DANISH ENERGY AUTHORITY

Danish Energy Authority · Amaliegade 44 · DK-1256 København K
Tel.: +45 33 92 67 00 · Fax: +45 33 11 47 43
e-mail: ens@ens.dk

www.ens.dk

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 2003 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 hydrocarbon production on the Danish economy.

This year's report also includes a special section on Denmark's hydrocarbon potential.

The report can be obtained from the Danish State Information Centre, tel. +45 7010 1881, an official telephone service directly connecting callers to anywhere in the public sector, or from the Danish Energy Authority's Internet bookstore, www.danmark.dk/netboghandel. The report is also available on the Danish Energy Authority's homepage, www.ens.dk.

ISBN 87-7844-433-0

Oil and Gas production in Denmark 2003

Oil and Gas Production in Denmark 2003

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 use 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.

The Danish Energy Authority
44 Amaliegade
DK-1256 Copenhagen K

Telephone + 45 33 92 67 00
Fax + 45 33 11 47 43
Homepage: www.ens.dk

Published: June 2004
Number printed: 1,500

Front page: Photos made available by DONG E&P A/S
Editor: Helle Halberg, the Danish Energy Authority
Maps and
illustrations: Lise Ott, the Danish Energy Authority

Print: Rosendahls Bogtrykkeri
Printed on: 100% recycled paper. Cover: 250 g Cyclus offset. Content: 130 g
Cyclus print
Layout: Advice A/S and the Danish Energy Authority
Translation: Rita Sunesen
ISBN 87-7844-433-0
ISSN 0907-2675

PREFACE

Activity and growth continue to characterize the Danish oil and gas sector. Thus, three new fields were brought on stream in 2003, a development that kept oil production at the same high level as in 2002.

In September 2003, the Danish state and A.P. Møller-Mærsk concluded an agreement regarding a continuation of the company's existing Sole Concession until 2042. This agreement has created a long-term basis for optimizing production from the numerous accumulations in the concession area, while also generating larger revenue for the state.

Recovering oil and natural gas from the North Sea remains attractive, and major investments will continue to be made in the Danish sector of the North Sea in the years ahead.

The Danish Energy Authority has carried out an assessment of prospective resources in the Danish area, which shows that considerable unidentified hydrocarbon resources may still be present. Consequently, the upcoming 6th Licensing Round is considered to offer major exploration opportunities. Continuous exploration is essential if the oil and gas sector is to contribute positively to the Danish economy also in the future.

In November 2002, the Government presented an action plan with initiatives aimed at safety on board the North Sea installations. The action plan underscores that safety standards on Danish offshore installations must continue to rank among the highest in the North Sea countries. The action plan involves intensifying the Danish Energy Authority's safety supervision. Thus, in 2003, the Danish Energy Authority made targeted efforts to implement the initiatives set out in the action plan. The Danish Energy Authority believes that the action plan has helped maintain the high level of health and safety in the Danish sector of the North Sea.

Copenhagen, June 2004

Ib Larsen

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 (metric units) and the so-called oil field units, which were originally introduced in the USA. This report uses SI 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 2003 based on figures from refineries. 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 or 1 Bscf.

	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	0.03994
	Nm^3	t.o.e.	953.95×10^{-6}
	Nm^3	kg·mol	0.0446158
	m^3 (st)	scf	35.3014
	m^3 (st)	GJ	0.03786
	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

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.*

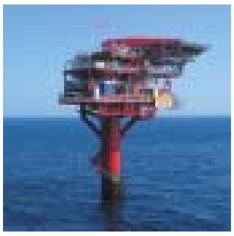
kg · mol — *kilogrammol; the mass of a substance whose mass in kilograms is equal to the molecular mass of the substance.*

γ — *gamma; relative density.*

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

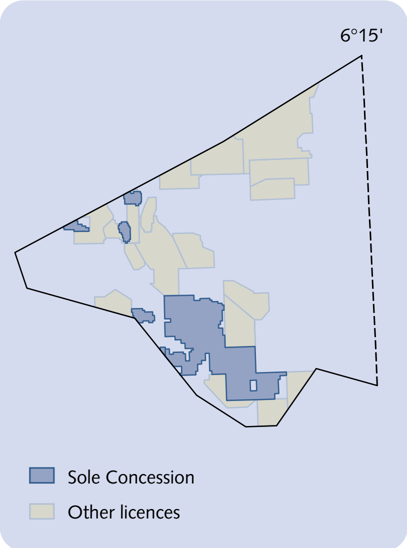
ft — *foot/feet; British unit of length. 1 ft = 12 in.*

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



1. LICENCES AND EXPLORATION

Fig. 1.1 Sole Concession of 8 July 1962



The Government's agreement with A.P. Møller–Mærsk to extend the Sole Concession made 2003 a crucial year for the future exploitation of Danish oil and gas resources.

The level of exploration activity in the Danish sector was satisfactory, particularly compared to the other North Sea countries. In 2003, a total of ten exploration and appraisal wells were drilled, leading to one new oil discovery. The Danish Energy Authority expects the activity level to be sustained throughout 2004.

CONTINUATION OF A.P. MØLLER-MÆRSK'S SOLE CONCESSION

During a debate on questions in the Danish Parliament in February 2003, the Government was asked to present a statement on the options for securing a larger share of the North Sea oil and gas production values for the state. In making this request, the Danish Parliament presupposed that a discussion was to be held with A.P. Møller-Mærsk to investigate the possibilities for a continuation of the 1962 Sole Concession.

On 29 September 2003, the Government entered into an agreement with A.P. Møller-Mærsk, and presented a statement on the North Sea to the Danish Parliament on 7 October 2003. Both the agreement and the statement are available on the Danish Energy Authority's website at www.ens.dk.

The main elements of the agreement of 29 September 2003 are outlined in Box 1 below. Fig. 1.1 shows the areas comprised by the agreement of 29 September 2003.

Box 1. Main elements of the agreement of 29 September 2003

Continuation of Sole Concession until 2042

A continuation of the Sole Concession for the period from 1 January 2004 to 8 July 2042 is in the process of being granted to A.P. Møller–Mærsk (the Concessionaires). The agreement includes provisions to the effect that the Concessionaires are to continue active exploration efforts and currently report to the public authorities on their plans for future production and the closure of fields. Any dispute about the scope or content of such work is to be settled by arbitration.

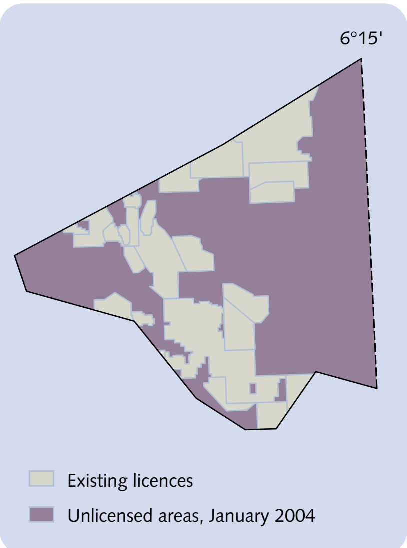
State participation

As from 1 January 2004 and through 8 July 2012, the Concessionaires and their partners are to pay the state an annual amount corresponding to 20% of the profit before tax and before net interest expenses. As from 9 July 2012, the state will become a partner of DUC, taking over a 20% share of all installations (platforms, processing plant, pipelines, etc.). The state will not pay for this takeover.

Hydrocarbon tax

With effect from the 2004 accounting year, the special investment allowance provided for in the Danish Hydrocarbon Tax Act – the hydrocarbon allowance – will be reduced to 5% over six years instead of 25% over ten years. For investments made prior to 1 January 2004, the hydrocarbon allowance will be reduced from

Fig. 1.2 Unlicensed areas



25% to 10% a year. Deductibility stops when the investment is more than ten years old. The hydrocarbon tax rate will be reduced from 70% to 52%. The field-based tax assessment will be abolished as from the 2004 accounting year. Unutilized losses on fields are to be determined at the end of the 2003 accounting year and can be deducted at the rate of 2.5% in each of the years 2004-2005 and at the rate of 6% in each of the years 2006-2016. The remaining 29% cannot be deducted. The special pay-back rule in the Hydrocarbon Tax Act has been abolished with effect from 1 January 2004.

Royalty and pipeline tariff

The provision regarding payment of royalty laid down in Section 10(1) of the 1962 Concession has been abolished with effect from 1 January 2004. The pipeline tariff payable according to the 1981 agreement between the Minister for Energy and A.P. Møller will be abolished with effect from 9 July 2012. The pipeline tariff is to be offset against hydrocarbon tax as from 1 January 2004 and not against the income base for either hydrocarbon tax or corporate income tax. Allowances not utilized in any one year may be carried forward to subsequent years.

Removal costs

Removal costs are payable by DUC and its partners. For tax purposes, removal costs can be deducted in the year defrayed. In the event that the allowance cannot be utilized in full due to insufficient positive hydrocarbon income at the time production is discontinued under the Concession, the state will reimburse the tax value of the unutilized allowance. However, the amount reimbursed cannot exceed the accumulated hydrocarbon tax payments less any amounts previously reimbursed in respect of removal costs under the same scheme.

Compensatory scheme

The DUC companies will be compensated for the effects of any amendments to existing or new legislation and other rules specifically impacting on hydrocarbon producers in the Danish part of the North Sea. The compensation will be fixed with a view to restoring the financial balance between the state and the Concessionaires and their partners, and cannot exceed the net benefit achieved by the state from the agreement of 29 September 2003. Any disputes in this respect are to be referred to arbitration. This scheme will not affect the state's general right of taxation.

In autumn 2003 and spring 2004, the Danish Parliament adopted amendments to the Danish Subsoil Act, Pipeline Act and Hydrocarbon Tax Act, and thus all the elements of the agreement have been implemented into legislation.

The statutory amendments will also become effective for future licences for the exploration and production of hydrocarbons.

6TH LICENSING ROUND

Six years have passed since areas were offered for licensing in the Central Graben and adjoining areas, i.e. west of 6° 15' eastern longitude.

Fig. 1.3 New and relinquished Open Door licences

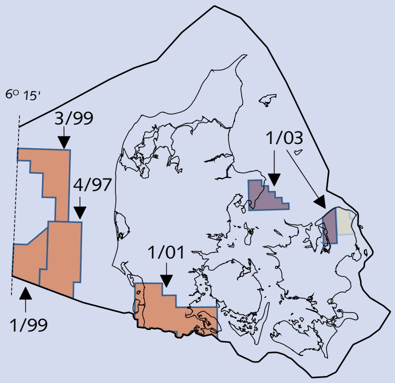


Table 1.1 Extended licence terms

Licence	Operator	Expiry
4/95	DONG E&P A/S	15-05-2005
6/95	DONG E&P A/S	15-05-2005
7/95	Mærsk Olie og Gas AS	15-11-2004
9/95	Mærsk Olie og Gas AS	01-01-2005
4/98	Phillips Petroleum Int. Corp.	15-06-2006
11/98	DONG E&P A/S	15-12-2005
13/98	Noble Energy (Europe) Limited	14-09-2004

Table 1.2 Partial relinquishment

Licence	Operator	Relinquished
7/89	Amerada Hess ApS	20-12-2003
2/95	DONG E&P A/S	01-03-2003
4/95	DONG E&P A/S	15-09-2003
9/95	Mærsk Olie og Gas AS	01- 12-2003
11/98	DONG E&P A/S	31-12-2003

Most of the work obligations undertaken by the oil companies in the 5th Licensing Round in 1998 have been fulfilled. Four out of the 12 exploration wells drilled under the licences awarded in the 5th Licensing Round have led to hydrocarbon discoveries. Cecilie came on stream in 2002, Connie is expected to be developed in 2004, while the Svane and Hejre discoveries are currently under appraisal.

The wells drilled in the Siri Fairway have confirmed the exploration model for Paleogene deposits, while the wells in the Central Graben have also shown new exploration potential in deep Jurassic sandstone deposits. Although exploration in the Danish sector of the North Sea commenced almost 40 years ago, results continue to show attractive exploration potential.

The most recent amendments to the Danish Subsoil Act, Pipeline Act and Hydrocarbon Tax Act have set the basic conditions for future licences. The Danish Energy Authority is now completing the terms and conditions for the 6th Licensing Round, expected to be opened in the course of 2004. Once applications have been invited in the new licensing round, the oil companies will have a time limit of about six months to submit offers for the unlicensed areas west of 6° 15' eastern longitude. Fig. 1.2 shows the areas available as of April 2004.

NEW LICENCES

On 18 December 2003, the Minister for Economic and Business Affairs granted Tethys Oil AB and Odin Energi A/S a licence for exploration and production of hydrocarbons in the so-called Open Door area. Tethys Oil AB, a company incorporated in Sweden, will be the operator of the licence, numbered 1/03. The licence comprises an area in northern Zealand where the same companies were granted a licence for an adjoining area in 2002, as well as an area extending from the Djursland peninsula into the Kattegat; see Fig. 1.3.

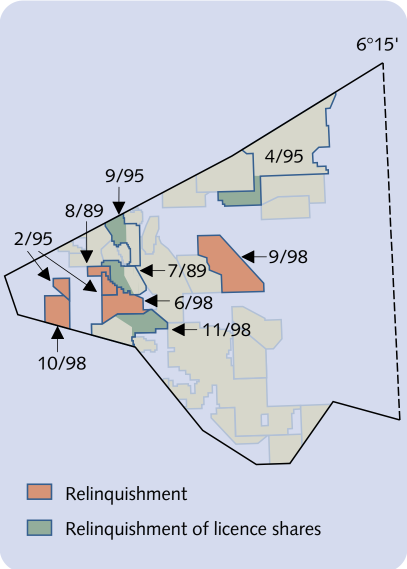
The licence was awarded under the Open Door procedure, which is an open invitation to oil companies to apply for licences for all unlicensed areas east of 6°15' eastern longitude. As in all other Open Door licences, the state-owned company DONG Efterforskning og Produktion A/S (DONG E&P A/S) holds a 20% share of the licence.

AMENDED LICENCES

The outline of licences on the Danish Energy Authority's website at www.ens.dk is continually updated and describes all amendments in the form of extended licence terms, the transfer of licence shares and relinquishments.

Licences for exploration and production of hydrocarbons are initially granted for a six-year term. Each licence includes a work programme specifying the exploration work that the licensee must carry out, including time limits for conducting the individual seismic surveys and drilling exploration wells. However, some licences may stipulate that the licensee is obligated to carry out specific work, such as the drilling of an exploration well, or to relinquish the licence by a certain date during the six-year term of the licence. After the initial six-year term, the Danish Energy Authority may extend the term of a licence by up to two years at a time, provided that the licensee, upon carrying out the entire original work programme, is prepared to undertake additional exploration commitments.

Fig. 1.4 Relinquishment west of 6°15' eastern longitude



Extended licence terms
In 2003, the Danish Energy Authority granted an extension of the terms of the licences indicated in Table 1.1. The licence terms were extended on the condition that the licensees undertake to carry out additional exploration work in the relevant licence areas.

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

Effective 1 January 2003, Odin Energi A/S increased its 10% share in licence 1/02 by taking over a 5% share from Tethys Oil AB.

Other amendments with regard to licence shares, etc. are mentioned in the outline of licences at the Danish Energy Authority's website.

Partial relinquishment
The main part of licence 7/89 was relinquished on 20 December 2003, when the most recent extension of the exploration term expired. With effect from that date, licence 7/89 only covers the delineated area comprising the South Arne Field, operated by Amerada Hess ApS. This licence was granted in the 3rd Licensing Round in 1989. Since then, the licence group has drilled six exploration and appraisal wells and acquired several sets of 3D seismic data. The relinquished area includes the Gwen and Nora discoveries, both made in Jurassic layers.

The DONG group relinquished two sub-areas of licence 2/95 on 1 March 2003. The companies in this group relinquished the remaining part of the licence area on 20 December 2003, when the exploration term expired.

A minor share of licence 4/95 was relinquished on 15 September 2003. The oil companies are carrying on exploration in the remaining licence area, in which the operator, DONG E&P A/S, is to drill an exploration well in 2004.

The exploration term for licence 9/95, operated by Mærsk Olie og Gas AS, was extended until 2005. However, this extension only comprised the eastern part of the original licence area.

In accordance with the terms and conditions applicable to licence 11/98, the DONG group relinquished half of the original licence area on 31 December 2003. The relinquished area includes the Upper Jurassic Ravn oil discovery made in 1986.

The relinquished areas appear from Fig. 1.4 and Table 1.2.

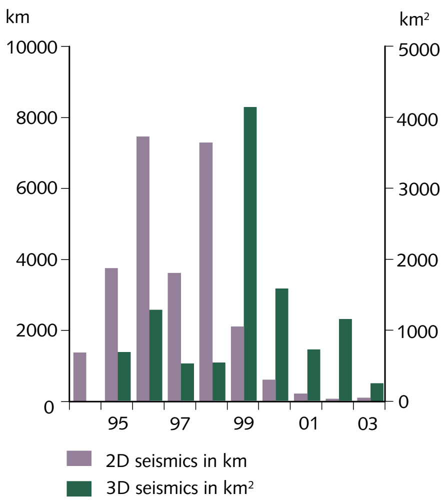
TERMINATED LICENCES
Licences for areas in and around the Central Graben and the Open Door area were relinquished in the course of 2003. The licences relinquished appear from Table 1.3 and Figs. 1.3 and 1.4.

Generally, data compiled under licences granted in pursuance of the Danish Subsoil Act are protected by a five-year confidentiality clause. However, the confidentiality period is limited to two years for licences that expire or are relinquished.

Table 1.3 Terminated licences

Licence	Operator	Terminated
8/89	DONG E&P A/S	20-12-2003
2/95	DONG E&P A/S	20-12-2003
4/97	Mærsk Olie og Gas AS	15-09-2003
6/98	Phillips Petroleum Int. Corp.	15- 12-2003
9/98	Norsk Agip A/S	15-05-2003
10/98	Norsk Agip A/S	15-05-2003
1/99	Norsk Agip A/S	15-02-2003
3/99	The Anschutz Overseas Corp.	20-12-2003
1/01	UAB Minijos Nafta	31-12-2003
2/01	Sterling Resources (UK)	05-01-2003

Fig. 1.5 Annual seismic surveying activities



Once the confidentiality period has expired, other oil companies have an opportunity to procure data for the exploration wells drilled and extensive 3D seismic surveys carried out in the relinquished areas. As a result, the companies are better able to map the subsoil and assess oil exploration potential in the relinquished areas.

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

EXPLORATORY SURVEYS

The level of activity and the areas where seismic surveys were performed appear from Figs. 1.5 and 1.7.

In August-September 2003, Denerco Oil A/S carried out a 3D seismic survey in the Norwegian-Danish Basin, due south of the area comprised by licence 16/98.

In June-July 2003, PGS Petrophysical AS performed a 2D seismic survey in the Norwegian-Danish Basin. Most of the seismic lines were shot in Norwegian territory, but several of the lines were extended into Danish territory.

WELLS

In 2003, five exploration wells and five appraisal wells were drilled; see Fig. 1.6. These statistics include wells spudded in 2003.

The location of the wells described below appears from Fig. 1.8. The appraisal wells drilled in the producing fields are also shown in the field maps in Appendix B.

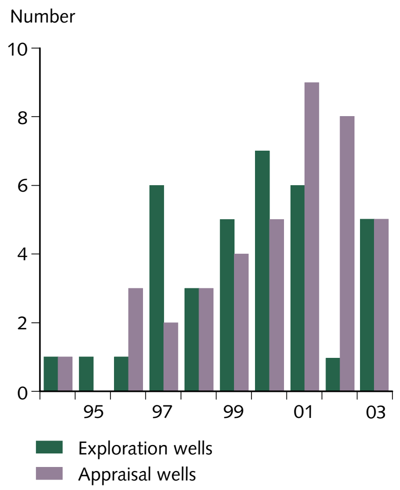
An outline of all Danish exploration and appraisal wells is available at the Danish Energy Authority's website.

Exploration wells

Olga-1X (5505/21-4)

Under licence 5/99, Mærsk Olie og Gas AS drilled the exploration well Olga-1X in January-June 2003. The licence area is situated due south of the Kraka Field in the North Sea. Olga-1X was drilled as a vertical well, terminating at a depth of 4,695 metres below sea level. The well encountered the expected Triassic sandstone reservoir, but no hydrocarbons were produced in a subsequent production test.

Fig. 1.6 Exploration and appraisal wells



Jette-1 (5604/29-7)

As operator for the oil companies holding licence 7/89, Amerada Hess ApS drilled the exploration well Jette-1 in cooperation with DONG E&P A/S in April-June 2003. This well was drilled at a position west of the South Arne Field. Jette-1 was drilled as a vertical well and terminated at a depth of 4,402 metres below sea level in Triassic layers. The Jette-1 well encountered the expected Upper Jurassic sandstone reservoir, but no hydrocarbons were discovered.

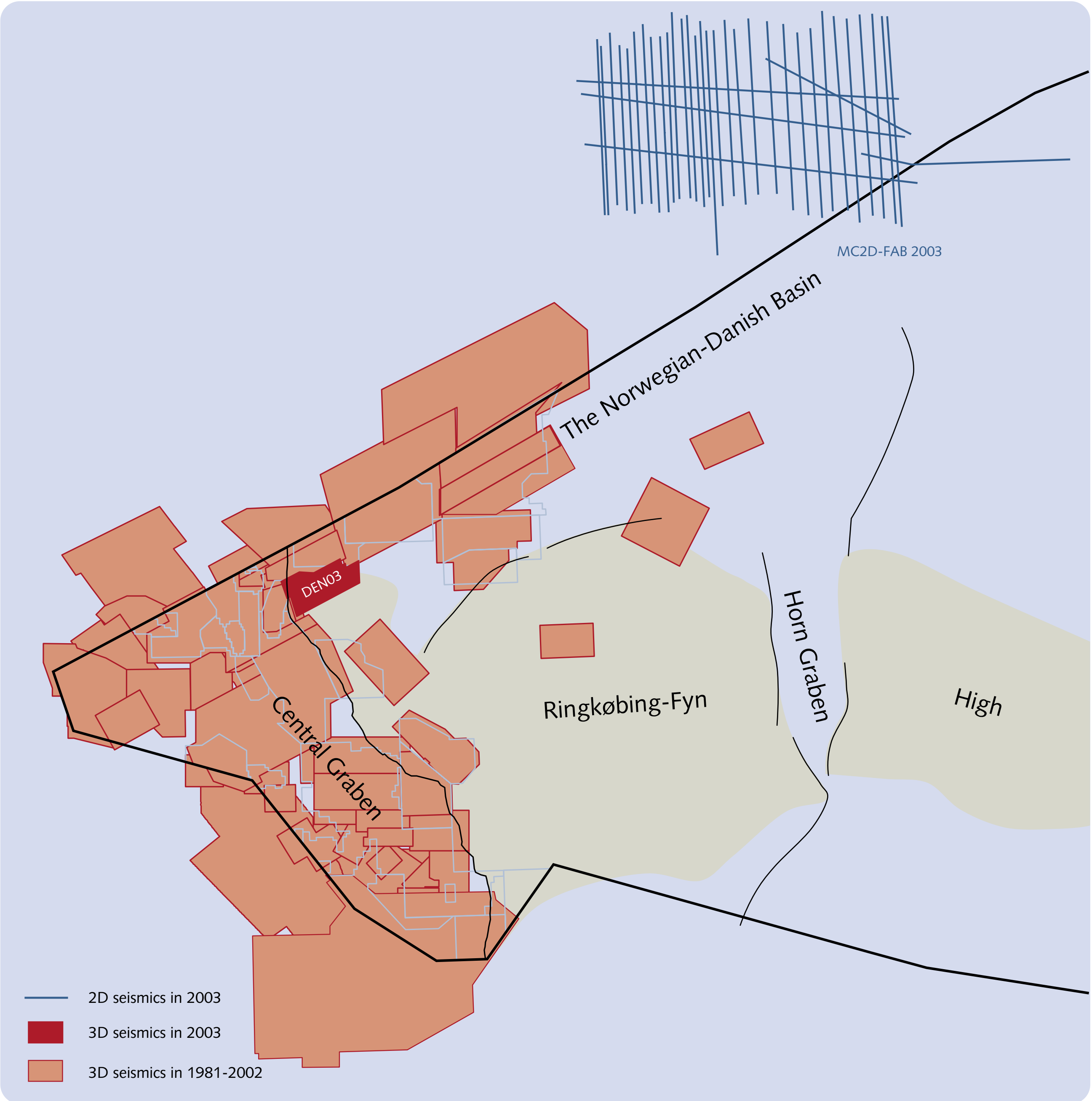
Sofie-1 (5605/13-3)

The Sofie-1 exploration well was drilled about 20 km northeast of the Siri Field. DONG E&P A/S, the operator for the oil companies holding licence 6/95, drilled the well in just over 14 days in May 2003. Sofie-1 was drilled as a vertical well, terminating at a depth of 1,988 metres below sea level in chalk of Danian age. Oil was discovered in Paleogene sandstone. Cores were taken from the oil reservoir, and samples of the oil were taken for evaluation purposes.

Hanne-1 (5504/6-5)

As operator for the oil companies holding licence 11/98, DONG E&P A/S drilled the exploration well Hanne-1 in July-August 2003. The exploration well was vertical and terminated at a depth of 2,965 metres below sea level in Upper Cretaceous layers. No hydrocarbons were encountered.

Fig. 1.7 Seismic surveys



Ophelia-1 (5603/32-4)

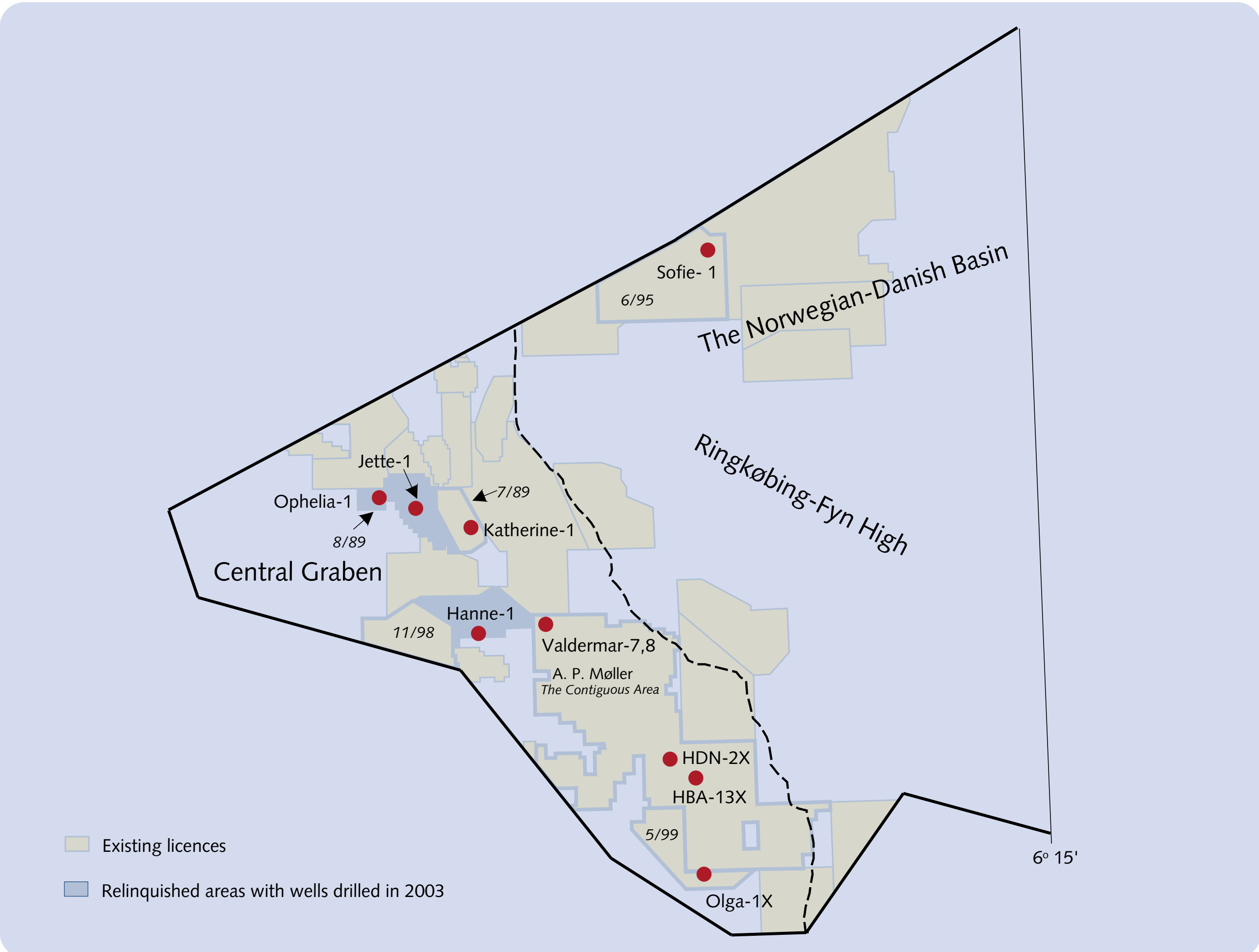
DONG E&P A/S, the operator for the oil companies holding licence 8/89, drilled the exploration well Ophelia-1 at a position about 15 km west of the South Arne Field in August-October 2003. The well was drilled as a vertical well and terminated at a depth of 4,919 metres below sea level in layers presumed to be of Rotliegendes age. Oil was discovered in the expected Upper Jurassic sandstone, but it was not deemed possible to initiate production from the tight reservoir.

Appraisal wells

Valdemar-7 (5504/7-10) and Valdemar-8 (5504/7-11)

In connection with the Valdemar Field development, Mærsk Olie og Gas AS drilled two wells, Valdemar-7 and Valdemar-8, from April to September 2003. As part of the Valdemar-7 well, a sidetrack was drilled to evaluate the hydrocarbon accumulation at the eastern flank of the Valdemar Field. The Valdemar-8 well was extended to investigate the reservoir properties in the northern part of the field. Both wells were subsequently completed as horizontal production wells in the Upper Cretaceous oil reservoir.

Fig. 1.8 Exploration and appraisal wells



HBA-13X (5505/13-9)
In May-June 2003, Mærsk Olie og Gas AS drilled the HBA-13X appraisal well. This well was drilled from the HBA platform in the Halfdan Field, where oil and gas have been discovered in both Danian and Maastrichtian chalk. HBA-13X was drilled as a horizontal well, penetrating Danian and Maastrichtian layers. Subsequent test production yielded satisfactory results. This well will be used as a production well in connection with the planned exploitation of the gas accumulation in the Halfdan and Sif Fields.

HDN-2X (5504/16-10)
In September 2003, Mærsk Olie og Gas AS drilled a vertical appraisal well, HDN-2X. This well provided important information about the extension of hydrocarbons in Danian chalk in the northwestern part of the Halfdan Field.

Katherine-1 (5604/30-4)
In cooperation with DONG E&P A/S, Amerada Hess ApS drilled the Katherine-1 appraisal well in the South Arne Field in September-December 2003. Katherine-1 was drilled as an almost vertical well in the crestal part of the chalk structure. Moreover, Katherine-1A, a deviated sidetrack, and Katherine-1B, an almost horizontal sidetrack, penetrated the eastern flank of the field.

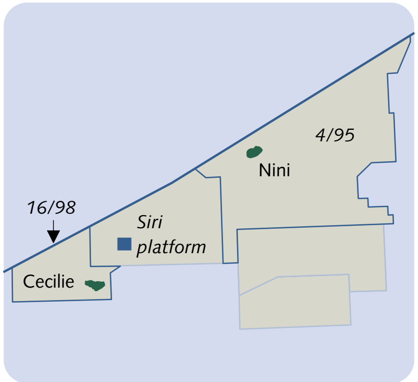
All three well sections fulfilled their objectives, encountering oil in both the crest of the structure and at the eastern flank of the field. The new data will be used for planning future production wells in the South Arne Field.

Geothermal well
Margretheholm-2 (5512/11-2)
As operator for HGS, Hovedstadsområdets Geotermiske Samarbejde (DONG, Energi E2, CTR, VEKS and Københavns Energi), DONG E&P A/S drilled the Margretheholm-2 well in June 2003. It was drilled at the Amagerværket power station to a depth of 2,750 metres below sea level. The well is not included in the statistics in Fig. 1.7.

Together with the Margretheholm-1 well, Margretheholm-2 will form part of a demonstration plant for exploiting geothermal energy. This plant is scheduled for commissioning in autumn 2004.

2. DEVELOPMENT

Fig. 2.1 Field development in the *Siri Fairway*



Development activity in the Danish sector of the North Sea remained high throughout 2003.

Production from three new fields commenced during 2003. Two new fields, Nini and Cecilie came on stream in August 2003, with DONG E&P A/S as operator; see Fig. 2.1. In spring 2003, platforms and pipelines were installed in the fields, and by the end of 2003 a total of five development wells had been completed.

Concurrently, production commenced from the Sif Field; see Fig. 2.3. At end-2003, a production test was carried out in the first well, and permanent production from the area will be initiated in the course of 2004. Production will take place from the installations in the nearby Halfdan Field.

New development wells were also drilled in a number of existing fields in 2003. A total of 24 development wells were drilled in 2003, corresponding to the level in preceding years. The number of drilling rigs operating in the Danish sector was lower than in previous years, as three rigs were used for accommodation purposes in the Halfdan and Siri Fields.

Fig. 2.2 shows existing production facilities in the Danish sector of the North Sea at the beginning of 2004.

Appendix B provides a survey of all the producing fields, including factual information about the fields and maps. Wells drilled in 2003 are marked with a light colour on the maps.

NEW FIELD DEVELOPMENTS

The Cecilie Field

The Cecilie Field, discovered in 2000, is situated in the so-called Siri Fairway in the northern part of the Danish sector; see Fig. 2.1.

In 2003, the field was developed as an unmanned satellite to the Siri platform. With the help of the world's largest crane vessel, Saipem 7000, the Cecilie platform was installed in the summer of 2003, and production from one well commenced in August 2003. An additional well was drilled at the beginning of 2004. Development plans also include the drilling of an injection well, as production from the field is based on water injection in order to maintain the reservoir pressure. DONG E&P A/S is the operator.

The Siri platform supplies injection water and lift gas to the Cecilie Field, while the gas produced is injected into the Siri reservoir to enhance recovery from the Siri Field.

Production from the Cecilie Field is conveyed to the Siri platform for processing, storage and further transport.

In January 2004, the Danish Energy Authority also received a plan for exploiting the Connie oil accumulation, located in the Cecilie licence area, by means of the installations in the Cecilie Field.

Fig. 2.2 Production facilities in the North Sea 2003

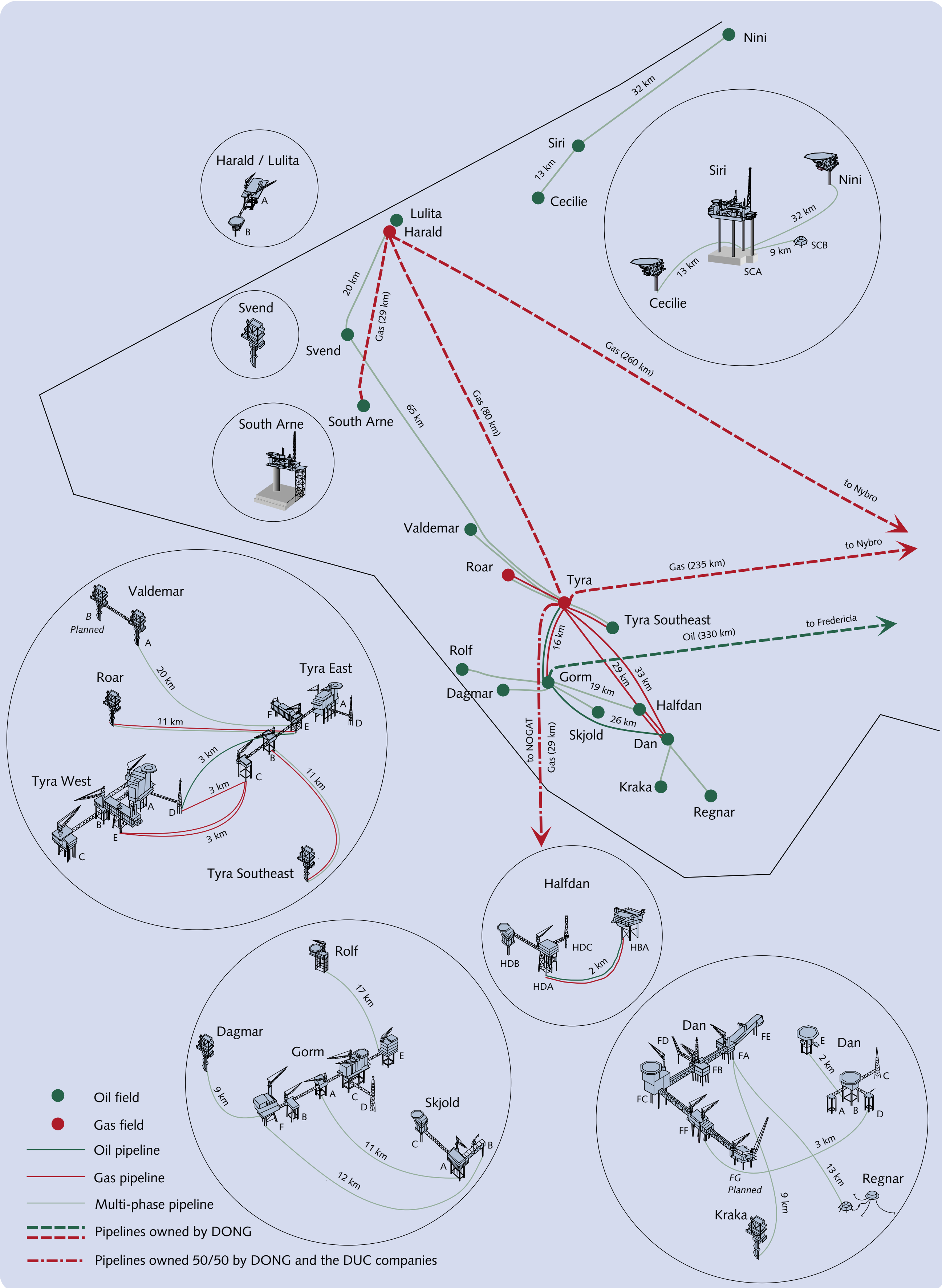
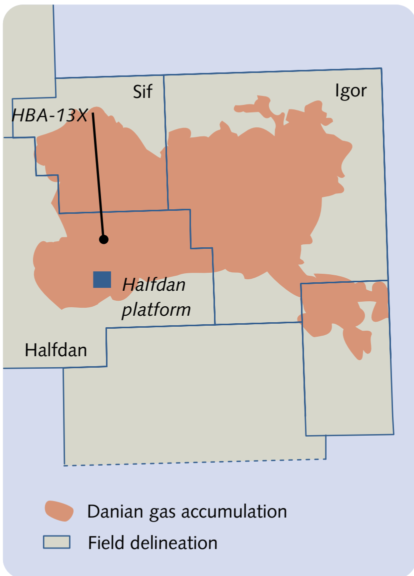


Fig. 2.3 Development of the Sif Field



The Nini Field

Like the Cecilie Field, the Nini Field was discovered in 2000. In July 2003, an unmanned platform was installed by means of the crane vessel Saipem 7000. The field was brought on stream in August 2003, with DONG E&P A/S as operator.

The field has been developed as a satellite to the Siri Field. Production from the Nini Field is piped to the Siri platform for processing. The Siri platform supplies injection water and lift gas to Nini, while the gas produced in the Nini Field is injected into the Siri reservoir to enhance recovery from the Siri Field.

By the end of 2003, a total of four development wells had been drilled in the field, three of which have been put into operation. Recovery is based on water injection.

The Sif Field

The Sif Field is part of a Danian gas accumulation extending across the Sif, Igor and Halfdan field delineations.

In 2003, a development plan was approved for the area. The plan involves phased development, with the first phases consisting of the drilling of development wells from the existing HBA satellite platform in the Halfdan Field. The platform has been extended with a gas-processing module. Mærsk Olie og Gas AS is the operator.

Spudded in the summer of 2003, the first well in the area, HBA-13X, reached a reservoir length of about 4,800 metres, after which the well underwent a production test. Temporary processing capacity limitations at the Halfdan platform mean that permanent production from the Sif Field is not expected to commence until the summer of 2004.

DEVELOPMENT OF EXISTING FIELDS

The Dan Field

The Dan Field is the largest Danish field. Although the field has carried on production since 1972, potential for further development continues to be found.

In 2001, a development plan was approved for the Dan Field, involving further development of the western flank towards the Halfdan Field. Of the eight wells planned, seven had been drilled by the end of 2003, four of them during 2003; see the field map in Appendix B. At the same time, seven existing wells were converted to water injection.

Towards the end of 2003, an updated well pattern for the western flank was approved, which provides for the drilling of four additional wells.

In 2002, a plan to change recovery strategy was approved for the area under the gas cap in the southeastern block of the field. Previously, production from this area had been carried out with conventional water injection, i.e. at rates sufficiently low to prevent the injection process from causing the reservoir rock to fracture. However, as part of the changed recovery strategy, tests with high-rate water injection have been initiated, which are expected to result in increased recovery due to fracturing of the reservoir. The test period runs until 1 October 2004.

A planned, new platform in the field, Dan FG, and the associated bridge module are to be equipped with new facilities, including a production separation system, produced-water treatment system, a gas-treatment and compression system and a water-injection system.

The Halfdan Field

Development of the Halfdan Field continues. The field came on stream in 1999, and has been developed in three phases to date. The overall development plan envisages a total of 46 wells, 25 production wells and 21 water-injection wells. In 2003, a total of seven wells were drilled in the field, and an additional three production wells were spudded.

As of end-2003, 26 wells were producing, while 13 wells were used for water injection; see the field map in Appendix B. The injection wells are used for production for a period of time before they are converted to water injection; see the section *Development*.

In the summer of 2003, a new processing module was also installed on the Halfdan HDA platform, along with an accommodation platform, HDB, and a flare stack, HDC. At the same time, receiving facilities for production from the Sif Field were installed, and a new gas pipeline was established from Halfdan HDA via Halfdan HBA to Tyra West.

The Rolf Field

Production in the Rolf Field was suspended for a large part of 2002, because the Rolf-3 well had to be shut in due to a leak in the production tubing. The shut-in of the Rolf-3 well caused a temperature drop in the pipeline to the Gorm Field, which meant that production from Rolf-5, the only producing well in the field, had to be stopped.

At the beginning of 2003, the Rolf-3 well was redrilled. The redrilled well, Rolf-3A, targeted the central, southern part of the Rolf Field; see the field map in Appendix B. The Rolf-3 well drained the Maastrichtian reservoir, whereas the new well section terminates in the Danian reservoir.

The Siri Field

The Siri Field was brought on stream in 1999. The Siri Field also comprises Stine segments 1 and 2; see the field map in Appendix B.

As a result of the tie-in of production from the three new satellite installations on the Siri platform, the oil, gas and water processing facilities at Siri require considerable expansion. Due to delays in the manufacturing of a new gas compressor, etc., final installation on the platform has been postponed until mid-2004. Because of the delay, some of the gas produced from Nini and Cecilie has been flared at Siri since the fields were commissioned in August 2003.

Production has been initiated from Stine segment 2, and the second horizontal production well, SCA-6, was drilled in the segment 2 area at the beginning of 2003. This well was drilled from the Siri platform.

Production from Stine segment 1 is expected to commence in 2004. The development of segment 1 provides for a subsea installation comprising a production well and an injection well. A pipeline will convey the production to the Siri platform for processing, storage and further transportation. Moreover, the Siri platform will supply injection water via a branch of the pipeline used for transporting water to the Nini Field.

The Skjold Field

In the summer of 2003, a horizontal water-injection well was drilled in the southwestern flank of the Skjold Field; see the field map in Appendix B. The aim is to increase pressure support in the area.

Moreover, according to the plan, the conversion of a few production wells to water injection is still outstanding.

The South Arne Field

A development plan for the field from 2001 is still under implementation. The ongoing phase of the plan involves the drilling of up to nine new wells.

In the spring of 2003, a production well was drilled in the northern part of the field. During the subsequent break in drilling activity over the summer and autumn, data acquired from the wells most recently drilled were evaluated. This evaluation led to the resumption of drilling operations in December 2003.

At the same time, the well pattern planned for the development has been updated. To date, hydrocarbons have been extracted from the Ekofisk formation through fractures made from production wells in the underlying Tor formation. But the updated well pattern means that wells are now also planned in the Ekofisk formation in order to optimize production. The first well drilled since drilling activity resumed is a dedicated Ekofisk well in the northern part of the field. Additional development wells are scheduled for drilling in 2004.

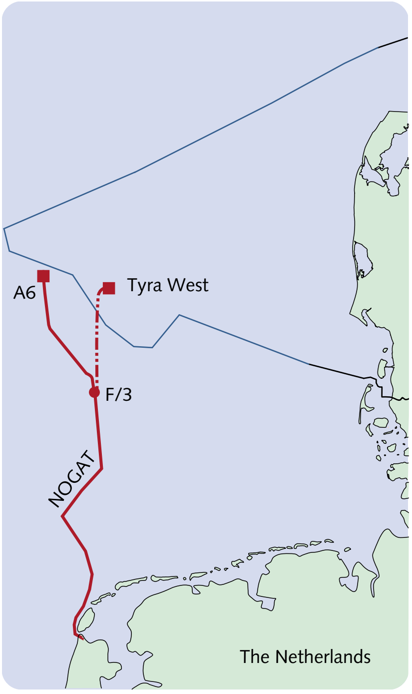
At the end of 2003, the exploration and appraisal well Katherine-1 was drilled in the South Arne Field; see the section *Licences and exploration*. The well was drilled as an almost vertical well in the actual ridge of the structure, with sidetracks targeting the eastern flank of the field. The aim was to compile data about the extent of the oil zone and the production properties of the central and eastern parts of the field. The new data from the Katherine wells will be used in planning future production wells in the South Arne Field.

The Tyra Southeast Field

Production from the Tyra Southeast Field commenced from five wells in 2002, and a sixth gas production well was drilled in the field in 2003; see the field map in Appendix B.

In addition, a plan for further developing the field with a seventh well was approved in 2003. Approval was also granted for an expansion of the existing water-processing facilities at Tyra East, which also treat the water produced at the Tyra Southeast Field.

Fig. 2.4 New pipeline trajectory



The Valdemar Field, the North Jens area

In the Valdemar Field, two new wells were drilled in 2003, both terminating in Upper Cretaceous layers. Appraisal sidetracks penetrating the Lower Cretaceous reservoir were also drilled as part of these wells.

In November 2003, the Danish Energy Authority received a plan for further developing the North Jens area in the Valdemar Field. This plan involves major development of the Lower Cretaceous reservoir and includes the drilling of eight horizontal production wells. Drilling is expected to commence in mid-2005 from a new unmanned platform with capacity for 12 wells. This platform will be bridge-connected to the existing Valdemar A platform. Concurrently, separation facilities will be established in the Valdemar Field, and the wet gas will be transported through a new pipeline to Tyra West, while the liquids produced will be transported through the existing pipeline to Tyra East.

Pipeline for exporting gas

A new 26" gas pipeline from Tyra West E to the F/3 platform in the Dutch sector was established in the autumn of 2003. From there, gas will be conveyed through the existing NOGAT pipeline to the Netherlands. The pipeline is expected to start operating in 2004.

The new pipeline, with a capacity of 15 million Nm^3 per day, will be owned by DONG (50%), Shell (23%), A.P. Møller (19.5 %) and Texaco (7.5%) and operated by Mærsk Olie og Gas AS.

FUTURE FIELDS

A number of minor fields, viz. Adda, Alma, Amalie, the Boje area, Elly and Freja, are expected to undergo development in the coming years.

Details about the fields, including planned commissioning dates, are available from the Danish Energy Authority's website at www. ens.dk.

3. PRODUCTION

OIL PRODUCTION

Danish fields in the North Sea produced 21.3 million m³ of oil in 2003. This is 1% less than in 2002, when Denmark set a production record.

Production from the Halfdan Field increased by a substantial 17% in 2003 compared to 2002, see Fig. 3.1, due to the continued development with new wells. However, a number of fields recorded declining production in 2003, so the year's total production was close to the production figure for 2002.

At end-2003, there were 20 producing oil and gas fields in Denmark. Three minor fields, Nini, Cecilie and Sif, were brought on stream during the year, see the section entitled *Development,* accounting for 2.6% of total production for the year.

Danish fields have a total of 240 wells from which oil and gas can be produced, while 113 wells can be used for injecting water and/or gas.

In 2003, ten companies received and sold oil and natural gas from the Danish fields. Fig. 3.2 shows each company's percentage contribution to total oil production in 2003.

NATURAL GAS PRODUCTION

In 2003, Danish fields produced 10.21 billion Nm³ of natural gas, of which 2.43 billion Nm³ was reinjected, while 0.65 billion Nm³ was utilized to operate production facilities offshore. Moreover, 0.23 billion Nm³ was flared for technical reasons. The section *The Environment* provides a detailed description of fuel consumption and gas flaring offshore.

Thus, 6.90 billion Nm³ of natural gas from the North Sea fields was sold in 2003, 5% less than total gas supplies in 2002.

Fig. 3.1 Oil production from the Halfdan Field

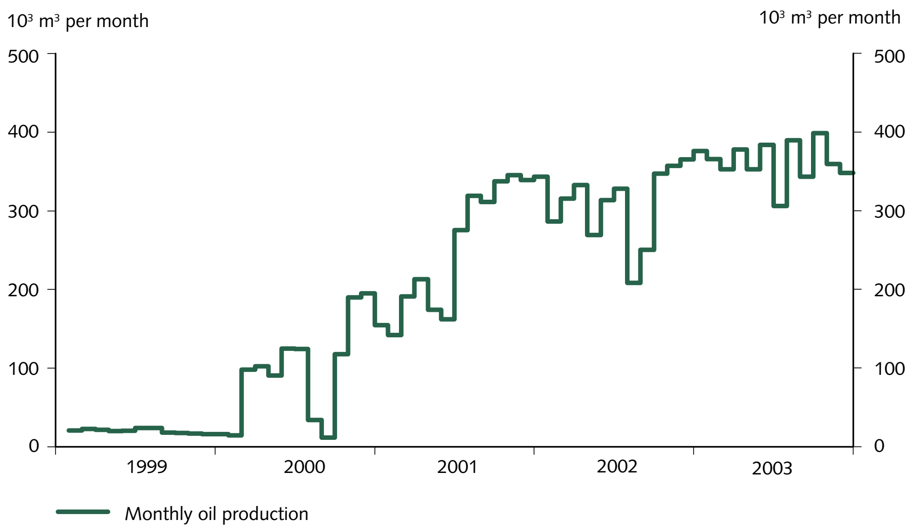
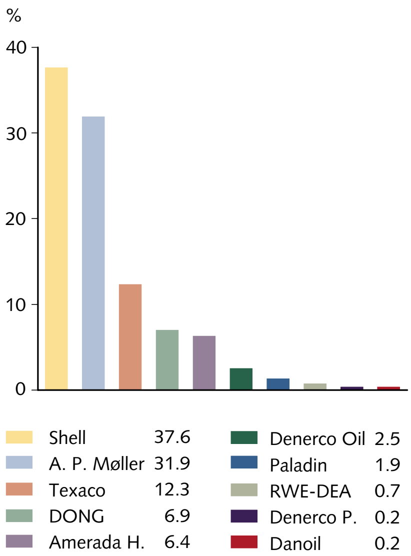


Fig. 3.2 Breakdown of oil production by company



WATER PRODUCTION

In addition to hydrocarbons, a reservoir always contains a certain amount of water. As a result, water makes up a percentage of the liquids produced. The reservoirs in the Danish area typically contain from 50% to 90% hydrocarbons, while the rest of the reservoir is water-filled. The water content of production increases as production progresses, because the surrounding water gradually displaces the oil.

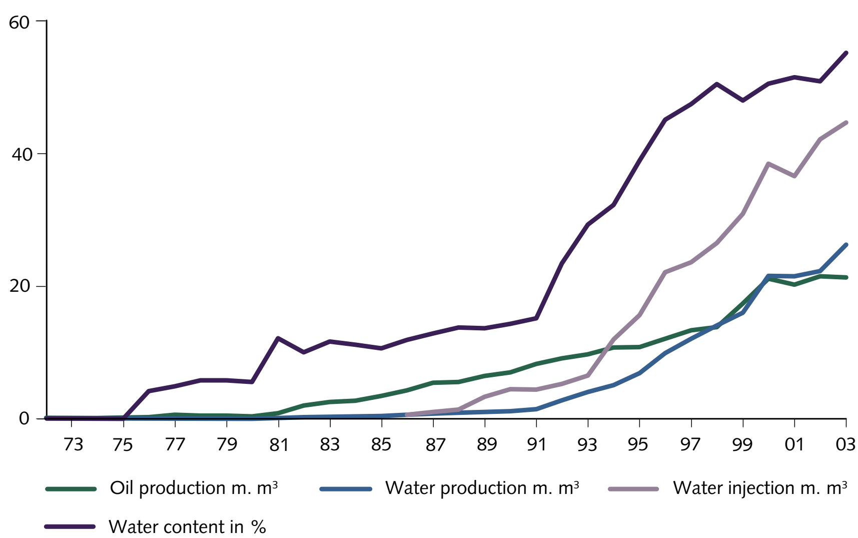
Injecting water into the field can accelerate the natural displacement of oil. The water content of total liquid production from Danish fields increased to more than 55% on average in 2003. This is a marked increase from 2002, when water represented a 51% share of production. Fig. 3.3 shows the development in oil and water production, as well as the water content of total liquid production from all Danish fields. This figure also shows the development in water injection.

The water-injection method has been used for many years in a number of fields and is becoming increasingly widespread. The aim is to maintain the reservoir pressure, which would otherwise fall as a consequence of production, and to displace oil from the reservoir. Thus, injecting large amounts of water helps stabilize, accelerate and increase oil production.

Efficient recovery of oil requires the injection of water quantities sufficient to flood the total reservoir volume several times. In a number of fields, the volume of water currently injected corresponds to total oil and water production, meaning that an equilibrium in volume terms is maintained.

In the South Arne Field, the volume of water injected in recent years substantially exceeds the volume extracted from the reservoir. The intention is to restore the reservoir pressure. This makes it possible to maintain current production rates, but since increased injection also results in higher water production, the water content is also expected to rise significantly in the years ahead.

Fig. 3.3 Development in water production



The water content of oil production from new wells is generally low at the outset. Oil production will then gradually decline, and the water content increases in step with the oil being produced. In an oil field where pressure support has been established by means of water injection, the high production rate can be maintained for a longer period of time. However, at some point, water injection will result in a substantially higher water content.

PRODUCING FIELDS

Danish oil production started in 1972 and was augmented as an increasing number of fields began producing; see Fig. 3.5. In the second half of 2003, another three minor fields came on stream, Nini, Cecilie and Sif. However, production from the Sif Field was limited to short-term test production. Once the installation of processing equipment on the Halfdan platform has been completed, regular production from the Sif Field can commence.

Appendix A shows figures for the production of oil and gas from the individual fields. Appendix A also provides figures for water production and injection, fuel consumption and gas flaring and gas injection, as well as a table of CO_2 emissions from the North Sea installations. Annual production figures since 1972 can be obtained from the Danish Energy Authority's website www.ens.dk.

Fig. 3.4 Danish oil and gas fields

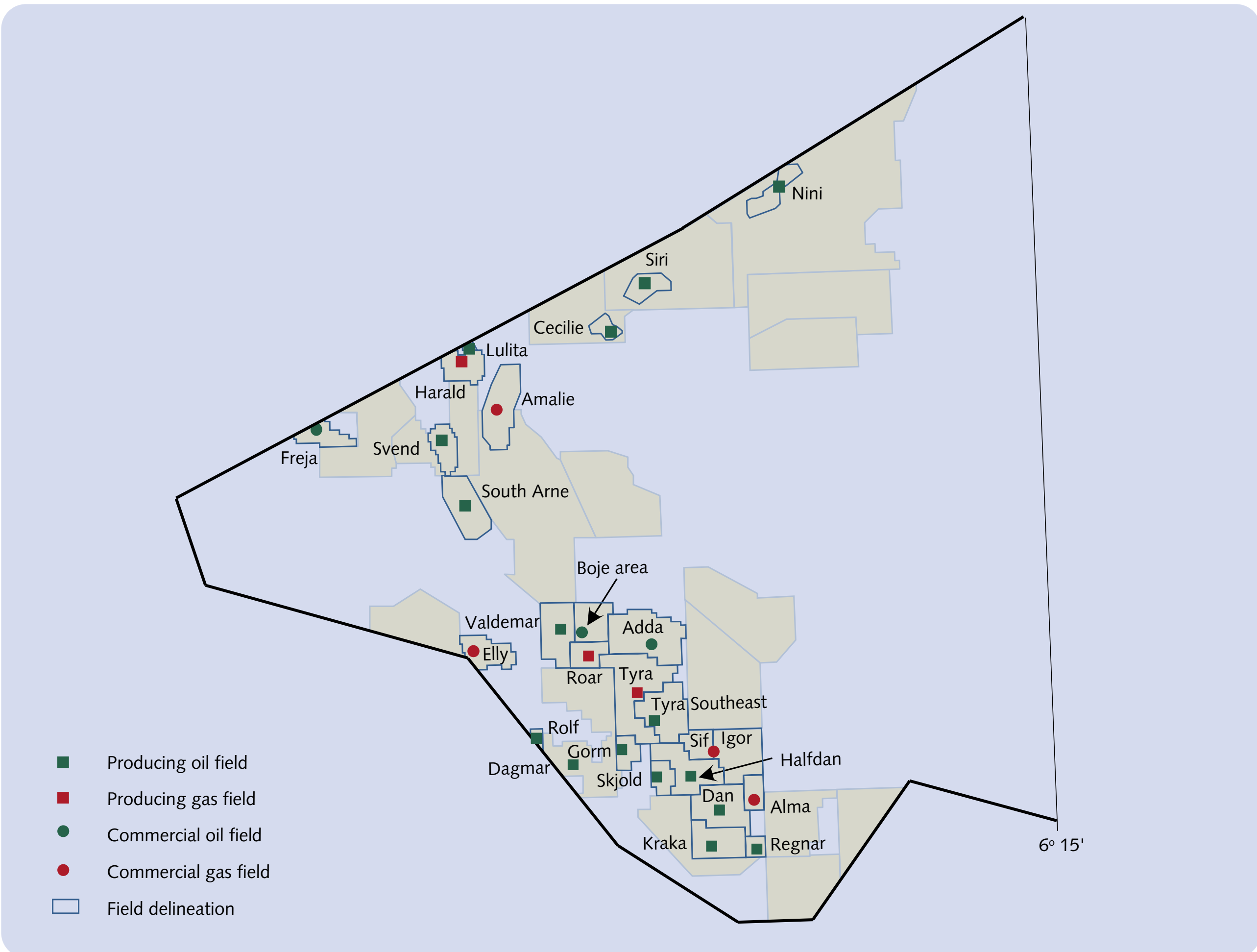
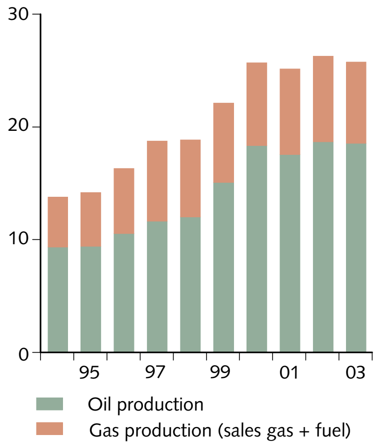


Fig. 3.5 Production of oil and gas

m. t. o. e.



Appendix B provides a schematic overview of the producing oil and gas fields. Major production developments in 2003 are briefly outlined below. Danish oil and gas fields are shown in Fig. 3.4.

The Dan Field

Oil production from the Dan Field dropped by 6% in 2003, corresponding to about 400,000 m^3. Thus, production has decreased for the second year in a row.

The capacity of the facilities processing gas from the Dan and Halfdan Fields limits the volume producible from the Dan Field. This makes it necessary to prioritize capacity when production from the two fields is processed. As production from the Halfdan Field has a lower gas/oil ratio (GOR), it is advantageous to produce oil from the Halfdan Field instead of from the Dan Field. Consequently, the Dan Field does not produce to capacity, although it remains the Danish field with the largest production. Since oil production started in 1972, the Dan Field has yielded an overall 69.5 million m^3 of oil, equal to about 30% of total Danish oil production.

In 2003, the water content of production rose to 55%, a figure that should be viewed in light of the large volumes of water injected into the field. The injected water volume now exceeds the volume of oil and gas produced. The use of high-rate water injection in large parts of the field accelerates oil production, while also increasing water production.

The Cecilie Field

The production of oil and gas from the Cecilie Field commenced in August 2003. This field is producing smaller quantities of oil than expected.

The Gorm Field

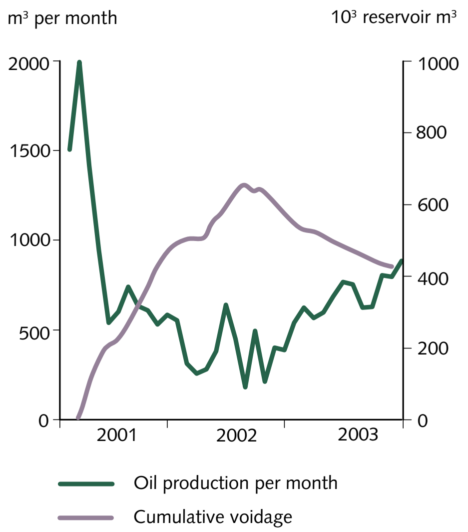
Production from the Gorm Field was stable in 2003, but the year's total production was 2% lower than in 2002. Large volumes of water are injected into the Gorm Field to maintain pressure, resulting in steadily increasing water production in the field. Thus, the water produced in 2003 represented 61% of total liquid production.

The Halfdan Field

The development of the Halfdan Field continued in 2003 with the completion of a number of new wells and the conversion of existing wells to water injectors; see the section entitled *Development*. This resulted in a 17% increase in oil production from the field. High-rate water injection was initiated in 2002, and this pressure support helps sustain production from the wells. Production continues with a low water content of about 10%.

The production figure for the HDA-8 well, as shown in Fig. 3.6, clearly illustrates the result of using water injection to maintain reservoir pressure. Production from this well was following a downward curve until pressure support was established in the area after about one year's production from the well. Two horizontal injection wells were placed on either side of the production well, with parallel well trajectories. Initiating water injection has yielded obvious results, with the decline reversing to show a steady upturn in production.

Fig. 3.6 Oil production from HDA-8



The development of the Halfdan Field is based on Fracture Aligned Sweep Technology, termed FAST by the operator, Mærsk Olie og Gas AS. The FAST technology involves drilling a pattern of alternating production and injection wells with long, parallel well trajectories. Future water injectors will first be used for production in order to benefit from high initial production rates and to reduce the reservoir pressure. Water is subsequently injected at low pressure. During this process, a parallel pattern of high- and low-pressure zones is established, which affects the principal stress directions in the reservoir rock, causing the minimum principal stress to run perpendicular to the wells.

Once the water-injection pressure is increased, the source rock fractures along the well trajectory, thus allowing an almost free flow of water into the fractures. This generates a continuous water front along the entire length of the well, which drives the oil in the direction of the production wells. This displaces the oil effectively and relatively swiftly. The disadvantage of this method is that, at some point, it will cause a rapid increase in water production, once the water front has reached the production wells.

To some extent, production from the Halfdan Field is limited by the capacity of production facilities in the Dan and Gorm Fields, which handle the Halfdan production. The Halfdan installations are used to separate the hydrocarbons produced. After separation, the gas is conveyed to the Dan Field processing facilities, while the oil from Halfdan is transported to the Gorm Field facilities for further processing. This practice will be discontinued upon the commissioning of the processing facilities in the Halfdan Field.

The Nini Field

The production of oil and gas from the Nini Field was initiated in August 2003. This field is producing larger quantities of oil than expected.

The Rolf Field

Production from the Rolf Field increased considerably once the Rolf-3 well had been redrilled. Thus, oil production in 2003 exceeded the volumes produced from Rolf in 2001 and 2002 together. However, the Rolf Field remains a minor Danish oil field.

The Siri Field

The Siri Field produces oil and gas from sandstone layers, with the combined injection of gas and water providing pressure support. Oil production declined by 38% in 2003, and the water content of production rose from 67% to 76% in 2003.

Extensive installation works were carried out in the Siri Field in 2003 as a result of the tie-in of the Nini and Cecilie Fields. These installation works involved a number of planned shutdowns of the processing facilities.

Moreover, the Nini and Cecilie Fields began producing in August 2003, before the expansion of the platform processing facilities had been completed. The installation of a new gas compressor and other equipment in the field is not expected to be completed until mid-2004.

To provide capacity for processing the gas from Nini and Cecilie, the production from Siri and Stine segment 2 was reduced considerably. This reduction was carried out to limit the extent of temporary gas flaring on the Siri platform.

The Skjold Field
Oil production from the Skjold Field fell by 8% in 2003, in keeping with the trend from previous years. At the same time, water production continued to rise in 2003, the water content of production from Skjold now totalling 70%.

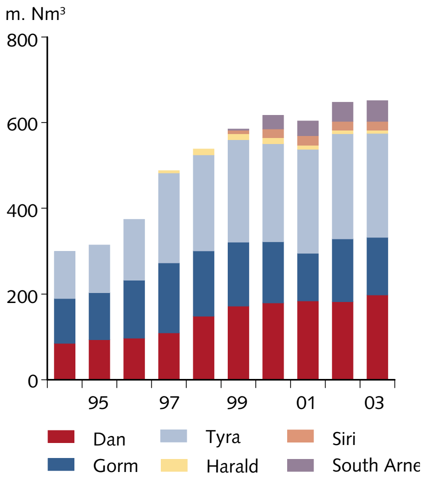
The South Arne Field
Oil production from the South Arne Field went up by 3% in 2003, due to the drilling of one new production well in the field. Moreover, water is injected at a very high rate. Thus, the amount of water injected is now almost double the total amount of liquids produced. Water production is more than twice as high as in the preceding year, now representing 26% of total liquid production.

The Tyra Southeast Field
After the field came on stream in March 2002, production decreased by 31% in 2003 compared to the year before. Water production has climbed substantially and now accounts for 63% of the liquid production.

The Valdemar Field
Two new wells were drilled in the Valdemar Field in 2003 to supplement the two successful production wells drilled in 2002. These wells have contributed to the 23% growth in oil production. Natural water production in the field remained stable in 2003 because of the new wells, which produce oil with a lower water content than average. A development plan for the Valdemar Field provides for the drilling of eight new wells in the Lower Cretaceous reservoir.

4. THE ENVIRONMENT

Fig. 4.1 Fuel consumption



CO_2 ALLOWANCE TRADING

An EU Directive on a proposed scheme for greenhouse gas allowance trading was adopted in October 2003 as part of the duty of EU countries to meet the Kyoto Protocol targets for reducing greenhouse gas emissions. Initially covering CO_2 emissions only, the Directive will be implemented in Denmark by an Act on CO_2 allowances to become effective on 1 January 2005.

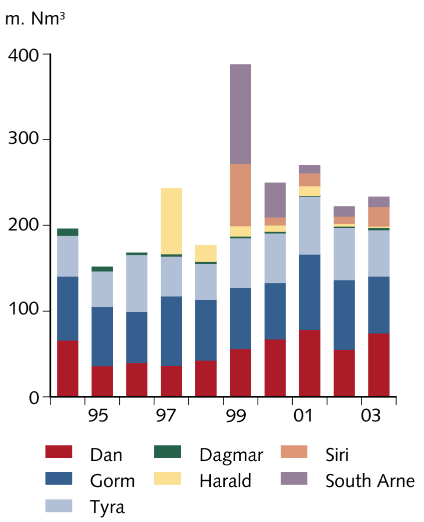
The Directive means that a number of enterprises carrying out activities comprised by the Directive must turn in allowances corresponding to their CO_2 emissions for the year. The activities falling under the new Act account for the equivalent of half all Danish CO_2 emissions in 2003. Energy consumption for generating electricity, power and heating in connection with oil and gas production and gas flaring is one of the activities covered by the allowance system. In Danish territory, installations in seven fields will be comprised by the allowance system.

In the Danish Bill for implementation of the Directive, the principle for allocating allowances to oil and gas production companies corresponds to the principles used for other Danish industries. For most types of production, energy consumption based on a given technology is proportionate to the size of production. In contrast, the energy consumption per t.o.e. increases over the lifespan of an oil or gas field due to natural conditions. Under this allocation model, oil companies are not compensated for this difference.

According to the Bill presented, allowances representing the emission of 2.3 million tons of CO_2 per year will be granted to oil and gas production companies. In addition, companies establishing new installations can apply for additional allowances from a pool. The new Act is expected to result in a 7.4% reduction of CO_2 emissions compared to the emissions expected if no measures had been taken. To meet the target set for 2008-12, the allocation of allowances will be reduced starting in 2008. How the individual activities will contribute to this reduction will be decided in 2006.

The Danish Energy Authority expects that it will be possible to modify some of the offshore installations to reduce CO_2 emissions, with the activities continuing unchanged. However, it is less probable that the sector overall will be able to carry out sufficient reductions so that the purchase of additional allowances can be avoided. Therefore, the Danish Energy Authority will follow the measures taken by oil companies to reduce CO_2 emissions.

Fig. 4.2 Gas flaring



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 sizeable amount of gas that cannot be utilized for safety reasons or due to the technical design of the plant has to be flared.

Gas consumed as fuel accounts for approx. three-fourths of the total volume of gas consumed and flared offshore. The North Sea installations release CO_2 into the atmosphere due to the use of gas and diesel oil as fuel and the flaring of gas. The volume emitted by the individual installation or field depends on the scale of production as well as plant-related and natural conditions.

Fig. 4.3 CO_2 emissions from production facilities in the North Sea

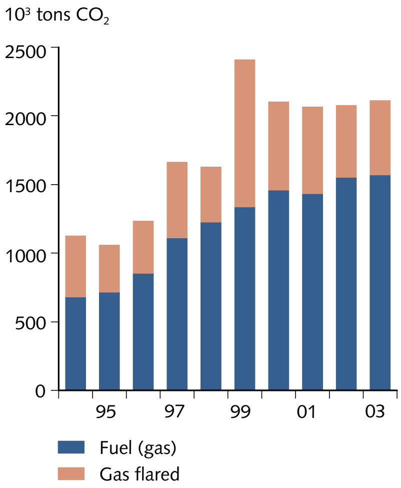
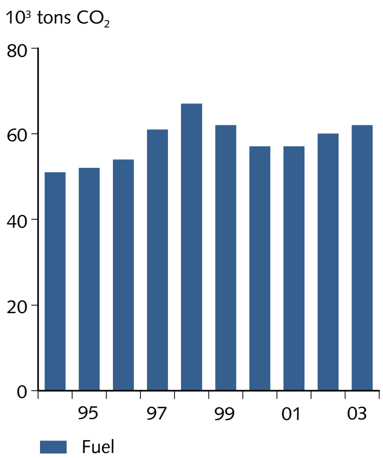


Fig. 4.4 CO_2 emissions from consumption of fuel per m. t.o.e.



Figs. 4.1 and 4.2 show the amounts of gas used as fuel in the processing facilities and the gas flared in the past ten years. It appears from these figures that rising production and the general ageing of the fields have caused the use of gas as fuel to increase considerably on the Danish production facilities during the past decade.

From 2002 to 2003, the amounts of gas flared increased slightly by some 12 million Nm^3, or about 5%. The DUC fields recorded a minor reduction in total gas flaring, but there were major variations among the individual processing centres.

In 2003, gas flaring in the South Arne Field remained at the same low level as the year before, while flaring in the Siri Field increased significantly compared to the period 2000-2002. This increase is mainly attributable to the tie-in of production from the Nini and Cecilie Fields on the Siri platform. Extraordinary amounts of gas had to be flared due to a delay in the expansion of the processing facilities on the Siri platform.

CO_2 emissions in 2003

The development in the emission of CO_2 from the North Sea production facilities since 1994 appears from Fig. 4.3. This figure shows that CO_2 emissions totalled about 2.1 million tons in 2003, virtually the same as in the period 2000-2002. The production facilities in the North Sea account for 3-4% of total CO_2 emissions in Denmark.

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

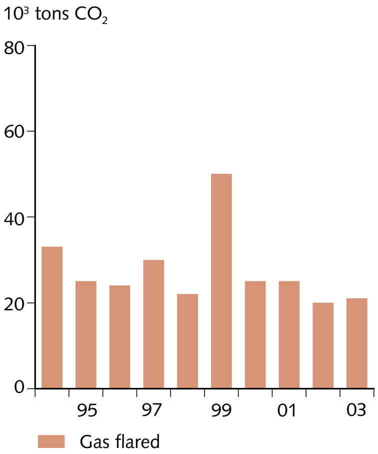
It appears from this figure that CO_2 emissions due to fuel consumption have generally increased relative to the size of production, from about 50,000 tons of CO_2 per million t.o.e. to about 60,000 tons of CO_2 per million t.o.e. over the past decade. One reason is the rising average age of the Danish fields. Energy consumption per produced t.o.e. increases over the life of a field due to natural conditions.

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 Fields resulted in extraordinary amounts of gas being flared temporarily. Both in 2002 and 2003, gas flaring relative to the volume of production reached the lowest level recorded in the past decade.

Compared to other North Sea countries and the scale of production, the Danish sector has relatively many production facilities. All things being equal, this limits the possibility to improve energy efficiency, thus increasing the CO_2 emission per produced t. o. e. However, the choice of technical equipment also plays a pivotal role for the energy efficiency of the facilities and the need for flaring. The introduction of CO_2 allowances as part of the overall climate strategy underscores the need to continue improving energy efficiency and reducing gas flaring at the North Sea production facilities.

Appendix A includes a table of the amounts of gas used annually as fuel at the individual production centres, the amounts of gas flared annually and calculated CO_2 emissions. In this connection, it should be noted that the figures indicated have undergone minor corrections compared to previous years. The most signifi-

Fig. 4.5 CO_2 emissions from gas flaring per m. t.o.e.



cant correction concerns the calorific value of the gas produced in the South Arne Field, resulting in an upward adjustment of 75% compared to previous years. The table does not include CO_2 emissions deriving from the consumption of diesel oil at the production facilities.

DISCHARGES INTO THE SEA

A range of chemicals is needed for the work of exploring and exploiting North Sea oil and gas reservoirs. These chemicals may occur naturally or be manufactured with special properties, and they must be used with due consideration for the working environment and the impact on the surrounding environment. The same applies to products extracted from the subsoil, i.e. hydrocarbons and any natural substances associated with hydrocarbons.

Substances extracted from the subsoil are generally handled in closed systems, while the chemicals used are transported from land and added to the processes. Residual products from production are transported to shore for processing, recycling or waste disposal or are discharged at the site, depending on the environmental assessments made.

The Danish Energy Authority supervises the storage and use of chemicals in the working environment on drilling rigs and production facilities in the Danish sector of the North Sea, while the Danish Environmental Protection Agency supervises the impact of chemicals on the surrounding environment. The two authorities work together to regulate this area.

The Danish Environmental Protection Agency grants permission for marine discharges based on various requirements, including those laid down in international cooperation with the other North Sea countries. This cooperation takes place under the auspices of the Oslo-Paris convention from 1992 (OSPAR), which entered into force in 1998. The OSPAR *Offshore Industry Committee* (OIC) deals with conditions offshore. At the same time, international efforts to formulate an EU strategy for the marine environment are ongoing.

OIC's current work includes establishing environmental goals for marine discharges of chemicals from drilling operations and production activities, as well as implementing these goals. Moreover, the work on goals and requirements for the discharge of oil with produced water continues.

At its most recent meeting in March 2004, OIC decided to implement programmes to measure the content of dissolved, light oil components in water discharged from production platforms, as well as the content of natural oil in cuttings from drilling operations in reservoir layers. This initiative was taken to evaluate the need for supplementing the existing requirements for the discharge of dispersed oil (oil droplets) and the total discharge of oil. The work on chemicals currently concentrates on identifying the chemicals used, introducing a harmonized environmental hazard classification and determining the quantities used.

The OSPAR activities include work on long-term generation goals for 2020, and a number of recommendations have been adopted to meet them. As a result, in 2006 the concentration of dispersed oil is to be reduced from 40 mg per litre to 30 mg per litre in discharged, treated production water. At the same time, the total discharge of oil into the sea is to be reduced by 15% compared to the amount discharged in 2000.

EIA for offshore activities

Approval of new offshore oil and gas development activities or major alterations to existing facilities require an evaluation of how the planned activities will affect the environment, a so-called Environmental Impact Assessment (EIA).

In 2003, no new Environmental Impact Assessments were prepared in connection with oil and gas development activities in the North Sea. All of the development activities approved by the Danish Energy Authority during the year were covered by previously prepared EIAs that have been submitted to public hearings.

In this connection, reference is made to previous editions of "Oil and Gas Production in Denmark".

5. HEALTH AND SAFETY

The high level of exploration and development activity in the Danish sector of the North Sea increased the focus on safety on offshore installations and the need for temporary accommodation in conjunction with the fixed offshore installations. It also resulted in increased transport to and from the individual installations.

In November 2002, the Government presented an action plan on the safety of oil and gas activities in the Danish sector of the North Sea. As part of implementing the action plan in 2003, the Danish Energy Authority increased its inspection activity and focus on the oil companies' efforts to improve safety and the working environment on oil and gas offshore installations.

ACTION PLAN

In May 2001, a gas explosion in the Gorm Field injured two persons and caused an oil production loss of more than DKK 1 billion; see the report "Oil and Gas Production in Denmark 2001".

At the Danish Energy Authority's request, the Norwegian SINTEF institute investigated safety conditions in the Gorm Field in 2002. Based on SINTEF's report, the Government presented an action plan in November 2002 with measures regarding safety on board the North Sea installations. The action plan underscores that safety standards on Danish offshore installations must continue to rank among the highest in the North Sea countries, and that safety may not be disregarded due to other interests.

In 2003, the Danish Energy Authority focused on implementing the seven initiatives set out in the action plan. The Danish Energy Authority believes that the action plan has contributed to maintaining the high level of health and safety on the installations in the Danish sector of the North Sea.

Information about the action plan is available in Danish at the Danish Energy Authority's website www.ens.dk, including reports on the individual elements of the action plan, outlines of inspections carried out in 2003, and a comprehensive statement to the Energy Policy Committee of the Danish Parliament on the implementation of the action plan.

Elements of the action plan

The action plan involved stepped-up inspection activity. In 2003, the Danish Energy Authority carried out 31 offshore inspections on fixed and mobile offshore units and seven onshore inspections, including reviews of information about the North Sea facilities on file at the oil companies' offices.

At the inspections, the Danish Energy Authority evaluated the oil companies' follow-up of the safety recommendations made by SINTEF, and found no major safety lapses.

The frequency of inspections at manned production installations will be stepped up starting in 2004, averaging once every eight months compared to about every 15 months in 2002 and prior to that.

As part of the action plan, the Danish Energy Authority conducted an audit of the North Sea operators' safety management and similar control systems in 2003. The aim of these systems is to ensure and document compliance with the statutory requirements for health and safety on the North Sea installations. The audit showed that the companies' safety management systems generally meet statutory requirements.

Safety cases must be prepared for all offshore installations to describe and document safety conditions on board. Safety cases include an assessment of the risks of major accidents and a description of the measures taken to minimize these risks. A review of the safety cases for all fixed offshore installations made in autumn 2003 showed that the safety cases are largely in compliance with statutory requirements.

Using information on injuries and "Near-miss" occurrences is an important element in preventing accidents and injuries. A review of the oil companies' registration and follow-up of "Near-miss" occurrences in 2003 showed that on the whole the companies attempt to investigate underlying causes and are alert to the need for technical improvements or changes in procedures, for example.

As part of the action plan, efforts are ongoing to update health and safety rules and improve their efficiency, including updating the Danish Energy Authority's guidelines for the design of fixed offshore installations. A new Offshore Installations Act is also being drafted.

Measuring the effect

The intensified efforts regarding inspections as well as other types of supervision will be continued in the years ahead. The Danish Energy Authority is working on a new initiative to develop indicators to measure the effect of supervision. In 2004, the Danish Energy Authority will attempt to establish a basis for developing measures of effect in the following areas:

- Inspection of fixed, manned offshore installations
- Prevention of gas leaks
- Visibility and perceived effect of the Danish Energy Authority's inspections (Questionnaire survey conducted offshore in 2004)
- Prevention of work-related accidents
- Maintenance of safety-critical equipment

Simplifying regulations

The existing set of regulations, developed since the Offshore Installations Act entered into force on 1 January 1982, has become increasingly impenetrable for users, i.e. companies and employees in the offshore oil and gas industry. The administration of these rules has also become relatively complex from the point of view of users as well as the authorities.

In 2002, a working group under the Coordination Committee on Offshore Installations began mapping existing legislation. The Committee is composed of representatives of the two sides of industry and the public authorities involved. The Committee assists the Danish Energy Authority in coordinating the supervisory authorities' work and drafting rules.

The above-mentioned working group was appointed to evaluate where changes are needed in order to simplify the existing rules and administrative system. They completed their work in November 2003.

The result is a rules structure that, when implemented, will be a simplified and updated version of the existing one.

Subsequently, the new set of rules will be drafted in cooperation between the public authorities and the two sides of industry. A new draft Act to replace the existing Offshore Installations Act is expected to be presented to the Danish Parliament in the spring of 2005. It was considered expedient to draft a completely new and updated Act that reflects the developments in working environment legislation and in the offshore health and safety area in the other North Sea countries.

MOBILE OFFSHORE UNITS AS ACCOMMODATION

In 2003, extensive maintenance, repair and installation works were carried out on the fixed offshore installations in the Danish sector of the North Sea. Some of this work involved safety measures, a number of which were implemented as a consequence of the experience gained from the explosion in the Gorm Field in 2001.

The fixed offshore installations are equipped with accommodation facilities that meet the expected requirements during normal operation and maintenance. When a new installation is constructed or very extensive works are carried out on an existing installation, temporary facilities are needed to house the extra manpower.

Mobile offshore units that are bridge-connected to a fixed installation can be used as temporary accommodation. The world market has a limited number of mobile offshore units that are specially designed or have been converted for use as accommodation. Moreover, accommodation facilities on drilling rigs can be used.

The flotels that can be rented on the world market have not been designed specifically to comply with Danish rules and regulations. Therefore, before a mobile unit is used for temporary accommodation in Danish territory, an assessment must be made of the overall conditions on board the installation. In this connection, it must be ensured that the use of flotels does not reduce the safety level for the fixed offshore installations and their personnel or the quality of their accommodation facilities.

The Danish Energy Authority and the Danish Maritime Authority jointly supervise mobile offshore units.

TRANSPORTING PERSONNEL TO AND FROM OFFSHORE INSTALLATIONS

The operation of both fixed and mobile offshore units and construction works at production installations require the necessary personnel to be transported to and from the work site. Such transport usually takes place by helicopter. Therefore, all mobile units and the majority of fixed production installations are provided with a helideck.

The high offshore activity level has forced up the number of helicopter operations, not only between shore and offshore installations, but also between the individual offshore installations. The Danish Civil Aviation Administration is responsible for supervising safety in connection with helicopter transport.

Table 5.1 Reported accidents by category

Reports	Mobile	Fixed
The victim falls, slips or trips over objects	18	1
Crush injury	15	3
Use of tools/equipment	8	2
Falling objects	1	0
Electrical injuries	1	0
Ergonomic injuries (lifting, pulling, pushing)	6	2
Other	0	3

A number of production installations have been designed and built as unmanned satellite platforms without a helideck, and transport to them is by boat. To protect the health and safety of the personnel working on such unmanned platforms, the Danish Energy Authority has set a number of limitations on the number of personnel allowed on the platforms and the conditions under which they may be manned.

SUPERVISION FOCUS AREAS

In cooperation with other Danish authorities, the Danish Energy Authority supervises health and safety matters associated with oil and natural gas exploration and production activities in the Danish sector of the North Sea.

Supervision, including inspections of installations, focuses on a number of basic safety and working environment conditions. In addition, supervision focuses on varying themes such as hazardous substances and materials and preventing work-related accidents, the themes for 2003.

To strengthen cooperation with the operators of fixed offshore installations in preventing work-related accidents, in 2003 the Danish Energy Authority invited the operators to discuss their accident-prevention initiatives; see the section below on personal injuries on offshore installations.

Based on the theme of the European Working Environment Week, the Danish Energy Authority's focus areas in 2003 also included handling and storing chemicals, as well as the companies' management of chemicals.

The European Working Environment Week in 2003 was an information campaign targeted at preventing the risks associated with dangerous substances and materials. The aim of the campaign was to promote activities to reduce the risks connected with work involving dangerous substances and materials.

In 2003, the Danish Energy Authority granted three offshore companies DKK 66,666 each in recognition of their special efforts to enhance health and safety on offshore installations. The companies in question are Noble Drilling, Maersk Contractors and DONG E&P A/S.

These three companies concentrated on such diverse areas as reducing noise and vibrations, physical impairment, heavy lifting, monotonous repetitive work and improving work postures. Other efforts focused on enhancing safety by improving cooperation between subcontractor personnel working temporarily offshore and the permanent personnel on offshore installations. One company made a special effort to reduce the risks associated with lifting operations.

PERSONAL INJURIES ON OFFSHORE INSTALLATIONS

The Danish Energy Authority receives reports on work-related accidents, work-related diseases and situations that might have resulted in an accident ("Near-miss") on offshore installations. Personal injuries resulting in an incapacity to work for one or more days beyond the injury date must be reported to the Danish Energy Authority. Personal injuries are defined as accidents or poisoning resulting in injury.

With effect from 5 January 2004, the Danish Energy Authority joined EASY, the electronic system designed by the National Working Environment Authority/the

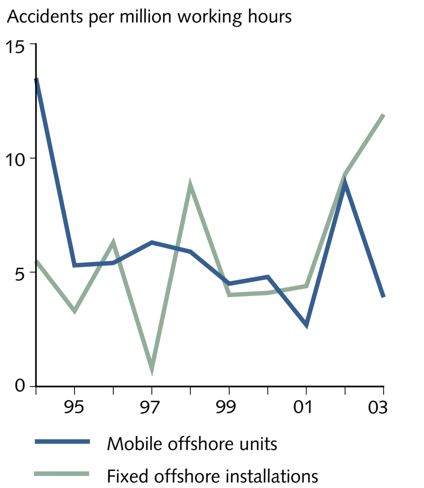
Tabel 5.2 Expected absence due to accidents on fixed offshore installations, 2003

Duration	No. of reports
1-3 days	6
4-14 days	18
2-5 weeks	16
More than 5 weeks	9

Tabel 5.3 Expected absence due to accidents on mobile offshore units, 2003

Duration	No. of reports
1-3 days	0
4-14 days	1
2-5 weeks	4
More than 5 weeks	2
Undisclosed	4

Fig. 5.1 Accident frequency on offshore installations



National Board of Injuries for reporting work-related accidents. The EASY electronic reporting system can be used for more systematic accident prevention, as the system also includes information about accidents on board the offshore installations, detailed descriptions of such accidents, and follow-up forms for use by safety committees on the offshore installations. Work-related accidents offshore can be reported via the Danish Energy Authority's website, which has a link to EASY.

Work-related accidents

In 2003, the Danish Energy Authority received 60 reports on work-related accidents, of which 49 occurred in connection with operation, maintenance and installation works on board fixed production installations and accommodation units. The remaining 11 accidents occurred on mobile units (drilling rigs). None of the accidents reported in 2003 were fatal.

In 2003, the number of reported work-related accidents on fixed production installations increased, while the number of reports on accidents on mobile units, comprising drilling rigs, pipe-laying barges, crane barges and other vessels, declined compared to the year before.

The accidents can be broken down by category, as shown in Table 5.1.

The expected periods of absence from work on fixed installations and mobile units reported by operators are indicated in Tables 5.2 and 5.3, respectively.

Accident frequency

Every year, the Danish Energy Authority calculates the overall accident frequency, which is defined as the number of accidents per million working hours.

The companies operating in the Danish sector of the North Sea in 2003 have reported that the number of working hours totalled 3.88 million for fixed production installations and associated accommodation units, while the comparable figure is 2.82 million working hours for mobile offshore units.

Thus, the accident frequency for 2003 can be calculated at 12.6 per million working hours for fixed production installations and accommodation units, while the corresponding figure for mobile offshore units is 3.9 per million working hours.

Development in work-related accidents

From 2002 to 2003, the number of reported work-related accidents on fixed production installations rose from 30 to 49, which corresponds to an increase in accident frequency from 9.1 to 12.6 per million working hours.

In contrast, the number of reported work-related accidents on mobile offshore units dropped from 2002 to 2003. In 2002, the Danish Energy Authority received 22 reports on work-related accidents, as compared to 11 reports in 2003. This corresponds to a decline in accident frequency from 8.9 to 3.9 per million working hours. Fig. 5.1 shows the annual accident frequency for the past ten years.

For the second year in a row, the accident frequency increased for fixed production installations, based on the work-related accidents reported. In 2003, the Danish Energy Authority asked the operators whether they could see a pattern in who was being injured. In the opinion of the operators, people with limited offshore experience are over-represented. Moreover, the Danish Energy Authority's assessment shows that there is an over-representation of people not employed by the operator, i.e. contractor employees.

In 2003, the Danish Energy Authority also discussed with the three operators how targeted efforts can be made to prevent work-related accidents effectively. The operators have given an account of the measures initiated to prevent work-related accidents, including new measures specially aimed at the past two years' increase in accident frequency.

The preventive measures include a two-hour behavioural safety course in conjunction with the statutory safety course, focus on new employees, checklists for safe job performance, an increase in meeting frequency between operators and contractors, as well as follow-up meetings between the operator and employer after each work-related accident where the injured person is a contractor employee.

Based on discussions with operators, the Danish Energy Authority considers these measures to be focused and proactive, particularly with regard to contractor employees.

The number of accidents on offshore installations is relatively low, and is therefore subject to great statistical uncertainty. Consequently, it is not possible to conclude on the basis of the figures alone whether the increased number of accidents is attributable to an actual decrease in safety level.

The reports on expected periods of absence on fixed offshore installations in 2003 include 24 reports with periods of absence of 1-14 days and 25 reports with more than two weeks' absence. This represents a shift towards longer periods of expected absence compared to the previous year. Thus, nine reports with an expected period of absence exceeding five weeks have been received, five of them attributable to fractured bones or sprains.

Following up on these reports is one of the means to prevent accidents. The Danish Energy Authority subjects each report received to an individual assessment. Moreover, during its inspection visits to the offshore installations, the Danish Energy Authority follows up on all accidents reported. As in 2003, the Danish Energy Authority's supervision in 2004 will focus on measures to prevent accidents.

Work-related diseases

In 2003, the Danish Energy Authority received a total of 11 reports of suspected or diagnosed work-related diseases that were attributable to work on an offshore installation.

An outline of the percentage distribution by main diagnosis of all the work-related diseases reported to the Danish Energy Authority since 1993 is shown at the Danish Energy Authority's website www.ens.dk.

"Near-miss" occurrences

In 2003, the Danish Energy Authority received nine reports on "Near-miss" occurrences on offshore installations, of which eight can be attributed to fixed production installations and one to a drilling rig. All the "Near-miss" occurrences reported are due to disregard of safety procedures. One of the "Near-miss" occurrences reported described a situation in which a heavy object weighing 2.2 kg dropped 6 metres and landed in front of someone. This situation could have led to serious personal injury or even death. Another occurrence concerned a gas leak.

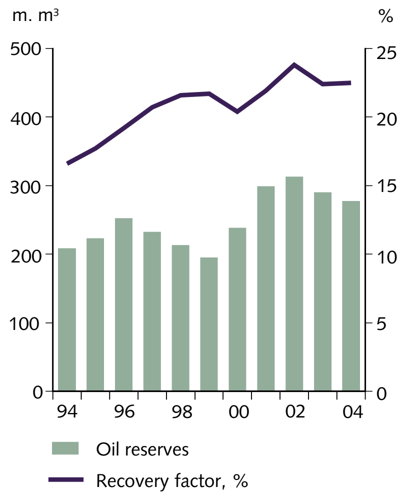
Following the gas explosion in the Gorm Field in May 2001, the Danish Energy Authority agreed with Mærsk Olie og Gas AS that the company would report all gas leaks. Thus, Mærsk Olie og Gas AS reported 43 leaks in processing piping in 2003. None of these leaks presented an immediate danger to persons and/or installations in either scope or nature, for which reason they were not reported as "Near-miss" occurrences.

As part of the Government's action plan, the Danish Energy Authority has investigated whether the operators' registration and handling of "Near-miss" occurrences meet the recommendations made in the SINTEF report. The Danish Energy Authority considers that the operators' follow-up goes beyond looking into the immediate causes of the occurrences. See also the section above on the elements of the action plan.

During its inspections of the platforms, the Danish Energy Authority reviews the reports on "Near-miss" occurrences together with the reports on work-related accidents. Moreover, the Danish Energy Authority closely follows the operators' reporting and utilization of the information contained in their reports on "Near-miss" occurrences.

6. RESERVES

Fig. 6.1 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's assessment at 1 January 2004 shows a decline in oil reserves of 4% and an increase in gas reserves of 5% compared to the assessment made at 1 January 2003. The decrease in oil reserves is mainly attributable to production in 2003, while gas reserves have been written up for a number of the major oil fields, as well as for Sif/Igor under the possible recovery category. Oil reserves have been estimated at 277 million m^3 and gas reserves at 136 billion Nm^3.

The average oil recovery factor for Danish fields, i.e. the ratio of ultimate recovery to total oil-in-place, was 22%, and thus the recovery factor is almost unchanged relative to the year before; see Fig. 6.1.

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 13, meaning that oil production is calculated to be sustainable at the 2003 level for the next 13 years. The R/P ratio has not changed compared to last year's assessment, when it was also 13.

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. 6.5 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 6.1.

Table 6.1 shows the Danish Energy Authority's assessment of oil and gas reserves, broken down by field and category.

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

Box 6.1 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.

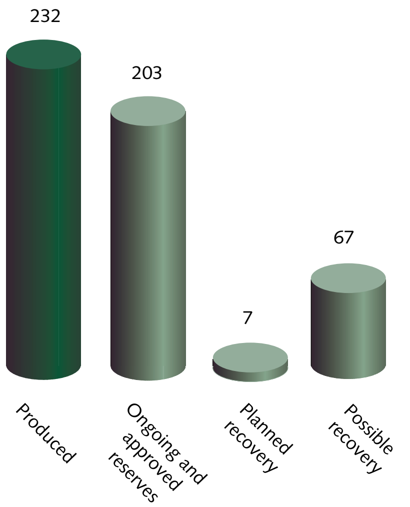
For discoveries for which a declaration of commerciality has not yet been filed, the recoverable reserves are categorized as possible recovery. This category also includes recovery from discoveries considered to be non-commercial.

Table 6.1 Production and Reserves at 1 January 2004

	OIL, million m³				GAS, billion Nm³			
	Ultimate Recovery				Ultimate Recovery			
	Produced	Reserves			Produced	Reserves		
		Low	Exp.	High		Low	Exp.	High
Ongoing and Approved Recovery:								
Adda	-	0	1	1	-	0	0	0
Alma	-	0	1	1	-	1	1	2
Boje area	-	1	1	1	-	0	0	0
Cecilie	0	1	3	4	-	-	-	-
Dagmar	1	0	0	0	0	0	0	0
Dan	69	34	63	90	19	6	8	11
Elly	-	1	1	1	-	4	4	4
Gorm	48	8	12	15	6	1	1	2
Halfdan	12	31	69	106	3	7	9	12
Harald	7	1	1	2	16	4	5	8
Kraka	4	1	1	1	1	1	1	2
Lulita	1	0	0	0	0	0	0	0
Nini	0	3	4	6	-	-	-	-
Regnar	1	0	0	0	0	0	0	0
Roar	2	0	1	2	11	3	6	9
Rolf	4	0	1	1	0	0	0	0
Sif/Igor	0	0	1	2	0	5	11	21
Siri	8	2	3	5	-	-	-	-
Skjold	36	4	9	12	3	0	1	1
Svend	5	1	1	1	1	0	0	0
South Arne	10	*	21	*	3	*	7	*
Tyra	21	2	5	9	35	22	26	29
Tyra Southeast	1	2	3	5	1	7	11	14
Valdemar	2	2	2	4	1	1	2	4
Subtotal	**232**		**203**		**100**		**94**	
Planned recovery:								
Amalie	-	*	2	3	-	*	3	5
Freja	-	1	1	2	-	0	0	0
Lulita	-	0	0	1	-	0	0	1
Valdemar	-	2	3	4	-	1	2	3
Subtotal			**7**				**6**	
Possible recovery:								
Prod. fields	-	24	47	77	-	16	25	32
Other fields	-	0	1	2	-	0	0	0
Discoveries	-	7	19	43	-	3	11	22
Subtotal			**67**				**36**	
Total	**232**		**277**		**100**		**136**	
January 2003	211		290		92		129	

** Not assessed*

Fig. 6.2 Oil recovery, m. m³



It appears from Fig. 6.2 that the expected amount of oil reserves ranges from 210 to 277 million m^3. The difference between the two figures, 67 million m^3, equals the reserves in the possible recovery category. The reserves assessed for the planned and possible recovery categories, respectively, reflect the increasing uncertainty as to whether such reserves can be exploited commercially.

Likewise, Fig. 6.3 illustrates that the expected amount of gas reserves ranges from 100 to 136 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 in the production process.

There have been several revisions of the Danish Energy Authority's assessment of reserves compared to the assessment made in January 2003. These revisions are attributable to 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 2003 included the reserves recoverable from the development of Sif/Igor (Halfdan Northeast). In June 2003, this development plan was approved, and the pertinent reserves have therefore been included under ongoing and approved recovery.

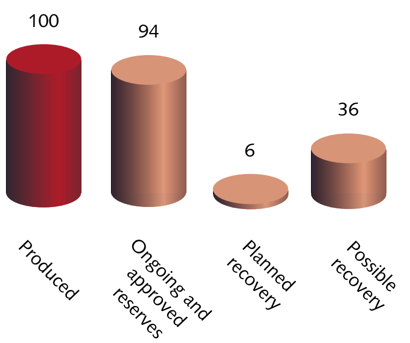
The reserves of the Cecilie Field have been written down due to new well data. In April 2004, a plan for developing the Connie accumulation as part of the Cecilie Field was approved, so the reserves of this accumulation have been included in the Cecilie reserves.

The Dan Field reserves have been written up on the basis of production experience and further development of the western flank of the field.

Positive production experience has led the Danish Energy Authority to write up the reserves of the Gorm Field.

The Dan and Halfdan Fields are estimated to have the largest oil reserves in this category, and the estimated reserves of these two fields account for about two-thirds of the category's total reserves.

Fig. 6.3 Gas recovery, bn. Nm³



Planned recovery

Due to the installation of water-processing facilities in the Lulita Field, reserves have been included in the planned recovery category for this field.

In November 2003, a plan was submitted for further development of the Valdemar Field. The Danish Energy Authority is currently reviewing this plan, for which reason the pertinent reserves have been included in the planned 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 that 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 oil reserves can be augmented by implementing water-injection projects in a number of fields.

The Danish Energy Authority has made a significant upward revision of hydrocarbons-in-place in the Gorm Field, but has so far made only a minor write-up of the reserves based on these hydrocarbons-in-place.

The drilling of horizontal wells is considered to further increase the production potential of the Sif/Igor and Valdemar Fields.

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

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 two-thirds of total oil production, and due to their development with horizontal wells and water injection, they still contain considerable reserves.

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 reserves derive from more than 30 fields and discoveries.

On average, the overall recovery factor for all Danish fields and discoveries is estimated at 22%. In fields like Dan, Gorm and Skjold, where the production conditions are favourable, an average recovery factor of 35% is expected, based on such recovery methods as water and gas injection. The recovery factor for these fields was 38% according to last year's assessment, and the decline in recovery factor compared to last year is chiefly attributable to the above-mentioned write-up of the hydrocarbons-in-place in the Gorm Field. However, the assessment also includes contributions from the relatively large oil accumulations in the Tyra and Tyra Southeast Fields, where the recovery factors are fairly low due to difficult production conditions.

PRODUCTION FORECASTS

Based on the assessment of reserves, the Danish Energy Authority prepares production forecasts for the recovery of oil and natural gas in the next five and 20 years, respectively.

Five-year production forecast

The five-year forecast uses the same categorization as the assessment of reserves, and includes the categories ongoing, approved, planned and possible 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 6.2. In this table, the oil production figures including planned recovery illustrate the planned course of production, while the figures including possible recovery illustrate the possible course of production.

Table 6.2 Oil production forecast, million m^3

	2004	2005	2006	2007	2008
Ongoing and approved:					
Adda	-	-	-	0.5	0.0
Alma	-	-	-	0.2	0.1
Boje area	-	-	-	0.1	0.1
Cecilie	0.7	0.7	0.6	0.4	0.2
Dagmar	0.0	0.0	0.0	0.0	0.0
Dan	6.0	5.9	5.5	4.9	4.5
Elly	-	-	-	0.1	0.1
Gorm	2.4	1.9	1.5	1.2	1.0
Halfdan	5.6	5.9	5.7	5.0	4.5
Harald	0.3	0.2	0.2	0.1	0.1
Kraka	0.1	0.1	0.1	0.1	0.1
Lulita	0.0	0.0	0.0	0.0	0.0
Nini	1.3	1.4	0.6	0.3	0.2
Regnar	0.0	0.0	0.0	0.0	0.0
Roar	0.1	0.1	0.1	0.1	0.1
Rolf	0.1	0.1	0.1	0.1	0.1
Sif/Igor	0.1	0.2	0.2	0.1	0.1
Siri	0.7	0.7	0.4	0.2	0.2
Skjold	1.4	1.2	1.0	0.8	0.8
Svend	0.2	0.2	0.1	0.1	0.1
South Arne	2.4	2.4	2.3	2.1	1.9
Tyra	0.7	0.7	0.6	0.5	0.4
Tyra Southeast	0.6	0.5	0.4	0.3	0.2
Valdemar	0.5	0.3	0.3	0.2	0.2
Total	**23.4**	**22.6**	**19.7**	**17.6**	**15.0**
Planned	-	0.4	0.8	0.8	0.8
Planned course of production:	**23.4**	**22.9**	**20.5**	**18.4**	**15.8**
Possible	-	1.8	3.4	4.6	6.9
Possible course of production:	**23.4**	**24.7**	**23.9**	**23.0**	**22.8**

The forecast for planned recovery shows a declining trend, and the forecast for possible recovery remains largely constant.

For 2004, oil production is expected to total 23.4 million m³, equal to about 403,000 barrels of oil per day.

Planned course of production

In relation to the planned course of production in last year's forecast, expected production figures are almost unchanged. Thus, the changes in the production forecast consist of a writedown of about 2% for 2004, and a write-up of about 4% for the years 2006 to 2008.

The forecast for 2004 was revised mainly because production was written down for the Halfdan Field.

Last year's forecast assumed that new processing facilities in the Halfdan Field would be commissioned in the autumn of 2003. However, the commissioning was delayed, for which reason production from the Halfdan Field was affected by operational and capacity limitations in the first quarter of 2004. This means that the production estimate for 2004 for this field has been downscaled compared to last year's forecast.

The production estimate for Dan has been adjusted in light of the most recent production experience and includes contributions from further development of the western flank.

The Dan and Halfdan Fields are projected to be the fields recording the largest production during the forecast period, accounting for an average share of total production of 53% in the planned recovery category.

In March 2004, the Danish Energy Authority granted an application to postpone the commissioning of the Boje area until 1 July 2007, and the production expected from this area has been adjusted accordingly.

For Cecilie, production in the forecast period has been written down due to changes in the underlying reserves, while production from the approved development of the Connie accumulation has been added to the Cecilie Field.

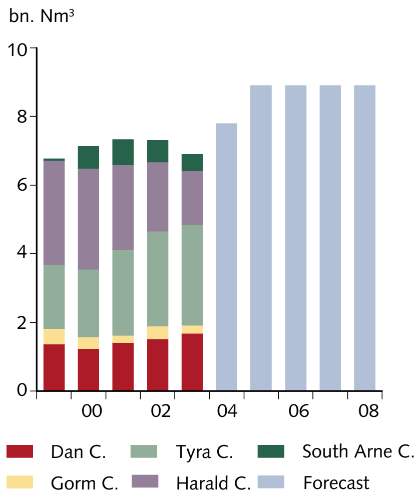
Production experience has led to an upward adjustment of the production estimates for the Gorm, Nini, Skjold and Valdemar Fields.

In the forecast made in January 2003, the planned recovery category included expected production from the development of the Sif/Igor gas accumulation (Halfdan Northeast). The plan for this development was approved in June 2003, and the contribution from this accumulation has now been included in the ongoing and approved recovery category.

The production estimate for the South Arne Field has been adjusted to reflect the recent plans for further development of the field.

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 Freja, Lulita and Valdemar.

Fig. 6.4 Natural gas production broken down by processing centre and estimated future sale of natural gas



Possible course of production
Table 6.2 includes contributions from the possible recovery category.

Within the possible recovery category, 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 forecast for the possible recovery category is more or less constant, with annual oil production averaging 23.6 million m^3, equal to about 407,000 barrels of oil per day, during the forecast period.

In last year's report, the possible production scenario included an assumed capacity extension of the oil pipeline to shore. This extension has not been initiated, and the difference between this year's and last year's forecast is mainly attributable to this change in the forecast assumptions.

The possible recovery category includes the future further development of the Dan, Halfdan, Gorm, Skjold, Tyra Southeast, Valdemar and South Arne Fields.

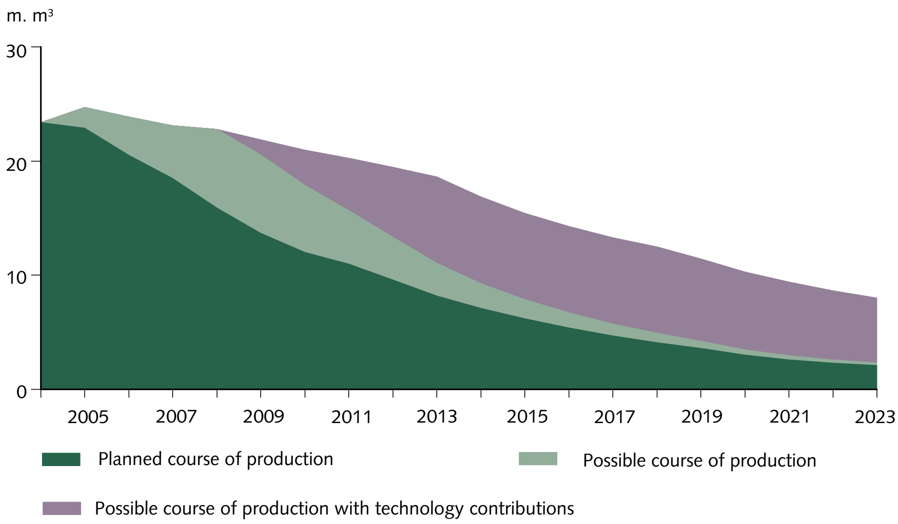
Natural gas production estimates are given in Fig. 6.4, broken down by processing centre. The forecast includes natural gas production resulting from new contracts for the export of gas through the pipeline from Tyra to the European continent. The section on *Development* gives a more detailed description of this pipeline. The production forecast in Table 6.2 includes additional condensate production resulting from increased gas production under new export contracts.

Twenty-year production forecast

The method used for making the 20-year forecast for the planned and possible courses of production is the same as for the five-year forecast. A forecast covering 20 years is most reliable in the first part of the period. Moreover, the methods used in making the forecasts imply that production must be expected to decline after a short number of years.

Planned and possible course of production
The forecast for planned recovery shows a downward trend, while the forecast for possible recovery is virtually constant until 2008, after which production is expected to decline; see Fig. 6.5.

Fig. 6.5 Production forecasts for the period 2004-2023



Mid-way through and at the end of the forecast period, production according to the possible recovery scenario is estimated to constitute about 50% and 10% of the production estimate for 2004, respectively. Thus, the forecast projects a downward plunge in oil production. This decline can possibly be curbed as a result of technological development and any new discoveries made as part of the ongoing exploration activity. A more detailed description of the exploration potential in Denmark is given in the section on *Hydrocarbon potential.*

Contributions from technological development

It is estimated that technological development will contribute significantly to production, particularly in the latter half of the forecast period. As a supplement to the reserves assessment, the Danish Energy Authority has assessed the volumes that may be recovered by means of new technology.

It should be noted that the method used for the Danish Energy Authority's reserves assessment does not take potential technological development into account, as the reserves assessed are assumed to be recoverable by means of known technology. In other words, there is reason to believe that the quantities that can be produced are higher than the reserves indicated.

Future technological development is expected to take two paths: firstly, existing techniques will be further developed and the cost reduced, and secondly, technological leaps will generate new techniques.

The fact that no-one can foresee the new techniques that will result from technological leaps makes it more difficult to estimate with any certainty how technological development will contribute to the forecast. Consequently, the Danish Energy Authority has chosen to estimate the contribution from technological development on the basis of a set of general assumptions, in contrast to the Authority's traditional forecasts, which are based on specific assessments of each individual field.

Natural gas production

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 the DUC companies 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 with DONG Naturgas A/S for the sale of the DONG group's share of gas produced from the Lulita Field.

In addition, the forecast includes the natural gas production resulting from new contracts for the export of gas through the pipeline from Tyra to the European continent.

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. 155 billion Nm^3 until the year 2019. In addition, the planned course of production for the South Arne Field accounts for 5 billion Nm^3.

7. HYDROCARBON POTENTIAL

In Denmark, source rocks and reservoir rocks occur at various depths and vary widely in age. An assessment of such source rocks and reservoirs, and thus their hydrocarbon potential, shows that the Danish area holds considerable potential before the upcoming 6th Licensing Round.

HYDROCARBON MIGRATION INTO RESERVOIRS

For hydrocarbon exploration to be successful, many factors must combine in exactly the right way. A crucial factor is the presence of underground rock strata in which hydrocarbons have originated at some point in time. This type of rock is called *source rock*. Hydrocarbon generation is based on organic matter present in the source rock. At the right depth, and thus with the right conditions of pressure and temperature, this organic matter is transformed into hydrocarbons.

The hydrocarbons may now leave the source rock and move towards areas with lower pressure. This hydrocarbon movement, also referred to as *migration*, takes place in permeable rocks or along faults and fractures in the subsurface.

The hydrocarbons may be retained or trapped in rocks. Rocks in which hydrocarbons are retained are called *reservoirs*. If a reservoir is encased in surrounding rocks with considerably lower permeability, the hydrocarbons cannot escape, even at very high reservoir pressures, and are thus caught in *a trap*. Such low-permeable rocks with ability to encase reservoir rocks are called *sealing rocks*.

There are several types of traps capable of retaining hydrocarbons. Structural traps are formed as a result of tectonic movements creating various types of pillow structures or fault traps. Stratigraphic traps originate in areas where major changes in rock porosity occur. This type of trap is independent of the structure. Further, there are an infinite number of possible combinations of structural and stratigraphic traps.

The section on *Hydrocarbon potential* is based on the article cited below. For more detailed information, see the full article at the Danish Energy Authority's website (www.ens.dk). Unless stated otherwise, the resource estimation and numeric data given are based on information available to the Danish Energy Authority up to and including summer 2003.

Hemmet, M. 2003: The hydrocarbon potential of the Danish Continental Shelf. Petroleum Geology of Northwest Europe: Proceedings of the 6th Conference. Geological Society, London, In Print.

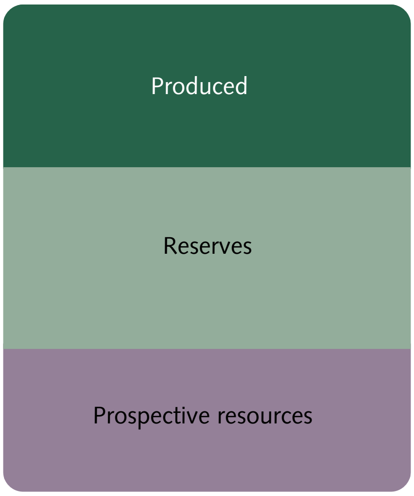
Two main types of reservoir rock are found in the Danish area, viz. chalk and sandstone. The chalk covers the entire Danish territory, except the island of Bornholm. With this type of reservoir, successful hydrocarbon exploration is a matter of identifying the areas in the chalk where hydrocarbons may have accumulated. Sandstone occurrences, on the other hand, are not nearly as extensive, and reservoir sediments may be limited to small areas. Successful hydrocarbon exploration in this type of reservoir is therefore rather a question of locating the sandstone targets.

EXPLORATION POTENTIAL

Continued exploration, even in well-known reservoirs, such as the Central Graben chalk, is revealing new traps, and thus potential for new hydrocarbon discoveries. The Danish area therefore offers broad scope for exploration, in both chalk plays and other types of reservoir.

In connection with the upcoming 6th Licensing Round, the Danish Energy Authority has assessed the hydrocarbon potential in the Danish part of the Central

Box 7.1 Categories of recovery



Graben and in the Siri Fairway; see Box 7.1. The Danish Energy Authority's annual assessment of hydrocarbon reserves covers only drilled structures, see the *Reserves* section, whereas the estimated hydrocarbon potential also includes hydrocarbons in structures yet to be drilled, the so-called *prospective resources*; see Box 7.1.

On the basis of the above-mentioned assessment of reserves, it is presumed that the Danish area still holds considerable hydrocarbon potential, and that this potential may be identified and exploited by using modern exploration and production techniques.

Hydrocarbon exploration history in Denmark

Danish hydrocarbon exploration began in 1935 when the first onshore wells were drilled, and for the next three decades, all exploration efforts were land-based. In 1966, the A-1 exploration well encountered the very first oil accumulation to be discovered in the North Sea. This discovery is now being produced at the Kraka Field. Many hydrocarbon deposits have subsequently been discovered in the Danish Central Graben, most of them in the chalk.

After the discovery of the Siri Field in 1995, some of the exploration focus was shifted to the Paleogene sandstones in the Siri Fairway. By the end of 2003, three out of four exploration wells in the area had discovered hydrocarbon deposits, including the Cecilie and Nini Fields, which were brought on stream in 2003. Most recently, the Sofie-1 well struck oil in May 2003 in Paleogene sandstone in the Siri Fairway; see the section on *Licences and exploration*.

PLAYS

When evaluating different play types, it is essential to have knowledge about both reservoirs and source rocks. This applies to both proven and potential source rocks; see Box 7.2.

This knowledge may be obtained from wells. By the end of 2003, a total of 176 exploration wells had been drilled in the Danish area; see Fig. 7.1. Several of these wells have demonstrated reservoirs containing hydrocarbons, as well as potentially hydrocarbon-bearing reservoir rocks where further exploration may reveal hydrocarbon accumulations.

Box 7.2 Plays

An exploration play is a geological model for evaluating:

- The presence and quality of reservoirs.
- The presence of mature source rock with potential for hydrocarbon generation after the formation of traps in the reservoir rocks.
- The presence of traps at a given point in time and subsequent potential hydrocarbon migration into the reservoir.
- The presence of rocks or faults sealing the top surface and, where applicable, the lateral surfaces of the trap.

Figs. 7.2 and 7.3 show the locations in the subsurface layers where hydrocarbon shows have been identified. Such shows may suggest the presence of a hydrocarbon accumulation close to the well site or deeper down, or the former presence of hydrocarbons in the area. This knowledge is important to our understanding of the petroleum system, and thus to our ability to predict hydrocarbon migration pathways.

Figs. 7.2 and 7.3 also show the prospectivity by indicating the locations of identified traps yet to be drilled in the geological column. As it appears from the figures, there are still many reservoirs of interest from an exploration point of view. The figures also show the wide variation in knowledge regarding the different plays.

The Central Graben chalk play

Exploration of the chalk in the Danish part of the Central Graben has been highly successful. By the end of 2003, 41 exploration wells had been drilled, with a 50% success rate. All but one of these discoveries have been declared commercial.

The chalk play comprises carbonate reservoirs of Cretaceous and Tertiary age. The source rock is the Jurassic Farsund Formation, while the structural and stratigraphic traps as well as the sealing rock are Tertiary claystone; see Fig. 7.2.

For some time, the hydrocarbon exploration potential in the chalk was considered nearly exhausted, since almost all identified structural traps had been drilled. However, this changed in 1999 when hydrocarbons were discovered in the stratigraphic/dynamic traps that define the Halfdan Field and the Sif/Igor area; see Fig. 7.4 and Box 7.3.

Fig. 7.1 Exploration wells in the Danish area

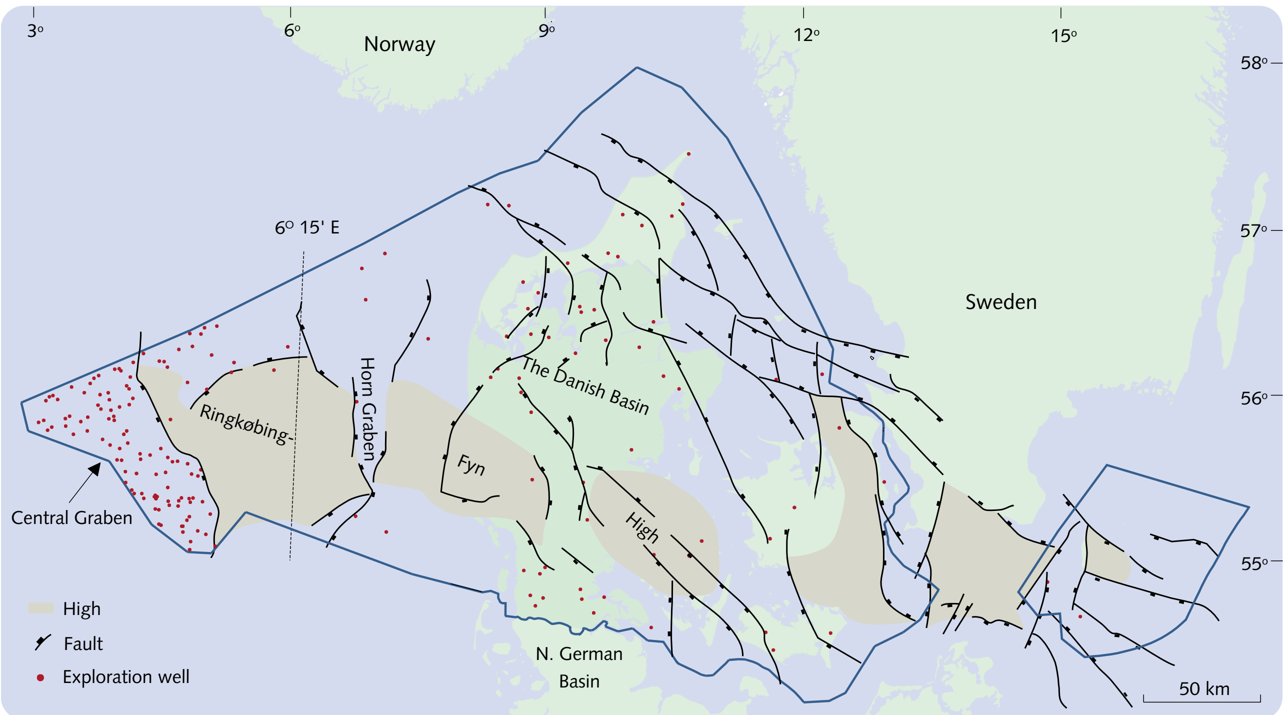


Fig. 7.2 Geological column for Central Graben

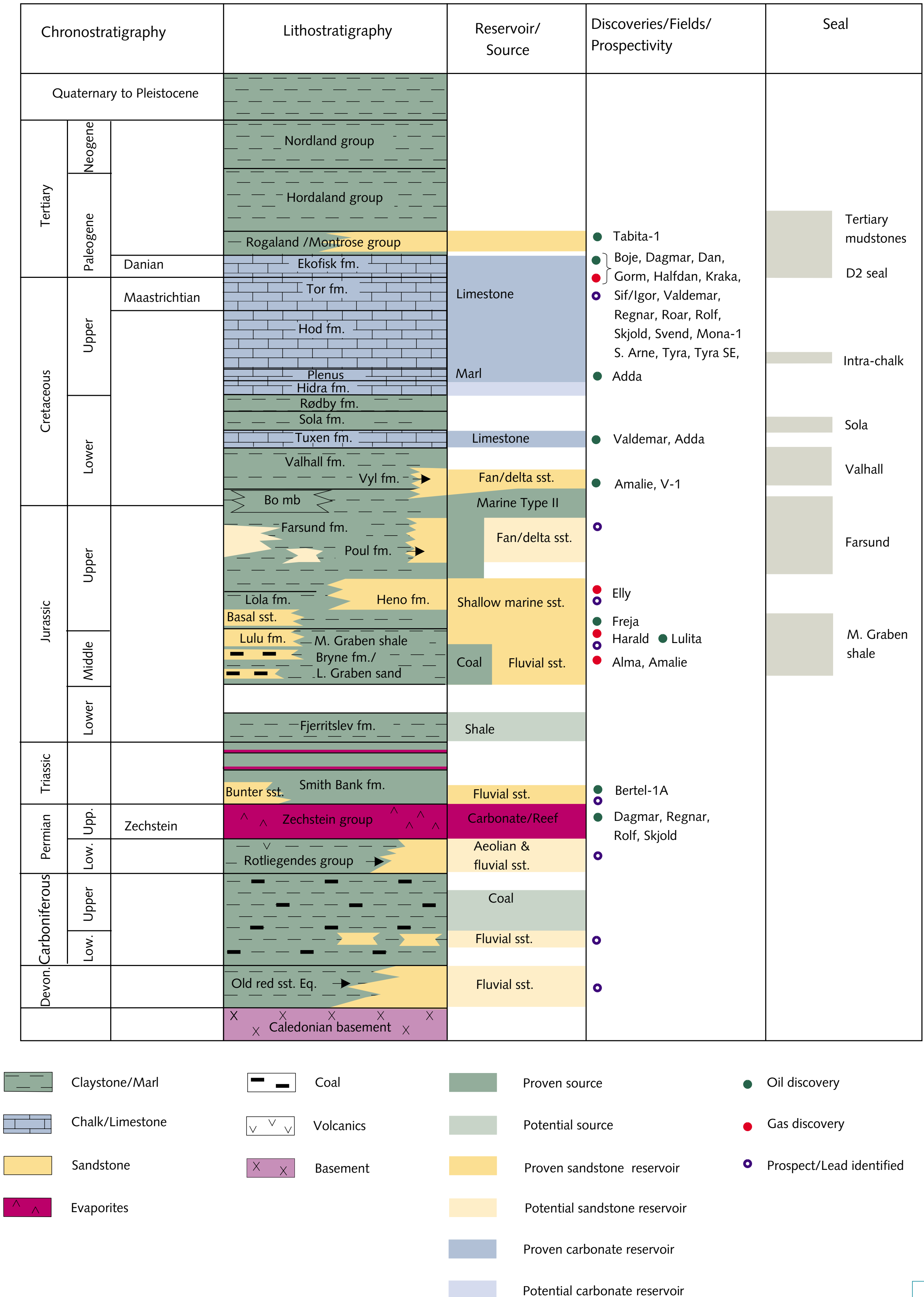
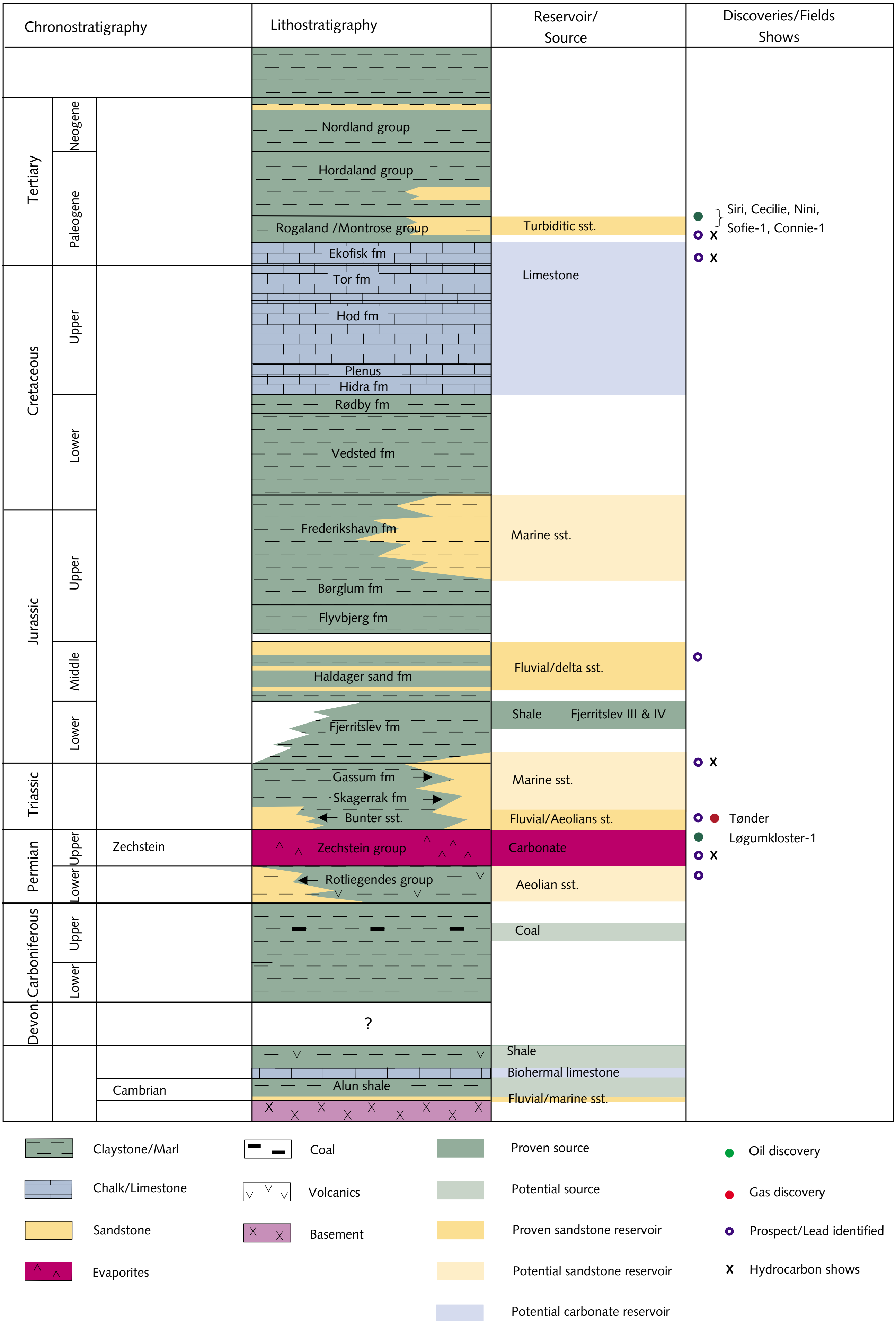


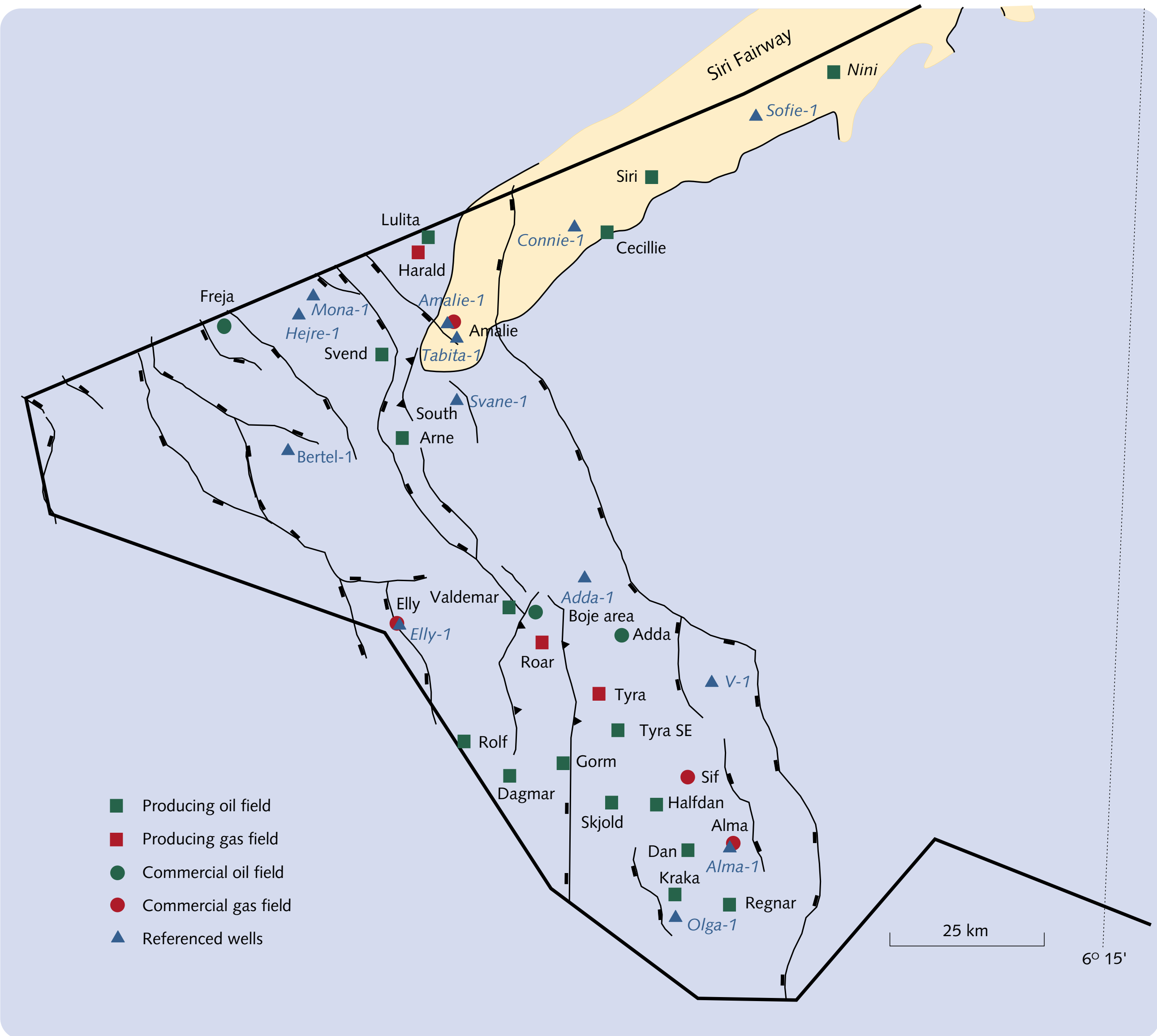
fig. 7.3 Geological column outside Central Graben



Identification of this new type of traps changed our understanding of the petroleum system of the chalk, since the system is now considered to be dynamic. The hydrocarbons in the chalk are not in equilibrium, and therefore continue to migrate extremely slowly (a few kilometres per million years). The lack of equilibrium in the petroleum system is due to the very slow fluid flow, the relatively late entry of the hydrocarbons into the chalk and continued tectonic movements. Such a dynamic system exists in the Halfdan and Dan area. Even today, hydrocarbons continue to migrate into the Halfdan Field and from there into the Dan Field.

Insight into the history of hydrocarbon migration in the chalk is considered critical to the future success of chalk exploration. Shifting the focus to the combined stratigraphic/dynamic traps and using improved exploration, development and production technology will most certainly increase reserves in the chalk.

Fig. 7.4 Oil and gas fields as well as referenced exploration wells



Jurassic sandstones in the Central Graben
Sandstones of Jurassic age constitute highly successful plays in the British and Norwegian sectors of the North Sea. To date, exploration has been less successful in the Danish Central Graben. By the end of 2003, 46 exploration wells had been drilled, with a success rate of 35%. Only two fields, Harald and Lulita, have been brought on stream, while the Alma, Elly and Freja Fields have been declared commercial; see Figs. 7.2 and 7.4.

The plays cover various sandstone reservoirs of Jurassic age. The Jurassic Farsund Formation and the Bryne Formation are source rocks, whereas the structural and stratigraphic traps as well as the sealing rock are Jurassic claystone; see Fig. 7.2.

All hydrocarbon deposits in the Jurassic sandstone in the Danish Central Graben were discovered by drilling into traps with largely structural closures, while many Jurassic accumulations in the remaining part of the North Sea occur in pure stratigraphic traps. Thus, Jurassic discoveries in stratigraphic traps seem to be under-represented in the Danish Central Graben. This indicates lower exploration maturity for sandstones in this area.

The sandstones were deposited in a variety of depositional environments, ranging from fluvial to deep marine. This means that the types of sand bodies to be identified vary widely. Previously, identifying individual sand bodies presented technical difficulties, but recent years' developments in seismic techniques offer great improvements in this respect.

The deep exploration wells Hejre-1 and Svane-1, drilled in 2001 and 2002, respectively, show that sandstone can retain high porosity at great depths; see Fig. 7.4. The Hejre-1 and Svane-1 wells were both drilled to depths of more than 5,200 metres and discovered the deepest deposits of oil and gas/condensate found to date in Denmark. The success of these two wells therefore considerably increased the prospectivity of the Jurassic sandstone.

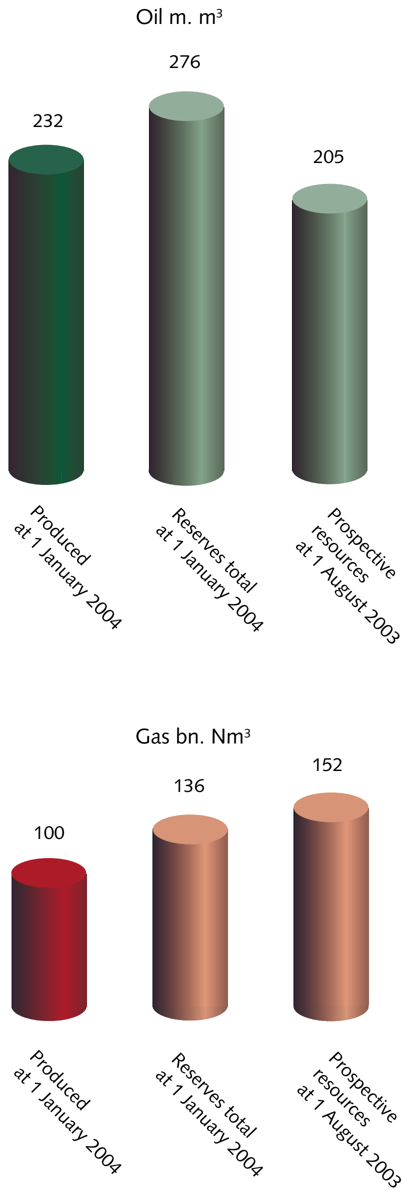
It is estimated that the future success of exploration activities in Jurassic sandstones depends on the ability to predict their location and reservoir quality.

Box 7.3 Definition of stratigraphic and dynamic traps in the chalk

Stratigraphic traps in the chalk:
Stratigraphic traps in the chalk are defined by areas of increased porosity. The porosity of the reservoir in well-defined structural traps has been preserved by the presence of hydrocarbons. As a result of later structural movements, the trap 'opened', but the lower porosity of the surrounding chalk now acted as a sealing mechanism.

Dynamic traps in the chalk:
Dynamic traps occur because of the low permeability of the chalk, which causes the hydrocarbons to migrate extremely slowly. They are therefore not actual, permanent traps, but the result of this very slow rate of pore fluid flow, which means that it will take millions of years for the hydrocarbons to migrate out of the area.

Fig. 7.5 Reserves and resources in the Central Graben and the Siri Fairway



Plays in the area east of 6°15'

As already mentioned, hydrocarbon exploration in Denmark was at first conducted on land. Since 1935, 83 exploration wells have been drilled in the Danish area outside the Central Graben, primarily onshore; see Fig. 7.1. Exploration activities in the area east of 6°15' have mainly targeted Jurassic and Triassic sandstones and Zechstein carbonates; see Fig. 7.3.

To date, no commercial hydrocarbon accumulations have been discovered in the area east of 6°15', but, for example, the Kiel area includes several producing Jurassic fields, the Rügen–Mecklenburg area has oil-producing Zechstein fields, and in Kaliningrad, hydrocarbons are produced from reservoirs of Cambrian age.

The sedimentary deposits in the area east of 6°15' generally have very good reservoir properties, and many structural traps have been identified here. Traditionally, however, their hydrocarbon potential has been considered low due to the uncertainty with regard to sourcing. The Cambrian alum shale has excellent source quality. But as the period of hydrocarbon generation in the Danish area probably predated the formation of structural traps, there was nothing to retain the hydrocarbons in the shale.

Claystone of Jurassic age from the Fjerritslev Formation is also believed to have good source rock potential. However, the burial depth of the layers is considered insufficient to allow other than local hydrocarbon generation around salt domes. Where present in the area, claystone of Carboniferous age is believed to have good hydrocarbon potential.

Several hydrocarbon shows have been found in the area east of 6°15', mainly in Jurassic and Triassic sandstone and in Zechstein carbonates. Most data from this area are relatively old, since more than half of the wells were drilled before 1970. Modern exploration methods may have major impact on our understanding of the petroleum systems in this area, and hence on the prospectivity of eastern Denmark.

EXISTING HYDROCARBON POTENTIAL

In connection with the upcoming 6th Licensing Round, the Danish Energy Authority has estimated the existing hydrocarbon potential, the so-called *prospective resources*, as already mentioned. The prospective resources have been assessed exclusively for the Central Graben in the Danish sector and for the Siri Fairway. This is due to the fact that these areas cover all the producing fields and commercial deposits present in Danish territory. Moreover, the two areas form part of the same petroleum system, which is sourced mainly from the Jurassic claystones of the Farsund Formation.

The prospective resources include an estimate of resources in identified traps yet to be drilled (prospects and leads) at all stratigraphic levels. The estimate is based on assessments of risked resources forwarded by the oil companies. The estimate further includes a risk-based assessment of 'yet-to-find' resources in non-identified traps in known and less known plays; see Box 7.3 and Fig. 7.2. This assessment is based on knowledge of the structures in the Danish Central Graben and the Siri Fairway, as well as on hydrocarbon discoveries and plays in areas adjoining the Danish sector.

At mid-2003, prospective resources were estimated at 205 million m^3 of oil and 152 billion Nm^3 of gas; see Fig. 7.5. This indicates that up to 30% of total hydrocarbons-in-place in the Danish part of the Central Graben and the Siri Fairway still remains to be found. This is quite an impressive volume, considering that the Danish part of the North Sea has been explored for almost 40 years.

The estimate does not include potential hydrocarbon accumulations under a commercial threshold of 0.8 million m^3 of oil and 0.8 billion Nm^3 of gas.

POTENTIAL IN THE 6TH LICENSING ROUND

Danish territory still offers many exploration opportunities. Thus, prospective hydrocarbon resources may be located in the successful and potentially still productive chalk reservoirs in the Central Graben and in the less known Jurassic sandstones.

Other plays in the Danish area are also being investigated. Successful exploration of Triassic sandstone reservoirs has been carried out in the Dutch part of the Central Graben. Exploration activities targeting the same reservoirs in the Danish part of the Central Graben have been hampered by uncertainty as to whether this sandstone extends into Danish territory. But in 2003, it was actually encountered by the Olga-1 exploration well; see the section on *Licences and exploration*. This may spark increased interest in this particular play.

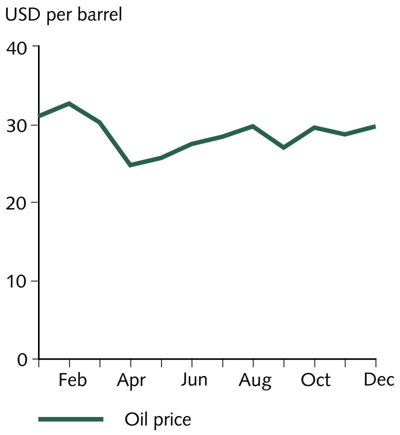
It is estimated that the highest number of less mature plays in the Central Graben is found in the Danish part. This is partly because hydrocarbon exploration in the Danish Central Graben has focused largely on a single type of reservoir rock, viz. the chalk. These less mature plays may hold a potential for increased hydrocarbon resources.

As mentioned above, the prospective resources in the Danish part of the Central Graben and the Siri Fairway are estimated at 205 million m^3 of oil and 152 billion Nm^3 of gas. By comparison, the reserves of the entire Danish area were assessed at 276 million m^3 of oil and 136 billion Nm^3 of gas at 1 January 2004. It should be noted, however, that the prospective resources are subject to a relatively high uncertainty, and that not all of these resources can be expected to be identified.

The prospective resources estimate shows that considerable unidentified hydrocarbon resources may still be present in the Danish sector. The Danish area therefore offers major exploration opportunities in the upcoming 6th Licensing Round.

8. ECONOMY

Fig. 8.1 Oil price development in 2003



Since 1997, Denmark has been more than self-sufficient in energy by virtue of the production of oil and gas in the North Sea. The production of hydrocarbons generates a surplus in socio-economic terms and thus has a positive impact on the Danish economy. The Danish state gets a share of this surplus through taxation and direct participation in the production activities.

The agreement made between the Government and A. P. Møller-Mærsk in 2003, which allows the company's Sole Concession to continue, means the state will obtain a larger share of the overall earnings. The agreement has provided a fixed framework for the Concessionaires, enabling them to make the long-term investments and plans that are crucial to efficient use of the resources.

OIL PRICE AND DOLLAR EXCHANGE RATE

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

The average oil price, as quoted for Brent oil, was USD 28.9 per barrel in 2003. This is considerably higher than the level for 2002, when oil prices averaged USD 24.9 per barrel. Fig. 8.1 shows the development in the oil price in 2003.

In 2003, the average dollar exchange rate was DKK 6.6 per USD. This represents a fall compared to 2002, when the average dollar exchange rate was DKK 7.9 per USD.

VALUE OF OIL AND GAS PRODUCTION

The total value of Danish oil and gas production was calculated at about DKK 31.1 billion in 2003, the same level as in 2002. Relative to 2002, production declined slightly, and the dollar exchange rate dropped. Therefore, the sustained high production value is attributable to the hike in oil prices in 2003. When viewed in a historical perspective, the production value estimated for 2003 is still considered to be very high.

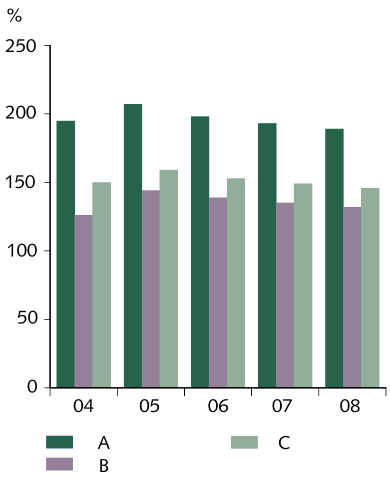
The estimates for 2003 show that oil production represented a value of DKK 25.5 billion, and gas production a value of DKK 5.6 billion. The breakdown of production in 2003 on the ten producing companies appears from Fig. 3.2 in the section on *Production*.

How the production value will develop in the years ahead depends on the production volume, the trend in oil and gas prices and the dollar exchange rate. The Danish Energy Authority prepares oil and gas production forecasts based on known and possible reserves; see the section on *Reserves*. However, the development in the oil price and dollar exchange rate is more difficult to predict, so any estimate concerning how production value will develop in the next few years will be subject to great uncertainty.

DEGREES OF SELF-SUFFICIENCY

Denmark has been self-sufficient in energy since 1997. The total production of oil, gas and renewable energy in 2003 was about 43% higher than total energy consumption. This is slightly less than the year before, when production exceeded consumption by 46%. In 2003, oil and gas production alone exceeded total energy consumption by 29% and total oil and gas consumption by 85%.

Fig. 8.2 Degrees of self-sufficiency



A. Oil and gas production vs. oil and gas consumption.
B. Oil and gas production vs.total energy consumption.
C. Production of oil, gas and renewable energy vs. total energy consumption.

Table 8.1 and Fig. 8.2 show the development in the degrees of self-sufficiency projected by the Danish Energy Authority for the next five years. Column A shows Danish oil and gas production relative to total domestic consumption of oil and gas, and column B shows Danish oil and gas production relative to total domestic energy consumption. Column C shows the expected development in total production of oil, gas and renewable energy relative to total energy consumption in Denmark.

The figures show that the Danish Energy Authority expects Denmark to continue being self-sufficient in energy for the next five years.

IMPACT OF PRODUCTION ON THE DANISH ECONOMY

Oil and gas activities have a favourable impact on the Danish economy. Besides making Denmark self-sufficient 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 gas

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

Since 1995, Denmark has had a surplus on the balance of trade for oil and gas products. This surplus has been preliminarily estimated at DKK 14 billion for 2003.

Impact on the balance of payments

The production of oil and 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.

The Danish Energy Authority has prepared an estimate of the impact 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 the oil companies' profits from the hydrocarbon activities.

Calculations have been made on the basis of a low, an intermediate and a high oil price scenario of USD 20, USD 25 and USD 30 per barrel, respectively, and a dollar exchange rate of DKK 6.4 per USD. The price scenarios merely serve to illustrate how sensitive economic projections are to fluctuations in the oil price.

Table 8.1 Degrees of self-sufficiency

	2004	2005	2006	2007	2008
Production (PJ)					
Oil	845	889	856	838	827
Gas	307	350	350	350	350
Renewable energy	121	125	125	126	126
Energy consumption (PJ)					
Total	1,273	1,363	1,331	1,313	1,303
Degrees of self-sufficiency (%)					
A	195	207	198	193	189
B	136	144	139	135	132
C	150	159	153	149	146

Fig. 8.3 The balance of trade for oil and gas and degree of self-sufficiency, 2003 prices

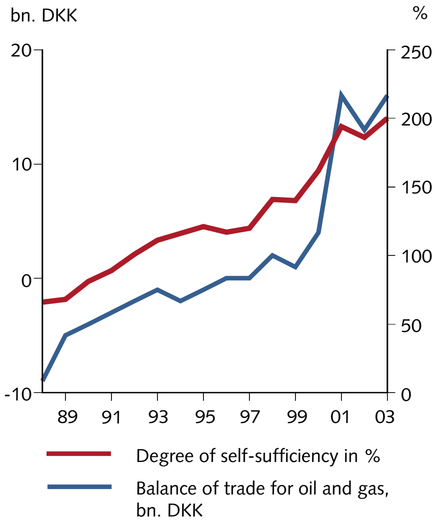


Table 8.2 shows the individual items used in calculating the impact of oil and gas activities on the balance of payments in the intermediate oil price scenario. The table also shows the calculated impact on the balance of payments current account when the low and high oil price scenarios are used.

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

Assuming that the oil price is USD 25 per barrel, the oil and gas activities will have an estimated DKK 19-21 billion impact on the balance of payments current account. In the low oil price scenario, the impact will be in the DKK 15-17 billion range, compared to DKK 24-26 billion in the high oil price scenario. The three scenarios show that oil prices greatly influence how the oil and gas activities affect the Danish economy. An exchange rate of DKK 6.4 per USD was chosen because the dollar exchange rate is low at present.

State revenue

The state generates direct revenue from North Sea oil and gas production via five different taxes and fees: *corporate income tax, hydrocarbon tax, royalty and oil pipeline tariff/compensatory fee.* In addition, the state receives indirect revenue based on DONG E&P A/S' participation in the activities. At the end of 2003, the state's aggregate revenue from oil and gas production amounted to DKK 78.6 billion in 2003 prices, while the aggregate production value amounted to DKK 314.3 billion. The aggregate value of the licensees' expenses for exploration, field developments and operations was DKK 175.8 billion.

The Government's agreement of 29 September 2003 with A. P. Møller-Mærsk has prompted various amendments to Danish tax legislation, effective 1 January 2004. These amendments will impinge on the state's future revenue from oil and gas production. The main elements of the agreement are outlined in the section on *Licences and exploration.*

Box 8.1 and appendix D specify the state's revenue base in the form of taxes and fees on hydrocarbon production.

Table 8.2 Impact of oil/gas activities on the balance of payments, DKK billion, 2003 prices, intermediate price scenario (25 USD/bbl)

	2004	2005	2006	2007	2008
Socio-economic production value	29	31	30	30	30
Import content	3	3	4	3	3
Balance of goods and services	26	29	26	27	27
Transfer of interest and dividends	6	7	6	7	7
Balance of payments current account	**19**	**21**	**20**	**20**	**20**
Balance of payments current account, low price scenario (20 USD/bbl)	**15**	**17**	**16**	**15**	**15**
Balance of payments current account, high price scenario (30 USD/bbl)	**24**	**26**	**25**	**24**	**24**

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 income 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 gas produced on which the assessment of state revenue is based.

Below, an outline is given of the state's sources of revenue, based on the statutory provisions applicable in 2003. With effect from 1 January 2004, these provisions were amended. The amendments appear from Appendix D and the section on *Licences and exploration.*

Corporate income tax payments

Corporate income tax payments are the chief source of revenue related to oil and gas. Although hydrocarbon production commenced in 1972, revenue from corporate income tax payments was not generated until the beginning of the 1980s, because oil and gas activities require fairly heavy investments, which are deductible as depreciation allowances over a number of years.

Hydrocarbon tax

Hydrocarbon tax was introduced in 1982 with the aim of taxing windfall profits, for example as a result of high oil prices. To ensure fuller and better exploitation of the resources in the subsoil, the Hydrocarbon Tax Act was also phrased in a manner that provides an incentive for the companies to invest in further exploration and development activities. Hydrocarbon tax became payable for a few years during the first half of the 1980s and again in 2002 and 2003, with total hydrocarbon tax payments amounting to approx. DKK 1,039 million in 2003 prices.

Royalty

Under the terms of A.P. Møller-Mærsk'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 holders of the Lulita share of licences 7/86 and 1/90 pay royalty based on the size of production attributable to their share of the 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 oil transported. DONG pays 95% of the proceeds from the 5% profit element to the state, termed the oil pipeline tariff.

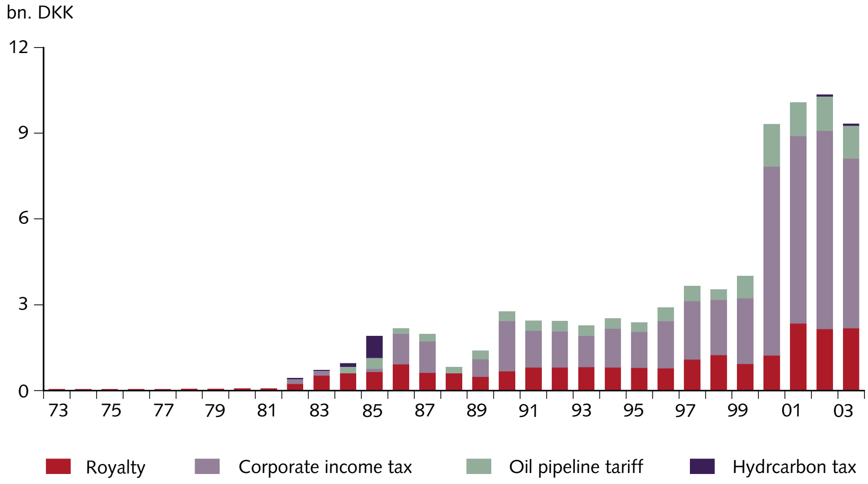
Compensatory fee

Any parties granted an exemption from the obligation regarding connection to and transportation through the oil pipeline are required to pay the state a fee amounting to 5% of the value of the oil and condensate comprised by the exemption. At present, the compensatory fee is payable on the production from the South Arne, Siri, Nini and Cecilie Fields.

DONG E&P A/S

DONG E&P A/S is a fully paying participant in the licences granted in the 4th and 5th 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. 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. 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 2003 amounts to DKK 201 million. The state's revenue from its ownership of DONG E&P A/S consists of dividend payments and the rising value of the company's shares.

Fig. 8.4 Development in total state revenue from oil/gas production 1972-2003, DKK billion, 2003 prices



Corporate income tax is a chief source of state revenue. During the period 1962-2003, the state's revenue from hydrocarbon production in the North Sea totalled almost DKK 80 billion (2003 prices). Of this amount, corporate income tax accounts for 58%, royalty for 28%, the oil pipeline tariff for 13% and hydrocarbon tax for 1%.

Fig. 8.4 shows the development in total state revenue broken down on the individual taxes and fees. It appears that from the year 2000 state revenue from hydrocarbon production in the North Sea has increased substantially, an increase that is due primarily to the positive development of production combined with high oil prices. In the past three years, the state has generated revenue of about DKK 10 billion a year; see Table 8.3.

For the past five 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 and South Arne Fields as well as a share of the Lulita Field. An outline of the companies holding shares in the individual licences is available at the Danish Energy Authority's website.

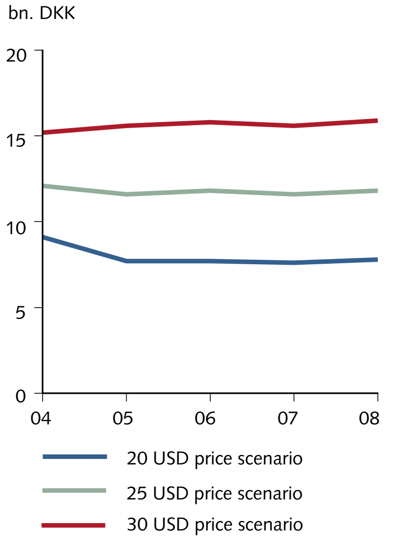
Based on the USD 25 oil price scenario, the Ministry of Taxation's five-year revenue forecast shows that the state's total revenue will come to DKK 12 billion in 2004, then hovering at around DKK 11.5 billion until the year 2008. The USD 30

Table 8.3 State revenue over the past five years, DKK million, nominal prices

	1999	2000	2001	2002	2003*
Hydrocarbon tax	-	-	-	65	64
Corporate income tax	2,082	6,170	6,273	6,794	5,943
Royalty	854	1,153	2,247	2,109	2,180
Oil pipeline tariff**	694	1,372	1,114	1,169	1,143
Total	**3,630**	**8,695**	**9,634**	**10,137**	**9,331**

** Estimate*
*** Incl. 5% compensatory fee*
Note: Payments received during the year

Fig. 8.5 Taxes and fees, 2004-2013, 2003 prices



price scenario is estimated to yield state revenue of DKK 15 billion in 2004, increasing to almost DKK 16 billion in 2008.

In addition to the uncertainty about oil prices and the dollar exchange rate, the future estimates of corporate income tax and hydrocarbon tax payments are subject to uncertainty because the calculations are based on various stylized assumptions, some of which concern the companies' financing costs as well as investment decisions.

THE FINANCES OF THE LICENSEES

For the period from 1963 to 2003, the aggregate production value amounted to about DKK 314 billion in 2003 prices. During the same period, the licensees' expenses for exploration, field developments and operations (including transportation) in respect of producing fields were calculated at DKK 24.5 billion, DKK 97.6 billion and DKK 53.7 billion, respectively, in 2003 prices.

Exploration costs

The Danish Energy Authority has preliminarily estimated total exploration costs in 2003 at DKK 0.8 billion, which is slightly lower than in 2002, when exploration costs totalled just over DKK 1 billion.

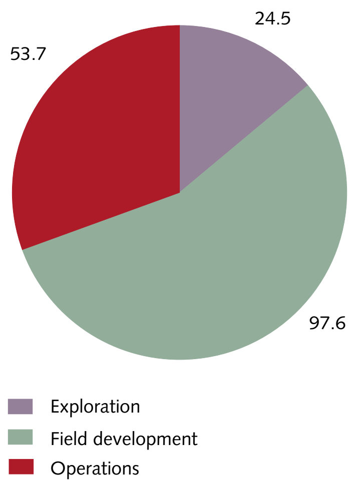
The Danish Energy Authority anticipates that the level of activity and costs recorded in 2003 will hold steady in 2004, and that the activity level will subsequently decline as the oil companies each fulfil their outstanding obligations under the licences issued in the 5th Licensing Round.

Table 8.4 Expected state revenue from oil and gas production, 2004-08, DKK billion, 2003 prices*

		2004	2005	2006	2007	2008
Corporate income tax	30 USD/bbl	6.0	6.7	6.4	6.2	6.2
	25 USD/bbl	4.6	5.2	5.0	4.8	4.8
	20 USD/bbl	3.2	3.7	3.5	3.3	3.4
Hydrocarbon tax	30 USD/bbl	1.6	2.7	3.3	3.3	3.6
	25 USD/bbl	1.0	1.4	2.0	2.0	2.2
	20 USD/bbl	0.6	0.3	0.6	0.7	0.8
Profit-sharing	30 USD/bbl	4.3	4.8	4.7	4.6	4.7
	25 USD/bbl	3.4	3.8	3.7	3.6	3.7
	20 USD/bbl	2.5	2.8	2.7	2.6	2.7
Royalty	30 USD/bbl	2.0	0.0	0.0	0.0	0.0
	25 USD/bbl	2.0	0.0	0.0	0.0	0.0
	20 USD/bbl	2.0	0.0	0.0	0.0	0.0
Oil pipeline tariff**	30 USD/bbl	1.3	1.4	1.3	1.3	1.3
	25 USD/bbl	1.1	1.1	1.1	1.1	1.1
	20 USD/bbl	0.9	0.9	0.9	0.9	0.8
Total	**30 USD/bbl**	**15.2**	**15.6**	**15.8**	**15.5**	**15.8**
	25 USD/bbl	12.1	11.6	11.8	11.5	11.7
	20 USD/bbl	9.1	7.7	7.7	7.5	7.8

*Payments received during the year
**Incl. 5% compensatory fee

Fig. 8.6 Total costs of all licensees, 1963-2003
DKK billion, 2003 prices



Presumably, the 6th Licensing Round, expected to open in the course of 2004, will counteract this downward trend in exploration activity. As the final terms and conditions for the 6th Licensing Round are being prepared, it is not possible at present to assess the scope and timing of the activities that will follow from the licences awarded in the upcoming 6th Licensing Round.

Investments in field developments

2003 was a year with major development activity. Thus, total investments in field developments for 2003 have been preliminarily estimated at DKK 7.6 billion, an increase of about DKK 2.2 billion compared to 2002.

In 2003, the DUC companies accounted for about 60% of total investments in field developments and about 80% of total production.

The Cecilie, Dan, Halfdan and Nini Fields and the NOGAT pipeline represented more than 75% of total investments in 2003. The two largest single investments in 2003 were the installation of an unmanned platform and the drilling of five wells in the Nini Field and the continued development of the Halfdan Field. Other investments include the development of the Cecilie Field, involving the addition of an unmanned platform and the drilling of one well, plus the continued development of the Dan Field; see the section entitled *Development*.

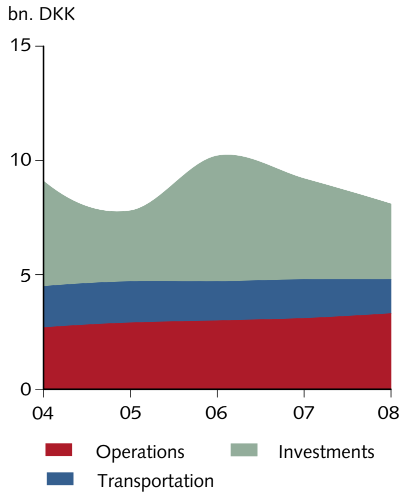
The Danish Energy Authority has considerably written up investments in field developments for the next few years, as compared to the forecast made at

Table 8.5 Investments, DKK million, nominal prices

	1999	2000	2001	2002	2003*
Cecilie				200	661
Dan	273	403	367	437	956
Gorm	26	12	240	242	105
Halfdan	204	886	1,518	2,412	1,684
Harald	32	175	-	0	4
Kraka	0	0	61	3	-
Lulita	-	-	-	-	7
Nini	-	-	-	285	1,697
Roar	80	17	-	-	37
Rolf	1	0	-	-	37
Sif / Igor	-	-	-	-	95
Siri	848	53	175	19	314
Skjold	399	404	89	5	91
Svend	189	-	115	223	-
South Arne	1,371	761	543	948	462
Tyra	152	330	198	-	414
Tyra SE	-	-	357	654	-
Valdemar	-	60	316	-1	230
NOGAT pipeline	-	-	-	-	766
Not allocated	-48	10	12	-	19
Total	**3,528**	**3,111**	**3,991**	**5,427**	**7,579**

* *Estimate*

Fig. 8.7 Investments in fields, and operating and oil transportation costs, 2003 prices



1 January 2003. The reason is that this year's investment forecast includes possible field developments, whereas the forecast made at 1 January 2003 only included ongoing, approved and planned field developments. The estimate of possible investments in field developments is based on the Danish Energy Authority's assessment of the potential for initiating further production beyond the production for which development plans have already been submitted; see the section on *Reserves*.

Operating, administration and transportation costs

Operating and administration costs have been preliminarily estimated at DKK 2.5 billion for 2003, which is higher than the comparable figure for 2002.

Total 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 production value of the oil transported. The Siri, South Arne, Nini and Cecilie 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. The oil produced is transported to shore by tanker.

Fig. 8.7 illustrates the Danish Energy Authority's estimate of developments in operating and transportation costs for the years to come.

Table 8.6 Investments in development projects, DKK billion, 2003 prices

	2004	2005	2006	2007	2008
Ongoing and approved					
Adda	-	-	0.4	0.1	-
Alma	-	-	0.4	0.1	-
Cecilie	0.2	-	-	-	-
Dan	1.1	0.4	-	-	0.1
Elly	-	0.0	0.4	0.2	-
Gorm	0.1	0.0	0.0	0.0	0.1
Halfdan	1.4	-	-	-	-
Sif / Igor	-	0.1	-	-	-
Nini	0.1	-	-	-	-
Rolf	-	-	-	-	-
Siri	0.2	-	-	-	-
Skjold	-	-	-	-	-
Svend	-	-	-	-	-
South Arne	0.7	0.4	-	-	-
Tyra	0.1	0.1	0.1	0.0	-
Tyra SE	0.2	0.0	-	-	-
Valdemar	-	-	-	-	-
NOGAT pipeline	0.1	-	-	-	-
Total	**4.2**	**1.1**	**1.3**	**0.5**	**0.2**
Planned	0.4	0.8	0.5	0.4	0.3
Possible	-	1.2	3.8	3.5	2.9
Expected	**4.6**	**3.1**	**5.5**	**4.4**	**3.3**

AMOUNTS PRODUCED AND INJECTED OIL thousand cubic metres

Production and sales

	1972-93	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Dan	18,366	3,496	3,713	3,799	3,858	4,767	5,745	6,599	6,879	6,326	5,929	69,477
Gorm	19,847	2,421	2,494	2,879	3,045	2,865	3,384	3,110	2,180	2,887	2,838	47,950
Skjold	17,542	1,715	1,979	2,023	2,011	1,896	1,825	1,975	1,354	1,659	1,529	35,509
Tyra	9,609	1,748	1,631	1,447	1,263	931	892	1,000	872	801	918	21,111
Rolf	2,936	92	216	218	96	92	77	83	51	51	104	4,016
Kraka	739	490	469	340	315	314	404	350	253	157	139	3,970
Dagmar	848	33	35	23	17	13	10	8	4	6	7	1,003
Regnar	145	429	86	41	27	43	29	14	33	18	19	885
Valdemar	53	304	165	161	159	95	86	77	181	353	435	2,070
Roar	-	-	-	319	427	327	259	285	317	175	121	2,231
Svend	-	-	-	836	1,356	635	521	576	397	457	279	5,056
Harald	-	-	-	-	794	1,690	1,332	1,081	866	581	425	6,768
Lulita	-	-	-	-	-	143	224	179	66	22	20	654
Halfdan	-	-	-	-	-	-	222	1,120	2,965	3,718	4,355	12,380
Siri	-	-	-	-	-	-	1,593	2,118	1,761	1,487	925	7,884
South Arne	-	-	-	-	-	-	757	2,558	2,031	2,313	2,383	10,042
Tyra SE	-	-	-	-	-	-	-	-	-	493	343	835
Cecilie	-	-	-	-	-	-	-	-	-	-	166	166
Nini	-	-	-	-	-	-	-	-	-	-	391	391
Sif	-	-	-	-	-	-	-	-	-	-	1	1
Total	**70,085**	**10,727**	**10,788**	**12,087**	**13,367**	**13,810**	**17,362**	**21,134**	**20,207**	**21,505**	**21,327**	**232,399**

Production GAS million normal cubic metres

	1972-93	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Dan	7,419	1,263	1,331	1,249	1,116	1,343	1,410	1,186	1,049	945	786	19,099
Gorm	8,723	922	761	674	609	633	537	426	306	479	339	14,408
Skjold	1,528	185	188	160	189	146	154	158	104	124	92	3,026
Tyra	27,307	3,646	3,839	3,843	4,229	3,638	3,878	3,826	3,749	3,948	3,993	65,898
Rolf	124	4	9	9	4	4	3	4	2	2	4	169
Kraka	269	119	128	95	85	106	148	119	100	52	25	1,245
Dagmar	124	8	5	4	3	2	2	2	1	1	3	155
Regnar	8	25	7	4	2	4	2	1	3	1	2	59
Valdemar	29	96	52	57	89	54	49	55	78	109	151	819
Roar	-	-	0	1,327	1,964	1,458	1,249	1,407	1,702	1,052	917	11,076
Svend	-	-	0	85	152	84	65	75	48	61	43	612
Harald	-	-	-	0	1,092	2,741	2,876	2,811	2,475	2,020	1,563	15,577
Lulita	-	-	-	-	-	69	181	160	27	5	5	448
Halfdan	-	-	-	-	-	-	37	178	522	759	1,139	2,634
Siri	-	-	-	-	-	-	142	197	176	157	110	781
South Arne	-	-	-	-	-	-	167	713	774	681	544	2,879
Tyra SE	-	-	-	-	-	-	-	-	-	447	452	898
Cecilie	-	-	-	-	-	-	-	-	-	-	14	14
Nini	-	-	-	-	-	-	-	-	-	-	29	29
Sif	-	-	-	-	-	-	-	-	-	-	3	3
Total	**45,530**	**6,269**	**6,321**	**7,506**	**9,534**	**10,281**	**10,901**	**11,316**	**11,116**	**10,844**	**10,213**	**139,829**

The monthly production figures for 2003 are available on the Danish Energy Authority's homepage www.ens.dk

GAS million normal cubic metres

Fuel*

	1972-93	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Dan	342	85	93	97	109	148	172	179	184	182	198	1,789
Gorm	795	104	111	135	164	152	149	142	111	146	135	2,144
Tyra	842	110	111	142	210	224	239	229	243	245	242	2,838
Dagmar	21	0	0	0	0	0	0	0	0	0	0	21
Harald	-	-	-	-	5	14	14	13	10	9	8	72
Siri	-	-	-	-	-	-	8	21	22	21	20	93
South Arne	-	-	-	-	-	-	3	32	34	45	49	163
Total	**1,999**	**299**	**314**	**375**	**488**	**539**	**585**	**618**	**604**	**648**	**652**	**7,121**

Flaring*

	1972-93	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Dan	1,356	66	36	40	36	43	56	67	79	55	74	1,907
Gorm	802	75	69	60	81	71	71	66	88	81	66	1,530
Tyra	377	48	42	67	46	42	58	58	68	61	54	920
Dagmar	103	8	5	2	3	2	2	2	1	1	3	133
Harald	-	-	-	-	77	19	12	7	11	3	1	131
Siri	-	-	-	-	-	-	73	9	15	9	23	129
South Arne	-	-	-	-	-	-	114	41	9	11	12	187
Total	**2,638**	**196**	**152**	**168**	**243**	**177**	**386**	**250**	**270**	**222**	**234**	**4,936**

Injection

	1972-93	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Gorm	7,853	70	28	26	62	24	25	45	4	14	6	8,157
Tyra	8,798	1,371	1,132	1,225	1,778	2,908	3,074	3,104	2,773	2,535	2,312	31,009
Siri**	-	-	-	-	-	-	61	167	139	126	109	602
Total	**16,651**	**1,441**	**1,160**	**1,251**	**1,840**	**2,933**	**3,160**	**3,316**	**2,916**	**2,675**	**2,428**	**39,769**

Sales*

	1984-93	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Dan	5,998	1,256	1,338	1,211	1,058	1,261	1,371	1,238	1,412	1,521	1,683	19,345
Gorm	925	863	750	622	495	535	448	334	209	364	228	5,773
Tyra	17,319	2,214	2,607	3,878	4,400	2,060	1,870	1,971	2,493	2,776	2,948	44,534
Harald	-	-	-	-	1,010	2,777	3,032	2,950	2,482	2,013	1,558	15,821
South Arne	-	-	-	-	-	-	50	640	730	625	483	2,529
Total	**24,242**	**4,332**	**4,695**	**5,710**	**6,963**	**6,633**	**6,770**	**7,133**	**7,326**	**7,299**	**6,900**	**88,003**

** The names refer to processing centres.*

*** Gas from the Cecilie and Nini Fields is injected into the Siri Field.*

CO_2 EMISSIONS thousand tons

	1972-93	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Fuel	4,550	681	715	853	1,110	1,226	1,337	1,460	1,442	1,562	1,576	16,512
Flaring	6,005	448	345	382	553	402	1,074	641	637	531	549	11,567
Total	10,555	1,130	1,061	1,235	1,664	1,628	2,410	2,101	2,079	2,092	2,125	28,079

Calorific value of gas (South Arne) : *70 MJ/Nm³*
Calorific value of gas (all other installations): *40 MJ/Nm³*

Emission factor :
Before 2000 *56.9 kg CO_2/GJ* *2002* *57.28 kg CO_2/GJ*
2001 *57.25 kg CO_2/GJ* *2003* *57.19 kg CO_2/GJ*

WATER thousand cubic metres

Production

	1972-93	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Dan	2,290	1,117	1,275	1,543	1,845	2,976	4,220	5,277	6,599	6,348	7,182	40,673
Gorm	5,495	824	948	1,921	2,906	3,177	3,468	3,980	3,353	4,017	4,420	34,510
Skjold	1,186	889	1,337	2,679	3,635	3,938	3,748	4,333	2,872	3,007	3,523	31,147
Tyra	2,847	1,290	1,749	2,161	2,215	2,020	2,033	3,046	2,545	2,261	3,038	25,205
Rolf	1,468	161	443	490	390	411	366	358	181	168	270	4,706
Kraka	371	188	251	272	287	347	329	256	352	306	208	3,166
Dagmar	623	367	464	507	408	338	246	241	102	160	375	3,831
Regnar	0	244	396	299	164	407	363	139	475	257	316	3,060
Valdemar	1	24	20	34	61	52	55	48	150	272	310	1,026
Roar	-	-	-	14	96	146	199	317	386	301	477	1,937
Svend	-	-	-	2	64	272	582	1,355	954	1,051	1,330	5,611
Harald	-	-	-	-	-	5	15	39	98	78	43	279
Lulita	-	-	-	-	-	3	5	11	23	15	16	74
Halfdan	-	-	-	-	-	-	56	237	493	367	500	1,653
Siri	-	-	-	-	-	-	319	1,868	2,753	3,041	2,891	10,872
South Arne	-	-	-	-	-	-	15	60	119	390	751	1,334
Tyra SE	-	-	-	-	-	-	-	-	-	250	596	846
Cecilie	-	-	-	-	-	-	-	-	-	-	25	25
Nini	-	-	-	-	-	-	-	-	-	-	3	3
Sif	-	-	-	-	-	-	-	-	-	-	0	0
Total	**14,281**	**5,103**	**6,882**	**9,922**	**12,072**	**14,093**	**16,020**	**21,566**	**21,456**	**22,289**	**26,274**	**169,958**

Injection

	1972-93	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	Total
Dan	2,838	3,808	5,884	8,245	8,654	11,817	14,964	17,464	18,176	16,123	18,063	126,035
Gorm	6,007	4,612	5,749	8,112	8,642	8,376	8,736	10,641	6,549	8,167	7,066	82,657
Skjold	18,194	3,511	3,985	5,712	6,320	6,291	5,866	6,520	4,805	6,411	6,115	73,730
Halfdan	-	-	-	-	-	-	82	13	620	2,532	5,162	8,410
Siri	-	-	-	-	-	-	1,236	3,778	4,549	4,507	3,383	17,453
South Arne	-	-	-	-	-	-	-	52	1,991	4,397	5,316	11,755
Nini	-	-	-	-	-	-	-	-	-	-	71	71
Total	**27,038**	**11,931**	**15,618**	**22,069**	**23,616**	**26,484**	**30,884**	**38,469**	**36,689**	**42,138**	**45,175**	**320,112**

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

CECILIE FIELD

Location:	Blocks 5604/19 and 20
Licence:	16/98
Operator:	DONG E&P A/S
Discovered:	2000
Year on stream:	2003
Producing wells:	1
Water depth:	60 m
Field delineation:	13.4 km²
Reservoir depth:	2,200 m
Reservoir rock:	Sandstone
Geological age:	Paleocene
Reserves at 1 January 2004:	
Oil:	1.7 million m³
Gas:	0.0 billion Nm³
Cum. production at 1 January 2004:	
Oil:	0.17 million m³
Gas:*	0.01 billion Nm³
Water:	0.03 million m³
Production in 2003:	
Oil:	0.17 million m³
Gas:*	0.01 billion Nm³
Water:	0.03 million m³
Total investments at 1 January 2004:	
2003 prices	DKK 0.9 billion

The gas has been injected into the Siri Field.

REVIEW OF GEOLOGY

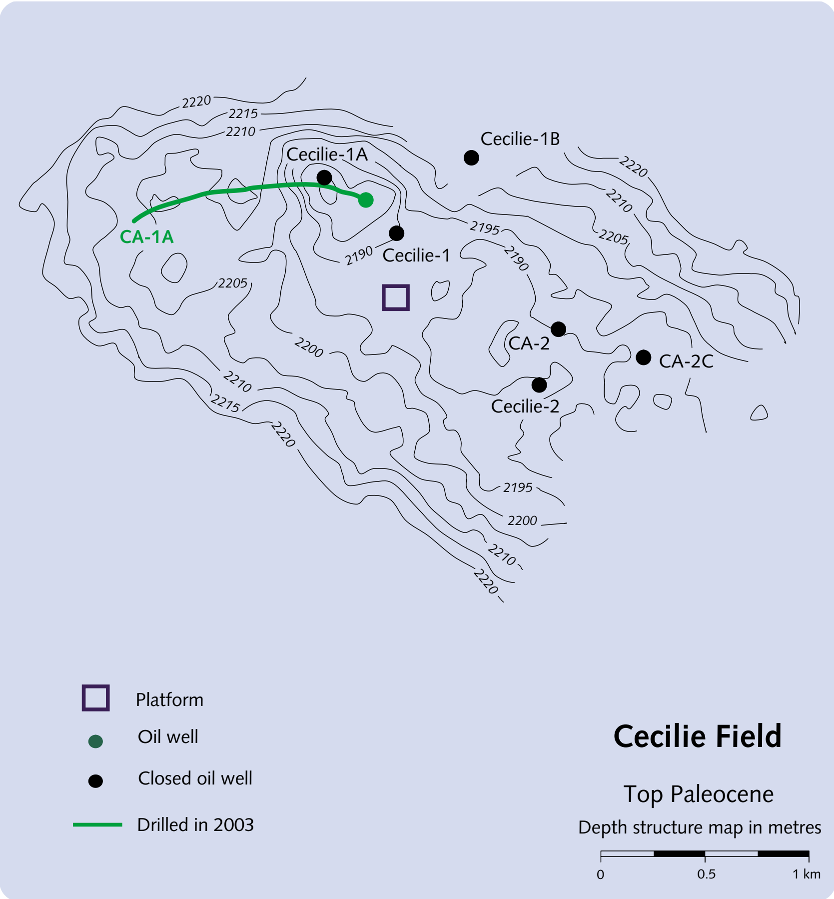
The Cecilie Field is an anticlinal structure induced through salt tectonics. Faults and shifted sands delimit the accumulation, which is thus a combined structural and stratigraphic trap.

PRODUCTION STRATEGY

Recovery is based on water injection to maintain reservoir pressure. The production wells will be drilled in the crest of the structure, while water will be injected in the flank of the field.

PRODUCTION FACILITIES

Cecilie is a satellite development to the Siri Field with one unmanned wellhead platform. The unprocessed production is transported to the Siri platform through a 12" multiphase pipeline. The oil is processed at the Siri platform and exported to shore via tanker. The gas produced is injected into the Siri Field. Injection water is conveyed to the Cecilie Field through a 10" pipeline.



DAGMAR FIELD

Prospect:	East Rosa
Location:	Block 5504/15
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1983
Year on stream:	1991
Producing wells:	2
Water depth:	34 m
Area:	9 km²
Reservoir depth:	1,400 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2004:	
Oil:	0.1 million m³
Gas:	0.0 billion Nm³
Cum. production at 1 January 2004:	
Oil:	1.00 million m³
Gas:	0.16 billion Nm³
Water:	3.83 million m³
Production in 2003:	
Oil:	0.01 million m³
Gas:	0.00 billion Nm³
Water:	0.38 million m³
Total investments at 1 January 2004:	
2003 prices	DKK 0.4 billion

REVIEW OF GEOLOGY

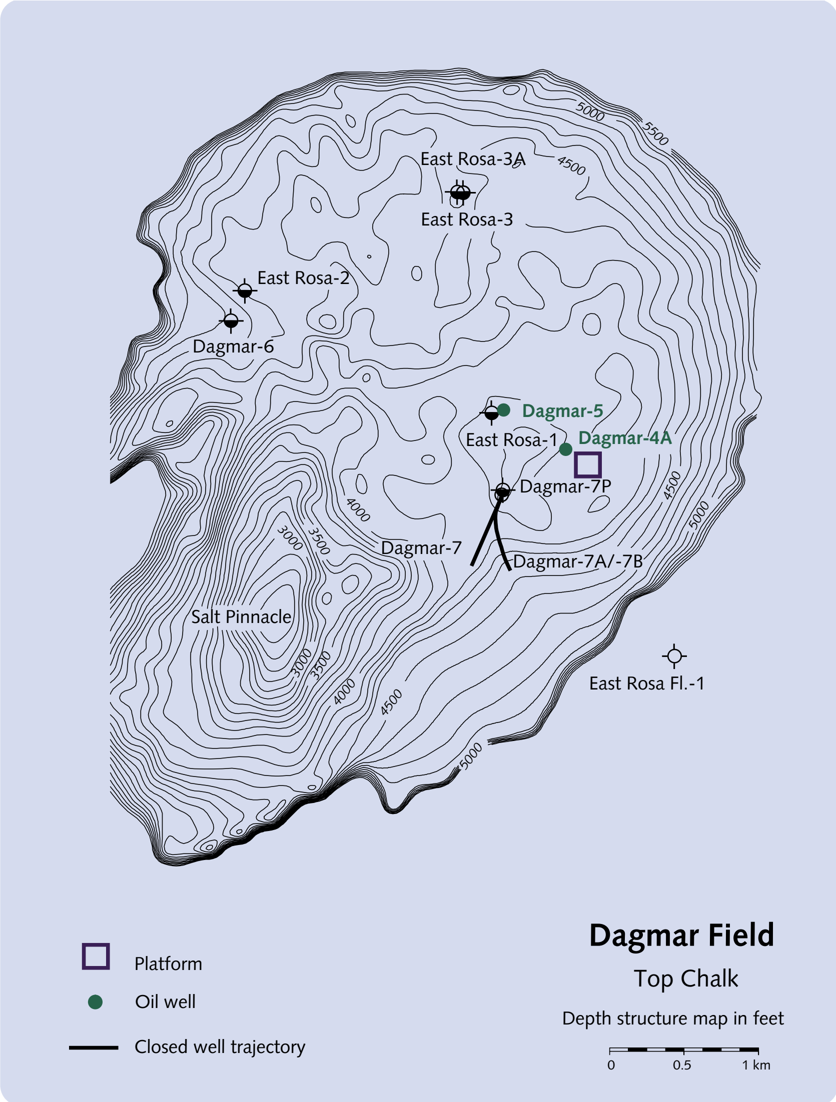
The Dagmar field is an anticlinal structure, induced through Zechstein salt tectonics. The uplift is so pronounced that the Dagmar oil reservoir is situated closer to the surface than any other hydrocarbon reservoirs in Danish territory. The reservoir is heavily fractured (compare Skjold, Rolf, Regnar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

Prospect:	Abby
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1971
Year on stream:	1972
Producing wells:	56
Water-injection wells:	48
Water depth:	40 m
Field delineation:	121 km²
Reservoir depth:	1,850 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2004:	
Oil:	62.5 million m³
Gas:	8.2 billion Nm³
Cum. production at 1 January 2004:	
Oil:	69.48 million m³
Gas:	19.10 billion Nm³
Water:	40.67 million m³
Cum. injection at 1 January 2004:	
Water:	126.04 million m³
Production in 2003:	
Oil:	5.93 million m³
Gas:	0.79 billion Nm³
Water:	7.18 million m³
Injection in 2003:	
Water:	18.06 million m³
Total investments at 1 January 2004:	
2003 prices	DKK 22.0 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 in large sections of the field. 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. Recovery is also based on water injection in this part of the field.

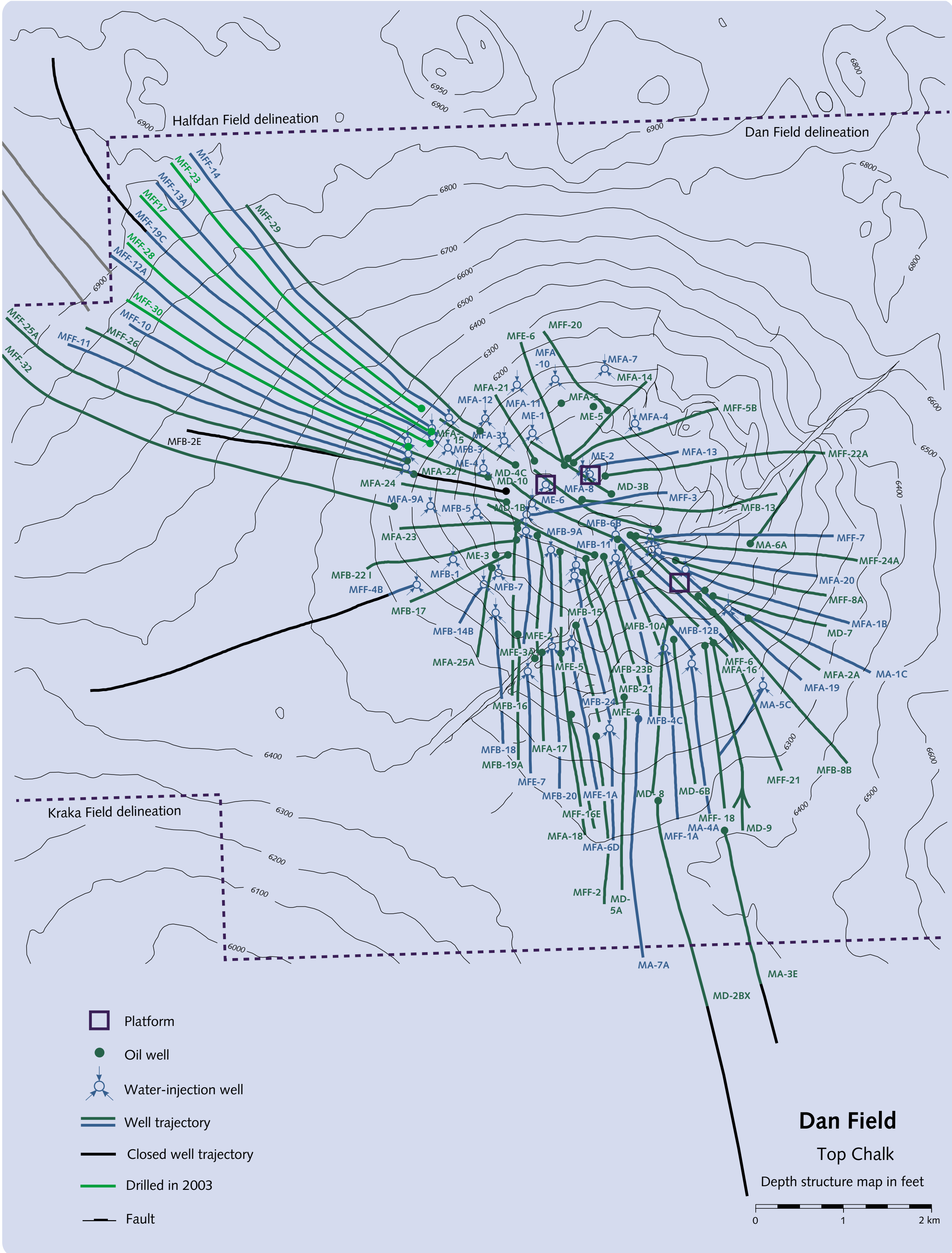
PRODUCTION FACILITIES

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.



Halfdan Field delineation
Dan Field delineation
Kraka Field delineation
Platform
Oil well
Water-injection well
Well trajectory
Closed well trajectory
Drilled in 2003
Fault
Dan Field
Top Chalk
Depth structure map in feet
0
1
2 km

GORM FIELD

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:	35
Gas-injection wells:	2
Water-injection wells:	14
Water depth:	39 m
Field delineation:	33 km^2
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2004:	
Oil:	11.9 million m^3
Gas:	1.2 billion Nm^3
Cum. production at 1 January 2004:	
Oil:	47.95 million m^3
Net gas:	6.25 billion Nm^3
Water:	34.51 million m^3
Cum. injection at 1 January 2004:	
Gas:	8.16 billion Nm^3
Water:	82.66 million m^3
Production in 2003:	
Oil:	2.84 million m^3
Net gas:	0.33 billion Nm^3
Water:	4.42 million m^3
Injection in 2003:	
Gas:	0.01 billion Nm^3
Water:	7.07 million m^3
Total investments at 1 January 2004:	
2003 prices	DKK 10.9 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).

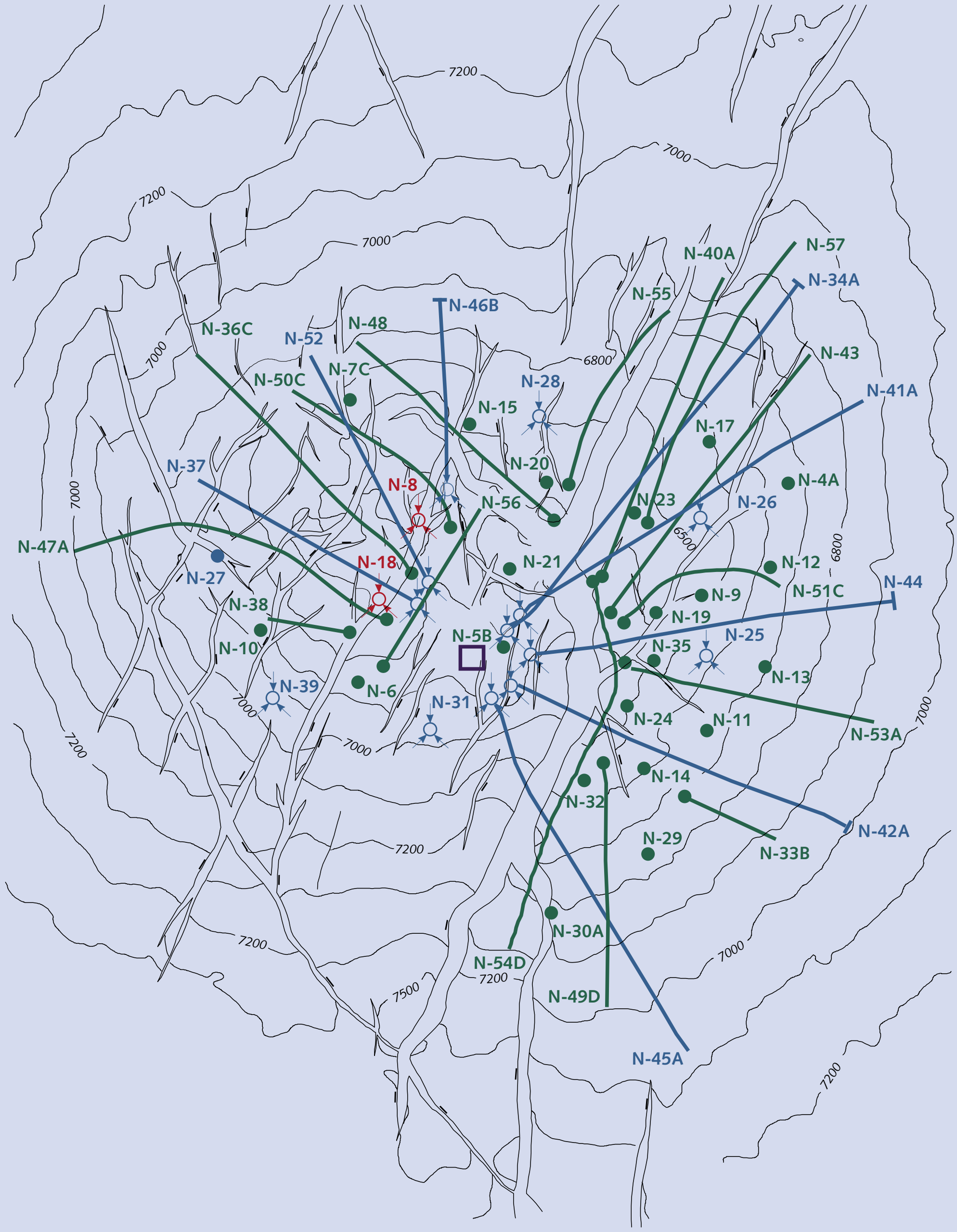
Gorm receives production from the satellite fields, Skjold, Rolf and Dagmar, as well as the liquids (hydrocarbons and water) produced in the Halfdan Field. The Gorm Field installations supply the Skjold Field with injection water and lift gas and the Rolf Field with lift gas. The gas produced is sent 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, produced-water treatment plant 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.



Platform

Oil well

Water-injection well

Gas-injection well

Well trajectory

Top Chalk penetrated from below

Fault

Gorm Field

Top Chalk

Depth structure map in feet

0 0.5 1 km

HALFDAN FIELD

Prospect:	Nana
Location:	Blocks 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1999
Year on stream:	1999
Producing wells:	26
Water-injection wells:	13
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 2004:	
Oil:	69.4 million m^3
Gas:	9.0 billion Nm^3
Cum. production at 1 January 2004:	
Oil:	12.38 million m^3
Gas:	2.63 billion Nm^3
Water:	1.65 million m^3
Cum. injection at 1 January 2004:	
Water:	8.41 million m^3
Production in 2003:	
Oil:	4.36 million m^3
Gas:	1.14 billion Nm^3
Water:	0.50 million m^3
Injection in 2003:	
Water:	5.16 million m^3
Total investments at 1 January 2004:	
2003 prices	DKK 6.7 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 away from the area. 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 porous, unfractured chalk is similar to that found in the western flank of the Dan Field. There is a gas cap above the northeastern part of the oil accumulation.

PRODUCTION STRATEGY

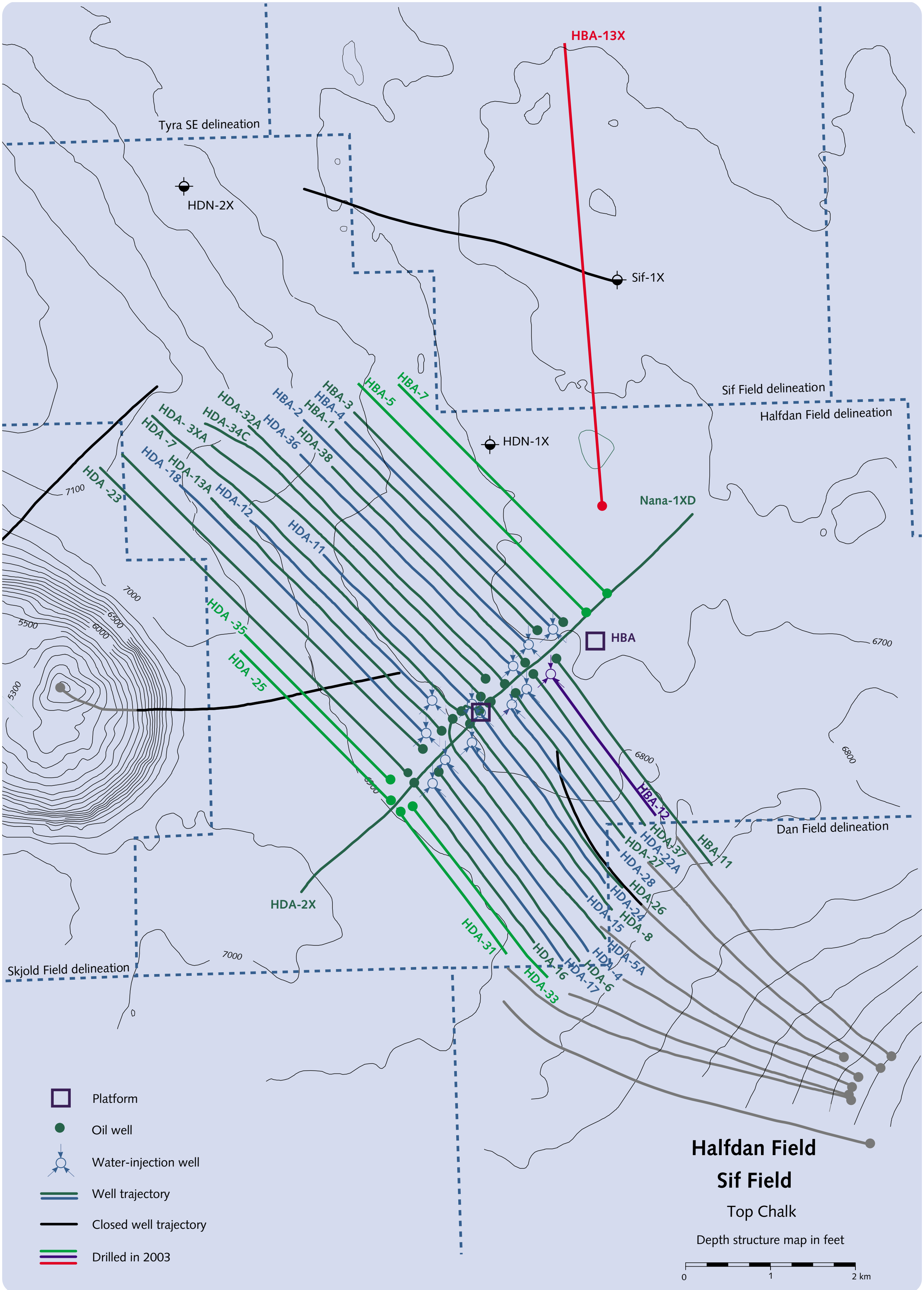
The recovery of oil and gas from the field is based on pressure support from water injection. The wells are arranged in a pattern of alternate production and injection wells with parallel well trajectories, about 180 metres apart. The injection wells are stimulated with acid, which makes it possible to inject large volumes of water.

The regular spacing of the wells optimizes the flooding of the reservoir, thus enhancing recovery.

PRODUCTION FACILITIES

The installations in the field consist of a wellhead platform (HDA) with minimal production facilities. The operation of the wellhead 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. Another wellhead platform (HBA) is placed about 2 km northeast of the HDA platform. As a temporary measure, the separated hydrocarbons produced from the HBA platform are conveyed via the HDA platform to the Gorm and Dan Fields for final processing.

The HDA platform installations have been further expanded by adding a processing module for three-phase separation with water-processing and gas-processing/compression facilities. Moreover, a 32-person accommodation platform (HDB) and a flare stack (HDC) have been installed, both with bridge connection to the HDA platform.


HBA-13X
Tyra SE delineation
HDN-2X
Sif-1X
Sif Field delineation
Halfdan Field delineation
HDN-1X
Nana-1XD
HBA
Dan Field delineation
HDA-2X
Skjold Field delineation
HBA-3
HBA-4
HBA-1
HBA-2
HBA-5
HBA-7
HDA-32A
HDA-34C
HDA- 3XA
HDA -7
HDA -18
HDA-13A
HDA-36
HDA-38
HDA-12
HDA-11
HDA -23
HDA -35
HDA -25
HBA-12
HBA-11
HDA-37
HDA-22A
HDA-27
HDA-28
HDA-26
HDA-24
HDA-15
HDA-8
HDA-5A
HDA-31
HDA-16
HDA-17
HDA-4
HDA-6
HDA-33
7100
7000
6500
6000
5500
5300
6700
6800
Platform
Oil well
Water-injection well
Well trajectory
Closed well trajectory
Drilled in 2003
Halfdan Field
Sif Field
Top Chalk
Depth structure map in feet
0
1
2 km

HARALD FIELD

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 2004:	
Oil and condensate:	1.2 million m^3
Gas:	5.3 billion Nm^3
Cum. production at 1 January 2004:	
Oil and condensate:	6.77 million m^3
Gas:	15.58 billion Nm^3
Water:	0.28 million m^3
Production in 2003:	
Oil and condensate:	0.43 million m^3
Gas:	1.56 billion Nm^3
Water:	0.04 million m^3
Total investments at 1 January 2004:	
2003 prices	DKK 3.2 billion

REVIEW OF GEOLOGY

The Harald Field consists of two accumulations, Lulu (Harald East) and West Lulu (Harald West), 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 the 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

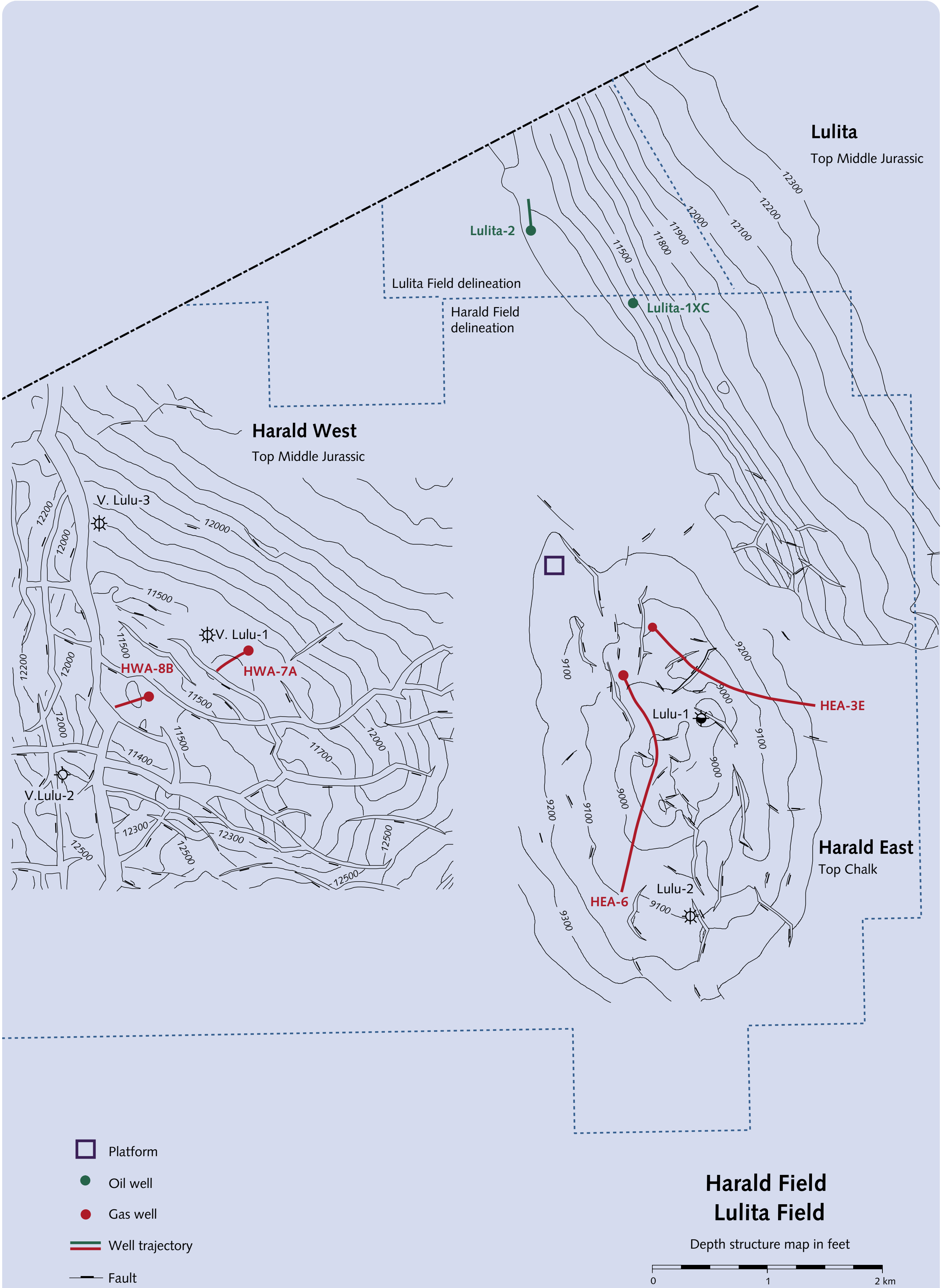
The Harald Field installations comprise a combined wellhead and processing platform (Harald A) and an accommodation platform (Harald B).

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.



Harald Field
Lulita Field

Depth structure map in feet

KRAKA FIELD

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 km²
Reservoir depth:	1,800 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2004:	
Oil:	0.8 million m³
Gas:	0.9 billion Nm³
Cum. production at 1 January 2004:	
Oil:	3.97 million m³
Gas:	1.25 billion Nm³
Water:	3.17 million m³
Production in 2003:	
Oil:	0.14 million m³
Gas:	0.03 billion Nm³
Water:	0.21 million m³
Total investments at 1 January 2004:	
2003 prices	DKK 1.4 billion

REVIEW OF GEOLOGY

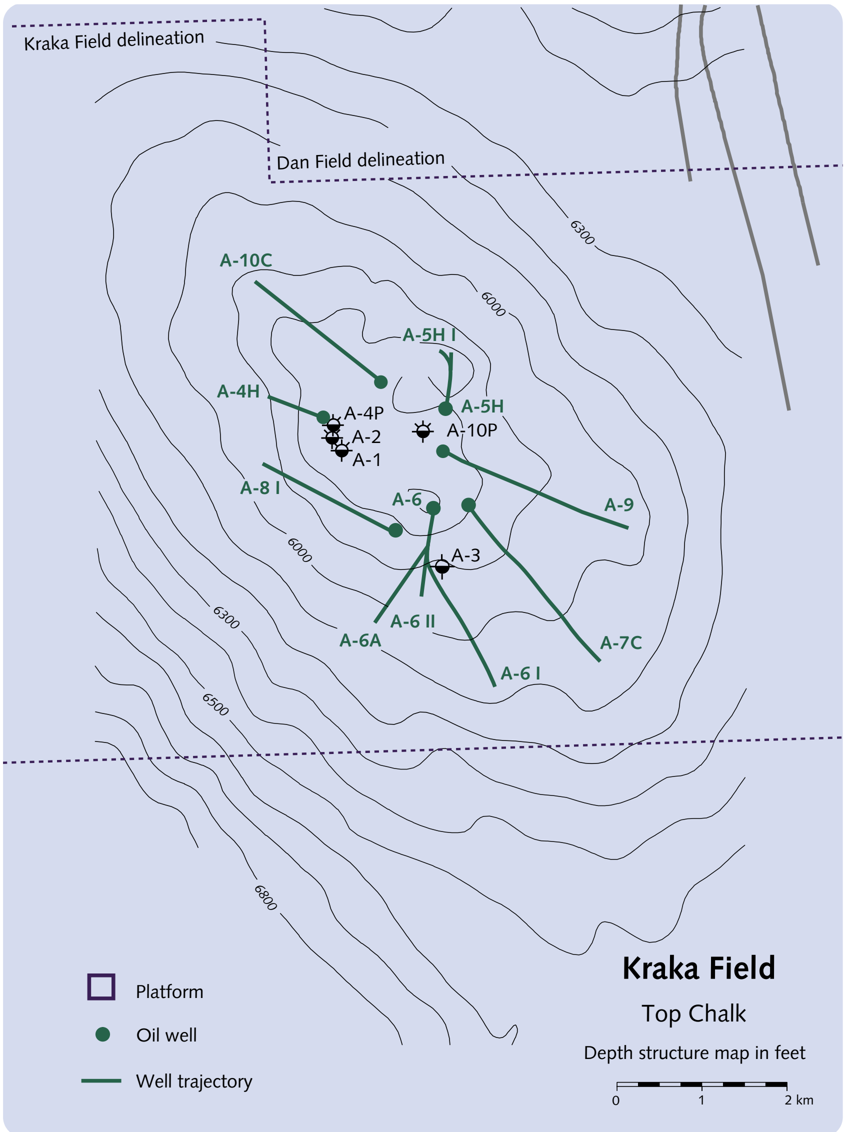
Kraka is an anticlinal structure induced through salt tectonics, which to a certain degree has caused fracturing in the chalk. The chalk reservoir has reasonable porosity, although low permeability. The thin oil pay zone is further characterized by high water saturations. There is a minor gas cap in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

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 km²
Reservoir depth:	3,525 m
Reservoir rock:	Sandstone
Geological age:	Middle Jurassic
Reserves at 1 January 2004:	
Oil:	0.2 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2004:	
Oil:	0.65 million m^3
Gas:	0.45 billion Nm^3
Water:	0.07 million m^3
Production in 2003:	
Oil:	0.02 million m^3
Gas:	0.01 billion Nm^3
Water:	0.02 million m^3
Total investments at 1 January 2004:	
2003 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.

NINI FIELD

Location:	Blocks 5605/10 and 14
Licence:	4/95
Operator:	DONG E&P A/S
Discovered:	2000
Year on stream:	2003
Producing wells:	2
Water-injection wells:	1
Water depth:	60 m
Field delineation:	48.8 km^2
Reservoir depth:	1,700 m
Reservoir rock:	Sandstone
Geological age:	Paleogene
Reserves at 1 January 2004:	
Oil:	3.9 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2004:	
Oil:	0.39 million m^3
Gas:*	0.03 million Nm^3
Water:	0.00 million m^3
Cum. injection at 1 January 2004:	
Water:	0.07 million m^3
Production in 2003:	
Oil:	0.39 million m^3
Gas:*	0.03 million Nm^3
Water:	0.00 million m^3
Injection in 2003:	
Water:	0.07 million m^3
Total investments at 1 January 2004:	
2003 prices	DKK 2.0 billion

REVIEW OF GEOLOGY

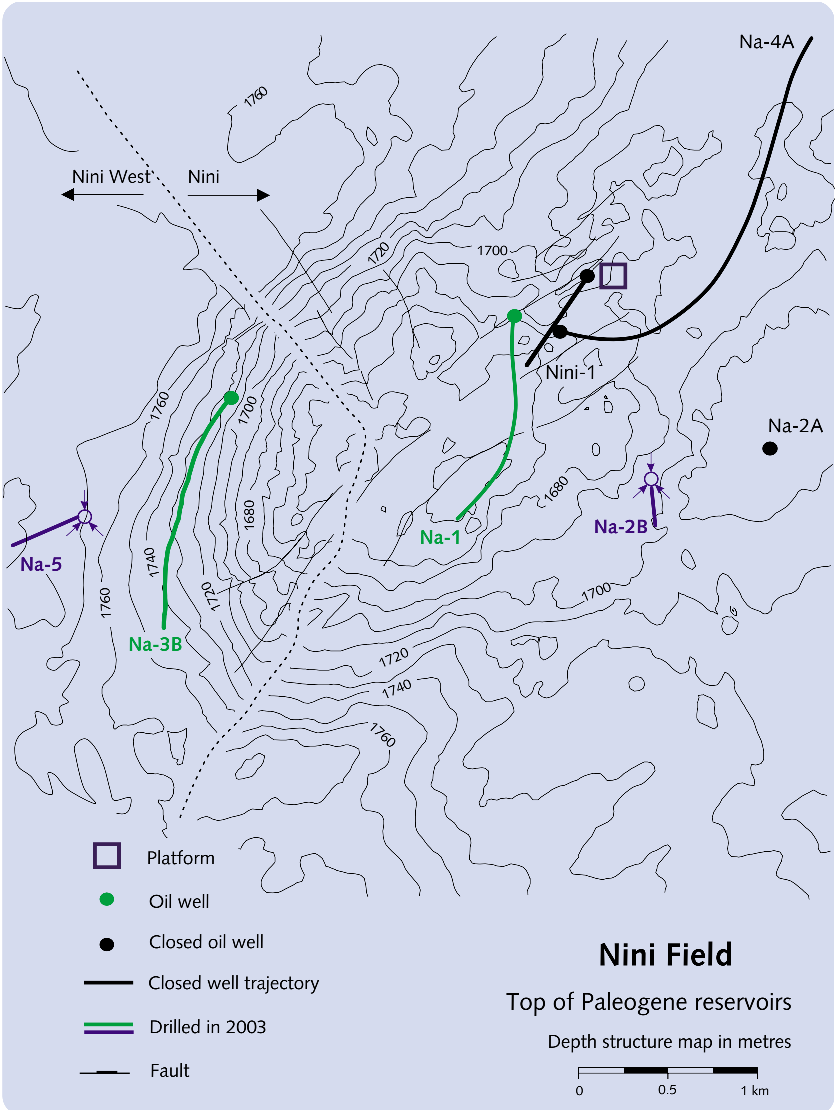
The Nini accumulation is defined by a combined structural and stratigraphic trap, the anticlinal structure being induced through salt tectonics. The reservoir consists of channel sands deposited in the Siri Fairway. The Nini Field also includes the Nini West area.

PRODUCTION STRATEGY

The production strategy is based on water injection to maintain reservoir pressure. The gas produced is injected into the Siri Field.

PRODUCTION FACILITIES

Nini is a satellite development to the Siri Field with one unmanned wellhead platform. The unprocessed production is transported through a 14" multiphase pipeline to the Siri platform where it is processed and exported to shore via tanker. Injection water and lift gas are conveyed from the Siri platform to the Nini platform through a 10" pipeline and a 4" pipeline, respectively.



* *The gas has been injected into the Siri Field.*

REGNAR FIELD

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 2004:

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

Cum. production at 1 January 2004:

Oil:	0.89 million m^3
Gas:	0.06 billion Nm^3
Water:	3.06 million m^3

Production in 2003:

Oil:	0.02 million m^3
Gas:	0.00 billion Nm^3
Water:	0.32 million m^3

Total investments at 1 January 2004:

2003 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).

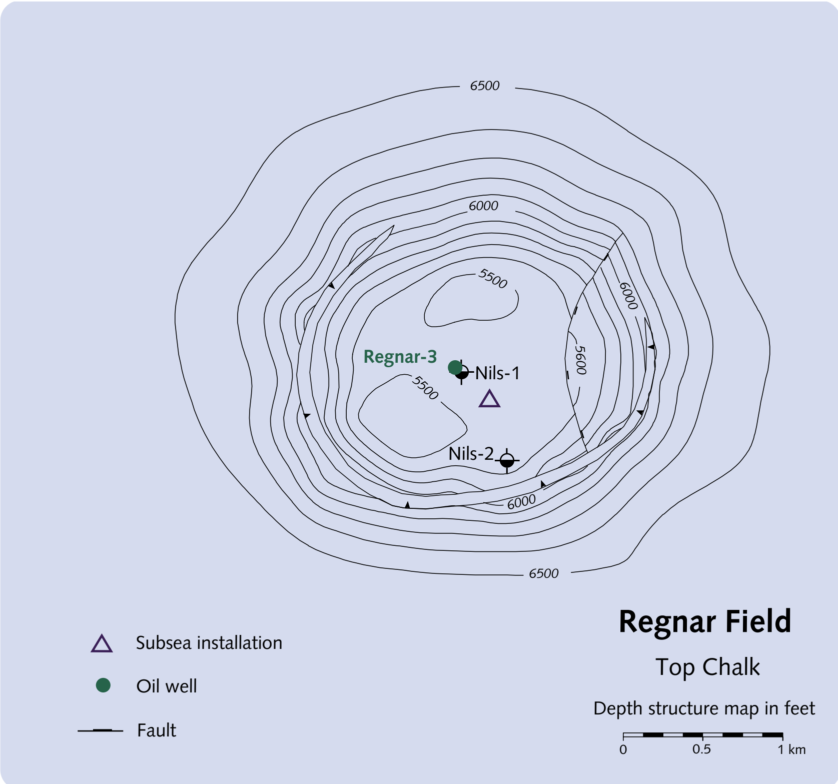
PRODUCTION STRATEGY

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 FIELD

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 km^2
Reservoir depth:	2,025 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

Reserves at 1 January 2004:

Oil and condensate:	0.8 million m^3
Gas:	5.9 billion Nm^3

Cum. production at 1 January 2004:

Oil and condensate:	2.23 million m^3
Gas:	11.08 billion Nm^3
Water:	1.94 million m^3

Production in 2003:

Oil and condensate:	0.12 million m^3
Gas:	0.92 billion Nm^3
Water:	0.48 million m^3

Total investments at 1 January 2004:

2003 prices	DKK 0.6 billion

REVIEW OF GEOLOGY

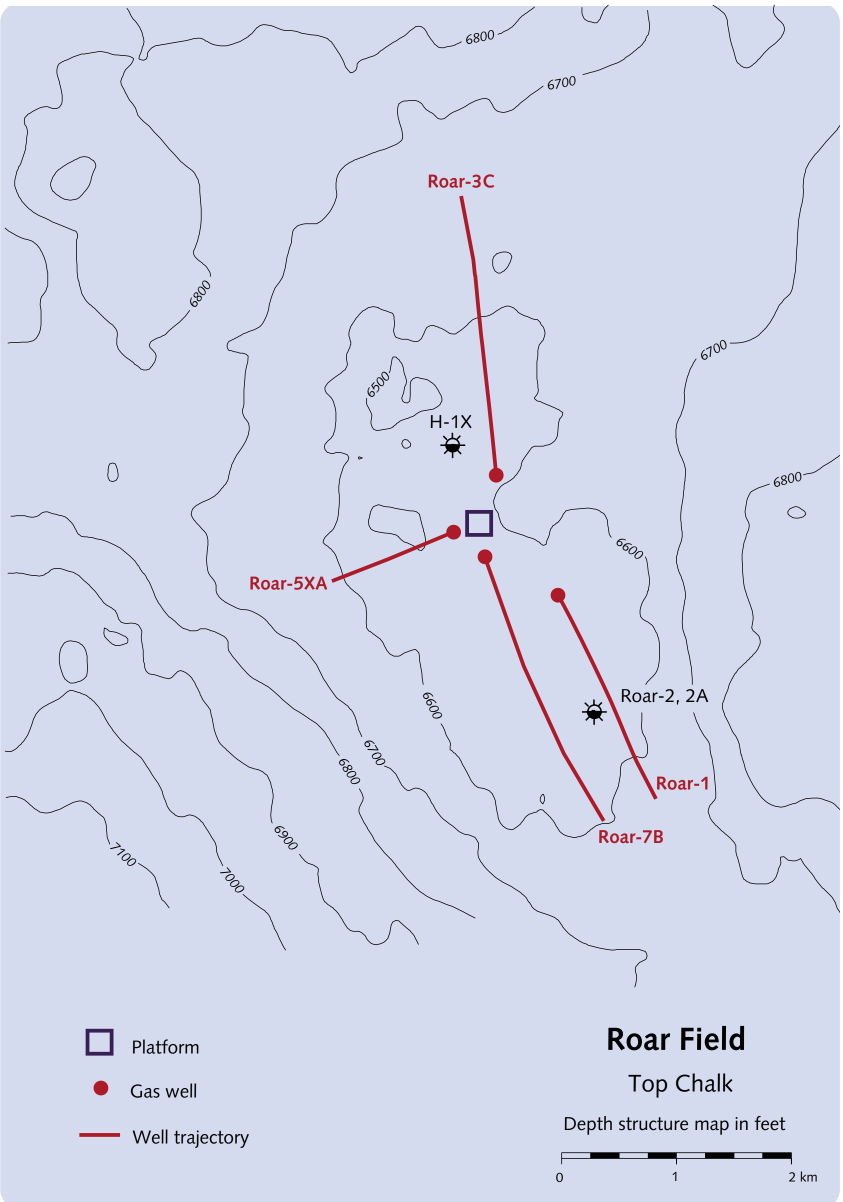
Roar is an anticlinal structure, induced through tectonic uplift. The accumulation consists of free gas containing condensate. The reservoir is only slightly fractured.

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 FIELD

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 km^2
Reservoir depth:	1,800 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein

Reserves at 1 January 2004:

Oil:	0.6 million m^3
Gas:	0.0 billion Nm^3

Cum. production at 1 January 2004:

Oil:	4.02 million m^3
Gas:	0.17 billion Nm^3
Water:	4.71 million m^3

Production in 2003:

Oil:	0.10 million m^3
Gas:	0.00 billion Nm^3
Water:	0.27 million m^3

Total investments at 1 January 2004:

2003 prices	DKK 1.0 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).

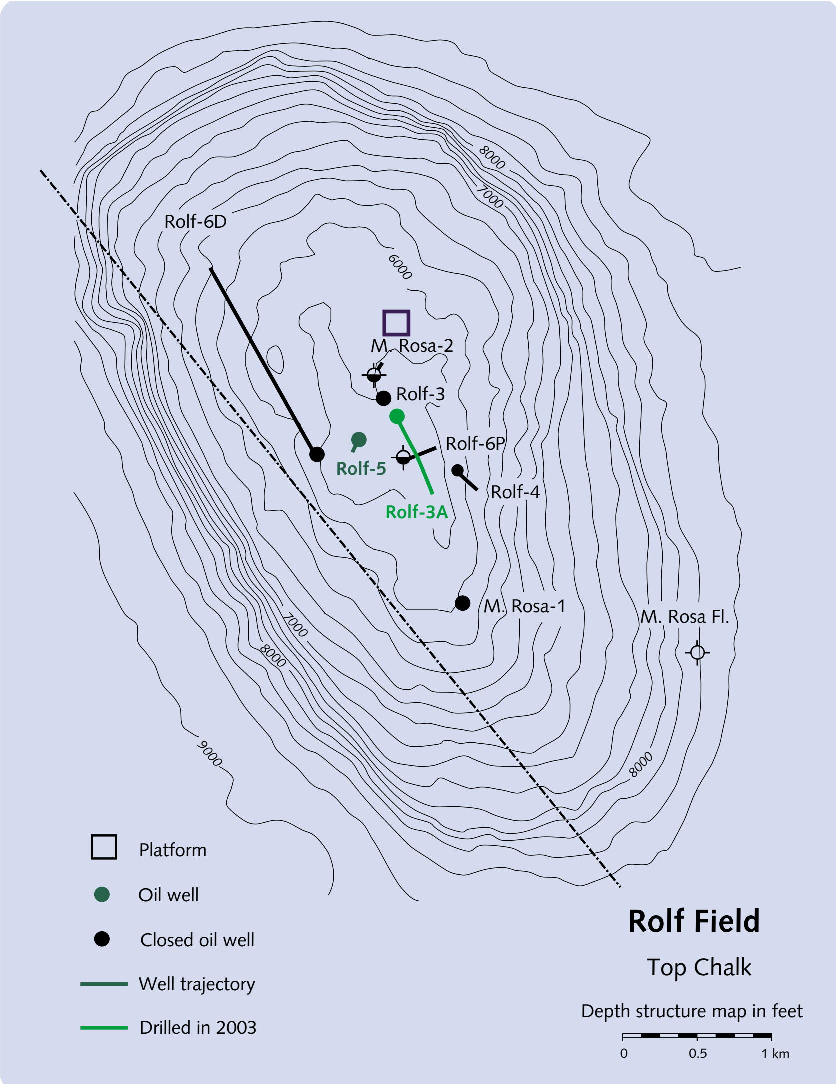
PRODUCTION STRATEGY

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.



SIF FIELD

Location:	Block 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1999
Year on stream:	Permanently in 2004
Producing wells:	1
Water depth:	44 m
Field delineation:	40 km^2
Reservoir depth:	2,050 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2004:	
Oil:	1.3 million m^3
Gas:	11.3 billion Nm^3
Cum. production at 1 January 2004:	
Oil:	0.00 million m^3
Gas:	0.00 billion Nm^3
Water:	0.00 million m^3
Production in 2003:	
Oil:	0.00 million m^3
Gas:	0.00 billion Nm^3
Water:	0.00 million m^3
Total investments at 1 January 2004:	
2003 prices	DKK 0.1 billion

REVIEW OF GEOLOGY

The Sif Field is part of a continuous gas accumulation in Danian layers, extending over the Igor, Sif and Halfdan field delineations. The field is located at the crest and down along the western flank of the Tyra-Igor inversion ridge. The accumulation is not primarily structurally defined, but the distribution of hydrocarbons is mainly determined by reservoir parameters.

PRODUCTION STRATEGY

Production is based on primary recovery, using the reservoir pressure.

PRODUCTION FACILITIES

The accumulation is exploited from the existing production facilities in the Halfdan Field.

The map of the Halfdan Field includes the Sif Field.

SIRI FIELD

Location:	Block 5604/20
Licence:	6/95
Operator:	DONG E&P A/S
Discovered:	1995
Year on stream:	1999
Producing wells:	5 (Siri Central)
	2 (Stine segment 2)
Water- and gas-injection wells:	2 (Siri Central)
Water depth:	60 m
Field delineation:	42 km^2
Reservoir depth:	2,060 m
Reservoir rock:	Sandstone
Geological age:	Paleogene
Reserves at 1 January 2004:	
Oil:	2.7 million m^3
Gas:	0.0 billion Nm^3
Cum. production at 1 January 2004:	
Oil:	7.88 million m^3
Net gas:	0.18 billion Nm^3
Water:	10.87 million m^3
Cum. injection at 1 January 2004:	
Gas:*	0.60 billion Nm^3
Water:	17.45 million m^3
Production in 2003:	
Oil:	0.93 million m^3
Net gas:	0.00 billion Nm^3
Water:	2.89 million m^3
Injection in 2003:	
Gas:*	0.11 billion Nm^3
Water:	3.38 million m^3
Total investments at 1 January 2004:	
2003 prices	DKK 4.0 billion

REVIEW OF GEOLOGY

The Siri Field is a structural trap with a Paleogene sandstone reservoir. The accumulation consists of oil with a relatively low content of gas. Recovery takes place from Siri Central as well as from the neighbouring Stine segment 2. In 2004, production from Stine segment 1 will be commenced.

PRODUCTION STRATEGY

Recovery from the field is based on the production of oil through the co-injection of water and gas. Measures are taken 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.

In addition, gas from the Cecilie and Nini Fields is injected into the Siri Field.

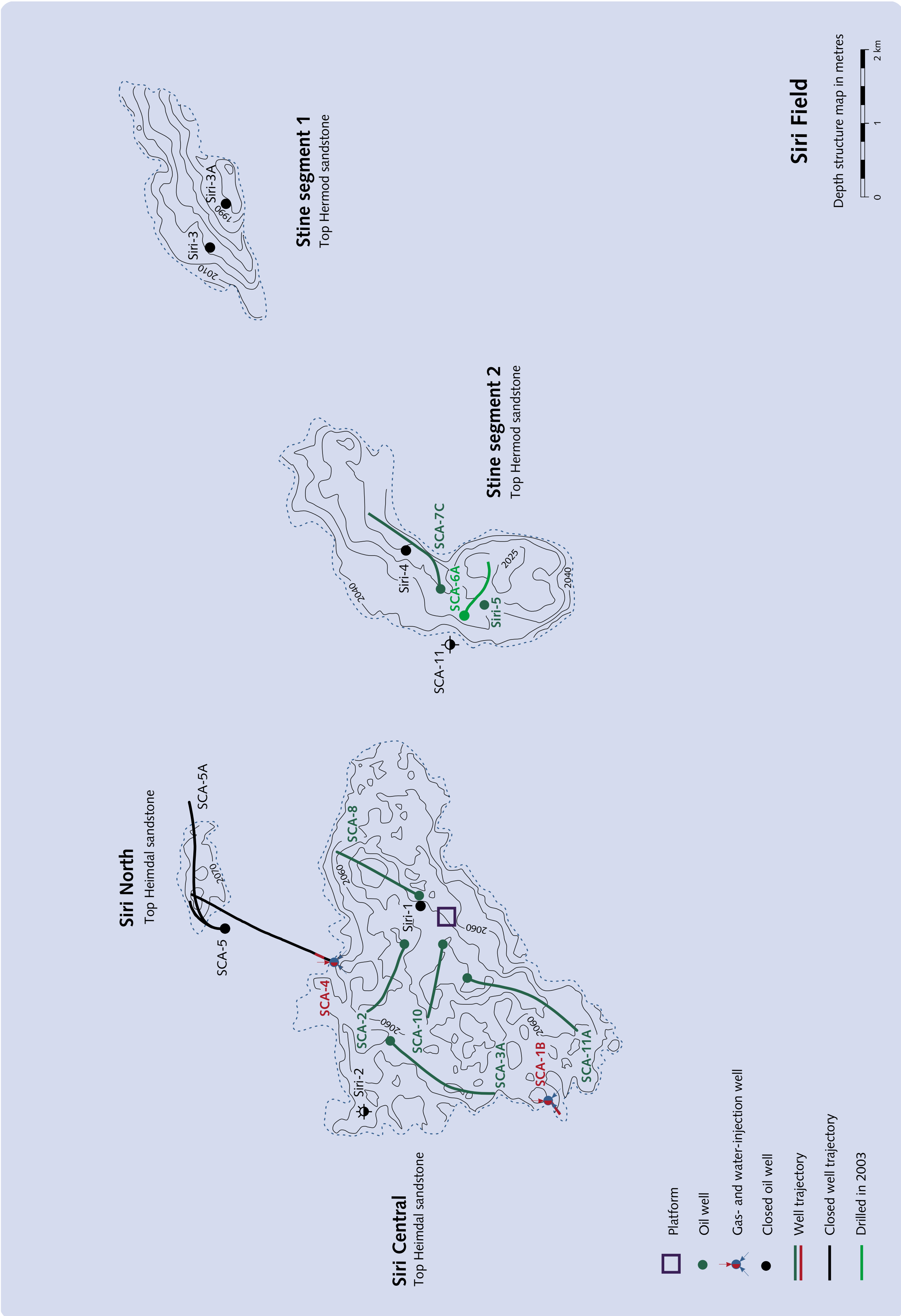
PRODUCTION FACILITIES

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 planned Stine segment 1 development will consist of a subsea installation and a 6" multiphase pipeline for transporting production to the Siri platform. Lift gas and injection water will be supplied from the Siri platform.

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.

**Gas from the Cecilie and Nini Fields has been injected into the Siri Field.*



Siri Field
Depth structure map in metres
0
1
2 km
Stine segment 1
Top Hermod sandstone
Siri-3A
Siri-3
1990
2010
Stine segment 2
Top Hermod sandstone
SCA-7C
Siri-4
SCA-6A
Siri-5
SCA-11
2025
2040
Siri North
Top Heimdal sandstone
SCA-5A
SCA-5
2010
Siri Central
Top Heimdal sandstone
SCA-8
Siri-1
SCA-4
SCA-2
SCA-10
SCA-3A
SCA-1B
SCA-11A
Siri-2
2060
Platform
Oil well
Gas- and water-injection well
Closed oil well
Well trajectory
Closed well trajectory
Drilled in 2003

SKJOLD FIELD

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 km^2
Reservoir depth:	1,600 m
Reservoir rock:	Chalk
Geological age:	Danian, Upper Cretaceous and Zechstein
Reserves at 1 January 2004:	
Oil:	8.6 million m^3
Gas:	0.8 billion Nm^3
Cum. production at 1 January 2004:	
Oil:	35.51 million m^3
Gas:	3.03 billion Nm^3
Water:	31.15 million m^3
Cum. injection at 1 January 2004:	
Water:	73.73 million m^3
Production in 2003:	
Oil:	1.53 million m^3
Gas:	0.09 billion Nm^3
Water:	3.52 million m^3
Injection in 2003:	
Water:	6.12 million m^3
Total investments at 1 January 2004:	
2003 prices	DKK 4.9 billion

REVIEW OF GEOLOGY

The Skjold Field is an anticlinal structure, induced through salt tectonics. The edge of the structure is mainly 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

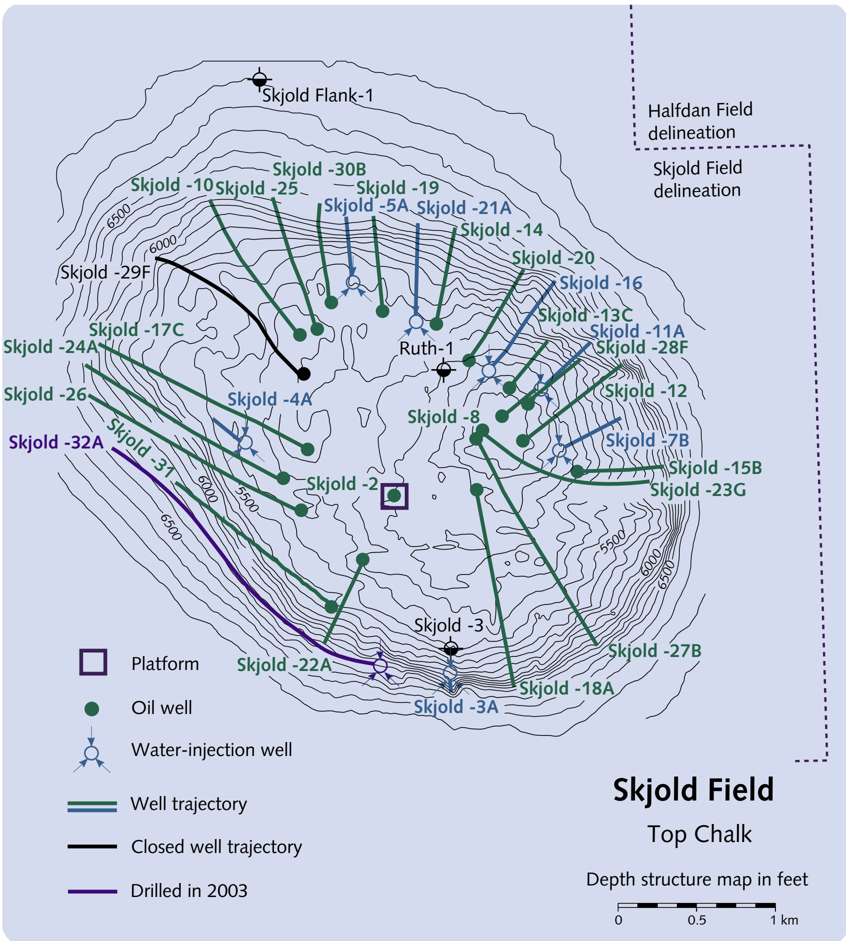
During the first years after production start-up, oil was produced from the crestal, central part of the reservoir. Water injection was initiated in the reservoir in 1986. Today, oil from the Skjold Field is mainly produced from horizontal wells at the flanks of the field. The production and injection 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. The Gorm facilities provide the Skjold Field with injection water and lift gas.

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



SOUTH ARNE FIELD

Location:	Blocks 5604/29 and 30
Licence:	7/89
Operator:	Amerada Hess ApS
Discovered:	1969
Year on stream:	1999
Producing wells:	9
Water-injection wells:	5
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 2004:	
Oil:	21.4 million m³
Gas:	7.1 billion Nm³
Cum. production at 1 January 2004:	
Oil:	10.04 million m³
Gas:	2.88 billion Nm³
Water:	1.33 million m³
Cum. injection at 1 January 2004:	
Water:	11.13 million m³
Production in 2003:	
Oil:	2.38 million m³
Gas:	0.54 billion Nm³
Water:	0.75 million m³
Injection in 2003:	
Water:	4.82 million m³
Total investments at 1 January 2004:	
2003 prices	DKK 7.1 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 seawater injection has subsequently been established.

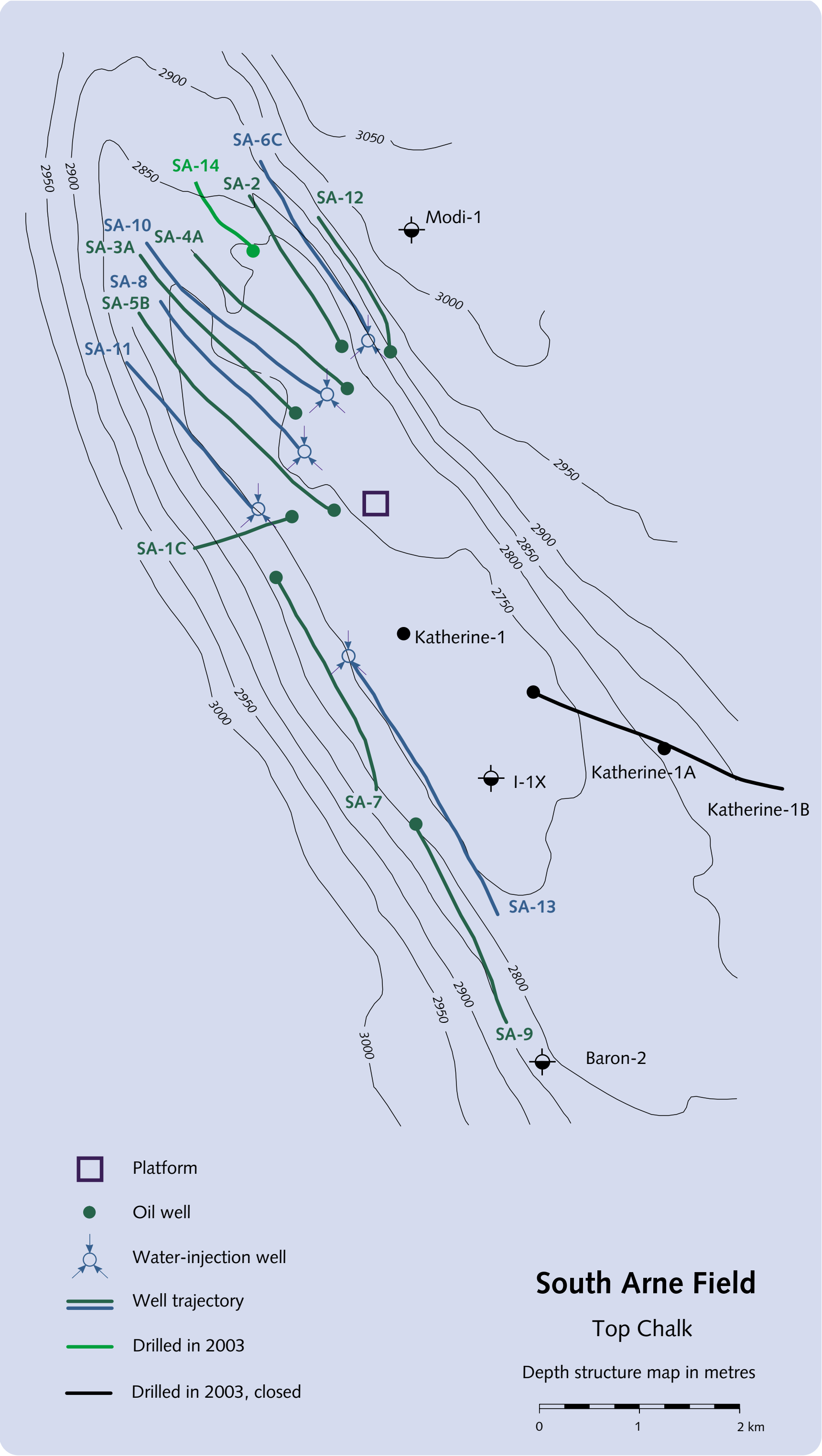
PRODUCTION FACILITIES

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 seawater 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.



South Arne Field

Top Chalk

Depth structure map in metres

SVEND FIELD

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:	4
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 2004:	
Oil:	1.1 million m³
Gas:	0.1 billion Nm³
Cum. production at 1 January 2004:	
Oil:	5.06 million m³
Gas:	0.61 billion Nm³
Water:	5.61 million m³
Production in 2003:	
Oil:	0.28 million m³
Gas:	0.04 billion Nm³
Water:	1.33 million m³
Total investments at 1 January 2004:	
2003 prices	DKK 1.1 billion

REVIEW OF GEOLOGY

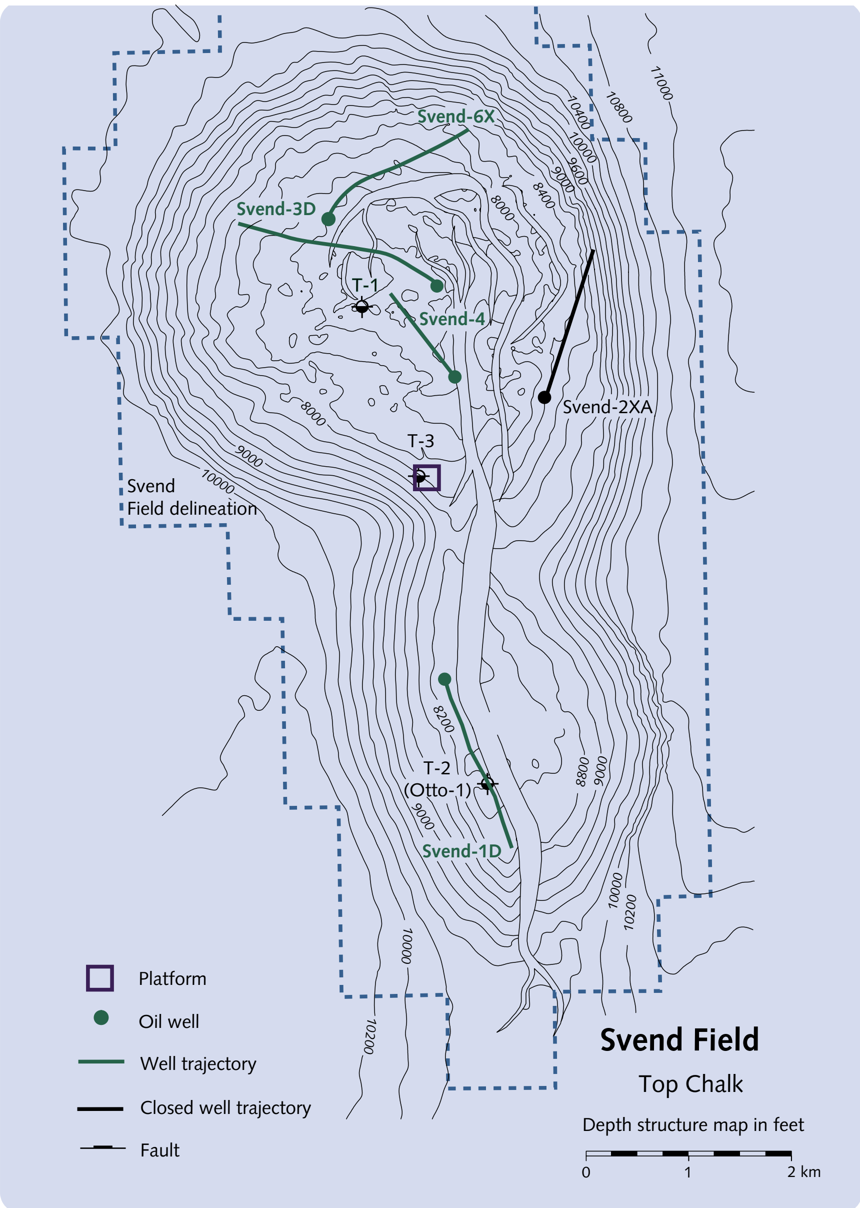
The Svend Field is an anticlinal structure, induced through salt tectonics. This led to fracturing of the chalk in the reservoir and divided the field into a western and an eastern block, separated by a major fault. The northern reservoir of the Svend Field is situated about 250 metres higher than the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

PRODUCTION STRATEGY

Oil and gas production from the Svend Field is 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 FIELD

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:	43
Producing/ injection wells:	20
Water depth:	37-40 m
Area:	90 km^2
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2004:	
Oil and condensate:	5.3 million m^3
Gas:	25.5 billion Nm^3
Cum. production at 1 January 2004:	
Oil and condensate:	21.11 million m^3
Net gas:	34.89 billion Nm^3
Water:	25.21 million m^3
Cum. injection at 1 January 2004:	
Gas:	31.01 billion Nm^3
Production in 2003:	
Oil and condensate:	0.92 million m^3
Net gas:	1.68 billion Nm^3
Water:	3.04 million m^3
Injection in 2003:	
Gas	2.31 billion Nm^3
Total investments at 1 January 2004:	
2003 prices	DKK 23.0 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

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 DUC's 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. Thus, the Tyra Field acts as a buffer.

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.

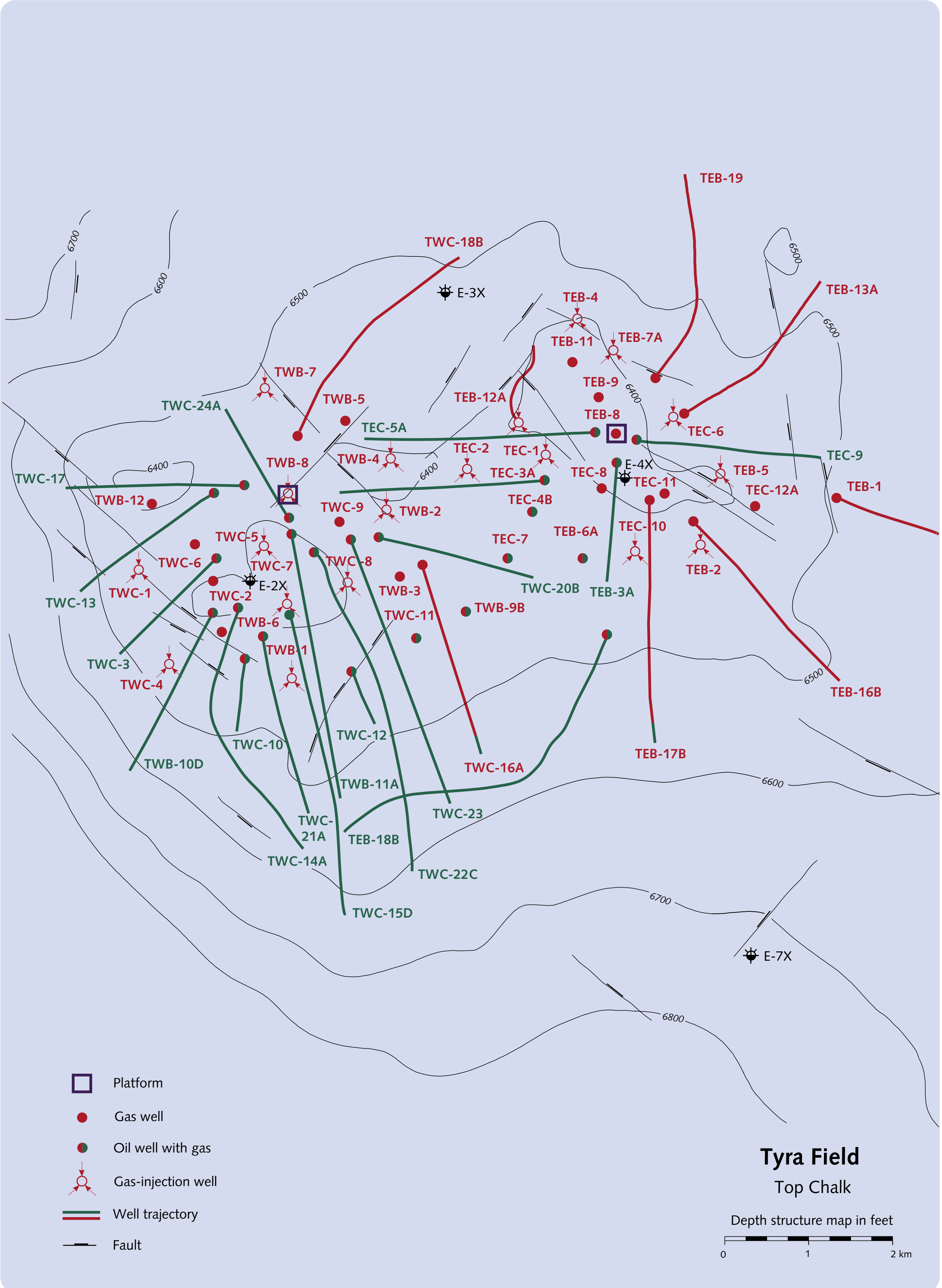
Tyra East consists of two wellhead platforms (TEB and TEC), one processing/ accommodation platform (TEA), one gas flare stack (TED), and one riser platform (TEE), as well as a bridge module supported by a STAR jacket (TEF).

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
TWC-18B
E-3X
TEB-4
TEB-13A
TEB-11
TEB-7A
TWB-7
TEB-9
TWC-24A
TWB-5
TEB-12A
TEB-8
TEC-6
TEC-5A
TEC-2
TEC-1
TEC-9
TWB-8
TWB-4
TEC-3A
TEC-8
E-4X
TEB-5
TWC-17
TEC-11
TEC-12A
TEB-1
TWB-12
TEC-4B
TWC-9
TWB-2
TEC-10
TEB-6A
TWC-5
TEC-7
TEB-2
TWC-6
TWC-8
TWC-7
TWC-1
E-2X
TWC-20B
TEB-3A
TWC-13
TWC-2
TWB-3
TWB-9B
TWB-6
TWC-11
TWB-1
TWC-3
TWC-4
TEB-16B
TWC-12
TWC-10
TEB-17B
TWB-10D
TWC-16A
TWB-11A
TWC-23
TWC-21A
TEB-18B
TWC-14A
TWC-22C
TWC-15D
E-7X
6400
6500
6600
6700
6800
Platform
Gas well
Oil well with gas
Gas-injection well
Well trajectory
Fault
Tyra Field
Top Chalk
Depth structure map in feet
0
1
2 km

TYRA SOUTHEAST FIELD

Location:	Block 5504/12
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1991
Year on stream:	2003
Producing wells:	6
Water depth:	38 m
Field delineation:	113 km²
Reservoir depth:	2,050 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous
Reserves at 1 January 2004:	
Oil:	3.2 million m³
Gas:	11.2 billion Nm³
Cum. production at 1 January 2004:	
Oil:	0.84 million m³
Gas:	0.90 billion Nm³
Water:	0.85 million m³
Production in 2003:	
Oil:	0.34 million m³
Gas:	0.45 billion Nm³
Water:	0.60 million m³
Total investments at 1 January 2004:	
2003 prices	DKK 1.0 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 two blocks separated by a northeastern-southwestern fault zone. The relief is less pronounced in this formation than in the Tyra Field. The structure is part of the major northwestern-southeastern uplift zone that also comprises the Roar, Tyra and Sif/Igor Fields.

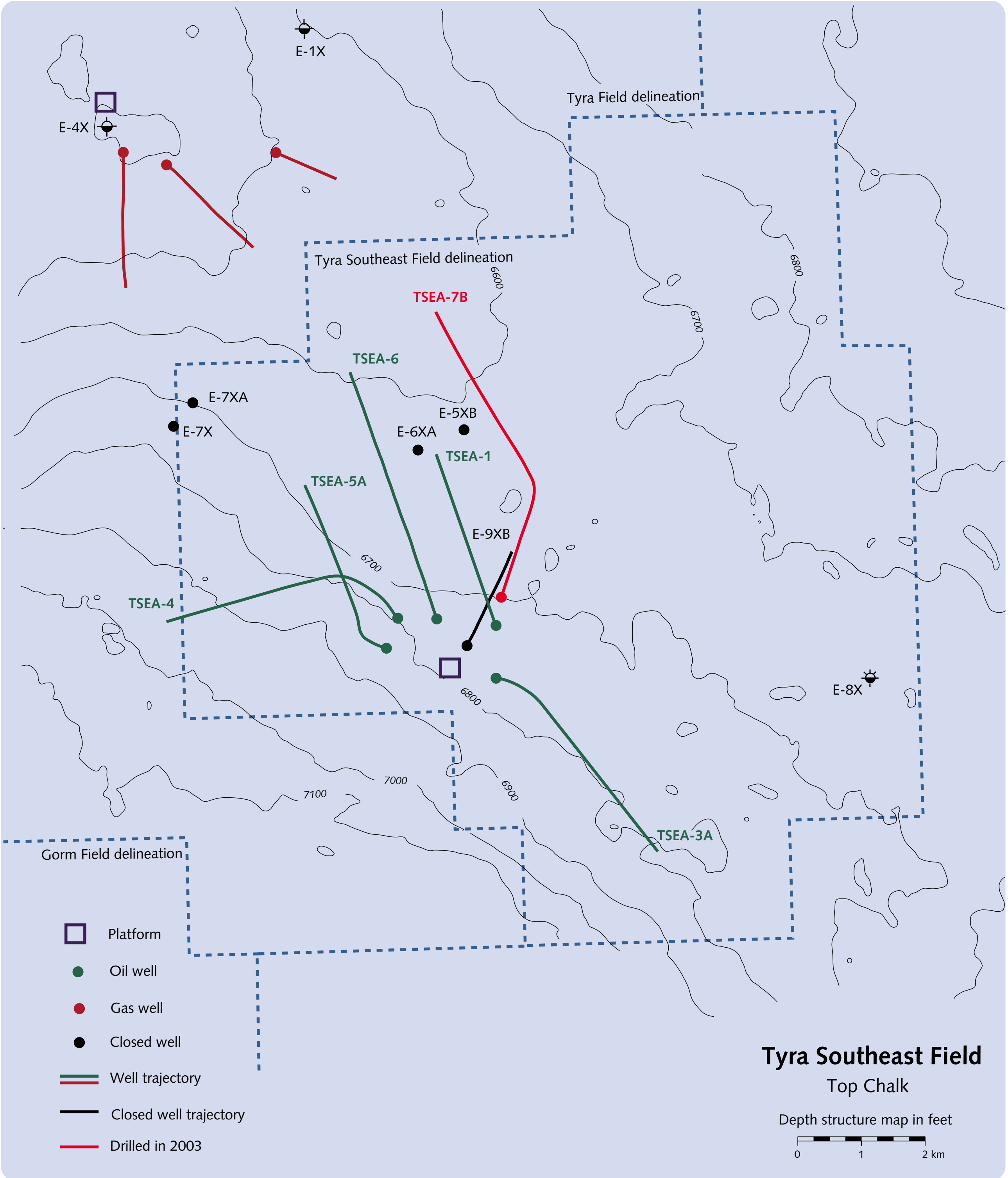
The Tyra Southeast accumulation consists of free gas overlying an oil zone in the southeastern part of the field.

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 wellhead platform of the STAR type. After separation into a gas and a liquid phase, the production is transported to Tyra East in two pipelines to be processed and subsequently exported ashore.


E-1X
E-4X
Tyra Field delineation
Tyra Southeast Field delineation
6600
6700
6800
TSEA-7B
TSEA-6
E-7XA
E-7X
E-5XB
E-6XA
TSEA-1
TSEA-5A
E-9XB
6700
TSEA-4
6800
E-8X
7000
7100
6900
TSEA-3A
Gorm Field delineation
Platform
Oil well
Gas well
Closed well
Well trajectory
Closed well trajectory
Drilled in 2003
Tyra Southeast Field
Top Chalk
Depth structure map in feet
0
1
2 km

VALDEMAR FIELD

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 km^2
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 2004:	
Oil:	2.2 million m^3
Gas:	1.8 billion Nm^3
Cum. production at 1 January 2004:	
Oil:	2.07 million m^3
Gas:	0.82 billion Nm^3
Water:	1.03 million m^3
Production in 2003:	
Oil:	0.44 million m^3
Gas:	0.15 billion Nm^3
Water:	0.31 million m^3
Total investments at 1 January 2004:	
2003 prices	DKK 1.8 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.

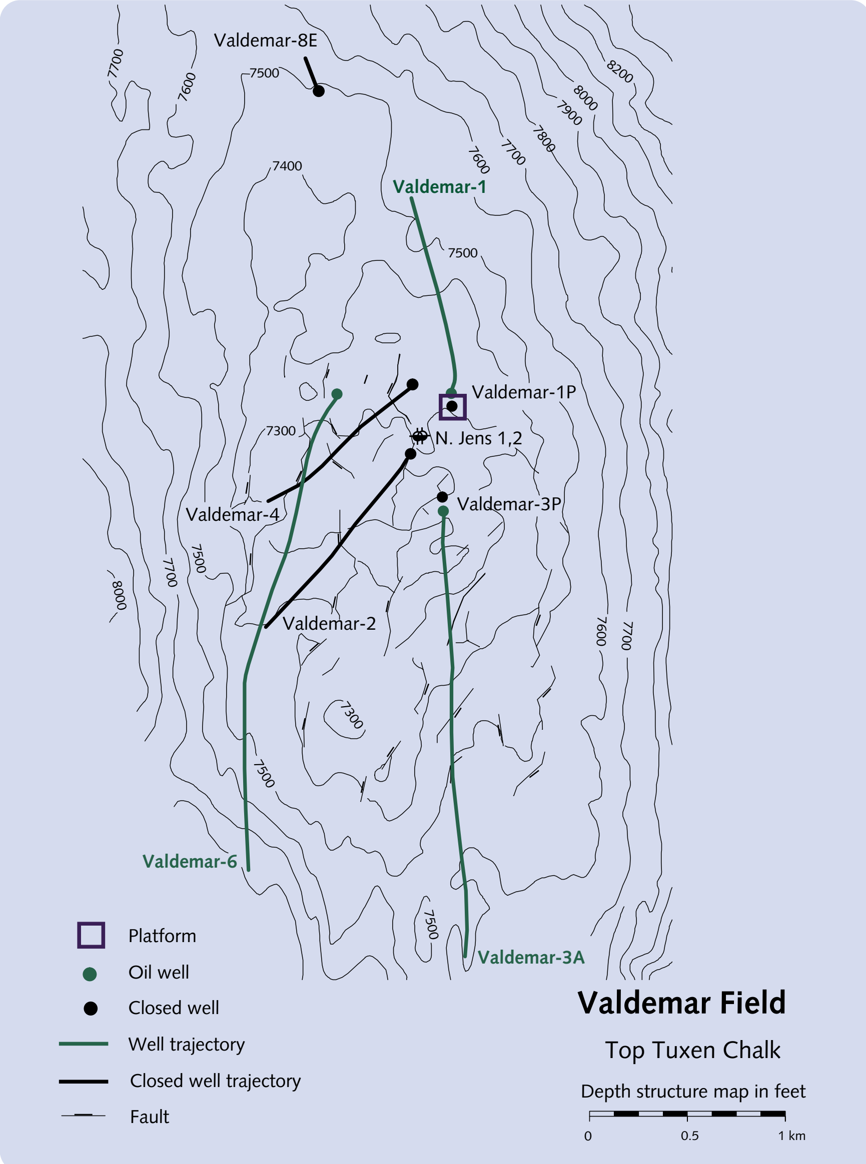
Valdemar comprises several separate reservoirs. Oil and gas have been discovered in Danian/Upper Cretaceous chalk, and vast amounts of oil-in-place have been identified in Lower Cretaceous chalk. While the properties of the Upper Cretaceous reservoirs are comparable to other Danish fields like Gorm and 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. In addition, recovery takes place from Danian/Upper Cretaceous layers.

PRODUCTION FACILITIES

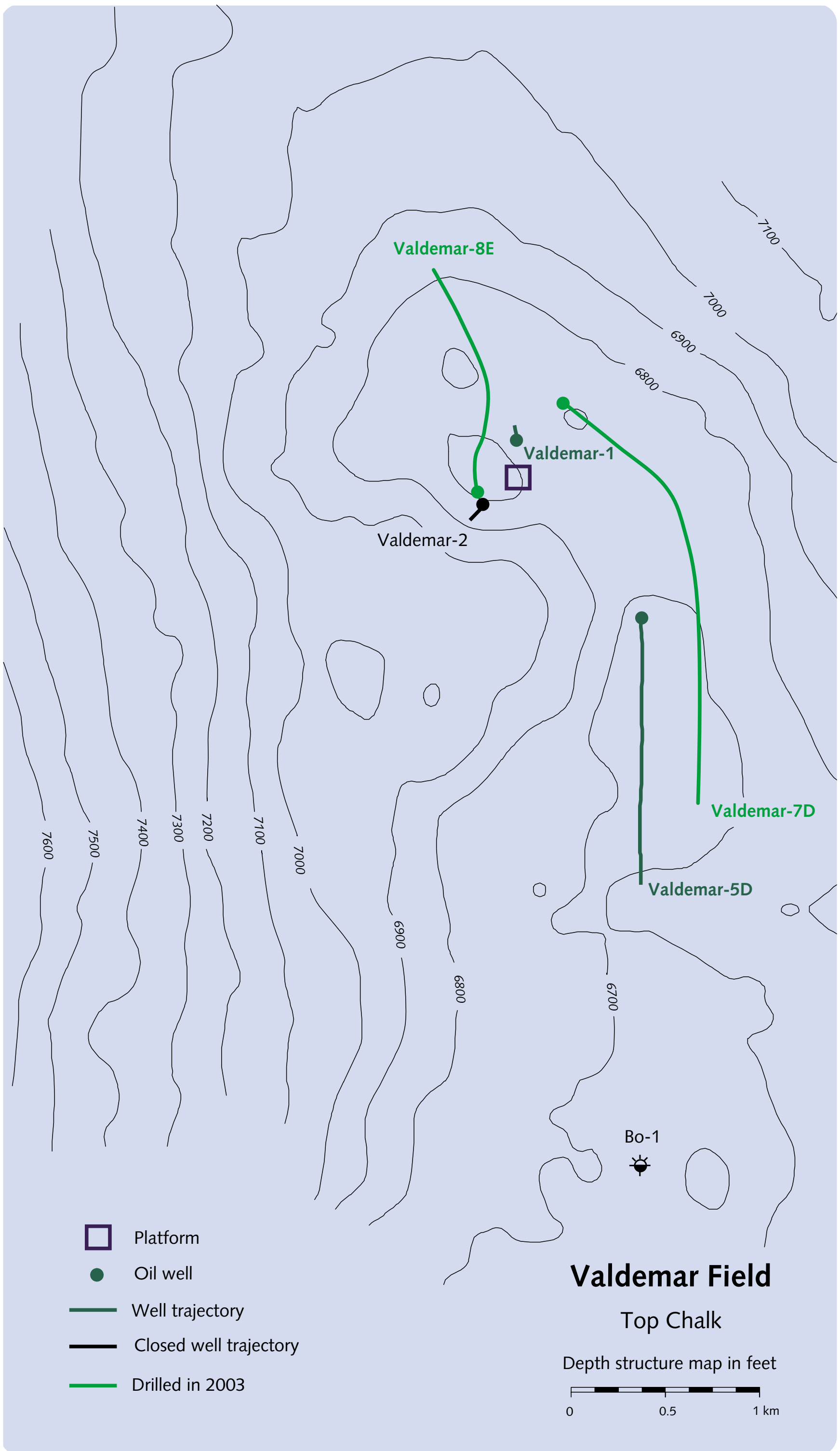
The Valdemar Field (the North Jens reservoir) has been developed as a satellite to Tyra, including an unmanned wellhead platform of the STAR type. The production is transported to Tyra East for processing and export ashore.



Valdemar Field

Top Tuxen Chalk

Depth structure map in feet


Valdemar-8E
Valdemar-1
Valdemar-2
Valdemar-7D
Valdemar-5D
Bo-1
7100
7000
6900
6800
7600
7500
7400
7300
7200
7100
7000
6900
6800
6700
Platform
Oil well
Well trajectory
Closed well trajectory
Drilled in 2003
Valdemar Field
Top Chalk
Depth structure map in feet
0
0.5
1 km

FINANCIAL KEY FIGURES

	Investments in Field Dev. DKK million	Field Operating Costs DKK million[1]	Exploration Costs DKK million	Crude Oil Price USD/bbl[2]	Exchange Rate DKK/USD	Inflation %[3]	Net Foreign-Currency Value DKK billion[4]	State Revenue DKK million
1972	105	29	30	3	7	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	6	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	8.4	10.2	-20.6	231
1983	3,554	544	566	30.5	9.1	6.9	-17.8	401
1984	1,598	1,237	1,211	28.2	10.4	6.3	-18.3	564
1985	1,943	1,424	1,373	27.2	10.6	4.7	-17.6	1,192
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	6.4	2.4	-1.9	1,889
1992	2,335	1,806	983	19.3	6	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	7	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	3,171
1998	5,306	2,037	406	12.8	6.7	1.9	0.9	3,125
1999	3,531	2,157	563	17.9	7	2.5	3.5	3,630
2000	3,100	2,758	627	28.5	8.1	2.9	14.9	8,695
2001	3,991	2,710	1,076	24.4	8.3	2.4	12.5	9,634
2002	5,494	3,252	965	24.9	7.9	2.3	13.2	10,137
2003*	7,579	2,950	840	28.8	6.6	2.1	14.4	9,331

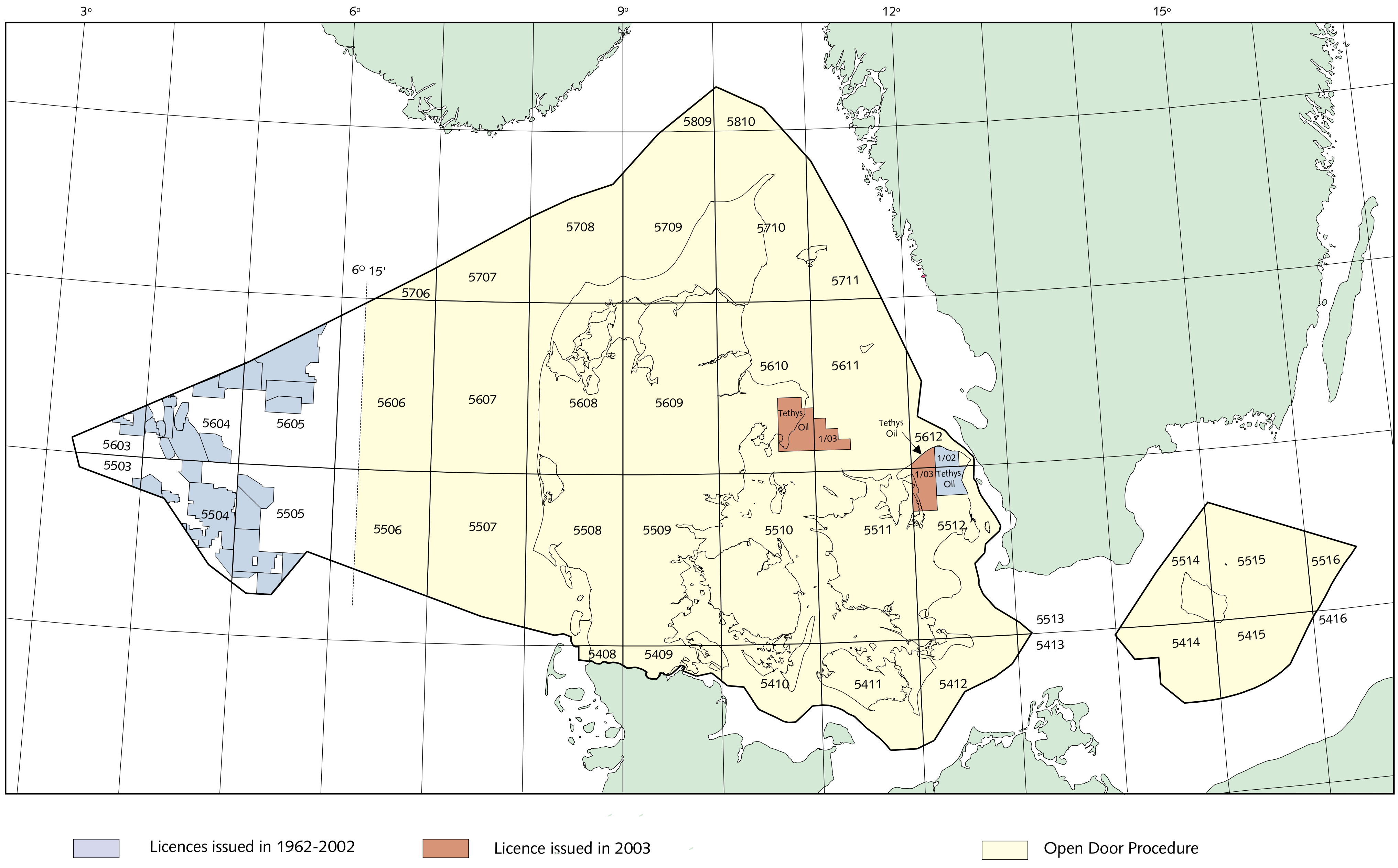
Nominal Prices
1) Including transportation costs
2) Brent crude oil
3) Consumer prices
4) Oil products and natural gas
**) Estimate*

FINANCIAL CONDITIONS APPLICABLE AT 1 JANUARY 2004

	Sole Concession before 1 January 2004	Sole Concession at 1 January 2004	Licences granted before 1 January 2004*	Licences granted after 1 January 2004
Corporate income tax	30 % Deductible from the hydrocarbon tax base	30 % Deductible from the hydrocarbon tax base	30 % Deductible from the hydrocarbon tax base	30 % Deductible from the hydrocarbon tax base
Hydrocarbon tax	70 % Allowance of 25 % over 10 years (a total of 250 %) for investments	52 % Allowance of 5 % over 6 years (a total of 30 %) for investments Transitional rules for investments made and unutilized field losses incurred before 1 January 2004	70 % Allowance of 25 % over 10 years (a total of 250 %) for investments	52 % Allowance of 5 % for 6 years (a total of 30 %) for investments
Royalty	8.5 % Deductible from the corporate income tax and hydrocarbon tax bases.	No	2nd round licences pay royalty as follows: 1000bbl/day — Rate 0 – 5 — 2% 5 – 20 — 8% 20 - — 16% Deductible from the corporate income tax and hydrocarbon tax bases.	No
Oil pipeline tariff/ compensatory fee	5 % The oil pipeline tariff/compensatory fee is deductible from the corporate income tax and hydrocarbon tax bases.	5 % until 8 July 2012, after which no tariff/fee is payable. The oil pipeline tariff can be offset against hydrocarbon tax, but not against the corporate income tax and hydrocarbon tax bases	5 % The oil pipeline tariff/compensatory fee is deductible from the corporate income tax and hydrocarbon tax bases.	5 % until 8 July 2012, after which no tariff/fee is payable. The oil pipeline tariff can be offset against hydrocarbon tax, but not against the corporate income tax and hydrocarbon tax bases
State participation	No	20 % from 8 July 2012	20 % 1st, 2nd and 3rd rounds: state participation with carried interest in the exploratory phase. A paying interest, depending on the size of production, in the development and production phases. 4th and 5th rounds and Open Door procedure: fully paying interest.	20 %
Profit-sharing	No	From 1 January 2004 to 8 July 2012, 20 % of the profit before tax and before net interest expenses is payable.	No	No

** At the licensees' request licences granted before 1 January 2004 may be taxed according to the "new" hydrocarbon tax rules in the 2004 tax return*

Danish Licence Area January 2004



Danish Licence Area   January 2004

The Western Area

- A. P. Møller, 1962 Licence
- Licences issued in 1986-1995
- Licences issued in 1998-2000