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

As in previous years, the report for 2007 describes exploration and development activities in the Danish area. The report also contains a review of production and the health, safety and environmental aspects of oil and gas production activities.

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

The report can be obtained from the Danish Energy Agency's website http://ens.netboghandel.dk/English/.

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# Oil and Gas Production in Denmark 07

DANISH ENERGY AGENCY

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

The DEA also has responsibility for national climate change initiatives.

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

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

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

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# PREFACE

The strong global demand for oil impacts on energy prices and the security of supply, also in Denmark.

In 2007, the Danish Government presented an energy strategy containing a number of ambitious goals for Danish energy policy until 2025. In February 2008, all parties in the Danish Parliament, with the exception of the Red-Green Alliance, concluded the Energy Agreement, which defines goals and strategies for the Danish energy system until 2011.

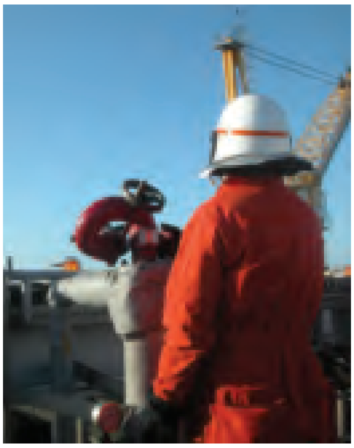
The agreement provides for the further expansion of renewable energy, a reduction in energy consumption and more efficient energy use. For the oil and gas sector, the agreement includes strategies for identifying avenues of action and setting up initiatives that will improve the energy efficiency of North Sea production activities. This work is to be completed in the course of 2008.

The agreement is aimed to reduce Denmark's dependency on coal, oil and natural gas. However, despite concentrated efforts to expand renewable energy and generate energy savings, the Danish oil and gas sector will continue having significant influence on the Danish economy and security of supply for many years ahead.

Despite an appreciable decline in oil and gas production, the Danish state generated close to DKK 28 billion in revenue from the North Sea activities in 2007. After growing for many years, state revenue in 2007 recorded its first downward trend. The decrease of about DKK 3 billion compared to 2006 results from a natural decline in production and a falling dollar exchange rate that could not be fully offset by increasing oil prices.

Continued high oil prices are spurring oil companies to invest in exploration, field developments and technological developments, and the DEA expects investments in exploration to increase over the next few years. These activities in particular are expected to curb the decline in oil and gas production and thus hopefully enable Denmark to continue deriving substantial income from future activities in the North Sea.

High health and safety standards in the Danish offshore sector are crucial to the people working on board offshore installations. Therefore, the DEA has launched a new supervision strategy that reflects the objectives of the Offshore Safety Act from 2006, with the aim of keeping health and safety standards among the highest in the North Sea countries.



Copenhagen, June 2008

Ib Larsen

# 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 tons and GJ are dependent on time. The table below shows the average for 2007 based on figures from refineries. The lower calorific value is indicated.

The SI prefixes m (milli), k (kilo), M (mega), G (giga), T (tera) and P (peta) stand for $10^{-3}$, $10^{3}$, $10^{6}$, $10^{9}$, $10^{12}$ and $10^{15}$, respectively.

A somewhat special prefix is used for oil field units: M (roman numeral 1,000). Thus, the abbreviated form of one million stock tank barrels is 1 MMstb, and the abbreviation used for one billion standard cubic feet is 1 MMMscf or 1 Bscf.

**Some abbreviations:**

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

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

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

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

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

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

*γ* — *gamma; relative density.*

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

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

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

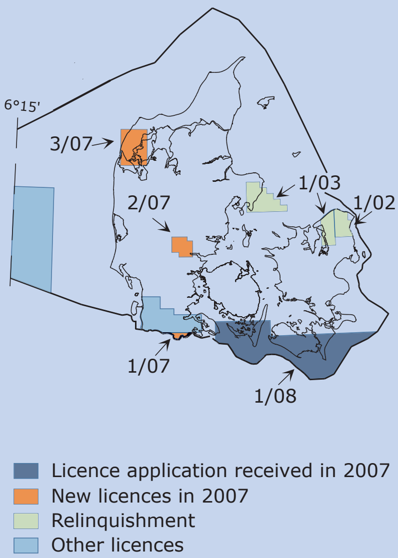
| | FROM | TO | MULTIPLY BY |
|---|---|---|---|
| Crude oil | $m^3$ (st) | stb | 6.293 |
| | $m^3$ (st) | GJ | 36.3 |
| | $m^3$ (st) | t | 0.86[i] |
| Natural gas | $Nm^3$ | scf | 37.2396 |
| | $Nm^3$ | GJ | 0.03959 |
| | $Nm^3$ | t.o.e. | $945.59 \cdot 10^{-6}$ |
| | $Nm^3$ | kg · mol | 0.0446158 |
| | $m^3$ (st) | scf | 35.3014 |
| | $m^3$ (st) | GJ | 0.03753 |
| | $m^3$ (st) | kg · mol | 0.0422932 |
| Units of volume | $m^3$ | bbl | 6.28981 |
| | $m^3$ | $ft^3$ | 35.31467 |
| | US gallon | $in^3$ | 231* |
| | bbl | US gallon | 42* |
| Energy | t.o.e. | GJ | 41.868* |
| | GJ | Btu | 947817 |
| | cal | J | 4.1868* |
| | **FROM** | **TO** | **CONVERSION** |
| Density | °API | $kg/m^3$ | 141364.33/(°API+131.5) |
| | °API | γ | 141.5/(°API+131.5) |

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

# CONTENTS

# 1 LICENCES AND EXPLORATION

**Fig. 1.1** New and relinquished Open Door licences




The exploration resulting from the new 6th Round licences made an auspicious start with the discovery of oil in the first well drilled, Rau-1.

The fact that three new licences were granted in the Open Door area and that yet another application for a licence was received in 2007 signals the oil companies' sustained interest in exploring the Danish subsoil, also outside the areas traditionally explored in the North Sea.

## OPEN DOOR LICENCES

In 2006, the DEA received three applications for licences in the Open Door area. On 12 February 2007, after the DEA had considered the applications, discussed them with the applicants and submitted them to the Energy Policy Committee of the Danish Parliament, the then Minister for Transport and Energy granted all three applicants licences for hydrocarbon exploration and production in the areas applied for; see figure 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 western part of the North Sea.

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

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

Licence 1/07 was granted to Geo-Center-Nord GmbH, 80 per cent, and the Danish North Sea Fund, 20 per cent. The licence comprises an area in the eastern part of South Jutland and surrounding waters. Geo-Center-Nord GmbH, a company incorporated in Germany, is the operator of the licence. This company has not previously held licence shares in Danish territory, but has an interest in a German licence due south of the above-mentioned area.

Licence 2/07 was granted to Jordan Dansk Corporation, 80 per cent, and the Danish North Sea Fund, 20 per cent. The licence covers an area northwest of Vejle in Jutland. Jordan Dansk Corporation, the operator of the licence, is an oil company incorporated in the USA. The company held a licence share in the same area during the period 1989-1993.

Licence 3/07 was granted to DONG E&P A/S, 80 per cent, and the Danish North Sea Fund, 20 per cent. DONG E&P A/S is the operator of the licence, which comprises an area in northwestern Jutland.

On 31 August 2007, Danica Resources ApS, a newly established Danish company, applied for a licence to explore for and recover hydrocarbons in an area in the western part of the Baltic Sea and in onshore areas on the islands of Lolland-Falster and

Langeland. Together with the Danish North Sea Fund, 20 per cent, Danica Resources ApS, 80 per cent, was granted a licence for this area, licence 1/08, on 31 March 2008. Danica Resources ApS is the operator of the licence.

## EXPLORATION POTENTIAL IN THE OPEN DOOR AREA

All commercial oil and gas discoveries in Denmark to date have been made in or around the Central Graben west of the Open Door area in the North Sea. Hydrocarbons have been encountered at great depths in geological layers consisting of chalk or sandstone. In terms of exploration, the area is mature as a great amount of well, seismic and production data is available.

Exploration activity in the Open Door area has been less intense, for which reason the presence of source and reservoir rock is more uncertain here; see box 1.1.

Figure 1.3b shows a cross-section through the Danish subsoil from the Central Graben up through the Danish Basin to the Skagerrak and Kattegat. The figure shows that the known Upper Jurassic oil-generating rock is buried at great depths in the Central Graben towards the west.

As the Upper Jurassic layers in the eastern part of the cross-section (the Open Door area) are not buried so deeply, they will not have been subjected to sufficiently high pressure and temperature conditions to generate hydrocarbons.

Therefore, in the Open Door area, oil and gas must have been formed by older layers than those which generated the oil discovered in the Central Graben.

It has proved difficult to find locations with the right combination of source rock, reservoir rock, migration and seal in the Open Door area. New data and a better understanding of existing data can be the key to discovering oil and gas fields in the area. New techniques for interpreting subsoil data can also aid in improving the understanding of hydrocarbon systems and selecting new exploration targets. In addition, ideas and experience from other parts of the world may contribute to successful exploration in the Open Door area.

**Box 1.1**

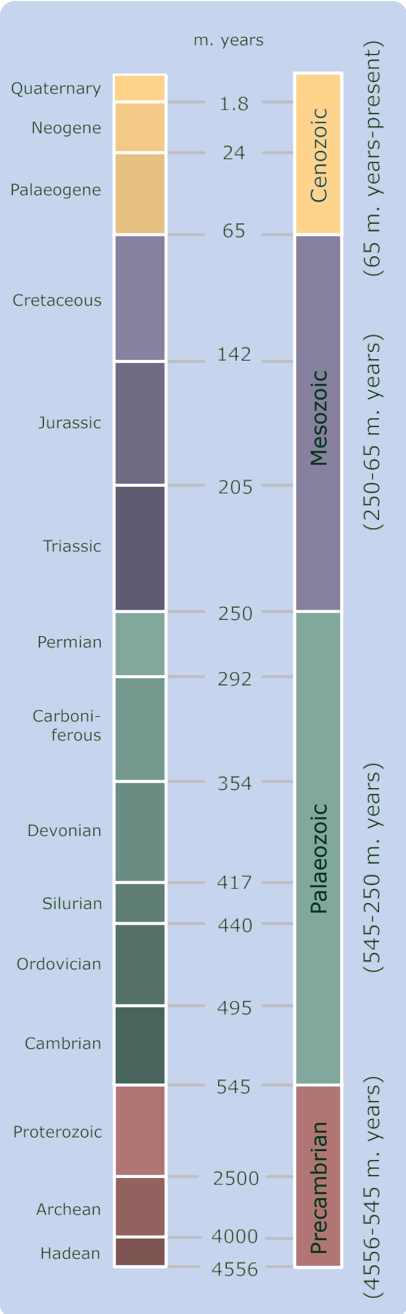
**Source rock** is a rock that contains so much organic matter that it has the potential to generate hydrocarbons, i.e. oil and gas, under the right temperature and pressure conditions.

**Reservoir rock** is a porous rock that may contain water, oil or gas in the pores between the mineral grains.

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

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

**Fig. 1.2** Stratigraphic chart




**Potential source rocks**

The greatest uncertainty concerning exploration in the Open Door area is associated with source rock.

For organic matter in the source rock to transform into hydrocarbons, it must be exposed to the right temperature and pressure conditions. Consequently, the source rock must be buried at a certain depth. A source rock not buried at a sufficient depth is termed immature. However, if it is buried at too great a depth, it is over-mature. If the source rock is over-mature, hydrocarbons can no longer form. Any amount of oil or gas formed in the source rock will presumably have seeped up towards the surface during the millions of years since its formation.

Because of the lower burial depth of source rock in the Open Door Area, it is uncertain whether sufficient amounts of oil and gas have been formed. Examples of potential source rocks are claystone with beds of coal from the Carboniferous period or shale with a high organic content from the Cambrian and Ordovician periods; see figure 1.2.

Data on the extent of source rocks is scarce for large parts of the Open Door area. Intensified exploration activity is required to interpret the geological formation history of hydrocarbons and their subsequent migration from source rocks to reservoir rocks.

**Potential reservoirs**

In most of the Danish subsoil, there are one or more porous sandstone formations that could contain oil or gas accumulations under the right conditions.

In the Danish Basin, the most important reservoirs consist of sandstone from the Triassic and Jurassic periods; see figures 1.2 and 1.3a. During the Triassic and early Jurassic periods, large parts of Denmark and the North Sea were land areas. In the uppermost (youngest) section of the Triassic the sea level began rising. It continued to rise up through the Jurassic, and the sea covered most of Denmark at that time. Some of the most important reservoirs from this period were formed by sand deposited in the coastal zone or in rivers in the areas still covered by land.

Sandstone formations from the Triassic and Jurassic have good reservoir potential, due to relatively high porosity of up to 30 per cent and thicknesses of up to 100 metres.

Carbonates in the Upper Permian can also function as reservoirs and can have a porosity of up to 15 per cent. In the North German Basin and the Danish Basin, such carbonates might function as reservoirs; see figure 1.3a.

## AMENDED LICENCES

**Approved transfers**

All contemplated transfers of licences and the relevant transfer conditions must be submitted to the DEA for approval.

In 2007, DONG Energy took over the company ConocoPhillips Petroleum International Corporation Denmark, incorporating it as a DONG Energy subsidiary. Thus, DONG also took over ConocoPhillips' shares and operatorships of licences 4/98, 5/98 and 1/06. With effect from 21 May 2007, the name of the subsidiary was changed to DONG Central Graben E&P Ltd. Subsequently, the DEA approved the

**Fig. 1.3a** Map of the Danish area. The Open Door area is situated east of 6°15 eastern longitude.

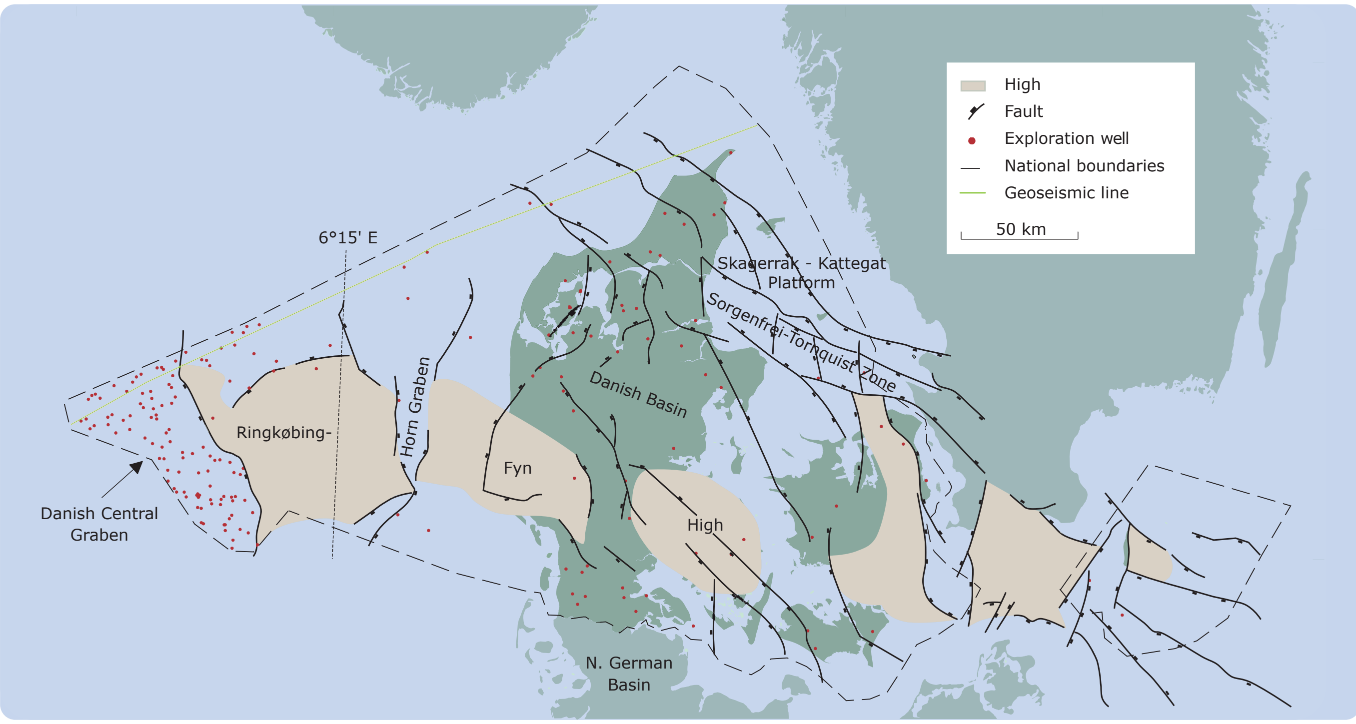



**Fig. 1.3b** Geoseismic cross-section of the Danish area.

A geoseismic cross-section of the Danish area, based on line RTD-81-22 (fig. 1.3a, green line), gives an overview of the thickness variations of the sedimentary deposits between the Danish Central Graben and the Danish Basin (modified after Vejbæk 1997).

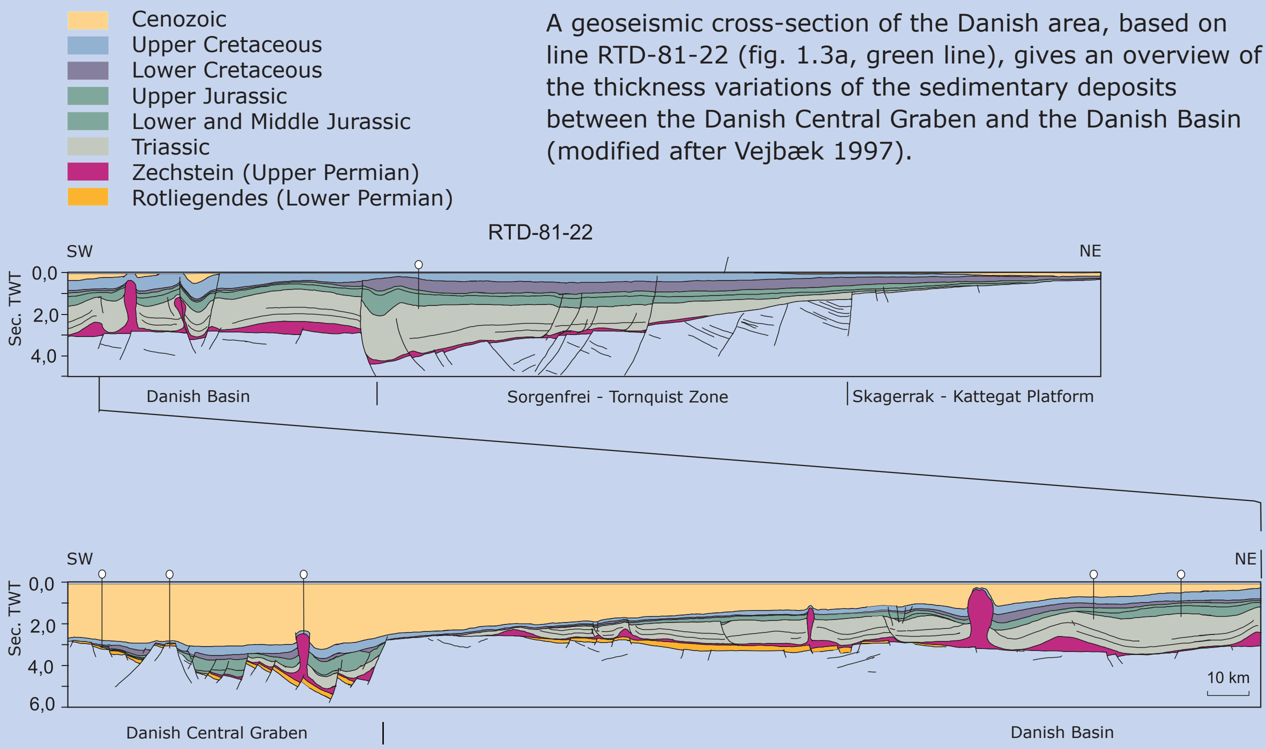
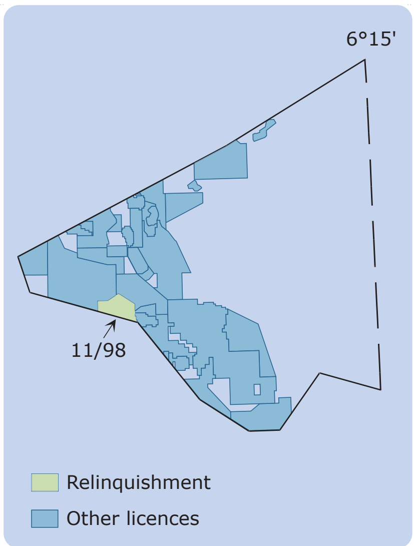


**Fig. 1.4** Relinquishment west of 6°15' eastern longitude




**Conditions of licences**

Licences for the exploration for and production of hydrocarbons are generally granted for a six-year term. Each licence includes a work programme specifying the exploration that the licensee must carry out, including time limits for conducting the individual seismic surveys and drilling exploration wells.

After the six-year term, the DEA may extend the term of a licence by up to two years at a time, provided that the licensee, upon carrying out the original work programme, is prepared to undertake additional exploration commitments. However, some licences may stipulate that the licensee is obligated to carry out specific work, such as the drilling of an exploration well, or to relinquish the licence by a certain date during the six-year term of the licence.

Generally, data that companies acquire under licences granted in pursuance of the Subsoil Act is protected by a five-year confidentiality clause. However, the confidentiality period is limited to two years if the licence has expired or been relinquished. When the confidentiality period has expired, other oil companies are given access to the data acquired from exploration wells and seismic surveys. 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).

transfer of DONG Central Graben Ltd.´s 30 per cent share of licence 5/98 and 24 per cent share of licence 1/06, including the operatorships under the two licences, to DONG E&P A/S. The transfer became effective on 1 July 2007.

The DEA approved the transfer of weXco ApS´ 40 per cent share of licence 1/05 to Polskie Górnictwo Naftowe i Gazownictwo SA (PGNiG), the Polish state-owned oil company. At the same time, PGNiG took over the operatorship under the licence. The transfer became effective on 13 December 2007.

Other amendments with regard to licence shares or areas, etc. are mentioned in the outline of licences at the DEA's website, www.ens.dk.

**Terminated licences and area relinquishment**

In 2007, two licences in the Open Door area and one licence in the western part of the Danish area were relinquished. The relinquished licences 11/98, 1/02 and 1/03 appear from figures 1.1 and 1.4.

Licence 11/98 in the western part of the Danish area expired on 11 January 2007. DONG E&P A/S was the operator and drilled two exploration wells, Hanne-1 in 2003 and Robin-1 in 2006.

Open Door licence 1/02, operated by Tethys Oil Denmark AB, was relinquished on 22 May 2007 and comprised an onshore area in northeastern Zealand. The exploration well Karlebo-1 was drilled in this area in 2006.

**Fig. 1.5** Annual seismic activities

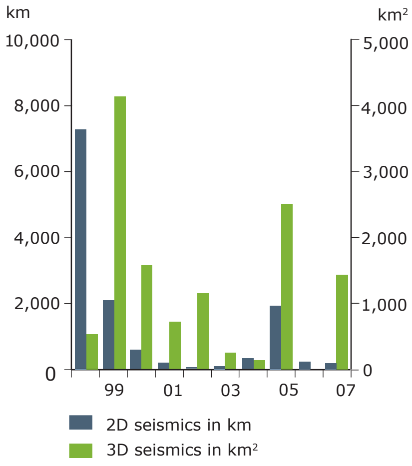
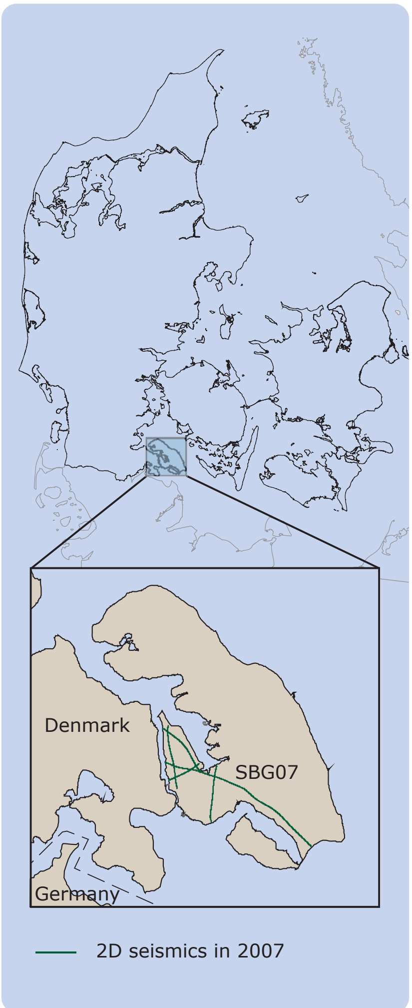



**Fig. 1.6** Seismic survey in the Open Door area




**The Danish North Sea Partner and the Danish North Sea Fund**
The Danish North Sea Partner is a state-owned entity administering the Danish North Sea Fund. The Fund is an independent foundation that is to defray the expenditure and receive the revenue associated with state participation in exploration and production licences. The Danish North Sea Fund and the Danish North Sea Partner were set up under a new Act passed in 2005.

As from 2005, the Fund will be in charge of the state's 20 per cent share of all licences, both Open Door licences and licences granted in connection with licensing rounds. From 9 July 2012, the Fund will also be responsible for the state's 20 per cent share in DUC, Dansk Undergrunds Consortium.

Open Door licence 1/03, operated by Tethys Oil Denmark AB, was also relinquished on 22 May 2007. This licence comprised an onshore area in north Zealand and an onshore area in east Jutland, with surrounding waters in the Kattegat.

The area of the Nini Field comprised by licence 4/95 was reduced. DONG E&P A/S is the operator of this field. The new field delineation became effective on 29 January 2008 and appears from figure 2.1 in the section *Development and production*.

### Extended licence terms

In 2007, the DEA extended the terms of two exploration licences, both in the western part of the Danish area. The licence terms were extended on the condition that the licensees undertake to carry out additional exploration in the relevant licence areas. The exploration term of licence 6/95, operated by DONG E&P A/S, has been extended until 15 May 2008.

The exploration term of licence 9/95, operated by Mærsk Olie og Gas AS, has been extended until 1 January 2009.

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

Moreover, reference is made to appendices F1 and F2, which provide an overview of the Danish licence area.

## EXPLORATORY SURVEYS

The level of activity and the areas where seismic surveys were performed in 2007 appear from figures 1.5, 1.6 and 1.7.

The level of seismic data acquisition was higher in 2007 than in 2006. Wintershall and PGS Petrophysical acquired 1,433 km² of 3D seismic data under Wintershall's 4/06 licence and adjoining areas in the Central Graben; see figure 1.7.

TGS Nopec carried out a 2D seismic survey in the North Sea. The main part of the survey took place in Norwegian and UK territory, but several seismic lines were extended into Danish territory, where they covered a total of 126 km; see figure 1.7.

**Fig. 1.7** Seismic surveys west of 6°15' eastern logitude

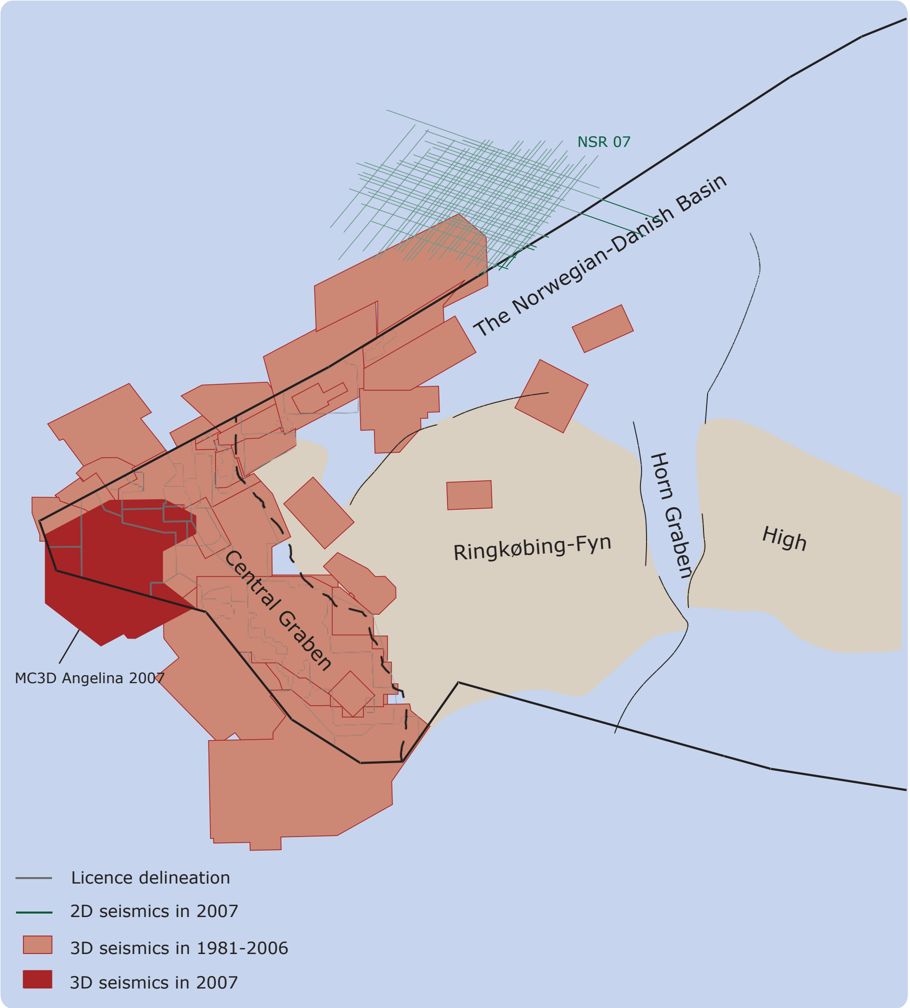
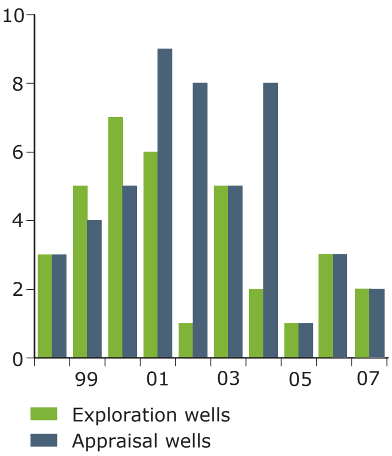



**Fig. 1.8** Exploration and appraisal wells




DONG VE A/S, using the seismic contractor GEOFIZYKA Krakow Sp. Zo.o., conducted a 39.4 km 2D seismic survey to investigate the potential for production of geothermal energy on the island of Als; see figure 1.6.

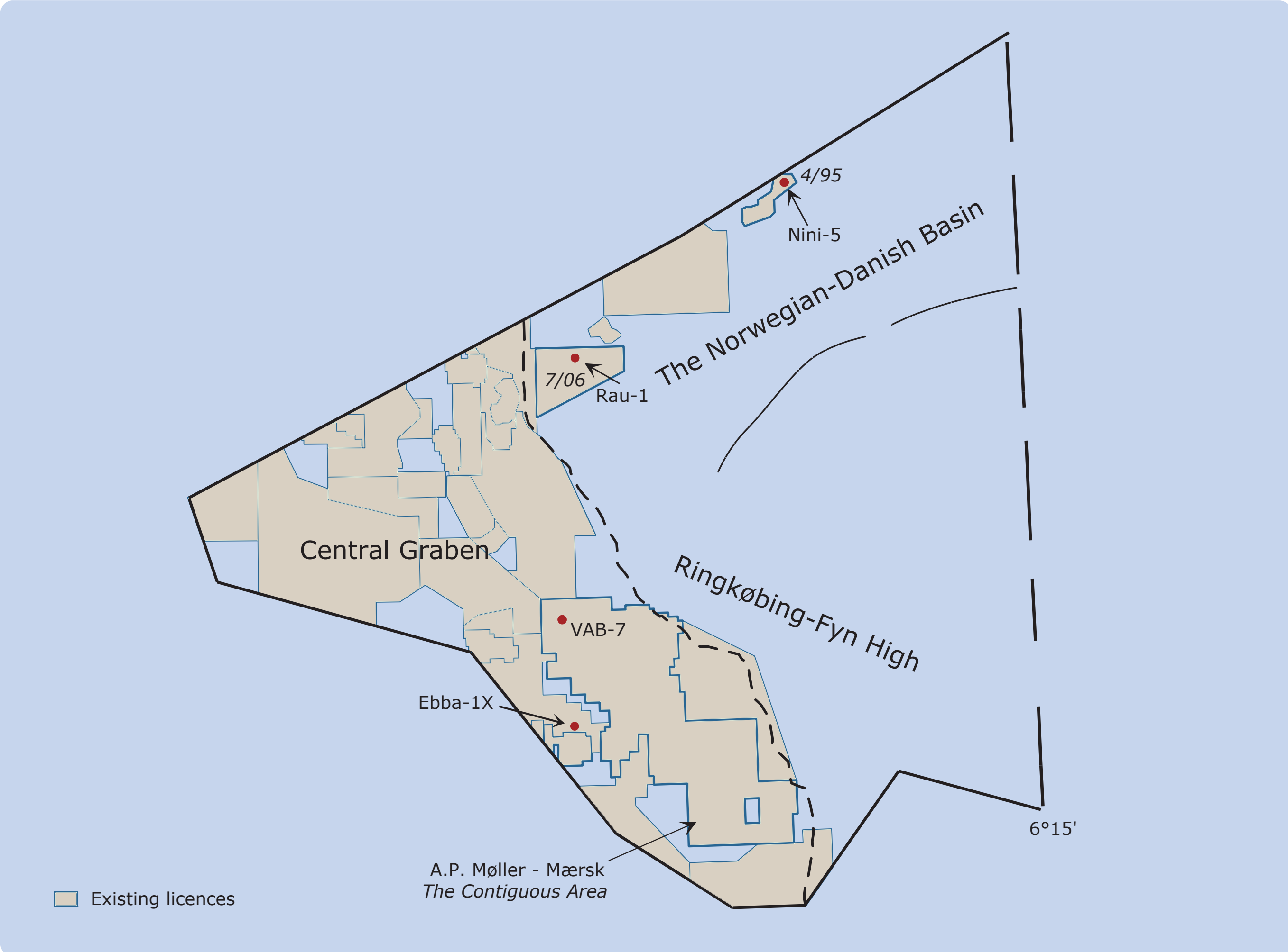
The University of Kiel carried out a 2D seismic survey in Flensborg Fjord and the western part of the Baltic Sea. This survey was made for scientific purposes and does not meet the same standards as usual “oil seismics”, but the seismic data acquired might be useful in oil exploration.

In addition, DONG E&P A/S collected nine seabed cores from the Limfjord area in northern Jutland under licence 3/07 for the purpose of geochemical studies. Preliminary tests have shown traces of crude oil, which seeps up from the subsoil. DONG E&P A/S will now proceed to interpret the data before initiating any further investigations in the form of seismic surveys.

## WELLS

In 2007, two exploration wells and two appraisal wells were drilled; see figure 1.8. The location of the wells described below appears from figure 1.9. The appraisal wells

**Fig. 1.9** Exploration and appraisal wells in 2007 west of 6°15' eastern logitude




drilled in the producing fields are also shown in the field maps in Appendix B. The number of wells drilled in 2007 was lower than in 2006. This was mainly because drilling rigs were difficult to procure, and thus the planned wells have either been delayed or postponed. The DEA anticipates higher exploration activity in 2008, with the drilling of at least six exploration and appraisal wells.

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

**Exploration wells**

*Rau-1 (5604/23-01)*

As the operator for the companies holding licence 7/06, Altinex drilled the exploration well Rau-1 (5604/23-01) east of the Central Graben in the North Sea; see figure 1.9. Rau-1 was the first exploration well to be drilled under a 6th Round licence.

The drilling operation took place during the period from 4 April until 17 May 2007. The Rau-1 well was drilled as a vertical well and terminated in Paleocene (Danian) chalk layers at a depth of 2,504 metres below mean sea level. The well encountered

**Seismic surveys**
Seismic surveys are carried out by sending pressure waves into the subsoil. When the pressure wave encounters different geological layers, part of the pressure wave is reflected back to the surface. Geophones placed at the surface record the reflection time of the seismic signals. An analysis of the pressure waves reflected produces a picture of the geological structures in the subsoil.

When marine seismic data is acquired from a vessel, a pressure gun on the vessel generates pressure waves that penetrate the subsoil. Long cables with hydrophones that accumulate data are towed behind the vessel.

A 2D seismic survey provides a vertical cross-section of the subsoil. If the 2D seismic surveys are closely spaced, they provide a spatial understanding of the geological structures, which is called a 3D seismic survey.

Virtually the whole Central Graben is covered by 3D seismic surveys. A comparison between 3D seismic data acquired for the same area at several-year intervals yields a fourth dimension: time.

4D seismic data can provide insight into the changes occurring in a producing field over time. For one thing, 4D seismic data can show the direction of hydrocarbon flow towards the wells and the location of any remaining hydrocarbon pockets. This information helps the licensees optimize recovery.

When marine seismic surveys are carried out, suitable measures must be taken to protect marine mammals, such as porpoises, and other species; see the section *Environment and climate*. The seismic programmes are subject to the DEA's approval.

oil-bearing sandstone layers of Paleocene age. Three sidetracks were drilled to investigate the extent of the accumulation and cores were extracted in one of the sidetracks. In addition, data about the production properties of the reservoir was collected, but an actual production test was not carried out.

This oil discovery is located in the Siri Fairway, the same geological area as the Cecilie, Siri and Nini Fields. The licensee is now evaluating the discovery more closely to determine whether a basis for developing the accumulation exists.

*Ebba-1X (5504/15-10)*
Mærsk Olie og Gas AS spudded the Ebba-1X well on 17 December 2007 as the operator for the companies holding licence 8/06, which comprises an area about five kilometres north of the Dagmar Field in the Central Graben in the North Sea. Ebba-1X was drilled as a vertical well and terminated in Upper Cretaceous chalk layers at a depth of 2,933 metres below mean sea level. No hydrocarbon discovery was made.

**Appraisal wells**
*Nini-5 (5605/10-08)*
As the operator for the holders of licence 4/95, DONG E&P A/S drilled the appraisal well Nini-5 (5605/10-08). The well, which was spudded on 25 May 2007, was located

**Wells**
Wells can generally be divided into exploration and appraisal wells, on the one hand, and development wells on the other. Exploration and appraisal wells are drilled to investigate whether a mapped structure contains oil and gas, and, in the affirmative, to determine the size of the accumulation.

A development well is a generic term for production wells and injection wells. Production wells bring oil, gas and water to the surface, whereas injection wells inject water or gas into the reservoirs to drive the oil towards the production wells and thus enhance recovery.

in the northeastern part of the Nini Field east of the Central Graben in the North Sea; see figure 1.9.

The Nini-5 well was drilled as a vertical well and terminated at a depth of 1,793 metres below mean sea level in Paleocene (Danian) chalk layers. The well encountered oil and small amounts of gas in Paleocene sandstone layers in the eastern part of the Nini Field. Cores were extracted and two sidetracks were drilled to investigate the extent of the accumulation, with positive results.

*VAB-7 (5504/07-14)*
As part of the further development of the Valdemar Field, the well VAB-7 was drilled in the North Jens area in 2007; see figure 1.9. Apart from testing the production potential, the well served an appraisal purpose as the first well to explore the northwestern flank. The area has complex geological features with faults and sharply dipping flanks. The geological model predicted the presence of additional potential in the area, for which reason the well was planned with two well sections to achieve geological control of the reservoir layers. The well could not demonstrate the existence of such potential and was completed as a horizontal production well in the Lower Cretaceous oil reservoir.

## OTHER USE OF THE SUBSOIL

### Carbon capture and storage (CCS)

On 1 February 2008, the DEA granted both DONG Energy A/S and Vattenfall A/S permission to carry out geophysical investigations in Denmark for the purpose of mapping specific areas and investigating their suitability for storing carbon dioxide ($CO_2$) in the subsoil.

### Geothermal energy

On 21 February 2007, the DEA received an application from DONG VE A/S and Sønderborg Fjernvarme A.m.b.a. for a licence to explore for and produce geothermal energy in the Sønderborg area. On 11 October 2007, the then Minister for Transport and Energy granted DONG VE A/S and Sønderborg Fjernvarme A.m.b.a. a joint licence for the project on a 50/50 basis.

On 12 June 2007, the DEA received an application from Dansk Geotermi ApS for a licence to explore for and produce geothermal energy in a number of old exploration wells in Jutland. On 6 May 2008, the Minister for Climate and Energy granted Dansk Geotermi a licence for this purpose.

Further information about Carbon Capture and Storage and geothermal power is available in the section *Development and production* and at the DEA's website www.ens.dk.

# 2 DEVELOPMENT AND PRODUCTION

Interest in improving oil and gas recovery from the Danish part of the North Sea remained high in 2007, particularly due to the stable high oil price prevailing in the international market. The high oil price level provides an incentive to develop minor fields. Consequently, attention continued to be focused on launching potential development activities, extending platform life and optimizing production.

## PRODUCTION IN 2007

The production of oil and gas from the Danish subsoil started in 1972. The location of producing fields is shown in figure 2.1, from which it appears that all oil production took place offshore in the Danish sector of the North Sea.

There is a total of 19 producing fields in Danish territory, and Denmark has three operators producing oil and gas, Mærsk Olie og Gas AS, DONG E&P A/S and Hess Denmark ApS. Each operator is responsible for operating one or more fields and cooperates with several partners. In all, ten companies have interests in the 19 producing fields. With 40.4 per cent, Shell is the company accounting for the largest share of total Danish oil production. Figure 2.2 shows the individual companies' shares of oil production.

**Fig. 2.1** Danish oil and gas fields

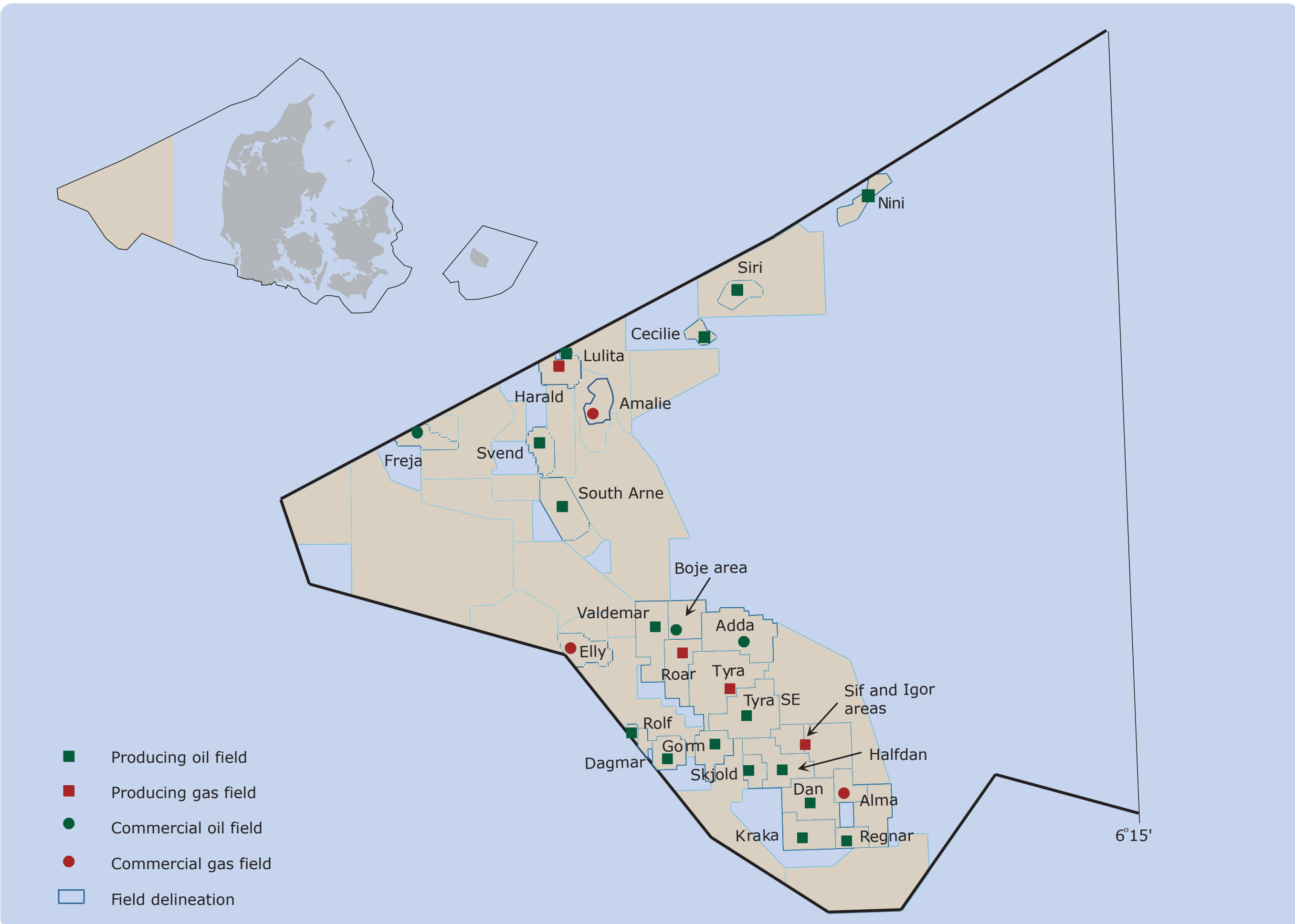
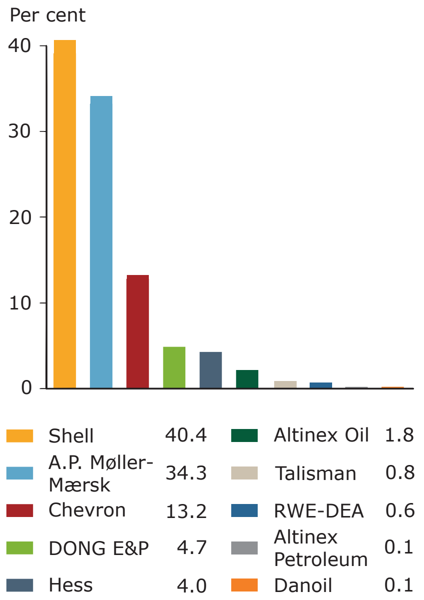



**Fig. 2.2** Breakdown of oil production by company




In 2007, oil production totalled 18.1 million $m^3$, an 8.5 per cent decline compared to last year and a 20 per cent decline on 2004, when oil production peaked at 22.6 million $m^3$. Figure 2.3 shows the historical development of Danish oil production since 1972, when production started.

Production has dropped in recent years because the age of most producing fields has passed the period of estimated peak production, using known technology.

Figure 2.4 shows the historical development of total Danish oil production compared to production from Denmark's oldest field, the Dan Field. The figure shows that the production volume for the Dan Field follows the same trend as all of the Danish fields. Thus, production increased for the first 30 years as new technology developed and new fields were phased in.

The decrease in production of recent years can be curbed by further developing existing fields, developing new technology to improve recovery and making new discoveries.

Thirty years ago, only 10-15 per cent of the oil-in-place in the fields could be recovered. With current technology, the ultimate recovery of oil could reach approx. 35 per cent for certain fields.

A total of 383 wells contributed to production in the Danish part of the North Sea in 2007. The distribution between types of development wells did not vary much compared to 2006. Thus, 195 wells produced oil and 63 produced gas, while 106 wells were used as water injectors and 19 as gas injectors. These figures may deviate from the number of wells indicated in Appendix B, the reason being that a few wells may have shifted from, for example, gas injection to production during a year or vice versa (production to water injection).

Figure 2.5 shows existing production facilities in the Danish sector of the North Sea at the beginning of 2008.

Natural gas production totalled 10.0 billion $Nm^3$ in 2007. Sales gas amounted to 8.0 billion $Nm^3$. This represents a 13 per cent decline on the two previous record years, due to lower gas sales to DONG Naturgas A/S.

**Fig. 2.3** Production of oil and gas

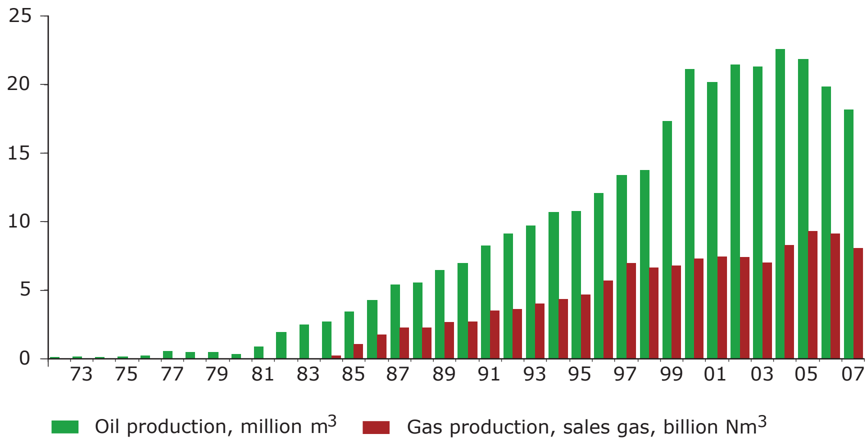
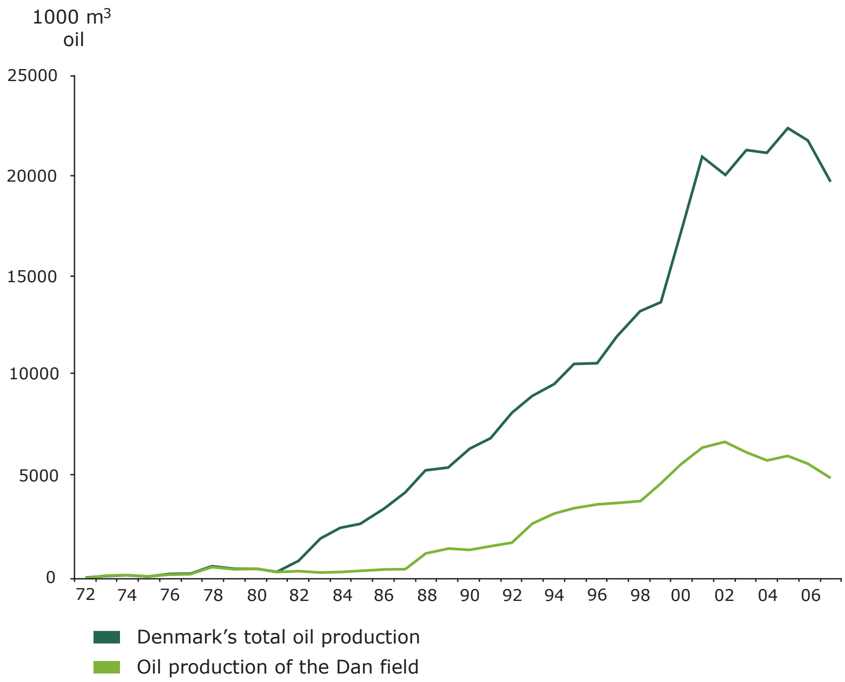


**Fig. 2.4** Denmark's total oil production compared to the oil production of the Dan field




The portion of produced gas not sold is instead injected in selected fields, primarily the Tyra Field, which acts as a buffer. This means that gas is injected into the Tyra Field in the summer, when consumption is low, for the purpose of boosting subsequent production. In addition, some gas is used as lift gas to improve the recovery of oil.

Some of the gas produced is used as fuel on the platforms, and a small volume of gas is flared for technical and safety reasons. Figure 2.3 shows the historical development in sales gas production.

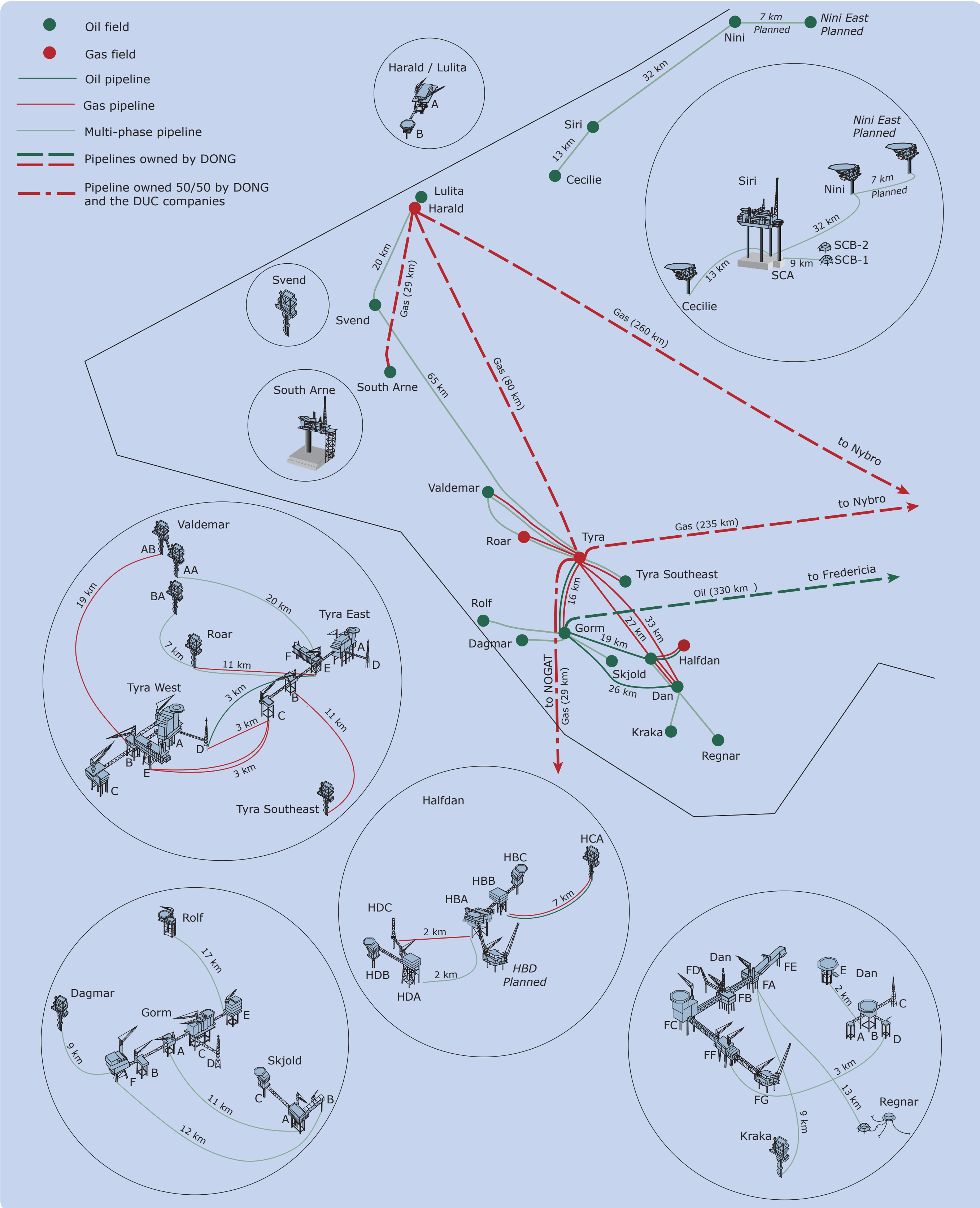
**Reallocation - changing oil production volumes retrospectively**

The oil produced from Danish fields is measured most accurately when being loaded on board tankers. For fields connected to the oil pipeline to shore, fiscal measurement takes place in Fredericia, while the fiscal measurement of oil produced from the Siri and South Arne Fields, which are not connected to the oil pipeline, takes place in connection with buoy loading. This fiscal measurement forms the basis for valuing and taxing the volumes of oil produced. Following conclusion of the North Sea Agreement in 2003, reallocation has no effect on taxation.

Based on less accurate measurements made in the fields, the fiscal oil volumes are allocated between the individual fields and wells, including for the purpose of evaluating the fields and the need for any additional production and development initiatives.

A reallocation means that the allocation of production between individual fields is changed for a past period of time. For example, reallocation may be necessary if a meter in one of the fields is found to be out of calibration.


**Fig. 2.5** Production facilities in the North Sea 2007



The injection of gas increased in 2007 because of lower gas sales. In 2007, 1.1 billion Nm$^3$ of gas was injected against 0.8 billion Nm$^3$ in 2006. The section *Environment and climate* contains a description of the utilization of gas offshore.

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.

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

## DEVELOPMENT ACTIVITY IN 2007

The high oil price has driven up demand in the market for equipment and personnel for development activities. Consequently, the oil companies' costs of exploration and development activities are at a high level.

In 2007, 20 new development wells were drilled, a number corresponding to 2006. Combined, these wells and other development activities represented total investments of about DKK 6.6 billion, an increase of DKK 1.2 billion compared to 2006.

Appendix B contains a detailed outline of producing fields, including various facts and a map of each individual field.

**Ongoing development in 2007:**

### The Halfdan Field

As part of the third phase of the Halfdan Field development, a new platform, HCA, of the STAR type (unmanned) was installed in the Halfdan northeast area in the third quarter of 2007. A new riser and wellhead platform, HBB, and an accommodation platform, HBC, were also installed. The two latter platforms are bridge-connected to the original wellhead platform, HBA.

In the Halfdan Field, two new oil production wells and one water-injection well were drilled from the HBA platform in 2007. On the new HCA platform in the northern part of the field, the previously drilled appraisal well, G-3X, was hooked up to the platform as HCA-8, and yet another gas production well, HCA-5, was drilled. Towards the end of the year, drilling of a dual-lateral gas well, i.e. a well with two well sections in the reservoir, commenced.

### The Valdemar Field

In the Valdemar Field, the Valdemar BA platform was installed and commissioned in 2007. Two drilling rigs worked in the Valdemar Field throughout the year. Energy Exerter drilled two oil wells in Lower Cretaceous layers in the North Jens structure. Noble Byron Welliver drilled one gas well in Upper Cretaceous layers and three oil wells in Lower Cretaceous layers in the Bo structure. The gas production well was redrilled due to technical drilling problems. The well was completed with equipment that allows the four zones to open and close from a control panel at the surface. The drilling operations will continue in 2008.


## USING POROUS ROCK IN THE SUBSOIL

To date, the subsoil has been used mainly for the recovery of oil and gas. However, mounting interest has been shown in using porous rock in the subsoil for geothermal power, $CO_2$ storage as well as natural gas and heat storage. Usually, the same types of formations can be used for different purposes. Therefore, the uses of suitable formations must be prioritized, because, e.g., a $CO_2$ storage site is a permanent facility.

**Geothermal power**

Geothermal power is produced from heat radiated from the inner core of the earth. This means that temperature increases with depth, at a gradient of 15-40 °C/km.

To exploit thermal energy, wells are drilled into porous, water-bearing zones. Hot water is pumped up from these zones and then passed through a heat exchanger or heat pump, giving off heat energy before being pumped back into the subsoil.

Combining heat storage with geothermy is a special form of geothermal use of the subsoil. In the case of heat storage, waste heat is used to heat water to, say, 200° C, after which the hot water is pumped back into porous rock in the subsoil. When the heat is to be utilized, the same process as for other geothermal energy recovery is applied.

**Natural gas storage**

At Stenlille, a gas storage facility is located in porous water-bearing rock about 1,500 metres below the earth's surface. During the summer, natural gas is pumped into the structure and stored for subsequent exploitation during the winter.

Natural gas is not poisonous, but is easily combustible. This creates a risk of explosion if natural gas escapes to the surface and a large volume is ignited. Therefore, the natural gas storage facility at Stenlille has undergone a specific risk assessment, combined with an extensive monitoring programme and emergency response planning.

**$CO_2$ storage**

The storage of $CO_2$ requires the same types of formations and the same method that natural gas storage does.

As $CO_2$ is heavier than atmospheric air, escapes of $CO_2$ may cause $CO_2$ to accumulate in shallows, where concentrations of above 10 per cent will lead to unconsciousness and above 50 per cent will asphyxiate humans and animals. Therefore, it must be ensured that no $CO_2$ escapes, not even over long intervals of time.

In terms of production technology, the wells in the Lower Cretaceous have proved more difficult than assumed, and a restimulation programme has been launched to improve the wells' production capacity.

Further development opportunities have been mapped south of the Bo area, and the Bo-3X appraisal well was drilled in early 2008 with positive results.

**The Tyra and Tyra Southeast Fields**
In the Tyra Field, a previously planned gas production well to exploit the gas in the southern flank between Tyra East and Tyra West was drilled. The well results met expectations.

The drilling of two gas wells was initiated from the Tyra Southeast platform in 2007, but this work encountered drilling problems, for which reason the operation was suspended until 2008.

**The Dan Field**
In the Dan Field, work is proceeding on two approved plans for the northeastern flank of the A-block and the western flank of the Dan Field. Two wells have been drilled in the northeastern part of the field. The further plans are being reviewed to determine whether to convert a well to water injection and thus improve recovery from the other wells. The extension of the existing well pattern is continuing in the southern part of the western flank. However, the well length has been reduced because the extent of the oil zone is limited towards the south.

**The Siri Field**
In 2006, the DEA approved a further development of the Siri Field with four wells, two of which were to be based on the coiled tubing drilling technology. Drilling started in 2006, but because of technical problems the work was abandoned at the beginning of 2007. The remaining drilling operations began at the end of 2007 with the use of an ordinary drilling rig, Ensco 70.

**The Nini Field**
The first phase in the development of the Nini Ty reservoir was completed with the drilling of oil production well NA-8 in 2007. This well has helped enhance recovery from the Nini Field. In the course of 2008, the need for establishing water injection or drilling additional production wells is to be assessed.

**The South Arne Field**
At the southwestern flank of the South Arne Field, the last two wells under the approved development plan, an oil production well and a water-injection well, were drilled in 2007.

The South Arne Field is situated about one kilometre lower than other Danish chalk fields. This means that the pressure for fracturing chalk is closer to the existing pore pressure in the reservoir. The flow resistance for circulating drilling mud increases with the length of the well, which represents a challenge to the drilling operation because it limits the horizontal length of the well.

For the first time on the Danish continental shelf, the drilling operation was therefore carried out as underbalanced drilling, which means that the drilling mud is lighter than the hydrostatic column. When penetrating the reservoir, oil and gas are produced as the well is being drilled.

**Approved development plans:**
Two development plans were approved in 2007. These plans provide for the drilling of additional wells from the existing platforms at Tyra Southeast and Halfdan HBA. Moreover, plans for additional wells at the western flank of the Dan Field have been


proposed. Combined, these development plans represent an investment of DKK 410 million over the next few years.

In addition, the DEA received a plan for further developing the Halfdan Field with a new processing platform and a plan for establishing a satellite development to the Nini Field, Nini East. The plan for the Nini East Field, comprising investments of DKK 2.1 billion, was approved in January 2008. The estimated investments associated with developing the Halfdan Field, approved in June 2008, total DKK 5.2 billion.

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

**The Dan Field**
In January 2007, Mærsk Olie og Gas AS applied for permission to drill additional wells in the western flank of the Dan Field within the framework of the existing approval. The plan provides for the drilling of one or two new production wells, the conversion of an existing well to water injection and possibly one new water-injection well.

Mærsk Olie og Gas AS expects to increase the production of oil by about 0.5 million $m^3$ by adding a new production well and converting an existing well to water injection. The DEA approved the first of these wells at the beginning of 2007.

**The Tyra Southeast Field**
In February 2007, Mærsk Olie og Gas AS submitted an application to drill a gas well with dual laterals by redrilling an existing well. Production from the new well is estimated to total about 1.6 billion $Nm^3$ of gas and 0.24 million $m^3$ of oil. The plan was approved on 2 March 2007.

**STORAGE OF CARBON DIOXIDE**
As part of its Energy & Climate Package, the European Commission presented a proposal on 23 January 2008 for a Directive on the geological storage of carbon dioxide ($CO_2$). The proposed Directive sets up a system for granting exploration and storage permits for $CO_2$ storage. It remains up to the individual Member States to decide whether the technology can be used and, in the affirmative, in which areas $CO_2$ can be stored. The Directive is expected to be adopted in 2009.

Carbon Capture and Storage (CCS) technology is used to capture $CO_2$ emissions from large point sources, for example power stations, and then transport the captured $CO_2$ to a suitable storage site in the subsoil.

Suitable geological formations must be used to store $CO_2$ in the subsoil, and presumably such formations exist many places in the Danish subsoil both on- and offshore.

$CO_2$ storage requires porous rock with specific geological properties. Moreover, the storage site must be located at a depth sufficient for the pressure to liquefy the $CO_2$, which means a depth of more than 1,000 metres. The formations viable for storing $CO_2$ can frequently be used for other purposes as well, such as natural gas storage or geothermal power production. A $CO_2$ storage site will be permanent, for which reason the uses of suitable formations must be prioritized.

**The Nini Field**
In November 2007, DONG E&P A/S applied for approval of development and production from the eastern area of the Nini Field.

The Nini Field was established as an unmanned satellite to the Siri Field and came on stream in 2003. Results from appraisal wells, seismic interpretation and depth conversion provide a basis for further developing the field.

The Nini East plan provides for the establishment of a new unmanned platform, similar to the existing Nini platform, with capacity for ten wells. The plan also encompasses the installation of pipelines for multiphase flow, lift gas and injection water between the Nini platform and the new Nini East platform. Moreover, the existing Nini platform is to be modified to fulfil the function of a transport hub.

The development plan is divided into two phases and comprises a total of five wells. The first phase consists of drilling two horizontal production wells and one water-injection well. The second phase may include the drilling of one additional production well and/or one water-injection well.

Total production in the Nini Field is expected to increase by 2.7 million $m^3$ of oil. The plan was approved on 29 January 2008.

**The Halfdan Field**
Mærsk Olie og Gas AS submitted an application for developing the fourth phase of the Halfdan Field in July 2007. The plan was approved in June 2008.

The production from Halfdan started in 1999, from which time the field has undergone continuous, phased development with sustained positive results.

The plan provides for a further development towards the northeast by extending the existing well pattern of parallel oil production wells and water-injection wells.

The plan comprises a total of ten new wells to be drilled from the new HBB platform, installed in summer 2007, and from the HDA platform. Moreover, plans are in place to establish a new processing platform, HBD, to be bridge-connected to the existing Halfdan HBA platform.

In their present form, the HBA and HBB platforms function as unmanned platforms, but the plan is to convert them to manned operation. The new processing platform, HBD, must be designed to handle three-phase separation, water treatment and gas compression.

According to the planned development activities, reserves are estimated to increase by 6.3 billion $Nm^3$ of gas and 15.9 million $m^3$ of oil.

# 3 ENVIRONMENT AND CLIMATE

**Fig. 3.1** Fuel consumption

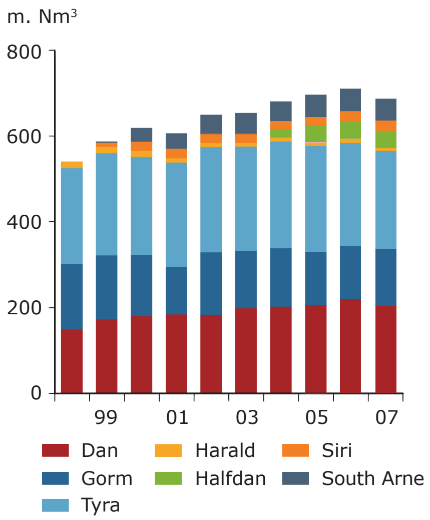
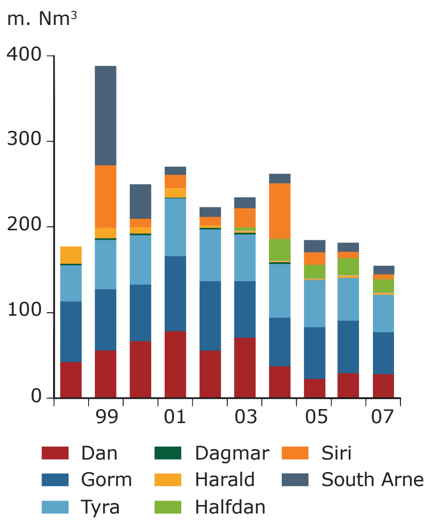



**Fig. 3.2** Gas flaring




The production of oil and gas in the North Sea results in emissions and discharges to the surrounding environment. Emissions to the atmosphere consist of such gases as $CO_2$ (carbon dioxide) and $NO_x$ (nitrogen oxide), while discharges into the sea include chemicals and oil residue.

## EMISSIONS TO THE ATMOSPHERE

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, gas that cannot be utilized for safety or plant-related reasons is flared.

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

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

### Consumption of fuel

Fuel gas accounted for about 82 per cent of total gas consumption offshore in 2007. The remaining 18 per cent was flared. It appears from figure 3.1 that the use of gas as fuel has increased on Danish production facilities during the past decade, although it decreased slightly from 2006 to 2007. The general increase is attributable to rising oil and gas production and ageing fields.

In recent years, the steadily ageing fields have particularly impacted on fuel consumption. Natural conditions in the Danish fields mean that energy consumption per produced t.o.e. increases the longer a field has carried on production. This is due to the fact that water accounts for an increasing share of the mixture of oil, gas and water recovered from the subsoil. 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.

The consumption of energy per t.o.e. is expected to continue climbing due to the increased requirements for water injection and gas compression.

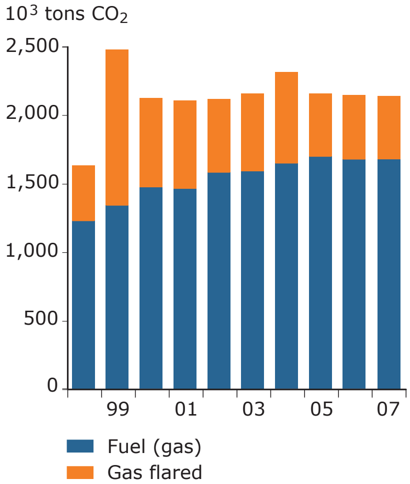
As figure 3.1 shows, fuel consumption varies from year to year at the individual installations. From 2006 to 2007, the use of fuel gas declined slightly or remained unchanged on all installations excepting the Gorm and South Arne Fields.

*$CO_2$ emissions*

The development in the emission of $CO_2$ from the North Sea production facilities since 1997 appears from figure 3.3. This figure shows that $CO_2$ emissions totalled about 2.1 million tons in 2007, which means that emissions remained at the same level as in 2005 and 2006. The production facilities in the North Sea account for about 4 per cent of total $CO_2$ emissions in Denmark.

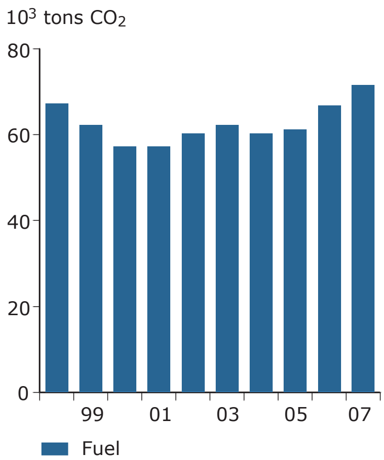
Figure 3.4 shows the past ten years' development in $CO_2$ emissions associated with the consumption of gas as fuel, relative to the volume of hydrocarbons produced. It appears from this figure that $CO_2$ emissions due to fuel consumption have increased relative to the size of production, from about 60,000 tons of $CO_2$ per million t.o.e. to about 70,000 tons of $CO_2$ per million t.o.e. over the past decade. $CO_2$ emissions

**Fig. 3.3** $CO_2$ 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 Danish Act on $CO_2$ Allowances and have included $CO_2$ emissions from diesel oil used as fuel.*

**Fig. 3.4** $CO_2$ 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 Danish Act on $CO_2$ Allowances and have included $CO_2$ emissions from diesel oil used as fuel.*

from the consumption of diesel oil have also been included for 2006 and 2007, which explains part of the increase.

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.

**Gas flaring**

The flaring of gas declined substantially from 2006 to 2007 due to the generally stable operation of production installations.

The volumes of gas flared appear from figure 3.2, and, as the figure shows, gas flaring varies considerably from year to year. These large fluctuations are partially due to the tie-in of new fields and the commissioning of new installations. In 2007, gas flaring totalled 154 million $Nm^3$, which is the lowest volume since 1998.

*$CO_2$ emissions*

$CO_2$ emissions from gas flaring relative to the size of production have shown a declining trend since the early 1990s. Figure 3.5 shows the past ten years' development in $CO_2$ emissions.

This trend has been broken in several cases, including in 1997, 1999 and 2004 when the startup of new fields and commissioning of new processing facilities involved the flaring of extraordinary volumes of gas. There was a marked drop in gas flaring from 2005 to 2007. However, as production decreased during that period, the volume of gas flared per produced t.o.e. increased.

*Flaring*

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

Gas is also flared under ordinary operating conditions. A portion of this gas can be recaptured by means of installing and using gas recapture 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 structure and layout of the individual installation, but not on the volumes of gas or oil produced.

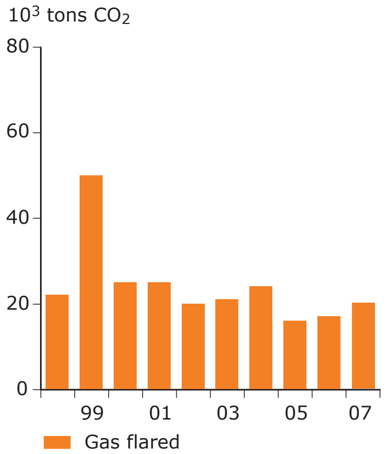
In 2007, $CO_2$ emissions from flaring came to almost 0.45 million tons of $CO_2$, relative to total $CO_2$ emissions from the offshore sector of 2.14 million tons. The volume of gas flared accounted for 1.5 per cent of total gas production in 2007. All $CO_2$ emissions are comprised by the $CO_2$ allowance scheme.

**Energy efficiency**

In February 2008, all parties in the Danish Parliament, with the exception of the Red-Green Alliance, entered into an Energy Agreement.

The strategies include mapping energy consumption for the recovery of oil and gas and proposing initiatives to enhance energy efficiency in the production of oil and gas. The results must be submitted to the parties to the Energy Agreement before 1 January 2009.

**Fig. 3.5** $CO_2$ 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 Danish Act on $CO_2$ Allowances.*

**The European $CO_2$ allowance scheme**
As of 1 January 2008, the $CO_2$ allowance scheme covered about 380 installations in Denmark, including seven in the offshore sector.

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

The Act on $CO_2$ Allowances has laid down the criteria for allocating free allowances for the first period from 2005 to 2007. During that period, free allowances averaging 2.2 million tons of $CO_2$ per year were allocated to the Danish offshore sector.

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 and scope for allocating extra allowances to new installations.

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

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

The DEA has involved players in the offshore sector in performing the analyses, which will incorporate experience from the other North Sea countries.

**Emission of $NO_x$**
In 2006, the Ministry of the Environment submitted a technical, economic report on $NO_x$ emissions in Denmark. The report illustrates the options that enable Denmark to meet its obligations under the EU Directive on National Emission Ceilings (the NEC Directive) in 2010 and onwards. The projections of $NO_x$ emissions show that the offshore sector's share of estimated future $NO_x$ emissions in Denmark is mounting.

To follow up on the Energy Agreement from February 2008, the Minister for Taxation introduced a Bill in the Danish Parliament in March 2008 that will impose a general $NO_x$ tax of DKK 5 per kg on atmospheric emissions, with effect from 1 January 2010, which will partially fulfil the Danish obligations. The Bill also covers 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 Technique (BAT) and Best Environmental Practice (BEP) principles.

## MARINE DISCHARGES

Marine discharges are part of the normal operation of production facilities and the drilling of wells. In addition, unintentional spills may occur.

In older oilfields, large volumes of water are produced together with the oil. In some Danish fields, the water cut may reach very high values before production is suspended.

On fixed offshore installations, the water is separated from the oil in processing facilities and subsequently treated and pumped back into the reservoirs to support production. Water that cannot be injected back into the subsoil is discharged into the sea.

Although treated before being discharged into the sea, the water still contains small amounts of oil and dissolved or suspended substances extracted with the water from the subsoil. The water also contains residues of the chemicals used to treat the oil, gas and water produced.

Marine discharges from drilling rigs consist mainly of oil and the chemicals added to water-based drilling mud. Drilling mud is used in connection with drilling new wells. Discharging oil-based drilling mud is prohibited, and such mud and drill cuttings are collected and transported to shore.

### Regulation of discharges

Marine discharges are regulated by Danish rules and regulations and the Minister for the Environment's Offshore Action Plan, as well as by agreements made under the International OSPAR Convention on the protection of the marine environment.

The Danish Environmental Protection Agency regulates discharges of chemicals by issuing discharge permits.

Requirements have been set for the concentration of residue oil in the treated production water discharged overboard. For the period 2000-2006, the OSPAR organization also established goals for the absolute volume of oil permitted in discharged water.

Under the auspices of OSPAR, issues regarding protection of the marine environment in the Northeast Atlantic, including the North Sea, are dealt with regularly. Previously, the work focused mainly on oil discharges, but is now aimed more broadly at all harmful substances by performing risk assessments at the individual points of discharge.

### Offshore environmental action plan

The Danish Environmental Protection Agency regularly supervises the operators' compliance with the Minister for the Environment's Offshore Action Plan and submits an annual status report to the Danish Parliament. Every year, the individual Danish operators prepare a publicly accessible report that accounts for the environmental impacts associated with oil and gas production in the Danish part of the North Sea.

## EIA OF THE HALFDAN FIELD DEVELOPMENT

Major projects in Danish territorial waters and the Danish continental shelf area may have a considerable impact on the environment. Therefore, permits are only granted for projects after an Environmental Impact Assessment, EIA, has been made. In addition, the general public, public authorities and organizations must have an opportunity to submit their opinions.

At present, the operator of the Halfdan Field, Mærsk Olie og Gas AS, is planning to develop the field further and has therefore prepared an addendum to the EIA that was subjected to public consultation in 2005/2006.

The addendum addresses the issues related to the development plan that are not covered by the existing EIA. The addendum was subjected to public consultation during the period from November 2007 to January 2008; see www.ens.dk. The operator has provided consultation responses. Subsequently, the Danish Environmental Protection Agency and the Agency for Spatial and Environmental Planning have assessed that the EIA basis for the planned development of the Halfdan Field is in place.

## CONSULTATION PROCEDURE FOR PIPELINE PROJECTS

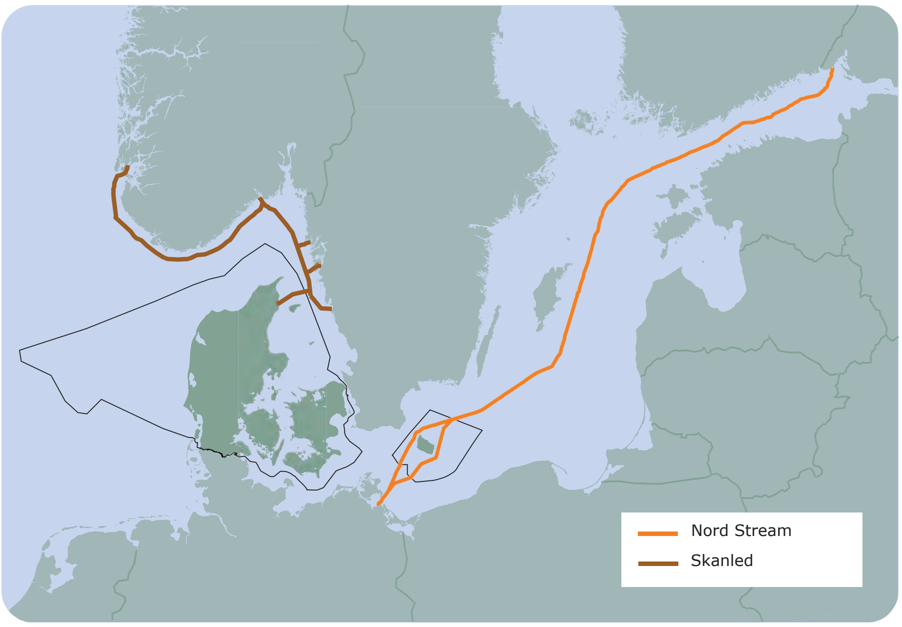
**The Nord Stream gas pipeline**

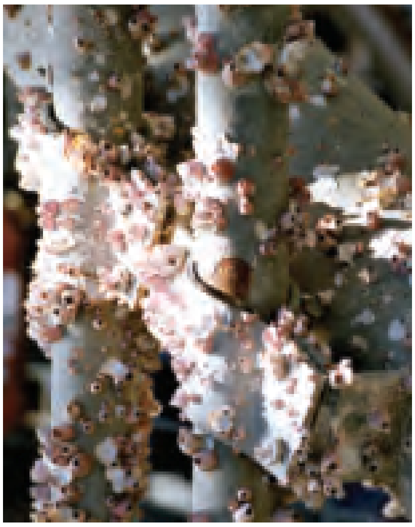
A consortium composed of GAZPROM (51 per cent), Wintershall (20 per cent), E.ON/Ruhrgas (20 per cent) and Gasunie (9 per cent) is planning to establish two 1,200 km 48" pipelines through the Baltic Sea from Vyborg in Russia to Greifswald in Germany; see figure 3.6.

The two pipelines are planned to traverse Russian, Finnish, Swedish, Danish and German offshore areas and will have a capacity to transport a total of 55 billion $m^3$ of natural gas a year. The first of the two pipelines is to be commissioned in 2011 and the second in 2013. The 55 billion $m^3$ of natural gas corresponds to about 11 per cent of the EU's estimated annual consumption of natural gas in 2011.

In connection with projecting the pipeline in the Baltic Sea, a so-called Espoo consultation procedure was initiated, which involves notifying the countries whose environments may be affected by the project. The consortium has prepared a document describing the project and its possible environmental impacts. The document has been submitted to all countries around the Baltic Sea.

**Fig. 3.6** Current pipeline projects, possible routes





In the Danish continental shelf area, the consortium is investigating the possibility of routing the pipeline either north or south of the island of Bornholm.

Subsequently, the consortium is to apply for permission to establish the pipeline. The application is to include an EIA for the overall pipeline project. The EIA will be subjected to public consultation.

**The Skanled gas pipeline**

In cooperation with the Norwegian company Gassco and the Swedish company Swedegas and several industrial and energy companies, the company Energinet.dk is investigating the possibility of establishing a pipeline system from Norway via Sweden to Denmark.

The pipeline system is to transport natural gas from the Kårstø gas-processing facilities on the Norwegian west coast to Rafnes on the Norwegian east coast and from there through the Skagerrak and Kattegat to Sweden and Denmark; see figure 3.6.

In Sweden, the pipeline is to come on shore at either Lysekil, Stenungsund or Varberg, and in Denmark on the east coast of Vendsyssel, near Frederikshavn or Sæby.

Energinet.dk plans to install a 120 km onshore pipeline from the landing point to the company's natural gas storage facility at Ll. Thorup in mid-Jutland, via Aalborg.

An Espoo consultation procedure has been initiated in connection with the Skanled project. The company Gassco has prepared a document describing the project and its possible environmental impacts. The document has been submitted to the above-mentioned Scandinavian countries as well as Germany and Poland.

The consultation responses submitted will be covered by the final EIA, expected for submission at the end of 2008 together with an application to establish the pipeline. A final decision to implement the Skanled project is expected in 2009.

## PROTECTION OF THE MARINE ENVIRONMENT

**Habitat assessment**

In May 2007, the Danish Parliament passed amendments to the Subsoil Act and the Continental Shelf Act to implement the EU Habitats Directive and Birds Directive for energy installations and pipelines in the offshore area.

The amendments mean that in some instances a habitat assessment is to supplement the EIA before a decision on offshore projects is made. This assessment is to describe how the project will impact the natural habitats, flora and fauna in the international nature protection areas designated to protect them.

The provisions on habitat assessments are meant to stop natural habitat types and habitats in nature protection areas from deteriorating and to prevent flora and fauna for whose protection the areas have been designated from being disturbed.

A revised executive order on environmental impact assessments (EIA), which will contain more detailed rules about habitat assessments and the protection of species in connection with projects for offshore activities and pipelines, is expected to be subjected to a consultation procedure in 2008.

The existing offshore oil and gas activities do not take place in the international protection areas designated to date. By 2008, the decision is to be made whether further marine nature protection areas are to be designated. The Minister for the Environment is authorized to designate new nature protection areas under the Environmental Targets Act.

**Noise from seismic surveys and piling works**
The Habitats Directive imposes strict measures for the protection of all species of whales and dolphins. Noise from seismic surveys and pile driving, etc., in the seabed may disturb marine mammals, such as porpoises.

Therefore, preventive measures must be taken to give marine mammals sufficient time to leave the area before any activities are initiated.

Thus, the licences issued under the Subsoil Act to carry out seismic surveys include a standard term that requires the use of a soft-start procedure. A soft start means that prior to a seismic survey, the noise level from the air gun to be used in the survey is to be increased gradually.

If the seismic surveys involve the detonation of explosives, minor warning detonations must also be carried out within a 20-30 minute period before the actual detonation for the survey occurs. Before carrying out seismic detonations, a seismic survey contractor may also be required to observe whether any marine mammals are in the area and, if so, to postpone detonations.

In 2007, licences were granted for four offshore seismic surveys, three in the North Sea and one in the waters south of the islands of Ærø and Langeland. Two of the surveys were performed for scientific purposes.

Terms requiring the use of soft start procedures are also included in permits for piling operations in the seabed when offshore installations are established, for example, piles to anchor platforms and conductors protecting the upper section of a well.

# 4 HEALTH AND SAFETY

The production installations on the Danish continental shelf in the North Sea, as well as drilling rigs and miscellaneous vessels associated with oil and gas production, provide jobs for up to 3,000 people. The employees have a multitude of different skills and include blacksmiths, electricians, geologists, engineers, painters, scaffolders, catering staff, medics, etc. The production installations consist of about 50 platforms, some of which are interconnected by bridges.

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

On behalf of the Danish state, the DEA cooperates with the Danish Maritime Authority in supervising whether companies comply with existing health and safety legislation when conducting their oil and gas activities.

## OFFSHORE SAFETY ACT

A new Act on Health and Safety on Offshore Installations, the Offshore Safety Act, entered into force on 1 July 2006. The Act regulates the safety of offshore installations as well as the employees' health and safety.

The Act replaces the former Offshore Installations Act, dating 25 years back, and includes transitional provisions on documentation for health and safety work and management systems. Until 1 July 2007, the companies had to prepare new documentation for all offshore installations in the form of Health and Safety Cases (HSCs), while at the same time adapting their management systems to the new requirements; see box 4.1.

Some of the provisions in the old Act have been maintained, but will gradually be replaced by new ones prepared by the DEA in consultation with the two sides of industry represented on the Offshore Safety Council; see box 4.2. The DEA's website

**Box 4.1**

**Health and Safety Case (HSC)**

A Health and Safety Case (HSC) must substantiate that the operating company has assessed the health and safety risks on the offshore installation.

As a minimum, an HSC must contain:

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

The HSC must be updated whenever the health and safety conditions on the installation are changed significantly.

contains more information about the Offshore Safety Act and the new rules, regulations and guidelines.

**Experience with Health and Safety Cases (HSCs)**
Since the Offshore Safety Act entered into force in 2006, applications submitted to the DEA have included Health and Safety Cases for the offshore installations.

For mobile units, Health and Safety Cases are to be prepared according to the guidelines for international HSE Cases[1], drawn up by the International Association of Drilling Contractors, IADC, and are thus familiar to the companies.

New Health and Safety Cases have been prepared for all production installations (fixed offshore installations). In the course of its supervision, the DEA has found shortcomings in the content of the Health and Safety Cases relative to applicable legislation, particularly in the documentation for working environment risk management. Through a dialogue with the operators, these shortcomings are being rectified.

**Box 4.2**

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

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

## APPROVALS AND PERMITS IN 2007

When designing an offshore installation, the operator must attempt to minimize the risk of accidents occurring during the operation of the finished installation. Before a fixed offshore installation is built, the DEA must approve the general design on the basis of an application that includes a Health and Safety Case; see box 4.1.

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

Before an offshore installation is commissioned, the operating company must obtain a permit from the DEA. The application must include a Health and Safety Case demonstrating that the health and safety risks associated with operating the installation have been reduced as much as reasonably practicable. This applies to fixed offshore installations as well as mobile offshore units.

Large personnel increases and major modifications to existing offshore installations impacting on installation safety (risk of major accidents) are subject to the DEA's prior approval.

In 2007, the DEA approved the general design plan to develop the northeastern part of the Halfdan Field. The development plan provides for the establishment of a satellite platform, Halfdan CA, about 7 km northeast of the existing Halfdan BA platform, as well as a riser platform, Halfdan BB, and an accommodation platform, Halfdan BC. The three platforms, Halfdan BA, Halfdan BB and Halfdan BC are connected by bridges.

Moreover, in 2007 the DEA granted permission for the commissioning of the Valdemar BA platform, located about 3.6 km from the Valdemar AA/AB platforms. The permission is subject to the condition that Valdemar will be bridge-connected to the drilling rig Noble Byron Welliver. Permission was also granted for the commissioning of Halfdan CA, Halfdan BB, Halfdan BC and the bridge between Halfdan BC and Halfdan BA.

In 2007, the DEA granted operating permits for a number of mobile units, including the drilling rigs Maersk Exerter, Maersk Enhancer, Ensco 71, Noble George Sauvageau and Ensco 70, as well as the flotels Safe Esbjerg and Atlantic Rotterdam.

*1) International Guidelines of Drilling Contractors, Health, Safety and Environmental Case (Guidelines for Mobile Offshore Drilling Units)*

## SUPERVISION IN 2007

Health and safety supervision comprises supervision of new production installations during the establishment phase, from the time when the general design is approved until the operating permit is issued, as well as supervision concerning the operation of finished installations.

On production installations, the DEA supervises the safety of the installation and the health and safety conditions in the working environment and the accommodation facilities. The Danish Maritime Authority supervises life-saving appliances.

On mobile offshore units, the DEA supervises health and safety in the working environment and accommodation facilities as well as equipment related to the "industrial" function of the unit, such as drilling equipment. The Danish Maritime Authority supervises safety issues of a "maritime" nature, including the electrical installations on the unit, fire protection and life-saving appliances.

In 2007, the DEA carried out 32 offshore inspections, distributed on 18 inspections of manned production installations, six inspections of unmanned production installations and eight inspections of mobile units, i.e. drilling rigs, flotels and crane vessels; see box 4.3. In addition, the DEA made six onshore inspections. An outline of all inspection visits in 2007 is available at the DEA's website, www.ens.dk.

As in previous years, supervision in 2007 focused on work-related accidents, near-miss occurrences, gas leakages and the maintenance of safety-critical equipment.

### Audit of lifting operations

Heavy lifting operations with cranes are a common occurrence on offshore installations. Supply vessels regularly deliver goods from shore that must be lifted from the vessel onto the installation. Moreover, heavy goods need to be moved from one location to another on the actual installation. These heavy lifting operations account for a large percentage of accidents and near-miss occurrences, both in the Danish area and in other parts of the North Sea.

In autumn 2006 and spring 2007, the DEA supervised the lifting procedures and operations of Mærsk Olie og Gas AS, DONG E&P A/S and Noble Drilling Limited by auditing the companies' onshore and offshore procedures, etc. The offshore audit was performed on the production installations Dan F and Siri and on the mobile offshore unit Nobel Byron Welliver. The audit was part of an international audit arranged by the North Sea Offshore Authorities Forum (NSOAF) that targeted lifting equipment and operations at companies with activities in several North Sea countries; see the section on international cooperation.

The audit revealed a need for continued focus on the choice of proper lifting equipment, the planning of lifting operations, risk assessment, internal supervision and personnel training.

The Danish part of the supervisory activities concentrated on risk assessment and communication between the crane operator and the persons receiving the goods on deck or readying them for the crane lifting operation.

### Maintenance of safety-critical equipment

On its inspection visits to offshore installations in 2007, the DEA checked whether

the operators adhere to their plans for maintaining installations and equipment, particularly safety-critical equipment.

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

**Box 4.3**

**Offshore inspection visits**
Offshore inspection visits 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 inspection visits, but may also make unannounced inspection visits.

An announced offshore inspection visit typically comprises:

An initial meeting with the safety organization, during which the DEA briefs the participants about the course of its inspection and discusses work-related accidents, reported near-miss occurrences and the follow-up procedures taken. Moreover, the parties discuss the status of risk management in the working environment (the Health and Safety Case) and any special matters appearing from the safety committee's minutes of meetings. Before the meeting is closed, the parties agree on a time schedule for the further course of the inspection.

A meeting with the safety representatives, where special working conditions are discussed and the DEA explains the content of statutory rules and regulations.

An interview of the management on board (Offshore Installation Manager, technical managers, medic, catering staff, etc.) during which the DEA systematically reviews the company's ability to establish, within designated areas, compliance with rules and regulations (and special conditions applicable to the installation) in the planning and performance of its work.

A tour of the installation with a supervisor and a safety representative during which the DEA randomly checks whether the health and safety conditions at the individual workstations comply with established rules and practice in the area.

A final meeting with the safety organization at which the DEA briefs the participants about the observations made, whether consisting of deviations from statutory rules and regulations, including from the company's own procedures, or areas where health and safety conditions can be improved. At this meeting the DEA will normally hand out an outline of the observations made.

After the inspection visit, the DEA prepares a supervision report for submission to the company. The report is to be made available to the members of the safety organization on the installation. The company then has a time limit to respond and indicate how it intends to address the observations made.

**Box 4.4**

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

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

Inspection visits in 2007 showed that the majority of all offshore installations maintain their safety-critical equipment as planned. Supervision will continue to focus on safety-critical equipment in 2008.

**Hydrocarbon releases**
The operators of the production installations are obliged to register all hydrocarbon releases (gas leakages) and to report any major releases to the DEA immediately; see boxes 4.8 and 4.9 regarding the reporting of near-miss occurrences/hydrocarbon releases.

As part of its supervision in 2007, the DEA reviewed the operators' follow-up on hydrocarbon releases, including the preventive measures taken to avoid similar releases in future. The supervision revealed that the operators follow up on hydrocarbon releases efficiently, a fact reflected in the declining number of releases since 2004; see figure 4.3.

**Supervision strategy**
The DEA launched a new supervision strategy in January 2008, which reflects the objectives of the Offshore Safety Act. The aim of supervising the installations in the Danish part of the North Sea is to ensure that health and safety standards remain among the top for the North Sea countries.

The Offshore Safety Act places the responsibility for health and safety issues with the operating companies, which means that supervision must place greater focus on the companies' health and safety management systems.

The supervision strategy includes the following activities:

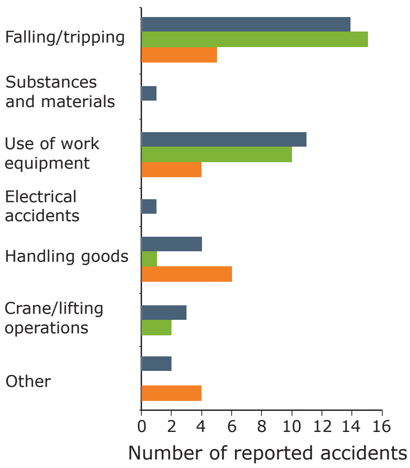
- One annual inspection visit to the individual installations, focusing on the general safety standard of each installation.
- One or more inspection visits to the individual installations that focus on specific subjects.
- Immediate inspections of installations in case of serious incidents.
- Regular supervision of drilling operations.
- Regular supervision from the time the design is approved until the operating permit for fixed offshore installations (production facilities) is issued.
- Supervision of modifications to installations in operation.
- Strengthened information initiatives.

The Offshore Safety Council has endorsed this supervision strategy; see box 4.2.

With a few exceptions, the DEA's supervision of offshore installations consisted of announced inspection visits. In 2008, the DEA is carrying out a number of unannounced inspections, so far including an inspection of Halfdan in March and of the drilling rig Ensco 70 in May.

**Psychological working environment**
As part of the Government's working environment initiatives until 2010, the DEA's supervision in 2008 will also focus on the psychological working environment on offshore installations. The DEA plans its supervision of the psychological working environment in more detail in cooperation with the two sides of industry represented on the Offshore Safety Council.

**Fig. 4.1** Comparisons between accidents reported in 2005, 2006 and 2007 for offshore installations broken down by cause of accident




## 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 4.4. Doctors must report suspected or diagnosed work-related diseases to the National Working Environment Authority and the National Board of Industrial Injuries. Reference is also made to the National Working Environment Authority's website www.at.dk.

### Work-related accidents

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

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 inspection visit after an accident, all work-related accidents since the last visit are addressed at a meeting with the safety organization on the installation. In some cases, the DEA carries out immediate inspections in cooperation with the police; see box 4.5.

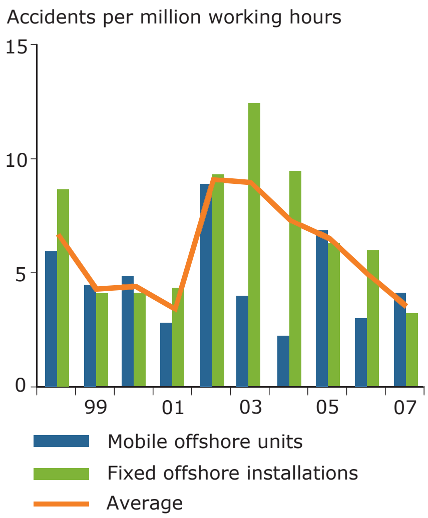
In 2007, the DEA registered a total of 19 reports concerning work-related accidents, 11 on fixed offshore installations, including mobile accommodation units, and eight on other mobile offshore units. The accidents are broken down by cause of accident, as shown in table 4.1 and figure 4.1.

Table 4.2 indicates the actual periods of absence from work attributable to the accidents reported, broken down on fixed and mobile offshore units. In the years before 2006, the expected period of absence, not the actual absence, was reported. This change in statistical method provides a truer picture of the seriousness of the accidents.

### Accident frequency

Every year, the DEA calculates the overall accident frequency, which is defined as the number of accidents reported per million working hours. In previous years, the number of working hours was based on a 13-hour working day. For 2007, this figure was changed to 12 hours, which yields a higher accident frequency than if a basis of 13 working hours were used. The figure was changed because the operating companies stated that a working day averages 12 working hours.

**Fig. 4.2** Accident frequency on offshore installations




**Box 4.5**

**Immediate inspections**

The operating company on the offshore installation must notify the police immediately in case of an accident that involves serious personal injury or major property damage. Major releases of substances and materials that pose a health or safety hazard must also be reported immediately. Against this background, the DEA decides whether to carry out an immediate inspection of the offshore installation in order to determine the more specific circumstances leading to the event.

The company must submit a written report on the event within nine days. Subsequently, the company must submit a review of its follow-up on the accident, including the sequence of events and information about the measures that have been or will be taken as a consequence of the event.

**Table 4.1** Reported accidents broken down by cause of accident for 2007

| Cause of accident | Fixed | Mobile |
|---|---|---|
| Falling/tripping | 4 | 1 |
| Use of work equipment | 2 | 2 |
| Handling goods | 1 | 5 |
| Other | 4 | 0 |
| **Total** | **11** | **8** |

**Table 4.2** Actual absence due to reported work-related accidents

| Duration | Fixed | Mobile |
|---|---|---|
| 1-3 days | 1 | 0 |
| 4-14 days | 1 | 0 |
| 2-5 weeks | 4 | 5 |
| More than 5 weeks | 4 | 2 |
| Still on sick leave | 1 | 1 |
| **Total** | **11** | **8** |

**Officially reporting offshore accidents in other countries**

The countries around the North Sea use different criteria for registering accidents connected with offshore oil and gas activities. Consequently, the databases for the accident statistics vary, thus preventing a direct comparison. Moreover, the workplaces covered by the offshore accident statistics differ in the individual countries.

**Denmark:** Accidents are reported when they result in incapacity to work for more than 24 hours beyond the injury date. The duration of absence from work is used to classify accident severity. This applies both on- and offshore.

**Norway:** Accidents are reported when they result in absence from work during the next 12-hour shift, or if the accident leads to a change of jobs. Accidents requiring medical treatment are also reported. Accident severity is classified according to type of accident.

**UK:** Accidents are reported when they result in full incapacity to work for more than three days beyond the injury date. Accident severity is classified according to type of accident.

The accident frequencies for fixed offshore installations and mobile offshore units in recent years appear from figure 4.2. The overall accident frequency for mobile units and fixed offshore installations came to *3.6 accidents per million working hours* in 2007. This is a reduction compared to 2006, when the accident frequency was 4.9 accidents per million working hours.

For mobile offshore units, eight work-related accidents were recorded in 2007, and the number of working hours totalled 1.91 million. Thus, the accident frequency for mobile offshore units increased from 2.9 accidents per million working hours in 2006 to *4.2 accidents per million working hours* in 2007. The number of work-related accidents

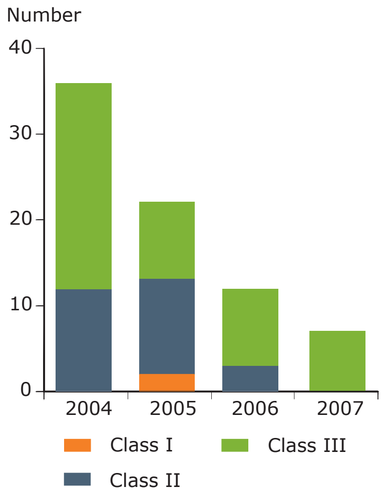
**Table 4.3** Accident frequencies in Danish offshore and onshore industries

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

*) *Overall accident frequency for fixe offshore installations and mobile offshore units as well as accommodation 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.*

**Fig. 4.3** Accidental hydrocarbon releases




on fixed offshore installations and accommodation units totalled 11 in 2007. The operators have stated that the number of working hours in 2007 totalled 3.43 million on these offshore installations. The accident frequency for fixed offshore installations and accommodation units was calculated at *3.2 accidents per million working hours* in 2007, a reduction compared to 2006 when the accident frequency came to 5.9.

Because of the relatively low number of accidents, the accident frequency may fluctuate widely from one year to the next. Thus, the trend over a number of years, and not the development from one year to another, provides the impression of any genuine decline in the accident frequency.

**Accident frequency in other Danish industries**
The DEA has compared the accident frequency on Danish offshore installations with data from comparable industries in Denmark.

Based on a number of assumptions, see box 4.6, the accident frequency has been calculated at 11.2 per million working hours for all 50 onshore industries in 2006. The National Working Environment Authority has not yet calculated the figure for 2007.

**Box 4.6**

**Accident frequency calculated by the National Working Environment Authority**
The National Working Environment Authority calculates the accident frequency 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 National Working Environment Authority uses workforce statistics indicating the number of persons who had their main job in the relevant industry in November in the year in question.

The figures for onshore companies are calculated 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. The figures are converted for the purpose of comparison with the special conditions existing offshore.

The National Working Environment Authority based its calculation of work-related accidents for 2006 on the year of registration, i.e. the year in which the accidents were reported. In previous years, the calculations were based on the year of accident, i.e. the year in which the accidents occurred.

This means that the figures in table 4.3 cannot be matched and compared with the figures in the DEA's previous annual reports. About 49,000 onshore work-related accidents were reported in 2006.

Table 4.3 shows the accident frequencies calculated by the DEA for 2004-2007 and the accident frequencies published by the National Working Environment Authority for 2004-2006. The table also contains the accident frequencies calculated for the Danish onshore industries whose jobs partially resemble those in the offshore sector.

## NEAR-MISS OCCURRENCES

Major near-miss occurrences must be reported to the DEA; see box 4.7.

**Box 4.7**

**Reporting near-miss occurrences**
Near-miss occurrences are defined as occurrences that could have directly led to an accident involving personal injury or damage to the offshore installation. Occurrences that might have led to serious personal injury must be reported to the DEA, as outlined in the Guidelines on Reporting Accidents available at the DEA's website.

**Power loss on the Siri platform**

On 12 May 2007, the Siri platform experienced a power loss that triggered a general alarm and emergency shutdown, resulting in production stoppage. Following unsuccessful attempts to start the standby generator, power supply was established with the emergency battery unit. Preparations for possible evacuation were made, it being impossible to remain on board without power for lighting, heating, etc. After about an hour, power supply was successfully established with the standby generator and the emergency was cancelled.

After discussion with the company, the DEA found that an immediate inspection was unnecessary from a safety viewpoint.

DONG E&P A/S carried out an investigation into the cause, but despite detailed technical examinations of the documentation and equipment, combined with extensive equipment testing, the findings were inconclusive. Based on the investigation, a series of recommendations have been implemented that will render the system more robust.

**Communication error between HLO (Helicopter Landing Officer) and crew**

During takeoff from the hotel platform Safe Esbjerg, situated alongside the Gorm installation, the crew of the helicopter misinterpreted the "clear deck" order, and the helicopter lifted approx. one metre off the deck with the HLO in the baggage hold. The HLO himself drew attention to the fact that he was still on board, and the helicopter landed again without anyone coming to harm.

The company reported the incident to the Danish Civil Aviation Authority (CAA-DK) and the DEA. The company launched an investigation into the incident immediately afterwards and prepared a report. The DEA followed up with an inspection visit and is carrying on a dialogue with CAA-DK about the incident and follow-up.

**Work-related accident during drilling operation**

On the afternoon of 17 March 2007, an employee was handling drill pipes on the floor of the drilling rig Maersk Enhancer. While working he was struck on the side of the head by a pipe and knocked over. After being attended to by the rig's medic, the employee concerned was flown to Esbjerg Hospital where he was mainly treated for concussion and then discharged.

Against this background, the DEA considered that an immediate inspection was unnecessary.

The day after the accident, the operator of the drilling operation, Mærsk Olie og Gas AS, sent an investigation team consisting of its own representatives and representatives of the rig operating company, Maersk Contractors, to the rig to examine the sequence of events.

As a result of the accident, a procedure for work performance on the drill floor was changed, and the sequence of events was discussed with all shifts on board the rig.

The DEA followed up on the accident during a subsequent inspection visit at which the change of procedure was confirmed and the DEA was informed that the lessons from the accident had been communicated to the company organization.

**Accident with power tool**
On 12 May 2007, an employee on board the drilling rig Noble Byron Welliver was injured while working on the drill floor. He was standing on a 40 cm high footstool screwing pipes together when the recoil from a hydraulic screwing tool propelled him backwards two metres.

The employee concerned injured his chest and was subsequently evacuated to Esbjerg Hospital where he was examined for broken ribs. He was pronounced fit for duty again after 24 days.

The rig operating company subsequently carried out an investigation into the incident. Among other things, the investigation found that the tool used by the employee is not normally used in the Danish sector. A Danish employee would therefore have less experience in using this type of tool.

The instruction and training procedure for using the hydraulic screwdriver has therefore been changed. A procedure for work performance on the drill floor has also been changed.

At its inspection of the drilling rig in March 2008, the DEA found that the accident follow-up carried out by the operating company was adequate.

**Fatality in the Gorm Field**
On Sunday, 3 June 2007, the DEA was notified by Mærsk Olie og Gas AS that a person had been found lifeless at the foot of a stairway on the Gorm F platform. Resuscitation attempts had been carried out on the spot, but the person was pronounced dead by a doctor summoned from the Admiral Danish Fleet headquarters.

The police, Mærsk Olie og Gas AS, a crisis counsellor and the DEA visited the Gorm installation the same evening to investigate the circumstances surrounding the fatality.

The subsequent post mortem found that the cause of death was attributable to illness-related indisposition and was not due to a fall or similar.

**Fire on board the drilling rig ENSCO 102**
On 17 June 2007, a fire started in the machinery room on board the drilling rig ENSCO 102. The electrician on night shift heard a loud bang and saw flames and smoke coming from under the hood of one of the generators. He immediately turned the generator off, after which the fire died down and was extinguished completely when the fire crew arrived shortly after.

The company contacted the DEA shortly after the fire had been extinguished, and the DEA closely monitored the company's subsequent investigations.

The company found the underlying cause of the fire to be friction between two cables that had worn away the cable insulation. ENSCO subsequently provided extra insulation around the cables in all similar generators and introduced revised inspection procedures.

**Box 4.8** Categories of hydrocarbon releases

**Class I:**
> 10 kg/sec. or more than 100 kg in total

**Class II:**
1-10 kg/sec. or more than 10 kg in total

**Class III:**
0.1-1 kg/sec. or more than 1 kg in total

In 2007, the DEA received a total of 45 reports on near-miss occurrences. This is a sharp increase compared to 2006. The rising number of reports is not considered to reflect a vast increase in the actual number of occurrences, but is rather an indication of the heightened focus put on reporting near-miss occurrences and the greater attention paid to safety. Thus, the increased number of reports gives a more representative view of the situations that might have developed into accidents under different circumstances.

Hydrocarbon releases (gas leakages) are considered near-miss occurrences, and the operators are obliged to report all class I and II incidents to the DEA; see box 4.8.

In 2007, no class I and II releases were reported. In addition, the operators have stated that there were seven class III releases, a slight decline compared to 2006; see figure 4.3.

## INTERNATIONAL COOPERATION

The DEA cooperates with the other health and safety authorities in the North Sea countries, on both a bilateral and a multilateral basis, through the North Sea Offshore Authorities Forum (NSOAF); see box 4.9. The NSOAF performs its work primarily through four working groups, described in more detail at the DEA's website, www.ens.dk.

### Mutual recognition of safety training

The Training Working Group, chaired by the DEA, has worked towards mutual recognition of the basic safety training course in the North Sea countries for a number

**Box 4.9**

**NSOAF (The North Sea Offshore Authorities Forum)**
NSOAF is an international cooperation forum that deals with issues related to offshore activities in the North Sea and adjoining areas.

The following countries participate in this cooperation (with the names of the public institutions shown in brackets):
Denmark (the DEA)
The Faroe Islands (Jarðfeingi)
The Netherlands (the State Supervision of Mines)
The Republic of Ireland (the Department of Communications, Energy and Natural Resources)
Norway (the Petroleum Safety Authority and the Ministry of Labour and Social Inclusion)
Sweden (the Geological Survey of Sweden)
Germany (Landesamt für Bergbau, Energie und Geologie and the Federal Ministry of Economics and Technology)
The UK (the Health & Safety Executive)

NSOAF primarily conducts its work through four permanent working groups – a Health Safety & Environment Working Group, a Training Working Group, a Wells Working Group and an EU Working Group. NSOAF members meet at an annual conference held in turn by the member countries, where they agree on the general objectives of the work to be performed by the working groups, among other issues.

of years, which would make a course taken, for example, in Denmark valid in, say, Norway.

In November 2007, an agreement between the operators' associations in Norway, Denmark, the UK and the Netherlands on mutual recognition of the basic safety training course entered into force. However, persons having completed a Danish safety training course are required to take a supplementary course in Helicopter Underwater Escape Training (HUET). As of 1 July 2008, the HUET course was made compulsory in Denmark, which means that the Danish training course fully corresponds to that in the other North Sea countries.

**Cooperation on offshore health and safety performance indicators**

Offshore safety standards are reflected not only by the accident frequency, but also by other parameters. Through NSOAF's Health Safety & Environment Working Group, the DEA cooperates with the industries in the North Sea countries on defining a number of common key performance indicators (KPIs) to measure health and safety standards on the offshore installations. NSOAF's common set of KPIs can be used as a basis for comparing the companies' health and safety standards across frontiers, and thus as an incentive to further improve health and safety standards, including accident prevention.

# 5 RESERVES

The DEA makes an assessment of Danish oil and gas reserves annually. At 1 January 2008, oil reserves were estimated at 214 million $m^3$ and gas reserves at 105 billion $Nm^3$.

The DEA's new assessment shows a decline in oil and gas reserves of 11 and 13 per cent, respectively, compared to the assessment made at 1 January 2007. The decrease in reserves is mainly attributable to production in 2007.

Estimated ultimate recovery of oil has been written down by 8 million $m^3$ compared to last year's assessment. Oil production amounted to 18 million $m^3$ in 2007, and oil reserves have thus declined by 26 million $m^3$ in total.

At 1 January 2008, 315 million $m^3$ of oil had been produced, with reserves amounting to 214 million $m^3$. Accordingly, total production during the period 1972-2007 amounts to 60 per cent of the expected ultimate recovery from known fields and discoveries; see figure 5.1.

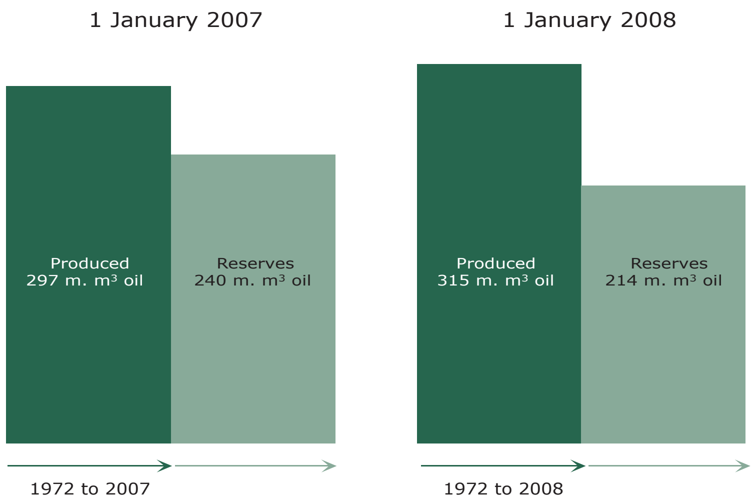
Appendix C shows the DEA's reserves assessment at 1 January 2008.

It is expected that technological developments and any new discoveries resulting from exploration activity, including under the licences from the 6th Licensing Round, will add new reserves to future assessments.

**Five-year production forecast**
The DEA prepares a five-year forecast for the production of oil and natural gas every spring and revises it every autumn.

*Oil*
For 2008, oil production is expected to total 16.4 million $m^3$, equal to about 283,000 barrels of oil per day; see table 5.1. This is a reduction of 9 per cent relative to 2007, when oil production totalled 18.1 million $m^3$. Compared to last year's forecast for 2008, this is an 8 per cent downward adjustment, which is due mainly to lowered production estimates for the South Arne, Halfdan and Dan Fields.

**Fig. 5.1** Oil production and oil reserves



Oil production is expected to decline further from 2008 to 2009, and then to level out and remain relatively constant during the rest of the forecast period. On average, the production estimate has been written down by 6 per cent for the forecast period relative to last year's forecast. This is primarily attributable to reduced expectations for production from the Dan Field and postponed production startup of the Hejre discovery.

*Natural gas*

Natural gas production is estimated at 8.6 billion $Nm^3$ for 2008; see table 5.1. On average, the production estimate has been written down by 6 per cent for the forecast period relative to last year's forecast. For the years 2008 and 2009, the writedown is based on the lower-than-estimated production of natural gas in 2007. The writedown for the rest of the forecast period is attributable to postponed production startup of the Hejre discovery and the Amalie Field.

**Table 5.1** Expected production of oil and natural gas

| | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|
| Oil, million $m^3$ | 16.4 | 15.0 | 15.7 | 15.4 | 15.4 |
| Natural gas, billion $Nm^3$ | 8.6 | 8.6 | 8.2 | 7.3 | 6.7 |

**Degrees of self-sufficiency for the next five years**

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

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

In 2007, the total production of oil, gas and renewable energy exceeded total energy consumption by 31 per cent. This is a decline compared to the year before, when production exceeded consumption by 44 per cent. This decline was caused mainly by lower oil production.

In 2007, oil and gas production was 15 per cent higher than total energy consumption and 92 per cent higher than total oil and gas consumption.

Table 5.2 shows the development in the degrees of self-sufficiency projected by the DEA for the next five years. The DEA prepares forecasts for the consumption of oil and natural gas in Denmark. The energy consumption shown is based on the forecast prepared by the DEA as a basis for the Energy Agreement of 2 February 2008.

Compared to the corresponding figures published in "Oil and Gas Production in Denmark 2006", the expected degrees of self-sufficiency in the table show a general decline. The main reason for this decline is the writedown of oil and gas production estimates compared to last year's estimates.

As appears from table 5.2, the DEA expects Denmark to continue being self-sufficient in energy for the next five years.

**Fig. 5.2** Contribution from reserves, oil

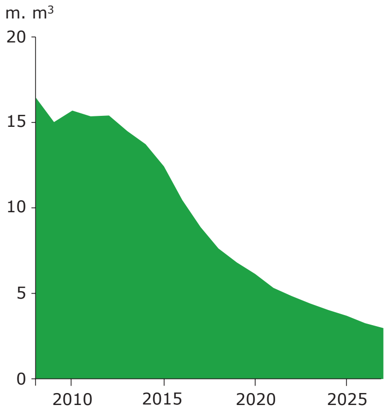



**Fig. 5.3** Contribution from reserves, natural gas

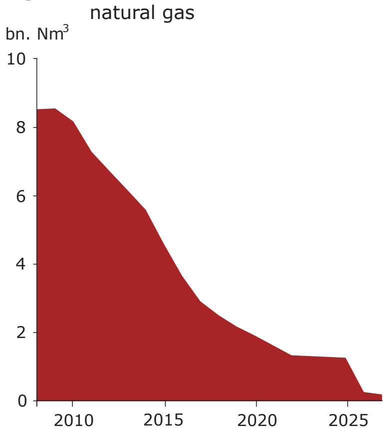



**Table 5.2** Degrees of self-sufficiency

| | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|
| **Production in PJ** | | | | | |
| Oil | 608 | 555 | 580 | 568 | 570 |
| Gas | 366 | 367 | 352 | 318 | 295 |
| Renewable energy | 156 | 163 | 181 | 181 | 187 |
| **Energy consumption in PJ** | | | | | |
| Total | 869 | 868 | 865 | 859 | 860 |
| **Degrees of self-sufficiency, per cent** | | | | | |
| A | 185 | 173 | 180 | 174 | 170 |
| B | 112 | 106 | 108 | 103 | 101 |
| C | 130 | 125 | 129 | 124 | 122 |

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

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

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

For oil, the contribution from reserves shows a generally declining trend; see figure 5.2. However, due to investments in the further development of existing fields and the development of new fields, the DEA forecasts relatively constant production during the period from 2009 through 2012.

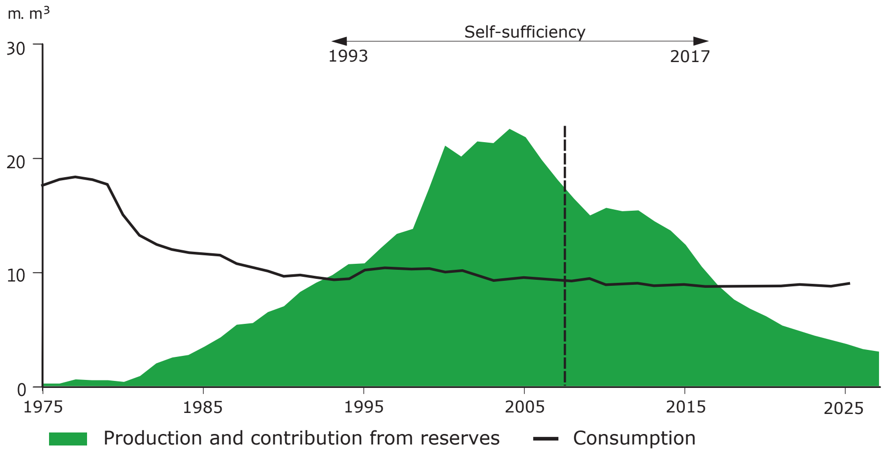
The forecast does not provide for major field developments after 2012, and 10 and 15 years from now production is expected to constitute 50 and 25 per cent of production in 2007, respectively.

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

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

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

**Fig. 5.4** Oil production and contribution from reserves




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.

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

Figure 5.3 shows the contribution from reserves for natural gas. The volume of production is expected to remain fairly constant for the next few years, and subsequently to decline.

**Degrees of self-sufficiency for the next 20 years**

Figure 5.4 shows the amount of oil produced and historical consumption, as well as the contribution from reserves and the forecast prepared by the DEA as a basis for the Energy Agreement of 2 February 2008. The forecasts of consumption and production diverge significantly.

The consumption forecast shows an almost constant trend, while the production forecast indicates a marked downward trend, apart from the beginning of the forecast period when production is expected to remain fairly constant.

Production shows a declining trend because the forecast does not include the further development of known fields by means of new technology or the development of new discoveries.

On the basis of these production assumptions, Denmark is expected to be self-sufficient in oil up to and including 2017.

The natural gas forecasts illustrate a scenario similar to the oil forecasts. Based on the contribution from reserves, Denmark is forecast to be self-sufficient in natural gas up to and including 2016.

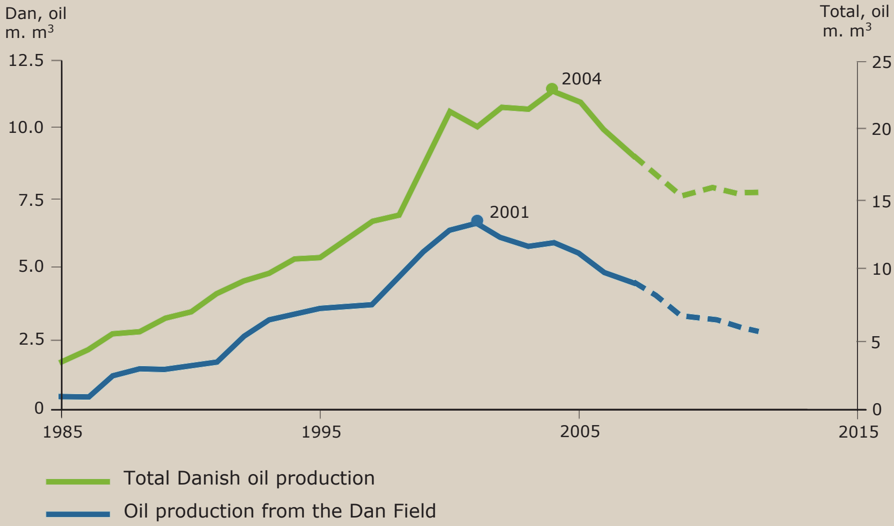
**Why is Denmark's oil production declining?**
Denmark's oil production peaked in 2004 and has since declined. By 2007, production had decreased by 20 per cent compared to 2004.

Production from a field declines for natural reasons. In a field where recovery is based on natural depletion, oil production will fall as pressure in the reservoir drops. Where the production strategy is to maintain reservoir pressure, for example by means of water injection, the volumes of oil and water produced will remain fairly constant throughout the life of the field. However, oil production will fall and water production increase as the water injected flows into the production wells.

The figure below shows historical oil production from the Dan Field since 1985 and a forecast for the next five years. It appears that production increased from the mid-80s until 2001, when production peaked. Oil production rose because the field was further developed with horizontal and water-injection wells.

The field was also developed after 2001, but the additional production deriving from new production initiatives has been unable to compensate for the natural drop in oil production. The five-year production forecast for the field also shows a downward trend.

**Oil production from the Dan field and all Danish fields, m. $m^3$**




Although Denmark's production consists of contributions from numerous fields, the production trend illustrated above for the Dan Field resembles the overall trend of Danish oil production. During the period from 1985 to 2004, several new fields were brought on stream while some of the major existing fields were developed with horizontal and water-injection wells, thus driving up Danish oil production.

Production figures have declined for most Danish fields since 2004, resulting in a drop in total production. As the above figure shows, production is estimated to remain fairly constant during the second half of the forecast period due to investments in further developing existing fields and developing several new fields.

Figure 5.2 shows the further course of production during the rest of the 20-year forecast period. However, technological developments and any new discoveries made as part of ongoing exploration activity, including under the licences from the 6th Licensing Round, are expected to curb the decline in production.

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

**RESOURCES**

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

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

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

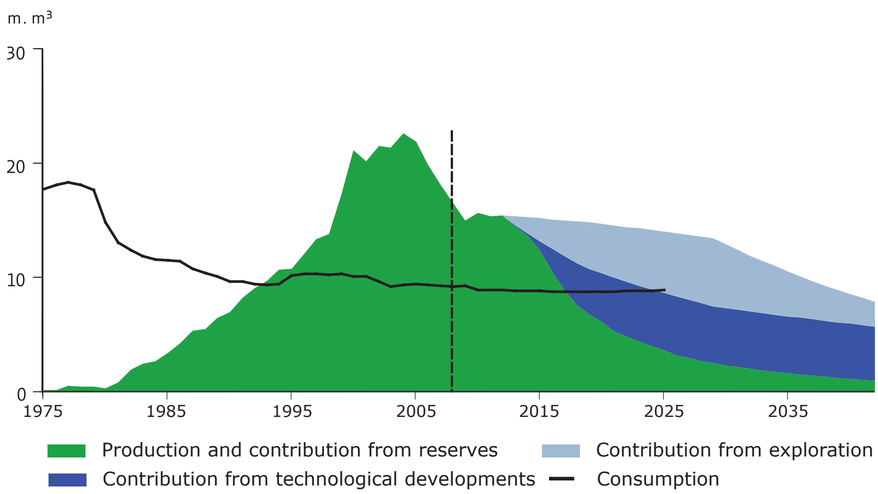
**A contribution from exploration**, estimated on the basis of the additional volumes of oil and gas likely to be recovered from new discoveries.

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

The DEA's estimate of the contribution from technological developments for oil is based on a 5-10 percentage point increase of the average recovery factor for Danish fields. The average recovery factor is the ratio of ultimate recovery to total oil-in-place. Based on the reserves assessment, the average expected recovery factor for oil is 23 per cent.

It should be noted that an assumption stating that the average recovery factor for oil will increase by about 5-10 percentage points is based on an evaluation of historical developments, as the average recovery factor has increased by 9 percentage points since 1990. It is impossible to foresee which new techniques will contribute to additional production or to estimate the impact of these techniques on production.

**Fig. 5.5** Oil production and production forecast



The report from May 2005 that analyzed oil and natural gas resources is a background report to "Energy Strategy 2025". This report used a contribution from technological developments that corresponded to a 5 percentage point increase of the recovery factor, based on the relatively low oil price prevailing at that time. It was also emphasized in the report that a relatively high oil price would provide a major incentive to develop new techniques. With today's relatively high oil prices, it is estimated that the recovery factor can be increased by 10 percentage points. The DEA has estimated that it will take longer to produce the amount deriving from technological developments than assumed in the last forecast.

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

The DEA's estimate of the contribution from exploration is based, inter alia, on an assessment of the exploration potential from mid-2003 made in connection with the 6th Licensing Round. In mid-2003, the exploration potential was assessed at 205 million $m^3$ of oil and 152 billion $Nm^3$ of gas. The report "Oil and Gas Production in Denmark 2003" contains a description of the assessment and the method used.

Figure 5.5 illustrates the DEA's oil production forecast when including the contributions from reserves, technological developments and exploration. It also shows the forecast prepared by the DEA as a basis for the Energy Agreement of 2 February 2008. Denmark is expected to be self-sufficient in oil up to and including 2017, based on the contribution from reserves. If the contributions from technological developments and exploration are included, Denmark is estimated to be self-sufficient in oil for another 20 years or so.

Denmark is expected to be self-sufficient in natural gas up to and including 2016, based on the contribution from reserves. For natural gas, the DEA anticipates no significant contribution from technological developments because current technology has already generated a much higher recovery factor than for oil. Thus, the DEA does not expect any such contribution to prolong Denmark's self-sufficiency in natural gas to an appreciable degree. When including the contributions from technological developments and exploration, the DEA estimates Denmark to be self-sufficient in natural gas for another ten years or so.

# 6 ECONOMY

Since 1997, the production of hydrocarbons has made an essential contribution to Denmark's self-sufficiency in 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 players 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 development in production, the international crude oil price and the dollar exchange rate.

The oil price increased by about 10 per cent compared to 2006. The average quotation for a barrel of Brent crude oil was USD 72.5 in 2007 against USD 65.1 in 2006, and thus the oil price has continued the upward trend of recent years. Figure 6.1 illustrates the oil price development in 2007.

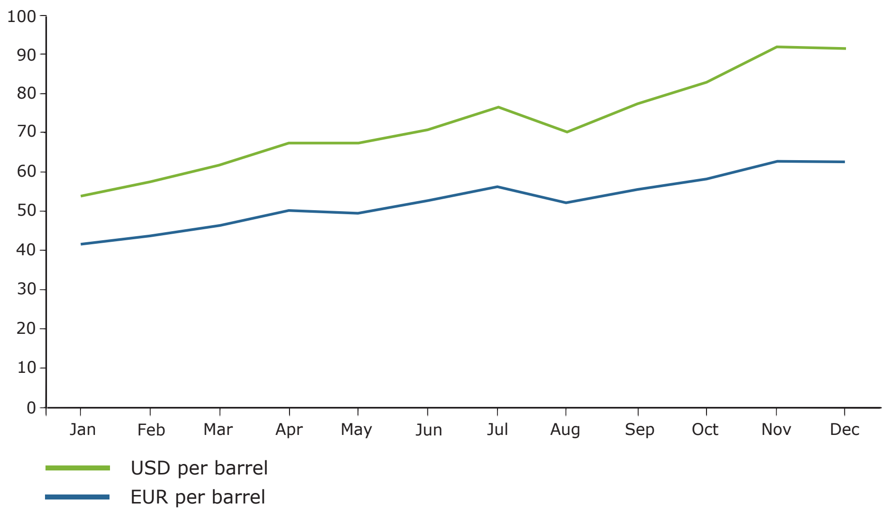
The average dollar exchange rate in 2007 was DKK 5.4 per USD. This is a marked drop compared to the period from 2004 to 2006 when the dollar exchange rate hovered around DKK 6 per USD.

Figure 6.1 also shows the oil price trend in EUR. As appears from the figure, the gap between the oil price in USD and EUR widened in 2007. While the oil price almost doubled in USD in 2007, the falling dollar exchange rate made the increase in EUR – and thus in DKK – much more moderate.

Accordingly, the falling dollar exchange rate means that the average oil price in DKK terms remained largely unchanged during the period from 2006 to 2007. The average price for a barrel of Brent crude oil was DKK 387.2 in 2006 and DKK 392.1 in 2007. Therefore, the hike in the oil price in USD did not engender a corresponding increase in earnings in DKK.

Figure 6.2 shows the oil price trend in USD from 1972 to 2007. It is noteworthy that the average oil price in real terms was higher at the beginning of the 1980s than in 2007.

**Fig. 6.1** Oil prices, 2007, USD and EUR



The drop in oil and gas production in 2007 led to a decline in the value of the production volume in DKK. Overall, the value of Danish oil and gas production totalled DKK 56 billion in 2007. According to preliminary estimates for 2007, oil production accounted for about DKK 44.6 billion and gas production for DKK 11.4 billion.

Overall, the production value decreased by about 7 per cent compared to the year before. This is because the oil price increases did not offset the fall in the exchange rate and in oil production.

The breakdown of oil production in 2007 on the ten producing companies in Denmark appears from figure 2.2 in the section *Development and production*.

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

Appendix D contains a detailed outline of financial key figures from 1972 to 2007.

## IMPACT OF PRODUCTION ON THE DANISH ECONOMY

Oil and gas production contributes to Denmark's net self-sufficiency in energy. The volume of production makes it possible to export oil as well as natural gas. 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 6.3 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.

The surplus amounted to DKK 28.3 billion in 2007 and thus remains at the high level of previous years, although the lower production figure and falling dollar exchange rate meant a decline compared to 2006, when the surplus amounted to DKK 31.5 billion.

**Fig. 6.2** Oil price development 1972-2007

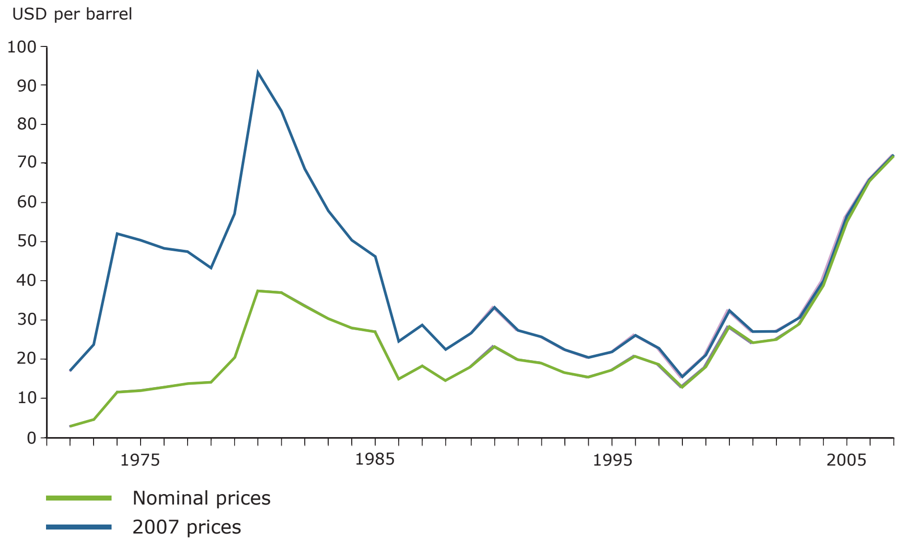
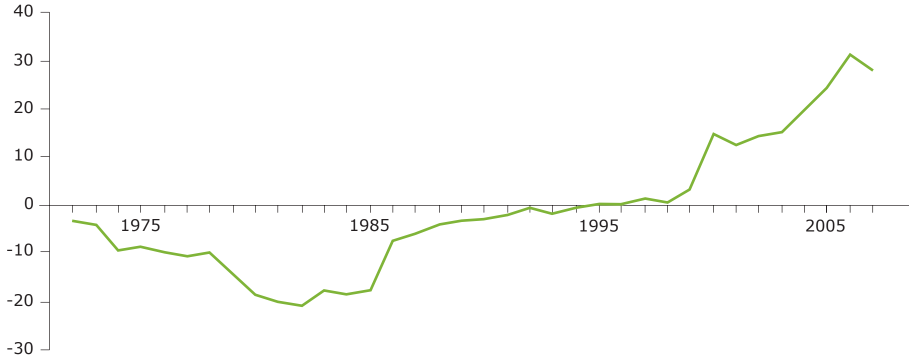


**Fig. 6.3** Balance of trade for oil and natural gas, DKK billion, nominal prices




**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.

The DEA's five-year forecast has been prepared for three different oil price scenarios this year. The purpose of preparing three scenarios is to illustrate the sensitivity of balance-of-payments effects to fluctuations in the oil price.

The three scenarios are based on an oil price of USD 62, 90 and 120 per barrel and a dollar exchange rate of DKK 5.07 per USD. An oil price of USD 62 per barrel reflects the IEA's long-term oil price projection.

Table 6.1 shows the individual items used in calculating the impact of oil and gas activities on the balance of payments in the USD 90 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 62 and USD 120 per barrel.

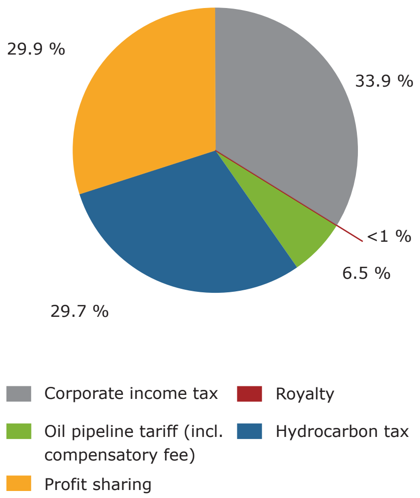
Assuming that the oil price is USD 90 per barrel, the oil and gas activities will have an estimated DKK 40-44 billion impact on the balance of payments current account per

**Table 6.1** Impact of oil/gas activities on the balance of payments, DKK billion, 2007 prices, price scenario (90 USD/bbl)

| | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|
| Production value | 59.3 | 55.2 | 56.6 | 54.4 | 53.8 |
| Import content | 4.7 | 4.4 | 4.4 | 3.9 | 3.6 |
| Balance of goods and services | 54.6 | 50.7 | 52.2 | 50.5 | 50.2 |
| Transfer of interest and dividends | 10.4 | 9.6 | 10.2 | 9.0 | 9.3 |
| Balance of payments current account | 44.1 | 41.1 | 42.0 | 41.5 | 40.9 |
| Balance of payments current account, low price scenario (62 USD/bbl) | 33.2 | 31.3 | 31.9 | 31.6 | 31.2 |
| Balance of payments current account, high price scenario (120 USD/bbl) | 56.1 | 52.0 | 53.3 | 52.1 | 50.2 |

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

Fig. 6.4 State revenue in 2007




year during the period 2008-2012. Moreover, it appears that a higher oil price intensifies the impact, and vice versa.

## State revenue

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

In addition to the direct revenue from taxes and fees, the Danish state receives indirect revenue from the North Sea by virtue of its shareholding in DONG Energy, generated by the subsidiary 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.

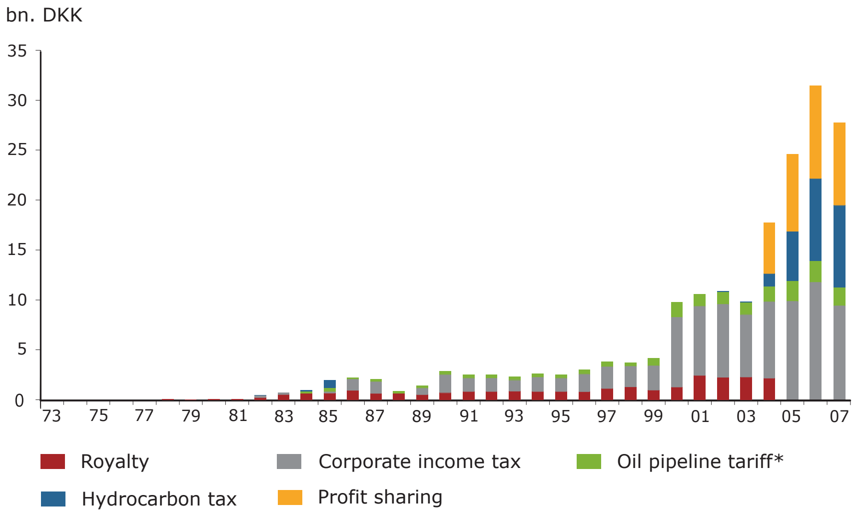
Box 6.1 contains a specification of the state's revenue base in the form of taxes and fees on oil and gas production.

With a share of almost 34 per cent, corporate income tax is the chief source of state revenue. Figure 6.4 shows the breakdown of state tax revenue in 2007. State revenue from hydrocarbon production in the North Sea aggregated DKK 186.9 billion in 2007 prices in the period 1963-2007.

Figure 6.5 shows the development in state revenue from 1972 to 2007. By way of illustration, the associated production value totalled DKK 543.7 billion during the same period, while the aggregate value of the licensees' expenses for exploration, field developments and operations was DKK 227.4 billion.

The development in 2007 was characterized by declining production figures and a weaker dollar exchange rate, not fully offset by the oil price hike. Total state revenue from oil and gas production is estimated at DKK 27.9 billion for 2007. By comparison, state revenue reached a record high at DKK 31.5 billion in 2006. As appears from figure 6.6, state revenue from oil and gas production accounted for almost 30 per cent of the state's surplus.

**Fig. 6.5** Development in total state revenue from oil and gas production 1973-2007, DKK billion, 2007 prices




** Incl. compensatory fee*

**Box 6.1** 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 2007. Detailed information appears from Appendix E and the DEA's website.

**Corporate income tax**
Corporate income tax is the most important source of revenue related to oil and gas. The corporate tax rate was reduced from 28 per cent to 25 per cent with effect from 1 January 2007.

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

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

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

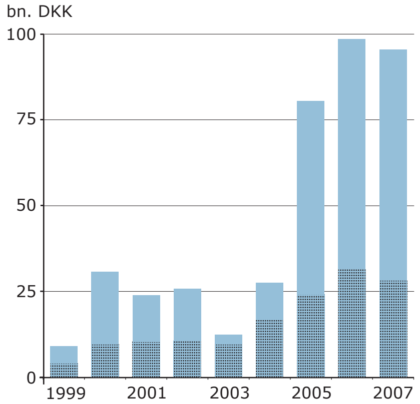
**Oil pipeline tariff**
DONG Oil Pipe A/S owns the oil pipeline from the Gorm Field to Fredericia. Users of the oil pipeline pay a fee to DONG Oil Pipe A/S, which includes a profit element of 5 per cent of the value of the crude oil transported. DONG Oil Pipe A/S pays 95 per cent of the proceeds from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

**Compensatory fee**
Any parties granted an exemption from the obligation regarding connection to and transportation through the oil pipeline are required to pay the state a fee amounting to 5 per cent of the value of the crude oil and condensate comprised by the exemption.

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

**Danish North Sea Fund**
As from 2004, the Danish state, represented by the Danish North Sea Fund, is to participate in all new licences with a 20 per cent share. In addition, the state will hold a 20 per cent share of DUC as from 9 July 2012.

**Fig. 6.6** Central government (CIL) surplus and central government revenue from the North Sea




Central government (CIL) surplus

Central government revenue from the North Sea

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

Table 6.2 shows total state revenue for the past five years, broken down on the individual taxes and fees.

State revenue has grown substantially since 2003 due to the higher oil price level. This is because 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. This means that the more profits the companies generate, for example due to higher oil prices, the more they have to pay in tax.

The state's share varies depending on whether the revenue is calculated by income tax year or by year of payment. In 2007, state revenue calculated by year of payment amounted to 60.5 per cent. Calculated by income tax year, the state's share amounted to 63 per cent.

For the next five years, the Ministry of Taxation estimates that the state's revenue will total about DKK 30-33 billion per year from 2008 to 2012, based on the USD 90 oil price scenario. Table 6.3 shows the development in expected state revenue for the three different oil price scenarios. It also appears from the table that the state's share of profits rises when the oil companies generate increasing earnings due to higher oil prices, for example.

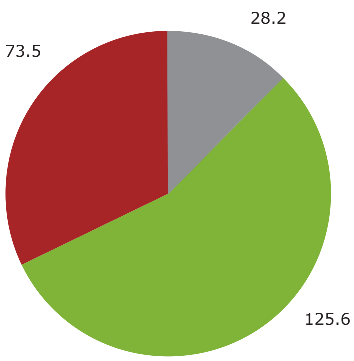
Future estimates of corporate income tax and hydrocarbon tax payments are subject to uncertainty with respect to oil prices, production volumes and the dollar exchange rate. In addition, uncertainty attaches to the calculations because they are based on various stylized assumptions, some of which concern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

**Investments and costs**

The licensees' initiatives with regard to exploration and field development, operation and maintenance are essential for the Danish state to maintain the current revenue level from the North Sea.

Investments in the development of existing and new fields account for more than half the licensees' total expenses. Figure 6.7 shows the breakdown of the licensees' expenses during the period from 1963 to 2007. The expenses for exploration, field developments and operations (including administration and transportation) accounted for 13, 55 and 32 per cent, respectively, of total expenses.

**Fig. 6.7** Total expenses of all licensees, 1963-2007, DKK billion, 2007 prices




Exploration

Field development

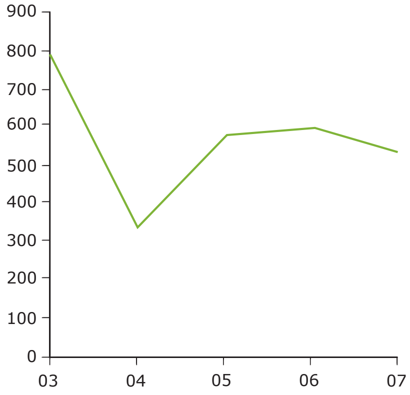
Operations

**Table 6.2** State revenue over the past fi e years, DKK million, nominal prices

| | 2003 | 2004 | 2005 | 2006 | 2007 |
|---|---|---|---|---|---|
| Hydrocarbon tax | 64 | 1,251 | 4,854 | 8,282 | 8,280 |
| Corporate income tax | 5,943 | 7,351 | 9,661 | 11,738 | 9,441 |
| Royalty | 2,181 | 2,104 | 1 | 1 | 2 |
| Oil pipeline tariff* | 1,144 | 1,496 | 2,052 | 2,156 | 1,815 |
| Profit sharing | - | 4,890 | 7,595 | 9,322 | 8,348 |
| **Total** | **9,331** | **17,092** | **24,163** | **31,499** | **27,886** |

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

**Fig. 6.8** Exploration costs, 2003-2007, DKK million, nominal prices




## Exploration costs

Figure 6.8 shows the development in exploration costs from 2003 to 2007. For 2007, total exploration costs are preliminarily estimated at DKK 0.54 billion. Thus, the total costs of exploration declined slightly compared to 2006, when exploration costs were calculated at DKK 0.6 billion.

The decline is attributable to the postponement of some activities until 2008. Thus, exploration costs are estimated to increase to DKK 0.8-1.0 billion in 2008 and 2009, particularly due to the activities under the 6th Round licences from 2006. The higher oil price level is also expected to result in increased exploration activity, including in areas outside the Central Graben.

## Investments in field developments

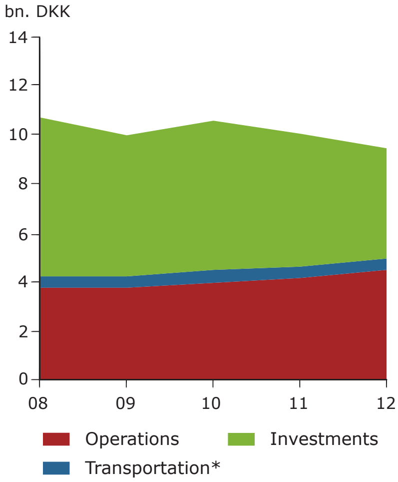
The largest expense item in the licensees' budget is the development of new and existing fields. Investments in field developments are estimated to total DKK 6.6 billion in 2007, an increase of DKK 1.1 billion on the previous year. By comparison, annual investments in field developments averaged almost DKK 5 billion in the past ten years. Table 6.4 illustrates investments in field developments over the period 2003-2007.

**Table 6.3** Expected state revenue from oil and gas production, DKK billion, nominal prices*

| | | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|---|
| Corporate income | 120 USD/bbl | 74.1 | 69.9 | 74.9 | 74.5 | 72.6 |
| tax base before taxes, | 90 USD/bbl | 52.8 | 49.8 | 53.5 | 53.1 | 51.4 |
| fees and profit sharing | 62 USD/bbl | 33.8 | 31.7 | 34.2 | 33.9 | 32.3 |
| Corporate income tax | 120 USD/bbl | 14.4 | 13.6 | 14.7 | 14.7 | 14.7 |
| | 90 USD/bbl | 10.2 | 9.7 | 10.5 | 10.4 | 10.3 |
| | 62 USD/bbl | 6.5 | 6.1 | 6.6 | 6.6 | 6.4 |
| Hydrocarbon tax | 120 USD/bbl | 16.0 | 15.0 | 15.4 | 15.9 | 18.0 |
| | 90 USD/bbl | 10.9 | 10.1 | 10.5 | 10.4 | 10.6 |
| | 62 USD/bbl | 6.3 | 5.8 | 6.1 | 6.1 | 6.3 |
| Profit sharing | 120 USD/bbl | 13.3 | 12.5 | 12.8 | 12.6 | 11.8 |
| | 90 USD/bbl | 9.6 | 9.0 | 9.3 | 9.1 | 8.5 |
| | 62 USD/bbl | 6.3 | 5.9 | 6.1 | 6.0 | 5.5 |
| Royalty | 120 USD/bbl | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | 90 USD/bbl | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| | 62 USD/bbl | 0.0 | 0.0 | 0.0 | 0.0 | 0.0 |
| Oil pipeline tariff** | 120 USD/bbl | 2.9 | 2.7 | 2.9 | 2.9 | 1.8 |
| | 90 USD/bbl | 2.2 | 2.0 | 2.2 | 2.2 | 1.4 |
| | 62 USD/bbl | 1.5 | 1.4 | 1.5 | 1.5 | 1.0 |
| **Total** | 120 USD/bbl | 46.6 | 43.8 | 45.9 | 46.2 | 46.3 |
| | 90 USD/bbl | 32.9 | 30.8 | 32.4 | 32.1 | 30.8 |
| | 62 USD/bbl | 20.6 | 19.2 | 20.3 | 20.2 | 19.2 |
| The state's share | 120 USD/bbl | 63.0 | 62.7 | 61.3 | 61.9 | 63.8 |
| (per cent) | 90 USD/bbl | 62.3 | 62.0 | 60.6 | 60.5 | 60.0 |
| | 62 USD/bbl | 60.9 | 60.4 | 59.3 | 59.5 | 59.5 |

** Assumed annual inflation rate of 1.73 per cent*
*** 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. 6.9** Investments in fields, operating and oil transportation costs, 2007 prices




**Excl. pipeline tariff/compensatory fee*

In 2007, the development activities in the Halfdan, South Arne, Tyra and Valdemar Fields represented the bulk of investments, accounting for almost 80 per cent of total investments in 2007.

Table 6.5 shows the DEA's estimate of development activity for the period from 2008 to 2012. The estimate is based on ongoing, approved, planned and possible investments. The forecast of possible field development activities is based on the DEA's assessment of the potential for initiating further production in the short term beyond the production for which development plans have already been submitted; see the section *Reserves*.

Estimated investments for the period 2008-2012 correspond to the level in last year's forecast. The DEA has revised some of the investments, for example doubling its estimate of investments in the "Ongoing and approved" category compared to last year, in part because plans have been submitted for projects that were included in the "Possible" category last year.

**Operating, administration and transportation costs**
For 2007, the DEA has calculated operating, administration and transportation costs at DKK 3.9 billion, a decline of almost 10 per cent compared to the year before. The main reason for this decline is the lower production volume in 2007. Transportation costs as well as operating and administration costs have decreased compared to the year before.

**Table 6.4** Investments in field de elopments, 2003-2007, DKK million, nominal prices

| | 2003 | 2004 | 2005 | 2006 | 2007* |
|---|---|---|---|---|---|
| Cecilie | 660 | 309 | -18 | 7 | 6 |
| Dagmar | 0 | 0 | 0 | 0 | 0 |
| Dan | 943 | 750 | 750 | 684 | 436 |
| Gorm | 107 | 108 | 291 | 303 | 158 |
| Halfdan | 1,779 | 1,124 | 683 | 1,244 | 2,120 |
| Harald | 4 | 22 | 53 | 1 | 4 |
| Kraka | 0 | 2 | 0 | 0 | 0 |
| Nini | 1,288 | 319 | 163 | 35 | 204 |
| Roar | 0 | 0 | 0 | 0 | 0 |
| Rolf | 37 | 4 | 0 | 1 | 2 |
| Siri | 406 | 425 | 73 | 153 | 220 |
| Skjold | 77 | 8 | 11 | 4 | 15 |
| South Arne | 764 | 762 | 310 | 478 | 1,088 |
| Svend | 0 | 0 | 0 | 0 | 0 |
| Tyra | 305 | 459 | 1,020 | 1,426 | 703 |
| Tyra Southeast | 82 | 96 | 45 | 45 | 306 |
| Valdemar | 200 | 52 | 553 | 991 | 1,322 |
| NOGAT Pipeline | 766 | 664 | 12 | - | - |
| Not allocated | -31 | 2 | 5 | - | 16 |
| **Total** | **7,386** | **5,105** | **3,951** | **5,373** | **6,600** |

** Estimate*

The increases in operating and transportation costs resulting from higher oil prices are levelling out and stabilizing at a substantially higher level than a few years back. For example, the rate of rental for a standard drilling rig is three times higher than the rate four years ago, with the estimated rental per day slightly exceeding USD 200,000.

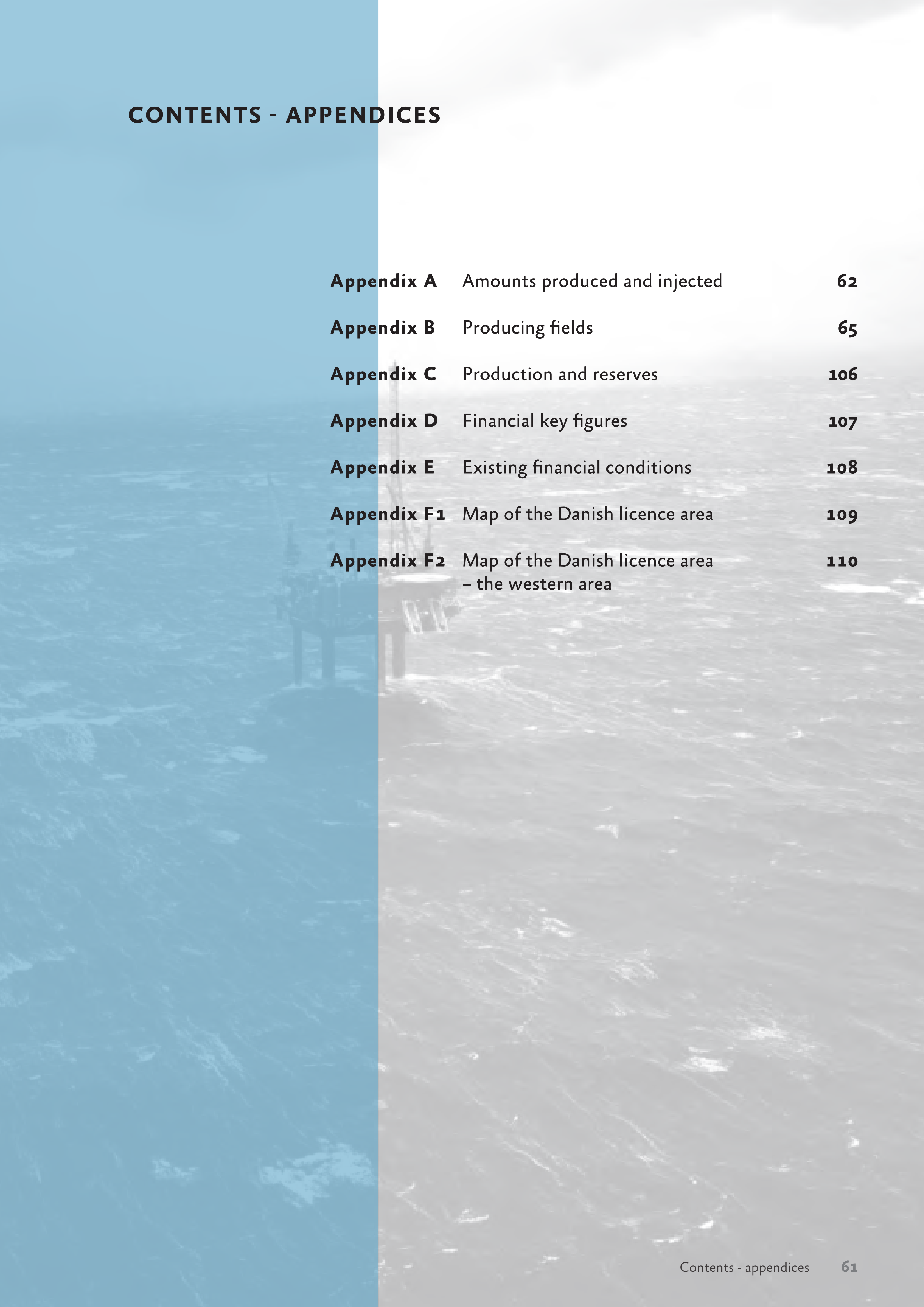
Figure 6.9 illustrates the DEA's estimate of developments in investments and operating and transportation costs for the period 2008-2012. Operating costs are expected to climb during the whole period, and transportation costs are estimated to exceed the level in 2007. At the beginning of the period, investments are projected to reach a higher level than in 2007, and then to decline towards the end of the period.

**Table 6.5** Estimated investments in development projects, 2008-2012, DKK billion, 2007 prices

| | 2008 | 2009 | 2010 | 2011 | 2012 |
|---|---|---|---|---|---|
| **Ongoing and approved** | | | | | |
| Adda | 0.3 | 1.0 | - | - | - |
| Alma | - | - | 0.6 | - | - |
| Boje | - | - | 0.5 | - | - |
| Cecilie | 0.0 | - | - | - | - |
| Dagmar | - | - | - | - | - |
| Dan | 0.4 | 0.0 | 0.3 | - | - |
| Gorm | 0.0 | - | - | - | - |
| Halfdan | 2.2 | 2.3 | 1.1 | 0.5 | 0.3 |
| Harald | 0.0 | 0.1 | 0.0 | - | - |
| Kraka | 0.3 | - | - | - | - |
| Lulita | - | - | - | - | - |
| Nini | 1.4 | 0.9 | - | 0.4 | 0.0 |
| Regnar | - | - | - | - | - |
| Roar | - | - | - | - | - |
| Rolf | - | - | - | - | - |
| Siri | 0.4 | - | - | - | - |
| Skjold | - | - | - | - | - |
| South Arne | 0.1 | - | - | - | - |
| Svend | - | - | - | - | - |
| Tyra | 0.3 | 0.4 | 0.1 | 0.8 | 0.5 |
| Tyra Southeast | 0.3 | - | - | - | - |
| Valdemar | 0.9 | 0.4 | - | - | - |
| **Total** | **6.5** | **5.1** | **2.6** | **1.7** | **0.9** |
| | | | | | |
| Planned | 0.0 | 0.0 | 0.0 | 0.2 | 0.7 |
| Possible | 0.0 | 0.7 | 3.4 | 3.5 | 3.0 |
| **Expected** | **6.5** | **5.8** | **6.1** | **5.4** | **4.5** |

# CONTENTS - APPENDICES





# APPENDIX A: AMOUNTS PRODUCED AND INJECTED

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

| | 1972-97 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Dan** | 33,232 | 4,767 | 5,745 | 6,599 | 6,879 | 6,326 | 5,929 | 6,139 | 5,712 | 5,021 | 4,650 | 90,999 |
| **Gorm** | 30,791 | 2,865 | 3,384 | 3,110 | 2,180 | 2,887 | 2,838 | 2,469 | 1,978 | 1,897 | 1,639 | 56,040 |
| **Skjold** | 25,348 | 1,896 | 1,825 | 1,975 | 1,354 | 1,659 | 1,532 | 1,443 | 1,310 | 1,214 | 1,015 | 40,571 |
| **Tyra** | 15,696 | 931 | 892 | 1,000 | 872 | 801 | 918 | 723 | 773 | 845 | 764 | 24,214 |
| **Rolf** | 3,375 | 92 | 77 | 83 | 51 | 51 | 104 | 107 | 79 | 89 | 103 | 4,212 |
| **Kraka** | 2,354 | 314 | 404 | 350 | 253 | 157 | 139 | 199 | 211 | 222 | 176 | 4,778 |
| **Dagmar** | 955 | 13 | 10 | 8 | 4 | 6 | 7 | 2 | 0 | 0 | 0 | 1,005 |
| **Regnar** | 728 | 43 | 29 | 14 | 33 | 18 | 19 | 19 | 16 | 11 | 0 | 930 |
| **Valdemar** | 842 | 95 | 86 | 77 | 181 | 353 | 435 | 491 | 423 | 470 | 881 | 4,335 |
| **Roar** | 747 | 327 | 259 | 285 | 317 | 175 | 121 | 98 | 94 | 51 | 35 | 2,509 |
| **Svend** | 2,192 | 635 | 521 | 576 | 397 | 457 | 280 | 326 | 324 | 296 | 299 | 6,301 |
| **Harald** | 794 | 1,690 | 1,332 | 1,081 | 866 | 578 | 425 | 314 | 237 | 176 | 139 | 7,632 |
| **Lulita** | - | 143 | 224 | 179 | 66 | 24 | 20 | 19 | 35 | 68 | 55 | 833 |
| **Halfdan** | - | - | 222 | 1,120 | 2,965 | 3,718 | 4,352 | 4,946 | 6,200 | 6,085 | 5,785 | 35,394 |
| **Siri** | - | - | 1,593 | 2,118 | 1,761 | 1,487 | 925 | 693 | 703 | 595 | 508 | 10,383 |
| **South Arne** | - | - | 757 | 2,558 | 2,031 | 2,313 | 2,383 | 2,257 | 2,371 | 1,869 | 1,244 | 17,783 |
| **Tyra SE** | - | - | - | - | - | 493 | 343 | 580 | 614 | 446 | 377 | 2,852 |
| **Cecilie** | - | - | - | - | - | - | 166 | 310 | 183 | 116 | 88 | 863 |
| **Nini** | - | - | - | - | - | - | 391 | 1,477 | 623 | 377 | 323 | 3,192 |
| **Total** | **117,054** | **13,810** | **17,362** | **21,134** | **20,207** | **21,505** | **21,327** | **22,612** | **21,886** | **19,847** | **18,083** | **314,827** |

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

| | 1972-97 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Dan** | 12,378 | 1,343 | 1,410 | 1,186 | 1,049 | 945 | 786 | 764 | 651 | 561 | 456 | 21,531 |
| **Gorm** | 11,695 | 633 | 537 | 426 | 306 | 480 | 339 | 216 | 218 | 207 | 175 | 15,231 |
| **Skjold** | 2,251 | 146 | 154 | 158 | 104 | 123 | 92 | 77 | 93 | 77 | 69 | 3,343 |
| **Tyra** | 42,861 | 3,638 | 3,878 | 3,826 | 3,749 | 3,948 | 3,994 | 4,120 | 3,745 | 3,792 | 3,916 | 81,468 |
| **Rolf** | 142 | 4 | 3 | 4 | 2 | 2 | 4 | 5 | 3 | 4 | 4 | 177 |
| **Kraka** | 695 | 106 | 148 | 119 | 100 | 52 | 25 | 23 | 24 | 28 | 28 | 1,348 |
| **Dagmar** | 144 | 2 | 2 | 2 | 1 | 1 | 3 | 2 | 0 | 0 | 0 | 158 |
| **Regnar** | 46 | 4 | 2 | 1 | 3 | 1 | 2 | 2 | 1 | 1 | 0 | 63 |
| **Valdemar** | 323 | 54 | 49 | 55 | 78 | 109 | 151 | 218 | 208 | 208 | 355 | 1,808 |
| **Roar** | 3,296 | 1,458 | 1,249 | 1,407 | 1,702 | 1,052 | 915 | 894 | 860 | 489 | 367 | 13,689 |
| **Svend** | 237 | 84 | 65 | 75 | 48 | 61 | 43 | 38 | 34 | 28 | 28 | 740 |
| **Harald** | 1,092 | 2,741 | 2,876 | 2,811 | 2,475 | 2,019 | 1,563 | 1,232 | 1,091 | 927 | 781 | 19,608 |
| **Lulita** | - | 69 | 181 | 160 | 27 | 6 | 5 | 5 | 13 | 38 | 33 | 537 |
| **Halfdan** | - | - | 37 | 178 | 522 | 759 | 1,142 | 1,449 | 2,582 | 2,948 | 2,675 | 12,292 |
| **Siri** | - | - | 142 | 197 | 176 | 157 | 110 | 63 | 115 | 58 | 47 | 1,064 |
| **South Arne** | - | - | 167 | 713 | 774 | 681 | 544 | 461 | 484 | 366 | 233 | 4,423 |
| **Tyra SE** | - | - | - | - | - | 447 | 452 | 1,233 | 1,337 | 1,108 | 848 | 5,426 |
| **Cecilie** | - | - | - | - | - | - | 14 | 24 | 15 | 8 | 6 | 67 |
| **Nini** | - | - | - | - | - | - | 29 | 107 | 49 | 29 | 24 | 239 |
| **Total** | **75,159** | **10,281** | **10,901** | **11,316** | **11,116** | **10,844** | **10,213** | **10,934** | **11,523** | **10,878** | **10,046** | **183,210** |

*The monthly production figures for 2007 are available at the DEA's website www.ens.dk*

## Fuel*

**GAS** *million normal cubic metres*

| | 1972-97 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Dan** | 726 | 148 | 172 | 179 | 184 | 182 | 198 | 201 | 205 | 218 | 208 | 2,621 |
| **Gorm** | 1,308 | 152 | 149 | 142 | 111 | 146 | 135 | 137 | 124 | 124 | 135 | 2,664 |
| **Tyra** | 1,415 | 224 | 239 | 229 | 243 | 245 | 242 | 249 | 247 | 241 | 233 | 3,808 |
| **Dagmar** | 21 | - | - | - | - | - | - | - | - | - | - | 21 |
| **Harald** | 5 | 14 | 14 | 13 | 10 | 9 | 8 | 8 | 7 | 8 | 8 | 104 |
| **Siri** | - | - | 8 | 21 | 22 | 21 | 20 | 19 | 21 | 25 | 25 | 183 |
| **South Arne** | - | - | 3 | 32 | 34 | 45 | 49 | 45 | 52 | 53 | 55 | 367 |
| **Halfdan** | - | - | - | - | - | - | - | 20 | 39 | 39 | 39 | 138 |
| **Total** | **3,475** | **539** | **585** | **618** | **604** | **648** | **652** | **679** | **694** | **709** | **703** | **9,906** |

## Flaring*

| | 1972-97 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Dan** | 1,534 | 43 | 56 | 67 | 79 | 55 | 71 | 37 | 23 | 29 | 27 | 2,020 |
| **Gorm** | 1,087 | 71 | 71 | 66 | 88 | 81 | 66 | 57 | 61 | 61 | 48 | 1,756 |
| **Tyra** | 580 | 42 | 58 | 58 | 68 | 61 | 54 | 63 | 55 | 51 | 43 | 1,132 |
| **Dagmar** | 121 | 2 | 2 | 2 | 1 | 1 | 3 | 2 | 0 | 0 | 0 | 135 |
| **Harald** | 77 | 19 | 12 | 7 | 11 | 3 | 1 | 1 | 1 | 2 | 2 | 138 |
| **Siri** | - | - | 73 | 9 | 15 | 9 | 23 | 65 | 15 | 7 | 7 | 222 |
| **South Arne** | - | - | 114 | 41 | 9 | 11 | 12 | 11 | 14 | 11 | 11 | 234 |
| **Halfdan** | - | - | - | - | - | - | 4 | 25 | 16 | 20 | 17 | 81 |
| **Total** | **3,397** | **177** | **386** | **250** | **270** | **222** | **234** | **262** | **185** | **181** | **154** | **5,717** |

## Injection

| | 1972-97 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Gorm** | 8,039 | 24 | 25 | 45 | 4 | 14 | 6 | 4 | 3 | 0 | 0 | 8,164 |
| **Tyra** | 14,303 | 2,908 | 3,074 | 3,104 | 2,773 | 2,535 | 2,312 | 1,612 | 1,285 | 761 | 1,094 | 35,760 |
| **Siri**** | - | - | 61 | 167 | 139 | 126 | 109 | 111 | 143 | 64 | 45 | 965 |
| **Total** | **22,343** | **2,933** | **3,160** | **3,316** | **2,916** | **2,675** | **2,428** | **1,727** | **1,431** | **824** | **1,139** | **44,890** |

## Sales*

| | 1984-97 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Dan** | 10,860 | 1,261 | 1,371 | 1,238 | 1,412 | 1,521 | 1,679 | 1,635 | 1,750 | 1,810 | 1,777 | 26,313 |
| **Gorm** | 3,654 | 535 | 448 | 334 | 209 | 364 | 228 | 99 | 126 | 103 | 66 | 6,166 |
| **Tyra** | 30,418 | 2,060 | 1,870 | 1,971 | 2,493 | 2,776 | 2,948 | 4,580 | 4,598 | 4,574 | 4,143 | 62,430 |
| **Harald** | 1,010 | 2,777 | 3,032 | 2,950 | 2,482 | 2,013 | 1,558 | 1,228 | 1,096 | 954 | 804 | 19,903 |
| **South Arne** | - | - | 50 | 640 | 730 | 625 | 483 | 406 | 418 | 302 | 168 | 3,822 |
| **Halfdan** | - | - | - | - | - | - | 4 | 319 | 1,226 | 1,421 | 1,091 | 4,062 |
| **Total** | **45,944** | **6,633** | **6,770** | **7,133** | **7,326** | **7,299** | **6,900** | **8,267** | **9,214** | **9,164** | **8,049** | **122,696** |

**) 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*

| | 1972-97 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Fuel** | 7,910 | 1,226 | 1,343 | 1,476 | 1,459 | 1,577 | 1,591 | 1,642 | 1,694 | 1,675 | 1,690 | 23,281 |
| **Flaring** | 7,732 | 402 | 1,126 | 645 | 646 | 535 | 564 | 664 | 457 | 470 | 449 | 13,690 |
| **Total** | **14,643** | **1,628** | **2,469** | **2,122** | **2,104** | **2,112** | **2,154** | **2,306** | **2,151** | **2,144** | **2,139** | **35,972** |

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

## Production

**WATER** *thousand cubic metres*

| | 1972-97 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Dan** | 8,071 | 2,976 | 4,220 | 5,277 | 6,599 | 6,348 | 7,183 | 8,053 | 9,527 | 10,936 | 12,152 | 81,343 |
| **Gorm** | 12,153 | 3,177 | 3,468 | 3,980 | 3,353 | 4,017 | 4,420 | 5,173 | 5,252 | 4,822 | 4,708 | 54,523 |
| **Skjold** | 9,808 | 3,938 | 3,748 | 4,333 | 2,872 | 3,007 | 3,525 | 3,688 | 4,270 | 4,328 | 3,885 | 47,403 |
| **Tyra** | 10,265 | 2,020 | 2,033 | 3,046 | 2,545 | 2,261 | 3,039 | 2,977 | 3,482 | 3,150 | 2,725 | 37,543 |
| **Rolf** | 2,793 | 411 | 366 | 358 | 181 | 168 | 270 | 308 | 290 | 316 | 383 | 5,843 |
| **Kraka** | 1,368 | 347 | 329 | 256 | 352 | 306 | 208 | 426 | 320 | 297 | 359 | 4,567 |
| **Dagmar** | 2,358 | 338 | 246 | 241 | 102 | 160 | 375 | 90 | 3 | 0 | 0 | 3,914 |
| **Regnar** | 1,103 | 407 | 363 | 139 | 475 | 257 | 316 | 396 | 352 | 255 | 1 | 4,064 |
| **Valdemar** | 139 | 52 | 55 | 48 | 150 | 272 | 310 | 325 | 792 | 937 | 854 | 3,933 |
| **Roar** | 110 | 146 | 199 | 317 | 386 | 301 | 476 | 653 | 662 | 498 | 560 | 4,308 |
| **Svend** | 66 | 272 | 582 | 1,355 | 954 | 1,051 | 1,330 | 1,031 | 1,309 | 1,205 | 1,200 | 10,356 |
| **Harald** | - | 5 | 15 | 39 | 98 | 78 | 43 | 15 | 12 | 12 | 18 | 335 |
| **Lulita** | - | 3 | 5 | 11 | 23 | 14 | 14 | 15 | 38 | 92 | 96 | 311 |
| **Halfdan** | - | - | 56 | 237 | 493 | 367 | 612 | 2,099 | 2,825 | 3,460 | 4,086 | 14,234 |
| **Siri** | - | - | 319 | 1,868 | 2,753 | 3,041 | 2,891 | 1,648 | 1,692 | 2,032 | 2,530 | 18,774 |
| **South Arne** | - | - | 15 | 60 | 119 | 390 | 751 | 1,124 | 800 | 1,136 | 1,652 | 6,046 |
| **Tyra SE** | - | - | - | - | - | 250 | 596 | 466 | 437 | 377 | 669 | 2,795 |
| **Cecilie** | - | - | - | - | - | - | 25 | 331 | 637 | 651 | 576 | 2,220 |
| **Nini** | - | - | - | - | - | - | 3 | 63 | 729 | 822 | 621 | 2,239 |
| **Total** | **48,235** | **14,093** | **16,019** | **21,566** | **21,456** | **22,287** | **26,386** | **28,879** | **33,429** | **35,325** | **37,075** | **304,750** |

## Injection

| | 1972-97 | 1998 | 1999 | 2000 | 2001 | 2002 | 2003 | 2004 | 2005 | 2006 | 2007 | Total |
|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Dan** | 29,429 | 11,817 | 14,964 | 17,464 | 18,176 | 16,123 | 18,063 | 20,042 | 20,281 | 21,520 | 20,230 | 208,108 |
| **Gorm** | 33,122 | 8,376 | 8,736 | 10,641 | 6,549 | 8,167 | 7,066 | 7,551 | 7,251 | 6,544 | 6,678 | 110,681 |
| **Skjold** | 37,722 | 6,291 | 5,866 | 6,520 | 4,805 | 6,411 | 6,386 | 6,451 | 6,045 | 5,711 | 6,098 | 98,307 |
| **Halfdan** | - | - | 82 | 13 | 620 | 2,532 | 5,162 | 5,759 | 9,710 | 11,026 | 12,107 | 47,012 |
| **Siri** | - | - | 1,231 | 3,778 | 4,549 | 4,507 | 3,383 | 1,681 | 1,347 | 1,923 | 3,499 | 25,898 |
| **South Arne** | - | - | - | 52 | 1,991 | 4,397 | 5,316 | 4,947 | 5,608 | 5,362 | 4,296 | 31,967 |
| **Nini** | - | - | - | - | - | - | 71 | 916 | 502 | 912 | 413 | 2,813 |
| **Cecilie** | - | - | - | - | - | - | - | 87 | 194 | 30 | 95 | 406 |
| **Total** | **100,273** | **26,484** | **30,878** | **38,469** | **36,689** | **42,138** | **45,446** | **47,435** | **50,937** | **53,027** | **53,416** | **525,192** |

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

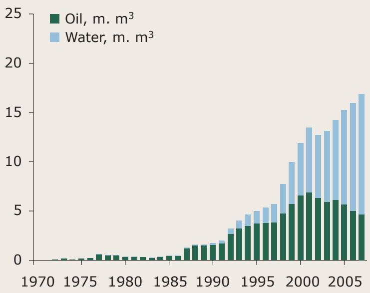
# APPENDIX B: PRODUCING FIELDS

## Explanation of field data

## PRODUCTION

**Cum. production at 1 January 2008**

| | |
|---|---|
| Oil: | 91.00 m. $m^3$ |
| Gas: | 21.53 bn. $Nm^3$ |
| Water: | 81.34 m. $m^3$ |




**Production of oil, gas and water**
The chart shows the primary production from the individual fields, i.e. oil or gas. The figures show the cumulati e production of oil, gas and water until 1 January 2008.

**Oil field (e.g. Dan, Halfdan, Siri** ■ Oil, m. $m^3$ ■ Gas, bn. $Nm^3$ ■ Water, m. $m^3$
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 reser oir to the surface, it degasses and the amount of gas produced also decreases.

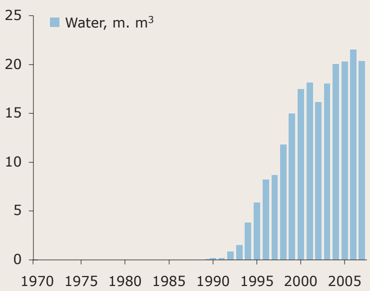
**Gas field (e.g. Harald** ■ Oil and condensate, m. $m^3$ ■ Gas, bn. $Nm^3$ ■ Water, m. $m^3$
Production from a gas field consists of gas, ater and condensate, which is a light oil. Due to the pressure difference between reservoir and surface, the gas condenses at the surface, which means that liquid hydrocarbons (condensate) are also produced.

**Oil and gas field (e.g. Tyra Southeast** ■ Oil and condensate, m. $m^3$ ■ Gas, bn. $Nm^3$ ■ Water, m. $m^3$
The production of oil, gas, condensate and water.

The production figures for 2007 appear from Appendix A

## INJECTION

**Cum. injection at 1 January 2008**
Water: 208.11 m. $m^3$




**Injection of water and gas**
The chart shows the primary injection in the individual fields, i.e. ater or gas. The figures show the cumulative injection of water and gas until 1 January 2008. The injection method is not used for all fields

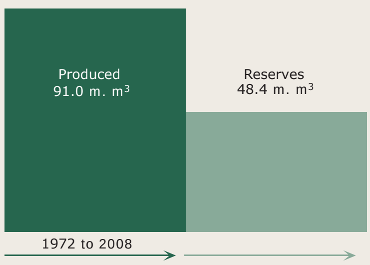
Injecting water into oil reservoirs maintains the pressure while forcing oil towards the production wells. The injection of gas also maintains pressure in the reservoir, but affects the viscosity of hydrocarbons at the same time.

**Fields with water injection (e.g. Halfdan, South Arne)** ■ Water, m. $m^3$
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. $Nm^3$
In a few fields, gas is injected to optimi e the production of liquid hydrocarbons.

## RESERVES

| | |
|---|---|
| Oil: | 48.4 m. $m^3$ |
| Gas: | 4.9 bn. $Nm^3$ |




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

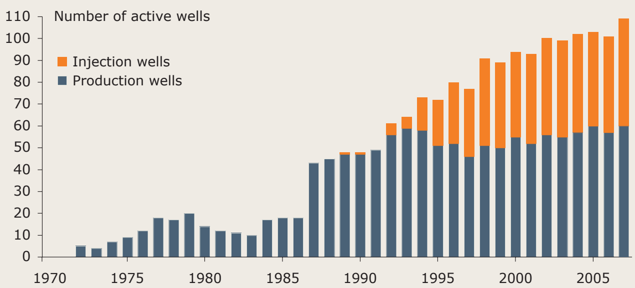
The chart shows the relationship between the amounts produced until 1 January 2008 and the estimated hydrocarbons-in-place, the reserves.

**Produced**
The cumulative production of oil or gas until 1 January 2008.

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

## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 27.2 billion




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

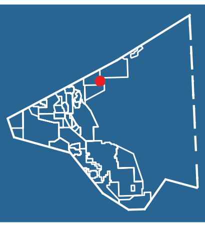
The chart shows the number of active wells in the individual years. Thus, wells that are closed in throughout a year will not be included in the figures for that ear.

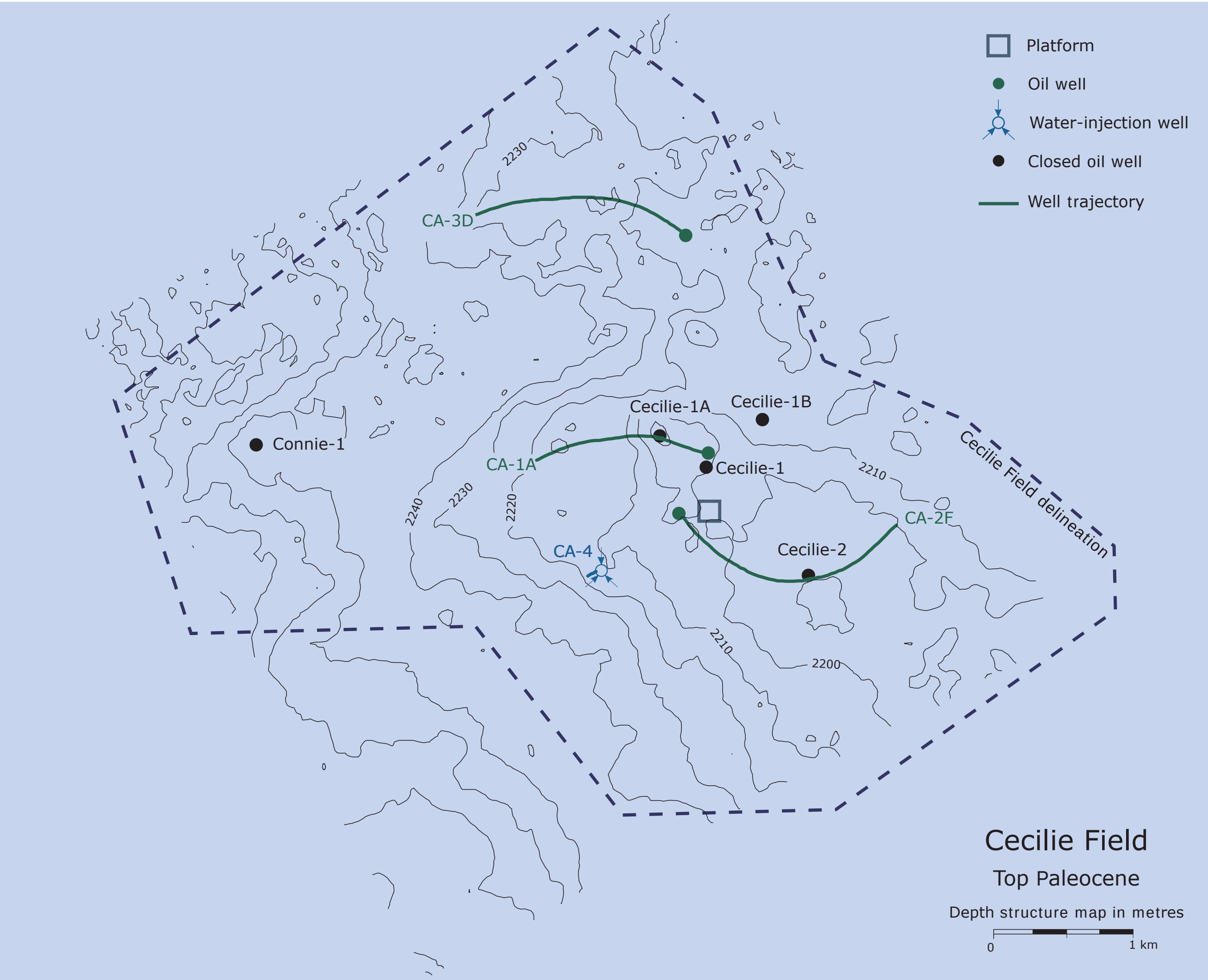
The wells are divided into production wells and injection wells. The chart shows the primary function of the wells in the relevant year, either production or injection. A well may be used for production for part of a year and then be converted to injection for the rest of the year.

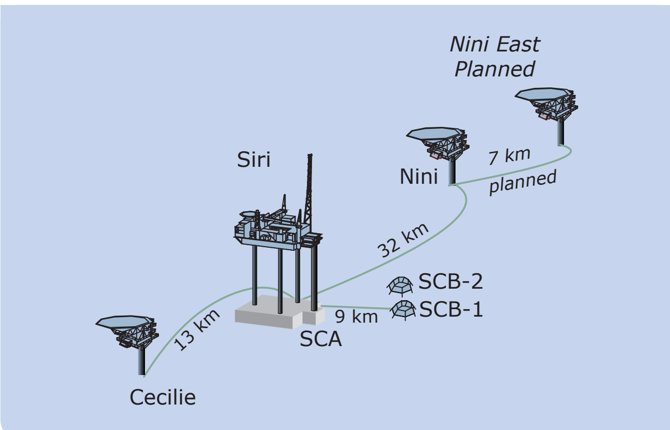
■ Injection wells ■ Production wells ■ Prod/Inject wells*
*Only relevant for the Tyra Field. A few wells alternate between injection and production.

# APPENDIX B: PRODUCING FIELDS

## THE CECILIE FIELD

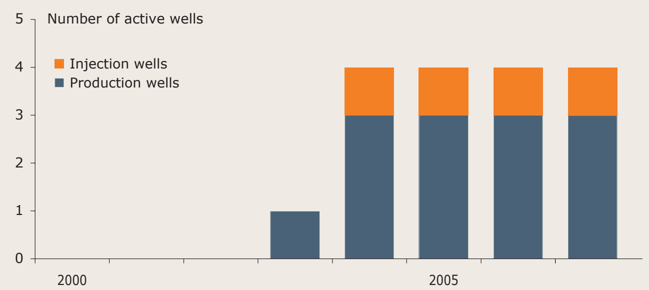





### DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 1.3 billion



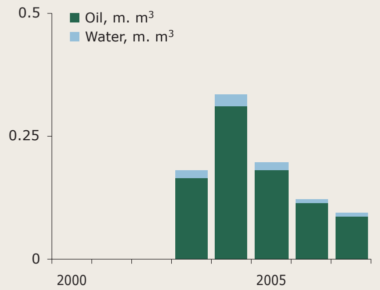
## FIELD DATA At 1 January 2008

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

## PRODUCTION

**Cum. production at 1 January 2008**

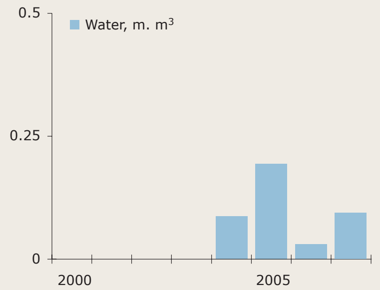
| | |
|---|---|
| Oil: | 0.86 m. m$^3$ |
| Gas: | 0.07 bn. Nm$^3$ |
| Water: | 2.22 m. m$^3$ |




## INJECTION

**Cum. injection at 1 January 2008**

| | |
|---|---|
| Water: | 0.95 m. m$^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 0.3 m. m$^3$ |
| Gas: | 0.0 bn. Nm$^3$ |


## REVIEW OF GEOLOGY

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.

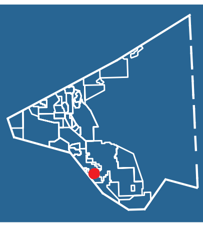
## PRODUCTION STRATEGY

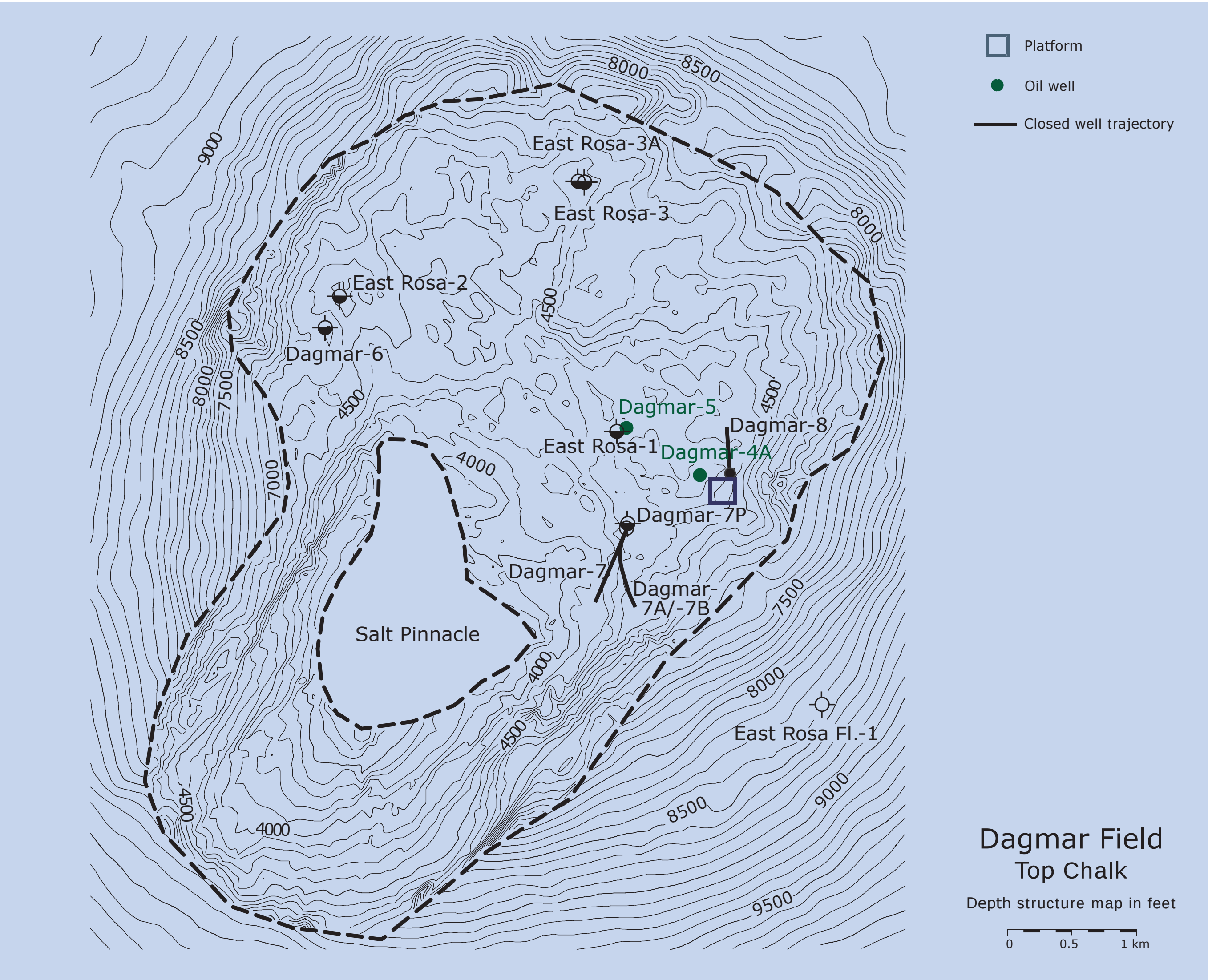
Recovery is based on water injection to maintain reservoir pressure. The production wells have been drilled in the crest of the structure, while water is injected in the flank of the field.

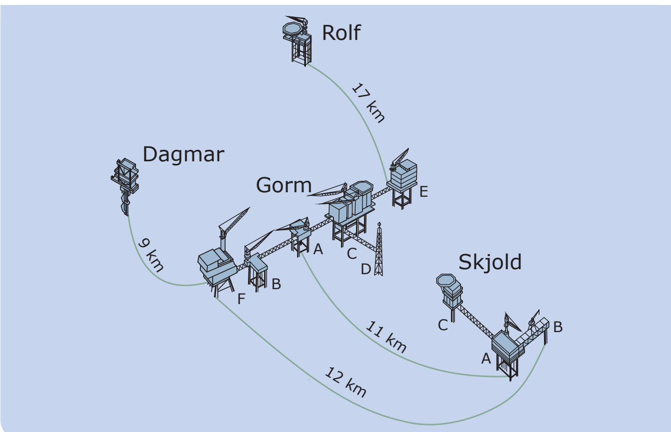
## PRODUCTION FACILITIES

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



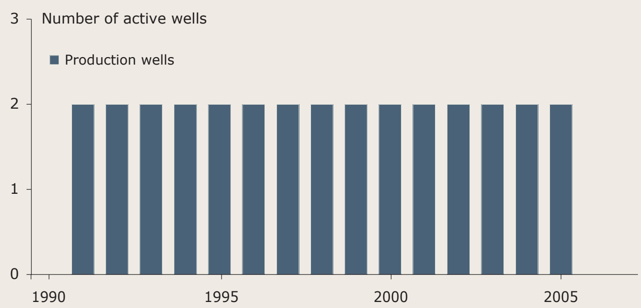



## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**

2007 prices DKK 0.5 billion



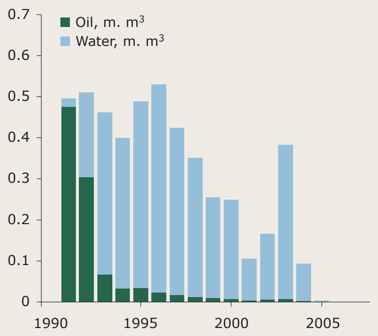
## FIELD DATA
At 1 January 2008

| | |
|---|---|
| Prospect: | East Rosa |
| Location: | Block 5504/15 |
| Licence: | Sole Concession |
| Operator: | Mærsk Olie og Gas AS |
| Discovered: | 1983 |
| Year on stream: | 1991 |
| Producing wells: | 2 |
| Water depth: | 34 m |
| Area: | 9 $km^2$ |
| Reservoir depth: | 1,400 m |
| Reservoir rock: | Chalk and Carbonates |
| Geological age: | Danian, Upper Creta-ceous and Zechstein |

## PRODUCTION

**Cum. production at 1 January 2008**

| | |
|---|---|
| Oil: | 1.01 m. $m^3$ |
| Gas: | 0.16 bn. $Nm^3$ |
| Water: | 3.91 m. $m^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 0.0 m. $m^3$ |
| Gas: | 0.0 bn. $Nm^3$ |


## REVIEW OF GEOLOGY

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.

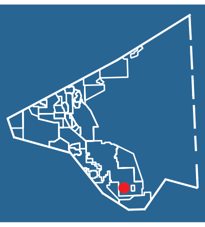
## PRODUCTION STRATEGY

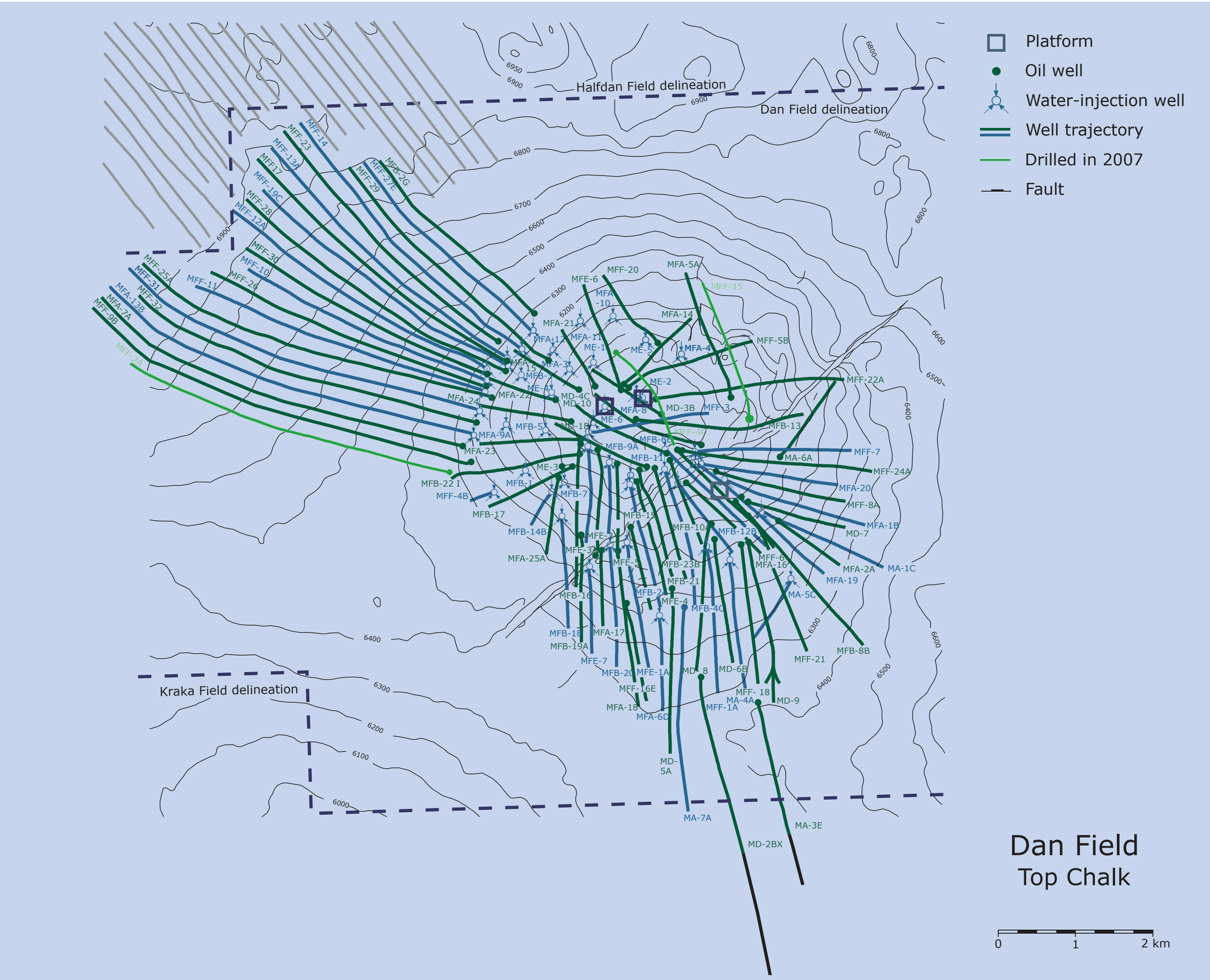
The recovery strategy for the Dagmar Field is based on achieving the highest possible production rate from the wells. Initially, the oil production rates were high in the Dagmar Field, but it has not been possible to sustain the good production performance characterizing the Skjold, Svend and Rolf Fields. In 2006 and 2007, the two production wells were closed in, but the plan is to reopen the two wells in 2008 to evaluate the remaining potential.

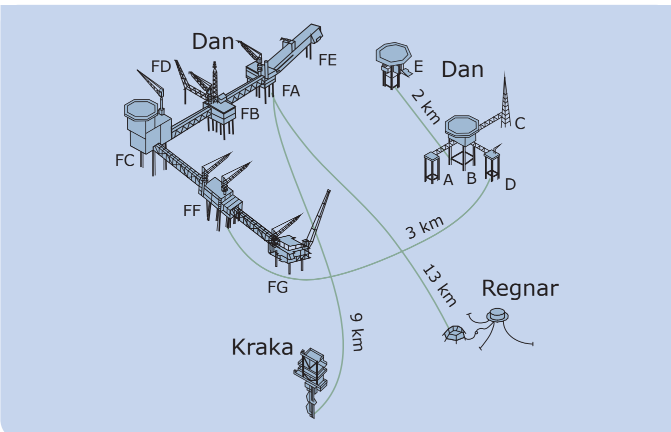
## PRODUCTION FACILITIES

The Dagmar Field is a satellite development to the Gorm Field with one unmanned wellhead platform without a helideck. The unprocessed production is 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 is flared due to its high content of hydrogen sulphide.

# THE DAN FIELD

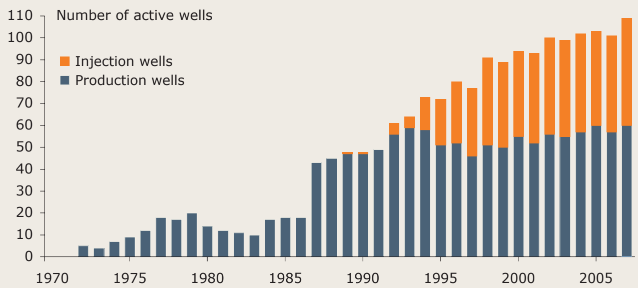





## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 27.2 billion



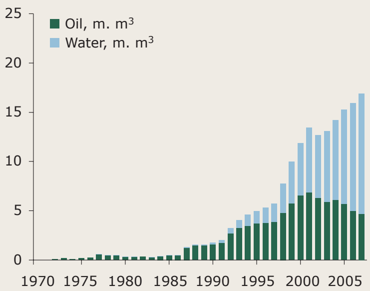
## FIELD DATA At 1 January 2008

| | |
|---|---|
| Prospect: | Abby |
| Location: | Block 5505/17 |
| Licence: | Sole Concession |
| Operator: | Mærsk Olie og Gas AS |
| Discovered: | 1971 |
| Year on stream: | 1972 |
| Producing wells: | 59 |
| Water-injection wells: | 50 |
| Water depth: | 40 m |
| Field delineation: | 121 km² |
| Reservoir depth: | 1,850 m |
| Reservoir rock: | Chalk |
| Geological age: | Danian and Upper Cretaceous |

## PRODUCTION

**Cum. production at 1 January 2008**

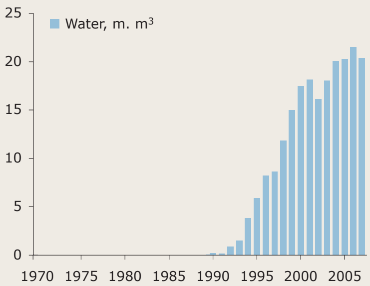
| | |
|---|---|
| Oil: | 91.00 m. m³ |
| Gas: | 21.53 bn. Nm³ |
| Water: | 81.34 m. m³ |




## INJECTION

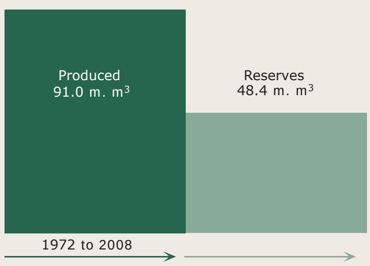
**Cum. injection at 1 January 2008**

| | |
|---|---|
| Water: | 208.11 m. m³ |




## RESERVES

| | |
|---|---|
| Oil: | 48.4 m. m³ |
| Gas: | 4.9 bn. Nm³ |




## REVIEW OF GEOLOGY

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

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.

## PRODUCTION STRATEGY

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

## PRODUCTION FACILITIES

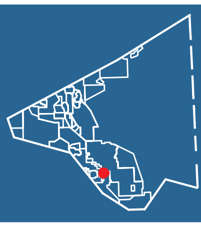
The Dan Field comprises six wellhead platforms, A, D, E, FA, FB and FE, a combined wellhead and processing platform, FF, a processing platform with a flare tower, FG, two processing and accommodation platforms, B and FC, and two gas flare stacks, C and FD.

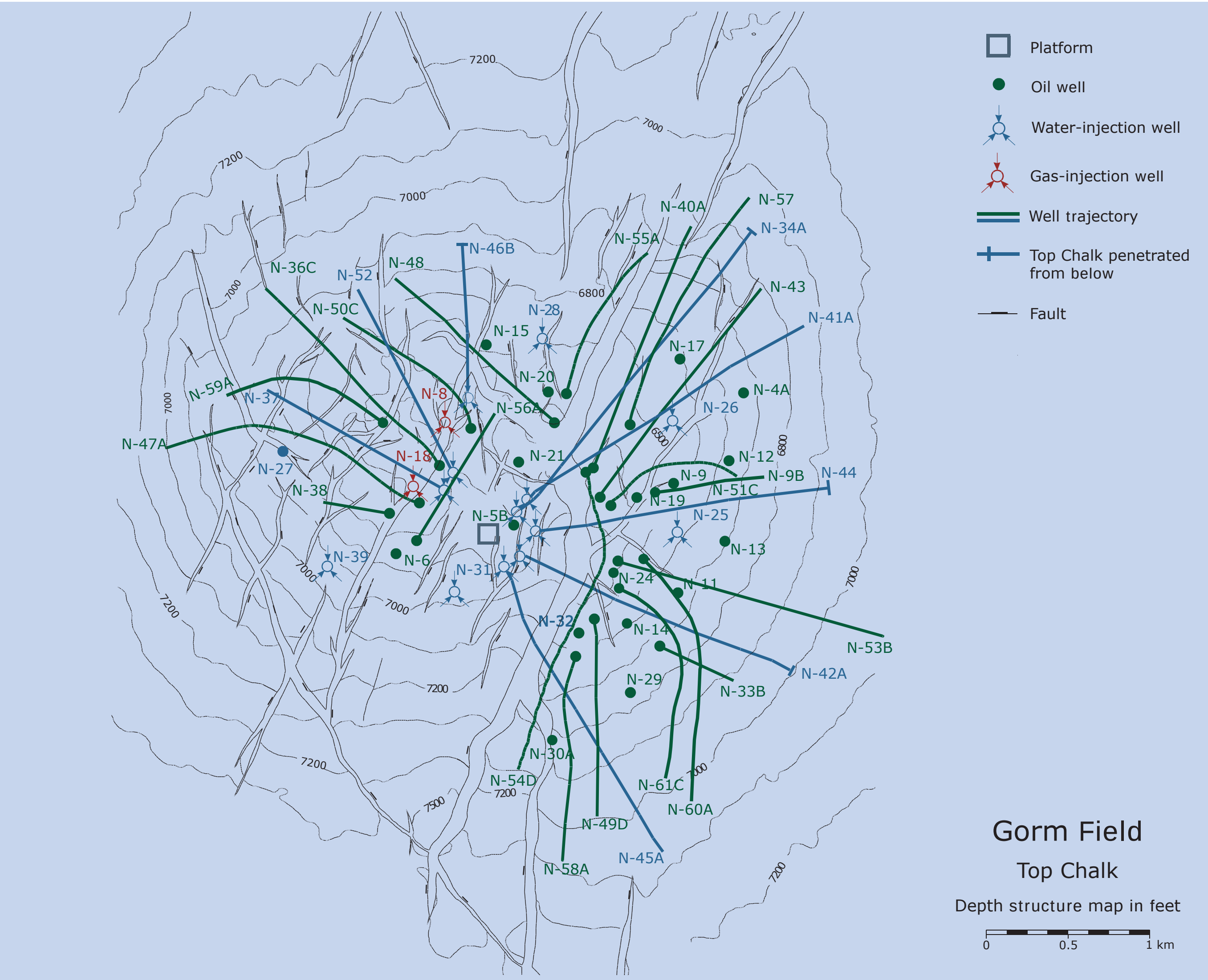
At the Dan Field, there are facilities for receiving production from the adjacent Kraka and Regnar satellite fields, as well as for receiving gas produced at the Halfdan Field. The Dan installations supply the Halfdan Field with injection water.

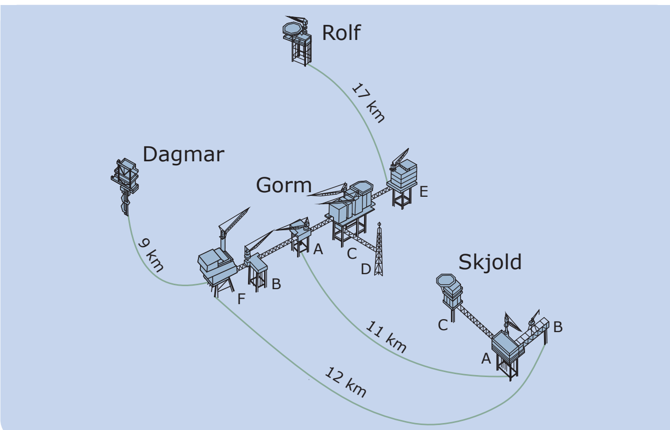
After final processing, the oil is transported to shore via the Gorm E platform. The gas is pre-processed and transported to Tyra East for final processing. Treated production water from Dan and its satellite fields is discharged into the sea.

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

# THE GORM FIELD

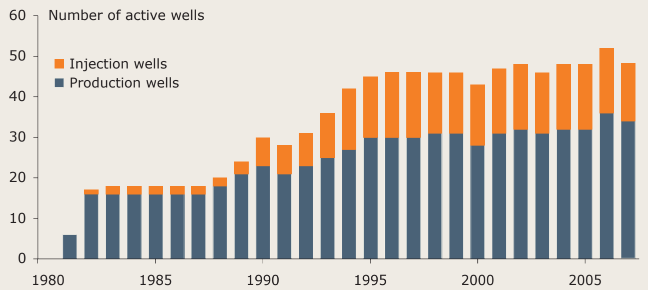





## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 13.0 billion



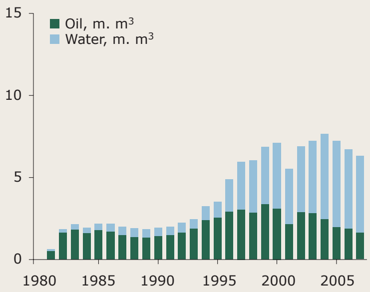
## FIELD DATA
At 1 January 2008

| | |
|---|---|
| Prospect: | Vern |
| Location: | Blocks 5504/15 and 16 |
| Licence: | Sole Concession |
| Operator: | Mærsk Olie og Gas AS |
| Discovered: | 1971 |
| Year on stream: | 1981 |
| Producing wells: | 36 |
| Gas-injection wells: | 2 |
| Water-injection wells: | 14 |
| Water depth: | 39 m |
| Field delineation: | 33 km$^2$ |
| Reservoir depth: | 2,100 m |
| Reservoir rock: | Chalk |
| Geological age: | Danian and Upper Cretaceous |

## PRODUCTION

**Cum. production at 1 January 2008**

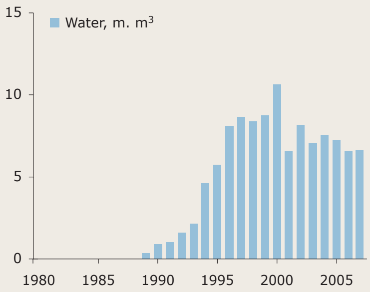
| | |
|---|---|
| Oil: | 56.04 m. m$^3$ |
| Gas: | 15.23 bn. Nm$^3$ |
| Water: | 54.52 m. m$^3$ |




## INJECTION

**Cum. injection at 1 January 2008**

| | |
|---|---|
| Gas: | 8.16 bn. Nm$^3$ |
| Water: | 110.68 m. m$^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 9.3 m. m$^3$ |
| Gas: | 0.9 bn. Nm$^3$ |


## REVIEW OF GEOLOGY

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

## PRODUCTION STRATEGY

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.

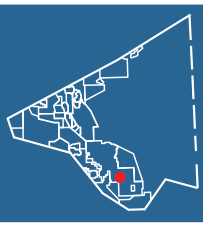
## PRODUCTION FACILITIES

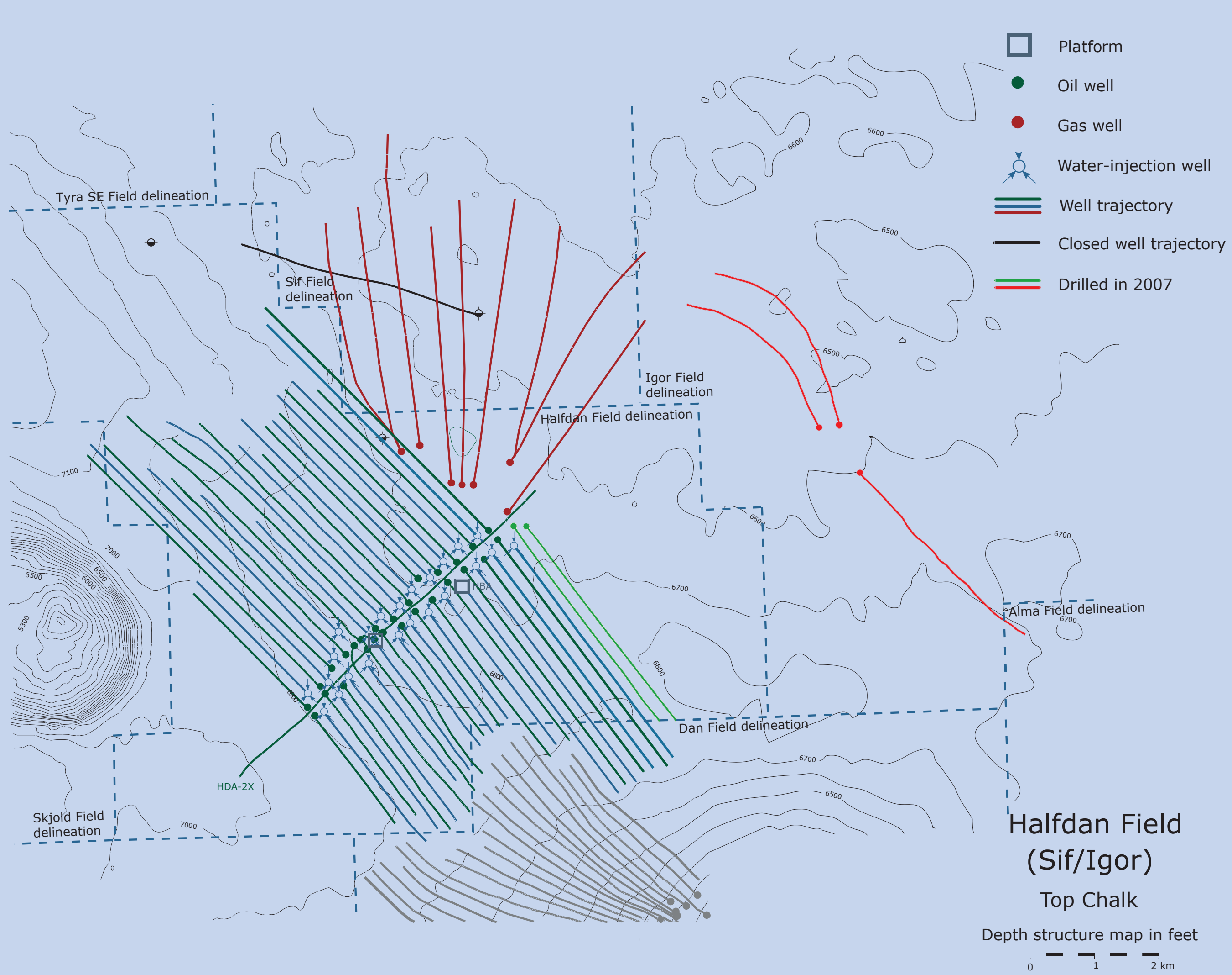
The Gorm Field consists of two wellhead platforms, Gorm A and B, one processing and accommodation platform, Gorm C, one gas flare stack, Gorm D, one riser platform, Gorm E (owned by DONG Oil Pipe A/S) and one combined wellhead, processing and riser platform, Gorm F.

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.

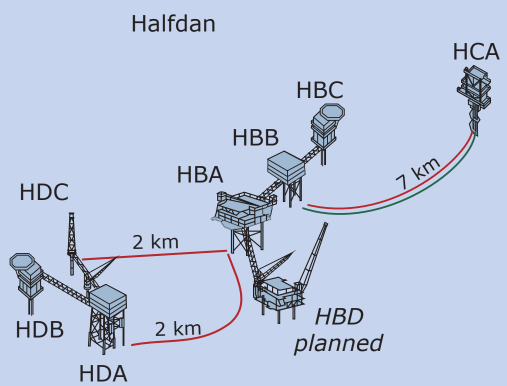
There are accommodation facilities on the Gorm C platform for 98 persons.

# THE HALFDAN FIELD INCL. SIF AND IGOR



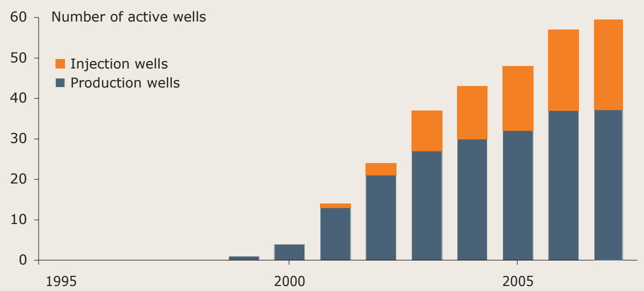



*For more detailed maps, see pages 74 and 75.*




## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 12.8 billion



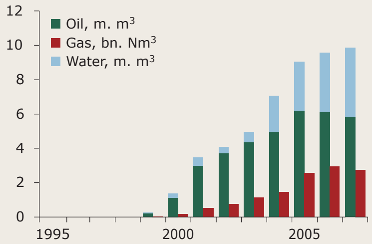
## FIELD DATA
At 1 January 2008

| | |
|---|---|
| Prospect: | Nana (Halfdan) |
| Location: | Blocks 5505/13 and 5504/16 |
| Licence: | Sole Concession |
| Operator: | Mærsk Olie og Gas AS |
| Discovered: | 1999 (Halfdan and Sif) 1968 (Igor) |
| Year on stream: | 1999 (Halfdan) 2004 (Sif and Igor) |
| Oil-prod. wells: | 29 (Halfdan) |
| Water-inj. wells: | 24 (Halfdan) |
| Gas-prod. wells: | 10 (Sif) |
| Water depth: | 43 m |
| Field delineation: | 107 km² (Halfdan) 109 km² (Igor) 40 km² (Sif) |
| Reservoir depth: | 2,050-2,100 m |
| Reservoir rock: | Chalk |
| Geological age: | Danian and Upper Cretaceous |

## PRODUCTION

**Cum. production at 1 January 2008**

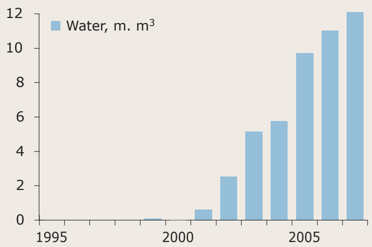
| | |
|---|---|
| Oil: | 35.39 m. $m^3$ |
| Gas: | 12.29 bn. $Nm^3$ |
| Water: | 14.23 m. $m^3$ |




## INJECTION

**Cum. injection at 1 January 2008**

| | |
|---|---|
| Water: | 47.01 m. $m^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 72.3 m. $m^3$ |
| Gas: | 26.4 bn. $Nm^3$ |


## REVIEW OF GEOLOGY

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

The accumulation is contained in a limited part of the chalk formation, which constituted a structural trap in earlier geological times. The structure gradually disintegrated, and the oil began migrating away from the area due to later movements in the reservoir layers. However, the oil and gas deposits have migrated a short distance only due to the low permeability of the reservoir. This porous, unfractured chalk is similar to that found in the western flank of the Dan Field.

## PRODUCTION STRATEGY

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

## PRODUCTION FACILITIES

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

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 platform, HBB. In addition, the Halfdan B complex has an accommodation platform, HBC.

Halfdan B is located about 2 km from Halfdan D, which provides it with power, injection water and lift gas.

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

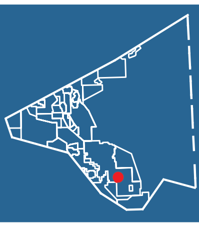
The Dan installations supply Halfdan D and B with injection water. Treated production water from Halfdan and Sif/Igor is discharged into the sea.

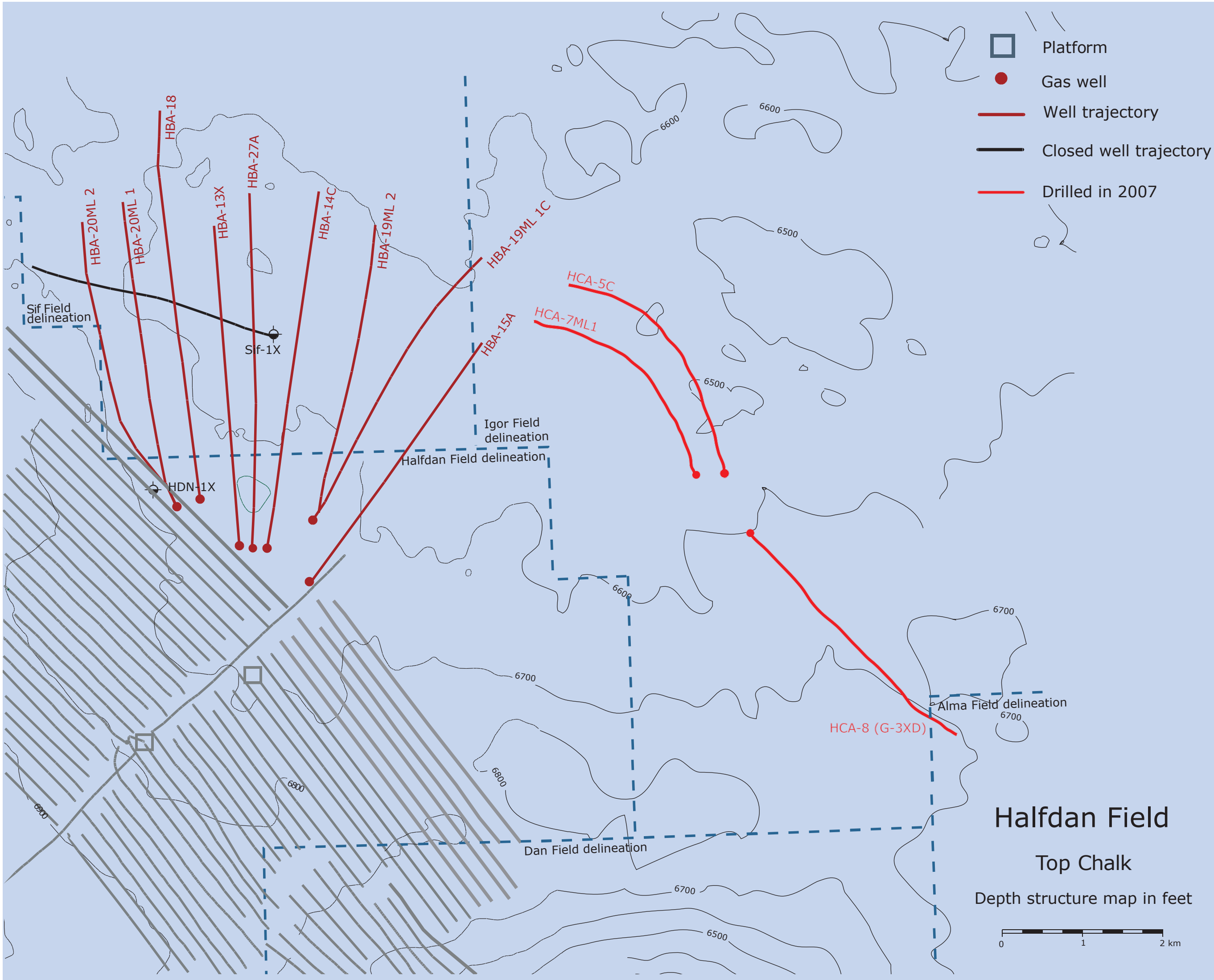
Halfdan HDB has accommodation facilities for 32 persons, while there are accommodation facilities for 80 persons at Halfdan HBC.

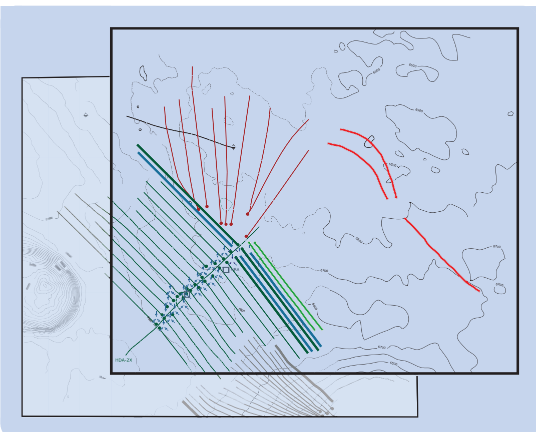
The Halfdan HCA satellite platform, with capacity for ten wells, is located about 7 km northeast of the Halfdan B complex. After being separated into liquids and gas at the Halfdan HCA platform, the production is transported through two new pipelines to Halfdan B.

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

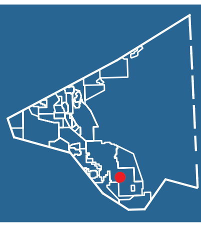
# THE HALFDAN FIELD NORTH

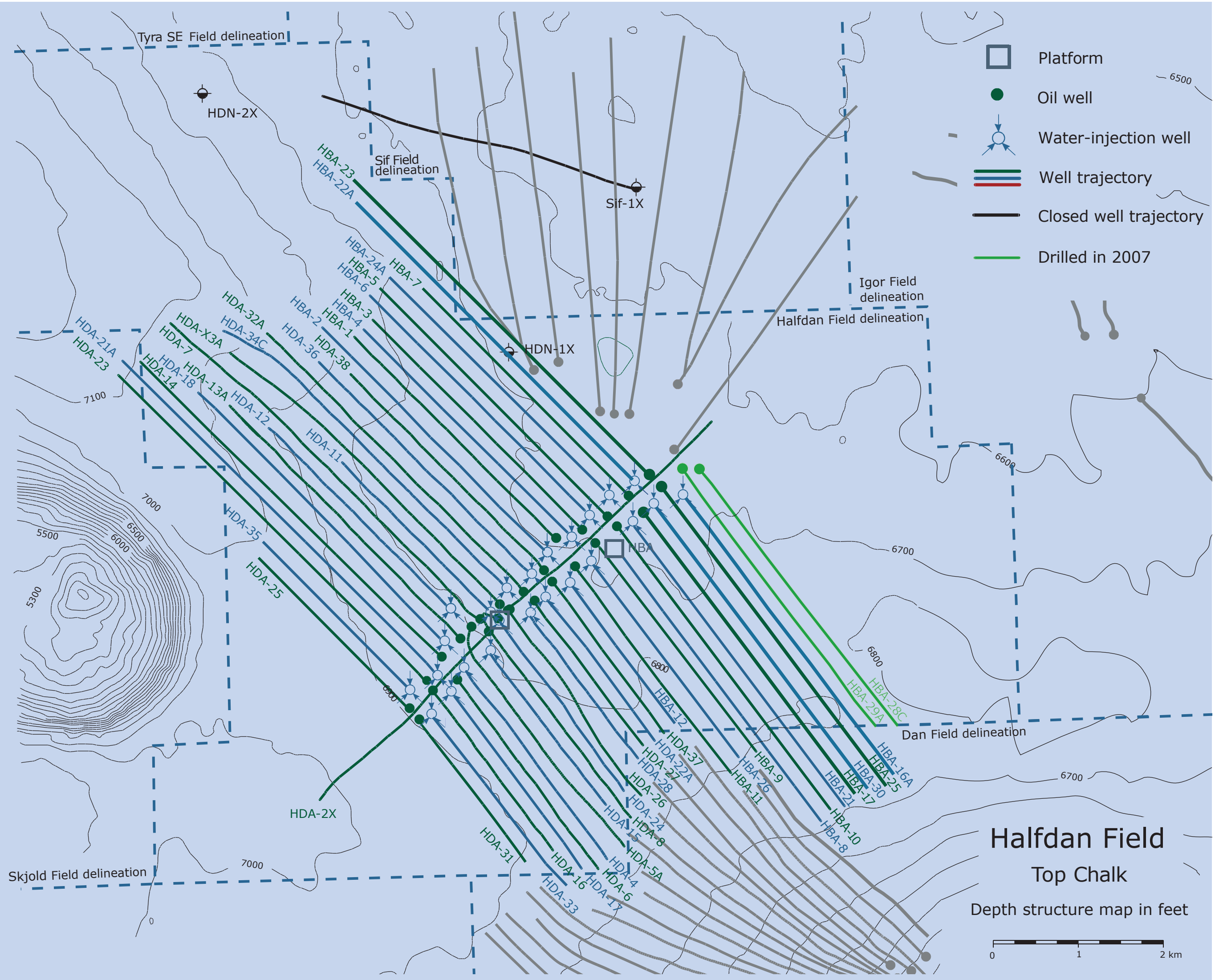


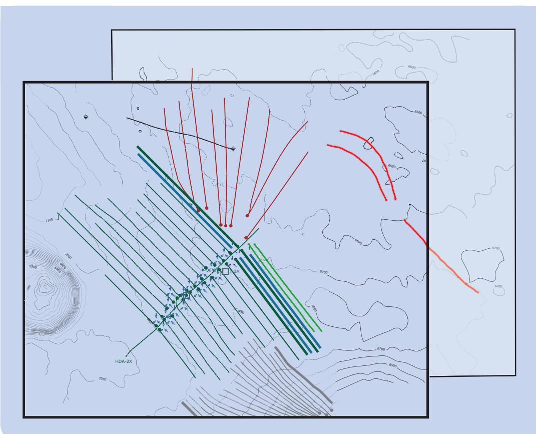


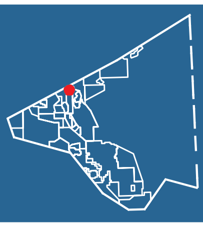
# THE HALFDAN FIELD SOUTH

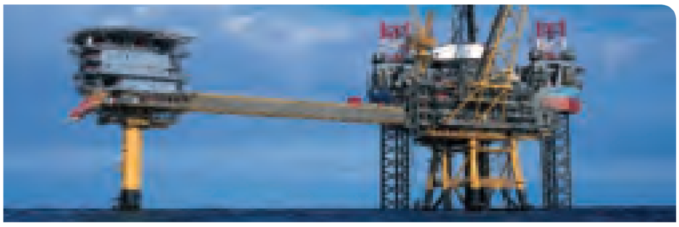


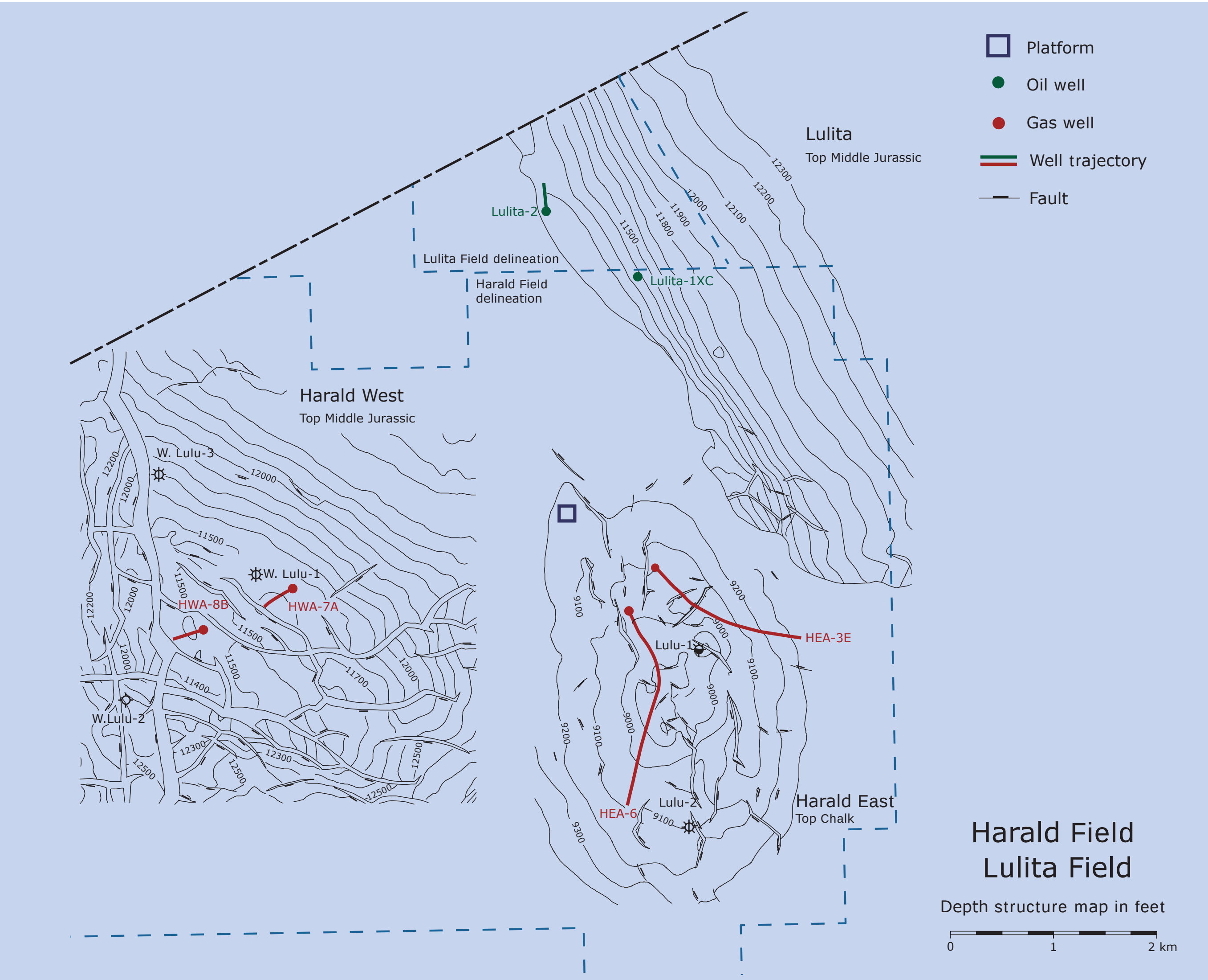


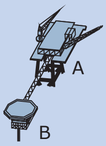



# THE HARALD FIELD



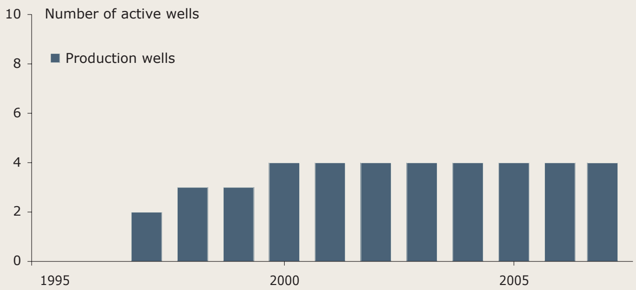





## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 3.6 billion



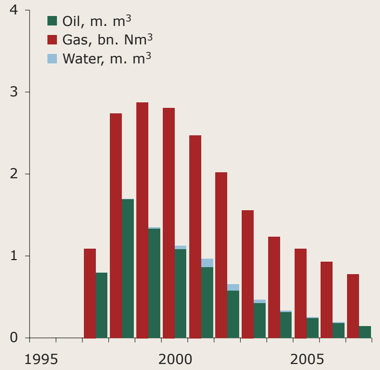
## FIELD DATA
At 1 January 2008

| | |
|---|---|
| Prospect: | Lulu/West Lulu |
| Location: | Blocks 5604/21 and 22 |
| Licence: | Sole Concession |
| Operator: | Mærsk Olie og Gas AS |
| Discovered: | 1980 (Lulu)<br>1983 (West Lulu) |
| Year on stream: | 1997 |
| Gas-producing wells: | 2 (Harald East)<br>2 (Harald West) |
| Water depth: | 64 m |
| Field delineation: | 56 $km^2$ |
| Reservoir depth: | 2,700 and 3,650 m, respectively |
| Reservoir rock: | Chalk (Harald East)<br>Sandstone (Harald West) |
| Geological age: | Danian, Upper Cretaceous and Middle Jurassic |

## PRODUCTION

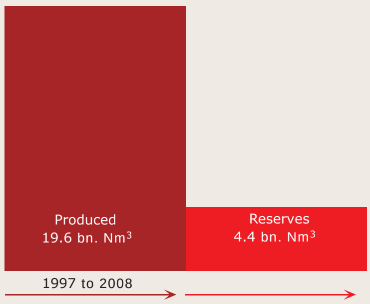
**Cum. production at 1 January 2008**

| | |
|---|---|
| Oil: | 7.63 m. $m^3$ |
| Gas: | 19.61 bn. $Nm^3$ |
| Water: | 0.34 m. $m^3$ |




## RESERVES

| | |
|---|---|
| Oil and condensate: | 0.9 m. $m^3$ |
| Gas: | 4.4 bn. $Nm^3$ |




## REVIEW OF GEOLOGY

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 metres thick.

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

## PRODUCTION STRATEGY

Recovery from both the Harald East and the Harald West reservoir takes place by gas expansion, with a moderate, natural influx of water into the reservoir.

Production from the Harald Field is based on the aim of optimizing the production of liquid hydrocarbons in the Tyra Field. By maximizing the drainage from the other gas fields, gas drainage from Tyra is minimized.

## PRODUCTION FACILITIES

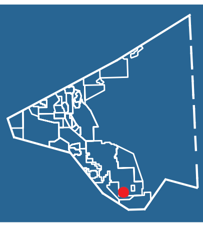
The Harald Field comprises a combined wellhead and processing platform, Harald A, and an accommodation platform, Harald B. The unprocessed condensate and the processed gas are transported to Tyra East. Treated production water is discharged into the sea.

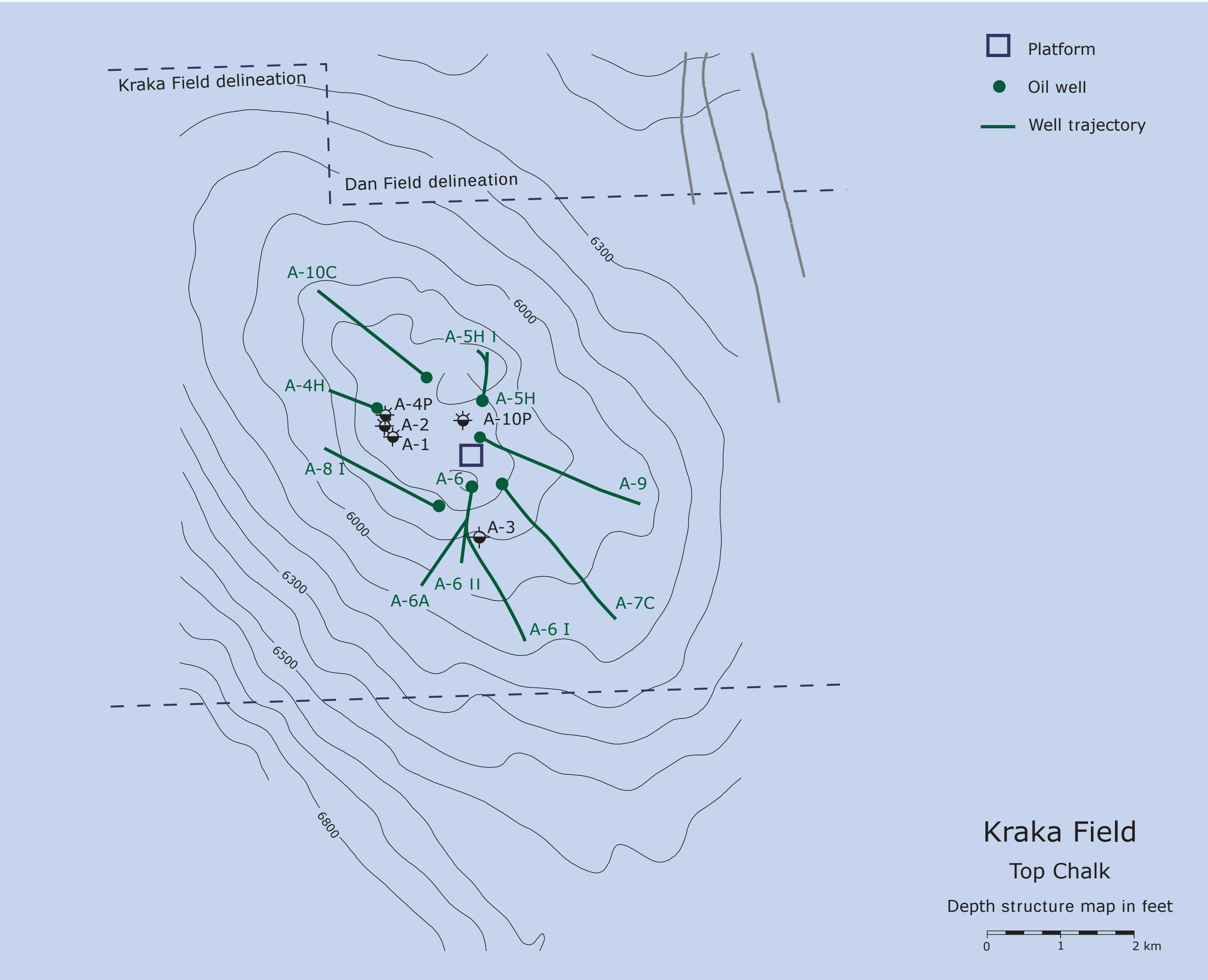
The Harald Field is hooked up to the gas pipeline that transports gas from the South Arne Field to Nybro. Normally, no gas is exported from Harald through the pipeline.

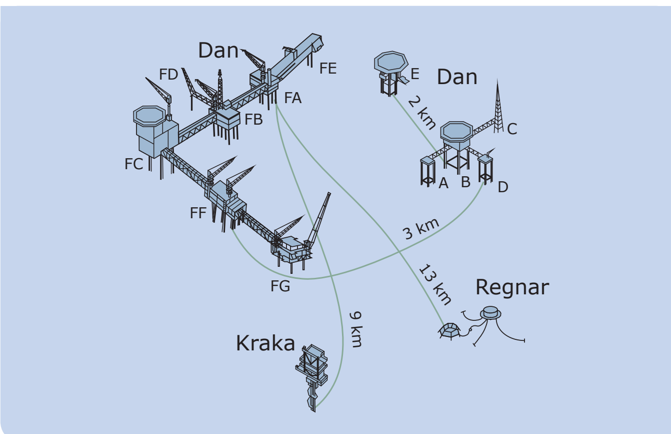
The Harald Field has accommodation facilities for 16 persons.

Reference is also made to the Lulita Field.

# THE KRAKA FIELD



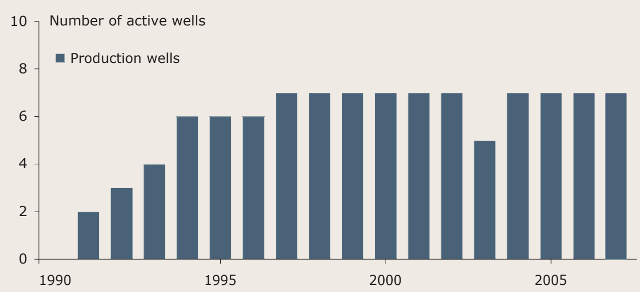




## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**

2007 prices DKK 1.5 billion



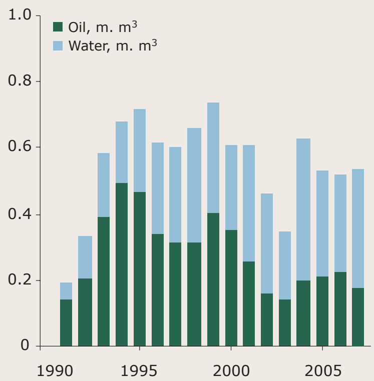
## FIELD DATA At 1 January 2008

| | |
|---|---|
| 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 2008**

| | |
|---|---|
| Oil: | 4.78 m. $m^3$ |
| Gas: | 1.35 bn. $Nm^3$ |
| Water: | 4.57 m. $m^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 2.2 m. $m^3$ |
| Gas: | 0.3 bn. $Nm^3$ |


## REVIEW OF GEOLOGY

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

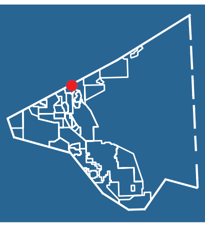
## PRODUCTION STRATEGY

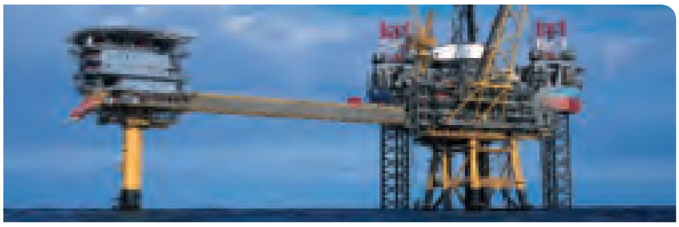
Recovery from Kraka is based on the natural expansion of the gas cap and aquifer support. The individual wells are produced at the lowest possible bottom-hole pressure. Oil production from the field is maximized by prioritizing gas lift in wells with a low water content and a low gas-oil ratio.

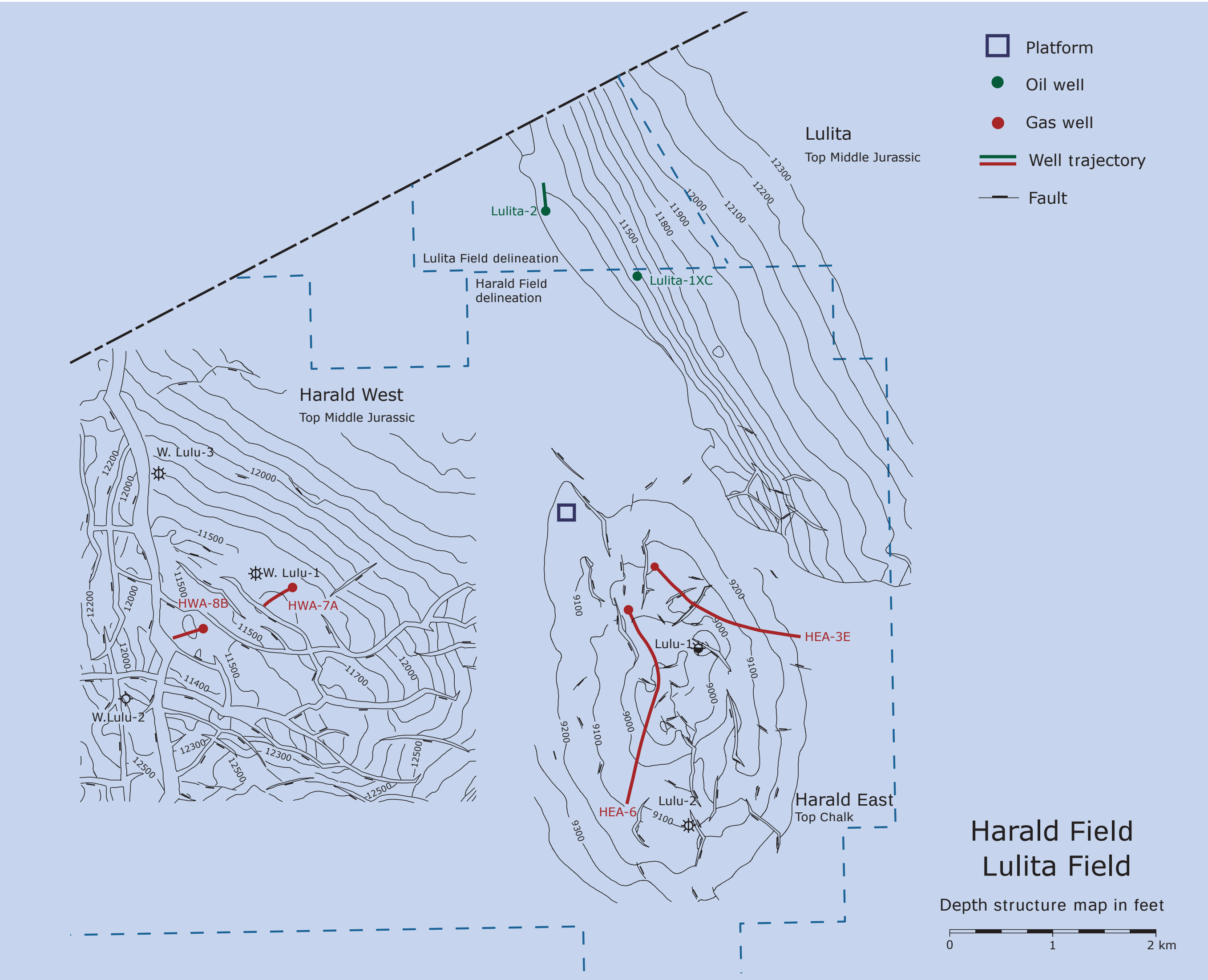
## PRODUCTION FACILITIES

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

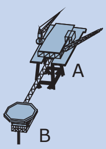
# THE LULITA FIELD





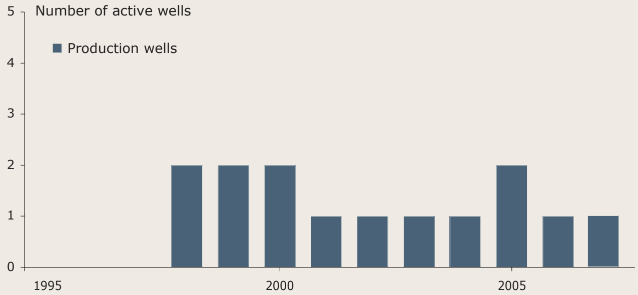



Harald / Lulita




## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 0.1 billion



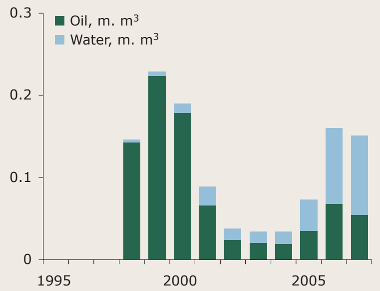
## FIELD DATA At 1 January 2008

| | |
|---|---|
| Location: | Blocks 5604/18 and 22 |
| Licence: | Sole Concession (50 per cent), 7/86 (34.5 per cent) and 1/90 (15.5 per cent) |
| Operator: | Mærsk Olie og Gas AS |
| Discovered: | 1992 |
| Year on stream: | 1998 |
| Producing wells: | 2 |
| Water depth: | 65 m |
| Area: | 3 km² |
| Reservoir depth: | 3,525 m |
| Reservoir rock: | Sandstone |
| Geological age: | Middle Jurassic |

## PRODUCTION

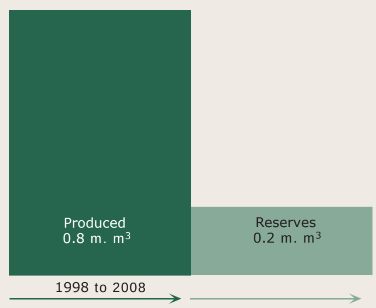
**Cum. production at 1 January 2008**

| | |
|---|---|
| Oil: | 0.83 m. m³ |
| Gas: | 0.54 bn. Nm³ |
| Water: | 0.31 m. m³ |




## RESERVES

| | |
|---|---|
| Oil: | 0.2 m. m³ |
| Gas: | 0.4 bn. Nm³ |




## REVIEW OF GEOLOGY

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

## PRODUCTION STRATEGY

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

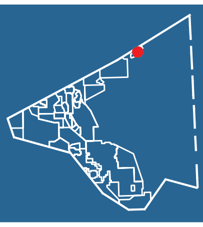
## PRODUCTION FACILITIES

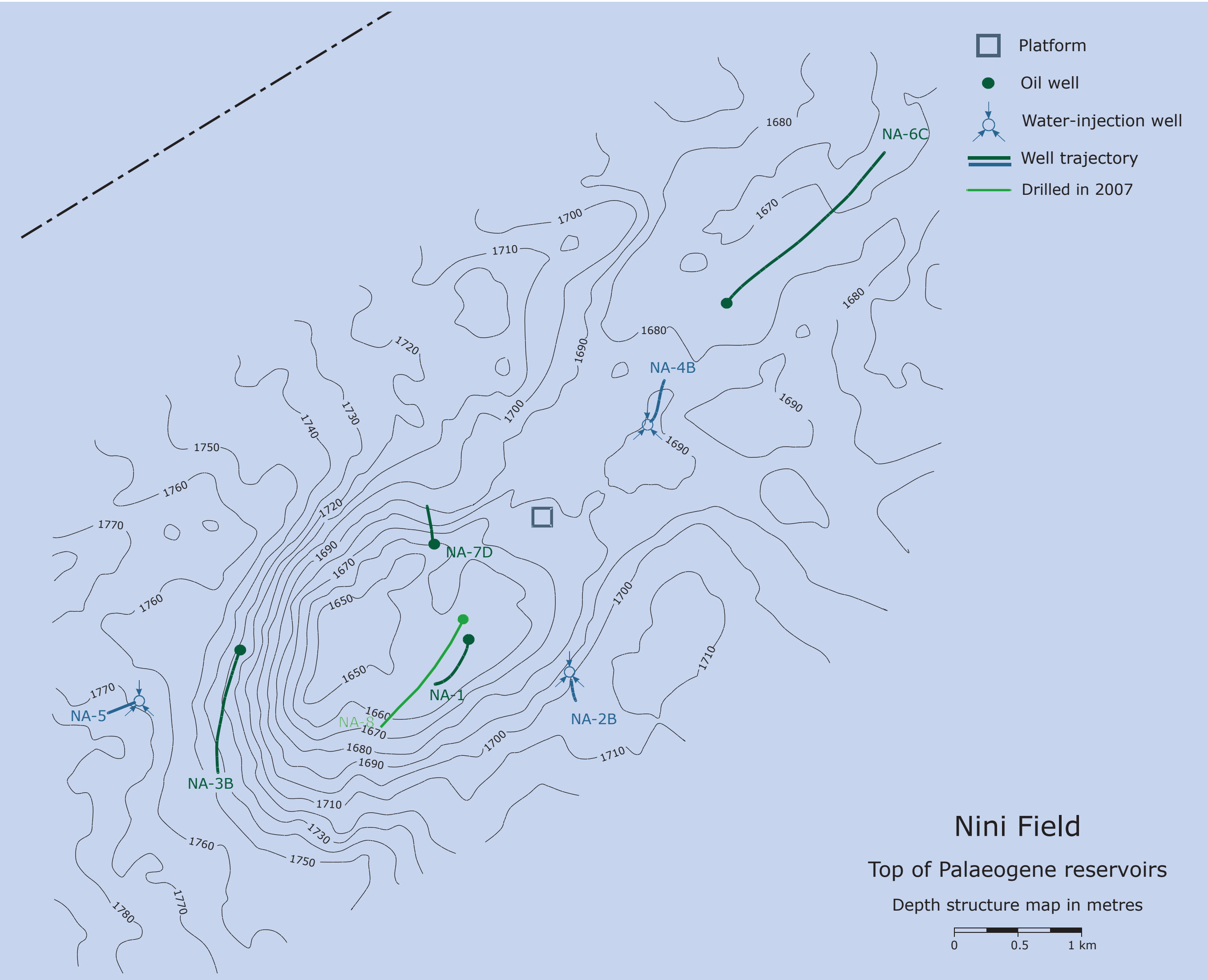
Production from the Lulita Field takes place from the fixed installations in the Harald Field. Thus, the Lulita facilities are hosted by the Harald A platform, and the Harald platform processing equipment also handles production from the Lulita Field.

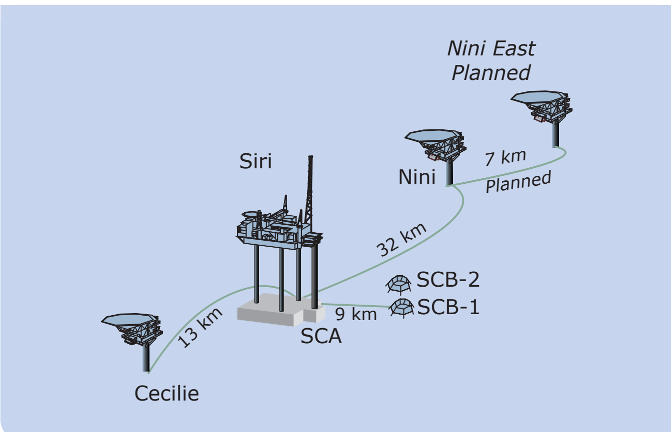
Together with condensate from the Harald Field, the oil produced is transported through a 16" pipeline to Tyra East for export ashore. The gas produced in the Lulita Field is transported to Tyra through the 24" pipeline connecting Harald with Tyra East, from where it is transported to shore. The water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

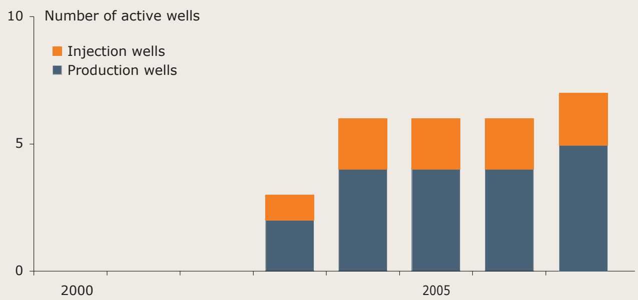





## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 2.4 billion



## FIELD DATA

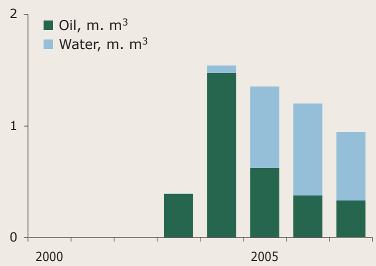
At 1 January 2008

| | |
|---|---|
| Location: | Blocks 5605/10 and 14 |
| Licence: | 4/95 |
| Operator: | DONG E&P A/S |
| Discovered: | 2000 |
| Year on stream: | 2003 |
| Producing wells: | 6 |
| Water-injection wells: | 2 |
| Water depth: | 60 m |
| Field delineation: | 48.8 km$^2$ (44.6 km$^2$ at 29.01.08) |
| Reservoir depth: | 1,700 m |
| Reservoir rock: | Sandstone |
| Geological age: | Eocene/Paleocene |

## PRODUCTION

**Cum. production at 1 January 2008**

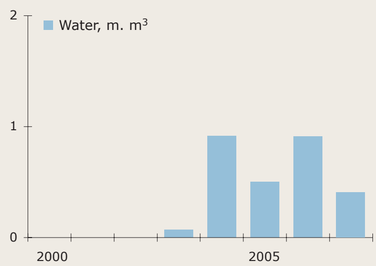
| | |
|---|---|
| Oil: | 3.19 m. m$^3$ |
| Gas: | 0.24 bn. Nm$^3$ |
| Water: | 2.24 m. m$^3$ |




## INJECTION

**Cum. injection at 1 January 2008**

| | |
|---|---|
| Water: | 2.81 m. m$^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 3.7 m. m$^3$ |
| Gas: | 0.0 bn. Nm$^3$ |


## REVIEW OF GEOLOGY

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

## PRODUCTION STRATEGY

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

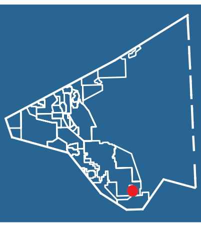
## PRODUCTION FACILITIES

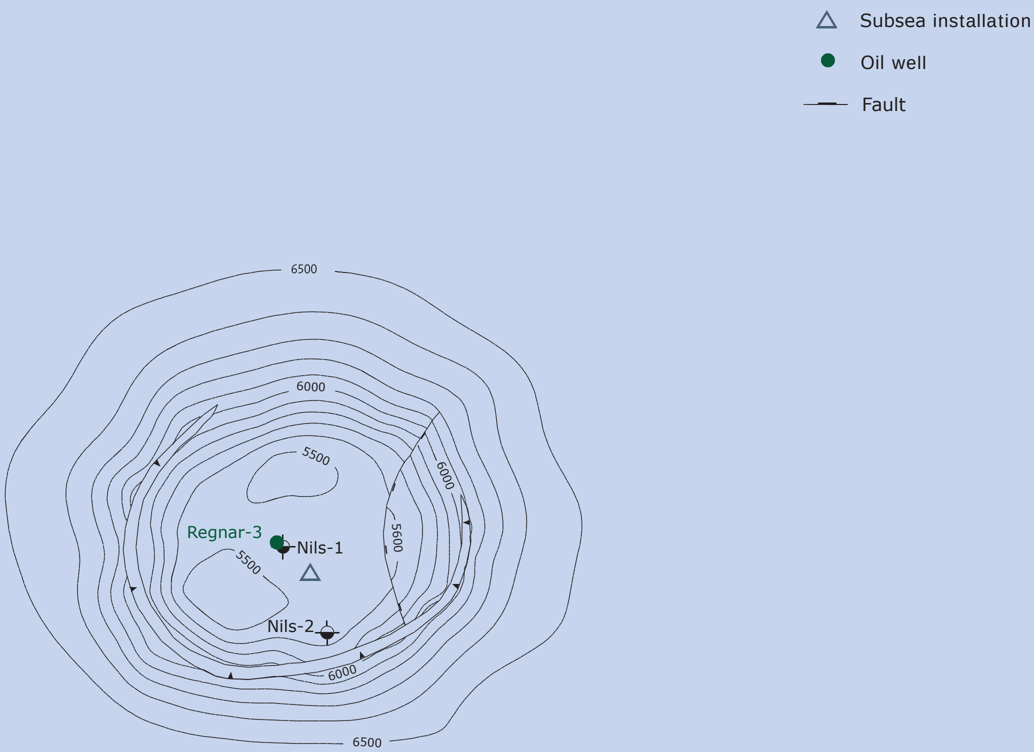
The Nini Field is a satellite development to the Siri Field with one unmanned wellhead platform with a helideck. The unprocessed production is transported through a 14" multiphase pipeline to the Siri platform where it is processed and exported to shore via tanker. Injection water and lift gas are transported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

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

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

# THE REGNAR FIELD



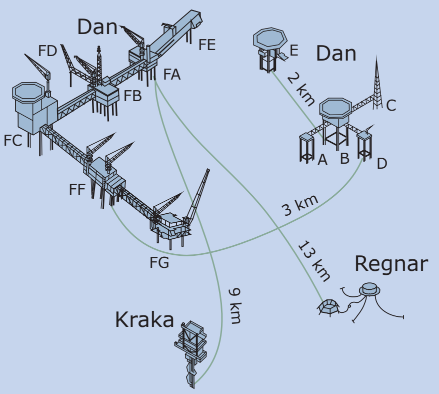



Regnar Field

Top Chalk

Depth structure map in feet

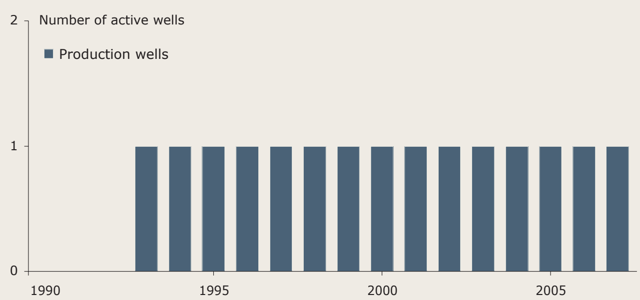
0 0.5 1 km




## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**

2007 prices DKK 0.3 billion



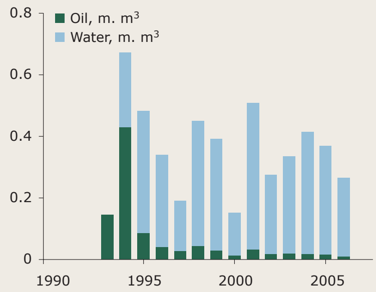
## FIELD DATA
At 1 January 2008

| | |
|---|---|
| Prospect: | Nils |
| Location: | Block 5505/17 |
| Licence: | Sole Concession |
| Operator: | Mærsk Olie og Gas AS |
| Discovered: | 1979 |
| Year on stream: | 1993 |
| Producing wells: | 1 |
| Water depth: | 45 m |
| Field delineation: | 20 $km^2$ |
| Reservoir depth: | 1,700 m |
| Reservoir rock: | Chalk and Carbonates |
| Geological age: | Upper Cretaceous and Zechstein |

## PRODUCTION

**Cum. production at 1 January 2008**

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




## RESERVES

| | |
|---|---|
| Oil: | 0.1 m. $m^3$ |
| Gas: | 0.0 bn. $Nm^3$ |


## REVIEW OF GEOLOGY

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

## PRODUCTION STRATEGY

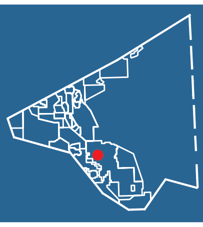
Production in the Regnar Field takes place from one vertical well on the crest of the structure. The oil is displaced towards the producing well by water flowing in from the underlying aquifer. The production strategy is to displace and produce as much of the oil as possible from the matrix of the formation.

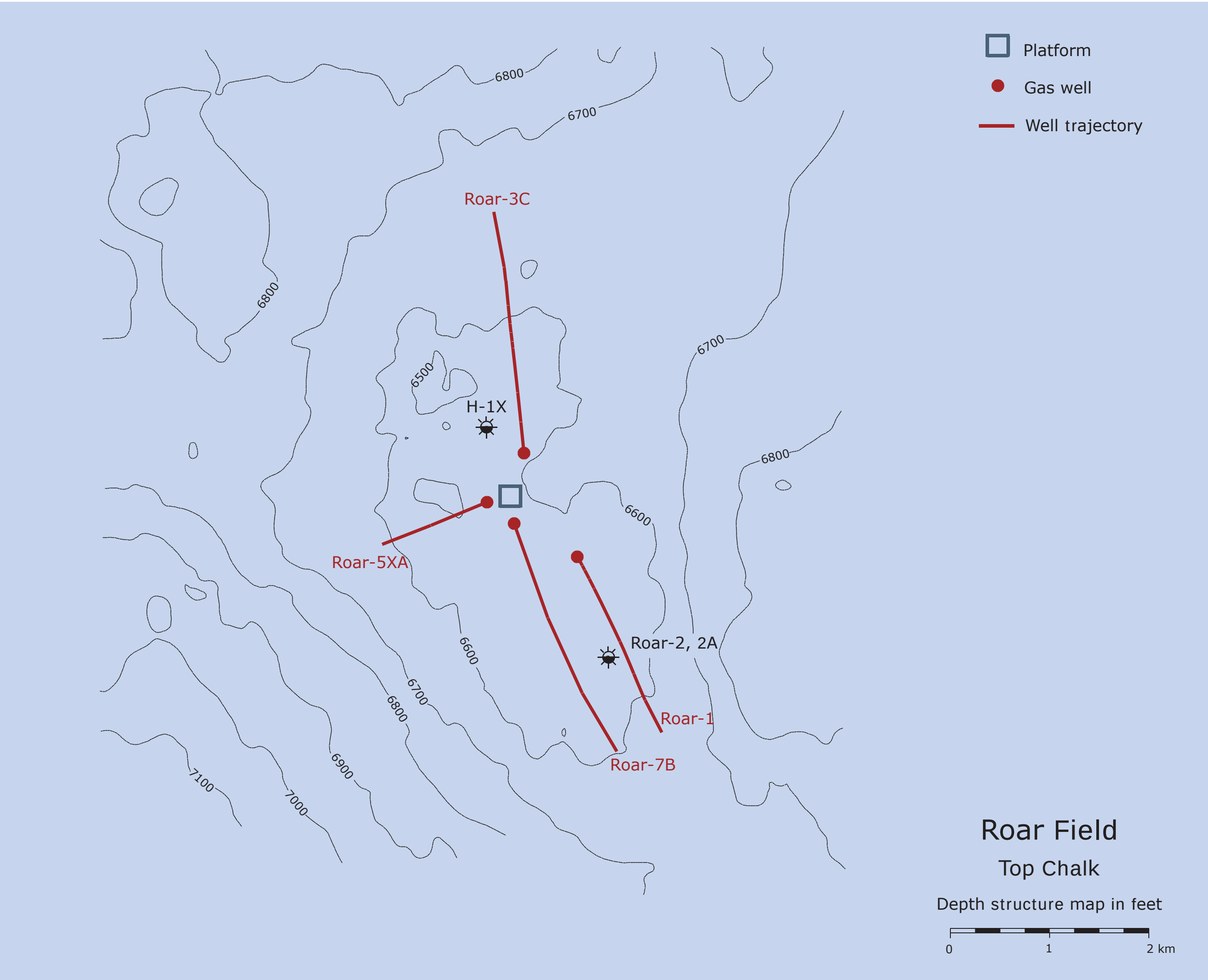
## PRODUCTION FACILITIES

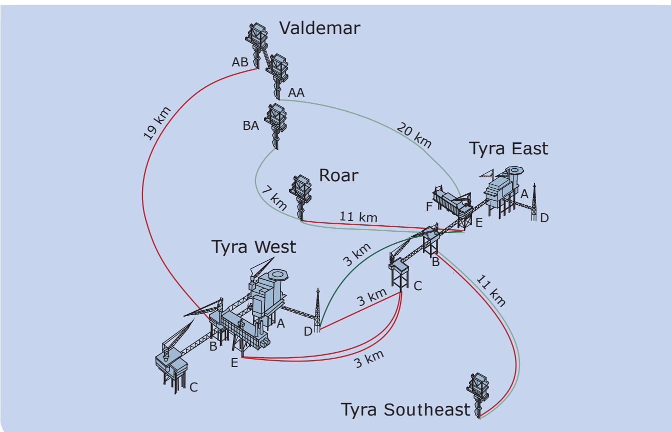
The Regnar Field has been developed as a satellite to the Dan Field. Production takes place in a subsea-completed well. The production is transported by pipeline in multiphase flow to Dan F for processing and export ashore.

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

# THE ROAR FIELD

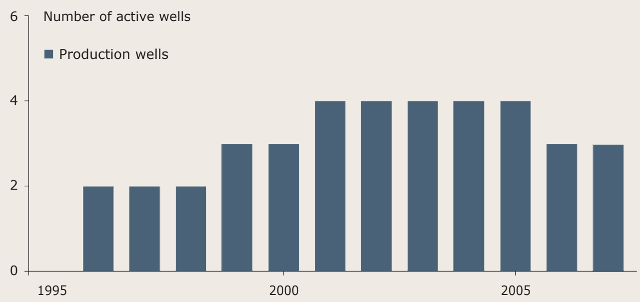





## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 0.7 billion



## FIELD DATA

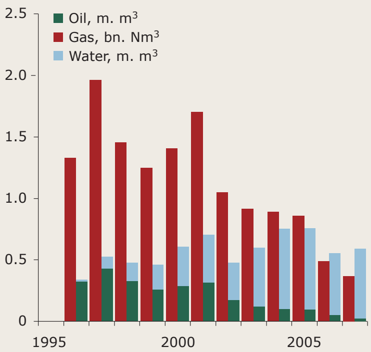
At 1 January 2008

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

## PRODUCTION

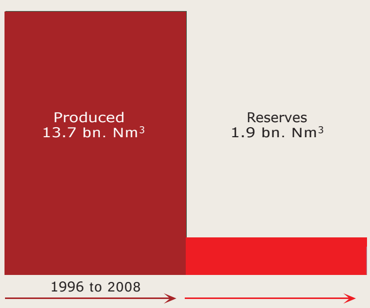
**Cum. production at 1 January 2008**

| | |
|---|---|
| Oil: | 2.51 m. m$^3$ |
| Gas: | 13.69 bn. Nm$^3$ |
| Water: | 4.31 m. m$^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 0.2 m. m$^3$ |
| Gas: | 1.9 bn. Nm$^3$ |




## REVIEW OF GEOLOGY

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

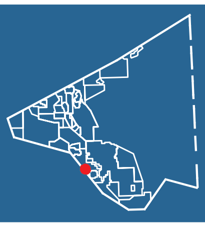
Recovery from the Roar Field takes place by gas expansion. The production strategy for the Roar Field is to optimize the production of liquid hydrocarbons in the Tyra Field by maximizing production from the other gas fields and thus minimizing gas drainage from Tyra.

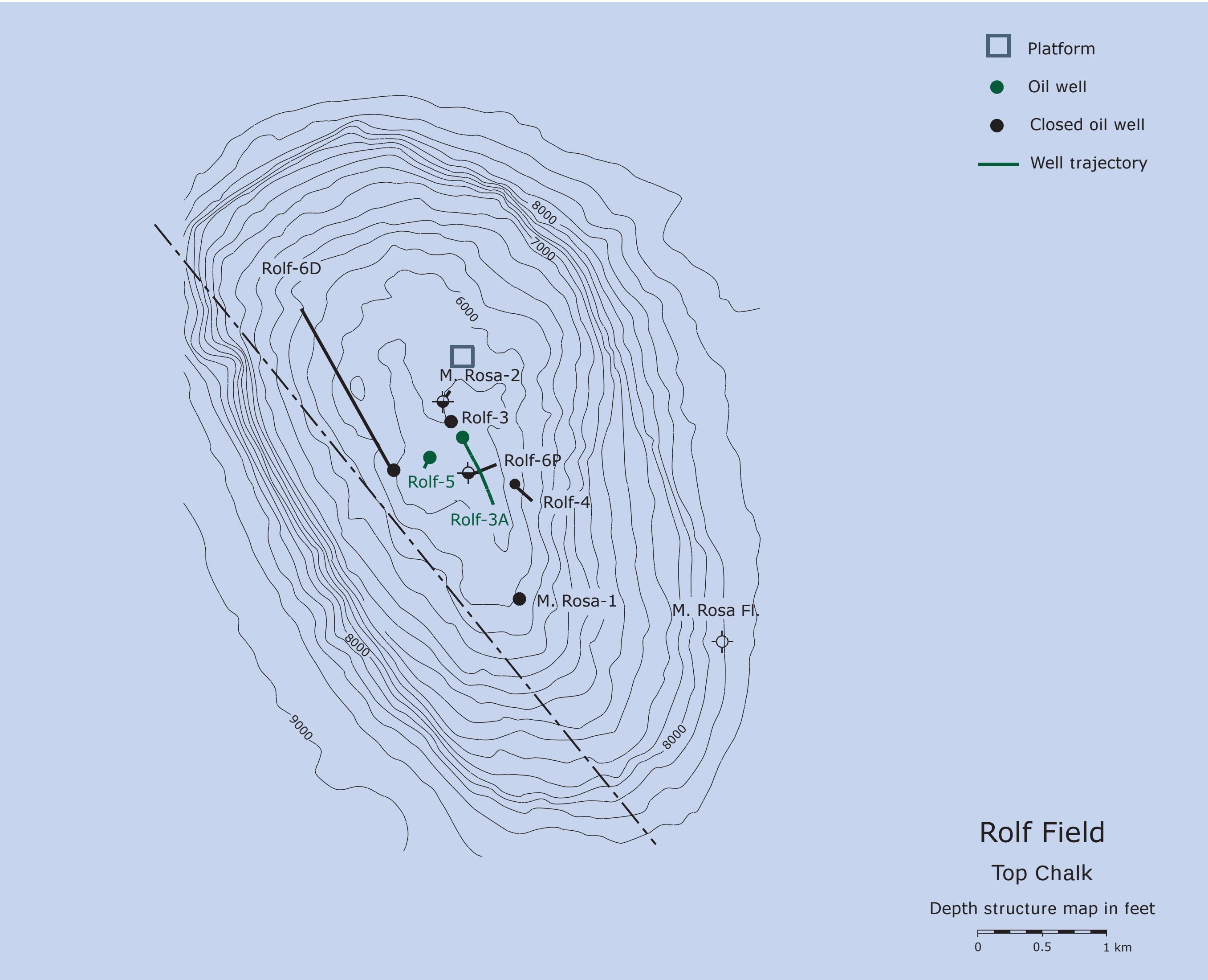
## PRODUCTION FACILITIES

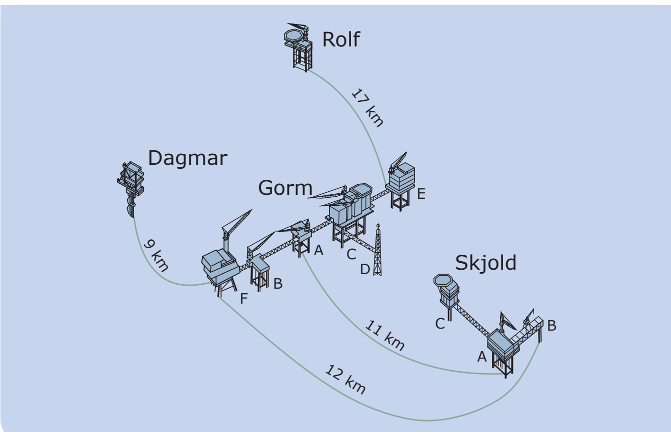
The Roar Field has been developed as a satellite to the Tyra Field with an unmanned wellhead platform of the STAR type, without a helideck. The production is separated into gas and liquids before being transported to Tyra East in two pipelines for further processing and subsequent export ashore. A pipeline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

In 2007, the gas pipeline between Roar and Tyra East was decommissioned. A new 16" multiphase pipeline has been established from the Valdemar BA platform to Tyra East via the Roar Field, which transports the gas produced from Roar to Tyra East.

# THE ROLF FIELD

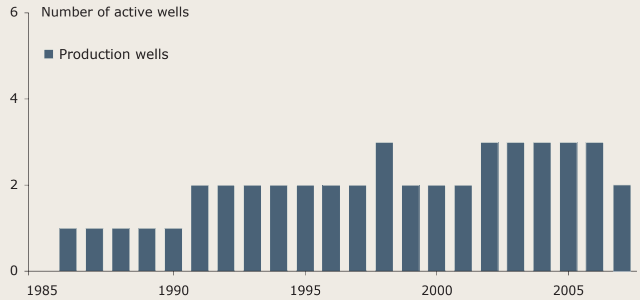





## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 1.1 billion



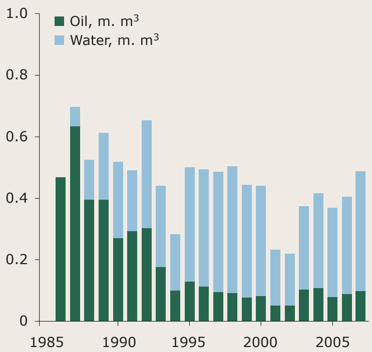
## FIELD DATA
At 1 January 2008

| | |
|---|---|
| Prospect: | Middle Rosa |
| Location: | Blocks 5504/14 and 15 |
| Licence: | Sole Concession |
| Operator: | Mærsk Olie og Gas AS |
| Discovered: | 1981 |
| Year on stream: | 1986 |
| Producing wells: | 2 |
| Water depth: | 34 m |
| Area: | 8 km$^2$ |
| Reservoir depth: | 1,800 m |
| Reservoir rock: | Chalk and Carbonates |
| Geological age: | Danian, Upper Cretaceous and Zechstein |

## PRODUCTION

**Cum. production at 1 January 2008**

| | |
|---|---|
| Oil: | 4.21 m. m$^3$ |
| Gas: | 0.18 bn. Nm$^3$ |
| Water: | 5.84 m. m$^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 0.7 m. m$^3$ |
| Gas: | 0.0 bn. Nm$^3$ |


## REVIEW OF GEOLOGY

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

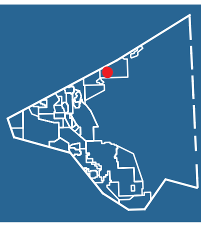
## PRODUCTION STRATEGY

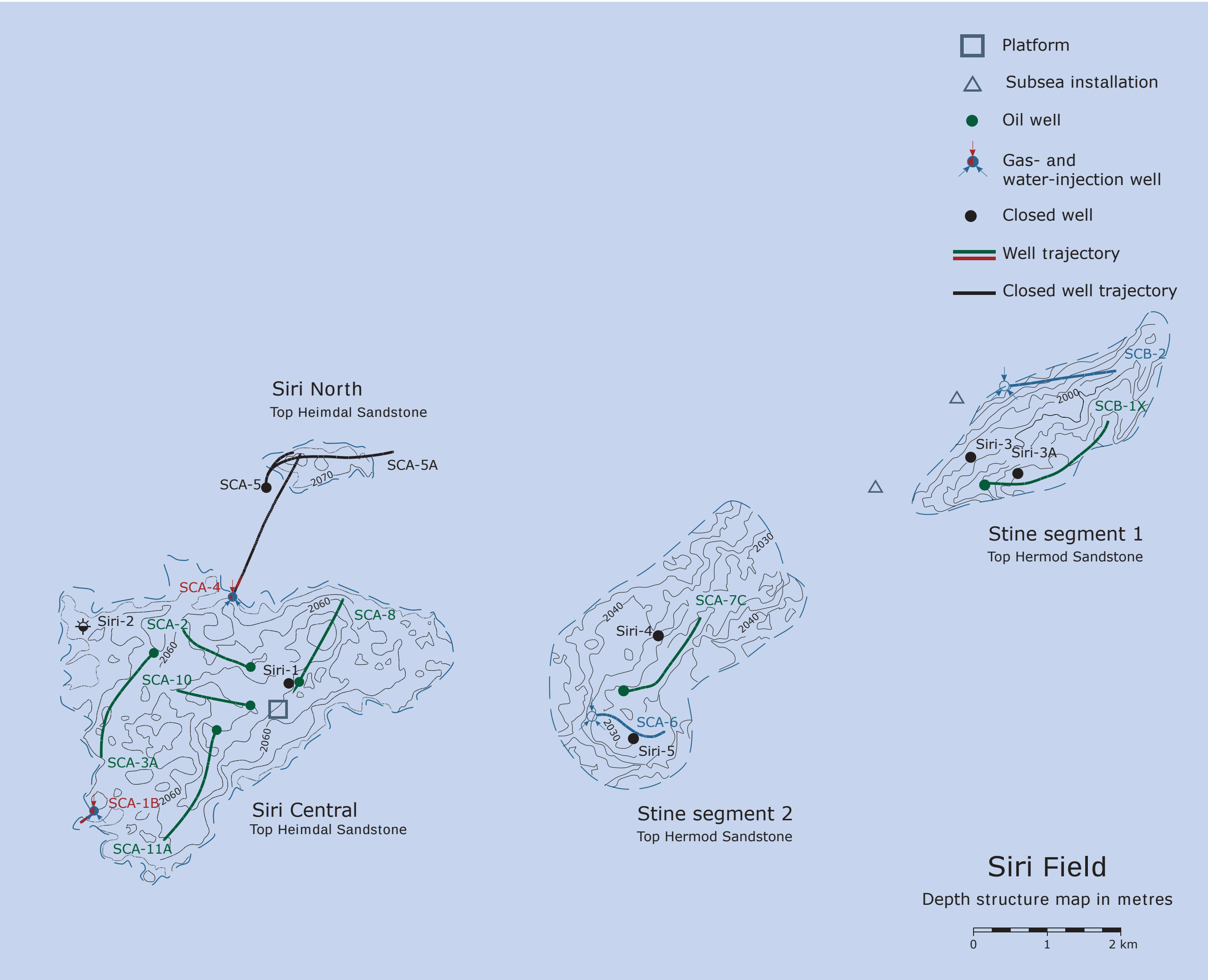
Production from the Rolf Field takes place from two wells drilled in the crest of the structure. The oil is displaced towards the producing wells by the water flow from an underlying aquifer. The natural influx of water from the water zone corresponds to the volume removed due to production in the central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

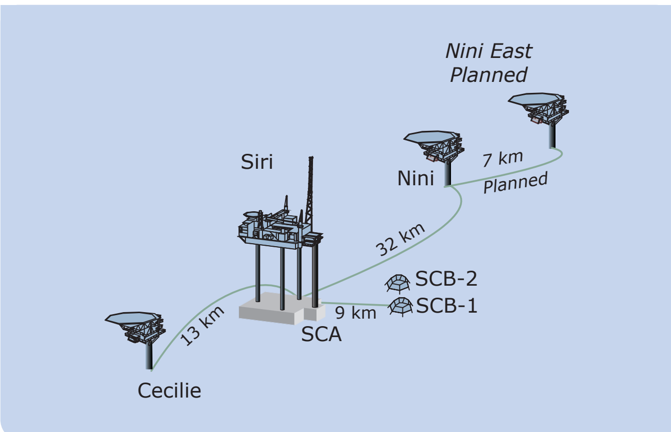
## PRODUCTION FACILITIES

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

# THE SIRI FIELD

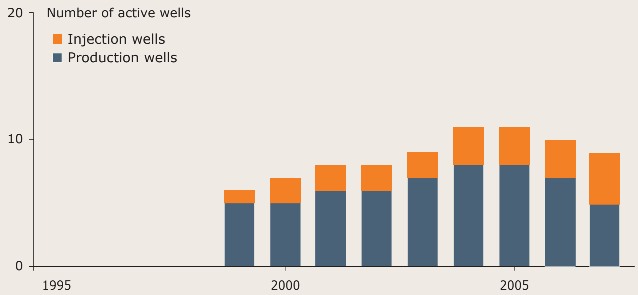





## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 5.5 billion



## FIELD DATA

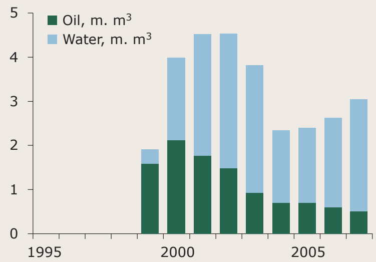
At 1 January 2008

| | |
|---|---|
| Location: | Block 5604/20 |
| Licence: | 6/95 |
| Operator: | DONG E&P A/S |
| Discovered: | 1995 |
| Year on stream: | 1999 |
| Producing wells: | 5 (Siri Central)<br>1 (Stine segment 1)<br>2 (Stine segment 2) |
| Water-/gas-injection wells: | 2 (Siri Central) |
| Water depth: | 60 m |
| Field delineation: | 42 $km^2$ |
| Reservoir depth: | 2,060 m |
| Reservoir rock: | Sandstone |
| Geological age: | Paleocene |

## PRODUCTION

**Cum. production at 1 January 2008**

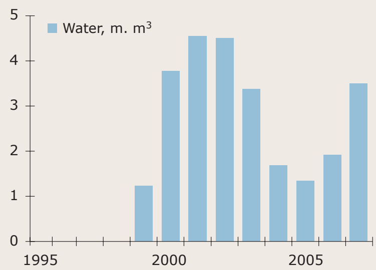
| | |
|---|---|
| Oil: | 10.38 m. $m^3$ |
| Gas: | 1.06 bn. $Nm^3$ |
| Water: | 18.77 m. $m^3$ |




## INJECTION

**Cum. injection at 1 January 2008**

| | |
|---|---|
| Gas: | 0.97 bn. $Nm^3$ |
| Water: | 25.90 m. $m^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 1.8 m. $m^3$ |
| Gas: | 0.0 bn. $Nm^3$ |


## REVIEW OF GEOLOGY

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

## PRODUCTION STRATEGY

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

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

## PRODUCTION FACILITIES

The Siri platform 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.

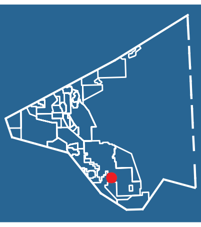
Stine segment 1 (SCB) is developed as a satellite to the Siri platform and consists of two subsea installations with a production and an injection well.

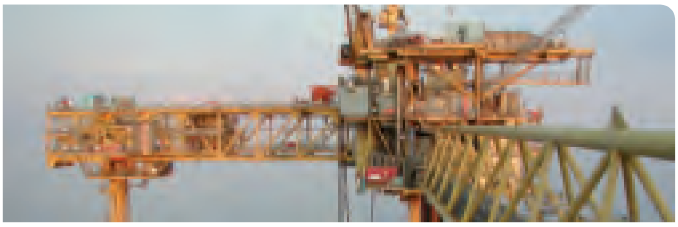
Production from SCB is conveyed to the Siri platform for final processing. The Siri platform also supplies injection water and lift gas to the satellite installations at SCB, Nini and Cecilie. Injection water is supplied to SCB via a branch of the water pipeline leading to Nini.

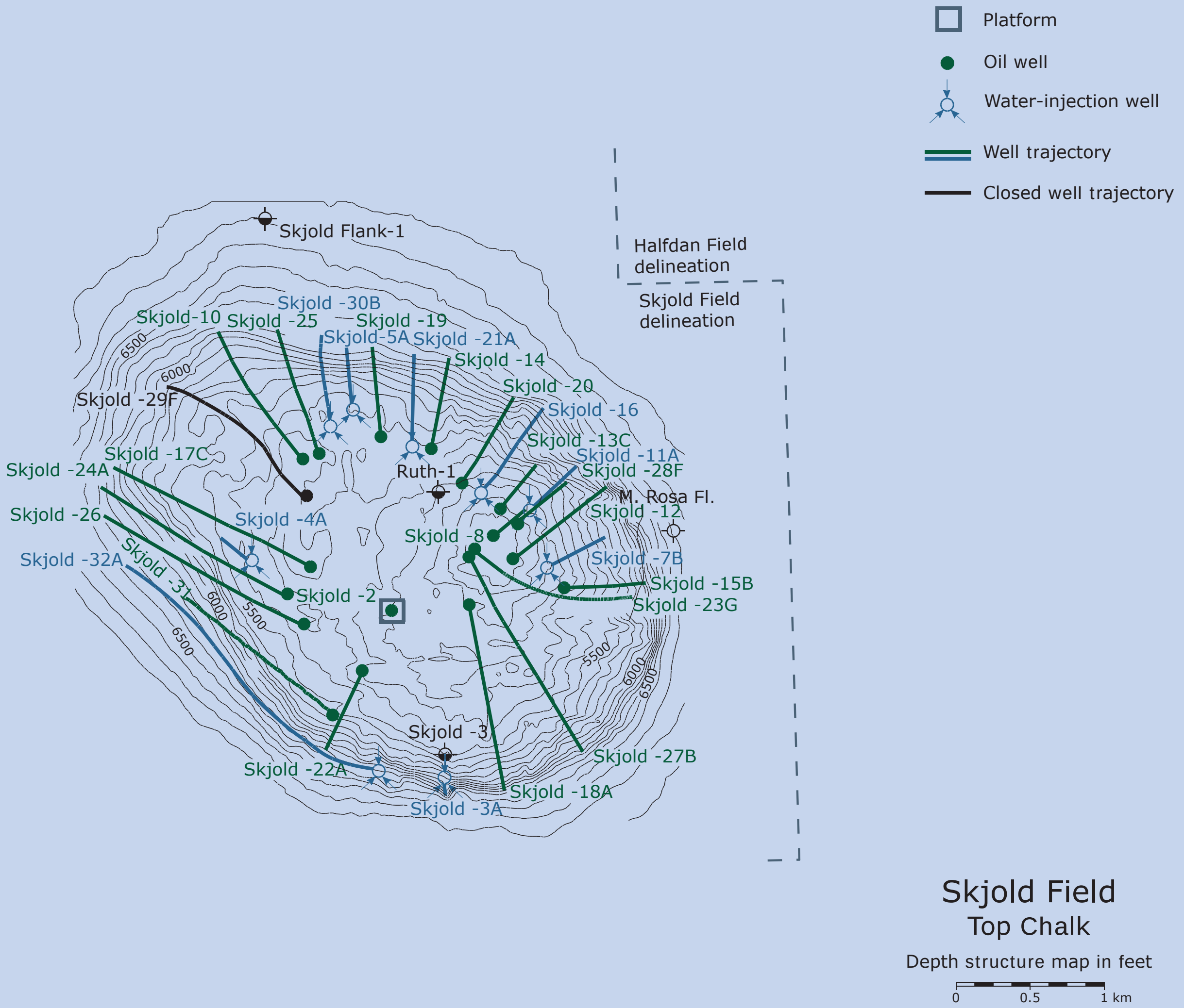
The oil produced is piped to a 50,000 $m^3$ storage tank on the seabed, and subsequently transferred to a tanker by means of buoy-loading facilities.

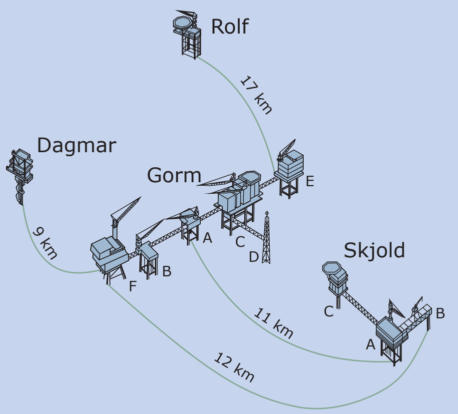
The Siri Field has accommodation facilities for 60 persons.

# THE SKJOLD FIELD



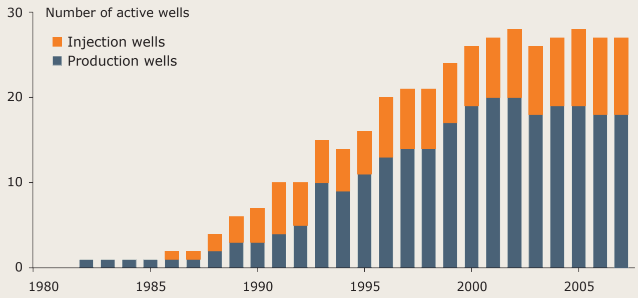





## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 5.5 billion



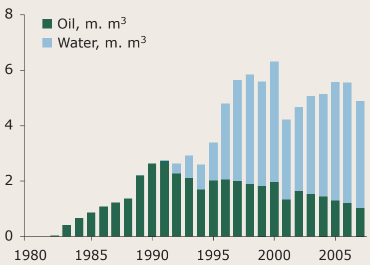
## FIELD DATA
At 1 January 2008

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

## PRODUCTION

**Cum. production at 1 January 2008**

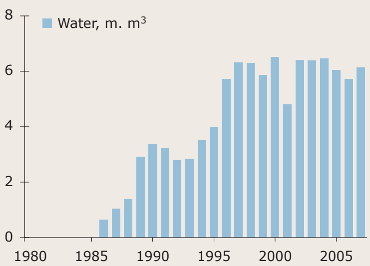
| | |
|---|---|
| Oil: | 40.57 m. m$^3$ |
| Gas: | 3.34 bn. Nm$^3$ |
| Water: | 47.40 m. m$^3$ |




## INJECTION

**Cum. injection at 1 January 2008**

| | |
|---|---|
| Water: | 98.31 m. m$^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 7.4 m. m$^3$ |
| Gas: | 0.5 bn. Nm$^3$ |


## REVIEW OF GEOLOGY

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

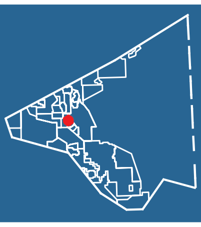
The strategy for producing oil from Skjold is to maintain reservoir pressure by means of water injection. Oil is mainly produced from horizontal wells at the flanks of the reservoir, where the production and injection wells are placed alternately in a radial pattern.

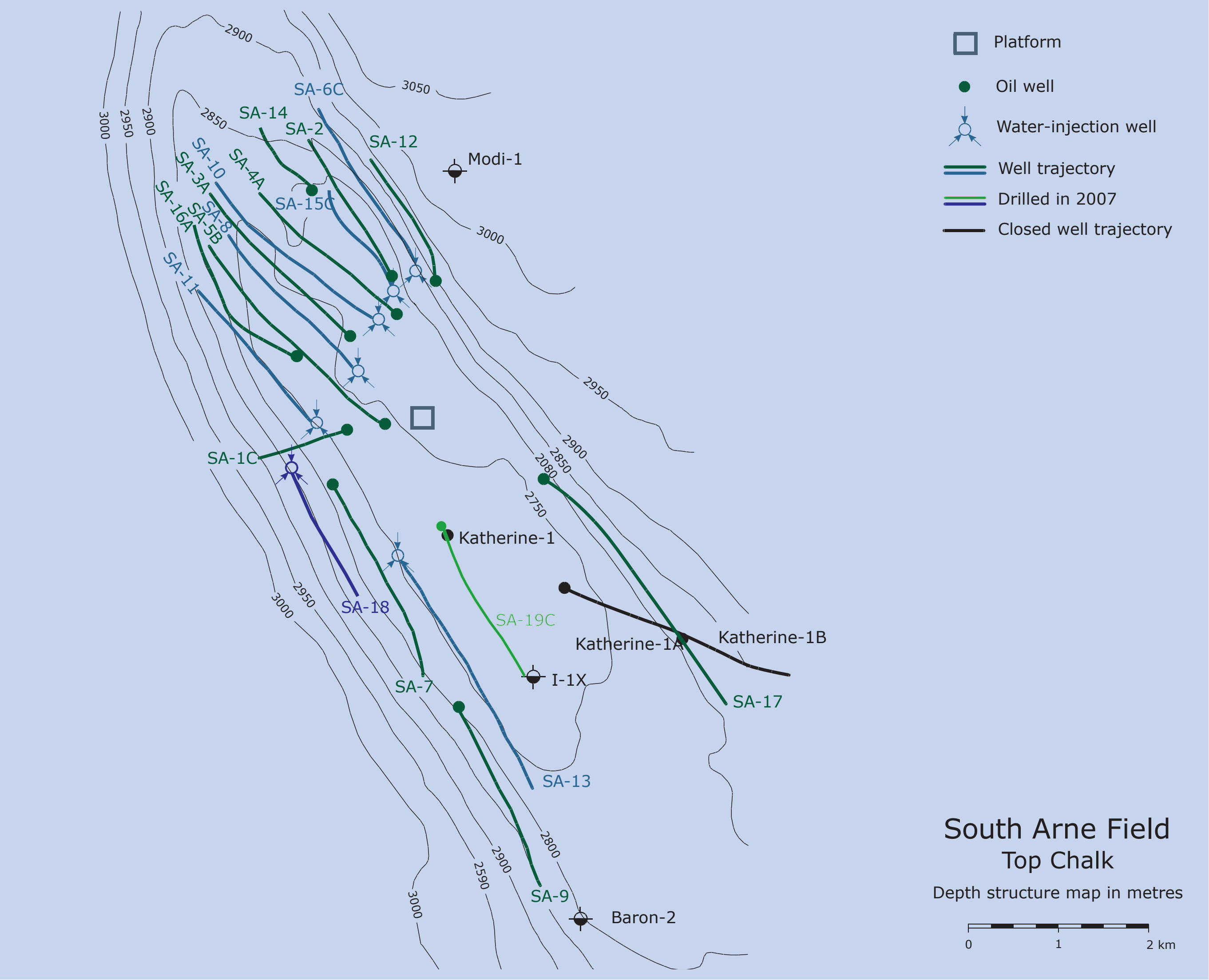
## PRODUCTION FACILITIES

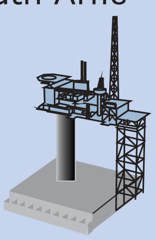
The Skjold Field comprises a satellite development to the Gorm Field, including two wellhead platforms, Skjold A and B, as well as an accommodation platform, Skjold C. There are no processing facilities at the Skjold Field, and the production is transported to the Gorm F platform for processing. The Gorm facilities provide the Skjold Field with injection water and lift gas.

The Skjold C platform has accommodation facilities for 16 persons.

# THE SOUTH ARNE FIELD

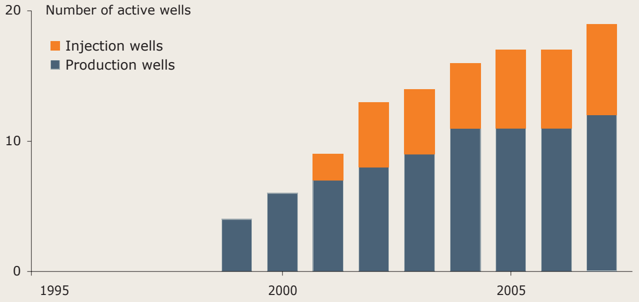





## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 10.9 billion



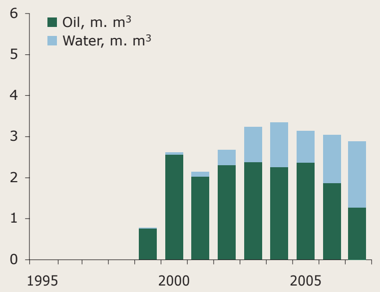
## FIELD DATA At 1 January 2008

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

## PRODUCTION

**Cum. production at 1 January 2008**

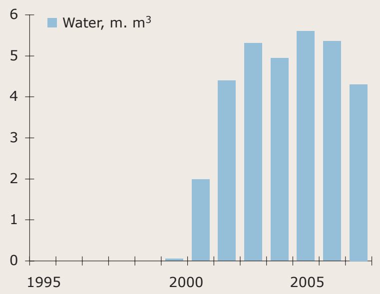
| | |
|---|---|
| Oil: | 17.78 m. $m^3$ |
| Gas: | 4.42 bn. $Nm^3$ |
| Water: | 6.05 m. $m^3$ |




## INJECTION

**Cum. injection at 1 January 2008**

| | |
|---|---|
| Water: | 31.97 m. $m^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 10.5 m. $m^3$ |
| Gas: | 5.2 bn. $Nm^3$ |


## REVIEW OF GEOLOGY

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

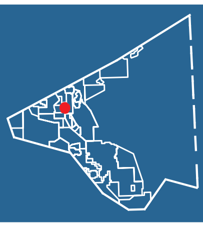
The South Arne Field installations comprise a combined wellhead, processing and accommodation platform.

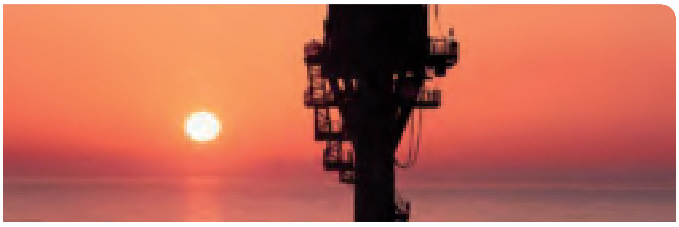
The processing facilities consist of a plant that separates the hydrocarbons produced as well as gas-processing facilities. In addition, processing facilities have been installed to treat the injection water before it is injected. Some of the water produced is injected into the field, while the rest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

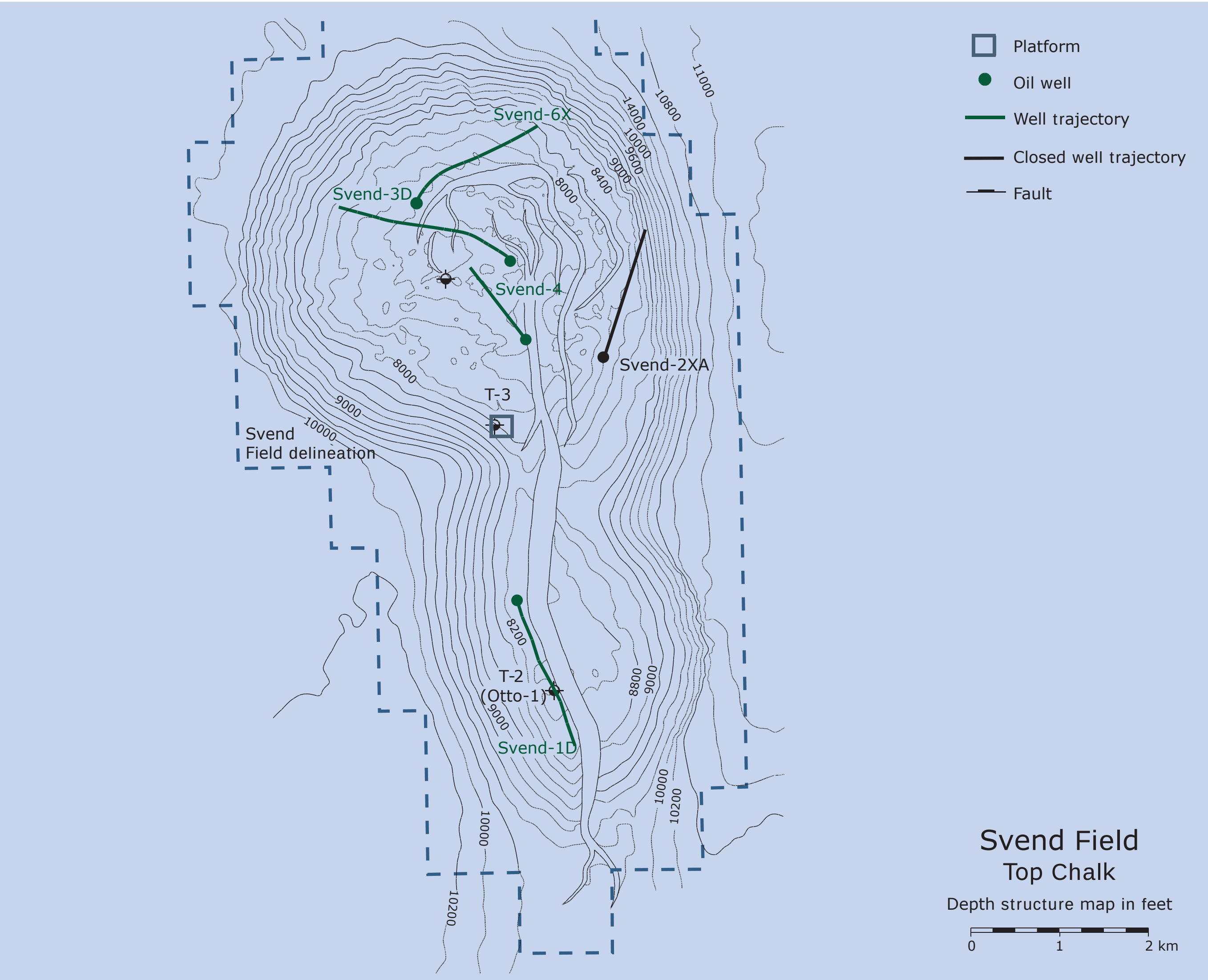
The oil produced is conveyed to an 87,000 $m^3$ storage tank on the seabed and is exported ashore by tanker. The gas produced is exported through a gas pipeline to Nybro on the west coast of Jutland.

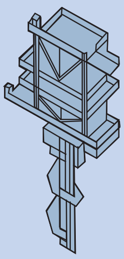
The South Arne Field has accommodation facilities for 57 persons.

# THE SVEND FIELD



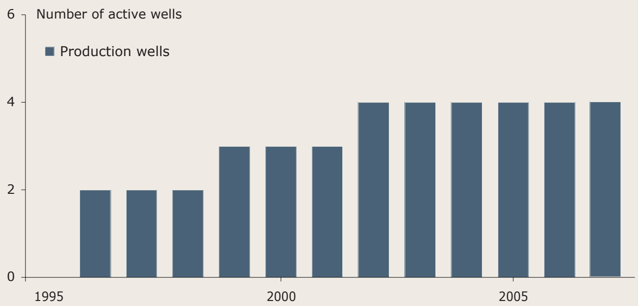





## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 1.2 billion



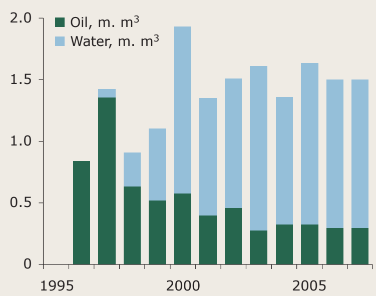
## FIELD DATA At 1 January 2008

| | |
|---|---|
| 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 2008**

| | |
|---|---|
| Oil: | 6.30 m. m$^3$ |
| Gas: | 0.74 bn. Nm$^3$ |
| Water: | 10.36 m. m$^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 0.8 m. m$^3$ |
| Gas: | 0.1 bn. Nm$^3$ |


## REVIEW OF GEOLOGY

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

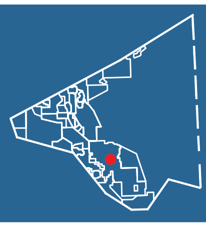
## PRODUCTION STRATEGY

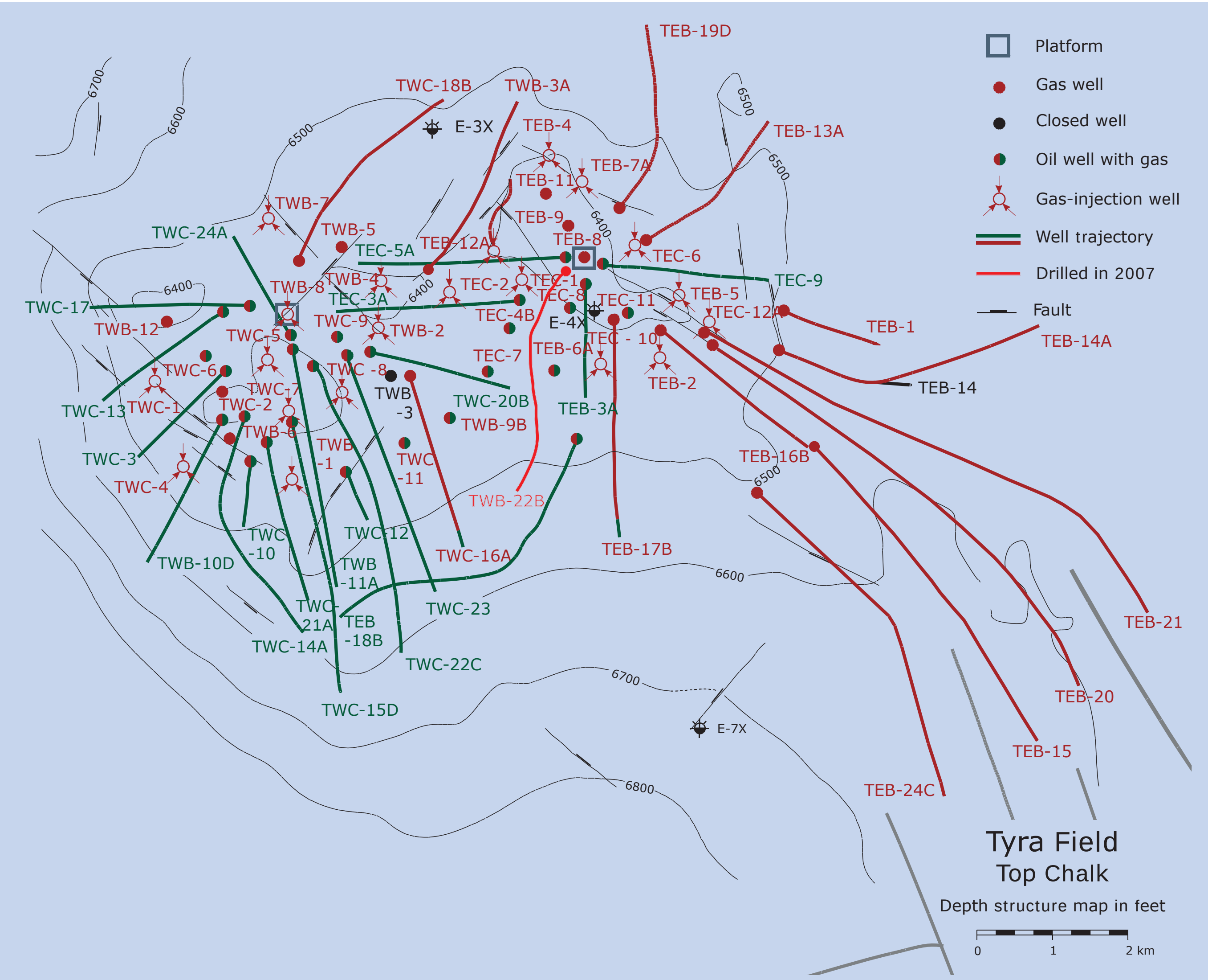
Production is based on primary recovery at a reservoir pressure above the bubble point of the oil, while ensuring maximum production uptime for the wells at the same time.

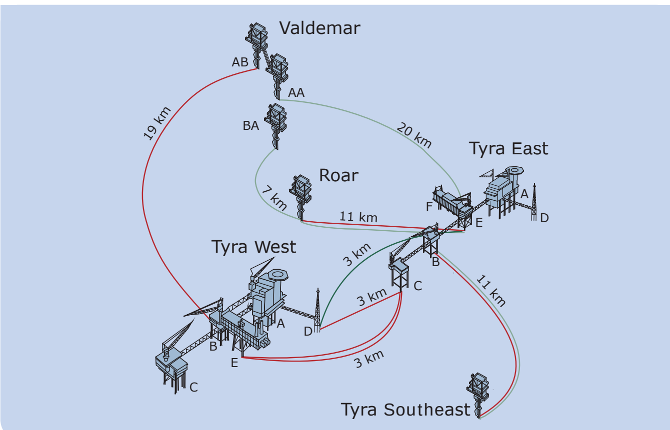
## PRODUCTION FACILITIES

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

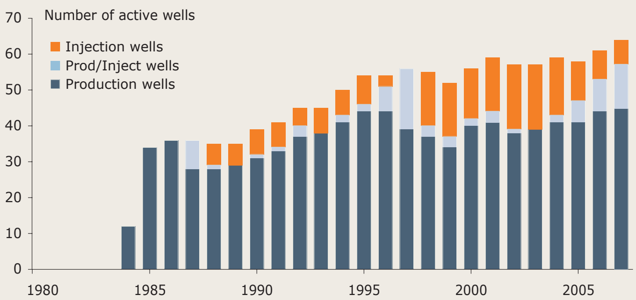





## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**
2007 prices DKK 29.3 billion



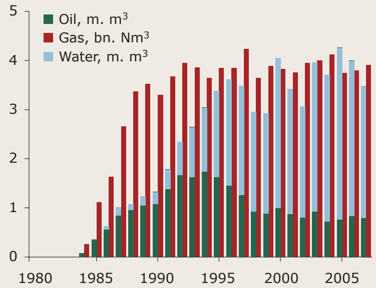
## FIELD DATA At 1 January 2008

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

## PRODUCTION

**Cum. production at 1 January 2008**

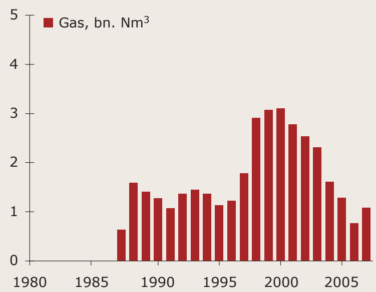
| | |
|---|---|
| Oil: | 24.21 m. $m^3$ |
| Gas: | 81.47 bn. $Nm^3$ |
| Water: | 37.54 m. $m^3$ |




## INJECTION

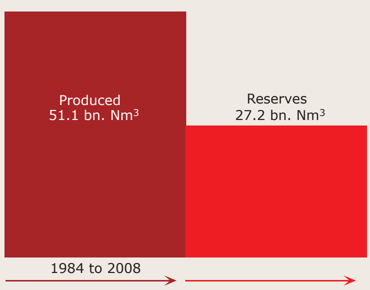
**Cum. injection at 1 January 2008**

| | |
|---|---|
| Gas: | 35.76 bn. $Nm^3$ |




## RESERVES*

| | |
|---|---|
| Oil: | 7.5 m. $m^3$ |
| Gas: | 27.2 bn. $Nm^3$ |




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

## REVIEW OF GEOLOGY

The Tyra Field is an anticlinal structure created by tectonic uplift. The accumulation consists of free gas containing condensate, overlying a thin oil zone. The reservoir is only slightly fractured.

## PRODUCTION STRATEGY

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

## PRODUCTION FACILITIES

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

Tyra West consists of two wellhead platforms, TWB and TWC, one processing and accommodation platform, TWA, and one gas flare stack, TWD, as well as a bridge module installed at TWB and supported by a four-legged jacket, TWE.

The Tyra West processing facilities include a plant for pre-processing 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 and processing facilities for the water produced. Tyra West receives part of the gas produced at Halfdan and Valdemar.

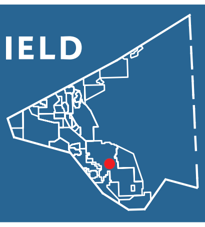
Tyra East consists of two wellhead platforms, TEB and TEC, one processing and accommodation platform, TEA, one gas flare stack, TED, and one riser platform, TEE, as well as a bridge module supported by a STAR jacket, TEF.

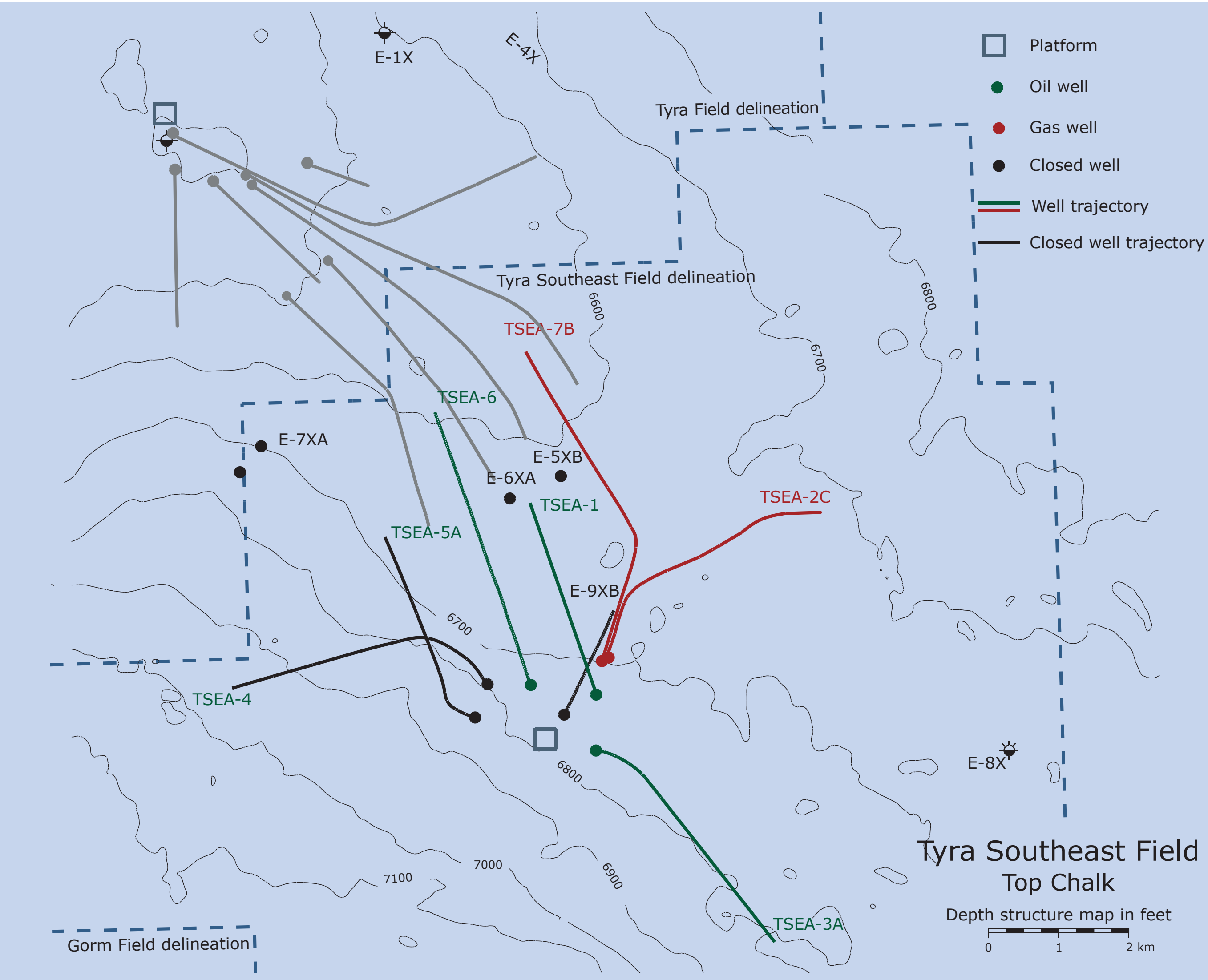
Tyra East receives production from the satellite fields, Valdemar, Roar, Svend, Tyra Southeast and Harald/Lulita, as well as gas production from the Gorm and Dan Fields. The Tyra East complex includes facilities for the final processing of gas, oil, condensate and water. Treated production water from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

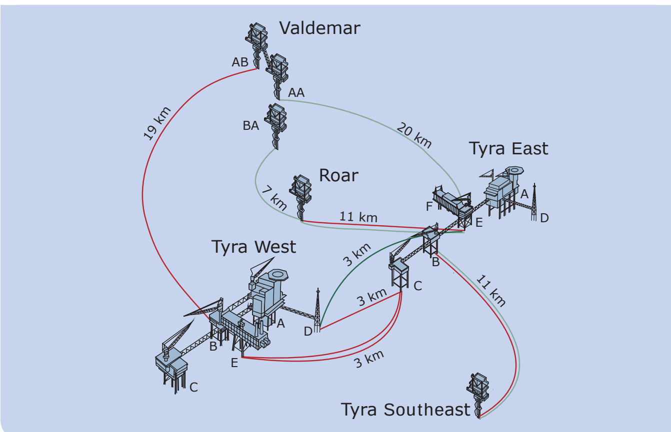
The two platform complexes in the Tyra Field are interconnected by pipelines in order to yield the maximum operational flexibility and reliability of supply. Oil and condensate production from the Tyra Field and its satellite fields is transported ashore via Gorm E, while the bulk of gas produced is 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



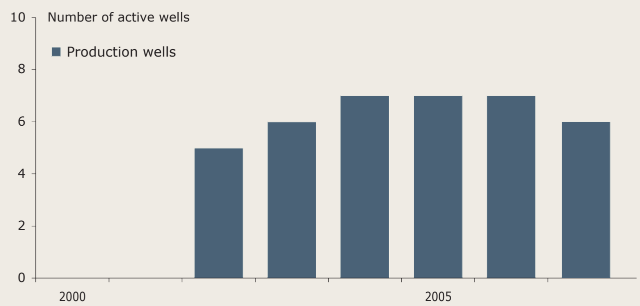




## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**

2007 prices DKK 1.6 billion



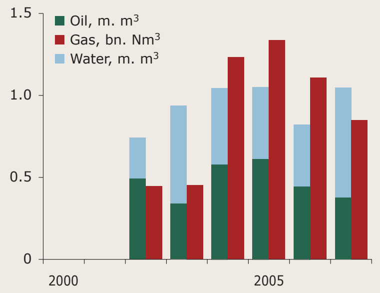
## FIELD DATA at 1 January 2008

| | |
|---|---|
| Location: | Block 5504/12 |
| Licence: | Sole Concession |
| Operator: | Mærsk Olie og Gas AS |
| Discovered: | 1991 |
| Year on stream: | 2003 |
| Oil-producing wells: | 3 |
| Gas-producing wells: | 2 |
| Water depth: | 38 m |
| Field delineation: | 113 km$^2$ |
| Reservoir depth: | 2,050 m |
| Reservoir rock: | Chalk |
| Geological age: | Danian and Upper Cretaceous |

## PRODUCTION

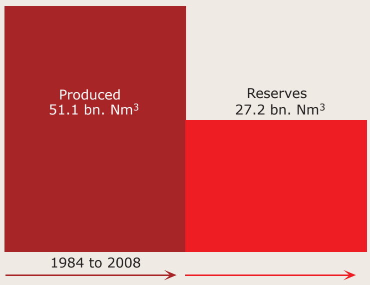
**Cum. production at 1 January 2008**

| | |
|---|---|
| Oil: | 2.85 m. m$^3$ |
| Gas: | 5.43 bn. Nm$^3$ |
| Water: | 2.80 m. m$^3$ |




## RESERVES*

| | |
|---|---|
| Oil: | 7.5 m. m$^3$ |
| Gas: | 27.2 bn. Nm$^3$ |




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

## REVIEW OF GEOLOGY

The Tyra Southeast Field is an anticlinal structure created by a slight tectonic uplift of Upper Cretaceous chalk layers. The structure is divided into two blocks separated by a northeastern-southwestern fault zone. The 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

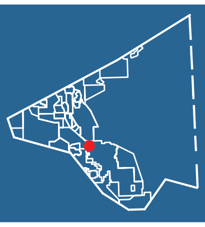
The production of oil and gas is based on natural depletion.

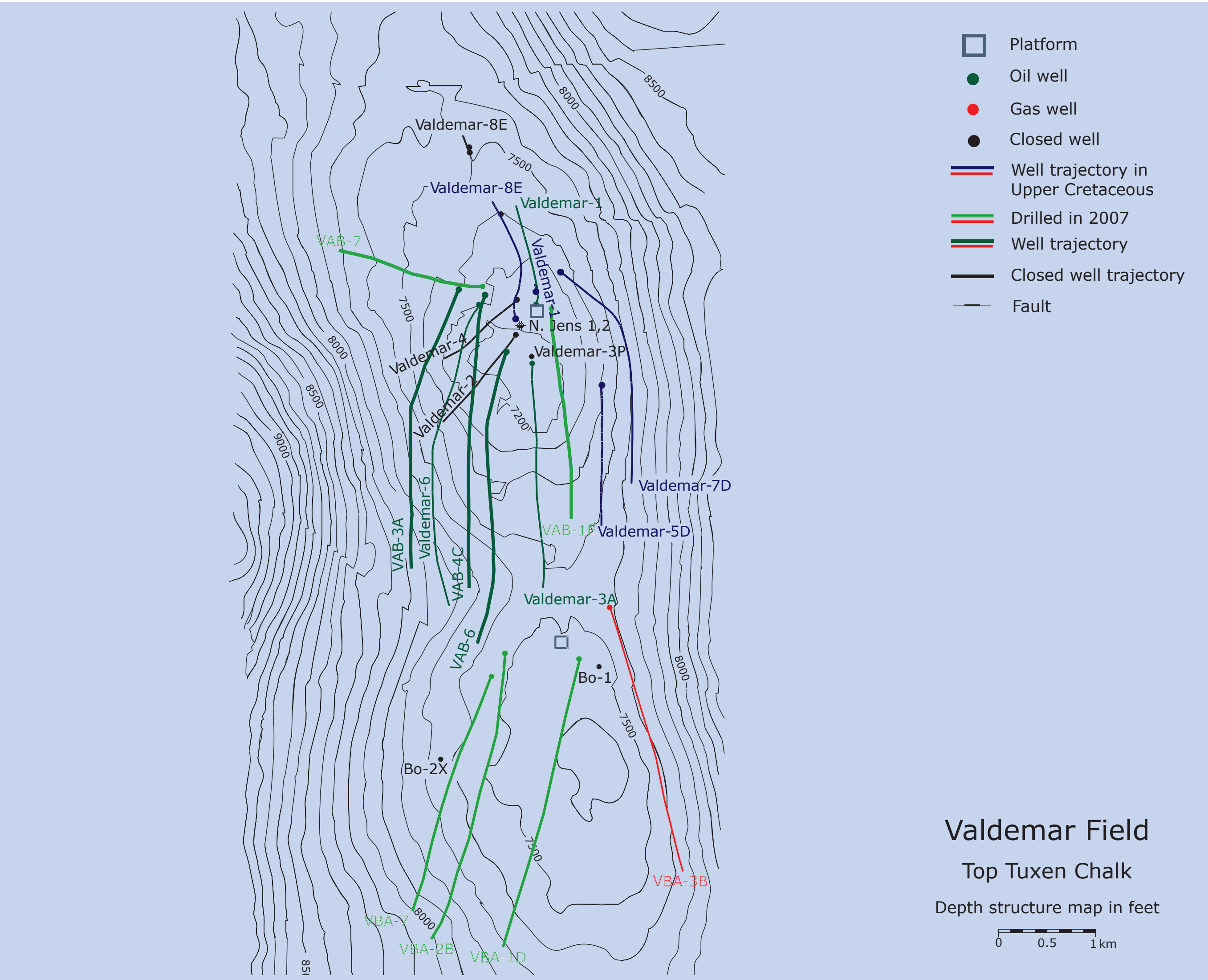
In 2007, two oil wells were closed for the purpose of being redrilled as gas wells.

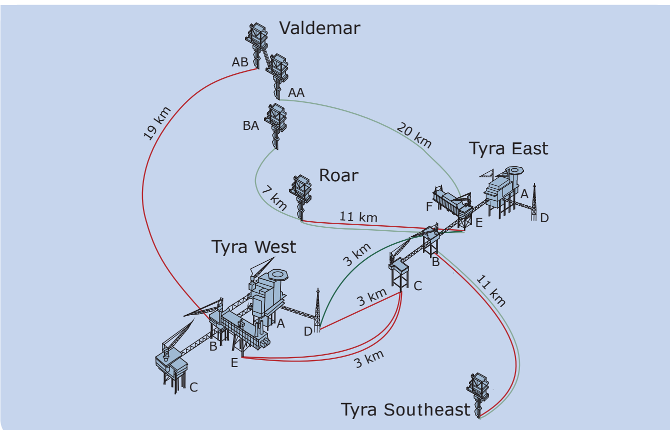
## PRODUCTION FACILITIES

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



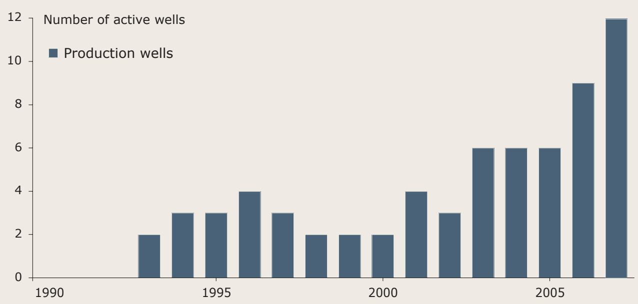



## DEVELOPMENT AND INVESTMENT

**Cum. investments at 1 January 2008**

2007 prices DKK 4.9 billion



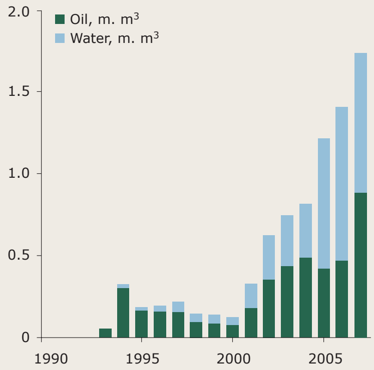
## FIELD DATA at 1 January 2008

| | |
|---|---|
| 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) |
| Oil-producing wells: | 14 |
| Gas-producing wells: | 1 |
| Water depth: | 38 m |
| Field delineation: | 96 $km^2$ |
| Reservoir depth: | 2,000 m (Upper Cretaceous) |
| | 2,600 m (Lower Cretaceous) |
| Reservoir rock: | Chalk |
| Geological age: | Danian, Upper and Lower Cretaceous |

## PRODUCTION

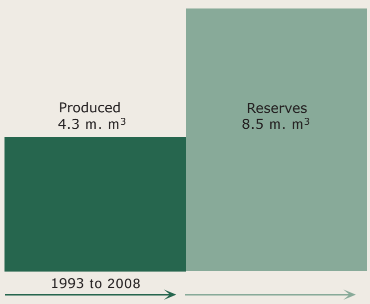
**Cum. production at 1 January 2008**

| | |
|---|---|
| Oil: | 4.34 m. $m^3$ |
| Gas: | 1.81 bn. $Nm^3$ |
| Water: | 3.93 m. $m^3$ |




## RESERVES

| | |
|---|---|
| Oil: | 8.5 m. $m^3$ |
| Gas: | 5.4 bn. $Nm^3$ |




## REVIEW OF GEOLOGY

The Valdemar Field consists of a northern reservoir called North Jens and a southern reservoir called Bo, which are both anticlinal chalk structures associated with tectonic uplift.

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

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

## PRODUCTION STRATEGY

The production of oil is based on natural depletion. The development of a production method based on long horizontal wells with numerous sand-filled, artificial fractures has made it possible to exploit the Lower Cretaceous reservoir commercially. In addition, recovery takes place from Danian/Upper Cretaceous layers.

## PRODUCTION FACILITIES

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

Production from the Bo area of the Valdemar Field started in March 2007.

# APPENDIX C: PRODUCTION AND RESERVES AT 1 JANUARY 2008

| OIL, m. $m^3$ | | | | |
|---|---|---|---|---|
| | Ultimate recovery | | | |
| | Produced | Reserves | | |
| | | Low | Exp. | High |
| **Ongoing and approved** | | | | |
| Adda | - | 0 | 1 | 1 |
| Alma | - | 0 | 0 | 1 |
| Boje area | - | 1 | 1 | 1 |
| Cecilie | 1 | 0 | 0 | 1 |
| Dagmar | 1 | 0 | 0 | 0 |
| Dan | 91 | 33 | 48 | 62 |
| Gorm | 56 | 5 | 9 | 14 |
| Halfdan | 35 | 50 | 72 | 95 |
| Harald | 8 | 1 | 1 | 1 |
| Kraka | 5 | 1 | 2 | 3 |
| Lulita | 1 | 0 | 0 | 0 |
| Nini | 3 | 2 | 4 | 6 |
| Regnar | 1 | 0 | 0 | 0 |
| Roar | 3 | 0 | 0 | 0 |
| Rolf | 4 | 0 | 1 | 1 |
| Siri | 10 | 1 | 2 | 4 |
| Skjold | 41 | 4 | 7 | 11 |
| South Arne | 18 | * | 11 | * |
| Svend | 6 | 1 | 1 | 1 |
| Tyra** | 27 | 4 | 8 | 10 |
| Valdemar | 4 | 4 | 8 | 12 |
| **Subtotal** | **315** | | **177** | |
| **Planned** | | | | |
| Amalie | - | 1 | 1 | 2 |
| Freja | - | 1 | 1 | 2 |
| **Subtotal** | | | **2** | |
| **Possible** | | | | |
| Producing fields | - | 4 | 8 | 12 |
| Other fields | - | 1 | 1 | 2 |
| Discoveries | - | 16 | 26 | 38 |
| **Subtotal** | | | **35** | |
| **Total** | **315** | | **214** | |
| January 2007 | 297 | | 240 | |

| GAS, bn. $Nm^3$ | | | | |
|---|---|---|---|---|
| | Ultimate recovery | | | |
| | Produced | Reserves | | |
| | | Low | Exp. | High |
| **Ongoing and approved** | | | | |
| Adda | - | 0 | 0 | 0 |
| Alma | - | 0 | 1 | 1 |
| Boje area | - | 0 | 0 | 0 |
| Cecilie | 0 | - | - | - |
| Dagmar | 0 | 0 | 0 | 0 |
| Dan | 22 | 3 | 5 | 7 |
| Gorm | 7 | 1 | 1 | 1 |
| Halfdan | 12 | 16 | 26 | 36 |
| Harald | 20 | 3 | 4 | 6 |
| Kraka | 1 | 0 | 0 | 0 |
| Lulita | 1 | 0 | 0 | 1 |
| Nini | 0 | - | - | - |
| Regnar | 0 | 0 | 0 | 0 |
| Roar | 14 | 1 | 2 | 2 |
| Rolf | 0 | 0 | 0 | 0 |
| Siri | 0 | - | - | - |
| Skjold | 3 | 0 | 1 | 1 |
| South Arne | 4 | * | 5 | * |
| Svend | 1 | 0 | 0 | 0 |
| Tyra** | 51 | 15 | 27 | 38 |
| Valdemar | 2 | 2 | 5 | 8 |
| **Subtotal** | **138** | | **79** | |
| **Planned** | | | | |
| Amalie | - | 1 | 2 | 3 |
| Freja | - | 0 | 0 | 0 |
| **Subtotal** | | | **2** | |
| **Possible** | | | | |
| Producing fields | - | 1 | 3 | 4 |
| Other fields | - | 1 | 4 | 7 |
| Discoveries | - | 8 | 17 | 31 |
| **Subtotal** | | | **24** | |
| **Total** | **138** | | **105** | |
| January 2007 | 129 | | 120 | |

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

# APPENDIX D: FINANCIAL KEY FIGURES

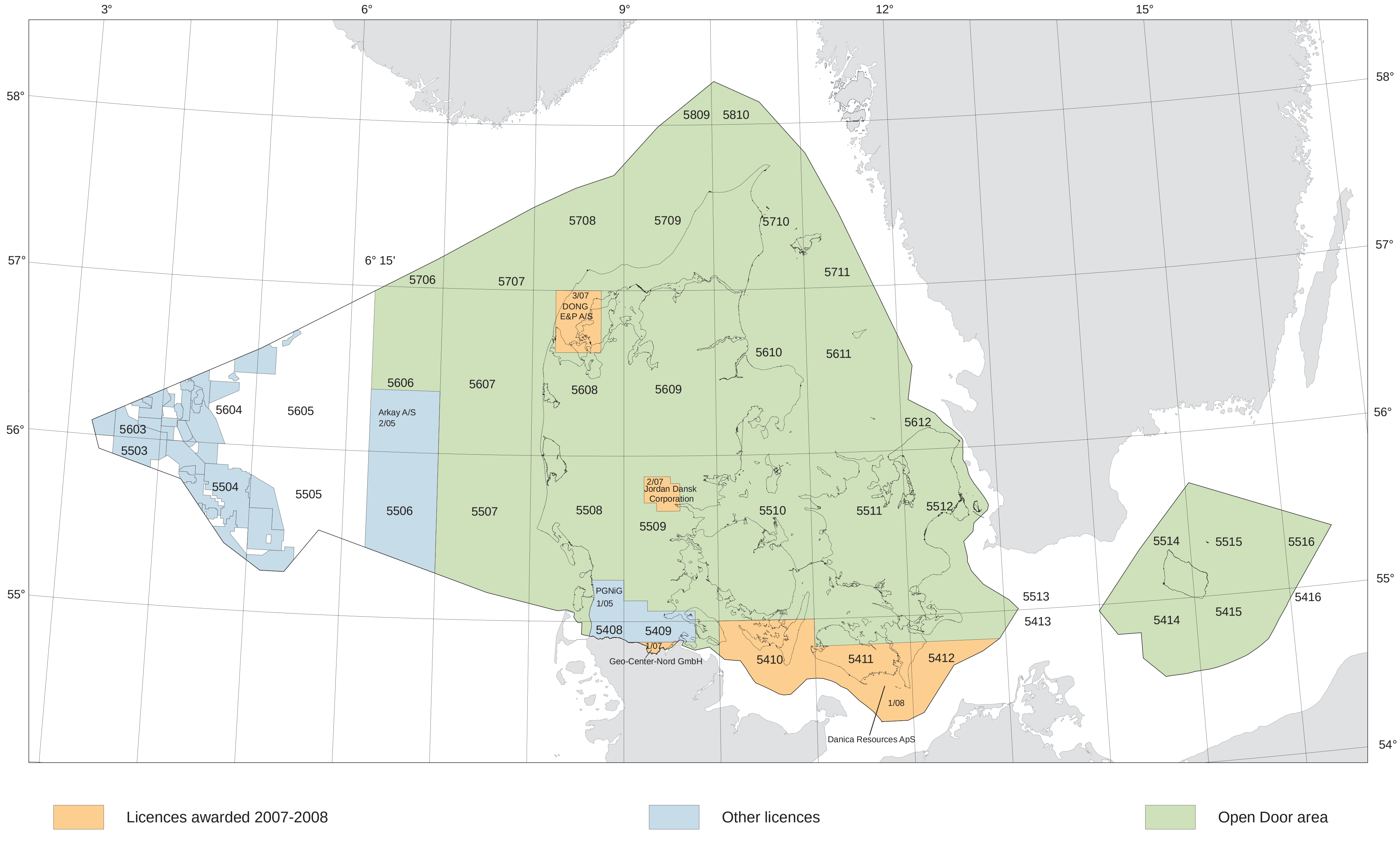
| | Investments in field dev. DKK million 5) | Field operating costs DKK million 1) | Exploration costs DKK million | Crude oil price USD/bbl 2) | Exchange rate DKK/USD | Inflation per cent 3) | Net foreign-currency value DKK billion 4) | State revenue DKK million |
|---|---|---|---|---|---|---|---|---|
| **1972** | 105 | 29 | 30 | 3.0 | 7.0 | 6.7 | -3.2 | - |
| **1973** | 9 | 31 | 28 | 4.6 | 6.1 | 9.3 | -4.0 | 1 |
| **1974** | 38 | 57 | 83 | 11.6 | 6.1 | 15.3 | -9.2 | 1 |
| **1975** | 139 | 62 | 76 | 12.3 | 5.8 | 9.6 | -8.5 | 2 |
| **1976** | 372 | 70 | 118 | 12.9 | 6.1 | 9.0 | -9.5 | 4 |
| **1977** | 64 | 85 | 114 | 14.0 | 6.0 | 11.1 | -10.4 | 5 |
| **1978** | 71 | 120 | 176 | 14.1 | 5.5 | 10.0 | -9.5 | 21 |
| **1979** | 387 | 143 | 55 | 20.4 | 5.3 | 9.6 | -13.7 | 19 |
| **1980** | 956 | 163 | 78 | 37.5 | 5.6 | 12.3 | -18.6 | 29 |
| **1981** | 1,651 | 320 | 201 | 37.4 | 7.1 | 11.7 | -20.1 | 36 |
| **1982** | 3,884 | 534 | 257 | 34.0 | 8.4 | 10.1 | -20.6 | 231 |
| **1983** | 3,554 | 544 | 566 | 30.5 | 9.1 | 6.9 | -17.8 | 401 |
| **1984** | 1,598 | 1,237 | 1,211 | 28.2 | 10.4 | 6.3 | -18.3 | 564 |
| **1985** | 1,943 | 1,424 | 1,373 | 27.2 | 10.6 | 4.7 | -17.6 | 1,192 |
| **1986** | 1,651 | 1,409 | 747 | 14.9 | 8.1 | 3.7 | -7.3 | 1,399 |
| **1987** | 930 | 1,380 | 664 | 18.3 | 6.8 | 4.0 | -5.9 | 1,328 |
| **1988** | 928 | 1,413 | 424 | 14.8 | 6.7 | 4.5 | -3.7 | 568 |
| **1989** | 1,162 | 1,599 | 366 | 18.2 | 7.3 | 4.8 | -3.2 | 1,024 |
| **1990** | 1,769 | 1,654 | 592 | 23.6 | 6.2 | 2.6 | -2.7 | 2,089 |
| **1991** | 2,302 | 1,898 | 985 | 20.0 | 6.4 | 2.4 | -1.9 | 1,889 |
| **1992** | 2,335 | 1,806 | 983 | 19.3 | 6.0 | 2.1 | -0.4 | 1,911 |
| **1993** | 3,307 | 2,047 | 442 | 16.8 | 6.5 | 1.2 | -1.7 | 1,811 |
| **1994** | 3,084 | 2,113 | 151 | 15.6 | 6.4 | 2.0 | -0.5 | 2,053 |
| **1995** | 4,164 | 1,904 | 272 | 17.0 | 5.6 | 2.1 | 0.3 | 1,980 |
| **1996** | 4,260 | 2,094 | 470 | 21.1 | 5.8 | 2.1 | 0.4 | 2,465 |
| **1997** | 3,760 | 2,140 | 515 | 18.9 | 6.6 | 2.2 | 1.4 | 3,171 |
| **1998** | 5,381 | 2,037 | 406 | 12.8 | 6.7 | 1.8 | 0.9 | 3,125 |
| **1999** | 3,531 | 2,118 | 656 | 17.9 | 7.0 | 2.5 | 3.5 | 3,630 |
| **2000** | 3,113 | 2,813 | 672 | 28.5 | 8.1 | 2.9 | 14.9 | 8,695 |
| **2001** | 4,025 | 2,756 | 973 | 24.4 | 8.3 | 2.4 | 12.6 | 9,634 |
| **2002** | 5,475 | 3,102 | 1,036 | 24.9 | 7.9 | 2.4 | 14.5 | 10,137 |
| **2003** | 7,386 | 3,522 | 789 | 28.8 | 6.6 | 2.1 | 15.3 | 9,255 |
| **2004** | 5,107 | 3,349 | 340 | 38.2 | 6.0 | 1.2 | 19.7 | 17,092 |
| **2005** | 3,983 | 3,760 | 578 | 54.4 | 6.0 | 1.8 | 24.8 | 24,163 |
| **2006** | 5,374 | 4,222 | 600 | 65.1 | 5.9 | 1.9 | 31.5 | 31,493 |
| **2007*** | 6,584 | 3,869 | 536 | 72.5 | 5.4 | 1.7 | 28.3 | 27,886 |

*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<br><br>Deductible from the hydrocarbon tax base. | 25 per cent<br><br>Deductible from the hydrocarbon tax base. | 25 per cent<br><br>Deductible from the hydrocarbon tax base. |
| **Hydrocarbon tax** | 52 per cent<br><br>Allowance of 5 per cent over 6 years (a total of 30 per cent) for investments.<br><br>Transitional rules for investments and unutilized losses made before 1 January 2004. | 70 per cent<br><br>Allowance of 25 per cent over 10 years (a total of 250 per cent) for investments. | 52 per cent<br><br>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:<br><br>1000bbl/day Rate<br>0 - 5 2 per cent<br>5 - 20 8 per cent<br>20 - 16 per cent<br><br>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.<br><br>The oil pipeline tariff can be offset against hydrocarbon tax, but not against the corporate income tax and hydrocarbon tax bases. | 5 per cent<br><br>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.<br><br>The oil pipeline tariff can be offset against hydrocarbon tax, but not against the corporate income tax and hydrocarbon tax bases. |
| **State participation** | 20 per cent from 9 July 2012 | 20 per cent<br><br>1st, 2nd og 3rd Rounds: State participation with carried interest in the exploratory phase.<br><br>A paying interest, depending on the size of production, in the development and production phases.<br><br>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 profit before tax and before net interest expenses is payable. | No | No |

# Appendix F1: Danish licence area - April 2008



# Appendix F2: Danish licence area - April 2008

## The western area