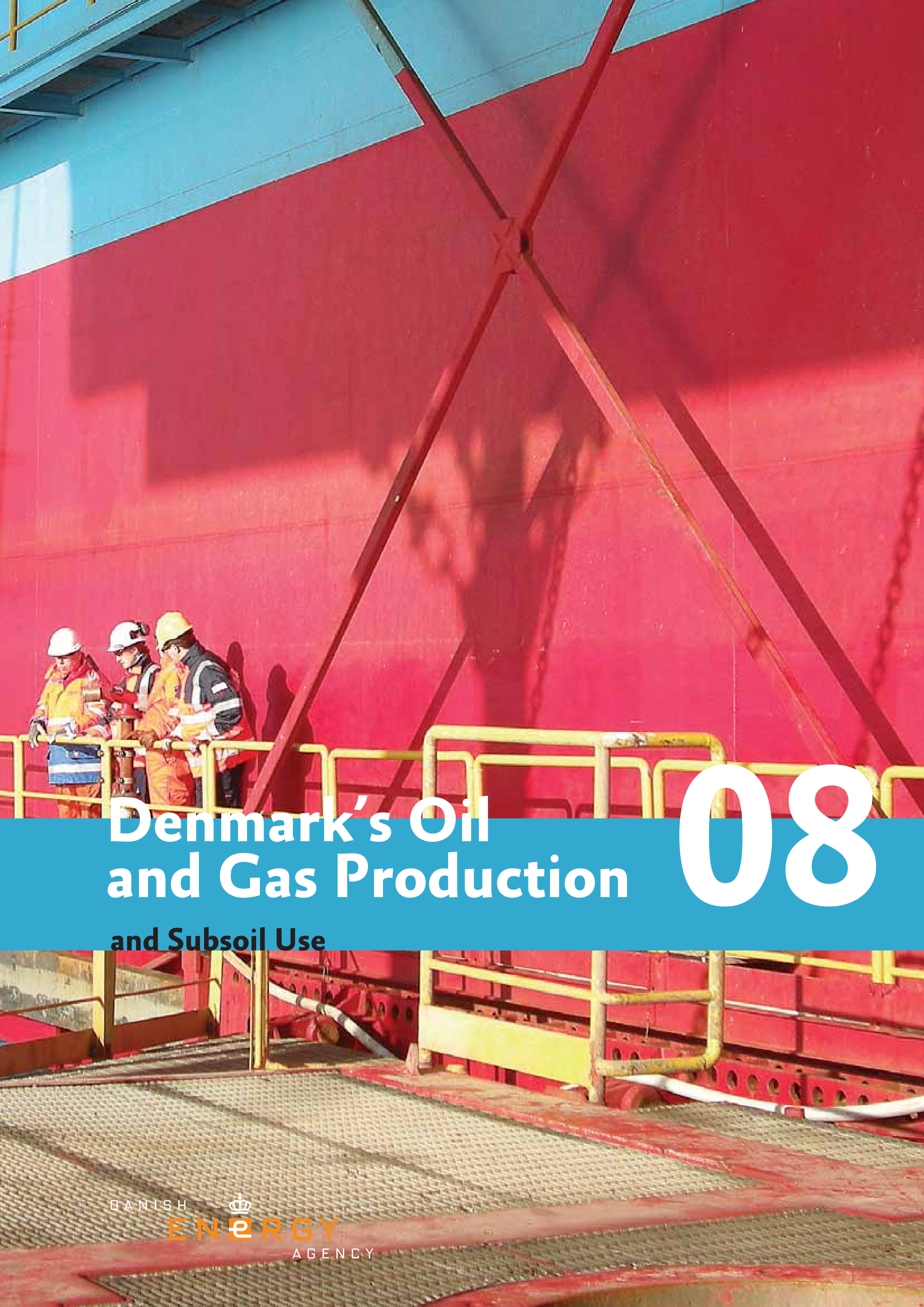

Denmark's Oil and Gas Production

08

and Subsoil Use

DANISH ENERGY AGENCY

The Danish Energy Agency, DEA, works nationally and internationally with tasks related to energy supply and consumption and CO_2-reducing measures. Thus, the DEA is responsible for the entire chain of tasks related to energy production and supply, transport and consumption, including improved energy efficiency and energy savings, renewable energy research and development projects, national CO_2 targets and initiatives to reduce the emission of greenhouse gases.

The DEA also has responsibility for national climate change initiatives.

In addition, the DEA performs analyses and assessments of climate and energy developments at national and international level, and safeguards Danish interests in international cooperation on climate and energy issues.

The DEA advises the Minister on climate and energy matters and administers Danish legislation in these areas.

The DEA was established in 1976 and was placed under the Ministry of Climate and Energy with effect from 23 November 2007.

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PREFACE

Production of oil and natural gas from the Danish sector of the North Sea has a major impact on Denmark's energy supply as well as its economy. The soaring oil prices seen during the first half of 2008 meant that Denmark once again generated many billions of kroner in revenue from the North Sea despite the expected downturn in production in 2008. Exploration and development activity remained at a high level during 2008, but the financial crisis and declining oil prices have since cooled interest somewhat. To complete the picture, it should be noted that the prospects for making new discoveries and improving recovery during the years ahead remain good.

The Danish Government has set the goal of making Denmark fossil-fuel-independent within a number of years. This will benefit the climate and our long-term security of supply. Fossil-fuel-independence requires endeavouring to procure a larger share of energy supplies from renewable energy sources, while also taking energy-saving measures.

Geothermal heat is a renewable energy source that can be utilized in district heating supply together with other forms of renewable energy. A report from 2008 assesses that geothermal heat has the potential to supply a substantial share of the residential heating required in the metropolitan region for several thousand years. It must be assumed that other parts of the Danish subsoil hold a corresponding hidden potential. Therefore, the DEA intends to submit a report on the possibilities and limitations of using geothermal heat throughout Denmark. Geothermal heat is one of the subjects addressed in the new chapter on use of the subsoil in this year's report.

Moreover, the Government aims to reduce emission of the greenhouse gas CO_2 to the atmosphere. Carbon Capture and Storage (CCS) is one of the technologies that can help reduce CO_2 emissions fairly quickly.

Great attention was focused on improving the energy efficiency of oil and gas production in 2008. In the late production phase of a field, the harder-to-access resources are more expensive and energy intensive to recover. For this reason, the Minister for Climate and Energy and the Danish operators have agreed to launch an action plan to reinforce the measures for reducing energy consumption offshore. This means that the offshore industry is also striving to cut down energy consumption and reduce CO_2 emissions, and the most recent figures point in the right direction. Energy efficiency initiatives in the offshore sector will continue in 2009 and the years ahead.

The DEA helps ensure that the Danish offshore sector can maintain its health and safety standards among the highest in the North Sea countries. For this purpose, the DEA carries out supervision of the oil companies' management systems and on- and offshore installations, while cooperating with the two sides of industry on laying down the regulatory framework.

Copenhagen, June 2009

Ib Larsen

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1 LICENCES AND EXPLORATION

Sustained interest in oil and gas exploration in the Danish subsoil in 2008 is reflected in the fact that one new licence was granted, two new applications for licences in the Open Door area were submitted and the number of appraisal wells increased compared to last year. In addition, experiments have been made with a new geophysical survey method in the North Sea.

Considerable oil and gas resources still exist in the Danish subsoil, and discoveries that may turn out to be substantial have been made at several locations. However, further exploration that may contribute to a better understanding of the areas is still vital. Continued research in new technology and the testing of new exploration methods also play a major role for Denmark's future oil and gas production.

THE SVANE DISCOVERY – POSSIBLY DENMARK'S LARGEST GAS FIELD

One of the exploration wells encountering hydrocarbons is Denmark's deepest well to date, Svane-1A. The well was drilled under licence 4/98 in 2001/2002, and the confidentiality period for well data from Svane-1A expired on 17 June 2008. Further evaluations of the discovery are quite likely to show that the Svane discovery can be developed into Denmark's largest gas field.

Svane-1A was drilled in the Tail End Graben in the northeastern area of the Danish part of the Central Graben; see figure 1.1. It was drilled as a vertical well with a single sidetrack to a depth of almost 6 km, penetrating quite deeply into Late Jurassic Layers. As Denmark's deepest well to date, Svane-1A has provided important information about the exploration potential in the deep sections of the Danish part of the Central Graben.

Fig. 1.1 Map of the Danish area of the North Sea showing the location of the Svane-1A well in the Tail End Graben and the approximate extent of the Svane discovery

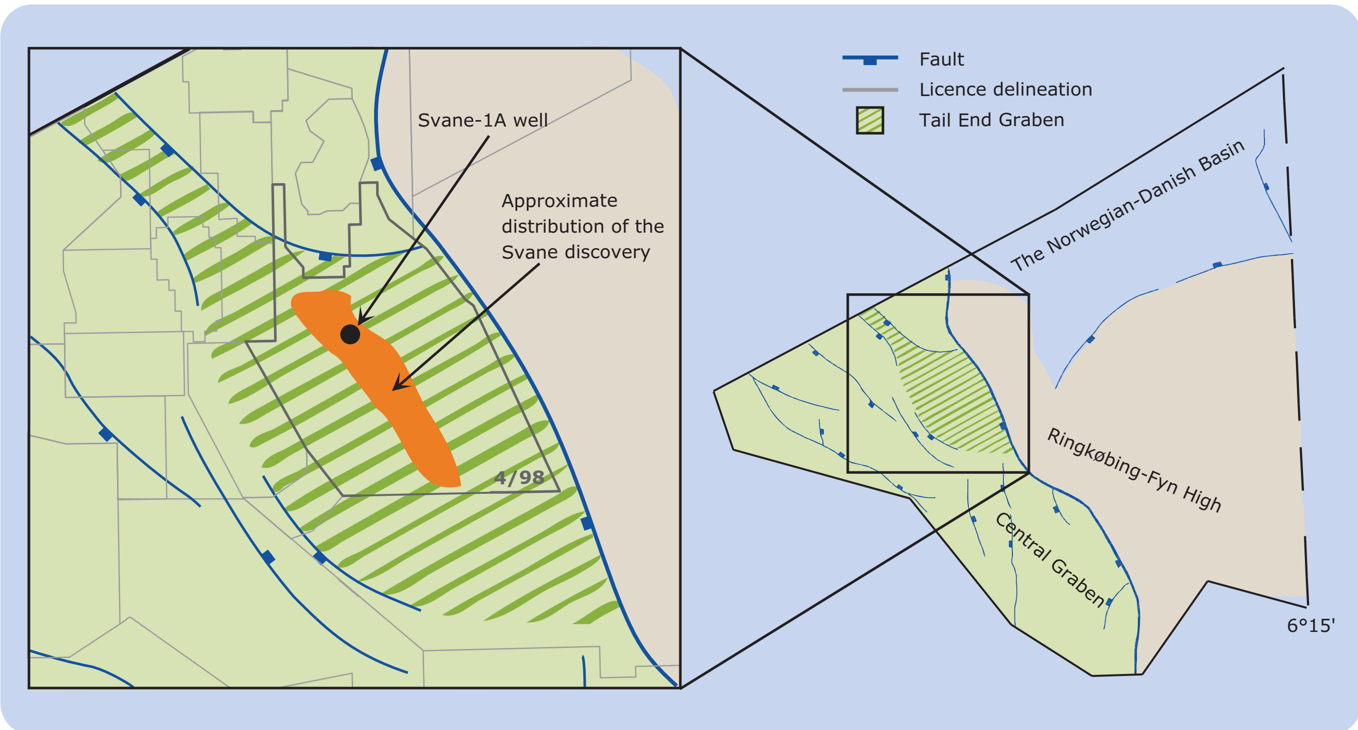
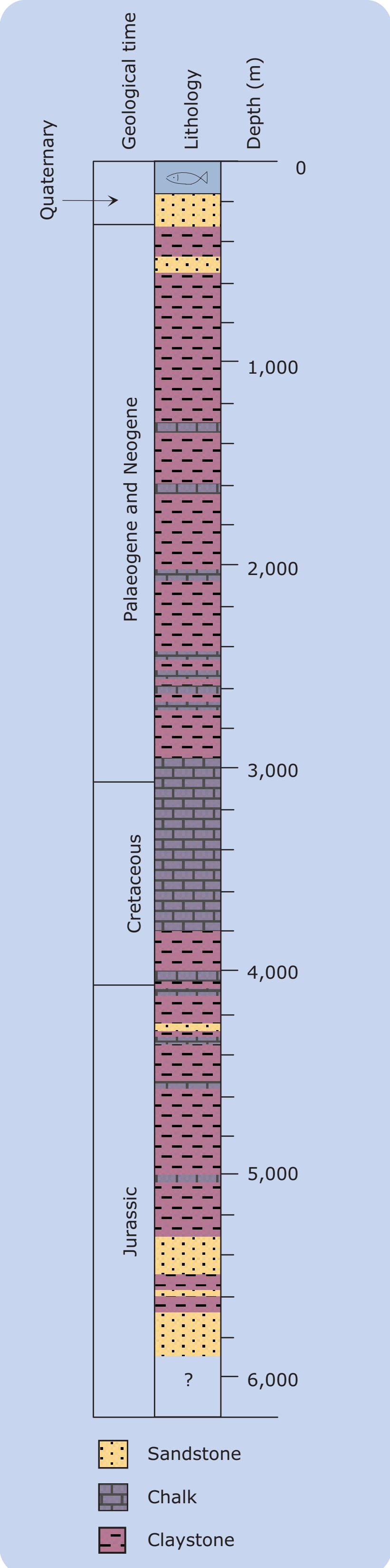


Fig. 1.2 Simplified stratigraphic column from the Svane-1A well



Hydrocarbons in the form of gas and condensate (see the list of terms in box 1.1) were discovered in several Late Jurassic sandstone layers at a depth of 5,400 to 5,900 m; see figure 1.2. Svane-1A, which was drilled about 300 m deeper than originally planned, penetrated more than 630 m of a gas-filled reservoir without reaching either the bottom of the reservoir sandstone or the gas-water contact. Because of the large depth it was not possible for technical reasons to drill the well deeper and reach the bottom of the reservoir. Gas and condensate were test-produced from the upper reservoir intervals, and dry gas is likely to exist in the lower, more massive sandstone layers.

The thickness of the gas-filled reservoir seems to indicate that it is covered by an effective seal that has been able to prevent the hydrocarbons from migrating away from the area. Moreover, the results show the existence of deeper-lying source rock that has the potential to generate gas under the right temperature and pressure conditions; see box 1.1. Geochemical analyses from the production test suggest that the gas is sourced from coal deposits. Therefore, the source rock probably consists of coal layers of Middle Jurassic and Carboniferous age situated at an even greater depth in the subsoil.

The penetrated parts of the reservoir indicate that the Svane discovery may prove to be larger than the Tyra Field, the field to have produced most gas to date in Denmark. If the reservoir in the Svane discovery extends to an even greater depth, further resources may be hidden in the subsoil.

Box 1.1

List of terms

Source rock is a rock that contains sufficient organic matter to generate hydrocarbons, i.e. oil and gas, under the right temperature and pressure conditions.

Reservoir rock is a porous rock that may contain water, oil or gas in the pores between the mineral grains. **Porosity** is the total of void spaces present within a rock and is a measure of the space available for fluids, while **permeability** indicates the ease with which fluids can pass through the rock.

If a reservoir contains gas, oil and water, the gas will accumulate above the oil, and the oil above the water, because of their different densities. The contact between gas and oil or gas and water is termed the **gas/fluid contact**.

Once hydrocarbons have been formed in a source rock, they will begin to **migrate** because oil and gas are lighter than the water present in the pores. Therefore, oil and gas seep upwards. Migration may take place in pores, in fractures and along faults in the various layers of the subsoil.

If the hydrocarbons migrate into reservoir rock with a **seal**, oil and gas will accumulate. A seal may consist of an impervious layer of, say, salt or clay that the oil and gas cannot penetrate.

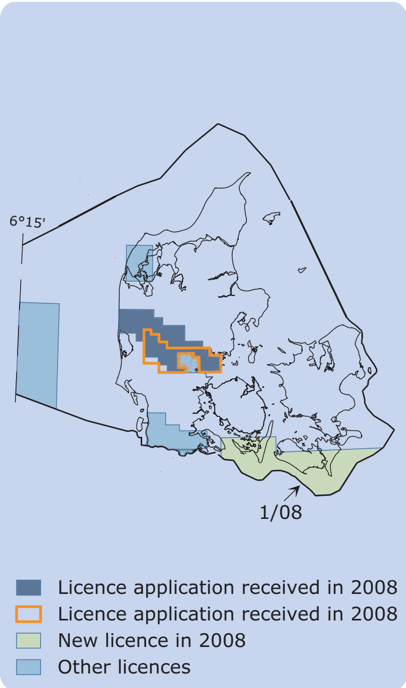
Naturally formed gas consists of different-weight molecules. If the gas consists of light molecules only, it is termed **dry gas**, while **wet gas** contains many heavy molecules. When the pressure and temperature drop, the heavy molecules condense into fluid, which is termed **condensate**.

One of the greatest challenges associated with production from the Svane discovery is the quality of the sandstone reservoir. Reservoir quality is determined in particular by the porosity and permeability of the reservoir rock; see box 1.1. The Svane-1A well showed low porosity and permeability in the reservoir layers, but seismic data from the whole area indicates that the reservoir quality in other parts of the structure not yet penetrated may be even better.

The sandstone that constitutes the reservoir of the Svane discovery is exposed to high temperatures and pressures due to the great depth. Consequently, the sandstone consists of very tight layers that make the production of hydrocarbons difficult. A field development is likely to require the drilling of a large number of deep wells with hydraulic fracturing (pressure fracturing) of the reservoir. In other parts of the world, hydraulic fracturing is used with great success to produce gas from sandstone reservoirs that are just as tight as the reservoir discovered in the Svane-1A well. Because of the complex reservoir conditions, the Svane discovery is still being appraised.

With the acquisition of further data and studies to improve the understanding of the reservoir quality of the Svane discovery, and assuming that technological advances are made in the development and production of fields with high temperatures and pressures, the Svane discovery may prove to be Denmark's largest gas field.

Fig. 1.3 Changes in the Open Door area in 2008



OPEN DOOR LICENCES

The fact that one new licence was granted and two new applications for licences were received for the Open Door area in 2008 signals the oil companies' sustained interest in exploring the Danish subsoil, also outside the areas traditionally explored in the North Sea; see figure 1.3.

On 31 March 2008, the Minister for Climate and Energy granted Danica Resources ApS (80 per cent) and the Danish North Sea Fund (20 per cent) a licence to explore

Box 1.2

Open Door procedure

In 1997, an Open Door procedure was introduced for all unlicensed areas east of 6° 15′ eastern longitude, i.e. the entire Danish onshore and offshore areas with the exception of the western part of the North Sea. The Open Door area is shown in appendix F1.

If the DEA receives more than one application for the same area, the first-come, first-served policy applies according to the licence conditions. This means that the first application to be considered is that received first.

To date, no commercial oil or gas discoveries have been made in the Open Door area. Open Door applications are therefore subject to more lenient work programme requirements than in the western part of the North Sea, where applications are invited in licensing rounds. Oil companies can continually apply for licences in the Open Door area within an annual application period from 2 January through 30 September.

A map of the area and a letter inviting applications for Open Door areas are available at the DEA's website, www.ens.dk.

for and produce oil and gas, licence 1/08, which covers an area in the western part of the Baltic Sea and onshore areas on the islands of Lolland-Falster and Langeland. Danica Resources ApS, the operator of the licence, was incorporated as a Danish company in 2007.

On 18 September 2008, Danica Jutland ApS, a newly established Danish company, applied for a licence to explore for and produce oil and gas under the Open Door

The Danish North Sea Fund – state participant in Danish oil and gas licences
Since holding the first licensing round in 1984, the Danish state has participated in all licences awarded. DONG is in charge of state participation in licences issued through 2004, while the Danish North Sea Fund undertakes the role of state participant in licences issued as from 2005. Today, the Danish North Sea Fund holds a 20 per cent share in all post-2004 Danish oil and gas licences, currently a total 19.

The Danish North Sea Fund participates in technical, financial, legal and commercial discussions with the operator and other co-licensees to determine which exploration and production activities are to be initiated. These discussions form the basis for a vast number of decisions impacting on future revenue and expenditure.

The objective of the Danish North Sea Fund is to help secure as high a financial return as possible for the state on the Fund's participation in the oil and gas activities. Consequently, the Danish North Sea Fund is required to be an active and competent partner that focuses on a coherent and cost-conscious exploration and production strategy in Denmark.

By means of its broad-based participation in oil and gas licences, the Danish North Sea Fund is closely acquainted with all the licensees' activities and plans and can thus contribute to coordinating existing knowledge about oil and gas exploration and production in Denmark. This will benefit the Danish state's overall know-how about the subsoil and can also be used as essential input to the licensees' decision-making basis.

In addition to participating in all post-2004 oil and gas licences, the Danish North Sea Fund will also hold a 20 per cent share in Dansk Undergrunds Consortium (DUC) together with Mærsk, Shell and Chevron as from 2012. During the next few years, the Danish North Sea Fund is therefore to build up an organization that is qualified to handle the state's share in DUC. For one thing, this requires the Fund to recruit staff with the commercial skills needed to optimize the sale of the substantial volumes of oil and gas produced.

The Danish North Sea Fund is a small organization that draws on existing state expertise, particularly from the DEA and the Geological Survey of Denmark and Greenland (GEUS), as well as on the expert knowledge of private oil and gas companies.

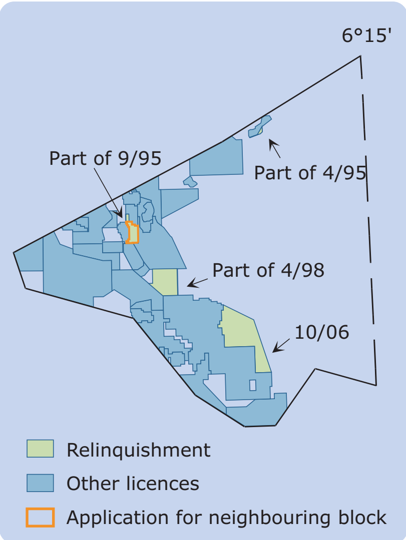
The Danish North Sea Fund participates in the following licences as of 1 January 2009:
1/05, 2/05, 1/06, 2/06, 3/06, 4/06, 5/06, 6/06, 7/06, 8/06, 9/06, 11/06, 12/06, 13/06, 14/06, 1/07, 2/07, 3/07 and 1/08.

procedure in an area located in Mid-Jutland. The DEA is now considering the application and carrying on negotiations with the applicant on an ongoing basis.

On 30 September 2008, GMT Exploration Company LLC and Jordan Dansk Corporation submitted an application for a licence in an area that mostly overlaps the area that Danica Jutland ApS applied for on 18 September 2008. As the first-come, first-served policy applies in the Open Door area, the DEA is only considering the application submitted first; see box 1.2.

On 9 April 2009, GMT Exploration Company LLC and Jordan Dansk Corporation withdrew their application.

Fig. 1.4 New and relinquished licences in the area west of 6°15' eastern longitude in 2008



APPLICATION FOR NEIGHBOURING BLOCK

DONG E&P has submitted an application to the DEA for a licence to explore an unlicensed area in the North Sea. The relevant area is a neighbouring block of the blocks covered by licence 4/98; see figure 1.4.

Before awarding a licence to explore for and produce oil and gas, the Minister for Climate and Energy has decided to initiate a so-called neighbouring block procedure, which allows all neighbouring licensees to apply for a licence for the area.

Therefore, the DEA has invited all neighbouring licensees to submit an application for a licence to explore for and recover oil and gas in the area, the deadline for applications being 4 May 2009.

Neighbouring block procedure
The neighbouring block procedure allows a licensee to apply for a neighbouring block if a prospect or a discovery extends beyond the licence area and into an area not already covered by a licence. If the conditions for applying for a neighbouring block have been met, the DEA may initiate a neighbouring block procedure. According to this procedure, the licensees in all adjoining areas are invited to submit an application for a licence to explore for and produce oil and gas.

AMENDED LICENCES

All contemplated licence transfers and extensions and the associated conditions must be submitted to the DEA for approval.

The outline of licences on the DEA'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.

Moreover, reference is made to appendices F1 and F2, which contain maps of the licences in the Danish licence area.

Transferred licences

Talisman Oil Denmark Limited transferred its 24 per cent share of licence 13/06 to Talisman Energy Denmark AS, a subsidiary of Talisman Energy Norge AS, effective 31 December 2007. Following the transfer, Talisman Oil Denmark Limited only held a share in licence 6/95. With effect from 1 January 2008, Norwegian Energy Company ASA (Noreco) took over Talisman Oil Denmark Limited, and thus the company's

30 per cent share of licence 6/95. On 19 June 2008, Talisman Oil Denmark Limited then changed its name to Siri (UK) Limited.

With effect from 1 January 2008, Bayerngas Danmark ApS took over Petro-Canada Denmark GmbH´s 25 per cent shares of licences 4/98 and 5/98 and its 20 per cent share of licence 1/06. Subsequently, the DEA approved Bayerngas Danmark ApS´ transfer of a 10 per cent share of licence 5/98 and an 8 per cent share of licence 1/06 to DONG E&P A/S. Bayerngas Danmark ApS has not previously held licences in the Danish area.

Altinex Oil Denmark took over Chevron Denmark Inc.´s 12 per cent shares of licences 9/95 and 9/06 effective 28 April 2008.

Shell Olie- og Gasudvinding Danmark B.V. (Holland), Danish branch, transferred its 36.8 per cent shares of licences 9/95 and 9/06 to Danoil Exploration A/S (10 per cent) effective 16 December 2008, and to PA Resources AB (26.8 per cent), effective 23 December 2008.

Jordan Dansk Corporation transferred a 55 per cent share of licence 2/07 to GMT Exploration Company LLC, thus retaining a 25 per cent licence share after the transfer. The transfer, approved on 7 April 2008, became effective on 27 September 2007 and also comprised the transfer of the operatorship from Jordan to GMT.

Conditions of licences

Licences for the exploration for and production of hydrocarbons are generally granted for a six-year term. Each licence includes a work programme specifying the exploration that the licensee must carry out, including time limits for the individual seismic surveys and exploration wells. In some cases, the work programme of the licence may stipulate that the licensee is obligated to carry out specific work, such as the drilling of an exploration well, or otherwise to relinquish the licence by a certain date before the six-year licence term expires.

When the six-year term expires, the DEA may extend the term of a licence by up to two years at a time, provided that the licensee, upon carrying out the original work programme, is prepared to undertake additional exploration commitments. In exceptional cases, the exploration term may be extended beyond ten years, for instance if it is considered appropriate to give the licensee sufficient time to clarify the production potential of a marginal discovery.

Generally, data that companies compile under licences granted in pursuance of the Danish Subsoil Act is protected by a five-year confidentiality clause. However, the confidentiality period is limited to two years if the licence has expired or been relinquished. When the confidentiality period has expired, other oil companies are given access to the data acquired. This allows the companies to improve their mapping of the subsoil and their assessments of exploration potential in the relevant 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 (GEUS).

Extended licence terms

A licence term may only be extended if the licensee undertakes to carry out additional exploration in the relevant licence area.

In 2008, the DEA extended the terms of four licences, all in the western part of the Danish area.

The exploration term of licence 6/95, operated by DONG E&P A/S, has been extended until 15 November 2009.

Following the relinquishment of the southern part of the licence area, the exploration term of licence 9/95, operated by Mærsk Olie og Gas AS, has been extended by one year until 1 January 2010. Relinquished areas appear from figure 1.4.

On 11 June 2008, the exploration term of licence 4/98, operated by DONG Central Graben E&P Ltd., was extended by 6½ months until 1 January 2009. On 18 December 2008, following relinquishment of the southern part of the licence area, the exploration term of the licence was extended by another two years until 1 January 2011.

The exploration term of licence 5/98, operated by DONG E&P A/S, has been extended until 15 June 2010.

Terminated licences and area relinquishment

In addition to the areas relinquished under licences 9/95 and 4/98 (see the section *Extended licence terms*), a minor part of licence 4/95 was relinquished and licence 10/06 expired in 2008. Relinquished areas appear from figure 1.4.

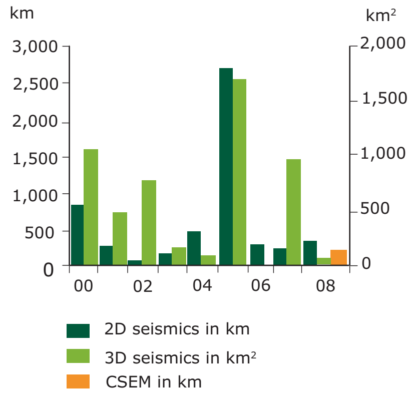
A minor share of the area covered by licence 4/95 was relinquished on 29 January 2008 in connection with the revision of the Nini Field delineation. The new field delineation also appears from figure 2.1 in chapter 2, *Production and development*. DONG E&P A/S is the operator of the licence.

Licence 10/06, which comprised an area in the southeastern part of the Central Graben, expired on 22 May 2008. Mærsk Olie og Gas AS was the operator of the licence.

EXPLORATORY SURVEYS

The level of 2D seismic surveying activity was higher in 2008 than in 2007, whereas the acquisition of 3D seismic data dropped compared to the year before. On the other hand 2008 was the first year that CSEM data, explained in more detail in box 1.3, was acquired in the Danish area. Figure 1.5 shows an outline of the 2D and 3D seismic data acquired, as well as the CSEM data acquired during the period from 2000 to 2008.

Fig. 1.5 Geophysical data acquired during the period 2000-2008



Geophysical surveys performed west of 6°15′eastern longitude in 2008 appear from figure 1.6.

Mærsk Olie og Gas AS carried out the first CSEM survey in the Danish area, with OHM Surveys as the seismic contractor, and acquired 110 km of CSEM data in the Contiguous Area and under licence 8/06.

In 2008, StatoilHydro conducted a 3D seismic survey in the Norwegian part of the North Sea, using Fugro Geoteam as the seismic contractor. A minor share of the area surveyed, covering 91 km², extended into Danish territory in the vicinity of licence 4/95.

Fig. 1.7 Exploratory surveys east of 6°15' eastern longitude in 2008

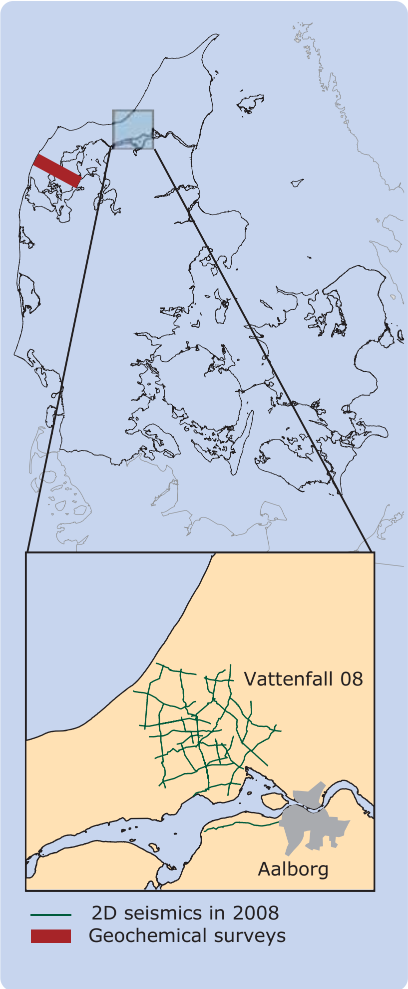


Fig. 1.6 Geophysical surveys west of 6°15' eastern longitude in 2008

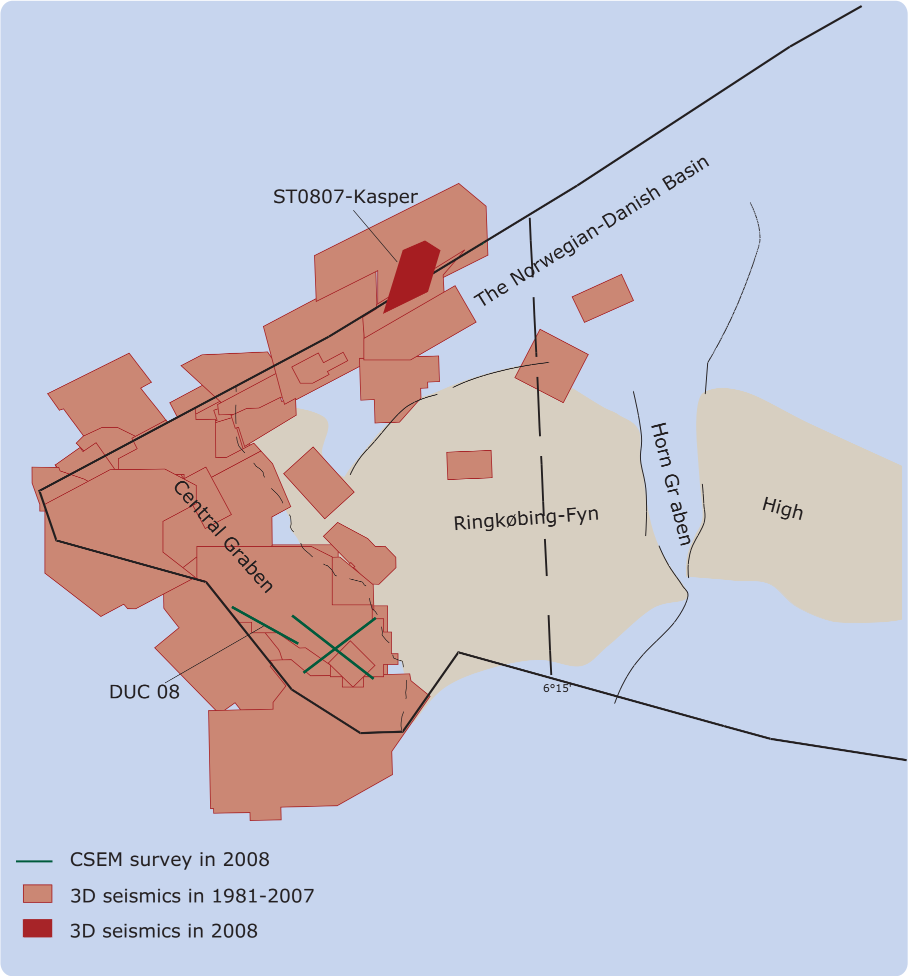


Figure 1.7 shows the areas surveyed east of 6°15´ eastern longitude.

On 1 February 2008, Vattenfall A/S was granted permission to carry out exploratory surveys throughout the Danish area for the purpose of investigating the possible existence of geological structures suitable for storing carbon dioxide (CO_2). In 2008, Vattenfall focused on an onshore area in northwestern Jutland and, using Deutsche Montan Technologie as the seismic contractor, acquired 238 km of 2D seismic data. In February 2009, Vattenfall A/S was granted an extension of the permit until 14 April 2010.

On 1 February 2008, DONG E&P A/S was granted permission to carry out exploratory surveys throughout the Danish area for the purpose of investigating the possible existence of geological structures suitable for storing carbon dioxide (CO_2). DONG E&P A/S has not yet carried out any surveys under the permit.

In cooperation with GORE Surveys, DONG E&P A/S has carried out a geochemical study in northwestern Jutland under licence 3/07. The study was performed by placing 256 units in the ground and in the seabed. The units, which can detect traces of hydrocarbons, have subsequently been recollected and analyzed geochemically. DONG E&P A/S is now carrying out further interpretations of the data acquired from these geochemical studies.

Box 1.3

Controlled Source ElectroMagnetics, CSEM
CSEM is a recent marine survey method and until a few years back, it was assumed that it could only be used at water depths of more than about 200 m. New data acquisition technology and improved data-processing methods have now made it possible to carry out such surveys at lower water depths with good results. Thus, the method can also be used in the Danish area.

The CSEM method is based on the fact that hydrocarbon-bearing sedimentary layers have low electrical conductivity, whereas water-saturated sedimentary layers have high electrical conductivity. Under the right conditions, it is therefore possible by means of the CSEM method to distinguish between hydrocarbon-bearing and water-bearing structures in the subsoil and thus reduce the risk of drilling a dry well.

The electrical conductivity of salt layers, for example, or tight rocks such as basalt may be very similar to that of hydrocarbon-filled sandstone. This may complicate the interpretation of data, particularly if the area to be investigated is not known very well beforehand. Moreover, CSEM data has a low resolution, which quickly deteriorates with depth. Therefore, it is important to integrate the interpretation of CSEM data with higher-resolution data, such as 3D seismics.

In CSEM surveys, an electric source (a transmitter) is towed just above the seabed. The source excites controlled electromagnetic energy that propagates through the subsoil. This induces an electric field in the subsurface layers, and the signal is recorded by receivers placed on the seabed beforehand. The receivers, which are collected and reused upon completion of data acquisition, record information about the electrical conductivity of subsurface structures.

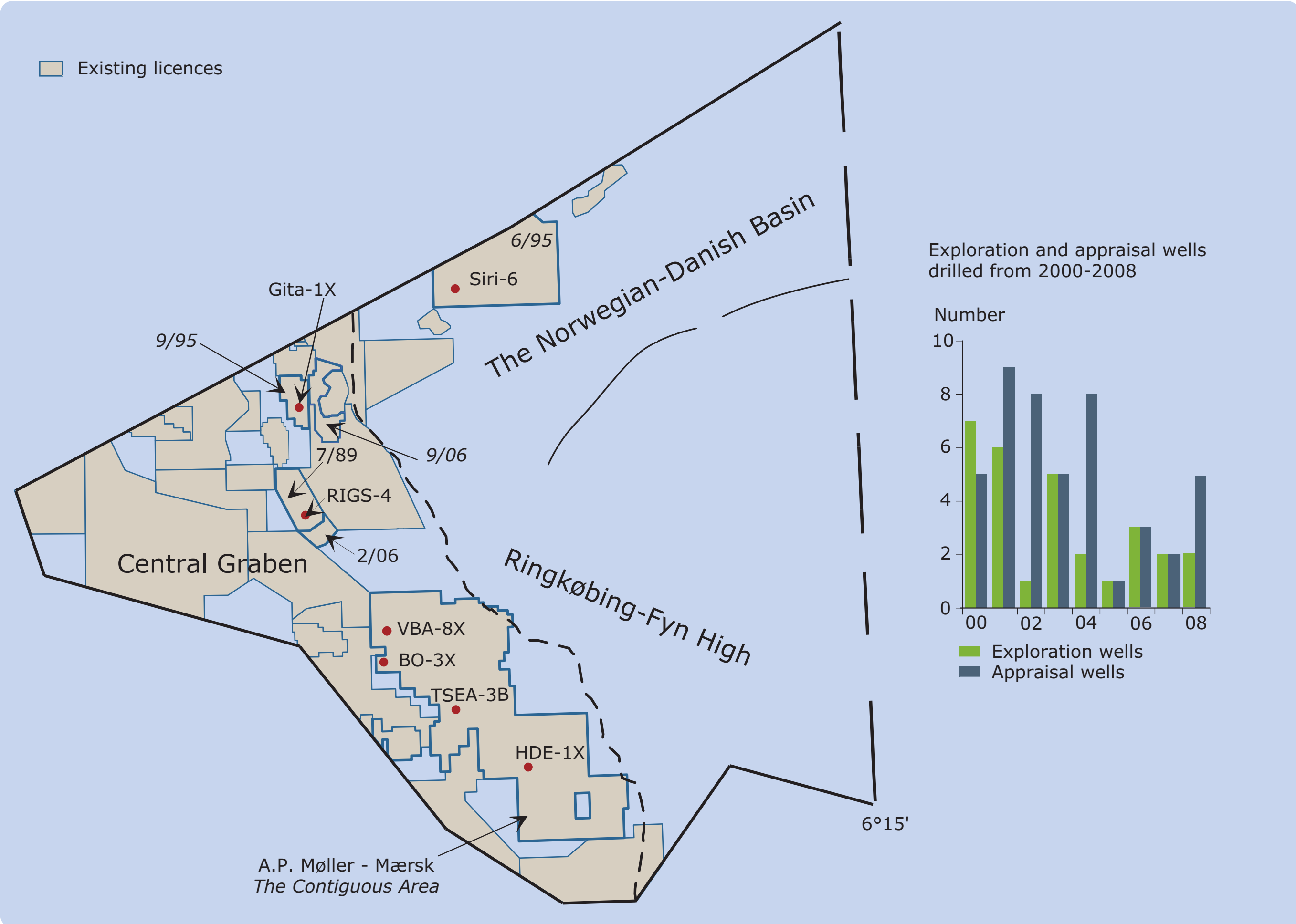
At present, extensive research is being conducted in electromagnetic technologies for use in hydrocarbon exploration, and CSEM is a method that is becoming increasingly popular throughout the world.

WELLS
In 2008, a total of seven exploration and appraisal wells were drilled, three more than in 2007. The location of the wells and a comparative diagram showing the number of exploration and appraisal wells drilled during the period from 2000 to 2008 appear from figure 1.8. The appraisal wells drilled in the fields are also shown in the field maps in appendix B.

An outline of all Danish exploration and appraisal wells is available at the DEA's website, www.ens.dk.

Exploration wells
Siri-6 (5604/20-10)
As the operator of licence 6/95, DONG E&P A/S drilled the exploration well Siri-6 about 4 km west of the Siri Field in the Danish part of the North Sea. The drilling operation took place during the period from 21 December 2008 until 30 January 2009.

Fig. 1.8 Exploration and appraisal wells drilled in 2008 west of 6°15' eastern longitude



Siri-6 was drilled as a vertical well and terminated in Danian chalk layers at a depth of 2,225 m below the seabed. The well encountered a sandstone reservoir in Paleocene layers, but no hydrocarbons. Cores were extracted from the well and measurements made for the purpose of a more detailed evaluation of the well.

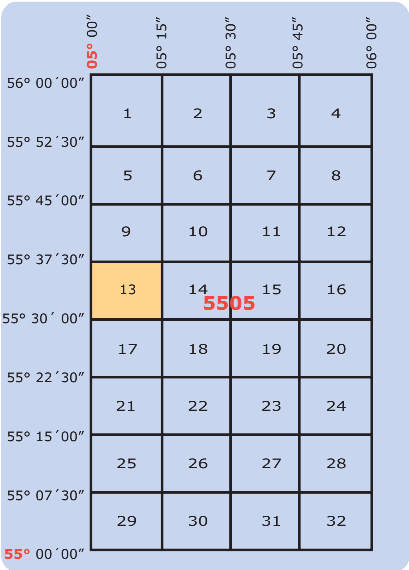
As not all the companies holding licence 6/95 wished to participate in drilling the well, it was drilled by DONG E&P A/S and Altinex Oil Denmark A/S as a so-called sole risk well. Thus, the third co-licensee, Siri (UK) Limited, did not participate in the drilling operation.

Gita-1X (5604/22-05)

As the operator of licences 9/95 and 9/06, Mærsk Olie og Gas AS drilled the Gita-1X exploration well about 10 km south of the Harald Field in the Danish part of the North Sea. The drilling operation commenced on 16 December 2008 and was completed on 21 April 2009.

Gita-1X, which was drilled as a vertical well and terminated in Middle Jurassic layers at a depth of 5,162 m, discovered Middle Jurassic sandstone layers with traces of hydrocarbons. Various measurements were performed for the purpose of evaluating the well results more closely.

Fig. 1.9 Illustration showing the subdivision of the Danish licence area. Well 5505/13-11 (HDE-1X) was drilled within the highlighted area



The holders of licence 9/95 and the adjoining licence 9/06 drilled the well as a joint venture on a 50/50 basis.

Wells

Wells in the subsoil can generally be divided into two groups, exploration and appraisal wells on the one hand, and development wells on the other. Exploration and appraisal wells are drilled to investigate whether a mapped structure contains oil and gas, and, in the affirmative, to determine the size of the accumulation, while the objective of development wells is to produce hydrocarbons from an accumulation.

All Danish exploration and appraisal wells are numbered using a general well-numbering system. For example, the appraisal well HDE-1X is numbered 5505/13-11. The first six digits indicate the geographical location of the well in the Danish licence area; see figure 1.9. The Danish licence area is divided into blocks on the basis of the geographical system of coordinates (European Datum 1950). Generally, the area is expressed in whole degrees of longitude and whole degrees of latitude. Thus, 5505 indicates that the block is located between 55° and 56° N and 5° and 6° E. Each of these blocks is subdivided into 32 minor blocks, and the next two digits indicate in which of these minor blocks the well has been drilled. The last two digits are the serial number of the relevant well in the specific block. HDE-1X is therefore the 11th exploration and appraisal well in block 5505/13.

A development well is a generic term for production wells and injection wells. Production wells bring oil, gas and water to the surface, whereas injection wells inject water or gas into the reservoirs to drive the oil towards the production wells and thus enhance recovery. Development wells are numbered according to the installation from which they have been drilled.

Appraisal wells

HDE-1X (5505/13-11)

In February 2008, Mærsk Olie og Gas AS drilled a vertical appraisal well northeast of the existing development of the Halfdan oil field in the Contiguous Area in the North Sea. The well terminated in Upper Cretaceous chalk layers to investigate the reservoir quality and hydrocarbon saturations. The well encountered hydrocarbons.

Bo-3X (5504/11-5)

From March to April 2008, Mærsk Olie og Gas AS drilled the Bo-3X well south of the Valdemar area in the Contiguous Area as part of the further development of the Valdemar-Bo Field. The Bo-3X well was drilled as a vertical appraisal well and terminated in Lower Cretaceous chalk layers. The well confirmed the presence of hydrocarbons, and studies are now ongoing to investigate the potential for recovery in the area.

Rigs-4/4A (5604/30-5)

As the operator for the holders of licences 7/89 and 2/06, Hess Danmark ApS began drilling the Rigs-4/4A well southeast of the South Arne Field on 3 July 2008. Rigs-4/4A was drilled as an almost vertical well and terminated in chalk layers of Early Cretaceous age at a depth of 2,968 m below the surface of the sea. The well encountered Late Cretaceous chalk layers containing oil. Cores were extracted from the well

and a sidetrack was also drilled about 1 km towards the southeast to evaluate the extent of oil-bearing layers. The results from the well are now to be evaluated more closely.

VBA-8XA (5504/7-15)
As part of the development of the Valdemar-Bo Field, Mærsk Olie og Gas AS drilled an appraisal well from October to November 2008 in the upper section of the chalk formation in the Bo area of the field. The well was drilled as a deviated well and subsequently completed as a gas well.

TSEA-3B (5504/12-14)
In November 2008, Mærsk Olie og Gas AS spudded an appraisal well in the southeastern part of the Tyra Field in the Contiguous Area. The well was drilled as a deviated well and terminated in Danian chalk layers. The objective of the well was to evaluate the oil accumulation in the upper chalk layers.

TSEA-3B was subsequently plugged and abandoned, and a gas production well, TSEA-3D, was drilled as a sidetrack in a northern direction towards the Tyra Field; see chapter 2, *Production and development*.

2 PRODUCTION AND DEVELOPMENT

Oil companies showed continued interest in investing in oil and gas recovery from the Danish subsoil in 2008. This interest was partly driven by the high oil price prevailing in the international market, which peaked at a price of about USD 148 per barrel in July 2008.

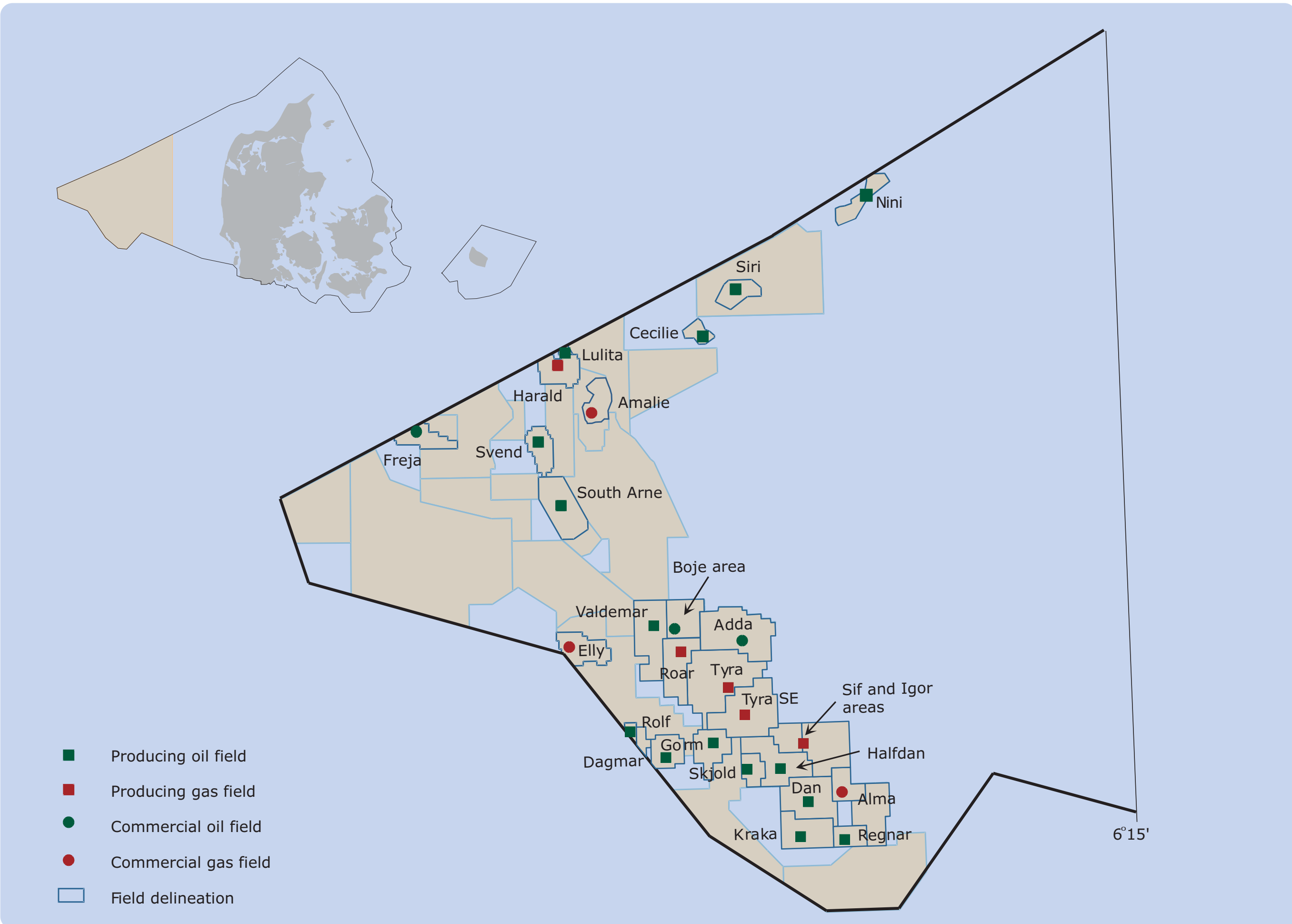
Most Danish fields have passed the period of peak production using known technology. Sustained interest in recovering oil and gas from existing fields in Denmark in future requires the development of new technology that allows the recovery of oil and gas resources that are more difficult to access and thus remain unproduced in the subsoil today.

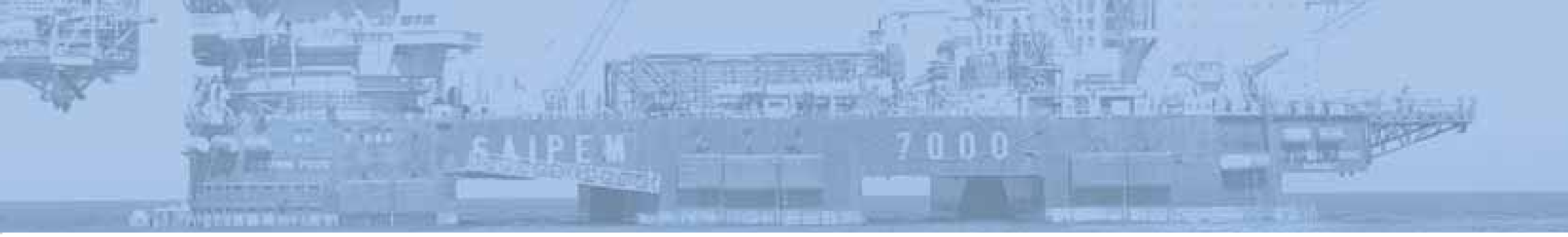
PRODUCTION IN 2008

All producing oil and gas fields in Denmark are located in the North Sea; see figure 2.1. In total there are 19 producing fields of varying size. Figure 2.2 shows the location of production installations and the most important production and water-injection pipelines. The platform complexes in the individual fields are described and illustrated in appendix B.

Three operators are responsible for the production of oil and gas: DONG E&P A/S, Hess Denmark ApS and Mærsk Olie og Gas AS. A total of ten companies have

Fig. 2.1 Danish oil and gas fields





interests in the producing fields, and the individual companies' shares of production appear from figure 2.3.

Production in the Danish part of the North Sea derived from a total of 283 production wells (204 oil, 79 gas) in 2008. Another 111 injection wells (4 gas, 107 water) were in operation. Compared to 2007, the number of production wells increased by about 10 per cent and the number of injection wells dropped by about 11 per cent. The number of wells indicated above may deviate from the number stated in appendix B, because a few wells may have shifted from injection to production during the year, or vice versa. Appendix B indicates the number of active wells at the end of 2008.

Fig. 2.2 Location of production facilities in the North Sea 2008

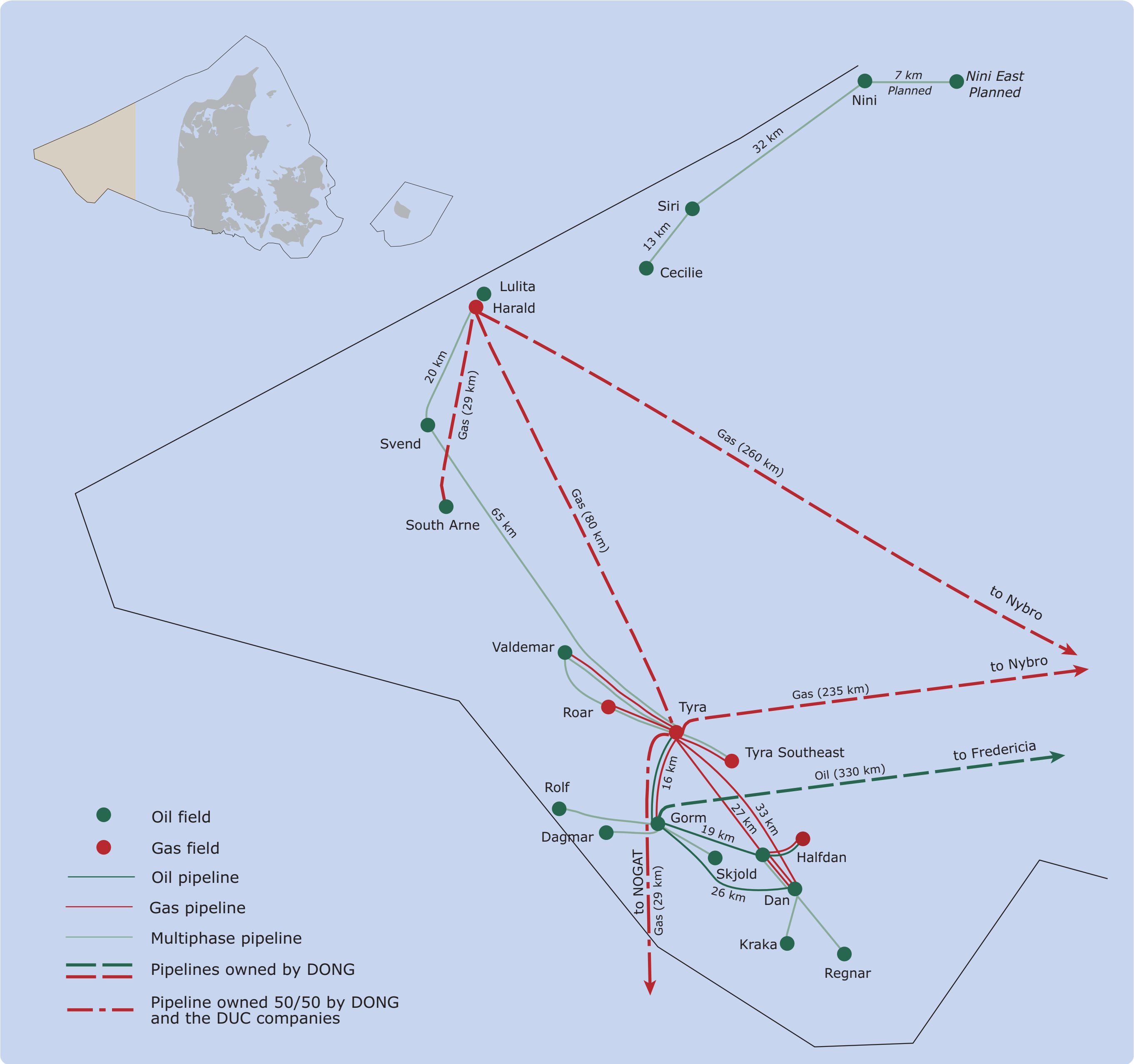
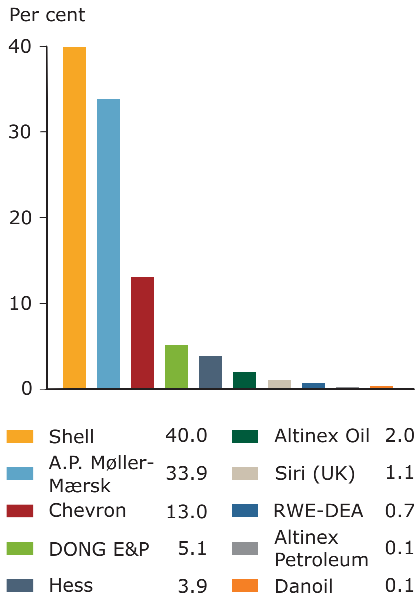


Fig. 2.3 Breakdown of oil production by company



Appendix A shows figures for the production of oil and gas from the individual fields. Gas production is broken down into sales gas, injection gas, fuel gas and flared gas. Appendix A also contains figures for the production and injection of water as well as for CO_2 emissions.

Annual production figures since production started in 1972 are available at the DEA's website, www.ens.dk.

Oil production

Oil production in 2008 totalled 16.7 million m^3, a 7.8 per cent decline compared to 2007.

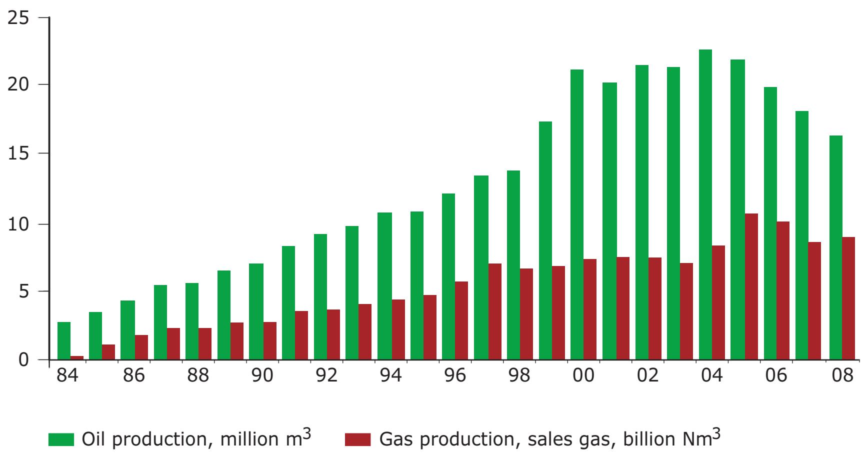
Oil production peaked at 22.6 million m^3 in 2004. Thus production from the Danish part of the North Sea continues its declining trend, as expected. However, production in 2008 exceeded the figures forecast for 2008. Figure 2.4 shows the historical development of production over the past 25 years.

New investment is required to turn around this downward trend, for example in the development of new production technology to improve the recovery factor and in exploration that allows new discoveries to be developed together with discoveries already made.

Today, about 20 per cent of the known resources in the Danish subsoil has been produced. An additional 6 per cent is also expected to be recoverable, leaving more than 70 per cent of unproduced oil resources in the subsoil. These remaining oil resources are considered to be either difficult or impossible to recover with today's production technology.

Historically, technological developments have previously helped increase the recovery factor. In the early years, recovery from the Danish oil fields in the North Sea was based on natural depletion, also termed primary recovery. In the mid-1980s, secondary recovery methods were introduced. Secondary recovery is based on the use of long horizontal wells and water injection and has been continuously developed since its introduction. This increased the recovery factor from 5-10 per cent to about 30 per cent, which is the recovery factor for several fields today. Figure 2.5 shows the current recovery factors for the individual fields.

Fig. 2.4 Production of oil and gas



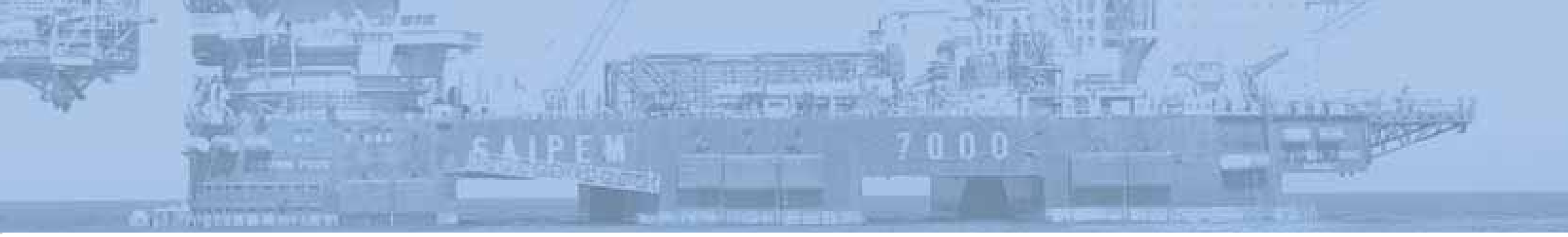
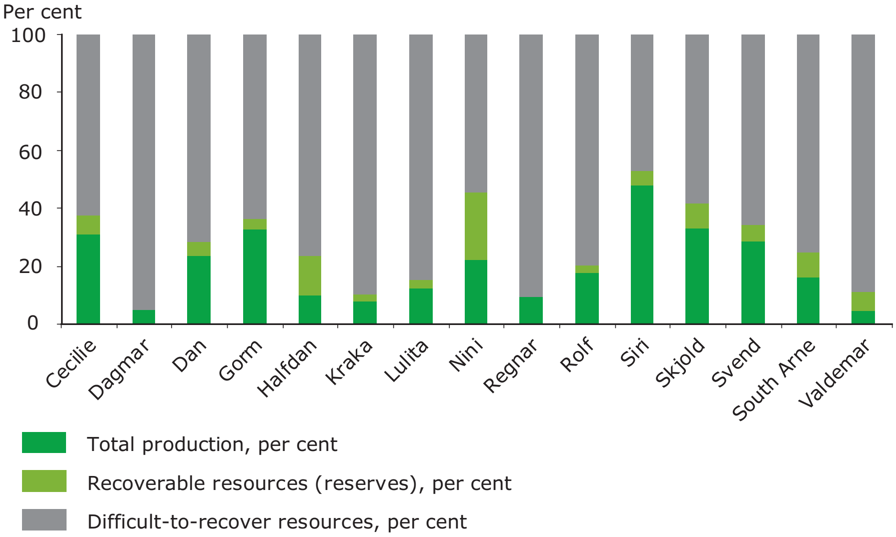


Fig. 2.5 Status of the recovery factors for Danish oil fields in 2008



A new generation of recovery technology, termed either tertiary recovery or EOR, is already in use several places in the world; see box 2.1. EOR is not yet used in Denmark, but research is being done to determine how EOR can be employed in the Danish fields and thus enable recovery of part of the 70 per cent that cannot be produced today.

Box 2.1

Enhanced Oil Recovery (EOR)
EOR is an abbreviation of Enhanced Oil Recovery.

EOR describes the next generation of recovery technology, which changes the properties of oil to make it flow more easily and thus become easier to recover.

Extensive research and development efforts are ongoing to discover new EOR methods, but EOR is not yet used in Denmark to enhance recovery from the fields.

To obtain an overview of known EOR methods used in the rest of the world, the Danish North Sea Fund, the DEA and Mærsk Olie og Gas AS have jointly commissioned the preparation of a report that contains an independent assessment of existing global experience with various EOR methods. The report shows that CO_2 injection is the only proven EOR method feasible in Danish fields.

The report on EOR is available at the DEA's website, www.ens.dk.

Gas production

Natural gas production totalled 9.9 billion Nm³ of gas in 2008, with sales gas accounting for 8.9 billion Nm³. By sales gas is meant the portion of the gas suitable for sale. Total production declined by 1 per cent from 2007, whereas the amount of sales gas increased by 11 per cent compared to 2007. Figure 2.4 shows the historical development in sales gas production over the past 25 years.

Less gas was injected in 2008 because of higher natural gas sales, ending at 0.2 billion Nm^3. By comparison, a total of 1.1 billion Nm^3 of gas was injected in 2007.

The Tyra Field acts as a buffer, which means that gas from other fields can be injected into the Tyra Field during periods of low gas consumption and thus low gas sales, for example in summer. When the demand for gas increases, the gas injected in the Tyra Field is produced again.

A buffer is generally needed because reducing production from the fields for periods of time is difficult. This difficulty results from reservoir considerations and the fact that equipment on the offshore installations has a limited useful life.

Moreover, reservoir conditions in the Tyra Field boost production when the field acts as a buffer. The dry gas injected (see box 1.1 in chapter 1, *Licences and exploration*) helps delay the decrease in gas cap pressure, thus optimizing the recovery of oil from the Tyra Field.

The unsold part of the gas produced is used primarily as fuel as part of the energy supply to the platforms. A small volume of gas is flared for technical and safety reasons. The volumes of gas consumed as fuel and flared are described in chapter 4, *Environment and climate*, and in appendix A.

DEVELOPMENT ACTIVITY IN 2008

Several of the existing fields were further developed in 2008. A total of 14 horizontal development wells were drilled, one water-injection well and five appraisal wells. One of the appraisal wells was subsequently converted into a gas production well. Thus, drilling activity remained at the same level as in 2007. The new wells and the other development and maintenance activities represent a total investment of DKK 6.1 billion, the same high investment level as in 2007, when investments totalled DKK 6.5 billion.

Appendix B contains diagrams showing development and investment activities for each individual field.

Development in progress and approved development plans

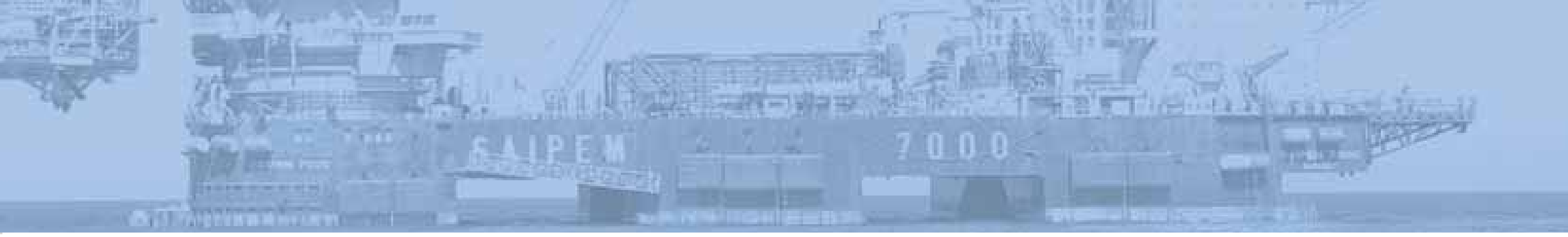
The Dagmar Field

The Dagmar Field has not carried on regular production since 2005, when the water content of production reached 98 per cent. The special production properties in the reservoir mean that only 5 per cent of the oil-in-place has been produced. This corresponds to the oil present in the fracture system of the Dagmar Field.

In 2008, the DEA received a report from the operator about the future of the field. The operator is currently re-evaluating the potential of the field and expects to reach a conclusion in 2009 about whether to develop the field or close it permanently. If the field is closed permanently, Dagmar will become the first Danish field to be decommissioned. The removal of installations is described in chapter 4, *Environment and climate*.

The Dan field

The drilling rig Energy Enhancer has drilled two oil production wells, MFF-34 and MFF-33A, from the Dan FF platform. Both wells drain an Upper Cretaceous reservoir in the southwestern flank of the Dan Field. The two wells, located at the southern-



most point of the well pattern in the western flank of the Dan Field, were both brought on stream in mid-2008. The long-term plan is to convert MFF-33A to a water injector.

Moreover, workovers were performed on five of the oldest wells in the field: two oil production wells (MFB-10 and MFB-13) and three water-injection wells (MFB-4C, MFB-6B and MFB-14B).

The Gorm Field
Due to upgrading and maintenance work in the field, the installations were closed for 2½ weeks. The fields using Gorm's processing facilities were thus closed down during the same period.

The Halfdan Field (incl. Sif and Igor)
In the northeastern part of the Halfdan Field, the Ensco 71 drilling rig was stationed at the new HCA platform during the whole year. The rig drilled a total of four wells (HCA-7ML, HCA-3ML, HCA-2ML and HCA-6). The wells are arranged in a helical pattern in the Danian reservoir and are all gas production wells. HCA-7ML, HCA-3ML and HCA-2ML are multilateral wells; see box 2.2. HCA-7ML was spudded in 2007, when the first lateral was drilled. The second lateral was drilled in 2008.

The HDE-1X appraisal well was drilled in the area between the HBA and HCA platforms; for further details please see chapter 1, *Licences and exploration*.

The fourth phase of the Halfdan development plan was approved in June 2008. The development plan provides for the installation of a new platform, HBD, with facilities to process the liquids and gas produced. The capacity will be 240,000 barrels of liquid per day and the separation of 80,000 barrels of oil per day. The new facilities will have a gas-separating capacity of 6.7 million Nm^3 per day. The new platform will be bridge-connected to the existing Halfdan B installation, which will be converted to manned operation at the same time.

Box 2.2

Multilateral wells
A well with two or more well sections targeting the reservoir is called a multilateral well.

A multilateral well only needs one individual wellhead on the platform. From the seabed to the top of the reservoir, the well is drilled as an ordinary single-bore well.

From the top of the reservoir, a single wellbore is first drilled into the reservoir. From here a lateral is drilled through the side of the well casing, and an additional well section is drilled into the reservoir. Thus, the well has two well sections draining the reservoir at the same time.

This technology enables production from a larger part of the reservoir, with a smaller number of wells and at less cost.

Multilateral wells are well-suited for conditions in the North Sea.

The fourth phase of the Halfdan development plan includes the drilling of up to 12 new wells. As part of this development plan, a ten-slot wellhead module was installed on the HBB riser platform in 2008. The plan provides for the drilling of seven new wells from the HBB platform in 2009. In April 2009, the DEA received an updated development plan according to which only five wells are expected to be drilled.

In December 2008, the DEA received an application to develop the Halfdan Field with an additional two multilateral wells (see box 2.2) east of the HCA platform. The wells will be drilled in extension of the existing helical well pattern at the HCA platform in the Igor area. The DEA considered and approved the application at the beginning of 2009.

Maintenance work was performed on Halfdan's gas compressors in July and September with the consequent shutdowns, which impacted production from the field.

The Nini Field
In November 2007, the operator applied for permission to develop the eastern area of the Nini Field. The plan, approved in January 2008, provides for the establishment of a new unmanned platform with capacity for ten wells, corresponding to the existing Nini platform.

Existing plans include the drilling of five wells, which are expected to increase production by a total of 2.7 million m^3 of oil.

Pipelines for multiphase flow, lift gas and injection water are to be installed between the Nini platform and the new Nini East platform. In this connection, the existing Nini platform is to be modified to fulfil the function of a transport hub between Siri and Nini East.

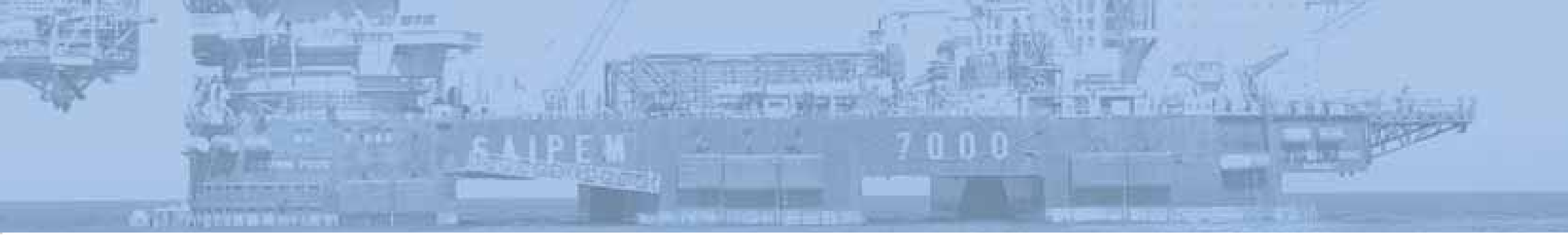
The Siri Field
In the Siri Field, the drilling rig Ensco 70 drilled two new oil production wells. The SCA-12C well is located at the southern flank of the Siri Field, while the SCA-3C well is located close to the previous SCA-3A well in the western part of the field. Both wells produce from the sandstone reservoir in the Heimdal formation.

The South Arne Field
A project to close a direct connection between a water injector and an oil production well in the reservoir was implemented in the South Arne Field, which significantly improved production from SA-12F.

The operator of the South Arne Field is expected to submit a proposed development plan for South Arne in mid-2009.

The appraisal well Rigs-4/4A was drilled south of the South Arne Field in 2008; for further details see chapter 1, *Licences and exploration*.

The Tyra Field (incl. Tyra Southeast)
In the Tyra Southeast Field, the drilling rig Energy Endeavour drilled two new gas production wells, TSEA-4G and TSEA-5F, and an appraisal well, TSEA-3B, in the Danian reservoir.



TSEA-4G is to drain an area east of the TSEA platform, while TSEA-5F was drilled in the northern flank of Tyra Southeast.

In 2008, the operator of the Tyra Southeast Field was granted permission to reuse the surface casing from the plugged and abandoned oil production well TSEA-3A for a new appraisal and production well. The drilling operation was divided into two phases: the first phase consisted of drilling the TSEA-3B in the area west of the Tyra Southeast platform to evaluate the oil accumulation in the Danian reservoir; for further details see chapter 1, *Licences and exploration*. Subsequently, the TSEA-3B well was plugged and abandoned. The second phase consisted of drilling the final gas production well, TSEA-3D, in a northern direction towards the Tyra Field in the Danian reservoir. TSEA-3D was not brought on stream until early 2009, for which reason it was not included as a production well in 2008. During its lifetime, the well is expected to produce about 0.64 billion Nm^3 of gas and 0.09 million m^3 of oil.

Moreover, re-stimulation programmes have been carried out on several of the older wells (TEB-16, TEB-24C and TEB-15E), which has enhanced recovery from the Tyra Field. More re-stimulation programmes are being planned.

The Valdemar Field
The drilling rigs Energy Exerter and Energy Endeavour were both used to drill a new oil production well, VAB-8, from the VAB platform in the Northern Jens area of the Valdemar Field. The VAB-8 well was drilled into a Lower Cretaceous reservoir placed between the existing VAB-6 and VAB-3A wells.

From the VBA platform in the Bo area of the Valdemar Field, two new oil production wells, VBA-5 and VBA-4A, were drilled into Upper Cretaceous and Lower Cretaceous reservoirs, respectively. Moreover, following approval of an application submitted in 2008, an appraisal well, VBA-8XA, was drilled later the same year into reservoirs of Danian and Upper Cretaceous age, respectively; for further details see chapter 1, *Licences and exploration*. The VBA-8XA well was subsequently converted to a gas production well. The new VBA-8XA gas production well is expected to increase production by about 0.35 billion Nm^3 of gas and 0.06 million m^3 of oil. The drilling rig Noble Byron Welliver drilled all three wells, which were brought on stream in 2008.

The Bo-3X appraisal well was drilled in the area south of the Valdemar Field; for further details see chapter 1, *Licences and exploration*.

Fields with no development activity in 2008
There was no development activity in 2008 in the following fields: Cecilie, Harald, Kraka, Lulita, Regnar, Roar, Rolf, Skjold and Svend.

All exploration and appraisal wells drilled in 2008 are described in more detail in chapter 1, *Licences and exploration*.

3 USE OF THE SUBSOIL

The Danish subsoil is used for more than just the production of oil and gas. This chapter describes the use of the subsoil to extract salt and geothermal heat and to store natural gas, and also the potential future use for storage of CO_2.

With the exception of salt extraction, it is largely the same types of layers in the subsoil which can be used for these various purposes. It is necessary to prioritize use of the subsoil for different purposes, as the storage of CO_2 will for example permanently prevent the layers from being used for other purposes.

In connection with geothermal heat production, the storage of natural gas and CO_2, subsoil porous and permeable sandstone layers (see box 1.1) at depths of 1,500 m to 2,500 m can be used in many areas in Denmark. The capture and storage of CO_2 and gas storage require the porous sandstone layers used for capture/storage to be part of a geological structure that permits the gases injected to be trapped in the porous layers. Above the porous layers, there must be a seal or cap consisting of tight clay layers which are impermeable to the injected gases. On the other hand, the use of porous sandstone layers for geothermal heat production does not require a subsoil structure. Porous sandstone layers which contain hot water are sufficient to enable the production of geothermal heat.

SALT EXTRACTION

In Denmark, salt is extracted from the subsoil for consumption and for use as industrial salt, road salt and chemically pure salt. Salt is only extracted from the Hvornum salt diapir, which is situated about 8 km southwest of Hobro; see figure 3.1 and box 3.1.

Fig. 3.1 Use of the subsoil for different purposes

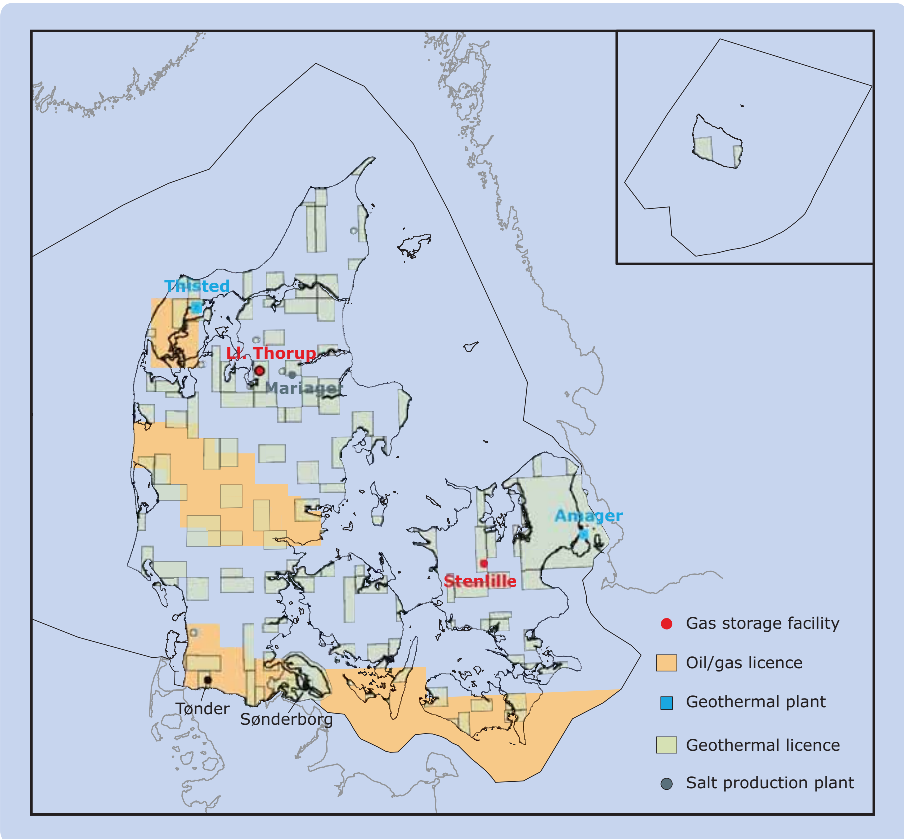
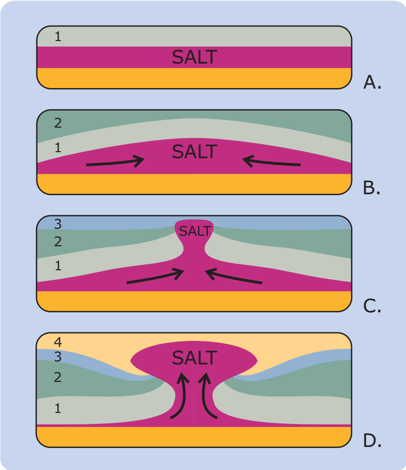


Fig. 3.2 The development of a salt diapir



Box 3.1

Salt diapirs
Salt can be found in some parts of the Danish subsoil. The salt was formed during the Permian period more than 250 million years ago. At the time, Denmark was covered by a warm inland sea much like the Dead Sea today. Here, salt was precipitated out as a kilometre-thick layer on the seabed; see figure 3.2 A. Subsequently, 4-5 km of clay, sand and chalk was deposited on top of the salt. Because of the weight of the overlying layers, which are denser than the salt, the salt will slowly try to force its way up through the overlying layers where they are weakest; see figures 3.2 B to D. This results in the formation of a salt diapir.

Akzo Nobel Salt A/S is the company undertaking the production of salt. The company has an exclusive licence for the production of salt from the Danish subsoil. The licence was issued in 1963 and runs for a 50-year period, which means that it will expire in 2013. The company has applied for a new licence to replace the existing one. The application is currently being processed by the DEA.

The salt diapir from which extraction takes place is approximately 3,000 m in diameter and 4,000 m deep, and the top is situated at around 300 m below the Earth's surface. Salt is extracted from depths of 1,000 to 1,500 m. The salt layers are dissolved by pumping water into them. The saltwater is pumped to a plant where the salt is evaporated by heating it. The salt is extracted via six wells, and the plant itself is situated next to Mariager Fiord. The plant has an annual production capacity of approximately 600,000 tons of salt.

A royalty is payable to the Danish state, currently amounting to DKK 9.07 per ton of salt produced. The Danish state receives about DKK 5-6 million a year in royalties from salt extraction.

GEOTHERMAL HEAT PRODUCTION

Geothermal heat from the interior of the Earth continually flows towards the Earth's surface. In Denmark, where the temperature in the subsoil layers typically increases by 25–30°C for every 1,000 m of depth, it is possible to utilize this heat for heating purposes in the form of district heating. The hot water that is found in porous and permeable sandstone layers is pumped up to the surface via wells. Here, the heat is extracted via heat exchangers, and the cooled water is then pumped back into the subsoil via another well.

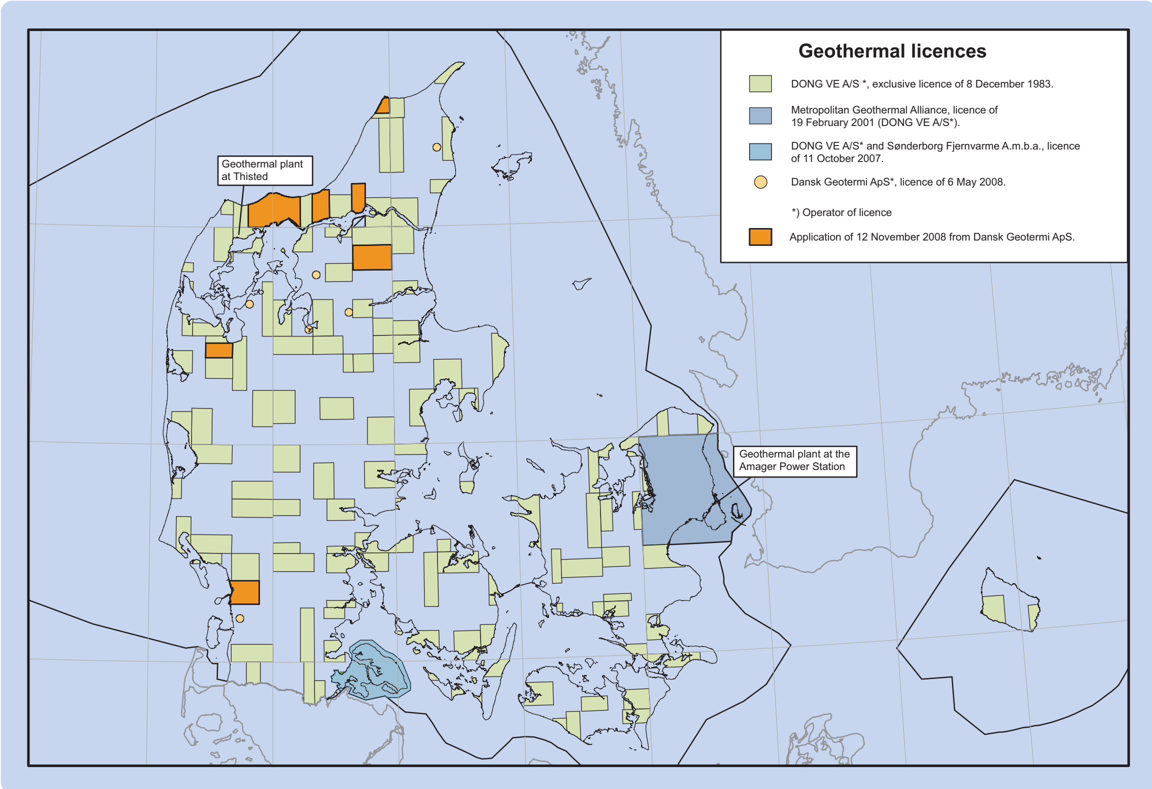
In Denmark, there is considerable potential for extracting geothermal heat. Throughout much of Denmark, there are porous and permeable sandstone layers from which geothermal heat can be produced for district heating purposes. However, the sandstone layers become less porous and permeable with depth, so although the layers, and therefore the water contained in the layers, become hotter with depth, there is a maximum depth at which it ceases to be cost-effective to extract geothermal heat. In Denmark, experience has shown that this limit is normally around a depth of 2,500 m.

The Metropolitan Geothermal Alliance (abbreviated HGS, from its Danish name), an alliance consisting of Centralkommunernes Transmissionsselskab I/S (CTR) (18 per cent), DONG VE A/S (28 per cent), KE Varme P/S (18 per cent), Energi E2 (18 per cent), and Vestegnens Kraftvarmeselskab I/S (18 per cent), made an assessment in 2008 of the geothermal reserves in the metropolitan region. The conclusion is that there are geothermal reserves of about 60,000 PJ in the entire licence area. The reserves are assessed to cover 30-50 per cent of the district heating requirements in the metropolitan region for thousands of years, and can thus contribute to increasing the share of renewable energy in Denmark if the necessary production installations are established.

Licences

The extraction of geothermal heating requires a licence pursuant to the provisions of the Danish Subsoil Act. At the end of 2008, four licences had been issued for the exploration for and extraction of geothermal energy. The licence locations appear from figure 3.3.

Fig. 3.3 Geothermal licences in Denmark in 2008



In 1983, DONG Energy was awarded an exclusive licence to explore for and extract geothermal energy in Denmark. This licence expires in 2013. In 1993 and 2003, areas were relinquished to the Danish state, which means that DONG's exclusive licence now covers only parts of Denmark.

In 2001, a licence was issued to explore for and extract geothermal energy in the metropolitan region to the Metropolitan Geothermal Alliance – HGS – the composition of which is shown above. DONG is the operator of the licence. In connection with the issuing of the licence to the HGS companies, DONG relinquished areas comprised by its licence dating from 1983, with the result that these areas are now covered by the licence issued to HGS.

In 2007, a licence was issued to explore for and extract geothermal energy in the Sønderborg area to DONG VE A/S (50 per cent), and Sønderborg Fjernvarme A.m.b.a. (50 per cent). DONG is the operator of the licence. In connection with the issuing of the licence, DONG relinquished areas comprised by its licence dating from 1983, with the result that these areas are now covered by the new licence.

In 2008, a licence was issued to the company Dansk Geotermi ApS to explore for and extract geothermal energy. The licence covers six areas at Sæby, Farsø, Rødding, Kvols, Hobro and Brøns. The areas in question have a radius of 2 km from deep exploration wells drilled previously.

In November 2008, the DEA received an application from the company Dansk Geotermi ApS for a new licence to explore for and extract geothermal energy. The

application covers seven areas in Jutland as shown in figure 3.3. The application is currently being processed by the DEA.

Geothermal plants

There are two geothermal plants in Denmark. One is situated at Thisted and the other on Amager. A third geothermal plant is under construction at Sønderborg.

The geothermal plant at Thisted was commissioned in 1984. This plant utilizes water at a temperature of around 45°C from sandstone layers at a depth of approximately 1,250 m. The hot water is cooled to approximately 12°C through a heat exchanger before being returned to the subsoil. The geothermal plant is connected to the town's waste-based CHP plant. The geothermal component of the plant can produce the equivalent of the annual heat consumption of approximately 2,000 households.

On Amager, heat production from the geothermal plant that is located adjacent to the Amager power station began in 2005. This plant produces hot water at a temperature of around 73°C from sandstone layers situated at a depth of approximately 2,600 m. The water is cooled in a heat exchanger to approximately 17°C, before being returned to the subsoil. The annual heat production from the hot water in the subsoil is equivalent to the consumption of around 4,600 households.

Two wells are planned to be drilled in autumn 2009 in the Sønderborg area, which will be used by a new geothermal plant at Sønderborg. The intention is to replace natural-gas-based district heating production with geothermal heating. The plant will be established in connection with the existing waste-to-energy CHP plant at Sønderborg. Work is in progress for the startup of geothermal heat production from the new plant some time during 2011.

GAS STORAGE

In Denmark, gas consumption varies throughout the year, topping during winter time. On a cold winter day, gas consumption may reach about 30 – 33 million Nm^3 on a daily basis. The maximum delivery of natural gas from the fields in the North Sea amounts to about 22 – 24 million Nm^3 on a daily basis. In order to manage this difference, gas storage facilities are necessary. During the summer, when consumption is low, natural gas is pumped down into the storage facilities, and during the winter the gas stores are used to cover consumer requirements.

In addition, the storage facilities function as emergency supplies in the event of an interruption in supplies from the Danish North Sea gas fields, or if there is a gas pipeline rupture in the transmission network. The storage facilities are dimensioned so as to handle supplies of natural gas to the uninterruptible gas market, which for instance comprises domestic heating, for a period of about 60 days. This is the estimated time it takes to repair a gas supply rupture in the North Sea.

There are currently two gas storage facilities in Denmark. The locations of these two facilities are shown in figure 3.1.

One facility is located at Stenlille on Zealand, where gas is stored in porous sandstone layers at a depth of around 1,500 m. This facility is owned by DONG Energy. Approximately 1.5 billion Nm^3 of natural gas is injected into the facility at Stenlille, of which approximately 580 million Nm^3 can be utilized (working gas).

The other gas storage facility is situated at Lille Torup in northern Jutland. At this facility, the gas is stored in seven large subsoil caverns that have been created by the flushing out of a salt diapir. Box 3.1 explains what a salt diapir is. The caverns, which are situated at depths of 1,000 – 1,700 m, are 200 – 300 m high and 40 – 60 m in diameter. This facility is owned by Energinet.dk. At the Lille Torup facility, approximately 700 million Nm^3 can be stored in the seven caverns, of which approximately 440 million Nm^3 of gas is utilized (working gas).

In 2007, the DEA received an application for a licence to establish and operate a new natural gas storage facility at Tønder. The application was filed by the company Dansk Gaslager ApS. The application is currently being processed by the DEA.

STORAGE OF CO_2

The potential for reducing atmospheric CO_2 emissions is a topical issue in many contexts. One possibility is to capture and then store CO_2 from major point sources such as power stations. This technology is often referred to as 'CCS', which stands for 'Carbon Capture and Storage'.

Technology is available today to remove CO_2 from the flue gases of power stations, and research is being carried out to improve and develop new technology to separate the CO_2 from power stations more energy-efficiently. The technology involves the CO_2 being trapped at the power station and then compressed and transported in liquid form to a special subsoil storage facility. The compressed CO_2 will be transported in pipelines.

The subsoil storage of CO_2 must take place at locations with suitable geological conditions. In Denmark, this will typically be porous and permeable sandstone layers at depths of more than approximately 1,000 m. Storage at this depth means that the CO_2 will be in liquid form due to the higher pressure. The sandstone layers must form a structure where the injected CO_2 can be trapped in the porous layers. Above the sandstone layers, there must be a tight clay formation, which is impermeable to CO_2, so that the stored CO_2 cannot escape. Such optimal geological conditions for the storage of CO_2 exist in many parts of the Danish subsoil, both on land and offshore.

The layers and structures in the subsoil that can be used for CO_2 storage may also be used for other purposes, such as storing natural gas or geothermal heat. Consequently, prioritizing the use of the subsoil is necessary.

Another possibility is to inject the CO_2 into the oil fields of the North Sea. This has the added benefit of enabling more oil to be produced from the fields, as the injection of CO_2 in an oil field can release more oil from the layers, oil that would not otherwise be recoverable. Some of the injected CO_2 will however be extracted together with the oil, and it is therefore necessary to separate this CO_2 from the oil and reinject it in the subsoil. This method is not yet being used in the oil fields of the North Sea, primarily because the method is considered to be very expensive, one reason being that it would require many new installations as well as modifications to existing installations in the North Sea.

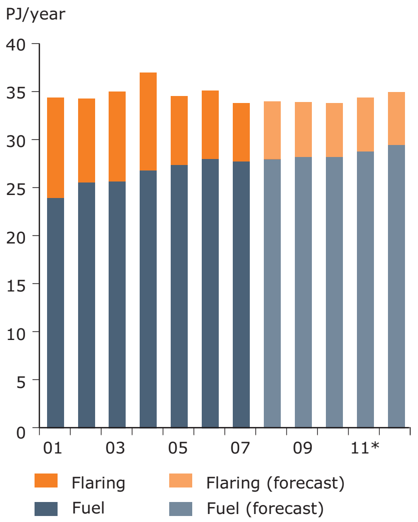
In 2008, licences were issued to both Vattenfall and DONG to undertake preliminary investigations of the Danish subsoil with a view to assessing the potential for storage of CO_2. In this context, in autumn 2008 Vattenfall performed a 2D seismic survey of the subsoil northwest of Aalborg in order to map the Vedsted structure. This seismic

survey is discussed in chapter 1, and the location of the seismic lines is shown in figure 1.7.

The existing Danish Subsoil Act addresses the use of the subsoil for storage purposes, including CO_2 storage. In connection with EU's climate and energy package, a new directive addressing carbon capture and storage in the subsoil has now been adopted. The directive contains a system for allocation of exploration and storage licences in connection with the deployment of carbon capture and storage. In addition, the directive contains a number of regulations regarding monitoring, etc. of the stored CO_2. It is still up to the individual member states to take a position as to whether they want to use this technology and, if so, determine the areas in which CO_2 will be stored. The new directive must now be implemented into Danish legislation. This is expected to take place by an amendment of the Danish Subsoil Act, among other statutory provisions.

4 ENVIRONMENT AND CLIMATE

Fig. 4.1 Energy consumption for oil and gas production in the Danish North Sea sector under business-as-usual assumptions, 2001-2012



* The figure has been copied from the report "Increased energy efficiency in oil and gas production - review and proposals", Dec. 2008.

The production of oil and natural gas impacts the environment, both through emissions to the atmosphere of gases like CO_2 and NO_x and through the discharge of chemicals and oil residue into the sea. Initiatives to reduce this impact are launched on an ongoing basis. In 2008, specific attention was focused on reducing energy consumption offshore and on the most recent follow-up of the Minister for the Environment's Offshore Action Plan, which aims to limit the discharge of foreign substances into the sea to the greatest extent possible.

ENERGY EFFICIENCY OFFSHORE

The broad energy policy agreement of 21 February 2008 sets out goals for the development of Danish energy consumption during the period 2008-2011. One of the general goals in this energy agreement is to reduce gross Danish energy consumption by 2 per cent in 2011 and 4 per cent in 2020 relative to 2006.

The agreement calls for a review of offshore energy consumption and proposals for initiatives to improve the energy efficiency of oil and gas production in the North Sea, to be prepared by the end of 2008.

Against this background, the DEA, supported by the Danish operators, prepared the report entitled "*Increased energy efficiency in oil and gas production - review and proposals*", Dec. 2008.

Fuel consumption

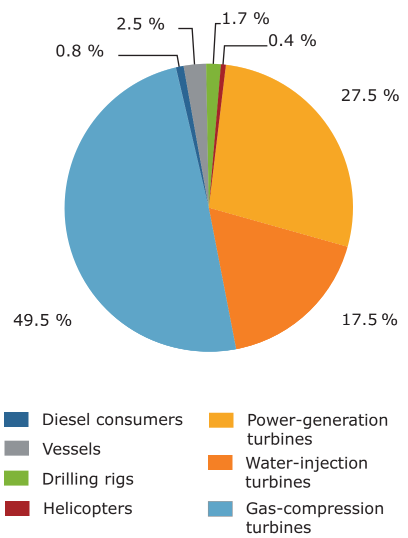
The review shows that offshore energy consumption, which is divided into fuel consumption and flaring (see box 4.1), has remained relatively constant at around 35 million GJ annually in recent years; see figure 4.1. This corresponds to approximately 4 per cent of Denmark's gross energy consumption. Of this figure, flaring accounted for 20 per cent in 2006.

Box 4.1

Flaring

The combustion of waste gas is called 'flaring'. Gas is flared on all offshore platforms with production facilities, and for safety reasons gas flaring is necessary in cases where plants must be emptied of gas quickly.

Fig. 4.2 Energy consumption in the Danish offshore sector in 2007

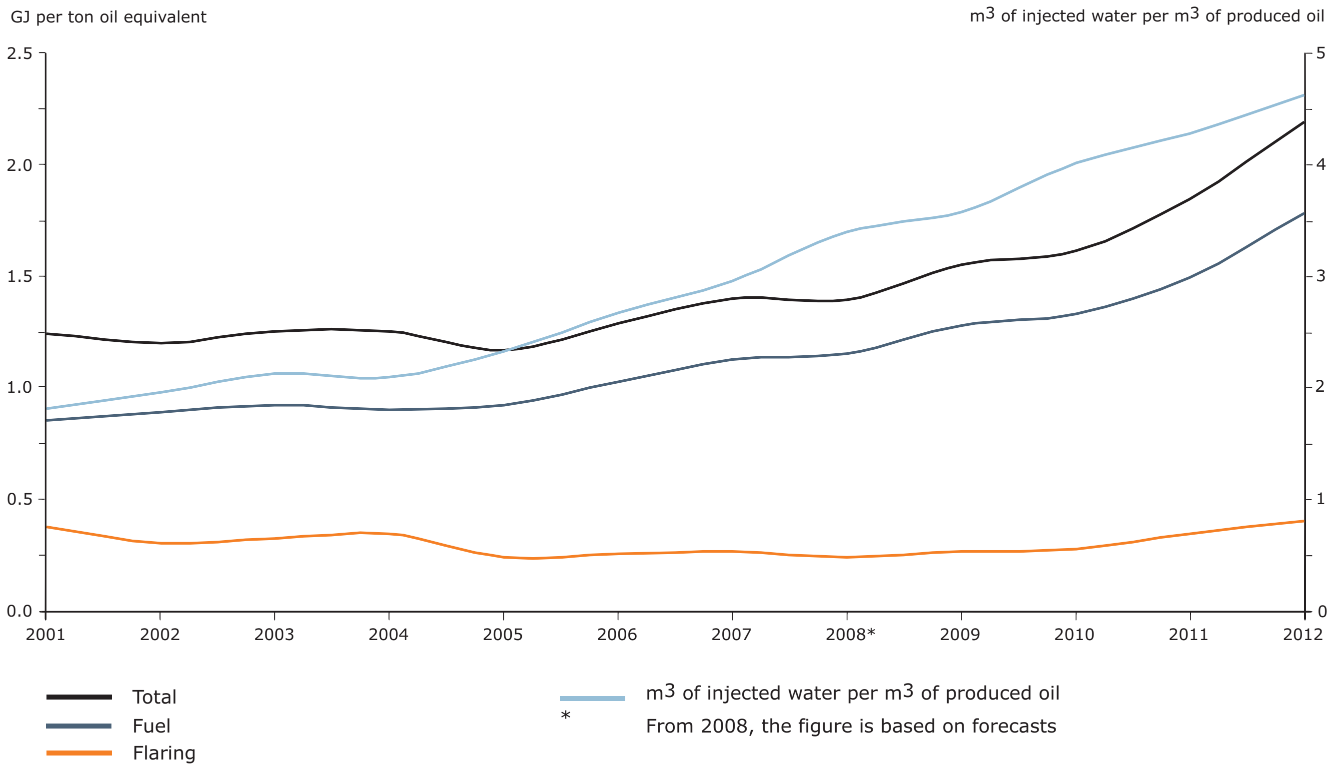


Natural gas that is used in gas turbines accounts for 95 per cent of fuel consumption (excluding flaring). Half of this quantity is used to generate electricity and drive water-injection pumps, while the other half is used to compress the natural gas to a higher pressure. The natural gas is compressed to a higher pressure partly for export to shore through the pipelines shown in figure 2.2 in chapter 2, *Production and development*, and partly for use as lift gas in oil production wells.

On installations operated by Mærsk Olie og Gas AS, around 60 per cent of the compression capacity is used to prepare gas for export and around 30 per cent is used for lift gas. The remaining compression capacity is used to compress gas in connection with stabilizing crude oil.

The remaining 5 per cent of fuel consumption consists of diesel oil. The distribution of fuel consumption between the various applications is shown in figure 4.2.

Fig. 4.3 Energy intensity of hydrocarbon production



Energy intensity

Energy intensity describes how much energy is used to generate one unit of energy. The constant energy consumption offshore must be seen in the context of falling oil and gas production. This means that energy intensity has been rising since around 2005; see figure 4.3.

This is a consequence of the efforts to improve the recovery factor by means of increased use of water injection. Substantial quantities of energy are used both for the injection of water into the reservoir and the subsequent separation of the produced oil and water.

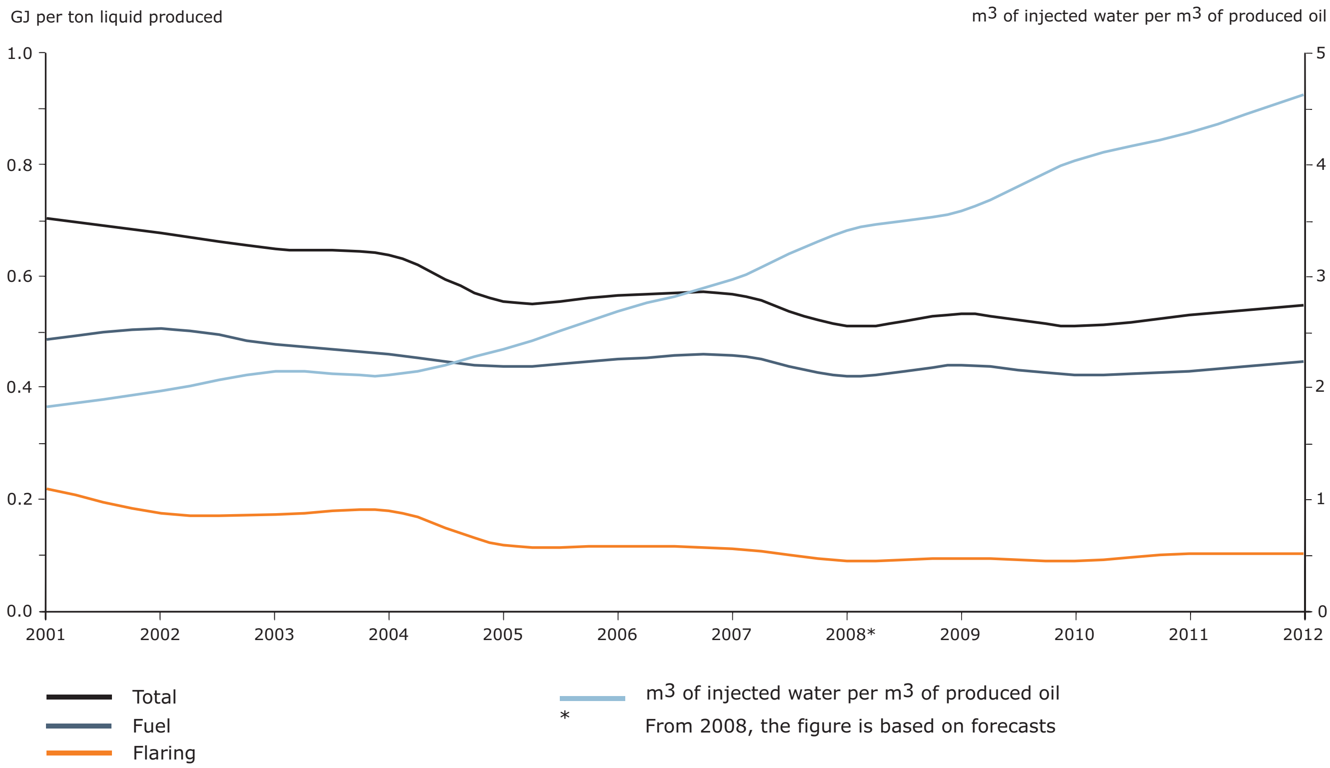
However, if the energy consumption is compared with the total quantity of liquid (oil and water) produced, a fall in energy intensity has occurred, and no increase is anticipated in the years to come; see figure 4.4.

Action plan to reduce offshore energy consumption

Based on the report "*Increased energy efficiency in oil and gas production - review and proposals*", Dec. 2008, the Minister for Climate and Energy has agreed on an action plan with the Danish operators to step up efforts to reduce offshore energy consumption.

This action plan contains a series of initiatives aimed at improving energy efficiency, which are collectively expected to result in a 3 per cent reduction of energy consumption during the period 2006-2011, compared with the previously expected slight increase of 1.5 per cent. These initiatives are therefore expected to result in total savings of around 4.5 per cent compared with 2006.

Fig. 4.4 Energy intensity of total liquid production

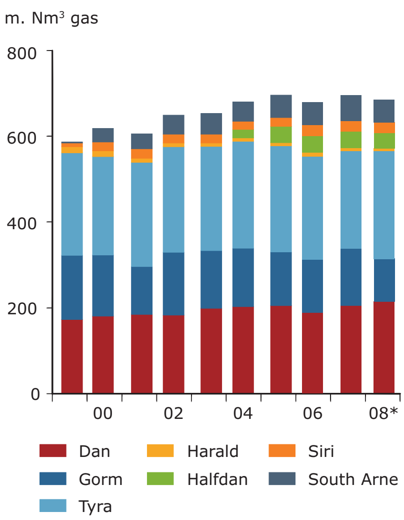


Approximately one quarter of the anticipated savings will come from reduced flaring as a result of changes to operations.

The action plan also incorporates a plan for making further analyses.

The action plan to reduce offshore energy consumption is available from the DEA's website, www.ens.dk.

Fig. 4.5 Fuel consumption



*As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the the Act on CO_2 Allowances

EMISSIONS TO THE ATMOSPHERE

The production of oil and gas in the North Sea results in various emissions and discharges to the surrounding environment.

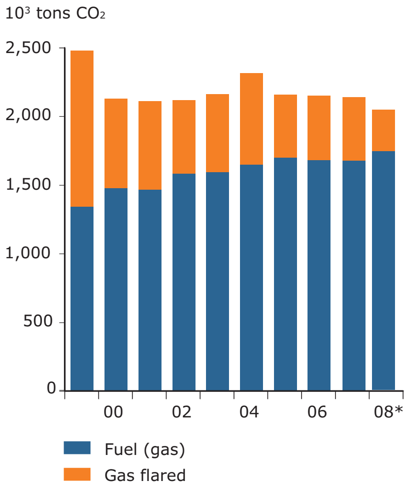
Emissions to the atmosphere consist of such gases as CO_2 (carbon dioxide) and NO_x (nitrogen oxide).

The combustion and flaring of natural gas and diesel oil produce CO_2 emissions to the atmosphere. Producing and transporting oil and gas require substantial amounts of energy. Furthermore, a volume of gas that cannot be utilized for safety or plant-related reasons has to be flared.

The volume emitted by the individual installation or field depends on the operational mode, the scale of production as well as plant-related and natural conditions.

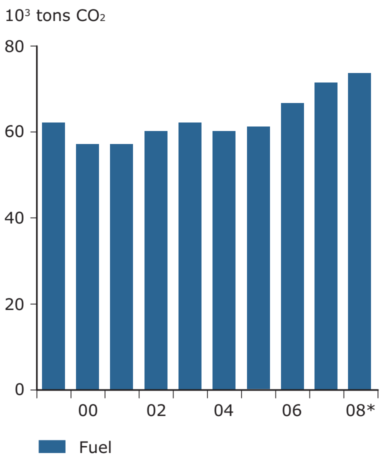
The Subsoil Act regulates the volumes flared, while CO_2 emissions are regulated by the Act on CO_2 Allowances.

Fig. 4.6 CO_2 emissions from production facilities in the North Sea



*As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the the Act on CO_2 Allowances and have included CO_2 emissions from diesel combustion

Fig. 4.7 CO_2 emissions from consumption of fuel per m. t.o.e.



*As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the the Act on CO_2 Allowances and have included CO_2 emissions from diesel combustion

Consumption of fuel

Fuel gas accounted for about 82 per cent of total gas consumption offshore in 2008. The remaining 18 per cent was flared. It appears from figure 4.5 that the use of gas as fuel has increased gradually on Danish production facilities during the past decade, although it decreased slightly from 2007 to 2008. The general increase is attributable to rising oil and gas production and ageing fields.

In recent years, the steadily ageing fields have particularly impacted on fuel consumption. Natural conditions in the Danish fields mean that energy consumption per produced t.o.e. increases the longer a field has carried on production. This is because the water content of production increases over the life of a field, and oil and gas production therefore accounts for a relatively lower share of total production. Assuming unchanged production conditions, this increases the need for injecting lift gas, and possibly water, to maintain pressure in the reservoir. Both processes are energy-intensive.

Fuel consumption varies from year to year at the individual installations; see figure 4.5. From 2007 to 2008, the use of fuel gas remained unchanged or declined slightly on all installations excepting the Dan and Tyra Fields, which used slightly more fuel gas.

CO_2 emissions due to fuel consumption

The development in the emission of CO_2 from the North Sea production facilities since 1999 appears from figure 4.6. This figure shows that CO_2 emissions totalled about 2.0 million tons in 2008, the lowest level in the past ten years. The production facilities in the North Sea account for about 4 per cent of total CO_2 emissions in Denmark.

Figure 4.7 shows the past ten years' development in CO_2 emissions associated with the consumption of gas as fuel, relative to the volume of hydrocarbons produced. It appears from this figure that CO_2 emissions due to fuel consumption have increased relative to the size of production, from about 57 ktons of CO_2 per million t.o.e. in 2000 to about 73 ktons of CO_2 per million t.o.e. in 2008.

Gas flaring

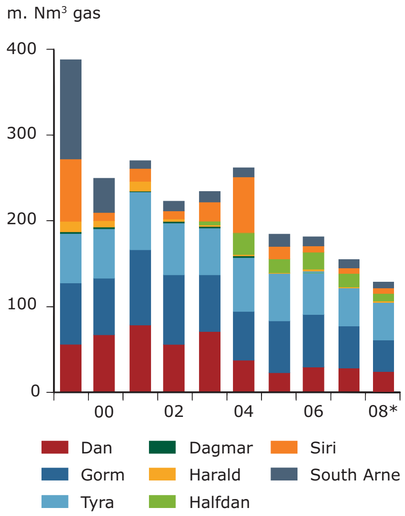
The flaring of gas declined substantially from 2007 to 2008 in all fields, with the exception of the Siri and Harald Fields, where volumes flared remained stable. The Tyra, Gorm, Halfdan and South Arne Fields accounted for the largest decreases in gas flaring, a development attributable to stable operating conditions on the installations and changes in operations.

The volumes of gas flared during the period 1999-2008 appear from figure 4.8, and, as the figure shows, gas flaring varies considerably from year to year. The large fluctuations in 1999 and 2004 are partially due to the tie-in of new fields and the commissioning of new facilities. In 2008, gas flaring totalled 132 million Nm^3, which is the lowest volume since 1998.

A portion of the flared gas can be recovered by means of installing and using gas recovery systems. Such systems exist on the platforms in Norway and on the Siri platform in the Danish sector of the North Sea. During normal operating conditions, the gas fed into the flare system is accumulated and compressed and then returned to the processing facilities on the platform.

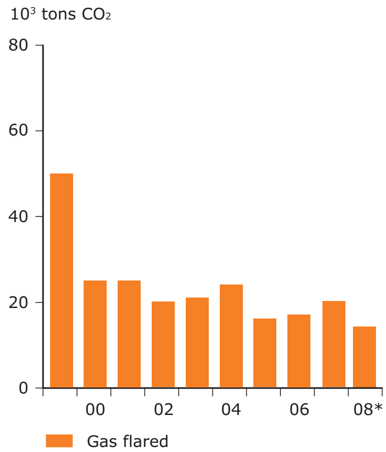
The volume of gas flared depends in part on the operational mode and the design and layout of the individual installation, but not on the volumes of gas or oil produced.

Fig. 4.8 Gas flaring



*As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the the Act on CO_2 Allowances

Fig. 4.9 CO_2 emissions from gas flaring per m. t.o.e.



*As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the the Act on CO_2 Allowances and have included CO_2 emissions from diesel combustion

CO_2 emissions from gas flaring

In 2008, CO_2 emissions from flaring came to 0.354 million tons of CO_2 out of total CO_2 emissions from the offshore sector of 2.025 million tons, i.e. 17.5 per cent of total emissions. The volume of gas flared accounted for 1.3 per cent of total gas production in 2008. All CO_2 emissions are comprised by the CO_2 allowance scheme; see box 4.2.

Flaring has declined steadily since 2004 and dropped significantly in 2008, down 21 per cent on 2007. However, as the production of hydrocarbons decreased during that period, the volume of gas flared per t.o.e. produced increased until 2007; see figure 4.9. From 2007 to 2008, the volume of gas flared per t.o.e. produced decreased, the

Box 4.2

The European CO_2 allowance scheme

As of 1 January 2009, the CO_2 allowance scheme covered about 380 installations in Denmark, including seven in the offshore sector.

An offshore installation is defined as all energy-producing facilities on all platforms in a field. For example, the Dan Field is defined as an installation, comprising all energy-producing facilities on all platforms in the Dan Field.

Installations have been required to monitor, measure and report their CO_2 emissions since 2005. At the same time as receiving an emission permit, each individual installation obtained approval of a plan for monitoring and measuring its CO_2 emissions. In March every year, each installation is to report its CO_2 emissions for the preceding year to the DEA and the Allowance Register. At the end of April, the individual installations surrender allowances corresponding to their CO_2 emissions.

The Act on CO_2 Allowances has laid down the criteria for allocating free allowances for the first period from 2005 to 2007. During that period, free allowances averaging 2.534 million tons of CO_2 per year were allocated to the Danish offshore sector. Danish verified offshore CO_2 emissions for which allowances had been granted totalled 2.206 million tons in 2005, 2.144 million tons in 2006 and 2.139 million tons in 2007.

If new installations are established or existing installations enlarged, further allowances can be allocated.

In March 2007, the Minister for the Environment submitted an allocation plan for the period 2008-2012 to the European Commission for approval. The allocation plan describes the amount of allowances and the criteria for allocating free allowances. The plan is based on the same principles as for the period 2005-2007, viz. historical emissions. Free allowances averaging 2.281 million tons of CO_2 per year have been allocated to the Danish offshore sector for the period 2008-2012.

In August 2007, the allocation plan was approved by the European Commission and implemented into Danish legislation through an amendment to the Act on CO_2 allowances, which entered into force on 1 January 2008.

Further information about the CO_2 allowance scheme is available at the DEA's website, www.ens.dk.

reduction in flaring having been substantial enough to offset the fall in hydrocarbon production.

Appendix A includes a table of the volumes of gas used annually as fuel at the individual production centres, the volumes of gas flared annually and calculated CO_2 emissions.

Emission of NO_x

In 2006, the Ministry of the Environment submitted a technical, economic report on NO_x emissions in Denmark, for one thing to illustrate the reduction options that will best enable Denmark to meet its obligations under the EU Directive on National Emission Ceilings (the NEC Directive) in 2010 and onwards.

On 17 June 2008, the Danish Parliament passed an Act that imposes a general NO_x tax of DKK 5 per kg on atmospheric emissions, with effect from 1 January 2010. The Act is one of several initiatives to ensure that Denmark complies with the provisions of the EU Directive, and also extends to the offshore sector.

For new installations to be established offshore, it will appear from the Environmental Impact Assessments (EIAs) that any new equipment to be installed must be low NO_x equipment, in due observance of Best Available Technology (BAT) and Best Environmental Practice (BEP) principles.

MARINE DISCHARGES

Chemicals, oil residue and subsoil material are discharged into the sea in connection with oil and gas production and the drilling of new wells. In addition, unintentional spills may occur.

To reduce the environmental impact from the discharge of chemical residue, environmentally hazardous chemicals are substituted by less hazardous ones where possible. Attempts are also made to reduce the discharge of oil residue; see box 4.3.

Regulation of discharges

Marine discharges are regulated by the Marine Environment Protection Act and the Minister for the Environment's Offshore Action Plan, which sets targets for the discharge of oil-containing water. Moreover, through agreements under the international OSPAR Convention on the protection of the marine environment, Denmark has committed itself to regulating discharges in the same way as the other North Sea countries.

The OSPAR Convention's requirement for the concentration of dispersed oil in discharged produced water was reduced to 30 mg/l in 2006 after being maintained at a level of 40 mg/l for several years. During the same period, this concentration was reduced to about 15 mg/l in the produced water discharged from Danish fields. Today, the average concentration is about 10 mg/l.

In 2001, the OSPAR member countries adopted a recommendation to reduce total discharged oil by 15 per cent, compared to the equivalent discharge in the year 2000, during the period until 2006.

In 2005, the Minister for the Environment launched the Offshore Action Plan, as it became clear towards the end of the period that Denmark could not meet the goal for a 15 per cent reduction from the 2000 level before 2006. As assumed in the 2005 plan, the Offshore Action Plan was revised in August 2008. In this connection, a fact-

Box 4.3

Discharge of oil residue into the sea
The discharge of oil residue into the sea takes place in connection with both the drilling of new wells and the production of oil and gas.

Drilling of new wells
During the drilling of new wells, drilling rigs discharge water-based drilling mud and drill cuttings. The water-based drilling mud used can contain both chemical additives and oil from the subsoil.

When oil-based drilling mud is used, the drilling mud and drill cuttings are collected, as the discharge of oil-based drilling mud is not permitted. The collected drilling mud and drill cuttings are then transported ashore, where they are treated and disposed of.

Production
Water is also produced during the production of oil and gas. In order to limit the discharge of oil into the sea, the produced water is treated before being either discharged or, wherever possible, reinjected into the reservoir in order to increase the pressure and thereby production. In Danish fields, water injection is necessary to maintain production.

Today, most of the injected water is treated seawater. The total volume of produced water is less than the volume of injected seawater. There is therefore theoretically sufficient capacity to reinject all the produced water. As an increase in the volume of reinjected produced water will replace the injection of seawater, this will not lead to any increase in energy consumption or CO_2 emissions to the atmosphere.

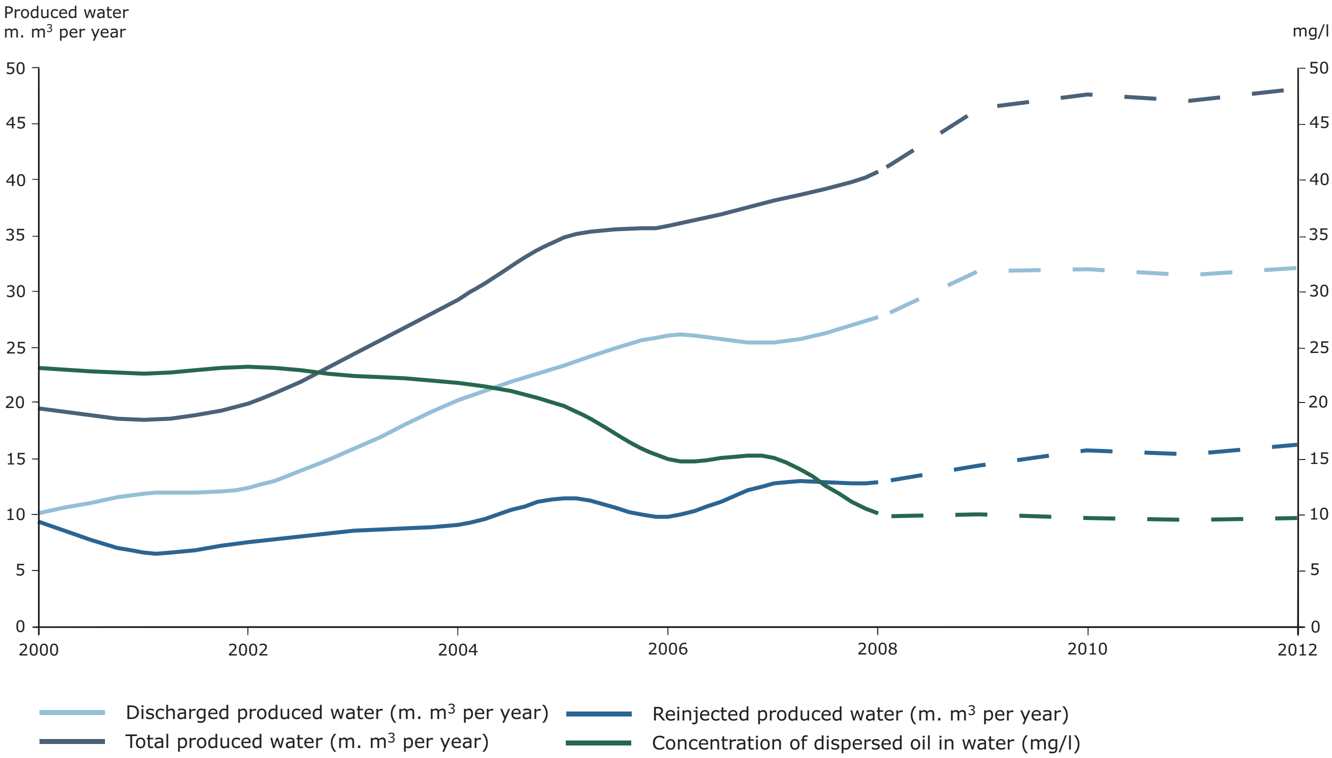
In sandstone fields, virtually all the produced water can be reinjected. In chalk fields, the reinjection of produced water can however adversely affect the quality of the reservoir and therefore harm recovery. An adequate understanding of the reservoir and the appropriate treatment of the produced water is therefore essential in order to increase reinjection. Most Danish hydrocarbon production originates from chalk fields.

The water content of production from an oil field increases over the life of a field and the production of water will therefore increase in future; see figure 4.10. The rising quantities of water represent an ongoing challenge, which will necessitate the increased treatment and reinjection of produced water.

finding process was initiated to investigate the possibilities of further reducing the discharge of dispersed oil in produced water.

The Danish Environmental Protection Agency regularly supervises the operators' compliance with the Offshore Action Plan and submits an annual status report to the Danish Parliament. Moreover, DONG E&P A/S, Hess Denmark ApS and Mærsk Olie og Gas AS prepare a publicly accessible report every year that accounts for the environmental impacts associated with oil and gas production in the Danish sector of the North Sea.

Fig. 4.10 Quantity of produced, discharged and reinjected water and the concentration of oil in discharged water



PIPELINE PROJECTS

Skanled – gas pipeline from Norway to Sweden and Denmark

The Skanled project envisaged building a gas pipeline from Norway to Sweden and Denmark. The Skanled project covers the construction of a 688 km 28" gas pipeline from Kårstø on the west coast of Norway to Sæby in Denmark through Norwegian, Swedish and Danish waters; see figure 4.11. The pipeline will have a branch to the east coast of Norway and three branches to Sweden. The pipeline will have a maximum capacity to Denmark of 4.7 billion Nm^3 per year.

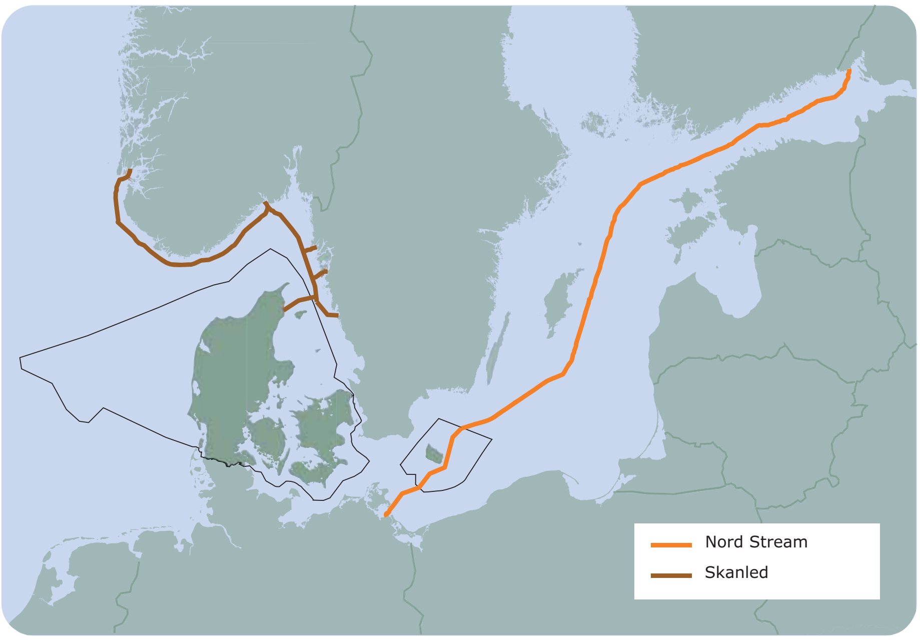
In Danish waters, the project will include 54 km of pipeline, which will be routed north of the island of Læsø in the Kattegat to the landing point south of Sæby. From the receiving terminal at the landfall, Energinet.dk is planning to establish a new onshore pipeline via Aalborg to the natural gas storage facility at Ll. Thorup and on to Egtved.

Behind the project is a consortium consisting of nine energy companies from Norway, Sweden, Denmark, Poland and Germany. Energinet.dk has a 10 per cent stake in the consortium. The Norwegian company Gassco AS is the project manager.

In connection with the Skanled project, investigations have been carried out with the aim of establishing the route of the gas pipeline and assessing the environmental impact of the project.

During the period November 2008 to January 2009, an Espoo consultation process was carried out (see box 4.4) in the three Nordic countries concerning the trans-

Fig. 4.11 Pipeline projects



boundary environmental impact of the Skanled project. The comments received during this consultation process will be presented in the final EIA report to be sent to the DEA together with an application for permission to build the pipeline.

On 29 April 2009, the Skanled consortium announced that the project had been suspended because of an increase in the commercial risk as well as global economic developments, which have resulted in uncertainty about the demand for gas.

Box 4.4

Espoo consultation process
The Convention of 25 February 1991 on Environmental Impact Assessment in a Transboundary Context, the Espoo (EIA) Convention, is aimed at preventing the adverse environmental impact of proposed activities across borders.

Consequently, the Espoo Convention contains provisions on environmental impact assessment (EIA), public participation and consultations between the affected countries to prevent, reduce and control significant adverse transboundary environmental impact.

In an Espoo consultation process, the public in the areas likely to be affected by a proposed project is given an opportunity to participate in the environmental impact assessment of the project, including in the areas affected in other countries.

Nord Stream – the gas pipeline project in the Baltic Sea
A consortium composed of the Russian company Gazprom (51 per cent), the German companies Wintershall (20 per cent) and E.ON Ruhrgas (20 per cent) and the Dutch

company Gasunie (9 per cent) is planning to establish two 48″ natural gas pipelines of 1,200 km through the Baltic Sea; see figure 4.11. The natural gas pipelines will run from Vyborg in Russia to Northern Germany at Greifswald east of Rügen and will pass through Finnish, Swedish and Danish territorial waters in the Baltic Sea.

The two pipelines will be capable of transporting a total of 55 billion Nm³ of natural gas per year, equivalent to approximately 11 per cent of the EU's consumption of natural gas in 2011. The two pipelines are to be commissioned in 2011 and 2012, respectively.

In Danish waters, 140 km of the 1,200 km pipelines will pass close to the island of Bornholm. Two routes have been discussed, with one route passing north and west of Bornholm and one route passing east and south of Bornholm. During the process, it has been vital for the Nord Stream consortium to ensure that the route avoids areas with dumped chemical and conventional ammunition.

Overall, the southeastern route has the lowest risk profile and environmental impact. The Nord Stream consortium has therefore submitted an application to route the two pipelines east and south of Bornholm.

The choice of the southeastern route will mean that the route will avoid the busy shipping route which passes north of Bornholm. This will reduce the risk of accidents after commissioning of the pipeline.

The southeastern route is also advantageous as regards minimizing the environmental impact, as the route will have the least environmental impact on the seabed.

Since 2006, Nord Stream, in partnership with the countries around the Baltic Sea, has worked on an EIA report, with the principal aim of describing the possible transboundary environmental impact of the two gas pipelines. The EIA report was distributed for comments through the Espoo consultation process (see box 4.4) within the Baltic countries during the period March to May 2009.

Nord Stream's application for permission for the Danish part of the project, together with a national EIA report, was also distributed for comments during the period 9 March to 8 May 2009. The comments received through the consultation process will be taken into account in the consideration of the application.

REMOVAL OF INSTALLATIONS

Oil and gas production from the Danish sector of the North Sea requires installations to be constructed and wells to be drilled. Once production is discontinued, the wells must be plugged and abandoned and the installations removed. This is a requirement under the licence conditions and the international treaties to which Denmark is a party. The aim of plugging and abandoning wells and removing installations is to prevent any impact on the environment and any disturbance to shipping and fishing operations.

As of 1 January 2009, the fields in the Danish sector of the North Sea comprised 423 production and injection wells and 54 platforms. An outline of wells and installations in the various fields is shown in appendix B. Moreover, there are plans to establish new installations in the Nini East, Elly, Amalie and Freja Fields. Most of the platforms are constructed of steel, while the South Arne platform is constructed of a combination of steel and concrete. In addition to the platforms, Danish installations comprise three subsea facilities on the seabed that are not located adjacent to a platform, viz. one in the Regnar Field and two in Stine segment 1. These subsea installations protect wells in fields that carry on production as satellites to a remote platform. The Regnar Field is the only field to have a buoy over the subsea installation.

Production from many of the fields is pooled and processed on one platform. Some fields have several platforms, some of which are interconnected by bridges. An extensive network of pipelines has been established to transport the oil, gas, condensate, chemicals and water associated with production. Figure 2.2 in chapter 2, *Production and development*, provides an overview of the key pipelines. Moreover, some of the platforms are connected by electrical cables.

When it is no longer viable to produce from a field, the installations must be shut down and removed. First, the installation must be emptied of residual oil, gas and chemicals. Then the abandoned wells must be plugged with cement. Any bridges to other platforms must be removed and transported to shore, and the pipelines connected to the platform must be cleaned, cut off and plugged. Subsequently, the topside facilities are cut off and lifted onto a barge for transport to shore. This allows the steel structure previously housing the topside facilities to be cut loose from the supporting piles in the seabed and transported to shore. Final cleaning takes place on shore, after which the installation is cut up into manageable sections to allow reuse of the steel.

No installations have been removed as yet in Denmark. A few pipelines have been decommissioned. After decommissioning, the pipelines were cleaned and the ends plugged.

The estimated costs of removing, cleaning and disposing of North Sea installations are substantial and must be paid by the installation owners. The DEA has estimated that the total cost of removing the existing installations in the Danish sector will amount to around DKK 29 billion in 2008 prices. In other words, this is the estimated cost if all installations had been removed in 2008.

The magnitude of the costs largely depends on the daily hire rates for the vessels used for the removal operation. Hire rates for crane vessels, diving vessels and drilling rigs have been very high in recent years due to the strong demand caused by high oil prices. Thus, when an installation is to be removed, the actual cost will depend on the hire rates payable for the vessels involved in the process and the US dollar exchange rate, as a high proportion of the costs is payable in USD.

As more experience is gained in the removal of installations, the efficiency of removal operations is expected to increase, thus resulting in lower costs. The simultaneous removal of several installations may also reduce costs.

Production from the North Sea fields is declining, and the first installations are expected to be decommissioned within a ten-year time horizon. Other installations may continue in operation until 2042, when the Sole Concession expires, or perhaps further into the future for as long as there are recoverable reserves.

5 HEALTH AND SAFETY

The Act on Health and Safety on Offshore Installations, the Offshore Safety Act, regulates the safety of offshore installations as well as the employees' health and safety. The DEA supervises compliance with the Offshore Safety Act.

The Offshore Safety Act replaced the Offshore Installations Act from 1981 and entered into force in July 2006.

The production installations in the Danish sector of the North Sea, as well as drilling rigs and miscellaneous vessels associated with oil and gas production, provide jobs for up to 3,000 people. The employees working offshore on a daily basis have a multitude of different skills and include welders, electricians, geologists, engineers, painters, scaffolders, catering staff, nurses, etc. The production installations in the 19 developed fields consist of about 54 platforms, some of which are interconnected by bridges, and three subsea installations.

High health and safety standards in the Danish offshore sector are vital to the people having their workplace on the offshore installations.

Together with the Danish Maritime Authority, the DEA supervises whether companies comply with existing health and safety legislation when conducting their oil and gas activities.

SUPERVISION STRATEGY

The DEA is to help ensure that the health and safety level associated with oil and gas production in the Danish offshore sector remain among the highest in the North Sea countries. Health and safety standards must be improved continuously so that they always meet technical and social requirements and reflect current developments in Danish society. The DEA uses health and safety supervision as a tool to ensure compliance with legislation.

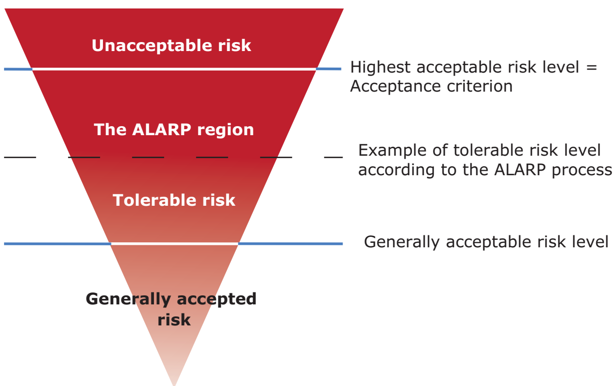
The DEA inspects all mobile units and manned fixed offshore installations at least once a year. The annual inspection is focused on health and safety issues on the offshore installation. Unmanned installations are inspected as and when required, for example when a drilling rig is positioned next to the installation.

The Danish Maritime Authority supervises life-saving appliances. On mobile offshore units, the Danish Maritime Authority also supervises safety issues of a "maritime nature", including the electrical installations on the unit, fire protection and life-saving appliances.

Risk analysis

The operators are responsible for continuously improving the health and safety of their personnel as well as the safety of installations and the environment. For this purpose, the operators carry out risk analyses in observance of the ALARP principle; see box 5.1.

Fig. 5.1 Risk levels of the ALARP principle



Previously, risk analysis was a tool used to establish that statutory requirements and limit values were observed. Now the operating company must continuously perform risk assessments and attempt to reduce risks whenever reasonably practicable. The aim is to ensure the implementation of improvements on a more contemporary basis.

Box 5.1

The ALARP principle and ALARP process
ALARP is an abbreviation of the expression "As Low As Reasonably Practicable", a principle used in the performance of risk analyses to denote risk reduced to the lowest, reasonably practicable level.

"As Low as Reasonably Practicable" means that the risk reduction achieved must be weighed against the cost of achieving it. Moreover, in evaluating whether it is reasonably practicable to make improvements, the technical and social development of society must be taken into account. This is in keeping with the principles of the Working Environment Act.

The ALARP principle operates with multiple levels of risk; see figure 5.1. Risks higher than the upper limit are unacceptable and must be reduced. All risks above the lower limit must be reduced wherever reasonably practicable. Risks under the lower limit are at a level generally perceived as acceptable. This process of reducing risks to an acceptable level is called the ALARP process.

In operational terms, the ALARP process involves companies having to define a risk profile by establishing the company's acceptance criteria for the highest level of risk accepted and the lowest level of risk intended, respectively. All specific requirements and instructions as well as threshold limit values in laws and regulations must naturally be observed.

Companies must then identify all health and safety risks. The company must subsequently assess whether it is possible to completely eliminate the health and safety risks identified. If the identified risks cannot be eliminated, the company must reduce them towards the lowest level of risk intended. This also applies in cases where the legislation contains no specific instructions or threshold limit values, but merely broad-based, functional requirements.

Supervision
The DEA supervises manned and unmanned fixed offshore installations, mobile units and pipelines.

A pivotal element of this supervision is the companies' health and safety management system. The companies must use this system to substantiate their compliance with existing legislation and regulations. The management system incorporates third-party verification, which must be carried out by acknowledged experts.

As part of the management system, the companies must ensure that the health and safety risks for persons working on or visiting offshore installations have been identified, assessed and reduced according to the ALARP principle. Moreover, the companies are required to ensure that health and safety risks on offshore installations are managed systematically.

The DEA carries out supervision in the form of project supervision, operations supervision and immediate inspections.

Project supervision
Project supervision consists of supervising development projects and modification projects.

Supervision of development projects covers the period from approval of the general design until the operating permit is issued. Supervision is performed via regular status meetings.

In addition, the DEA may monitor the companies' own supervision of their construction and installation contractors.

The DEA can also supervise third-party verification, checking how the verification procedure has been incorporated into the companies' management system.

Supervision of modification projects comprises the projects that the companies submit for the DEA's approval, viz. projects that will materially affect the risk of major accidents. In each case the DEA will determine whether to employ the procedure for supervising development projects or whether the approval of a modification project is unnecessary and can be replaced by follow-up supervision of operations.

Operations supervision
Operations supervision is performed as follows:
- Regular annual inspections of manned installations
- Inspections of unmanned offshore installations
- Supervision of special issues
- Unannounced inspections

Regular annual inspections of manned installations are targeted at working environment issues and the general safety of the installation. The DEA systematically follows up on the three focus areas: work-related accidents, hydrocarbon releases and the maintenance of safety-critical equipment. Moreover, the DEA supervises specific modification projects and implementation of the management system.

The DEA also performs inspections of unmanned offshore installations.

The supervision of special priority subjects is targeted at specific action areas, such as noise, process safety, musculoskeletal disorders, psychological working environment, the ageing of installations, etc. Such supervision is carried out on a continual basis and is directed at an individual installation, an individual operator or all operators in Denmark. One action area is the companies' management system, with supervision taking place mainly at the companies' onshore offices. Follow-up inspections may also be made on the offshore installations.

The DEA also carries out inspections without giving the usual 14-day period of notice (unannounced inspections) in connection with special activities or if a snapshot picture of the conditions is required. In such cases, the inspection will be aimed at a specific issue, limited in scope and of short duration.

Immediate inspections
Immediate inspections are offshore inspections made in case of incidents or near-miss occurrences that involve or could have involved serious personal injury or major property damage to an offshore installation. The operating company must notify the police immediately of such serious incidents or near-miss occurrences. The police will then notify the DEA. Next, the DEA will decide whether to carry out an immediate inspection to determine the more specific circumstances leading to the occurrence, the goal being to prevent repetitions.

Major releases of substances and materials that pose a health or safety hazard must also be reported immediately.

INSPECTIONS IN 2008
In 2008, the DEA carried out 24 offshore inspections, distributed on 15 inspections of manned production installations, one inspection of an unmanned production installation and eight inspections of mobile units, i.e. drilling rigs and accommodation units. Five of these inspections were unannounced. In addition, the DEA made eight inspection visits to operators and contractors on shore. Finally, the DEA carried out three inspections of drilling rigs in Norway, the UK and Singapore before granting them a permit to operate in the Danish area.

An outline of all inspections in 2008 is available at the DEA's website, www.ens.dk.

As in previous years, supervision in 2008 focused on work-related accidents, near-miss occurrences, hydrocarbon releases, the maintenance of safety-critical equipment and the companies' management systems.

Offshore inspections
Offshore inspections are targeted mainly at the individual company's health and safety management system.

The DEA usually gives the operating company about a fortnight's notice of inspections, but may also make unannounced inspections.

An offshore inspection typically comprises:

- An initial meeting with the safety organization
- A meeting with the safety representatives
- An interview of the management on board (Offshore Installation Manager, technical managers, medic, catering staff, etc.)
- A tour of the installation with a supervisor and a safety representative
- A final meeting with the safety organization

After the inspection, the DEA prepares a supervision report for submission to the company.

Unannounced inspections
In 2008, the DEA made unannounced inspections of the Halfdan B, Gorm, Siri and South Arne platforms and the ENSCO 70 drilling rig while it was stationed at the Siri

platform. The inspection of ENSCO 70 was made in continuation of an announced inspection of the Siri platform.

Unannounced inspections are made if announcing the inspection would compromise its purpose, for example when the DEA is checking compliance with resting periods, accommodation requirements and emergency procedures for increased manning of offshore installations, major painting projects, etc. Moreover, unannounced inspections are made if unlawful conditions are reported or if warranted by health and safety considerations.

The DEA focused on unannounced inspections in 2008. The evaluation of unannounced inspections in 2008 shows that no conditions were observed that deviated significantly from observations made at announced inspections. The DEA will continue to make unannounced inspections in future, as well.

Fire in the turbine, Tyra East, on 17 June 2008
A detector in the turbine air inlet registered gas above 20 per cent of the lower explosion limit (LEL), but there was no automatic shutdown of the turbine, as the fire and gas detection system near the turbine had been temporarily deactivated for reasons of maintenance. The detector showed the normal state approximately three seconds later.

Staff were sent to the site and saw smoke escaping from the noise attenuation cabin around the turbine and triggering the water mist system to cool the turbine/exhaust manifold.

Two fire watches were posted to ensure that the situation remained under control. After some 40 minutes the fire watches observed that the flange to which the exhaust manifold was fastened was red hot, and the fire watches started cooling the system with fire-extinguishing equipment through a door in the noise attenuation cabin. At the same time, the fire alarm was actuated manually from the control room and the crew mustered. The sprinkler system in the area was triggered and the processing plant depressurized in order to minimize the risk of fire and explosion.

At no point were flames observed in the noise attenuation cabin around the turbine or in the exhaust system. Similarly, there was no alarm from the turbine's heat detectors.

The company's provisional conclusion:
A serious mechanical breakdown in the gas turbine caused a momentary stoppage, resulting in a leak in the turbine's inner lubrication system, i.e. rupturing pipes, bearings and packing rings, etc. either in the turbine's compressor section or the combustion section.

At the same time, the oil pump, designed to lubricate and cool bearings, had been feeding in lubricating oil, setting off the fire and fuelling it due to the high temperatures, until the pump was stopped manually.

The turbine was subsequently sent to Great Britain for closer examination of the cause of the breakdown.

Work-related accident on the Energy Exerter drilling rig on 29 March 2008

The accident occurred in the course of dismantling the blowout preventer (BOP), designed to prevent uncontrolled blowout, in connection with a lifting operation. The lift was classified as a critical lifting operation, entailing a "blind lift" of a hose running from the drilling floor out across the Valdemar AB platform. The hose consisted of two parts joined by a coupling. A special hoist was used for the blind lift.

On the Valdemar platform, two people were standing 2-3 metres apart. One person had to keep an eye on the hose while the other had radio contact with the hoist operator. At some point the hose got caught up in scaffolding on Valdemar AB and the look-out (signal person) shouted "stop". The other person radio-relayed the message to the hoist operator, but the hose in the coupling simultaneously split and one section of the hose fell approximately 8-10 metres, hitting and injuring the look-out.

The injured person was evacuated to Skejby Hospital, where it turned out that he had fractured three vertebrae and received a gash to the head.

Immediately after being notified, the DEA went out to the rig to clarify the circumstances of the accident and arrived together with one representative from the police, the operator and the operating company. Among other things, it was observed that:

- The hose had been joined with a home-made coupling which had not been approved or evaluated by others.
- The person in charge of radio communications was unable to see that the hose was stuck in the Valdemar AB scaffolding, but had to learn this from the look-out, who was not in radio communication with the hoist operator, for which reason the stop message was delayed.
- The permit for the operation included a Safe Job Analysis, which should have been reviewed prior to starting the work. This was not done.
- There was no risk evaluation of the lift, and no lifting procedure had been established.

Based on the above and the subsequent police report, the DEA reported the incident to the police.

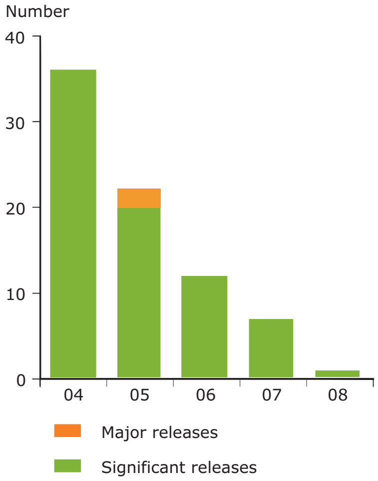
Work-related accident on Halfdan A on 2 July 2008

An employee was making his way up a 5 metre vertical ladder to a roughly 3 metre high scaffold landing. He was carrying an air hose weighing 5.4 kg over his left shoulder. Two rungs away from the scaffold landing he lost his grip on the ladder, fell over backwards and landed with his back on a wooden crate that had just been positioned on a pallet approximately 1 metre from the ladder.

The employee was wearing safety shoes, work gloves, a hardhat and safety goggles. The ladder was positioned vertically in order not to block an escape route and secured at the bottom with two straps. The DEA assesses the accident to be an unfortunate combination of the ladder being in the vertical position and the employee carrying a sizable roll of hose over one shoulder. These conditions will result in the employee falling over backwards if the grip on the ladder is lost. Furthermore, the roll of hose will inhibit the employee's movements and prevent him from obtaining a good grip on the ladder.

Since the accident, two of the company's procedures for using ladders and scaffolding have been changed.

Fig. 5.2 Accidental hydrocarbon releases, 2004-2008



Box 5.2

Categories of reportable hydrocarbon releases

Major releases
A quantity of more than 300 kg or a release rate of more than 1 kg/sec. for more than 5 minutes

Significant releases
A quantity of 1-300 kg or a release rate of 0.1-1 kg/sec. for 2-5 minutes

Box 5.3

Reporting work-related accidents
Work-related accidents resulting in incapacity to work for one or more days beyond the injury date must be reported.

Employers are obliged to report accidents, but all other parties are entitled to file reports.

"An injured person who is unable to fully perform his or her ordinary duties" is considered to be unfit for work.

Immediate inspections
In 2008, the DEA carried out an immediate inspection of Tyra East in connection with a fire in a turbine. Immediate inspections of the Energy Exerter drilling rig and Halfdan A were made to follow up on work-related accidents.

Maintenance of safety-critical equipment
At its offshore inspections in 2008, the DEA continued its practice of checking whether the operators adhere to their plans for maintaining installations and equipment, with particular focus on safety-critical equipment.

Safety-critical equipment is equipment where a single failure would involve a serious risk of major accidents. It includes equipment used in systems for fire and gas detection, for the shutdown and depressurization of processing plants and for fire-fighting and evacuation, as well as general safety equipment.

Supervision in 2008 showed that not all operators maintain safety-critical equipment in accordance with their time schedules. The DEA has cautioned the relevant operating companies and will pay special attention to these companies' maintenance in 2009.

Supervision will continue to focus on the maintenance of safety-critical equipment in 2009.

Hydrocarbon releases
The operating companies are obliged to register all hydrocarbon releases and to report releases above a certain limit to the DEA immediately. From June 2008, hydrocarbon releases must be reported in two categories, *major releases* and *significant releases*. The new categories of reportable hydrocarbon releases are shown in box 5.2 and correspond to the categories used in the other North Sea countries.

Only one significant hydrocarbon release was reported in 2008. It was of short duration and had a release rate of 0.7 kg/sec., occurring from an instrument tube. The production installation was shut down manually before the detectors were able to record a gas concentration that would shut down the installation automatically.

Since the DEA targeted its focus at accidental hydrocarbon releases, the total number of releases has dropped from 36 in 2004 to one release in 2008; see figure 5.2. This decrease shows that the companies' efforts to reduce accidental hydrocarbon releases have been efficient.

WORK-RELATED INJURIES
Work-related injury is a generic term for work-related accidents and work-related diseases. Work-related accidents on offshore installations must be reported to the DEA. Doctors are under a duty to report work-related diseases to the DEA, the Danish Working Environment Authority and the National Board of Industrial Injuries.

Work-related accidents
The DEA registers and processes all reported work-related accidents on Danish offshore installations and evaluates the follow-up procedures taken by the companies. At the DEA's first inspection after an accident, the work-related accident is addressed at a meeting with the safety organization on the installation. In case of serious accidents, the DEA carries out immediate inspections in cooperation with the police; see also the sections *Supervision* and *Inspections in 2008*.

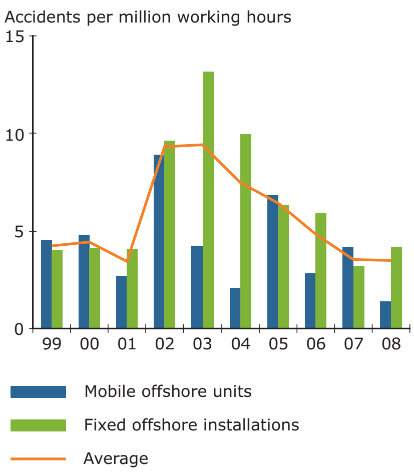
Table 5.1 Reported accidents broken down by cause of accident for 2008

Cause of accident	Fixed	Mobile
Falling/tripping	8	0
Use of work equipment	2	0
Handling goods	2	0
Crane and lifting operations	1	2
Falling object	2	0
Other	3	0
Total	**18**	**2**

Table 5.2 Actual absence due to reported work-related accidents for 2008

Duration	Fixed	Mobile
1-3 days	0	0
4-14 days	4	1
2-5 weeks	6	0
More than 5 weeks	8	1
Total	**18**	**2**

Fig. 5.4 On- and offshore accident frequency



The aim of the DEA's follow-up on work-related accidents is to ensure that the companies and their safety organizations take concerted action to reinforce preventive measures on offshore installations.

In 2008, the DEA registered a total of 20 reports concerning work-related accidents, 18 on fixed offshore installations, including mobile accommodation units, and two on other mobile offshore units. The accidents are broken down by category in table 5.1 and figure 5.3.

Fig. 5.3 Comparison between accidents reported in 2005, 2006, 2007 and 2008 for offshore installations broken down by cause of accident

Table 5.2 indicates the actual periods of absence from work attributable to the accidents reported, broken down on fixed and mobile offshore units.

In previous years, the DEA received a few delayed reports of work-related accidents, usually because the consequences of an incident appear later. This means that the accidents were reported too late to be included in the DEA's report "Oil and Gas Production in Denmark" for the relevant year. During the period from 1999 to 2007, the DEA received a total of five delayed reports concerning work-related accidents, four of which were received in 2004. One of these accidents had occurred in 2002 and the remaining three in 2003. In addition, the DEA received a report in 2005 concerning an accident occurring in 2004.

The DEA has decided to change its procedure in future, which means that future annual reports will restate the figures for work-related accidents to include accidents reported belatedly, in accordance with the procedure used for onshore accidents. Thus, work-related accidents occurring in 2008, but reported in a later year, will be included in future annual reports.

Therefore, the DEA has adjusted figure 5.4, which now also reflects the work-related accidents from previous years that were reported in a later year.

Accident frequency

Every year, the DEA calculates the overall accident frequency, which is the number of accidents reported per million working hours.

The accident frequencies for fixed offshore installations and mobile offshore units in recent years appear from figure 5.4. The overall accident frequency for mobile units

and fixed offshore installations came to 3.5 in 2008. This is about the same level as in 2007, when the accident frequency was 3.6.

For mobile offshore units, two work-related accidents were recorded in 2008, and the number of working hours totalled 1.42 million. Thus, the accident frequency for mobile offshore units decreased from 4.2 in 2007 to 1.4 in 2008.

The number of work-related accidents on fixed offshore installations and mobile accommodation units totalled 18 in 2008. The operating companies have stated that the number of working hours totalled 4.32 million on these offshore installations. The accident frequency for fixed offshore installations is thus 4.2 for 2008, an increase on 2007 when the accident frequency came to 3.2.

Because of the relatively low number of accidents on offshore installations, merely a few accidents may change the picture from year to year. Thus, the trend over a number of years, and not the development from one year to another, provides the impression of any genuine decline in the accident frequency.

Work-related accident in connection with valve painting work on 28 Nov. 2008
On Tyra East an employee was working on a valve suspended from a hook. The valve weighed approximately 30-35 kg. During the work, the employee needed to rotate the valve, which resulted in the hook straightening out and the valve falling onto the employee's foot.

It transpired that the valve was suspended from a non-approved item of equipment. The incident has subsequently been examined at the safety meetings, and the need to adopt correct lifting equipment procedures at all times has been impressed upon workers.

At its next inspection, the DEA will investigate whether the operating company's follow-up to the accident has been adequate.

Work-related accident due to lack of cordoning on 15 January 2008
An employee on Tyra West was injured when he stepped down into an uncordoned hole on which the cover had been removed. The employee fractured a bone in the left ankle.

The employee had been called in to shut off a valve. Just prior to that, the team of welders had lifted the cover to allow access to close the valve. The hole was not cordoned off and the injured person was therefore unaware that the cover had been removed when he arrived on the spot.

The accident occurred because the employee, who was not part of the welders' team, had unhindered access to a working area where the aperture created was known only to the welders' team.

The company has subsequently amended the procedure for short-term removal of small-size hatches and grilles, so that these will always be cordoned off in future. At its inspection of the installation in November 2008, the DEA ascertained that the procedure had been implemented satisfactorily.

Onshore accident frequency

The DEA has compared the accident frequency on Danish offshore installations with the onshore accident frequency, as shown in table 5.3.

Table 5.3 Accident frequencies in Danish offshore and onshore industries

Industry	Frequency				
	2004	2005	2006	2007	2008
Offshore installations*	7.1	6.4	4.9	3.6	3.5
Total onshore industries	10.2	11.0	11.2	11.0	
Of which:					
- Shipyards	38.5	50.6	57.6	47.4	
- Earthwork, building and road construction	21.3	23.5	24.0	23.5	
- Masonry, joinery and carpentry	15.0	18.0	17.5	16.7	
- Insulation and installation work	16.1	18.7	18.9	19.8	
- Chemical industry	12.4	13.1	12.2	15.4	
- Heavy raw materials and semi-manufactures**	12.7	12.1	11.1	14.5	

*) *Overall accident frequency for fixed offshore installations and mobile offshore units.*

**) *"Heavy raw materials and semi-manufactures" covers many industries. For example, some of the subgroups within "Heavy raw materials and semi-manufactures" include the extraction of crude oil and natural gas and technical services related to oil and gas extraction activities.*

Box 5.4

Work-related accidents calculated by the Danish Working Environment Authority

The Danish Working Environment Authority calculates the incidence of work-related accidents for onshore industries in Denmark on the basis of the number of accidents reported proportionate to the entire workforce, i.e. the number of employees. The Danish Working Environment Authority uses register-based labour force statistics from Statistics Denmark ("RAS statistics"), which are workforce statistics indicating the number of persons who have their main job in the relevant industries in November of the year preceding the year of calculation. The annual statistics compiled by the Danish Working Environment Authority indicate the incidence per 10,000 employees. Thus, for all onshore industries, the incidence was 173 reports per 10,000 employees in 2007.

This incidence is not directly comparable with the calculation of accidents relative to the number of hours worked (for example, per 1 million working hours). Converting the number of employees to the number of working hours would only result in an approximation, as it is assumed that one employee corresponds to one full-time equivalent (FTE). The figures for onshore companies are converted on the assumptions that the total number of working days is 222 days per year and that each working day averages 7.12 working hours, a full-time equivalent of 1,580 hours.

A total of 48,882 work-related accidents were reported for onshore companies in 2007. With a workforce of 2,821,641 employees (~ approx. 4.5 billion working hours) in 2007 (November 2006), the accident frequency in 2007 for all 50 onshore industries can be calculated at 11.0 reports per 1 million working hours. The calculation is based on the assumptions described in box 5.4. The Danish Working Environment Authority has not yet calculated the number of work-related accidents and the number of employees for 2008.

Work-related diseases

A work-related disease is defined as an illness or a disease that is due to long-term exposure to work-related factors or the conditions under which the work is performed on the offshore installation.

As from 1 July 2008, doctors have been obliged to report all diagnosed or suspected work-related diseases contracted in connection with work on offshore installations to the DEA. In addition, doctors must still report work-related diseases to the Danish Working Environment Authority and the National Board of Industrial Injuries.

The Danish Working Environment Authority has completed its work regarding work-related diseases for 2007, but has not yet published statistics for 2008

For 2007, the DEA received 12 reports on suspected work-related diseases from the Danish Working Environment Authority, based on a doctor's assessment that the relevant work-related disease was primarily contracted due to work on an offshore installation. By comparison, ten suspected work-related diseases were reported in 2006. The diseases reported for 2007 are distributed on three hearing injuries, seven musculoskeletal disorders and two stress-related diseases.

Over the years, the DEA has focused on issues related to noise and musculoskeletal disorders and will continue to focus on these issues in future with the aim of reducing suspected work-related diseases in the offshore sector. The Government's action plan for the period through 2010 also prioritizes these working environment issues.

NEAR-MISS OCCURRENCES

Major near-miss occurrences must be reported to the DEA; see box 5.5. In 2008, the DEA received a total of 27 reports on near-miss occurrences, a drop compared to 2007, but still a significantly higher number than in previous years. The changed number of reports is not considered to reflect a change in the number of occurrences, but rather indicates that the companies raised the reporting level in 2008 as compared to previous years. The number of reports also indicates the continued focus on learning from occurrences and the employees' awareness of safety issues.

Box 5.5

Reporting near-miss occurrences

Near-miss occurrences are defined as occurrences that could have directly led to an accident involving personal injury or damage to the offshore installation. The occurrences to be reported to the DEA are specified in the Guidelines on Reporting Accidents, available at the DEA's website, www.ens.dk.

Hydrocarbon releases are also defined as near-miss occurrences, and the DEA received one report on a hydrocarbon release in the "significant release" category in 2008; see the section *Inspections in 2008*.

Collision with the Halfdan DB platform on 9 December 2008
A supply vessel came into contact with one of the legs of the Halfdan DB accommodation platform. The cause was a failure in the vessel's bow propeller. The contact involved only negligible damage, including a bent ladder on the installation. The DEA will follow up the incident at its next inspection of Halfdan D.

Any damage to the vessel falls under the Danish Maritime Authority's province of authority.

Near-miss occurrence on Tyra East on 1 December 2008
A welder on Tyra East was working in a tent below the production deck. The welder opened a bottle of propane gas to pre-heat the structure. He lit the spark igniter and then discovered fire around him. Attempting to shut off the valve on the propane gas bottle, he noticed flames darting out of the bottle at right angles. Since the employee was unable to extinguish the fire himself, he left the tent and alerted the fire watch, who had the situation under control seven minutes later.

The company has subsequently informed the DEA that ten recommendations have been drawn up, including changes to procedures to be followed in future in order to prevent any possible repeat of a similar situation.

The DEA has followed the company's investigations into the incident and agrees with the recommendations, which have now been implemented.

APPROVALS AND PERMITS GRANTED PURSUANT TO THE OFFSHORE SAFETY ACT IN 2008

The supervision of health and safety on fixed and mobile offshore units in the Danish sector of the North Sea also involves granting approvals and permits for design, commissioning and modifications that impact the risk of major accidents, as well as for the decommissioning of offshore installations.

When designing an offshore installation, the operator must attempt to minimize the risk of accidents occurring during the operation of the finished installation. Before a fixed offshore installation is built, the DEA must approve the general design on the basis of an application that includes a Health and Safety Case (HSC) for the installation; see box 5.6.

The HSC is updated concurrently with details about health and safety matters becoming available during the design, fabrication and installation phases. The DEA supervises the project throughout all these phases and subsequently supervises the operation of the installation.

In 2008, the DEA issued the following approvals:

The Halfdan Field
The general design of a new processing platform, Halfdan BD, was approved. Halfdan BD will be connected by a bridge to Halfdan BA and located approximately 100 m southwest of Halfdan BA. The Halfdan BD processing platform will be equipped with a control room and various processing equipment. The platform is expected to be commissioned in 2011.

Permits were issued for the installation of a new wellhead module on the Halfdan BB platform, the commissioning of a new crane, also on Halfdan BB, and increased manning on Halfdan BA and Halfdan BB.

The Dan Field
Following the commissioning of the well caisson (protection for the conductors), slots and wellhead module at the western flank of the Dan Field, a new operating permit was issued in March 2008 for the Dan F installation.

The Nini Field
Development and production from the Nini East accumulation was approved in January 2008. The approval also covers the general design of a new production platform and pipelines to the existing Nini platform. The Nini East platform and associated pipelines are expected to be installed during 2009. The template for the Nini East wells was installed in November 2008.

The water-injection pipeline from Siri to Nini has been damaged, and in July 2008 the DEA permitted replacement of the pipeline, which is expected to be carried out in 2009.

The Tyra Field
Permission has been granted to strengthen the load-bearing structure and establish a new boat-landing facility for the Tyra East A platform.

Permission has been granted to operate at low pressure in the Harald Field.

The original permit to commission the unmanned production platform Valdemar BA was subject to the establishment of a bridge link between the Valdemar BA platform and the Noble Byron Welliver drilling rig, as the drilling rig was also used for accommodation purposes for personnel working on Valdemar BA. In 2008, Noble Byron Welliver was moved from Valdemar BA, and a new operating permit without any condition concerning a bridge link to the drilling rig was therefore issued.

Mobile units
In 2008, an operating permit was issued for the ENSCO 71 drilling rig, and the operating permit for the ENSCO 101 drilling rig was renewed. A five-year operating permit was also granted for the Noble Byron Welliver drilling rig. In addition, an operating permit was issued for the completely new drilling rig Mærsk Resolute.

Moreover, the operating permit for the Safe Esbjerg flotel, which is located at the Gorm Field, has been renewed.

Box 5.6

Approvals and permits in the lifecycle of a fixed offshore installation

A number of approvals and permits must be obtained from the DEA for the purpose of developing a hydrocarbon discovery into a field, commissioning the installation and finally closing down the field and decommissioning the installation; see figure 5.5. In the interim period between approvals, the DEA supervises the operating company's compliance with regulatory requirements and its own health and safety procedures.

Section 10 of the Subsoil Act stipulates that oil and gas production must be carried on in a manner that prevents any waste of hydrocarbons. To meet this requirement, the operator must submit a development plan to the DEA for approval before starting to develop a discovery. The development plan must include a production plan and a description of the installations. The operator must submit a new development plan for approval if further developing the field. Approvals granted pursuant to the Subsoil Act in 2008 are described in chapter 2, *Production and development*.

The Offshore Safety Act stipulates that an approval must be granted before the development of an installation can be initiated. This approval is granted in pursuance of section 27 of the Offshore Safety Act and must ensure that health and safety aspects are factored into the general design phase. The pertinent application must include the Health and Safety Case (HSC) and an overall time schedule for fabrication and installation.

As a minimum, a Health and Safety Case must include:

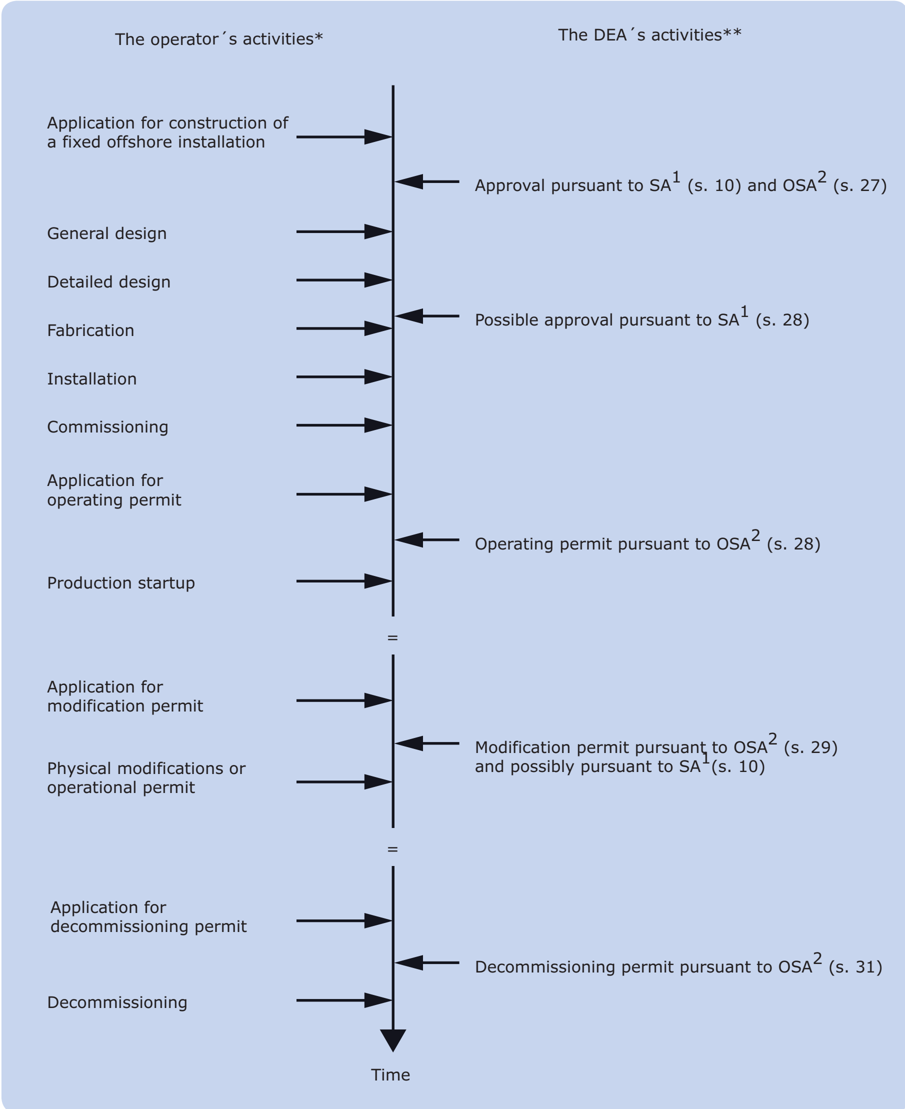
- A detailed description of the offshore installation and its operating conditions.
- A detailed description of the health and safety management system, which is to ensure and substantiate compliance with legislation in both normal and critical situations.
- An identification of the risks of major accidents and harmful effects on the working environment.
- An assessment of the risks and documentation showing that such risks are "as low as reasonably practicable" (ALARP).
- Documentation showing that employees can be evacuated to a safe place in an efficient and controlled manner in critical situations.

The HSC must be updated whenever the health and safety conditions on the installation are changed significantly. In accordance with section 29 of the Offshore Safety Act, an application for permission to carry out any changes materially affecting the risk of major accidents on the installation must be submitted beforehand. Such changes may consist of physical modifications of the installation or changes to the operational conditions on the installation.

Before commissioning the installation, the operator must obtain an operating permit in accordance with section 28 of the Offshore Safety Act.

When a field is ultimately to be closed down and the installation decommissioned, the operator must apply for a permit in accordance with section 31 of the Offshore Safety Act.

Fig. 5.5 Timeline for approvals and permits in the lifecycle of a fixed offshore installation



* The operator prepares and updates the Health and Safety Case (HSC) for the installation
** In addition, the DEA supervises the installation throughout its lifecycle
1 SA: The Subsoil Act
2 OSA: The Offshore Safety Act

AMENDED OFFSHORE SAFETY ACT

The Act on Health and Safety on Offshore Installations, the Offshore Safety Act, regulates the safety of offshore installations as well as employees' health and safety.

A Bill to amend the Offshore Safety Act was put forward in the Danish Parliament at the end of 2008. The Act has been passed and will enter into force on 1 July 2009.

The amendment clarifies when licensees are to apply for approval or permission for the construction of new installations, extensions or the commissioning and modification of existing offshore installations. The clarified rules contribute to higher safety standards for modification projects for existing fixed offshore installations, as the supervisory authority will be involved in such projects at an earlier stage in future.

Box 5.7

Offshore Safety Council
The Offshore Safety Council, appointed under section 58 of the Danish Offshore Safety Act, is to assist in laying down rules pursuant to the Act, follow the technical and social development concerning offshore installations and discuss other conditions covered by the Act.

The Offshore Safety Council consists of a chairman and 19 members representing public authorities and employer and employee federations.

Moreover, as a consequence of the amendment to the Act, the Minister for Climate and Energy will have the same powers to issue rules regarding the recognition of professional qualifications for work on offshore installations as the Minister for Employment has onshore. The rules on recognition will be discussed with the parties in the Offshore Safety Council; see box 5.7.

Finally, the provision regarding the use of recognized norms and standards will be extended to apply in general to the construction, arrangement and equipment of offshore installations. This amended provision will also contribute to heightening the safety level for offshore installations.

The Offshore Safety Act, which was passed with the support of all parties in the Danish Parliament in December 2005, replaced the previous Offshore Installations Act. Some of the provisions in the old Act have been maintained, and the work on updating these provisions is still ongoing. The new provisions are being prepared by the DEA in consultation with the two sides of industry represented on the Offshore Safety Council; see box 5.7.

6 RESERVES

The DEA makes an assessment of Danish oil and gas reserves annually. At 1 January 2009, oil reserves were estimated at 200 million m³ and gas reserves at 107 billion Nm³.

The DEA's new assessment shows a decline in oil reserves of 7 per cent and an increase in gas reserves of 2 per cent, compared to the assessment made at 1 January 2008. The 14 million m³ decrease in oil reserves is mainly attributable to production in 2008.

Estimated ultimate recovery of gas has been written up by 12 billion Nm³ compared to last year's assessment. Gas production amounted to 10 billion Nm³ in 2008, and gas reserves have thus increased by 2 billion Nm³.

At 1 January 2009, 331 million m³ of oil had been produced, with oil reserves amounting to 200 million m³. Accordingly, total production during the period 1972-2008 amounts to 62 per cent of the expected ultimate recovery from known fields and discoveries; see figure 6.1.

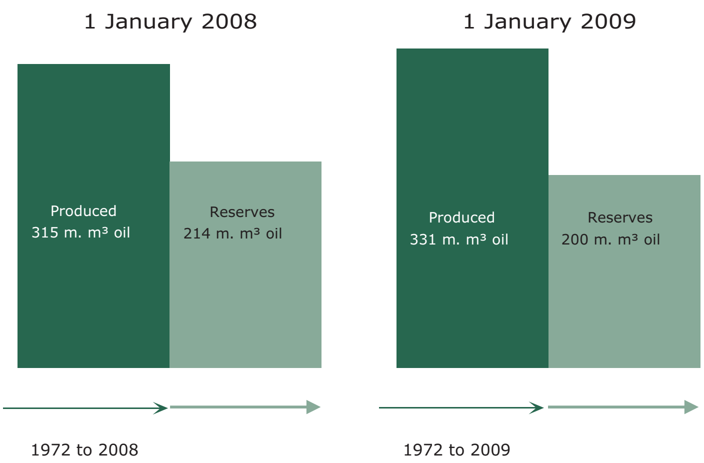
Appendix C shows the DEA's reserves assessment at 1 January 2009. As a result of developments in international practice for assessing oil and gas reserves, some operators have changed their method of assessment. This has led to changes in the oil companies' reports that form the basis for the DEA's reserves assessment. Consequently, the DEA can no longer include a high estimate of oil and gas reserves in appendix C. The DEA intends to launch a work process to clarify the principles for its future reserves assessments.

Technological developments and any new discoveries resulting from exploration activity, including under the licences from the 6th Licensing Round, may add new reserves to future assessments.

Five-year production forecast
For the purpose of its annual report, the DEA prepares a five-year forecast for the production of oil and natural gas. This forecast is revised every autumn.

Oil
For 2009, oil production is expected to total 15.5 million m³, equal to about 267,000 barrels of oil per day; see table 6.1. This is a reduction of 7 per cent relative to 2008,

Fig. 6.1 Oil production and oil reserves



when oil production totalled 16.7 million m³. Compared to last year's forecast for 2009, this is a 3 per cent upward adjustment, which is due mainly to increased production estimates for the Skjold and South Arne Fields.

Oil production is expected to decline further from 2009 to 2013. The production estimates have not been changed significantly from last year's forecast for 2009 and 2010, while the production estimates for the period 2011-2013 have been written down by 19 per cent on average compared to last year. The writedown is primarily attributable to reduced expectations for production from the Dan and Halfdan Fields and postponed production startup of the Hejre discovery.

Natural gas

Natural gas production is estimated at 8.5 billion Nm³ for 2009; see table 6.1. The production estimates have not been changed significantly from last year's forecast for the period 2009-2011, while the production estimates for 2012 and 2013 have been written down by 13 per cent on average compared to last year. The writedown is primarily attributable to postponed production startup of the Hejre discovery.

Table 6.1 Expected production of oil and natural gas

	2009	2010	2011	2012	2013
Oil, million m³	15.5	15.0	13.6	12.4	11.0
Natural gas, billion Nm³	8.5	8.2	7.2	6.2	5.1

Degrees of self-sufficiency for the next five years

Denmark has been net self-sufficient in energy since 1997. Denmark is self-sufficient in energy when energy production exceeds energy consumption, calculated on the basis of energy statistics.

The consumption of various energy products is not distributed in the same way as energy production, and therefore some products are imported even though Denmark is self-sufficient in energy, taken overall.

In 2007 and 2008, the total production of oil, gas and renewable energy exceeded total energy consumption by 30 per cent. This degree of self-sufficiency can be maintained because declining energy production is offset by a corresponding decrease in energy consumption.

In 2008, oil and gas production was 14 per cent higher than total energy consumption and 91 per cent higher than total oil and gas consumption.

Table 6.2 shows the development in the degrees of self-sufficiency projected by the DEA for the next five years. The consumption estimate indicated derives from "The DEA's baseline scenario, April 2009".

Compared to the corresponding figures published in "Oil and Gas Production in Denmark 2007", the expected degrees of self-sufficiency in the table show a generally declining trend. The main reason for this decline is the writedown of oil and gas production estimates compared to last year's estimates.

Table 6.2 Degrees of self-sufficiency

	2009	2010	2011	2012	2013
Production in PJ					
Oil	573	555	502	457	405
Gas	365	352	312	272	231
Renewable energy	168	183	195	203	212
Total	**1,106**	**1,090**	**1,009**	**932**	**847**
Energy consumption in PJ	866	869	855	847	834
Degrees of self-sufficiency, per cent					
A	178	179	163	149	133
B	108	104	95	86	76
C	128	125	118	110	102

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

Twenty-year production forecast

Every year, the DEA prepares a 20-year forecast for the production of oil and natural gas, based on the reserves assessment. The forecast is subdivided into a contribution from oil reserves and a contribution from natural gas reserves.

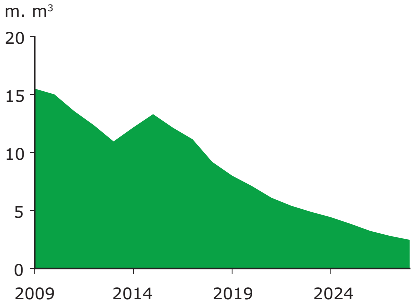
A forecast covering 20 years is most reliable in the first part of the period. The methods used in making the forecast imply that production will decline after a short number of years.

For oil, the contribution from reserves shows a generally declining trend; see figure 6.2. However, production is expected to increase in 2014 and 2015 due to the development of new fields and the further development of some existing fields. Ten and 15 years from now, production is expected to constitute about 50 and 25 per cent of production in 2008, respectively.

However, this decline is expected to be curbed due to technological developments that may improve recovery from the fields covered by the forecasts and due to any new discoveries made as part of the ongoing exploration activity, including under the licences from the 6th Licensing Round.

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.

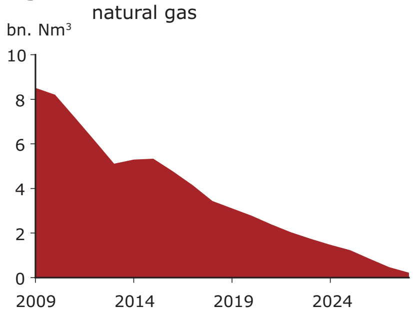
Fig. 6.2 Contribution from reserves, oil



Since the start of gas sales in 1984, natural gas produced under A.P. Møller's Sole Concession has been supplied primarily 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 Hess Denmark ApS 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.

Fig. 6.3 Contribution from reserves, natural gas



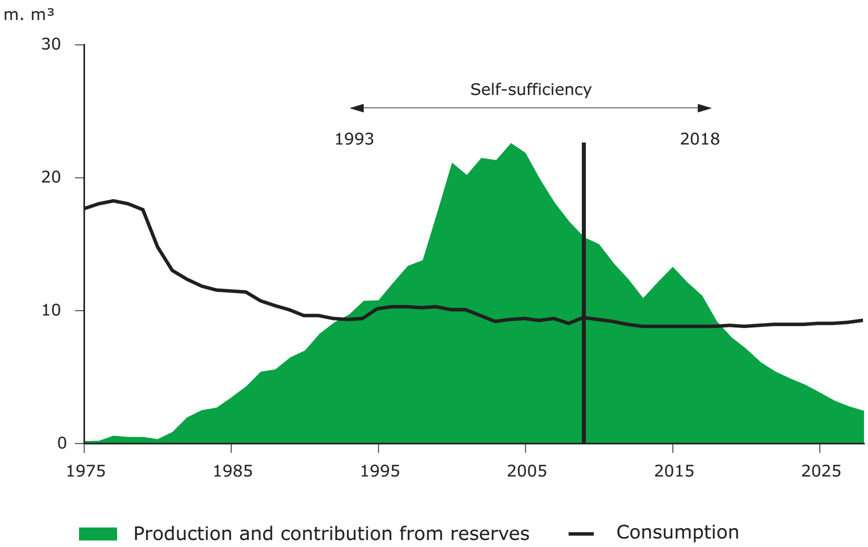
In addition, the forecast includes the natural gas production resulting from contracts for the export of gas through the pipeline from Tyra West via the NOGAT pipeline to the Netherlands.

Figure 6.3 shows the contribution from reserves for natural gas. Like oil, natural gas production is expected to show a general declining trend. Production is anticipated to increase slightly in 2014 and 2015 and subsequently to decline.

Degrees of self-sufficiency for the next 20 years

The DEA prepares forecasts for the consumption of oil and natural gas in Denmark. Figure 6.4 shows the amount of oil produced and historical consumption. In addition, the contribution from reserves and the DEA's consumption forecast appear from "The DEA's baseline scenario, April 2009".

Fig. 6.4 Oil production and contribution from reserves



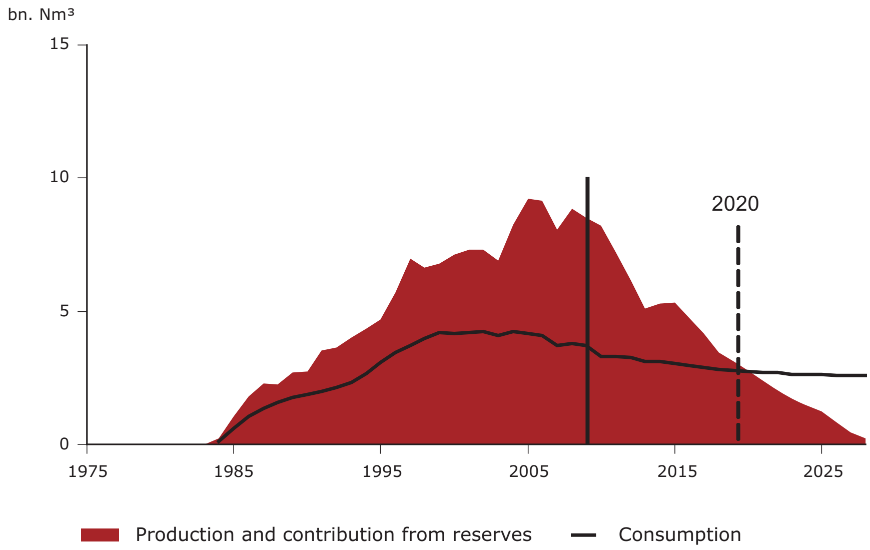
The forecasts of consumption and production diverge significantly. The consumption forecast shows an almost constant trend, while the production forecast indicates a marked downward trend, apart from a few years in the first half of the forecast period when production is expected to increase. Production shows a declining trend because the forecast does not include the further development of known fields by means of new technology or the development of new discoveries.

On the basis of these production assumptions, Denmark is expected to be self-sufficient in oil up to and including 2018.

The natural gas forecasts illustrate a scenario similar to the oil forecasts. Based on the contribution from reserves, Denmark is forecast to be self-sufficient in natural gas up to and including 2020; see figure 6.5.

However, technological developments and any new discoveries made as part of the ongoing exploration activity are expected to contribute with additional production and thus prolong Denmark's period of self-sufficiency in oil and natural gas; see below.

Fig. 6.5 Natural gas production and contribution from reserves



RESOURCES

An estimate of Danish oil and gas resources can be subdivided into three components:

A contribution from reserves, which is calculated on the basis of the volumes of oil and gas that can be recovered from known fields and discoveries by means of existing production methods.

A contribution from technological developments, estimated on the basis of the additional volumes of oil and gas likely to be recovered by means of new technology.

A contribution from exploration, estimated on the basis of the additional volumes of oil and gas likely to be recovered from new discoveries.

It should be emphasized that estimates of the contributions from technological developments and exploration are subject to great uncertainty.

The DEA's estimate of the contribution from technological developments for oil is based on a 5 percentage point increase of the average recovery factor for Danish fields. The average recovery factor is the ratio of ultimate recovery to total oil-in-place. Based on the reserves assessment, the average expected recovery factor for oil is 23 per cent today.

The assumption that the average recovery factor for oil can be increased by 5 percentage points is based on an evaluation of historical developments. Thus, the average recovery factor increased by 9 percentage points during the period from 1990 to 2000, but has not increased significantly since 2000. However, it is very difficult to foresee which new techniques will contribute to additional production in future or to estimate the impact of these techniques on production.

The report from May 2005 that analyzed oil and natural gas resources is a background report to "Energy Strategy 2025". This report assumed that the contribution from technological developments would correspond to a 5 percentage point increase of the recovery factor, based on the relatively low oil price prevailing at that time. It was also emphasized in the report that a relatively high oil price would provide a major incentive to develop new techniques.

New recovery methods must be implemented while the fields are still producing. Once a field has been closed down, it will usually not be financially viable to introduce new technology. This means that a limited period is available for the development and introduction of new methods.

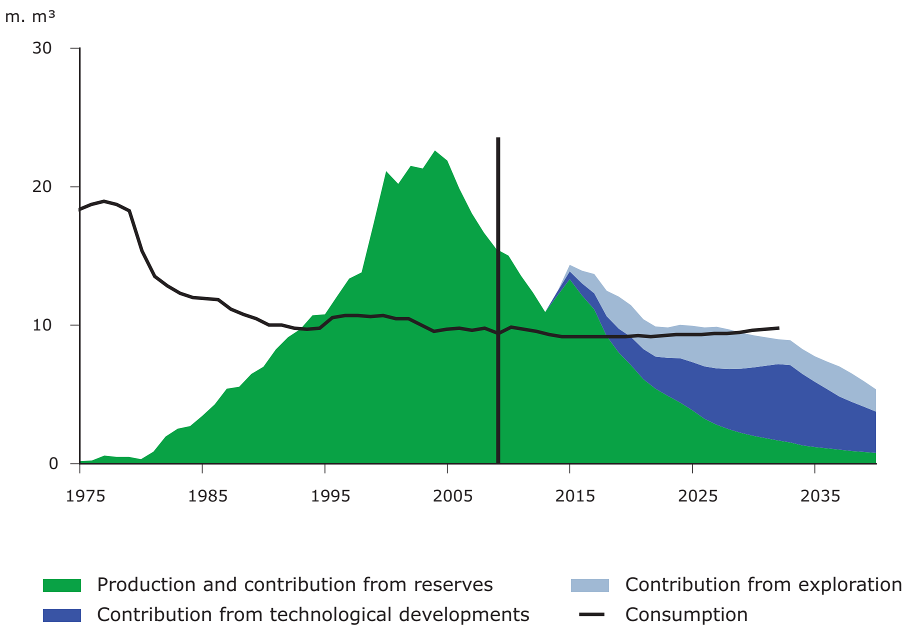
Most of the 5 per cent contribution from technological developments is expected to derive from new techniques used for injecting CO_2 into the large producing fields where recovery is based on water injection, while the remaining minor contributions will derive from other technological initiatives. It has been assumed that CO_2 injection will not contribute to production until the period from 2020-25. The remaining contributions to increased production are assumed to be spread over the forecast period.

The DEA's estimate of the contribution from exploration stems from a new assessment of the exploration potential from the beginning of 2009. This assessment is based on the exploration prospects known today and assessments of the additional reserves expected to be found during the forecast period. The exploration potential is estimated at 60 million m³ of oil and 45 billion Nm³ of gas.

The DEA intends to launch a work process to clarify the principles for its future assessments of contributions from technological developments and exploration and to initiate an evaluation of Denmark's self-sufficiency outlook.

The DEA's oil production forecast consists of contributions from reserves, technological developments and exploration; see figure 6.6. The figure also shows the consumption forecast from "The DEA's baseline scenario, April 2009". It appears from the figure that Denmark is anticipated to be self-sufficient in oil for ten years up to

Fig. 6.6 Oil production and production forecast

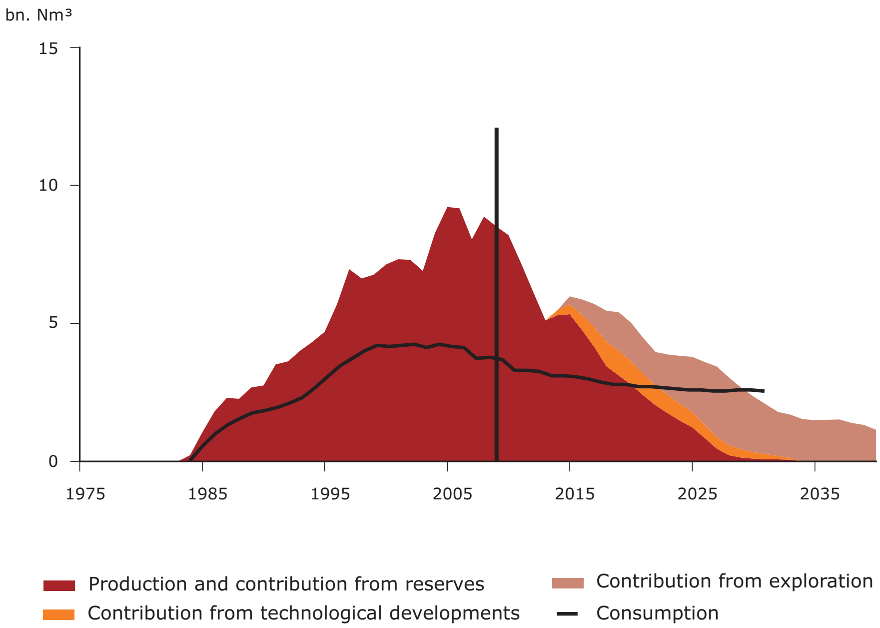


and including 2018, based on the contribution from reserves. The extent of self-sufficiency based on the contribution from reserves can be assessed fairly reliably, as the production deriving from this contribution is known with a great degree of certainty and is expected to decline substantially, while consumption is expected to remain fairly constant.

The oil production forecast including contributions from technological developments and exploration shows a slightly declining trend from 2022 and the next ten years or so. From 2022, the difference between the production forecast and consumption forecast is about 10 per cent or less. Therefore, the duration of self-sufficiency is subject to a high degree of uncertainty. When including the contributions from technological developments and exploration, Denmark is estimated to be self-sufficient in oil for about 20 years reckoned from 2009.

Figure 6.7 illustrates the DEA's natural gas production forecast when including the contributions from reserves, technological developments and exploration. The figure also shows the consumption forecast from "The DEA's baseline scenario, April 2009". Denmark is expected to be self-sufficient in natural gas for 12 years, up to and including 2020, based on the contribution from reserves.

Fig. 6.7 Natural gas production and production forecast



For natural gas, the DEA anticipates no significant contribution from technological developments because current technology has already generated a much higher recovery factor than for oil. Thus, the DEA does not expect any such contribution to prolong Denmark's self-sufficiency in natural gas to an appreciable degree. When including the contributions from technological developments and exploration, the DEA estimates Denmark to be self-sufficient in natural gas for about 20 years reckoned from 2009.

7 ECONOMY

Oil and gas production from the North Sea has an impact on the Danish economy, and thus on the balance of trade and balance of payments, through the Danish state's tax revenue and the profits generated by the players in the oil and gas sector, and not least, it provides jobs for numerous people.

Moreover, the production of hydrocarbons has meant that Denmark has been self-sufficient in energy since 1997.

VALUE OF OIL AND GAS PRODUCTION

Three factors influence the value of oil and gas production: the development in production, the international crude oil price and the dollar exchange rate.

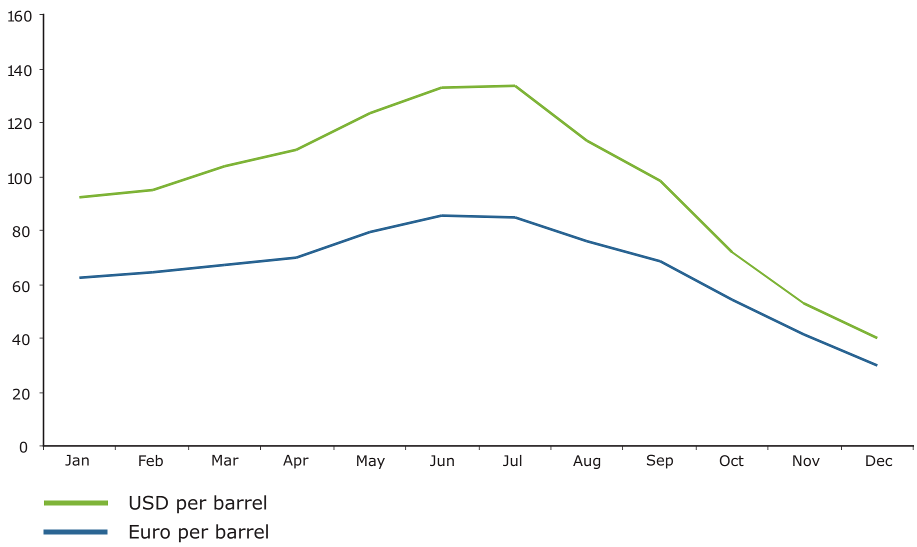
The average quotation for a barrel of Brent crude oil was USD 97.2 in 2008. Thus, the oil price continues the upward trend of previous years, increasing by almost 35 per cent from 2007, when the oil price averaged USD 72.5 per barrel.

Figure 7.1 illustrates the oil price trend in 2008. As appears from the figure, the oil price peaked temporarily in July 2008 at an average of about USD 133 per barrel, and then dropped dramatically in the second half of the year. Figure 7.1 also shows the oil price trend in EUR. As appears from the figure, the gap between the oil price in USD and EUR narrowed in 2008. The fluctuations in oil price denominated in USD are heavier than in EUR, due mainly to the development in the dollar exchange rate.

The average dollar exchange rate in 2008 was DKK 5.1 per USD against DKK 5.4 the year before. The dollar exchange rate underwent major fluctuations during 2008 and ended at a substantially higher average level than at the beginning of the year (DKK 5.57 per USD versus DKK 5.06 per USD), reaching the lowest average monthly level in July (DKK 4.73 per USD). There is a clear correlation between the oil price level that month and the weak dollar exchange rate.

The average price for a barrel of Brent crude oil in DKK increased to DKK 485.8 in 2008 from DKK 392.1 in 2007. Thus, the hike in the USD oil price offsets some of the

Fig. 7.1 Oil prices, 2008, USD and EUR



fall in the dollar exchange rate. In DKK the oil price rose by almost 25 per cent from 2007 to 2008.

Figure 7.2 shows the oil price development in USD from 1972 to 2008. In fixed prices, the oil price reached the same level in 2008 as in the record years of the early 1980s.

According to preliminary estimates for 2008, oil production accounts for about DKK 51.5 billion and gas production for DKK 15.5 billion of the total production value.

The total estimated value of Danish oil and gas production in 2008 is DKK 67 billion, up 10 per cent on the year before. The rise in production value is attributable to the higher oil price, which more than offsets the decline in production and the falling dollar exchange rate.

The breakdown of oil production in 2008 on the ten producing companies in Denmark appears from figure 2.3 in chapter 2, *Production and development*.

The DEA prepares forecasts of the future development of production based on the reserves assessment; see chapter 6, *Reserves*.

Appendix D contains a detailed outline of financial key figures from 1972 to 2008.

IMPACT OF PRODUCTION ON THE DANISH ECONOMY

The oil and gas activities have a favourable impact on both the balance of trade and the balance of payments current account. This is because oil and gas production makes Denmark self-sufficient in energy and also allows for exports.

The balance of trade for oil and natural gas

Since 1995, Denmark has had a surplus on the balance of trade for oil and gas. The increase in the oil price is the main reason why the surplus on the balance of trade for oil and natural gas, including oil products, ended at DKK 26.6 billion in 2008. This has kept the surplus at a high level, although it dropped from DKK 28.3 billion in

Fig. 7.2 Oil price development 1972-2008, USD per barrel

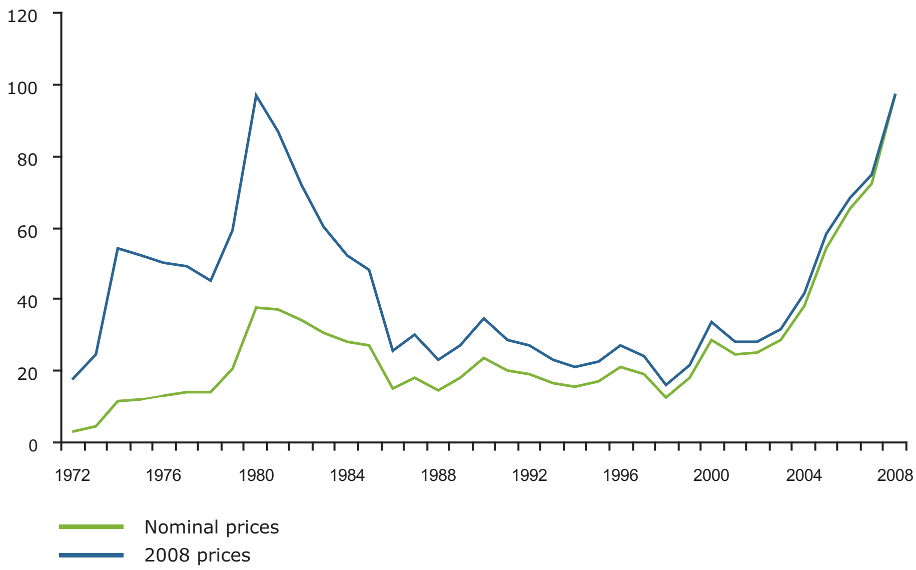
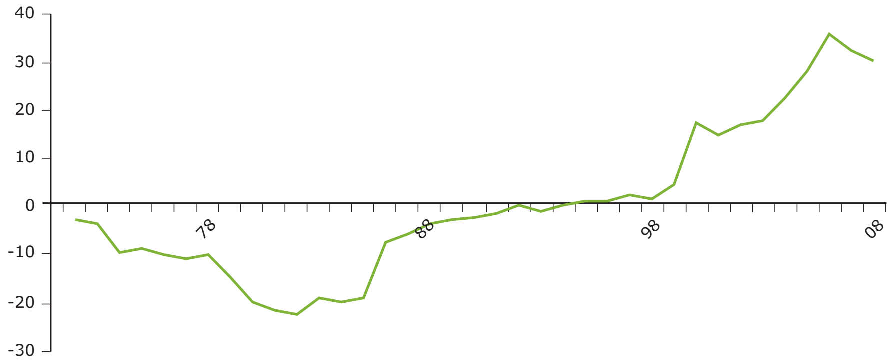


Fig. 7.3 Balance of trade for oil and natural gas, DKK billion, nominal prices



2007 due to lower production and the exchange rate. Figure 7.3 shows the trend in Denmark's external trade in oil and natural gas.

Impact on the balance of payments

The DEA prepares an estimate of the impact of oil and gas activities on the balance of payments current account for the next five years on the basis of its own forecasts for production, investments, operating and transportation costs. The underlying calculations are based on a number of assumptions about import content, interest expenses and the oil companies' profits from the hydrocarbon activities.

This year, the DEA's five-year forecast has been prepared for three different oil price scenarios. The purpose of preparing three scenarios is to illustrate the sensitivity of balance-of-payments effects to fluctuations in the oil price. Thus, the only variable in the three scenarios is the oil price. The calculations include no dynamic or derived effects.

The three scenarios are based on an oil price of USD 30, 60 and 120 per barrel and a dollar exchange rate of DKK 5.6 per USD. An oil price of USD 120 per barrel corresponds fairly closely to the IEA's long-term oil price projection.

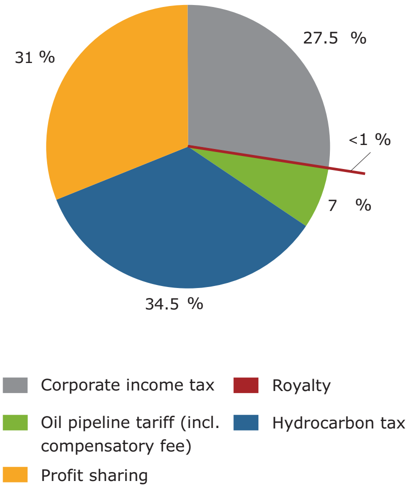
Table 7.1 shows the individual items used in calculating the impact of oil and gas activities on the balance of payments in the USD 60 oil price scenario. The lower part

Table 7.1 Impact of oil/gas activities on the balance of payments, DKK billion, 2008 prices, price scenario (60 USD/bbl)

	2009	2010	2011	2012	2013
Production value	48	46	41	37	32
Import content	4	5	4	3	4
Balance of goods and services	43	41	37	34	28
Transfer of interest and dividends	11	11	9	8	6
Balance of payments current account	32	30	28	27	22
Balance of payments current account, low price scenario (30 USD/bbl)	21	19	18	17	13
Balance of payments current account, high price scenario (120 USD/bbl)	55	52	49	45	38

Note: Based on the DEA's five-year forecast

Fig 7.4 State revenue in 2008



of the table also shows the calculated impact on the balance of payments current account when using the price scenarios of USD 30 and USD 120 per barrel.

Assuming that the oil price is USD 60 per barrel, the oil and gas activities will have an estimated DKK 22-32 billion impact on the balance of payments current account per year during the period 2009-2013. Moreover, it appears that a higher oil price intensifies the impact, and vice versa.

State revenue

The Danish state derives proceeds from North Sea oil and gas production via direct revenue from various taxes and fees: corporate income tax, hydrocarbon tax, royalty, the oil pipeline tariff, compensatory fee and profit sharing.

In addition to the direct revenue from taxes and fees, the Danish state receives indirect revenue from the North Sea by virtue of its shareholding in Dong Energy, generated by DONG E&P A/S' participation in oil and gas activities. In the long term, the state will also receive revenue through the Danish North Sea Fund.

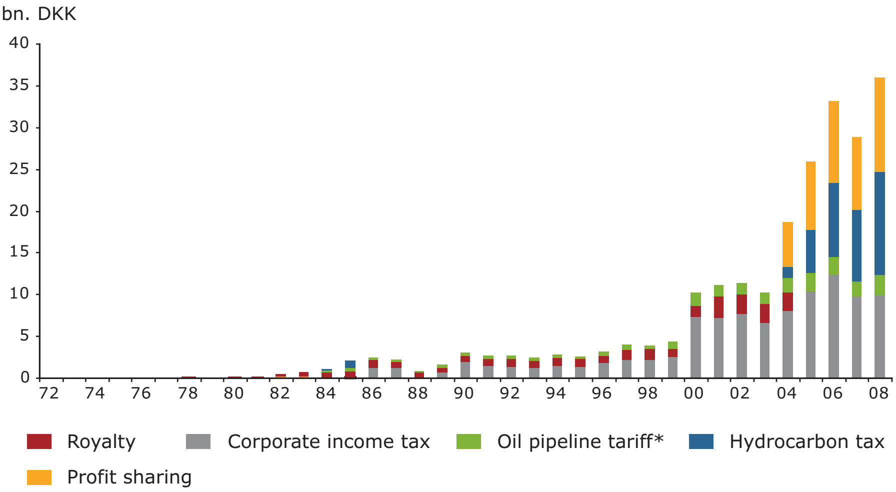
Box 7.1 contains a more detailed explanation of the state's revenue base in the form of taxes and fees on oil and gas production.

With a share of almost 35 per cent, hydrocarbon tax is the chief source of state revenue. Figure 7.4 shows the breakdown of state tax revenue in 2008.

State revenue from hydrocarbon production in the North Sea aggregated DKK 229 billion in 2008 prices in the period 1963-2008. Figure 7.5 shows the development in state revenue from 1972 to 2008. The cumulative production value was DKK 568 billion during the same period, while the aggregate value of the licensees' expenses for exploration, field developments and operations was DKK 245 billion.

Falling oil production and fluctuations in the oil price and dollar exchange rate characterized the development in 2008. The state's total revenue for 2008 is estimated at

Fig. 7.5 Development in total state revenue from oil and gas production 1972-2008, DKK billion, 2008 prices



** Incl. compensatory fee*
Note: Accrual according to the Finance Act (year of payment)

Box 7.1

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 SKAT (the Danish Central Tax Administration), while the DEA administers profit sharing and the collection of royalty, the oil pipeline tariff and compensatory fee. Moreover, the DEA 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 2008. Detailed information appears from Appendix E and the DEA's website.

Corporate income tax
Corporate income tax is one of the most important sources of revenue related to oil and gas.

Hydrocarbon tax
This tax was introduced in 1982 with the aim of taxing windfall profits, for example as a result of high oil prices.

Royalty
Older licences include a condition regarding the payment of royalty, which is payable on the basis of the value of hydrocarbons produced, after deducting transportation costs. New licences contain no requirement for the payment of royalty.

Profit sharing
With effect from 1 January 2004 and until 8 July 2012, the Concessionaires and their partners under the Sole Concession are to pay 20 per cent of their profits before tax and net interest expenses.

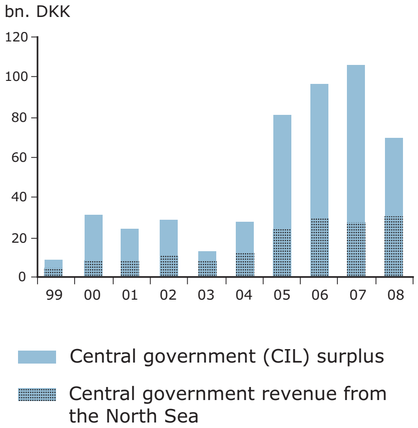
Oil pipeline tariff
DONG Oil Pipe A/S owns the oil pipeline from the Gorm Field to Fredericia. Users of the oil pipeline pay a fee to DONG Oil Pipe A/S, which includes a profit element of 5 per cent of the value of the crude oil transported. DONG Oil Pipe A/S pays 95 per cent of the proceeds from the 5 per cent 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 per cent of the value of the crude oil and condensate comprised by the exemption.

DONG E & P A/S
DONG E&P A/S is a fully paying participant with a 20 per cent share in the licences granted in the 4th and 5th Licensing Rounds. The same applies to licences granted in the Open Door area up to and including 2004. In some cases, DONG E&P A/S has supplemented this share on commercial terms by purchasing additional licence shares. DONG E&P A/S holds a share in the individual licences on the same terms as the other licensees, and therefore the company pays taxes and fees to the state. Moreover, DONG Energy's oil and gas activities contribute to the dividends received by the state on its shareholding in DONG Energy.

Danish North Sea Fund
As from 2005, the Danish state, represented by the Danish North Sea Fund, participates in all new licences with a 20 per cent share. On 9 July 2012, profit sharing will cease because the Danish North Sea Fund, on behalf of the state, will join DUC as an active partner with a 20 per cent share. Thus, profit sharing will be replaced by corporate income tax and hydrocarbon tax revenue as well as profits from the Danish North Sea Fund's activities. These profits will depend on the Fund's repayment of Government loans and its investments in exploration and production.

Fig. 7.6 Central government (CIL) surplus and central government revenue from the North Sea



Note: The CIL surplus (central government balance on the current investment and lending account) is the difference between total central government revenue and total central government expenditure.

DKK 35.9 billion, an increase of almost 30 per cent on the year before and an even higher figure than the record revenue of DKK 31.5 billion in 2006.

Table 7.2 shows total state revenue for the past five years, broken down on the individual taxes and fees.

State revenue has grown substantially since 2003 on account of the higher oil price level. Another reason for this growth is that the Danish Government concluded an agreement with A.P. Møller Mærsk, the so-called North Sea Agreement, in 2003. The agreement involved a restructuring of tax allowances, which resulted in steeper progressive tax rates.

The state's share of oil company profits is estimated at 65 per cent for 2008, calculated by year of payment. The marginal income tax is about 71 per cent according to the new rules, including profit sharing, and about 29 per cent according to the old rules, excluding hydrocarbon tax. Apart from the Sole Concession, licences awarded before 2004 are taxed according to the old rules.

Figure 7.6 shows the proportion of revenue from the oil and gas activities to the state's total surplus. As appears from the figure, state revenue from the Danish part of the North Sea accounted for almost 50 per cent of the state's total surplus in 2008.

For the next five years, the Ministry of Taxation estimates that the state's annual revenue will be in the DKK 13-22 billion range from 2009 to 2013, based on the USD 60 oil price scenario. Table 7.3 shows the development in expected state revenue for the three different oil price scenarios. It also appears from the table that the state's share of profits rises when the oil companies generate increasing earnings due to higher oil prices, for example. The revenue from the Danish North Sea Fund is included as from 2012 at the same time as revenue from profit sharing is phased out. This is because the Danish state will join DUC with a 20 percent share as of 9 July 2012.

Future estimates of corporate income tax and hydrocarbon tax payments are subject to uncertainty with respect to oil prices, production volumes and the dollar exchange rate. In addition, uncertainty attaches to the calculations because they are based on various stylized assumptions, some of which concern the companies' finance costs.

Investments and costs

In the same way that oil prices impact on state revenue from production in the North Sea, the licensees' initiatives play a vital role in both the current and future activity level and thus potential revenue.

Table 7.2 State revenue over the past five years, DKK million, nominal prices

	2004	2005	2006	2007	2008
Hydrocarbon tax	1,251	4,854	8,282	8,245	12,392
Corporate income tax	7,351	9,661	11,738	9,475	9,863
Royalty	2,104	1	1	2	2
Oil pipeline tariff*	1,496	2,052	2,156	1,815	2,511
Profit sharing	4,890	7,595	9,322	8348	11,145
Total	**17,092**	**24,163**	**31,499**	**27,885**	**35,913**

** Incl. 5 per cent compensatory fee*
Note: Accrual according to the Finance Act (year of payment)

Fig. 7.7 All licensees' total costs, 1963-2008, DKK billion, 2008 prices

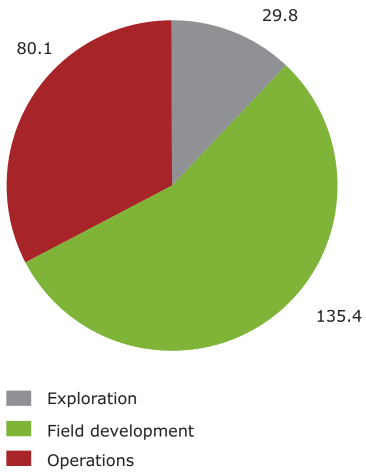


Figure 7.7 shows the breakdown of the licensees' costs during the period from 1963 to 2008. Investments in the development of existing and new fields account for more than half the licensees' total costs. The costs of exploration, field developments and operations (including administration and transportation) accounted for 12, 55 and 33 per cent, respectively, of total costs.

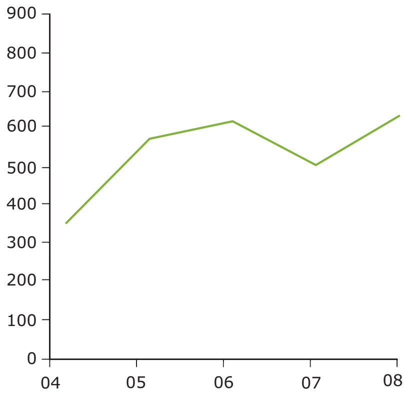
Box 7.2 illustrates the DUC companies' accounting figures from 2004 to 2007. When the figures for 2008 become available, they will be submitted to the Energy Policy Committee of the Danish Parliament and published on the DEA's website.

Table 7.3 Expected state revenue from oil and gas production, DKK billion, nominal prices*

		2009	2010	2011	2012	2013
Corporate income tax base before taxes, fees and profit sharing	120 USD/bbl	83.4	81.7	73.8	64.6	54.7
	60 USD/bbl	36.3	35.5	31.7	26.5	21.3
	30 USD/bbl	12.8	12.4	10.7	8.3	6.1
Corporate income tax	120 USD/bbl	16.3	16.1	14.5	13.9	13.6
	60 USD/bbl	7.0	6.9	6.1	5.6	5.3
	30 USD/bbl	2.4	2.1	1.9	1.7	1.5
Hydrocarbon tax	120 USD/bbl	17.7	17.4	17.3	17.5	19.3
	60 USD/bbl	6.5	6.0	5.5	5.5	6.8
	30 USD/bbl	0.9	0.7	0.6	0.7	1.0
Profit sharing	120 USD/bbl	14.7	13.9	12.8	6.9	0.0
Danish North Sea Fund post-tax profits**	120 USD/bbl	0.0	0.0	0.0	1.7	3.3
	60 USD/bbl	6.6	6.2	5.7	3.1	0.0
	60 USD/bbl	0.0	0.0	0.0	0.5	1.1
	30 USD/bbl	2.6	2.3	2.1	1.1	0.0
	30 USD/bbl	0.0	0.0	0.0	0.0	0.0
Royalty	120 USD/bbl	0.0	0.0	0.0	0.0	0.0
	60 USD/bbl	0.0	0.0	0.0	0.0	0.0
	30 USD/bbl	0.0	0.0	0.0	0.0	0.0
Oil pipeline tariff***	120 USD/bbl	3.2	3.2	2.9	1.5	0.3
	60 USD/bbl	1.6	1.6	1.4	0.8	0.2
	30 USD/bbl	0.8	0.8	0.7	0.4	0.1
Total	120 USD/bbl	51.9	50.6	47.5	41.6	36.6
	60 USD/bbl	21.7	20.7	18.8	15.4	13.4
	30 USD/bbl	6.6	5.9	5.3	4.0	2.5
The state's share (per cent)	120 USD/bbl	62.2	61.9	64.4	64.4	66.9
	60 USD/bbl	59.7	58.3	59.2	58.1	62.8
	30 USD/bbl	51.6	47.9	49.8	48.0	41.3
The state's share (per cent) adjusted for the Danish North Sea Fund's initial values and utilized losses	120 USD/bbl	62.2	61.9	64.4	65.1	67.4
	60 USD/bbl	59.7	58.3	59.2	60.0	64.3
	30 USD/bbl	51.6	47.9	49.8	54.1	50.7

** Assumed annual inflation rate of 1.73 per cent*
*** On 9 July 2012, the Danish North Sea Fund will join DUC with a 20 per cent share. The Danish North Sea Fund is liable to pay tax, for which reason the revenue from state participation appears under different headings, including in corporate income tax and hydrocarbon tax revenue. The Danish North Sea Fund's post-tax profits accrue to the state. However, it should be noted that the Fund must first repay loans raised with the Danish central bank and finance its continuous investments before delivering any profits to the state.*
**** Incl. 5 per cent compensatory fee*
Source: Ministry of Taxation
Note 1: Based on the DEA's five-year forecast
Note 2: Accrual according to the National Accounts (income year)

Fig. 7.8 Exploration costs, 2004-2008
DKK million, nominal prices



DUC is an abbreviation of Dansk Undergrunds Consortium, which is composed of the companies A.P. Møller – Mærsk, Chevron Denmark Inc. and Shell Olie- og Gasudvinding Danmark BV.

Box 7.2

DUC's production and accounting figures

The production figures for 2004 to 2007 are shown in table 7.4. The production figures are grouped under two headings: the fields comprised by A.P. Møller – Mærsk's Sole Concession of 8 July 1962 (shown as DUC in the table) and all Danish fields.

Table 7.4 Oil and gas production from DUC's fields and from all Danish fields

	Oil production m. m^3		Oil production bn. Nm^3	
	DUC	**All fields**	**DUC**	**All fields**
2004	17.9	22.6	7.9	8.3
2005	18.0	21.9	8.8	9.2
2006	16.9	19.8	8.8	9.2
2007	15.9	18.1	7.9	8.0

The DEA's estimates of the DUC companies' pre-tax profits for 2004-2007 are summarized in table 7.5. The figures for 2008 will be published on the DEA's website as soon as they are available.

Table 7.5 The DUC companies' pre-tax profits in DKK million (nominal prices)

	2004	**2005**	**2006**	**2007**
Revenue	32,252	45,765	54,355	51,829
Operating costs*	2,724	4,161	4,575	4,512
Interest expenses, etc.	171	215	233	187
Foreign-exchange adjustments**	1,129	1,212	67	578
Gross profit	28,228	40,177	49,480	46,552
Depreciation and amortization	3,164	3,622	4,262	3,987
Profit before taxes and fees	**25,064**	**36,555**	**45,218**	**42,565**

**Production, administration and exploration costs*
***Incl. foreign-exchange losses and losses on hedging transactions*

Exploration costs

Figure 7.8 illustrates the development in exploration costs from 2004 to 2008. The preliminary figures for 2008 show that exploration costs increased almost 30 per cent from 2007 to 2008, the reason being that more appraisal wells were drilled in 2008. For 2008, total exploration costs are preliminarily estimated at DKK 0.65 billion.

Exploration activities are expected to increase to about DKK 1.2 billion for 2010, particularly as a consequence of the licences granted under the 6th Licensing Round in 2006. Activity is then expected to decline until 2013.

Investments in field developments

The most cost-intensive activity for the licensees is the development of new and existing fields. Investments in field developments are estimated to total DKK 6.1 billion in 2008, down DKK 0.4 billion on the previous year. Compared to annual investments in field developments in the past ten years, averaging about DKK 5 billion, the investment level remains high. Table 7.6 illustrates investments in field developments over the period 2004-2008.

In 2008, the development activities in the Halfdan, Tyra and Valdemar Fields represented the bulk of investments, accounting for almost 70 per cent of total investments in 2008.

Table 7.7 shows the DEA's estimate of investments in development activity for the period from 2009 to 2013, based on the DEA's categorization of reserves. The forecast of possible field development activities is based on the DEA's assessment of the potential for initiating further production beyond the production for which development plans have already been submitted; see the definitions of reserves on the DEA's website.

Total investments for the period covered by the forecast remain largely unchanged compared to last year's report, although the figures for some fields have been substantially revised. For example, this applies to the Hejre Field because the estimated startup of production was postponed.

Operating, administration and transportation costs

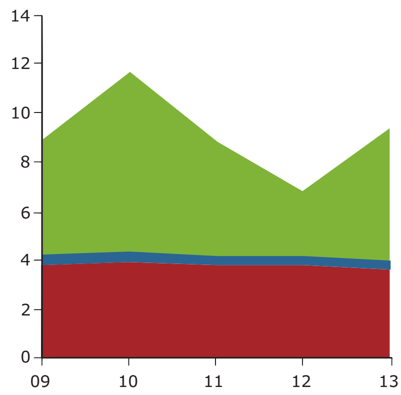
For 2008, the DEA has calculated operating, administration and transportation costs at DKK 4.5 billion, an increase of almost 30 per cent compared to the year before. This

Table 7.6 Investments in field developments, 2004-2008, DKK million, nominal prices

	2004	2005	2006	2007	2008*
Cecilie	309	-18	7	7	12
Dagmar	0	0	0	0	0
Dan	750	750	684	436	411
Gorm	108	291	303	158	265
Halfdan	1,124	683	1,244	2,112	1,848
Harald	22	53	1	4	20
Kraka	2	0	0	2	0
Nini	319	163	35	183	565
Roar	0	0	0	0	0
Rolf	4	0	1	2	25
Siri	425	73	153	210	563
Skjold	8	11	4	15	12
South Arne	762	310	31	1,087	198
Svend	0	0	0	0	0
Tyra	459	1,020	1,426	624	937
Tyra Southeast	96	45	45	384	0
Valdemar	52	553	991	1,313	1,267
NOGAT Pipeline	664	12	-	-	-
Not allocated	2	5	-	-	-
Total	**5,107**	**3,956**	**4,927**	**6,538**	**6,123**

** Estimate*

Fig. 7.9 Investments in fields operating and oil transportation costs, 2008 prices



*Excl. pipeline tariff/compensatory fee

is because operating and transportation costs have stagnated at a significantly higher level than a few years back and because extensive maintenance work was carried out in the course of 2008.

Figure 7.9 illustrates the DEA's estimate of developments in investments and operating and transportation costs for the period 2009-2013. Operating costs are expected to stagnate at a level of about DKK 4 billion throughout the period. Transportation costs are expected to show a slightly declining trend over the whole period. Investments are estimated to vary considerably through the period 2009-2013, averaging about DKK 5 billion.

Table 7.7 Estimated investments in development projects, 2009-2013, DKK billion, 2008 prices

	2009	2010	2011	2012	2013
Ongoing and approved					
Adda	0.5	-	-	-	-
Alma	-	0.5	-	-	-
Boje	-	-	0.3	-	0.3
Cecilie	0.0	0.0	0.0	0.0	0.0
Dagmar	-	-	-	-	-
Dan	0.1	-	-	-	-
Elly	-	-	-	-	-
Gorm	-	-	-	-	-
Halfdan	2.5	1.7	0.1	-	-
Harald	0.1	0.0	-	-	-
Kraka	-	0.4	-	-	-
Lulita	-	-	-	-	-
Nini	0.6	0.0	0.0	0.0	0.0
Regnar	-	-	-	-	-
Roar	-	-	-	-	-
Rolf	-	-	-	-	-
Siri	0.2	0.1	0.1	0.1	0.1
Skjold	-	-	-	-	-
South Arne	0.1	0.1	0.1	0.0	0.0
Svend	-	-	-	-	-
Tyra	0.2	0.2	0.8	0.4	0.2
Tyra Southeast	-	-	-	-	-
Valdemar	0.3	-	-	-	-
Total	**4.5**	**3.0**	**1.4**	**0.5**	**0.6**
Planned	-	-	0.7	0.1	1.0
Possible	0.5	4.8	2.8	2.3	4.1
Expected	**5.0**	**7.8**	**5.0**	**2.8**	**5.7**

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. 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 ton (t) and gigajoule (GJ) are dependent on time. The table below shows the average for 2008. The lower calorific value is indicated.

The SI prefixes m (milli), 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.

Some abbreviations:

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

psia — *pound per square inch absolute.*

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.*

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

scf — *standard cubic foot/feet. Unit of measurement used for natural gas in a reference state: 15°C and 101.325 kPa in this report.*

stb — *stock tank barrel. Barrel in a reference state of 15°C and 101.325 kPa. Used for oil.*

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 — *kilogram-mole. The mass of a substance whose mass in kilograms is equal to the molecular mass of the substance.*

γ — *gamma. Relative density.*

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

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

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

ft — *foot/feet. British unit of length. 1 foot = 12 in = 0.3048 m.*

	FROM	TO	MULTIPLY BY
Crude oil	m^3 (st)	stb	6.293
	m^3 (st)	GJ	37.0[i]
	m^3 (st)	t	0.85[i]
Natural gas	Nm^3	scf	37.2396
	Nm^3	GJ	0.03948[i]
	Nm^3	t.o.e.	$942.96 \cdot 10^{-6}$[i]
	Nm^3	kg · mol	0.0446158
	m^3 (st)	scf	35.3014
	m^3 (st)	GJ	0.03743[i]
	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)

i) Average value for Danish fields.

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APPENDIX A: AMOUNTS PRODUCED AND INJECTED

Production and sales — **OIL** *thousand cubic metres*

	1972-98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Dan	37,999	5,745	6,599	6,879	6,326	5,929	6,139	5,712	5,021	4,650	4,241	95,240
Gorm	33,656	3,384	3,110	2,180	2,887	2,838	2,469	1,978	1,897	1,639	1,053	57,092
Skjold	27,244	1,825	1,975	1,354	1,659	1,532	1,443	1,310	1,214	1,015	989	41,560
Tyra	16,627	892	1,000	872	801	918	723	773	845	764	551	24,765
Rolf	3,466	77	83	51	51	104	107	79	89	103	78	4,290
Kraka	2,668	404	350	253	157	139	199	211	222	176	112	4,890
Dagmar	969	10	8	4	6	7	2	0	0	0	0	1,005
Regnar	771	29	14	33	18	19	19	16	11	0	0	930
Valdemar	937	86	77	181	353	435	491	423	470	881	1,268	5,604
Roar	1,074	259	285	317	175	121	98	94	51	35	28	2,537
Svend	2,827	521	576	397	457	280	326	324	296	299	278	6,580
Harald	2,484	1,332	1,081	866	578	425	314	237	176	139	114	7,746
Lulita	143	224	179	66	24	20	19	35	68	55	47	880
Halfdan	-	222	1,120	2,965	3,718	4,352	4,946	6,200	6,085	5,785	5,326	40,720
Siri	-	1,593	2,118	1,761	1,487	925	693	703	595	508	598	10,980
South Arne	-	757	2,558	2,031	2,313	2,383	2,257	2,371	1,869	1,245	1,139	18,923
Tyra SE	-	-	-	-	493	343	580	614	446	377	429	3,281
Cecilie	-	-	-	-	-	166	310	183	116	88	66	928
Nini	-	-	-	-	-	391	1,477	624	377	323	355	3,548
Total	**130,864**	**17,362**	**21,134**	**20,207**	**21,505**	**21,327**	**22,612**	**21,886**	**19,847**	**18,084**	**16,672**	**331,500**

Production — **GAS** *million normal cubic metres*

	1972-98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Dan	13,721	1,447	1,364	1,571	1,704	1,925	1,894	2,007	2,081	1,860	1,504	21,998
Gorm	12,328	537	426	306	480	339	216	218	207	175	119	15,350
Skjold	2,397	154	158	104	123	92	77	93	77	69	60	3,403
Tyra	46,499	3,878	3,826	3,749	3,948	3,994	4,120	3,745	3,792	3,916	3,130	84,598
Rolf	146	3	4	2	2	4	5	3	4	4	3	180
Kraka	801	148	119	100	52	25	23	24	28	28	36	1,384
Dagmar	146	2	2	1	1	3	2	0	0	0	0	158
Regnar	49	2	1	3	1	2	2	1	1	0	0	63
Valdemar	377	49	55	78	109	151	218	208	208	355	593	2,401
Roar	4,754	1,249	1,407	1,702	1,052	915	894	860	489	367	417	14,106
Svend	321	65	75	48	61	43	38	34	28	28	24	764
Harald	3,832	2,876	2,811	2,475	2,019	1,563	1,232	1,091	927	781	690	20,298
Lulita	69	181	160	27	6	5	5	13	38	33	30	566
Halfdan	-	-	-	-	-	4	319	1,226	1,428	1,271	2,067	15,396
Siri	-	142	197	176	157	110	64	112	55	47	63	1,121
South Arne	-	167	713	774	681	544	461	485	366	234	225	4,650
Tyra SE	-	-	-	-	447	452	1,233	1,337	1,108	848	889	6,314
Cecilie	-	-	-	-	-	14	22	13	8	6	4	67
Nini	-	-	-	-	-	29	109	46	28	24	26	262
Total	**85,439**	**10,901**	**11,316**	**11,116**	**10,844**	**10,213**	**10,934**	**11,517**	**10,873**	**10,046**	**9,879**	**193,078**

The monthly production figures for 2008 are available at the DEA's website www.ens.dk

Fuel*

GAS *million normal cubic metres*

	1972-98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Dan	874	172	179	184	182	198	201	205	209	222	225	2,851
Gorm	1,460	149	142	111	146	135	137	124	124	132	117	2,777
Tyra	1,639	239	229	243	245	242	249	247	241	228	233	4,035
Dagmar	21	-	-	-	-	-	-	-	-	-	-	21
Harald	19	14	13	10	9	8	8	7	8	7	7	110
Siri	-	8	21	22	21	20	19	20	25	25	25	207
South Arne	-	3	32	34	45	49	45	52	53	58	53	424
Halfdan	-	-	-	-	-	-	20	39	39	39	38	174
Total	**4,014**	**585**	**618**	**604**	**648**	**652**	**679**	**694**	**697**	**711**	**699**	**10,599**

As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the Act on CO_2 Allowances.

Flaring*

	1972-98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Dan	1,576	56	67	79	55	71	37	23	32	30	25	2,050
Gorm	1,157	71	66	88	81	66	57	61	61	48	41	1,797
Tyra	622	58	58	68	61	54	63	55	54	56	44	1,192
Dagmar	123	2	2	1	1	3	2	0	0	0	0	135
Harald	96	12	7	11	3	1	1	1	2	2	2	139
Siri	-	73	9	15	9	23	65	15	6	7	7	228
South Arne	-	114	41	9	11	12	11	14	11	11	7	241
Halfdan	-	-	-	-	-	4	25	16	20	17	8	89
Total	**3,574**	**386**	**250**	**270**	**222**	**234**	**262**	**184**	**186**	**170**	**132**	**5,870**

As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the Act on CO_2 Allowances.

Injection

	1972-98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Gorm	8,063	25	45	4	14	6	4	3	0	0	0	8,164
Tyra	17,212	3,074	3,104	2,773	2,535	2,312	1,612	1,285	761	1,094	119	35,880
Siri**	-	61	167	139	127	109	111	135	61	45	61	1,016
Total	**25,275**	**3,160**	**3,316**	**2,916**	**2,676**	**2,428**	**1,727**	**1,423**	**821**	**1,139**	**180**	**45,060**

Sales*

	1984-98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Dan	12,121	1,371	1,238	1,412	1,521	1,682	1,681	1,804	1,862	1,653	1,293	27,637
Gorm	4,189	448	334	209	364	228	99	126	103	66	23	6,189
Tyra	32,478	1,870	1,971	2,493	2,776	2,948	4,580	4,598	4,574	4,143	4,652	67,082
Harald	3,787	3,032	2,950	2,482	2,013	1,558	1,228	1,096	954	804	710	20,613
South Arne	-	50	640	730	625	483	406	419	302	168	167	3,991
Halfdan	-	-	-	-	-	4	274	1,172	1,370	1,215	2,020	6,054
Total	**52,576**	**6,770**	**7,133**	**7,326**	**7,299**	**6,903**	**8,267**	**9,215**	**9,164**	**8,049**	**8,865**	**131,568**

**) The names refer to processing centres.*
***) Gas from the Cecilie and Nini Fields is injected into the Siri Field.*

Emissions

CO_2 EMISSIONS *thousand tons*

	1972-98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Fuel	9,136	1,343	1,476	1,459	1,577	1,591	1,642	1,694	1,675	1,690	1,670	24,952
Flaring	8,134	1,126	645	646	535	564	664	457	470	449	354	14,044
Total	**16,271**	**2,469**	**2,122**	**2,104**	**2,112**	**2,154**	**2,306**	**2,151**	**2,144**	**2,139**	**2,025**	**37,997**

CO_2 emissions from the use of diesel oil were not included 1972 through 2005.
CO_2 emissions have been calculated on the basis of parameters specific to the individual year and the individual installation as from 1998.
As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the Act on CO_2 Allowances and have included CO_2 emissions from diesel combustion.

Production

WATER *thousand cubic metres*

	1972-98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Dan	11,046	4,220	5,277	6,599	6,348	7,183	8,053	9,527	10,936	12,152	13,946	95,288
Gorm	15,330	3,468	3,980	3,353	4,017	4,420	5,173	5,252	4,822	4,708	3,976	58,499
Skjold	13,747	3,748	4,333	2,872	3,007	3,525	3,688	4,270	4,328	3,885	3,636	51,039
Tyra	12,285	2,033	3,046	2,545	2,261	3,039	2,977	3,482	3,150	2,725	3,103	40,645
Rolf	3,204	366	358	181	168	270	308	290	316	383	349	6,192
Kraka	1,715	329	256	352	306	208	426	320	297	359	436	5,004
Dagmar	2,696	246	241	102	160	375	90	3	0	0	13	3,927
Regnar	1,510	363	139	475	257	316	396	352	255	1	0	4,064
Valdemar	191	55	48	150	272	310	325	792	937	854	925	4,857
Roar	256	199	317	386	301	476	653	662	498	560	586	4,894
Svend	339	582	1,355	954	1,051	1,330	1,031	1,309	1,205	1,200	1,022	11,378
Harald	5	15	39	98	78	43	15	12	12	18	21	357
Lulita	3	5	11	23	14	14	15	38	92	96	91	402
Halfdan	-	56	237	493	367	612	2,099	2,825	3,460	4,086	4,766	19,001
Siri	-	319	1,868	2,753	3,041	2,891	1,641	1,683	2,032	2,528	2,686	21,441
South Arne	-	15	58	112	370	857	1,127	1,790	1,830	1,861	2,174	10,195
Tyra SE	-	-	-	-	250	596	466	437	377	669	602	3,397
Cecilie	-	-	-	-	-	25	331	637	651	576	456	2,675
Nini	-	-	-	-	-	-	63	730	822	619	660	2,895
Total	**62,328**	**16,020**	**21,564**	**21,449**	**22,268**	**26,490**	**28,875**	**34,410**	**36,019**	**37,280**	**39,448**	**346,149**

Injection

	1972-98	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	Total
Dan	41,245	14,964	17,464	18,176	16,123	18,063	20,042	20,281	21,520	20,230	17,562	225,670
Gorm	41,498	8,736	10,641	6,549	8,167	7,066	7,551	7,251	6,544	6,678	4,814	115,495
Skjold	44,013	5,866	6,520	4,805	6,411	6,115	5,607	6,045	5,711	6,098	4,497	101,689
Halfdan	-	82	13	620	2,532	5,162	5,759	9,710	11,026	12,107	11,651	58,663
Siri	-	1,228	3,738	4,549	4,517	3,383	1,683	1,350	1,973	3,499	2,695	28,614
South Arne	-	-	58	1,991	4,397	5,332	4,949	5,608	5,362	4,296	4,279	36,272
Nini	-	-	-	-	-	81	918	502	912	413	883	3,708
Cecilie	-	-	-	-	-	-	93	198	30	91	42	455
Total	**126,756**	**30,875**	**38,435**	**36,689**	**42,148**	**45,201**	**46,603**	**50,945**	**53,077**	**53,412**	**46,423**	**570,566**

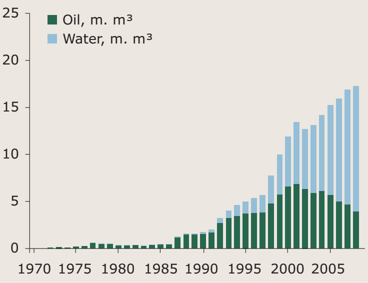
Water injection includes the injection of produced water and seawater. Most of the water produced in the Gorm, Skjold, Dagmar and Siri Fields is reinjected.

APPENDIX B: PRODUCING FIELDS

Explanation of field data

PRODUCTION

Cum. production at 1 January 2009
Oil: 95.24 m. m³
Gas: 22.00 bn. Nm³
Water: 95.29 m. m³



Production of oil, gas and water
The chart shows the primary production from the individual fields, i.e. oil or gas. The figures show the cumulative production of oil, gas and water until 1 January 2009.

Oil field (e.g. Dan, Halfdan, Siri) Oil, m. m³ Gas, bn. Nm³ Water, m. m³
At the time of production startup, the percentage of oil produced is high, but over time, the percentage of water produced increases. When oil flows from the reservoir to the surface, it degasses and the amount of gas produced also decreases.

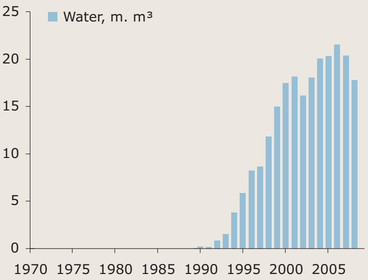
Gas field (e.g. Harald) Oil and condensate, m. m³ Gas, bn. Nm³ Water, m. m³
Production from a gas field consists of gas, water and condensate, which is a light oil. Due to the pressure difference between reservoir and surface, the gas condenses at the surface, which means that liquid hydrocarbons (condensate) are also produced.

Oil and gas field (e.g. Tyra Southeast) Oil and condensate, m. m³ Gas, bn. Nm³ Water, m. m³
The production of oil, gas, condensate and water.

The production figures for 2008 appear from Appendix A.

INJECTION

Cum. injection at 1 January 2009
Water: 225.67 m. m³



Injection of water and gas
The chart shows the primary injection in the individual fields, i.e. water or gas. The figures show the cumulative injection of water and gas until 1 January 2009. The injection method is not used for all fields.

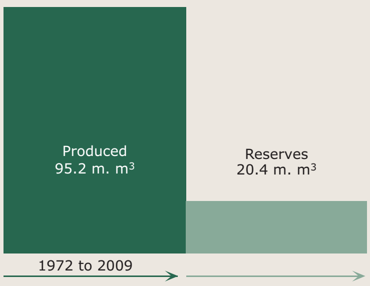
Injecting water into oil reservoirs maintains the pressure while forcing oil towards the production wells. The injection of gas also maintains pressure in the reservoir, but affects the viscosity of hydrocarbons at the same time.

Fields with water injection (e.g. Halfdan, South Arne) Water, m. m³
In the Halfdan Field, for example, water is injected to displace the oil towards the production wells.

Fields with gas injection (e.g. Tyra) Gas, bn. Nm³
In a few fields, gas is injected to optimize the production of liquid hydrocarbons.

RESERVES

Oil: 20.4 m. m³
Gas: 2.1 bn. Nm³



Reserves compared to cumulative production
Figures for oil and gas reserves are indicated for each individual field.

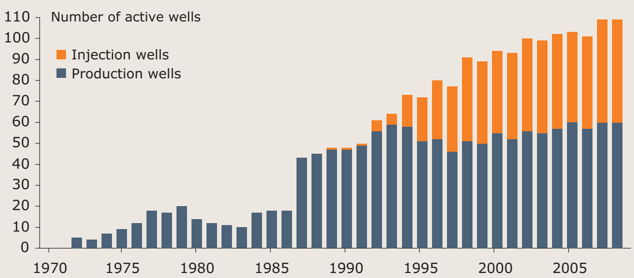
The chart shows the relationship between the amounts produced until 1 January 2009 and the estimated hydrocarbons-in-place, the reserves.

Produced
The cumulative production of oil or gas until 1 January 2009.

Reserves
The estimated amounts of oil and gas that can be recovered by means of known technology under the prevailing economic conditions.

DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 28.5 billion



Development and investment
Total investments comprise the costs of developing installations and wells.

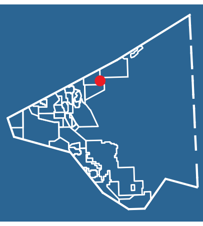
The chart shows the number of active wells in the individual years. Thus, wells that are closed in throughout a year will not be included in the figures for that year.

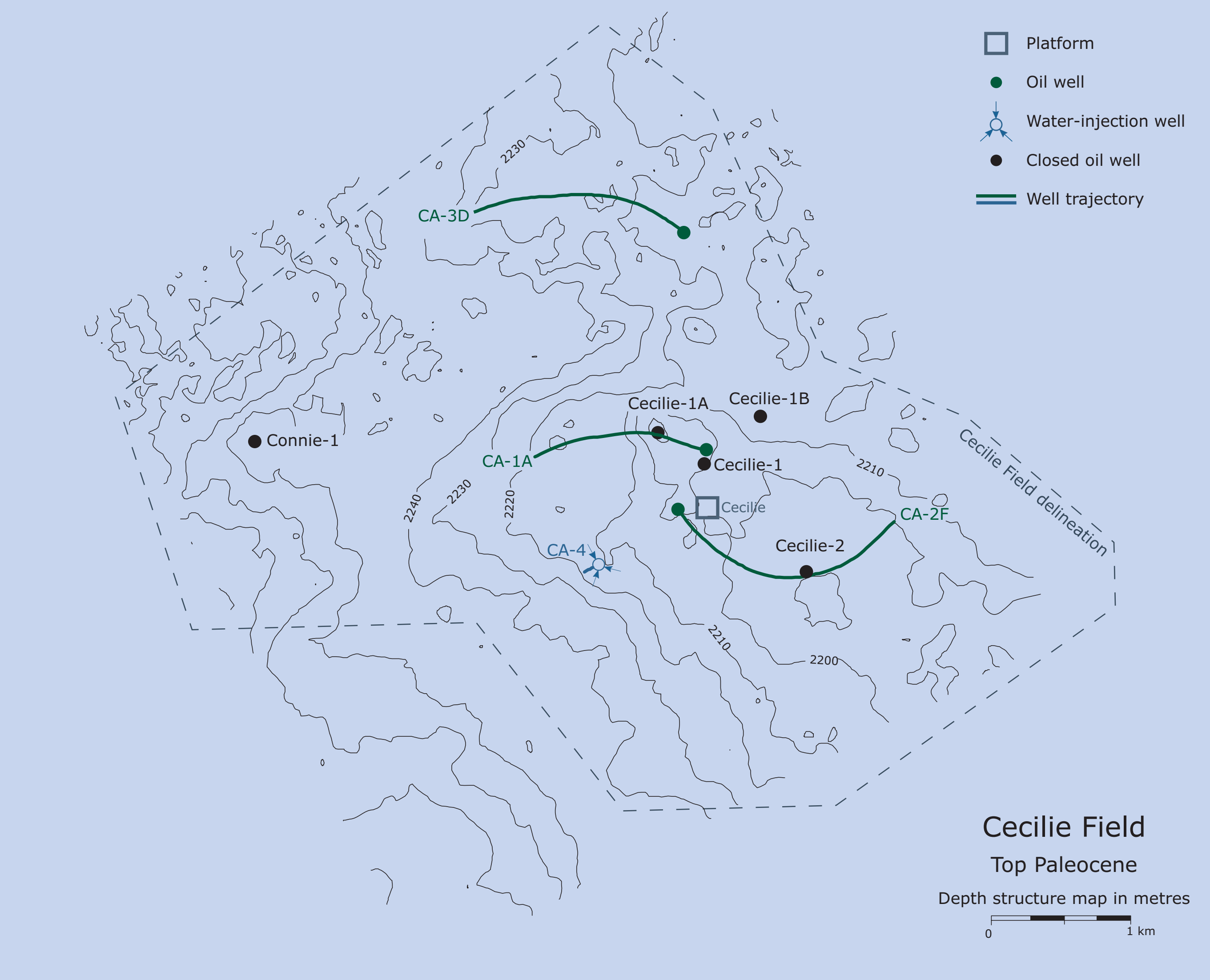
The wells are divided into production wells and injection wells. The chart shows the primary function of the wells in the relevant year, either production or injection. A well may be used for production for part of a year and then be converted to injection for the rest of the year.

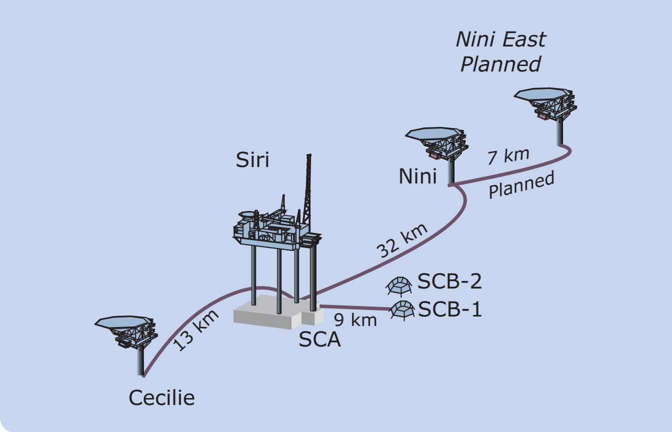
Injection wells Production wells Prod/Inject wells*
*Only relevant for the Tyra Field. A few wells alternate between injection and production.

APPENDIX B: PRODUCING FIELDS

THE CECILIE FIELD

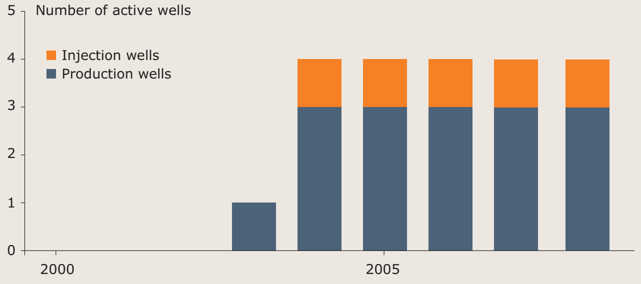






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 1.3 billion



FIELD DATA

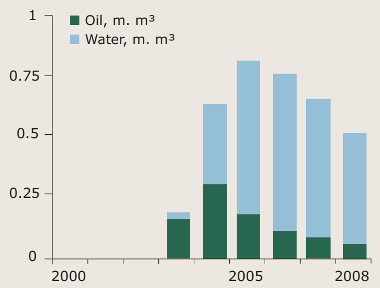
At 1 January 2009

Location:	Blocks 5604/19 and 20
Licence:	16/98
Operator:	DONG E&P A/S
Discovered:	2000
Year on stream:	2003
Producing wells:	3
Water-injection wells:	1
Water depth:	60 m
Field delineation:	22.6 km^2
Reservoir depth:	2,200 m
Reservoir rock:	Sandstone
Geological age:	Paleocene

PRODUCTION

Cum. production at 1 January 2009

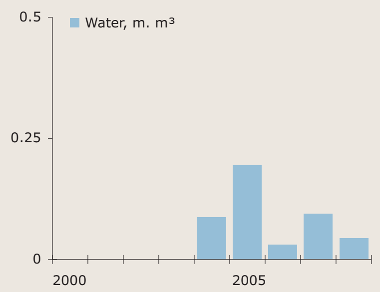
Oil:	0.93 m. m^3
Gas:	0.07 bn. Nm^3
Water:	2.68 m. m^3



INJECTION

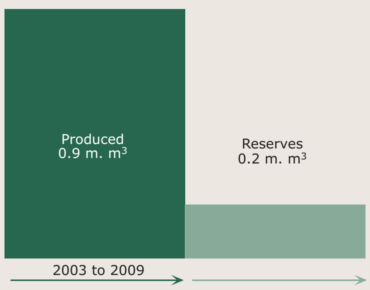
Cum. injection at 1 January 2009

Water:	0.45 m. m^3



RESERVES

Oil:	0.2 m. m^3
Gas:	0.0 bn. Nm^3



REVIEW OF GEOLOGY, THE CECILIE FIELD

The Cecilie accumulation is a combined structural and stratigraphic trap. It is an anticlinal structure induced through salt tectonics, delimited by faults and redeposited sands. The Cecilie Field also comprises the Connie accumulation.

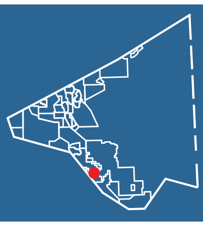
PRODUCTION STRATEGY

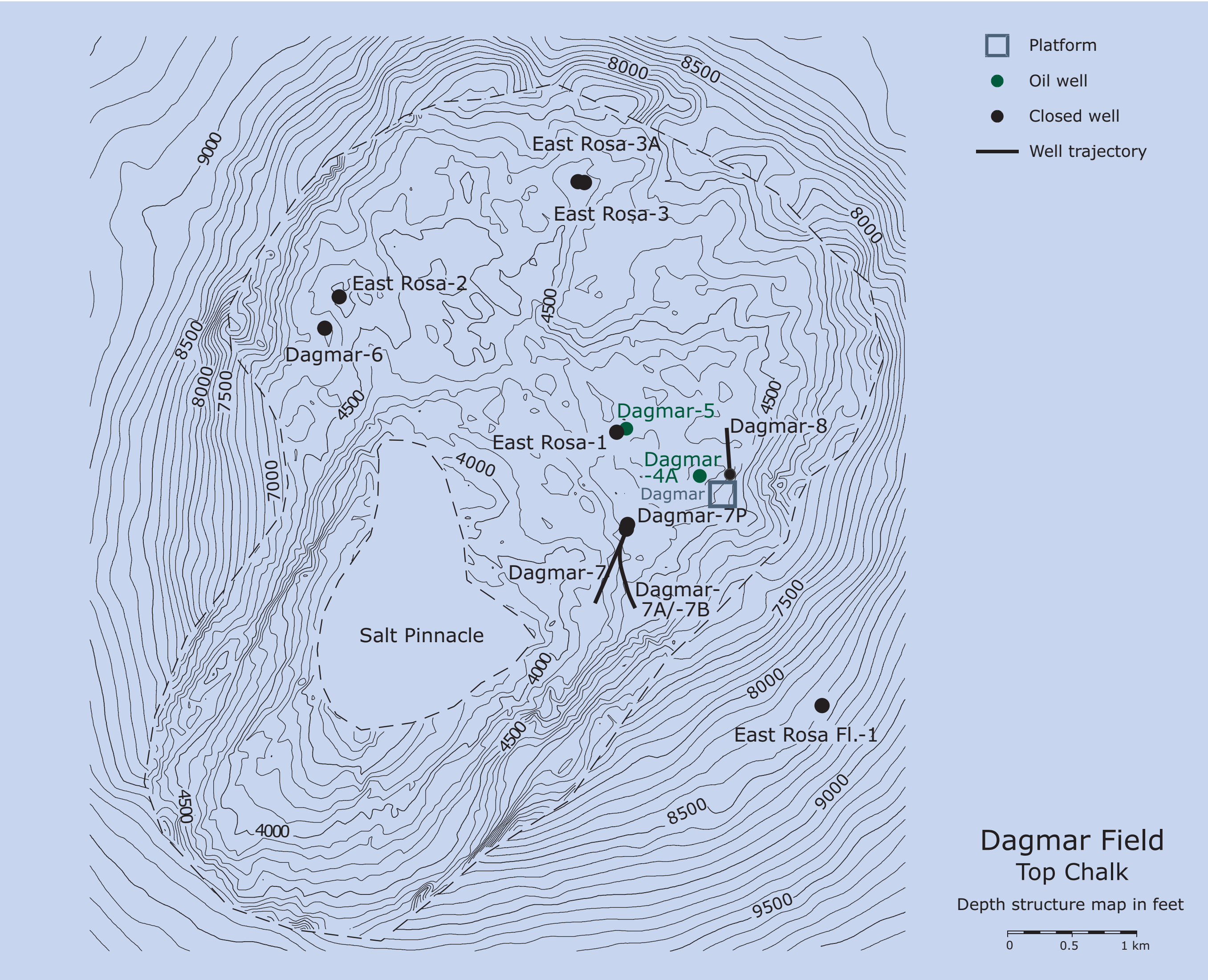
Recovery is based on water injection to maintain reservoir pressure. To assess its effect, water injection has been suspended for periods of time. The production wells have been drilled in the crest of the structure, while water is injected in the flank of the field.

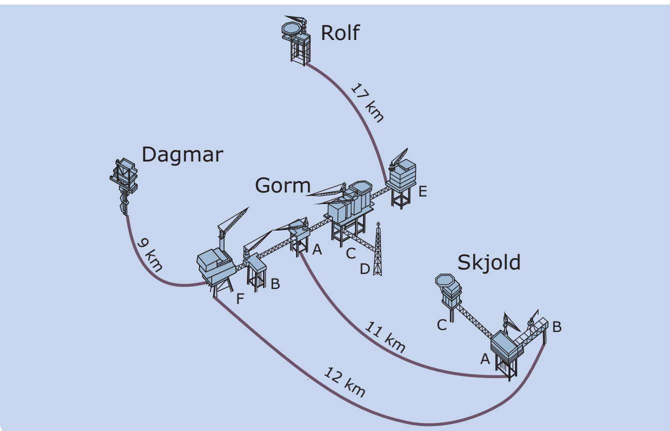
PRODUCTION FACILITIES

The Cecilie Field is a satellite development to the Siri Field with one unmanned wellhead platform with a helideck. 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 transported to the Cecilie Field through a 10″ pipeline.

THE DAGMAR FIELD



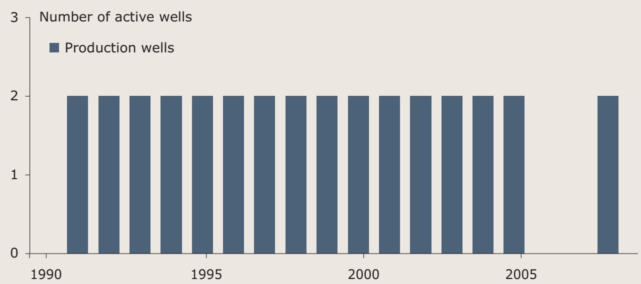




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009

2008 prices DKK 0.5 billion



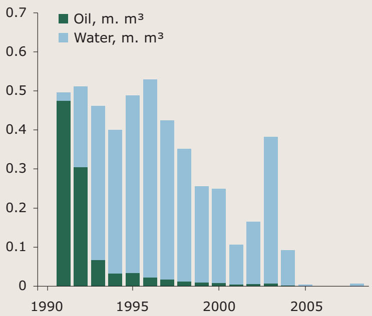
FIELD DATA
At 1 January 2009

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

PRODUCTION

Cum. production at 1 January 2009

Oil:	1.01 m. m³
Gas:	0.16 bn. Nm³
Water:	3.93 m. m³



RESERVES

Oil:	0.0 m. m³
Gas:	0.0 bn. Nm³

REVIEW OF GEOLOGY, THE DAGMAR FIELD

The Dagmar Field is an anticlinal structure, induced through salt tectonics. The uplift is very pronounced, and 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.

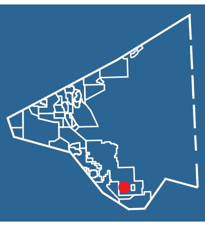
PRODUCTION STRATEGY

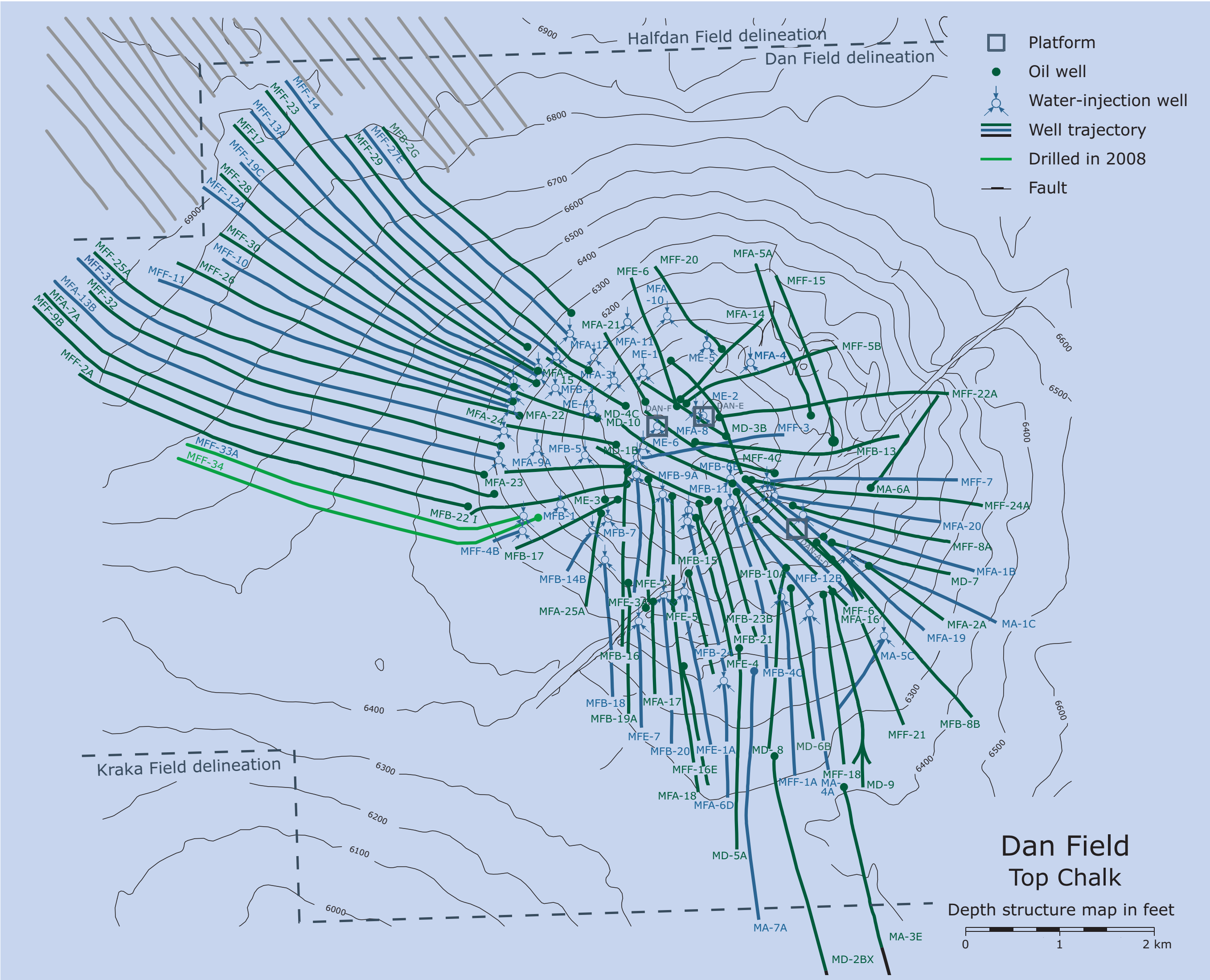
Both wells in the field have been suspended. The recovery strategy for the Dagmar Field was based on achieving the highest possible production rate from the wells. Initially, the oil production rates were high in the Dagmar Field, but later it was not possible to sustain the good production performance. In 2006 and 2007, the two production wells in the field were closed in. When reopened in 2008, the wells produced very little oil with a water content of 98 per cent in a production test. Therefore, the wells were closed in again, and the potential of the field is being reassessed.

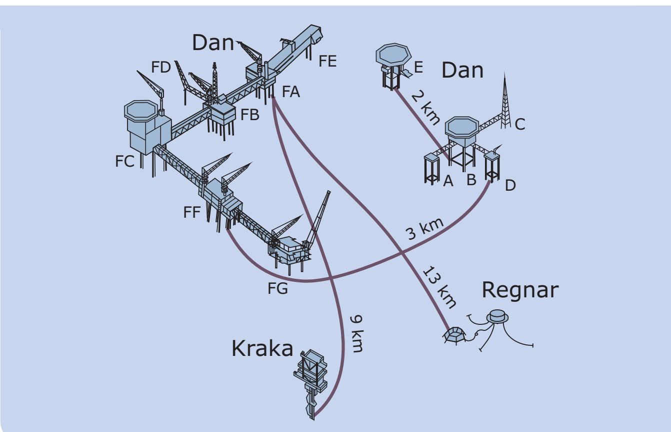
PRODUCTION FACILITIES

The Dagmar Field is a satellite development to the Gorm Field with one unmanned wellhead platform without a helideck. The unprocessed production can be transported to the Gorm F platform, where separate facilities for handling the sour gas from the Dagmar Field have been installed. The small amount of gas produced from Dagmar was flared due to its high content of hydrogen sulphide.

THE DAN FIELD

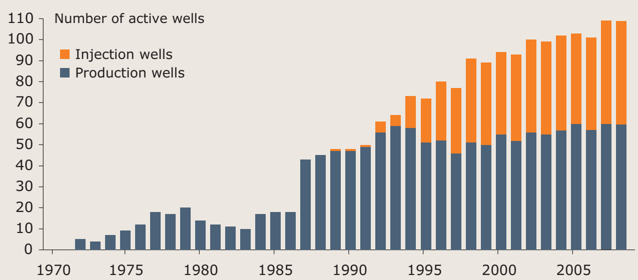






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 28.5 billion



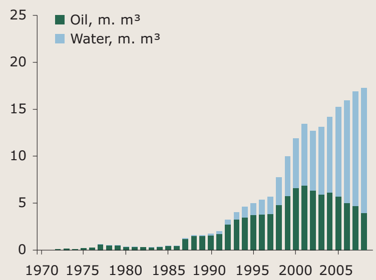
FIELD DATA
At 1 January 2009

Prospect:	Abby
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1971
Year on stream:	1972
Producing wells:	61
Water-injection wells:	50
Water depth:	40 m
Field delineation:	121 km²
Reservoir depth:	1,850 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2009

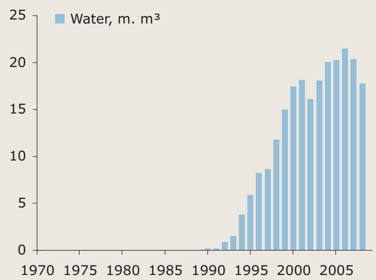
Oil:	95.24 m. m³
Gas:	22.00 bn. Nm³
Water:	95.29 m. m³



INJECTION

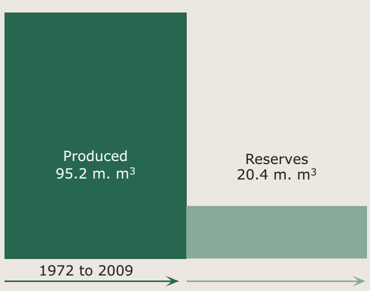
Cum. injection at 1 January 2009

Water:	225.67 m. m³



RESERVES

Oil:	20.4 m. m³
Gas:	2.1 bn. Nm³



REVIEW OF GEOLOGY, THE DAN FIELD

The Dan Field is an anticlinal structure, 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. This oil field has a gas cap.

Recovery takes place from the central part of the Dan Field and from large sections of the flanks of the field. Particularly the western flank of the Dan Field, close to the Halfdan Field, has demonstrated good production properties. The presence of oil in the western flank of the Dan Field was not confirmed until 1998 with the drilling of the MFF-19C well, which also established the existence of the Halfdan Field.

PRODUCTION STRATEGY

Recovery from the field is based on the simultaneous production of oil and injection of water to maintain reservoir pressure. Water injection was initiated in 1989, and has gradually been extended to the whole field. The recovery of oil is optimized by flooding the reservoir with water to the extent possible.

PRODUCTION FACILITIES

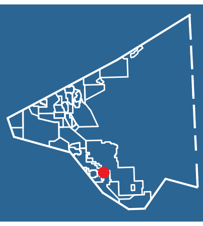
The Dan Field comprises six wellhead platforms, A, D, E, FA, FB and FE, a combined wellhead and processing platform, FF, a processing platform with a flare tower, FG, two processing and accommodation platforms, B and FC, and two gas flare stacks, C and FD.

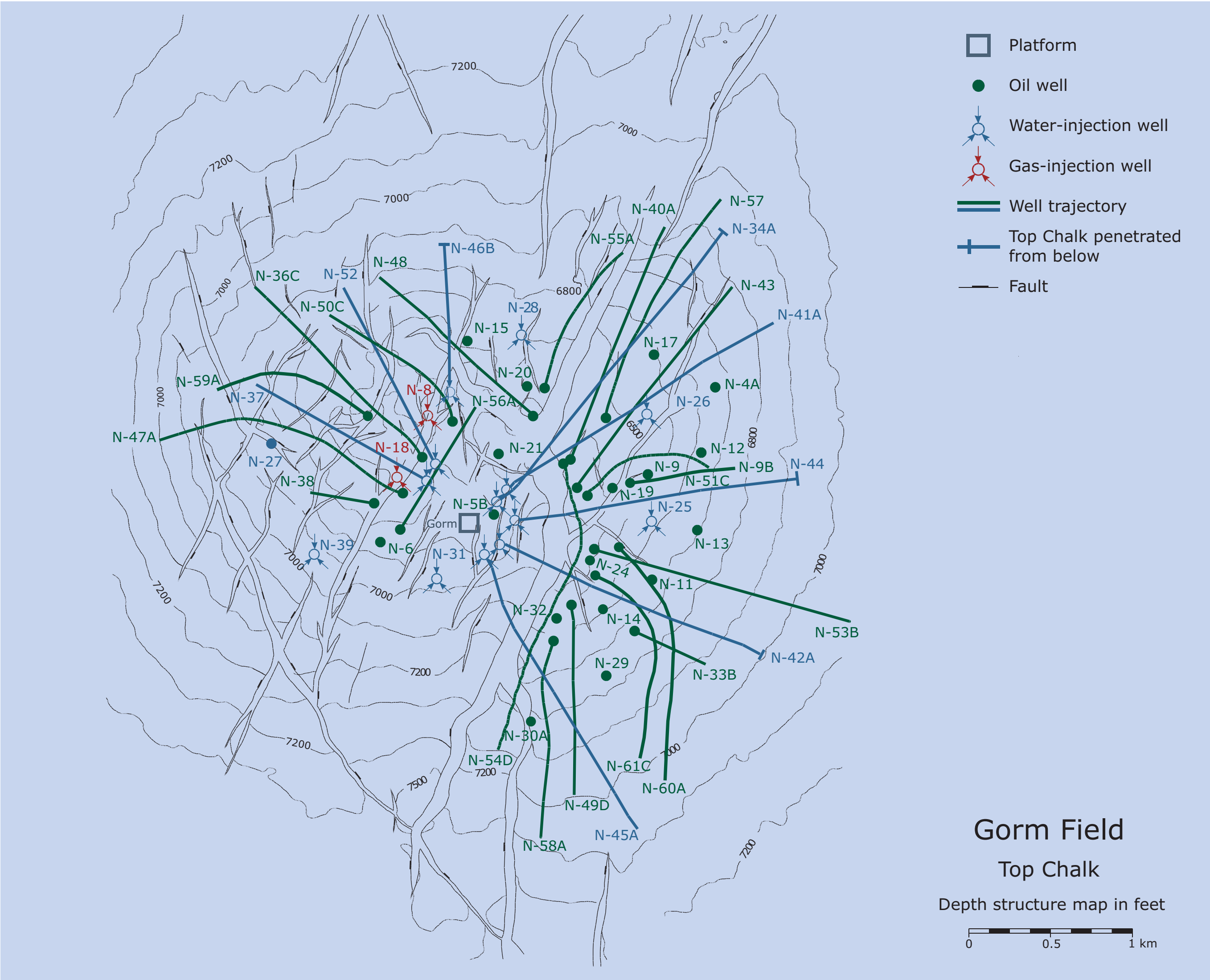
At the Dan Field, there are facilities for receiving production from the adjacent Kraka and Regnar satellite fields, as well as for receiving gas produced at the Halfdan Field. The Dan installations supply the Halfdan Field with injection water.

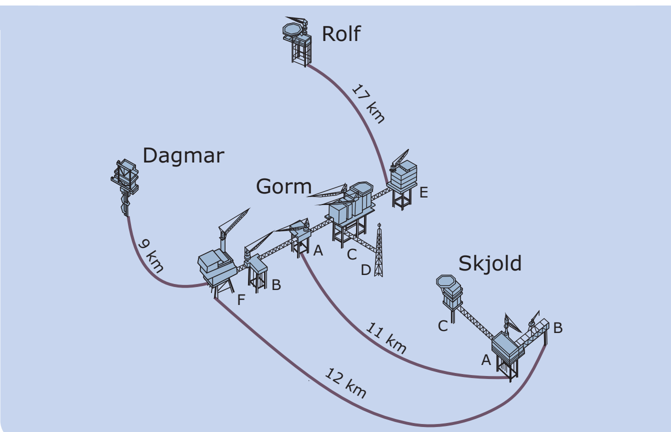
After final processing, the oil is transported to shore via the Gorm E platform. The gas is pre-processed and transported to Tyra East for final processing. Treated production water from Dan and its satellite fields is discharged into the sea.

In the Dan Field, there are accommodation facilities for 97 persons on the FC platform and five persons on the B platform.

THE GORM FIELD

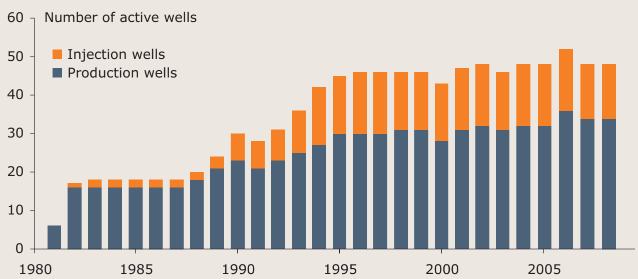






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 13.7 billion



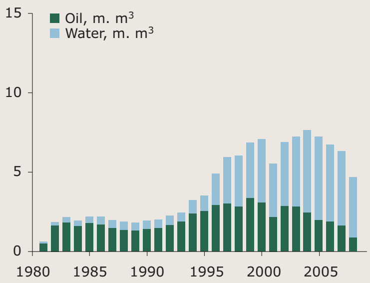
FIELD DATA
At 1 January 2009

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:	36
Gas-injection wells:	2
Water-injection wells:	14
Water depth:	39 m
Field delineation:	33 km²
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2009

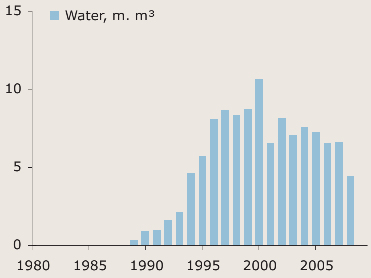
Oil:	57.09 m. m³
Gas:	15.35 bn. Nm³
Water:	58.50 m. m³



INJECTION

Cum. injection at 1 January 2009

Gas:	8.16 bn. Nm³
Water:	115.50 m. m³



RESERVES

Oil:	6.4 m. m³
Gas:	0.8 bn. Nm³

REVIEW OF GEOLOGY, THE GORM FIELD

The Gorm Field is an anticlinal structure, induced through 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

The production strategy for the Gorm Field is to maintain reservoir pressure through water injection, which was initiated in 1989. In addition, the influx of water from the aquifer and compaction in the reservoir stimulate production. Water injection takes place both at the flank of the field and the bottom of the reservoir. Produced water is reinjected.

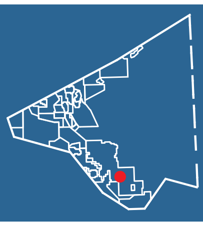
PRODUCTION FACILITIES

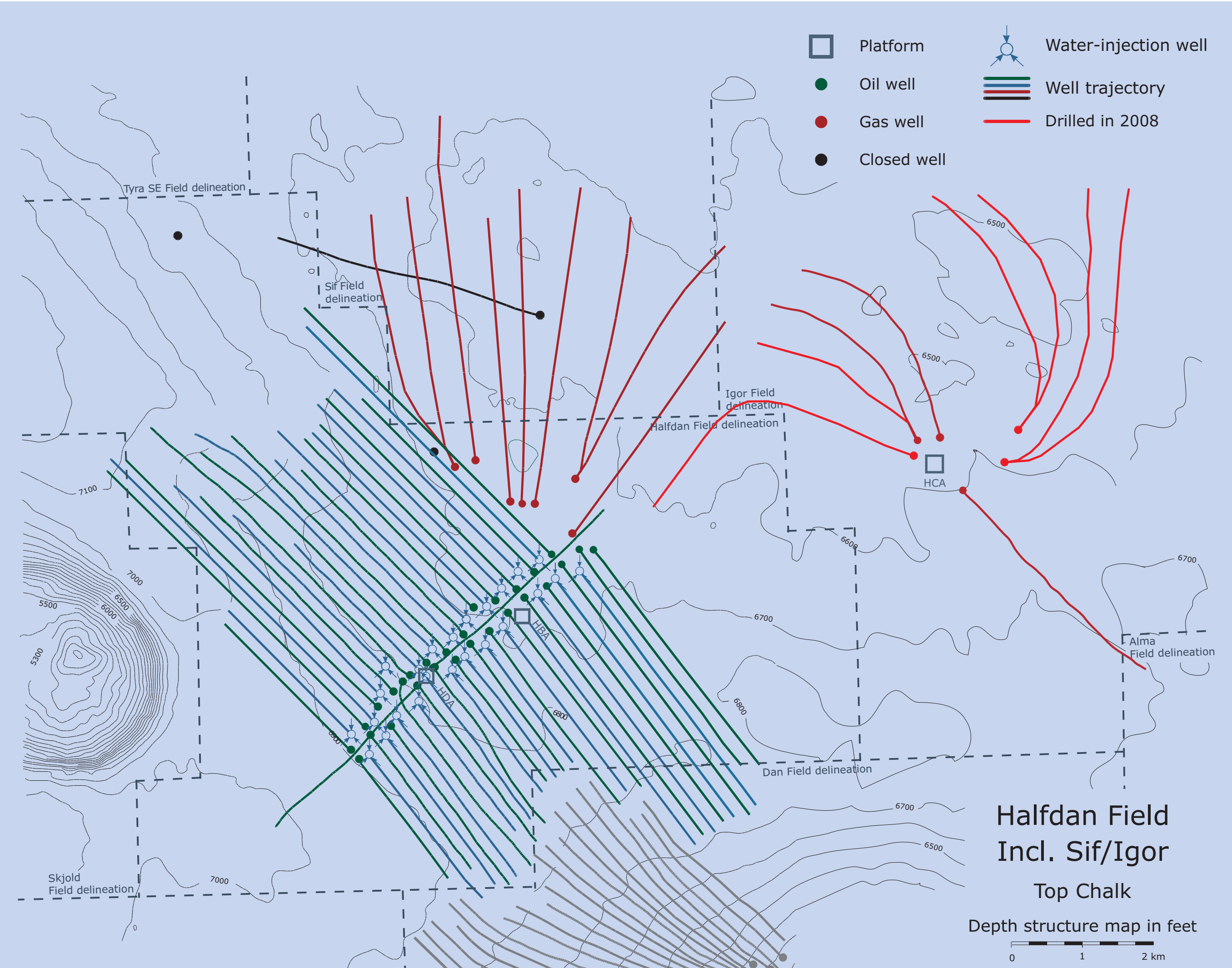
The Gorm Field consists of two wellhead platforms, Gorm A and B, one processing and accommodation platform, Gorm C, one gas flare stack, Gorm D, one riser and export platform, Gorm E (owned by DONG Oil Pipe A/S) and one combined wellhead, processing and riser platform, Gorm F.

Gorm receives production from the satellite fields, Skjold, Rolf and Dagmar. The Gorm Field installations supply the Skjold Field with injection water and lift gas and the Rolf Field with lift gas. The stabilized oil from all DUC's facilities is transported ashore via the riser platform Gorm E. The gas produced is sent to Tyra East. The oil produced at the Halfdan Field is transported to Gorm C for final processing.

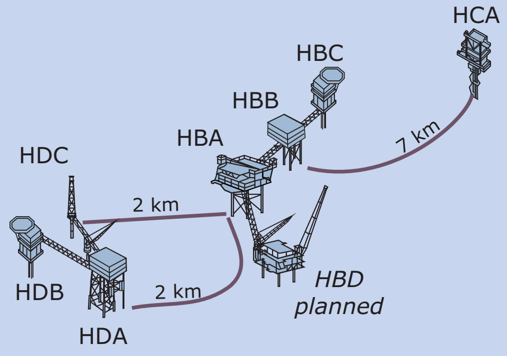
There are accommodation facilities on the Gorm C platform for 98 persons.

THE HALFDAN FIELD INCL. SIF AND IGOR



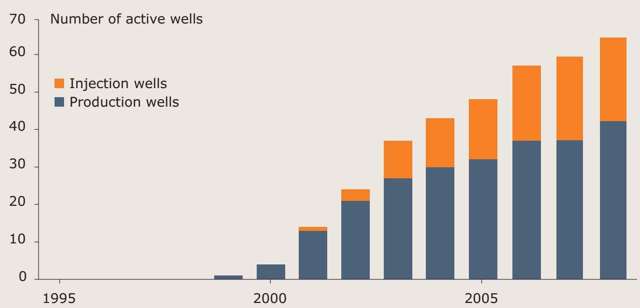


For more detailed maps, see pages 92 and 93.



DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 15.0 billion



FIELD DATA
At 1 January 2009

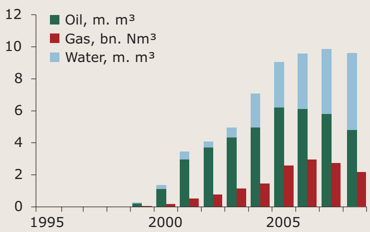
Prospect:	Nana, Sif and Igor
Location:	Blocks 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1968, 1999
Year on stream:	1999, 2004 and 2007
Oil-producing wells:	30 (Halfdan)
Water-injection wells:	25 (Halfdan)
Gas-producing wells:	13 (Sif and Igor)
Reservoir depth:	2,030-2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

Further details appear from the boxes on pages 92 and 93.

PRODUCTION

Cum. production at 1 January 2009

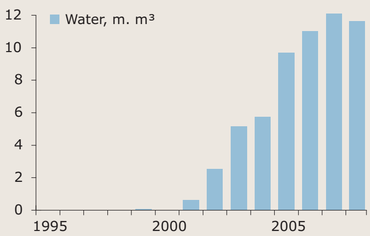
Oil:	40.72 m. m^3
Gas:	15.40 bn. Nm^3
Water:	19.00 m. m^3



INJECTION

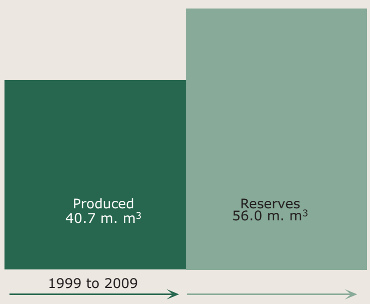
Cum. injection at 1 January 2009

Water:	58.66 m. m^3



RESERVES

Oil:	56.0 m. m^3
Gas:	19.9 bn. Nm^3



REVIEW OF GEOLOGY, THE HALFDAN FIELD

The Halfdan Field comprises the Halfdan, Sif and Igor areas and contains a continuous hydrocarbon accumulation at different strata levels. The southwestern part of the field primarily contains oil in Maastrichtian layers, while the area towards the north and east primarily contains gas in Danian layers.

The accumulation is contained in a limited part of the chalk formation, which constituted a structural trap in earlier geological times. The structure gradually disintegrated, and the oil began migrating away from the area due to later movements in the reservoir layers. However, the oil and gas deposits have migrated a short distance only 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.

PRODUCTION STRATEGY

Recovery is based on the Fracture Aligned Sweep Technology (FAST), where long horizontal wells are arranged in a pattern of alternate production and water-injection wells with parallel well trajectories. Varying the injection pressure in the well causes the rock to fracture. This generates a continuous water front along the whole length of the well, which drives the oil in the direction of the production wells.

The production of gas from Danian layers is based on primary recovery from multilateral horizontal wells, using the reservoir pressure. The Sif wells extend from the Halfdan BA platform in a fan-like pattern, while the Igor wells form a helical pattern from the Halfdan CA platform.

PRODUCTION FACILITIES

The Halfdan Field comprises two platform complexes, Halfdan D and Halfdan B, as well as an unmanned satellite platform, Halfdan CA.

Halfdan B is located about 2 km from Halfdan D, which provides it with power, injection water and lift gas. Halfdan CA, with capacity for ten wells, is located about 7 km northeast of the Halfdan B complex.

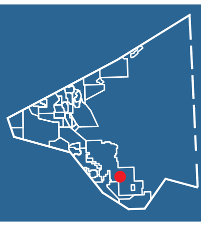
The Dan installations supply Halfdan D and B with injection water. Treated production water from Halfdan and Sif/Igor is discharged into the sea.

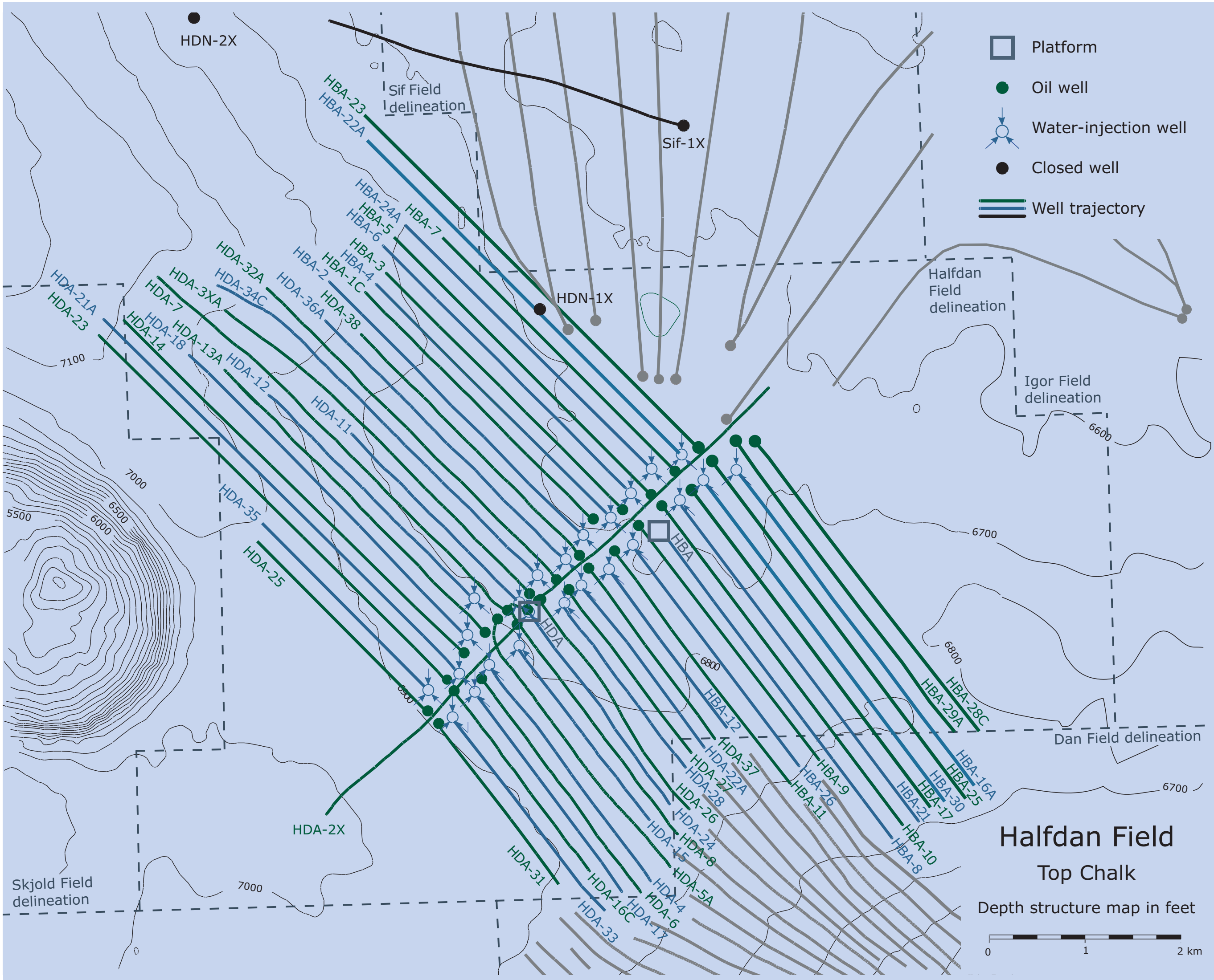
To increase the processing and transportation capacity for production from the Halfdan Field, a new 20” pipeline has been established to transport oil and produced water from the Halfdan B complex to the Dan FG platform in the Dan Field.

Halfdan HDB has accommodation facilities for 32 persons, while there are accommodation facilities for 80 persons at Halfdan HBC.

More details about the facilities can be found on pages 92 and 93.

THE HALFDAN FIELD (MAIN FIELD)





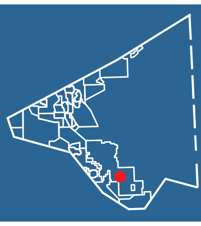
FIELD DATA At 1 January 2009

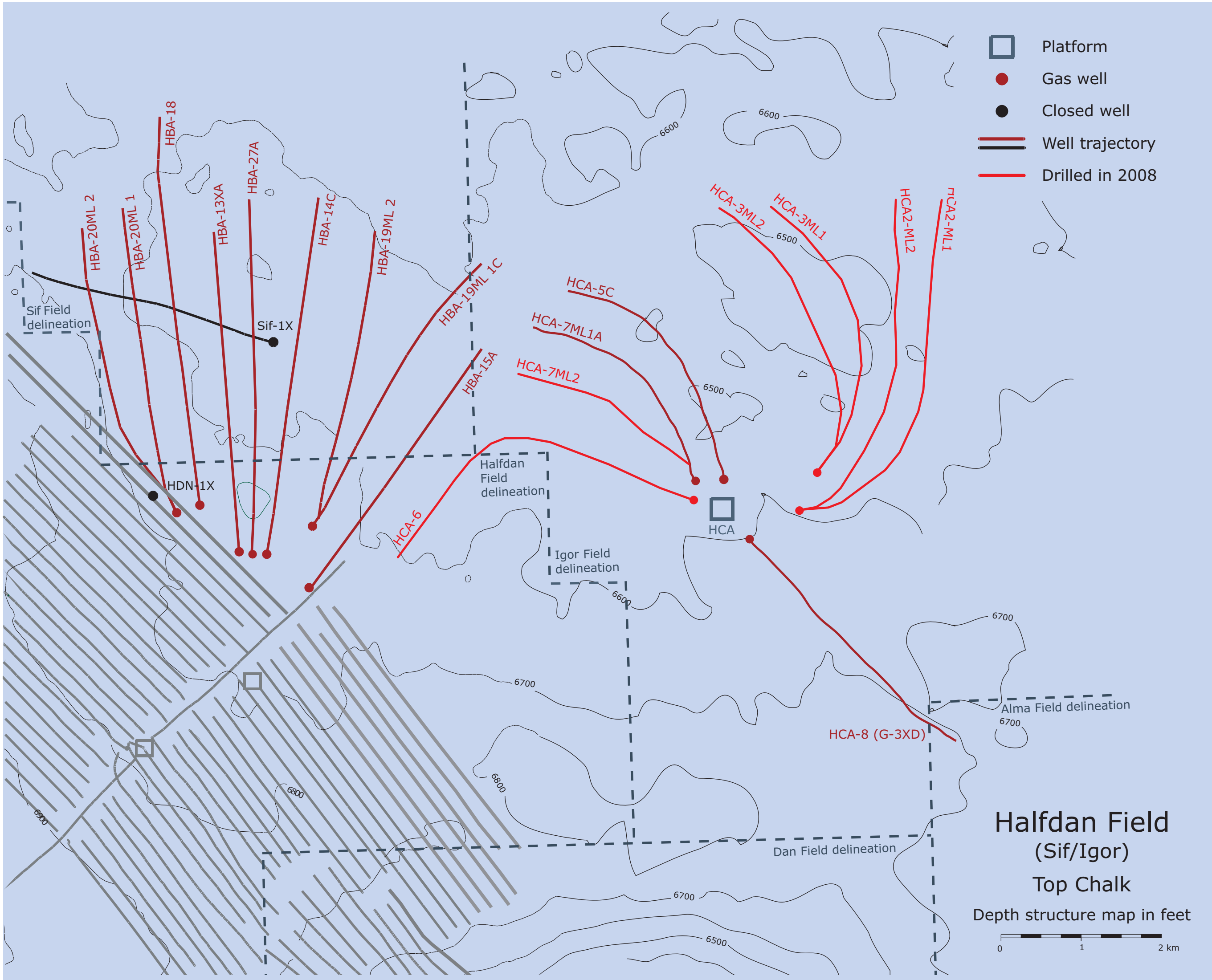
Prospect:	Nana
Location:	Blocks 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1999
Year on stream:	1999
Oil-producing wells:	30 (Halfdan)
Water-injection wells:	25 (Halfdan)
Water depth:	43 m
Field delineation:	107 km² (Halfdan)
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Upper Cretaceous

Halfdan D consists of a combined wellhead and processing platform, HDA, an accommodation platform, HDB, a gas flare stack, HDC, while Halfdan B consists of an unmanned wellhead platform, HBA, and an unmanned riser and wellhead platform, HBB. In addition, the Halfdan B complex has an accommodation platform, HBC, which is connected to HBB by a bridge. A new processing platform, HBD, has been approved and is scheduled for commissioning in about 2011.

Production from the oil wells at HBA and the liquid production from Sif/Igor is transported to the Halfdan D complex for processing, and from there to Gorm for final processing and export ashore.

THE HALFDAN FIELD (NORTHEAST)





FIELD DATA

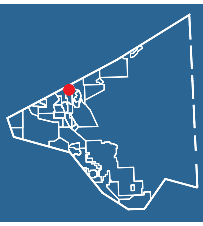
At 1 January 2009

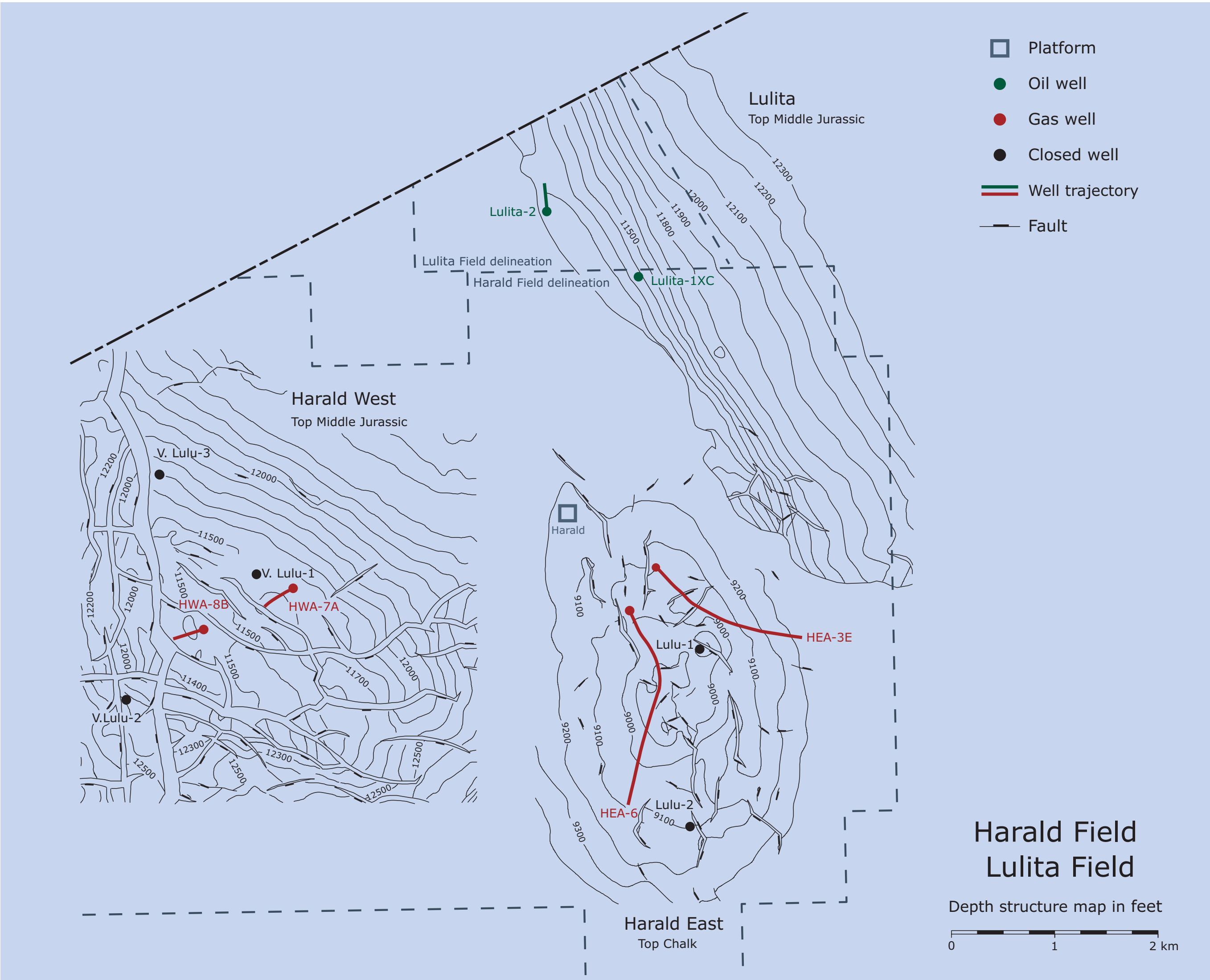
Prospect (former and current names):	Sif and Igor
Location:	Block 5505/13
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1999 (Sif), 1968 (Igor)
Year on stream:	2004 (Sif), 2007 (Igor)
Gas-producing wells:	7 (Sif), 6 (Igor)
Water depth:	44 m (Sif), 45 m (Igor)
Field delineation:	40 km² (Sif) 109 km² (Igor)
Reservoir depth:	2,030 m
Reservoir rock:	Chalk
Geological age:	Danian

After being separated into liquids and gas, the production from the Halfdan HCA platform is transported through two new pipelines to the Halfdan B complex.

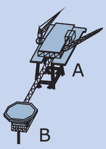
The gas from the Sif/Igor installations on the HBA platform is conveyed to Tyra West, while the gas from Halfdan D is transported to Dan for export ashore via Tyra East or to Tyra West for export to the Netherlands through the NOGAT pipeline.

THE HARALD FIELD



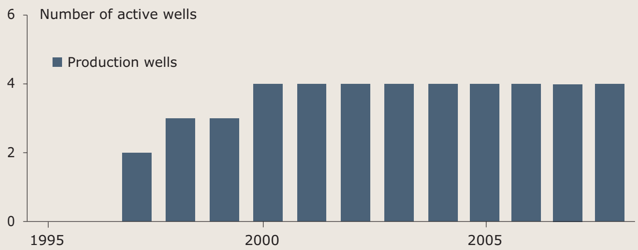


Harald / Lulita



DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 3.8 billion



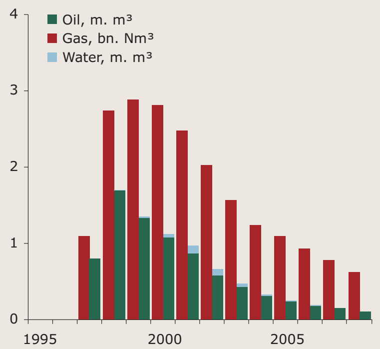
FIELD DATA At 1 January 2009

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
Gas-producing wells:	2 (Harald East)
	2 (Harald West)
Water depth:	64 m
Field delineation:	56 km²
Reservoir depth:	2,700 m (Harald East)
	3,650 m (Harald West)
Reservoir rock:	Chalk (Harald East)
	Sandstone (Harald West)
Geological age:	Danian/Upper Cretaceous and Middle Jurassic, respectively

PRODUCTION

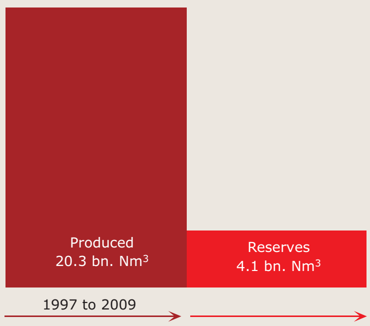
Cum. production at 1 January 2009

Oil:	7.75 m. m³
Gas:	20.30 bn. Nm³
Water:	0.36 m. m³



RESERVES

Oil and condensate:	0.7 m. m³
Gas:	4.1 bn. Nm³



REVIEW OF GEOLOGY, THE HARALD FIELD

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

The Harald East structure is an anticline induced through salt tectonics. The gas zone is up to 75 m thick.

The Harald West structure is a tilted Jurassic fault block. The sandstone reservoir is of Middle Jurassic age, and is 100 m thick.

PRODUCTION STRATEGY

Recovery from both the Harald East and the Harald West reservoir takes place by gas expansion, with 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. By maximizing the drainage from the other gas fields, gas drainage from Tyra is minimized.

PRODUCTION FACILITIES

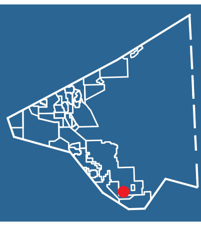
The Harald Field comprises a combined wellhead and processing platform, Harald A, and an accommodation platform, Harald B. The unprocessed condensate and the processed gas are transported to Tyra East. Treated production water is discharged into the sea.

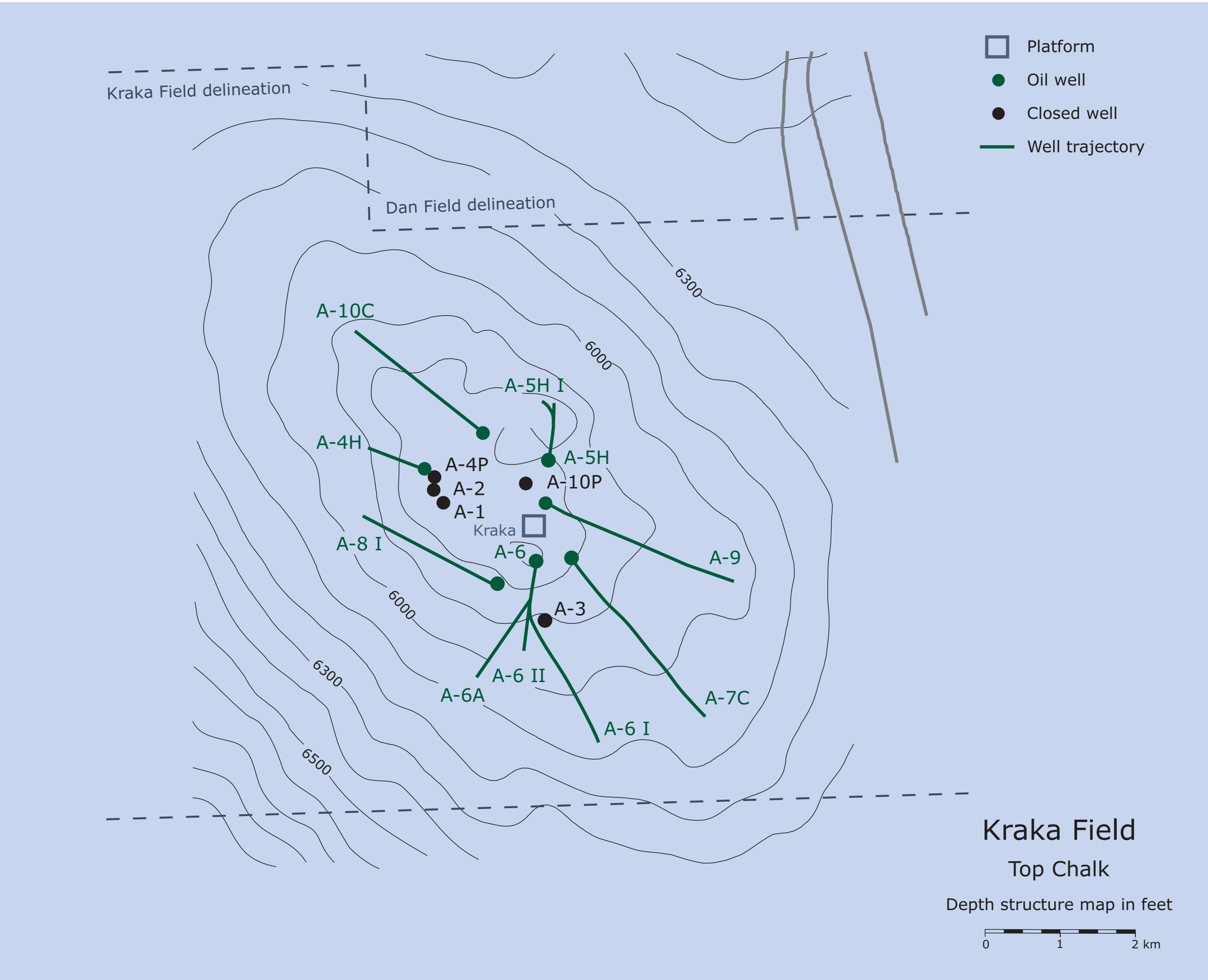
The Harald Field is hooked up to the gas pipeline that transports gas from the South Arne Field to Nybro. Normally, no gas is exported from Harald through the pipeline.

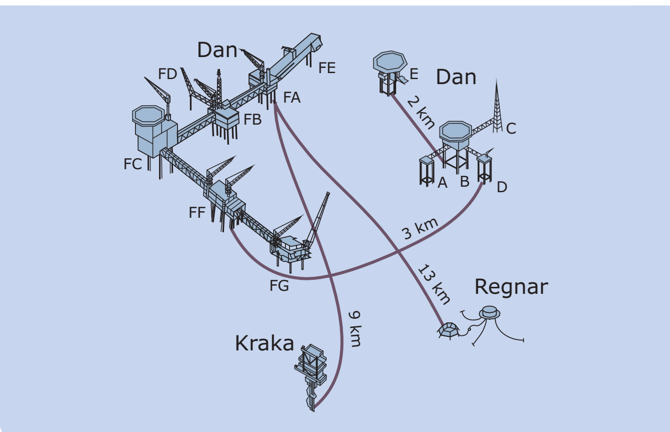
The Harald Field has accommodation facilities for 16 persons.

For more information, reference is made to the Lulita Field, which is hosted by the Harald A platform.

THE KRAKA FIELD



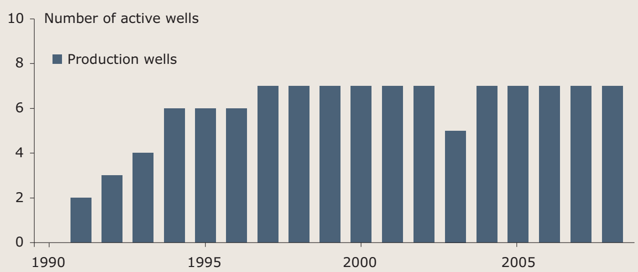




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009

2008 prices DKK 1.6 billion



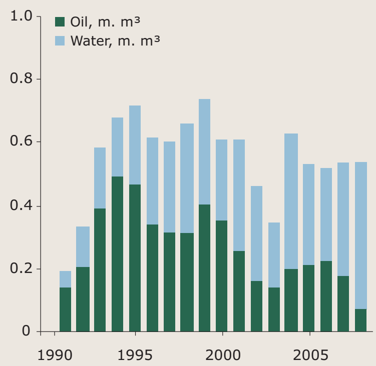
FIELD DATA
At 1 January 2009

Prospect:	Anne
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1966
Year on stream:	1991
Producing wells:	7
Water depth:	45 m
Field delineation:	81 km^2
Reservoir depth:	1,800 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

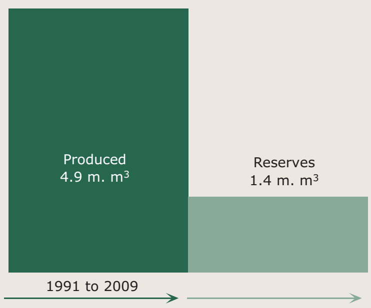
Cum. production at 1 January 2009

Oil:	4.89 m. m^3
Gas:	1.38 bn. Nm^3
Water:	5.00 m. m^3



RESERVES

Oil:	1.4 m. m^3
Gas:	0.4 bn. Nm^3



REVIEW OF GEOLOGY, THE KRAKA FIELD

Kraka is an anticlinal structure induced through salt tectonics, which has caused some fracturing in the chalk. The 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 field.

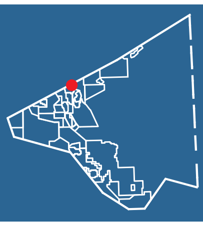
PRODUCTION STRATEGY

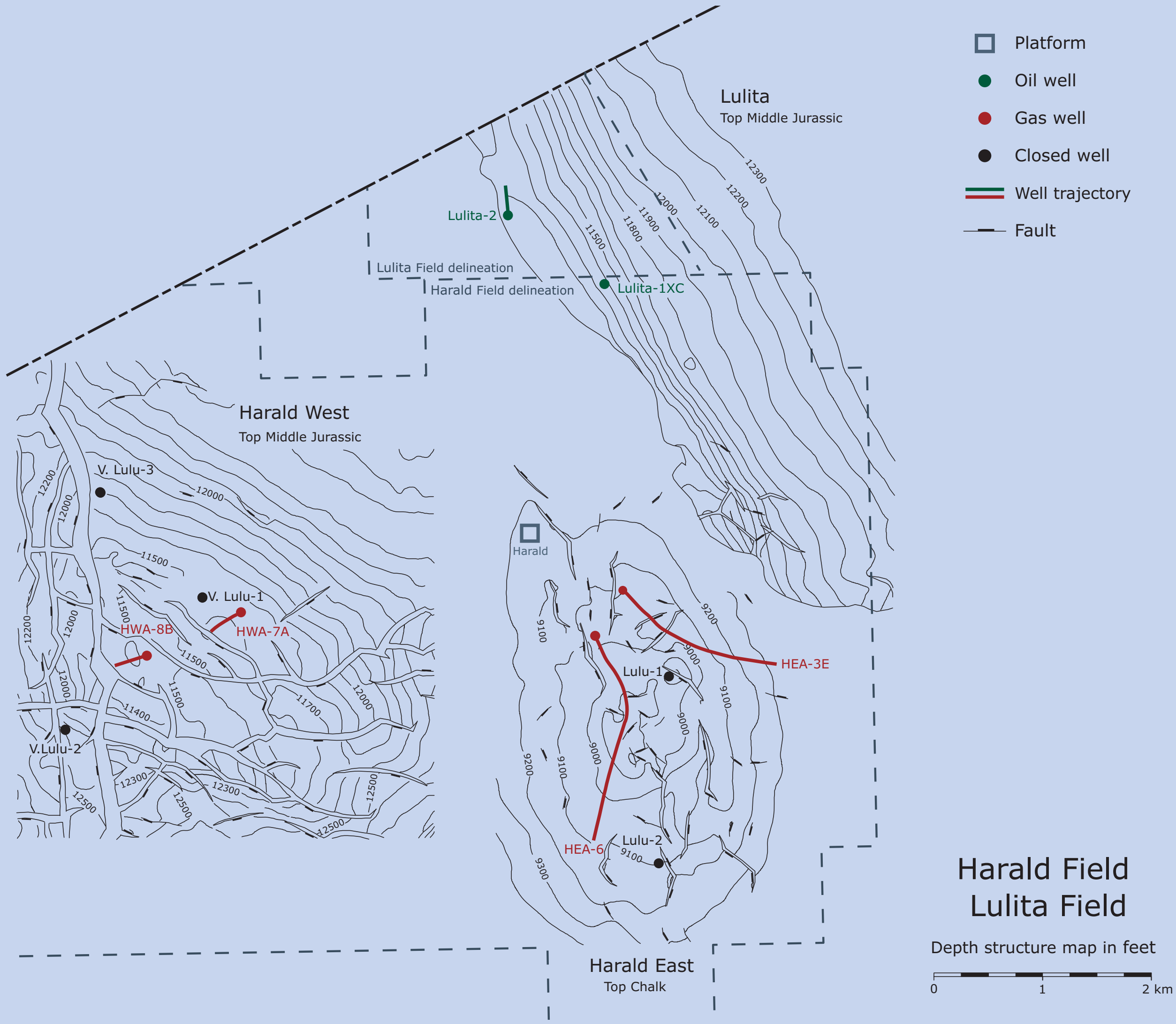
Recovery from Kraka is based on the natural expansion of the gas cap and aquifer support. The individual wells are produced at the lowest possible bottom-hole pressure. Oil production from the field is maximized by prioritizing gas lift in wells with a low water content and a low gas-oil ratio.

PRODUCTION FACILITIES

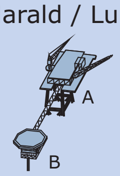
Kraka is a satellite development to the Dan Field with one unmanned wellhead platform without a helideck. The production is transported to Dan F for processing and export ashore. Lift gas is imported from the Dan Field.

THE LULITA FIELD





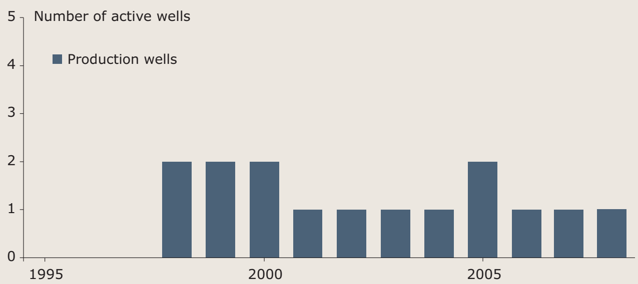
Harald / Lulita



DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009

2008 prices	DKK 0.1 billion



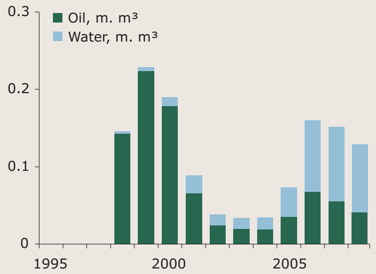
FIELD DATA
At 1 January 2009

Location:	Blocks 5604/18 and 22
Licence:	Sole Concession (50 per cent), 7/86 (34.5 per cent) and 1/90 (15.5 per cent)
Operator:	Mærsk Olie og Gas AS
Discovered:	1992
Year on stream:	1998
Producing wells:	2
Water depth:	65 m
Area:	3 km^2
Reservoir depth:	3,525 m
Reservoir rock:	Sandstone
Geological age:	Middle Jurassic

PRODUCTION

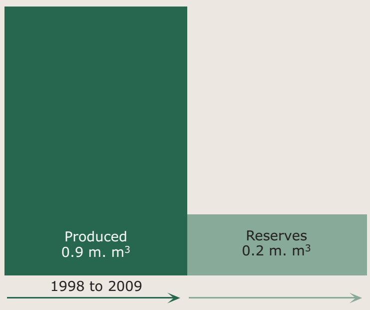
Cum. production at 1 January 2009

Oil:	0.88 m. m^3
Gas:	0.57 bn. Nm^3
Water:	0.40 m. m^3



RESERVES

Oil:	0.2 m. m^3
Gas:	0.1 bn. Nm^3



REVIEW OF GEOLOGY, THE LULITA FIELD

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.

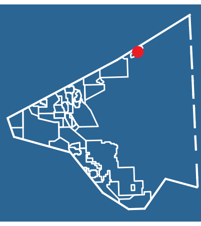
PRODUCTION FACILITIES

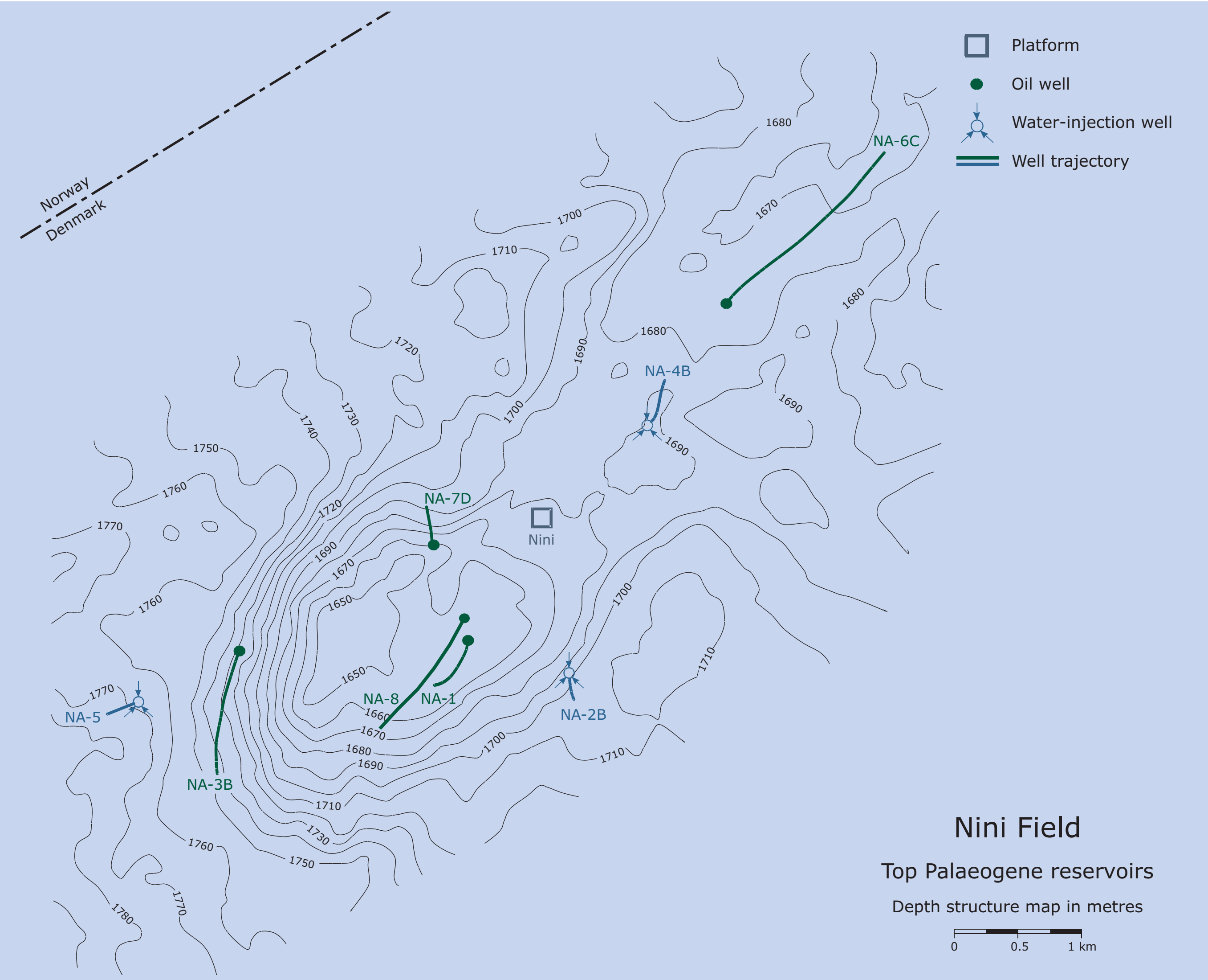
Production from the Lulita Field takes place from the fixed installations in the Harald Field. Thus, the Lulita facilities are hosted by the Harald A platform, and the Harald platform processing equipment also handles production from the Lulita Field.

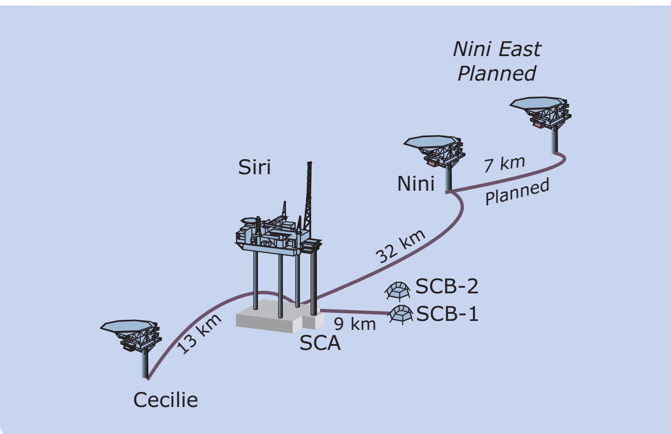
Together with condensate from the Harald Field, the oil produced is transported through a 16" pipeline to Tyra East for export ashore. The gas produced in the Lulita Field is transported to Tyra through the 24" pipeline connecting Harald with Tyra East, from where it is transported to shore. The water produced at the Lulita Field is processed at the Harald Field facilities and subsequently discharged into the sea.

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

THE NINI FIELD



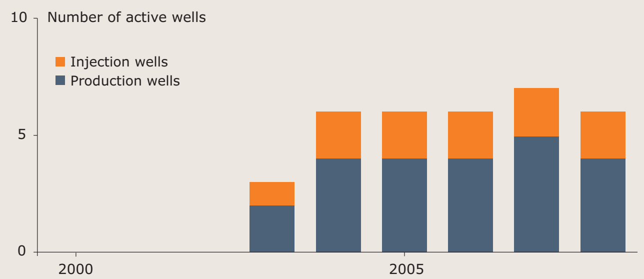




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009

2008 prices DKK 3.1 billion



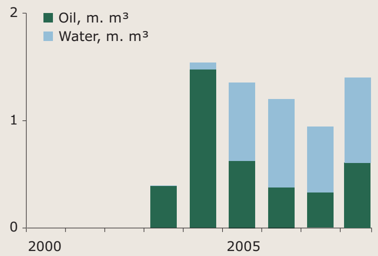
FIELD DATA
At 1 January 2009

Location:	Blocks 5605/10 and 14
Licence:	4/95
Operator:	DONG E&P A/S
Discovered:	2000
Year on stream:	2003
Producing wells:	5
Water-injection wells:	3
Water depth:	60 m
Field delineation:	44.6 km²
Reservoir depth:	1,700 m
Reservoir rock:	Sandstone
Geological age:	Eocene/Paleocene

PRODUCTION

Cum. production at 1 January 2009

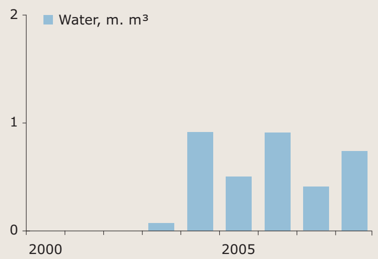
Oil:	3.55 m. m³
Gas:	0.26 bn. Nm³
Water:	2.89 m. m³



INJECTION

Cum. injection at 1 January 2009

Water:	3.71 m. m³



RESERVES

Oil:	3.7 m. m³
Gas:	0.0 bn. Nm³

REVIEW OF GEOLOGY, THE NINI FIELD

The Nini accumulation is defined by a combined structural and stratigraphic trap, the anticlinal structure being induced through salt tectonics. The reservoir consists of sands deposited in the Siri Fairway. The field comprises more or less well-defined accumulations.

PRODUCTION STRATEGY

The production strategy is to maintain reservoir pressure by means of water injection. The gas produced is injected into the Siri Field.

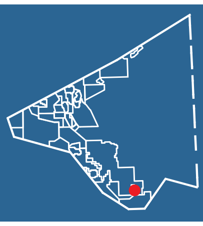
PRODUCTION FACILITIES

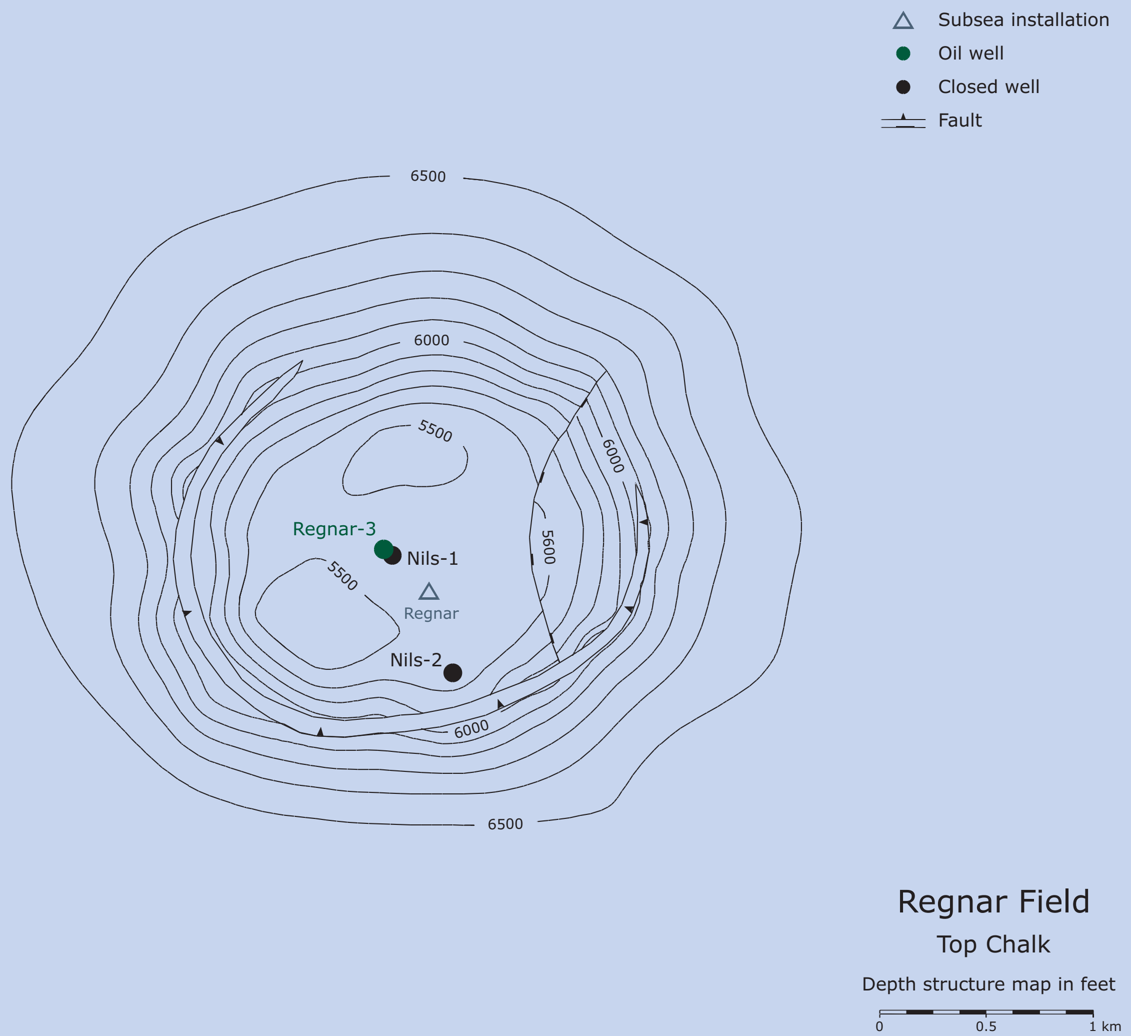
The Nini Field is a satellite development to the Siri Field with one unmanned wellhead platform with a helideck. The unprocessed production is transported through a 14" multiphase pipeline to the Siri platform where it is processed and exported to shore via tanker. Injection water and lift gas are transported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

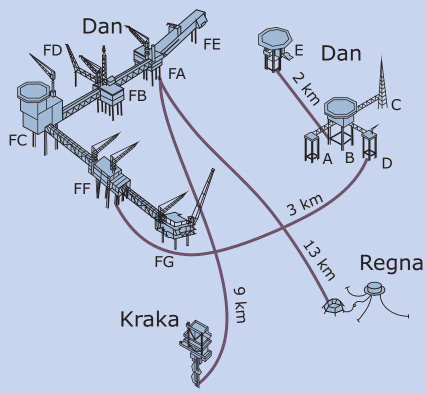
On 29 January 2008, the DEA approved the establishment of a new unmanned wellhead platform in the eastern part of the Nini Field. This platform, which is currently under establishment, is called Nini East. The platform is similar to the Nini platform and will be provided with a helideck. The unprocessed production from Nini East will be sent to Siri via Nini. Siri will supply Nini East with injection water and lift gas via the Nini platform.

The new Nini East platform and three new pipelines are expected to be installed in 2009.

THE REGNAR FIELD

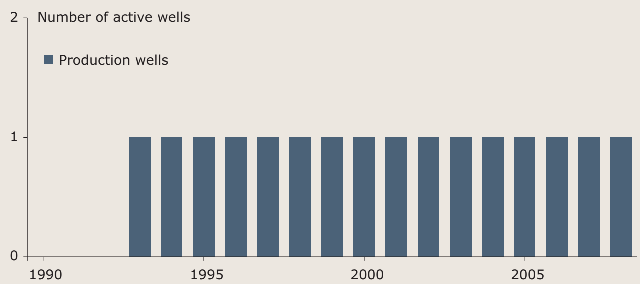






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 0.3 billion



FIELD DATA

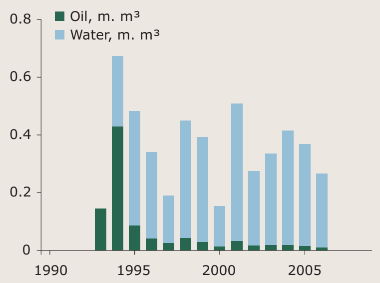
At 1 January 2009

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

PRODUCTION

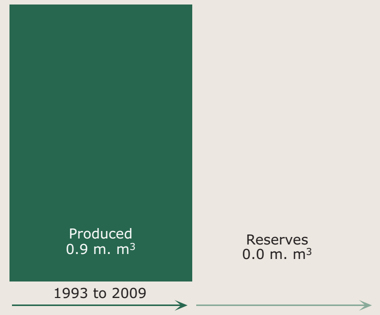
Cum. production at 1 January 2009

Oil:	0.93 m. m^3
Gas:	0.06 bn. Nm^3
Water:	4.06 m. m^3



RESERVES

Oil:	0.0 m. m^3
Gas:	0.0 bn. Nm^3



REVIEW OF GEOLOGY, THE REGNAR FIELD

The Regnar Field is an anticlinal structure, induced through salt tectonics. The reservoir is heavily fractured.

PRODUCTION STRATEGY

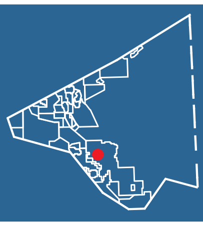
Production in the Regnar Field takes place from one vertical well on the crest of the structure. The oil is displaced towards the producing well by water flowing in from the underlying aquifer. The production strategy is to displace and produce as much of the oil as possible from the matrix of the formation.

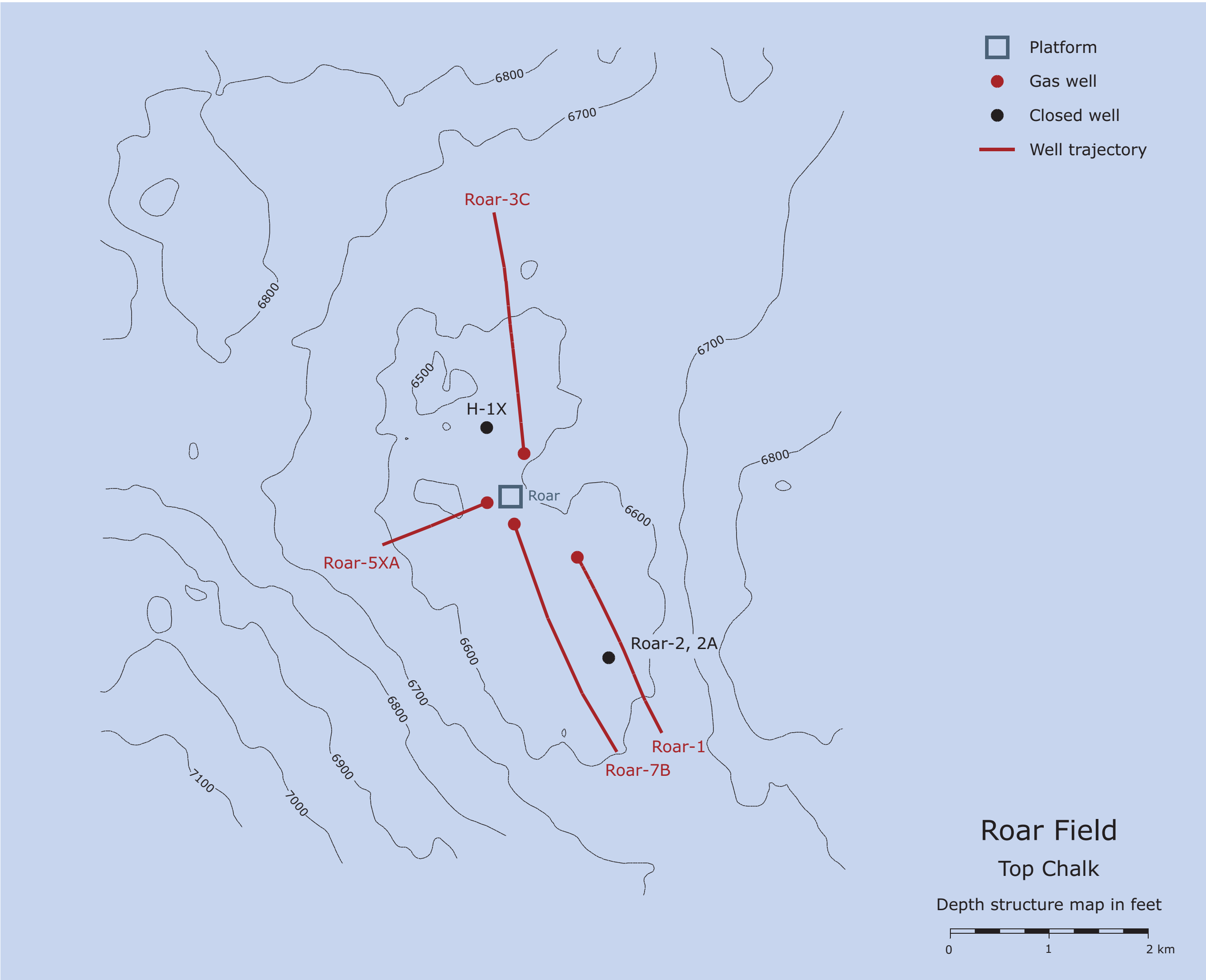
PRODUCTION FACILITIES

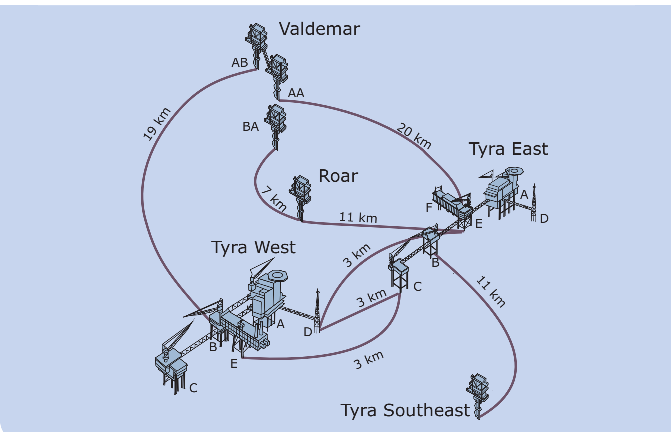
The Regnar Field has been developed as a satellite to the Dan Field. Production takes place in a subsea-completed well. The production is transported by pipeline in multiphase flow to Dan F for processing and export ashore.

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

THE ROAR FIELD

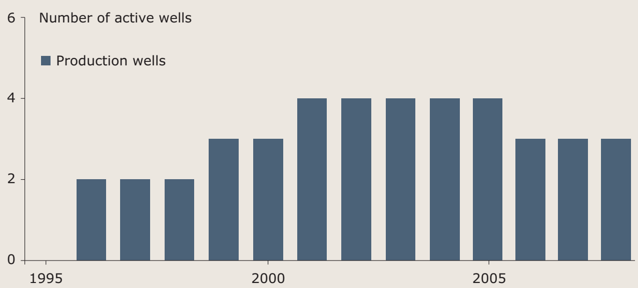






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 0.7 billion



FIELD DATA

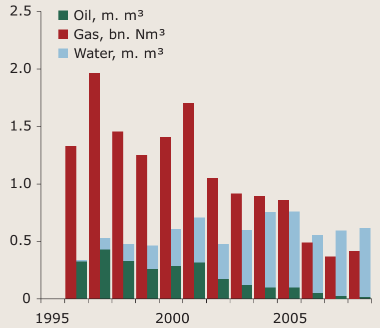
At 1 January 2009

Prospect:	Bent
Location:	Block 5504/7
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1968
Year on stream:	1996
Gas-producing wells:	4
Water depth:	46 m
Field delineation:	41 km²
Reservoir depth:	2,025 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

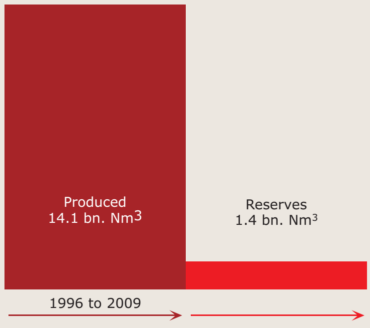
Cum. production at 1 January 2009

Oil:	2.54 m. m³
Gas:	14.11 bn. Nm³
Water:	4.89 m. m³



RESERVES

Oil:	0.1 m. m³
Gas:	1.4 bn. Nm³



REVIEW OF GEOLOGY, THE ROAR FIELD

The Roar Field is an anticlinal structure created by tectonic uplift. The accumulation consists of gas containing condensate. The reservoir is only slightly fractured.

PRODUCTION STRATEGY

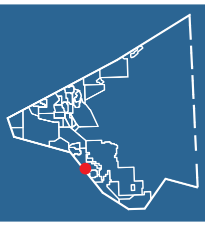
Recovery from the Roar Field takes place by gas expansion. The production strategy for the Roar Field is to optimize the production of liquid hydrocarbons in the Tyra Field by maximizing production from the other gas fields and thus minimizing gas drainage from Tyra.

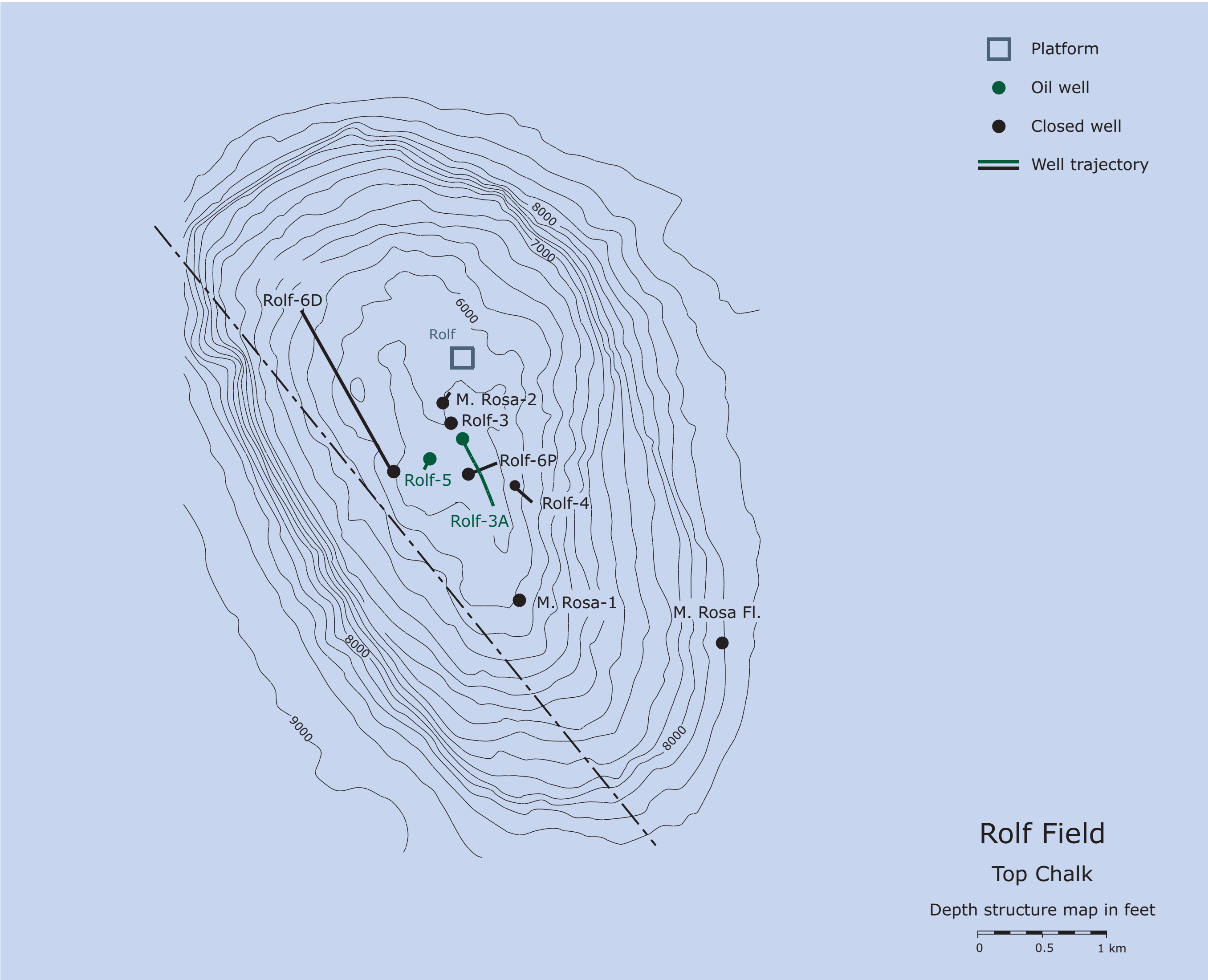
PRODUCTION FACILITIES

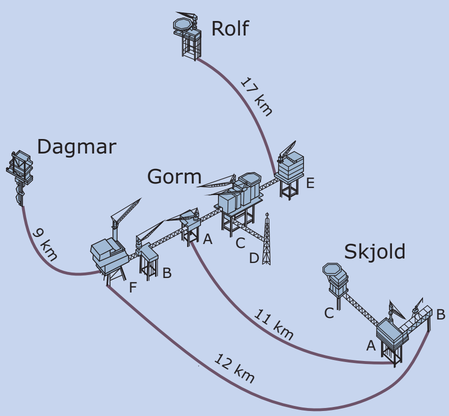
The Roar Field has been developed as a satellite to the Tyra Field with an unmanned wellhead platform of the STAR type, without a helideck. The production is separated into gas and liquids before being transported to Tyra East in two pipelines for further processing and subsequent export ashore. A pipeline from Tyra East supplies chemicals to the Roar platform.

A new 16” multiphase pipeline has been established from the Valdemar BA platform to Tyra East via the Roar Field, which transports the gas produced from Roar to Tyra East.

THE ROLF FIELD

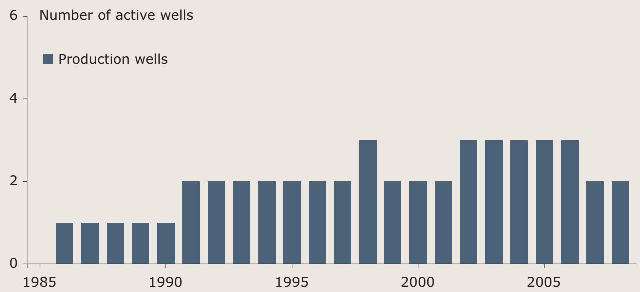






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 1.1 billion



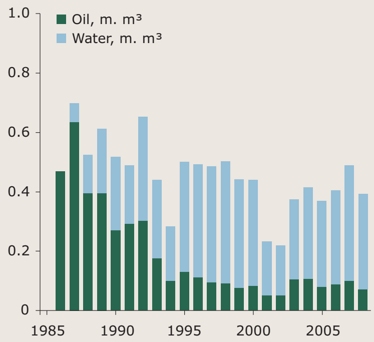
FIELD DATA
At 1 January 2009

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

PRODUCTION

Cum. production at 1 January 2009

Oil:	4.29 m. m^3
Gas:	0.18 bn. Nm^3
Water:	6.19 m. m^3



RESERVES

Oil:	0.6 m. m^3
Gas:	0.0 bn. Nm^3

REVIEW OF GEOLOGY, THE ROLF FIELD

The Rolf Field is an anticlinal structure, induced through salt tectonics. The reservoir is heavily fractured.

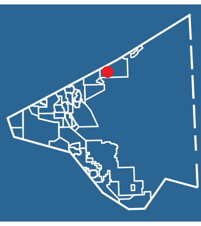
PRODUCTION STRATEGY

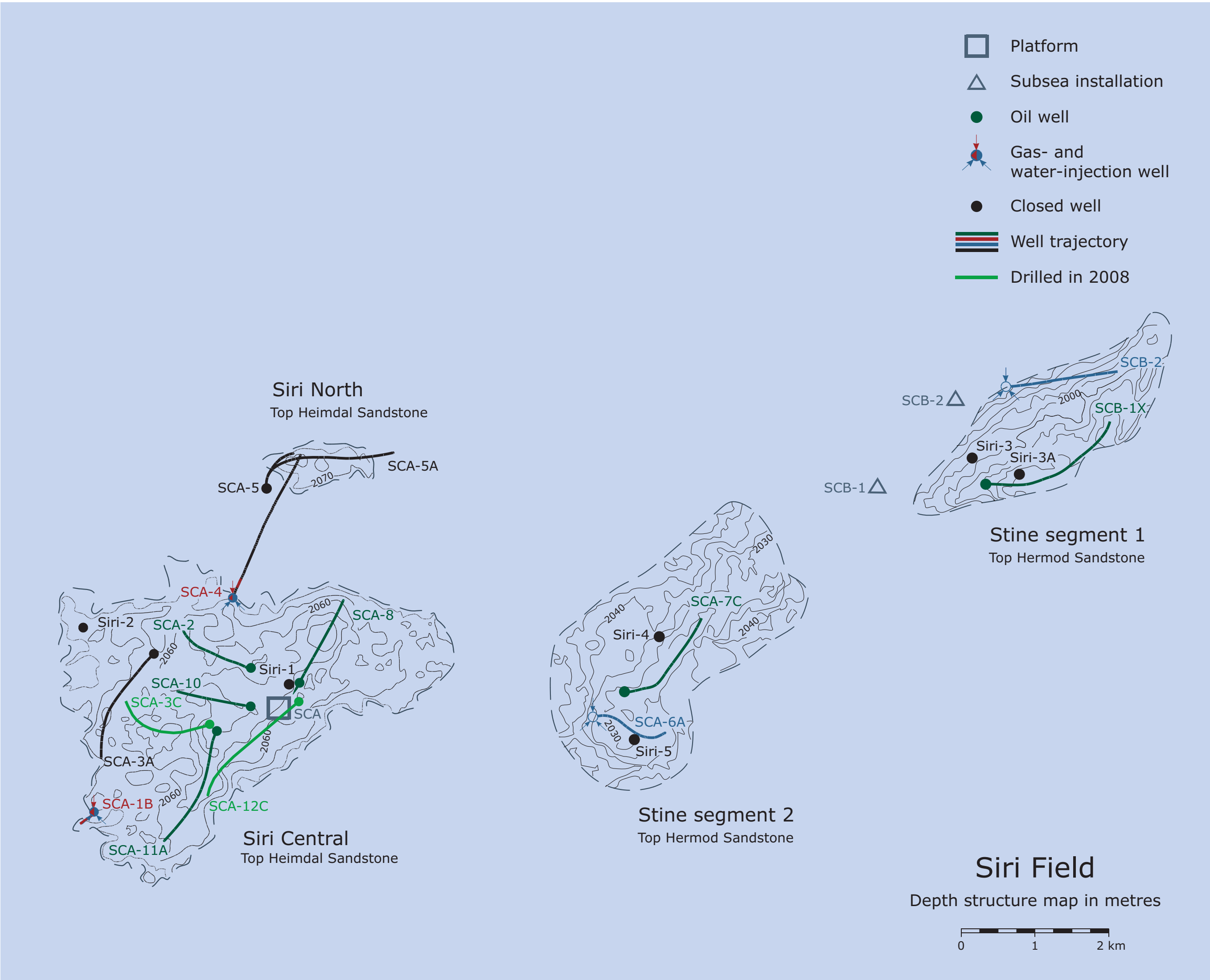
Production from the Rolf Field takes place from two wells drilled in the crest of the structure. The oil is displaced towards the producing wells by the water flow from an underlying aquifer. The natural influx of water from the water zone corresponds to the volume removed due to production in the central part of the structure.

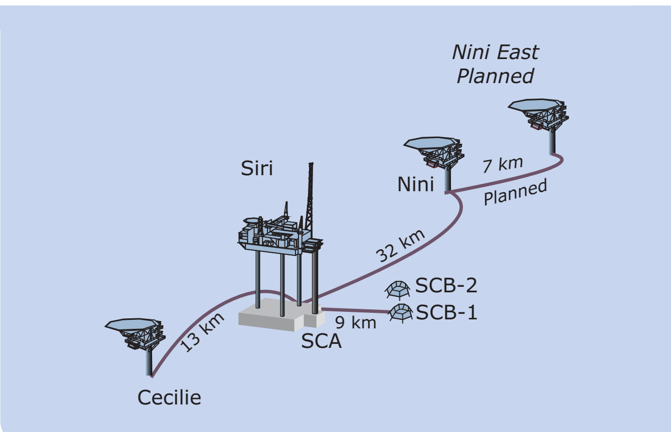
PRODUCTION FACILITIES

The Rolf Field is a satellite development to the Gorm Field with one unmanned wellhead platform with a helideck. The production is transported to the Gorm C platform for processing. Rolf is also supplied with power and lift gas from the Gorm Field.

THE SIRI FIELD



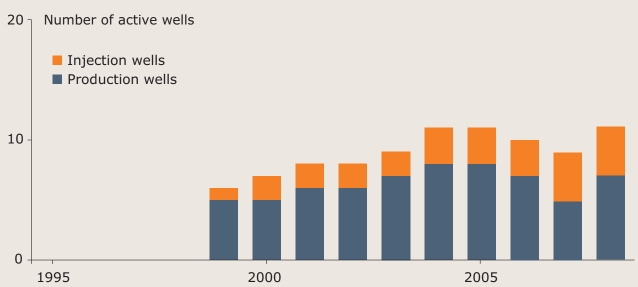




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009

2008 prices DKK 6.2 billion



FIELD DATA

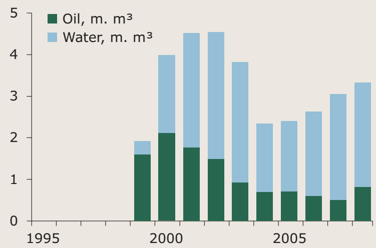
At 1 January 2009

Location:	Block 5604/20
Licence:	6/95
Operator:	DONG E&P A/S
Discovered:	1995
Year on stream:	1999
Producing wells:	6 (Siri Central) 1 (Stine segment 1) 1 (Stine segment 2)
Water-/gas-injection wells:	2 (Siri Central) 1 (Stine segment 1) 1 (Stine segment 2)
Water depth:	60 m
Field delineation:	42 km^2
Reservoir depth:	2,060 m
Reservoir rock:	Sandstone
Geological age:	Paleocene

PRODUCTION

Cum. production at 1 January 2009

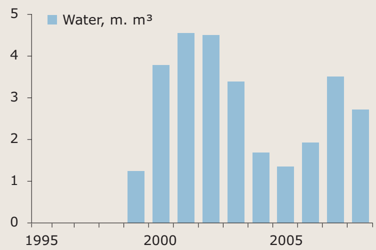
Oil:	10.98 m. m³
Gas:	1.12 bn. Nm³
Water:	21.44 m. m³



INJECTION

Cum. injection at 1 January 2009

Gas:	1.02 bn. Nm³
Water:	28.61 m. m³



RESERVES

Oil:	1.2 m. m³
Gas:	0.0 bn. Nm³

REVIEW OF GEOLOGY, THE SIRI FIELD

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

PRODUCTION STRATEGY

Recovery takes place from Siri Central as well as from the neighbouring Stine segments 1 and 2. The strategy for producing oil from Siri Central is to maintain reservoir pressure by means of the co-injection of water and gas. In addition, gas from the Cecilie and Nini Fields is injected into the Siri Field.

The recovery from Stine segment 1 is based on water injection to maintain reservoir pressure. Before 2006, when water injection was initiated, recovery from Stine segment 2 was based on natural depletion.

PRODUCTION FACILITIES

Siri and Stine segment 2 (SCA) comprise a combined wellhead, processing and accommodation platform.

The processing facilities consist of a plant that separates the hydrocarbons produced and a plant for processing the water produced. The platform also houses equipment for co-injecting gas and water.

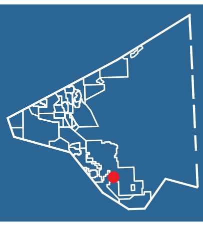
Stine segment 1 (SCB) is developed as a satellite to the Siri platform and consists of two subsea installations with a production well and an injection well.

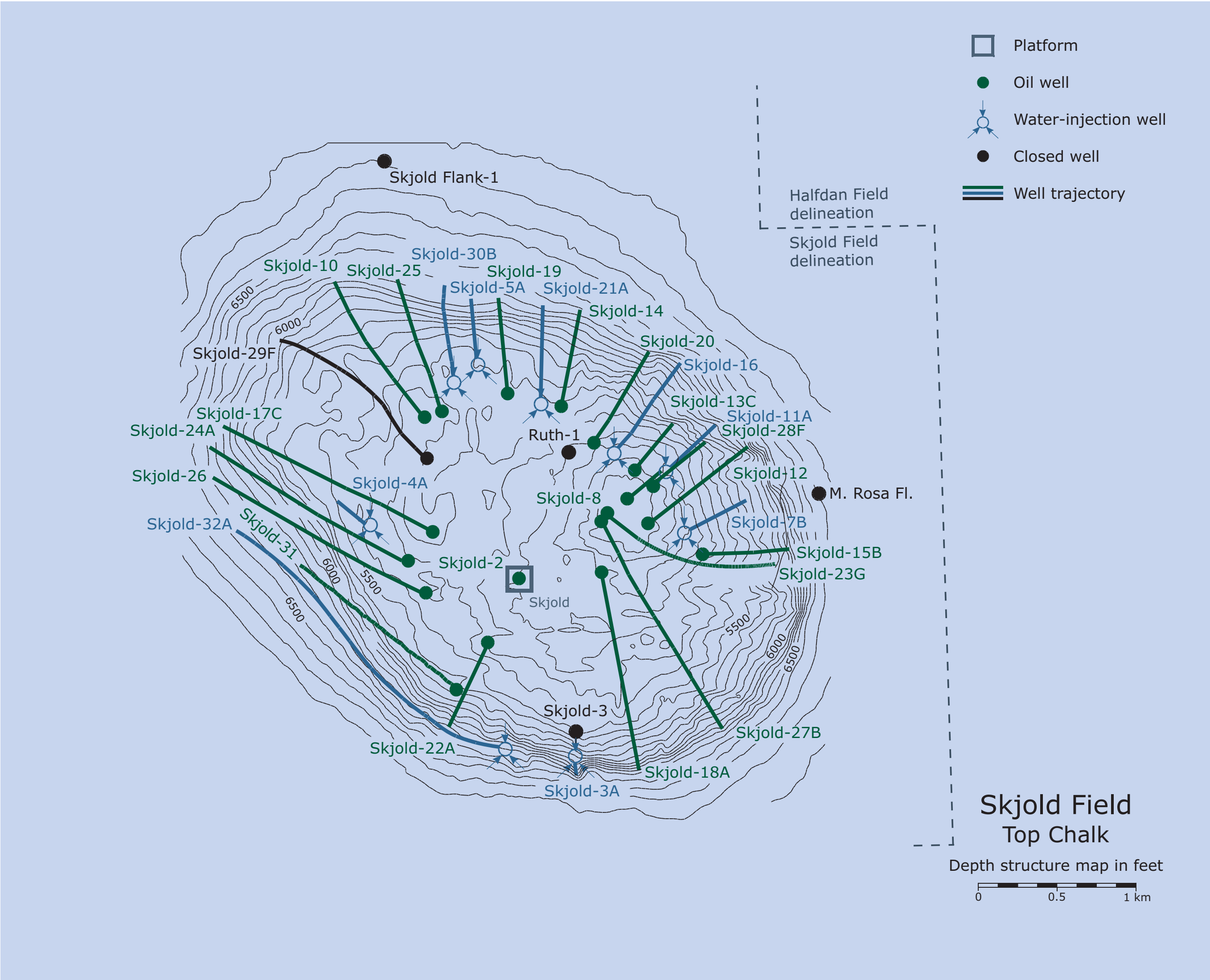
Production from SCB is conveyed to the Siri platform for processing. The Siri platform also supplies injection water and lift gas to the satellite installations at SCB, Nini and Cecilie. Injection water is supplied to SCB via a branch of the water pipeline leading to Nini.

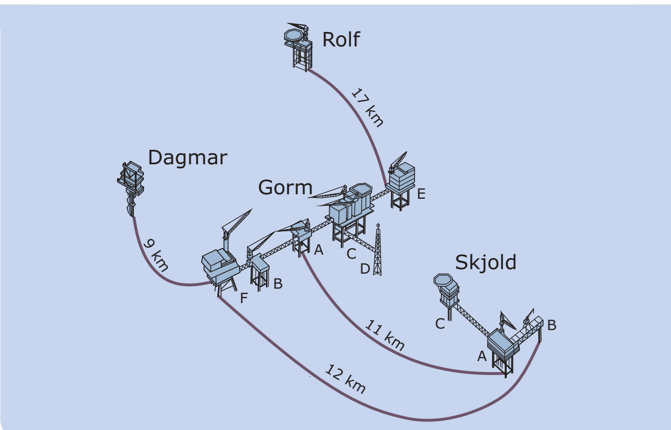
The oil produced is piped to a 50,000 m³ storage tank on the seabed, and subsequently transferred to a tanker by means of buoy-loading facilities.

The Siri Field has accommodation facilities for 60 persons.

THE SKJOLD FIELD



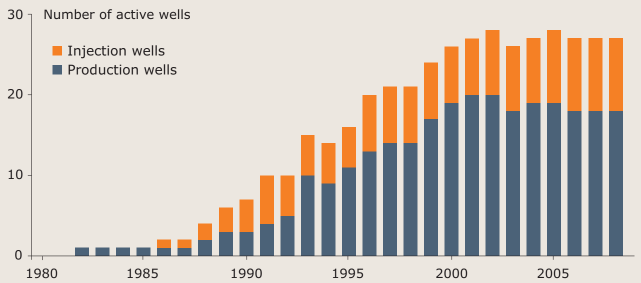




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009

2008 prices DKK 5.7 billion



FIELD DATA

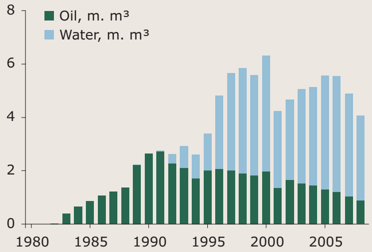
At 1 January 2009

Prospect:	Ruth
Location:	Block 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1977
Year on stream:	1982
Producing wells:	19
Water-injection wells:	9
Water depth:	40 m
Field delineation:	33 km^2
Reservoir depth:	1,600 m
Reservoir rock:	Chalk
Geological age:	Danian, Upper Cretaceous and Zechstein

PRODUCTION

Cum. production at 1 January 2009

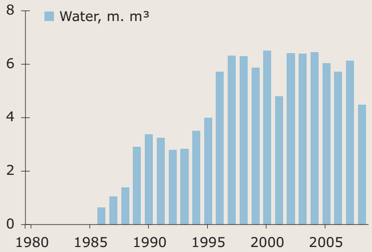
Oil:	41.56 m. m^3
Gas:	3.40 bn. Nm^3
Water:	51.04 m. m^3



INJECTION

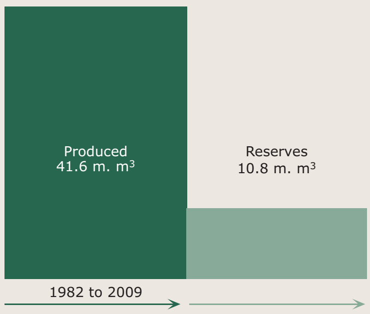
Cum. injection at 1 January 2009

Water:	101.69 m. m^3



RESERVES

Oil:	10.8 m. m^3
Gas:	0.6 bn. Nm^3



REVIEW OF GEOLOGY, THE SKJOLD FIELD

The Skjold Field is an anticlinal structure, induced through salt tectonics. 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

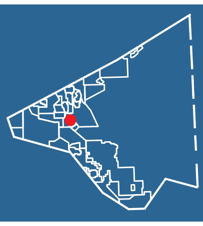
The strategy for producing oil from Skjold is to maintain reservoir pressure by means of water injection. Oil is mainly produced from horizontal wells at the flanks of the reservoir, where the production and injection wells are placed alternately in a radial pattern.

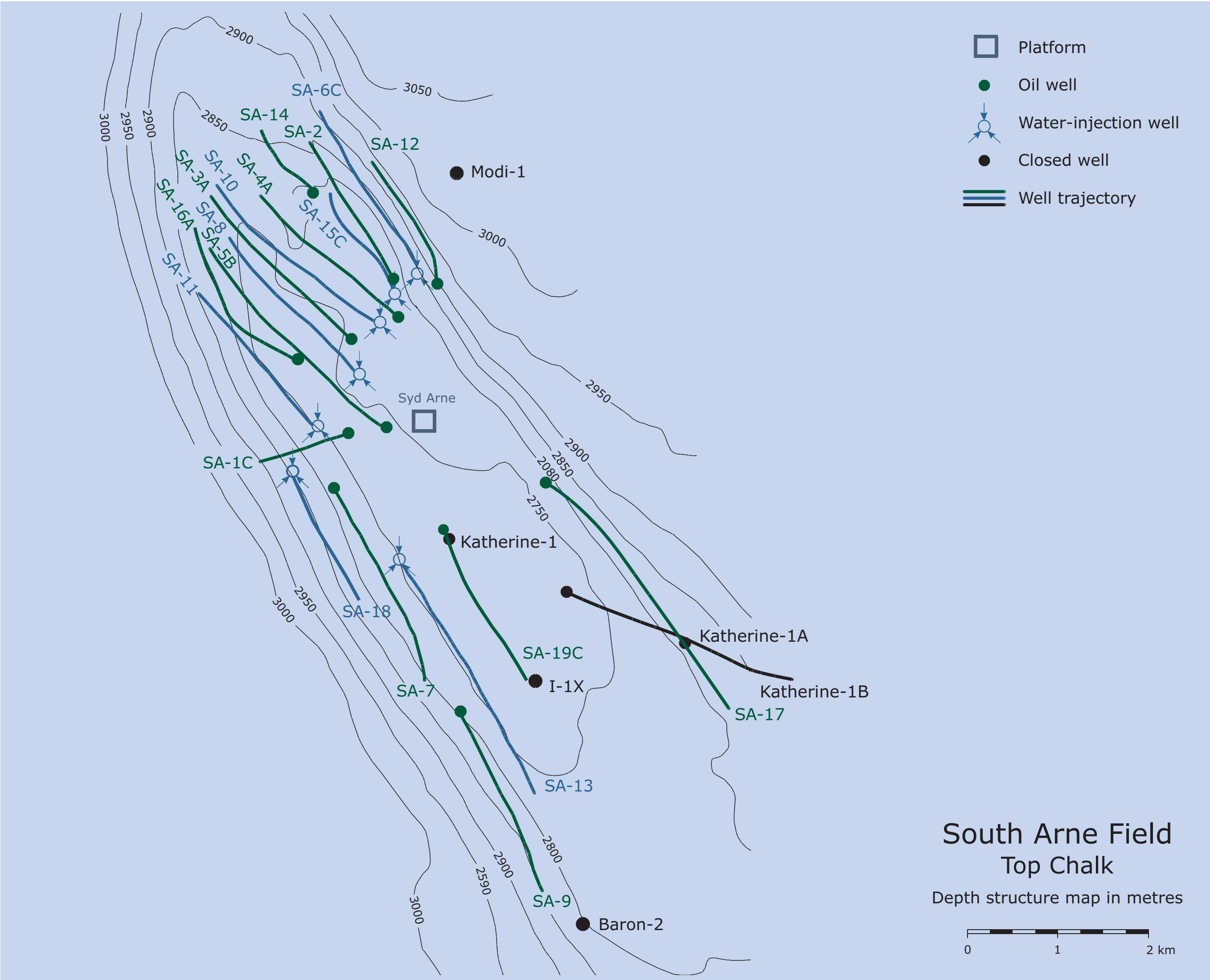
PRODUCTION FACILITIES

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 for processing. The Gorm facilities provide the Skjold Field with injection water and lift gas. Produced water is reinjected.

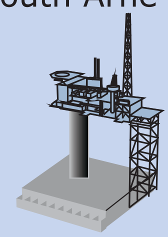
The Skjold C platform has accommodation facilities for 16 persons.

THE SOUTH ARNE FIELD



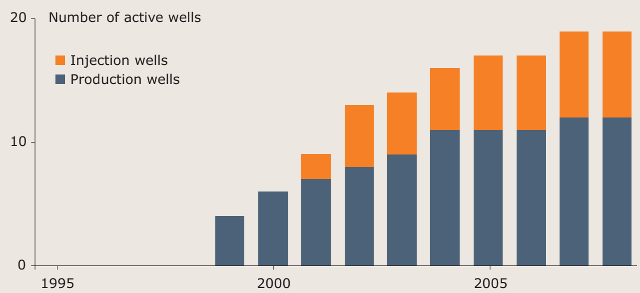


South Arne



DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices   DKK 11.0 billion



FIELD DATA

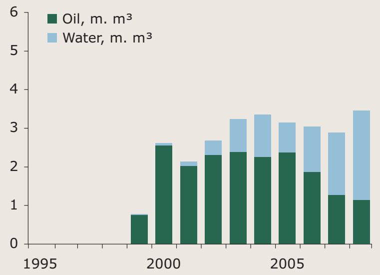
At 1 January 2009

Location:	Blocks 5604/29 and 30
Licence:	7/89
Operator:	Hess Denmark ApS
Discovered:	1969
Year on stream:	1999
Producing wells:	12
Water-injection wells:	7
Water depth:	60 m
Field delineation:	93 km^2
Reservoir depth:	2,800 m
Reservoir rock:	Chalk
Geological age:	Danian, Upper Cretaceous and Lower Cretaceous

PRODUCTION

Cum. production at 1 January 2009

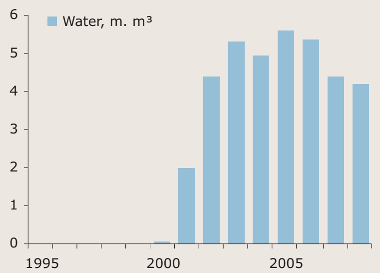
Oil:	18.92 m. m^3
Gas:	4.65 bn. Nm^3
Water:	10.19 m. m^3



INJECTION

Cum. injection at 1 January 2009

Gas:	3.99 bn. Nm^3
Water:	36.27 m. m^3



RESERVES

Oil:	10.3 m. m^3
Gas:	5.0 bn. Nm^3

REVIEW OF GEOLOGY, THE SOUTH ARNE FIELD

South Arne is an anticlinal structure, induced through tectonic uplift, which has caused the chalk to fracture. The structure contains oil with a relatively high content of gas.

PRODUCTION STRATEGY

The production of hydrocarbons is based on pressure support from water injection.

PRODUCTION FACILITIES

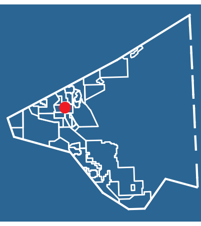
The South Arne Field installations comprise a combined wellhead, processing and accommodation platform.

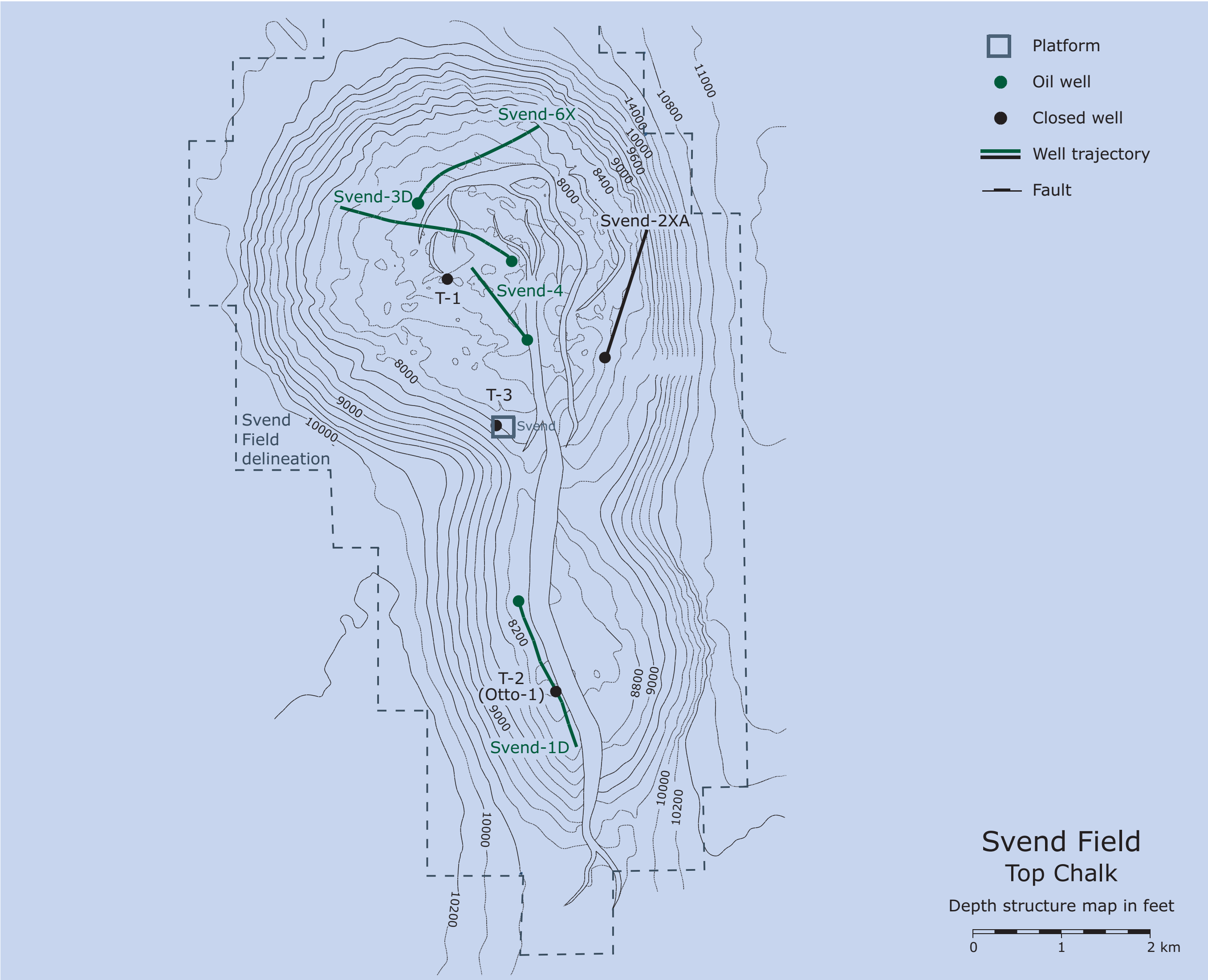
The processing facilities consist of a plant that separates the hydrocarbons produced as well as gas-processing facilities. In addition, processing facilities have been installed to treat the injection water before it is injected. Some of the water produced is injected into the field, while the rest is processed and discharged into the sea.

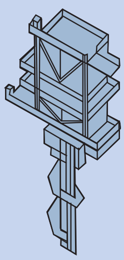
The oil produced is conveyed to an 87,000 m^3 storage tank on the seabed and is exported ashore by tanker. The gas produced is exported through a gas pipeline to Nybro on the west coast of Jutland.

The South Arne Field has accommodation facilities for 57 persons.

THE SVEND FIELD



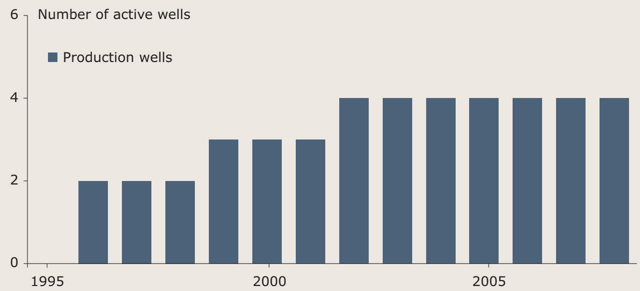




Svend

DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 1.2 billion



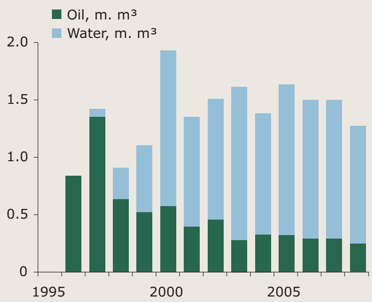
FIELD DATA — At 1 January 2009

Prospect:	North Arne/Otto
Location:	Block 5604/25
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1975 (North Arne)
Year on stream:	1982 (Otto)
Producing wells:	4
Water depth:	65 m
Field delineation:	48 km^2
Reservoir depth:	2,500 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2009

Oil:	6.58 m. m^3
Gas:	0.76 bn. Nm^3
Water:	11.38 m. m^3



RESERVES

Oil:	1.3 m. m^3
Gas:	0.1 bn. Nm^3

REVIEW OF GEOLOGY, THE SVEND FIELD

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 southern reservoir of the Svend Field is situated about 250 m lower than the northern reservoir. The northern reservoir has proved to have unusually favourable production properties.

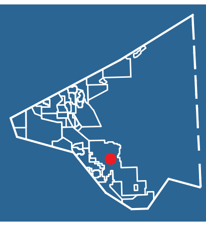
PRODUCTION STRATEGY

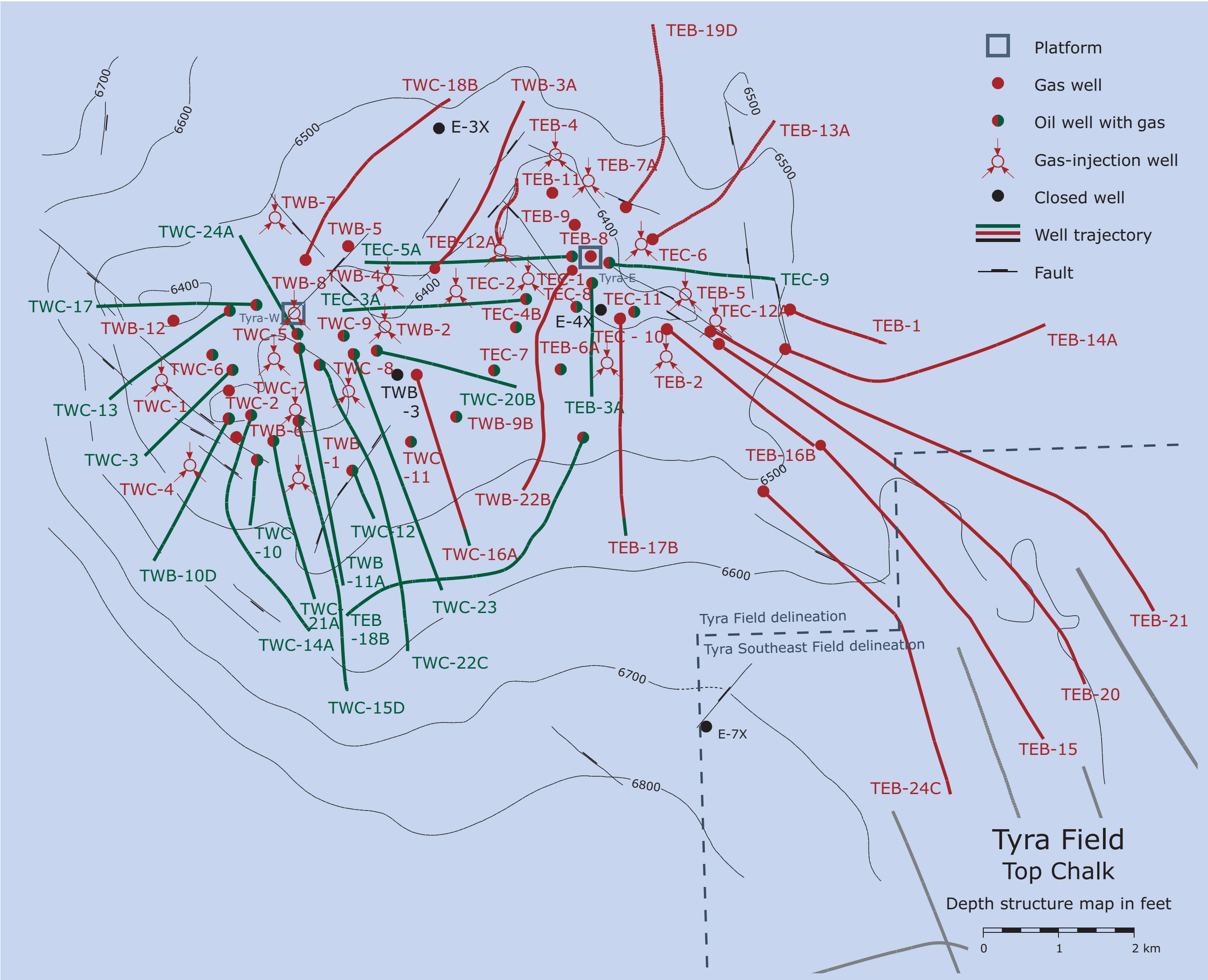
Production is based on primary recovery at a reservoir pressure above the bubble point of the oil, while ensuring maximum production uptime for the wells at the same time.

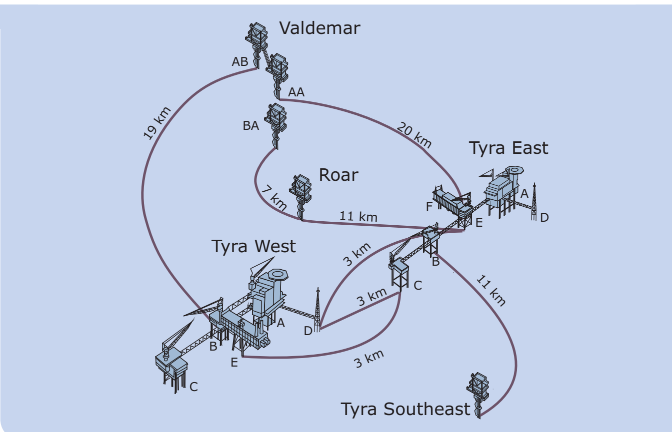
PRODUCTION FACILITIES

Svend is a satellite development to the Tyra Field with one unmanned wellhead platform without a helideck. The hydrocarbons produced are piped to Tyra East for processing and export ashore. The Svend Field is connected to the 16" pipeline from Harald to Tyra East.

THE TYRA FIELD



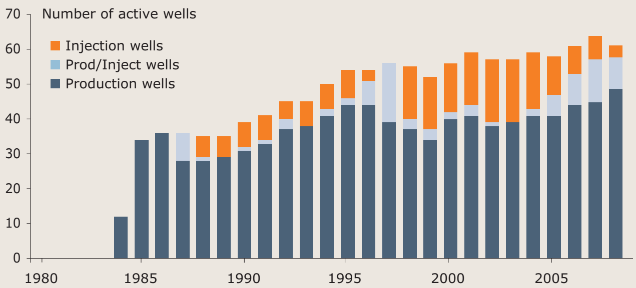




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009

2008 prices DKK 31.1 billion



FIELD DATA

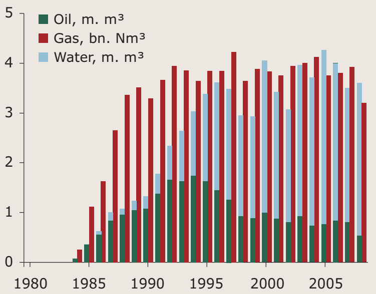
At 1 January 2009

Prospect:	Cora
Location:	Blocks 5504/11 and 12
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1968
Year on stream:	1984
Gas-producing wells:	20
Oil-/Gas-prod. wells:	28
Producing/Inj. wells:	20
Water depth:	37-40 m
Area:	90 km²
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2009

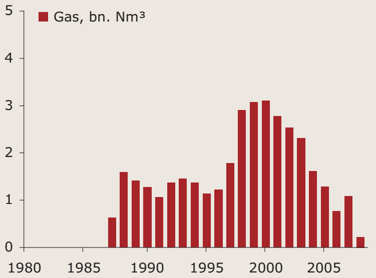
Oil:	24.77 m. m³
Gas:	84.60 bn. Nm³
Water:	40.65 m. m³



INJECTION

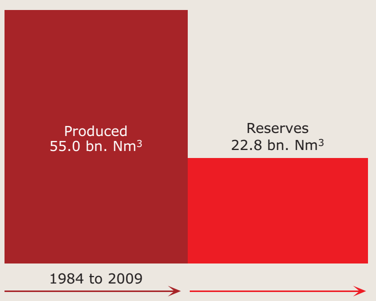
Cum. injection at 1 January 2009

Gas:	35.88 bn. Nm³



RESERVES*

Oil:	5.0 m. m³
Gas:	22.8 bn. Nm³



*) *The chart shows the combined figures for Tyra and Tyra SE*

REVIEW OF GEOLOGY, THE TYRA FIELD

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

The Tyra Field acts as a gas production buffer so as not to deteriorate condensate and oil production conditions by reducing the reservoir pressure at too early a stage. Thus, increased gas production from DUC's other fields, in particular the Harald and Roar gas fields, optimizes the recovery of liquid hydrocarbons from the Tyra Field.

PRODUCTION FACILITIES

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

Tyra West consists of two wellhead platforms, TWB and TWC, one processing and 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 are used to pre-process oil and condensate production from the wells at Tyra West. Moreover, the Tyra West complex houses gas-processing facilities and facilities for the injection and/or export of gas as well as processing facilities for the water produced. Tyra West receives part of the gas produced at Halfdan and Valdemar.

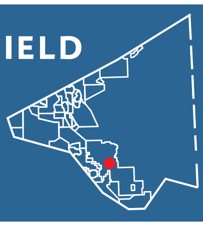
Tyra East consists of two wellhead platforms, TEB and TEC, one processing and accommodation platform, TEA, one gas flare stack, TED, and one riser platform, TEE, as well as a bridge module supported by a STAR jacket, TEF.

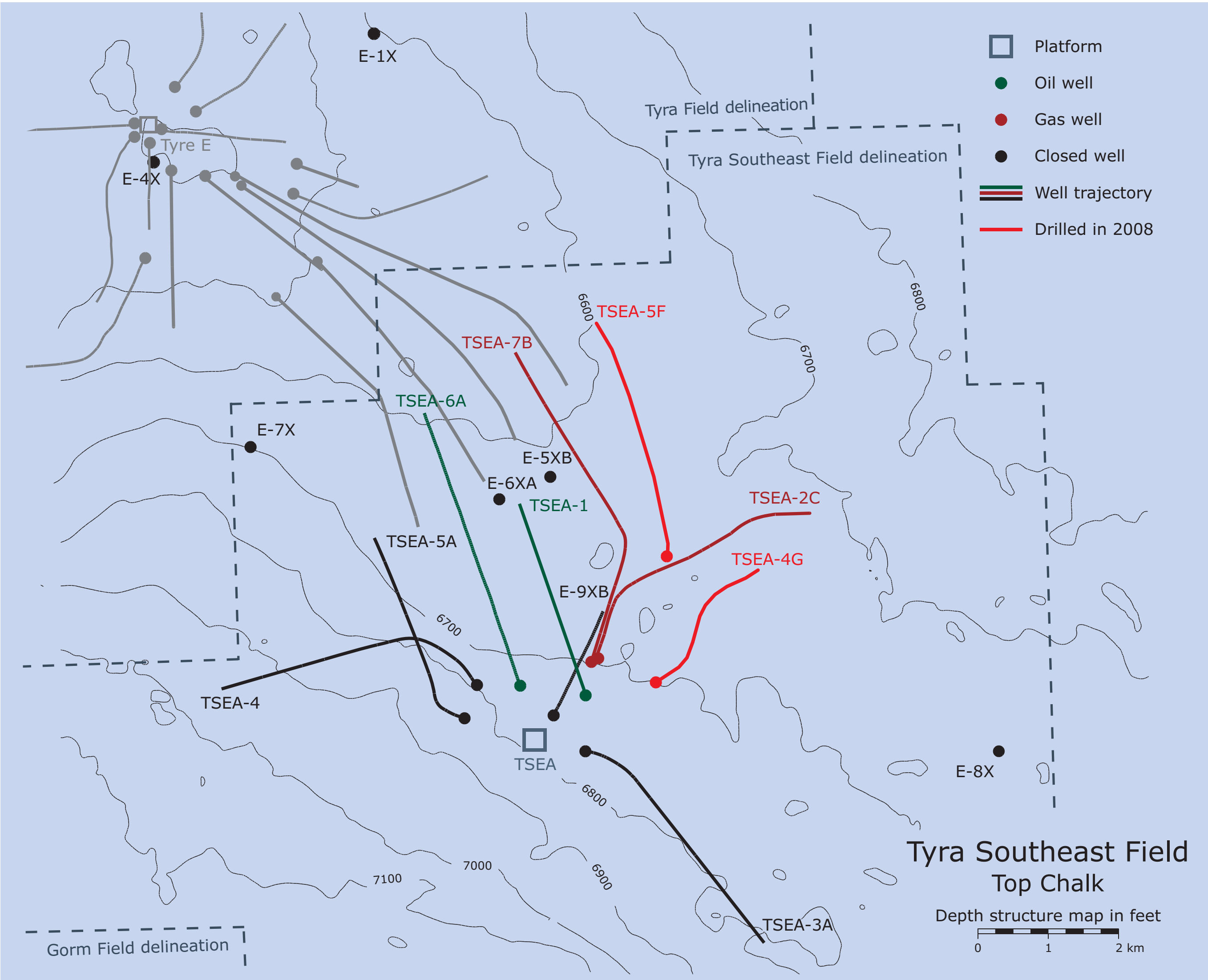
Tyra East receives production from the satellite fields, Valdemar, Roar, Svend, Tyra Southeast and Harald/Lulita, as well as gas production from Gorm, Dan and parts of Halfdan D. The Tyra East complex includes facilities for the final processing of gas, oil, condensate and water. Treated production water from the whole of the Tyra Field is discharged into the sea.

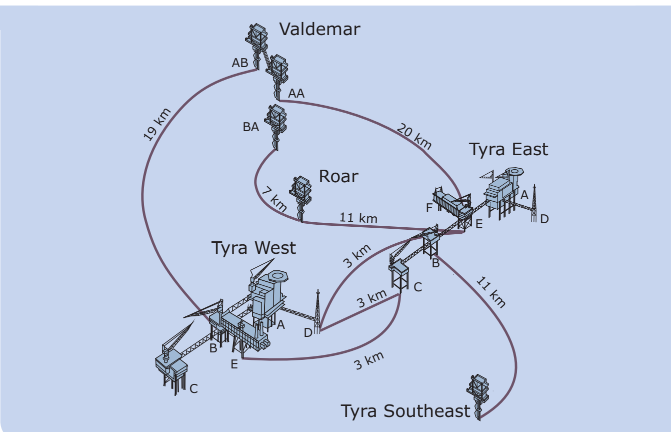
The two platform complexes in the Tyra Field are interconnected by pipelines in order to yield the maximum operational flexibility and security of supply. Oil and condensate production from the Tyra Field and its satellite fields is transported ashore via Gorm E. The bulk of gas produced is transported from TEE at Tyra East to shore and the rest is transported from TWE at Tyra West to the NOGAT pipeline.

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

THE TYRA SOUTHEAST FIELD

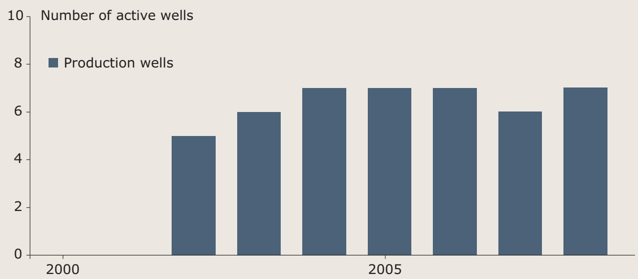






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 1.7 billion



FIELD DATA

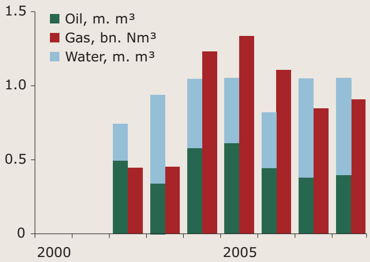
At 1 January 2009

Location:	Block 5504/12
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1991
Year on stream:	2003
Oil-producing wells:	2
Gas-producing wells:	4
Water depth:	38 m
Field delineation:	113 km^2
Reservoir depth:	2,050 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

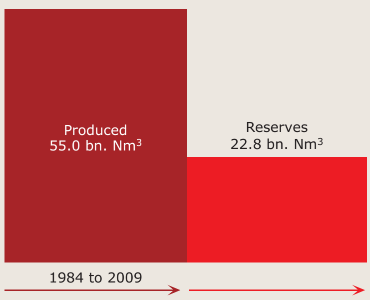
Cum. production at 1 January 2009

Oil:	3.28 m. m^3
Gas:	6.31 bn. Nm^3
Water:	3.40 m. m^3



RESERVES*

Oil:	5.0 m. m^3
Gas:	22.8 bn. Nm^3



*) *The chart shows the combined figures for Tyra and Tyra SE*

REVIEW OF GEOLOGY, THE TYRA SOUTHEAST FIELD

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 NE-SW fault zone. The structure is part of the major uplift zone that also comprises Roar, Tyra and parts of the Halfdan Field.

The Tyra Southeast accumulation contains free gas overlying an oil zone in the south-eastern part of the field.

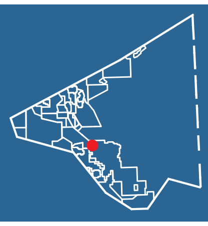
PRODUCTION STRATEGY

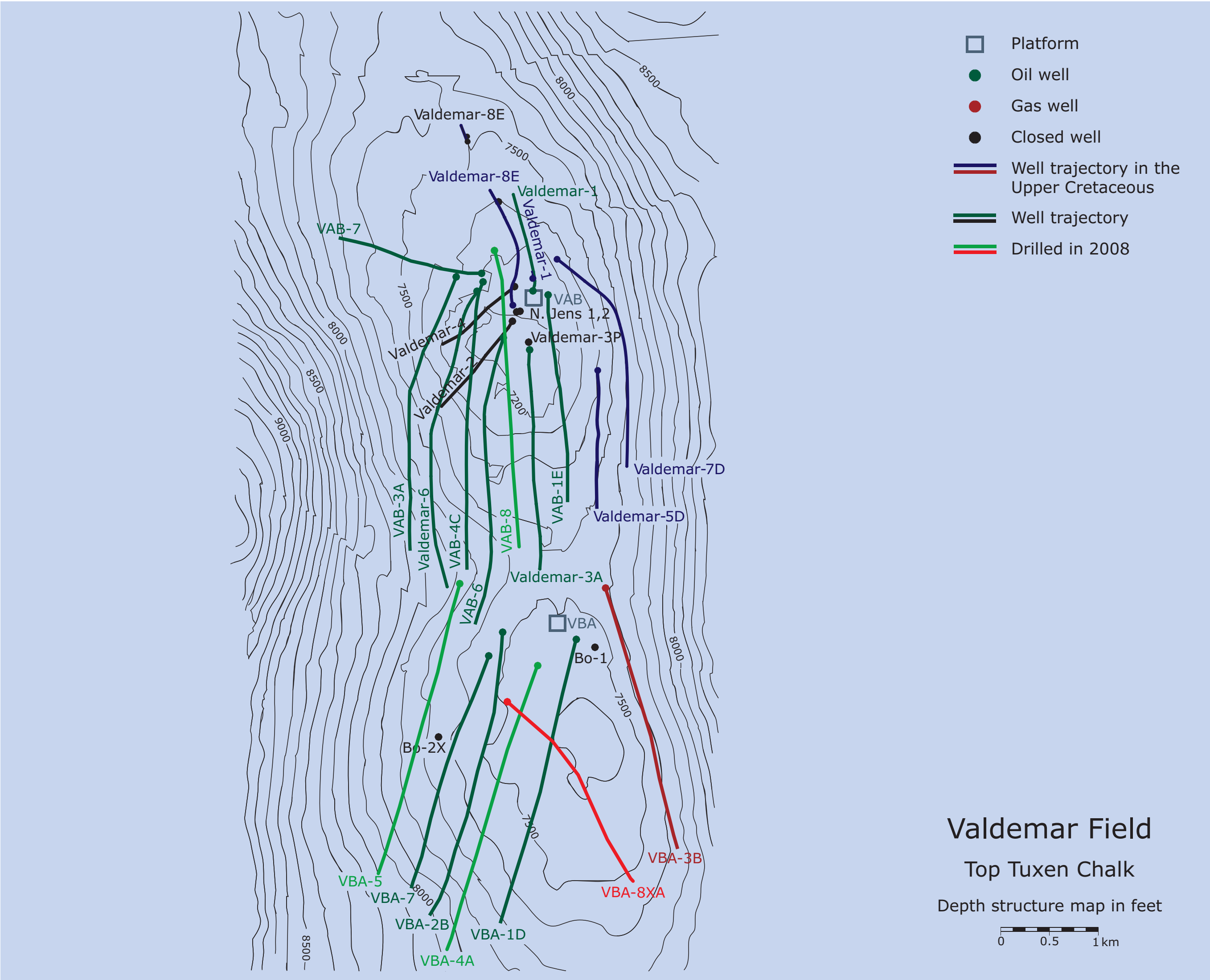
The production of oil and gas is based on natural depletion.

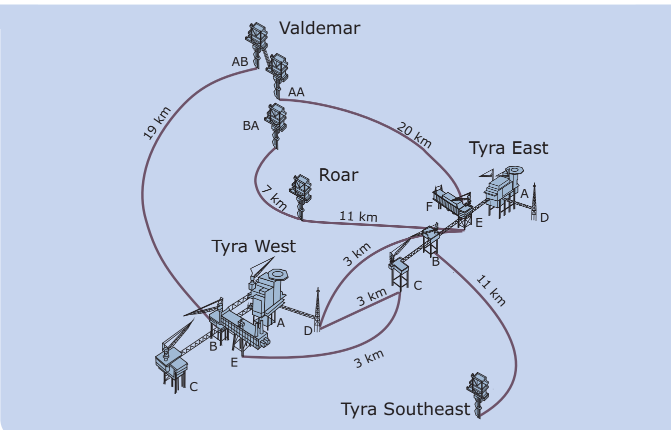
PRODUCTION FACILITIES

The Tyra Southeast Field has been developed as a satellite to the Tyra Field with an unmanned platform. The production is separated into gas and liquids before being transported to Tyra East for further processing.

THE VALDEMAR FIELD

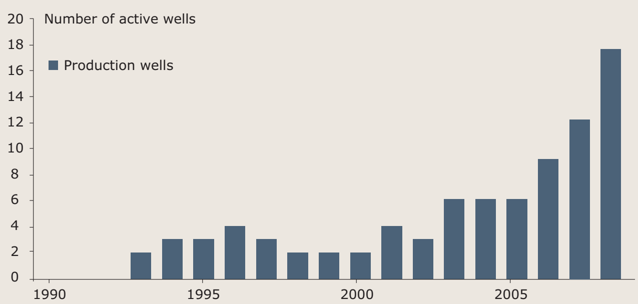






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2009
2008 prices DKK 6.3 billion



FIELD DATA

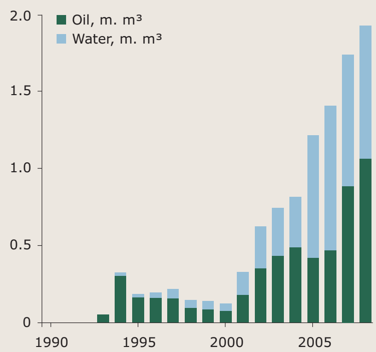
At 1 January 2009

Prospect:	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) 2007 (Bo)
Oil-producing wells:	17
Gas-producing wells:	2
Water depth:	38 m
Field delineation:	96 km²
Reservoir depth:	2,000 m (Upper Cretaceous) 2,600 m (Lower Cretaceous)
Reservoir rock:	Chalk
Geological age:	Danian, Upper and Lower Cretaceous

PRODUCTION

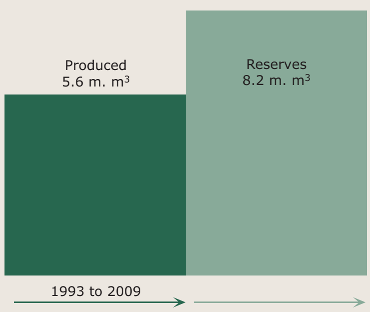
Cum. production at 1 January 2009

Oil:	5.60 m. m³
Gas:	2.40 bn. Nm³
Water:	4.86 m. m³



RESERVES

Oil:	8.2 m. m³
Gas:	4.0 bn. Nm³



REVIEW OF GEOLOGY, THE VALDEMAR FIELD

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.

The Valdemar Field comprises several separate accumulations. Oil and gas have been discovered in Danian/Upper Cretaceous chalk, and large volumes of oil have been identified in Lower Cretaceous chalk. The extremely low-permeable layers in the Lower Cretaceous chalk possess challenging production properties in some parts of the Valdemar Field, whereas the properties of the Upper Cretaceous reservoirs are comparable to other Danish fields like Gorm and Tyra.

In the Bo area, it has turned out that other parts of the Lower Cretaceous have better production properties. This has led to the development of the Bo reservoir.

PRODUCTION STRATEGY

The production of oil is based on natural depletion. The development of a production method based on 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 North Jens area of the Valdemar Field has been developed as a satellite to the Tyra Field with two bridge-connected, unmanned wellhead platforms, Valdemar AA and AB, without helidecks. Production is separated at the Valdemar AB platform. The liquids produced are piped to Tyra East for processing and export ashore, while the gas produced is piped to Tyra West. The Valdemar AA/AB complex is provided with chemicals from Tyra East and with power from Tyra West.

The Bo area of the Valdemar Field has been developed with an unmanned wellhead platform, Valdemar BA, without a helideck. A 16" multiphase pipeline transports the production from Valdemar BA to Tyra East, via Roar.

APPENDIX C: PRODUCTION AND RESERVES AT 1 JANUARY 2009

OIL, m. m³			
		Ultimate recovery	
	Produced	Reserves	
		Low	Exp.
Ongoing and approved			
Adda	-	0	1
Alma	-	0	0
Boje area	-	1	1
Cecilie	1	0	0
Dagmar	1	0	0
Dan	95	11	20
Gorm	57	3	6
Halfdan	41	36	56
Harald	8	1	1
Kraka	5	1	1
Lulita	1	0	0
Nini	4	2	4
Regnar	1	0	0
Roar	3	0	0
Rolf	4	0	1
Siri	11	1	1
Skjold	42	6	11
South Arne	19	*	10
Svend	7	1	1
Tyra**	28	1	5
Valdemar	6	5	8
Subtotal	**331**		**129**
Planned			
Amalie	-	1	1
Freja	-	1	1
Subtotal			**2**
Possible			
Producing fields	-	20	39
Other fields	-	2	3
Discoveries	-	16	26
Subtotal			**68**
Total	**331**		**200**
January 2008	315		214

GAS, bn. Nm³			
		Ultimate recovery	
	Produced	Reserves	
		Low	Exp.
Ongoing and approved			
Adda	-	0	0
Alma	-	0	1
Boje area	-	0	1
Cecilie	0	-	-
Dagmar	0	0	0
Dan	22	1	2
Gorm	7	0	1
Halfdan	15	12	20
Harald	20	3	4
Kraka	1	0	0
Lulita	1	0	0
Nini	0	-	-
Regnar	0	0	0
Roar	14	1	1
Rolf	0	0	0
Siri	0	-	-
Skjold	3	0	1
South Arne	5	*	5
Svend	1	0	0
Tyra**	55	6	23
Valdemar	2	2	4
Subtotal	**148**		**63**
Planned			
Amalie	-	1	1
Freja	-	0	0
Subtotal			**2**
Possible			
Producing fields	-	10	19
Other fields	-	2	5
Discoveries	-	8	17
Subtotal			**42**
Total	**148**		**107**
January 2008	138		105

**) Not assessed*
***) Tyra Southeast included*

APPENDIX D: FINANCIAL KEY FIGURES

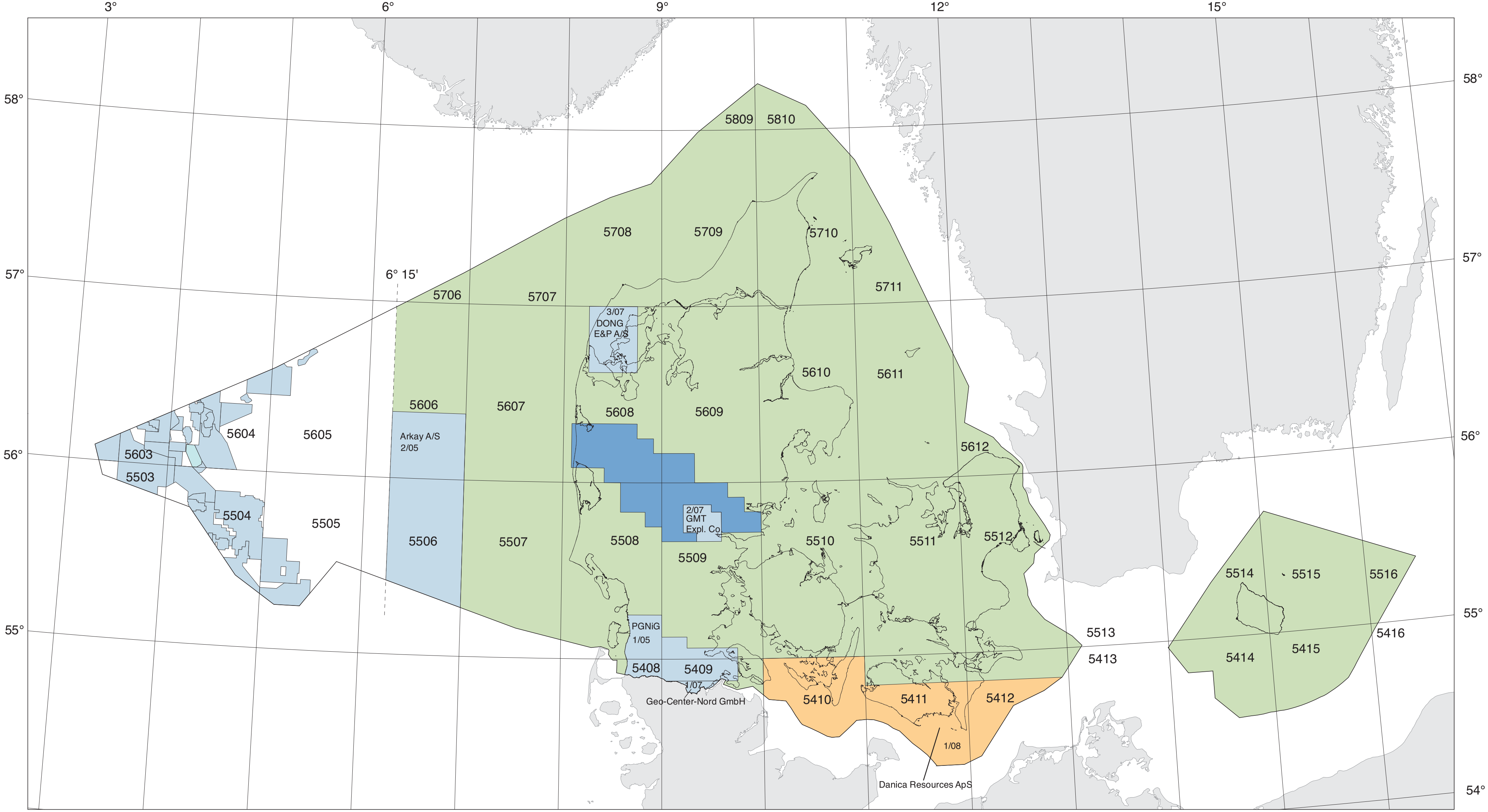
	Investments in field dev. DKK million 5)	Field operating costs DKK million 1)	Exploration costs DKK million	Crude oil price USD/bbl 2)	Exchange rate DKK/USD	Inflation per cent 3)	Net foreign-currency value DKK billion 4)	State revenue DKK million
1972	105	29	30	3.0	7.0	6.7	-3.2	-
1973	9	31	28	4.6	6.1	9.3	-4.0	1
1974	38	57	83	11.6	6.1	15.3	-9.2	1
1975	139	62	76	12.3	5.8	9.6	-8.5	2
1976	372	70	118	12.9	6.1	9.0	-9.5	4
1977	64	85	114	14.0	6.0	11.1	-10.4	5
1978	71	120	176	14.1	5.5	10.0	-9.5	21
1979	387	143	55	20.4	5.3	9.6	-13.7	19
1980	956	163	78	37.5	5.6	12.3	-18.6	29
1981	1,651	320	201	37.4	7.1	11.7	-20.1	36
1982	3,884	534	257	34.0	8.4	10.1	-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	3.7	-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	4.5	-3.7	568
1989	1,162	1,599	366	18.2	7.3	4.8	-3.2	1,024
1990	1,769	1,654	592	23.6	6.2	2.6	-2.7	2,089
1991	2,302	1,898	985	20.0	6.4	2.4	-1.9	1,889
1992	2,335	1,806	983	19.3	6.0	2.1	-0.4	1,911
1993	3,307	2,047	442	16.8	6.5	1.2	-1.7	1,811
1994	3,084	2,113	151	15.6	6.4	2.0	-0.5	2,053
1995	4,164	1,904	272	17.0	5.6	2.1	0.3	1,980
1996	4,260	2,094	470	21.1	5.8	2.1	0.4	2,465
1997	3,760	2,140	515	18.9	6.6	2.2	1.4	3,171
1998	5,381	2,037	406	12.8	6.7	1.8	0.9	3,125
1999	3,531	2,118	656	17.9	7.0	2.5	3.5	3,630
2000	3,113	2,813	672	28.5	8.1	2.9	14.9	8,695
2001	4,025	2,756	973	24.4	8.3	2.4	12.6	9,634
2002	5,475	3,102	1,036	24.9	7.9	2.4	14.5	10,138
2003	7,386	3,522	789	28.8	6.6	2.1	15.3	9,331
2004	5,107	3,289	340	38.2	6.0	1.2	19.7	17,092
2005	3,956	3,760	578	54.4	6.0	1.8	24.8	24,163
2006	4,927	4,165	628	65.1	5.9	1.9	31.5	31,499
2007	6,538	3,474	502	72.5	5.4	1.7	28.3	27,885
2008*	6,123	4,513	647	97.2	5.1	3.4	26.6	35,913

Nominal prices
1) Incl. transportation costs
2) Brent crude oil
3) Consumer prices, source: Statistics Denmark
4) Surplus on the balance of trade for oil products and natural gas, source: external trade statistics, Statistics Denmark
5) Investments include the NOGAT pipeline
**) Estimate*

APPENDIX E: EXISTING FINANCIAL CONDITIONS

	Sole Concession at 1 Jan. 2004	Licences granted before 1 Jan. 2004	Licences granted after 1 Jan. 2004
Corporate income tax	25 per cent Deductible from the hydrocarbon tax base.	25 per cent Deductible from the hydrocarbon tax base.	25 per cent Deductible from the hydrocarbon tax base.
Hydrocarbon tax	52 per cent Allowance of 5 per cent over 6 years (a total of 30 per cent) for investments. Transitional rules for investments and unutilized field losses made before 1 january 2004.	70 per cent Allowance of 25 per cent over 10 years (a total of 250 per cent) for investments.	52 per cent Allowance of 5 per cent for 6 years (a total of 30 per cent) for investments.
Royalty	No	2nd Round licences pay royalty as follows: 1000 bbl/day — Rate 0 - 5 — 2 per cent 5 - 20 — 8 per cent 20 - — 16 per cent Deductible from the corp. income tax and hydrocarbon tax bases.	No
Oil pipeline tariff/ compensatory fee	5 per cent 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 tax and hydrocarbon tax bases.	5 per cent The oil pipeline tariff/compensatory fee is deductible from the royalty base and the corporate income tax and hydrocarbon tax bases.	5 per cent 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 tax and hydrocarbon tax bases.
State participation	20 per cent from 9 July 2012	20 per cent 1st, 2nd og 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 per cent
Profit sharing	From 1 January 2004 to 8 July 2012, 20 per cent of the taxable profit before tax and before net interest expenses is payable.	No	No

Appendix F1: Danish licence area - April 2009



Licences awarded 1962-2007

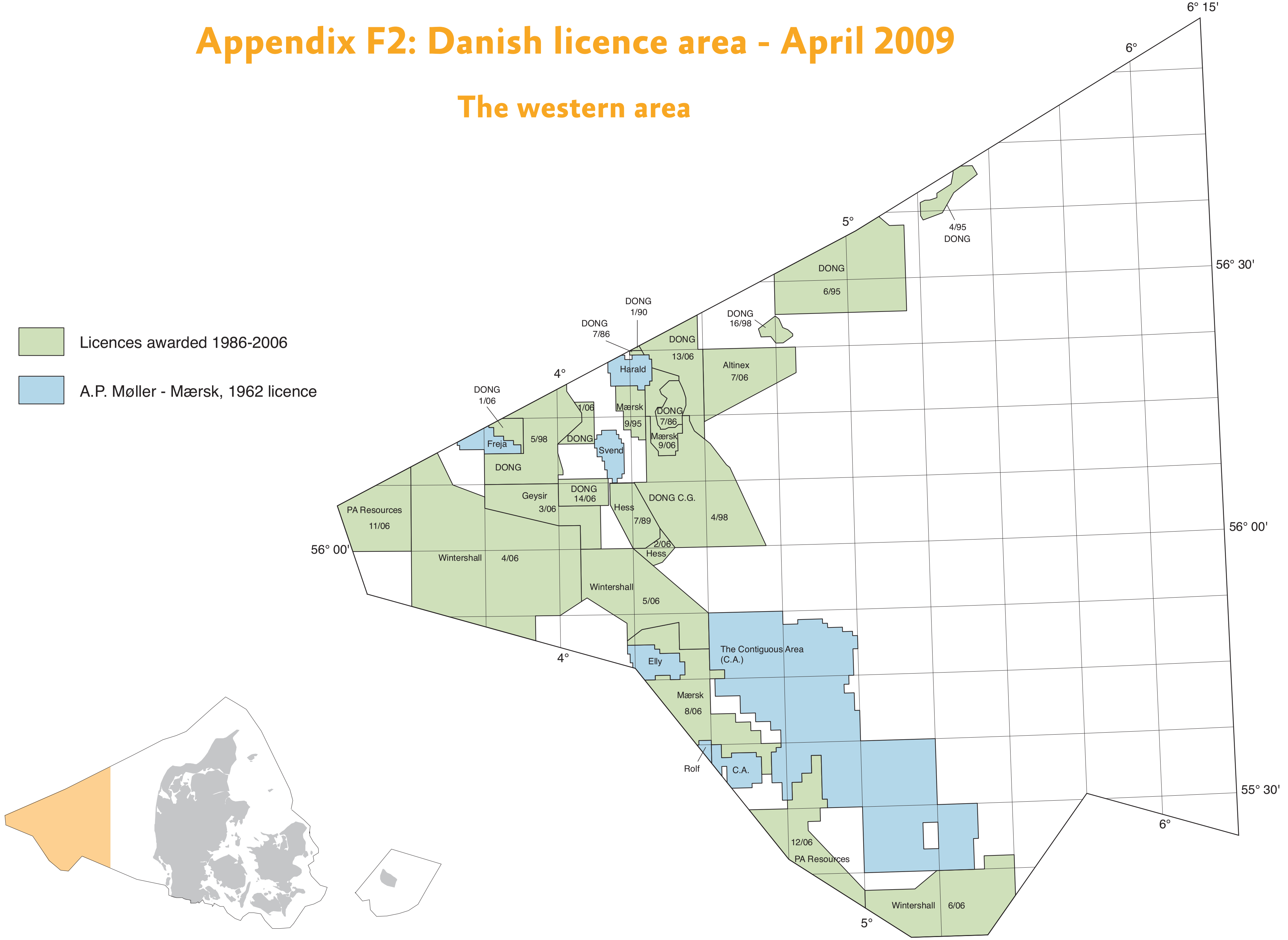
Licence awarded in 2008

Licence application in the Open Door area

Open Door area

Appendix F2: Danish licence area - April 2009

The western area



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

As in previous years, the report for 2008 describes exploration and development activities in the Danish area as well as production. A new feature of this year's report is the description of alternative uses of the Danish subsoil, including the exploitation of geothermal energy and the potential for Carbon Capture and Storage (CCS).

The report also contains a review of the health and safety aspects of oil and gas production activities, the environment and climate.

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

The report can be obtained from the DEA's Internet website, http://www.ens.dk/en-us/Sider/forside.aspx

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