Project no.:
019672

Project acronym:
DYNAMIS

Project title:
Towards Hydrogen and Electricity Production with Carbon Dioxide Capture and Storage

Instrument : Integrated project
Thematic priority : 6.1.3.2.4
Capture and sequestration of CO_2, associated with cleaner fossil fuels

Start date of project: 2006-03-01
Duration: 3 years

D 4.1.1
Shortlist of potential CO_2 storage sites

Revision: Draft, **0**, 1, 2, ...

Due date of deliverable: 2006-10-31
Actual submission date: 2007-04-03

Organisation name of lead contractor for this deliverable:
Geological Survey of Denmark and Greenland

Project co-funded by the European Commission within the Sixth Framework Programme (2002-2006)		
Dissemination Level		
PU	Public	PU
PP	Restricted to other programme participants (including the Commission Services)	
RE	Restricted to a group specified by the consortium (including the Commission Services)	
CO	Confidential , only for members of the consortium (including the Commission Services)	

Deliverable number:	D 4.1.1
Deliverable name:	Shortlist of potential CO_2 storage sites
Work package:	WP 4.1 Technology screening and selection of CO_2 storage sites
Lead contractor:	GEUS

Status of deliverable		
Action	**By**	**Date**
Submitted (Author(s))	Thomas Vangkilde-Pedersen, GEUS; Finn Dalhoff, GEUS; Birgit Willscher, BGR; Idar Akervoll, SINTEF PR; Karen Kirk, BGS; Dave Evans, BGS; Dan Bossie-Codreanu, IFP; Yann Le Gallo, IFP; Erik Simmelink, TNO	2007-04-03
Verified (WP-leader)	Thomas Vangkilde-Pedersen, GEUS	2007-04-03
Approved (SP-leader)	Yann Le Gallo, IFP	2007-04-03

Author(s)		
Name	**Organisation**	**E-mail**
Thomas Vangkilde-Pedersen	GEUS	tvp@geus.dk
Finn Dalhoff	GEUS	fd@geus.dk
Birgit Willscher	BGR	Birgit.willscher@bgr.de
Idar Akervoll	SINTEF PR	idar.akervoll@iku.sintef.no
Karen Kirk	BGS	klsh@bgs.ac.uk
Dave Evans	BGS	dje@bgs.ac.uk
Dan Bossie-Codreanu	IFP	Dan.Bossie-Codreanu@ifp.fr
Yann Le Gallo	IFP	Yann.Le-Gallo@ifp.fr
Erik Simmelink	TNO	Erik.Simmelink@tno.nL
Bert van der Meer	TNO	Bert.vanderMeer@tno.nl

Abstract

This document is the deliverable from WP4.1, part of SP4 of the DYNAMIS project. The objective of SP4 is to generate the basis for recommending possible storage sites for CO_2 from a full-scale HYPOGEN demonstration plant. Based on an initial list of screening criteria, defining the information needed for a multi-criteria selection of possible storage sites, characteristics for a total of 80 storage sites have been collected. Data have been collected using existing GIS information from a number of other EU projects along with existing petroleum and public domain databases. The considered types of geological storage include depleted or mature oil and gas reservoirs, saline aquifers and abandoned gas storages.

Within DYNAMIS it has been agreed to perform the work of SP4 on an assumed plant size of 400 Mw being operational in 2012. Two fuels, gas and coal, are to be considered and are assumed to generate approx. 2.0 and 3.33 Mt CO_2 per year, respectively. With a plant lifetime of 30 years the corresponding total amounts of CO_2 is 60 and 100 Mt. Given the project constraints and the technical/geological constraints concerning geological storage of CO_2, a set of 10 final site selection criteria has been defined. Based on these a multi-criteria site selection has been performed, resulting in a shortlist of potential storage sites including 16 sites.

All the sites on the shortlist have been described in detail comprising geological setting, wells, trap and seal, storage potential etc. and in Appendix III are listed essential parameters for each site. Finally it is concluded that the selected sites all are well suited for storage of the amounts of CO_2 expected from a HYPOGEN demonstration plant.

TABLE OF CONTENTS

Page

1 INTRODUCTION

This document is the deliverable from WP4.1, part of SP4 of the DYNAMIS project.

The objective of SP4 is to generate the basis for recommending possible storage sites for CO_2, including alternative industrial use of CO_2 such as enhanced recovery of oil and gas. Thus the purpose of this deliverable is to identify a few underground storage sites for CO_2 that each can provide the necessary storage capacity, safety of storage and residence time for the CO_2 from a full-scale HYPOGEN demonstration plant.

Once a number of sites have been selected in WP4.1 the SP will focus on generic storage site definition and characterization in WP4.2 in order to assess the performance and design requirements for CO_2 storage.

Some of the information collected in the screening process are confidential and will not be published in this report. Enclosed as Appendix II is, however, a tabulated list of the sites included in the investigation with brief information about each site[1].

[1] The remaining part of the collected data rests with the relevant project partners or has been published in the DYNAMIS eroom for project use only.

2 INITIAL SCREENING CRITERIA

An initial list of screening criteria has been established. The screening criteria define the information that forms a basis for the multi-criteria selection of possible storage sites. The screening criteria list includes characteristics within the following groups:

- Geographical location
- Storage capacity
- Geological information
- Structural information
- Petrophysical information
- Fluid in place
- Flow conditions in reservoir
- Wells in structure
- Production/injection history

The total list of characteristics is enclosed as Appendix I. During the screening of existing data sources for information about storage sites, further characteristics have been added individually to the list, based on existence of information.

To guide the geographical search, the potential hydrogen market was assumed to be located in the major population area in Europe thus requiring near-by storage. The major initial markets for hydrogen were assumed to be in London area, Antwerp-Rotterdam area, Berlin area, Paris area, Barcelona-Madrid area and Milan area.

3 SCREENING FOR STORAGE SITES

Based on the initial list of screening criteria described in section 2, characteristics for a total of 80 storage sites and 3 regional aquifers have been collected. A list of the 80 sites is enclosed as Appendix II.

The screening has been carried out using existing GIS information from GESTCO, CASTOR and GeoCapacity as well as information from the projects CO2STORE, PICORE and CARNOT along with existing petroleum and public domain databases.

The considered types of geological storage include depleted or mature oil and gas reservoirs, saline aquifers and abandoned gas storages.

The following number and types of sites are included:

- 6 onshore and 24 offshore gas fields (depleted and producing)
- 5 onshore and 9 offshore oil fields (producing)
- 10 onshore and 25 offshore saline aquifers
- 1 onshore natural gas storages (in use)

The sites are located in the following countries:

- UK, 15 gas fields and 23 saline aquifers
- Germany, 2 gas fields and 2 saline aquifers
- France, 5 oil fields and 2 *regional* saline aquifers
- Denmark, 3 gas fields, 1 natural gas storage, 8 oil fields and 10 saline aquifers
- The Netherlands, 7 gas fields
- Norway, 3 depleted gas fields, 1 oil field and the *regional* Utsira saline aquifer.

No detailed geological information was available (within the DYNAMIS consortium) for Northern Spain[2] and Northen Italy locations at the time of this report.

[2] According to the Joule II program, Spain has a theoretical capacity for CO_2 storage in saline aquifers of 1466 Mt. Several initiatives, both European (GeoCapacity) and national (CENITCO2) are currently assessing potential storages in Spain.

4 FINAL SITE SELECTION CRITERIA

For optimal storage capacity the CO_2 must be in a dense (liquid or supercritical) phase. Thus the P,T conditions must exceed the critical point for CO_2 which as a general rule of thumb is achieved below c. 800 m corresponding to a pressure of c. 80 bar.

Within DYNAMIS and after discussions with SP2 and SP5 leaders, it has been agreed to perform the work of SP4 based on an assumed plant size of 400 Mw being operational in 2012. Two fuels are to be considered namely gas and coal. A gas fired power plant is assumed to generate approx. 2.0 Mt CO_2 per year and a coal fired power plant approx. 3.33 Mt CO_2 per year. Assuming a power plant lifetime of 30 years the corresponding total amounts of CO_2 will be 60 and 100 Mt, respectively. Obviously the storage site must be available by the time the power plant is operational. Only one storage locations are considered for the life time of the plant: no combination ofstorages.

A large number of the considered storage sites are included in the GESTCO database. In the GESTCO database the storage capacity for hydrocarbon fields have been calculated based on the volume of ultimately recoverable oil or gas at standard conditions (UR or initial proven reserves) multiplied by the respective formation volume factor and the CO_2 density at reservoir conditions. The storage capacity of trapped saline aquifers in GESTCO are calculated using the volume of the structure multiplied by the net sand ratio, the porosity, the storage efficiency coefficient and the CO_2 density at reservoir conditions. The storage efficiency coefficients are typically estimated and may vary from formation to formation and/or from country to country/region to region. It should be noted that the validity of the estimates of e.g. the storage efficiency coefficient and the ultimately recoverable volume of oil and gas may have a great impact on the true storage capacity and that the storage capacity in some cases have been calculated/estimated in other ways.

As a general rule of thumb the formation permeability must exceed 200 mD for a specific reservoir to provide injectivity (van der Meer,L.G.H., 1993) in the order of magnitude as described above.

Using a cylindrical reservoir (20x1x20 grid blocks) around the injection well as illustrated in Figure 4.1, the IFP CO_2 simulator, COORES, was used to compute the pressure increase due to injection in the storage near the injection well (Figure 4.2). The average pressure is computed from the median value of pressure of the perforated interval.

Assuming an initial pressure of 80 bars and a temperature of 40°C, the injection rate was set to 2.5 Mt CO_2/y (which is in the order of magnitude of what is foreseen) i.e. 14625 m^3/d at reservoir conditions where CO_2 density is about 281 Kg/m^3. The injection takes place in the center of the storage. The outer radius is at constant initial pressure (open in the upper half, closed in the lower half). The reservoir is homogeneous (uniform porosity = 12%). The horizontal permeability (Kh) and vertical permeability (Kv) vary in the different runs.

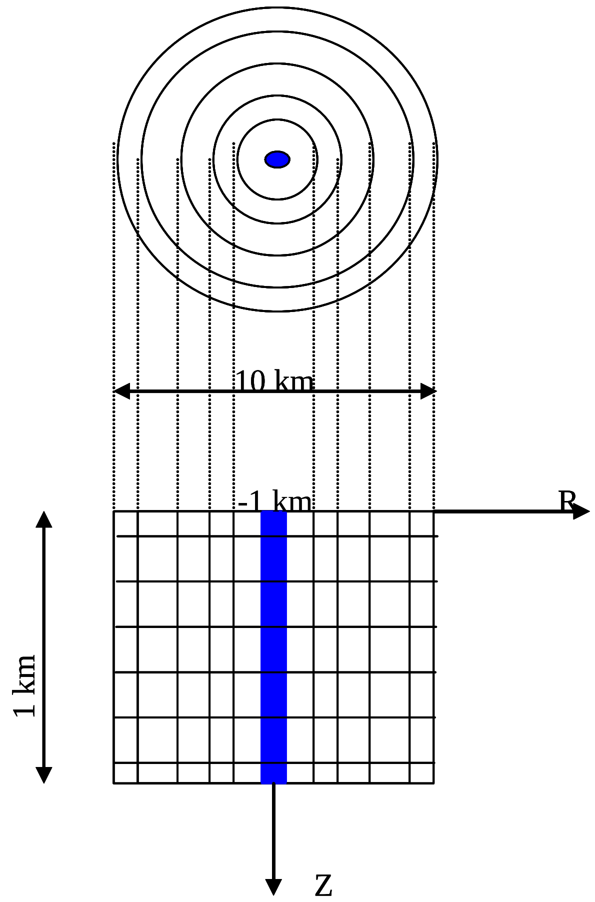

Figure 4.1 Schematic of the storage model

Figure 4.2 confirm the key role of permeability on the maximum pressure in the reservoir (near the well bore) and the choice of 200 mD as a general cut off value. Obviously, if more than one well is used for injection, the over pressure will be much smaller as illustrated in Figure 4.3. The overpressure, and consequently the pore entry pressure of the cap rock for CO_2, of 400 bars implies a cap rock permeability less than about 4 10^{-8} mD using correlation for gas storage (Tek, 1987) and correcting for interfacial tension difference between CH_4 and CO_2. This cap rock permeability requirement increase to about 1 μD if the number of injection wells is increased to 5, i.e., the injection flow rate divided by 5 and assuming no interference between the injection wells. The overpressure during the injection could be mitigated depending on the economic and operational and geological conditions. However, some pressure interference in the injection pattern may become a limiting condition.

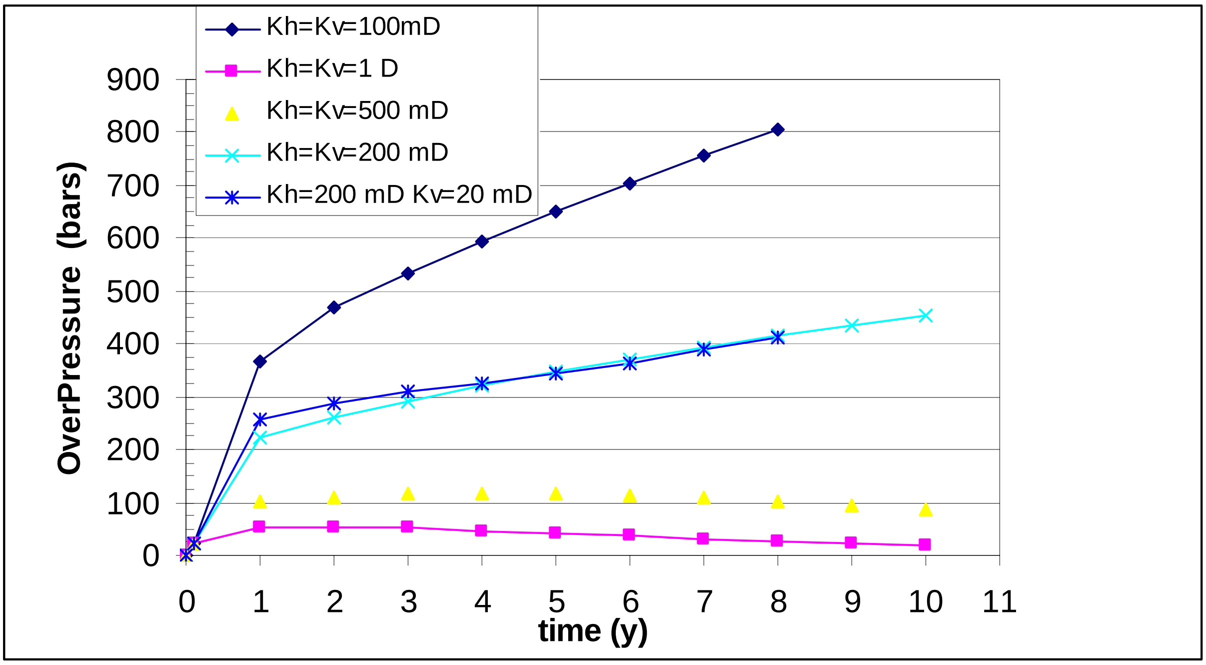

Figure 4.2 Pressure increase above the initial average pressure due to injection of 2.5 $MtCO_2/y$ in a single well.

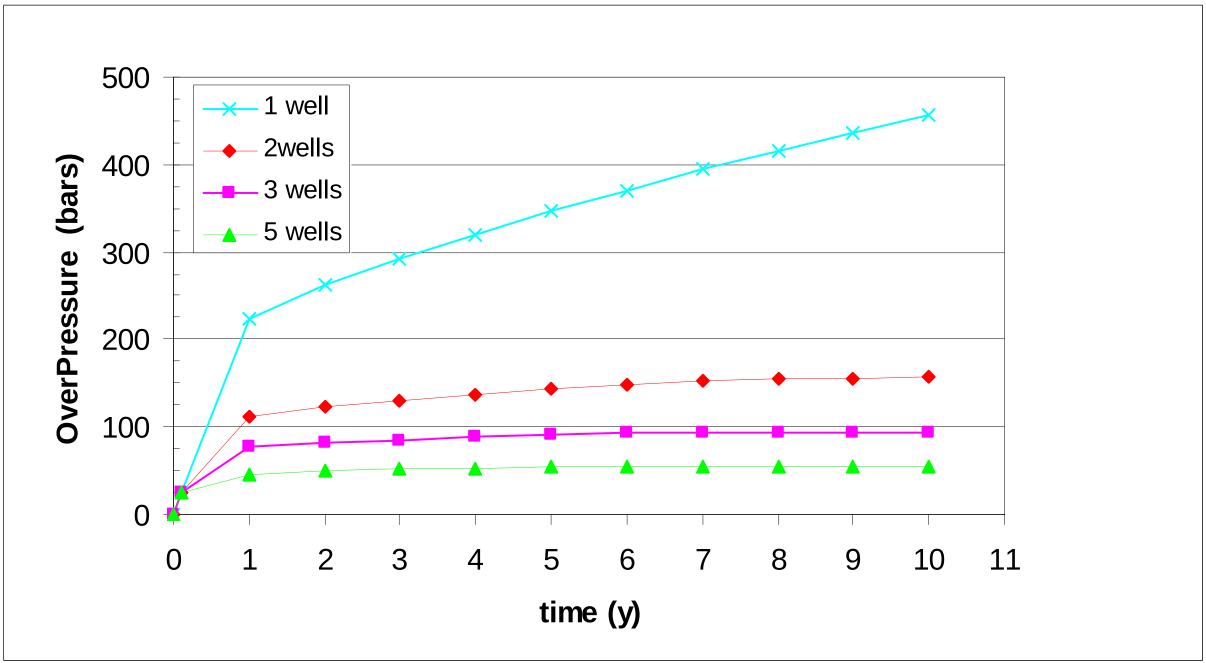

Figure 4.3 Pressure increase above the initial average pressure due to injection of 2.5 $MtCO_2/y$ with several identical wells.

Storage of CO_2 is dependent not only on the properties of the reservoir, but also on the integrity of the sealing formation. Typical formations with sealing properties are lacustrine and marine mudrocks, evaporates and carbonates. The integrity of the seal is governed by the thickness of the sealing formation, the presence (or absence) of faults crossing the formation as well as the impact of geochemical interactions between the CO_2 and the caprock.

In order to assess the reservoir and seal properties geological information such as contour maps of structure, well information providing the geological succession, porosity and permeability values, pressure and temperature data etc. is essential.

Full deployment of a European hydrogen infrastructure depends on the development of fuel cell vehicles and the extent of a pioneer hydrogen market in Europe may be limited to areas with a high population density. Thus possible future locations of a HYPOGEN power plant must be taken into consideration in terms of geographical representation of possible storage sites.

Finally the possible storage sites should represent a number of different geological conditions in terms reservoir and sealing formation as well as different storage types in terms of depleted oil and gas reservoirs, saline aquifers etc.

Given the project constraints above, a set of 10 final site selection criteria has been defined:

1. Depth > 800 m or P-ini > 80 bar or Supercritical CO_2
2. Total storage capacity > 60 Mt CO_2
3. Injectivity > 2.0 Mt CO_2 per year or permeability > 200 mD
4. Integrity of seal in terms of thickness, faults etc.
5. Availability of geological data
6. Availability of site by 2012
7. Location of site compared to Power/Hydrogen Market
8. Geographical representation of sites
9. Variety of geological conditions
10. Variety of storage types

Selection criteria 1-3 are more or less straight forward or objective criteria definitions either including or excluding a specific site, while selection criteria 7-10 are of a more subjective nature and criteria 4-6 somewhere in between.

5 SHORTLIST OF POSSIBLE STORAGE SITES

Based on the final site selection criteria described in section 4, a total of 16 possible storage sites have been selected for the shortlist. All the sites selected for the shortlist fulfill criteria 1-3, while other sites also fulfilling these three criteria has been excluded from the list based on the more subjective criteria definitions, typically one or more of criteria 4, 5 and 6. The shortlist is enclosed in Appendix III.

In Appendix IV, further possible storage locations from the Joule II project are reported, which did not meet the DYNAMIS selection criteria, mainly the geographical location criteria.

A map of pipelines in the Southern North Sea is given in Figure 5.1 and below is a short description of each site included on the shortlist.

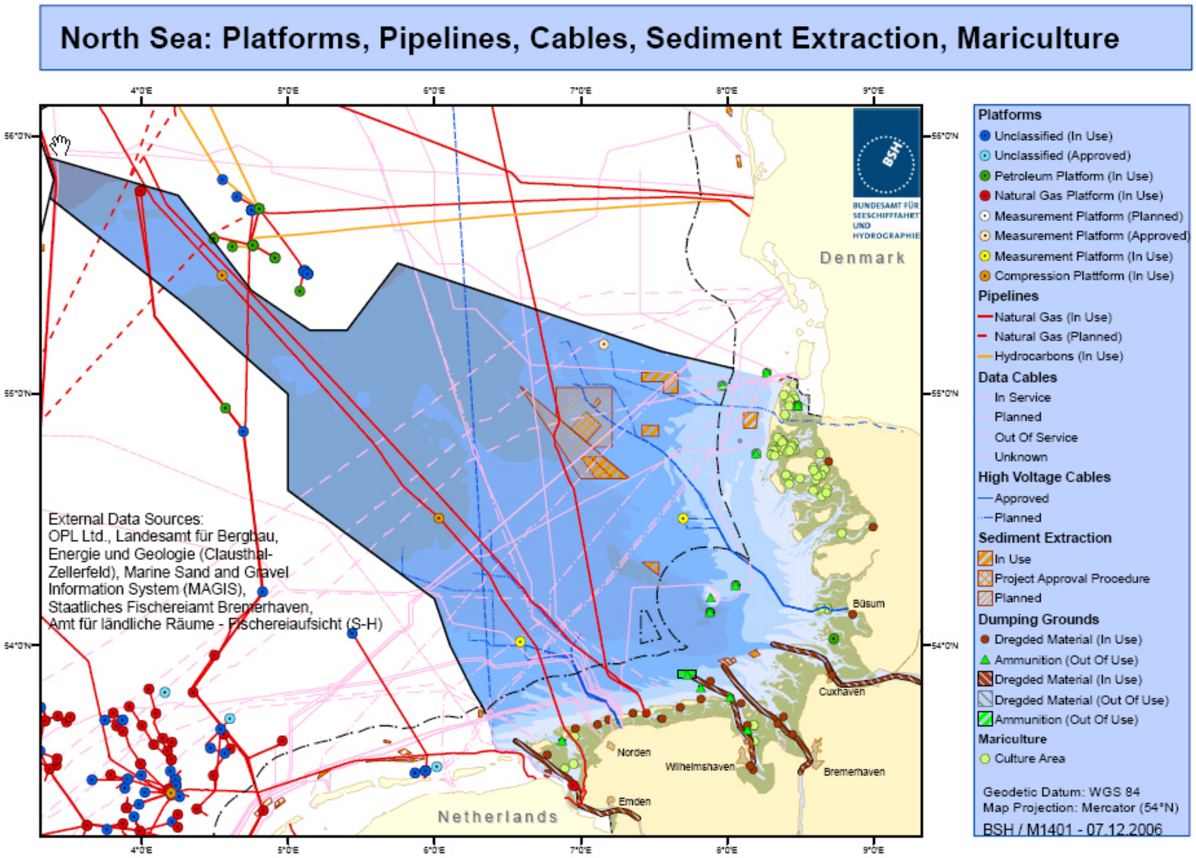

Figure 5.1: Pipelines in the Southern North Sea (NorthSeaPipelinesCablesExtraction).

5.1 UK

Figure 5.2 shows the location of the short listed UK sites.

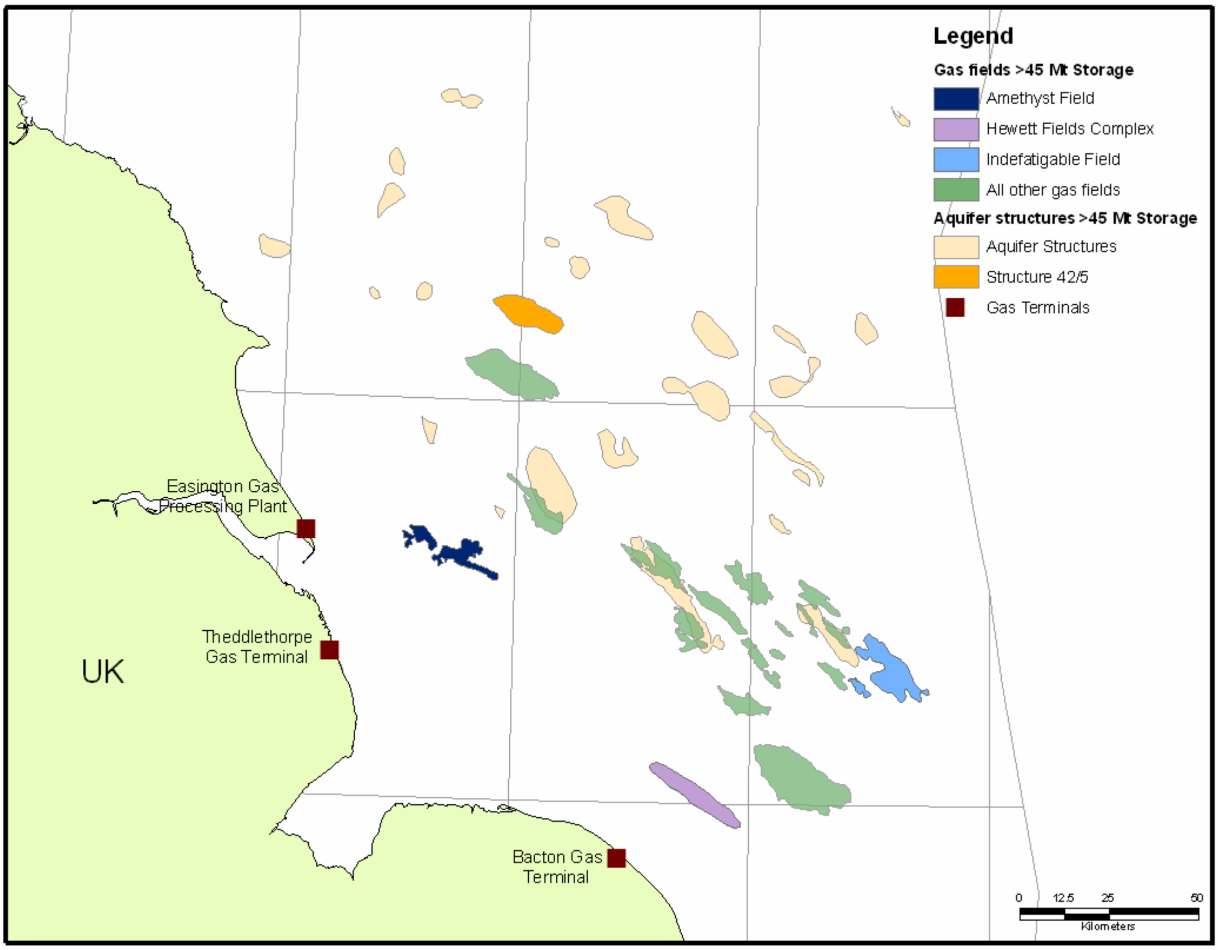

Figure 5.2: Map showing location of the potential UK CO_2 storage sites

5.1.1 Hewett Fields complex

The Hewett fields complex is located 28 km north-east of the Bacton gas terminal in the southwestern area of the southern North Sea (Figure 5.2). It comprises a total of seven fields in which there are ten producing reservoirs lying in blocks 48/28a, 48/29, 48/30, 52/4a and 52/5a.

5.1.1.1 General geological setting

The main Hewett field comprises three gas-producing reservoirs: the (Triassic) Upper Bunter Sandstone and the Hewett (or Lower Bunter) Sandstone and the (Permian) Zechsteinkalk carbonates. The reservoir in the Zechsteinkalk is too small to meet the CO_2 storage criterion and therefore is not discussed further.

The Hewett structure formed during reverse fault action along the Dowsing and south Hewett faults during the Late Cretaceous (Cooke-Yarborough & Smith, 2003).

The Lower Bunter Sandstone has excellent permeabilities, typically ranging from several hundred mD to over 1 D, whilst the Upper Bunter Sandstone has permeabilities up to 500 mD.

The field is located just to the north of the London-Brabant Massif, in the southern reaches of the Sole Pit Trough. The crest of the fields lie at depths of 792 m and 1227 m and reservoir thicknesses are approximately 165 m and 41 m in the Upper Bunter and Lower (Hewett) Bunter reservoirs respectively.

5.1.1.2 Wells
There are a total of 39 wells penetrating the three reservoirs (Upper and Lower Bunter, and Zechsteinkalk).

5.1.1.3 Trap and Seal
The trap is a NW-SE trending anticline bounded by faults on its NE and SW flanks. (Cooke-Yarborough & Smith, 2003). The overlying Bunter Shale and Dowsing Formations provide an effective seal to the Lower Bunter Sandstone and Upper Bunter Sandstone reservoirs respectively.

5.1.1.4 Storage potential
From a geological perspective, the Lower Bunter (Hewett) Sandstone reservoir appears to be an excellent prospect for CO_2 storage in the Southern North Sea as it combines high permeability, no water influx and no compartmentalisation with very large CO_2 storage capacity, estimated at a maximum of 237 Mt.

The maximum CO_2 storage capacity of the Upper Bunter unit is estimated at 122 Mt. However, major water influxes in the Upper Bunter reservoir threatened production and it was thought that the reservoir was about to water-out until production commenced in an adjacent field, Little Dotty. The two fields share common aquifers and at this point water influx slowed (Cooke-Yarborough & Smith, 2003). This may make the Upper Bunter reservoir less suitable for storage than the Lower Bunter.

5.1.2 Indefatigable Field

The Indefatigable field lies in blocks 49/18, 49/19, 49/23 and 49/24 on the northern side of the Sole Pit Trough (Figure 5.2).

5.1.2.1 General geological setting
The field reservoir consists of stacked aeolian dunes interbedded with occasional sabkha deposits within the (Permian) Rotliegend Leman Sandstone Formation (McCrone et al., 2003). The crest of the field lies at a depth of 2285 m and the reservoir is approximately 45-122 m thick.

Most of the field is a single large structure but there are two minor separate accumulations; Indefatigable SW and Baird, which lie to the SW of the main field. The main field is complex with 11 gas/water contacts and 15 reservoir compartments. As the reservoir has been depleted some of the faults between compartments have stopped acting as complete lateral seals allowing some communication. The field has generally good permeability, with values ranging between 1 – 1000 mD. There are no indications from well data of any vertical permeability barriers within the sequence.

5.1.2.2 Wells

There are 56 producing wells and 23 development wells penetrating the Indefatigable reservoir, a large number of wells have been drilled due to the compartmentalisation in the reservoir.

5.1.2.3 Trap and Seal

The trap is a major NW-SE trending structural horst with several sealing faults. The overlying Zechstein evaporites provide a thick (600-750 m) effective seal. A very small number of wells exhibit water production, these are located on the flanks of the field and gas production is generally unaffected. There is no evidence of an active aquifer (McCrone et al., 2003).

5.1.2.4 Storage potential

The main field is a large and apparently excellent prospect for CO_2 storage and combines good permeability with low water encroachment. The maximum CO_2 storage capacity for Indefatigable is estimated at 357 Mt. Reservoir compartmentalisation means that the field would require careful reservoir management.

5.1.3 Amethyst Field

The Amethyst gas field lies in blocks 47/8a, 47/9a, 47/13a, 47/14a and 47/15a of the southern North Sea, 40.2 km east of the Easington gas terminal (Figure 5.2), within the Sole Pit Trough.

5.1.3.1 General geological setting

The reservoir is in the Rotliegend Group Leman Sandstone Formation and is up to 36 m thick with the crest of the field lying at a depth of 2682 m. Two facies types are present; aeolian and wadi. Within the aeolian sandstones in the Leman Sandstone, the permeability reaches 100 mD, whereas in the wadi deposits the permeabilities are much lower, between 0.5-10mD (Garland, 1991). Severe late anhydrite cementation near to fault zones affects the reservoir.

The Amethyst gas field comprises five separate accumulations. The three western pools are known as Amethyst West, sharing common gas-water contacts and a common pressure regime suggesting communication prior to production (Garland, 1991). The two eastern pools are known as Amethyst East. In 1991, it was assumed that production would be by pressure depletion alone. At that time, the possibility of lateral aquifer movement, which provides a threat of water encroachment, was being investigated; unfortunately no further information about this is available at present.

5.1.3.2 Wells

There are a total 20 appraisal and development wells that penetrate the various accumulations. Some of the appraisal wells suffered from low permeability because the aeolian sandstones were absent.

5.1.3.3 Trap and Seal

The trap is a faulted anticline with Zechstein Group halites and anhydrites forming an effective seal.

5.1.3.4 Storage potential

Amethyst offers high permeabilities in the aeolian sandstones and close proximity to shore terminals. However, it has five separate pools, which may complicate injection. The gas has a relatively high CO_2 content (0.64 Mol%) and the production tubing is made from high-chrome steel. Consequently, infrastructure resistant to the corrosive effects of CO_2 is already in place.

5.1.4 Structure 42/5

Structure 42/5 lies in blocks 42/25 and 43/21 around 85 km northeast of the Easington gas terminal (Figure 5.2), within the Sole Pit Trough.

5.1.4.1 General geological setting

The crest of this saline water-bearing structure lies in the Bunter Sandstone Formation at a depth of 1800 m with the anticipated reservoir being approximately 150m thick. The structure overlies a salt dome caused by gentle movement in the underlying Zechstein Salt, which has folded the Bunter Sandstone and overlying sediments. Only minor faulting is apparent over the crestal area of the structure, related to the gentle folding. Three faults with small offsets are observed on seismic reflection data, with one fault apparently penetrating the top of the Bunter Sandstone. This fault doesn’t propagate to the seabed and may be sealed by the younger Rot Salt.

5.1.4.2 Wells

Two wells penetrate the structure and the seal above it, 42/25-1 and 43/21-1.

5.1.4.3 Seal

The structure and aquifer is overlain by the Haisborough Group, comprising mudstones and evaporites. The Rot Halite at the base of the Haisborough Group may help to provide an effective seal to this salt-induced anticline.

5.1.4.4 Storage potential

The maximum storage capacity of the closure at 40% pore space saturation of CO_2 is estimated at 836 Mt (Holloway et al., 2006). A flat spot can be seen on seismic reflection data on the right and left flanks of the structure, indicating at least some gas in place in the past.

5.2 Germany

5.2.1 Greifswalder Bodden

The site is described as a GESTCO case study (May et al. 2004). The saline aquifer represents widely spread geological and structural conditions of the Middle Bunter Sandstone in the North German Basin in north-eastern Germany.

5.2.1.1 Location

The structure is located offshore in the coastal area northeast of Greifswald.

5.2.1.2 Geological setting and cap rocks

Storage potential for CO_2 is given in the Middle Bunter Sandstone. Marked permeability (500 – 2000 mD) can be measured in the basal parts of the three upper cycles (Dethfurt, Hardegsen, and Solling). The cumulative thickness of the sandstones is about 80 m. The Middle Bunter Sandstone is sealed by Röt claystones.

5.2.1.3 Structural setting

The potential storage site is located within a nearly 10 x 40 km large NW-SE striking block, Figure 5.3. The Middle Bunter Sandstone is situated at 1100 m depth. Apart from the fault zones that limit the block only a very few minor faults are present. The strata are dipping from the limiting fault zones towards the centre of the block forming a large syncline with low amplitude. Saline groundwater indicates fault zone permeability of the Möckow-Dargibell fault zone in the southwest (Mayer et al. 1998). Therefore the storage site should be located at the northeastern flank of the syncline near the Freester fault zone and the Samtens fault zone.

5.2.1.4 Wells

That part of the block which can serve as storage site has not yet been explored by wells. Four wells penetrate the block near the potential storage site. There are further wells in the southern part of the block and at its edges. There are data available about porosity and formation water quality. Several seismic surveys on- and offshore are described in Diener et al. (1992) and Mayer et al. (1998).

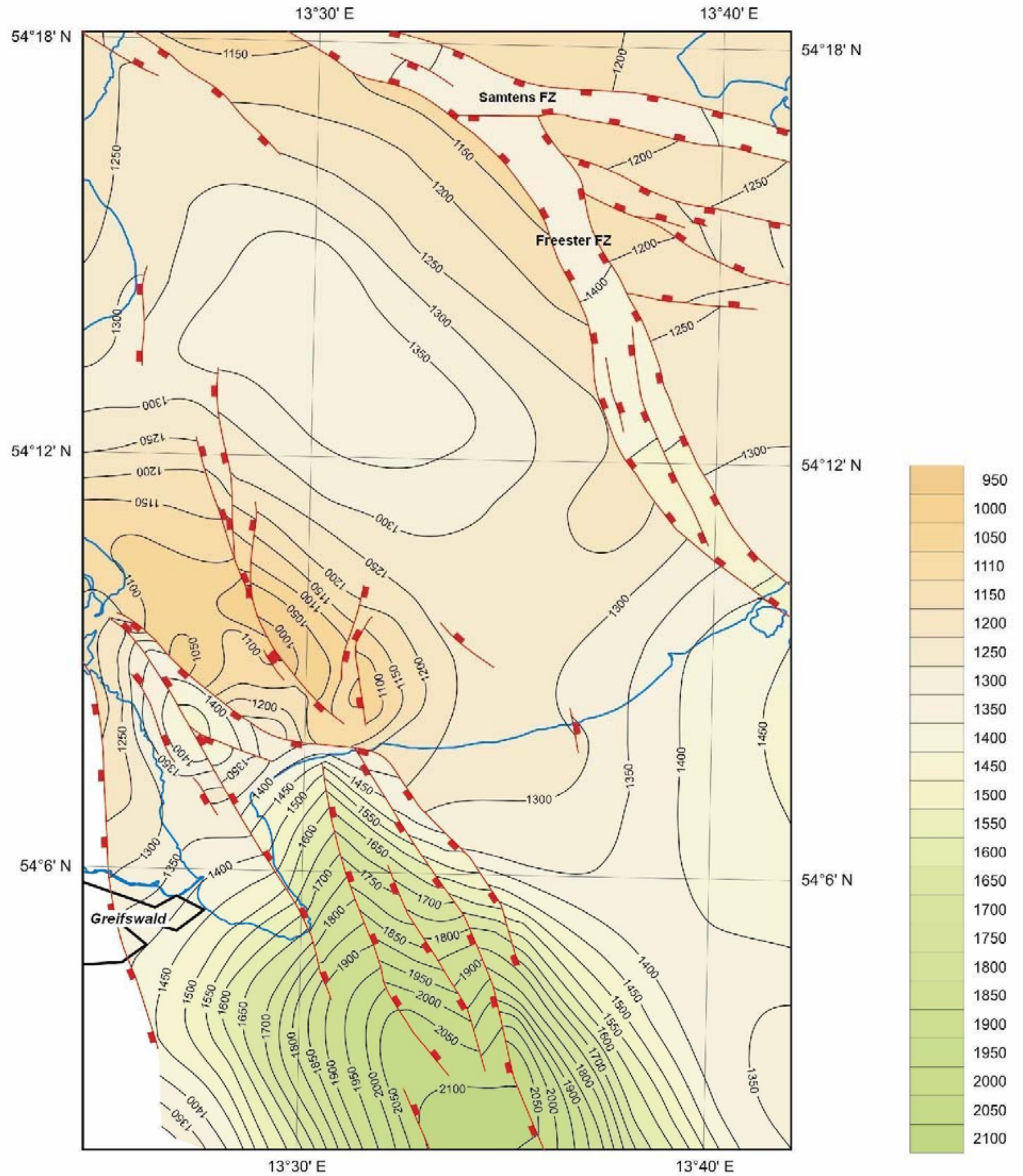

Figure 5.3: Topography of seismic reflector S2 that marks the top of the Middle Bunter Sandstone (area northeast of Greifswald, blue: coastline, depth: metres below sea level, from May et al. 2004).

5.2.2 Schweinrich

The site is described as a CO2STORE case study (Meyer et al. 2006, Chadwick et al. 2007 in press). The saline aquifer represents sandstone aquifers in the North German Basin, in north-eastern Germany.

5.2.2.1 Location

The structure is located in northern Brandenburg extending into Mecklenburg-Vorpommern.

5.2.2.2 Geological setting and cap rocks

The anticlinal structure “Schweinrich” contains two reservoir formations, predominantly fine-grained and well sorted, highly porous sand and silt stones of the lowest Jurassic (Hettang) and the uppermost Triassic (Contorta), interbedded by silty and clayey layers with minor amounts of coal. Both reservoirs are separated by a major shale layer (Triletes). Porosity values of the reservoir sandstones range, dependent on the sand/silt-clay ratio between 10 and 32 percent with permeability values up to 2000 mD. The entire reservoir is sealed by several thick Jurassic clay formations.

5.2.2.3 Structural setting

The structure Schweinrich is a passive anticlinal structure that has formed during the ascent of adjacent salt pillows. Within the structural closure, the reservoir formations lie at depths between 1.300 to 1.800 metres below mean sea level and have a lateral extend of about 100 km^2.Gross thickness of the reservoir interval ranges between 270 m in the West to 380 m in the East. Several older seismic profiles exist in the vicinity of the structure and its surroundings, indicating the existence of faults in the overburden of the structure.

5.2.2.4 Wells

The anticline itself has not yet been explored by wells. Several wells near the potential storage site indicate facies variations within the reservoir formations.

5.3 France

The selection of sites for France is based on an analysis of the French Bassin Parisien, following previously work done for GESTCO[3]. Thus, the two aquifer groups investigated are:

- the Triassic aquifers
- the Dogger aquifers

5.3.1 Triassic aquifer

The Triassic aquifers (central and southern part of the Bassin Parisien) are found at depths varying from 1500 to 3000m, at temperatures of 70 to 120 °C and pressures varying from 200 to 300 bars. These aquifers are capped by anhydritic clays and their use is restricted to oil recovery and gas storage (Chemery gas storage). The few attempts to use these aquifers for geothermal purposes ran into problems caused by "fines", which created plugging problems at injection wells. The capacities for the Triassic aquifers are:

Formation	Area	Average net thickness	Mean porosity	Total pore volume	Storage capacity (unconfined aquifers)	Storage capacity (confined aquifers)
	km^2	km		km^3	Mt CO_2	Mt CO_2
Bundsandstein	21000	0,2	0,1	420	17640	529
Keuper	27500	0,025	0,15	103	4331	130
Triassic total	48500	0,225		523	21971	659

5.3.2 Dogger aquifer

The Dogger aquifers are to be found above the Triassic aquifers, at depths varying from 1700 to 2000 m, at temperatures between 60 and 80 C and pressures of 140 to 150 bars (data obtained from the zone are from the analogue of the geothermal exploitation is currently taking place in other part of the aquifer). The porosity of these aquifers are 0.1 and their transmissivity exceeds 30 D*m. The overlying cap rock is described as clayey and having permeabilities varying from 10^{-1} to 10^{-2} μD and a thickness of 100 m. These aquifers support about 55 well-doublets (injector-producer) associated to geothermal activity. The capacities for the Dogger aquifers:

Formation	Area	Average net thickness	Mean porosity	Total pore volume	Storage capacity (infinite acting)	Storage capacity (bounded aquifers)
	km2	km		km3	Mt CO_2	Mt CO_2
Dogger	15000	0,1	0,1	150	4320	8.64
Paris geothermal reservoir	2484	0,02	0,15	7	215	0,43

[3] The calculation method is the one used for the GESTCO project, namely a volumetric equation which considers a 6% volume capacity for unconfined aquifers. The storage capacities in confined aquifers are estimated to be 3% hereof for the Triassic aquifers and 0.2% hereof for the Dogger aquifers.

5.4 Denmark

5.4.1 Gassum structure

The following description is based on Larsen et al. (2003). The Gassum structure is situated in eastern Jutland and the closure is mapped at the top Gassum Formation level (Late Triassic – Early Jurassic age).

5.4.1.1 General geological setting

The structure is situated in the central part of the Danish Basin and is caused by uplift due to post depositional salt tectonics (Figure 5.4). Depth to top of the formation is 1460 m below msl and the Gassum Formation reach a thickness of 130 m although the net sand thickness is only 53 m due to shaling out of the formation from east towards west in the Danish Basin. The Gassum Formation is well-known in the Danish Basin and is described in detail (Nielsen et al. 1989; Hamberg 1994; Hamberg & Nielsen 2000; Nielsen 2003).

5.4.1.2 Well database

The seal and reservoir is penetrated by the Gassum-1 well located close to the top point of the structure. Data for the Gassum aquifer is extrapolated from the wells Gassum-1, Hobro-1 and Voldum-1.

5.4.1.3 Seismic coverage

The structure is interpreted from the depth structure map of the “Top Triassic” as defined by Japsen and Langtofte (1991).

5.4.1.4 Storage potential

The closure is defined by an almost circular domal structure, approximately 800 m high and with very steep flanks. The spill point is at 2300 m below msl towards the south and the closure defines an area of approximately 242 km^2. With a porosity up to 25 % and a permeability from 300–2000 mD and with normal pressure and temperature gradients for the Danish Basin this leads to an estimated maximum storage capacity of 705 Mt CO_2 for the this structure.

5.4.1.5 Seal

The Gassum Formation is overlain by 320 m marine mudstones of the Fjerritslev Formation, forming the seal of the structure.

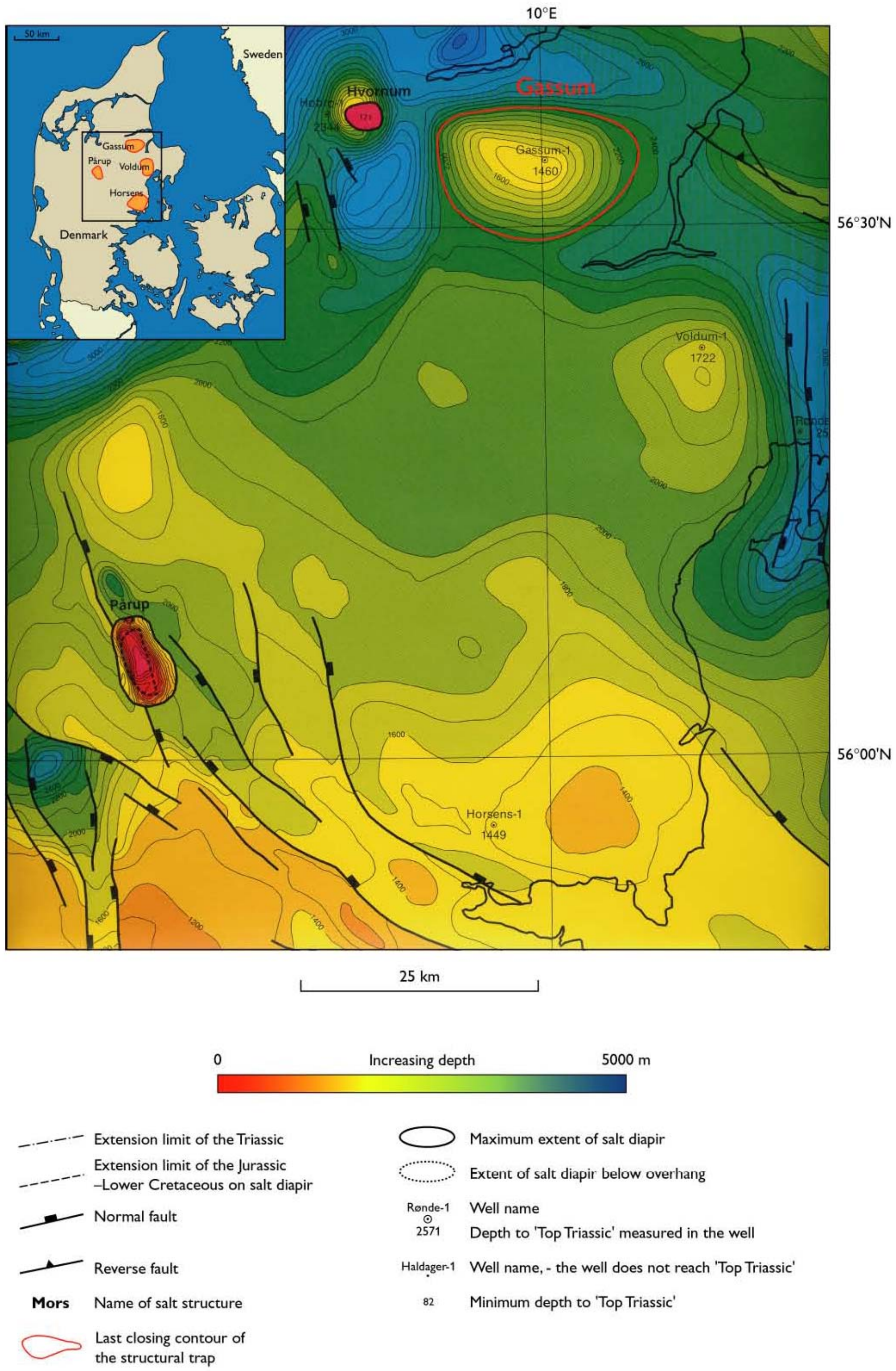

Figure 5.4: Outline of the structural trap defining the potential storage site at Gassum. The structure is interpreted from the depth structure map of the Top Triassic" as defined by Japsen and Langtofte (1991).

5.4.2 Horsens structure

The following description is based on Larsen et al. (2003). The Horsens structure is situated in eastern Jutland and the closure is mapped at the top Gassum Formation level (Late Triassic – Early Jurassic age).

5.4.2.1 General geological setting

The structure is situated in the central part of the Danish Basin and is a result of uplift caused by post depositional salt tectonics (Figure 5.5). Shaling out of the Gassum Formation from east towards west results in a relatively thin formation of only 94 m at the site. The Gassum Formation is well-known in the Danish Basin and is described in detail (Nielsen et al. 1989; Hamberg 1994; Hamberg & Nielsen 2000; Nielsen 2003).

5.4.2.2 Well database

The seal and reservoir is penetrated by the Horsens-1 well situated at the western edge of the closure. The reservoir is evaluated using well information from Horsens-1, Rønde-1, Stenlille-1 and Stenlille-19.

5.4.2.3 Seismic coverage

The structure is interpreted from the depth structure map of the “Top Triassic” as defined by Japsen & Langtofte (1991).

5.4.2.4 Storage potential

The closure is defined by a flat, circular, approximately 100 m high, domal structure covering 318 km^2. The depth to top aquifer is estimated to be 1500 m below msl, with the spill point situated towards the southeast. The aquifer is expected to hold a normal temperature and pressure gradient for the Danish Basin and the maximum storage capacity is calculated to be 490 Mt CO_2 with reservoir thickness of 94 m, and net/gross of 0.26. The porosity has been measured to 25 % in core and the gas permeability to 500 mD (Michelsen et al. 1981).

5.4.2.5 Seal

The Gassum Formation is overlain by marine mudstones of the Fjerritslev Formation forming the seal of the structure. In Horsens-1 the Fjerritslev Formation reaches 210 m in thickness.

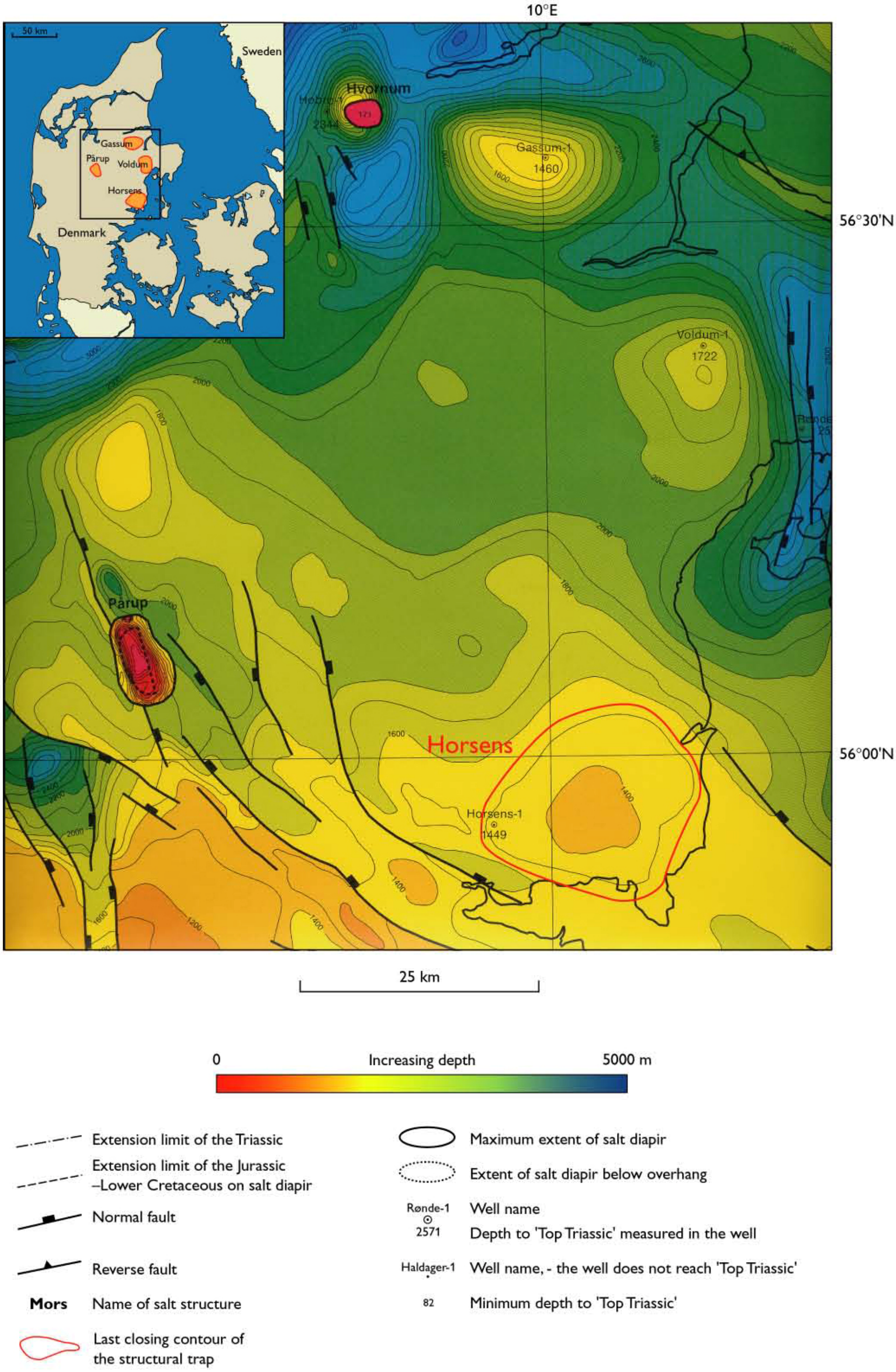

Figure 5.5: Structural map outlining the storage site at Horsens. The structure is interpretd from the depth structure map of the "Top Triassic" as defined by Japsen and Langtofte (1991).

5.4.3 Vedsted structure

The following description is based on Larsen et al. (2003). The Vested structure is situated in northern Jutland close to the city of Ålborg. The main reservoir is mapped in the Upper Triassic – Lower Jurassic Gassum Formation.

5.4.3.1 General geological setting

The Vedsted structure is a domal structure situated in a small graben bounded by northwest-southeast trending faults. The graben structure is part of a Triassic rift system forming the deep Fjerritslev Trough. The Vedsted structure is governed by movements of an underlying salt pillow.

5.4.3.2 Well database

From the top point of the structure, the Vedsted-1 well has penetrated both the seal and reservoir (Figure 5.6). The well Haldager-1 is situated nearby to the east, but is outside of the small graben structure.

5.4.3.3 Seismic coverage

The structure is interpreted from the depth structure map of the “Top Triassic” as defined by Japsen and Langtofte (1991).

5.4.3.4 Storage potential

The Upper Triassic – Lower Jurassic sandstones of the Gassum Formation form the primary reservoir unit. Deposition of the sandstone was in part controlled by the Triassic rift system and both the Gassum and Haldager Sand Formations show increased thicknesses (Bertelsen 1980) at this site with a reservoir unit of 139 m with net/gross as high as 0.74. The porosity has been measured to be between 20 and 24 % and the gas permeability to 1000 mD (Michelsen et al. 1981). The structure is a small ellipsoid closure approximately 250 m high, covering 32 km^2 and top aquifer is 1898 m below msl. The spill point is situated towards the southeast. With a normal pressure and temperature gradient for the Danish Basin the reservoir the structure is calculated to hold a storage potential of 161 Mt CO_2.
The Middle Jurassic Haldager Sand Formation forms an upside potential with excellent reservoir properties. This formation thus has a net sandstone thickness of 55 m with porosity above 30 % and gas permeability measured to 2000 mD (Michelsen et al. 1981). Including this reservoir unit in the Vedsted structure increases the storage potential to almost 320 Mt CO_2.

5.4.3.5 Seal

The reservoir is sealed by 525 m of marine claystones of the Fjerritslev Formation. The fault situated to the southwest of the structure may form a potential risk for a migration pathway through the seal.

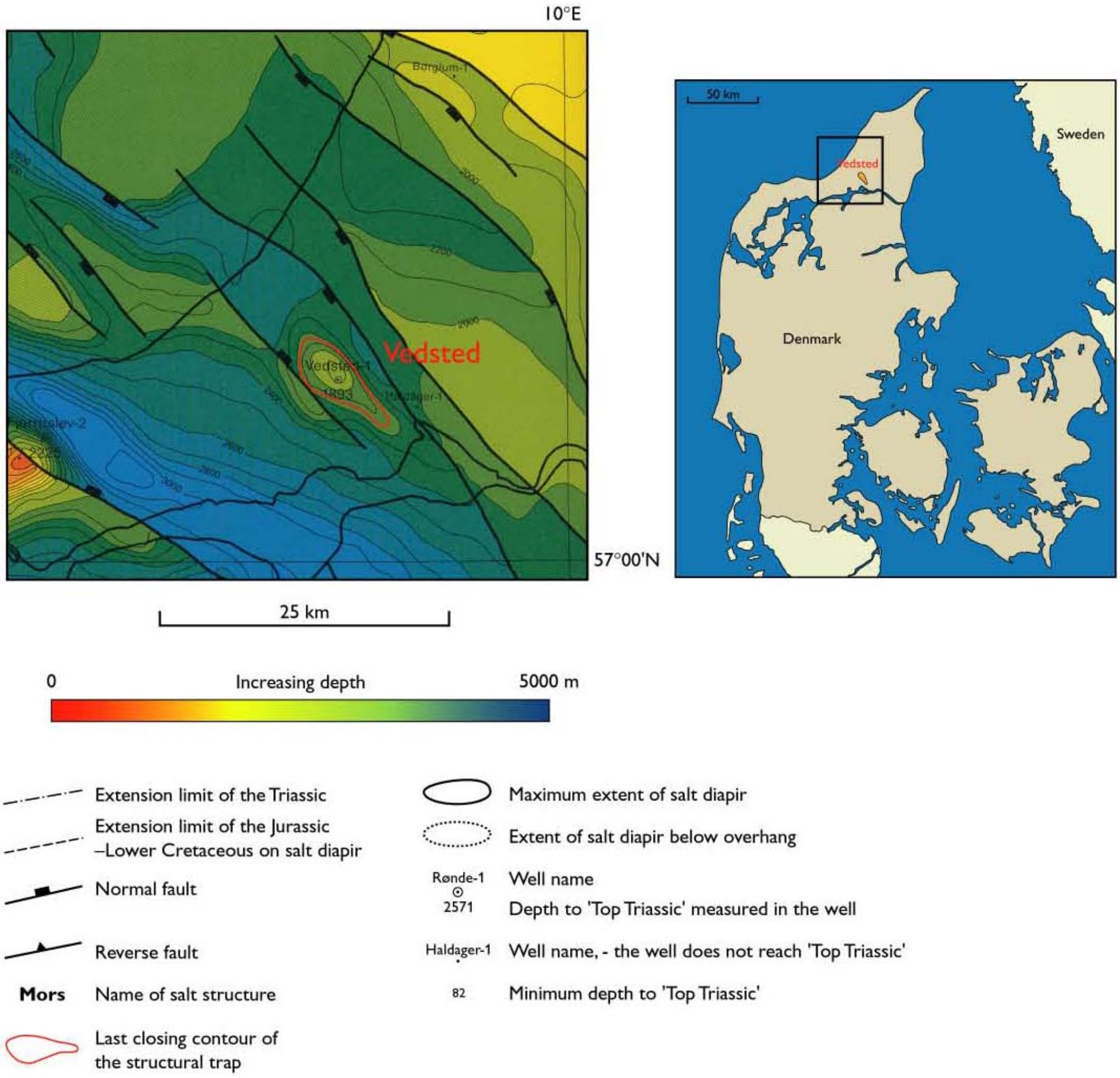

Figure 5.6: Outline of the structural trap defining the potential storage site at Vedsted. The structure is interpreted from the depth structure map of the "Top Triassic" as defined by Japsen and Langtofte (1991).

5.5 Norway

Three depleted gas-fields, one oil field and the giant Utsira aquifer have been identified as possible storage sites on the Norwegian Continental Shelf. The Utsira aquifer is well described in "Best Practice Manual from SACS - Saline Aquifer CO_2 Storage Project" (SACSBestPractiseManual.pdf). The depleted gas fields and the oil field are described in the following in the context as storage sites. Potential storage sites in the great Ekofisk area are excluded here due to long distance from source.

5.5.1 Frigg field and connected aquifers

The Frigg field is a nearly depleted gas and condensate field with reservoir and aquifer properties that seem very suitable for CO_2 storage: high porosity (29%) and permeability (0.5 – 4.0 Darcy), moderate depth (1800 m) and a verified sealing integrity. CO_2 injection in the reservoir may contribute to enhanced gas and condensate recovery and the injected CO_2 can be stored in the field subsequent to final gas and condensate production. This could provide additional income for the license owners. Possible re-use of the existing infrastructure is another issue that makes this concept interesting. The location of Frigg, Heimdal and Odin Fields are shown in
Figure 5.7.

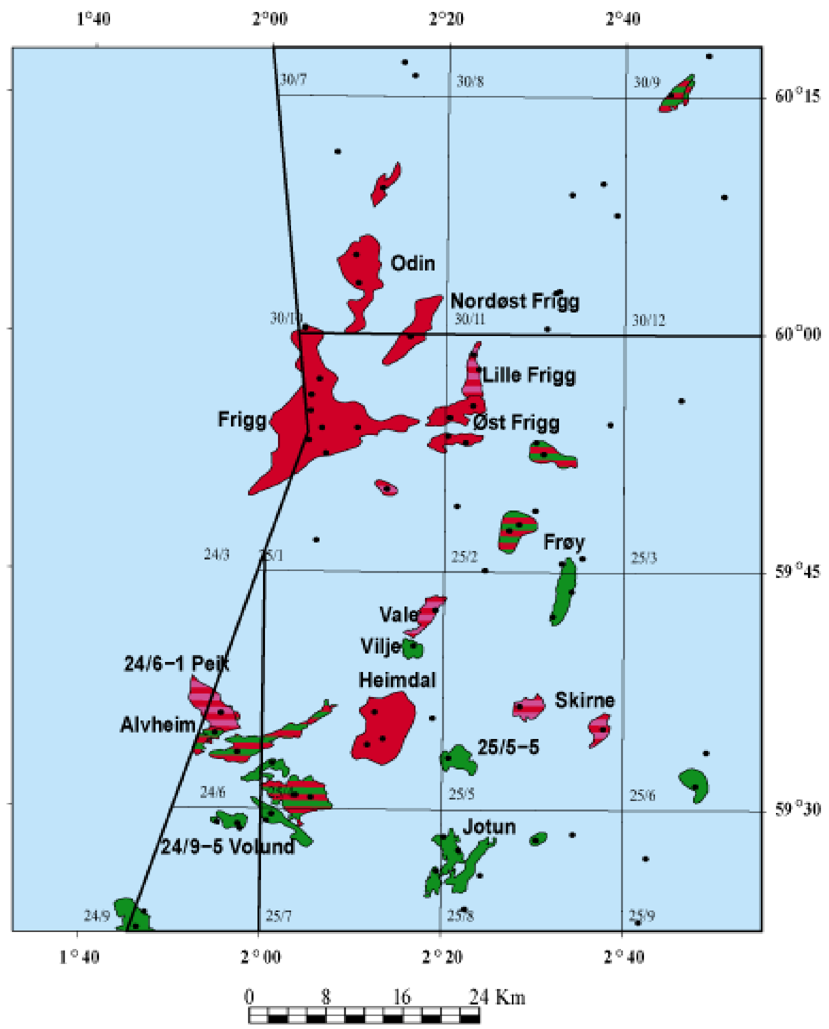

Figure 5.7: The Frigg area in the North Sea (http://www.npd.no/Frigg.gif).

5.5.1.1 General geological setting

The Frigg Field is located approximately 190 km off the Norwegian coast (northwest of Stavanger) and is predominantly in Block 25/1 on the Norwegian side of the boarder and in Block 10/1 on the British side (60.82% of the resources are located on the Norwegian side of the border (http://www.npd.no/). The license was awarded Elf as operator in May 1969, and the license expires May 2015.

The Frigg Field occurs in the sand/shale sequence of the Frigg Formation which is Early Eocene/Late Palaeocene in age and overlies the tuffaceous Balder Formation. The Frigg Field is situated in the axial part of the Viking Graben which developed as a major rift system between Triassic and Early Cretaceous. Chalk deposition in Frigg area ceased during Early Palaeocene, and central parts of the graben were in-filled by turbidites from the edges of the Shetland Platform to the west (Brewster and Jeangeot).

The field is a four-way, dip-closed, stratigraphic trap which is sealed by a combination of depositional topography, sand body geometry, draping and differential compaction. The reservoir sand contains local shales that have provided hydrodynamic barriers (De Leebeek 1987) similar to the Utsira formation. These barriers could enhance distribution of the CO_2 in the reservoir and thereby accelerate its dissolution in the formation water which would be positive for storage safety.

5.5.1.2 Storage potential

The estimated total storage capacity is 363 Mt CO_2 (GESTCO data base). The top of the reservoir is at approximately 1800 m below msl. From seismic and well control the gas height is about 160 m covering over 100 km^2 at the gas oil contact. The gas is underlain by an oil disc of 8.6 m in average thickness (De Leebeeck, 1987).

5.5.1.3 Seal

The Frigg chalk gas reservoir is overlain by the Maureen Formation which is predominantly shale but can contain sand bodies. The Lista Formation overlies the Maureen. This is a predominantly marine shale sequence in the Frigg area. The Sele Formation which overlies the Lista Formation is a more complex clastic sequence of thin sands intercalated with shales.

5.5.1.4 Utilization of present infrastructure, injection wells and well integrity

It should be evaluated to what extent the present infrastructure can be used in a CO_2 injection project. An estimate should also be made of the constraints that a possible use of this infrastructure will put on the injection profile. The integrity of the wells during possible enhanced gas and condensate production, during injection for storage and after abandonment needs to be studied. Remediation procedure of eventual well leakage needs also to be straightened out.

The Frigg field is unitized, developed and produced in a cooperative effort between Norway and the United Kingdom. The gas pipelines to St. Fergus from the Frigg Field and the Heimdal Field (Vesterled pipeline) is shown in Figure 5.8. However, it should be said that on 26 September 2003, the Government of Norway decided that the steel installation (DP2), steel jacket (DP1) and the topsides of the concrete installation (TCP2) on the Norwegian side of the Frigg field will be removed and brought to land for disposal.

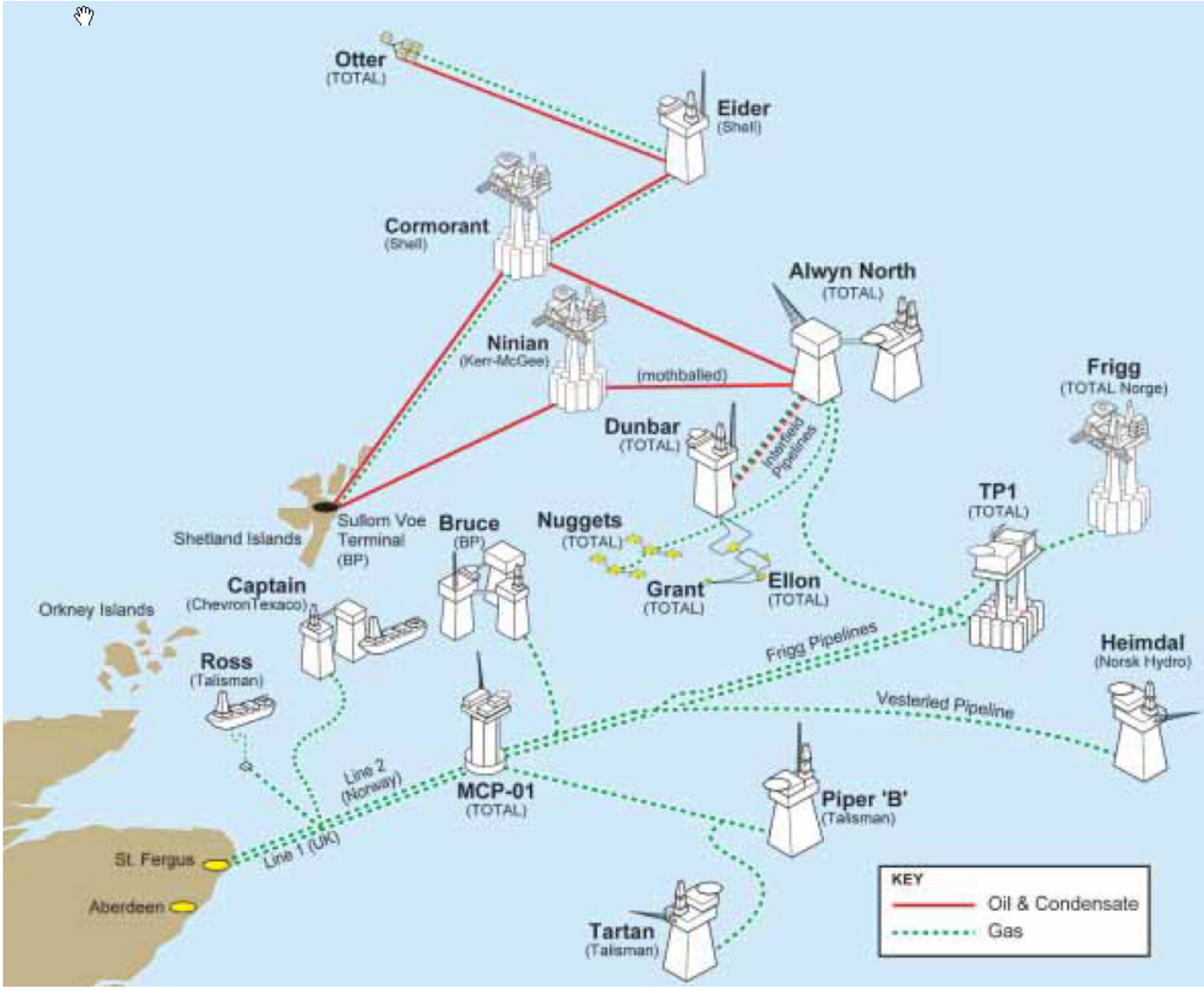

Figure 5.8: Frigg pipeline and Heimdal Vesterled pipeline to St. Fergus (http://www.uk.total.com/).

5.5.2 Gullfaks Field

The Gullfaks oil field is located in the Norwegian sector of the North Sea, in block 34/10, approximately 175 km northwest of Bergen (Hesjedal, 2000). The field was discovered in 1978 and put on production in 1986. The field has been developed with three integrated processing, drilling and accommodation facilities with concrete bases and steel topsides, Gullfaks A, B and C. Gullfaks B has a simplified processing plant with only first-stage separation. Gullfaks A and C receive and process oil and gas from Gullfaks Sør. The facilities are also involved in production and transport from Tordis, Vigdis and Visund (
Figure 5.9). The Tordis production is processed in a separate facility on Gullfaks C.

5.5.2.1 General geological setting

The reservoir units are sandstones of early and middle Jurassic age (Brent group), around 1800 m below msl and the thickness is several hundred meters (H.M. Ånes, 1991). The Gullfaks reservoirs are located in rotated fault blocks in the west and in a structural horst in the east, with an intermediate highly faulted area.

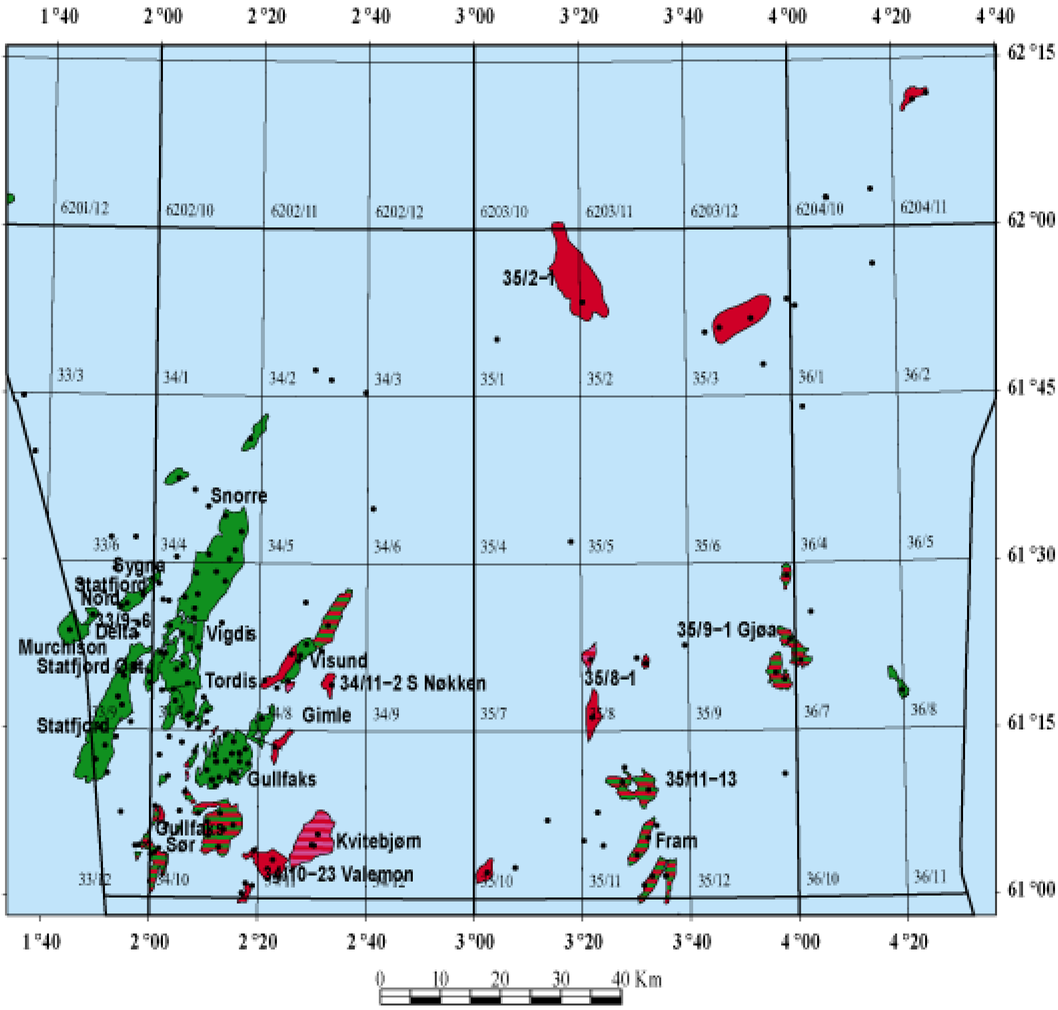

Figure 5.9: Location of the Gullfaks Field in the North Sea (http://www.npd.no/).

Structurally, the field is very complex and can be divided into three regions (Fossen et al, Geological Society, London, Special Publications, 127, 231-261.): the so-called 'Domino Area' with rotated fault blocks in the west, and a Horst area in the east; in between is a complex 'Adaptation Zone', characterized by folding structures. The north-south faults that divide up the field have throws up to 300 meters. In the western part the faults slope downward to the east, whereas in the eastern horst they slope downwards to the west. The field is further cut by smaller faults, with throws of zero to few tens of meters, both in the dominant north-south as well as east-west direction. This results in complex reservoir communication and drainage patterns, and is a major challenge in optimally placing wells in the reservoir.

5.5.2.2 Storage potential

The estimated total storage capacity is 272 Mt CO_2 (GESTCO data base). Reservoir quality is generally very high, with permeability ranging from few tens of mD to several Darcys depending on layer and location. The reservoirs are over-pressured, with an initial pressure of 310 bar at datum depth of 1850 m below msl, and a temperature of 70°C. The oil is under-saturated, with a saturation pressure of approximately 245 bars, depending on formation depth and location. The GOR ranges between 90 and 180 Sm^3 /Sm^3 , with stock tank oil gravity around 860 kg/m^3.

Production from the field is now on decline, reduced by a third from the peak year 1994, when oil production exceeded 30 MSm^3. Recoverable reserves are currently estimated at 319 MSm^3, of which approximately 250 MSm^3 have been produced to date. The uppermost Brent sequence contains roughly 80% of the reserves, with the deeper Cook and Statfjord formations contributing the remainder. The field has been produced with pressure maintenance, mostly through water injection, but natural water influx has also contributed. Gas injection has been employed in the past to drain attic oil, but also WAG injection is also being employed in parts of the field to improve vertical sweep. Large differences in reservoir quality between adjacent layers have in some parts of the field resulted in water override and inefficient vertical sweep. The dense fault pattern has necessitated close well spacing in some areas, which again; often combined with good internal reservoir quality, has resulted in rapid water and gas breakthrough in producers. A few wells are currently shut in due to high H_2S levels.

5.5.2.3 Seal

The sealing is provided by Cretaceous shales. The oil is trapped mainly in Brent sandstone which is overlain by Jurassic, Cretaceous and Paleocene. The two last are very strong seismic reflectors and sets of time lapse (4D) seismic have been performed.

5.5.2.4 Utilization of present infrastructure, injection wells and well integrity

Production from Gullfaks is in the decline phase. Efforts are being made to increase recovery, partly by locating and draining pockets of remaining oil in water-flooded areas, and partly through massive water circulation. Comprehensive analysis has also been carried out to calculate the potential for injecting CO_2 into the reservoir (Agustsson et al, 1999).

The field was developed with wells producing to the GF-A platform, the first of the three gravity base concrete platforms. Water depth is between 130 and 180 m. The GF-B and GF-C platforms were installed and started production in 1988 and 1990 respectively. GF-A and GF-C have integrated production and drilling, as well as water and gas injection, facilities. GF-B has 1st stage separation only, with further fluid processing on GF-A and GF-C, and is without gas injection facilities. Following a three-stage separation process, the field gas production is exported by sub-sea pipeline to shore, where NGLs are removed, while the produced oil is stored offshore and exported by tankers.

Primary drilling is now practically complete on GF-A and GF-B, and identification is under way of infill drilling targets to secure continued, efficient, oil extraction. On GF-C only a few primary drilling targets remain. The platforms have in total 136 drilling slots in addition to initial 6 sub-sea wells tied back to GF-A. A total of 106 platform wells, 79 producers and 27 injectors, are currently in operation. Many of the wells are "designer wells", with multiple reservoir targets and long high angle and/or horizontal sections (Samsonsen et al, 1998).

Field production is currently limited by well potential and runs at 30-35% above initial design processing capacity. In order to further utilize the processing capacity of the Gullfaks installations, third party processing on GF-C of fluids from the nearby Tordis Field commenced in 1994. Later the Vigdis and Visund fields have been hooked up the GF-A for oil storage and export. Production from the Gullfaks South sub sea development, operated by the Gullfaks license group, started in 1998 to GF-A. Preparations are now under way for Phase-2 of the this development, with upgrading of facilities on GF-C to receive additional oil and gas volumes. Both enterprises will significantly boost the oil and gas output from Gullfaks in the next century. Nevertheless, capacity is still available for the processing increased volumes from the main field. The third party processing contributes to the IOR potential by extending the economic life of the installations, as well as offering a welcome source of injection gas.

It should be evaluated to what extent the present infrastructure and wells can be used in a CO_2 injection project and an estimate should be made of the constraints that a possible use of this infrastructure will put on the injection profile. The integrity of the wells during possible enhanced gas and condensate production, during injection for storage and after abandonment needs to be studied. Remediation procedure of eventual well leakage needs also to be straightened out.

5.5.3 Heimdal Field and satellites

The Heimdal Field is located in the Norwegian sector of the North Sea, in block 25/4, 35 kilometers south of the Frigg field, and 180 kilometers west of Stavanger. The production started in February 1986. The water depth is 120 m.

5.5.3.1 General geological setting

The sandstones of the Heimdal Formation are the last clastic members of the Paleocene sub-marine fan, deposited in northern part of the Tertiary South Viking Graben, half-way between the Shetland Platform to the west and the Utsira High to the east (Mure, 1987).

5.5.3.2 Storage potential in Heimdal and satellites

The estimated total storage capacity is 107 Mt CO_2 (GESTCO data base). The reservoir consists of Tertiary sandstones in the Heimdal Formation deposited as deep-marine turbidites. These consist of: a) Heimdal sand in the Lista Formation with upper limit in the base Hermod sand in the Sele Formation and the lower limit in the top of Ty sand in the Våle Formation. b) Hugin Formation with the upper limit in the top sand in the Hugin Formation and lower limit in the top of marine shales of the Dunlin Group.

5.5.3.3 Seal

The gas reservoir rock is overlain by late Paleocene open-marine shales and tuffs of the Balder Formation (Mure, 1987).

5.5.3.4 Utilization of present infrastructure, injection wells and well integrity

Originally, gas was sent by pipeline from Heimdal to Statpipe, but may also now be transported by other pipelines. Condensates are transported by pipeline to Brae in the British sector. After HGS was installed, a new gas pipeline (Vesterled) has been connected to the existing gas pipeline from Frigg to St. Fergus. A gas pipeline has also been laid from HRP to Grane for gas injection. Huldra, Vale and Skirne are tied to Heimdal for processing via a joint pipeline.

The Heimdal Gas Center, on Production License (PL) 036, is a hub for the processing and distribution of gas. It consists of an integrated steel platform, and a new riser platform. Gas from Heimdal is processed together with gas from the Huldra and Vale fields. In addition, Heimdal receives gas from the Oseberg Field Center through the Oseberg Gas Transport system (OGT). Periodically, reverse gas flow from the Statpipe pipeline goes to Heimdal and on to Vesterled. Heimdal is also equipped to export gas as pressure support to produce oil on the Grane field, after it started operating on October 1, 2003. The total maximum rate of processed gas on Heimdal is comparable to some 15-20 percent of Norway’s total gas export.

A new gas/condensate field on PL036 and connected to Heimdal is Vale. The field is developed as a satellite with a sea floor template tied into a riser platform on Heimdal. Vale started production in May 2002. From the first quarter of 2004, the Byggve and Skirne fields will also deliver gas to Heimdal. They are two smaller gas fields situated 16 and 24 kilometers, respectively, east of Heimdal. They will be connected as satellites via wells on the sea floor. Planned production start is the first quarter 2004.

Gas from the Oseberg Gas Transport system (OGT) will, together with gas from Huldra, Heimdal and Vale, be divided between the Statpipe and Vesterled pipelines, and sent on, respectively, to the European continent and the UK. Condensate from processed gas on Heimdal will be sent by pipeline to the Brae platform in the UK sector. It will go from there to the Forties Pipeline System, and further on to land facilities in the UK.

5.5.4 Odin Field

The Odin Field is located in the Norwegian sector of the North Sea, in block 30/10 (close to the northern part of the Frigg field), 180 kilometers north-west of Stavanger and 175 km south of Bergen. The production started October 1984 from a fixed platform. Eleven production wells and two exploration wells were drilled.

5.5.4.1 General geological setting

The Odin Field is located in the central part of the Viking Graben between the East Shetland Platform to the west and the Bergen - Utsira High to the east. When the block-faulting and extensional tectonics of the Late Kimmerian phase ceased in Early Cretaceous time, passive Upper Cretaceous and Tertiary subsidence of the North Sea Basin took place. The Odin Field is situated slightly west of the deepest part of this basin (Nordgård, 1987).

5.5.4.2 Storage potential in Odin

The estimated total storage capacity is 102 Mt CO_2 (GESTCO data base). The reservoir rocks of the Odin field, which have a total thickness of nearly 80 m (well 30/10-A4), belong to the Lower Eocene Frigg Formation and consist of sandstone, inter-bedded with relatively thin shale layers an a few calcite-cemented streaks (Nordgård, 1987).

5.5.4.3 Seal

The Odin gas reservoir of mounded Lower Eocene, Ypresian sands is overlain and capped by impermeable Upper Eocene shales. The trap is filled to the structural spill-point, and the vertical extent of the closure is 61 m.

5.5.4.4 Utilization of present infrastructure

The produced gas was piped to the Frigg TCP-2 platform for processing. The Odin gas reservoir is depleted.

5.6 The Netherlands

5.6.1 Annerveen Gas field

The following description is based on Veenhof, 1996.

The Annerveen gas field is situated in the south of the Province of Groningen (Figure 5.10) and the closure is mapped at the top Upper Rotliegend Group level (last stage of the Early Permian).

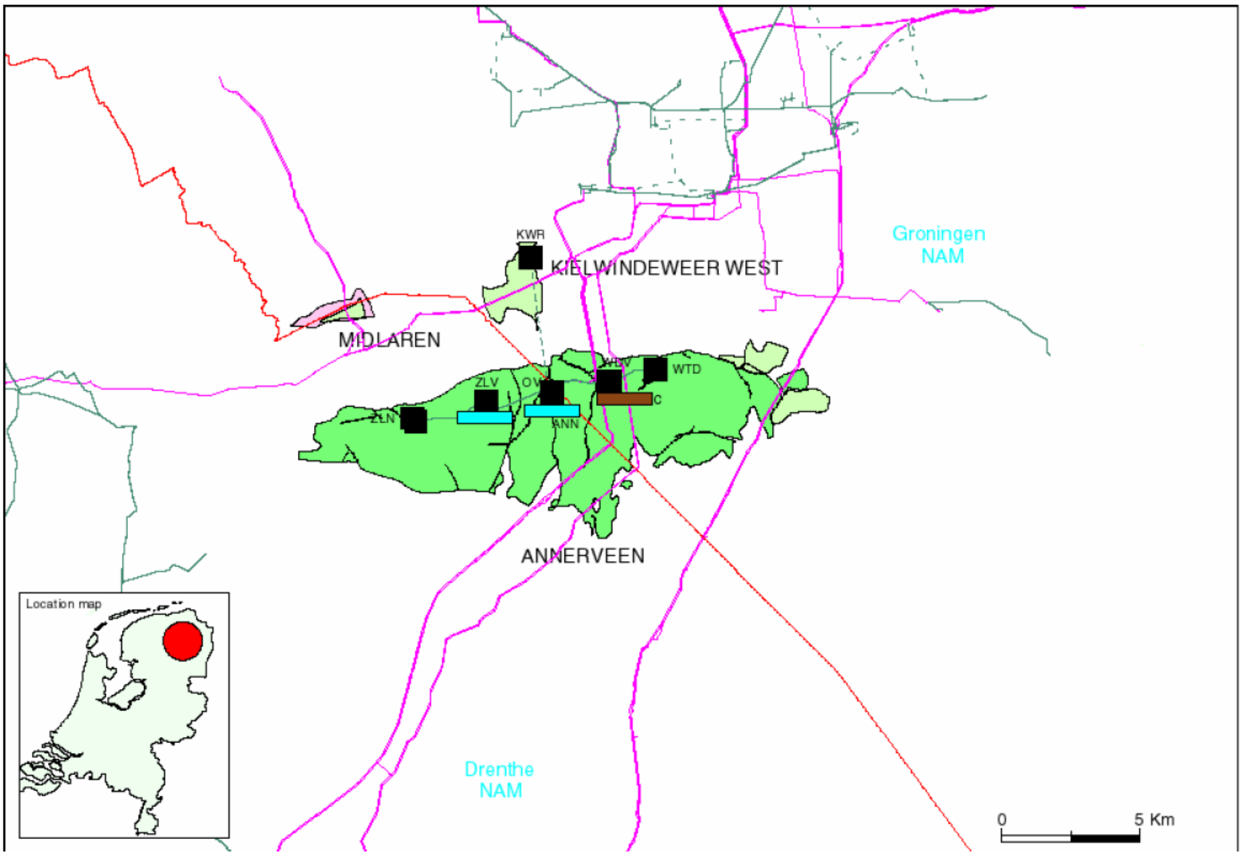

Figure 5.10: Location of the Annerveen gas field.

5.6.1.1 General geological setting

The pre-Zechstein structure is situated at the southern margin of the southern Permian basin. The gas is contained in an east-west trending elongated horst block, bounded by two main boundary fault zones. It originates from Late Kimmerian reactivation of Variscan structural elements. The field is dip closed to the west. Overall, the horst block is tilted to the south. At its eastern side the structure is masked by the overlying Veendam salt wall.

The Upper Rotliegend sediments contain the gas (Figure 5.11) and are commonly known as the most prominent reservoir rock in the Netherlands. The sediments have been deposited in a mixed fluvial, eolian and lacustrine environment under arid conditions. They are described in various publications.

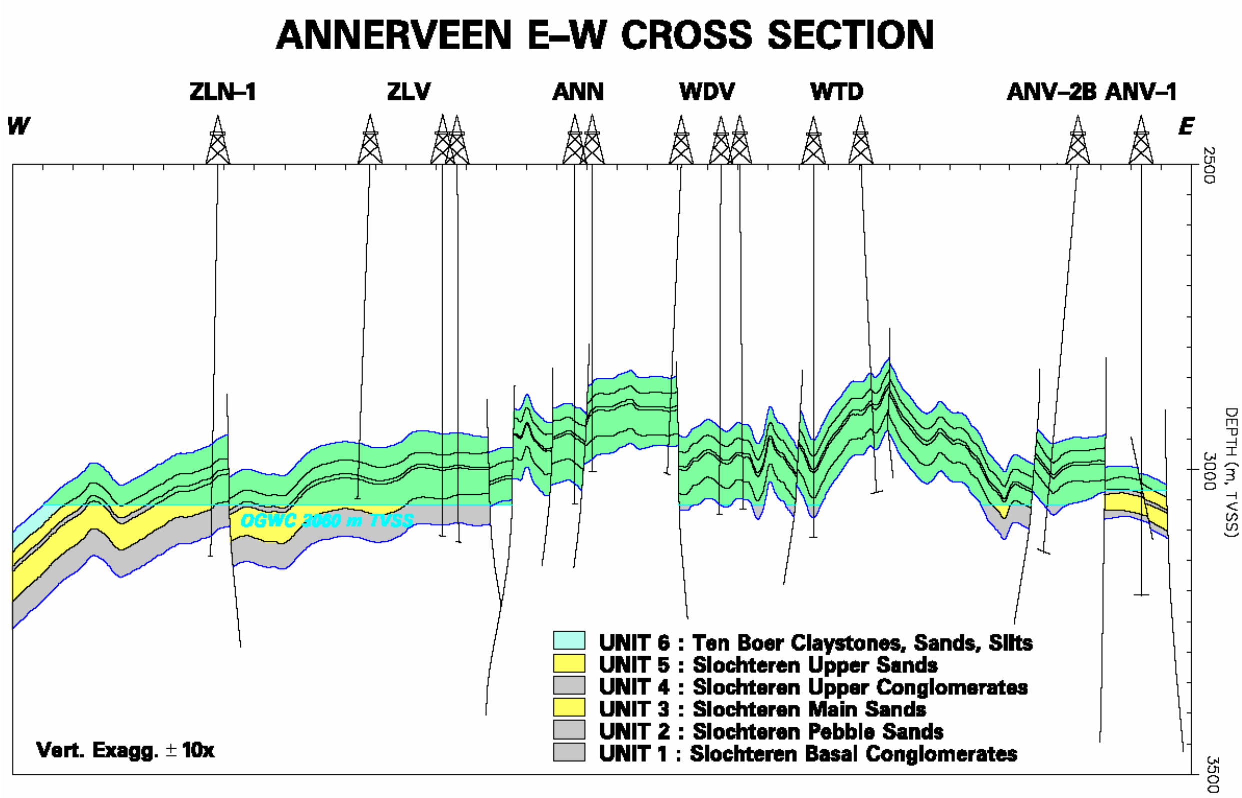

Figure 5.11: Cross-section through the Annerveen gas field.

5.6.1.2 Well database

Figure 5.11 displays the well penetration. Production was started in 1973 from five clusters: the Annerveen (ANN), Wildervank (WDV), Westerdiep(WTD), Zuidlaren (ZLN), Zuidlaarderveen (ZLV). From these clusters 18 wells were drilled. In addition several observation wells (ANV, ANS, ETV) have been drilled. The well information of these wells can be used to re-evaluate reservoir and seal sediments.

5.6.1.3 Seismic coverage

The Annerveen field is covered by 3D seismic reflection data from 1984 (the eastern part of the field) and 1992 (the western part of the field).

5.6.1.4 Storage potential

The overall thickness of the sandstones varies between 100 and 150 m. The different members have permeabilities in the range of 1-1000 mD, with some high permeable zones (over 1 D). The top of the reservoir lies at a depth of 2800-2900 m. Based on an estimated ultimate recovery of about 60 bcm (at 30 bar abandonment pressure) the maximum storage capacity is estimated to 160 Mt of CO_2.

5.6.1.5 Seal

The Upper Rotliegend Group is overlain by Zechstein evaporites and carbonates, deposited during a Late Permian marine transgression. All major Zechstein cycles are present at Annerveen. Halokinesis has caused large thickness variations, which is e.g. expressed in the Veendam salt wall on the eastern flank of the Annerveen field. The impermeable zechstein evaporites are interpreted to form the seal of the Annerveen field.

5.6.2 L10 CDA gas field

The following description is based on the production plan of L10, 2003.

The L10-CDA gas field is situated in the L10 concession on the Dutch continental territory (Figure 5.12) and the closure is mapped at the top Upper Rotliegend Group level (last stage of the Early Permian).

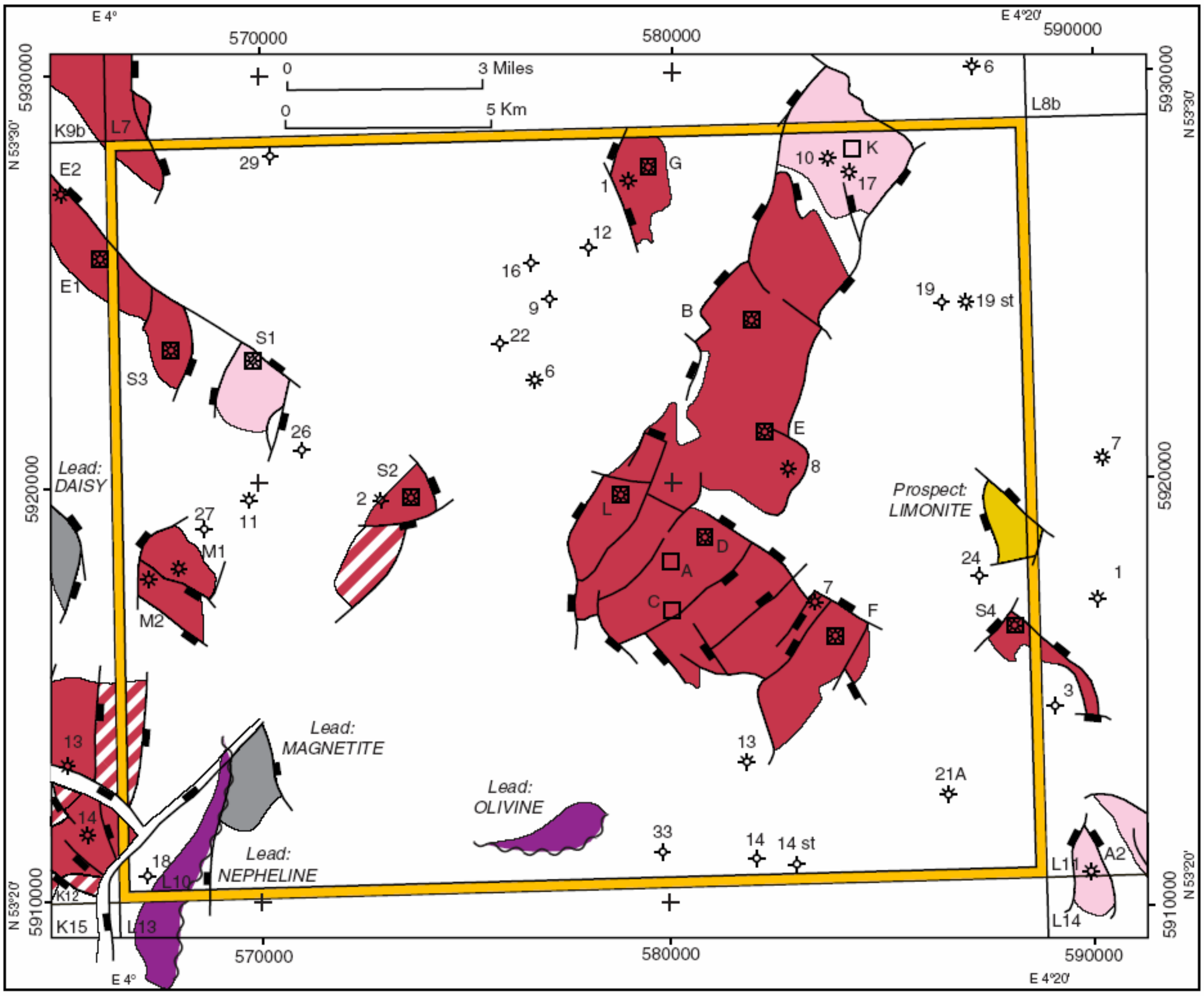

Figure 5.12: Location of the L10-CDA gas field.

5.6.2.1 General geological setting

The pre-Zechstein structure is situated at the southern margin of the southern Permian basin. The gas is contained in an SW to NE trending elongated horst block, bounded by two main boundary fault zones. It originates from Late Kimmerian reactivation of Variscan structural elements. At its southern side the structure is masked by a salt diapir.

The Upper Rotliegend sediments contain the gas (Figure 5.13) and are commonly known as the most prominent reservoir rock in the Netherlands. The sediments have been deposited in a mixed fluvial, eolian and lacustrine environment under arid conditions. They are described in various publications.

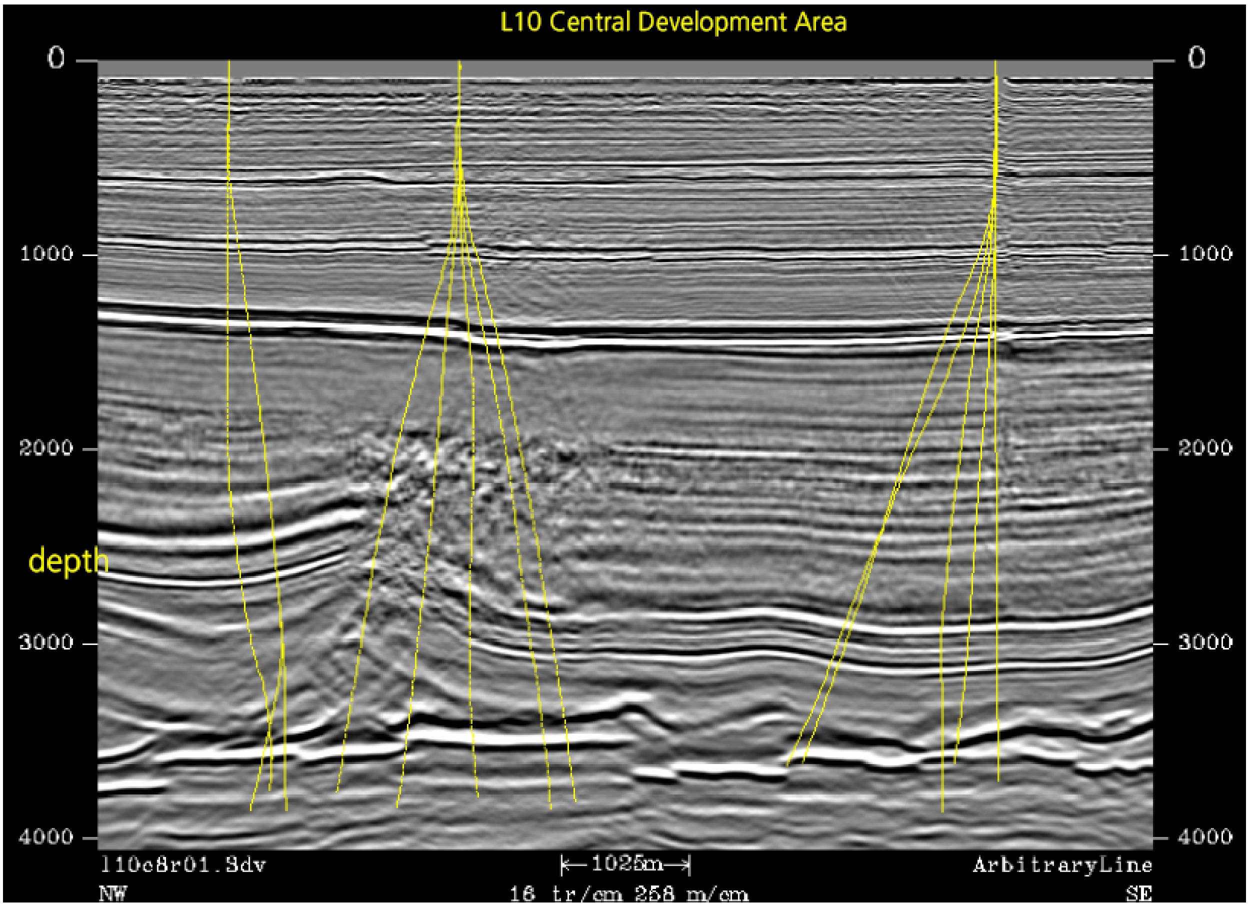

Figure 5.13: Well lay-out overlaid on seismic section through the L10 gas field.

5.6.2.2 Well database

Figure 5.13 displays the well penetration. Production has started in 1975 from the main Cluster L10-A and 7 satellite platforms. From these clusters 53 wells were drilled. The information from these wells can be used to re-evaluate reservoir and seal sediments.

5.6.2.3 Seismic coverage

The Annerveen field is covered by 3D seismic reflection data from 1989 (the southern part of the field) and 1991 (the northern part of the field).

5.6.2.4 Storage potential

The overall thickness of the sandstones varies between 100 and 200 m. The permeability of the sandstones members is in the range of 0.1-1000 mD. The top of the reservoir lies at a depth of 3800-4000 m. Based on an estimated ultimate recovery of about 35 bcm the maximum storage capacity is estimated to 90 Mt CO_2.

5.6.2.5 Seal

The Upper Rotliegend Group is overlain by Zechstein evaporites and carbonates, deposited during a Late Permian marine transgression. All major Zechstein cycles are present at Annerveen. Halokinesis has caused large thickness variations, which e.g. is expressed in the mentioned salt diapir. The impermeable zechstein evaporites are interpreted to form the seal of the L10-CDA field.

6 CONCLUSIONS

Data have been collected for a large number of storage sites (80) within the zone of interest for a HYPOGEN plant, subject to availability of knowledge and possible location of plant.

A number of 16 sites have been selected for the shortlist in Appendix III of potential storage sites for a full-scale HYPOGEN demonstration plant. The selection of sites has been based on especially 3 objective technical criteria concerning the phase of CO_2, the storage capacity and the injectivity of the site, which all the selected sites fulfill. Furthermore 3 more geologically oriented criteria regarding seal, availability of data and availability in time have been applied and sites fulfilling the more objective technical criteria mentioned above may have been excluded due to these. Finally 4 more subjective criteria concerning location, geographical representation and variety of geological conditions and storage types have been taken into consideration.

It has been shown that the permeability of the reservoir plays a key role and the choice of 200 mD as a general cut-off value has been confirmed. Background information as to the calculation of storage capacity has also been provided.

The selected sites have been described in detail comprising geological setting, wells, trap and seal, storage capacity etc. and in Appendix III essential parameters for each site are listed. Following this it can be concluded that the sites on the shortlist all are well suited for storage of the amounts of CO_2 expected from a HYPOGEN demonstration plant. Further data on the selected sites will be made available by the respective partners for the work following in WP4.2 regarding generic storage site definition and characterization.

7 REFERENCES

Agustsson H., Stroenen L.K., and Solheim, O.A.,: "The Gullfaks Field: "Creating Value by means of a Multidisciplinary Reservoir Management Approach", paper OTC 10739 presented at the 1999 Offshore Technology Conference, Houston, Texas, 3-6 May 1999.

Bertelsen, F. 1980: Lithostratigraphy and depositional history of the Danish Triassic. Danmarks Geologiske Undersøgelse. Serie B, Nr. **4**, 59 pp.

Brewster, J. and Jeangeot, G.: "The production geology of the Frigg Field", North Sea Oil & Gas Reservoirs I, edited by Kleppe et.al, 1987.

Chadwick, A., Arts, R., Bernstone, C., May, F., Thibeau, S & Zweigel, P. (eds., 2007 in press): BEST PRACTICE FOR THE STORAGE OF CO2 IN SALINE AQUIFERS. Observations and guidelines from the SACS and CO2STORE projects.

De Leebeek, A: "The Frigg Field reservoir, characteristics and performance", North Sea Oil & Gas Reservoirs I, edited by Kleppe et.al, 1987.

Diener, I., Wormbs, J., Pasternak, G., Stollberg, K., Tesch, M., Tessin, R. (1992): Geologische Grundlagen zur Geothermienutzung in Nordostdeutschland (Kartenwerk 1:200 000) – Blatt Rostock/Stralsund. – Bundesministerium für Forschung und Technologie, Projektträger (BEO) Biologie, Ökologie, Energie, Forschungszentrum Jülich, Jülich, 228 p., (unpubl.).

Fossen H. & Hesthammer J: "Structural Geology of the Gullfaks Field, northern North Sea", In Coward M.P., Daltaban T.S. & Johnson H. (editors) Structural Geology in Reservoir Characterization. Geological Society, London, Special Publications, 127, 231-261.

Hamberg, L. 1994: Anatomy of clastic coastal sequences of the Rhaetian Gassum Formation, Stenlille, Denmark, Unpublished PhD Thesis thesis, University of Copenhagen, Denmark,

Hamberg, L. & Nielsen, L.H. 2000: Shingled, sharp-based shoreface sandstones and the importance of stepwise forced regression in a shallow basin, Upper Triassic Gassum Formation, Denmark. In: Hunt, D. & Gawthorpe, T.L. (eds) Sedimentary responses to forced regressions. Geological Society Special Publication (London) **172**, 69–89.

Hesjedal, A.: "Introduction to the Gullfaks Field", Statoil http://www.ipt.ntnu.no/landsbyen/Gullfakslandsbyen2006/gullfaks_introduksjon.htm

Holloway, S, Vincent, C.J & Kirk, K.L. 2005: Industrial carbon dioxide emissions and carbon dioxide storage potential in the UK. British Geological Survey. Commercial Report, CR/06/185N. 57pp.

Garland, C R. 1991: The Amethyst Field, Blocks 47/8a, 47/9a, 47/13a, 47/14a, 47/15a, UK North Sea. In: United Kingdom Oil and Gas fields, 25 Years Commemorative Volume. Geological Society (London), **14**, pp 387-393.

Japsen, P. & Langtofte, C. 1991: Geological map of Denmark, 1:400 000. The Danish Basin, 'Top Trias' and the Jurassic–Lower Cretaceous (two-way traveltime and depth, thickness and interval velocity). Danmarks Geologiske Undersøgelse Kortserie **30**, 4 pp., 4 maps.

Larsen, M., Bidstrup, T. & Dalhoff, F. 2003: Mapping of deep saline aquifers in Denmark with potential for future CO_2 storage. A GESTCO contribution. Danmarks og Grønlands Geologiske Undersøgelse Rapport **2003/39**, 83 pp.

Lindeberg, E., Bergmo, P.: "The Long-term Fate of CO_2 Injected into an Aquifer", GHGT-6, October 2002.

McCrone, C W, Gainski, M and Lumsden, P J. 2003: The Indefatigable Field, Blocks 49/18, 49/19, 49/23 & 49/24, UK North Sea. In United Kingdom Oil and Gas fields, Commemorative Millennium Volume. Geological Society (London), **20**, pp 741 - 747.

Maritvold, R., "Frigg Field reservoir Management", North Sea Oil & Gas Reservoirs II, edited by Kleppe et.al, 1989.

May , F., Krull, P., Gerling, P. (2004): CO_2 Storage Scenarios in North Germany. GESTCO Project Case Studies. – Bundesanstalt für Geowissenschaften und Rohstoffe, 50 p.

Mayer, P., Krauß, M., Wirth, H. (1998): Abschlußbericht zum Projekt SASO II Erfassung des präquartären Strukturbaus der östlichen Boddengewässer Vorpommerns und angrenzenden Ostsee anhand geologischer und reflexionsseismischer Daten. – Ernst-Moritz-Arndt-Universität Greifswald, 92 p. + maps and extensions.

Meyer, R., May, F., Krull, P., Durst, P., Gaus, I., Kreft, E., van der Meer, L.G.H., Geel, K., Svensson, R. & Bernstone, C. (2006): Geological characterisation of the structure Schweinrich - a suitable candidate site for industrial scale CO2-storage in Germany ? — Greenhouse Gas Control Technologies Conference 8, Trondheim 18.-22.6.2006, 6 p. 6 p. Springer, CD.

Michelsen, O. *et al.* 1981: Kortlægning af potentielle geotermiske reservoirer i Danmark. Danmarks Geologiske Undersøgelse. Serie B, Nr. **5**, 96 pp.

Mure, E.: “Heimdal” in Geology of the Norwegian Oil and Gas Fields edited by A.M. Spencer et al., Graham&Trotman, 1985.

Nielsen, L.H., Larsen, F. & Frandsen, N. 1989: Upper Triassic – Lower Jurassic tidal deposits of the Gassum Formation on Sjælland, Denmark. Geological Survey of Denmark. DGU Series A **23**, 30 pp.

Nielsen, L.H. 2003: Late Triassic – Jurassic development of the Danish Basin and the Fennoscandian Border Zone, southern Scandinavia. In: Ineson, J.R. & Surlyk, F. (eds) The Jurassic of Denmark and Greenland. Geological Survey of Denmark and Greenland Bulletin **1**, 459–526.

Samsonsen B., Jacobsen B.G., Skagestad T. & Kerr S., Statoil a.s.: "Drilling and Completing a High Angle Well with Coiled Tubing Technology" paper SPE 48941 presented at the 1998 SPE Annual Technical Conference and Exhibition held in New Orleans, Louisiana 27-30 September.

Tek, M.R.1987:Underground Storage of natural gas, Gulf Publishin , Houston

van der Meer, L.G.H., 1993: The Conditions Limiting CO2 Storage in Aquifers, Energy Convers. Mgmt 34 (9-11) 959-966

Veenhof, E.N. 1996: Geological aspects of the Annerveen gas field, the Netherlands. In: Rondeel, H.E., Batjes, D.A.J.& Nieuwenhuijs, W.H. (eds), Geology of Gas and Oil under the Netherlands, Kluwer, Dordrecht, 79-92.

Ånes, H.M., Haga, O., Instefjord, R., and Jakobsen, K.G.: "The Gullfaks Lower Brent Waterflood Performance" paper presented at The 6th European Symposium on Improved Oil Recovery, 21-23 May 1991 in Stavanger, Norway.

http://www.co2store.org/TEK/FOT/SVG03178.nsf/Attachments/SACSBestPractiseManual.pdf/$FILE/SACSBestPractiseManual.pdf

http://www.bsh.de/en/Marine%20uses/Industry/CONTIS%20maps/NorthSeaPipelinesCablesExtractionDumpingMariculture.pdf

Characteristics	Name
Location	longitude latitude distance to source availability 2012-2042 (yes/no) *surface monitoring* *cap rock monitoring* *soil monitoring, vadose zone* *risk assessment*
Capacity	size (Mt of CO2) injectivity rate (Mt/y of CO2) *group of injectors* *initial reservoir/aquifer pressure* *depletion pressure curve* *dissolution in water/oil phases* *residual CO2 saturation after water encroachment*
Geological	Formation type (sandstone/carbonate) Depositional environement *Formation rock integrity at CO2 exposure* *Geomechanical studies* *Geochemistry studies* *spill over points*
Structural	Fault Trap type (stratigraphic..) *Anticlinal* *Trap with spill over pont* *Trap open to the sea floor or lake* *Dipping, stratigrafic trap* *Groundwater trap* *Ground water dynamics*
Petrophysical	Average permeability Average porosity Anisotropy (Kv/Kh) Heterogeneity factor *Well logs (digital)* *Layering, shale layers* *Net to gross values* *compressibility*
Fluid in place	water salinity (TDS) oil API *formation water analysis, pH, ionoc strength* *viscosity; water, oil, CO2 vs pressure and temperature* *density; water, oil, CO2 vs pressure and temperature* *gas/water contact, reference pressure* *compressibility; water, oil, gas, CO2*
Flow	Pressure (initial, current) Temperature (initial, current)
Well	number location of each well in the grid completion type and depth *tept to BHP reference depth* *well path* *VFP, gaslift tables* *well radius, equivalent radius* *skin factor* *connection (to grid) factor* *age* *down hole gauges, valves, monitoring* *group injectionb rate control, BHP control* *well bore integrity* *observation well* *CO2 interaction with cement, casing* *leakage to annulus, pressure buildup* *remediation precedures if leakage* *abondanment procedures* *reservoir monitoring*
Production/injection history	rate duration

Field name	Type	Lat	Long	Distance to source or gas terminal (km)	CO_2 storage capacity (10^6 ton)	Formation Type	Trap type
Amethyst	Gas field	53.5	0.7	40-68	**63**	Sandstone	Structural
Audrey	Gas field	53.6	2.0	63-120	**53**	Sandstone	Structural
Barque	Gas field	53.6	1.6	72-94	**108**	Sandstone	Structural/Stratigraphic
Clipper	Gas field	53.4	1.7	72-109	**60**	Sandstone	Structural
Galleon	Gas field	53.5	1.8	55-112	**137**	Sandstone	Structural
Hewett L Bunter	Gas field	53.0	1.8	28-130	**237**	Sandstone	Structural
Hewett U Bunter	Gas field	53.0	1.8	28-130	**122**	Sandstone	Structural
Indefatigable	Gas field	53.3	2.6	90-168	**357**	Sandstone	Structural
Leman	Gas field	53.2	2.3	50-153	**1203**	Sandstone	Structural
Ravenspurn North	Gas field	54.1	0.9	66-98	**93**	Sandstone	Structural/Stratigraphic
Ravenspurn South	Gas field	54.0	1.0	72-95	**52**	Sandstone	Structural
V Fields	Gas field	53.3	2.0	55-131	**143**	Sandstone	Structural
Victor	Gas field	53.3	2.4	57-140	**70**	Sandstone	Structural
Viking	Gas field	53.5	2.3	64-148	**221**	Sandstone	Structural
West Sole	Gas field	53.7	1.1	60-72	**143**	Sandstone	Structural
47/2	Aquifer	53.7	0.9	54-102	**51**	Sandstone	Structural
42/1	Aquifer	54.8	0.7	128-215	**57**	Sandstone	Structural
43/1	Aquifer	54.4	1.1	105-173	**58**	Sandstone	Structural
42/3	Aquifer	54.3	0.4	69-172	**69**	Sandstone	Structural
47/1	Aquifer	53.9	0.6	44-133	**95**	Sandstone	Structural
49/2	Aquifer	53.8	2.2	119-141	**113**	Sandstone	Structural
42/7	Aquifer	54.6	0.4	106-204	**119**	Sandstone	Structural
49/3	Aquifer	53.7	2.1	103-130	**132**	Sandstone	Structural
42/4	Aquifer	54.3	0.6	74-168	**154**	Sandstone	Structural
44/3	Aquifer	54.2	2.1	145-155	**198**	Sandstone	Structural
42/6	Aquifer	54.6	0.4	96-196	**264**	Sandstone	Structural
44/2	Aquifer	54.2	2.4	163-173	**304**	Sandstone	Structural
41/1	Aquifer	54.4	-0.1	79-196	**49**	Sandstone	Structural
49/1	Aquifer	53.9	2.1	123-139	**472**	Sandstone	Structural
44/4	Aquifer	54.1	2.1	139-146	**583**	Sandstone	Structural
43/3	Aquifer	54.5	1.4	122-176	**622**	Sandstone	Structural
42/5	Aquifer	54.2	1.0	86-154	**836**	Sandstone	Structural
48/1	Aquifer	53.9	1.4	88-111	**814**	Sandstone	Structural
43/4	Aquifer	54.0	1.8	125-148	**1051**	Sandstone	Structural
49/4	Aquifer	53.5	2.2	87-148	**1114**	Sandstone	Structural
43/5	Aquifer	54.0	1.8	119-130	**1335**	Sandstone	Structural
48/3	Aquifer	53.6	1.5	77-105	**2302**	Sandstone	Structural
48/2	Aquifer	53.7	1.2	73-100	**3169**	Sandstone	Structural
Alfeld-Elze	Depleted gas field	52.2	9.7	4	**8**	Sandstone	Structural/Stratigraphic
Altmark	Mature gas field	52.8	11.0	0-250	**600**	Sandstone	Stratigraphic
Greifswalder Bodden	Aquifer	54.3	13.6	0	**443**	Sandstone	Structural
Schweinrich	Aquifer	53.2	12.6	80	**430-720**	Sandstone	Structural
Chateaurenard	Oil field	48.0	3.0	137	**22**	Sandstone	Stratigraphic
Villeperdue	Oil field	48.9	3.6	133	**23**	Carbonate	Structural/Stratigraphic
Chaunoy	Oil field	48.6	2.8	90	**20**	Sandstone	Structural/Stratigraphic
Parentis	Oil field	44.3	-1.1	90	**119**	Carbonate	Structural
Cazeaux	Oil field	44.5	-1.2	70	**46**	Sandstone	Structural
Frigg	Gas and condensate field	59.5	2.1	200-350	**364**	Chalk	Stratigraphic
Gullfaks	Oil field	61.1	2.1	150	**272**	Sandstone	Structural
Heimdal	Gas field	59.3	2.2	190-340	**107**	Sandstone	Structural
Odin	Gas field	60.0	2.1	200-350	**102**	sandstone	Structural
Gassum	Aquifer	56.6	10.0	38-47	**631**	Sandstone	Structural
Hanstholm	Aquifer	57.3	8.2	58-114	**2752**	Sandstone	Structural
Havnsø	Aquifer	55.7	11.3	16-80	**923**	Sandstone	Structural
Horsens	Aquifer	55.9	10.1	25-100	**490**	Sandstone	Structural
Pårup	Aquifer	56.3	9.3	60-100	**90**	Sandstone	Structural
Rødby	Aquifer	54.7	11.4	60-85	**151**	Sandstone	Structural
Stenlille	Aquifer	55.5	11.6	35-65	**62**	Sandstone	Structural
Thisted	Aquifer	57.0	8.7	13-80	**10987**	Sst/congl.	Structural
Tønder	Aquifer	55.0	8.9	37-61	**93**	Sandstone	Structural
Vedsted	Aquifer	57.1	9.7	20	**161**	Sandstone	Structural
Voldum	Aquifer	56.4	10.3	13-25	**288**	Sandstone	Structural
Dan	Oil field	55.5	5.1	200-350	**134**	Chalk	Structural
Gorm	Oil field	55.6	4.7	200-350	**59**	Chalk	Structural
Halfdan	Oil field	55.5	5.0	200-350	**36**	Chalk	Stratigraphic
Harald	Gas condensate field	56.3	4.3	200-350	**71**	Chalk	Structural
Kraka	Oil field	55.4	5.1	200-350	**7**	Chalk	Structural
Roar	Gas condensate field	55.8	4.6	200-350	**38**	Chalk	Structural
Siri	Oil field	56.5	4.9	200-350	**5**	Sandstone	Structural
Skjold	Oil field	55.5	4.9	200-350	**12**	Chalk	Structural
South Arne	Oil field	55.1	4.3	200-350	**35**	Chalk	Structural
Tyra	Gas condensate field	55.7	4.9	200-350	**223**	Chalk	Structural
Valdemar	Oil and gas condensate field	55.8	4.6	200-350	**9**	Chalk	Structural
Annerveen	Gas field	53.1	6.8	40	**160**	Sandstone	Structural/Stratigraphic
Coevorden	Gas field	52.7	6.7	90	**100**	Carbonate/Sandstone	Structural/Stratigraphic
Ameland Oost	Gas field	53.5	6.0	60	**95**	Sandstone	Structural/Stratigraphic
Emmen	Gas field	52.8	6.8	70	**90**	Carbonate	Structural/Stratigraphic
Friesland	Gas field	53.1	5.9	70	**70**	Sandstone	Stratigraphic
K02-FA	Gas field	54.0	3.7	220	**70**	Sandstone	Structural/Stratigraphic
L10 CDA	Gas field	53.4	4.2	170	**90**	Sandstone	Structural/Stratigraphic

Field name	Type	Lat	Long	Distance to source or gas terminal (km)	Availability	CO_2 storage capacity (10^6 ton)	Formation Type	Reservoir name (age)	Depositional environment	Faults	Trap type	Average porosity (%)	Average permeability (mD)	Initial pressure (bar)	Initial temperature (Celsius)	No. of wells	Well age	Well completion type	Production rate Mm^3/day (based on 2005 yearly rate)	Production duration (years up to 2006)
Amethyst	Gas field	53.5	0.7	40-68	2010/2015	**63**	Sandstone	Leman Sst	Aeolian	Faulted anticline	Structural	11-25	1-1000	283	88	20	17-32	development, appraisal	1.57	16
Hewett L Bunter	Gas field	53.0	1.8	28-130	Now	**237**	Sandstone	Hewett (L Bun.Sst)	Fluvial channel/sheetflood	Faulted anticline	Structural	23	1000	137	52	13	39	development	1.09	37
Hewett U Bunter	Gas field	53.0	1.8	28-130	Now	**122**	Sandstone	U Bunter Sst	Fluvial channel/sheetflood	Faulted anticline	Structural	21	500	94	42	5	39	development	1.09	37
Indefatigable	Gas field	53.3	2.6	90-168	Now	**357**	Sandstone	Leman Sst	Aeolian	NW-SE trending horst block	Structural	15	10-1000	284	91	79	18-39	producers, development	1.67	35
42/5	Aquifer	54.2	1.0	86-154	Now *	**836**	Sandstone	Bunter Sst	Fluvial channel/sheetflood	Faults with small offsets	Structural	22	670	142	52	2	36	Abandoned	0	0
Greifswalder Bodden	Aquifer	54.3	13.6	0	Now *	**443**	Sandstone	M Bunter	North German Basin	Möckow-Dargibell fz and further fault zones in the N and E	Structural	22	500-2000	Unk.	Unk.	Few	Unk.	Unknown	0	0
Schweinrich	Aquifer	53.2	12.6	80	Now *	**430-720**	Sandstone	U Keuper/Lias	North German Basin, transgressive	3 normal faults in the central area and on western flank	Structural	28	<1000	130	60-80	14	Unk.	Unknown	0	0
Frigg	Gas field	59.5	2.1	200-350	Now	**364**	Chalk	Frigg Formation	Viking Graben	Four-way, dip-closed, stratigraphic trap	Stratigraphic	28	1300	197	60	48	26-29	producers and abandoned wells	50	29
Gullfaks	Oil field	61.1	2.1	150	About 2015	**272**	Sandstone	Jurassic	Viking Graben	Rotated fault blocks (west) and structural horst (east)	Structural	28	1000	310	70	106	20	injectors, producers, multi-laterals, branched	30	20
Heimdal	Gas field	59.3	2.2	190-340	unknown	**107**	Sandstone	Heimdal F/Paleocene	Submarine-fan sands	Tilted blocks, trap is filled to spill-point	Structural	25	1000	217	76	13	21	Producers, appraisals	9	21
Odin	Gas field	60.0	2.1	200-350	Now	**102**	sandstone	Frigg Form./L. Eocene	Submarine-fan sands	Tilted blocks, trap is filled to spill-point	Structural	30	>1000	206	65	5	30	Producers, appraisals	1	30
Gassum	Aquifer	56.6	10.0	38-47	Now *	**631**	Sandstone	Gassum Sst.	Repeated progradation of shoreface and delta units	Faults E and W of structure	Structural	25	300-2000	146	49	1	56	Abandoned	0	0
Horsens	Aquifer	55.9	10.1	25-100	Now *	**490**	Sandstone	Gassum Sst.	Repeated progradation of shoreface and delta units	Two faults to the SW and NE outside structure closure	Structural	25	500	151	50	1	49	Abandoned	0	0
Vedsted	Aquifer	57.1	9.7	20	Now *	**161**	Sandstone	Gassum Sst.	Repeated progradation of shoreface and delta units	Two faults NE and SW of structure closure	Structural	20	1000	190	62	1	49	Abandoned	0	0
Annerveen	Gas	53.1	6.8	40	> 2010	**160**	Sandstone	Slochteren sst	Fluvial/aeolian	Two faults N and S of structure, crosscutting faults offs. res.	Struc/Strat	11	1-1000	346	98	22	44	18 producing, 4 observation	0.75	22
L10 CDA	Gas	53.4	4.2	170	> 2010	**90**	Sandstone	Slochteren sst	Fluvial/aeolian	numerous crosscutting faults offsetting reservoirs	Struc/Strat	12-14	0.1-1000	414	115	18	10-37	13 producing , 5 unknown	0.8	30

* depending on legal conditions for aquifer storage

Additional potential storage locations

This list of additional storages was compiled from the Joule II results but did not comply to Dynamis selection criteria.

Field Name	CO2 storage (Mt)	Type	Location
UK			
43/2	236	aquifer	N Sea
Alwyn North	120	oil	N Sea
Beryl	182	oil	N Sea
Brae N,S,Central	242	oil	N Sea
Brae East	178	condensate	N Sea
Brent	432	oil	N Sea
Bruce	297	condensate	N Sea
Claymore	73	oil	N Sea
Cormerant	89	oil	N Sea
Everest	86	condensate	N Sea
Forties	376	oil	N Sea
Fulmar	99	oil	N Sea
Magnus	128	oil	N Sea
Morecambe Bay	818	gas	N Sea
Ninnian	173	oil	N Sea
Pickerel	80	gas	N Sea
Piper	141	oil	N Sea
Scott	60	oil	N Sea
Thistle	63	oil	N Sea
Norway			
Sleipner East	152	gas	N Sea
Sleipner West	357	gas	N Sea
Ekofisk	465	oil	N Sea
Eldfisk	139	oil	N Sea
Valhal	108	oil	N Sea
Statfjord	746	oil	N Sea
Snoore	142	oil	N Sea
Ula	68	oil	N Sea
Heidrun	169	oil	N Sea
Osberg	496	oil	N Sea
Germany			
Grenzbereich	164	gas	onshore
Hengstlage	174	gas	onshore
Rehden	63	gas	onshore
Siedeberg	118	gas	onshore
Visbek	103	gas	onshore
Sohlingen	113	gas	onshore
Heidberg-Mellin	117	gas	onshore
Salzwedel-Perkensen	435	gas	onshore

France			
Lacq	692	gas	
Meillan	140	gas	
Italy			
Malossa	94	gas	onshore
Gagliano	72	gas	onshore
Candela	73	gas	onshore
Caviaga	70	gas	onshore
San Salvo	97	gas	onshore
Selva	83	gas	onshore
Dosso degli Angeli	70	gas	onshore
Porto Corsini Terra	70	gas	onshore
Agustino	269	gas	off-shore
Barbera	88	gas	off-shore
Porto Corsini	70	gas	off-shore
Luna	78	gas	off-shore
Amelia	70	gas	off-shore
David	70	gas	off-shore
Ireland			
Kinsale Head	160	gas	off-shore

