NORWEGIAN PETROLEUM DIRECTORATE

CO_2 STORAGE ATLAS

NORWEGIAN NORTH SEA

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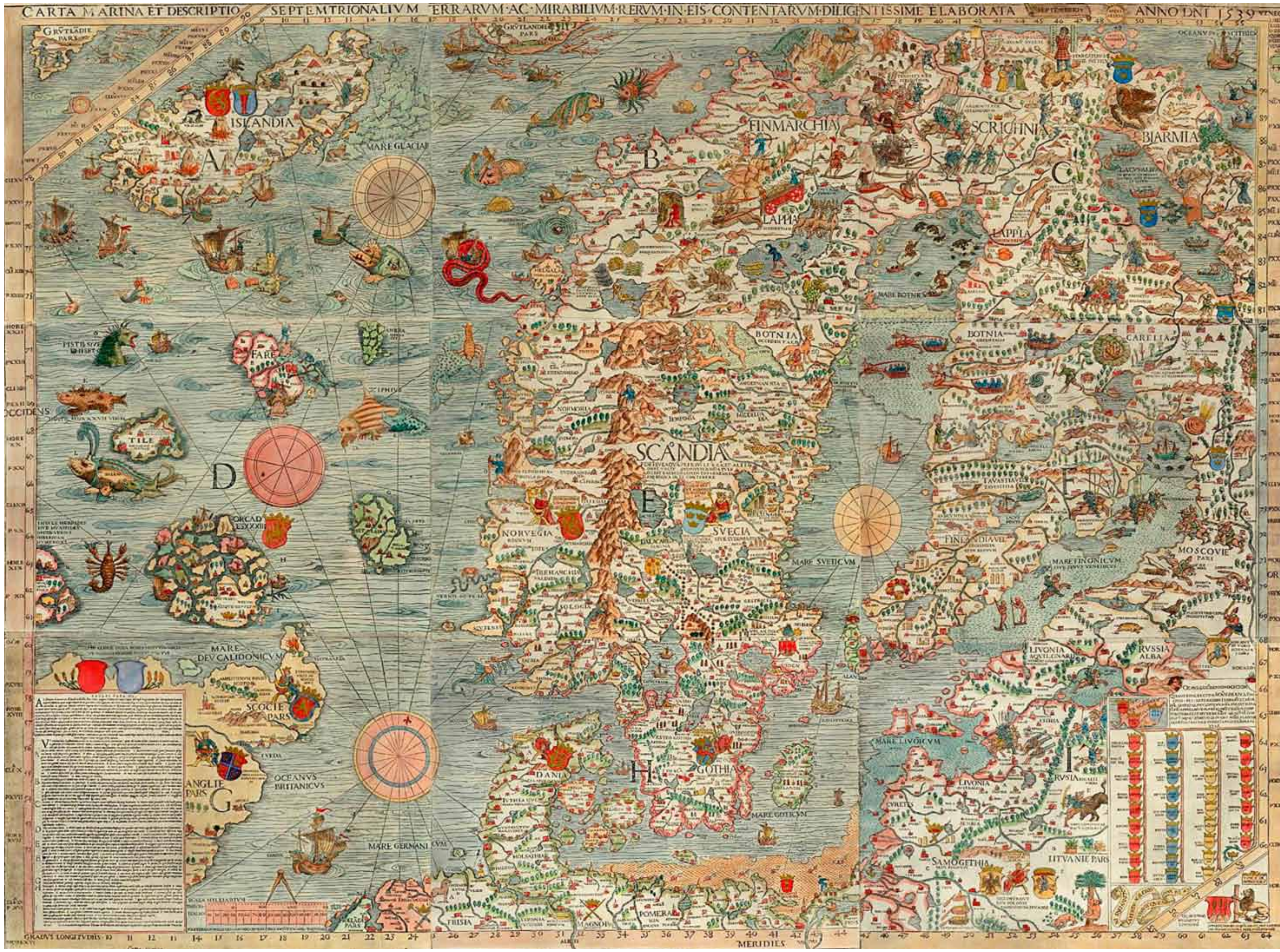

Norway's (Scandinavia's) first resource map, Olaus Magnus, 1539

CO_2 STORAGE ATLAS

NORWEGIAN NORTH SEA

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Preface

The CO_2 Storage Atlas of the Norwegian part of the North Sea has been prepared by the Norwegian Petroleum Directorate, on request by the Ministry of Petroleum and Energy. One of the key objectives for this atlas is to provide input on where it is possible to implement safe long-term storage of CO_2, and how much capacity there is for geological storage of CO_2.

This study is based on detailed work on all relevant geological formations and hydrocarbon fields in the Norwegian part of the North Sea. The work is based on several studies as well as data from more than 40 years of petroleum activity in the North Sea basin.

21 geological formations have been individually assessed, and grouped into saline aquifers. The aquifers were evaluated with regard to reservoir quality and presence of relevant sealing formations. Those aquifers that may have a relevant storage potential in terms of depth, capacity and injectivity have been considered. Structural maps and thickness maps of the aquifers are presented in the atlas, and were used to calculate pore volumes. Several structural closures have been identified, some were further assessed.

A new geological study of the largest aquifer in the Norwegian sector of the North Sea, the Utsira-Skade aquifer, is included. A study of the CO_2 storage potential in the Frigg field is provided, together with a summary of the CO_2 storage potential in abandoned oil and gas fields. CO_2 storage in enhanced oil recovery projects is also discussed.

The methodology applied for estimating storage capacity is based on previous assessments, but the storage efficiency factor has been assessed individually for each aquifer based on simplified reservoir simulation cases. The assessed aquifers have been ranked according to guidelines which have been developed for this study.

This atlas is based on large amount of data from seismic, exploration and production wells, together with production data. This data base is essential for the evaluation and documentation of geological storage prospectivity.

We hope that this study will fulfil the objective that the information can be useful for future exploration for CO_2 storage sites.

We have not attempted to assess the uncertainty range in the atlas, but we have made an effort to document the methods and main assumptions.

The assessments described in this atlas will be accompanied by a GIS data base (geographical information system). This will be published on the NPD web site spring 2012.

Acknowledgements

This CO_2 Storage Atlas has been developed by a team at the Norwegian Petroleum Directorate. The support from colleagues through discussions, and the support from the Ministry of Petroleum and Energy have been of great importance. Sincere thanks to Tor Eidvin, Bernt Egeland, Asbjørn Thon, Robert Williams and Van T. H. Pham for constructive contributions. The Norwegian CO_2 Storage Forum has contributed with its expertise in our meetings over the last two years. Ola Eiken, Statoil, Per Aagaard, University of Oslo, Erik Lindeberg, SINTE F, Svein Eggen, Climit/Gassnova, Rolf Birger Pedersen, University of Bergen, Mike Carpenter, DnV and experts on well integrity from the Petroleum Safety Authorities have contributed with texts and figures to this atlas. GEUS has made important contributions to improve our understanding of the geology of the Norwegian-Danish Basin and the Skagerrak area. AGR has contributed to the reservoir modeling related to CO_2 storage.

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1. Introduction

1. Introduction

Production of power and other use of fossil energy is the largest source of greenhouse gas emissions globally. Capture and storage of CO_2 in geological formations emerges as an important potential measure to reduce global emissions. The Norwegian government places great emphasis on Carbon Capture and Storage (CCS) as a measure to reduce CO_2 emissions. The government has set ambitious goals for achieving CO_2 capture at gas fired power plants and for establishing a chain for transport and injection of CO_2.

In its Special Report on Carbon Dioxide Capture and Storage (2005), the United Nations Intergovernmental Panel on Climate Change (IPCC) concludes that capture and storage of CO_2 may account for as much as one half of emission reductions in this century. However, major challenges must be solved before this potential can be realised. The IPCC report points out that there is as yet no experience from capture of CO_2 from large coal and gas power plants.

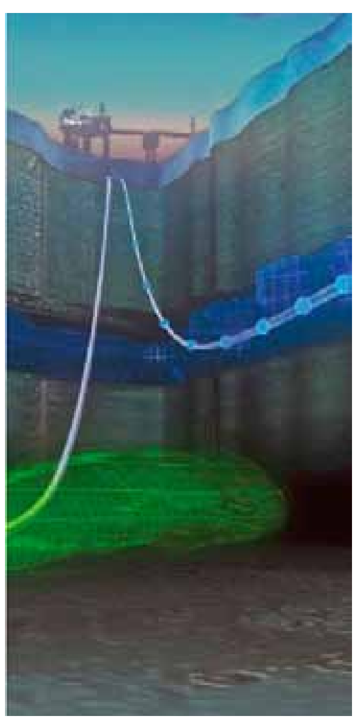
Norway has extensive experience in storage of CO_2 in geological structures. Since 1996, approximately one million tonnes of CO_2 per year have been separated from gas production on the Sleipner Vest field in the North Sea for storage in Utsira, a geological formation 1000 metres below the seabed. In connection with treatment of the well stream from the Snøhvit field and the LNG production on Melkøya, there is capacity for separation and storage of 700,000 tonnes of CO_2 in a reservoir 2 600 metres below the seabed.

There is significant technical potential for storing CO_2 in geological formations around the world. Producing oil and gas fields, abandoned oil and gas fields and other formations such as saline aquifers are all candidates for such storage. Storage in reservoirs that are no longer in operation is a good solution in terms of geology because these structures are likely to be impermeable after having held oil and gas for millions of years. Other formations are also considered to be secure storage alternatives for CO_2.

Environmentally sound storage of CO_2 is a precondition for a successful CCS chain. Consequently, the mapping, qualification and verification of storage sites is indispensable for CCS as a climate change mitigation measure. Geological formations offshore Norway are expected to be well-suited for storing large quantities of CO_2. It is important to have the best possible understanding of what can be the CO_2 storage potential.

These factors necessitate an enhanced effort within the mapping and investigation of CO_2 storage sites. The production of this CO_2 storage atlas is at the very centre of this effort, and the atlas will be a key component in the development of aquifers at the Norwegian Continental Shelf as storage sites for CO_2.

Various Norwegian research institutions and commercial enterprises have extensive experience and competence within CO_2 storage.



Statoil

***Sleipner:** More than 13 million tonnes of carbon dioxide are now stored in the Utsira formation in the North Sea. Every year since 1996, one million tonnes of carbon dioxide has been captured from natural gas production at the Sleipner field, and stored in an aquifer more than 800 metres below the seabed. The layer contains porous sandstone filled with saline water.*

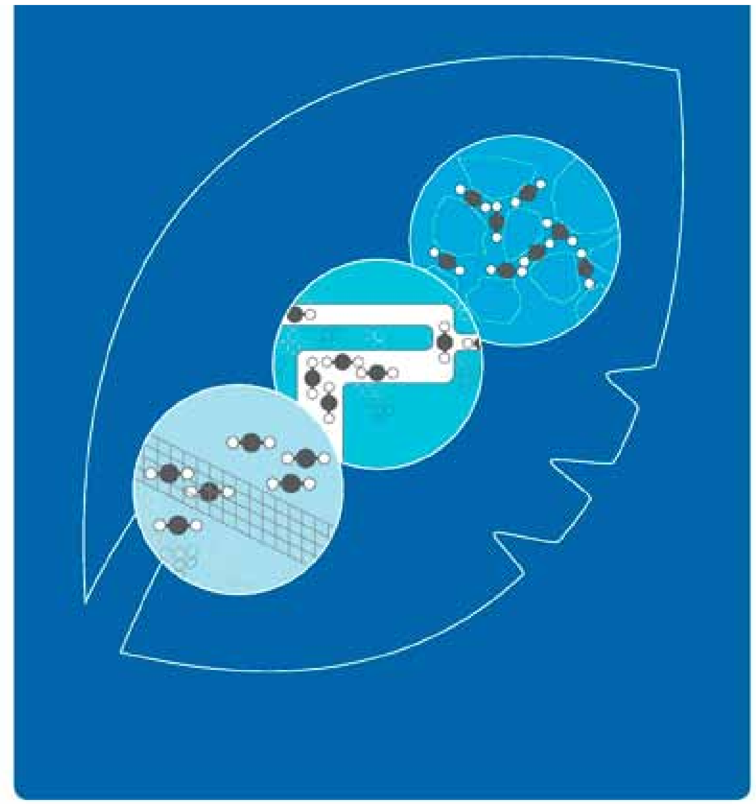
***Snøhvit:** There is capacity for separation and storage of 700 000 tonnes annually in water saturated sandstone reservoirs under the Snøhvit Field in the Barents Sea. A shale cap which lies above the sandstone will seal the reservoir and ensure that the CO_2 stays underground.*

1. Introduction

The CLIMIT program — by Svein Eggen, Climit / Gassnova

The CLIMIT program was established by the Ministry of Petroleum and Energy to promote technology for carbon capture and storage with the following objectives:

Accelerate the commercialization of CO_2 sequestration through economic stimulation of research, development and demonstration



The program is administered by Gassnova in cooperation with the Norwegian Research Council. The Norwegian Research Council is responsible for research projects, and Gassnova for prototype and demonstration projects.

By supporting testing and demonstration projects, Gassnova will contribute to the development of cost-effective and innovative technology concepts for CO_2 capture. This includes knowledge and solutions for:

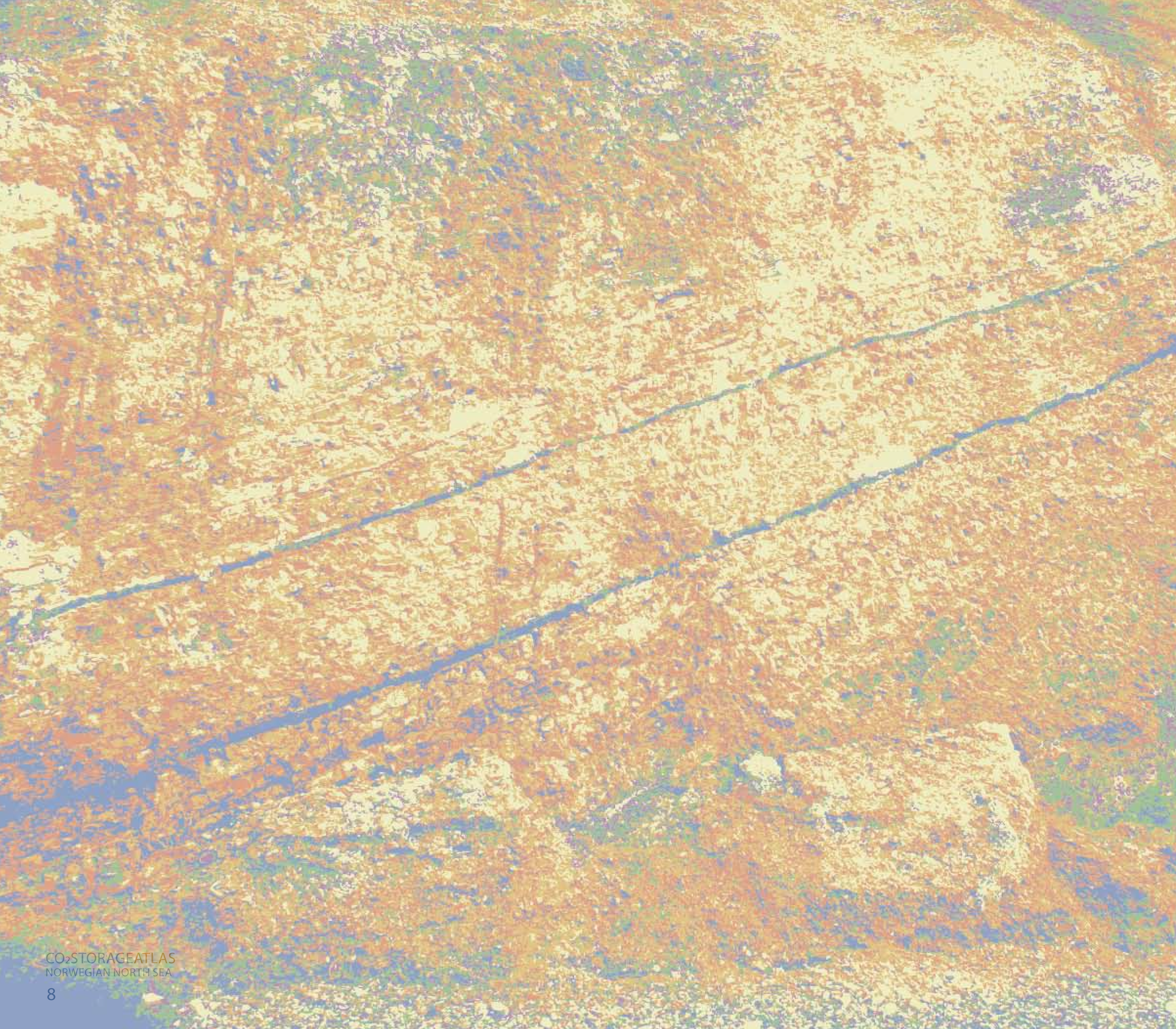
- CO_2 capture before, during or after power production
- Compression and handling of CO_2
- Transport of CO_2
- Long-term storage of CO_2 in terms of injection, storing or other application areas

Gassnova will focus on co-funding projects that are considered to have a clear commercial potential and that include a market-based business plan. A detailed description of the program strategy is found in the program plan on *www.climit.no*

For investment in CO_2 storage, the following main objectives have been identified:

- Develop and verify the knowledge and technology for safe and cost-effective storage and monitoring of CO_2.
- Help develop and verify commercially viable methods, service concepts and technologies.
- Contribute to increased knowledge on geological storage.

The primary focus for the work on CO_2 storage is to support the development of geological storage of CO_2. This involves storage in water-bearing formations located deep enough to keep the CO_2 in a dense phase. Through the petroleum industry and our storage options on the shelf, Norway is in a good position to develop a competitive industry that can serve a future CO_2 storage market. CLIMIT wants to support such a development.



2. Petroleum activity in the North Sea

2. Petroleum activity in the North Sea

The year 2011 marks the 45th anniversary of the arrival of *Ocean Traveler* in Norway and the spudding of the first well on the Norwegian Continental Shelf (NCS), and the 40th anniversary of the start of oil production from the Ekofisk field in the North Sea.

In May 1963, the Norwegian government proclaimed sovereignty over the NCS. A new act stipulated that the State was the landowner, and that only the King (Government) could grant licenses for exploration and production.

With the discovery of the Ekofisk field in 1969, the Norwegian oil and gas adventure started in earnest. Production from the field began on 15 June 1971. During the following years, several large discoveries were made in the North Sea. In the 1970s the exploration activity was concentrated in this area, but the shelf was also gradually opened northwards. Only a limited number of blocks were announced for each licensing round, and the most promising areas were explored first. This led to world class discoveries. Production from the North Sea has been dominated by the large fields Ekofisk, Statfjord, Oseberg, Gullfaks and Troll. These fields have been, and are still, very important for the development of petroleum activities in Norway. The large field developments have led to the establishment of infrastructure, enabling tie-in of a number of other fields.

Currently, 70 fields are in production on the NCS. Twelve fields are not in production as of 31 December 2010. However, there are re-development plans for some of these abandoned fields.

Production on the NCS is still high. Norway was in 2010 the world's seventh largest exporter of oil and the second largest exporter of natural gas. Oil production has declined since the peak production in 2001 and is expected to decline further. Gas production continues to increase, but this will not prevent a decline in total production on the shelf.

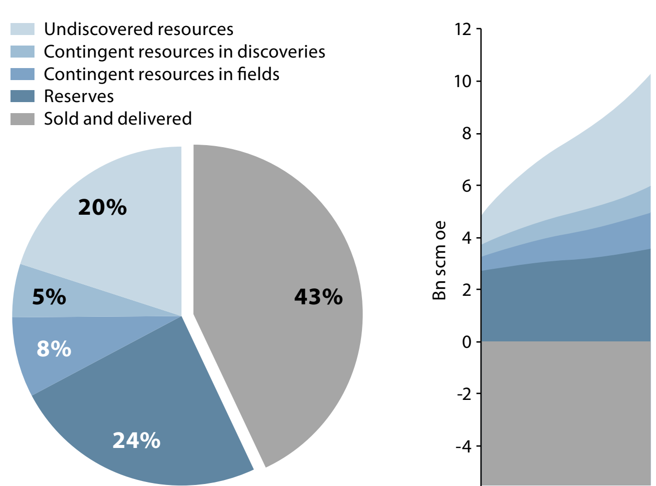
The North Sea is the best-mapped area of the NCS. Many wells have been drilled and the geology is well known. Uncertainty in our estimates for undiscovered resources in the North Sea is accordingly lower than for the other areas on the shelf. Although well explored with many large discoveries, the North Sea still has a substantial potential. Most discoveries since 2006 have been made in Jurassic and Triassic plays. Substantial volumes of both gas and oil have been found in the Triassic to Middle Jurassic play in the northern North Sea sector, and some of the largest fields on the NCS belong to this play.

Current production and future opportunities in the southern part of the North Sea are linked to the chalk reservoirs in the area. The area is a mature petroleum province with limited undiscovered resources. The majority of today's production comes from the Ekofisk, Eldfisk, Tor, Valhall and Hod chalk fields. Together, these fields will still contain very significant oil volumes when production is scheduled to cease according to current plans. There are a number of shut-down chalk fields with low recovery rates in the area, as well as discoveries that have not yet been developed.

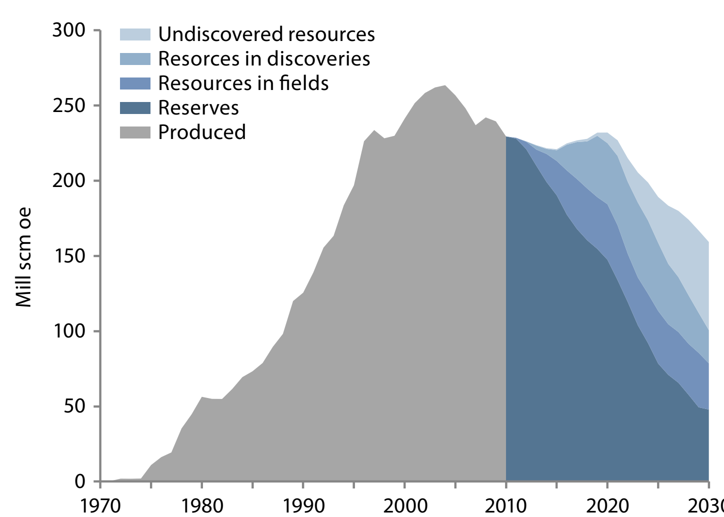
The central part of the North Sea has a long history of petroleum activity. The first development in the area was the Frigg gas field which produced for nearly 30 years before it was shut down in 2004. Sleipner is also an important hub for the Norwegian gas transport system, as both the UK market and the Continental market can be reached. Sleipner also has facilities designed to reduce the CO_2 content of the gas. For nearly 15 years, the CO_2 extracted from the Sleipner well stream has been stored under the seabed, yielding important experience and knowledge about subsurface storage of CO_2.

The central North Sea area is characterized with discoveries in many different types of petroleum reservoirs. The Utsira High is an interesting area in central North Sea where mainly oil has been discovered. Exploration activity has taken place since 1967 and the geology is well-known. Although the Utsira High is considered a mature area, new types of reservoirs have been discovered here in the last five years. The structure in which the 16/2-6 ("Avaldsnes") discovery was made during 2010 extends into the neighbouring licence, where the 16/2-8 ("Aldous Major South") find was made in August 2011. Although that discovery still needs to be appraised, the area might contain so much oil that it enters the top 10 list of discoveries on the NCS and might prove the biggest find there since the 1980s.

Oil and gas have been produced in the northern part of the North Sea since the late 1970s. There are significant remaining reserves and resources in the area, both

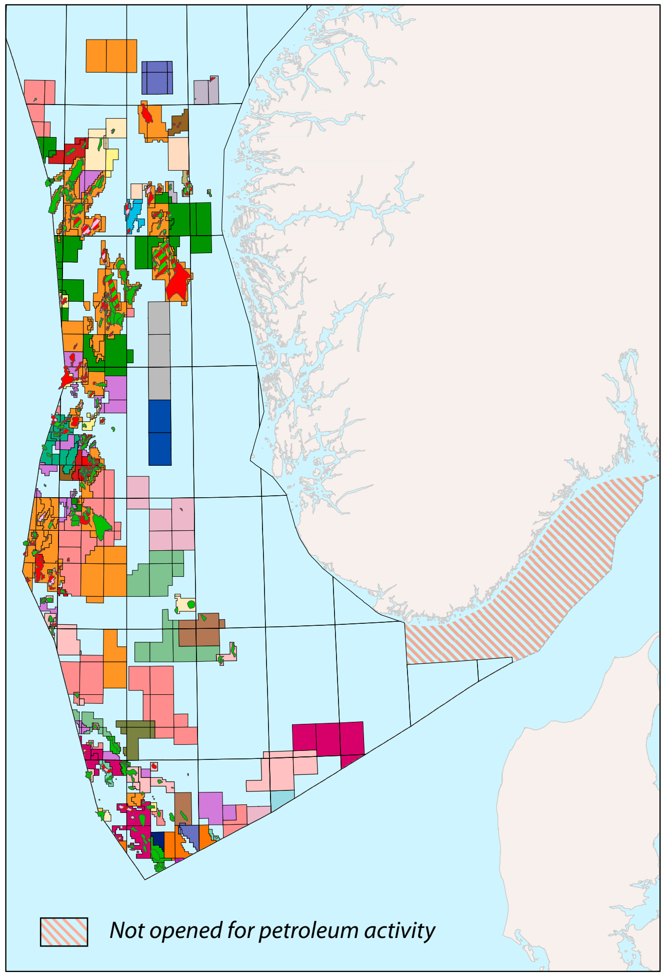


Distribution of total recoverable petroleum resources at 31December 2010, including the uncertainty range



Historical petroleum production and forecast 2030

2. Petroleum activity in the North Sea



Licenses and fields

Pipelines

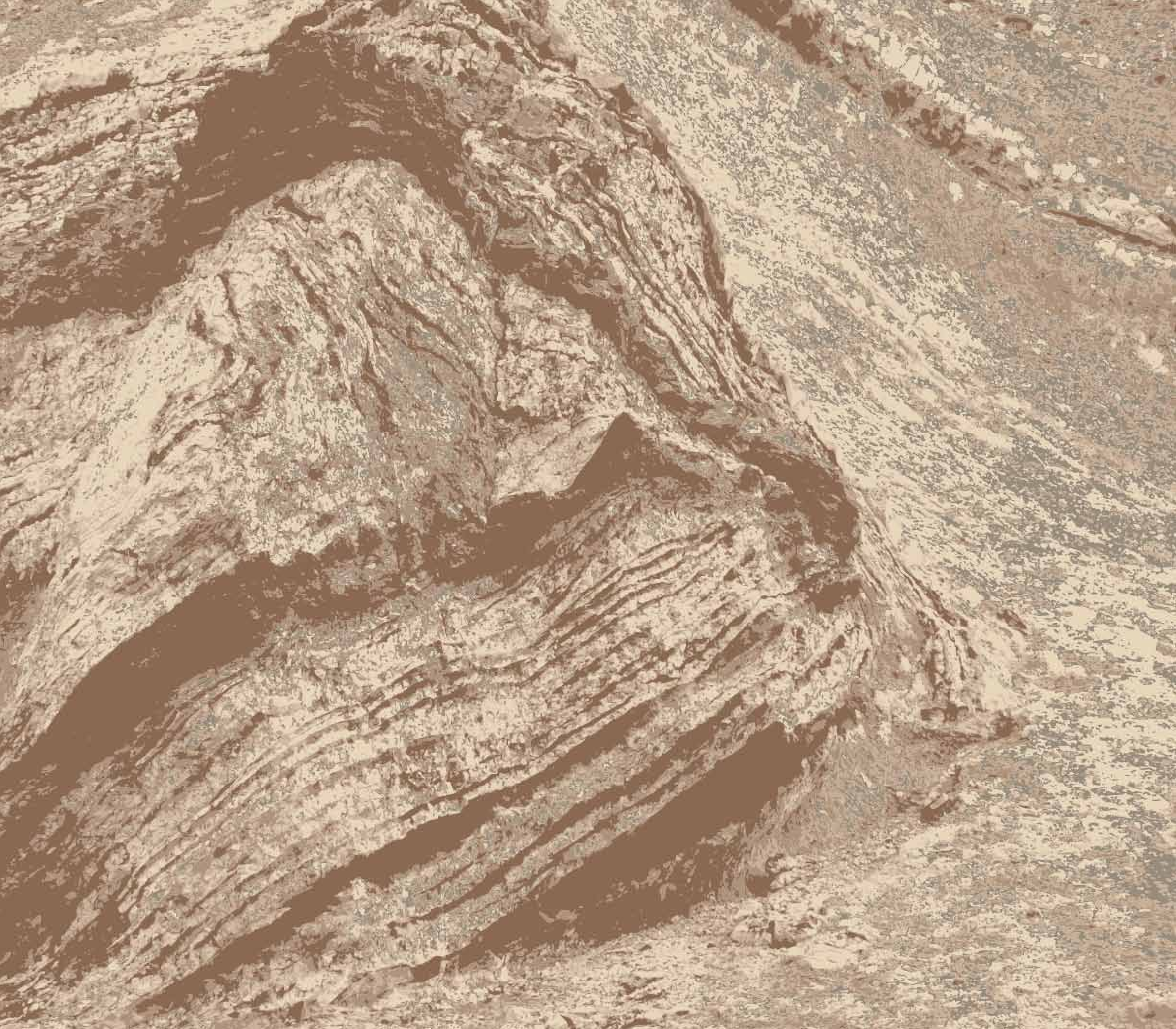
in fields and discoveries. The northern part of the North Sea consists of two main petroleum provinces: Tampen and Oseberg/Troll.

Exploration activity on the NCS has been high in recent years, with extensive seismic surveying and a large number of exploration wells. Maintaining a high level of exploration activity will also be necessary in the years to come, in order to clarify the potential of the undiscovered resources and to make new discoveries which can be developed.

The fields and discoveries are related to the burial of the Upper Jurassic source rock. In the Norwegian-Danish Basin, Stord Basin and southern part of the Horda platform, it is considered that petroleum generation has been low and oil discoveries are related to the very deepest part of these areas.

Norway's gas pipelines have a total length of ca. 8000 kilometres. The gas flows from production installations to process plants, where natural gas liquids are separated out and exported by ship.

The remaining dry gas is piped on to receiving terminals in continental Europe and the UK. There are four receiving terminals for Norwegian gas on the Continent; two in Germany, one in Belgium and one in France. In addition, there are two receiving terminals in the UK. Norwegian gas is important for the European energy supply and is exported to all the major consumer countries in Western Europe. Norwegian gas export covers close to 20 per cent of European gas consumption. The transport capacity in the Norwegian pipeline system is currently about 120 billion scm per year.



3. Methodology

3.1 Geological storage

Depending on their specific geological properties, several types of geological formations can be used to store CO_2. In the North Sea Basin, the greatest potential capacity for CO_2 storage will be in deep saline-water saturated formations or in depleted oil and gas fields.

CO_2 will be injected and stored as a supercritical fluid. It then migrates through the interconnected pore spaces in the rock, just like other fluids (water, oil, gas).

To be suitable for CO_2 storage, saline formations need to have sufficient porosity and permeability to allow large volumes of CO_2 to be injected in a supercritical state at the rate it is supplied at. It must further be overlain by an impermeable cap rock, acting as a seal, to prevent CO_2 migration into other formations or to sea.

CO_2 is held in-place in a storage reservoir through one or more of five basic trapping mechanisms: stratigraphic, structural, residual, solubility, and mineral trapping. Generally, the initial dominant trapping mechanisms are stratigraphic trapping or structural trapping, or a combination of the two.

In residual trapping, the CO_2 is trapped in the tiny pores in rocks by the capillary pressure of water. Once injection stops, water from the surrounding rocks begins to move back into the pore spaces that contain CO_2. As this happens, the CO_2 becomes immobilized by the pressure of the added water.

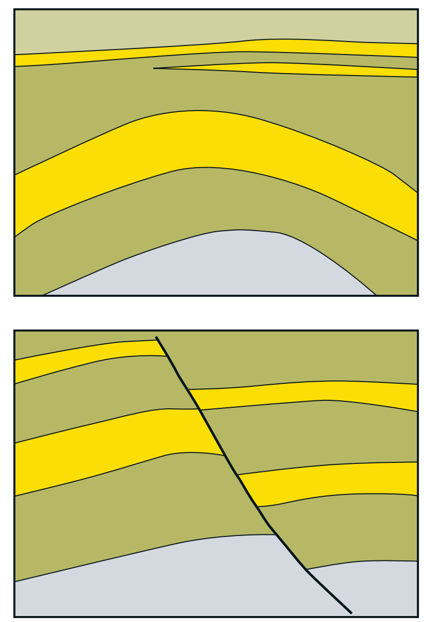
Much of the injected CO_2 will eventually dissolve in the saline water, or in the oil that remains in the rock. This process, which further traps the CO_2, is solubility (or dissolution) trapping. Solubility trapping forms a denser fluid which may sink to the bottom of the storage formation. Depending on the rock formation, the dissolved CO_2 may react chemically with the surrounding rocks to form stable minerals. Known as mineral trapping, this provides the most secure form of storage for the CO_2, but it is a slow process and may take thousands of years.

Porosity is a measure of the space in the rock that can be used to store fluids. Permeability is a measure of the rock's ability to allow fluid flow. Permeability is strongly affected by the shape, size and connectivity of the pore spaces in the rock. By contrast, the seals covering the storage formation typically have low porosity and permeability so that they will trap the CO_2. Another important property of the storage site is injectivity, the rate at which the CO_2 can be injected into a storage reservoir.

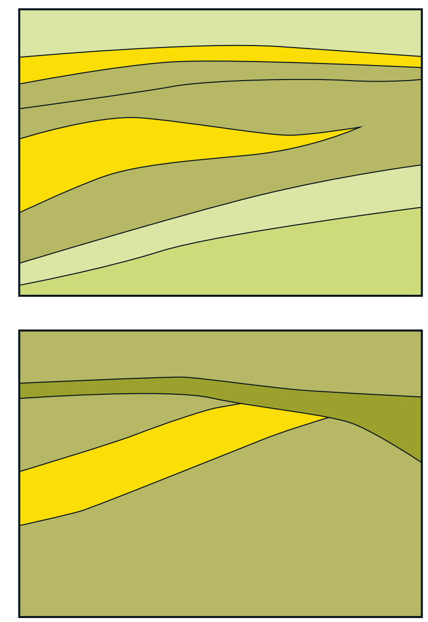
Oil and gas reservoirs are a subset of saline formations, and therefore they generally have similar properties. That is, they are permeable rock formations acting as a reservoir with an impermeable cap rock acting as a seal.

The reservoir is the part of the saline formation that is generally contained within a structural or stratigraphic closure (e.g. an anticline or dome). Therefore it is also able to physically trap and store a concentrated amount of oil and/or gas.

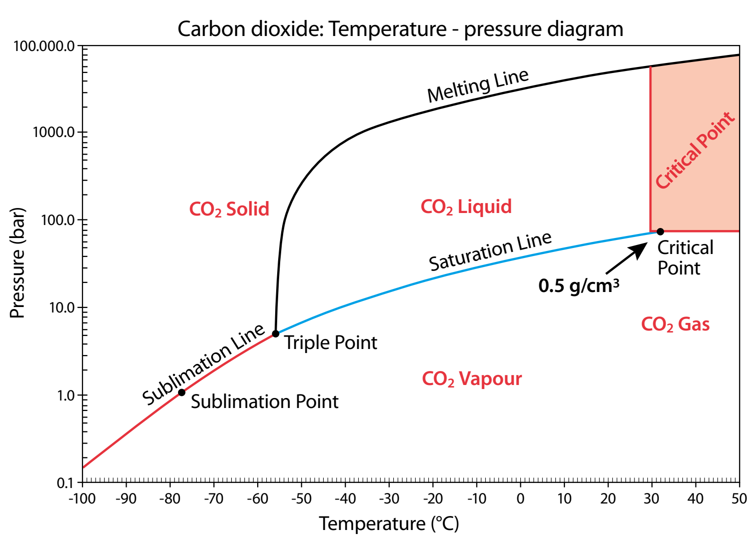
There is great confidence in the seal integrity of oil and gas reservoirs with respect to CO_2 storage, as they have held oil and gas for long time periods. However, a drawback of such reservoirs compared with deep saline aquifers is that they are penetrated by many wells. Care must be taken to ensure that exploration and production operations have not damaged the reservoir or seal.

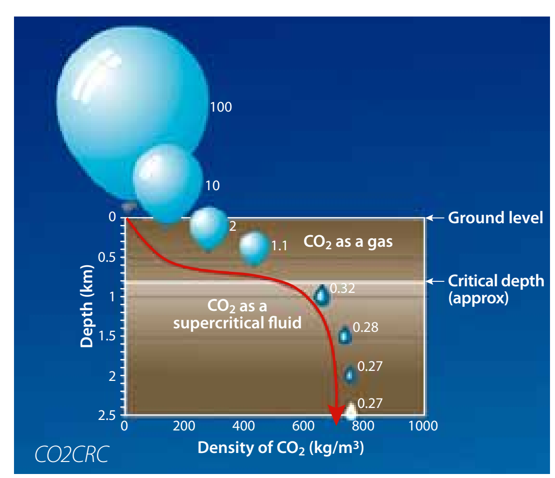


Structural traps



Stratigraphical traps





Supercritical fluids behave like gases, in that they can diffuse readily through the pore spaces of solids. But, like liquids, they take up much less space than gases. Supercritical conditions for CO_2 occur at 31.1°C and 7.38 megapascals (MPa), which occur approximately 800 meters below surface level. This is where the CO_2 has both gas and liquid properties and is 500 to 600 times denser (up to a density of about 700 kg/m3) than at surface conditions, while remaining more buoyant than formation brine.

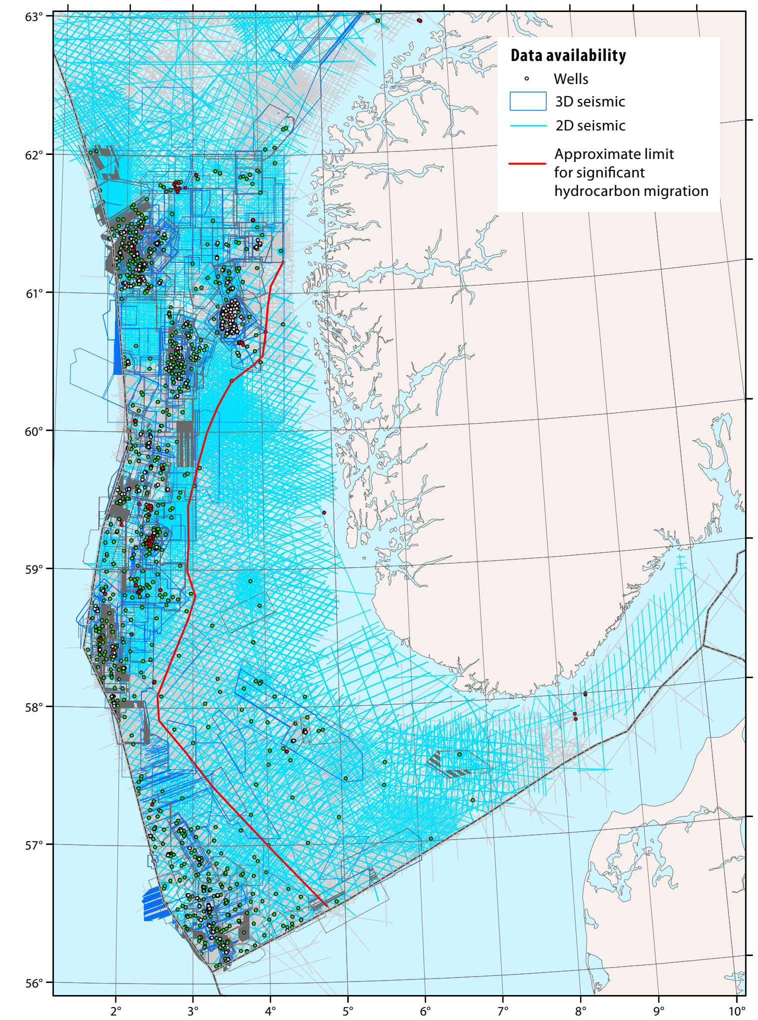
3.2 Data availability

The authorities' access to collected and analysed data is stipulated in law and based on the following statements: "The Norwegian State has the proprietary right to subsea petroleum deposits and the exclusive right to resource management" and "The right to submarine natural resources is vested in the State". This is regulated by The Petroleum Act (29 November 1996 No.72 1963), Regulations to the Act, the Norwegian Petroleum Directorate's resource regulations and guidelines, and Act of 21 June 1963 No. 12 "Scientific research and exploration for and exploitation of subsea natural resources other than petroleum resources".

The Norwegian Petroleum Directorate (NPD) has access to all data collected on the NCS and has a national responsibility for the data. The NPD's data, overviews and analyses make up an important fact basis for the oil and gas activities.

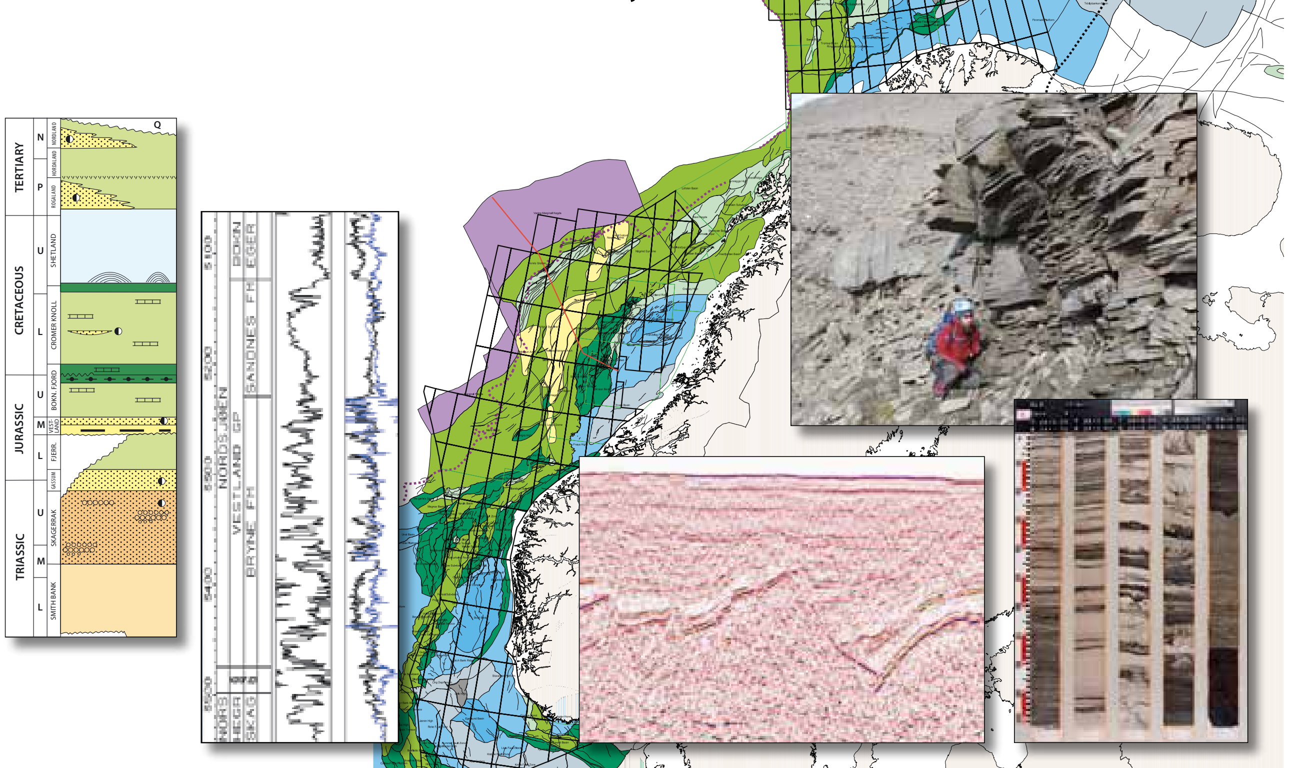
The main objective of these Reporting Requirements from the NPD is to support the efficient exploitation of Norway's hydrocarbon reserves. More than 40 years of petroleum activity has generated a large quantity of data. This covers 2D and 3D data, data from exploration and production wells such as logs, cuttings and cores as well as test and production data. These data, together with many years of dedicated work to establish geological play models for the North Sea, have given us a good basis for the work we are presenting here.

How these data are handled is regulated in: *http://www.npd.no/en/Regulations/Regulations/Petroleum-activities/*



Our playground

NPD has access to all data collected offshore Norway



3.3 Workflow and characterization

Characterization

Aquifers and structures have been evaluated in terms of capacity and safe storage of CO_2. Reservoir quality depends on the calculated volume and communicating volumes as well as the reservoir injectivity. Sealing quality is based on evaluation of the sealing layers (shales) and possible fracturing of the seal. Existing wells through the aquifers/structures and seals have also been evaluated.

Parameters used in the characterization process are based on data and experience from the petroleum activity on the NCS and the fact that CO_2 should be stored in the supercritical phase to have the most efficient and safest storage.

Each of the criteria in the table below is given a score together with a description of the data coverage (good, limited or poor). The score for each criteria is based on a detailed evaluation of each aquifer/structure. A checklist for reservoir properties has been developed. This list gives a detailed overview of the important parameters regarding the quality of the reservoir. Important elements when evaluating the reservoir properties are aquifer structuring, traps, the thickness and permeability of the reservoir. A corresponding checklist has been developed for the sealing properties. Evaluation of faults and fractures through the seal, in addition to old wells, are important for the sealing quality.

An extensive database has been available for this evaluation. Nevertheless some areas have limited seismic coverage and no well information. The data coverage is colour-coded to illustrate the data available for each aquifer/structure.

CHARACTERIZATION OF AQUIFERS AND STRUCTURES

	Criteria		Definitions, comments
Reservoir quality	Capacity, communicating volumes	**3**	Large calculated volume, dominant high scores in checklist
		2	Medium - low estimated volume, or low score in some factors
		1	Dominant low values, or at least one score close to unacceptable
	Injectivity	**3**	High value for permeability * thickness (k*h)
		2	Medium k*h
		1	Low k*h
Sealing quality	Seal	**3**	Good sealing shale, dominant high scores in checklist
		2	At least one sealing layer with acceptable properties
		1	Sealing layer with uncertain properties, low scores in checklist
	Fracture of seal	**3**	Dominant high scores in checklist
		2	Insignificant fractures (natural / wells)
		1	Low scores in checklist
Other leak risk	Wells	**3**	No previous drilling in the reservoir / safe plugging of wells
		2	Wells penetrating seal, no leakage documented
		1	Possible leaking wells / needs evaluation
Data coverage	**Good data coverage**		**Limited data coverage** / **Poor data coverage**

Other factors:
How easy / difficult to prepare for monitoring and intervention. The need for pressure relief. Possible support for EOR projects. Potential for conflicts with future petroleum activity.

Data coverage
Good : 3D seismic, wells through the actual aquifer/structure
Limited : 2D seismic, 3D seismic in some areas, wells through equivalent geological formations
Poor : 2D seismic or sparse data

3.3 Workflow and characterization

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

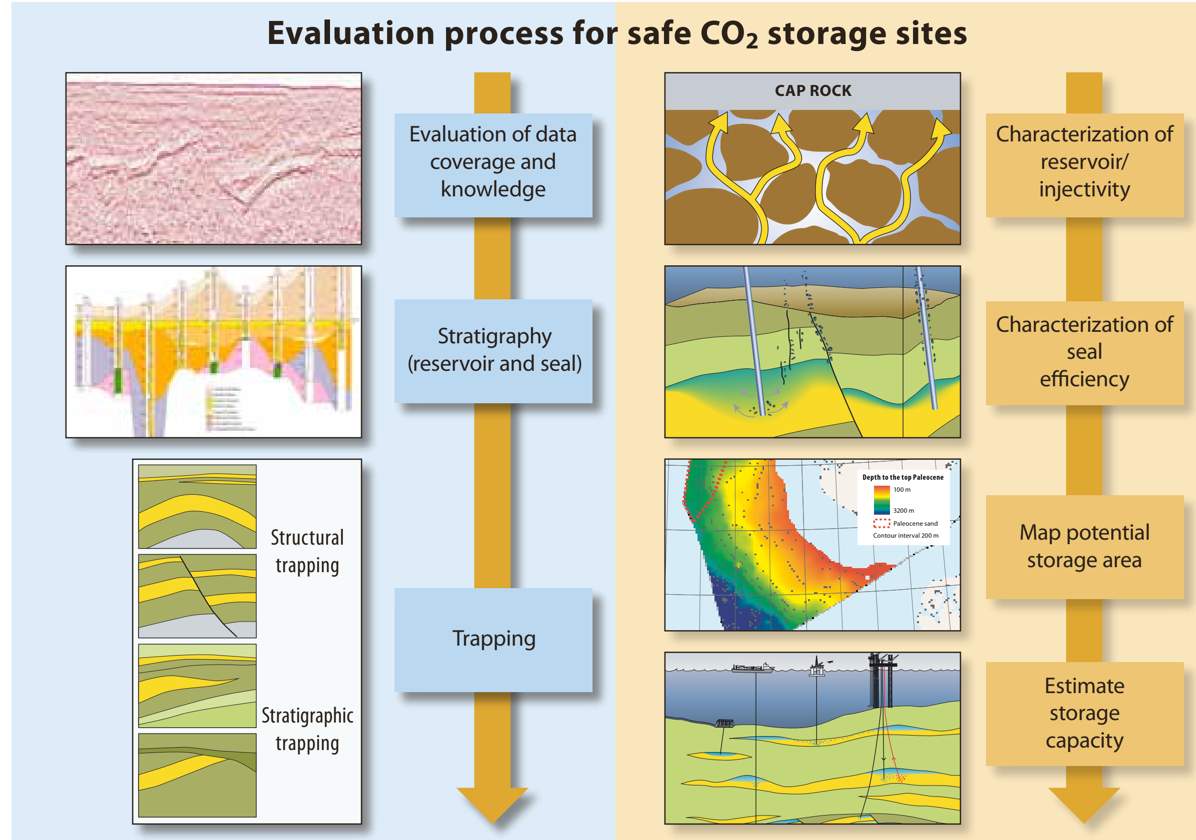
FOR SEALING PROPERTIES			
Typical high and low scores			
Sealing Properties	High	Low	Unacceptable values
Sealing layer	More than one seal	One seal	No known sealing layer over parts of the reservoir
Properties of seal	Proven pressure barrier/ > 100 m thickness	< 50 m thickness	
Composition of seal	High 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	

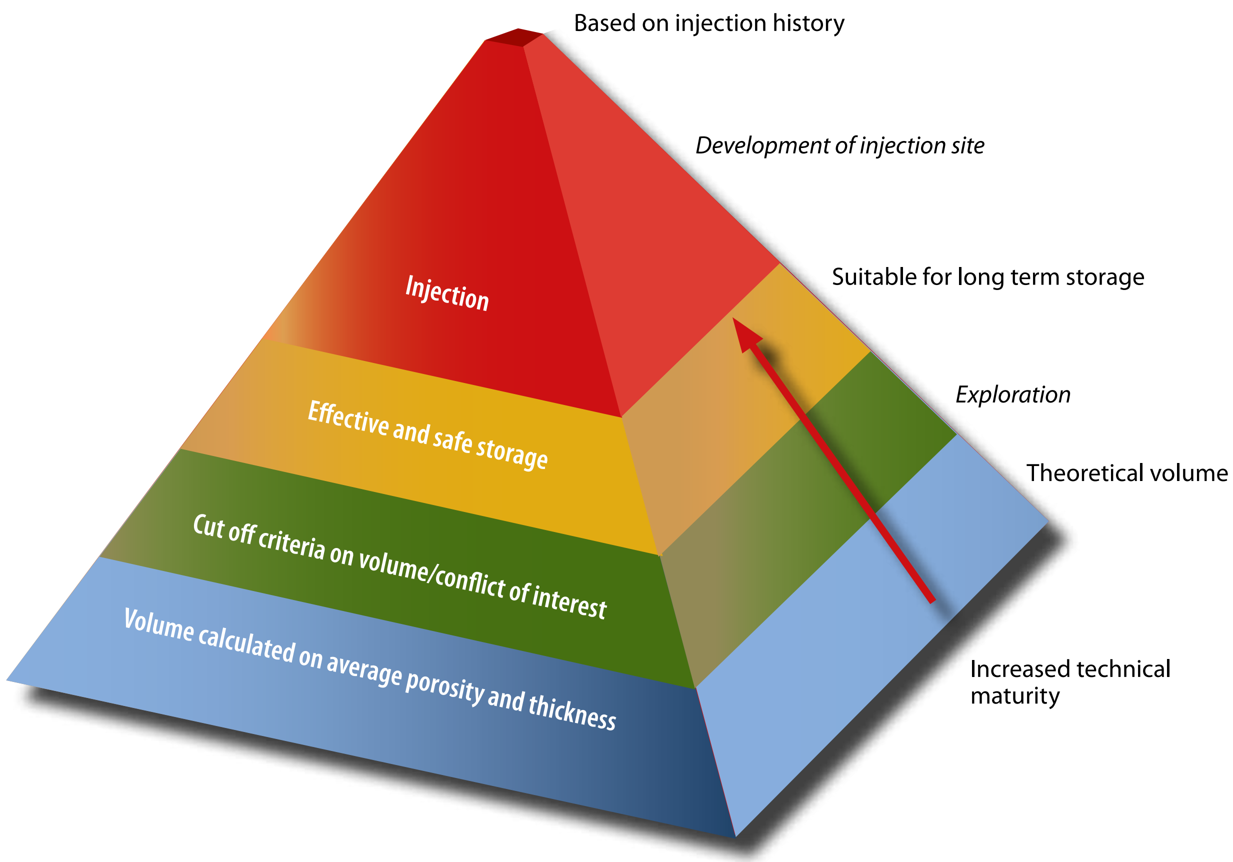
3.3 Workflow and characterization

Workflow

NPD's approach for assessing the suitability of the geological formations for CO_2 storage is summed up in this flowchart. The intention is to identify, in a systematic way, the aquifers and which aquifers are prospective in terms of large-scale storage of CO_2.

In subsequent steps in the workflow, each potential reservoir and seal identified, are evaluated and characterized for their CO_2 storage prospectivity. Based on this, the potential storage sites are mapped and the storage capacity is calculated. The evaluation is based on available data in the given areas. This evaluation does not provide an economic assessment of the storage sites.





The maturation pyramid

The evaluation of geological volumes suitable for injecting and storing CO_2 can be viewed as a step-wise approximation, as shown in the maturation pyramid. Data and experience from over 40 years in the petroleum industry will contribute in the process of finding storage volumes as high up as possible in the pyramid.

Step 4 is the phase when CO_2 is injected in the reservoir. Throughout the injection period, the injection history is closely evaluated and the experience gained provides further guidance on the reservoirs' ability and capacity to store CO_2.

Step 3 refers to storage volumes where trap, reservoir and seal have been mapped and evaluated in terms of regulatory and technical criteria to ensure safe and effective storage.

Step 2 is the storage volume calculated when areas with possible conflicts of interest with the petroleum industry have been removed. Only aquifers and prospects of reasonable size and quality are evaluated. Evaluation is based on relevant available data.

Step 1 is the volume calculated on average porosity and thickness. This is done in a screening phase that identifies possible aquifers suitable for storage of CO_2. The theoretical volume is based on depositional environment, diagenesis, bulk volume from area and thickness, average porosity, permeability and net/gross values.

3.4 Estimation of storage capacity

CO_2 can be stored in producing oil fields, depleted oil and gas fields, or in saline aquifers. In a producing oil field, CO_2 can be used for enhanced recovery before it is stored. In a depleted oil and gas field, CO_2 can be injected until the initial pressure has been reached, or it can be over-pressured.

Storage capacity depends on several factors, primarily the pore volume and to what extent the reservoir is depleted. It is also important to know if there is communication between multiple reservoirs. If the reservoir is not in pressure communication with other reservoirs, the capacity will primarily depend on how much it can be pressurized without fracturing. The degree of pressurization depends on the difference between the fracturing pressure and the The relation between pressure and volume increase depends on the compressibility of the rock and the fluids in the reservoir. The solubility of the CO_2 in the different phases will also play a part.

The CO_2 will preferably be store in a supercritical phase in order to occupy small space in the reservoir.

For saline aquifers the amount of CO_2 to be stored can be given by the following formula:

$M_{CO_2} = Vb \times Ø \times n/g \times \rho_{CO_2} x S_{eff}$

- M_{CO_2} *amount of* CO_2 *in tons*
- *Vb bulk volume*
- *Ø porosity*
- *n/g net to gross ratio*
- ρ_{CO_2} *density of* CO_2 *at reservoir conditions*

(Geocapacity 2009)

S_{eff} is calculated as the fraction of stored CO_2 relative to the pore volume. The CO_2 in the pores will appear as a free, mobile or immobile phase (trapped). Most of the CO_2 will be in a mobile phase. Simulations show that approximately 10-20 % of the CO_2 can be dissolved in the water. When injection stops, the CO_2 will continue to migrate upward in the reservoir, and the water will follow and trap some of the CO_2 behind the water. This CO_2 behind the water will become immobile. The trapped gas saturation can reach about 30 % depending on how long the migration continues. The diffusion of CO_2 into the water will be small, but may have an effect over a long period.

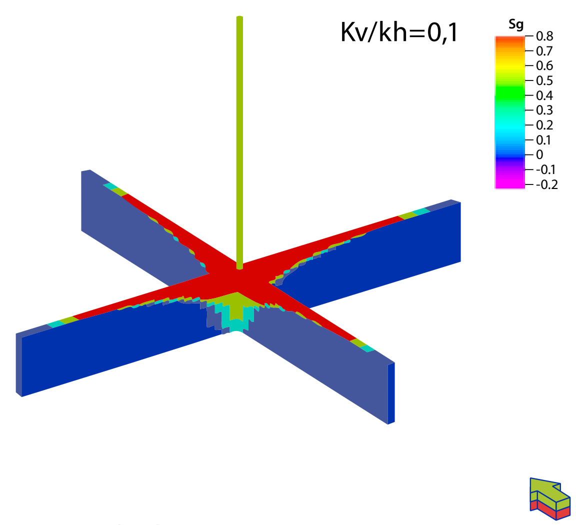
The injection rate will depend on the permeability and how much of the reservoir is exposed to the injection well. The number of wells needed to inject a certain amount of CO_2 will depend on the size of the reservoir and the injectivity.

For a homogenous reservoir with a permeability of 200 mD and reservoir thickness of 100m, the storage efficiency in a closed system is simulated to be 0.4 to 0.8 %, with a pressure increase of 50 to 100 bar. In a closed system, a pressure increase between 50 and 100 bar is a reasonable range for reservoirs between 1000 and 3000 m, but this needs to be evaluated carefully for each reservoir.

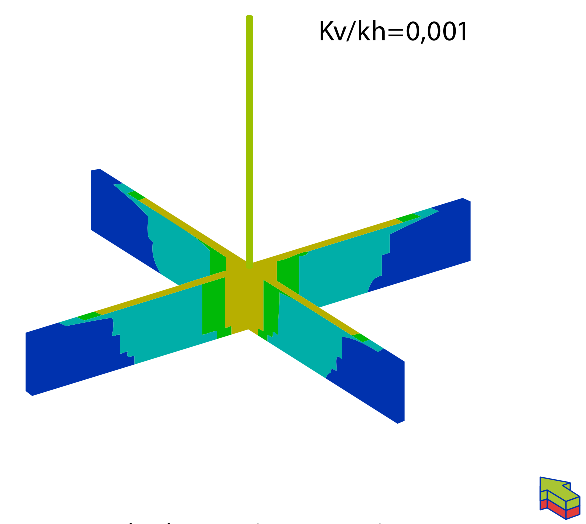
If the reservoir is fully open, the reservoir pressure will stay constant during injection, as the water will be pushed beyond the boundaries. The CO_2 stored will be the amount injected until it reaches the boundaries. The efficiency will be ~5 % or more, depending primarily on the relationship between the vertical and horizontal permeability. A low vertical to horizontal permeability ratio will distribute the CO_2 better over the reservoir than a high ratio.

In this case the storage efficiency goes from 5 to 12% if the vertical to horizontal permeability ratio (kv/kh) decreases from 0.1 to 0.001.

For abandoned oil and gas fields, the amount of CO_2 that can be injected depends on how much has been produced, and to what extent the field is depleted. A material balance can be used to calculate water influx during depletion when one knows the reservoir volumes of oil, gas and water produced as well as the initial and abandonment pressure. The water influx has to be subtracted from the produced volumes to calculate the amount of CO_2 to be injected. In water-flooded oil reservoirs where the reservoir pressure is built up to almost initial pressure, injection of CO_2 can occur either by pressurising the reservoir or by injecting at a constant pressure. With pressure increase, the storage efficiency will be small, around 1% of pore volume. If the injection is to occur at constant pressure, water has to be produced out of the field, preferably from the water zone. Then CO_2 injection will occur in a half open situation and the storage efficiency will be between 5 and 10% depending on the heterogeneities in the reservoir, primarily the kv/kh.



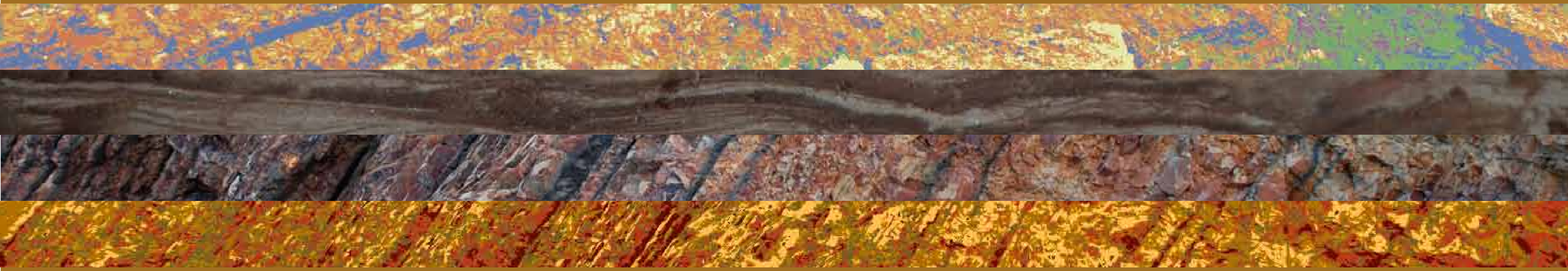
SCO_2 development (open system)



SCO_2 development (open system)

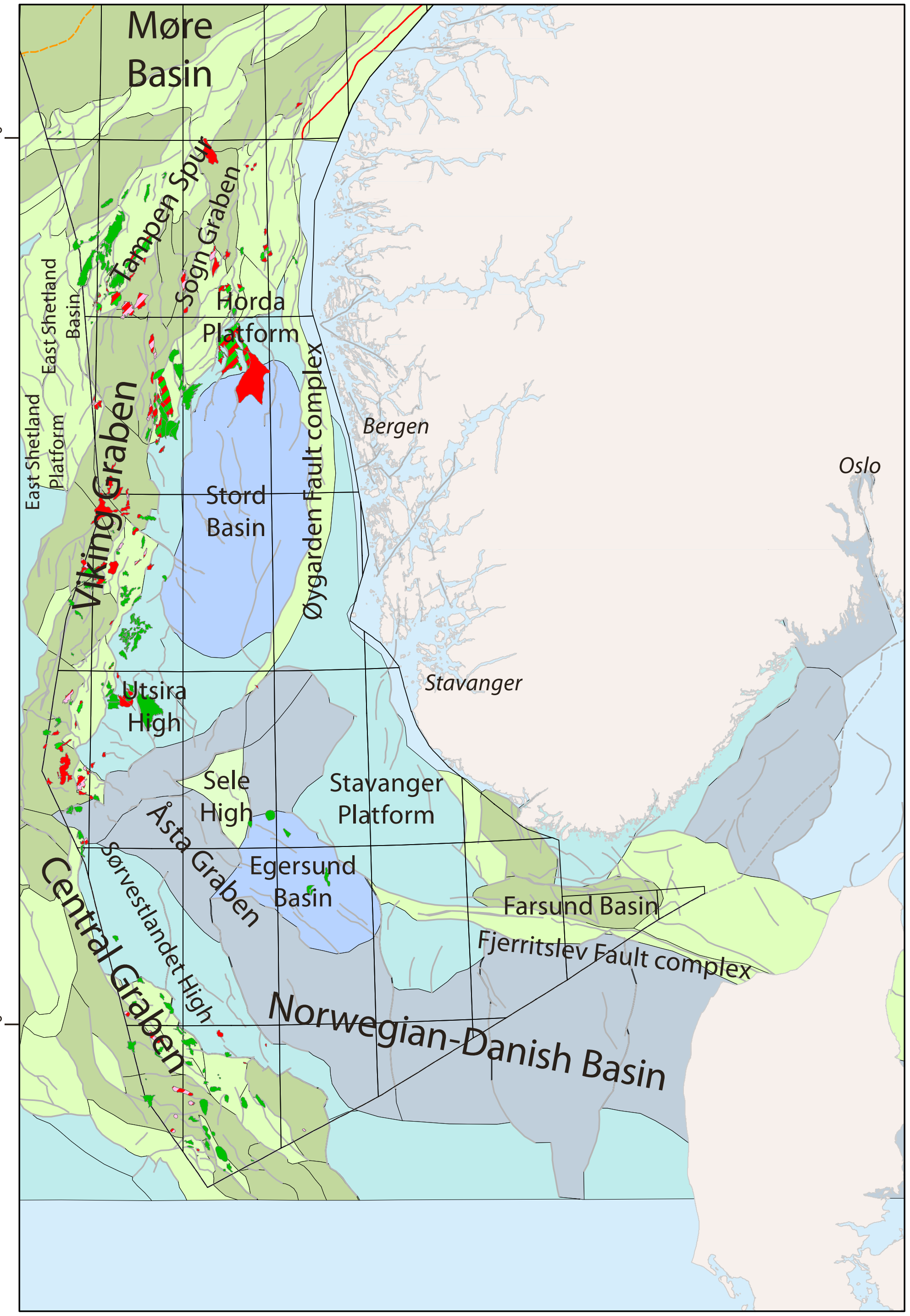
Cross sections of a flat reservoir with injection for 50 years

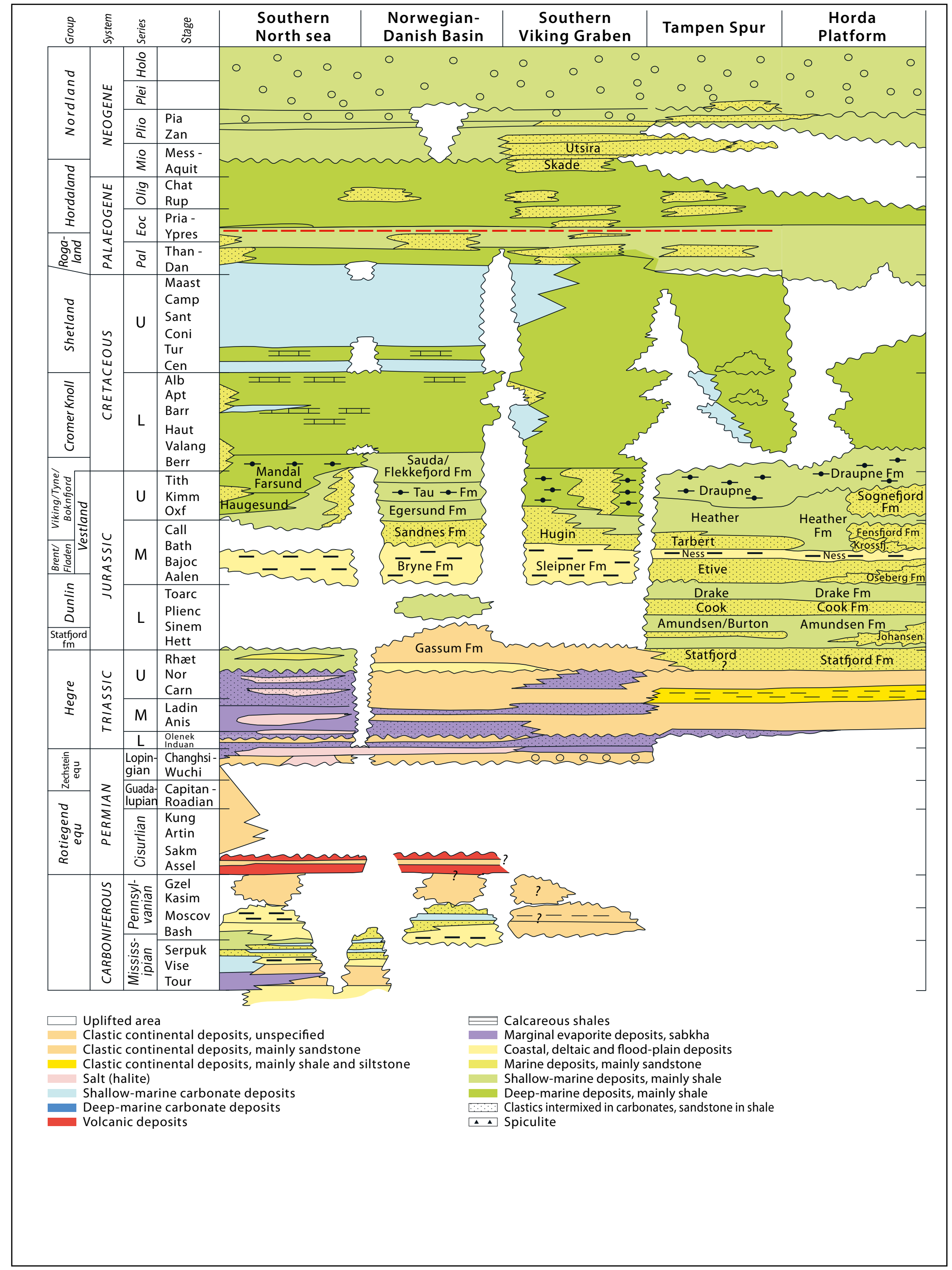
4. Geological description of the North Sea



4. Geological description of the North Sea

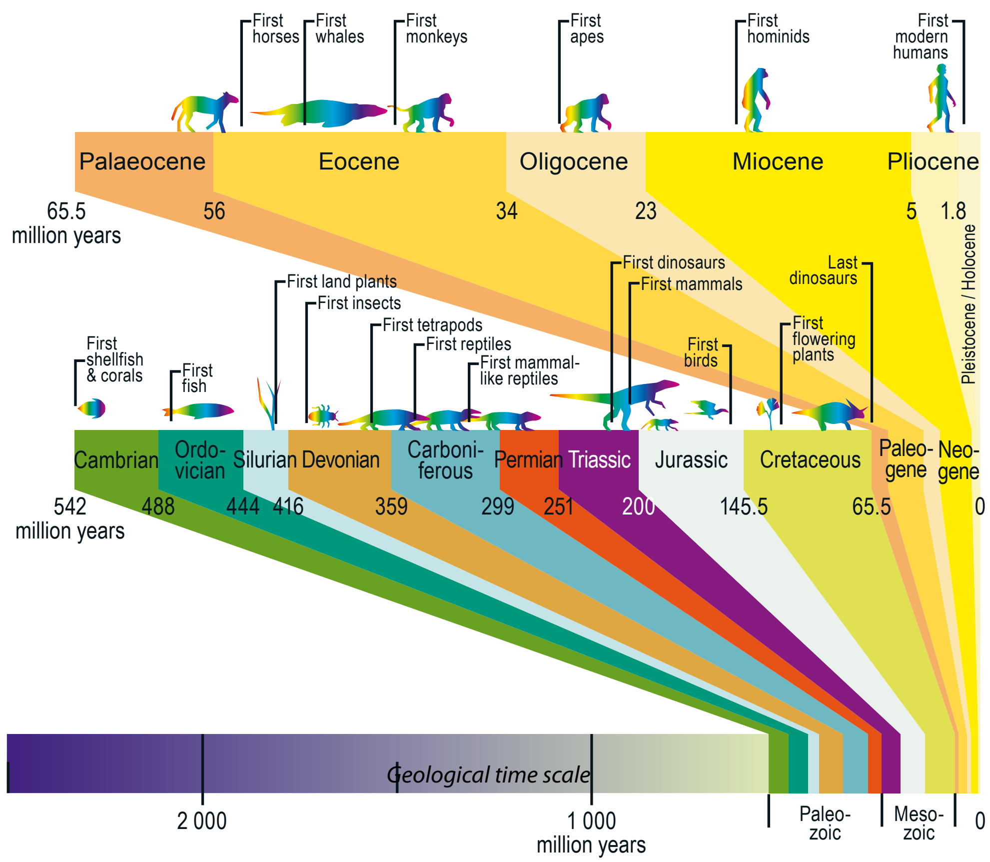
4.1 Geological development of the North Sea

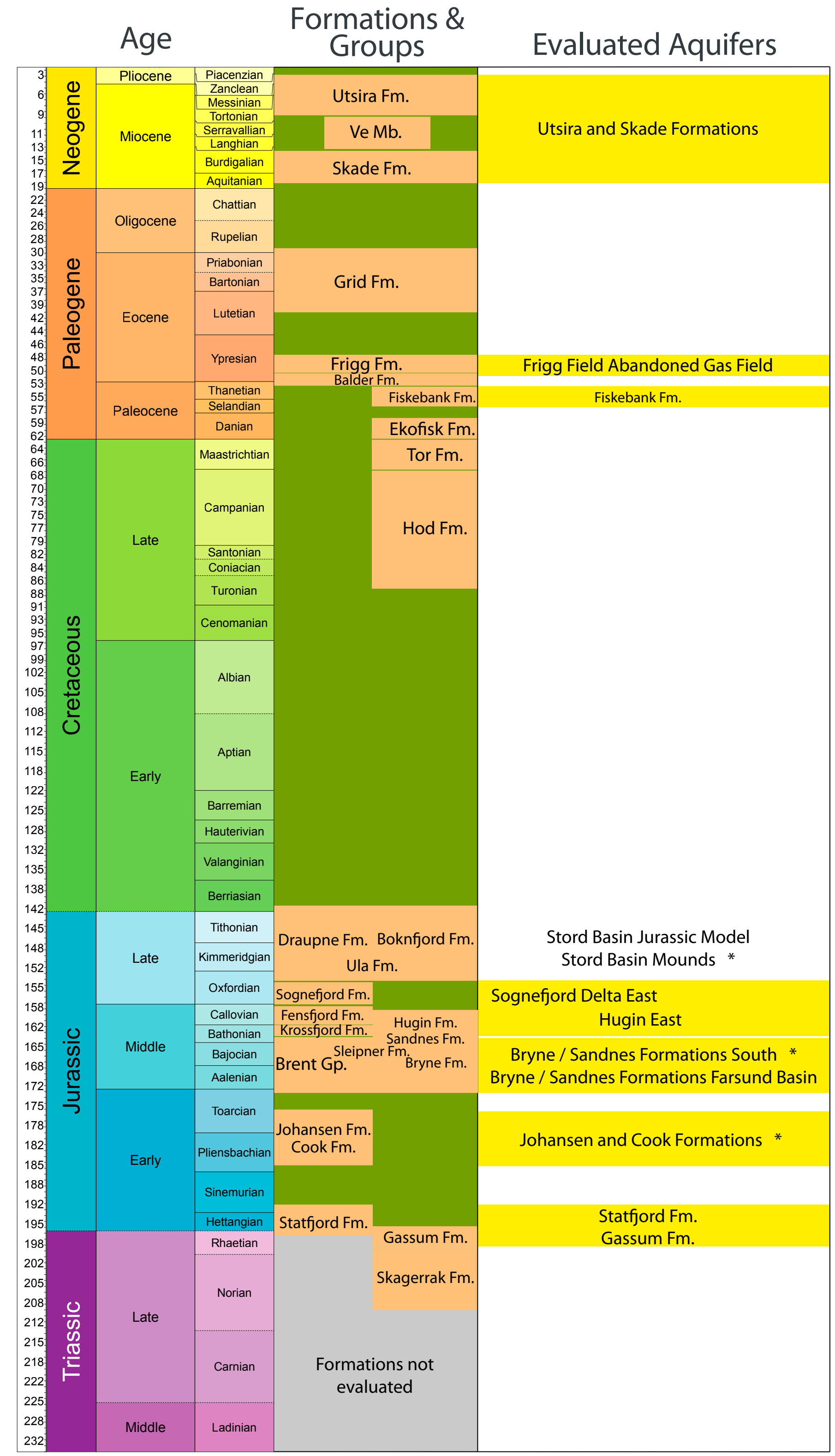




Lithostratigraphic chart of the North Sea

4.1 Geological development of the North Sea





* Evaluated prospects

4.1 Geological development of the North Sea

The basic structural framework of the North Sea is mainly the result of Upper Jurassic/ Lower Cretaceous rifting, partly controlled by older structural elements.

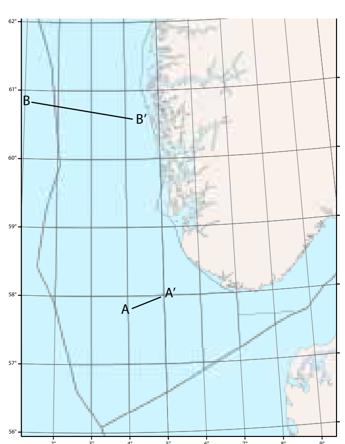
Carboniferous-Permian: Major rifting with extrusion of basic volcanics and deposition of reddish eolian and fluvial sandstones (Rotliegendes). Two basins were developed with deposition of thick evaporate sequences (Zechstein). When overlain by a sufficient amount of younger sediments, buoyancy forces caused the salt to move upwards (halokinesis). This is important for generation of closed structures, including hydrocarbon traps, in the southern part of the North Sea and also as a control on local topography and further sedimentation.

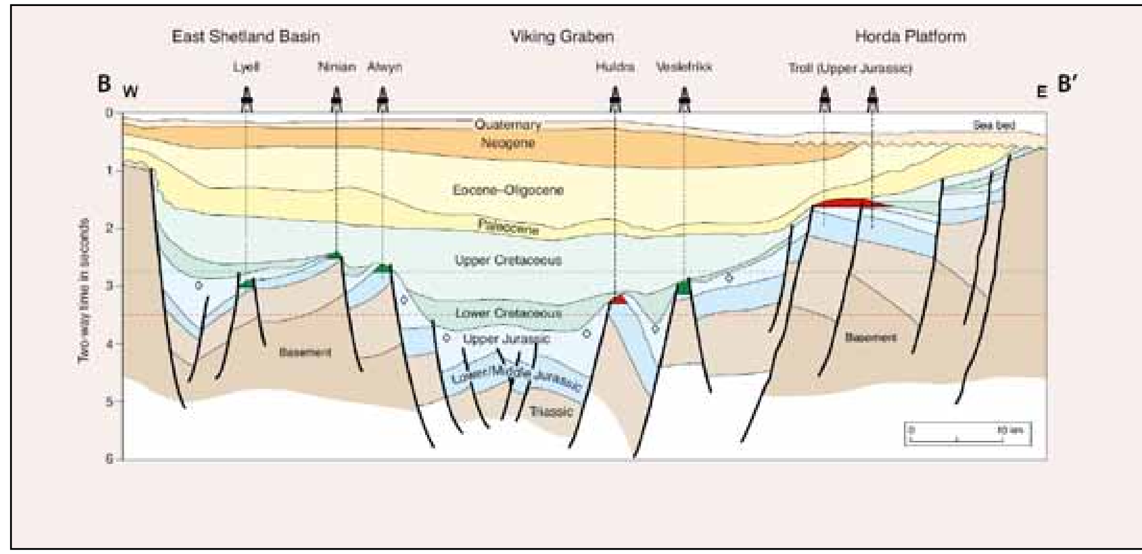
Triassic: Major N-S to NE-SW rifting with thick coarse fluvial sediments deposited along rift margins, grading into finer-grained river and lake deposits in the centre of the basins. The transition between the Triassic and Jurassic is marked by a widespread marine transgression, both from north and south.

Jurassic: The marine transgression was followed by the growth of a volcanic dome centred over the triple point between the Viking Graben, the Central Graben and the Moray Firth Basin. The doming caused uplift and erosion and was followed by rifting. Large deltaic systems containing sand, shale and coal were developed in the northern North Sea and the Horda Platform (Brent Group). In the Norwegian-Danish Basin and the Stord Basin, the Vestland Group contains similar deltaic sequences overlain by shallow marine/ marginal marine sandstones.
The most important Jurassic rifting phase in the North Sea area took place during the Late Jurassic and lasted into the Early Cretaceous. During this tectonic episode, major block faulting caused uplift and tilting and created considerable local topography with erosion and sediment supply. In anoxic basins thick sequences of shale accumulated, producing the most important source rock and also the Draupne Formation, which is an important seal for hyrdocarbon traps in the North Sea area.

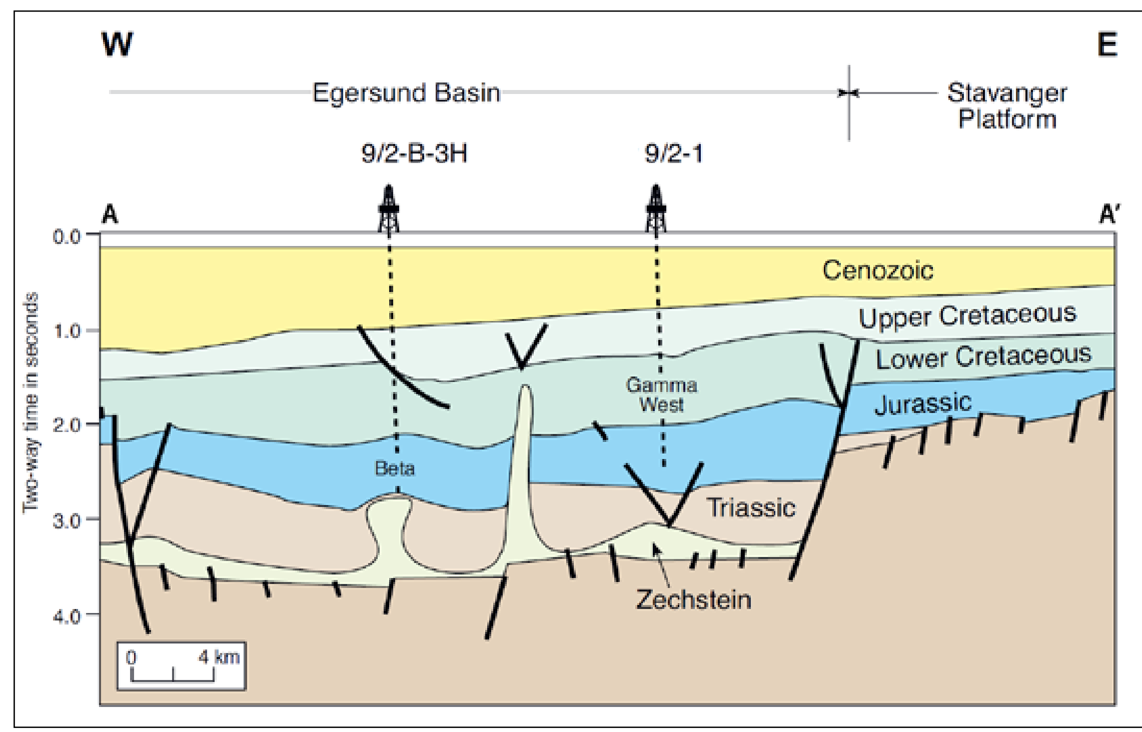
Cretaceous: The rifting ceased and was followed by thermal subsidence. The Upper Cretaceous in the North Sea is dominated by two contrasting lithologies. South of 61⁰ N there was deposition of chalk, while to the north the carbonates give way to siliclastic, clay-dominated sediments.

Cenozoic: In the Paleocene/Eocene there were major earth movements with the onset of sea floor spreading in the north Atlantic and mountain building in the Alps/Himalaya. In the North Sea, deposition of chalk continued until Early Paleocene. Uplift of basin margins, due to inversion, produced a series of submarine fans transported from the Shetland Platform towards the east. These sands interfinger with marine shales in both the Rogaland and the Hordaland Groups. In the Miocene a deltaic system had developed from the Shetland Platform towards the Norwegian sector of the North Sea, and is represented by the Skade and Utsira Formations. Due to major uplift and Quaternary glacial erosion of the Norwegian mainland, thick sequences were deposited into the North Sea during the Neogene. This led to burial of the Jurassic source rocks to depths where hydrocarbons could be generated and the seals were effective.





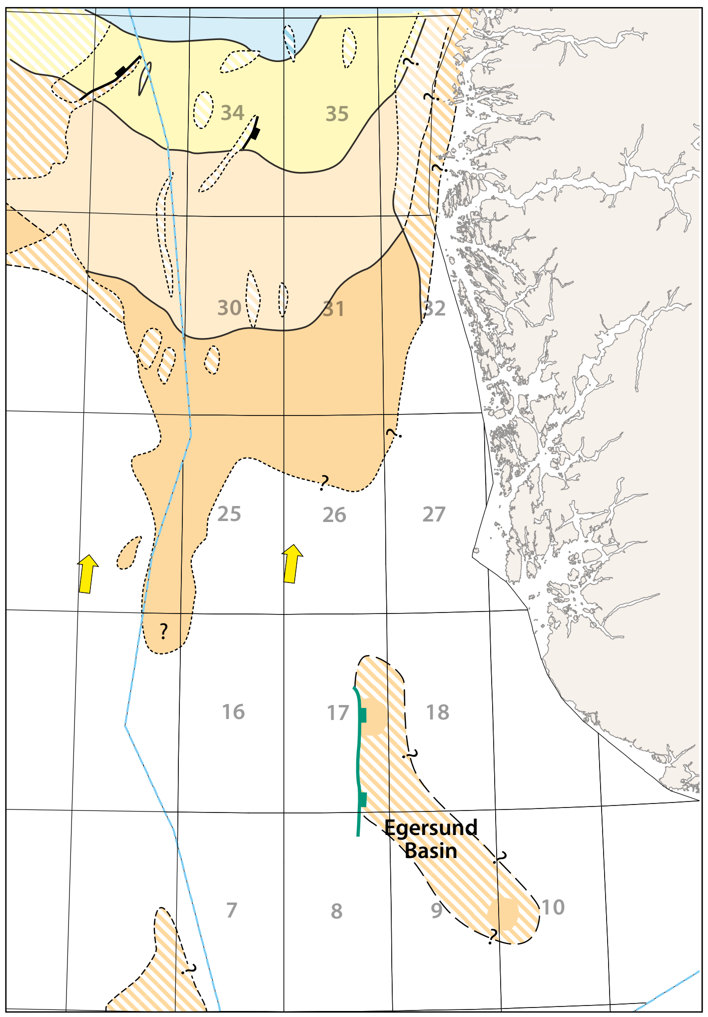
Geoseismic cross section in the northern North Sea. From the Millennium atlas 2001



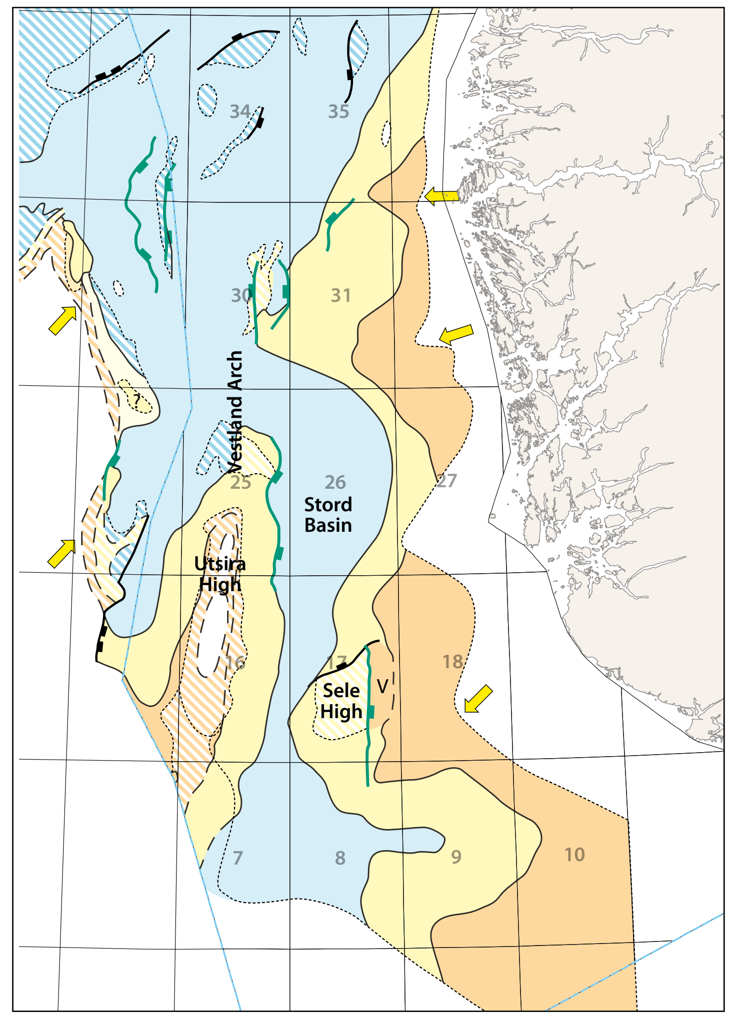
Geoseismic cross section in the Egersund basin. From the Millennium atlas 2001

4.1 Geological development of the North Sea

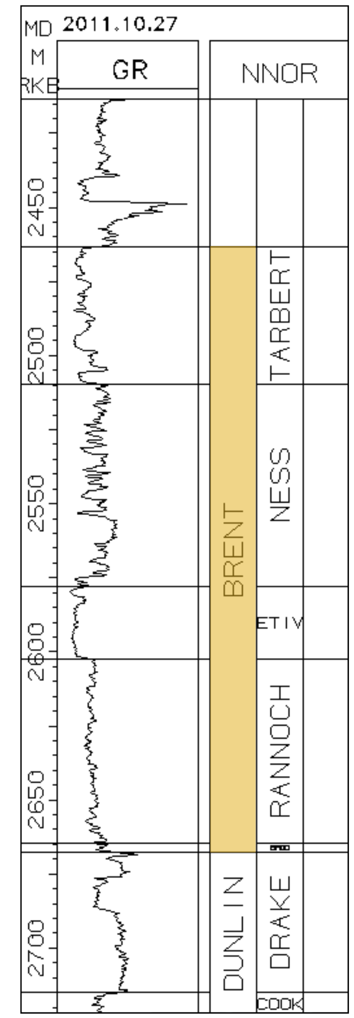
FACIESMAP Bajocian



FACIESMAP Mid- to late Callovian



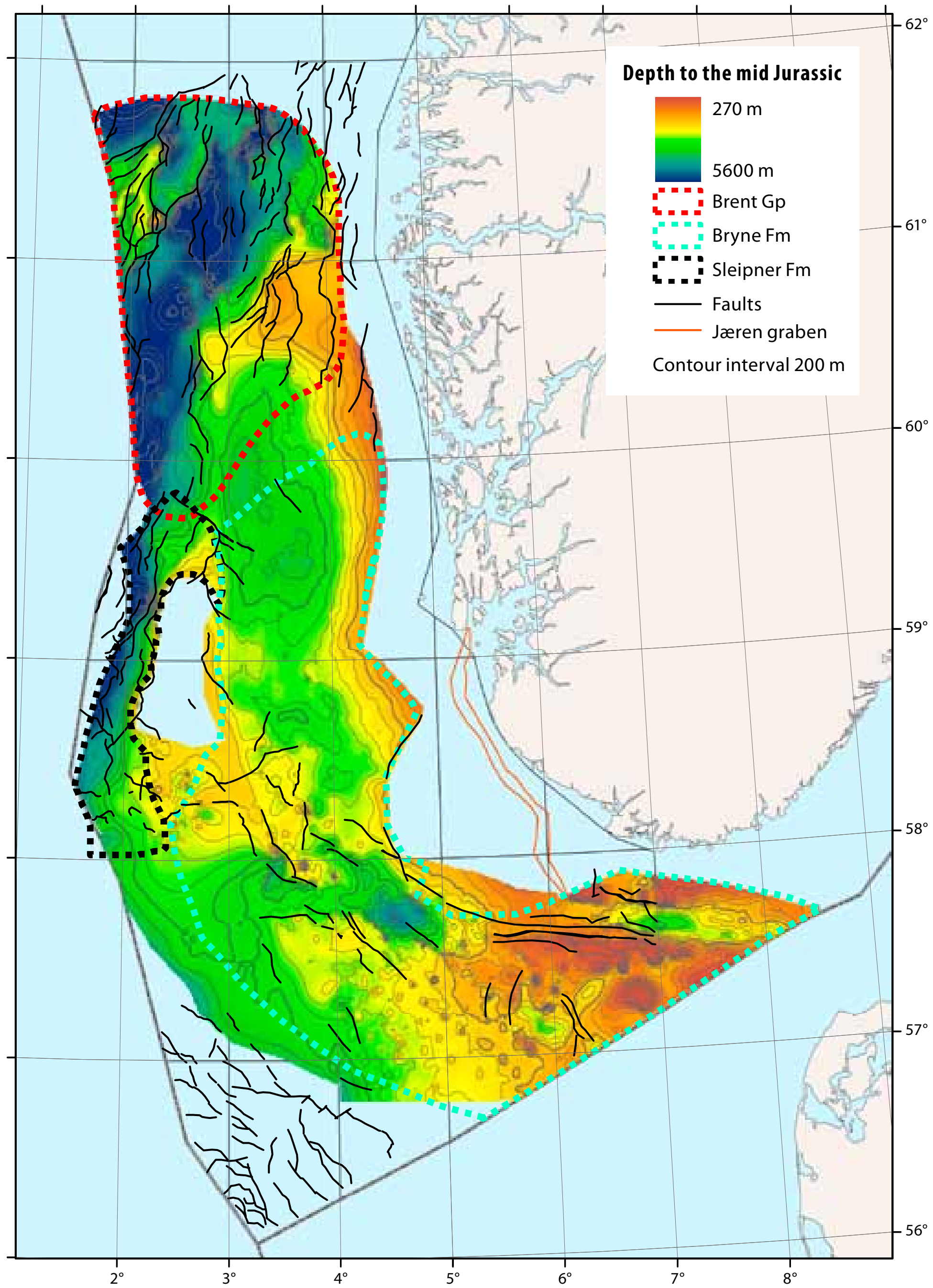
WELL LOG 33/9-1

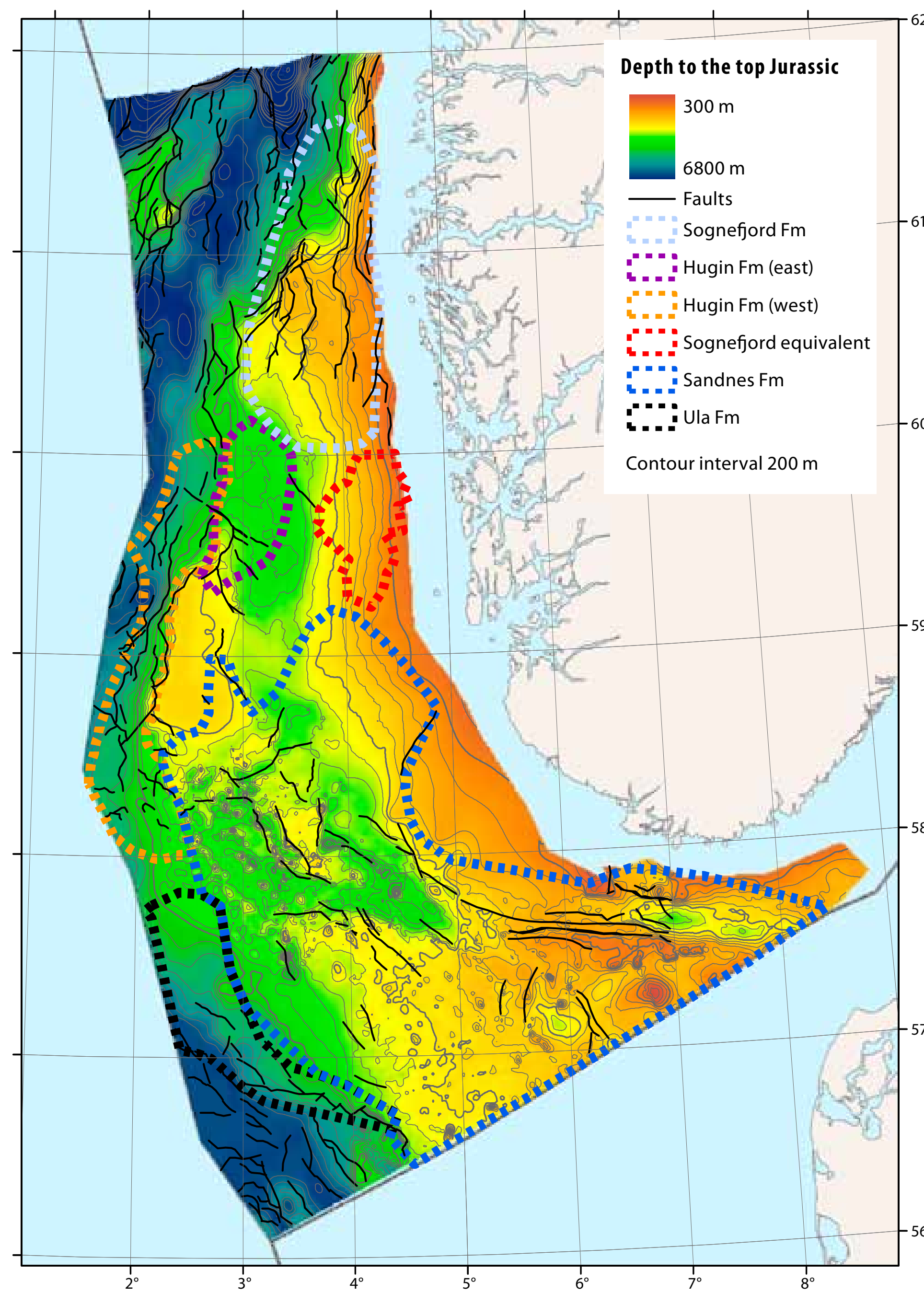


Examples of mid Jurassic relationship between continental and marine deposits in central and northern North Sea. Continental sediments in brownish colour, shallow marine in yellow and offshore marine in blue.

The map to the left displays the development of the Brent delta and the early stage of the deposition of the Bryne Formation. The map to the right shows the development of the Sognefjord delta and the Sandnes and Hugin Formations after the Brent delta was transgressed.

4.1 Geological development of the North Sea





Mapping of the upper and middle Jurassic forms the basis of many of the following depth and thickness maps of assessed geological formations. The top Jurassic refers to the top of Upper Jurassic sandstones or their equivalents.

4.2 Geological description

The Statfjord Formation

AGE: **Uppermost Triassic and Lower Jurassic** (Rhaetian to Sinemurian)

In the type well (33/12-2) the base of the Statfjord Fm is defined at the transition from the fining upward mega-sequence of the Lunde Fm and a coarsening upward mega-sequence of the Statfjord Fm. The Statfjord Fm is subdivided into three members (Raude, Eiriksson and Nansen). The upper boundary of the Statfjord Fm is sharp against the fully marine mudstones of the overlying Dunlin Group that could act as a regional seal.

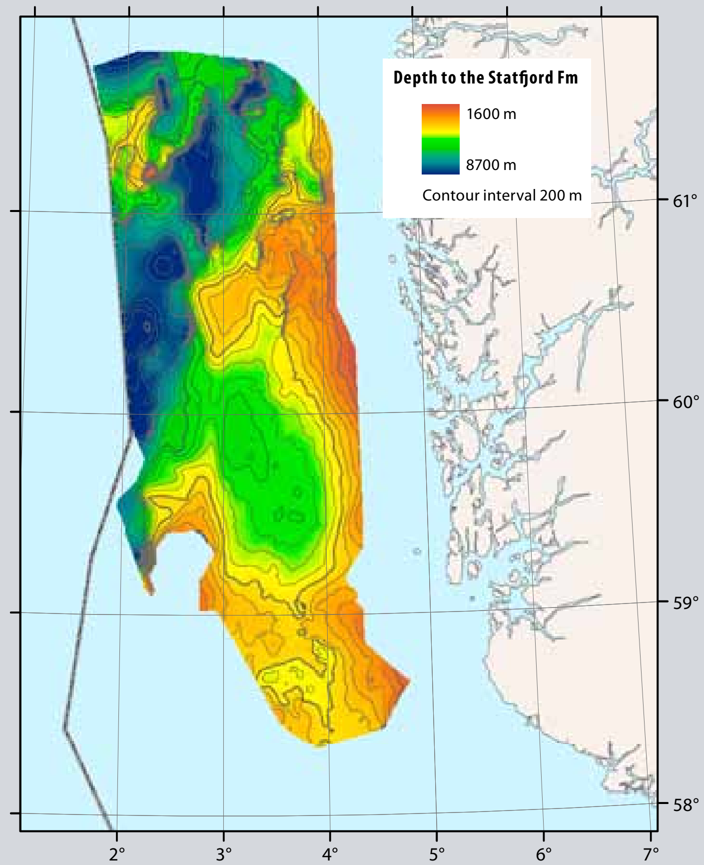
The Statfjord Fm can be recognized in the entire area between the East Shetland Platform to the west and the Øygarden Fault Complex against the Fennoscandian Shield to the east. To the south the Statfjord Fm has been recognized as far south as Norwegian blocks 25/8 and 11, and has not to date been identified north of the Tampen Spur.

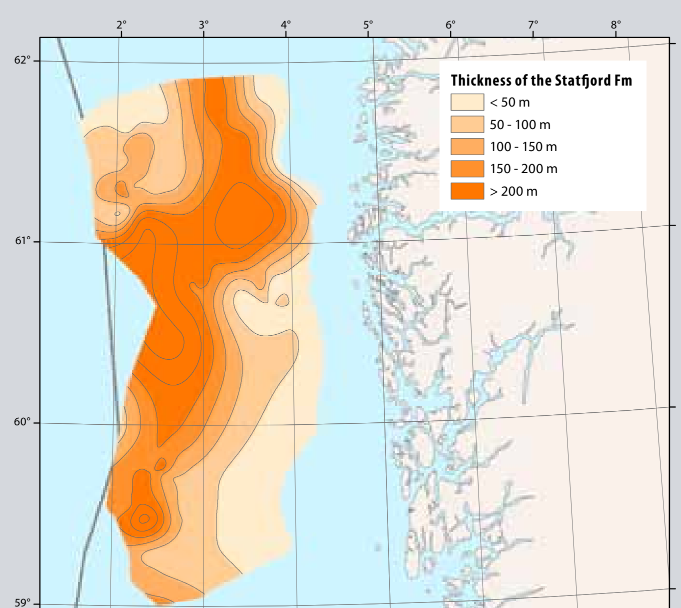
Thickness from wells in the type area varies from 140 m to 320 m. The Statfjord Fm displays large thickness variations due to regional differential subsidence. In a NW-SE traverse from the Tampen Spur to the Horda Platform, it is relatively thin in the Tampen area (140 m on the Snorre Field), thickens across the Viking Graben and thins again on the Horda Platform towards the Norwegian mainland.

Depositionally the Statfjord Fm records the transition from a semi-arid, alluvial plain (Raude Mbr) to dominantly fluvial sandstones (Eiriksson and Nansen Mbrs) with occasional marine influence in the upper part (Nansen Mbr).

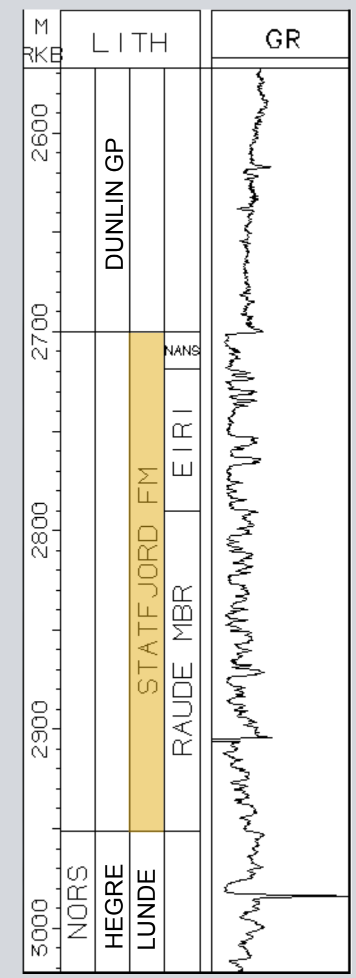
Generally the formation is buried in excess of 2000 m. In the Snorre Field where the crest of the structure is 2335 m, porosities between 16-28 % and permeabilities in the order of 250-4000 mD have been reported.

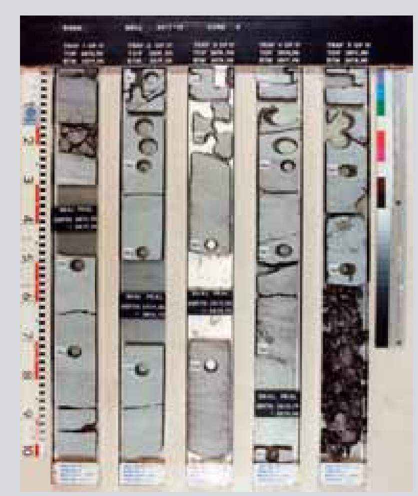
A time equivalent to the Statfjord Fm is the Gassum Fm in the Norwegian-Danish Basin.





WELL LOG 33/12-2




Core photo well 34/7-13, 2873-2878 m

The Dunlin Group

AGE: **Lower to Middle Jurassic**
(Hettangian to Bajocian)

The Dunlin Gp represents a major marine transgressive sequence overlying the Statfjord Fm. It is divided into five formations; the Amundsen, Johansen, Burton, Cook and Drake Fms. The type well is UK well 211/29-3 and a Norwegian reference well is 33/9-1. The Amundsen, Burton and Drake Fms are mainly silt and marine mudstones, while the Johansen and Cook Fm are mainly marine/marginal marine sandstones. The upper boundary is the deltaic sequences of the Brent Gp.

The group is recognized over most of the East Shetland Basin, fringing the East Shetland Platform, and the northern part of the Horda Platform. To the south the Dunlin Gp has been recognized in wells as far south as 59^{0}N.

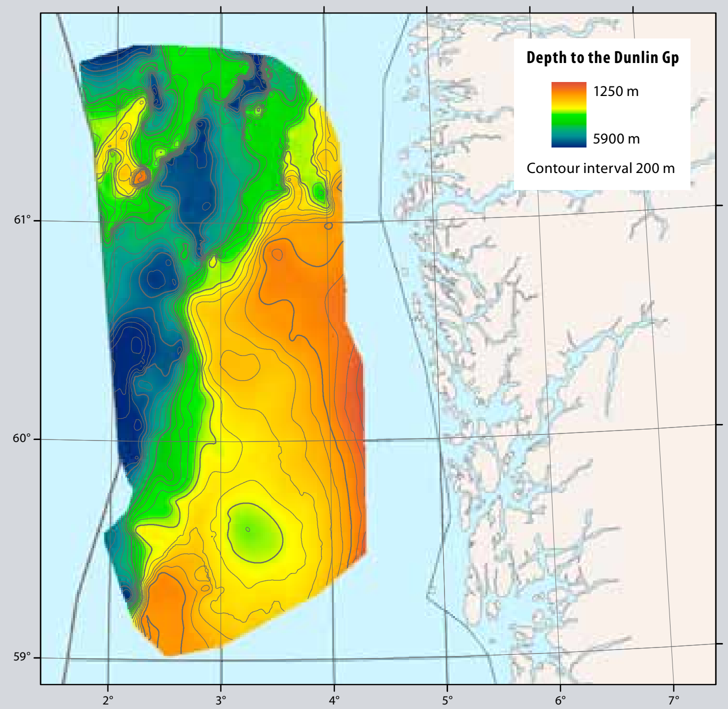
In the type and reference well the thicknesses are 222 m and 255 m respectively. The Dunlin Gp has its maximum thickness (possible 1000 m) in the axial part of northern Viking Graben, and a thickness of more than 600 m has been drilled in the western part of the Horda Platform (well 30/11-4).

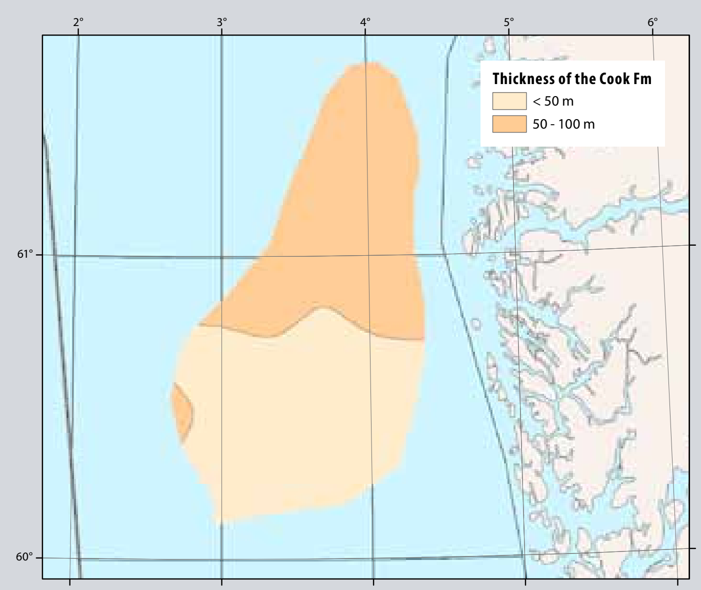
The Amundsen Fm (Sinemurian to Pliensbachian) contains mainly marine silts and mudstones deposited on a shallow marine shelf. It is distributed widely in the East Shetland Basin and the northern Viking Graben, forming a seal to the underlying Statfjord Fm and possibly the Johansen Fm.

The Johansen Fm (Sinemurian to Pliensbachian) sandstones split the Amundsen Fm in an area restricted to the eastern part of the Horda Platform (well 31/2-1), and the formation can be mapped northwards to approximately 60^0 N. The Johansen Fm is interpreted in terms of deposition on a high energy shallow marine shelf with sediment input from the east.

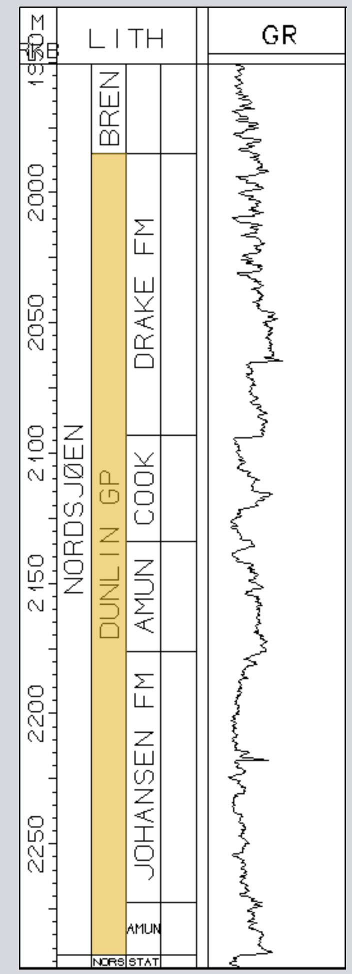
The Burton Fm (Sinemurian to Pliensbachian) is mainly marine mudstones that overlie the Amundsen Fm. The Burton Fm is found over most of the area, but it is not present on the Horda Platform. It forms mainly a basinal facies and passes into the Amundsen Fm towards the margins.

The Cook Fm (Pliensbachian to Toarcian) is dominated by sandstone tongues that interfinger with the Drake mudstones at several distinct stratigraphic levels. Typically each of the sandstones are characterized by a lower zone of sharp-based, upward-coarsening shoreface sandstones and siltstones and an upper erosive surface of thin tidal flat and thick deltaic/estuarine sandstones.





WELL LOG 31/2-1



Core photo well 34/4-5, 3427-3430 m

The Drake Fm (Toarcian to Bajocian) silts and mudstones were deposited during a continued rise in the relative sea level and the formation acts as a seal towards the underlying Cook sandstones. The upper boundary of the Drake Fm is marked by the more sandy sediments at the base of the deltaic Brent Group. Locally there is some sand towards the top of the Drake Fm.

A time equivalent to the Dunlin Gp is the Fjerritslev Fm in the Norwegian –Danish Basin.

4.2 Geological description

Johansen Formation

AGE: **Lower Jurassic**
(Sinemurian to Pliensbachian)

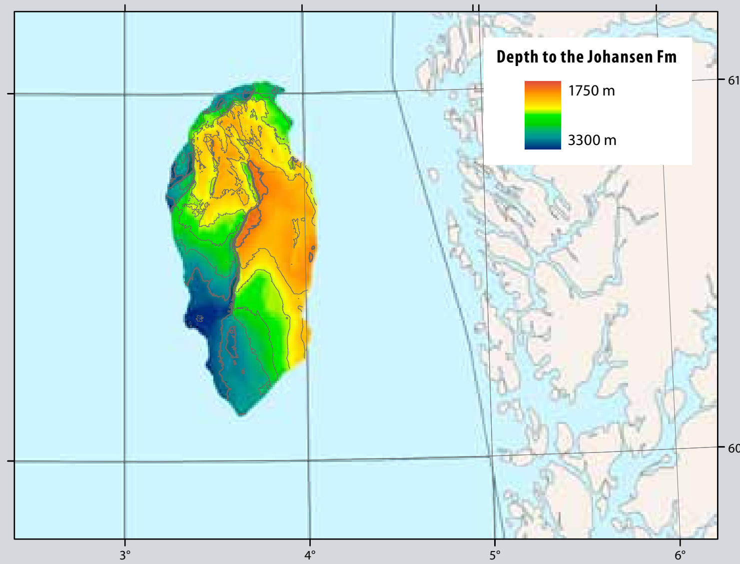
The Johansen Fm has its type area on the Horda Platform (type well 31/-2-1) where the sandstones of the formation split the marine siltstones and mudstones of the Amundsen Fm. Thus the Amundsen Fm might function as seal for the Johansen Fm.

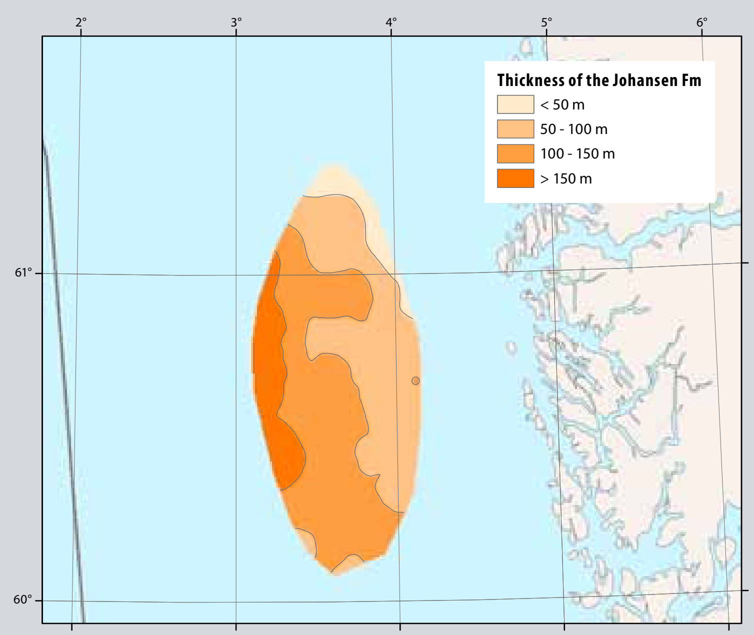
The Johansen Fm is found in a restricted area extending from the eastern part of the Horda Platform and north towards 62⁰N.

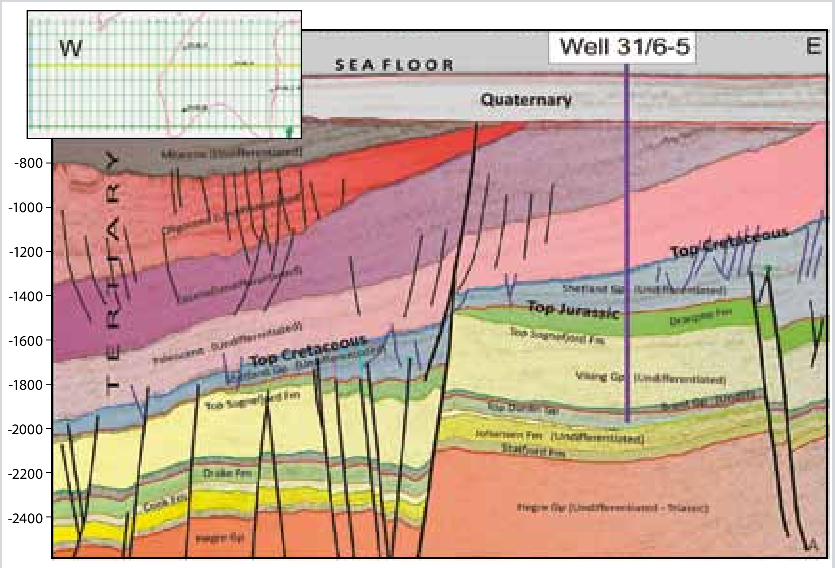
The thickness in the type well is 96 m. In an E-W traverse on the northern part of the Horda Platform the formation thickens to the west towards the northern Viking Graben, where thicknesses in excess of 200 m have been drilled (well 30/11-4). Towards the east the formation thins to a thickness of some tens of meters towards the Øygarden Fault Complex.

The Johansen Fm was probably deposited in a high energy shallow marine shelf with sediment input from the east.

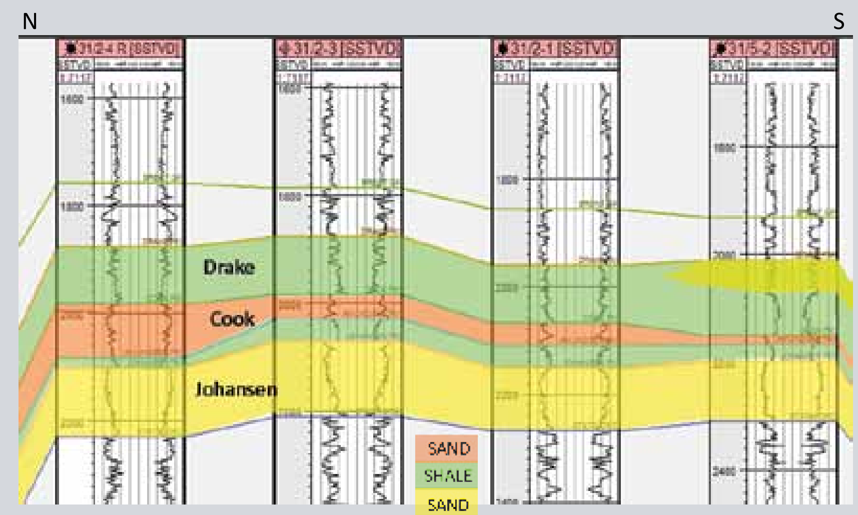
Generally the formation is buried to a depth of more than 2000 m, increasing towards the west into the northern Viking Graben area. In the Troll Field, where the crest of the Johansen Fm is approximately 2300 m, porosities and permeabilities in the order of 15-24% and 100-1000 mD respectively have been recorded.







Gassnova



Core photo well 31/2-3, 2116-2118 m

4.2 Geological description

The Brent Group

AGE: **Uppermost Lower Jurassic to Middle Jurassic** (Upper Toarcian–Bajocian)

The Brent Gp has its type area in the East Shetland Basin and contains five formations; the Broom, Rannoch, Etive, Ness and Tarbert Fm. On the Horda Platform the Oseberg Fm is defined as part of the Brent Gp. Type well and reference well for the Brent Gp is well 211/29-3(UK) and 33/9-1. For the Oseberg Fm the type well is 30/6-7. The lower boundary is the marine silts and mudstone of the Dunlin Gp. The upper boundary is the Heather/Draupne Fm marine mudstones of the Viking Group, forming a regional seal.

The Brent Gp is found in the East Shetland Basin and is recognizable over most of the East Shetland Platform and the northern part of the Horda Platform. South of the Frigg area, broadly equivalent sequences to the Brent Gp are defined as the Vestland Group. To the north the deltaic rocks of the Brent Gp shales out into marine mudstones between 61°30´N and 62° N.

The thickness of the group varies considerably due to differential subsidence and post Middle Jurassic faulting and erosion. Variable amounts of the group may be missing, particularly over the crests of rotated fault blocks.

Depositionally the Brent Gp records the outbuilding of a major deltaic sequence from the south and the subsequent backstepping or retreat. The Oseberg sandstones form a number of fan-shaped sand-bodies with a source area to the east. The sandstones in the lower part are deposited in a shallow marine environment, overlain by more alluvial sands and capped by sand reworked by waves.

Due to the Upper Jurassic faulting, uplift/erosion and differential subsidence, the Brent Group is located at a wide range of depths, varying from 1800 m on the Gullfaks Field to more than 3500 m on the Huldra Field. As a result there is a complex distribution of porosity and permeability.

The Broom Fm (Upper Toarcian to Bajocian) is thin, locally developed, shallow marine coarse-grained and poorly sorted conglomeratic sandstones and a precursor for the regressive sequence of the overlying Rannoch Fm.

The Rannoch Fm (Upper Toarcian to Bajocian) in the type area is well-sorted very micaceous sandstones, showing a coarsening upwards motif, deposited as delta front or shoreface sands. The upper boundary is defined by cleaner sandstones of the overlying Etive Fm. The thickness of the Rannoch Fm in the type area varies between 35 and 63 m.

The Etive Fm (Bajocian) contains less micaceous sandstones than the underlying Rannoch Fm. The upper boundary is the first significant shale or coal of the overlying Ness Fm. The depositional environment for the Etive Fm is interpreted as upper shoreface, barrier bar, mouth bar and channel deposits. The thickness of the formation varies considerably from 11 m to more than 50 m.

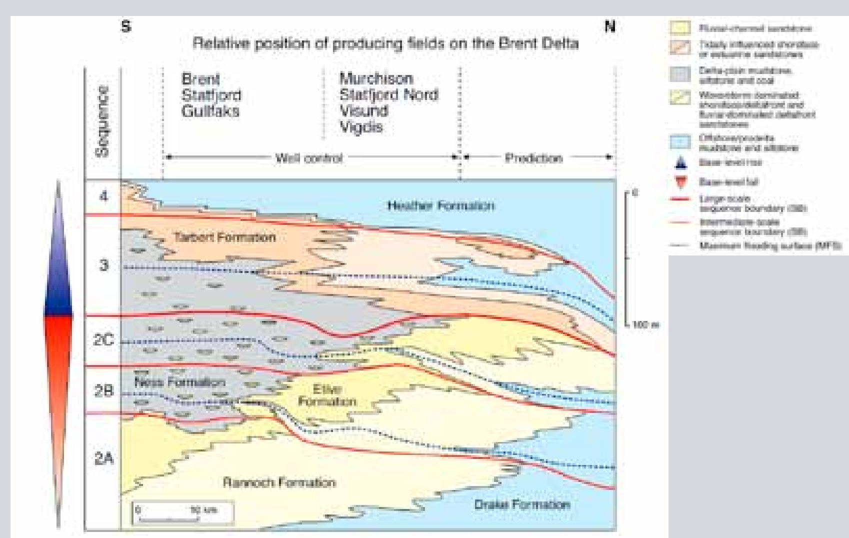
The Ness Fm (Bajocian to Bathonian) consists of an association of coals, mudstones, siltstones and fine to medium sandstones. Characteristic features are numerous rootlet horizons and a high carbonaceous content. The upper boundary is the change to the more massive and cleaner sandstones of the overlying Tarbert Fm. The formation is interpreted to represent delta plain or coastal plain deposition. The amount of siltstones and mudstones in the formation may act as a local seal. The Ness Fm show large thickness variations from 26 m to ca 140 m.

The Tarbert Fm (Bajocian to Bathonian) consists of grey to brown sandstones. The base of the formation is taken at the top of the last fining upward unit of the Ness Fm, either a coal-bearing shale or a coalbed. It is deposited in a marginal marine environment. Thickness in the type area varies between 14 and 45 m.

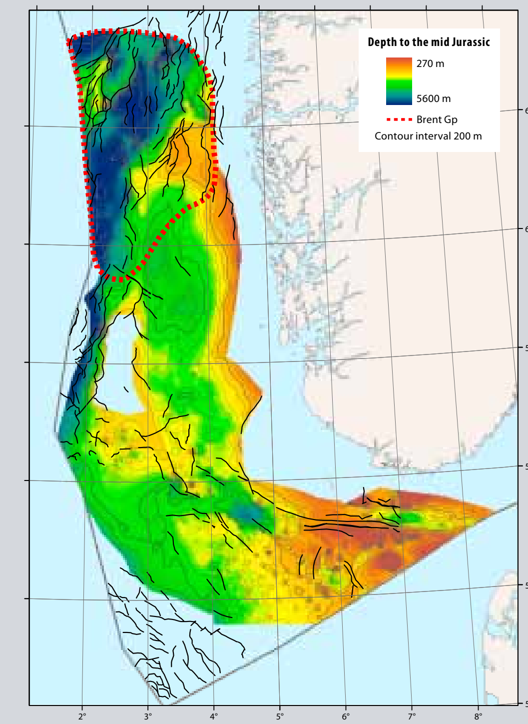
The Oseberg Fm (Upper Toarcian to Lower Bajocian) consists of relatively homogenous coarse-grained sandstones defined from the Oseberg Field (block 30/6) between the Viking Graben and the Horda Platform. The base of the formation is shales of the Dunlin Gp and the upper boundary is the micaceous sandstones of the Rannoch Fm. The formation has been correlated with various formations of the Brent Group, but whereas the Brent Group forms a deltaic unit building out from the south, the Oseberg Fm has its source area to the east. The thickness in the type area is between 20-60 m. The sandstones in the lower part are deposited in a shallow marine environment, overlain by alluvial sands and capped by sand reworked by waves.

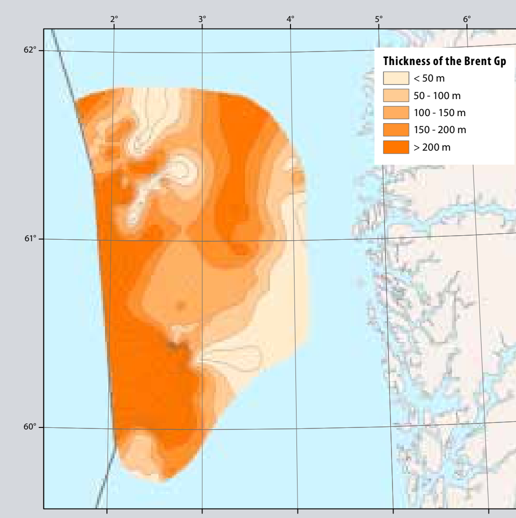
Burial depth of the Oseberg Fm varies between 2100 and 2800 m and porosities and permeabilities in the order of 23-26 % and 250-2000 mD, respectively, are reported.

A time equivalent to the Brent Gp is the Vestland Gp which is defined in the southern part of the Norwegian North Sea.



Cross-section through the Brent delta






Core photo well 30/6-7, 2679-2683 m (Ness Fm)

4.2 Geological description

The Viking Group

AGE: **Upper Middle Jurassic to Upper Jurassic / Lower Cretaceous** (Bathonian to Ryazanian)

The Viking Gp has its type area in the northern North Sea north of 58⁰N and east of the East Shetland Platform boundary fault. The Viking Gp is subdivided into five formations: the Heather, Draupne, Krossfjord, Fensfjord and the Sognefjord Fms. The lower boundary is marked by finer-grained sediments deposited over the sandy lithologies of the Brent and Vestland Gps. In the northernmost area, where the Brent Gp is missing, the Viking Gp often sits unconformably on the Dunlin Gp. The upper boundary is, over most of the area, an unconformity overlain by low radioactivity Cretaceous to Paleocene sediments.

The Heather and Draupne Fms are regionally defined and contain mainly silt and mudstones. The Draupne Fm in particular contains black mudstone with very high radioactivity due to high organic carbon content. The Krossfjord, Fensfjord and Sognefjord Fms represent more sandy facies and are restricted to the Horda Platform and northwards towards 62⁰N.

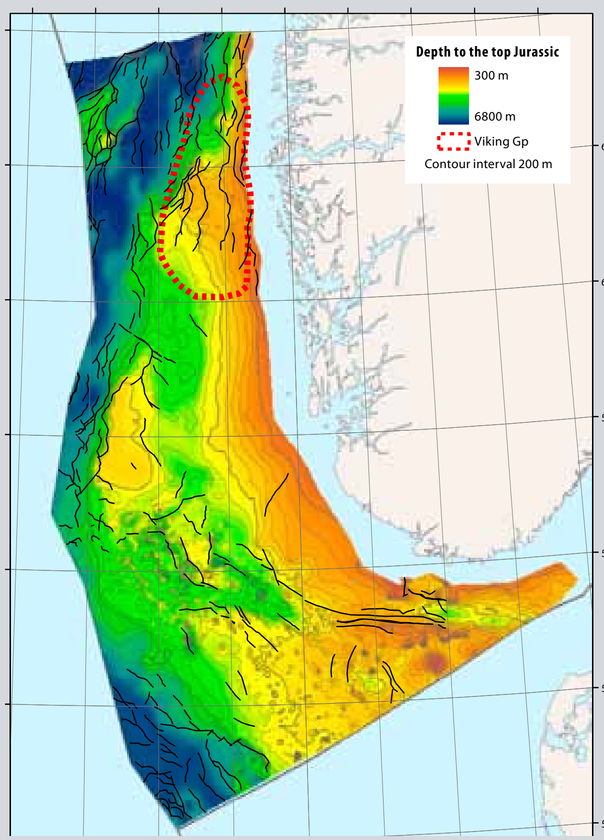
The thickness of the group varies considerably since the sediments were deposited on a series of tilted fault blocks, reflecting pre and syn-depositional fault activity and differential subsidence. The thicknesses from wells vary from a few metres up to 1039 m.

The Heather Fm (Upper Middle Jurassic to Upper Jurassic) overlying the Brent Gp sandy sequences consists of mainly grey silty claystones, deposited in an open marine environment. The type well for the Heather Fm is well 211/21-1A (UK) and 33/9-1. The upper boundary is the radioactive and carbonaceous Draupne Fm.

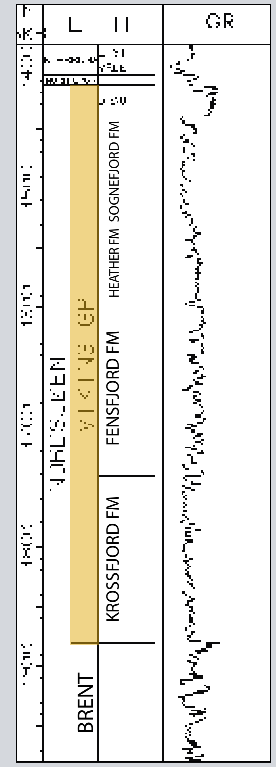
The Draupne Fm (Upper Jurassic/Lower Cretaceous) overlies the Heather Fm diachronically, and on the northern part of the Horda Platform, the Draupne overlies the sandstones of the Sognefjord Fm (type well 30/6-5). The Draupne Fm was deposited in a marine environment with restricted bottom circulation, often with anaerobic conditions. This led to the most prolific hydrocarbon source in the northern North Sea. Time-wise and environmentally, the Draupne Fm is equivalent to the UK Kimmeridge Clay Fm and the Tau Fm of the Norwegian-Danish Basin.

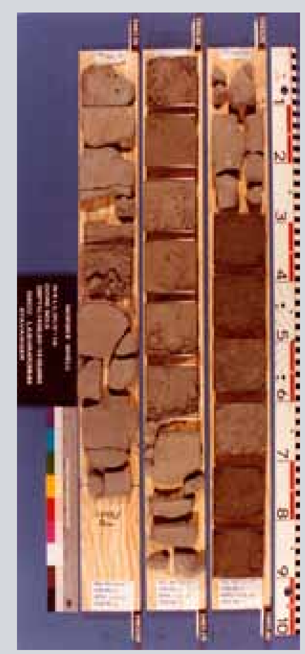
The Krossfjord Fm (Upper Middle Jurassic, Bathonian), **the Fensfjord Fm** (Upper Middle Jurassic, Callovian) and **the Sognefjord Fm** (Upper Jurassic, Oxfordian to Kimmeridgian) represent three coastal-shallow marine sands that interfinger with the Heather Fm on the gigantic Troll Field on the northern part of Horda Platform. The type well is 31/2-1. The total thickness of the three formations is in the order of 400-500 m. Each of the formations has been interpreted in terms of a "forestepping to backstepping" rift marginal wedge. This pattern has been interpreted as the response to eustatic sea-level changes or basin-wide changes in sediment supply, but also as a response to three separate rift events.

The burial depth varies from 1500-1600 m on the Horda Platform to more than 3500 m in the Sogn Graben. Porosities and permeabilities in the order of 19-34 % and 1-1000 mD, respectively, have been reported from the Troll Field. The abundance of detrital mica in the sands is important in controlling the permeability.

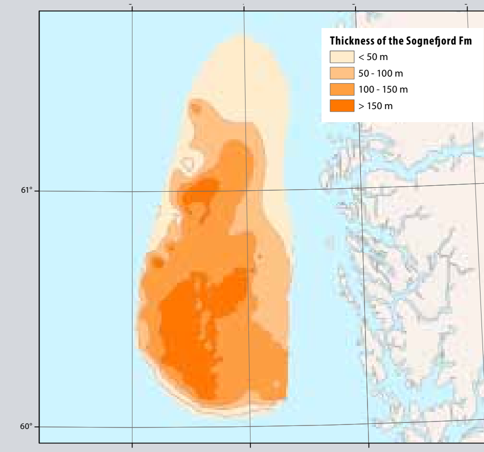


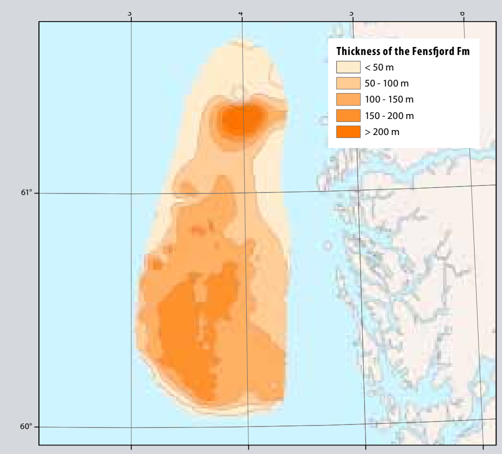
WELL LOG 31/2-1

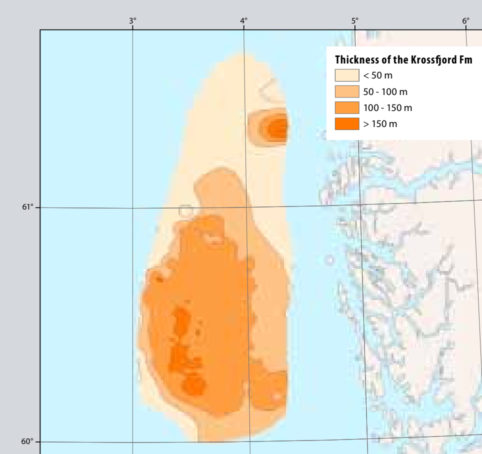




Core photo well 31/2-1R, 1459-1462 m (Sognefjord Fm)







4.2 Geological description

The Skagerrak Formation

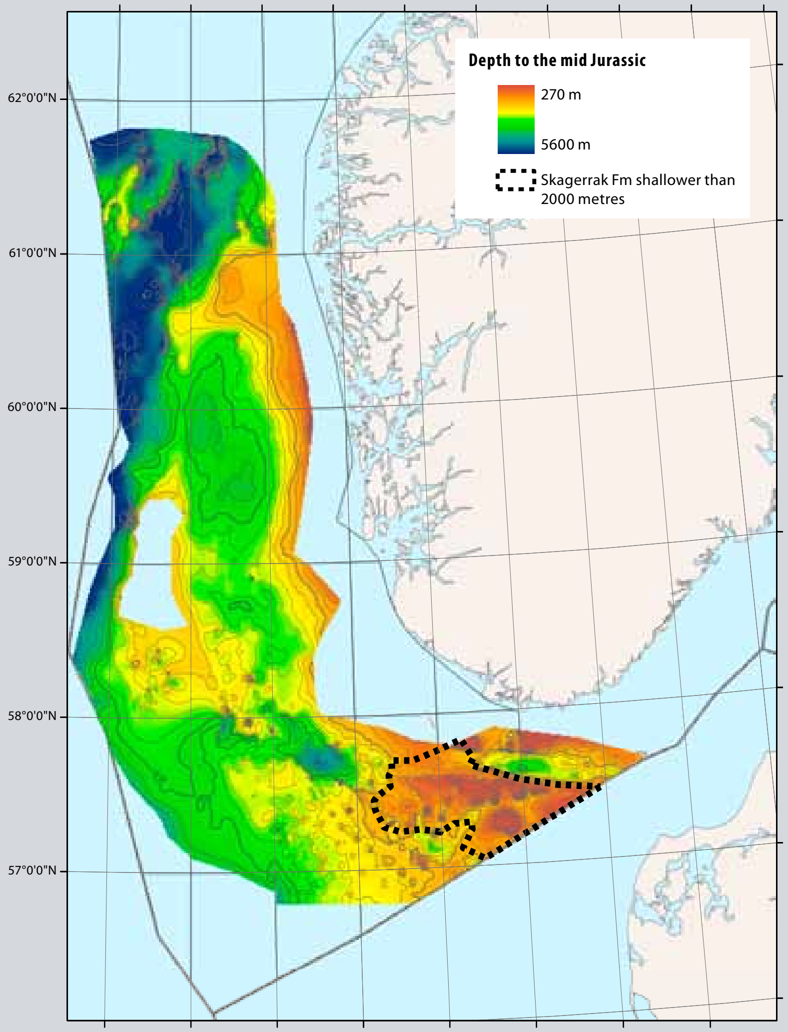
AGE: **Middle to Upper Triassic**

The Skagerrak Fm is present throughout the eastern part of the Central North Sea and the western Skagerrak, but may be missing over structural highs due to erosion and/or halokinesis. The type section is defined in well 10/8-1 in the eastern part of the Norwegian-Danish Basin. The base of the formation is sharp or gradational over claystones of the Smith Bank Fm. Over structural highs the formation may rest on pre-Triassic rocks. The upper boundary is normally an unconformity and overlain by Jurassic or younger sediments, but in a few wells it passes up into the Gassum Fm, a time equivalent to the Statfjord Fm of the northern North Sea.

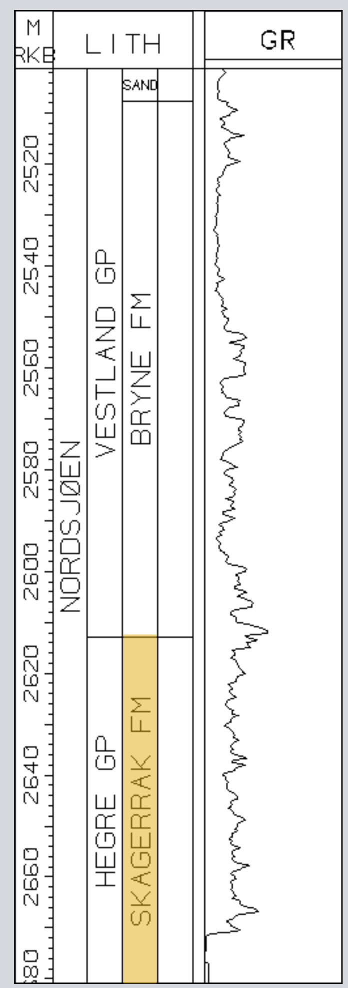
The thickness in the type well is 1182 m, but based on seismic data a maximum thickness in excess of 3000 m is indicated further to the east. To the north-west and south-west, well control indicate a maximum thickness in the order of 660 and 250 m respectively.

The sediments were mainly deposited in alluvial fans and plains in a structurally controlled basin. Minor marine incursions are reflected by the local occurrence of glauconite in the uppermost part of the formation.

The burial depth of the formation in general exceeds 1500 m in western Skagerrak and more than 3000 m in the Egersund and Farsund basins. Porosity and permeability calculations shows mean values of 12.8 % and <10 mD, respectively.



WELL LOG 9/4-3



Core photo well 15/6-7, 3414-3419 m

4.2 Geological description

The Gassum and Fjerritslev Formations

AGE: **Uppermost Triassic to Lower Jurassic**
(Rhaetian in the west, Hettangian-Sinemurian in the northeast)

The Gassum Fm is defined from the Danish well No 1, and in the Norwegian-Danish Basin, well 17/10-1 is used as the reference well. The base of the formation is the Skagerrak Fm and the upper boundary is often the Lower Jurassic shales of the Fjerritslev Fm. In well 11/10-1 the Gassum Fm is overlain by marine silts and mudstones of the Boknfjord Gp forming a regional seal.

The formation is considered to occur throughout the Norwegian-Danish Basin, on the Sørvestlandet High and along the northeastern margin of the Central Graben.

In the Danish part of the basin, the thickness of the Gassum Fm varies from 50 m to more than 300 m northeast of the Fjerritslev Fault Complex. The distribution of the formation in the Norwegian part of the basin is more ambiguous because of few well penetrations. However, very often the wells are located on top or on the flanks of salt structures where the Gassum Fm most likely has been removed by erosion due to halokinesis and/or in relation to the mid-Jurassic erosional episode. Seismic profiles may indicate that the Gassum Fm is present in the Farsund Basin and sub-basins south of the Fjerritslev Fault Complex. Further to the west the formation is absent or below seismic resolution.

The formation represents deposition in fluvio-deltaic, deltaic and shoreface environments influenced by repeated sea level fluctuations.

The mean burial depth exceeds 2000 m in the Norwegian part of the basin, but is less than 1500 m over structural highs, e.g. salt structures. Porosity and permeability calculations are based on Danish well data and show mean values of 20.3 % and 400-500 mD, respectively.

A time equivalent to the Gassum Fm is the Statfjord Fm in northern North Sea.

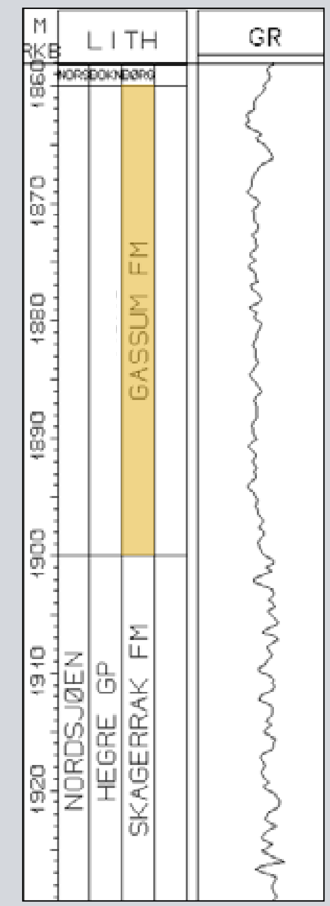
The Fjerritslev Fm is predominantly a silt and mudstone sequence. The type section of the formation is defined in the Fjerritslev-2 well. The lower boundary is defined at an abrupt change from sandy deposits of the Gassum and Skagerrak Fm to the claystones of the Fjerritslev Fm that may form a regional seal. The upper boundary is the overlying Middle to Upper Jurassic sandstones of the Haldager Fm.

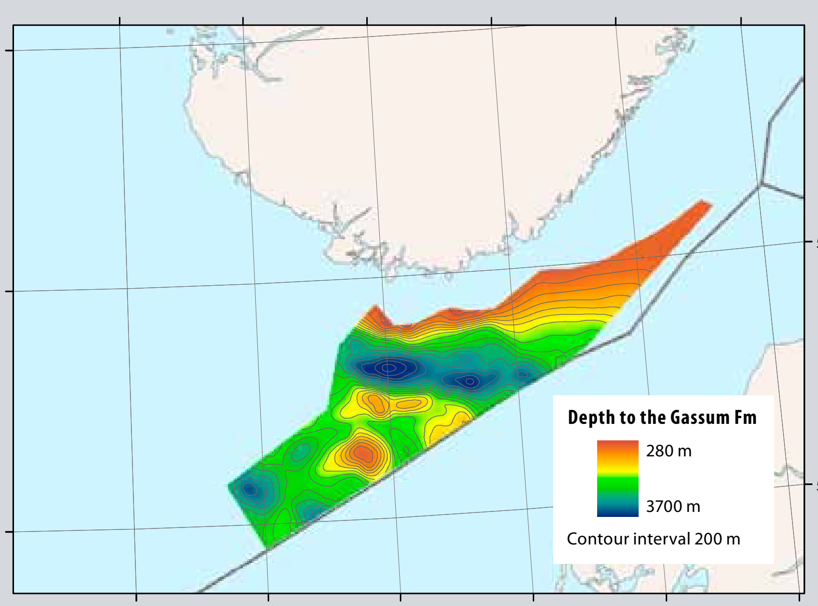
The formation is present over most of the Danish part of the Norwegian-Danish Basin.

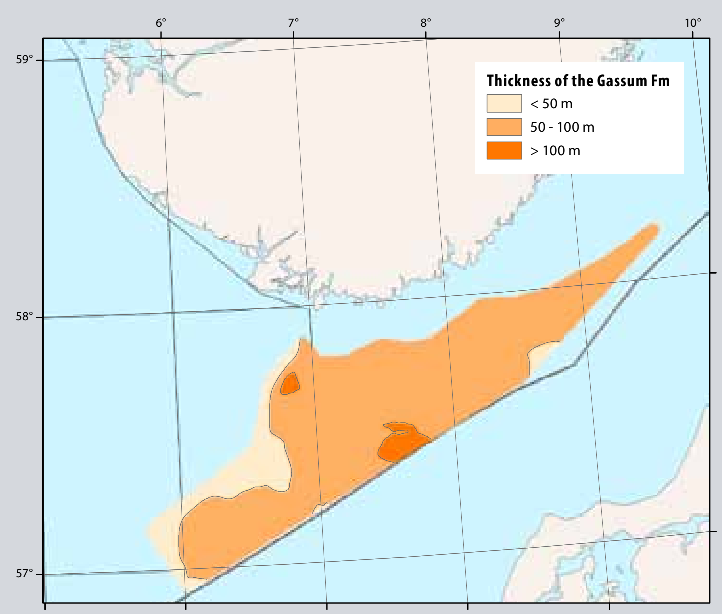
The thickness of the formation may exceed 1000 m locally but is very variable due to basin relief, halokineses and mid-Jurassic erosion. In the Norwegian part of the basin the formation is only patchily preserved. However, similar to the Gassum Fm, seismic profiles reveal intervals, locally more than 300 m thick, which are thinning out or become truncated toward the flanks of salt structures.

The formation represents deposition in a deep offshore to lower shoreface environment.

WELL LOG 11/10 1







The Vestland Group

AGE: **Middle Jurassic to Upper Jurassic**
(Bajocian to Volgian)

The Vestland Gp is divided into five formations: The Sleipner, Hugin, Bryne, Sandnes and Ula Fm.

The lower boundary is the Lower Jurassic mudstones of the Dunlin Gp or the Fjerritslev Fm and the upper boundary is defined by the incoming of mudstone-dominated sequences: The Viking Gp in the Southern Viking Graben, the Tyne Gp in the Central Graben and the Boknfjord Gp in the Norwegian-Danish Basin. These mudstone-dominated groups are important as regional seals.

The Vestland Gp is widely distributed in the southern part of the Norwegian Sea. The Sleipner and Hugin Fm are defined from the Southern Viking Graben fringing the Utsira High. The Bryne Fm is defined from the Central Graben and the Norwegian-Danish Basin, the Sandnes Fm from the Norwegian Danish Basin and the Ula Fm from the western margin of the Sørvestlandet High.

The thickness of the group varies considerably, from 123 to more than 450 m reported from wells, but seismic mapping indicate greater thicknesses in syn-sedimentary fault-bounded sub-basins related to halokinesis. On structural highs the group or part of the group may be missing due to erosion.

The depositional environment varies from deltaic coal-bearing, silt and shale sequences at the base with more marine-influenced sands in deeper parts of the basin. The upper part of the group consists mainly of fairly clean marine sands.

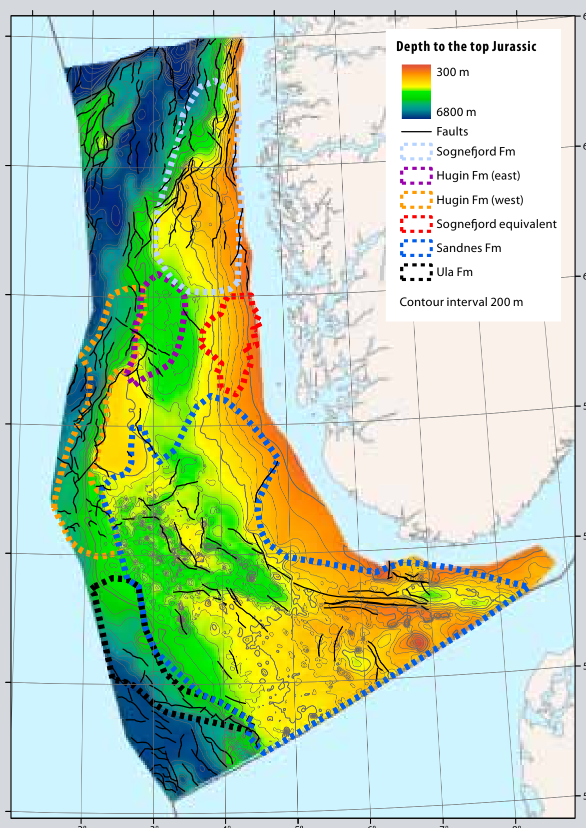
The Sleipner Fm is defined in the southern Viking Graben between approximately 58^0 and 60^0N, in a fluvio-deltaic coaly setting. The Fm is broadly equivalent to the Ness Fm of the Brent Gp in the East Shetland Basin. Thickness in the type area varies between 40 and 50 m. Non-marine sands of equivalent age in the Central Graben and Norwegian-Danish Basin are referred to as the Bryne Fm.

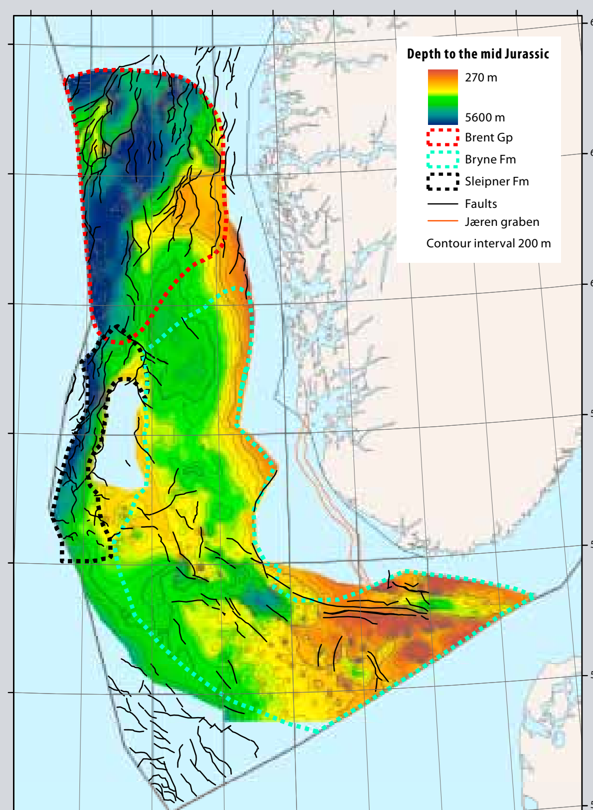
The Hugin Fm, overlying the Sleipner Fm, represents mainly a near-shore, shallow marine sandstone. The Fm is located in the southern Viking Graben in the northern part of the Sørvestlandet High. The upper boundary of the formation represents a transition into silt and mudstones of the Viking Gp. Thickness from wells in the type area is in the order of 50 to 170 m.

The Bryne Fm is defined from the Norwegian-Danish Basin and Central Graben, representing a fluvial/deltaic environment. The base of the Fm is the partly eroded shales of the Fjerritslev Fm or Triassic sandy rocks. The top is defined by siltstones and mudstones of the Boknfjord Gp, forming a regional seal.

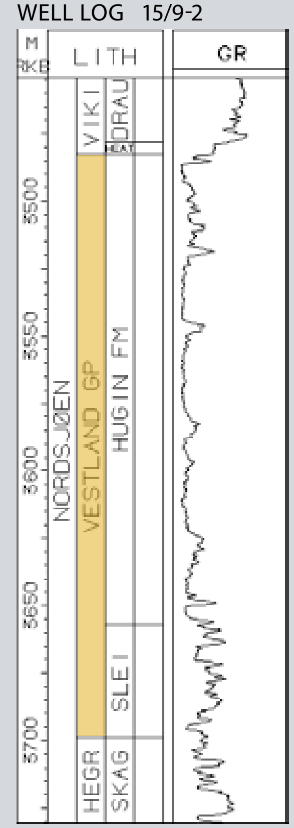
The Sandnes Fm is defined from the northern part of the Åsta Graben and Egersund Basin representing a coastal/shallow marine environment. The contact with the underlying Bryne Fm or older rocks is usually an unconformity and it is overlain by siltstones and mudstones of the Boknfjord Gp.

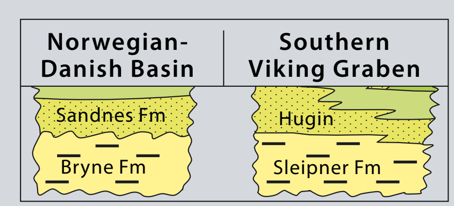
The Ula Fm is defined around the eastern highs flanking the Central Graben and represents a shallow marine deposit. The base of the Fm is towards the non-marine Bryne Fm and the top is where the marine sands are overlain by the silts and mudstones of the Tyne Gp.





WELL LOG 15/9-2





The Sleipner Formation

AGE: **Middle Jurassic** (Bajocian to Early Callovian)

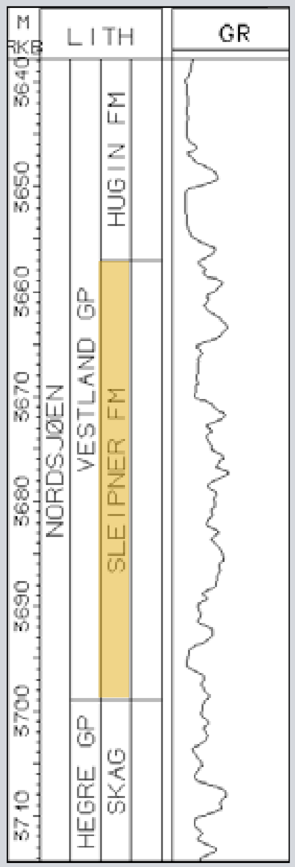
The Sleipner Fm is defined at the base of the Vestland Gp in the southern Viking Graben. The formation lies unconformably over Lower Jurassic and older rocks. The upper boundary in the type well (15/9-2) is the sands of the Hugin Fm, but the formation can also be overlain by shales of the Viking Gp.

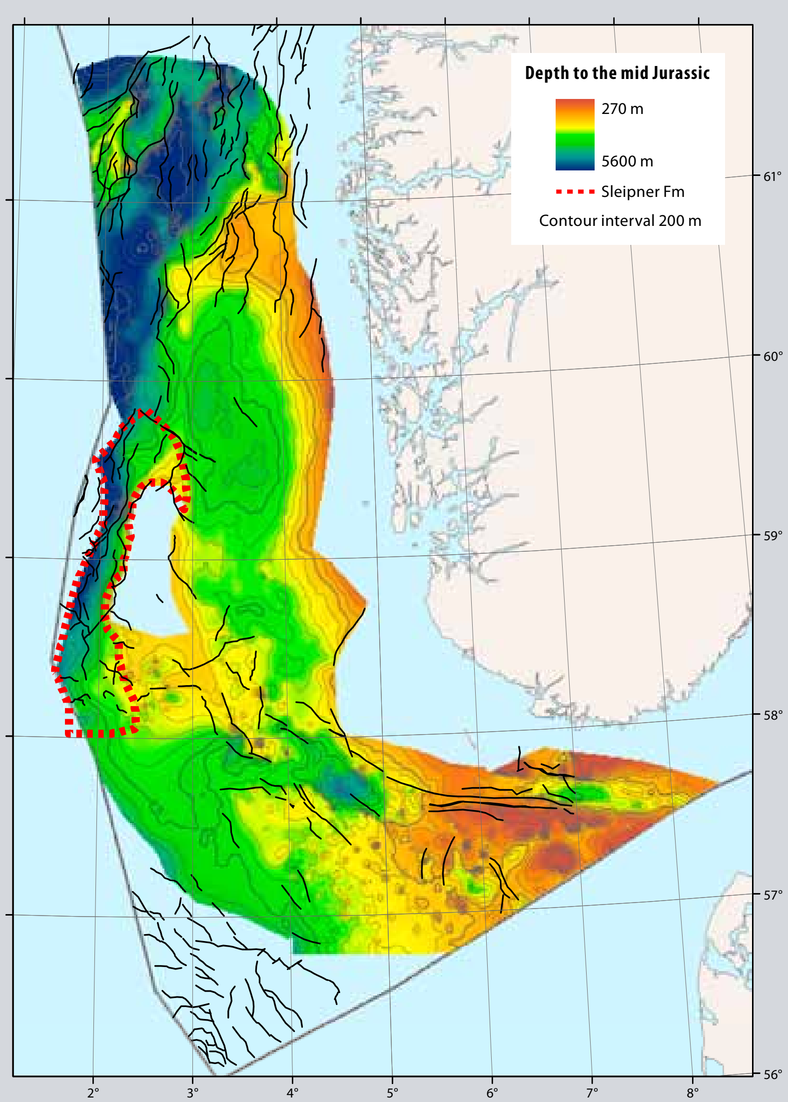
The Sleipner Fm is found in the southern Viking Graben between approximately 58^0 and 60^0N. The Fm is broadly equivalent to the Ness Fm of the Brent Gp in the northern North Sea. The name Sleipner Fm should be applied when the marine sandstones underlying the coal-bearing sequence is missing. Non-marine sands of equivalent age in the Central Graben and the Norwegian-Danish Basin are defined as the Bryne Fm.

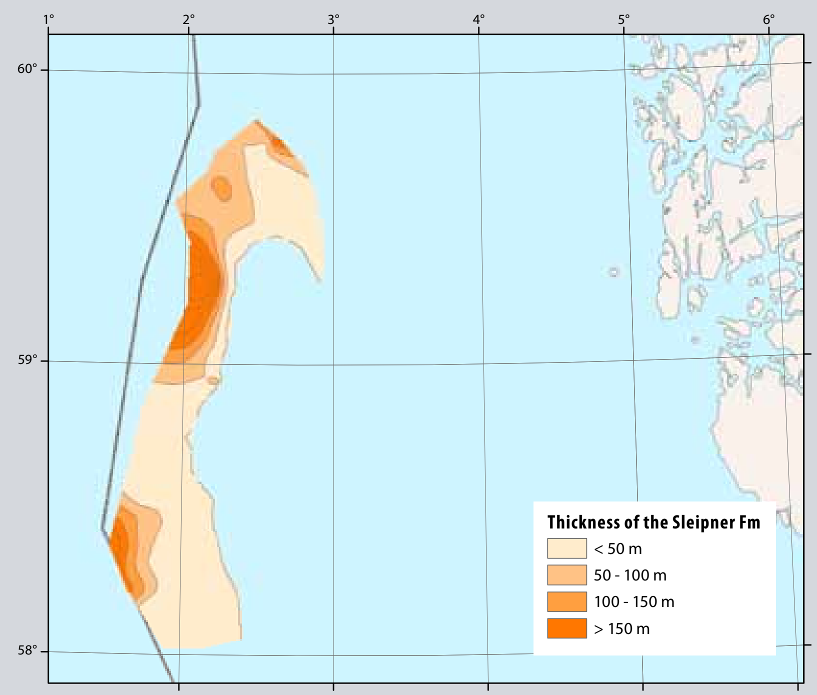
Thickness in the type area varies between 40 and 50 m. The Sleipner Fm represents a continental fluvio-deltaic coal-bearing sequence.

Burial depth of the formation over the Sleipner West Field is approximately 3400 m and average porosities and permeabilities of 16-20 % and 0.1-4000 mD, respectively, are reported.

WELL LOG 15/9-2







Core photo well 15/12-10 S, 3427-3432 m

4.2 Geological description

The Hugin Formation

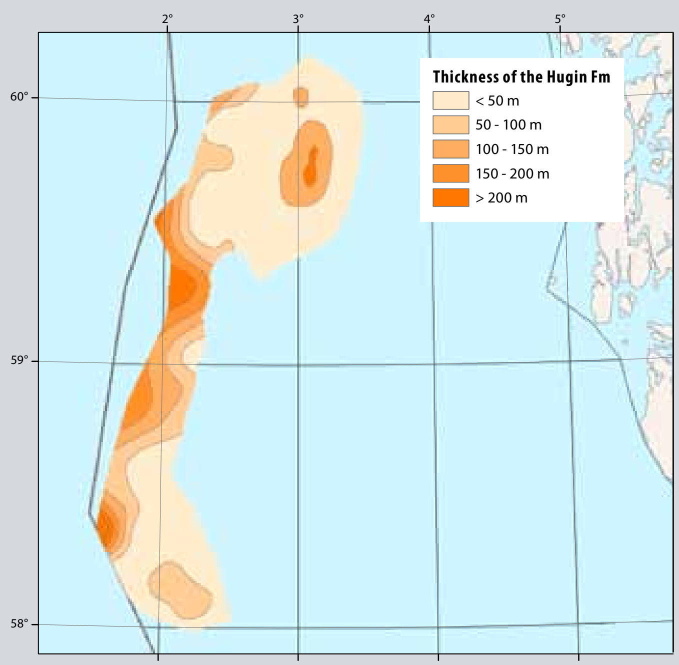
AGE: **Middle Jurassic to Upper Jurassic**
(Lower Bathonian to Lower Oxfordian)

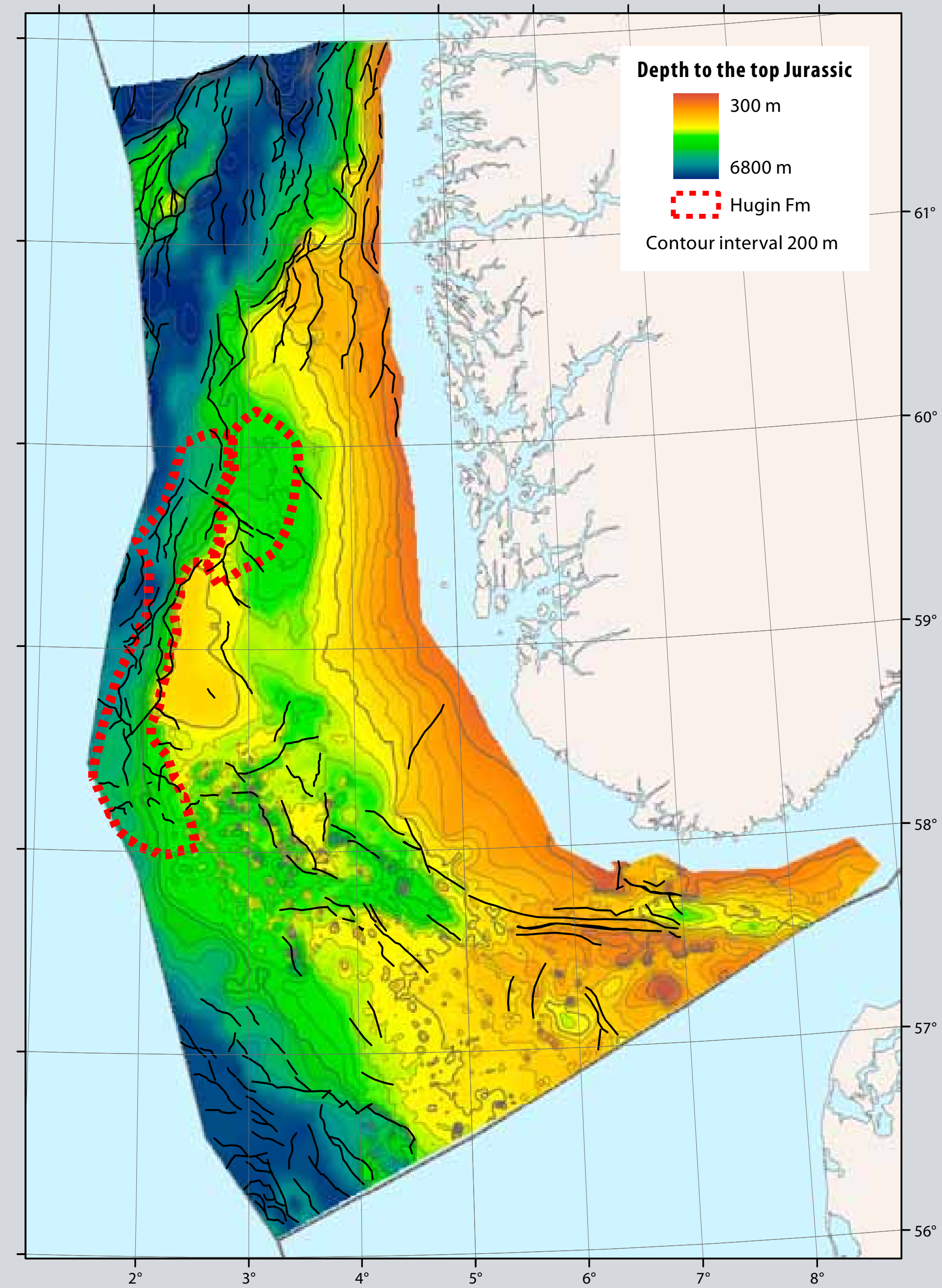
The Hugin Fm is found in the southern Viking Graben in the northwestern part of the Sørvestlandet High, where it overlies the deltaic coal-bearing Sleipner Fm. The upper boundary is the shales of the Viking Gp.

Thickness in the type well 15/9-2 is 174 m. Generally the thickness decreases to the east and north. The thickness distribution of the Hugin Fm is partly controlled by salt tectonics.

The depositional environment is interpreted in terms of a near-shore, shallow marine environment with some continental fluvio-deltaic influence.

Burial depth of the formation over the Sleipner West Field is approximately 3400 m and average porosities and permeabilities of 16-20 % and 0.1-4000 mD, respectively, are reported.





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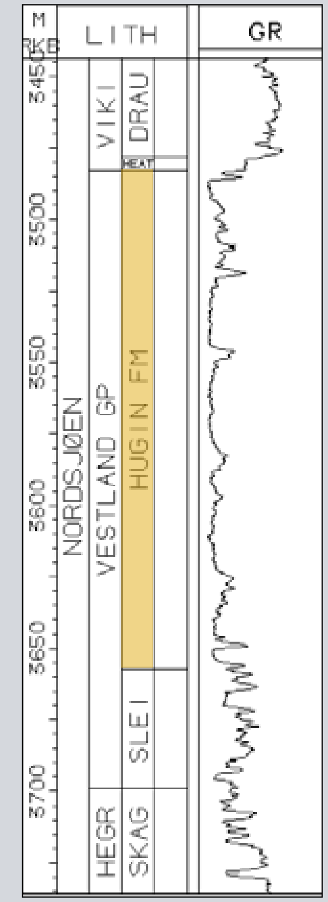


Core photo well 25/2-15R2, 3574-3579 m

4.2 Geological description

The Bryne Formation

AGE: **Middle Jurassic** (Bajocian to Early Callovian)

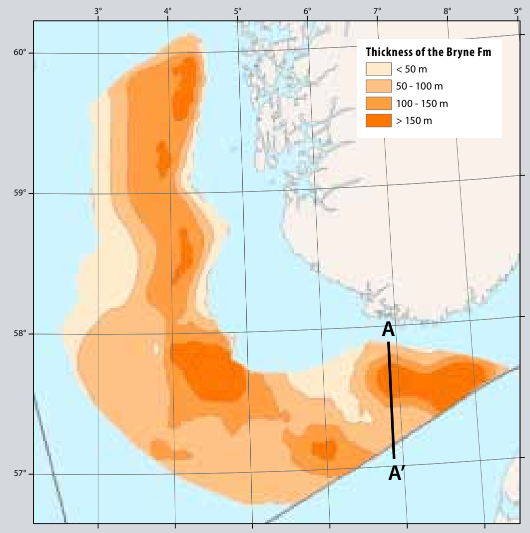
The Bryne Fm forms the base of the Vestland Gp in the Norwegian-Danish Basin and in the Central Gaben. The lower boundary represents an unconformity, with partly eroded shales of the Fjerritslev Fm or with Triassic rocks below. The upper boundary is siltstones and mudstones of the Boknfjord Gp that could form a regional seal.

The type section for the formation is defined in well 9/4-3 with a thickness of 106 m. The formation is thin and patchy in western Skagerrak, but the seismic indicates thicknesses of several hundred meters in syn-sedimentary fault-bounded sub-basins, e.g. Egersund and Farsund Basins, and local depocentres south of the Fjerritslev Fault Zone.

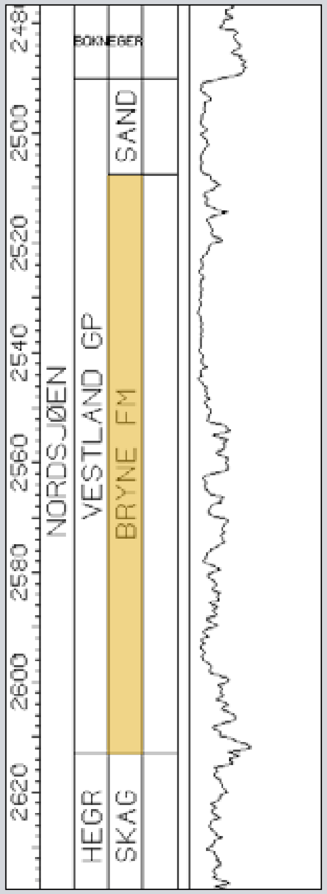
The Bryne Fm reflects deposition in fluvial, deltaic and lacustrine environments. Shallow marine environments may in periods have prevailed in the fault-controlled sub-basins.

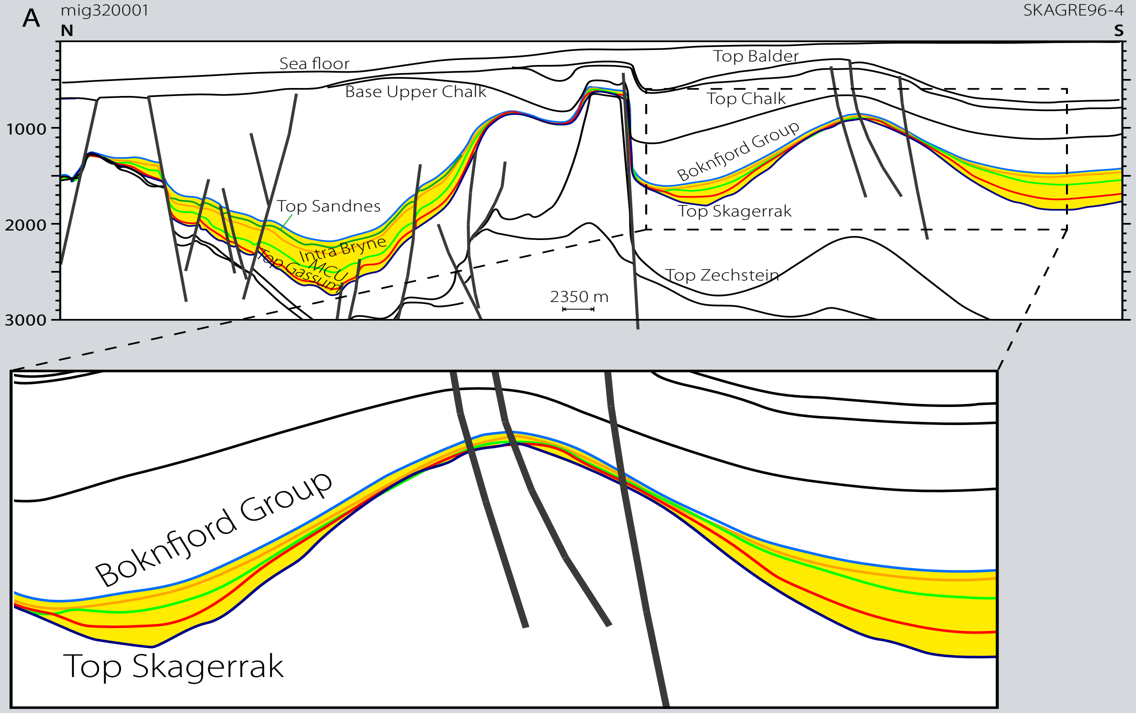
The burial depth is in general more than 1500 m, except over structural highs where it may be less than 1000 m. In the Egersund Basin the burial depth exceeds 3000 m. Porosity and permeability calculations shows mean values of 20.4 % and 100-200 mD, respectively.

The formation corresponds to the Haldager Fm in the Danish part of the Norwegian-Danish Basin.

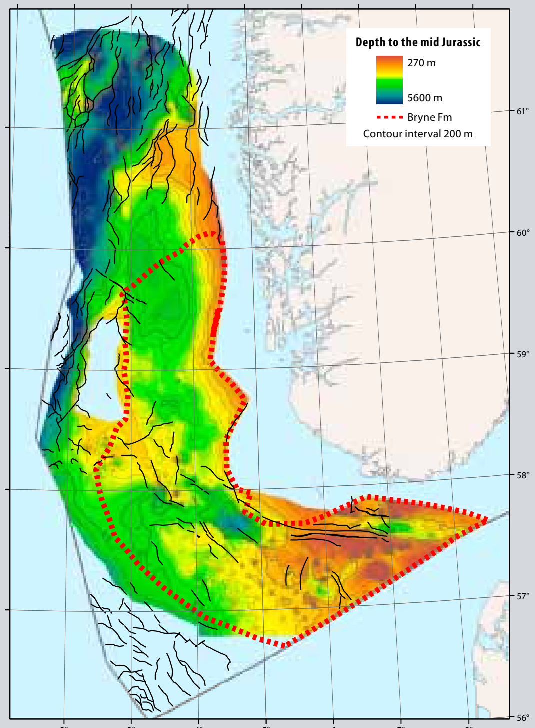


WELL LOG 9/4-3





The enlarged rectangle shows the Jurassic section within a salt-induced structure. MCU is the base of the Bryne Formation.



Core photo well 3/7-4, 3479-3483 m

4.2 Geological description

The Sandnes Formation

AGE: **Middle Jurassic to Upper Jurassic**
(Upper Callovian to Lower Oxfordian)

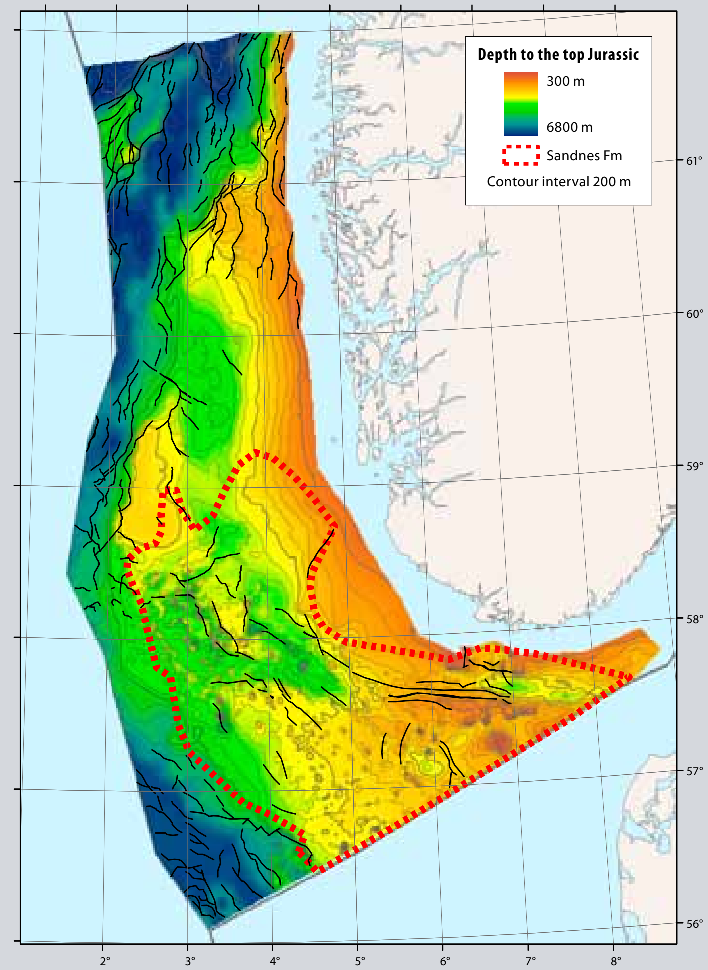
The Sandnes Fm is defined from the Norwegian-Danish Basin. The lower boundary, to the non-marine Bryne Fm or older rocks, is commonly defined at the base of massive and clean sand. The upper boundary is the marine silts and mudstones of the Boknfjord Gp, which could form a regional seal. The type section for the formation is well 9/4-3.

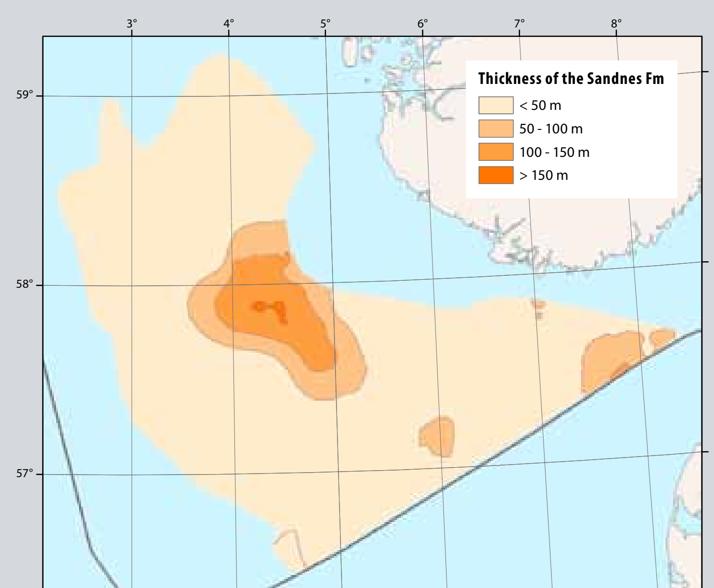
The formation is developed in the southern part of the Åsta Basin and the Egersund Basin. Based on seismic mapping and well data in the Egersund Basin, the thickness in large areas exceeds 100 m. Similar thicknesses may be reached in other local depocentres, but otherwise the thickness is less than 50 m. Where the Sandnes Fm is thick, the lower part may represent a distal facies that is time equivalent to the uppermost part of the Bryne Fm.

The Sandnes Fm mainly reflects deposition in a shallow marine (e.g. shoreface) to offshore environment.

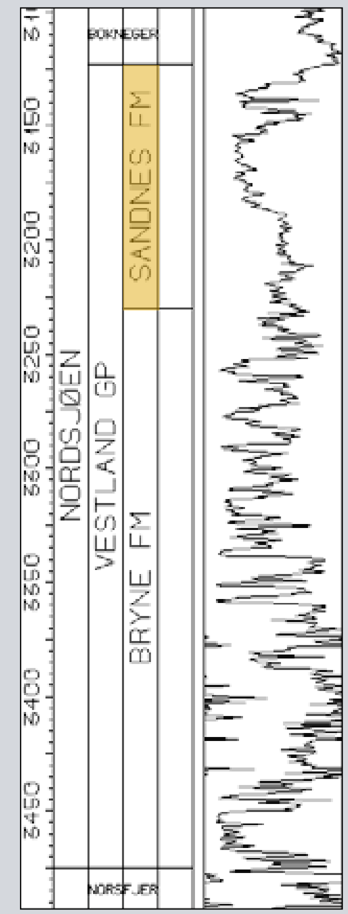
The burial depth is in general more than 1500 m except over structural highs where it may be less than 1000 m. In the Egersund and Farsund basins and the south-western part of the Åsta Graben the burial depth exceeds 2500 m. Porosity and permeability calculations show mean values of 23.0 % and 400-500 mD, respectively.

The formation is broadly comparable in lithofacies and depositional environments with the Hugin Fm in the southern Viking Graben.





WELL LOG 9/2-2



Core photo well 3/7-4, 3452-3457 m

4.2 Geological description

The Ula Formation

AGE: **Upper Jurassic-Lower Cretaceous**
(Oxfordian- Ryazanian)

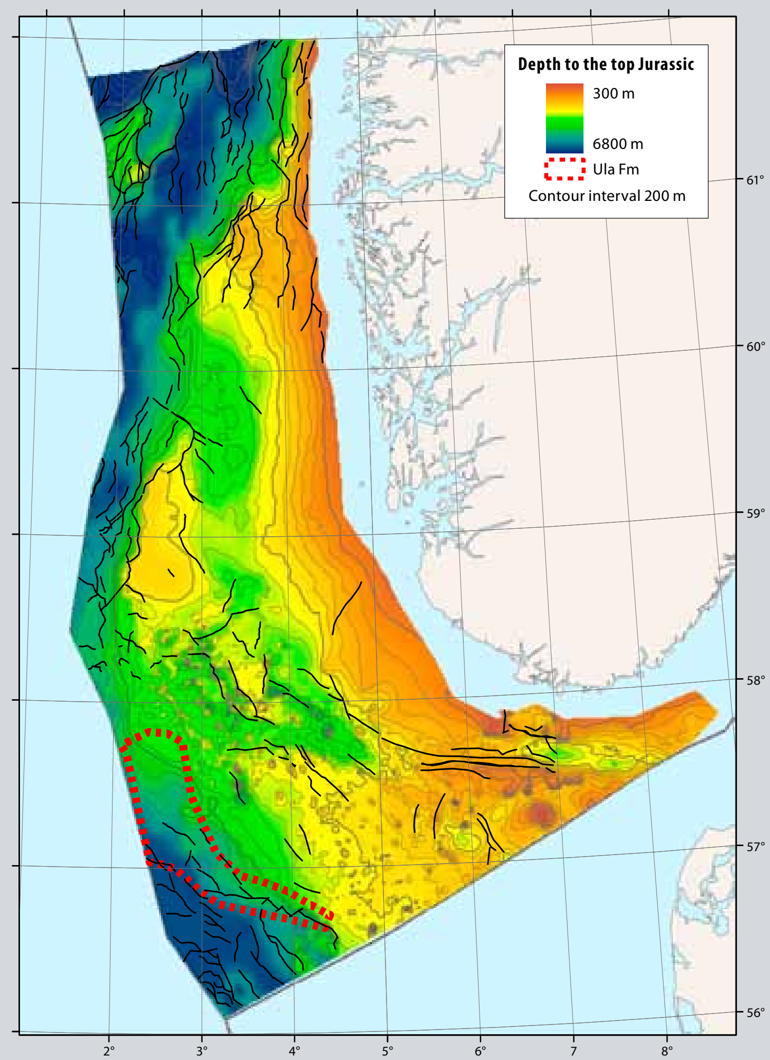
The Ula Fm is defined from the western boundary of the Sørvestlandet High from the Ula Field. The base of the formation is the non-marine Bryne Fm and the top is the marine siltstones and mudstones of the Tyne Gp, forming a regional seal.

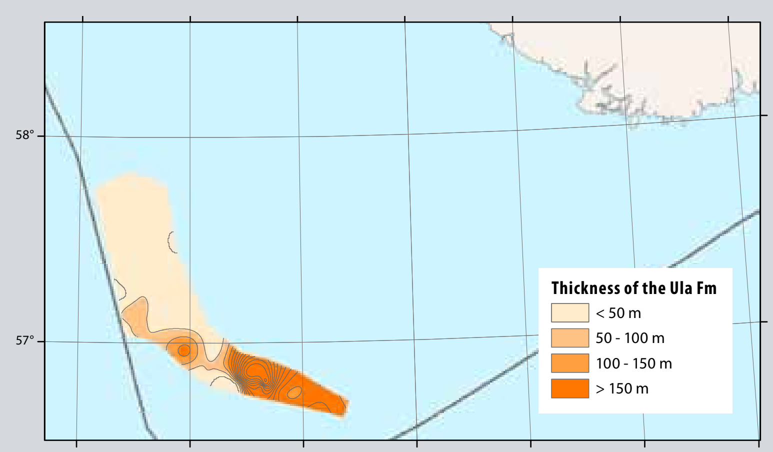
The Ula Fm is defined around the eastern flanking highs of the Central Graben, in particular on the south-west flank of the Sørvestlandet High, and moving towards the basin, i.e. to the west, into marine shale. In the type well 7/12-2 the thickness is 152 m. It thins rapidly towards the east, but can be followed along the NW-SE structural grain controlled by halokinesis.

The sands of the Ula Fm are generally deposited in a shallow marine environment.

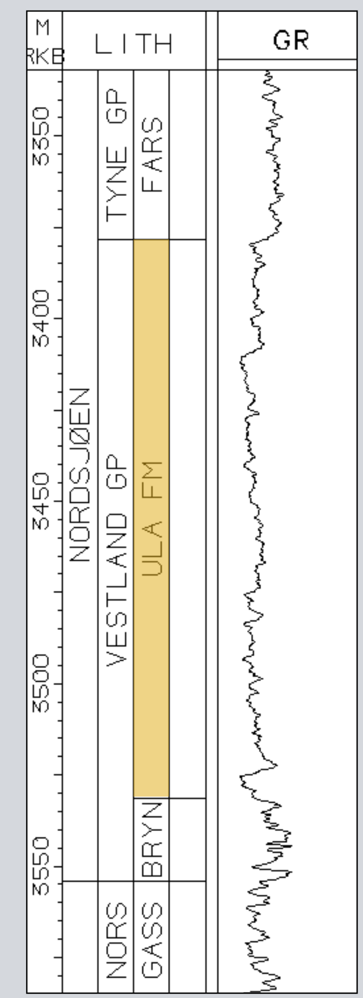
In the type area, the Ula Fm is buried to a depth of more than 3000 m. In the Ula Field the crest of the structure is 3345 m and porosities and permeabilities are reported in the range 15-22 % and 0.2-2800 mD, respectively.

The Ula Fm has similarities both in lithofacies and partly in age with the Hugin Fm in the southern Viking Graben (Sleipner area) and the Sandnes Fm in the Norwegian-Danish Basin.





WELL LOG **7/12-2**



Core photo well 2/12-1, 4648-4653 m

4.2 Geological description

The Boknfjord Group

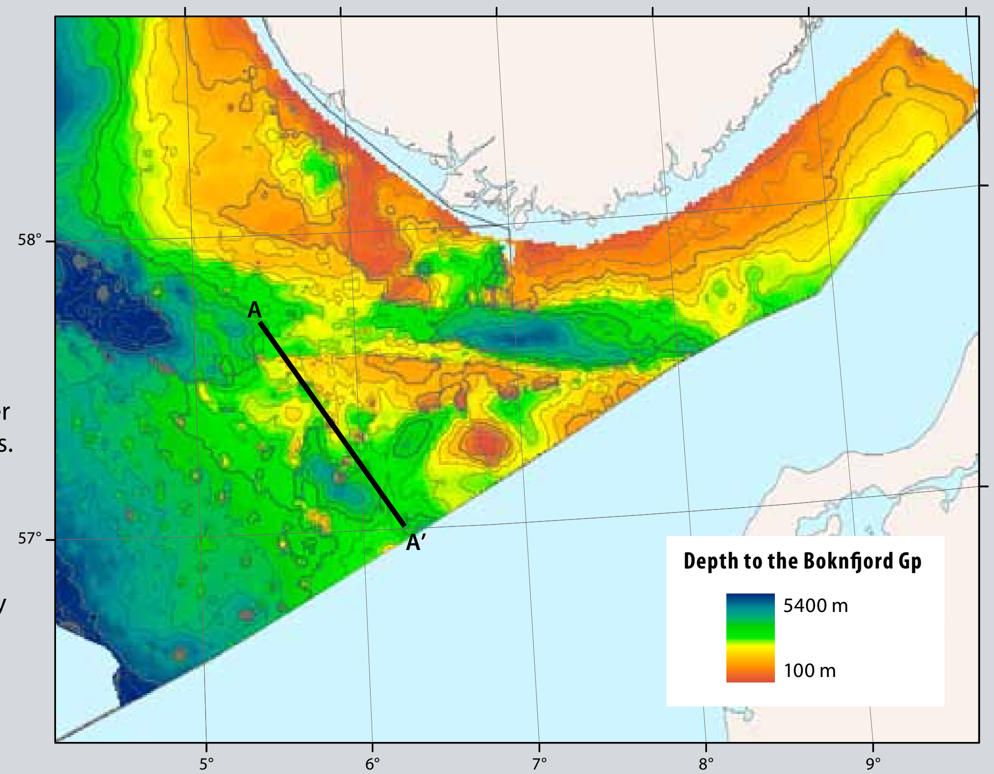
AGE: **Middle Jurassic to Upper Jurassic**
(Callovian to Ryazanian)

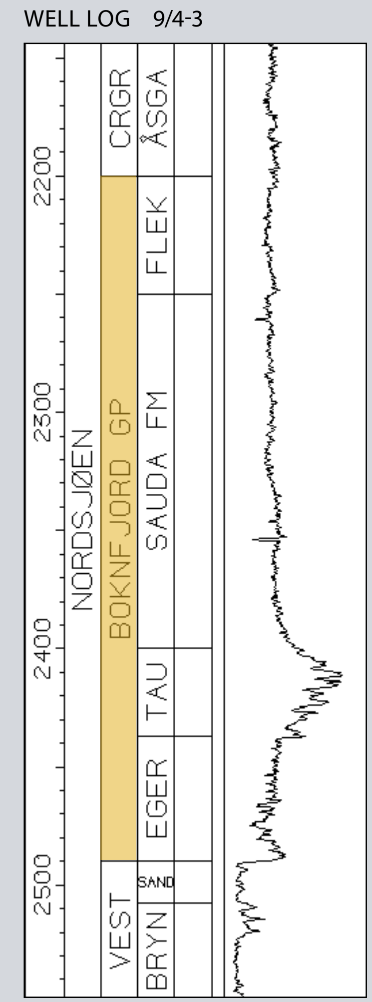
The Boknfjord Gp is defined from the Fiskebank and Egersund Basin and the type well is well 9/4-3. The Boknfjord Gp is dominated by shales and is considered as the primary seal for the underlying potential CO_2 aquifers. The group is subdivided into four formations:

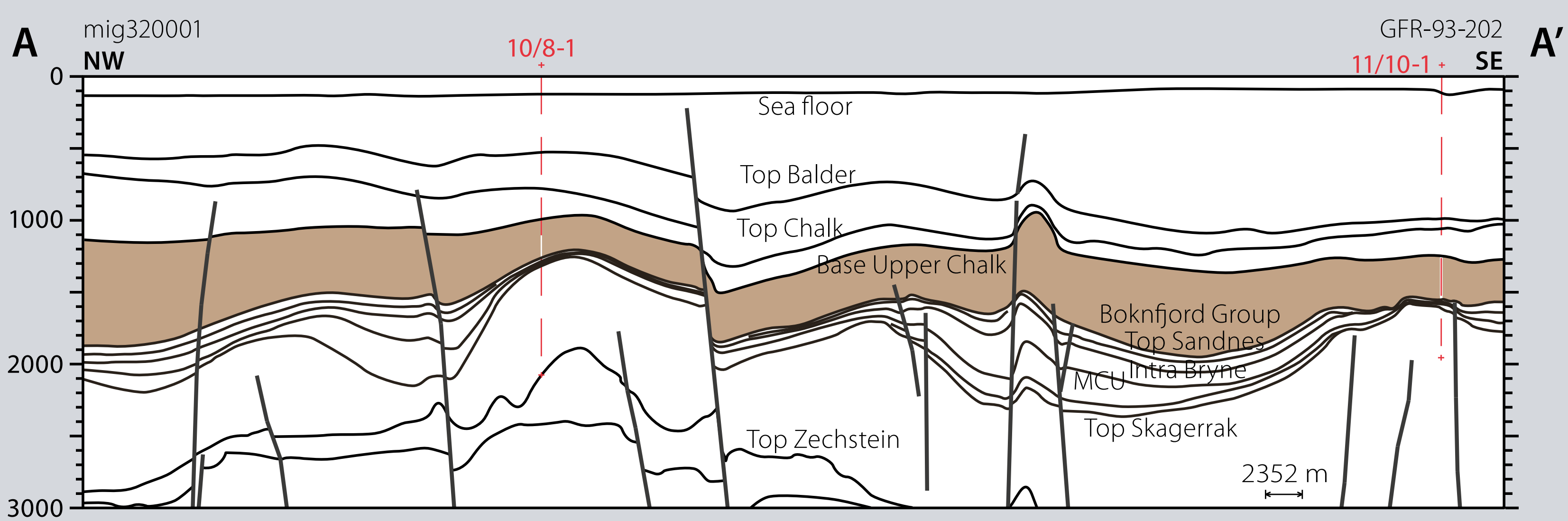
The Egersund (base), Tau, Sauda and Flekkefjord Fms. As all of the formations have seal properties, they will be treated as one composite seal. The lower boundary is the sandstones of the Sandnes or Bryne formations. The upper boundary is the Cromer Knoll Gp dominated by claystones.

The Boknfjord Gp is present in the Norwegian part of the Norwegian-Danish Basin. Well data show that the group in general is more than 100 m thick in western Skagerrak, and in the Egersund Basin up to 500 m thick. The upper boundary is the Cromer Knoll Gp dominated by mudstones with a varying content of calcareous material. It forms a secondary seal for the underlying potential CO_2 aquifers. The Boknfjord and Cromer Knoll Gp form a combined seal which can be mapped seismically. The seal is in general several hundred metres thick and may be more than 2000 m thick in the Egersund and Farsund Basins. The sealing package is locally truncated by salt diapirs, as seen in well 11/9-1.

The sediments of the Boknfjord Group were mainly deposited in open marine, low energy basin environments.







4.2 Geological description

The Rogaland Group

AGE: **Paleocene-Lower Eocene**

The Rogaland Gp is subdivided into twelve formations. This description will focus on possible aquifers. In general the sequences start off from the west as more proximal and interfinger with more distal sediments to the east. The group is widely developed in the northern and central North Sea. The base of the group is the contact with underlying chalk or marl sequences of the Shetland Gp. The upper boundary is the change from laminated tuffaceous shales (Balder Fm) to sediments of the Hordaland Gp.

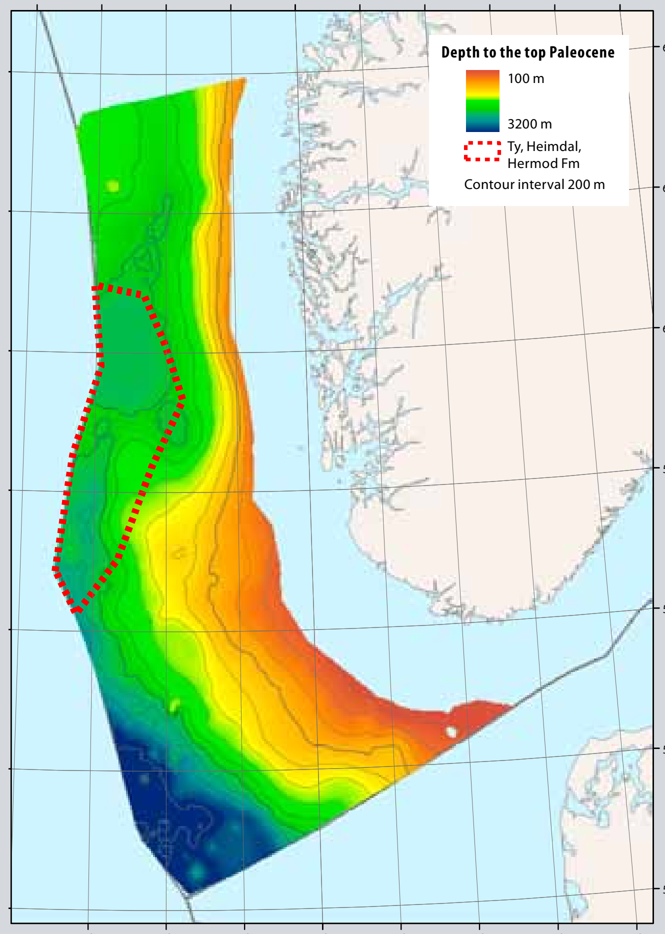
The Rogaland Gp is thickest in the west in the UK sector (ca 700 m), thinning eastwards and southwards with recorded well thickness in the order of 100 m.

Depositionally the Rogaland Gp represents submarine fan /gravity flow sediments transported into deeper water. The sand-bodies are generally lobe shaped and pass laterally into silt and mudstones to the east.

The Ty Fm (Lower Paleocene) was deposited from the Shetland Platform as a deep marine fan and has been identified in the southern Viking Graben in the north-western part of quadrant 25, and northern part of quadrant 15. The formation consists mainly of clean sandstones with a thickness in well 15/3-1 of 159 m. The lower boundary is calcareous rocks of the Shetland Gp, and the upper boundary is transitional to the shales of the Lista Fm, but also against the sands of the Heimdal Fm. The formation may also interfinger with the Våle Fm to the east.

The Heimdal Fm (Paleocene) was deposited as a submarine fan sourced by shallow marine sands on the East Shetland Platform. It is identified in the western parts of quadrant 30, most of quadrant 25 and 15 and as cleaner sand in the south-eastern part of quadrant 15 into the north-western part of quadrant 16 (Meile Mbr (informal)). The thickness of the Heimdal Fm is 356 m in the type well (25/4-1) and 236 m in well 15/9-5. It thins rapidly east of these wells and south of well 15/9-5. The base is usually the transition from the shales of the Lista Fm, but also sandstones of the Ty Fm. The upper boundary is usually a transition from the Heimdal sandstones into the shales of the Lista Fm. Locally it is overlain by the sands of the Hermod Fm.

The Hermod Fm (Upper Paleocene) consists of mainly fine-grained sandstones deposited in a submarine fan setting connected to the deltaic Moray Gp in the UK sector. The formation is located mainly in the South Viking Graben in the north-western part of quadrant 25 and extends into the southern part of quadrant 30. The thickness of the formation is 140 m in the type well 25/2-6 and it thickens toward the central part of the distribution area. The lower boundary of Hermod Fm is usually a transition to silts and mudstones of the Lista Fm or the Sele Fm. It may also rest directly on the more varied sandstones of the Heimdal Fm. The upper boundary of the Hermod Fm is sharp against the dark silt and mudrocks of the time-equivalent Sele Fm.

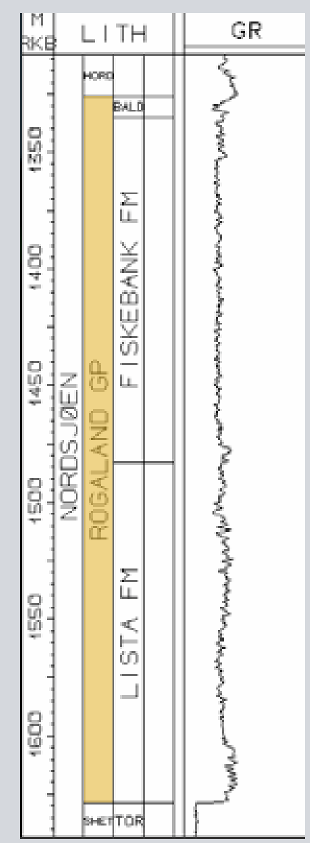


The Fiskebank Fm (Upper Paleocene) has been identified from the Norwegian-Danish Basin and in the type well, 9/11-1, with a thickness of 148 m. The lower boundary is silt and mudstones of the Lista Fm and the upper boundary is tuffaceous shales of the Balder Fm. The formation is developed mainly in the Åsta Graben in the Norwegian-Danish Graben.

The thickness in wells varies between 26 to 148 m. The Fiskebank Fm probably represents basin margin deposit and appears to be mostly time equivalent with the Sele Fm.

The Balder Fm (Paleocene to Upper Eocene) consists of varicoloured laminated shales, interbedded with sandy tuffs and distributed over much of the North Sea. The thickness varies between less than 20 m to more than 100 m. The Balder Fm was deposited in a deep marine environment and the tuffaceous material probably came from more than one volcanic source. The lower boundary of the Sele or Lista Fm is marked by the incoming of tuffaceous material. The upper boundary is defined at the transition from the laminated Balder Fm to the non-laminated, often glauconitic and reddish overlying sediments of the Hordaland Gp.

WELL LOG 9/11-1



4.2 Geological description

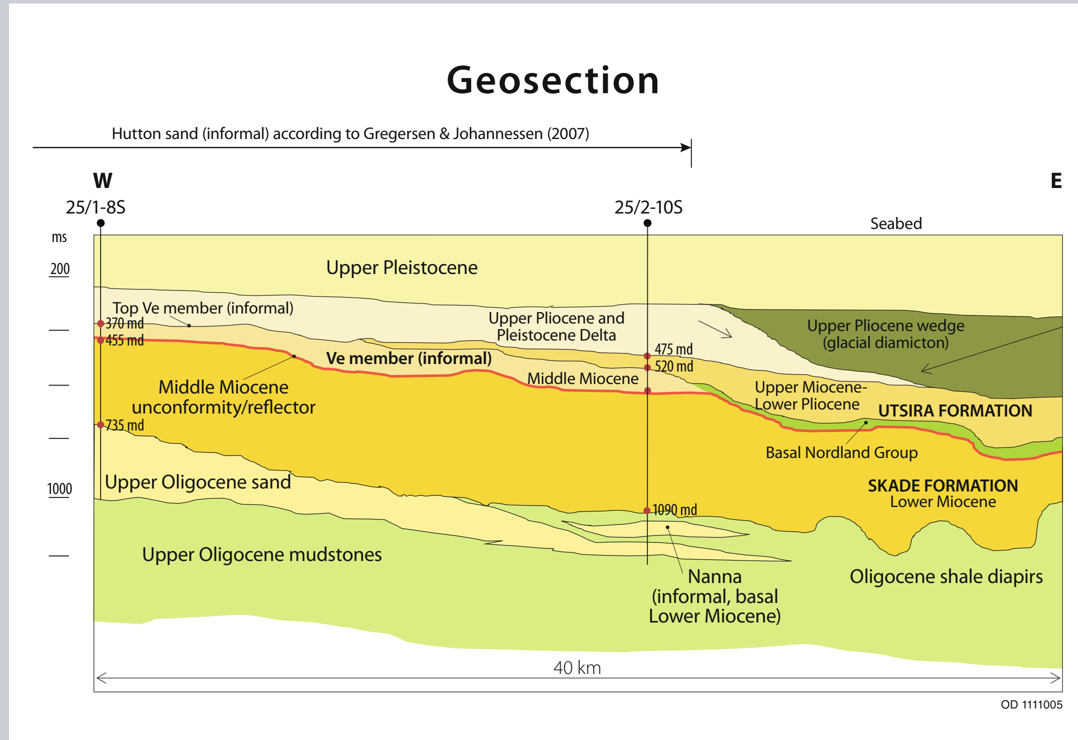
The Skade Formation

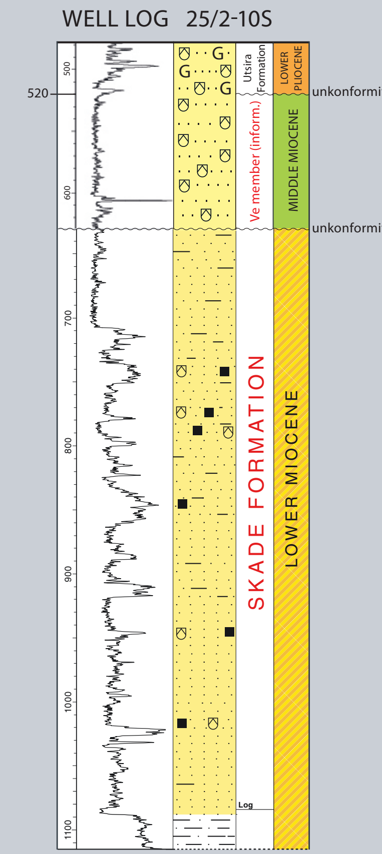
AGE: **Early Miocene**

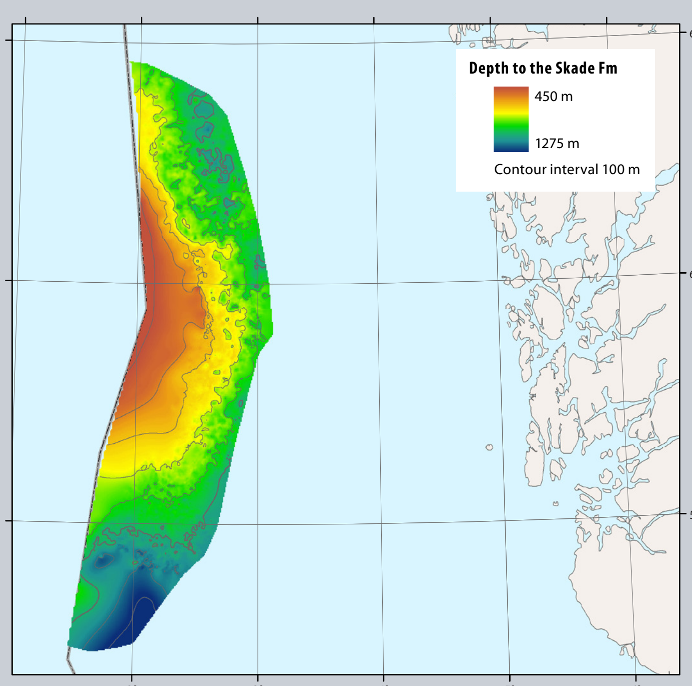
The Skade Formation, the Ve Member (informal), the Utsira Formation and Upper Pliocene sands of the Nordland Group form the outer part of a large deltaic system with its source area on the East Shetland Platform. The proximal parts of this system are mainly located in the UK sector, and these deposits are named the Hutton sand (informal). In the Norwegian sector, the Miocene –Lower Pliocene sands belonging to the system are the Skade Fm, Ve Mbr (informal name) and Utsira Fm .

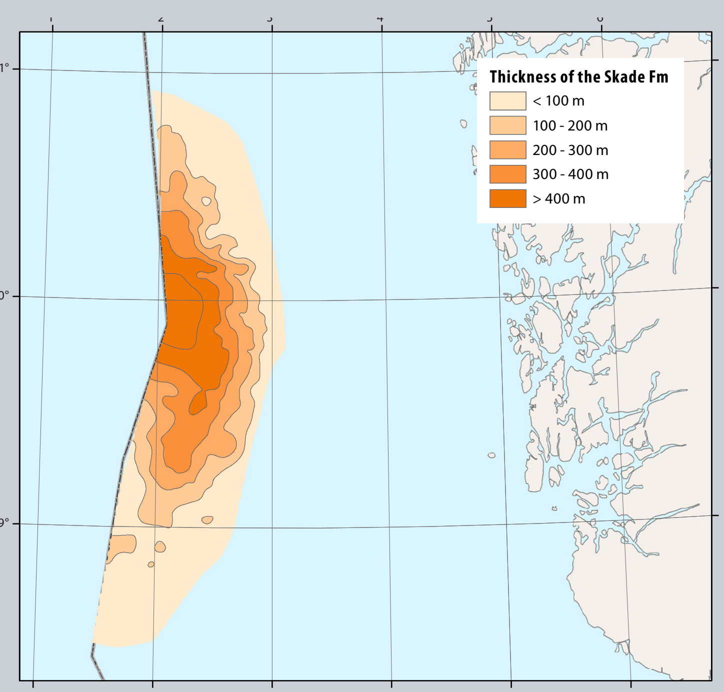
The Skade Fm, Lower Miocene, consists of marine sandstones (turbidites?) deposited over a large area of the Viking Graben (from 16/1-4 in the south to 30/5-2 in the north). The maximum thickness exceeds 300m and decreases rapidly towards the east, where the sands terminate towards large shale diapirs.

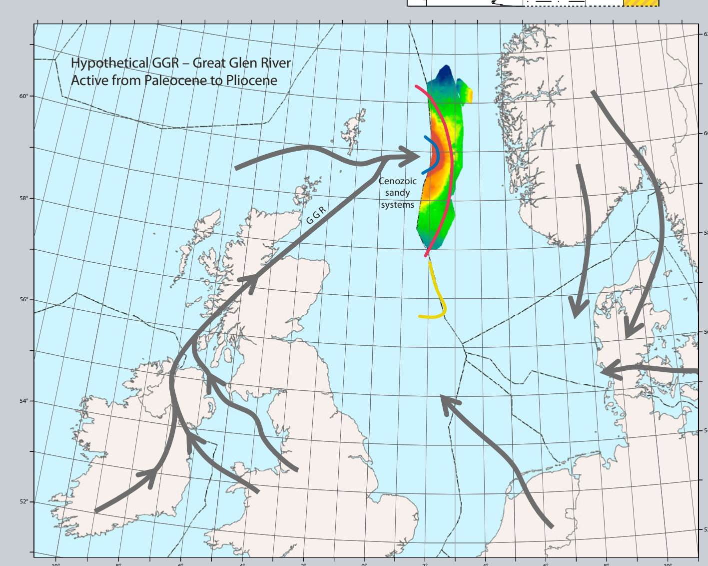
The Ve Mbr (informal), Middle Miocene, is a more local sand development, recorded in a few wells in the Viking Graben, including 15/9-13 in the south-east and 25/10-2S farther north. The Ve Mbr overlies the mid Miocene unconformity and forms the base of the Nordland Gp. Elsewhere in the North Sea the Middle Miocene is dominantly mudstones.











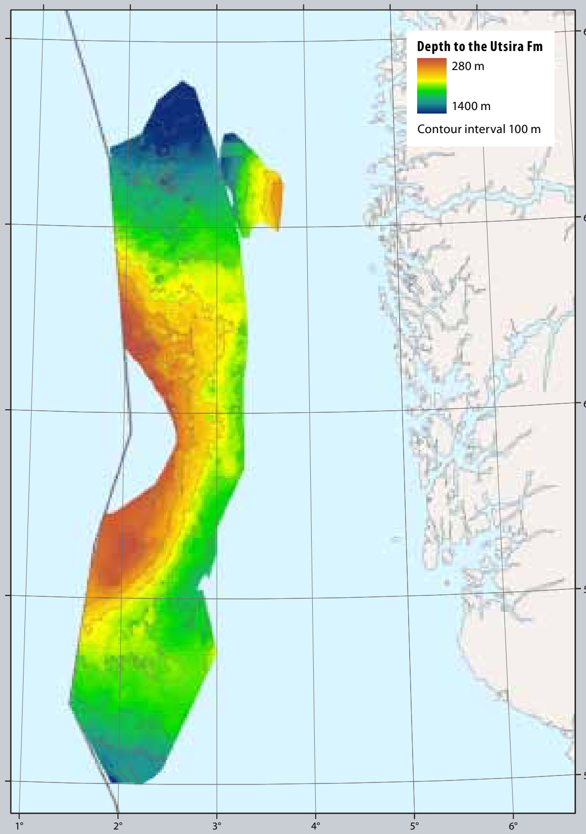
Suggested drainage patterns for Miocene deposits in the North Sea area. Drainage through the Great Glen trend in Scotland has not been documented.

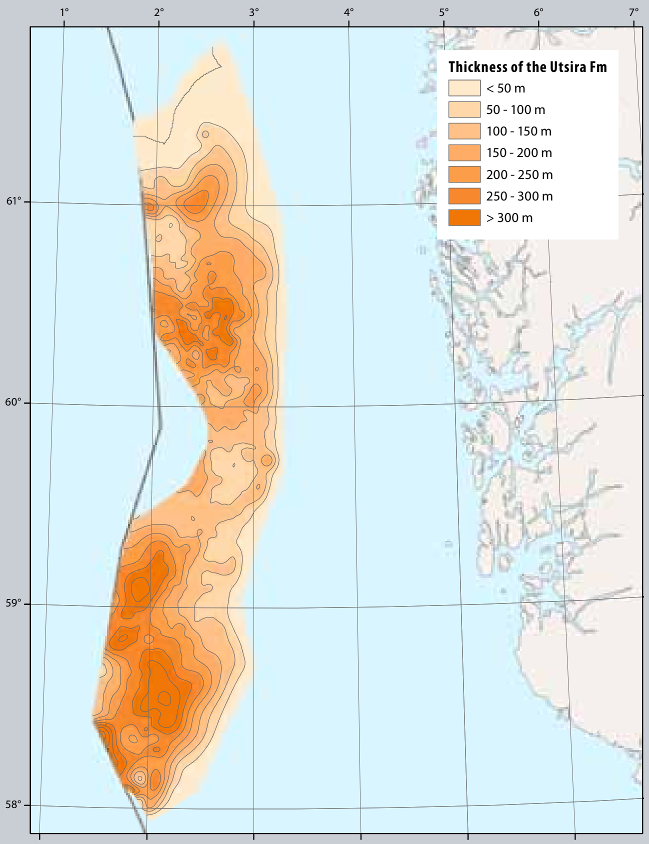
4.2 Geological description

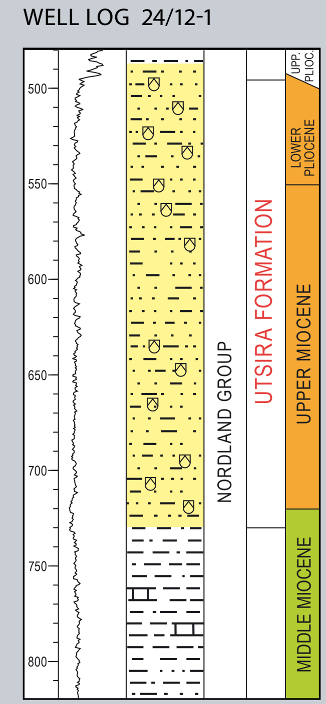
The Utsira Formation

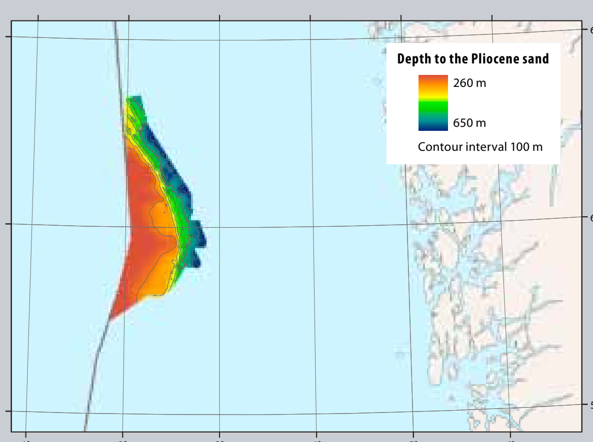
The Utsira Fm (Upper Miocene to Lower Pliocene) consists of marine sandstones with source area to the west. The maximum thickness exceeds 300 m. The sands of the Utsira Fm display a complex architecture and the elongated sand body extends some 450 km N-S and 90 km E-W. The northern and southern parts consist mainly of large mounded sand systems. In the middle part the deposits are thinner, and in the northernmost part (Tampen area) they consist of thin beds of glauconitic sands.

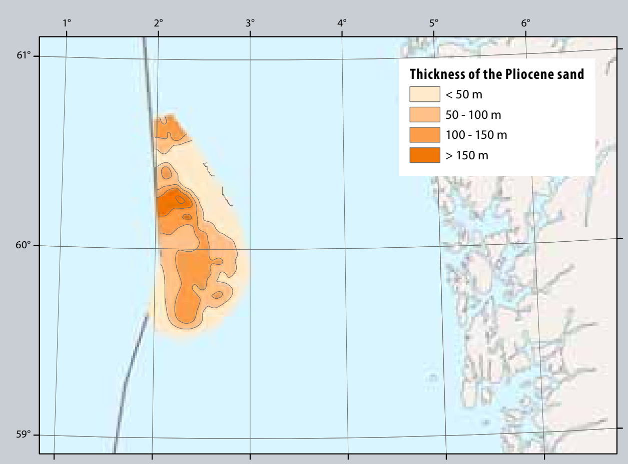
Upper Pliocene deltaic sand deposits overlie the Utsira Formation and Ve Member with a hiatus. In the wells we have investigated, there is sand-sand contact at the boundary, consequently we regard the Upper Pliocene sand as a part of the large Utsira-Skade aquifer system. The Upper Pliocene sand has previously often been assigned to the Utsira Formation. The top of the sand is found at about 150 m below the sea floor in the Norwegian sector. Top surface maps of the equivalent Hutton sand in the UK sector have not been available for this study.

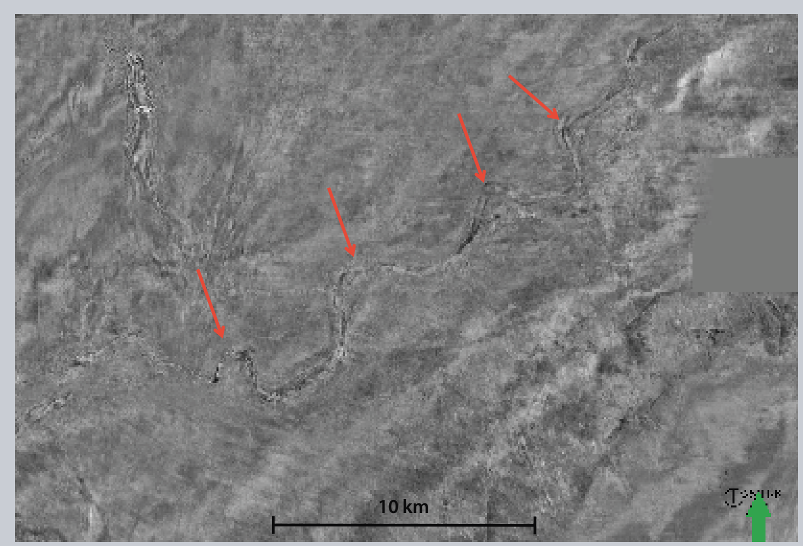












Channels in the uppermost part of the Utsira Formation , 25/10-2 and 25/11-6 area. Time slice 540 ms

The Hordaland Group

AGE: **Eocene to Lower Miocene, possibly Middle Miocene in the Central Graben**

The Hordaland Gp has its type area in the North Sea Tertiary Basin. The main lithology of the group is marine claystones with minor sandstones. Within the Hordaland Gp four sandstone formations are defined: The Frigg, Grid, Skade and Vade Fms.

Since the Skade Fm is in contact with the Utsira Fm, they form an aquifer. Maximum thickness of the group varies from 1100-1400 m in the central and southern part of the Viking Graben, thinning towards the margins. Thicknesses of wells in the type area (wells 2/2-1 and 24/12-1) are 1060 m and 1365 m. In the northern Viking Graben the group is only a few hundred metres thick. The group was deposited in an open marine environment. The base of the Hordaland Gp is the Balder Fm or sands of the Frigg Fm.

The Frigg Fm (Lower Eocene) was deposited as submarine fans sourced from the East Shetland Platform to the west. The formation is located in the south-western part of quadrant 30 and north-western part of quadrant 25. At about 59^{0}30'N, the Frigg sands are connected to the sands in the UK sector. The thickness of the Frigg Fm is 279 m in type well (25/1-1) and it is located in a depocentre with a maximum thickness of approximately 300 m. The lower boundary is the Balder Fm and the upper boundary is claystones of the Hordaland Gp that could form a regional seal.

The crest of the Frigg Field is approximately 1850 m and porosities and permeabilities are reported in the range of 27-32 % and 1-4 Darcy, respectively.

The Grid Fm (Middle to Upper Eocene) consists of a series of sand-bodies probably sourced from the East Shetland Platform and located in the Viking Graben between 58^{0}30'N and approximately 60^{0}30'N. The type well is 15/3-3. The lower boundary and upper boundary are towards marine claystones of the Hordaland Gp.

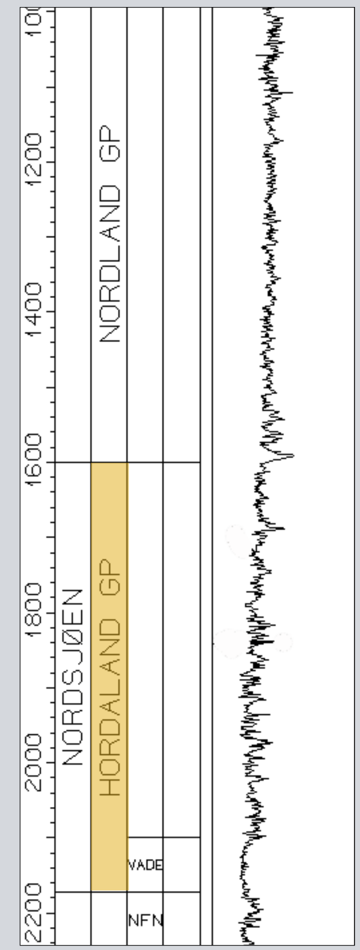
The thickness in the type well is 370 m. The formation thins eastward and is not identified in wells on the Utsira High. There is a considerable difference in thickness north and south of 59^{0}N. To the north the thickness is less than 200 m and to the south nearly 400 m. This is due to the fact that sand deposition started earlier in the south. Due to soft sediment deformation, there may be poor connectivity between individual sand bodies, and some sands may be interpreted as injectites.

The deposition of the formation took place in an open marine environment during regression.

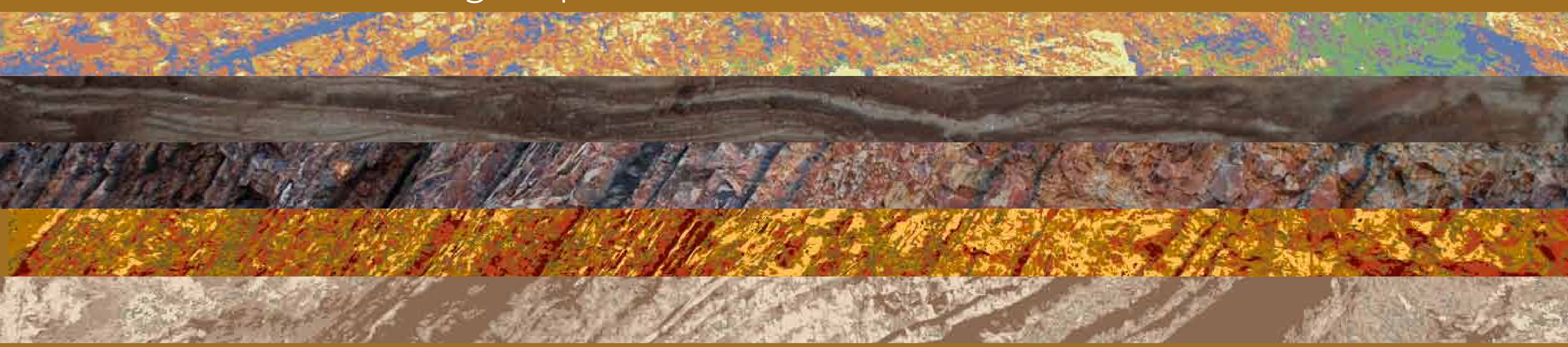
The Vade Fm (Upper Oligocene) is defined in well 2/2-1 located on the Sørvestlandet High, east of the Central Graben. The lower and upper boundary is claystones of the Hordaland Gp.

In the type well the thickness is 72 m, but the formation has only been penetrated by a few wells.
The Vade Fm sandstones were deposited in a shallow marine environment, either related to a eustatic fall in sea level or a tectonic uplift. Regional considerations indicate a source area to the east or north-east.

WELL LOG 2/2-1



5. Storage options



5.1 Saline aquifers

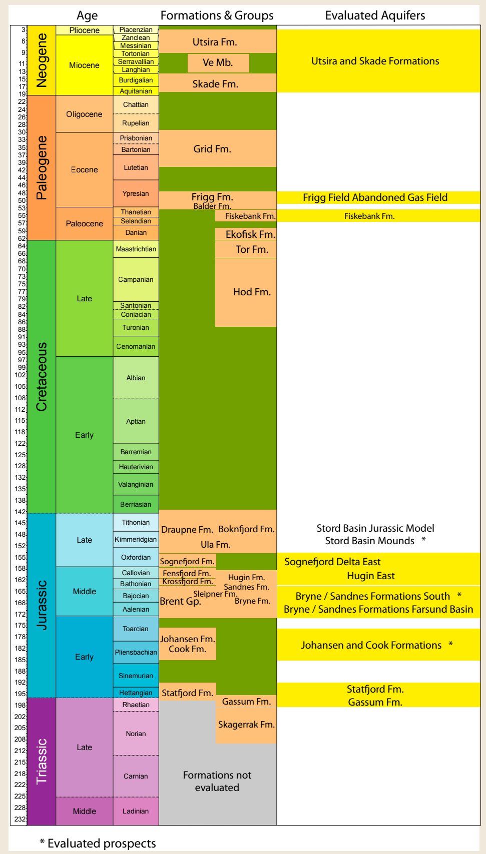
Definition and principles for selection of storage sites

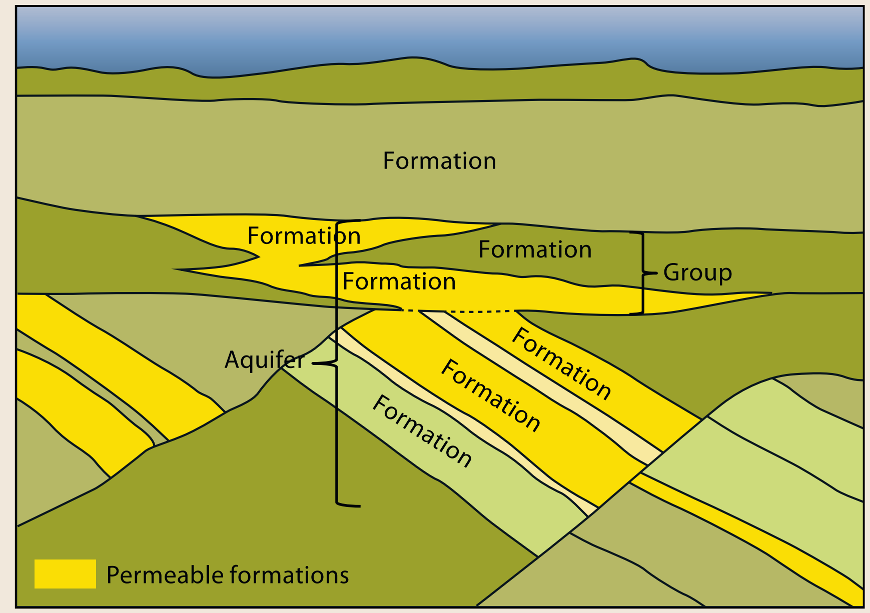
An aquifer is a body of porous and permeable sedimentary rocks where the water in the pore space is in communication throughout. Aquifers may consist of several sedimentary formations and cover large areas. They may be somewhat segmented by faults and by low permeable layers acting as baffles to fluid flow. Maps, profiles and pore pressure data have been utilized in order to define the main aquifers. All the identified aquifers in the area of this atlas are saline, most of them have salinities in the order of sea water or higher.

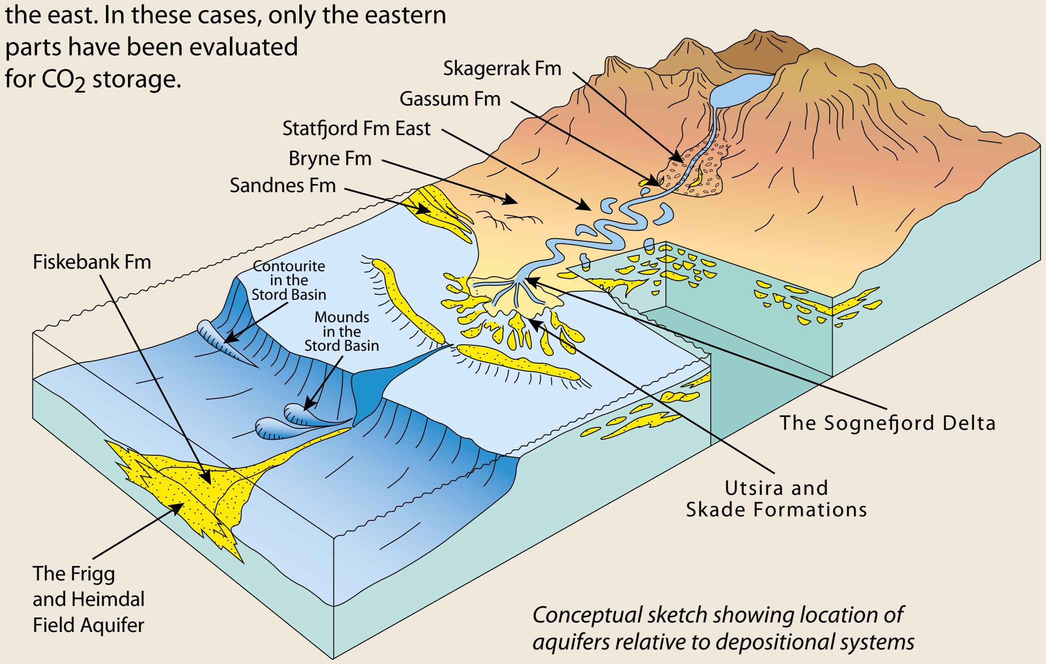
In the western provinces, west of the red line in the lower middle figure, Paleogene and older aquifers contain hydrocarbons. East of the line, discoveries have only been made in local basins where the Jurassic source rock has been buried to a sufficiently high temperature to generate hydrocarbons.

In the eastern area, all the large aquifers have been selected based on the established criteria (section 3.3) and storage capacity is estimated by the method described in section 3.4. In the petroleum provinces, it is considered that exploration and production activities will continue for many years to come. The most realistic sites of CO_2 storage will be some of the abandoned fields, in particular the gas fields. Consequently, an indication of the storage capacity of the fields has been given, but no aquifer volumes have been calculated. Some of the oil fields are considered to have a potential for use of CO_2 to enhanced oil recovery (EOR, section 5.3). Some of the CO_2 used for EOR will remain trapped. The capacity for this type of CO_2 trapping has not been calculated.

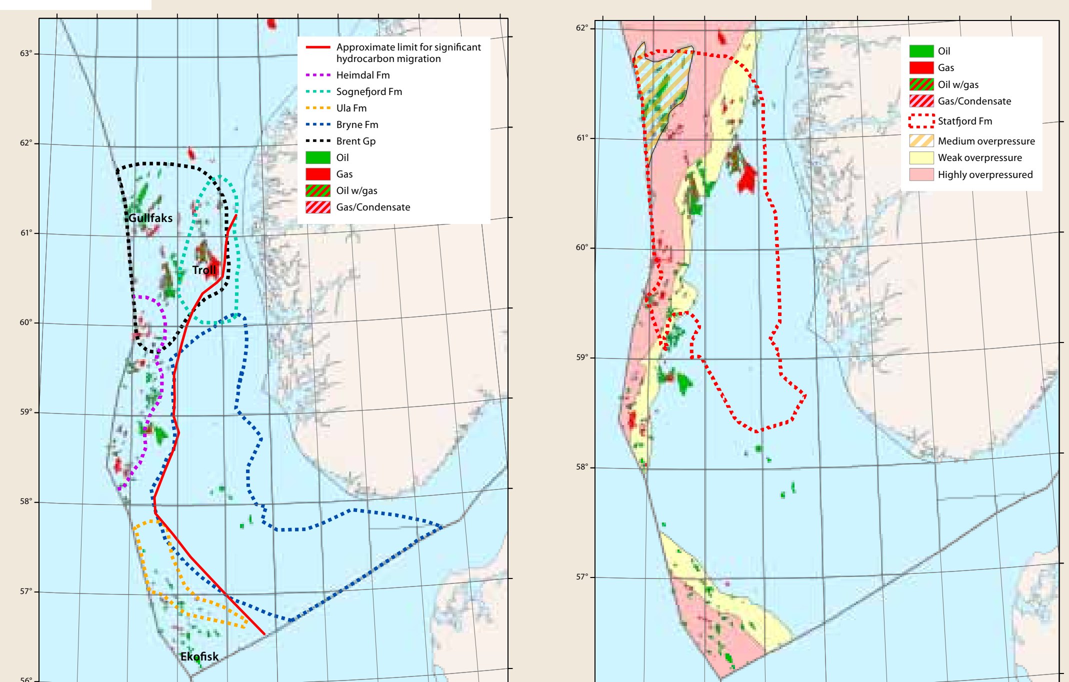
The Sognefjord Delta aquifer and the Statfjord Formation aquifer (figure) are developed both within the petroleum provinces in the west and as saline aquifers with small amounts or no petroleum in the east. In these cases, only the eastern parts have been evaluated for CO_2 storage.







Conceptual sketch showing location of aquifers relative to depositional systems



Distribution of major aquifers at the Jurassic levels relative to the petroleum provinces

Stord basin - long distance CO_2 migration

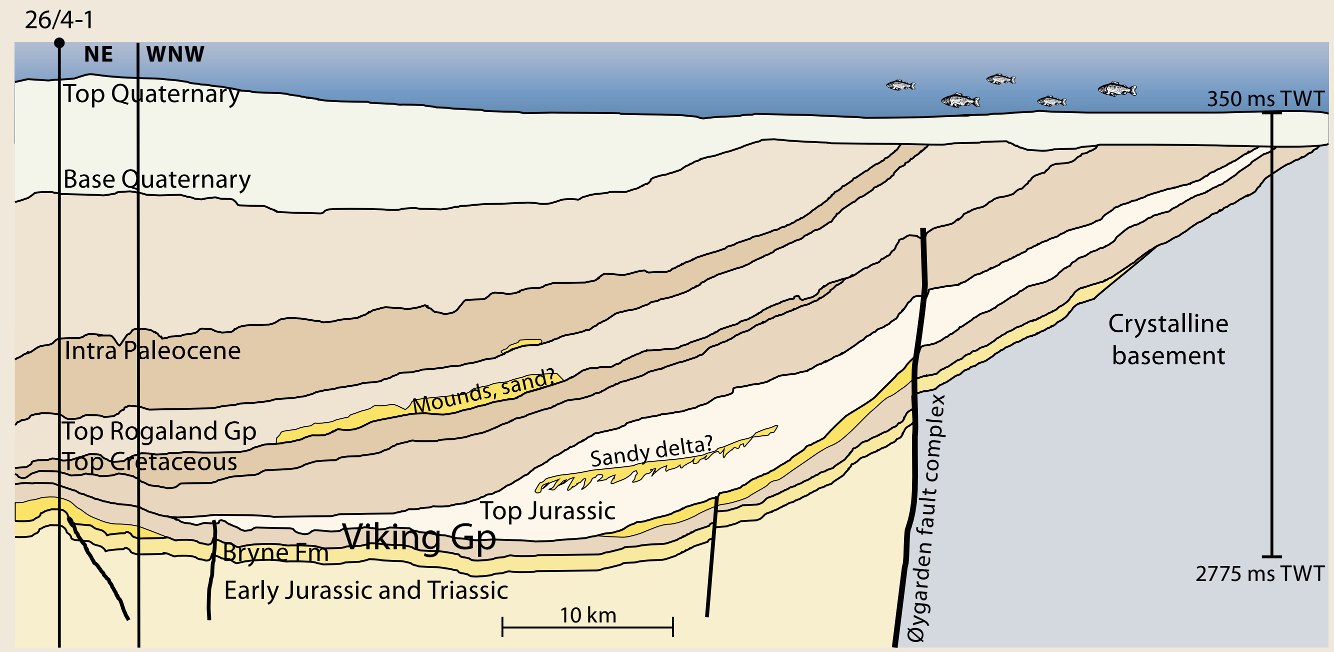
Modelling of CO_2 injection and migration in the Stord basin. The aquifers in the eastern part of the North Sea typically have a consistent dip of about one degree from the Norwegian coast down to the basinal areas. In the case that there are permeable beds along this dip slope, there is a risk that CO_2 injected in the downdip aquifer can migrate up to where the aquifer is truncated by Quaternary glacial sediments. At that depth, the CO_2 will be in gas phase. The glacial sediments mainly consist of clay and tills and their thickness ranges from about 50 m and up to more than 200 m (figure). Understanding the timing and extent of long distance CO_2 migration is of importance for the evaluation of the storage capacity of outcropping aquifers. Consequently, a modelling study was set up on a possible aquifer in the Stord Basin.

The Stord Basin is bordered by faults between the Utsira High in the west and the Øygarden fault complex in the east. The syn-rift basin acted as a depocentre for infilling sediments from all surrounding highs, the main source being the eastern hinterland. The basin is overlain by post-rift sediments ranging from late Jurassic to Quaternary age. Sand is mainly found in the Triassic and Jurassic. The main risks of leakage of injected CO_2 in the Stord basin area are sideways migration towards the east, and migration along fault planes. Absence of syn-rift sedimentary rocks on the upthrown side of the Øygarden fault complex may reduce the risk of sideways migration in this section.

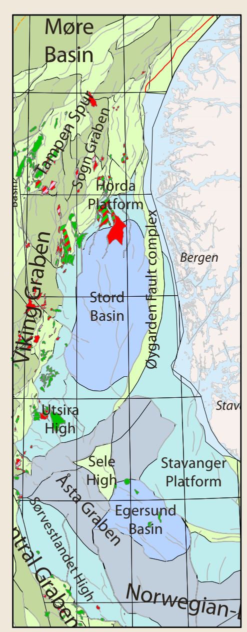
A simulation model of a possible Upper Jurassic sand deposit (referred to as Sandy delta in the cross-section) was built based on a geological model derived from seismic interpretation. The model shown in the figure has been used to simulate CO_2 injection in the sand deposit, which will act as an aquifer.

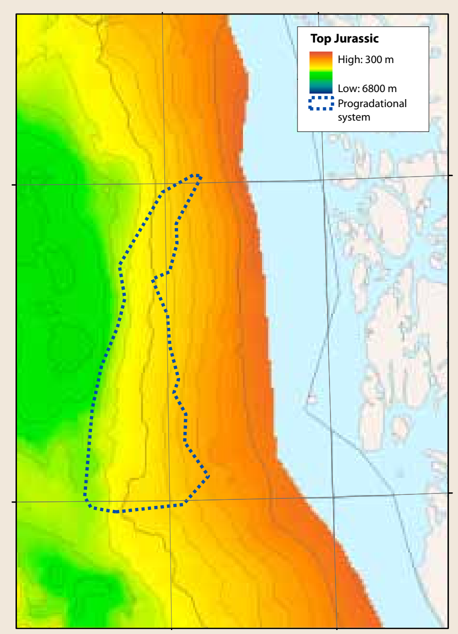
The modeled depositional system has not been drilled, and the interpretation is based on seismic 2D data. Although there is a reservoir risk in this particular model, the results can be applied to analogous aquifers with gentle dips.

Three injection wells are shown in the areas with highest permeability (green). A water producer is located on the east side of the grid, acting as a leaking point in the shallowest part. The permeability and porosity distribution around well 1 is shown in the profiles. The model was run with 50 years of injection with different rates. After shut-in of injection, migration continued until the CO_2 had migrated up to the east side of the model and begun to enter the Quaternary formations above. The simulations were run with one, three and five wells.

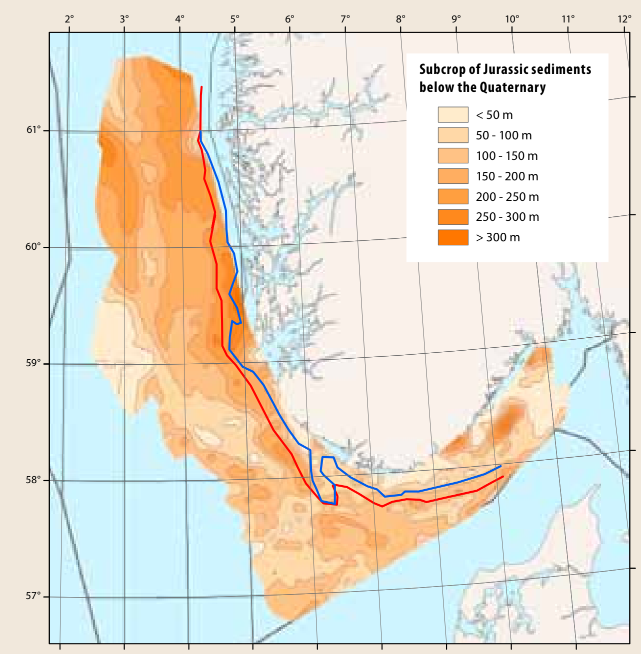


Seismic panel including well 26/4-1, Stord basin



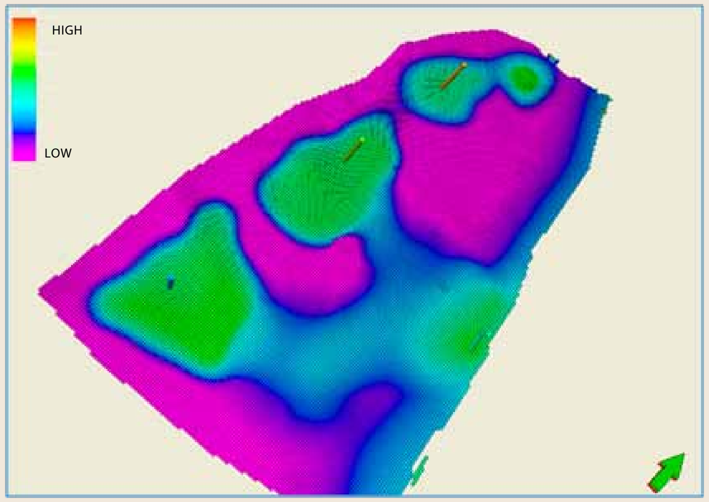


Polygon depicting modelled aquifer

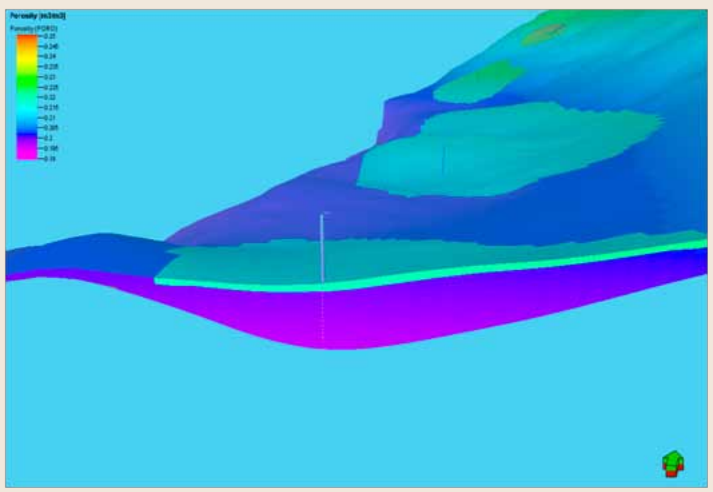


Thickness of Quaternary deposits and Jurassic subcrop

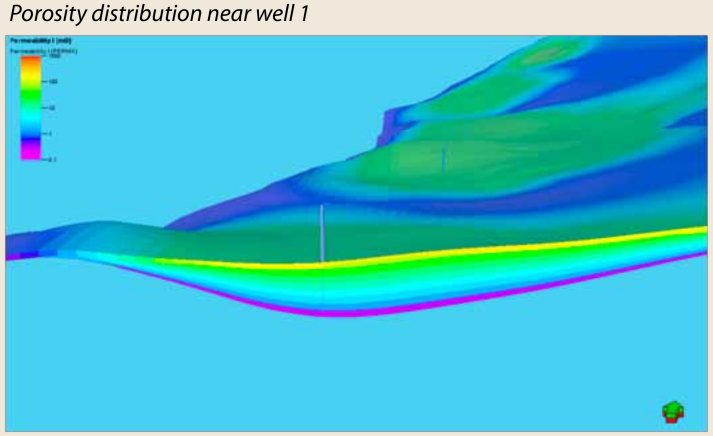
5.1 Saline aquifers



Permeability in upper layer 1



Porosity distribution near well 1



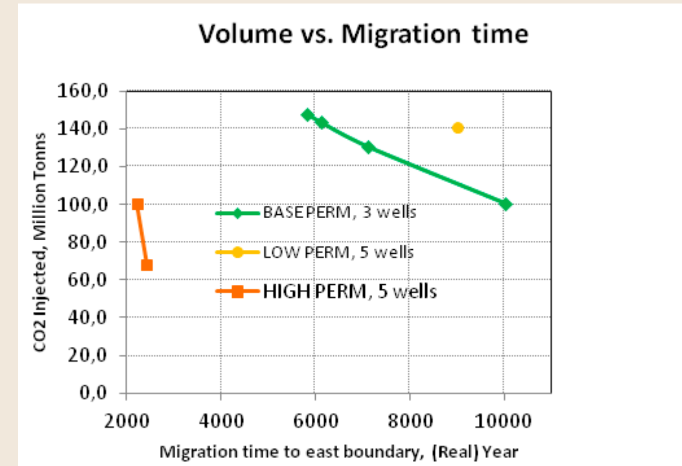
Porosity distribution near well 1

Three cases with different x-y permeabilities were run. Near well 1 the permeabilities vary from 0.14 mD in the bottom layer, to 199 mD in the top layer. The cases were run with the following model setups:

1. Base model
2. High perm model (permeability 20 times base case in top layer)
3. Low perm model (0.5 times base permeability in all layers)

The results for the different models are shown in the figure, with three and five wells.
The results show that in the base model with 3 mill Sm3/d, the reservoir can store 100 mill tons CO_2 before CO_2 reaches the eastern boundary of the reservoir in the year 10 000. If extrapolated to 10 000 years of storage, the maximum amount stored will be about 75 mill tons. With a high permeability layer at the top (high case), and 3 mill Sm^3/d, the CO_2 will reach the boundary in year 2416 after about 400 years of migration.

When the CO_2 reaches the eastern boundary it is in gas phase and might migrate slowly upwards into the overlying Quaternary layers as discussed above.

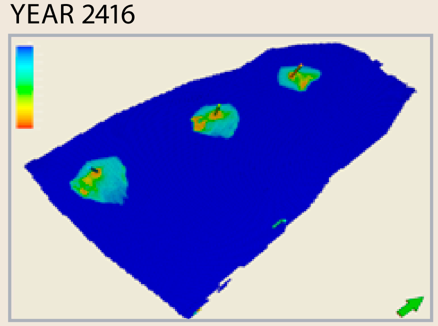


Volume of CO_2 injected vs. migration time

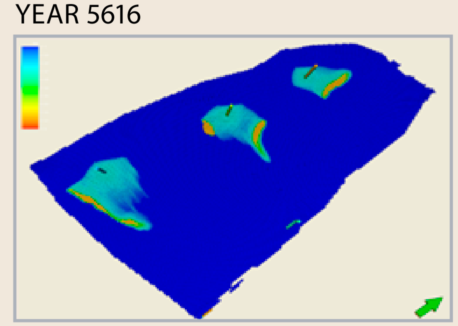
Conclusions
The results show that the CO_2 plume is distributed mostly in the high permeability (upper) layers of the reservoir.

With the base permeability model, about 100 mill tons is the maximum storage capacity with migration for about 8000 years to boundary (year 10 000), if 3 mill Sm^3/d is injected in three wells. Higher rates will give a shorter migration time. With the low perm model and 9 mill Sm3/d with five wells, the injected volume might be up to 140 mill tons. A high permeability streak in the top layer will result in a short migration time, about 400 years. Low permeability and favourable communication reduces the risk of CO_2 escape. The results indicate that migration velocities are slow unless the permeability and communication are very high, implying that subcropping aquifers could be of interest for CO_2 storage.

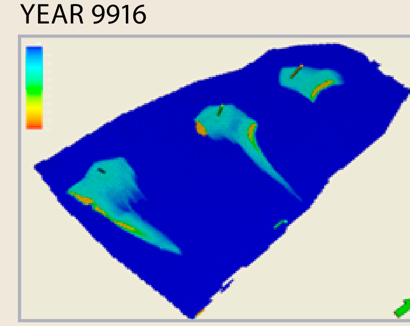
YEAR 2416



YEAR 5616



YEAR 9916



Volume of CO_2 injected vs. migration time

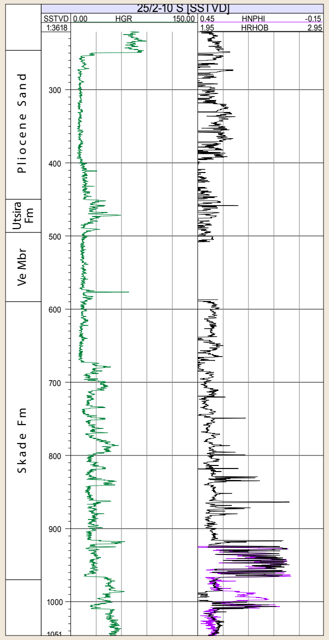
5.1 Saline aquifers

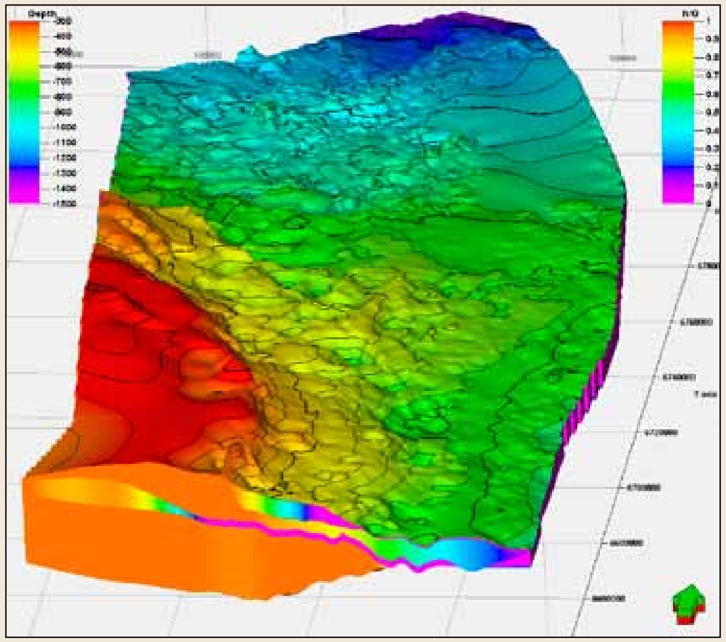
The Utsira and Skade aquifer

Approximately 1 Mt CO_2 from the Sleipner Field has been successfully injected annually in the Utsira Formation since 1996, proving that the formation is an excellent reservoir for CO_2 storage. Due to its size, the formation has been regarded as attractive for storage of large volumes. However, the formation is part of a much larger sandy deltaic complex located at both sides of the UK-Norway boundary. The upper parts of this system are buried to less than 200 m below the sea floor, and the communication between the different sandy formations has not yet been studied in detail. In this atlas we present the results of an NPD study based on 3D seismic interpretation and biostratigraphy. The Miocene and Pliocene aquifer is subdivided into four major units which are in communication towards the west. The largest pore volumes in the system are in the Utsira and Skade Formations, which appear to be separated by a Middle Miocene shale in the eastern/distale parts. There is a regional dip upward towards the west, and consequently there is a risk that injected CO_2 will migrate updip to levels which are too shallow to be accepted for storage. Three areas are assumed suitable for CO_2 injection:

1. The southern part of the Utsira Formation below approximately 750 m. This area has several structures which could accumulate CO_2 and prevent it from migrating upslope. Large volumes can also be trapped as residual and dissolved CO_2 in the aquifer.
2. Volume in the NE part of the Utsira Formation. This part of the Utsira Formation is in communication with a delta which was built out from the Sognefjord area in the east. The top of the eastern fan reaches the base of the Quaternary and it has not been evaluated for storage.
3. The outer part of the Skade Formation where it is sealed by Middle Miocene shale and could be trapped within structures formed by clay diapirism.

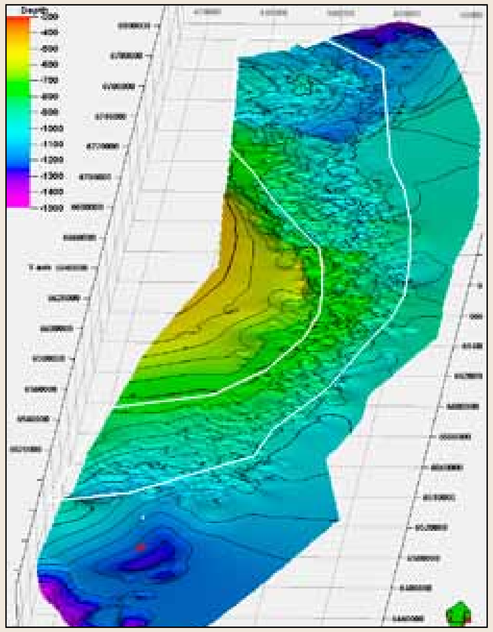
Pore volumes for this aquifer are presented together with storage capacities calculated for the three suggested sub- areas.



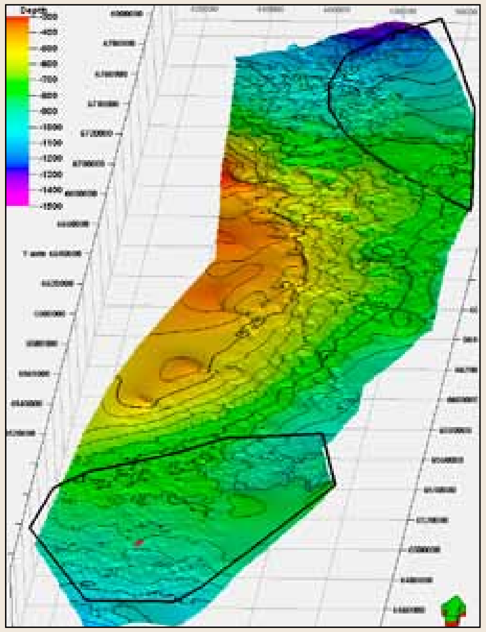


Cross-section and top surface of the aquifer model. Cross-section shows net-gross values.

Utsira and Skade Fm		Summary
Storage system	half open to fully open	
Rock volume, m^3		2,5 E+12
Pore volume, m^3		5,26 E+11
Average depth		900 m
Average permeability		>1000 mD
Storage efficiency		4
Storage capacity aquifer		16 Gigatons
Storage capacity prospectivity		0,5-1,5 Gigatons
Reservoir quality		
	capacity	3
	injectivity	3
Seal quality		
	seal	2
	fractured seal	3
	wells	2
Data quality		
Maturation		level 2-4



Top of Skade Formation. The white polygon indicates area which may be favorable for CO_2 storage. Red dot shows Sleipner injection area. The grid squares are 20 km x 20 km.



Top of Utsira Formation. The black polygons indicate areas which may be favorable for CO_2 storage.

5.1 Saline aquifers

The Bryne and Sandnes Formations

The southern part of the Norwegian Sea has a well developed sandy sequence, which is made up of the Lower Jurassic, Sandnes and Bryne formations with occasional contact with the sands of the Triassic Gassum and Skagerrak formations. The fine grained, lowermost Jurassic Fjerritslev Formation, is partly developed as a seal between the Gassum and Bryne Formations.

The Sandnes formation is generally developed as a well sorted and widely distributed sand, above the thicker silt and sandstones of the Bryne formation. The vertical permeability of the Bryne formation is lowered by the coaly layers developed in most of the formation. The connectivity in the Bryne formation is hampered by the typical development of isolated channels and channel belts of the delta plain. The two formations typically thin on the crests of salt structures and thicken in the basins. The yellow polygon in the figure outlines the Farsund Basin. This basin is bounded by a basement high to the south, and has been treated as a separate segment within the aquifer.

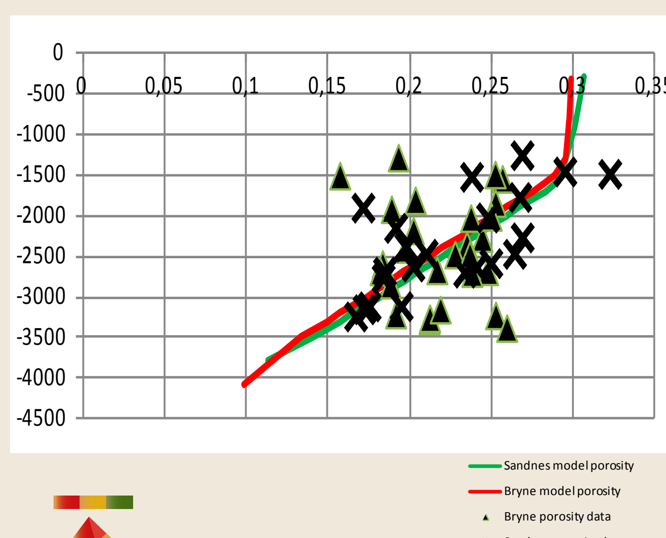
There is a limited amount of well data for constructing detailed petrophysical maps. In the present aquifer model, an average thickness is presented. For the porosity a general depth trend was applied, and for the net gross factor, a correlation to the formation thickness was attempted.

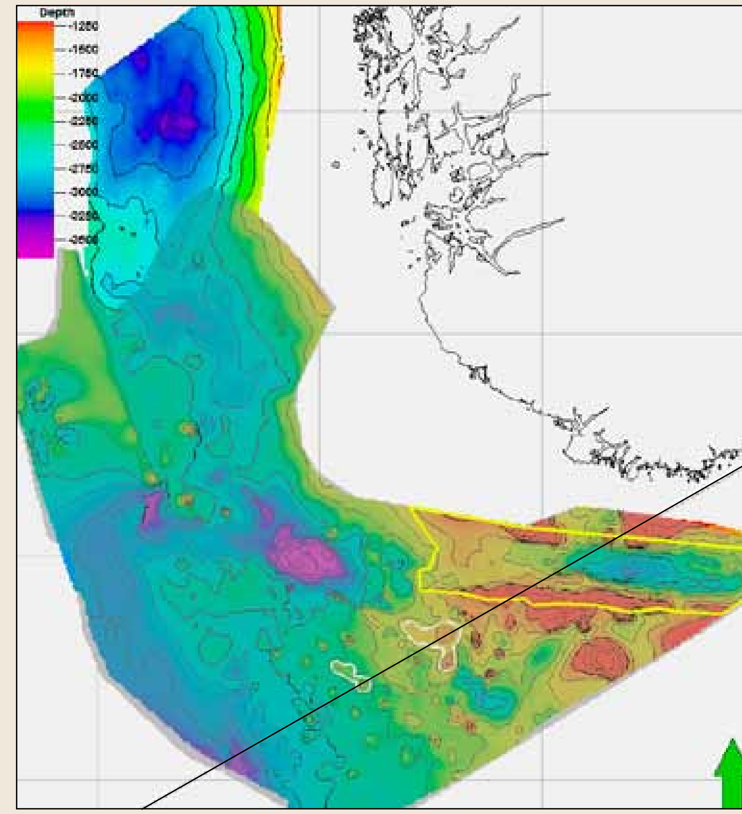
The aquifer is considered quite well suited for CO_2 storage due to the well developed reservoir rocks. The aquifer is capped by the generally thick and robust mud- and claystones of the Boknfjord Formation.

Seal integrity should be investigated further above salt structures and in major faults. To get an idea of the storage capacity of these structures is an estimation of two structural closures presented in the table. The smaller structure is thought to be representative for the aquifer. There also seems to be a possibility for larger structures in the saddle area between the Stord Basin and the Egersund Basin. Assuming that the aquifer could contain a few of the bigger structures and that there are many salt structures which could form prospects, a capacity range of 0.5 to 2 Gt for the prospects is assumed. The integrity and reservoir quality of each prospect would have to be investigated, hence they are assigned to level 2 in the pyramid.

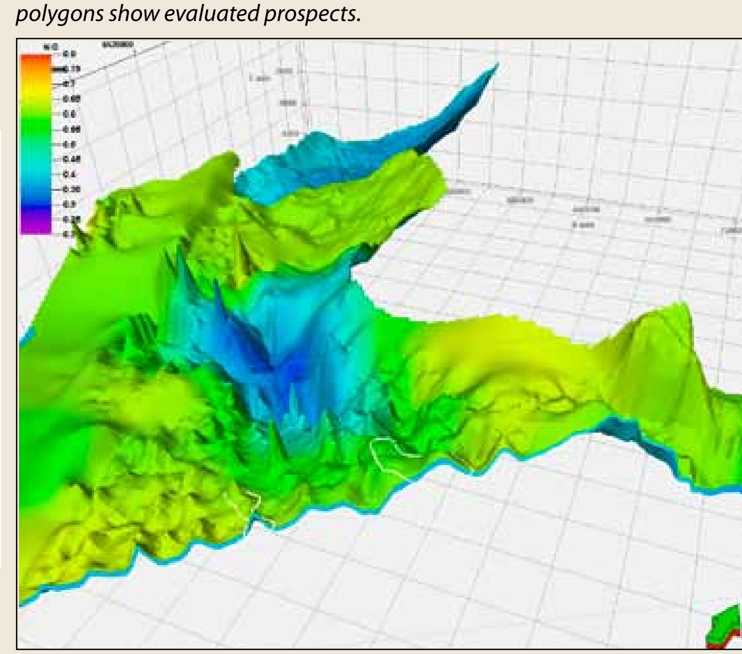
Farsund Basin		Summary
Storage system	half open	
Rock volume, m³		8,55201E+11
Pore volume, m³		8,21E+10
Average depth		
Average permeability		
Storage efficiency		4
Storage capacity aquifer		2 Gigatons

Bryne and Sandnes Fm		Summary
Storage system	half open	
Rock volume, m³		5,04E+12
Pore volume, m³		4,41E+11
Average depth		1700 m
Average permeability		150 mD
Storage efficiency		4,5
Storage capacity aquifer		14 Gigatons
Storage capacity prospectivity		0,5-2 Gt
Reservoir quality		
	capacity	3
	injectivity	2
Seal quality		
	seal	3
	fractured seal	2
	wells	3
Data quality		
Maturation		





The Bryne and Sandnes aquifer. Yellow polygon shows Farsund Basin, white polygons show evaluated prospects.


Top surface and cross-section of the Bryne-Sandnes aquifer.

The Sognefjord Delta aquifer

The Sognefjord delta aquifer includes the sandstones belonging to the Viking Group. The Krossfjord, Fensfjord and Sognefjord Formations are partly separated by thin shale units (Heather Formation). Oil and gas production from the giant Troll Field has caused pressure reduction in all the three formations. The three formations are here treated as one aquifer. Influence of the Troll depletion on the aquifers in the older Jurassic formations is less pronounced. These sandy formations will be in communication through local juxtaposition along faults or by local sand-sand contact. In the area east of the Troll Field the sands are in direct contact with each other and constitute a good reservoir.

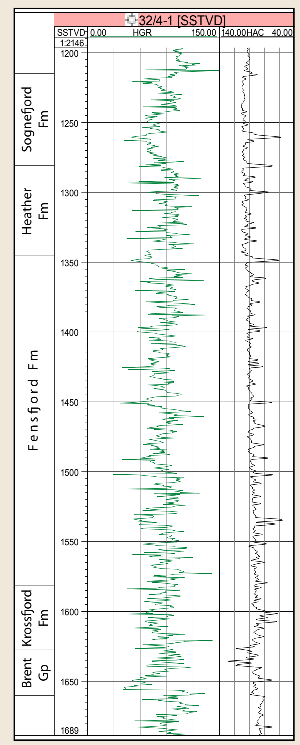
The storage capacity of the western part of the Sognefjord delta has not been included because it forms reservoir rock of the Troll field and other fields north of Troll. The aquifer is treated in the same way as in the main petroleum provinces.

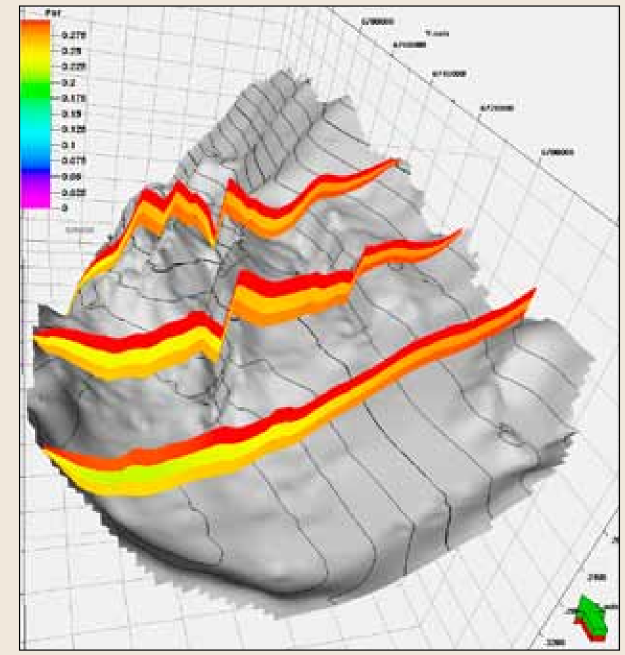
The eastern part of the Sognefjord Delta aquifer (within the black polygon in the figure) is structured by faults in the Øygarden Fault Complex. Two water-filled structural traps have been drilled in this area. This part of the aquifer is considered to be outside the area of large scale hydrocarbon migration, and closed structures may be attractive for CO_2 storage.

The porosity used for volume calculation is based on depth trends derived from wells in the area.

Several gas accumulations in the western part of the aquifer indicate a good quality seal. The sealing capacity of the fault zones in the Øygarden Fault Complex has to be investigated further. The aquifer subcrops below the Quaternary in the east, and there might be a risk of lateral migration of injected CO_2 towards the subcrop area.

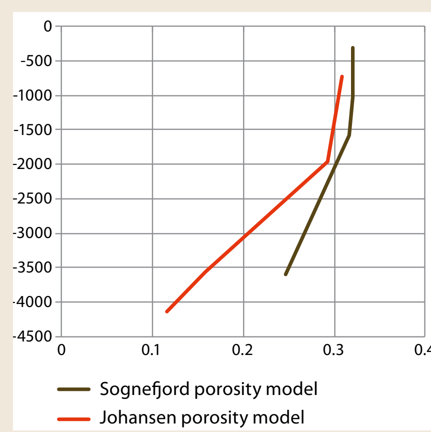
WELL 32/4-1

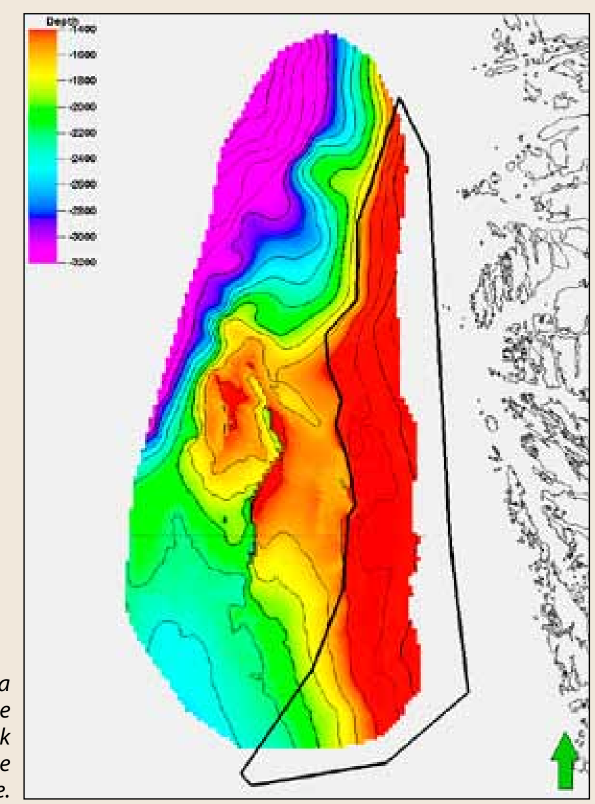




Cross-sections showing the Krossfjord, Fensfjord and Sognefjord formations with modelled porosity values above the Top Brent surface within the Sognefjord Delta.

Sognefjord Delta		Total aquifer Summary	East aquifer Summary
Storage system	half open		
Rock volume, m^3		2,67E+12	5,54E+11
Pore volume, m^3		4,78E+11	1,08E+11
Average depth		1750 m	1750 m
Average permeability		300 mD	300 mD
Storage efficiency		5,5	5,5
Storage capacity aquifer		18 Gigatons	4 Gigatons
Storage capacity prospectivity			
Reservoir quality			
	capacity	3	3
	injectivity	3	3
Seal quality			
	seal	3	3
	fractured seal	2	2
	wells	2	2
Data quality			
Maturation			





Top of the Sognefjord delta aquifer. The eastern past of the aquifer, outlined by the black polygon, is outside the petroleum province.

5.1 Saline aquifers

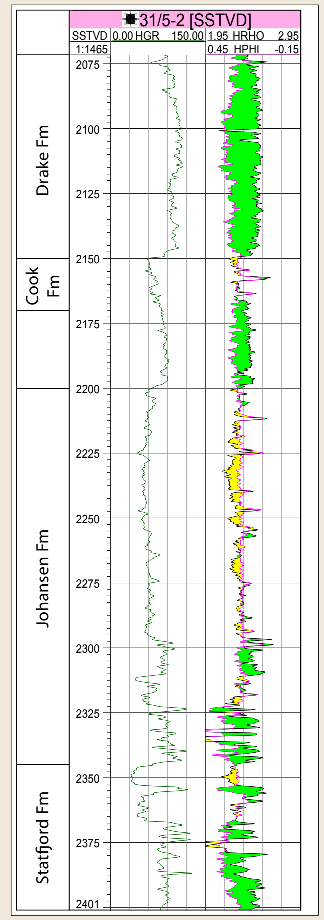
The Johansen and Cook Formation aquifer

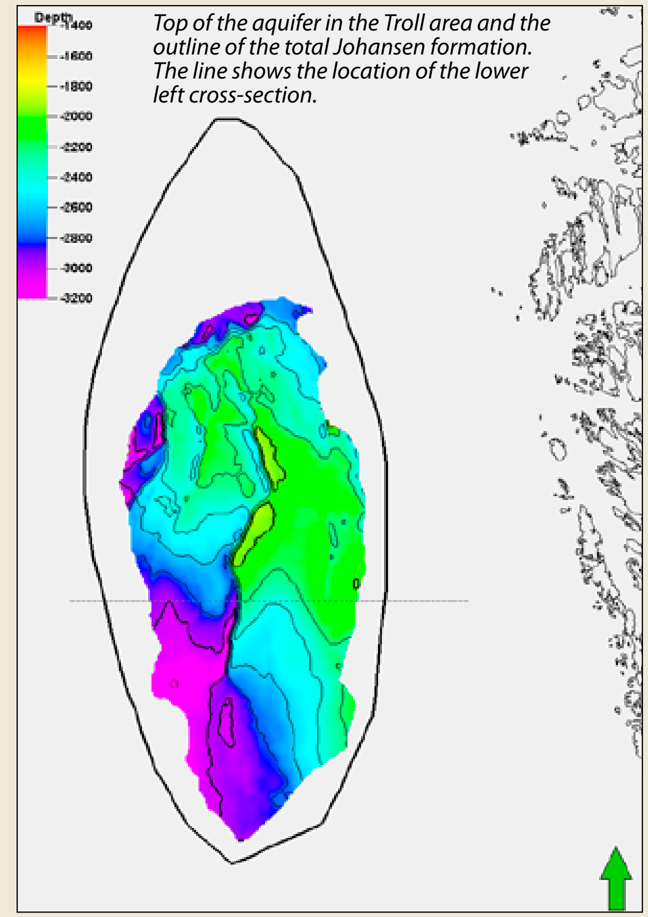
The Johansen and Cook Formations are mainly separated by shales and siltstones, but due to fault juxtaposition, they will be treated as one aquifer. The Johansen Formation sandstones have good reservoir properties in several wells in the Troll Field, and seismic data imply that the sand distribution is similar to the overlying Sognefjord Delta. The Cook Formation and the underlying Statfjord Formation extend to the Tampen Spur. The upper part of the Dunlin Group in the Troll area consists of the thick Drake Formation shale which is the main seal (figure).

The Johansen Formation south of the Troll Field was suggested by the NPD in 2007 as a potential storage site for CO_2 from Mongstad, and several studies have been carried out in order to qualify the aquifer for CO_2 storage. The NPD and Gassnova have acquired 3D seismic data in the most promising area. The studies indicate that the formation has sufficient capacity to store the volumes from Mongstad, but a well is important to clarify the reservoir and seal properties in the area south of Troll. Migration of CO2 to the surface is unlikely due to the large capacity of the Sognefjord Delta aquifer.

The capacity of the Johansen and Cook aquifer depends on the communication within the aquifer, and if it is in communication with the Statfjord and/or the Sognefjord Delta aquifers across major faults.

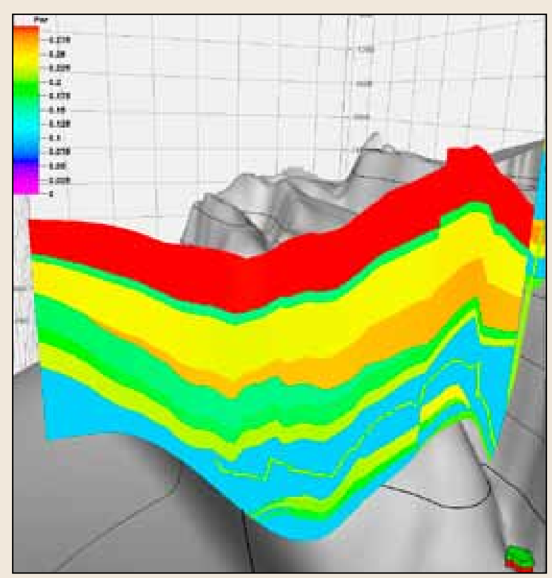
The pore volume and the storage capacity in prospects given in the table are based on calculations by Gassnova. These calculations do not include the northernmost part of the aquifer in the area north of Troll, see figure.



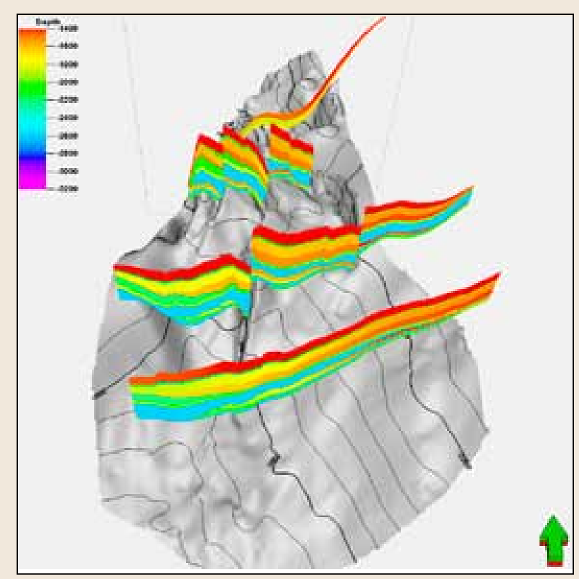


Top of the aquifer in the Troll area and the outline of the total Johansen formation. The line shows the location of the lower left cross-section.

Cook Johansen aquifer		Summary
Storage system	half open	
Rock volume, m^3		5,91E+11
Pore volume, m^3		9,14E+10
Average depth		1700 m
Average permeability		400 mD
Storage efficiency		3
Storage capacity aquifer		2 Gigatons
Storage capacity prospectivity		150 Mtons
Reservoir quality		
	capacity	3
	injectivity	2
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		



Cross-section of the porosity model of the Sognefjord delta. The Johansen and Cook Formations are the two deepest porous layers.

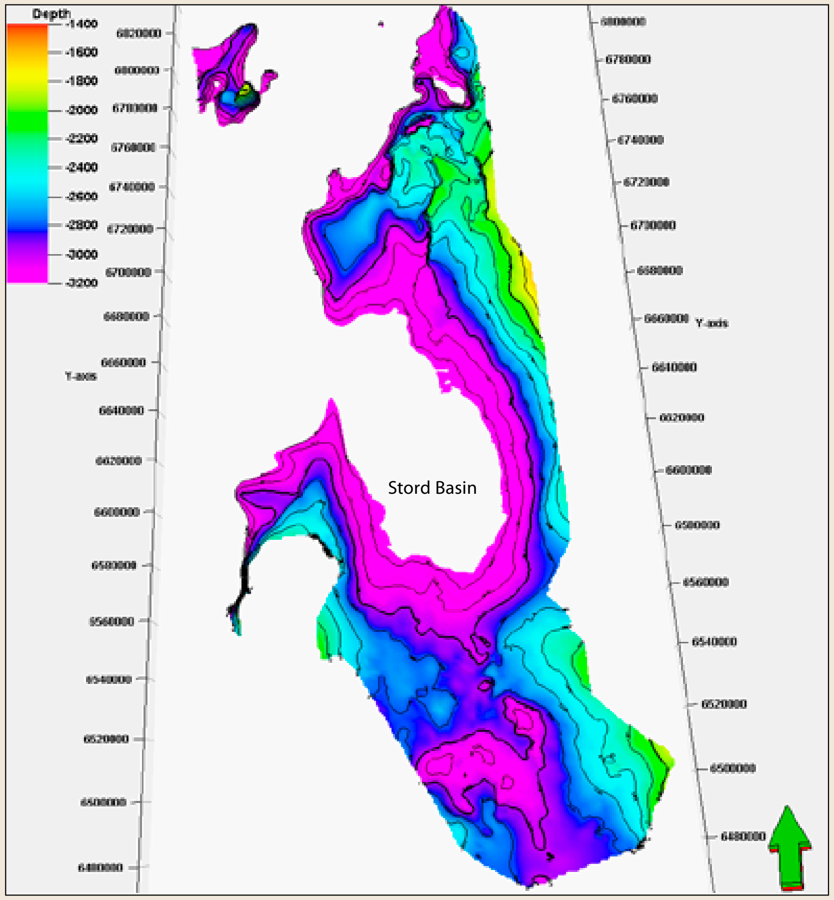


Several cross-sections showing juxtaposition of porous formations across faults. The basal surface is the top of the Statfjord Formation.

The Statfjord Formation aquifer

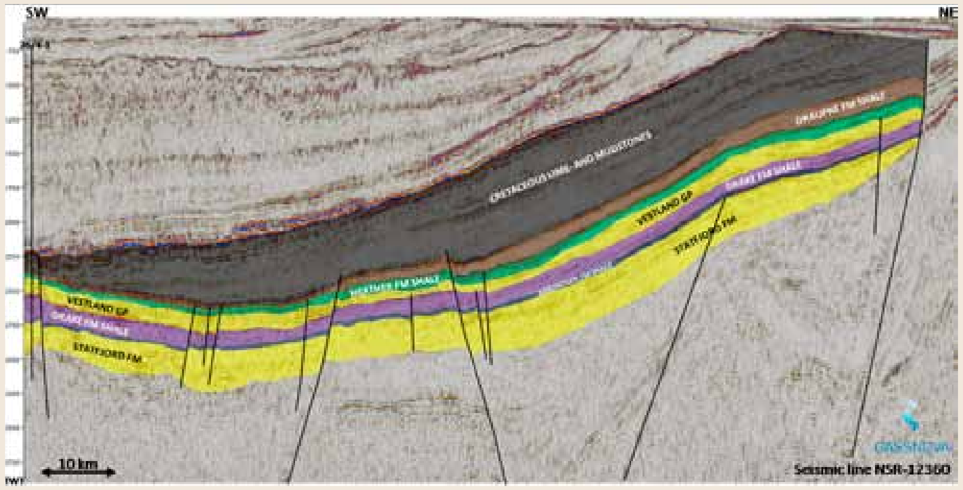
The Statfjord Formation contains hydrocarbons in the Viking Graben, Tampen High and north of the Stord Basin. South of the Horda Platform, it is assumed to be mainly water bearing. In the Stord Basin and its surroundings, it is separated from the overlying Jurassic aquifers by the Dunlin Group which is expected to form the seal. Towards the south and towards the Norwegian coast, the Lower Jurassic and large parts of the Middle Jurassic pinch out, and there may be communication between the Statfjord Formation aquifer and the shallower aquifers.

Few wells have been drilled in the Stord Basin area, and neither the formation properties nor its distribution and thickness are well known. A heterogeneous formation with locally good quality reservoirs, but with limited lateral and vertical continuity can be expected. For the purpose of calculation of theoretical storage capacity, an average net gross of 50 % has been applied to the whole area and a porosity-depth trend similar to the Bryne Formation was applied. This is based on the general geological understanding of the area. In the Stord Basin (fig), parts of the formation are located below 3500 m, and has been excluded from the volume calculation.



The top of the Statfjord Formation above 3500 m. The Tampen area to the NW was not included in the volume calculations.

Statfjord Fm east		Summary
Storage system	half open	
Rock volume, m3		1,13E+12
Pore volume, m3		1,2E+11
Average depth		2400 m
Average permeability		200 mD
Storage efficiency		4,5
Storage capacity aquifer		4 Gigatons
Storage capacity prospectivity		
Reservoir quality		
	capacity	3
	injectivity	2
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		



SW-NE cross-section in the northern part of the Stord Basin

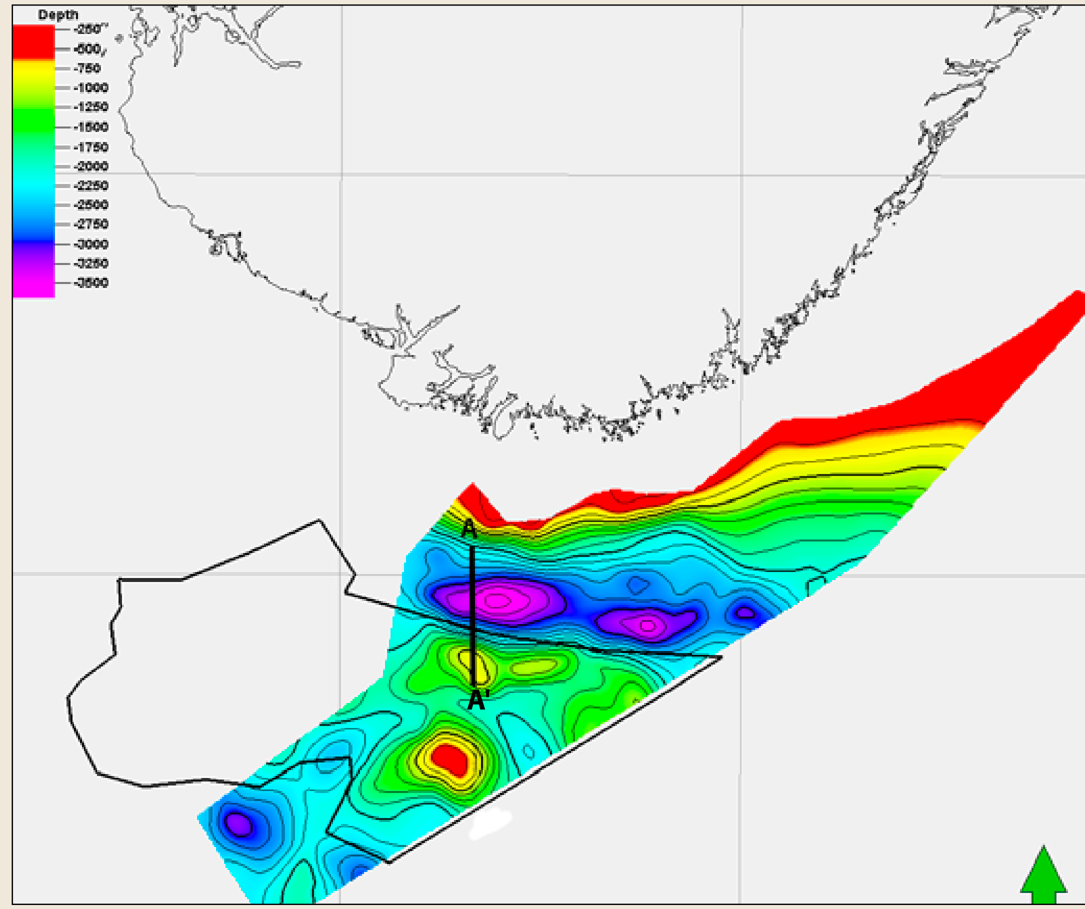
The Gassum Formation aquifer and the Skagerrak Formation

The aquifer was developed as river dominated system in the latest Triassic time, mainly as a well drained braided river system . The sandstones are believed to be of good quality. The type wells for these sandstones are in the Danish sector, and the Norwegian part is not explored in the same detail. Outside the mapped area indicated in the figure, the latest Triassic fluvial systems are more clay rich and are developed as discontinuous river sands. In the area indicated, the formation is sealed by the Fjerritslev Formation.

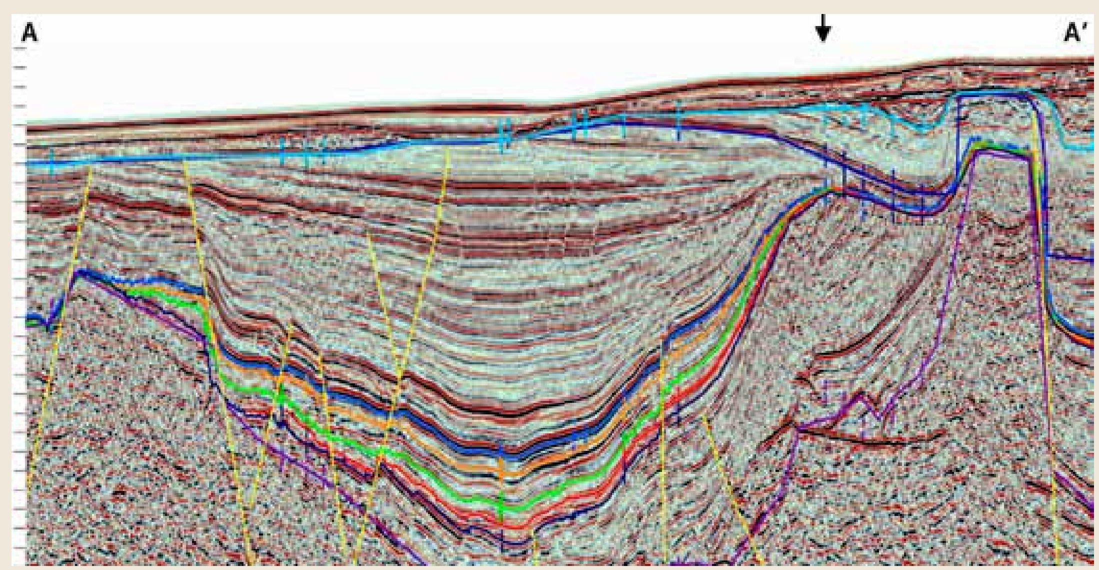
In the Skagerrak area, the Gassum Formation outcrops to the sea floor, and is covered by a Quaternary section which is typically less than 100 m thick. The sealing risks include faults, fracturing above salt structures and long distance migration towards the sea floor. The red areas in the map shows where the burial depth is less than 600 m. Migration of CO_2 into these areas should be avoided. The Gassum Formation can be a candidate for CO_2 injection in the Skagerrak area, but more data is required to investigate its potential.

The underlying Skagerrak formation is developed as a braidplain in an arid desert environment and as alluvium bordering the emergent land area east of the Danish-Norwegian Basin. Scarce well data indicate that the thick sandy sequences of the formation have low permeability, but locally they could interact with the overlying Gassum aquifer. The Skagerrak Formation in the Norwegian sector is poorly known, and with more data it is possible that a storage potential could be defined. In the figure, the outlined area indicates where the Skagerrak Formation is buried to less than 2000 m.

Gassum Fm		Summary
Storage system	half open	
Rock volume, m^3		6,53E+11
Pore volume, m^3		7,61E+10
Average depth		2200 m
Average permeability		450 mD
Storage efficiency		5,5
Storage capacity aquifer		3 Gigatons
Storage capacity prospectivity		
Reservoir quality		
	capacity	2
	injectivity	3
Seal quality		
	seal	3
	fractured seal	2
	wells	3
Data quality		
Maturation		

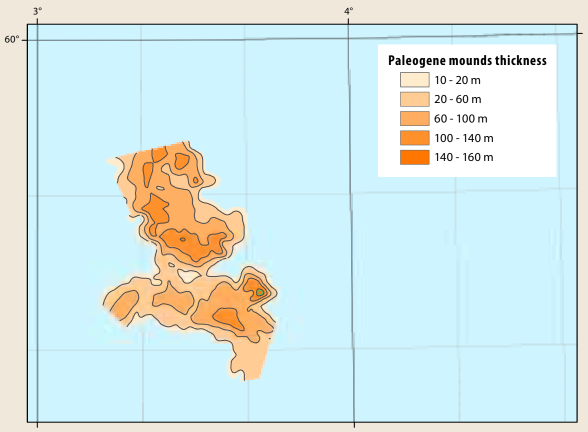


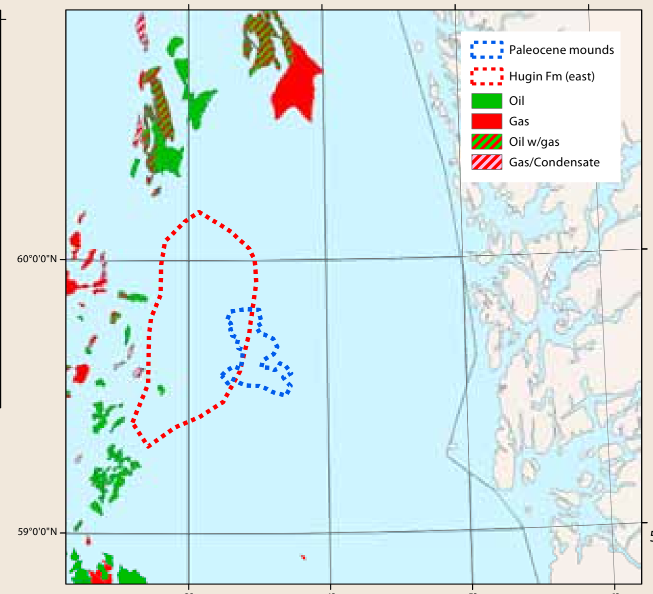
Top of the Gassum Formation

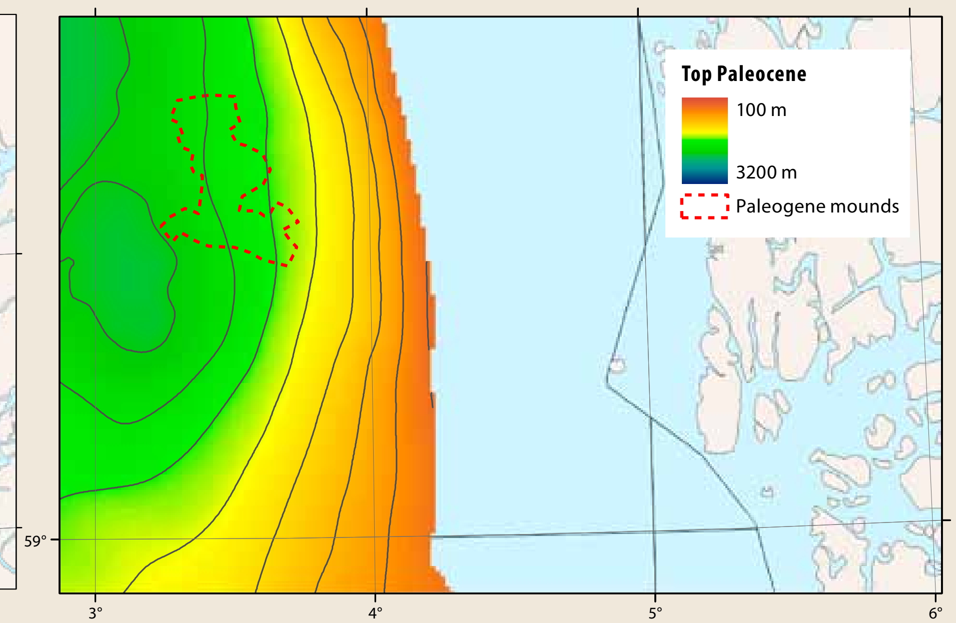


Seismic section across the Farsund Basin. The Gassum aquifer is located between the red and the dark blue horizon at the base of the Jurassic section.

Paleogene Mounds, Stord Basin
The Hugin East Formation aquifer







Paleogene mounds

This prospect is based on seismic 2D interpretation on a mounded reflector in the Paleocene/Eocene sequence in the central part of the Stord Basin. The reflection pattern has been interpreted as a possible deep marine fan system which could have a high content of reservoir sand. There are few wells in the area, and sand have not been proved by drilling in this particular interval. If sand is present, the mapped structure can be regarded as a structural/stratigraphical trap with good seals. The aquifer outside the mapped structure is considered to be limited. Calculation of storage capacity is based on 28 % porosity and a net gross ratio of 0.8 within a closed aquifer volume.

Hugin East Aquifer

One well has been drilled in this aquifer, which has been mapped on 2D seismic data. The reservoir rock is equivalent to the Hugin and Sandnes Formations, and is believed to have good quality. A simplified calculation of theoretical storage capacity was carried out, using a constant net gross value and a porosity trend similar to the Sandnes Formation.

Mounds, Stord basin		Summary
Storage system	half open	
Rock volume, m^3		4,50E+10
Pore volume, m^3		9,72E+09
Average depth		1900 m
Average permeability		1000 mD
Storage efficiency		0,8
Storage capacity aquifer		
Storage capacity prospectivity		50 Mtons
Reservoir quality		
	capacity	2
	injectivity	2
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		

Hugin fm east of the Utsira High		Summary
Storage system	half open	
Rock volume, m^3		1,93E+10
Pore volume, m^3		2,42E+09
Average depth		1700 m
Average permeability		500 mD
Storage efficiency		5,5
Storage capacity aquifer		100 Mtons
Storage capacity prospectivity		
Reservoir quality		
	capacity	1
	injectivity	3
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		

5.1 Saline aquifers

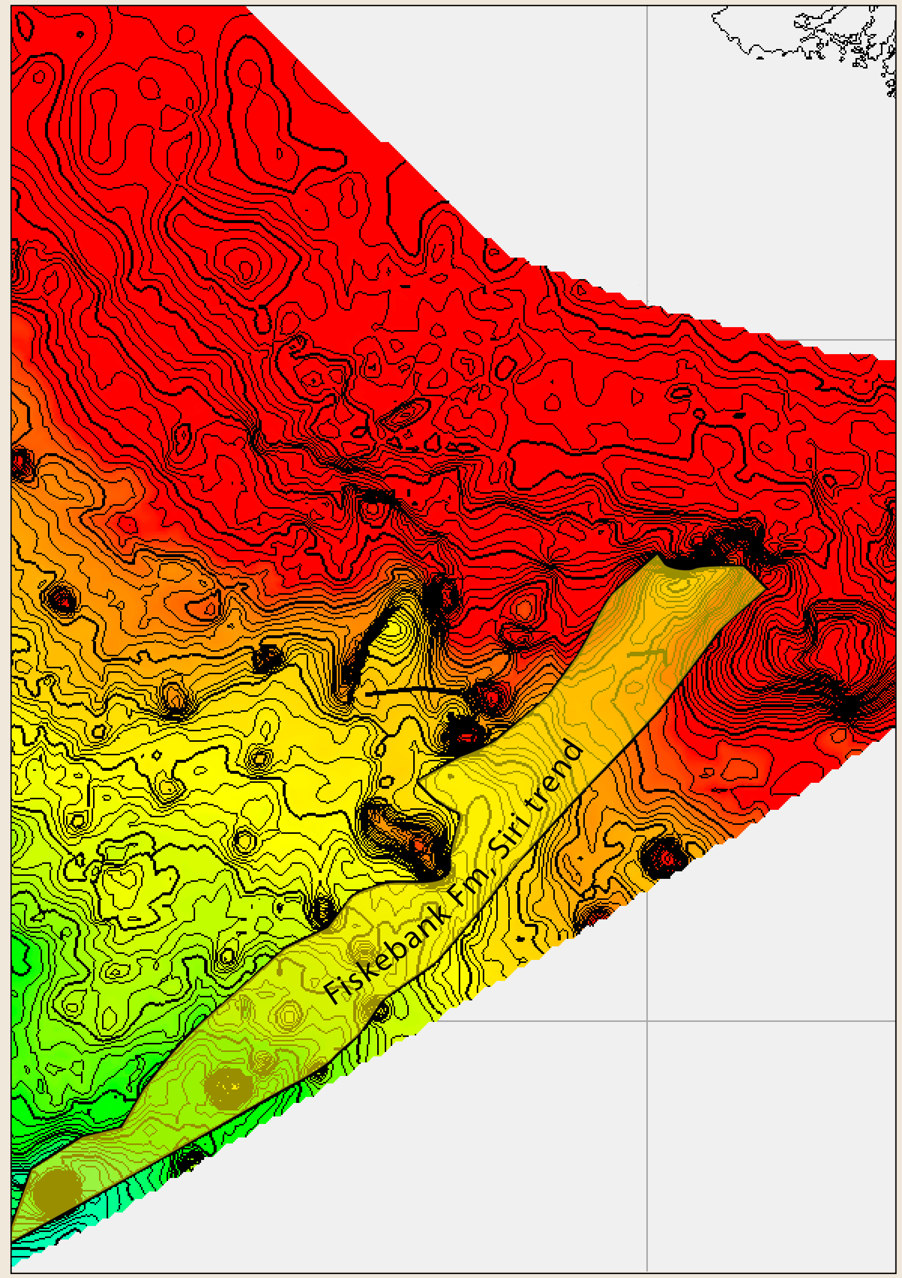
The Fiskebank Formation aquifer (The Siri trend)

In the Norwegian-Danish Basin, deep water sandstones of upper Palaeocene age, hold some smaller hydrocarbon fields and discoveries on the Danish sector close to the border with Norway. The sands on the Norwegian side have been drilled by the dry well 3/6-1 and are highly porous and permeable.

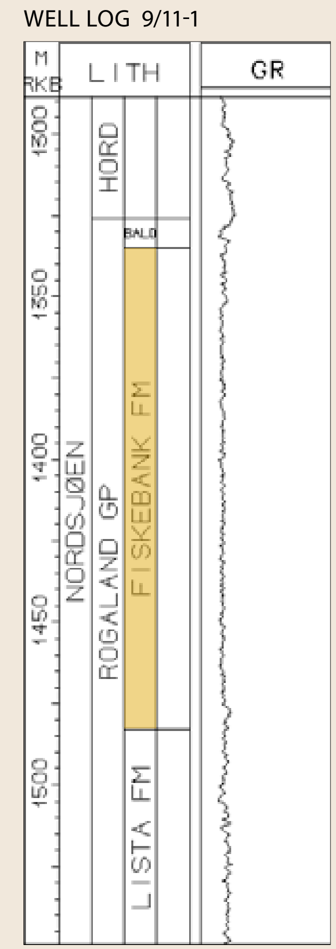
The suggested Fiskebank Formation aquifer is located in a depression in the top chalk surface as shown in the figure. More wells are needed to confirm the existence of high quality sands.

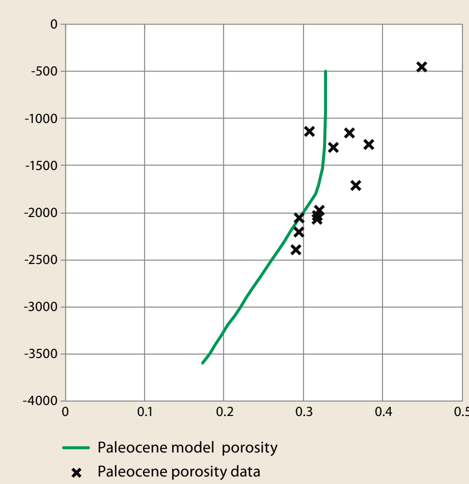
There is some hydrocarbon exploration activity in this area, which is not considered to be fully explored.
The sealing capacity of the Paleocene caprocks is generally thought to be good. Fracturing related to salt structures may occur.

Fiskebank Fm, (Siri trend)		Summary
Storage system	half open	
Rock volume, m^3		1,00E+11
Pore volume, m^3		2,50E+10
Average depth		
Average permeability		1000 mD
Storage efficiency		5,5
Storage capacity aquifer		1 Gigaton
Storage capacity prospectivity		
Reservoir quality		
	capacity	3
	injectivity	3
Seal quality		
	seal	3
	fractured seal	3
	wells	3
Data quality		
Maturation		



Top of the chalk surface. The polygon shows the location of the Fiskebank Formation aquifer.





5.2 Abandoned hydrocarbon fields

Storage in abandoned fields

The estimate of CO_2 storage potential in the petroleum provinces is based on abandoned fields. This is in accordance with the Governmental policy that any negative consequences of CO_2 storage projects for existing and future petroleum activity should be minimized.

At the end of 2011 there are 12 abandoned fields on the Norwegian shelf. Of these three oil fields, four gas-condensate fields and five gas fields. Of the 12 fields, CO_2 storage volumes have been calculated for nine. The chosen fields have been pressure depleted, and the calculations are based on material balance, taking into account the produced volumes of oil, condensate and gas. Some of the fields are chalk fields in the Ekofisk area with low permeability reservoirs. To get decent injection rates, the wells need to be long with advanced completions. The fields have an EOR potential because they contain a rest of hydrocarbons that might be mobilized and produced during the injection. The CO_2 storage capacity for today’s producing fields are estimated based on the close of the production year, and summarized for the years 2030 and 2050.

The Frigg field is studied in more detail and simulated due to its large storage potential. The fields and the main aquifers in the petroleum provinces in the North Sea are shown in the maps.

Many of the big fields in the Lower –Middle Jurassic Statfjord, Brent and Sleipner aquifers are located in areas with weak to moderate overpressure. In parts of the aquifers, the pressure has been depleted due to production. The highly overpressured parts of the aquifers (red color in the pressure maps) are not suitable for CO_2 injection.

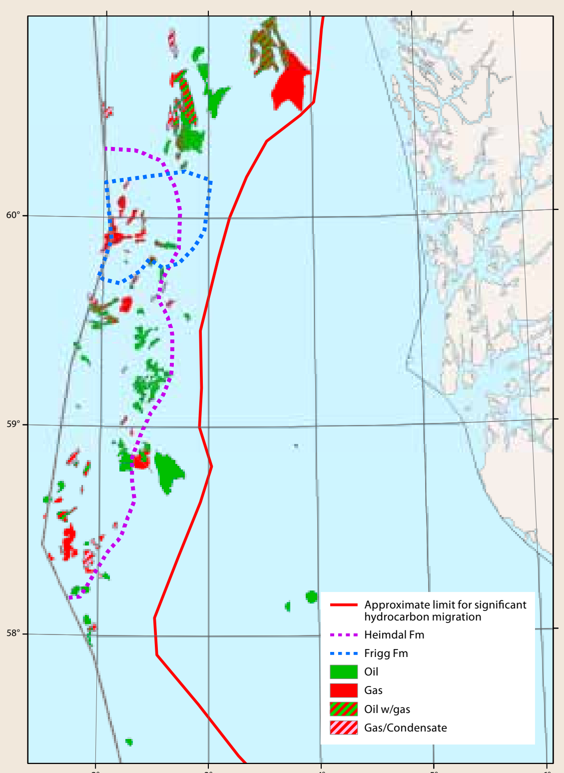
The Sognefjord and Hugin aquifers are hydrostatically pressured to weakly overpressured. The aquifers surrounding the big gas fields have been depleted due to gas production. The Ula Formation has oil fields which are weakly overpressured and relatively deeply buried.

The chalk formations in the southern part of the Norwegian sector have low permeabilities and have not been evaluated for CO_2 storage. The large oil fields have interesting potential for use of CO_2 to enhance the recovery (section 5.3).

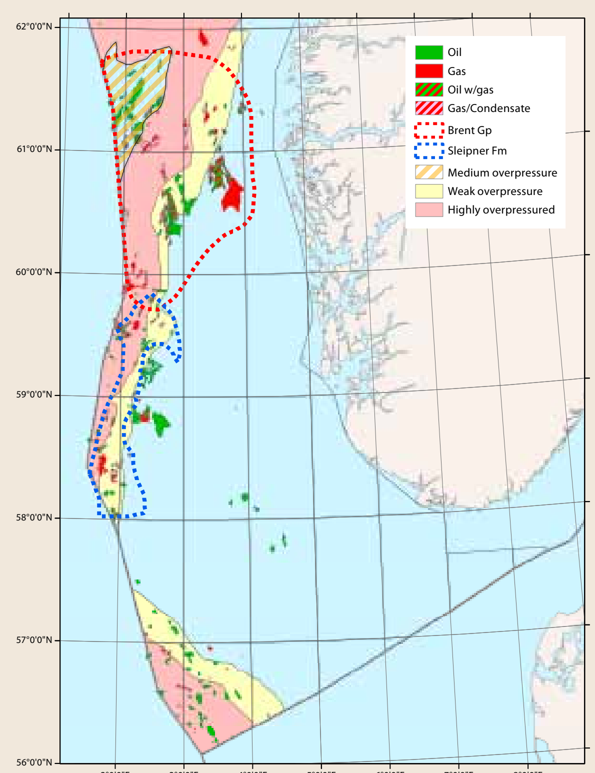
Abandoned fields	Storage capacity, Gtons
CO_2 storage in depleted fields	3 Gtons
Producing fields	
Close of production in 2030	4 Gtons
Close of production in 2050	6 Gtons
Storage potensial in the Troll field is not included, expected to be available after 2050.	

The Paleocene and Eocene Ty, Heimdal, Hermod, Balder and Frigg Formations constitute a large hydrostatically pressured aquifer with both oil and gas fields. There is a significant pressure depletion due to gas production in Frigg and Heimdal. The storage potential in the abandoned Frigg Field is presented in the following section.

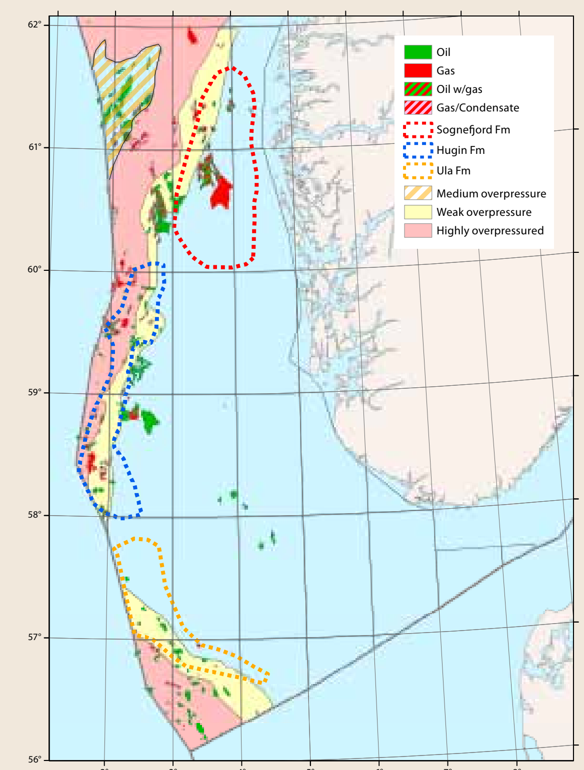
The table shows an evaluation of storage potential in abandoned fields and in today's producing fields, based on close of production year.



Frigg and Heimdal Formations. Hydrostatic pressure/underpressure



Brent Gp and Sleipner Fm, and overpressured areas.



Sognefjord, Hugin and Ula Formations

5.2 Abandoned hydrocarbon fields

FRIGG FIELD

The Frigg field was abandoned in 2004 after 27 years of gas production. The field was produced together with Nordøst Frigg, Lille-Frigg, Øst Frigg and Odin, which used the process facilities on Frigg. The field is located approximately 190 km west of Haugesund in Norway. Frigg is a transboundary field between Norway and the UK.

The reservoir consists of unconsolidated sand in the upper part. The properties are generally very good with porosity ranging from 27% to 32% and permeability from 1 to 5 Darcy.

The initial gas pressure was 197.9 bars at 1900 m MSL, and the initial aquifer pressure (Sele/Lista formations) was found to be 223.4 bars at 2191 m MSL. The water depth in the area is about 100 m.

The initial gas in-place volume was 247 GSm^3, of which about 191 GSm^3 has been recovered.

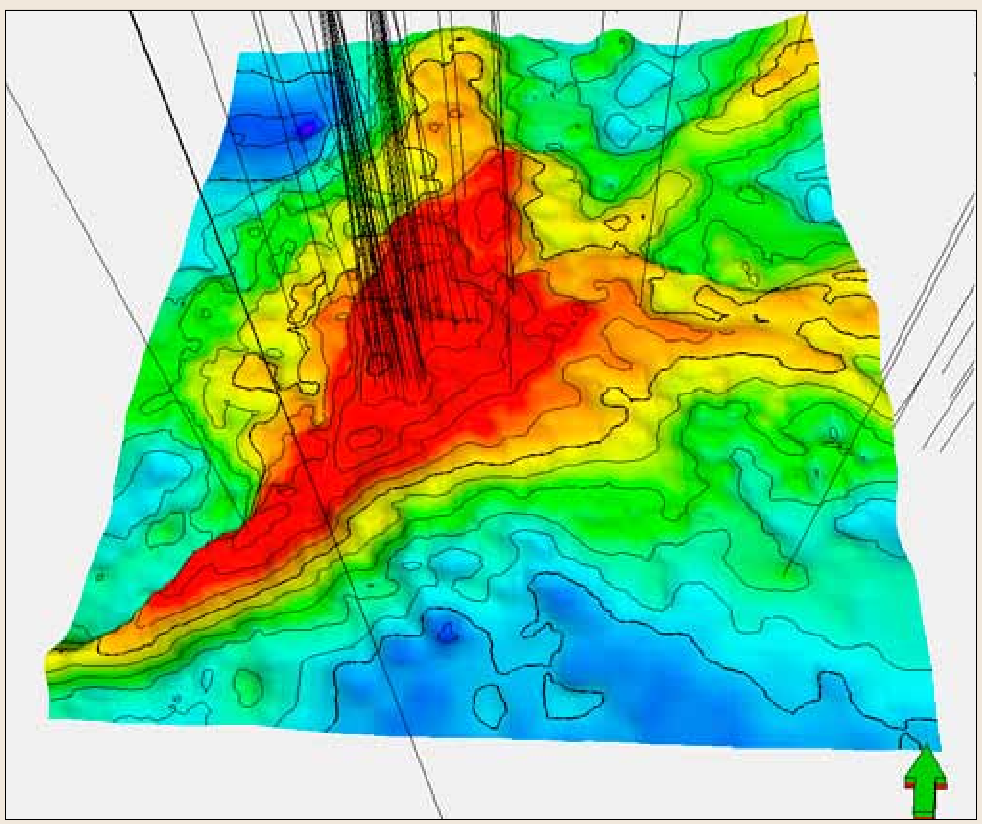
A CO_2 injection study was done by the NPD in 2010 to see if the abandoned field and its satellites might be a candidate for future CO_2 storage. A reservoir simulation model made by Total for the full field was used and converted to an Eclipse E300 compositional model. The model was matched both with regard to PVT and production history. The fluid was described with four component groups: CO_2, N2+C1, C2-C6 and water.

The simulation model included a huge aquifer around the Frigg fields. The model is shown in the lower right figure with grid cells, hydrocarbon accumulation and rock compaction regions. The main cases run were the following:

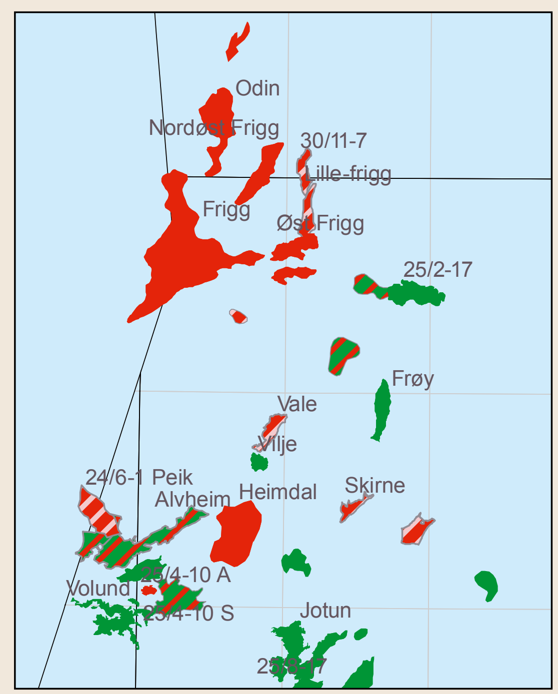
1. Production of remaining gas together with CO_2 injection
2. Injection with closed aquifer, no gas production
3. Injection with leaking aquifer, no gas production.

In case 1, 10 mill Sm^3/d of CO_2 was injected for 55 years from one well in the aquifer, and remaining methane gas was produced from the top of the Frigg field. In cases 2 and 3, CO_2 injection with 10 and 50 mill Sm^3/d was applied in an open aquifer. An open aquifer was simulated by producing water in the corners of the aquifer, thus keeping the pressure increase quite slow. The results are shown in Table 5.2.1. The range in methane gas volume produced is due to the uncertainty in trapped gas saturation, where low values of trapped gas correspond to high volumes produced. Base case trapped gas saturation (Sgr) is 0.28 and gives 0.3 Gsm^3. An Sgr of 0.14 gives 18.8 GSm^3.

In cases 2 and 3, pressure builds up from about 183 bar in Frigg, which is about 20 bars below initial pressure, to 208 bars in case 2 and 278 bars in case 3. The behaviour of CO_2 in the formation water has a long-term effect, as more and more of the free CO_2 will dissolve. This leads to heavier formation water which will start to move downward as shown in the figure.



Structural map of the Frigg field with all wells



Frigg field with satellites. Hydrocarbon fields in the Frigg area

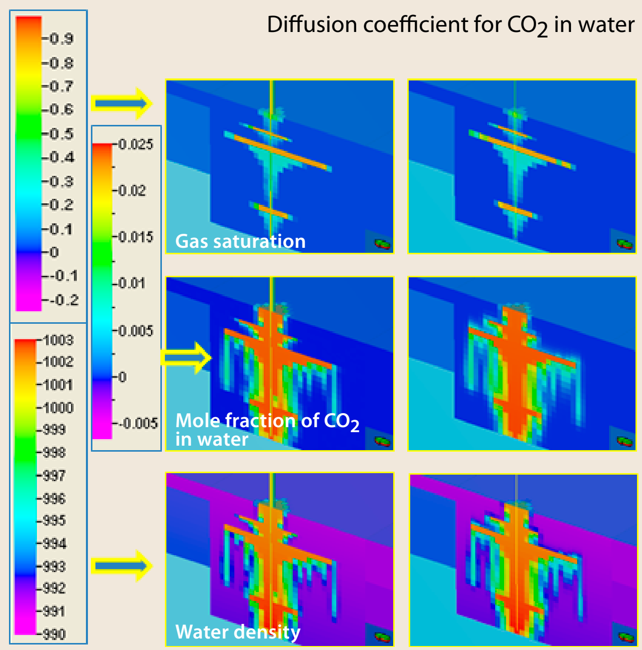
5.2 Abandoned hydrocarbon fields

Table 5.2.1

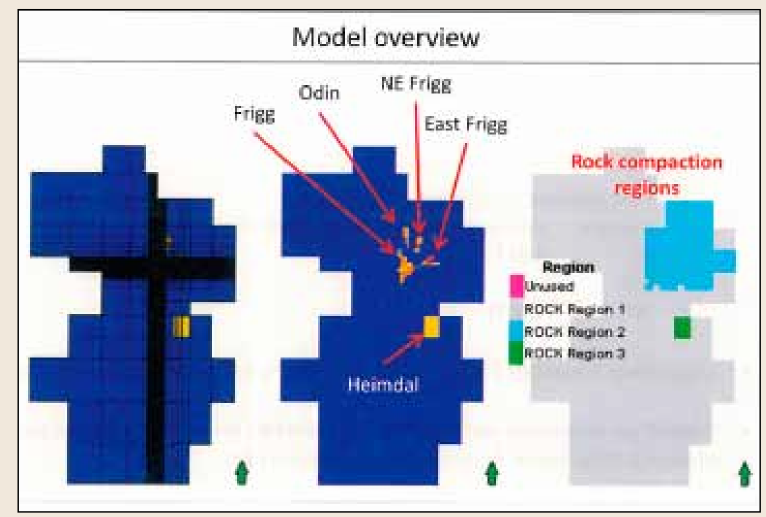
Case	Description	Gas produced, GSm3	Injection period, years	Injection rate	Pressure increase, bar	CO_2 injected mill ton	Storage efficiency, % of PV (incl. aquifer)
1	Gas production and CO_2 injection	0.3 – 18.8	55	10		445	0.06
2	Injection in half open aquifer		85	10	25	689	0.09
3	Injection in half open aquifer		85	50	95	3443	0.46
	The results show that remaining gas can be produced without CO_2 contamination into the gas.						

Conclusion
The Frigg field has a large potential for CO_2 storage due to remaining gas in the field itself and a huge aquifer that is connected to the field. The simulation shows that there is a higher potential than what is simulated if the pressure increase is compensated with more water production out of the aquifer.

Some thought should be given to the abandoned wells on the Frigg field and its satellites as their sealing capacity for CO_2 has not been studied in detail. If storage is implemented in Frigg, integrity studies and monitoring of the old wells will be an important issue.



Long term effects of CO_2 injection for two alternative values of diffusion coefficient.



Simulation model

5.3 Producing fields (EOR)

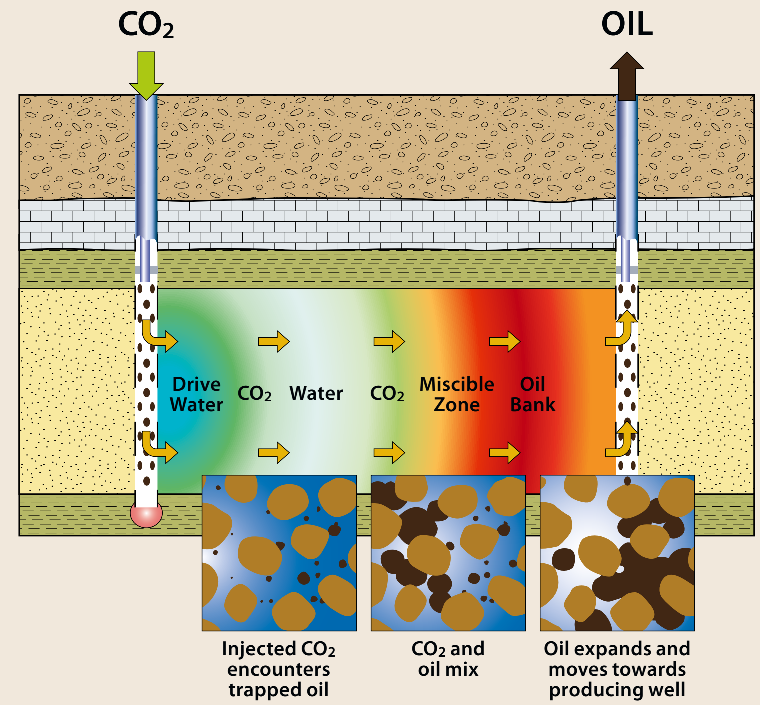
Injection of CO_2 in oil fields has for many years been used as a method to enhance oil recovery, primarily in the United States, where the CO_2 source has mostly come from reservoirs with almost pure CO_2. The CO_2 injected for enhanced recovery will at the end be stored. On the Norwegian shelf, several oil fields have been examined with regard to possible enhanced recovery through CO_2 injection. Some of the fields have proved to be promising candidates. Others are not suitable for CO_2 flooding due to reservoir conditions. Some interesting field studies on the use of CO_2 for EOR are shown in the textboxes.

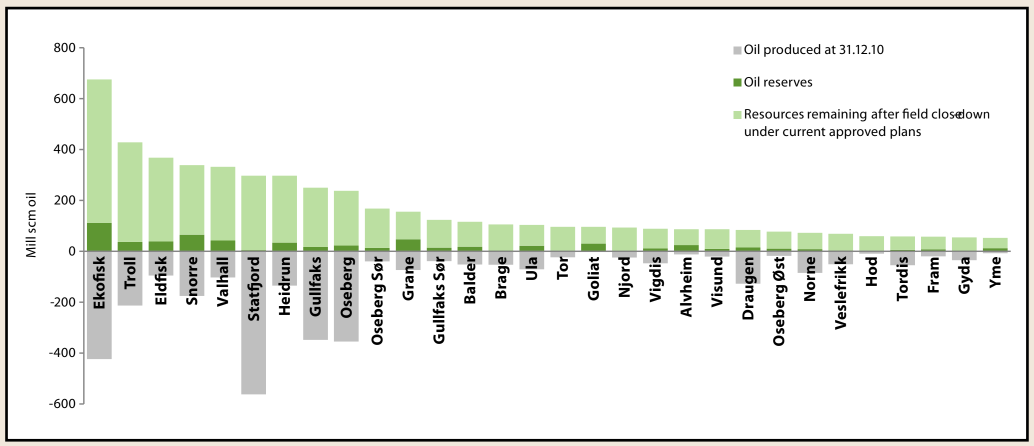
A study carried out by the NPD in 2005, and revised in 2008 indicated an additional oil recovery with CO_2 in the order of 3–7 percentage points from certain fields. The NPD estimated the technical potential from 20 fields that could use CO_2, to 150–300 million Sm^3 of oil. More detailed work must be done in each field to get a better evaluation of the EOR potential and the challenges that must be addressed. In addition, the fields must have access to sufficient and stable amounts of CO_2.

The best effect of CO_2 is obtained when CO_2 and oil are miscible in the reservoir. In addition, CO_2 have many properties that enables to increase production. It swells the oil, reduces oil viscosity and increases oil density. It is soluble in water, can evaporate and extract oil, and it reduces surface tension between oil and water providing a more efficient displacement. The sweep efficiency of CO_2 flooding can be improved by applying WAG, which is alternating injection of CO_2 and water.

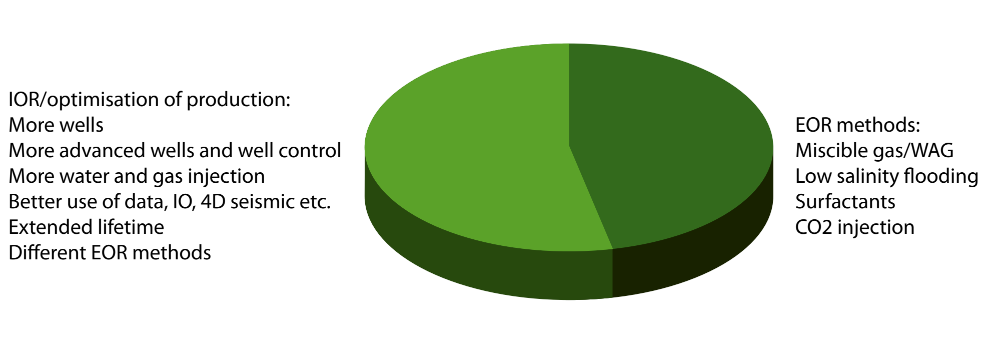
Corrosion is a critical factor as CO_2 mixes with water. This fluid will eventually reach the wells and process plant.

Cross section of a reservoir with CO_2 WAG





Mobile and immobile oil and different recovery methods



Gullfaks. Statoil conducted studies of CO_2 injection in the Brent reservoir in 2003 -2004. These studies showed a potential for increased recovery of approximately 14 million Sm3. This is equivalent to about 3 % of the remaining resources with an injection of 5 million tons CO_2/y over a 10-year period. Continued injection of reproduced CO_2 for another 10 years might increase the reserves by 22 million Sm3, including a profitable tail production, i.e. a total increase of approximately 8 %. Net injection of CO_2 in the field was estimated at about 50 million tons over a 20-year period. The field owners concluded that the project was not profitable due to the estimated oil price path at the time.

Ekofisk. Research work and field studies are ongoing in the license related to enhanced oil recovery by means of CO_2. The licensees are looking at future CO_2 injection as the method that has the best potential in addition to water injection and drilling of wells. A full field project will require large quantities of CO_2. In addition there is a risk of further compaction of the chalk reservoir, due to injection of CO_2 and further subsidence of the seabed. A pilot is considered to obtain more information about the effects and consequences of using CO_2 in full-scale production.

5.4 Summary of aquifer evaluation

The results of the evaluation of theoretical storage capacity in the North Sea are summarized in the tables. Excluding the aquifers in the petroleum systems, two aquifers with significantly greater theoretical storage potential than the others have been identified. These are the Utsira – Skade Formation aquifer and the Bryne – Sandnes Formation aquifer.

The Utsira Formation is already used by the petroleum industry for CO_2 storage. Structures in the Utsira Formation which are equivalent to the site used for the Sleipner injection have been classified within the 3rd level of the maturation pyramid. Only about 25 % of the total pore volume of the Utsira – Skade aquifer has been included in the calculation of storage capacity. The reason is that the top of the aquifer is too shallow to be suitable for CO_2 storage.

The Bryne-Sandnes aquifer has a lower level of maturity than the Utsira formation. In any proposed storage site, reservoir quality and seal integrity must be studied carefully. The aquifer is located in a salt basin, and closed structures formed by salt tectonics may be attractive for CO_2 injection.

The Johansen – Cook Formation aquifer has a smaller pore volume than the two aquifers mentioned above, but it has good reservoir and seal properties. A potential storage site in the Johansen Formation has recently been matured by Gassnova, and is here included in the 3rd step of the pyramid.

In the petroleum provinces, the storage potential was calculated from the extracted volume of hydrocarbons in depleted fields. The main contribution to the present theoretical storage capacity comes from the abandoned Frigg Field and its satellites, which are located in the huge Frigg-Heimdal Formation aquifer. The increase of storage capacity in abandoned fields has been estimated for 2030 and 2050. The storage capacity of that part of the large Sognefjord Delta aquifer which belongs to the Troll Field has been grouped together with the abandoned fields.

CO_2 storage in abandoned and depleted fields will usually require a careful study of the integrity of the wells which have been drilled into the field. If oil has been present, it is relevant to study the potential for enhanced recovery by CO_2 injection. The CO_2 storage potential achieved by potential EOR projects is discussed, but has not been quantified in this study.

	Avg Depth	Bulk volume	Pore volume	Avg K	Open/closed	Storage eff	Storage Vol	Density	Storage Capasity
Evaluated Aquifers		Rm3	Rm3	mD		%	Rm3	tons/Rm3	Gtons
Utsira Formasjon and Skade	1000	2.49E+12	5.26E+11	>1000	Open	4	2.10E+10	0.75	15.77
Bryne/Sandnes Formations	1700	5.04E+12	4.41E+11	150	Half open	4.5	1.99E+10	0.69	13.60
Sognefjord Delta east	1750	5.54E+11	1.08E+11	300	Half open	5.5	5.93E+09	0.69	4.09
Statfjord Formation East	2400	1.13E+12	1.21E+11	200	Half open	4.5	5.44E+09	0.66	3.59
Gassum Formation	1700	6.53E+11	7.61E+10	450	Half open	5.5	4.19E+09	0.68	2.85
Farsund Basin	2000	8.55E+11	8.21E+10	150	Half open	4	3.28E+09	0.70	2.30
Johansen and Cook Form.	1700	N/A	9.14E+10	300	Faults	3	2.74E+09	0.65	1.78
Fiskebank Formation	1600	1.00E+11	2.50E+10	1000	Half open	5.5	1.38E+09	0.70	0.96
Stord basin, Jurassic model	1450	2.70E+11	1.62E+10	5 - 20	Half open	0.8	1.43E+08	0.71	0.10
Hugin East	1700	1.93E+10	2.42E+09	500	Half open	5.5	1.33E+08	0.70	0.09

	Avg Depth	Bulk volume	Pore volume	Avg K	Open/closed	Storage eff	Storage Vol	Density	Storage Capacity
Evaluated Prospects		Rm3	Rm3	mD		%	Rm3	tons/Rm3	Mtons
Bryne/Sandnes1	1700	1.25E+10	1.60E+09	150	Open	20	3.20E+08	0.69	220
Bryne/Sandnes2	1700	3.30E+09	1.50E+08	150	Open	20	3.00E+07	0.69	21
Johansen	2900	N/A	N/A	300	Half Open	N/A	N/A	N/A	150
Stord Basin mounds	1900	4.50E+10	9.72E+09	1000	Closed	0.8	7.78E+07	0.69	53

Total aquifers	Avg Depth	Bulk volume	Pore volume	Avg K	Open/closed
Utsira total	1000	8.54E+12	1.80E+12	>1000	Open
Sognefjorddelta_total	1750	2.67E+12	4.78E+11	300	Half open

Abandoned and producing Fields

	Storage Capacity Gtons
Abandoned fields	3
Producing fields	
Close of production within 2030	4
Close of production within 2050	6

5.4 Summary of aquifer evaluation

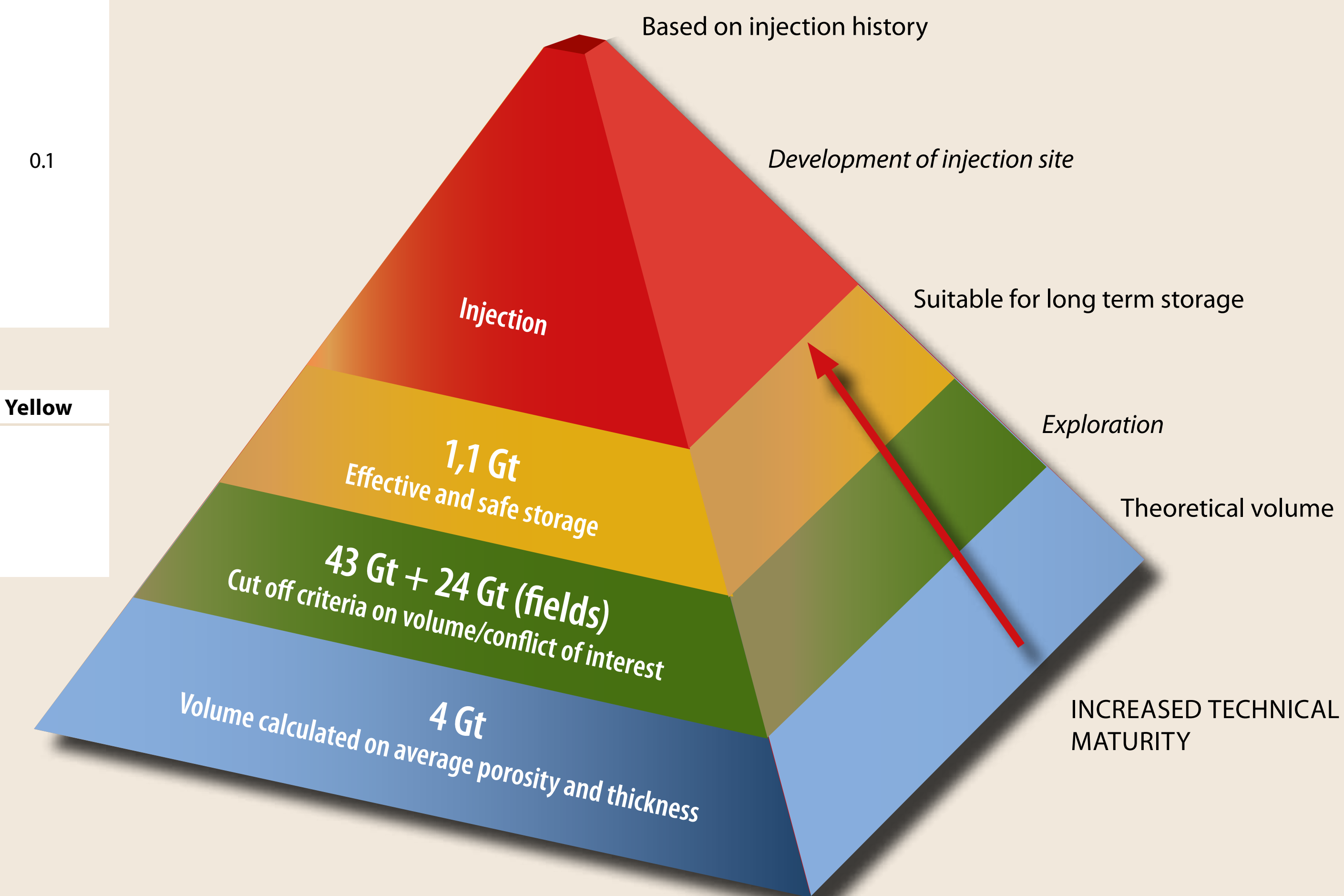
Storage capacity in Gigatons and technical maturity

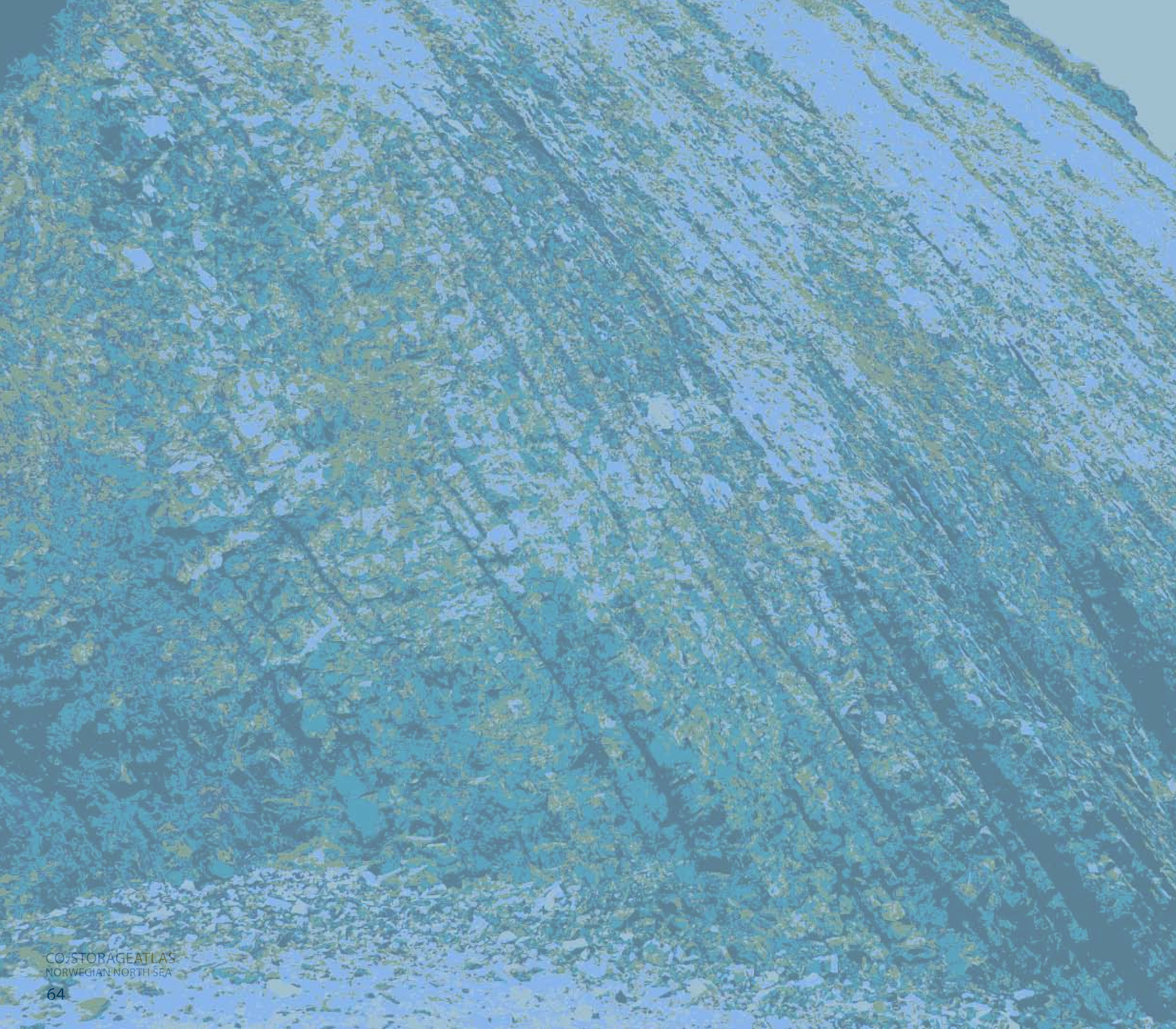
Aquifers

Basin/reservoir	**Storage capacity**	**Maturity**		
	Total	Blue	Green	Yellow
Utsira and Skade	15.8		14.8	1
Bryne/Sandnes southern parts	13.6		13.6	
Sognefjord Delta east	4.1		4.1	
Statfjordfm øst	3.6		3.6	
Gassum	2.9	2.9		
Bryne/Sandnes Farsund basin	2.3		2.3	
Johansen and Cook	1.8		1.7	0.1
Fiskebank	1	1		
Hugin East	0.1		0.1	
Stord basin, Jura	0.1	0.1		
Stord basin , mounds	0.05	0.05		

Field related

		Blue	**Green**	**Yellow**
Abandoned fields	3		3	
Fields in production 2030	4		4	
2050	6		6	
Sognefjord delta including Troll	14		14	





6. Monitoring

6. Monitoring

Monitoring of injected CO_2 in a storage site is important for two main reasons: Firstly, to see that the CO_2 is contained in the reservoir according to plans and predictions, and secondly, that if there are deviations, to provide data which can be used to update the reserservoir models and support eventual mitigation measures.

A wide range of monitoring technologies have been used by oil and gas industry to track fluid movement in the subsurface. These techniques can easily be adapted to CO_2 storage and monitor the behavior of CO_2 subsurface. For example, repeated seismic surveying provides images of the subsurface, allowing the behavior of the stored CO_2 to be mapped and predicted. Other techniques include pressure and temperature monitoring, down-hole and surface CO_2 sensors and satellite imaging, as well as seabed monitoring. In this chapter we present some of the challenges related to CO_2 storage and some of the available monitoring techniques.

Seal considerations for CO_2 storage — by prof. Per Aagaard, UiO

The main criteria for selecting a site for geological CO_2 storage (IPCC report on Geological CO_2) are adequate CO_2 storage capacity and injectivity, safety and security of storage (i.e., minimization of leakage), and minimal environmental impact. A potential reservoir thus needs a seal or caprock above the reservoir, i.e. physical and/or hydrodynamic barriers that will confine the CO_2 to the reservoir.

Typical rocks forming seals or caprocks offshore in Norway, are sediments like mudstones, shales or fine-grained chalks. The pores are water-filled, while the reservoir beneath may have oil, gas or supercritical CO_2. The seal should prevent the migration of these fluids into the fine-grained caprock. To form an efficient seal, the rock has to have a small pore throat radius, giving them a high capillary pressure. This prevents the migration of fluids like oil and gas or supercritical CO_2 into the caprock, because the capillary pressure is greater than the buoyancy effect.

The capillary sealing is normally sufficient to prevent migration of fluid CO_2 into caprock, and a diffusion of CO_2 dissolved in the pore water of the caprock will also have very limited penetration in time scales of less than thousands of years. But we know from oil and gas reservoirs that caprocks may leak, and seepage of small gas volumes is commonly observed above the big oil and gas fields on the Norwegian shelf. This occurs either through small fractures or faults, which may open up under certain conditions. The seepage process is slow due to a combination of capillary pressures and low permeability in the caprock and the fracture systems. During injection, the caprocks can in particular be affected by: 1) the pressure rise in the storage formation induced by the injection process, and 2) geomechanical and geochemical processes that may affect the integrity and safety of the storage formation. In tectonically active areas, leakage can be induced by earthquakes. This is not an important risk in the North Sea, as recorded earthquake foci are deep-seated.

Fine-grained sediments undergo major changes after their initial deposition as mud. First they are compacted due to the weight of overlying sediments, and later, as the temperature increases with burial depth, chemical reactions also create cement between the sediment grains. Thus there is a transformation from ductile mudstones to more brittle shale or chalk, which mechanically is stronger, but more likely to fracture. Generally, thicker mudstone/shale formations will make better seals, but even rather thin, young sediments have been shown to be effective caprocks. The shallow Peon gas field has a less than 200m thick seal of Pleistocene mud. Several groups are active in research on geomechanics and rock physics of caprock research in Norway under petroleum research programs.

The CO_2 will react with the caprock, and there is considerable concern as to how these processes may affect the seal integrity. In addition, well cement may also deteriorate under reaction with CO_2. There is quite some dedicated research on CO_2 - caprock interaction, both internationally and nationally. In Norway, several research projects are run both under the CLIMIT program (SSC-Ramore) and within the SUCCESS and BIGCCS Centres for Environment-friendly Energy Research (FME).

6. Monitoring

Monitoring of CO_2 injection and the storage reservoir — by Ola Eiken, Statoil

Monitoring of CO_2 injection as well as acquisition and interpretation of various kinds of well and reservoir data are important for control during the injection period and afterwards. Firstly, monitoring gives feedback to the injection process; it can lead to adjustment of rates, guide well intervention or decisions on new injection wells. In case of unwanted reservoir behaviour, monitoring data can lead to a number of mitigation measures. Furthermore, monitor data are needed to confirm storage reservoir behaviour and are crucial for operating CO_2 quota systems. To obtain public acceptance of a storage site and wide recognition of CCS as a measure to prevent climate change, monitoring will play an important role. Also, predictions of a storage site's long-term behaviour (over hundreds or thousands of years) should be calibrated against monitor data. Finally, public regulations, such as the EU directive 2009/31/EC, Article 13, on the geological storage of carbon dioxide, require monitoring of the storage reservoir.

Monitoring data can be acquired in the injection well(s), in observation wells and by surface measurements. Crucial measurements at the well head are rate, composition and pressure/temperature. Downhole pressure/temperature measurements are of further value, because sensors closer to the reservoir give more accurate responses of pressure build-up during injection and of fall-offs during shut-ins. These can be used to constrain reservoir models and to predict maximum injection rates and storage capacity. Observation wells can, if they penetrate the storage reservoir, give data on pressure build-up and CO_2 breakthrough. This is done by installing various sensors, by logging the reservoir interval regularly and by fluid sampling. Regional pressure development within a basin is of particular importance in large-scale storage. A number of surface measurement techniques can be applied. 4-D seismic has proven most successful on the industry-scale offshore projects of Sleipner and Snøhvit, yielding the geometry of the CO_2 plume with high resolution, while gravimetry has given complementary information on CO_2 in-situ density and dissolution rates in the formation water. Onshore, surface elevation and microseismic data have given valuable information on injection and storage, and these techniques can be extended to offshore applications. Cost is an important aspect of a monitoring program, and subsurface and surface conditions that vary from site to site make a tailor-made plan necessary for each site. Equipment reliability and a system of documentation which works over a time-span of generations are also important for a monitoring program. With a proper monitoring program, a leakage out of the storage complex should be detected long before CO_2 reaches the sea floor or the surface, so that mitigating measures can be implemented.

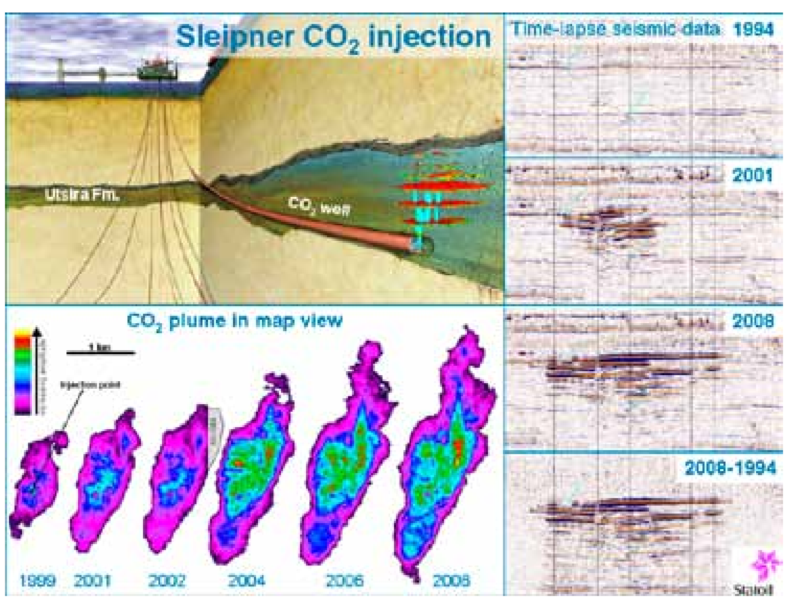


Figure of the Sleipner *CO_2 injection 4-D seismic monitoring. Upper left: sketch of the injection well and storage reservoir. To the right is a seismic section along the long axis of the plume (south-west to north-east) for different vintages and for a time-lapse difference. Note the lack of reflectivity on the seismic difference above the storage formation, showing no signs of leakage. Lower left: Maps of the development through time of cumulative amplitudes for all layers.*
By 2008 the area of the CO_2 plume was about 3 km^2, and it was steadily growing.

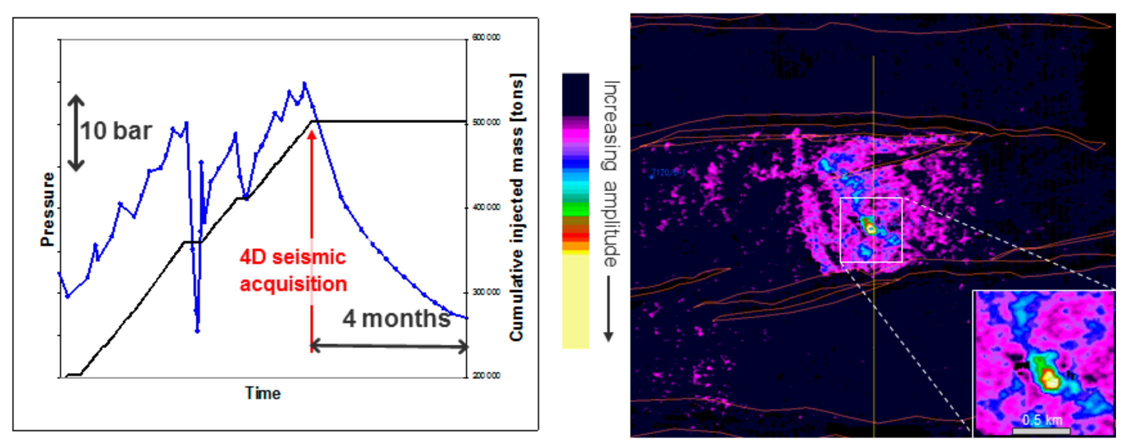


Figure from the Snøhvit *CO_2 injection. Left: Cumulative injection (black line) and estimated bottom-hole pressure (blue line) spanning year 2009, showing pressure increase during periods of injection and pressure fall-off during stops. The timing of a 4-D seismic survey is shown in the figure. Right: A 4D seismic difference amplitude map of the lowest Tubåen Fm. level, showing highest amplitudes close to the injection point, and with decaying amplitudes outwards from the well – falling below the noise level about 1 km away.*

Seafloor monitoring of sub-seafloor CO_2-storage sites — by prof. Rolf Birger Pedersen, UiB

A leakage of CO_2 from a storage reservoir can result from a failure during injection or due to a migration of CO_2 from the reservoir to the seafloor along unforeseen pathways for fluid flow. Whereas the first would be detected by instrumentation at the injection sites, monitoring of the seabed may reveal the latter.

The flow of fluids from the subsurface, across the seabed and into the water column has been studied extensively since the late nineteen seventies - when deep-sea hydrothermal venting was first discovered. Since then, the instrumentation and procedures to locate and monitor the flow of fluids (i.e. gases and liquids) from the seafloor has been developed during research investigations both at hot vents and cold seeps. Therefore, when strategies and procedures for monitoring sub-seafloor CO_2 storage sites are being developed today, they are based on over four decades of basic research of natural seafloor fluid-flow systems.

Within the sediments below the seabed, chemical compounds like CO_2 and CH_4 form naturally through microbial activity and sediment diagenesis. There is a natural flux of these and other fluids across the seabed. These fluxes range from widespread and slow diffusion processes, to focused fluid flow at discrete seepage sites. Fluid flow at seepage sites results in distinct topographic, geochemical and biological signatures on the seafloor, as well as chemical and physical imprints in the water column above. Any change in these natural fluid-flow-patterns may indicate the first warning of leakage. Thus the flow of natural, reduced pore water at existing or new seepage sites is expected to be a distinct, initial sign of CO_2 seepage from a subsurface reservoir.

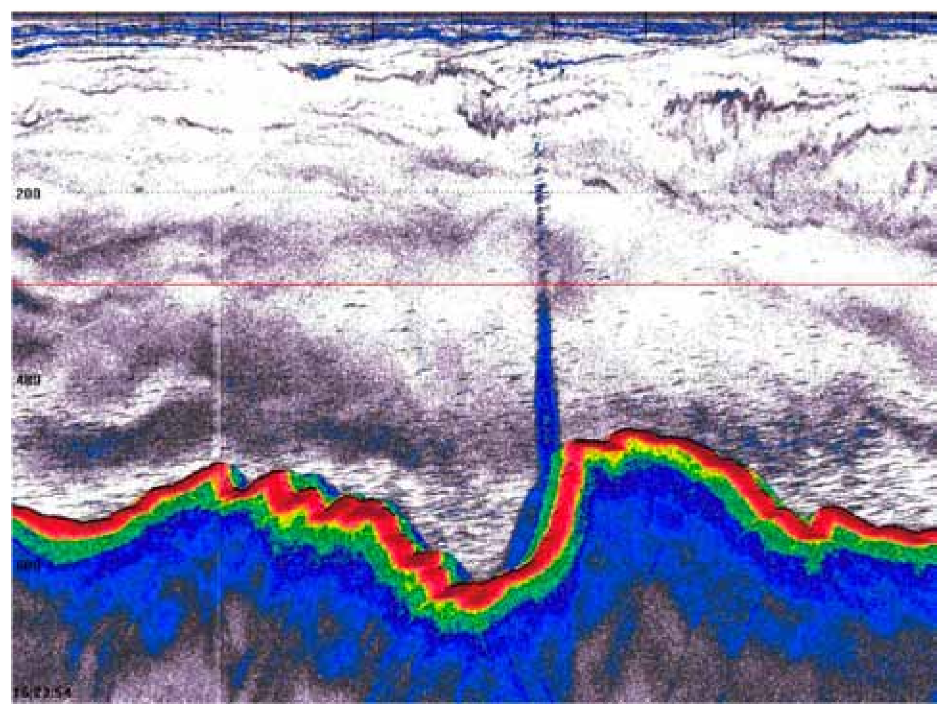
Seafloor monitoring programs are now being designed to detect CO_2 leakages and such early warnings. These schemes include: 1) scanning of the water column with acoustic systems to reveal any changes in the release of gas bubbles from the seafloor; 2) acoustic imaging of the seafloor at ultrahigh resolution to detect topographic changes that might reveal the formation of new fluid escape pathways; 3) imaging of bacterial mats and fauna at seepage sites to document environmental changes related to fluid-flow, and 4) chemical analyses of sea- and pore-water at natural seepage sites to monitor changes in the composition of the fluids emanating from the seafloor.

This monitoring requires advanced instrumentation that is either already available or currently under development. Hull-mounted multi-beam systems that scan the water column while simultaneously mapping the seafloor are now available. With a beam width of five times the water depth, these systems scan large areas in short time spans, detecting even small releases of gas bubbles from the seafloor. Autonomic underwater vehicles (AUV), which can dive for 24 hours and move at speeds of up to four knots at heights of just a few meters above the seafloor, can image the seafloor with side scan sonar systems at 10 cm scale resolution. At such resolutions, the appearance of new fluid flow pathways can be detected by small changes in the seafloor topography.

Where reduced subsurface fluids seep out, microorganisms will colonize the seafloor. They utilize the chemical energy in the fluids and form distinct, white bacterial mats that easily are detected by optical imaging of the seafloor using AUVs and ROVs as platforms for the camera. Today, thousands of images can be geo-referenced and assembled in large photo-mosaics. Repeated seafloor imaging of areas with evidence of fluid flow will be used to monitor the seabed fluid flow regime through the behaviour of microbial colonies and the seafloor biota.

AUVs and ROVs may also carry sensors that directly measure dissolved CO_2 and CH4 in the water just above the seafloor. At present, these sensors lack the sensitivity as well as a rapid enough response time to be effective monitoring tools. Sensors with the needed capability are under development, and in a few years' time they will be available for use in combination with acoustic and optical methods to monitor the state of the seabed fluid flow pattern.

Monitoring of the seafloor at regular intervals with these types of methods will not only be capable of detecting direct CO_2 leakages, but also the subtle changes in the seabed fluid flow pattern that may represent early warnings. If the monitoring reveals anomalies relative to the baseline acquired before the CO_2 injection starts, then special measures should be taken to investigate these areas in more detail. A range of geochemical, geophysical and biological methods is available to examine if the changes are related to leakage from the CO_2-storage reservoir rather than natural variations.

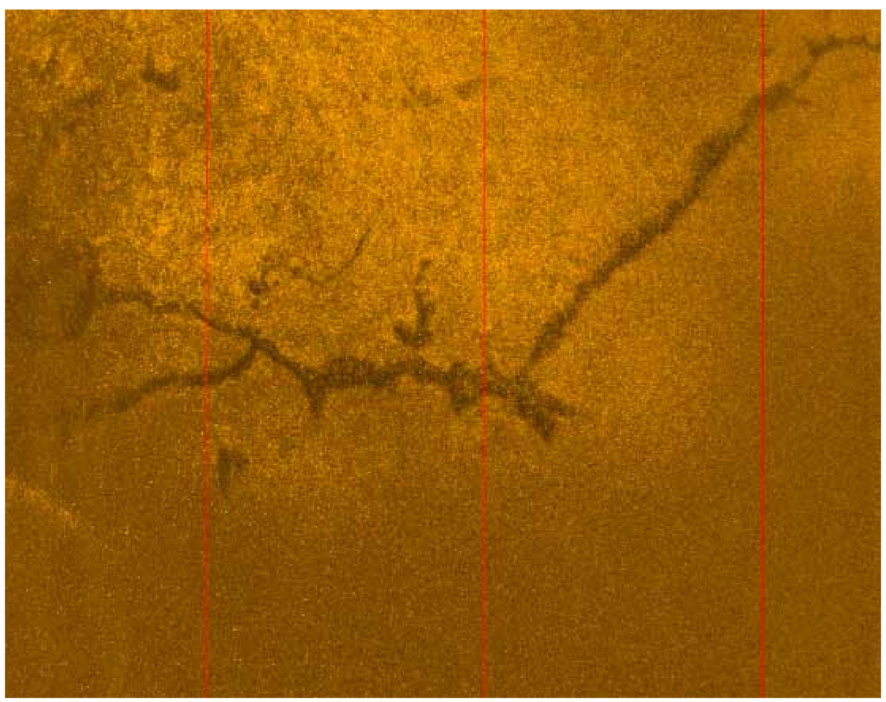


Detection of gas bubbles by echo sounder systems. The figure shows the acoustic signature generated by CO_2 bubbles being naturally released from the Jan Mayen vent fields. The CO2 bubbles are here seen as a blue flare that rises around 500 metres from the seafloor through "clouds" of plankton in the water column.

Seafloor monitoring of sub-seafloor CO_2-storage sites

At such anomalies, a necessary next step may be to place instrumentation on the seabed to obtain time series data. Called seafloor observatories, these instruments are capable of relaying sensor data and images to onshore laboratories via satellite links or fibre optic cable-connections. Seafloor observatories are at the cutting edge of today's marine sciences. Presently, cable based seafloor observatories for basic research are being deployed at natural seabed fluid flow sites in the Pacific. As part of these and other research programs, a range of specialised instrumentation has been developed to monitor natural seabed fluid flow systems. These include: 1) acoustic systems to monitor the flux of gases into the water column; 2) mass spectrometers and chemical sensors to measure fluid components; 3) high-definition camera systems to monitor seafloor biota responses; and 4) broad-band seismometers for detecting cracking events related to subsurface fluid flow. Whereas most of these technologies may be directly transferable to the monitoring of CO_2 storage sites, some may need further development and adaptation.

In conclusion, the know-how and technology developed partly by research on natural seabed fluid flow systems is currently available and can be transferred to the monitoring of CO_2-storage sites. Monitoring schemes can therefore be designed and implemented to document the integrity of these sites, as well as providing early warnings of developing leakage situations from sub-seafloor storage sites.



Detection of seafloor fluid flow structures using side-scan sonar imaging. The image shows a fracture system in the seabed where fluids are slowly seeping out from the subsurface. (Scale: 50 metres between red lines)

Detection of seafloor fluid flow using biologic signatures. The photo mosaic shows white bacterial mats that form a distinct biologic signature of fluid flow across the seabed. (sea star for scale)

6. Monitoring

Wells

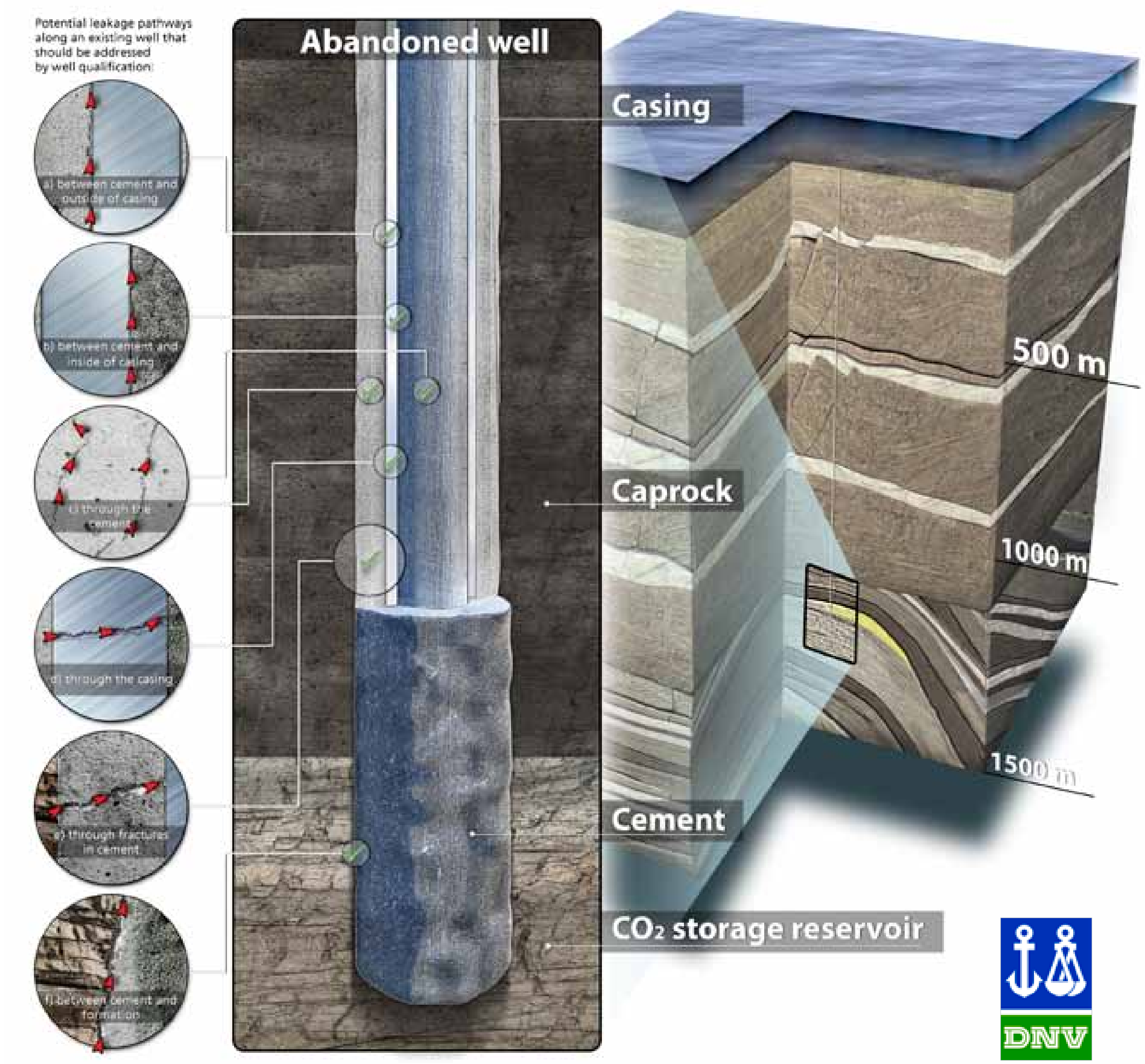
By: The Petroleum Safety Authority Norway

- **A potential CO_2 storage location can be penetrated by a number of adjacent wells that represent potential leakage sources.**
- **Adjacent wells are defined as wells that might be exposed to the injected CO_2. These wells can be abandoned wells as well as production, injection and disposal wells.**
- **Adjacent wells can have well integrity issues that might allow CO_2 to leak into the surroundings.**

There are challenges concerning the design of these adjacent wells, since they were not planned to withstand CO_2. The carbon dioxide in water is called carbonic acid and it is very corrosive to materials such as cement and steel. This situation can over time cause damage to downhole tubulars and mechanical barrier elements and lead to degradation of well integrity.

The general concern regarding CO_2 injection wells is the need of a common recognized industry practice related to design of CO_2 injection wells. This includes qualification of well barrier elements and testing related to CO_2 for medium to long term integrity and low temperatures. A CO_2 resistant design includes considerations related to CO_2 resistant cement, casing, tubing, packers and other exposed downhole and surface equipment.

A common industry practice is also needed concerning plug and abandonment of CO_2 injection wells and adjacent wells.



- **Proposed ISO standard related to CO_2 injection well design and operation.**
- **DNV – "Guideline for risk managment of existing wells at CO_2 geological storage sites" (CO_2WELLS)**

6. References

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