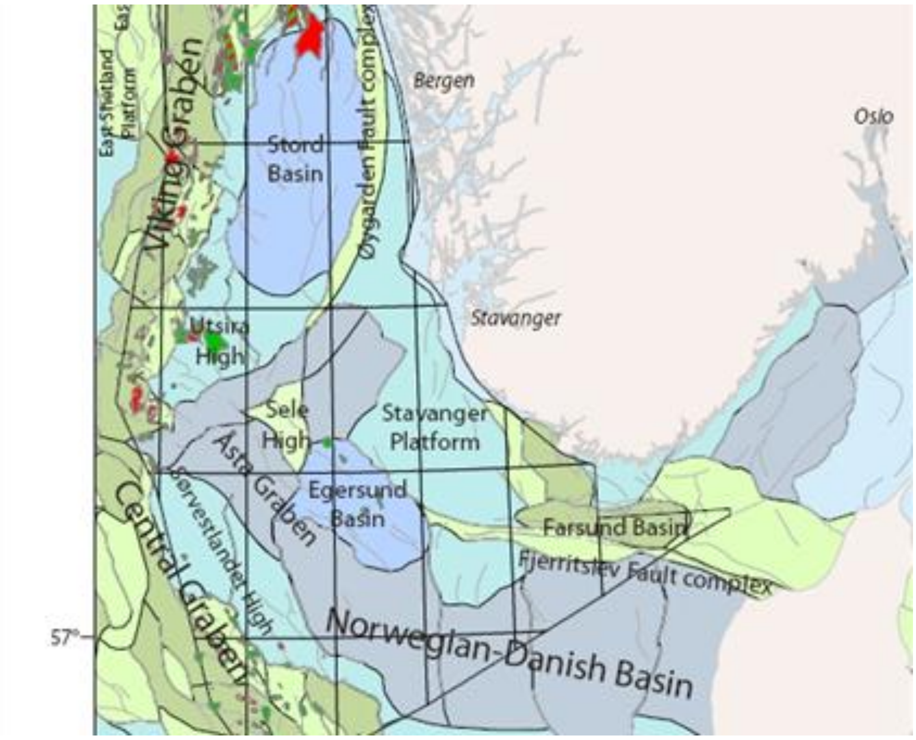
Master Thesis, Department of Geosciences

Geological potential for carbon storage in the Sele High, Åsta Graben and NW Egersund Basin area

Daniel Long



UNIVERSITY OF OSLO

FACULTY OF MATHEMATICS AND NATURAL SCIENCES

Geological potential for carbon storage in the Sele High, Åsta Graben and NW Egersund Basin area

Daniel Long

Master Thesis in Geosciences

Discipline: Geology

Department of Geosciences

Faculty of Mathematics and Natural Sciences

University of Oslo

2012

Abstract

The rise of carbon dioxide (CO_2) emissions in the Earth's atmosphere has led to an increased focus on ways to reduce these emissions. One way of doing this is by using carbon capture and storage (CCS) technology whereby CO_2 is collected or captured at point sources and then injected into deep geological formations to be stored indefinitely.

The Sele High, Åsta Graben and the NW Egersund Basin were investigated in an attempt to identify potential reservoirs for storing carbon dioxide and then calculating a storage capacity. This was done using well analysis and seismic interpretation, and was guided by the Norwegian Petroleum Directorate's *CO_2 Storage Atlas 2012*.

After investigation of multiple wells and the structures they intersect, two were identified as having moderate potential. The storage capacity for wells 17/10-1 and 18/10-1 were calculated to be 750-850 Mt and 35 Mt respectively. The weakest aspect of both prospects were their limited extent, which is in contrast to existing CO_2 storage operations such as the Sleipner Project that has a storage capacity of approximately 1-10 Gt of CO_2. This will be a challenge considering the extensive halokinesis throughout the Norwegian-Danish Basin in particular.

Acknowledgements

I would like to thank my supervisor Per Aargaard for his guidance and patience.

I would also like to thank Michel Heeremans for his technical support.

A special thanks goes to the Administration team at the Geology Department for all there help.

I would especially like to thank my family for their love support and encouragement.

Daniel Long

December 2012

TABLE OF CONTENTS

TABLE OF FIGURES

1. INTRODUCTION

1.1 INTRODUCTION

There has been a lack of attention paid to climate change over the past few years, thanks to the ongoing global economic crisis and more recently the Arab Spring taking precedence when it comes to media coverage and political debate. As a result, issues surrounding climate change seem to have fallen off the political radar as governments attempt to stave off bankruptcy, or in the case of the Arab Spring, fight mass protests and violence. There appears to be no political will to make the necessary changes required to have an impact on the atmospheric levels of greenhouse gases (GHG).

As a result, GHG levels in the atmosphere continue to rise as a result of anthropogenic activities (IPCC 2007). According to the IPCC's Fourth Assessment Report (2007), the most important of these gases is carbon dioxide (CO_2) due to its abundance and radiative forcing. While there are many possible mitigation options when it comes to reducing CO_2, such as improving energy efficiency, switching fuel types, investing and using renewable energy, and carbon capture and storage (CCS), it is likely to be a range of mitigation measures that has any significant impact on CO_2 emissions.

As a geologist, the area I can focus on is the carbon storage component of CCS. This thesis will look at potential storage options for CO_2 in the Sele High, Asta Graben and North West Egersund Basin area of the North Sea.

It has already been demonstrated that CO_2 storage in the North Sea is possible, evidenced by the Sleipner Project operated by Statoil in the North Sea, so the challenge will be to identify one or two potential storage sites using available seismic surveys and well data.

It was noted in the Norwegian Petroleum Directorate's (NPD) CO_2 Storage Atlas: Norwegian North Sea (2011) that an enhanced effort was required in the mapping and investigation of CO_2 storage sites. It is with this "call to arms", that I embark on my CO_2 storage site journey of discovery.

2. GEOLOGICAL SETTING

2.1 Location and geological setting of study area

The study area chosen is geographically located off the Norwegian southwest coastline in the Norwegian North Sea and is geologically centred on the Sele High; a local basement high located to the northwest of the Egersund Basin (Figure 1). The structural elements to be investigated as part of this study are the northwest portion of the Egersund Basin, the Åsta Graben, and a small area of the Norwegian-Danish Basin to the west of the Sele High.

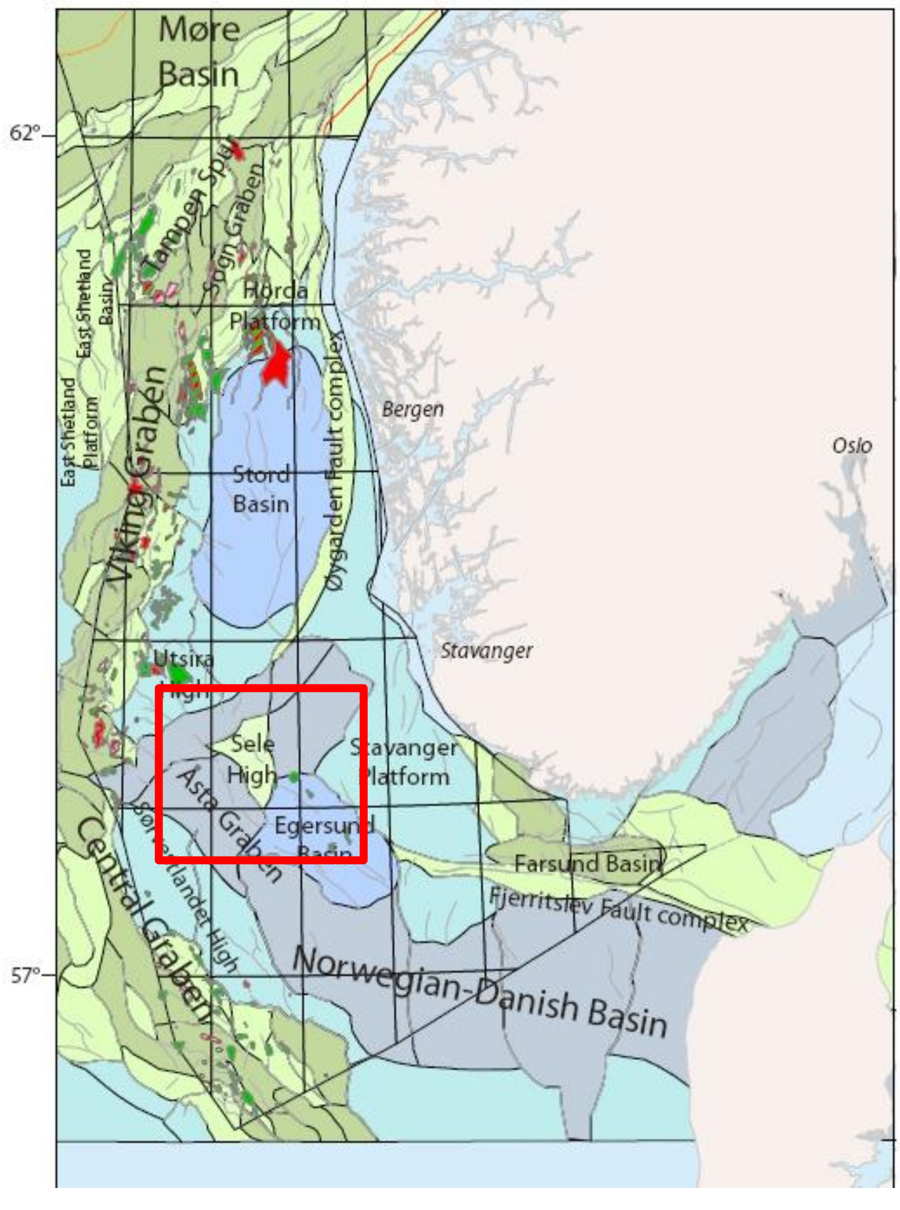


Figure 1. Location map with the red outline defining the study area. Image modified from NPD 2011.

2.2 Regional Geology

The North Sea area has experienced a quite complex tectonic history. There have been four tectonic events that have controlled the structural development of the area since the Cambrian (Ziegler 1990; Brekke *et al*. 2001; Lyngsie *et al*. 2006):

1. The Caledonian collision during Late Ordovician to Early Silurian,
2. Subsequent rifting and basin formation predominantly in the Late Carboniferous to Late Permian/Early Triassic,
3. Further rifting and associated graben formation during the Middle Jurassic to Early Cretaceous accompanied by relative sea level rise,
4. The Late Cretaceous to Early Tertiary saw a shift to basin inversion.

The Permian saw major rifting with early periods of magmatism followed by widespread erosion (Brekke et al. 2001) and deposition of aeolian and fluvial sandstones forming the Early Permain Rotliegendes (NPD 2011). Two basins were developed, the North Permian basin and the South Permian basin (Heeremans and Faleide 2004; NPD 2011), which dominated the structure of the North Sea area up until the Cretaceous (Glennie and Underhill 2009). The two basins were east-west trending and were separated by the Mid North Sea Rynkobing-Fyn system of highs (Heeremans and Faleide 2004; Lyngsie et al 2006; Glennie and Underhill 2009). They were formed during the Permian allowing for the deposition of thick evaporate sequences forming the Late Permian Zechstein Formation (NPD 2011).

The major N-S and NE-SW rifting associated with the start of the Triassic was followed by clastic infilling and a shallowing of basin areas (Brekke *et al*. 2001; NPD 2011), with thick coarse-grained fluvial sediments accumulating along rift margins, becoming finer grained towards the basin centres (Vollset and Dore 1984; NPD 2011). The Triassic to Early Jurassic is marked by thermal subsidence resulting in widespread marine transgression from both the north and south (Gabrielsen et al. 1990; NPD 2011), ending the influence of continental sediments (Vollset and Dore 1984).

Following the marine transgression, the beginning of the Middle Jurassic saw uplift caused by volcanic doming at the triple junction point between the Viking Graben, the Central Graben and the Moray Firth Basin (Gabrielsen et al. 1990; NPD 2011). The uplift resulted in erosion with large deltaic systems containing sand, shale and coal being developed in the northern North Sea and the Horda Platform forming the Brent Group (Figure 2) (Vollset and

Dore 1984; NPD 2011). Similar deltaic systems formed the Vestland Group in the Norwegian- Danish Basin, the Stord Basin, and the Central Graben and were overlain by shallow marine to marginal marine sandstones (Vollset and Dore 1984; NPD 2011). Lower Jurassic marine sediments are absent in much of the area south of the Ling Depression and Egersund basin presumably due the erosion associated with the uplift (Vollset and Dore 1984).

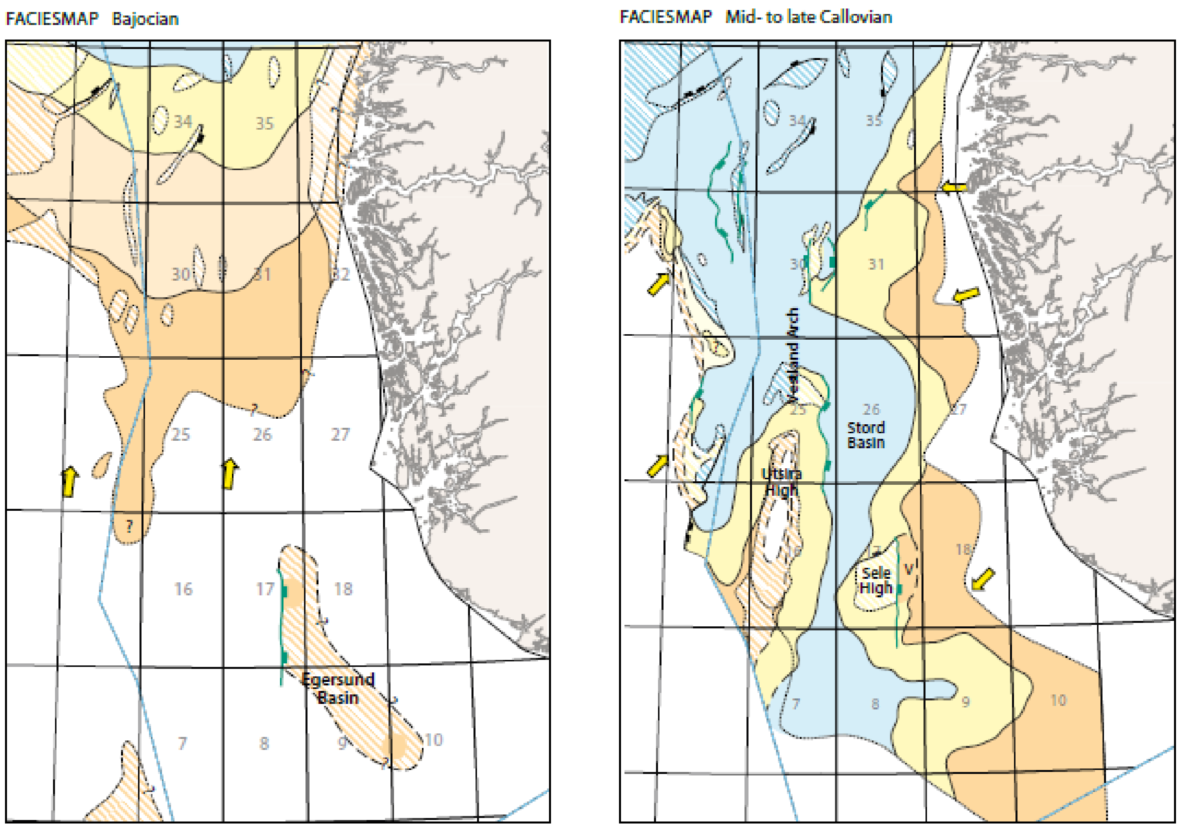


Figure 2. Examples of mid Jurassic relationship between continental and marine deposits in central and northern North Sea. Continental sediments in brownish colour, shallow marine in yellow and offshore marine in blue. The development of the Brent delta and the early stage of the deposition of the Bryne Formation (left), and the development of the Sognefjord delta and the Sandnes and Hugin Formations after the Brent delta was transgressed (right). Image source: CO2 Atlas, NPD 2011.

By the end of the Middle Jurassic, marine conditions had returned as a result of rising sea levels and the collapse of the uplifted volcanic dome (Vollset and Dore 1984). Shales accumulated in the basin centres and marginal marine sands were deposited along the basin margins (Vollset and Dore 1984).

Renewed rifting in the North Sea area took place during the Late Jurassic and lasted into the Early Cretaceous (Brekke et al. 2001; Vollset and Dore 1984; NPD 2011). Major block faulting and tilting lead to uplift and erosion with periods of non-deposition (Vollset and Dore; NPD 2011). Subsequent to this Late Jurassic tectonic activity, rifting ceased and was followed by thermal subsidence (NPD 2011). Large basins began to subside as sea levels rose throughout the Cretaceous (Brekke et al. 2001) but by the latest Cretaceous infilling had resulted in the northern North Sea becoming a wide, low-relief shallow basin (Gabrielsen et al. 2010). Sediment was sourced from the emerging East Shetland Platform and Scottish Highlands in the west, and the Norwegian mainland in the east (Faleide et al. 2002; Gabrielsen et al. 2010).

In the North Sea, deposition of chalk that had started during the Cretaceous continued until Early Paleocene, which also saw the onset of sea-floor spreading in the North Atlantic and mountain building in the Alps/Himalayas (Brekke et al. 2001; NPD 2011). During the Oligocene there appears to have been uplift of basin margins due to inversion (Gabrielsen et al. 2010; NPD 2011), producing a series of submarine fans with sediments sourced from the Shetland Platform to the west (NPD 2011). The Rogaland and Hordaland Groups were formed by these submarine fans interfingering with marine shales, leading to a deltaic system developing towards the Norwegian North Sea and forming the Skade and Utsira Formations (NPD 2011). In the Neogene, sediment input was the result of major uplift and glacial erosion (Brekke et al. 2001; NPD 2011), resulting in thick sequences being deposited in the North Sea. This had the effect of burying Jurassic source rocks to depths capable of generating hydrocarbons (NPD 2011).

2.3 Ling Depression

The Ling Depression (Figure 3) acts as a divider between the Utsira High in the north and the Sele High in the south (Heeremans and Faleide 2004). Together with the Åsta Graben, it forms the northern limit of the Zechstein basin (Heeremans and Faleide 2004).

Figure 3 shows a cross-section through the southern part of the Ling Depression, the Sele High and the Åsta Graben.

2.4 Sele High

The Sele High is a shallow basement feature developed locally to the north west of the Egersund Basin, the south-southeast of the Ling Depression, the Åsta Graben to the northeast, and the Fiskebank Sub-Basin to the southwest (Figure 3).

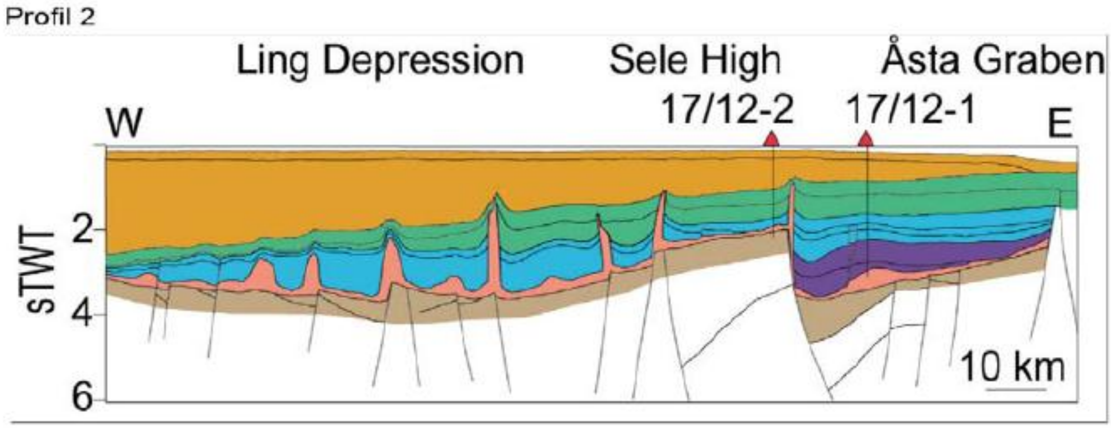


Figure 3. Diagrammatic cross section showing the Ling Depression, Sele High and the Åsta Graben. Image source: Heeremans and Faleide 2004.

2.5 Egersund Basin

The Egersund Basin is a small extensional basin situated approximately 100 km west of the southernmost part of Norway (Hermanrud et al. 1990). It is a symmetrical basin with its main depositional axis running NNW-SSE (Figure 1)

The Egersund Basin has been heavily affected by halokinesis and diapirism with Late Permian Zechstein salt having been intersected in ten wells and halokinetic movements observed in numerous seismic lines throughout the basin (Figure 4) (Sorensen and Tangen 1995).

The Egersund Basin differs from the graben areas to the west, insofar as it is not part of the main extensional zone of the Central and Viking Grabens (Hermanrud *et al.* 1990; Sorensen and Tangen 1995). Rather it is more structurally related to the evolution of the Norwegian-Danish Basin (Sorensen and Tangen 1995). The Late Jurassic were relatively quiet tectonic times throughout the Egersund Basin in contrast to the Central and Viking Grabens

(Sorensen and Tangen 1995). The Egersund Basin was less affected by the heating related to the late Jurassic stretching, experiencing subsidence and local inversion but to a lesser extent (Hermanrud *et al.* 1990; Sorensen and Tangen 1995).

The most attractive feature of the Egersund Basin from an exploration point of view is the presence of a thick Mesozoic sequence (Sorensen and Tangen 1995). The potential of finding suitable reservoir rocks for CO2 storage is quite promising considering the Triassic section is over 1500 m in parts of the basin, with the Jurassic and Cretaceous sequences considerably thinner.

It is also worth noting the continuous deposition that has occurred across the Jurassic-Cretaceous boundary, with no unconformity present (Sorensen and Tangen 1995). There is almost a complete Cenozoic sequence in the west of the basin, but it appears that as a result of uplift, the Neogene strata are incomplete in the east (Sorensen and Tangen 1995).

Between the Egersund Basin and the Åsta Graben, 26 exploration wells have been drilled

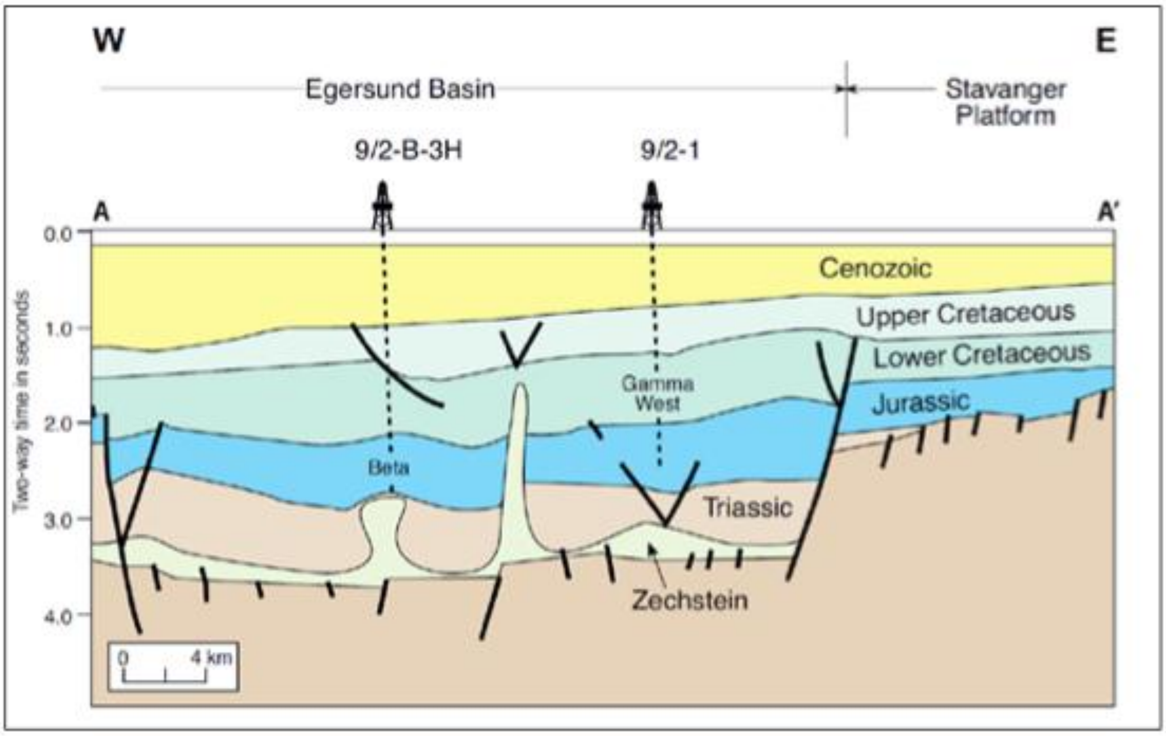


Figure 4. Diagrammatic cross section of the Egersund Basin. Image source: CO2 Atlas, NPD 2011.

2.6 Åsta Graben

The Åsta Graben is a west-tilted half graben with its main depositional axis trends N-S (Figure 3). It is less affected by halokinetic movements than the neighbouring Egersund Basin, which it is separated from by a ridge running approximately east-west (Sorensen and Tangen 1995).

2.7 Fiskebank Sub-Basin and the Norwegian-Danish Basin

The Fiskebank Sub-Basin is an ENE trending sub-basin that is actually the western extension of the regionally significant Norwegian-Danish Basin (Figure 5) (Pegrum 1984). The Fiskebank Sub-Basin was transgressed from the east during the Early Jurassic, when deposition of the Fjerritslev Formation shales was under way (Cope et al 1992).

The Norwegian-Danish Basin (Figure 5) is a WNW-ESE trending basin mainly of Permian to Early Jurassic age situated in the North Sea between Norway and Denmark (Hospers & Holthe 1984; Hospers et al. 1988), and is filled with sediments that are in places 8 km thick (Hospers et al. 1988). The Upper Permian Zechstein salt occurs throughout the basin giving rise to the widespread and in places, severe salt tectonics (Hospers & Holthe 1984; Hospers et al. 1988).

The Norwegian-Danish Basin is defined by the Ringkobing-Fyn High to the south, the Central Graben and adjacent highs to the southwest and west, the Horda Platform to the northwest and the Fennoscandian Shield to the north and northeast (Hospers et al. 1988). It comprises a number of distinct tectonic sub-units which are the focus of this thesis (Figure 5).

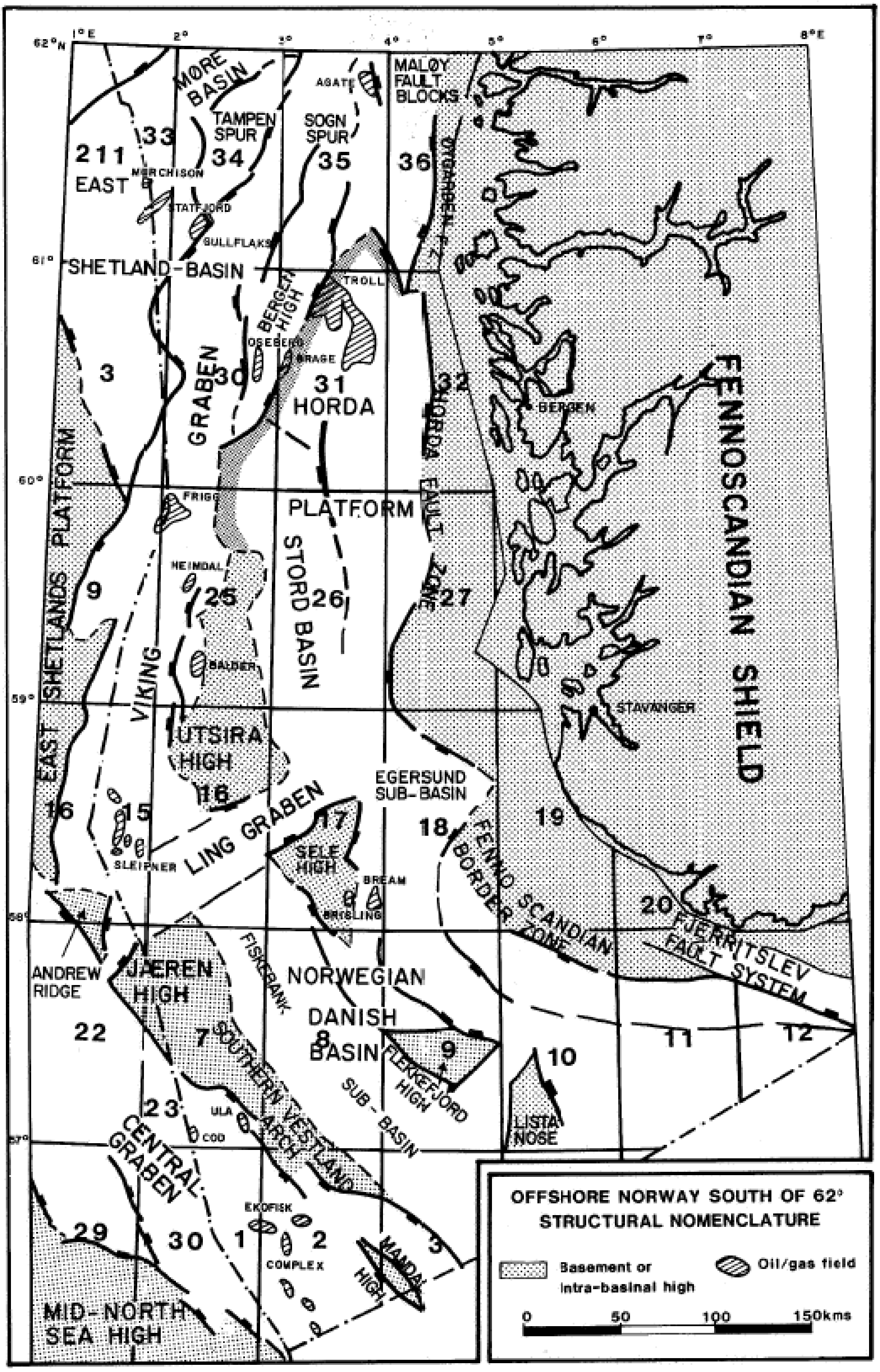


Figure 5. Structural Nomenclature of the Norwegian North Sea. Image source: Vollset and Dore 1984.

3. STRATIGRAPHY

Stratigraphy in the study area most closely resembles that described for the Norwegian-Danish Basin (Figure 6), and more specifically the Jurassic lithostratigraphy (Figure 7).

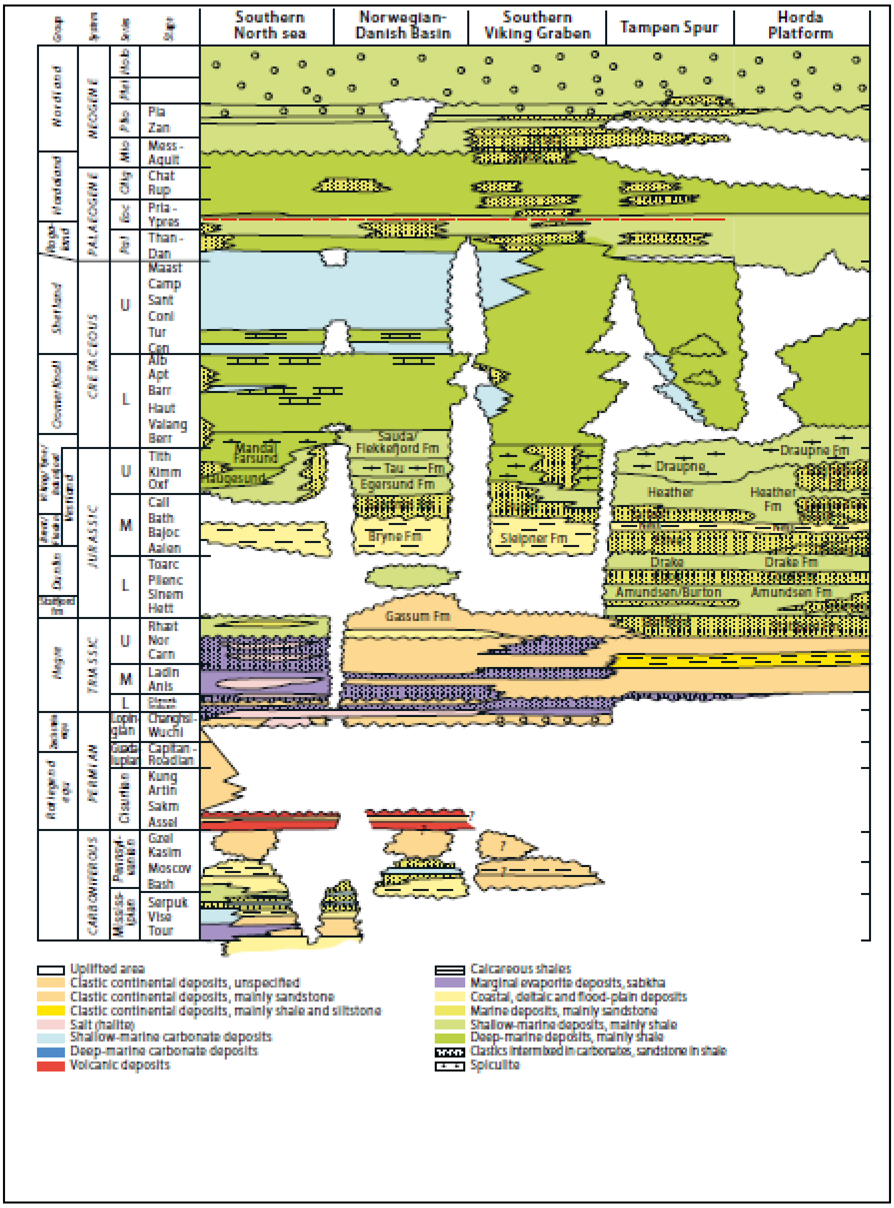


Figure 6. Lithostraigraphic chart of the North Sea. Source:NPD 2011.

Hospers et al. (1988) describes the typical stratigraphic sequence encountered in the Norwegian- Danish Basin as follows (from bottom to top):

- Thick sequence of Zechstein salt deposits,
- Very thick Triassic clastic sediments,
- Moderately thick Jurassic sediments,
- Lower Cretaceous clastic sediments,

- Upper Cretaceous (and locally also Danian) limestone,
- Overlain by very thick Tertiary clastic sediments, and
- Relatively thin Quaternary deposits.

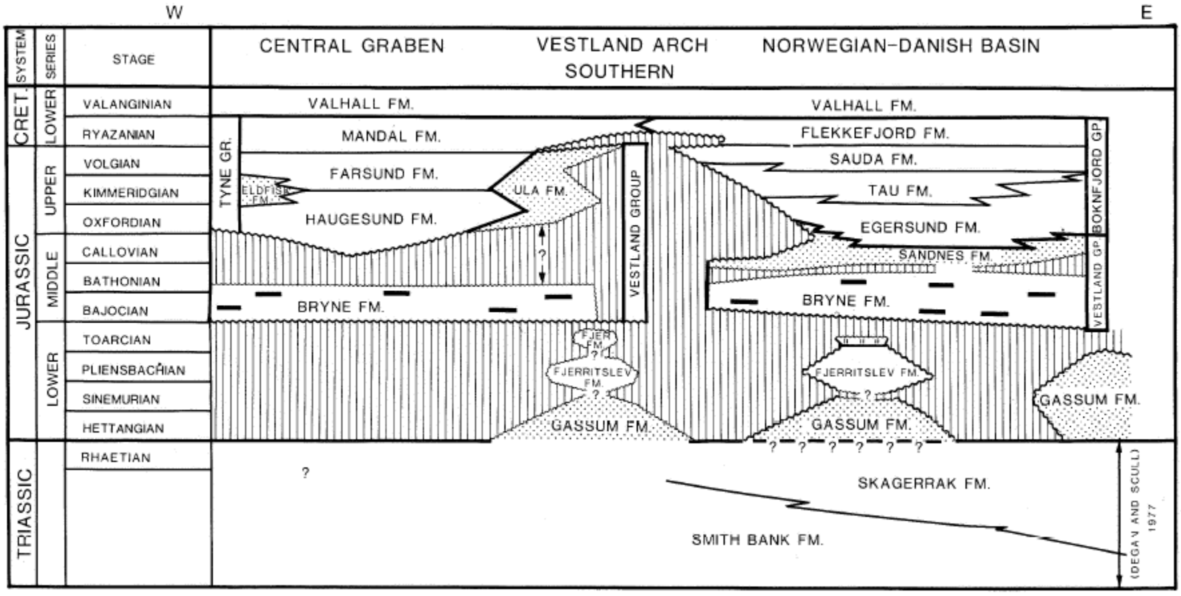


Figure 7. Jurassic lithostratigraphic nomenclature for the central North Sea - Norwegian Danish Basin. Source: Vollset & Dore 1984.

3.1 Reservoir rocks

The most prospective reservoir rocks in the study area are the Lower Jurassic Sandnes Formation and to a lesser extent the Bryne Formation (Figure 8). The majority of petroleum exploration has focused on the Sandnes Formation and several oil discoveries have been made at this stratigraphic level. Other possibilities are the Late Triassic-Early Jurassic Gassum Formation, which is developed locally throughout the Norwegian-Danish Basin, and the Late Triassic Skagerrak Formation, which is well developed throughout the study area.

There have been a number of small hydrocarbon discoveries made in the Egersund Basin and Asta Graben, with only the 9/2-1 discovery seriously evaluated for development (Sorensen and Tangen 1995). The high proportion of dry wells has reduced the exploration interest in these areas over the years, which means there has been relatively less focus on understanding potential play concepts than some of the more productive areas in the North Sea.

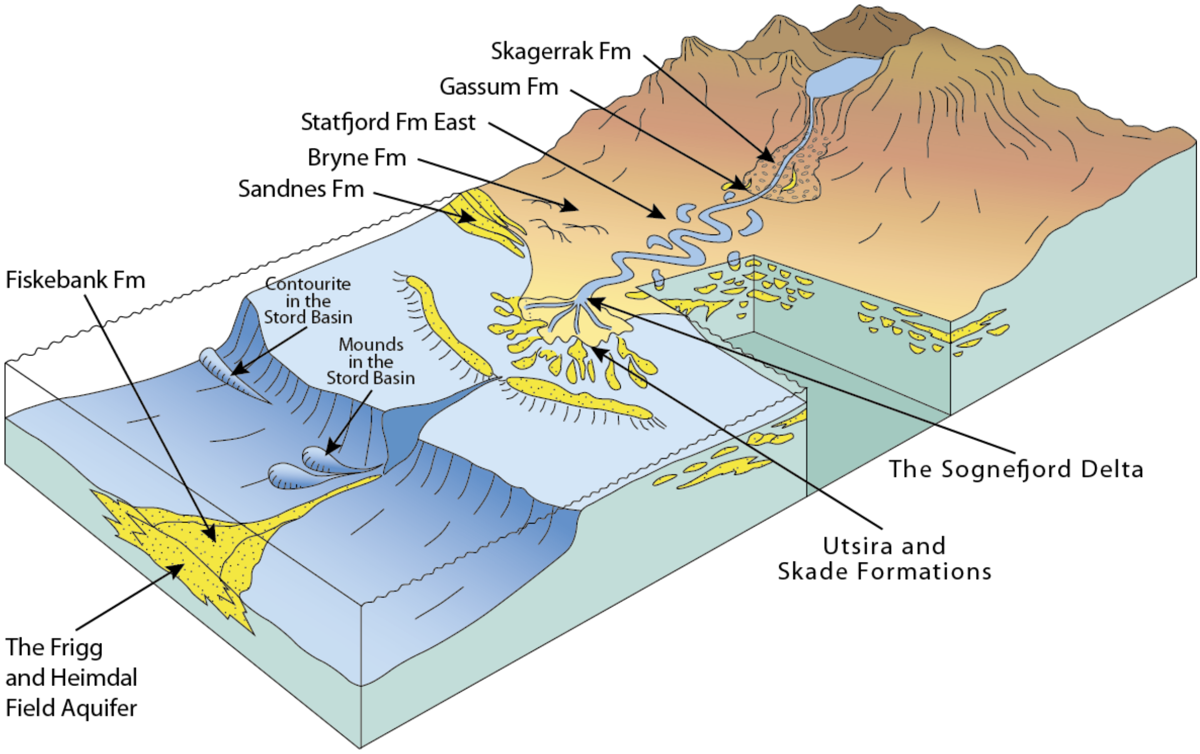


Figure 8. Diagram illustrating the depositional systems of potential CO2 reservoirs of the North Sea. (Image source: NPD 2011)

3.1.1 *Sandnes Formation*

The Sandnes Formation is part of the Vestland Group and was deposited in a coastal to shallow marine environment (Figure 8). It is generally developed as a well-sorted and widely distributed sand (Figure 9) (NPD 2011), and in the type well (9/4-3) it consists of a massive white, very fine to coarse-grained glauconitic sandstone (NPD 2012). It is firm to friable, and in parts, poorly sorted and slightly silty. Towards the eastern margin of the Egersund Basin in the reference well 18/11-1, the formation comprises interbedded sandstones and shales (NPD 2012).

The Sandnes Formation usually overlies the non-marine Bryne Formation or older Jurassic or Triassic rocks unconformably (NPD 2012).

The Sandnes Formation is distributed throughout the Fiskebank Sub-Basin and in the Egersund Basin and is broadly equivalent to the Hugin Formation in the southern Viking Graben (NPD 2012).

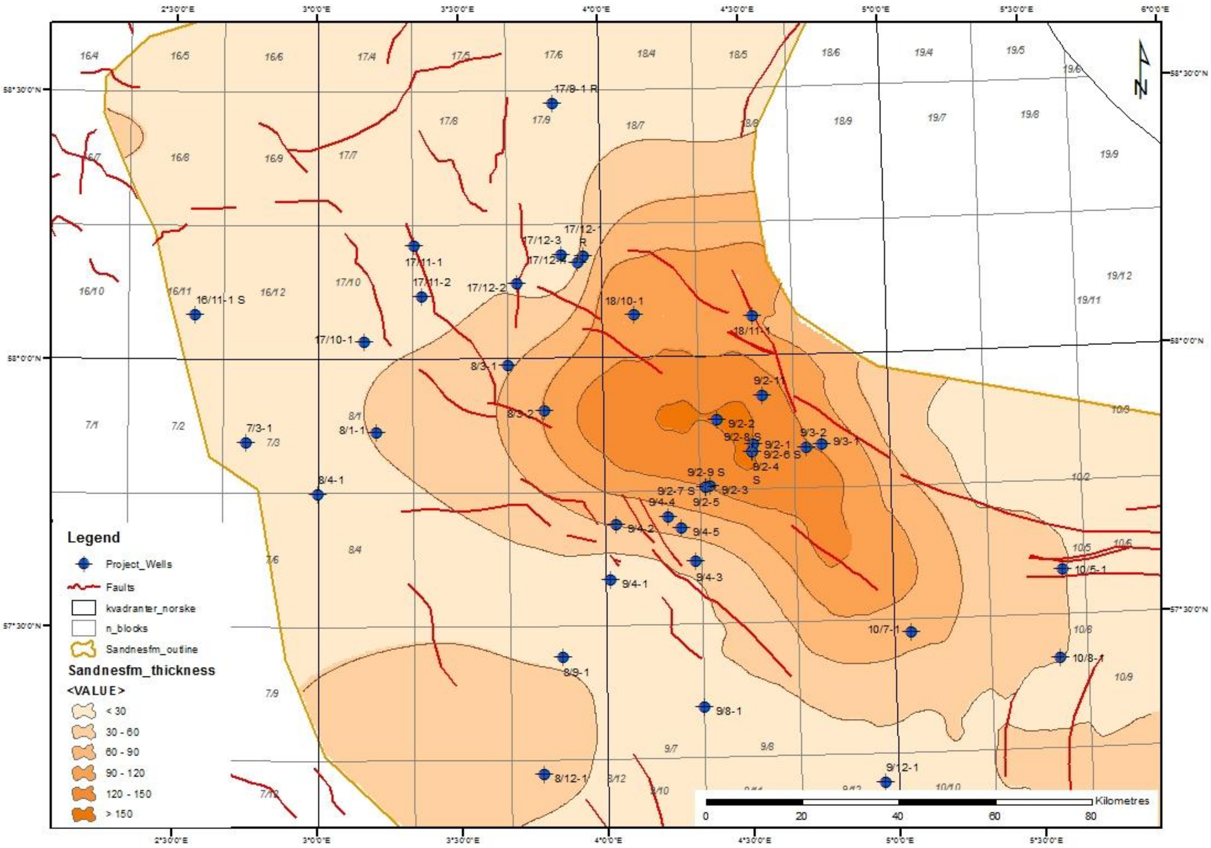


Figure 9. Plan showing the thickness and distribution of the Sandnes Formation in the study area.

3.1.2 Bryne Formation

The Bryne Formation conformably underlies the Sandnes Formation and is dominated by fluvial to non-marine deposits. There is a hiatus in age between the two formations but the two have a somewhat similar seismic signature making them difficult to distinguish. The Bryne Formation has a higher clay content compared to the Sandnes Formation reducing its reservoir properties (Sorensen and Tangen 1995).

The Bryne Formation consists of interbedded sandstones, siltstones, shales and coals. The sandstones are white to grey, very fine to coarse grained, poorly sorted, friable to hard and occasionally kaolinitic (NPD 2012).

The Bryne Formation is developed throughout the Norwegian-Danish Basin (Figure 10) and in the Central Graben and is approximately equivalent in age and lithofacies to the Sleipner Formation of the Southern Viking Graben (NPD 2012).

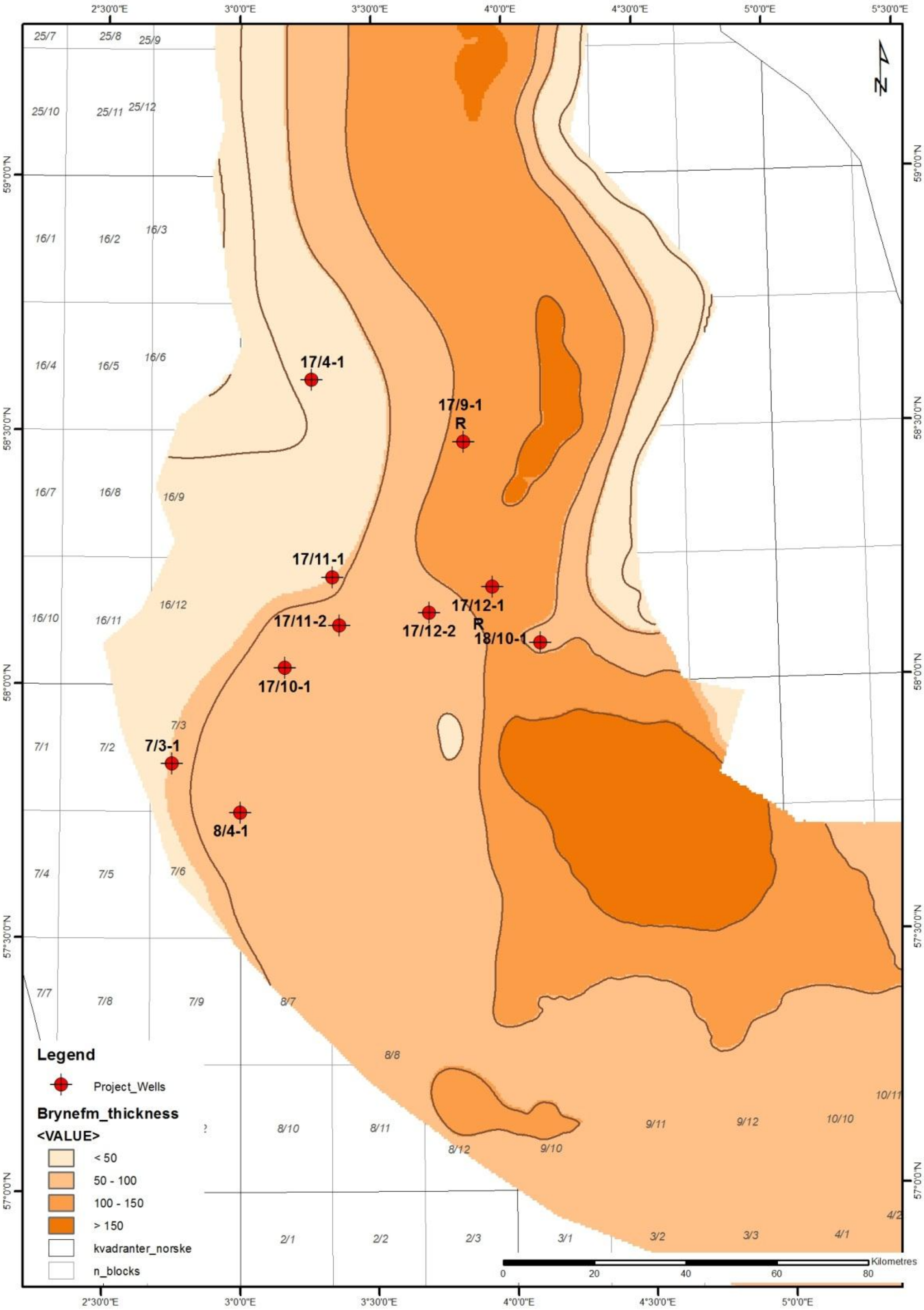


Figure 10 Bryne thickness contours over the study area. Image created by author using NPD data.

3.1.3 Gassum Formation

In the Norwegian sector, the Gassum Formation is predominantly a white to light grey, mainly fine to medium grained sandstone, but frequently contains coarse sand and gravel. It is often calcite cemented and in some instances contains glauconite (NPD 2012).

The Gassum Formation occurs throughout the Norwegian-Danish Basin, on the Southern Vestland Arch and along the northeastern margin of the Central Graben but it is often completely or partially eroded as a result of mid-Jurassic earth movements (NPD 2012).

The Gassum Formation is possibly equivalent to the Stratfjord Formation but correlation is uncertain (Vollset and Dore 1984). To overcome this, Vollset and Dore (1984) recommend using the Gassum Formation south of the Ling Depression. Given that the study area is south of the Ling Depression, the name Gassum Formation has been adopted herein.

The Gassum Formation hasn't been studied from a sedimentological point of view in the Norwegian sector, but it is thought to be deposited as fluvial to marginal marine deposits laid down during a transgressive phase at the Triassic/Jurassic transition (NPD 2012).

3.1.4 Skagerrak Formation

The Skagerrak Formation consists of poor to moderate sorted sandstones and conglomerates with interbedded siltstones and shales (Deegan and Scull 1977; Nielsen *et al.* 2011).

It was deposited as alluvial fan and braided river sediments (Nielsen *et al*. 2011; NPD 2011), with the majority of the formation being deposited in a prograding system of alluvial fans along the eastern and southern flanks of a structurally controlled basin (Deegan and Scull 1977).

The Skagerrak Formation is present throughout the Central North Sea and the western Skagerrak but is most likely absent over structural highs due to erosion and in some cases halokinesis (NPD 2011).

4. THEORETICAL BACKGROUND

4.1 Geological storage of carbon dioxide (CO_2)

4.1.1 The need for CO_2 storage

Forward modelling by the International Energy Agency (IEA) shows that global energy demand is set to increase by 40 per cent between now and 2030 with 80 per cent of this energy demand being met by fossil fuels (Figure 11) (CO_2 CRC 2011). This increase in demand for fossil fuels is likely to be met by coal, particularly for electricity generation in China and India (CO_2 CRC 2011). This is despite a rapid increase in the use of renewable energy like wind, solar and geothermal. It will be a huge challenge to change the way we generate electricity and fuel, particularly for energy hungry developing countries like China and India who are able to grow at such a rate due partly to the cheap source of energy that coal and other fossil fuels provide.

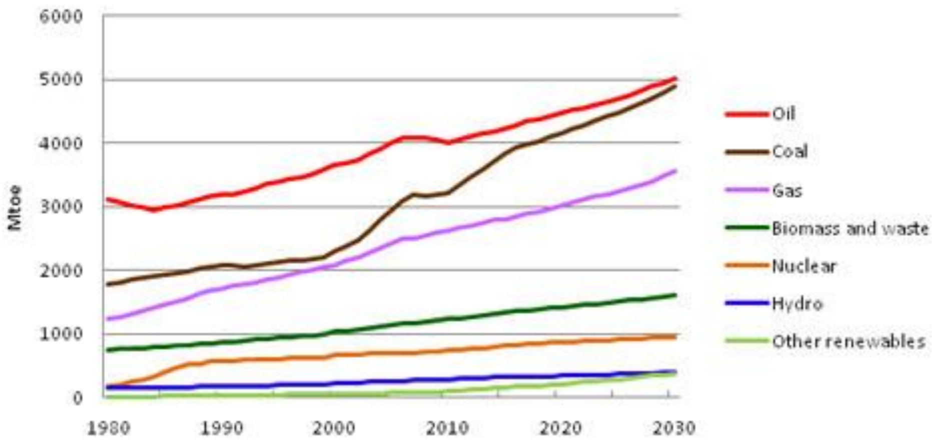


Figure 11. World energy demand expands by 40%between now and 2030 –an average rate of increase of 1.5% per year – with coal accounting for more than a third of the overall rise (Data for graph obtained from World Energy Outlook - OECD/IEA 2009)

The widespread practice of carbon capture and storage (CCS) would allow for a more gradual transition from the world we live in today where we are heavily dependent on fossil fuels for our energy needs, to one where we can rely solely on renewable sources of energy. It would be next to impossible for industries and households alike to switch overnight from fossil fuels to renewable energy. Renewable energy technologies are not advanced enough to meet the world’s energy needs, nor are the world’s economies ready for such a dramatic shift. CCS has the potential to be an effective transition technology whereby industry emissions on climate change are minimised while simultaneously minimising the impact on global economies and energy and electricity generation. (IEA 2008; IPCC 2005)

The capture and storage of carbon dioxide is an important mitigation tool for the overall reduction of anthropogenic CO_2 emissions. However, it cannot be seen as a cure all for the problem, but rather one weapon in the arsenal against climate change. Techniques such as enhanced oil recovery (EOR) using CO2, for example, could form an integral part of the solving two big problems; where to store all this excess CO2? And how do we extract the worlds diminishing oil supplies in the most efficient and responsible way?

4.1.2 What is Carbon Capture and Storage (CCS)?

The most widely recognised form of carbon capture and storage involves the capture of CO_2 from major stationary point sources that would otherwise be emitted into the atmosphere, such as coal fired power plants and heavy industry, compressing the CO_2 into a supercritical liquid and storing it deep underground in porous rock formations (CSIRO 2011; IEA 2008). This is known as geological storage, geological sequestration or geosequestration (IEA 2008). Other forms of CCS involve biological storage and ocean storage.

The geological storage of CO_2 is a process that has been occurring naturally in the Earth's subsurface for hundreds of millions of years. Indeed, this is where most of the world's carbon is held; in coals, oil, gas, organic-rich shales and carbonate rocks (IPCC 2005). Therefore, it is that the same geological forces that have naturally held CO_2 will be the same principles under which injected CO_2 will be held (IEA 2008). After the CO_2 is injected it will be trapped in tiny pores within the rock formations far below the surface, separated from fresh groundwater by thick, impermeable layers of rock (Figure 12) (IEA 2008).

What many government organisations, research institutes and private investors are now doing is building on the knowledge of this natural process in the hope of using CO_2 storage as a mitigation option for reducing their CO_2 emissions. A good example of this is coal-fired power generators that are hugely important to many countries in terms of power generation but are also huge stationary CO_2 emitters; a prime candidate for carbon capture and storage. Figure 13 shows how this might work.

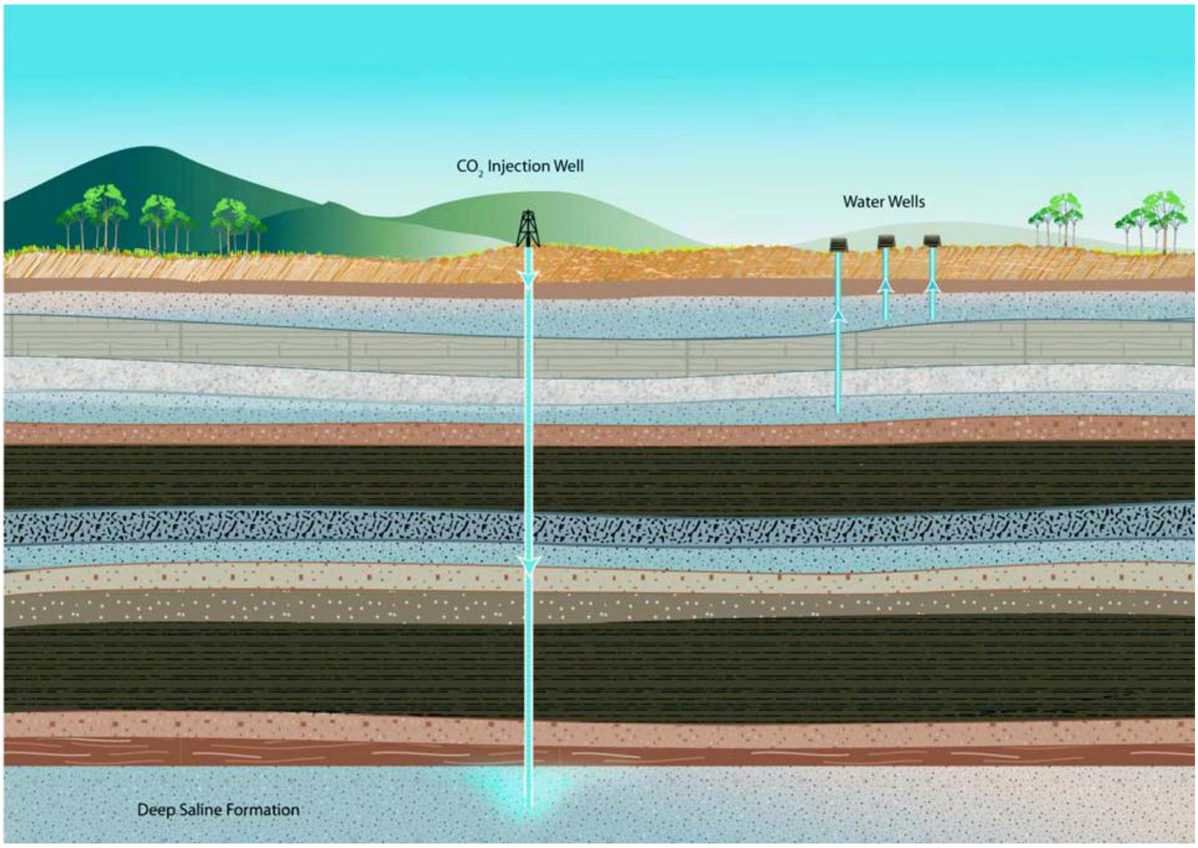


Figure 12. Illustration of the separation between the deep saline aquifers to be used for CO2 storage and the fresh water aquifers much closer to the surface. Image source: CO2CRC 2011.

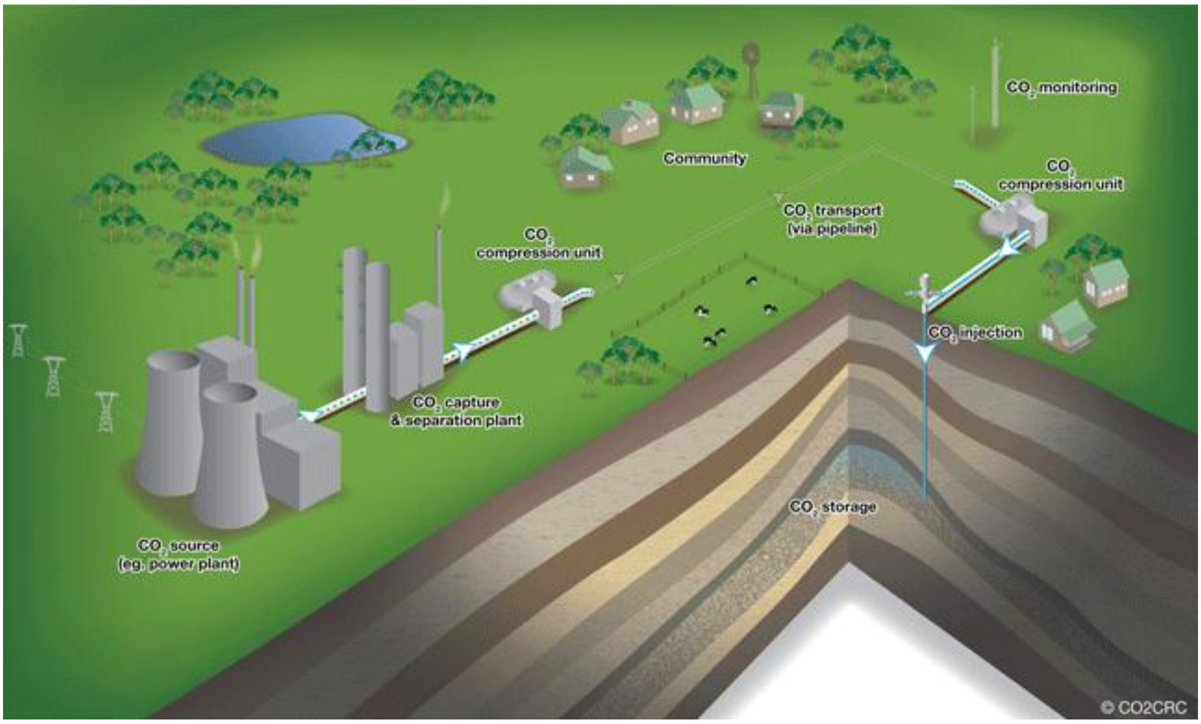


Figure 13. Illustration of the main processes at work in a CCS operation. Image source: CO2CRC

4.1.3 How is CO2 stored?

In order to store CO2 in geological formations, it must first be compressed to form a super critical liquid. The degree to which the CO2 is compressed is dependent on temperature and pressure and therefore the amount of compression increases with depth. This means the amount of space taken up by the supercritical CO2 decreases as depth increases. (IPCC 2005; IEA 2008)

After the CO2 has been compressed, it must pumped into a suitable rock formation or reservoir. For example, this could be deep unmined coal seams, depleted oil fields or deep saline aquifers (IPCC 2005; IEA 2008).

The storage of CO2, once in a supercritical state, involves trapping the CO2 by way of either physical trapping or geochemical trapping. According to Chadwick *et al*. (2008) there are four basic mechanisms with which this can be achieved (Figure 16):

- Structural and stratigraphical trapping (Figure 15) occurs where the migration of free (gas, liquid, fluid) CO2 in response to its buoyancy and/or pressure gradients within the reservoir is prevented by low permeability barriers (caprocks) such as layers of mudstone or halite.

- Residual saturation trapping occurs when capillary forces and adsorption onto the surfaces of mineral grains within the rock matrix immobilise a proportion of the injected CO2 along its migration path (Figure 14).

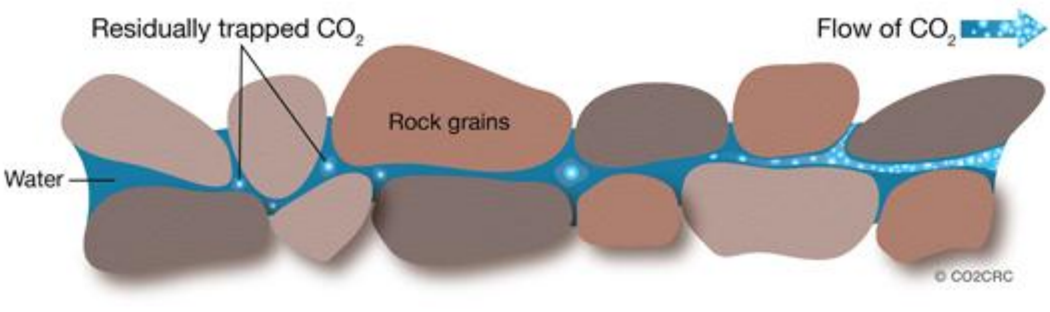


Figure 14 illustrates the residual trapping of CO2. Source: CO2CRC 2012

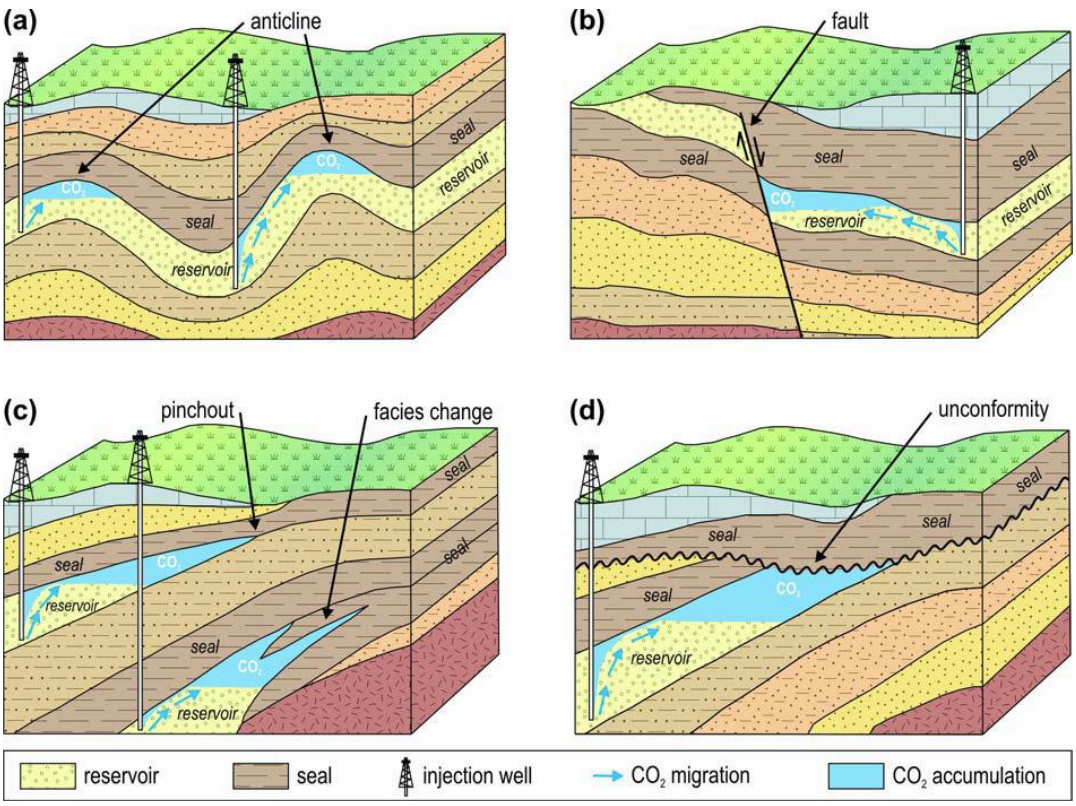


Figure 15 Examples of structural and stratigraphic traps for CO2: (a) anticline structural traps; (b) fault structural trap; (c) pinchout and lateral facies change stratigraphic traps; and (d) unconformity stratigraphic trap. Source: Gibson-Poole

- Dissolution trapping occurs where injected CO2 dissolves and becomes trapped within the reservoir brine.

- Geochemical trapping occurs when in which dissolved CO2 reacts with the native pore fluid and/or the minerals making up the rock matrix of the reservoir. CO2 is incorporated into the reaction products as solid carbonate minerals and aqueous complexes dissolved in the formation water.

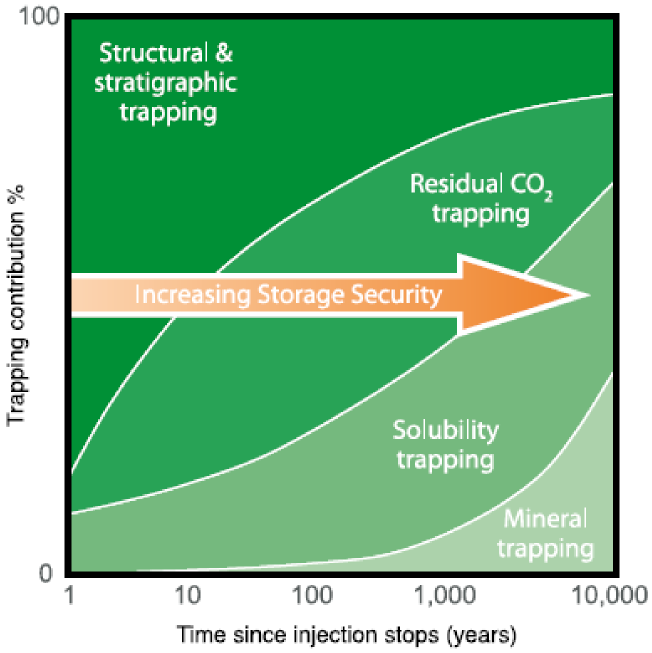


Figure 16. There are four basic mechanisms to store CO2. They involve a combination of physical and geochemical trapping. Source: IPCC 2005.

4.1.4 Who is storing CO2 and where?

There are many pilot projects currently underway all around the world (Figure 17), the most famous of which is probably the Sleipner Project 250km off the coast of Norway. It is the first commercial CO2 storage facility and was born out of the need to deal with the high CO2 content of the gas being produced at the Sleipner West Gas Field. Once the CO2 is separated, it is then injected into the Utsira Formation, a large saline aquifer approximately 800m -1000m below the seafloor (Figure 18).

The injected CO2 is constantly being monitored in order to study its behaviour over time. Approximately 1 Mt of CO2 is injected each year with a total of 20 Mt expected to be injected over the lifetime of the project.

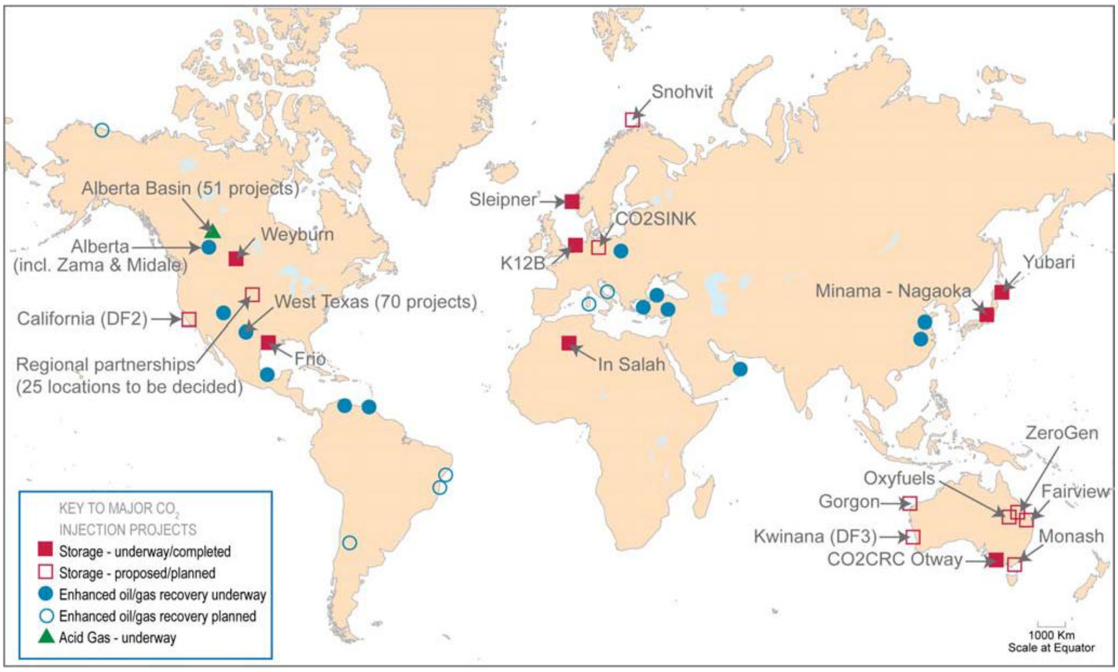


Figure 17.Geologic storage and related projects are in operation or proposed around the world. Most are research, development or demonstration projects. Several are part of industrial facilities in commercial operation. Image Source: CO2CRC 2012.

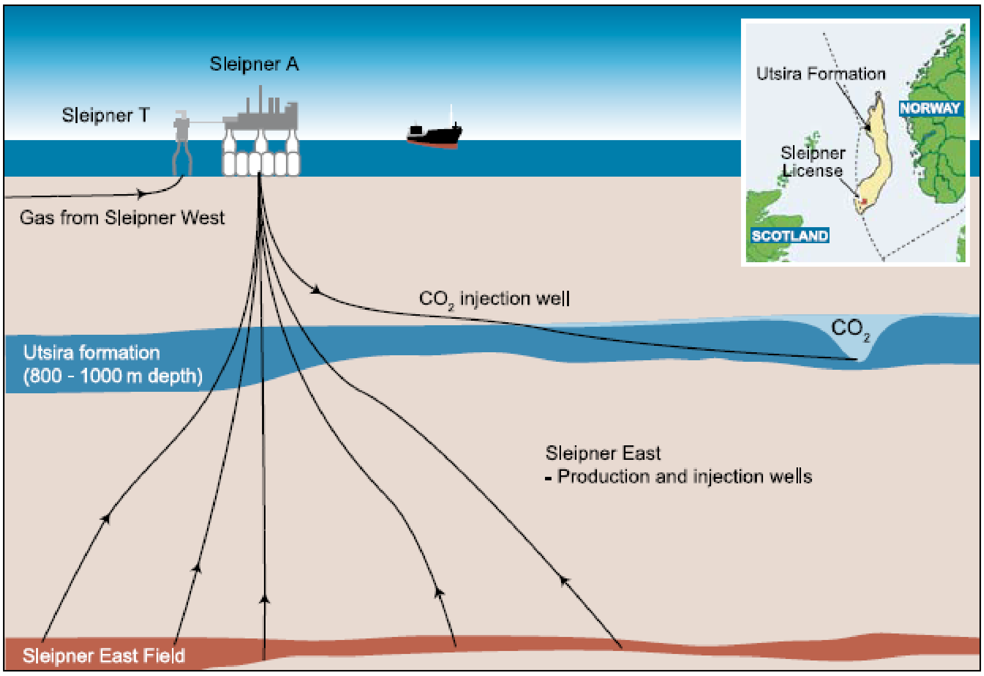


Figure 18 shows a simplified diagram of the Sleipner Project. Source: IPCC 2005

Examples of other projects still in pilot or development phases include the Otway Project in the Victoria, Australia (Figure 19), and the Gorgon Project off the northwest coast of the Australia (Figure 20).

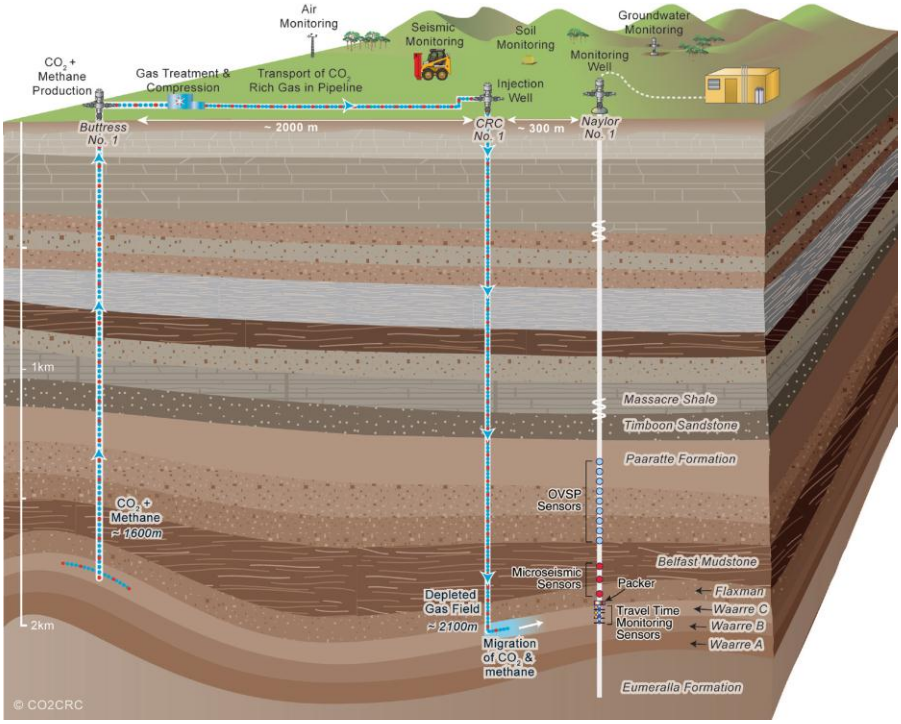


Figure 19 shows a simplified diagram of the Otway Project in Australia.Source CO2CRC 2012

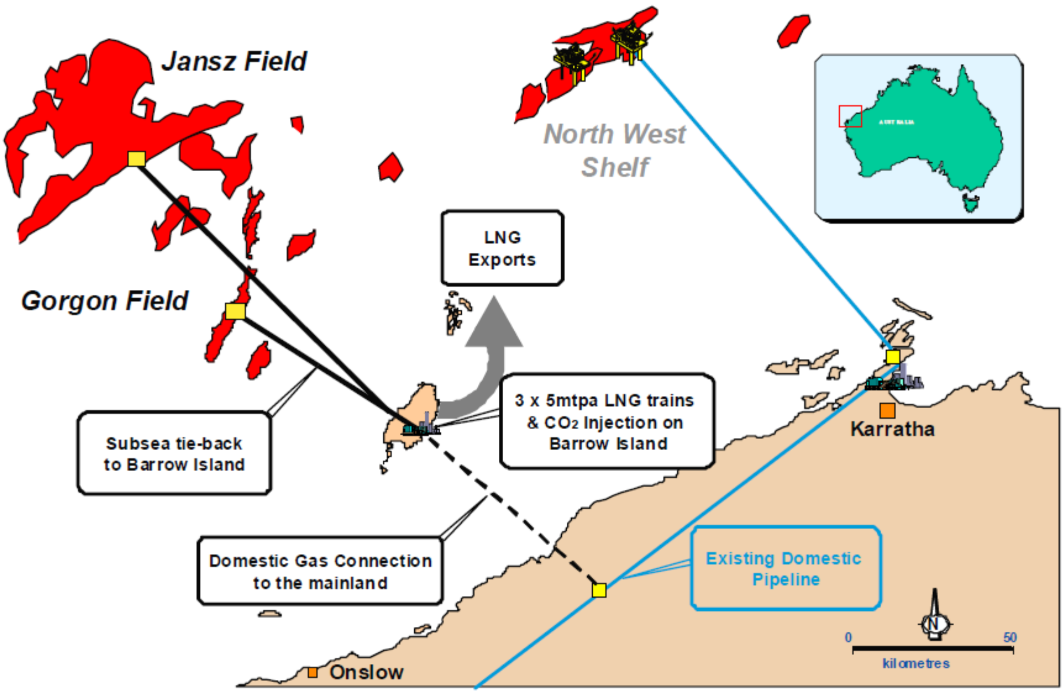


Figure 20 shows a simplified diagram of the Gorgon Project off the northwest coast of Australia. Source:Flett et al 2008.

4.2 Classification / ranking schemes used in the CO2 Atlas

The Norwegian Petroleum Directorate (NPD) has developed a checklist as a way of classifying reservoirs and their seals (Figure 20). It was used as a screening tool as part of this study to help determine the most appropriate parameter cut offs.

.

CHECKLIST FOR RESERVOIR PROPERTIES		
Typical high and low scores		
Reservoir Properties	High	Low
Aquifer Structuring	Mapped or possible closures	Tilted, few /uncertain closures
Traps	Defined sealed structures	Poor definition of traps
Pore pressure	Hydrostatic or lower	Overpressure
Depth	800- 2500 m	< 800 m or > 2500 m
Reservoir	Homogeneous	Heterogeneous
Net thickness	> 50 m	< 15 m
Average porosity in net reservoir	> 25 %	< 15 %
Permeability	> 500 mD	< 10 mD

FOR SEALING PROPERTIES			
Typical high and low scores			
Sealing Properties	High	Low	Unacceptable values
Sealing layer	More than one seal	One seal	No known sealing layer over parts of the reservoir
Properties of seal	Proven pressure barrier/ > 100 m thickness	< 50 m thickness	
Composition of seal	High clay content, homogeneous	Silty, or silt layers	
Faults	No faulting of the seal	Big throw through seal	Tectonically active faults
Other breaks through seal	No fracture	sand injections, slumps	Active chimneys with gas leakage
Wells (exploration/ production)	No drilling through seal	High number of wells	

Figure 21 Checklists for reservoir and sealing properties. Source: NPD 2011

5. METHODS AND DATA

5.1 Dataset

This study focuses on eight wells that were selected based on their geographic location; wells 18/10-1 located in the NW Egersund Basin, wells 17/11/1 and 17/11-2 on the margins of the Sele High, 17/4-1 in the Ling Depression, 17/9-1 in the Åsta Graben, and wells 17/10-1, 7/3-1 and 8/4-1 in the Fiskebank Sub-basin.

5.1.1 Wells

There are eight wells used as part of the thesis: 7/3-1, 8/3-1, 17/9-1, 17/10-1, 17/11-1, 17/11-2, 17/4-1, 18/10-1 (Figure 22). The wells were used for stratigraphic control when interpreting the seismic data away from well control and to calculate properties of the interpreted sequences. They were particularly useful when calculating properties such as porosity and permeability to determine reservoir suitability. After initial screening, which included well log and seismic analysis, two wells were determined to have the most suitable reservoir properties for CO2 storage. These were well 17/10-1 located in the Åsta Graben adjacent to the Sele High, and well 18/10-1 in the NW Egersund Basin.

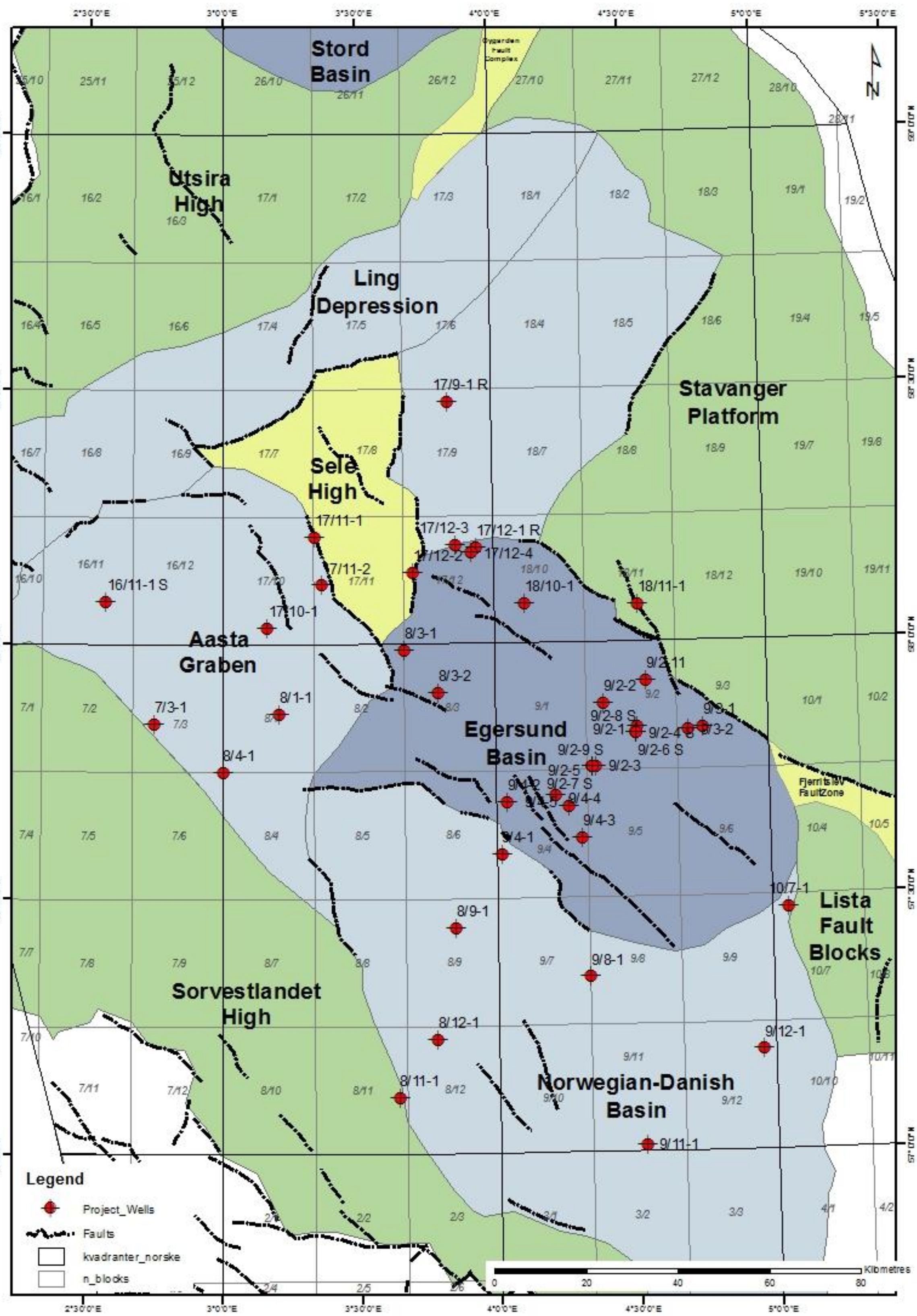


Figure 22. Location plan showing location of wells in the study area. Source??

Well 7/3-1

Exploration well 7/3-1 was drilled by Amoco Norway Oil Company in 1969. It was drilled on the Sørvestlandet High on the western side of the Norwegian - Danish Basin to a depth of 4700 m in what is assumed to be Carboniferous age rocks.

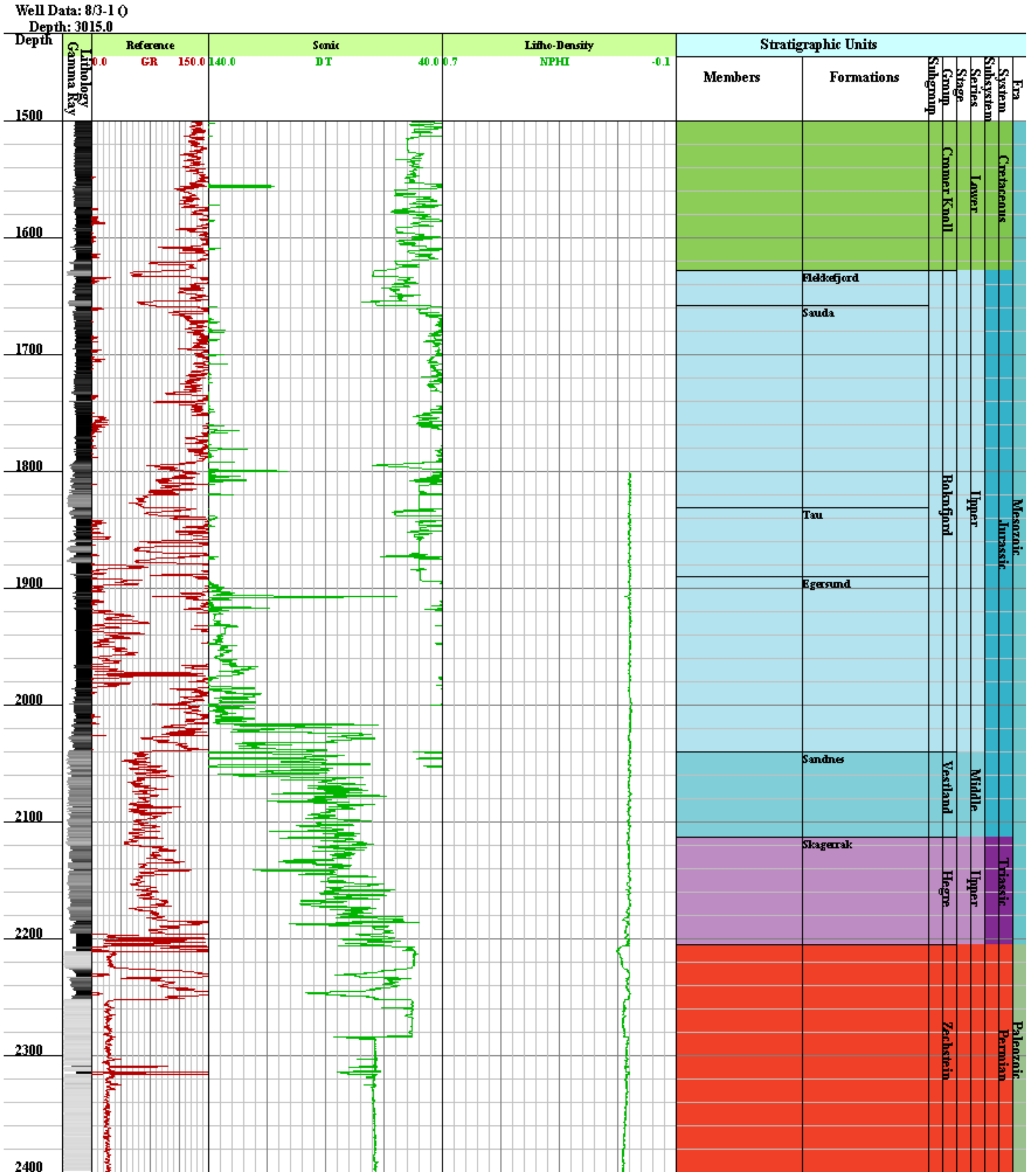
The well penetrated relatively complete Tertiary, Cretaceous, Late Jurassic, and the Permian sequences. The Triassic and the Early Jurassic were missing. The Permian Zechstein salt was 1437 m thick, resting on a thin Kupferschiefer sequence.

Well 8/3-1

Well 8/3-1 was the first well drilled in Norwegian waters. Esso Exploration and Production Norway AS drilled it in the north-western part of the Norwegian-Danish Basin to a total depth of 3015m into basement. The purpose of the well was to investigate the stratigraphic sequence and the rock lithologies on an attractive seismic structure in this unexplored region of the North Sea.

The lithologies intersected transitioned from shales and clays towards the top of the well, into chalk and shales throughout the middle section of the well, with the bottom section of the well dominated by evaporites.

Potential reservoir rocks were intersected in the chalk section identified as the Ekofisk Formation, and in the sands of the Sandnes Formation.



Well 17/4-1

Well 17/4-1 was drilled by Elf Petroleum Norge AS in 1968 to a depth of 3997m. It was drilled on a NNE-SSW trending monocline in the Ling Depression with the objective to test the hydrocarbon potential of the Mesozoic sands.

The well encountered Jurassic and Triassic sandstones with medium to good porosities but mostly poor permeabilities due to calcite cement. The stratigraphic units intersected are illustrated in the well panel below (Figure 23).

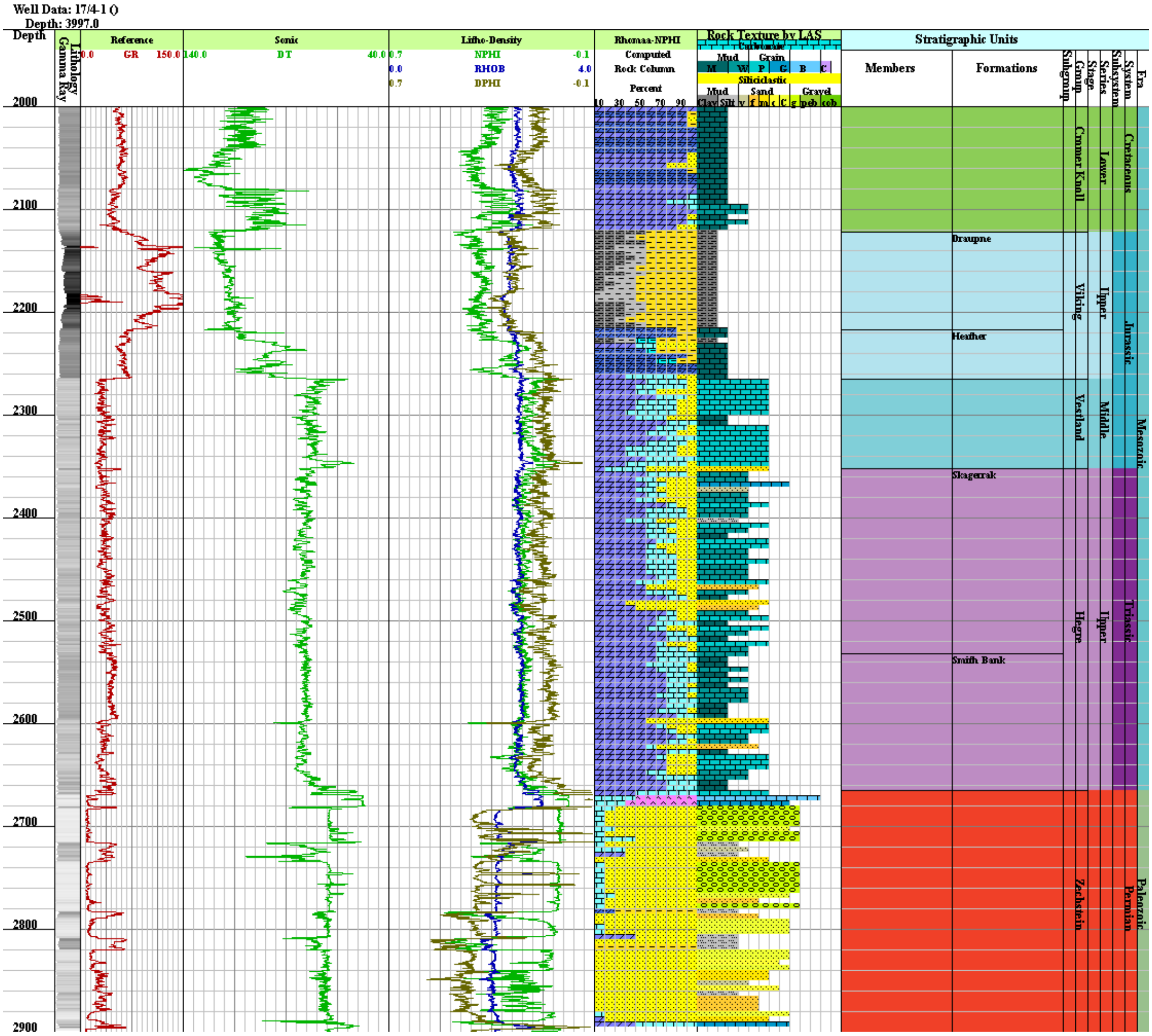


Figure 23 Stratigraphic units and log for well 17/4-1.

Well 17/9-1

Well 17/9-1 was drilled by Esso Exploration and Production Norway A/S in 1973 to a depth of 2816m before being re-entered as 17/9-1R and drilled to a total depth of 3161m. It was drilled in the Åsta Graben approximately 30km north of the 17/12-1R Discovery well with the primary objective to investigate the sands at the base of the Jurassic sequence.

Well 17/9-1 was found to have no rocks with any reservoir potential. The stratigraphic units intersected are illustrated in the well panel below (Figure 24).

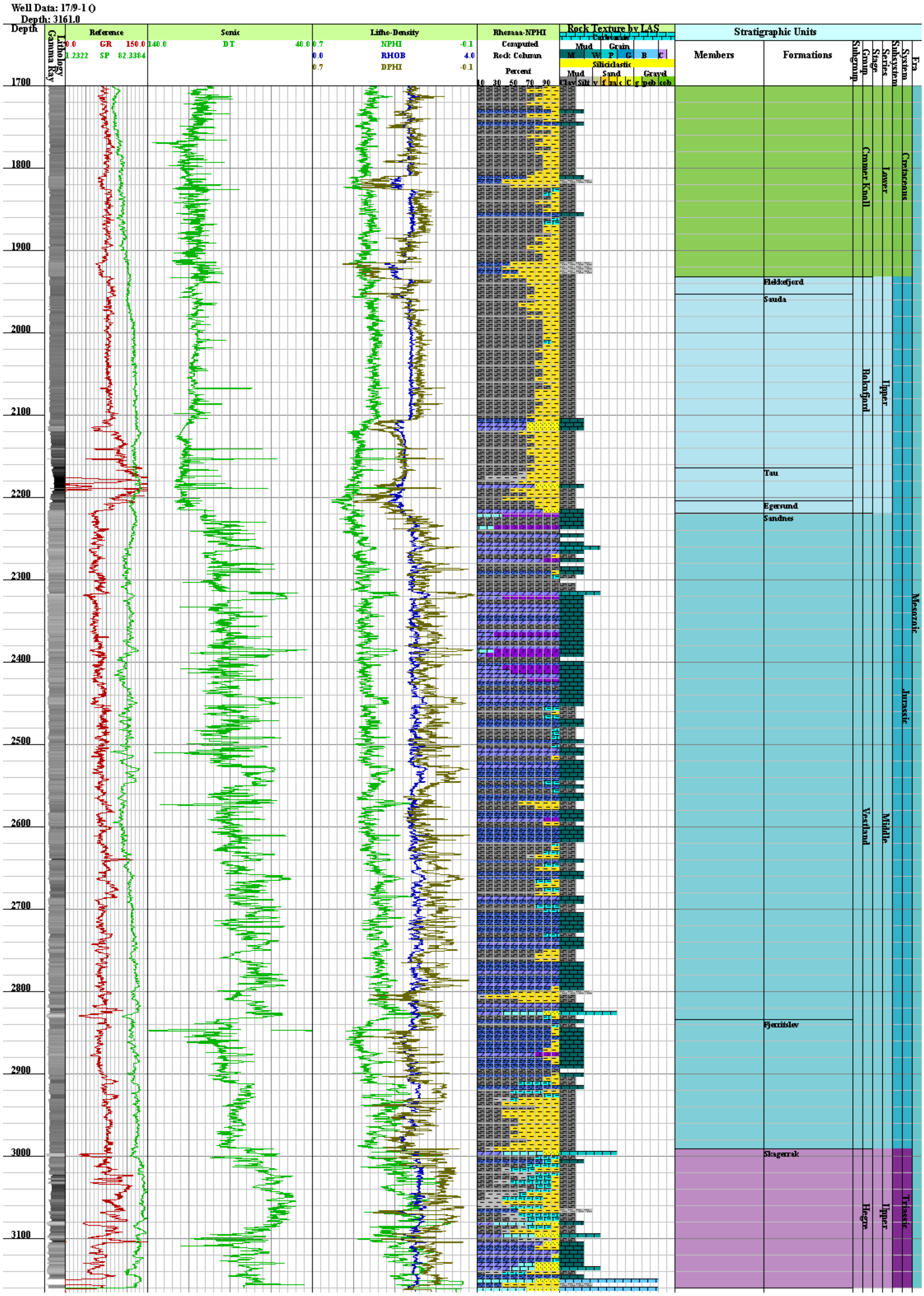


Figure 24 Stratigraphic units and log for well 17/9-1.

Well 17/10-1

Well 17/10-1 was drilled by Norske Shell AS in 1968 to a total depth of 3591m. It was drilled in the Norwegian-Danish Basin near the western margin of the Sele High. The objective was to test the Mesozoic section of a gentle anticline in an area with prominent salt walls.

The massive Jurassic and Triassic sandstones of the Gassum and Skagerrak Formations were intersected with promising porosities of between 20% to 25%. The stratigraphic units intersected are illustrated in the well panel below (Figure 25).

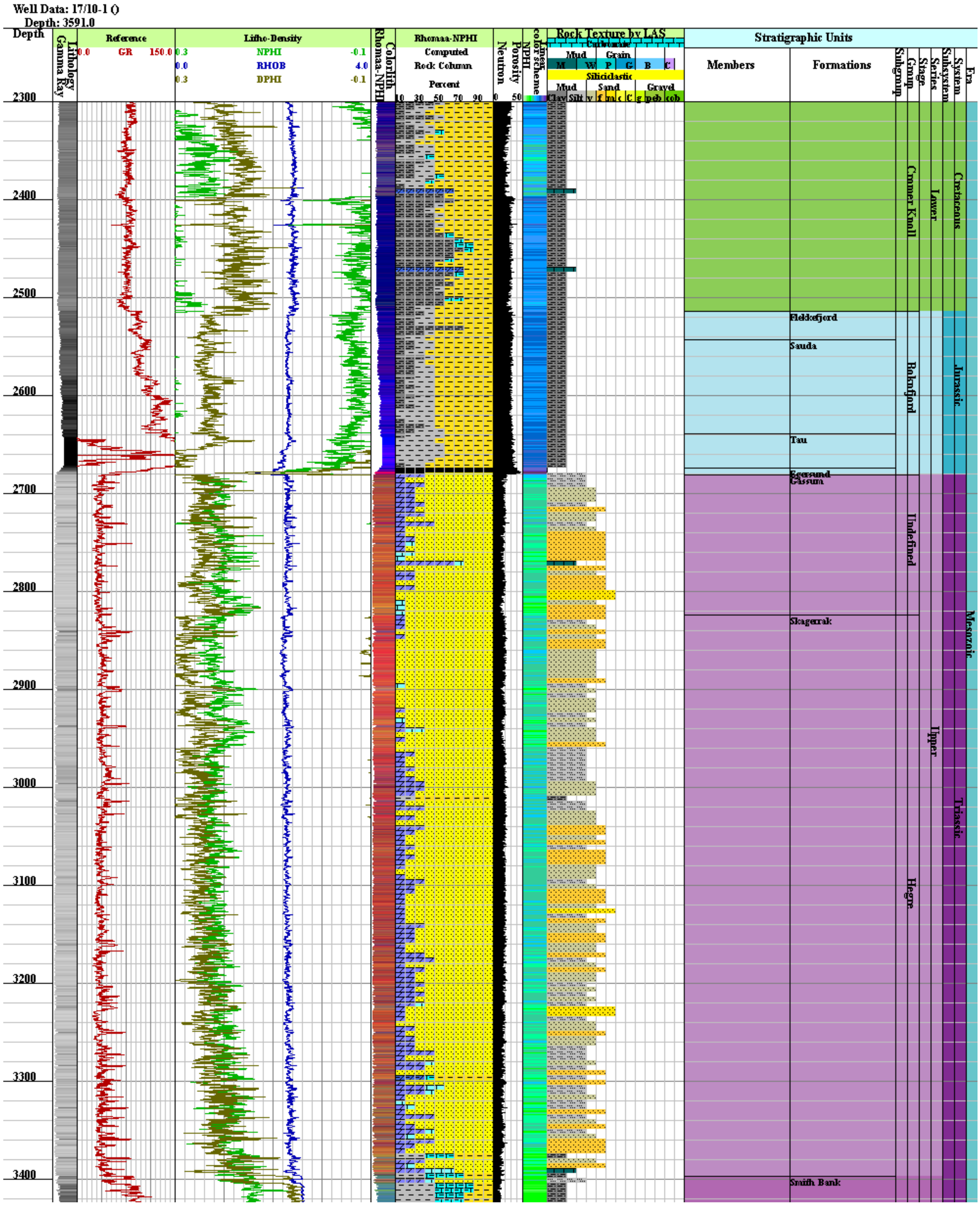


Figure 25 Stratigraphic units and log for well 17/10-1.

Well 17/11-1

Well 17/11-1 was drilled by Norske Shell AS in 1968 to a total depth of 3269m. It was drilled on the western edge of the Sele High in the North Sea with the objective to evaluate the Tertiary and Mesozoic sequences before interesting the Zechstein salt and underlying formations.

No formations of reservoir quality were intersected. The stratigraphic units intersected are illustrated in the well panel below (Figure 26).

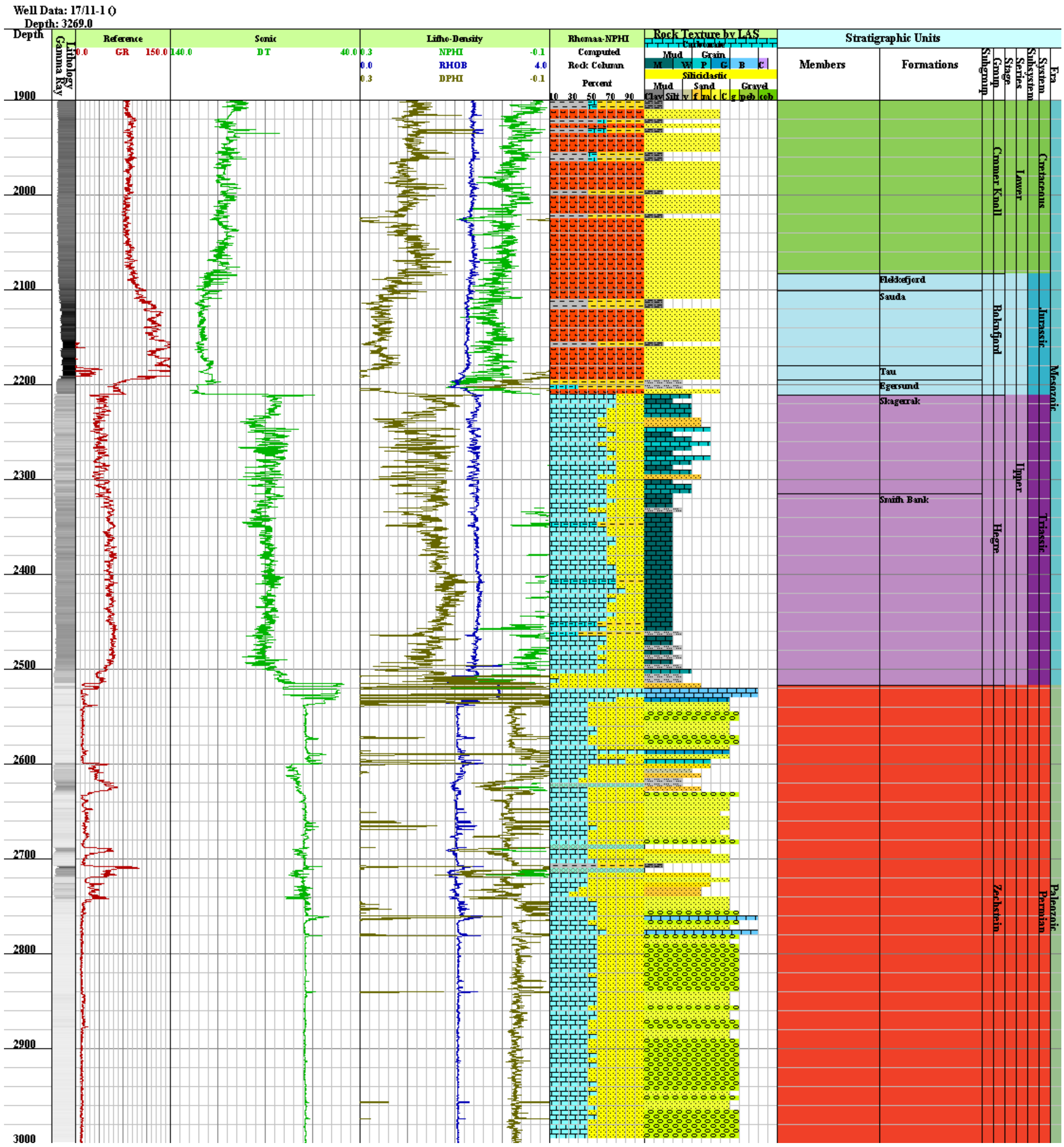


Figure 26 Stratigraphic units and log for well 17/11-1.

Well 17/11-2

Well 17/11-2 was drilled by Norske Shell AS in 1976 to a total depth of 2644m. It was drilled in the Egersund Basin to the west of the marginal Bream and Brisling discoveries with the objective to evaluate the Middle Jurassic/Triassic sands on the west flank of a NNE-SSW salt wall.

The top section of the target Skagerrak Formation showed promising porosities. The stratigraphic units intersected are illustrated in the well panel below (Figure 27).

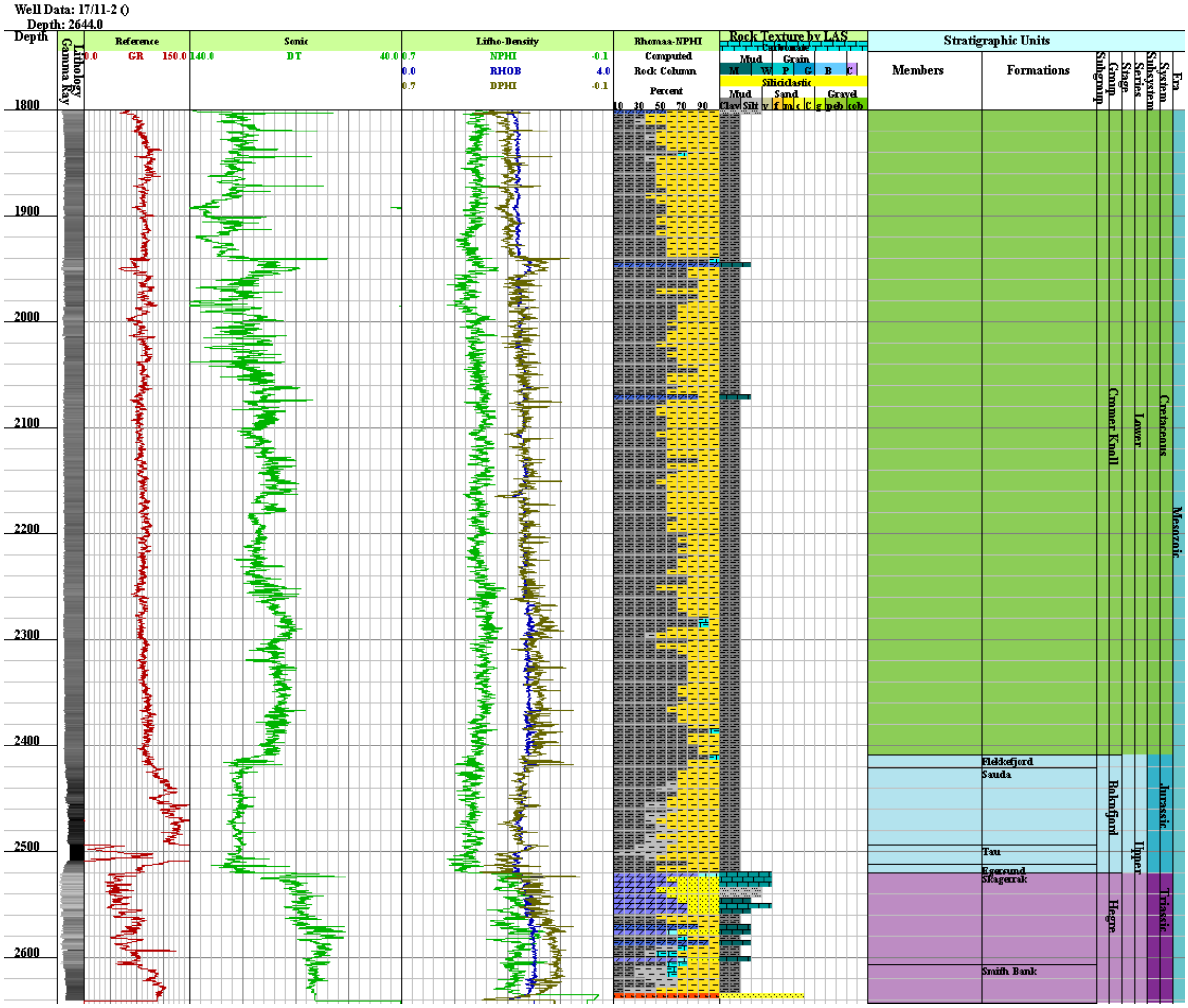


Figure 27 Stratigraphic units and log for well 17/11-2.

Well 18/10-1

Well 18/10-1 was drilled by Elf Petroleum Norge AS in 1979 to a total depth of 2800m. It was drilled in the Egersund Basin in the North Sea with the objective to evaluate a seismic feature on the same trend as the marginal Bream discovery. The target was the Middle Jurassic sandstones.

The target sands of the Sandnes and Bryne Formations were intersected at 2405m with the reservoir zone separated by a thin shale barrier. The stratigraphic units intersected are illustrated in the well panel below (Figure 28).

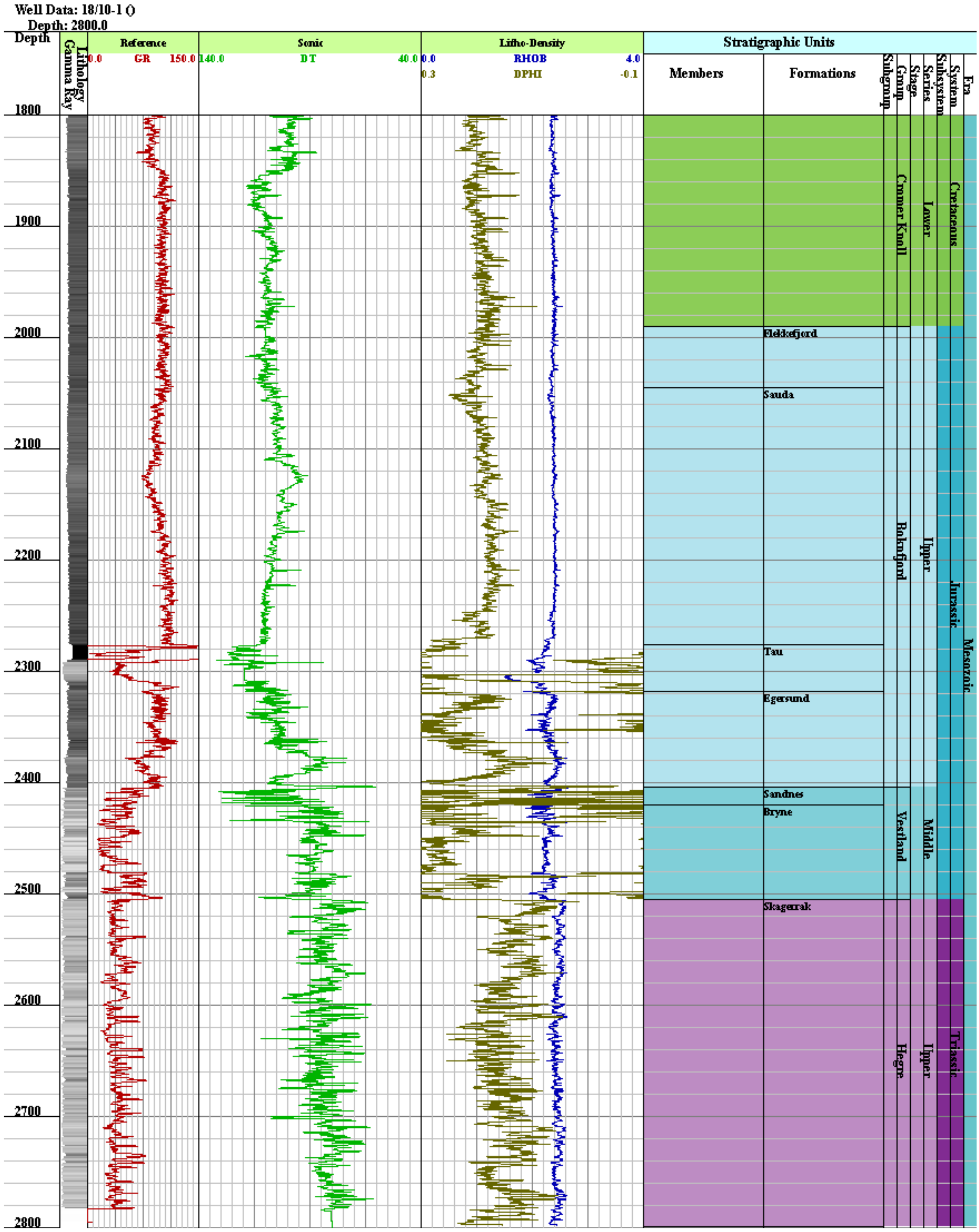


Figure 28 Stratigraphic units and log for well 18/10-1.

5.1.2 Well log quality checks

The quality of the well log data can be affected by several environmental factors throughout the drilling and logging process. The density and porosity logs in particular are important to the methodology of this study so quality checks were performed on the logs to identify any irregularities or suspicious readings.

This was done by evaluating the caliper log to check for large variations of the borehole diameter due to caving, and the density correction log (DRHO), which records absolute deviations of the log signal. If this deviation exceeds 0.15 or -0.15 g/cm^3, the log signal can no longer be trusted and should be ignored (Ramaekers 2006 in Benedictus 2007).

Caving of the borehole can result in misleading values for density (too low), and porosity (too high).

5.1.3 Well Log Analysis

Geophysical well logs were analysed and used to calculate various petrophysical parameters and properties such as porosity (effective and total), permeability, volume of shale, and net-to-gross ratio. All calculations were done in Microsoft Excel to make it possible to calculate the various properties for every log interval within the potential reservoir. This enabled the calculation of hundreds of interval throughout the reservoir and then an average was taken to give a representative result.

Matrix and fluid densities used as part of these calculations were taken from widely accepted estimates of 2.65 g/cm3 (quartz/sandstone) and 1.03 cm/3 (formation water) respectively (see Table 1).

Table 1. Typical values for matrix and fluid densities.

Typical values for matrix and fluid densities (g/cm^3)	
Sandstone	2.65
Limestone	2.71
Dolomite	2.87
Anhydrite	2.98
Halite	2.03

Gypsum	2.35
Clay	2.7-2.8
Freshwater	1
Seawater	1.03-1.06
Oil	0.6-0.7
Gas	0.15

Porosity

Porosity will be estimated using the density log;

$$\Phi_D = \rho_{matrix} - \rho_b / \rho_{matrix} - \rho_f$$

Where:

Φ_D = Porosity derived from density log

ρ_{matrix} = Matrix density (obtained from Table 1)

ρ_b = Bulk density from log

ρ_f = Fluid density (obtained from Table 1)

Permeability

Permeability will be estimated using the concept of Flow Zone Indicator (FZI) as described by Chandra (2008). Flow Zone Indicator will be obtained from the combined use of the available well log data. FZI will be calculated for the selected reservoir intervals using the technique given by Xue and Dutta Gupta (1997). This technique is based on the transformation of gamma ray (GR), neutron porosity (NPHI), density (RHOB) and resistivity (LLD) logs as given below:

GR_Tr = 4.7860E-03 GR2 – 1.7320E-01 GR + 1.0614E+00 ------------ -------(3)

NPHI_Tr = -8.1102E+00 NPHI 2 + 9.6676E-01 NPHI + 1.7170E-01 --------- (4)

RHOB_Tr = 7.1926E+00 RHOZ 2 – 3.6727E+01 RHOB + 4. 5873E+01 -----(5)

LLD_Tr = -1.6859E-04 HLLD 2 – 3.8016E-02 LLD + 4. 3712E-01 -------- ---(6)

SUMTr = GR_Tr + NPHI_Tr +RHOB_Tr + LLD_Tr -------------------- -----(7)

FZI = 4.4306E-01 SUMTr2 + 6. 08575E-01 SUMTr + 3.8229E-01 ------------ (8)

SUMTr is the sum of all transforms given by equations 3-6. Equation 8 gives the relation between the logs and FZI.

Volume of shale calculations

Volume of shale can be determined by using any of the described in Figure 29, after which the lowest estimate should be applied to shale corrections for porosity (Doveton 2001). The theory is that all the shale equations will overestimate the shale content because there will generally be other components in the rock other than shale that will lead to increased log readings of shaliness (Doveton 2001).

Gamma Ray Index

$$I_{GR} = \frac{GR_{log} - GR_{min}}{GR_{max} - GR_{min}}$$

I_{GR} = Gamma Ray index	GR_{log} = GR reading from the log
GR_{min} = minimum GR	GR_{max} = maximum GR

$$V_{shale} = I_{GR}, \quad \text{Linear response, 1st order estimate}$$

$$V_{shale} = 0.08\left(2^{3.7 \cdot I_{GR}} - 1\right), \quad \text{Larionov (1969), Tertiary rocks}$$

$$V_{shale} = \frac{I_{GR}}{3 - 2 \times I_{GR}}, \quad \text{Steiber (1970)}$$

$$V_{shale} = 1.7 - \left[3.38 - \left(I_{GR} - 0.7\right)^2\right]^{1/2}, \quad \text{Clavier (1971)}$$

$$V_{shale} = 0.33 \times \left(2^{2 \cdot I_{GR}} - 1\right), \quad \text{Larionov (1969), for older rocks}$$

Figure 29. Volume of Shale equations.

Net/Gross Ratio

Net-to-gross ratio aims to describe the portion of the reservoir rock which contributes to production, or in this case storage. It is a notoriously subjective parameter and so is defined for this study as using the following criteria:

Porosity > 15%

Permeability > 10 mD

$V_{shale} < 0.25$

5.2 Seismic surveys

The 2D seismic dataset has been obtained from three separate surveys and covers the parts of the Asta Graben, Ling Depression, Egersund Basin, Norwegian-Danish Basin and the entire Sele High. The seismic surveys were:

- The UG97 lines were acquired and processed by Fugro in 1997. The survey was sponsored by Statoil and was known as 1997 Up-Dip Graben.
- The UGI98 lines were acquired and processed by Fugro in 1998. The survey was sponsored by Statoil and was known as 1998 Up-Dip Graben Infill.
- The UGX98 lines were acquired and processed by Fugro and was known as 1998 Up-Dip Graben Extension.
- The UG97 2D seismic survey was acquired by Geco in 1992.

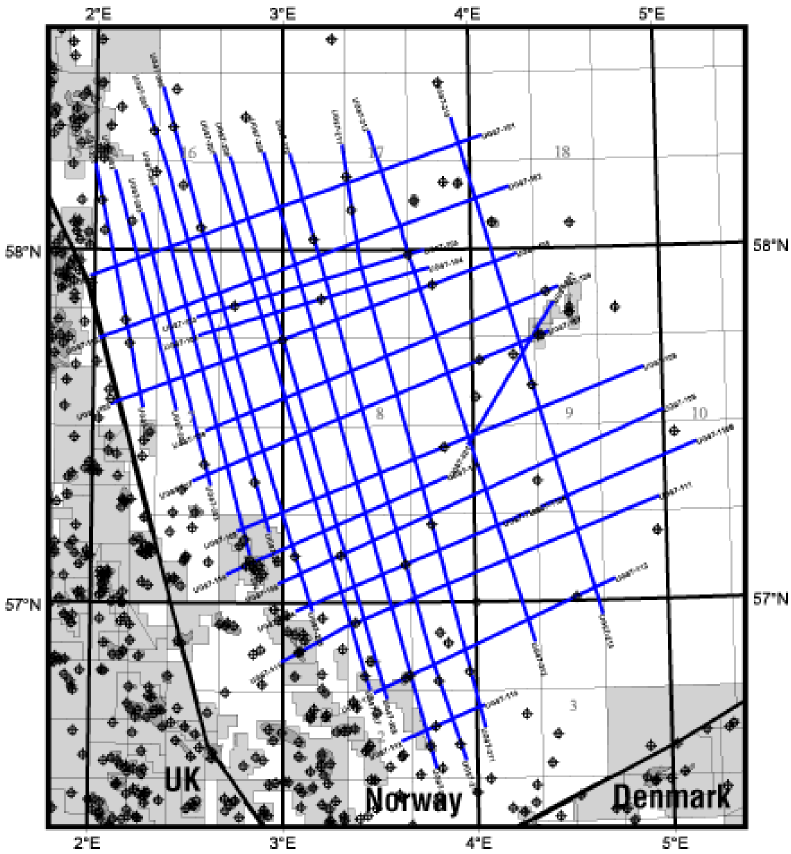


Figure 30. 1997 Up-Dip Graben (UG97)

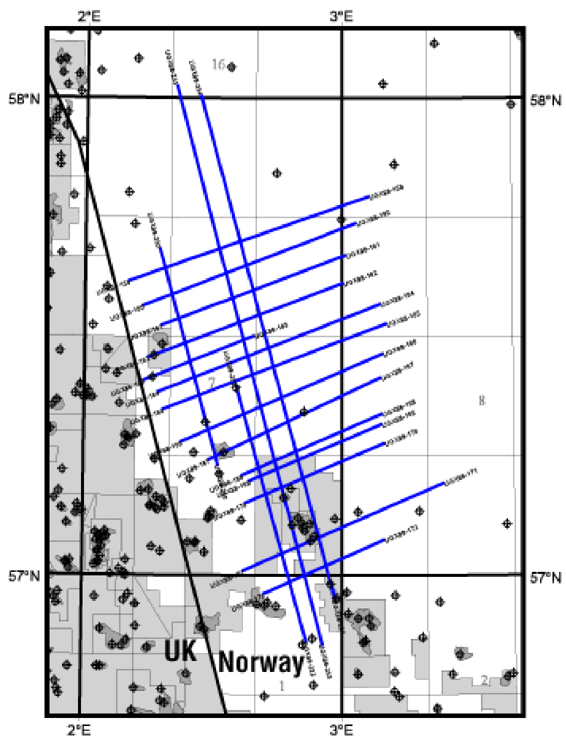


Figure 31. 1998 Up-Dip Graben Extension (UGX98)

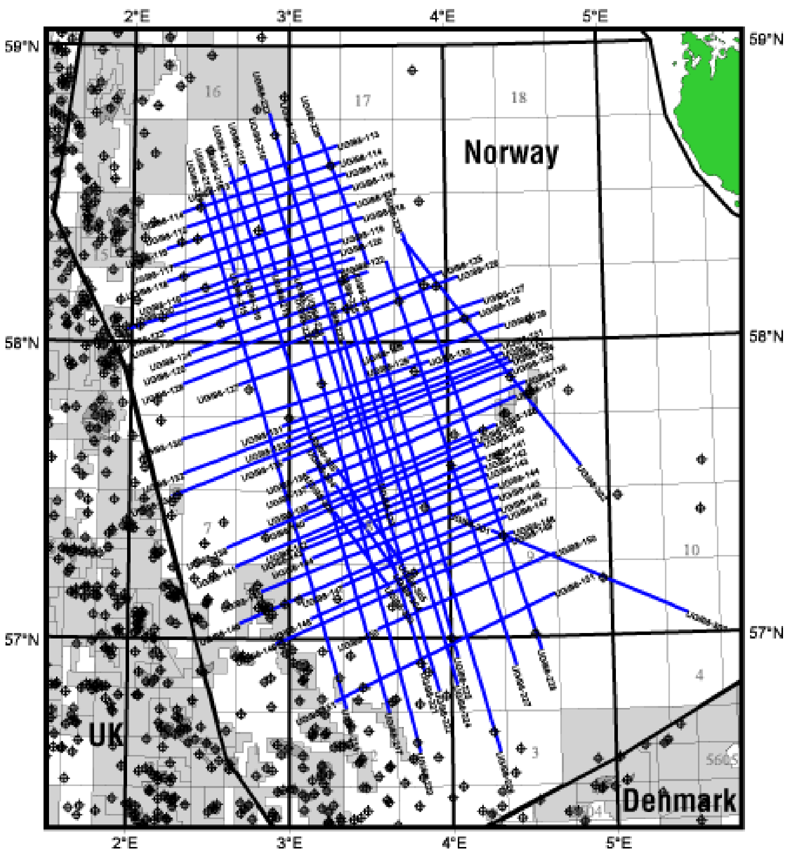


Figure 32. 1998 Up-Dip Graben Infill (UGI98)

5.2.1 Seismic Interpretation

The interpretation of the seismic data provided will be performed using the open source software **OpendTect.** It can be used for processing, visualizing and interpreting multi-volume seismic data.

Key stratigraphic boundaries were interpreted across much of the study area. These included:

- Shetland Group (Top Cretaceous)
- Cromer Knoll Group
- Boknfjord Group (Top Jurassic)
- Vestland Group
- Gassum Formation
- Hegre Group (Top Triassic)
- Zechstein Formation

The seismic reflectors were picked after studying the literature and finding a few reference seismic lines that had previously been interpreted. In this way, it was possible to build on my interpretation while being able to tie back to the reference lines. An example of a reference line used was GLD92-204 (Heeremans and Faleide 2004).

5.2.2 Seismic-to-well tie

A seismic-to-well tie was performed on each of the selected wells using the OpendTect software. This involved using the well logs for each of the wells and tying them to the 2D seismic lines that intersect those wells.

5.3 Storage Capacity Calculation

As is the case with the CO_2 Atlas published by the Norwegian Petroleum Directorate, the method for calculating effective storage capacity for a potential CO_2 reservoir is shown in Equation 1.

$$M_{CO_2e} = A \times h \times \phi \times \rho_{CO_2r} \times S_{eff}$$

- M_{CO_2e}: effective storage capacity
- A: area of aquifer
- h: average height of aquifer × average net to gross ratio
- ϕ: average reservoir porosity
- ρ_{CO_2r}: CO_2 density at reservoir conditions
- S_{eff}: storage efficiency factor

Equation 1. Equation used for calculating effective storage capacity. Image Source: Vangkilde-Pedersen 2009.

6. RESULTS

6.1 Potential Storage Sites

After extensive investigation into potential CO2 storage sites within the study area, including literature studies, seismic interpretation and investigation, well analysis of the existing available data (Table 2), there were two sites that were chosen for further investigation and eventually ranked for suitability. These were 1) a domal structure in the NW Egersund Basin that had previously drilled with hydrocarbon shows (well 18/10-1), and 2) a dry well (17/10-1) that had been drilled into a domal structure bounded by salt diapirs,

Table 2 Summary of well analysis

Well	Reservoir (average values)					
	Formation	Depth	Thickness	Porosity	Permeability	Net-to-gross ratio
17/11-1	Skagerrak	2211	104	12%	8mD	0.24
17/11-2	Skagerrak	2521	87	12%	18mD	0.32
7/3-1	Sandnes	2655	41	10%	6mD	0.17
8/4-1	Bryne	2397	116	12%	23mD	0.19
17/9-1	Vestland Gp	2220	615	10%	12mD	0.15
17/4-1	Vestland Gp	2265	87	11%	2.5mD	-

6.2 18/10-1 prospect

The domal structure penetrated by Well 18/10-1 is an attractive prospect for CO2 storage. The storage site scores somewhere in the medium range with regards to the checklists for reservoir and seal properties outlined by the NPD's CO2 Atlas.

6.2.1 Reservoir properties

Table 3. Summary of reservoir properties for well 18/10-1.

Name	Sandnes Formation + Bryne Formation (Vestland Group)
Porosity	24%
Permeability	50-100 mD
Net-to-gross ratio	0.76
Reservoir Temperature	80^{o}C

Bottom Hole Temperature	88°C
Thickness	100 m
Area	20 km2
Depth	2405 m

6.2.2 Porosity

Porosity was estimated using the density log (equation 1); and then also calculated by compensating for Vshale (equation 2). This was done in excel

Equation 1

$$\Phi_D = \rho_{matrix} - \rho_b / \rho_{matrix} - \rho_f$$

Where:

Φ_D = Porosity derived from density log

ρ_{matrix} = Matrix density

ρ_b = Bulk density from log

ρ_f = Fluid density

Equation 2

$$\phi_D^{V_{sh}} = \frac{\rho_{ma} - \rho_b}{\rho_{ma} - \rho_f} - V_{sh} \cdot \frac{\rho_{ma} - \rho_{sh}}{\rho_{ma} - \rho_f}$$

where $\phi_D^{V_{sh}}$ = porosity compensated for presence of shale

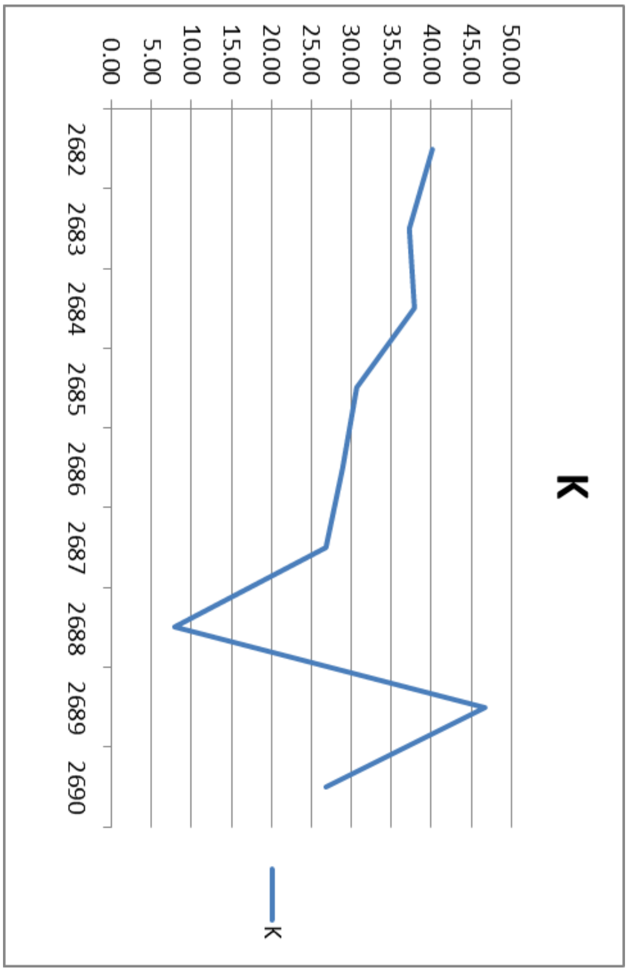
ρ_{sh} = shale density

The porosity was calculated to be an average of approximately 24%.

Porosity values calculated between 2431-2433m were not included as these were found to be erroneously high. The caliper log was checked as part of the quality control process and there was several intervals that were found to be problematic. The caliper log showed a widening of the well, which can lead to misleading geophysical log readings, in this case higher than expected neutron porosity readings and lower than expected bulk densities.

6.2.3 *Permeability*

Permeability was calculated using the Flow Zone Indicator method described in the methods section. It was calculated to be between 50-100mD.



The above chart shows permeability versus depth to illustrate how permeability changes as depth increases.

6.2.4 Net-to-gross ratio

Net-to-gross ratio is a notoriously subjective parameter and so is defined for this study as using the following criteria:

Porosity > 15%

Permeability > 10 mD

$V_{shale} < 0.25$

6.2.5 Seal and caprock

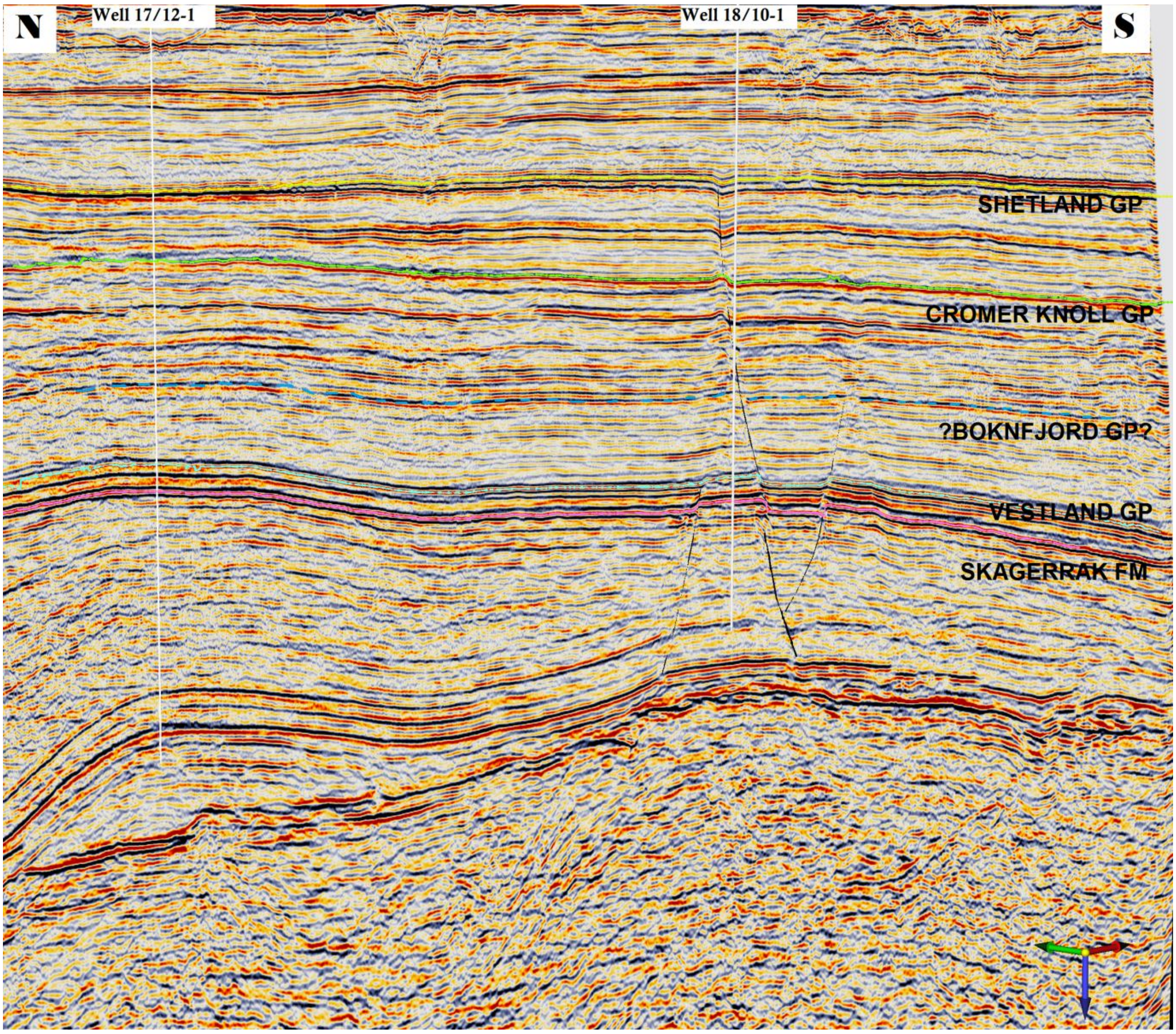
The caprock for this prospect is the regional stratigraphic seal, the Boknfjord Group, which which consists of several shale formations. This widespread group consists predominantly of shales, mudstones and claystones, but also includes varying amounts of siltstone, sandstone, and limestone stringers (NPD 2012). Caprock thickness is approximately 400 metres in this part of the basin.

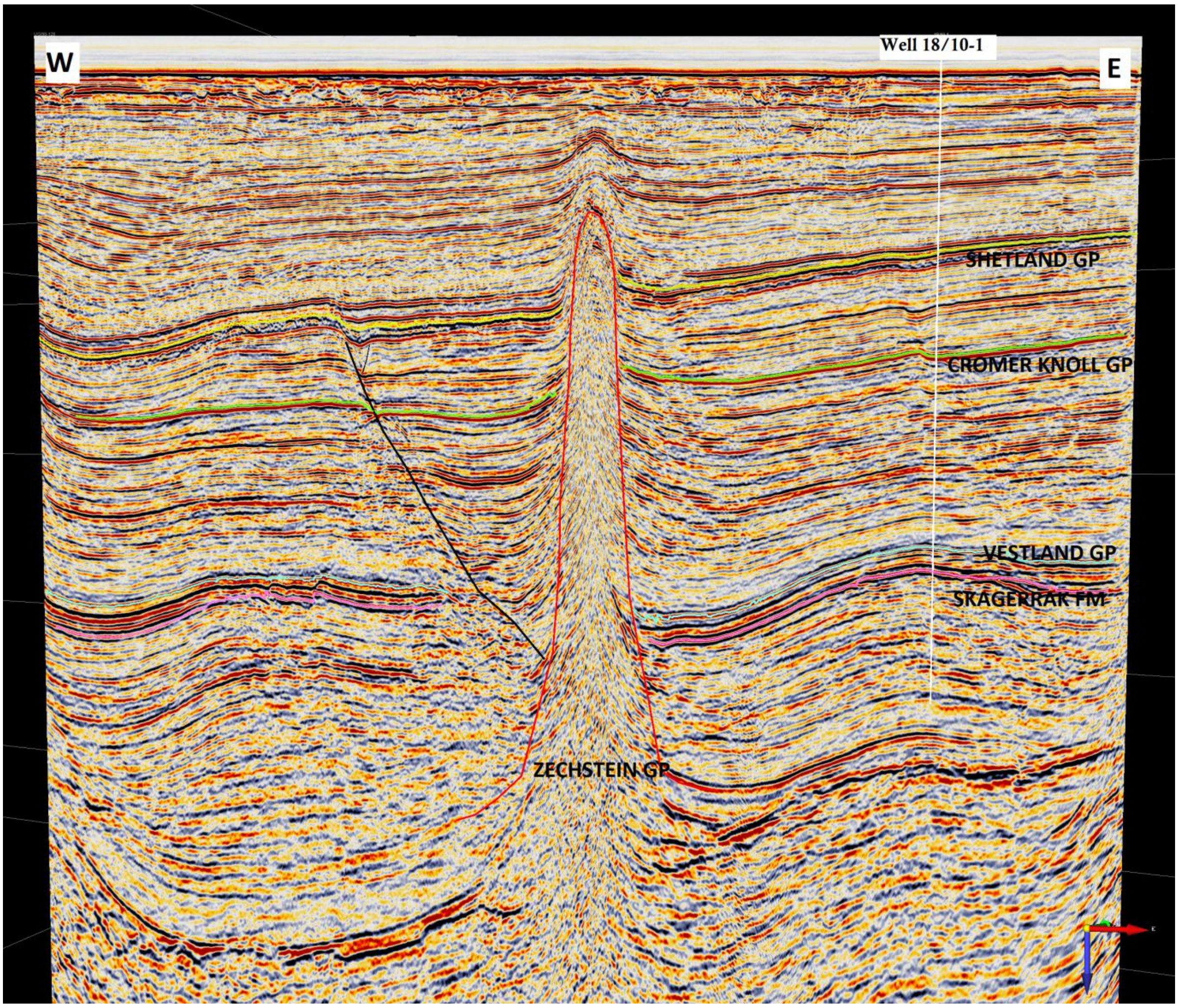
The dome structure is broken by minor faulting which defines a kind of slump close to the top of the structure. Given the thickness of the caprock, this small scale faulting is unlikely to have any impact on the integrity of the seal.

6.2.6 Trap

The trap type for the 18/10-1 prospect is a structural trap. Underlying salt movement (halokinesis) has uplifted part of the overlying strata forming a semi-closed domal structure.

When talking about storage capacity for saline aquifers it is important to consider whether the trap is closed, semi-closed or open, as this will greatly affect the storage efficiency factor.


N
Well 17/12-1
Well 18/10-1
S
SHETLAND GP
CROMER KNOLL GP
?BOKNFJORD GP?
VESTLAND GP
SKAGERRAK FM



6.2.7 Storage Capacity

Storage capacity has been calculated using the method outlined by Vangkilde-Pedersen (2009). It is important to distinguish between bulk volume estimates of regional aquifers and estimates for individual structural or stratigrahic traps.

CO_2 density at this depth and temperature should be approximately 650 kg/m^3 accounting for temperature, depth and pressure.

Using the equation in Figure 36, storage capacity was calculated to be approximately 35 Mt.

$A = 20$ km2

$h = 76$ m (100 x 0.76)

$\Phi = 24\%$

$\rho_{CO2} = 650$ kg/m3

$S_{eff} = 15\%$

Therefore:

$M_{CO2e} = 35$ Mt

Assumptions:

The potential CO_2 reservoir intersected by well 17/10-1 is a semi-closed acquifer and as such the "rule of thumb" approach was used to calculate the storage efficiency S_{eff} (Figure 37). The reservoir is semi-closed, bounded on two sides by the salt ridges. The reservoir quality is neither high or low but rather somewhere in between so the storage coefficient chosen was 15%.

6.2.8 Enhanced Oil Recovery (EOR)

The BREAM discovery may also be a candidate for CO2 injection as it is known to have low reservoir pressure and so will require artificial lift to extract the HC. This may also be the case for the YME field further south in the Egersund Basin.

6.3 17/10-1 prospect

The main reservoir zone of interest was the Jurassic/Triassic sandstone (Gassum and Skagerrak Formations) from 2682 m to 2899m. This section has porosities between 6 % and 30 % (average of 22%) and was entirely water bearing. There is a major unconformity on top of these sands to the overlying Late Jurassic shales. The claystones and mudstones of the Tau and Egersund Formations overlying the Gassum Formation, had exceptionally high gamma ray values. These are expected to form part of the seal for this prospect.

Table 4. Summary of reservoir properties for well 17/10-1.

Name	Gassum Formation
Porosity	6 - 30% (average 22%)
Permeability	2 – 162 mD (average 33 mD)
Net-to gross ratio	0.88
Reservoir Temperature	64.7^{o}C
Bottom Hole Temperature	106.6^{o}C
Thickness	217 m
Area	~180-200 km2
Depth	2682 m This is a little bit deep. Please comment/discuss in text

Calculation of reservoir temperature

$y = (mx) + c$

where:

y = temperature (bottom hole temp, BHT)

c = constant (eg. surface temp, $T_{surface}$)

x = depth (total depth, TD)

Therefore, geothermal gradient:

Geothermal gradient = (BHT - $T_{surface}$)/TD

Geothermal gradient = (106.6 – 20)/3591

= 0.024

Therefore:

Reservoir temperature = 0.024 x 2682

= 64.7°C

6.3.1 Porosity

Porosity was estimated using the density log;

$$\Phi_D = \rho_{matrix} - \rho_b / \rho_{matrix} - \rho_f$$

Where:

Φ_D = Porosity derived from density log

ρ_{matrix} = Matrix density

ρ_b = Bulk density from log

ρ_f = Fluid density

Porosity was calculated to be an average 22%.

6.3.2 Permeability

Permeability was calculated using the Flow Zone Indicator method described in the methods section. It was calculated to be between 2 -162 mD with an average of 33 mD.

6.3.3 Net-to-gross ratio

Net to gross ratio for the Gassum Formation was calculated as 0.88 using the following conditions/cut-offs:

Porosity greater than 15%

Vshale less then 0.15

Permeability greater than 10 mD

6.3.4 Seal and caprock

The caprock for this prospect is the regional stratigraphic seal, the Boknfjord Group, which consists of several shale formations. This widespread group consists predominantly of shales, but also includes varying amounts of siltstone, sandstone, and limestone stringers (NPD 2012). Caprock thickness is approximately 150 metres in this part of the basin.

6.3.5 Trap

The trap type for prospect 17/10-1 is a structural trap. The domal structure here is the result of halokinesis. The structure on which this well was drilled is a very gentle dipping aniticline in an area with prominent salt walls (Olsen 1979). Some of these features can be seen in Figure 33.

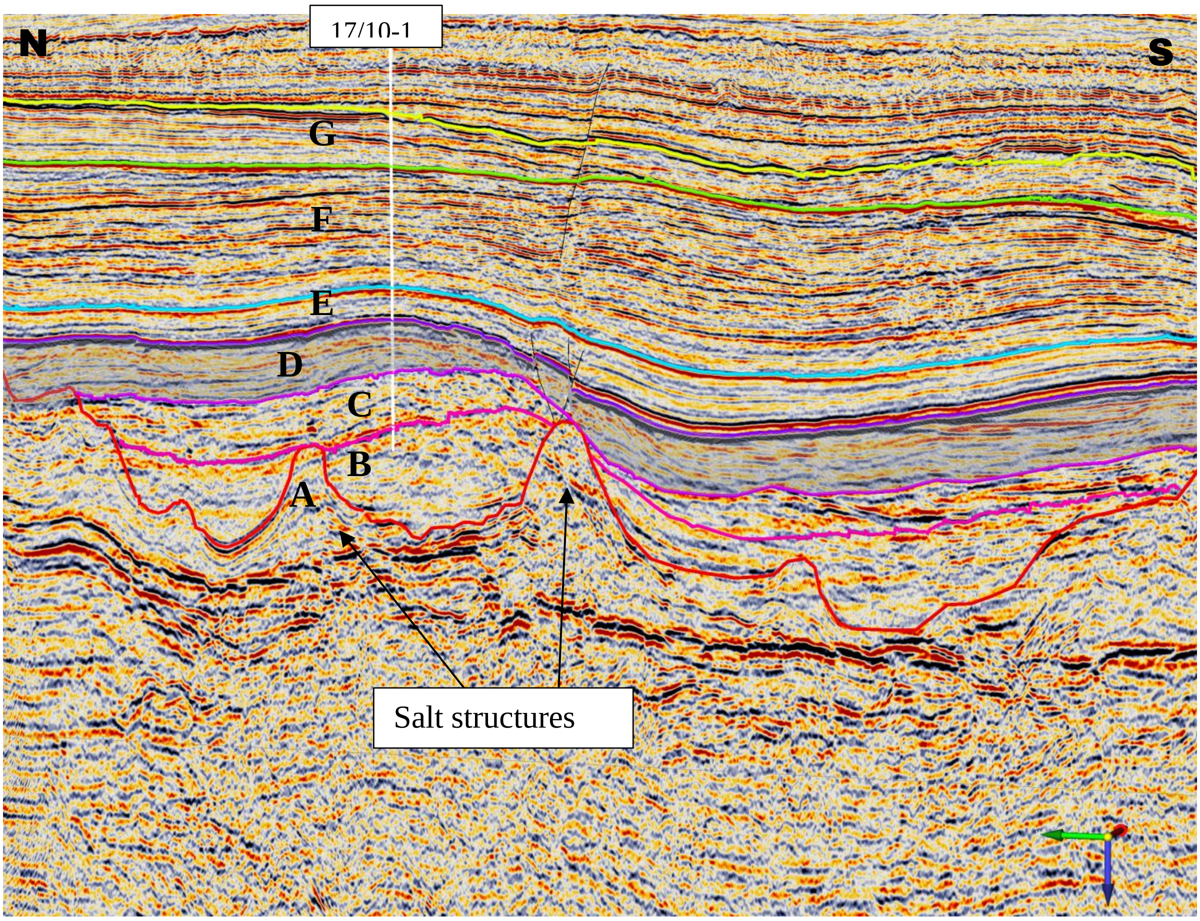


Figure 33. Interpretation of a part of seismic line UG97-210. Gassum Formation (D) highlighted in grey. Unit A: Zechstein Formation; Unit B: Smith Bank Formation; Unit C: Skaggerak Formation; Unit E: Boknfjord Group; Unit F: Cromer Knoll Group; Unit G: Shetland Group.

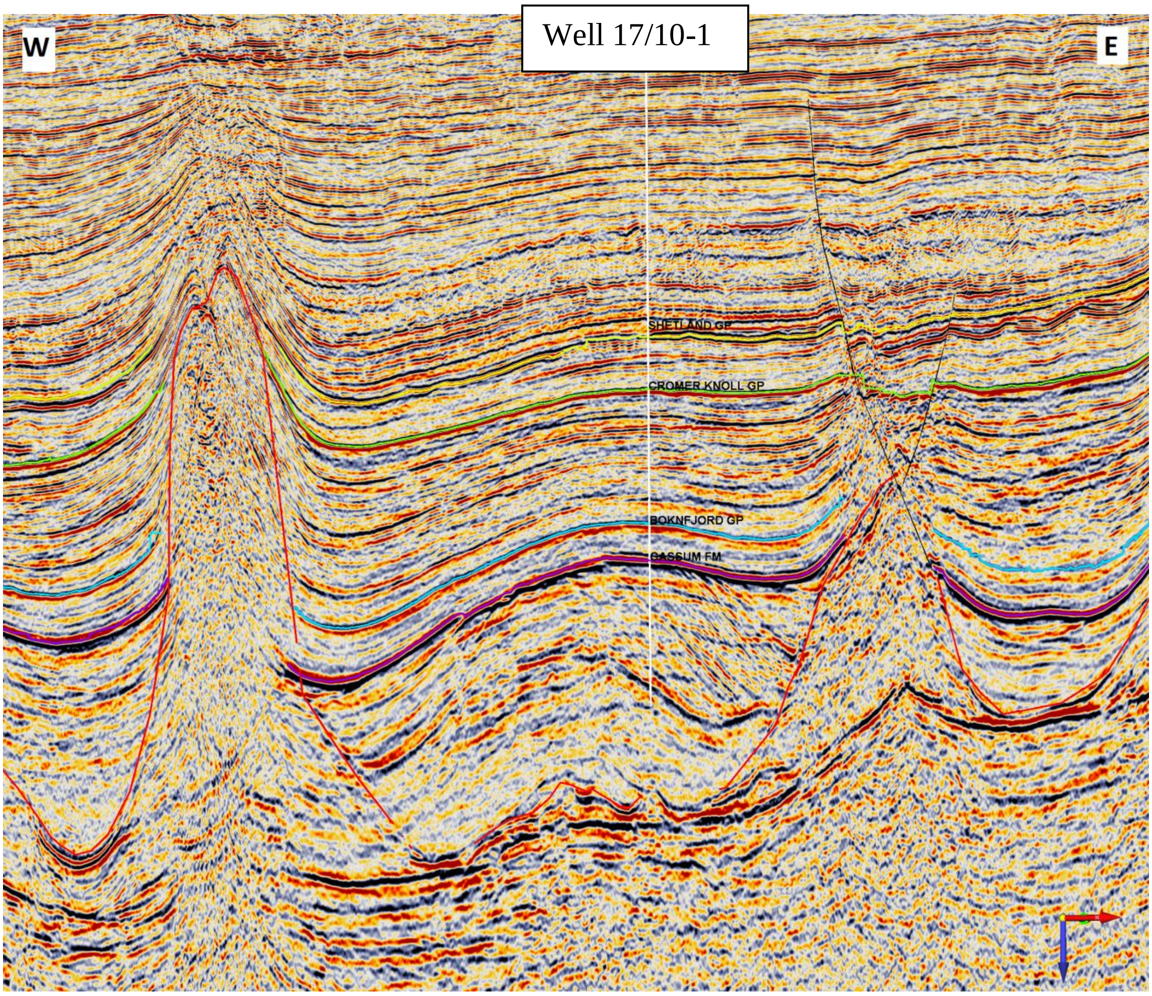


Figure 34 Interpretation of seismic line UGI98-126.

The reservoir is constrained on the east and west margins by salt ridges (or elongate salt pillows) and groups of salt diapirs that trend in an NNW-SSE direction. These trends have been recognised in the Norwegian-Danish Basin by others including Hospers et al. (1988) (Figure 35) which are postulated to have formed along basin margins.

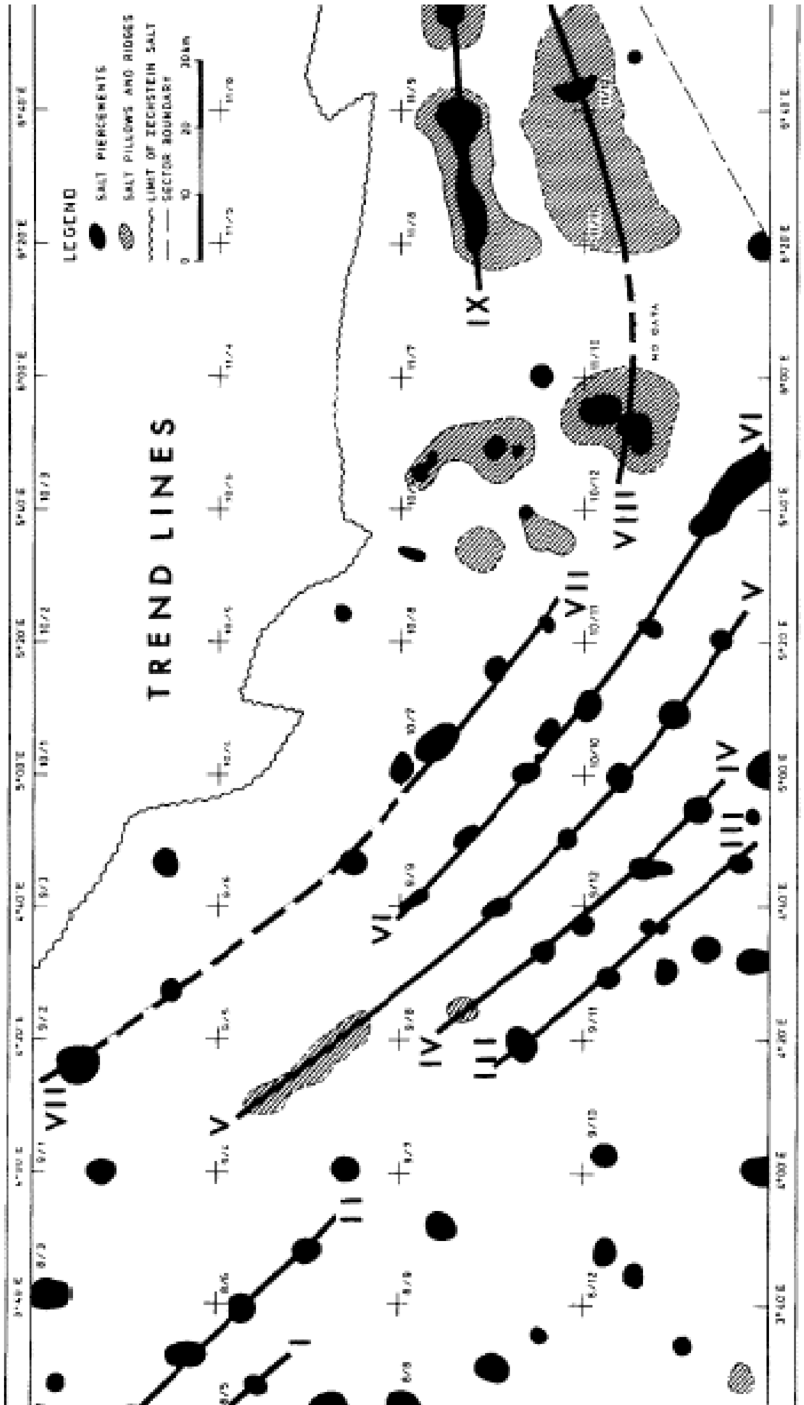


Figure 35. Map showing position of salt structures and the trend lines through those structures. Image source: Hospers et al. (1988).

6.3.6 Storage Capacity

As is the case with the CO_2 Atlas published by the Norwegian Petroleum Directorate, the method for calculating effective storage capacity for a potential CO_2 reservoir is shown in Figure 36.

$$M_{CO2e} = A \times h \times \phi \times \rho_{CO2r} \times S_{eff}$$

- M_{CO2e}: effective storage capacity
- A: area of aquifer
- h: average height of aquifer × average net to gross ratio
- ϕ: average reservoir porosity
- ρ_{CO2r}: CO_2 density at reservoir conditions
- S_{eff}: storage efficiency factor

Figure 36. Equation used for calculating effective storage capacity. Image Source: Vangkilde-Pedersen 2009.

Storage capacity has been calculated using the method outlined by Vangkilde-Pedersen (2009). It is important to distinguish between bulk volume estimates of regional aquifers and estimates for individual structural or stratigrahic traps. Using the above equation, storage capacity was calculated to be between 750 – 850 Mt.

A = 180 – 200 km2

h = 192 m (218 x 0.88)

Φ = 22%

ρ_{CO2} = 650 kg/m3

S_{eff} = 15%

Therefore:

M_{CO2e} = 750 – 850 Mt

Assumptions:

The potential CO_2 reservoir intersected by well 17/10-1 is a semi-closed acquifer and as such the "rule of thumb" approach was used to calculate the storage efficiency S_{eff} (Figure 37). The reservoir is semi-closed, bounded on two sides by the salt ridges. The reservoir quality is neither high or low but rather somewhere in between so the storage coefficient chosen was 15%.

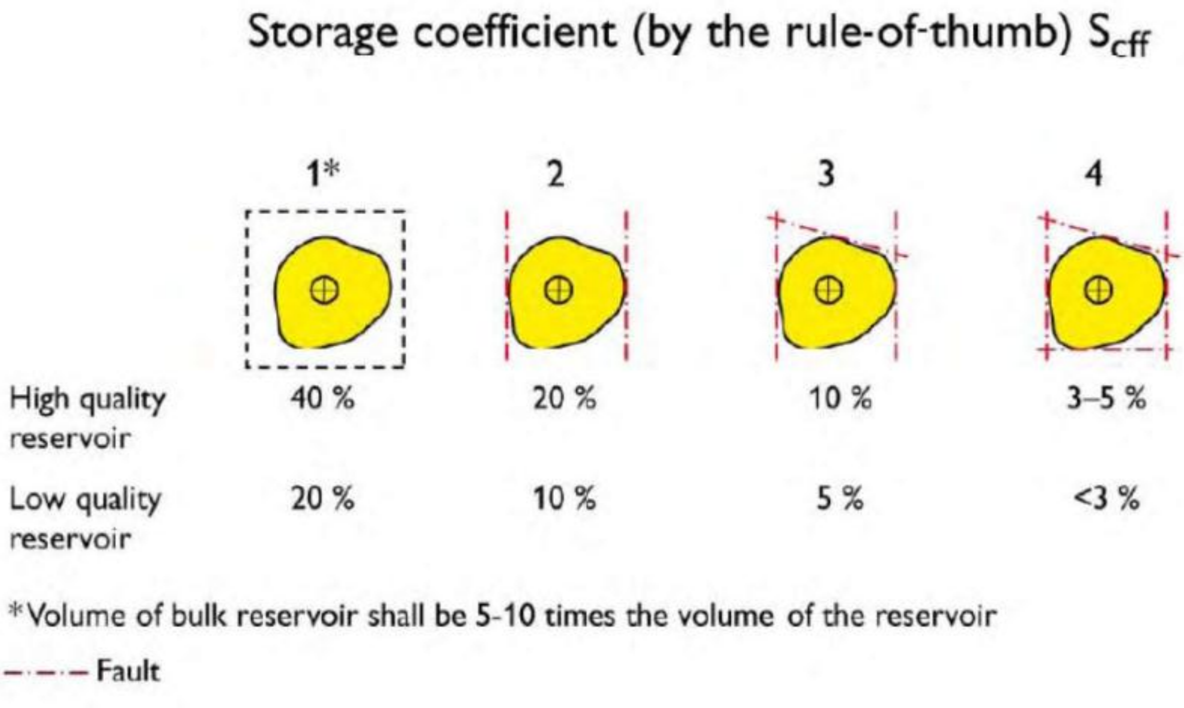


Figure 37. The rule of thumb recommended for estimating the storage efficiency factor (storage coefficient). Image source: Vangkilde-Pedersen 2009.

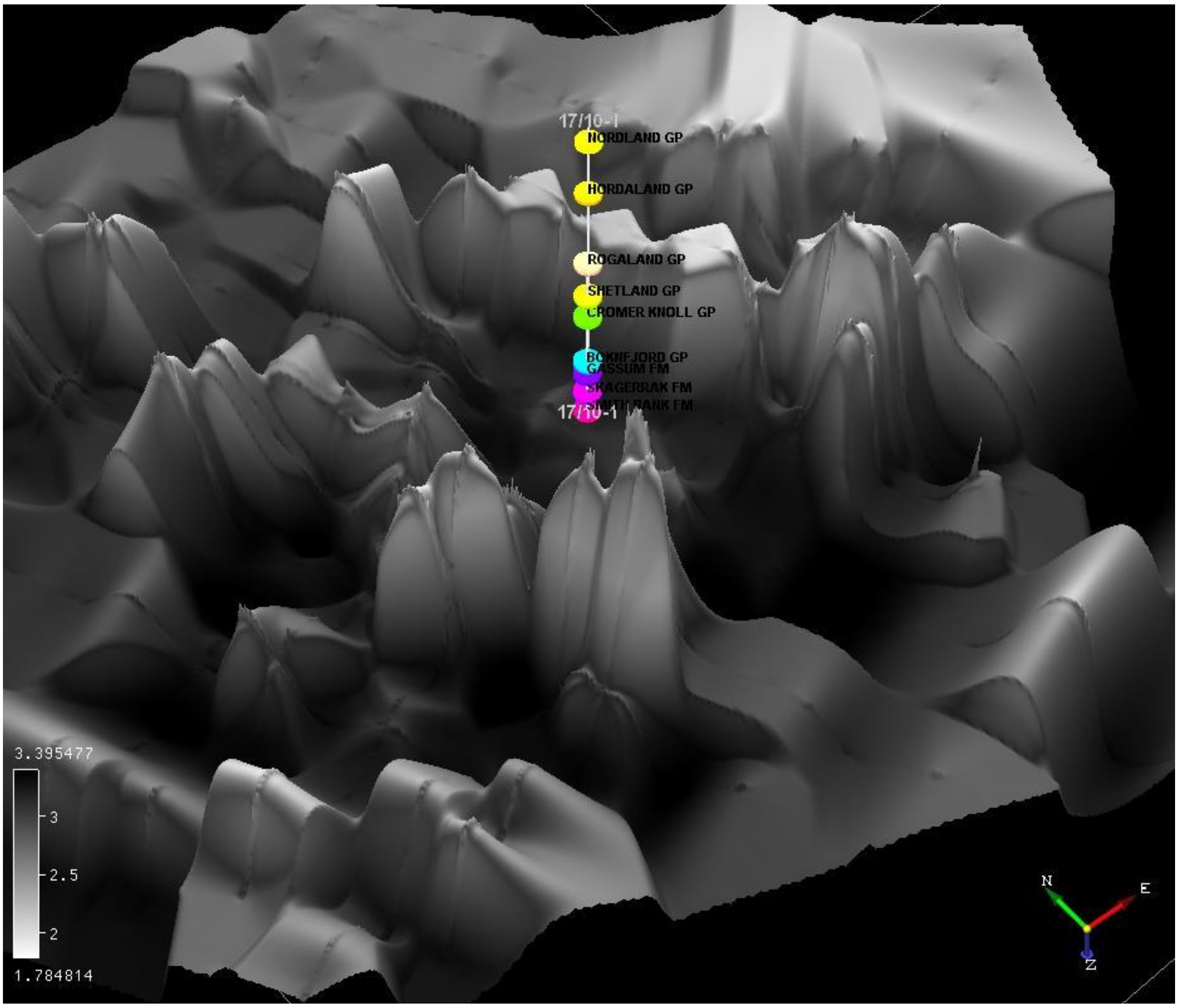


Figure 38. Top of the Zechstein Formation showing the numerous salt domes and diapirs in the vincinity of Well 17/10-1. Screenshot taken from Opendtect project.

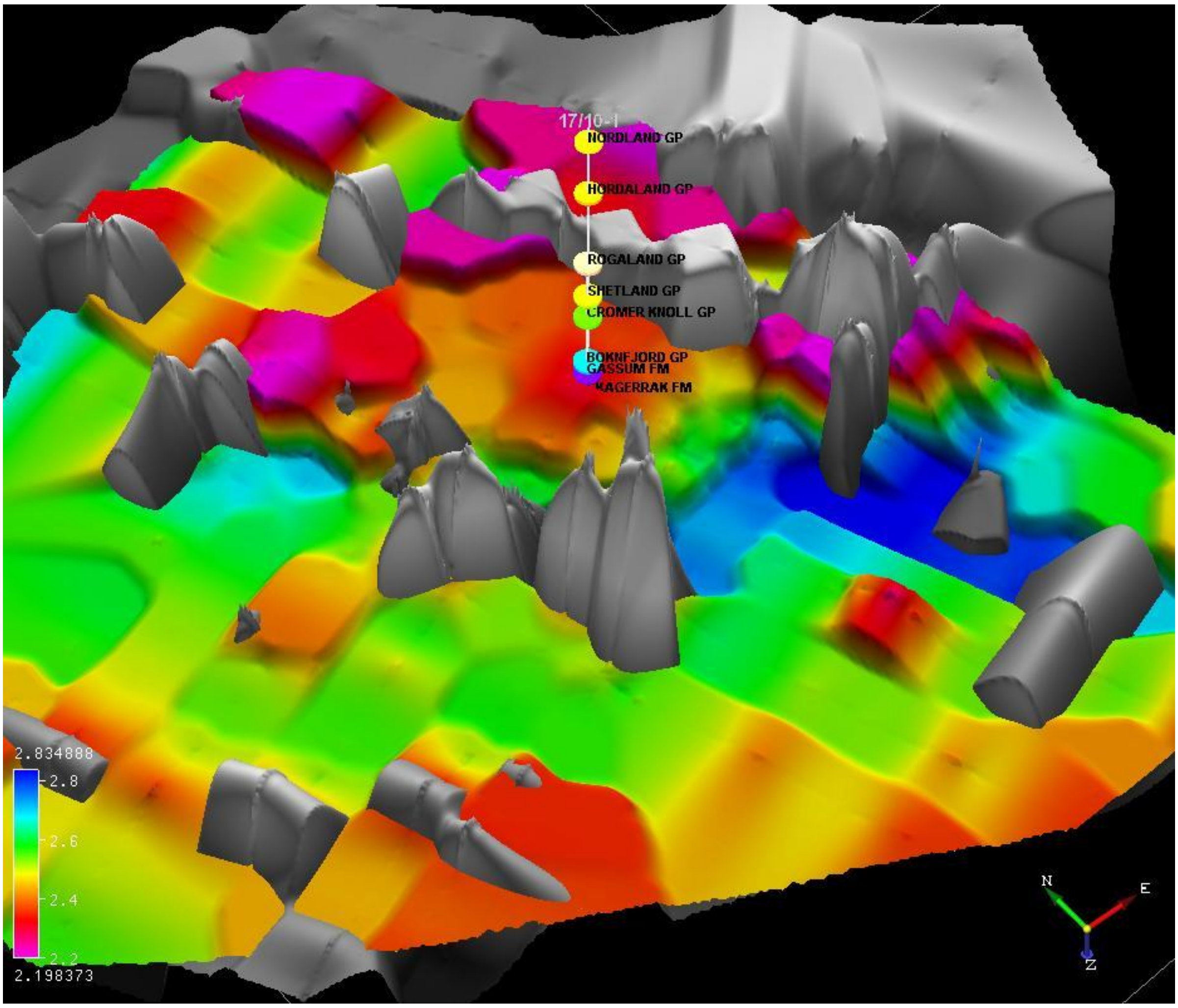


Figure 39. The Permian Zechstein Formation (greyscale horizon) intruding the overlying Gassum Formation (coloured horizon).

7. DISCUSSION

7.1 Discussion

An attractive option for the Sandnes / Bryne reservoir is the possibility of subsidizing a potential storage operation with oil production utilizing the Enhanced Oil Recovery (EOR) method. The reservoir was explored and tested for oil at the beginning of the eighties but was considered uneconomic and unlikely to be developed. However, if the production of the oil was in conjunction with CO2 storage, the prospect may well become economic.

From the geological well prognosis for well 18/10-1, it was noted that "the seismic character of the Jurassic sandstone does not vary from the 17/12-1 to 18/10-1". 17/12-1 is the BREAM discovery, which is in the planning phase and classified as Resource Class 4F. Therefore, it is reasonable to assume that the favourable reservoir properties could be extrapolated to the well 18/10-1 prospect examined as part of this project.

It is also noted that the depth of the Gassum Formation reservoir in the 17/10-1 prospect is deeper than the depth range recommended by NPD in the CO2 Atlas. Reservoirs deeper than 2500m are classified with a low score.

7.2 Limitations of this study

The nature of this study means that there is much estimation involved throughout the process. The estimation of porosity for example doesn't take into account the loss of porosity due to cementation and diagenetic alteration of minerals such as quartz and kaolinite.

Another important part of the evaluation process is studying flow behaviour of target reservoirs. Using computer simulations for modelling flow behaviour is an aspect of a potential CO2 storage site that needs to be considered in order to understand how the injected CO2 will behave 100 years, 1000 years 100000 years after injection as this is hoped to be long term / permanent storage of the CO2.

7.3 Salt structures

Due to the highly pervasive nature of the salt bodies and the effect of salt tectonics in both the Norwegian-Danish Basin and the Egersund Basin, huge regional CO_2 reservoirs like the

Utsira Formation being used by the Sleipner Project are not possible or at least too difficult to study and predict their behaviour. It is much more likely that there is the possibility of numerous more localised reservoirs being contained by these salt bodies. Examples of the various salt body forms are illustrated in the diagram below (Figure 40).

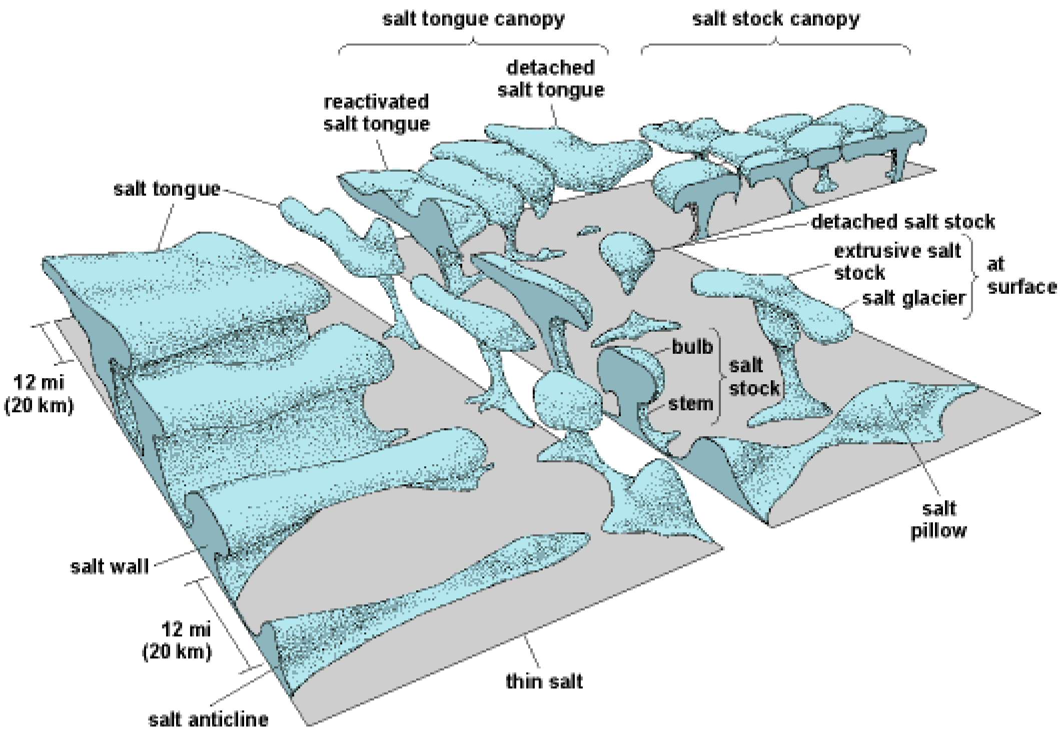


Figure 40. Various forms of salt bodies. (GEO4240 lecture slides).

8. CONCLUSION

- The Gassum Formation in the 17/10-1 prospect has moderate potential as a reservoir for the geological storage of CO_2. Using the NPD's criteria for assessing potential CO_2 storage reservoirs, the Gassum formation could neither be classed as having high potential or low potential, but rather falls somewhere in between. The depth of the reservoir is of most concern as it falls outside the optimal range of between 800m to 2500m. It is likely that there has been significant porosity reduction due to the burial depth as well as calcite cementation.

- It is unlikely that any reservoirs of sufficient capacity exist in the study area to warrant investment on the scale needed, or to store the volumes of CO_2 that could conceivably make an impact on anthropogenic CO_2 emissions. The 17/10-1 prospect was calculated to have a storage capacity of between 750 – 850 Mt of CO2, while the 18/10-1 prospect had a much smaller storage capacity at approximately 35 Mt of CO2. This was due to the much smaller area of the reservoir as well as being approximately half the thickness of the 17/10-1 prospect. By comparison, the Utsira Formation being used as a CO2 reservoir as part of the Sleipner Project has a storage capacity of approximately 1-10 Gt of CO2.

- Based on the wells analysed as part of this study, it is unlikely there is any suitable reservoirs in the Middle Jurassic sands of the Vestland Group or Upper Triassic sands in the Gassum Formation or Skagerrak Formation. Porosity and permeability results calculated from well data are mostly poor with slightly more positive results obtained from the wells 18/10-1 and 17/10-1.

- Results indicate there is limited potential for CO_2 storage in the study area but more detailed work needs to be done for this to be confirmed. Reservoir properties of the wells analysed were poor, and the halokinesis, while creating potential plays, also complicates the structure of the area. This makes it difficult to determine whether reservoirs are connected and makes seismic interpretation harder as the image quality deteriorates closer to the salt bodies.

9. REFERENCES

Akervoll, I. and Eirik Bergmo, P., 2010. CO2 EOR From Representative North Sea Oil Reservoirs, Sintef. SPE International Conference on CO2 Capture, Storage, and Utilization. New Orleans, Louisiana, USA. DOI 10.2118/139765-MS.

Björnsson, S. 1991. Imaging and understanding the lithosphere of Scandinavia and Iceland papers from a Nordic Symposium, S.l., Science Direct.

Brekke, H., Sjulstad, H. I., Magnus, C. and Williams, R. W. 2001. Sedimentary environments offshore Norway – an overview. *In:* Martinsen, O. J. and Dreyer, T. (eds.) *Sedimentary environments offshore Norway – Palaeozoic to Recent*. Norwegian Petroleum Society (NPF) Special Publication; No 10.

Chadwick, R A, Arts, R, Bernstone, C, May, F, Thibeau, S, and Zweigel, P. 2008. Best practice for the storage of CO2 in saline aquifers. Keyworth, Nottingham: British Geological Survey Occasional Publication No. 14.

Chandra, T. 2008. Permeability estimation using flow zone indicator from well log data. *7th International Conference & Exposition on Petroleum Geophysics.* Hyderabad.

Cope, J. C. W., Ingham, J. K. and Rawson, P. F., (Ed) 1992. Atlas of Palaeogeography and Lithofacies. *The Geological Society Memoir No. 13*.

CO2CRC, 2008. *Storage Capacity Estimation, Site Selection and Characterisation for CO2 Storage Projects*. Cooperative Research Centre for Greenhouse Gas Technologies, Canberra. CO2CRC. Report No. RPT08-1001. 52pp.

Deegan, C. E. and Scull, B. J. (compilers) 1977. A standard lithostratigraphic nomenclature for the Central and Northern North Sea. UK Institute of Geological Sciences, Report 77/25. The Norwegian Petroleum Directorate, NPD-Bulletin No. 1, 36 pp.

Doveton, J. H. 1986. Log analysis of subsurface geology. New York: Wiley Interscience. pp273.

Doveton, J. H., 2001. All Models are Wrong, but Some Models are Useful: "Solving" the Simandoux Equation. From Session J of the International Association for Mathematical Geology Conference, 2001, Cancun, Mexico.

IEA Greenhouse Gas R&D Programme, 2008. *Geologic Storage of Carbon Dioxide: Staying Safely Underground.* International Energy Agency (IEA).

Intergovernmental Panel on Climate Change*: IPCC Special Report on Carbon dioxide Capture and Storage (CCS)*. Chapter 5 Underground Geological Storage.

Flett et al., 2008. *Gorgon Project: Subsurface Evaluation of Carbon Dioxide Disposal under Barrow Island.* Society of Petroleum Engineers (SPE).

Fredriksen, S., Nielsen, S.B., Balling, N. 2001. A numerical dynamic model for the Norwegian– Danish Basin, *Tectonophysics*, **343**, 165-183.

Gabrielsen, R.H., Faerseth, R., Steel, R. J., Idil, S., Kløvjan, O. S. 1990. Architectural styles of basin fill in the northern Vking Graben. *In*: D.J. Blundell and A. D. Gibbs (eds.) *Tectonic evolution of the North Sea rifts*. New York, Oxford University Press, InternationalLithosphere Program Publication, **181**, 158-179.

Gabrielsen, R. H., Faleide, J. I., Pascal, C., Braathen, A., Nystuen, J. P., Etzelmuller, B. & O'Donnell, S. 2010. Latest Caledonian to Present tectonomorphological development of southern Norway. *Marine and Petroleum Geology,* 27**,** 709-723.

Glennie, K. W. and Underhill, J. R., 2009. Origin, Development and Evolution of Structural Styles, in Petroleum Geology of the North Sea: Basic Concepts and Recent Advances, Fourth Edition (ed K. W. Glennie), Blackwell Science Ltd, Oxford, UK. doi: 10.1002/9781444313413.ch2

Heeremans, M. and Faleide, J.I. 2004. Late Carboniferous - Permian tectonics and magmatic activity in the Skagerrak, Kattegat and the North Sea. *In*: Wilson, M., Neumann, E.-R., Davies, G.R., Timmerman, M.J., Heeremans, M., and Larsen, B.T. (eds) *Permo-Carboniferous Magmatism and Rifting in Europe.* Geological Society, London, Special Publications, **223**, 157-176.

Hermanrud, C., Eggen, S., Jacobsen, Carlsen, T., E. M. and Pallesen, S. 1990. On the accuracy of modelling hydrocarbon generation and migration: The Egersund Basin oil find, Norway. *Advances in Organic Geochemistry.* Vol. 16, Nos 1-3, pp. 389-399.

Hospers, J., Rathore, J. S., Jianhua, F., Finnstrom, E. G., and Holthe, J. 1988. Salt tectonics in the Norwegian-Danish Basin. *Tectonophysics,* 149, 35-60**.** Elsevier Science Publishers B.V., Amsterdam.

Hospers, J. and Holthe, J., 1984. Growth of salt-induced structures in the Norwegian-Danish Basin. *Tectonophysics,* 107, 81-104 81. Elsevier Science Publishers B.V., Amsterdam.

Kaasschieter, J.P.H.; Reijers, T.J.A. (Eds.), 1982. Petroleum Geology of the Southeastern North Sea and the Adjacent Onshore Areas.

Lyngsie, S.B., Thybo, H., Rasmussen, T.M., 2006. Regional geological and tectonic structures of the North Sea area from potential field modelling. *Tectonophysics* 413, 147–170, Elsevier.

Martins-neto, M. A. & Catuneanu, O. 2010. Rift sequence stratigraphy. *Marine and Petroleum Geology,* 27**,** 247-253.

Michelsen, O. & Nielsen, L. H. 1993. Structural development of the Fennoscandian Border Zone, offshore Denmark. *Marine and Petroleum Geology,* 10**,** 124-134.

Muir-Wood, R., 1987. Major fault systems on the Norwegian Continental Shelf. In: Løken, T. (eds.) *Earthquake loading on the Norwegian Continental Shelf – ELOCS Report 1-4.* Norwegian Geotechnical Institute.

Nielsen, L.H., Weibel, R., Kristensen, L., Dybkjaer, K., Japsen, P., Olivarius, M., Bidstrup, T., Mathiesen, A., 2011. Contributions to predictions of stratigraphy and reservoir properties in Eastern Norwegian-Danish Basin. Geological Survey of Greenland and Denmark.

Norwegian Petroleum Directorate. 2011. CO2 Storage Atlas: Norwegian North Sea.

Norwegian Petroleum Directorate, 2012. http://npd.no/en

Norwegian Petroleum Directorate, 2012. Fact Pages. http://factpages.npd.no/factpages

Olsen, R. C. 1979. Lithology Well 17/10-1. *NPD Paper No. 21*. Norwegian Petroleum Directorate, Stavanger.

Pegrum, R. M. 1984. The extension of the Tornquist Zone in the Norwegian North Sea. *Geologiska Föreningen i Stockholm Förhandlingar,* 106**,** 394-395.

Sørensen, S. & Tangen, O. H. 1995. Exploration trends in marginal basins from Skagerrak to Stord. *In:* hanslien, S. (ed.) *Norwegian Petroleum Society Special Publications.* Elsevier.

Vangkilde-Pedersen, T. 2009. Aquifer capacity estimation. *GeoCapacity results and the future of geological storage of CO2.* EU GeoCapacity open final conference held in Copenhagen, Denmark.

Vollset, J. and Dore, A. G. (Ed.), 1984. *A revised Triassic and Jurassic lithostratigraphic nomenclature for the Norwegian North Sea*. NPD Bulletin No 3. Norwegian Petroleum Directorate

Ziegler, P.A. 1990. Geological atlas of Western and Central Europe. Shell International Petroleum Maatschappij B.V., Geological Society, Bath.