In 1966, the first discovery of oil and natural gas was made in Denmark. Since 1986, the Danish Energy Authority has published its annual report "Oil and Gas Production in Denmark".

As in previous years, the report for 2001 describes exploration and development activities in the Danish area. The report also contains a review of production and the health, safety and environmental aspects of oil and gas production activities.

In addition, the report contains an assessment of Danish oil and gas reserves and a section on the impact of oil and gas production on the Danish economy.

Finally, this year's report includes a special section on the accident that occurred in the Gorm Field in 2001.

The report can be obtained from the Danish Energy Information Centre, tel. +45 70 21 80 10, on request and is also available on the Danish Energy Authority's homepage, www.ens.dk.

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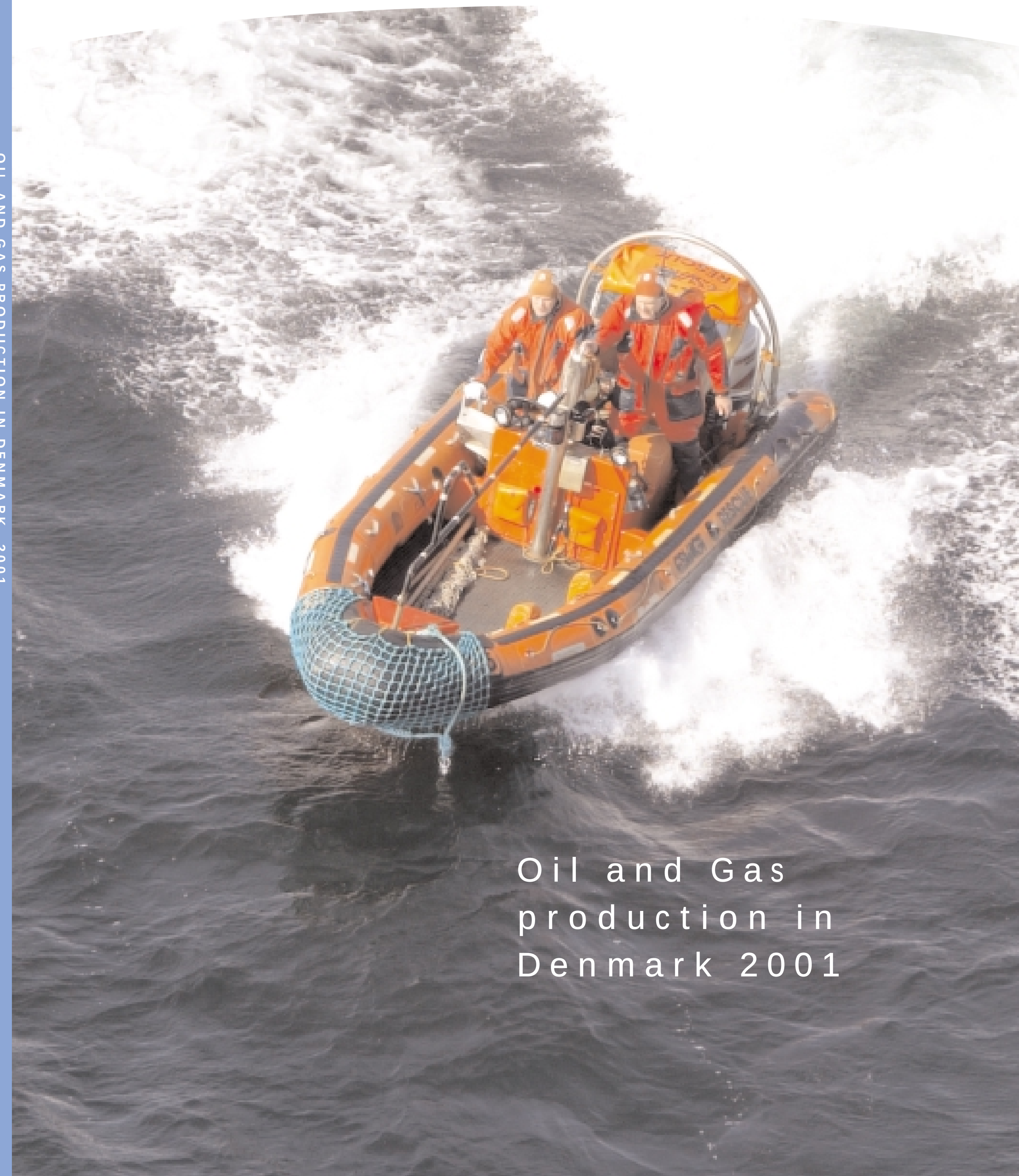
OIL AND GAS PRODUCTION IN DENMARK 2001

DANISH ENERGY AUTHORITY



Oil and Gas production in Denmark 2001

Established by law in 1976, the Danish Energy Authority is an authority under the Ministry of Economic and Business Affairs that deals with matters relating to the production, supply and consumption of energy. On behalf of the Government, its task is to ensure that the Danish energy sector develops in a manner appropriate to society, the environment and safety.

The Danish Energy Authority prepares and administers Danish energy legislation, analyzes and evaluates developments in the energy sector, and makes forecasts and assessments of Danish oil and gas reserves.

The Danish Energy Authority works closely with local, regional and national authorities, energy distribution companies and licensees, etc. At the same time, the Danish Energy Authority maintains relations with international partners in the energy area, including the EU, IEA, as well as the Nordic Council of Ministers.

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PREFACE

2001 was a year of growth and intense activity in the Danish oil and gas sector.

Thus, the oil companies carried out extensive exploration activity in Danish territory, drilling six exploration wells and nine appraisal wells. Auspiciously, two of the exploration wells struck new oil.

The Danish Energy Authority approved eight development plans for existing fields in 2001, which will involve total investments of approx. DKK 10 billion over the next few years. Moreover, seven drilling rigs operated in the producing fields throughout the year, drilling 29 new recovery wells, the highest number ever drilled in a year.

The production of oil and natural gas from the North Sea is pivotal for Danish society and secures substantial income for the state. The total estimated value of Danish oil and gas production for 2001 exceeded DKK 30 billion. Although this represents a slight decline from the year before, the production value estimated for 2001 is still considered very high seen from a historical perspective. The production of oil and gas also impacts positively on the Danish balance of payments.

In 2001, Denmark was self-sufficient in energy for the fifth year in a row, chiefly as a result of the oil and natural gas produced in the North Sea.

Overall, the year 2001 saw a favourable development in the exploration for and production of oil and natural gas. The numerous activities coupled with new discoveries give grounds for optimism and an expectation that Denmark can continue to exploit the resources in the North Sea for many years yet, thereby experiencing additional growth.

Copenhagen, June 2002

Ib Larsen

Director

CONVERSION FACTORS

Reference pressure and temperature for the units mentioned:

		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

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

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).

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.

The composition, and thus the calorific value, 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. The table below shows the average for 2001. The lower calorific value is indicated.

The SI prefixes m (million), k (kilo), M (mega), G (giga), T (tera) and P (peta) stand for 10^{-3}, 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.

Some abbreviations:

kPa — *kilopascal. Unit of pressure. 100 kPa = 1 bar*

Nm^3 — *Normal cubic metre. Unit of measurement used for natural gas in the reference state 0°C and 101.325 kPa.*

m^3 (st) — *Standard cubic metre. Unit of measurement used for natural gas and crude oil in a reference state of 15°C and 101.325 kPa.*

Btu — *British Thermal Unit. Other thermal units are J (= Joule) and cal (calorie).*

bbl — *Blue barrel. In the early days of the oil industry when oil was traded in physical barrels, different barrel sizes soon emerged. To avoid confusion, Standard Oil painted their standard-volume barrels blue.*

kg · mol — *kilogrammol; the mass of a substance whose mass in kilograms is equal to the molecular mass of the substance.*

g — *gamma; relative density.*

in — *inch; British unit of length. 1 inch = 2.54 cm*

ft — *foot/feet; British unit of length. 1 ft = 12 in.*

t.o.e. — *tons oil equivalent; this unit is internationally defined as 1 t.o.e. = 10 Gcal.*

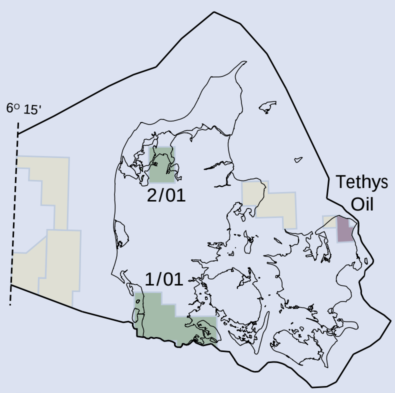
	FROM	TO	MULTIPLY BY
Crude Oil	m^3 (st)	stb	6.293
	m^3 (st)	GJ	36,3
	m^3 (st)	t	0.86[i]
Natural Gas	Nm^3	scf	37.2396
	Nm^3	GJ	0.040
	Nm^3	kg·mol	0.0446158
	m^3 (st)	scf	35.3014
	m^3 (st)	GJ	0.0379
	m^3 (st)	kg·mol	0.0422932
Units of Volume	m^3	bbl	6.28981
	m^3	ft^3	35.31467
	US gallon	in^3	231*
	bbl	US gallon	42*
Energy	t.o.e.	GJ	41.868*
	GJ	Btu	947817
	cal	J	4.1868*

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

*) *Exact value*
i) *Average value for Danish fields*

1. LICENCES

Fig. 1.1 New Open Door Licences



NEW LICENCES

No licensing round was held in 2001, but two new licences were granted under the Open Door procedure on 5 March 2001.

Under the Open Door procedure, applications for licences for exploration and production of hydrocarbons are invited for all unlicensed areas east of 6°15' East longitude every year in the period from 2 January through 30 September. DONG Efterforskning og Produktion A/S (DONG E&P A/S) is to have a 20% share of all licences in the Open Door area.

Licence 1/01 covers a major area in South Jutland. The participating companies are UAB Minijos Nafta (operator), Sterling Resources (UK) Ltd., Dansk Venture Olieefterforskning ApS and DONG E&P A/S.

Licence 2/01 applies to an area near Salling in North Jutland. The companies participating in this licence are Sterling Resources (UK) Ltd. (operator), Dansk Efterforskningsselskab ApS and DONG E&P A/S.

The areas comprised by the new licences are shown in Fig. 1.1. The companies' shares in the licences appear from Appendix A.

The work programmes for Open Door licences are generally divided into phases, which means that the licensees undertake further work commitments with each new phase. Considering the work done initially, the holders of several licences previously granted in the Open Door area have decided to continue their exploration activities.

Since the Open Door procedure was introduced in 1997, a total of 11 licences for exploration and production of hydrocarbons have been granted. However, some of these licences have since been relinquished, leaving six active Open Door licences at the end of 2001.

On 25 January 2002, Tethys Oil AB, a company incorporated in Sweden, submitted an application to the Danish Energy Authority for a licence for exploration and production of hydrocarbons in an area in North Zealand; see Fig. 1.1. The area that Tethys has applied for is almost identical to the area comprised by licence 5/97, which was relinquished in September 2001.

AMENDED LICENCES

Extended Licence Terms

In 2001, the Danish Energy Authority granted an extension of the terms of ten licences; see Table 1.1.

Table 1.1 Extended Licence Terms

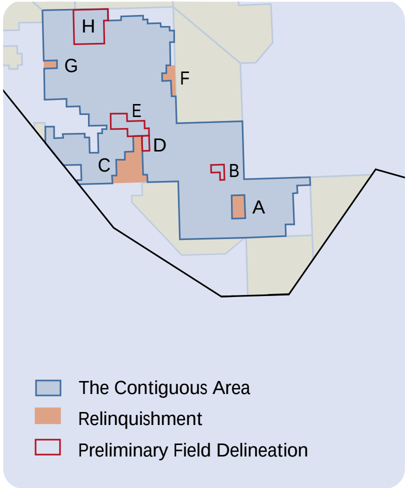
Licence	Expiry
7/89	20 Dec. 2003
8/89	20 Dec. 2003
10/89	20 Dec. 2002
1/95	15 Nov. 2001
2/95	20 Dec. 2003
4/95	15 Nov. 2002
6/95	15 Nov. 2002
7/95	15 Nov. 2002
8/95	15 May 2003
9/95	15 May 2002

The licence terms were extended on the condition that the licensees undertake to carry out additional exploration work in the licence areas. As mentioned below, licence 1/95 expired in November 2001.

Approved Transfers

All contemplated transfers of licences and the relevant terms of transfer must be submitted to the Danish Energy Authority for approval.

Fig. 1.2 Relinquishment in the Contiguous Area



Effective 2 April 2001, Northern Petroleum took over a 5% share of Open Door licence 4/99 from Odin Energi ApS, which held a 20% share prior to the transfer.

With effect from 1 July 2001, Paladin Resources plc. took over Enterprise Oil Denmark Ltd., and thus the company's shares of licences 6/95 and 7/98. Licence 7/98 was subsequently relinquished in September 2001. On 17 September 2001, Paladin changed the name of the former Enterprise company to Paladin Oil Denmark Ltd.

In licence 4/95, DENERCO OIL A/S took over a 5% share from EWE AG, which has thus ceased to be a licensee in the Danish area. This transfer became effective on 1 September 2001. Licence 4/95 includes the Nini discovery, to be developed in 2002/2003.

With effect from 31 December 2001, Phillips Petroleum International Corporation Denmark transferred its share of licence 6/95 to Paladin Oil Denmark Limited, DENERCO OIL A/S and DONG E&P A/S. Consequently, these three companies have increased their shares of the Siri Field by 5.2630%, 3.6185% and 3.6185%, respectively.

DENERCO OIL A/S acquired the share capital of LD Energi A/S effective 31 December 2001. The acquired company will carry on as a subsidiary of DENERCO OIL A/S, under the name DENERCO Petroleum A/S. Thus, DENERCO Petroleum A/S has taken over LD Energi A/S's shares of licences 7/86 (the Amalie share), 7/86 (the Lulita share), 1/90 and 16/98.

The composition of the groups of companies participating in each of the licences granted in the Danish area appears from Appendix A. The Danish Energy Authority's homepage at *www.ens.dk* provides a similar outline, which is updated each time the composition of a group changes.

Appendix B provides an outline of the individual companies' participation in individual fields and exploration licences.

Partial Relinquishment

In the Contiguous Area, which is part of A.P. Møller's Sole Concession of 8 July 1962, preliminary maximum borders were established for several fields in connection with the partial relinquishment at 1 January 2000. According to the agreement made, the Concessionaires are to relinquish areas A-H by 31 December 2001, although area E by 31 December 2002, if no activities leading to production in the areas have been initiated or planned. Consequently, the Concessionaires relinquished the areas shown in Fig. 1.2 on 31 December 2001. On the basis of development plans submitted, the Danish Energy Authority has approved that areas B and H are not to be relinquished on 31 December 2001.

The areas that are not to be relinquished will be finally delineated following negotiations between the Danish Energy Authority and the Concessionaires in spring 2003, and in 2004 as far as area E is concerned.

A minor share of licence 5/99, granted as a neighbouring block to the Sole Concession in 1999, was likewise relinquished on 31 December 2001; see Fig. 1.3.

Fig. 1.3 Relinquishment outside the Contiguous Area

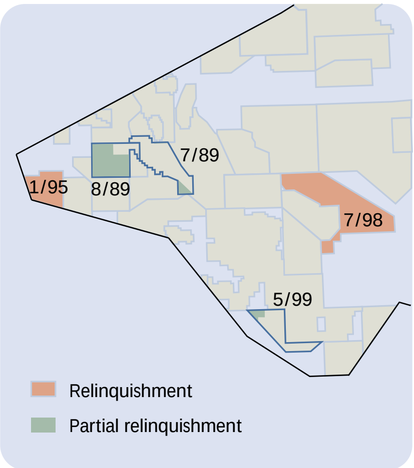
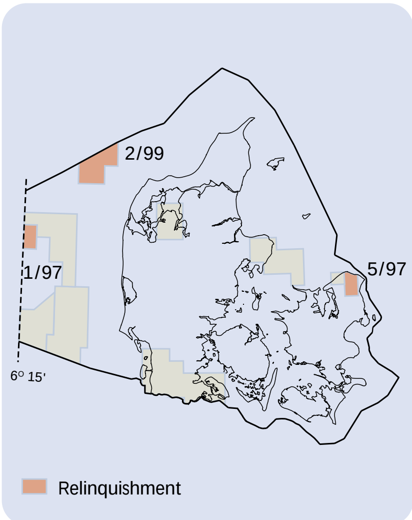


Fig. 1.4 Relinquishment in the Open Door Area



In connection with the extension of the exploration terms of licences 7/89 and 8/89, parts of the areas previously comprised by the licences were relinquished on 20 December 2001. The holder of licence 8/89 relinquished almost an entire block, including the area in which the Bertel-1 well encountered oil in Triassic sandstone in 1992. Only a minor share of licence 7/89 was relinquished.

TERMINATED LICENCES

Five licences for exploration and production of hydrocarbons terminated in 2001. The areas relinquished appear from Fig. 1.3 and Fig. 1.4.

Licence 1/95 expired on 15 November 2001. This licence was granted in the Fourth Licensing Round and covered an area adjoining the UK/Danish border. The oil companies participating in the licence were Amerada Hess ApS (operator), Premier Oil B.V., DENERCO OIL A/S and DONG E&P A/S. The companies' exploration work under the licence included the acquisition of 3D seismics and the drilling of two exploration wells, Saxo-1 and Wessel-1, in 1997. The wells encountered Upper Jurassic sandstone with good reservoir quality, as well as traces of hydrocarbons in both Jurassic sandstone and Zechstein carbonates. In UK territory, oil was encountered in the Fergus Field only about 7 kilometres from the border.

Licence 7/98 was relinquished on 15 September 2001. This licence was awarded to Enterprise Oil Denmark Limited (operator), Denerco Oil A/S and DONG E&P A/S in the Fifth Licensing Round. In 1999, 2D seismic data were acquired in the licence area, which was situated on the Ringkøbing-Fyn High due east of the Central Graben.

Licence 1/97 was relinquished on 15 September 2001. The companies participating in the licence were Agip Denmark B.V. and DONG E&P A/S. Norsk Agip A/S was operator for the licence, which covered an area in the Norwegian-Danish Basin. In 1998, the companies acquired 3D seismic data in the area. Licence 1/97 was among the first licences to be granted in 1997 upon the introduction of the Open Door procedure for the area east of 6˚ 15" East longitude.

Open Door licence 5/97 was relinquished on 19 September 2001. The companies participating in the licence were Odin Energi ApS, Sterling Resources (UK) Ltd. (operator) and DONG E&P A/S. In 2000 and 2001, the licensee conducted geochemical surveys in the licence area in North Zealand to look for indications of hydrocarbon generation in the subsoil.

Licence 2/99 terminated on 20 March 2001. It was granted in 1999 under the Open Door procedure to Gustavson Associates (operator) and DONG E&P A/S. This licence covered an area in the Norwegian-Danish Basin adjoining the Norwegian/Danish border.

Due to the expiry of the licences, the confidentiality period for data from seismic surveys etc. and wells completed under the above-mentioned licences has been reduced to two years.

2. EXPLORATION

Exploration activity was high in 2001, with six exploration wells and nine appraisal wells being drilled. Two of the six wells led to new oil discoveries.

DEEP WELLS

Terminating at a depth exceeding 5,800 metres below sea level, the Phillips group's Svane-1 exploration well became the deepest well drilled to date in Danish territory. The well was the second of two deep Phillips wells spudded in 2001 to explore the Jurassic layers in the Central Graben. The first well drilled by the Phillips group, Hejre-1, encountered the deepest Danish oil accumulation ever. The results of the Svane-1 well were not available at the time this publication went to press.

The exploration of Jurassic sand layers in the Central Graben began back in 1967 with the A-2X well, the second Danish offshore exploration well. Since then, almost half of all 88 exploration wells in the area have penetrated Jurassic layers in the attempt to find hydrocarbon-bearing sand layers in the subsoil. Some of the other exploration wells have reached Jurassic layers but without drilling through the entire Jurassic section.

Fig. 2.1 Cross-section and Map of Exploration Wells in the Central Graben

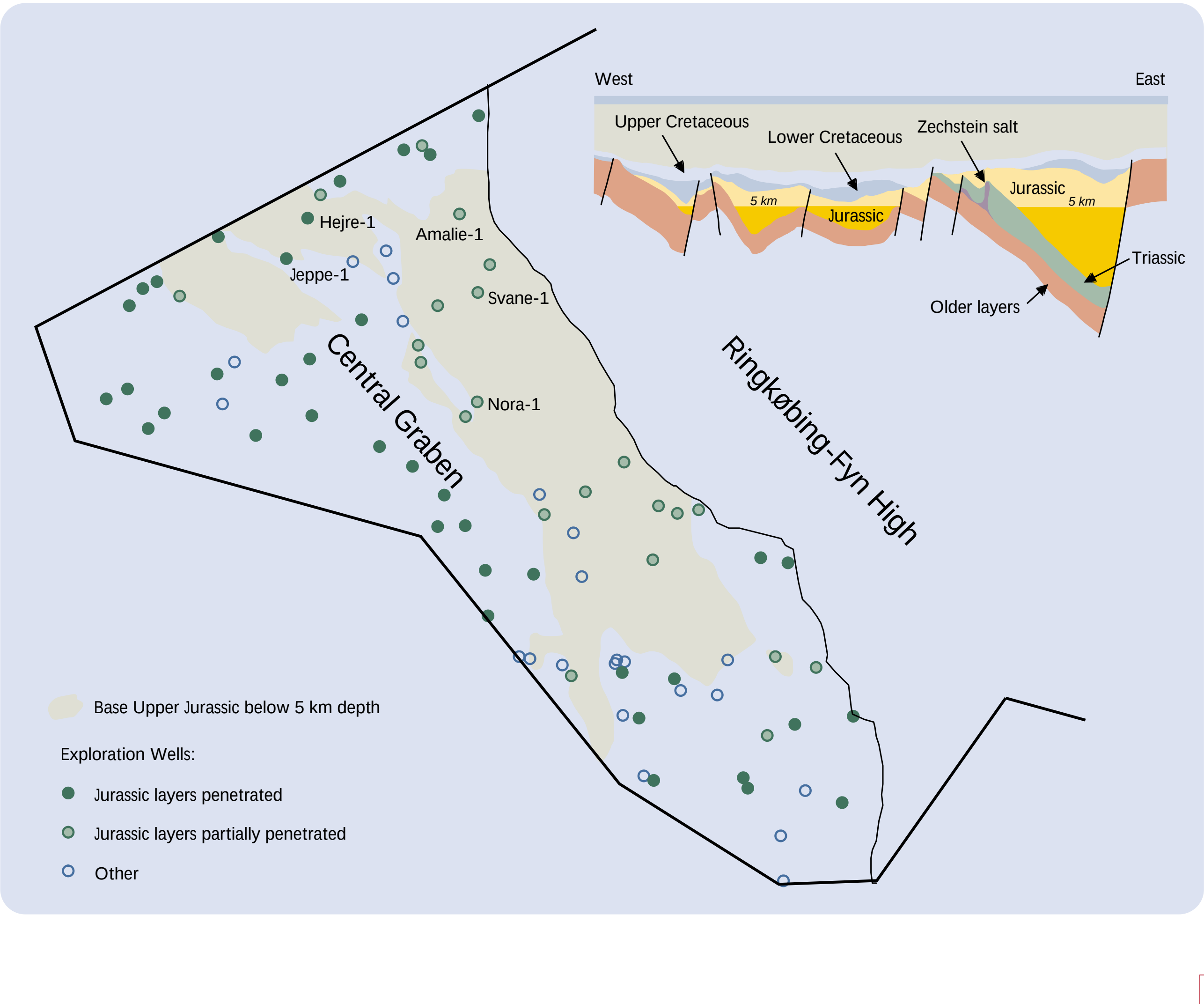
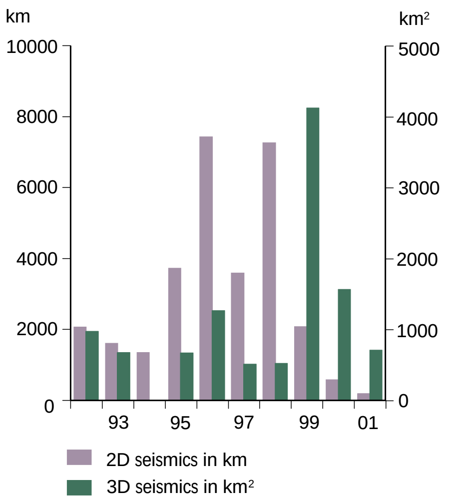


Fig. 2.2 Annual Seismic Surveying Activities



Apart from Svane-1 and Hejre-1, only the Nora-1, Jeppe-1 and Amalie-1 exploration wells have previously been drilled to a depth greater than 5 kilometres. The map and the schematic cross-section in Fig. 2.1 show the areas in the Central Graben where Jurassic sand layers are typically found below 5 kilometres' depth.

Experience from exploring Jurassic sand layers shows that it can be difficult to predict the location of the sand layers and the quality of the sand (porosity and permeability). Generally, sand layers become more compact the deeper they are buried, because minerals precipitate into the voids between the sand grains. As a result, the sand can hold relatively less oil or gas, which makes production from these accumulations more difficult. Under favourable conditions, the oil or gas may have migrated into the sand layers at an early stage, thus preventing the mineral precipitation that normally occurs as the sand layers become more and more deeply buried in the subsoil over time.

Thus, the Phillips group's Hejre-1 well showed that, even at great depths, sandstone with very good reservoir properties can be found. This well therefore raises hopes that more oil and gas can be discovered in areas where Jurassic layers are situated at a great depth. The development of new technology has spawned drilling and logging equipment with better resistance to the high pressures and temperatures encountered at great depths. Consequently, the limit to which it pays to drill has moved one step downwards in the subsoil.

Fig. 2.3 Seismic Surveys in 2001

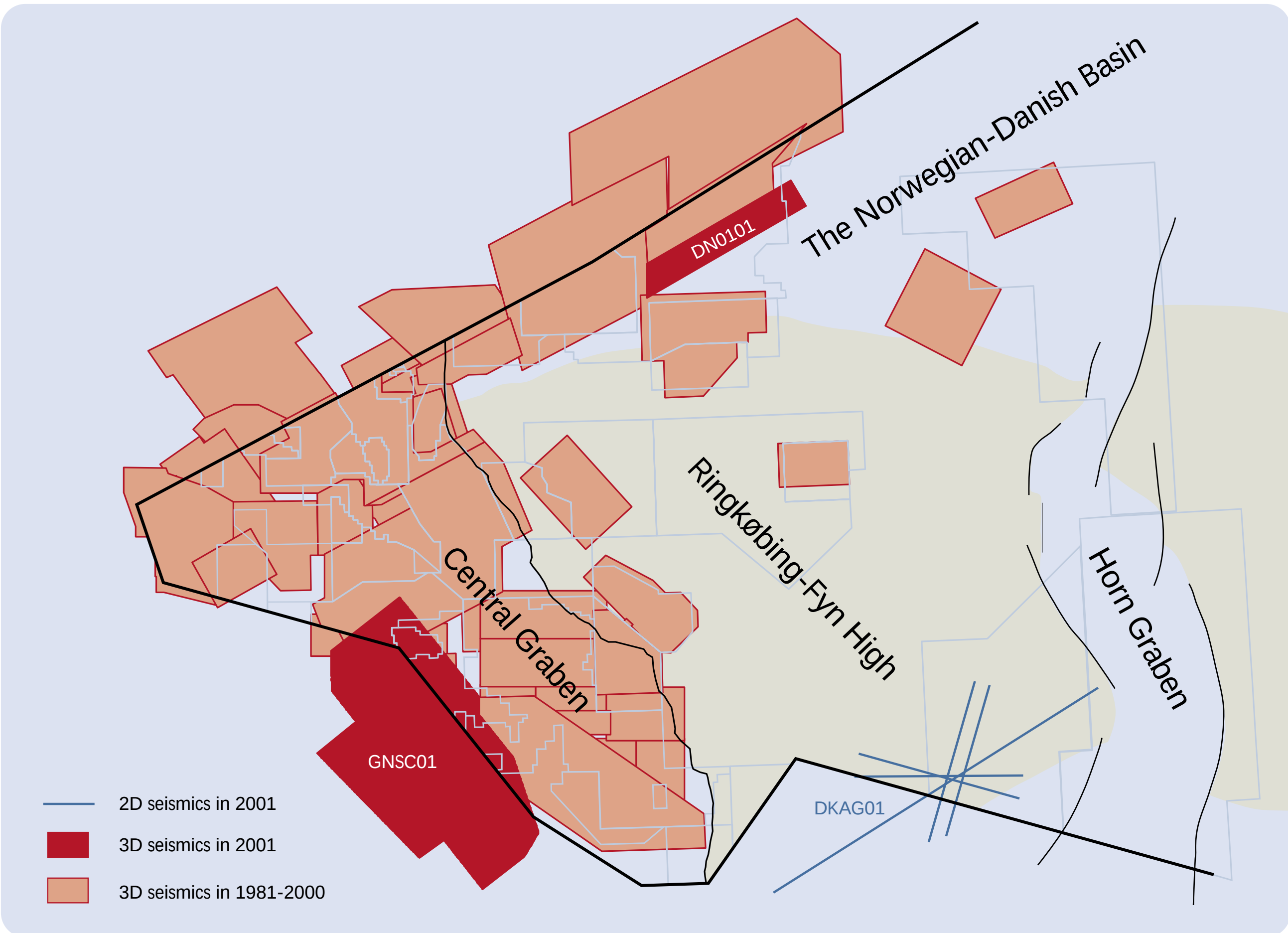
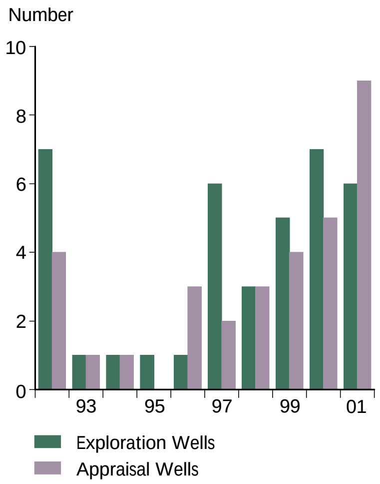


Fig. **2.4** Exploration and Appraisal Wells



EXPLORATORY SURVEYS

The scope of seismic surveys in 2001 decreased somewhat compared to previous years. The level of activity and the areas where seismic surveys were performed appear from Figs. 2.2 and 2.3. Appendix C provides an outline of exploratory surveys in 2001.

Under licence 4/95, DONG E&P A/S began acquiring 3D seismic data in August 2001 as part of the continued exploration of the area where the Nini oil discovery was made in 2000. However, poor weather conditions forced DONG E&P A/S to interrupt the survey in autumn 2001. DONG E&P A/S plans to complete the rest of the 620 km^2 survey at the beginning of 2002.

As operator in German territory, Wintershall carried out an extensive 3D seismic programme during the period May-August 2001. This programme mainly covered the company's German licence area, but the investigations also extended into Danish territory west of the Contiguous Area.

In the Open Door area, Norsk Agip performed a 2D seismic survey in October 2001, as operator of licence 1/99. This licence area adjoins the German/Danish border.

In October 2001, Mærsk Olie og Gas AS collected samples from the sea floor in the southern part of the Contiguous Area. The aim of this study was to investigate whether the samples indicated the presence of hydrocarbons in the subsoil.

In January 2001, Sterling Resources (UK) Ltd. collected soil samples for a geochemical survey under licence 5/97 in North Zealand. This survey supplemented a previous, comparable survey carried out in 2000.

WELLS

In 2001, six exploration wells and nine appraisal wells were drilled; see Fig. 2.4. These statistics include wells spudded in 2001. Some of the included appraisal wells were drilled as combined appraisal and production wells in connection with field developments.

Two of the exploration wells encountered new oil discoveries. One of these discoveries was made in Jurassic sandstone in the Central Graben, where no discoveries have been made in Jurassic sandstone since 1992. The appraisal wells in the Siri and Nini areas encountered additional amounts of oil east of the Central Graben.

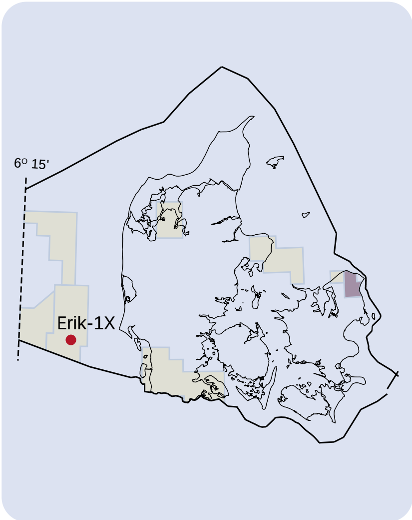
The location of the wells described below appears from Figs. 2.5 and 2.6. The appraisal wells drilled in the producing fields are also shown in the field maps in Appendix E.

Exploration Wells

Connie-1 (5604/19-2)

Following the discovery of the Cecilie oil accumulation under licence 16/98 at end-2000, the DONG group continued the exploration of this area at the beginning of 2001. The Connie-1 well was drilled to a depth of 2,351 metres and terminated in Danian chalk. The well encountered oil in Palaeogene sandstone. The DONG group has subsequently decided not to initiate any further appraisal of this discovery until further notice.

Fig. 2.6 Exploration Well in the Open Door Area



Hejre-1 (5603/28-4)

In the deep Hejre-1 exploration well, the Phillips group discovered oil in sandstone of late Jurassic age. Phillips Petroleum Int. Corporation Denmark operated the well, which was drilled in April-August in the area comprised by licence 5/98. An extensive well/logging programme showed extremely good reservoir properties, and against this background the Phillips group considered it unnecessary to carry out an actual production test. The Hejre-1 well was carried to a depth of 5,265 metres and terminated in late Palaeozoic layers. The Phillips group is now performing a detailed appraisal of the extent of the discovery.

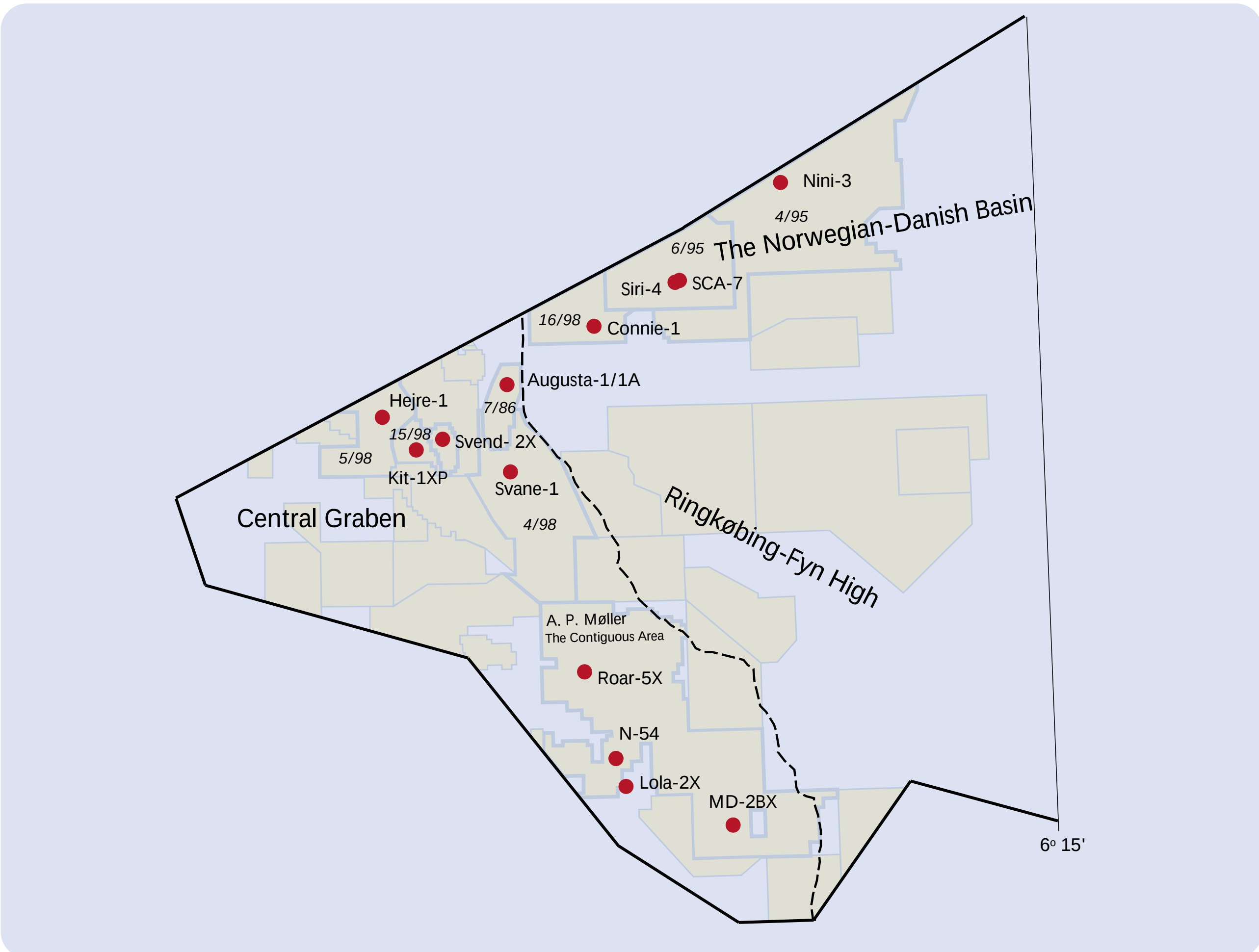
Svane-1 (5604/26-4)

Immediately after completing Hejre-1, the Phillips group continued the exploration of the Central Graben by drilling the Svane-1 well in the area covered by licence 4/98. In spring 2002, the well terminated at a depth exceeding 5,800 metres, which is a record in the Danish sector. The results of the well were not available at the time this publication went to press.

Kit-1XP (5604/25-4)

As operator for the oil companies holding licence 5/98, Mærsk Olie og Gas AS drilled the Kit-1XP exploration well in May-July 2001. This well was drilled approx. 5 kilometres west of the Svend Field and terminated at a depth of 4,192 metres in Lower Cretaceous layers. The well encountered no traces of hydrocarbons.

Fig. 2.5 Exploration and Appraisal Wells



When oil companies discover hydrocarbons in an exploration well, they are required to submit a description of the discovery and an appraisal programme no later than six months after completing the well. The appraisal programme is a plan of the work to be performed to evaluate whether the discovery is commercial. If the initial description of the discovery shows that in all probability the discovery is uninteresting, no appraisal programme is conducted. Conversely, if the description indicates that the discovery may be exploitable, an appraisal programme could include supplementary seismic surveying and the drilling of one or more additional wells (appraisal wells) to determine the extent and quality of the discovery.

Lola-2X (5504/16-9)
In August 2001, Mærsk Olie og Gas AS drilled the Lola-2X well in the southwestern part of the Contiguous Area. The well location was approx. 2.5 kilometres west of the U-1X well, which encountered hydrocarbons in Upper Cretaceous chalk and Middle Jurassic sandstone in 1975. The results of the Lola-2X well did not, however, meet expectations, and A.P. Møller relinquished the area comprising the two wells on 1 January 2002.

Erik-1X (5507/18-1)
In August-September 2001, the Mærsk group drilled the first well in the Open Door area since the Open Door procedure was introduced in 1997. The well was drilled under licence 4/97 and terminated in layers of early Triassic age at a depth of 3,563 metres. The Erik-1X well encountered the expected sand layers, but no hydrocarbons were discovered.

Appraisal Wells

Augusta-1/1A (5604/22-4)
In March 2001, DONG E&P A/S drilled an appraisal well in the area covered by licence 7/86 (the Amalie share), where previous wells have encountered oil and gas in sandstone of Middle Jurassic, Upper Jurassic, Lower Cretaceous and Palaeocene age. The Augusta-1 well terminated in Danian chalk at a depth of 2,952 metres. A deviated sidetrack, August-1A, was subsequently sunk to a depth of 3,007 metres below sea level, also terminating in chalk. The wells encountered the expected reservoir, but no hydrocarbons were discovered.

Nini-3 (5605/10-3)
After completing the Nini-2 well at end-2000, the DONG group continued to appraise the Nini oil accumulation under licence 4/95 with yet another appraisal well. The Nini-3 well was drilled at a more eastern location than the previous Nini wells. The well confirmed the presence of oil in Palaeogene sandstone. Thus, the presence of oil has been proved at the greatest distance to date from the source area in the Central Graben, viz. at a distance of 65 km. The well terminated in the Ekofisk Formation at a depth of 1,811 metres.

MD-2BX (5505/17-17)
To evaluate the hydrocarbon saturations in the southern flank of the Dan Field, Mærsk Olie og Gas AS drilled the MD-2BX well at the beginning of 2001. This well encountered producible hydrocarbons in Maastrichtian chalk at the saddle point between the Dan and Kraka Fields, and has been put on production.

Roar-5X (5504/7-8)
Based on appraisal results from the Tyra Field and other data, Mærsk Olie og Gas AS drilled the Roar-5X well in the western flank of the Roar Field in April-May 2001. The well failed to encounter the expected flank potential and has now been completed as a production well in the main field.

Siri-4 (5604/20-6) and SCA-7 (5604/20-7)
Statoil Efterforskning og Produktion A/S, the operator for licence 6/95, drilled the Siri-4 appraisal well in June 2001. The well was located between Siri Central and Siri East, where there is oil in Palaeogene sandstone. The Siri-4 well terminated in the Våle Formation at a depth of 2,091 metres and encountered oil in Palaeogene sandstone.

Based on the results from Siri-4, it was decided to continue drilling a horizontal appraisal well that was initially drilled from the Siri wellhead platform to the Siri-4 area. In a production test from the horizontal SCA-7 well, oil was initially produced at a rate of up to 3,700 m^3 per day. The Danish Energy Authority has subsequently approved using the SCA-7 well as a production well.

N-54 (5504/16-8)
In April-May 2001, Mærsk Olie og Gas AS drilled the N-54 well to investigate the hydrocarbon saturations in a crestal area along the main fault in the Gorm Field ‘B’ block. The results were positive and the well was put on production.

Svend-2X (5604/25-5) and Svend-6X (5604/25-6)
In October 2001, Mærsk Olie og Gas AS spudded two appraisal wells in the Svend oil field. Both wells were drilled from the wellhead platform.

The Svend-2X well explored the potential in the northeastern flank of the field. No basis was established for starting up production in the area, and the well has been suspended. The Svend-6X well has now been completed as a production well.

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, for licences granted since the First Licensing Round in 1984, the confidentiality period is limited to two years for data pertaining to areas for which the licence has terminated. In 2001, data regarding the following exploration and appraisal wells were released:

Well	Well no.	Operator
Rigs-2	5604/29-5	Amerada Hess ApS
Saxo-1	5503/02-1	Amerada Hess ApS
Wessel-1	5503/02-2	Amerada Hess ApS
Siri-2	5604/20-2	Statoil Efterforskning og Produktion A/S
Siri-3	5605/13-1	Statoil Efterforskning og Produktion A/S

A list of all Danish exploration and appraisal wells is available on the Danish Energy Authority’s homepage, *www.ens.dk*.

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

3. DEVELOPMENT AND PRODUCTION

The high level of activity to develop North Sea fields continued in 2001. In 2001, 29 development wells were drilled in the producing fields in the Danish sector. Twenty-three of these were production wells, while the remaining six were water-injection wells. This is the largest number of wells ever completed in one year.

At the beginning of 2002, oil and/or gas was produced from a total of 16 Danish fields. Oil and gas were produced through 214 wells, and gas and/or water was injected into 93 wells.

A platform was installed at the Tyra Southeast Field in 2001, and drilling in the field commenced. The field was brought on stream on 3 March 2002.

Appendix E provides a schematic outline and maps of the individual producing fields. Wells drilled in 2001 are indicated by a special symbol.

Fig. 3.1 is a map showing the location of the Danish producing fields, expected future field developments (commercial fields) and field delineation.

Fig. 3.1 Danish Oil and Gas Fields

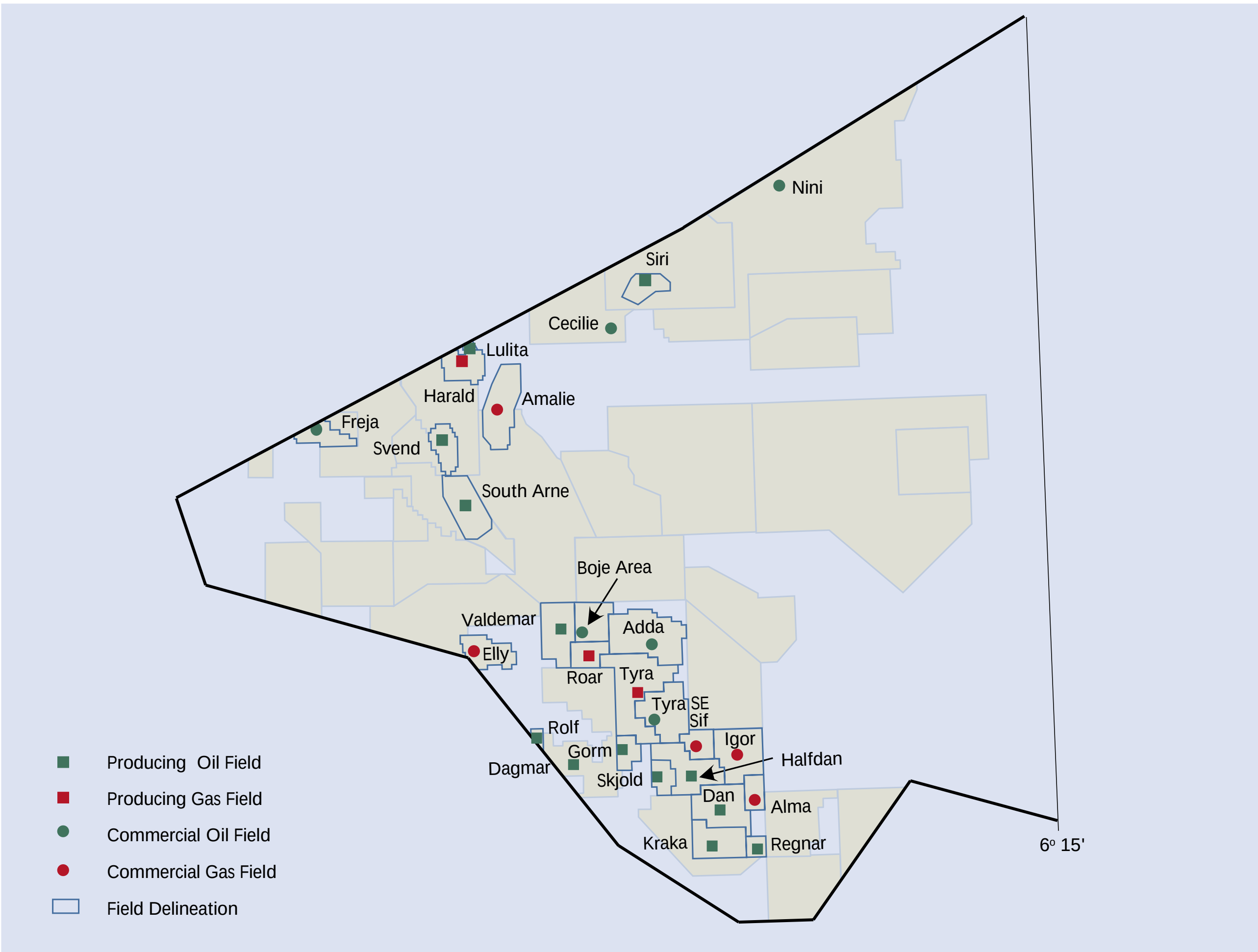


Fig. 3.2 Breakdown of Oil Production by Company

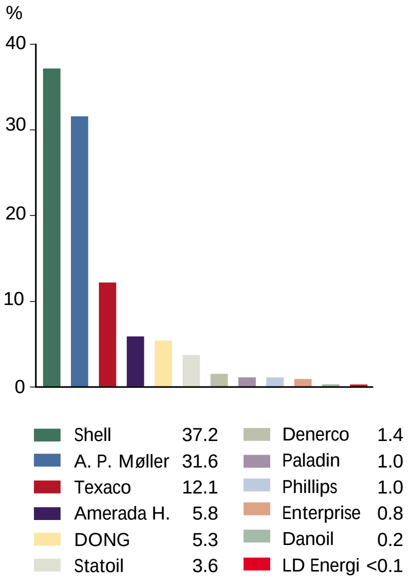
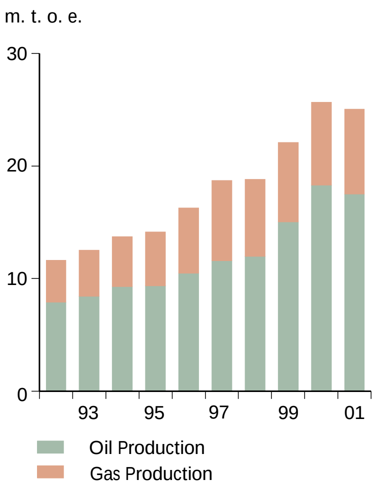


Fig. 3.3 Production of Oil and Natural Gas



PRODUCTION

Danish oil production totalled 20.21 million m^3 in 2001. This is 4% down from the previous year. The fall is due to the temporary suspension of the oil production from some of the fields operated by Mærsk Olie og Gas AS following an incident at the Gorm Field. The consequences of this incident are described in the section *Incident in the Gorm Field.*

Moreover, there was a marked decline in oil production from both South Arne and Siri in 2001 compared to 2000. On the plus side, it should be noted that oil production from the Halfdan Field in 2001 reached a level of more than 2.5 times the production in 2000.

The amount of oil produced from each field varied a great deal from 2000 to 2001. The declining production from individual fields in 2001 does not necessarily indicate a general downward trend of production potential, since the figures reflect the fact that production from some of the fields had to be suspended for some time due to the incident in the Gorm Field; see Appendix D.

As operators, Amerada Hess ApS, Mærsk Olie og Gas AS and Statoil Efterforskning og Produktion A/S are responsible for the technical aspects of producing oil and gas from the North Sea fields. In addition to these operator companies, a number of other companies participate in the individual licences. The composition of the company groups appears from Appendix A, and Appendix B contains a list of the individual companies' percentage shares in the licences concerned.

The oil and gas production from the 16 fields is allocated among the companies that hold shares in the individual licences. In 2001, 12 companies received and sold oil and gas from the Danish fields. Fig. 3.2 shows total Danish oil production in 2001 broken down by participating company. The production of oil continues to be dominated by Shell, A.P. Møller and Texaco. These three companies, all participants of DUC, together accounted for 81% of Danish oil production in 2001.

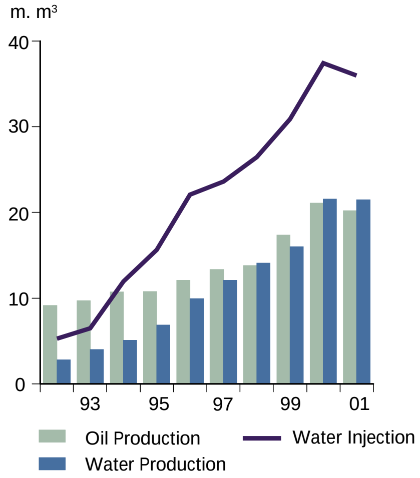
In 2001, 7.33 billion Nm^3 of gas was supplied to DONG Naturgas A/S, while the net gas production was 8.20 billion Nm^3. The difference between the net gas produced and the amount of gas sold (11% of the net gas) was either utilized as fuel or flared on the platforms. Gas is flared solely for safety and technical reasons. The section on the *Environment* provides more details on gas flaring. Furthermore, the section on the *Incident in the Gorm Field* describes the effect of this incident on the volumes of gas flared in 2001.

Fig. 3.3 shows trends in Danish oil and gas production for the period 1992 – 2001. Appendix D provides an outline of the oil and gas production since 1972 when the first oil was produced from the Dan Field. Appendix D also includes figures for water produced and water injected, fuel consumption, gas flaring and gas injection, as well as an outline of CO_2 emissions from the North Sea installations. The corresponding figures for the years before 1992 may be viewed at the Danish Energy Authority's website: *www.ens.dk.*

WATER PRODUCTION

In order to boost oil recovery, large volumes of water are injected into several of the Danish oil fields. Water injection is used to maintain the reservoir pressure in the oil- and gas-bearing layers, thus facilitating the flow of oil to the production wells. A further advantage of this technique is that the water floods the oil-bearing

Fig. 3.4 Production of Oil and Water and Water Injection



layers and forces out more oil. Use of the water-injection method is a major reason why it is still possible to recover substantial amounts of oil from the Danish chalk reservoirs.

To date, the amount of water injected into the Dan, Gorm and Skjold Fields is at least equal to the combined total volume of oil and water produced from these fields. In recent years, the quantity of water injected into the Dan and Gorm Fields each year has by far exceeded the total annual oil and water production.

The production of oil and gas is accompanied by the production of water. The water produced has to be disposed of in an environmentally safe manner.

When water is injected into a field, more water is produced together with the oil and gas compared to production without the use of water injection.

The water produced is separated from the oil and gas at the North Sea facilities and subjected to further purification. About 40% of the purified water is injected into the oil- and gas-bearing subsoil layers, while the rest is discharged into the sea. The remaining proportion of the water injected is made up by sea water. The treatment standards applying to the discharge of produced water into the sea are defined in the section on the *Environment*.

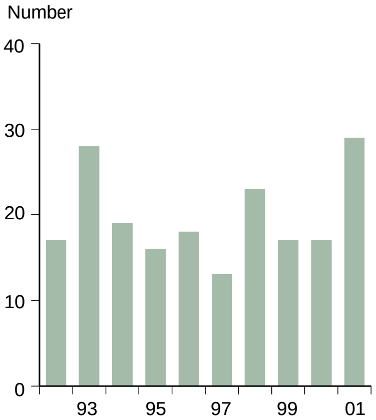
The annual volumes of produced and injected water and the annual oil production are shown in Fig. 3.4. The water production from the Danish fields has increased considerably over the last decade. This is due partly to the increased oil production, partly to a higher water content in the liquid produced from the fields. Between 1992 and 2001, water production from the Danish fields increased tenfold. Over this period, the water content of total production rose from 23% in 1992 to 52% in 2001.

In the years ahead, water injection will continue to be used in a number of the Danish fields. In the younger fields of South Arne, Siri and Halfdan, water injection is also used as the principal method for boosting oil recovery.

PRODUCING FIELDS

Development activities were ongoing in a great many fields throughout 2001. New plans were approved for the Dan, Halfdan, Skjold, Svend, Siri, South Arne and Tyra Southeast Fields. A platform was installed in Tyra Southeast, and all the year through six to seven rigs were employed in drilling new wells in the producing fields.

Fig. 3.5 Production Wells



A total of 29 wells were completed in the producing fields. The number of new wells completed in the producing fields over the last decade is shown in Fig. 3.5. Never before have so many new wells been drilled in a single year. Since 1992, a total of 197 new wells have been drilled in the producing fields.

Fig. 3.6 shows existing North Sea production facilities. Fig. 3.7 shows developments in natural gas supplies to DONG Naturgas A/S over the last ten years, and Fig. 3.8 shows the distribution of the oil production by field for the period 1992-2001.

The most important activities in the producing fields in 2001 are reviewed below. A schematic overview of the oil- and gas-producing fields is given in Appendix E.

Fig. 3.6 Production Facilities in the North Sea 2001

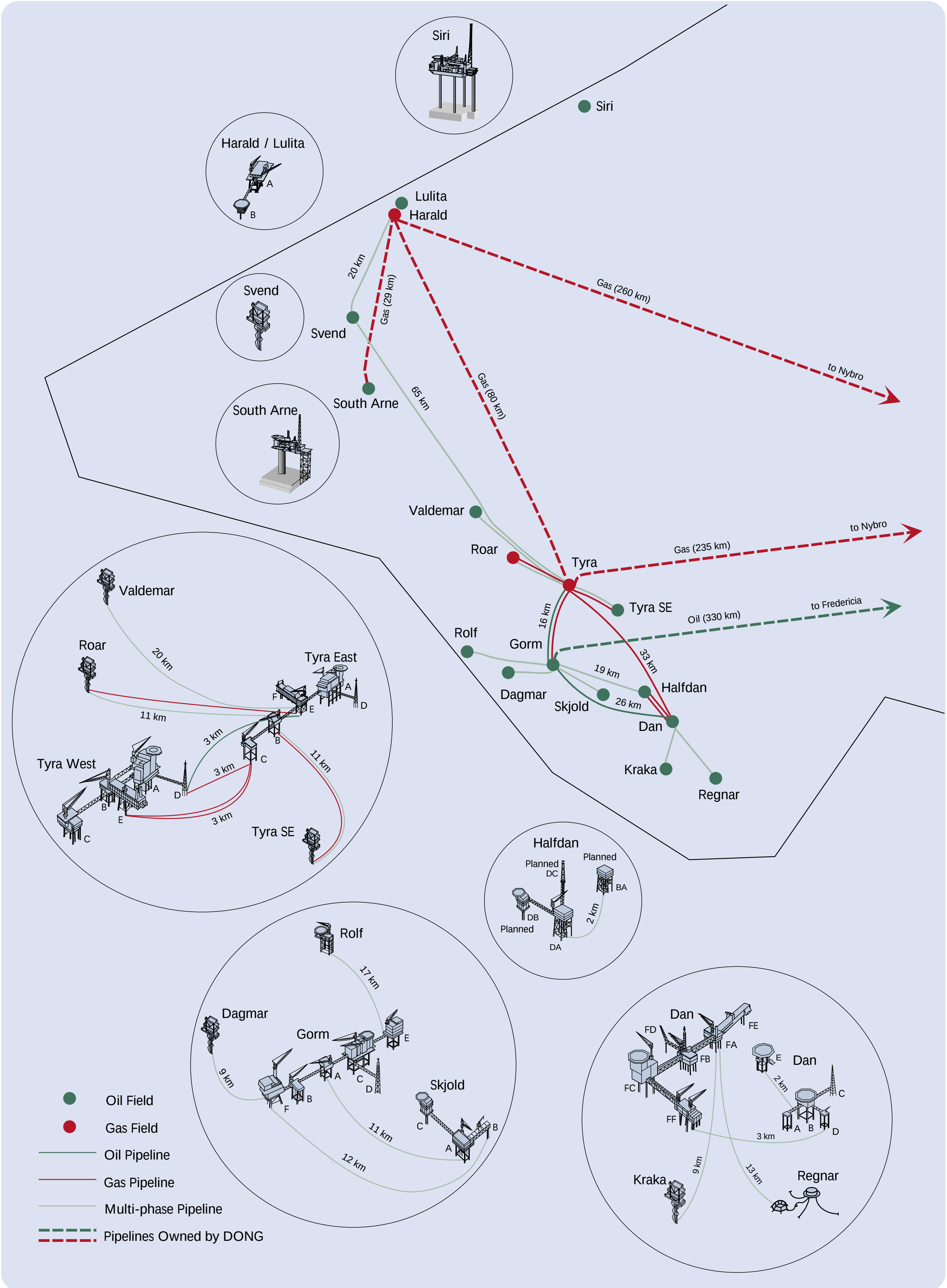
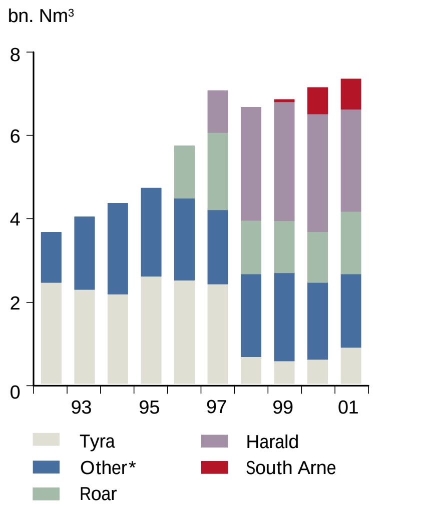
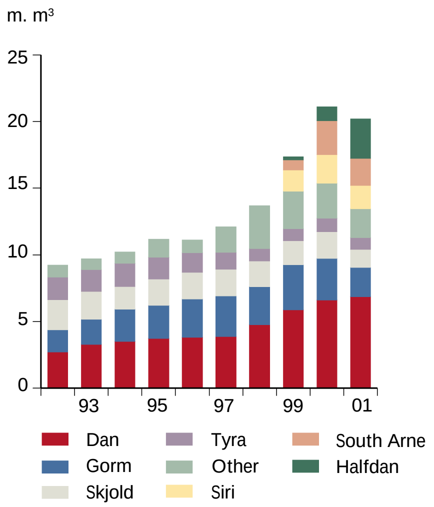


Fig. 3.7 Natural Gas Supplies Broken down by Field



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

Fig. 3.8 Distribution of Oil Production by Field



The Dan Field

Since the early 1990s, the operator of the Dan Field has currently assessed the potential for oil production from the flank areas of the field. Several appraisal wells have been drilled, and seismic mapping using new, sophisticated methods has been carried out. In particular, the field's western flank has shown a high potential for oil production, and several production wells have been completed in the western flank area adjacent to the Halfdan Field.

A plan for further development of the Dan Field's western flank was approved in 2001. The plan involves the drilling of eight new, long, horizontal production wells. In this connection, water injection will be established to support the reservoir pressure, as the existing production wells in the area will be converted into water-injection wells. The new wells are to be drilled from the existing Dan FF platform. New plant will be installed as the need for further water-injection capacity increases. The capacity of separation equipment and gas- and water-treatment facilities will also be increased.

Further, in 2001 approval was granted for a development plan for the southeastern flank of the field in an area adjacent to the Kraka Field. The plan involves recovery of oil and gas from an area only recently assessed as having production potential. Depending on the results from the first wells, the plan provides for establishing up to a total of four wells in the area. The wells are to be drilled from an existing platform in the Dan Field, and the production will likewise be processed at existing facilities.

The Halfdan Field

The positive experience with production from the Halfdan Field has provided a basis for proceeding with the further development and production plans for the Halfdan Field.

A phase-3 development plan for this field was approved in 2001. The plan involves drilling 11 new horizontal production wells and 11 new horizontal water-injection wells. The plan also envisages the installation of additional processing and auxiliary equipment on the existing Halfdan platform, as well as treatment facilities for produced water. An accommodation platform and a flare stack are to be established, both of which will be connected by bridge to the existing Halfdan platform. Finally, a new wellhead platform with capacity for 30 wells is to be established approx. two km northeast of the existing Halfdan platform.

Eight new production wells and five new water-injection wells were drilled in the field in 2001. Two mobile drilling rigs were working all year long on drilling these wells at the existing platform HDA.

After the completion of phase 3 of the field's development, Halfdan is expected to have a total of 25 production wells and 21 water-injection wells.

In connection with the approval of the phase-3 development and production plan for the field, Mærsk Olie og Gas AS prepared an Environmental Impact Assessment (EIA) of the activities in the Halfdan Field. The assessment was submitted to the relevant parties for hearing, and provided the basis for the Danish Energy Authority's approval of the development plan.

The upward trend in oil production from this field continues as new wells are being completed. In 2001, it reached a level surpassed only by the Dan Field. The water content in the oil produced in 2001 was approx. 14%.

All the wells in the field will be arranged according to a regular pattern of alternating production and water-injection wells, with the individual well conduits spaced about 180 m apart; see the map in Appendix E. All the wells will be positioned parallel to the orientation of the maximum main horizontal stress in the chalk layers. This will cause fractures to be created parallel to the individual wells when the well is stimulated by pumping hydrochloric acid down the borehole. In order to ensure that the fractures extend in the desired direction, a pressure reduction is created in the production wells along either side of the planned injection well before it is drilled and stimulated.

Furthermore, the casings installed in the production wells are provided with a number of pre-drilled holes spaced at varying distances. This ensures that the hydrochloric acid pumped down the well to stimulate production is distributed evenly along the well conduit. This technique was developed by the operator, Mærsk Olie og Gas AS.

The Kraka Field

In 2000, a routine underwater inspection revealed a minor leak in the 9 kilometre long 10” multi-phase pipeline between the Kraka and Dan FA platforms. Closer inspection showed that the leak was very likely caused by corrosion due to a high level of bacterial activity in the pipeline. The pipeline was subsequently repaired, and stricter monitoring was introduced.

In 2001, Mærsk Olie og Gas AS decided to install a new pipeline between the Kraka Field and the Dan Field parallel to the old pipeline and connected to its riser pipes. The new pipeline was commissioned in January 2002. The Danish Energy Authority has granted its permission for the old pipeline to be left on the seabed for the time being.

The Siri Field

In light of the results from the Siri-4 appraisal well, the operator Statoil Efterforskning og Production A/S decided that there is a basis for production from the eastern part of the Siri Field, designated Stine Segment 2. For a description of the results from Siri-4, see the section on *Exploration.*

A development and production plan for this area of the Siri Field was approved by the Danish Energy Authority in 2001. The plan involves drilling a horizontal production well. This well was completed in 2001 and hooked up to the production facilities on the Siri platform.

The Svend Field

In 2001, a new development plan was approved for the Svend Field. The plan envisages the production of oil and gas from the field's northern and eastern flanks. The most recent seismic mapping of this area has demonstrated a potential for enhancing the recovery of oil and gas in place. There is considerable uncertainty about the extent of these reserves, but the new wells will provide important information.

The approved plan comprises up to four new wells, two of which are to be drilled initially. The section on *Exploration* provides information about the appraisal performed in connection with drilling these wells.

The South Arne Field

The development and production plan approved in 2001 involves drilling up to a total of nine new production and water-injection wells. When the plan has been implemented, the South Arne Field, which is operated by Amerada Hess ApS, will have a total of 19 wells. In addition, an appraisal well will be drilled to the central part of the structure.

The operator has positive experience with water injection in the South Arne Field. The new development and production plan for the field therefore provides for gradually increasing the use of water injection in major parts of the field and drilling additional production wells.

Oil production fell by approx. 21% from 2000 to 2001 in step with the falling reservoir pressure. The fraction of water in the oil produced continues to be limited, and in 2001 amounted to about 6% of the total liquids produced from the field. After preliminary experiments with water injection in 2000, the injection of large volumes of water was initiated in the field in 2001. The amount of water injected into the field in 2001 nearly equalled the amount of oil produced.

In 2001, one water-injection well and one production well were completed. Additional wells, both for production and for water-injection, are expected to be drilled over the next few years, and to result in increasing production from the field.

The Tyra Southeast Field

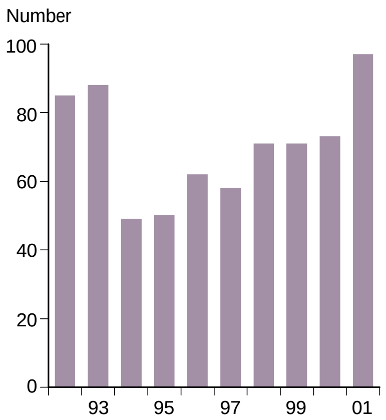
A new, revised development and production plan for the Tyra Southeast Field was approved in 2001. In autumn 2001, a STAR-type platform was installed in the field, and pipelines were established to the Tyra Field. The first well in the Tyra Southeast Field was brought on stream in March 2002. During the drilling operation, important new information was obtained about parts of the field.

The planned development of the Tyra Southeast Field includes drilling up to six production wells, four of which are expected to be drilled in the first development phase. The oil and gas production from the field will be transported through the new pipelines to the existing processing facilities at the Tyra Field.

The Valdemar Field

To date, the oil and gas production in this field has been recovered from a chalk reservoir of Lower Cretaceous age. In connection with the further development of the Valdemar Field, Mærsk Olie og Gas AS drilled the Valdemar-5 appraisal well, in order to examine the production potential of Upper Jurassic rock in the western flank of the Valdemar Field, where the operator believed there was a production potential from fractured clay. In addition, a well section was drilled in the Upper Cretaceous chalk in a southern direction. The result of test production from the Upper Jurassic layers was disappointing, while the well section in the chalk is used for oil production.

Fig. 3.9 Rig Months



In spring 2001, the Valdemar-6 well was drilled in a southern direction in the Lower Cretaceous chalk reservoir. The well's trajectory and design were optimized in order to prevent stability problems and improve the production properties of the relatively thin reservoir layers. So far, the production rates achieved from the well are promising.

Against this background, oil production from the Valdemar Field more than doubled in 2001 compared to 2000.

DRILLING ACTIVITY

As already mentioned, drilling activity in the Danish sector was extraordinarily high in 2001, involving the work of nine drilling rigs on a scale corresponding to a total of 97 rig months. The corresponding figure for 2000 was only 70.

Fig. 3.9 shows developments in the drilling work performed annually from drilling rigs in the Danish sector 1992 – 2001, expressed in number of rig months.

As seen from the figure, the activity level was considerably higher in 2001 than in any previous year, including the early 1990s when the number of active drilling rigs averaged about six per year.

One of the reasons for the high activity in 2001 is that the number of exploration and appraisal wells drilled remained at the same high level as in the preceding years, also as a result of work in the Fifth Round areas from 1998 being completed. Furthermore, a record-high number of production wells were completed in 2001, due, in particular, to the development activities in the Halfdan Field.

FUTURE FIELD DEVELOPMENTS

In December 2001, the Danish Energy Authority received a development and production plan for the Amalie Field, which is a minor gas reservoir.

The Danish Energy Authority is also considering development and production plans for the Freja, Nini and Cecilie Fields and for Stine Segment 1 and the Boje area. According to the plans submitted, these fields are to be developed as satellites to existing fields.

Appendix F contains an outline of future field developments approved by the Danish Energy Authority.

JOINT CHALK RESEARCH (JCR)

The Fifth Phase of the so-called Joint Chalk Research programme between a number of oil companies and the Danish and Norwegian authorities was completed in April 2000. Steps have now been taken to initiate a new phase of the programme.

At a meeting in Copenhagen in autumn 2001, the oil companies agreed on an overall plan for the Sixth Phase and its contents. This Phase is expected to begin in the early summer of 2002, and will run for about three years.

4. THE ENVIRONMENT

EIA FOR OFFSHORE ACTIVITIES

In recent years, there has been increasing focus both nationally and internationally on the environmental effects associated with offshore activities.

Thus, it is now a requirement for obtaining approval of offshore projects that applicants undertake an examination of how the planned activities will affect the environment, a so-called Environmental Impact Assessment (EIA). The rules for performing this assessment are set out in the Executive Order on Environmental Impact Assessments of 2000.

In 2001, an Environmental Impact Assessment was prepared in connection with the approval of phase three of the development plan for the Halfdan Field. In addition, development permits were granted in 2001 for a number of fields comprised by previously submitted Environmental Impact Assessments, including the South Arne Field and the Stine Segment 2 area in the Siri Field, operated by Amerada Hess ApS and Statoil Efterforskning og Produktion A/S, respectively, and the Dan, Skjold, Svend and Tyra Southeast Fields, for which Mærsk Olie og Gas AS is the operator.

As something new, Environmental Impact Assessments were prepared in 2001 for two projects for natural gas pipelines to be established in the Baltic Sea. One of the projects is the *BalticPipe*, through which natural gas will be conveyed from Denmark to Poland, and which is intended to be used at a later stage to ensure reliability of supply to the Danish market. The other project is the *Baltic Gas Interconnector,* which is to run from northern Germany to eastern Denmark, with a branch to the south of Sweden. This pipeline will be used to import natural gas to Denmark and Sweden.

Both pipelines will extend over the continental shelf of several countries. The Environmental Impact Assessments were therefore prepared in close co-operation between the project applicants and the authorities of the countries affected. Furthermore, in accordance with the Espoo Convention on the Environmental Impact Assessment in a Transboundary Context and the Helsinki Convention on the Protection of the Marine Environment of the Baltic Sea Area, the Danish Energy Authority has notified the other Baltic Sea countries of both projects.

In connection with these notifications, the Danish Energy Authority informed the authorities of the other Baltic Sea countries about the projects and their environmental effects. Under both conventions, the parties affected are entitled to comment on the Environmental Impact Assessments with regard to the effects of the pipelines on their territories. In the opinion of most Baltic Sea countries the project will not affect their territories to any significant degree. However, Sweden has expressed concern about the potential effects on fish stocks and the fishing industry. In consultation with the project applicants, the Danish Energy Authority will decide how to follow up on the comments submitted.

Fig. 4.1 Fuel Consumption

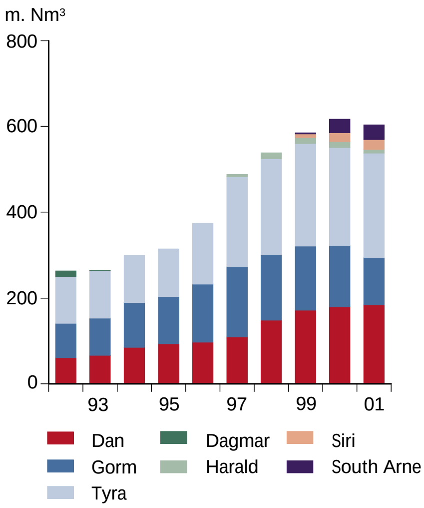
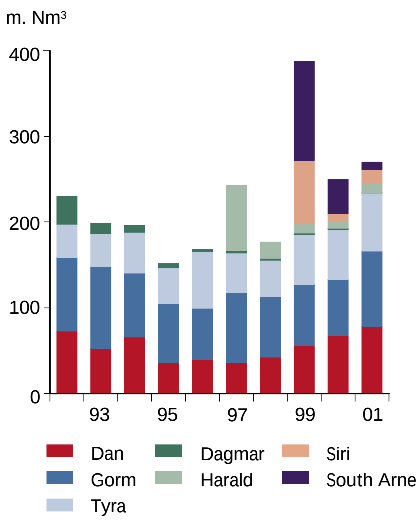


Fig. 4.2 Gas Flaring



REDUCTION IN VOLUME OF OIL DISCHARGED INTO THE SEA WITH PRODUCED WATER

In 1992, as a result of the increasing international interest in harmonized protection of the marine environment, a number of North East Atlantic countries initiated a co-operative effort under the OSPAR Convention. The North Sea represents a very significant part of the Convention's jurisdictional area, and in addition to Denmark, countries such as Norway, the United Kingdom, Germany and the Netherlands participate in this initiative. The OSPAR Convention is generally concerned with preventing and providing protection against pollution of the North East Atlantic, including from substances and materials discharged into the sea.

The Danish participation in the OSPAR effort is handled by the Danish Environmental Protection Agency. The Danish Energy Authority assists the Agency in its work on technical matters and health and safety issues on the OSPAR Offshore Industry Committee (OIC).

In recent years, increasing interest has been focused on creating a regulatory framework for the discharge of oil with produced water from fixed offshore installations, partly due to the general increase in such discharges through the 1990s, which is expected to continue, partly as a result of public debate on the release to the environment of the so-called PAH compounds (Polycyclic Aromatic Hydrocarbons).

The current regulations are based on the principles of the Best Available Techniques (BAT) and the Best Environmental Practice (BEP). Operators are required to base their equipment choice and daily operations on these principles, in order to minimize discharges based on an environmental, technical and financial assessment. Moreover, the concentration of dispersed oil in produced water must not exceed 40 mg/l at any point of discharge.

In 2001, OSPAR set a target to be achieved at the national level, viz. to reduce the volume of oil discharged with produced water from offshore installations by 15% from 2000 to 2006.

It was further decided to lower the limit value for discharges of dispersed oil with produced water from individual points of discharge from 40 mg/l to 30 mg/l by 2006, and to submit proposals in 2003 for specific limit values for the discharge of aromatic hydrocarbons, including PAH compounds.

Further information about OSPAR is available at the organization's website *www.ospar.org*.

CO_2 EMISSIONS FROM OFFSHORE INSTALLATIONS

Gas used as fuel and gas flaring

Producing and transporting oil and natural gas requires substantial amounts of energy. Furthermore, a sizable amount of gas that cannot be utilized for safety or technical reasons has to be flared.

Due to the consumption of gas for energy production purposes and gas flaring, the North Sea installations release significant quantities of CO_2 into the atmosphere. The volume emitted by the individual installation/field depends on the scale of production as well as on plant-related and natural conditions.

Fig. 4.3 CO_2 Emissions from Production Facilities in the North Sea

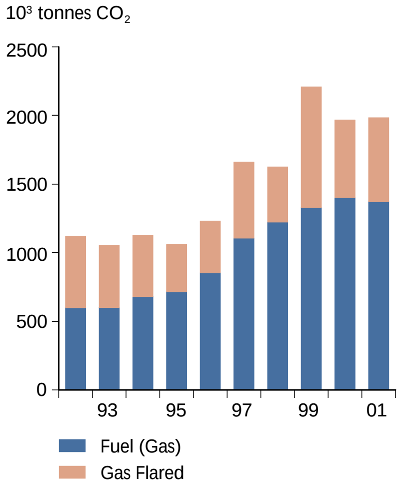
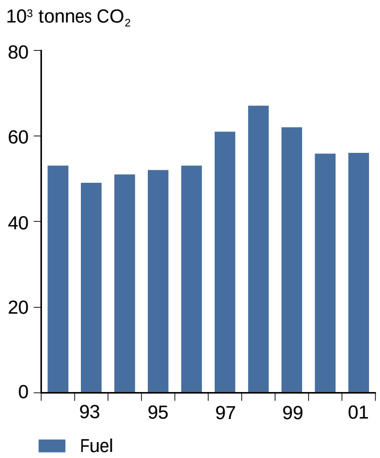


Fig. 4.4 CO_2 Emissions from Consumption of Fuel per m. t.o.e.



Gas consumed as fuel accounts for approx. 2/3 of the total volume of gas consumed and flared offshore. Most of this gas is used as fuel in gas turbines driving electric generators, gas compressors and water-injection pumps.

The amounts of gas used as fuel in the processing facilities and the gas flared are illustrated by Figs. 4.1 and 4.2.

It appears from these figures that over the past ten years, rising production and the general ageing of the fields have escalated the use of gas as fuel on the Danish production facilities in the North Sea. It is also seen from the figures that the volume of gas flared was considerably higher in 1999 than in previous years. This was due to major problems in connection with the commissioning of the new production facilities at Siri and South Arne. In both 2000 and 2001, flaring was again largely down to the previous level.

However, from 2000 to 2001 there was an increase of some 20 million Nm^3, or about 10%. The main reason for this increase was the incident in the Gorm Field in May 2001 and the subsequent extensive gas flaring during the restarting period; see the section on the *Incident in the Gorm Field*.

In 2001, flaring in the South Arne Field was reduced by approx. 30 million Nm^3 compared to the previous year, but this reduction was more than outbalanced by the increased flaring in the Dan, Gorm and Tyra Fields resulting from the course of events following the Gorm Field incident.

Public Regulation of Gas Consumption and Gas Flaring

The consumption of gas as fuel and gas flaring offshore are regulated in pursuance of section 10 of the Danish Subsoil Act, which provides that "exploration and exploitation shall be carried out in a proper and appropriate manner, and so that any waste of raw materials is avoided". The Act is administered by the Danish Energy Authority.

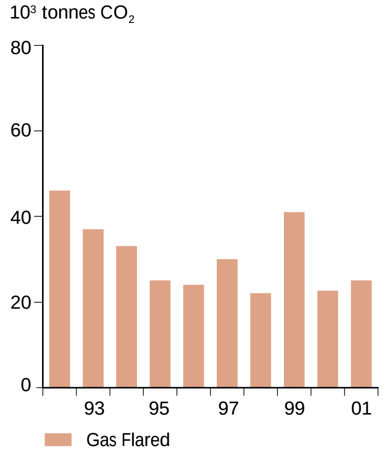
Regulation is based on the principle that a permit is required for the consumption of gas as fuel and gas flaring on offshore installations. Gas consumption is regulated through an approval of the operators' development plans, as the material submitted with the application for approval must include a description of the planned measures for optimal energy utilization.

Flaring is regulated through two kinds of permit, one of which applies to daily gas flaring under normal conditions of operation. This permit also covers flaring in connection with planned maintenance and as the result of minor equipment defects and brief machinery breakdown.

In addition, operators are granted a special quota for each calendar year that applies in the case of major equipment defects and machinery breakdown that cannot be repaired directly.

The level of daily flaring permitted and the special quota (breakdown allowance) is operator-specific.

Fig. 4.5 CO_2 Emissions from Gas Flaring per m. t.o.e.



CO_2 Emissions in 2001

The production facilities in the North Sea account for about 3.7% of total CO_2 emissions in Denmark. The development in the emission of CO_2 from the North Sea production facilities since 1992 appears from Fig. 4.3. This figure shows that total CO_2 emissions in 2001 amounted to about 2.0 million tonnes. This is largely the same as in 2000.

Fig. 4.4 shows the development in CO_2 emissions associated with the consumption of fuel, relative to the volume of hydrocarbons produced.

The figure shows a slightly increasing trend in CO_2 emissions due to fuel consumption relative to the size of production over the period 1992-2001, from about 50,000 tonnes of CO_2 per million t.o.e. (tonnes oil equivalents) at the beginning of the decade to about 56,000 tonnes of CO_2 per million t.o.e. in 2001, with minor annual variations.

Fig. 4.5 shows that emissions of CO_2 from gas flaring relative to the size of production have declined steadily since the early 1990s, except in 1997 and 1999 when the commissioning of the Harald, Siri and South Arne facilities resulted temporarily in extraordinary amounts of gas being flared.

In 2001, the CO_2 emission level relative to the size of production was somewhat higher than in 2000. This was because the fields whose production is processed at the Gorm Centre were put back on stream after the Gorm C incident.

Relative to the scale of production, the Danish sector of the North Sea has many production facilities. All things being equal, this limits the possibility of improving energy efficiency, thus increasing the CO_2 emission per produced t. o. e. However, the choice of technical equipment is also a highly important factor determining the energy efficiency of the facilities and the need for flaring. The Danish Energy Authority is currently reviewing the scope for further improvement of the energy efficiency and reduction of gas flaring at the North Sea production facilities.

5. HEALTH AND SAFETY

The production of oil and gas in the Danish sector involves a large number of installations, such as production facilities, drilling rigs, pipelines, ships and vessels. Matters concerning the working environment, health and safety are governed by the Danish Act on Certain Offshore Installations of 1981.

The supervision of health and safety matters in connection with the exploration and recovery of oil and natural gas in the Danish sector of the North Sea is handled by the Danish Energy Authority, which also has certain supervisory responsibilities relating to environmental protection. A number of other authorities also participate in supervising the offshore sector. The allocation of supervisory tasks is shown in Box 5.1.

WORK-RELATED INJURIES

All industrial injuries sustained onboard offshore installations comprised by the Danish Act on Certain Offshore Installations must be reported to the Danish Energy Authority. 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.

Box 5.1 Supervision of Health, Safety and Environment

The Danish Energy Authority:
- Working environment, welfare and safety conditions related to the design, construction and operation of production installations.
- Environmental protection measures implemented on the installations.
- Environmental Impact Assessment (EIA).

The Danish Maritime Authority:
- Design, structural strength, buoyancy and layout of drilling rigs and other mobile installations, as well as any equipment of a maritime nature on board such installations.
- Life-saving appliances and launching systems on production installations.
- Diving operations, including diving equipment and commercial diving.

The Danish Environmental Protection Agency:
- Marine discharges from offshore installations.
- Emergency preparedness against marine pollution caused by offshore installations.

The Danish Veterinary and Food Administration:
- Food safety.

The National Board of Health:
- Offshore medic work; layout and equipment of treatment room.
- Radioactive sources.

The Civil Aviation Administration:
- Helicopter safety, including safety on helidecks.

On an average annual basis, the Danish Energy Authority receives about 20 notifications of work-related accidents at workplaces comprised by the Danish Act on Certain Offshore Installations, while the number of reported cases of work-related diseases and dangerous occurrences varies. An outline of the reports received in 2001 follows below.

In order to identify any general tendencies as to the causes and consequences of the injuries reported, as well as any common features of the reports, all work-related accidents, work-related diseases and dangerous occurrences reported to the Authority in the period 1999-2001 have been reviewed. Since the number of reports is limited, the statistics compiled on the basis of this material are subject to some uncertainty.

WORK-RELATED ACCIDENTS IN 2001

In 2001, the Danish Energy Authority received 18 reports on accidents offshore, broken down as 11 accidents on fixed production installations and seven on mobile offshore installations. None of the accidents reported in 2001 were fatal.

Accidents on Fixed Production Installations

The reports on accidents occurring on fixed production installations comprise accidents sustained in connection with the operation and maintenance of the installations and accidents on accommodation units.

Of the 11 accidents on fixed production installations, four were caused by the victims tripping or falling while going about their daily routines on board the installations, one by the use of tools, one by a falling object, one by the victim suffering a crush injury, while four can be attributed to other causes.

For these accidents, the following expected periods of incapacity for work were reported:

1-3 days:	2 reports
4-14 days:	2 reports
2-5 weeks:	4 reports
More than 5 weeks:	3 reports

Accidents on Mobile Offshore Installations

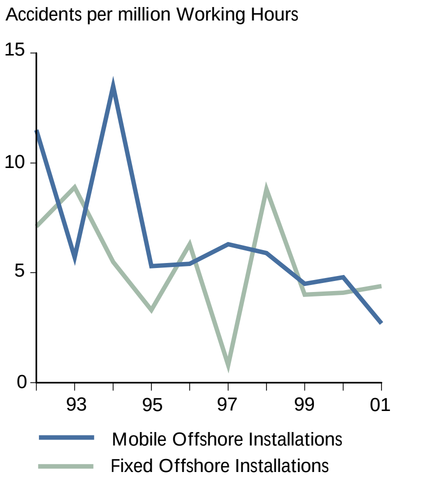
Mobile offshore installations comprise drilling rigs, pipe-laying barges, crane barges and vessels from which offshore activities are carried out.

All seven accidents on mobile offshore installations occurred on drilling rigs. Four out of the seven accidents were reported to have occurred during work on drill floors and in derricks, two happened on helidecks and one on a catwalk (pipe-handling area).

For the mobile offshore installations, the expected periods of incapacity for work reported by the companies break down as follows:

1-3 days	0 reports
4-14 days:	0 reports
2-5 weeks:	4 reports
More than 5 weeks:	3 reports

Fig. 5.1 Accident Frequency on Offshore Installations



Accident Frequency

According to information received from the companies operating in the Danish North Sea sector in 2001, the total number of working hours was 2.69 million for fixed production installations, including associated accommodation units, and 2.58 million for mobile offshore installations.

Relating the number of work-related accidents reported to the number of hours worked, gives the accident frequency per million working hours. Thus in 2001, the accident frequency per million working hours was 4.0 for fixed production installations and 2.7 for mobile offshore installations. Fig. 5.1 shows the annual accident frequency for the last ten years. Compared to the accident frequency for comparable industries onshore, the accident frequency offshore continues to be very low.

WORK-RELATED ACCIDENTS 1999-2001

A review of the approx. 60 reports of work-related accidents received by the Authority during this period shows a tendency for injuries to happen in connection with the activities mentioned below. About 7% of the accidents reported are related to other activities.

Falling/Slipping/Tripping Accidents

More than 25% of the industrial injuries reported for the period were sustained by personnel while going about their daily routines. Accidents of this type occur on both fixed and mobile offshore installations, and may be categorized under the following three headings:

- Falling, e.g. down steps, often while carrying things
- Slipping
- Tripping over objects (twisting an ankle)

Fall accidents often cause serious leg and/or arm injuries, e.g. ligament damage or bone fractures combined with soft-tissue and/or wound injuries to other parts of the body. Accidents in the other two subgroups generally involve less serious injuries.

Use of Tools

These accidents, which account for about 13% of the reports, happen on both fixed and mobile offshore installations, and are often due to carelessness while using or cleaning a tool. Injuries range from minor wound injuries to serious bone fractures.

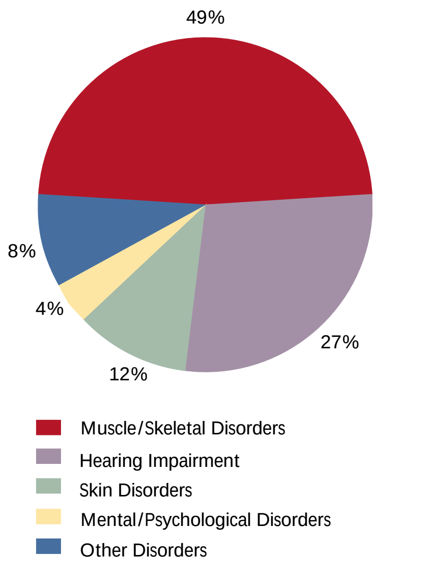
Striking Against or Being Struck by an Object

Working with cranes or hoists involves a risk of being hit, for instance, by goods, materials or drill piping. This type of accident, which accounts for about 25% of the reports, occurs on both fixed and mobile offshore installations. They also happen in connection with scaffolding work on fixed installations. Injuries range from minor wound injuries to serious bone fractures.

Crush Injury

On fixed offshore installations, this type of accident occurs, for example, in connection with the use of winches. However, they happen most frequently on mobile offshore installations, especially in connection with handling drilling gear

Fig. 5.2 Work-Related Diseases Reported, 1993-2001



on rigs. The resulting injuries are usually serious, such as amputation of a body part or bone fracture, but less serious soft-tissue injuries also occur. This type of accident represents approx. 21% of the injuries reported.

Heavy Lifting

Approx. 8% of the injuries reported are caused by accidents in connection with manual handling of heavy loads, and are sustained by personnel on both fixed and mobile offshore installations. This type of accident usually causes serious injury to the victim's back or vertebrae, e.g. straining or spraining.

WORK-RELATED DISEASES IN 2001

If a doctor suspects or ascertains that a disease has been induced by work on an installation comprised by the Act on Certain Offshore Installations, the Danish Energy Authority must be notified.

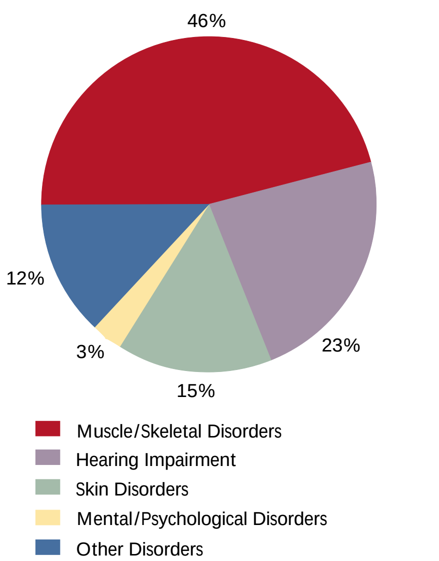
The number of such notifications is relatively low. In 2001, the Danish Energy Authority received 12 notifications of suspected or diagnosed work-related diseases. Since 1993, the Danish Energy Authority has been notified of 49 suspected or diagnosed cases of work-related diseases. Fig. 5.2 shows these cases broken down by main diagnosis.

WORK-RELATED DISEASES 1999-2001

During the period 1999-2001, the Danish Energy Authority received a total of 21 reports of suspected or diagnosed work-related diseases that may be attributed to working on installations comprised by the Danish Act on Certain Offshore Installations. All the reports may be categorized under the main diagnoses for work-related diseases stated below.

Figs. 5.2 and 5.3 show the percentage distribution by main diagnosis of the cases of work-related diseases reported 1993-2001 and 1998-2000, respectively. The latter period has been included to allow comparison with the corresponding reference period for onshore industries; see Fig. 5.4.

Fig. 5.3 Work-Related Diseases Reported, 1998-2000



Muscle/Skeletal Disorders

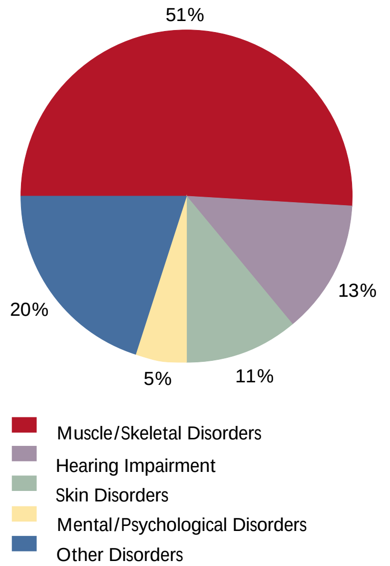
These disorders often affect persons who have been performing work that involves repetitious heavy lifting for a relatively long time. They also affect persons who have been engaged in other kinds of monotonous repetitive work, e.g. working in a squatting position or working on their knees. As it appears from Figs. 5.3 and 5.4, muscle/skeletal disorders account for about half the total number of reported cases of work-related diseases – both offshore and onshore.

Hearing Impairment

All reports of hearing impairment submitted 1999-2001 involved tinnitus resulting from long-term noise-exposure. As seen from Figs. 5.3 and 5.4, the percentage of noise injuries reported is higher offshore than onshore. Far more statistics on this subject are available for onshore than for offshore industries, and the statistical uncertainty associated with onshore industries is therefore smaller.

However, the statistical material for onshore industries includes various trades and industries in which noise problems do not occur, or occur only to a very limited extent. This partially explains the lower reporting percentage for onshore industries. In any one industry, such as fishing, towing and rescue operations, etc., hearing

Fig. 5.4 Work-Related Diseases Reported Onshore, 1998-2000



impairment accounted for some 30% of all cases of work-related injuries reported in the period 1995-2000.

Skin Disorders
Skin contact with drilling mud, various types of substances and materials, such as paint, and the use of survival suits may cause allergic reactions. As seen from Figs. 5.3 and 5.4, however, the percentage share of skin disorders for the offshore industry is approximately the same as for onshore industries.

Mental/Psychological Disorders
Reports of suspected or diagnosed mental and psychological disorders that may be attributed to working on an offshore installation are relatively rare, and the statistical material is therefore very limited. As seen from Figs. 5.3 and 5.4, the material available indicates, however, that the percentage share of reported cases of mental or psychological disorders attributable to working on an offshore installation is largely the same as for onshore industries.

Other Disorders
The percentage share of other work-related disorders reported is somewhat lower for the offshore sector than for onshore industries. To some extent, this is because some of the reports for onshore industries relate to conditions that seem to be less frequent in the offshore industry, e.g. respiratory disorders. Moreover, in relatively many of the reports from the onshore industries the disorder is inadequately described, which means that it cannot be classified directly under a main diagnosis, and is consequently grouped with “Other Disorders”.

DANGEROUS OCCURRENCES IN 2001

The occurrence of a hazardous situation that might have resulted in an accident, a so-called *dangerous occurrence*, at a workplace comprised by the Act on Certain Offshore Installations must be reported to the Danish Energy Authority. A dangerous occurrence is subject to notification if it involved a major risk of personal injury that would render the victim unfit for work for 1 day or more beyond the day of injury, or if the incident involved a great risk of other than minor damage to the structure or equipment of the installation.

In 2001, the Danish Energy Authority received only one dangerous occurrence notification. While approaching a drilling rig, the pilots of a helicopter became aware that crane operations were in progress over part of the helideck and had to postpone landing. This dangerous occurrence was due to procedure failure, and caused neither damage to equipment nor personal injury.

DANGEROUS OCCURRENCES 1999-2001

During the period 1999-2001, the Danish Energy Authority received a total of six notifications of dangerous occurrences at workplaces comprised by the Danish Act on Certain Offshore Installations. All the occurrences reported involved mobile installations. Three of the incidents were caused by equipment failure, while the remaining three were due to human error. However, as the reports concern very different situations, it is not possible to infer more specific tendencies from these notifications.

Box 5.2 Mobile Offshore Installations in the Danish Sector in 2001

DRILLING RIGS

Mærsk Olie og Gas
Mærsk Endeavour, all year.
Maersk Exerter, all year.
Transocean Shelf Explorer, all year.
Noble Byron Welliver, all year.
ENSCO 71, all year.
Noble Kolskaya, from the beginning of April.
Drilling rigs used in 2001 by Mærsk Olie og Gas in the drilling of production wells in various fields and in exploratory drilling.

Amerada Hess
Noble Kolskaya, until April.
ENSCO 101, from April.
Drilling rigs used by Amerada Hess in cooperation with DONG E&P for drilling wells in the South Arne Field.

DONG E&P
ENSCO 70, all year.
Drilling rig used by DONG E&P as operator and in partnership with other operators to drill exploration wells in various licence areas.

Statoil Efterforskning og Produktion
Noble George Sauvageau, for about 3½ months in mid-2001.
Drilling rig used by Statoil for operations in the Siri Field in the Danish sector in 2001.

OTHER MOBILE OFFSHORE INSTALLATIONS

Mærsk Olie og Gas
Skandi Navica, for several periods during the autumn Pipe-laying barge used for pipeline work at the Halfdan, Tyra Southeast and Kraka Fields.
SSCV Thialf, approx. 10 days in May and September.
Crane barge used to install the Tyra SE platform, equipment on the Gorm E platform and a pipe-bridge on the Halfdan platform.
Safe Scandinavia, 3 months from July. Accommodation unit, at Gorm.
Rigmar 301, from December Accommodation unit, at Gorm.

ACTIVE MOBILE OFFSHORE INSTALLATIONS IN 2001

Mobile offshore installations include drilling rigs, pipe-laying barges, crane barges and accommodation units, as well as ships used in connection with oil and gas exploration or production or during the construction of a fixed offshore installation. Box 5.2 lists all mobile offshore installations operating in the Danish sector in 2001.

6. INCIDENT IN THE GORM FIELD

For a number of years, the frequency of work-related accidents on offshore installations in Danish territory has been very low. Moreover, the accident frequency offshore is much lower than for comparable industries onshore; see the section on Health and Safety. The majority of accidents resulting in personal injury on fixed and mobile offshore installations are due to falling or tripping, heavy lifting or striking against or being struck by an object.

On 20 May 2001, an accident occurred on the Gorm C platform in the Gorm Field, for which Mærsk Olie og Gas AS is the operator. The accident was the consequence of a gas explosion in the platform compressor module. Two persons close to the scene of the accident suffered minor burns. The explosion caused great damage to the equipment in the module and had major consequences for production, as several oil fields were out of normal operation for a prolonged period.

Because of the great interest shown in this incident, an outline is given of the explosion and its consequences below.

GAS EXPLOSION

The gas explosion occurred when gas escaping from a leak in the outlet pipe on one of the platform compressors ignited. The pipe transports gas at a pressure of approx. 50 bars and a temperature of about 100°C. From the leak in the outlet pipe, the gas escaped into the compressor module and reached the upper decks of the module via the ventilation grilles in the module walls. There is a strong indication that the gas ignited upon contact with the hot exhaust pipes of the gas turbines in the module.

All the North Sea installations used for oil and gas production have elaborate safety systems designed to record any irregularities in the operation of the plant very quickly and thus to prevent or minimize any injuries to personnel and/or any damage to the installations.

The Gorm platform safety system responded appropriately when the accident occurred. The gas leakage was detected, production was shut down, and the system was depressurized. However, the situation developed so fast that the safety system could not prevent the escaping gas from igniting and exploding. Nevertheless, the platform safety system stopped the accident from escalating, and, all things considered, the scope of the damage was fairly limited.

When the explosion occurred, the platform fire alarm was activated. The deluge system began operating and extinguished the fire, while the platform fire team carried out follow-up extinguishing. The two injured persons received full treatment from the platform medic.

Immediately after the accident, the operator mobilized an investigation team. Representatives of the supervisory authorities also arrived on the scene to inspect the extent of the damage and draw up a report on the incident.

IMMEDIATE CONSEQUENCES

As a consequence of the explosion, the production of hydrocarbons from the Gorm Field as well as the satellite fields Skjold, Rolf and Dagmar was suspended immediately. Moreover, production was interrupted in the Halfdan Field, the Dan Field and the Dan satellite fields, Kraka and Regnar.

When the operator had formed a general view of the extent of the damage to the Gorm installations, it was decided to restart the systems in the Dan Field. About four hours after the explosion, the oil pumping equipment on the Gorm E platform was put back on stream, and immediately afterwards the oil began flowing from the Dan Field again. A few days after the incident, on 24 May, production was resumed in the Halfdan Field, the oil produced being redirected to the Dan Field installations for processing and further transport.

Production from the Tyra Field and its satellites as well as from the Harald and Svend Fields was not directly affected by the incident in the Gorm Field.

INVESTIGATION OF THE CAUSE

In order to determine the cause of the accident, the damaged pipe was dismantled and sent to the FORCE Institute in Denmark and the CAPCIS Institute in the UK for further examination. The CAPCIS Institute is affiliated with the Institute of Science and Technology of the University of Manchester.

The examinations performed by the two institutes showed that the pipe rupture resulting in the gas leakage was due to corrosion, which was caused by chemicals added to the gas in the form of a hydrogen sulphide scavenger. The scavenger is added to the gas in order to reduce its hydrogen sulphide content in accordance with the quality standards for gas to be exported. Hydrogen sulphide is undesirable in natural gas because of its toxicity and corrosive properties. In addition, gas flaring results in the emission of SO_2, which is a main source of pollution.

The scavenger, which contains active chemicals in an aqueous solution, is injected into the processing piping at various points in the plant, including the above-mentioned pipe in the compressor plant.

The examinations demonstrated that, contrary to expectation, the chemicals are corrosive under the operating conditions existing in certain parts of the plant, as the chemicals decompose at approx. 90°C. One of the decomposition products is formic acid, which is highly corrosive. Corrosion tests also show that the presence of CO_2 in the gas further increases the corrosivity of the chemicals.

RESUMPTION OF PRODUCTION

The Danish Energy Authority stressed that production from the affected fields was not to be resumed until the conditions were absolutely safe. On these premises, production was resumed as quickly as the relevant parts of the installations were ready for operation in order to minimize the financial losses.

The Danish Energy Authority made it a condition for approving the resumption of production, that the installations affected undergo extensive inspection and repairs, and, to ensure satisfactory quality of the work performed, that the repair work be subjected to third-party verification. The relevant parts of the Gorm installations were therefore to be certified by Det Norske Veritas (DNV), and documentation was to be produced showing that all parts of the installations affecting operational safety had been checked and inspected before being put back into operation. Further, once the cause of corrosion had been established, it was stipulated that the processing piping was to be checked around all points through which the chemicals in question had been/were being injected.

The work associated with repairing the damaged sections of the installations and checking other sections was very extensive. To accommodate the large number of personnel brought in to perform the work, the Gorm Field accommodation platform was supplemented with a flotel.

Operations at the Gorm Field production facilities were resumed in three phases as the individual sections became ready for use. At the end of June, the Gorm C separation module was able to return to processing the oil and water produced in the Halfdan Field.

At the end of July, the Gorm F platform facilities, which process production from the Gorm and Skjold Fields, came on stream again. However, as the gas processing module on Gorm C was not yet ready for operation, production from the Gorm and Skjold wells was restricted due to the unavailability of lift gas.

The last repairs and safety checks were not completed until the end of August 2001, and on 24 August 2001 the Danish Energy Authority granted its approval for the gas processing facilities in the Gorm Field to return to production.

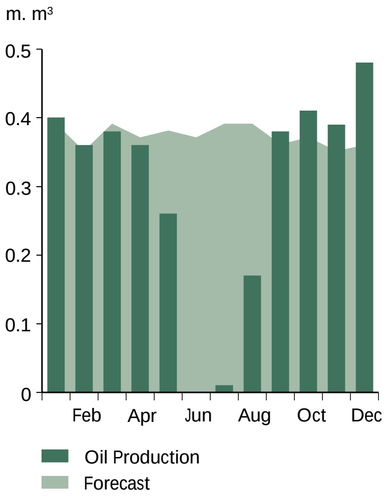
The installations were put back into operation on 2 September 2001, and normal production conditions in the adjoining fields were restored. However, the small satellite fields Rolf and Dagmar were not brought on stream until September and November, respectively.

CONSEQUENCES FOR PRODUCTION

The fields hooked up to the Gorm processing facilities, viz. Gorm, Skjold, Rolf and Dagmar, suffered most from the incident. Normally, oil production from the Gorm and Skjold Fields accounts for about 20% of total Danish production.

Production from the Halfdan Field was not affected to the same degree, as it proved possible after the explosion to convey the production to the Dan Field. Moreover, the separation module on Gorm C, which normally processes the oil and water from Halfdan, became operational again fairly quickly.

Fig. 6.1 Oil Production and Forecast for the Gorm, Skjold, Rolf and Dagmar Fields



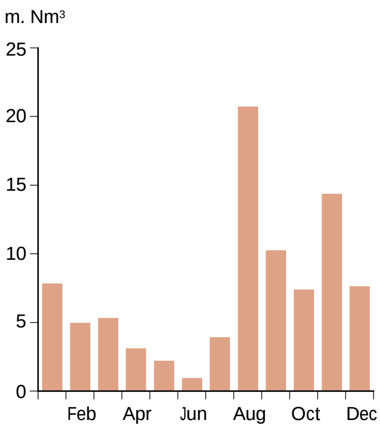
Production from the remaining fields was affected by the Gorm incident to a minor degree only, mainly in connection with checking comparable injection points for corrosion damage.

Fig. 6.1 shows the Danish Energy Authority's production forecast at 1 January 2001 for the Gorm, Skjold, Rolf and Dagmar Fields as well as the actual production for 2001.

The oil production forecast for the above-mentioned fields had a slight downward trend, except in the middle of the year when a small increase in production reflected the tie-in of a new production well.

The explosion occurred on 20 May, and production was suspended until 27 July, from which time production in the Gorm and Skjold Fields was partially resumed.

Fig. 6.2 Gas Flaring in the Gorm Field



The installations were slowly restarted, and full-scale production from these fields was resumed in September. As mentioned above, the Rolf and Dagmar Fields returned to production in September and November, respectively.

For the period from January through April 2001, the actual production figures for the Gorm, Skjold, Rolf and Dagmar Fields largely meet the forecast. From May through August 2001, the production forecast was 1.5 million m^3 of oil, whereas only 0.4 million m^3 of oil was actually produced from these fields.

For the rest of the year, oil production exceeded the forecast for the above-mentioned fields by 0.2 million m^3. The increase was attributable in part to some wells yielding a so-called flush production. This phenomenon occurs after a prolonged period of shut-down until production has stabilized. Another reason for the higher production figure was the output from two additional wells not included in the forecast for this period.

Increased Gas Flaring

The incident in the Gorm Field had a major impact on the amount of gas flared. The Gorm Field gas processing facilities were out of operation for more than four months, and in connection with the phased start-up of production from the adjoining fields, the gas produced could not be utilized, but had to be flared.

In August and September 2001, 20.7 million Nm^3 and 10.2 million Nm^3 of gas was flared, compared to a monthly average of about 5 million Nm^3 the year before. Fig. 6.2 shows the amounts of gas flared for every month of 2001.

As far as the other DUC production centres are concerned, the inspection and checking programmes carried out in the wake of the Gorm Field incident also pushed up gas flaring in these centres, as it was necessary to suspend the processing of gas during some periods.

INCIDENT FOLLOW-UP

Immediately after the accident on the Gorm C platform, the Danish Energy Authority informed the other operators in the Danish sector that injecting hydrogen sulphide scavenger in the piping of the processing systems may cause corrosion of the relevant piping.

All operators in Denmark were asked to carry out an extraordinary inspection and checking programme, including measurement of the wall thickness of the processing piping into which hydrocarbon scavenger was or had previously been injected.

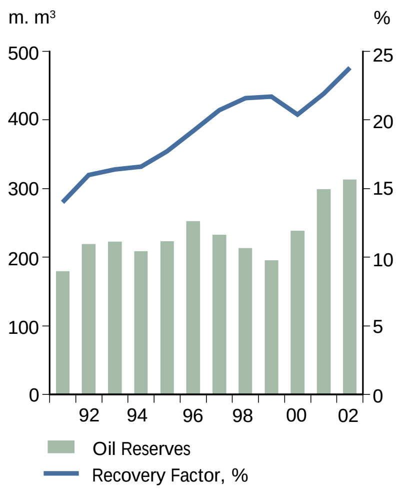
When the result of the examinations was available, and it was established that the cause of corrosion was the injection of scavenger into hot piping, efforts were initiated to find a permanent solution to the corrosion problem as quickly as possible.

These efforts focus on alternative options to the chemicals used to date and on replacing the critical piping with piping of corrosion-resistant material. Until a permanent solution can be implemented, more rigorous monitoring of the piping system around the critical injection points has been introduced.

In spring 2002, the Minister for Economic and Business Affairs decided to initiate an independent survey of the safety conditions on the Gorm Field installations.

7. RESERVES

Fig. 7.1 Oil Reserves and Recovery Factor



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

The Danish Energy Authority made the largest upward adjustment of oil reserves ever in last year's assessment. The reserves according to this year's assessment are largely unchanged compared to the year before. The write-up of expected ultimate recovery only slightly exceeds production in 2001.

Like oil reserves, gas reserves remain at almost the same level as last year. The write-up of expected ultimate recovery falls just below production in 2001.

The overall oil recovery factor, the ratio of ultimate recovery to total oil in place, increased from 22% to 24% relative to the year before; see Fig. 7.1. This increase is mainly attributable to a writedown of the hydrocarbons in place in the Dan Field and a write-up of the reserves in the Dan and Halfdan Fields.

Viewed in a greater perspective, the expected recovery factory has gone up from 14% to 24% since 1990, an increase of almost 75% generated by the further development of fields through the drilling of horizontal wells and the use of water injection.

R/P RATIO AND PRODUCTION

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 calculated number of years for which oil production is estimated to be sustained at the same level.

Based on the new assessment of reserves, the R/P ratio is 15, meaning that oil production is calculated to be sustainable at the 2001 level for the next 15 years.

As the R/P ratio was 14 according to last year's assessment, this year's figure is about the same as the year before.

The R/P ratio is frequently used because it yields a comparable measure of how long reserves will last. However, this ratio cannot replace an actual forecast, especially not where large variations in the size of future production are expected; see Fig. 7.5 and the accompanying text 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 volume of hydrocarbons in place that can be recovered over the life of a field is termed the ultimate recovery. Thus, the difference between ultimate recovery and the volume produced at any given time constitutes the reserves.

The method used by the Danish Energy Authority in calculating the reserves and preparing the production forecasts is described in Box 7.1.

Table 7.1 shows the Danish Energy Authority's assessment of oil and gas reserves, broken down by field and category.

Box 7.1 Categories of Reserves

The method used by the Danish Energy Authority 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.

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.

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. 7.2 that the expected amount of oil reserves ranges from 230 to 313 million m^2. The difference between the two figures, 83 million m^2, equals the reserves in the possible recovery category. The reserves assessed for the planned and possible recovery categories, respectively, reflect the increasing uncertainty as

Table 7.1 Production and Reserves at 1 January 2002

	OIL, million m³				GAS, billion Nm³				
	Ultimate Recovery					Ultimate Recovery			
	Produced	Reserves				Produced	Reserves		
		Low	Exp.	High			Low	Exp.	High
Ongoing and Approved Recovery:					**Ongoing and Approved Recovery:**				
Adda	-	1	1	1	Adda	-	0	0	1
Alma	-	0	1	1	Alma	-	1	1	2
Dagmar	1	0	0	0	Dagmar	0	0	0	0
Dan	57	37	60	84	Dan	17	3	8	13
Elly	-	0	1	1	Elly	-	2	5	7
Gorm	42	8	14	19	Gorm	5	1	2	3
Halfdan	4	47	74	104	Halfdan	1	5	9	12
Harald	6	2	3	4	Harald	12	8	12	16
Kraka	4	1	2	3	Kraka	1	0	1	2
Lulita	1	0	0	0	Lulita	0	0	0	0
Regnar	1	0	0	0	Regnar	0	0	0	0
Roar	2	1	1	2	Roar	9	5	8	11
Rolf	4	0	1	1	Rolf	0	0	0	0
Siri	6	1	3	4	Siri	-	-	-	-
Skjold	32	6	13	21	Skjold	3	0	1	2
Svend	4	1	2	3	Svend	1	0	0	1
South Arne	5	*	27	*	South Arne	2	*	7	*
Tyra	19	3	6	9	Tyra	32	25	29	32
Tyra Southeast	-	3	5	6	Tyra Southeast	-	8	11	14
Valdemar	1	1	2	2	Valdemar	1	1	2	4
Subtotal	**190**		**214**		**Subtotal**	**84**		**94**	
Planned Recovery:					**Planned Recovery:**				
Amalie	-	*	2	3	Amalie	-	*	3	5
Boje Area	-	1	1	1	Boje Area	-	0	0	0
Cecilie	-	3	4	6	Cecilie	-	-	-	-
Freja	-	1	1	2	Freja	-	0	0	0
Igor	-	0	1	1	Igor	-	3	8	13
Nini	-	4	6	9	Nini	-	-	-	-
Sif	-	0	1	2	Sif	-	2	5	8
Subtotal			**16**		**Subtotal**			**17**	
Possible Recovery:					**Possible Recovery:**				
Prod. fields	-	31	61	92	Prod. fields	-	6	12	18
Other fields	-	2	3	5	Other fields	-	4	7	11
Discoveries	-	7	19	43	Discoveries	-	3	11	22
Subtotal			**83**		**Subtotal**			**30**	
Total	**190**		**313**		**Total**	**84**		**141**	
January 2001	169		299		January 2001	76		144	

* *Not assessed*

Fig. 7.2 Oil Recovery, m. m³

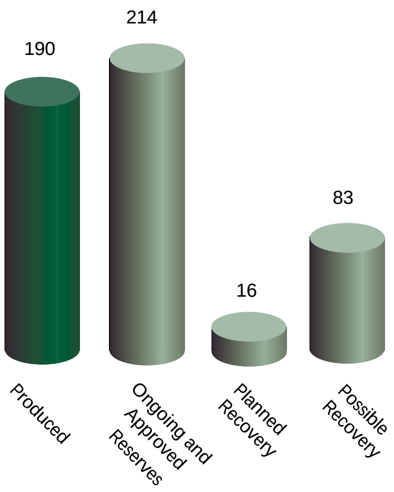
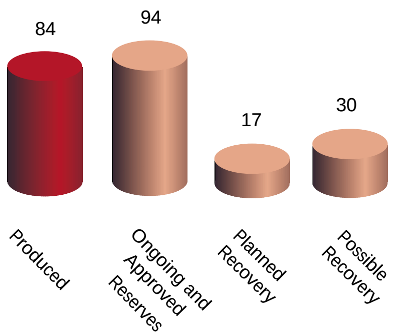


Fig. 7.3 Gas Recovery, bn. Nm³



to whether such reserves can be exploited commercially. The reserves in the ongoing/approved recovery category are the highest figures assessed by the Danish Energy Authority to date.

Likewise, Fig. 7.3 illustrates that the expected amount of gas reserves ranges from 111 to 141 billion Nm^3. 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 that 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 Authority's assessment of reserves compared to the assessment made in January 2001. These revisions are attributable to new discoveries, more production experience and new reservoir models of some of the fields resulting from improved knowledge of the fields.

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

Ongoing and Approved Recovery

In the planned recovery category, the reserves assessment made in January 2001 included the reserves recoverable from the development of Tyra Southeast, based on the development plan submitted for the field. This plan was approved later in 2001, and the reserves of the Tyra Southeast Field have therefore been included under ongoing and approved recovery.

The Lola Field has been relinquished, so the reserves of this field have been included in the possible recovery category.

Production experience or the drilling of additional wells has led the Danish Energy Authority to write up the reserves of the Gorm, Roar, Siri, Skjold and Svend Fields.

As development plans for the further development of the Dan and Halfdan Fields were approved in September 2001 and October 2001, respectively, the reserves of these fields have been written up on the basis of these plans as well as production experience.

Positive well results have engendered an upward adjustment of the Tyra Southeast reserves.

Planned Recovery

Revised plans were submitted for the development of Igor and the Boje Area in December 2001 and for Freja in January 2002. Moreover, development plans were submitted for Amalie in December 2001 and for Cecilie and Nini in March 2002. Thus, the reserves of these fields have been included in the planned recovery category.

Bertel has been relinquished, so the contribution from this field has been included in the possible recovery category.

POSSIBLE RECOVERY

The Danish Energy Authority 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 by implementing water-injection projects in a number of fields.

The drilling of horizontal wells is considered to further increase the production potential of the Boje Area, Igor, Kraka, Sif and Valdemar.

Finally, discoveries that are under appraisal are included in this category, e.g. Hejre. This category also includes discoveries that are considered to be non-commercial based on current technology and prices.

On average, the total amount of oil that is recoverable from all Danish fields and discoveries with the use of known technology constitutes approx. 24% of the hydrocarbons in place. In fields like Dan, Gorm and Skjold, where the production conditions are favourable, an average recovery factor of 38% of the oil in place is expected, based on the assumption that known methods are used, including water and gas injection. However, the assessment also includes contributions from the relatively large oil accumulations in the Tyra, Tyra Southeast and Valdemar Fields, where the recovery factors are fairly low due to difficult production conditions.

Table 7.2 Oil Production Forecast, million m³

	2002	2003	2004	2005	2006
Ongoing and Approved:					
Adda	-	-	-	0.5	0.1
Alma	-	-	-	0.1	0.1
Dagmar	0.0	0.0	0.0	0.0	0.0
Dan	6.8	6.7	6.3	5.9	5.4
Elly	-	-	-	0.2	0.1
Gorm	2.8	2.6	2.1	1.7	1.2
Halfdan	4.4	5.6	6.1	6.2	5.6
Harald	0.7	0.5	0.4	0.3	0.2
Kraka	0.2	0.2	0.2	0.2	0.1
Lulita	0.0	0.0	0.0	0.0	0.0
Regnar	0.0	0.0	0.0	0.0	0.0
Roar	0.3	0.2	0.2	0.0	0.1
Rolf	0.1	0.1	0.1	0.1	0.1
Siri	1.2	0.6	0.4	0.3	0.2
Skjold	1.7	1.3	1.1	1.0	0.9
Svend	0.5	0.4	0.3	0.2	0.1
South Arne	2.5	2.9	2.9	2.9	2.9
Tyra	0.8	0.8	0.8	0.5	0.6
Tyra Southeast	0.8	1.0	0.6	0.4	0.3
Valdemar	0.3	0.2	0.2	0.2	0.2
Subtotal	**23.1**	**23.0**	**21.5**	**20.7**	**18.2**
Planned:	**-**	**1.5**	**2.3**	**2.8**	**2.1**
Expected:	**23.1**	**24.5**	**23.8**	**23.5**	**20.3**

PRODUCTION FORECASTS

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

The present five-year forecast shows the Danish Energy Authority's expectations for production until the year 2006. Moreover, the Danish Energy Authority has assessed the production potential for oil and natural gas for the next 20 years.

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 start-up is approved or from the earliest date on which production can be commenced.

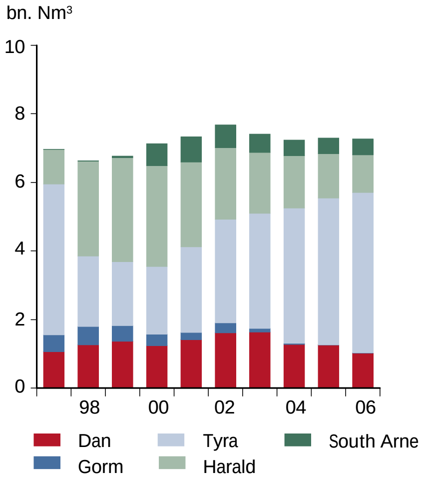
Expected oil production appears from Table 7.2. The oil production forecast shown in this table illustrates the planned course of production, and the total production figure remains fairly constant, averaging about 23.0 million m³ of oil per year. For 2002, oil production is expected to total 23.1 million m³, equal to about 398,000 barrels of oil per day.

In relation to the forecast in last year's report, expected production figures have been written up by an average of about 40%. The figures are higher chiefly because they include the development of the Cecilie and Nini Fields and the further development of the Dan and Halfdan Fields. In addition, the production estimates for several fields have been adjusted upwards.

The revisions to the production forecast are dealt with below.

In the forecast made in January 2001, the planned recovery category included expected recovery from the development of the Lola and Tyra Southeast Fields. As mentioned above, Lola was relinquished after a reappraisal of the accumulation,

Fig. 7.4 Natural Gas Production (Forecast) Broken down by Processing Centre



and the contribution from the Tyra Southeast Field has now been included in the ongoing and approved recovery category.

Based on production experience or the drilling of additional wells, expected production figures have been written up for the Gorm, Siri, Skjold and Svend Fields.

The forecast for the Dan and Halfdan Fields has been adjusted upwards in light of production experience and the approval of plans for their further development. By 2005, Halfdan is expected to be the field producing the most oil, accounting for a 25% share of total production.

Based on well results, the production expected for Tyra Southeast in the period covered by the forecast has more than tripled on average, compared to last year's 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 Boje Area, Cecilie, Freja, Igor, Nini and Sif.

Natural gas production estimates are given in Fig. 7.4, broken down by processing centre.

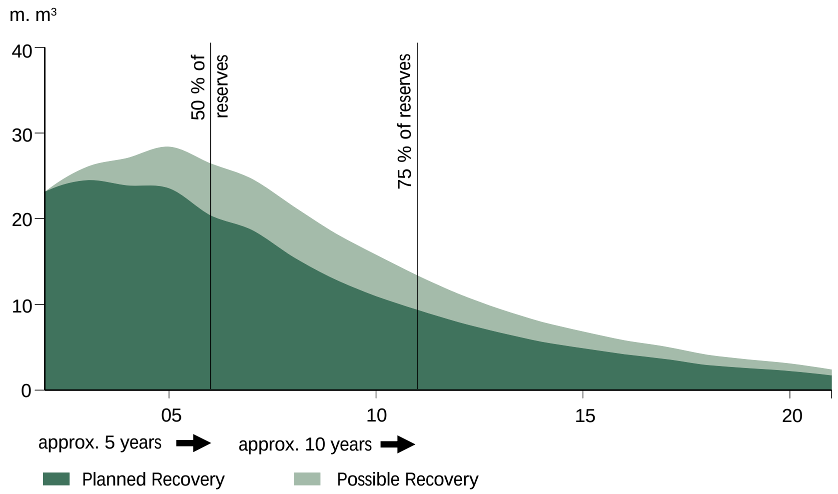
Twenty-Year Production Forecast

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 until 2021, it has been assumed that the course of production will be determined on the basis of the technical potential of the fields, without taking legal and operational constraints into account.

Fig. 7.5 illustrates two oil production scenarios. The curve illustrating the planned

Fig. 7.5 Oil Production Forecast 2002-2021



course of production is simply a continuation of the development shown in Table 7.2, while the second curve also includes possible recovery.

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

The Danish Energy Authority estimates that the increased use of water injection in several fields represents further oil production potential, and moreover, that a potential exists for enhancing recovery from the Boje Area, Igor, Kraka, Sif and Valdemar.

It appears from Fig. 7.5 that the planned course of production is expected to remain fairly constant at a level of about 24 million m³ for the period from 2003 to 2005, after which production is expected to decline. When including the possible recovery category, oil production is projected to peak at approx. 28 million m³ in 2005, after which it is expected to fall.

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 roughly five and ten years, respectively.

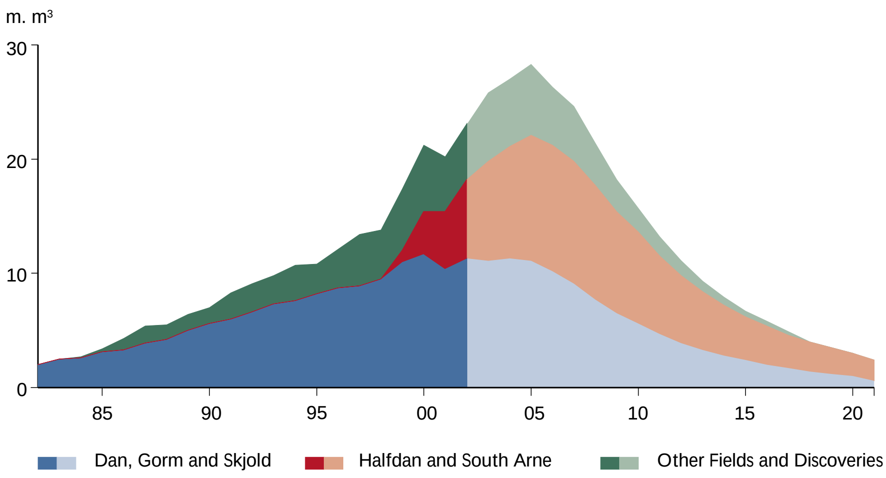
It is characteristic that a few fields only have produced the bulk of Danish oil, and that the oil reserves are concentrated in relatively few fields.

Dan, Gorm and Skjold are the three oldest, producing Danish fields. These fields account for about 70% of total oil production, and due to their development with horizontal wells and water injection, they still contain considerable reserves; see Fig. 7.6.

The Halfdan and South Arne Fields were brought on stream in 1999 and are not yet fully developed.

The reserves of the Dan, Gorm, Skjold, Halfdan and South Arne Fields are estimated to represent about 80% of total Danish oil reserves. The remaining 20% of

Fig. 7.6 Oil Production and Forecasts for the Period 1982-2021



reserves derive from more than 30 fields and discoveries.

Although the forecast covers a period of 20 years, it is only possible to predict the development for a few years ahead. 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 possibly be curbed as a result of new discoveries made, e.g. in connection with the exploration activity initiated in the Fifth Licensing Round, as well as by advances in technological research and development.

Thus, so-called technological leaps, i.e. the use of new forms of technology, may have a major impact on ultimate recovery.

The following example illustrates the potential resources inherent in technological leaps. If the average recovery factor increases by about 5 percentage points for the Dan, Gorm, Skjold, Halfdan and South Arne Fields, this potential corresponds to the reserves assessed for all other fields and discoveries. The increase in recovery factor should be viewed on the basis of the average recovery factor expected for these five fields, viz. 37%.

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.

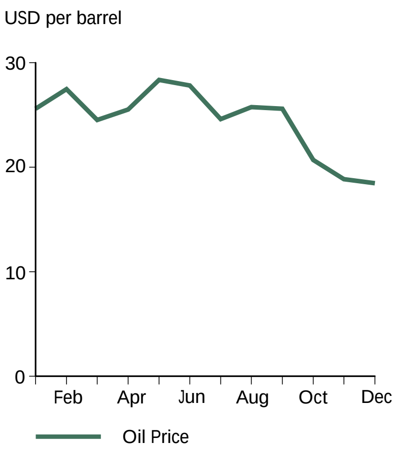
Since the start of gas sales in 1984, natural gas produced under A.P. Møller's Sole Concession has been supplied under gas sales contracts concluded between DUC and DONG Naturgas A/S. The present gas sales contracts do not stipulate a fixed total volume, but rather an annual volume that will be supplied 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 DONG Naturgas A/S for the sale of gas from the South Arne Field, and, in 1998, a contract was concluded between the Statoil group and DONG Naturgas A/S for the sale of the Statoil group's share of the gas produced from the Lulita Field.

The Danish Energy Authority's forecast for the planned course of production is based on the contracts with DUC providing for total gas supplies of approx. 140 billion Nm^3 until the year 2012. In addition, the planned course of production for the South Arne Field accounts for 5 billion Nm^3.

8. ECONOMY

Fig. 8.1 Oil Price in 2001



The oil and gas production from the North Sea has a positive impact on the Danish economy. Since 1991, Denmark has been self-sufficient in oil and gas. Moreover, in 2001 Denmark was self-sufficient in energy for the fifth year in a row, mainly as a result of the production of oil and natural gas in the North Sea. This production also favourably affects the Danish balance of payments and generates revenue for the state.

CRUDE OIL PRICE AND DOLLAR EXCHANGE RATE

The production value of oil and natural gas depends on the development of the international crude oil price and the dollar exchange rate.

The average oil price, as quoted for Brent oil, was USD 24.4 per barrel in 2001. This is slightly lower than in 2000, when the average oil price was just under USD 28 per barrel. In the first half of 2001, the oil price level had already fallen compared to the second half of 2000, a downward trend that continued in the second half of 2001.

In January 2001, the average oil price was almost USD 27 per barrel, and the average for December 2001 was about USD 18 per barrel. The decline from USD 27 to USD 18 per barrel did not follow a steady line. As appears from Fig. 8.1, oil prices fluctuated throughout the year, which is in keeping with their usual course of development.

OPEC has made it a goal to keep the oil price within the USD 22-28 range per barrel, and has basically succeeded in the past few years. However, from a historical perspective, this is a relatively high price; by comparison, the average price in the 1990s hovered just above USD 18 per barrel.

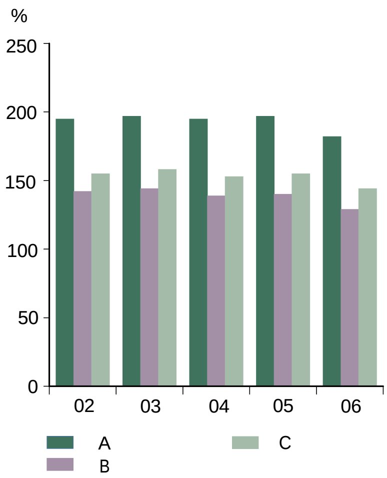
The tragic events in the USA on 11 September 2001 precipitated a temporary surge in the oil price. The price then began falling in response to fears that a recession would dampen demand. At end-September 2001, OPEC held a meeting at which it was decided not to cut down production, even though the oil price had reached its lowest level since 1999. In the last three months of 2001, the oil price continued falling. This downward trend was reversed in the first months of 2002.

In 2001, the average dollar exchange rate was DKK 8.3 per USD. This represents a slight increase compared to 2000, when the average dollar exchange rate was DKK 8.1 per USD. The development in the dollar exchange rate has checked the fall in the oil price in terms of Danish kroner, and thus in the production value of the oil produced in the Danish part of the North Sea.

VALUE OF OIL AND GAS PRODUCTION

The estimated value of total Danish oil and gas production declined to about DKK 31.3 billion in 2001, a 10% drop compared to 2000. This decline is attributable to the slight reduction in production caused by the accident in the Gorm Field, see the section on the *Incident in the Gorm Field*, and to the lower oil price level. However, when viewed in a historical perspective, the production value estimated for 2001 is still considered to be very high.

Fig. 8.2 Degrees of Self-Sufficiency



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

In 2000, the value of oil production was DKK 30.0 billion, while the value of gas production was estimated at DKK 4.8 billion. Preliminary estimates for 2001 show that oil production represented a value of DKK 24.7 billion, and gas production a value of DKK 6.6 billion. It should be noted that the estimated production value of gas increased while the production value of oil decreased. This is partly because the gas price is tied to the oil price with a certain delay. Thus, the very high oil price in 2000 becomes one of the factors determining the value of gas in 2001. The breakdown of production in 2001 on the 11 producing companies appears from Fig. 3.2 in the section on *Development and Production.*

How the production value will develop in the years ahead depends both on production and the trend in oil prices and the dollar exchange rate. Considering the amount of known reserves, the Danish Energy Authority estimates that oil production will reach a slightly higher level in the period 2002-2005 and then start declining if no new development initiatives are taken. Gas production is expected to remain constant for a number of years. However, the development in oil prices is very difficult to predict, so any estimate of how the production value will develop in the years to come will be subject to great uncertainty.

DEGREES OF SELF-SUFFICIENCY

Denmark has been self-sufficient in energy since 1997. Total Danish production of oil, natural gas and renewable energy in 2001 was about 37% higher than total energy consumption. This represents a minor change from the year before, when production exceeded consumption by 39%. In 2001, the production of oil and natural gas exceeded total oil and gas consumption by 26% and 85%, respectively.

The Danish Energy Authority's projected development in the degrees of self-sufficiency for the next four years appears from Table 8.1 and Fig. 8.2.

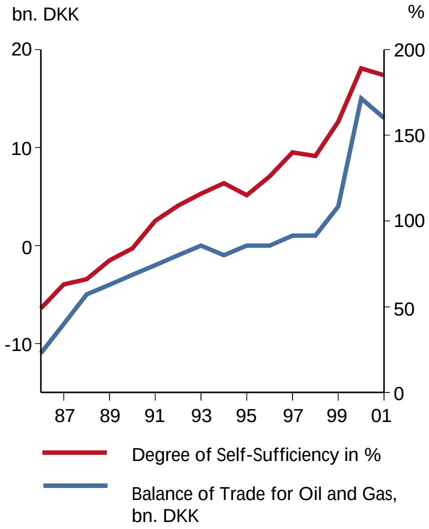
Column A shows the extent to which the production of oil and natural gas from the North Sea covers domestic oil and natural gas consumption. Since 1991, Denmark has been self-sufficient in oil and gas, and in 2002 Danish oil and natural gas production is expected to exceed consumption by about 95%.

It appears from column B that total oil and natural gas production in 2002 is estimated to exceed Denmark's total energy consumption by about 42%.

Table 8.1 Degrees of Self-Sufficiency

	2002	2003	2004	2005	2006
Production (PJ)					
Crude Oil	841	870	834	845	755
Gas	302	290	283	286	285
Renewable Energy	110	114	112	118	120
Energy Consumption (PJ)					
Total	807	807	805	807	807
Degrees of Self-Sufficiency (%)					
A	195	197	195	197	182
B	142	144	139	140	129
C	155	158	153	155	144

Fig. 8.3 The Balance of Trade for Oil and Gas and Degree of Self-Sufficiency, 2001 Prices



Column C indicates how large a share of total energy consumption is covered by Denmark's production of oil, natural gas and renewable energy. In 2002, production is expected to exceed consumption by 55%.

IMPACT OF PRODUCTION ON THE DANISH ECONOMY

The oil and natural gas activities in the North Sea have a favourable impact on the Danish economy. In addition to contributing to Denmark's self-sufficiency in energy, the activities impact positively on the balance of trade and the balance of payments current account.

The Balance of Trade for Oil and Natural Gas

The balance of trade for oil and natural gas expresses the difference between the value of total imports and total exports of oil and natural gas products; see Fig. 8.3.

Since the mid-1980s, the deficit on the balance of trade for oil and natural gas products has been gradually decreasing, in 1995 becoming a DKK 293 million surplus. This auspicious development continued throughout the 1990s, and a record-high DKK 14.4 billion surplus was recorded in 2000.

For 2001, the surplus on the balance of trade for oil and natural gas products has been preliminarily estimated at DKK 13 billion.

Impact on the Balance of Payments

The production of oil and natural gas has a positive impact on the balance of payments. A share of production is exported, and the share consumed in Denmark replaces the energy imports otherwise required.

Based on a number of simplifying assumptions, the Danish Energy Authority has prepared an estimate of the effect of oil and gas activities on the balance of payments current account for the next five years.

The estimate is based on the Danish Energy Authority's forecasts of production, investments and operating and transportation costs. Moreover, a number of assumptions have been made about import content, interest expenses and profits on the hydrocarbon activities.

Finally, calculations have been made on the basis of a low and a high oil price scenario of USD 20 and USD 25 per barrel, respectively, and a dollar exchange rate of DKK 8.1 per USD. The two alternative price scenarios merely serve to illustrate the sensitivity of economic projections to fluctuations in the oil price.

Table 8.2 Effect of Oil/Gas Activities on the Balance of Payments, DKK billion, 2001 prices, "Low" Price Scenario (20 USD/bbl)

	2002	2003	2004	2005	2006
Socio-Economic Production Value	29	29	28	28	26
Import Share	8	8	5	2	2
Balance of Goods and Services	21	21	23	27	24
Transfer of Interest and Dividends	7	7	7	7	6
Balance of Payments Current Account	**14**	**14**	**16**	**20**	**18**
Balance of Payments Current Account "High" Price Scenario (25 USD/bbl)	**18**	**19**	**22**	**26**	**23**

Fig. 8.4 Total State Revenue from Oil/Gas Production 1972-2001, DKK billion, 2001 Prices

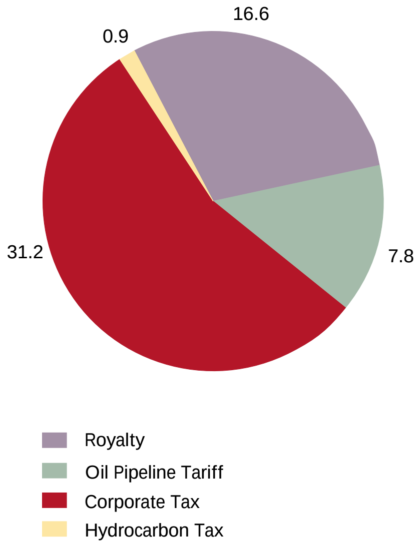


Table 8.2 shows the individual stages of the calculation (subtotals) for the low oil price scenario. The table also shows the calculated effect on the balance of payments current account when the high oil price scenario is used.

The socio-economic production value is defined as the sum total of the production value of produced oil and the production value of natural gas consumption and natural gas exports. The import content of expected expenses is then deducted from the socio-economic production value. Finally, estimated dividends and interest payments transferred abroad are deducted, thus yielding the effect of oil and gas activities on the balance of payments current account.

Assuming that the oil price is USD 20 per barrel, the oil and gas activities will have an estimated DKK 14-20 billion impact on the balance of payments current account, while the impact will be in the DKK 18-26 billion range in the high oil price scenario. The two scenarios show that oil prices greatly influence how the oil and gas activities affect the Danish economy.

State Revenue

The state generates direct revenue from North Sea oil and gas production via five different taxes and fees: *corporate tax, hydrocarbon tax, royalty and oil pipeline tariff/ compensatory fee*. In addition, the state receives an annual dividend payment from DONG E&P A/S. At the end of 2001, the state's aggregate revenue from oil and gas production amounted to DKK 56.5 billion in 2001 prices. By way of comparison, the aggregate production value at end-2001 amounted to DKK 242.6 billion in 2001 prices. The corresponding aggregate value of the licensees' expenses for exploration, field development and operations was DKK 146.3 billion. Box 8.1 specifies the state's revenue base in the form of taxes and fees on hydrocarbon production.

Fig. 8.4 shows total state revenue broken down on the individual taxes and fees.

The sustained relatively high oil price and dollar exchange rate in 2001 greatly influenced state revenue. Further, several oil companies have reached a phase of their production where a large proportion of the initial major investments have been depreciated. Thus, the state's total revenue of about DKK 10.2 billion in 2001 represents a 22% increase over the revenue for 2000, which was double the amount recorded in 1999.

As Table 8.3 illustrates, the state revenue generated from oil and gas production rose by about DKK 1.9 billion relative to 2000. Apart from the oil price impact, the reason for this striking growth is that the DUC companies pay royalty on the previous year's production. Consequently, the royalty received by the state in 2000

Table 8.3 State Revenue over the Past Five Years, DKK million, Nominal prices

	1997	1998	1999	2000	2001*
Hydrocarbon Tax	0	0	0	0	0
Corporate Tax	1,743	1,709	2,310	5,750	6,800
Royalty	944	1,098	854	1,153	2,243
Oil Pipeline Tariff**	444	310	619	1,401	1,111
Total	**3,131**	**3,117**	**3,784**	**8,304**	**10,154**

* *Estimate*
***Including compensatory fee*

was based on the production value for 1999, when oil prices and oil production figures were somewhat lower than in 2000. In 2001, the state received royalty payments from the DUC companies based on the very high production value in 2000, which was considerably higher than the 1999 production value on which royalty was paid in 2000. The same will apply in 2002, when the DUC companies will pay royalty based on the sustained high production value in 2001, regardless of oil price developments in 2002.

For the past three years, the state has received tax payments from companies other than the DUC companies. These tax payments were made by the companies holding shares in the Siri Field (licence 6/95), the South Arne Field (licence 7/89) and the Lulita share of licences 7/86 and 1/90. It appears from Appendix A which companies hold shares in the individual licences. The state-owned company DONG E&P A/S participates in the production from these three fields.

DONG E&P A/S is a fully paying participant in the licences granted in the Fourth and Fifth Licensing Rounds and in the Open Door Procedure, with a fixed 20% share. In some cases, DONG E&P A/S has supplemented this share on commercial terms by purchasing additional licence shares. Thus, DONG E&P A/S participates on the same terms as the other companies, paying its share of expenses and receiving the corresponding share of profit.

The form of state participation adopted in the Fourth and Fifth Licensing Rounds does not influence the profitability of a given project, but only the size of the financial result, since the companies' exploration, investment and operating costs are reduced by the same share as their income. The main objective of state participation in the licences is to secure the state a share in the proceeds from oil and gas recovery.

The Ministry of Taxation has contributed to this report with the following estimates and comments on the state's future revenue from the production of hydrocarbons:

"The five-year revenue forecast shows, based on the USD 20 price scenario, that the state's total revenue will come to DKK 7.5 billion in 2002 and then hover at that level until the year 2006; see Table 8.4. The USD 25 price scenario is estimated to yield state revenue of DKK 10.1 billion in 2002, increasing to DKK 12.0 billion in 2006.

Table 8.4 Expected State Revenue from Oil and Gas Production, DKK billion, 2001 Prices

	2002	2003	2004	2005	2006
Corporate Tax USD 20/bbl	4.5	4.5	4.2	4.7	4.3
USD 25/bbl	*6.3*	*6.3*	*5.9*	*6.4*	*5.8*
Hydrocarbon Tax	0.0	0.1	0.2	0.2	0.6
	0.2	*0.5*	*2.0*	*3.2*	*3.1*
Royalty	1.8	1.8	1.7	1.7	1.5
	2.3	*2.3*	*2.2*	*2.2*	*1.9*
Oil Pipeline Tariff*	1.1	1.1	1.1	1.1	1.0
	1.4	*1.4*	*1.4*	*1.4*	*1.2*
Total	**7.5**	**7.6**	**7.3**	**7.8**	**7.3**
	10.1	*10.5*	*11.4*	*13.2*	*12.0*

** Including compensatory fee*

Box 8.1 State Revenue from North Sea Oil and Gas Production

The taxes and fees imposed on the production of oil and gas secure an income for the state. 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 compensatory fee is administered by the Danish Energy Authority. Moreover, the Danish Energy Authority supervises the metering of the amounts of oil and natural gas produced on which the assessment of state revenue is based.

Corporate tax payments

Corporate tax payments are the state's most important source of income related to oil and natural gas. Revenue from corporate tax payments was not generated until the beginning of the 1980s, because the oil and gas sector requires fairly heavy investments, which are deductible as depreciation allowances over a number of years. With effect from 1 January 2001, the corporate tax rate was reduced from 32% to 30%.

Hydrocarbon tax

This tax was introduced in 1982 with the aim of taxing windfall profits, for example as a result of high oil prices. In addition, the Act provides an incentive for the companies to reinvest in further exploration and development activities in order to ensure increased and better exploitation of the resources in the subsoil. 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 900 million in 2001 prices.

Royalty

Under the terms of A.P. Møller's Sole Concession, royalty is payable on the basis of production. For the Sole Concession, royalty at the rate of 8.5% is payable on the total value produced after deducting transportation costs. In addition, the Statoil group pays royalty based on the size of the production attributable to the company's share of the Lulita Field. New licences contain no requirement for the payment of royalty.

Oil pipeline tariff

The oil pipeline tariff is a tax payable by DONG Olierør A/S, which owns the oil pipeline from the Gorm Field to Fredericia. The users of the oil pipeline pay a fee to DONG Olierør A/S, which includes a profit element of 5% of the value of the crude oil transported. DONG pays 95% of the income from the 5% profit element to the state, termed the oil pipeline tariff.

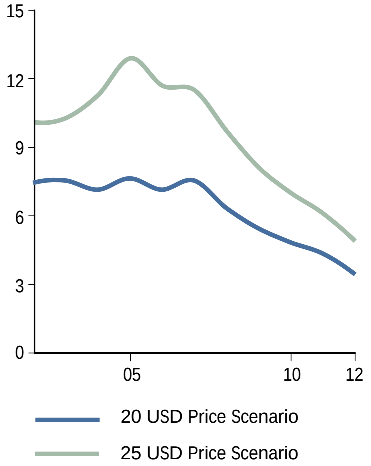
Compensatory fee

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 amounting to 5% of the value of the crude oil and condensate comprised by the exemption. To date, the compensatory fee has only become payable on the production from the South Arne and Siri Fields.

DONG Efterforskning & Produktion A/S

As DONG E&P A/S holds a share in the individual licences on the same terms as the other licensees, the company pays taxes and fees to the state at the current rates and thus contributes to the state's direct revenue from hydrocarbon production. Since DONG E&P A/S is a wholly state-owned company, its financial result reflects the value of the state's interest. DONG E&P A/S' profit after tax for 2001 amounts to DKK 414 million.

Fig. 8.5 Taxes and Fees, 2002-2012, 2001 Prices



In recent years, oil prices have been relatively high and production has increased in the Danish area. Combined with declining investments in profit-yielding fields, this means that the losses brought forward from previous years for setoff against the income subject to hydrocarbon tax have gradually shrunk over the years. Therefore, the Ministry of Taxation estimates that the losses brought forward will no longer be able to outweigh the profits from the fields.

The estimates of future corporate and hydrocarbon tax payments have made no allowance for changes in the companies' behaviour, including in particular their powerful incentive to invest when they become liable to hydrocarbon tax. According to the report from the Hydrocarbon Tax Committee (Recommendation no. 1408), oil companies are able to obtain tax allowances of a magnitude that makes it altogether doubtful that hydrocarbon tax will become payable in any more than a few isolated years. In fact, no one has been liable to pay hydrocarbon tax since 1985.

The future estimates of corporate and hydrocarbon tax payments are subject to further uncertainty because the calculations are based on various stylized assumptions, some of which concern the companies' financing costs. Likewise, changes in the oil price will mean that the estimates have to be revised."

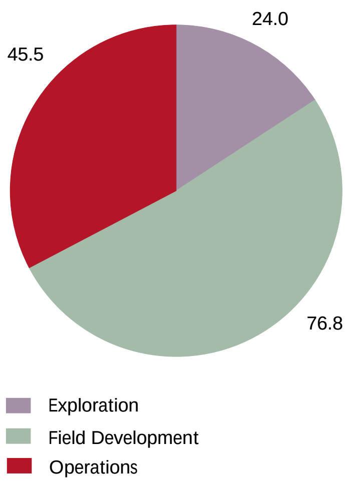
Fig. 8.5 shows that tax revenue will decline in step with the projected development of production.

Table 8.5 Investments in Development Projects, DKK million, Nominal Prices

	1997	1998	1999	2000	2001*
Adda	144	67	–	–	–
Dagmar	0	0	–	–	–
Dan	1,272	1,076	273	403	366
Gorm	73	167	26	12	239
Halfdan	–	–	204	886	1,517
Harald	486	99	32	175	–
Kraka	99	118	0	0	61
Lulita	81	–	–	–	–
Roar	2	0	80	17	–
Rolf	1	0	1	0	–
Siri	750	1,475	848	43	178
Skjold	1	16	399	404	89
Svend	0	13	189	–	115
South Arne	589	2,123	1,374	760	529
Tyra	236	169	152	330	198
Tyra Southeast	-	-	-	-	357
Valdemar	1	0	0	60	316
Not allocated	49	-19	-48	10	13
Total	**3,784**	**5,306**	**3,531**	**3,100**	**3,978**

**Estimate*

Fig. 8.6 Total Costs of all Licensees, 1963-2001, DKK billion, 2001 Prices



THE FINANCES OF THE LICENSEES

During the period from 1963 to 2001, the licensees' expenses for exploration, field developments and operations (including transportation) in respect of producing fields totalled DKK 24.0 billion, DKK 76.8 billion and DKK 45.5 billion, respectively, in 2001 prices.

A great deal of interest has been shown in the DUC companies' earnings. Consequently, the Danish Energy Authority has asked the Department of Accounting and Auditing at the Copenhagen Business School to analyze and assess the DUC companies' financial results for the Danish part of the North Sea since 1962.

Exploration Costs

The Danish Energy Authority has preliminarily estimated total exploration costs in 2001 at DKK 1.1 billion, the licences from the Fifth Round accounting for about half the total amount. The DUC companies' exploration activity under the Sole Concession and under new licences represents a 27% share of total exploration costs in 2001.

Relative to 2000, total exploration costs rose by about DKK 0.4 billion.

The Danish Energy Authority expects the activity level in 2001, which involved the drilling of six exploration wells and nine appraisal wells, to remain high for the next three years; see the section on *Exploration*. The activity level is then expected to fall.

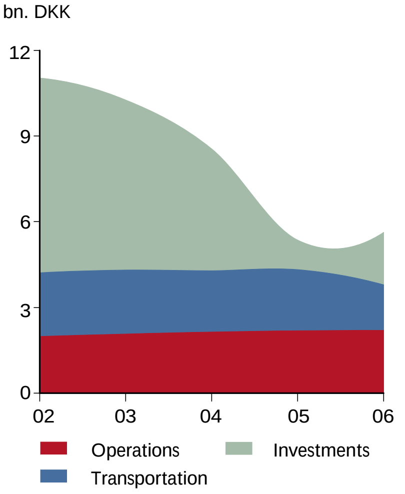
Investments in Field Developments

Total investments in field developments for 2001 have been preliminarily estimated at DKK 4 billion, representing an increase of about DKK 0.9 billion compared to

Table 8.6 Investments in Development Projects, DKK billion, 2001 Prices

	2002	2003	2004	2005	2006
Ongoing and Approved					
Adda	–	–	0.3	–	–
Alma	–	–	0.4	–	0.2
Dan	0.7	0.5	0.1	0.2	0.2
Elly	–	0.2	0.7	–	–
Gorm	0.2	–	–	–	–
Halfdan	2.5	2.1	0.7	–	–
Svend	0.1	–	–	–	–
South Arne	1.2	1.1	–	–	–
Tyra	0.1	0.1	0.7	0.6	0.6
Tyra Southeast	0.7	–	–	–	–
Valdemar	–	–	0.1	–	–
Total	**5.7**	**4.0**	**3.0**	**0.8**	**1.0**
Planned	1.2	1.8	0.9	0.2	0.2
Expected	**6.8**	**5.9**	**3.8**	**1.0**	**1.2**

Fig. 8.7 Investments in Fields, and Operating and Oil Transportation Costs, 2001 Prices



2000. Investments in two of the DUC companies' fields, Tyra Southeast and Halfdan, account for a large share of this increase.

The DUC companies account for more than 80% of total investments in 2001 and for about 81% of total oil production in 2001; see the section on *Development and Production.*

With 14 wells drilled, nine production wells and five injection wells, the Halfdan Field represents by far the largest investment in 2001; see the section on *Development and Production.* Other major investments included the installation of a platform in the Tyra Southeast Field and the further development of the South Arne Field.

As in 2000, the Halfdan and South Arne Fields account for more than half the total investments in field developments in 2001.

The Danish Energy Authority's estimate of investments in field developments for future years has been written up significantly compared to the forecast made at 1 January 2001.

In 2002, field development costs are expected to total about DKK 6.8 billion, representing a DKK 2.6 billion increase over last year's projection. This increase is largely attributable to the development of the Dan, Halfdan and South Arne Fields. The development of these three fields accounts for more than half the total investments projected for 2002. The planned development of the Nini and Cecilie Fields plus the further development of the three above-mentioned fields has spurred the Danish Energy Authority to write up its investment forecast for 2003 by DKK 2.4 billion compared to last year's forecast.

The projection for 2004 has been written up by DKK 3.6 billion, chiefly because a number of development projects have been postponed. For 2005 and 2006, minor changes have been made compared to last year's forecast.

Operating and Transportation Costs

In recent years, annual operating and administration costs have ranged between DKK 1.5 billion and DKK 2.0 billion. Preliminary figures show that total operating and administration costs amounted to about DKK 2.2 billion in 2001, which corresponds to the level in 2000.

Total crude oil transportation costs consist of the operating costs and capital cost associated with the use of the oil pipeline from the Gorm Field to shore, as well as the 5% profit element, which is payable on the basis of the value of the crude oil transported.

Neither the Siri Field nor the South Arne Field makes use of the oil pipeline from the Gorm Field to shore, as the oil produced is conveyed through a buoy loading system and transported to shore by tanker. The two fields are exempt from the obligation to use the oil pipeline, but must instead pay a compensatory fee constituting 5% of the production value of the oil.

Fig. 8.7 illustrates the Danish Energy Authority's expected development in operating, transportation and investment costs for the years to come.

9. STATUTES AND EXECUTIVE ORDERS

In 2001, the Danish Act on Certain Offshore Installations was amended, and two new Executive Orders based on this Act were introduced. The main content of the new provisions introduced is described in more detail below.

A right for employees to leave their workplace in case of serious and imminent danger
Act No. 331 of 16 May 2001 to Amend the Working Environment Act and the Act on Certain Offshore Installations.

The Act on Certain Offshore Installations was amended in 2001, for one thing to improve employees' legal rights in situations where they are placed at a disadvantage, possibly in the form of dismissal, because serious and imminent danger causes them to leave their workplace. This amendment makes it possible to award compensation to employees who are placed at a disadvantage in such situations. Thus, this statutory amendment concerns the legal relationship between employer and employees.

This Amendment Act implements provisions in Directive 89/391/EEC (the Framework Directive). For technical reasons, the Minister for Labour introduced the amendment together with an amendment to the Working Environment Act, such that sections 17a, 17b and 17c of the Working Environment Act apply to installations comprised by the Act on Certain Offshore Installations.

Chemical Agents
Executive Order No. 737 of 14 August 2001 on Substances and Materials at Work on Offshore Installations.

This Executive Order implements Directive 98/24/EC on chemical agents in the offshore area, and includes provisions on

- specific assessment of health and safety at work involving hazardous chemicals;
- substitution, to ensure that hazardous substances and materials are removed or substituted with non-dangerous or less dangerous chemicals;
- a right for employees to undergo health surveillance where an assessment reveals that they have been exposed to dangerous chemicals, and
- rules regulating work with epoxy etc., and code-numbered products.

This Executive Order affords employees working offshore the same level of protection against hazardous substances and materials as employees working onshore, with due regard being paid to the special working conditions prevailing offshore.

The new Executive Order replaces the Executive Order from 1996 on Substances and Materials Used on Offshore Installations and the Executive Order from 2000 on Paintwork etc. on Offshore Installations.

Limit Values for Substances and Materials

Executive Order No. 1029 of 12 December 2001 on Limit Values for Substances and Materials Used on Offshore Installations.

In continuation of the above-mentioned Directive on chemical agents, the Directive on limit values was amended in order to bring the list of limit values into accordance with the new provisions in the Directive on the Protection of the Health and Safety of Workers from the Risks related to Chemical Agents at Work.

The new Executive Order on Limit Values implements Directive 2000/39/EC on Establishing a First List of Indicative Occupational Exposure Limit Values in the offshore area.

The Executive Order replaces the Executive Order from 1994 on Limit Values for Substances and Materials on Offshore Installations.

NEW RULES AND REGULATIONS IN THE FIRST QUARTER OF 2002

A number of new rules and regulations entered into force in the first quarter of 2002. These rules and regulations are described in more detail below.

Amendments to the Act on Certain Offshore Installations, the Subsoil Act and the Pipeline Act

On 5 December 2001, the Minister for Economic and Business Affairs introduced a Bill to amend the Act on Certain Offshore Installations, the Subsoil Act and the Pipeline Act. The Bill was passed on 7 February 2002 and entered into force on 15 March 2002.

This Act regulates the following matters relating to the subsoil:

- *Border-straddling accumulations of hydrocarbons*
  The Act authorizes the Minister to enter into agreements with neighbouring countries about the exploitation of border-straddling accumulations of hydrocarbons.

- *Payment of 5% profit element for the transportation of foreign oil through the oil pipeline from the Gorm Field to Fredericia*
  A right has been introduced to collect the 5% profit element on the value of oil produced abroad that is transported through the oil pipeline from the Gorm Field to Fredericia. In this way, Danish oil and foreign oil are transported under equal terms.

- *Refunding public authorities' expenses for administrative case handling*
  The rules laid down in the Subsoil Act and the Act on Certain Offshore Installations regarding the refunding of public authorities' expenses for administrative case handling have been clarified, and a similar right has been introduced for public authorities to collect fees pursuant to the Pipeline Act. Consequently, a new Executive Order on the refunding of such expenses has been issued, taking effect on 15 March 2002. This Executive Order replaces the existing payment rules contained in the Ministry of Energy's Executive Order No. 79 of 8 February 1990.

Biological Agents

A new Executive Order on Biological Agents entered into force on 2 March 2002. The new Executive Order replaces the Executive Order from 1994 on Biological Agents and the Working Environment on Offshore Installations.

Use of Work Equipment

A new Executive Order on the Use of Work Equipment, replacing the Executive Order from 1992 on the Use of Work Equipment on Offshore Installations, entered into force on 2 March 2002.

Submission of Data about the Danish Subsoil

A new Executive Order on Submission of Samples and Other Information replacing the Executive Order from 1991 took effect on 1 March 2002. The new Executive Order also makes allowance for technological progress, thus providing wide scope for submitting data in digital form.

DRAFTING OF OTHER RULES AND REGULATIONS

In 2001, the Danish Energy Authority also initiated work on drafting the rules and regulations mentioned below.

The Executive Order on Safety Training

A permanent working group under the Coordination Committee, a committee set up pursuant to the Act on Certain Offshore Installations, initiated discussions in 2001 to revise the Executive Order from 2000 on Safety Training, Drills, etc. on Certain Offshore Installations.

The 1981 Executive Order on safety conditions

In 2001, the Danish Energy Authority began revising the 1981 Executive Order on the Rules on Safety Conditions on Offshore Installations, which with Certain Amendments Remain in force after the Coming into force of the Act on Certain Offshore Installations. Moreover, a working group appointed by the Coordination Committee is to take part in this revision.

Agreement between the Danish Energy Authority and offshore companies about rewards for a particularly good working environment

On 28 February 2002, the Minister for Employment introduced a Bill to abolish the working environment tax with effect from end-2002. The tax will be collected through 2001 and 2002. The existing legislation on incentives to improve the working environment operates with a subsidy scheme, so that a share of the proceeds from the working environment tax is used to reward companies with a particularly good working environment.

If this Bill is adopted, a sum of DKK 100,000 will be available for each of the years 2001 and 2002 in which the tax continues to be collected, for distribution among offshore companies that have a particularly good working environment. The Danish Energy Authority intends to enter into agreements with the offshore companies about the guidelines to be used for the Danish Energy Authority's awarding of subsidies.

LICENCES IN DENMARK

At 1 January 2002

Licence	Sole Concession of 8 July 1962
Operator	Mærsk Olie og Gas AS
Licence granted	8 July 1962
Blocks	5504/7, 8, 11, 12, 15, 16; 5505/13, 17, 18 ("Contiguous Area") 5504/5, 6 (Elly) 5603/27, 28 (Freja) 5504/10, 14 (Rolf) 5604/25 (Svend) 5604/21, 22 (Harald)
Area (km²)	1633.0 ("Contiguous Area") 64.0 (Elly) 44.8 (Freja) 8.4 (Rolf) 48.0 (Svend) 55.7 (Harald)
Company	**Share (%)**
Shell Olie- og Gasudvinding Danmark B.V.	46.000
A.P.Møller (Concessionaires)	39.000
Texaco Denmark Inc.	15.000

Licence	7/86 (Amalie Share)
Operator	DONG Efterforskning og Produktion A/S
Co-operator	Amerada Hess Energi ApS
Licence granted	24 June 1986 (2nd Round)
Blocks	5604/22, 26
Area (km²)	106.8
Company	**Share (%)**
Amerada Hess Energi ApS	41.105
DONG Efterforskning og Produktion A/S	28.205
DENERCO OIL A/S	19.929
DENERCO Petroleum A/S	10.761

Licence	7/86 (Lulita Share)
Operator	DONG Efterforskning og Produktion A/S
Co-operator	Statoil Efterforskning og Produktion A/S
Licence granted	24 June 1986 (2nd Round)
Block	5604/22
Area (km²)	2.6
Company	**Share (%)**
Statoil Efterforskning og Produktion A/S	37.642
DONG Efterforskning og Produktion A/S	27.184
DENERCO OIL A/S	24.260
DENERCO Petroleum A/S	10.914

Licence	7/89
Operator	Amerada Hess ApS
Co-operator	DONG Efterforskning og Produktion A/S
Licence granted	20 December 1989 (3rd Round)
Blocks	5504/2; 5604/25, 29, 30
Area (km²)	243.6
Company	**Share (%)**
Amerada Hess ApS	65.690
DONG Efterforskning og Produktion A/S	25.000
DENERCO OIL A/S	7.500
Danoil Exploration A/S	1.810

Licence	7/89 (South Arne Share)
Operator	Amerada Hess ApS
Co-operator	DONG Efterforskning og Produktion A/S
Licence granted	20 December 1989 (3rd Round)
Blocks	5604/29, 30
Area (km²)	93.3
Company	**Share (%)**
Amerada Hess ApS	57.47875
DONG Efterforskning og Produktion A/S	34.37500
DENERCO OIL A/S	6.56250
Danoil Exploration A/S	1.58375

Licence	8/89
Operator	DONG Efterforskning og Produktion A/S
Co-operator	Amerada Hess ApS
Licence granted	20 December 1989 (3rd Round)
Blocks	5603/32; 5604/29
Area (km²)	48.6
Company	**Share (%)**
Amerada Hess ApS	63.263
DONG Efterforskning og Produktion 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
Area (km²)	27.1
Company	**Share (%)**
A.P. Møller	26 2/3
Shell Olie- og Gasudvinding Danmark B.V.	26 2/3
Texaco Denmark Inc.	26 2/3
DONG Efterforskning og Produktion A/S	20.000

Licence	1/90
Operator	DONG Efterforskning og Produktion A/S
Technical assistant	Statoil Efterforskning og Produktion A/S
Licence granted	3 July 1990
Block	5604/18
Area (km²)	1.2
Company	**Share (%)**
Statoil Efterforskning og Produktion A/S	37.642
DONG Efterforskning og Produktion A/S	27.184
DENERCO OIL A/S	24.260
DENERCO Petroleum A/S	10.914

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 Danmark B.V.	36.800
A.P.Møller	31.200
DONG Efterforskning og Produktion A/S	20.000
Texaco Denmark Inc.	12.000

Licence	2/95
Operator	DONG Efterforskning og Produktion A/S
Co-operator	Amerada Hess ApS
Licence granted	15 May 1995 (4th Round)
Blocks	5503/3, 4; 5603/31; 5604/29
Area (km²)	331.1
Company	**Share (%)**
Amerada Hess ApS	63.263
DONG Efterforskning og Produktion A/S	23.624
DENERCO OIL A/S	10.564
Danoil Exploration A/S	2.549

Licence	4/95
Operator	DONG Efterforskning og Produktion A/S
Licence granted	15 May 1995 (4th Round)
Blocks	5604/20; 5605/7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17;
Area (km²)	1087.5
Company	**Share (%)**
DONG Efterforskning og Produktion A/S	40.000
RWE-DEA AG	30.000
DENERCO OIL A/S	30.000

Licence	6/95
Operator	Statoil Efterforskning og Produktion A/S
Co-operator	DONG Efterforskning og Produktion A/S
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	40.0000
Paladin Oil Denmark Limited	25.2630
DONG Efterforskning og Produktion A/S	23.6185
DENERCO OIL A/S	11.1185

Licence	7/95
Operator	Mærsk Olie og Gas AS
Licence granted	15 May 1995 (4th Round)
Blocks	5505/22
Area (km²)	195.9
Company	**Share (%)**
A.P.Møller	26 2/3
Shell Olie- og Gasudvinding Danmark B.V.	26 2/3
Texaco Denmark Inc.	26 2/3
DONG Efterforskning og Produktion 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 B.V.	36.800
A.P.Møller	31.200
DONG Efterforskning og Produktion A/S	20.000
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 B.V.	36.800
A.P.Møller	31.200
DONG Efterforskning og Produktion A/S	20.000
Texaco Denmark Inc.	12.000

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 B.V.	40.000
DONG Efterforskning og Produktion A/S	20.000

Licence	1/98
Operator	CLAM Petroleum Danske B.V.
Licence granted	15 June 1998 (5th Round)
Blocks	5505/1, 5, 6
Area (km²)	285.5
Company	**Share (%)**
CLAM Petroleum Danske B.V.	80
DONG Efterforskning og Produktion A/S	20

Licence	2/98
Operator	CLAM Petroleum Danske B.V.
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
DONG Efterforskning og Produktion A/S	20

Licence	3/98
Operator	Marathon Petroleum Denmark, Ltd.
Licence granted	15 June 1998 (5th Round)
Blocks	5605/28; 5605/32
Area (km²)	216.4
Company	**Share (%)**
Marathon Petroleum Denmark, Ltd	80
DONG Efterforskning og Produktion A/S	20

Licence	4/98
Operator	Phillips Petroleum Int. Corp. Denmark
Licence granted	15 June 1998 (5th Round)
Blocks	5604/26, 27, 30, 31; 5504/2, 3
Area (km²)	604.4
Company	**Share (%)**
Phillips Petroleum Int. Corp. Denmark	30
Saga Petroleum Danmark AS	25
Veba Oil Denmark GmbH	25
DONG Efterforskning og Produktion A/S	20

Licence	5/98
Operator	Phillips Petroleum Int. Corp. Denmark
Licence granted	15 June 1998 (5th Round)
Blocks	5603/24, 28; 5604/21, 25
Area (km²)	232.6
Company	**Share (%)**
Phillips Petroleum Int. Corp. Denmark	30
Saga Petroleum Danmark AS	25
Veba Oil Denmark GmbH	25
DONG Efterforskning og Produktion A/S	20

Licence	6/98
Operator	Phillips Petroleum Int. Corp. Denmark
Licence granted	15 June 1998 (5th Round)
Blocks	5504/1, 2; 5604/29
Area (km²)	213.8
Company	**Share (%)**
Phillips Petroleum Int. Corp. Denmark	30
Saga Petroleum Danmark AS	25
Veba Oil Denmark GmbH	25
DONG Efterforskning og Produktion A/S	20

Licence	8/98
Operator	Kerr-McGee International ApS
Licence granted	15 June 1998 (5th Round)
Blocks	5605/18, 19
Area (km²)	359.1
Company	**Share (%)**
Kerr-McGee International ApS	40
ARCO Denmark Limited	40
DONG Efterforskning og Produktion A/S	20

Licence	9/98
Operator	Norsk Agip A/S
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
DONG Efterforskning og Produktion A/S	20

Licence	10/98
Operator	Norsk Agip A/S
Licence granted	15 June 1998 (5th Round)
Blocks	5503/3, 7
Area (km²)	169.5
Company	**Share (%)**
Agip Denmark B.V.	80
DONG Efterforskning og Produktion A/S	20

Licence	11/98
Operator	DONG Efterforskning og Produktion A/S
Licence granted	15 June 1998 (5th Round)
Blocks	5503/8; 5504/1, 2, 5, 6
Area (km²)	352.8
Company	**Share (%)**
Amerada Hess ApS	42
Veba Oil Denmark GmbH	20
DONG Efterforskning og Produktion A/S	25
DENERCO OIL A/S	13

Licence	12/98
Operator	Amerada Hess ApS
Licence granted	15 June 1998 (5th Round)
Blocks	5604/27, 28, 31, 32
Area (km²)	276.2
Company	**Share (%)**
Amerada Hess ApS	50
DENERCO OIL A/S	30
DONG Efterforskning og Produktion A/S	20

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)	40
Pogo Denmark ApS	40
DONG Efterforskning og Produktion A/S	20

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 2/3
Shell Olie- og Gasudvinding Danmark B.V.	26 2/3
Texaco Denmark Inc.	26 2/3
DONG Efterforskning og Produktion A/S	20

Licence	15/98
Operator	Mærsk Olie og Gas AS
Licence granted	15 June 1998 (5th Round)
Blocks	5604/25
Area (km²)	70.5
Company	**Share (%)**
Shell Olie- og Gasudvinding Danmark B.V.	36.80
A.P. Møller	31.20
DONG Efterforskning og Produktion A/S	20.00
Texaco Denmark Inc.	12.00

Licence	16/98
Operator	DONG Efterforskning og Produktion A/S
Licence granted	15 June 1998 (5th Round)
Blocks	5604/15, 18, 19, 20
Area (km²)	216.9
Company	**Share (%)**
DENERCO OIL A/S	37.000
DENERCO Petroleum A/S	24.000
DONG Efterforskning og Produktion A/S	22.000
RWE-DEA AG	17.000

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.	36.80
A.P. Møller	31.20
DONG Efterforskning og Produktion A/S	20.00
Texaco Denmark Inc.	12.00

Licence	1/99
Operator	Norsk Agip A/S
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
DONG Efterforskning og Produktion A/S	20

Licence	3/99
Operator	The Anschutz Overseas Corporation
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 Denmark ApS	80
DONG Efterforskning og Produktion A/S	20

Licence	1/01
Operator	UAB Minijos Nafta
Licence granted	5 March 2001 (Open Door)
Blocks	5408/3, 4; 5409/1, 2, 3, 4, 6, 7, 8; 5508/23, 24, 27, 28, 31, 32; 5509/25, 29, 30, 31, 32
Area (km²)	3851.4
Company	**Share (%)**
Dansk Venture Olieefterforskning ApS	40
UAB Minijos Nafta	20
Sterling Resources (UK), Ltd	20
DONG Efterforskning og Produktion A/S	20

Licence	4/99
Operator	Amerada Hess ApS
Licence granted	1 May 1999 (Open Door)
Blocks	5610/19, 20, 23, 24, 28; 5611/21, 22, 25, 26, 30; 5612/29
Area (km²)	2372.1
Company	**Share (%)**
Courage Energy Inc.	32
DONG Efterforskning og Produktion A/S	20
Amerada Hess ApS	16
Odin Energi ApS	15
Emerald Energy Denmark Limited	12
Northern Petroleum (UK)	5

Licence	2/01
Operator	Sterling Resources (UK), Ltd
Licence granted	5 March 2001 (Open Door)
Blocks	5608/8, 12, 16; 5609/5, 9, 13
Area (km²)	1278.6
Company	**Share (%)**
Sterling Resources (UK), Ltd	75
DONG Efterforskning og Produktion A/S	20
Dansk Efterforskningsselskab ApS	5

Licence	5/99
Operator	Mærsk Olie og Gas AS
Licence granted	27 November 1999 (neighbouring block)
Blocks	5504/20, 24; 5505/21
Area (km²)	170.0
Company	**Share (%)**
Shell Olie- og Gasudvinding Danmark B.V	36.8
A.P. Møller (licensee)	31.2
DONG Efterforskning og Produktion A/S (licensee)	20.0
Texaco Denmark Inc.	12.0

The licence shares indicated are those appearing from the licences issued. Reference is made to the maps of the Danish licence area at the back of the report. The list and the maps will be updated on the Danish Energy Authority's homepage www.ens.dk.

COMPANIES

At 1 January 2002

Alphabetical list of companies involved in field developments, exploration and production.

*   denotes operator.
** denotes co-operator.

A.P. Møller

Operatorships are handled by Mærsk Olie og Gas AS. The shares indicated are based on A.P. Møller's share of DUC (a joint venture between A.P. Møller, Shell and Texaco).

Adda *	39.000%	Sole Conces. of 8 July 1962
Alma *	39.000%	Sole Conces. of 8 July 1962
Boje Area *	39.000%	Sole Conces. of 8 July 1962
Dagmar *	39.000%	Sole Conces. of 8 July 1962
Dan *	39.000%	Sole Conces. of 8 July 1962
Elly *	39.000%	Sole Conces. of 8 July 1962
Freja *	39.000%	Sole Conces. of 8 July 1962
Gorm *	39.000%	Sole Conces. of 8 July 1962
Halfdan *	39.000%	Sole Conces. of 8 July 1962
Harald *	39.000%	Sole Conces. of 8 July 1962
Igor *	39.000%	Sole Conces. of 8 July 1962
Kraka *	39.000%	Sole Conces. of 8 July 1962
Lulita *	19.500%	Sole Conces. of 8 July 1962
Regnar *	39.000%	Sole Conces. of 8 July 1962
Roar *	39.000%	Sole Conces. of 8 July 1962
Rolf *	39.000%	Sole Conces. of 8 July 1962
Sif *	39.000%	Sole Conces. of 8 July 1962
Skjold *	39.000%	Sole Conces. of 8 July 1962
Svend *	39.000%	Sole Conces. of 8 July 1962
Tyra *	39.000%	Sole Conces. of 8 July 1962
Tyra SE *	39.000%	Sole Conces. of 8 July 1962
Valdemar *	39.000%	Sole Conces. of 8 July 1962

The company participates in exploration under the following licences: Sole Concession of 8 July 1962*, 3/90*, 10/89*, 7/95*, 8/95*, 9/95*, 4/97*, 14/98*, 15/98*, 17/98*, 5/99*

Agip Denmark B.V.

Operatorships are handled by Norsk Agip A/S.

The company participates in exploration under the following licences: 9/98*, 10/98*, 1/99*

Amerada Hess ApS

South Arne *	57.479%	7/89

The company participates under exploration under the following licences:
7/89*, 8/89**, 11/98, 12/98*, 2/95**, 4/99*

Amerada Hess Energi ApS

Amalie **	41.105%	7/86 (Amalie Share)

Anschutz Denmark ApS

Operatorship is handled by the Anschutz Overseas Corporation.

The company participates in exploration under the following licence: 3/99*

ARCO Denmark Limited

The company participates in exploration under the following licence: 8/98

CLAM Petroleum Danske B.V.

The company participates in exploration under the following licences: 1/98*, 2/98*

Courage Energy Inc.

The company participates in exploration under the following licence: 4/99

Danoil Exploration A/S

South Arne	1.584%	7/89

The company participates in exploration under the following licences: 2/95, 7/89, 8/89

Dansk Efterforskningsselskab ApS

The company participates in exploration under the following licence: 2/01

Dansk Venture Olieefterforskning ApS

The company participates in exploration under the following licence: 1/01

DENERCO OIL A/S

Amalie	19.929%	7/86 (Amalie Share)
Lulita	12.130%	7/86 (Lulita Share)+1/90
Siri	11.119%	6/95
South Arne	6.563%	7/89

The company participates in exploration under the following licences: 7/89, 8/89, 2/95, 4/95, 6/95, 11/98, 12/98, 16/98

DENERCO Petroleum A/S

Amalie	10.761%	7/86 (Amalie Share)
Lulita	5.457%	7/86 (Lulita Share)+1/90

The company participates in exploration under the following licence:
16/98

DONG Efterforskning og Produktion A/S

Amalie *	28.205%	7/86 (Amalie Share)
Lulita	13.592%	7/86 (Lulita Share)+1/90
Siri **	23.619%	6/95
South Arne **	34.375%	7/89

The company participates in exploration under the following licences:
7/89**, 8/89*, 10/89, 3/90, 2/95*, 4/95*, 6/95**, 7/95, 8/95, 9/95, 4/97, 1/98, 2/98, 3/98, 4/98, 5/98, 6/98, 8/98, 9/98, 10/98, 11/98*, 12/98, 13/98, 14/98, 15/98, 16/98*, 17/98, 1/99, 3/99, 4/99, 5/99, 1/01, 2/01

EDC (Denmark)

Operatorship is handled by EDC (Europe) Ltd.

The company participates under exploration under the following licence:
13/98*

Emerald Energy Denmark Limited

The company participates under exploration under the following licence:
4/99

Kerr-McGee International ApS

The company participates under exploration under the following licence:
8/98*

Marathon Petroleum Denmark, Ltd

The company participates under exploration under the following licence:
3/98*

Northern Petroleum (UK)

The company participates in exploration under the following licence:
4/99

Odin Energi ApS

The company participates under exploration under the following licence:
4/99

Paladin Oil Denmark Limited

Siri	25.263%	6/95

The company participates in exploration under the following licence:
6/95

Phillips Petroleum International Corporation Denmark

The company participates in exploration under the following licences:
4/98*, 5/98*, 6/98*

Pogo Denmark ApS

The company participates in exploration under the following licence:
13/98

RWE-DEA AG

The company participates in exploration under the following licences:
4/95, 16/98

Saga Petroleum Danmark AS

The company participates in exploration under the following licences:
4/98, 5/98, 6/98

Shell Olie- og Gasudvinding Danmark BV

The shares indicated are based on Shell Olie- og Gasudvinding Danmark BV's share of DUC (a joint venture between A.P. Møller, Shell and Texaco).

Adda	46.000%	Sole Conces. of 8 July 1962
Alma	46.000%	Sole Conces. of 8 July 1962
Boje Area	46.000%	Sole Conces. of 8 July 1962
Dagmar	46.000%	Sole Conces. of 8 July 1962
Dan	46.000%	Sole Conces. of 8 July 1962
Elly	46.000%	Sole Conces. of 8 July 1962
Freja	46.000%	Sole Conces. of 8 July 1962
Gorm	46.000%	Sole Conces. of 8 July 1962
Halfdan	46.000%	Sole Conces. of 8 July 1962
Harald	46.000%	Sole Conces. of 8 July 1962
Igor	46.000%	Sole Conces. of 8 July 1962
Kraka	46.000%	Sole Conces. of 8 July 1962
Lulita	23.000%	Sole Conces. of 8 July 1962
Regnar	46.000%	Sole Conces. of 8 July 1962
Roar	46.000%	Sole Conces. of 8 July 1962
Rolf	46.000%	Sole Conces. of 8 July 1962
Sif	46.000%	Sole Conces. of 8 July 1962
Skjold	46.000%	Sole Conces. of 8 July 1962
Svend	46.000%	Sole Conces. of 8 July 1962
Tyra	46.000%	Sole Conces. of 8 July 1962
Tyra SE	46.000%	Sole Conces. of 8 July 1962
Valdemar	46.000%	Sole Conces. of 8 July 1962

The company participates in exploration under the following licences:
Sole Concession of 8 July 1962(1), 10/89, 3/90, 7/95, 8/95, 9/95, 4/97, 14/98, 15/98, 17/98, 5/99(1)

(1) Denotes participation through DUC.

Statoil Efterforskning og Produktion A/S

Lulita	18.821%	7/86 (Lulita Share)+1/90
Siri *	40.000%	6/95

The company participates in exploration under the following licence:
6/95*

Sterling Resources (UK), Ltd.

The company participates in exploration under the following licences:
1/01, 2/01*

Texaco Denmark Inc.

The shares indicated are based on Texaco Denmark Inc.'s share of DUC (a joint venture between A.P. Møller, Shell and Texaco).

Adda	15.000%	Sole Conces. of 8 July 1962
Alma	15.000%	Sole Conces. of 8 July 1962
Boje Area	15.000%	Sole Conces. of 8 July 1962
Dagmar	15.000%	Sole Conces. of 8 July 1962
Dan	15.000%	Sole Conces. of 8 July 1962
Elly	15.000%	Sole Conces. of 8 July 1962
Freja	15.000%	Sole Conces. of 8 July 1962
Gorm	15.000%	Sole Conces. of 8 July 1962
Halfdan	15.000%	Sole Conces. of 8 July 1962
Harald	15.000%	Sole Conces. of 8 July 1962
Igor	15.000%	Sole Conces. of 8 July 1962
Kraka	15.000%	Sole Conces. of 8 July 1962
Lulita	7.500%	Sole Conces. of 8 July 1962
Regnar	15.000%	Sole Conces. of 8 July 1962
Roar	15.000%	Sole Conces. of 8 July 1962
Rolf	15.000%	Sole Conces. of 8 July 1962
Sif	15.000%	Sole Conces. of 8 July 1962
Skjold	15.000%	Sole Conces. of 8 July 1962
Svend	15.000%	Sole Conces. of 8 July 1962
Tyra	15.000%	Sole Conces. of 8 July 1962
Tyra SE	15.000%	Sole Conces. of 8 July 1962
Valdemar	15.000%	Sole Conces. of 8 July 1962

The company participates in exploration under the following licences:
Sole Concession of 8 July 1962(1), 10/89, 3/90, 7/95, 8/95, 9/95, 14/98, 15/98, 17/98, 5/99(1)

(1) Denotes participation through DUC.

UAB Minijos Nafta

The company participates in exploration under the following licence:
1/01*

Veba Oil Denmark GmbH

The company participates in exploration under the following licences:
4/98, 5/98, 6/98, 11/98

EXPLORATORY SURVEYS 2001

Survey Licence	Operator Contractor	Type	Initiated Completed	Area Block no.	Acquired in 2001
GNSC01 Excl.	Wintershall Noordzee B.V. PGS Exploration AS	Offshore 3D seismics	03-05-2001 20-08-2001	CG 5504	400 km^2*)
DN0101 4/95	DONG E&P A/S PGS Geophysical AS	Offshore 3D seismics	21-08-2001 21-11-2001	NDB 5604, 5605	315 km^2
DKAG01 1/99	Norsk Agip A/S TGS-Nopec	Offshore 2D seismics	11-10-2001 13-10-2001	RFH, HG 5506	187 km*)
DSO, 5/99	Mærsk Olie og Gas AS Svitzer Ltd.	Offshore Geochemical	14-10-2001 05-11-2001	CG 5504, 5505	88 samples
5/97	Sterling Resources Ltd. Wexco/GRDC	Onshore Geochemical	23-01-2001 25-01-2001	NDB 5512	49 samples

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

**) Only the Danish share of the survey has been included.*

AMOUNTS PRODUCED AND INJECTED

OIL thousand cubic metres

Production and sales

	1972-91	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Total
Dan	12,405	2,699	3,262	3,496	3,713	3,799	3,858	4,767	5,745	6,599	6,870	57,214
Gorm	16,297	1,661	1,889	2,421	2,494	2,879	3,045	2,865	3,384	3,110	2,184	42,229
Skjold	13,159	2,281	2,103	1,715	1,979	2,023	2,011	1,896	1,825	1,975	1,356	32,323
Tyra	6,300	1,669	1,639	1,748	1,631	1,447	1,263	931	892	1,000	872	19,392
Rolf	2,457	304	176	92	216	218	96	92	77	83	51	3,861
Kraka	144	205	390	490	469	340	315	314	404	350	253	3,675
Dagmar	475	305	67	33	35	23	17	13	10	8	4	990
Regnar	-	-	145	429	86	41	27	43	29	14	33	847
Valdemar	-	-	53	304	165	161	159	95	86	77	181	1,282
Roar	-	-	-	-	-	319	427	327	259	285	317	1,935
Svend	-	-	-	-	-	836	1,356	635	521	576	397	4,320
Harald	-	-	-	-	-	-	794	1,690	1,332	1,081	866	5,763
Lulita	-	-	-	-	-	-	-	143	224	179	66	612
Halfdan	-	-	-	-	-	-	-	-	222	1,120	2,966	4,308
Siri	-	-	-	-	-	-	-	-	1,593	2,118	1,761	5,472
South Arne	-	-	-	-	-	-	-	-	757	2,558	2,031	5,345
Total	**51,236**	**9,125**	**9,724**	**10,727**	**10,788**	**12,087**	**13,367**	**13,810**	**17,362**	**21,134**	**20,207**	**189,567**

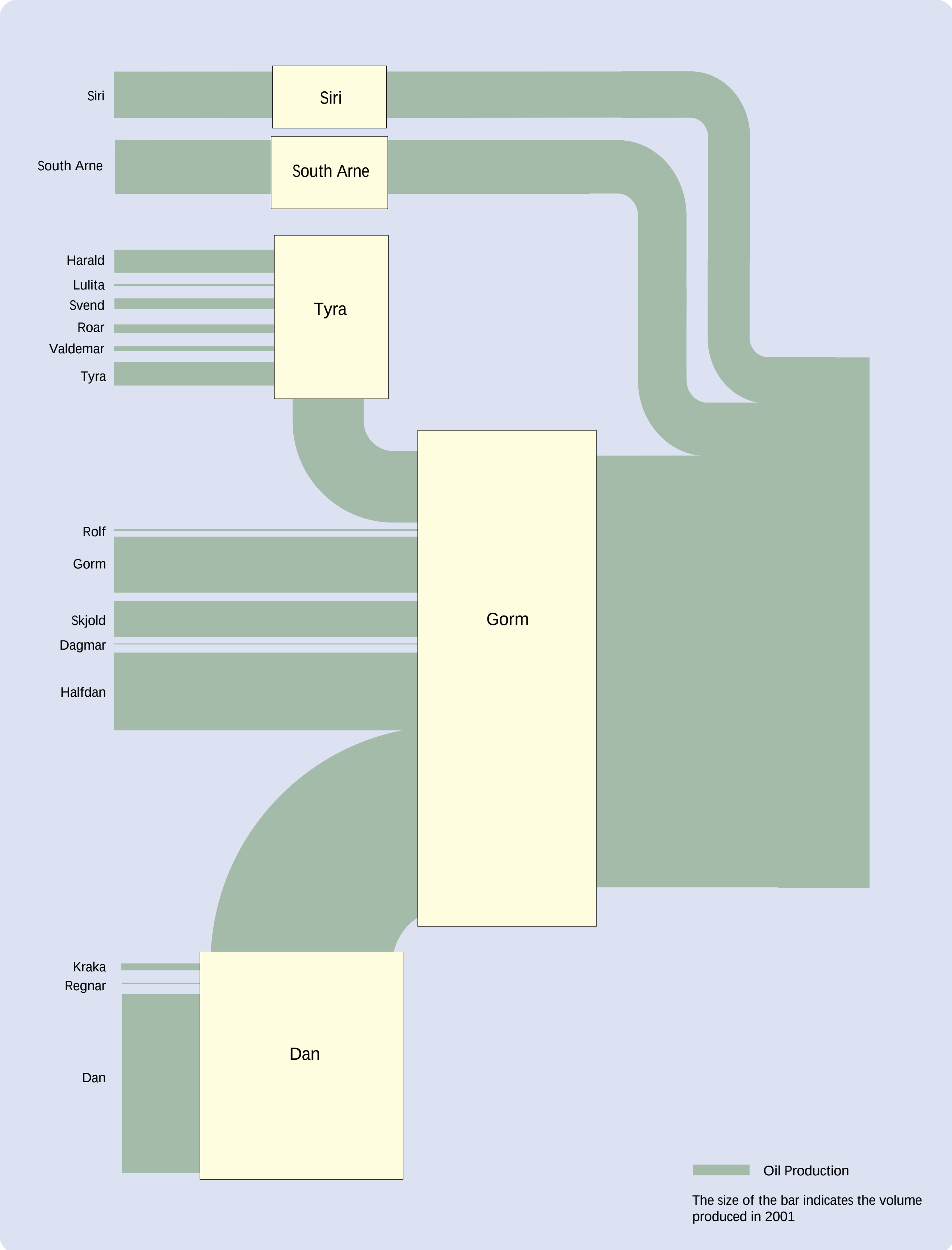
GAS million normal cubic metres

Production

	1972-91	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Total
Dan	5,027	1,056	1,336	1,263	1,331	1,249	1,116	1,343	1,410	1,186	1,048	17,365
Gorm	7,103	844	775	922	761	674	609	633	537	426	306	13,590
Skjold	1,121	212	195	185	188	160	189	146	154	158	104	2,810
Tyra	19,510	3,944	3,853	3,646	3,839	3,843	4,229	3,638	3,878	3,826	3,749	57,957
Rolf	104	12	8	4	9	9	4	4	3	4	2	163
Kraka	56	88	125	119	128	95	85	106	148	119	100	1,169
Dagmar	65	46	13	8	5	4	3	2	2	2	1	151
Regnar	-	-	8	25	7	4	2	4	2	1	3	56
Valdemar	-	-	29	96	52	57	89	54	49	55	78	559
Roar	-	-	-	-	0	1,327	1,964	1,458	1,249	1,407	1,702	9,106
Svend	-	-	-	-	0	85	152	84	65	75	48	508
Harald	-	-	-	-	-	0	1,092	2,741	2,876	2,811	2,475	11,995
Lulita	-	-	-	-	-	-	-	69	181	160	27	438
Halfdan	-	-	-	-	-	-	-	-	37	178	523	738
Siri	-	-	-	-	-	-	-	-	142	197	176	515
South Arne	-	-	-	-	-	-	-	-	167	713	774	1,654
Total	**32,986**	**6,203**	**6,342**	**6,269**	**6,321**	**7,506**	**9,534**	**10,281**	**10,901**	**11,316**	**11,116**	**118,772**

The monthly production figures for 2001 are available on the Danish Energy Authority's homepage www.ens.dk

WHERE DOES THE OIL ORIGINATE



GAS million normal cubic metres

Fuel

	1972-91	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Total
Dan	215	61	66	85	93	97	109	148	172	179	184	1,409
Gorm	627	81	87	104	111	135	164	152	149	142	111	1,863
Tyra	623	109	110	110	111	142	210	224	239	229	243	2,351
Dagmar	7	13	1	0	0	0	0	0	0	0	0	21
Harald	-	-	-	-	-	-	5	14	14	13	10	56
Siri	-	-	-	-	-	-	-	-	8	21	22	52
South Arne	-	-	-	-	-	-	-	-	3	32	34	69
Total	**1,471**	**264**	**264**	**299**	**314**	**375**	**488**	**539**	**585**	**618**	**604**	**5,820**

Flaring

	1972-91	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Total
Dan	1,230	73	53	66	36	40	36	43	56	67	79	1,778
Gorm	622	86	95	75	69	60	81	71	71	66	88	1,382
Tyra	300	39	39	48	42	67	46	42	58	58	68	805
Dagmar	58	33	12	8	5	2	3	2	2	2	1	128
Harald	-	-	-	-	-	-	77	19	12	7	11	126
Siri	-	-	-	-	-	-	-	-	73	9	15	97
South Arne	-	-	-	-	-	-	-	-	114	41	9	164
Total	**2,209**	**230**	**199**	**196**	**152**	**168**	**243**	**177**	**386**	**250**	**270**	**4,480**

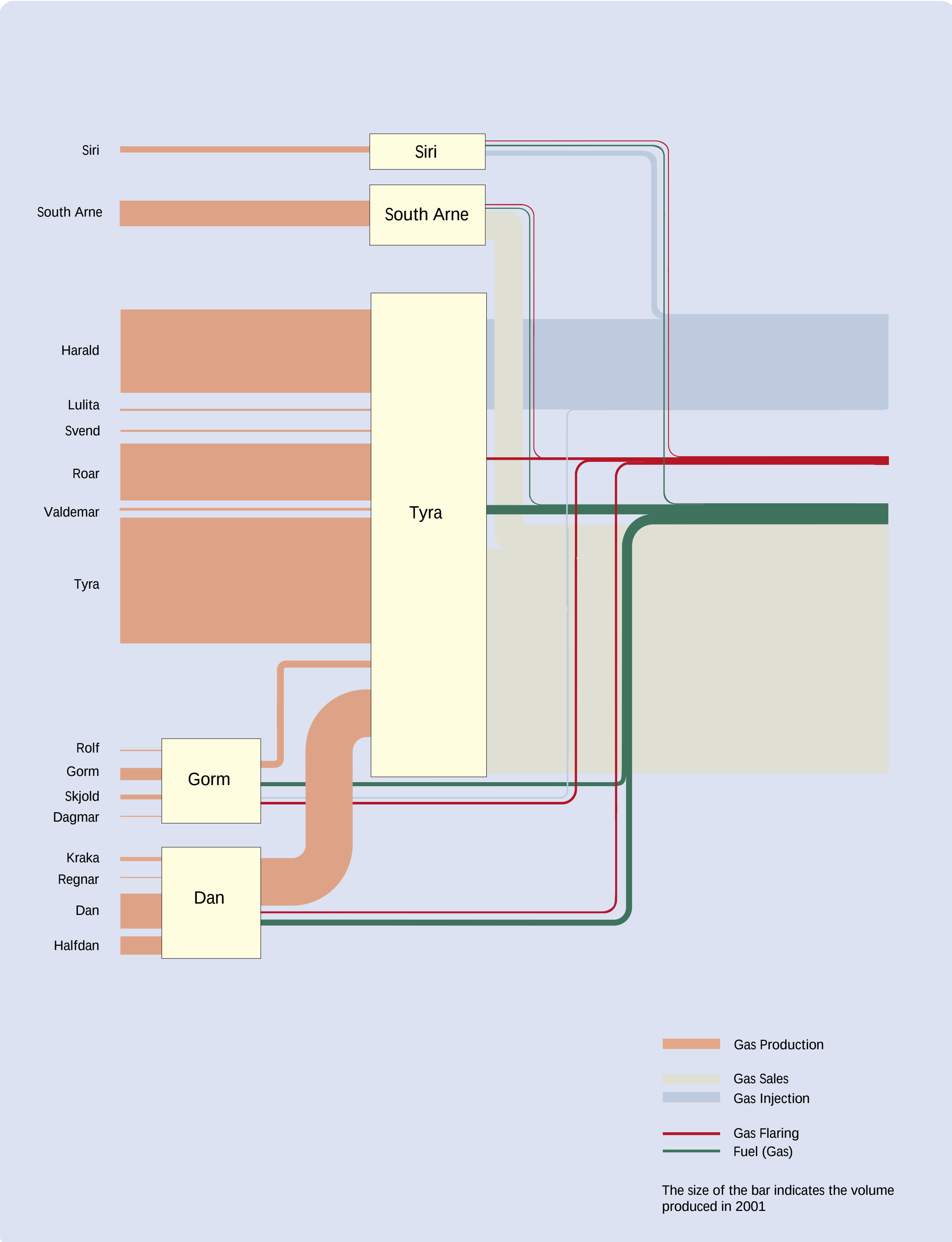
Injection

	1972-91	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Total
Gorm	6,722	711	420	70	28	26	62	24	25	45	4	8,137
Tyra	5,977	1,370	1,451	1,371	1,132	1,225	1,778	2,908	3,074	3,104	2,773	26,163
Siri	-	-	-	-	-	-	-	-	61	167	139	367
Total	**12,699**	**2,081**	**1,871**	**1,441**	**1,160**	**1,251**	**1,840**	**2,933**	**3,160**	**3,316**	**2,916**	**34,666**

Sales

	1972-91	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Total
Dan	3,637	1,010	1,350	1,256	1,338	1,211	1,058	1,261	1,371	1,238	1,412	16,141
Gorm	358	191	376	863	750	622	495	535	448	334	209	5,181
Tyra	12,611	2,426	2,281	2,214	2,607	3,878	4,400	2,060	1,870	1,971	2,493	38,811
Harald	-	-	-	-	-	-	1,010	2,777	3,032	2,950	2,482	12,250
South Arne	-	-	-	-	-	-	-	-	50	640	730	1,421
Total	**16,607**	**3,628**	**4,007**	**4,332**	**4,695**	**5,712**	**6,963**	**6,633**	**6,770**	**7,133**	**7,326**	**73,806**

WHERE DOES THE GAS ORIGINATE



CO_2 EMISSIONS thousand tonnes

	1972-91	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Total
Fuel	3,361	603	603	683	717	857	1,115	1,232	1,337	1,412	1,380	13,299
Flaring	5,048	526	454	448	347	384	555	404	882	571	617	10,237
Total	8,409	1,129	1,057	1,131	1,064	1,241	1,670	1,636	2,219	1,983	1,997	23,536

WATER thousand cubic metres

Production

	1972-91	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Total
Dan	997	513	781	1,117	1,275	1,543	1,845	2,976	4,220	5,277	6,601	27,145
Gorm	4,355	583	557	824	948	1,921	2,906	3,177	3,468	3,980	3,360	26,080
Skjold	30	339	817	889	1,337	2,679	3,635	3,938	3,748	4,333	2,878	24,623
Tyra	1,171	671	1,005	1,290	1,749	2,161	2,215	2,020	2,033	3,046	2,545	19,906
Rolf	854	350	265	161	443	490	390	411	366	358	181	4,268
Kraka	46	130	195	188	251	272	287	347	329	256	353	2,652
Dagmar	21	206	395	367	464	507	408	338	246	241	102	3,295
Regnar	-	-	-	244	396	299	164	407	363	139	475	2,487
Valdemar	-	-	1	24	20	34	61	52	55	48	150	444
Roar	-	-	-	-	-	14	96	146	199	317	386	1,159
Svend	-	-	-	-	-	2	64	272	582	1,355	953	3,230
Harald	-	-	-	-	-	-	-	5	15	39	98	157
Lulita	-	-	-	-	-	-	-	3	5	11	23	43
Halfdan	-	-	-	-	-	-	-	-	56	237	493	786
Siri	-	-	-	-	-	-	-	-	319	1,868	2,753	4,941
South Arne	-	-	-	-	-	-	-	-	15	60	119	194
Total	**7,473**	**2,792**	**4,016**	**5,103**	**6,882**	**9,922**	**12,072**	**14,093**	**16,020**	**21,566**	**21,471**	**121,409**

Injection

	1972-91	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	Total
Dan	439	865	1,534	3,808	5,884	8,245	8,654	11,817	14,964	17,464	18,176	91,849
Gorm	2,268	1,598	2,140	4,612	5,749	8,112	8,642	8,376	8,736	10,009	6,462	66,705
Skjold	12,567	2,791	2,836	3,511	3,985	5,712	6,320	6,291	5,866	6,132	4,750	60,761
Halfdan	-	-	-	-	-	-	-	-	82	13	54	149
Siri	-	-	-	-	-	-	-	-	1,236	3,778	4,549	9,563
South Arne	-	-	-	-	-	-	-	-	-	39	1,986	2,025
Total	**15,275**	**5,253**	**6,510**	**11,931**	**15,618**	**22,069**	**23,616**	**26,484**	**30,884**	**37,436**	**35,977**	**231,053**

Water injection includes the injection of produced water and sea water. Most of the water produced in the Gorm, Skjold, Dagmar and Siri Fields is re-injected.

PRODUCING FIELDS

DAGMAR

Prospect:	East Rosa
Location:	Blok 5504/15
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1983
Year on stream:	1991
Producing wells:	2
Water depth:	34 m
Area:	9 km^2
Reservoir depth:	1,400 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2002:	
Oil:	0.1 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2002:	
Oil:	0.99 million m^3
Gas:	0.15 billion Nm^3
Water:	3.30 million m^3
Production in 2001:	
Oil:	0.004 million m^3
Gas:	0.001 billion Nm^3
Water:	0.10 million m^3
Tot. investments at 1 January 2002:	
2001 prices	DKK 0.4 billion

REVIEW OF GEOLOGY

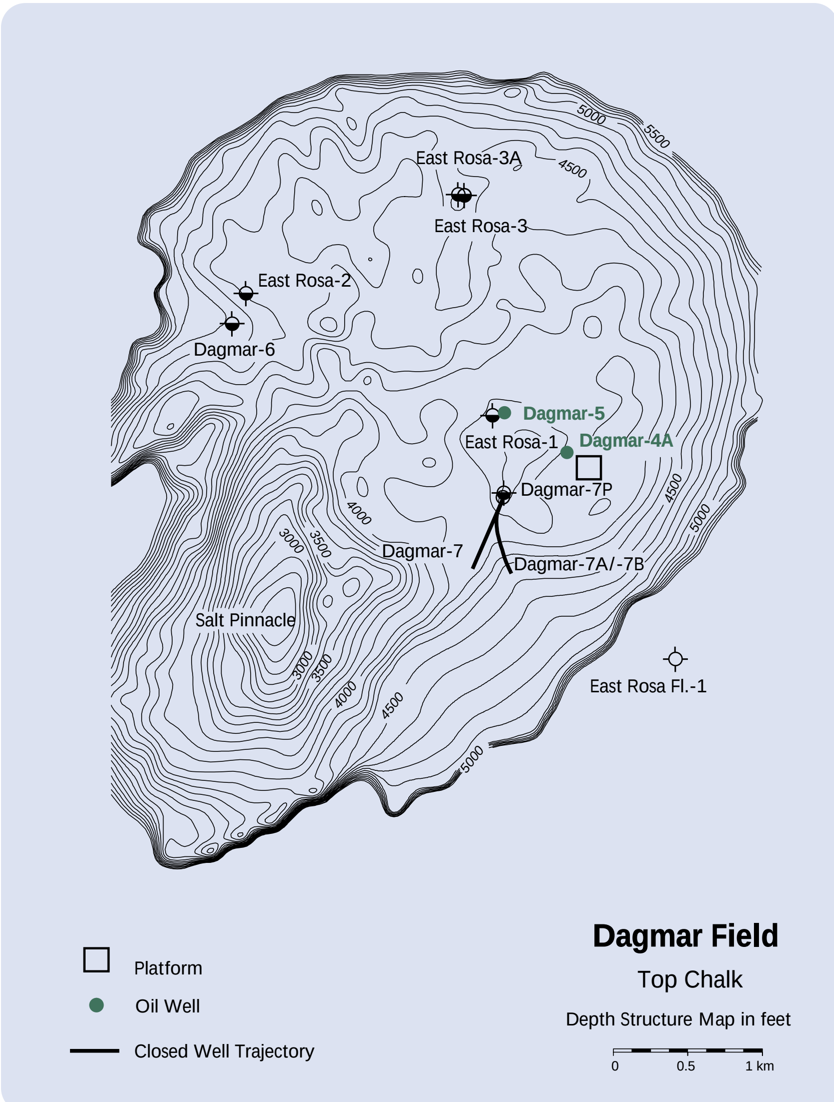
The Dagmar field is an anticlinal structure, induced through Zechstein salt tectonics. The uplift is so pronounced that the Dagmar reservoir is situated closer to the surface than any other hydrocarbon reservoirs in Danish territory. The reservoir is heavily fractured (compare Skjold, Rolf, Regnar and 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, Svend 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.



DAN

Prospect:	Abby
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1971
Year on stream:	1972
Producing wells:	60
Water-injection wells:	41
Water depth:	40 m
Field delineation:	121 km^2
Reservoir depth:	1,850 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2002:	
Oil:	59.6 million m^3
Gas:	7.8 billion Nm^3
Cum. production at 1 January 2002:	
Oil:	57.21 million m^3
Gas:	17.37 billion Nm^3
Water:	27.15 million m^3
Cum. injection at 1 January 2002:	
Water:	91.85 million m^3
Production in 2001:	
Oil:	6.87 million m^3
Gas:	1.05 billion Nm^3
Water:	6.60 million m^3
Injection in 2001:	
Water:	18.18 million m^3
Total investments at 1 January 2002:	
2001 prices	DKK 20.6 billion

REVIEW OF GEOLOGY

Dan is an anticlinal structure partly induced through salt tectonics. 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, and later high-rate water injection was introduced. 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 water.

In addition, production takes place in the western flank of the Dan Field. Initially, production is based on natural depletion, which means that no energy is added to the reservoir by water injection. However, water injection is being established in this part of the field.

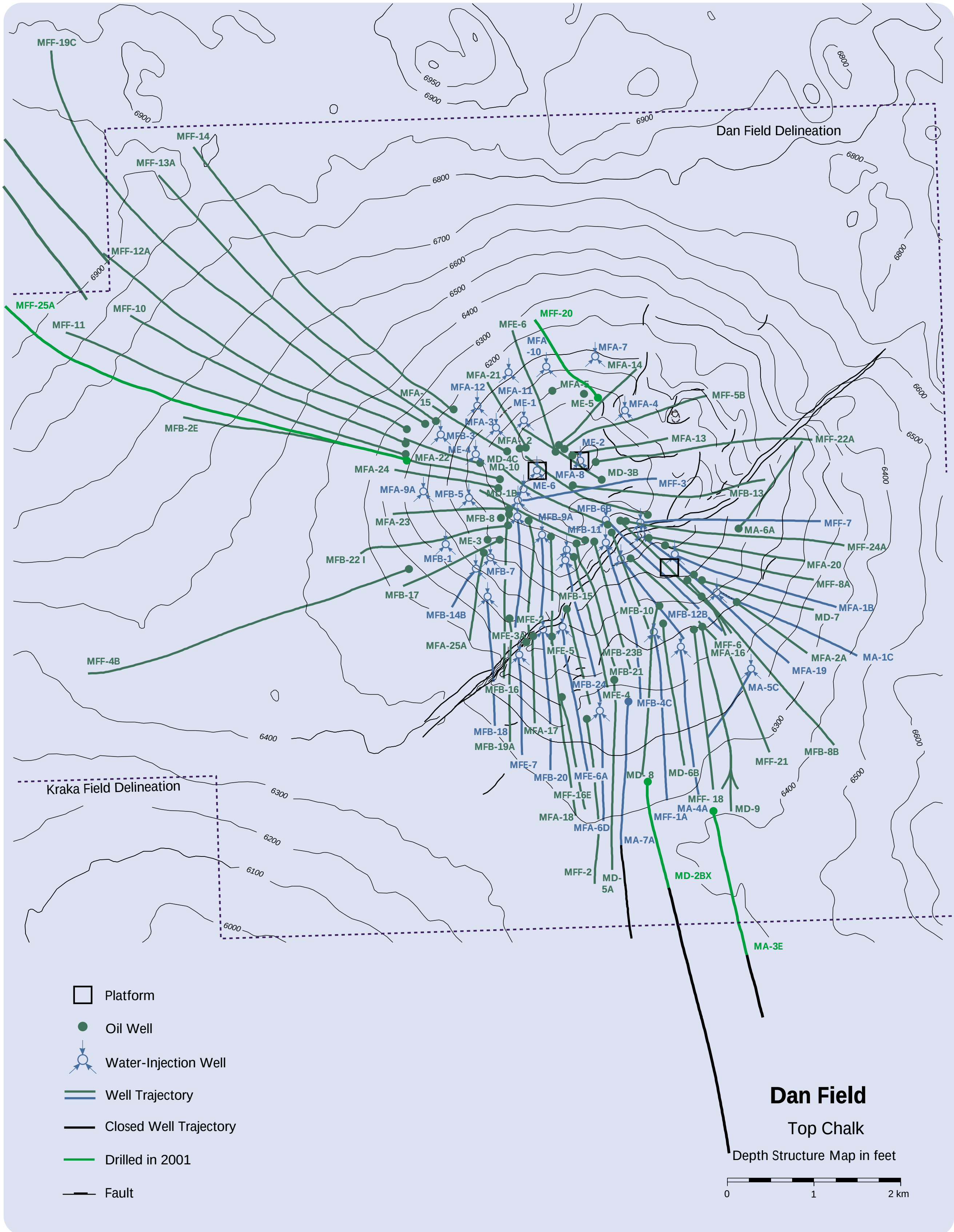
PRODUCTION FACILITIES

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. Moreover, the Dan Field installations handle gas production from the Halfdan Field and also provide the Halfdan Field with injection water.

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.


Dan Field
Top Chalk
Depth Structure Map in feet
0
1
2 km
Platform
Oil Well
Water-Injection Well
Well Trajectory
Closed Well Trajectory
Drilled in 2001
Fault
Dan Field Delineation
Kraka Field Delineation
6950
6900
6800
6700
6600
6500
6400
6300
6200
6100
6000
MFF-19C
MFF-14
MFF-13A
MFF-12A
MFF-25A
MFF-10
MFF-11
MFB-2E
MFF-4B
MFE-6
MFF-20
MFA-10
MFA-7
MFA-14
MFA-21
MFA-12
MFA-11
MFA-5
MFA-15
ME-1
ME-5
MFA-4
MFF-5B
MFA-3
MFB-3
MFA-2
ME-2
MFA-13
MFF-22A
ME-4
MFA-22
MD-4C
MD-10
MFA-8
MD-3B
MFA-24
ME-6
MFF-3
MFB-13
MFA-9A
MFB-5
MD-1B
MFB-6B
MFF-7
MFA-23
MFB-8
MFB-9A
MFB-11
MA-6A
MFF-24A
ME-3
MFB-22 I
MFB-1
MFA-20
MFB-7
MFF-8A
MFB-17
MFB-15
MFA-1B
MFB-14B
MFB-10
MFB-12B
MD-7
MFE-2
MFA-25A
MFE-3A
MFF-6
MFA-16
MFE-5
MFB-23B
MFA-2A
MA-1C
MFA-19
MFB-21
MFB-24
MA-5C
MFE-4
MFB-16
MFB-4C
MFB-18
MFA-17
MFB-19A
MFB-8B
MFE-7
MFF-21
MFB-20
MFE-6A
MD-8
MD-6B
MFF-16E
MFF-18
MA-4A
MD-9
MFA-18
MFF-1A
MFA-6D
MA-7A
MFF-2
MD-5A
MD-2BX
MA-3E

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:	33
Gas-injection wells:	2
Water-injection wells:	14
Water depth:	39 m
Field delineation:	33 km²
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2002:	
Oil:	13.6 million m³
Gas:	1.5 billion Nm³
Cum. production at 1 January 2002:	
Oil:	42.23 million m³
Net gas:	5.45 billion Nm³
Water:	26.08 million m³
Cum. injection at 1 January 2002:	
Gas:	8.14 billion Nm³
Water:	66.71 million m³
Production in 2001:	
Oil:	2.18 million m³
Net gas:	0.30 billion Nm³
Water:	3.36 million m³
Injection in 2001:	
Gas:	0.00 billion Nm³
Water:	6.46 million m³
Total investments at 1 January 2002:	
2001 prices	DKK 10.6 billion

REVIEW OF GEOLOGY

Gorm is an anticlinal structure partly due to 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. Water is injected into the water and oil zones of the field.

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 DONG Olierør A/S, and one combined wellhead/processing/booster platform (Gorm F).

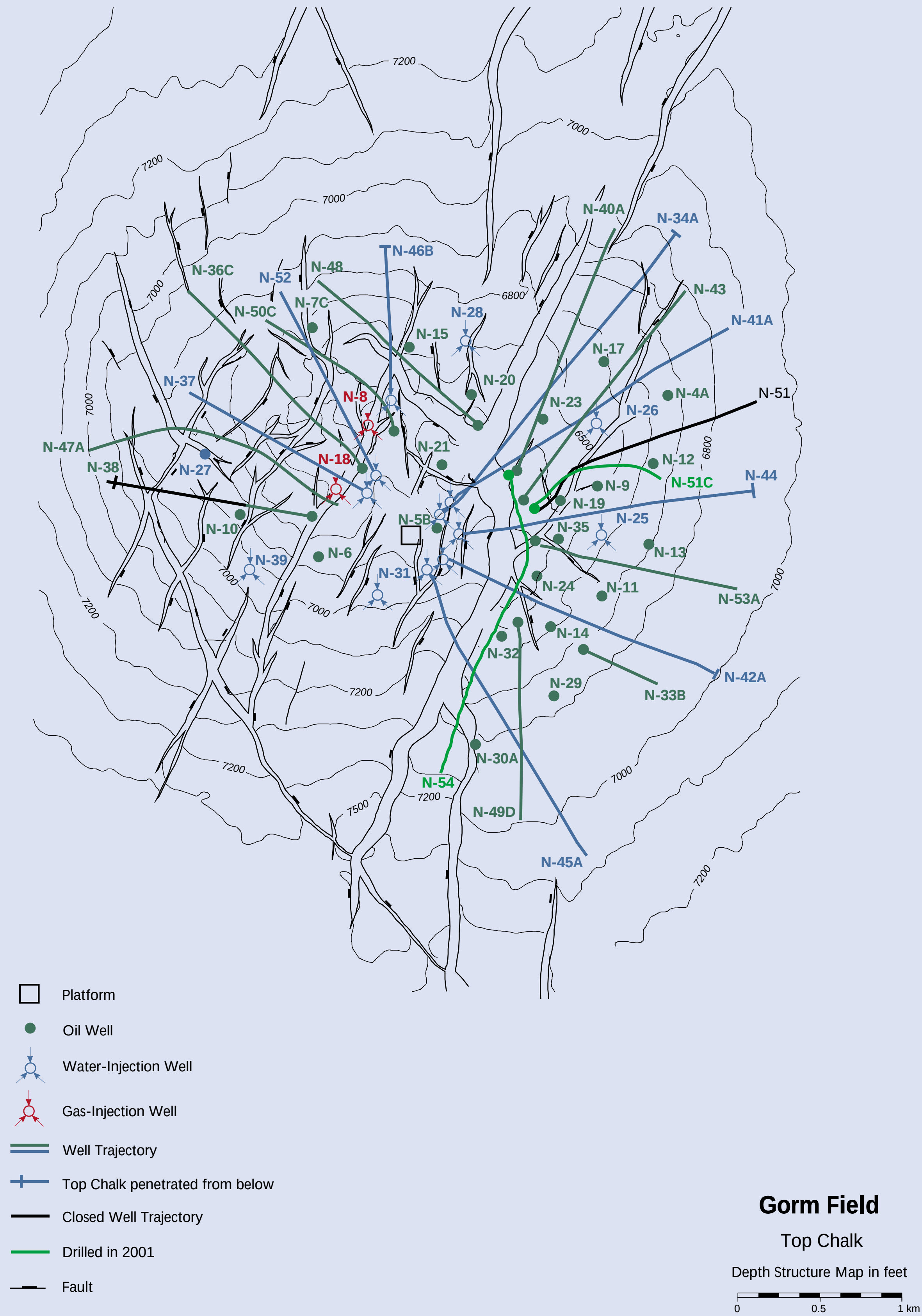
Gorm receives production from the satellite fields, Skjold, Rolf and Dagmar, as well as the liquids (hydrocarbons and water) produced in the Halfdan Field. The Gorm Field installations supply the Skjold Field with injection water and lift gas and the Rolf Field with lift gas. The gas produced is sent to Tyra East. The stabilized oil from all DUC's processing facilities 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 and Halfdan Fields is processed, plant for purifying the water produced and 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.

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



Gorm Field

Top Chalk

Depth Structure Map in feet

HALFDAN

Prospect:	Nana
Location:	Blocks 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1999
Year on stream:	2000
Producing wells:	13
Water-injection wells:	6
Water depth:	43 m
Field delineation:	107 km^2
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2002:	
Oil:	74.2 million m^3
Gas:	8.5 billion Nm^3
Cum. production at 1 January 2002:	
Oil:	4.31 million m^3
Gas:	0.74 billion Nm^3
Water:	0.79 million m^3
Cum. injection at 1 January 2002:	
Water:	0.15 million m^3
Production in 2001:	
Oil:	2.97 million m^3
Gas:	0.52 billion Nm^3
Water:	0.49 million m^3
Injection in 2001:	
Water:	0.05 million m^3
Total investments at 1 January 2002:	
2001 prices	DKK 2.6 billion

REVIEW OF GEOLOGY

The Halfdan accumulation is found in a pocket in chalk layers and constituted a structural trap in earlier geological times. Due to later movements in the reservoir layers, the structure gradually disintegrated, and the oil began migrating towards the southeast, in the direction of the Dan Field. This means that today the structure does not appear from maps of the chalk surface, and that the oil continues to migrate. However, there is still an accumulation of oil and gas due to the low permeability of the reservoir. This type of trap has not previously been encountered in Danish territory.

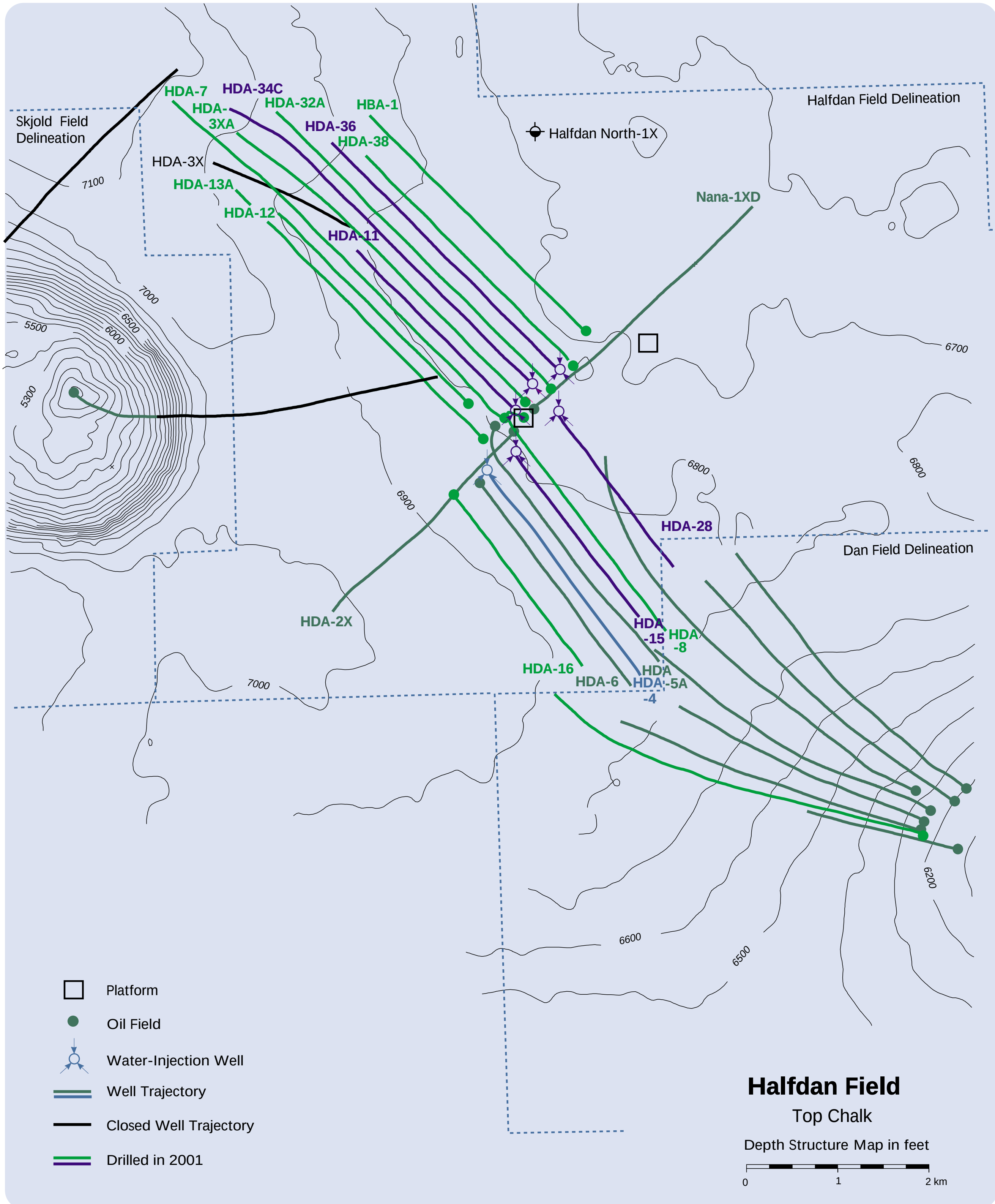
This porous, unfractured chalk is similar to that found in the western part of the Dan Field. There is a gas cap above the northeastern part of the oil accumulation.

PRODUCTION STRATEGY

In the initial development phase, the recovery of oil and gas from the field is based on natural depletion, meaning no secondary recovery techniques are used, either in the form of gas or water injection. The pressure in the reservoir is boosted in step with the completion of water-injection wells.

PRODUCTION FACILITIES

The installations in the field consist of a production platform with minimal production facilities. In addition, a template, later to be supplemented with a wellhead platform, has been installed on the seabed. The operation of the production platform is supported by a drilling rig. Production is separated into a gas and a liquid phase (oil and water). The liquid production is conveyed by pipeline to the Gorm Field, and the gas produced is transported through a pipeline to the Dan Field. The Gorm and Dan Field installations process the production from the Halfdan Field. In addition, Dan supplies the Halfdan Field with injection water.



* *Not all wells in the Dan and Skjold Fields are shown.*

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:	2 (Lulu), 2 (West Lulu)
Water depth:	64 m
Field delineation:	56 km^2
Reservoir depth:	2,700 m and 3,650 m, respectively
Reservoir rock:	Chalk (Lulu) Sandstone (West Lulu)
Geological age:	Danian/ Upper Cretaceous (Lulu) Middle Jurassic (West Lulu)
Reserves at 1 January 2002:	
Oil and condensate:	3.1 million m^3
Gas:	11.7 billion Nm^3
Cum. production at 1 January 2002:	
Oil and condensate:	5.76 million m^3
Gas:	12.00 billion Nm^3
Water:	0.16 million m^3
Production in 2001:	
Oil and condensate:	0.87 million m^3
Gas:	2.48 billion Nm^3
Water:	0.10 million m^3
Tot. investments at 1 January 2002:	
2001 prices	DKK 3.2 billion

REVIEW OF GEOLOGY

The Harald Field consists of two accumulations, Lulu and West Lulu, which contain gas mainly.

The Lulu structure is an anticline induced through salt tectonics. The gas zone is up to 75 metres thick and extends over an area of 6.5 km^2.

The West Lulu structure is a tilted Jurassic fault block. The sandstone reservoir is of Middle Jurassic age, and 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 from the Harald Field is based on the aim of optimizing the production of liquid hydrocarbons in the Tyra Field. This presupposes that the Tyra 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 Harald Field helps optimize the Tyra production conditions.

PRODUCTION FACILITIES

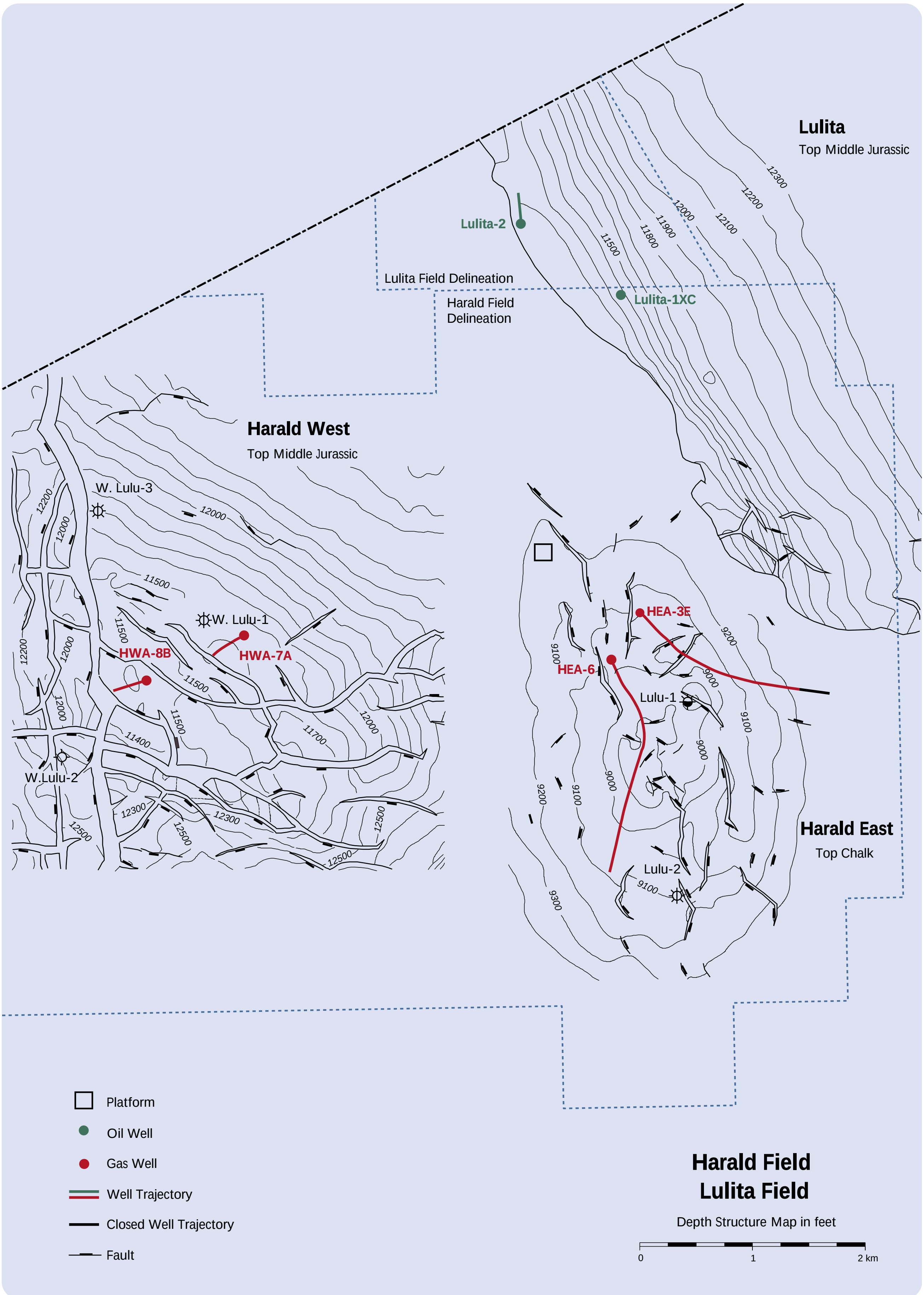
The Harald Field installations comprise a combined wellhead and processing platform (Harald A) and an accommodation platform (Harald B).

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.

The Harald Field is hooked up to the gas pipeline that conveys gas from the South Arne Field to Nybro. Normally, no gas is exported from Harald through the pipeline.

The Harald Field has accommodation facilities for 16 persons.


Lulita
Top Middle Jurassic
Lulita-2
Lulita-1XC
Lulita Field Delineation
Harald Field
Delineation
Harald West
Top Middle Jurassic
W. Lulu-3
W. Lulu-1
HWA-8B
HWA-7A
W.Lulu-2
HEA-3E
HEA-6
Lulu-1
Lulu-2
Harald East
Top Chalk
Platform
Oil Well
Gas Well
Well Trajectory
Closed Well Trajectory
Fault
Harald Field
Lulita Field
Depth Structure Map in feet
0
1
2 km

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
Water depth:	45 m
Field delineation:	81 km^2
Reservoir depth:	1,800 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2002:	
Oil:	1.8 million m^3
Gas:	1.2 billion Nm^3
Cum. production at 1 January 2002:	
Oil:	3.68 million m^3
Gas:	1.17 billion Nm^3
Water:	2.65 million m^3
Production in 2001:	
Oil:	0.25 million m^3
Gas:	0.10 billion Nm^3
Water:	0.35 million m^3
Tot. investments at 1 January 2002:	
2001 prices	DKK 1.4 billion

REVIEW OF GEOLOGY

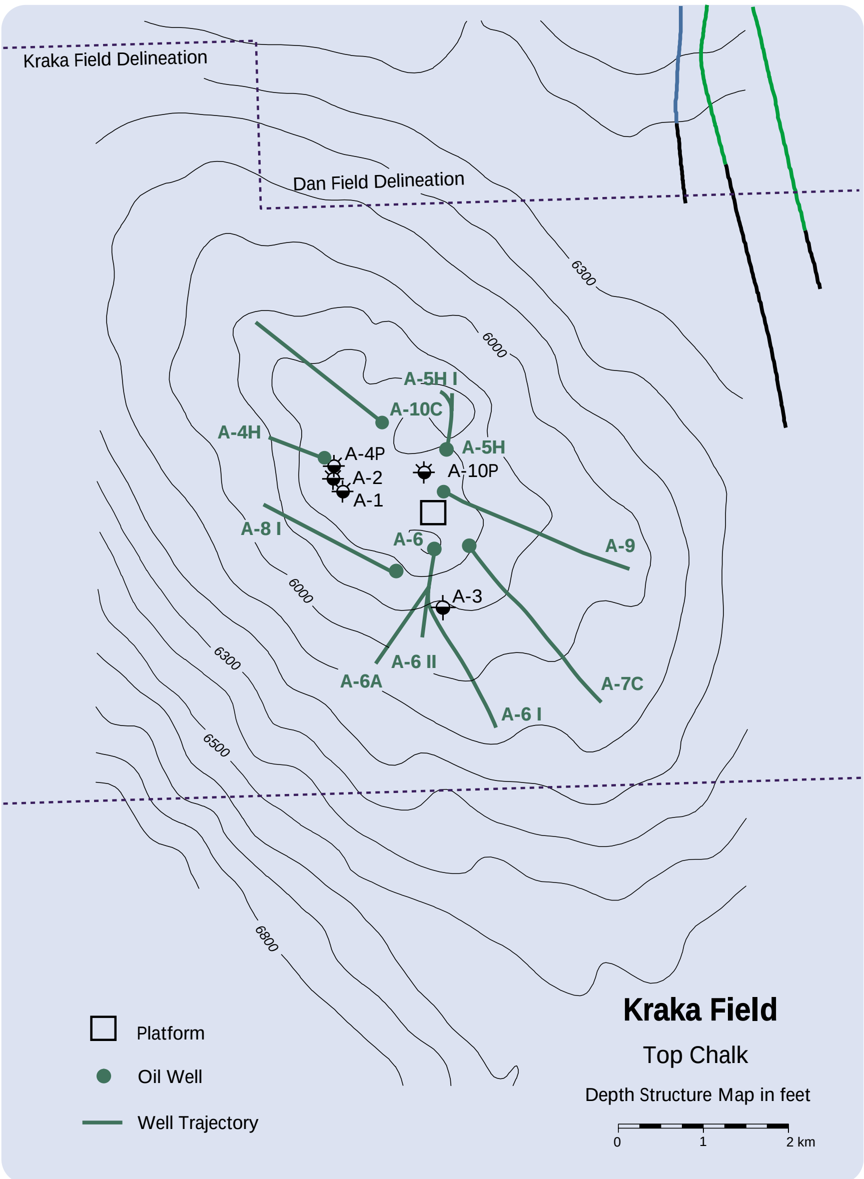
Kraka is an anticlinal structure induced through salt tectonics, which to a certain degree has caused fracturing in the chalk. The chalk reservoir has high porosity, although low permeability. The thin oil pay zone is further characterized by high water saturations. There is a minor gas cap in the reservoir.

PRODUCTION STRATEGY

The production of oil and gas from the field is based on natural depletion, 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 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. The produced oil and gas are transported to the Dan FC platform for processing and export ashore. Lift gas is imported from the Dan FF platform.



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
Area:	3 km^2
Reservoir depth:	3,525 m
Reservoir rock:	Sandstone
Geological age:	Middle Jurassic
Reserves at 1 January 2002:	
Oil:	0.2 million m^3
Gas:	0.1 billion Nm^3
Cum. production at 1 January 2002:	
Oil:	0.61 million m^3
Gas:	0.44 billion Nm^3
Water:	0.04 million m^3
Production in 2001:	
Oil:	0.07 million m^3
Gas:	0.03 billion Nm^3
Water:	0.02 million m^3
Tot. investments at 1 January 2002:	
2001 prices	DKK 0.1 billion

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 production of oil and gas is based on natural depletion.

PRODUCTION FACILITIES

Production from the Lulita Field takes place from the fixed installations in the Harald Field. Thus, the Lulita wellheads are hosted by the Harald A platform, and the Harald platform facilities also 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 from the Lulita Field.

The map of the Harald Field includes the Lulita Field.

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
Field delineation:	20 km^2
Reservoir depth:	1,700 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Upper Cretaceous and Zechstein

Reserves at 1 January 2002:

Oil:	0.1 million m^3
Gas:	0.0 billion Nm^3

Cum. production at 1 January 2002:

Oil:	0.85 million m^3
Gas:	0.06 billion Nm^3
Water:	2.49 million m^3

Production in 2001:

Oil:	0.03 million m^3
Gas:	0.00 billion Nm^3
Water:	0.48 million m^3

Tot. investments at 1 January 2002:

2001 prices	DKK 0.2 billion

REVIEW OF GEOLOGY

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

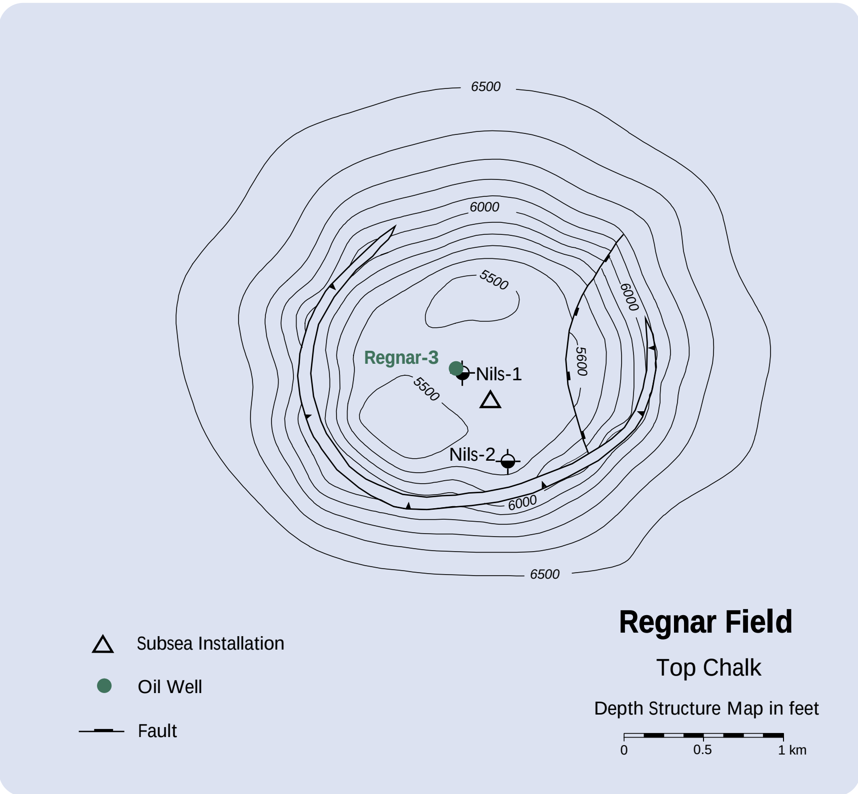
PRODUCTION STRATEGY

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.



ROAR

Prospect:	Bent
Location:	Block 5504/7
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1968
Year on stream:	1996
Producing wells:	4
Water depth:	46 m
Field delineation:	41 km²
Reservoir depth:	2,025 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2002:	
Oil and condensate:	1.1 million m³
Gas:	7.8 billion Nm³
Cum. production at 1 January 2002:	
Oil and condensate:	1.94 million m³
Gas:	9.11 billion Nm³
Water:	1.16 million m³
Production in 2001:	
Oil and condensate:	0.32 million m³
Gas:	1.70 billion Nm³
Water:	0.39 million m³
Tot. investments at 1 January 2002:	
2001 prices	DKK 0.6 billion

REVIEW OF GEOLOGY

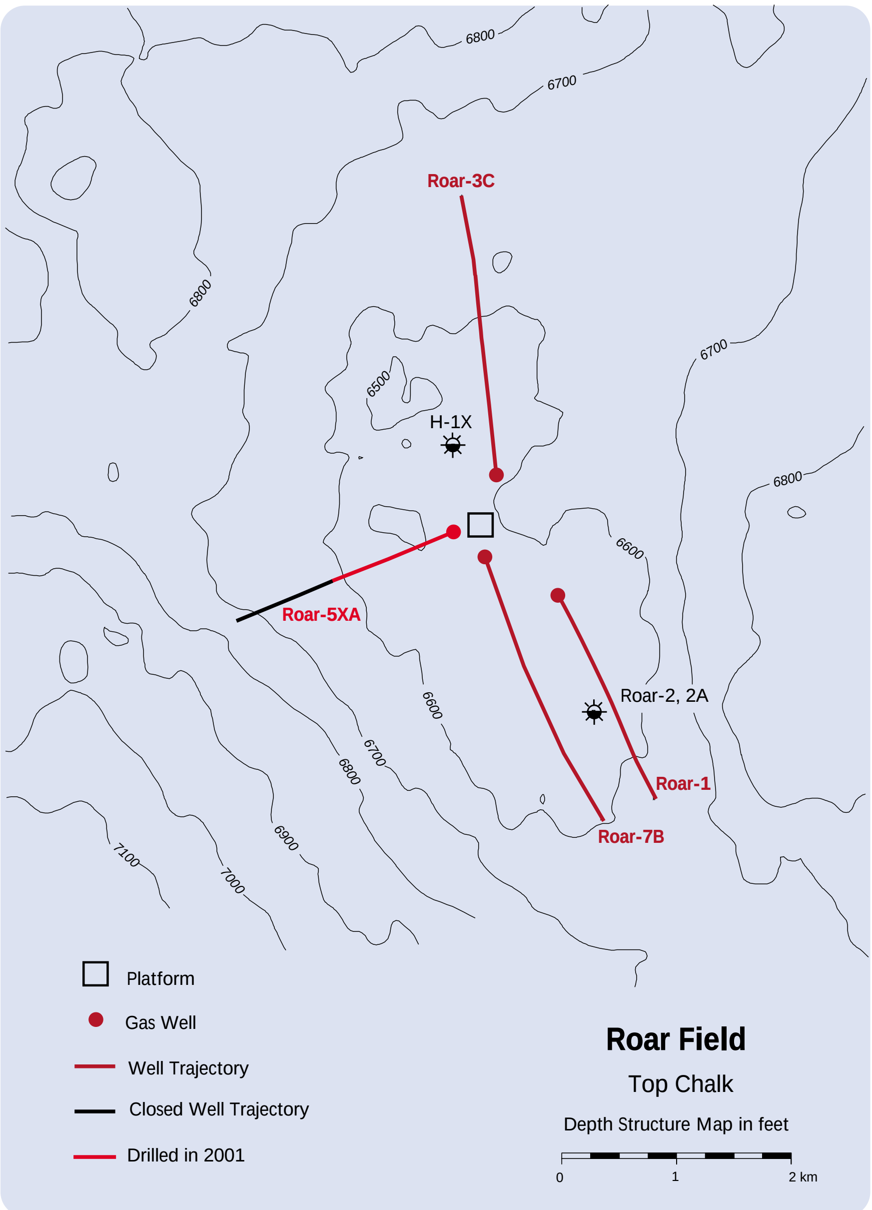
Roar is an anticlinal structure, induced through tectonic uplift. The accumulation consists of free gas containing condensate. The reservoir is only slightly fractured.

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 Tyra 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. After separation into a gas and a liquid phase, the hydrocarbons produced are conveyed through two pipelines to Tyra East for processing and export ashore.



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
Area:	8 km²
Reservoir depth:	1,800 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2002:	
Oil:	0.6 million m³
Gas:	0.0 billion Nm³
Cum. production at 1 January 2002:	
Oil:	3.86 million m³
Gas:	0.16 billion Nm³
Water:	4.27 million m³
Production in 2001:	
Oil:	0.05 million m³
Gas:	0.00 billion Nm³
Water:	0.18 million m³
Tot. investments at 1 January 2002:	
2001 prices	DKK 0.9 billion

REVIEW OF GEOLOGY

Rolf is an anticlinal structure created through salt tectonics. The chalk reservoir is heavily fractured (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 electricity and lift gas from the Gorm Field.

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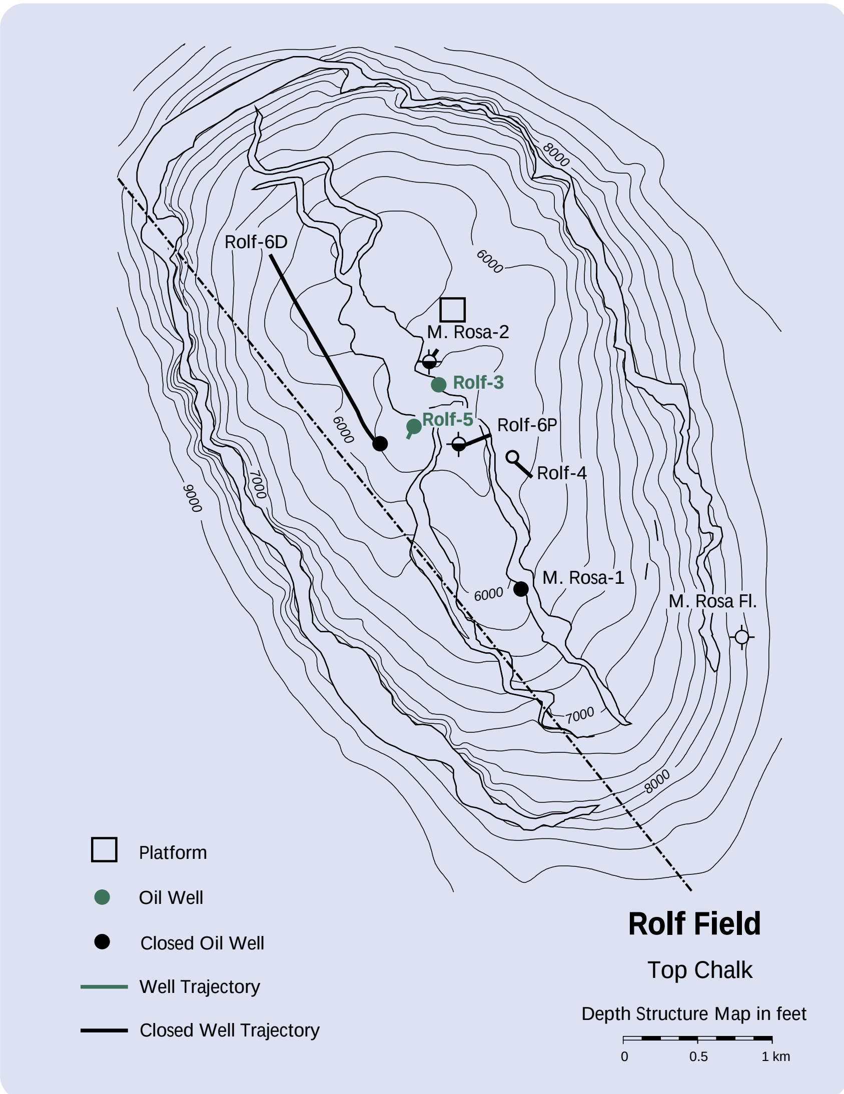


SKJOLD

Prospect:	Ruth
Location:	Block 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1977
Year on stream:	1982
Producing wells:	21
Water-injection wells:	8
Water depth:	40 m
Field delineation:	33 km²
Reservoir depth:	1,600 m
Reservoir rock:	Chalk
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2002:	
Oil:	13.1 million m³
Gas:	1.1 billion Nm³
Cum. production at 1 January 2002:	
Oil:	32.32 million m³
Gas:	2.81 billion Nm³
Water:	24.62 million m³
Cum. injection at 1 January 2002:	
Water:	60.76 million m³
Production in 2001:	
Oil:	1.36 million m³
Gas:	0.10 billion Nm³
Water:	2.88 million m³
Injection in 2001:	
Water:	4.75 million m³
Tot. investments at 1 January 2002:	
2001 prices	DKK 4.8 billion

REVIEW OF GEOLOGY

The Skjold Field is an anticlinal structure, induced through salt tectonics. Along most of its edge, the structure is delimited by a series of ring faults. The reservoir is intersected by numerous, minor faults in the central part of the structure. At the flanks of the structure, the reservoir is less fractured. Unusually favourable production properties have been shown to exist in the reservoir.

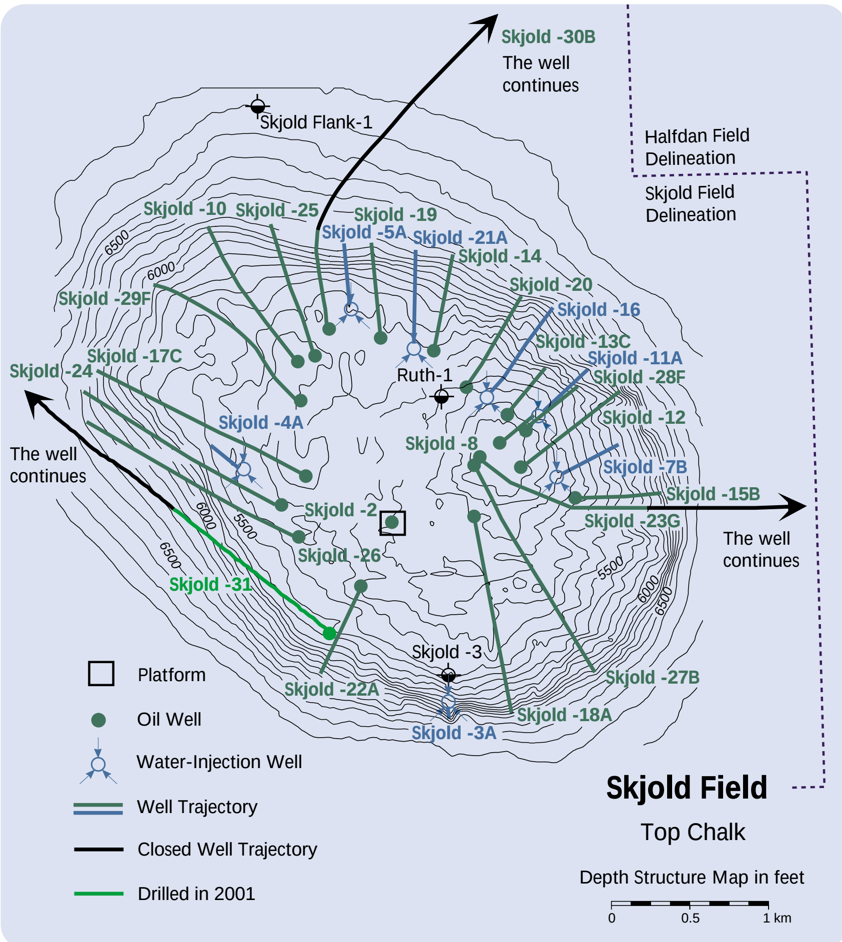
PRODUCTION STRATEGY

During the first years after production start-up, oil was produced from 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. 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.



SIRI

Location:	Block 5604/20
Licence:	6/95
Operator:	Statoil Efterforskning og Produktion A/S
Discovered:	1995
Year on stream:	1999
Producing wells:	6
Water- and gas-injection wells:	2
Water depth:	60 m
Field delineation:	42 km^2
Reservoir depth:	2,060 m
Reservoir rock:	Sandstone
Geological age:	Palaeocene
Reserves at 1 January 2002:	
Oil:	2.8 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2002:	
Oil:	5.47 million m^3
Gas:	0.52 billion Nm^3
Water:	4.94 million m^3
Cum. injection at 1 January 2002:	
Gas:	0.37 billion m^3
Water:	9.56 million m^3
Production in 2001:	
Oil:	1.76 million m^3
Gas:	0.18 billion Nm^3
Water:	2.75 million m^3
Injection in 2001:	
Gas:	0.14 billion m^3
Water:	4.55 million m^3
Tot. investments at 1 January 2002:	
2001 prices	DKK 3.5 billion

REVIEW OF GEOLOGY

The Siri Field is a structural trap with a Palaeocene sandstone reservoir. The accumulation consists of oil with a relatively low content of gas.

PRODUCTION STRATEGY

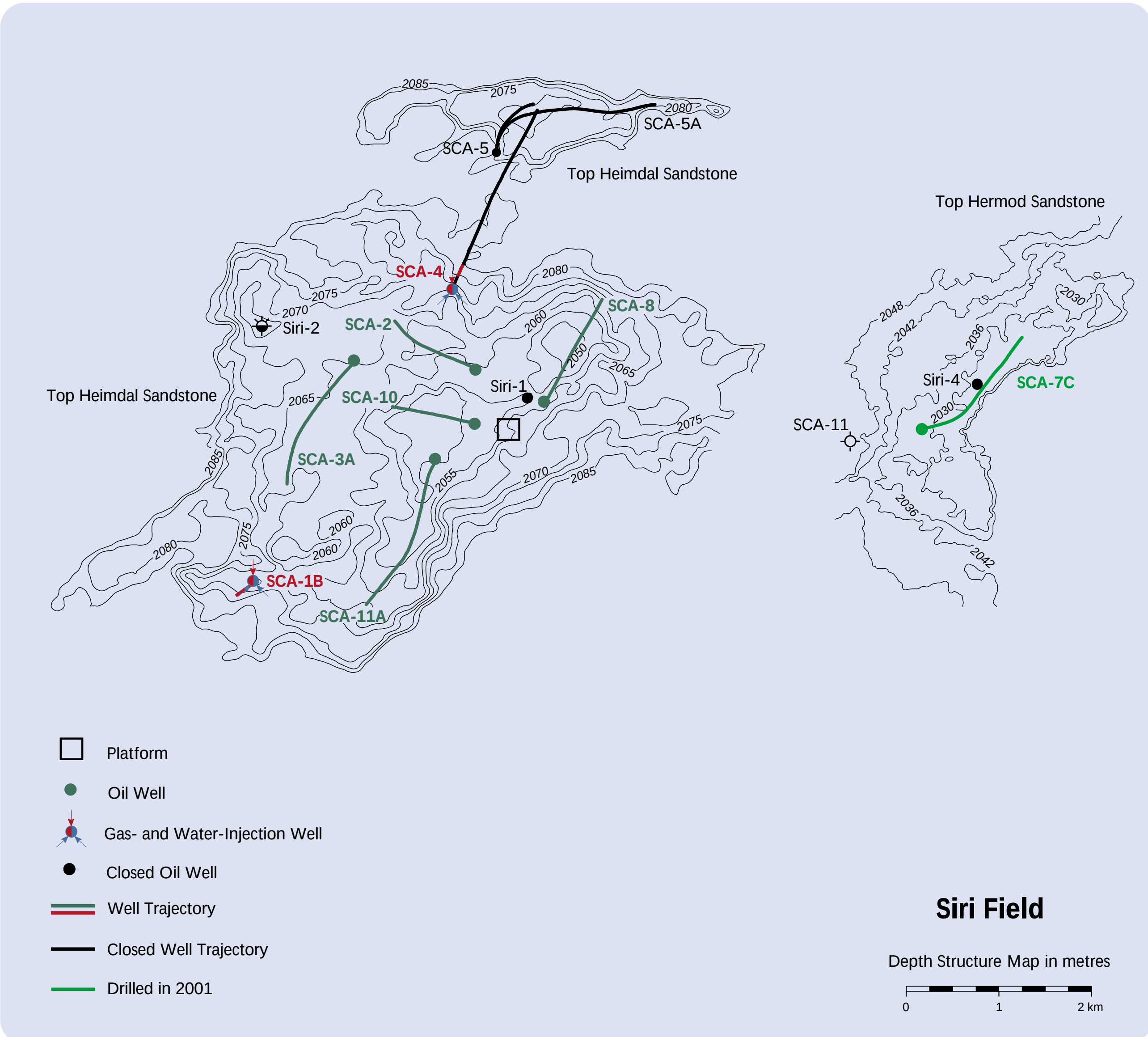
Recovery from the field is based on the production of oil through the co-injection of water and gas. Attempts are made to maintain the reservoir pressure at a level close to the initial pressure, and the volume of water injected is balanced with the volume of liquid produced from the reservoir.

PRODUCTION FACILITIES

The Siri Field installations comprise a combined wellhead, processing and accommodation platform. The processing facilities consist of a plant that separates the hydrocarbons produced. The platform also houses equipment for co-injecting gas and water.

The oil produced is conveyed to a 50,000 m^3 storage tank on the seabed. When the tank is full, the oil is transferred to a tanker by means of buoy loading facilities.

The Siri Field has accommodation facilities for 60 persons.


SCA-5A
SCA-5
Top Heimdal Sandstone
Top Hermod Sandstone
SCA-4
Siri-2
SCA-2
SCA-8
Siri-1
Top Heimdal Sandstone
SCA-10
SCA-3A
SCA-1B
SCA-11A
Siri-4
SCA-7C
SCA-11
Platform
Oil Well
Gas- and Water-Injection Well
Closed Oil Well
Well Trajectory
Closed Well Trajectory
Drilled in 2001
Siri Field
Depth Structure Map in metres
0
1
2 km

SOUTH ARNE

Location:	Blocks 5604/29 and 30
Licence:	7/89
Operator:	Amerada Hess ApS
Discovered:	1969
Year on stream:	1999
Producing wells:	7
Water-injection wells:	3
Water depth:	60 m
Field delineation:	93 km²
Reservoir depth:	2,800 m
Reservoir rock:	Chalk
Geological age:	Danian, Upper Cretaceous and Lower Cretaceous
Reserves at 1 January 2002:	
Oil:	27.1 million m³
Gas:	6.7 billion Nm³
Cum. production at 1 January 2002:	
Oil:	5.35 million m³
Gas:	1.65 billion Nm³
Water:	0.19 million m³
Cum injection at 1 january 2001:	
Water:	2.03 million m³
Production in 2001:	
Oil:	2.03 million m³
Gas:	0.77 billion Nm³
Water:	0.12 million m³
Injection in 2002:	
Water:	1.99 million m³
Tot. investments at 1 January 2002:	
2001 prices	DKK 5.7 billion

REVIEW OF GEOLOGY

South Arne is an anticlinal structure, induced through tectonic uplift (both of the Danian/Upper Cretaceous and Lower Cretaceous), which has caused the chalk to fracture. The structure contains oil with a relatively high content of gas. The field is the deepest chalk field in Denmark.

PRODUCTION STRATEGY

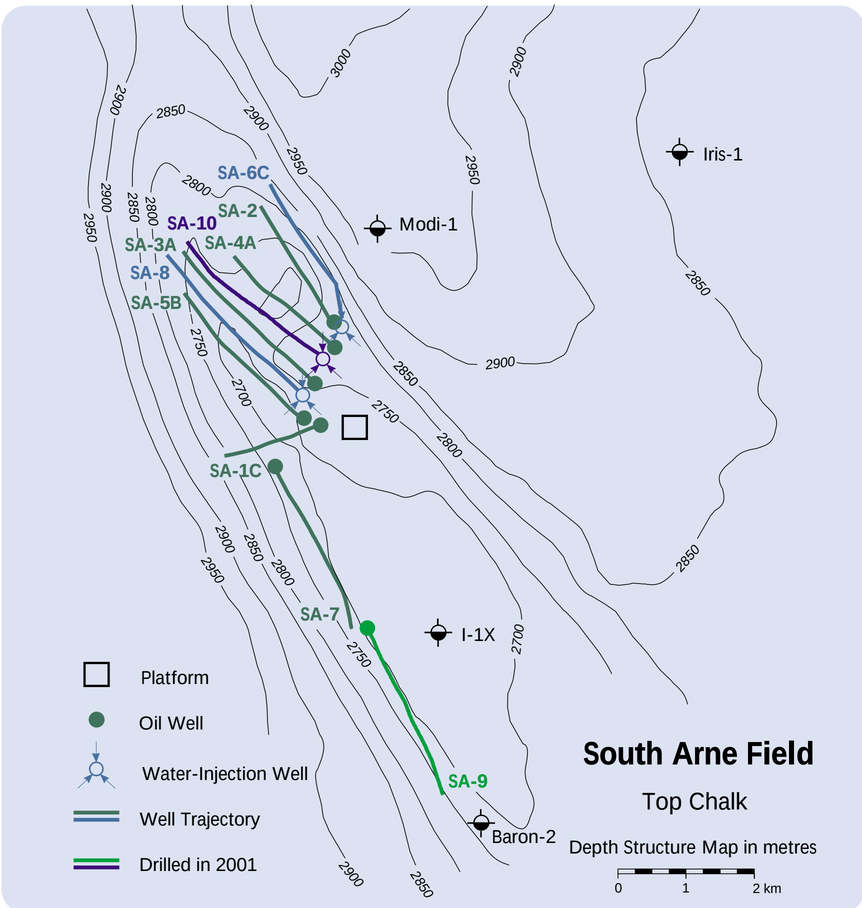
In the initial development phase, the recovery of oil and gas from the field was based on natural depletion, i.e. without the use of gas or water injection. The wells have good production properties. Pressure support from water injection is being established in the field. The drilling of additional production and injection wells in the field has been approved.

PRODUCTION FACILITIES

The South Arne Field installations comprise a combined wellhead, processing and accommodation platform. The processing facilities consist of a plant that separates the hydrocarbons produced as well as gas-processing facilities. The platform also houses equipment for water injection. In order to prevent the depositing of sparingly soluble salts in and around the injection wells, a system for removing the sulphate ions from the sea water prior to injection has been installed.

The oil produced is conveyed to an 87,000 m³ storage tank on the seabed. When the tank is full, the oil is transferred to a tanker by means of buoy loading facilities. The gas produced is transported through a gas pipeline to Nybro on the west coast of Jutland.

The South Arne Field has accommodation facilities for 57 persons.



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:	3
Water depth:	65 m
Field delineation:	48 km²
Reservoir depth:	2,500 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2002:	
Oil:	1.7 million m³
Gas:	0.3 billion Nm³
Cum. production at 1 January 2002:	
Oil:	4.32 million m³
Gas:	0.51 billion Nm³
Water:	3.23 million m³
Production in 2001:	
Oil:	0.40 million m³
Gas:	0.50 billion Nm³
Water:	0.95 million m³
Tot. investments at 1 January 2002:	
2001 prices	DKK 0.9 billion

REVIEW OF GEOLOGY

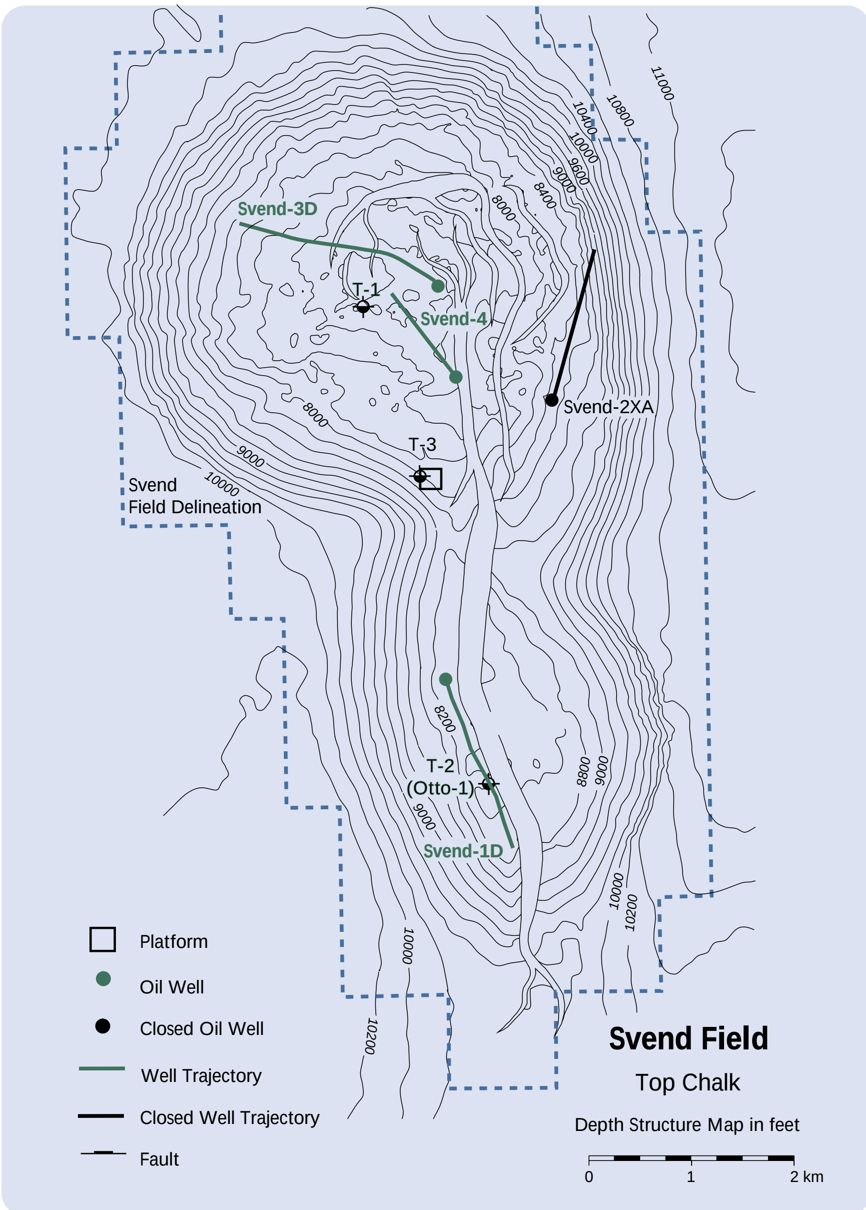
The Svend Field is an anticlinal structure, induced through salt tectonics. This led to fracturing of the chalk in the reservoir and divided the field into a western and eastern block, separated by a major fault. The northern reservoir of the Svend Field is situated about 250 metres higher than the southern reservoir. The northern 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.

PRODUCTION FACILITIES

The Svend Field has been developed as a satellite to the Tyra Field, with an unmanned STAR 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.



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:	42
Producing/ injection wells:	20
Water depth:	37-40 m
Area:	90 km²
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2002:	
Oil and condensate:	6.3 million m³
Gas:	28.5 billion Nm³
Cum. production at 1 January 2002:	
Oil and condensate:	19.39 million m³
Net gas:	31.79 billion Nm³
Water:	19.91 million m³
Cum. injection at 1 January 2002:	
Gas:	26.16 billion Nm³
Production in 2001:	
Oil and condensate:	0.87 million m³
Net gas:	0.98 billion Nm³
Water:	2.55 million m³
Injection in 2001:	
Gas:	2.77 billion Nm³
Tot. investments at 1 January 2002:	
2001 prices	DKK 22.6 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. The reservoir is only 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 DONG Naturgas A/S, the balance is supplied from the Tyra Field.

Attempts are made not to deteriorate condensate and oil production conditions by reducing the reservoir pressure 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. Any excess production of gas is reinjected into the Tyra Field in order to enhance the recovery of oil and condensate.

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.

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, Svend and Harald Fields, as well as plant for processing the water produced by the satellite fields.

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 Tyra and its satellite fields are transported to shore via Gorm E, while the gas produced at the Tyra Centre is transported to shore via the TEE platform together with the gas production from the Dan, Gorm and Harald Centres.

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

TEB-19
TEC-1
E-3X
TEB-4
TEB-13A
TEB-11
TEB-7A
TWB-7
TEB-9
TWB-5
TEB-12
TEB-8
TWC-24A
TWC-18B
TEC-6
TEC-5A
TEC-2
TEC-1
TEC-9
TWB-8
TWB-4
TEB-5
TWC-17
TEC-3A
TEC-8
E-4X
TEC-11
TEC-12A
TEB-1
TWB-12
TEC-4B
TWC-9
TWB-2
TEB-6A
TEC-10
TWC-5
TEC-7
TWC-8
TEB-2
TWC-6
TWC-7
TWC-1
E-2X
TWC-13
TWC-2
TWC-20B
TEB-3A
TWC-11
TWB-9B
TWB-6
TWB-1
TWC-3
TWC-4
TEB-16B
TWC-10
TWC-12
TWB-10B
TEB-17B
TWC-16A
TWB-11A
TWC-21A
TWC-23
TEB-18B
TWC-22C
TWC-15B
E-7X
6400
6500
6600
6700
6800
Platform
Gas Well
Oil Well with Gas
Gas-Injection Well
Well Trajectory
Closed Well Trajectory
Drilled in 2001
Fault
Tyra Field
Top Chalk
Depth Structure Map in feet
0
1
2 km

TYRA SOUTHEAST

Location:	Block 5504/12
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1991
Year on stream:	2002
Producing wells:	1
Water depth:	38 m
Field delineation:	113 km^2
Reservoir depth:	2,050 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2002:	
Oil:	4.6 million m^3
Gas:	11.1 billion Nm^3
Cum. production at 1 January 2002:	
Oil:	0.00 million m^3
Gas:	0.00 billion Nm^3
Water:	0.00 million m^3
Production in 2001:	
Oil:	0.00 million m^3
Gas:	0.00 billion Nm^3
Water:	0.00 million m^3
Tot. investments at 1 January 2002:	
2001 prices	DKK 0.4 billion

REVIEW OF GEOLOGY

The Tyra Southeast Field is an anticlinal structure created by a slight tectonic uplift of Upper Cretaceous chalk layers. The structure is divided into an A and a B block separated by a NE-SW fault zone. The relief is less pronounced in this formation than in the Tyra Field. The structure is part of the major NW-SE uplift zone that also comprises the Roar, Tyra and Igor Fields.

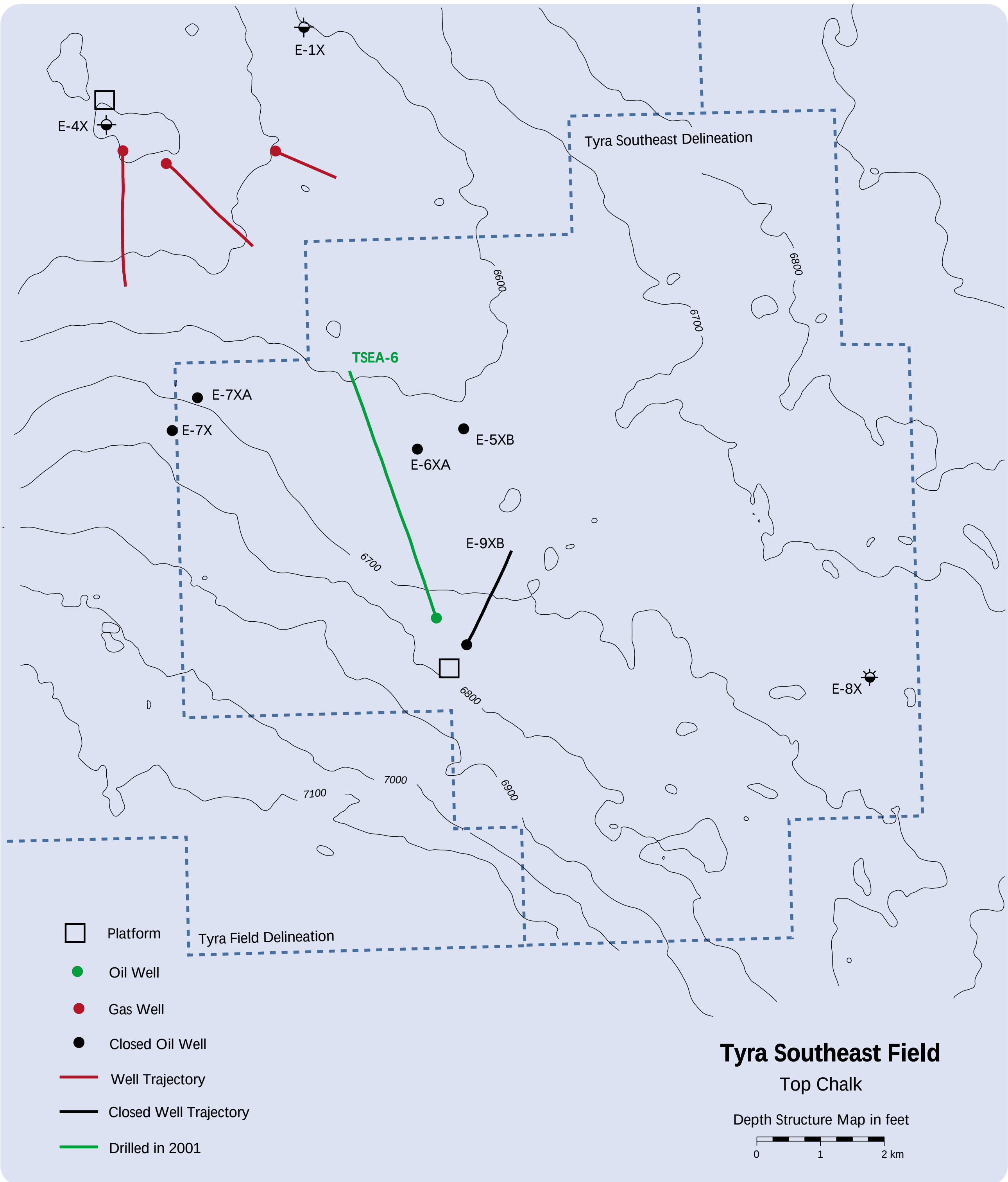
The Tyra Southeast accumulation consists of free gas overlying an oil zone in the southeastern part of the field.

PRODUCTION STRATEGY

Production from the Tyra Southeast Field is based on natural depletion.

PRODUCTION FACILITIES

The Tyra Southeast Field 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.


E-1X
E-4X
Tyra Southeast Delineation
6600
6800
6700
TSEA-6
E-7XA
E-7X
E-5XB
E-6XA
E-9XB
6700
6800
E-8X
7100
7000
6900
Tyra Field Delineation
Platform
Oil Well
Gas Well
Closed Oil Well
Well Trajectory
Closed Well Trajectory
Drilled in 2001
Tyra Southeast Field
Top Chalk
Depth Structure Map in feet
0
1
2 km

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:	6
Water depth:	38 m
Field delineation:	96 km²
Reservoir depth:	2,000 m (Upper Cretaceous) 2,600 m (Lower Cretaceous)
Reservoir rock:	Chalk
Geological age:	Danian, Upper and Lower Cretaceous

Reserves at 1 January 2002:

Oil:	1.6 million m^3
Gas:	1.7 billion Nm^3

Cum. production at 1 January 2002:

Oil:	1.28 million m^3
Gas:	0.56 billion Nm^3
Water:	0.44 million m^3

Production in 2001:

Oil:	0.18 million m^3
Gas:	0.08 billion Nm^3
Water:	0.15 million m^3

Tot. investments at 1 January 2002:

2001 prices	DKK 1.6 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, see the Top Chalk map, and vast amounts of oil in place have been identified in Lower Cretaceous chalk, see the Top Tuxen Chalk map. While the properties of the Upper Cretaceous reservoirs are comparable to other Danish fields like Gorm and Tyra, the Lower Cretaceous chalk possesses very difficult production properties due to its extremely low permeability.

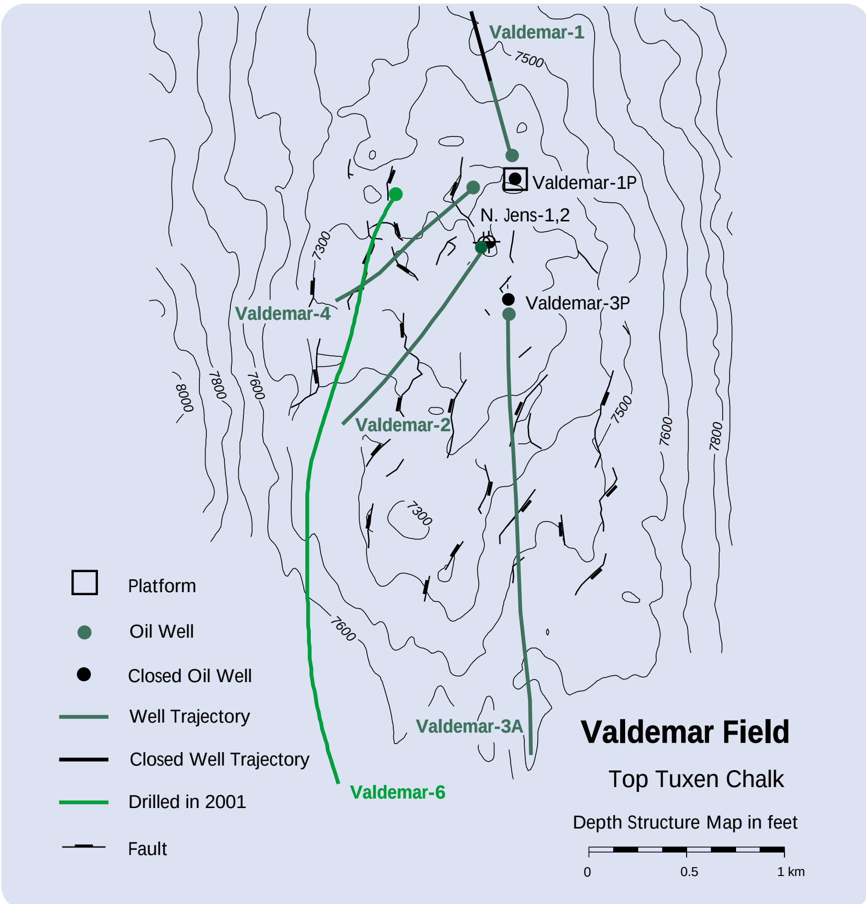
Production from the field is based on primary recovery.

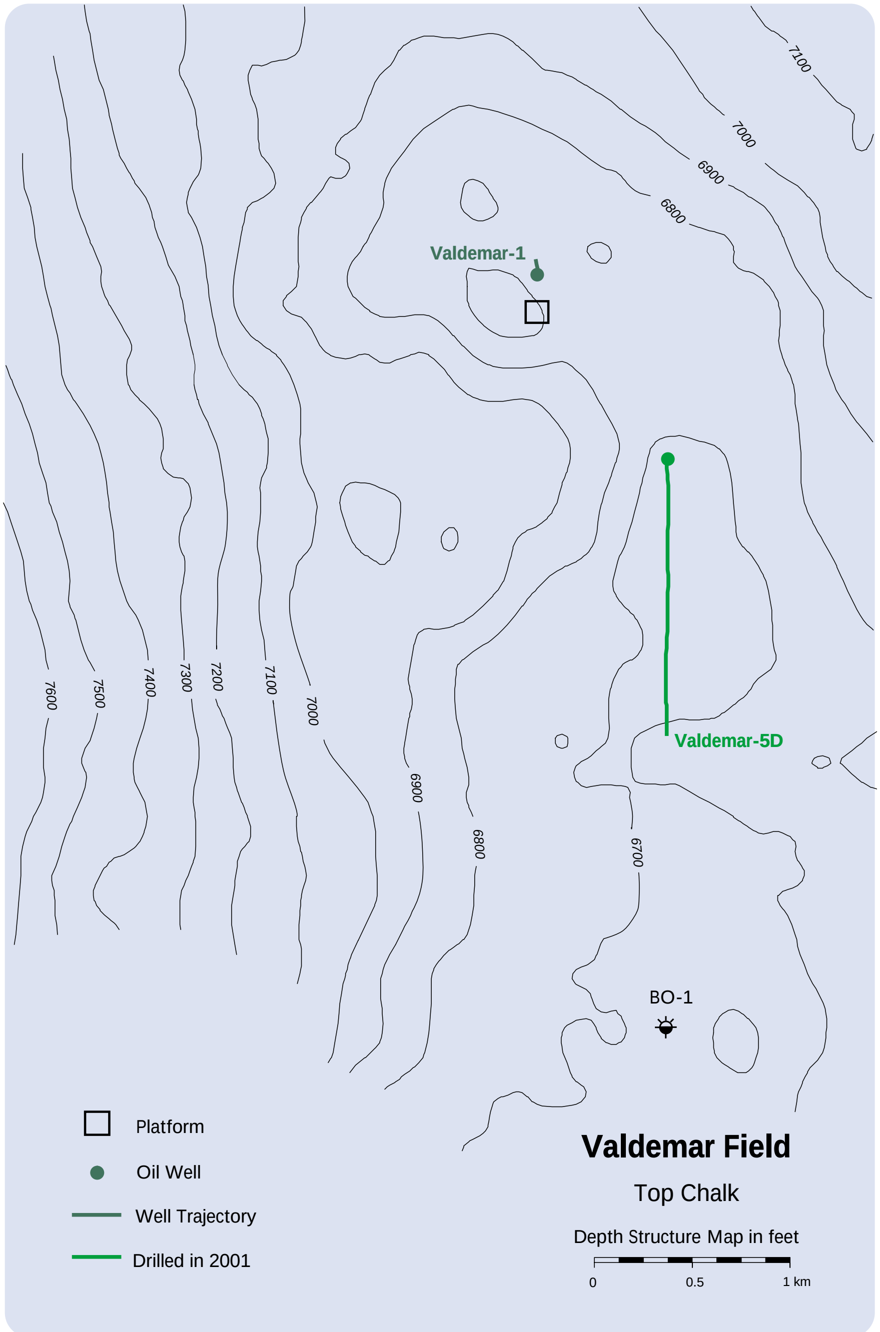
PRODUCTION STRATEGY

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.





7100
7000
6900
6800
Valdemar-1
7600
7500
7400
7300
7200
7100
7000
6900
6800
6700
Valdemar-5D
BO-1
Platform
Oil Well
Well Trajectory
Drilled in 2001
Valdemar Field
Top Chalk
Depth Structure Map in feet
0
0.5
1 km

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:	2005
Water depth:	38 m
Reservoir depth:	2,200 m and 2,300 m
Reservoir rock:	Chalk
Geological age:	Upper and Lower Cretaceous
Type of hydrocarbons:	Oil and gas

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:	2005
Water depth:	43 m
Reservoir depth:	3,600 m
Reservoir rock:	Sandstone
Geological age:	Jurassic
Type of hydrocarbons:	Gas

Field name	Amalie
Location:	Blocks 5604/22 and 26
Licence:	7/86
Operator:	DONG E&P A/S
Discovered:	1991
Dev. plan approved:	Dev. plan being considered by the Danish Energy Authority
Year on stream:	2006
Water depth:	66 m
Reservoir depth:	5,000 m
Reservoir rock:	Sandstone
Geological age:	Upper and Middle Jurassic
Type of hydrocarbons:	Gas and oil

Field name	Boje Area
Location:	Block 5504/7
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1982
Dev. plan approved:	2000
Year on stream:	2003
Water depth:	40 m
Reservoir depth:	2,000 and 2,500 m
Reservoir rock:	Chalk
Geological age:	Danian, Upper and Lower Cretaceous
Type of hydrocarbons:	Oil

Field name	Cecilie
Location:	Blocks 5604/19 and 20
Licence:	16/98
Operator:	DONG E&P A/S
Discovered:	2000
Dev. plan approved:	Dev. plan being considered by the Danish Energy Authority
Year on stream:	2003
Water depth:	60 m
Reservoir depth:	2,200 m
Reservoir rock:	Sandstone
Geological age:	Palaeocene
Type of hydrocarbons:	Oil

Field name	Elly
Location:	Block 5604/6
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1984
Dev. plan approved:	1995
Year on stream:	2005
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**
Location:	Blocks 5503/27 and 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	**Igor/Sif**
Location:	Block 5503/13/Block 5504/16
Licence:	Sole Concession of 8 July 1962
Operator:	Mærsk Olie og Gas AS
Discovered:	1968/1999
Dev. plan approved:	1990/-
Year on stream:	2005/-
Water depth:	44 m
Reservoir depth:	2,000 m/2,050 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Type of hydrocarbons:	Gas/gas and oil

Field name	**Nini**
Location:	Blocks 5605/10 and 14
Licence:	4/95
Operator:	DONG E&P A/S
Discovered:	2000
Dev. plan approved:	Dev. plan being considered by the Danish Energy Authority
Year on stream:	2003
Water depth:	60 m
Reservoir depth:	1,700 m
Reservoir rock:	Sandstone
Geological age:	Palaeocene
Type of hydrocarbons:	Oil

FINANCIAL KEY FIGURES

	Inv. In Field Dev. DKK million	Field Op. Costs DKK million[1]	Exploration Costs DKK million	Crude Oil Price USD/bbl[2]	Excange Rate DKK/USD	Inflation %[3]	Net. Foreing-Currency Value DKK Billion4	State Revenue DKK million
1972	105	29	30	3,0	7,0	6,6	-3,2	
1973	9	31	28	4,6	6,1	9,4	-4,0	1
1974	38	57	83	11,6	6,1	15,2	-9,2	1
1975	139	62	76	12,3	5,8	9,7	-8,5	2
1976	372	70	118	12,9	6,1	9,0	-9,5	4
1977	64	85	114	14,0	6,0	11,1	-10,4	5
1978	71	120	176	14,1	5,5	10,1	-9,5	21
1979	387	143	55	20,4	5,3	9,6	-13,7	19
1980	956	163	78	37,5	5,6	12,3	-18,6	29
1981	1.651	320	201	37,4	7,1	11,7	-20,1	36
1982	3.884	534	257	34,0	8,4	10,2	-20,6	234
1983	3.554	544	566	30,5	9,1	6,9	-17,8	399
1984	1.598	1.237	1.211	28,2	10,4	6,3	-18,3	488
1985	1.943	1.424	1.373	27,2	10,6	4,7	-17,6	1.289
1986	1.651	1.409	747	14,9	8,1	3,6	-7,3	1.399
1987	930	1.380	664	18,3	6,8	4,0	-5,9	1.328
1988	928	1.413	424	14,8	6,7	4,6	-3,7	568
1989	1.162	1.599	366	18,2	7,3	4,8	-3,2	1.024
1990	1.769	1.654	592	23,6	6,2	2,6	-2,7	2.089
1991	2.302	1.898	985	20,0	6,4	2,4	-1,9	1.889
1992	2.335	1.806	983	19,3	6,0	2,1	-0,4	1.911
1993	3.307	2.047	442	16,8	6,5	1,2	-0,4	1.811
1994	3.084	2.113	151	15,6	6,4	2,0	-0,5	2.053
1995	4.164	1.904	272	17,0	5,6	2,1	0,3	1.980
1996	4.257	2.094	470	21,1	5,8	2,1	0,4	2.465
1997	3.781	2.140	515	18,9	6,6	2,2	1,4	3.131
1998	5.306	2.037	406	12,8	6,7	1,9	0,9	3.117
1999	3.531	2.157	563	17,9	7,0	2,5	3,5	3.784
2000	3.100	2.816	627	28,5	8,1	2,9	14,4	8.304
2001*	3.978	2.704	1.076	24,4	8,3	2,3	13,0	10.154

Nominel Prices
1) Including transportation cost
2) Brent crude oil
3) Consumer prices
4) Oil products and natural gas
**) Estimate*
Note: Figures updated compared to the printed version as these were unfortuneately incorrect.

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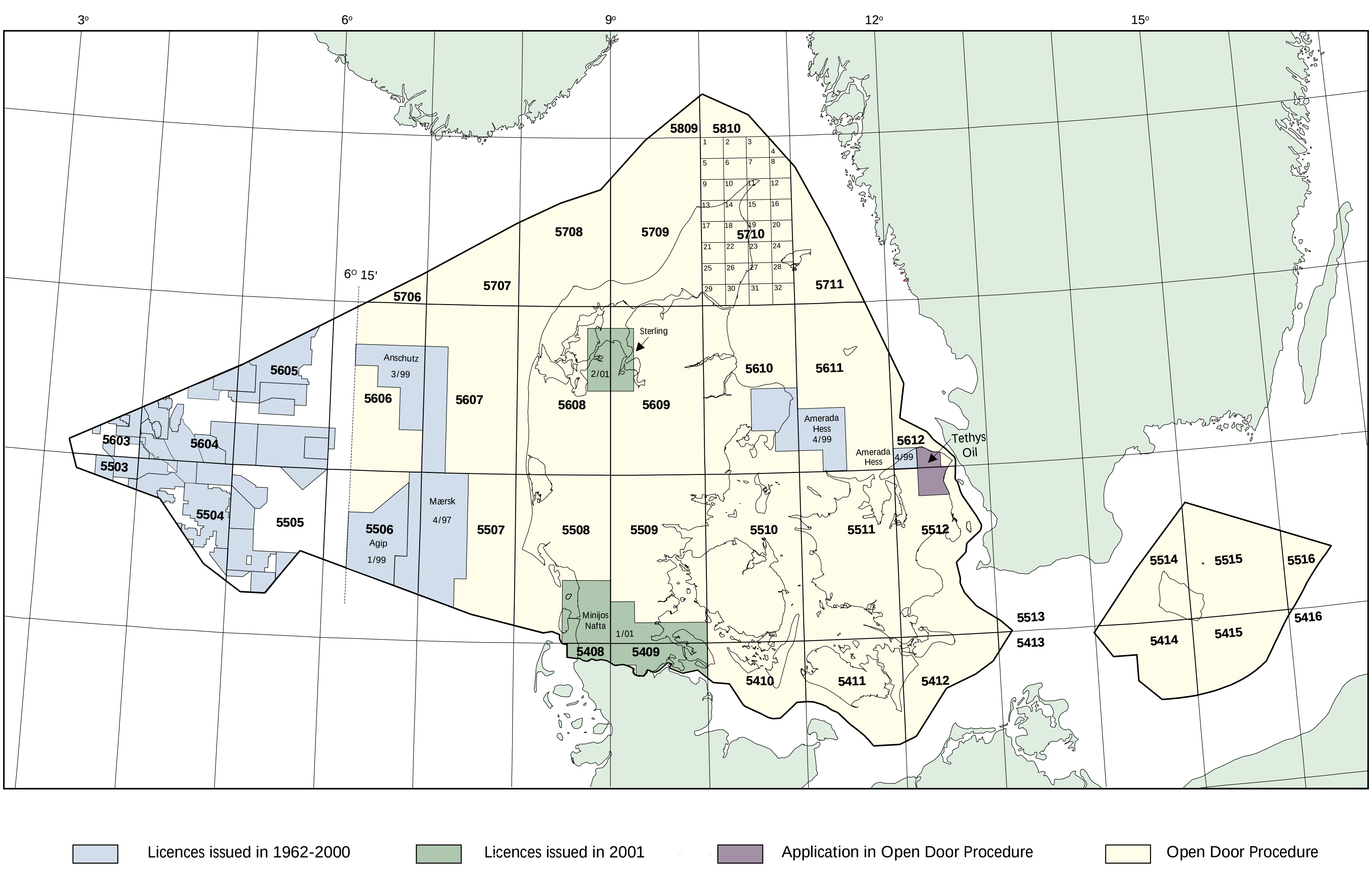

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The Western Area