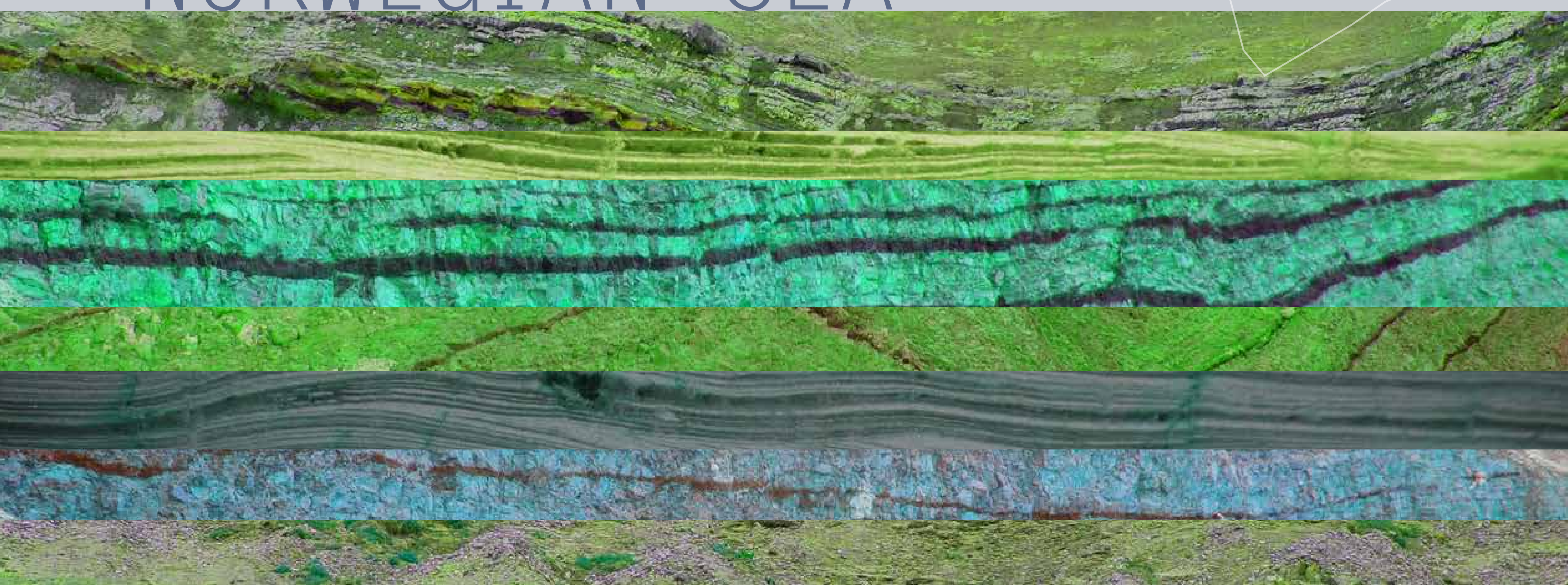
NORWEGIAN PETROLEUM
DIRECTORATE

CO_2 STORAGE ATLAS

NORWEGIAN SEA



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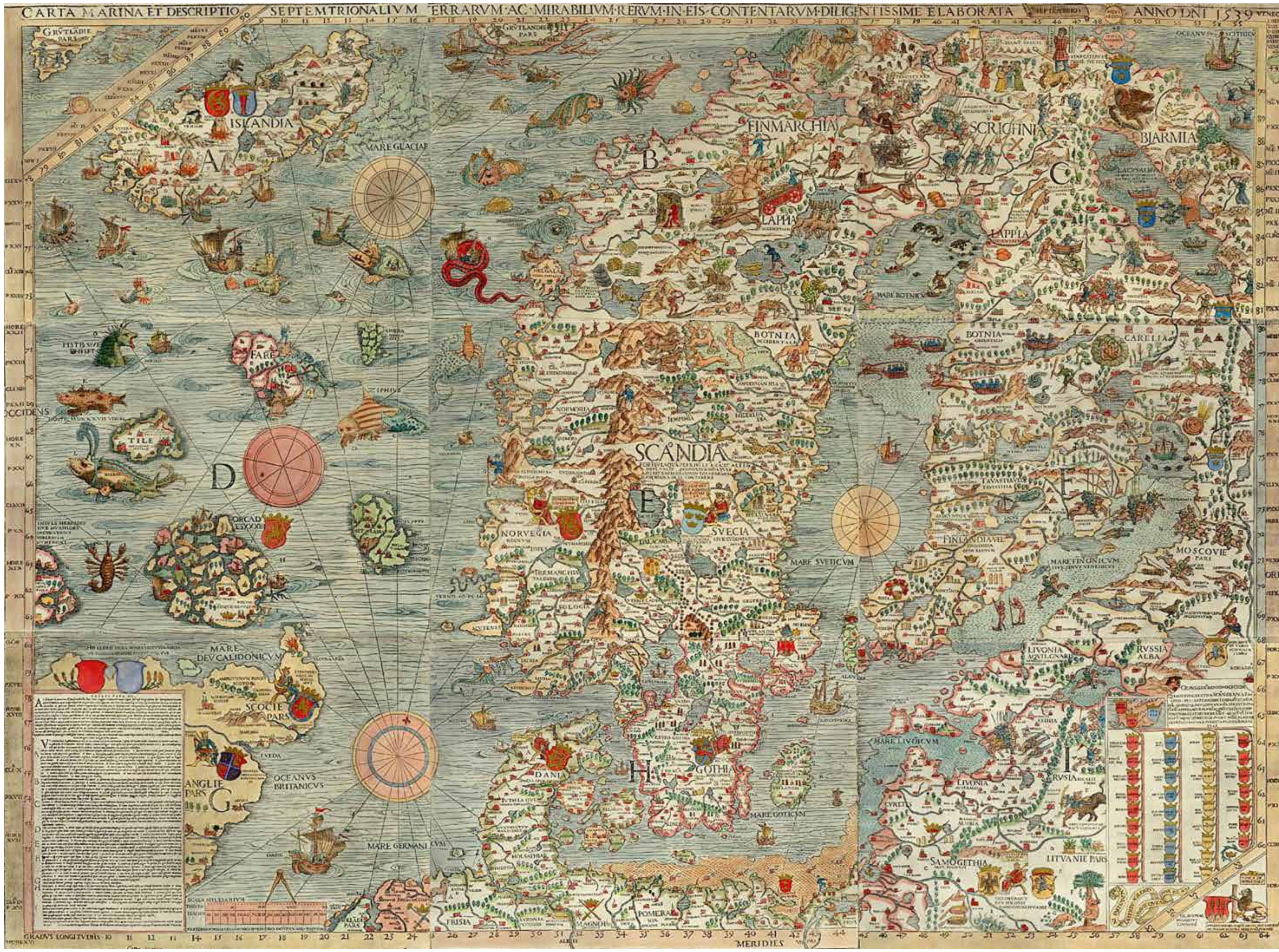
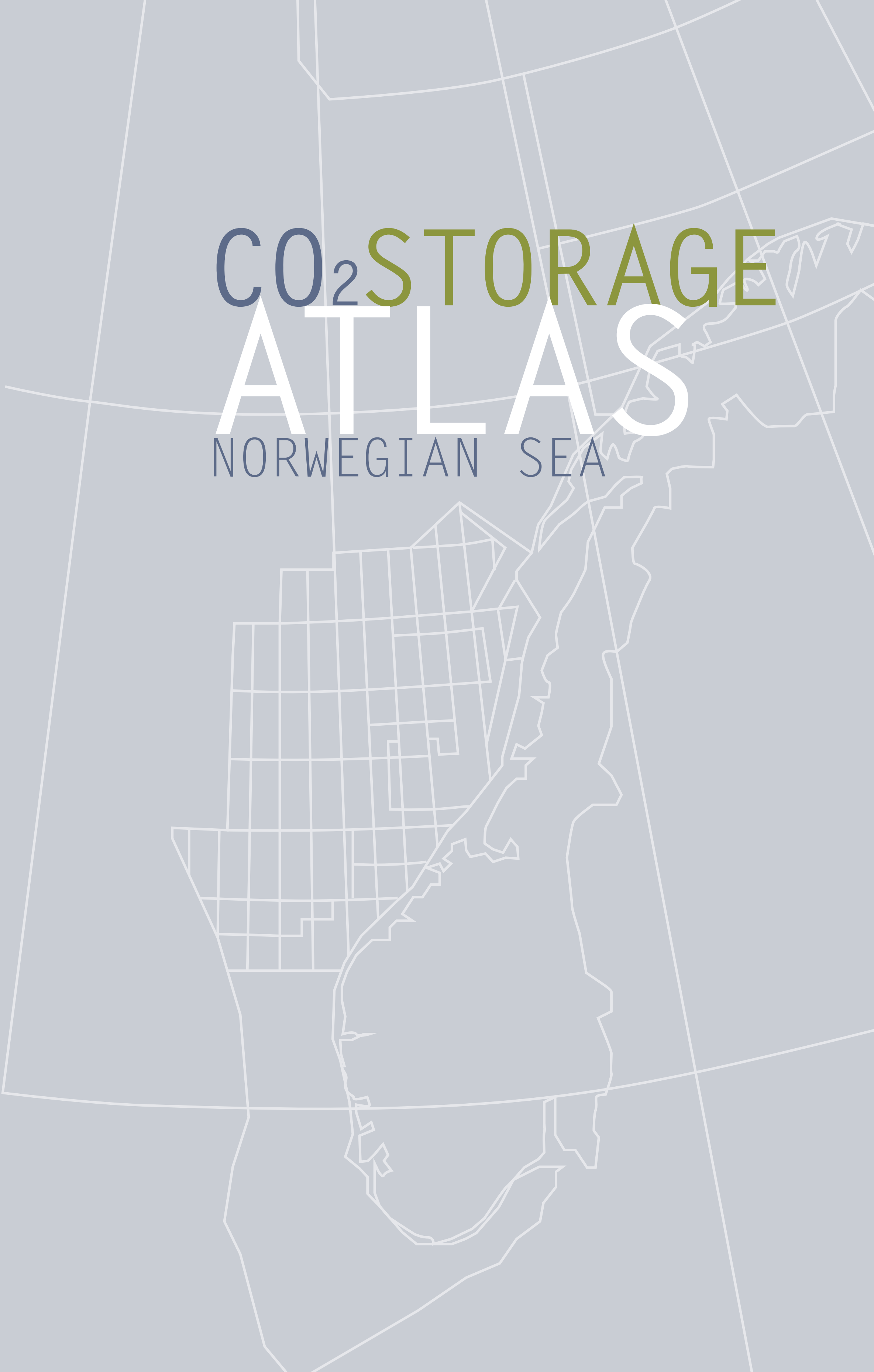


Norway's (Scandinavia's) first resource map, Olaus Magnus, 1539

CO_2 STORAGE ATLAS NORWEGIAN SEA



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Preface

The CO_2 Storage Atlas of the Norwegian Sea has been prepared by the Norwegian Petroleum Directorate, at the request of the Ministry of Petroleum and Energy. The studied areas are in opened parts of the Norwegian Continental Shelf (NCS). The main objectives have been to identify the safe and effective areas for long-term storage of CO_2 and to avoid possible negative interference with ongoing and future petroleum activity. We have also built on the knowledge we have from the petroleum industry and from the two CO_2 storage projects on NCS (Sleipner and Snøhvit). This study is based on detailed work on all relevant geological formations and hydrocarbon fields in the Norwegian Sea. The work is based on several studies as well as data from more than 40 years of petroleum activity on the Norwegian Continental Shelf.

6 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 geological formations are presented in the atlas, and were used to calculate pore volumes. Several structural closures have been identified; some of them were further assessed.

A new geological study of the coastal-near aquifers in the Norwegian Sea, is included. A study of the CO_2 storage potential in relevant dry-drilled structures and mapped structures in the area is provided, together with a summary of the CO_2 storage potential in 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 developed for the CO_2 Storage Atlas of the Norwegian part of the North Sea (2011).

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

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

We have not attempted to assess the uncertainty range for storage capacities in this 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 database (geographical information system).This will be published on the NPD website *www.npd.no*

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 Asbjørn Thon, Robert Williams and Dag Helliksen for constructive contributions. The Norwegian CO_2 Storage Forum has contributed with its expertise in our meetings over the last three 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. 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 measure with great potential 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.

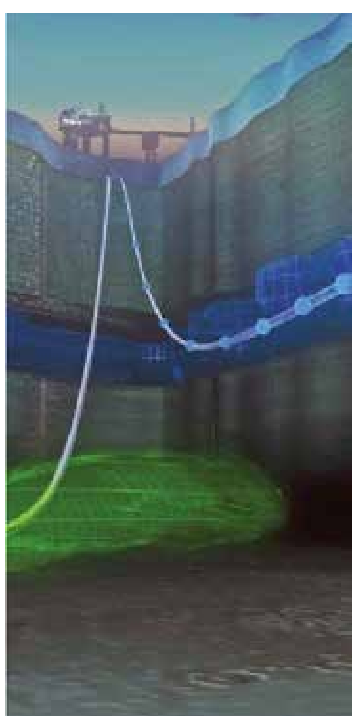
In its Special Report on Carbon Dioxide Capture and Storage (2005), the United Nations Intergovernmental Panel on Climate Change (IPCC) concludes that capture and storage of CO_2 may account for as much as one half of emission reductions in this century. However, major challenges must be solved before 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 around 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. 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:

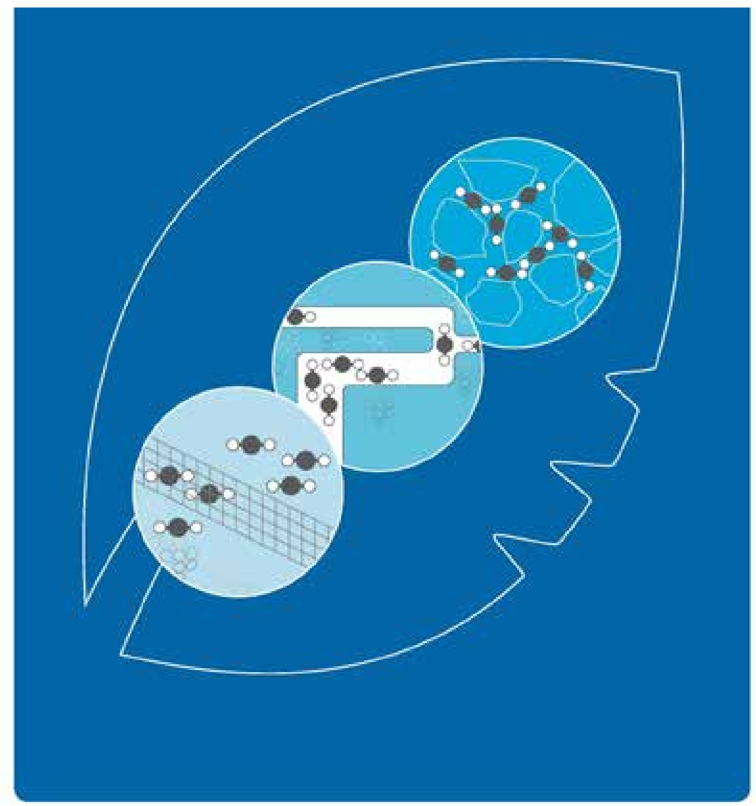
- CO_2 capture before, during or after power production
- Compression and handling of CO_2
- Transport of CO_2
- Long-term storage of CO_2 in terms of injection, storing or other application areas

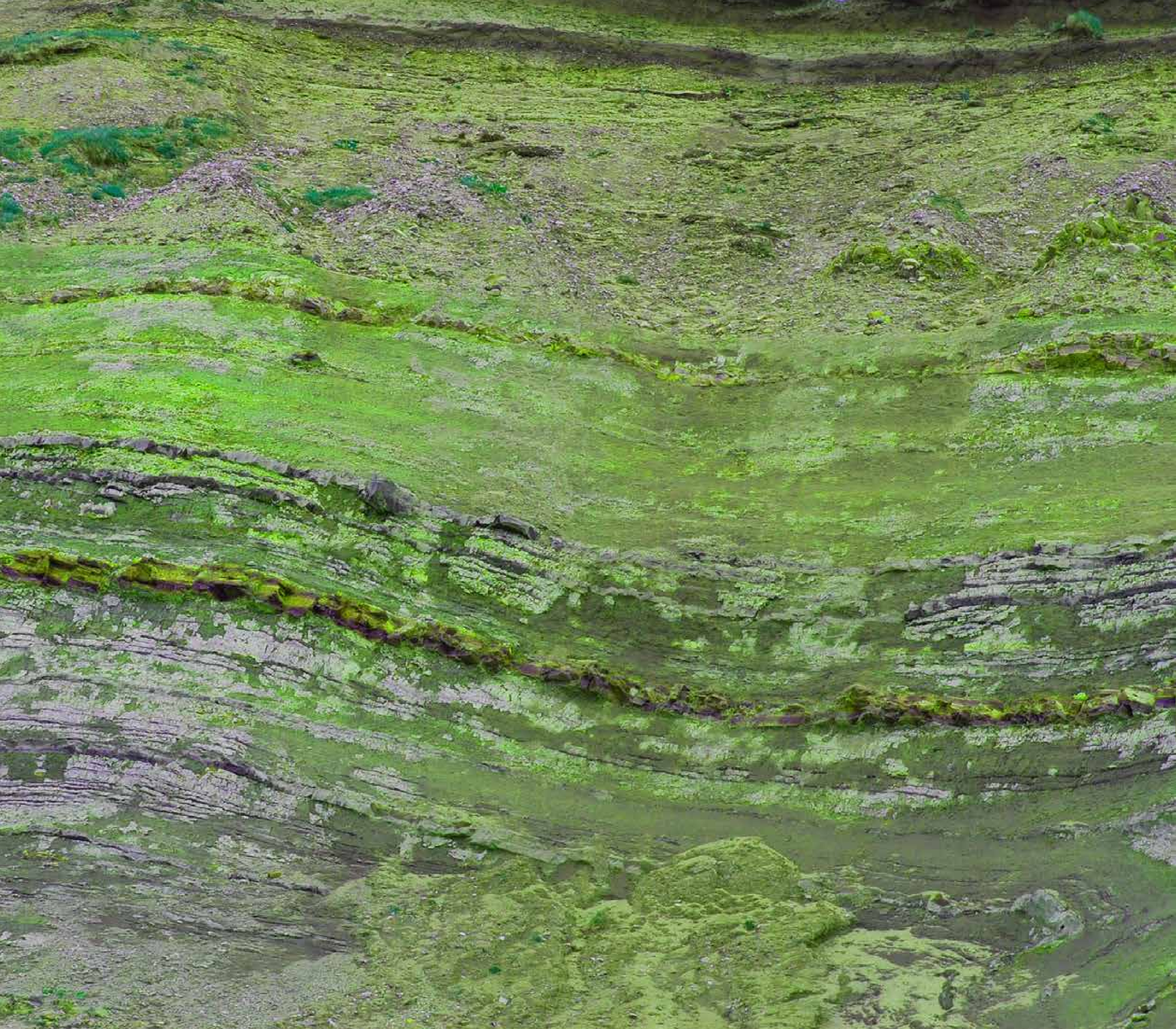
Gassnova will focus on co-funding projects that are considered to have a clear commercial potential and that include a market-based business plan. A detailed description of the program strategy is found in the program plan on *www.climit.no*

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

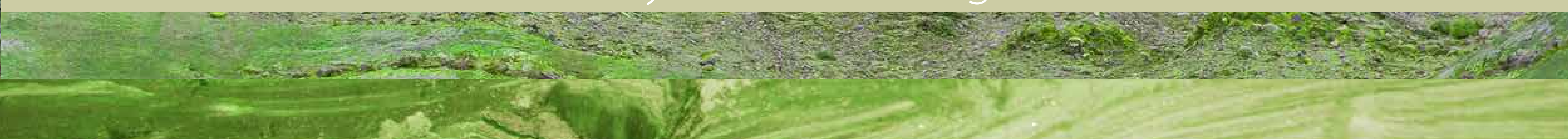
- Develop and verify the knowledge and technology for safe and cost-effective storage and monitoring of CO_2.
- Help develop and verify commercially viable methods, service concepts and technologies.
- Contribute to increased knowledge on geological storage.

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 Norwegian Sea



2. Petroleum activity in the Norwegian 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), as well as 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 large fields such as 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.

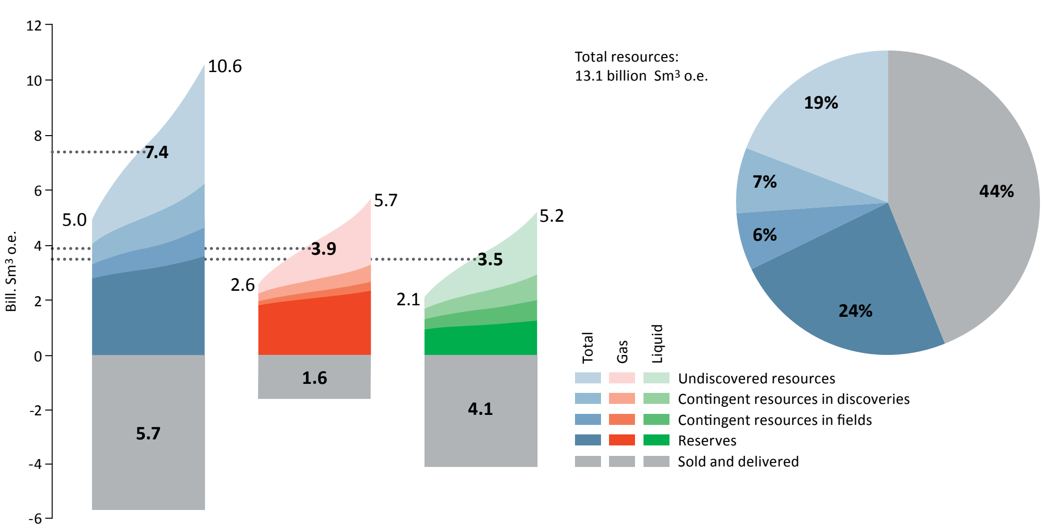
Currently, 70 fields are in production on the NCS. Twelve fields have been abandoned of 31 December 2011. However, there are re-development plans for some of these abandoned fields.

Production on the NCS is still high. In 2011, Norway was 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.

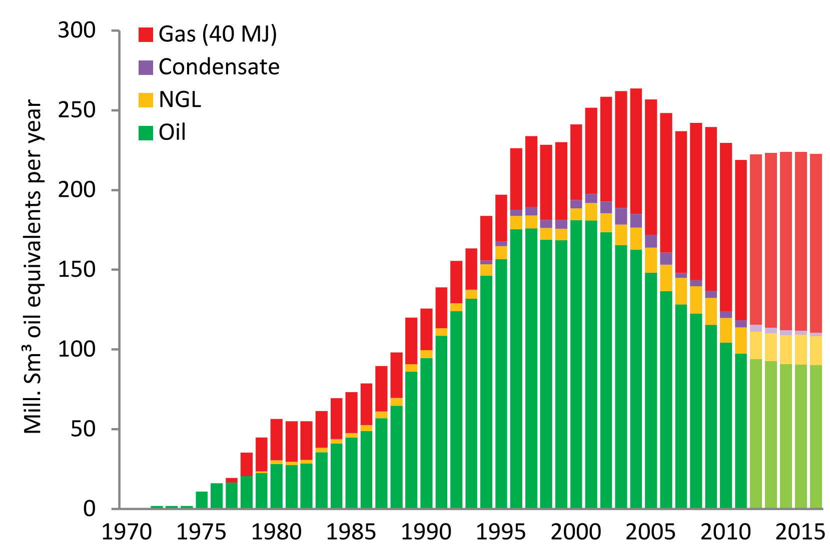
The Norwegian Sea was opened for exploration activity in 1980. The first field to commence production in the area was Draugen in 1993. A number of fields have since been developed. Several smaller fields around existing infrastructure have been put into production in recent years.

Today, the Haltenbanken area and Ormen Lange field are mature areas with considerable oil and gas production, along with well-developed infrastructure. There are also areas in the Norwegian Sea that have not yet been developed or even opened up for exploration activity. Oil production from the major fields in the area is declining. The gas export capacity from Haltenbanken, through the Åsgard transport system (ÅTS), is fully utilised for several decades into the future. This could affect the timing for phase-in of new discoveries on Haltenbanken. The timing for production of gas that up to now has been used as pressure support for oil production will affect how long the current capacity is fully utilised. Gas injection has been used for the Åsgard field, and will continue to be a key factor in maintaining reservoir pressure and oil production.

It has been proven that the Norwegian Sea contains significant volumes of gas. Produced gas from the fields is transported in the ÅTS pipeline to Kårstø in Rogaland county, and in Haltenpipe to Tjeldbergodden in Møre og Romsdal county. The gas from Ormen Lange runs in a pipeline to Nyhamna, and from there on to the United Kingdom. The CO_2 content of the gas produced from several of these fields is relatively high, which is also the case for several of the discoveries in the area. Gas from these fields is therefore blended with other gas with lower CO_2 content to achieve compliance with gas quality requirements. This blending takes place from fields both in the Norwegian Sea and from fields located further south. This creates interdependence between the fields in the Norwegian Sea, and affects how the individual fields are produced. The Vøring area in the Norwegian

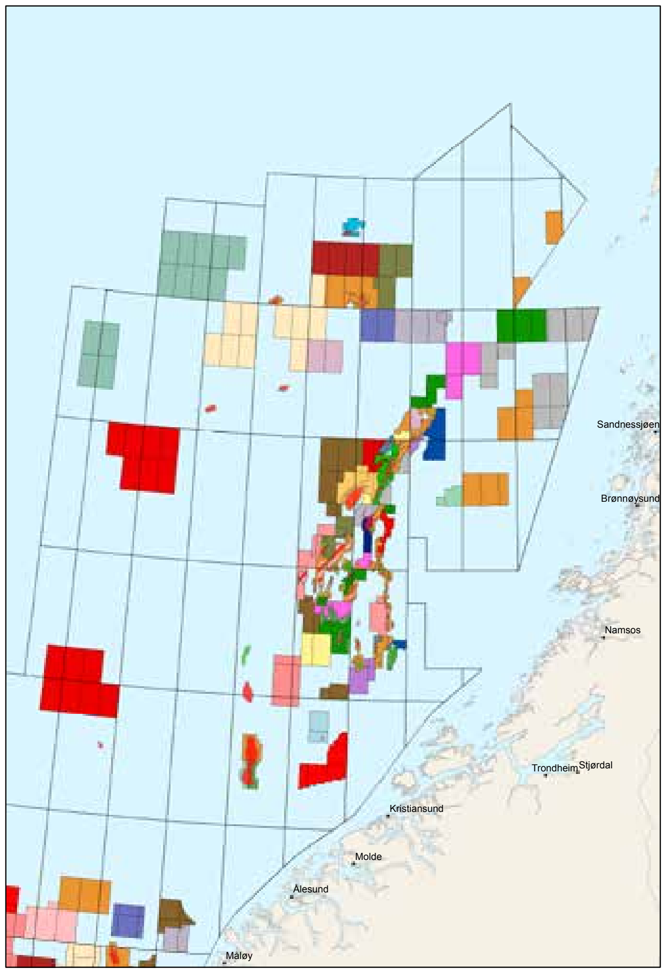


Petroleum resources and uncertainty in the estimates per 31.12.2011



Historical petroleum production of oil and gas and production forecast for the coming years

2. Petroleum activity in the Norwegian Sea



Licenses and fields

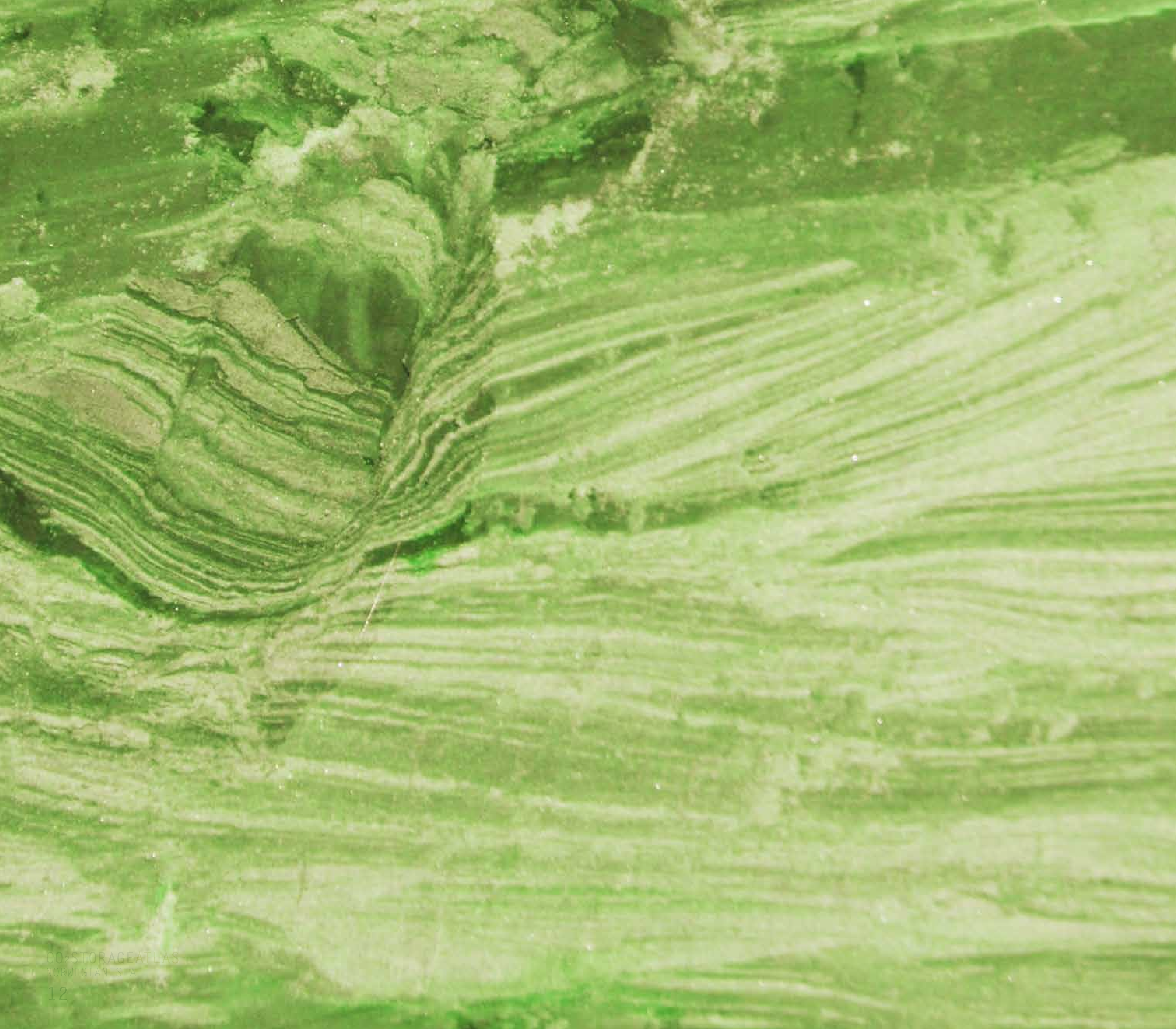
Pipelines

Sea is currently an area without infrastructure. Several gas discoveries have been made in the area.

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.

Norway's gas pipelines have a total length of approx. 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. 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.

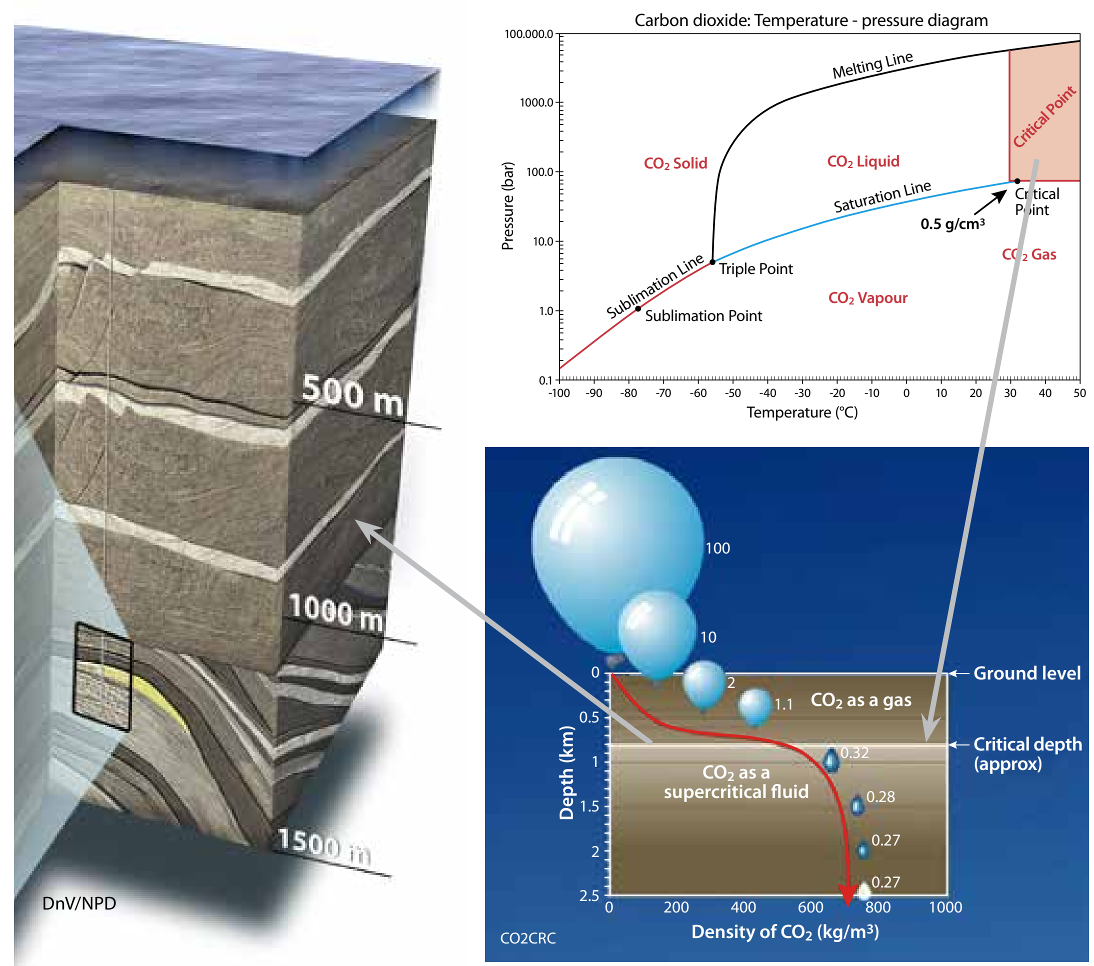
In residual trapping, the CO_2 is trapped in the tiny pores in rocks by the capillary pressure of water. Once injection stops, water from the surrounding rocks begins to move back into the pore spaces that contain CO_2. As this happens, the CO_2 becomes immobilized by the pressure of the added water.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

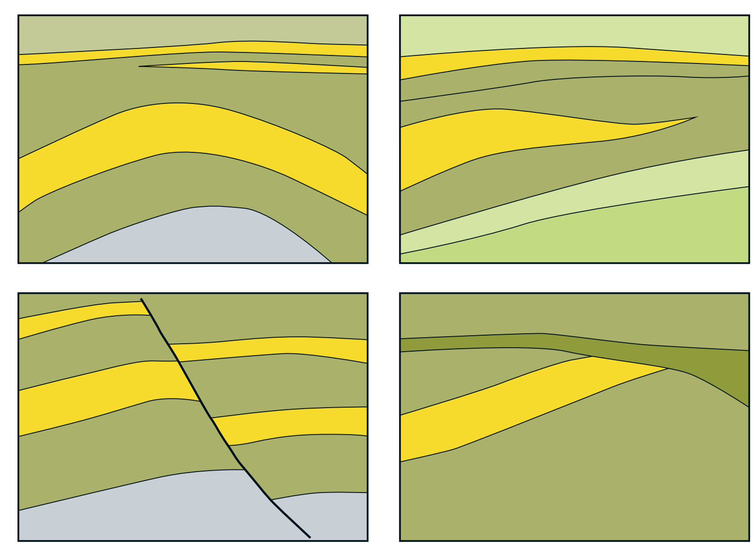
Oil and gas reservoirs are a subset of saline formations, and therefore they generally have similar properties. That is, they are permeable rock formations acting as a reservoir with an impermeable cap rock acting as a seal.

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.



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.



Structural traps *Stratigraphical traps*

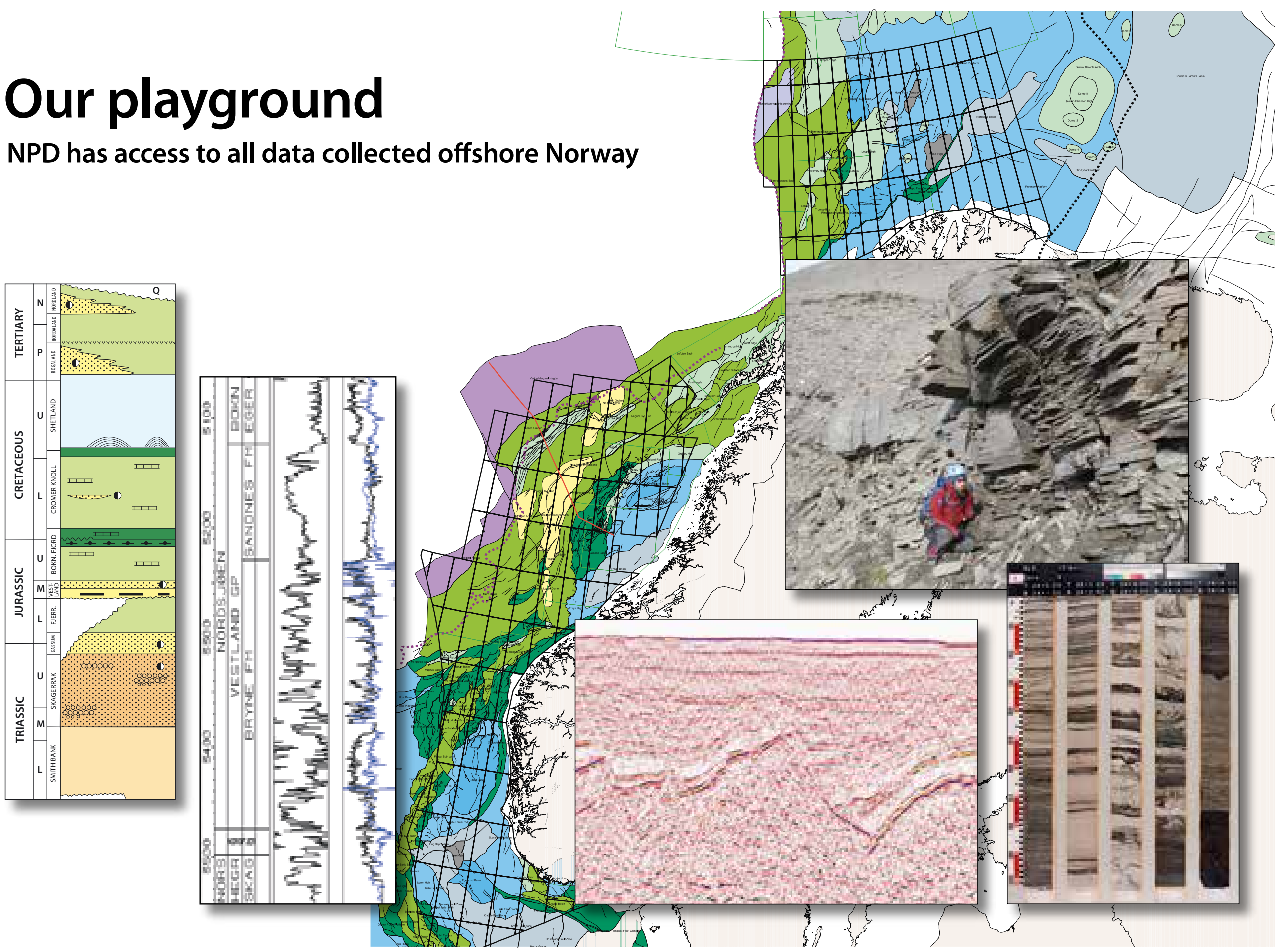
3.2 Data availability

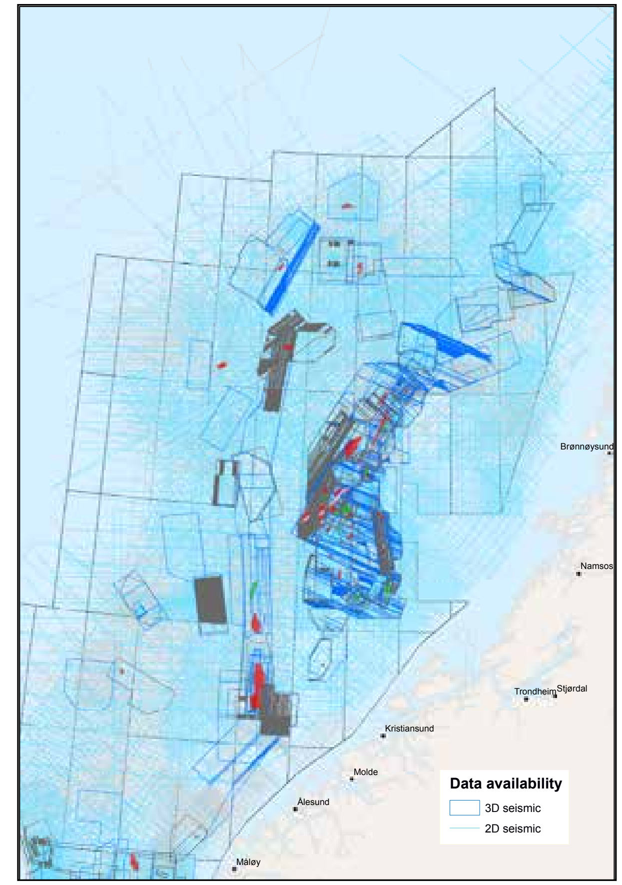
The authorities' access to collected and analysed data is stipulated in law and based on the following statements: "The Norwegian State has the proprietary right to subsea petroleum deposits and the exclusive right to resource management" and "The right to submarine natural resources is vested in the 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".

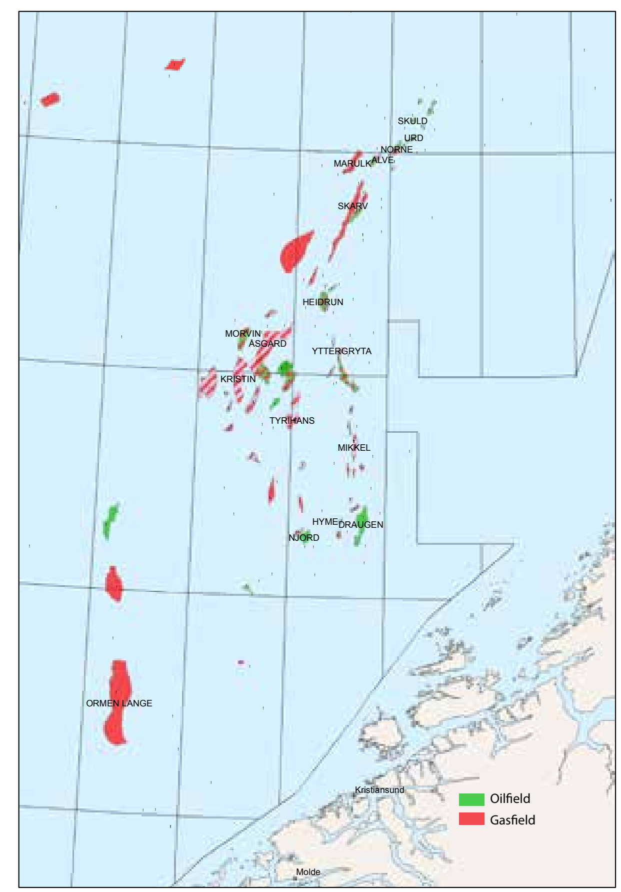
The Norwegian Petroleum Directorate (NPD) has access to all data collected on the NCS and has a national responsibility for the data. The NPD's data, overviews and analyses make up an important fact basis for the oil and gas activities.

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/*







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	

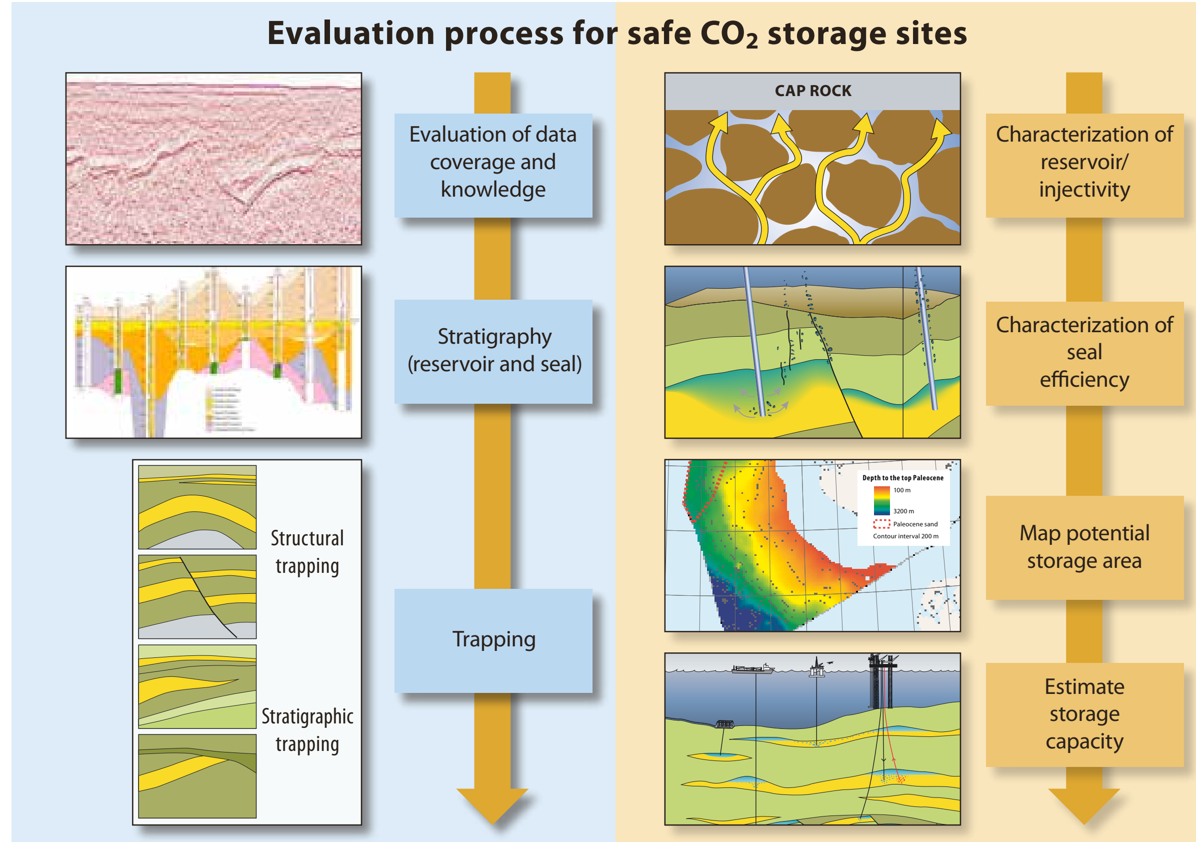
3. Methodology

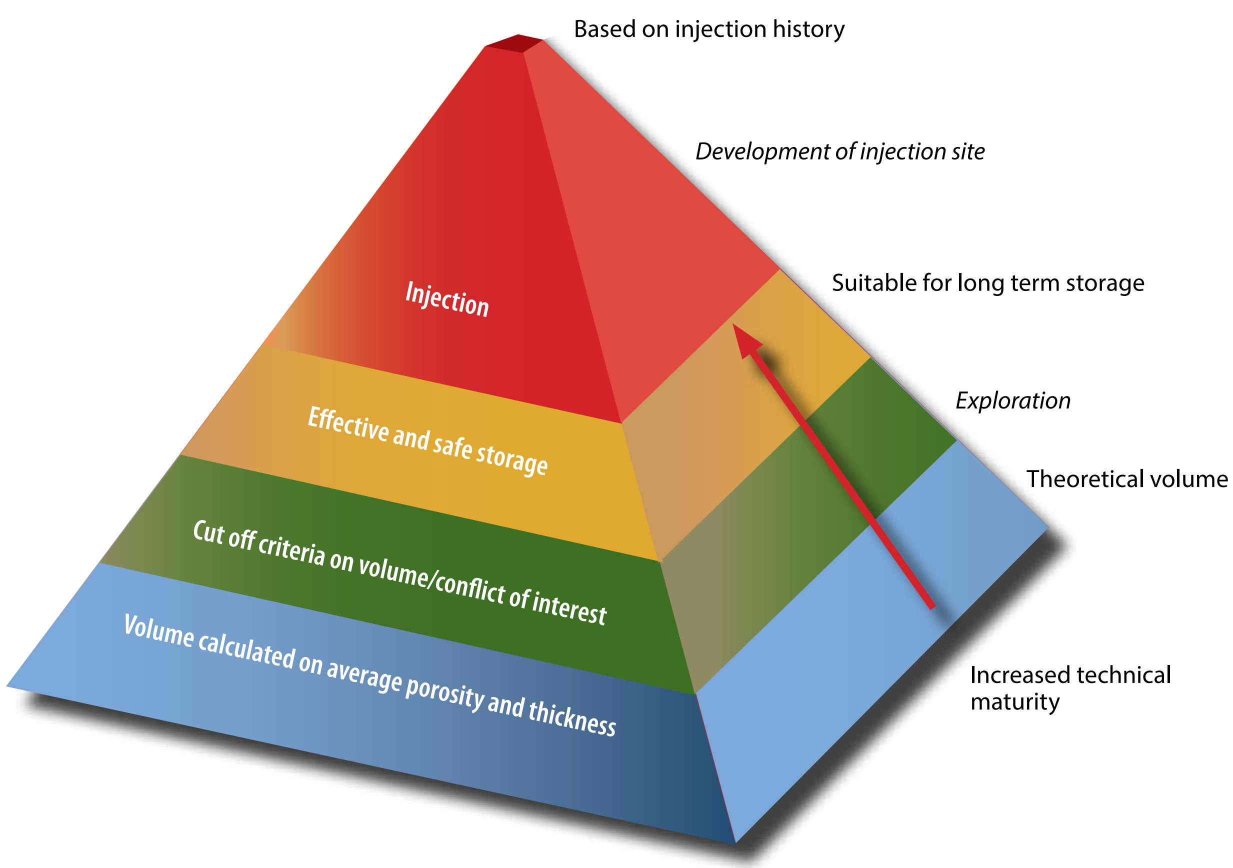
3.3 Workflow and characterization

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 produced oil and gas fields, or in saline aquifers. In a producing oil field, CO_2 can be used to enhance recovery before it is stored. A depleted gas field can be used for CO_2 storage by increasing the pressure in the reservoir. Some of the remaining gas can be recovered during the CO_2 injection. Even if EOR is not the purpose, oil and gas fields can be used as storage for CO_2 by increasing the pressure in the reservoir or by overpressuring it within certain limits. In saline aquifers, CO_2 can be stored as dissolved CO_2 in the water, free CO_2 or trapped CO_2 in the pores.

Storage capacity depends on several factors, primarily the pore volume and how much the reservoir can be pressurized. It is also important to know if there is communication between multiple reservoirs, or if the reservoirs are in communication with larger aquifers. The degree of pressurization depends on the difference between the fracturing pressure and the reservoir pressure. The ratio between pressure and volume change 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 stored in a supercritical phase to take up the least possible volume in the reservoir.

For saline aquifers, the amount of CO_2 to be stored can be determined using the following formula:

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

- M_{CO_2} *mass of CO_2*
- *Vb* *bulk volume*
- *Ø* *porosity*
- *n/g* *net to gross ratio*
- ρ_{CO_2} *density of CO_2 at reservoir conditions*
- S_{eff} *storage efficiency factor*

(Geocapasity 2009)

Seff is calculated as the fraction of stored CO_2 relative to the pore volume. The CO_2 in the pores will appear as a mobile or immobile phase (trapped). Most of the CO_2 will be in a mobile phase. Some CO_2 will be dissolved in the water and simulations show that approximately 10-20% of the CO_2 will behave in this manner. When injection stops, the CO_2 will continue to migrate upward in the reservoir, and the water will follow, trapping some of the CO_2 behind the water. 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.

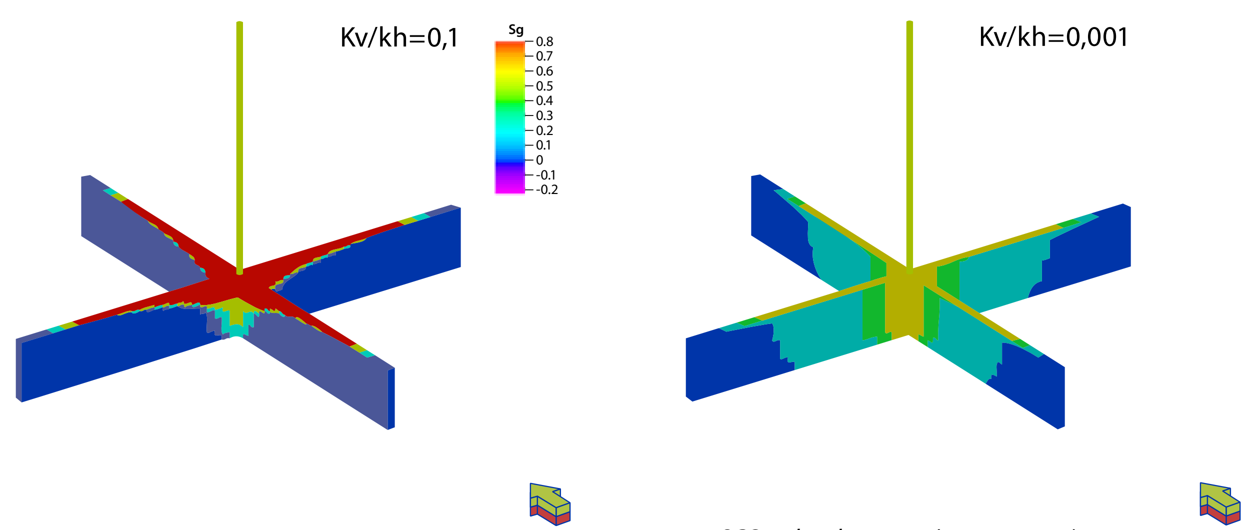
For a homogenous reservoir with a permeability of 200mD and reservoir thickness of 100m, the storage efficiency in a closed system is simulated to be 0.4 to 0.8%, with a pressure increase of 50 to 100 bar. In a closed system, a pressure increase between 50 and 100 bar is a reasonable range for reservoirs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

If the reservoir is in communication with a large aquifer, the reservoir pressure will stay almost constant during CO_2 injection, as the water will be pushed beyond the boundaries of the reservoir. 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.

A cross-section of a flat reservoir with injection for 50 years is shown below.

For abandoned oil and gas fields, the amount of CO_2 that can be stored depends on how much of the hydrocarbons have been produced, and to what extent the field is depleted.

The gas fields will normally have low pressure at abandonment, and the oil fields will have a low oil rate and high water cut. The fields may have an EOR potential for CO_2 at abandonment, which must be considered before CO_2 storage starts. For a gas field, the amount is the CO_2 injected from abandonment pressure up to initial pressure. Some of the natural gas left in the reservoir can either be produced during the pressure increase or left in place. For an oil reservoir, CO_2 can be stored by pressure increase or by producing out water. CO_2 can be stored when using it for EOR by pushing out some of the oil and water and replacing that with CO_2.

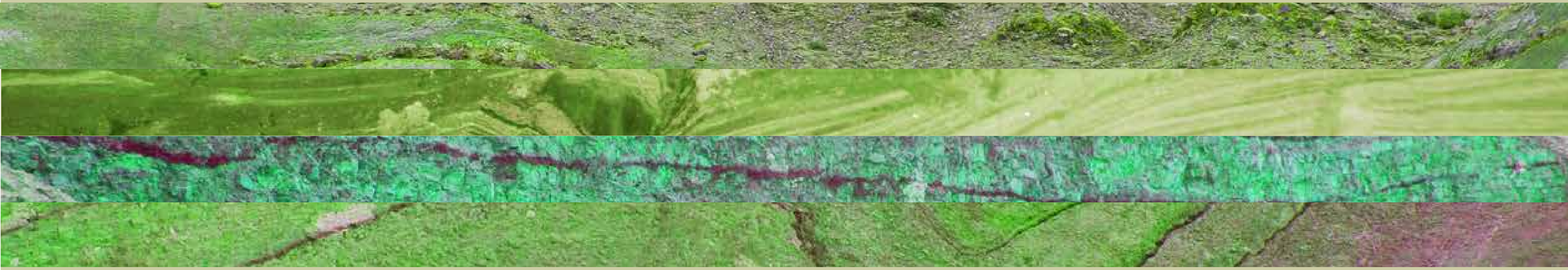


SCO_2 development (open system)

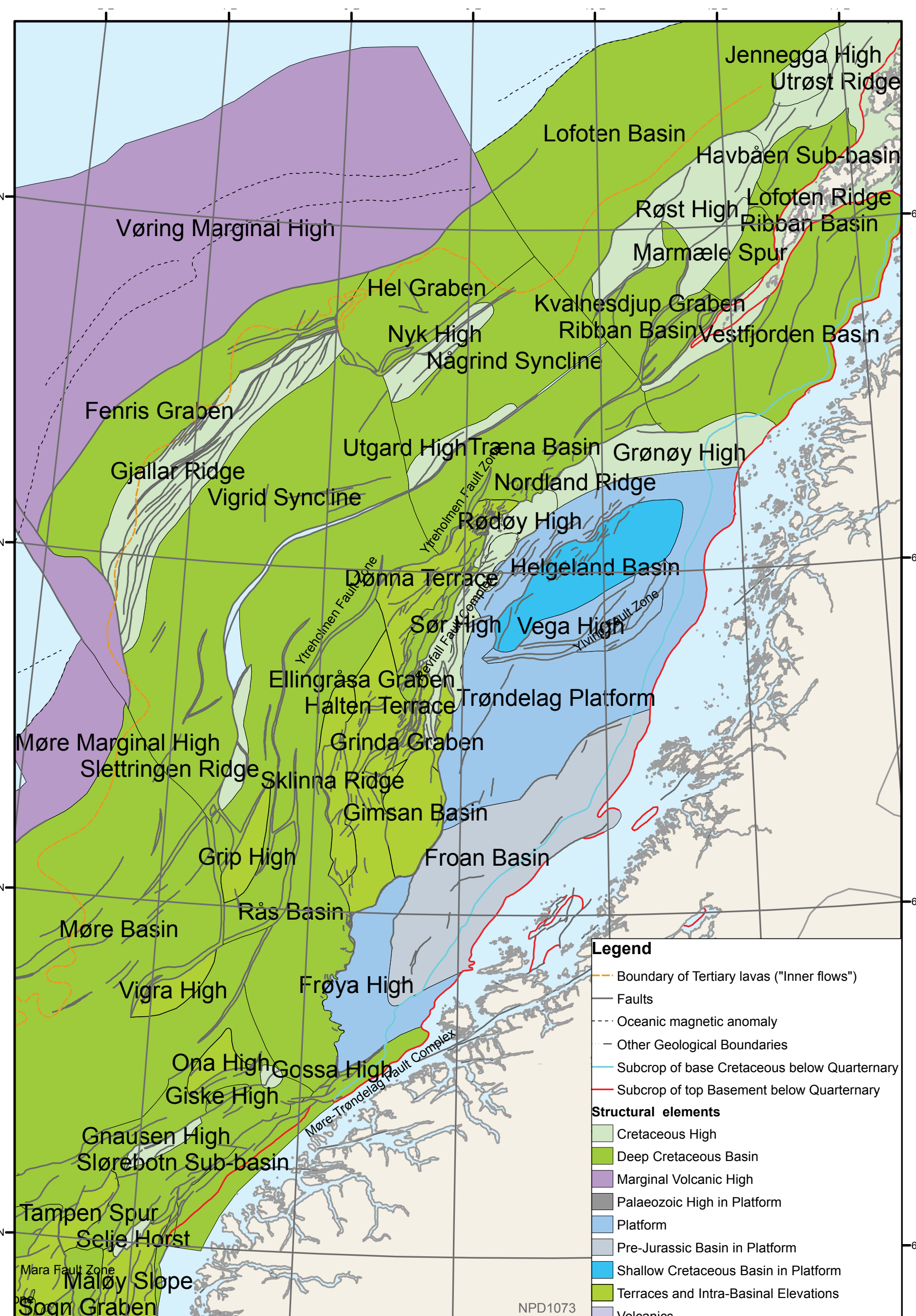
SCO_2 development (open system)

A cross section of a flat reservoir with injection for 50 years.

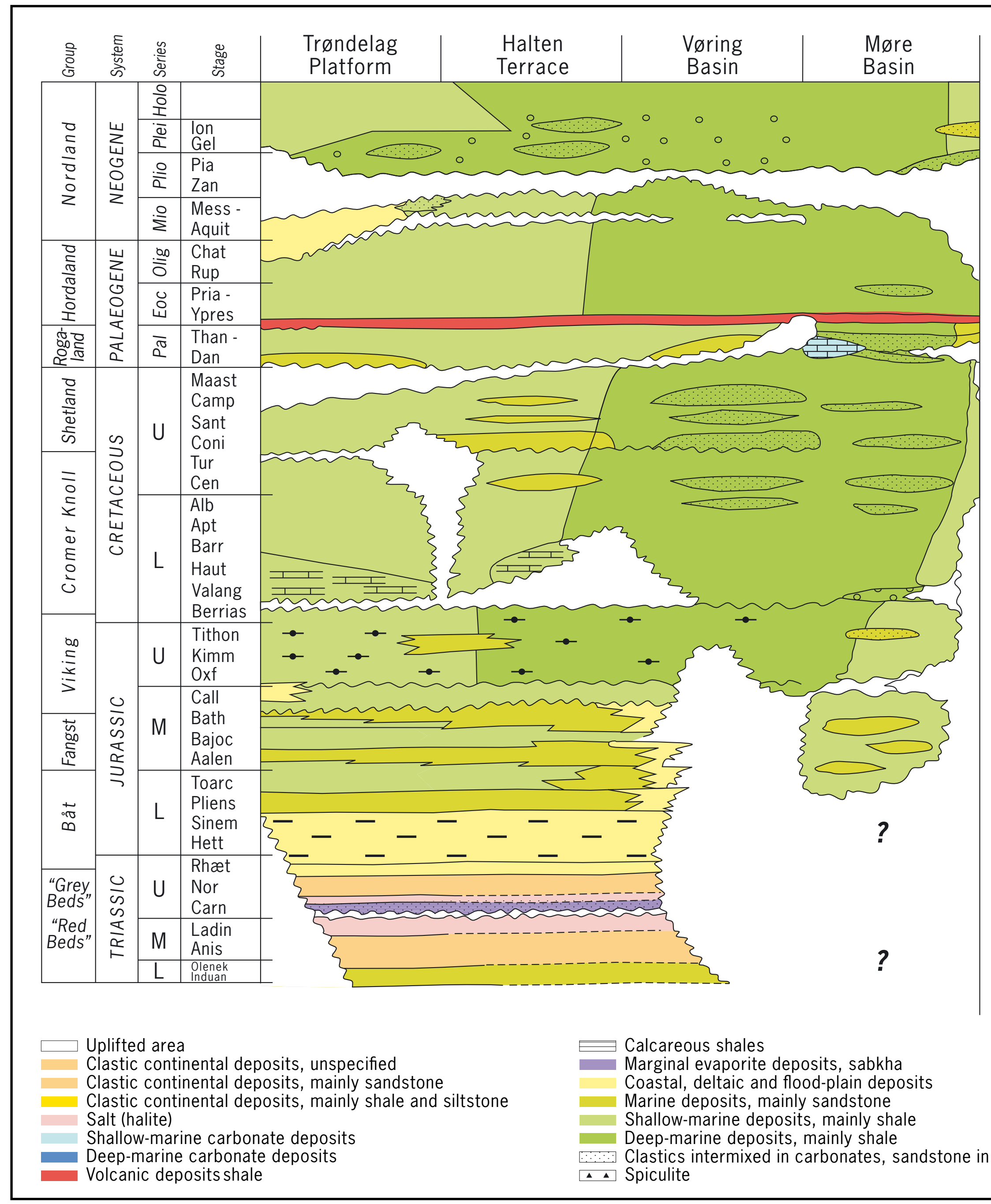
4. Geological description of the Norwegian Sea



4.1 Geological development of the Norwegian Sea

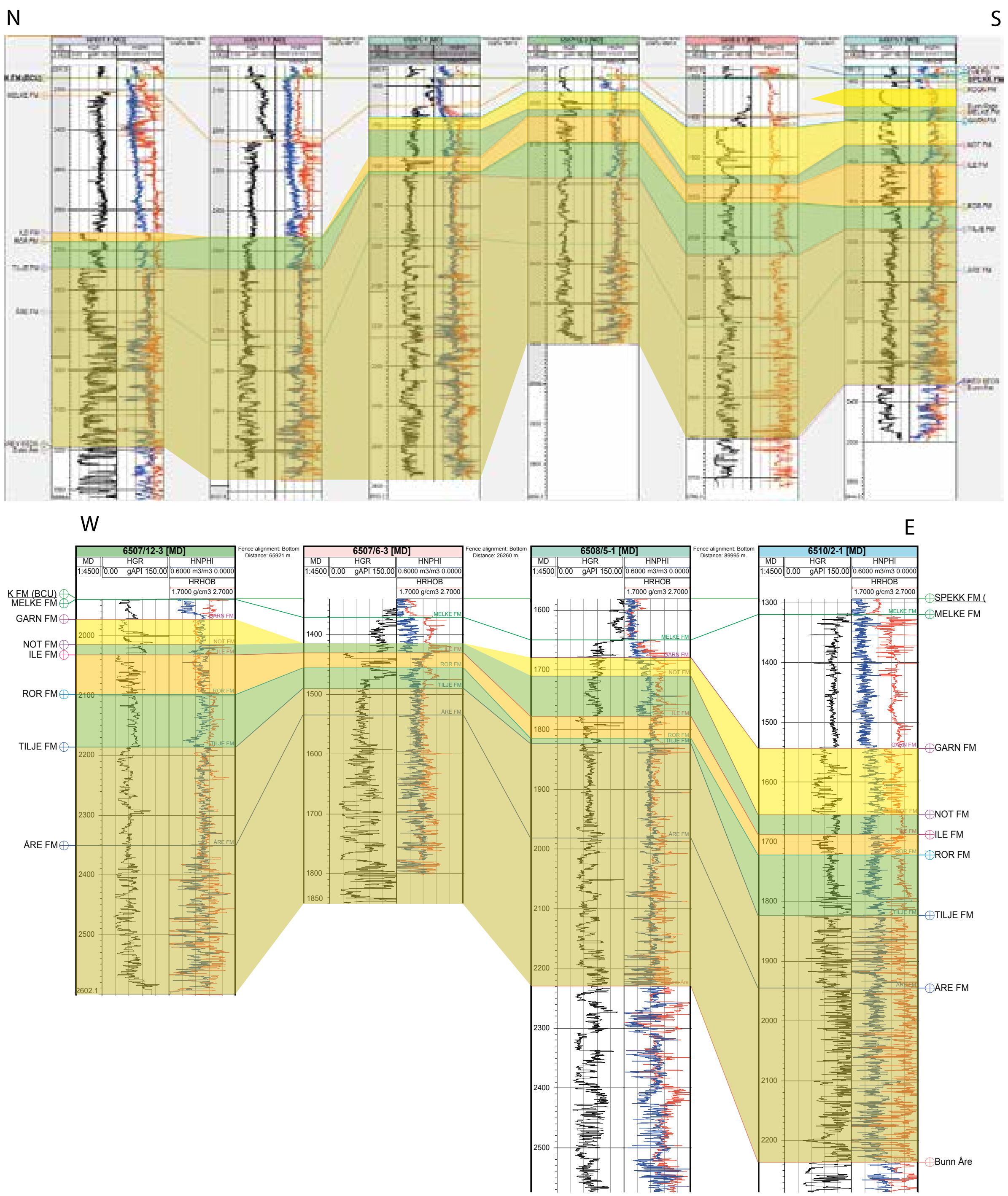


Structural elements in the Norwegian Sea

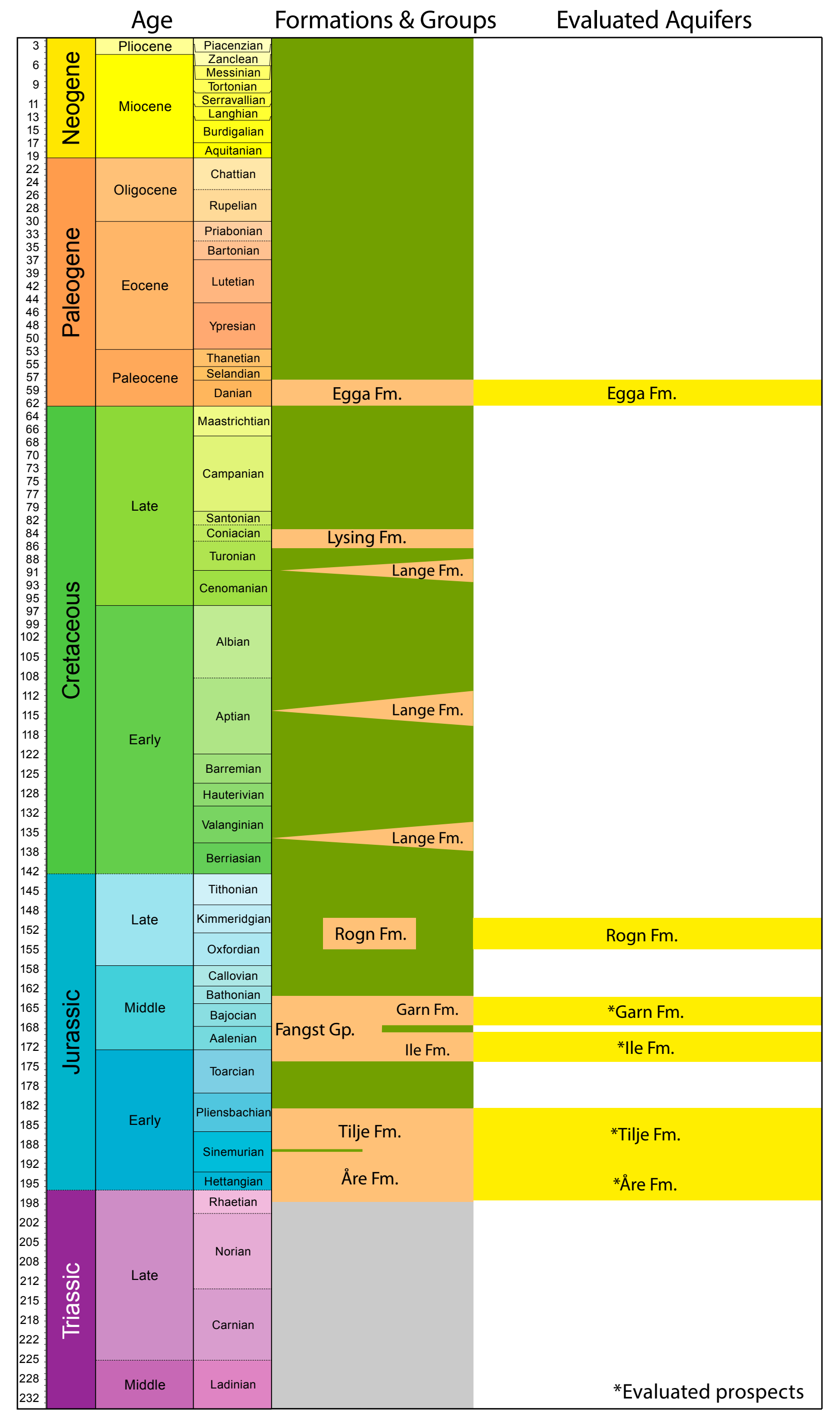


Lithostratigraphic chart of the Norwegian Sea

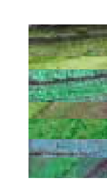
4.1 Geological development of the Norwegian Sea



Well section panels showing gamma and neutron/density logs reflecting thickness variations of the different formations. The Åre and Tilje Fms show more or less constant thickness throughout the area. The Ile and Garn Fms are thinning and shaling out towards the north. The Garn Fm is quite thick in well 6510/2-1, but less sandy, and is thinning towards the west.



Evaluated geological formations, prospects and aquifers.



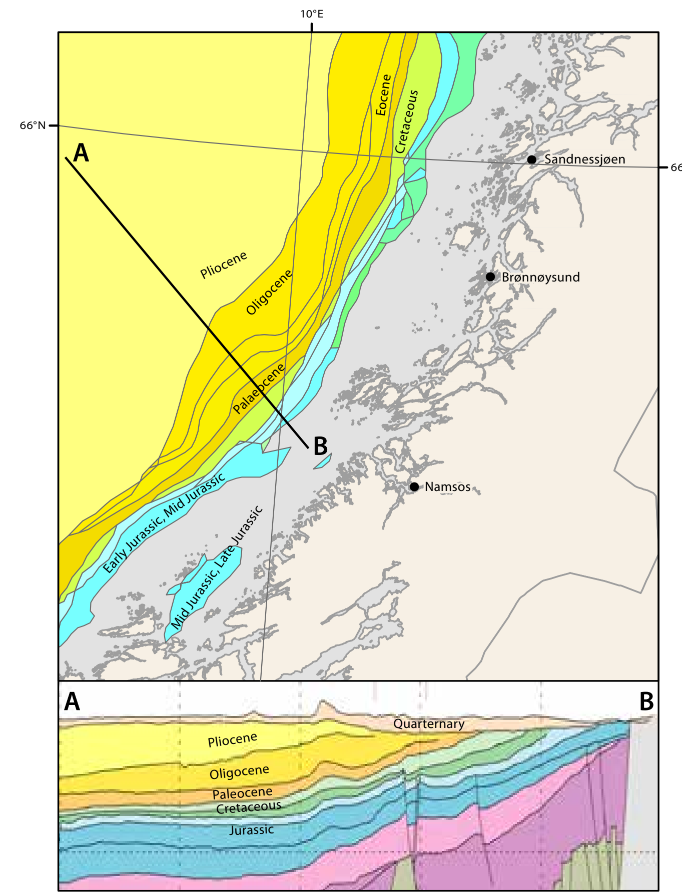
4.1 Geological development of the Norwegian Sea

The Norwegian Sea covers most of the continental margin between approximately 62° and 69°30′ N. The tectonic history of the Norwegian Sea can be divided into three major episodes: A) Final closure of the Iapetus Ocean during the Caledonian Orogeny (Late Silurian/ Early Devonian). B) A series of mainly extensional deformation episodes (Late Devonian to Paleocene), culminating with the continental separation between Greenland and Eurasia. C) Active seafloor spreading in the North Atlantic between Eurasia and Greenland (Earliest Eocene to present).

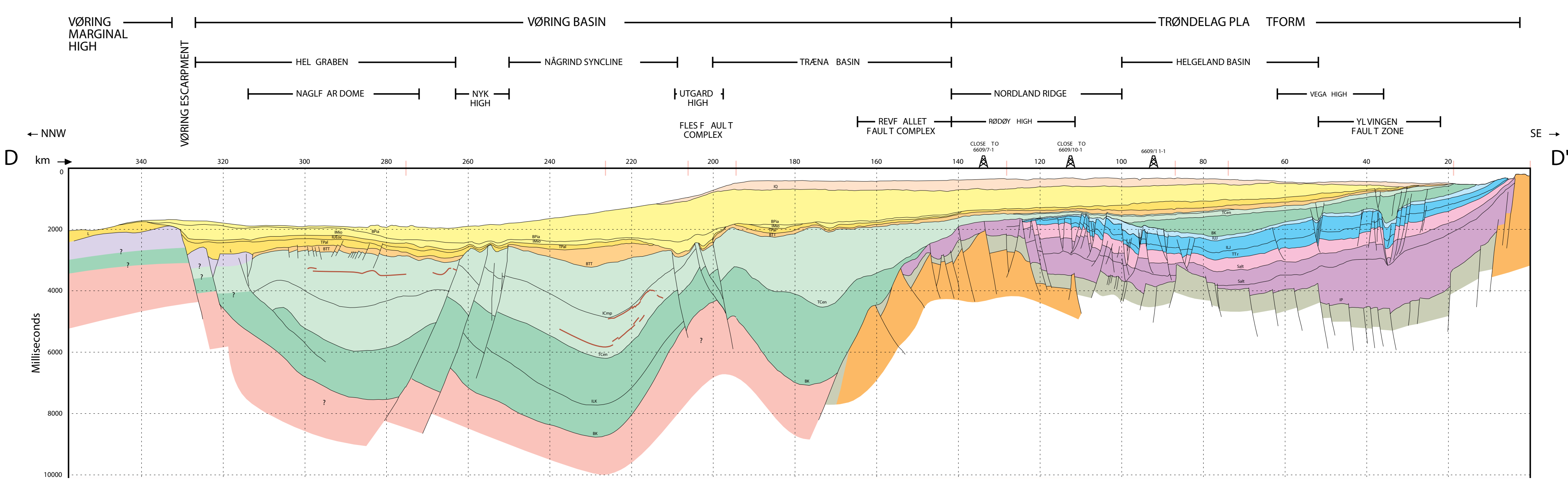
The area with the best potential for storage of CO_2 is the Trøndelag Platform (63° to 67° N), one of the main structural elements of the Norwegian Sea. The Trøndelag Platform contains the following structural elements: the Nordland Ridge, the Helgeland Basin, the Vega High, the Ylvingen Fault Zone, the Froan Basin and the Frøya High. The areas further west and south are considered less suitable for storage of CO_2 due to active production of hydrocarbons, high temperature and high pressure and depth to the relevant reservoirs.

Carboniferous, Permian and Triassic: Rifting and formation of N-S to NE-SW-trending rotated fault blocks occurred on the Halten Terrace and parts of the Trøndelag Platform in late Permian/early Triassic times and was followed by deposition of a thick continental Triassic succession. Drilling in the Helgeland Basin has proved up to 2500m thickness of Triassic (Grey and Red Beds) including two Middle Triassic evaporite intervals up to 400m thick. The evaporite intervals represent detachment levels for later extensional faults. These thick sequences are related to pronounced subsidence and deposition in a fluvial sabkha environment. Possibly this tectonic event was preceded by Carboniferous and Permian rifting.

Jurassic and Cretaceous: During the Early and Middle Jurassic, the Trøndelag Platform and the Halten/ Dønna Terrace were parts of a large NS-trending subsiding basin which was infilled by a deltaic to fluvial depositional system. Sediment input from several directions have been interpreted. The Jurassic sediments thin towards the Nordland Ridge and the thickness increases over the Vega High and the Helgeland

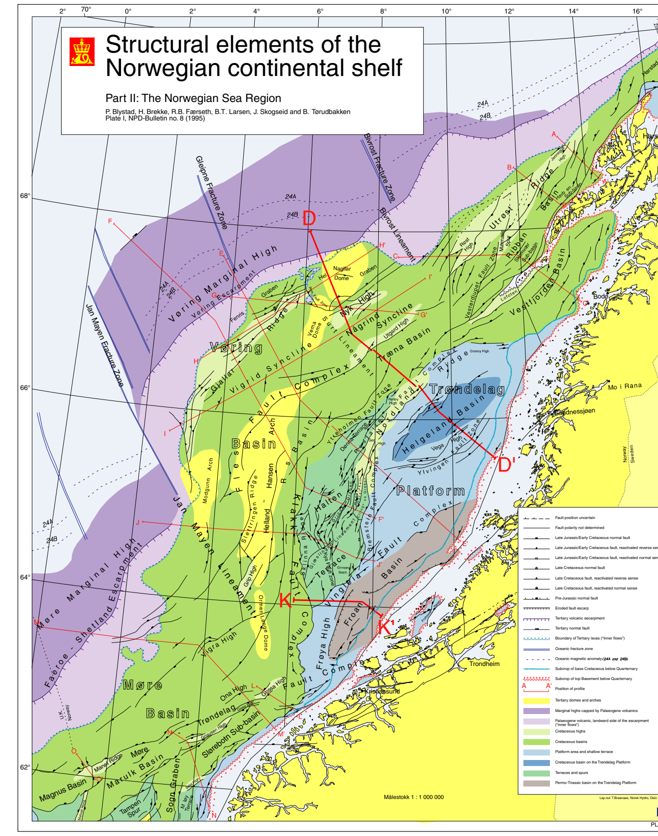


Subcroping strata under the Quaternary offshore Mid Norway. Offshore map from NGU, Sigmond.

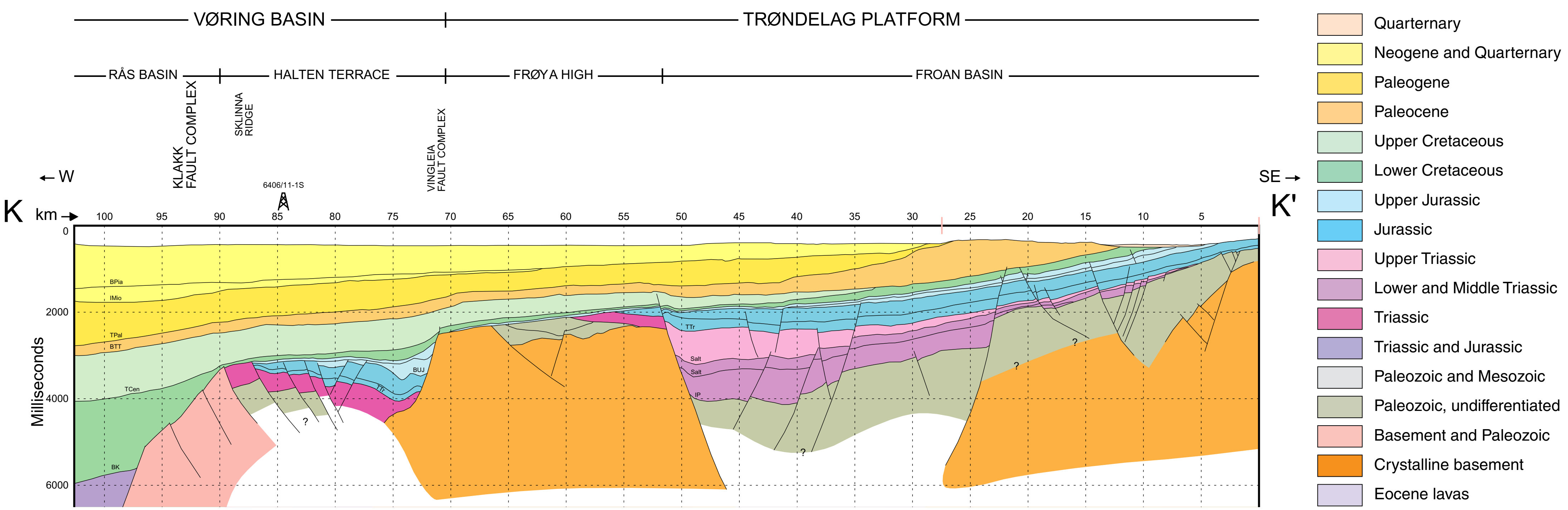


Basin. Starting in the middle Jurassic and culminating in the late Jurassic/ early Cretaceous, the Norwegian Sea underwent a major tectonic phase with extension, faulting and thinning of the upper crust. The Halten and Dønna Terrace were downfaulted in relation to the Trøndelag Platform. Further to the west, the Vøring Basin subsided in relation to the terrace areas. During this extensional phase, both large-scale basement faults and listric faults were active, soling out into the Triassic salt. In the middle Jurassic, the Nordland Ridge and the Frøya High were uplifted, while the Helgeland Basin area subsided. Later, the Vega High was inverted, and faulting continued along the major faults well into the Cretaceous. The Froan Basin was a shallow sea during Late Jurassic, and was later covered by thin, condensed Cretaceous sediments. In contrast, the Helgeland Basin area continued to subside and has a thickness of up to 1500m of Cretaceous sediments. During the Late Cretaceous, there was a rapid subsidence west of the Nordland Ridge due to increased rifting in the west. At the same time, the structural highs and the Lofoten-Vesterålen area were uplifted.

Cenozoic: In the Paleocene, uplift of the Norwegian mainland resulted in progradation of clastic sediments from Scandinavia into the Norwegian Sea. Sandy deposits, partly with good reservoir properties have been recorded north of the Nordland Ridge and in the Møre Basin (Egga sand). The progradation continued into the Eocene. The separation between Greenland and Eurasia and the onset of ocean floor spreading started in the Earliest Eocene. This is reflected in deposition of tuffs and tuffaceous sediments on a regional scale (the Tare Fm). On the Vøring and Møre Marginal Highs, lava flows and basaltic dike complexes were emplaced. The sediment input from Scandinavia was reduced in the Oligocene and Miocene. The deltaic Molo Formation has good reservoir sands, but they are not sealed towards the sea floor. The Nordland Ridge was uplifted in the Late Cenozoic. In the Pliocene and Pleistocene, new uplift and glaciations caused erosion and deposition of thick sedimentary wedges onto the mid Norwegian shelf.



Structural element map of the Norwegian Sea. The Trøndelag Platform is shown by blue and gray colours. The depth and thickness maps in the following pages cover the Trøndelag Platform.



NPD Bulletin No 8

Permian-Triassic

Upper Permian to Upper Triassic

On the Rødøy High, along the western margin of the Nordland Ridge, well 6609/7-1 drilled 34m of Upper Permian dolomitic limestone with thin sandstone layers overlying metamorphic quartzites.

The Permian rocks have not been given formal group or formation status, but are often correlated with the Permian in East Greenland.

The Triassic rocks are given informal Group names: Grey Beds and Red Beds.

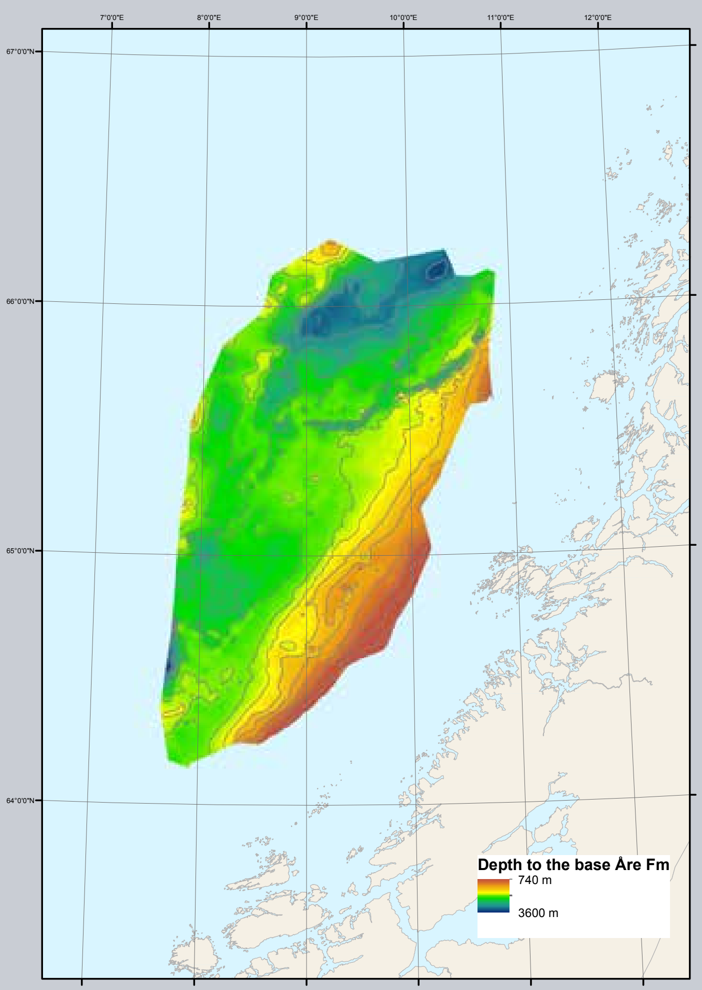
So far, no complete Triassic section has been drilled, but combined thicknesses of more than 2700m of both Grey Beds and Red beds have been drilled (well 6507/6-1).

The Red Beds form the lowest part of the drilled Triassic sequences and represent continental clastics deposited in an arid climate. The maximum thickness of Red Beds is in the order of 2600m (well 6507/6-1, 2615m) and has been drilled on the southern extension of the Nordland Ridge.

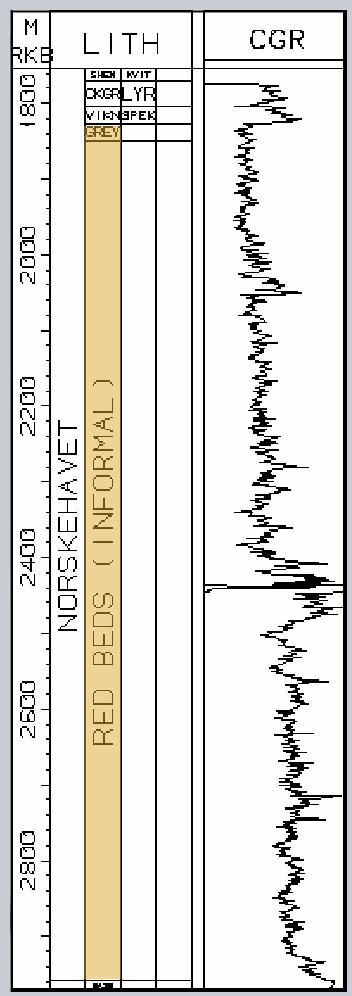
The Grey Beds are interpreted to represent continental clastics deposited in a more humid climate than the Red Beds. Maximum thickness of the Grey Beds is in the order of 2500m (well 6610/7-2, 2489m). The upper boundary of the Grey Beds is towards the Upper Triassic and Lower Jurassic (Rhaetian to Toarcian) coal-bearing sediments of the Båt Gp (the Åre Fm).

The Triassic also contains two evaporite sequences of Upper/Middle Triassic age (Ladinian–Carnian).

Shallow boreholes (6611/09-U-1 & 2) along the Norwegian coast (66ºN) have drilled a combined thickness of 750m of Upper Permian and Lower Triassic sediments, including a possible source rock.



WELL LOG 6407/10-3



6507/12-1 REDBEDS, 3710.7 - 3708.9 m

4.2 Geological description

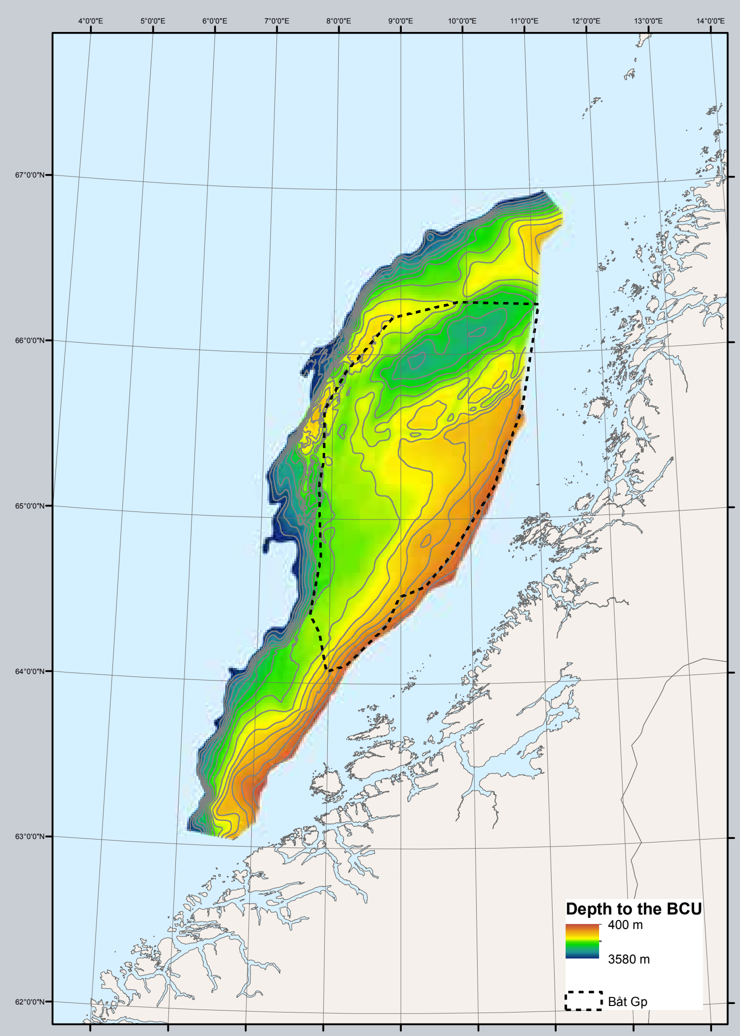
The Båt Group

Uppermost Triassic and Lower Jurassic
(Rhaetian to Toarcian)

The Båt Group is dominated by sediments deposited in deltaic to shallow marine environments overlying Triassic Grey and Red Beds (informal). This group is subdivided into four formations, the Åre, Tilje, Ror and Tofte Formations. The type well (6507/12-1) is located in the transition zone between the Halten Terrace and the Trøndelag Platform. The lower boundary of the group is defined below the first appearance of coal above the Triassic Grey Beds. The upper boundary is defined at the base of a generally coarsening upwards sequence of the Ile Fm in the Fangst Gp. Marine influence increases towards the top of the succession and also to the north and west.

The Båt group is present in most of the wells drilled on Haltenbanken and Trænabanken with a maximum thickness up to 1000m (707m in the type well) in the eastern part of the Halten Terrace. Due to erosion, the upper part of the succession is progressively truncated towards the crestal parts of the Nordland Ridge. Shallow boreholes off the Trøndelag and Nordland coast indicate that mid Jurassic sediments onlap the metamorphic basement.

The burial depth of the Båt Gp. varies from 1000-2500m on the Trøndelag Platform and marginal areas of the Helgeland Basin. West of the Nordland Ridge the burial depth increases to more than 4000m. Porosities and permeabilities in the order of 25-35% and 100 mD to several darcys, have been reported. However, rocks on the eastern part of the Trøndelag Platform have probably been buried deeper than the present depths indicate, due to Neogene erosion.



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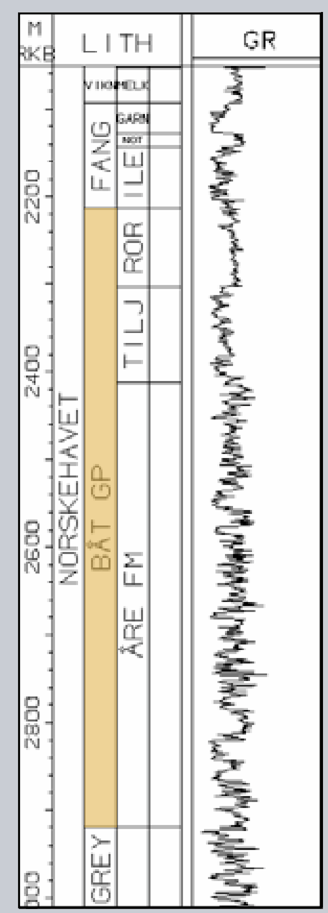


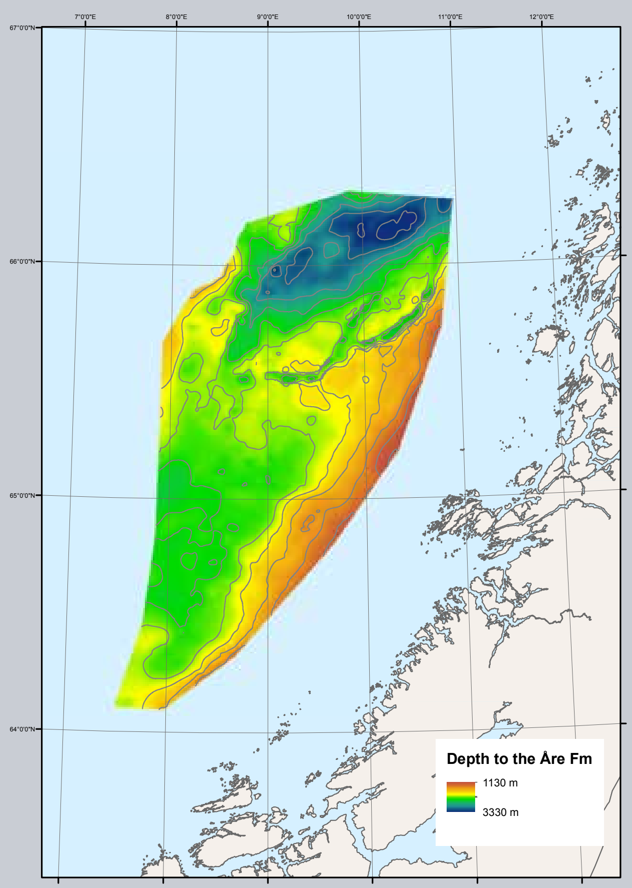
4.2 Geological description

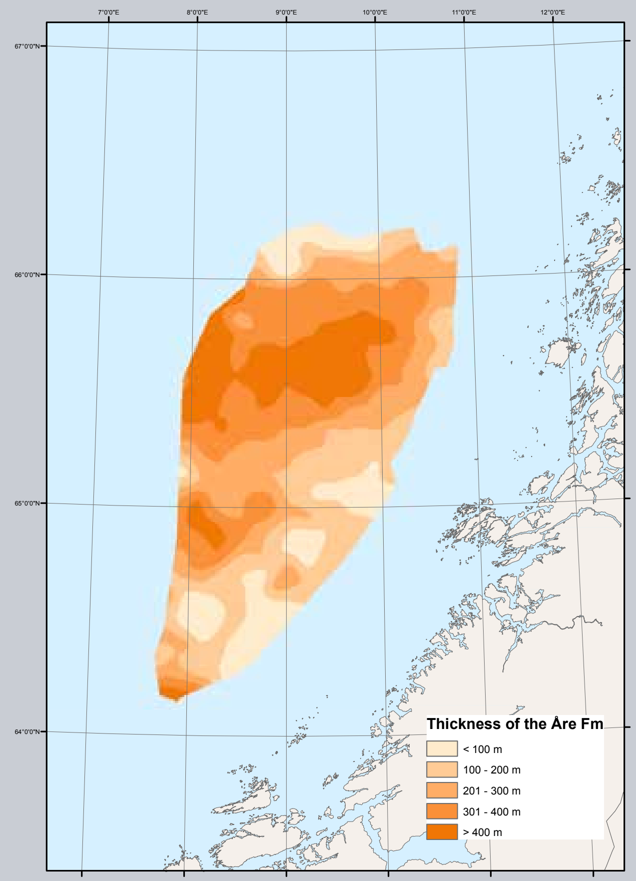
The Båt Group

The Åre Formation (Rhaetian to Pliensbachian) represents delta plain deposits (swamps and channels) at the base with up to 8m thick individual coal seams. Generally, where the coal bearing sequences are thinner, the sandstones are coarser grained. The Åre Fm is present in most wells drilled in the Haltenbanken and Trænabanken region, locally missing over the crest of the Nordland Ridge due to erosion.

The thickness in the type well (6507/12-1) is 508m and in the reference well (6047/1-2), the thickness is 328m. Generally the thickness of the Åre Fm varies between 300 to 500m, with a maximum thickness of 780m in the eastern part of the Halten Terrace (Heidrun area).

The well coverage over the central and eastern Trøndelag Platform is limited. But well 6510/2-1R, located on the Vega High and Ylvingen Fault Zone, drilled 291m of Åre Fm. Wells along the western margin of the Trøndelag Platform down to the Draugen field show thicknesses of the Åre Fm between 250-300m. In the Froan and Helgeland Basins area the Åre Fm varies in thickness between 300-500m from south to north.





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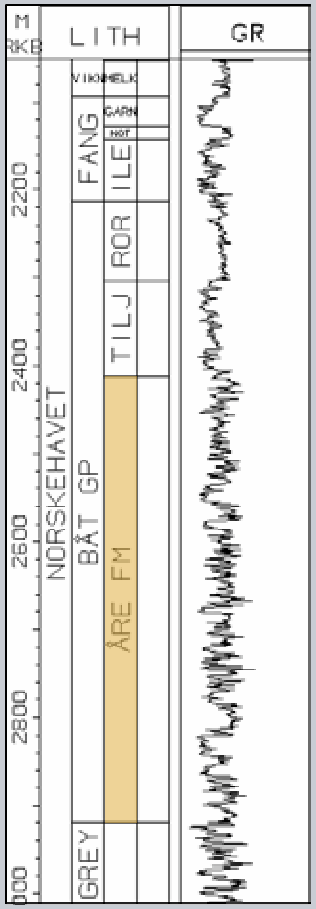


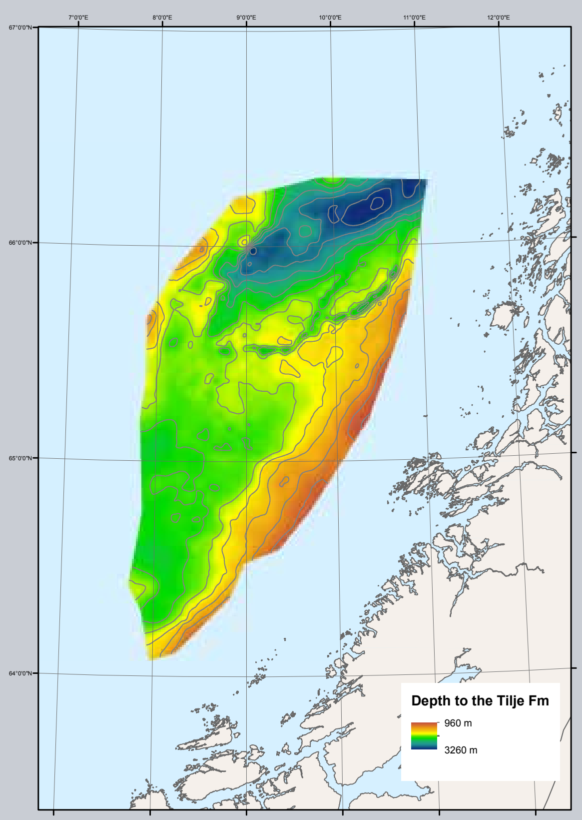
6507/12-1 ÅRE 2707.0 - 2709.7 m

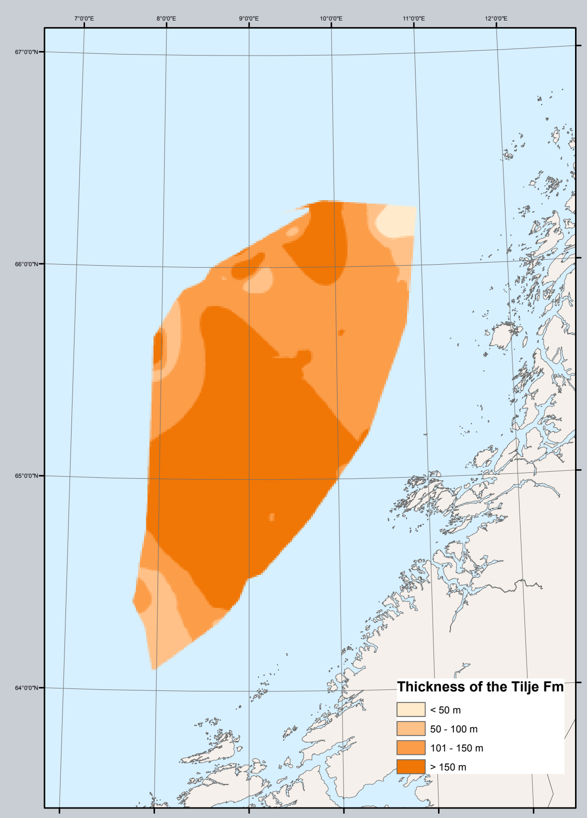
4.2 Geological description

The Båt Group

The Tilje Formation (Sinemurian to Pliensbachian) is defined at the top of a mudstone interval and consists of more sandy sediments deposited in near shore to intertidal environments with increased thickness of individual sandbodies. The mudstone interval is most pronounced on the Halten Terrace, but is difficult to pick further east on the Trøndelag Platform. Here coal beds are developed at a higher stratigraphic level than on the Halten Terrace. The formation is present in most wells in the Haltenbanken and Trænabanken region, locally absent on the Nordland Ridge.

In the type well (6507/11-1), the thickness of the Tilje Fm is 98m and on the Halten Terrace thicknesses in the order of 100-150m are reported. Shallow boreholes close to the coast indicate time equivalent deposits dominated by coarser clastics. The same thicknesses are observed in the Trøndelag Platform area.





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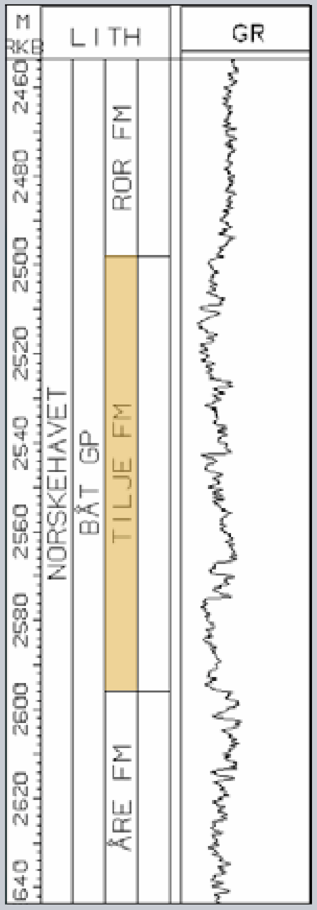


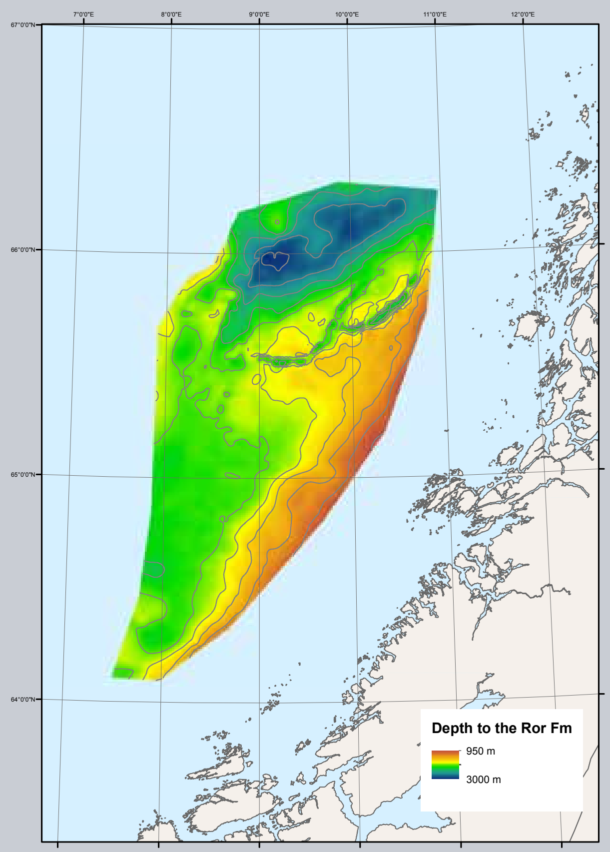
6507/11-1 TILJE 2527.7 - 2543.0 m

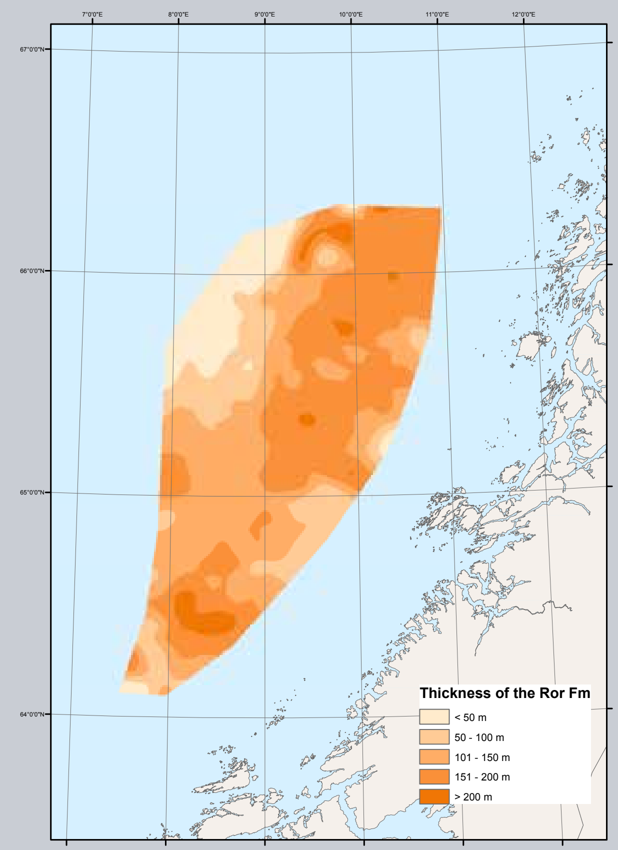
4.2 Geological description

The Båt Group

The Ror Formation (Pliensbachian to Toarcian) is defined by the abrupt transition from the sandstones in the Tilje Fm into mudstones, indicating an erosive base. The Ror Fm is present in all wells drilled on Haltenbanken, generally thinning towards the northeast. To the west, it interfingers with the sandstones of the Tofte Fm, and the oldest part of the Ror Fm is often absent. The Tofte Fm represents an eastward prograding fan delta, reflecting a source area in the west. In the study area, the Tofte Formation does not occur, although local sandy beds have been encountered in the wells. The Ror Fm does not occur over large areas on the Nordland Ridge due to erosion/non-deposition. On a regional scale, the mudstones of the Ror Fm might represent a seal, particularly towards the east.

In the type well (6407/2-1), the thickness of the Ror Fm is 104m and thicknesses in the order of 70 to 170m have been recorded in wells on the Halten Terrace. On the Trøndelag Platform thicknesses between 100-200m are observed.





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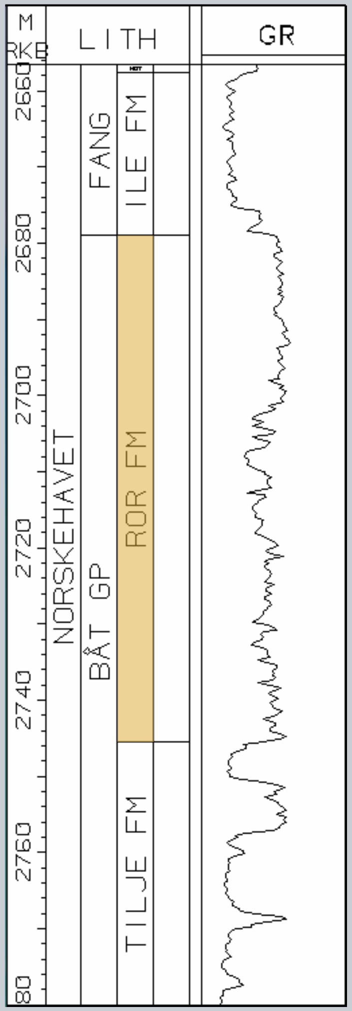


6610/7-1 ROR 2707.0 - 2713.0 m

4.2 Geological description

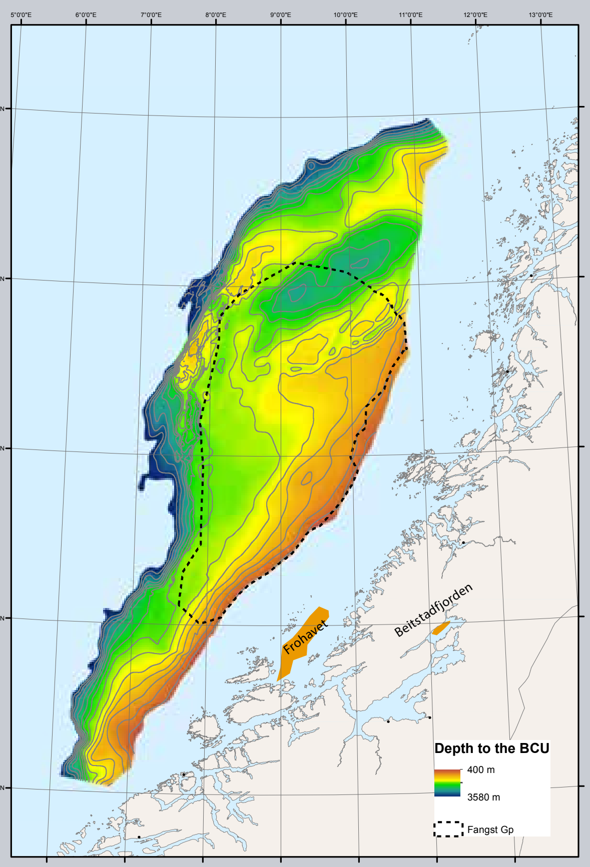
The Fangst Group

Lower to Middle Jurassic
(Upper Toarcian to Bathonian)

The Fangst Group is dominated by sediments deposited in shallow marine to coastal/deltaic environments overlying the Båt Group. It is divided into three formations, the Ile, Not and Garn Formations. The formation is present over most of the Haltenbanken and Trænabanken area, except for the crestal parts of the Nordland Ridge, where it is eroded. The main development of the Fangst Gp is on the Halten Terrace. Along the southern margin of the Nordland Ridge, the succession is much thinner. On Trænabanken, there is a lateral facies change to marine mudstones of the Viking Gp and only the lowest part of the Fangst Gp (the Ile Fm) is recognised.

Time equivalent sandstone dominated sequences subcrop on the seafloor along the eastern margin of the Trøndelag Platform. Outliers of Middle Jurassic sediments are present east of the Froan islands and in Beitstadfjorden area in Trøndelag. Increased continental influence is inferred towards the Trøndelag Platform to the east, but the well control is limited.

In the type well (6507/11-3), the thickness of the Fangst Gp is 124m and typically varies between 100 to 250m.



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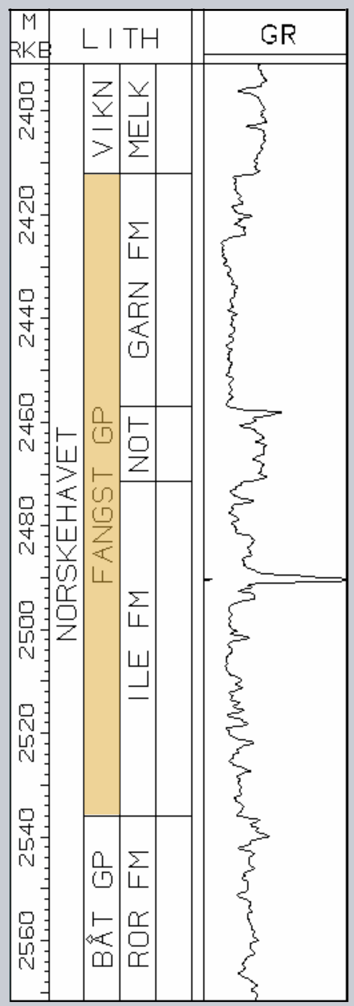
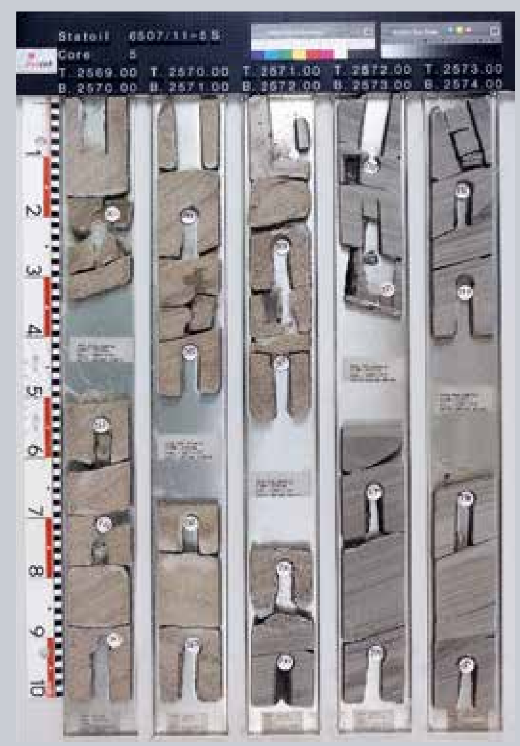


ILE 6507/11-5s 2569 - 2574 m



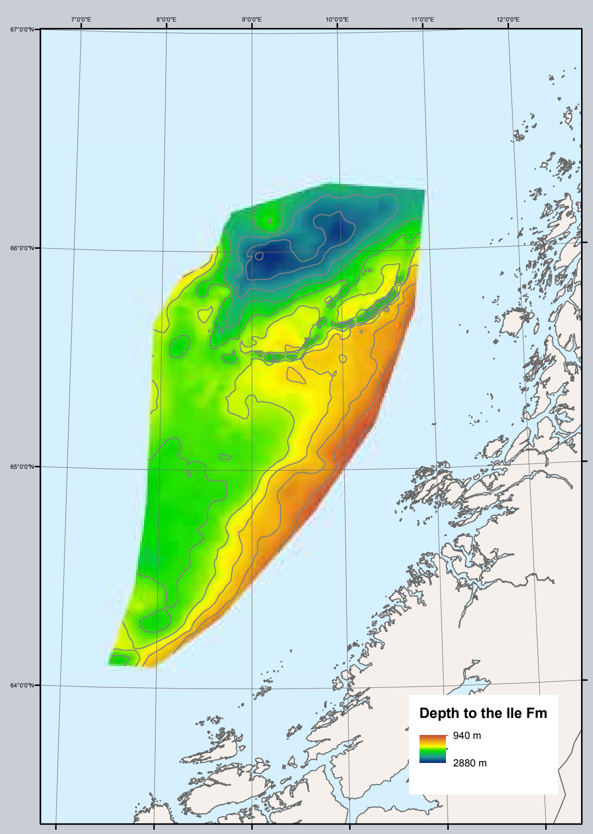
4.2 Geological description

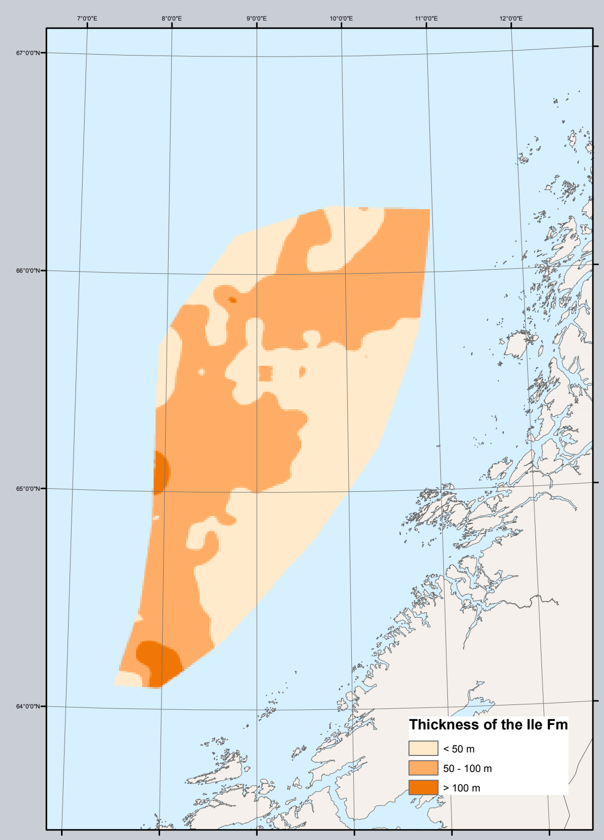
The Fangst Group

The Ile Formation (Upper Toarcian to Aalenian) is defined at the base of a generally upwards coarsening sequence from siltstone to sandstone, often associated with more carbonate beds. The sediments of the Ile Fm are deposited in tidal or shoreline environments. The upper boundary is defined by the mudstones of the Not Fm. The Ile Fm is present over most of Haltenbanken, with a general thickening to the west and marked thinning to the northeast.

The thickness in the type well (6507/11-3) is 64.5m and 72m in the reference well (6407/1-3). The thickness of the Ile Fm varies between 50 to 100m over most of the Haltenbanken-Trænabanken area.

Sandstone dominated successions of similar age have been reported from shallow boreholes and sea bottom sampling in the eastern part of the Trøndelag Platform. However the succession is thinner ranging from 30-60m. The formation is shale dominated in the Vega High and Helgeland Basin.





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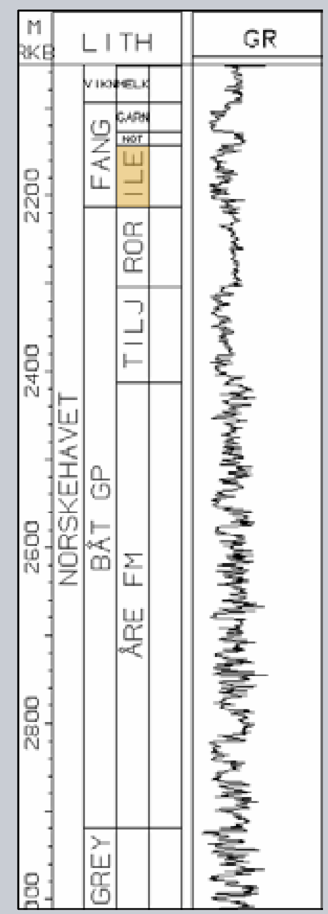


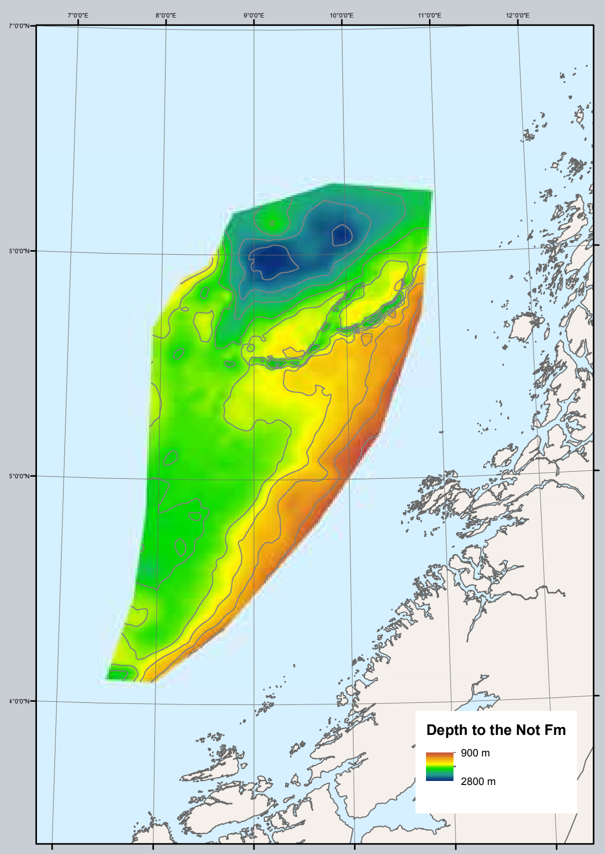
6508/5-1 ILE 1791 - 1795 m

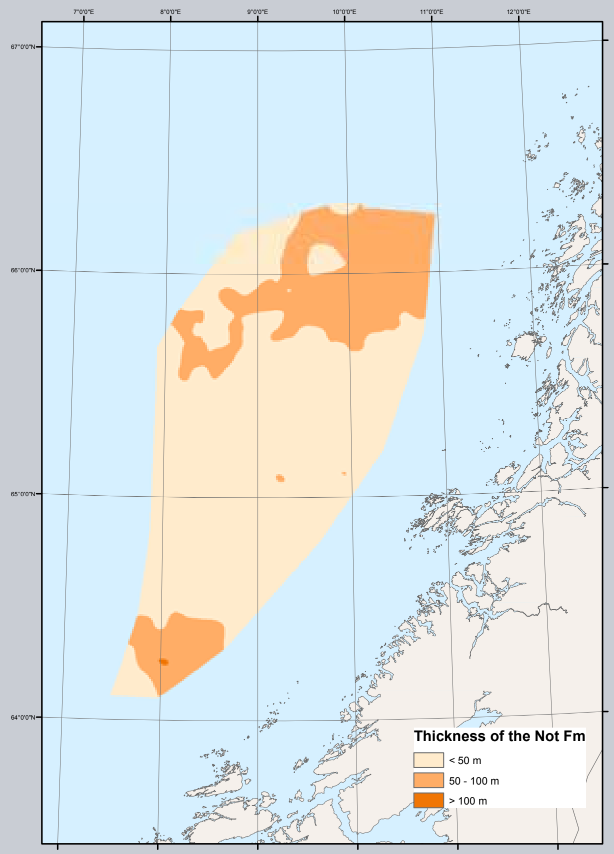
4.2 Geological description

The Fangst Group

The Not Formation (Aalenian to Bajocian) is developed as a mudstone dominated sequence coarsening upwards into bioturbated fine-grained sandstones deposited in lagoons or sheltered bays. The Not Fm is recognised over the entire Haltenbanken area, except on the eroded highs. The thickest development (<50m) of the Not Fm is on the southwestern part of the Halten Terrace and the unit thins towards the east. On the Trøndelag Platform it has a consistent thickness of approximately 40m. The mudstones of the Not Fm could act as seal.

In the type well (6507/1-3) the thickness is 14.5m and 37m in the reference well (6407/1-3).





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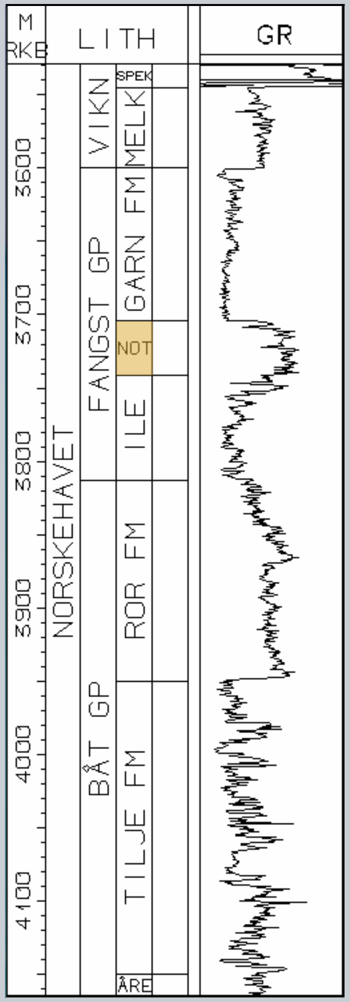


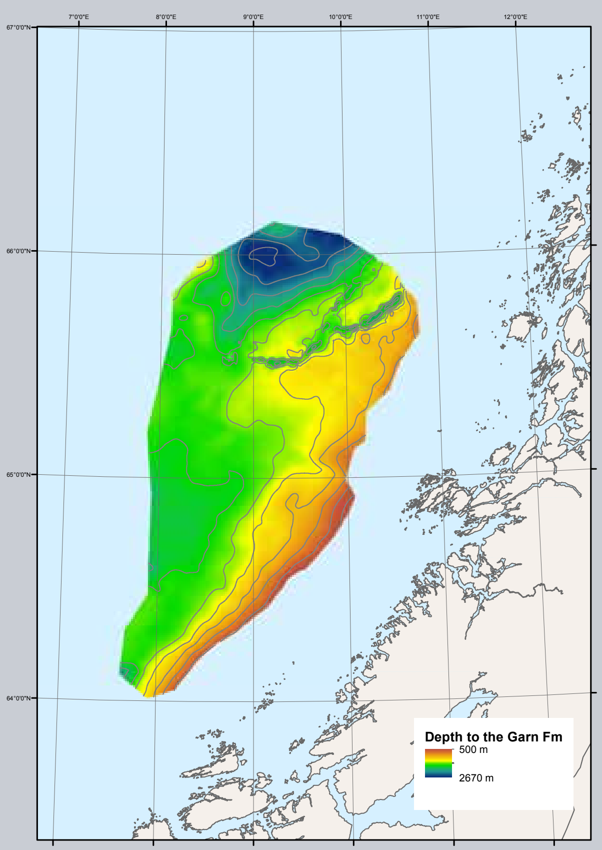
6507/11-3 NOT 2467 - 2472 m

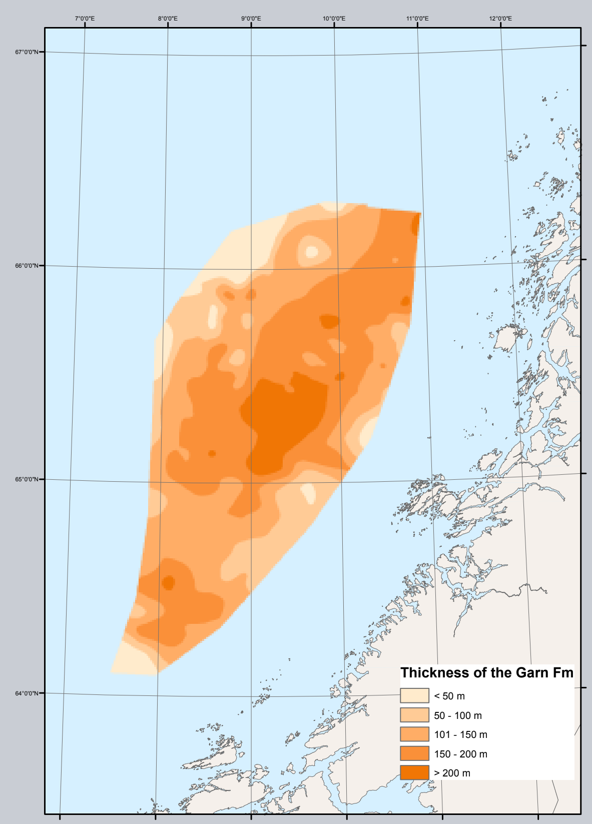
The Fangst Group

The Garn Formation (Bajocian to Bathonian) is interpreted in terms of deposition and progradation of braided delta lobes over the mud dominated Not Fm. The Garn Fm is present over the central part of the Halten and Dønna Terrace and the Trøndelag Platform, except over structural highs (Nordland Ridge) where the entire formation may be eroded. In the Ylvingen Fault Zone (well 6510/2-1R), the Garn Fm contains more silt, and further north, siltstones and mudstones are the lateral equivalents of the sandstones in Garn Fm. It must be noted that the well control on the eastern part of the Trøndelag Platform and in the deeper areas to the west is limited.

Depositionally, the sandstones of the Garn Fm are interpreted in terms of a wave-dominated shoreface system with marine mud-dominated sediments deposited towards the south and north.

The thickness in the type well (6407/1-3) is 104m, and the formation may reach more than 100m on the Halten Terrace. The thickness of the Garn Fm is about 150m on the Trøndelag Platform. In the Froan Basin the formation is sand dominated compared to the northern part, where it becomes more shale dominated .





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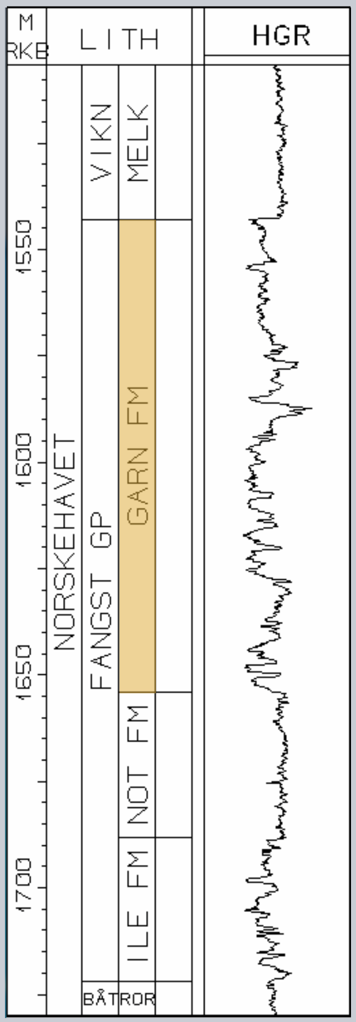


6407/1-3 GARN 3671.0 - 3675.0 m

4.2 Geological description

The Viking Group

Middle Jurassic to Upper Jurassic/Lower Cretaceous
(Bajocian to Berriasian)

The Viking Group is defined in the northern North Sea and on Haltenbanken and Trænabanken. It is divided into three formations, the Melke, Rogn and Spekk Fms. The group is present over most of the Trøndelag Platform area, but thins toward the Nordland Ridge where it is locally absent. The dominant lithology of the Viking Gp is mudstones and siltstones, with the exception of locally developed sands (Rogn Fm) in the Draugen field area and on the Frøya High. Sediments correlated with the Viking Gp have been found by shallow drilling and seafloor sampling in the eastern part of the Trøndelag Platform.

The thickness of the Viking Gp in the type well (6506/12-4) is 124.5m and 61m in the reference well (6407/9-1). Thicknesses up to 1000m are indicated on seismic data in down-faulted basins, and well 6507/7-1 on the Dønna Terrace drilled 658m sediments of the Viking Gp.

The Melke Formation (Bajocian to Oxfordian) is deposited in an open marine environment over most of Haltenbanken, but contains local sands in parts of the Dønna Terrace, the Revfallet Fault Complex and over the southern part of the Rødøy High. In the type well (6506/12-4), the thickness is 116.5m, but thicknesses in the order of 550m have been drilled in the area west of the Nordland Ridge.

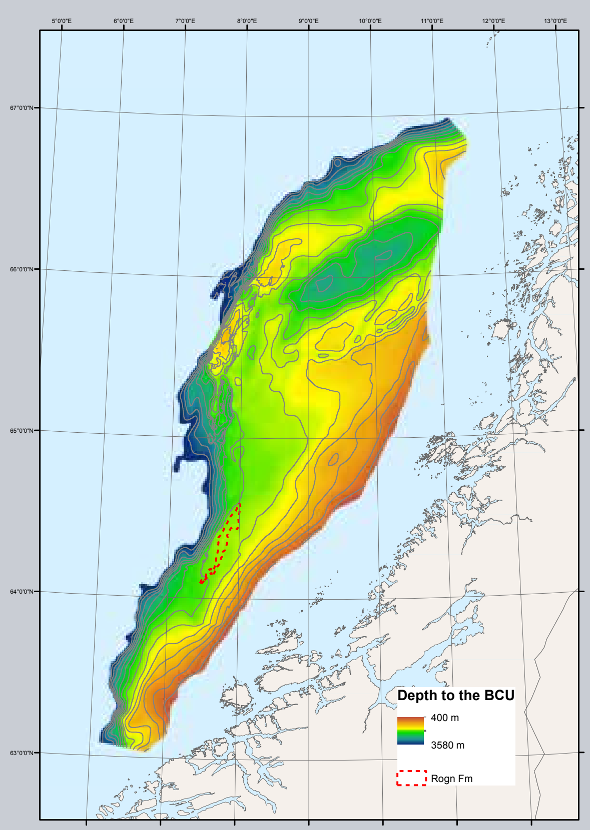
The Rogn Formation (Oxfordian to Kimmeridgian) sandstones occur within mudstones of the Spekk Fm in the Draugen field, the western part of the Froan Basin. A similar development is found on the Frøya High (well 6306/6-1). The sandstones of the Rogn Fm are interpreted as shallow marine bar deposits.

In the type well (6407/9-1), the thickness of the Rogn Fm is 49m and in reference well 6306/6-1 the thickness is 93m.

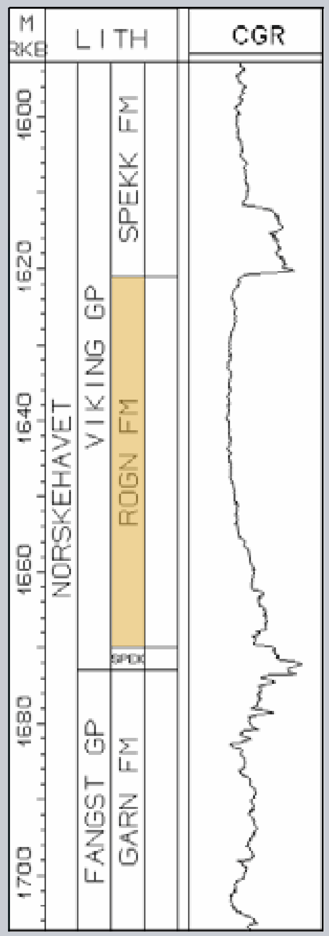
The burial depth of the sandstones of the Rogn Fm is around 1600-1700m in the Draugen field and porosities and permeabilities in the order of 30% and up to 6 darcy, respectively, have been reported.

The Spekk Formation (Oxfordian-Berriasian) overlies the Melke Fm. The Spekk Fm was probably deposited over most of the Haltenbanken and Trænabanken area, but may be absent over structural highs such as the Nordland Ridge. The mudstones were deposited in marine anoxic water conditions resulting in high organic content comparable with the time equivalent Draupne Fm in the northern North Sea, thus forming a major hydrocarbon source rock.

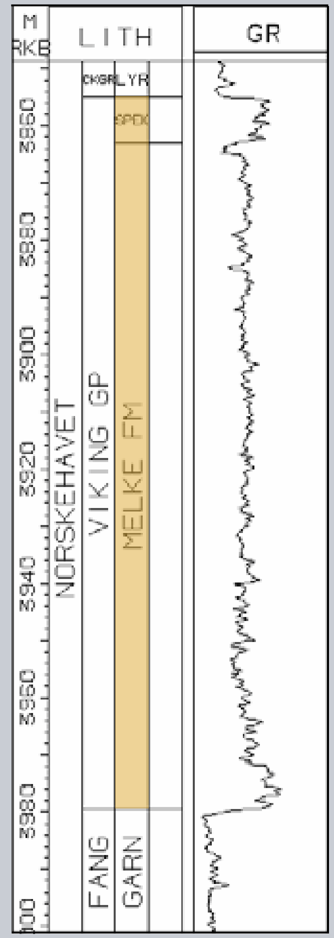
In the type well (6407/2-1), the thickness of the Spekk Fm is 65.5m, but thicker sections may be present in structural lows as on the Dønna Terrace. Black mudstones of similar age, also with high organic content, have been found in shallow boreholes off the coast of Trøndelag. The Viking Gp varies from 100-200m in the Trøndelag Platform area.



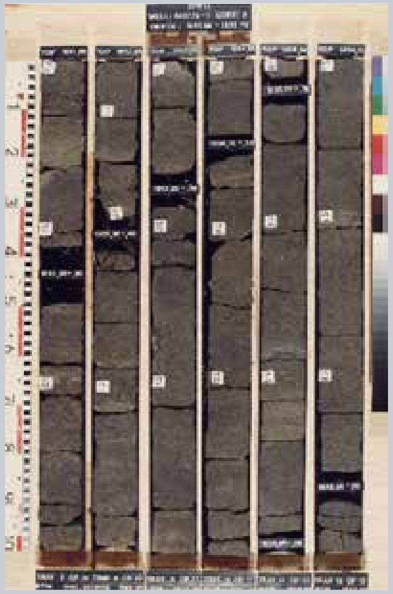
WELL LOG 6407/9-1



WELL LOG 6506/12-4



6407/9-1 ROGN 1651.0 - 1656.8 m



6306/10-1 MELKE 2747.0 - 2752.0 m

Cretaceous

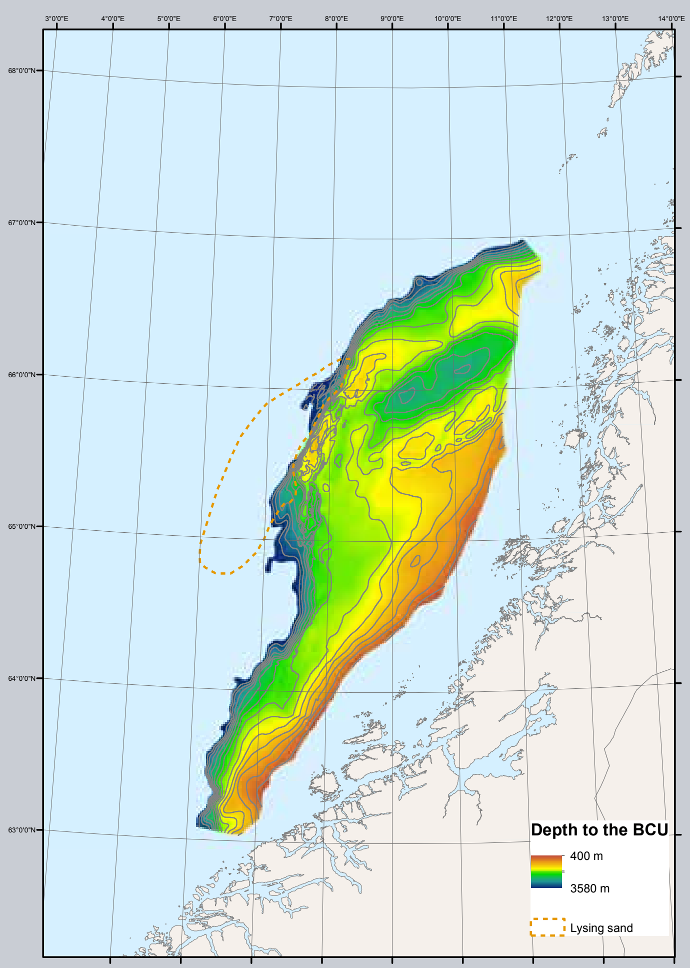
Upper Cretaceous
(Turonian to Maastrichtian)

The Cretaceous sediments in the Norwegain Sea are dominated by mudstones and siltstones, which form good seals. In the Halten and Dønna Terrace, certain intervals including the Lower Cretaceous Lange Formation and the Turonian-Coniacian Lysing Formation, contain locally developed sandstone units. In the northern part of the Vøring Basin, north of 67°N, the Nise Formation contains a thick succession of sandstones deposited as mass flows in a deep marine environment. The Santonian - Campanian sandstones of the Nise Formation were sourced from Greenland and shale out towards the south and east. Some methane gas discoveries have been made in the Nise sandstones. Although the Nise sandstones have quite good reservoir properties and large volume, their CO_2 storage potential was not evaluated, partly because of their remote location, partly because they are located in a petroleum province. Within the Lange Fm there are several local sandstone bodies which could act as thief sands. They are buried too deeply and have too small volumes to have any CO_2 storage potential.

Maastrichtian sandstones within the Springar Formation occur locally in the deep water areas. Their volumes and reservoir properties do not make them attractive for CO_2 storage.

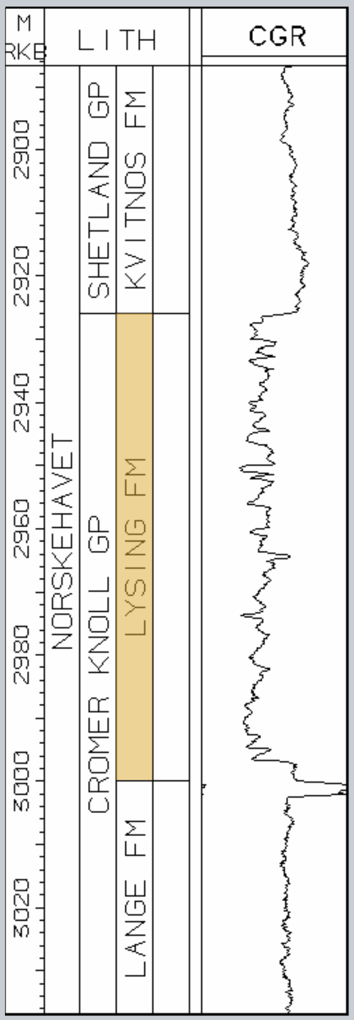
The Lysing Formation (Upper Cenomanian to Turonian/Coniacian)
The Lysing Fm forms the upper part of the Cromer Knoll Group, which consists of the Lyr, Lange and Lysing Fms. In the type well (6507/7-1), on the Halten Terrace west of the Nordland Ridge, the thickness of the Lysing Fm is 74m. In the Dønna Terrace area, sandstones within the Lysing Formation form a reservoir section with a thickness up to about 70 m. The Lysing Fm sandstones in the Dønna Terrace were probably deposited as submarine fans in a deep marine environment. Their source area is believed to be the Nordland Ridge and the highs further north. A few
methane gas discoveries have been made in the Lysing Fm sands west of the Skarv Field.

Although the Lysing Fm sands have a significant aquifer volume, it was decided to exclude it from a further evaluation of its storage potential. The main reason is that the aquifer is overpressured in the main depositional area in the Dønna Terrace, leaving a small pressure window for CO_2 injection before the fracture gradient is reached. Also, it is located in a zone of petroleum exploration and future production where conflicts of interest with CO_2 injection projects could occur.



Outline of the Lysing formations and Base Cretaceous depth map.

WELL LOG 6507/7-1



6506/12-4 LYSING 3134.0 - 3139.0 m

4.2 Geological description

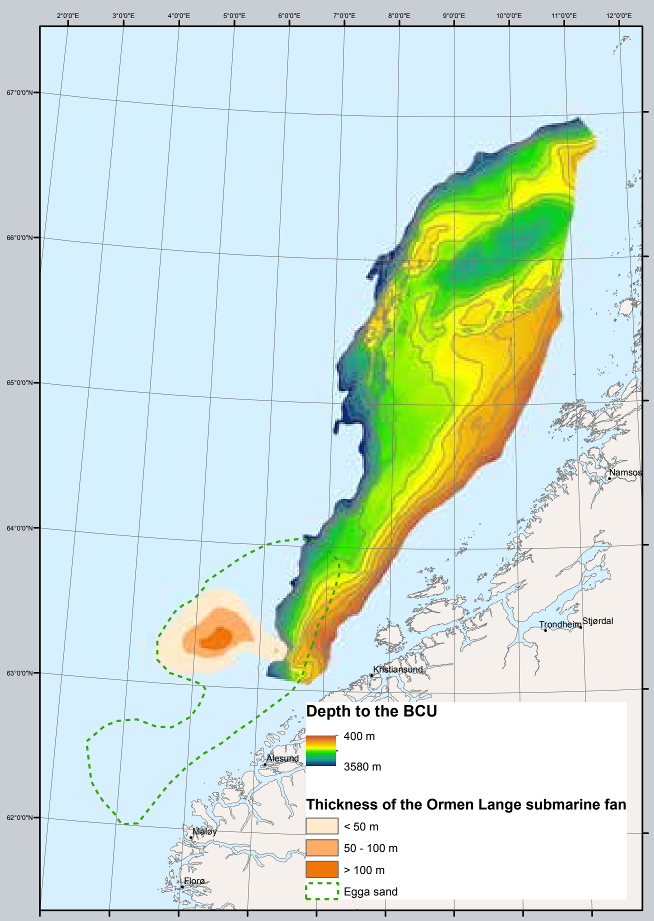
Paleocene

Paleogene
(Danian)

The Late Cretaceous deposits in the Norwegian Sea were dominated by fine grained sediments and the source areas for sands were located to the north and west. In the Paleocene, the transport of sediments from Greenland to the Vøring Basin continued, but there was also significant sediment supply from Scandinavia to the Trøndelag Platform and Møre Basin. The main reservoir sand from the Paleocene-Eocene period is the Danian Egga sandstone.

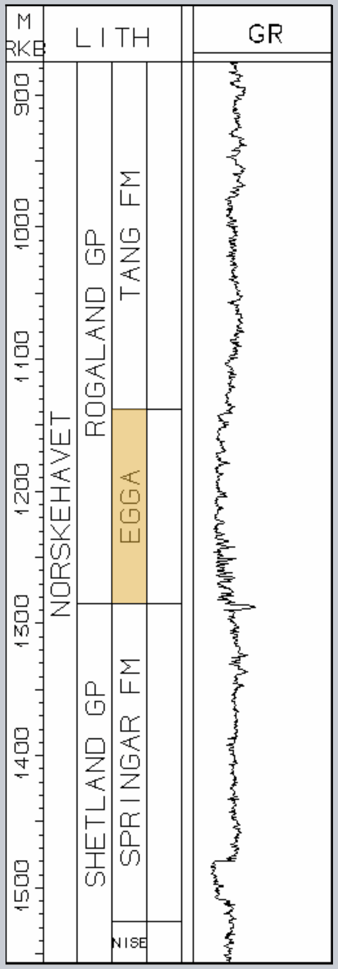
The Egga sandstone (Danian)
This Danian sandstone forms the main reservoir of the giant Ormen Lange gas field. At present, there is no type well or reference well defined. The sandstone has so far no formal stratigraphic formation name but has been referred to informally as the Egga Formation in the NPD website. It is defined in the Ormen Lange field as a deep marine mass flow sandstone unit within the Rogaland Gp. In the field, a maximum thickness of 80m was found in well 6305/7-1. The Egga Fm sandstones are found in several exploration wells in the Møre Basin and Slørebotn sub-basin. The reservoir quality and thickness vary considerably depending on where the well was located in the different submarine fan systems. The Ormen Lange fan is possibly the largest submarine fan within the Egga sand, and a thickness map of this fan is shown in the figure along with the approximate outline of the sand system.

The shallow eastern part of the Møre Basin has a monoclinal structure where all sedimentary beds dip from the coast into the basin. Any structural closures are likely to be small. Consequently, an injection site for large volumes of CO_2 would probably need to have a stratigraphic component to the structure. Possibly the Egga sand aquifer could be used for injection of small volumes of CO_2 which could be residually trapped before they migrate to the sea floor. Such a case has been modeled for a Jurassic aquifer in the Froan Basin in section 5. This case has not been evaluated for the Møre Basin.

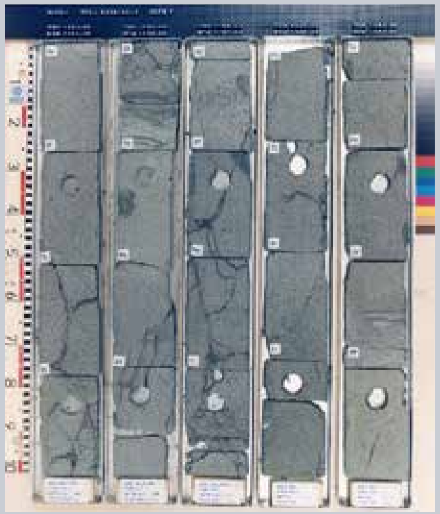


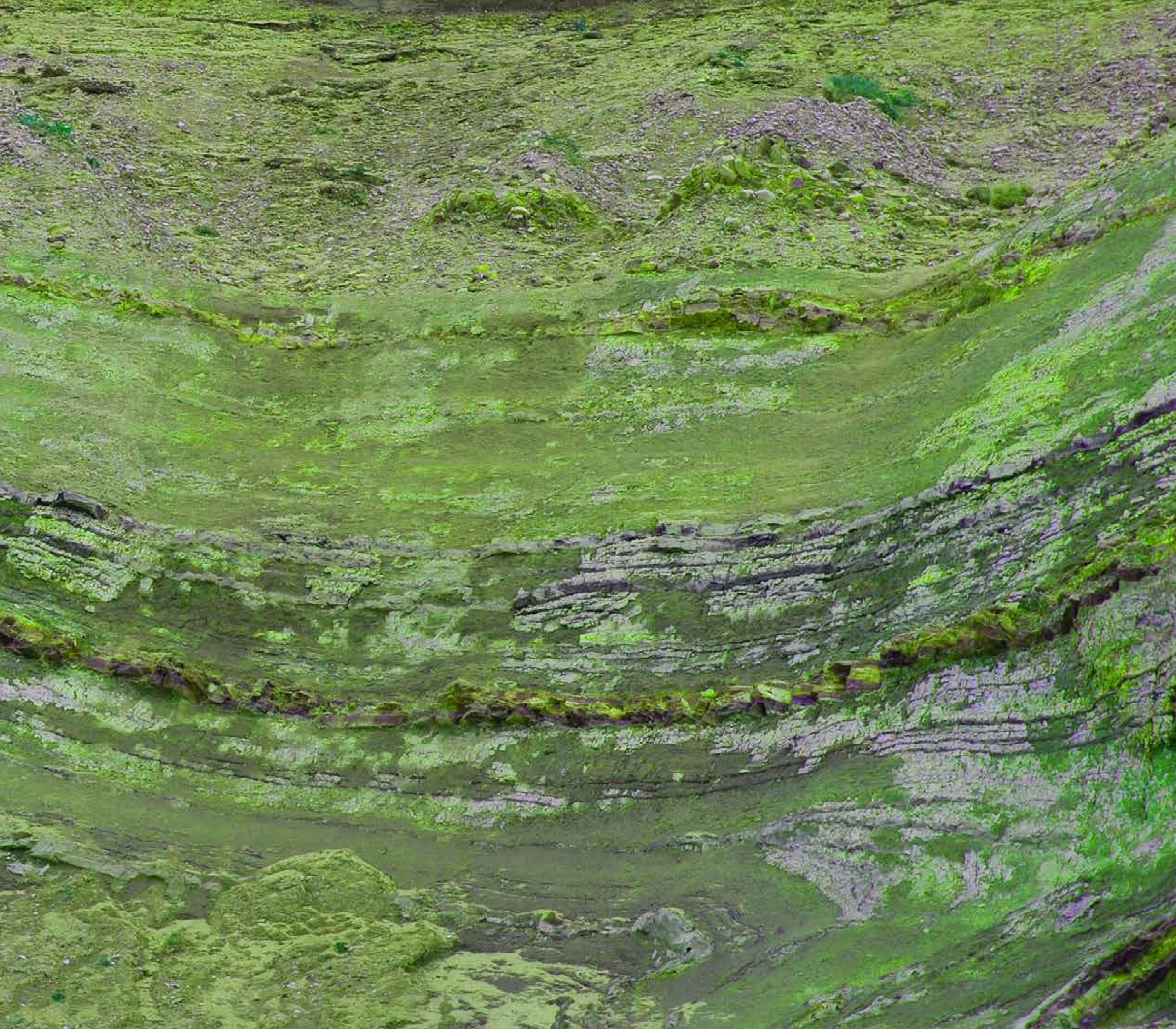
Base Cretaceous map and outline of the Egga Formation. Distribution and thickness of the Ormen Lange submarine fan.

WELL LOG 6306/10-1

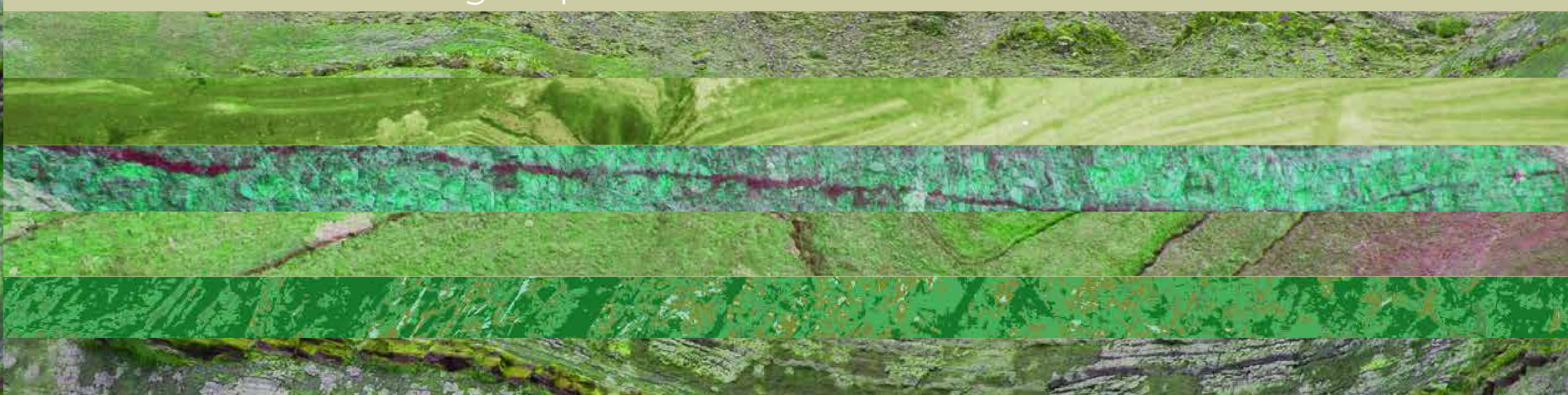


6306/10-1 EGGA 1164.0 - 1169.0 m





5. Storage options



5.1 Introduction

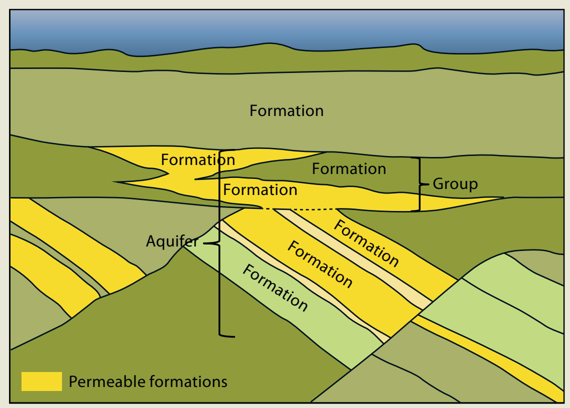
An aquifer is a body of porous and permeable sedimentary rocks where the water in the pore space is in communication throughout. Aquifers may consist of several sedimentary formations and cover large areas. They may be somewhat segmented by faults and by low permeable layers acting as baffles to fluid 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 with salinities in the order of seawater or higher. The aquifers which have been evaluated for CO_2 storage are located at a depth between 600 and 3500 m and have a sufficiently high permeability, porosity and connectivity to enable injection and storage of CO_2. In the Norwegian Sea, these general conditions are met in the Trøndelag Platform including the Nordland Ridge, and in the Møre Basin. Potential CO_2 storage in the shelf slope and deep sea provinces of the of Norwegian Sea has not been evaluated (Cretaceous formations, see section 4).

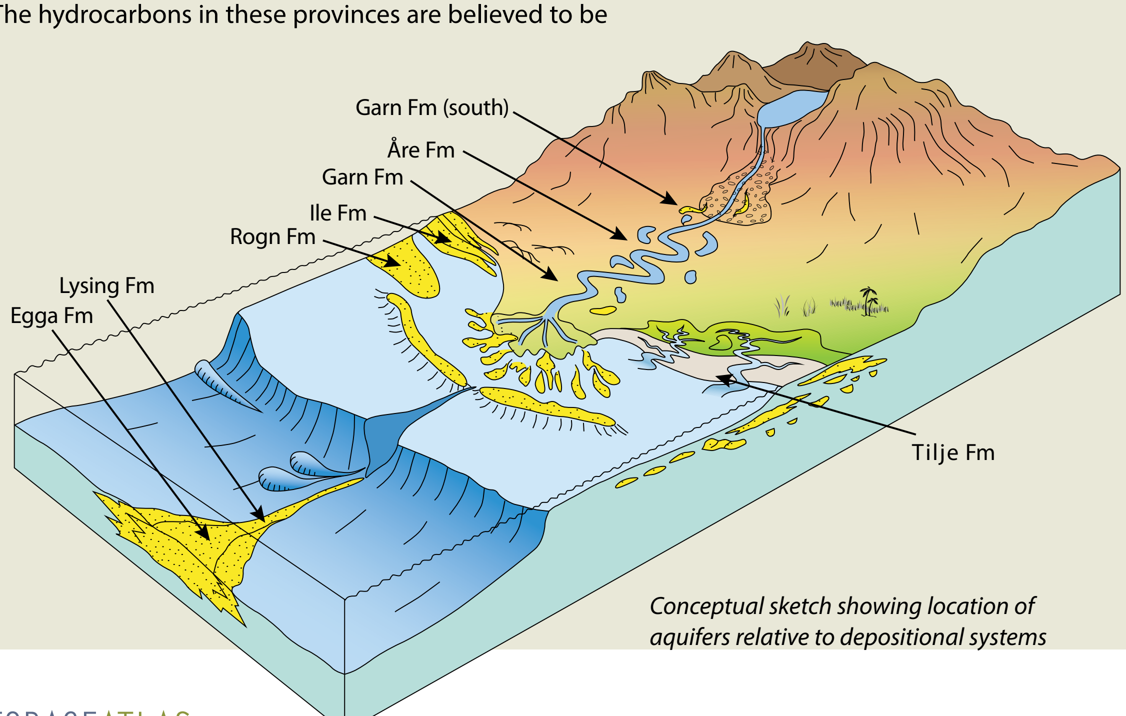
The aquifers in the Trøndelag Platform have been studied by compilation of published maps, new seismic mapping, well studies and well correlation. The Draugen area and the Nordland Ridge have a good data coverage with 3D seismic and several wells, while the remaining area has 2D seismic data and a few exploration wells.

As described in section 4, the Jurassic succession in the Norwegian Sea shelf is thick and contains several aquifers with storage potential for CO_2. The Halten and Dønna terraces are important petroleum provinces. The hydrocarbons in these provinces are believed to be generated from Jurassic source rocks, mainly the Spekk and Åre Formations. In the Trøndelag Platform, the Jurassic source rocks have not been buried deep enough to reach the oil and gas maturation window, and the hydrocarbons occurring here have migrated from the deeper basins and terraces. The approximate limit for hydrocarbon generation and migration is indicated by the red line. Some oil and gas may have been generated in the deepest part of the Helgeland Basin although until now there has been no exploration success in this area.

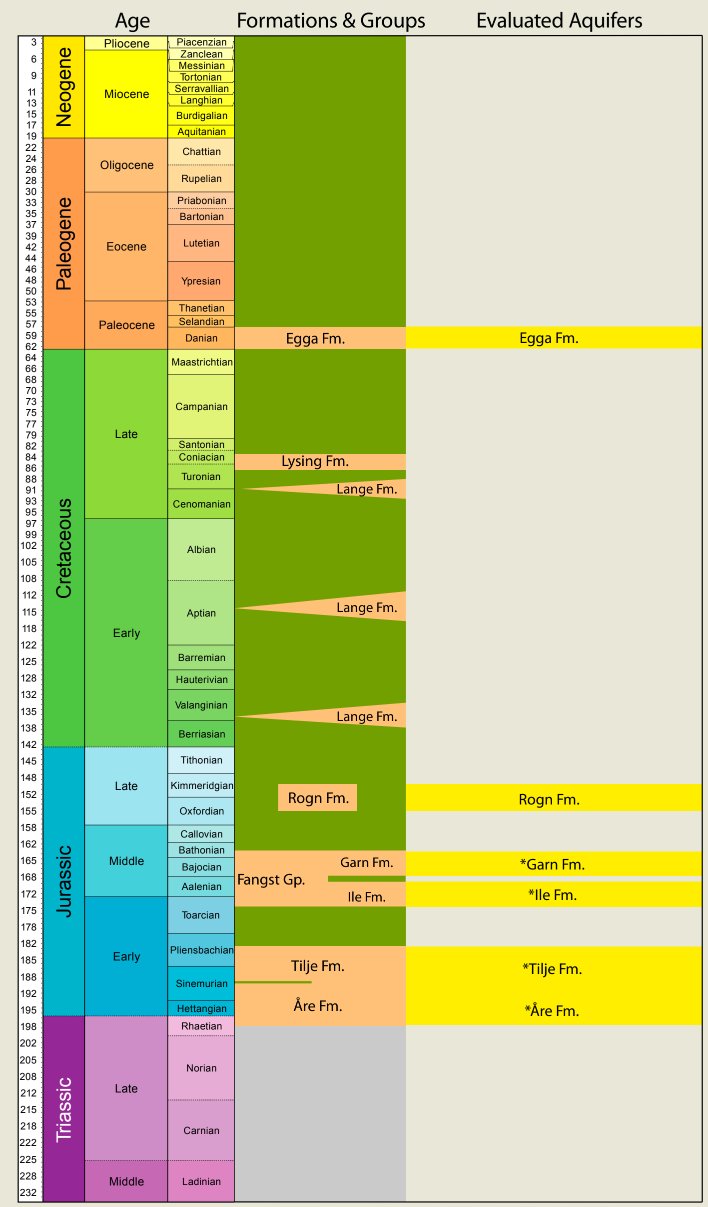
In the petroleum provinces (west of the red line), it is considered that exploration and production activities will continue for many years to come. The most realistic sites for CO_2 storage in the petroleum province will be some of the abandoned fields. Consequently, an indication of the storage capacity of the fields has been given, but no aquifer volumes have been calculated in this area. Some of the oil fields are considered to have a potential for enhanced oil recovery (EOR) by use of CO_2 (section 5.3). Some of the CO_2 used for EOR will remain trapped.

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.





Conceptual sketch showing location of aquifers relative to depositional systems



* Evaluated prospects

5.2 Saline aquifers

Froan and Helgeland Basins

The evaluated Jurassic aquifers are located at the Trøndelag Platform, east of the Cretaceous basins which have a green colour in the structural element map. The aquifers are bounded by the subcrop to the Quaternary along the coast to the east, by the Nordland Ridge to the NW and north, and the Frøya High to the SW. The shallow Jurassic aquifers are separated from the Gimsan Basin by large faults and steep slopes. The pore pressure regimes in the Halten Terrace show a general trend from high overpressure to hydrostatic pressure from the west towards the Trøndelag Platform in the east. This indicates that in geological time there has been pressure equilibration across the faulted boundary.

In the Helgeland and Froan Basins, all pore pressures are hydrostatic.

The Åre and Tilje Formations are treated as one aquifer at a regional scale due to the lack of regional sealing shales in the stratigraphy. Both these formations are heterogeneous, with coal beds and shale beds separating channelized sandstones. Internal baffles and barriers at a km scale should be expected, both within the Åre Formation and possibly between Åre and Tilje. Consequently, there is a risk that there can be significant internal barriers within the aquifer and that the communicating volumes can be less than predicted. In the case of low connectivity, a higher number of injection wells than anticipated would be necessary to realize the desired injection volume of CO_2.

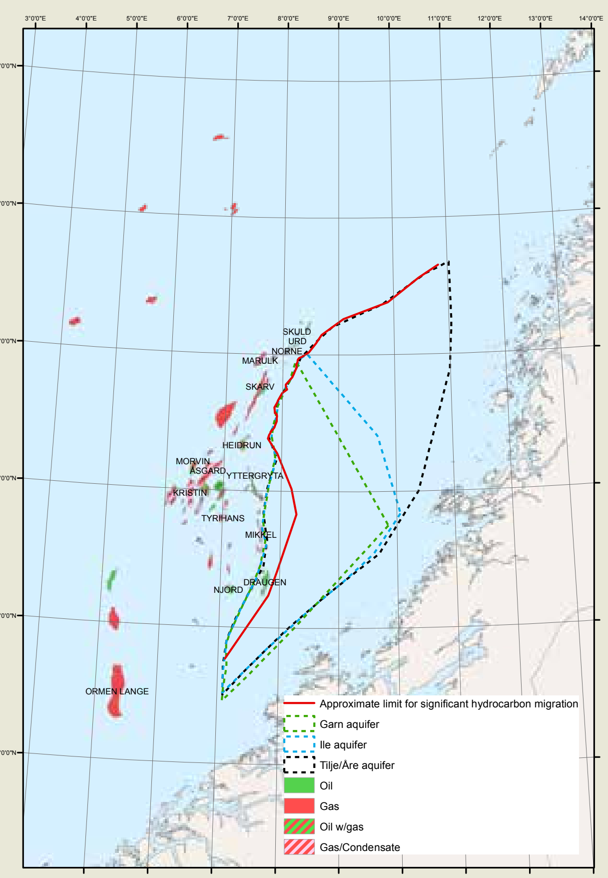
The Ror Formation is assumed to form a regional seal between the Tilje and Ile formations. The formation often forms a pressure barrier in the fields in the Halten terrace and tight shales have been proved in the Ror Fm in wells drilled in the Trøndelag Platform. Laterally, the seal could be broken by large faults.

The Not Formation is developed as a shale in the Trøndelag Platform, and the seismic data indicate that it is regionally distributed. Consequently, it could be expected that the Not Formation will act as a barrier between the Ile and Garn Formations. In the modeling, however, Ile and Garn Fm have been grouped as one aquifer. This simplification was made because of the small volume of the Ile Fm and existence of faults which could offset the Not Formation and juxtapose Ile with Garn.

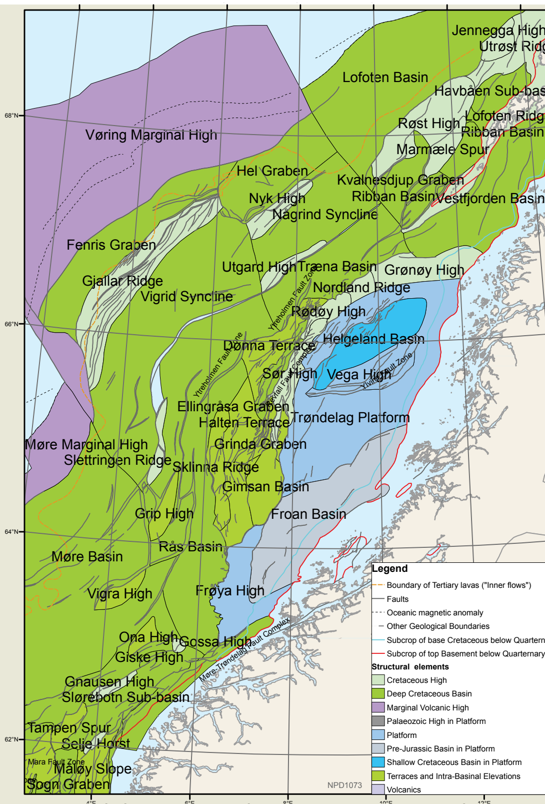
The Ile and Garn Formations have very good reservoir properties at the shallow depths encountered in the Trøndelag Platform. The porosity and permeability used in the geomodel are based on the well log data and a few core measurements. The Garn Formation in the Froan Basin is dominated by shallow marine sediments where much better connectivity can be expected than in the tidal dominated Ile and Tilje Formations. The Ile and Garn formations shale out towards the Helgeland Basin.

The Rogn Formation in the Draugen area has very good reservoir properties. It is separated from the Garn Formation by Spekk Formation shales of variable thickness. It is likely that there will be communication between the Rogn and Garn reservoirs.

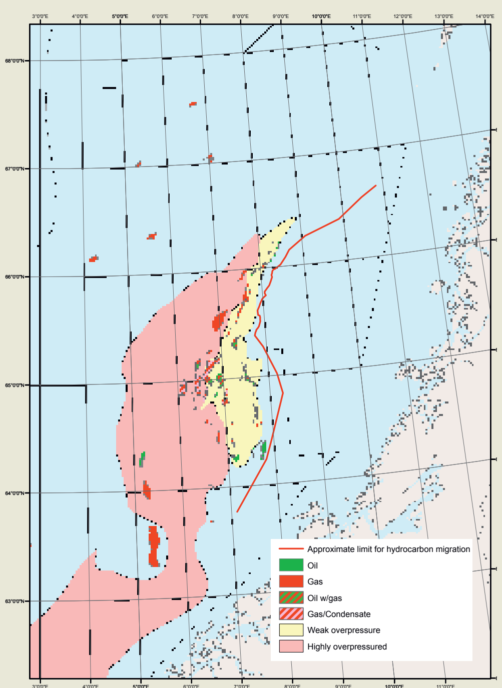
The Spekk, Melke and Cretaceous shales above the Garn Formation constitute an excellent top seal for the Jurassic aquifers.



Distribution of aquifers in the Trøndelag Platform. Red line shows the approximate limit for hydrocarbon migration



Structural element map. The green area represents basins with thick Cretaceous infill, where Jurassic sediments are generally deeply buried.

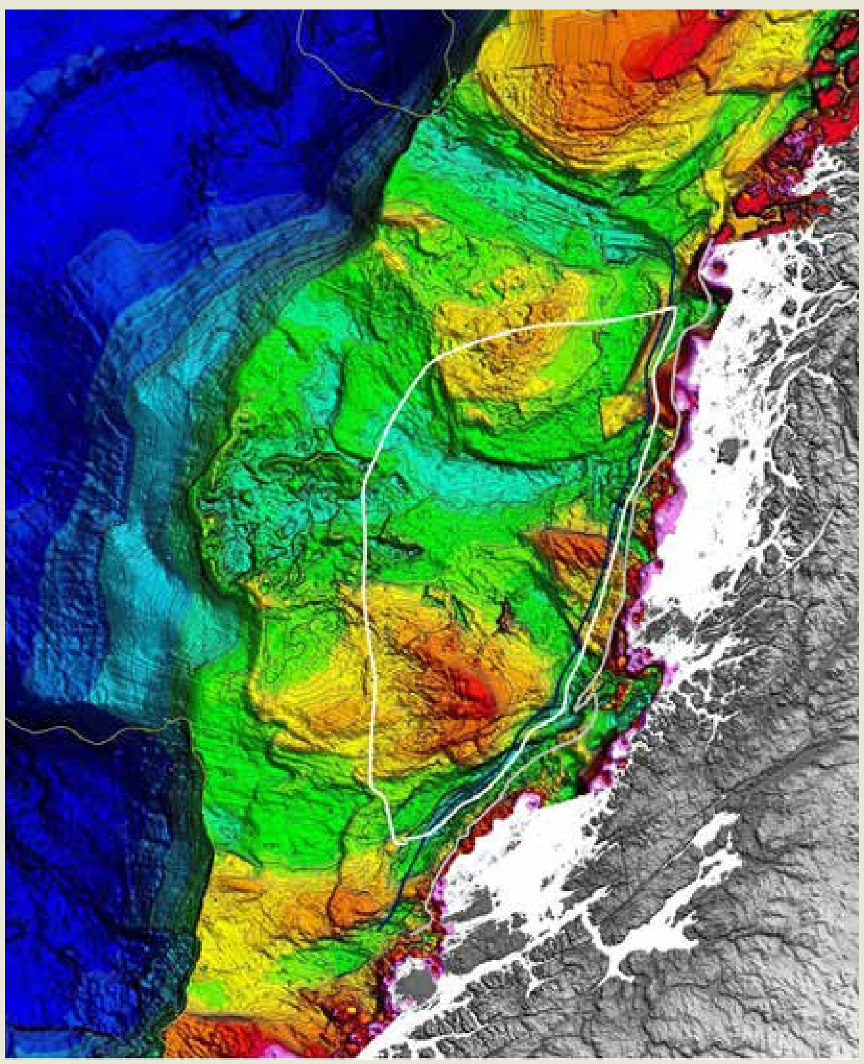


Hydrocarbon accumulations and pore pressure regimes in the Jurassic aquifers

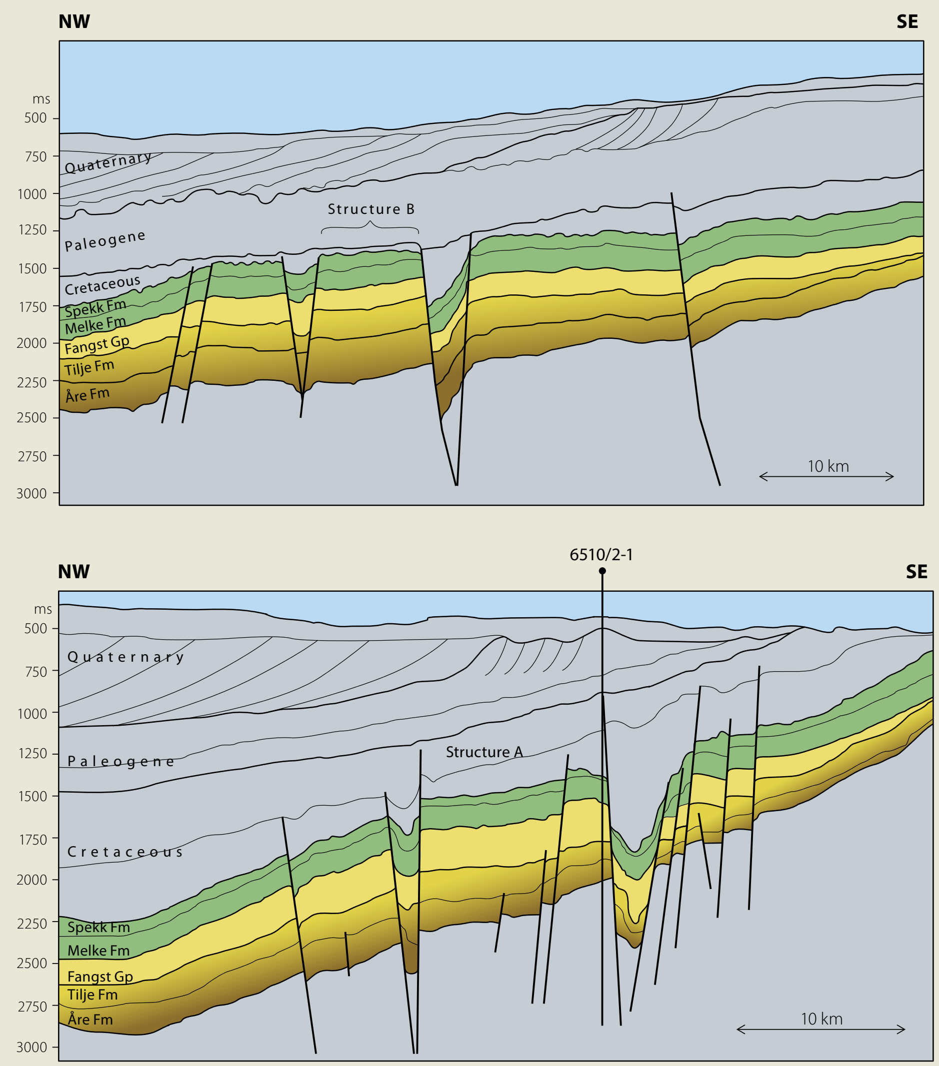
5.2 Saline aquifers

Compartmentalization
The northern part of the Trøndelag Platform and the Sør High of the Nordland Ridge are characterized by large graben features such as the Ylvingen Fault Zone and Ellingråsa Graben. These grabens were probably formed by extension and collapse in the late Jurassic and early Cretaceous. Their size and depth suggest that they could be barriers to fluid flow in the Jurassic aquifers.

In the geomodel, the Ellingråsa graben is treated as the western boundary of the Jurassic aquifers in the Trøndelag Platform. The Ylvingen Fault zone could possibly seal off the northern from the southern part of the Åre-Tilje aquifer. Towards the north, in the Grønøy High, the aquifers are truncated by erosion. In the modeling of CO_2 injection, the lateral boundaries towards fault structures in the south, west and north are assumed to be closed. Towards the east, aquifers in the Froan Basin terminate at the base of Quaternary sediments below the sea floor. The sealing capacity of the Quaternary sediments along the eastern subcrop is probably low. As shown in the map, the topography of the sea floor is rugged, with basins and ridges carved out by glacial erosion. Comparison with seismic data indicates that the Quaternary cover can be several tens of meters thick in the basins, but much thinner in the slopes. The shallow well 6408/12-U-1 in the Froan Basin has only 6 m Quaternary cover. Most likely, there will be pressure communication between the Jurassic aquifers and the sea water along the subcrop line.



Bathymetry map with outlines of the main study area and subcrop lines of Base Cretaceous and the basement. Bathymetry from the Geological Survey of Norway (NGU). Storegga slide to the SW.



NW – SE profiles across the SE flank of the Helgeland Basin. The closed structures A and B are indicated. The location is shown in p. 44.

5.2 Saline aquifers

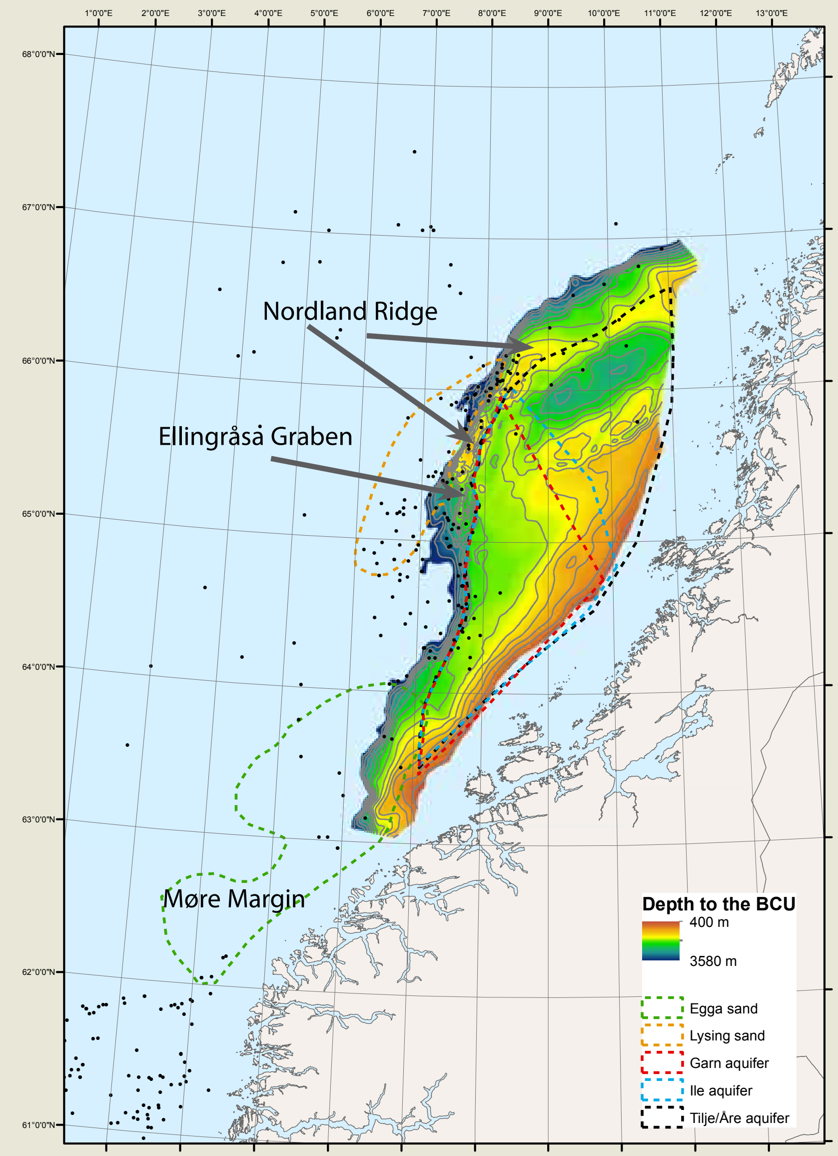
The Nordland Ridge aquifer
The Nordland Ridge has three large culminations, the Sør High, the Rødøy High and the Grønøy High. These highs are separated from the petroleum bearing terraces and basins to the west by large faults. The Sør High is located close to many producing fields, discoveries and prospects. Because some of the gas discoveries, like 6506/6-1 Victoria, have a high CO_2 content, it is of interest to identify possible storage sites close to these discoveries where there could be an option to inject excess CO_2 from future production.

The Sør High is a structural closure with a culmination at 1000 m below sea level and an area exceeding 500 km^2. It is covered by 3D seismic data and 4 wells have been drilled. The stratigraphy in the wells is interpreted in the NPD website as a few meters of Fangst Group overlying the Åre Formation. The seismic data show that there is an angular unconformity between the Åre Formation and the thinned Fangst Group. Small amounts of dry methane gas, possibly biogenic, have been encountered. There were no shows indicating heavier hydrocarbons. Due to tilting and block faulting below the unconformity, the Åre Formation has a variable thickness, commonly more than 200 m. The sandstones in the Åre Formation have similar properties as in the Froan Basin. Triassic grey beds may contribute to the volume of the aquifer.

The Åre aquifer will probably have several local internal baffles and barriers. The top seal will be the overlying Quaternary sediments belonging to the Naust Formation, which has a minimum thickness of about 650 m. The sediments in the Naust Formation are unfaulted and consist of silt and clay. The geological setting of this top seal is analogous to the Utsira Formation in the Sleipner area. The small accumulations of methane gas in the Sør High show that the Naust Formation has a sealing capacity. Further maturation of the Sør High as an injection site for CO_2 would require a better quantification of the Naust sealing capacity.

Møre Margin
The Møre margin south of the Frøya High is separated from the Froan Basin by the Jan Mayen Fracture zone lineament. Its Mesozoic and Cenozoic geology is very different from the Trøndelag Platform. Along the Møre margin, a thin Jurassic and thick Cretaceous section dip towards the deep Møre Basin. In this setting of regionally dipping strata, only a few closed structures of small sizes exist. The Jurassic reservoir sands tend to be thin, and no Cretaceous reservoir of interest has so far been proved by drilling. A few exploration wells drilled in the area have proved that gas has migrated into closed structures close to the coast. A possible storage option in the Møre Margin is thought to be the Paleocene submarine fans of the Egga sandstone which constitute the reservoir of the Ormen Lange Field. This sand was derived from the Møre Paleogene highlands and has not been encountered in the Froan and Helgeland Basins. A limited Jurassic storage potential could exist in a narrow zone close to the coast. Both the Egga and the Jurassic aquifers subcrop towards a thin Quaternary section below the sea floor. CO_2 migration to the subcrop area and leakage to the sea is the most obvious risk for these aquifers. No closed structures suitable for CO_2 injection have been identified in the Møre Margin.

Ellingråsa Graben
The dry exploration well 6507/12-1 was drilled near the culmination of a large closed structure in the southern part of the Ellingråsa Graben. The well penetrated the Åre-Tilje, Ile and Garn aquifers between 2100 and 2900 m depth below sea level. The structure is within the area of possible hydrocarbon migration. Since this well was dry and no shows were reported, it is very unlikely that hydrocarbons can have migrated further into the Ellingråsa Graben. The 6507/12-1 structure has been evaluated as a possible target for CO_2 injection. The storage efficiency depends on the communication with the aquifers in the Halten Terrace and the producing Midgard gas field to the west. The calculation of the storage volume within the structure is based on a closure of 200 m and storage in all aquifers with a storage efficiency of 10 %. Maturation of this prospect should include an evaluation of the communication with the Halten Terrace, Nordland Ridge and Trøndelag Platform. The 3D seismic data show that the Jurassic aquifers are strongly faulted, with the risk that the reservoir could be divided in many compartments. The faults do not appear to offset the Upper Jurassic and Lower Cretaceous sealing shales.



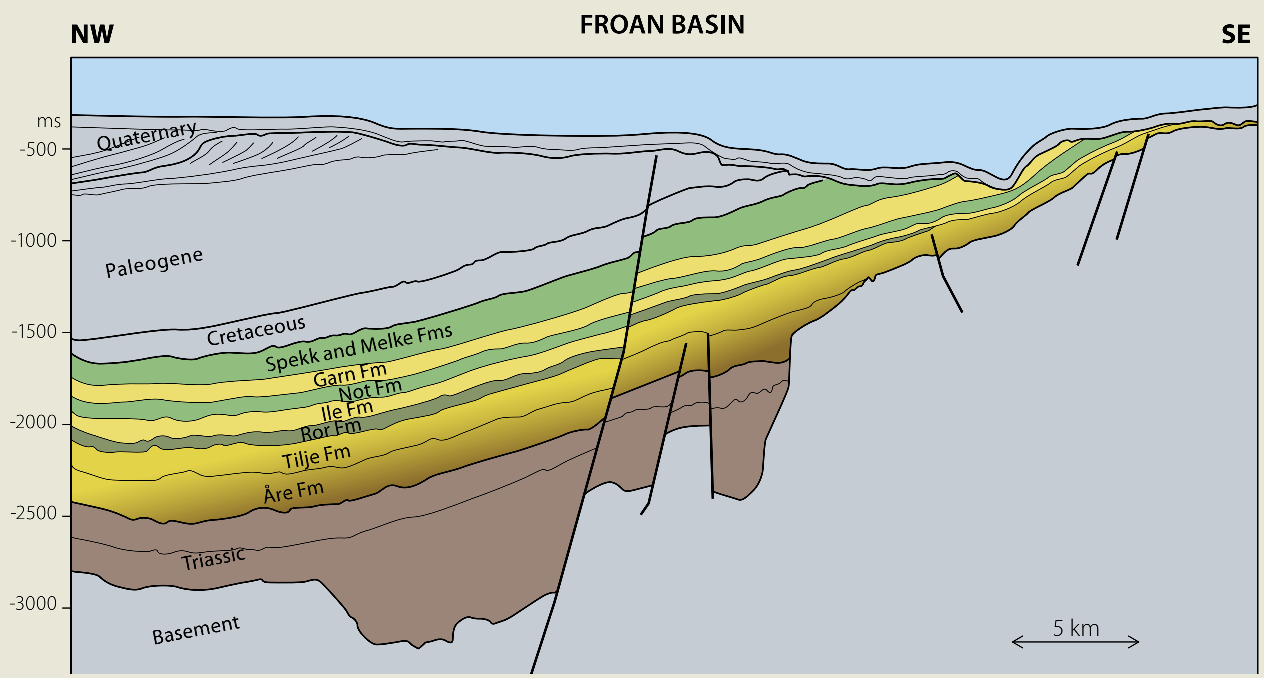
Froan Basin – long distance CO_2 migration

Modeling of CO_2 injection and migration in the Froan Basin

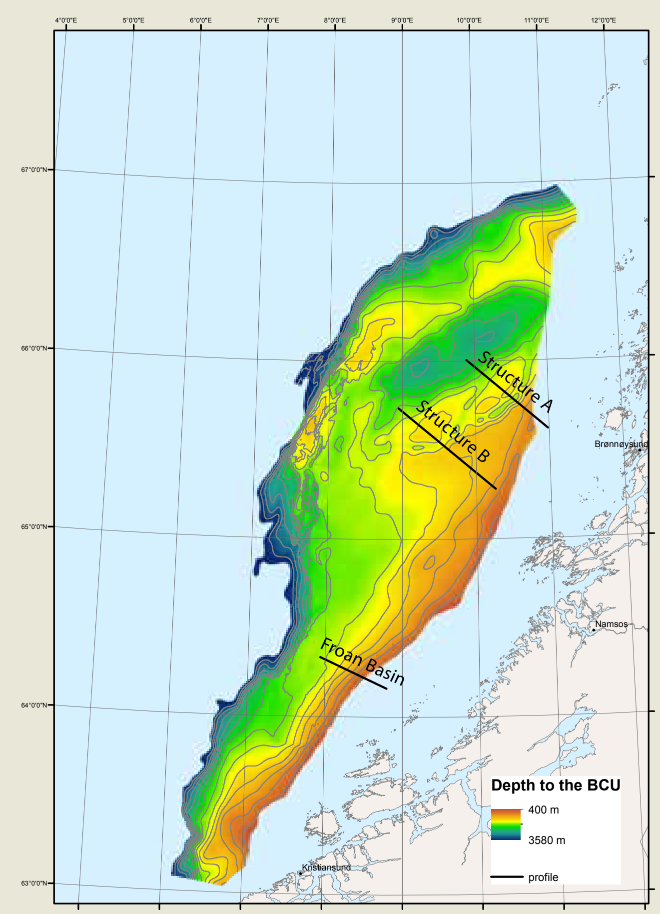
The aquifers in the southeastern part of the Norwegian Sea typically have a consistent dip of 1-2 degrees from the Norwegian coast to the basinal areas. In the case of permeable beds occurring along the dip slope there is a risk that CO_2 injected downdip can migrate up to where the aquifer is truncated 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 10 m and up to more than 200 m. 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 modeling study has been conducted on possible aquifers in the Froan Basin.

The Froan Basin is a sub-element of the Trøndelag Platform. It is bound by the Frøya High in the south, the Gimsan Basin and the Halten Terrace in the west, outcropping basement in the east and the Trøndelag Platform in the north. The Froan Basin was formed by Permian/early Triassic block faulting .The pre-Jurassic rocks of the Trøndelag Platform were deposited in NE-SW trending en echelon basins. In the early and middle Jurassic, the platform area subsided as one large basin and the rate of sedimentation was in equilibrium with the rate of subsidence. Consequently, there is a relatively uniform thickness of Jurassic sediments overlying the Triassic and locally Paleozoic graben fill. Reservoirs which could possibly be used for CO_2 injection are the Triassic and Jurassic sandstones. The main seal rocks are the middle - upper Jurassic Melke and Spekk shales as well as the overlying fine grained Cretaceous section. The main risk of leakage is the migration of CO_2 against the Quaternary layer.

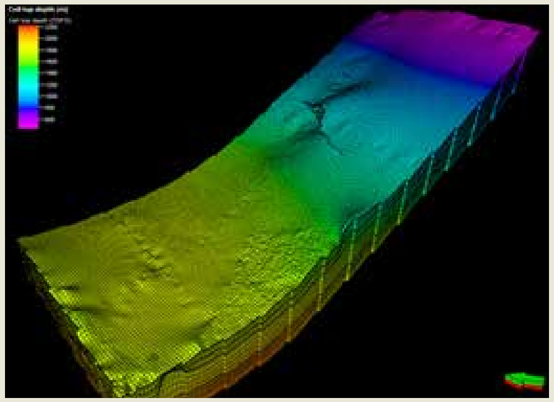
Based on simulation results (upscaling of sector model) about 400 mill tons CO_2 can be stored in the Garn and Ile aquifer (8 mill tons/year over 50 years). This will require 4 injection wells (2 mill tons/year per well) and yield acceptable pressure increase (<20bar). After 10000 years most of the gas will have gone into solution with the formation water or is residually trapped.



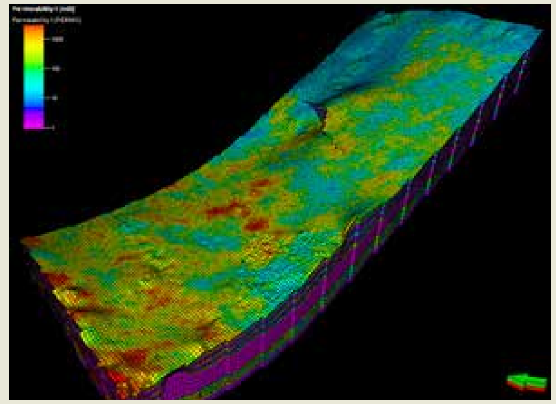
NW-SE profile showing the geometry of aquifers (yellow) and sealing formations (green) in the simulation model.



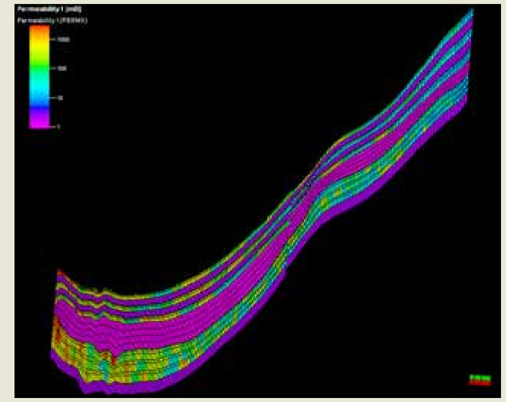
Froan Basin – long distance CO_2 migration



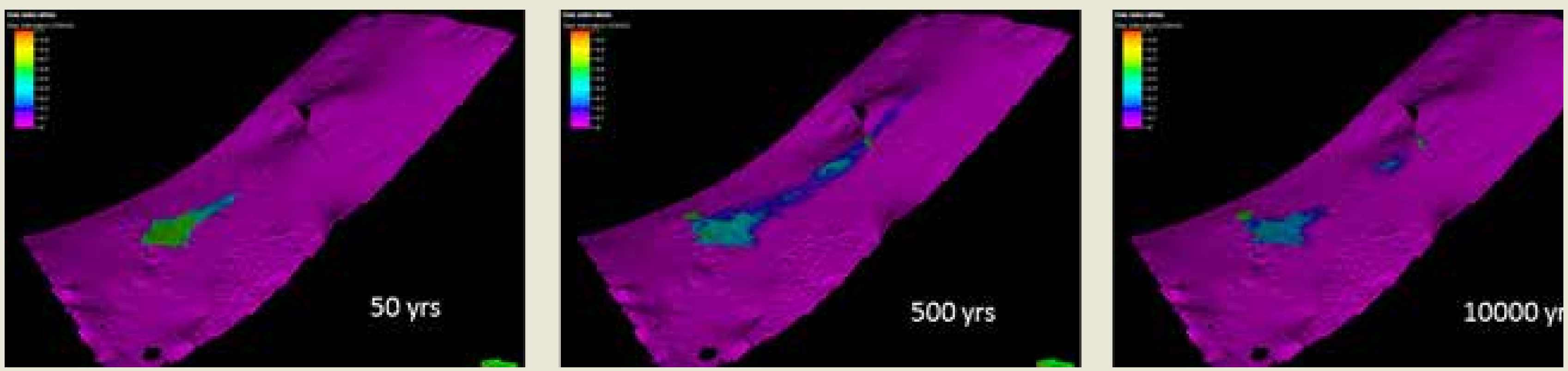
Simulation sector model, depths



Permeability distribution, top Garn



Permeability distribution, west-east cross-section



CO_2 plume top Garn vs. time. The size of the model is 16 x 35 km.

A simulation sector model of the Garn/Not/Ile Formations was built covering about 10% of the total expected communicating aquifer volume. Top structure (Garn) depth is about 1800m in the western area and becomes shallower towards east, with model cut-off at about 500m depth. The main storage reservoirs are Garn and Ile with average permeability of about 400mD, separated by tight Not shale. The Garn Formation consists of three reservoirs, separated by low permeable shale. The porosity and permeability have been stochastically modeled with both areal and vertical variation. The model layers are fine (<1m) at the top reservoir and underneath the shales to capture the vertical CO_2 saturation distribution.

The CO_2 injection well is located down dip, but alternative locations and injection zones have been simulated, with different injection rates. The injection period is 50 years, and simulation then continues for 10000 years to check the long term CO_2 migration effects.

The main criteria for evaluation of CO_2 storage volumes are acceptable pressure increase and confinement of CO_2 migration (no migration to eastern model boundary within 10000 years). CO_2 will continue to migrate upwards as long as it is in a free, movable state. Migration stops when CO_2 is permanently bound or trapped, by going into solution with the formation water or by being residually or structurally trapped (mineralogical trapping not considered). To achieve trapping of sufficient volumes, good spreading of the injected CO_2 is important. Vertical spreading can, to some extent, be controlled by injecting in lower reservoir zones, but is sensitive to vertical permeability and also zonal permeability distribution in the near well area. Areal spreading can mainly be achieved through use of several injectors.

The figures in the second row illustrate the free CO_2 saturation (green/blue) over 10000 years.

5.2 Saline aquifers

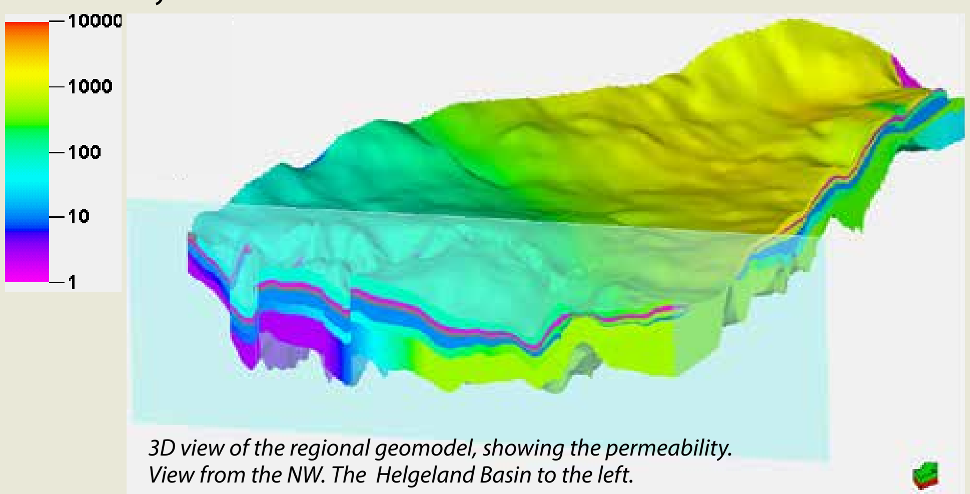
Storage capacity Tilje/Åre

In order to estimate the pore volumes and the storage capacities of the aquifers, a regional geomodel was built with the Petrel software. The model was set up with a 500x500 m grid in the horizontal directions. In the vertical direction, each formation was represented by one layer. Average values for net/gross and porosity were estimated from the logs and well reports from the exploration wells in the area and manually contoured between the wells.

The maps reflect the general shaling out trend of the Ile and Garn formations to the NE. The major faults which have a potential to form barriers between different segments of the aquifers were included in the model.

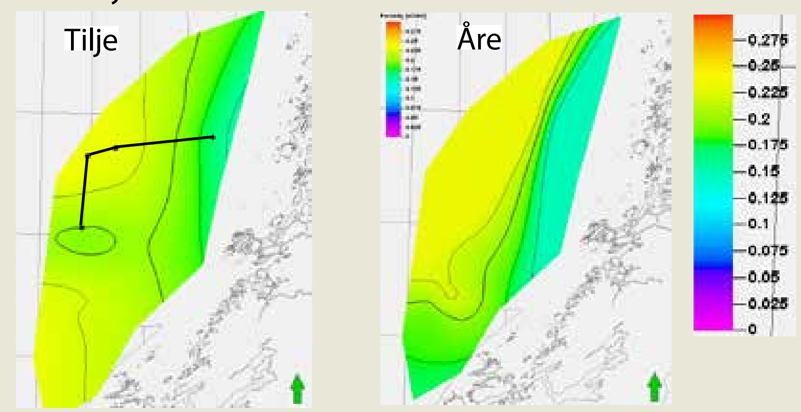
The purpose of this model was to calculate the total pore volumes of each aquifer and to evaluate how they are connected. The regional model cannot be used for simulation studies.

Permeability

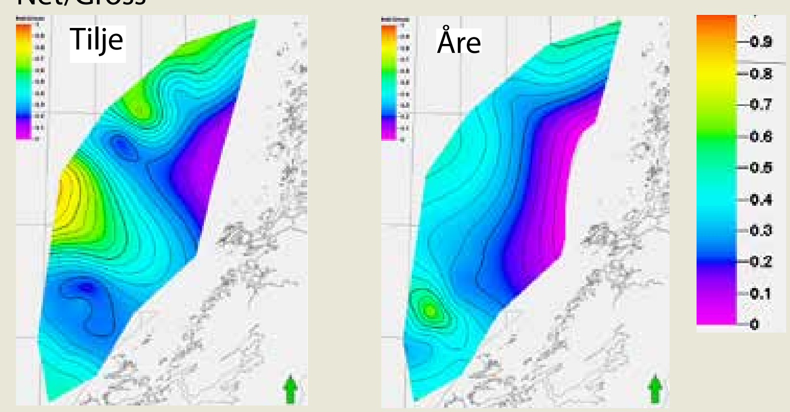


3D view of the regional geomodel, showing the permeability. View from the NW. The Helgeland Basin to the left.

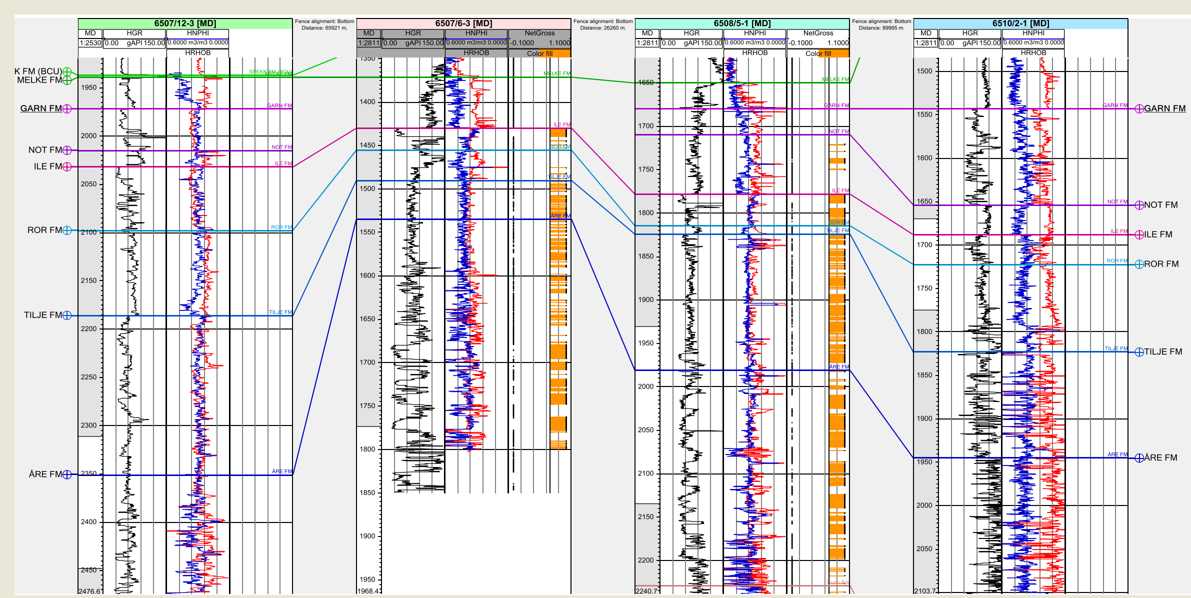
Porosity



Net/Gross



The Tilje/Åre aquifer		Summary
Storage system		closed
Rock volume, m^3		9.2E+12
Net volume, m^3		2.7E+12
Pore volume, m^3		0.6E+12
Average depth		1940 m
Average net/gross		0.30
Average porosity		0.21
Average permeability		140 mD
Storage effieciency		0.7 %
Storage capacity aquifer		4.0E+9 tons
Reservoir quality		
	capacity	2
	injectivity	2
Seal quality		
	seal	3
	fractured seal	2
	wells	3
Data quality		
Maturation		



Log correlation panel with gamma, porosity density and calculated net/gross. Layout showed in Tilje porosity map.

5.2 Saline aquifers

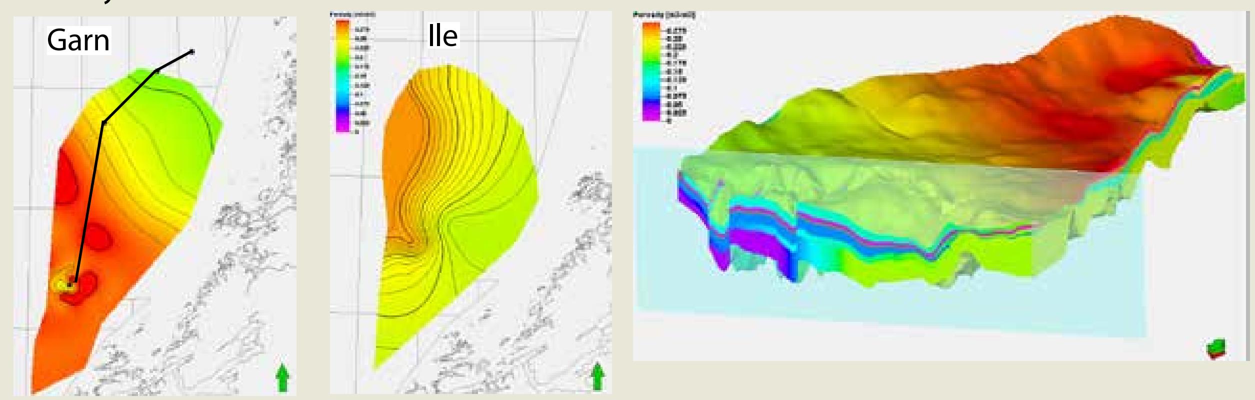
Storage capacity Garn/Ile

We have tested different approaches to estimate the storage capacities of the aquifers. One approach was to calculate the total pore volume and use a storage efficiency representing a closed system. A second approach was to calculate the pore volumes of the largest closed structures A, B and C presented below, and assume they are in communication with the larger aquifer (half open system). The third approach was the simulation of injection in the Garn-Ile aquifer presented above, where the injected CO_2 volume is restricted because it is not allowed to reach the coastal subcrop.

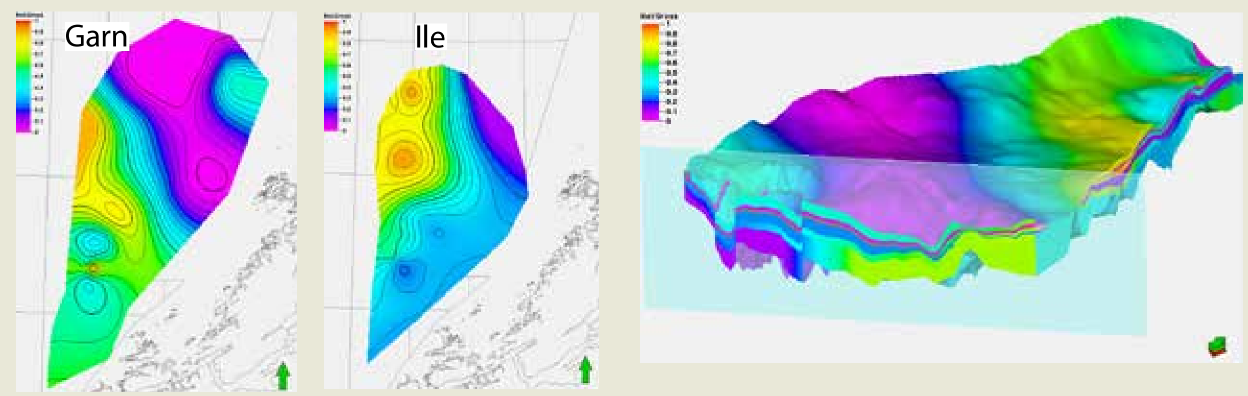
In the table below showing the results for the Garn – Ile aquifer, a half-open case and a closed case for the whole aquifer are presented to illustrate how important this assumption is for the estimates of storage volumes. Large volumes can theoretically be stored if the aquifer is in pressure communication with additional large water volumes. In the Garn-Ile case, such a pressure communication could be with the sea along the subcrop line. Another alternative to create a half-open system could be to inject CO_2 and produce water. The most optimistic case would be to assume that closed structures with a large storage capacity exist and could be filled with CO_2, without any migration to the half-open eastern boundary. Although interesting structures exist, we have not been able to identify such large storage volumes in closed structures in our mapping of the Garn-Ile aquifer. Based on the structures we can map and the simulations we have performed, we have chosen the lower estimate (closed aquifer) as the most likely scenario.

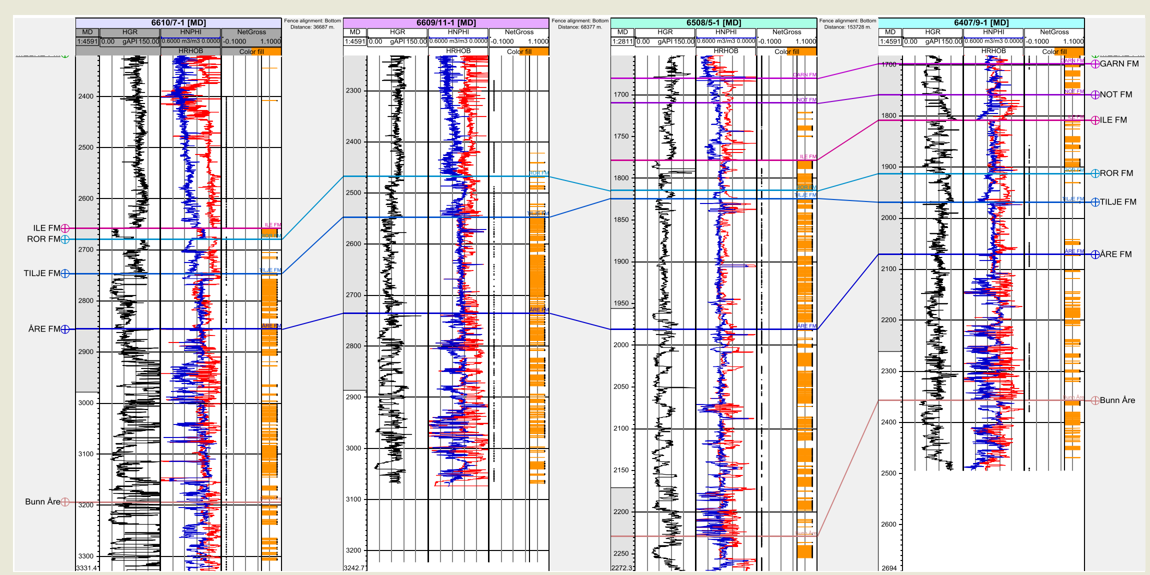
The Garn/Ile aquifer		Summary	Summary
Storage system		half open	closed
Rock volume, m^3		4.4E+12	4.4E+12
Net volume, m^3		1.1E+12	1.1E+12
Pore volume, m^3		0.3E+12	0.3E+12
Average depth Garn Fm		1675 m	1675 m
Average depth Ile Fm		1825 m	1825 m
Average net/gross		0.25	0.25
Average porosity		0.27	0.27
Average permeability		580 mD	580 mD
Storage effieciency		4 %	0.2 %
Storage capacity aquifer		8.E+9 tons	0.4E+9 tons
Reservoir quality			
	capacity	2	2
	injectivity	3	3
Seal quality			
	seal	3	3
	fractured seal	3	3
	wells	3	3
Data quality			
Maturation			

Porosity

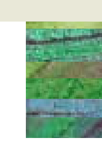


Net/Gross





Log correlation panel with gamma, porosity density and calculated net/gross. Layout showed in Garn porosity map.



5.2 Saline aquifers

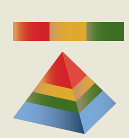
Possible injection prospects

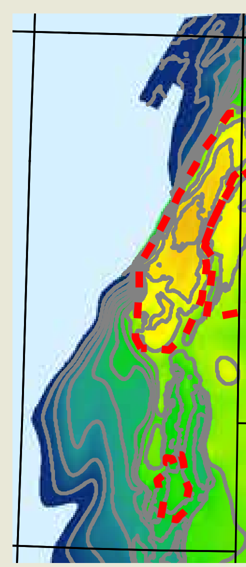
CO_2 can be injected in closed structures or in open aquifers. In a closed structure, the amount of CO_2 injected will be restricted by the maximum frac'ing pressure of the structure with a safety margin. Some of the CO_2 will be trapped as free CO_2 by the seal of the structure, some dissolved in the water. In an open aquifer the amount of CO_2 will not be restricted by pressure but can gradually be trapped as residual and dissolved CO_2 in the water phase. In the Trøndelag Platform and Nordland Ridge, both alternatives have been studied. The map shows the outlines of 5 large closed structures which have been identified in the study. Structure A and B are located SE of the Helgeland Basin, and comprise only the Åre-Tilje Trøndelag Platform aquifer. Structure C is bounded by the Ellingråsa Graben to the west, and could trap CO_2 in all the aquifers of the Trøndelag Platform. Structure D belongs to the Nordland Ridge Åre Formation aquifer, while structure E is located in the Ellingråsa Graben, outside the Trøndelag Platform aquifer. The volumes of structures D and E are listed in the table. The volumes of prospects A, B and C are included in the calculation of the Trøndelag Platform aquifers. In a closed aquifer, the limiting factor of the volume which can be injected is the total pore volume of the aquifer, not the pore volume of the structure.

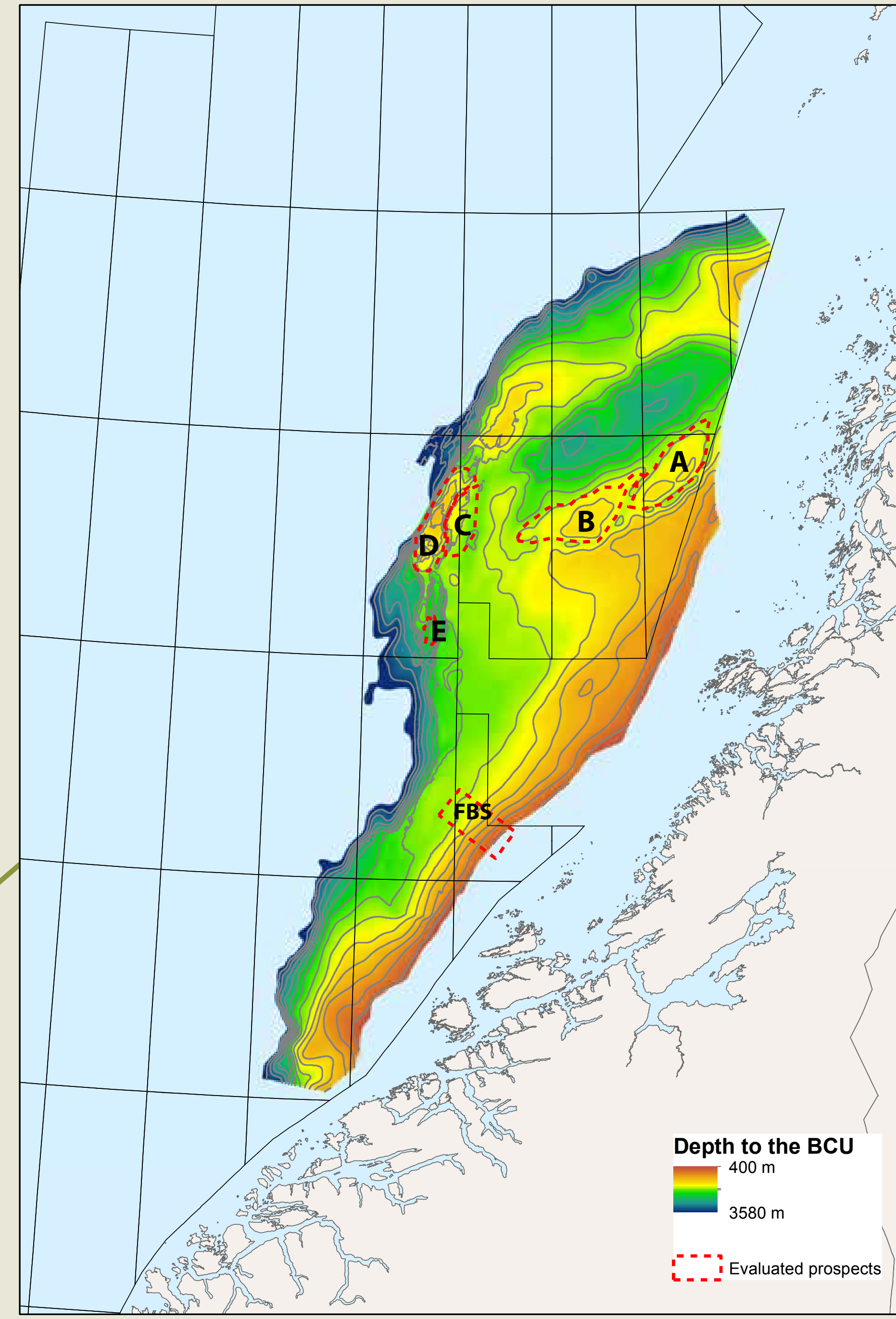
Seismic mapping was also carried out east of the Frøya High, south of the Draugen Field to investigate for closed structures suitable for CO_2 trapping in that area. It was concluded that such structures may exist, but there is uncertainty related to their definition on 2D seismic data and to how far petroleum has migrated into the area east of the Frøya High.

The rectangle in the map shows the model area for the study of open aquifer injection into the Ile and Garn Formations.

Prospects			
Prospect name		D	E
Storage system		Half open	Open
Rock volume, m^3		2.7E+11	1.0E+10
Net volume, m^3		0.5E+11	0.4E+10
Pore volume, m^3		1.4E+10	1.E+9
Average depth		1300	2200
Average net/gross		0.3	0.4
Average porosity		0.26	0.25
Average permeability		140 mD	300mD
Storage efficiency		1 %	10 %
Storage capacity prospect		0.1E+9 tons	0.07E+9 tons
Reservoir quality			
	capacity	3	2
	injectivity	2	2
Seal quality			
	seal	2	3
	fractured seal	3	3
	wells	3	3
Data quality			
Maturation			







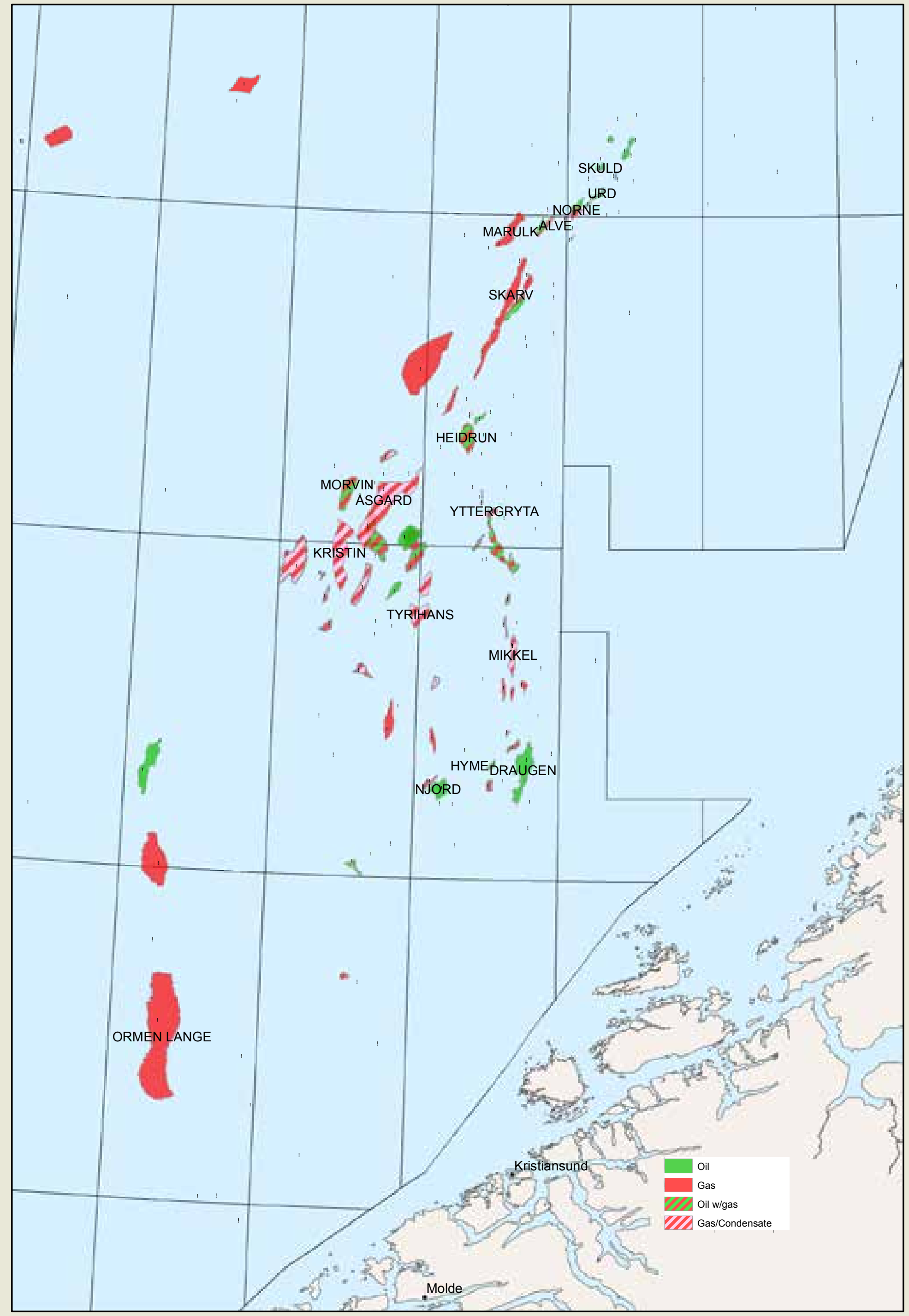
Regional BCU map showing the locations of prospects A to E and the location of the simulation grid in the Froan Basin (FBS). The map to the left is zoomed in on structures C, D and E.

5.3 Abandoned hydrocarbon fields

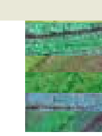
The estimate of CO_2 storage potential in the petroleum provinces is based on abandoned fields. This is in accordance with the Government policy that any negative consequences of CO_2 storage projects for existing and future petroleum activity should be minimized.

At the end of 2012, there are no abandoned fields in the Norwegian Sea. Seven of today's producing fields have been evaluated for CO_2 storage. Two of the fields are gas fields and five are oil fields. The oil fields may have an EOR potential because they contain remnants of hydrocarbons that might be mobilized and produced during the injection of CO_2. The CO_2 storage capacity for today's producing fields is estimated based on the end of the production year, and summarized for the years 2030 and 2050. The gas fields will have low pressure and the oil fields will have low oil rate and a high water cut. For the gas fields, no EOR potential is calculated. For the oil fields, the CO_2 storage capacity has been calculated as if some of the oil is removed as EOR oil. The calculated CO_2 stored volumes are listed in the table.

Abandoned fields	Storage capacity, Gtons
Producing fields	
Closure of production 2020 -2030	0.9
Closure of production 2030 -2050	0.2



Hydrocarbon fields in the Norwegian Sea.



5.4 Producing fields (EOR)

Injection of CO_2 in oil fields has, for many years, been used to enhance oil recovery (EOR), primarily in the USA where the CO_2 has been available from natural CO_2 sources. Most of the CO_2 has been stored during the enhanced recovery process. On the Norwegian Shelf, several oil fields have been examined with regard to EOR using CO_2. Some of the fields seem to be promising candidates from a technical point of view. Others are not suitable due to reservoir conditions or negative project economy. In the Norwegian Sea, two fields have been studied as discussed below. In addition to enhanced oil recovery, a significant amount of CO_2 can be stored in these fields.

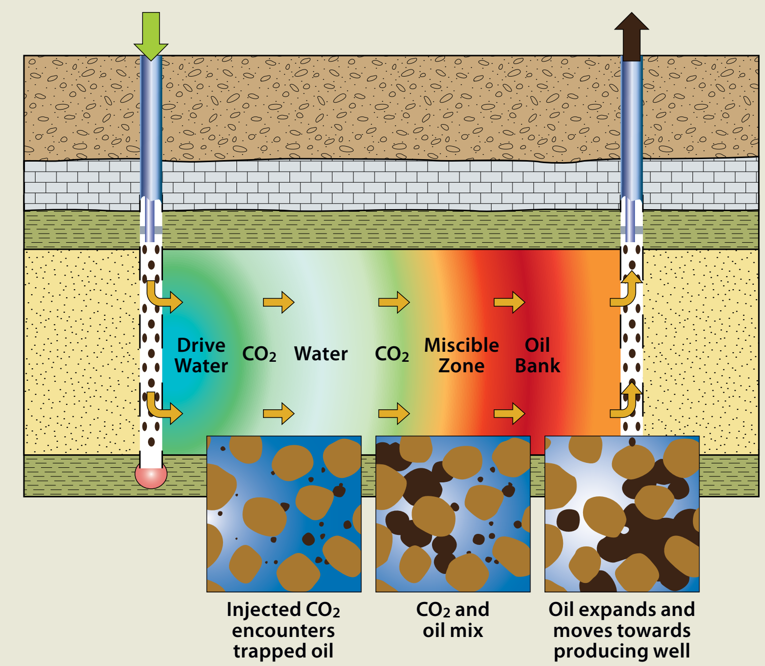
A study carried out by the Norwegian Petroleum Directorate (NPD) in 2005, indicated additional oil recovery with use of CO_2 in the order of 3–7 percent from fields of interest. To secure good recovery of oil, it is important to have enough CO_2 and the best effect is obtained when CO_2 and oil are miscible in the reservoir. Sweep efficiency of CO_2 flooding can be improved by applying WAG (alternating injection of CO_2 and water).

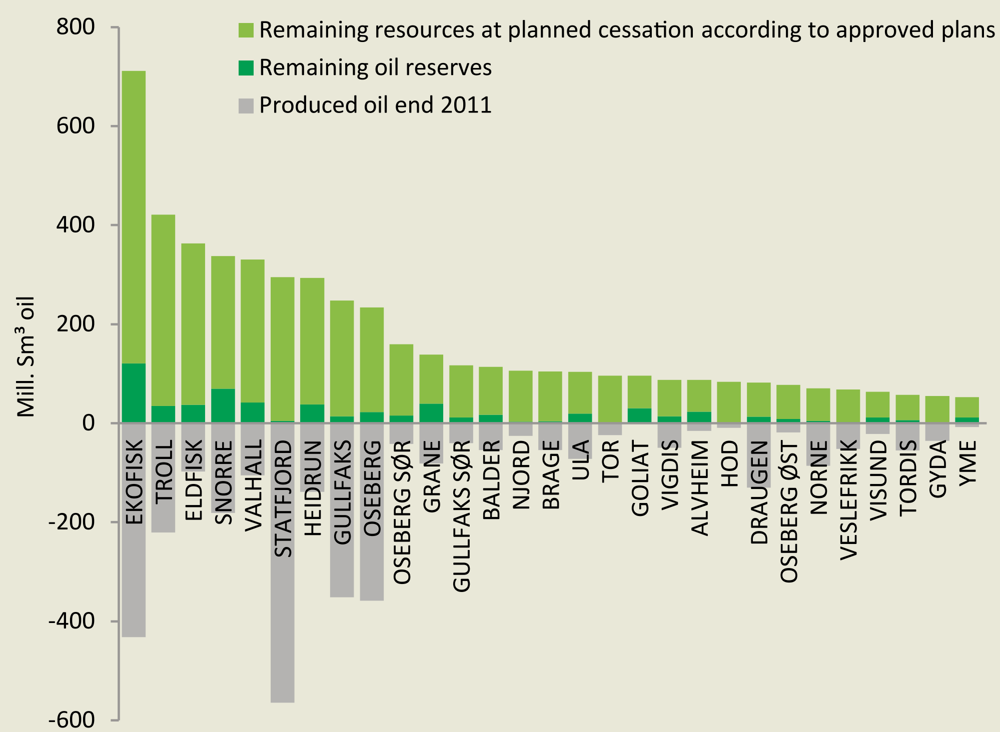
When CO_2 is injected and mixes with water in the reservoir, it will create a corrosive mixture which can cause problems in connection with breakthrough in the producing wells and in the process equipment on the platform. This has to be taken into account when planning CO_2 flooding on a field.

In the Norwegian Sea there are a couple of fields that have been looked at as CO_2 EOR candidates. In 2006, Shell and Statoil announced a co-operation to develop a large-scale CO_2 EOR project on Draugen and Heidrun, and also supply the fields with electric power from shore. A pipeline from Heidrun would supply a gas power station on Tjeldbergodden with gas. The gas power station would deliver 2.5 million tonnes of CO_2 for injection. The studies showed an increase in recovery of 2.6% (of OIIP). High modification and rebuilding costs for the facilities resulted, however, in negative project economics. The oil price at the time of study was $60/bbls. The study showed that use of CO_2 in the Heidrun Field after planned injection in Draugen was not an optimal solution. It was too little available CO_2 for good recovery.

When the gas power station was cancelled, the studies were not continued.

Cross section of a reservoir with CO_2 WAG





5.5 Summary of aquifer evaluation

The results of the evaluation of the aquifer storage capacity is summarized in the tables. The Trøndelag Platform including the Nordland Ridge is the area which is best suited for CO_2 storage. A thick Jurassic section is present, and has been divided in two aquifers. The burial depth is typically 1500-2000 m and the reservoir quality of the clean sandstones is excellent.

The lower Åre-Tilje aquifer is distributed over the whole area and the potential injection volume is calculated to approximately 4Gt. The reservoir is heterogeneous, dominated by fluvio-deltaic to tidal deposits and the connectivity both on a local and regional scale is uncertain. The upper Ile and Garn aquifers are developed as good reservoirs in the southern part (Froan Basin). The Garn reservoir has the best permeability and connectivity of the Jurassic sandstones. All the aquifers are subcropping towards the sea floor along the coast. The thickness of the Quaternary cover is variable. CO_2 injection projects should be planned to avoid long distance migration towards the subcrop and possible further seepage to the sea floor. Modelling of injection in the aquifer indicates that it is possible to inject at a rate and volume where the CO_2 is trapped and/or dissolved before it reaches the subcrop area. The conclusion is that the Garn and Ile storage capacity is relatively low, about 0.4 Gt.

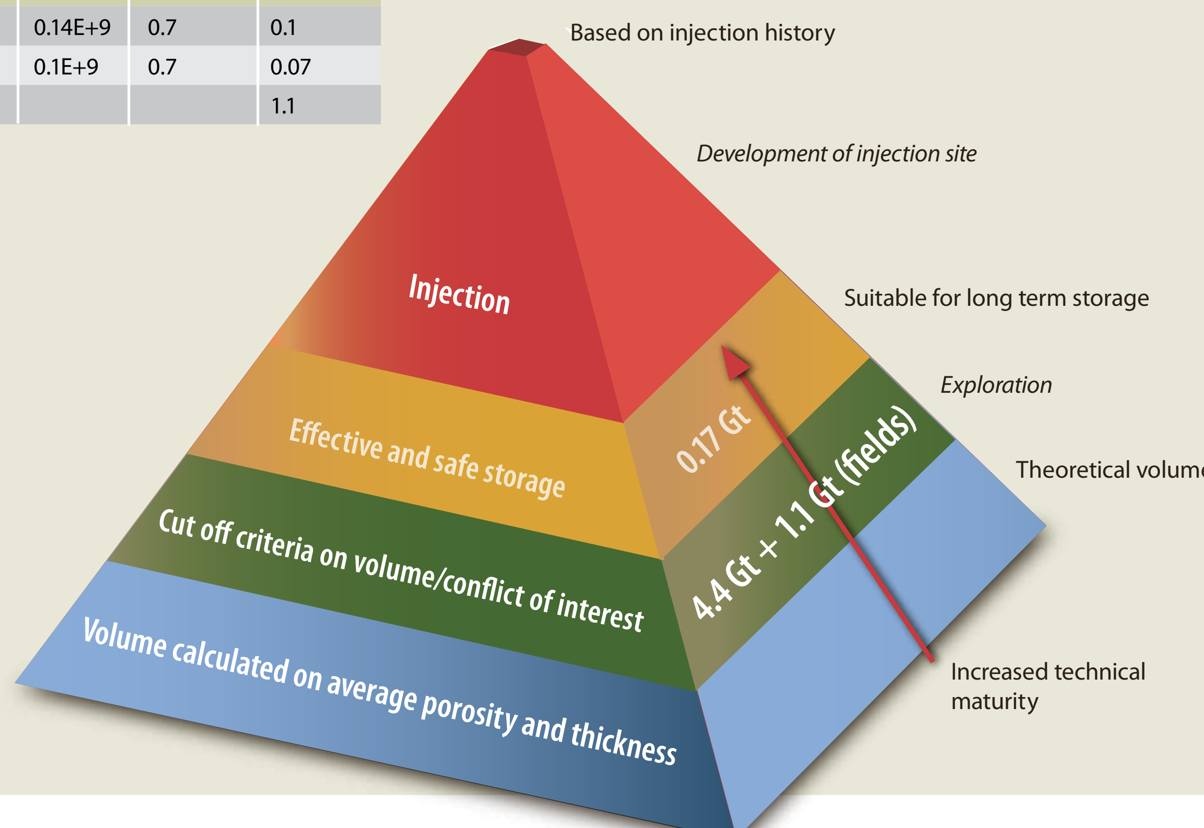
Five large structural closures have been identified. Two of them (structures D and E) are located outside the Trøndelag Platform and add storage capacity to the area. Structures D and E are covered by 3D seismic data and wells and are regarded as more mature than the other structures and evaluated aquifers.

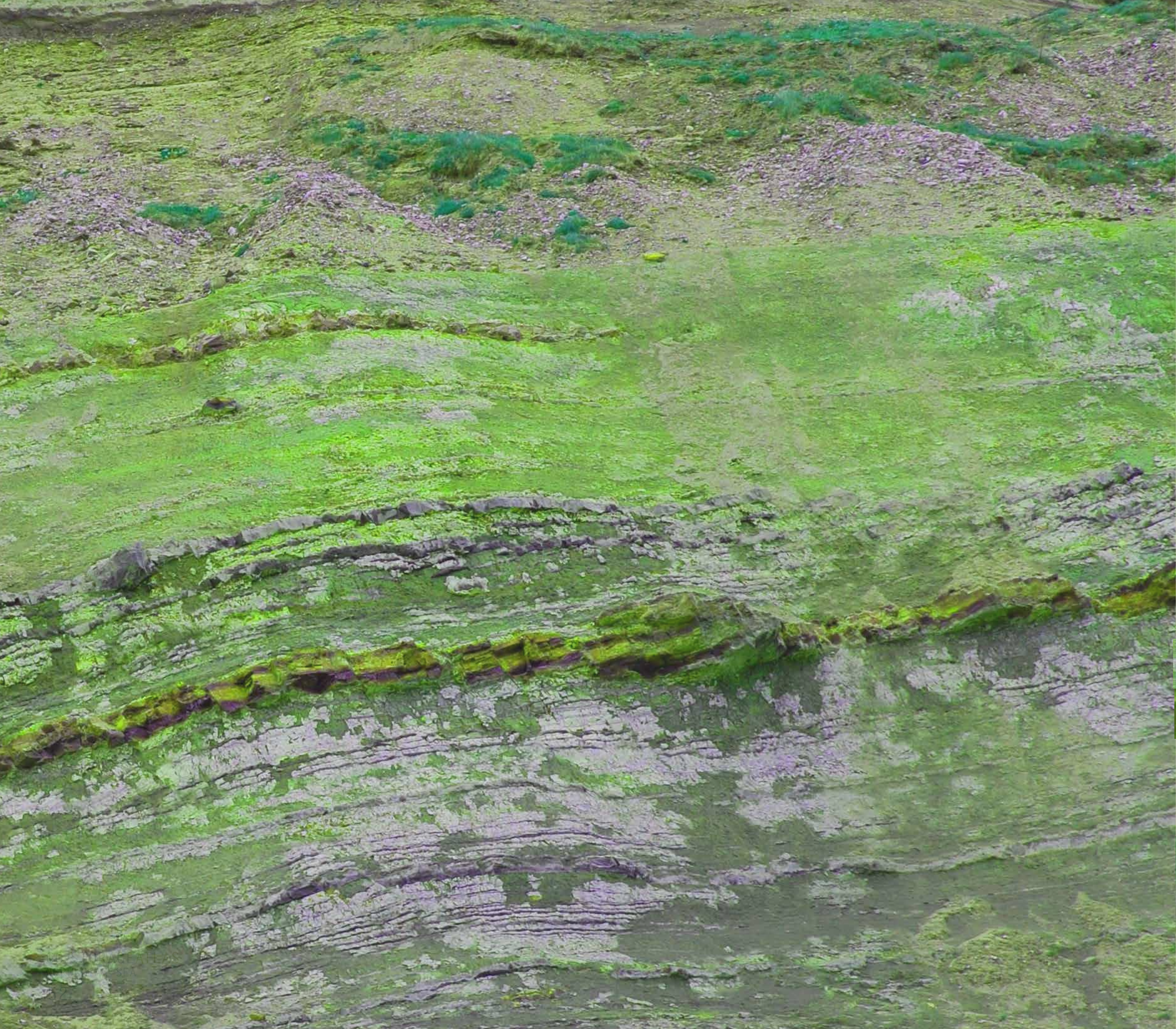
The Møre Margin is geologically different from the Trøndelag Platform, and does not seem to hold a large storage potential due to the proximity to deep basins and subcropping aquifers.

In the petroleum provinces, the storage potential was calculated from the extracted volume of hydrocarbons in depleted fields. Such storage will usually require a 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 increased recovery by CO_2 injection. Studies of EOR by CO_2 injection were performed some years ago for the Draugen and Heidrun fields.

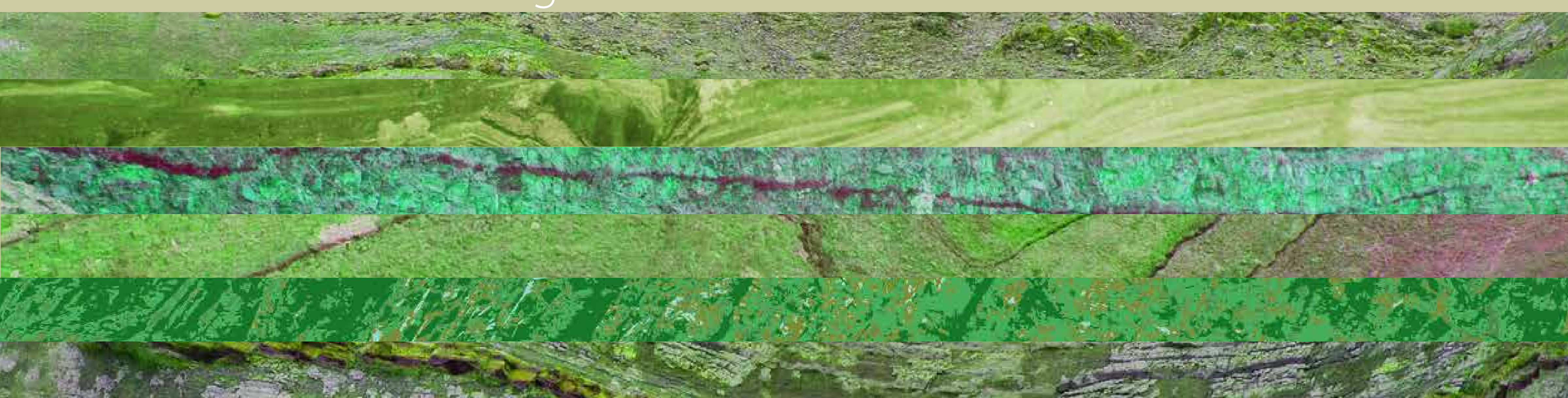
Evaluated aquifers	Avg depth	Bulk volume	Pore volume	Avg K	Open/closed	Storage eff	Storage volume	Density	Storage capacity
Unit	*m*	*Rm^3*	*Rm^3*	*mD*		*%*	*Rm^3*	*tons/Rm^3*	*Gtons*
Garn/Ile	1675	4.4E+12	0.3E+12	580	closed	0.2	0.6E+9	0.7	0.4
Tilje/Åre	1940	9.2E+12	0.6E+12	140	closed	1	6.0E+9	0.7	4.0
Evaluated prospects									
Prospect D Åre	1300	2.7E+11	1.4E+10	140	half open	1	0.14E+9	0.7	0.1
Prospect E Åre-Tilje, Ile-Garn	2200	1.0E+10	1.0E+9	300	open	10	0.1E+9	0.7	0.07
Producing fields									1.1

For the Norwegian Sea, the total storage capacity in the green level of the pyramid is estimated to be 5.5 Gigatonnes. In the more mature areas (yellow level) the capacity is estimated to be 0.17 Gigatonnes





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 CO2 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.

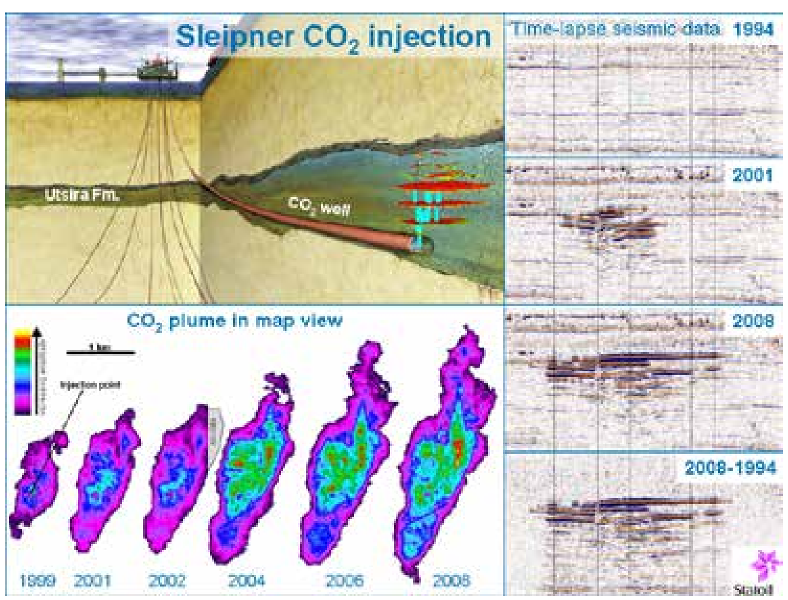


Figure of the Sleipner *CO_2 injection 4-D seismic monitoring. Upper left: sketch of the injection well and storage reservoir. To the right is a seismic section along the long axis of the plume (south-west to north-east) for different vintages and for a time-lapse difference. Note the lack of reflectivity 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.*

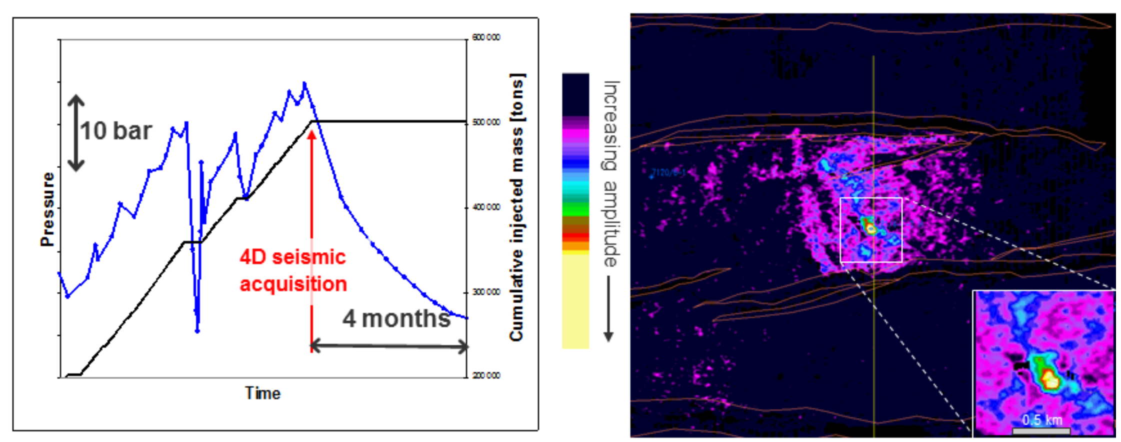


Figure from the Snøhvit *CO_2 injection. Left: Cumulative injection (black line) and estimated bottom-hole pressure (blue line) spanning year 2009, showing pressure increase during periods of injection and pressure fall-off during stops. The timing of a 4-D seismic survey is shown in the figure. Right: 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.

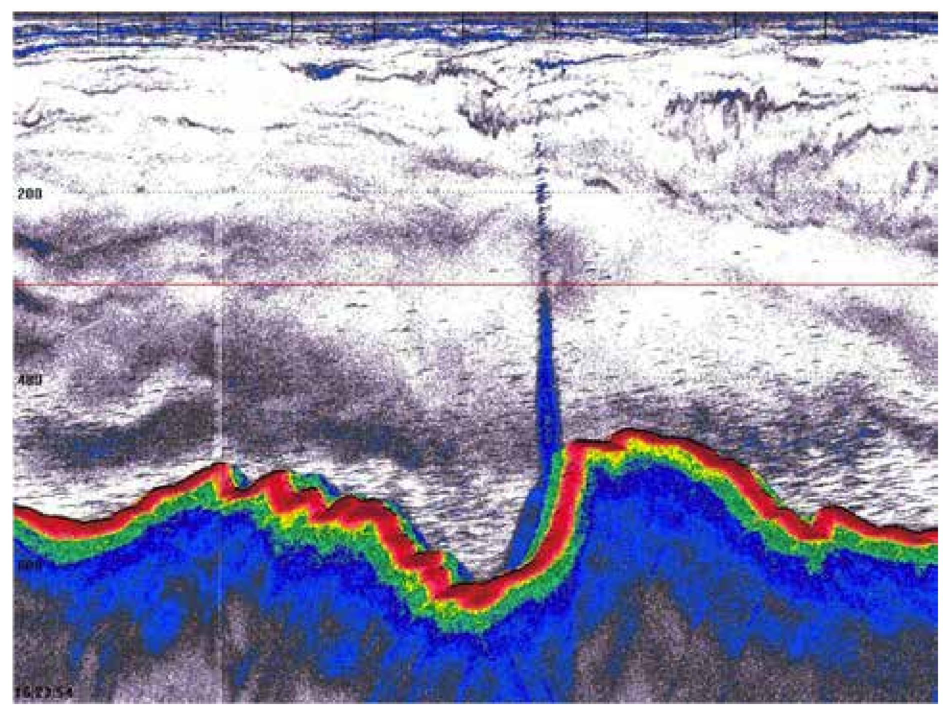
Seafloor monitoring programs are now being designed to detect CO_2 leakages and such early warnings. These schemes include: 1) scanning of the water column with acoustic systems to reveal any changes in the release of gas bubbles from the seafloor; 2) acoustic imaging of the seafloor at ultrahigh resolution 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.

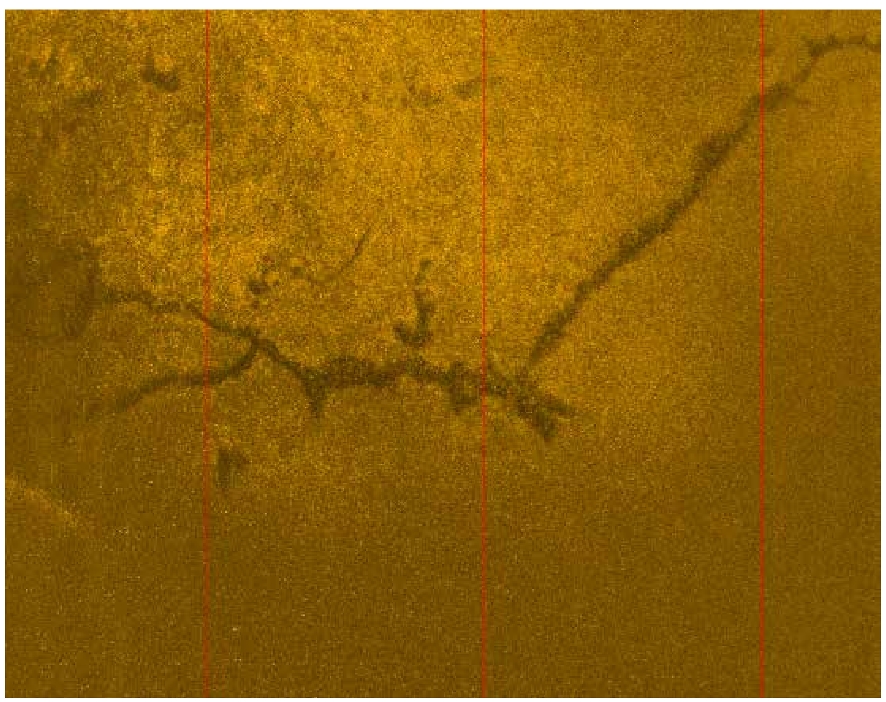


Detection of gas bubbles by echo sounder systems. The figure shows the acoustic signature generated by CO_2 bubbles being naturally released from the Jan Mayen vent fields. The CO2 bubbles are here seen as a blue flare that rises around 500 metres from the seafloor through "clouds" of plankton in the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

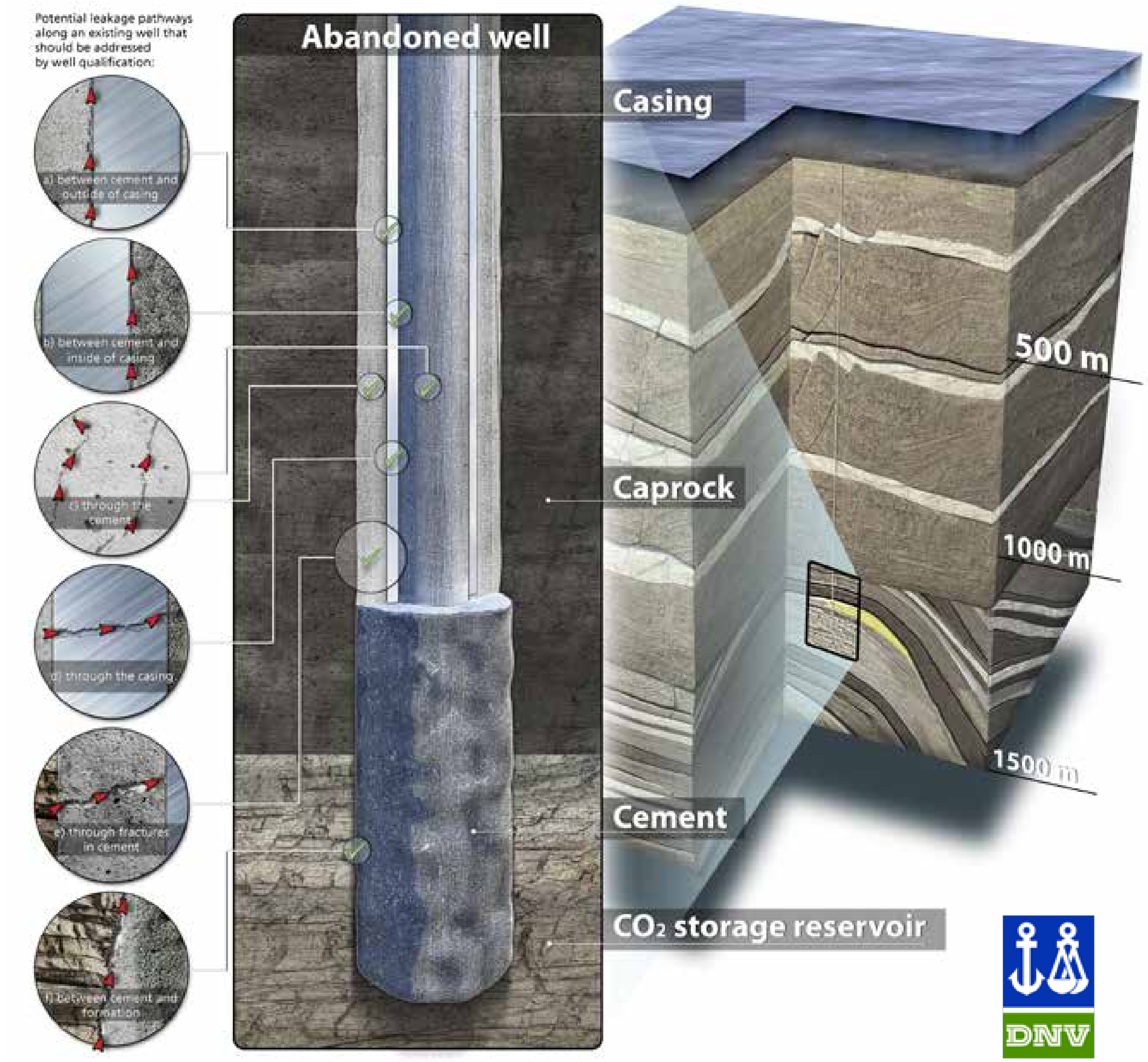
Detection of seafloor fluid flow using biologic signatures. The photo mosaic shows white bacterial mats that form a distinct biologic signature of fluid flow across the seabed. (sea star for scale)

Centre for Geobiology

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)**

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Web resources:

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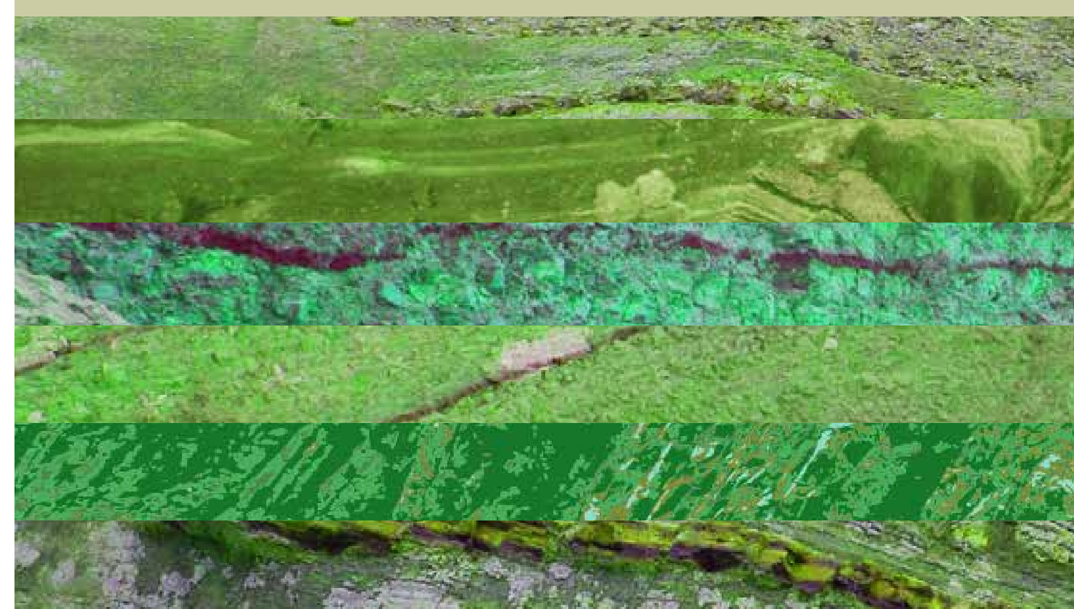
CO2CRC: *http://www.co2crc.com.au/*

Geocapacity: *http://www.geology.cz/geocapacity*

GESTCO: *http://www.geus.dk/programareas/energy/denmark/co2/GESTCOsummary_report_2ed.pdf*



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