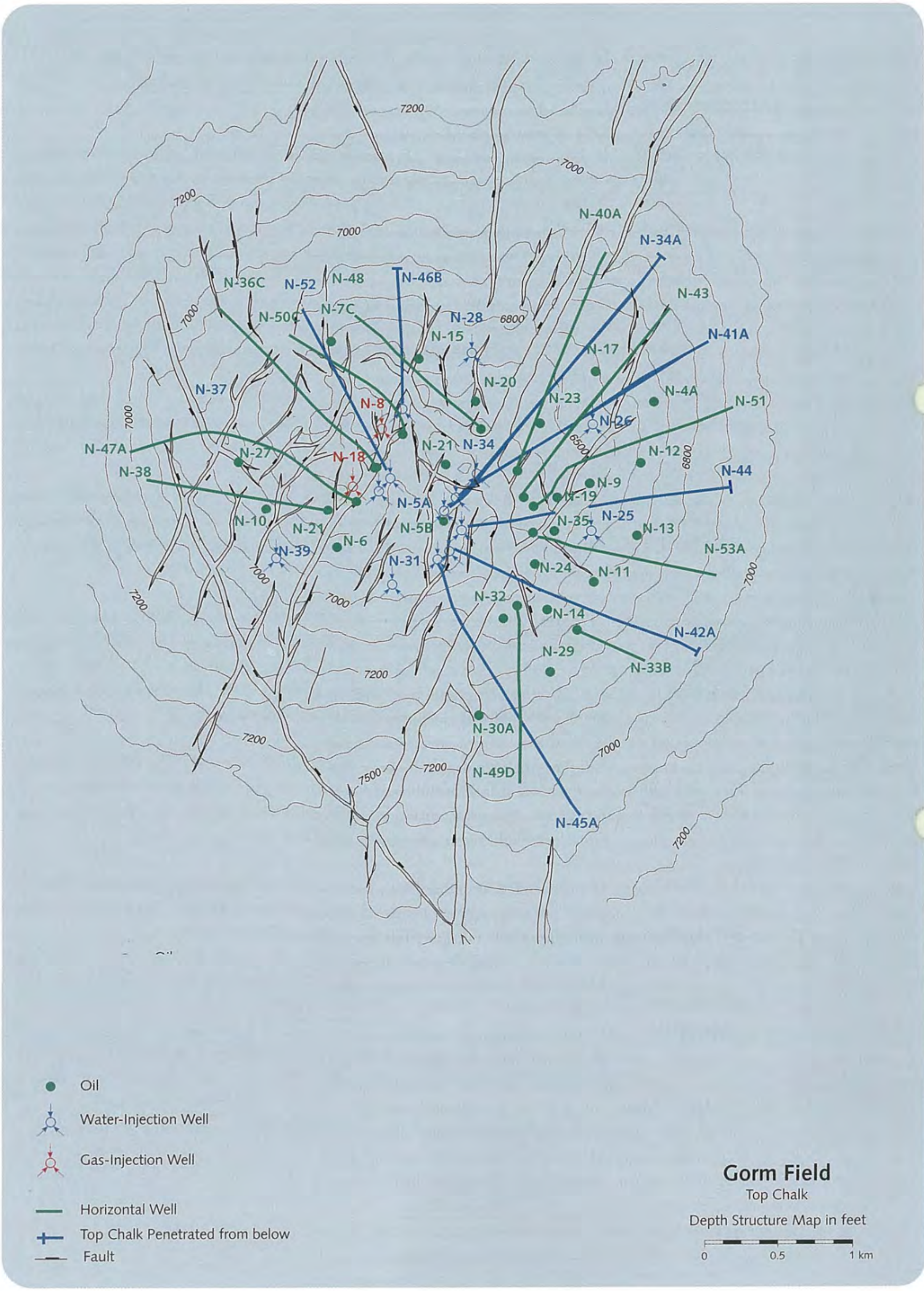
The processing facilities on the Gorm C platform consist of an oil stabilization plant, where the oil from the Rolf Field is processed, plants for the final processing of gas and for purifying the water produced, as well as facilities for processing and compressing the gas produced.

The processing facilities on the Gorm F platform consist of two oil stabilization plants, one receiving the sour oil and gas from the Dagmar Field, and the other receiving the production from the Gorm and Skjold Fields.

The Gorm F platform houses wellhead compression facilities to reduce the wellhead pressure in the Gorm and Skjold wells.

The water-injection capacity at the Gorm Centre constitutes about 17 million m³ per year (300,000 bbls per day).

There are accommodation facilities on the Gorm C platform for 98 persons.



Gorm Field

Top Chalk

Depth Structure Map in feet

THE GORM CENTRE

Field name:	**Skjold**
Prospect:	Ruth
Location:	Block 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1977
Year on stream:	1982
Producing wells:	14 (11 horizontal/ parallel with the strata)
Water-injection wells:	7 (all horizontal/ parallel with the strata)
Water depth:	40 m
Acreage:	10 km²
Reservoir depth:	1,600 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 99:	
Oil:	15.3 million m³
Gas:	1.3 billion Nm³
Cum. production at 1 Jan. 99:	
Oil:	27.17 million m³
Gas:	2.40 billion Nm³
Water:	13.67 million m³
Cum. injection at 1 Jan. 99:	
Water:	44.01 million m³
Production in 98:	
Oil:	1.90 million m³
Gas:	0.15 billion Nm³
Water:	3.94 million m³
Injection in 98:	
Water:	6.29 million m³
Tot. investments at 1 Jan. 99:	
98 prices	DKK 3.6 billion

REVIEW OF GEOLOGY

The Skjold Field is an anticlinal structure, induced through Zechstein salt tectonics. The reservoir is intersected by numerous, minor faults extending northwest-southeast. Unusually favourable production properties have been shown to exist in the reservoir.

PRODUCTION STRATEGY

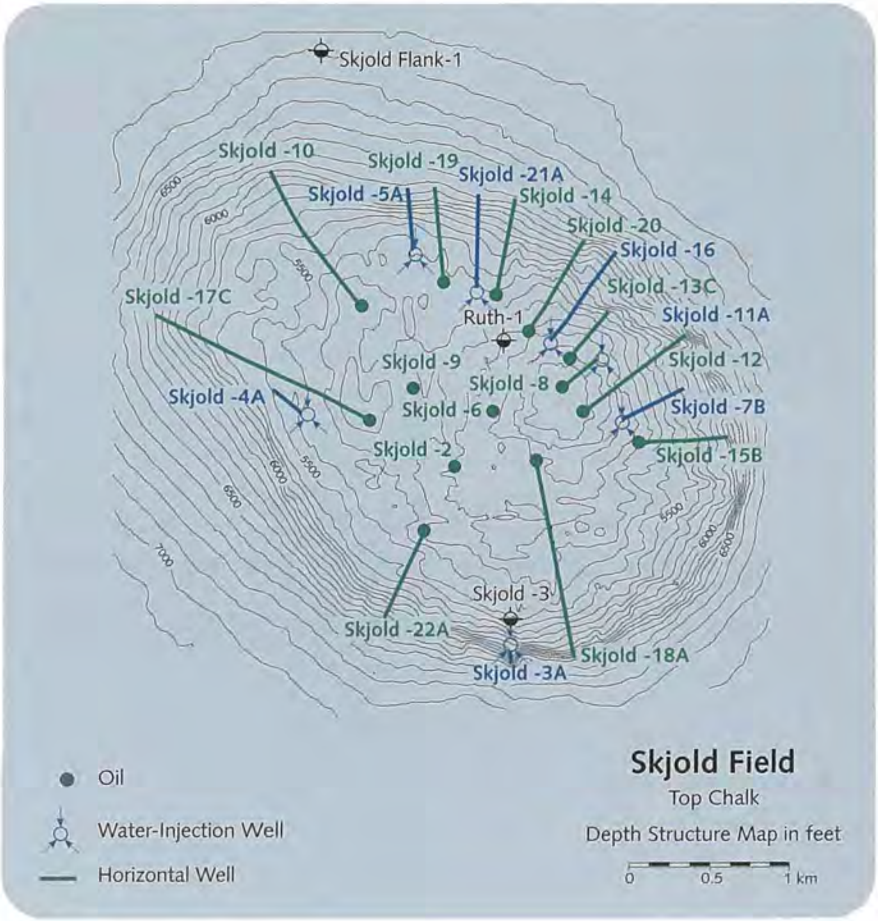
During the first years after production startup, oil was produced from individual wells drilled in the crestal, central part of the reservoir. Water injection was initiated in the reservoir in 1986. Today, oil from the Skjold Field is mainly produced from horizontal wells at the flanks of the reservoir. The production and injection wells are placed alternately in a radial pattern from the platform. The recovery of oil is optimized by flooding the greatest possible part of the reservoir with as much water as possible. The injection of water has stabilized the reservoir pressure above the bubble point of the oil.

PRODUCTION FACILITIES

The Skjold Field comprises a satellite development to the Gorm Field, including two wellhead platforms, Skjold A and B, as well as an accommodation platform, Skjold C.

There are no processing facilities at the Skjold Field, and the production is transported to the Gorm F platform in the Gorm Field for processing there. The Gorm facilities provide the Skjold Field with injection water and lift gas.

At Skjold C, there are accommodation facilities for 16 persons.



THE GORM CENTRE

Field name:	Rolf
Prospect:	Middle Rosa
Location:	Blocks 5504/14 and 15
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1981
Year on stream:	1986
Producing wells:	2
Water depth:	34 m
Acreage:	8 km²
Reservoir depth:	1,800 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, U. Cret. and Zechstein
Reserves at 1 Jan. 99:	
Oil:	0.6 million m³
Gas:	0.0 billion Nm³
Cum. production at 1 Jan. 99:	
Oil:	3.65 million m³
Gas:	0.15 billion Nm³
Water:	3.36 million m³
Production in 98:	
Oil:	0.09 million m³
Gas:	0.00 billion Nm³
Water:	0.41 million m³
Tot. investments at 1 Jan. 99:	
98 prices	DKK 0.9 billion

REVIEW OF GEOLOGY

Rolf is an anticlinal structure created through Zechstein salt tectonics. The chalk reservoir is heavily fractured resulting in highly favourable reservoir conductivity (compare Skjold, Dagmar, Regnar and Svend).

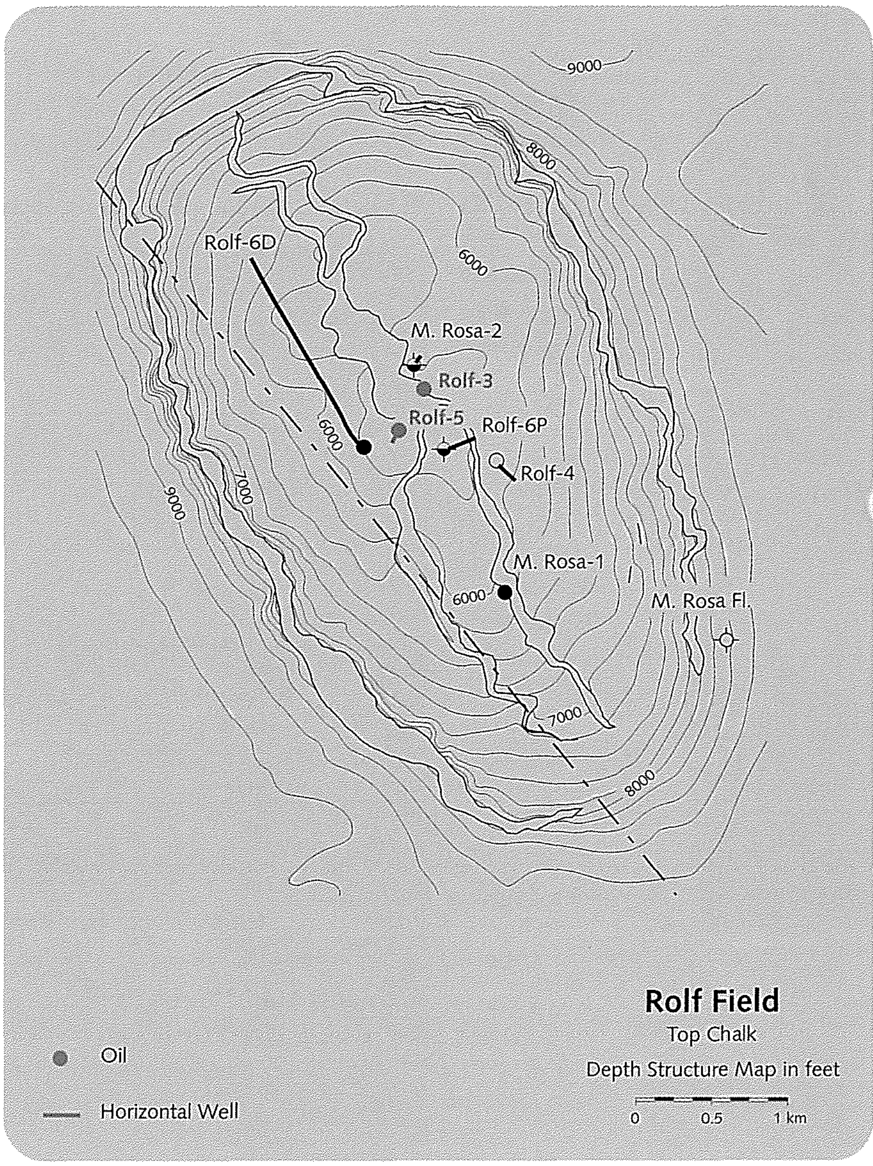
PRODUCTION STRATEGY

Production from the Rolf Field takes place from two wells drilled in the crest of the structure. The oil is forced towards the producing wells by the water flowing in from an underlying water zone. The natural influx of water from the water zone corresponds to the volume removed due to production in the central part of the structure. To date, it has not been found necessary to add energy to the reservoir by water injection.

PRODUCTION FACILITIES

The Rolf Field is a satellite development to the Gorm Field with an unmanned wellhead platform.

The production is transported to the Gorm C platform for processing. Rolf is supplied with lift gas from the Gorm Field.



THE GORM CENTRE

Field name:	Dagmar
Prospect:	East Rosa
Location:	Block 5504/15
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1983
Year on stream:	1991
Producing wells:	2
Water depth:	34 m
Acreage:	9 km^2
Reservoir depth:	1,400 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, U. Cret. and Zechstein

Reserves at 1 Jan. 99:	
Oil:	0.1 million m^3
Gas:	0.0 billion Nm^3

Cum. production at 1 Jan. 99:	
Oil:	0.97 million m^3
Gas:	0.15 billion Nm^3
Water:	2.71 million m^3

Production in 98:	
Oil:	0.01 million m^3
Gas:	0.00 billion Nm^3
Water:	0.34 million m^3

Tot. investments at 1 Jan. 99:	
98 prices	DKK 0.4 billion

REVIEW OF GEOLOGY

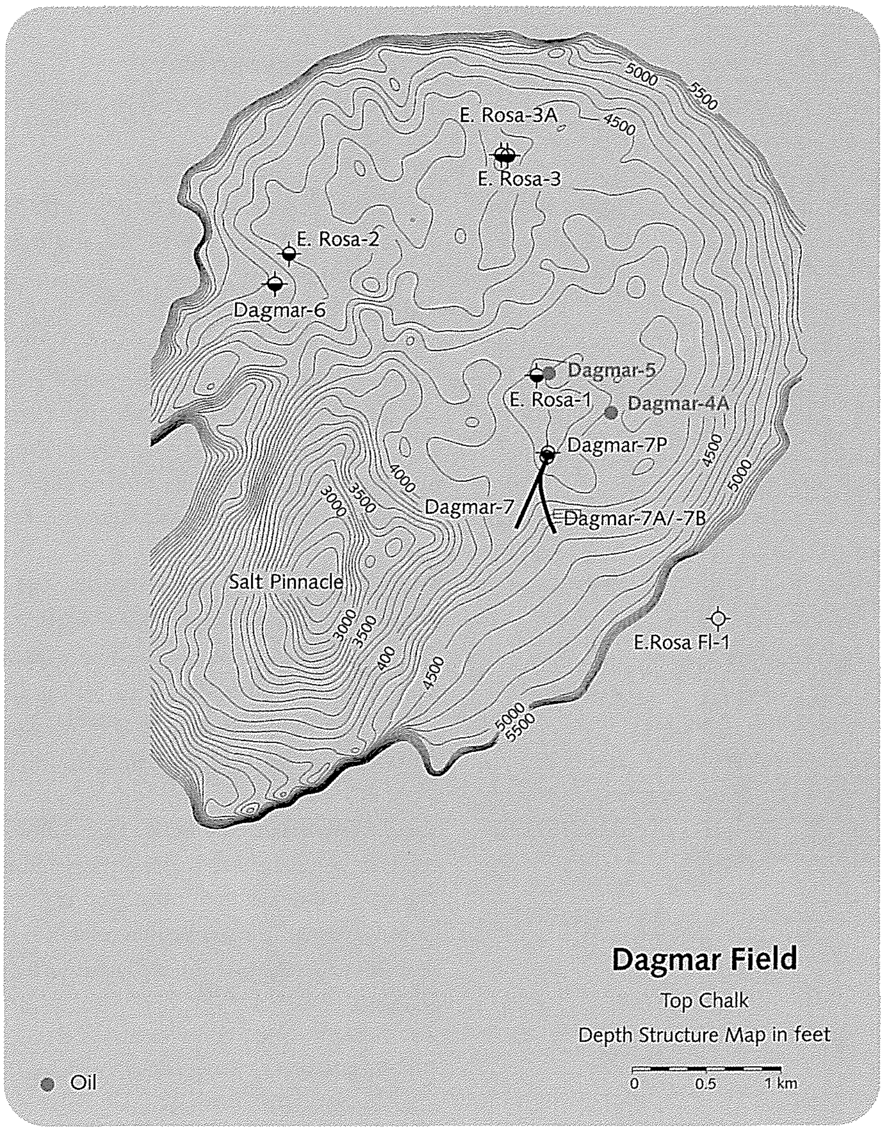
The Dagmar field is an anticlinal structure, induced through Zechstein salt tectonics. The uplift is so pronounced that the Dagmar reservoir is situated closer to the surface than any other hydrocarbon reservoirs in Danish territory. The reservoir is heavily fractured (compare Skjold, Rolf, Regnar and Svend). However, the water zone does not appear to be particularly fractured.

PRODUCTION STRATEGY

Initially, the oil production rates were high in the Dagmar Field, but it has not been possible to sustain the good production performance characterizing the Skjold and Rolf Fields.

PRODUCTION FACILITIES

The Dagmar Field is a satellite development to Gorm including one unmanned production platform of the STAR type. The unprocessed production is transported to the Gorm F platform in the Gorm Field, where special facilities for handling the sour gas from the Dagmar Field have been installed. The relatively small amount of gas produced from Dagmar is flared due to the high content of hydrogen sulphide.



Dagmar Field

Top Chalk

Depth Structure Map in feet

THE TYRA CENTRE

Field name:	Tyra
Prospect:	Cora
Location:	Blocks 5504/11 and 12
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1968
Year on stream:	1984
Producing wells:	38 (22 horizontal)
Producing/ injection wells:	20
Water depth:	37-40 m
Acreage:	90 km²
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 99:	
Oil and condensate:	5.6 million m³
Gas:	46.9 billion Nm³
Cum. production at 1 Jan. 99:	
Oil and condensate:	16.65 million m³
Net gas:	29.29 billion Nm³
Water:	12.34 billion m³
Cum. injection at 1 Jan. 99:	
Gas:	17.21 billion Nm³
Production in 98:	
Oil and condensate:	0.93 million m³
Net gas:	0.73 billion Nm³
Water:	2.07 million m³
Injection in 98:	
Gas:	2.91 billion Nm³
Tot. investments at 1 Jan. 99:	
98 prices	DKK 20.3 billion

REVIEW OF GEOLOGY

The Tyra Field is an anticlinal structure created by tectonic uplift. The accumulation consists of free gas containing condensate, overlying a thin oil zone. A pronounced permeability barrier covering a large part of the reservoir separates the Danian chalk layers from those of Upper Cretaceous age. The reservoir is slightly fractured.

PRODUCTION STRATEGY

As far as natural gas supplies are concerned, the Tyra Field acts as a buffer, so that if the other Danish oil and gas fields do not produce sufficient gas to meet the contractual obligation to supply gas to Dansk Naturgas A/S, the balance is supplied from the Tyra Field.

Excess production capacity in the Tyra Field is used to reinject produced gas, thereby increasing the recovery of liquid hydrocarbons.

Attempts are made not to deteriorate condensate and oil production conditions by reducing the reservoir pressure in the gas zone at too early a stage. Increased gas production from the other fields, in particular the Harald and Roar gas fields, meets the objective of optimizing the recovery of liquid hydrocarbons from the Tyra Field.

PRODUCTION FACILITIES

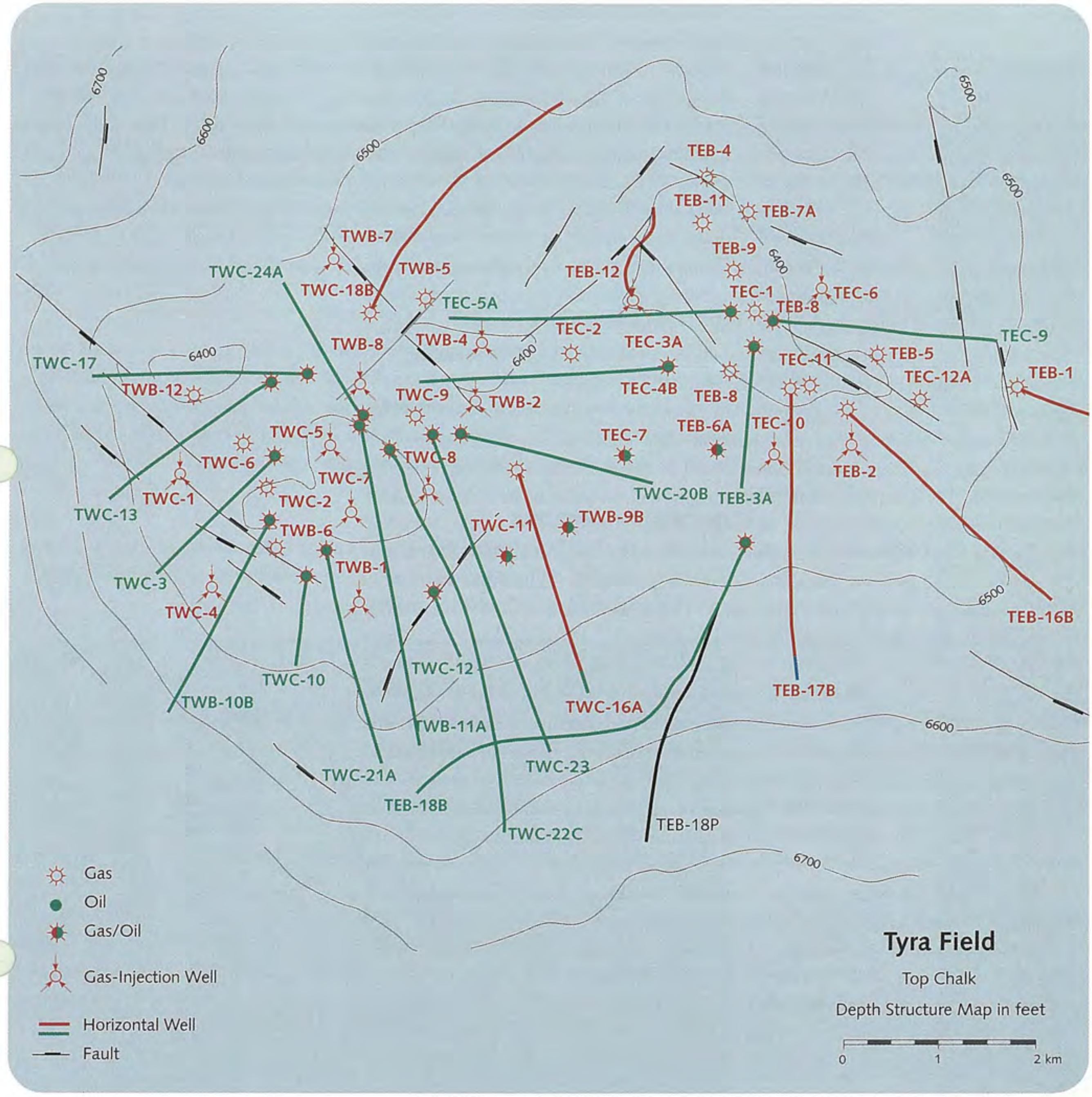
The Tyra Field installations comprise two platform complexes, Tyra West (TW) and Tyra East (TE).

Tyra West consists of two wellhead platforms (TWB and TWC), one processing/ accommodation platform (TWA) and one gas flare stack (TWD), as well as a bridge module installed at TWB and supported by a four-legged jacket (TWE). The Tyra West processing facilities include plant for pre-processing oil and condensate production from the wells at Tyra West. Moreover, the Tyra West complex houses processing and compression facilities for the injection and/or export of gas and processing facilities for the water produced. Oil and condensate are transported to Tyra East for final processing. The Tyra West facilities have the compression capacity to inject about 21 million Nm³ of gas per day into the Tyra Field. Gas is injected from both Tyra East and Tyra West.

Tyra East consists of two wellhead platforms (TEB and TEC), one processing/ accommodation platform (TEA), one gas flare stack (TED), and one riser platform (TEE), as well as a bridge module supported by a STAR jacket (TEF). The Tyra East complex includes facilities for the final processing of gas, oil, condensate and water. The bridge module houses the facilities for receiving and handling production from the Valdemar, Roar and Svend Fields, as well as the Harald Centre.

The two platform complexes in the Tyra Field are interconnected by pipelines in order to generate the maximum operational flexibility and reliability of supply. The oil and condensate produced at the Tyra Centre are transported to shore via Gorm E, while the gas produced at the Tyra Centre, together with the gas production from the Dan, Gorm and Harald Centres, is transported to shore via the TEE platform.

Tyra East has accommodation facilities for 96 persons, while there are accommodation facilities for 80 persons at Tyra West.



TEB-4
TEB-11
TEB-7A
TEB-9
TEB-12
TEC-1
TEC-6
TEB-8
TWB-7
TWC-24A
TWB-5
TWC-18B
TEC-5A
TEC-2
TEC-3A
TEC-9
TWB-8
TWB-4
TEC-11
TEB-5
TEC-12A
TEB-1
TWC-17
TWB-12
TWC-9
TWB-2
TEC-4B
TEB-8
TWC-5
TEC-7
TEB-6A
TEC-10
TWC-6
TWC-8
TEB-2
TWC-1
TWC-7
TWC-20B
TEB-3A
TWC-13
TWC-2
TWC-11
TWB-9B
TWB-6
TWC-3
TWB-1
TWC-4
TEB-16B
TWC-10
TWC-12
TEB-17B
TWB-10B
TWC-16A
TWB-11A
TWC-21A
TWC-23
TEB-18B
TWC-22C
TEB-18P
6400
6500
6600
6700
Gas
Oil
Gas/Oil
Gas-Injection Well
Horizontal Well
Fault
Tyra Field
Top Chalk
Depth Structure Map in feet
0
1
2 km

THE TYRA CENTRE

Field name:	Valdemar
Prospects:	Bo/North Jens
Location:	Blocks 5504/7 and 11
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1977 (Bo), 1985 (North Jens)
Year on stream:	1993 (North Jens)
Producing wells:	4 (all horizontal)
Water depth:	38 m
U. Cret. res:	
Acreage:	15 km²
Reservoir depth:	2,000 m
L. Cret. res:	
Acreage:	15 km²
Reservoir depth:	2,600 m
Reservoir rock:	Chalk
Geological age:	Danian, U. and L. Cret.
Reserves at 1 Jan. 99:	
Oil:	0.8 million m³
Gas:	0.6 billion Nm³
Cum. production at 1 Jan. 99:	
Oil:	0.94 million m³
Gas:	0.38 billion Nm³
Water:	0.19 million m³
Production in 98:	
Oil:	0.10 million m³
Gas:	0.05 billion Nm³
Water:	0.05 million m³
Tot. investments at 1 Jan. 99:	
98 prices	DKK 1.1 billion

REVIEW OF GEOLOGY

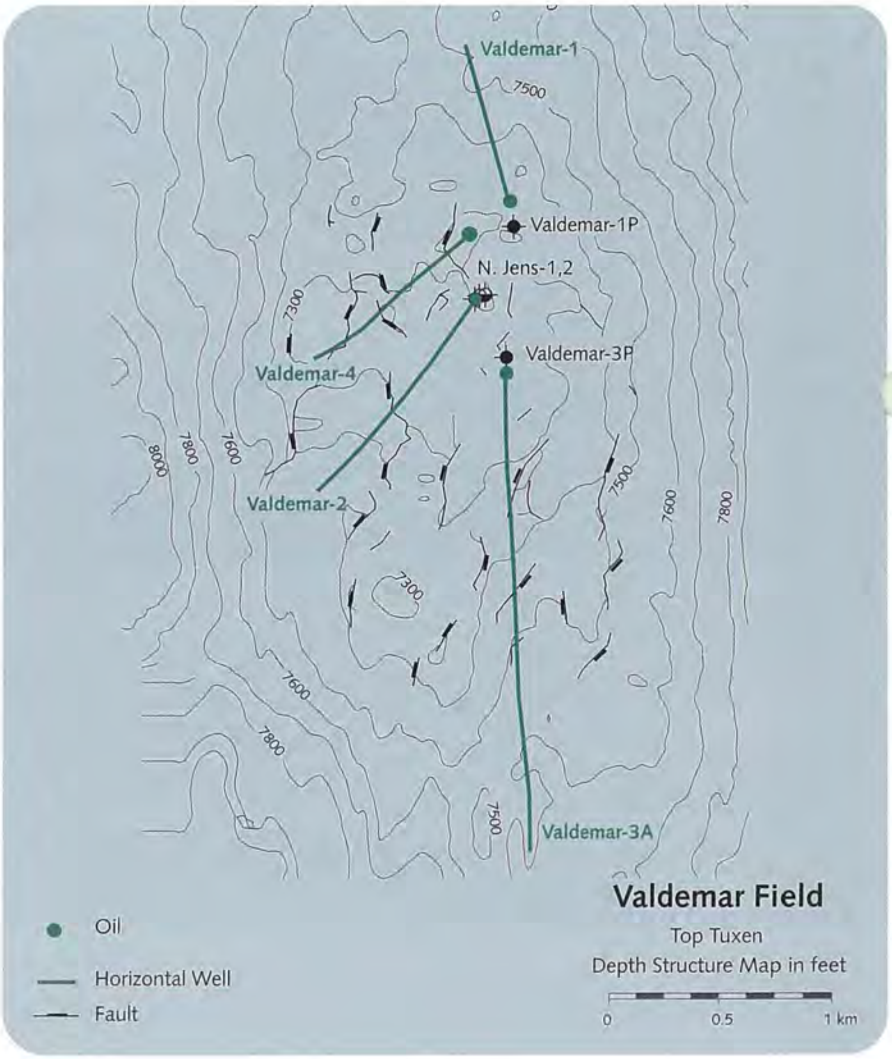
The Valdemar Field consists of a northern reservoir called North Jens and a southern reservoir called Bo, which are both anticlinal chalk structures associated with tectonic uplift. Valdemar comprises several separate reservoirs. Oil and gas have been discovered in Danian/Upper Cretaceous chalk. In the Lower Cretaceous reservoir, vast amounts of oil in place have been identified in Aptian/Barremian chalk. While the properties of the Upper Cretaceous reservoirs are comparable to other Danish fields like Gorm and Tyra, the Lower Cretaceous chalk, although featuring high porosity, possesses very difficult production properties due to its extremely low permeability. Production from the field is based on primary recovery.

PRODUCTION STRATEGY

The development of a recovery technique based on drilling long horizontal wells with numerous sand-filled, artificial fractures has made it possible to exploit the Lower Cretaceous reservoir commercially. Expectations for production from the North Jens reservoir are subdued. It is uncertain which recovery techniques may enhance the recovery of oil from this extremely tight reservoir.

PRODUCTION FACILITIES

The Valdemar Field (the North Jens reservoir) has been developed as a satellite to Tyra, including an unmanned production platform of the STAR type. The production is transported to Tyra East for processing and export ashore.



THE TYRA CENTRE

Field name:	Roar
Prospect:	Bent
Location:	Block 5504/7
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1968
Year on stream:	1996
Producing wells:	2 (both horizontal)
Water depth:	46 m
Acreage:	14 km²
Reservoir depth:	2,025 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

Reserves at 1 Jan. 99:	
Condensate:	2.0 million m³
Gas:	9.4 billion Nm³

Cum. production at 1 Jan. 99:	
Condensate:	1.08 million m³
Net gas:	4.75 billion Nm³
Water:	0.26 million m³

Production in 98:	
Condensate:	0.33 million m³
Net gas:	1.46 billion Nm³
Water:	0.15 million m³

Tot. investments at 1 Jan. 99:	
98 prices	DKK 0.4 billion

REVIEW OF GEOLOGY

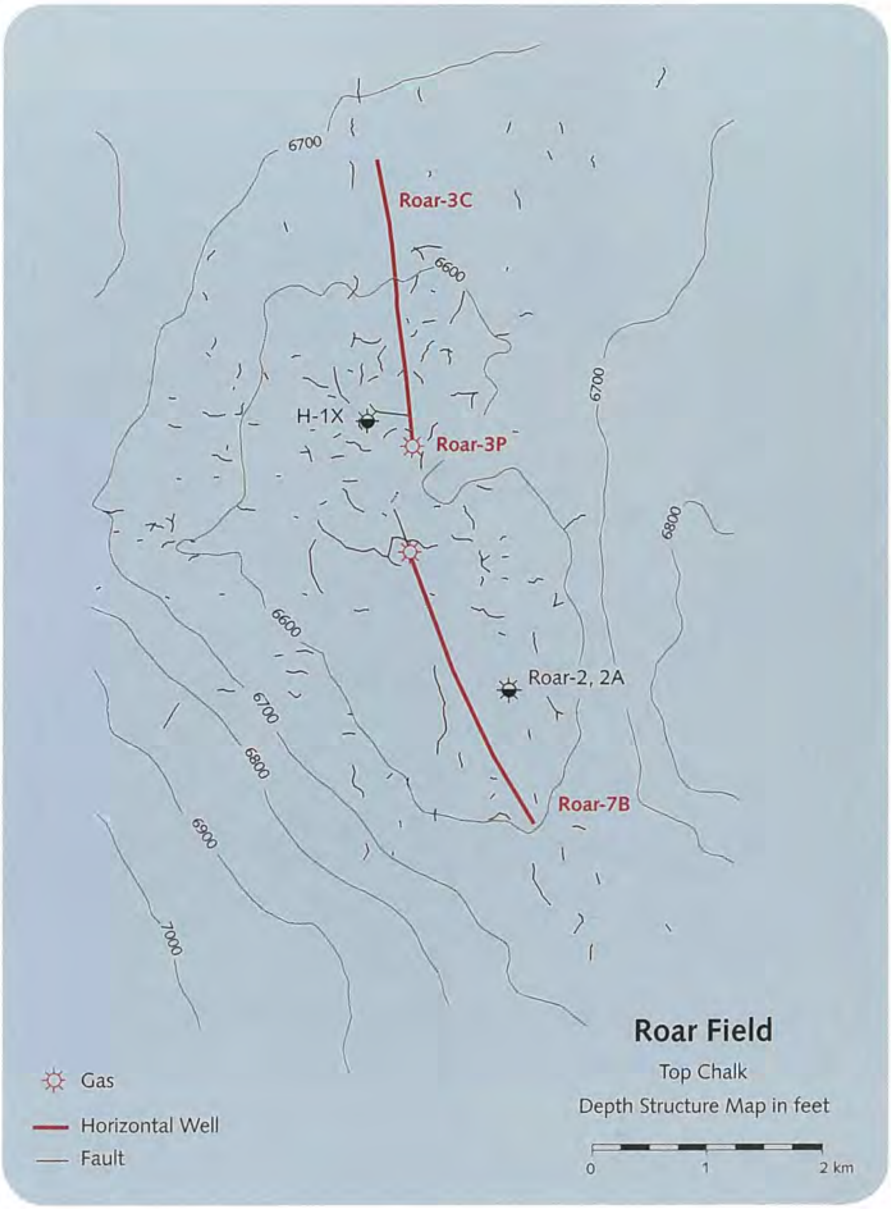
Roar is an anticlinal structure, induced through tectonic uplift. The accumulation consists of free gas containing condensate. The chalk formation is only slightly fractured.

PRODUCTION STRATEGY

Production from the Roar Field is based on the aim of optimizing the production of liquid hydrocarbons in the Tyra Field. This presupposes that the reservoir pressure is stabilized by maximizing production from the other gas fields and thus minimizing the drainage from the Tyra Field. Therefore, increased production from the Roar Field helps optimize the Tyra production conditions.

PRODUCTION FACILITIES

The Roar Field has been developed as a satellite to the Tyra Field with an unmanned wellhead platform of the STAR type. The hydrocarbons produced are separated at the Roar platform and conveyed to Tyra East for processing and export ashore.



THE TYRA CENTRE

Field name:	Svend
Prospect:	North Arne/Otto
Location:	Block 5604/25
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1975 (North Arne) and 1982 (Otto)
Year on stream:	1996
Producing wells:	2 (both horizontal)
Water depth:	65 m
Acreage:	25 km²
Reservoir depth:	2,500 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 Jan. 99:	
Oil:	3.5 million m³
Gas:	0.4 billion Nm³
Cum. production at 1 Jan. 99:	
Oil:	2.84 million m³
Gas:	0.32 billion Nm³
Water:	0.34 million m³
Production in 98:	
Oil:	0.64 million m³
Gas:	0.08 billion Nm³
Water:	0.27 million m³
Tot. investments at 1 Jan. 99:	
98 prices	DKK 0.5 billion

REVIEW OF GEOLOGY

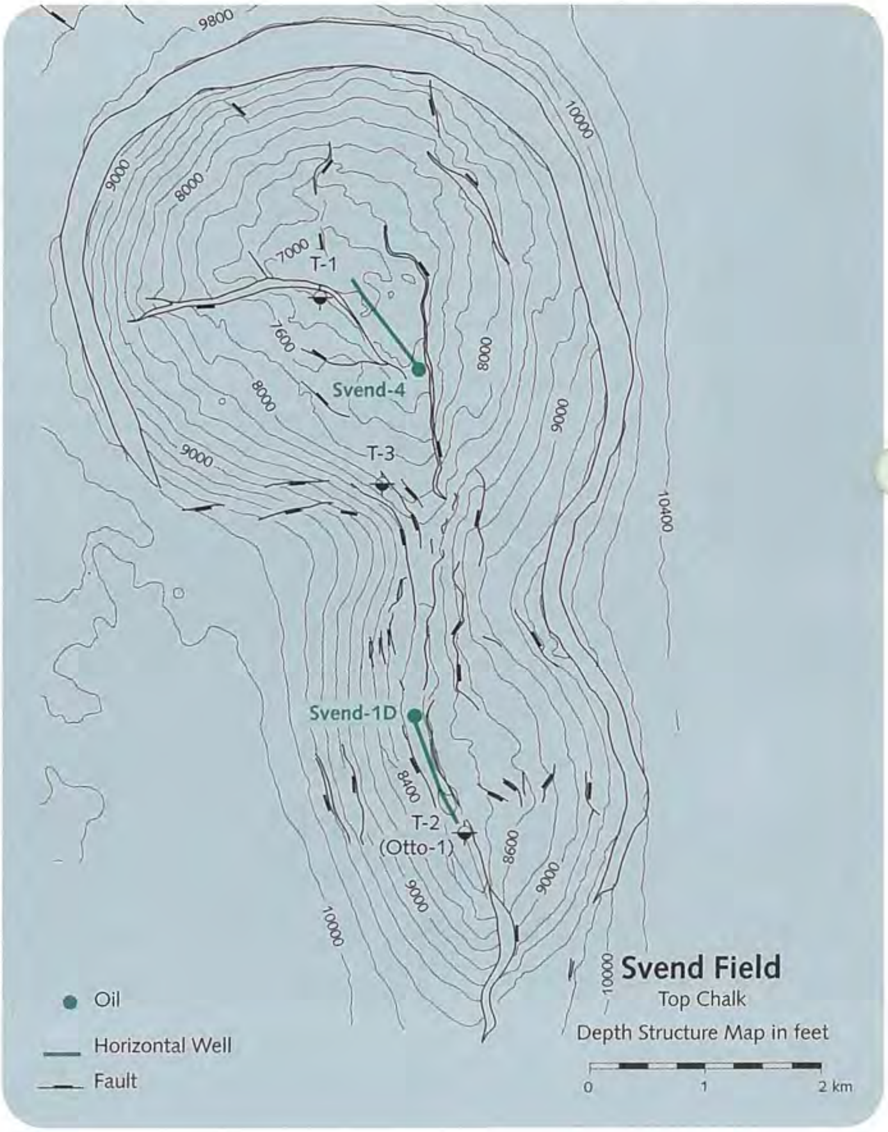
The Svend Field is an anticlinal structure, induced through Zechstein salt tectonics. This has led to fracturing of the chalk in the reservoir. The Svend Field consists of a northern reservoir called North Arne, and a southern reservoir called Otto. The Otto reservoir is situated 250 metres deeper than the North Arne reservoir. The North Arne reservoir has proved to have unusually favourable production properties.

PRODUCTION STRATEGY

Oil and gas production from the Svend Field is currently based on primary recovery at a pressure above the bubble point of the oil in the reservoir. The natural drive mechanism supplied by the underlying water zone has not yet been evaluated. The field has only produced for a short period, and it is uncertain as yet which recovery technique is best in the longer term.

PRODUCTION FACILITIES

The Svend Field has been developed as a satellite to the Tyra Field, with an unmanned STAR wellhead platform. The hydrocarbons produced are conveyed to Tyra East for processing and export ashore. The Svend Field is connected to the 16" pipeline from Harald to Tyra East.



THE HARALD CENTRE

Field name:	Harald
Prospect:	Lulu/West Lulu
Location:	Blocks 5604/21 and 22
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1980(Lulu) 1983(West Lulu)
Year on stream:	1997
Producing wells:	1 (Lulu), 2 (West Lulu)
Water depth:	64 m
Acreage:	25 km²
Reservoir depth:	2,700 m (Lulu) 3,650 m (West Lulu)
Reservoir rock:	Chalk (Lulu) Sandstone (West Lulu)
Geological age:	Danian/U. Cret. (Lulu) Middle Jurassic (West Lulu)
Reserves at 1 Jan. 99:	
Condensate:	5.5 million m^3
Gas:	18.2 billion Nm^3
Cum. production at 1 Jan. 99:	
Condensate:	2.44 million m^3
Gas:	3.83 billion Nm^3
Water:	0.00 million m^3
Production in 98:	
Condensate:	1.70 million m^3
Gas:	2.74 billion Nm^3
Water:	0.00 million m^3
Tot. investments at 1 Jan. 99:	
98 prices	DKK 2.8 billion

REVIEW OF GEOLOGY

The Lulu structure is an anticline induced through Zechstein salt tectonics. The gas zone is up to 75 metres thick and extends over an area of 6.5 km².

The West Lulu structure is a tilted Jurassic fault block. The sandstone reservoir in the Middle Jurassic Bryne Formation contains gas under such pressure conditions that production will result in precipitation of condensate (retrograde gas/condensate). The structure is situated at a depth of about 3,600 metres. The effective thickness of the sandstone is 100 metres.

PRODUCTION STRATEGY

Recovery from both the Lulu and West Lulu reservoir takes place by letting the gas expand, supplemented by a moderate, natural influx of water into the reservoir.

PRODUCTION FACILITIES

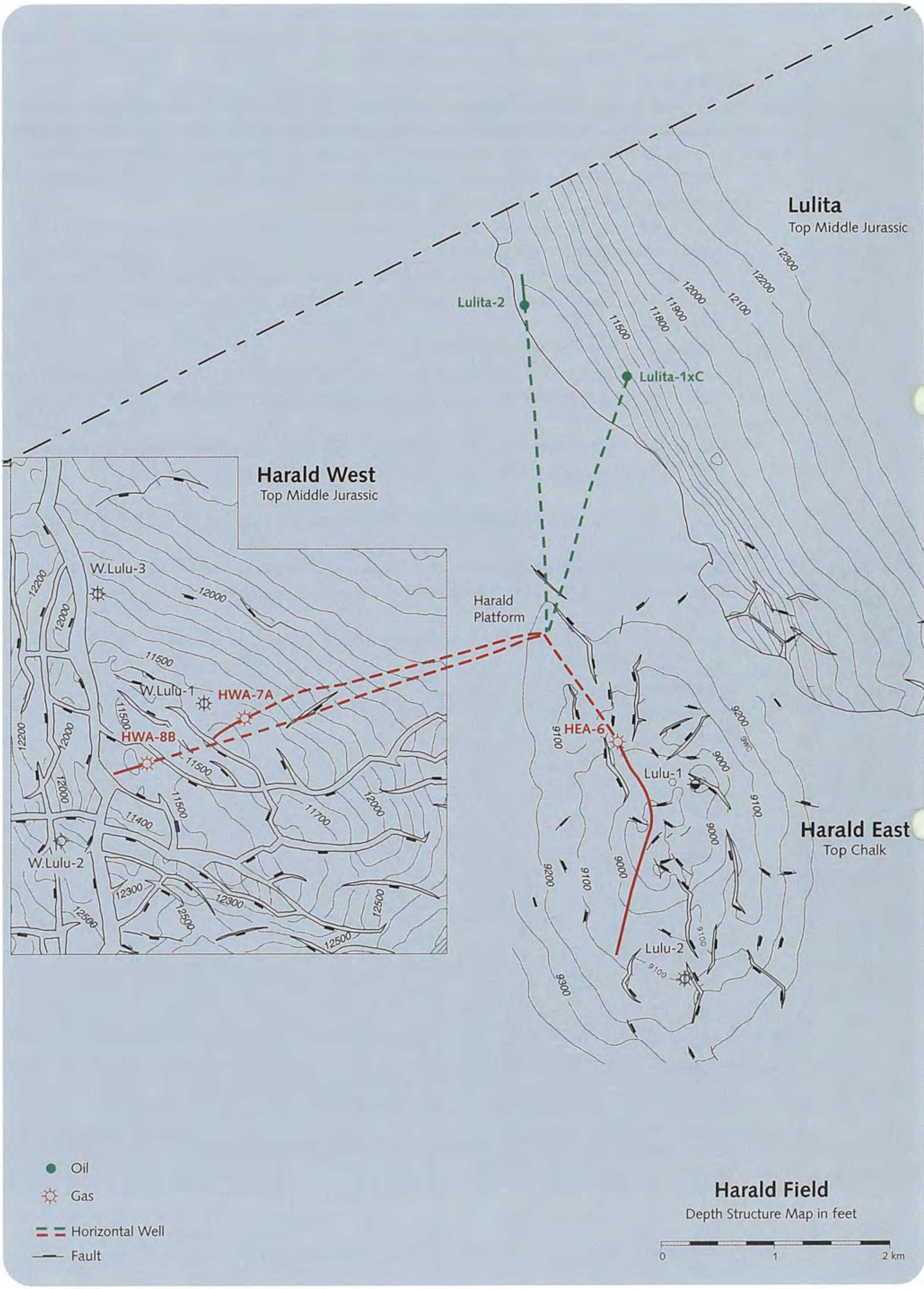
The Harald Field installations comprise a combined wellhead and processing platform (Harald A) and an accommodation platform (Harald B).

The processing facilities consist of a plant that separates the hydrocarbons produced, as well as a plant for the final processing of the gas produced.

The unprocessed condensate and the processed gas are transported to Tyra East.

There are no facilities at the Harald Field for processing the water produced. The Harald Field facilities also handle production from the Lulita Field.

The Harald Field has accommodation facilities for 16 persons.


Lulita
Top Middle Jurassic
12300
12200
12100
12000
11900
11800
11500
Lulita-2
Lulita-1xC
Harald West
Top Middle Jurassic
W.Lulu-3
12200
12000
11500
W.Lulu-1
HWA-7A
HWA-8B
11400
11700
12300
12500
W.Lulu-2
Harald Platform
HEA-6
9100
9200
9000
Lulu-1
Lulu-2
9300
Harald East
Top Chalk
Oil
Gas
Horizontal Well
Fault
Harald Field
Depth Structure Map in feet
0
1
2 km

THE HARALD CENTRE

Field name:	Lulita
Location:	Blocks 5604/18 and 22
Licence:	Sole Concession (50%), 7/86 (34.5%) and 1/90 (15.5%)
Operator:	Mærsk Olie og Gas AS
Discovered:	1992
Year on stream:	1998
Producing wells:	2
Water depth:	65 m
Acreage:	3 km²
Reservoir depth:	3,525 m
Reservoir rock:	Sandstone
Geological age:	Middle Jurassic
Reserves at 1 Jan. 99:	
Oil:	0.3 million m³
Gas:	0.3 billion Nm³
Cum. production at 1 Jan. 99:	
Oil:	0.15 million m³
Gas:	0.07 billion Nm³
Water:	0.00 million m³
Production in 98:	
Oil:	0.15 million m³
Gas:	0.07 billion Nm³
Water:	0.00 million m³
Tot. investments at 1 Jan. 99:	
98 prices	DKK 0.2 billion

Under the approved unitization agreement, the Lulita Field is divided into the following shares:

Sole Concession	50.0%
The Lulita share of licence 7/86	34.5%
Licence 1/90	15.5%

REVIEW OF GEOLOGY

The Lulita Field is a structural fault trap with a Middle Jurassic sandstone reservoir. The accumulation consists of oil with a gas cap.

PRODUCTION STRATEGY

The Lulita Field development plan consists of two phases. The first phase, which has been implemented, is based on production from two wells by natural depletion.

PRODUCTION FACILITIES

The Lulita Field is being produced from the fixed installations in the Harald Field. Thus, the Lulita wellheads are hosted by the Harald A platform, where the facilities have been upgraded to handle production from the Lulita Field.

Together with condensate from the Harald Field, the oil produced is conveyed through a 16" pipeline to Tyra East for export ashore. The gas produced in the Lulita Field is transported to Tyra through the 24" pipeline connecting Harald with Tyra East, from where it is transported to shore.

The Harald A platform has special equipment for separate metering of the oil and gas produced in the Lulita Field.

The number of wells indicated is the number existing at the turn of the year.

FINANCIAL KEY FIGURES

	Investments in Field Development DKK million	Operating Costs for Fields[1] DKK million	Exploration Costs DKK million	Crude Oil Price[2] USD/bbl	Exchange Rate DKK/USD	Inflation Rate[3] per cent	Net Foreign-Currency-Value[4] DKK billion
1972	105	32	28	3.0	7.0	6.6	-3.2
1973	9	34	83	4.6	6.1	9.3	-4.0
1974	38	58	76	11.6	6.1	15.2	-9.2
1975	139	64	118	12.3	5.8	19.6	-8.5
1976	372	71	114	12.9	6.1	10.3	-9.5
1977	64	88	176	14.0	6.0	11.2	-10.4
1978	71	128	55	14.1	5.5	10.0	-9.2
1979	387	146	78	20.4	5.3	9.6	-13.7
1980	956	169	201	37.5	5.6	12.3	-18.6
1981	1,651	402	257	37.4	7.1	11.7	-20.1
1982	3,948	652	566	34.0	8.4	10.2	-20.6
1983	3,528	615	1,264	30.5	9.1	6.9	-17.8
1984	1,596	1,405	1,211	28.2	10.4	6.3	-18.3
1985	1,953	1,677	1,373	27.2	10.6	4.7	-17.6
1986	1,695	1,533	747	14.9	8.1	3.6	-7.3
1987	908	1,560	664	18.3	6.8	4.0	-5.9
1988	897	1,550	424	14.8	6.7	4.6	-3.7
1989	1,153	1,819	366	18.2	7.3	4.8	-3.2
1990	1,738	1,924	592	23.6	6.2	2.6	-2.7
1991	2,260	2,176	986	20.0	6.4	2.4	-1.9
1992	2,402	2,080	983	19.3	6.0	2.1	-0.4
1993	3,358	2,324	442	16.8	6.5	1.2	-1.7
1994	3,140	2,395	151	15.6	6.4	2.0	-0.5
1995	4,167	2,176	272	17.0	5.6	2.1	0.0
1996	4,259	2,491	470	21.1	5.8	2.1	0.0
1997	3,825	2,772	521	18.9	6.6	2.2	2.0
1998*	5,308	2,119	322	12.8	6.7	1.6	1.0

Nominal Prices
1) Including transportation costs, including profit element
2) Danish crude oil
3) Consumer prices
4) Oil products and natural gas
**) Estimate*

ERP PROJECTS

Projects Funded under ERP 99

Reference Number 1313/	Project Title	Project Budget DKK 1,000	ERP Funding DKK 1,000	Participants
99-0003	Palaeozoic sedimentary deposits and basement structures in the Danish area	3,042	2,070	Københavns Universitet, Geologisk Institut
99-0009	Priority - Improved recovery from Lower Cretaceous reservoirs	12,000	4,000	Mærsk Olie og Gas AS, GEUS, DTU, GI
99-0011	On the significance of three-phase displacement mechanisms for recovery efficiency in connection with the planning and optimization of WAG/CGW injection	3,212	1,600	GEUS
99-0013	Free span burial instrumentation pig – Phase A	2,150	1,450	Force Instituttet, Dansk Olie-og Gasproduktion A/S
99-0014	Improved design basis for offshore flexible pipes	9,016	4,500	NKT Cables A/S, Institut for kemiteknik-DTU
99-0024	Mapping and evaluation of the Nuussuaq Basin	5,417	2,611	GEUS, Grønlands Hjemmestyre-Råstofdirektoratet, Århus Universitet-Maringeologisk Afdeling
99-0025	An integrated study of the stratigraphy and hydrocarbon prospectivity of Palaeozoic sediments offshore south-western Greenland	4,042	2,000	GEUS
Total		38,879	18,231	

ERP Projects Completed in 1998

Reference Number 1313/	Project Title	Participating Institutions/ Businesses (Project Leader)
Exploration: 94-0001	Secondary migration in the Central Trough	GEUS (Claus Andersen)
95-0002	Identification of sequence stratigraphic key-surfaces and units based on optical and geochemical parameters	GEUS (Jan Andsbjerg)
95-0003	Petroleum source potential of Middle Jurassic deposits in the Danish Central Trough	GEUS (Jørgen Bojesen-Koefoed)
96-0002	Evaluation of potential reservoir units within a marine basinal fan system in the Gertrud Graben	GEUS (Erik S. Rasmussen)

Recovery Methods:		
94-0003	Evaluation of EOR processes using network models	GEUS (Anatol Winter), DTU
95-0005	Geostatistical reservoir characterization of the Dan Field by inversion of seismic data	ØD-S Holding A/S (Jacob M. Pedersen), GEUS, COWI
95-0007	Comparative investigations of the applicability of different physical methods in the study of displacement processes in porous rock	Institut for Automation (Poul L. Ølgaard), Institut for Fysik, -Kemi og -Kemiteknik, GEUS
96-0004	Determination of 2D saturation profiles in cores	Institut for Automation DTU (Poul L. Ølgaard), Institut for Fysik DTU
96-0005	Determination of saturation functions	Institut for Energiteknik DTU, GEUS (Dan Olsen)
96-0006	Scale-up and stochastic modelling	COWI (Birger N. Thorsen), GEUS, Institut for Energiteknik DTU
Equipment and Installations:		
95-0001	Organic phases in hydrocarbon reservoir fluids	Institut for kemiteknik DTU (Erling H. Stenby)
95-0006	Microbiologically influenced corrosion and cracking of steel	Institut for procesteknik DTU (Lars V. Nielsen), Force Instituttet, Dansk Olie og Naturgas A/S, Hovedstadens Naturgas I/S
95-0008	Tracer methods for measurements of multiphase flow	Force Instituttet (Jens R. Christensen)
Arctic Conditions:		
94-0006	Oil geology and thermal history of the eastern part of Northern Greenland	GEUS (Lars Stemmerik)
95-0004	Modelling of uplift history from maturity and apatite fission track data. Nuussuaq, Western Greenland	GEUS (Anders Mathiesen)
96-0010	Reservoir modelling – West Nuussuaq	GEUS (Gregers Dam, Martin Sønderholm), Grønlands Hjemmestyre-Råstofdirektoratet, Fault Analysis Group
Eastern European Projects:		
95-0009	The Polish Middle to Late Jurassic epicratonic basin, stratigraphy, facies and basin history	GEUS (Niels Poulsen), University of Warsaw
96-0001	Petrology of Upper Silurian reservoir rocks from the Kurdirka Atoll, Lithuania	GEUS (Niels Stentoft), Vilnius University, Lithuania Institute of Geology

GEUS is the Geological Survey of Denmark and Greenland
DTU is the Technical University of Denmark

CATEGORIES OF RESERVES

As in previous years, the assessment only includes reserves in structures in Danish territory where the presence of hydrocarbons has been conclusively established through drilling and testing.

The method used by the Danish Energy Agency in calculating the reserves makes allowance for the uncertainty involved in all the parameters used in the calculation. For each oil and gas field, the reserves assessed are expressed by three values: *low*, *expected* and *high*, reflecting the margins of uncertainty tied to the oil and gas reserves in the relevant field.

Only a percentage of the oil and gas in place can be recovered. The amount of oil and gas that can be recovered throughout the life of the field is termed the ultimate recovery. Thus, the difference between ultimate recovery and the amounts of oil and gas produced at any given time constitutes the reserves.

The projects which are ongoing or for which the operator has submitted plans are divided into three categories: *ongoing*, *approved* and *planned recovery*.

The Danish Energy Agency assesses the reserves recoverable under *possible recovery* projects for which the operator has not submitted specific plans to the authorities. The categories of reserves are defined as follows:

Ongoing Recovery

This category includes the reserves that are recoverable with the use of existing production facilities and wells. It is assumed that ordinary maintenance and workover operations are performed to ensure the continued functioning of the existing facilities.

Approved Recovery

If production has not yet been initiated under an approved development plan or any part of an approved plan, the reserves assessed to be recoverable are categorized as approved recovery. This applies to the development of new fields as well as extensions and modifications of existing installations.

Planned Recovery

Planned recovery denotes projects described in a development plan that is being considered by the authorities. Likewise, the reserves attributable to discoveries for which a declaration of commerciality has been filed are termed planned recovery.

Possible Recovery

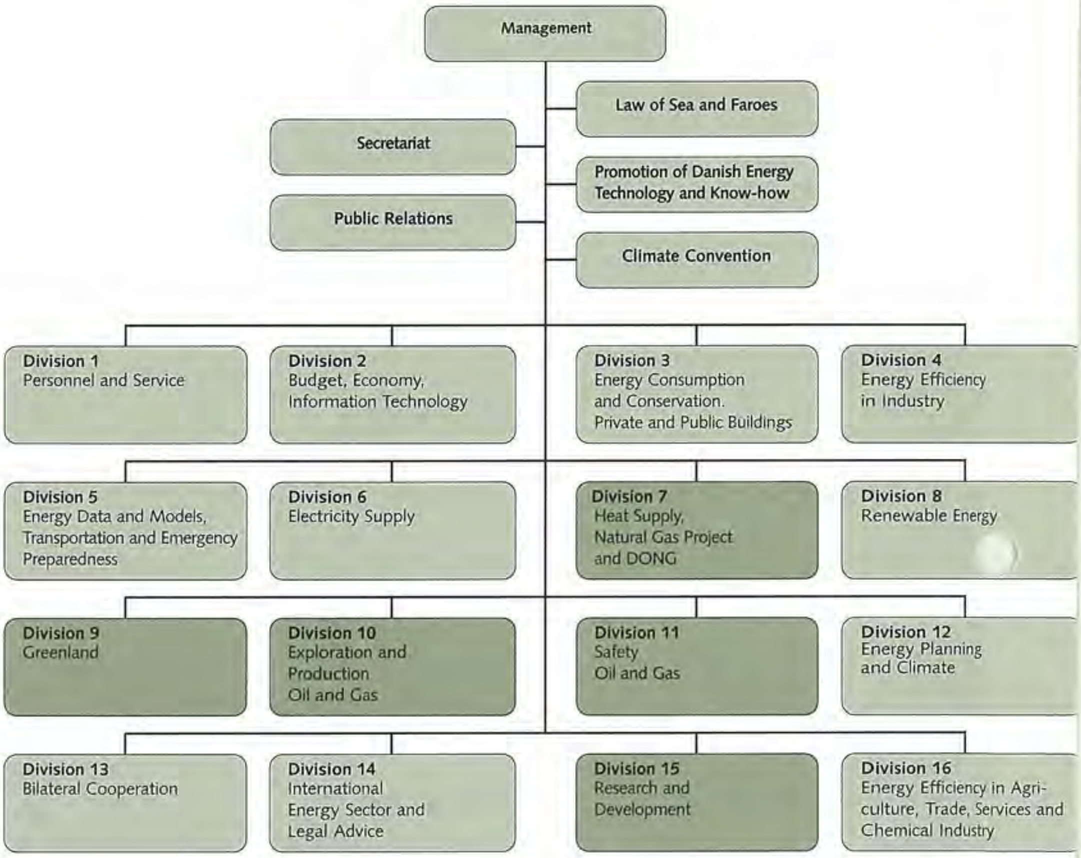
Possible recovery denotes reserves recoverable with the use of known technology, i.e. technology which is currently used in areas where the conditions are comparable to those prevailing in the North Sea. For instance, this includes water injection on a larger scale than before or wider application of horizontal wells. For discoveries for which a declaration of commerciality has not yet been filed, the recoverable reserves are categorized as possible recovery. This category also includes recovery from discoveries considered to be non-commercial.

ORGANIZATION

The Danish Energy Agency is an institution under the Ministry of Environment and Energy. The Agency handles all technical matters, administrative and political tasks within the energy area, in which connection the Agency prepares the energy-related matters to be submitted to the Minister, and handles relations and coordination with external parties.

The Danish Energy Agency has 16 divisions, as well as a few staff functions reporting to Management. The administration of oil and gas activities is handled by the 10th and 11th divisions of the Agency, assisted by the 7th, 9th and 15th divisions to some extent. How responsibilities between the oil and gas divisions are divided is dealt with in more detail on the following page.

At the turn of the year 1998/99, the Agency employed the equivalent of about 280 full-time employees, about 40 of whom are involved in the administration of oil and gas activities.



The Tenth Division: Exploration and Production of Oil and Gas

Head of division: Søren Enevoldsen

Supervising exploration and production activities in terms of resources, as well as financial and legal aspects. Licensing policy and administration, licensing rounds and the awarding of licences. Approving appraisal programmes and work programmes. Evaluating declarations of commerciality. Approving development plans and production profiles. Addressing matters concerning the obligation to connect production facilities to existing pipelines and exemptions from payment of the pipeline tariff. Matters concerning unitization. Geological evaluations and reservoir engineering. Preparing analyses, evaluating the potential and making forecasts of Danish oil and gas reserves. Evaluating commercial viability, including work on energy plans. Considering political and administrative issues related to DOPAS. Advising the Bureau of Minerals and Petroleum (BMP) under the Greenland Home Rule Authority on legal and technical issues. Responsibility for the Danish Energy Agency's oil/gas-related system exports. Advising the BMP for Greenland on other issues falling within its area of expertise.

The Eleventh Division: Safety in the Oil/Gas Sector

Head of division: Uffe Danvold
Activities concerning safety, working environment and other environmental issues under the provisions of the Danish Act on offshore Installations, the Subsoil Act and the Continental Shelf Act. Approving mobile and fixed installations as well as pipelines. Supervising the safety, working environment and other environmental aspects of offshore installations and pipelines, as well as monitoring drilling operations in terms of safety. Approving and supervising manning tables and organizational charts, as well as undertaking the tasks related to membership of the Action Committee, the Coordination Committee and the Average Commission for Offshore Installations. Monitoring supplies conveyed through the transmission systems belonging to Dansk Naturgas A/S and supervising the technical safety aspects of the gas storage facilities established by Dansk Naturgas A/S. Considering political and administrative issues related to DORAS and the Danish Oil Pipeline Act. Moreover, the division draws up regulations in this area. Advising the BMP under the Greenland Home Rule Authority on legal and technical issues.

The Seventh Division: Heat Supply, the Natural Gas Project and DONG

Head of division: Thomas Bastholm Bille
Matters concerning the DONG group and the regional natural gas companies. The financial, legal, technical and organizational matters related to the implementation of the natural gas project. Parliamentary Acts on natural gas supplies. Matters concerning the purchase and export of natural gas. Activities under the provisions of the Danish Heat Supply Act. Expanding decentralized combined heat and power systems and using environmentally friendly energy sources. Legal/administrative and financial issues. Approving projects and hearing appeals under the Heat Supply Act. The Danish Act on Subsidies for the Generation of Electricity. Agenda 21 planning and work on the 'Brundtlandby' project.

The Ninth Division: Greenland

Head of division: Uffe Strandkjær
Governmental tasks related to the work of the Joint Committee on Mineral Resources in Greenland. Advising the Danish members of the committee on exploration and production of mineral resources in Greenland. Assisting with the preparation of legislation and agreements in this area. Advising/assisting the Bureau of Minerals and Petroleum for Greenland.

The Fifteenth Division: Research and Development

Head of division: Henrik Andersen
National and international activities regarding energy research. The national activities include administering energy research programmes, research policy proposals and statements, as well as acting as the secretariat of the Advisory Oil and Natural Gas Research Committee. The international activities relate mainly to the EU research programmes, the IEA and the Nordic Energy Research Programme.

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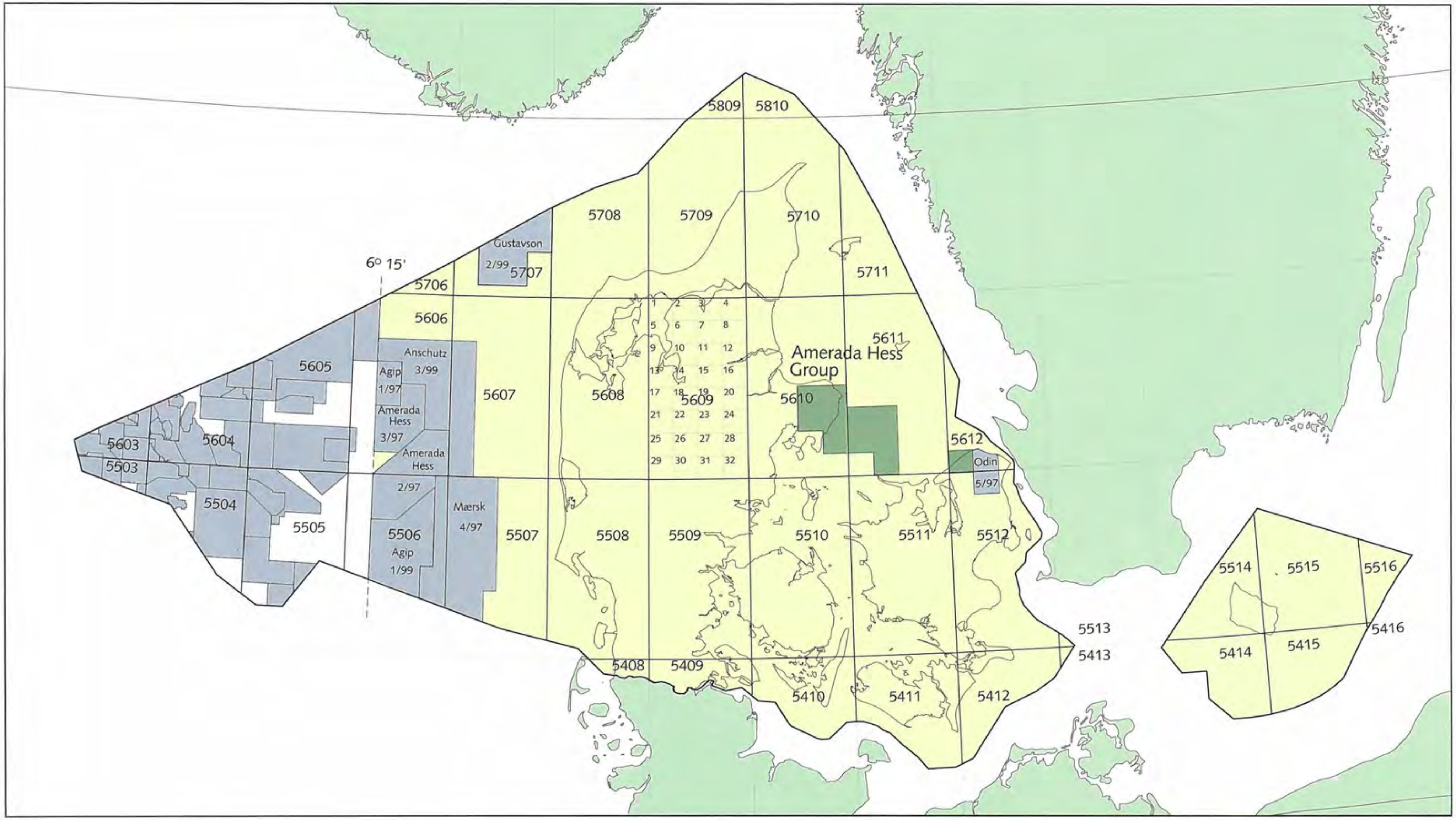

Existing Licences

Application in Open Door Procedure

Open Door Procedure

Danish Licence Area March 1999. The Western Area