OIL AND GAS PRODUCTION IN DENMARK 2012

and Subsoil Use

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PREFACE

Against the backdrop of historical developments in Danish oil and gas production, 2012 will be remembered for two particular reasons.

The date 4 July 2012 marked the 40th anniversary of Danish oil and gas production, which started up from the Dan Field, a field still producing oil and gas today. Since 1972 close to 28 per cent of total Danish oil production has been extracted from the Dan Field, and current projections show that the field will keep producing oil and gas for many years to come.

On 9 July 2012 the state-owned company "Nordsøfonden" (the Danish North Sea Fund) joined Dansk Undergrunds Consortium (DUC) as a partner with a 20 per cent interest. This added the Danish North Sea Fund to the list of oil-producing companies in Denmark. The Danish North Sea Fund became a DUC partner as a result of the North Sea Agreement from 2003, and thus safeguards the Danish state's interests in DUC.

After 40 years' production, the Danish sector of the North Sea can be termed a mature area with a primary focus on optimizing current production and maintaining existing installations.

The exploration for new oil and gas fields continues, and investments are still being made in new oil and gas production installations. In 2012 investments in exploration activity totalled about DKK 1.2 billion, of which investments in new installations accounted for about DKK 5.7 billion, an increase on 2011.

The commitment to upholding health, safety and environmental standards permeates all aspects of oil and gas production. A new EU Directive on the safety of offshore oil and gas operations will strengthen the focus on preventing and limiting the consequences of major accidents.

Another of Denmark's priorities is to improve the energy-efficiency of oil and gas production. To this end, a new action plan was concluded in 2012 to reinforce measures aimed at reducing energy consumption on the North Sea installations in the period 2012-2014. The new action plan is based on the valuable experience gained from the previous action plan for 2006-2011, which successfully reduced energy consumption by 18 per cent. An additional drop in energy consumption is anticipated as a result of the new action plan.

As last year, the report on Oil and Gas production in Denmark for 2012 will be published solely at the Danish Energy Agency's website, www.ens.dk, and thus will not be available in print.

Copenhagen, June 2013

Ib Larsen

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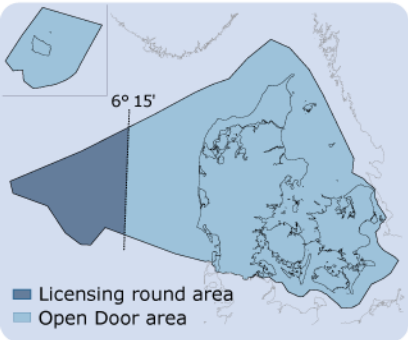
1 LICENCES AND EXPLORATION

Fig. 1.1 The Danish licence area



This year marks the 50th anniversary of the first licence for oil and gas exploration in the North Sea, and new discoveries are still being made. The first exploration well in the North Sea was drilled in 1966. To date, a total of 132 exploration wells have been drilled in the western part of the North Sea, almost half of which have led to the discovery of oil or gas. About half the discoveries made have proved to be commercial, a fact that makes prospects for the upcoming 7th Licensing Round bright.

7TH LICENSING ROUND

In Denmark, the area west of 6° 15’ eastern longitude is generally offered for licensing in licensing rounds (see figure 1.1 and box 1.1), while the rest of the Danish licensing area is offered for licensing according to the Open Door procedure (see figure 1.1 and box 1.2). The most recent licensing round, the 6th Round, was held in 2005-2006. Since then, there has been a high degree of exploration activity under the 14 licences issued in the Round. Some of the 6th Round licences have been relinquished, while discoveries are being evaluated or additional exploration activities being carried out in the remaining licence areas.

Box 1.1

Facts about the upcoming licensing round in the North Sea

The area in the Danish sector of the North Sea west of 6° 15’ eastern longitude is offered for licensing after a public invitation of applications in a so-called licensing round. Following submission to the Climate, Energy and Building Committee of the Danish Parliament, the terms and conditions of the licensing round are published in the Official Journal of the European Union and the Danish Official Gazette at least 90 days before the deadline for submitting applications. The letter inviting applications and information about terms and conditions and unlicensed areas, etc. can subsequently be found at the DEA's website, www.ens.dk.

In pursuance of section 5 of the Danish Subsoil Act, the Minister for Climate, Energy and Building issues the licences. Emphasis is placed on the following:

- that the applicants have the necessary expertise and financial resources;
- that society gains maximum insight into and benefit from the activities under the licence;
- and the exploration activities that the applicants offer to carry out.

Moreover, the Minister may set up other relevant, objective and non-discriminatory selection criteria.

Before granting a licence, the Minister must submit the matter to the Climate, Energy and Building Committee of the Danish Parliament.

Exploration licences are granted for a term of up to six years. The individual licences include a work programme describing the exploration work that the licensee is obliged to carry out.

The most recent licensing round in Denmark, the 6th Round, was held in 2006. The 7th Danish licensing round is to be held in 2013.

In cooperation with the Geological Survey of Denmark and Greenland (GEUS) and the Danish North Sea Fund, the DEA has launched a website, www.oilgasin.dk, where all information about the 7th Round will be posted as soon as it becomes available.

The DEA is preparing the invitation of applications for the licensing round area and expects the 7th Danish Licensing Round to be officially opened at the end of 2013. After submitting the matter to the Climate, Energy and Building Committee of the Danish Parliament, the Minister for Climate, Energy and Building will announce the timing and terms and conditions for the 7th Round, which will also be published in the Official Journal of the European Union and the Danish Official Gazette.

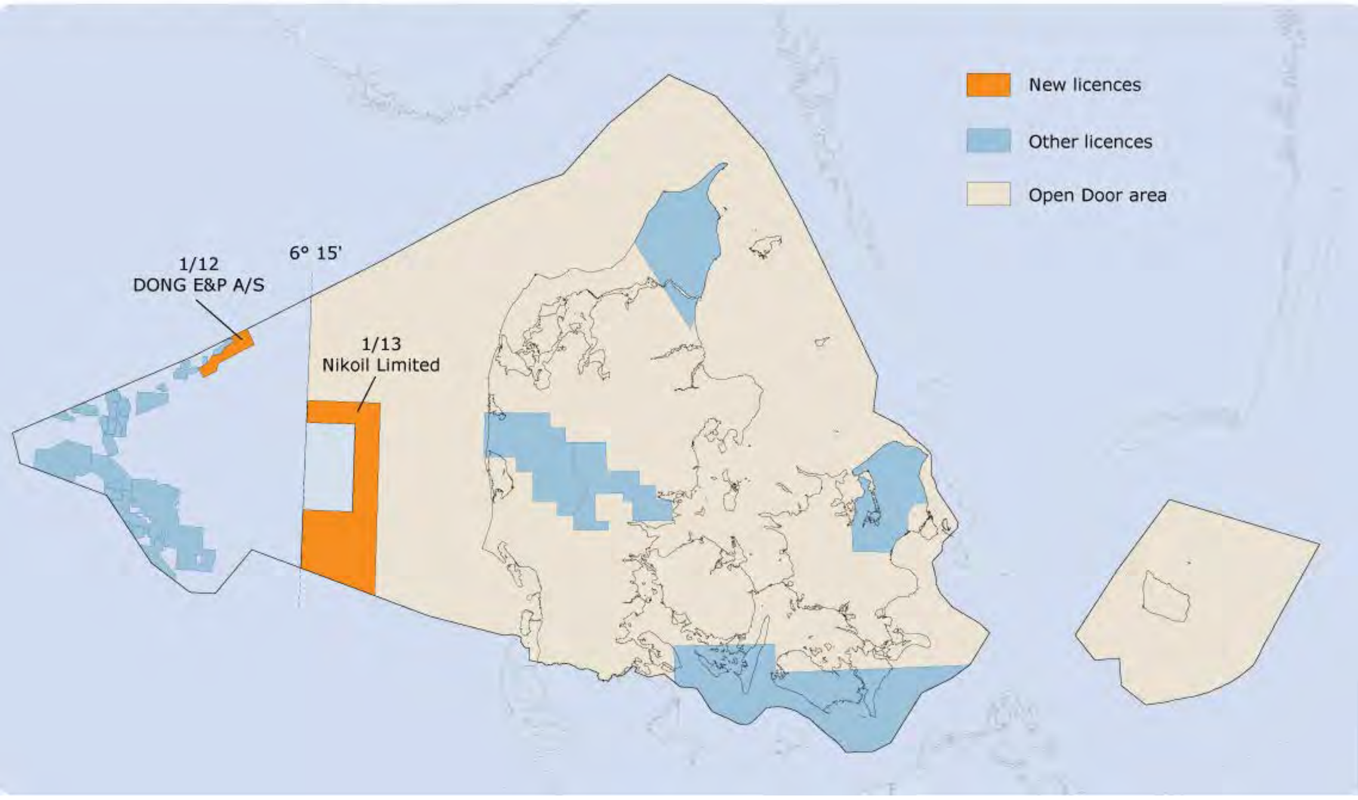
As part of the preparations for a new licensing round, a strategic environmental assessment (SEA) will be performed of the licensing round area. The results of this SEA will be taken into account when drafting the terms and conditions for the 7th Round.

There are still many interesting exploration prospects in the Danish sector of the North Sea. Although the licensing round area must be considered mature, various exploration targets that have not been intensively explored still remain. In recent years, increased focus has been placed on sandstone of Late and Middle Jurassic age, and the Geological Survey of Denmark and Greenland (GEUS) has launched a major project to shed light on Jurassic exploration potential. However, younger parts of these strata may also contain interesting prospects. Several oil companies are currently evaluating discoveries in strata just above the chalk of Paleogene age and in even younger strata of Neogene age; see appendix F.

NEW LICENCES

On 23 November 2012, the Minister for Climate, Energy and Building granted a licence for hydrocarbon exploration and production to DONG E&P A/S and to the Danish North Sea Fund, which hold an 80 per cent and a 20 per cent share, respectively. This licence, numbered 1/12, covers an area in the vicinity of the Siri and Nini Fields in the North Sea; see figure 1.2. The Danish North Sea Fund manages the state's 20 per cent share of all new licences.

Fig. 1.2 New licences in 2012 and early 2013



Box 1.2

Open Door procedure

In 1997 an Open Door procedure was introduced for all unlicensed areas east of 6° 15' eastern longitude, i.e. the entire Danish onshore and offshore areas with the exception of the westernmost part of the North Sea. The Open Door area is shown in figure 1.1 and appendix H1. In the westernmost part of the North Sea, applications are invited in licensing rounds.

Oil companies can continually apply for licences in the Open Door area within an annual application period from 2 January through 30 September, based on the first-come, first-served policy.

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.

In June 2012 the Minister for Energy, Climate and Building suspended the issuance of new licences for exploration and production of hydrocarbons in onshore areas where the target is natural gas in shale layers (shale gas). The suspension has been introduced to investigate the possibilities of promoting safe and environmentally sound production of shale gas.

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

The Minister for Climate, Energy and Building issues the licences after submitting the matter to the Climate, Energy and Building Committee of the Danish Parliament.

The licence was awarded after the holding of a mini licensing round. This procedure is mandatory when it is decided to process an uninvited application for an exclusive licence to explore for and produce hydrocarbons. The procedure is intended to give oil companies other than the applicant a similar opportunity to submit an application for the area.

The decision to process the application was made in light of the relatively short expected useful life of the infrastructure in the area, so as to ensure that any new discoveries that depend on the existing infrastructure can be exploited.

On 17 April 2013, the Minister for Climate, Energy and Building granted a licence for hydrocarbon exploration and production to Nikoil Ltd. (an 80 per cent share) and to the Danish North Sea Fund (a 20 per cent share). This licence, numbered 1/13, was granted under the Open Door procedure and covers an area due east of the licensing round area in the North Sea; see figure 1.2 and box 1.2.

STATE PARTICIPATION IN DUC FROM JULY 2012

With effect from 9 July 2012, the Danish North Sea Fund joined DUC (Dansk Undergrunds Consortium) with a 20 per cent share. Thus, the Danish North Sea Fund has taken over a substantial share of production activity in the North Sea and has become a co-owner of the relevant platforms, processing facilities and pipelines. State participation was one of the main requirements set out in the North Sea Agreement of 2003 regarding the extension of the Sole Concession until 2042.

A.P. Møller – Mærsk A/S and Mærsk Olie og Gas A/S are the Concessionaires according to the Sole Concession, and Mærsk Olie og Gas A/S is the operator of the Concession. Through the DUC partnership with Shell and Chevron, Mærsk Olie og Gas A/S has carried out oil and gas exploration and production in the concession area for a number of years. Through the Danish North Sea Fund, the Danish state has now taken over a 20 per cent share of this partnership. Shell Olie og

Fig. 1.3 Division of licences 4/06 and 8/06 into sub-areas

Gasudvinding Danmark B.V., Holland, Danish Branch, holds a 36.8 per cent share, A.P. Møller - Mærsk A/S and Mærsk Olie og Gas A/S hold a 31.2 per cent share, and Chevron Denmark, Branch of Chevron Denmark Inc., USA, hold a 12.0 per cent share.

AMENDED LICENCES

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

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

Appendix G contains information about the licences applicable at 1 May 2013. The licence maps in appendices H1 and H2 show the locations of the licence areas.

Transferred licences

With effect from 22 May 2012, PA Resources Denmark ApS withdrew from licence 9/95. The company's 26.8 per cent share was taken over proportionately by the remaining licence holders, A.P. Møller - Mærsk A/S, DONG E&P A/S, Noreco Oil Denmark A/S and Danoil Exploration A/S.

When the term of licence 4/06 was extended beyond 22 May 2012, the licence was divided into two sub-areas; see figure 1.3. Two of the companies – Bayerngas Petroleum Danmark A/S and EWE Vertrieb GmbH – withdrew from the licence for the southwestern sub-area, now designated 4/06, sub-area B. These companies' shares of 30 per cent and 15 per cent, respectively, were taken over by Wintershall Noordzee B.V., which now holds 80 per cent of the licence for the relevant sub-area.

With effect from 22 May 2012, DONG E&P A/S took over the 40 per cent share of licence 7/06 held by Altinex Oil Denmark A/S (Noreco). DONG, which thus has an 80 per cent licence share, took over the operatorship of the licence at the same time.

Under licence 8/06, Chevron Denmark, Branch of Chevron Denmark Inc., USA, took over a 12 per cent share of a small sub-area bordering on the Valdemar Field, which is comprised by the Sole Concession. This transfer became effective on 15 January 2013. The share was transferred by A.P. Møller - Mærsk A/S and Shell Olie- og Gasudvinding Danmark B.V. (Holland), Danish Branch, which reduced their shares of the sub-area correspondingly. Following the transfer, the area is designated 8/06, sub-area B, while the rest of the licence area is designated sub-area A; see figure 1.3.

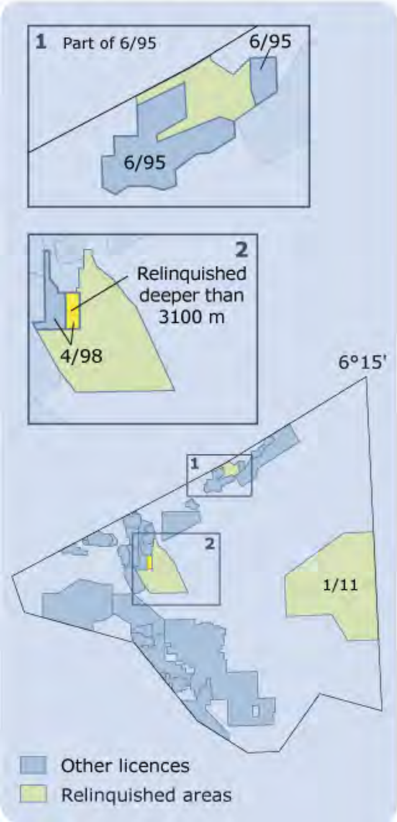
Effective 15 June 2012, New World Resources ApS took over a 12.5 per cent share of licence 1/08 from Danica Resources ApS. New World Resources took over an additional 12.5 per cent share from Danica Resources with effect from 31 January 2013, which means that the company now has a 25 per cent share of the licence. As at 15 June 2012, New World Resources Operations ApS took over the operatorship of the licence from Danica Resources.

Effective 6 May 2012, New World Jutland ApS took over 12.5 per cent shares of licences 1/09 and 2/09 from Danica Jutland ApS. With effect from 15 September 2012, New World Jutland took over an additional 12.5 per cent share of each of the two licences from Danica Jutland, thus increasing its licence shares to 25 per cent. New World Operations ApS took over the operatorship of the licences from Danica Jutland with effect from 1 October 2011.

Extended licence terms

In 2012 and at the beginning of 2013, the DEA extended the terms of the licences shown in table 1.1 for the purpose of exploration. The licence terms were extended

Fig. 1.4 Areas relinquished in the area west of 6°15' eastern longitude



on the condition that the licensees undertake to carry out additional exploration in the relevant licence areas.

Table 1.1: Licences extended for the purpose of further exploration

Licence	Operator	Expiry
4/98 (top 3,100 m)	DONG E&P A/S	29-06-2013
9/95	Mærsk Olie og Gas A/S	22-05-2014
7/06	DONG E&P A/S	22-05-2014
9/06	Mærsk Olie og Gas A/S	22-05-2014
1/05	PGNiG	05-10-2012
12/06	PA Resources UK Ltd.	22-05-2014
5/06	Wintershall Noordzee B.V.	22-08-2013
4/06 (sub-area A)	Wintershall Noordzee B.V.	22-11-2013
4/06 (sub-area B)	Wintershall Noordzee B.V.	22-01-2015

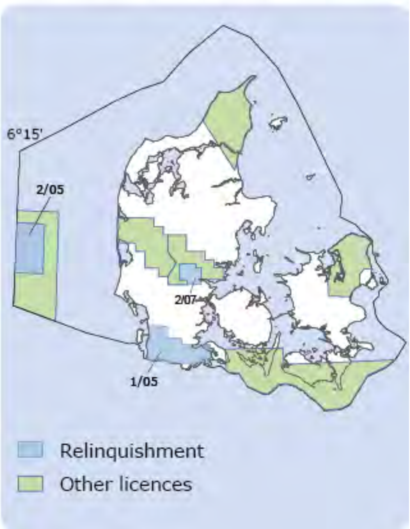
Terminated licences and area relinquishment

Parts of licence 6/95 (Siri) were relinquished on 15 November 2012. Following this relinquishment, the licence only comprises the field delineation of the Siri accumulations as well as areas with accumulations that are being appraised; see figure 1.4.

The licensee holding licence 4/98 relinquished the greater part of the licence area as at 1 January 2013. The relinquished area contains the Svane structure in which the Svane-1 well in 2002 encountered gas under high pressure in Upper Jurassic sandstone at a depth of almost 6 kilometres. The licensee has kept the northwestern part of the 4/98 licence area, which is assessed to contain part of the Solsort oil accumulation. As appears from figure 1.4, the licence no longer covers the area below a depth of 3,100 metres.

Licences 2/05 and 1/11 were both relinquished on 27 January 2013; see figures 1.4 and 1.5. The two licences, granted according to the Open Door procedure and the licensing round procedure, covered neighbouring areas in the central part of the Danish North Sea. Noreco Oil Denmark A/S was the operator of the licences, and both licences were held by the companies Noreco Oil Denmark A/S (47 per cent), Elko Energy A/S (33 per cent) and the Danish North Sea Fund (20 per cent). The companies cooperated in drilling the Luna-1 exploration well under licence 1/11 at the beginning of 2012; see the section on exploration wells below.

Fig. 1.5 Areas relinquished in the Open Door area in 2012



Licence 2/07 was relinquished on 24 February 2012. The licence covered an onshore area in the Open Door area in mid-Jutland. The licence was held by GMT Exploration Company Denmark ApS (37.5 per cent), JOG Corporation (27.5 per cent), Armstrong Dansk, LLC (5 per cent), Dunray, LLC (5 per cent), Jimtown Ranch Corporation (5 per cent) and the Danish North Sea Fund (20 per cent). Under this licence, the exploration well Løve-1 was drilled in 2011 without encountering hydrocarbons.

Licence 1/05 expired on 5 October 2012. Polskie Górnictwo Naftowe i Gazownictwo SA (PGNiG) was the operator of the licence, which covered a large area in South Jutland. The licence was held by PGNiG (80 per cent) and the Danish North Sea Fund (20 per cent). Under this licence, 2D and 3D seismic surveys were carried out in 2009, and at the end of 2011/beginning of 2012, the Feldsted-1 exploration well was drilled without encountering hydrocarbons.

EXPLORATORY SURVEYS

In 2012 the DEA extended the confidentiality period from five to ten years for “spec” seismic data acquired under licences for preliminary investigations pursuant to section 3 of the Subsoil Act. The change only applies to new licences for prelimi-

Fig. 1.6 Seismic data acquired during the period 2002-2012

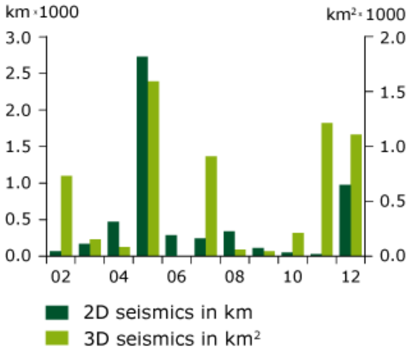


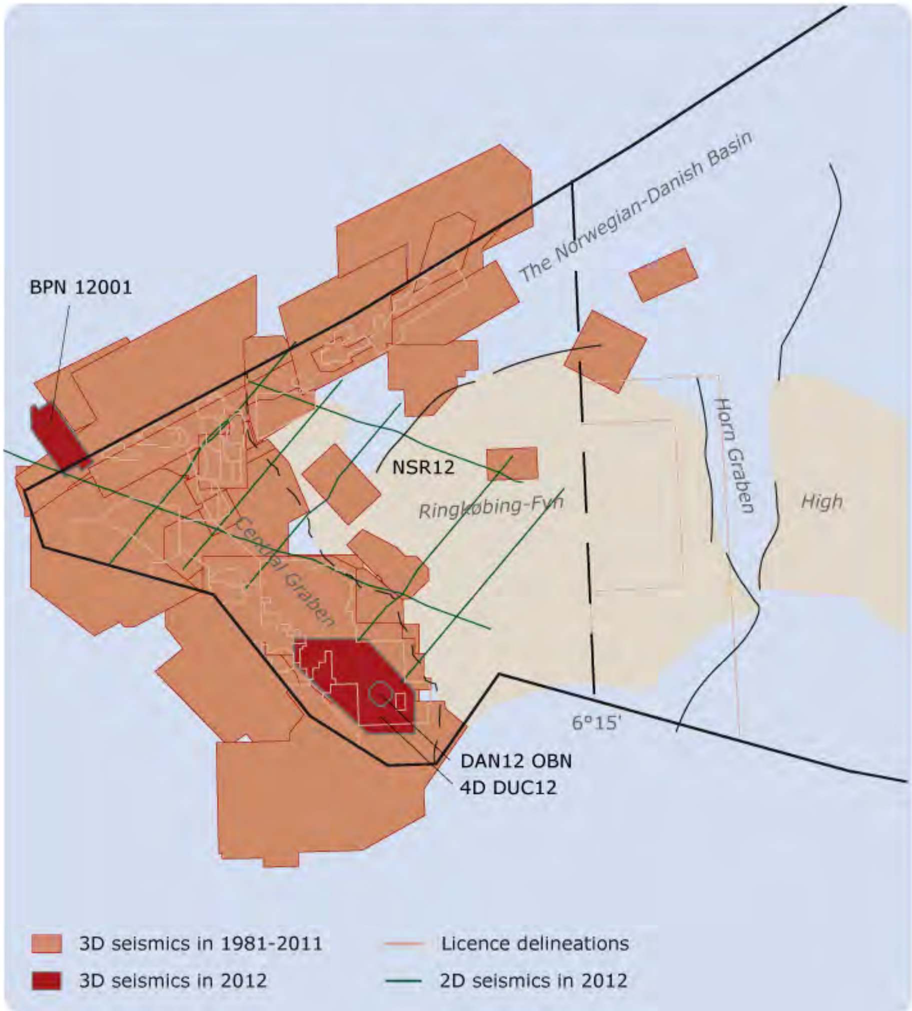
Fig. 1.8 Onshore geophysical surveys in 2012

nary investigations that are carried out by specialist firms with a view to reselling the seismic data to oil companies. Following the change, the conditions now correspond to those currently used by a number of other North Sea countries.

The level of activity for seismic surveys in 2002-2012 is shown in figure 1.6. Figure 1.7 shows the location of the exploratory surveys in the North Sea, while figure 1.8 shows the location in the Open Door area. The DEA's website, www.ens.dk, contains an overview with supplementary information regarding the exploratory surveys mentioned below.

In August-September 2012 BP Norge AS carried out a 4D seismic survey in the Norwegian Hod Field. The survey extended into Danish territory to a limited extent.

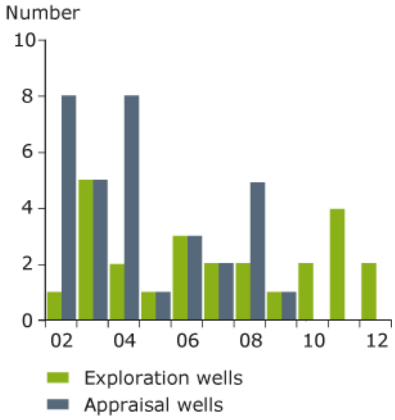
Fig. 1.7 Geophysical surveys west of 6°15' eastern longitude



During the period May-August, Mærsk Olie og Gas A/S conducted a 4D seismic survey of the oil fields in the southern part of the Contiguous Area under the Sole Concession. From October to December 2012 a so-called "Ocean Bottom Node" 3D seismic survey was also carried out in the Dan Field. With this type of survey, hydrophones are placed on the seabed. This makes it possible to record both S- and P-waves from the reflected seismic signals, providing a better basis on which to assess the lithological properties and fluid content of the chalk reservoir.

In April 2012 TGS-Nopec Geophysical Company ASA conducted a regional 2D seismic survey in the North Sea. Data was acquired from the Central Graben and east of the graben.

Fig 1.9 Exploration and appraisal wells drilled from 2002-2012



Through its Danish subsidiaries, New World Resources Operations ApS and New World Operations ApS, the oil company New World Oil and Gas has carried out 2D seismic surveys onshore. In March-April 2012 and again in July-August 2012, surveys were carried out in mid-Jutland under licences 1/09 and 2/09. In August-September 2012, the surveys were continued on the islands of Lolland-Falster, Langeland and Ærø. From December 2012 to January 2013, the surveys in mid-Jutland were followed up by a more detailed 3D seismic survey north of Grindsted.

In partnership with Dansk Fjernvarmes Geotermiselskab, Hjørring Varmeforsyning carried out a 2D seismic survey east of Hjørring in connection with identifying the opportunities for producing geothermal energy. The survey was carried out in August-September 2012.

In addition to the above-mentioned geophysical surveys, a geochemical survey was conducted in 2012. The survey was carried out in June-July 2012 by DONG E&P A/S. In connection with this survey, a total of 132 seabed samples were collected from the Solsort and Siri accumulations in the North Sea.

WELLS

In 2012 two exploration wells were drilled in the Central Graben, Luna-1 and Hibonite-1; see figure 1.10. The level of activity for exploration drilling from 2002-2012 is shown in figure 1.9. Here the wells are placed in the year in which drilling of the well commenced.

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

Exploration wells

Luna-1

As operator for licence 1/11, Altinex Oil Denmark A/S (Noreco) drilled the Luna-1 exploration well in February-March 2012. The well, which was drilled in a joint venture with licence 2/05 to the east, did not encounter any hydrocarbons.

Luna-1 was drilled in a Rotliegendes prospect on the Ringkøbing-Fyn High in the western part of the North Sea, around 60 km from the Central Graben.

Luna-1 was drilled as a vertical well and terminated in volcanic conglomerates presumed to be of Rotliegendes age at a depth of 2,073 metres below mean sea level.

A core was taken, sidewall cores drilled and extensive measurements performed.

In addition to Noreco, the oil company Elko Ltd. and the Danish North Sea Fund were involved in drilling the well. Based on the results, the licence holders decided in January 2013 to relinquish the two licences. The licence holders decided at the same time that the well data could be released.

Hibonite-1

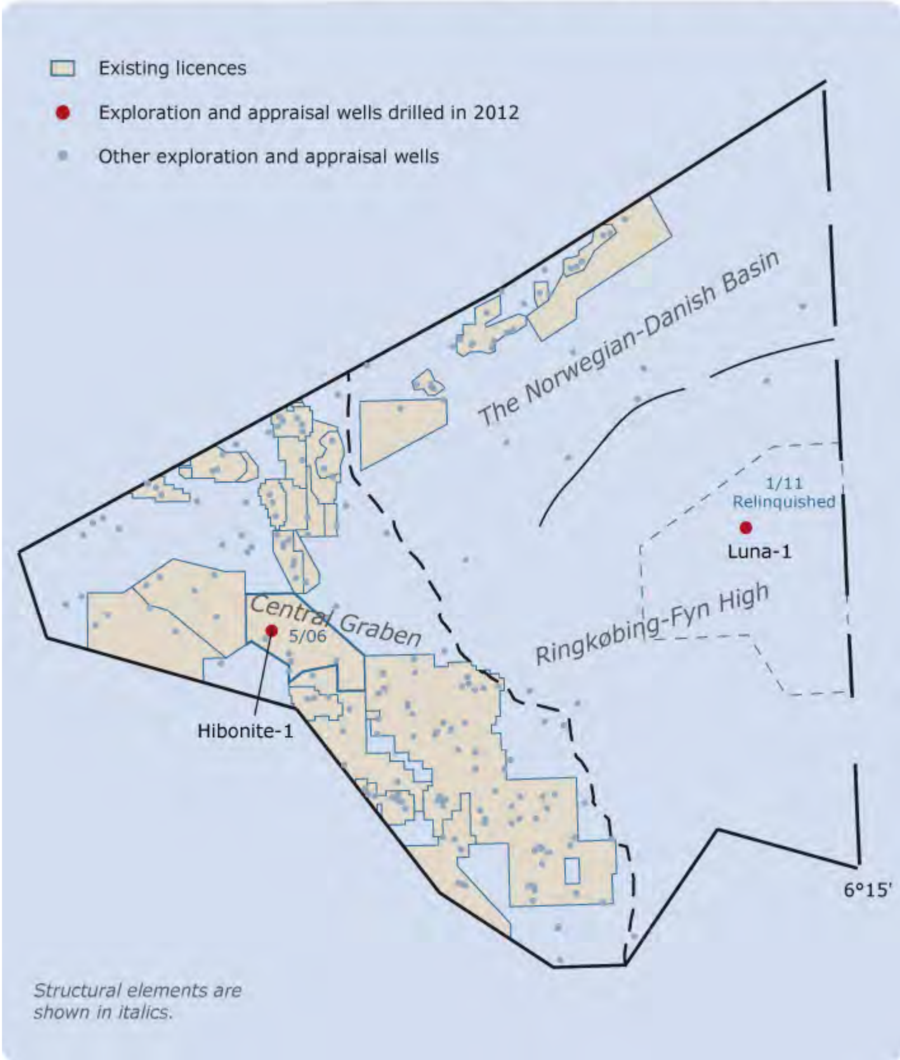
From September 2012 to April 2013, Wintershall Noordzee B.V., which is the operator for licence 5/06, drilled the exploration well Hibonite-1 (5504/1-3) in the western part of the North Sea. The well discovered oil in Upper Jurassic sandstone.

Hibonite-1 was drilled as a deviated well and terminated in clay of Jurassic age at a vertical depth of 4,431 metres below mean sea level. Cores were taken and a logging programme was carried out. Oil and gas were produced during a test production period.

In order to assess the extent of the oil discovery, two sidetracks were drilled, Hibonite-1A and Hibonite-1B. Both sidetracks confirmed the presence of oil-bearing sandstone of Late Jurassic age.

The oil companies holding the licence will now evaluate the results in more detail and then draw up a plan for the additional work required to determine whether the oil discovery can be exploited commercially. In addition to Wintershall, the oil companies Bayerngas and EWE, as well as the Danish North Sea Fund, took part in drilling the well.

Fig. 1.10 Exploration and appraisal wells drilled in 2012 west of 6°15' eastern longitude



2 OTHER USE OF THE SUBSOIL

This chapter describes use of the subsoil for purposes other than oil and gas production. In Denmark the subsoil is also used to produce salt, explore for and produce geothermal heat and store natural gas. All these activities are regulated by the Act on the Use of the Danish Subsoil, usually referred to as the Subsoil Act.

GEOTHERMAL HEAT PRODUCTION

Geothermal heat is recovered from the hot salt water that is present in porous and permeable sandstone layers in the subsoil. Geothermal heat can be found in large parts of Denmark and can be utilized for the production of district heating.

There are currently three plants producing geothermal heat for district heating purposes. The Thisted plant has been producing heat since 1984, and a plant at Amager since 2005. A new plant was under establishment at Sønderborg in 2012, and heat production from the plant was initiated in February 2013.

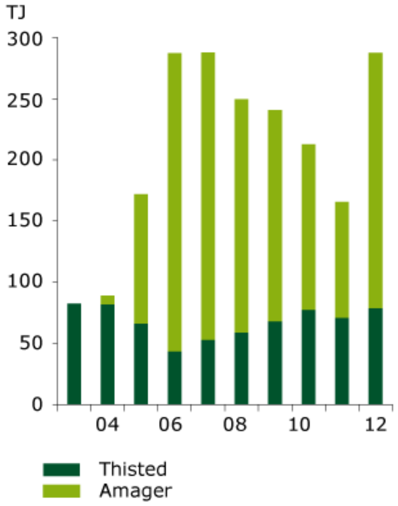
Figure 2.1 shows the production of geothermal energy during the past ten years. In total, 288 TJ of geothermal energy was produced for district heating purposes during 2012, which corresponds to the heat consumption of about 4,400 households. This is an increase of about 74 per cent on 2011 and is due to the Amager plant operating more reliably throughout 2012 compared to the year before.

Environmental assessment

On 17 August 2012, the DEA submitted a draft plan to invite applications for licences to explore for and produce geothermal energy, including an environmental assessment, for public consultation. The consultation process was initiated on the basis of the applicable provisions in the Act on Environmental Assessment of Plans and Programmes, see Consolidated Act No. 936 of 24 September 2009, and was completed on 12 October 2012. On the basis of the consultation responses received, the DEA decided to implement the plan to offer areas for exploration and production of geothermal energy.

The final version of the plan, complete with the environmental report and summary statement, was published on the DEA's website on 14 January 2013. According to this plan, applications may be submitted for new licences to explore for and produce geothermal energy. The more detailed terms and conditions are available at the DEA's website. Applications for new licences can be submitted twice a year, the deadlines being 1 February and 1 September.

Fig. 2.1 Production of geothermal energy, 2003-2012



New licences and applications

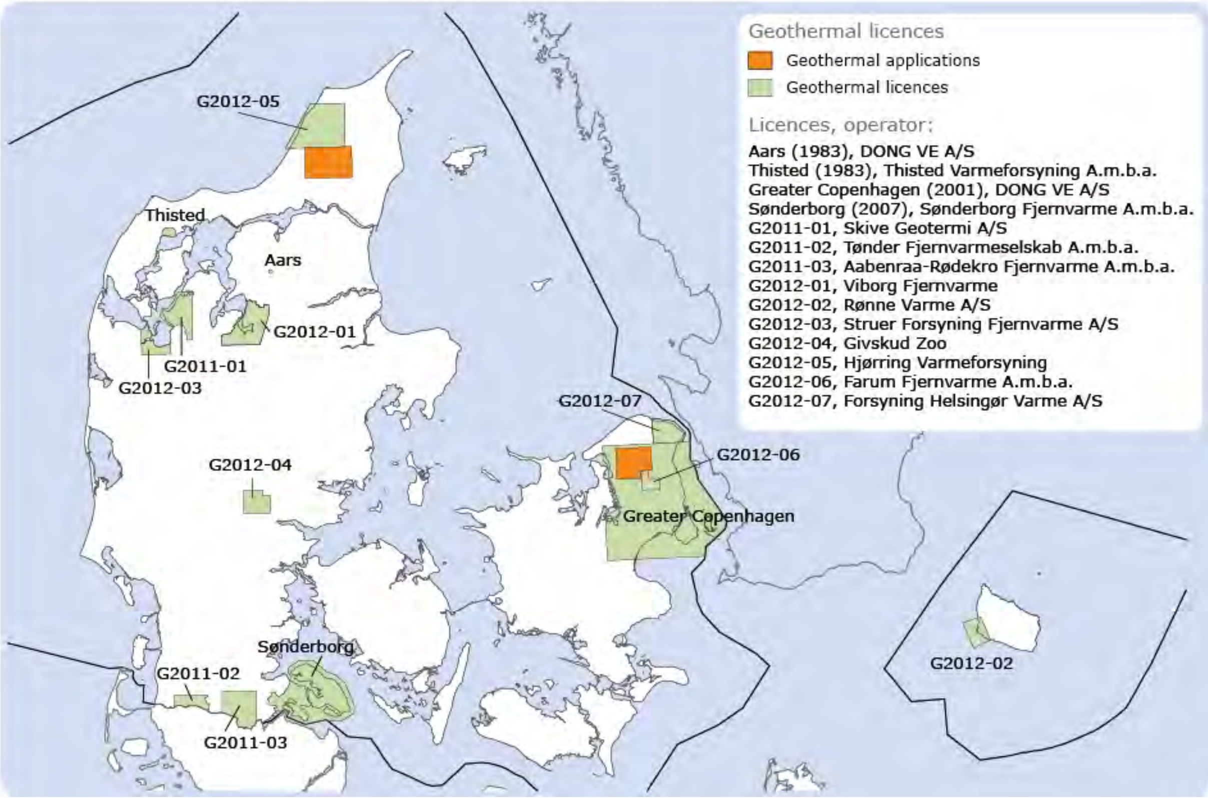
Seven new licences to explore for and produce geothermal energy were issued in 2012, covering areas near Viborg, Rønne, Struer, Givskud, Hjørring, Farum and Elsinore.

Moreover, two new applications for licences to explore for and produce geothermal energy near Brønderslev and Hillerød were received in February 2013.

The areas covered by the new licences issued in 2012 and by the applications received in February 2013 are shown in figure 2.2.

Hjørring Varmeforsyning carried out a seismic survey in August-September 2012 to identify the possibilities of producing geothermal energy. Vibroseismic equipment was used to acquire about 57 km of 2D seismic lines. The location of these lines is shown in figure 1.8.

Fig. 2.2 Geothermal licences and applications at the beginning of 2013



Kvols-2 exploration well near Viborg

The Kvols-2 exploration well was drilled near Viborg during the period from February to June 2012. The well was drilled to investigate whether there are any sandstone layers suitable for geothermal energy production. Kvols-2 was drilled as a deviated well and terminated at a depth of 2,763 metres below ground level, corresponding to a vertical depth of about 2,481 metres below ground level. The well did not penetrate the expected sandstone layers and was sealed with cement in a way that will allow drilling to be resumed in Kvols-2 at a possible future date. The top hole section of the planned Kvols-3 well was drilled in February 2012 to a depth of 241 metres below ground level. Due to the problems encountered when drilling Kvols-2, drilling in Kvols-3 was terminated. The geothermal heat production project in the vicinity of Viborg was postponed because of the problems connected with drilling the Kvols-2 well, and the companies behind the licence are currently evaluating the project.

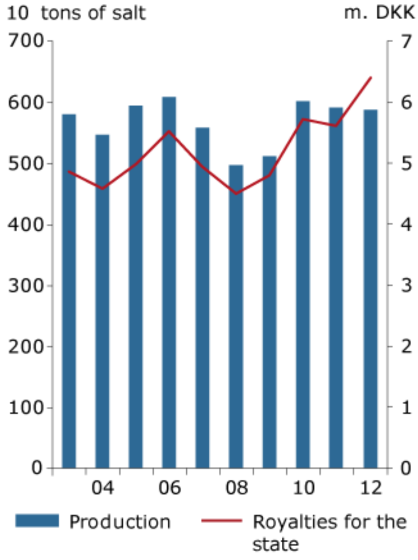
Government support to promote geothermal energy production

When the energy policy agreement was concluded on 22 March 2012, a special fund totalling DKK 35 million for the years 2012-2015 was set up to promote renewable energy (RE) technology in district heating (geothermal energy, large-scale heat pumps, etc.).

A meeting about geothermal energy was held with a number of interested parties on 11 September 2012. At the meeting, experience from ongoing geothermal energy projects was exchanged, and the participants shared ideas for using the means from the RE fund to improve the options for geothermal heat production. A range of possible new initiatives has been described based on the outcome of this meeting.

The plan is to launch a number of initiatives to analyze the options for managing risks, screening for geothermal potential in various towns and cities, adapting district heating systems to the use of geothermal energy, developing a scenario for geothermal energy and establishing a web-based GIS platform to provide access to

Fig. 2.3 Salt production and state revenue from royalties, 2003-2012



data about the subsoil. Initially, the GIS platform is expected to be established by the Geological Survey of Denmark and Greenland (GEUS) in the course of 2013. Offers for the remaining initiatives are expected to be invited in 2013.

GAS STORAGE

There are currently two gas storage facilities in Denmark. One facility is located at Stenlille on Zealand and is owned by DONG Storage A/S, while the other is situated at Lille Torup in northern Jutland and is owned by Energinet.dk Gaslager A/S.

More information about the Stenlille and Lille Torup gas storage facilities is available in the DEA's report "Denmark's Oil and Gas Production – and Subsoil Use, 2009".

SALT EXTRACTION

In Denmark, salt is extracted at one location only, at Hvornum about 8 km southwest of Hobro, where the company Akzo Nobel Salt A/S produces salt from a salt diapir. The company has an exclusive licence for the production of salt from the Danish subsoil. The salt is used for consumption and for use as industrial salt and road salt.

The production of salt totals about 500,000 to 600,000 tons per year, and the Danish state receives about DKK 5 million a year in royalties. Figure 2.3 shows the past ten years' production of salt and the Danish state's revenue in the form of royalties.

3 PRODUCTION AND DEVELOPMENT

2012 saw the 40th anniversary of the start of oil and gas production in Denmark. The first producing field was the Dan Field, which came on stream on 4 July 1972 and continues to produce oil and gas.

After 40 years of production, Denmark can be considered a mature region, with a strong focus on production optimization and the maintenance of existing wells as regards all installations in the North Sea. At the same time, efforts are being made to implement many of the previously approved development plans, and the DEA approved a new plan for the further development of an existing field in 2012. A de-

Fig. 3.1 Location of production facilities in the Danish North Sea 2012

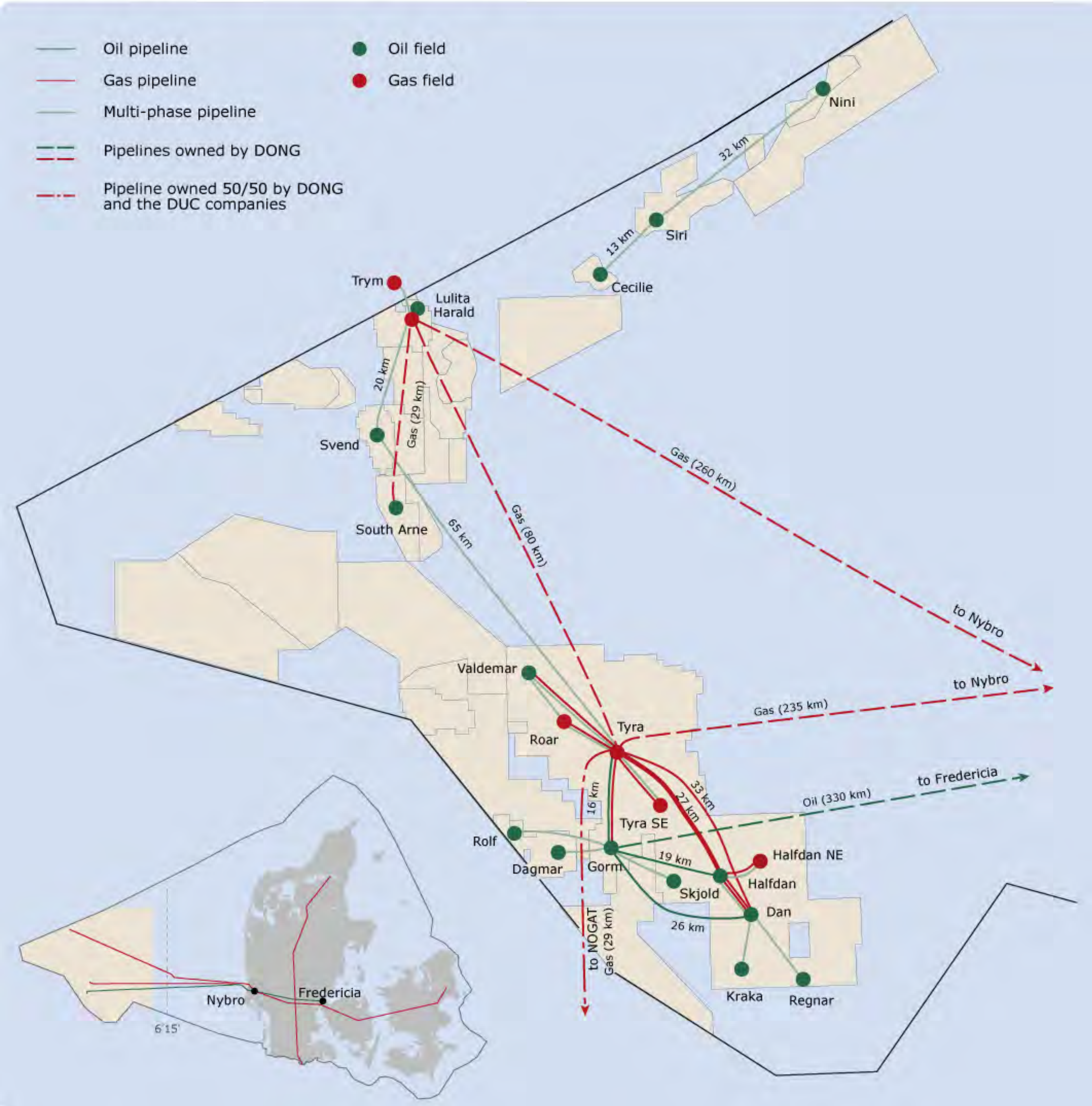
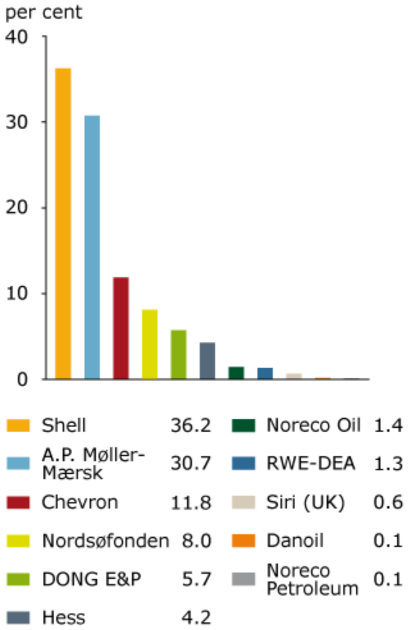


Fig. 3.2 Breakdown of oil production by company



scription of all producing fields can be found in appendix B, *Producing fields*. The overview contains information about development and investment activities, historical production and remaining reserves. There is also a brief description for each field of the geological conditions, production strategy and the installations, in addition to a field map showing the existing development and injection wells.

PRODUCTION IN 2012

All producing fields in Denmark are located in the North Sea and appear from figure 3.1, which also shows the key pipelines. In total there are 19 producing fields of varying size, and three operators are responsible for production from these fields: DONG E&P A/S, Hess Denmark ApS and Mærsk Olie og Gas A/S.

A total of 11 companies participate in production from Danish fields. Figure 3.2 shows the individual companies' shares of oil production. On 9 July 2012 the state-owned company "Nordsøfonden" (the Danish North Sea Fund) joined Dansk Undergrunds Consortium (DUC) as a partner with a 20 per cent interest. The interests of the three other DUC partners were reduced correspondingly, which means that Shell now has an interest of 37 per cent, A.P. Møller Mærsk an interest of 31 per cent, and Chevron an interest of 12 per cent. DUC is the largest oil producer and gas exporter, accounting for 87 per cent of oil production and 97 per cent of gas exports.

In 2012 production in the Danish part of the North Sea derived from a total of 278 active production wells, of which 199 were oil wells and 79 were gas wells. In addition, 106 active water-injection wells and three gas-injection wells contributed to production.

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.

Production figures for each year are available at the DEA's website, www.ens.dk. These statistics date back to 1972, when production started in Denmark.

Oil production

Oil production in 2012 totalled 11.7 million m^3, an 8.6 per cent decline compared to 2011. Production from the Danish sector of the North Sea is therefore continuing to decline as expected, and production has now halved since 2004. The main reason for this trend is that the majority of fields have already produced the bulk of the anticipated recoverable oil. In addition, these ageing fields require more maintenance as regards wells, pipelines and platforms. This maintenance work often causes a loss or delay in production, as the wells and possibly even the entire platform must be shut down while the work is carried out. The development in oil and gas production during the past 25 years appears from figure 3.3.

The development of existing and new fields may help to counter the declining production. In addition, the implementation of both known and new technology may help to optimize production from existing fields.

Gas production

The production of natural gas totalled 5.6 billion Nm^3 in 2012, of which 4.9 billion Nm^3 of gas was exported ashore as sales gas, a 13.7 per cent decline compared to 2011.

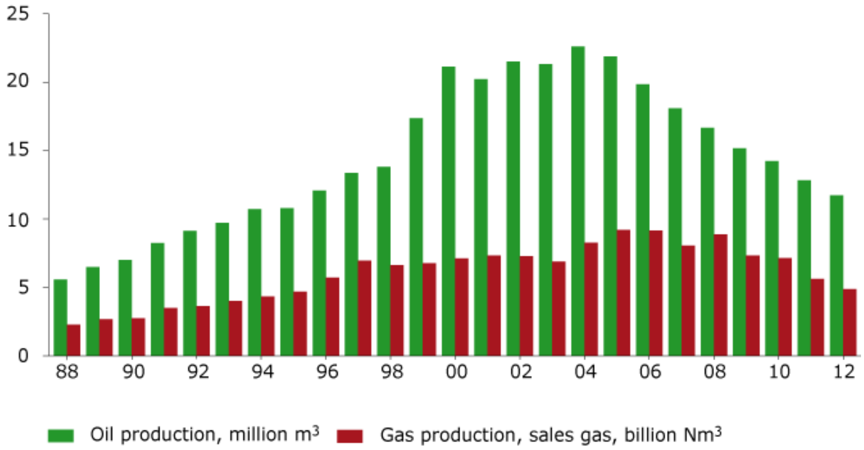
The remainder of the gas produced was mainly used as fuel on the platforms. A small volume of unutilized gas is flared for technical and safety reasons. In the Siri Field the surplus gas is reinjected as it cannot be exported. The volumes of gas consumed as fuel and flared are described in chapter 5, *Climate and environment*. Appendix A gives an outline of historical developments since 1972.

Water production and water injection

Water is produced as a by-product in connection with the production of oil and gas. The water can originate from natural water zones in the subsoil and from the water injection that is carried out in order to enhance oil production. The content of water relative to the total liquids produced in the Danish part of the North Sea is increasing and reached 74.5 per cent in 2012. A high amount of energy is required to handle these large volumes of produced water, as high as about 90 per cent for some of the old fields. In 2012 water production totalled 34.4 million Nm^3, a decline of about 3.5 per cent compared to 2011. Water injection in 2012 dropped by 11 per cent relative to 2011.

Since 2008 water production declined mainly due to falling oil and gas production. The water content of total liquid production is increasing for most fields, see above, and the operators are therefore attempting to reverse this trend, for one thing by closing off production from zones with high water production.

Fig. 3.3 Production of oil and sales gas 1988-2012



DEVELOPMENT ACTIVITY IN 2012

A new production well in the Tyra Field, TWC -19, was drilled and completed in 2012, in addition to a new water-injection well in the Halfdan Field, HBB-2; however, this well will initially serve as a production well.

Six old wells in the Dan and Gorm Fields were closed, of which four of the wells in the Gorm Field are expected to be reused for new wells. Repairs or maintenance work requiring the use of a drilling rig was carried out on 16 wells in the Dan, Gorm, Tyra and Halfdan Fields. Maintenance was also carried out on a number of other wells using other equipment.

Overall, the number of completely new wells drilled in 2012 was lower than in 2011. On the other hand, there has been a focus on optimization and maintenance of old wells. The rate of development was affected by the fact that three of the drilling rigs operating in the Danish sector of the North Sea were at shipyards for two to three months each for upgrading during the course of the year.

The wells drilled and additional development activities represented total investments of DKK 5.7 billion, an increase of about 10 per cent compared to 2011.

Approved development plans and ongoing activities

The Dan Field

Work has been carried out in the Dan Field to drill a new production well, MFF-35; however, this work was not completed as expected. The drilling has been temporarily suspended just above the reservoir due to technical problems. The well forms part of a development plan approved in 2011, and represents a redrill of the previously closed MD-1B well. The MD-3 well was closed in 2012.

The field is undergoing a programme of maintenance and repair or closure of existing wells and installations.

The Gorm Field

Five wells have been closed in the Gorm Field as part of a development plan approved in 2011, and it is planned that four of these wells will be reused for new and more productive wells.

The Halfdan Field

A new water-injection well, HBB-2, was drilled in the Halfdan Field in 2012 as part of a development plan approved in 2008. Work on another new well began in 2012 and is expected to be completed in 2013.

The Hejre Field

Work is being carried out in the Hejre Field to implement the development plan approved in 2011. The work has consisted of planning and design, and the new installation is expected to be ready in 2015.

The Siri Field

Work is still being carried out on the Siri installation to establish a permanent reinforcement of the subsea structure. The work has encountered challenges along the way and been delayed, but is expected to be completed by the end of 2014. The situation affects production from both the Siri platform and the associated Nini and Cecilie satellite platforms, as the entire installation is shut down for safety reasons during the periods when the expected wave height exceeds six metres.

The South Arne Field

The new platform in the South Arne Field, which was approved in 2010, has been installed, and work is under way on the final completion and hook-up of the platform to the existing platform. Maintenance work has been carried out concurrently on a number of wells.

The Tyra Field

A new oil production well, TWC-19D, has been drilled from the Tyra West platform, which forms part of the development plan approved for Tyra in 2011. The purpose of the well is to explore and exploit the oil accumulation in the southern part of the Tyra Field.

The Tyra Southeast Field

A comprehensive plan for the further development of the Tyra Southeast Field was approved on 20 November 2012. The plan includes the establishment of a new four-leg platform to accommodate 16 wells. The new platform will be connected to the existing TSEA platform by a bridge. The project also includes the establishment of a pipeline from the Tyra East platform to the new platform for the supply of lift gas to both new and old wells. Power supply and control signal cables will be laid parallel to the pipeline.

Based on the 12 production wells planned initially, total production from the field is expected to increase by around 3.3 million m^3 of oil and around 4.6 billion Nm^3 of gas. Production from the new wells is expected to start in spring 2015. Total investments in connection with the development are estimated at DKK 5 billion.

The Valdemar Field

The final works in connection with the VBA-9 well in the Valdemar Field were carried out in 2012. A major maintenance programme for a several older Valdemar wells was approved in December 2012 and is expected to be implemented in 2013.

Remaining fields

There were no major development activities in the Cecilie, Dagmar, Harald, Kraka, Lulita, Nini, Regnar, Roar, Rolf, Skjold and Svend Fields in 2012.

A clarification of the future of the Dagmar Field, which has been closed since 2005 due to poor or non-existent hydrocarbon production, is expected in 2013.

The exploration and appraisal wells drilled in 2012 are described in more detail in chapter 1, *Licences and exploration*. Information about approved development plans and new plans under consideration is also available at the DEA's website, www.ens.dk.

4 HEALTH AND SAFETY

Health and safety on fixed and mobile offshore units in the Danish continental shelf area are regulated by the Danish Offshore Safety Act and regulations issued under the Act. The Offshore Safety Act with associated regulations can be found at the DEA's website www.ens.dk.

The Offshore Safety Act is based on the premise that the companies should set high health and safety requirements and reduce risks as much as reasonably practicable. Moreover, the Offshore Safety Act presupposes that the companies have a health and safety management system enabling them to control their own risks and ensure compliance with statutory rules and regulations.

Together with the Danish Maritime Authority, the DEA supervises the companies' risk control, including compliance with rules and regulations. The DEA also cooperates with other national authorities as well as national and international organizations, including the Offshore Safety Council, the Danish Environmental Protection Agency, the North Sea Offshore Authorities Forum (NSOAF) and the International Regulators' Forum, about continuous improvements to health and safety conditions on the offshore installations.

High health and safety standards are vital to the almost 3,000 people who have their workplace on offshore installations in the Danish continental shelf area.

An EU Directive on the safety of offshore oil and gas operations is expected to be adopted in the summer of 2013. The purpose of the Directive is to prevent major accidents and limit the consequences of such accidents, should they occur. This will heighten the safety level and the protection of the marine environment throughout

Box 4.1

EU Directive on safety of offshore oil and gas operations

In April 2010, an explosion occurred on the Deepwater Horizon mobile drilling rig, which was carrying out drilling operations in BP's Macondo Field. Eleven people died, the drilling rig sank and more than 4.9 million barrels (780,000 m^3) of oil streamed out into the Gulf of Mexico over a period of three months.

In response to the accident, the European Commission initiated an analysis to assess whether a similar accident could occur in EU territorial waters. The European Commission found that the legislative framework for the exploration and exploitation of oil and gas in the EU did not provide the most effective starting point to deal with major accidents in all the EU Member States. It was also not clear where the responsibility for the clean-up and remediation of damage following a major oil spill lay.

On the basis of its analysis, the European Commission put forward a proposal in October 2011 for the regulation of offshore oil and gas operations, which has now resulted in a proposed Directive, which is expected to be adopted in the summer of 2013 and must be implemented into national legislation no later than two years after adoption.

Implementation of the Directive will result in changes to Danish legislation within the area. Concurrently with the implementation of the Directive, existing Directives concerning the working environment, etc. will continue to be implemented as before. In addition, a new aspect of the Directive will be the requirement to establish a so-called "competent authority", which will perform tasks such as supervision in accordance with the Directive. The competent authority will be assigned to a regulatory body that is independent of the regulatory body or bodies responsible for economic development, including the awarding of licences and the collection of taxes, duties and charges.

The Directive is not expected to have a major impact on the legislative requirements imposed on the industry in relation to the requirements of the Offshore Safety Act. Nevertheless, the Directive imposes additional requirements as to when there must be public sector participation in the drilling of exploration wells as compared to existing legislation and requirements regarding the obligatory independent verification to the effect that safety-critical elements are in compliance with safety requirements, etc.

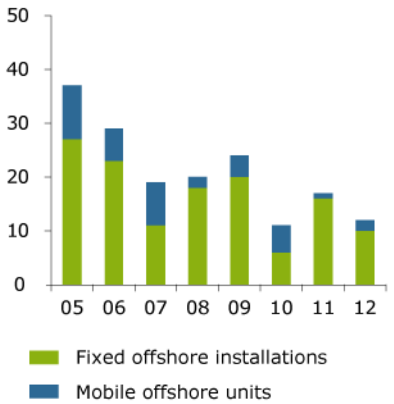
Table 4.1 Reported accidents broken down by cause of accident

Cause of accident	Fixed	Mobile
Falling/tripping	3	0
Use of work equipment	1	0
Falling objects	1	0
Electrical accidents	0	0
Handling goods	2	0
Crane/lifting operations	0	2
Other	3	0
Total	**10**	**2**

Table 4.2 Actual absence due to reported work-related accidents in 2012

Duration	Fixed	Mobile
1-3 days	0	0
4-14 days	2	0
2-5 weeks	3	0
More than 5 weeks	5	1
Undisclosed	0	1
Total	**10**	**2**

Fig. 4.1 Number of work-related accidents on offshore installations, 2005-2012



the EU. The Directive is the European Commission's response to the "Deepwater Horizon" disaster in the Gulf of Mexico in April 2010, as a result of which 11 people died, the drilling rig sank and more than 4.9 million barrels (780,000 m^3) of oil flowed into the sea; see box 4.1.

INSPECTIONS IN 2012

In 2012 the DEA carried out 40 inspections, distributed on 25 offshore inspections and 15 onshore inspections.

The offshore inspections consisted of 21 inspections of fixed installations and four inspections of mobile units, i.e. drilling rigs and accommodation units. Three of these inspections were carried out as unannounced inspections.

The onshore inspections consisted of eight inspections of mobile units at different shipyards, three inspections at pipeline operators and four inspections in connection with the design and construction of new offshore installations.

The DEA strives to heighten the health and safety level in the Danish offshore sector through dialogue and continuous supervision of the companies.

INDUSTRIAL INJURIES

An industrial injury covers two different concepts - work-related accidents and occupational diseases (previously termed work-related diseases). Work-related accidents on offshore installations must be reported to the DEA; see box 4.2. Doctors are required to report occupational diseases to the DEA, the Danish Working Environment Authority and the National Board of Industrial Injuries. However, in the course of 2013 a new Executive Order on the Recording and Notification of Industrial Injuries will be issued, according to which occupational diseases must only be reported to the Danish Working Environment Authority and the National Board of Industrial Injuries; see the section *Occupational diseases* below.

Box 4.2

Reporting work-related accidents

Work-related accidents resulting in incapacity to work for one or more days beyond the injury date must be reported. Employers are obliged to report accidents, but all other parties are entitled to file reports. "An injured person who is unable to fully perform his or her ordinary duties" is considered to be unfit for work.

Work-related accidents

The DEA registers and processes all reported work-related accidents on Danish offshore installations and evaluates the follow-up procedures taken by the companies. At the DEA's first inspection after an accident, the work-related accident is addressed at a meeting with the safety organization on the installation. This procedure applies to all work-related accidents. In case of serious accidents, the DEA carries out an immediate inspection on the relevant installation, possibly in cooperation with the police.

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

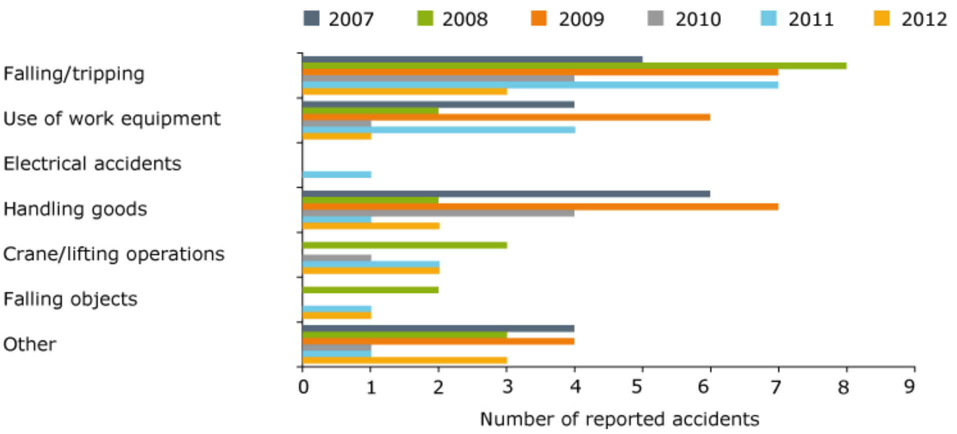
In 2012 the DEA registered 12 reports concerning work-related accidents, ten on fixed offshore installations and mobile accommodation units, while two work-related accidents occurred on other mobile offshore units. The number of accidents on mobile and fixed installations respectively is indicated in figure 4.1 from 2005 to 2012.The accidents are broken down by cause in table 4.1 for 2012 and in figure 4.2.

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

Accident frequency

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

Fig. 4.2 No. of work-related accidents on offshore installations, 2007-2012, shown by cause of accident



The overall accident frequencies for fixed offshore installations and mobile offshore units in recent years are shown in figure 4.3. As appears from the figure, the accident frequency for fixed and mobile units combined was 2.18 in 2012. This is a decrease compared to 2011, when the overall accident frequency came to 3.5.

For mobile offshore units, two work-related accidents were recorded in 2012, and the number of working hours totalled 1.6 million. Thus, the accident frequency for mobile offshore units increased slightly from 0.7 in 2011 to 1.3 in 2012.

The number of work-related accidents on fixed offshore installations and mobile accommodation units, which is calculated on a combined basis, totalled ten in 2012. The operating companies have stated that the number of working hours in 2012 totalled 4 million on these offshore installations. The accident frequency for fixed offshore installations is thus 2.5 for 2012, a decrease on 2011 when the accident frequency came to 4.8.

Box 4.3

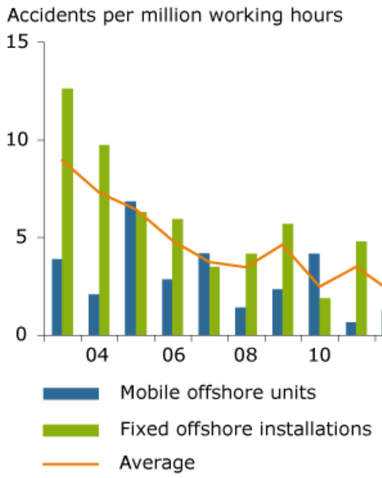
Work-related accident at Tyra East

A group of two people were slackening bolts on a flange. A hydraulic clamping tool weighing around 8 kg was being used for this task. One of the people left the workplace to fetch something. The other person then had to stop working, as the hydraulic hose was too short for him to reach the next bolt. He put down the clamping tool and went over to move the hydraulic pump. About 1.5 m below the workplace, a group of three people were carrying out other work.

While they were discussing the task, the clamping tool fell and landed on the hand of one of them. The injured person received treatment by a medic, who established an open fracture and soft tissue injuries on the person's right index finger.

The accident was subsequently discussed at safety meetings on the installation so as to ensure future focus on how to leave a workplace, even if only for a relatively short period of time. The DEA will follow this up during its next inspection.

Fig. 4.3 Offshore accident frequency



Box 4.4

Work-related accident on the GSF Monarch drilling rig

The GSF Monarch drilling rig had received a transport case from shore containing materials. The materials were to be unloaded and placed in one of the rig's designated containers, so that they could be further transported around the installation. A fork-lift truck was used for the reloading. As the fork-lift truck was about to place a load of 108 kg in the container, there was a misunderstanding between an employee and the fork-lift truck operator. This resulted in the forks of the truck being lowered onto the lid of the container where the employee's hand was placed. The employee's hand then became trapped between the lid of the container and the fork.

The injured person received treatment by a medic and was then sent ashore for further examination. Subsequent examination revealed that the injured person had a broken finger.

During the subsequent inspection, the DEA established that there was limited visibility through the safety grill in front of the fork-lift's windscreen. This highlights the importance of good communication between people who are working together on a job. In future, the participation of experienced employees must be ensured when lifting operations are to be carried out with a fork-lift truck, just as the risk assessment should reflect the actual lifting situation. The procedure for using a fork-lift truck on the rig has been revised to reflect this.

Box 4.5

Work-related accident on the Noble George Sauvageau drilling rig

Two steel girders were being moved by crane from the drill floor to a storage location at the top of the lifting system enclosure on one of the rig's legs. The steel girders were I-type girders and were around 2 m long and weighed about 400 kg each. Towards the end of the lifting operation when the two steel girders were to be lowered down onto the storage location, the injured employee attempted to guide the girders manually instead of using guide lines, at which point his left hand became trapped between the girders. The work was stopped immediately, and the injured person was treated by a medic and subsequently sent ashore for further treatment. The employee's middle finger proved to be so badly injured that it had to be amputated.

The accident was subsequently investigated by the company, which concluded that several of its procedures had been breached during the work. During the investigation, several areas for improvement were established, including training, supervision and communication between people involved in lifting operations.

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

In addition to work-related accidents resulting in absence from work for more than one day, accidents rendering the injured employee incapable to resume his or her full workload are also reported. Incapacity to work is frequently termed "Restricted Work Day Case". In 2012 four work-related accidents resulting in incapacity to work were reported, compared to two accidents in 2011.

Onshore accident frequency

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

A total of 42,567 work-related accidents were reported for onshore companies in 2011. With a workforce of 2,667,424 employees (~ approx. 4.21 billion working hours) in 2011, the accident frequency in 2011 for all onshore industries can be calculated at 10.1 reports per 1 million working hours. The calculation is based on the assumptions described in box 4.6. The Danish Working Environment Authority has not yet calculated the number of work-related accidents and the number of employees for 2012.

In 2009 the Danish Working Environment Authority changed its classification, reducing the number of onshore activity codes from 49 to 36. This means that the figures for individual industries from 2009 and onwards are not comparable to the figures shown by industry for previous years. Therefore, the table only shows the onshore accident frequency for selected industries from 2009. The DEA has calculated the accident frequencies and the total accident frequencies for on- and offshore industries for 2009, 2010 and 2011.

Table 4.3 Accident frequencies in Danish offshore and onshore industries

	Frequency Accidents per million manhours			
Industry	**2009**	**2010**	**2011**	**2012**
Offshore installations *	4.6	2.3	3.5	2.2
Total onshore industries	9.6	10.4	10.1	
Of which:				
- Completion of construction projects	16.0	17.0	18.1	
- Energy and raw materials	7.8	8.7	6.9	
- Installation/repair of machinery and equipment	9.4	9.2	10.6	
- Chemical and medical industries	8.7	8.1	7.1	

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

Box 4.6

Work-related accidents calculated by the Danish Working Environment Authority

The Danish Working Environment Authority calculates the incidence of work-related accidents for onshore industries in Denmark on the basis of the number of accidents reported proportionate to the entire workforce, i.e. the number of employees. The Danish Working Environment Authority uses register-based labour force statistics from Statistics Denmark ("RAS statistics"), which are workforce statistics indicating the number of persons who had their main job in the relevant industries in November of the year preceding the year of calculation. The annual statistics compiled by the Danish Working Environment Authority indicate the incidence per 10,000 employees. For all onshore industries, the incidence was 160 reports per 10,000 employees in 2011.

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

Occupational diseases

An occupational disease (previously termed a “work-related disease”) is defined as an illness or a disease that is due to long-term exposure to work-related factors or the conditions under which the work is performed on the offshore installation.

Until 15 April 2013, doctors were obliged to submit reports of all diagnosed or suspected occupational diseases to the DEA, with copies to the Danish Working Environment Authority and the National Board of Industrial Injuries. In future, occupational diseases must be reported exclusively via the Danish Working Environment Authority’s EASY reporting system. This system incorporates an option to indicate whether the occupational disease is assumed to have been contracted offshore, and the Danish Working Environment Authority then passes on this information to the DEA. The system has been changed because, in practice, doctors only reported suspected occupational diseases to the Danish Working Environment Authority and the National Board of Industrial Injuries. Therefore, the Danish Working Environment Authority and the DEA continuously exchanged information about such reports. Accordingly, the rules have now been changed and simplified.

The Danish Working Environment Authority has now completed its analysis of occupational diseases for 2011 and passed on 18 reports of suspected occupational diseases to the DEA, based on a doctor’s assessment that the relevant occupational disease was primarily contracted due to work on an offshore installation. The diseases reported for 2011 are distributed on four hearing injuries, ten musculoskeletal disorders, one skin disorder and three psychological disorders.

The Danish Working Environment Authority has not yet published data for 2012.

NEAR-MISS OCCURRENCES

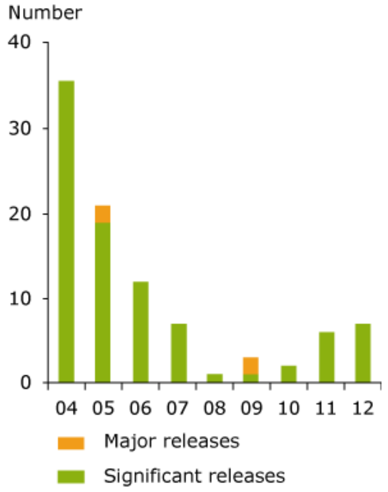
In 2012 the DEA received a total of 21 reports on near-miss occurrences, which is on a par with previous years. By comparison, 20 near-miss occurrences were reported in 2011.

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

HYDROCARBON GAS RELEASES

There were no major hydrocarbon gas releases in 2012, but seven significant releases were reported, with the quantities released ranging from 1 kg to 33 kg. For three of the seven releases, it was stated that the quantity released could not be estimated. Therefore, the DEA has chosen to include these three releases in the “significant releases” category.

Fig. 4.4 Accidental hydrocarbon gas releases, 2004-2012



Since the DEA targeted its focus at accidental hydrocarbon gas releases, the total number of releases dropped from 36 in 2004 to two releases in 2010, increasing to six releases in 2011 and seven releases in 2012; see figure 4.4.

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

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

APPROVALS AND PERMITS GRANTED IN 2012

In 2012 the DEA granted the following approvals and permits for the design, operation and modification of fixed installations and mobile units as well as pipelines in the Danish sector of the North Sea:

The South Arne Field

Permits have been granted for the operation of an unmanned wellhead platform about 2.5 km north of the existing South Arne installation and a wellhead and riser platform with a bridge connection to the South Arne installation, as well as pipelines between the installations. Operation is expected to start in 2013.

Permits have been granted to increase the level of manning on the South Arne platform and the occupancy of cabins during the commissioning of the new facilities until 31 March 2013. The permits have subsequently been extended until 1 December 2013.

In addition, a permit has been granted for setting up Maersk Resolute at the northern platform to be used as accommodation for a construction crew for about two months and subsequently as a drilling unit until 2014.

The Hejre Field

The general design for the construction of a new integrated Hejre offshore installation has been approved, together with pipelines for the export of oil and gas.

The Siri Field

The permit granted for the increased level of manning on the Siri Field installation in 2012 has been extended until 31 December 2013 in order to establish guyed support of the platform as well as an independent support structure for the well caisson to relieve the tank console supporting the caisson.

The Halfdan Field

A permit has been granted to modify the Halfdan Field process system in order to optimize operations. In addition, a permit has been granted for the conversion of an injection well to a production well and for setting up Energy Endeavour as a drilling unit at Halfdan A.

The Dan Field

A permit has been granted to modify the Dan Field process system in order to optimize operations. In addition, a permit has been granted for changes in connection with the development of new wells and for setting up Ensco 71 as a drilling unit at Dan F.

The Gorm Field

A permit has been granted to make modifications to Gorm and for setting up Energy Enhancer as a drilling unit at Gorm B and Safe Esbjerg as an accommodation unit at Gorm F.

The Tyra Field

A permit has been granted for optimization of the Tyra Field processing facilities, in addition to a permit for setting up Atlantic Labrador as an accommodation unit at Tyra East and Ensco 72 as a drilling unit at Tyra West and Valdemar BA, respectively. In addition, a permit has been granted for increasing the level of manning at Tyra East for a trial period of six months.

Mobile units

New operating permits were granted for ENSCO 71, ENSCO 72, Energy Endeavour, Energy Enhancer, GSF Monarch, Maersk Resolute, Noble George Sauvageau and Atlantic Esbjerg in 2012.

In addition, permits were also granted for modifications to GSF Monarch, ENSCO 72, Energy Endeavour and Atlantic Labrador in connection with the operation of the rigs at fixed offshore installations.

Pipelines

In 2012 a permit was granted for changed use of the oil pipeline from Gorm E to shore, as well as a permit for operation of the Nord Stream pipeline 2 in Danish territory.

5 CLIMATE AND EVIRONMENT

IMPACT ON THE SURROUNDINGS

Like other activities, offshore hydrocarbon exploration, production and final decommissioning of obsolete installations have an impact on the environment. In order to permit these activities to take place, it is therefore an important prerequisite that this impact is identified and controlled in such a way that the consequences are acceptable.

The various activities affect the environment with varying levels of intensity over very different timescales. Seismic surveys and the laying of pipelines are examples of activities of a relatively short duration over a large area, while drilling and the establishment or removal of installations – although of fairly short duration – have a more intensive effect on a limited locality. However, hydrocarbon production involves a more constant local impact over a very long period of time, and is associated with air and ship transport via the infrastructure required for such production.

Impacts on the environment come from discharges and any marine spills, atmospheric emissions, noise from activities, changes in the subsoil from which the hydrocarbons are extracted, in addition to the physical presence of installations and infrastructure in the seabed, water column and air space.

With regard to climatic and environmental impacts, the DEA manages atmospheric emissions of CO_2 from the combustion and flaring of natural gas and diesel oil, the effects of offshore oil and gas activities on conditions in established international nature protection areas and the impact of oil and gas projects on the marine environment. For more details about protection of the natural environment, reference is made to the annual report for 2011.

Emissions, discharges and any marine spills are managed by the Ministry of the Environment, partly on the basis of regulations issued under the auspices of the international collaboration under the Oslo and Paris Convention (OSPAR). The Convention concerns the protection of the marine environment, and covers the North-East Atlantic. A total of 15 countries have signed and ratified the Convention, including Denmark.

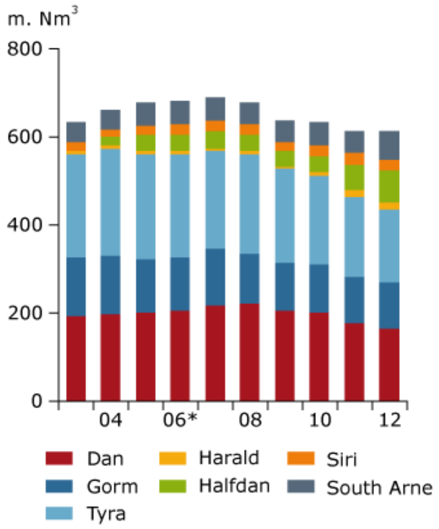
ENERGY EFFICIENCY OFFSHORE

In April 2012 the Minister for Climate, Energy and Building and the Danish operators agreed on a new action plan to reinforce the measures for reducing energy consumption offshore. The plan covers the period from 2012 to 2014 and contains targets for further reducing energy consumption, so that during the years 2012-2014 energy consumption will be reduced by 19, 26 and 29 per cent, respectively, compared with energy consumption in 2006.

The energy consumption figures measured as the use of fuel gas and gas flared in 2012 indicate that the target for 2012 has been achieved, as consumption amounted to 699 million , compared to the action plan target of 716 million in 2012. This corresponds to a reduction of around 20 per cent.

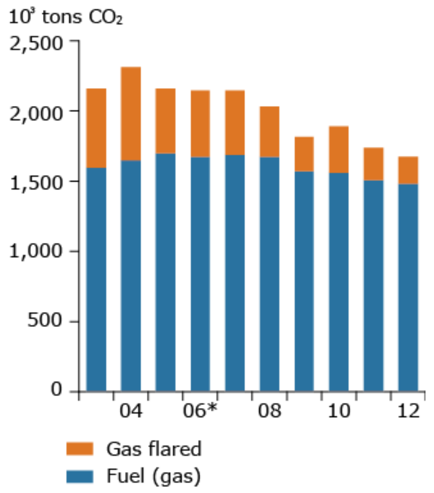
The action plan is based on experience gained from a similar action plan in April 2009, which set out a series of energy-efficiency initiatives. The target of this action plan was to reduce energy consumption by 3 per cent during the period 2006-2011, compared to the previously expected increase of 1.5 per cent. Implementation of the initiatives in the action plan resulted in an 18 per cent reduction of the energy consumption related to North Sea oil and gas production as of end-2011.

Fig. 5.1 Fuel consumption (gas)



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

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



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

Box 5.1

Action plan to improve the energy efficiency of North Sea oil and gas production 2012-2014

The action plan covers the period 2012-2014. The plan contains targets for further reducing energy consumption during the period covered by the action plan, 2012 to 2014. The target is to reduce the consumption of gas as fuel for processing and transporting the hydrocarbons produced at installations in the Danish sector of the North Sea and for flaring, so that during the years 2012-2014 it will fall by 19, 26 and 29 per cent, respectively, relative to the 2006 figure.

Experience gained from the action plan for the period 2009-2011 indicates that the introduction of energy management has had a significant effect on reducing energy consumption. A number of elements in the action plan for 2009-2011 have therefore been carried on by the action plan covering the period from 2012. Some of these elements are:

- The operators use energy management according to the principles in the energy management standard DS/EN 16001 or ISO 50001 in connection with the operation of all installations in the North Sea
- The operators will use energy-conscious design and BAT (Best Available Techniques) in connection with new developments and modifications to existing installations, and will also assess whether it is possible to set up an energy-efficient external power supply for the installation
- In connection with the development of new fields, the operators will assess whether the energy efficiency can be improved for both existing installations and new fields by exploiting existing energy production capacity instead of installing new capacity
- The operators have drawn up individual action plans to reduce flaring
- The operators are conducting a new survey of energy consumption on offshore installations. On the basis of this survey, the operators will select the areas where there is greatest potential for effecting savings and establish specific targets for energy savings
- The DEA will supervise the operators' use of energy management.

EMISSIONS TO THE ATMOSPHERE

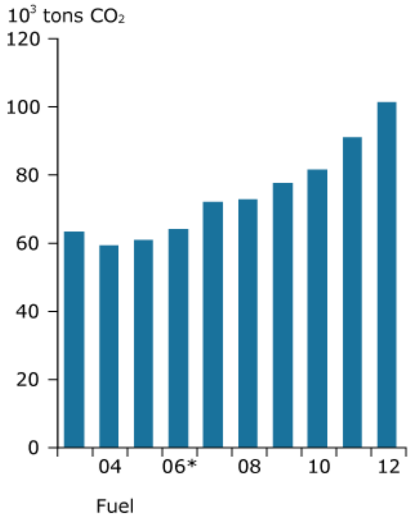
Emissions to the atmosphere consist of such gases as CO_2 (carbon dioxide) and NO_x (nitrogen oxide).

The combustion and flaring of natural gas and diesel oil produce CO_2 emissions to the atmosphere. Producing and transporting oil and gas require substantial amounts of energy. Furthermore, a certain volume of gas has to be flared for safety or plant-related reasons. Gas is flared on all offshore platforms with production facilities, and for safety reasons gas flaring is necessary in cases where installations must be emptied of gas quickly.

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

The Danish Subsoil Act regulates the volumes of gas flared, while CO_2 emissions (including from flaring) are regulated by the Danish Act on CO_2 Allowances.

Fig. 5.3 CO_2 emissions from consumption of fuel per m. t.o.e.



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

Consumption of fuel

Fuel gas accounted for close to 90 per cent of total gas consumption offshore in 2012. The remaining 10 per cent was flared. The development in the use of gas as fuel on Danish production installations appears from figure 5.1. The general increase until 2007 is attributable to rising oil and gas production and ageing fields. The main reason for the sharp drop from 2008 is energy-efficiency measures taken by the operators.

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

The development in the emission of CO_2 from the North Sea production facilities since 2003 appears from figure 5.2. This figure shows that CO_2 emissions totalled about 1.695 million tons in 2012, the lowest level in the past ten years.

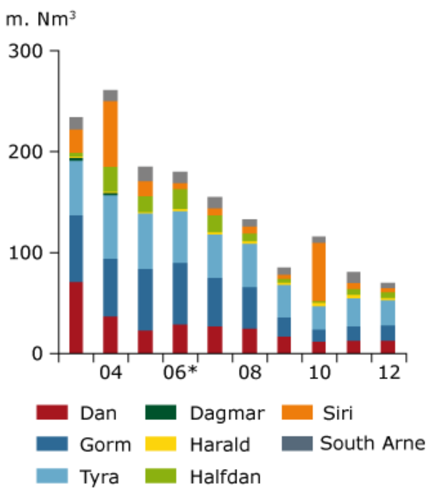
It appears from figure 5.3 that CO_2 emissions due to fuel consumption have increased relative to the size of hydrocarbon production over the past decade. The reason for this increase is that oil and gas production has dropped more sharply than fuel consumption, which means that CO_2 emissions due to fuel consumption have increased relative to the size of production.

Gas flaring

The flaring of gas declined substantially from 2006 to 2012 in all fields with the exception of the Harald Field where flaring has remained unchanged, even though the Norwegian Trym Field was hooked up to Harald in 2010. This development is attributable to more stable operating conditions on the installations, changes in operations and focus on energy efficiency. As appears from figure 5.4, which shows the volumes of gas flared, flaring varies considerably from one year to another. The large fluctuation in 2004 is partially due to the tie-in of new fields and the commissioning of new facilities. In 2012, gas flaring totalled 71 million Nm^3.

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

Fig. 5.4 Gas flaring



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

In 2012, CO_2 emissions from flaring came to 0.192 million tons of CO_2 out of total CO_2 emissions from the offshore sector of 1.695 million tons, i.e. 11 per cent of total emissions. All CO_2 emissions are comprised by the CO_2 allowance scheme.

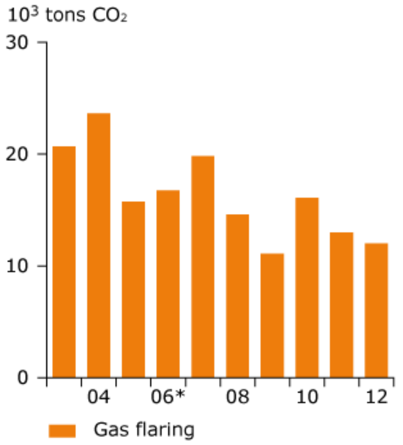
Emissions from flaring declined steadily from 2004 to 2009, increased again in 2010 and then dropped in 2012 to the lowest level since 1998.

The production of hydrocarbons has declined over the past decade, and thus the volume of gas flared per ton oil equivalent (t.o.e.) produced increased until 2007; see figure 5.5. From 2008 to 2012, the volume of gas flared per t.o.e. produced fell to just under 13 ktons of CO_2 per million t.o.e., which means that flaring has dropped significantly, even when the simultaneous fall in hydrocarbon production is taken into account.

THE MARINE STRATEGY FRAMEWORK DIRECTIVE

The Marine Strategy Framework Directive, Directive 2008/56/EC establishing a framework for community action in the field of marine environmental policy, sets out a common approach for the Member States that aims to maintain or achieve a good environmental status in the marine environment by the year 2020 at the latest.

Fig. 5.5 CO_2 emissions from gas flaring per m. t.o.e.



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

A range of activities were completed in 2012, resulting in four separate reports that combine to make up Denmark's marine strategy:

- Basic analysis
- Socio-economic analysis
- Summary of socio-economic analysis
- Report on environmental targets

The reports can be found at the Danish Nature Agency's website, www.nst.dk

The aim of the marine strategy is to protect, conserve and prevent deterioration of the marine environment and, insofar as possible, restore marine ecosystems in areas where negative impacts have already occurred. A further aim is to reduce and prevent pollution of the marine environment and its harmful effects.

The marine strategy includes oil and gas exploration activities such as the discharge of waste material related to drilling for oil and gas in the North Sea, as well as the impact of offshore platforms on the marine environment, as also described in the basic analysis.

The next step is to prepare monitoring programmes that make it possible to observe changes in the condition of the marine environment. These monitoring programmes must have been prepared and launched by 15 July 2014.

The DEA will participate in this work as part of a group of authority representatives set up in this connection.

MARITIME SPATIAL PLANNING AND INTEGRATED COASTAL MANAGEMENT

On 12 March 2013 the European Commission presented a proposal for a Directive on a framework for maritime spatial planning and integrated coastal management. The proposal sets out an obligation for Member States to prepare spatial plans for maritime areas and strategies for integrated coastal management. The proposal also sets out an obligation for Member States to collaborate across national borders in maritime regions. The aim is to create coherence and ensure effective implementation of the numerous policies that impact on coastal and marine areas. The Ministry of the Environment will be responsible for representing Denmark in the forthcoming negotiations concerning the proposed Directive, and the DEA will participate in the associated inter-ministerial collaboration.

STRATEGIC ENVIRONMENTAL ASSESSMENT

The DEA is planning a 7th Licensing Round for the purpose of oil and gas exploration and production in the western part of the Danish sector of the North Sea (the area west of 6°15' E) and a separate licensing procedure for permits for the injection of CO_2 (to enhance oil recovery) in existing oil fields in the same area (west of 6°15' E). The licensing procedure for permits for the injection of CO_2 in existing oil fields, aimed at enhancing oil recovery, is not expected to be initiated until companies have specifically expressed an interest in CO_2 injection.

The DEA submitted the plan and the strategic environmental assessment for the new licensing round/licensing procedure for consultation by the public and by the Norwegian, German, Dutch and British authorities during the period from 10 July to 25 September 2012.

There has been keen interest in the plan and the environmental assessment, and numerous consultation responses have been received. The DEA is in the process of preparing a summary report, which will also assess and review the consultation responses. Once the summary report has been prepared, preparations for the 7th Licensing Round for the purpose of oil and gas exploration and production can be completed. There are a number of opportunities to appeal along the way, which may extend the process, but the 7th Licensing Round is expected to be opened in 2013.

Box 5.2

Strategic environmental assessment

In accordance with the Act on Environmental Assessment of Plans and Programmes (Consolidated Act No. 936 of 24 September 2009) and guidance notes (no. 9664 of 18 June 2006), an environmental assessment must be carried out for a plan if its implementation could have a significant impact on the environment, a so-called Strategic Environmental Assessment (SEA). The aim of a strategic environmental assessment is to identify, describe and assess the probable significant impacts of the plan on the environment. A strategic environmental assessment is an overall assessment and does not replace, for instance, EIAs (Environmental Impact Assessments) for specific projects.

ENVIRONMENTAL IMPACT ASSESSMENTS (EIAS)

Regulation

On 22 June 2012 a revised Executive Order on EIA entered into force, Executive Order No. 632 of 11 June 2012 on Environmental Impact Assessment (EIA) concerning international nature protection areas and the protection of certain species in connection with offshore hydrocarbon exploration and production, storage in the subsoil, pipelines etc. The main amendment is that the requirement for a screening procedure to determine the need for an EIA in connection with deep drilling has been extended to drilling operations associated with hydrocarbon exploration and production. In practice this means that companies wanting to drill an exploration well must carry out a screening procedure to evaluate whether the well is expected to have a significant environmental impact. Against this background, the DEA can determine whether an EIA must be prepared as part of the company's application for approval of the exploration well.

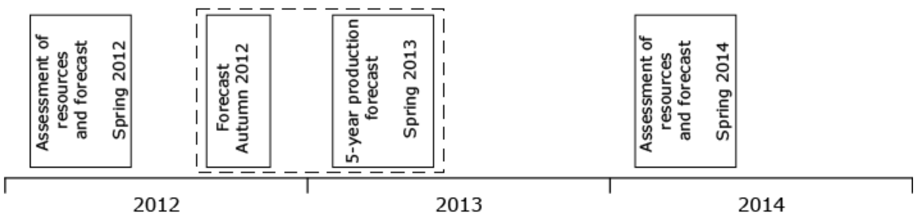
6 RESOURCES

The DEA uses a classification system for hydrocarbons to assess Denmark's oil and gas resources. The aim of the classification system is to determine resources in a systematic way. A description of the classification system is available at the DEA's website, www.ens.dk. Based on the assessment of resources, the DEA prepares short- and long-term oil and gas production forecasts.

The DEA plans to make an assessment of Danish oil and gas resources every other year. Consequently, the DEA has not made an assessment of resources this year. The most recent resource assessment can be found in the report "Oil and gas production in Denmark – and Subsoil Use 2011".

In future, the DEA thus plans to prepare an assessment of resources and a long-term production forecast in spring every second year. In the alternate years, the plan is to prepare a short-term production forecast (the so-called five-year forecast) in spring; see figure 6.1.

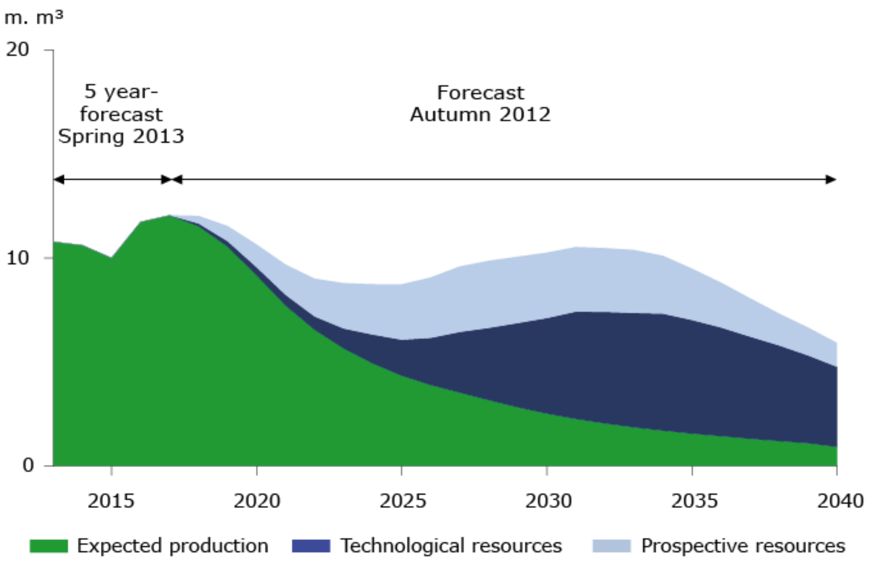
Fig. 6.1 Timeline for the DEA's assessment of resources and forecasts



As a result, the DEA only prepared a short-term forecast of oil and gas production in spring 2013 (the five-year forecast).

Accordingly, the long-term production forecast from spring 2013 consists of the forecast from autumn 2012 and the five-year forecast from spring 2013; see figure 6.2. The production contributions used to make the forecast are set out below.

Fig 6.2 Forecasts



PRODUCTION FORECASTS

The DEA uses its resource assessment to prepare forecasts of Danish oil and gas production. The forecasts consist of the following contributions: **Expected production profile**, **technological resources** and **prospective resources**. For each contribution, the DEA indicates the time at which it has made any revisions relative to the production forecasts published in the report "Oil and gas production in Denmark – and Subsoil Use 2011".

The expected production profile is a forecast of production from existing fields and discoveries based on existing technology. The short-term forecast (the five-year forecast) was revised in autumn 2012 and spring 2013 relative to the above-mentioned report. The long-term forecast was revised in autumn 2012 relative to the report.

Technological resources are an estimate of the volumes recoverable by means of new technology. The forecast from autumn 2012 has not been revised relative to the forecast provided in the report.

Prospective resources are an estimate of the volumes recoverable from future new discoveries made as a result of ongoing exploration activity and future licensing rounds. A revision was made in autumn 2012 relative to the contribution indicated in the report.

SHORT-TERM FORECAST (FIVE-YEAR FORECAST)

The DEA prepares its five-year forecast of oil and gas production on the basis of the expected production profile. This forecast is prepared for the use of the Danish Ministry of Taxation in making its forecasts of state revenue. The DEA publishes the five-year forecast in its annual report "Oil and gas production in Denmark and Subsoil Use".

Table 6.1 Expected production for oil and sales gas

	2013	2014	2015	2016	2017
Oil, m. m^3	10.7	10.5	9.9	11.6	12.0
Sales gas, bn. Nm^3	4.0	4.1	3.7	5.1	5.4

Oil

For 2013 the DEA expects oil production to total 10.7 million m^3, equal to about 184,000 barrels of oil per day; see table 6.1. This is a reduction of 9 per cent relative to 2012, when oil production totalled 11.7 million m^3. Compared to last year's estimate for 2013, this constitutes a writedown of 3 per cent, mainly attributable to the lower production figure expected by the DEA for South Arne.

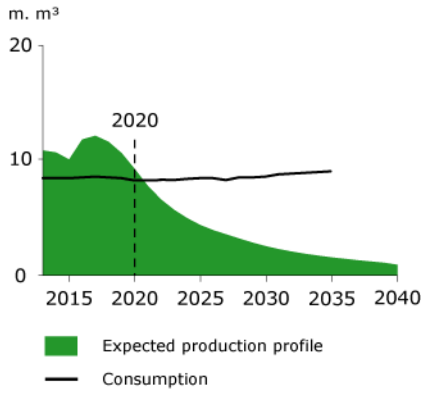
The DEA expects oil production to decline for the period from 2013 to 2015, and then anticipates a rise in production as new fields are developed and some existing ones are further developed. Compared to last year's forecast, the DEA has written up the production estimate for the period from 2013 to 2017 by an average of 3 per cent, mainly as a result of the higher production expected from the Halfdan Field.

A more detailed forecast is available at the DEA's website, www.ens.dk.

Sales gas

The DEA estimates that sales gas production will total 4.0 billion Nm^3 for 2013; see table 6.1. This is a decline of 18 per cent relative to 2012, when production totalled 4.9 billion $Nm^{3.}$ Compared to the estimate for 2013 made by the DEA last year, this is an upward revision of 14 per cent based on the DEA's expectation of higher gas production in the Halfdan and Tyra Fields.

Fig. 6.3 Expected production profile, oil



Compared to last year's forecast, the DEA has written up the production estimate for the period from 2013 to 2017 by an average of 9 per cent, chiefly because it expects higher gas production figures for the Halfdan and Tyra Fields.

LONG-TERM FORECAST

The DEA has prepared a long-term forecast for the production of oil and sales gas, based on the expected production profile.

A forecast covering a long period is most reliable in the first part of the period. The methods used in making the forecast imply that production will decline after a short number of years. The reason is that all commercial development projects are implemented as quickly as possible. Therefore no development projects have been planned for the latter part of the forecast period, even though it must be assumed that development projects will also be undertaken during that period if the oil companies consider such projects to be commercial.

The production profile for oil expected by the DEA shows a generally declining trend; see figure 6.3. However, production is expected to increase in 2016 due to the development of new fields and the further development of some existing fields. About ten years from now, production is expected to have been halved compared to production in 2013.

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

Figure 6.3 shows the consumption forecast from "The DEA's baseline scenario, 2012". The baseline scenario is a scenario in which it is assumed that no measures will be taken other than those already decided with a parliamentary majority. Therefore, the baseline scenario is not a forecast of future energy consumption, but a description of the development that could be expected during the period until 2035 based on a number of assumptions regarding technological developments, prices, economic trends, etc., assuming that no new initiatives or measures are taken.

Based on these production and consumption assumptions, Denmark is expected to be a net exporter of oil up to and including 2020.

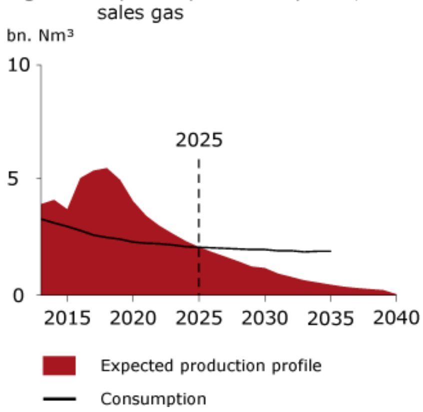
As opposed to oil, which is most frequently sold as individual tanker loads from the North Sea at the prevailing market price, the production of sales gas is subject to the condition that sales contracts have been concluded. Such contracts may either be long-term contracts or spot contracts for very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

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

In 1997 a contract was concluded between the Hess Denmark ApS group and DONG Naturgas A/S for the sale of gas from the South Arne Field, and, in 1998 a contract was concluded with DONG Naturgas A/S for the sale of the DONG group's share of gas produced from the Lulita Field. In addition, the forecast includes the gas production resulting from contracts for the export of gas through the pipeline from Tyra West via the NOGAT pipeline to the Netherlands.

All the above-mentioned contributions have been included in the DEA's production forecast for sales gas.

Fig. 6.4 Expected production profile, sales gas



The DEA's forecast based on the expected production profile for sales gas is shown in figure 6.4. The forecast shows a generally declining trend, as is the case for oil. However, the DEA expects production to increase in 2016 due to the development of new fields and the further development of some existing fields. The DEA's forecast indicates the quantities expected to be technically recoverable. However, as mentioned above, the actual production depends on the sales based on existing and future gas sales contracts.

According to international regulations, the consumption of fuel associated with production must be included in the calculation of energy consumption, but here this fuel consumption has been deducted to allow a comparison with production. Denmark is anticipated to be a net exporter of sales gas up to and including 2025 based on the expected production profile; see figure 6.4. It should be noted that Denmark is expected to be a net exporter for a period three years longer than expected in "Oil and gas production in Denmark – and Subsoil Use 2011", mainly because gas consumption in "The DEA's baseline scenario, 2012" has been written down relative to the previous estimate.

However, technological developments and any new discoveries made as part of the ongoing exploration activity are expected to contribute with additional production and thus prolong Denmark's period as a net exporter of oil and sales gas.

NET EXPORTS/NET IMPORTS BASED ON TOTAL RESOURCES

To illustrate the potential for prolonging Denmark's period as a net exporter of oil and gas due to the use of new technology and new discoveries resulting from exploration activity, a forecast based on total resources was made in autumn 2012, which is termed the possible production profile. It should be emphasized that estimates of the technological resources and prospective resources are subject to great uncertainty.

The technological resources have not been revised relative to the report "Oil and gas production in Denmark – and Subsoil Use 2011", and reference is made to that report for a detailed review of the contribution from technological resources.

The DEA's estimate of technological oil resources is based on a five percentage point increase of the average recovery factor for Danish fields and discoveries. The average recovery factor is the ratio of ultimate recovery to total oil originally in place.

Most of the five per cent contribution from technological developments is expected to derive from new techniques used for injecting CO_2 into the large producing fields where recovery is based on water injection, while the remaining minor contributions will derive from other technological initiatives. It has been assumed that CO_2 injection will contribute to production during the period from 2020 to 2025. The remaining contributions to increased production from other initiatives are assumed to be spread over the forecast period as from 2018.

An analysis - instigated by Mærsk Olie og Gas A/S, the Danish North Sea Fund and the DEA - was performed by the well-known University of Texas in Austin, which demonstrates that the best way to substantially increase oil production from the largest Danish fields is to inject CO_2 into the fields. The analysis is available at the DEA's website, www.ens.dk.

Moreover, the DEA has had a report prepared, "Socio-economic Analysis of CCS/EOR in Denmark". The report contains a budgetary and socio-economic analysis of a CCS/EOR project regarding the injection of CO_2 from Danish power plants into Danish oil fields. The report is available at the DEA's website, www.ens.dk.

In February 2013 the Government completed an overhaul of the terms and conditions for oil and gas production in the North Sea. On the basis of this overhaul, the

Government will start preparing a strategy to improve recovery from the Danish fields. As an element of this strategy, the DUC partners will establish a research centre that is to cooperate with Danish and foreign research environments on improving recovery. Thus, these initiatives have strengthened the foundation for realizing the potential inherent in technological resources.

The DEA's estimate of prospective resources is based on the exploration prospects known today in which exploration drilling is expected to take place. Moreover, the estimate includes assessments of the additional prospects expected to be demonstrated later in the forecast period.

Prospective oil resources were written up from 45 million m^3 to 55 million m^3 in autumn 2012, and the sales gas resources were written up from 30 billion Nm^3 to 35 billion Nm^3 relative to the figure stated in the report "Oil and gas production in Denmark – and Subsoil Use 2011".

The oil production forecast is divided into the three above-mentioned contributions, the expected production profile, technological resources and prospective resources, which are shown in figure 6.5 along with the consumption forecast from "The DEA's baseline scenario, 2012".

It appears from the figure that Denmark is anticipated to be a net exporter of oil for eight years up to and including 2020, based on the expected production profile. The period in which Denmark will be a net exporter can be assessed fairly reliably for the expected production profile, as the production deriving from this contribution is known with a great degree of certainty and is expected to decline substantially, while consumption is expected to remain fairly constant.

The oil production forecast that includes technological resources and prospective resources fluctuates somewhat from 2015 to around 2035, after which estimated production is expected to decline. If technological and prospective resources are included, Denmark is estimated to remain a net exporter until about 2035. However, it should be noted that around 2025, the amount produced, based on all contributions, is not expected to differ significantly from the amount consumed.

Fig. 6.5 Production and possible production profile, oil

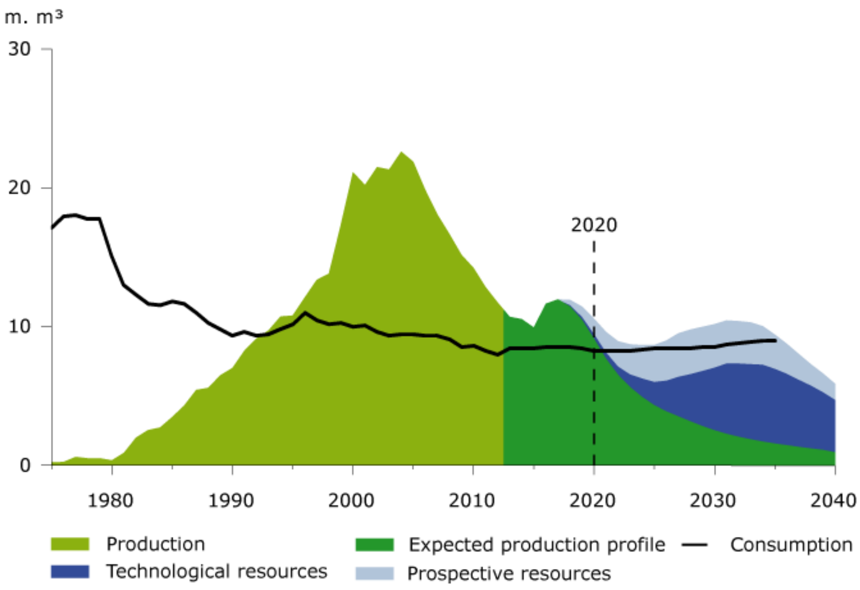
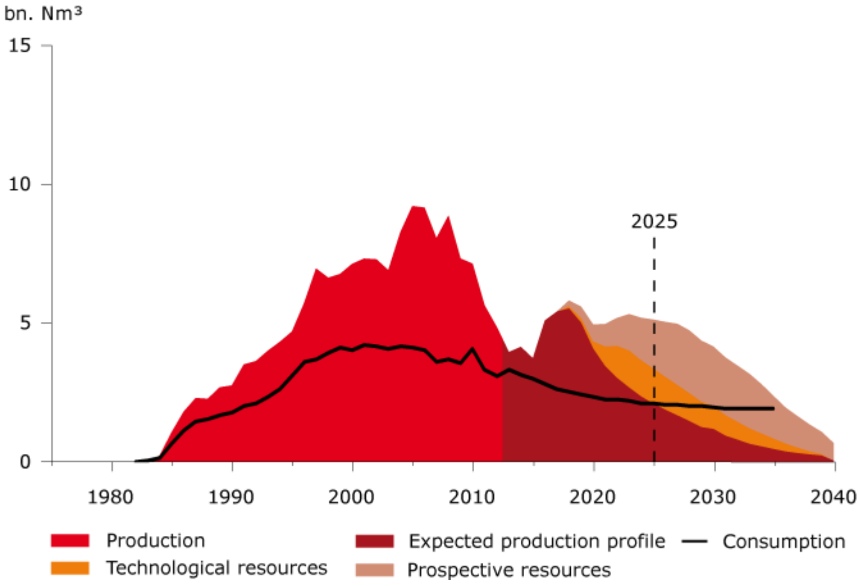


Figure 6.6 shows the sales gas production forecast, divided into the expected production profile, technological resources and prospective resources. The figure also shows the consumption forecast from "The DEA's baseline scenario, 2012". It appears from the figure that Denmark is anticipated to be a net exporter of sales gas for 13 years up to and including 2025, based on the expected production profile.

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

If technological and prospective resources are included, Denmark is estimated to remain a net exporter of natural gas until about 2035.

Fig. 6.6 Production and possible production profile, sales gas



7 ECONOMY

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

Denmark has been self-sufficient in energy since 1997 due to the production of hydrocarbons mainly, but also because of energy savings and the utilization of renewable energy. Thus, Denmark is the only EU country that is a net exporter of energy.

VALUE OF OIL AND GAS PRODUCTION

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

The average quotation for a barrel of Brent crude oil was USD 111.7 in 2012 against USD 111.4 in 2011. Thus, the average oil price was stable in 2012 compared to the year before.

Figure 7.1 illustrates the oil price trend in 2012. The year was characterized by a fairly stable oil price of about USD 110 per barrel, but with heavy price fluctuations, particularly the drop in the second quarter of the year. It appears from figure 7.1 that the EUR/USD rate remained relatively constant throughout 2012. Figure 7.2 shows the oil price development in USD from 1972 to 2012.

The average dollar exchange rate in 2012 was DKK 5.8 per USD. This is an increase of 7.4 per cent compared to 2011 when the average dollar exchange rate was DKK 5.4 per USD.

The development in the dollar exchange rate and the oil price caused the oil price in DKK to rise by just over 11 per cent from 2011 to 2012. The average price for a barrel of Brent crude oil in DKK increased to DKK 663.9 in 2012 from DKK 596.8 in 2011.

Fig 7.1 Oil prices, 2012, USD and EUR

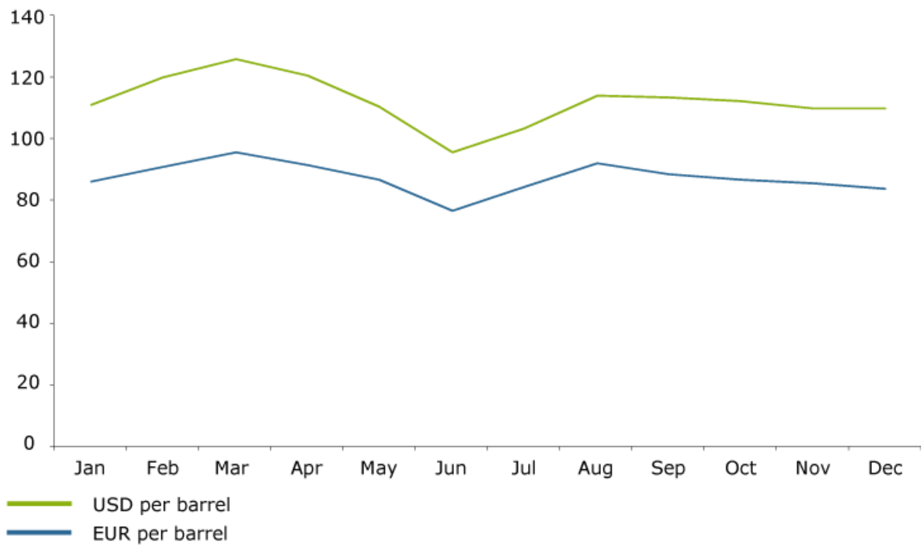
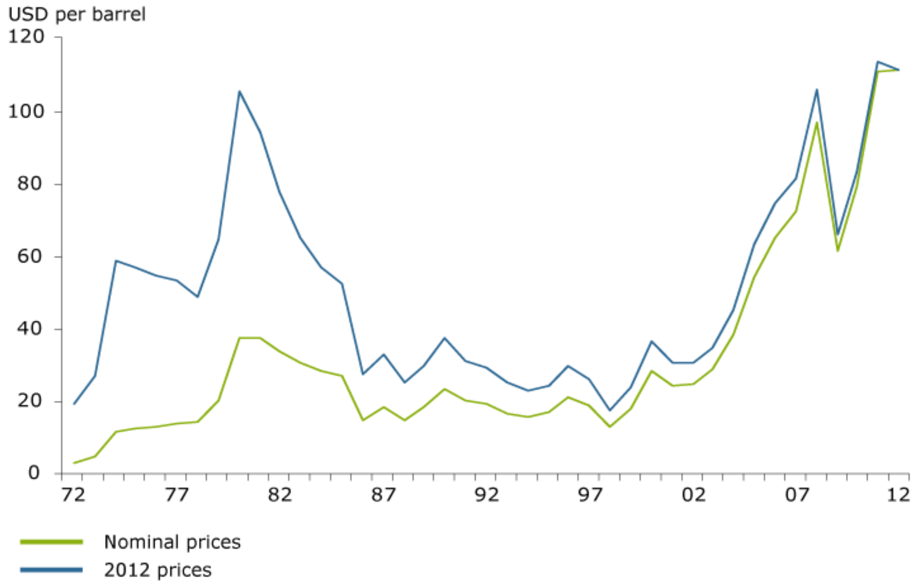


Fig 7.2 Oil price development 1972-2012, USD per barrel



According to preliminary estimates for 2012, oil production accounts for about DKK 47.3 billion and gas production for about DKK 10.2 billion of the total production value.

The total estimated value of Danish oil and gas production in 2012 is DKK 57.5 billion, corresponding to the value of production last year.

The breakdown of oil production in 2012 on the 11 producing companies in Denmark appears from figure 3.2 in chapter 3, *Production and development*.

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

Appendix D contains a detailed outline of financial key figures from 1972 to 2012.

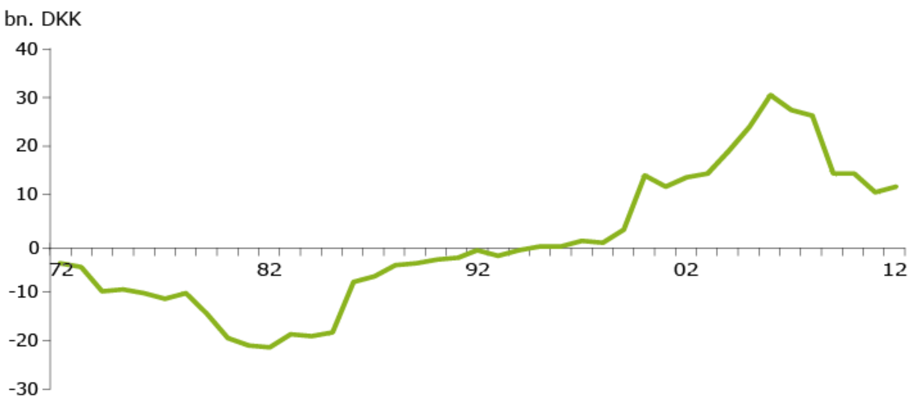
IMPACT OF PRODUCTION ON THE DANISH ECONOMY

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

The balance of trade for oil and natural gas

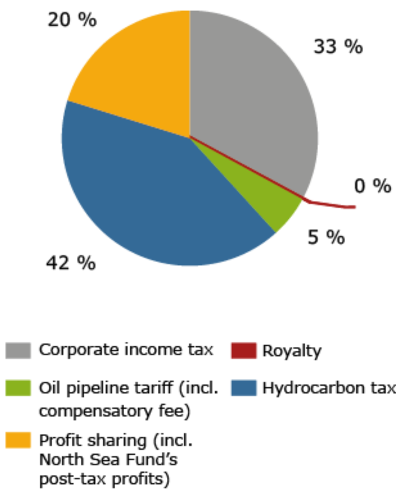
Figure 7.3 shows the trend in Denmark's external trade in oil and natural gas. Since 1995 Denmark has had a surplus on the balance of trade for oil and gas.

Fig 7.3 Balance of trade for oil and natural gas 1972-2012, nominal prices



The surplus amounted to DKK 12.5 billion in 2012, an increase of about 10 per cent on the year before.

Fig 7.4 State revenue in 2012



The DEA's website, www.ens.dk, includes an estimate of the impact of oil and gas activities on the balance of payments.

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. The sources of revenue are described in more detail at the DEA's website, www.ens.dk, and in appendix E.

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, which participates in oil and gas activities. In the long term, the state will also receive revenue through the Danish North Sea Fund.

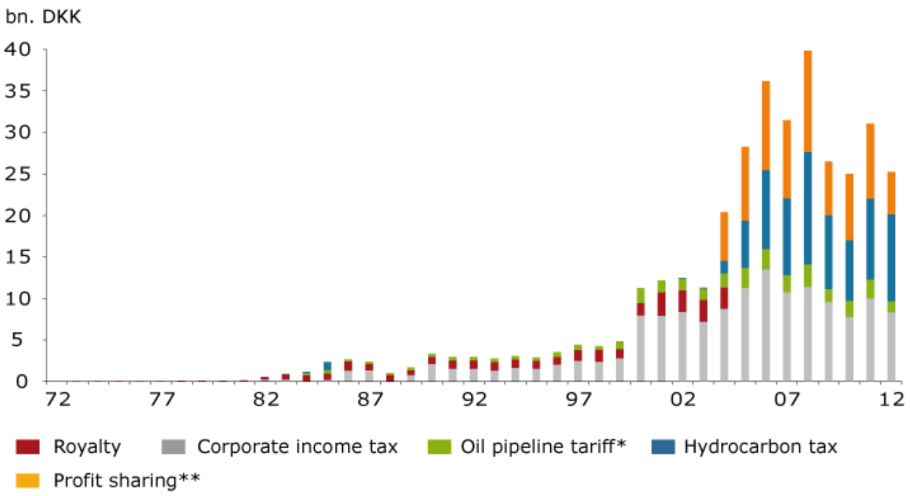
A more detailed explanation of the state's revenue base in the form of taxes and fees from oil and gas production is available at the DEA's website, www.ens.dk.

With a share of about 42 per cent, hydrocarbon tax is the main source of state revenue. Figure 7.4 shows the breakdown of state tax revenue in 2012.

State revenue from hydrocarbon production in the North Sea aggregated DKK 358 billion in 2012 prices in the period 1963-2012. The associated production value totalled about DKK 850 billion during the same period, while the aggregate value of the licensees' expenses for exploration, field developments and operations was about DKK 316 billion (2012 prices). Figure 7.5 shows the development in state revenue from 1972 to 2012.

The development in 2012 was characterized by a fall in production and a stable oil price. Total revenue is estimated at DKK 25.2 billion for 2012, a decline of just over 15 per cent from 2011.

Fig 7.5 Development in total state revenue from oil and gas production 1972-2012, 2012 prices



** Incl. compensatory fee*
*** Incl. North Sea Fund's post-tax profits*
Note: Accrual according to the Finance Act (year of payment)

Table 7.1 shows total state revenue for the past five years, broken down on the individual taxes and fees.

Table 7.1 State revenue over the past five years, DKK million, nominal prices

	2008	2009	2010	2011	2012*
Hydrocarbon tax	12,407	8,254	6,940	9,521	10,467
Corporate income tax	10,417	8,876	7,377	9,754	8,304
Royalty	2	0	0	1	2
Oil pipeline tariff**	2,511	1,431	1,824	2,201	1,337
Profit sharing***	11,145	6,027	7,594	8,819	5,090
Total	36,481	24,588	23,736	30,296	25,200

** Estimate*
*** Incl. 5 per cent compensatory fee*
**** Incl. North Sea Fund's post-tax profits*
Note: Accrual according to the Finance Act (year of payment)

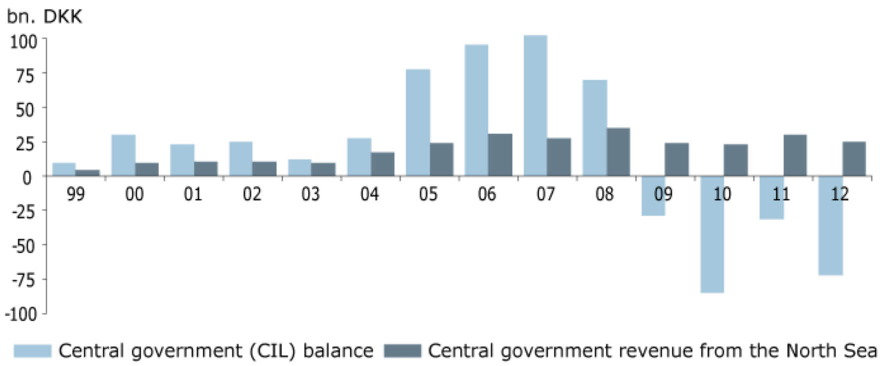
State revenue has grown substantially since 2003 on account of the higher oil price level. Another reason for this growth is that the Danish Government concluded an agreement with A.P. Møller - Mærsk, the so-called North Sea Agreement, in 2003. The agreement involved a restructuring of tax allowances, which resulted in steeper progressive tax rates. Information about Dansk Undergrunds Consortium's pre-tax profits can be found at www.ens.dk. As in previous years, this information will also be submitted to the Climate, Energy and Building Committee of the Danish Parliament.

The state's share of oil company profits, calculated by year of payment, is estimated at 65 per cent for 2012, including state participation. The marginal income tax rate is about 64 per cent according to the new rules, excluding state participation. When including state participation, about 71 per cent of earnings in the top tax bracket will accrue to the state according to the new rules.

According to the old rules, the marginal tax rate is about 29 per cent when excluding hydrocarbon tax. The rules regarding the hydrocarbon allowance mean that companies taxed according to the old rules do not pay hydrocarbon tax in practice. Licences awarded before 2004 are taxed according to the old rules.

Figure 7.6 shows the proportion of revenue from the oil and gas activities to the central government balance on the current investment and lending account. As appears from the figure, state revenue from the Danish part of the North Sea contributed to reducing the central government deficit in 2012.

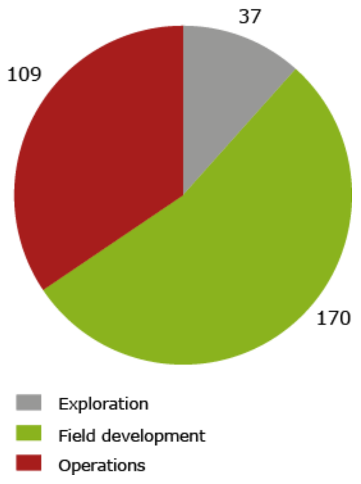
Fig. 7.6 Central government (CIL) balance and central government revenue from the North Sea, nominal prices



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

For the next five years, the Ministry of Taxation estimates that the state's total revenue will range from DKK 24 to DKK 30 billion per year from 2013 to 2017, based on the USD 125 oil price scenario. Table 7.2 shows the development in expected state revenue for the three different oil price scenarios of USD 85, 125 and 165 per

Fig. 7.7 All licensees´ total costs 1963-2012, DKK billion, 2012 prices



barrel. It also appears from the table that the state's share of profits increases when the oil companies generate increasing earnings due to higher oil prices, for example. The state's share is declining because an increasing percentage of production is being taxed according to the old rules.

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.

Table 7.2 Expected state revenue from oil and gas production, DKK billion, nominal prices*

			2013	2014	2015	2016	2017
Corporate income tax base before taxes, fees and profit sharing	165	USD/bbl	63.9	64.0	58.0	71.2	73.7
	125	USD/bbl	44.3	44.2	39.5	49.2	50.8
	85	USD/bbl	25.2	24.4	21.1	27.3	27.9
State revenue							
- Corporate income tax	165	USD/bbl	15.9	16.0	14.6	17.7	18.3
	125	USD/bbl	11.0	11.1	10.0	12.3	12.6
	85	USD/bbl	6.3	6.0	5.4	6.9	7.0
- Hydrocarbon tax	165	USD/bbl	22.1	21.1	18.1	18.8	20.7
	125	USD/bbl	15.3	14.5	12.3	12.7	13.2
	85	USD/bbl	8.6	8.0	6.4	6.6	7.0
- Danish North Sea Fund	165	USD/bbl	4.1	3.5	2.7	2.9	3.3
post-tax profits **	125	USD/bbl	2.9	2.3	1.6	1.8	2.2
	85	USD/bbl	1.6	1.1	0.5	0.6	1.0
- Royalty	165	USD/bbl	0.0	0.0	0.0	0.0	0.0
	125	USD/bbl	0.0	0.0	0.0	0.0	0.0
	85	USD/bbl	0.0	0.0	0.0	0.0	0.0
- Oil pipeline tariff ***	165	USD/bbl	0.5	0.6	0.7	1.2	1.2
	125	USD/bbl	0.4	0.5	0.5	0.9	0.9
	85	USD/bbl	0.2	0.3	0.3	0.6	0.6
Total	165	USD/bbl	42.5	41.2	36.0	40.5	43.6
	125	USD/bbl	29.6	28.4	24.4	27.5	28.9
	85	USD/bbl	16.8	15.4	12.7	14.7	15.6
The state's share (per cent)****	165	USD/bbl	66.5	64.3	62.1	56.9	59.1
	125	USD/bbl	66.7	64.1	61.6	55.9	56.9
	85	USD/bbl	66.6	63.0	60.2	53.8	55.9

** Based on an annual inflation rate of 1.8 per cent and existing Danish legislation*
*** On 9 July, the Danish North Sea Fund joined DUC with a 20 per cent share. The Danish North Sea Fund is liable to pay tax, for which reason the revenue from state participation appears under different headings, including under corporate income tax and hydrocarbon tax revenue. The Danish North Sea Fund's post-tax profits accrue to the state.*
**** Incl. 5 per cent compensatory fee*
***** The state's share incl. state participation*
Source: Ministry of Taxation
Note 1: Based on the DEA's five-year forecast
Note 2: Accrual according to the National Accounts (income year)

Fig. 7.8 Exploration costs 2008-2012, nominal prices

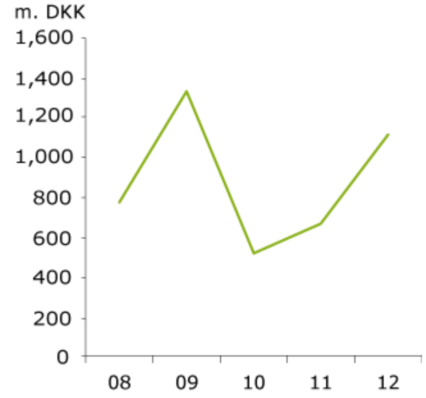


Fig. 7.9 Investments in field developments 2008-2012, nominal prices

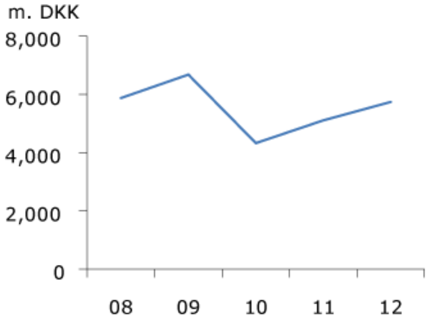
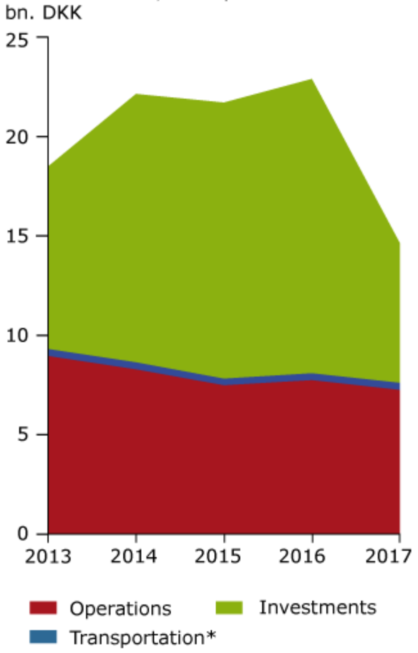


Fig. 7.10 Investments in fields and operating and oil transportation costs, 2012 prices



**Excl. pipeline tariff/compensatory fee*

Investments and costs

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

Figure 7.7 shows the breakdown of the licensees' costs during the period from 1963 to 2012. Development costs and investments account for more than half the licensees' total costs. The costs of exploration, field developments and operations (including administration and transportation) account for 12, 55 and 33 per cent, respectively, of total costs.

Exploration costs

Figure 7.8 illustrates the development in exploration costs from 2008 to 2012. The preliminary figures for 2012 show that exploration costs increased about 65 per cent from 2011 to 2012. Exploration costs include the oil companies' expenses for both exploration wells and seismic surveys. For 2012 total exploration costs are preliminarily estimated at slightly less than DKK 1.2 billion.

In 2013-2016 investments in exploration are expected to total about DKK 4.1 billion. The activities will include further exploration both onshore and in the Danish part of the North Sea.

Investments in field developments

The most cost-intensive activity for the licensees is the development of new and existing fields. Investments in field developments are estimated to total about DKK 5.7 billion in 2012, almost 10 per cent higher than the year before. The investment level in 2012 is on a par with the past decade's average annual investments of about DKK 5.6 billion. Figure 7.9 illustrates investments in field developments over the period 2008-2012. A table showing the investments by field is available at the DEA's website.

Table 7.3 shows the DEA's estimate of investments in development activity for the period from 2013 to 2017. The estimate is based on the following resource categories: ongoing recovery and approved for development, justified for development and risk-weighted contingent resources; see chapter 6, *Resources*.

Table 7.3 Estimated investments in development projects, 2013-2017, DKK million, 2012 prices

	2013	2014	2015	2016	2017
On-going and approved	8,853	10,717	7,537	6,518	1,435
Justified for development	-	-	-	-	512
Risk-weighted contingent resources	310	2,766	6,328	8,266	5,072
Expected, total	9,162	13,483	13,865	14,784	7,018

The investments in the category ongoing recovery and approved for development are shown broken down by field at the DEA's website.

Operating, administration and transportation costs

For 2012 the DEA has calculated operating, administration and transportation costs at DKK 7.9 billion, an increase of just over 15 per cent compared to the year before.

Figure 7.10 illustrates the DEA's estimate of developments in investments and operating and transportation costs for the period 2013-2017.

APPENDIX A: AMOUNTS PRODUCED AND INJECTED

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

	1972-2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Dan	63,548	5,929	6,139	5,712	5,021	4,650	4,241	3,549	2,979	2,474	2,260	106,503
Gorm	45,217	2,838	2,469	1,978	1,897	1,639	1,053	924	923	713	593	60,245
Skjold	34,057	1,532	1,443	1,310	1,214	1,015	989	918	835	778	679	44,771
Tyra	20,191	918	723	773	845	764	551	415	856	744	627	27,407
Rolf	3,729	104	107	79	89	103	78	76	60	1	0	4,427
Kraka	3,832	139	199	211	222	176	112	37	67	170	129	5,294
Dagmar	996	7	2	0	0	0	0	0	0	0	0	1,005
Regnar	865	19	19	16	11	0	0	0	0	0	0	930
Valdemar	1,635	435	491	423	470	881	1,268	1,410	909	817	843	9,582
Roar	2,111	121	98	94	51	35	28	30	24	16	2	2,610
Svend	4,777	280	326	324	296	299	278	195	190	145	171	7,281
Harald	6,341	425	314	237	176	139	114	65	70	95	79	8,055
Lulita	636	20	19	35	68	55	47	24	36	36	32	1,008
Halfdan	8,025	4,352	4,946	6,20	6,085	5,785	5,326	5,465	5,119	4,905	4,617	60,826
Siri	6,959	925	693	703	595	508	598	326	286	161	239	11,993
Syd Arne	7,659	2,383	2,257	2,371	1,869	1,245	1,139	1,164	1,066	1,004	803	22,959
Tyra Se	493	343	580	614	446	377	429	374	225	165	148	4,193
Cecilie	0	166	310	183	116	88	66	38	33	39	32	1,070
Nini	0	391	1,477	624	377	323	355	159	544	569	475	5,294
Total	**211,072**	**21,327**	**22,612**	**21,886**	**19,847**	**18,084**	**16,672**	**15,169**	**14,223**	**12,834**	**11,728**	**385,454**

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

	1972-2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Dan	18,312	786	764	651	561	456	467	364	360	327	330	23,380
Gorm	14,077	339	216	218	207	175	119	109	99	67	52	15,676
Skjold	2,935	92	77	93	77	69	60	58	87	69	62	3,678
Tyra	61,900	3,994	4,120	3,745	3,792	3,916	3,130	2,007	1,664	1,320	1,405	90,994
Rolf	157	4	5	3	4	4	3	3	3	0	0	186
Kraka	1.221	25	23	24	28	28	36	8	12	46	35	1,485
Dagmar	153	3	2	0	0	0	0	0	0	0	0	158
Regnar	57	2	2	1	1	0	0	0	0	0	0	63
Valdemar	668	151	218	208	208	355	593	510	791	579	515	4,797
Roar	10,163	915	894	860	489	367	417	398	213	171	24	14,913
Svend	568	43	38	34	28	28	24	16	27	24	27	858
Harald	14,014	1,563	1,232	1,091	927	781	690	400	592	573	542	22,405
Lulita	443	5	5	13	38	33	30	15	18	20	19	638
Halfdan	1,495	1,142	1,449	2,582	2,948	2,675	3,104	3,401	2,886	2,343	1,709	25,734
Siri	671	110	64	112	55	47	63	44	67	48	50	1,330
Syd Arne	2,335	544	461	485	366	234	225	271	248	238	1	5,602
Tyra Se	447	452	1,233	1,337	1,108	848	889	939	911	626	611	9,402
Cecilie	0	14	22	13	8	6	4	2	2	3	2	76
Nini	0	29	109	46	28	24	26	12	76	57	40	447
Total	**129,616**	**10,213**	**10,934**	**11,517**	**10,873**	**10,046**	**9,879**	**8,559**	**8,057**	**6,511**	**5,617**	**221,822**

Fuel *

	1972-2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Dan	1,591	198	201	205	209	222	225	207	206	179	167	3,610
Gorm	2,010	135	137	124	124	132	117	116	111	107	107	3,219
Tyra	2,596	242	249	247	241	227	233	219	219	188	171	4,832
Dagmar	21	0	0	0	0	0	0	0	0	0	0	21
Harald	64	8	8	7	8	7	7	4	8	16	17	156
Siri	73	20	19	20	25	25	25	19	27	28	26	306
Syd Arne	114	49	45	52	53	58	53	54	55	41	64	638
Halfdan	0	0	20	39	39	39	38	39	36	62	76	389
Total	**6,469**	**652**	**679**	**694**	**699**	**710**	**698**	**658**	**662**	**621**	**628**	**13,170**

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

Flaring *

	1972-2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Dan	1,833	71	37	23	32	29	25	17	12	13	13	2,104
Gorm	1,463	66	57	61	61	48	41	19	12	15	15	1,858
Tyra	866	54	63	55	54	56	44	32	23	28	25	1,300
Dagmar	130	3	2	0	0	0	0	0	0	0	0	135
Harald	130	1	1	1	2	2	2	2	3	3	2	149
Siri	105	23	65	15	6	7	7	4	58	6	4	300
Syd Arne	175	12	11	14	11	11	7	7	6	11	5	269
Halfdan	0	4	25	16	20	17	8	4	5	6	6	110
Total	**4,702**	**234**	**262**	**184**	**186**	**169**	**133**	**85**	**118**	**81**	**70**	**6,224**

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

Injection

	1972-2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Gorm	8,151	6	4	3	0	0	0	0	0	0	0	8,164
Tyra	28,698	2,312	1,612	1,285	761	1,094	119	451	89	94	0	36,514
Siri	493	109	111	135	61	45	61	35	57	74	64	1,246
Total	**37,342**	**2,428**	**1,727**	**1,423**	**821**	**1,139**	**180**	**486**	**146**	**168**	**64**	**45,924**

Sales *

	1984-2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Dan	17,662	1,679	1,681	1,804	1,862	1,653	1,293	947	1,20	1,017	826	31,626
Gorm	5,545	228	99	126	103	66	23	33	64	12	0	6,298
Tyra	41,586	2,948	4,580	4,598	4,574	4,143	4,652	3,163	3,283	2,410	2,389	78,327
Harald	14,263	1,558	1,228	1,096	954	804	710	408	598	577	545	22,742
Syd Arne	2,046	483	406	419	302	168	167	212	199	180	130	4,712
Halfdan	0	4	274	1,172	1,370	1,215	2,020	2,560	1,798	1,439	974	12,822
Total	**81,103**	**6,90**	**8,267**	**9,215**	**9,164**	**8,049**	**8,865**	**7,324**	**7,141**	**5,635**	**4,865**	**156,528**

** The names refer to processing centres*

Emissions

CO_2-EMISSIONS *)

thousand tons

	1972-2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Fuel	14,991	1,591	1,642	1,694	1,675	1,690	1,670	1,572	1,559	1,510	1,503	31,096
Flaring	11,086	564	664	457	470	449	354	241	331	230	192	15,038
Total	**25,077**	**2,154**	**2,306**	**2,151**	**2,144**	**2,139**	**2,025**	**1,813**	**1,890**	**1,740**	**1,695**	**45,135**

*) CO_2-emissions have been calculated on the basis of parametres specific to the individual year and the individual installation
CO_2-emissions from the use of diesel oil were not included 1972 through 2005

**) As from 2006, the figures have been based on verified CO_2-emission data from reports filed under the act on CO_2-allowances and have included CO_2-emissions from diesel combustion

Production

WATER

thousand cubic metres

	1972-2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Dan	33,492	7,183	8,053	9,527	10,936	12,152	13,946	12,889	12,111	11,059	10,468	141,814
Gorm	30,149	4,420	5,173	5,252	4,822	4,708	3,976	4,737	4,904	4,654	3,897	76,691
Skjold	27,707	3,525	3,688	4,270	4,328	3,885	3,636	3,855	3,895	3,861	3,978	66,628
Tyra	22,169	3,039	2,977	3,482	3,150	2,725	3,103	2,677	1,980	1,811	1,515	48,630
Rolf	4,277	270	308	290	316	383	349	381	281	8	0	6,861
Kraka	2,958	208	426	320	297	359	436	183	166	358	237	5,948
Dagmar	3,446	375	90	3	0	0	13	0	0	0	0	3,927
Regnar	2,744	316	396	352	255	1	0	0	0	0	0	4,064
Valdemar	715	310	325	792	937	854	925	812	1,207	1,026	893	8,795
Roar	1,460	476	653	662	498	560	586	624	275	200	34	6,027
Svend	4,281	1,330	1,031	1,309	1,205	1,20	1,022	804	664	585	685	14,116
Harald	235	43	15	12	12	18	21	11	37	113	152	669
Lulita	56	14	15	38	92	96	91	49	65	73	86	674
Halfdan	1,153	612	2,099	2,825	3,460	4,086	4,766	4,814	5,519	6,149	6,139	41,622
Siri	7,981	2,891	1,641	1,683	2,032	2,528	2,686	1,778	2,868	2,593	2,876	31,556
Syd Arne	555	857	1,127	1,790	1,830	1,861	2,174	2,285	2,068	1,883	2,317	18,747
Tyra Se	250	596	466	437	377	669	602	716	568	485	440	5,606
Cecilie	0	25	331	637	651	576	456	266	317	452	377	4,087
Nini	0	0	63	730	822	619	660	522	195	330	311	4,253
Total	**143,628**	**26,490**	**28,875**	**34,410**	**36,019**	**37,280**	**39,448**	**37,402**	**37,121**	**35,640**	**34,405**	**490,716**

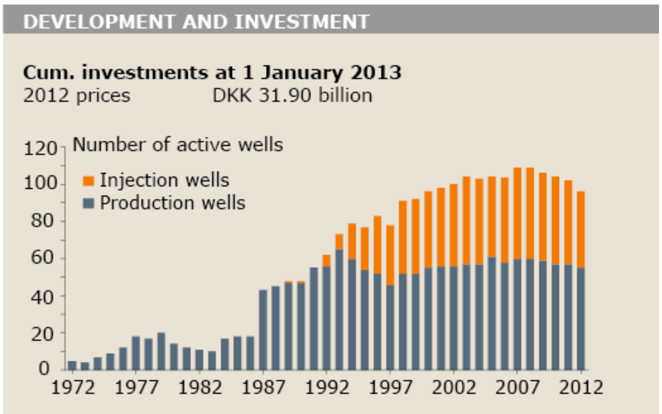
Injection

	1972-2002	2003	2004	2005	2006	2007	2008	2009	2010	2011	2012	Total
Dan	107,972	18,063	20,042	20,281	21,520	20,230	19,275	16,712	15,148	14,508	11,684	285,436
Gorm	75,591	7,066	7,551	7,251	6,544	6,678	5,251	4,777	4,408	5,459	3,709	134,285
Skjold	67,615	6,115	5,607	6,045	5,711	6,098	4,989	5,285	4,155	4,374	5,093	121,088
Halfdan	3,247	5,162	5,759	9,710	11,026	12,107	12,727	11,485	11,945	12,277	10,912	106,358
Siri	14,032	3,383	1,683	1,350	1,973	3,499	2,695	1,692	2,692	3,201	3,018	39,216
Syd Arne	6,446	5,332	4,949	5,608	5,362	4,296	4,279	3,872	3,427	3,240	4,104	50,916
Nini	0	81	918	502	912	413	883	501	1,558	1,365	1,150	8,281
Cecilie	0	0	93	198	30	91	42	97	47	221	35	854
Total	**274,904**	**45,201**	**46,603**	**50,945**	**53,077**	**53,412**	**50,141**	**44,420**	**43,379**	**44,646**	**39,705**	**746,435**

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: DENMARK'S PRODUCING FIELDS

LEGEND FOR FIELD DATA



DEVELOPMENT AND INVESTMENT

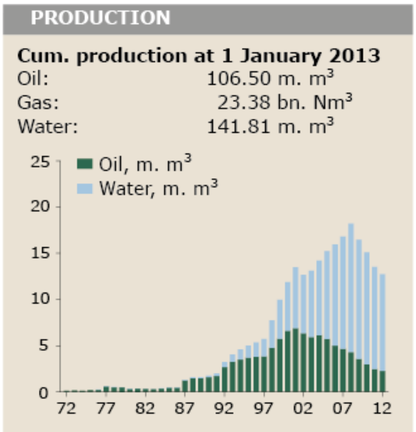
Total investments comprise the costs of developing installations and wells.

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

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

Injection well Production well Production/Injection well*

*Only relevant for the Tyra Field. A few wells alternate between injection and production.



PRODUCTION OF OIL, GAS AND WATER

The chart shows the primary production from the individual fields, i.e. oil or gas as well as water. The figures show the cumulative production of oil, gas and water until 1 January 2013.

Oil field (e.g. Dan) Oil, m. m^3 Gas, bn. Nm^3 Water, m. m^3

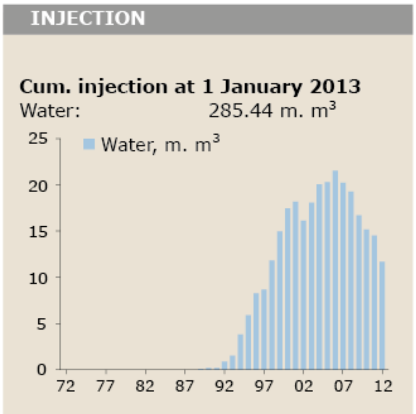
At the time of production startup, the percentage of oil produced is high, but over time, the percentage of water produced increases. When oil flows from the reservoir to the surface, it degases and lower gas production is thus achieved.

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, water and condensate, which is a light oil. Due to the pressure difference between reservoir and surface, the gas condenses at the surface, which means that liquid hydrocarbons (condensate) are also produced.

Oil and gas field (e.g. Tyra Southeast) Oil and condensate, m. m^3 Gas, bn. Nm^3 Water, m. m^3

Some fields contain both oil and gas reservoirs. Oil, gas, condensate and water are produced from these fields.



INJECTION OF WATER AND GAS

The chart shows the primary injection in the individual fields, i.e. water or gas. The figures show the cumulative injection of water and gas until 1 January 2013. The injection method is not used for all fields.

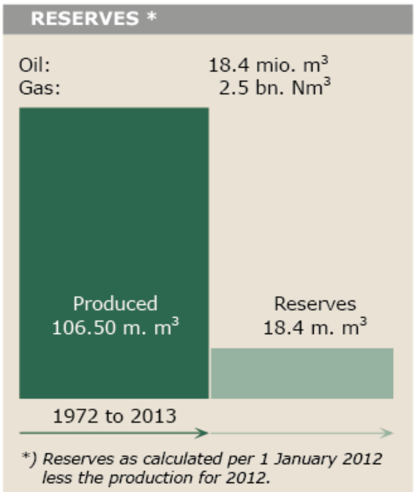
Injecting water into oil reservoirs maintains the reservoir pressure while forcing oil towards the production wells. The injection of gas also maintains pressure in the reservoir. Moreover, the gas affects the viscosity of hydrocarbons.

Fields with water injection (e.g. Halfdan) Water, m. 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 optimize the production of liquid hydrocarbons.



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 2013 and the estimated hydrocarbons-in-place, the reserves.

Produced

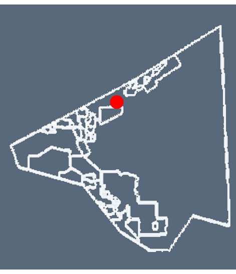
The cumulative production of oil or gas until 1 January 2013.

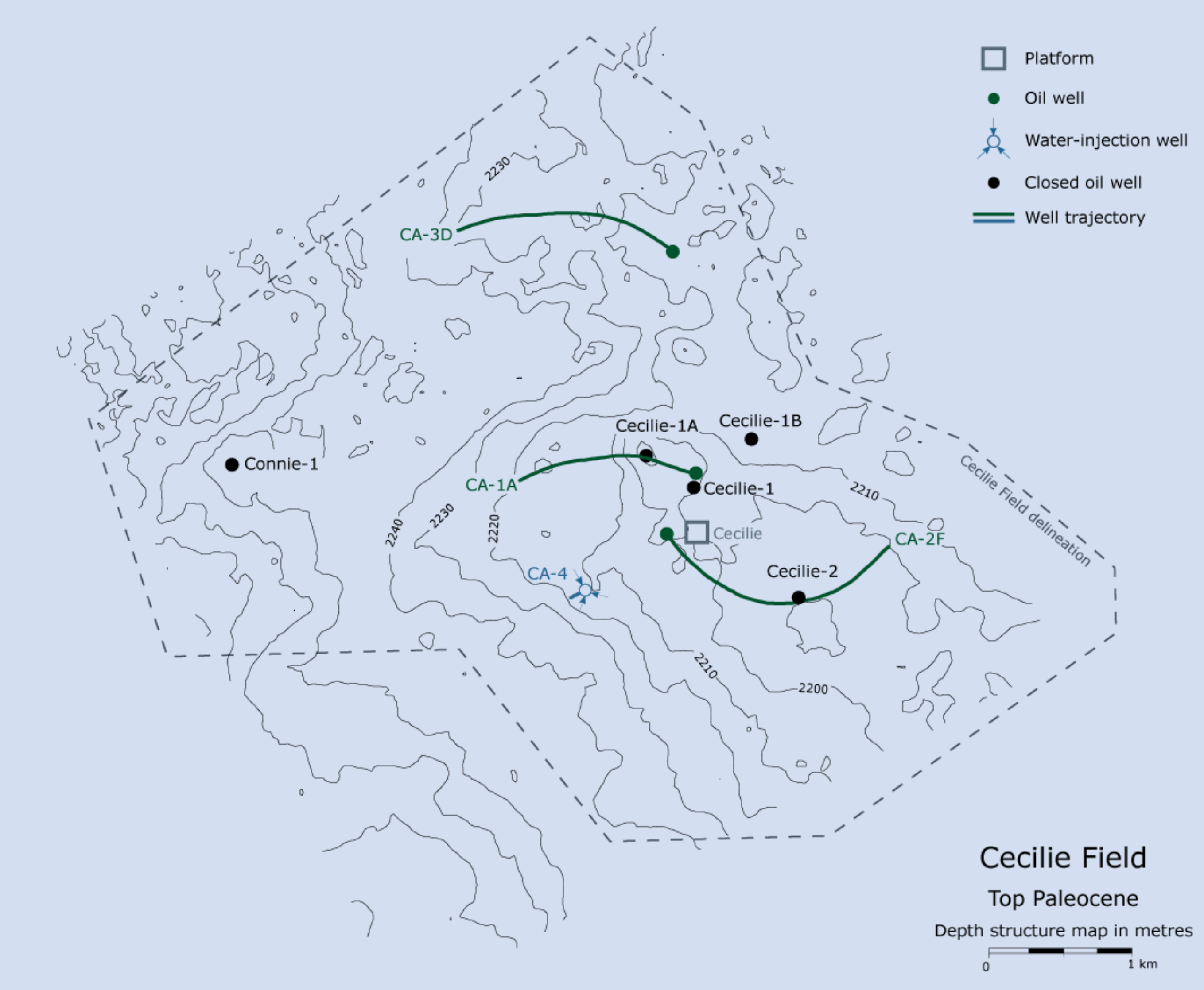
Reserves

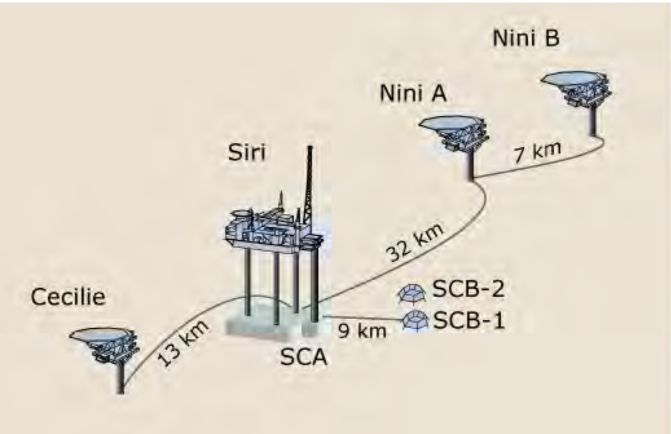
The estimated amounts of oil and gas that can be recovered by means of known technology under the prevailing economic conditions.

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

THE CECILIE FIELD

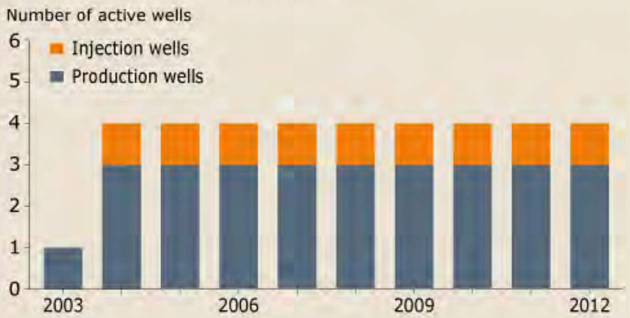






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013
2012 prices DKK 1.50 billion



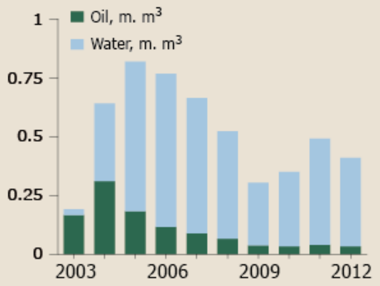
FIELD DATA At 1 January 2013

Location:	Blocks 5604/19 and 20
Licence:	16/98
Operator:	DONG E&P A/S
Discovered:	2000
Year on stream:	2003
Production wells:	3
Water-injection wells:	1
Water depth:	60 m
Field delineation:	23 km^2
Reservoir depth:	2,200 m
Reservoir rock:	Sandstone
Geological age:	Palaeocene

PRODUCTION

Cum. production at 1 January 2013

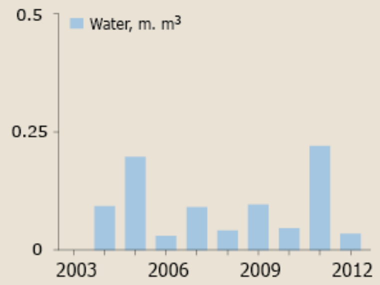
Oil:	1.07 m. m^3
Gas:	0.08 bn. Nm^3
Water:	4.09 m. m^3



INJECTION

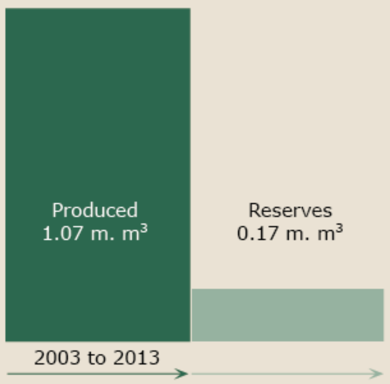
Cum. injection at 1 January 2013

Water:	0.85 m. m^3



RESERVES *

Oil:	0.17 m. m^3
Gas:	0 bn. Nm^3



*) *Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE CECILIE FIELD

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

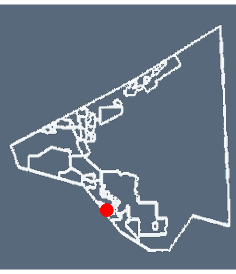
PRODUCTION STRATEGY

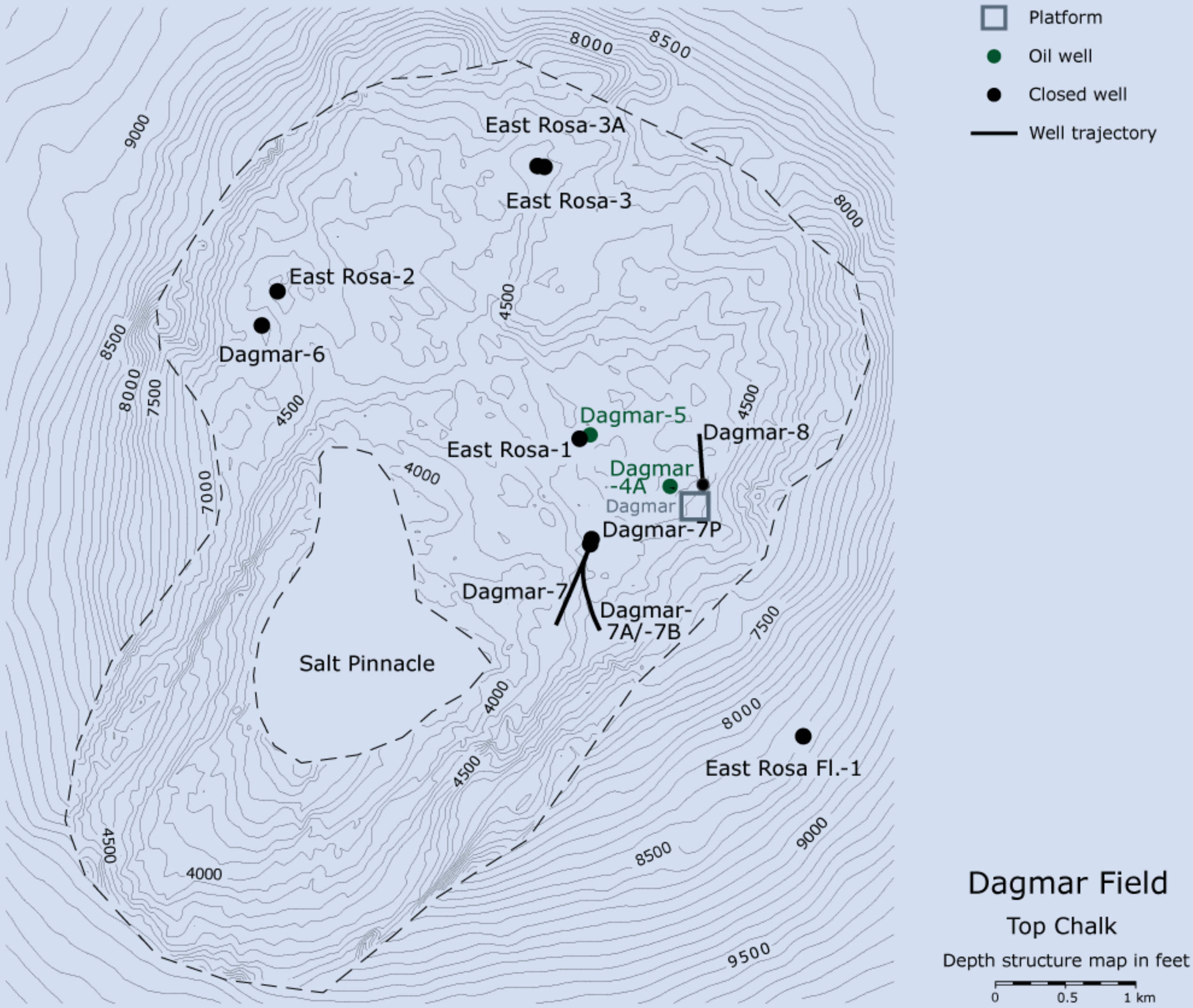
Recovery is based on water injection to maintain reservoir pressure. To assess its effect, water injection has been suspended for periods of time. The production wells have been drilled in the crest of the structure, while water is injected in the flank of the field.

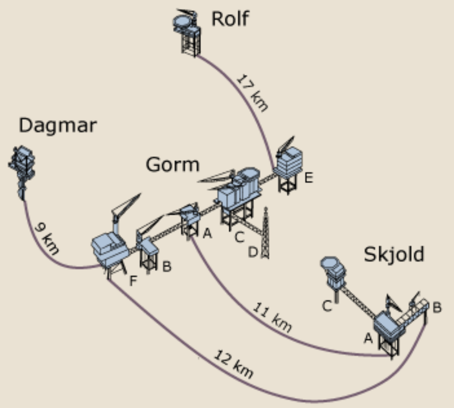
PRODUCTION FACILITIES

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

THE DAGMAR FIELD



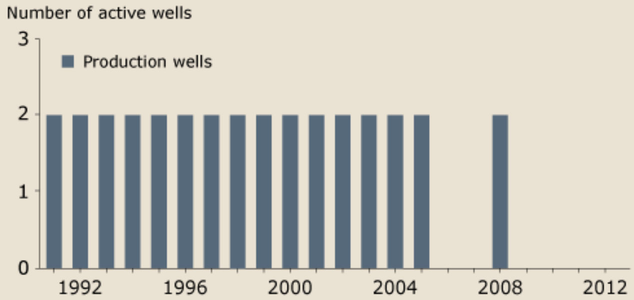




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013

2012 prices	DKK 0.53 billion



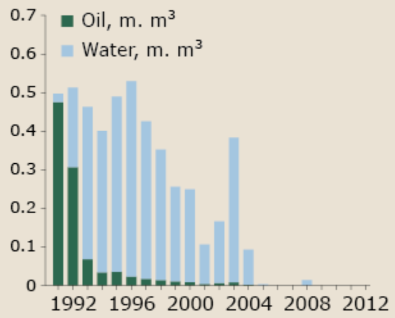
REVIEW OF GEOLOGY, THE DAGMAR FIELD

FIELD DATA	At 1 January 2013
Prospect:	East Rosa
Location:	Block 5504/15
Licence:	Sole Concession
Operator:	Mærsk Oile og Gas A/S
Discovered:	1983
Year on stream:	1991
Production wells:	2
Water depth:	34 m
Field delineation:	50 km²
Reservoir depth:	1,400 m
Reservoir rock:	Chalk and Carbonates
Geological age:	Danian, Upper Cretaceous and Zechstein

PRODUCTION

Cum. production at 1 January 2013

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



RESERVES

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

The Dagmar Field is an anticlinal structure induced through salt tectonics. The uplift is very pronounced, and the Dagmar oil reservoir is situated closer to the surface than any other hydrocarbon reservoirs in Danish territory. The reservoir is heavily fractured (compare Skjold, Rolf, Regnar and Svend). However, the water zone does not appear to be particularly fractured.

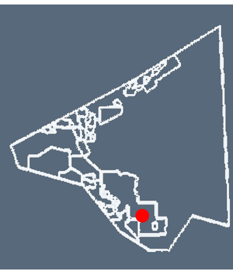
PRODUCTION STRATEGY

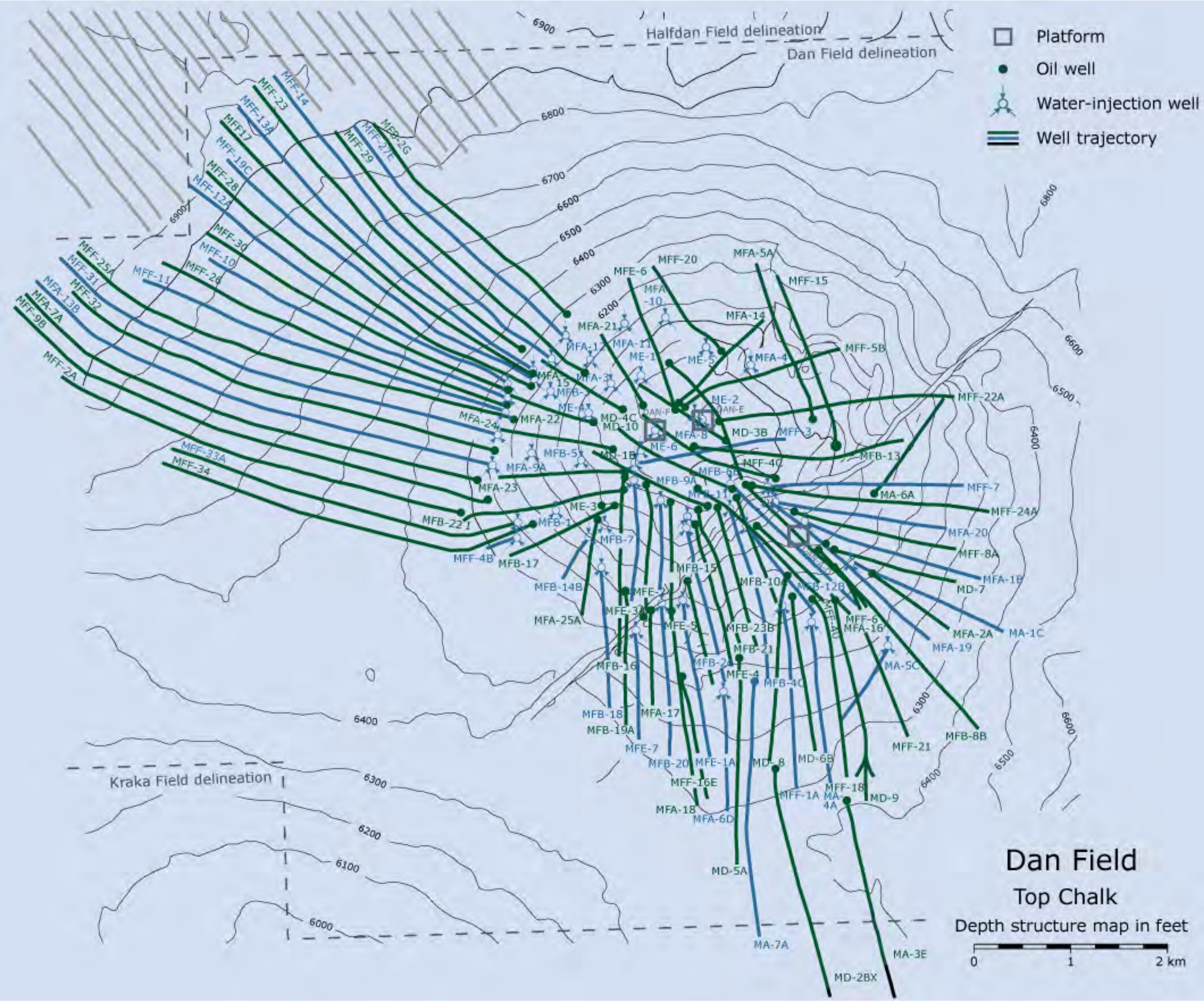
Both wells in the field have been closed in. The recovery strategy for the Dagmar Field was based on achieving the highest possible production rate from the wells. Initially, the oil production rates were high in the Dagmar Field, but later it was not possible to sustain the good production performance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

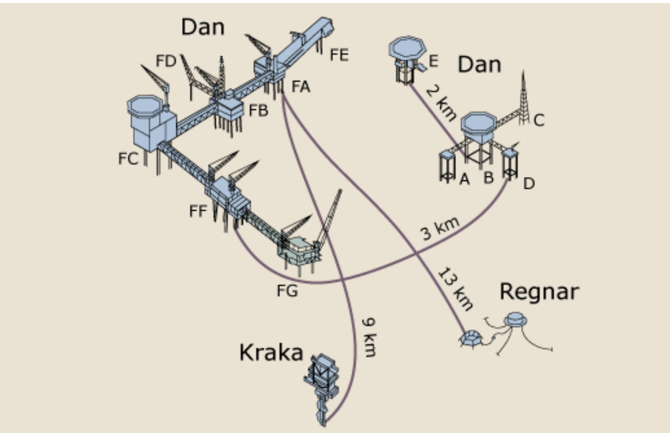
PRODUCTION FACILITIES

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

THE DAN FIELD



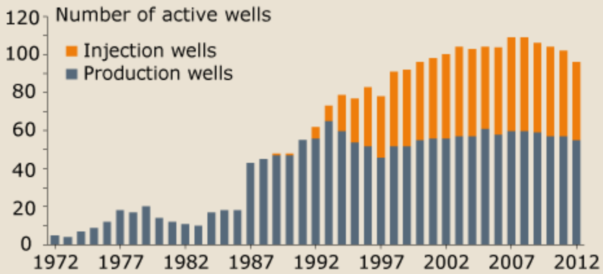




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013

2012 prices DKK 31.90 billion



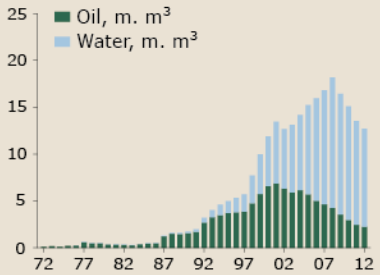
FIELD DATA At 1 January 2013

Prospect:	Abby
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Oile og Gas A/S
Discovered:	1971
Year on stream:	1972
Production wells:	62
Water-injection wells:	49
Water depth:	40 m
Field delineation:	104 km^2
Reservoir depth:	1,850 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2013

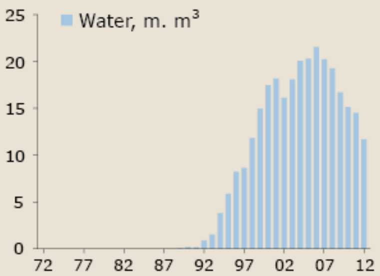
Oil:	106.50 m. m^3
Gas:	23.38 bn. Nm^3
Water:	141.81 m. m^3



INJECTION

Cum. injection at 1 January 2013

Water:	285.44 m. m^3



RESERVES *

Oil:	18.4 mio. m^3
Gas:	2.5 bn. Nm^3

**) Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE DAN FIELD

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

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

PRODUCTION STRATEGY

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

PRODUCTION FACILITIES

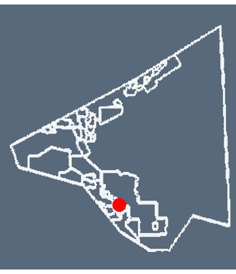
The Dan Field comprises two manned installations consisting of five wellhead platforms, A, D, FA, FB and FE, a combined wellhead and processing platform, FF, a processing platform with a flare tower, FG, two processing and accommodation platforms, B and FC, and two gas flare stacks, C and FD. In addition, the field has an unmanned injection platform, E.

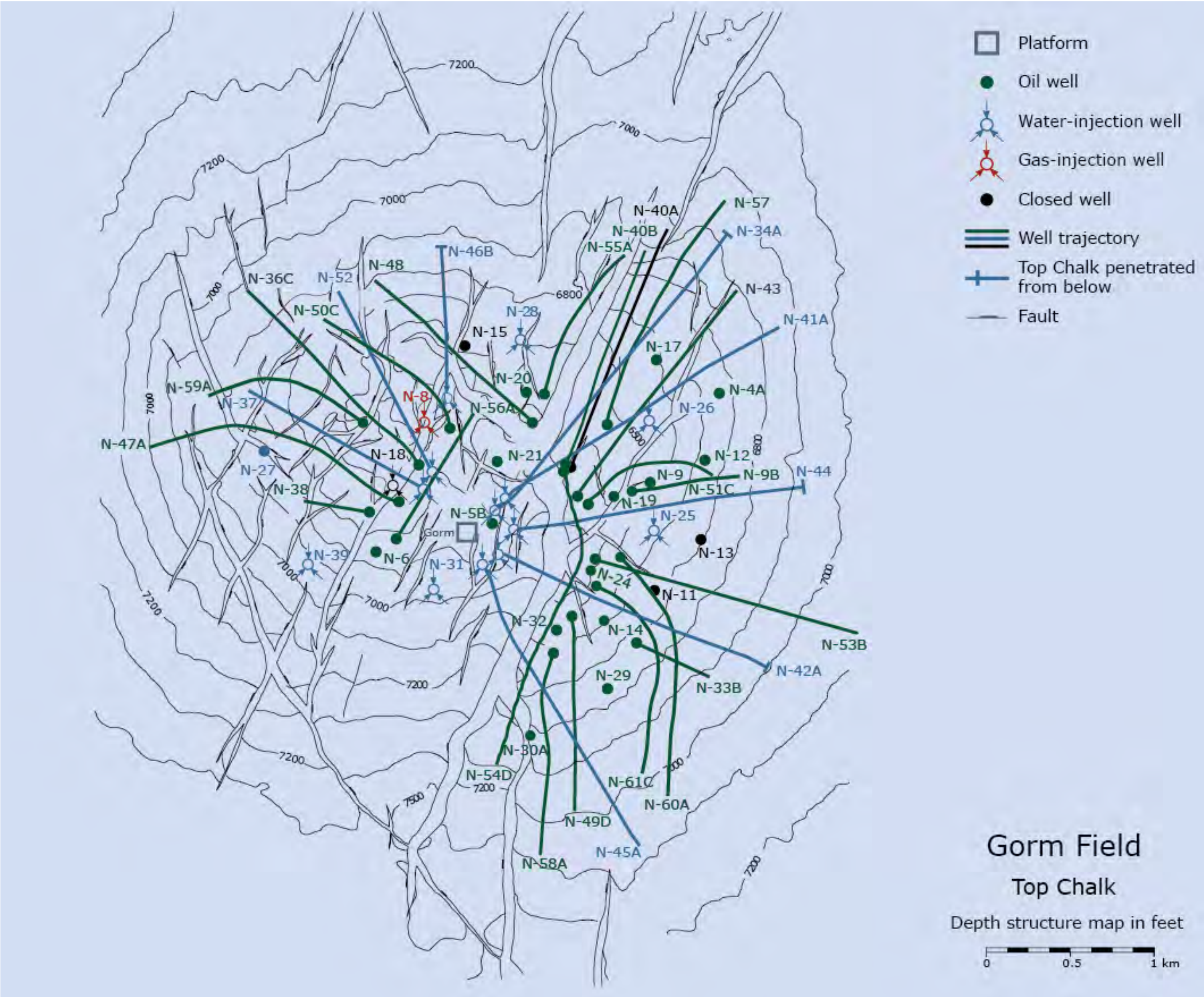
On the Dan F installation there are facilities for receiving production from the adjacent unmanned Kraka and Regnar satellite fields, as well as for receiving some of the gas produced at the Halfdan Field. The Dan F and Dan E installations supply the Halfdan Field with injection water.

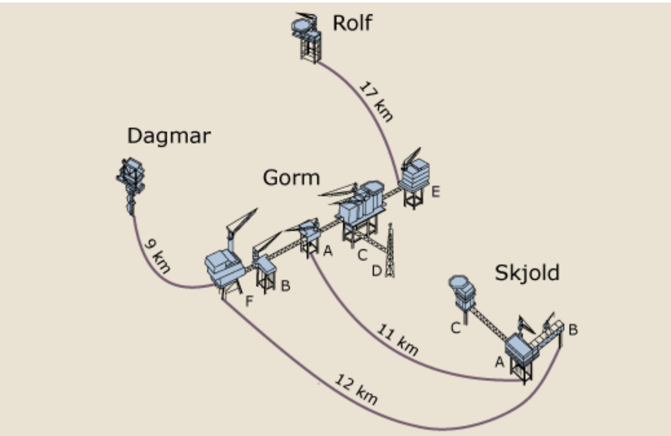
After final processing, the oil is transported to shore via the Gorm installation. The gas is pre-processed and transported to the Tyra East installation for final processing. Production water from the Dan Field and its satellite fields is treated at the Dan F installation before being discharged into the sea.

In the Dan Field there are accommodation facilities for 95 persons on the FC platform and five persons on the B platform. The accommodation facilities are supplemented by flotels during the execution of major construction works and maintenance programmes.

THE GORM FIELD

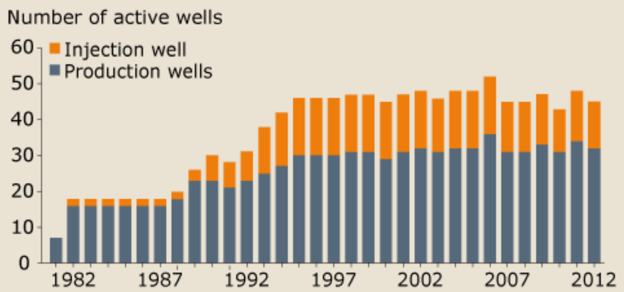






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013
2012 prices DKK 15.55 billion



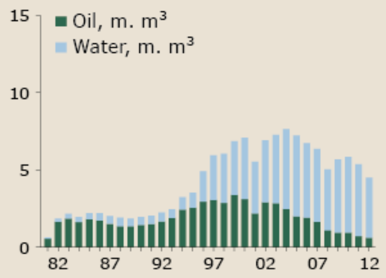
FIELD DATA At 1 January 2013

Prospect:	Vern
Location:	Blocks 5504/15 and 16
Licence:	Sole Concession
Operator:	Mærsk Oil and Gas A/S
Discovered:	1971
Year on stream:	1981
Production wells:	32
Gas-injection wells:	1
Water-injection wells:	14
Water depth:	39 m
Field delineation:	63 km²
Reservoir depth:	2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2013

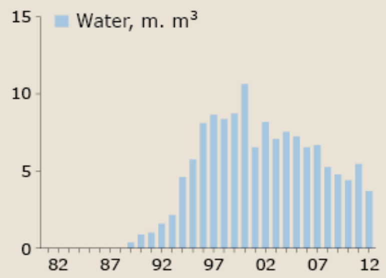
Oil:	60.25 m. m³
Gas:	15.68 bn. Nm³
Water:	76.69 m. m³



INJECTION

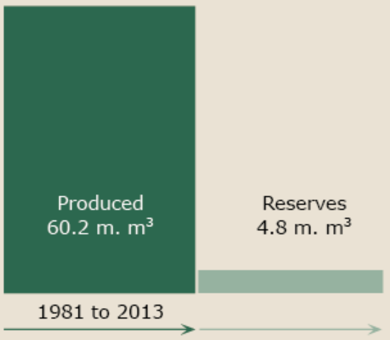
Cum. injection at 1 January 2013

Gas:	8.16 bn. Nm³
Water:	134.28 m. m³



RESERVES *

Oil:	4.8 m. m³
Gas:	0.5 bn. Nm³



**) Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE GORM FIELD

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

PRODUCTION STRATEGY

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

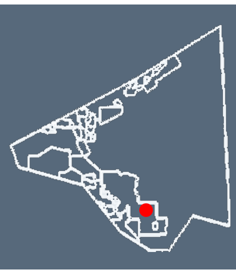
PRODUCTION FACILITIES

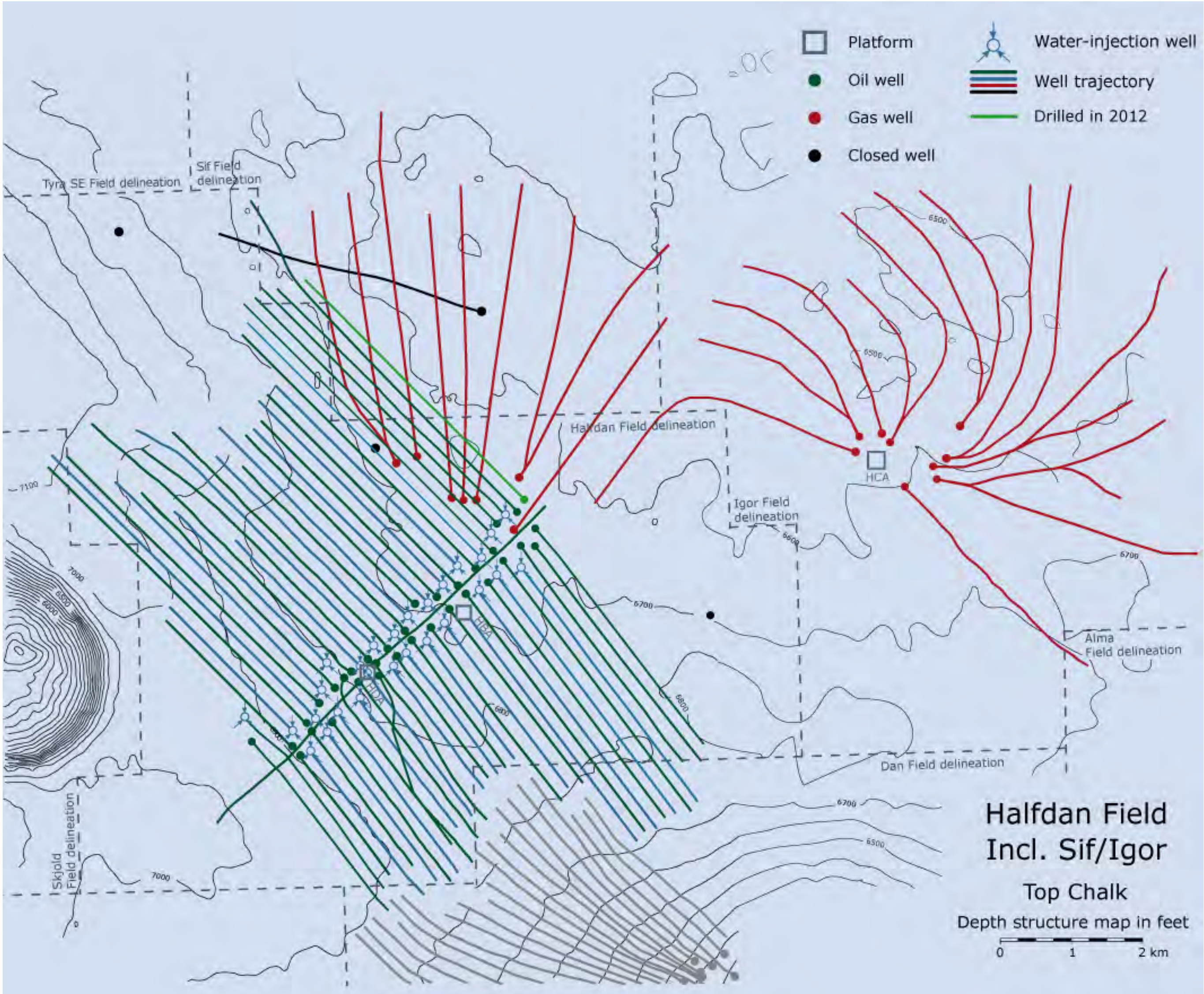
The Gorm Field consists of two wellhead platforms, Gorm A and B, one processing and accommodation platform, Gorm C, one gas flare stack, Gorm D, one riser and export platform, Gorm E (owned by DONG Oil Pipe A/S) and one combined wellhead, processing and riser platform, Gorm F.

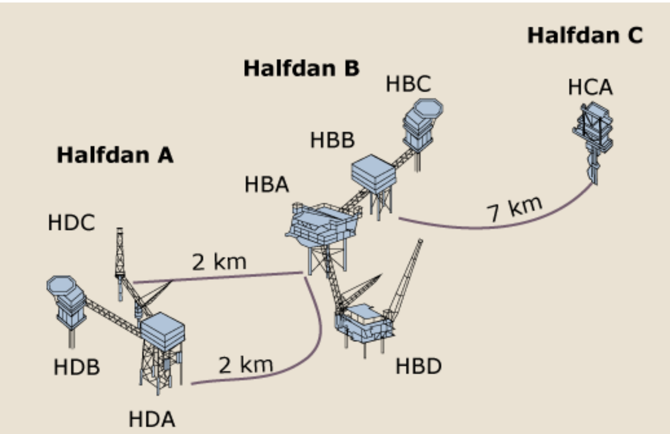
Gorm receives production from the satellite fields, Skjold, Rolf and Dagmar. The Gorm Field installations supply the Skjold Field with injection water and lift gas and the Rolf Field with lift gas. The stabilized oil from all DUC's facilities is transported ashore via the riser platform Gorm E. The gas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

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

THE HALFDAN FIELD INCL. SIF AND IGOR

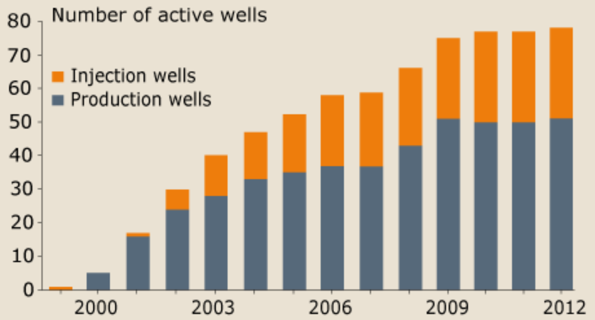






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013
2012 prices DKK 22.23 billion



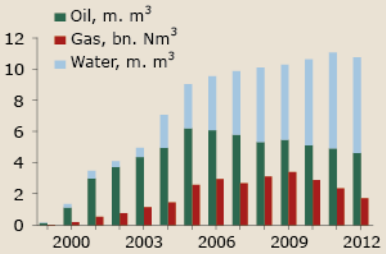
FIELD DATA At 1 January 2013

Prospect:	Nana, Sif and Igor
Location:	Blocks 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Oile og Gas A/S
Discovered:	1968, 1999
Year on stream:	1999, 2004 and 2007
Oil-producing wells:	37 (Halfdan)
Water-injection wells:	27 (Halfdan)
Gas-producing wells:	16 (Sif and Igor)
Reservoir depth:	2,030-2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2013

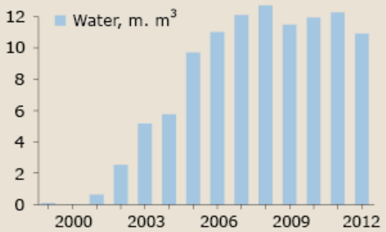
Oil:	60.83 m. m^3
Gas:	25.73 bn. Nm^3
Water:	41.62 m. m^3



INJECTION

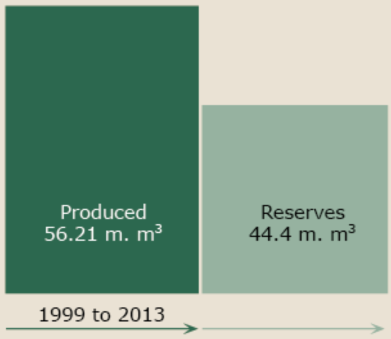
Cum. injection at 1 January 2013

Water:	106.36 m. m^3



RESERVES *

Oil:	39.8 m. m^3
Gas:	6.3 bn. Nm^3



**) Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE HALFDAN FIELD

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

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

PRODUCTION STRATEGY

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

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

PRODUCTION FACILITIES

The Halfdan Field comprises two installations, Halfdan A and Halfdan B, as well as an unmanned wellhead platform, Halfdan CA. The distance between Halfdan A and Halfdan B is about 2 km.

Halfdan CA is located about 7 km northeast of the Halfdan B complex.

The Halfdan A complex has accommodation facilities for 32 persons, while there are accommodation facilities for 80 persons at the Halfdan B complex.

From the Halfdan A installation (HDA), HP gas can be imported and exported through a 12" pipeline to the Dan installation, and LP gas can be exported through another 12” pipeline. Lift gas is exported/imported between Halfdan A and Halfdan B through a 6” pipeline.

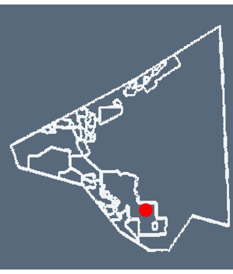
The Dan installation supplies both Halfdan A and Halfdan B with injection water through a 16” pipeline. Injection water is transported to Halfdan B via Halfdan A.

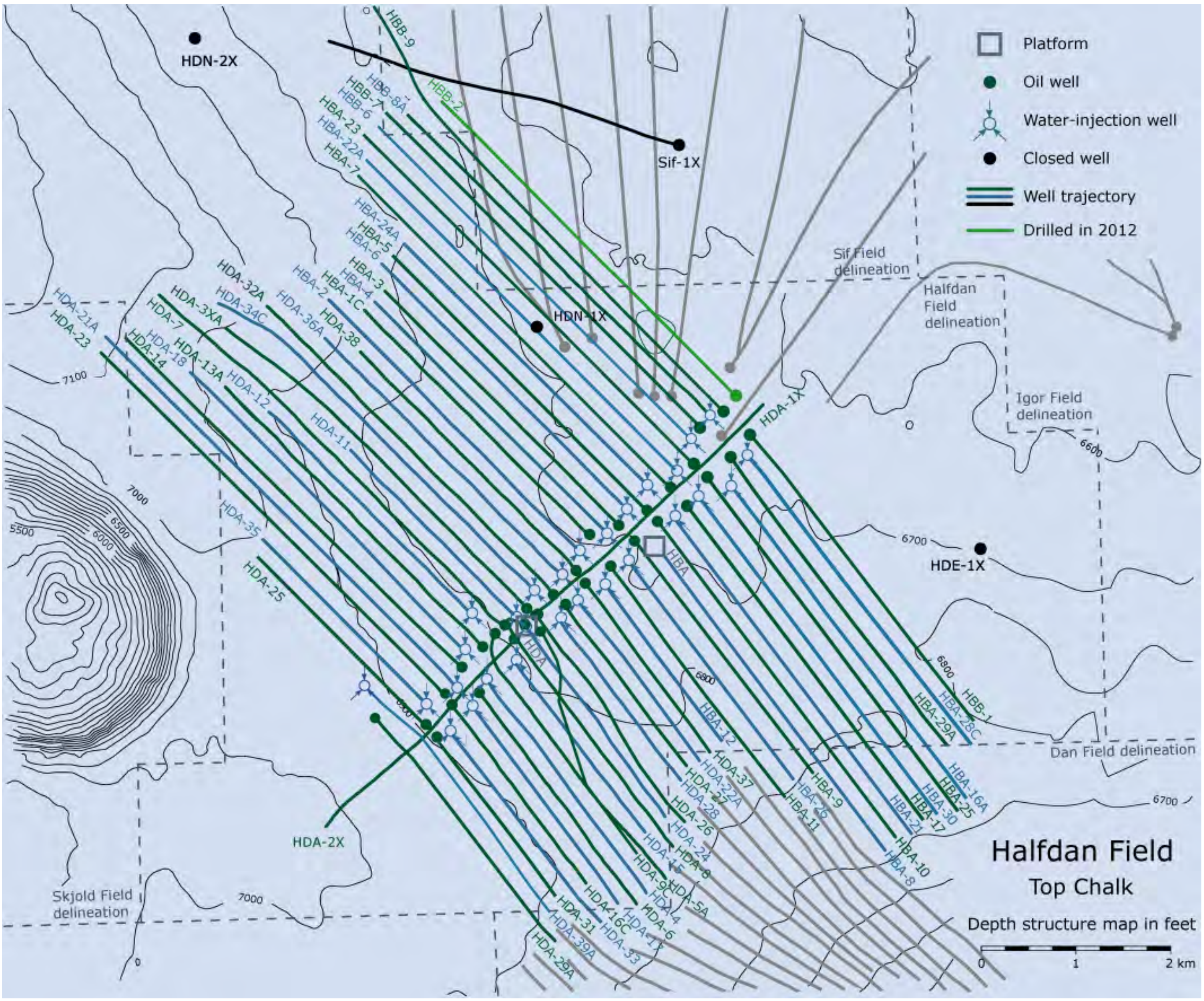
Water produced at Halfdan A and Halfdan B is discharged into the sea. No produced water is discharged from Halfdan CA.

Halfdan A and Halfdan B have their own power supply, but a 3 kW cable has been laid between Halfdan A and Halfdan B that can be used in case of power failure, etc. Halfdan CA is provided with power from Halfdan B.

More details about the facilities can be found on the next two pages.

THE HALFDAN FIELD (MAIN FIELD)





FIELD DATA	At 1 January 2013
Prospect:	Nana
Location:	Blocks 5505/13 and 5504/16
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered:	1999
Year on stream:	1999
Oil-producing wells:	37 (Halfdan)
Water-injection wells:	27 (Halfdan)
Water depth:	43 m
Field delineation:	100 km^2
Reservoir depth:	2,030-2,100 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

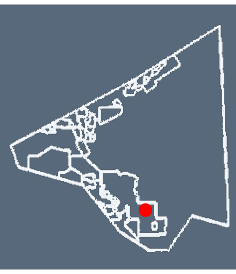
Halfdan A consists of a combined processing and wellhead platform, HDA, an accommodation platform, HDB, and a gas flare stack, HDC. The platforms are interconnected by combined foot and pipe bridges.

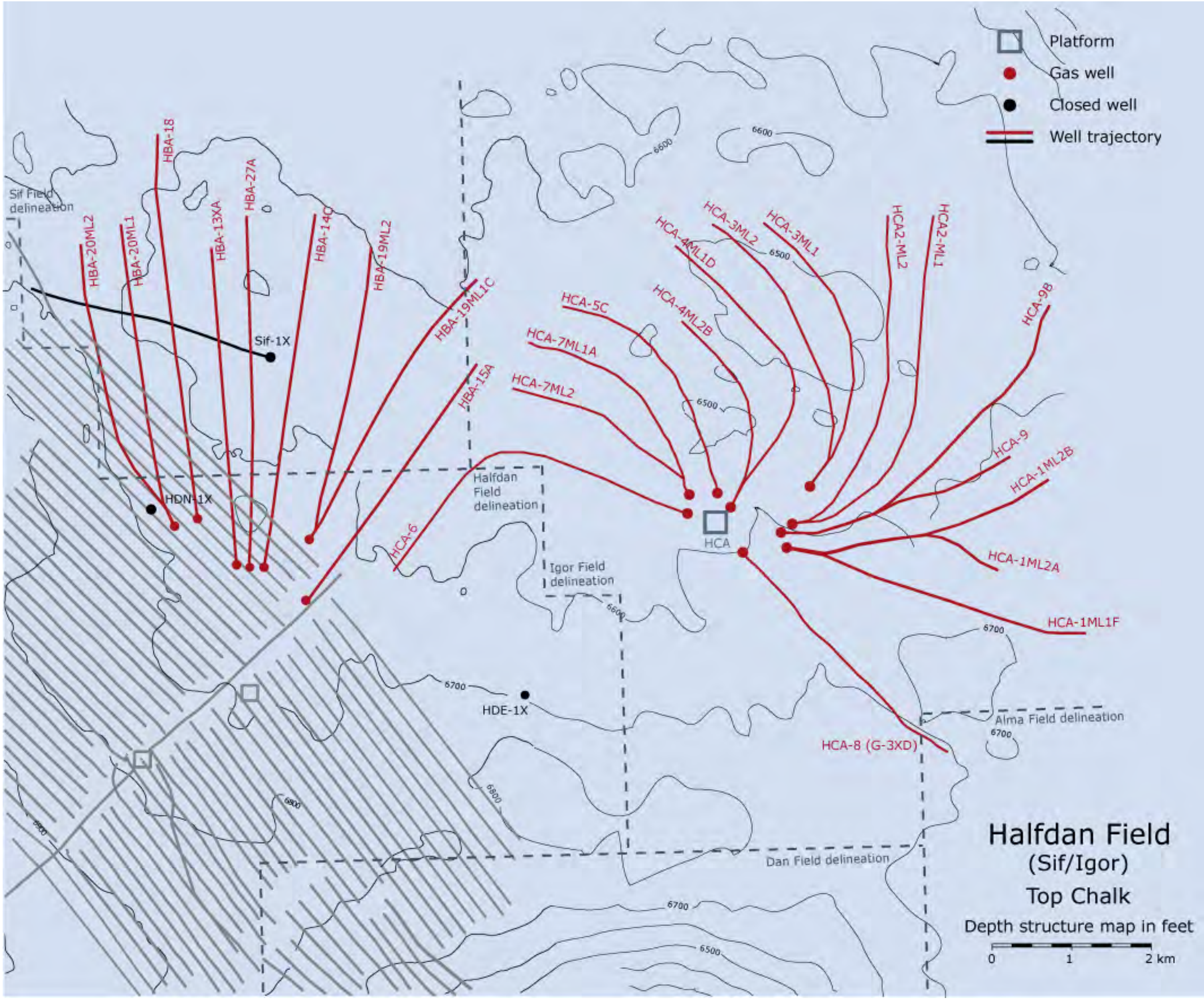
The gas produced at Halfdan A is transported to Tyra West through a 24” pipeline. The oil produced is conveyed to Gorm through a 14” pipeline.

Halfdan B consists of a wellhead platform, HBA, a riser platform, HBB, an accommodation platform, HBC, and a processing platform, HBD. The platforms are interconnected by combined foot and pipe bridges.

The gas is conveyed through a 16” pipeline, which is connected to a 24" pipeline leading to Tyra West. The oil is transported through a 14" pipeline to the riser at Halfdan A, from where it is transported to Gorm through the 14" pipeline connecting Halfdan with Gorm.

THE HALFDAN FIELD (NORTHEAST)



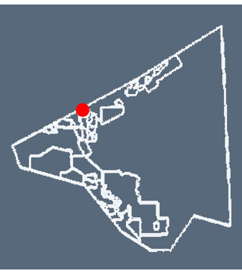


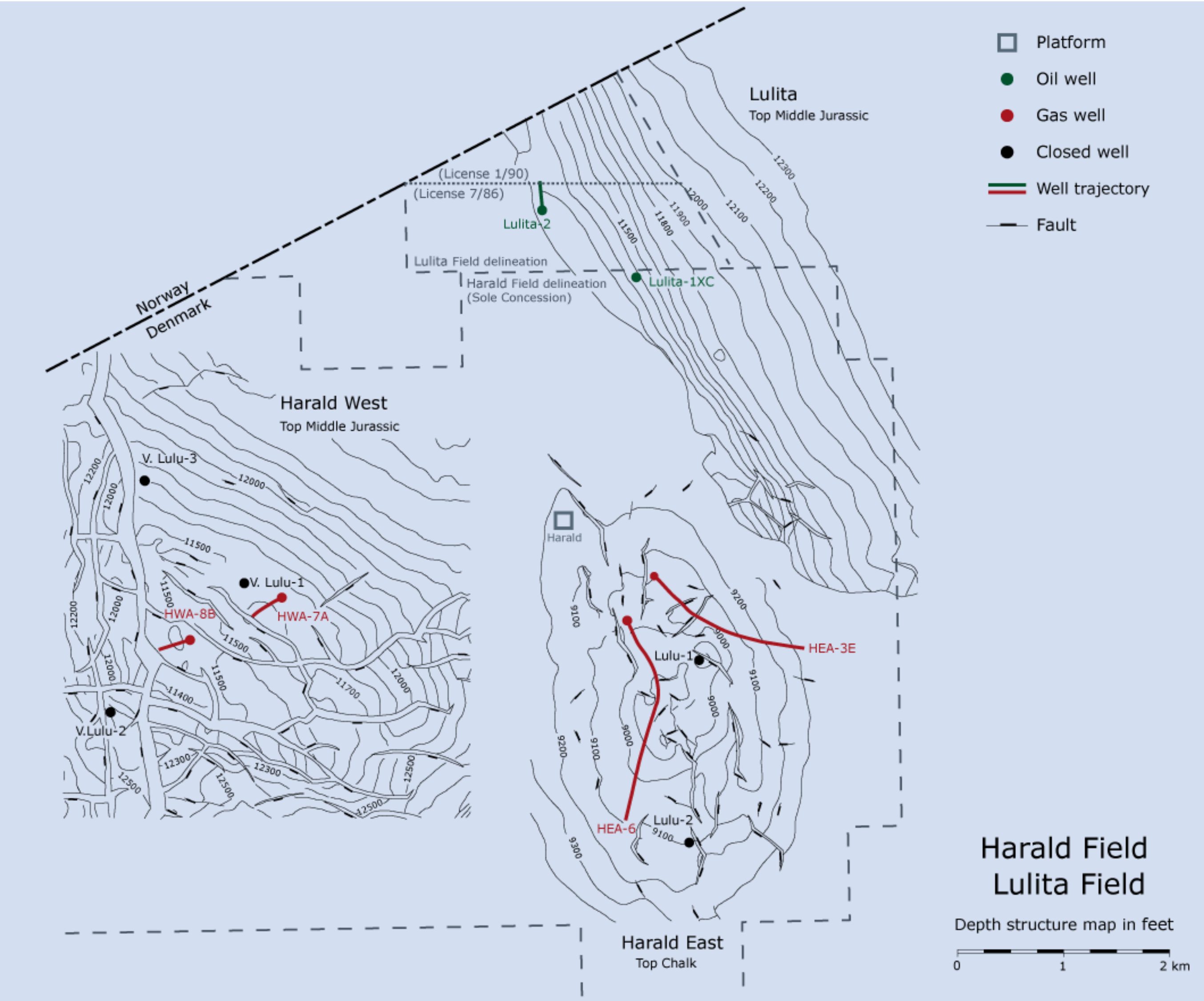
FIELD DATA	At 1 January 2013
Prospect:	Sif and Igor
Location:	Block 5505/13
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered:	1999 (Sif), 1968 (Igor)
Year on stream:	2004 (Sif), 2007 (Igor)
Gas-producing wells:	7 (Sif), 9 (Igor)
Water depth:	44 m (Sif), 45 m (Igor)
Field delineation:	40 km^2 (Sif)
	109 km^2 (Igor)
Reservoir depth:	2,030 m
Reservoir rock:	Chalk
Geological age:	Danian

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

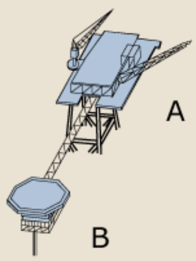
The gas is conveyed via the Halfdan B riser to Tyra West, while condensate is transported to Halfdan B (HBD) for processing. From Halfdan B, the oil is then transported to the Gorm installation via the riser on the Halfdan A complex (HDA).

THE HARALD FIELD





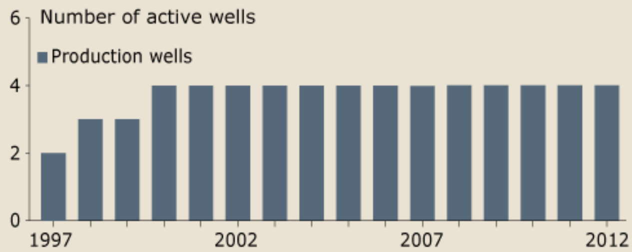
Harald / Lulita



DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013

2012 prices DKK 4.37 billion



FIELD DATA

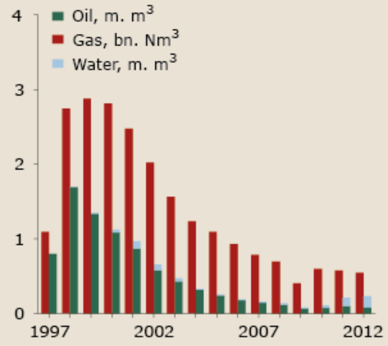
At 1 January 2013

Prospect:	Lulu/West Lulu
Location:	Blocks 5604/21 and 22
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered:	1980 (Lulu) 1983 (West Lulu)
Year on stream:	1997
Gas-producing wells:	2 (Harald East) 2 (Harald West)
Water depth:	64 m
Field delineation:	56 km²
Reservoir depth:	2,700 m (Harald East) 3,650 m (Harald West)
Reservoir rock:	Chalk (Harald East) Sandstone (Harald West)
Geological age:	Danian/Upper Cretaceous (Harald East) and Middle Jurassic (Harald West)

PRODUCTION

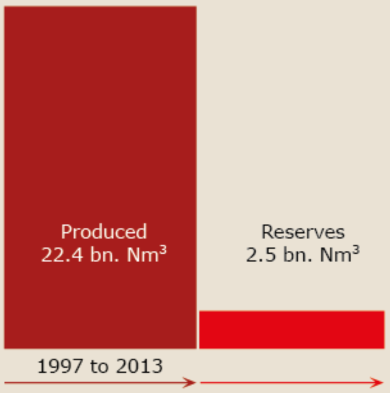
Cum. production at 1 January 2013

Oil:	8.06 m. m³
Gas:	22.41 bn. Nm³
Water:	0.67 m. m³



RESERVES *

Oil:	0.3 m. m³
Gas:	2.5 bn. Nm³



*) *Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE HARALD FIELD

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

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

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

PRODUCTION STRATEGY

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

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

PRODUCTION FACILITIES

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

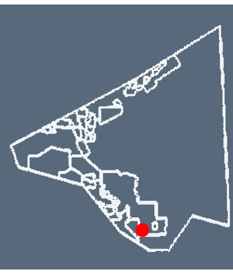
The Harald Field is hooked up to the gas pipeline that transports gas from the South Arne Field to Nybro. Normally, no gas is exported from Harald through the South Arne pipeline.

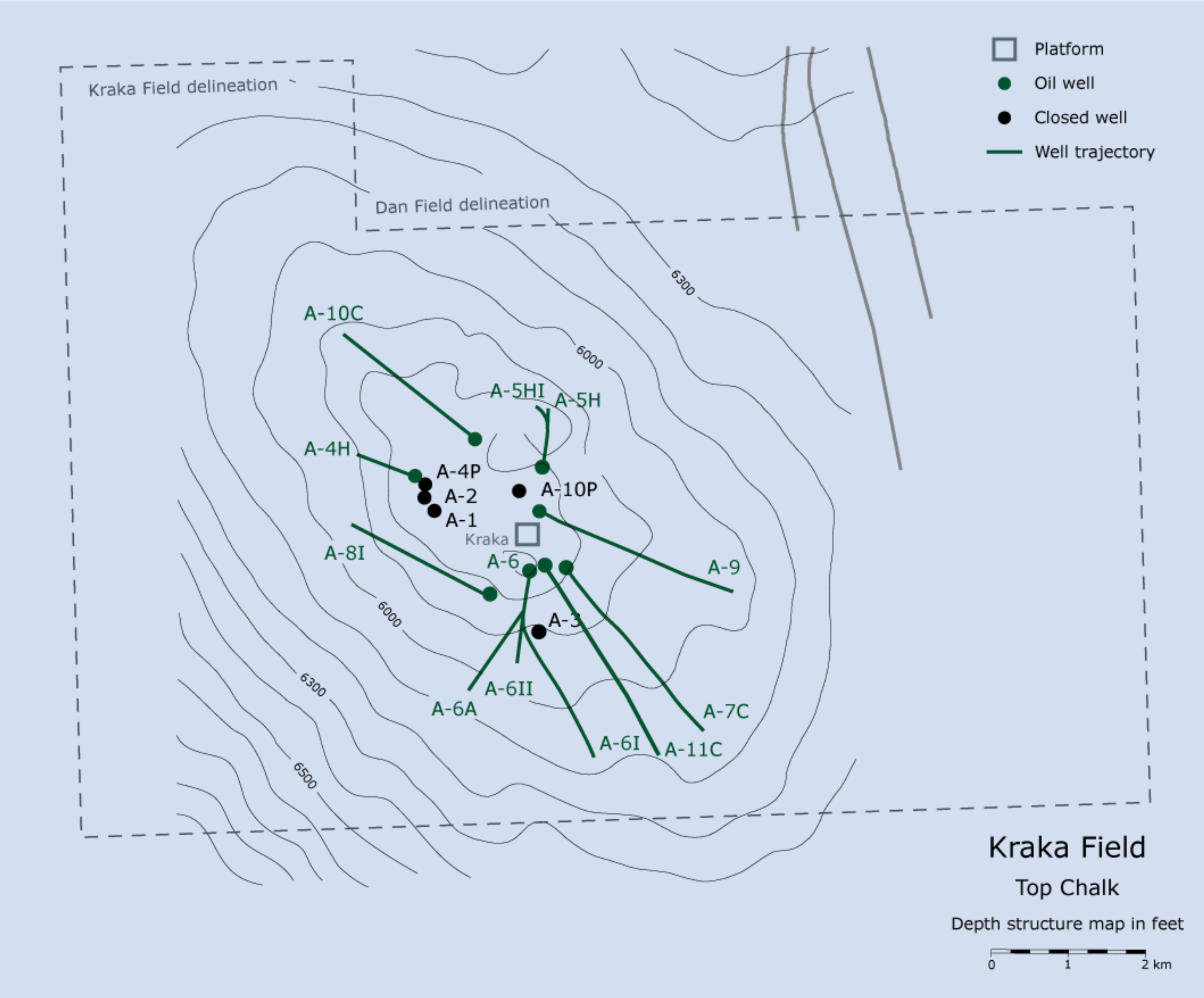
The Norwegian Trym gas field is connected by an 8" multiphase pipeline to the Harald Field, from where the production is transported to Tyra East. The Harald A platform has special equipment for separate metering of the oil and gas produced from Trym.

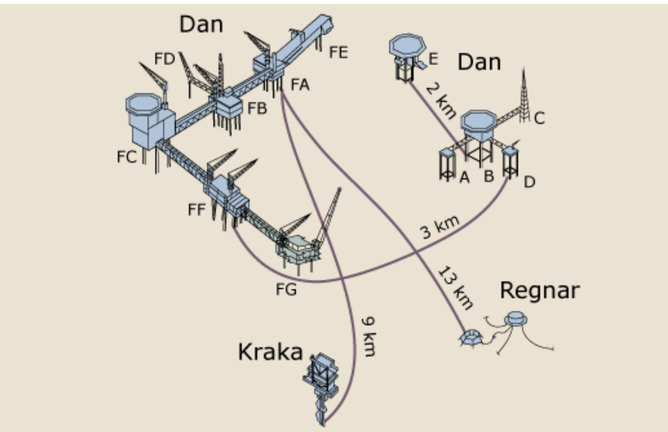
The Harald Field has accommodation facilities for 16 persons.

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

THE KRAKA FIELD



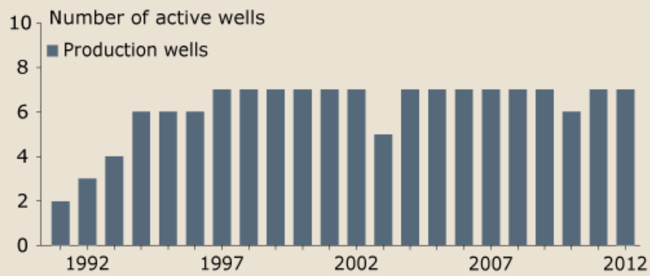




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013

2012 prices	DKK 2.02 billion



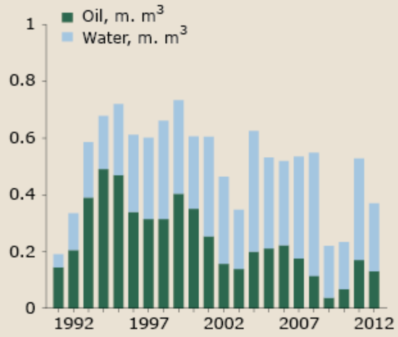
FIELD DATA At 1 January 2013

Prospect:	Anne
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered:	1966
Year on stream:	1991
Production wells:	8
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 2013

Oil:	5.29 m. m^3
Gas:	1.48 bn. Nm^3
Water:	5.95 m. m^3



RESERVES *

Oil:	0.7 m. m^3
Gas:	0.1 bn. Nm^3

*) Reserves as calculated at 1 January 2012 less the production for 2012.

REVIEW OF GEOLOGY, THE KRAKA FIELD

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

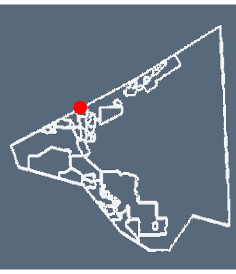
PRODUCTION STRATEGY

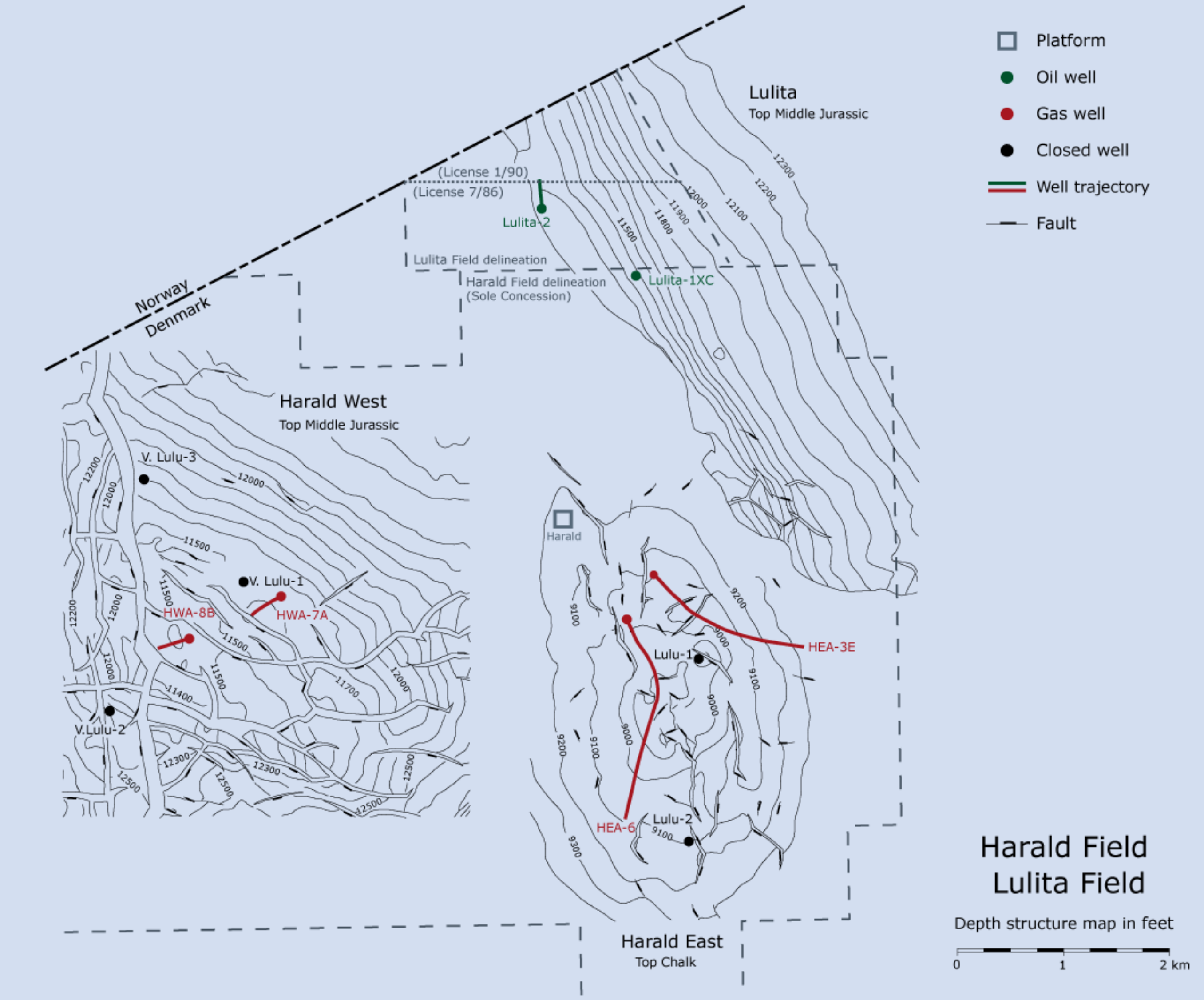
Recovery from Kraka is based on the natural expansion of the gas cap and aquifer support. The individual wells are produced at the lowest possible bottom-hole pressure. Oil production from the field is maximized by prioritizing gas lift in wells with a low water content and a low gas-oil ratio.

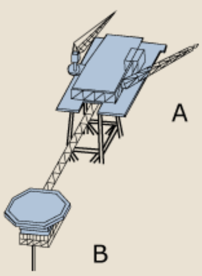
PRODUCTION FACILITIES

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

THE LULITA FIELD

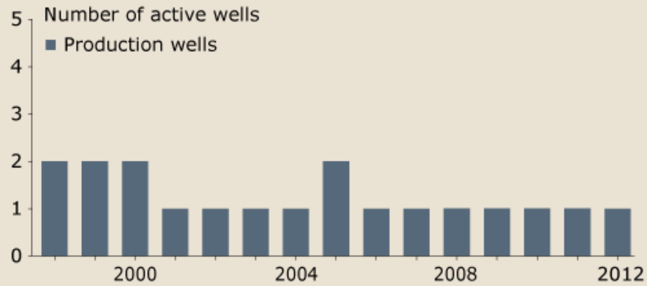






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013
2012 prices DKK 0.11 billion



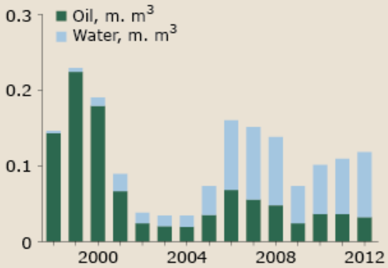
FIELD DATA At 1 January 2013

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 A/S
Discovered:	1992
Year on stream:	1998
Production wells:	2
Water depth:	65 m
Field delineation:	4 km^2
Reservoir depth:	3,525 m
Reservoir rock:	Sandstone
Geological age:	Middle Jurassic

PRODUCTION

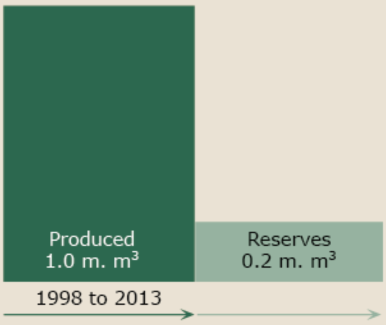
Cum. production at 1 January 2013

Oil:	1.01 m. m^3
Gas:	0.64 bn. Nm^3
Water:	0.67 m. m^3



RESERVES *

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



**) Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE LULITA FIELD

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

PRODUCTION STRATEGY

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

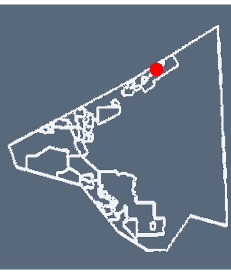
PRODUCTION FACILITIES

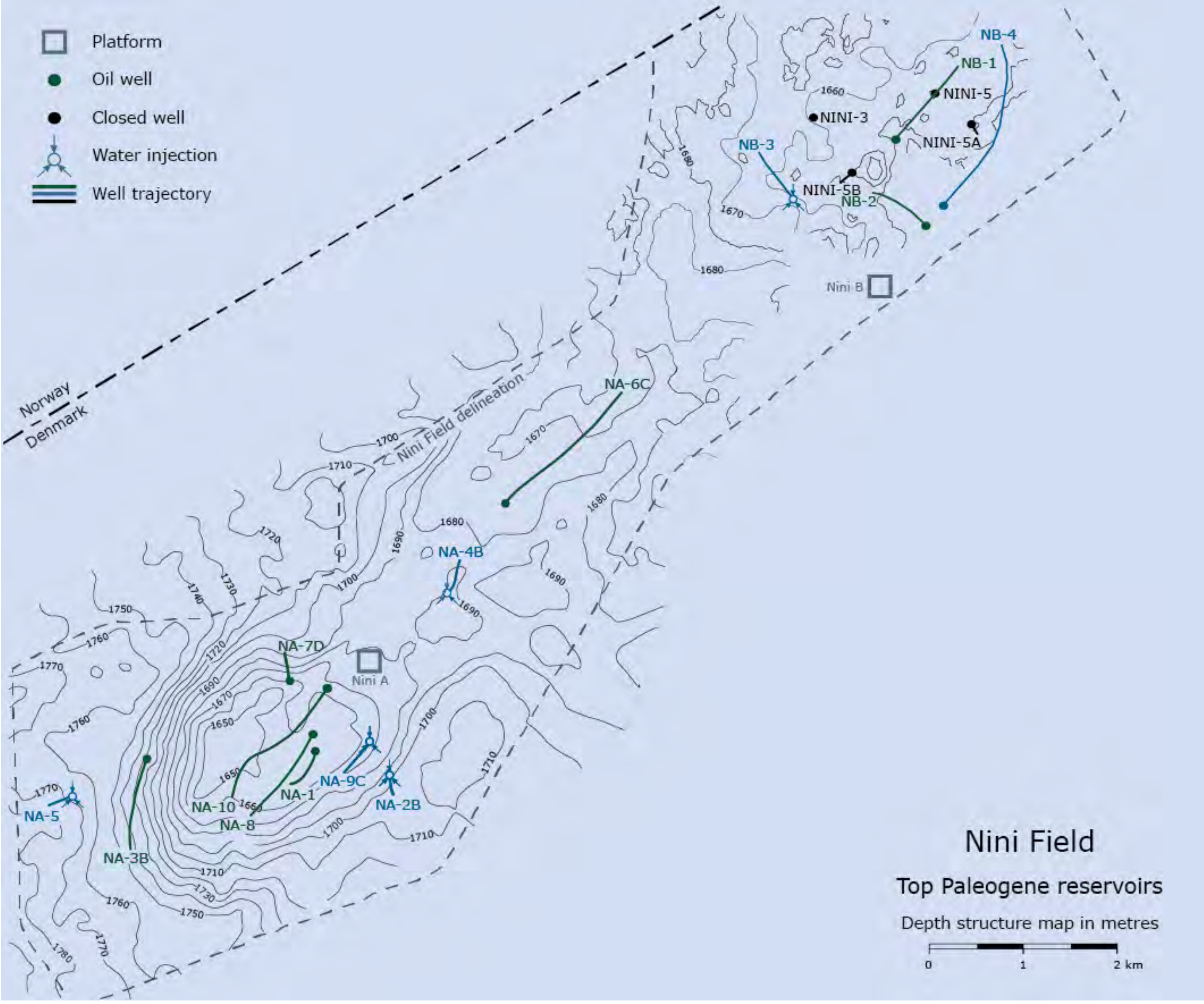
Production from the Lulita Field takes place from the fixed installations in the Harald Field. Thus, the Lulita facilities are hosted by the Harald A platform, and the Harald platform processing equipment also handles production from the Lulita Field.

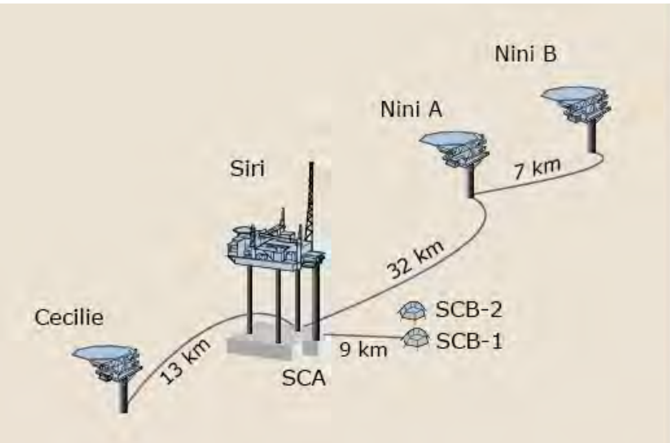
Together with condensate from the Harald Field, the oil produced is transported through a 16” pipeline to Tyra East for export ashore. The gas produced in the Lulita Field is transported to Tyra through the 24” pipeline connecting Harald with Tyra East, from where it is transported to shore. The water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

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

THE NINI FIELD



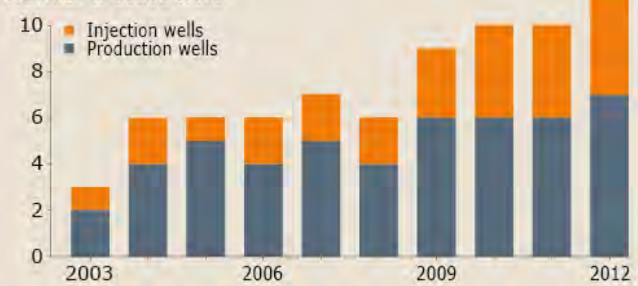




DEVELOPMENT AND INVESTMENT

Cum. investment at 1 January 2013
2012 prices DKK 5.60 billion

Number of active wells



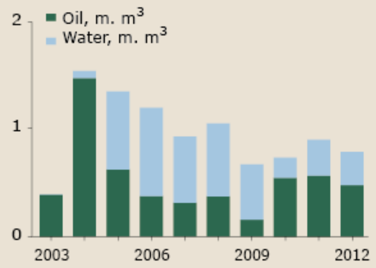
FIELD DATA At 1 January 2013

Location:	Blocks 5605/10 and 14
Licence:	4/95
Operator:	DONG E&P A/S
Discovered:	2000
Year on stream:	2003
Production wells:	8
Water-injection wells:	6
Water depth:	60 m
Field delineation:	45 km^2
Reservoir depth:	1,700 m
Reservoir rock:	Sandstone
Geological age:	Eocene/Paleocene

PRODUCTION

Cum. production at 1 January 2013

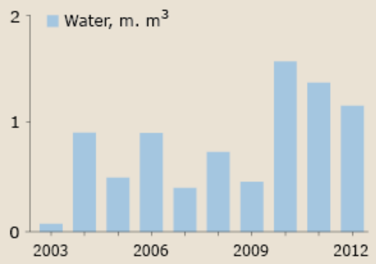
Oil:	5.29 m. m^3
Gas:	0.45 bn. Nm^3
Water:	4.25 m. m^3



INJECTION

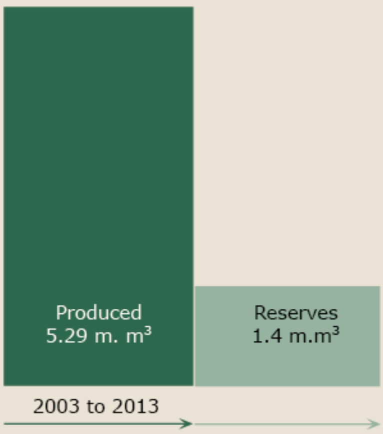
Cum. injection at 1 January 2013

Water:	8.28 m. m^3



RESERVES *

Oil:	1.4 m. m^3
Gas:	0 bn. Nm^3



**) Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE NINI FIELD

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

PRODUCTION STRATEGY

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

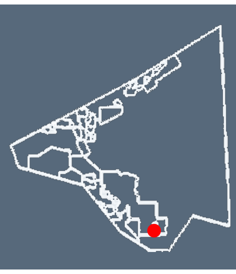
PRODUCTION FACILITIES

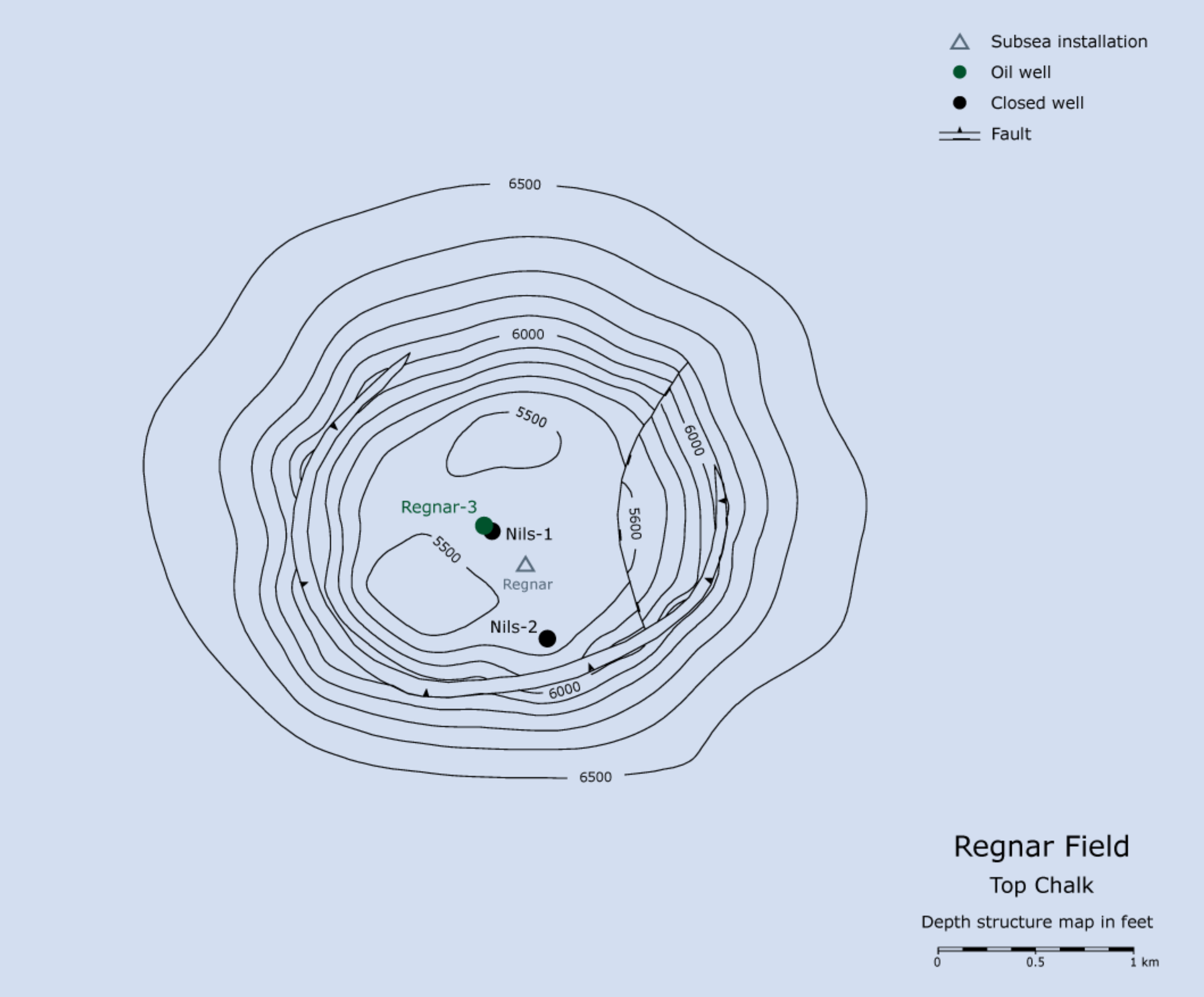
Nini (NA) and Nini East (NB) are satellite developments to the Siri Field with two unmanned wellhead platforms, both with a helideck. The Nini East platform was installed in 2009, and production from the platform started in 2010.

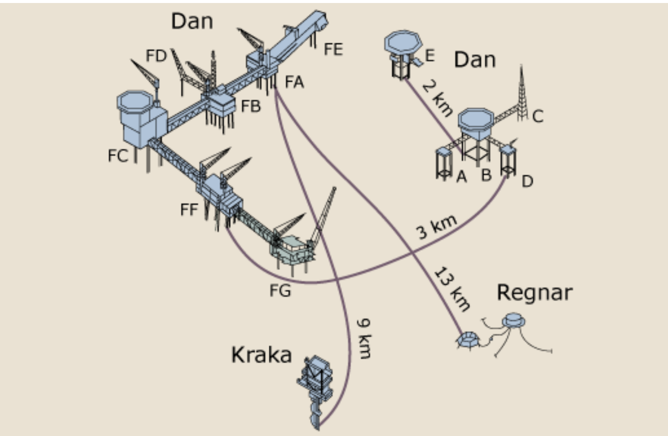
The unprocessed production from Nini East is sent through an 8” multiphase pipeline to Nini. From here, total production from Nini East and Nini is transported through a 14” multiphase pipeline to the Siri platform. The production is processed on the Siri platform and exported to shore via tanker. Siri supplies Nini and Nini East with injection water and lift gas via the Nini platform. Injection water is supplied through a 10” pipeline and lift gas through a 4” pipeline.

The old 10” water-injection pipeline from Siri (SCA) to Nini (NA) was replaced by a new one in 2009, at the same time being extended by a further pipeline to Nini East (NB).

THE REGNAR FIELD



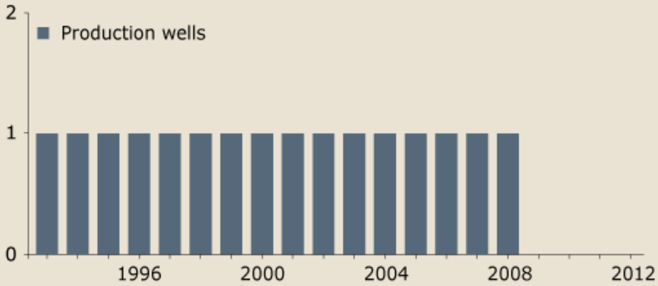




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013
2012 prices DKK 0.29 billion

Number of active wells



FIELD DATA

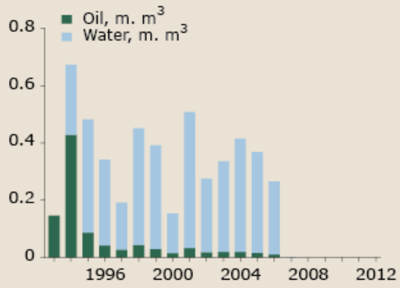
At 1 January 2013

Prospect:	Nils
Location:	Block 5505/17
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered:	1979
Year on stream:	1993
Production wells:	1
Water depth:	45 m
Field delineation:	34 km^2
Reservoir depth:	1,700 m
Reservoir rock:	Chalk
Geological age:	Upper Cretaceous

PRODUCTION

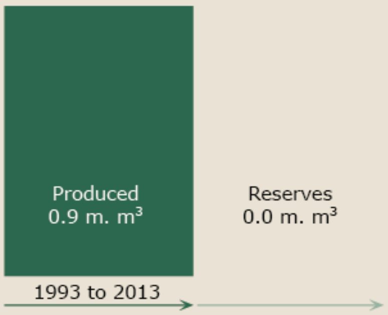
Cum. production at 1 January 2013

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



RESERVES

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



REVIEW OF GEOLOGY, THE REGNAR FIELD

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

PRODUCTION STRATEGY

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

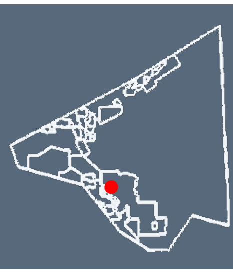
Production in the Regnar Field has been suspended due to problems with the equipment.

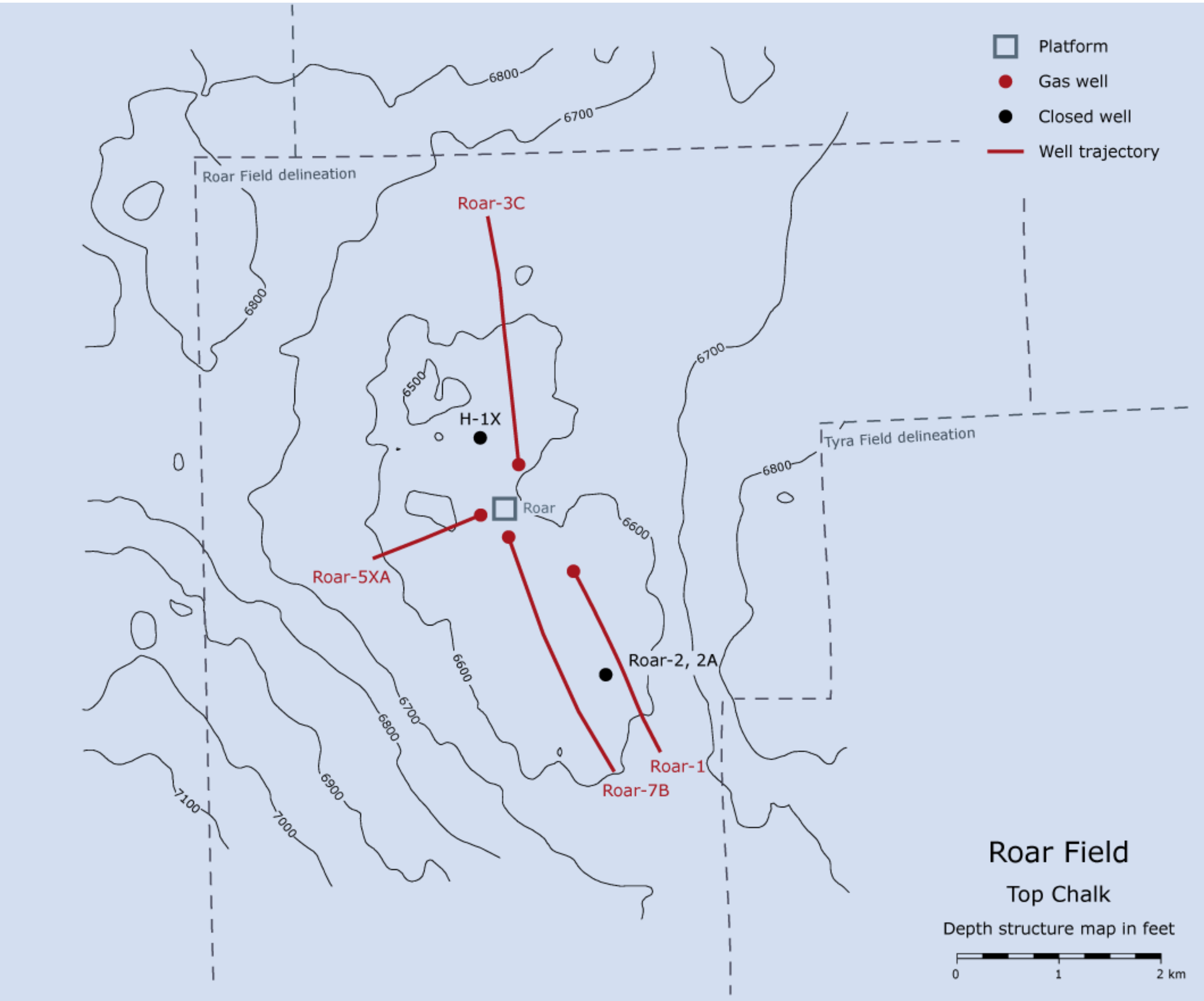
PRODUCTION FACILITIES

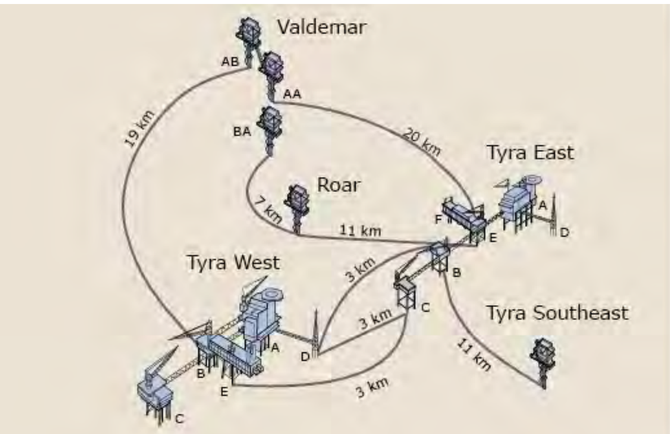
The Regnar Field has been developed as a satellite to the Dan Field and production takes place in a subsea-completed well. The production is transported by a multi-phase pipeline to the Dan F installation for processing and export ashore.

The well is remotely monitored and controlled from the Dan F installation.

THE ROAR FIELD



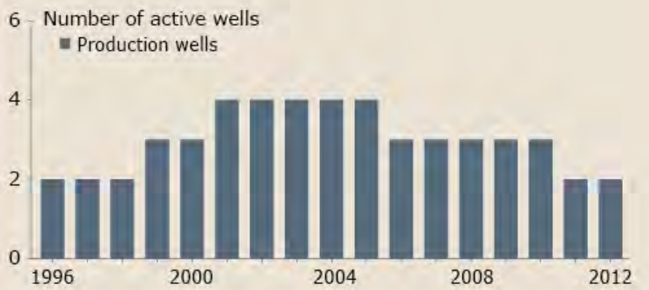




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013

2012 prices DKK 0.73 billion



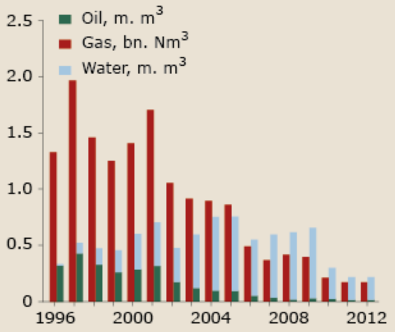
FIELD DATA At 1 January 2013

Prospect:	Bent
Location:	Block 5504/7
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered:	1968
Year on stream:	1996
Gas-producing wells:	4
Water depth:	46 m
Field delineation:	84 km²
Reservoir depth:	2,025 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

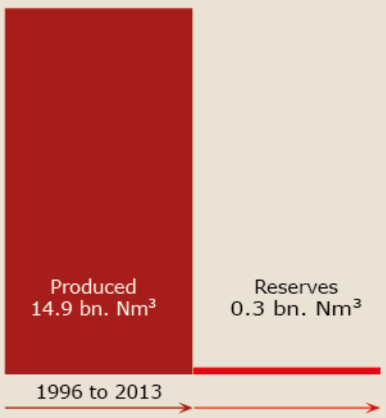
Cum. production at 1 January 2013

Oil:	2.61 m. m^3
Gas:	14.91 bn. Nm^3
Water:	6.03 m. m^3



RESERVES *

Oil:	0.1 m. m^3
Gas:	0.3 bn. Nm^3



**) Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE ROAR FIELD

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

PRODUCTION STRATEGY

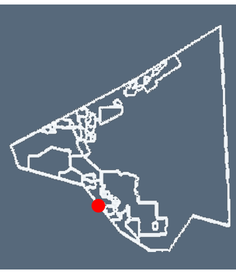
Recovery from the Roar Field takes place by gas expansion. The production strategy for the Roar Field is to optimize the production of liquid hydrocarbons in the Tyra Field by maximizing production from the other gas fields and thus minimizing gas drainage from Tyra.

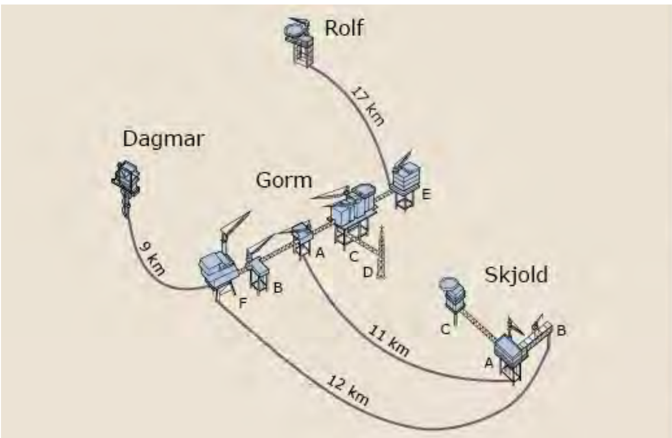
PRODUCTION FACILITIES

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

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

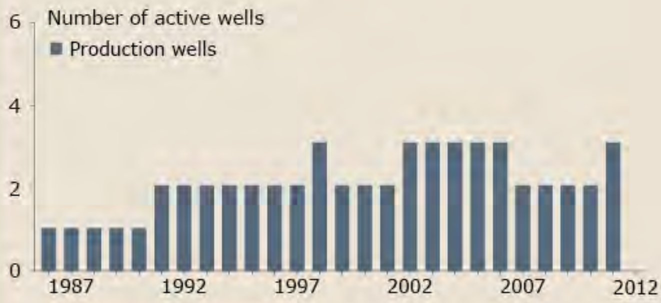
THE ROLF FIELD





DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013
2012 prices DKK 1.26 billion

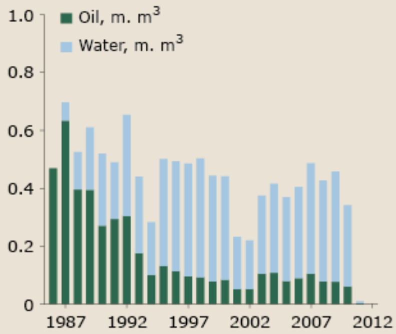


FIELD DATA	At 1 January 2013
Prospect:	Middle Rosa
Location:	Blocks 5504/14 and 15
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered:	1981
Year on stream:	1986
Producing wells:	3
Water depth:	34 m
Field delineation:	22 km²
Reservoir depth:	1,800 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2013

Oil:	4.43 m. m^3
Gas:	0.19 bn. Nm^3
Water:	6.86 m. m^3



RESERVES

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

REVIEW OF GEOLOGY, THE ROLF FIELD

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

PRODUCTION STRATEGY

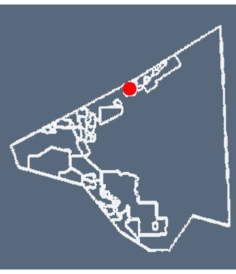
Production from the Rolf Field takes place from two wells drilled in the crest of the structure. The oil is displaced towards the producing wells by the water flow from an underlying aquifer. The natural influx of water from the water zone corresponds to the volume removed due to production in the central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

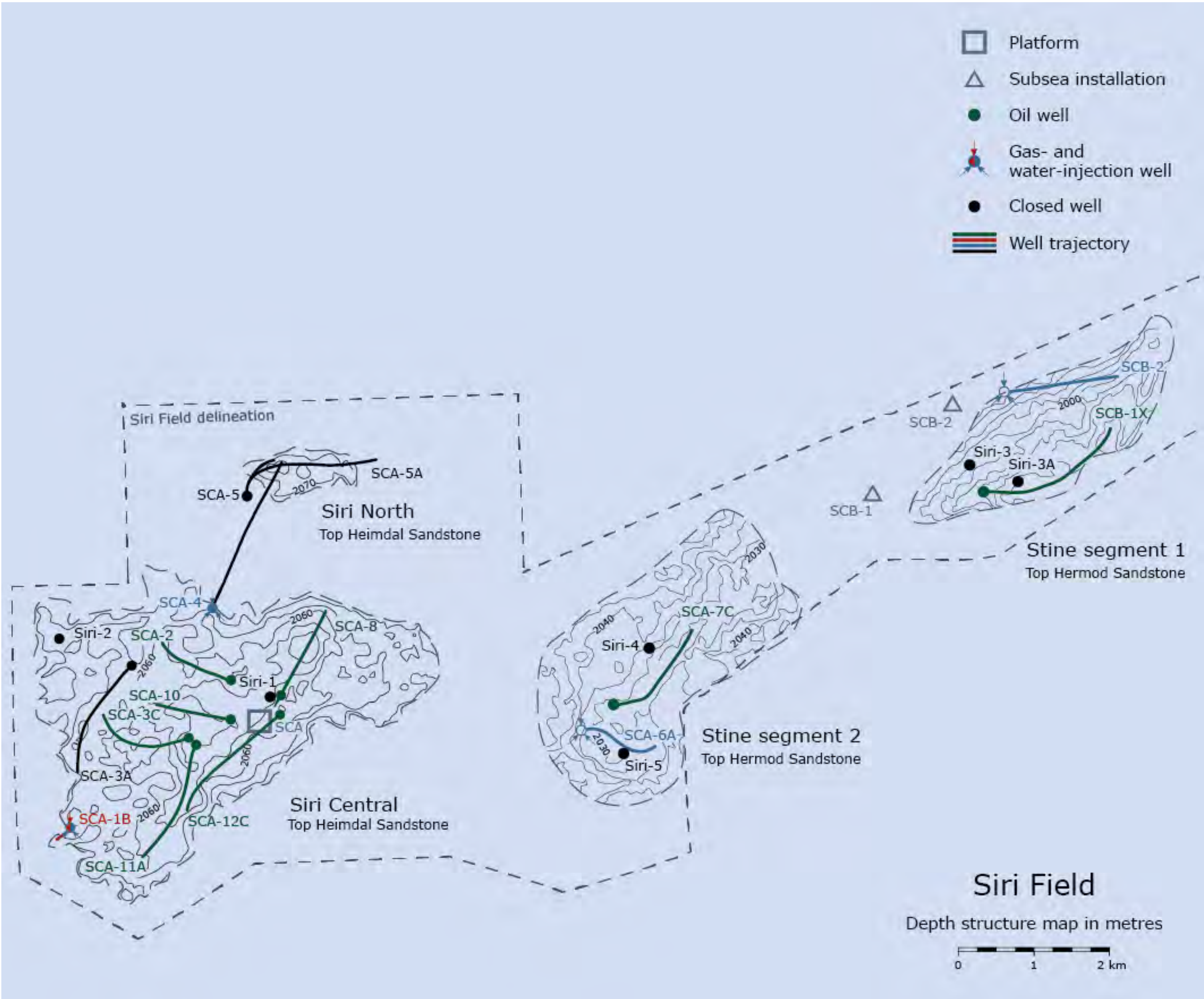
Production from the Rolf Field has been suspended since March 2011 due to a leak in the pipeline from the Rolf Field to the Gorm Field. Efforts are being made to reach a solution.

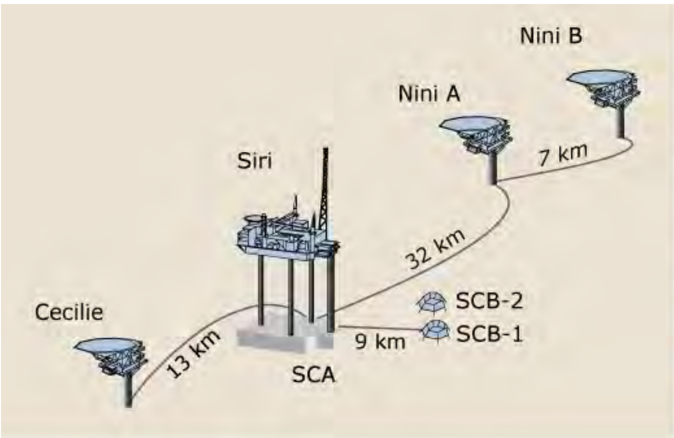
PRODUCTION FACILITIES

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 lift gas from the Gorm Field. The power supply cable is not used because it has been damaged for a prolonged period of time. Instead diesel generators are used to supply power for the Rolf Field.

THE SIRI FIELD



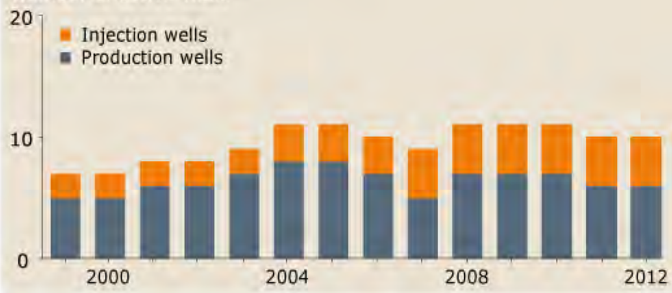




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013
2012 prices DKK 7.10 billion

Number of active wells



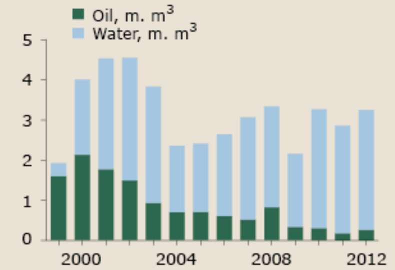
FIELD DATA At 1 January 2013

Location:	Block 5604/20
Licence:	6/95
Operator:	DONG E&P A/S
Discovered:	1995
Year on stream:	1999
Producing wells:	6 (Siri central) 1 (Stine segment 1) 1 (Stine segment 2)
Water-/gas-injection wells:	2 (Siri central) 1 (Stine segment 1) 1 (Stine segment 2)
Water depth:	60 m
Field delineation:	63 km²
Reservoir depth:	2,060 m
Reservoir rock:	Sandstone
Geological age:	Paleocene

PRODUCTION

Cum. production at 1 January 2013

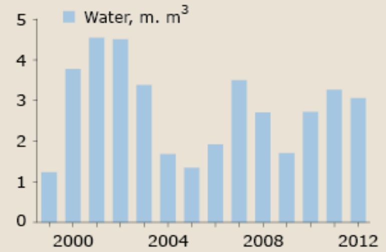
Oil:	11.99 m. m³
Gas:	1.33 bn. Nm³
Water:	31.56 m.m³



INJECTION

Cum. injection at 1 January 2013

Gas:	1.25 bn. Nm³
Water:	39.22 m. m³



RESERVES *

Oil:	1.6 m. m³
Gas:	0.0 bn. Nm³

**) Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE SIRI FIELD

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

PRODUCTION STRATEGY

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

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

PRODUCTION FACILITIES

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

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

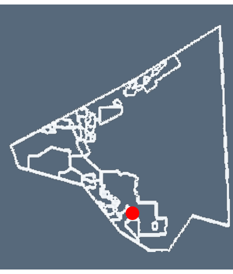
Stine segment 1 (SCB) has been developed as a satellite to the Siri platform and consists of two subsea installations with a production well and an injection well.

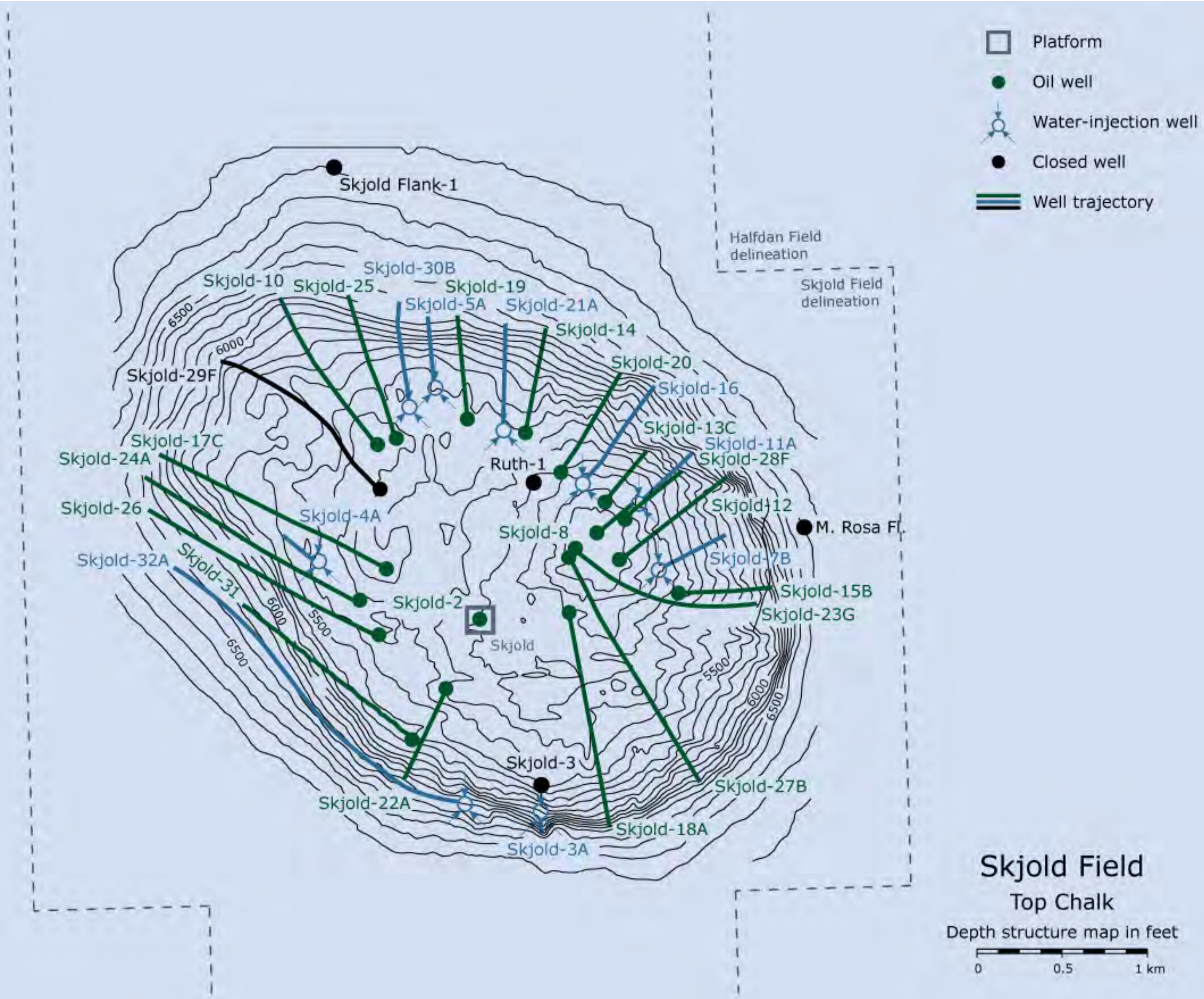
Production from SCB is conveyed to the SCA platform for processing. The SCA platform also supplies injection water and lift gas to the satellite installations at SCB, Nini, Nini East and Cecilie. The water-injection pipeline to Nini was replaced in 2009 and extended by a further pipeline to Nini East. Injection water is supplied to SCB via a branch of this pipeline.

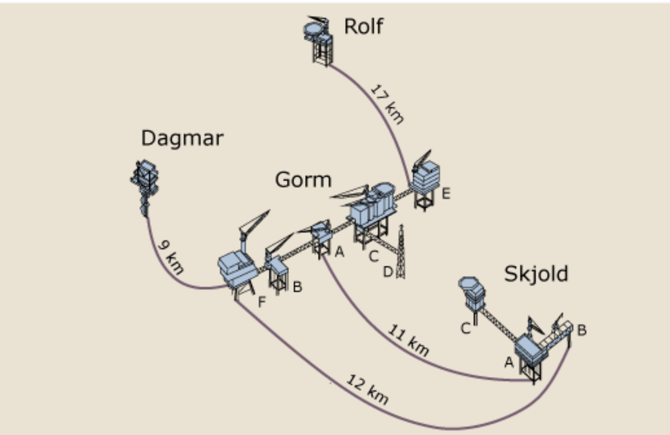
The oil produced is piped to a 50,000 m³ storage tank on the seabed, and subsequently transferred to a tanker by means of buoy-loading facilities.

The Siri Field has accommodation facilities for 60 persons.

THE SKJOLD FIELD

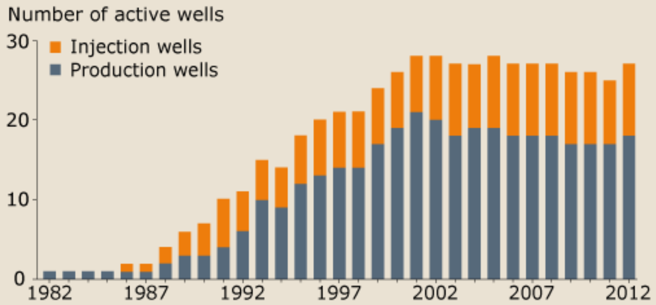






DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013
2012 prices DKK 6.60 billion



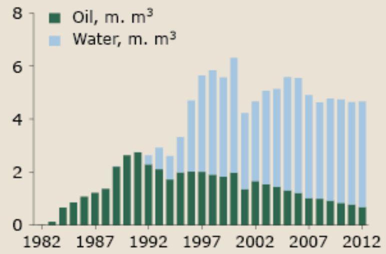
FIELD DATA
At 1 January 2013

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

PRODUCTION

Cum. production at 1 January 2013

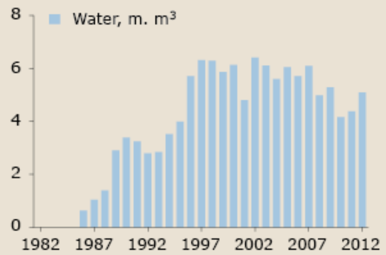
Oil:	44.77 m. m^3
Gas:	3.68 bn. Nm^3
Water:	66.63 m. m^3



INJECTION

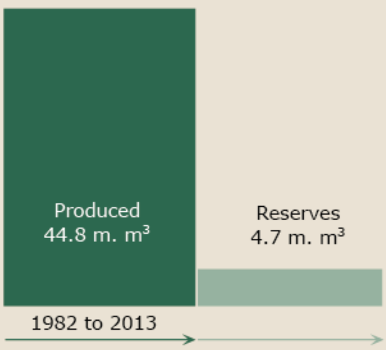
Cum. injection at 1 January 2013

Water:	121.09 m. m^3



RESERVES *

Oil:	4.7 m. m^3
Gas:	0.4 bn. Nm^3



*) *Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE SKJOLD FIELD

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

PRODUCTION STRATEGY

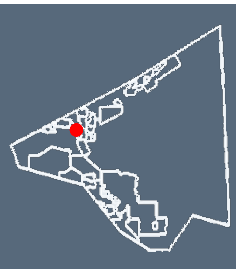
The strategy for producing oil from Skjold is to maintain reservoir pressure by means of water injection. Oil is mainly produced from horizontal wells at the flanks of the reservoir, where the production and injection wells are placed alternately in a radial pattern.

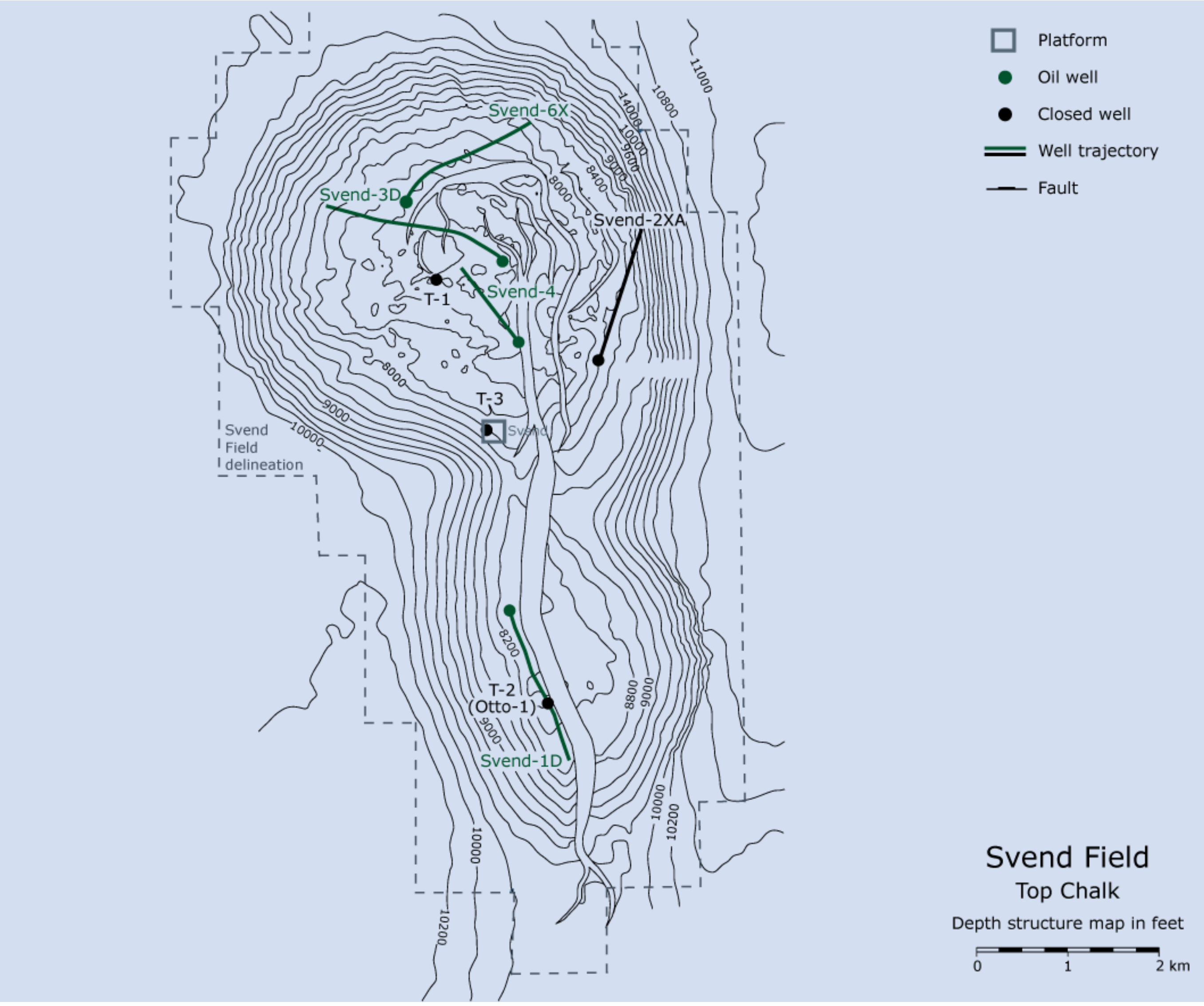
PRODUCTION FACILITIES

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

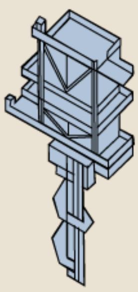
The Skjold C platform has accommodation facilities for 16 persons.

THE SVEND FIELD





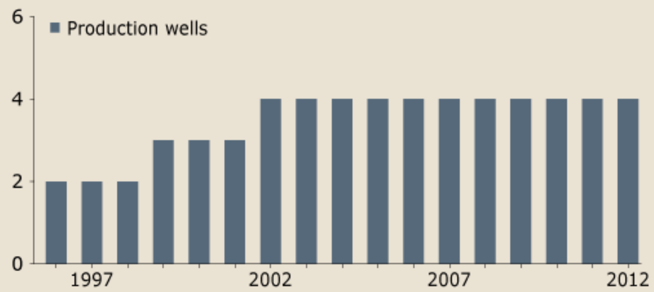
Svend



DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013
2012 prices DKK 1.36 billion

Number of active wells

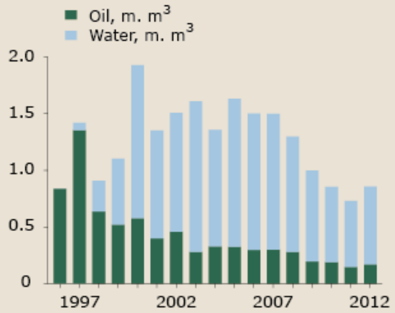


FIELD DATA	At 1 January 2013
Prospect:	North Arne/Otto
Location:	Block 5604/25
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered:	1975 (North Arne) 1982 (Otto)
Year on stream:	1996
Producing wells:	4
Water depth:	65 m
Field delineation:	48 km^2
Reservoir depth:	2,500 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2013

Oil:	7.28 m. m^3
Gas:	0.86 bn. Nm^3
Water:	14.12 m. m^3



RESERVES *

Oil:	0.4 m. m^3
Gas:	0.1 bn. Nm^3

**) Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE SVEND FIELD

The Svend Field is an anticlinal structure induced through salt tectonics. This led to fracturing of the chalk in the reservoir, with a major north-south fault dividing the field into a western and an eastern block. In addition, the southern reservoir of the Svend Field is situated about 250 m lower than the northern reservoir. The northern reservoir has proved to have unusually favourable production properties.

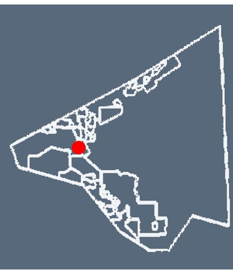
PRODUCTION STRATEGY

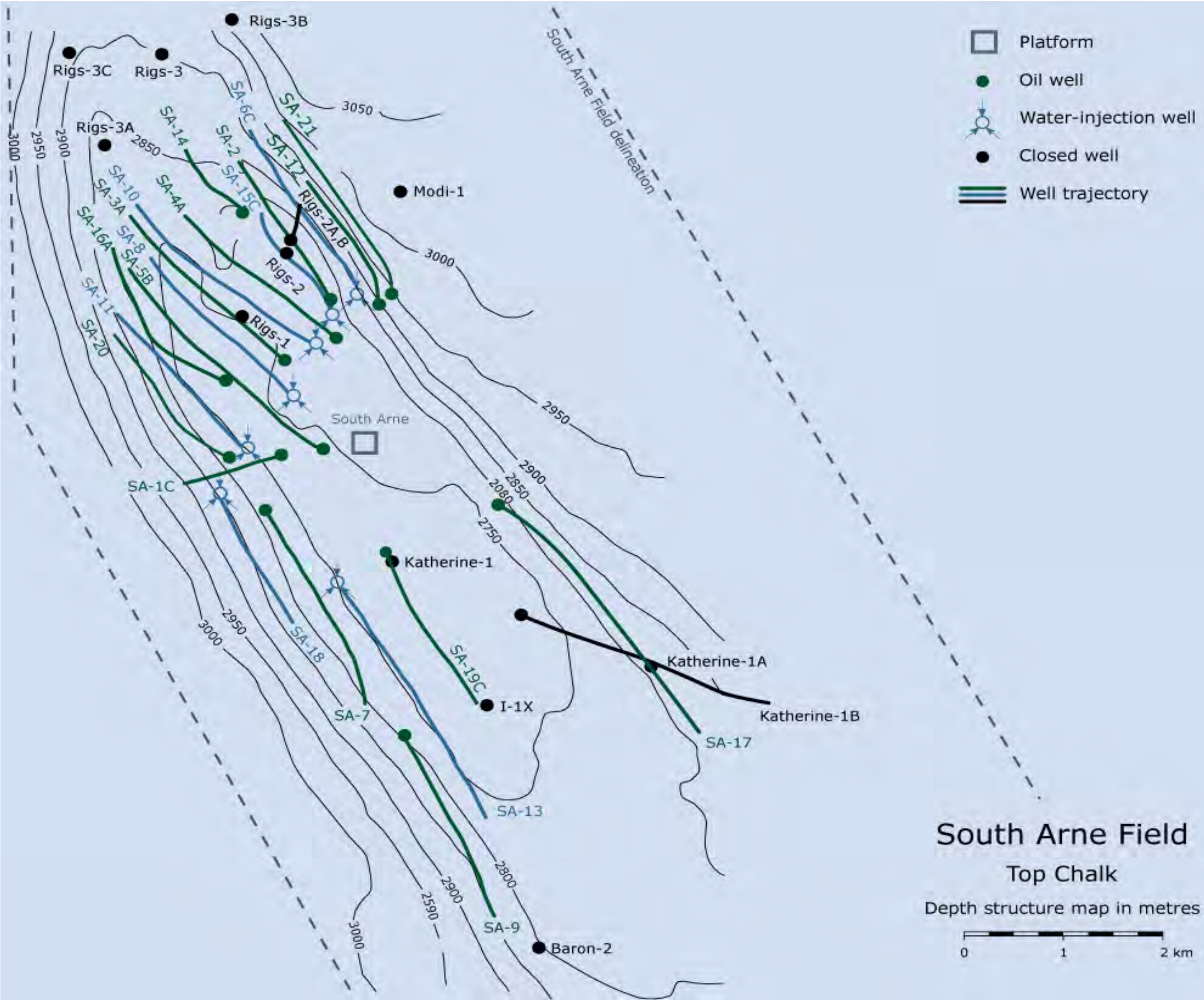
Production is based on primary recovery at a reservoir pressure above the bubble point of the oil, while ensuring maximum production uptime for the wells at the same time.

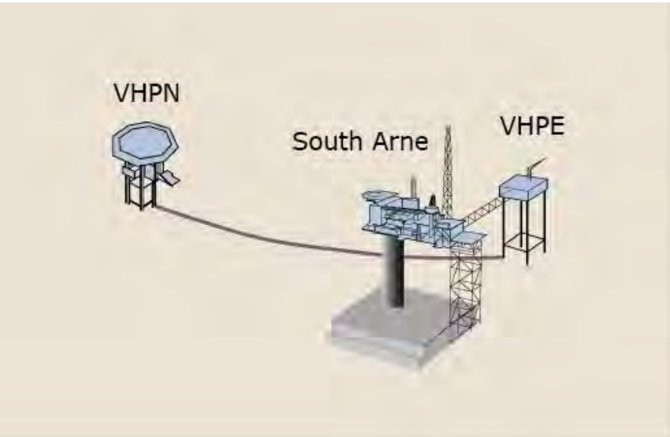
PRODUCTION FACILITIES

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

THE SOUTH ARNE FIELD



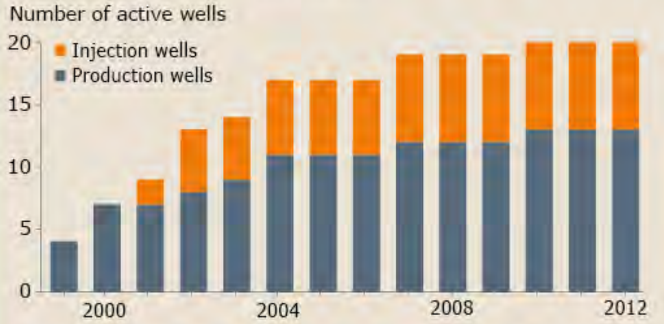




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013

2012 prices DKK 13.88 billion



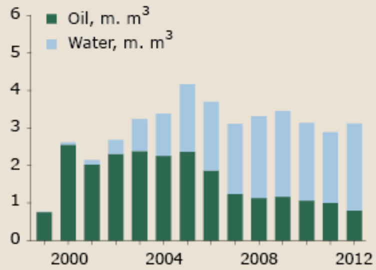
FIELD DATA At 1 January 2013

Location:	Blocks 5604/29 and 30
Licence:	7/89
Operator:	Hess Denmark A/S
Discovered:	1969
Year on stream:	1999
Producing wells:	13
Water-injection wells:	7
Water depth:	60 m
Field delineation:	93 km^2
Reservoir depth:	2,800 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2013

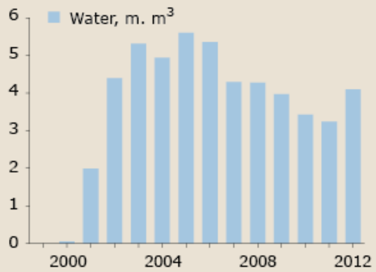
Oil:	22.96 m. m^3
Gas:	5.60 bn. Nm^3
Water:	18.75 m. m^3



INJECTION

Cum. injection at 1 January 2013

Gas:	4.20 bn. Nm^3
Water:	50.92 m. m^3



RESERVES *

Oil:	12.9 m. m^3
Gas:	2.6 bn. Nm^3

**) Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE SOUTH ARNE FIELD

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

PRODUCTION STRATEGY

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

PRODUCTION FACILITIES

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

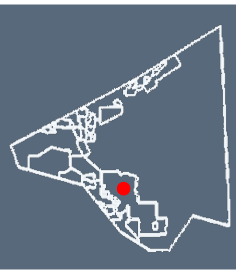
The processing facilities consist of a plant that separates the hydrocarbons produced. The oil produced is conveyed to an 87,000 m^3 storage tank on the seabed and is exported ashore by tanker. The treated gas is exported by pipeline to Nybro. Some of the water produced is injected into the field, while the rest is processed and discharged into the sea. Processing facilities have been installed to treat the injection water before it is injected.

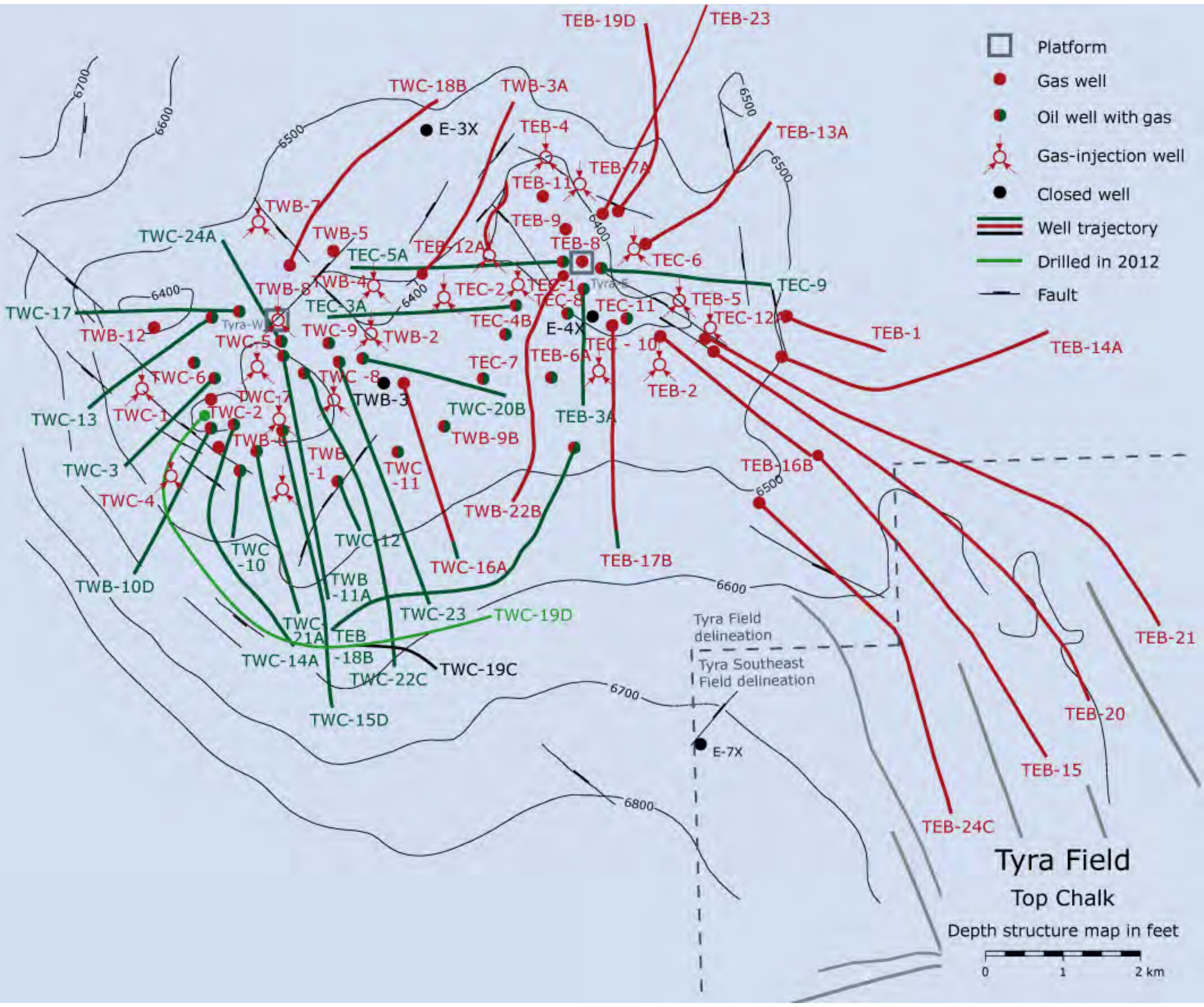
In 2012 the wellhead platform WHP-N and the riser and wellhead platform WHP-E were established in the South Arne Field. Hook-up and commissioning of the new platforms is expected to be completed by mid-2013. The two new platforms will be hooked up to the existing facilities and infrastructure. WHP-N is an unmanned platform with a helideck and is placed about 2.5 km north of the existing South Arne platform. WHP-E is placed about 80 m east of the existing South Arne platform and connected to it by a combined foot and pipe bridge.

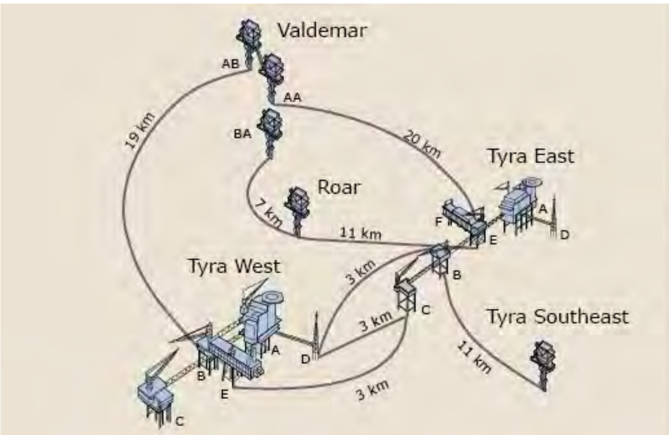
A bundle pipeline has been established between WHP-N and WHP-E. The bundle incorporates a production pipeline, lift gas and water-injection pipelines and power supply cables, etc.

South Arne has accommodation facilities for 57 persons. In 2013 the accommodation facilities are to be supplemented by 18 new single cabins.

THE TYRA FIELD



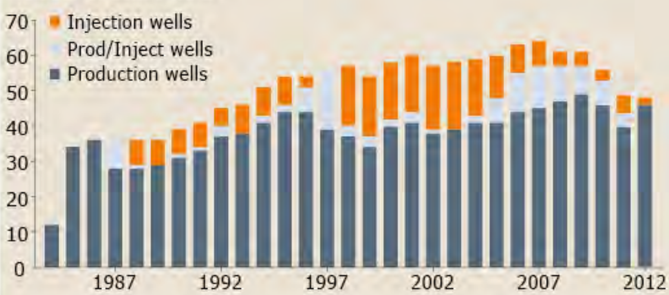




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013
2012 prices DKK 36.02 billion

Number of active wells



FIELD DATA At 1 January 2013

Prospect:	Cora
Location:	Blocks 5504/11 and 12
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered:	1968
Year on stream:	1984

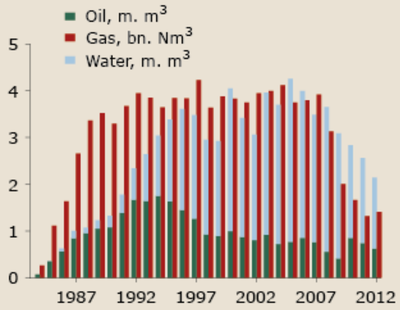
Gas producing wells:	23
Oil-/gas- prod. wells:	29
Producing/Inj. wells:	18

Water depth:	37-40 m
Field delineation:	177 km²
Reservoir depth:	2,000 m
Reservoir rock:	Chalk
Geological age:	Danian and Upper Cretaceous

PRODUCTION

Cum. production at 1 January 2013

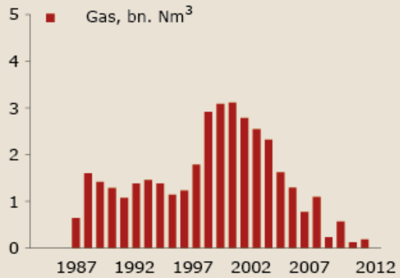
Oil:	27.41 m. m³
Gas:	90.99 bn. Nm³
Water:	48.63 m. m³



INJECTION

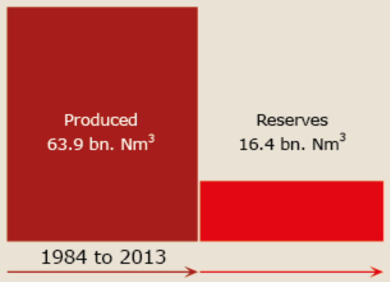
Cum. injection at 1 January 2013

Gas:	36.51 bn. Nm³



RESERVES *

Oil:	7.6 m. m³
Gas:	16.4 bn. Nm³



**) The chart shows the combined figures for Tyra and Tyra SE and reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE TYRA FIELD

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

PRODUCTION STRATEGY

The Tyra Field acts as a buffer, which means that gas from other fields can be injected into the Tyra Field during periods of low gas consumption and thus low gas sales, for example in summer. When the demand for gas increases, the gas injected in the Tyra Field is produced again. The injected dry gas helps delay the decrease in gas cap pressure, thus optimizing the recovery of oil from the Tyra Field. Thus, using the Tyra Field as a buffer helps ensure that the condensate and oil production conditions do not deteriorate as a consequence of the reservoir pressure dropping at too early a stage. Thus, increased gas production from DUC's other fields, in particular the Harald and Roar gas fields, optimizes the recovery of liquid hydrocarbons from the Tyra Field.

PRODUCTION FACILITIES

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

Tyra West consists of two wellhead platforms, TWB and TWC, one processing and accommodation platform, TWA, and one gas flare stack, TWD, as well as a bridge module, TWE, for gas processing and compression placed at TWB.

The Tyra West processing facilities are used to pre-process oil and condensate production from the wells at Tyra West. Moreover, the Tyra West complex houses gas-processing facilities and facilities for the injection and/or export of gas as well as processing facilities for the water produced. All gas from the DUC platforms is finally processed at Tyra West before being exported to NOGAT or Nybro. The water produced is processed at Tyra West and subsequently discharged into the sea.

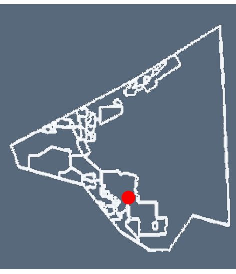
Tyra East consists of two wellhead platforms, TEB and TEC, one processing and accommodation platform, TEA, one gas flare stack, TED, and one riser platform, TEE, as well as a bridge module, TEF, with receiving facilities.

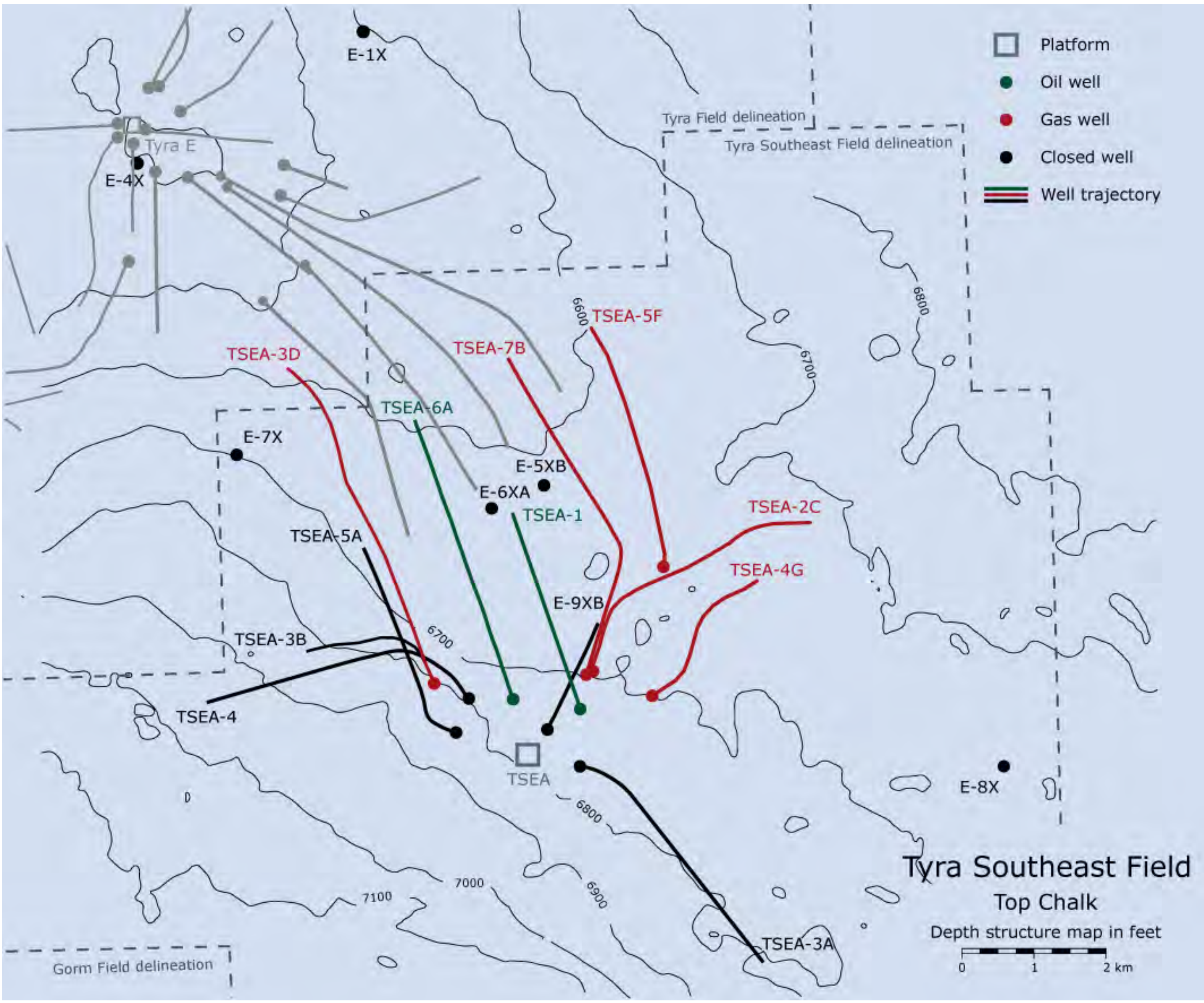
Tyra East receives production from the satellite fields, Valdemar, Roar, Svend, Tyra Southeast and Harald/Lulita/Trym, as well as gas production from the Gorm, Dan and Halfdan Fields. The Tyra East complex includes facilities for the processing of gas, oil, condensate and water. The water produced is processed at Tyra East and subsequently discharged into the sea.

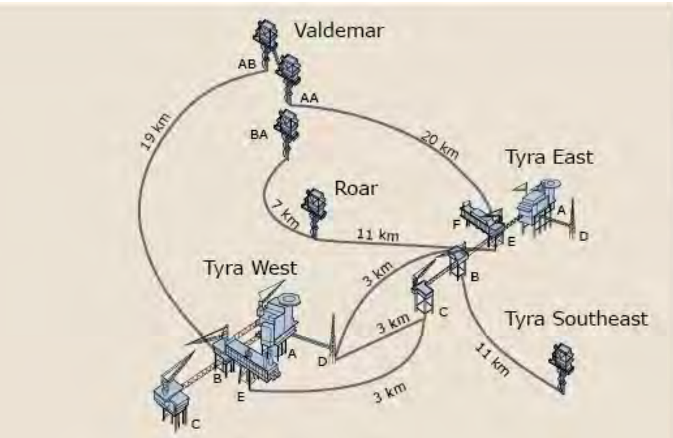
The two platform complexes in the Tyra Field are interconnected by pipelines in order to allow flexibility and ensure optimum use of the facilities. Oil and condensate production from the Tyra Field and its satellite fields is transported ashore via Gorm E. The bulk of gas produced is transported from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

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

THE TYRA SOUTHEAST FIELD







DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013

2012 prices	DKK 2.57 billion

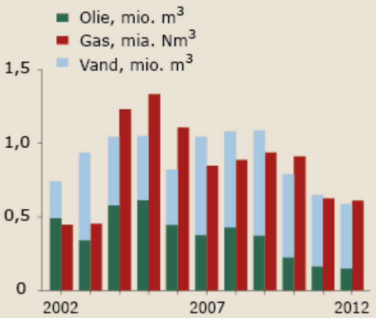
FELT DATA PR. 1.1.2013

Beliggenhed:	Blok 5504/12
Tilladelse:	Eneretsbevillingen
Operatør:	Mærsk Olie og Gas A/S
Fundet år:	1991
I drift år:	2002
Olieprod. brønde:	2
Gasprod. brønde:	5
Vanddybde:	38 m
Feltafgrænsning:	142 km²
Reservoirdybde:	2.050 m
Reservoirbjergart:	Kalksten
Geologisk alder:	Danien og Øvre Kridt

PRODUKTION

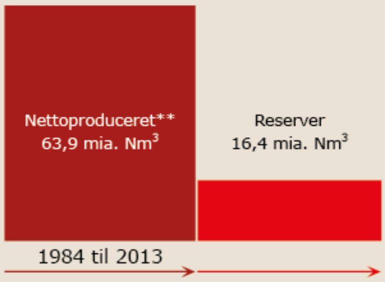
Akk. Produktion pr. 1. januar 2013

Olie:	4,19 mio. m^3
Gas:	9,40 mia. Nm^3
Vand:	5,61 mio. m^3



RESERVER *

Olie:	7,6 mio. m^3
Gas:	16,4 mia. Nm^3



*) Figuren viser Tyra og Tyra SØ samlet og reserver er opgjort pr.1.1.2012 fratrukket 2012 produktionen.

**) Nettoproduceret: historisk produktion fratrukket injektion.

REVIEW OF GEOLOGY, THE TYRA SOUTHEAST FIELD

The Tyra Southeast Field is an anticlinal structure created by a slight tectonic uplift of Upper Cretaceous chalk layers. The structure is divided into two blocks separated by a NE-SW fault zone. The structure is part of the major uplift zone that also comprises Roar, Tyra and parts of the Halfdan Field.

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

PRODUCTION STRATEGY

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

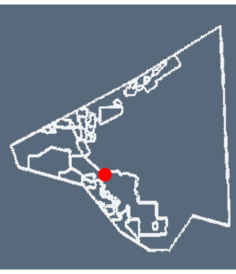
PRODUCTION FACILITIES

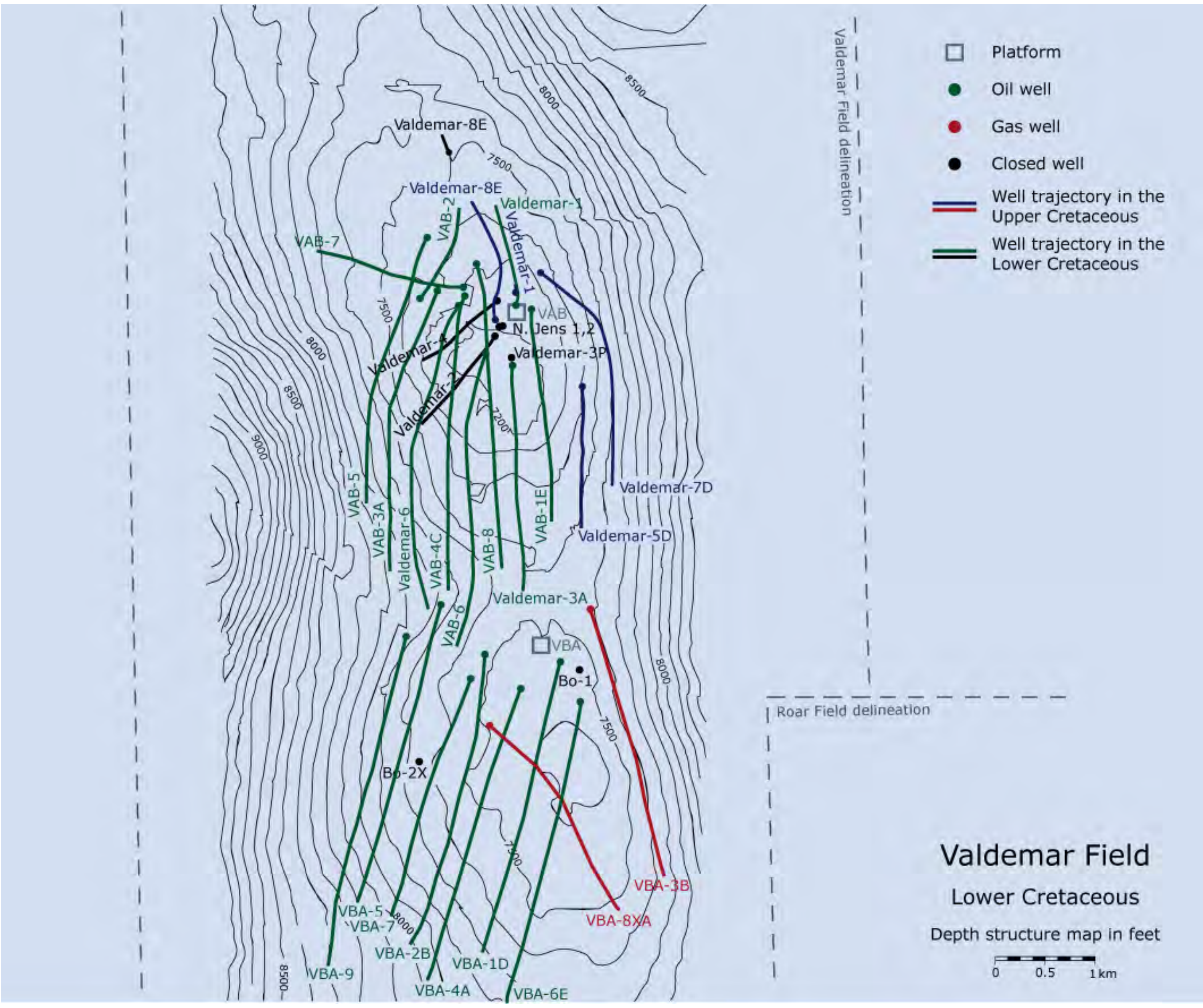
The Tyra Southeast Field has been developed as a satellite (TSEA) to the Tyra Field with one unmanned platform.

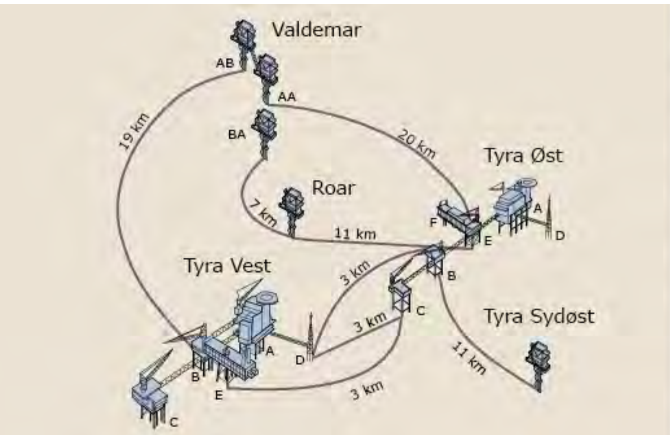
The production is separated into gas and liquids before being transported to Tyra East for further processing.

In 2013 permission was granted for further developing Tyra SE with a new platform with capacity for 16 wells. The new platform will be connected to the existing TSEA platform by a bridge. In addition, a new lift gas pipeline from Tyra East to the new and existing wells will be established. Power supply and control signal cables will run parallel to the pipeline.

THE VALDEMAR FIELD



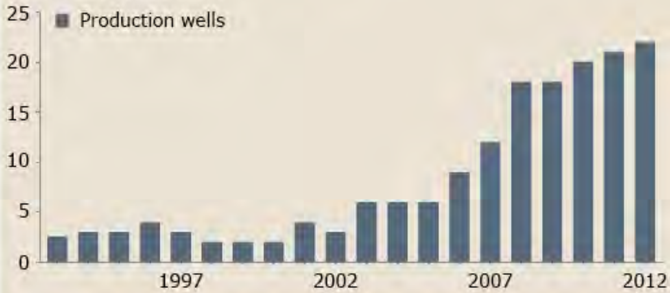




DEVELOPMENT AND INVESTMENT

Cum. investments at 1 January 2013
2012 prices DKK 8.63 billion

Number of active wells



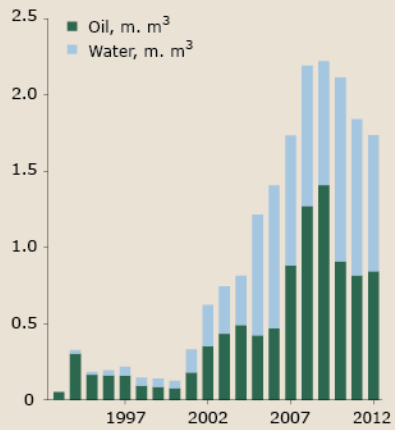
FIELD DATA At 1 January 2013

Prospect:	Bo/North Jens
Location:	Blocks 5504/7 and 11
Licence:	Sole Concession
Operator:	Mærsk Olie og Gas A/S
Discovered:	1977 (Bo) 1985 (North Jens)
Year on stream:	1993 (North Jens) 2007 (Bo)
Oil-producing wells:	21
Gas-producing wells:	2
Water depth:	38 m
Field delineation:	110 km^2
Reservoir depth:	2,000 m (Upper Cretaceous) 2,600 m (Lower Cretaceous)
Reservoir rock:	Chalk
Geological age:	Danian, Upper and Lower Cretaceous

PRODUCTION

Cum. production at 1 January 2013

Oil:	9.58 m. m^3
Gas:	4.80 bn. Nm^3
Water:	8.79 m. m^3



RESERVES *

Oil:	6.9 m. m^3
Gas:	4.7 bn. Nm^3

*) *Reserves as calculated at 1 January 2012 less the production for 2012.*

REVIEW OF GEOLOGY, THE VALDEMAR FIELD

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

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

The Upper and Lower Cretaceous reservoirs have been developed in both the Bo and North Jens areas.

PRODUCTION STRATEGY

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

PRODUCTION FACILITIES

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

The Bo area of the Valdemar Field has been developed with an unmanned wellhead platform, Valdemar BA, without a helideck. A 16” multiphase pipeline transports the production from Valdemar BA to Tyra East via Roar. At present there is no production at Valdemar BA, as a new pipeline to Tyra East via Roar is to be established.

APPENDIX C: PRODUCTION, RESERVES AND CONTINGENT RESOURCES AT 1 JANUARY 2012

(Please note that this appendix has not been updated as of 1 January 2013)

OIL, m. m^3		
	Produced	**Resources**
		Exp.
		Reserves
Ongoing recovery and approved for development		
Cecilie	1.0	0.2
Dagmar	1.0	0.0
Dan	104.2	20.7
Gorm	59.7	5.4
Halfdan	56.2	44.4
Harald	8.0	0.4
Hejre	-	16.2
Kraka	5.2	0.8
Lulita	1.0	0.2
Nini	4.8	1.9
Regnar	0.9	0.0
Roar	2.6	0.1
Rolf	4.4	0.0
Siri	11.8	1.8
Skjold	44.1	5.4
Svend	7.1	0.6
South Arne	22.2	13.7
Tyra **	30.8	8.4
Valdemar	8.7	7.7
Justified for development	-	0
Subtotal	**374**	**128**
		Contingent resources
Development pending	-	*26*
Development unclarified	-	*15*
Development not viable	-	*11*
Subtotal		**53**
Total	**374**	**181**
January 2011	361	185

GAS, bn. Nm^3			
	Net Produced*	**Resources**	
		Net gas * Exp.	**Sales gas * Exp.**
		Reserves	
Ongoing recovery and approved for development			
Cecilie	0.1	-	-
Dagmar	0.2	0.0	0
Dan	23.1	2.8	0
Gorm	7.5	0.6	0
Halfdan	24.0	8.0	7
Harald	21.9	3.0	3
Hejre	-	10.0	9
Kraka	1.5	0.1	0
Lulita	0.6	0.1	0
Nini	0.4	-	-
Regnar	0.1	0.0	0
Roar	14.9	0.3	0
Rolf	0.2	0.0	0
Siri	0.1	-	-
Skjold	3.6	0.5	0
Svend	0.8	0.1	0
South Arne	5.4	2.8	2
Tyra **	61.9	18.4	14
Valdemar	4.3	5.2	5
Justified for development	-	3	3
Subtotal	**170**	**55**	**43**
		Contingent resources	
Development pending	-	*18*	*16*
Development unclarified	-	*12*	*11*
Development not viable	-	*10*	*9*
Subtotal		**40**	**37**
Total	**170**	**95**	**79**
January 2011	164	101	84

*) *Net production: historical production less injection*
Net gas: future production less injection
Sales gas: future production less injection and less fuel gas and flaring
**) *Tyra Southeast included*

APPENDIX D: FINANCIAL KEY FIGURES

	Investments in field dev. DKK million 1)	Field operating costs DKK million 2)	Exploration costs DKK million	Crude oil price USD/bbl 3)	Exchange rate DKK/USD	Inflation per cent 4)	Net foreign-currency value DKK billion 5)	State revenue DKK millon 6)
1972	105	21	30	3.0	7.0	6.7	-3.2	0
1973	9	23	28	4.6	6.1	9.3	-4.0	1
1974	38	44	83	11.6	6.1	15.3	-9.2	1
1975	139	47	76	12.3	5.8	9.6	-8.5	2
1976	372	53	118	12.9	6.1	9.0	-9.5	4
1977	64	61	114	14.0	6.0	11.1	-10.4	5
1978	71	83	176	14.1	5.5	10.0	-9.5	21
1979	387	197	55	20.4	5.3	9.6	-13.7	19
1980	956	407	78	37.5	5.6	12.3	-18.6	29
1981	2	197	201	37.4	7.1	11.7	-20.1	36
1982	4	407	257	34.0	8.4	10.1	-20.6	231
1983	4	431	566	30.5	9.1	6.9	-17.8	401
1984	2	1	1,211	28.2	10.4	6.3	-18.3	564
1985	2	1	1,373	27.2	10,6	4.7	-17.6	1,192
1986	2	1	747	14.9	8.1	3.7	-7.3	1,399
1987	930	1	664	18.3	6.8	4.0	-5.9	1,328
1988	928	1,210	424	14.8	6.7	4.5	-3.7	568
1989	1	1,409	366	18.2	7.3	4.8	-3.2	1,024
1990	2	1,450	592	23.6	6.2	2.6	-2.7	2,089
1991	2,302	1,670	985	20.0	6.4	2.4	-1.9	1,889
1992	2	1,560	983	19.3	6.0	2.1	-0.4	1,911
1993	3	1,816	442	16.8	6.5	1.2	-1.7	1,811
1994	3	1,907	151	15.6	6.4	2.0	-0.5	2,053
1995	4	1,707	272	17.0	5.6	2.1	0.3	1,980
1996	4,260	1,915	470	21.1	5.8	2.1	0.4	2,465
1997	3,760	1,946	515	18.9	6.6	2.2	1.4	3,156
1998	5,381	1,797	406	12.8	6.7	1.8	0.9	3,158
1999	3,531	1,910	656	17.9	7.0	2.5	3.5	3,786
2000	3,113	2,577	672	28.5	8.1	2.9	14.9	8,305
2001	4,025	2,557	973	24.4	8.3	2.4	12.6	9,630
2002	5,475	2,802	1,036	24.9	7.9	2.4	14.5	10,106
2003	7,386	3,380	789	28.8	6.6	2.1	15.3	9,330
2004	5	3,174	340	38.2	6.0	1.2	19.7	17,102
2005	4	4,005	578	54.4	6.0	1.8	24.8	24,163
2006	5	5,182	600	65.1	5.9	1.9	31.5	31,500
2007	7	4,129	547	72.5	5.4	1.7	28.3	27,885
2008	6	5,402	820	97.2	5.1	3.4	27.1	36,481
2009	7	5,284	1,413	61.6	5.4	1.3	15.0	24,588
2010	4,330	5,471	548	79.5	5.6	2.3	15.3	23,736
2011*	5	6,699	706	111.4	5.4	2.8	11.4	30,296
2012*	6	7,939	1,182	111.7	5.8	2.4	12.5	25,199

Nominal prices

1) Investments include the NOGAT pipeline

2) Incl. transportation costs

3) Brent crude oil

4 Consumer prices, source: Statistics Denmark

5) Surplus on the balance of trade for oil products and natural gas, source: external trade statistics, Statistics Denmark

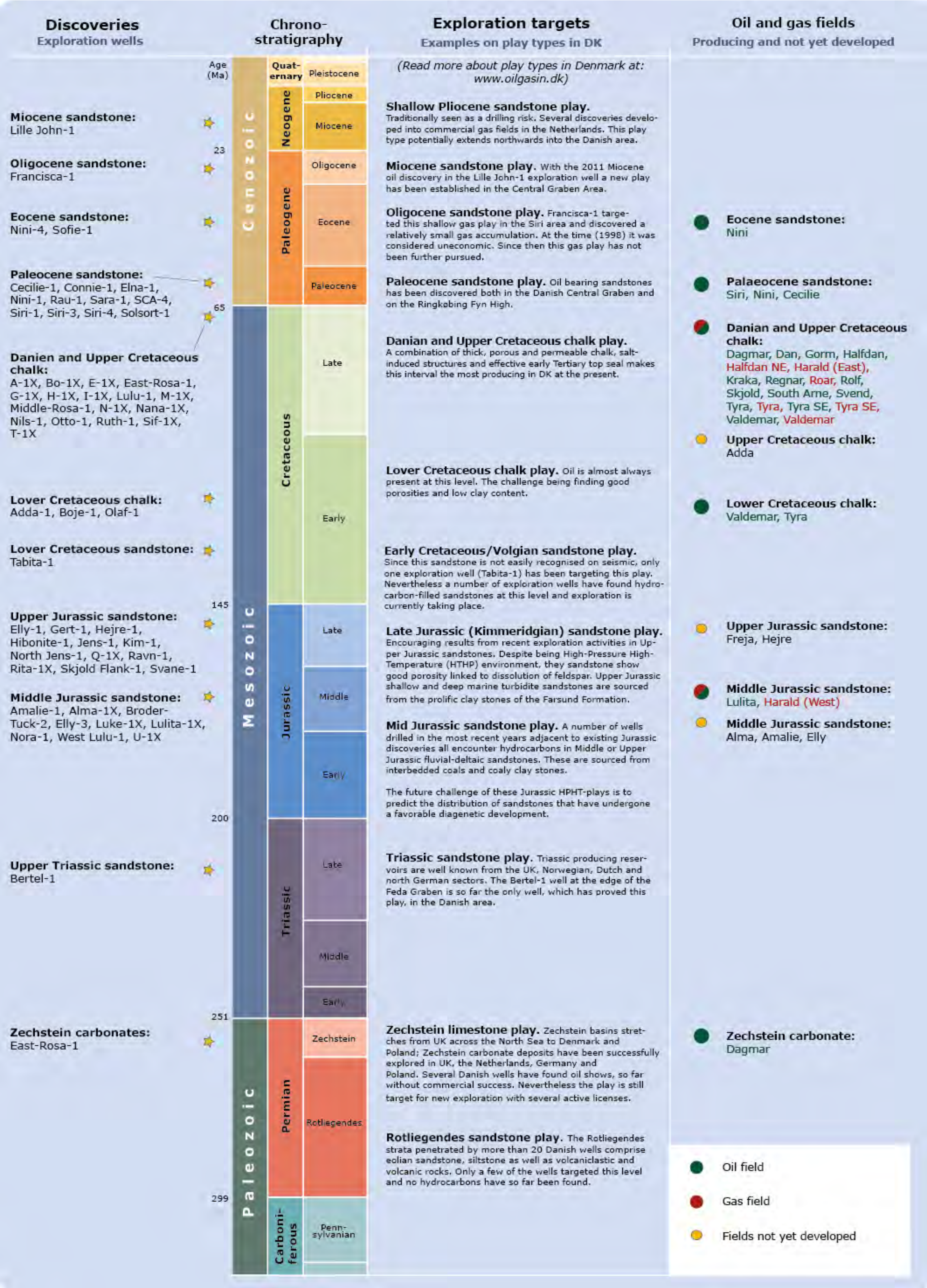
6) State revenue has been adjusted as from 1997

**) Estimate*

APPENDIX E: EXISTING FINANCIAL CONDITIONS

	Sole Concession at 1 Jan. 2004	Licences granted before 1 Jan. 2004	Licences granted after 1 Jan. 2004
Corporate income tax	25 per cent Deductible from the hydrocarbon tax base.	25 per cent Deductible from the hydrocarbon tax base.	25 per cent Deductible from the hydrocarbon tax base.
Hydrocarbon tax	52 per cent Allowance of 5 per cent over 6 years (a total of 30 per cent) for investments. Transitional rules for investments and unutilized field losses made before 1 January 2004.	70 per cent Allowance of 25 per cent over 10 years (a total of 250 per cent) for investments.	52 per cent Allowance of 5 per cent for 6 years (a total of 30 per cent) for investments.
Royalty	No	2nd Round licences pay royalty as follows: 1,000 bbl/day — Rate 0 - 5 — 2 per cent 5 - 20 — 8 per cent 20 - — 16 per cent Deductible from the corp. income tax and hydrocarbon tax bases.	No
Oil pipeline tariff/ compensatory fee	5 per cent until 8 July 2012, after which no tariff/fee is payable. The oil pipeline tariff/compensatory fee can be offset against hydrocarbon tax, but not against the corporate tax and hydrocarbon tax bases.	5 per cent The oil pipeline tariff/compensatory fee is deductible from the royalty base and the corporate income tax and hydrocarbon tax bases.	5 per cent until 8 July 2012, after which no tariff/fee is payable. The oil pipeline tariff/compensatory fee can be offset against hydrocarbon tax, but not against the corporate tax and hydrocarbon tax bases.
State participation	20 per cent from 9 July 2012	20 per cent 1st, 2nd and 3rd Rounds: State participation with carried interest in the exploratory phase. A paying interest, depending on the size of production, in the development and production phases. 4th and 5th Rounds and Open Door procedure: Fully paying interest.	20 per cent
Profit sharing	From 1 January 2004 to 8 July 2012 20 per cent is payable on the taxable profit before tax and before net interest expenses.	No	No

APPENDIX F: GEOLOGICAL TIME SCALE



APPENDIX G: LICENCES AND LICENSEES - MAY 2013

Licence	Sole Concession of 8 July 1962	Company	Share (pct.)
Operator	**Mærsk Olie og Gas A/S**	Shell Olie- og Gasudvinding Danmark B.V. Holland. Danish Branch.	36.8
Licence granted	8 July 1962	A.P. Møller - Mærsk A/S and Mærsk Olie og Gas A/S (Concessionaires)	31.2
Licence expiry date	8 July 2042	Chevron Denmark, Branch of Chevron Denmark Inc., USA	12.0
Blocks	5504/7, 8, 11, 12, 15, 16; 5505/13, 17, 18 ("Contiguous Area")	Danish North Sea Fund	20.0
	5504/5, 6 (Elly)		
	5603/27, 28 (Gert)		
	5504/10, 14 (Rolf)		
	5604/25 (Svend)		
	5604/21, 22 (Harald/Lulita)		
Area (km²)	1478.8 ("Contiguous Area")		
	64.0 (Elly)		
	44.8 Gert		
	8.4 (Rolf)		
	48.0 (Svend)		
	55.7 (Harald/Lulita)		

Licence	7/86 (Amalie part)	Company	Share (pct.)
Operator	**DONG E&P A/S** Hess Energi ApS is co-operator	Hess Energi ApS	40.077
Licence granted	24 June 1986 (2nd Round)	DONG E&P A/S	30.000
Licence expiry date	14 August 2026	Noreco Oil Denmark A/S	19.431
Blocks	5604/22, 26	Noreco Petroleum Denmark A/S	10.492
Area (km²)	47.0		
Delineation by depth (mbmsl *)	5,500		

Licence	7/86 (Lulita part)	Company	Share (pct.)
Operator	**DONG E&P A/S**	DONG E&P A/S	43.594
Licence granted	24 June 1986 (2nd Round)	Noreco Oil Denmark A/S	38.904
Licence expiry date	17 February 2027	Noreco Petroleum Denmark A/S	17.502
Blocks	5604/29, 30		
Area (km²)	9.3		
Delineation by depth (mbmsl *)	3,750		

Licence	7/89 (South Arne Field)	Company	Share (pct.)
Operator	**Hess Denmark ApS**	Hess Denmark ApS	61.51572
Licence granted	20 December 1989 (3rd Round)	DONG E&P A/S	36.78930
Licence expiry date	8 March 2026	Danoil Exploration A/S	1.69498
Blocks	5604/22		
Area (km²)	2.6		
Delineation by depth (mbmsl *)	Eastern part: 3,200 Western part: 5,100		

Licence	1/90 (Lulita)	Company	Share (pct.)
Operator	**DONG E&P A/S**	DONG E&P A/S	43.594
Licence granted	3 July 1990	Noreco Oil Denmark A/S	38.904
Licence expiry date	8 March 2026	Noreco Petroleum Denmark A/S	17.502
Blocks	5604/18		
Area (km²)	1.2		
Delineation by depth (mbmsl *)	3,750		

Licence	4/95 (Nini Field)	Company	Share (pct.)
Operator	**DONG E&P A/S**	DONG E&P A/S	40
Licence granted	15 May 1995 (4th Round)	RWE Dea AG	30
Licence expiry date	18 June 2032	Noreco Oil Denmark A/S	30
Blocks	5605/10, 14		
Area (km²)	44.6		
Delineation by depth (mbmsl *)	1,950		

Licence	6/95	Company	Share (pct.)
Operator	DONG E&P A/S	DONG E&P A/S	70
Licence granted	15 May 1995 (4th Round)	DONG E&P (Siri) UK Limited	30
Licence expiry date	15 November 2013 (Siri Field delineation in 6/95 expires 18 July 2027)		
Blocks	5604/16, 20; 5605/13, 17		
Area (km²)	114.5		

Licence	9/95	Company	Share (pct.)
Operator	**Mærsk Olie og Gas A/S**	A.P. Møller - Mærsk A/S	42.6
Licence granted	15 May 1995 (4th Round)	DONG E&P A/S	27.3
Licence expiry date	22 May 2014	Noreco Oil Denmark A/S	16.4
Blocks	5604/21, 22, 25, 26	Danoil Exploration A/S	13.7
Area (km²)	55.6		

Licence	4/98	Company	Share (pct.)
Operator	**DONG E&P A/S**	DONG E&P A/S	35
Licence granted	15 June 1998 (5th Round)	Bayerngas Danmark ApS	30
Licence expiry date	29 June 2013	VNG Danmark ApS	15
Blocks	5604/26, 30	Danish North Sea Fund	20
Area (km²)	62.9		
Delineation by depth (mbmsl *)	Eastern part: 3,100		

Licence	5/98 (Hejre Field)	Company	Share (pct.)
Operator	**DONG E&P A/S**	DONG E&P A/S	60
Licence granted	15 June 1998 (5th Round)	Bayerngas Petroleum Danmark AS	25
Licence expiry date	15 October 2040	Bayerngas Danmark ApS	15
Blocks	5603/24, 28; 5604/21, 25		
Area (km²)	76.6		
Delineation by depth (mbmsl *)	6,000		

Licence	16/98 (Cecilie Field)	Company	Share (pct.)
Operator	**DONG E&P A/S**	Noreco Oil Denmark A/S	37
Licence granted	15 June 1998 (5th Round)	Noreco Petroleum Denmark A/S	24
Licence expiry date	18 June 2032	DONG E&P A/S	22
Blocks	5604/19, 20	RWE Dea AG	17
Area (km²)	2.6		
Delineation by depth (mbmsl *)	2,400		

Licence	1/06	Company	Share (pct.)
Operator	**DONG E&P A/S**	DONG E&P A/S	48
Licence granted	22 May 2006 (6th Round)	Bayerngas Petroleum Danmark AS	20
Licence expiry date	15 October 2040	Bayerngas Danmark ApS	12
Blocks	5603/28; 5604/21, 25	Danish North Sea Fund	20
Area (km²)	22.0		
Delineation by depth (mbmsl *)	6,000		

Licence	4/06 (northeastern part)	Company	Share (pct.)
Operator	**Wintershall Noordzee B.V.**	Wintershall Noordzee B.V.	35
Licence granted	22 May 2006 (6th Round)	Bayerngas Petroleum Danmark AS	30
Licence expiry date	22 November 2013	EWE Vertrieb GmbH	15
Blocks	5603/31, 32; 5503/3, 4; 5604/29; 5504/1	Danish North Sea Fund	20
Area (km²)	326		

Licence	4/06 (southwestern part)	Company	Share (pct.)
Operator	**Wintershall Noordzee B.V.**	Wintershall Noordzee B.V.	80
Licence granted	22 May 2006 (6th Round)	Danish North Sea Fund	20
Licence expiry date	22 January 2015		
Blocks	5603/31; 5503/3, 4, 7, 8;		
Area (km²)	356		

Licence	5/06	Company	Share (pct.)
Operator	**Wintershall Noordzee B.V.**	Wintershall Noordzee B.V.	35
Licence granted	22 May 2006 (6th Round)	Bayerngas Petroleum Danmark AS	30
Licence expiry date	22 August 2013	EWE Vertrieb GmbH	15
Blocks	5504/1, 2, 5, 6	Danish North Sea Fund	20
Area (km²)	333		

Licence	7/06	Company	Share (pct.)
Operator	**DONG E&P A/S**	DONG E&P A/S	40
Licence granted	22 May 2006 (6th Round)	RWE Dea AG	40
Licence expiry date	22 May 2014	Danish North Sea Fund	20
Blocks	5604/23, 24, 27		
Area (km²)	203		

Licence	8/06, sub-area A	Company	Share (pct.)
Operator	**Mærsk Olie og Gas A/S**	Shell Olie- og Gasudvinding Danmark B.V. Holland. Danish Branch.	43.3
Licence granted	22 May 2006 (6th Round)	A.P. Møller - Mærsk A/S	36.7
Licence expiry date	22 May 2014	Danish North Sea Fund	20.0
Blocks	5504/5, 6, 10, 11, 15		
Area (km²)	289.7		

Licence	8/06, sub-area B	Company	Share (pct.)
Operator	**Mærsk Olie og Gas A/S**	Shell Olie- og Gasudvinding Danmark B.V. Holland. Danish Branch.	36.8
Licence granted	22 May 2006 (6th Round)	A.P. Møller - Mærsk A/S	31.2
Licence expiry date	22 May 2014	Chevron Denmark, Branch of Chevron Denmark Inc., USA	12.0
Blocks	5504/7	Danish North Sea Fund	20.0
Area (km²)	5.8		

Licence	9/06	Company	Share (pct.)
Operator	**Mærsk Olie og Gas A/S**	A.P. Møller - Mærsk A/S	31.2
Licence granted	22 May 2006 (6th Round)	PA Resources Denmark ApS	26.8
Licence expiry date	22 May 2014	Noreco Oil Denmark A/S	12.0
Blocks	5604/22, 26	Danoil Exploration A/S	10.0
Area (km²)	71	Danish North Sea Fund	20.0

Licence	12/06	Company	Share (pct.)
Operator	**PA Resources UK Ltd.**	PA Resources UK Ltd.	64
Licence granted	22 May 2006 (6th Round)	Spyker Energy ApS	8
Licence expiry date	22 May 2014	Danoil Exploration A/S	8
Blocks	5504/16, 19, 20, 24	Danish North Sea Fund	20
Area (km²)	229		

Licence	1/08	Company	Share (pct.)
Operator	**New World Resources Operations ApS**	Danica Resources ApS	55.0
Licence granted	31 March 2008 (Open Door)	New World Resources ApS	25.0
Licence expiry date	31 March 2014	Danish North Sea Fund	20.0
Blocks	5410/1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 14, 15, 16; 5411/5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 18, 19, 20, 23, 24; 5412/5, 6, 7, 8, 9, 10, 11, 13, 14, 17		
Area (km²)	6,418.0		

Licence	1/09	Company	Share (pct.)
Operator	**New World Operations ApS**	Danica Jutland ApS	55.0
Licence granted	17 May 2009 (Open Door)	New World Jutland ApS	25.0
Licence expiry date	17 May 2015	Danish North Sea Fund	20.0
Blocks	5508/3, 4, 7, 8; 5509/1, 5; 5608/21, 22, 23, 25, 26, 27, 28, 29, 30, 31, 32		
Area (km²)	2,439.1		

Licence	2/09	Company	Share (pct.)
Operator	**New World Operations ApS**	Danica Jutland ApS	55.0
Licence granted	17 May 2009 (Open Door)	New World Jutland ApS	25.0
Licence expiry date	17 May 2015	Danish North Sea Fund	20.0
Blocks	5509/1, 2, 3, 5, 7, 8, 9, 10, 11, 12; 5609/25, 26, 29, 30		
Area (km²)	1,666.3		

Licence	3/09	Company	Share (pct.)
Operator	**DONG E&P A/S**	DONG E&P A/S	35
Licence granted	29 June 2009	Bayerngas Danmark ApS	30
Licence expiry date	29 June 2015	VNG Danmark ApS	15
Blocks	5604/25,26,29,30	Danish North Sea Fund	20
Area (km²)	51.3		

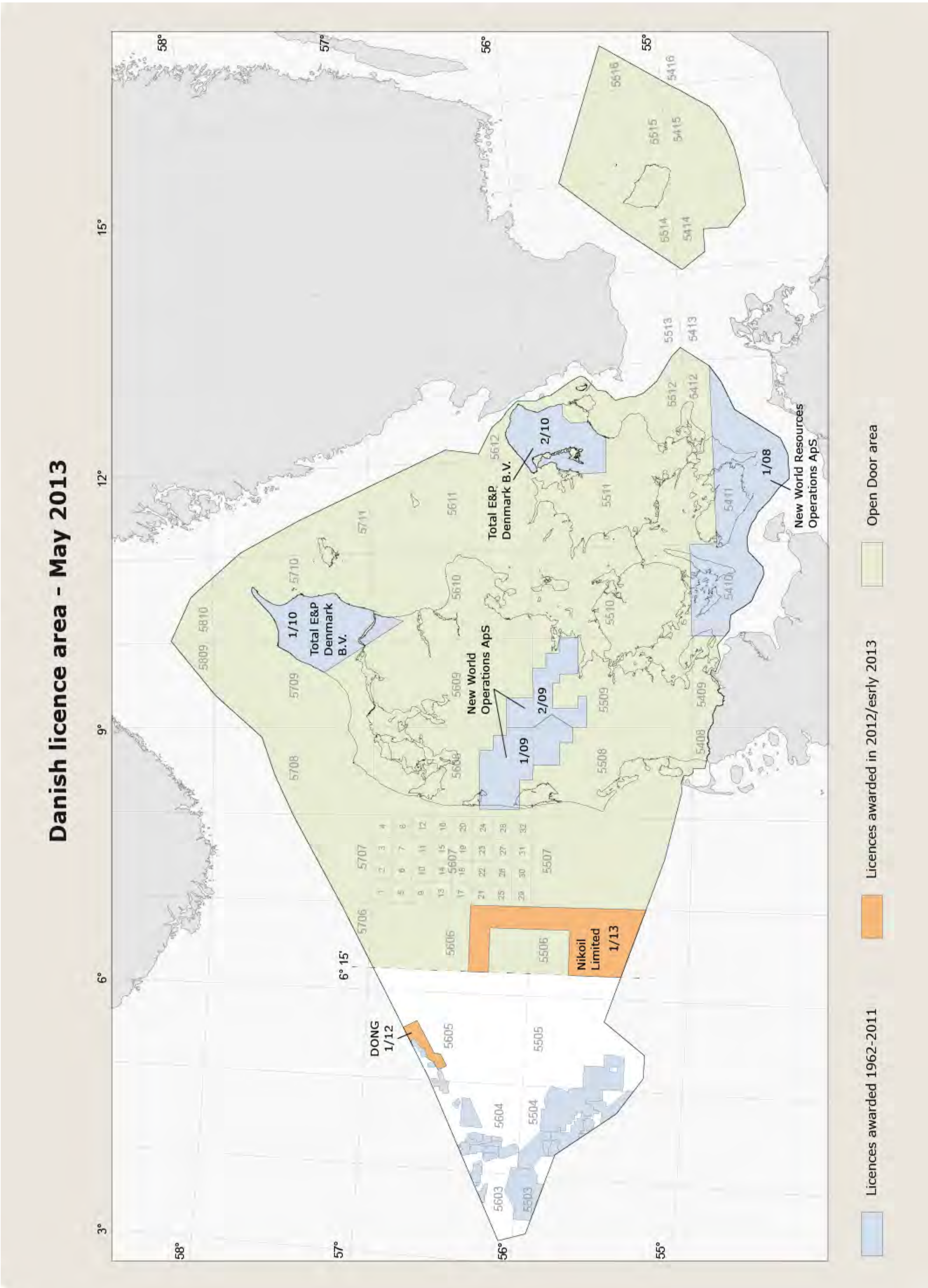
Licence	1/10	Company	Share (pct.)
Operator	**Total E&P Denmark B.V.**	Total E&P Denmark B.V.	80
Licence granted	5 June 2010 (Open Door)	Danish North Sea Fund	20
Licence expiry date	5 June 2016		
Blocks	5609/4; 5610/1, 2, 5, 6; 5709/16, 19, 20, 23, 24, 27, 28, 32; 5710/7, 10, 11, 13, 14, 17, 18, 19, 21, 22, 23, 25, 26, 27, 29, 30		
Area (km²)	2,971.7		

Licence	2/10	Company	Share (pct.)
Operator	**Total E&P Denmark B.V.**	Total E&P Denmark B.V.	80
Licence granted	5 June 2010 (Open Door)	Danish North Sea Fund	20
Licence expiry date	5 June 2016		
Blocks	5511/4, 8, 12, 16; 5512/1, 2, 3, 5, 6, 7, 9, 10, 13, 14; 5611/32; 5612/26, 29, 30, 31		
Area (km²)	2,288.9		

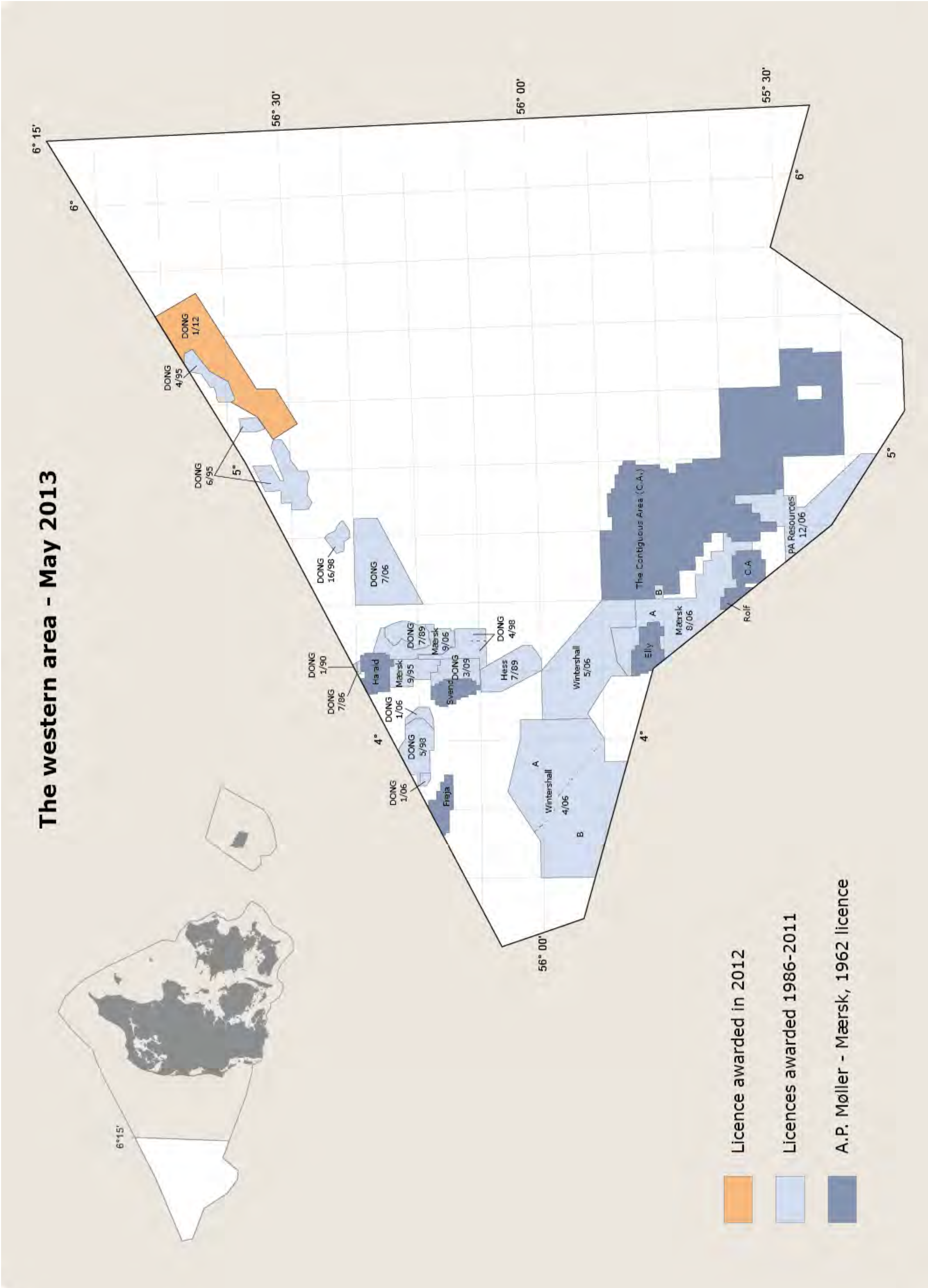
Licence	1/12	Company	Share (pct.)
Operator	**DONG E&P A/S**	DONG E&P A/S	80
Licence granted	23 November 2012	Danish North Sea Fund	20
Licence expiry date	23 November 2018		
Blocks	5605/7, 10, 11, 13, 14, 17		
Area (km²)	288.3		

* mbmsl: an abbreviation of *metres below mean sea level*

APPENDIX H1: DANISH LICENCE AREA – MAY 2013



APPENDIX H2: DANISH LICENCE AREA – MAY 2013



CONVERSION FACTORS

Reference pressure and temperature for the units mentioned:

		TEMP.	PRESSURE
Crude oil	m^3 (st)	15°C	101.325 kPa
	stb	60°F	14.73 psia[ii]
Natural gas	m^3 (st)	15°C	101.325 kPa
	Nm^3	0°C	101.325 kPa
	scf	60°F	14.73 psia

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

In the oil industry, two different systems of units are frequently used: SI units (metric units) and the so-called oil field units, which were originally introduced in the USA. The SI units are based on international definitions, whereas the use of oil field units may vary from one country to another, being defined by tradition.

The abbreviations used for oil field units are those recommended by the SPE (Society of Petroleum Engineers).

Quantities of oil and natural gas may be indicated by volume or energy content. As gas, and, to some extent, oil are compressible, the volume of a specific amount varies according to pressure and temperature. Therefore, measurements of volume are only unambiguous if the pressure and temperature are indicated.

The composition, and thus the calorific value, of crude oil and natural gas vary from field to field and with time. Therefore, the conversion factors for ton (t) and gigajoule (GJ) are dependent on time. The lower calorific value is indicated.

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

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

Abbreviations:

kPa	*kilopascal. Unit of pressure. 100 kPa = 1 bar.*
psia	*pound per square inch absolute.*
m³ (st)	*standard cubic metre. Unit of measurement used for natural gas and crude oil in a reference state: 15°C and 101.325 kPa in this report.*
Nm³	*Normal cubic metre. Unit of measurement used for natural gas in the reference state 0°C and 101.325 kPa.*
scf	*standard cubic foot/feet. Unit of measurement used for natural gas in a reference state: 60°F and 14.73 kPa in this report.*
stb	*stock tank barrel; barrel in a reference state of 60°F and 14.73 kPa. Used for oil.*
bbl	*blue barrel. In the early days of the oil industry when oil was traded in physical barrels, different barrel sizes soon emerged. To avoid confusion, Standard Oil painted their standard-volumen barrels blue.*
kg · mol	*kilogram-mol. The mass of a substance whose mass in kilograms is equal to the molecular mass of the substance.*
γ	*gamma; relative density.*
Btu	*British Thermal Unit. Other thermal units are J (=Joule) and cal (=calorie).*
t.o.e.	*ton oil equivalent. This unit is internationally defined as: 1 t.o.e.=10 Gcal.*
in	*inch; British unit of length. 1 inch =2.54 cm.*
ft	*foot/feet; British unit of length. 1 foot = 12 in = 0.3048 m.*

	FROM	TO	MULTIPLY BY
Crude oil	m^3 (st)	stb	6.293
	m^3 (st)	GJ	36.55[i]
	m^3 (st)	t	0.85[i]
Natural gas	Nm^3	scf	37.2396
	Nm^3	GJ	0.03951[i]
	Nm^3	t.o.e.	$942.49 \cdot 10^{-6}$ [i]
	Nm^3	kg · mol	0.0446158
	m^3 (st)	scf	35.3014
	m^3 (st)	GJ	0.03741[i]
	m^3 (st)	kg · mol	0.0422932
Units of volume	m^3	bbl	6,28981
	m^3	ft^3	35.31467
	US gallon	in^3	231*
	bbl	US gallon	42*
Energy	t.o.e.	GJ	41.868*
	GJ	Btu	947,817
	cal	J	4.1868*
Density	**FROM**	**TO**	**CONVERSION**
	°API	kg/m^3	141,364.33/(°API+131.5)
*	°API	γ	141.5/(°API+131.5)

**) Exact value.*
i) Average value for Danish fields for 2012.

The Danish Energy Agency, DEA, was established in 1976 and is placed under the Ministry of Climate, Energy and Building. The DEA works nationally and internationally with tasks related to energy supply and consumption and CO_2-reducing measures. Thus, the DEA is responsible for the entire chain of tasks related to energy production and supply, transport and consumption, including improved energy efficiency and energy savings, as well as national CO_2 targets and initiatives to reduce the emission of greenhouse gases.

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

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

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This report went to press on 1 May 2013.

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

As in previous years, the report for 2012 describes exploration and development activities in the Danish area as well as production. Moreover, the report describes the use of the Danish subsoil for purposes other than oil and gas production, focusing on exploration and production of geothermal energy for district heating purposes.

The report also contains a review of the health and safety aspects of oil and gas production activities, the environment and climate.

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

The report can be obtained from the DEA’s website: www.ens.dk

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