Denmark's Oil and Gas Production

- and Subsoil Use

09

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PREFACE

Denmark is a net exporter of oil and gas, and state revenue from oil and gas production remains at a high level. However, we must look beyond the present and plan the future pattern of energy consumption and supply, thus maintaining the security of supply and Denmark's favourable revenue position.

The declining production of natural gas from the Danish North Sea fields calls for initiatives aimed at securing future supplies for Danish consumers. Only a few years from now, Danish production will not suffice to cover Danish consumption and the Swedish consumption currently covered by gas produced in Denmark. Therefore, in spring 2010 a working group considered various possibilities for expanding the infrastructure for transmission of gas.

With the present infrastructure, it is not possible to import gas. Therefore, a decision has been made to establish a new compressor station that will enable import via the pipeline through South Jutland to Germany. In the period until then, other temporary solutions will secure the supply of gas.

Another important tool for maintaining high security of supply is more energy efficient consumption, on the parts of both the individual consumer and the industrial sector. The oil and gas industry has also addressed energy efficiency, one result being that a substantially lower volume of gas is flared in connection with Danish oil and gas production. Denmark will increase its future security of supply by converting energy use to renewable energy sources, such as wind, biomass and geothermal energy. Interest in utilizing the geothermal potential in the Danish subsoil has been record high, as reflected in the fact that seven applications for new geothermal licences were submitted in 2009. The DEA has prepared a report on the possibilities of geothermal heat production in Denmark, published in October 2009.

There remain undiscovered hydrocarbons in the Danish subsoil. At the end of 2009 and the beginning of 2010, hydrocarbons were discovered when two exploration wells were drilled in the Danish part of the North Sea. Additionally, there are plans to drill more exploration wells in the North Sea in the period ahead. There is also a high level of exploration activity on land. Three new Open Door licences were granted in the course of 2009, and the first 3D onshore seismic survey was carried out in South Jutland in early 2010.

Unfortunately, 2009 also showed what happens when safety procedures for oil and gas production are not observed. An employee suffered a fatal accident during work on pressure testing nitrogen equipment. The key to preventing future work-related accidents is for the oil companies and the authorities to follow up on the near-miss occurrences and accidents that happen. The DEA supervises the offshore installations and reviews the companies' management systems both on- and offshore. In cooperation with employers and unions and the other authorities represented on the Offshore Safety Council, the DEA continually focuses on improving the safety level for employees on offshore installations.

Copenhagen, June 2010

Ib Larsen

CONTENTS

1 LICENCES AND EXPLORATION

Two successful Jurassic wells were drilled in the North Sea in 2009, which has heightened expectations for the presence, and thus the possible exploitation, of deeper oil and gas resources.

The award of three new Open Door licences, a neighbouring block licence and a new licence application in the Open Door area show that the level of interest in oil and gas exploration in Denmark remains high. The new trend in 2009 is that the oil companies are also focusing their interest on unconventional resources; see box 1.2.

EXPLORATION IN THE OPEN DOOR AREA

Since 1997, companies have had the option of applying for a licence to explore for and produce oil and gas in the Open Door Area; see box 1.1 and figure 1.1.

When the door was opened for the first time in 1997, five licences were granted, and four more were issued during the next two years. Since then, the number of licences granted per year in the Open Door area has ranged between three and nine, as shown in figure 1.2. In 2009, there were a total of nine Open Door licences, the highest number since 2001, which demonstrates the considerable interest in the area.

Fig. 1.1 Approximate extent of the Alum Shale and Zechstein carbonates in the Danish Open Door area

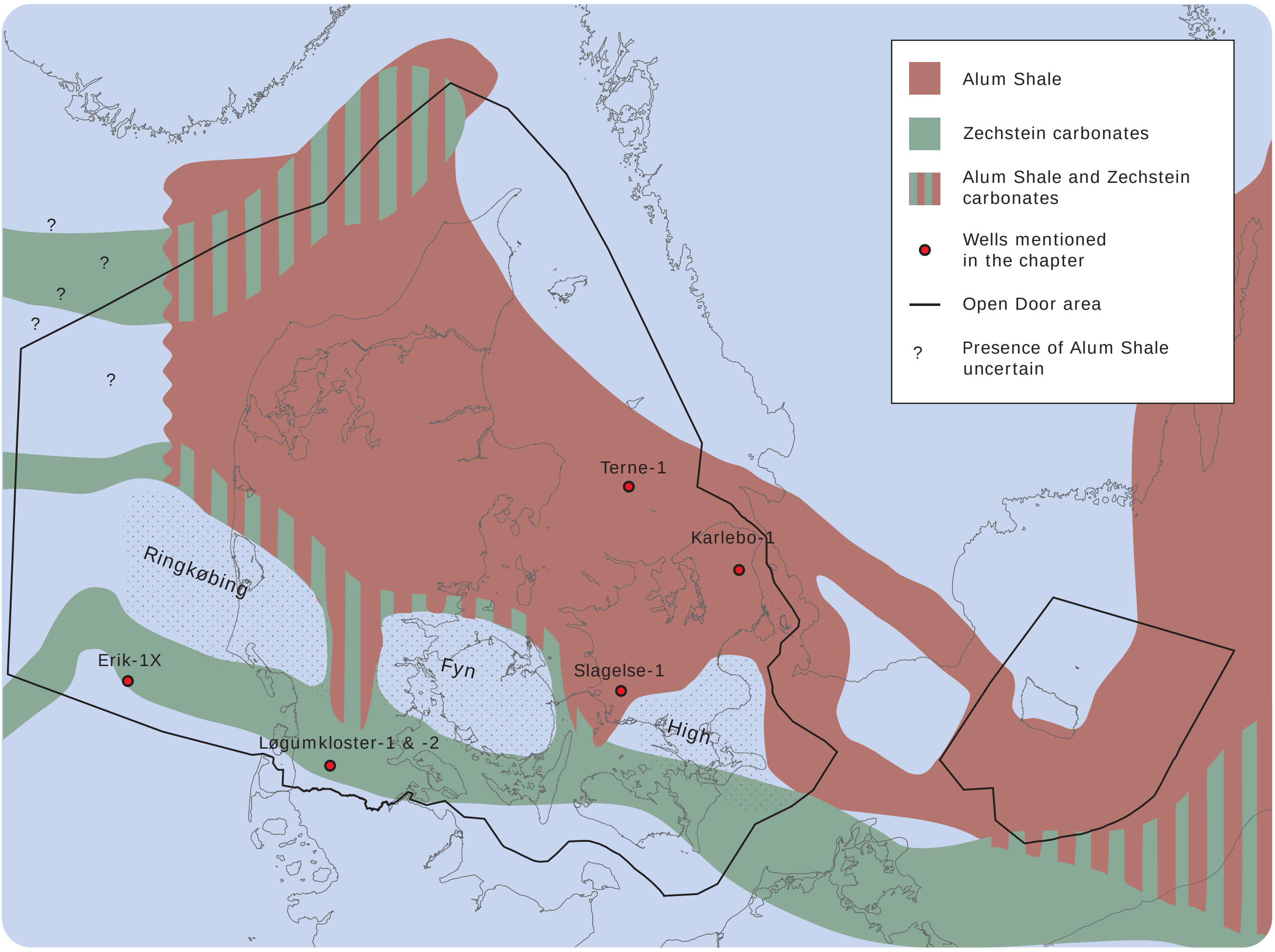
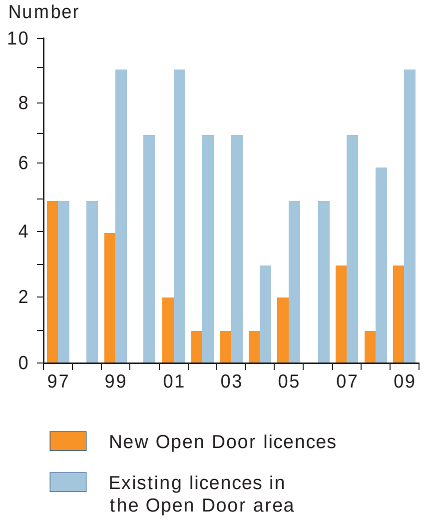


Fig. 1.2 Number of Open Door licences issued, and number of Open Door licences granted per year during the period 1997-2009



Licences for the exploration and production of hydrocarbons are generally valid for a term of six years, but some licences may contain provisions according to which the licensee must either relinquish the licence or undertake to carry out further exploration, e.g. drill an exploration well, during the six-year term.

The above-mentioned exploration activity in the Open Door area has still not led to any commercial oil and gas discoveries, but traces of hydrocarbons have been found, and minor discoveries have been made in South Jutland.

As figure 1.2 shows, the level of interest in exploration in the Open Door area has fluctuated. Up until 2009 inclusive, the licences had resulted in two wells being drilled. The Erik-1X well was drilled in the southeastern part of the North Sea, while Karlebo-1 was drilled in northern Zealand. The locations of these wells are shown in figure 1.1. The wells were drilled during 2001 and 2006 respectively, and neither of them encountered hydrocarbons.

Since 1997, just under 5,000 km of 2D seismic data, around 700 km² of 3D seismic data, almost 2,500 geochemical samples and 3,700 km of aeromagnetic data have been acquired in the Open Door area. By comparison, during the same period, 12,000 km of 2D and 12,500 km² of 3D seismic data were acquired in the licensing round area in the westernmost part of the North Sea, which represents almost 15 per cent of the total Danish area.

New ideas for exploration targets and new methods of oil and gas extraction mean that many companies still hope to make commercial discoveries in the Open Door area.

Box 1.1

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 westernmost part of the North Sea. The Open Door area is shown in appendix G1. In the westernmost part of the North Sea, 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. 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.

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

The Minister for Climate and Energy issues the licences after submitting the matter to the Parliamentary Energy Policy Committee.

Unconventional exploration targets (see box 1.2 and the section on the *Alum Shale*) are attracting increasing attention from the oil industry. The conventional method of carrying out exploration, involving the acquisition of 3D seismic and other data, cannot always be used for these exploration targets. Instead, unconventional exploration targets require a well to be drilled at an early stage in the exploration phase in order to demonstrate the presence of hydrocarbons.

The oil companies are currently focusing on many different types of exploration target in their exploration of the Open Door area. These exploration targets may prove to contain oil and gas resources that can be exploited in the future. Internationally, discoveries have been made in similar rock types, and in many locations oil and gas are being produced from such discoveries.

The exploration targets, which principally consist of the Alum Shale, Zechstein carbonates and sandstones from the Triassic and Jurassic periods, lie at different stratigraphic levels, which means that the subsoil layers targeted are of different geological age; see appendix F.

Box 1.2

Explanation of terms
Source rock is a rock that contains so much organic matter that it can 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 (fluids) in the pores between the mineral particles. **Porosity** indicates the total of void spaces present within a rock and able to contain fluids. **The permeability** of the pore system indicates the ease with which fluids can pass through the rock.

Once hydrocarbons have been formed in a source rock, they will begin to **migrate** if the pressure is high enough. The reason is that oil and gas are lighter than the water present in the pores and therefore begin to 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 shale that the oil and gas cannot penetrate.

Conventional resources are resources that can be recovered with the aid of traditional technology, either onshore or offshore. Traditional technology covers horizontal wells, for example, which are used for oil and gas production in the Danish part of the North Sea.

In the exploration for conventional resources, the companies look for structures in the subsoil, e.g. with the aid of detailed 3D seismic surveys, which are described in more detail in box 1.4 on seismic surveys.

Unconventional resources are resources that were previously considered too expensive or technically difficult to recover. For example, new technological advances now make it possible to produce hydrocarbons from source rocks such as shale and to produce gas from tight, deep sandstone layers.

The Alum Shale

One of the exploration targets that have come into focus in Denmark is the Alum Shale. The financially viable production of gas from similar shales abroad, e.g. in the USA, has led the oil companies to look for similar rock types around the world, including in Denmark.

The Alum Shale was deposited during the Middle Cambrian to Early Ordovician period; see appendix F. At that time, the whole of Denmark was covered by sea. The Alum Shale was deposited under calm conditions at water depths of 50-200 metres, where the oxygen content was low. This is one of the reasons why a high content of organic material has been preserved. The high content of organic material makes the Alum Shale a potential source rock, and the possibility of producing gas directly from the source rock is being investigated. One of the questions to be answered during the exploration of the Alum Shale is whether there are still hydrocarbons left in the shale due to the high age of the rocks.

The shales are laterally and vertically very homogenous, and the approximate current distribution of the Alum Shale can be seen in figure 1.1.

In Denmark, only two wells have penetrated the Alum Shale. The Slagelse-1 well dating from 1959 in West Zealand reached the shale at a depth of 2,900 metres, while the Terne-1 well in the Kattegat from 1985 reached the shale at a depth of 3,200 metres. Neither of the wells encountered hydrocarbons. A number of oil companies have previously explored for oil formed from the Alum Shale. This exploration focused on reservoirs in younger rocks, but all the wells were dry, i.e. they did not demonstrate the presence of hydrocarbons.

The Alum Shale is an unconventional exploration target; see box 1.2. The exploration methods that are being used to determine whether the Alum Shale contains commercial resources are therefore different from those used in the exploration for oil and gas in traditional oil structures; see appendix B. The extension and thickness of the Alum Shale and whether the formation is displaced by large faults are the key considerations. In most cases, this can be determined using 2D seismic surveys. A knowledge of the shale's physical and chemical properties, e.g. whether it could be fractured, leading the formation to crack in the right way, and whether it contains hydrocarbons, is essential in order to assess whether the Alum Shale has the potential for financially viable production. In order to determine this, wells must be drilled and samples taken from the shale or test production must be carried out.

Exploration of the Alum Shale is still at a very early stage, and it is not yet known whether the Danish Alum Shale has the potential to be a gas resource.

Zechstein carbonates

Another exploration target that is the subject of interest in the Open Door area is the Zechstein carbonates from the Upper Permian geological time period; see appendix F and figure 1.1. For many years, oil and gas have been produced from these layers in Germany and Poland.

From the 1950s until 1993, a number of wells were drilled for hydrocarbons in the Zechstein carbonates, and in 1980 the Løgumkloster-1 well encountered hydrocarbons at this level for the first time. Test production was carried out from this well, but the production rates were too low to establish financially viable production. In 1993,

another company discovered hydrocarbons in the same layers via the Løgumkloster-2/2A well, and test production was also carried out from this well. The production rates from the well were considered too low to be financially viable, and the well was subsequently plugged and abandoned.

The potential reservoir rocks in the Zechstein carbonates were deposited in the coastal zone in a warm sea under high energy conditions. The environment would have been very similar to the current depositional environments that exist today around the Bahamas, with tidal flats, lagoons, barrier islands and reef structures. The physical properties of the Zechstein layers vary considerably both vertically and horizontally over relatively short distances, making exploration difficult. To increase the chances of making discoveries, it is necessary to carry out a comprehensive analysis of existing data and acquire 3D seismic data. The 3D seismic data is necessary in order to create a detailed map of the structures that could contain oil and gas, thus increasing the probability of drilling a successful well that intersects layers with good reservoir properties. The presence of hydrocarbons and whether the physical properties of the rocks are sufficiently good to enable production from the reservoir can only be demonstrated by drilling wells.

Sandstone reservoirs

A third exploration target is sandstone reservoirs. Across most of Denmark, there are one or more porous sandstone layers in the subsoil (see figure 2.1) that could contain hydrocarbons under the right conditions.

The possible sandstone reservoirs date from the Triassic and Jurassic geological time periods (see appendix F) and consist of sand which was deposited in the coastal zone of a former sea or in rivers in the areas on land. During the Triassic period, much of Denmark and the North Sea was land. The sea level began to rise during the Late Triassic, which is the youngest part of the Triassic period. The sea level continued to rise into the Jurassic and, by the end of the Jurassic period, the sea covered most of Denmark. The coastal zone therefore moved across Denmark over the course of millions of years.

Sandstones from the Triassic and Jurassic periods can be up to 100 metres thick and often have good reservoir properties with relatively high porosities of up to 30 per cent. If they do not contain hydrocarbons and lie at the right depth, these sandstone reservoirs can potentially be used for other purposes; see chapter 2, *Use of the subsoil*.

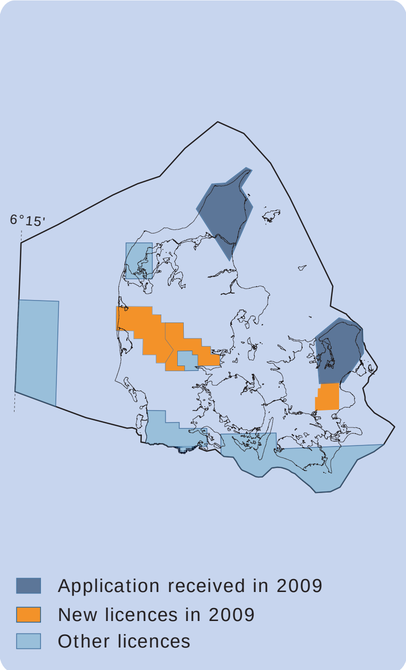
In addition to the above-mentioned exploration targets, exploration is carried out for hydrocarbons in Permian and other layers from the Palaeozoic.

OPEN DOOR LICENCES

On 17 May 2009, the Minister for Climate and Energy issued two new licences – 1/09 and 2/09 – to Danica Jutland ApS (80 per cent) and the Danish North Sea Fund (20 per cent). The licences cover two adjoining onshore areas in mid-Jutland. Danica Jutland ApS, the operator of the licences, is a newly established Danish company.

In 2008, GMT Exploration Company LLC and Jordan Dansk Corporation submitted an application for a licence in an area that mostly overlapped the area that Danica Jutland ApS had already applied for, but chose to withdraw their application on 9 April 2009.

Fig. 1.3 Changes in the Open Door area in 2009



On 17 November 2009, the Minister for Climate and Energy granted a new licence – 4/09 – for an onshore area on Zealand to Schuepbach Energy LLC (80 per cent) and the Danish North Sea Fund (20 per cent). Schuepbach Energy LLC, the operator of the licence, is a company based in the USA.

On 22 September 2009, the DEA received an application for a licence to explore for and produce hydrocarbons in the Open Door area. The application covers two large onshore areas, one in northern Jutland and the other on northeastern Zealand. The applicant is Devon Energy Netherlands BV, a subsidiary of Devon Energy Corporation. The DEA is currently processing the application.

All changes in the Open Door area appear from figure 1.3.

NEIGHBOURING BLOCK LICENCE

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 neighbouring block procedure may be initiated. 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.

On 29 June 2009, the Minister for Climate and Energy granted a new licence – 3/09 – under the neighbouring block procedure. The licence covers an area adjoining licence 4/98 in the Danish part of the North Sea; see figure 1.4.

The licence was granted to DONG E&P A/S (50 per cent), Bayerngas Danmark ApS (30 per cent) and the Danish North Sea Fund (20 per cent).

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.

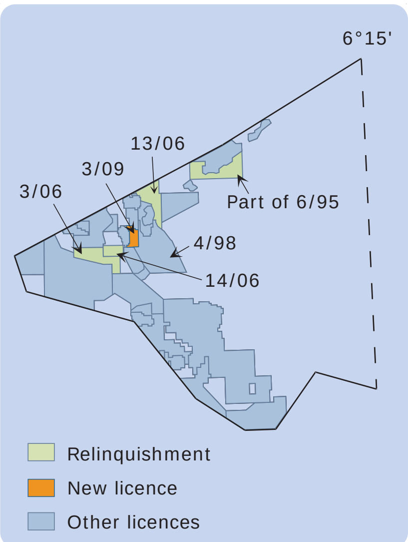
Moreover, reference is made to appendices G1 and G2, which contain maps of the licences in the Danish licence area.

Transferred licences

The DEA has approved the transfer of shares in licence 4/98. After Saga Petroleum Danmark A/S withdrew from the licensee group, the licence was held by DONG E&P A/S (70 per cent) and Bayerngas Danmark ApS (30 per cent) as from 1 January 2009. With effect from 1 July 2009, DONG E&P A/S transferred a 20 per cent share of licence 4/98 to the Danish North Sea Fund, thus reducing its share from 70 per cent to 50 per cent.

With effect from 3 April 2009, Polskie Górnictwo Naftowe i Gazownictwo SA (PGNiG) took over Odin Energi A/S' 40 per cent share of licence 1/05. Accordingly, PGNiG, the operator of the licence, has an 80 per cent share of the licence, while the Danish North Sea Fund holds the remaining 20 per cent.

Fig. 1.4 New and relinquished licences in the area west of 6°15' eastern longitude in 2009



The DEA has approved the transfer of PA Resources AB's shares in licences 9/95 and 9/06 to PA Resources Denmark ApS. The transfer became effective on 22 December 2009.

Extended licence terms

A licence term may be extended to ensure the best possible exploration of the area, and thus to identify the hydrocarbon potential and allow for the utilization of any hydrocarbon accumulations. Generally, a licence term may only be extended if the licensee undertakes to carry out additional exploration in the relevant licence area; see box 1.3.

In 2009, the DEA extended the exploration term of licence 6/95, located in the western part of the Danish area. The licence term has been extended by two years until 15 November 2011. On 15 November 2009, the licensee relinquished the southern part of the licence area.

With effect from 12 November 2009, the DEA changed the delineation of the area of licence 6/95 that is to be used for production, i.e. the Siri Field delineation.

Box 1.3

Conditions of licences

A licence for the exploration for and production of hydrocarbons is 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 essentially 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 can get 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); see box 2.2 in chapter 2, *Use of the subsoil*.

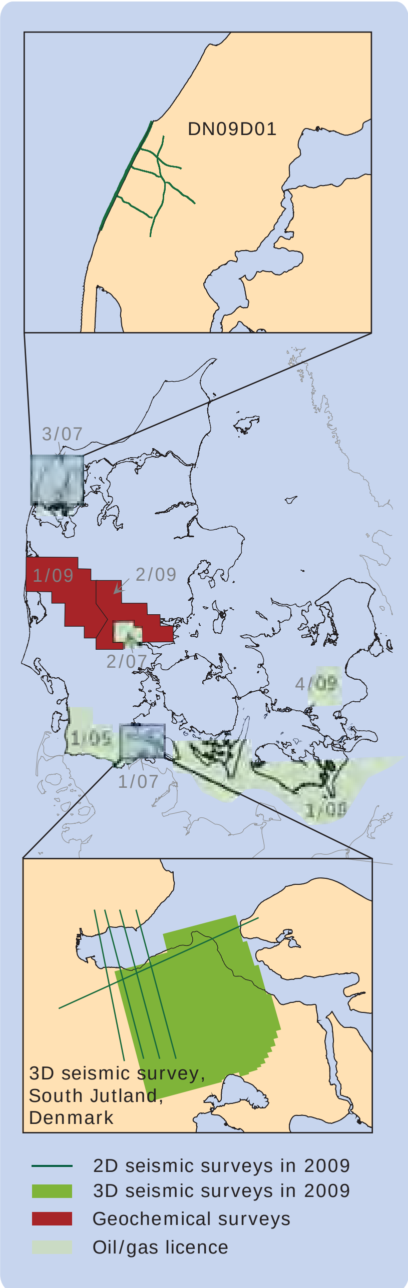
In 2009, the DEA extended the exploration term of licence 9/95 until 31 December 2011.

Terminated licences and area relinquishment
Two licences granted in the 6th Licensing Round – 3/06 and 14/06 – expired on 22 May 2009.

Licence 3/06 was held by Sagex Petroleum hf (80 per cent) and the Danish North Sea Fund (20 per cent), and the exploration activity under the licence included the acquisition of 3D seismic data in 2007.

Licence 14/06 was held by DONG E&P A/S (80 per cent) and the Danish North Sea Fund (20 per cent).

Fig. 1.5 Exploratory surveys in 2009



Another licence issued in the 6th Licensing Round – 13/06 – expired on 22 November 2009. The licence was held by DONG E&P A/S (36 per cent), Talisman Energy Denmark AS (24 per cent), Gaz de France Production Nederland BV (20 per cent) and the Danish North Sea Fund (20 per cent). The licensee drilled an exploration well in the part of the prospect extending into Norwegian territory.

The changes appear from figure 1.4.

EXPLORATORY SURVEYS

All exploratory surveys in 2009 were carried out in the Open Door area and the greater part of seismic data was acquired onshore, also see box 1.4, as appears from figure 1.5. This is a significant change from previous years in which the majority of exploration activities took place in the licensing round area west of 6°15' eastern longitude. The quantity of geophysical data acquired during the period from 2001 to 2009 appears from figure 1.6.

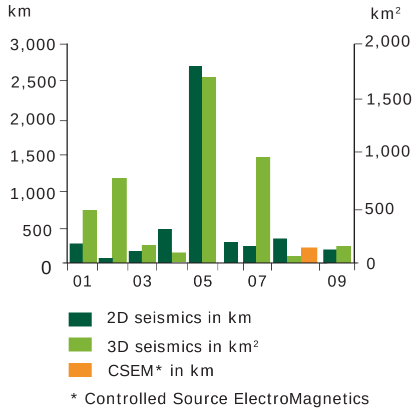
On 25 August 2009, Polskie Górnictwo Naftowe i Gazownictwo SA (PGNiG) was granted permission to acquire 2D and 3D seismic data under licence 1/05, operated by PGNiG. On 27 November 2009, the term of the permit to carry out exploratory surveys was extended as the seismic surveys took longer than anticipated due to heavy rainfall in South Jutland. Seismic data acquisition took place from September to November 2009 and was resumed in the period from January to February 2010. The survey was completed on 14 February 2010, and 146 km² of 3D seismic data and 70 km of 2D seismic data was acquired.

DONG E&P A/S carried out a 2D seismic survey under licence 3/07 during the period from September to October 2009. DONG E&P A/S used Rambøll Danmark A/S as the seismic contractor and acquired 50 km of 2D seismic data in northwestern Jutland.

Under licences 1/09 and 2/09 in mid-Jutland, Danica Jutland ApS performed a geochemical survey during the period from August through October 2009. Danica Jutland took 1,200 soil samples at a depth of one metre and analyzed the samples for the presence of hydrocarbons.

In November 2009, Danica Resources ApS carried out a geochemical survey under licence 1/08, taking 50 soil samples at a depth of one metre. The samples were subsequently analyzed for the presence of hydrocarbons.

Fig. 1.6 Geophysical data acquired during the period 2001-2009



Box 1.4

Seismic surveys

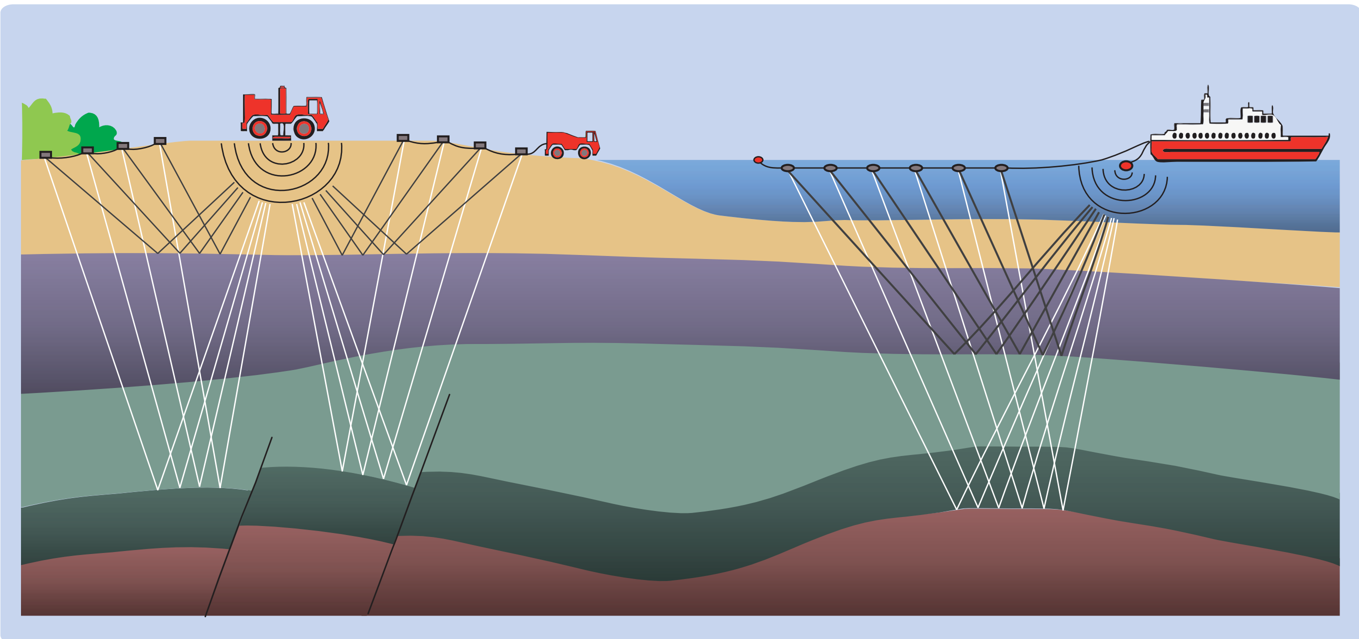
The purpose of seismic surveys is to obtain information about subsurface layers. Seismic surveys are carried out by sending pressure waves into the subsoil from a sound source. When the pressure wave encounters different geological layers, part of the pressure wave is reflected back to the surface. Special receivers placed at the surface beforehand record the reflected wave; see figure 1.7. The result is a picture of the geological structures in the subsoil. This picture can be used to find geological structures that may contain oil and gas under the right conditions.

A **2D seismic survey** provides a vertical cross-section of the subsoil. Putting the 2D seismic lines together in a fine-meshed grid produces a three-dimensional picture of the subsoil. This is called **3D seismics**. When 3D seismic data is acquired in the same area at several-year intervals and compared, a fourth dimension is obtained – time. For instance, **4D seismic data** can provide insight into the changes occurring in a producing field over time. With 4D seismics, it can sometimes be possible to see which way the oil has flowed towards the production wells and which areas in the field have not been drained adequately. This information helps the oil companies optimize recovery.

Onshore seismic surveys

On land, the pressure waves are usually created using vibrators. These vibrators are mounted on special large vehicles called vibrator vehicles. Vibrator vehicles

Fig. 1.7 Schematic drawing of on- and offshore seismic data acquisition



are equipped with heavy and powerful pistons (see figure 1.7), which are pressed against the surface. This generates the necessary pressure waves. The reflected pressure waves are recorded using small, simple microphones, known as 'geophones'. The geophones are placed on the surface of the earth in rows up to several kilometres in length. The many geophones, of which there can be several thousand, are connected to a recording unit, which is often a lorry full of advanced electronics and powerful computers.

In order to give the pressure waves sufficient energy to enable the geophones to capture the reflections from the deeper layers being investigated for hydrocarbons, several vibrator vehicles are often used simultaneously.

Previously, dynamite was used as a sound source, but today this technique is only used in very special cases where it is necessary to acquire seismic data in waterlogged areas such as wetlands, etc.

When a seismic survey is to be carried out on land, the company that is responsible for the survey must obtain permission from the landowners on whose property the data is to be acquired. In cases where a landowner does not give his consent, the company can apply to the DEA for a temporary permit to enter the property. The company must demonstrate that it is necessary to gain access to the property concerned and document that reasonable efforts have been made to obtain the landowner's consent and, in particular, what measures have been taken to reach an agreement with the landowner.

The DEA will then decide whether it is necessary to carry out the investigation on this particular property in order to obtain the necessary information about the subsoil. If the DEA concludes that it is necessary to carry out the survey on the property, the company will be entitled to proceed. In such cases, the landowner may appeal the DEA's decision to the Minister for Climate and Energy.

Offshore seismic surveys
When seismic data is to be acquired at sea, the seismic equipment is towed behind a specially equipped vessel. The pressure wave is created by an air gun that is towed behind the vessel; see figure 1.7. Instead of geophones, hydrophones are used to capture the reflected signals. The hydrophones are placed on 5-8 km long cables, which are also towed behind the vessel. If the data is to be acquired in shallow areas, the method is the same but smaller boats are used and the hydrophone cables are shorter.

When offshore seismic surveys are carried out, suitable measures must be taken to protect marine mammals, such as porpoises, and other species; see the section *Noise from seismic surveys* in chapter 5, *Environment and climate*.

The DEA must always approve seismic investigation programmes in advance and this applies to both on- and offshore seismic surveys.

WELLS

In 2009, one exploration well and one appraisal well were drilled, both encountering hydrocarbons in Jurassic reservoirs. The two positive results have raised expectations concerning the hydrocarbon potential of deep reservoirs.

The locations of the wells and a comparison of the numbers of exploration and appraisal wells drilled during the period from 2001 to 2009 are shown in figure 1.8. The appraisal wells drilled in the fields are also shown in the field maps in appendix B.

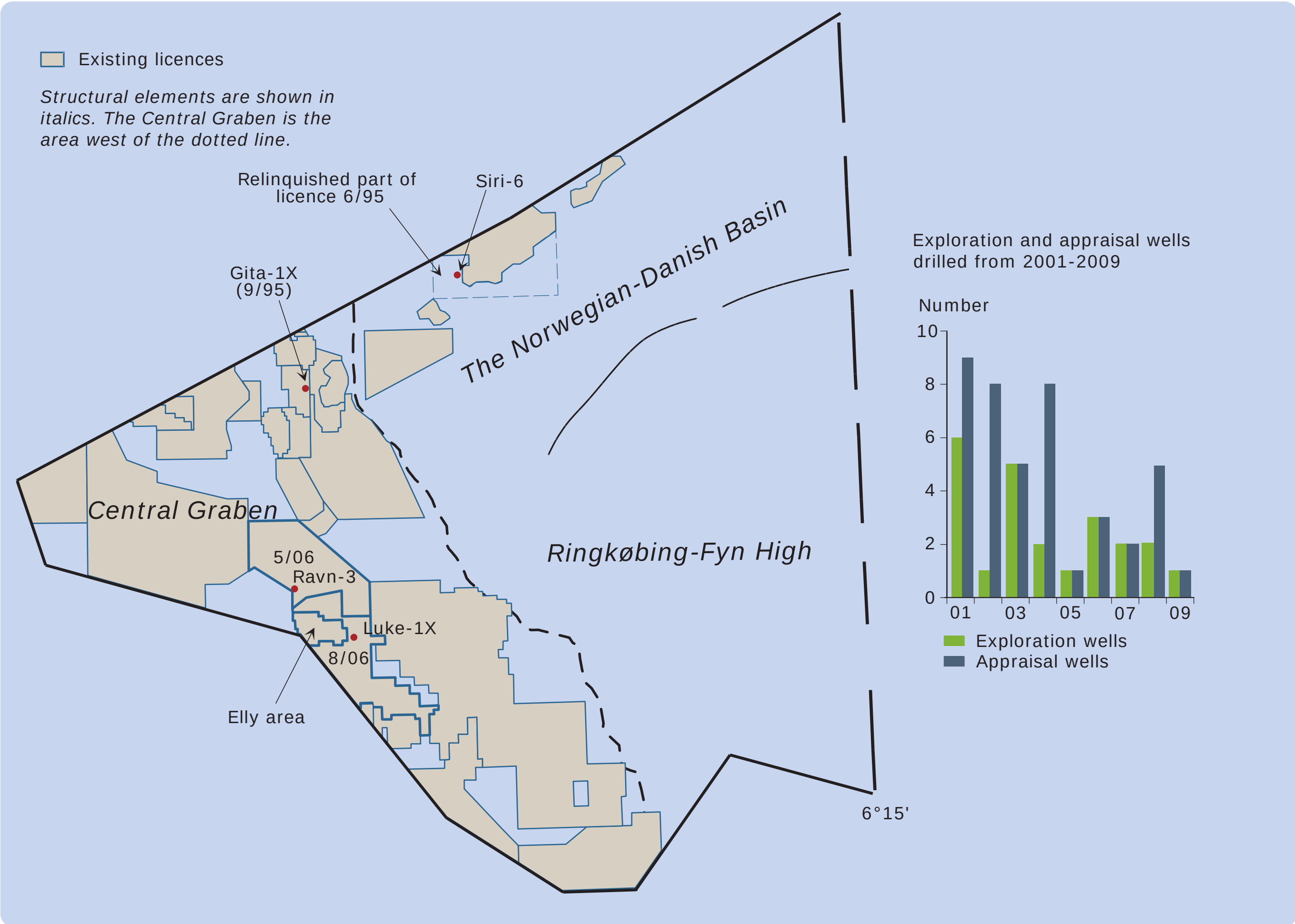
The wells Siri-6 and Gita-1X were completed in 2009, but as these wells were spudded in late 2008, they are not included in the statistics for 2009.

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

Luke-1X (5504/6-6)

As operator for licence 8/06, Mærsk Olie og Gas AS has drilled the exploration well Luke-1X in the westernmost part of the Danish North Sea area. The well discovered gas and condensate (see box 1.5) in sandstones of Middle Jurassic age.

Fig. 1.8 Exploration and appraisal wells drilled in 2009 west of 6°15' eastern longitude



Box 1.5

Hydrocarbons consist of molecules that are primarily made up of carbon (C) and hydrogen (H). Small, light hydrocarbon molecules are called **gas**, while **oil** consists of larger and heavier hydrocarbon molecules. In the reservoir, the pressure and temperature are initially high. When the hydrocarbons are produced and the pressure and temperature fall, the heaviest gas molecules condense to form a liquid, which is called **condensate**.

The drilling of Luke-1X was commenced on 7 August 2009 by the drilling rig Mærsk Resolve and was completed on 7 February 2010.

Luke-1X was drilled as a vertical well and terminated in clay layers presumed to be of Lower Jurassic age at a depth of 4,572 metres below the surface of the sea. The well encountered hydrocarbons in sandstone layers in the Middle Jurassic Bryne Formation, and core samples and measurements were taken in order to evaluate the discovery. In order to assess the discovery further, a sidetrack – Luke-1XA – was also drilled towards the north. After the drilling operation, both well sections were plugged and abandoned.

Luke-1X was drilled just east of the Elly gas/condensate field, which is located within A.P. Møller – Mærsk A/S' Sole Concession. A collaboration agreement was therefore made between licence 8/06 and the Sole Concession concerning the drilling of the well.

Ravn-3 (5504/5-2)
As operator for licence 5/06, Wintershall Nordzee B.V. has drilled the appraisal well Ravn-3 in the westernmost part of the Danish North Sea area. The well was terminated in layers of Triassic age at a depth of 4,469 metres measured vertically below the surface of the sea. Ravn-3 encountered Upper Jurassic sandstone layers containing oil and gas. Oil and gas were produced during a test production period.

The drilling of Ravn-3 was commenced on 15 September 2009 by the drilling rig Noble George Sauvageau and was completed on 25 December 2009. The well was suspended allowing for further use.

Ravn-3 is located approximately 1.5 km south of the Ravn-1 well, where oil and gas were discovered in 1986. After the Ravn-2 appraisal well, which was drilled in 1987, the licensee concluded that there was no basis for establishing a field development and therefore relinquished the licence.

2 USE OF THE SUBSOIL

The use of the subsoil for various purposes is regulated by the Act on the Use of the Danish Subsoil, usually referred to as the Danish Subsoil Act. This chapter describes use of the subsoil for purposes other than oil and gas production. In Denmark, the subsoil is also used to produce salt, explore for and produce geothermal heat and store natural gas. Moreover, interest has been shown in storing CO_2 in the subsoil.

GEOTHERMAL HEAT PRODUCTION

There are substantial quantities of heat in the Danish subsoil. This geothermal heat can be recovered from the saltwater that is present in porous sandstone layers (see box 1.2 in chapter 1, *Licences and exploration*) that can be found in much of Denmark's subsoil. Geothermal heat from the subsoil can be utilized for district heating purposes; see box 2.1.

Box 2.1

Ground source heat and geothermal energy

Ground source heat has become more widespread in recent years. Heat from the soil is absorbed by a liquid that circulates in a system of hoses buried at a depth of around 1 metre. The heat from the liquid is recovered using an electric heat pump. In terms of size, ground source heat systems can be adapted to ordinary detached houses. In the case of ground source heat, the heat from the sun that reaches the uppermost soil layers is utilized. The establishment of ground source heat systems is governed by the Executive Order on Ground Source Heat Systems issued by the Danish Ministry of the Environment. Ground source heat systems may not be established until the municipal authority has given its permission for the system in accordance with the provisions of the Danish Environmental Protection Act.

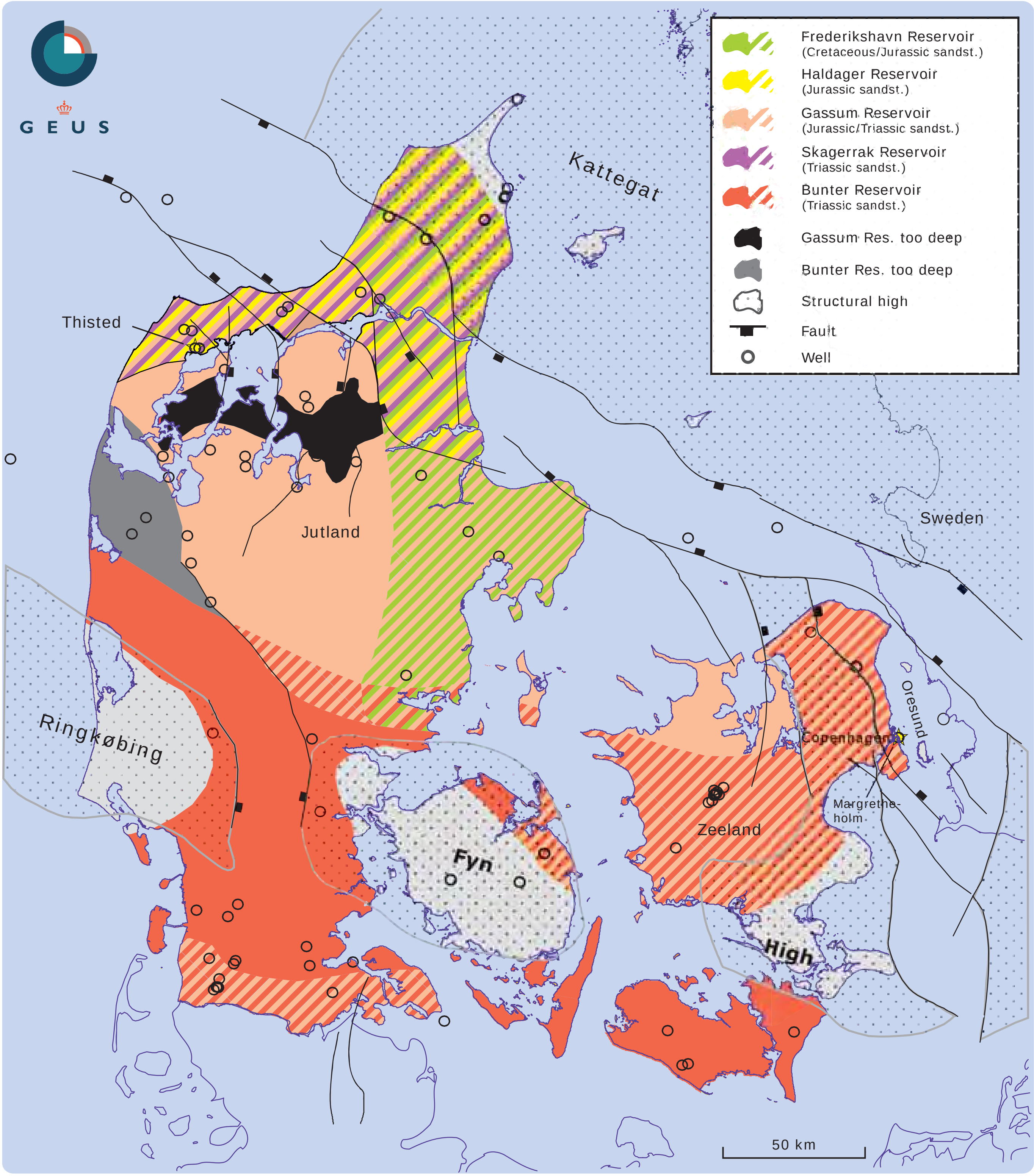
Geothermal energy is recovered from the hot water that exists naturally in porous and permeable sandstone layers (see box 1.2 in chapter 1, *Licences and exploration*), which in Denmark are typically present at depths between 800 and 3,000 metres. Geothermal systems are expensive to construct, partly because of the deep wells that are required. Geothermal systems are therefore suitable for use in large district heating systems. In the case of geothermal energy, heat that flows outwards from the Earth's interior, where the temperature can be up to 5,000°C, is recovered. In the Earth's interior, the heat is generated through radioactive processes similar to those that take place in the sun. The recovery of geothermal energy is governed by the Subsoil Act, which is administered by the DEA.

Utilization of geothermal energy

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

In autumn 2009, the DEA published the report "Geothermal Energy – heat from the interior of the Earth, status and possibilities in Denmark", which describes the possibilities of geothermal heat production in Denmark. The DEA's report is based on a report entitled "Evaluation of the geothermal potential in Denmark" prepared by the Geological Survey of Denmark and Greenland, GEUS; see box 2.2. The DEA's and GEUS' reports are available (in Danish) at the DEA's website, www.ens.dk.

Fig. 2.1 Regional geological potential for the use of sandstone reservoirs for geothermal heat production



Box 2.2

The Geological Survey of Denmark and Greenland (GEUS)
The Geological Survey of Denmark and Greenland (GEUS) is a research and advisory institution under the Danish Ministry of Climate and Energy. GEUS is a public entity and its duties are laid down in the Danish Act on the Geological Survey of Denmark and Greenland (Act No. 536 of 6 June 2007).

GEUS is responsible for the scientific exploration of the geological conditions in Denmark and Greenland and associated shelf areas. GEUS carries out research that is of importance to the utilization and protection of geological natural values and also carries out mapping, monitoring, data acquisition, data management as well as information activities. GEUS carries out its research independently of the Minister for Climate and Energy.

GEUS provides research-based geological advice to the DEA and other public authorities relating to natural, environmental, energy and raw material issues. GEUS is also a national geological data centre and in this capacity makes data and knowledge available to authorities, educational institutions, enterprises and private individuals, etc.

GEUS has prepared a map showing where sandstone layers that are suitable for geothermal energy production are likely to be present; see figure 2.1. This map shows a regional assessment of the geothermal potential and represents a generalization of large areas; therefore, the local conditions in the subsoil may differ from those shown on the map. Local conditions can only be determined by carrying out geological investigations such as seismic mapping and exploration wells.

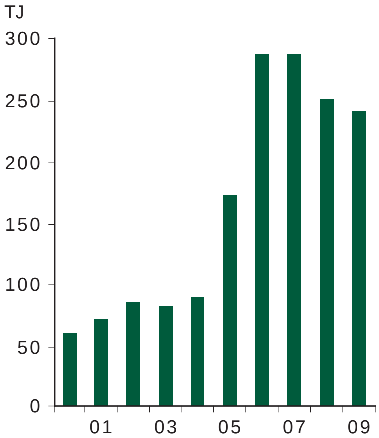
There are a number of sandstone layers in the Danish subsoil that could potentially be utilized for geothermal heat production. These sandstone layers were deposited 250 million to 100 million years ago during the periods of the Earth's history known as the Triassic, Jurassic and Lower Cretaceous; see appendix F. In figure 2.1, these sandstone layers are indicated by the following names: the Bunter, Skagerrak, Gassum, Haldager and Frederikshavn Formations. For a more detailed description of these sandstone layers, see the above-mentioned report from GEUS.

The map of the regional geothermal potential (see figure 2.1) shows the areas where sandstone layers with a thickness of at least 25 metres may be present at depths of 800-3,000 metres. GEUS believes that the sandstone layers must be at this depth and have a minimum thickness of 25 metres in order to have the necessary properties (sufficient water production and temperature) for utilization for heat production.

Across much of Denmark, there are good opportunities for finding sandstone layers that can be utilized for geothermal heat production. In some parts of the country, there is even the possibility of utilizing two or more of the sandstone layers at different depths. These areas are indicated by hatching in the figure. There are good opportunities for finding suitable sandstone layers across most of Jutland, north-eastern Funen and much of Zealand, Lolland and Falster.

However, there are areas in Denmark where there is little chance of finding sandstone layers at a suitable depth. This applies to most of Funen, southeastern Zealand and

Fig. 2.2 Production of geothermal energy, 2000-2009



parts of western and northern Jutland and the whole of Bornholm. Areas without geothermal potential are shown in figure 2.1 in grey and black. In these areas, the sandstone layers are either absent, too shallow, and consequently have too low a temperature or are buried too deep with insufficient porosity and permeability; see box 1.2 in chapter 1, *Licences and exploration*.

In the future, geothermal energy could play a role as a heat source in many existing district heating grids in Denmark. The DEA's report states that there could be potential to establish geothermal energy production in 32 existing district heating grids with a heat supply of more than 400 TJ/year. More detailed analyses are however necessary in order to determine whether it would be attractive to establish geothermal energy production at a given location.

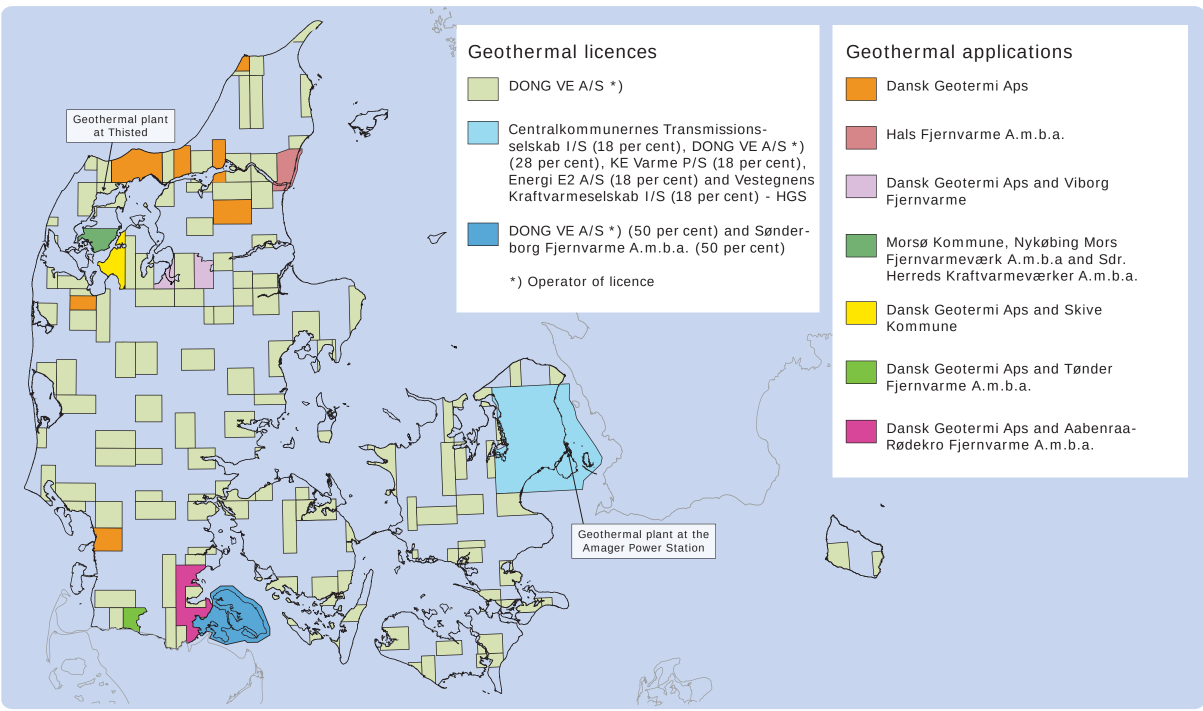
There are currently two geothermal heat plants in Denmark. One plant at Thisted has been producing heat since 1984, and a plant at Amager since 2005. A third geothermal energy plant is on the way at Sønderborg, expected to start production in 2012.

The production of geothermal energy during the past ten years is shown in figure 2.2. In total, 241 TJ of geothermal energy was produced for district heating production during 2009. By comparison, a total of approximately 124,000 TJ of district heating is produced every year in Denmark.

Licences

At the end of 2009, three licences had been issued for the exploration for and extraction of geothermal heat. DONG has an exclusive licence from 1983 that covers large areas of Denmark. Originally, DONG's exclusive licence covered all of Denmark, but in 1993 and again in 2003 DONG relinquished areas making up one-third of the original area. The term of the licence expires in December 2013. In the metropolitan region,

Fig. 2.3 Geothermal licences in Denmark in 2009



a licence was issued in 2001 to the companies in Hovedstadsområdets Geotermiske Samarbejde – HGS (the Metropolitan Geothermal Alliance), and in 2007 a licence covering the municipality of Sønderborg was issued. The licence locations appear from figure 2.3.

At the end of 2009, the DEA was processing a total of seven applications for licences to explore for and extract geothermal energy. The areas covered by the applications appear from figure 2.3.

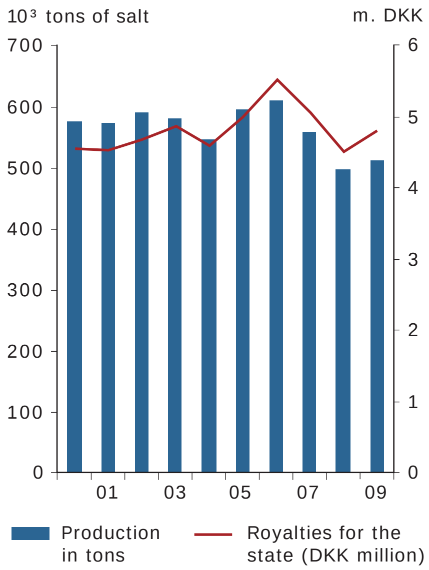
Companies interested in the unlicensed areas can submit an application to the DEA for a licence to explore for and extract geothermal energy; see box 2.3.

Box 2.3

Geothermal applications and licences
The exploration for and extraction of geothermal energy requires a licence pursuant to the provisions of the Subsoil Act. The licence is issued by the Minister for Climate and Energy pursuant to section 5 of the Subsoil Act upon submitting the matter to the Energy Policy Committee of the Danish Parliament. An application for a licence to explore for and extract geothermal energy may be submitted to the DEA in respect of areas not covered by an existing licence. The application fee amounts to DKK 25,000.

The company or group of companies holding a licence is called the licensee. Prior to initiating geothermal energy production, the licensee must submit a plan for the activities, including the production strategy and the facilities to be used, in accordance with the provisions of section 10 of the Subsoil Act. The plan is subject to approval by the DEA. Moreover, municipal approvals are required for the establishment of facilities for producing geothermal energy.

Fig. 2.4 Salt production and state revenue from royalties, 2000-2009



SALT EXTRACTION

In Denmark, salt is extracted at one location only, viz. from the Hvornum salt diapir about 8 km southwest of Hobro. The company Akzo Nobel Salt A/S extracts the salt, which is used for consumption, for use as industrial salt and road salt. The company has an exclusive licence for the production of salt from the Danish subsoil. The licence will expire in 2013, and the company has applied for a new licence to replace the existing one, which was issued in 1963.

In spring 2010, the Minister for Climate and Energy granted Akzo Nobel Salt A/S a new licence for the solution mining of salt.

The production of salt totals about 500,000 to 600,000 tons per year, and the Danish state receives about DKK 5-6 million a year in royalties. Figure 2.4 shows the past ten years' production of salt and the Danish state's revenue in the form of royalties.

STORAGE OF CO_2

The subsoil storage of CO_2 can take place at locations with suitable geological conditions. In Denmark, this will typically be porous and permeable sandstone layers (see box 1.2 in chapter 1, *Licences and exploration*) 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 high pressure. The sandstone layers must form a structure where the injected CO_2

Fig. 2.5 Application for licence for CO_2 storage

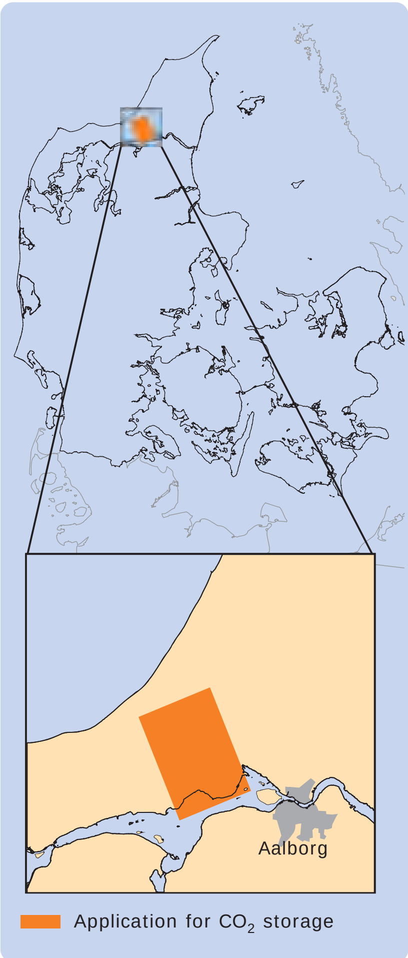
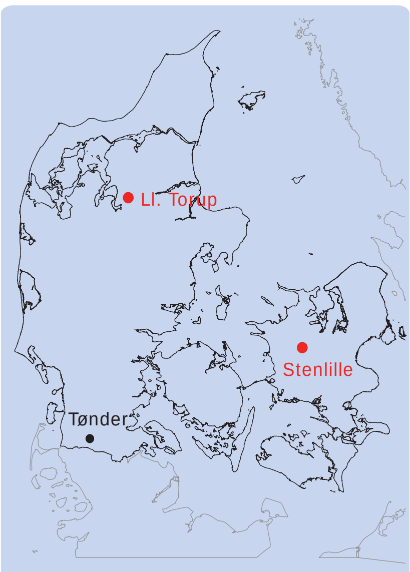


Fig. 2.6 Gas storage facilities in Denmark in 2009



can be trapped in 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.

However, detailed investigations and assessments of a given location will be required before decisions can be made on a specific project for the storage of CO_2.

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. DONG's licence expired in 2009, while Vattenfall's licence was extended for the purpose of carrying out preliminary investigations.

In autumn 2008, Vattenfall performed a 2D seismic survey of the subsoil northwest of Aalborg in order to map the Vedsted structure. On 29 June 2009, Vattenfall submitted an application for a licence to utilize the subsoil for the storage of CO_2. The application concerns an area of approximately 12 km x 17 km, which covers the Vedsted structure; see figure 2.5. In September 2009, Vattenfall announced that its project to capture and store CO_2 had been postponed. The work that is described in the application (3D seismics, deep exploration wells, etc.) has therefore been deferred and will be carried out at a later date. In March 2010, Vattenfall submitted a revised application, which is now under consideration.

Consideration is also being given to injecting CO_2 in the North Sea oil fields in order to increase oil production. The injection of CO_2 could release more oil from the layers and thereby improve the recovery factor. Mærsk Olie og Gas AS is investigating whether it would be possible to establish such a project in a Danish oil field and has therefore been in contact with Finnish companies concerning a project under which around 1.2 million tons of CO_2 will be collected annually at a power station in Finland, transported by tanker vessel to the North Sea and injected into Danish oil fields there. The injection of CO_2 will require modifications to the platform and pipelines in the oil field.

In April 2009, the EU adopted a directive concerning the storage of CO_2, which will be implemented into Danish legislation, and the DEA is in the process of preparing draft legislation for this purpose. The directive contains a system for allocating exploration and storage licences in connection with the storage of CO_2, and regulates many aspects concerning monitoring, etc. Each Member State is free to decide whether, and if so where, they wish to store CO_2 in the subsoil.

GAS STORAGE

Natural gas is used in Denmark to heat homes, among other things. In order to secure natural gas supplies during the winter months when consumption exceeds production, and in the event of a rupture in the natural gas pipelines from the North Sea, gas storage facilities have been established.

There are currently two gas storage facilities in Denmark. One facility is located at Stenlille on Zealand, while the other is situated at Lille Torup in northern Jutland; see figure 2.6.

At the Stenlille gas storage facility, which is owned by DONG Storage A/S, gas is stored in porous sandstone layers at a depth of around 1,500 m. Approximately 1.5

billion Nm^3 of natural gas is stored at the Stenlille facility, of which about 580 million Nm^3 can be utilized (working gas). In 2009, the Stenlille storage facility was developed further with another well for injection and production, together with a fourth compressor which will increase the pumping capacity by 100,000 Nm^3 per hour to 200,000 Nm^3 per hour.

DONG Storage A/S, which owns and operates the gas storage facility, has applied to the DEA for an extension of the licence term as well as permission for operation of the facility until 2037. The DEA is currently processing the application.

At the Lille Torup facility, the gas is stored in seven large subsoil caverns that have been created by leaching a salt diapir. This gas storage facility is owned by Energinet.dk Gaslager A/S. The caverns, which are situated at depths of 1,200-1,700 metres, are 300-350 metres high and 50-65 metres in diameter. At the Lille Torup facility, approximately 700 million Nm^3 of gas can be stored in the seven caverns, of which about 440 million Nm^3 of gas is utilized (working gas).

Energinet.dk Gaslager A/S, which owns and operates the gas storage facility, has applied to the DEA for an extension of the storage licence until 2037. An application has also been submitted for permission to increase the quantity of natural gas pumped into the facility by 1,580 million m^3 to approximately 2,280 million m^3. Energinet.dk Gaslager A/S will expand the capacity by leaching new caverns and re-leaching existing caverns. The application is under consideration.

In addition to the two existing gas storage facilities, the company Dansk Gaslager ApS has submitted an application to establish and operate a new natural gas storage facility at Tønder. The DEA is processing the application.

3 PRODUCTION AND DEVELOPMENT

Oil and gas production declined during 2009 as expected. Oil companies are striving to develop technology that will enable the recovery of a higher proportion of the resources that have already been discovered. This will also make smaller discoveries more profitable.

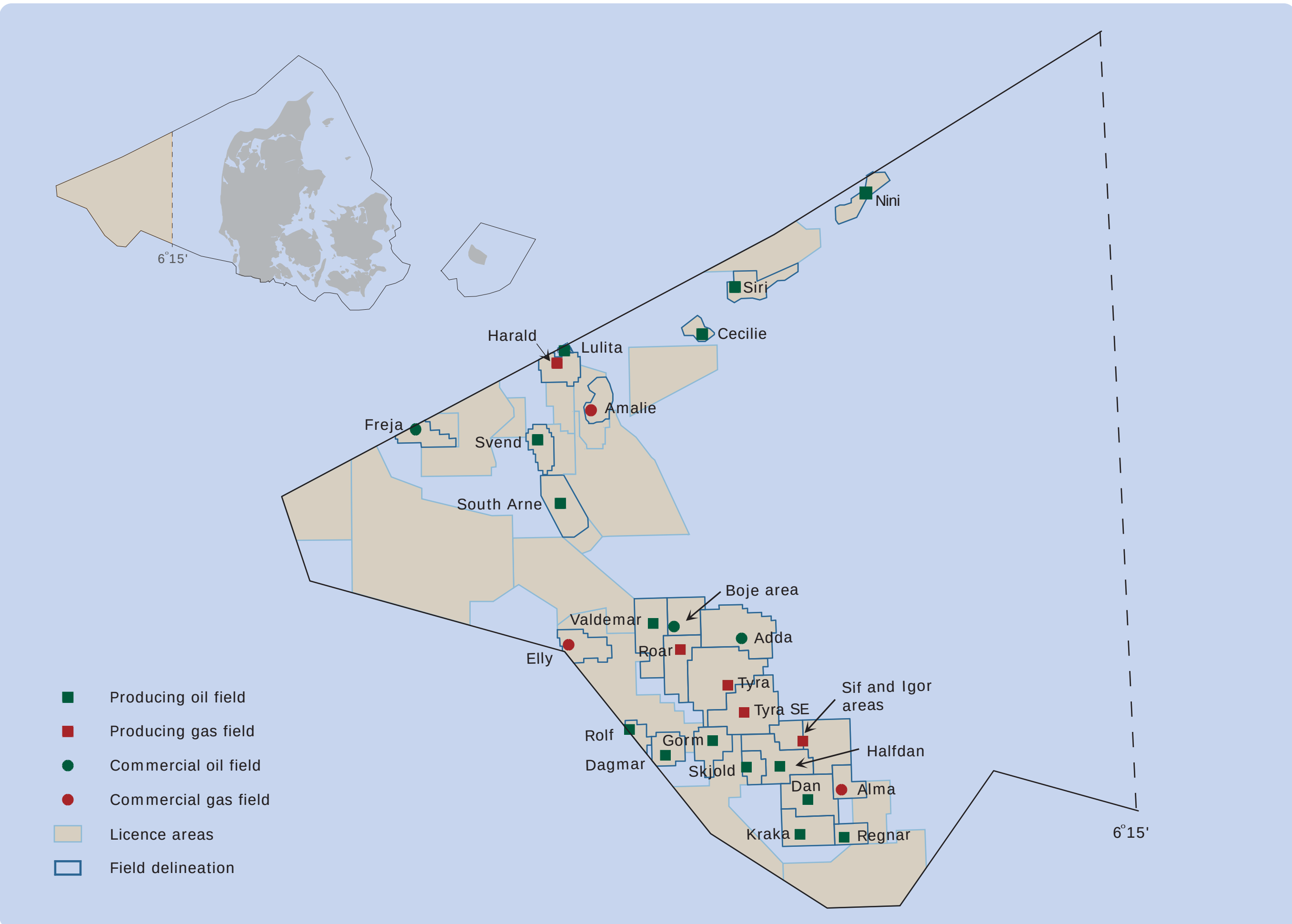
PRODUCTION IN 2009

Danish production takes place exclusively from offshore installations in the North Sea; see figure 3.1. In total there are 19 producing fields of varying size. Figure 3.2 shows the location of production installations and the major production and water-injection pipelines connected to the installations. The platform complexes in the individual fields are described and illustrated in appendix B.

Three operators and their partners are responsible for production: DONG E&P A/S, Hess Denmark ApS and Mærsk Olie og Gas AS. A total of ten companies have interests in the producing fields, and the companies' shares of total Danish oil production appear from figure 3.3.

During 2009, 290 production wells (203 oil, 87 gas) and 112 injection wells (6 gas, 106 water) were in operation. Compared to 2008, the number of active wells increased by eight wells in 2009. 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

Fig. 3.1 Danish oil and gas fields



production during the year, or vice versa. Appendix B (field data) indicates the number of active wells at the end of 2009.

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. Moreover, appendix A contains figures for the production and injection of water as well as for CO_2 emissions.

Fig. 3.2 Location of production facilities in the North Sea 2009

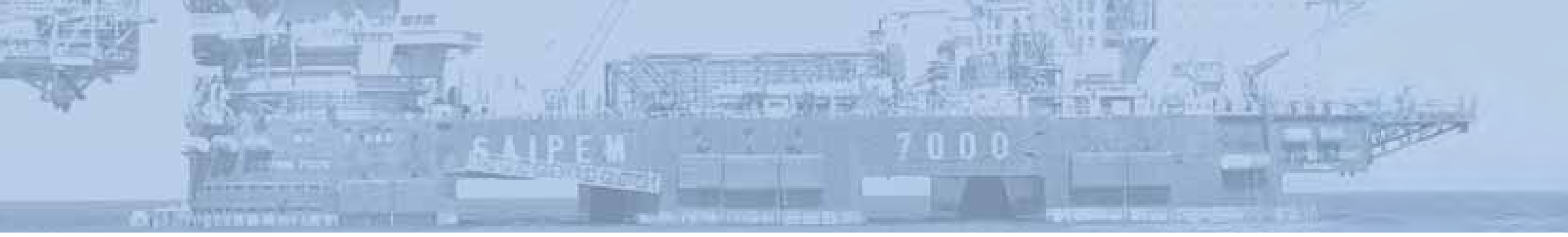
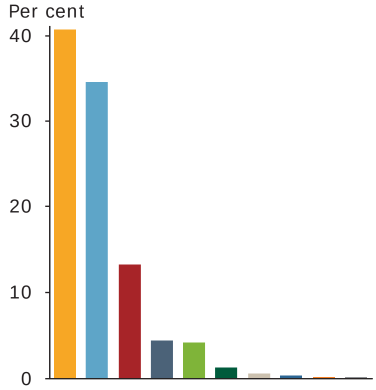


Fig. 3.3 Breakdown of oil production by company



Shell	40.9	Altinex Oil	1.4
A.P. Møller-Mærsk	34.6	Siri (UK)	0.6
Chevron	13.3	RWE-DEA	0.4
Hess	4.4	Danoil	0.1
DONG E&P	4.2	Altinex Petroleum	0.1

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

Oil production

Oil production in 2009 totalled 15.2 million m³, a 9.0 per cent decline compared to 2008.

In addition to the expected fall in total Danish production, some of this downturn is due to the shutdown of several fields for shorter or longer periods of time in connection with maintenance, repairs, modifications or, as regards the Siri platform, the identification of cracks in the wellhead caisson support structure.

Because of these cracks, production from the Siri platform was shut down from 1 September 2009 until mid-January 2010; see also the section entitled *Inspections in 2009* in chapter 4, *Health and safety*. In connection with a routine inspection of the storage tank, cracks were identified in the part of the structure that supports the caisson. The caisson is a protective section of pipe which encases all the Siri Field's production pipe from a couple of metres above the seabed up to the platform. At year-end, work was still under way on a seabed support solution. A temporary solution was in place in January 2010, enabling production from the field to resume. A permanent solution is expected to be ready during the third quarter of 2010.

The shutdown of the Siri platform resulted in the suspension of production not only from the Siri Field, but also from the Cecilie and Nini Fields, as production from these fields is sent to the Siri platform.

On other installations, improved production has been achieved in certain old wells following the completion of clean-up and refurbishment programmes.

Figure 3.4 shows the historical development in production over the past 25 years.

Gas production

Natural gas production totalled 8.6 billion Nm³ of gas in 2009, with sales gas accounting for 7.3 billion Nm³. By sales gas is meant the portion of the gas suitable for sale. Production dropped by 13.1 per cent compared to 2008.

Fig. 3.4 Production of oil and sales gas 1985-2009

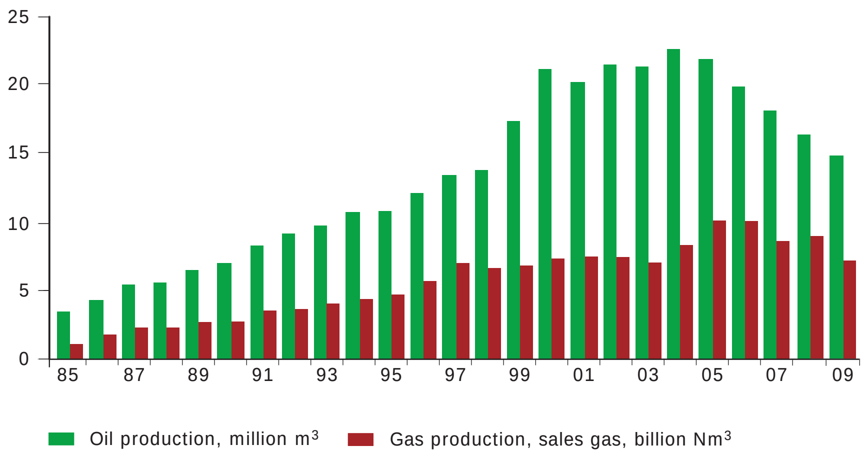


Figure 3.4 shows the historical development in sales gas production over the past 25 years. Annual production figures since production started in 1972 are available at the DEA's website, www.ens.dk.

Gas injection in the Tyra Field rose by approximately 75 per cent in 2009 compared with 2008. This proportionally large increase must be viewed in light of the very low injection in 2008. Gas exports were also significantly lower than in 2008. However, gas injection in the Siri Field dropped by about 75 per cent, largely due to the shutdown of the Siri Field during the last four months of 2009.

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 5, *Environment and climate*, and in appendix A.

Water production and water injection

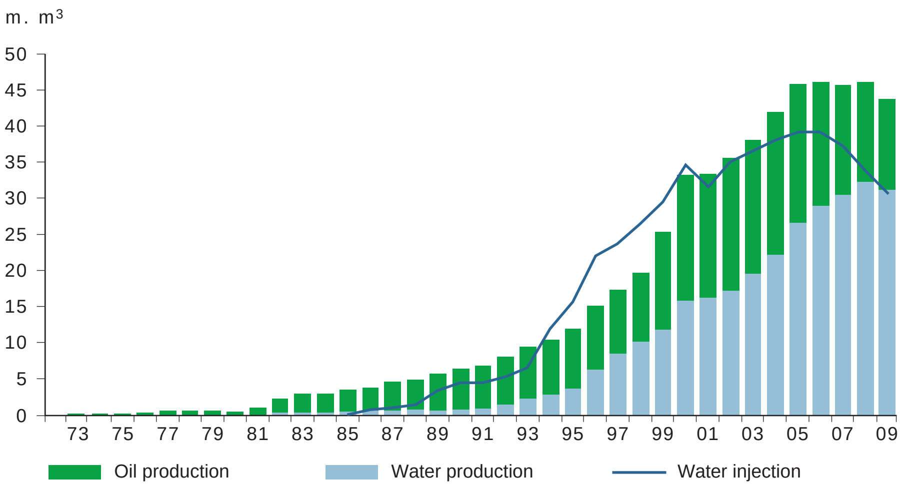
Water is produced as a by-product in connection with the production of oil and gas. The water can originate from natural water zones in the subsoil or from the water injection that is carried out in order to enhance oil production.

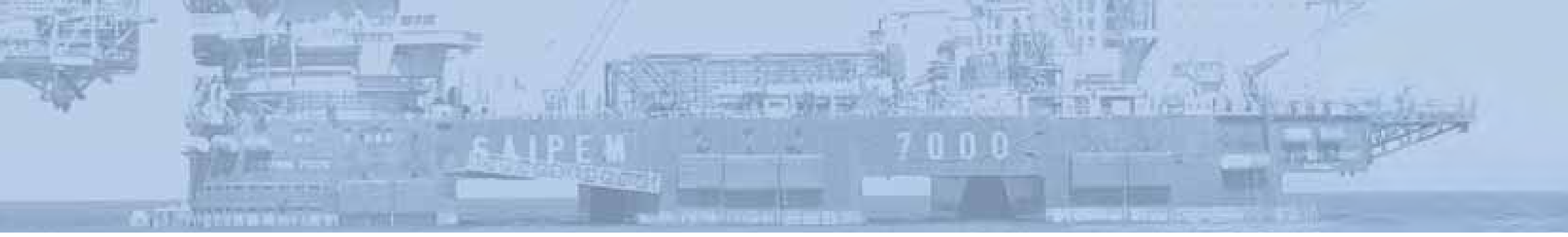
In Denmark, 37.5 million m³ of water was produced and 44.4 million m³ of water was injected during 2009, of which around a third was reinjected production water, while the remainder was treated seawater. The injection of water has fallen by 12.9 per cent since 2008, while the quantity of produced water has decreased by 5.3 per cent compared with 2008, when water production peaked.

The use of water injection

During the initial production phase of a new field, there is a substantial pressure difference between the reservoir and the surface. The excess pressure in the reservoir enables the oil to be produced through natural drainage for a certain period of time. As the oil is produced, the pressure in the reservoir will fall. Injecting water into the reservoir maintains the pressure, and the oil is displaced as it flows towards the production wells. Flushing the reservoir with injection water can also benefit production to some extent, depending on the chemical composition of the water.

Fig. 3.5 Production and injection in Danish fields with water injection





Injection takes place through wells, which correspond to production wells. These wells must be located optimally relative to the production wells. In fields with low reservoir thickness, such as the Danish fields, horizontal production and injection wells are drilled alternately in a parallel pattern across the reservoir. This type of pattern can clearly be seen in the main Halfdan Field and on the northwestern flank of the Dan Field. In these production/injection patterns, it is important that the outermost well is always a production well to ensure that oil is not forced away from the production wells.

In Denmark, the first injection well was drilled in the Skjold Field in 1986. Since then, the technique has been developed in eight fields with a total of 106 active water-injection wells in 2009. Figure 3.5 shows the relationship between produced and injected quantities in the eight Danish fields that use water injection. The figure shows that oil production is accompanied by large volumes of produced water. The volume of injected water is decreasing, and in 2009 it corresponded approximately to the volume of produced water.

The quality and chemical composition of the water injected must not cause unnecessary wear on the materials and equipment in the wells. For example, seawater cannot be used directly because of its oxygen content, which corrodes iron.

The water that is produced contains oil residues and geological material, among other things. It must therefore be treated before reinjection. Alternatively, treated seawater can be used. In case of some fields, this water is supplied from another processing plant, e.g. from Dan to the Halfdan Field. Efforts are being made to optimize the processes concerning produced water and injection water, allowing a greater proportion of the produced water to be reinjected. This will reduce the discharge of oil residues into the sea; see also the section entitled *Marine discharges* in chapter 5, *Environment and climate*.

DEVELOPMENT ACTIVITY IN 2009

A total of 19 new well sections were drilled in the Danish fields in 2009: 11 production wells, including one with two well sections, five water-injection wells, one appraisal well and one exploration well. Thus, drilling activity remained at the same level as in 2008.

The above-mentioned wells and additional development activities represented total investments of DKK 7.05 billion, an increase of almost 20 per cent compared to 2008.

Appendix B contains a description of the individual fields, including development and investment activities, as well as maps showing the location of the most important wells.

Approved development plans and ongoing activity

The Dagmar Field

The operator is working to reassess the field's potential and has so far concluded that the field has residual potential which it may be possible to exploit. A final plan is anticipated during 2010. The field is therefore not facing imminent decommissioning and removal of the installations.

The Dan Field

During 2009, maintenance (see box 3.1) was carried out on five old wells. These wells have been restimulated (see box 3.2) and zones with a risk of water breakthrough have been closed.

Box 3.1

Maintenance activities on offshore structures are often called **workovers** (WO) or **well interventions**.

Workover activities can comprise restimulation (see box 3.2) or installation, replacement or repair of mechanical equipment on the platform or in the well.

Well interventions can comprise the clean-up and removal of undesirable materials such as sand or chalk that seep into the well during production, or scale that is formed when injected seawater reacts with formation water. Sand, chalk and scale can all plug the well. Well interventions can also comprise zone adaptation in the wells. Some wells are completed with separate zones in the reservoir section. These zones can be opened or closed in order to optimize the production of hydrocarbons.

Well interventions are often carried out using equipment that is secured to a wire or coil tubing and controlled from the platform or a drilling rig adjacent to the platform. Whether a drilling rig has to be used for the work will depend on the scope of the maintenance work and the design of the platform.

Several restimulation campaigns were carried out in 2009.

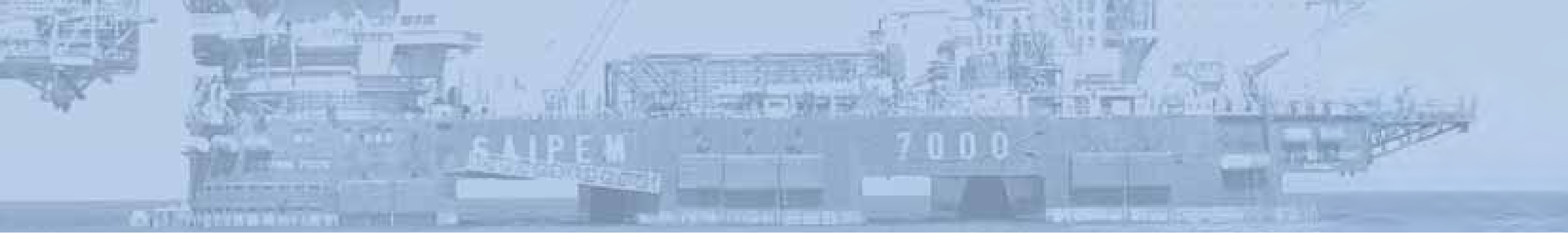
Box 3.2

Stimulation and restimulation
A very simple description of the principle of an oil well is that a pipe connection is established from the platform to the reservoir that contains hydrocarbons. In the section of pipe that is located at the very bottom of the reservoir, a series of holes are made to allow hydrocarbons to flow into the pipe and then continue up through the pipe to the platform.

To increase production, a **stimulation** treatment of the well is carried out immediately before the well is brought on stream. Stimulation is a process where dilute hydrochloric acid is forced out through the well's holes under high pressure. This results in some of the calcareous material in the reservoir being dissolved and increases the surface area, which improves production. When the well has been producing for a period of time, it may be necessary to repeat the stimulation process in order to re-optimize the flow conditions to the well. This repeat stimulation is called **restimulation**.

The Gorm Field
In mid-2009, well N-40B was drilled as a redrilling of well N-40A. A collapsed section of N-40A could not be restored and the well had to be closed. As there is still the potential for producing oil at the location, the well was replaced with a redrill from the old well. The new well, N-40B, is located parallel to the original well. The redrill has shown positive production results.

The Halfdan Field
In December 2008, the operator applied for approval of a plan to further develop the northeastern part of the Halfdan Field. The plan comprises drilling and subsequent



production from another two dual-lateral gas production wells, HCA-1ML and HCA-9ML; see box 3.3. The wells were approved individually in January and April 2009 respectively. Total production from the two wells is estimated at 0.97 billion Nm³ of gas and 0.08 million m³ of oil.

There was considerable drilling activity in the Halfdan Field during 2009. A total of nine new wells were drilled, of which the last was completed in early 2010.

Three gas production wells were drilled using the drilling rig Ensco 71: HCA-4ML, HCA-1ML and HCA-9. All three wells were located so as to form part of the existing helical pattern extending from the HCA platform. HCA-9 was originally planned as a dual-lateral well, but was drilled with only a single well section for technical reasons. All three wells produce from a reservoir of Danian age.

In the western part of the Halfdan Field, oil production well HDA-29 and water-injection well HDA-39 were drilled using the drilling rig Noble Byron Welliver. Both wells were drilled in a western extension of the existing, regular well pattern and are located in a reservoir of Upper Cretaceous age. In the northwestern extension of the same regular well pattern, there were originally plans for seven new wells from the HBB platform. This has been reduced to five wells, HBB-1, HBB-6, HBB-7, HBB-8 and HBB-9, which were drilled using the drilling rig Energy Endeavour in 2009. HBB-6 and HBB-8 are water injectors, and the other three wells are oil production wells. The drilling of HBB-9 was begun in 2009, but work on the well was not completed until 2010. This is because the original plan for HBB-9 was revised and the well has been extended towards the northwest to a total well length of 31,140 ft, which corresponds to approximately 9.5 km. The well is therefore Denmark's longest horizontal well.

In addition to well operations, a 20" multiphase pipeline from Halfdan (HBB) to Dan F was replaced.

Box 3.3

A well with two or more well sections targeting the reservoir is called a **dual-lateral** or 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. ML (multilateral) is added to the name of the well to indicate that it has several well sections in the reservoir, e.g., HCA-1ML. Further well sections may be added in the same way.

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

Multilateral wells are suitable for conditions in several Danish fields.

The Nini Field
The Nini Field has been developed with two new wells from the Nini A platform, an oil production well, NA-10, and a water-injection well, NA-9, both of which have their reservoir section in the Ty Formation. Both wells were drilled using the drilling rig Mærsk Resolute.

From the new Nini B platform, also known as the Nini East platform, a total of three new wells were drilled during 2009: two new oil production wells, NB-1 and NB-2, and a water-injection well, NB-3, with the Hermod Formation as the reservoir. All the wells were drilled using the drilling rig Mærsk Resolute.

A fatal accident occurred during the completion of well NB-3. This accident is referred to in more detail in the section on work-related injuries in chapter 4, *Health and safety*.

The Siri Field
The Siri Field was not developed during 2009, but as described in the production section, work is under way to repair the caisson on the Siri platform, where a temporary support structure was established in January 2010; see also the section entitled *Inspections in 2009* in chapter 4, *Health and safety*. In the long term, the plan is to implement a support solution with a three-legged structure, which will stand on the seabed and secure the caisson above the storage tank, thus reducing the caisson's movements and stopping the formation of cracks. As mentioned in the production section, the permanent solution is expected to be in place in the third quarter of 2010.

The South Arne Field
As part of the third development phase for the South Arne Field, in May 2009 Hess Denmark ApS submitted an application for approval of the first of three stages in the further development of the field. The approval was granted in September and covers a permit to drill and produce from a further two oil production wells, SA-20 and SA-21.

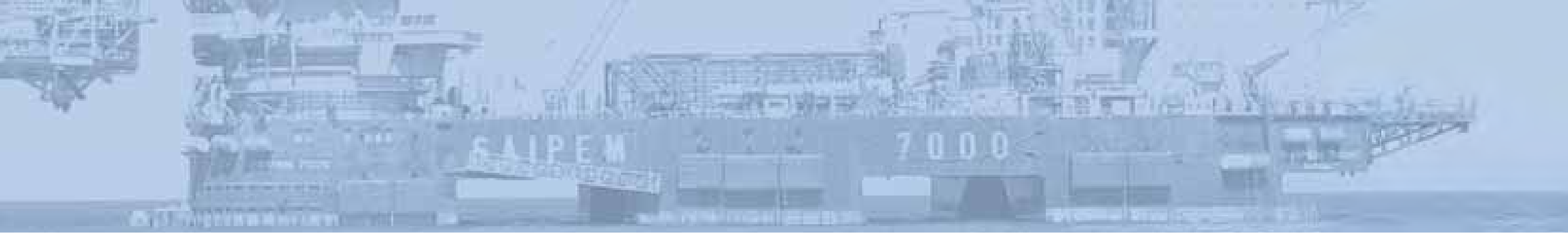
These two wells are an extension of the drainage area on the flanks of the South Arne structure. One is located on the western flank of the main field west of SA-11 in a reservoir of the Tor Formation, while the other is located on the eastern flank of the main field between SA-6 and SA-12 in reservoirs of both the Ekofisk and Tor Formations.

Total production from the two wells is estimated at 1.11 million m^3 of oil and 0.33 billion Nm^3 of gas.

Some maintenance work has been carried out in the South Arne Field, involving the clean-up of old wells aimed at improving production; see also box 3.1.

The Tyra Field
In October 2009, the operator applied for a permit to drill a new well, TEB-23. The plan was approved in October 2009. The well is to be drilled in a northeastern direction from the Tyra East B platform as a long-reach horizontal well. The well is to be drilled into reservoirs in both the Tyra and the Adda Fields. The well will be drilled using a wellhead module which is available on the Tyra East B platform.

Total production from the well is estimated at 1.2 billion Nm^3 of gas and 1.2 million m^3 of oil, about 84 per cent from the Tyra Field and about 16 per cent from the Adda Field.



If the TEB-23 well leads to the startup of production from the Adda reservoir, the Adda Field will then be classified as a producing field.

Some of the pipe on the Tyra East platform was replaced during 2009.

Tyra Southeast

As mentioned in the annual report for 2008, the TSEA-3D well was completed and brought on stream in early 2009 as expected.

The Valdemar Field

In October 2009, the operator applied for approval of a plan to further develop the Valdemar Field (the Bo area). This approval was granted in December 2009 and comprises a permit to drill three new wells using existing wellhead modules. The wells are to be placed on either side of the existing well pattern on the eastern and western flanks of the Bo structure, respectively, in a reservoir of Lower Cretaceous age.

Total production from the three new wells is estimated at 1.7 million m^3 of oil and 0.8 billion Nm^3 of gas.

The exploration and appraisal wells drilled in 2009 are described in more detail in chapter 1, *Licences and exploration*.

Information about approved development plans and plans under consideration is also available at the DEA's website, www.ens.dk.

Fields with no major activity and no approved development plans in 2009

There was no development or other major activity in the following fields in 2009: Cecilie, Dagmar, Harald, Kraka, Lulita, Regnar, Roar, Rolf, Skjold and Svend.

THE TRYM-HARALD PIPELINE

In December 2008, DONG E&P Norge AS applied for a permit in accordance with the Danish Continental Shelf Act to establish a pipeline from the Trym Field in the Norwegian sector to the Harald platform. The applicant's plan is to establish a subsea installation in the Trym Field, which will be hooked up to the Harald platform via an approximately 5 km long 8" multiphase pipeline, of which about 3½-4 km is to be placed on the Danish continental shelf; see figure 3.2. The subsea installation will be controlled from the Harald platform.

The oil and gas that is produced from the Norwegian Trym Field will be exported through the pipeline to the Harald platform, where it will be processed and conveyed through the Danish pipelines. The gas will be transported via Tyra through either the Dutch gas pipeline NOGAT to the town of Den Helder or through the Tyra-Nybro pipeline to Denmark, while the condensate (see box 1.5 in chapter 1, *Licences and exploration*), will be transported via Gorm through the oil pipeline to Fredericia.

In connection with the application, an EIA screening for the pipeline project was submitted.

In September 2009, Mærsk Olie og Gas AS applied for a permit under section 29 of the Danish Offshore Safety Act for the necessary modifications to the Harald platform in connection with the Trym hook-up project. The DEA granted the permit for this modification project on 10 February 2010.

The permit for the actual pipeline between the Trym Field and the Harald platform was granted by the DEA on 3 April 2010.

An agreement concerning the pipeline from the Trym Field to the Harald platform and concerning the transport, measurement and supervision of the produced oil and gas through the pipeline was concluded between the Norwegian and Danish Governments in 2010.

AMENDMENT OF THE DANISH PIPELINE ACT

The Danish Pipeline Act regulates the establishment and use of the pipeline from the Gorm Field in the North Sea to the terminal at Fredericia; see figure 3.2. The bulk of Danish oil production, with the exception of production from the South Arne, Siri, Nini and Cecilie Fields, is transported through this pipeline.

To date, it has not been necessary to separate the crude oil transported. However, the plans to develop the Hejre discovery have created a need for separation.

The Hejre discovery has a high content of condensate, i.e. hydrocarbons with a molecular composition between oil and gas. The possible development involves that both the light hydrocarbons and the crude oil from the Hejre field are to be transported through the pipeline to Fredericia. The crude oil and condensate from the Hejre Field will be mixed with the crude oil and condensate from the other North Sea fields transported through the pipeline. Thus, the piped crude oil and condensate will have a higher content of light hydrocarbons than today. After transport through the pipeline, the light hydrocarbons are to be separated to allow crude oil and condensate products to be shipped separately. Condensate will be separated into butane and propane. The Pipeline Act was amended in spring 2010 to provide for the establishment of separation facilities, which was not previously envisaged by the Act.

As a consequence of the amendment, the Minister for Climate and Energy has been granted authority to regulate the establishment of separation facilities, as well as issues related to operation and payment. The proposed amendments to the Pipeline Act were introduced on 4 March 2010, and the Danish Parliament is expected to consider the amendment bill before its summer recess; see the website of "Folketinget", www.ft.dk.

Users of the oil pipeline pay a five per cent pipeline fee, see box 7.1 in chapter 7, *Economy*. Previously, any users of the pipeline transporting oil from abroad had to pay for the transport according to the same rules as the existing users. However, this provision has never been used. Following the amendment of the Act, users transporting oil from abroad are no longer to pay five per cent of the value of the oil transported as part of the pipeline fee, as this element was akin to a state tax and thus incompatible with EU law. Thus, no pipeline fee will be payable for production to be exported from the Norwegian Trym Field through the Danish pipeline via the Harald platform.

The possibility of reducing the oil pipeline fee was also eliminated as a consequence of the amendment. Likewise, the possibility of reducing the compensatory fee, see box 7.1, in chapter 7, *Economy*, was eliminated. Both a reduction of the oil pipeline fee and the compensatory fee could have caused problems in relation to the EU provisions on government subsidies. The provisions allowing for a reduction of the oil pipeline fee and the compensatory fee have never been used.

4 HEALTH AND SAFETY

The DEA cooperates with the Danish Maritime Authority in supervising that the companies operating in the Danish area comply with existing health and safety legislation when conducting their oil and gas activities. Moreover, the DEA collaborates with various national authorities as well as national and international organizations, including the Offshore Safety Council, the Danish Environmental Protection Agency and the North Sea Offshore Authorities Forum, about continuous improvements to health and safety conditions on the offshore installations.

High health and safety standards in the Danish offshore sector are vital to the almost 3,000 people having their workplace on the offshore installations.

SUPERVISION OF HEALTH AND SAFETY ON THE NORTH SEA INSTALLATIONS

Working on Danish offshore installations should be safe. Through inspections and dialogue with the companies in the oil industry, the DEA therefore makes great efforts to ensure that the health and safety level in the Danish offshore sector remains among the highest in the North Sea countries.

The Danish Offshore Safety Act (Act on Health and Safety on Offshore Installations) regulates the safety of offshore installations as well as the employees' health and safety. The Offshore Safety Act entered into force in July 2006, and the DEA supervises compliance with the Act.

The three main types of supervision are immediate inspections, project supervision and operations supervision.

Immediate inspections

Immediate inspections are carried out in connection with work-related accidents and major near-miss occurrences. In the event of immediate inspections, the DEA will assist in clarifying the sequence of events in cases where the police are involved, while the DEA will be solely responsible for this clarification if the police are not involved. The police authority itself will assess whether or not it will become involved in clarifying a work-related accident. If the DEA believes that significant provisions in the Offshore Safety Act have been contravened in connection with a work-related accident, the DEA will recommend to the police that those responsible should be prosecuted.

Project supervision

Project supervision consists of supervising new facilities and major modifications to existing offshore installations.

Operations supervision

Most supervision tasks concern operations. The DEA uses various approaches in this connection, including both announced regular inspections and unannounced inspections, in addition to supervision of special topics. These inspection types are described below.

Regular inspections

The core element of the DEA's health and safety inspections is an annual inspection of the operating conditions on all manned fixed installations and mobile units. A predetermined programme is carried out during this inspection; see box 4.1. Among other things, the programme covers three fixed inspection items: a review of work-related accidents, hydrocarbon gas releases and the maintenance of safety-critical equipment.

Box 4.1

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 health and safety representatives
- A meeting with the health and safety groups
- 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. The report is to be made available to everyone on the relevant offshore installations.

The DEA uses the three categories mentioned above as indicators of the physical condition of the installation and its working environment. In terms of statistics, it is difficult to describe trends, as the figures recorded for the indicators are relatively low.

In accordance with the Offshore Safety Act, the risk of accidents on offshore installations must be reduced so that it is As Low As Reasonably Practicable (ALARP principle); see box 4.2. This is to be achieved through the thorough planning of work, the identification and assessment of risks and the establishment of preventive measures. The philosophy is that the risk of work-related accidents, work-related injuries, the discharge of chemicals and hydrocarbons and other unplanned incidents that could lead to an accident can be significantly reduced through thorough planning and prevention.

Nevertheless, unplanned incidents will occur in spite of thorough planning and risk assessments. These incidents are recorded by the companies with the aim of learning from them and thus reducing the risk associated with future work as much as possible. Serious incidents such as work-related accidents and major hydrocarbon gas releases must also be reported to the DEA in accordance with the Executive Order on the Registration and Reporting of Work-Related Injuries, etc.

During the offshore inspections, the DEA will review the accidents and incidents that could have led to accidents together with the safety organization. The main objective is to ensure that the operating company/operator follows up on incidents and learns from them in order to avoid similar incidents in the future.

In addition to the three fixed inspection items, a review is also carried out of the changes made on the installation since the last inspection. The DEA provides information about relevant issues, e.g. legislative amendments in the area, and meetings are held by collaborative bodies regarding health and safety work on the installation. Issues that become apparent during the inspection are either addressed on-site or noted and taken up subsequently.

Box 4.2

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 Danish Working Environment Act.

The ALARP principle operates with multiple levels of risk. 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 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. This also applies in cases where the legislation contains no specific instructions or threshold limit values, but merely broad-based, functional requirements.

The inspection and dialogue with the companies in connection with the inspections ensure that the health and safety conditions on the offshore installations comply with the technical and social standards in Danish society at all times, and reflect developments in society.

Until 2006, when the legislation in this area was amended and the Offshore Safety Act entered into force, the DEA's operations supervision was geared more towards "factory inspections" of areas where the activities were physically taking place. Since the implementation of the Offshore Safety Act, the focus on management systems has increased, and the DEA's inspections are increasingly targeted at the entire organization. In practice, this means that operations supervision on an offshore installation also includes an inspection of the operating company's offices on shore before or after the offshore inspection. As a result, both the management system and its practical application offshore are reviewed during the inspection.

The result of an inspection is typically a number of observed regulatory deviations that are described in the DEA's inspection report to the operating company (see box 4.3), including the DEA's recommendation and – in more serious cases – improvement notices requiring the company to bring the issues raised into line with applicable regulations. Efforts are made to conclude the subsequent communication and follow-up between the DEA and the company in a short period of time, so that the inspection can be finalized before the next regular inspection.

Box 4.3

Inspection report
An inspection report describes the course and results of the inspection. The report typically includes:

- The purpose of the inspection
- The persons/functions interviewed
- The persons present from the operating company's onshore organization
- The findings resulting from the tour of the installation
- A summary that includes observations of health and safety issues that deviate from the Offshore Safety Act and related Executive Orders.

The report is accompanied by:

- A list of the observations made by the DEA during the inspection
- The list will also be handed out at the concluding meeting with the safety organization offshore.
- A description of the course of the inspection, including for example the course of the initial meeting with the safety organization, interviews with the Offshore Installation Manager, technical managers, medic, catering staff, etc. and the tour of the installation.
- A list of the documentary material supplied in connection with the inspection.

Unmanned installations are inspected less frequently, primarily when a drilling rig is positioned next to the installation.

Unannounced inspections
Unannounced inspections are carried out if announcing the inspection would compromise its purpose, e.g. when checking compliance with the regulations regarding rest periods, accommodation facilities and emergency procedures for the increased manning of installations, painting projects, etc. Moreover, unannounced inspections are carried out if unlawful circumstances are reported, or if otherwise warranted by employee health and safety considerations.

As the Danish installations are all located in the North Sea and transport to these installations takes place by helicopter, unannounced inspections will often be known from around the time when the representatives of the DEA meet in the departure lounge at Esbjerg Airport.

An unannounced inspection differs from an annual inspection in the sense that the programme normally only focuses on two or three relevant issues.

Supervision of special topics
The supervision of special topics at the operating companies (see box 4.4) has been carried out since 2007. The supervision of special topics involves one inspection in which one specific topic is considered.

In a report prepared by the Working Environment Council submitted to the Danish Parliament on 13 December 2005, the Government presented its priorities for the working environment programme for the period through 2010, which listed work-related accidents, noise, psychological working environment and musculoskeletal dis-

orders as priority areas. On this basis and in a dialogue with the parties in the Offshore Safety Council, the DEA has prepared a plan for prioritizing and incorporating all four topics in the DEA's offshore inspections. Since 2007, the DEA has been focusing on:

Work-related accidents (2007)
Noise (2008)
Psychological working environment (2009 – 2010)
Musculoskeletal disorders (2010 – 2011)

The ongoing supervision of special topics concerning the psychological working environment has been divided into three phases; see box 4.5.

Phase 1 is a read-through of specific parts of the management system related to the topic during which the DEA will obtain and review the aspects of the operating company's management system that concern the psychological working environment. Phase 2 consists of an onshore inspection of the operating company. During this inspection, the operating company will expand on the aspects of the management system that the DEA has reviewed during the work in connection with phase 1. In addition to focusing on the elements that concern the psychological working environment, the DEA also addresses the interaction between the management system and practice.

Box 4.4

The licensee is the company or group of companies that has a licence to explore for and extract hydrocarbons from the subsoil.

The operator is the company that carries out exploration or extraction of hydrocarbons on behalf of the licensee. Typically, the operator will be one of the companies forming part of the consortium that holds the licence.

For pipelines, the operator is the company responsible for transporting hydrocarbons through the pipeline on behalf of the licensee or owner.

The operating company is the company responsible for the operation of an offshore installation, a pipeline or a special-purpose vessel. As regards fixed offshore installations, the operating company will typically be the operator, while the operating company for a drilling rig will be the respective drilling company. For mobile accommodation units, the operating company is the company responsible for the operation of such units.

Box 4.5

Psychological working environment
The inspection of psychological working environment is based on the relevant guidelines of the Danish Working Environment Authority. Psychological working environment is included under "Other risks" in sections 14, 16 and 19 of Executive Order No. 729 of 3 July 2009 on Health and Safety Management on Offshore Installations, etc.

Psychological working environment must be described in the company's management system and covers many different topics, such as workload and time pressure, monotonous work, work rotation, cooperation and communication. Other topics include the relationship between management and employee in the form of, e.g., division of responsibility, feedback, managerial support, prioritization and clear definition of tasks, influence on and predictability of own work, education and training. Undisturbed rest and noise are other topics of importance to the psychological working environment.

A more detailed list of factors influencing psychological working environment can be found in the relevant guidelines of the Danish Working Environment Authority at its website www.at.dk.

The DEA carried out phases 1 and 2 of its psychological working environment inspection of all operating companies in the Danish sector of the North Sea in 2009 and the first quarter of 2010. During the inspections conducted at the operating companies' onshore offices, the components of psychological working environment and the interaction between management system and practice were discussed.

When phase 3 is carried out in 2010, the DEA will follow up on the observations made during the first two phases by addressing the topic during the annual inspections offshore.

Phase 3 is an inspection of the psychological working environment at the operating companies' offshore installations. The work concerning musculoskeletal disorders will follow the same model.

SUPERVISION OF AGEING INSTALLATIONS AND THE REMOVAL OF INSTALLATIONS

The production of oil from the Danish sector of the North Sea began in 1972, while the production of gas commenced in 1984. There are currently more than 50 platforms in use in connection with production. The load-bearing structure of a platform is normally designed to have a life of 25 years, and as many of the platforms were constructed in the 1980s and 1990s, a significant number of the installations are nearing the end of the design life for which they were originally constructed. The operators of the installations must therefore ensure that the strength of the load-bearing structures in the installations still complies with the original requirements that were imposed.

Ageing installations

The design life of certain installations has been exceeded. The operator has recalculated the strength and stability of the load-bearing structure for these installations. The recalculations were performed using data from regular systematic investigations of the structure both above and below the water surface. These regular structural investigations have provided the basis for the ongoing maintenance of the structures. The DEA is monitoring the progress of this work.

Changes in the effects of the physical surroundings on the installation are also monitored. Such changes can include subsidence of the seabed as a result of production from gas reservoirs in particular. In cases of seabed subsidence, there will be a reduction in the air gap, i.e. the distance between the cellar deck of the platform and the sea. In certain cases, the air gap may become less than the maximum calculated wave height, leading to a risk of the cellar deck flooding. The structure of the platform can be strengthened and equipment can be removed from the cellar deck in order to reduce the risk of accidents in the event of flooding. Manning restrictions can also be introduced on the cellar deck so that the deck is cordoned off during stormy conditions.

The ongoing maintenance and systematic monitoring of the structures must demonstrate that an extension to the operational period of an installation beyond its original design life is completely safe. The DEA supervises that the companies carry out maintenance and monitoring in a satisfactory manner.

Lifespan is not normally determined for platform equipment, but equipment must be maintained appropriately in terms of safety at all times. Problems can arise concerning the availability of spare parts and supplier skills in connection with the maintenance of older equipment. In general, it is more time-consuming to maintain older equipment. The DEA monitors the maintenance of safety-critical equipment in connection with its inspection of installations.

Removal of installations

Production from the North Sea fields is declining, and the first installations are expected to be decommissioned within a ten-year time horizon. This can occur as part of the simplification of production facilities, as the current production capacity will exceed demand as a result of falling production. There may also be fields where production may not be financially viable, i.e. where the costs exceed the revenue that is generated, which means that the production facilities can be removed completely. 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 resources.

When an installation is decommissioned, the Danish state will have the opportunity to take over the installation in accordance with the conditions that are set out in the individual licences. The installations will be removed in cases where the state does not wish to do so. This means that 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. It is the DEA's task to supervise that the removal of the installation is carried out in such a way that both the health and safety of employees and environmental issues are taken into consideration.

Pipelines are also decommissioned. The vast majority of the more than 1,800 km of pipelines in the Danish sector are buried in the seabed. A pipeline may have to be removed following the end of its life. However, the scope of the work in terms of area should be assessed in relation to the possibility of allowing the cleaned pipelines to remain in place with regular monitoring, with a view to intervention if part of the pipeline should become exposed on the seabed. It is the companies' responsibility to carry out this monitoring, but the DEA will supervise the monitoring process.

Future use of North Sea installations

As oil and gas production declines in the Danish sector of the North Sea, some of the production installations will gradually become redundant. However, it may be appropriate to retain some of the installations for other purposes, e.g. the importing and storage of natural gas.

Danish production facilities are currently connected to the Dutch infrastructure via a gas pipeline running from Tyra West to the NOGAT pipeline system, which terminates in the Dutch town of Den Helder. The pipeline is currently being used to export Danish gas to the Dutch market, but it has also been designed for the import of gas. In connection with decommissioning production facilities, the appropriateness of retaining some of the North Sea installations must be determined, as they could be used for the future import of gas into Denmark. Transit pipelines transporting Norwegian gas to Germany, the Netherlands and France cross the Danish sector. Any future import of Norwegian gas may take place via connections to these pipelines or via direct connections to Norwegian production installations. The DEA will also play an active supervisory role in connection with this.

Consideration is currently being given to the potential for using CO_2 captured from power stations in order to increase hydrocarbon recovery from existing producing fields. This would involve a certain amount of underground CO_2 storage, which would be regulated by the CCS Directive. However, the injection of CO_2 into existing wells would require modifications to the installations and therefore greater investment; see also the section on the storage of CO_2 in chapter 2, *Use of the subsoil*.

Alternative uses of installations, e.g. in connection with CO_2 storage in underground formations, may be included in future assessments of what will happen to installations in fields that can no longer produce commercially.

OBSERVATIONS DURING OFFSHORE INSPECTIONS 2005-2009

In December 2009, the DEA presented a report to the Offshore Safety Council on the health and safety observations made during inspections on offshore installations during the period from 2005 up to and including the third quarter of 2009.

The report "*Review of observations from offshore inspections during the period 2005 – 2009*" was prepared to assess the supervision strategy and identify whether there are any general health and safety issues common to all installations, the criticality of these issues and what should be given special emphasis in the future. In addition, the DEA wished to clarify whether there is a need to revise the method of supervision that is used, including in particular the relationship between offshore and onshore inspections and the frequency of unannounced inspections. The DEA identified the following points in the analysis underlying the report:

- The types of observations made on fixed offshore installations and mobile offshore units overlap.
- The majority of observations concern the physical conditions on the platform (layout of the workplace, accommodation facilities, etc.).
- A number of these observations have been assessed as safety-critical, i.e. conditions that influence the risk of major accidents or personal injury.
- A relatively high proportion of the observations can be attributed to a lack of control over health and safety risks, i.e. failures in the management systems.
- There have been relatively few observations concerning ergonomic, psychological or biological circumstances, possibly as a result of the focus of the supervision.
- No circumstances have been observed in unannounced inspections that deviate significantly from the observations in announced inspections.
- The number of reportable unintentional hydrocarbon gas releases fell from 22 releases in 2005 to three releases in 2009.

The analysis shows that in certain areas it would be appropriate to alter the method of supervision. The work associated with the analysis resulted in the following conclusions, which have been endorsed by the Offshore Safety Council:

- The inspections should focus more on the companies' health and safety management systems in audits of the onshore organization where the systems are established and maintained. In addition, the inspections should follow up on the use of the systems offshore.
- For a predetermined period, the supervision should focus on ergonomic, psychological and biological conditions to assess whether the current low number of observations within these areas is representative of the offshore conditions.
- The inspections should continue to focus on the companies' follow-up of unintended hydrocarbon gas releases on fixed installations with the aim of preventing such releases.
- The current number of between two and five unannounced inspections per year will be retained, partly in order to document that the conditions observed during announced inspections are representative, and partly to prevent any myths arising that circumstances only need to be addressed when an inspection has been announced.

INSPECTIONS IN 2009

In 2009, the DEA carried out 29 offshore inspections, distributed on 15 inspections of manned production installations, four inspections of unmanned production installations and ten inspections of mobile units, i.e. drilling rigs and accommodation units.

Five of the inspections of manned production installations were unannounced and were carried out on the Dan B, Halfdan B, Harald, Tyra East and Siri platforms; see box 4.6. The majority of the inspections did not result in the identification of any highly safety-critical conditions.

Box 4.6

Inspection of the Siri platform

During the annual inspection of the Siri platform's subsurface structure in 2009, cracks were identified in a console supporting a well caisson with a height of around 90 metres, a diameter of 5.3 metres and a weight of 950 tons.

The Siri platform is supported by three legs, which stand on a subsea tank used to store the oil production from the Siri, Nini and Cecilie Fields prior to collection by tanker. The subsea storage tank has a console that acts as an equalization tank and supports a caisson, which contains the wells and risers, among other things. It was in this console that the cracks arose.

Due to the risk of the caisson support structure collapsing, production from Siri, Nini and Cecilie was suspended and the storage tank emptied. In addition, the number of employees on the platform, normally up to 60 people, was reduced to 12 and restrictions were imposed on work in the wellhead area in which the caisson is located. Furthermore, special emergency procedures were established.

Following a number of further investigations of the structure, DONG E&P was granted a permit to man the platform again, up to the normal manning level. The DEA made the permit subject to the conditions that the risks associated with working and residing on the platform should correspond to those associated with normal operations, and that the evacuation analysis should show that the platform could be evacuated in the event of the caisson support failing.

The DEA also granted a permit for work in the wellhead area, consisting of the installation of further monitoring equipment and preliminary work to secure the caisson. This permit was made conditional on continuous monitoring of the cracks.

The DEA made an unannounced inspection of the Siri platform on 17 November 2009. This inspection was particularly aimed at the monitoring of the caisson, the administration of restrictions on work in the wellhead area and the functionality of the platform emergency procedures.

The inspection identified no critical points in regard to the monitoring and administration of the guidelines for work in the area or the established emergency procedures.

At the beginning of January 2010, DONG E&P installed temporary support for the console to take the weight of the caisson in the event of the console failing, and production was then resumed. The support structure has a lifespan of between two and 12 years, depending on the load. DONG E&P is continuing its efforts to find a permanent solution for supporting the caisson.

In addition, the DEA made three inspections on shore in connection with development projects, as well as five inspections of the onshore bases of operators and operating companies (see box 4.4) to follow up on the psychological working environment.

Finally, the DEA carried out three inspections of drilling rigs in the Netherlands and Denmark before granting them a permit to operate in the Danish area.

The DEA made three immediate inspections to follow up on work-related accidents in 2009, one on the Energy Endeavour drilling rig and the other two on the Mærsk Resolute drilling rig; see also the section *Work-related injuries*.

An outline of all inspections in 2009 is available at the DEA's website, www.ens.dk.

As in previous years, supervision in 2009 focused on work-related accidents, near-miss occurrences, hydrocarbon gas releases, the maintenance of safety-critical equipment and the companies' management systems. Moreover, the DEA continuously supervises the emergency response system offshore. In this connection, the DEA checks that the persons forming part of the emergency response system have the requisite training for the emergency functions to be performed by them; see box 4.7.

Box 4.7

Emergency training
Persons on board offshore installations must have completed a basic safety training course. The purpose of the course is to enable the participants to attend to their personal safety in case of evacuation or other emergencies, render assistance and first aid, and conduct themselves safely on board an offshore installation in observance of the work and safety culture prevailing at the workplace.

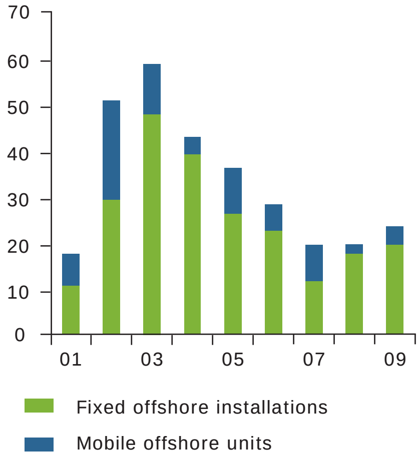
Supplementary training courses are required for certain special emergency functions. This applies to:

- Fire team members
- Fire team leaders
- Lifeboat captains, who must be able to launch and navigate the lifeboats in a situation where evacuation by sea is necessary.
- Helicopter Landing Officers (HLOs), who must assist during helicopter takeoff and landing on board the installation

All persons on board installations where there is potential danger or presence of hydrogen sulphide (H_2S) must undergo a special H_2S course. In the case of the fixed installations, this applies to Gorm, Dagmar and Skjold. Where mobile units are concerned, the course is mandatory for those on board if the drilling rig is operating in, say, an area where there is danger or known presence of H_2S.

The North Sea nations are working to harmonize the legal requirements for basic safety training courses and have agreed on mutual recognition of training certificates. Some nations impose further requirements that necessitate taking, say, one or two additional training modules. A Danish basic safety training certificate acquired under Executive Order No. 688 on Emergency Response pursuant to the Offshore Safety Act can therefore also be used in the other North Sea countries.

Fig. 4.1 Number of work-related accidents on offshore installations, 2000-2009



Maintenance of safety-critical equipment
One of the DEA's focus areas in connection with inspections is the companies' maintenance of safety-critical equipment. The DEA's supervision aims to ensure that the operating companies (see box 4.4) prioritize their preventive maintenance initiatives. Therefore, in connection with its offshore inspections in 2009, the DEA checked whether the operators adhere to their plans for maintaining installations and equipment, including 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.

Inspections in 2009 revealed that not all companies had observed the time schedule for maintaining safety-critical equipment. The DEA cautioned the relevant company and will follow up on the company's maintenance at the next inspection.

The DEA's inspections in 2010 will continue to focus on the maintenance of safety-critical equipment on manned fixed installations.

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; see box 4.8. 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. This procedure applies to all work-related accidents. In case of serious accidents, the DEA carries out immediate inspections in cooperation with the police.

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

In 2009, the DEA registered a total of 24 reports concerning work-related accidents, 20 on fixed offshore installations, including mobile accommodation units, and four on other mobile offshore units; see figure 4.1. These figures include one fatal accident, which occurred on a mobile unit, see the section *Fatal work-related accident*. The accidents are broken down by category in table 4.1 and figure 4.2.

In addition, the DEA has received a report on a work-related accident which occurred on a mobile unit. This accident is not included in the tables, as the National Board of Industrial Injuries is assessing the report to determine whether it should be recorded as a work-related musculoskeletal disorder instead. Based on the outcome of the National Board of Industrial Injuries' investigation, this incident will be included in the appropriate category in the DEA's future statistics.

Box 4.8

Reporting work-related accidents
Work-related accidents must be reported to the DEA in accordance with the Executive Order on the Registration and Reporting of Work-Related Injuries, etc. Work-related accidents are defined as accidents resulting in incapacity to work for one or more days beyond the injury date.

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.

Table 4.1 Reported accidents broken down by cause of accident

Cause of accident	Fixed	Mobile
Falling/tripping	6	1
Use of work equipment	5	2
Handling goods	6	1
Other	3	0
Total	**20**	**4**

Table 4.2 Actual absence due to reported work-related accidents in 2009

Duration	Fixed	Mobile
1-3 days	0	0
4-14 days	3	0
2-5 weeks	6	0
More than 5 weeks	11	3
Total	**20**	**3**

Table 4.2 indicates the actual periods of absence from work, broken down on fixed offshore installations and mobile offshore units.

The DEA changed its procedure in connection with publishing the report *Denmark's Oil and Gas Production and Subsoil Use 2008*, which means that the figures for work-related accidents are now restated to include accidents reported belatedly. Thus, work-related accidents occurring in 2009, but reported in a later year, will be included in future annual reports.

In 2009, the DEA received one report of an accident that occurred in 2007. The statistics for 2007 have therefore been restated to include this accident.

Fatal work-related accident

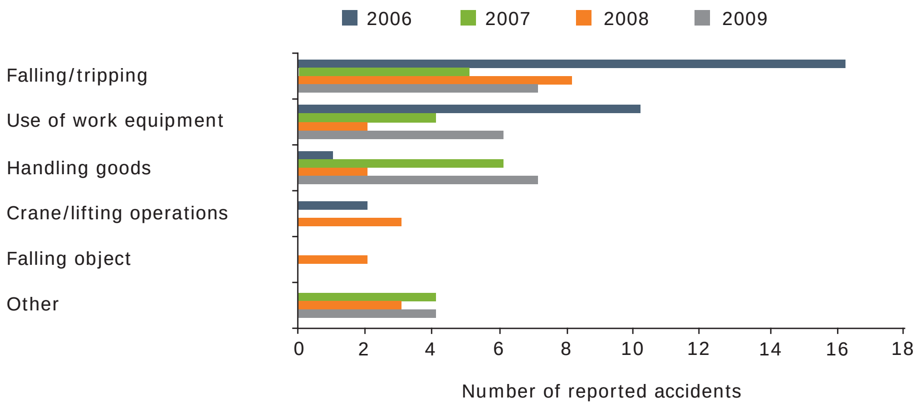
A fatal work-related accident occurred on 15 November 2009 on the drilling rig Mærsk Resolute. Immediately after being notified of the accident, the DEA paid a visit to Mærsk Resolute to clarify the circumstances of the accident together with representatives of the police and Esbjerg's medical officer of health. The DEA's report on the accident is available at the DEA's website, www.ens.dk.

On 16 November 2009 at around 12.30 am, the DEA's drilling expert on duty received notification of the accident from the South Jutland Police. The fatally injured person was employed by Schlumberger and worked as an operator on a short-term task in connection with the clean-up of a well; see box 4.9 for background information about the activities on a drilling rig. The accident occurred when a safety valve fitted to a riser in an area with pressure equipment was triggered during a pressure test of well-cleaning equipment. Due to the blowout, the riser collapsed and hit the person concerned on the right-hand side of the head. The victim was probably also affected by the nitrogen gas released from the valve. There were no witnesses to the accident; however, a loud bang and the sound of gas leaking were heard by several people.

The companies' investigation of the accident

The companies' investigation into the accident has subsequently shown that a pressure printer had been loaded with printer paper with an incorrect scale, which meant that the printer indicated a pressure that was too low. The actual pressure was higher than the crew believed, i.e. 6,900 psi (475 bar) compared with a reading of 4,500 psi (310 bar). In addition, the printer had been located incorrectly within the area of pres-

Fig. 4.2 Number of work-related accidents on offshore installations from 2006 to 2009 broken down by category



Box 4.9

Activities on a drilling rig
Mobile drilling rigs are used in Danish oil and gas fields to drill wells for oil and gas production or for water injection. Mobile drilling rigs are also used to drill exploration wells. The operating company that is responsible for the development and operation of an oil and gas field will hire a drilling rig for a specific period when there is a need to drill new or repair old wells.

Drilling rigs have a certain amount of drilling equipment as well as offices and resting and sleeping facilities. Up to around 100 people can work on a drilling rig, and drilling takes place 24 hours a day.

Equipment used for the drilling process could for example consist of long steel tubes (drill pipe and casing), high-pressure pumps for circulating drilling mud and cement, cranes for moving the equipment to and from supply vessels and around the drilling rig, a derrick used for lifting equipment in and out of the well, valve arrangements for regulating the flow of formation fluids in and out of the well and to prevent blowouts from the well, systems for storing and treating drilling mud and generators to generate the electricity used on the rig. In addition, there may be other equipment that is only used on a short-term basis for particular tasks and which is therefore hired for the period required. For example, separators and pumps may be hired in connection with the test production of oil and gas from the well, or pumps and tanks could be hired for injecting nitrogen in connection with the treatment of drilling mud from a well before it can be brought on stream. In connection with the temporary hire and use of such equipment, there will usually be specialist personnel on board the drilling rig to operate the equipment. Moreover, some of the equipment permanently installed on the drilling rig is only used for short periods, and specialist personnel will be sent to the drilling rig to operate such equipment whenever it is used.

There are companies that specialize in performing such special short-term tasks. These companies typically hire both the specialist equipment and the personnel required. Schlumberger is one of the companies specializing in the clean-up of completed wells with nitrogen, and Schlumberger dispatches both the equipment and the personnel to operate the equipment to the drilling rigs.

sure equipment, and the printer had also been incorrectly used as the primary pressure reading meter. The pressure meter fitted to the pump panel should have been used as the primary pressure meter. At the time of the accident, the operator had been in the process of reading the printer. It was also established that the overpressure emergency shutdown was not functioning as intended.

The DEA's assessment
Based on the companies' investigation into the accident, the DEA has concluded that the checks carried out by the crew from Schlumberger as well as their qualifications in relation to the company's own practice were deficient. Moreover, the crew had apparently not received the necessary health and safety instructions for performing the task.

In addition, the DEA has concluded that neither the contractor, nor the operator or the operating company had carried out adequate supervision of the equipment setup and the risks posed by the work, and in particular failed to ensure that all procedures and other health and safety issues both before and during the nitrogen work had been dealt with satisfactorily. The established system of work permits and "Tool Box Talk", during which procedures concerning the performance of the work and the use of safety equipment are discussed, had apparently been used superficially, and the underlying documentation in the form of risk analyses and checklists had not been used correctly.

On the basis of the above, the DEA has referred the matter to the South Jutland Police with a recommendation that charges be brought against the three companies involved, DONG E&P A/S, Maersk Drilling and Schlumberger, with a claim for fines to be imposed.

Moreover, the DEA has initiated an ongoing dialogue with the companies concerning the initiatives that have been taken on the basis of the investigations.

The Accident Investigation Commission's conclusions

The Accident Investigation Commission (see box 4.10) was involved immediately after the fatal accident occurred. The Accident Investigation Commission was in contact with the DEA via a series of meetings during the investigation into the accident and

Box 4.10

The Accident Investigation Commission

Pursuant to the Offshore Safety Act, the Minister for Climate and Energy appoints an Accident Investigation Commission in case of major incidents on an offshore installation. The Accident Investigation Commission is composed of a group of impartial persons who are to investigate major incidents. Such incidents must have caused serious personal injury or damage to the installation and equipment on the installation, or they must have occurred due to external factors with resulting fatalities, serious personal injury or serious damage to the installation.

The objective of the Accident Investigation Commission's work is to clarify how the incident arose and developed, its scope and adverse impact, as well as technical and organizational issues that may have had relevance for the incident.

Work-related accident during relocation of drilling rig

On 21 August 2009, an employee on board a drilling rig was injured when it was being relocated from one position to another. The employee suffered a compression injury to the last four fingers of one hand and subsequently lost between 1 and 1½ cm of the last three fingers.

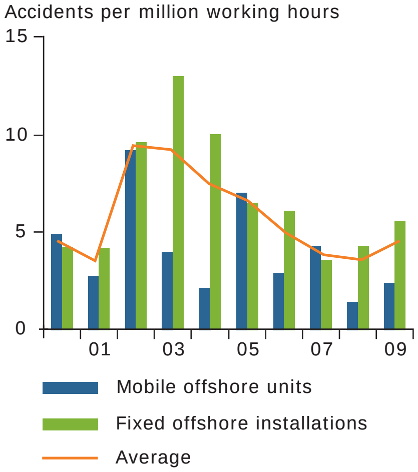
After positioning the drilling rig, the standby vessels were unhooked, and cables and chains used in towing the rig were to be bundled and secured on the rig's deck. This was done by the crane operator, assisted at one point by the employee in question. When the final cable was being hoisted, the employee's left hand was caught in the tackle block while he was attempting to move a cable clear of a cover plate that it was touching.

The DEA inspected the drilling rig the same day as the accident occurred. It transpired that the injured person did not normally work in this area and that the task was regarded as a standard operation, despite only being performed when the rig is relocated from one place to another, normally at several-month intervals.

The DEA did not consider the job a standard operation, and according to the company's internal procedures, a risk assessment should have been carried out, and a "Tool Box Talk" should have taken place to discuss the work procedures. Furthermore, the tackle block was placed at a height that could result in people getting their hands trapped. These were all deviations from the provisions of the Offshore Safety Act, and resulted in DEA cautioning the company.

The DEA will follow up on the company's learning from the incident at the next inspection of the drilling rig.

Fig. 4.3 On- and offshore accident frequency



the subsequent period. The Accident Investigation Commission's work resulted in an independent report, which – based on the accident investigation – made a recommendation that the companies should further analyze whether the system procedures and safety aspects had been fully implemented, and how to ensure their implementation. In addition, the Accident Investigation Commission noted that the DEA would respond to the accident by carrying out follow-up supervision in relation to the companies' subcontractors on mobile drilling rigs.

The Accident Investigation Commission's report is available at the DEA's website, www.ens.dk.

Accident frequency

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

The overall accident frequency for fixed offshore installations and mobile offshore units in recent years appears from figure 4.3, which also shows that the overall accident frequency for fixed installations and mobile units was 4.5 in 2009. This is an increase compared to 2008, when the overall accident frequency came to 3.5.
For mobile offshore units alone, four work-related accidents were recorded in 2009, and the number of working hours totalled 1.7 million. Thus, the accident frequency for mobile offshore units increased from 1.4 in 2008 to 2.4 in 2009.

The number of work-related accidents on fixed offshore installations and mobile accommodation units, which is calculated on a combined basis, totalled 20 in 2009. The operating companies have stated that the number of working hours in 2009 totalled 3.7 million on these offshore installations. The accident frequency for fixed offshore installations is thus 5.4 for 2009, which is also an increase relative to 2008, when the accident frequency came to 4.2.

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 overall picture of the accident frequency.

Onshore accident frequency

The DEA has compared the accident frequency on Danish offshore installations with the onshore accident frequency, as shown in table 4.3.

A total of 48,464 work-related accidents were reported for onshore companies in 2008. With a workforce of 2,857,565 employees (~ approx. 4.5 billion working hours) in 2008, the accident frequency in 2008 for all 49 onshore industries can be calculated at 10.7 reports per 1 million working hours. The calculation is based on the assumptions described in box 4.11. The Danish Working Environment Authority has not yet calculated the number of work-related accidents and the number of employees for 2009.

Table 4.3 shows the accident frequencies calculated by the DEA for 2005-2009.

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.

Box 4.11

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 had 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.

Table 4.3 Accident frequencies in Danish offshore and onshore industries

Industry	Frequency					
	2004	2005	2006	2007	2008	2009
Offshore installations*	7.1	6.4	4.9	3.7	3.5	4.5
Total onshore industries	10.2	11.0	11.2	11.0	10.7	
Of which:						
- Shipyards	38.5	50.6	57.6	47.4	48.7	
- Earthwork, building and road construction	21.3	23.5	24.0	23.5	21.3	
- Masonry, joinery and carpentry	15.0	18.0	17.5	16.7	16.4	
- Insulation and installation work	16.1	18.7	18.9	19.8	19.9	
- Chemical industry	12.4	13.1	12.2	15.4	10.6	
- Heavy raw materials and semi-manufactures**	12.7	12.1	11.1	14.5	13.8	

*) *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.*

As from 1 July 2008, doctors have been obliged to report all diagnosed or suspected work-related diseases contracted in connection with offshore work 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.

To ensure that the DEA has received all reports of suspected work-related diseases attributable to work on an offshore installation, the DEA has awaited data from the

Danish Working Environment Authority. The Danish Working Environment Authority has completed its work regarding work-related diseases for 2008, but has not yet published statistics for 2009.

For 2008, the DEA received 15 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, 12 suspected work-related diseases were reported in 2007. The diseases reported for 2008 are distributed on six hearing injuries, five musculoskeletal disorders and four skin disorders/eczema.

Over the years, the DEA has focused on issues related to noise, chemicals and musculoskeletal disorders and will continue to focus on these issues 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.

Box 4.12

Reporting near-miss occurrences
Near-miss occurrences must be reported to the DEA in accordance with the Executive Order on the Registration and Reporting of Work-Related Injuries, etc.

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.

NEAR-MISS OCCURRENCES

Major near-miss occurrences must be reported to the DEA; see box 4.12. In 2009, the DEA received a total of 28 reports on near-miss occurrences, the same level as in 2008. The number of reports also indicates that the companies continue to focus on learning from occurrences and the employees' awareness of safety issues.

Hydrocarbon gas releases are also defined as near-miss occurrences; see the section *Hydrocarbon gas releases*.

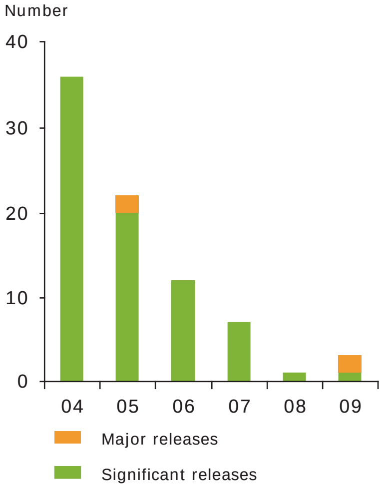
Near-miss occurrence on Mærsk Resolute
On 6 January 2009, there was a near-miss occurrence on board the drilling rig Mærsk Resolute in which the top drive, which lifts equipment down into the well, collided with the bridge crane. A bridge crane is positioned above the drilling floor and is used to handle the drill pipe. Maersk Drilling, the operating company for the rig, stopped work and launched an investigation into the incident. The company also contacted the equipment supplier to notify the incident. The supplier subsequently located and rectified the fault, which proved to be a software error.

The DEA contacted Maersk Drilling to ensure that the company would follow up on the incident and received confirmation that the fault would be rectified on all drilling rigs using this software so as to avoid similar future incidents.

Uncontrolled lift on Energy Endeavour
On 27 March 2009, a serious near-miss occurrence took place during a crane lift on board the drilling rig Energy Endeavour. Casing weighing around seven tons was lowered onto the drilling floor in an uncontrolled lifting operation. No-one was injured. The incident proved due to a fault in the crane's hydraulic pump. The company's own investigation concluded that parts of the pump motor were damaged and the relevant components were replaced immediately.

The DEA followed up on the incident during a subsequent inspection, which included an examination of maintenance procedures. The recommendations resulting from the investigation were found to have been implemented.

Fig. 4.4 Accidental hydrocarbon gas releases, 2004-2009



HYDROCARBON GAS RELEASES

The operating companies are obliged to report all major releases and significant releases of hydrocarbon gas to the DEA immediately.

Major releases are releases of more than 300 kg or with a release rate of more than 1 kg/sec. for more than five minutes.

Significant releases are releases of 1-300 kg or with a release rate of 0.1-1 kg/sec. with a duration of two to five minutes.

Two major releases and one significant release were reported in 2009.

One hydrocarbon gas release occurred on an unmanned satellite platform, for which reason the duration of the release is uncertain. The release had a release rate of 0.41 kg/sec., with an estimated duration of between 0 and 16 hours. In order not to underestimate the release, it has been categorized as a major release.

Since the DEA targeted its focus at accidental hydrocarbon gas releases, the total number of releases has dropped from 36 in 2004 to three releases in 2009; see figure 4.4. This decrease shows that the companies' efforts to reduce accidental hydrocarbon gas releases have been efficient.

APPROVALS AND PERMITS GRANTED IN 2009

The supervision of health and safety on fixed offshore installations and mobile offshore units in the Danish sector of the North Sea 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; see box 4.13.

Box 4.13

Approvals and permits under the Offshore Safety Act

The overall design of a production installation must be approved according to section 27 of the Offshore Safety Act prior to detailed project design and construction.

Before oil or gas production can commence, the installation must have an operating permit in accordance with section 28 of the Offshore Safety Act. Similarly, a mobile offshore unit, such as a drilling rig, must have an operating permit prior to use in Danish territory.

In the case of significant modifications to existing installations, the operating company (see box 4.4) must apply for a permit under section 29 of the Offshore Safety Act. And finally, when decommissioning a fixed offshore installation, the licensee must apply for a permit under section 31 of the Offshore Safety Act.

In 2009, the DEA granted the following approvals and permits for fixed installations and mobile units as well as a pipeline in the Danish sector of the North Sea:

The Halfdan Field

In 2009, a permit was granted to carry out modifications to the Halfdan CA platform in the Halfdan Field in connection with the hook-up of four new wells.

A permit was granted for the manning of Halfdan BA and Halfdan BB with up to 27 people while the drilling rig Energy Endeavour was placed at the HBB platform.

In addition, a permit was granted for the commissioning of the new Halfdan BB wellhead module. In September 2009, a permit was granted for the commissioning of a temporary lifeboat on the HBA platform. The lifeboat will later be relocated and used on the new HBD platform, which is expected to be commissioned in 2011. In November 2009, a permit was granted for the manning of Halfdan BA and Halfdan BB with up to 45 people, which corresponds to the capacity of the temporary lifeboat.

Finally, a permit was granted for the establishment of an 11.4 km 20" multiphase pipeline between Halfdan D (the HDA platform) and the Dan FG offshore installations to replace a damaged pipeline. A permit was also granted in accordance with section 31 of the Offshore Safety Act for the dismantling of the existing damaged pipeline segment.

The Siri Field
In August 2009, cracks were found in a console supporting the well module on the Siri platform (see box 4.6), for which reason the manning of the Siri platform was reduced to a maximum of 12 people. When an overview had been provided of the extent of the cracks, a permit was granted for increasing the manning to its normal level (60 people) on the platform itself. A permit was also granted for time-limited work in the wellhead area where the pipelines from the Nini and Cecilie Fields link up to the offshore installation. The permit for work in the wellhead area was extended on several occasions from October to November 2009, because no developments in the cracks could be identified during the period of observation and because risk assessments indicated that it was safe to work in the wellhead area, subject to certain specified conditions. In December 2009, a permit was granted for the installation of a temporary supporting structure for the production pipelines on the Siri offshore installation. The temporary supporting structure will be placed on the seabed.

In December 2009, an operating permit was granted for the Nini B platform, and in this connection a permit was also granted for modifications to the existing Nini platform.

The Gorm Field
A permit for modifications was granted in 2009 in connection with the installation of a condensate separator on the Gorm F platform in the Gorm Field.

The South Arne Field
Two permits were granted for modifications in the South Arne Field in 2009. For one thing, passive fire protection has been removed from some pressure vessels and a sprinkler system has been installed. In addition, two lifeboats have been replaced with two new boats with reinforced hulls of the same type and manufacture. The lifeboats have been replaced with the aim of improving safety conditions during use and training.

The Tyra Field (including the Harald Field)
Four permits were granted for modifications in the Tyra Field in 2009. One of these permits was granted for the final phase of the low-pressure project in the Harald Field. Furthermore, a permit was granted for the ENSCO 70 drilling rig to be stationed in the Harald Field. A permit was granted for the further development of a well on Tyra East, and finally a permit was also granted in 2009 for the relocation of lifeboats.

Box 4.14

Areas of responsibility of Danish authorities offshore
The DEA is the authority responsible for health and safety on offshore installations. In this context "offshore installations" refers to installations for the exploration for and production of oil and gas from the subsoil below the seabed. Offshore wind farms do not fall within this definition.

"Safety" refers to the process and structural safety of installations and equipment as well as safety at workplaces and during work performance. "Health" refers to health conditions in the working environment and other health-related situations, including stays on offshore installations. Offshore installations are not covered by the Working Environment Act and therefore also fall outside the remit of the Danish Working Environment Authority.

Besides the DEA, a number of other authorities supervise health, safety and environment on offshore installations, of which the most important – apart from the DEA – are listed below.

Danish Maritime Authority
The Danish Maritime Authority has been granted authority for the following areas under the Offshore Safety Act:
- Design, strength, buoyancy, fitting-out and equipment of a maritime nature on drilling rigs and other mobile units.
- Fitting-out of the treatment room ("hospital") on mobile units, such as drilling rigs, including drugs cabinets.
- Rescue appliances and associated launch arrangements on fixed offshore installations and mobile offshore units.
- Diving operations, including divers' equipment and professional diving activities.

These areas of responsibility are more specifically defined in an agreement between the DEA and the Danish Maritime Authority. The agreement can be found on the DEA's website, www.ens.dk.

Danish Environmental Protection Agency
- Marine discharges from offshore installations.
- Emergency response to marine pollution, such as oil spills, from offshore installations.
- Environmental measures on offshore installations, such as spill trays.

Danish National Board of Health
- Training requirements for offshore medic.
- Treatment room ("hospital") on fixed installations: fitting-out and equipment.
- Radioactive sources (Danish National Institute of Radiation Hygiene).

Danish Civil Aviation Administration (CAA-DK)
- Helicopter safety, including helidecks.
- Manning, fire-fighting, communications equipment and other helideck equipment.

The South Jutland Police
- Investigation of serious accidents and fatalities on offshore installations.

Danish Veterinary and Food Administration
- Food safety.

The Dan Field

In 2009, one permit was granted for major modifications to the existing installations in the Dan Field in accordance with section 29 of the Offshore Safety Act. The permit concerns the removal of a riser with its associated protective casing on the Dan B installation.

Via a pipeline, the riser connected the Dan B installation to the Dan E installation, where hydrocarbon production has now been suspended. The pipeline has therefore been decommissioned and the connection to Dan B is now redundant. In addition to providing space on the already compact installation, the removal of the unused equipment has made ongoing maintenance easier.

Mobile units

Noble George Sauvageau, ENSCO 70 and ENSCO 71 were granted new operating permits in 2009. Mærsk Resolute was granted a permit for modifications in connection with combined operations on the Nini installations. Mærsk Resolute was a granted an operating permit later in the year for work at the South Arne installation.

COOPERATION REGARDING OFFSHORE HEALTH AND SAFETY

The DEA cooperates with a considerable number of parties both nationally and internationally in connection with health and safety issues on offshore installations. Some of this cooperation has been laid down in legislation, while other cooperation has been established to strengthen the DEA's role in offshore health and safety work.

Box 4.15

Preparation of an Executive Order under the Offshore Safety Act

Before an Executive Order can be issued and enter into force under the Offshore Safety Act, it must go through the following process:

1) The DEA drafts a memo on the purpose, etc. of the Executive Order.
2) After any necessary adjustments, the memo is approved by the Offshore Safety Council's working group.
3) The DEA prepares a draft Executive Order.
4) The draft Executive Order is approved by the Offshore Safety Council's working group, typically after a series of discussions.
5) The draft Executive Order is approved by the Offshore Safety Council at an ordinary meeting, normally without changes if the working group has been unanimous in its approval.
6) The draft undergoes a public consultation process after quality control by the DEA's Legal Service.
7) Relevant responses from the public consultation process are specifically addressed and implemented in the draft.
8) After a last quality control by the DEA's Legal Service, the Executive Order is now final and is issued by the DEA's Director General. In some cases the nature of the Executive Order may be such that it must be issued by the Danish Minister for Climate and Energy.
9) The Order is published in the Danish Law Gazette (www.lovtidende.dk) and the Danish Government Legal Database (www.retsinformation.dk).
10) The Executive Order enters into force and normally becomes effective simultaneously for the areas covered by it. In some cases the Executive Order may specify a later effective date.

Box 4.16

Offshore Safety Council
In accordance with section 58 of the Offshore Safety Act, an Offshore Safety Council has been appointed to assist in the drafting of health and safety regulations for offshore installations, monitor technical and social developments relating to such installations, and discuss other issues covered by the Act. The Offshore Safety Act also requires employers and unions (the social partners) in the offshore sector to work together on health and safety issues through a safety organization.

One of the tasks of the Offshore Safety Council is to cooperate with the DEA in preparing health and safety regulations for offshore installations, as the Offshore Safety Act stipulates that representatives of the social partners and a number of authorities must assist in drafting regulations under the Act. The Offshore Safety Council has therefore appointed a working group in which the details concerning new regulations are discussed.

The Offshore Safety Council consists of a chairman appointed by the DEA as well as the following members:
- Five members representing the Danish Confederation of Trade Unions (LO).
- One member representing the Confederation of Professionals in Denmark (FTF).
- One member jointly representing the Danish Engineers Association and the Danish Association of Trade Union General Secretaries.
- Seven members jointly representing the Confederation of Danish Employers and the Danish Shipowners' Association.
- One member representing the DEA.
- One member representing the Danish Maritime Authority.
- One member representing the Danish Working Environment Authority.
- One member representing the Danish Environmental Protection Agency.
- One member representing the Danish Civil Aviation Administration (CAA-DK).

The members and their deputies are elected for a four-year term. New members and deputies are due for election on 1 November 2010.

The Offshore Safety Council holds four ordinary meetings a year, in March, June, September and December.

The DEA acts as chairman and secretariat for the above working group in which details of new regulations are discussed. The remaining members of the working group are:
- LO: The Danish Metalworkers' Union, the Danish Union of Electricians, CO-Industri and the United Federation of Danish Workers (3F): one representative each.
- The Confederation of Danish Employers' and the Danish Shipowners' Association's joint representatives: Mærsk Olie og Gas AS, DONG Energy E&P, Hess Denmark ApS and Maersk Drilling: one representative each.
- The Danish Maritime Authority: one representative.

Representatives of other authorities may also attend working group meetings as and when necessary.

The cooperation partners consist of employers and unions in the offshore industry, the Danish authorities, other Danish institutions and international offshore authorities and organizations.

Health and safety management on offshore installations
Oil and gas production operations in Denmark create many offshore jobs, and the associated health and safety issues are regulated by the Act on Health and Safety on Offshore Installations, known as the Offshore Safety Act. The Offshore Safety Act regulates the safety of offshore installations and the employees' health, safety and working environment. 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.

A number of new Executive Orders issued under the Offshore Safety Act entered into force concurrently with the Act. However, these Executive Orders did not fully replace the previous regulations laid down under the Offshore Installations Act. It was therefore necessary to retain a number of the old regulations on a provisional basis. These regulations are being phased out as the new ones are issued.

The work in connection with phasing out the old regulations is expected to be completed in the course of 2010.

The preparation of new regulations is taking place in cooperation with employers and unions in the offshore sector; see boxes 4.15 and 4.16.

Accommodation facilities on offshore installations
One of the Offshore Safety Act's new Executive Orders concerns accommodation facilities on offshore installations.

Permission was granted for sleeping cabins on fixed offshore installations constructed before 1988 to be fitted out for use by two people. From 1988 onwards, new regulations required sleeping cabins on new fixed installations to be designed for one person only. This requirement has been retained in the new regulations.

Permits and approvals which are covered by the Offshore Safety Act and which were granted before the Act entered into force will continue to be valid. This means that existing offshore installations (fixed and mobile) that held an operating permit when the Offshore Safety Act entered into force on 1 July 2006 retained their permit. As a result, two-person cabins are still permitted on fixed installations from before 1988.

Sleeping cabins on mobile offshore units constructed since mid-1992, when the previous regulations concerning sleeping cabins on mobile offshore units entered into force, should be fitted out to accommodate a maximum of two people. Prior to this, regulations applying to ships were used.

Improvements to existing conditions
With regard to sleeping cabins on fixed offshore installations constructed before 1988, the parties themselves have initiated discussions through the so-called Labour Market Forum for Cooperation regarding Fixed Offshore Installations concerning how and when accommodation conditions on existing fixed installations can be improved. The composition of the parties within the cooperation is shown in the section *Offshore safety organization*.

In addition, the DEA has in several cases imposed a requirement for two-person sleeping cabins on offshore installations (fixed and mobile) to be used by people working opposite shifts, thus allowing each person to sleep alone.

Offshore safety organization

As on land, employees and management cooperate on health and safety issues on manned fixed offshore installations and mobile units. This cooperation takes place through a safety organization consisting of a number of safety groups and a safety committee. The regulations concerning the work within the safety organization and associated rights and obligations generally correspond to those applicable on land under the Working Environment Act.

In the course of 2010, the existing regulations will be replaced by new ones as part of phasing out the previous regulations under the Offshore Installations Act. This work coincides with changes to the regulations on land, which will include amendments to the Working Environment Act. The changes are the result of an agreement between the Danish Working Environment Authority and the employee and employer organizations on land (the so-called Tripartite Agreement). The new regulations for the offshore sector will incorporate the aspects of the agreement that are relevant to this sector. Basically, the changes will facilitate greater flexibility in the structure of safety organizations and a modernization of the training to be undertaken by the safety group.

In connection with drawing up new offshore regulations, the parties are discussing the contents of them in the so-called Labour Market Forum for Cooperation regarding Fixed Offshore Installations, which consists of the operators of the producing fields, Mærsk Olie og Gas AS, DONG Energy E&P and Hess Denmark of the one part and the Danish Metalworkers' Union, the Danish Union of Electricians, CO-Industri and the United Federation of Danish Workers (3F) of the other part. The result of these negotiations will be included in the Offshore Safety Council's working group discussions; see box 4.16.

Cooperation with the Danish authorities

The DEA cooperates with a number of Danish authorities concerning health and safety issues on offshore installations. Some of this cooperation has been formalized through the Offshore Safety Act, e.g. supervisory tasks, the Offshore Safety Council and the authorities' Emergency Response Committee. The cooperation concerning supervision is described in box 4.14 in the section *Approvals and permits granted in 2009*, while the Offshore Safety Council is described in box 4.16.

The authorities' Emergency Response Committee

The authorities' Emergency Response Committee is to coordinate the authorities' rescue and containment measures in case of major accidents or near-miss occurences on offshore installations, for example in connection with fire or explosion, uncontrolled blowouts, oil or gas spills or aircraft crashes at or close to an installation. The Committee is also to supervise the measures taken by the company operating the offshore installation in case of any major accident on the installation.

The members of the Committee are appointed by the Minister for Climate and Energy, one member and one deputy each from the Danish Maritime Authority, the Danish Environmental Protection Agency, the South Jutland Police, Defence Command Denmark and the DEA. The DEA chairs the Committee and acts as secretary. The

Committee members can be convened at short notice and will operate from the emergency response room on the premises of Defence Command Denmark at Holmen.

The Committee holds regular drills.

Cooperation with other authorities
In addition to statutory cooperation, the DEA cooperates with a number of authorities regarding health and safety issues:

- **The Danish Working Environment Authority**
  EU regulations concerning the working environment area. The Danish Working Environment Authority is the focal point in Denmark for the European Commission concerning health and safety in the workplace.
  Technical working environment issues.
- **The Danish Safety Technology Authority**
  Electrical safety.
- **National Board of Health**
  Authorization of offshore medics, i.e. the trained medical personnel on an offshore installation.
  Radioactive sources.
- **Danish Agency for International Education (formerly CIRIUS)**
  Recognition of professional qualifications for people from other EU and EEA countries.

Cooperation with other institutions
In addition to Danish authorities, the DEA cooperates with a number of other institutions such as the Centre of Maritime Health and Safety and Danish Standards.

Centre of Maritime Health and Safety
The DEA is represented on the steering committee for the Centre of Maritime Health and Safety, a centre based at the University of Southern Denmark (SDU) in Esbjerg, whose objective is to provide expertise to ensure and develop the best possible health and safety conditions for seamen, fishermen and employees on offshore installations.

The centre fulfils its objective through research, documentation, advice, education and clinical studies. One of the research projects concerns accident prevention in the offshore industry.

The steering committee consists of members from the Danish Maritime Authority and the DEA, SEAHEALTH Denmark, the Offshore Safety Council and SDU, and is tasked with guiding the centre in its work. The steering committee meets about twice a year.

Further information about the centre and its work can be found at the centre's website: www.sdu.dk/ist/cmss.

Norms and standards
Norms and standards help increase the safety level on offshore installations.

In terms of legislation, the Offshore Safety Act stipulates the requirement that recognized norms and standards concerning health and safety in the construction, layout and equipment of offshore installations must be observed.

However, norms and standards may be deviated from where appropriate in order to achieve a higher health and safety level, or as a result of technical developments. It is assumed that any deviations will lead to the reduction of health and safety risks as much as reasonably practicable.

In the event of there being no recognized norms or standards as mentioned above, the health and safety risks associated with the construction of an offshore installation should be identified, assessed and reduced as much as reasonably practicable.

Norms and standards are particularly used in connection with the construction and lay-out of offshore installations and pipelines, and for equipment used on the installations.

As in previous years, in 2009 the DEA provided financial support for the standardization work being carried out within the offshore sector via Danish Standards.

International cooperation

The DEA participates in international cooperation in a number of areas related to health, safety and the environment on offshore installations. In addition, the DEA takes part in cooperation on environmental issues; see chapter 5, *Environment and climate*.

NSOAF

NSOAF (the North Sea Offshore Authorities Forum) is a cooperation forum between the public authorities of the North Sea countries that deals mainly with health and safety issues on offshore installations. The following countries participate in the NSOAF cooperation (with the names of the public institutions shown in brackets):

- Denmark (the DEA)
- The Faroe Islands (Jarðfeingi – the Faroese Earth and Energy Directorate)
- The Netherlands (Staatstoezicht op de Mijnen - the State Supervision of Mines)
- The Republic of Ireland (the Department of Communications, Energy and Natural Resources)
- Norway (Petroleumstilsynet – the Petroleum Safety Authority Norway)
- Sweden (Sveriges Geologiske Undersøgelse - the Geological Survey of Sweden)
- Germany (Landesbergamt für Bergbau, Energie und Geologie - LBEG)
- The UK (the Health & Safety Executive)

NSOAF performs its work primarily through working groups. The member countries meet at an annual conference, where they agree on the general objectives of the work to be performed by these working groups.

Working group for health, safety & environment (NSOAF-HS&E)

The group works on the harmonization of requirements related to health, safety and the environment on offshore installations. In addition, experience is exchanged and discussed in connection with problems and accidents occurring offshore. The working group also cooperates with the International Association of Drilling Contractors (IADC) on issues of common interest, such as the preparation of an "HSE (Health, Safety and Environment) Case" in connection with drilling operations. The HSE Case provides a basis for ensuring that drilling rigs fulfil applicable EU legislation regarding a health and safety document, such that the drilling companies need not prepare a completely new document whenever the drilling rig crosses a border between two North Sea countries, but can instead simply add sections in order to meet particular national requirements.

Under the auspices of the working group, joint audits are also carried out in regard to health and safety on offshore installations across national boundaries. To date, four such audits have been carried out covering selected themes, of which the most recent concerned the companies' management-related supervision on installations.

Finally, the group has established two project groups; one concerning emergency preparedness and one concerning indicators for measuring health and safety using Key Performance Indicators (KPIs).

Working group for safety training (NSOAF-TWG)
Denmark chairs this working group, which is working towards the mutual recognition of safety training requirements in the North Sea countries. The mutual recognition of the basic safety training course has taken effect, and the working group is now investigating the need to extend this mutual recognition to include training for other safety functions.

Working group on drilling and well control (NSOAF-WWG)
This working group exchanges information and cooperates on health and safety issues relating to drilling and well operations, including issues concerning the prevention of uncontrolled blowouts.

Among other things, the aim is for the group's activities to contribute to the further improvement of health and safety during drilling operations and other well-related activities, while at the same time working to reduce the administrative burdens for those companies working across national boundaries in the North Sea.

EU working group (NSOAF-EUWG)
This working group exchanges views and experience related to EU Directives and proposed Directives.

One of the group's projects is the market surveillance of equipment, etc. that is covered by EU Directives e.g. the Machinery Directive and the Pressure Equipment Directive.

OMHEC
OMHEC (the Offshore Mechanical Handling Equipment Committee) is an international forum whose members include the DEA, representatives of offshore regulatory authorities from other countries (the UK, Norway and the Netherlands), and verification bodies and specialists in the area.

One objective is to prepare guidance documents that can provide a common platform for health and safety issues associated with crane and lifting operations. These guidance documents are available to the offshore industry free of charge.

OMHEC has launched its own website, www.omhec.org, which contains information about the organization, contact persons in the individual member countries and the guidance documents prepared.

Bilateral cooperation
Once a year, the DEA meets bilaterally with the Petroleum Safety Authority in Norway and the UK Health & Safety Executive, respectively. General experience is exchanged and various activities are discussed at the meetings between the countries in relation to offshore health and safety.

5 ENVIRONMENT AND CLIMATE

Exploration and production of hydrocarbons impact 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. Another environmental impact consists of noise from the acquisition of data about the subsoil and the construction of installations. The DEA makes targeted efforts to reduce these impacts to the lowest possible level.

EMISSIONS TO THE ATMOSPHERE

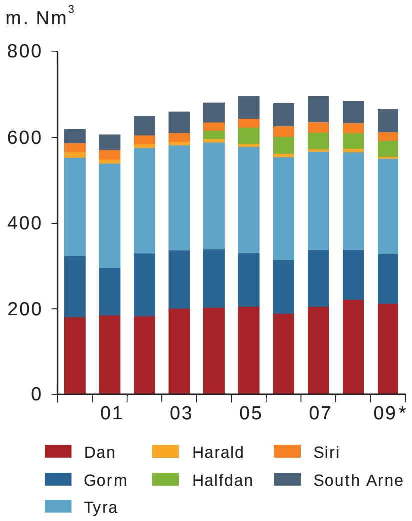
Emissions to the atmosphere consist of such gases as CO_2 (carbon dioxide) and NO_x (nitrogen oxide).

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. Gas is flared on all offshore platforms with production facilities, and for safety reasons gas flaring is necessary in cases where installations must be emptied of gas quickly.

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

The Danish Subsoil Act regulates the volumes flared, while CO_2 emissions (including from flaring) are regulated by the Danish Act on CO_2 Allowances; see box 5.1.

Fig. 5.1 Fuel consumption (gas)



*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

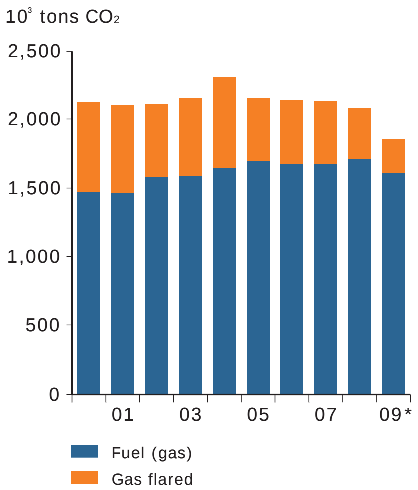
Consumption of fuel

Fuel gas accounted for close to 89 per cent of total gas consumption offshore in 2009. The remaining 11 per cent was flared. During the past decade, the gradual increase in the use of gas as fuel on Danish production installations until 2007 was followed by a sharp drop, particularly from 2008 to 2009; see figure 5.1. The general increase was attributable to rising oil and gas production and ageing fields. The reason for the sharp drop is falling production combined with energy efficiency measures taken by the operators.

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 ton oil equivalent (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 5.1. From 2008 to 2009 the use of gas as fuel was reduced significantly on all installations except South Arne, which remained at the same level as in 2008. The Siri Field was out of operation for a period of time (see the section *Oil production* in chapter 3, *Production and development*, and the section *Inspections in 2009* in chapter 4, *Health and safety*), thus cutting back its fuel consumption substantially compared to 2008.

Fig. 5.2 CO_2 emissions from production facilities in the North Sea

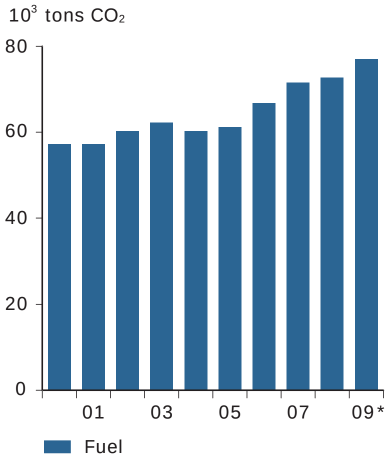


*As from 2006, the figures have been based on verified CO_2 emission data from reports filed under the the Act on CO_2 Allowances and have included CO_2 emissions from diesel combustion

CO_2 emissions due to fuel consumption

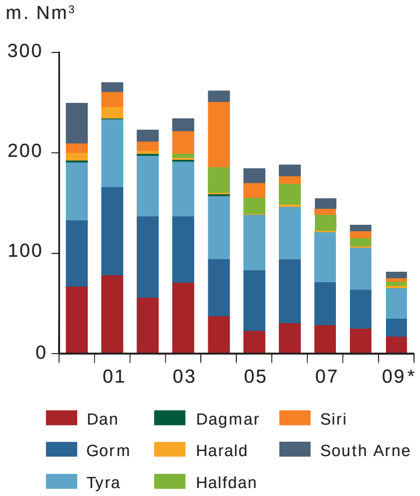
The development in the emission of CO_2 from the North Sea production facilities since 2000 appears from figure 5.2. This figure shows that CO_2 emissions totalled about 1.8 million tons in 2009, the lowest level in ten years and a 6.7 per cent reduc-

Fig. 5.3 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

Fig. 5.4 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

tion from 2008. The production facilities in the North Sea account for less than 3 per cent of total CO_2 emissions in Denmark.

Figure 5.3 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 78 ktons of CO_2 per million t.o.e. in 2009. The reason for this increase is that oil and gas production has dropped more sharply than fuel consumption, which means that CO_2 emissions due to fuel consumption have increased relative to the size of production.

Gas flaring

The flaring of gas declined substantially from 2008 to 2009 in all fields, with the exception of the Harald and South Arne Fields, where volumes flared remained stable. This development is attributable to stable operating conditions on the installations, changes in operations and focus on energy efficiency. Moreover, as described in the section *Consumption of fuel*, the Siri Field was out of operation for some time.

The volumes of gas flared during the period 2000-2009 appear from figure 5.4, and, as the figure shows, gas flaring varies considerably from year to year. The large fluctuation in 2004 is partially due to the tie-in of new fields and the commissioning of new facilities. In 2009, gas flaring totalled 85 million Nm^3, which is the lowest volume since 1980.

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 design and layout of the individual installation, but not on the volumes of gas or oil produced.

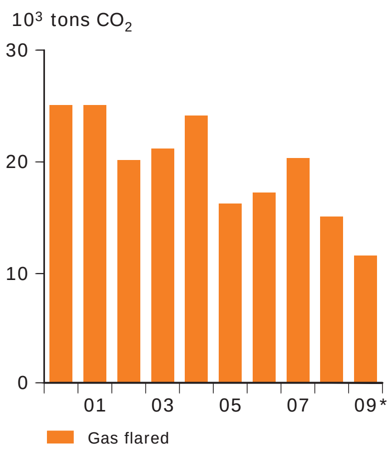
CO_2 emissions from gas flaring

In 2009, CO_2 emissions from flaring came to 0.241 million tons of CO_2 out of total CO_2 emissions from the offshore sector of 1.813 million tons, i.e. 13 per cent of total emissions. The volume of gas flared accounted for 1.2 per cent of total gas production in 2009. All CO_2 emissions are comprised by the CO_2 allowance scheme; see box 5.1.

Flaring has declined steadily since 2004 and dropped by 32 per cent in 2009 compared to 2008. The production of hydrocarbons decreased during that period, and thus the volume of gas flared per t.o.e. produced increased until 2007; see figure 5.5. The volume of gas flared per t.o.e. produced fell from 15.5 ktons of CO_2 per million t.o.e. in 2008 to about 12 ktons of CO_2 per million t.o.e. in 2009. Thus, the reduction in flaring was so substantial that it more than 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.

Fig. 5.5 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

Box 5.1

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.

If new installations are established, 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.

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.

In 2009, an amendment to the EU Emission Trading Directive was adopted, which will become effective from 2013 and onwards. The amendment will involve that free allowances for installations comprised by the allowance scheme will be allocated on the basis of other criteria than before, making the scheme uniform across the EU. Free allowances will no longer be allocated for the generation of electricity, and allowances will be allocated to, e.g., the industrial sector on the basis of common benchmarks for the relevant sector, for instance being based on the 10 per cent installations with the highest efficiency in producing a specific product. As a result of the amendment, the European Commission will issue a number of regulations in the course of 2010 and at the beginning of 2011.

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

ENERGY EFFICIENCY OFFSHORE

The energy policy agreement entered into between the Government and the Danish Social Democrats, the Danish People's Party, the Socialist People's Party, the Danish Social-Liberal Party and New Alliance on 21 February 2008 set 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 Danish gross energy consumption by 2 per cent in 2011 and 4 per cent in 2020 relative to the level in 2006.

According to the agreement, a review of offshore energy consumption and proposals for initiatives to improve the energy efficiency of North Sea oil and gas production were 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.

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 agreed on an action plan with the Danish operators in April 2009, which was supplemented by an addendum in February 2010. The aim of the action plan is 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. Approximately one quarter of the anticipated savings will come from reduced flaring as a result of changes to operations.

One of the central elements in the action plan is the operators' commitment to introduce energy management, based on the principles laid down in the energy management standard. This will help ensure that the focus on energy efficiency is maintained and strengthened, both in daily operations and in connection with the establishment of new projects.

The action plan also incorporated a plan for making further analyses. These analyses have now been carried out, and the results were presented at the beginning of May 2010, along with a status report on the implementation of the action plan. The action plan is expected to be updated in mid-2011.

The action plan is available at the DEA's website, www.ens.dk.

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 NEC 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 ENVIRONMENTAL IMPACTS
All production of hydrocarbons in Denmark currently takes place offshore, and the actual production and drilling of wells result in discharges into the marine environment. It is also offshore that most exploration activities, including the acquisition

Box 5.2

OSPAR
The Oslo-Paris Convention (OSPAR) for the Protection of the Marine Environment covers the North-East Atlantic and comprises 15 countries, including Denmark.

In the oil and gas area, the DEA assists the Danish Environmental Protection Agency with technical expertise related to the work under OSPAR for the protection of the marine environment, e.g., in the North Sea. The detailed content and scope of the Convention can be read on OSPAR's website, www.ospar.org.

The work concerning the oil and gas industry is primarily carried out in a committee called the Offshore Industry Committee (OIC), which works on an ongoing basis and meets annually.

of seismic data, have taken place. As a result, marine flora and fauna are exposed to impacts. In partnership with many other authorities and organizations, the DEA is responsible for protecting the marine environment.

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 oil 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.

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 in produced water and chemicals as well as atmospheric pollution. Through agreements under the international OSPAR Convention on the Protection of the Marine Environment (see box 5.2), Denmark has committed itself to regulating discharges in the same way as the other Contracting Parties. The objective of the OSPAR Convention is to protect the marine environment of the North-East Atlantic, including the North Sea.

Under the OSPAR Convention's requirements concerning the discharge of produced water, the concentration of dispersed oil has not been permitted to exceed 30 mg/l since 2006. In the discharged produced water from the Danish fields, the average concentration today is considerably lower. The negotiations that are under way between the OSPAR member countries are moving towards a risk-based approach for the determination of restrictions on discharges.

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.

To achieve this goal, the Minister for the Environment launched the Offshore Action Plan in 2005, followed by a revised plan for the period 2008-2010. In this connection, investigations were commenced to assess the potential for further reductions in the discharge of oil with produced water. This work was continued during 2009 with a study looking at the opportunities for increasing the reinjection of produced water to replace treated seawater as a source of pressure support for production.

One of the challenges associated with reinjecting produced water into the chalk reservoirs that make up the majority of Danish oil fields is to achieve adequate water treatment in order to avoid a reduction in the reservoir's performance and increased wear on equipment. Tests are planned to determine whether the reinjection of produced water could replace treated seawater as a source of pressure support for production.

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, the Danish operators (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.

Noise from seismic surveys

Another environmental impact of oil and gas operations is noise from the acquisition of seismic data. During seismic surveys, a sound source sends out pressure waves, which are reflected by the layers in the subsoil; see box 1.4 in chapter 1, *Licences and exploration*. This noise can disturb marine mammals such as the porpoise, a species of whale that is protected by the EU Habitats Directive. The Habitats Directive imposes strict measures for the protection of all species of whale and dolphin. In Denmark, porpoises are found in the inner Danish waters and in the North Sea, where most of the Danish oil and gas operations take place. The DEA has therefore introduced a series of conditions for the acquisition of seismic data.

The DEA must approve all seismic surveys before the work is commenced. When a company wishes to acquire seismic data in an area, the company must submit an application to the DEA. Before the company is permitted to carry out the seismic survey, the DEA will in each individual case review the information in the application concerning equipment, programme and method of execution. The DEA will also specifically assess the possible adverse impacts on animal life in the affected areas, including whether the seismic survey would be carried out in accordance with the provisions of the EU Habitats Directive.

To ensure that the seismic surveys are carried out in accordance with the Habitats Directive, the DEA will make the approval conditional on the company implementing preventive measures to give the marine mammals sufficient time to leave the area before the seismic activities are initiated.

One standard condition is that companies must use what is known as a "soft start procedure" when the seismic survey is carried out. The soft start procedure is based on slowly increasing the sound level from the seismic air gun up to the operational level. If marine mammals are observed at a distance of less than 200 metres from the sound source, the soft start procedure must be postponed. The soft start procedure must be carried out in accordance with a set of "best practice" guidelines, prepared by the National Environmental Research Institute (NERI) at Aarhus University.

In rare cases, explosives will be used as a sound source instead of an air gun. In such cases, corresponding conditions are imposed which require small warning detonations within a 20-30 minute period before the survey detonation itself. When dynamite is used, it is a condition that the company checks the area for marine mammals before carrying out the seismic detonations. If there are marine mammals in the area, the detonations must be postponed.

The conditions that are imposed in connection with the approval of seismic surveys at sea are partly based on the latest data and information concerning the presence and behaviour of the marine mammals that live in the Danish offshore area. The DEA continually reassesses and updates the conditions as new knowledge about the subject is acquired, e.g. via conditions in licences, in order to ensure compliance with the requirements of the Habitats Directive concerning the strict protection of whales and dolphins.

At the end of 2009, the DEA received preliminary reports concerning the provisional results from two monitoring programmes relating to, e.g., the behaviour and distribution of porpoise in the western area of the North Sea from Mærsk Olie og Gas AS. Mærsk Olie og Gas AS has monitoring programmes carried out as part of the company's obligations in connection with oil and gas operations. Based on the results in the reports, the DEA has instigated work to clarify whether further initiatives will

be required to ensure the best protection of porpoises and dolphins. The DEA has therefore consulted DMU and the Agency for Spatial and Environmental Planning and is awaiting DMU's assessment of the results from the two reports. The reassessment of the conditions is expected to be completed during the summer of 2010.

When this report went to press, the ongoing reassessment of the conditions imposed for the approval of offshore seismic surveys had not been completed. When the reassessment has been completed, the results will be placed on the DEA's website, www.ens.dk.

Conditions requiring the use of soft start procedures, etc. are also imposed in connection with other noise-generating activities such as piling works in the seabed. Piling works are for example carried out in connection with the installation of piles to anchor platforms and during the drilling of wells, where conductors protecting the upper section of a well are driven into the seabed.

The Marine Strategy Framework Directive

The Marine Strategy Framework Directive is intended to establish a framework for the EU's marine environment policy measures. Via the Marine Strategy Framework Directive, a common timetable has been agreed at EU level to ensure good environmental status in marine areas by 2020. The Marine Strategy Framework Directive must be implemented into Danish legislation by 15 July 2010. For this purpose, the Minister for the Environment presented a Marine Strategy Bill in the Danish Parliament on 21 January 2010.

In this connection, the DEA has taken part in analyses concerning possible consequences of implementing the Marine Strategy Framework Directive in Denmark. These analyses have been carried out by the Agency for Spatial and Environmental Planning.

Integrated maritime policy

The "Maritime Blue Book" on an integrated EU maritime policy was adopted by the European Commission in October 2007 and subsequently approved by the Council of Europe. In June 2008, the Commission subsequently issued guidelines for an integrated approach to maritime policy.

The preparation of a Danish integrated maritime policy was begun in 2009 as a project under the Danish Maritime Authority. The aim is to draw up a Danish integrated maritime policy, which can form the basis for growth-oriented and environmentally and climatically sustainable commercial development for the maritime sectors. The intention is not to replace, but to supplement, the sector-based policies. The project will seek to link together the many considerations in the maritime area, create a series of concrete initiatives and promote coordination between authorities with tasks within the maritime area. The maritime sectors in a broad sense also include offshore energy production. Against this background, the DEA has participated in the project and contributed with regard to oil and gas production offshore and offshore wind turbines. The Ministry of Economic and Business Affairs expects the integrated maritime policy, which will set out the Government's policies in the area, to be issued in 2010.

ENVIRONMENTAL IMPACT ASSESSMENTS (EIAS)

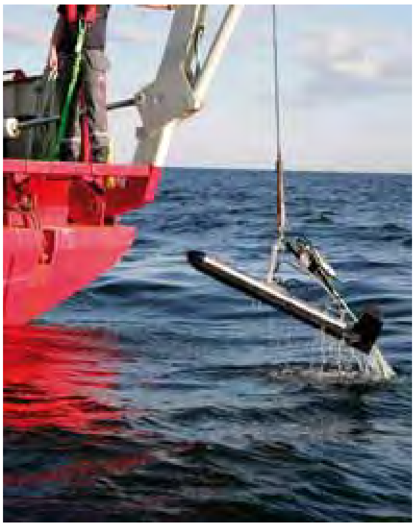
By law, oil companies are obliged to reduce the environmental impacts of hydrocarbon production. In the case of major development projects for the production of hydrocarbons and the establishment of large pipelines in Danish territorial waters and continental shelf area, the oil companies are therefore obliged to prepare an assessment of the environmental impact (known as an EIA); see box 5.3.

Box 5.3

Environmental impact assessment (EIA)

An environmental impact assessment (EIA) must be made before the DEA can grant permission for major projects pursuant to sections 10, 17 and 28 of the Danish Subsoil Act and section 4 of the Danish Continental Shelf Act.

The detailed rules regarding EIAs appear from Executive Order No. 359 of 25 March 2010 on the Environmental Impact Assessment (EIA) of International Protection Areas and the Protection of Certain Species in connection with Projects to Produce Hydrocarbons, Establish Pipelines, etc. in the Sea Territory and the Continental Shelf. The Executive Order is available at the DEA's website, www.ens.dk. The Executive Order on EIAs entered into force on 15 April 2010.



An EIA report covers various areas of impact, depending on the nature, dimension and location of the project. The assessment typically addresses environmental impacts of discharges into the sea and atmosphere, physical impacts, any unintentional chemical and oil spills, and the decommissioning and removal of installations or pipelines. If it is anticipated that the project would affect designated international nature protection areas, a habitat assessment must also be carried out.

The EIA report must be subjected to public consultation before the DEA can approve the project. The DEA, the Danish Environmental Protection Agency and the Agency for Spatial and Environmental Planning cooperate with regard to the authority processing of EIAs.

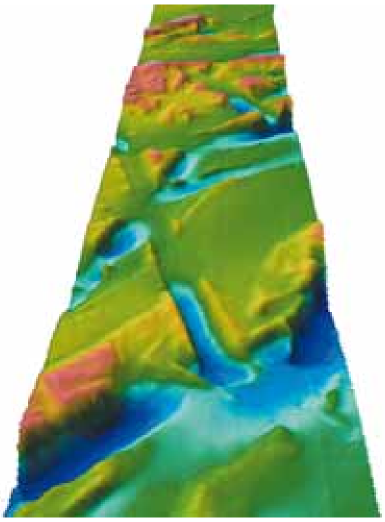
EIA reports have been prepared for all the Danish installations in the North Sea.

ENVIRONMENTAL IMPACT ASSESSMENT PROJECTS IN 2009

Nord Stream – the natural gas pipeline project in the Baltic Sea

The company Nord Stream AG is planning to establish two parallel 1,220 km natural gas pipelines from Vyborg in Russia through the Baltic Sea to the German coast near Greifswald; see figure 6.12 in chapter 6, *Resources*. The pipelines will pass through Russian, Finnish, Swedish, Danish and German territorial waters and are therefore a transboundary project. In Danish waters, the project envisages around 137 km for each of the pipelines along a route which passes east and south of Bornholm. The Nord Stream pipeline project is also referred to in the section entitled *Gas infrastructure and security of supply* in Chapter 6, *Resources*.

In connection with the Nord Stream project, both an EIA report, which focuses on the Danish section of the pipelines, and an Espoo EIA report (see box 5.4), which shows the entire project and any transboundary impacts, have been prepared. The preparation of the Espoo EIA report for the Nord Stream pipelines has involved all the Baltic countries, and there have been a number of public consultations concerning the project as part of the process.



Box 5.4

Espoo consultation process

The Espoo (EIA) Convention (the Convention of 25 February 1991 on Environmental Impact Assessment in a Transboundary Context) is a UN Convention, ratified by Denmark and a large number of other countries, that is aimed at preventing the adverse environmental impact of proposed activities across borders. In this connection, it is a requirement for the EIAs to be made at an early stage of planning.

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.

Alternative pipeline routes were investigated in connection with the preparation of the EIA report. The first alternative had to be abandoned, as the pipelines would have passed through an area which both Poland and Denmark lay claim to, while the second alternative was a route passing north and west of Bornholm, which gave rise to concerns on the part of the Swedish and Danish maritime authorities due to the heavy shipping traffic in the area between Sweden and Bornholm. This would also have required seabed intervention works in several locations, either through dredging or backfilling, to ensure that the pipelines were stable along this section.

The alternative chosen was a route passing east and south of Bornholm; see figure 6.12. Overall, the southeastern route has the lowest risk profile and environmental impact.

On 4 March 2009, the DEA received an application from Nord Stream AG for a permit to establish the Danish section of the pipeline project. Nord Stream AG is owned by the Russian natural gas company Gazprom (51 per cent), the two German companies BASF (20 per cent) and E.ON (20 per cent) and the Dutch company Gas Unie (9 per cent).

Denmark and the other countries around the Baltic Sea have signed the UN Convention on the Law of the Sea, which establishes a right to lay pipeline on the continental shelf, i.e. a sort of free passage. Coastal states can thus not prohibit such pipelines, but may demand that due consideration be given to natural resources and the environment. Routes must also be approved by the coastal states concerned. In Denmark, permits for transit pipelines in maritime areas are issued by the DEA in collaboration with several other authorities in accordance with the Danish Continental Shelf Act.

The application included both the EIA report concerning the Danish part of the project and the Espoo EIA report. Both EIA reports were subjected to public consultation in 2009 in both Denmark and the other Baltic Sea countries. The other Baltic Sea countries were asked to express their opinion as to whether the Danish section of the pipelines could impact on the environment in their respective areas. None of the consultation responses contained any suspensive conditions.

On 20 October 2009, the DEA granted a permit to Nord Stream AG under the Danish Continental Shelf Act to construct and lay the Danish section of the Nord Stream natural gas pipelines. In order to subsequently commission the pipelines, the company must also apply to the DEA for an operating permit.

While the Danish application was being processed, the company's applications for a permit for the Nord Stream project were also being considered by the authorities in Russia, Finland, Sweden and Germany. The authorities in these countries have also issued permits for the pipeline project.

The Danish decision has been appealed to the Danish Energy Board of Appeal by the Estonian Naturalists' Society. Appeals have also been submitted against the German, Swedish and Finnish permits. In addition, two Estonian NGOs have lodged a complaint with the European Commission in which they claim that Denmark, Sweden, Finland and Germany have not properly complied with and correctly implemented the Environmental Impact Assessment Directive in this case.

One of the factors considered in the EIA reports is whether the inflow conditions in the Baltic Sea would be affected by the installation of the pipelines. An analysis of the

flow conditions in the Baltic Sea has therefore been carried out and submitted. This analysis indicates that the pipelines would not have any significant negative impact.

The risk of contact with conventional and chemical ammunition dumped following the two world wars is also considered in the EIA reports. As conventional and chemical ammunition has been dumped in an area east of Bornholm, the Nord Stream company has investigated whether pipeline installation in the area could result in increased pollution of the Baltic Sea from the chemical ammunition and whether the ammunition constitutes any other risks. The company has checked the 137 km pipeline route in the Danish area for both chemical and conventional ammunition and taken approximately 100 samples of the seabed. These samples were investigated by both the National Environmental Research Institute (NERI) in Denmark and a laboratory under the University of Helsinki, which is certified in accordance with the Chemical Weapons Convention. The results show either a low or no concentration of chemicals in the seabed, and the conclusion is that laying the pipelines along the chosen route will not result in any measurable environmental impact from the dumped chemical ammunition.

Fishing interests have also been taken into account. It appears that even though the pipeline will not be damaged by a trawl being dragged over it, the cutter vessels used by fishermen from Bornholm do not have sufficient engine power to drag the equipment over the pipelines. A solution has been found through an agreement between the fishermen and the Nord Stream company, which will result in the fishermen concerned receiving financial support from the company to invest in new fishing equipment that can be lifted over the pipelines. As an additional benefit, the equipment will reduce the fuel consumption of the fishing vessels.

Archaeological finds of cultural heritage significance have been made close to the pipeline route. Some of these finds, e.g. certain shipwrecks, are protected by the Danish Museum Act. The pipelines will therefore circumvent these finds. A wooden rudder from a 17th century ship has been raised from the seabed for conservation and subsequent exhibition at a Danish museum.

Development of the Hejre Field

The partners in licences 5/98 and 1/06 (see appendix G2), which consist of DONG E&P, Bayerngas Petroleum Danmark AS, Bayerngas Danmark ApS and the Danish North Sea Fund, are planning to commence oil and gas production from the Hejre discovery and will therefore prepare an EIA report for the planned development of the Hejre Field. The DEA, the Danish Environmental Protection Agency and the Agency for Spatial and Environmental Planning have been given a preliminary briefing on the development plans.

Further development of the South Arne Field

Hess Denmark ApS is planning to further develop the South Arne Field on the Danish continental shelf in the North Sea with the aim of producing oil and gas. Hess has prepared a screening report, which concludes that the existing EIA report for the South Arne Field covers the planned development. The DEA has asked the Danish Environmental Protection Agency and the Agency for Spatial and Environmental Planning to submit any comments on the EIA screening report. The DEA has provisionally concluded that the changes described in the report and the consequent environmental impacts will not give rise to any requirement for a new EIA report.

6 RESOURCES

The DEA makes an assessment of Danish oil and gas reserves annually. During the past year, the DEA has worked on clarifying the principles for the future assessment of resources.

THE DEA'S CLASSIFICATION SYSTEM FOR OIL AND GAS RESOURCES

The DEA uses a classification system for hydrocarbons (see box 6.1) to assess Denmark's oil and gas resources. The assessment of resources is used as a basis for preparing oil and gas production forecasts, which can be used in turn to provide an estimate of future state revenue. The aim of the classification system is to determine resources in a systematic way.

The DEA obtains the data for its assessment from the oil and gas companies that are operators in the Danish area. In recent years, some of the operators have changed their classification systems in accordance with the guidelines laid down by the Society of Petroleum Engineers, SPE (see box 6.2), for determining oil and gas reserves. As a consequence, the DEA has chosen to change its classification system for future assessments of resources. This means that the DEA's classification system now divides Danish oil and gas resources into four classes: reserves, contingent resources, technological resources and prospective resources.

Box 6.1

A **classification system for oil and gas resources** is a system that categorizes hydrocarbons according to the probability of their being recovered. Today, there is no international system that all countries and oil/gas companies must follow to enable direct comparability of their resources portfolios. It may therefore be difficult to get an overall picture of global, fossil fuel resources.

The DEA uses a classification system to obtain an overview of Denmark's future revenue from the oil and gas sector and to evaluate the extent to which Denmark will be a net exporter or importer of oil and gas in future. Oil and gas companies use the classification system in making their reserves assessments and forecasts, including for the purpose of providing estimates of future income and company values.

The classification system has been prepared based on a review of some of the classification systems used internationally. The review included the classification systems used by recognized international organizations such as the UN and SPE (see box 6.2) and in other North Sea countries such as Norway and the UK.

A description of the review and the background for the classification system is given in the section *Resources and forecast methodology*.

Resources and forecast methodology

The DEA has chosen to model its classification system on SPE's system, SPE-PRMS (see box 6.2), as this system is internationally recognized and is used by several countries' authorities and many oil companies. Moreover, the SPE-PRMS classification system is also the system preferred by most operators in the Danish area, whose information is used by the DEA in preparing resources assessments and production forecasts.

The DEA's classification system is presented in figure 6.1, which also shows a comparison with the DEA's previous system.

Box 6.2

The resources classification systems of international organizations
Many countries and oil companies use the classification systems of internationally recognized organizations, including those of the Society of Petroleum Engineers (SPE) and the UN, two of the most important classification systems.

SPE's classification system (SPE-PRMS)
SPE is an international organization composed of members who work in the oil and gas sector or related areas. SPE's mission is to collect, disseminate and exchange technical knowledge concerning the exploration, development and production of oil and gas resources, and related technologies for the public benefit.

The SPE's Petroleum Resources Management System (SPE-PRMS) was made public in 2007 and is divided into three main classes:

- Reserves
- Contingent resources
- Prospective resources

In addition, the system defines a class for the quantities that cannot be recovered or are difficult to recover, which is termed unrecoverable resources.

The three main classes are divided into sub-classes describing the maturity of a project, i.e. the probability of the commercial viability of a development project and the chance of discovery for an exploration project.

Further information about SPE-PRMS is available at SPE's website, www.spe.org/industry/reserves.

SPE-PRMS is sponsored by SPE, the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE).

The UN classification system (UNFC-2009)
The UN has drawn up a system which was most recently updated in 2009. The UN classification system was prepared for the purpose of classifying resources of fossil energy (coal, oil and gas) and mineral resources and is termed the United Nations Framework Classification for Fossil Energy and Mineral Reserves and Resources (UNFC-2009). The UN classification system is more complex than SPE-PRMS, as it is designed for assessing all types of natural resources, but the most recent version corresponds more closely to SPE-PRMS.

Further information about UNFC-2009 is available at the website www.unece.org/energy.

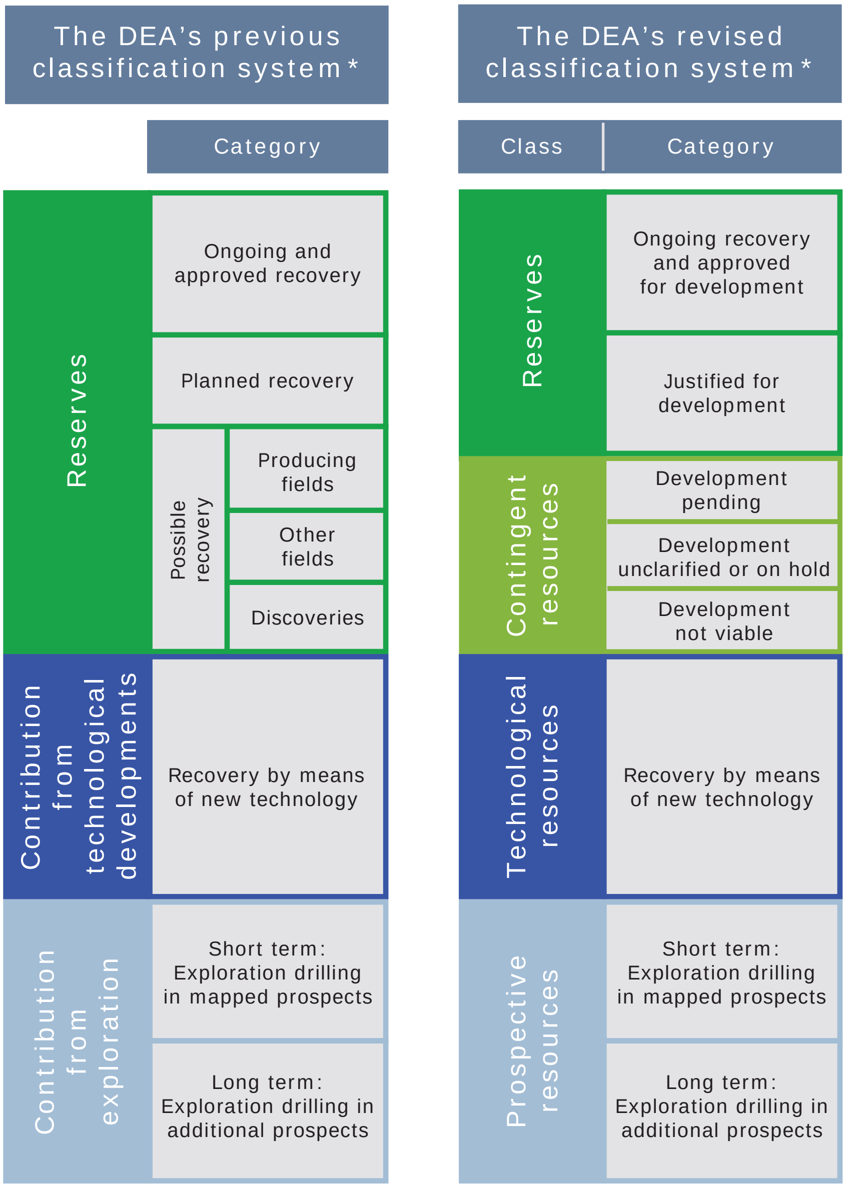
The classification system divides Danish oil and gas resources into four classes (reserves, contingent resources, technological resources and prospective resources) against three classes in the previous classification system; see figure 6.1. Each class is subdivided into a number of categories.

Reserves
This class comprises future recovery from existing production facilities and projects justified for development, and consists of the categories:

Ongoing recovery
This category comprises the reserves recoverable with existing production facilities and wells. It is assumed that ordinary maintenance will be carried out to uphold the functionality of the existing facilities.

Approved for development
If an approved development plan or parts of an approved plan are available, and production has not yet started, the pertinent reserves are categorized as approved for

Fig. 6.1 The DEA´s revised classification system compared to the DEA´s previous system



* The DEA's classification system is shown with the colour code for oil.

development. This applies to the development of new fields and the further development and modification of existing facilities.

Justified for development
This category comprises the development of new fields and the further development and modification of existing facilities for which a plan approved by the authorities is not yet available, but with a high degree of probability of the development project being implemented.

This category comprises development projects described in a production plan that is being considered by the authorities as well as development projects about which there are expectations that all internal and external approvals will be granted. There must be an intention to carry out such development projects within a reasonable time horizon, which means within about five years.

The reserves class has been reduced compared to “reserves” in the DEA’s previous system. The reason is that most of the possible recovery category now belongs under the class “contingent resources”.

Contingent resources
This class comprises projects for the development of discoveries and new fields or the further development of existing fields for which the technical or commercial basis has not been sufficiently clarified to make a final development decision. These projects are subdivided into three categories:

Development pending
This category comprises projects with potential for commercial development where data acquisition is ongoing (e.g., drilling and seismic data acquisition) to confirm possible commercial viability and to provide the basis for a development plan.

Development unclarified or on hold
This category comprises projects that are believed to have potential for commercial development, but which require further investigations.

The category also includes projects and development plans that are not commercially viable in the current financial situation, but could become viable in the near future.

Development not viable
This category comprises development projects not considered commercially viable under the existing conditions, for example because of the lack of infrastructure, technical difficulties or because the resources have too small a production potential. If the conditions change, there may be potential for implementing development projects categorized as not viable.

The class “contingent resources” was not included in the DEA’s previous system. This class includes part of the possible recovery category under the previous system; see figure 6.1.

Technological resources
The class “technological resources” was previously called “the contribution from technological developments”. The class “technological resources” is an estimate of the

additional volumes of oil and gas assessed to be recoverable by means of new technology, for example the use of CO_2 injection.

In the past, the use of new technology has had great impact on Denmark's oil and gas production, and will continue to have an impact in the future, particularly on oil production. Therefore, the DEA has chosen to uphold the class "technological resources" even though it differs from SPE's system where technological resources are included in the class "unrecoverable resources". The rest of the unrecoverable resources class is not calculated in the DEA's classification system as such unrecoverable resources are irrelevant to the DEA's work. This is a continuation of the practice used to date.

The content of the technological resources class is unchanged and corresponds to the class termed "the contribution from technological developments" in the previous system.

Prospective resources

The class "prospective resources" was termed "the contribution from exploration" in the DEA's previous system. Prospective resources are an estimate of the quantities believed to be recoverable from new discoveries and are divided into two categories, exploration drilling in mapped prospects and exploration drilling in additional prospects.

The first category comprises the exploration prospects known today in which exploration drilling is expected to start within about five years.

"Exploration drilling in additional prospects" comprises the estimated resources expected to become the target of exploration drilling in the long term.

Box 6.3

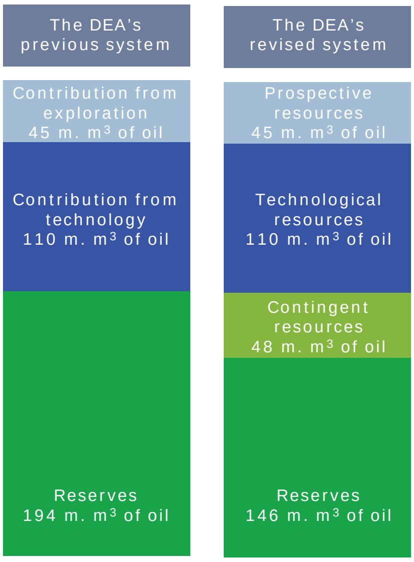
The formation of an oil or gas field is subject to a number of conditions being fulfilled. The most important preconditions are the existence of layers in which hydrocarbons have formed (a source rock) and that the hydrocarbons are trapped in porous reservoir layers, i.e. layers with many pores and thus considerable void space for hydrocarbons, for example. See also box 1.2 in chapter 1, *Licences and exploration*.

The oil companies' oil and gas exploration is based on the use of exploration models, known as **plays**. A play is a schematic account of how geologists expect the subsoil to look, and the general strata levels within which there may be the possibility of finding hydrocarbons. An example of a play is the model showing that there could be chalk deposits in the Central Graben of the North Sea from the Late Cretaceous period filled with oil from Upper Jurassic source rocks. An overview of the time periods is shown in appendix F.

As a general rule, there are areas within a play where there is a greater chance of finding hydrocarbons. Naturally, these areas are of particular interest and are called **leads** or exploration opportunities. Examples of leads include the chalk deposits above the salt structures in the Central Graben.

If further exploration of a lead suggests that there is the potential of finding sufficient quantities of hydrocarbons for financially viable recovery, this is referred to as a **prospect** or an exploration target. For example, this could be the salt structures that are demonstrated by seismic data to have porous chalk deposits.

Fig. 6.2 Comparison of assessments of Danish oil and gas resources according to the previous and revised systems (at 1 January 2010)



This categorization in the DEA's classification system differs from SPE's system, which subdivides prospective resources into prospects, leads and plays; see box 6.3. The DEA does not assess prospective resources on the basis of leads and plays, but instead estimates the quantity of resources expected to be subjected to exploration drilling in the long term.

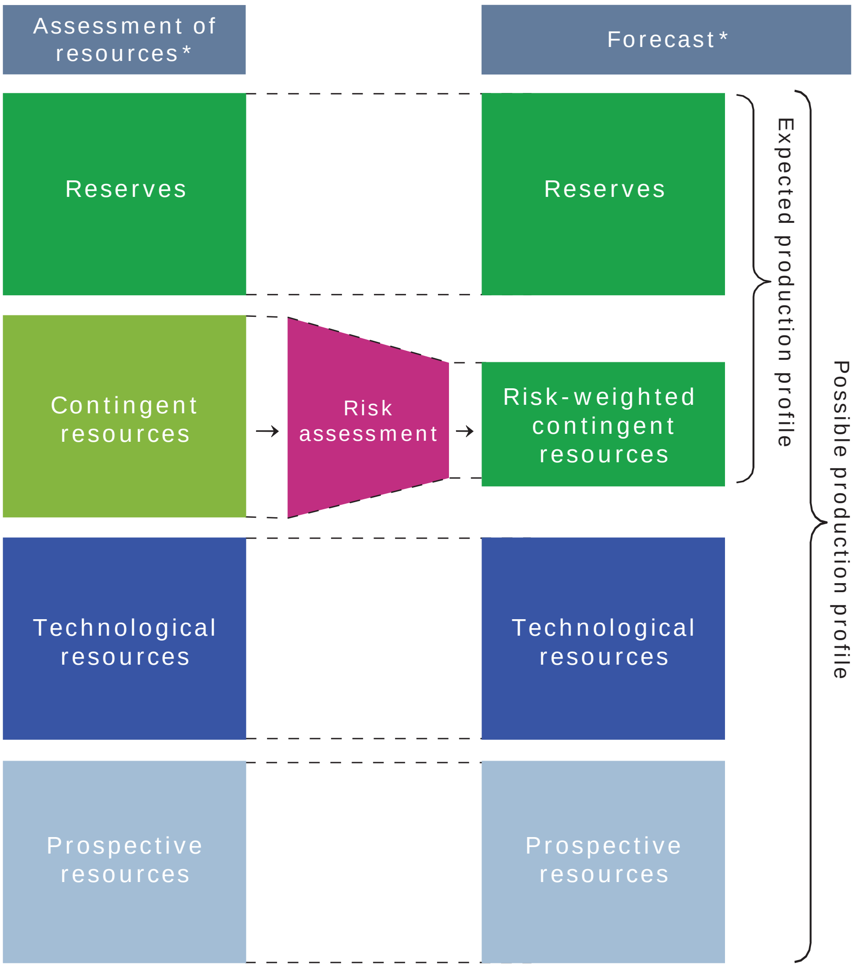
The content of the class "prospective resources" is unchanged and thus corresponds to the class "the contribution from exploration" in the DEA's previous system.

Figure 6.2 shows a comparison between the DEA's previous system and the revised system, showing the status of assessed resources as at 1 January 2010. It appears from the figure that a new class, contingent resources, has been introduced, which includes part of the class "reserves" in the previous system, which means that the sum total of reserves and contingent resources in the revised system equals the reserves class in the previous system.

Production forecasts

Based on the reserves and contingent resources classes in the classification system and total resources, the DEA prepares oil and gas production forecasts; see figure 6.3.

Fig. 6.3 Correlation between the DEA's assessment of resources and production forecast



* The assessment of resources and the forecast are shown with the colour code for oil.

As opposed to the reserves class, the development projects included in the contingent resources class are characterized by the uncertainty attaching to their implementation.

Therefore, a risk assessment of such development projects is made during the preparation of forecasts (forecasting), such that a probability from 0 to 1 of the project being implemented is estimated for each individual project. Subsequently, the recovery under each individual project is weighted with the estimated probability of development.

Discoveries are included in the contingent resources class. The discoveries not forming part of an exploration licence are accorded a development probability of 0. Such discoveries were not included in previous forecasts, either.

The resulting recoverable amount is termed risk-weighted contingent resources and is included in the basis for drawing up the expected production profile and the forecast of total resources; see figure 6.3. In connection with forecasting, it should be noted that the risk-weighted contingent resources are expected to be produced.

ASSESSMENT OF RESOURCES IN 2010

The quantities produced and the Danish resources assessed according to the DEA's classification system appear from table 6.1. Two figures are indicated for gas: net gas, which consists of future production less reinjection; and sales gas, which is future production less reinjection, gas used as fuel and gas flared. In the DEA's previous assessments, the quantity of net gas was indicated. The quantity of net gas is shown in the table to enable a comparison with the DEA's previous assessments. Sales gas is used in the resources assessments based on SPE's guidelines, for which reason the quantities of sales gas are also shown.

Table 6.1 Production and resources calculated at 1 January 2010

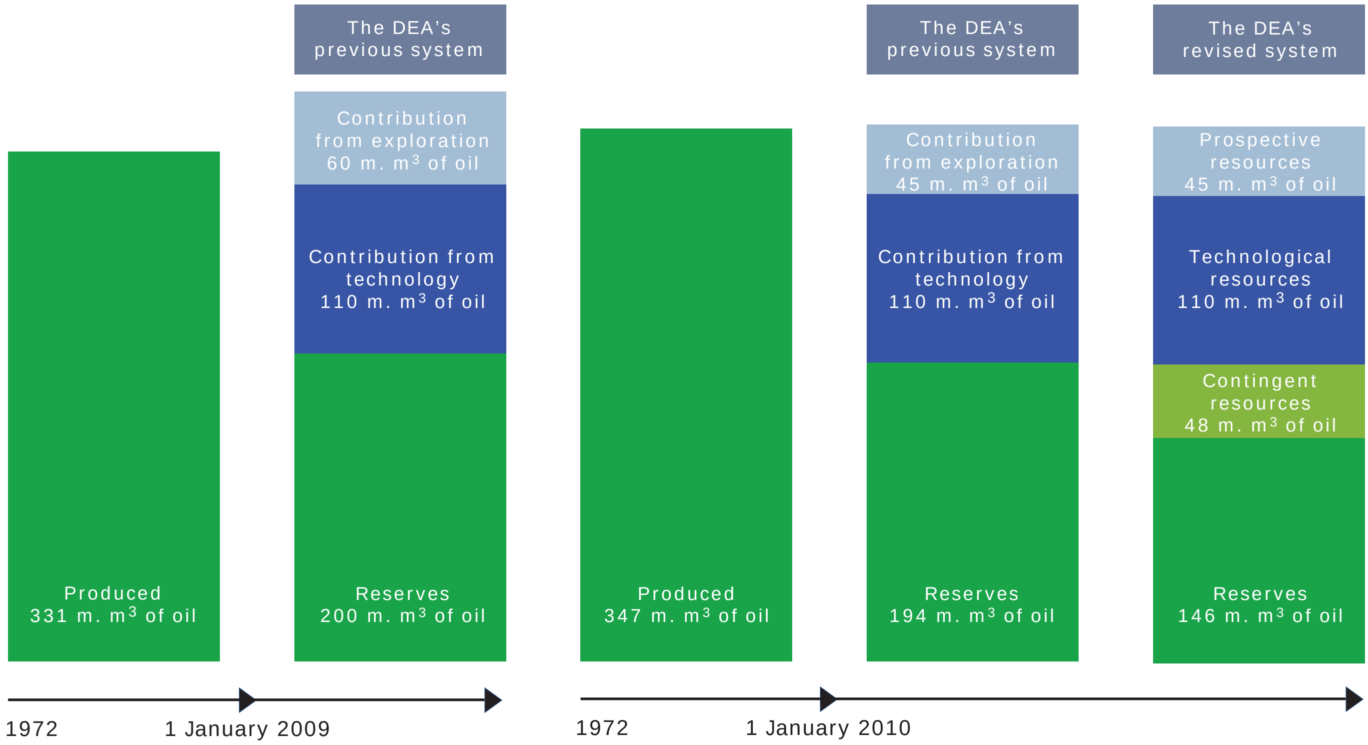
	Oil (m. m³)	**Net gas** (bn. Nm³)	**Sales gas** (bn. Nm³)
Produced	347	156	139
Reserves	146	79	64
Contingent resources	48	26	21
Technological resources	110		15
Prospective resources	45		30

A more detailed assessment of production, reserves and contingent resources appears from appendix C.

Production in 2009 consisted of 15.2 million m³ of oil and 8.1 billion Nm³ of net gas or 7.3 billion Nm³ of sales gas.

Figure 6.4 shows a comparison between last year's oil resources and the current assessment. The oil reserves of 200 million m³ in 2009 should be compared with the sum total of reserves and contingent resources of 194 million m³ in 2010. Oil production totalled 15.2 million m³ in 2009 and the estimate of future recovery has been adjusted upwards by 9 million m³, which results in a difference of 6 million m³ of oil between the two assessments. The upward adjustment of future recovery is due mainly to the inclusion of additional reserves attributable to the further development of the South Arne Field.

Fig. 6.4 Produced oil and oil resources



The estimate of enhanced oil recovery due to new technology, previously called the contribution from technological developments and now technological resources, is unchanged compared to last year's assessment.

Prospective oil resources have been assessed at 45 million m³. Compared to the previous assessment, oil resources have been written down by 15 million m³ due to revised evaluations based on new well data, among other things.

For the purpose of assessing net gas, the sum total of reserves and contingent resources of 105 billion Nm³ in 2010 must be compared with reserves of 107 billion Nm³ in 2009. Gas production in 2009 totalled 8.1 billion Nm³, and the estimate of future recovery has been written up by 6 billion Nm³, which means that the difference between the two assessments amounts to 2 billion Nm³ of gas. The upward adjustment of future recovery is due mainly to the assumption that the Tyra Field will produce for a longer period than previously anticipated.

In estimating the consumption of gas as fuel and gas flared, it has been assumed that the majority of the processing facilities, for example the Tyra facilities, are expected to produce during the forecast period. The total consumption of gas as fuel and gas flared for the reserves and contingent resources classes is estimated at 20 billion Nm³ of gas.

The estimate of gas recovered by means of new technology is 15 billion Nm³ and has been written up by 5 billion Nm³ compared to last year's assessment. The upward adjustment is attributable to the potential for developing new well technology.

Prospective gas resources have been estimated at 30 billion Nm^3 of gas, which is a 15 billion Nm^3 writedown compared to last year's assessment. As is the case for oil, the writedown is due to revised assessments made on the basis of new well data, among other things.

The resources assessment forms the basis for the DEA's preparation of oil and gas production forecasts.

PRODUCTION FORECASTS, SPRING 2010

The DEA prepares forecasts for expected Danish oil and gas production for five- and twenty-year periods, respectively.

The basis for the DEA's forecasts is an expected production profile, and in principle it is equally probable that the forecast turns out to be too optimistic or too pessimistic.

The DEA's forecasts of oil and gas production and of the investments and operating costs associated with production are used, among other things, for calculating expected state revenue from oil and gas production.

In addition, the DEA uses the oil and gas production forecasts together with its consumption forecasts to determine whether Denmark is a net importer or exporter of oil and gas. Denmark is a net exporter of energy when energy production exceeds energy consumption, calculated on the basis of energy statistics.

As mentioned in the section *Resources and forecast methodology*, production forecasts are prepared on the basis of assessed resources. As far as contingent resources are concerned, the resources assessment is adjusted by estimating the probability that the development projects comprised by the resources assessment will be implemented; see figure 6.3.

For oil, the risk assessment means that the difference between contingent resources and risk-weighted contingent resources ranges around 30 million m^3 of oil. About one third of this amount is attributable to resources in discoveries not comprised by an exploration licence, while the balance consists of a reduction resulting from the probability weighting of the development projects.

For the quantity of net gas, the risk assessment means that the difference between contingent resources and risk-weighted contingent resources ranges around 15 million m^3 of gas. Of this amount, about 10 billion Nm^3 of gas consists of resources in discoveries not comprised by an exploration licence, while the balance is a reduction resulting from the probability weighting of the development projects.

The expected production profile (see figure 6.3) forms the basis for the DEA's preparation of five-and twenty-year forecasts, including for determining whether Denmark is a net exporter or net importer of oil and gas.

To illustrate the potential for prolonging Denmark's period as a net exporter of oil and gas due to the use of new technology and new discoveries resulting from exploration activity, a forecast of total resources has been used as a basis for determining whether Denmark will be a net exporter or a net importer. The forecast based on total resources is termed the possible production profile; see figure 6.3.

Five-year production forecast

The DEA prepares five-year forecasts of oil and gas production to be used by the Danish Ministry of Finance for its forecasts of state revenue. The DEA publishes the five-year forecast in its report "Denmark's Oil and Gas Production and Subsoil Use". Moreover, the forecast is revised every autumn.

Oil

For 2010, oil production is expected to total 13.4 million m³, equal to about 230,000 barrels of oil per day; see table 6.2. This is a reduction of 12 per cent relative to 2009, when oil production totalled 15.2 million m³. Compared to last year's forecast for 2010, this is a 11 per cent downward adjustment, which is due mainly to lowered production estimates for the Halfdan and Nini Fields.

Oil production is expected to decline during the five-year period from 2010 to 2014. On average, the production forecast for the period from 2010 to 2014 has been written down by 10 per cent relative to last year's forecast. The writedown is due mainly to the risk assessment of the development projects and to the reassessment of development of the Rau discovery.

Sales gas

Sales gas production is estimated at 7.0 billion Nm³ for 2010; see table 6.2. Compared to last year's forecast for 2010, this is a 15 per cent downward adjustment, which is due mainly to lowered production estimates for the Tyra and Tyra Southeast Fields.

On average, the production forecast for the period from 2010 to 2014 has been written down by 22 per cent relative to last year's forecast. This writedown is also primarily attributable to lowered expectations for production from the Tyra and Tyra Southeast Fields during the forecast period. On the other hand, production from these fields is expected to increase later in the forecast period.

Table 6.2 Expected production profile for oil and sales gas

	2010	2011	2012	2013	2014
Oil, m. m³	13.4	12.8	11.3	10.1	10.0
Sales gas, bn. Nm³	7.0	5.3	4.3	3.7	4.5

Net exports/net imports in the next five years

Denmark has been a net exporter of energy since 1997. Denmark is a net exporter of energy when energy production exceeds energy consumption, calculated on the basis of energy statistics.

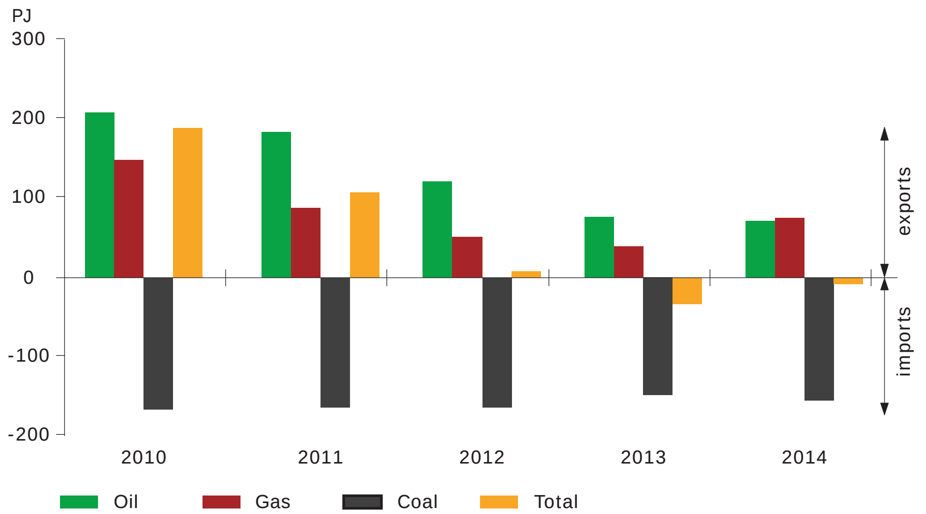
The consumption of different energy products is not distributed in the same way as energy production. Therefore, some products may be imported even though Denmark is a net exporter calculated on the basis of energy statistics.

In 2009, oil production exceeded oil consumption by 234 PJ (petajoule), while gas production exceeded gas consumption by 149 PJ. In 2009, the total production of oil, gas and renewable energy exceeded total energy consumption by 192 PJ.

Based on the production forecasts in table 6.2 and "*The DEA's baseline scenario, April 2010*", the expected development for Denmark as a net exporter/net importer of fos-

sil fuels (oil, gas and coal) is shown in figure 6.5 for the period from 2010 to 2014. In calculating the difference between total energy production and total energy consumption, it has been assumed in the DEA's baseline scenario that the production of renewable energy equals consumption, and therefore the contribution from renewable energy was not included when calculating the difference.

Fig 6.5 Denmark as a net exporter/net importer



The DEA's report "Denmark's Oil and Gas Production and Subsoil Use 08" included a table with degrees of self-sufficiency (table 6.2). This table has been included in the forecasts memorandum available at the DEA's website, www.ens.dk.

It appears from the figure that Denmark will be a net exporter of oil and gas during the forecast period, but based on total energy production relative to total energy consumption, Denmark is only expected to be a net exporter of energy up to and including 2012 due to its import of coal.

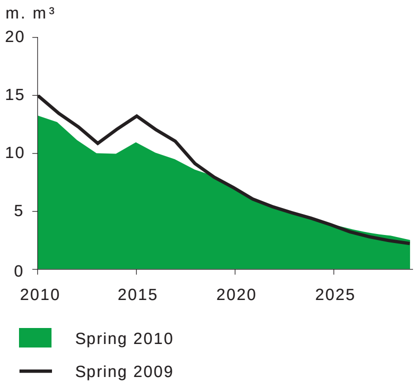
During the forecast period, Denmark will continue to be a net exporter of oil and gas, but the amount of net exports will decline. Net gas exports are forecast to reach the lowest level in 2013.

The gas supplied to Sweden derives from the Danish North Sea fields and is transported through Denmark. As expected Swedish consumption will exceed Danish net gas exports in 2013, it will be necessary to supplement Danish gas production from the North Sea by imported gas.

Twenty-year production forecast
Every year, the DEA prepares a 20-year forecast for the production of oil and sales gas, based on the expected production profile.

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. The reason is that all commercial development projects are implemented as quickly as possible. Therefore no development projects have been planned for the latter part of the forecast period, even though it must be assumed that

Fig. 6.6 Expected production profile, oil



development projects will also be undertaken during that period if the oil companies consider such projects to be commercial.

The expected production profile for oil shows a generally declining trend; see figure 6.6. However, production is expected to increase slightly in 2015 due to the development of new fields and the further development of some existing fields. Ten years from now, production is expected to constitute about 50 per cent of production in 2010.

The production profile in spring 2010 and the contribution from reserves assessed in spring 2009 are illustrated for oil in figure 6.6. The expected production profile assessed according to the DEA's revised classification system corresponds to the contribution from reserves according to the previous classification system. The reduction of the forecast has been made mainly on the basis of the risk assessment of development projects previously mentioned; see the section *Resources and forecast methodology*.

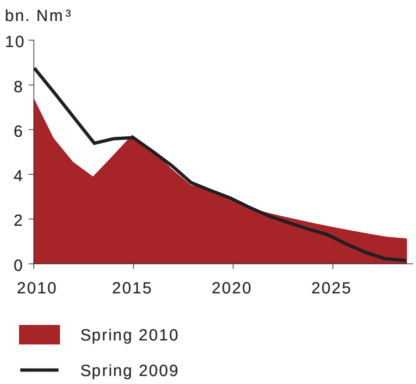
However, to some extent this decline may be curbed due to technological developments that may improve recovery from the fields and due to production from any new discoveries made as part of the ongoing exploration activity, including under the licences from the 6th Licensing Round and in the Open Door area; see chapter 1, *Licences and exploration*.

As opposed to oil, which is most frequently sold as individual tanker loads from the North Sea at the prevailing market price, the production of sales gas is subject to the condition that sales contracts have been concluded. Such contracts may either be long-term contracts or spot contracts for very short-term delivery of gas.

Since the start of gas sales in 1984, gas produced under A.P. Møller - Mærsk's Sole Concession has been supplied primarily under long-term 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. 6.7 Expected production profile, sales gas



To this should be added the gas production resulting from contracts for the export of gas through the pipeline from Tyra West via the NOGAT pipeline to the Netherlands; see also the section *Gas infrastructure and security of supply* regarding the volumes exported.

All the above-mentioned contributions have been included in the production forecast for sales gas. The forecast based on the expected production profile for sales gas is shown in figure 6.7. The forecast shows a generally declining trend, as is the case for oil. However, production is expected to increase substantially in 2014 and 2015 due to the development of new fields and the further development of some existing fields.

The expected production profile estimated in spring 2010 and the contribution from reserves assessed in spring 2009 are illustrated for sales gas in figure 6.7. Expected production has been reduced substantially during the first five years of the forecast

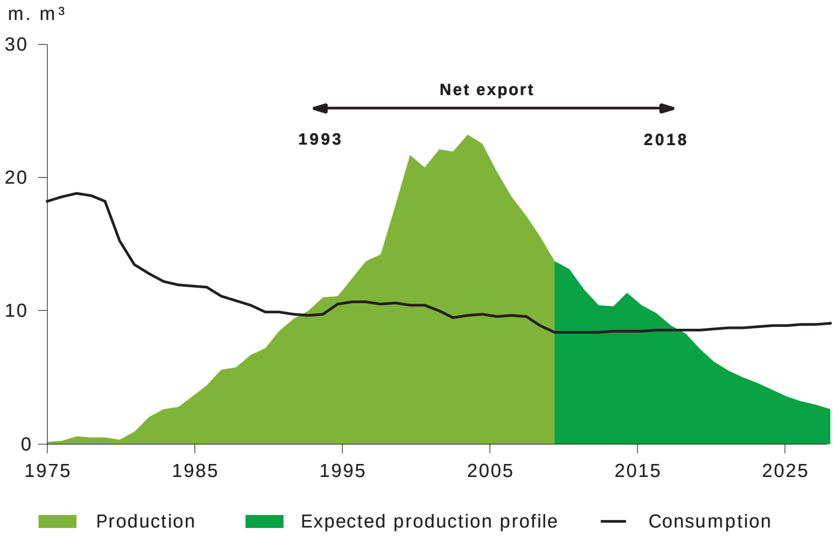
period and increased during the last part of the production period due to the reassessment of the production properties for the remaining part of production from the Tyra and Tyra Southeast Fields, as mentioned in the section about the five-year forecast. The production profile has also changed because the Tyra Field previously acted as a buffer, which meant that a gradually declining production profile was assumed for a number of fields, including Tyra, such that the difference between the overall profile and production from the remaining fields was produced by Tyra. The changed production properties mean that the Tyra Field cannot perform this function in future. Moreover, as is the case for oil, natural gas production has been reduced as a consequence of the risk assessment of development projects.

Net exports/net imports for the next 20 years

The DEA prepares forecasts for the consumption of oil and natural gas in Denmark. The DEA uses the oil and gas production forecasts together with its consumption forecasts to assess when Denmark is expected to cease being a net exporter. Denmark is a net exporter of energy when energy production exceeds energy consumption, calculated on the basis of energy statistics.

Figure 6.8 shows the amount of oil produced and historical consumption. In addition, the expected production profile and the DEA's consumption forecast appear from "*The DEA's baseline scenario, April 2010*".

Fig 6.8 Production and expected production profile, oil



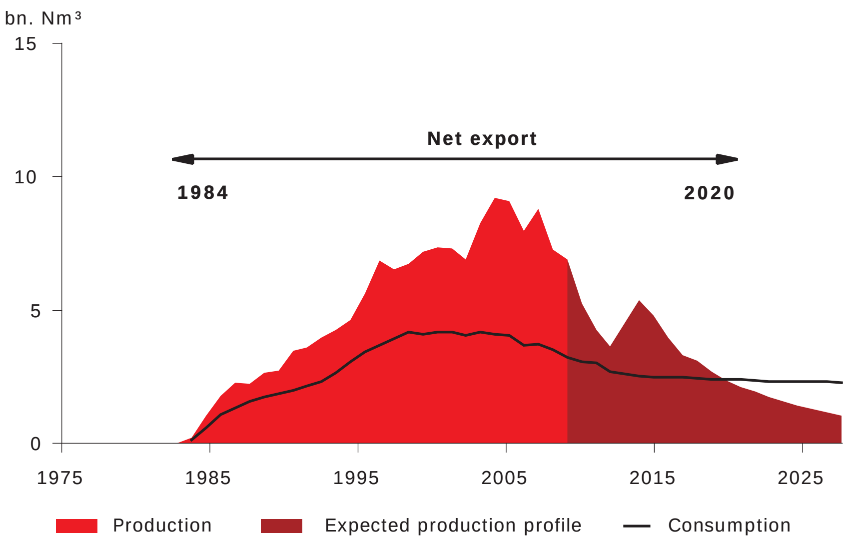
The DEA's baseline scenario is a scenario in which it is assumed that no initiatives will be taken other than those already decided. Therefore, the baseline scenario is not a forecast of future energy consumption, but a description of the development that could be expected during the period until 2030 based on a number of assumptions regarding technological developments, prices, economic trends, etc., assuming that no new initiatives or measures are taken.

The forecasts of consumption and production diverge significantly. The consumption forecast shows an almost constant trend, while the production forecast has a marked downward trend, apart from 2015 when production is expected to increase slightly. 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.

Based on these production assumptions, Denmark is expected to be a net exporter of oil up to and including 2018.

The sales gas forecasts have a profile similar to the one for oil. However, production is expected to increase substantially in 2014 and 2015. Denmark is expected to be a net exporter of sales gas up to and including 2020 based on the expected production profile; see figure 6.9.

Fig 6.9 Production and expected production profile, sales gas



According to international regulations, the consumption of fuel in connection with production must be included in the calculation of energy consumption, and a forecast of fuel consumption is therefore included in the DEA's baseline scenario. The fuel consumption forecast is updated in connection with updating the production forecasts. However, the production forecasts and consumption forecasts are not updated at the same time, so the DEA has chosen not to include fuel consumption in determining whether Denmark will be a net exporter/net importer.

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 as a net exporter of oil and sales gas; see the section *Net exports/net imports based on total resources* below.

Net exports/net imports based on total resources
A forecast based on total resources can be divided into the following contributions: Reserves, risk-weighted contingent resources, technological resources and prospective resources; see figure 6.3.

It should be emphasized that estimates of the technological resources and prospective resources are subject to great uncertainty.

The DEA's estimate of technological oil resources 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 originally in place.

Based on production, reserves and risk-weighted contingent resources, the average expected recovery factor for oil is 23.6 per cent.

The assumption that the average recovery factor for oil can be increased by five percentage points is based on an evaluation of historical developments. Thus, the average recovery factor increased by nine percentage points during the period from 1990 to 2000. There has been no significant increase in the recovery factor since 2000. However, it is very difficult to predict which new technologies will contribute to production in future and to estimate the amounts contributed by such technologies.

Most of the five 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 contribute to production during the period from 2020-25. The remaining contributions to increased production from other initiatives are assumed to be spread over the forecast period as from 2015. Compared to last year's forecast, the contribution from other technological initiatives has been reduced during the first part of the forecast period, as the implementation of such initiatives is expected to extend over a longer period than previously assumed.

Any new recovery methods must be implemented while the fields are still producing, as the introduction of new technology will usually not be financially viable once a field has been decommissioned. This means that a limited period is available for the development and introduction of new technology.

The DEA makes its estimate of prospective resources according to a method based on the exploration prospects known today in which exploration drilling is expected to take place. Moreover the method includes assessments of the additional prospects expected to be demonstrated during the forecast period.

The oil production forecast is divided into the three above-mentioned contributions: the expected production profile, technological resources and prospective resources; see figure 6.10. The figure also shows the consumption forecast from "*The DEA's baseline scenario, April 2010*".

It appears from the figure that Denmark is anticipated to be a net exporter of oil for nine years up to and including 2018, based on the production forecast. The period in which Denmark will be a net exporter can be assessed fairly reliably for the expected production profile, as the development in production 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 that includes technological resources and prospective resources varies somewhat from 2015 to around 2035, after which estimated produc-

Fig 6.10 Production and possible production profile, oil

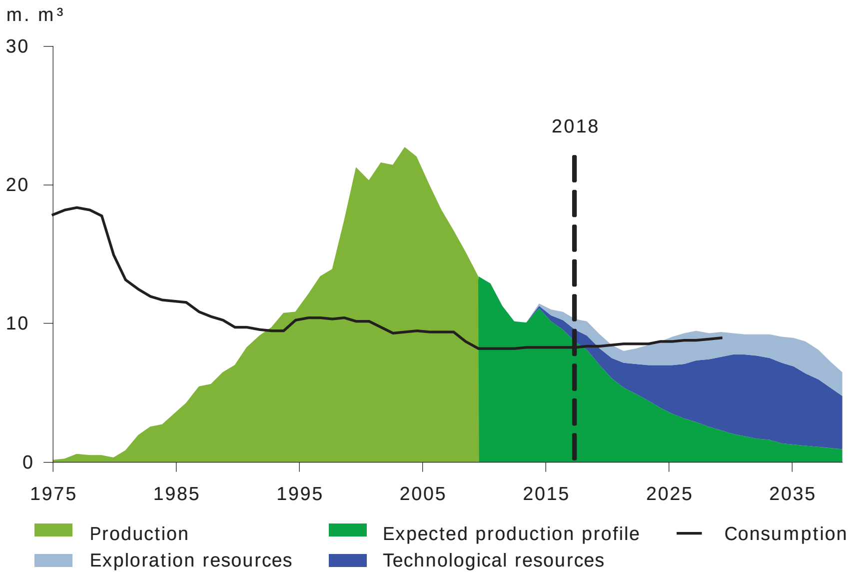
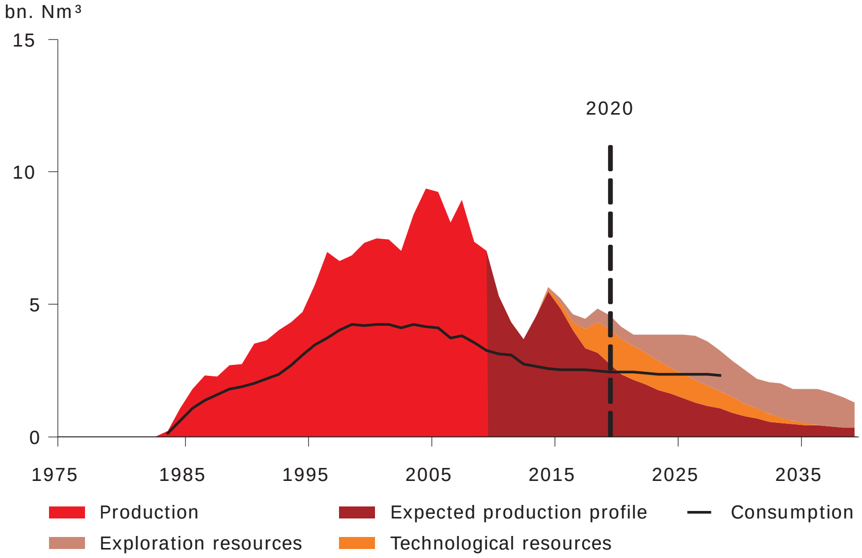


Fig 6.11 Production and possible production profile, sales gas



tion is expected to decline. If technological and prospective resources are included, they will contribute substantially to production from around 2020. The forecast means that after 2020 Denmark will alternate between being a net exporter and a net importer of oil until 2035.

Figure 6.11 shows the sales gas production forecast, divided into the expected production profile, technological resources and prospective resources. The figure also shows the consumption forecast from "*The DEA's baseline scenario, April 2010*". Denmark is anticipated to be a net exporter of natural gas for just over ten years up to and including 2020, based on the expected production profile.

For sales gas, the DEA anticipates no significant contribution from technological resources in producing fields because current technology has already generated a much higher recovery factor than for oil. However, a contribution reflecting the potential for developing new well technology has been included.

When including technological resources and prospective resources, the DEA estimates that Denmark will be a net exporter of gas for just over 20 years reckoned from 2010.

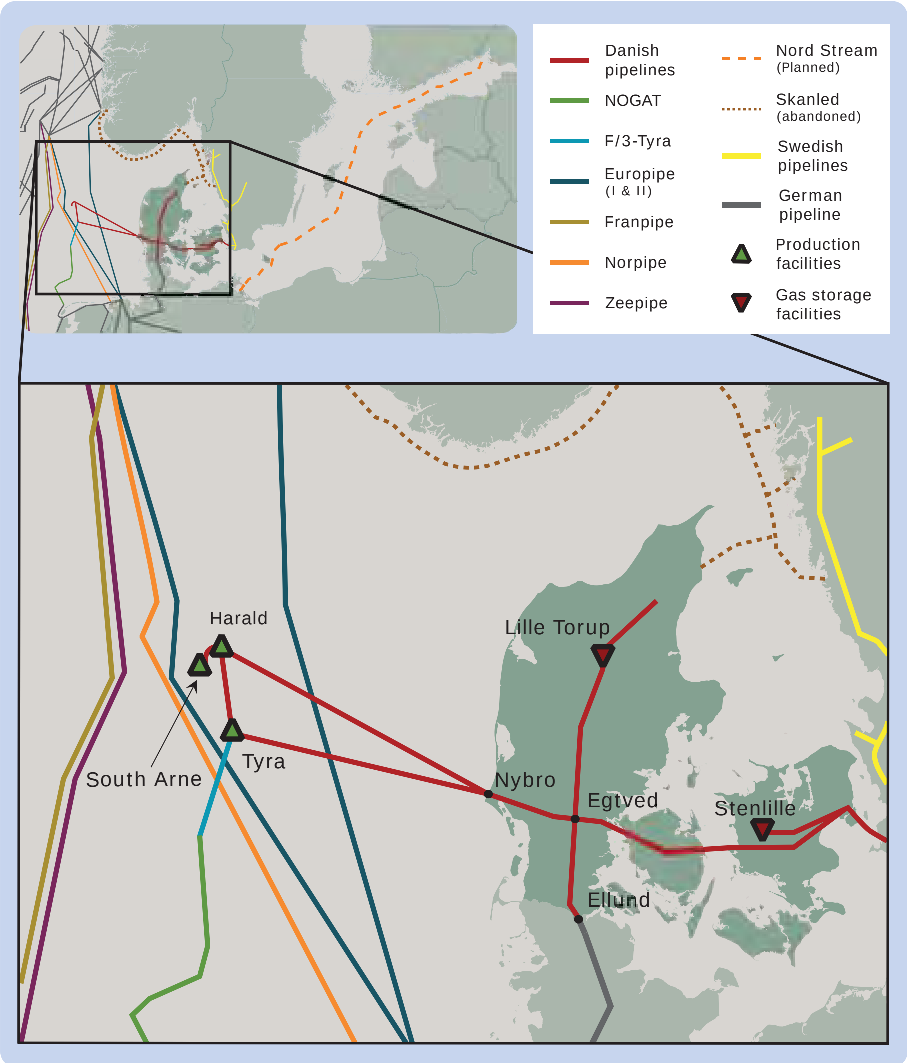
GAS INFRASTRUCTURE AND SECURITY OF SUPPLY

Denmark is currently a net exporter of gas, and this situation is expected to continue until 2020 inclusive. Gas represents a significant part of Danish energy supplies, and the security of gas supplies will therefore continue to be given a high priority on the political agenda in future.

Production of gas from the Danish North Sea fields and the Danish gas infrastructure

Gas from the Danish sector of the North Sea is primarily produced from the Tyra,

Fig. 6.12 Regional natural gas pipelines around Denmark



Halfdan, Dan and Tyra SE Fields. These fields account for around 75 per cent of the gas production. The gas is processed on the Tyra installation prior to being transported ashore.

The gas is transported ashore via two pipelines from the Tyra and South Arne Fields, respectively, to the gas-processing facilities at Nybro; see figure 6.12. The Tyra pipeline was commissioned in 1984, while the South Arne pipeline was commissioned in 1999. The security of supply was improved with the South Arne pipeline, as it is possible to redirect gas production from the Tyra facilities to the South Arne pipeline. In addition, a new pipeline was commissioned in 2004, connecting the Tyra facilities to the F/3 platform in the Dutch sector; see figure 6.12. The pipeline allows the transport of gas through the existing NOGAT pipeline to the Netherlands for the purpose of selling gas to the Dutch market. It is not currently possible to import gas into Denmark via the pipeline.

In 2009, sales gas production amounted to 7.3 billion m^3, of which around 3.5 billion m^3 was used in Denmark and around 3.8 billion m^3 was exported to Sweden, Germany and the Netherlands. Almost 1.6 billion m^3 was exported via the Tyra installation to the NOGAT pipeline, while around 1.2 billion m^3 was exported to Sweden. In addition, almost 1.1 billion m^3 of gas is exported to Germany by land. More information concerning gas production volumes from the Danish fields is given in Chapter 3, *Production and development*, and in appendix A.

The gas is transported in a pipeline network, which comprises the general gas transmission grid operated at a high pressure, and the gas distribution networks operated at lower pressures, transporting the gas to the consumers. The gas transmission grid was constructed in the early 1980s and consists of around 800 km of pipelines, 42 metering and regulating stations (M/R stations) and four metering stations. The main purpose of the M/R stations is to reduce the gas pressure from as much as 80 bar in the transmission grid to either 40 or 19 bar, which is the pressure at which the distribution networks operate.

Two natural gas storage facilities have been established in Denmark (see figure 6.12) with a total capacity of around 921 million m^3 of working gas. The storage facilities are primarily used to even out seasonal fluctuations, as the demand for natural gas is greatest during the winter, but are also used as emergency storage facilities in case of interruptions to gas deliveries. Energinet.dk has in excess of 150-175 million m^3 of stored gas available annually, which is used to balance the system and to function as emergency supplies.

The Danish gas transmission grid is connected to the German gas transmission grid at Ellund on the Danish/German border; see figure 6.12. In addition, the transmission network is connected to the Swedish gas system at Dragør; see figure 6.12. Sweden is solely supplied with gas via the Danish gas system.

Gas production forecast and new infrastructure needed for gas imports
Denmark is expected to be a net exporter of sales gas until 2020 inclusive; see figure 6.11. This projection is based on the production of assessed reserves and contingent resources as well as the consumption forecast from "*The DEA's baseline scenario, April 2010*". If technological resources and prospective resources are included (see the section *Resources and forecast methodology*), Denmark will be a net exporter for a longer period of time.

Considering that the Swedish market is supplied with gas through Denmark and that market conditions may lead Danish gas producers to sell Danish gas to foreign markets, there could be a need to import gas significantly earlier than 2020, when Denmark is anticipated to become a net importer; see above.

Therefore, the time at which it becomes necessary to import gas depends on a number of factors, including the consumption of gas, prices in both Danish and foreign gas markets, the capacity of the pipelines between Denmark and the foreign gas markets and the costs associated with transport. In addition, the potential for maintaining a satisfactorily high level of production during the winter months in order to meet demand will also have an effect on import requirements.

The commercial gas companies have more conservative expectations of Danish gas supplies from the North Sea than those contained in the DEA's production forecasts. This is because the assessments made by the companies only include the production to be supplied by the companies under contracts concluded. In cases where the companies enter into legally binding agreements with customers concerning the supply of gas, the gas companies need to have complete security that they can dispose of the necessary gas quantities to fulfil their obligations. In comparison, the DEA's forecast also contains potential, but as yet uncertain, supplies from fields that have not been brought on stream at the current time.

EU gas supply situation
The EU is expected to become increasingly dependent on gas supplies from third countries in the years ahead.

Exports of gas from Norway to other parts of Europe have been increasing, a trend most recently exemplified by the commissioning of the Ormen Lange Field.

In order to secure gas supplies to its Member States, the EU has also adopted a number of strategies, including prioritized pipeline projects known as Trans-European Networks. One of these projects is the so-called 'NG1 axis', which is a corridor for gas imports from Russia to the UK via continental Northern Europe. The Nord Stream connection (see also *Environmental Impact Assessment Projects in 2009* in Chapter 5, *Environment and climate*) from Vyborg in Russia to Greifswald in Germany is included in the establishment of this corridor (see figure 6.12) and will be able to transport 55 billion m³ of gas annually. This corresponds to around 11 per cent of the EU's anticipated annual gas consumption in 2011. The company behind Nord Stream expects to commence the installation of the pipeline in 2010. According to the plan, gas deliveries are expected to commence as early as the autumn of 2011, while the entire project will be completed in 2012. DONG Energy has purchased gas in Russia for delivery through the Nord Stream connection. The Nord Stream project is estimated to cost EUR 7.5 billion, which corresponds to around DKK 55.8 billion.

In addition, efforts are ongoing to establish a gas transport corridor to southern Europe. The objective of a southern corridor is to improve Europe's security of supply by ensuring access to new gas reserves. Moreover, the security of supply will be improved by having several supply routes in the event of interruptions.

In addition to the import of gas through pipelines, work is proceeding on the import of gas in liquid form known as LNG (Liquefied Natural Gas). This work is focusing on the establishment of new and existing LNG terminals in several EU countries, e.g.

Box 6.4

Open Season process
Open Season is the term for a procedure used by the operator of an infrastructure, e.g. the operator of a transmission system (often abbreviated to TSO), in order to clarify future transport capacity requirements. Users of the infrastructure are asked whether there is a demand for new or increased transport capacity, and whether they would contractually commit to using this capacity if the operator established it. There has been considerable variation in the different operators' organization of Open Season procedures. In Denmark, Energinet.dk is the operator of the overall gas transmission grid.

Rotterdam in the Netherlands and Swinoujscie in Poland, for the import of LNG from the Middle East, Algeria and other third countries. The potential for imports of LNG will also help to increase the EU's security of supply compared to the current situation with relatively few gas transport routes to the EU.

Access to foreign gas reserves
Denmark is geographically well positioned for receiving piped gas supplies. Supplies of Norwegian gas can be received by connecting Danish pipelines to existing hubs or to one of the five pipelines transporting Norwegian gas across the Danish continental shelf in the North Sea to the continent; see figure 6.12. Denmark's future gas imports will take place in competition with other European countries, yet there will also be a need for cooperation with our neighbouring countries in connection with the development of a common infrastructure.

The Skanled project was partly planned to transport gas through the Danish system; see figure 6.12. However, in April 2009 the operator of the Norwegian gas infrastructure, Gassco, announced that the partnership behind the Skanled project had decided to suspend the project due to the commercial risk and uncertainty regarding demand for gas. The Skanled project consisted of an offshore gas pipeline from Kårstø in Norway with a branch to Greenland south of Oslo; the pipeline was then to continue through the Kattegat with branches to the Gothenburg area and Sæby.

In January 2009, an Open Season process (see box 6.4) was launched by Energinet.dk, which is the operator of the overall Danish transmission grid. The objective of the process is to establish the requirements and wishes of the commercial gas companies for the transport of gas through the Danish system.

During the process, two stakeholders expressed a need for deliveries from Germany to meet the Danish/Swedish demand for gas around 2012/2013. The DEA's forecast of gas production from the North Sea also indicates that there will be a need for gas imports, as the anticipated production from the North Sea will not be able to meet demand in both Denmark and Sweden by around 2012/2013. The volume of imports depends on the proportion of Danish production that is exported to the Netherlands, among other factors.

The import of gas would require the establishment of new infrastructure. A decision has therefore been made to invest in a new compressor station, which would allow imports from Germany to Denmark. In addition, in spring 2010 a further analysis commenced with the participation of various stakeholders in the Danish gas market. The objective is to investigate the consequences for the North Sea producers of investing in a new pipeline, which would run parallel to the existing pipeline from Ellund to Egtved; see figure 6.12. Alternatively, import capacity could be created by making foreign gas imports possible via the existing platforms and pipelines in the North Sea. This analysis remained incomplete when this report went to press. Information on this topic will be available at the DEA's website (www.ens.dk) following completion of the analysis.

7 ECONOMY

Since 1997, Denmark has been a net exporter of energy due to the production of hydrocarbons mainly, but also because of energy savings and the utilization of renewable energy.

In many ways, oil and gas production 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 stakeholders in the oil and gas sector, and not least, it provides jobs for numerous people.

VALUE OF OIL AND GAS PRODUCTION

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

The oil price was 37 per cent lower in 2009 than in 2008, based on an average quotation of USD 61.6 for a barrel of Brent crude oil in 2009 against USD 97.2 in 2008.

Despite the substantial drop from 2008 to 2009, the oil price actually rose steadily through 2009. The oil price trend in 2009 appears from figure 7.1. Thus, the trend at the end of 2008, when the oil price dropped, has reversed. Figure 7.2, which shows the oil price development from 1972 to 2009, illustrates how the average oil price dropped from 2008 to 2009 after reaching its highest level since the end of the 1970s.

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 widened at the end of 2009.

The average dollar exchange rate in 2009 was DKK 5.4 per USD. This is an increase of almost 6 per cent compared to 2008 when the average dollar exchange rate was DKK 5.1 per USD. The dollar exchange rate in 2009 hovered at about the same level as in 2007, but was still substantially lower than the level of about DKK 6 per USD in the years 2004 to 2006.

The dollar exchange rate fluctuated greatly in 2009 and weakened towards the end of the year. While the oil price in USD rose significantly, the declining dollar exchange

Fig 7.1 Oil prices, 2009, USD and EUR

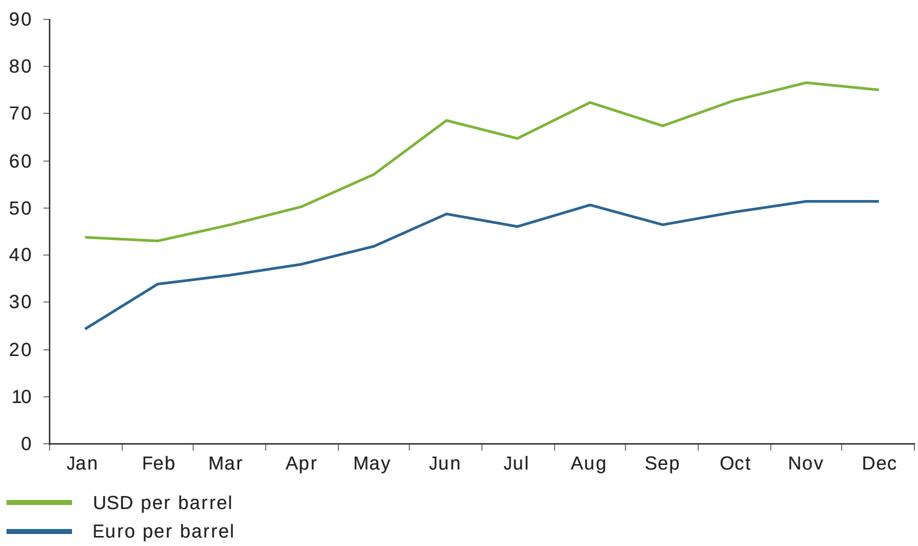
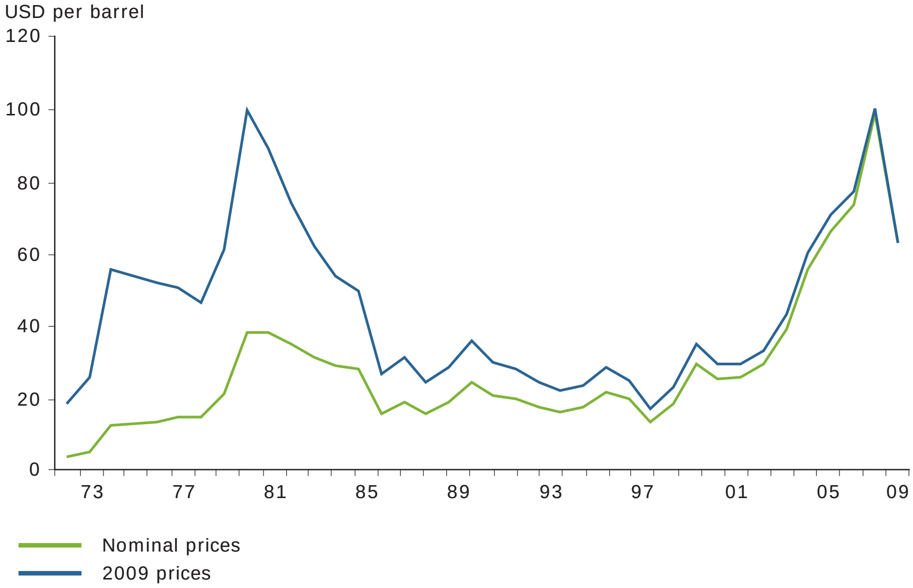


Fig 7.2 Oil price development 1972-2009



rate meant that the increase in terms of EUR – and thus DKK – was not as steep. The widening gap between the oil price in EUR and USD appears from figure 7.1. This illustrates that the dollar exchange rate strongly impacts how the oil price develops in USD.

The slightly increasing dollar exchange rate and the substantial drop in the oil price in USD compared to the average price in 2008 meant that the oil price in DKK decreased by almost 33 per cent from 2008 to 2009. The average price for a barrel of Brent crude oil in DKK fell from DKK 485.8 in 2008 to DKK 326.1 in 2009. The rising dollar exchange rate is the reason that the oil price drop is not fully reflected in DKK, compared to the drop in USD.

Two of the factors determining the value of oil and gas production, the oil price and the volume of production, decreased in 2009. At the same time, the increase in the third factor, the exchange rate, was too moderate to offset this decline. Overall, the value of Danish oil and gas production totalled DKK 43 billion in 2009, down 37 per cent on the year before.

According to preliminary estimates for 2009, oil production accounts for about DKK 31 billion and gas production for DKK 12 billion of the total production value.

The breakdown of oil production in 2009 on the ten producing companies in Denmark appears from figure 3.3 in chapter 3, *Production and development*.

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

Appendix D contains a detailed outline of financial key figures from 1972 to 2009.

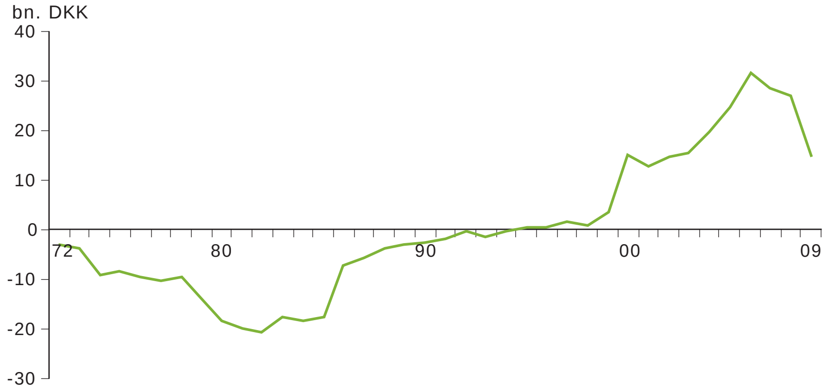
IMPACT OF PRODUCTION ON THE DANISH ECONOMY

Oil and gas production contributes to Denmark being a net exporter of energy. This export has a favourable impact on both the balance of trade and the balance of payments current account.

The balance of trade for oil and natural gas

Figure 7.3 shows the trend in Denmark's external trade in oil and natural gas. As appears from the figure, Denmark generated a surplus on the balance of trade for oil and natural gas in 1995 and has maintained a surplus ever since.

Fig 7.3 Balance of trade for oil and natural gas 1972-2009, nominal prices



The surplus amounted to DKK 14.6 billion in 2009 and thus remains at a sound level, although the lower production figure and falling oil price meant a decline compared to 2008, when the surplus amounted to DKK 27.1 billion.

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 three scenarios are based on an oil price of USD 75, 95 and 115 per barrel and a dollar exchange rate of DKK 5.02 per USD for the years 2010-2012. For 2013 and 2014, the dollar exchange rate is assumed to be DKK 5.25 and DKK 5.47 per USD, respectively. An oil price of USD 115 per barrel reflects the IEA's long-term oil price

Table 7.1 Impact of oil/gas activities on the balance of payments, DKK billion, 2009 prices, price scenario (95 USD/bbl)

	2010	2011	2012	2013	2014
Socio-economic production value	51.5	47.1	40.8	36.4	37.5
Import content	4.4	4.2	3.1	4.4	4.8
Balance of goods and services	47.1	42.9	37.7	31.9	32.7
Transfer of interest and dividends	11.0	9.9	9.3	8.8	8.5
Balance of payments current account	36.1	33.1	28.4	23.2	24.3
Balance of payments current account, low price scenario (75 USD/bbl)	30.2	27.3	23.5	18.9	20.1
Balance of payments current account, high price scenario (115 USD/bbl)	42.1	38.9	33.3	27.4	28.5

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

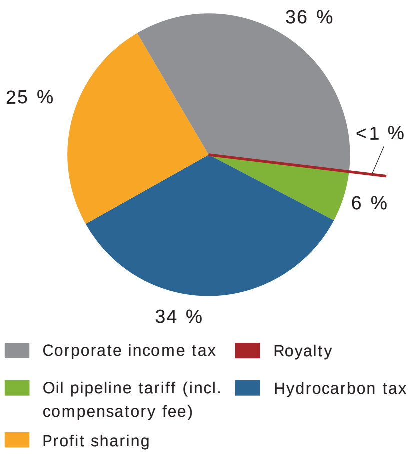
projection (2008 prices). The scenario of USD 75 per barrel corresponds fairly closely to the current oil price level.

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.

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 95 oil price scenario. The lower part of the table also shows the calculated impact on the balance of payments current account when using the price scenarios of USD 75 and USD 115 per barrel.

Assuming that the oil price is USD 95 per barrel, the oil and gas activities will have an estimated DKK 20-35 billion impact on the balance of payments current account per year during the period 2010-2014. Moreover, it appears that a higher oil price intensifies the impact, and vice versa.

Fig 7.4 State revenue in 2009



State revenue

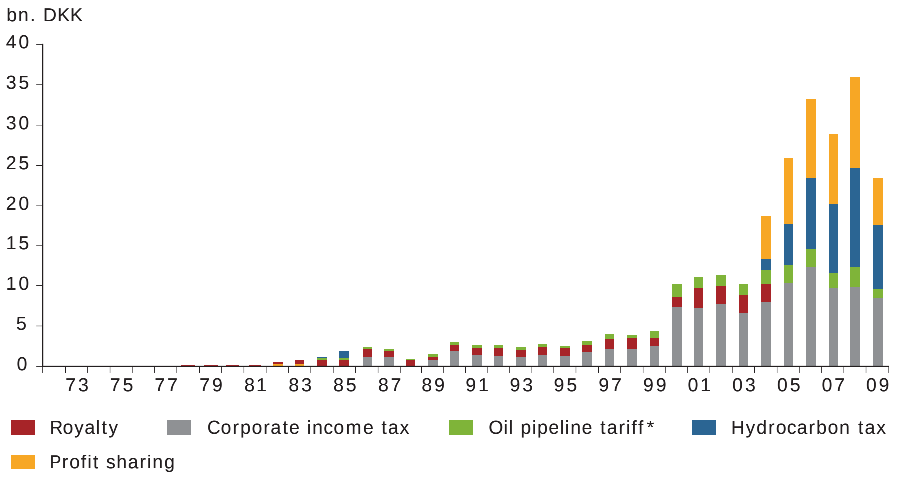
The Danish state derives proceeds from North Sea oil and gas production via direct revenue from various taxes and fees: corporate income tax, hydrocarbon tax, royalty, the oil pipeline tariff, compensatory fee and profit sharing.

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 about 36 per cent, corporate income tax is the main source of state revenue. Figure 7.4 shows the breakdown of state tax revenue in 2009.

Fig 7.5 Development in total state revenue from oil and gas production 1972-2009, 2009 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 2010. Detailed information appears from appendix E and the DEA's website, www.ens.dk.

Corporate income tax
Corporate income tax is the most important source 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. Danish 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 by purchasing additional licence shares on commercial terms. 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
The Danish state, represented by the Danish North Sea Fund, participates with a 20 per cent share in all new licences awarded as from 2005. In addition, the state will hold a 20 per cent share of DUC as from 9 July 2012. In principle, the transition from profit sharing to state participation has no impact on state revenue. 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 Danish North Sea Fund must first repay its debt and finance its continuous investments before any profits will accrue to the state. Further information about the Danish North Sea Fund is available at www.nordsoeen.dk.

State revenue from hydrocarbon production in the North Sea aggregated DKK 257 billion in 2009 prices in the period 1963-2009. Figure 7.5 shows the development in state revenue from 1972 to 2009. The cumulative production value was DKK 685 billion during the same period, while the aggregate value of the licensees' expenses for exploration, field developments and operations was DKK 263 billion.

Falling production and a declining oil price characterized the development in 2009, and total state revenue for 2009 is estimated at DKK 24.6 billion, a 31 per cent drop from the record level in 2008. Despite this decrease, state revenue has been maintained at a high level.

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

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

	2005	2006	2007	2008	2009**
Hydrocarbon tax	4,854	8,282	8,245	12,405	8,254
Corporate income tax	9,661	11,738	9,475	10,092	8,876
Royalty	1	1	2	2	0
Oil pipeline tariff*	2,052	2,156	1,815	2,511	1,432
Profit sharing	7,595	9,322	8,348	11,145	6,027
Total	**24,163**	**31,499**	**27,885**	**36,155**	**24,588**

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

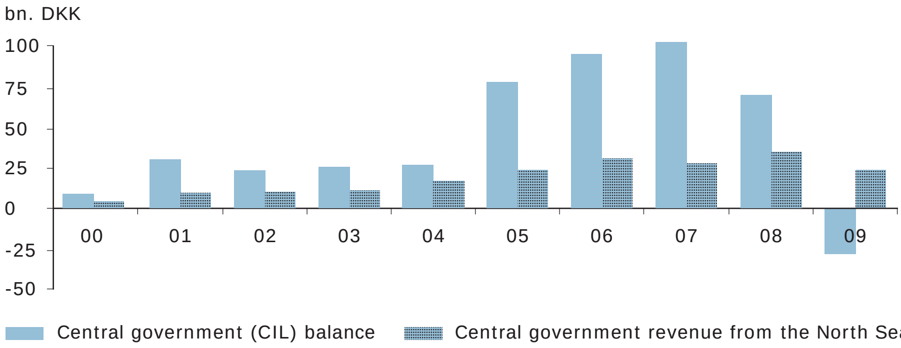
State revenue has grown substantially since 2003 on account of the higher oil price level. Another reason for this growth is that the Danish Government concluded an agreement with A.P. Møller - Mærsk, the so-called North Sea Agreement, in 2003. The agreement involved a restructuring of tax allowances,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

The state's share of oil company profits is estimated at 63 per cent for 2009, 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. The rules regarding the hydrocarbon allowance mean that companies taxed according to the old rules do not pay hydrocarbon tax in practice. 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 central government balance on the current investment and lending account. As appears from the figure, state revenue from the Danish part of the North Sea contributed largely to reducing the central government deficit in 2009.

For the next five years, the Ministry of Taxation estimates that the state's revenue will range from DKK 21 to DKK 27 billion per year from 2010 to 2014, based on the USD 95 oil price scenario. Table 7.3 shows the development in expected state revenue for the three different oil price scenarios of USD 75, 95 and 115 per barrel. It also appears from the table that the state's share of profits increases when the oil companies generate increasing earnings due to higher oil prices, for example. The revenue

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



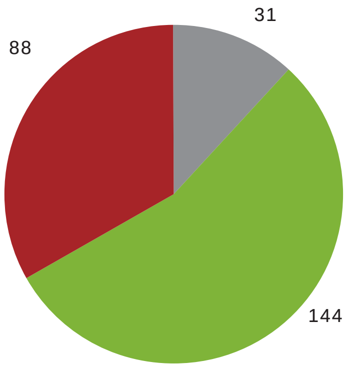
Note: The CIL balance (central government balance on the current investment and lending account) is the difference between total central government revenue and total central government expenditure

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

		2010	2011	2012	2013	2014
Corporate income tax base before taxes, fees and profit sharing	115 USD/bbl	55.8	51.1	44.0	40.2	43.4
	95 USD/bbl	44.3	40.3	34.6	31.5	33.9
	75 USD/bbl	32.7	29.5	25.3	22.8	24.4
Corporate income tax	115 USD/bbl	11.0	10.0	9.5	10.0	10.7
	95 USD/bbl	8.6	7.8	7.5	7.8	8.4
	75 USD/bbl	6.3	5.7	5.4	5.6	6.0
Hydrocarbon tax	115 USD/bbl	10.9	9.9	10.8	12.4	13.2
	95 USD/bbl	8.3	7.5	8.2	9.6	10.2
	75 USD/bbl	5.6	5.0	5.6	6.7	7.2
Profit sharing	115 USD/bbl	9.6	8.9	4.7	0.0	0.0
Danish North Sea Fund post-tax profits**	115 USD/bbl	0.0	0.0	1.3	2.5	2.7
	95 USD/bbl	7.7	7.1	3.8	0.0	0.0
	95 USD/bbl	0.0	0.0	1.0	2.0	2.2
	75 USD/bbl	5.8	5.3	2.8	0.0	0.0
	75 USD/bbl	0.0	0.0	0.8	1.5	1.6
Royalty	115 USD/bbl	0.0	0.0	0.0	0.0	0.0
	95 USD/bbl	0.0	0.0	0.0	0.0	0.0
	75 USD/bbl	0.0	0.0	0.0	0.0	0.0
Oil pipeline tariff***	115 USD/bbl	2.3	2.2	1.1	0.4	0.5
	95 USD/bbl	1.9	1.8	0.9	0.3	0.4
	75 USD/bbl	1.5	1.5	0.7	0.3	0.3
Total	115 USD/bbl	33.8	31.0	27.4	25.3	27.2
	95 USD/bbl	26.5	24.2	21.3	19.7	21.2
	75 USD/bbl	19.2	17.4	15.3	14.1	15.2
The state's share (per cent)	115 USD/bbl	60.6	60.8	62.3	62.9	62.6
	95 USD/bbl	59.9	60.1	61.6	62.6	62.5
	75 USD/bbl	58.7	59.0	60.4	61.9	62.4

** Assumed annual inflation rate of 1.8 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. 7.7 All licensees' total costs, 1963-2009, DKK billion, 2009 prices



DUC is an abbreviation of Dansk Undergrunds Consortium, which is composed of the companies A.P. Møller - Mærsk (39 per cent), Chevron Denmark Inc. (15 per cent) and Shell Olie- og Gasudvinding Danmark BV (46 per cent).

from the Danish North Sea Fund is included as of 2012 at the same time as revenue from profit sharing is phased out. This is because the Danish state, via the Danish North Sea Fund, 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, uncertainties are attached 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.

Figure 7.7 shows the breakdown of the licensees' costs during the period from 1963 to 2009. Investments in the development of existing and new fields account for more

Box 7.2

DUC's production and accounting figures

The production figures for 2004 to 2008 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. m³		Gas production bn. Nm³	
	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
2008	14.5	16.7	8.7	8.9

The DUC companies' pre-tax profits for 2004-2008 are summarized in table 7.5. The figures for 2009 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)

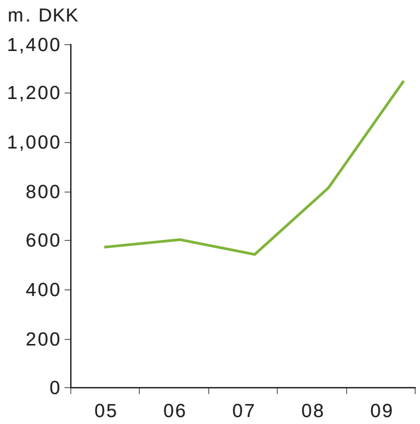
	2004	**2005**	**2006**	**2007**	**2008**
Revenue	32,252	45,765	54,355	51,829	61,505
Operating costs*	2,724	4,161	4,575	4,512	5,219
Interest expenses, etc.	171	215	233	187	2
Foreign-exchange adjustments**	1,129	1,212	67	578	-1,563
Gross profit	28,228	40,177	49,480	46,552	57,847
Depreciation and amortization	3,164	3,622	4,262	3,987	3,947
Profit before taxes and fees	**25,064**	**36,555**	**45,218**	**42,565**	**53,900**

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

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 2008. When the figures for 2009 become available, they will be submitted to the Energy Policy Committee of the Danish Parliament and published on the DEA's website.

Fig. 7.8 Exploration costs 2005-2009, nominal prices



Exploration costs

Figure 7.8 illustrates the development in exploration costs from 2005 to 2009. The preliminary figures for 2009 show that exploration costs increased about 52 per cent from 2008 to 2009, the reason being that more deep exploration wells were drilled in 2009. For 2009, total exploration costs are preliminarily estimated at DKK 1.25 billion.

In 2010-2011, investments in exploration are expected to total about DKK 2.1 billion. The activities will include further exploration under the licences from the 6th Licensing Round and appraisal activities in connection with the Svane discovery. Preliminary forecasts and budgets indicate that activities will subsequently diminish.

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 7 billion in 2009, up DKK 1.17 billion on the previous year. Compared to annual investments in field developments in the past ten years, averaging about DKK 5.5 billion, the investment level has increased substantially. Table 7.6 illustrates investments in field developments over the period 2005-2009.

Table 7.6 Investments in field developments, 2005-2009, DKK million, nominal prices

	2005	2006	2007	2008	2009*
Cecilie	-18	7	7	12	11
Dagmar	0	0	0	0	0
Dan	750	684	436	411	348
Gorm	291	303	158	265	240
Halfdan	683	1,244	2,112	1,824	3,674
Harald	53	1	4	20	192
Kraka	0	0	2	0	0
Nini	163	35	183	565	1,673
Roar	0	0	0	0	0
Rolf	0	1	2	25	5
Siri	73	153	210	557	103
Skjold	11	4	15	12	8
South Arne	310	31	1,087	6	132
Svend	0	0	0	0	0
Tyra	1,020	1,426	624	479	633
Tyra Southeast	45	45	384	459	0
Valdemar	553	991	1,313	1,243	31
NOGAT Pipeline	12	-	-	-	-
Not allocated	5	80	-14	1	-
Total	**3,956**	**5,006**	**6,524**	**5,879**	**7,050**

** Estimate*

Table 7.7 Estimated investments in development projects, 2010-2014, DKK billion, 2009 prices

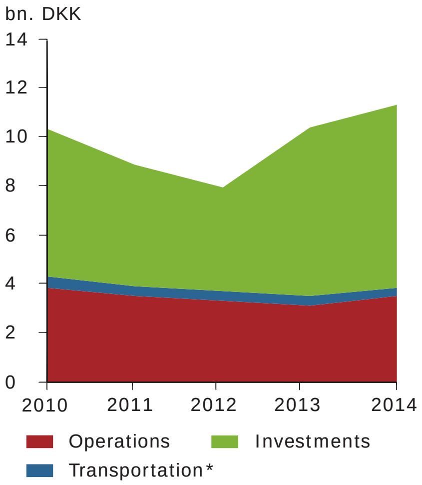
	2010	2011	2012	2013	2014
Ongoing and approved					
Adda	0.07	-	-	-	-
Alma	0.48	-	-	-	-
Boje	-	0.30	-	0.30	-
Cecilie	0.03	0.02	0.01	0.01	0.01
Dagmar	-	-	-	-	-
Dan	0.29	0.18	0.11	0.11	0.11
Elly	-	0.37	0.57	1.27	0.65
Gorm	0.00	-	-	-	-
Halfdan	1.41	0.13	-	-	0.07
Harald	0.00	-	-	-	-
Kraka	0.27	-	-	-	-
Lulita	-	-	-	-	-
Nini	0.14	0.38	0.05	0.04	0.05
Regnar	-	-	-	-	-
Roar	-	-	-	-	-
Rolf	-	-	-	-	-
Siri	0.21	0.10	0.08	0.04	0.05
Skjold	-	-	-	-	-
South Arne	0.88	0.07	0.01	0.01	0.01
Svend	-	-	-	-	-
Tyra	0.72	0.88	0.40	1.30	1.04
Tyra Southeast	-	-	-	-	-
Valdemar	1.10	0.63	-	-	-
Total	**5.60**	**3.06**	**1.23**	**3.08**	**1.98**
Justified for development	0.08	1.12	2.18	3.03	3.85
Risk-weighted contingent resources	0.40	0.82	0.89	0.85	1.67
Expected	**6.07**	**5.00**	**4.30**	**6.96**	**7.50**

In 2009, the development activities in the Halfdan and Nini Fields represented the bulk of investments, accounting for about 78 per cent of total investments in 2009.

Table 7.7 shows the DEA's estimate of investments in development activity for the period from 2010 to 2014. The estimate is based on the resource categories ongoing recovery, approved for development and justified for development as well as risk-weighted contingent resources. This is the first time that contingent resources have been risk weighted in the annual report. The risk weighting of contingent resources has resulted in a writedown of the investment level for this category; see chapter 6, *Resources*, for further information about the DEA's assessment of resources.

However, the DEA has generally adjusted its estimate of future investments upwards for the period 2010-2014 compared to its forecast in the last annual report. The main reason for this upward adjustment is increased activity in the Tyra and South Arne Fields. The increase in investments more than offsets the negative effect from the risk weighting of contingent resources on the estimated investment level. Nevertheless, the investment level is expected to be adjusted downwards in 2010, due mainly to Rau no longer being included in the forecast and the effect of risk weighting.

Fig. 7.9 Investments in fields and operating and oil transportation costs, 2009 prices



Excl. pipeline tariff/compensatory fee

Operating, administration and transportation costs

For 2009, the DEA has calculated operating, administration and transportation costs at DKK 4.5 billion, a decline of about 16 per cent compared to the year before. This decline is partly attributable to extensive maintenance work being carried out in 2008.

Figure 7.9 illustrates the DEA's estimate of developments in investments and operating and transportation costs for the period 2009-2014. Operating and transportation costs are expected to decline slightly until 2013 and subsequently to increase slightly in 2014.

CONTENTS - APPENDICES

APPENDIX A: AMOUNTS PRODUCED AND INJECTED

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

	1972-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
Dan	43,744	6,599	6,879	6,326	5,929	6,139	5,712	5,021	4,650	4,241	3,549	98,789
Gorm	37,041	3,110	2,180	2,887	2,838	2,469	1,978	1,897	1,639	1,053	924	58,016
Skjold	29,069	1,975	1,354	1,659	1,532	1,443	1,310	1,214	1,015	989	918	42,479
Tyra	17,519	1,000	872	801	918	723	773	845	764	551	415	25,180
Rolf	3,544	83	51	51	104	107	79	89	103	78	76	4,366
Kraka	3,072	350	253	157	139	199	211	222	176	112	37	4,927
Dagmar	978	8	4	6	7	2	0	-	-	0	-	1,005
Regnar	800	14	33	18	19	19	16	11	0	-	-	930
Valdemar	1,023	77	181	353	435	491	423	470	881	1,268	1,410	7,013
Roar	1,333	285	317	175	121	98	94	51	35	28	30	2,567
Svend	3,347	576	397	457	280	326	324	296	299	278	195	6,774
Harald	3,816	1,081	866	578	425	314	237	176	139	114	65	7,810
Lulita	367	179	66	24	20	19	35	68	55	47	24	904
Halfdan	222	1,120	2,965	3,718	4,352	4,946	6,200	6,085	5,785	5,326	5,465	46,184
Siri	1,593	2,118	1,761	1,487	925	693	703	595	508	598	326	11,306
South Arne	757	2,558	2,031	2,313	2,383	2,257	2,371	1,869	1,245	1,139	1,164	20,087
Tyra SE	-	-	-	493	343	580	614	446	377	429	374	3,655
Cecilie	-	-	-	-	166	310	183	116	88	66	38	966
Nini	-	-	-	-	391	1,477	624	377	323	355	159	3,706
Total	**148,226**	**21,134**	**20,207**	**21,505**	**21,327**	**22,612**	**21,886**	**19,847**	**18,084**	**16,672**	**15,169**	**346,668**

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

	1972-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
Dan	15,131	1,186	1,049	945	786	764	651	561	456	467	364	22,362
Gorm	12,865	426	306	480	339	216	218	207	175	119	109	15,458
Skjold	2,550	158	104	123	92	77	93	77	69	60	58	3,461
Tyra	50,377	3,826	3,749	3,948	3,994	4,120	3,745	3,792	3,916	3,130	2,007	86,605
Rolf	150	4	2	2	4	5	3	4	4	3	3	183
Kraka	950	119	100	52	25	23	24	28	28	36	8	1,392
Dagmar	148	2	1	1	3	2	0	-	-	0	-	158
Regnar	52	1	3	1	2	2	1	1	0	-	-	63
Valdemar	426	55	78	109	151	218	208	208	355	593	510	2,912
Roar	6,003	1,407	1,702	1,052	915	894	860	489	367	417	398	14,505
Svend	386	75	48	61	43	38	34	28	28	24	16	780
Harald	6,709	2,811	2,475	2,019	1,563	1,232	1,091	927	781	690	400	20,698
Lulita	250	160	27	6	5	5	13	38	33	30	15	581
Halfdan	37	178	522	759	1,142	1,449	2,582	2,948	2,675	3,104	3,401	18,797
Siri	142	197	176	157	110	64	112	55	47	63	44	1,165
South Arne	167	713	774	681	544	461	485	366	234	225	271	4,921
Tyra SE	-	-	-	447	452	1,233	1,337	1,108	848	889	939	7,253
Cecilie	-	-	-	-	14	22	13	8	6	4	2	69
Nini	-	-	-	-	29	109	46	28	24	26	12	274
Total	**96,340**	**11,316**	**11,116**	**10,844**	**10,213**	**10,934**	**11,517**	**10,873**	**10,046**	**9,879**	**8,559**	**201,637**

The monthly production figures for 2009 are available at the DEA's website www.ens.dk

Fuel*

GAS *million normal cubic metres*

	1972-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
Dan	1,046	179	184	182	198	201	205	209	222	225	207	3,058
Gorm	1,610	142	111	146	135	137	124	124	132	117	116	2,893
Tyra	1,879	229	243	245	242	249	247	241	228	233	219	4,254
Dagmar	21	-	-	-	-	-	-	-	-	-	-	21
Harald	32	13	10	9	8	8	7	8	7	7	4	114
Siri	8	21	22	21	20	19	20	25	25	25	19	226
South Arne	3	32	34	45	49	45	52	53	58	53	52	476
Halfdan	-	-	-	-	-	20	39	39	39	38	39	214
Total	**4,599**	**618**	**604**	**648**	**652**	**679**	**694**	**697**	**711**	**699**	**656**	**11,256**

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*

	1972-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
Dan	1,632	67	79	55	71	37	23	32	30	25	17	2,067
Gorm	1,229	66	88	81	66	57	61	61	48	41	19	1,816
Tyra	679	58	68	61	54	63	55	54	56	44	32	1,223
Dagmar	125	2	1	1	3	2	0	-	-	0	-	135
Harald	108	7	11	3	1	1	1	2	2	2	2	141
Siri	73	9	15	9	23	65	15	6	7	7	4	232
South Arne	114	41	9	11	12	11	14	11	11	7	7	248
Halfdan	-	-	-	-	4	25	16	20	17	8	4	93
Total	**3,960**	**250**	**270**	**222**	**234**	**262**	**184**	**186**	**170**	**132**	**85**	**5,955**

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

	1972-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
Gorm	8,088	45	4	14	6	4	3	0	-	-	-	8,164
Tyra	20,286	3,104	2,773	2,535	2,312	1,612	1,285	761	1,094	119	451	36,330
Siri**	61	167	139	127	109	111	135	61	45	61	35	1,051
Total	**28,435**	**3,316**	**2,916**	**2,676**	**2,428**	**1,727**	**1,423**	**821**	**1,139**	**180**	**486**	**45,545**

Sales*

	1984-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
Dan	13,492	1,238	1,412	1,521	1,679	1,681	1,804	1,862	1,653	1,293	947	28,580
Gorm	4,638	334	209	364	228	99	126	103	66	23	33	6,223
Tyra	34,347	1,971	2,493	2,776	2,948	4,580	4,598	4,574	4,143	4,652	3,163	70,246
Harald	6,818	2,950	2,482	2,013	1,558	1,228	1,096	954	804	710	408	21,021
South Arne	50	640	730	625	483	406	419	302	168	167	212	4,204
Halfdan	-	-	-	-	4	274	1,172	1,370	1,215	2,020	2,560	8,614
Total	**59,345**	**7,133**	**7,326**	**7,299**	**6,900**	**8,267**	**9,215**	**9,164**	**8,049**	**8,865**	**7,324**	**138,887**

*) 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*

	1972-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
Fuel	10,479	1,476	1,459	1,577	1,591	1,642	1,694	1,675	1,690	1,670	1,572	26,523
Flaring	9,260	645	646	535	564	664	457	470	449	354	241	14,285
Total	**18,740**	**2,122**	**2,104**	**2,112**	**2,154**	**2,306**	**2,151**	**2,144**	**2,139**	**2,025**	**1,813**	**39,810**

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 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*

	1972-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
Dan	15,266	5,277	6,599	6,348	7,183	8,053	9,527	10,936	12,152	13,946	12,889	108,177
Gorm	18,798	3,980	3,353	4,017	4,420	5,173	5,252	4,822	4,708	3,976	4,737	63,236
Skjold	17,495	4,333	2,872	3,007	3,525	3,688	4,270	4,328	3,885	3,636	3,855	54,894
Tyra	14,318	3,046	2,545	2,261	3,039	2,977	3,482	3,150	2,725	3,103	2,677	43,322
Rolf	3,570	358	181	168	270	308	290	316	383	349	381	6,572
Kraka	2,044	256	352	306	208	426	320	297	359	436	183	5,187
Dagmar	2,942	241	102	160	375	90	3	-	-	13	-	3,927
Regnar	1,873	139	475	257	316	396	352	255	1	-	-	4,064
Valdemar	246	48	150	272	310	325	792	937	854	925	812	5,669
Roar	455	317	386	301	476	653	662	498	560	586	624	5,518
Svend	921	1,355	954	1,051	1,330	1,031	1,309	1,205	1,200	1,022	804	12,182
Harald	21	39	98	78	43	15	12	12	18	21	11	368
Lulita	8	11	23	14	14	15	38	92	96	91	49	450
Halfdan	56	237	493	367	612	2,099	2,825	3,460	4,086	4,766	4,814	23,815
Siri	319	1,868	2,753	3,041	2,891	1,641	1,683	2,032	2,528	2,686	1,778	23,219
South Arne	15	58	112	370	857	1,127	1,790	1,830	1,861	2,174	2,334	12,529
Tyra SE	-	-	-	250	596	466	437	377	669	602	716	4,113
Cecilie	-	-	-	-	25	331	637	651	576	456	266	2,941
Nini	-	-	-	-	0	63	730	822	619	660	522	3,417
Total	**78,347**	**21,564**	**21,449**	**22,268**	**26,490**	**28,875**	**34,410**	**36,019**	**37,280**	**39,448**	**37,452**	**383,601**

Injection

	1972-99	2000	2001	2002	2003	2004	2005	2006	2007	2008	2009	Total
Dan	56,209	17,464	18,176	16,123	18,063	20,042	20,281	21,520	20,230	19,275	16,712	244,096
Gorm	50,234	10,641	6,549	8,167	7,066	7,551	7,251	6,544	6,678	5,251	4,777	120,709
Skjold	49,879	6,520	4,805	6,411	6,115	5,607	6,045	5,711	6,098	4,989	5,285	107,466
Halfdan	82	13	620	2,532	5,162	5,759	9,710	11,026	12,107	12,727	11,485	71,224
Siri	1,228	3,738	4,549	4,517	3,383	1,683	1,350	1,973	3,499	2,695	1,692	30,306
South Arne	-	58	1,991	4,397	5,332	4,949	5,608	5,362	4,296	4,279	3,872	40,144
Nini	-	-	-	-	81	918	502	912	413	883	501	4,208
Cecilie	-	-	-	-	-	93	198	30	91	42	97	552
Total	**157,631**	**38,435**	**36,689**	**42,148**	**45,201**	**46,603**	**50,945**	**53,077**	**53,412**	**50,141**	**44,420**	**618,705**

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.

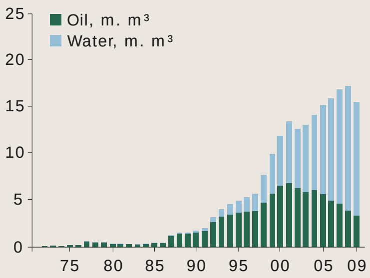
APPENDIX B: PRODUCING FIELDS

Explanation of field data

The location of the fields in geological time appears from appendix F.

PRODUCTION

Cum. production at 1 January 2010
Oil: 98.79 m. m³
Gas: 22.36 bn. Nm³
Water: 108.18 m. m³



Production of oil, gas and water
The chart shows the primary production from the individual fields, i.e. oil or gas as well as water. The figures show the cumulative production of oil, gas and water until 1 January 2010.

Oil field (e.g. Dan) 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 degases and lower gas production is thus achieved.

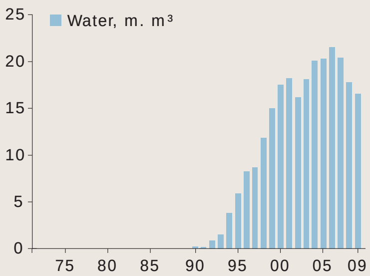
Gas field (e.g. Harald) Oil and condensate, m. m³ Gas, bn. Nm³ Water, m. m³
Production from a gas field consists of gas, water and condensate, which is a light oil. Due to the pressure difference between reservoir and surface, the gas condenses at the surface, which means that liquid hydrocarbons (condensate)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

Oil and gas field (e.g. Tyra Southeast) Oil and condensate, m. m³ Gas, bn. Nm³ Water, m. m³
Some fields contain both oil and gas reservoirs. Oil, gas, condensate and water are produced from these fields.

The production figures for 2009 appear from appendix A.

INJECTION

Cum. injection at 1 January 2010
Water: 244.10 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 2010. The injection method is not used for all fields.

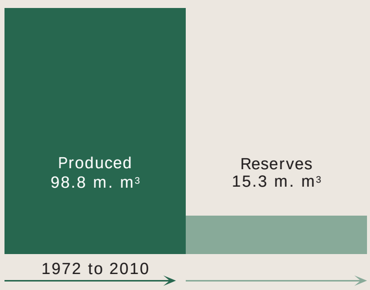
Injecting water into oil reservoirs maintains the reservoir pressure while forcing oil towards the production wells. The injection of gas also maintains pressure in the reservoir. Moreover, the gas affects the viscosity of hydrocarbons.

Fields with water injection (e.g. Halfdan) 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: 15.3 m. m³
Gas: 1.5 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 2010 and the estimated hydrocarbons-in-place, the reserves.

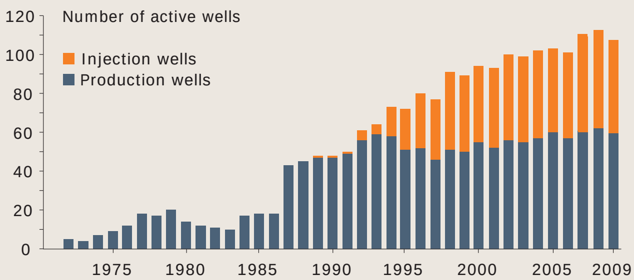
Produced
The cumulative production of oil or gas until 1 January 2010.

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

For gas fields, both the amounts produced and the reserves have been calculated on a net gas basis.

DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010
2009 prices DKK 29.26 billion



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

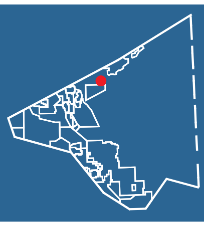
The chart shows the number of wells that were active in the individual years.

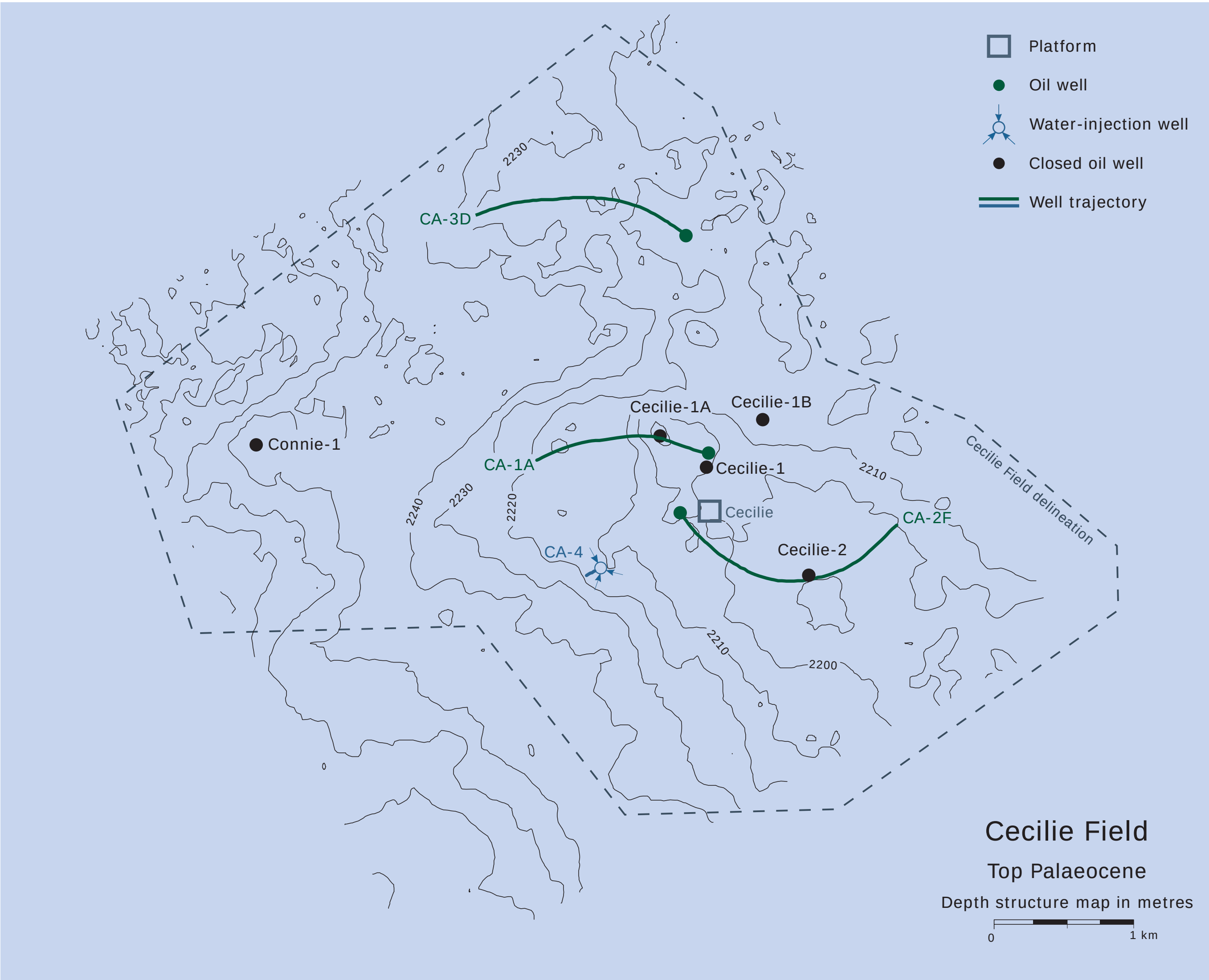
The wells are divided into production wells and injection wells. The chart shows the primary function of the wells in the relevant year, either production or injection. A well may be used for production for part of a year and then be converted to injection for the rest of the year.

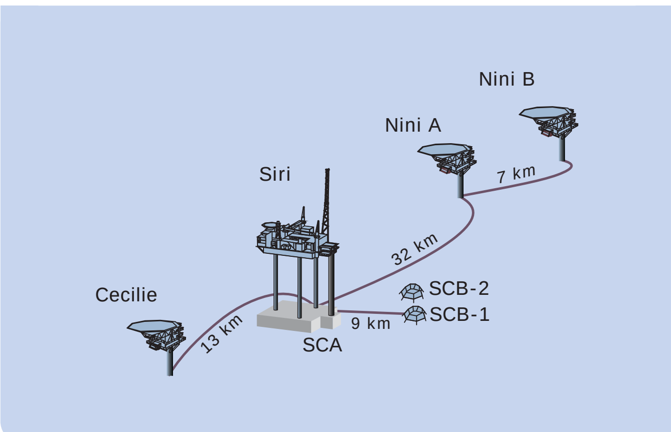
Injection wells Production wells Prod/Inject wells*
*Only relevant for the Tyra Field. A few wells alternate between injection and production.

APPENDIX B: PRODUCING FIELDS

THE CECILIE FIELD

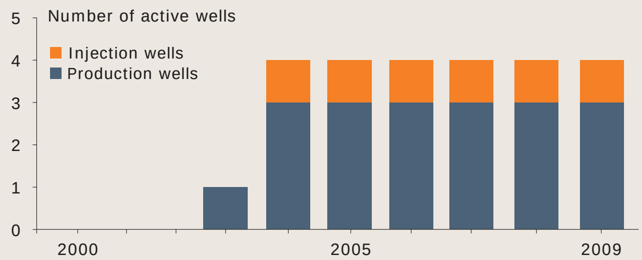






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010
2009 prices DKK 1.35 billion



FIELD DATA

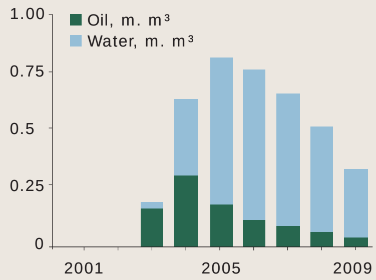
At 1 January 2010

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:	23 km^2
Reservoir depth:	2,200 m
Reservoir rock:	Sandstone
Geological age:	Palaeocene

PRODUCTION

Cum. production at 1 January 2010

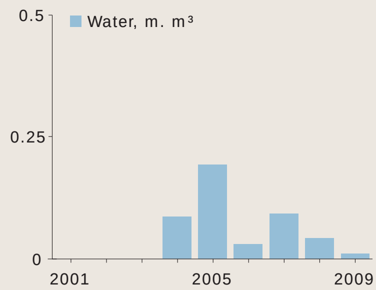
Oil:	0.97 m. m^3
Gas:	0.07 bn. Nm^3
Water:	2.94 m. m^3



INJECTION

Cum. injection at 1 January 2010

Water:	0.55 m. m^3



RESERVES

Oil:	0.4 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.

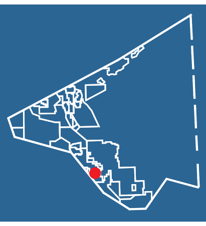
PRODUCTION STRATEGY

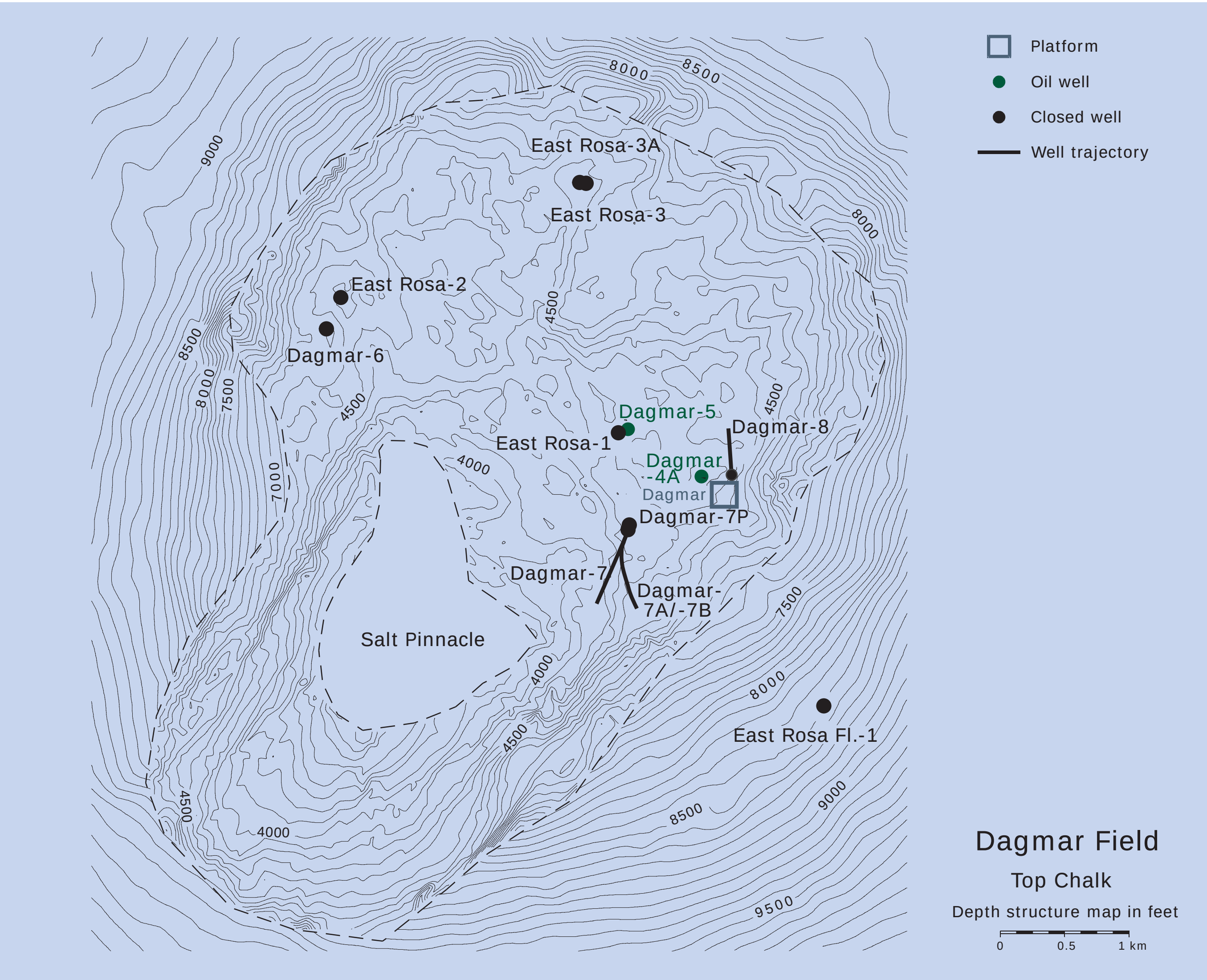
Recovery is based on water injection to maintain reservoir pressure. To assess its effect, water injection has been suspended for periods of time. The production wells have been drilled in the crest of the structure, while water is injected in the flank of the field.

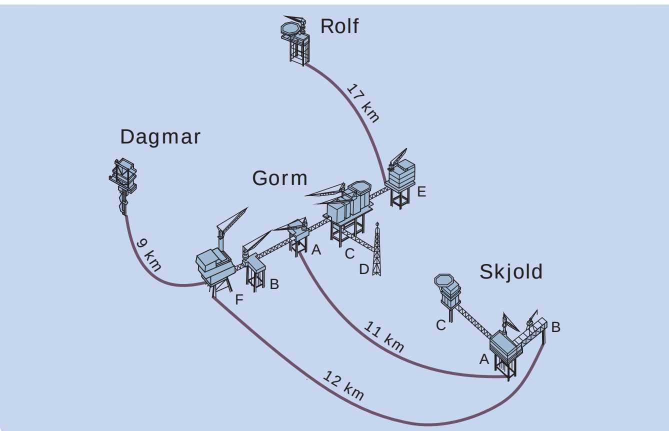
PRODUCTION FACILITIES

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

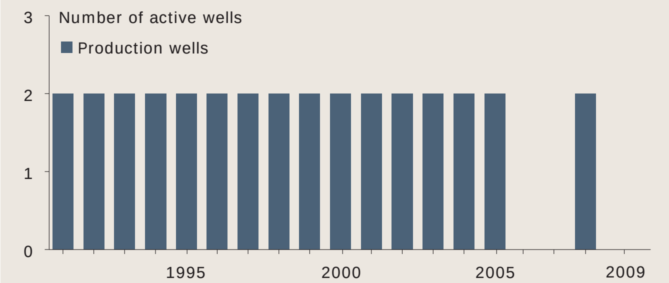






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010
2009 prices DKK 0.50 billion



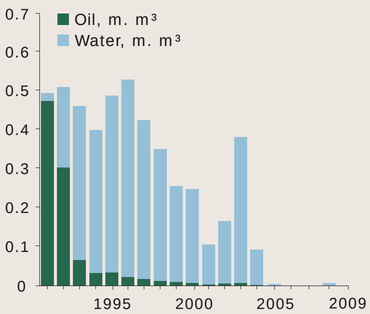
FIELD DATA
At 1 January 2010

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
Field delineation:	50 km²
Reservoir depth:	1,400 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein

PRODUCTION

Cum. production at 1 January 2010

Oil:	1.01 m. m^3
Gas:	0.16 bn. Nm^3
Water:	3.93 m. m^3



RESERVES

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

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.

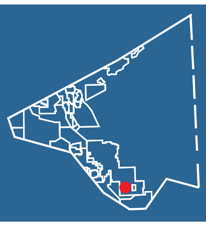
PRODUCTION STRATEGY

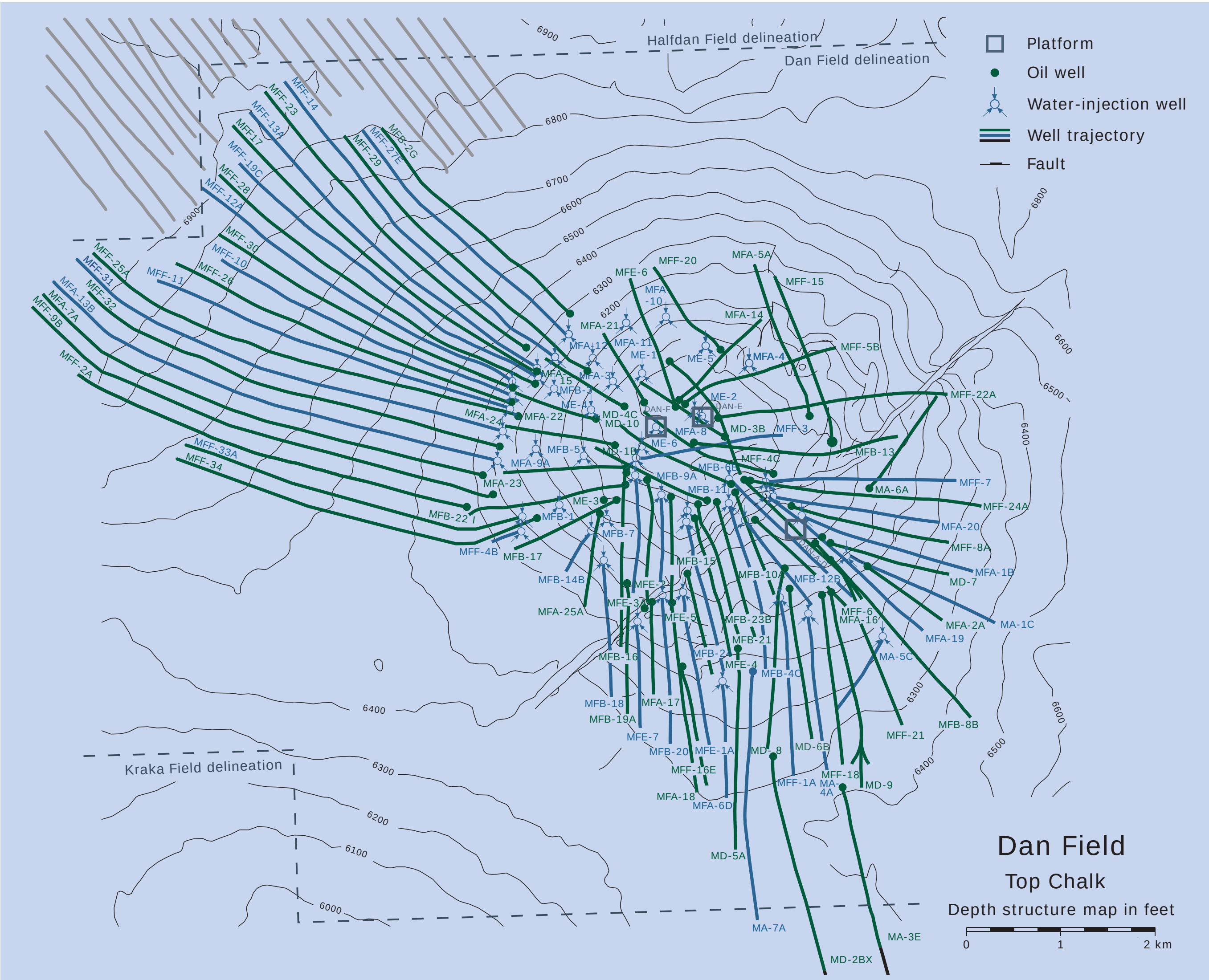
Both wells in the field have been suspended. The recovery strategy for the Dagmar Field was based on achieving the highest possible production rate from the wells. Initially, the oil production rates were high in the Dagmar Field, but later it was not possible to sustain the good production performance from the matrix. 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.

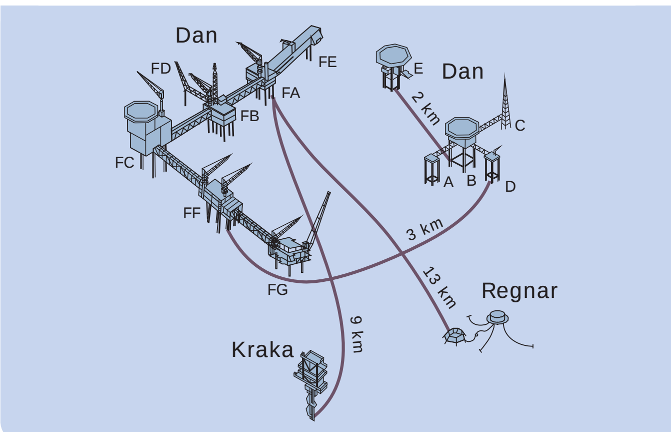
PRODUCTION FACILITIES

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

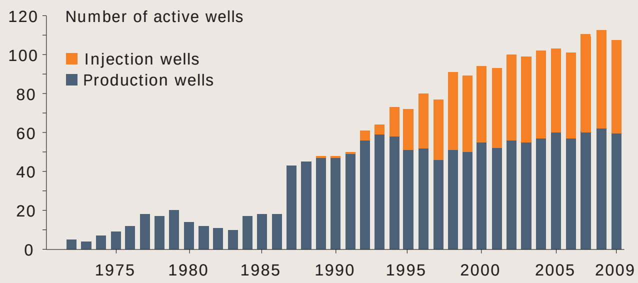






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010
2009 prices DKK 29.26 billion



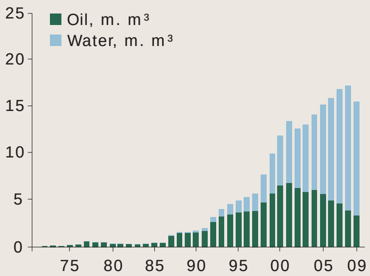
FIELD DATA
At 1 January 2010

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:	104 km^2
Reservoir depth:	1,850 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2010

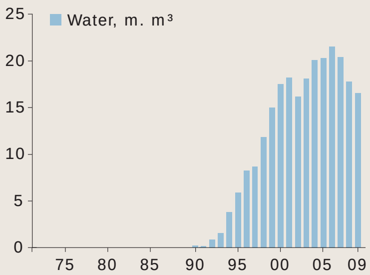
Oil:	98.79 m. m^3
Gas:	22.36 bn. Nm^3
Water:	108.18 m. m^3



INJECTION

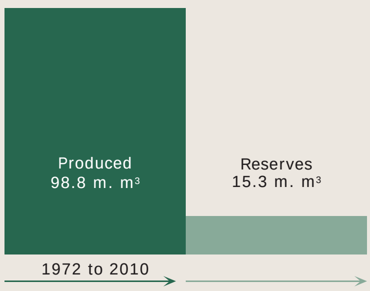
Cum. injection at 1 January 2010

Water:	244.10 m. m^3



RESERVES

Oil:	15.3 m. m^3
Gas:	1.5 bn. Nm^3



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. The Dan 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

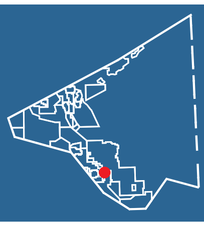
The Dan Field comprises six wellhead platforms, A, D, E, FA, FB and FE, a combined wellhead and processing platform, FF, a processing platform with a flare tower, FG, two processing and accommodation platforms, B and FC, and two gas flare stacks, C and FD.

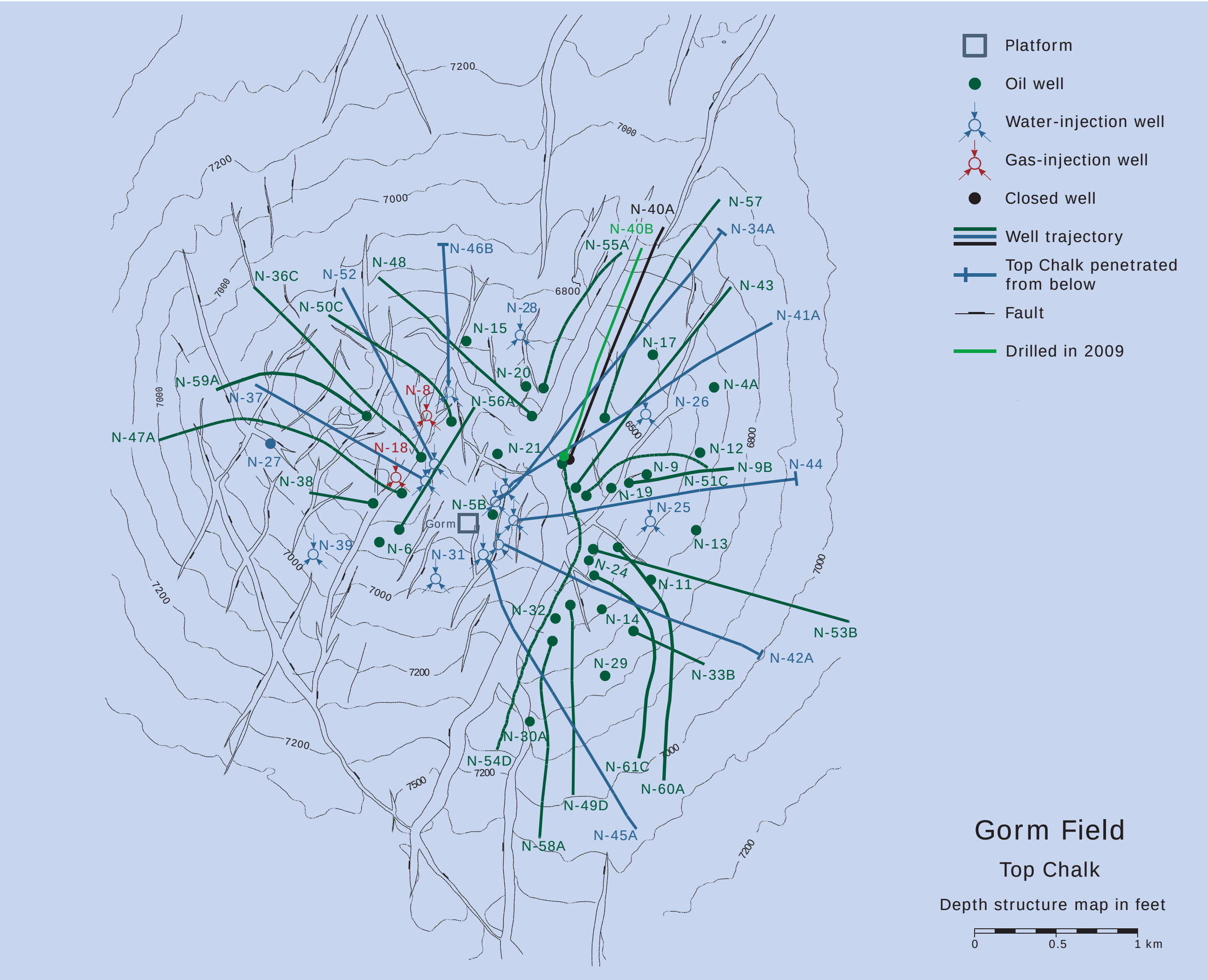
At the Dan Field, there are facilities for receiving production from the adjacent Kraka and Regnar satellite fields, as well as for receiving some of the gas produced at the Halfdan Field. The Dan installations supply the Halfdan Field with injection water.

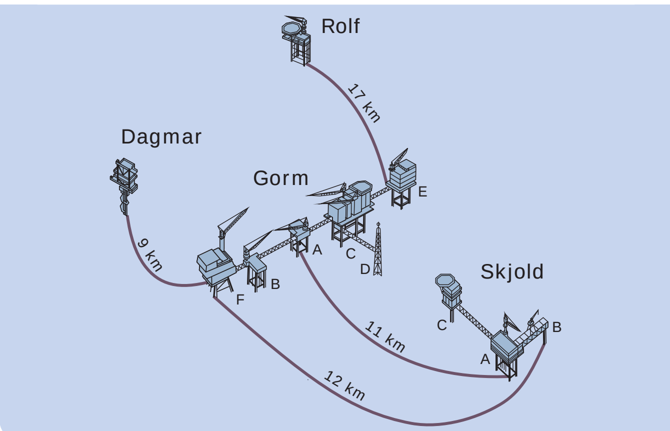
After final processing, the oil is transported to shore via the Gorm E platform. The gas is pre-processed and transported to Tyra East for final processing. Treated production water from Dan and its satellite fields is discharged into the sea.

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



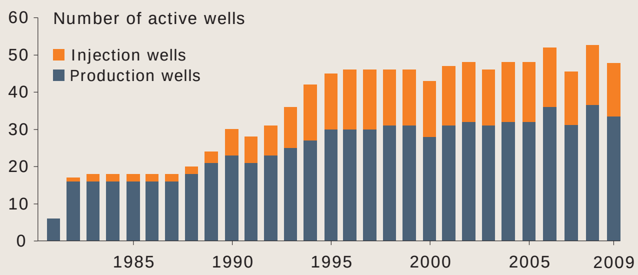




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010

2009 prices DKK 14.17 billion



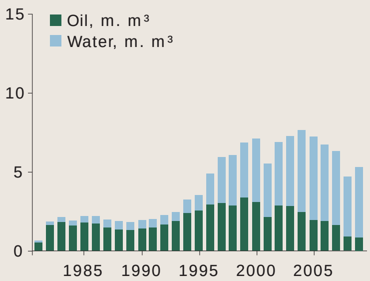
FIELD DATA
At 1 January 2010

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:	63 km^2
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2010

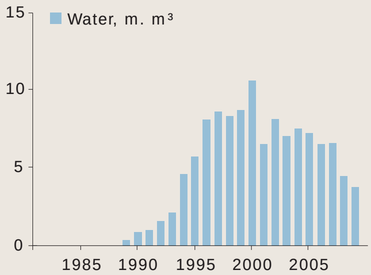
Oil:	58.02 m. m^3
Gas:	15.46 bn. Nm^3
Water:	63.24 m. m^3



INJECTION

Cum. injection at 1 January 2010

Gas:	8.16 bn. Nm^3
Water:	120.71 m. m^3



RESERVES

Oil:	5.2 m. m^3
Gas:	0.5 bn. Nm^3

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.

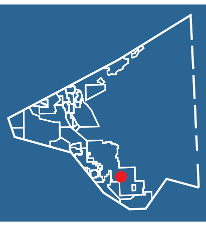
PRODUCTION FACILITIES

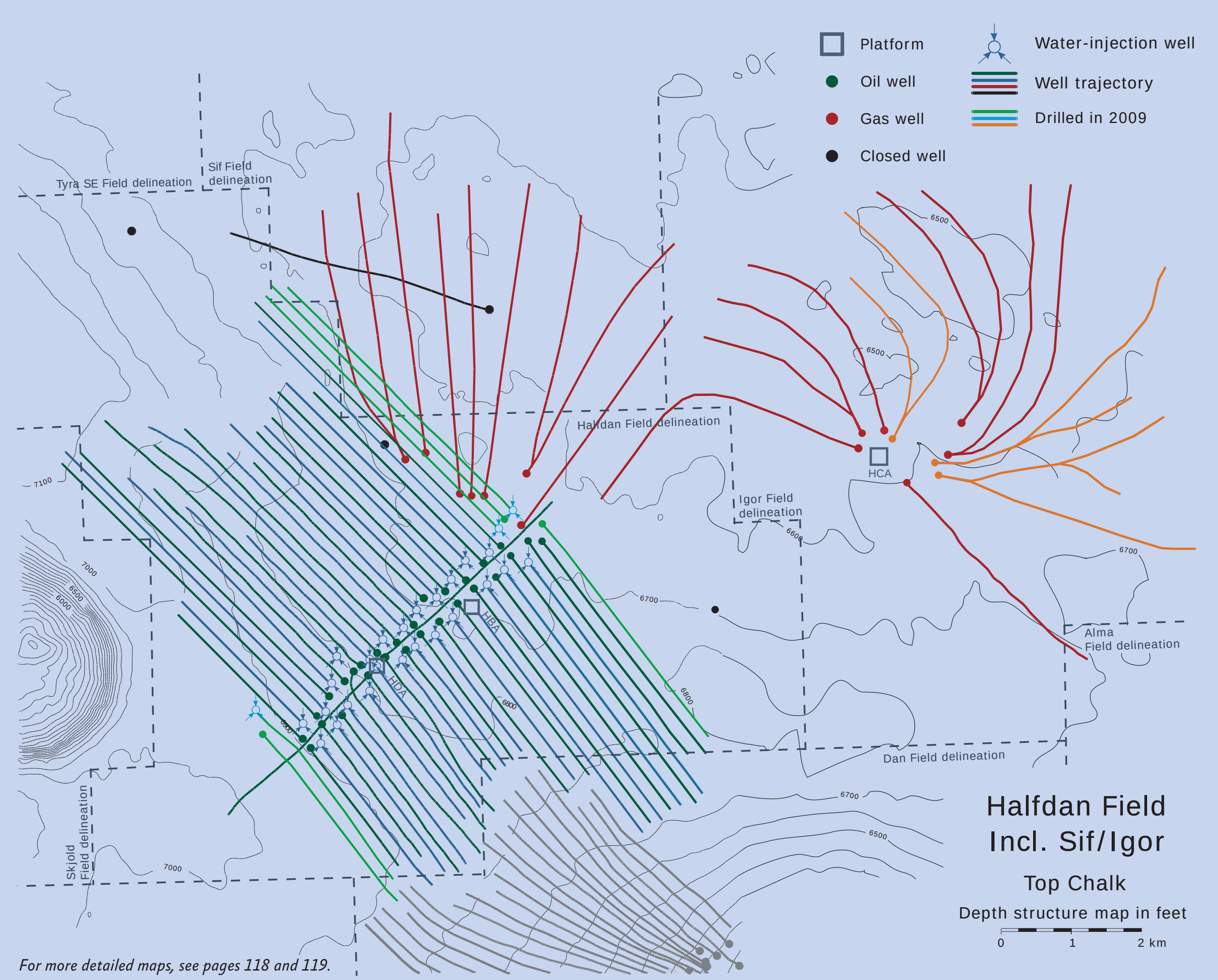
The Gorm Field consists of two wellhead platforms, Gorm A and B, one processing and accommodation platform, Gorm C, one gas flare stack, Gorm D, one riser and export platform, Gorm E (owned by DONG Oil Pipe A/S) and one combined wellhead, processing and riser platform, Gorm F.

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.

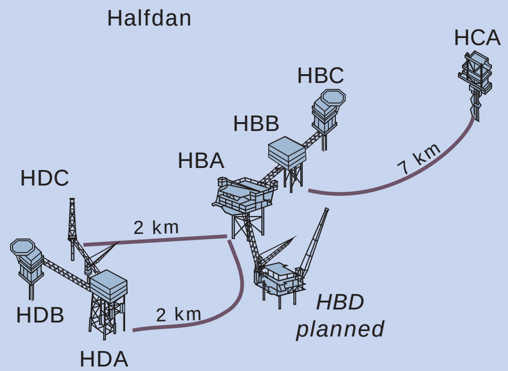
There are accommodation facilities on the Gorm C platform for 98 persons.

THE HALFDAN FIELD INCL. SIF AND IGOR



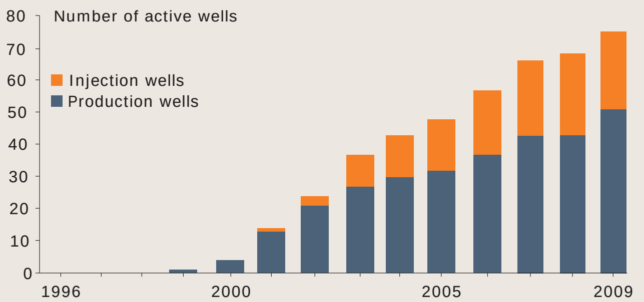


For more detailed maps, see pages 118 and 119.



DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010
2009 prices DKK 18.88 billion



FIELD DATA At 1 January 2010

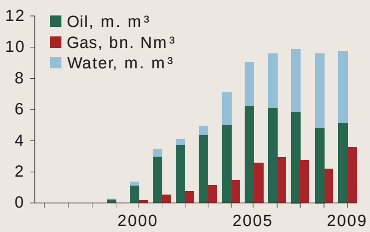
Prospect:	Nana, Sif and Igor
Location:	Blocks 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1968, 1999
Year on stream:	1999, 2004 and 2007
Oil-producing wells:	35 (Halfdan)
Water-injection wells:	26 (Halfdan)
Gas-producing wells:	16 (Sif and Igor)
Reservoir depth:	2,030-2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

Further details appear from the boxes on pages 118 and 119.

PRODUCTION

Cum. production at 1 January 2010

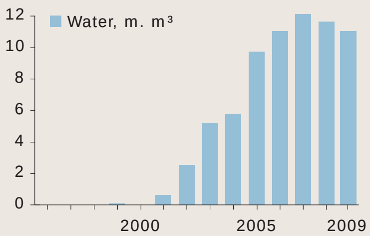
Oil:	46.18 m. m³
Gas:	18.80 bn. Nm³
Water:	23.81 m. m³



INJECTION

Cum. injection at 1 January 2010

Water:	71.22 m. m³



RESERVES

Oil:	53.0 m. m³
Gas:	17.3 bn. Nm³

REVIEW OF GEOLOGY, THE HALFDAN FIELD

The Halfdan Field comprises the Halfdan, Sif and Igor areas and contains a continuous hydrocarbon accumulation. 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 subsoil. 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.

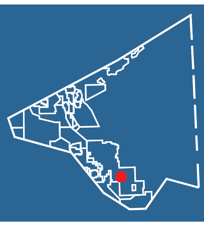
The Dan installations supply Halfdan D and B with injection water. Treated production water from Halfdan and Sif/Igor is discharged into the sea.

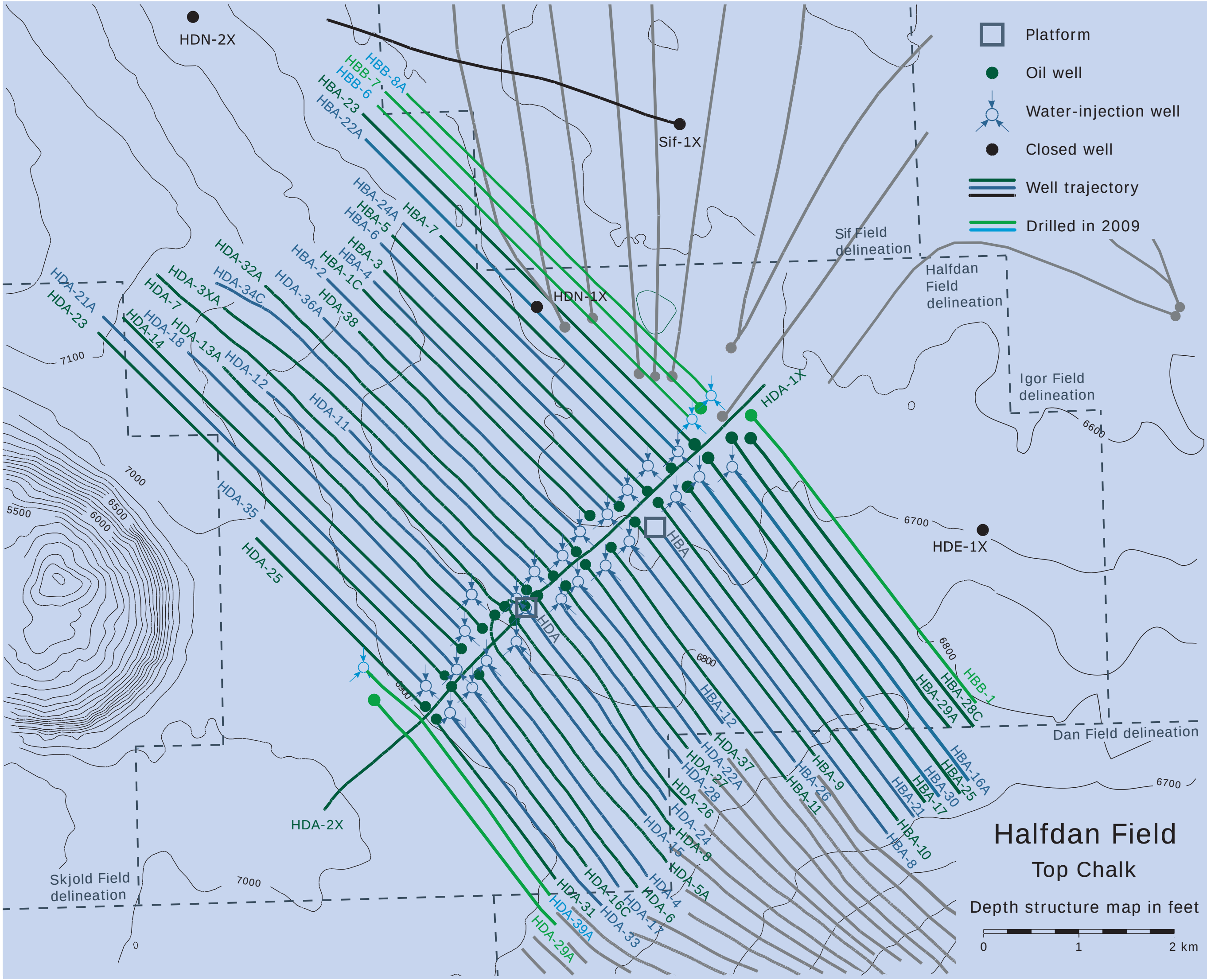
To increase the processing and transportation capacity for production from the Halfdan Field, a 20” pipeline has been established to transport oil and produced water from the Halfdan B complex to the Dan FG platform in the Dan Field.

The HDB platform (the Halfdan D complex) has accommodation facilities for 32 persons, while the HBC platform (the Halfdan B complex) has accommodation facilities for 80 persons.

More details about the facilities can be found on pages 118 and 119.

THE HALFDAN FIELD (MAIN FIELD)





FIELD DATA

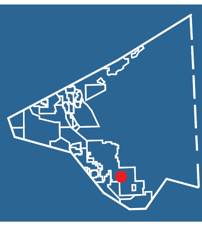
At 1 January 2010

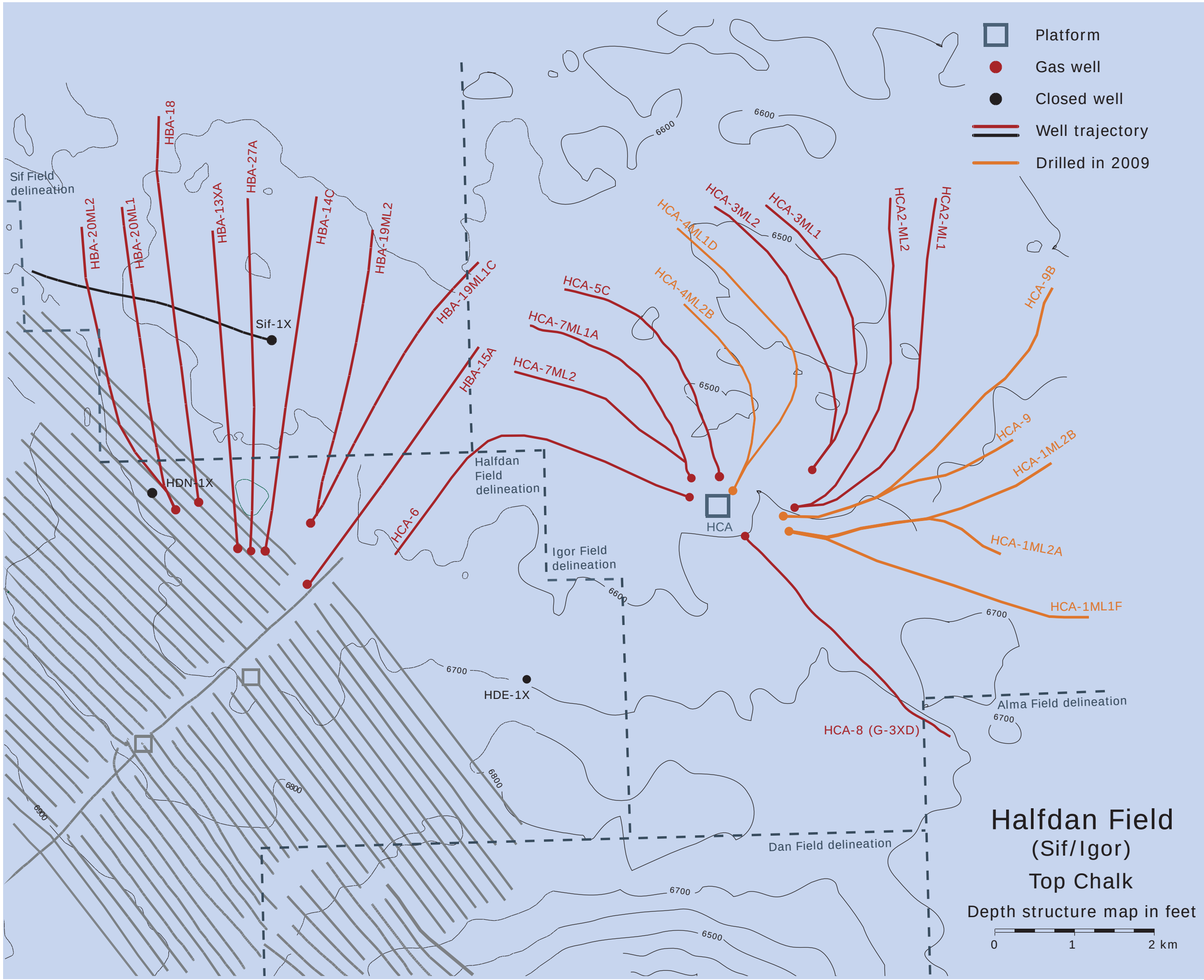
Prospect:	Nana
Location:	Blocks 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1999
Year on stream:	1999
Oil-producing wells:	35 (Halfdan)
Water-injection wells:	26 (Halfdan)
Water depth:	43 m
Field delineation:	100 km² (Halfdan)
Reservoir depth:	2,100 m
Reservoir 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

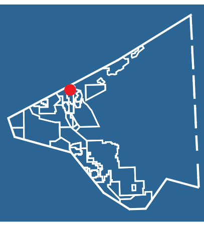
At 1 January 2010

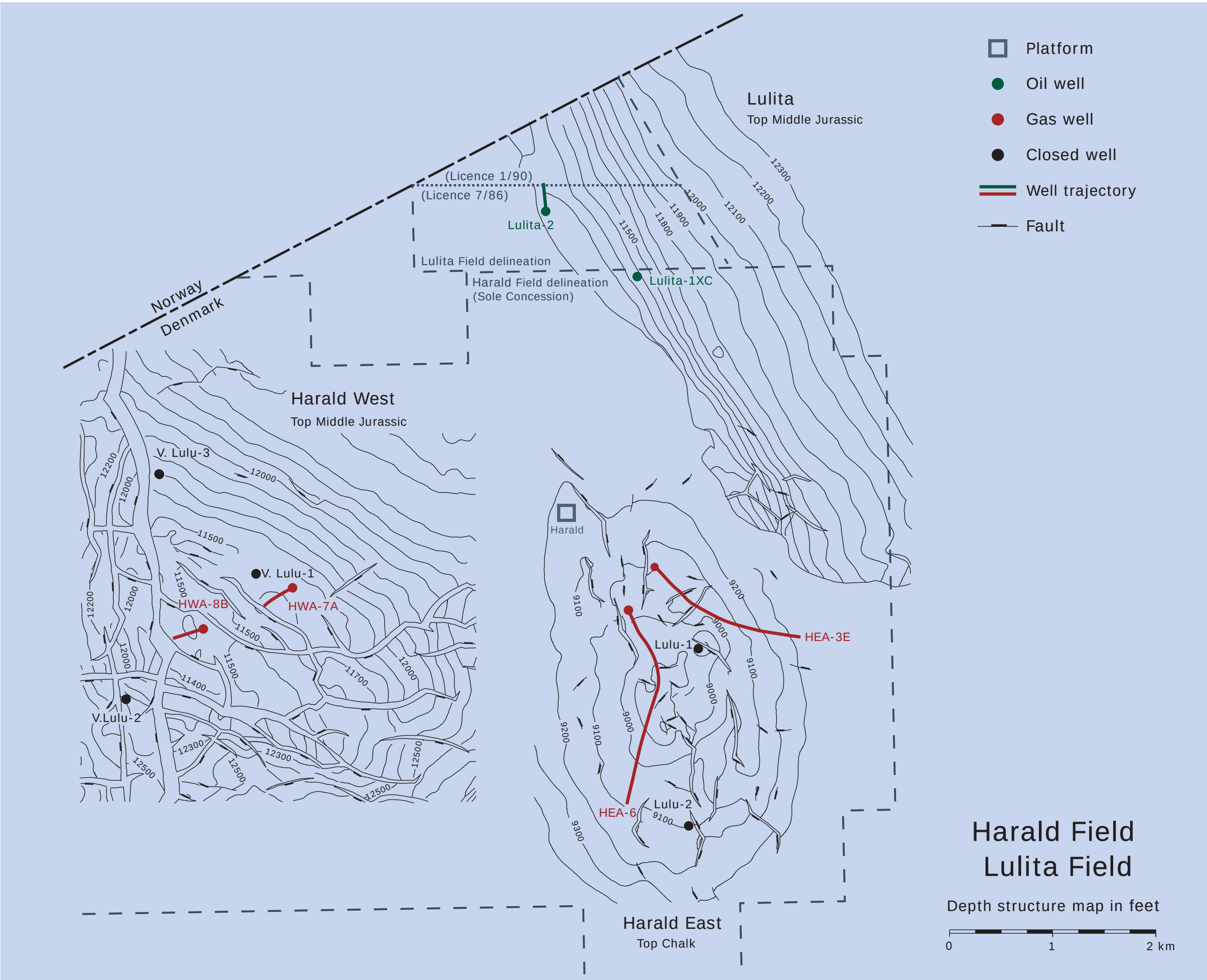
Prospect (former and current names):	Sif and Igor
Location:	Block 5505/13
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1999 (Sif), 1968 (Igor)
Year on stream:	2004 (Sif), 2007 (Igor)
Gas-producing wells:	7 (Sif), 9 (Igor)
Water depth:	44 m (Sif), 45 m (Igor)
Field delineation:	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 pipelines to the Halfdan B complex.

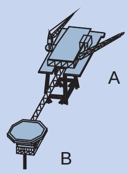
The gas from Sif/Igor is conveyed directly to Tyra West via the HBA platform, while the gas from Halfdan D is transported to Dan for export ashore via Tyra East or to Tyra West for export to the Netherlands through the NOGAT pipeline.

THE HARALD FIELD



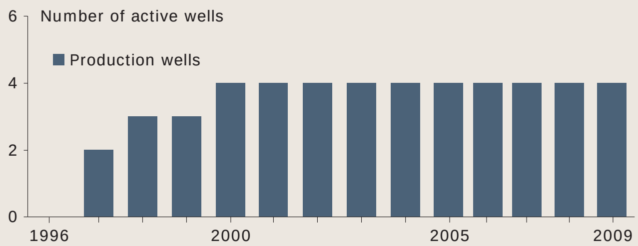


Harald / Lulita



DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010
2009 prices   DKK 4.03 billion



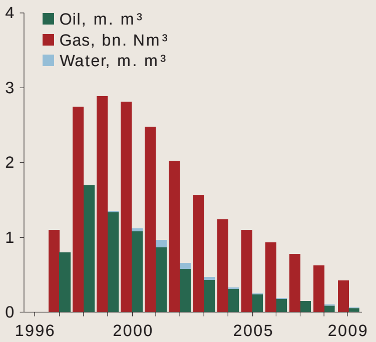
FIELD DATA
At 1 January 2010

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 (Harald East) and Middle Jurassic (Harald West)

PRODUCTION

Cum. production at 1 January 2010

Oil:	7.81 m. m³
Gas:	20.70 bn. Nm³
Water:	0.37 m. m³



RESERVES

Oil and condensate:	0.5 m. m³
Gas:	3.2 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

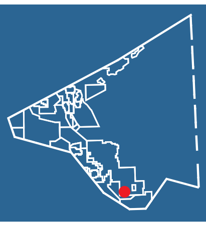
The Harald Field comprises a combined wellhead and processing platform, Harald A, and an accommodation platform, Harald B. The unprocessed condensate and the processed gas are transported to Tyra East. Treated production water is discharged into the sea.

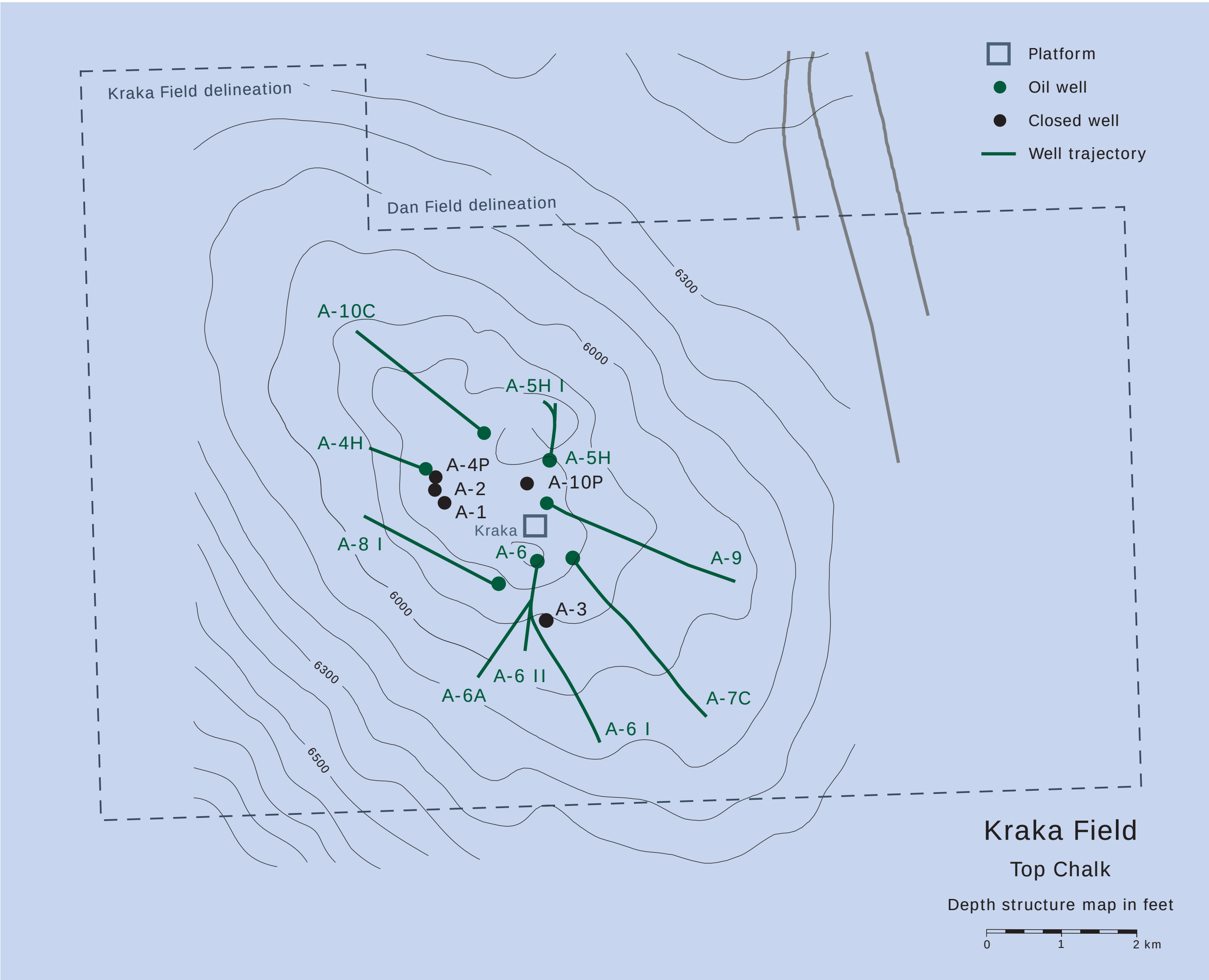
The Harald Field is hooked up to the gas pipeline that transports gas from the South Arne Field to Nybro. Normally, no gas is exported from Harald through the South Arne pipeline.

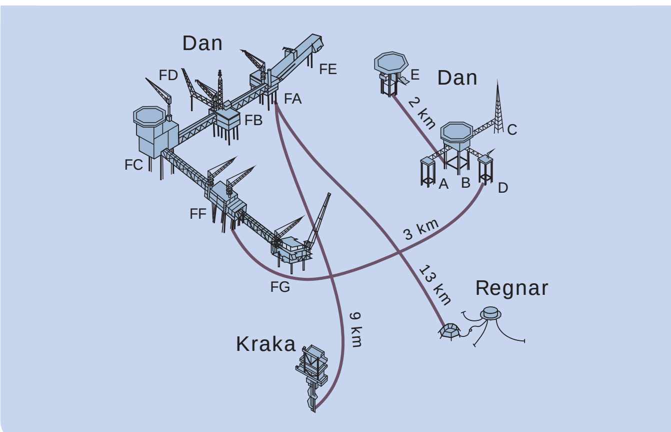
The Harald Field has accommodation facilities for 16 persons.

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

THE KRAKA FIELD



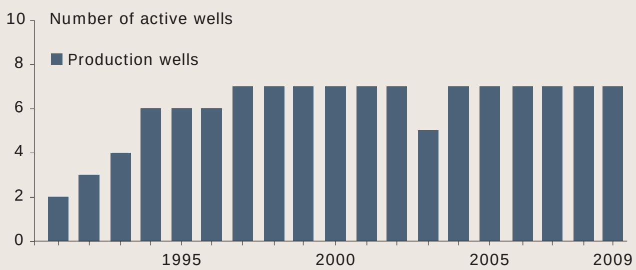




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010

2009 prices DKK 1.62 billion



FIELD DATA

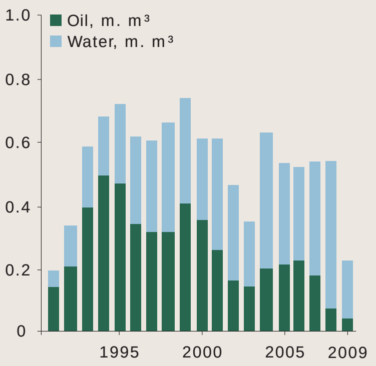
At 1 January 2010

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 2010

Oil:	4.93 m. m^3
Gas:	1.39 bn. Nm^3
Water:	5.19 m. m^3



RESERVES

Oil:	1.2 m. m^3
Gas:	0.3 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.

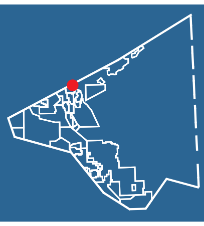
PRODUCTION STRATEGY

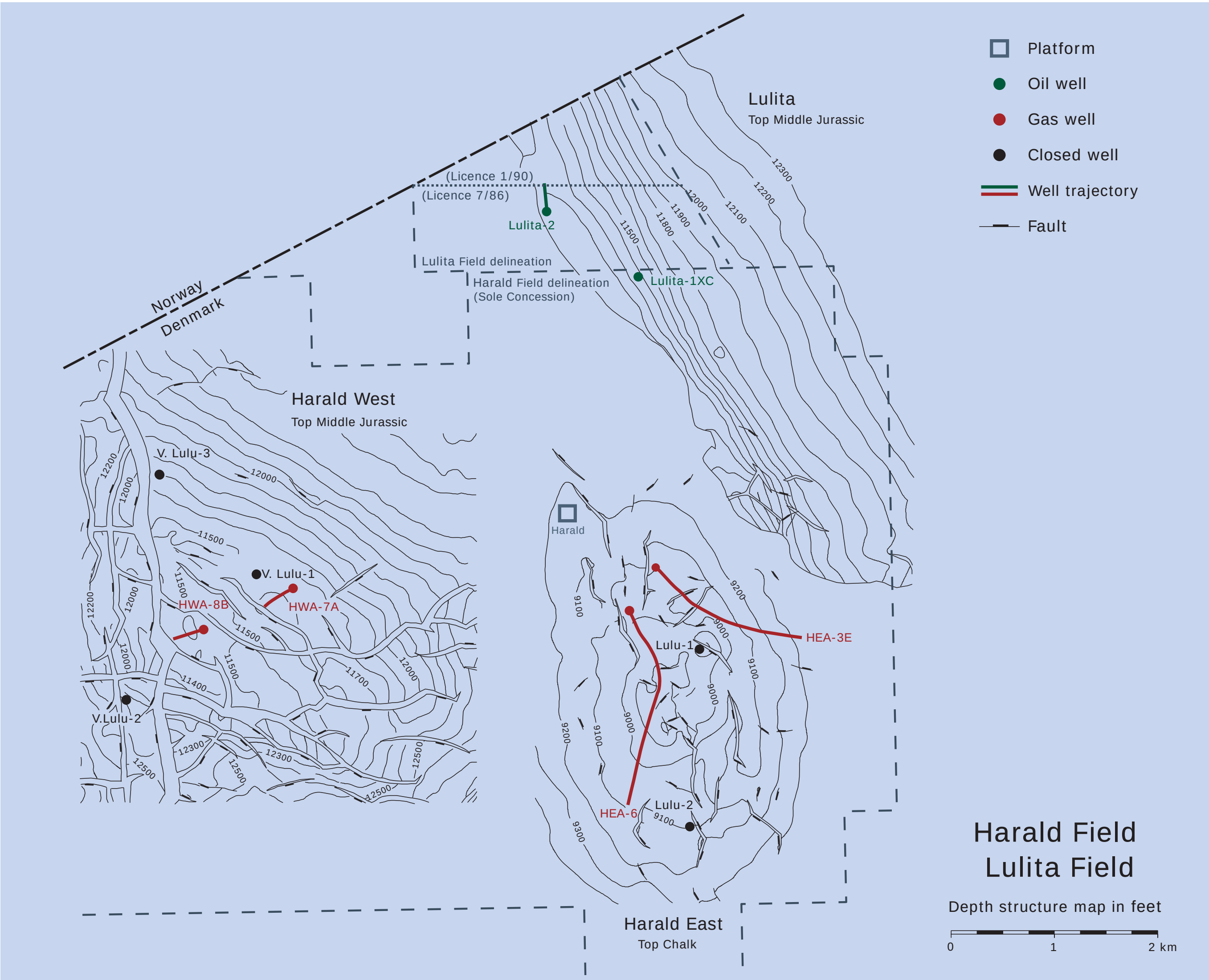
Recovery from Kraka is based on the natural expansion of the gas cap and aquifer support. The individual wells are produced at the lowest possible bottom-hole pressure. Oil production from the field is maximized by prioritizing gas lift in wells with a low water content and a low gas-oil ratio.

PRODUCTION FACILITIES

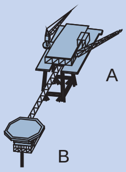
Kraka is a satellite development to the Dan Field with one unmanned wellhead platform without a helideck. The production is transported to Dan F for processing and then exported ashore. Lift gas is imported from the Dan Field.

THE LULITA FIELD



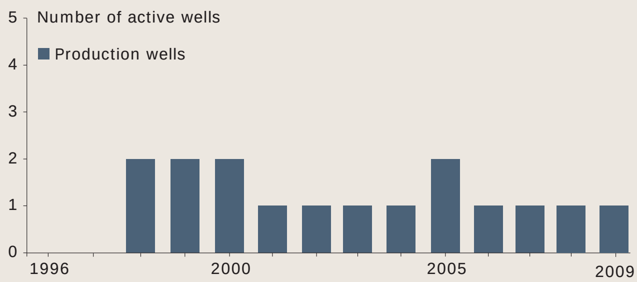


Harald / Lulita



DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010
2009 prices DKK 0.10 billion



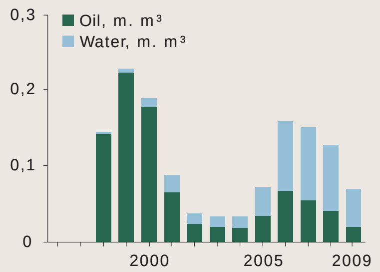
FIELD DATA At 1 January 2010

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
Field delineation:	4 km^2
Reservoir depth:	3,525 m
Reservoir rock:	Sandstone
Geological age:	Middle Jurassic

PRODUCTION

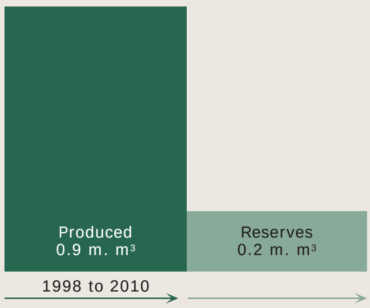
Cum. production at 1 January 2010

Oil:	0.90 m. m^3
Gas:	0.58 bn. Nm^3
Water:	0.45 m. m^3



RESERVES

Oil:	0.2 m. m^3
Gas:	0.2 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.

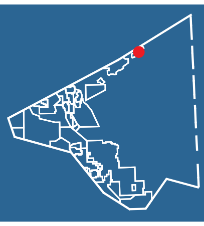
PRODUCTION FACILITIES

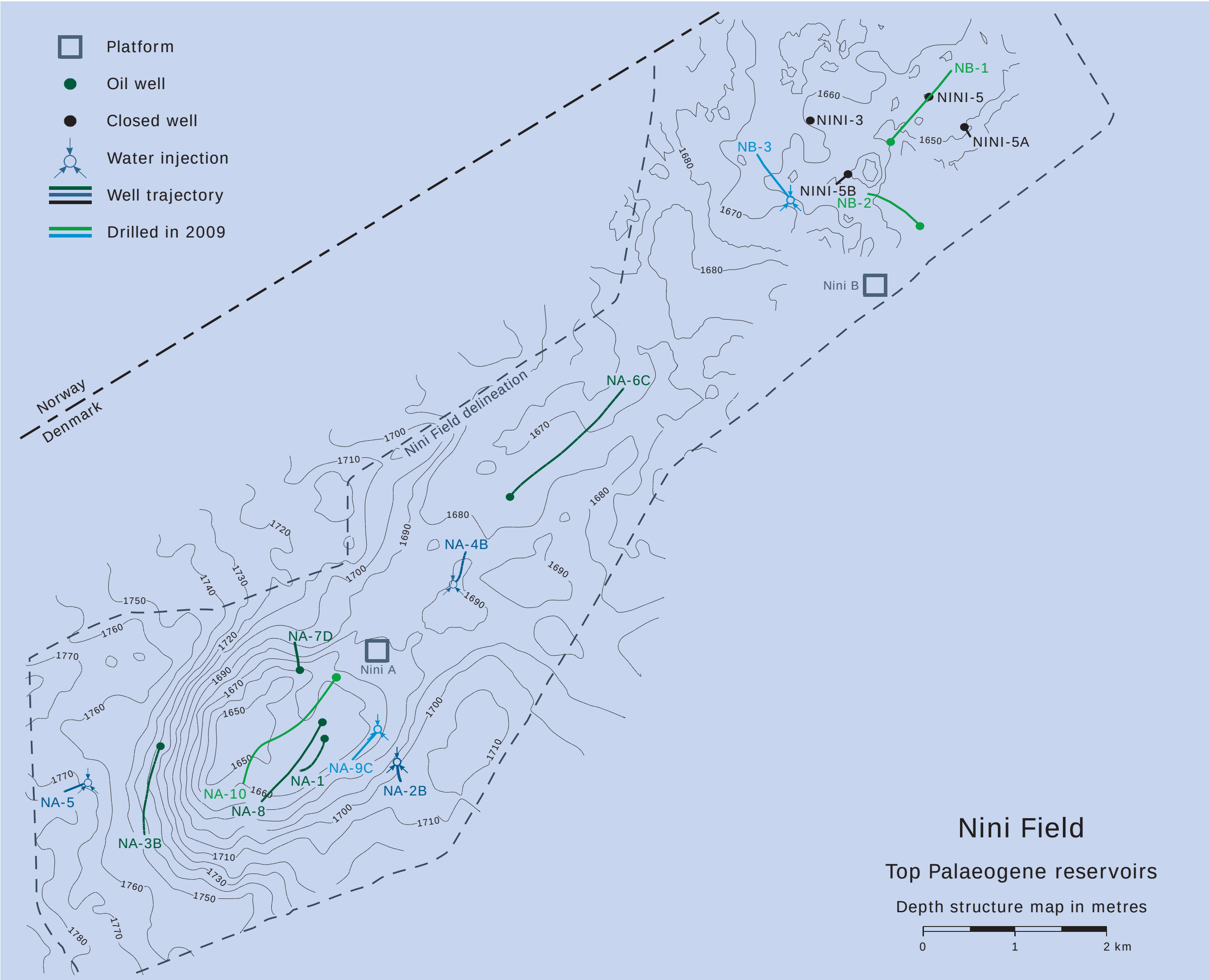
Production from the Lulita Field takes place from the fixed installations in the Harald Field. Thus, the Lulita facilities are hosted by the Harald A platform, and the Harald platform processing equipment also handles production from the Lulita Field.

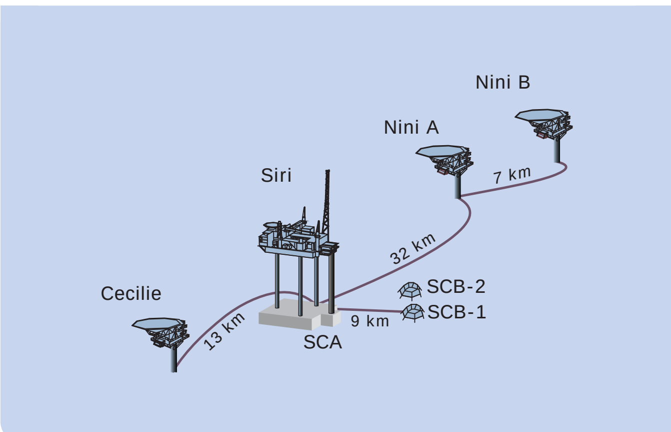
Together with condensate from the Harald Field, the oil produced is transported through a 16” pipeline to Tyra East for export ashore. The gas produced in the Lulita Field is transported to Tyra through the 24” pipeline connecting Harald with Tyra East, from where it is transported to shore. The water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



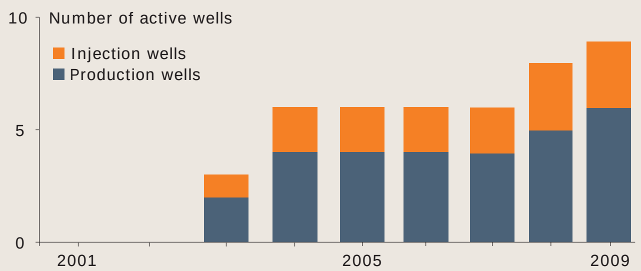




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010

2009 prices DKK 4.77 billion



FIELD DATA

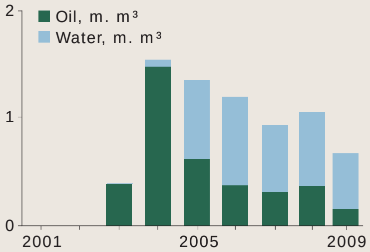
At 1 January 2010

Location:	Blocks 5605/10 and 14
Licence:	4/95
Operator:	DONG E&P A/S
Discovered:	2000
Year on stream:	2003
Producing wells:	8
Water-injection wells:	5
Water depth:	60 m
Field delineation:	45 km²
Reservoir depth:	1,700 m
Reservoir rock:	Sandstone
Geological age:	Eocene/Palaeocene

PRODUCTION

Cum. production at 1 January 2010

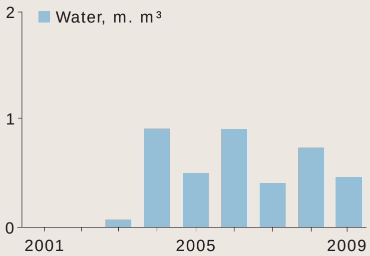
Oil:	3.71 m. m^3
Gas:	0.27 bn. Nm^3
Water:	3.42 m. m^3



INJECTION

Cum. injection at 1 January 2010

Water:	4.21 m. m^3



RESERVES

Oil:	3.4 m. m^3
Gas:	0.0 bn. Nm^3

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.

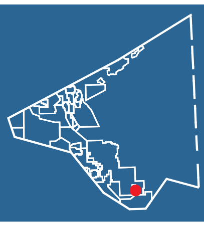
PRODUCTION FACILITIES

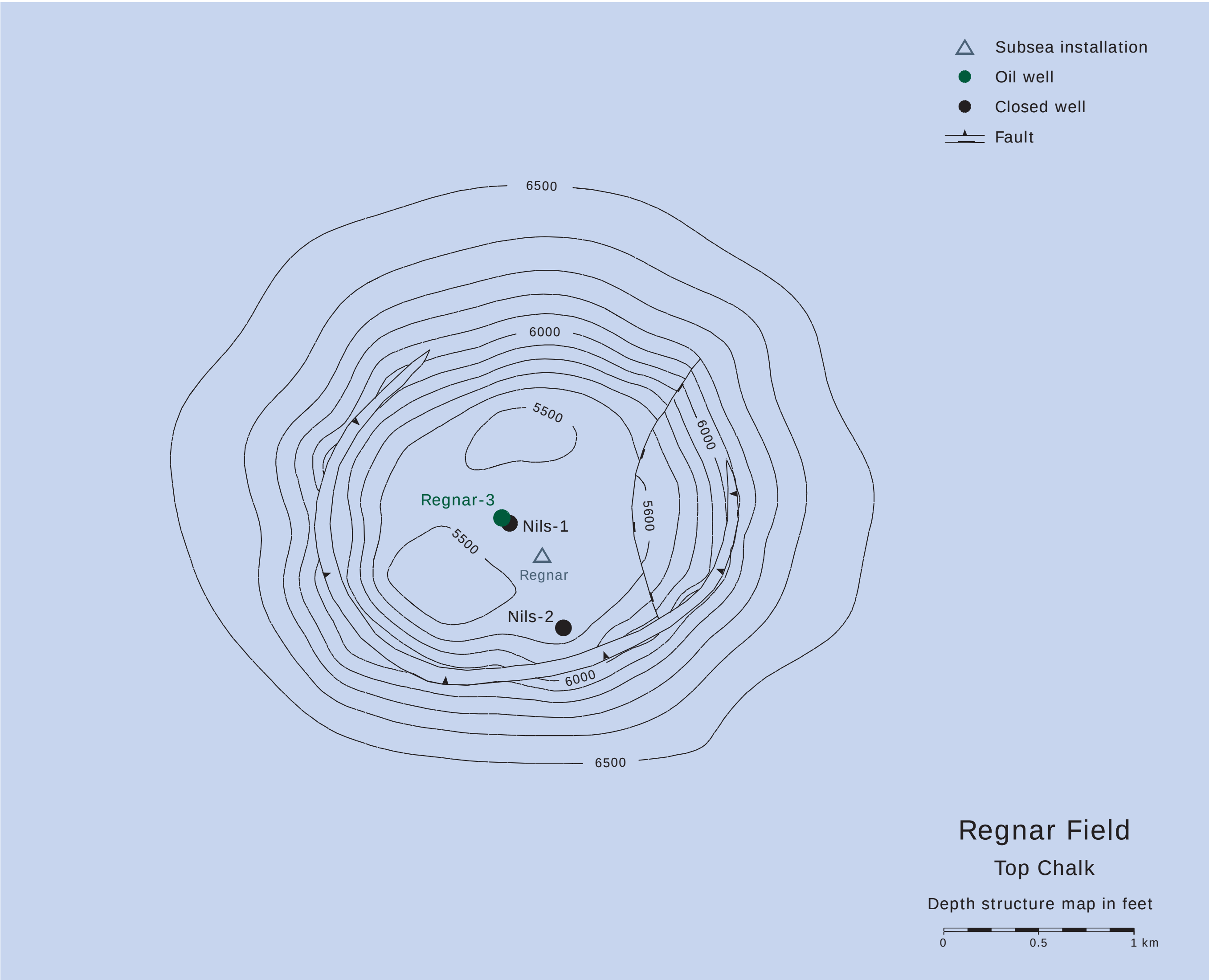
Nini (NA) and Nini East (NB) are satellite developments to the Siri Field with two unmanned wellhead platforms, both with a helideck. The Nini East platform was installed in 2009, and production from the platform commenced in 2010.

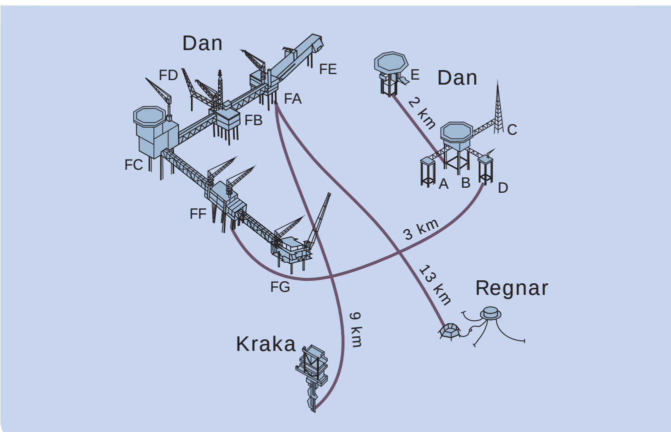
The unprocessed production from Nini East is sent through an 8" multiphase pipeline to Nini. From here, total production from Nini East and Nini is transported through a 14" multiphase pipeline via the Siri platform. The production is processed on the Siri platform and exported to shore via tanker. Siri supplies Nini and Nini East with injection water and lift gas via the Nini platform. Injection water is supplied through a 10" pipeline and lift gas through a 4" pipeline.

The old 10" water-injection pipeline from Siri (SCA) to Nini (NA) was replaced by a new one in 2009, at the same time being extended by a further pipeline to Nini East (NB).

THE REGNAR FIELD

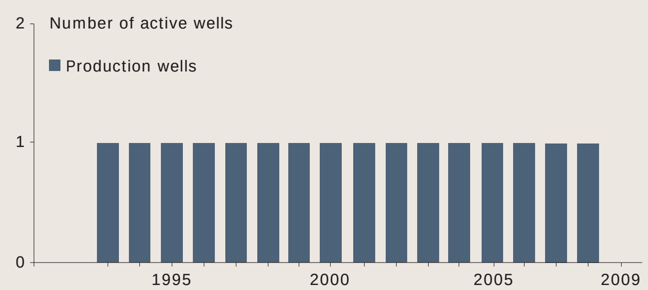






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010
2009 prices DKK 0.27 billion



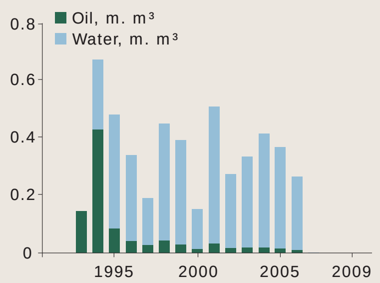
FIELD DATA
At 1 January 2010

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:	34 km²
Reservoir depth:	1,700 m
Reservoir rock:	Chalk
Geological age:	Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2010

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.

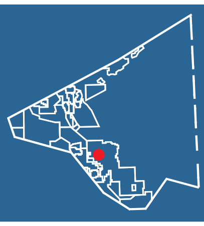
Production in the Regnar Field has been suspended since 2006 due to problems with the equipment.

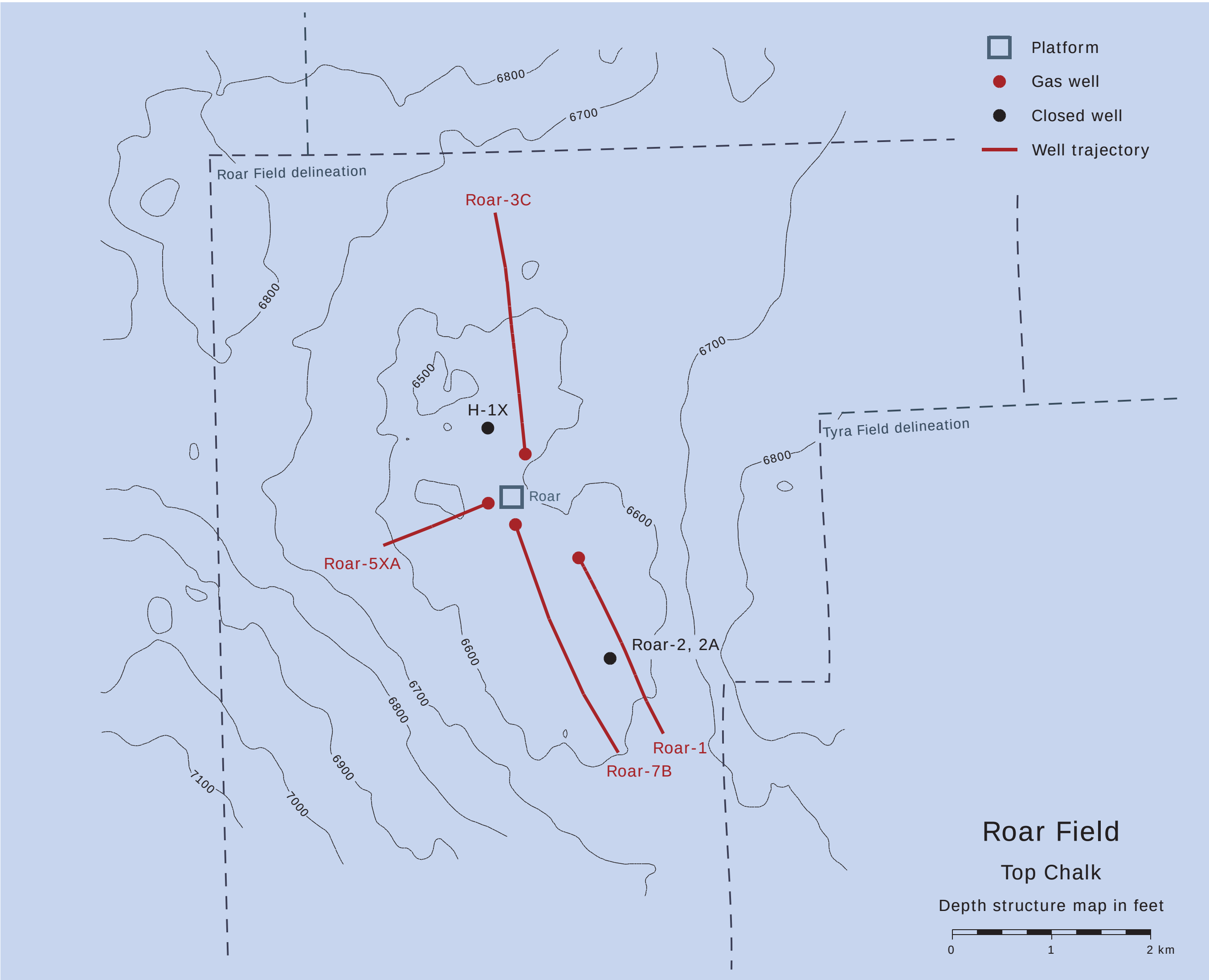
PRODUCTION FACILITIES

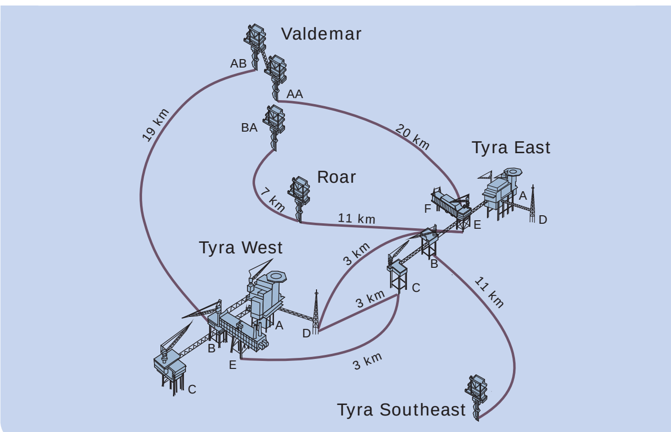
The Regnar Field has been developed as a satellite to the Dan Field and production takes place in a subsea-completed well. The production is transported by a multiphase pipeline to Dan F for processing and export ashore.

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

THE ROAR FIELD



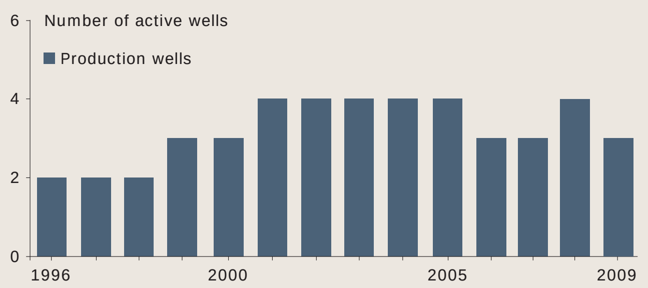




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010

2009 prices DKK 0.68 billion



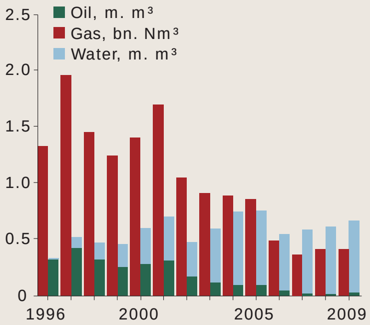
FIELD DATA
At 1 January 2010

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

PRODUCTION

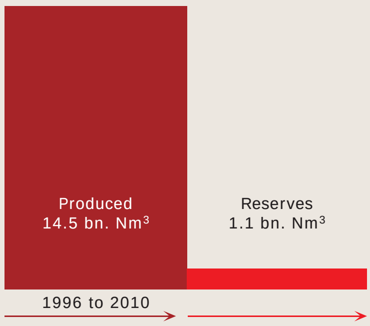
Cum. production at 1 January 2010

Oil:	2.57 m. m^3
Gas:	14.50 bn. Nm^3
Water:	5.52 m. m^3



RESERVES

Oil:	0.1 m. m^3
Gas:	1.1 bn. Nm^3



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.

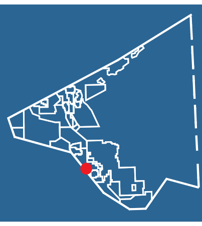
PRODUCTION STRATEGY

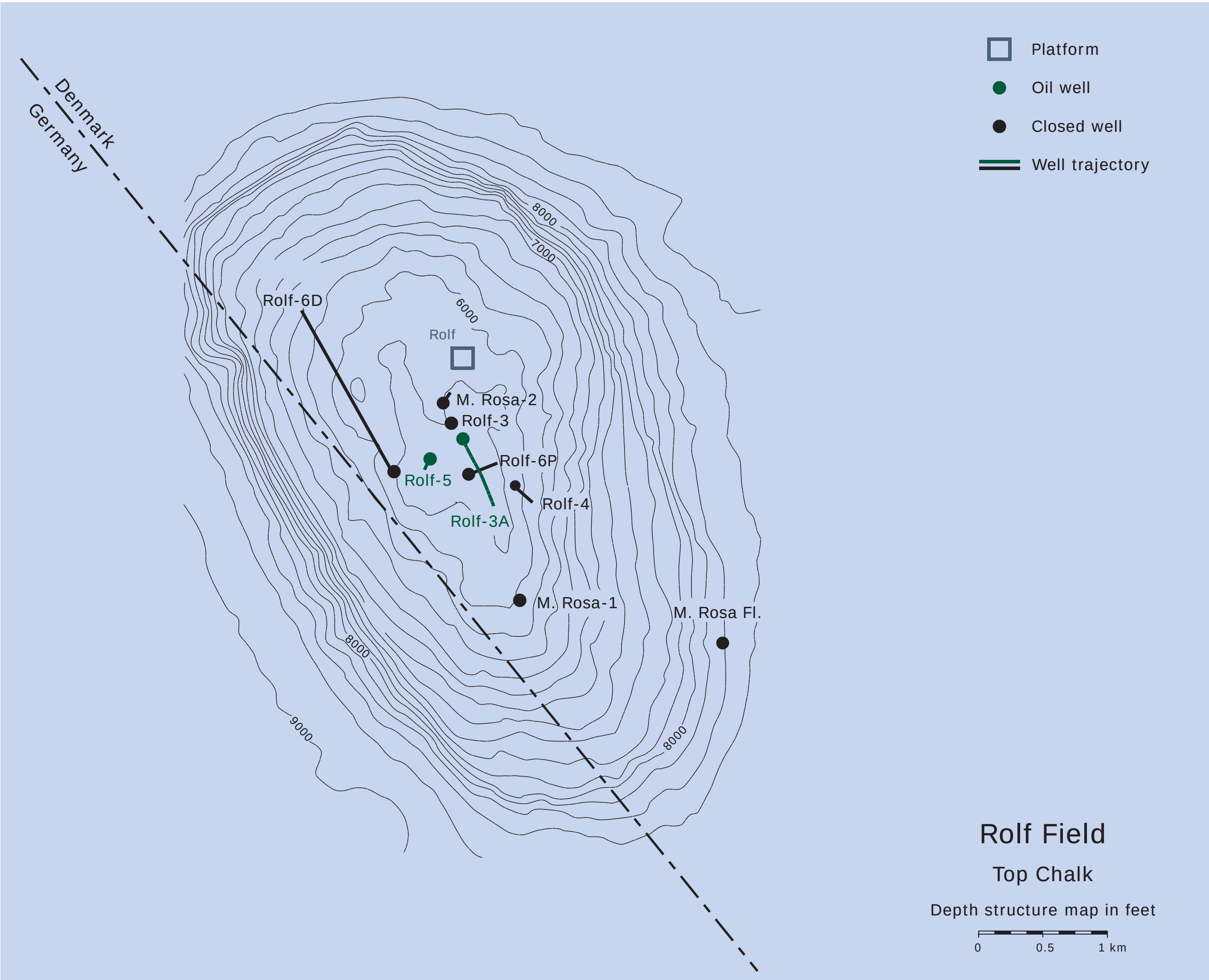
Recovery from the Roar Field takes place by gas expansion. The production strategy for the Roar Field is to optimize the production of liquid hydrocarbons in the Tyra Field by maximizing production from the other gas fields and thus minimizing gas drainage from Tyra.

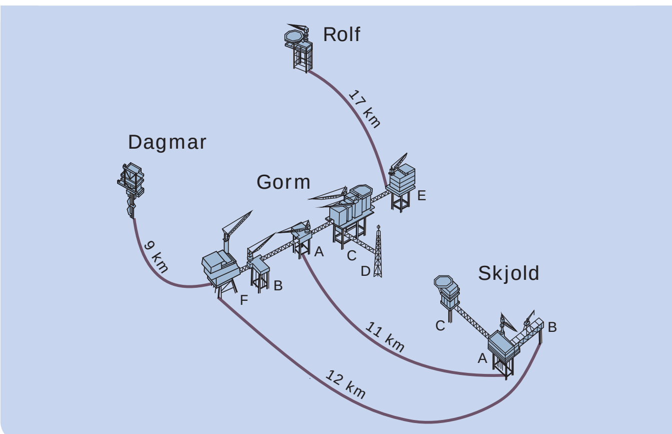
PRODUCTION FACILITIES

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.

THE ROLF FIELD

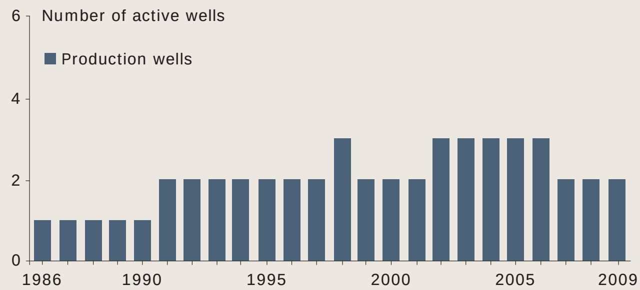






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010
2009 prices DKK 1.16 billion



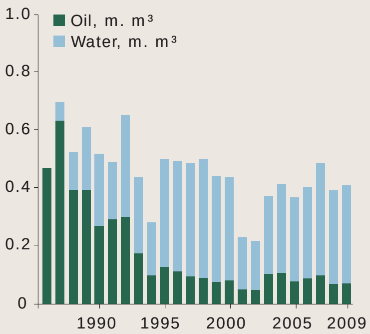
FIELD DATA
At 1 January 2010

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
Field delineation:	22 km^2
Reservoir depth:	1,800 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

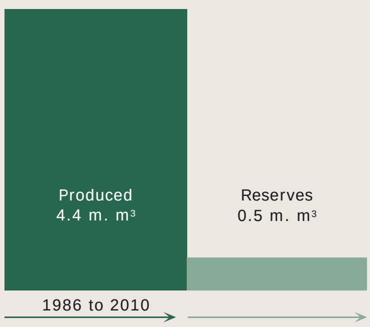
Cum. production at 1 January 2010

Oil:	4.37 m. m^3
Gas:	0.18 bn. Nm^3
Water:	6.57 m. m^3



RESERVES

Oil:	0.5 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.

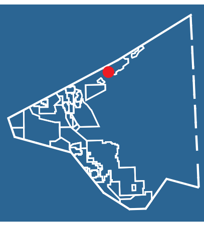
PRODUCTION STRATEGY

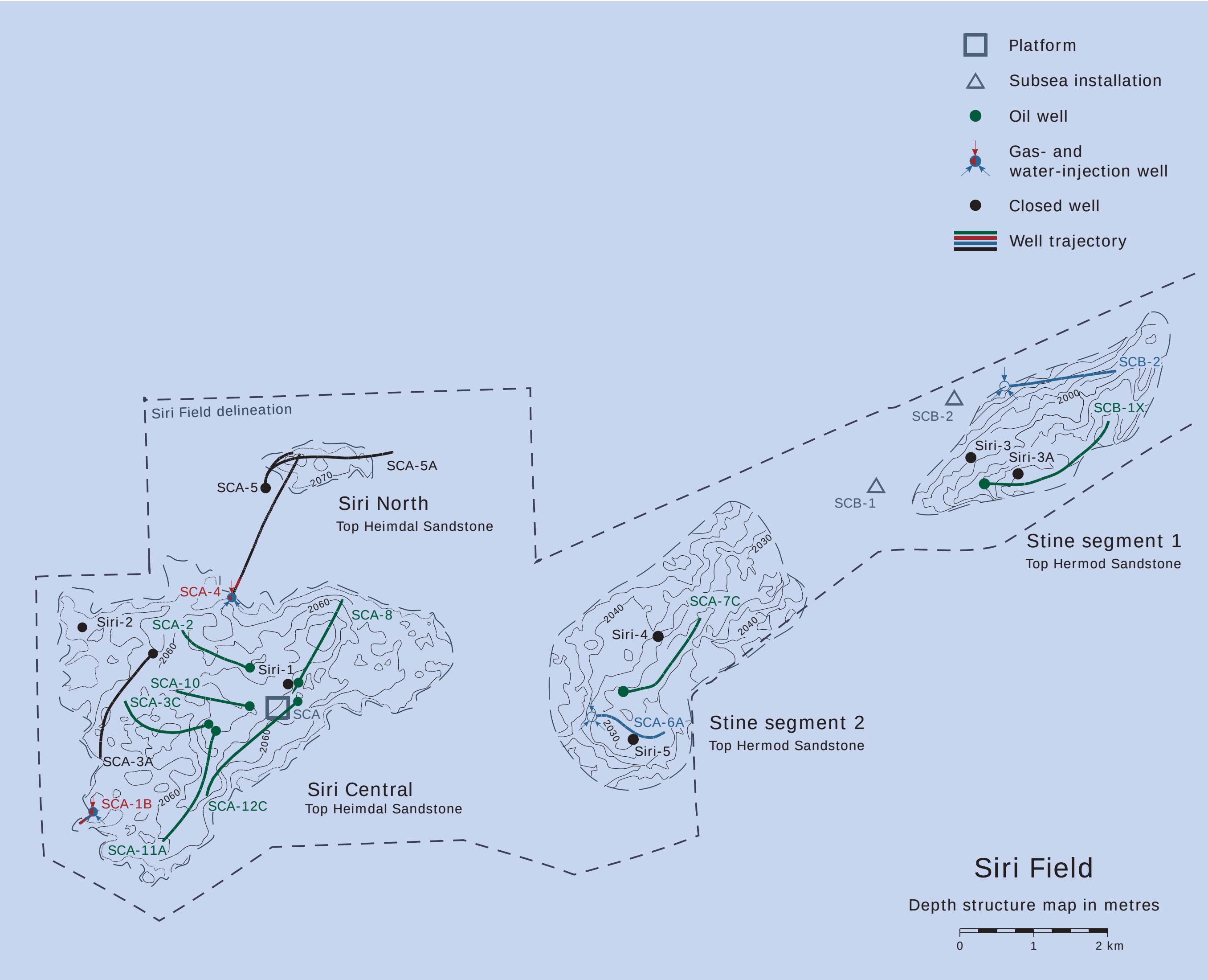
Production from the Rolf Field takes place from two wells drilled in the crest of the structure. The oil is displaced towards the producing wells by the water flow from an underlying aquifer. The natural influx of water from the water zone corresponds to the volume removed due to production in the central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

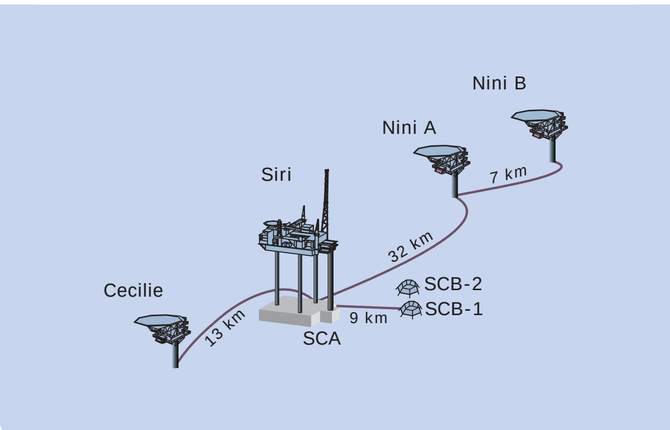
PRODUCTION FACILITIES

The Rolf Field is a satellite development to the Gorm Field with one unmanned well-head 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



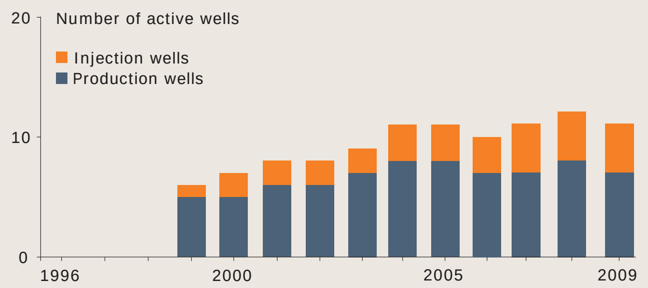




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010

2009 prices DKK 6.41 billion



FIELD DATA

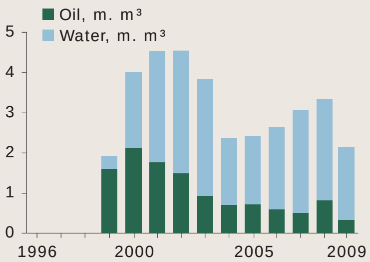
At 1 January 2010

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:	63 km^2
Reservoir depth:	2,060 m
Reservoir rock:	Sandstone
Geological age:	Palaeocene

PRODUCTION

Cum. production at 1 January 2010

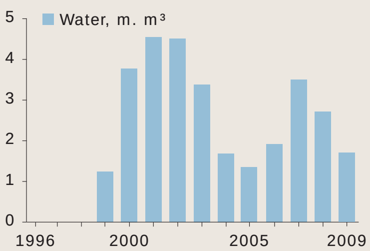
Oil:	11.31 m. m^3
Gas:	1.16 bn. Nm^3
Water:	23.22 m. m^3



INJECTION

Cum. injection at 1 January 2010

Gas:	1.05 bn. Nm^3
Water:	30.31 m. m^3



RESERVES

Oil:	1.8 m. m^3
Gas:	0.0 bn. Nm^3

REVIEW OF GEOLOGY, THE SIRI FIELD

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

PRODUCTION STRATEGY

Recovery 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.

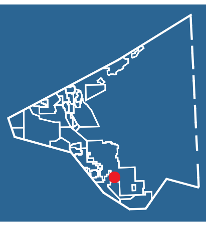
Stine segment 1 (SCB) is developed as a satellite to the Siri platform and consists of two subsea installations with a production well and an injection well.

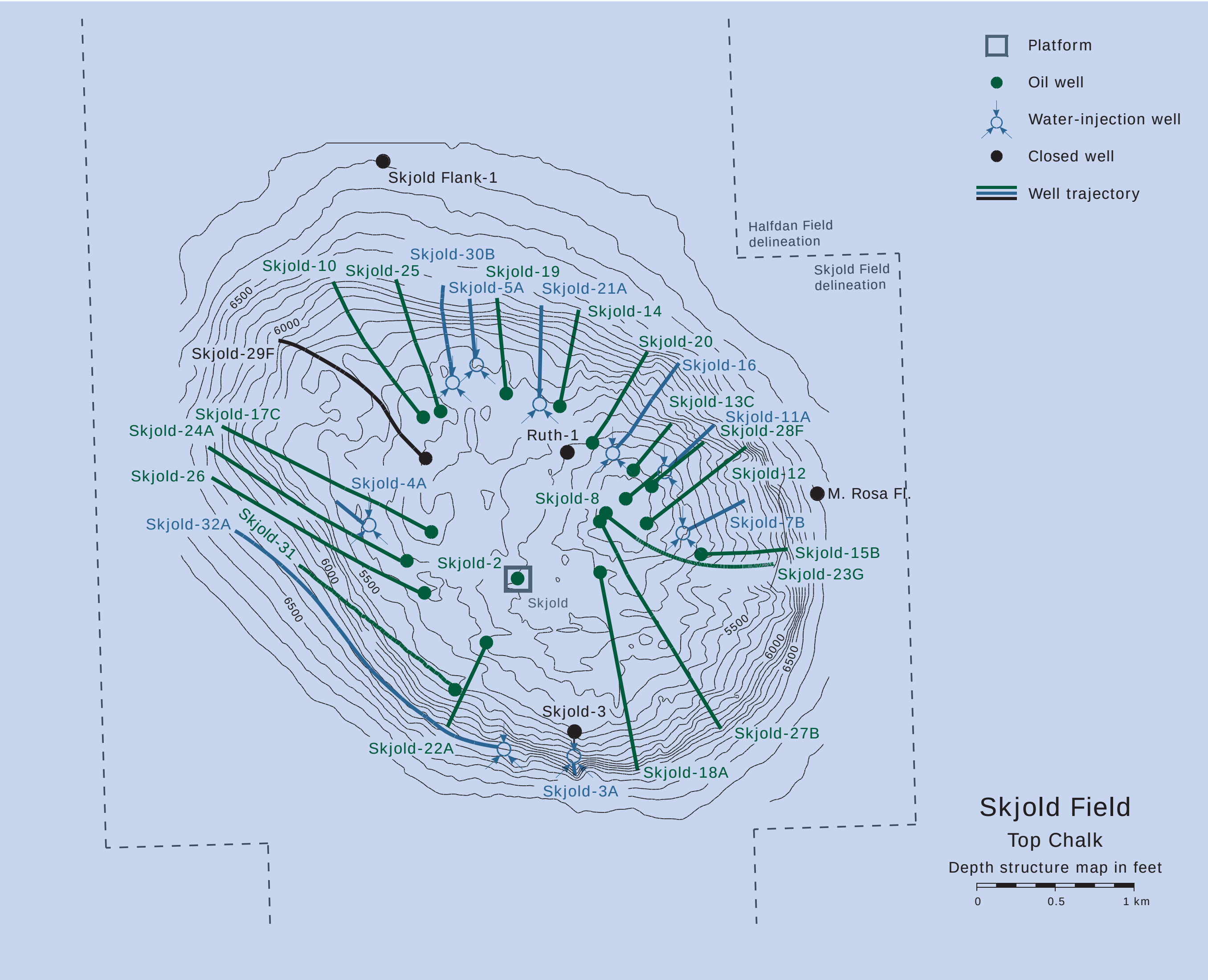
Production from SCB is conveyed to the SCA platform for processing. The SCA platform also supplies injection water and lift gas to the satellite installations at SCB, Nini, Nini East and Cecilie. The water-injection pipeline to Nini was replaced in 2009 and extended by a further pipeline to Nini East. Injection water is supplied to SCB via a branch of this pipeline.

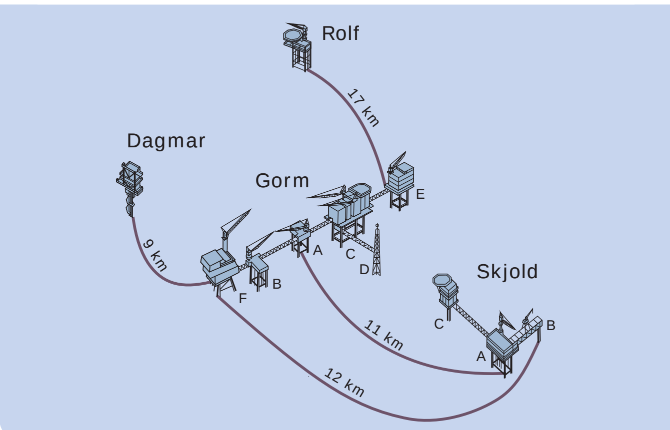
The oil produced is piped to a 50,000 m^3 storage tank on the seabed, and subsequently transferred to a tanker by means of buoy-loading facilities.

The Siri Field has accommodation facilities for 60 persons.

THE SKJOLD FIELD



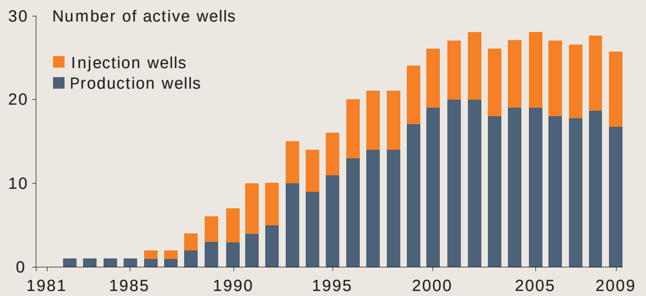




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010

2009 prices DKK 5.78 billion



FIELD DATA

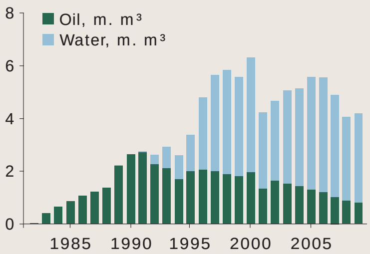
At 1 January 2010

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 and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2010

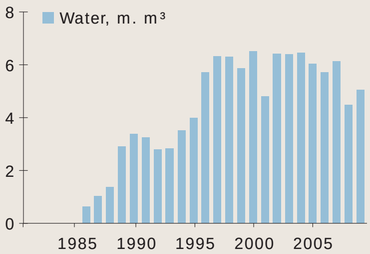
Oil:	42.48 m. m^3
Gas:	3.46 bn. Nm^3
Water:	54.89 m. m^3



INJECTION

Cum. injection at 1 January 2010

Water:	107.47 m. m^3



RESERVES

Oil:	7.6 m. m^3
Gas:	0.4 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

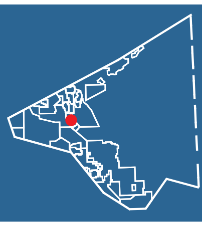
The strategy for producing oil from Skjold is to maintain reservoir pressure by means of water injection. Oil is mainly produced from horizontal wells at the flanks of the reservoir, where the production and injection wells are placed alternately in a radial pattern.

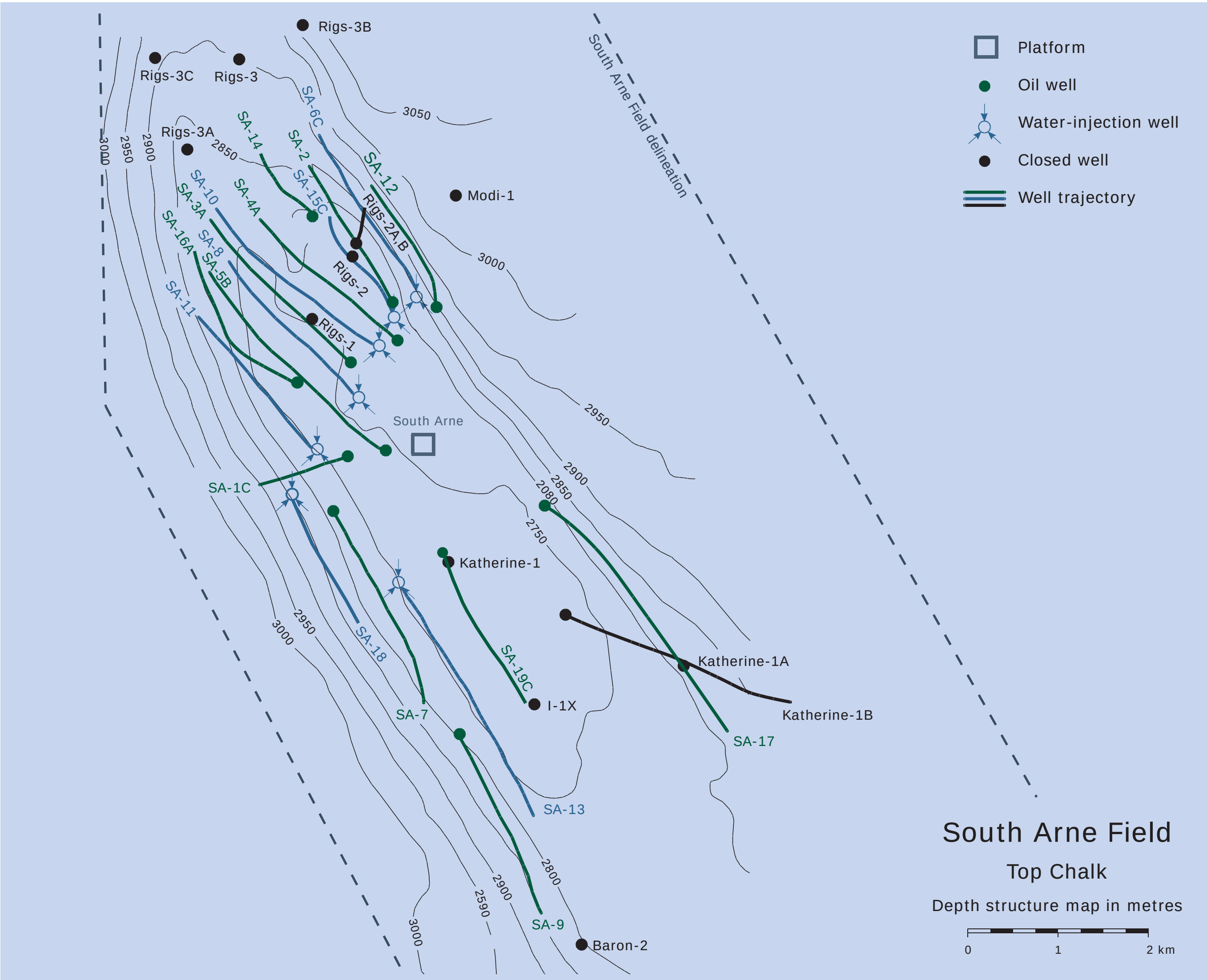
PRODUCTION FACILITIES

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.

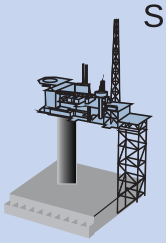
The Skjold C platform has accommodation facilities for 16 persons.

THE SOUTH ARNE FIELD



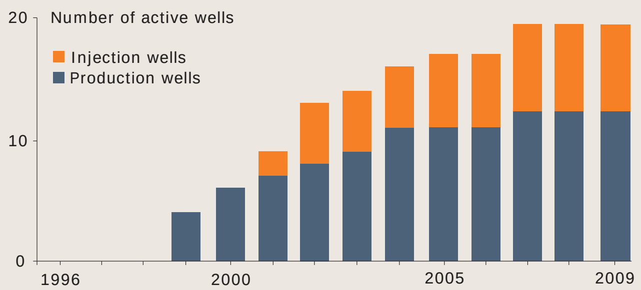


South Arne



DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010
2009 prices DKK 11.04 billion



FIELD DATA

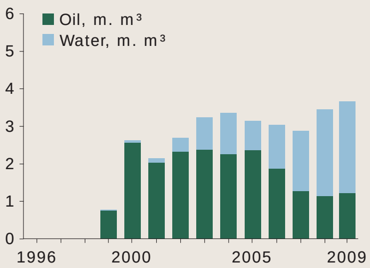
At 1 January 2010

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 and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2010

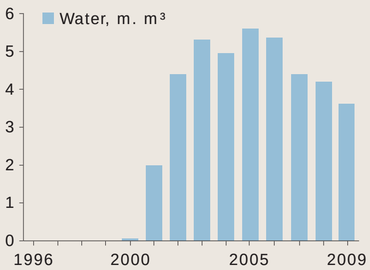
Oil:	20.09 m. m^3
Gas:	4.92 bn. Nm^3
Water:	12.53 m. m^3



INJECTION

Cum. injection at 1 January 2010

Gas:	4.20 bn. Nm^3
Water:	40.14 m. m^3



RESERVES

Oil:	10.5 m. m^3
Gas:	1.9 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

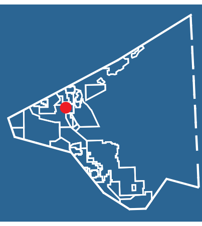
The South Arne Field installations comprise a combined wellhead, processing and accommodation platform.

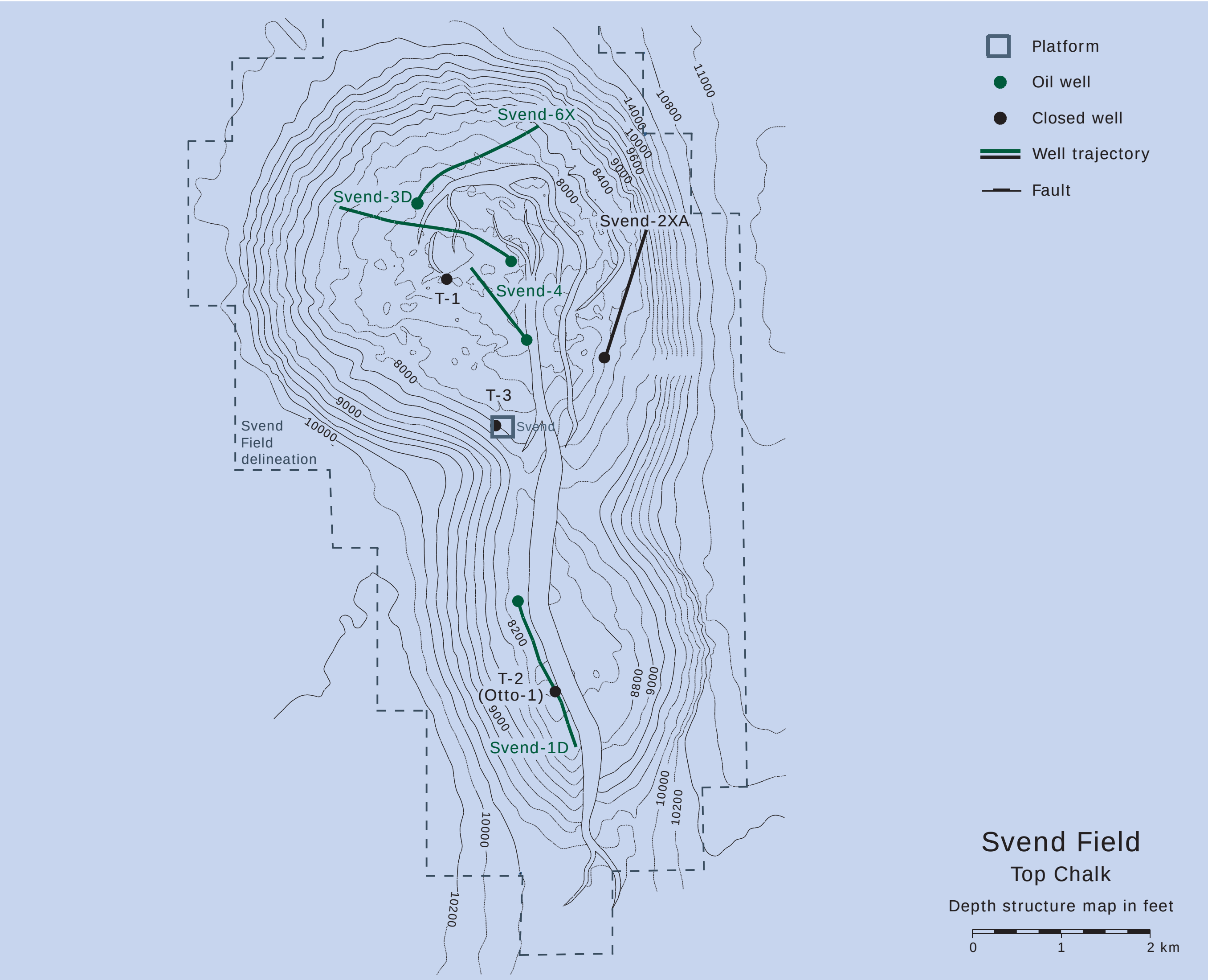
The processing facilities consist of a plant that separates the hydrocarbons produced as well as gas-processing facilities. In addition, processing facilities have been installed to treat the injection water before it is injected. Some of the water produced is injected into the field, while the rest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

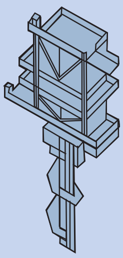
The oil produced is conveyed to an 87,000 m^3 storage tank on the seabed and is exported ashore by tanker. The gas produced is exported through a gas pipeline to Nybro on the west coast of Jutland.

The South Arne Field has accommodation facilities for 57 persons.

THE SVEND FIELD



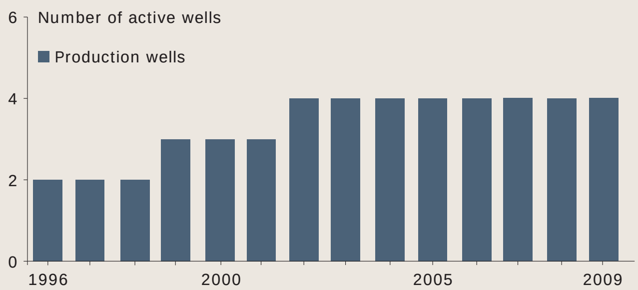




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010

2009 prices DKK 1.26 billion



FIELD DATA

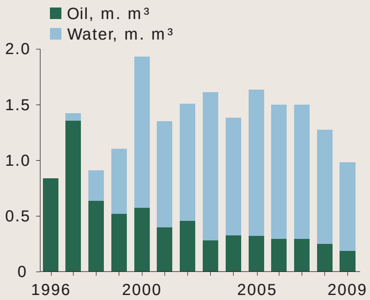
At 1 January 2010

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 2010

Oil:	6.77 m. m^3
Gas:	0.78 bn. Nm^3
Water:	12.18 m. m^3



RESERVES

Oil:	1.0 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, with a major north-south fault dividing the field into a western and an eastern block. In addition, 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.

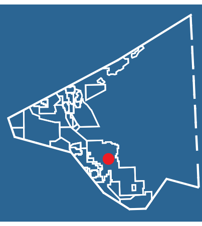
PRODUCTION STRATEGY

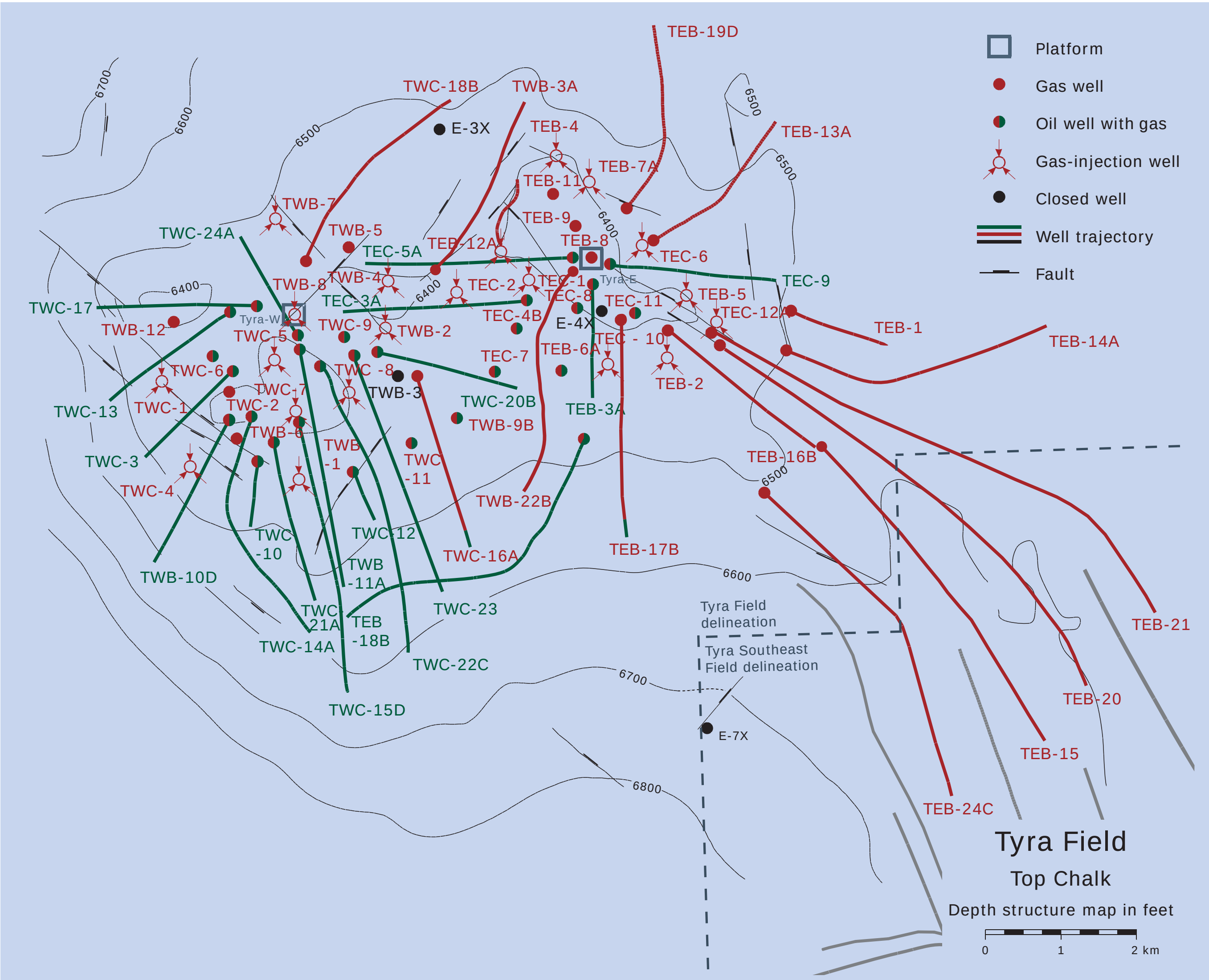
Production is based on primary recovery at a reservoir pressure above the bubble point of the oil, while ensuring maximum production uptime for the wells at the same time.

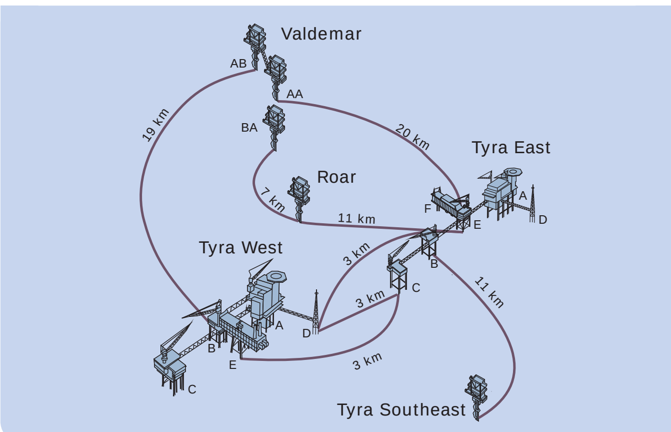
PRODUCTION FACILITIES

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



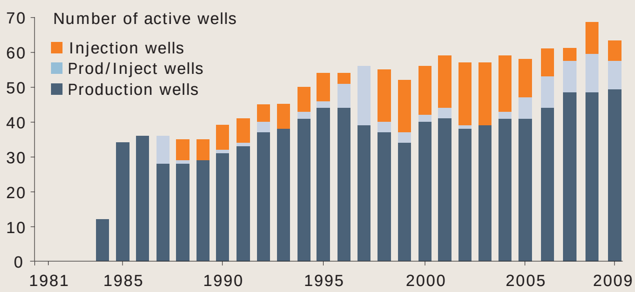




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010

2009 prices DKK 31.73 billion



FIELD DATA

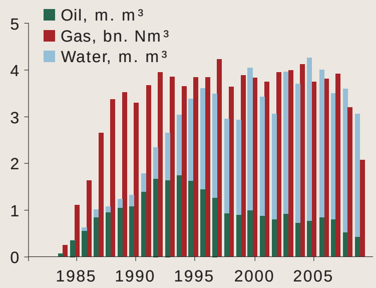
At 1 January 2010

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:	22
Oil-/Gas-prod. wells:	28
Producing/Inj. wells:	18
Water depth:	37-40 m
Field delineation:	177 km^2
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2010

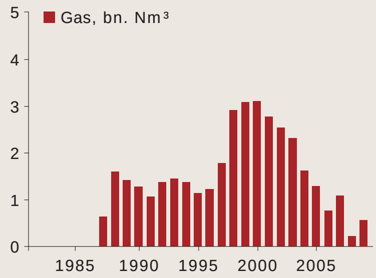
Oil:	25.18 m. m^3
Gas:	86.60 bn. Nm^3
Water:	43.32 m. m^3



INJECTION

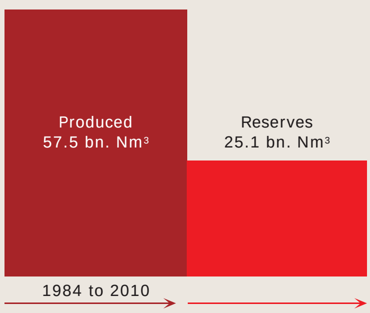
Cum. injection at 1 January 2010

Gas:	36.33 bn. Nm^3



RESERVES*

Oil:	9.6 m. m^3
Gas:	25.1 bn. Nm^3



**) 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 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. The injected dry gas helps delay the decrease in gas cap pressure, thus optimizing the recovery of oil from the Tyra Field. Thus, using the Tyra Field as a buffer helps ensure that the condensate and oil production conditions do not deteriorate as a consequence of the reservoir pressure dropping 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.

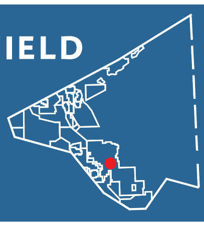
Tyra East consists of two wellhead platforms, TEB and TEC, one processing and accommodation platform, TEA, one gas flare stack, TED, and one riser platform, TEE, as well as a bridge module supported by a STAR jacket, TEF.

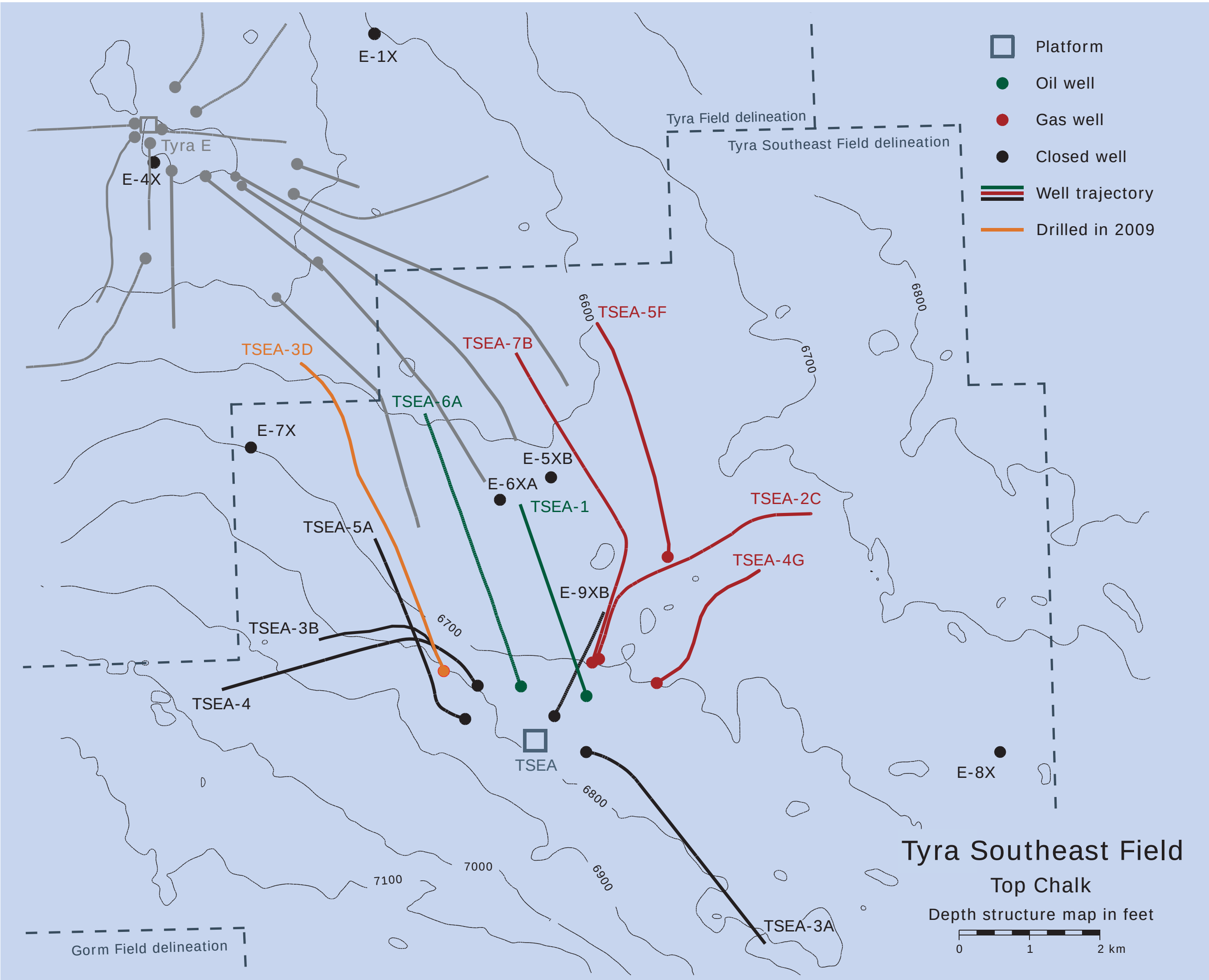
Tyra East receives production from the satellite fields, Valdemar, Roar, Svend, Tyra Southeast and Harald/Lulita, as well as gas production from Gorm, Dan and parts of Halfdan D. The Tyra East complex includes facilities for the final processing of gas, oil, condensate and water. Treated production water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

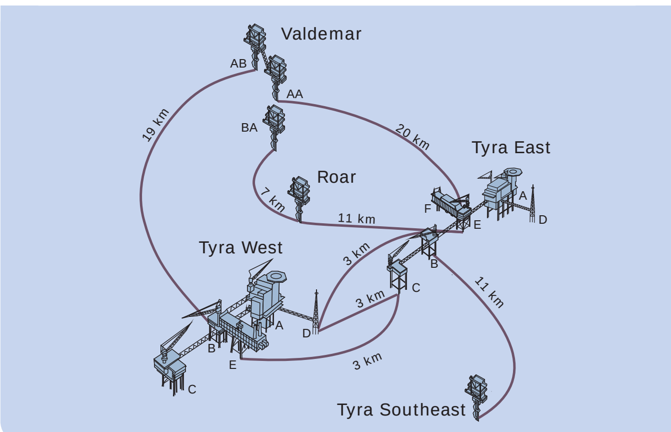
The two platform complexes in the Tyra Field are interconnected by pipelines in order to yield the maximum operational flexibility and security of supply. Oil and condensate production from the Tyra Field and its satellite fields is transported ashore via Gorm E. The bulk of gas produced is transported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



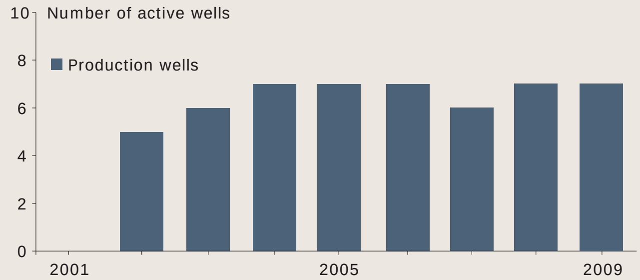




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010

2009 prices DKK 2.23 billion



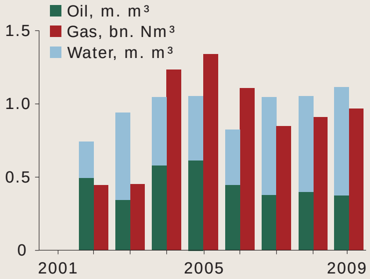
FIELD DATA At 1 January 2010

Location:	Block 5504/12
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas AS
Discovered:	1991
Year on stream:	2002
Oil-producing wells:	2
Gas-producing wells:	5
Water depth:	38 m
Field delineation:	142 km^2
Reservoir depth:	2,050 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

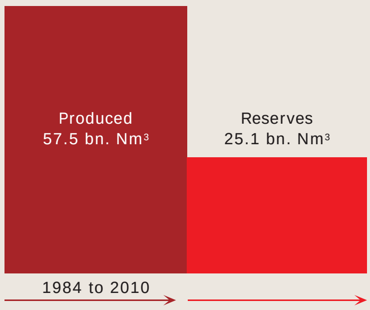
Cum. production at 1 January 2010

Oil:	3.65 m. m^3
Gas:	7.25 bn. Nm^3
Water:	4.11 m. m^3



RESERVES*

Oil:	9.6 m. m^3
Gas:	25.1 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.

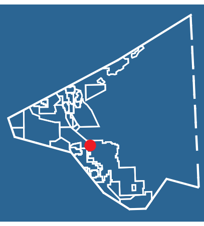
PRODUCTION STRATEGY

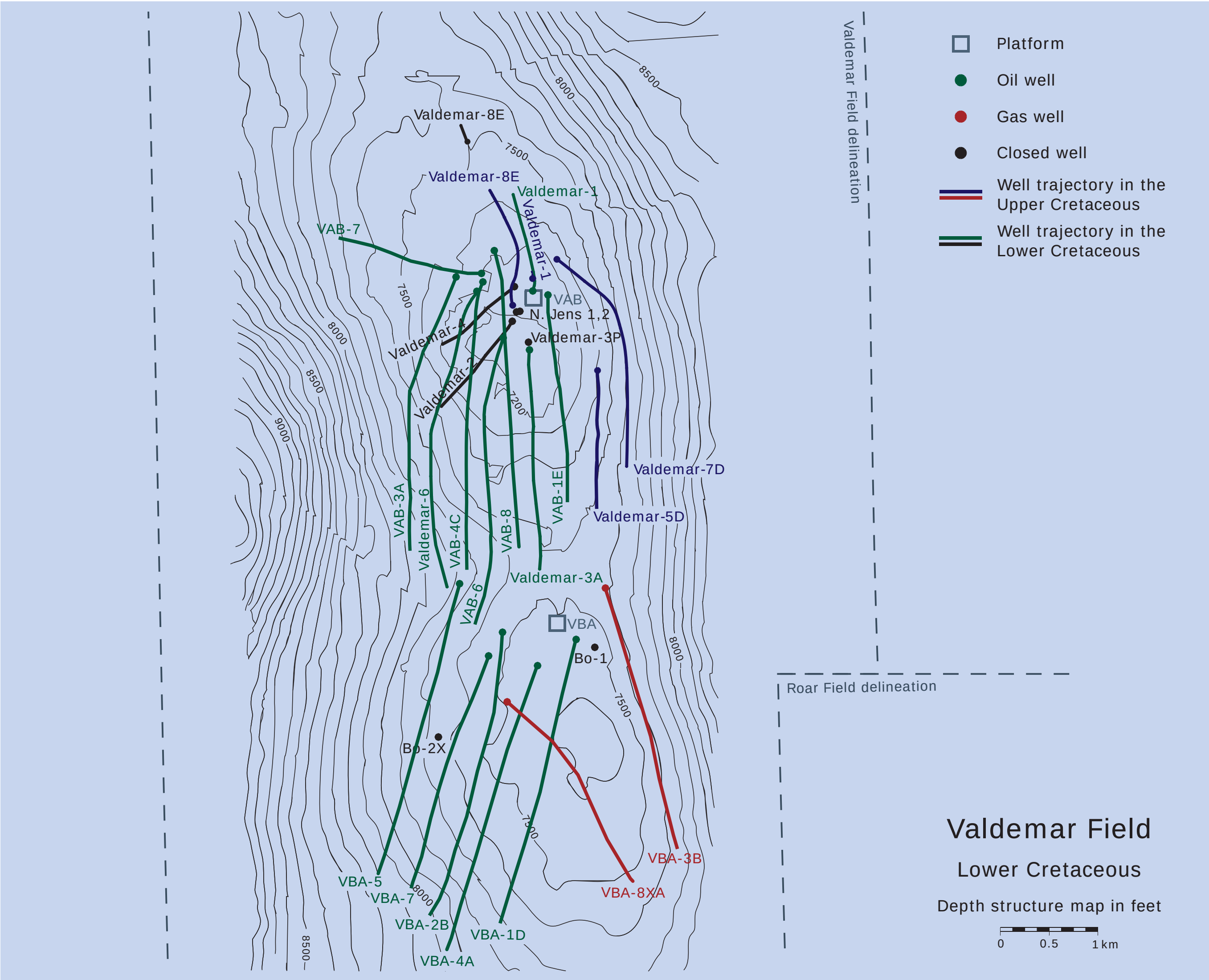
The production of oil and gas is based on natural depletion.

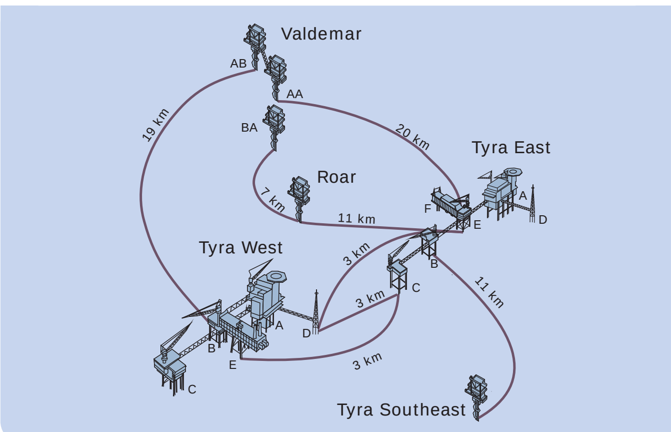
PRODUCTION FACILITIES

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



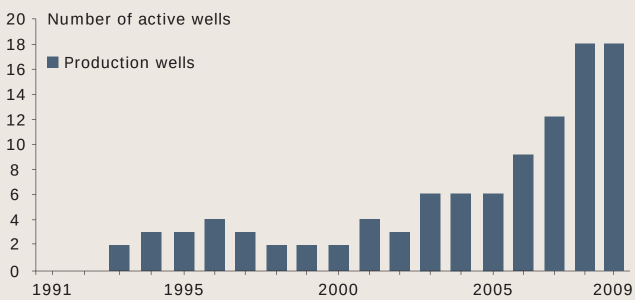




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2010

2009 prices DKK 6.44 billion



FIELD DATA

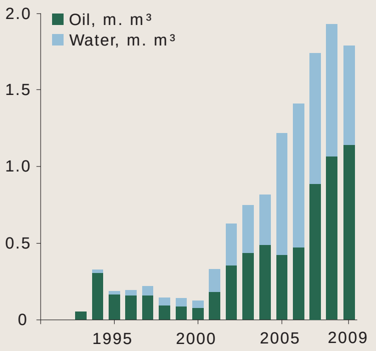
At 1 January 2010

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:	110 km^2
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 2010

Oil:	7.01 m. m^3
Gas:	2.91 bn. Nm^3
Water:	5.67 m. m^3



RESERVES

Oil:	11.1 m. m^3
Gas:	5.9 bn. Nm^3

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, while the reservoir layers in the Bo area have proven to have better production properties. The properties of the Upper Cretaceous reservoirs are comparable to other Danish fields like Gorm and Tyra.

The Upper and Lower Cretaceous reservoirs have been developed in both the Bo and North Jens areas.

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, RESERVES AND CONTINGENT RESOURCES AT 1 JANUARY 2010

OIL, m. m³	Produced	Resources Low	Resources Exp.
		Reserves	
Ongoing recovery and approved for development			
Adda	-	0.1	0.2
Alma	-	0.2	0.4
Boje area	-	0.9	1.4
Cecilie	1.0	0.2	0.4
Dagmar	1.0	-	-
Dan	98.8	7.1	15.3
Elly	-	0.2	0.4
Gorm	58.0	2.8	5.2
Halfdan	46.2	33.8	53.0
Harald	7.8	0.3	0.5
Kraka	4.9	0.4	1.2
Lulita	0.9	0.0	0.2
Nini	3.7	2.3	3.4
Regnar	0.9	-	-
Roar	2.6	0.1	0.1
Rolf	4.4	0.2	0.5
Siri	11.3	1.3	1.8
Skjold	42.5	3.0	7.6
South Arne	20.1	9.1	10.5
Svend	6.8	0.5	1.0
Tyra**	28.8	2.2	9.6
Valdemar	7.0	3.9	11.1
Justified for development	-	11	22
Subtotal	**347**		**146**
		Contingent resources	
Development pending	-	*6*	*13*
Development unclarified	-	*12*	*24*
Development not viable	-	*5*	*11*
Subtotal			**48**
Total	**347**		**194**
January 2009	331		200

GAS, bn. Nm³	Net produced*	Net gas* Low	Net gas* Exp.	Sales gas* Exp.
		Reserves		
Ongoing recovery and approved for development				
Adda	-	0.1	0. 2	0
Alma	-	0.4	0.7	0
Boje area	-	0.4	0.8	1
Cecilie	0.1	-	-	-
Dagmar	0.2	-	-	-
Dan	22.4	0.8	1.5	0
Elly	-	1.4	3.9	4
Gorm	7.3	0.3	0.5	0
Halfdan	18.8	12.3	17.3	14
Harald	20.7	1.7	3.2	3
Kraka	1.4	0.1	0.3	0
Lulita	0.6	0.0	0.2	0
Nini	0.3	-	-	-
Regnar	0.1	-	-	-
Roar	14.5	0.9	1.1	1
Rolf	0.2	0.0	0.0	0
Siri	0.1	-	-	-
Skjold	3.5	0.1	0.4	0
South Arne	4.9	1.7	1.9	1
Svend	0.8	0.1	0.1	0
Tyra**	57.5	9.1	25.1	20
Valdemar	2.9	2.0	5.9	5
Justified for development	-	8	16	14
Subtotal	**156**		**79**	**64**
		Contingent resources		
Development pending	-	*3*	*7*	*4*
Development unclarified	-	*5*	*9*	*7*
Development not viable	-	*3*	*10*	*10*
Subtotal			**26**	**21**
Total	**156**		**105**	**85**
January 2009	148		107	

*) Net production: historical production less injection
Net gas: future production less injection
Sales gas: future production less injection and less fuel gas and flaring
**) Tyra Southeast included

APPENDIX D: FINANCIAL KEY FIGURES

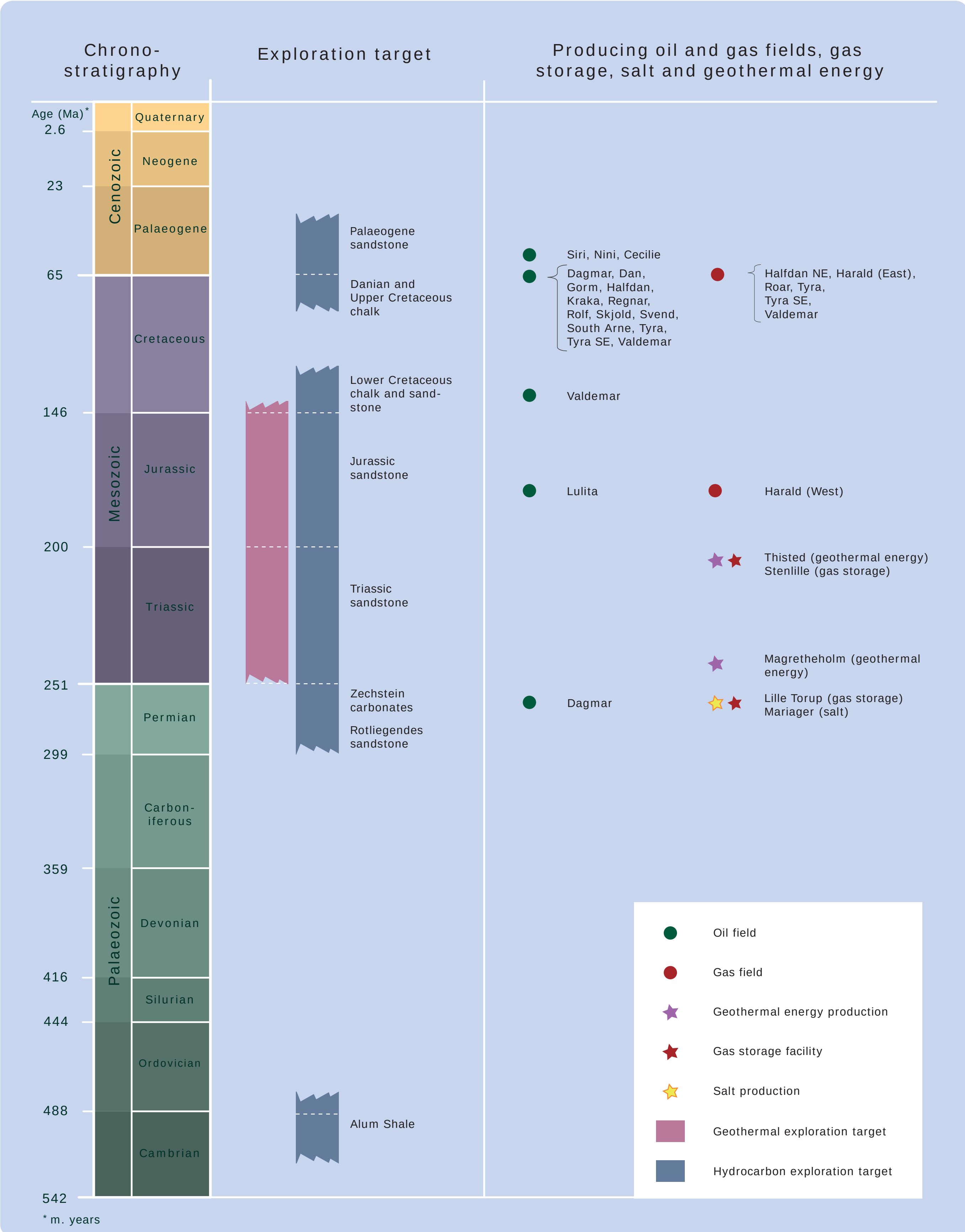
	Investments in field dev. DKK million 5)	Field operating costs DKK million 1)	Exploration costs DKK million	Crude oil price USD/bbl 2)	Exchange rate DKK/USD	Inflation per cent 3)	Net foreign-currency value DKK billion 4)	State revenue DKK million
1972	105	29	30	3.0	7.0	6.7	-3.2	-
1973	9	31	28	4.6	6.1	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	10,137
2003	7,386	3,522	789	28.8	6.6	2.1	15.3	9,255
2004	5,104	3,289	340	38.2	6.0	1.2	19.7	17,092
2005	3,951	3,760	578	54.4	6.0	1.8	24.8	24,163
2006	5,007	4,744	600	65.1	5.9	1.9	31.5	31,493
2007	6,524	4,129	547	72.5	5.4	1.7	28.3	27,886
2008	5,879	5,402	820	97.2	5.1	3.4	27.1	35,913
2009*	7,050	4,556	1,245	61.6	5.4	1.3	14.6	24,282

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*

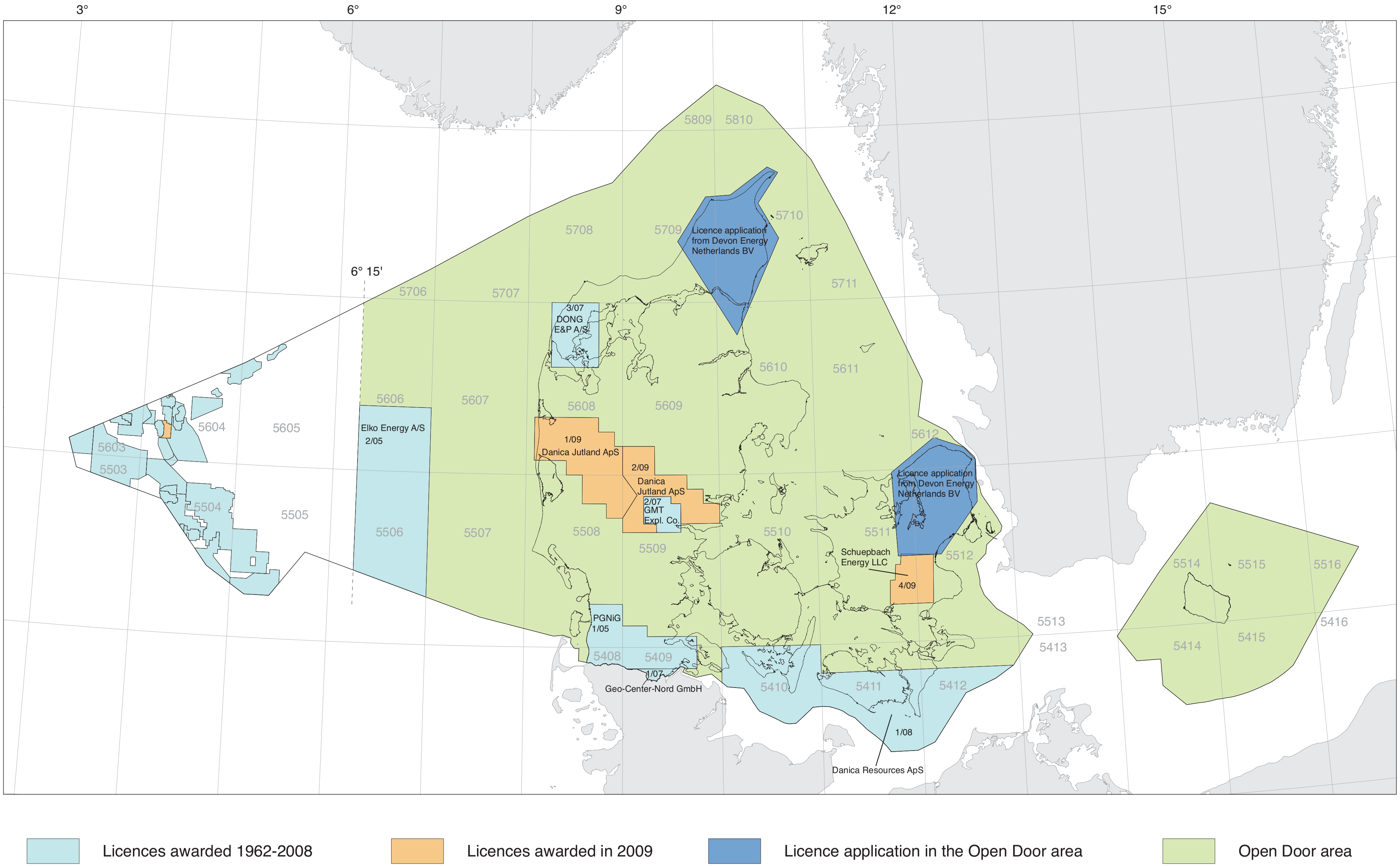
APPENDIX E: EXISTING FINANCIAL CONDITIONS

	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: 1,000 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/compensatory fee 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/compensatory fee 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 F: GEOLOGICAL TIME SCALE

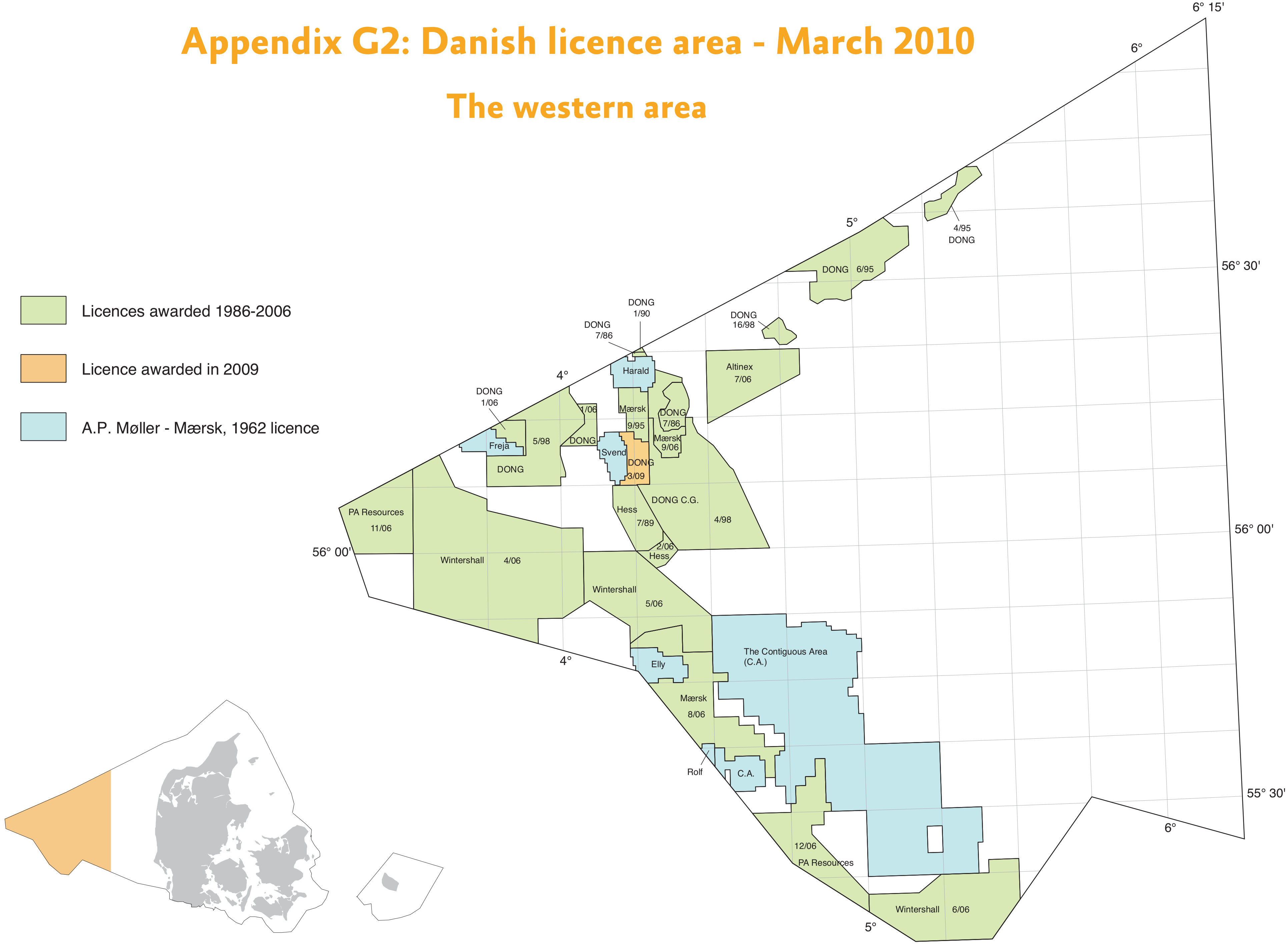


Appendix G1: Danish licence area - March 2010



Appendix G2: Danish licence area - March 2010

The western area



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 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 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.

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: 15°C and 101.325 kPa in this report.*
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	36.55 [i]
	m^3 (st)	t	0.86 [i]
Natural gas	Nm^3	scf	37.2396
	Nm^3	GJ	0.03946 [i]
	Nm^3	t.o.e.	$942.49 \cdot 10^{-6}$ [i]
	Nm^3	kg · mol	0.0446158
	m^3 (st)	scf	35.3014
	m^3 (st)	GJ	0.03741 [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	947,817
	cal	J	4.1868*
	FROM	**TO**	**CONVERSION**
Density	°API	kg/m^3	141,364.33 / (°API+131.5)
	°API	γ	141.5 / (°API+131.5)

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

The Danish Energy Agency, DEA, was established in 1976 and is placed under the Ministry of Climate and Energy. The DEA works nationally and internationally with tasks related to energy supply and consumption, including renewable energy and security of supply, as well as 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.

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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 "Denmark's Oil and Gas Production".

As in previous years, the report for 2009 describes exploration and development activities in the Danish area as well as production. Moreover, the report describes the use of the Danish subsoil for purposes other than oil and gas production, 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 website: www.ens.dk

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