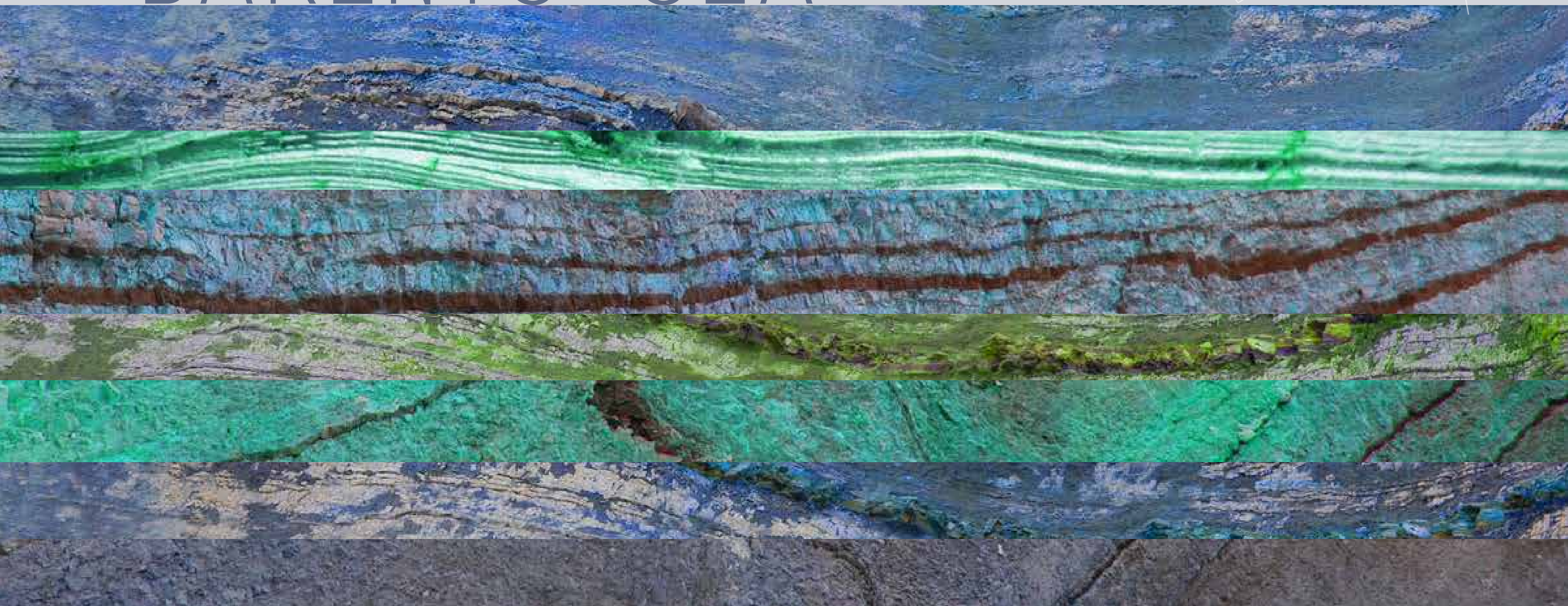
NORWEGIAN PETROLEUM DIRECTORATE

CO_2 STORAGE ATLAS

BARENTS SEA



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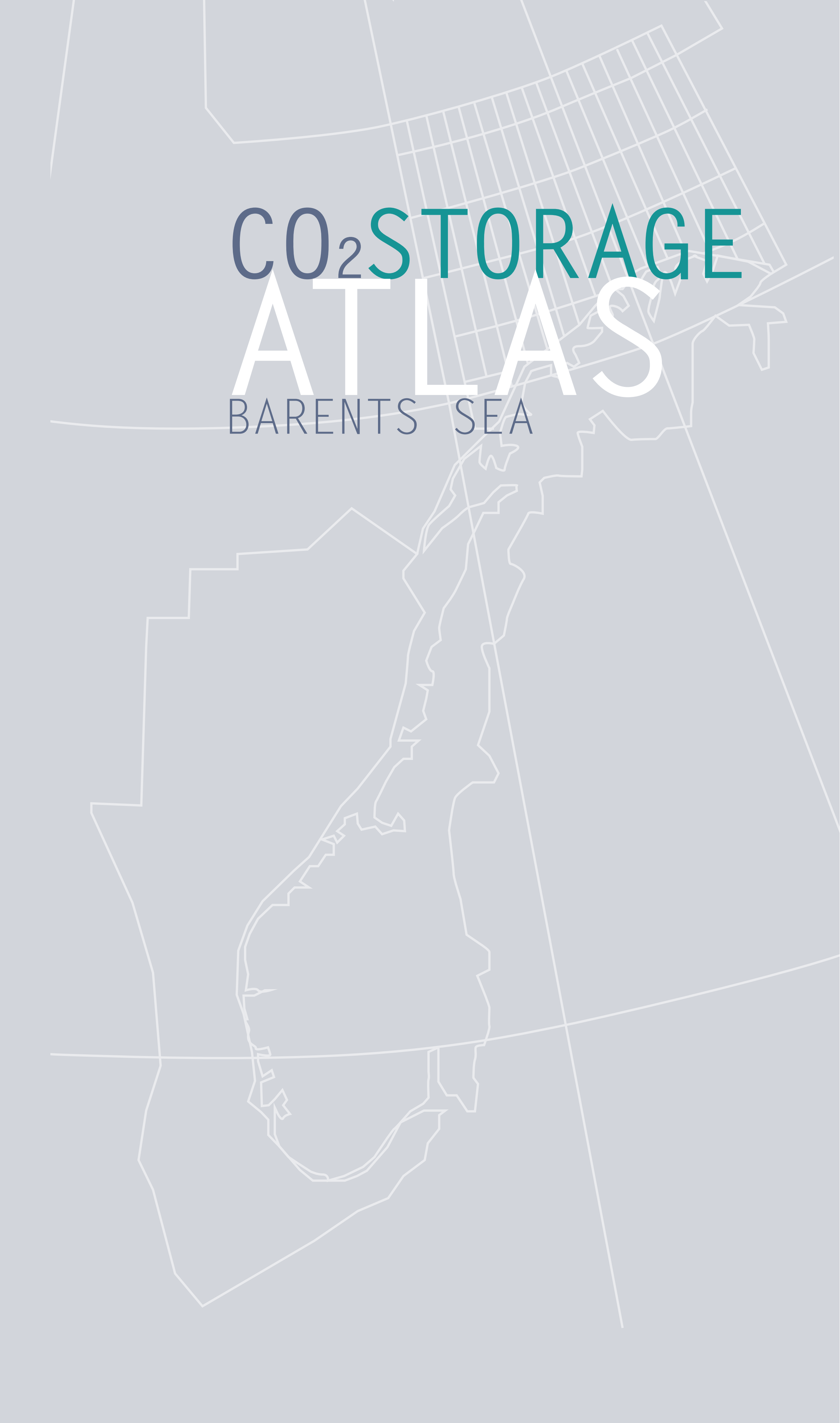
Norway's (Scandinavia's) first resource map, Olaus Magnus, 1539



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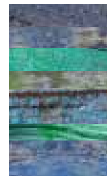

Preface

The CO_2 Storage Atlas of the Barents Sea has been prepared by the Norwegian Petroleum Directorate, at the request of the Ministry of Petroleum and Energy. The studied areas are located 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, discoveries and hydrocarbon fields in the Barents 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.

9 geological formations have been 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 and some of them were further assessed.

A study of the CO_2 storage potential in relevant dry-drilled structures and mapped structures in the area is provided. CO_2 storage in enhanced oil recovery projects is also discussed and a new study of CO_2 for EOR and CO_2 injected in residual oil zones has been outlined.

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 fulfill 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, Dag Helliksen, Alexey Deryabin and Rune Mattingsdal (NPD) for constructive contributions. The Norwegian CO_2 Storage Forum has contributed with its expertise in our meetings over the last four years. Arne Graue (University of Bergen), Ola Eiken (Statoil), Per Aagaard (University of Oslo), Erik Lindeberg (SINTEF), 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

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 annually 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.

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.*

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

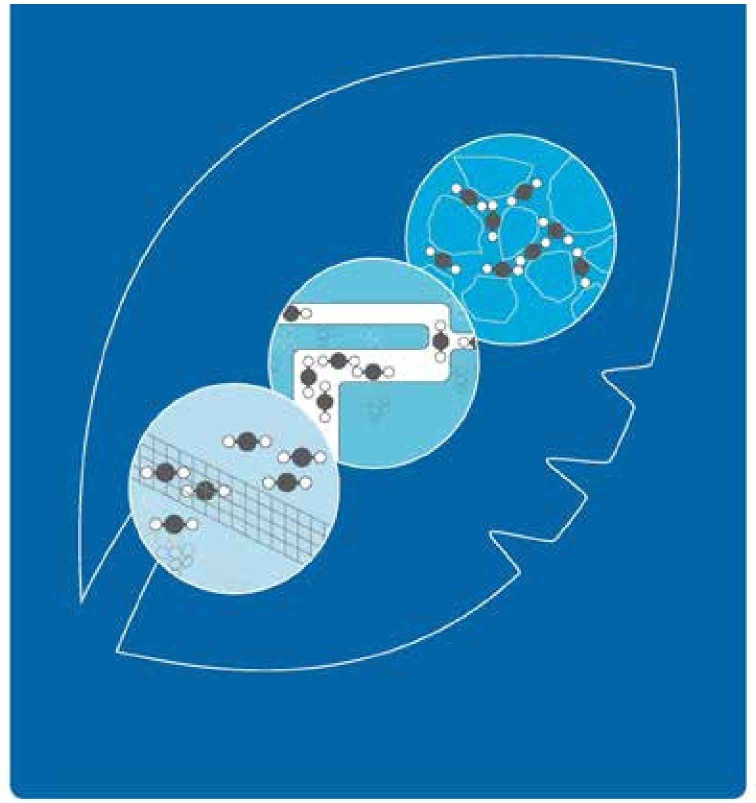
Gassnova will focus on co-funding projects that are considered to have a clear commercial potential and that include a market-based business plan. A detailed description of the program strategy is found in the program plan on *www.climit.no*

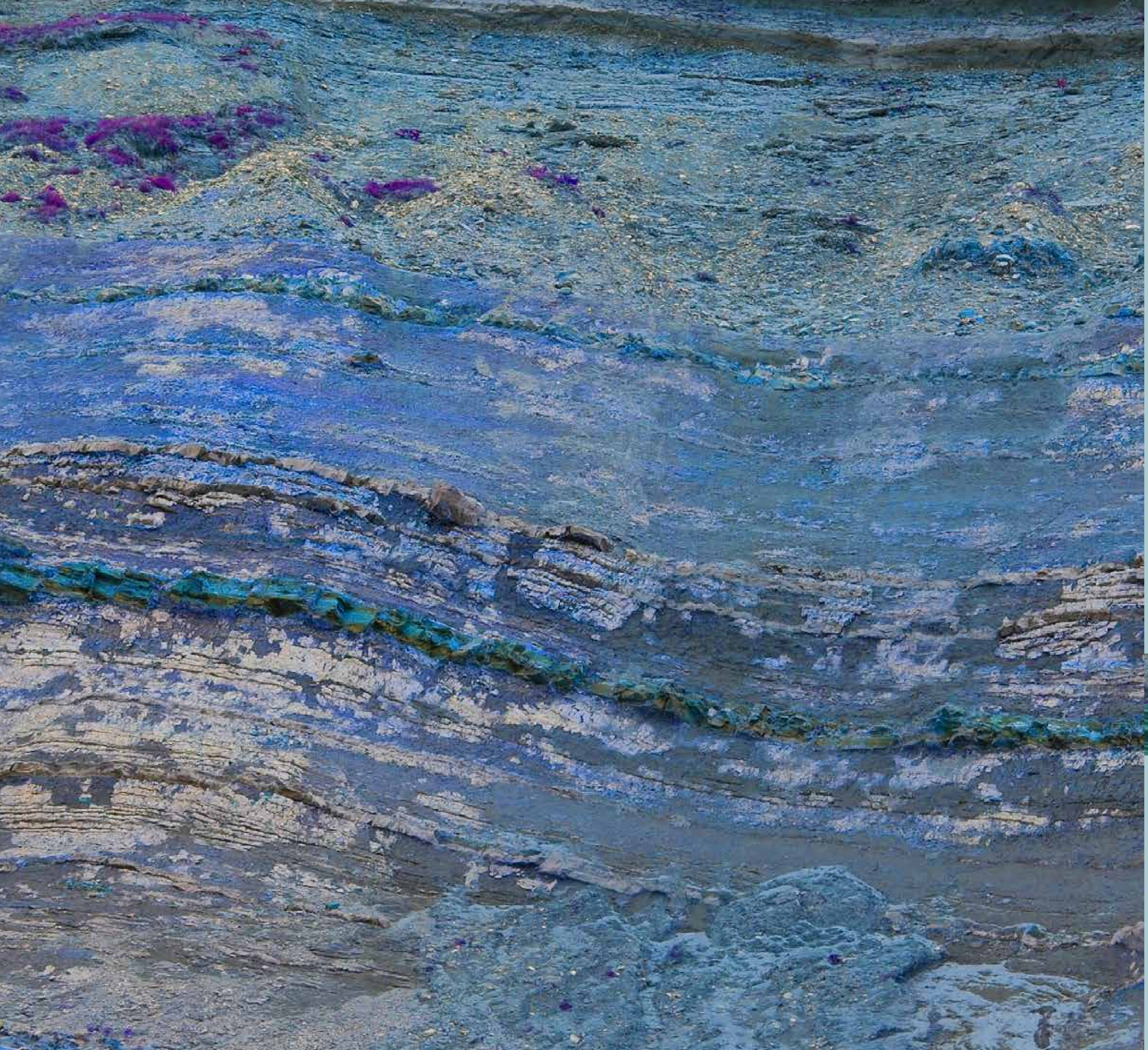
For investment in CO_2 storage, the following main objectives have been identified:

- 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.

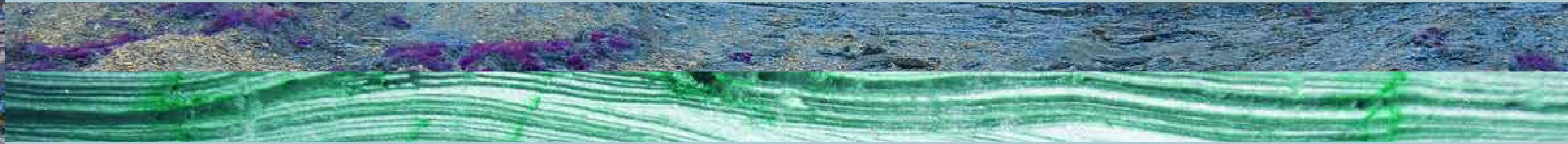
The primary focus for the work on CO_2 storage is to support the development of geological storage of CO_2. This involves storage in water-bearing formations located deep enough to keep the CO_2 in a dense phase. Through the petroleum industry and our storage options on the shelf, Norway is in a good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

CLIMIT





2. Petroleum activity in the Barents Sea



2. Petroleum activity in the Barents Sea

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 petroleum activity gradually expanded northwards. 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.

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 still are, 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, 76 fields are in production on the NCS. Twelve fields have been abandoned of 31 December 2012. However, there are re-development plans for some of these abandoned fields.

Production on the NCS is still high. In 2012, Norway was the world's seventh largest exporter of oil and the third largest exporter of natural gas (2011). 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 Barents Sea is considered an immature petroleum province. The Barents Sea is part of the Arctic Ocean. The area covers 1.3 million km2 and the water depth varies between 200 and 500 m, and is as shallow as than 50 m in the Spitsbergen Bank.

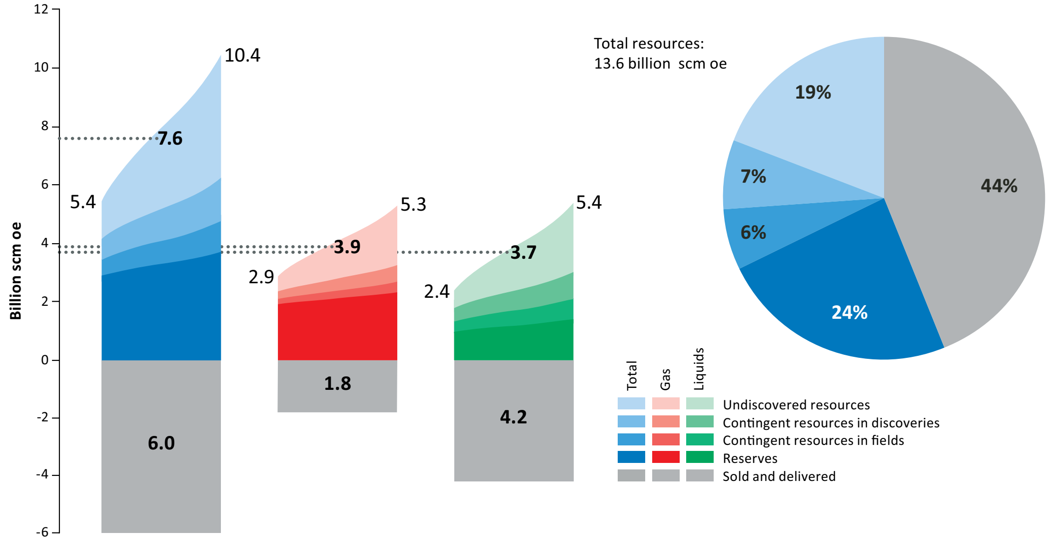
Generally the water in the Barents Sea circulates counter clockwise, in such a way that relatively warm water (a branch of the Norwegian Atlantic current) penetrates the south, and cold Arctic water (Bjørnøy Stream) flows southwest through the northern part. This heat flow keeps the southern part of the Barents Sea ice-free during winter.

The southern part of the Barents Sea is in general opened for petroleum activities, with the first announcement in 1979. Through numbered concession rounds and awards in predefined areas (APA) we see a growing interest in the area. Today there are 53 active licenses in the Barents Sea. Approximately 100 exploration wells has been drilled in the Barents Sea, which around 80 wildcats,which resulted in around 35 discoveries. It has been proven roughly 390 billion scm of gas and 210 million scm of liquids in the Barents Sea reported by the end of December 2012.

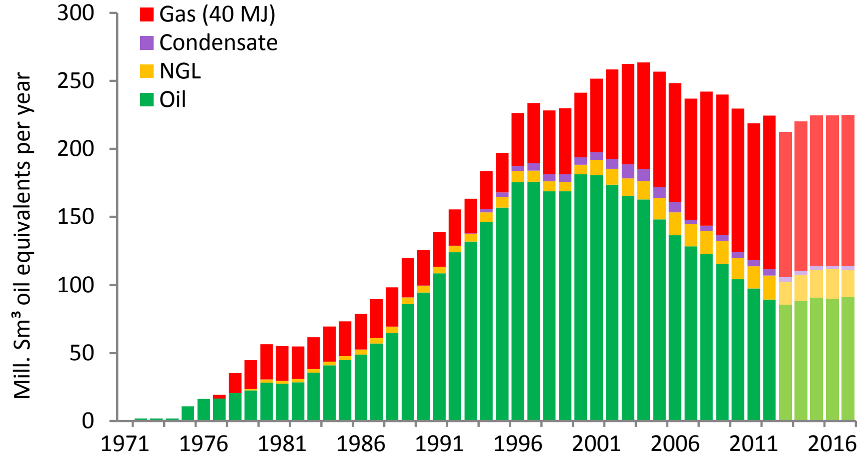
The first wildcats in the Barents Sea were spudded in 1980. The first discovery was made by the third wildcat, 7120/8-1 Askeladd. The biggest gas discovery is 7121/4-1 Snøhvit drilled in 1984. The Snøhvit gas field also comprises four discoveries made prior to 7121/4-1 Snøhvit and the development comprise 8 discoveries.

The Upper Triassic to Middle Jurassic play in the Hammerfest Basin is the most thoroughly explored Barents Sea play. This is where the Snøhvit discovery was made. The play also embraces the Goliat oil field, currently under development. Although drilling began in this area in 1980, there have been periods with few wells and small discoveries, particularly in the 1990s. Petroleum activities in the Barents Sea were temporarily suspended for a couple of years soon after 2000.

Little exploration has taken place in the Lower to Upper Triassic play on the Bjarmeland Platform. Approximately 10 wildcats have been drilled and three gas discoveries made, with 7225/3-1 (Norvarg) as the largest. The first well

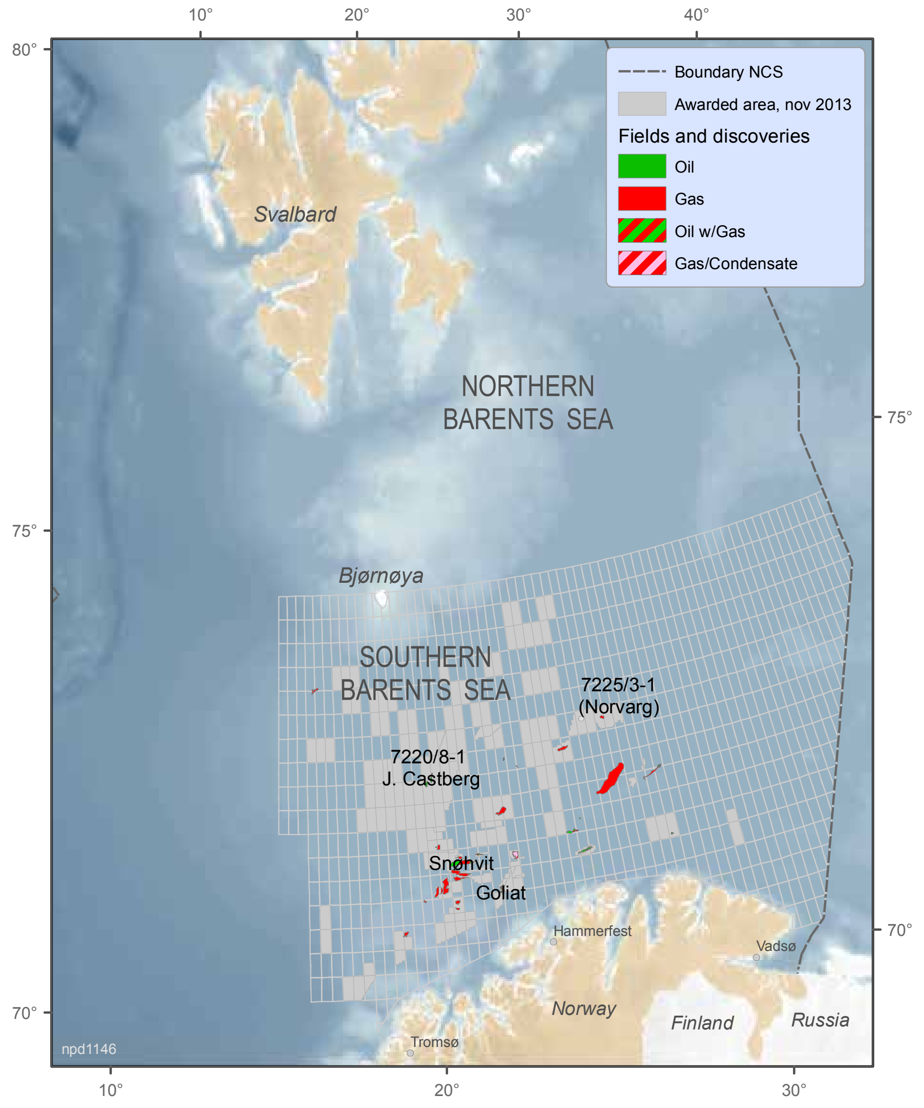


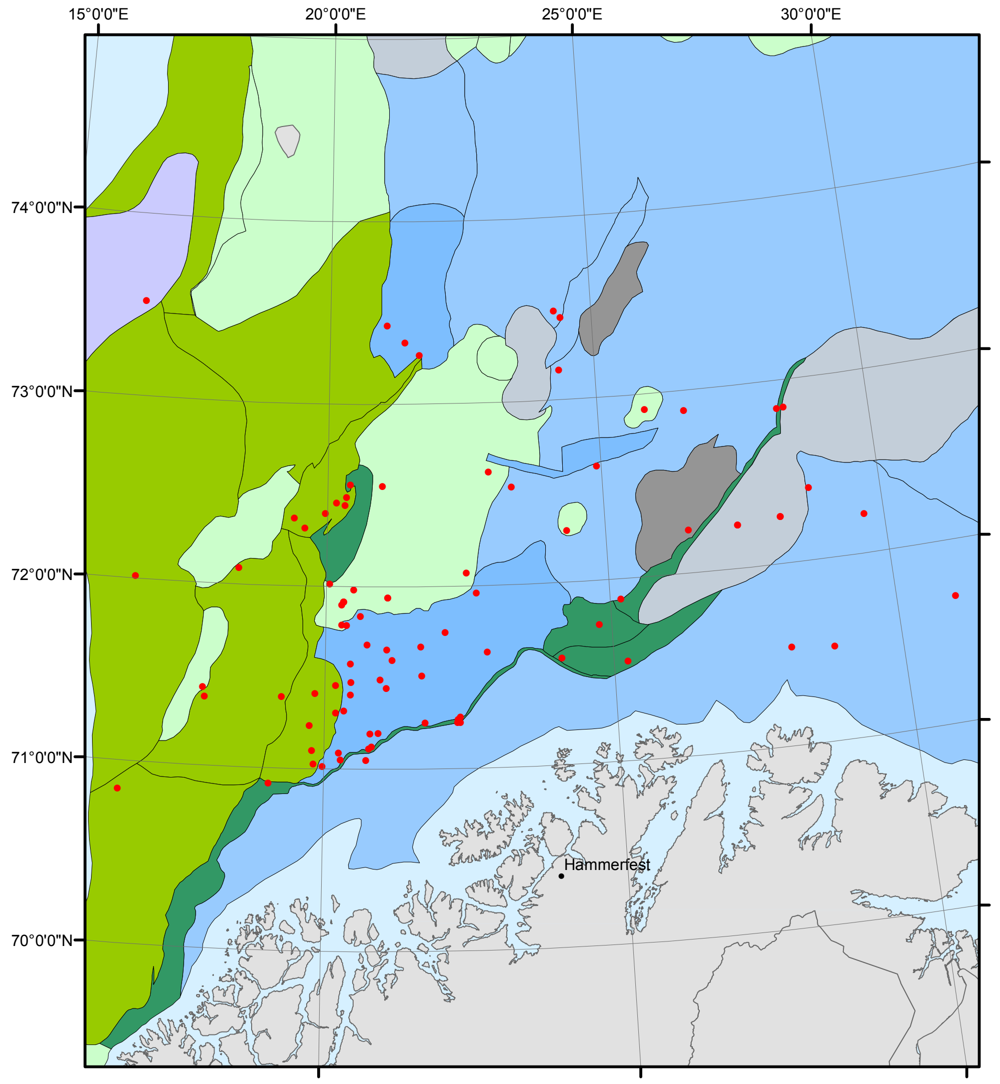
Petroleum resources and uncertainty in the estimates for the Norwegian Continental Shelf per 31.12.2012. (Source: Norwegian Petroleum Directorate)



Historical petroleum production of oil and gas, and prognosis for production in coming years (Source: Norwegian Petroleum Directorate)

2. Petroleum activity in the Barents Sea





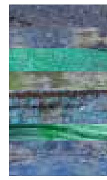
Exploration wells drilled in the south western Barents Sea (as of 25.11.2013)

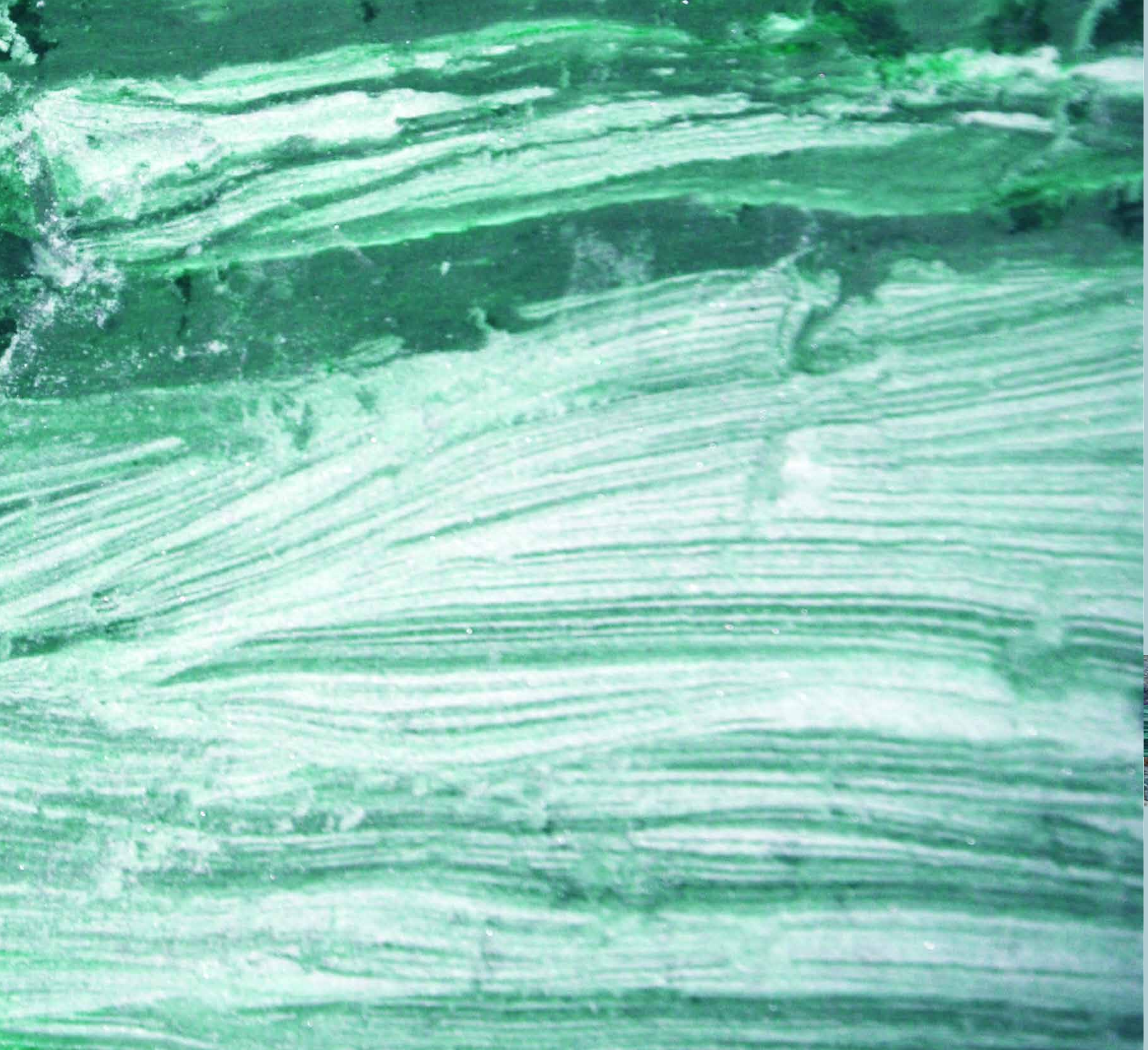
to test the play was drilled in 1987, and the next five wells were dry. A couple of discoveries were significantly smaller than expected. The gas discovery 7225/3-1 (Norvarg) is encouraging, and the estimate of undiscovered resources shows that the potential remains large.

The Upper Triassic to Lower Cretaceous plays along the Ringvassøya- Loppa and Bjørnøyrenne fault complex are relatively unexplored, with about 16 wildcats. More than half of these were dry. The first well in these plays was drilled in 1983, and the first gas discovery 7019/1-1 was made in 2000. This well showed gas with a very high CO_2 content. Finding oil in Johan Castberg (7220/8-1 Skrugard and 7220/7-1 Havis) has prompted a new view of the plays, and interest in exploring them is great.

The Snøhvit gas field started production in 2007 and is the only field developed so far, with Statoil as operator. In the same area Norwegian Eni are developing the Goliat oil field. The gas from Snøhvit is transported to a land terminal at Melkøya and forwarded refrigerated as LNG (liquefied natural gas) by ship. The CO_2 is separated from the gas stream onshore on Melkøya and transported by a 360km pipeline offshore and injected into the Stø geological formation in the Snøhvit field.

Oil and gas discoveries in the Barents Sea have been made since the 1980`s, but it is in the new millennium that development of the oil resources in the Barents Sea have started.





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.

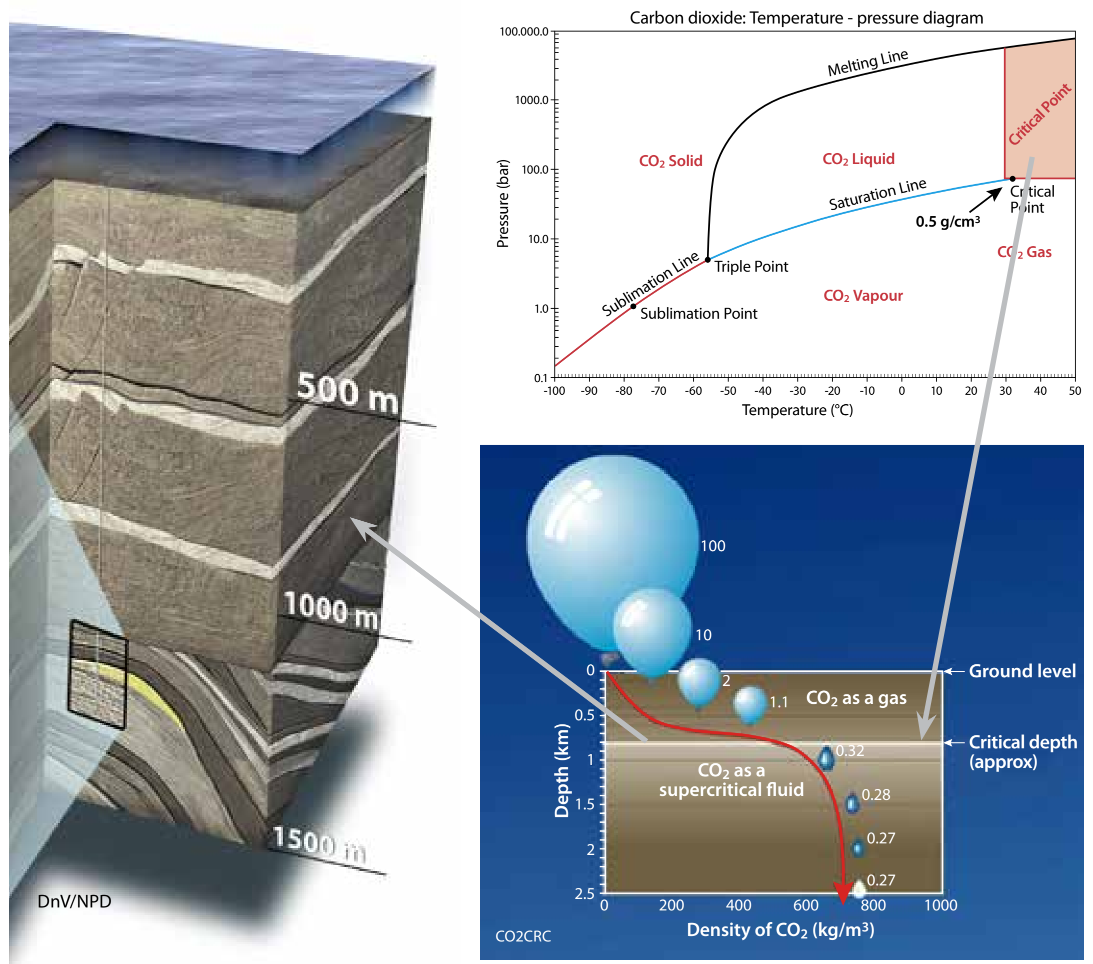
In residual trapping, the CO_2 is trapped in the tiny pores in rocks by the capillary pressure of water. Once injection stops, water from the surrounding rocks begins to move back into the pore spaces that contain CO_2. As this happens, the CO_2 becomes immobilized by the pressure of the added water.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

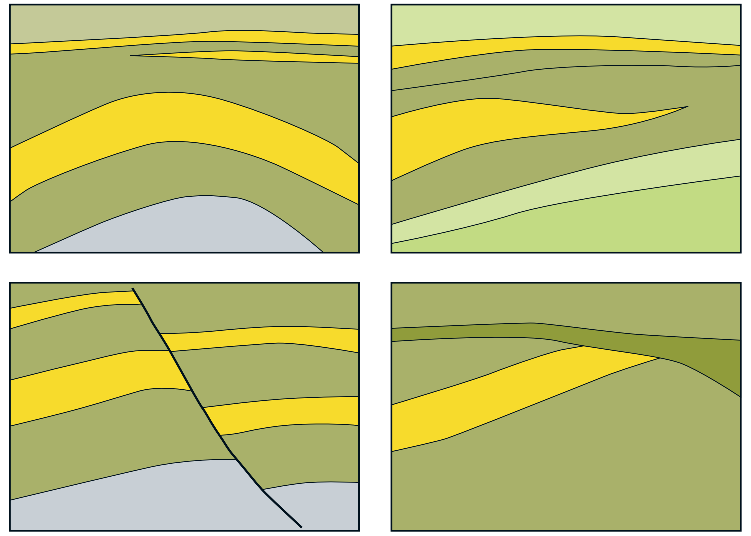
Oil and gas reservoirs are a subset of saline formations, and therefore they generally have similar properties. That is, they are permeable rock formations acting as a reservoir with an impermeable cap rock acting as a seal.

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

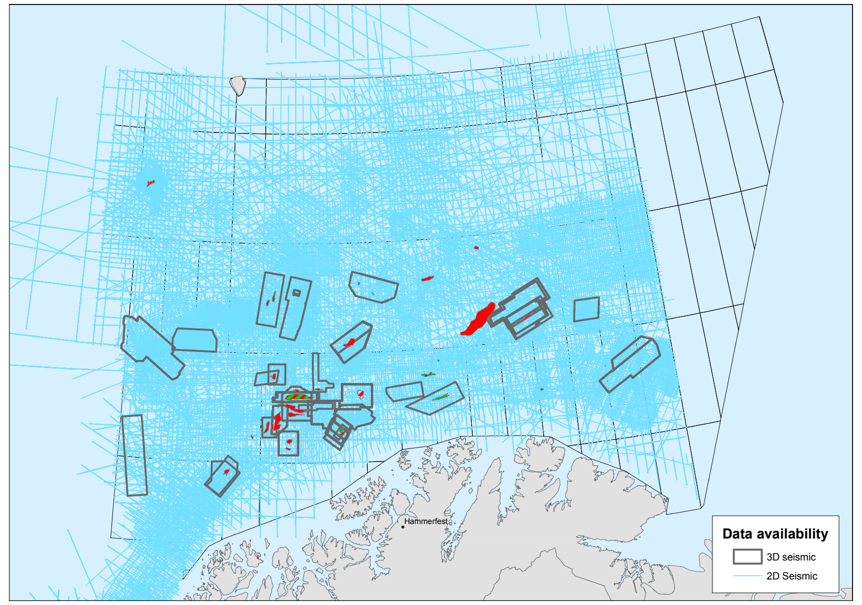
3.2 Data availability

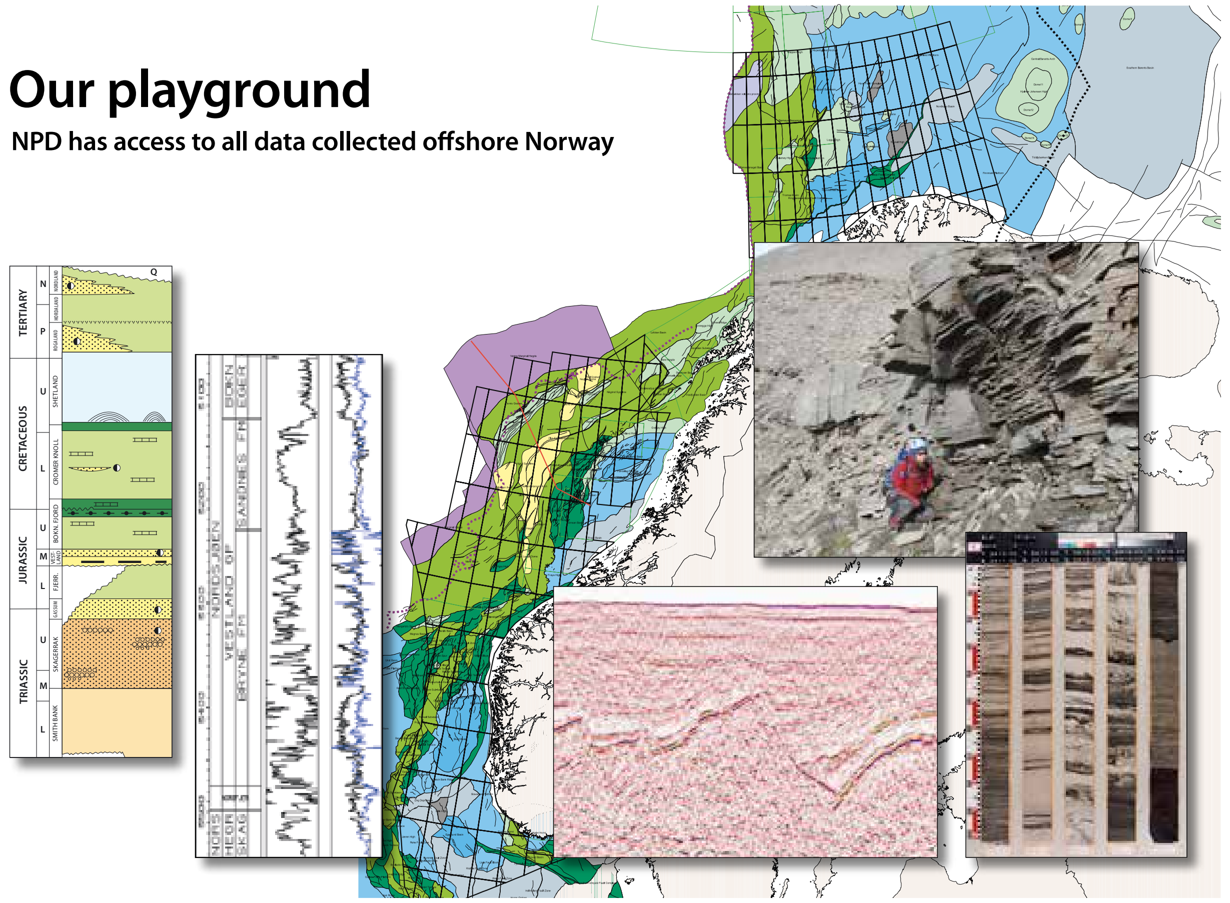
The authorities' access to collected and analysed data is stipulated in law and based on the following statements: "The Norwegian State has the proprietary right to subsea petroleum deposits and the exclusive right to resource management" and "The right to submarine natural resources is vested in the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

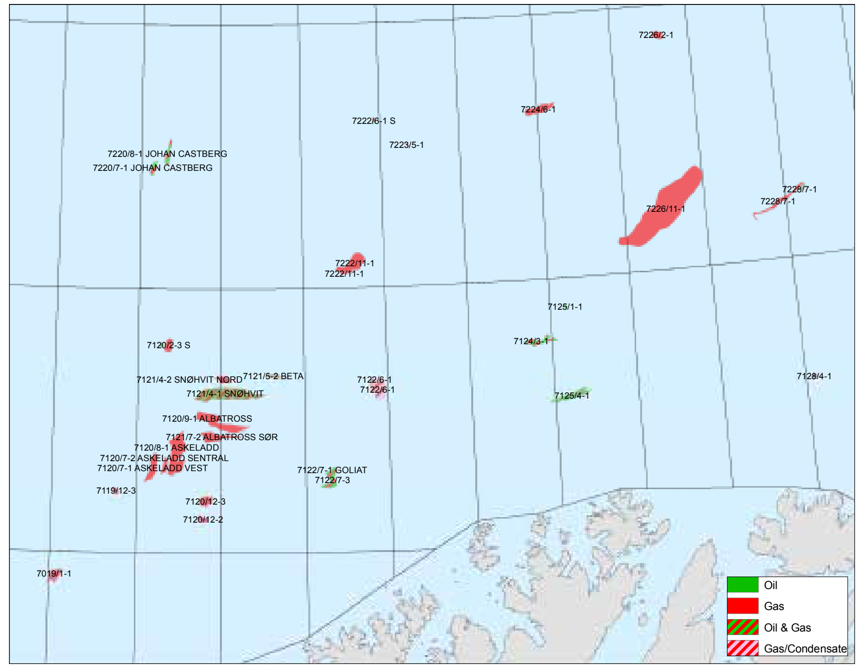
The Norwegian Petroleum Directorate (NPD) has access to all data collected on the NCS and has a national responsibility for the data. The NPD's data, overviews and analyses make up an important fact basis for the oil and gas activities.

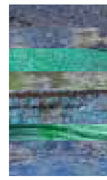
The main objective of these Reporting Requirements from the NPD is to support the efficient exploitation of Norway's hydrocarbon reserves. More than 40 years of petroleum activity has generated a large quantity of data. This covers 2D and 3D data, data from exploration and production wells such as logs, 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

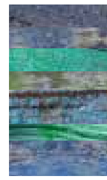
3.3 Workflow and characterization

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	

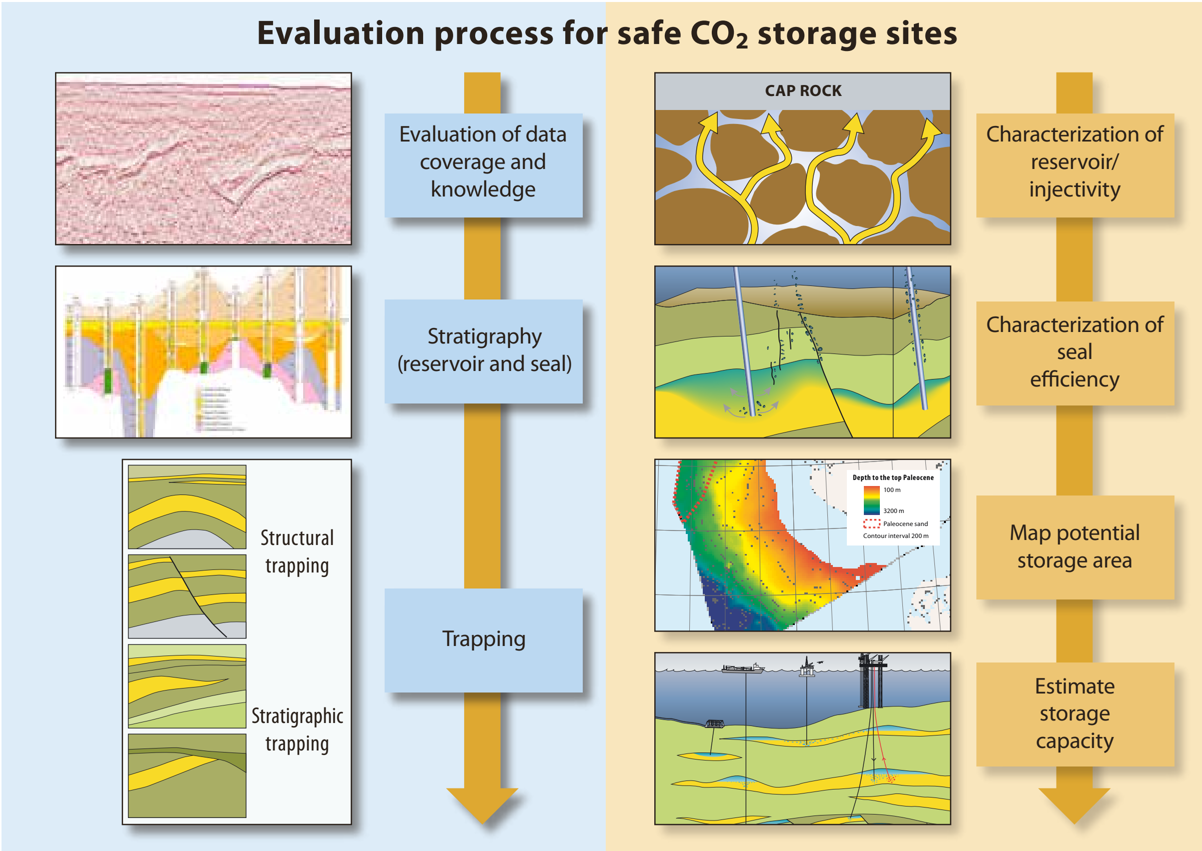


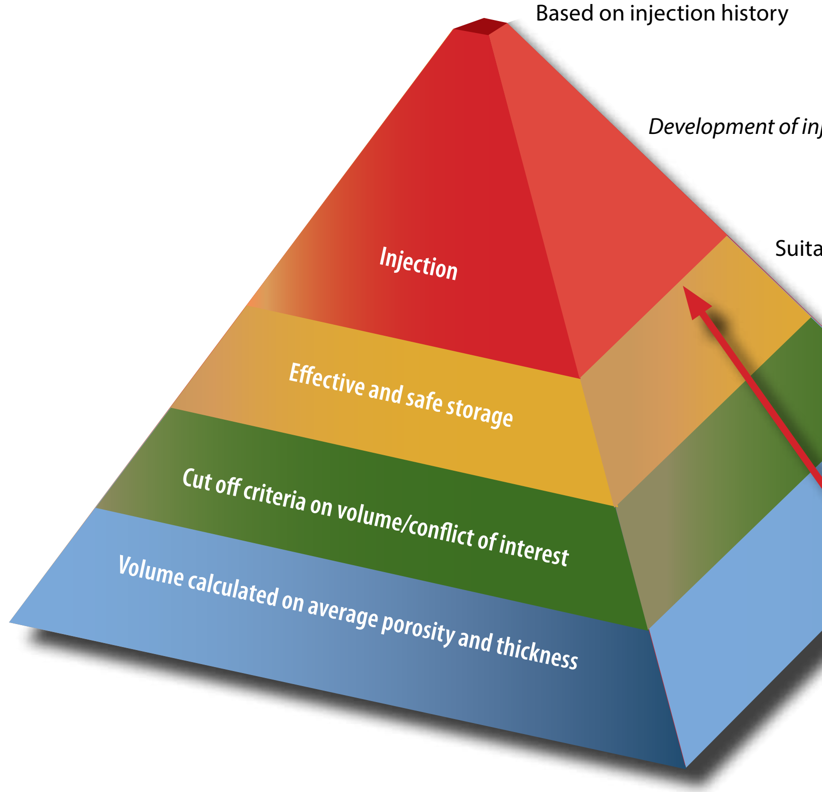
3.3 Workflow and characterization

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 CO2*
- Vb *bulk volume*
- $Ø$ *porosity*
- n/g *net to gross ratio*
- ρ_{CO_2} *density of CO2 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.

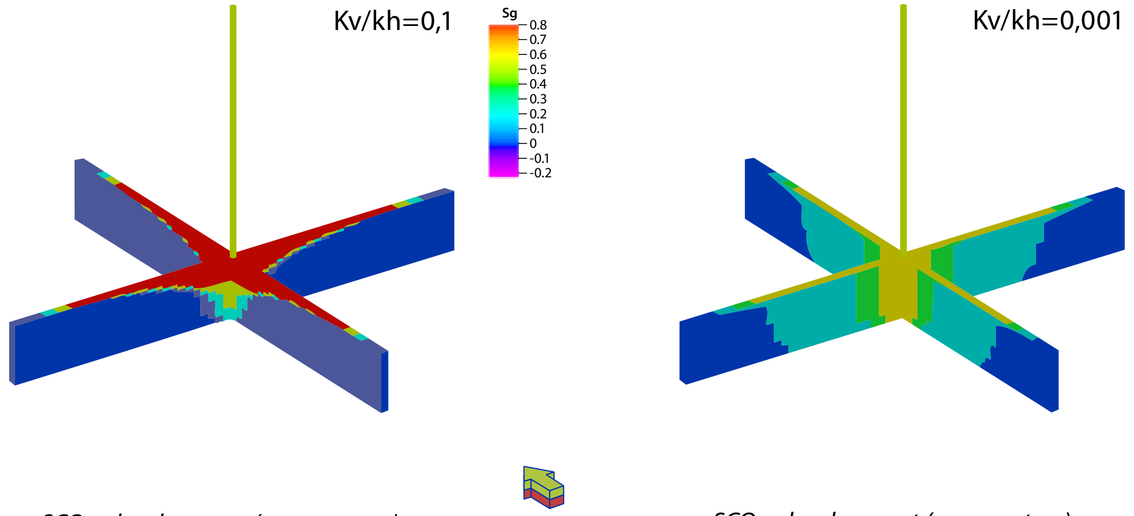
For a homogenous reservoir with a permeability of 200mD and reservoir thickness of 100m, the storage efficiency in a closed system is simulated to be 0.4 to 0.8%, with a pressure increase of 50 to 100 bar. In a closed system, a pressure increase between 50 and 100 bar is a reasonable range for reservoirs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

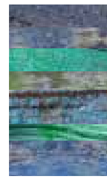
For abandoned oil and gas fields, the amount of CO_2 that can be stored depends on how much of the hydrocarbons have been produced, and to what extent the field is depleted.

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.

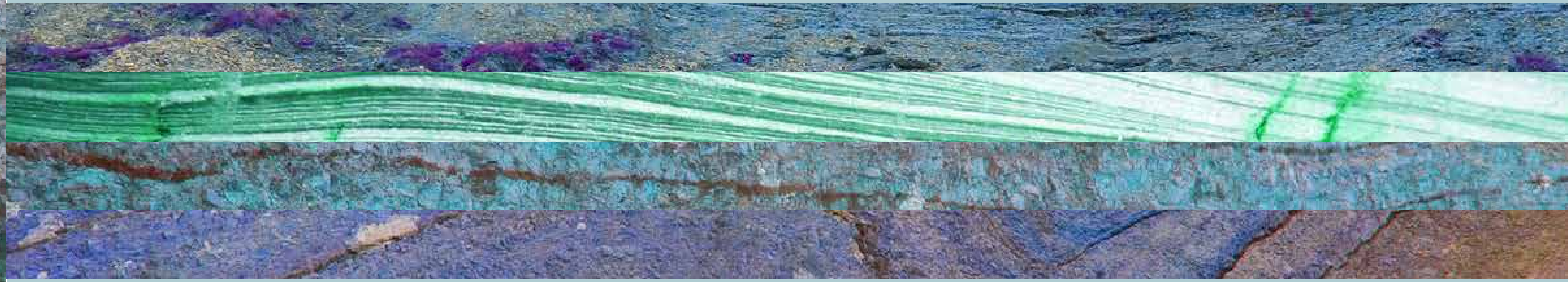


SCO_2 development (open system) *SCO_2 development (open system)*

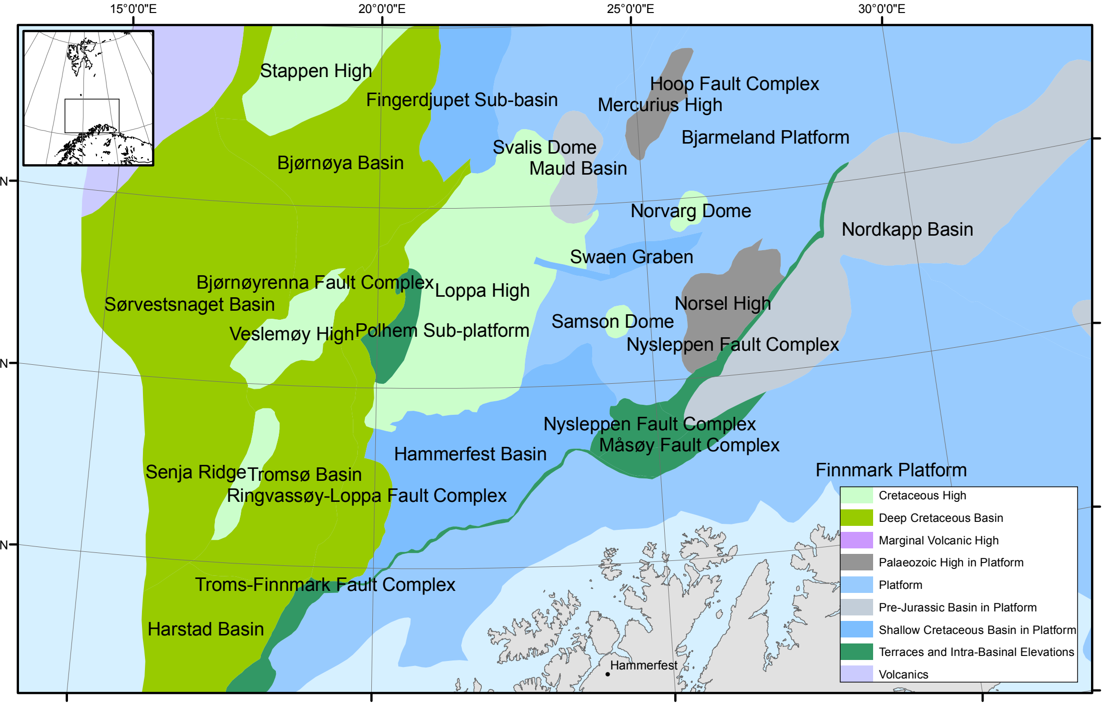
A cross section of a flat reservoir with injection for 50 years.



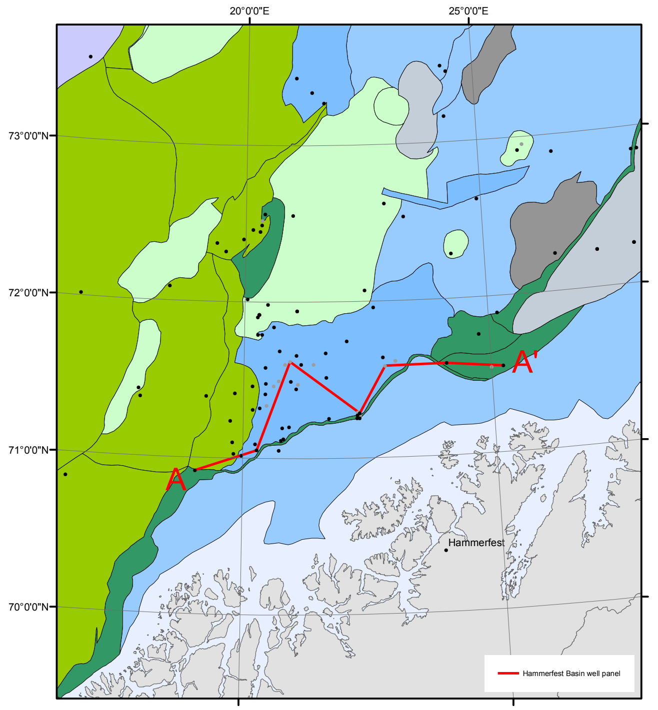
4. Geological description of the Barents Sea



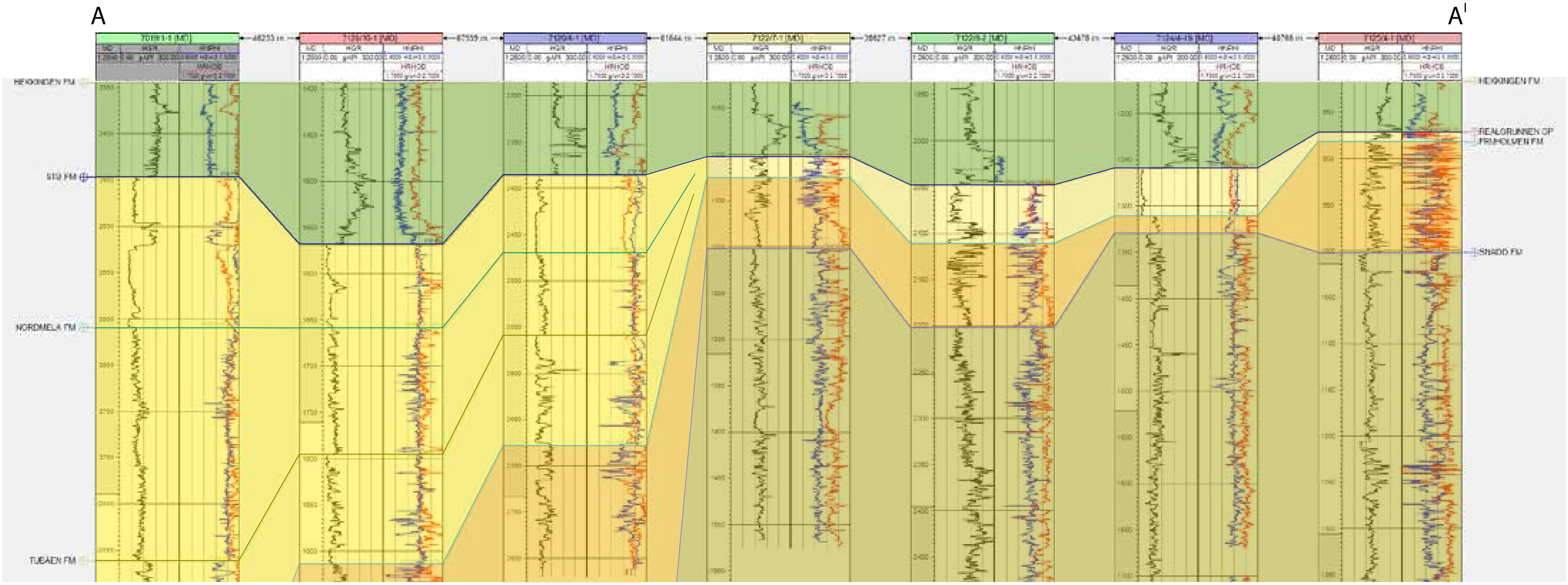
4.1 Geological development of the Barents Sea



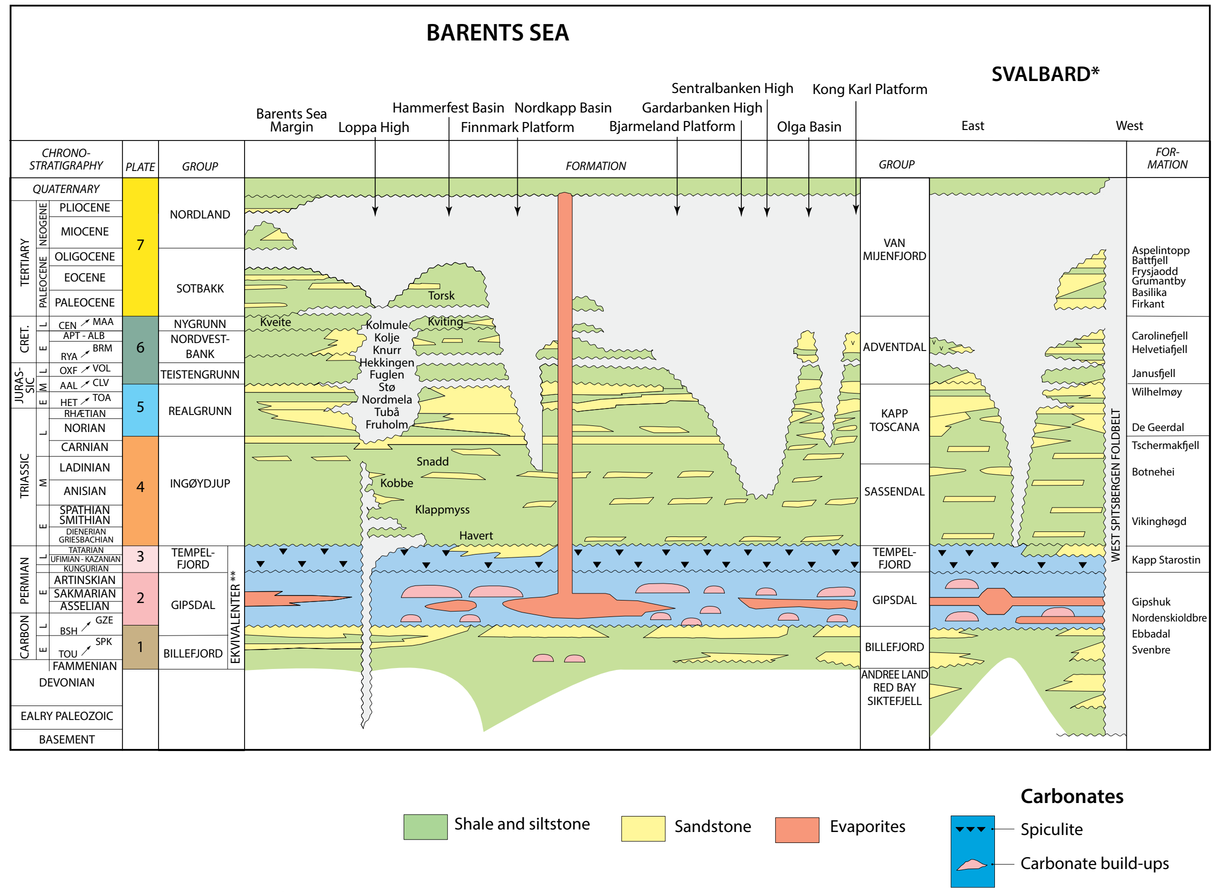
Structural elements of the Southern Barents Sea.



Transect from the Harstad Basin to the Måsøy Fault Complex (AA`).



Well section panels (AA`) showing gamma and neutron/density logs reflecting thickness variations of the different formations.



* Lithostratigraphic nomenclature for Svalbard is under revision
** Lithostratigraphic nomenclature for The Barents Sea Paleozoic is in preparation

Lithostratigraphic nomenclature

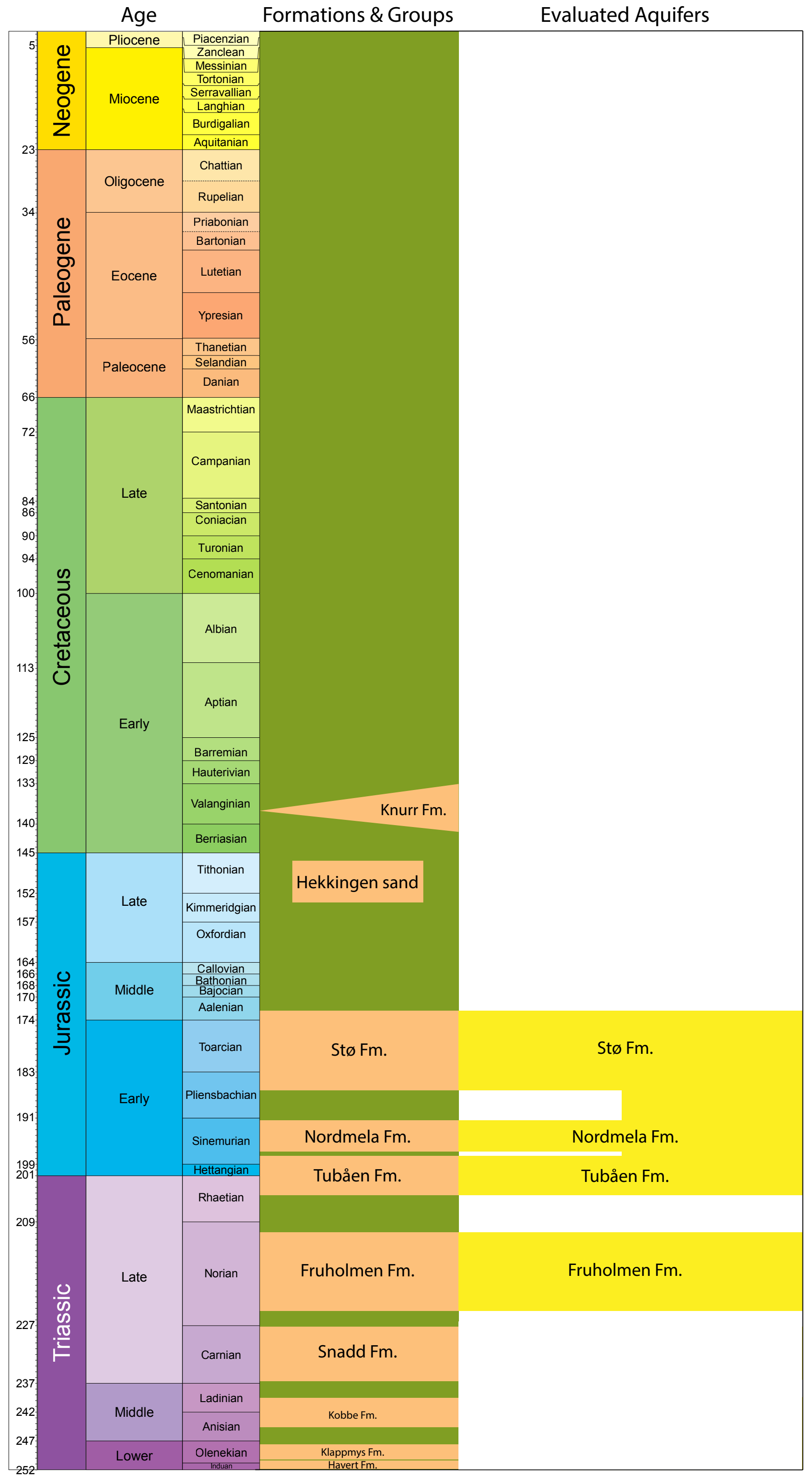
The lithostratigraphic nomenclature for the post Caledonian successions of the southern Barents Sea has been a matter discussion since the southern Barents Sea was opened for hydrocarbon exploration and the first well was drilled in 1980.

In NPD Bulletin No 4 (Dalland et.al. 1988) a lithostratigraphic scheme was defined for the Mesozoic and Cenozoic successions offshore mid- and northern Norway.

Dallmann et.al (1999) suggested a revised lithostratigraphic scheme for the Upper Paleozoic, Mesozoic and Cenozoic successions from the Svalbard area including the southern Barents Sea.

In NPD Bulletin No 9 (Larssen et.al 2002) a formalized Upper Paleozoic lithostratigraphy for the southern Norwegian Barents Sea was presented.

In this Atlas we use the original definitions from NPD Bulletin No 4 (Dalland et.al 1988) for the Mesozoic and Cenozoic successions as they are defined from the southern Barents Sea. For the Upper Paleozoic successions we use the official nomenclature from NPD bulletin No 9 (Larssen et.al 2002).



Evaluated geological formations, and aquifers.

4.1 Geological development of the Barents Sea

The Barents Sea is located in an intracratonic setting between the Norwegian mainland and Svalbard. It has been affected by several tectonic episodes after the Caledonian orogeny ended in Late Silurian/Early Devonian.

There is a marked difference, both in time, trend and magnitude, between the tectonic and stratigraphic development in the western and eastern parts of the southern Barents Sea. This boundary is defined by the dominantly N-S to NNE-SSW trending **Ringvassøy-Loppa and Bjørnøyrenna Fault Complexes**. The area to the west of this boundary was tectonically veryactive throughout Late Mesozoic and Cenozoic times, with deposition of enormous thicknesses of Cretaceous, Paleogene and Neogene sediments in the **Harstad, Tromsø and Bjørnøya Basins**. NNE-SSW, NE-SW and locally N-S trending faults dominate in this western part. In contrast the southeastern Barents Sea is dominated by thick Upper Paleozoic and Mesozoic sequences, where E-W, WNW-ESE to ENE-SSW fault trends dominate.

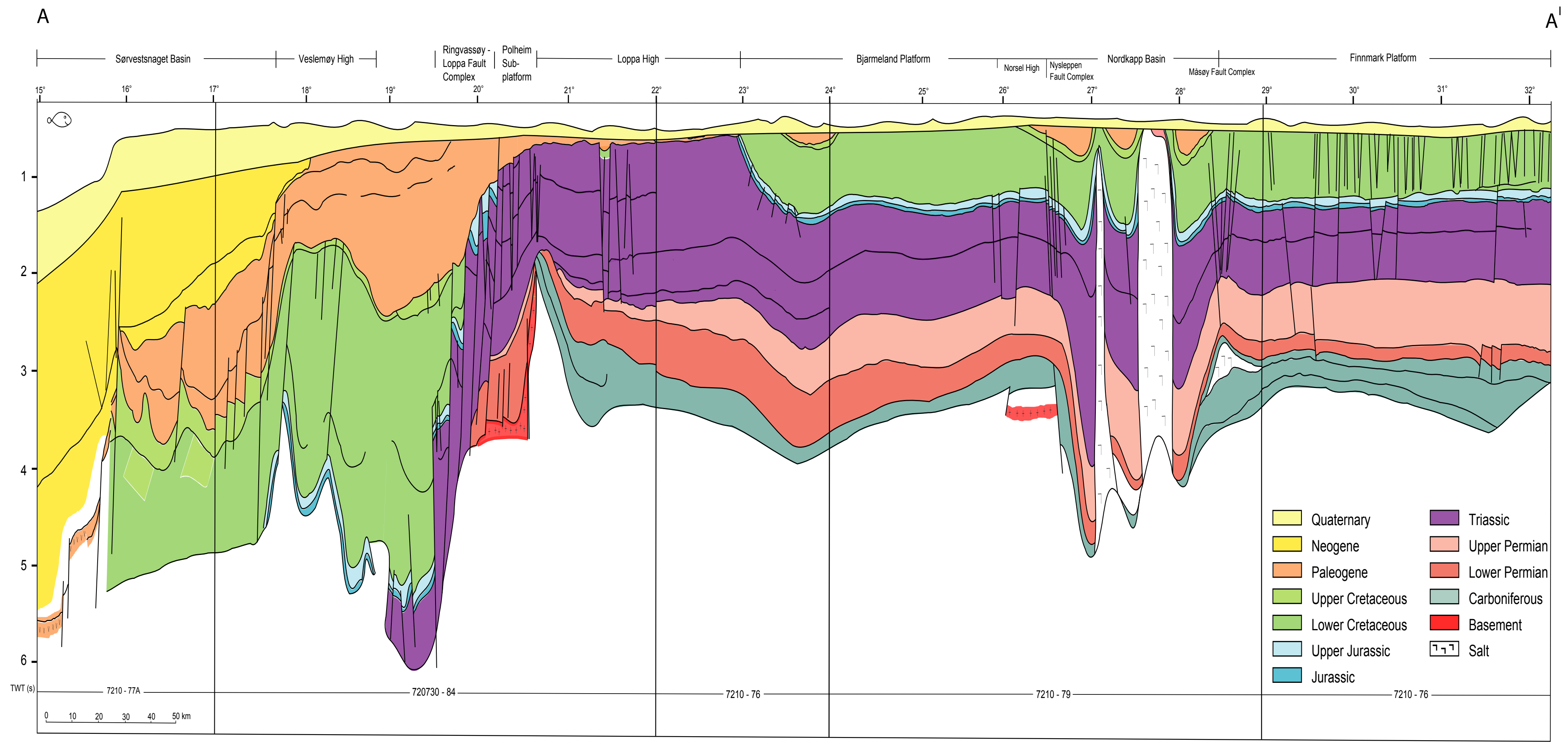
The area evaluated for CO_2 storage is defined to the west by the N-S to NNE-SSW trending **Ringvassøy-Loppa and Bjørnøyrenna Fault Complexes**, to the south/southeast by the **Troms-Finnmark Fault Complex** and **the Finnmark Platform**, to the north by an east-west line approximately along the 73^{O} N parallel, and to the east by a north-south line running approximately along the 28^{O}E meridian.

The southern Barents Sea Shelf is divided into several main structural elements. The most important are: **The Hammerfest and Nordkapp Basins, the Finnmark and Bjarmeland Platforms and the Loppa High**. There are also several smaller structural elements, like the Polheim Sub-platform, Senja Ridge, Veslemøy, Norsel High. Bordering and partly defining the main structural elements are a series of complex fault zones: **Troms-Finnmark, Ringvassøy-Loppa, Bjørnøyrenna, Måsøy, Nysleppen and Asterias Fault Complexes.**

The Hammerfest Basin is fault controlled: To the west against the Ringvassøy-Loppa Fault Complex; to the south against the Finnmark Platform (Troms–Finnmark Fault Complex); to the north against the Loppa High (Asterias Fault Complex) and the Bjarmeland Platform. Internally E-W to WNW-ESE trending faults dominates.

The basin was probably established by Early to Late Carboniferous rifting. Two wells have penetrated the Upper Paleozoic succession. Well 7120/12-2, drilled on the southern margin, penetrated a 1000m thick Upper Permian sequence overlying Lower Permian dolomites and red beds resting on Precambrian/Caledonian basement. Well 7120/9-2 in the central part of the basin reached TD 117m into the Upper Permian Røye Formation.

Major subsidence occurred in the Triassic, Jurassic and Early Cretaceous overlain by a thin highly condensed sequence of Late Cretaceous and Early Paleocene shale. There is no evidence for diapirism of Upper Paleozoic evaporites as seen in the Tromsø Basin to the west and Nordkapp Basin to the east. Internally the basin is characterized by a central E-W trending faulted dome-structure, related to the Late Jurassic tectonic episode.



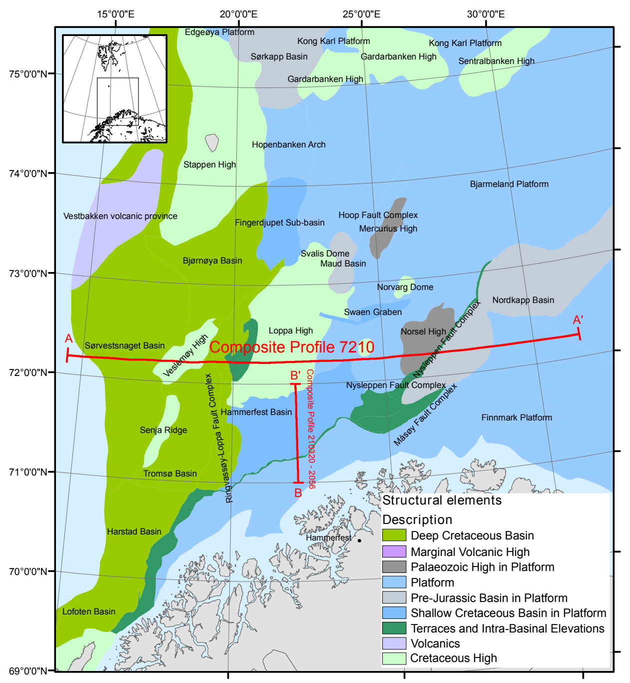
The Nordkapp Basin is fault-controlled and located along a SW-NE trending Upper Paleozoic rift. It is bounded by the Bjarmeland Platform to the northwest and the Finnmark Platform to the southeast. The northwestern boundary is defined by the Nysleppen Fault Complex and the southeastern boundary is defined by the Måsøy Fault Complex.

During the Late Paleozoic (Late Carboniferous to Early Permian) thick sequences of halite were deposited (Gipsdalen Gp) giving rise to pronounced salt diapirism, beginning in the Early Triassic. The basin is dominated by thick Mesozoic, mainly Triassic successions, with a significant thickness of Upper Paleozoic rocks.

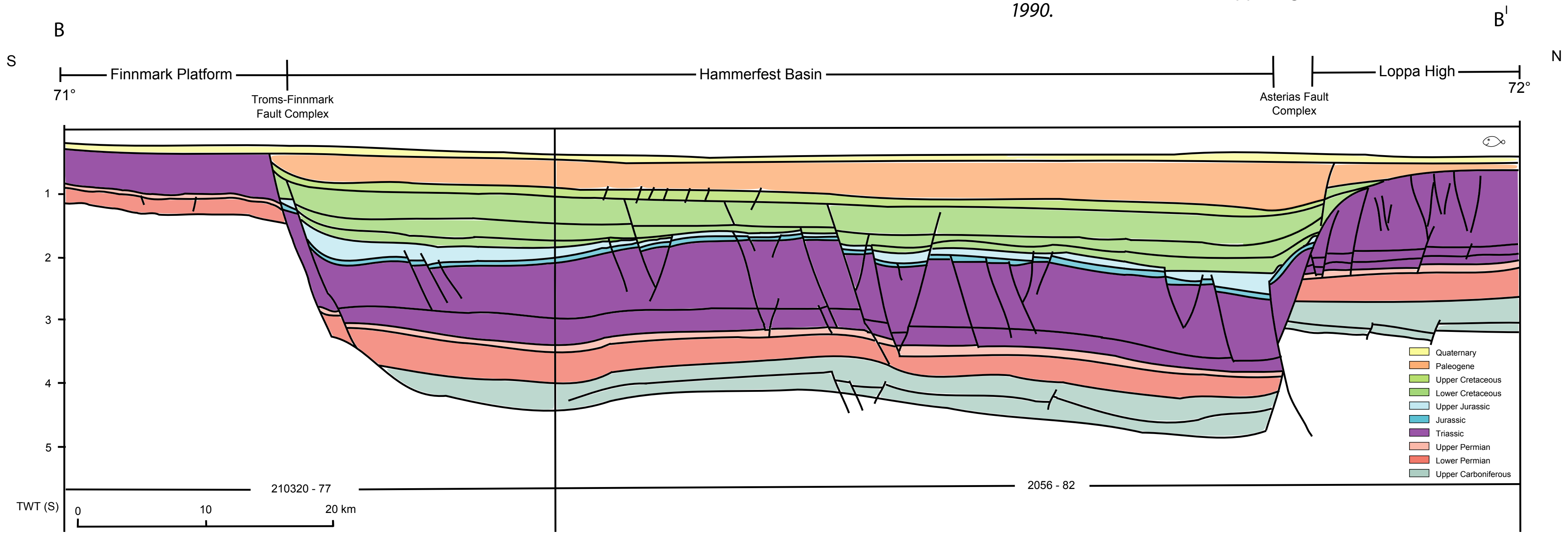
The Troms-Finnmark Platform is bounded by the Norwegian mainland to the south, to the west by the southwestern extension of the Ringvassøy-Loppa Fault Complex and by the Hammerfest and Nordkapp Basins to the north.

The central part of the Troms-Finnmark Platform in the Norwegian sector shows a rift topography with halfgrabens containing siliciclastic rocks of Early Carboniferous age (Billefjorden Gp). During the Permian the stable western part of the platform was transgressed. Late Permian and Late Jurassic movements followed by Cenozoic tectonism and uplift resulted in a gentle northward tilt of the Finnmark Platform. In the northeastern part of the Platform thick sequences of Mesozoic, mainly Triassic rocks have been drilled.

The Bjarmeland Platform is part of an extensive platform area east of the Loppa High and north of the Nordkapp Basin. The platform was established in the Late Carboniferous and Permian, but subsequent Paleogenetectonism tilted the Paleozoic and Mesozoic sequences towards the south so that presently unconsolidated Pleistocene sediments overlie successively older rocks to the north. Towards the south and west, the platform is divided into minor highs and sub-basins mainly formed by salt tectonics (Samson Dome).



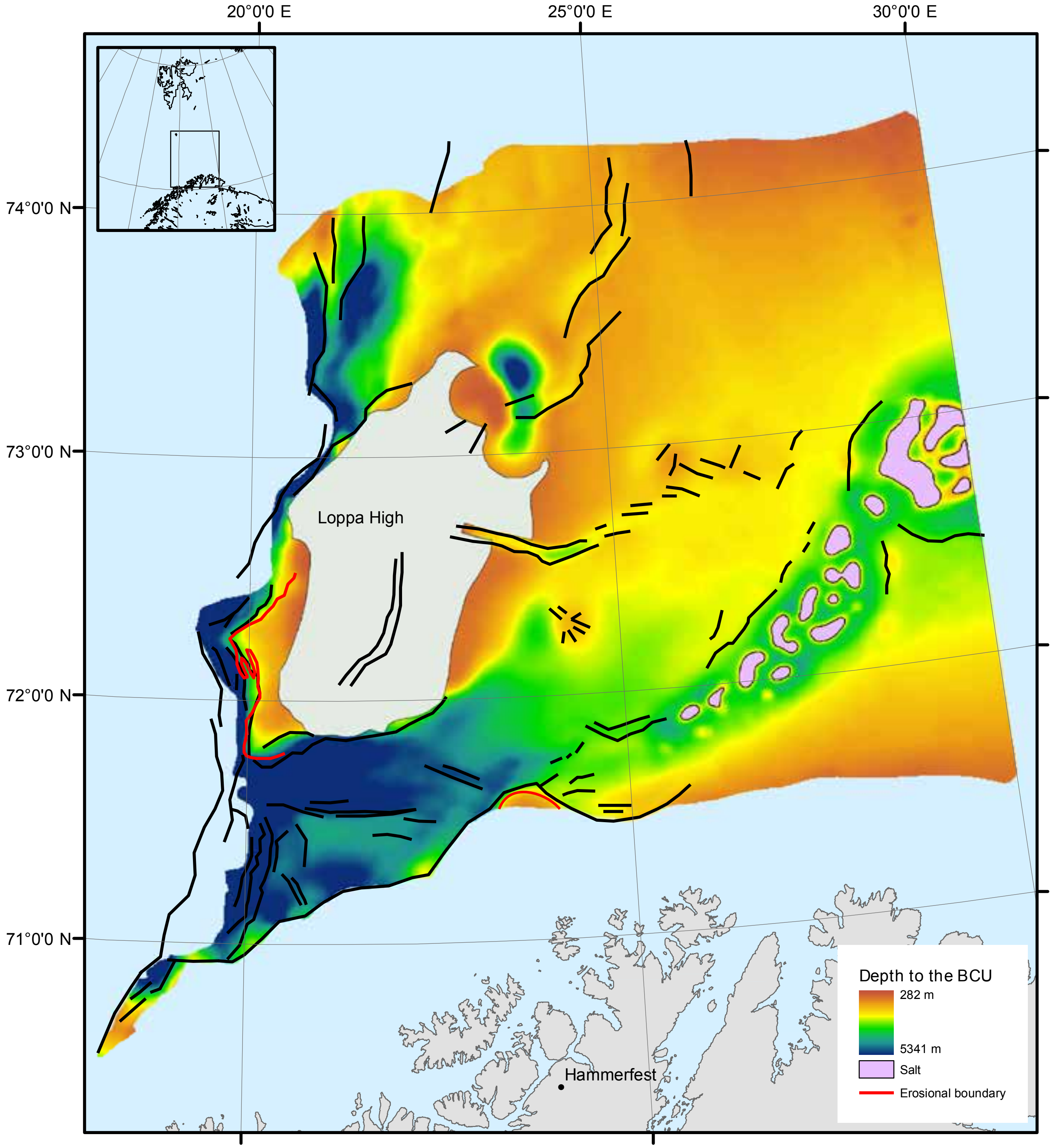
Transects of the geosections from the western part of the Sørvestsnaget Basin to the eastern part of the Finmark Platform (AA`) and from the Finmark Platform across the Hammerfest Basin to the Loppa High (BB`). Gabrielsen et al. 1990.



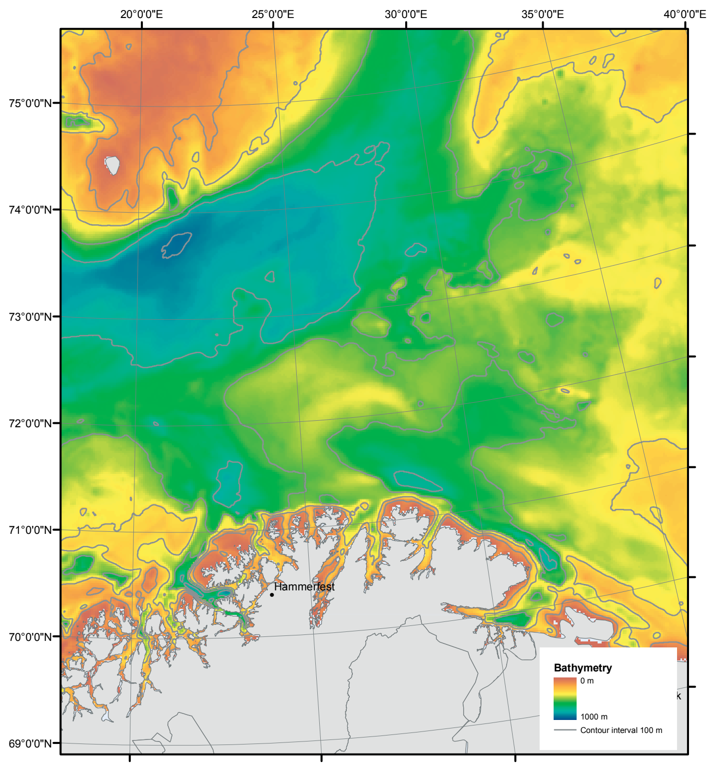
The Bjarmeland Platform is characterized by a thick Triassic succession of the Ingøydjupet Gp, with a maximum drilled thickness of 2862m on the Nordvarg Dome (well 7225/3-1). The thickness of the Realgrunnen Gp, varies between 100-200m.

The Loppa High is a marked (N-S) trending structural feature, separated from the Hammerfest Basin in the south by the E-W trending Asterias Fault Complex. To the west it is separated from the Tromsø and Bjørnøya Basins by the Ringvassøy-Loppa and Bjørnøyrenna Fault Complexes. To the east it grades into the Bjarmeland Platform. The Loppa High has complex geological history with several phases of uplift/subsidence followed by tilting and erosion. Late Carboniferous rift topography was filled and overlain by Upper Paleozoic siliciclastics, evaporites and carbonate. During the Late Permian to Early Triassic the Loppa Ridge was uplifted and tilted. This was followed by a gradual onlap during the Early and Middle Triassic, before deposition of a thick Upper Triassic succession (Snadd Fm). On the southern crest of the Loppa High the eroded remnants of a sequence of Paleogene shale (Sotbakken Gp) is overlying Middle Triassic claystones.

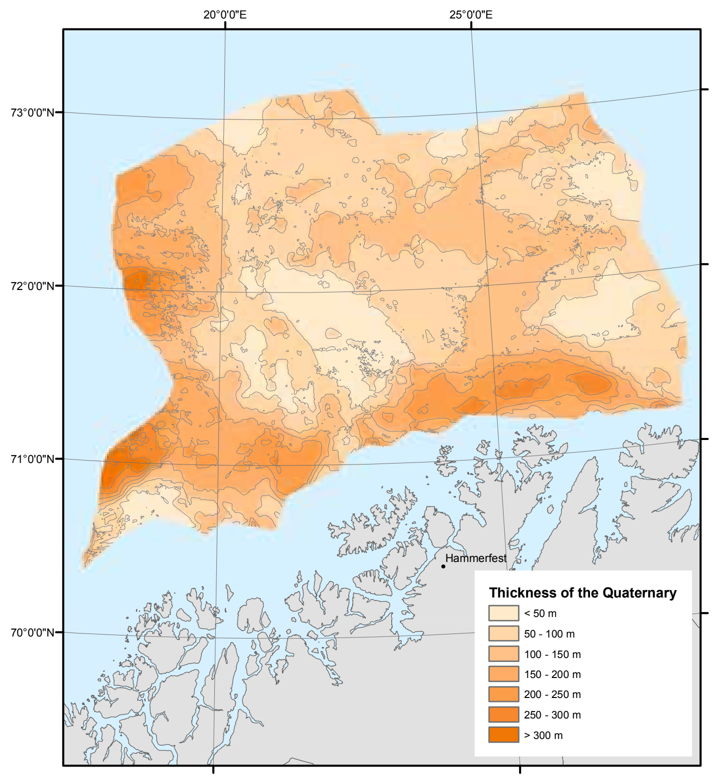
An important geological factor for the Barents Sea region is the major Paleogene tectonism and uplift and the following Paleogene and Neogene erosion. Generally the net uplift, defined as the difference between maximum and present burial, is largest in the northwestern part towards Bjørnøya/Stappen High (calculated to be up to 3000m), and is less towards the east and south. The Paleogene tectonism is suggested to be partly related to the plate tectonic movements in relation to the opening of the Atlantic and Arctic Oceans. An important part of the erosion took place in the Quaternary when erosion rates increased due to the glacial conditions.



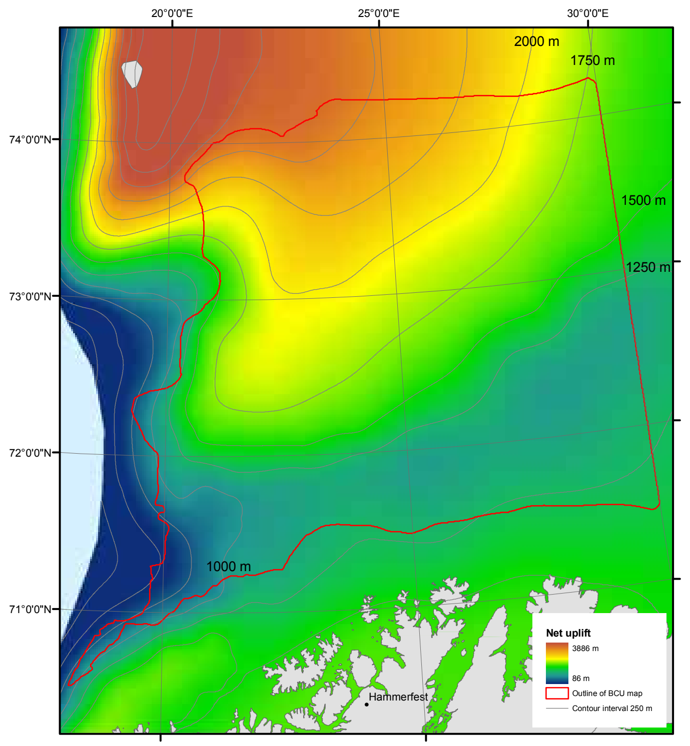
Depth to the Base Cretaceous Unconformity. To the west the surface is deeper than 3000m. The red line outlines areas where the Jurassic section is eroded.



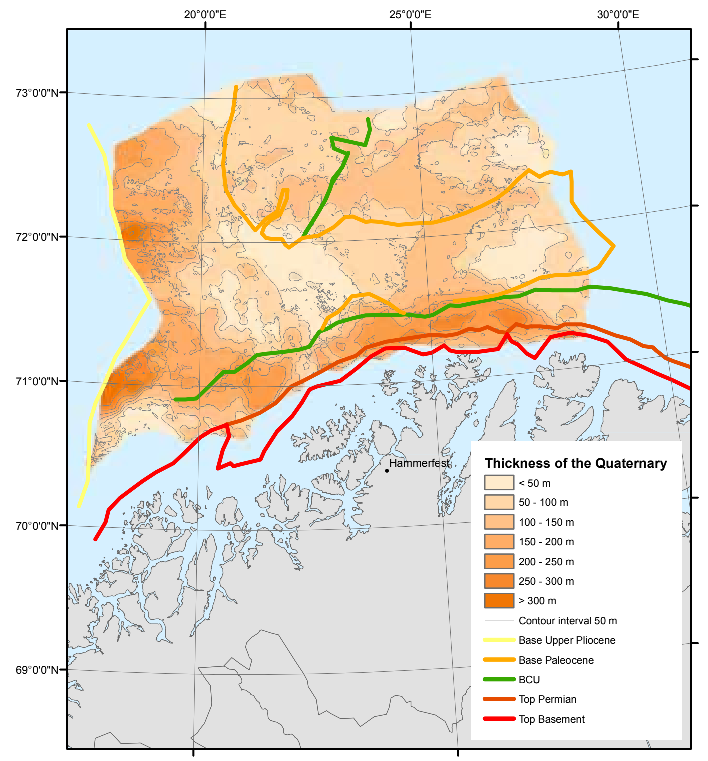
Bathymetri of the southwestern Barents Sea. Based on Jakobsson et al. 2012.



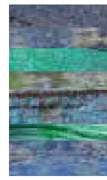
Thickness map of Quaternary in the Barents sea. During the last 2.5 m years glaciers and cold climate dominated in the region, eroding the remnant highs offshore Finnmark and Northern Troms.



Map showing Cenozoic and Quaternary erosion of the Barents Sea. Modified from Henriksen et al. 2011.



Thickness map of Quaternary sediments including subcrop lines of basement, top Permian, BCU, base Paleocene and base upper Pliocene



Lower and Middle Triassic

The Ingøydjupet Group

(Induan to Anisian)

The Ingøydjupet Group is subdivided into four formations, the Havert, Klappmyss, Kobbe and Snadd Formations. The lower boundary is defined towards the Upper Paleozoic mixed siliciclastic and carbonate sequences and the upper boundary is marked by a shale interval at the base of the Fruholmen Formation of the Realgrunnen Group. This represents an important transgression which produced a sequence boundary traceable throughout most of the Artic from the Barents Sea to the Sverdrup Basin.

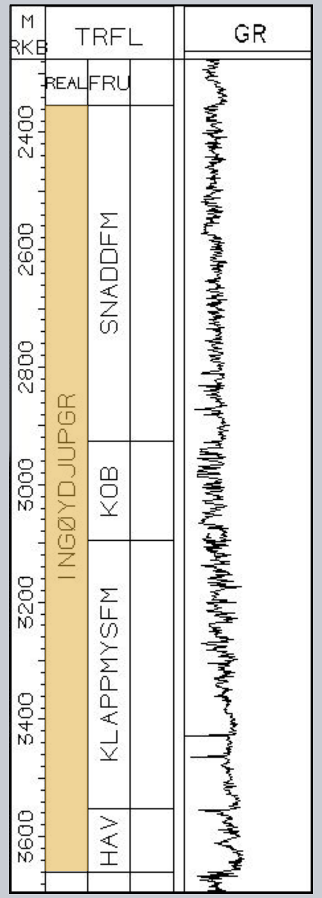
The type and reference area for the Ingøydjupet group is blocks 7120/12 and 7120/9 in the western part of the Hammerfest Basin. In the type area the thickness is approximately 1700m thickening northwards towards the reference area to 2400m (well 7120/9-2). The group is thick throughout the Hammerfest Basin with the lower part onlapping the Loppa High to the north. Thick sequences are also found to the east on the Bjarmeland Platform, Norsel High and along the southeastern margin of the Nordkapp Basin. The upper part of the group (Snadd Formation) has been eroded on the Finnmark Platform, but still more than 1000m have been drilled in the central parts (wells 7128/4-1 and 7128/6-1).

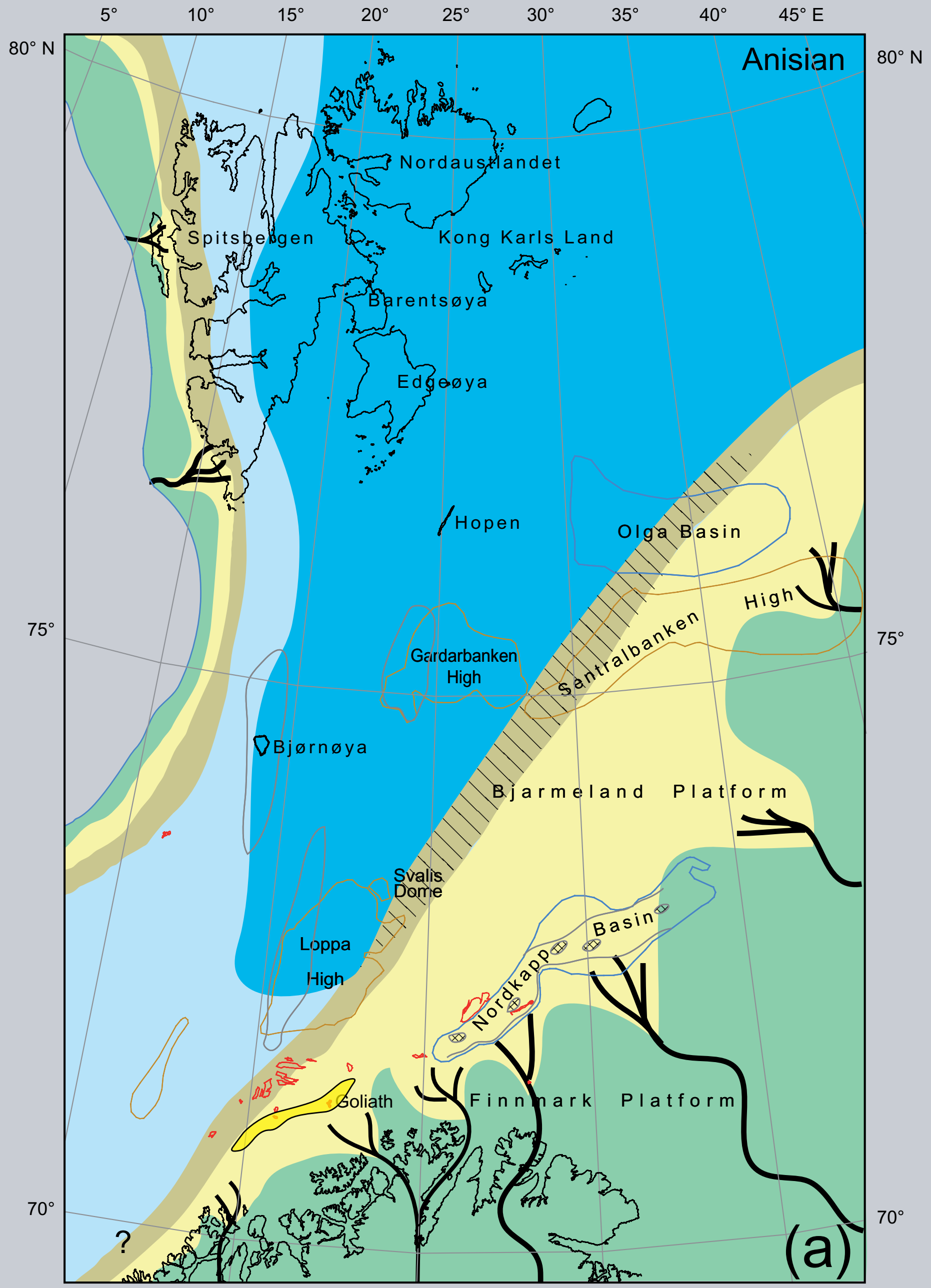
The dominant lithology of the Ingøydjupet group is black shale and claystone with thin grey siltstones and sandstones, particularly in the upper parts. Minor carbonate and coal interbeds are also present.

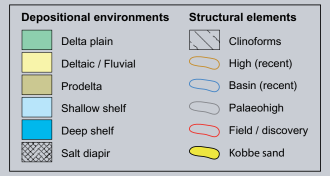
Marine environments encountered by wells in the lower parts of the group, together with seismic data, show evidence for coastlines to the south and southeast of the Hammerfest Basin and progressive onlap of the submerged Loppa High to the north. The upper parts of the group reflect northwestward outbuilding of deltaic sequences over an extensive, low relief depositional basin.

Internal sequences and general development show great similarities to the Sassendalen group and lower parts of the Kapp Toscana group on Svalbard.

INGØYDJUPET GROUP
WELL LOG 7120/12-2







Palaeogeographic map showing the progradation of sediments into the Middle Triassic marine embayment, and the development of a paralic platform in the Late Triassic. In the map, the detailed boundaries between depositional areas are simplified, and the positions of the rivers are conceptual. The Kobbe aquifer in the Goliat area is indicated. (Riis et al. 2008)

Lower and Middle Triassic

The Havert Formation (Induan)
In the type well (7120/12-2) in the Hammerfest Basin, the formation consists of medium to dark grey shale with minor grey siltstone and thin sandstone layers comprising two generally coarsening upwards sequences.

The thickness in the type well is 105 m. Further to the north the reference well (7120/9-2) has a thickness of 150m with a more monotonous silt and shale sequence. Further to the east, on the Bjarmeland Platform and Norsel High, thicknesses in the order of 1000m have been reported. Here the dominant lithology is silt and claystone with subordinate sandstone. On the Finnmark Platform more than 600m has been drilled.

In well logs the lower boundary is defined at the top of the underlying Upper Paleozoic mixed siliciclastic and carbonate rocks.

The formation was deposited in a shallow marine to open marine setting with coastal environments to the south and southeast.

The Klappmyss Formation
(Olenekian)

In the type well (7120/12-2) in the Hammerfest Basin the formation consists of medium to dark grey shale passing upwards into siltstones and sandstones. The reference well (7120/9-2) shows a similar trend, but with more shale.

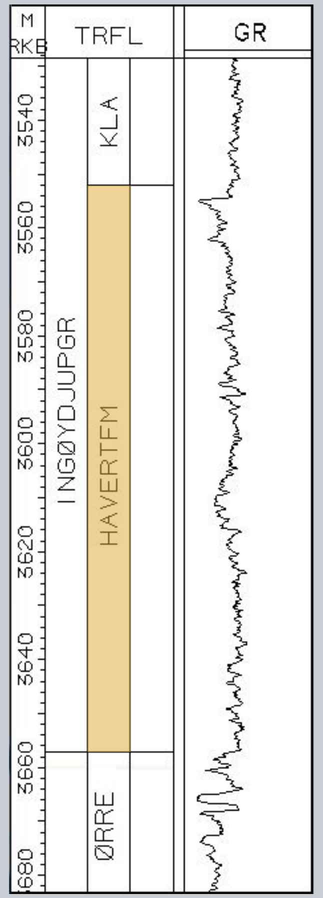
The thickness is 457m in the type well and 561m in the reference well. Thicknesses of 600m have been reported from the Bjarmeland Platform (7226/2-1) and the Norsel High (7226/11-1). On the central Finnmark Platform (7128/4-1 and 6-1) thicknesses around 260m have been drilled.

Generally the formation thickens and becomes finer northwards from the southern margins of the Hammerfest Basin.

In well logs the lower boundary is defined at the top of the underlying Havert Formation, interpreted to represent a sequence boundary. This boundary can be correlated across the southwestern Barents Sea Shelf indicating a lower Triassic transgression.

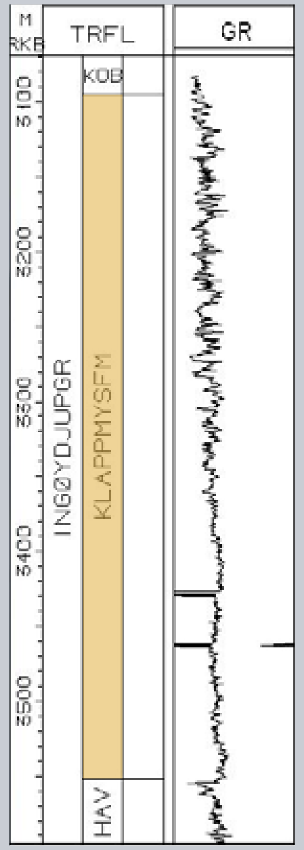
The Klappmyss Formation was deposited in shallow to open marine environment, with renewed north- to northwestward coastal progradation.

WELL LOG 7120/12-2

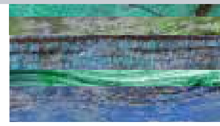


7226-11-1 - HAVERT, 3057-3062 m

WELL LOG 7120/12-2



7228-7-1A - KLAPPMYSS, 2852-2857 m



Lower and Middle Triassic

The Kobbe Formation (Anisian)
In the type well (7120/12-2), the base is defined by a 20m thick shale sequence related to a transgressive episode. This transgression is followed by outbuilding of marginal marine sediments from the south/southeastern coastal areas.

The thickness is 168m in the type well and 283m in the reference well (7120/9-2). The unit shows proximal facies development, with coarser sediments along the southern margin of the Hammerfest Basin and fining towards the basin axis. The thickness of the formation increases from approximately 140m on the Finnmark Platform to more than 700m further to the north.

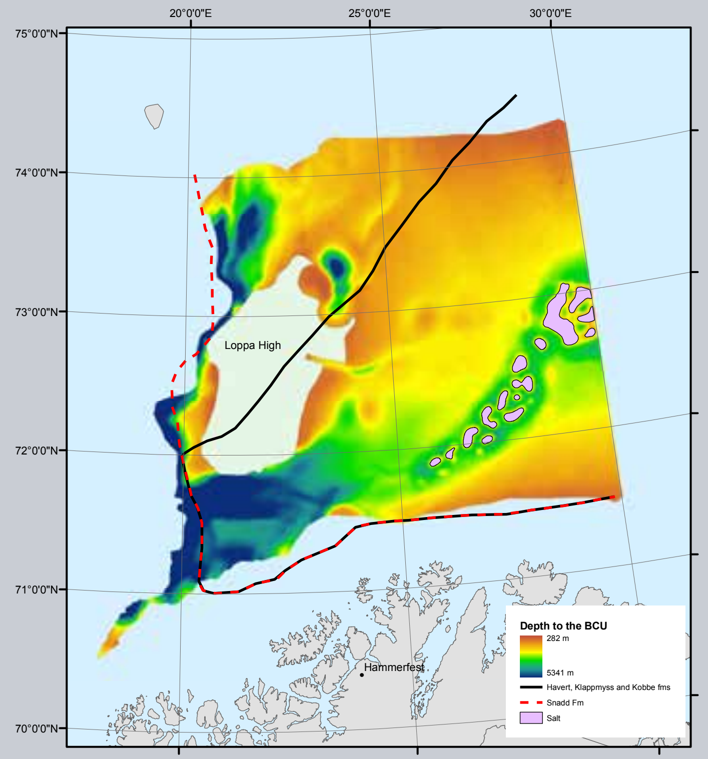
The base of the formation is a distinct regional marker, which on Svalbard marks the onset of deposition of phosphatic organic rich mudstones (Botneheia Formation). On the Svalis Dome similar lithologies are found in the Steinkobbe Formation. The oldest sediments of the Steinkobbe Formation are older than the Botneheia Formation.

The Snadd Formation (Ladinian to Norian) is defined at the base of a 60m shale interval above the mixed lithologies of the Kobbe Formation. The upper boundary is defined at the basal shales of the Fruholmen Formation.

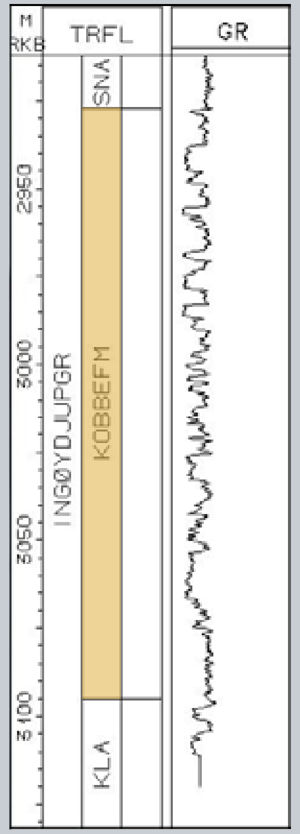
In the reference wells (7120/12-1 and 7120/9-2) the thickness is 944m and 1410m respectively, while in the type well (7120/12-2), the thickness is only 573m due to faulting out of 400m of the middle and upper part of the unit. On the Loppa High thicknesses are in the order of 1300-1400m. On the Nysleppen and Måsøy Fault the thickness is between 200 and 550m. The Bjarmeland Platform has thicknesses in the order of 600 to 850m. The basal grey shale coarsens up into shale interbedded with grey siltstones and sandstones. In the middle and lower part of the unit calcareous layers are relatively common with thin coaly lenses further upwards.

High rates of deposition occurred throughout the area with little differentiation between negative and positive elements. The Ladinian sequence represents relatively distal marine environments, following a major transgression which submerged all structural highs and platform areas. The Carnian is marked by a large scale progradation of deltaic systems derived from the south/southeast over the entire region.

The Snadd Formation shows great similarities in age and development to the lower and middle parts of the Kapp Toscana Gp of Svalbard (the Tschermakfjellet and De Geerdalen Formations).

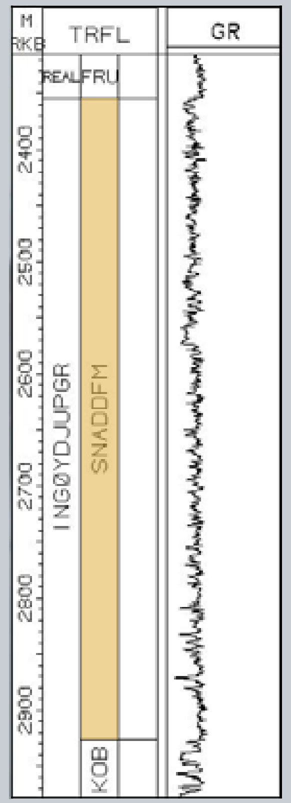


WELL LOG 7120/12-2



7120-12-1 - KOBBE, 3521-3524 m

WELL LOG 7120/12-2



7121-5-1 - SNADD, 3088-3094 m

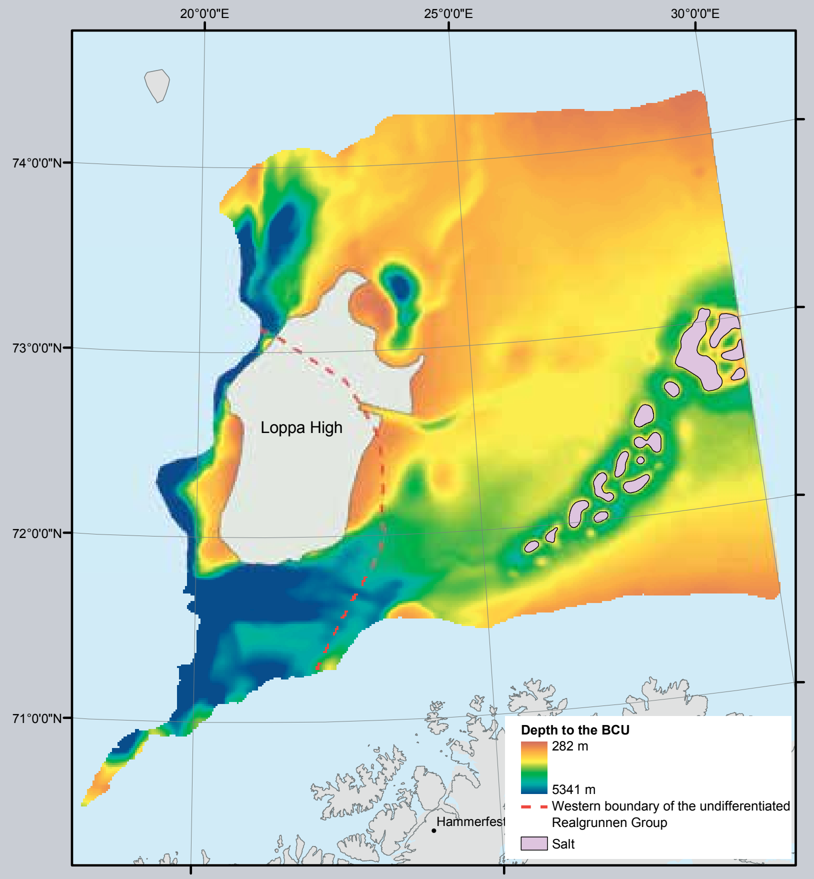
Late Triassic to Middle Jurassic

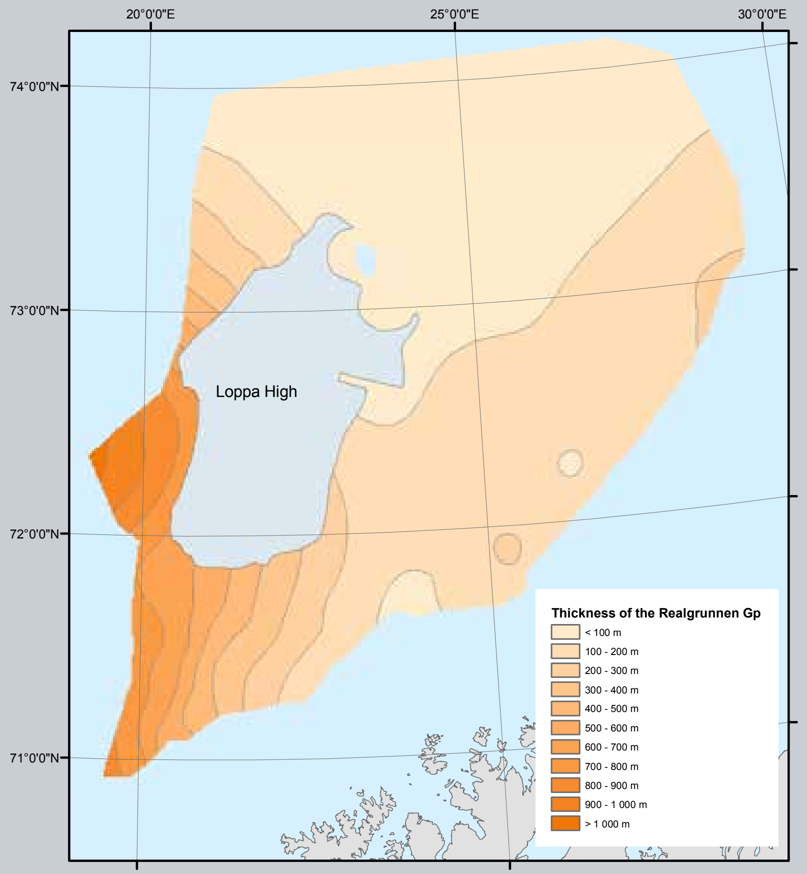
The Realgrunnen Group
(Early Norian to Bathonian)

The Realgrunnen Group was originally defined in the west central Hammerfest Basin with its type area in block 7121/5. It is subdivided into four formations, the Fruholmen, Tubåen, Nordmela and Stø formations. The thickness in the type well (7121/5-1) is 424m and 488m in well 7120/12-1. Thicknesses of up to 871m have been drilled in the southern part of the Bjørnøyrenna Fault Complex (well 7219/9-1). The group is thinly developed on the Bjarmeland Platform and definition of various formations is not so clear. The group is mostly eroded on the Troms-Finnmark Platform.

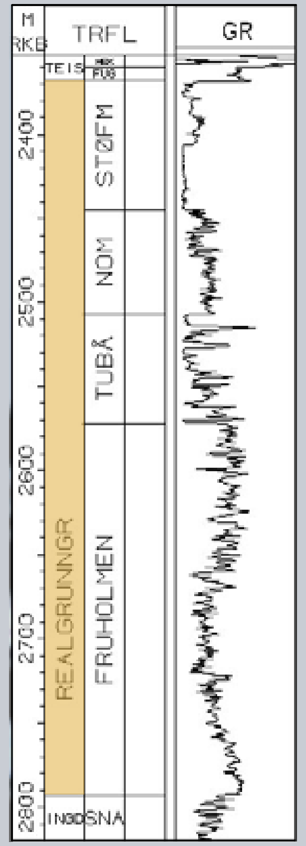
The dominant lithology is pale grey sandstone, especially in the middle and upper parts, while shale and thin coal are more common in the lower parts. The lower boundary is defined by the lower Norian basal shales of the Fruholmen Formation..

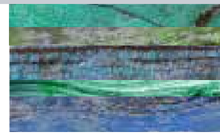
Following the transgression in the early Norian, deltaic systems developed over the southern parts of the Hammerfest Basin up through the Triassic. In the early Jurassic, coastal marine environments developed, grading into a variety of shoreface, barrier and tidal environments from the Toarcian to the Bajocian. Rocks of the Realgrunnen Gp have been deposited in general nearshore deltaic environments and are characterized by shallow marine and coastal reworking of deltaic and fluviodeltaic sediments.





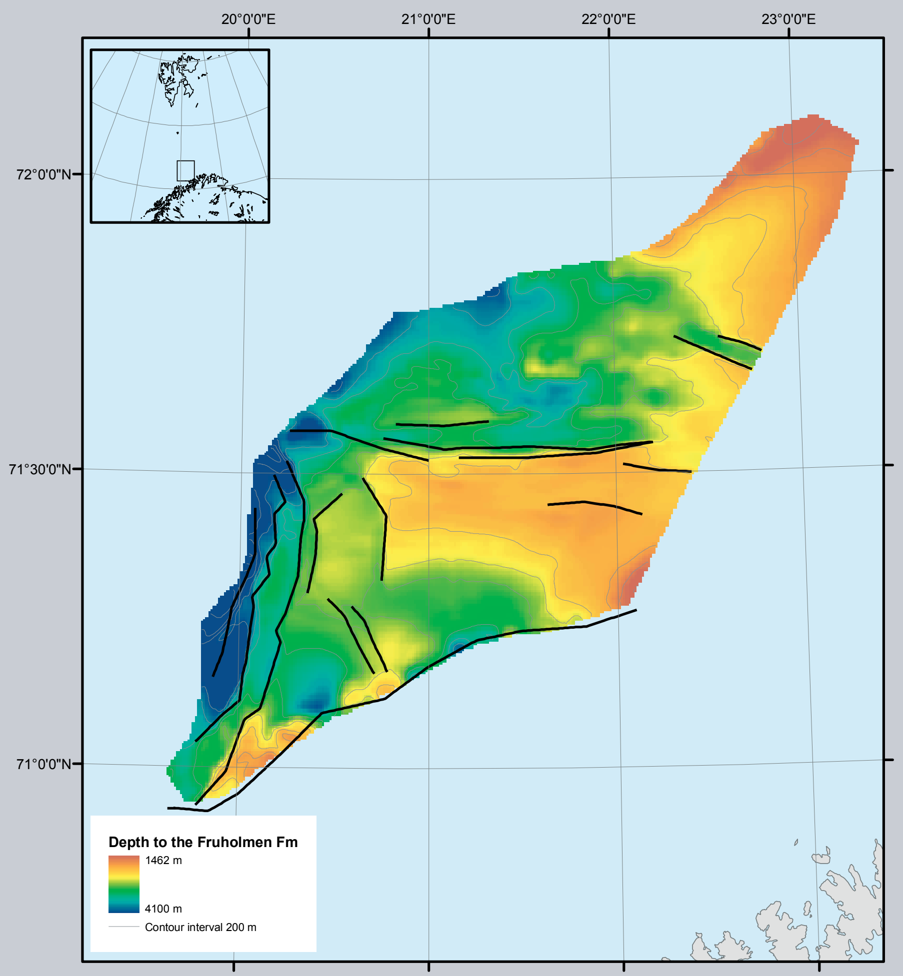
REALGRUNNEN
WELL LOG 7121/5-1



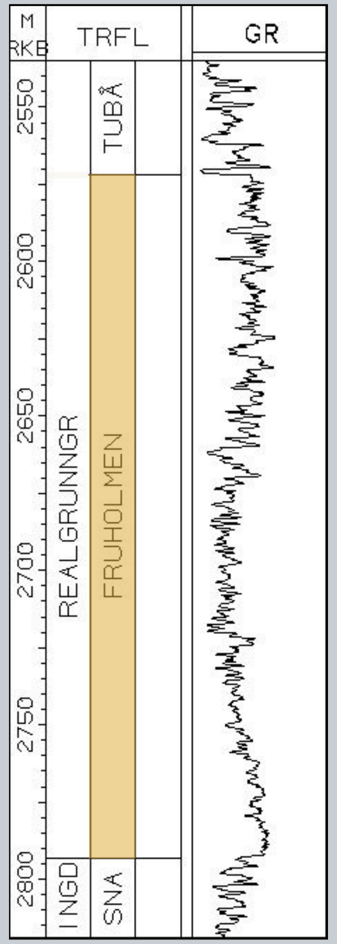


Late Triassic to Middle Jurassic

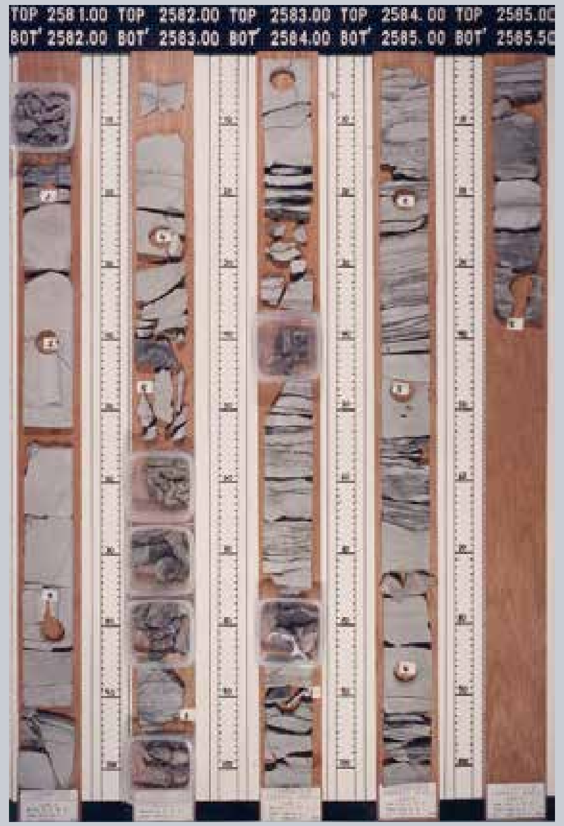
The Fruholmen Formation (Norian to Rhaetian) consists of grey to dark shale passing upwards into interbedded sandstone, shale and coals. Sands dominate in the middle part of the formation while the upper part is dominated by shales. This lithological development has resulted in a threefold subdivision of the formation with the shale-dominated **Akkar Member** at the base, overlain by the more sandy **Reke Member** which in turn the overlain by the more shale rich **Krabbe Member**. Depositionally this has been interpreted in terms of open marine shales (Akkar Mb) passing into coastal and fluvial dominated sandstones of the Reke Formation. These represent northward fluviodeltaic progradation with a depocentre to the south. As the main deltaic input shifted laterally, most of the central and southern parts of the basin became the site of flood-plain deposition, with more marine environments to the north (Krabbe Member).
In the type well (7121/5-1) the thickness of the formation is 221m and 262m in the reference well (7120/9-2). The thickest sequence, drilled so far (572m, well 7219/9-1), is within the Bjørnøyrenna Fault Complex.



WELL LOG 7121/5-1



7120-1-2 - FRUHOLMEN, 2581-2585 m



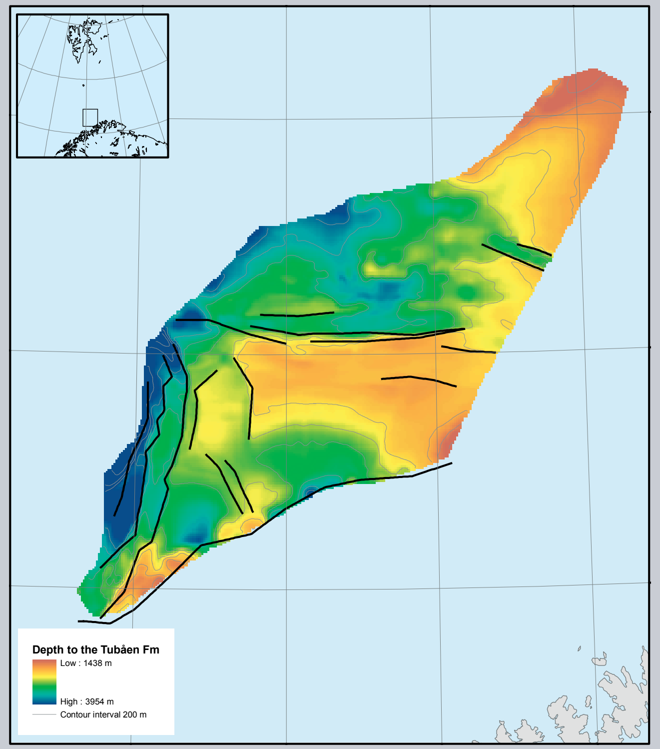
Late Triassic to Middle Jurassic

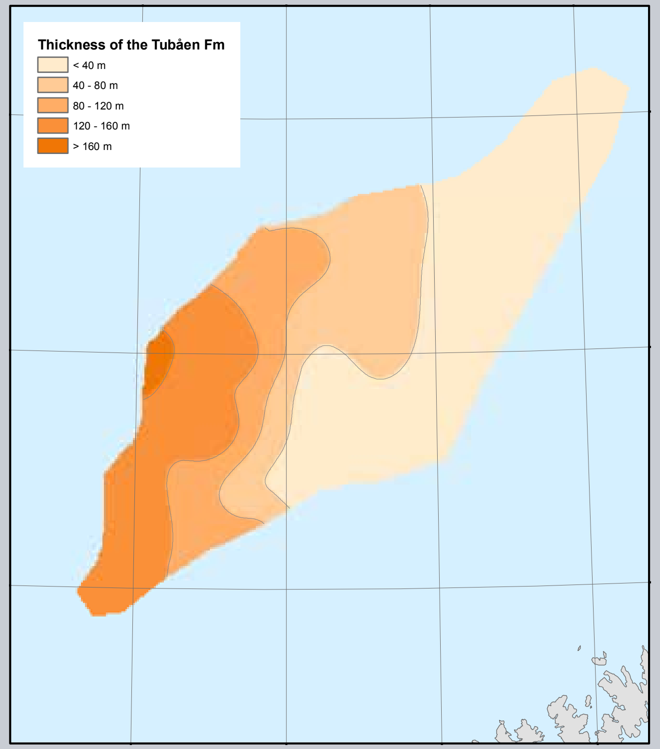
The Tubåen Formation (Late Rhaetian to early Hettangian,locally Sinemurian) is dominated by sandstones with subordinate shale and coals. Coals are most abundant near the southeastern basinal margins and die out towards the northwest. Generally the formation can be divided into three parts with a lower and upper sand-rich unit separated by a more shaly interval.

The shale content increases towards the northwest where the Tubåen Formation may interfinger with a lateral shale equivalent.

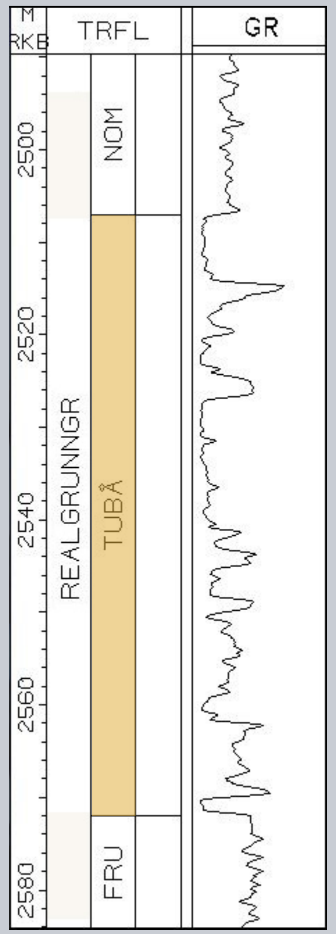
In the type well (7121/5-1) the thickness of the Tubåen Formation is 65 m and in the reference well (7120/12-1) it is 85m with a maximum thickness of 261m (well 7120/6-1) on the Snøhvit Field.

The sandstones of the Tubåen Formation are thought to represent stacked series of fluviodeltaic deposits (tidal inlet and/or estuarine). Marine shales reflect more distal environments to the northwest, while coals in the southeast were deposited in protected backbarrier lagoonal environments.

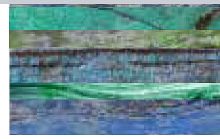




WELL LOG 7121/5-1



7121-5-1 - TUBÅEN, 2519-2524 m



Late Triassic to Middle Jurassic

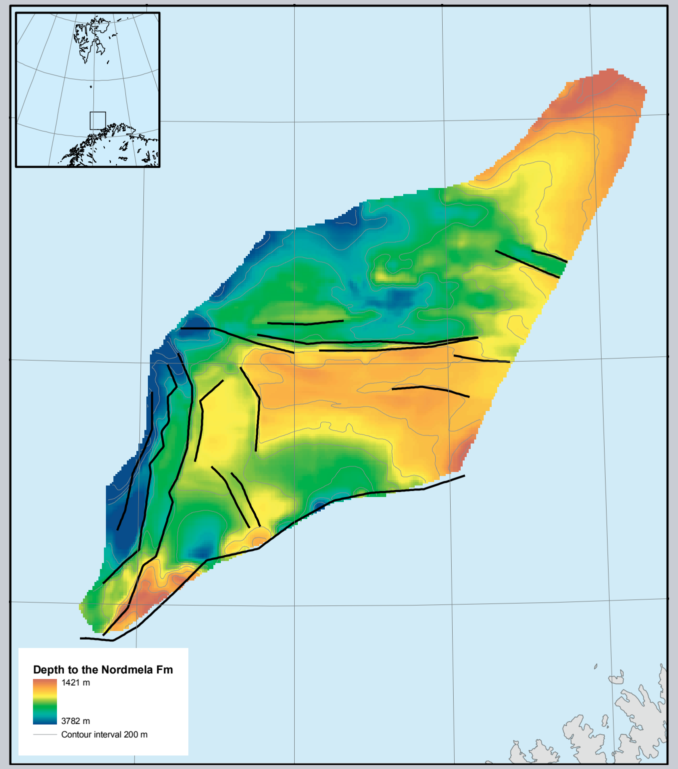
The Nordmela Formation (Sinemurian-Late Pliensbachian) consists of interbedded siltstones, sandstones, shale and mudstones with minor coals. Sandstones become more common towards the top.

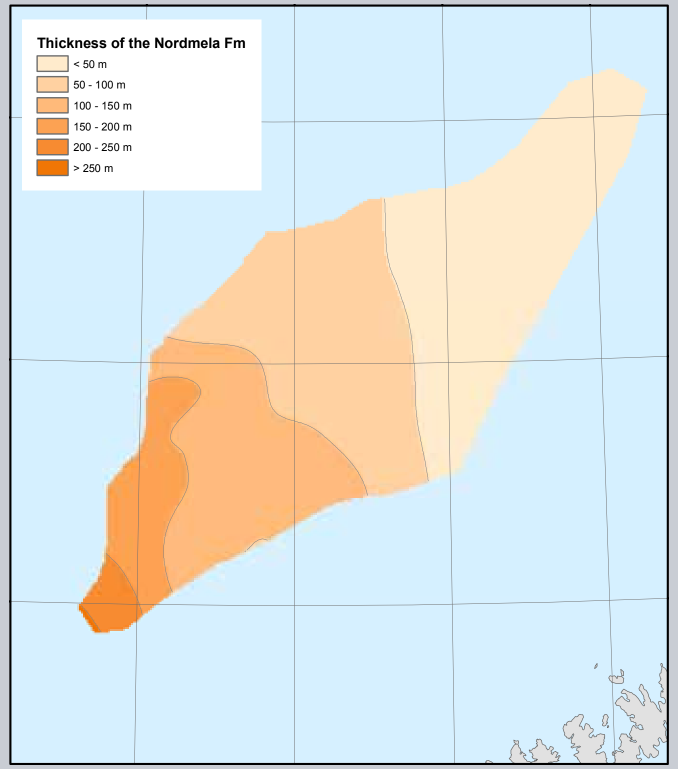
In the Hammerfest Basin the formation seems to form a westsouthwestward thickening wedge, similar to the underlying Tubåen Formation. It may be diachronous, younging eastwards.

The formation represents deposits in a tidal flat to flood-plain environment. Individual sandstones represent estuarine and tidal channels.

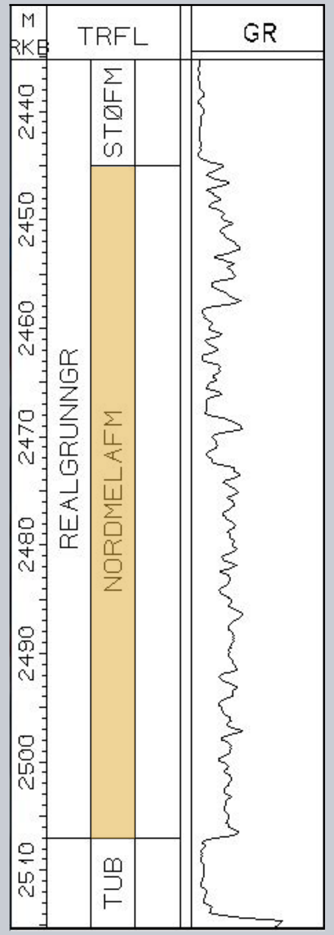
In the type well (7121/5-1) the thickness is 62m and in the reference well (7119/12-2) it is 202m.

This thickness variation between the type well and reference well clearly illustrates a southwest thickening wedge. Westward thickening is characteristic for all the three Lower and Middle Jurassic formations and may be the result of early Kimmerian subsidence of and tilting towards the Tromsø and Bjørnøya Basins.





WELL LOG 7121/5-1



7121-5-1 - NORDMELA, 2503-2506 m

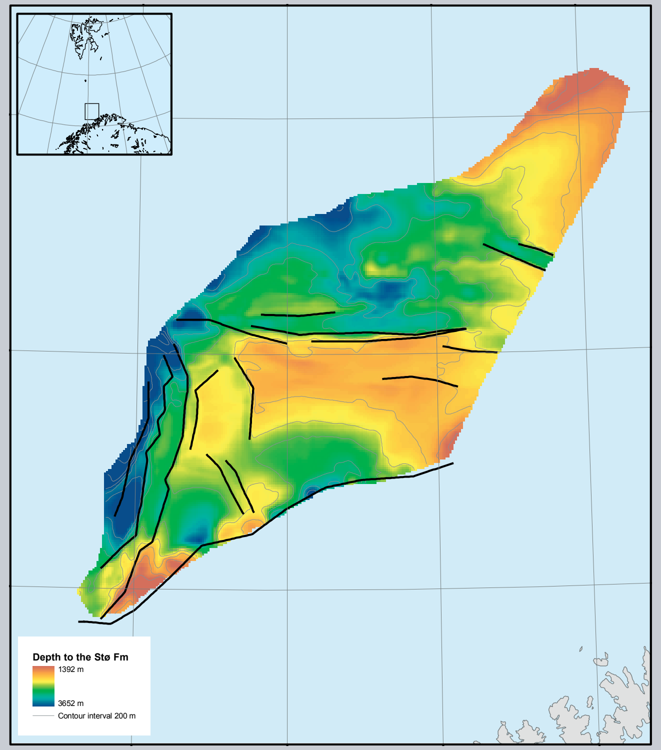
Late Triassic to Middle Jurassic

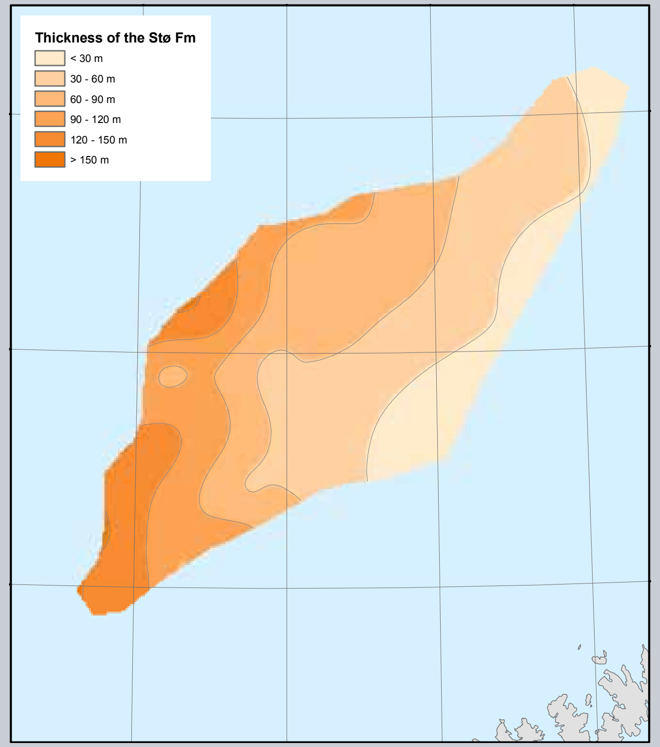
The Stø Formation (Late Pliensbachian to Bajocian) is defined with the incoming of sandy sequences above the shale dominated sediments of the Nordmela Formation.

The dominant lithology of the Stø Formation is well sorted and mineralogically mature sandstone. Thin units of shale and siltstone represent regional markers. Especially in the upper part of the Stø Formation phosphatic lag conglomerates can be found.

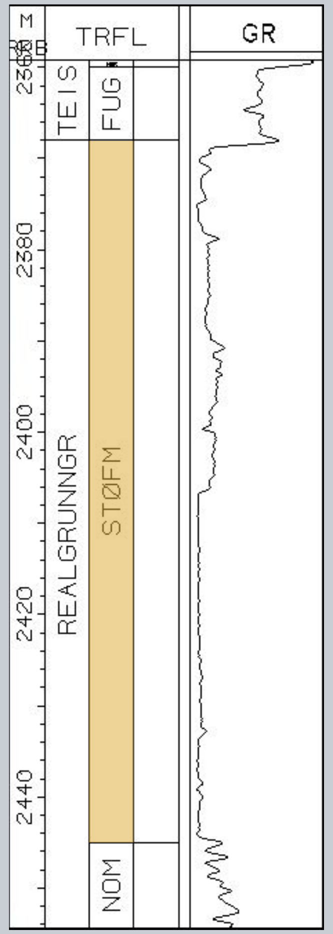
In the type well (7121/5-1) the thickness is 77m and in the reference well (7119/12-2) it is 145m. In general the Stø Formation thickens westwards in consistence with the underlying Nordmela Formation. The unit may be subdivided into three depositional episodes with bases defined by transgressions. The basal unit is only present in the western parts of the Hammerfest Basin. The middle part (Upper Toarcian–Aalenian) represents the maximum transgression in the area. The uppermost (Bajocian) unit is highly variable owing to syndepositional uplift and winnowing, and to later differential erosion.

The sands in the Stø Formation were deposited in prograding coastal regimes, and a variety of linear clastic coast lithofacies are represented. Marked shale/siltstone intervals represent regional transgressive pulses in the late Toarcian and late Aalenian.





WELL LOG 7121/5-1



7121-5-1 - STØ, 2400-2405 m

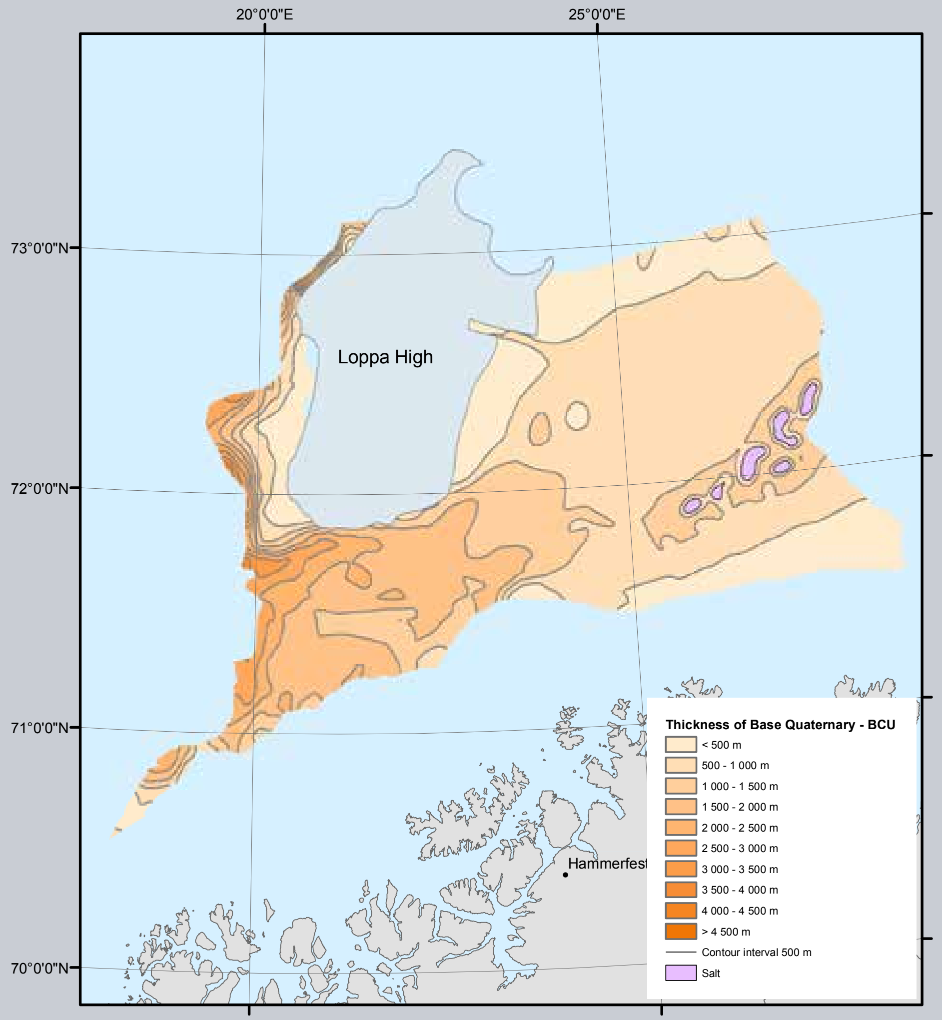
Upper Jurassic to Lower Cretaceous

Teistengrunnen Group
(Bathonian to Cenomanian)

The Teistengrunnen Group is subdivided into the Fuglen and Hekkingen formations, with its type area in the northern part of block 7120/12 in the Hammerfest Basin. The thickness varies from more than 900 m in the Bjørnøyrenna Fault complex (7219/8-1S) to 300m just north of the Troms-Finnmark Fault Complex to approximately 60m or less on structural highs in the center of the Hammerfest Basin, reflecting the effect of Upper Jurassic tectonic movements.

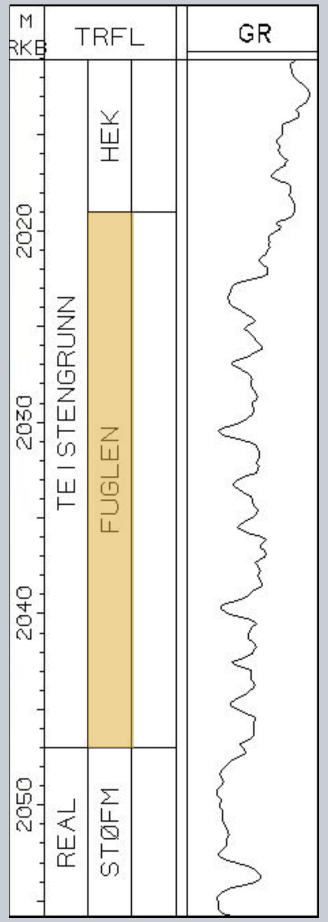
The group is dominated by dark marine mudstones, locally including deltaic and shelf sandstones as well as carbonate.

The **Hekkingen** Formations is an important hydrocarbon source rock. Both the Fuglen and Hekkingen Formation constitute good cap rocks.



Thickness of the secondary seal, defined as the thickness between the BCU and the base Quaternary

WELL LOG 7120-12-1



7120-12-1 - FUGLEN, 2044-2047 m

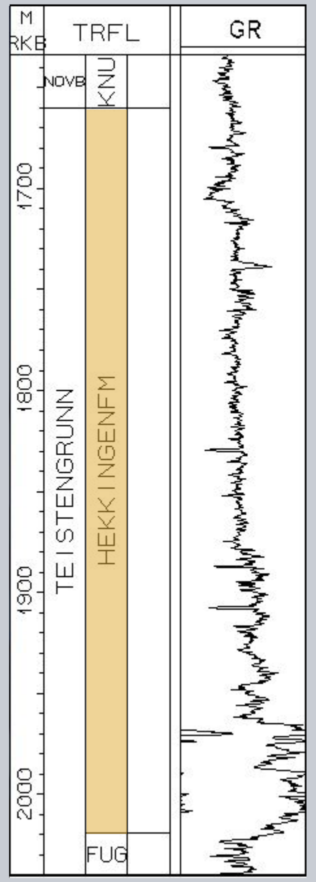
The Hekkingen Fm (Upper Oxfordian–Tithonian) has been drilled in the Hammerfest Basin, the eastern part of the Bjørnøya Basin (Fingerdjupet Subbasin) and the Bjarmeland Platform. The lower boundary is defined by the transition from carbonate cemented and pyritic mudstone to poorly consolidated shale (**Fuglen Fm**) and the upper boundary in the reference well (7120/12-1) is defined towards a thin sandy limestone of the **Knurr** Formation.

The thickness in the type well (7120/12-1) is 359m and in the reference well (7119/12-1) the thickness is 113m. Within the Hammerfest Basin the thickest sequence is found in the type well, thinning northwards to less than 100m. Very high thicknesses are interpreted along the eastern margins of the Harstad Basin and Bjørnøya Basin, as shown in well 7219/8-1S in the southern part of the Bjørnøyrenna Fault Complex (856m thickness). Thin sequences are found on the Bjarmeland Platform.

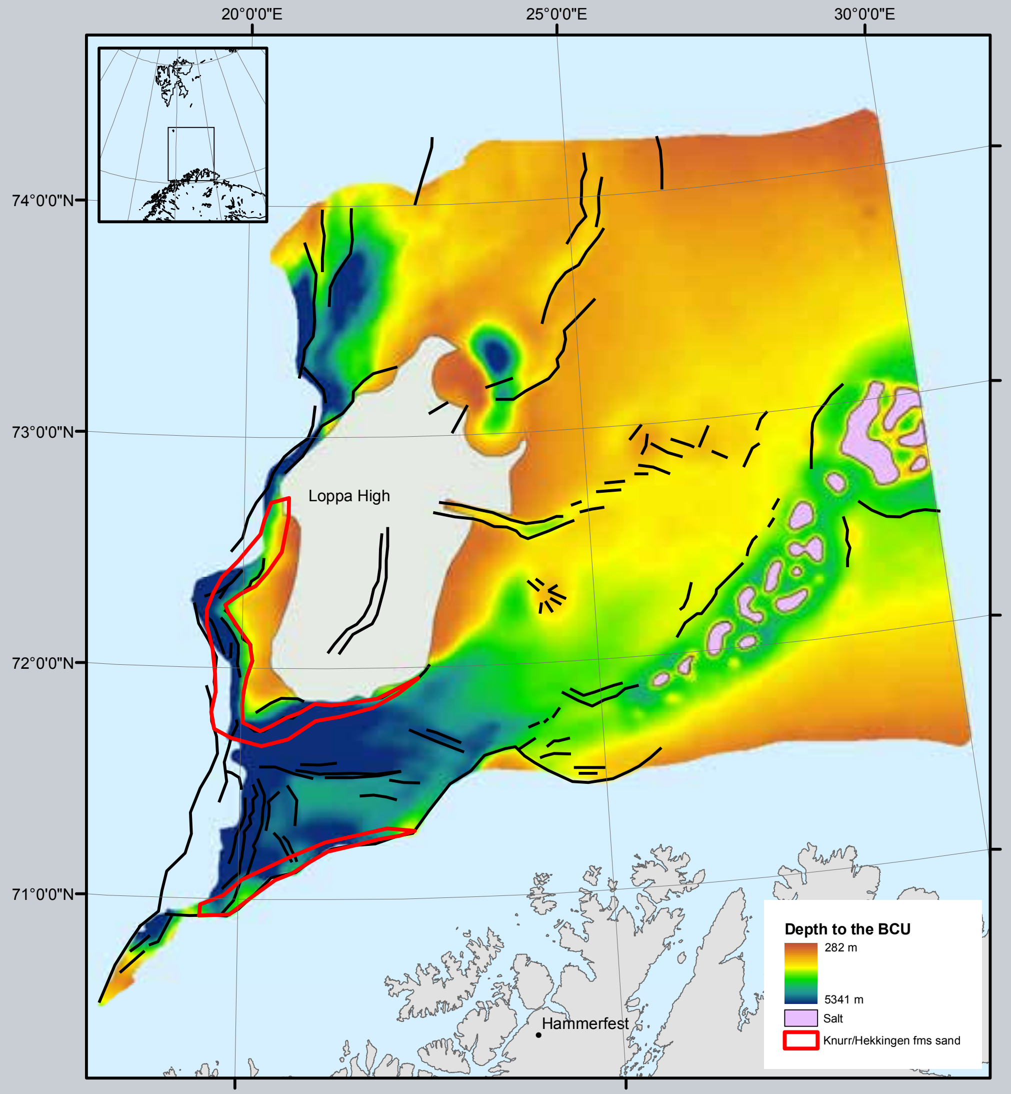
The dominant lithology in the formation is shale and mudstone with occasional thin interbeds of limestone, dolomite, siltstone and sandstone. The amount of sandstone increases towards the basin margins.

The formation was deposited in a deep shelf with partly anoxic conditions.

WELL LOG 7120-12-1



7120-12-1 - HEKKINGEN, 1702-1705 m



Areas where Knurr and/or Hekkingen sandy deposits occur are outlined.

Lower Cretaceous

Nordvestbanken Group
(Berriasian/Valanginian to Cenomanian)

The Nordvestbanken Group is subdivided into three formations: The Knurr, Kolje and Kolmule formations. The dominant lithology is dark to grey-brown shale with thin interbeds of siltstone, limestone, dolomite and local sandstone. The type area for the group is the eastern part of the Ringvassøy-Loppa Fault Complex (block 7119/12) and the southwestern part of the Hammerfest Basin (block 7120/12). The thickness is in the order of 1000-1400m in the type area. Thicknesses within the Hammerfest Basin are closely related to Upper Jurassic structural development. The group is thickest along basin margins and thins towards the central part of the Hammerfest Basin. Here we focus on the Knurr Formation as this may represent thief sands in relation to the main Mesozoic aquifers.

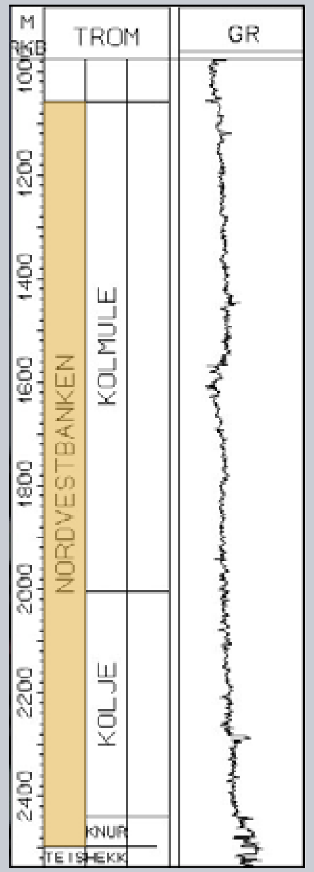
The Knurr Formation (Berriasian/Valanginian to lower Barremian) is distributed over the southwestern part of the Barents Shelf, mainly in the Hammerfest Basin,the Ringvassøy-Loppa Fault Complex and the Bjørnøyrenna Fault complex. A thin Knurr section is also found locally on the Bjarmeland Platform.

The thickness of the Knurr Formation is 56m in the type well (7119/12-1) and 285 m in the reference well (7120/12-1). The thickest drilled section so far is 978m (well 7219/8-1S) in the Bjørnøyrenna Fault Complex east of the Veslemøy High. The base is defined by a thin sandy limestone overlying the Hekkingen Formation and the upper boundary is defined by incoming of dark brown to grey shale in the Kolje Formation.

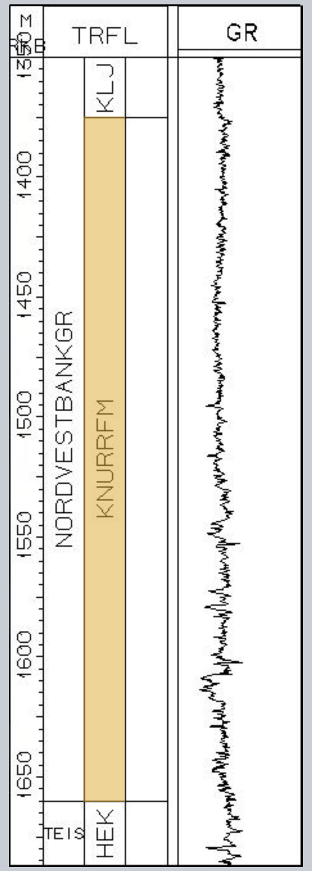
Although the formation shows similar lithology in most wells, the sand content is higher close to the Troms-Finnmark Fault Complex and in the Ringvassøy-Loppa fault Complex. The sandstones are located in the lower part of the formation, pinching out laterally into the Hammerfest Basin and Bjørnøya Basin.

The formation was deposited in an open generally distal marine environment with local restricted bottom conditions.

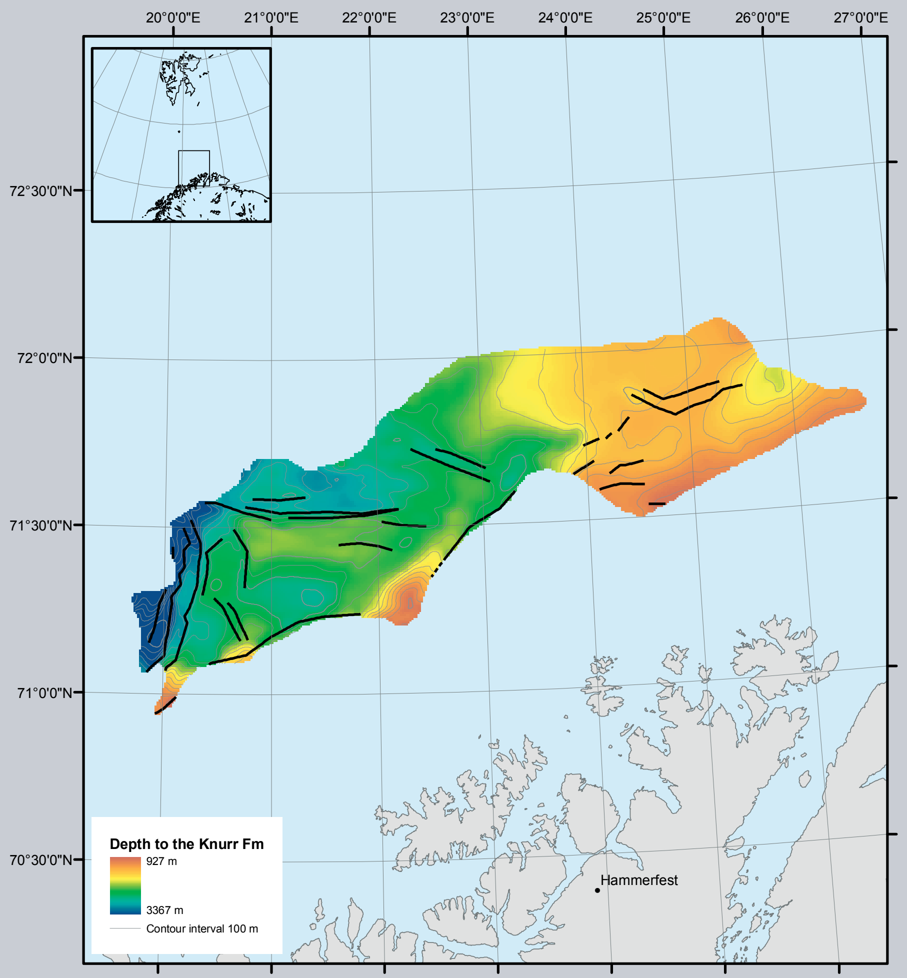
NORDVESTBANKEN
WELL LOG 7119/12-1



WELL LOG 7120-12-1

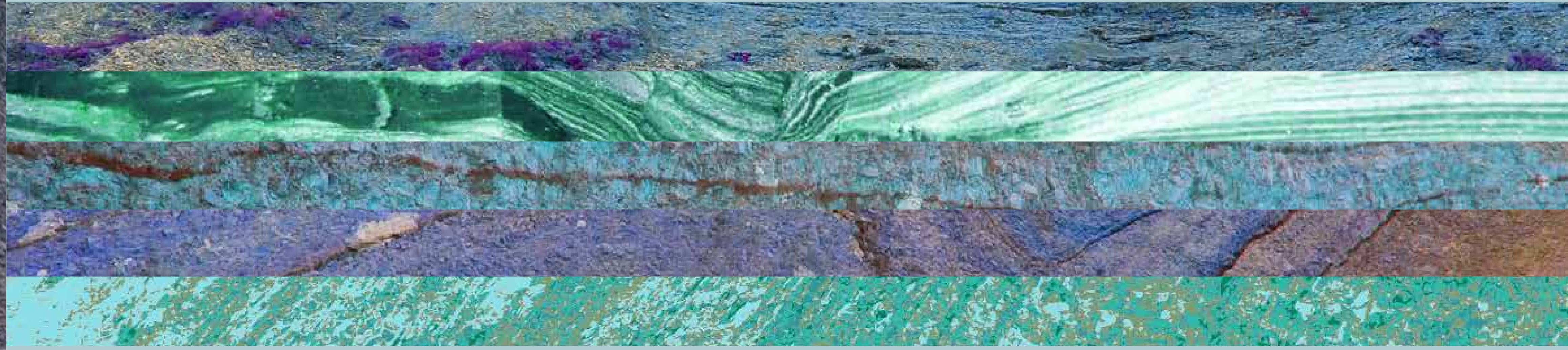


7019-1-1 - KNURR, 2225-2230 m



The Triassic succession in the southern Barents Sea continues to the north and the outcrops of Svalbard are very good analogs. The photo shows the Triassic section at Blanknuten, Edgeøya, with the distal Lower Triassic Vikinghøgda Formation, the distinct Middle Triassic Botneheia and Tschermakfjellet shales and the overlying channelized Upper Triassic reservoir sandstones in the de Geerdalen Formation. The cliff-forming Botneheia shale is analogous to the Steinkobbe shale and the de Geerdalen Formation is analogous to the Snadd Formation.

5. Storage options



5.1 Introduction

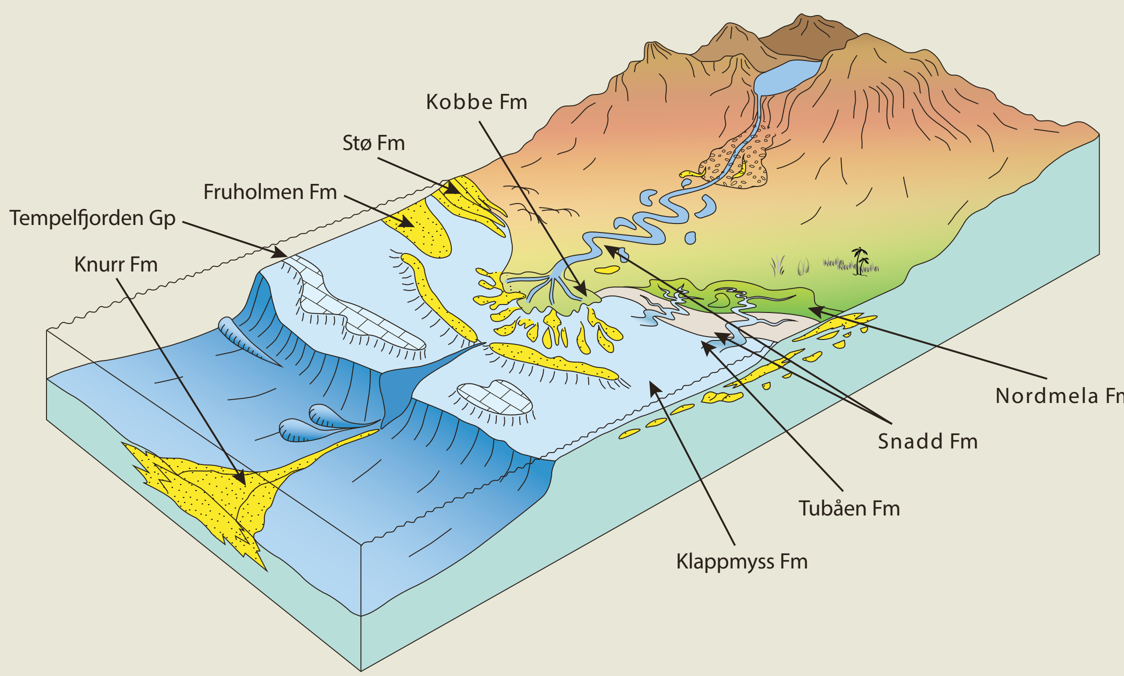
The parts of northern Fennoscandia adjacent to the Norwegian sector of the Barents Sea are sparsely populated and the industrial activity generates only small amounts of CO_2 emissions. CO_2 associated with the production of natural gas in the Snøhvit Field is separated at Melkøya, Hammerfest, and injected in the aquifer of the field. CO_2 associated with gas production is believed to be the main source for CO_2 storage and EOR in the near future. In a more distant future, storage of anthropogenic CO_2 from industrial activity may become an option.

For detailed evaluation of storage capacity large areas in the north and east were screened out. The areas north of 74^o were excluded because they were considered to be too remote and because the good Jurassic aquifers are generally thin and poorly sealed due to shallow overburden. The Finnmark Platform east of 29^o was screened out because there is limited infrastructure and industrial activity in this area, and the main aquifers of interest are poorly structured and generally monoclinally dipping with only a Quaternary seal towards the sea floor. The area selected for detailed evaluation of storage capacity is shown in the map.

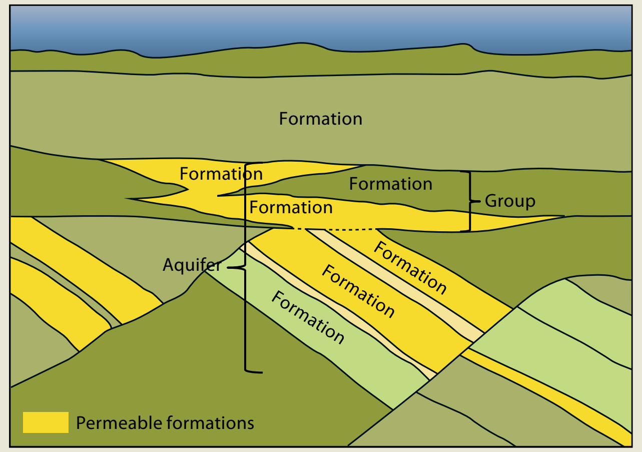
The petroleum systems of the Barents Sea are more complex than in the North Sea and Norwegian Sea. Important source rocks occur in the Upper Jurassic, Middle Triassic and Late Paleozoic sections. Because of Cenozoic tectonism and Quaternary glacial erosion, the maximum burial of these source rocks in the evaluated area occurred in the past. The reservoir porosity and permeability is related to the temperature and pressure at maximum burial. Due to extensive erosion, good reservoir quality is encountered only at shallower depth than what is found in the North Sea and Norwegian Sea. Below 3000 m the porosity and permeability is generally too low for large scale injection.

The Cenozoic history has also affected the distribution of hydrocarbons in the evaluated area. Residual oil is very commonly found, both in water-bearing traps and below the gas cap in gas-bearing traps. Hydrocarbons and traces of hydrocarbons have been found in several aquifers, and at the present stage in exploration, it is thought that most of the area selected for evaluation of CO_2 storage will also be subject to further exploration and exploitation by the petroleum industry. Consequently, storage of CO_2 in the southern Barents Sea must take place in concordance with the interests of the petroleum industry. The main storage options considered in this study are limited to structurally defined traps, and to depleted and abandoned gas fields. In areas where the pressure exceeds the miscibility pressure of CO_2 and oil, it may be considered to use CO_2 injection to recover some of these oil resources (CCUS).

The main aquifer system in the study area consists of Lower and Middle Jurassic sandstones belonging to the Realgrunnen Subgroup (section 4). This aquifer system can be defined in three distinct geographical areas which are described in section 5.2.



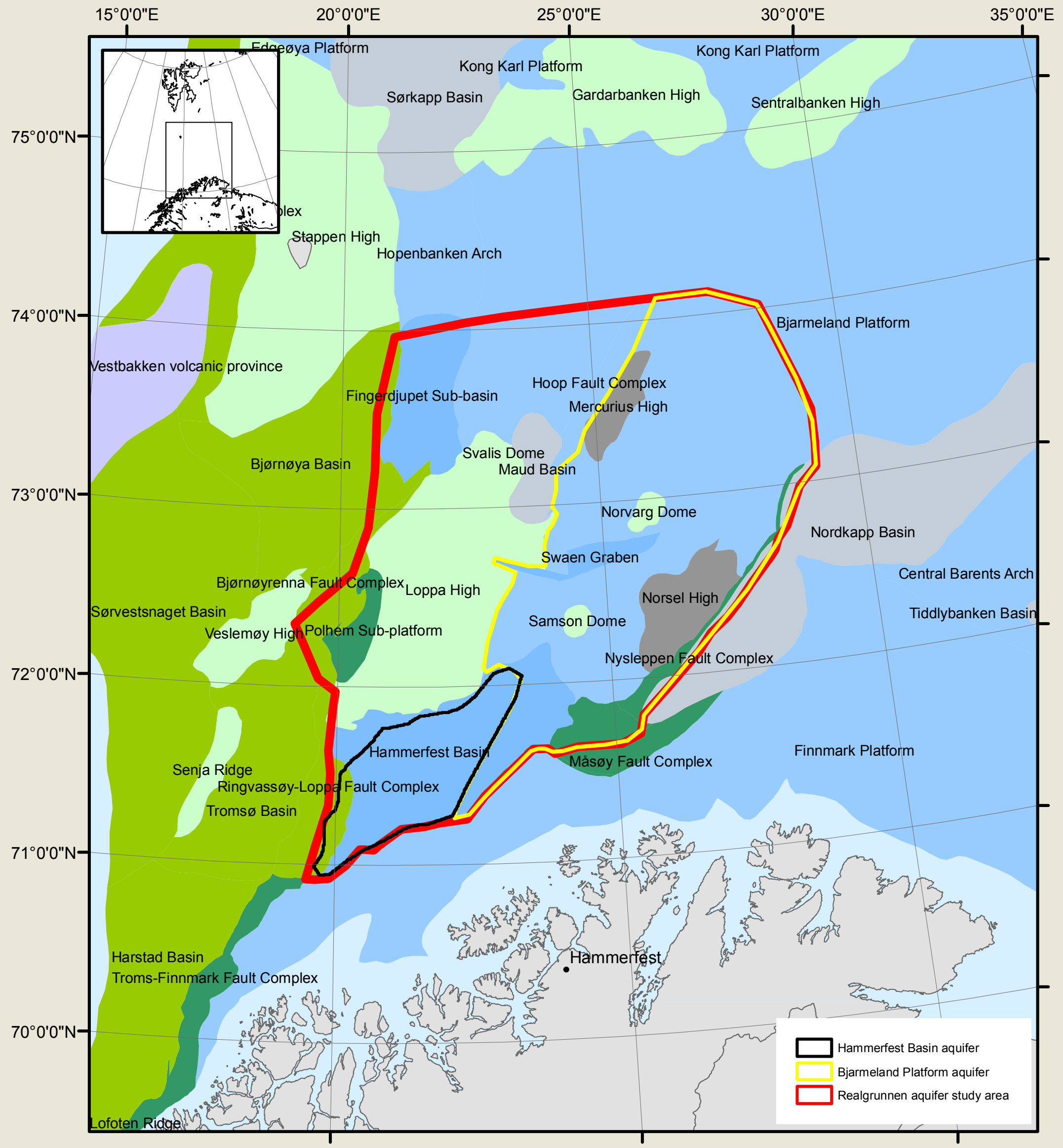
Conceptual sketch showing location of aquifers relative to depositional systems



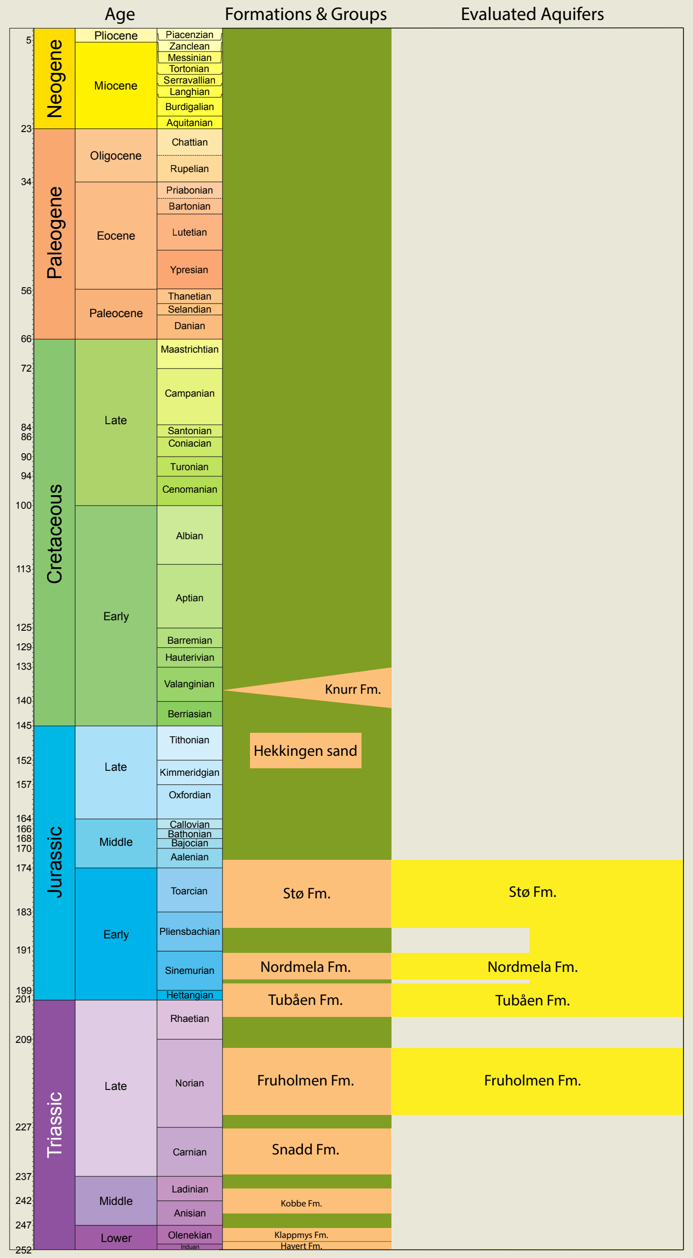
Relation between geological formations and aquifers.

5.1 Introduction

Hydrocarbons have been encountered in several reservoir levels pre-dating the Jurassic, notably in the Late Triassic Fruholmen and Snadd Formations, the Middle Triassic Kobbe Formation and in Permian carbonates and spiculites, thus proving there is a reservoir and seal potential for these formations. Their storage potential is not as promising as for the Jurassic aquifer, and is briefly discussed in section 5.2. Upper Jurassic and Lower Cretaceous sandstones are limited to the flanks of active highs and do not form major aquifers. Eocene reservoir sandstones have been encountered in two wells in the western margin of the Barents Sea, but are not considered for this study.



The evaluated area (red outline). The Jurassic aquifers are eroded in the Loppa High.

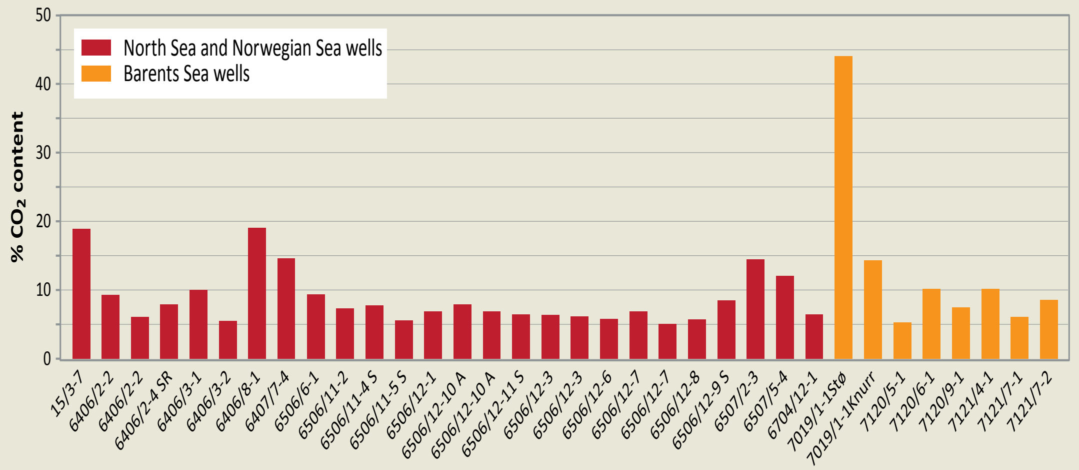


Naturally occurring CO_2 in geological formations

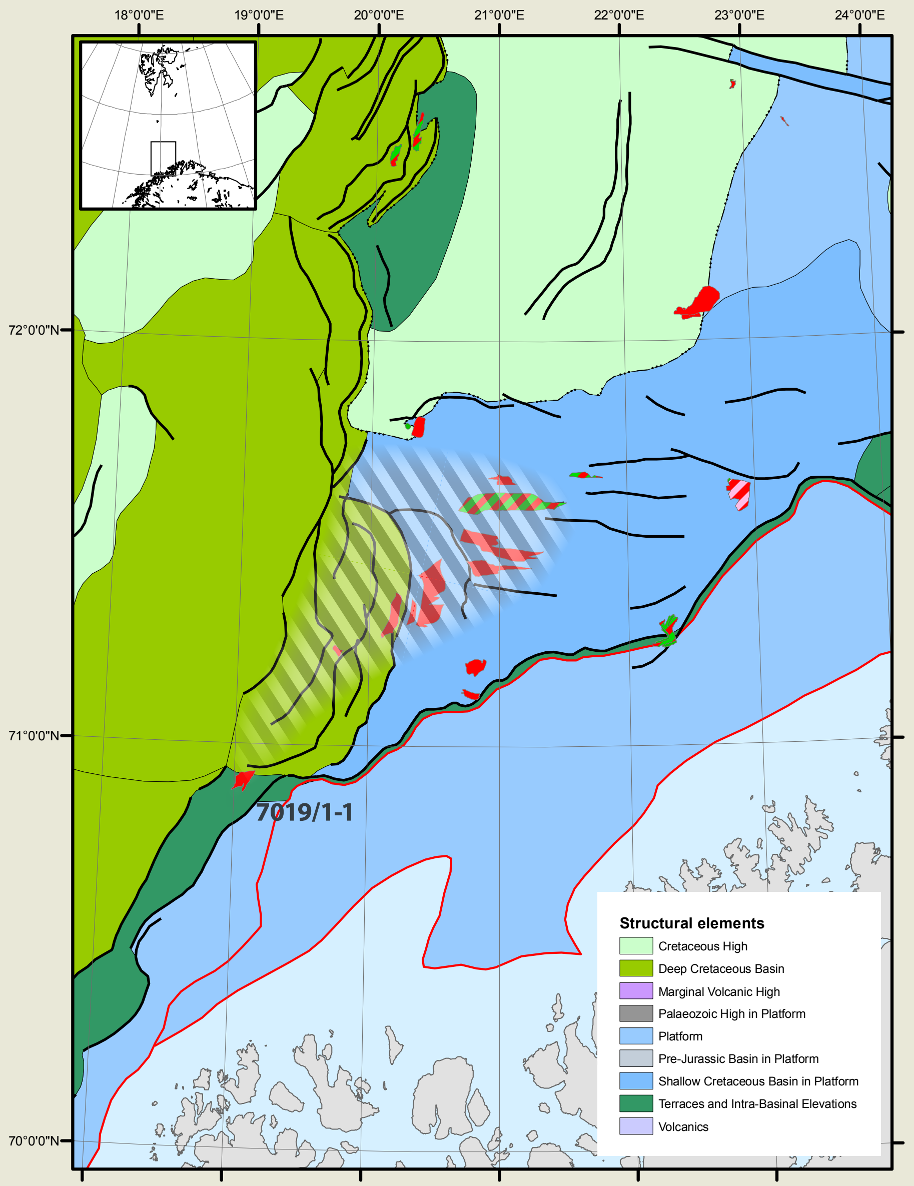
CO_2 occurs in some metamorphic rocks and is an integrated component in intrusive and extrusive volcanic rocks. The gas exported from Norway to the European continent cannot have more than 2.5% CO_2. Some of our producing gas fields have higher CO_2 content which require dilution with gas having low CO_2-content or CO_2 has to be separated from the gas stream and injected into saline aquifers.

Gas from the Snøhvit Field and the Sleipner Field have high CO_2 concentrations that require CO_2 capture and storage. Some of the discoveries in the Norwegian Sea offshore Nordland also have a high CO_2 content that will require capture and storage of CO_2 if the gas is produced. CO_2-rich gas occurs in the western parts of the Halten- and Dønna terraces. In the western part of the Vøring Basin, one well showed a CO_2 content of 7%. Other gas discoveries in the deeper parts of the Møre- and Vøring Basins do not show significant CO_2 content.

In general, in the Norwegian shelf, the percentage of CO_2 associated with methane in gas fields can be correlated with the depth of burial of the source rock which has generated the gas. In the Barents Sea, CO_2 rich gas has been encountered along the margins of the deep Harstad, Tromsø and Bjørnøya basins. One accumulation of gas with a CO_2 content in the order of 50 % was found in well 7019/1-1 (NPD web site), while in other gas discoveries in the western Barents Sea, the percentage of CO_2 typically does not exceed 10. Further east, the CO_2 content appears to be lower. The reason for the increased CO_2 content in those areas is not clear, although the close vicinity to Paleogene volcanic sill intrusions may explain a lot of the natural CO_2 in 7019/1-1. Both organic processes and degassing of metamorphic and overheated sedimentary rocks may contribute to the CO_2 generation.



A selection of wellbores with CO_2 content above 5%.



Wells with high CO_2 content.

Cretaceous High
Deep Cretaceous Basin
Platform
Shallow Cretaceous Basin in Platform
Terraces and Intra-Basinal Elevations
Wells with high CO_2 content

7019/1-1 discovery

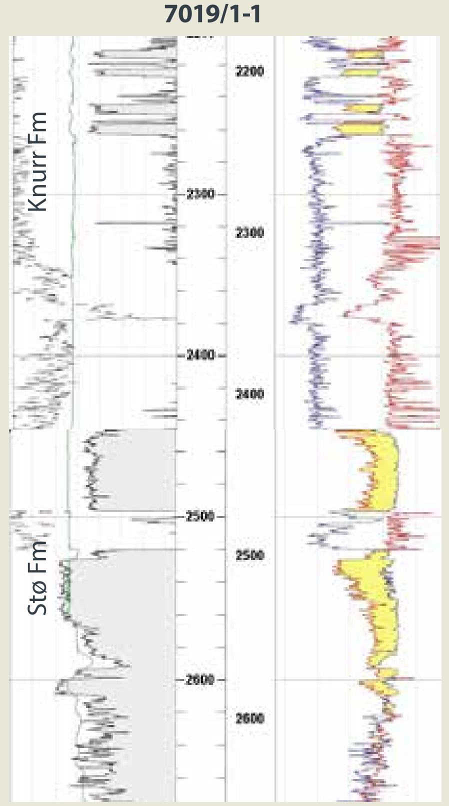
The 7019/1-1 well was drilled by ENI in 2000 on a rotated, down-faulted block facing the Harstad Basin. The well encountered gas in two reservoir horizons, the Middle Jurassic Stø Formation and the Lower Cretaceous Knurr Formation. It was reported that the Jurassic Stø Formation contained at least 50% CO_2. The gas would not ignite during a short test. The CO_2 content in the Lower Cretaceous is less, roughly 15%. The permeability was low in the Stø Formation due to diagenesis and stylolitization at that depth, while some of the sandstone layers in the Lower Cretaceous 300 m shallower had good permeability and porosity.

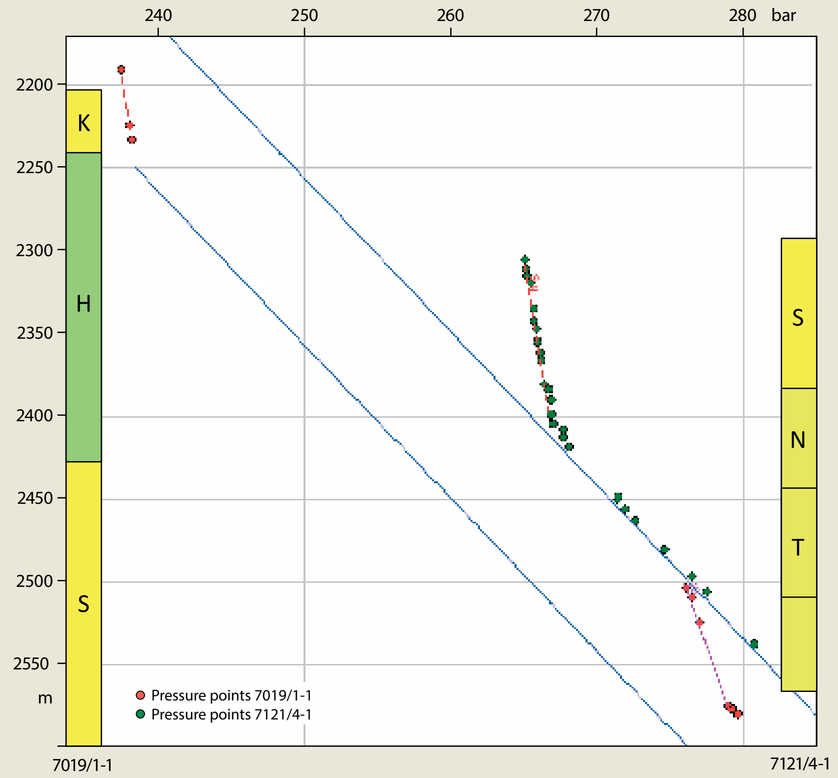
A test was performed in the interval 2526 to 2563 m in the Stø Formation. The well flowed 606000 m3 gas per day (no liquid) from a 40/64 choke. Gas gravity was 1,133 (air = 1), CO_2 content 60 - 70%, and H2S content 6 - 13 PPM. The test was stopped during the clean up phase due to the high CO_2.

A plot of the pore pressures shows that the difference in pressure between the Cretaceous and Jurassic gas gradients is almost 3 MPa (30 bar). There are no pressure data from the water zone in the Knurr Formation. Assuming a contact of 2250 m based on the log data, the pressure difference between the water zones is 0.5 MPa (5 bar). The Cretaceous gas gradient from the pressure plot is similar or slightly lower than the gas gradient in the Snøhvit field (0.018 bar/m), while the Jurassic gradient indicates a considerably heavier gas (more than 0.03 bar/m). These gradients seem to be consistent with a high CO_2 content in the Jurassic reservoir reported from the well test, while the proportion of CO_2 in the Cretaceous reservoir is interpreted to be similar to the Snøhvit area.

The pressure data show that the Upper Jurassic shale between the two reservoirs has good sealing properties. A large difference in CO_2 concentration between the two reservoirs implies that the Upper Jurassic seal is capable to contain CO_2 in a long time period (time scale of millions of years). This observation is relevant for the eroded Barents Sea Jurassic reservoirs, because the amount of erosion and cooling of the 7019/1-1 well (based on the diagenesis of the Stø Formation) appears to be higher than in the Hammerfest Basin.

The pressure plot also shows that the pore pressure in the water zone is lower in 7019/1-1 than in the Snøhvit area. Similarly, slightly lowered water pressures are observed in block 7120/12. One possible explanation for this is that the salinity of the aquifer brine is lower in these areas.





Plot of measured pore pressure in the 7019/1-1 well compared with 7121/4-1 in Snøhvit. Upper blue line: Average water gradient in the Snøhvit area. Lower blue line: Interpreted water gradient in the Cretaceous section of 7019/1-1. Red lines: gas gradients. Color bars show the formation depth in each well. K – Knurr, H – Hekkingen, S- Stø, N – Nordmela, T- Tubåen. Vertical scale: Depth below sea level.

Hammerfest Basin

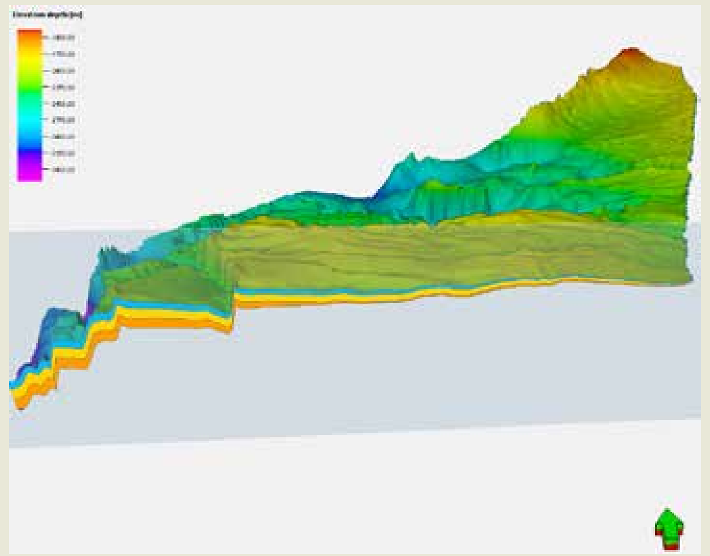
In the Hammerfest Basin, the Jurassic Tubåen, Nordmela and Stø Formations increase in thickness towards west. The western part of the basin is bounded by large faults to the north and south which juxtapose the Jurassic aquifer towards tight Triassic formations. Towards north-east, the Jurassic aquifers subcrop against the sea floor with a thin Quaternary cover, while in the eastern part there is a gradual transition to thinner formations in the Bjarmeland Platform aquifer. Faults within the basin commonly juxtapose Stø towards Nordmela and Tubåen Formations. Paleo fluid contacts indicate that the faults are open where there is sand-sand contact.

Pressure data from exploration wells show that the Jurassic formations are hydrostatically pressured at depths shallower than 2600 m. The data indicates that the pore pressure has equilibrated between the three formations. The most important regional stratigraphic barrier in the succession is considered to be the shaly lower part of the Nordmela Formation. Pressure data indicate that the thin shaly continuous layers in the middle part of the Stø Formation can create baffles for vertical flow during production. In general, the Tubåen and Nordmela Formations are heterogeneous reservoirs where individual channels have good reservoir properties while they may be poorly connected to other parts of the reservoir.

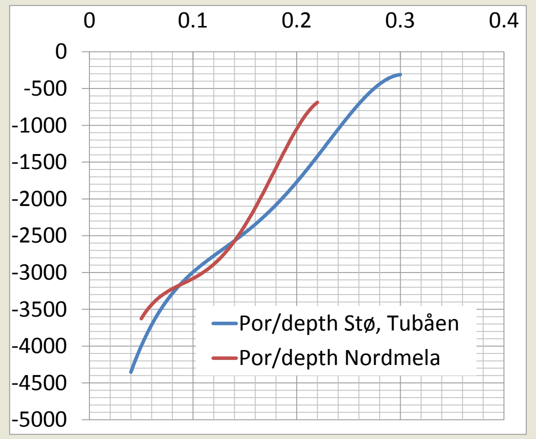
For the evaluation of storage potential it was decided to define the Stø, Nordmela and Tubåen Formations as one single aquifer system. The geological data show that the Stø Formation is very well connected laterally. The underlying, heterolithic formations are believed to contribute to the aquifer at a regional scale. At a smaller scale, in an injection site, stratigraphic barriers may allow gas to accumulate at different stratigraphic levels within a structural closure. This is shown by local small oil and gas accumulations below the main contacts of the Snøhvit and Albatross accumulations. The experience from CO_2 injection in the Snøhvit Field showed that CO_2 was contained within the Tubåen Formation with no upwards migration into the Nordmela and Stø Formations.

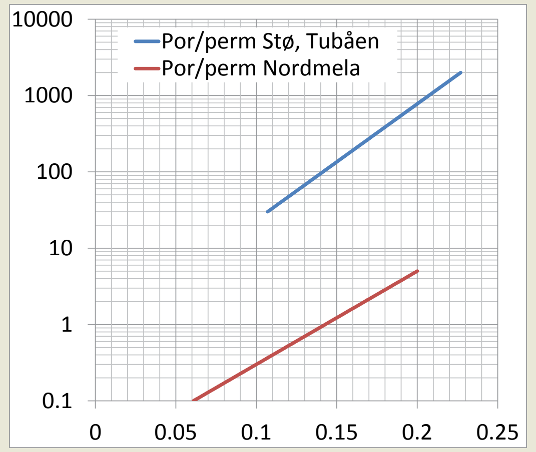
The calculations of storage capacity in structures are based on injection and storage in the Stø Formation. For the aquifer volume the storage capacity includes the Nordmela and Tubåen Formations. The experience from the Snøhvit CO_2 injection shows that many injection wells may be needed to realize a large storage potential in these heterolithic formations. The formation water in the aquifer is strongly saline, with salinities generally exceeding 100 000 ppm. The water density at standard conditions in the Snøhvit Field is around 1.1 g/cm^3. Somewhat lower salinity is indicated in the 7125/4-1 discovery and in some wells in the southwestern part. High salinity may cause problems for CO_2 injection due to salt precipitation near the wells. Another effect of salinity is that CO_2 is less soluble in high salinity brines than in sea water, the amount of CO_2 trapped by dissolution can then be relatively small.

Residual oil is widely distributed in the Jurassic Hammerfest Basin aquifer. Apparently, the megastructures in the central part of the basin were filled with oil and gas at the time of maximum burial. Large volumes of gas have seeped out whereas the oil is still remaining. The oil saturation is believed to be small. Theoretically, residual oil will reduce the effective permeability of the aquifer due to relative permeability effects.



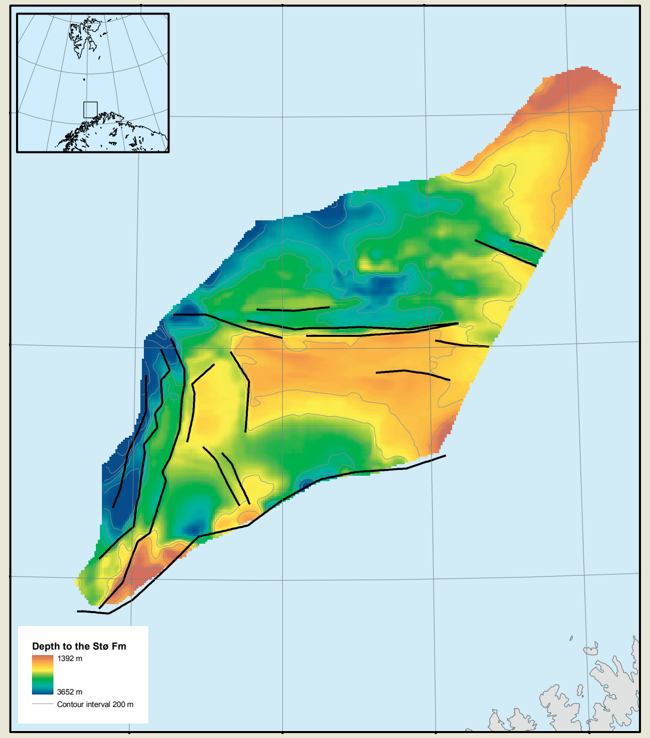
W–E cross-section through the Hammerfest Basin 3D geological model, showing the Stø, Nordmela and Tubåen aquifers.

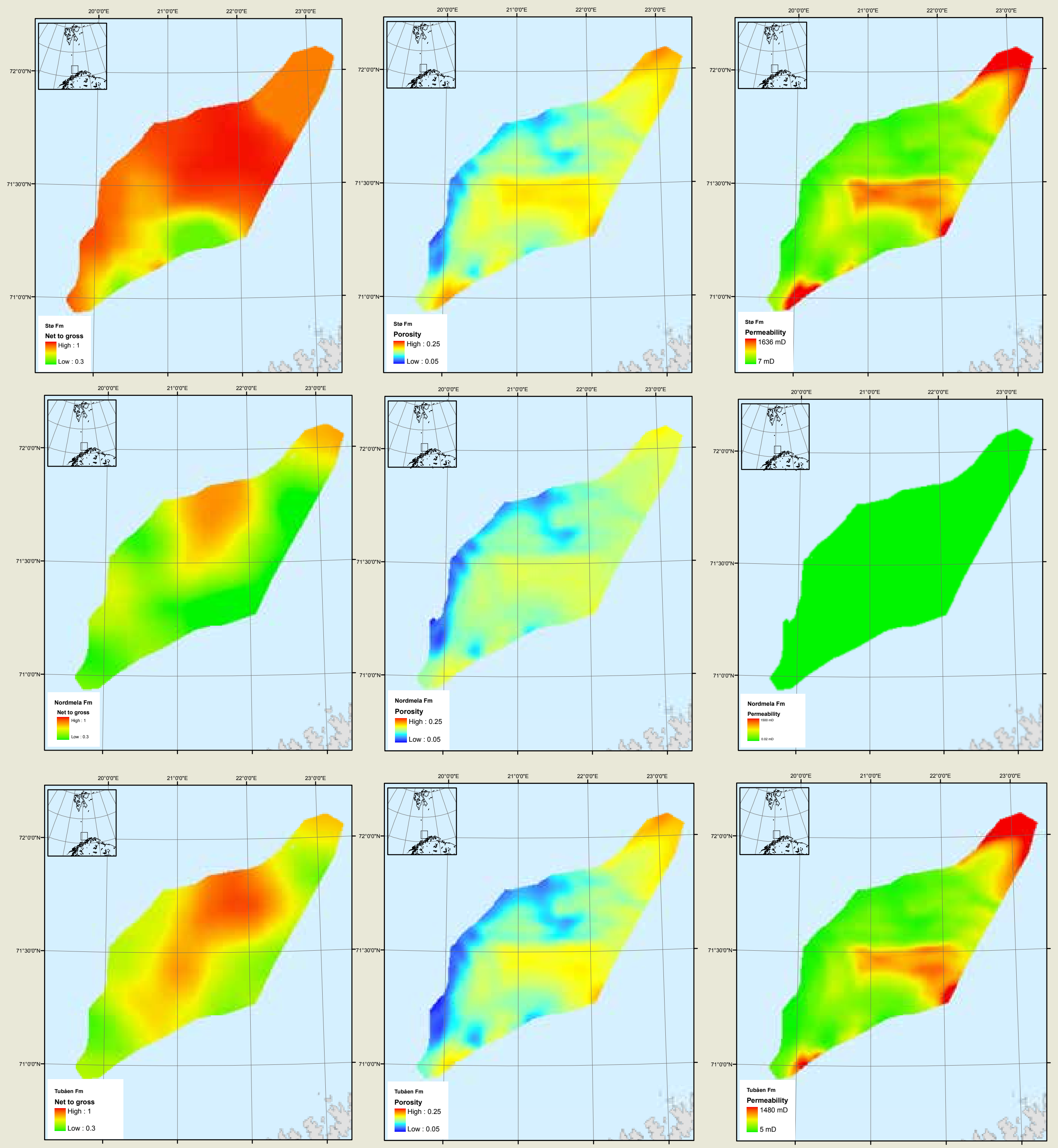




Porosity depth and porosity permeability plots based on core and log data from the Hammerfest Basin.

Hammerfest Basin aquifer	Summary
Storage system	Half open
Rock Volume, m^3	1,23E+12
Net volume, m^3	7,90E+11
Pore volume, m^3	1,2E+11
Average depth, m	2400
Average net/gross	0,65
Average porosity	0,15
Average permeability, mD	1-500
Storage effeciency, %	3
Storage capacity aquifer	2500 Mtons
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	





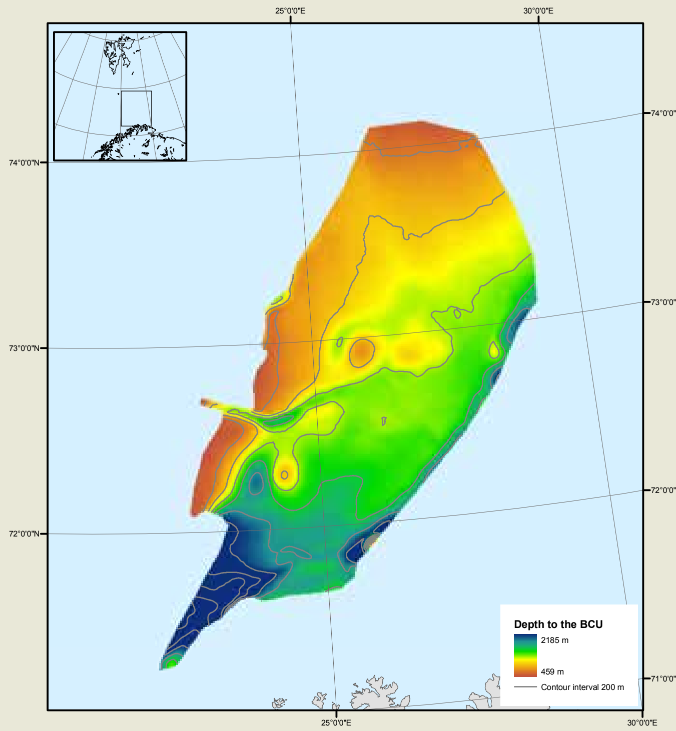
Bjarmeland Platform

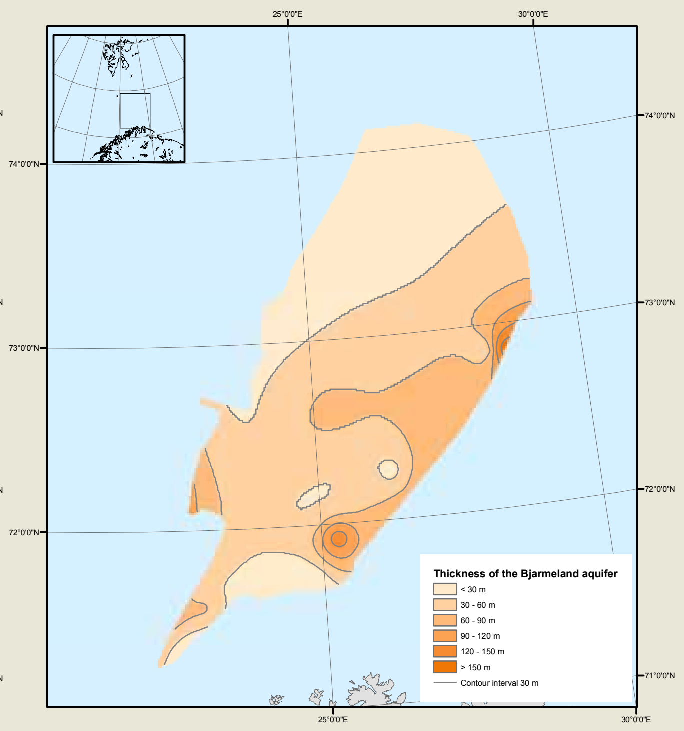
The Bjarmeland Platform is located north of 72 degrees N and extends beyond 74 degrees N, north of the Nordkapp Basin. 10 exploration wells and some shallow stratigraphic wells are drilled in the larger area of the Bjarmeland Platform including the western part towards the Loppa High (by 2013).

A condensed Lower and Middle Jurassic section is developed in large areas in the central Barents Sea and Svalbard. In the Bjarmeland Platform the thickness of the Realgrunnen Group decreases from around 100 m in south to a few tens of meters in the north. The sedimentary facies are similar to the Tubåen, Fruholmen and Stø Formations in the Hammerfest Basin. The boundary between the Hammerfest Basin aquifer and the Bjarmeland Platform aquifer is transitional.

According to well data, the best quality of the aquifer in the Bjarmeland Platform is found in the saddle area between the Nordkapp and Hammerfest Basins. The structuring of the Bjarmeland Platform is mainly related to salt tectonics which has resulted in domes, rim synclines and normal faults. In the northern part of the platform and towards Loppa High and Svalis Dome in the west , the Jurassic strata are eroded and Triassic sedimentary rocks outcrop at the seabead. The Quaternary thickness is generally less than 100 m along the subcrop lines.

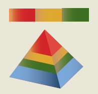
The pore pressure is hydrostatic. It is likely that the degree of communication within the regional Bjarmeland Platform aquifer is not as good as within the Stø aquifer in the Hammerfest Basin due to reduced thickness and more heterolithic facies.





Depth map and thickness map of the Realgrunnen aquifer, Bjarmeland Platform area.

Bjarmeland Platform aquifer	Summary
Storage system	Half open
Rock Volume, m^3	1,48E+12
Net volume, m^3	1,07E+12
Pore volume, m^3	2,45E+11
Average depth, m	1100
Average net/gross	0,72
Average porosity	0,23
Average permeability, mD	5-1000
Storage effeciency, %	3
Storage capacity aquifer	4800 Mtons
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	



Additional aquifers

Fruholmen Formation

The sandy parts of the Fruholmen Formation were deposited in large parts of the evaluated area in a fluvio-deltaic environment. Channelized sandstones have good reservoir properties along the basin margins where they are not too deeply buried and they have trapped oil in the Goliat Field and in the 7125/4-1 discovery. The Fruholmen Formation is not evaluated as an aquifer with large injection potential, since the lateral connectivity is uncertain. In a regional scale, the formation may contribute to the aquifer volume of the overlying Realgrunnen aquifer.

Snadd Formation

The sandstones in the Snadd Formation is separated from the sandy part of the Fruholmen Formation by a shale section (Akkar Member) which acts as a regional seal. Channelized sandy systems are widely distributed in the Snadd Formation, and can be mapped in 3D seismic data. Gas accumulations have been encountered in a few wells. The Snadd formation has not been evaluated for large scale CO_2 injection, because of poor lateral connectivity and because several of the undrilled channel sandstones may have a potential for hydrocarbons.

Kobbe Formation

The Kobbe Formation consists of marine shales, silts and deltaic sands, mainly fine to medium grained. The formation is developed as reservoir sandstones along the Troms-Finnmark fault zone as described in section 4. The Kobbe Formation constitutes the main reservoir in the Goliat Field. It has not been evaluated for large scale CO_2 injection because only a limited volume of the aquifer is buried at sufficiently shallow depth to maintain high porosity and permeability.

Late Paleozoic reservoirs

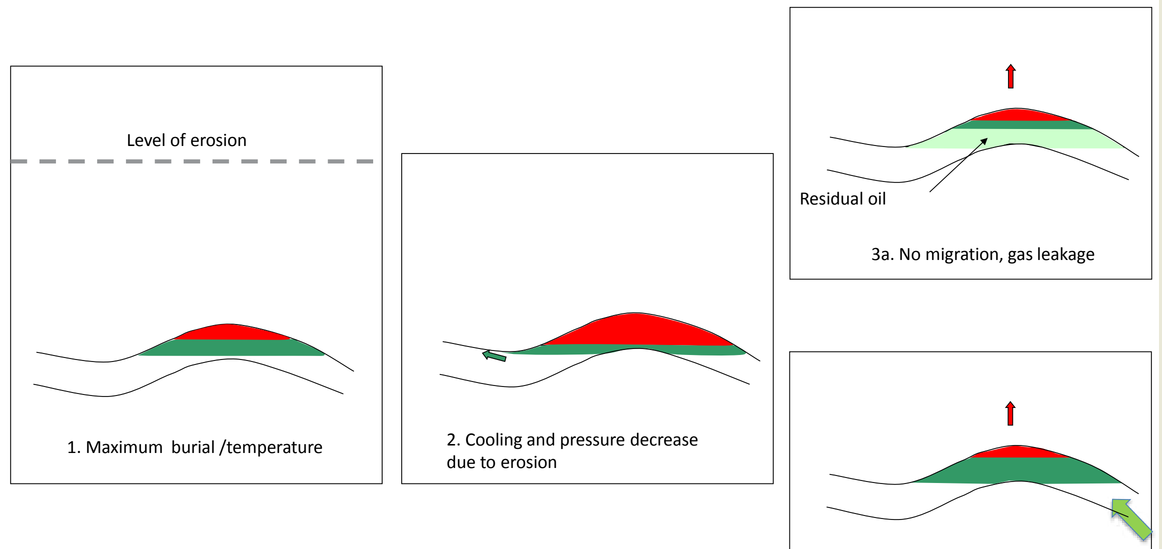
Late Paleozoic sandstones and carbonates and Early Triassic sandstones outcrop along the coast of Troms and Finnmark south of the evaluated area. Reservoir properties are proved by a few exploration wells and stratigraphic cores. Because of limited seismic and well data coverage close to the coast, no attempt was made to map potential prospects for CO_2 storage.

Sealing properties

The Jurassic reservoirs in the Hammerfest Basin and Bjarmeland Platform have thick zones with residual oil and oil shows. The distribution of oil in the Hammerfest Basin indicates that the main structural closures in the central part of the basin were filled with oil and gas to spill point in the past. The gas has seeped or leaked out of the structures, while most of the oil may be preserved as residual oil down to the paleo oil-water contact. This setting is important for the evaluation of the properties of the sealing rocks. Two questions should be answered:

1. What is the typical rate of methane seepage from gas filled structures in the Barents Sea ?
2. What will be the rate of seepage from a plume of CO_2 in dense phase compared with a methane seepage ?

Methane seepage is commonly observed on seismic data and on the seabed at the Norwegian Continental Shelf, in particular in areas of active hydrocarbon generation. In the studied area, gas chimneys and shallow gas is seen on seismic data in the Bjørnøya Basin and the western part of the Hammerfest Basin. In the Bjørnøya Basin, gas chimneys are commonly capped by gas hydrates and associated with gas flares (Chand et al. 2012). This shows that gas seepage is active today. The most active seepage takes place in the Bjørnøya Basin and Bjørnøyrenna Fault Complex. Here, the source rocks generate hydrocarbons and several traps are filled to spill point. This indicate that the rate of gas seepage is slower or in equilibrium with the rate of gas generation. Consequently this is interpreted as a slow process related to a time scale of hundreds or thousands of years, which is the time scale of interest for CO_2 sequestration. Concerning the sealing capacity for CO_2 compared to methane, the case of 7019/1-1 shows that the Upper Jurassic seal in this well is capable of maintaining a 30 bar pressure difference between the 50 % CO_2/methane mixture in the Jurassic reservoir and the methane with 10-15% CO_2 in the Cretaceous reservoir. Our interpretation is that in this well, the rate of seepage of CO_2 is significantly lower than for methane. These observations and interpretations are used in the characterization of the sealing rocks. The conclusion is that we can use the same guidelines as we used for the North Sea and the Norwegian Sea. There is however a concern that some types of cap rocks and some structural settings could have been influenced by the unloading and cooling processes to become more fractured, consequently with a reduced sealing capacity.



Conceptual model for development of residual oil zone following deep erosion . Red colour is gas, green is oil

Storage capacity Snøhvit area

The Snøhvit Field is located in the central part of the Hammerfest Basin in the Barents Sea. The water depth is 340 m and the reservoirs are found in the Stø and Nordmela Formation (Early and Middle Jurassic age), at depths of approximately 2300 m. The hydrocarbon phase in the Snøhvit main field is mainly gas with minor condensate and a 10-15 m thick oil leg.

The Stø Fm is mainly shallow marine, while the Nordmela Fm was deposited in a coastal environment. Maximum burial of the reservoirs was approximately 1000 m deeper than the present burial, resulting in massive quartz cementation of the sandstones and lowered reservoir quality below 2900-3000 m. The reservoir quality in the fields is fairly good. Porosity as high as 20 % and permeability at 700 mD have been interpreted on logs in the best zones of the Stø Formation. The Snøhvit field developments include the Askeladd and Albatross structures. These structures have reservoirs in the same formations. In addition the 7121/4-2 Snøhvit North discovery contains gas and condensate which is still not in production.

The natural gas produced from the fields contains about 5-8 % CO_2. The CO_2 is separated from the gas at Melkøya in an amine- process. Compressed CO_2 in liquid phase is returned to the field in a 153 km long pipeline to be stored 2500 m below sea level.

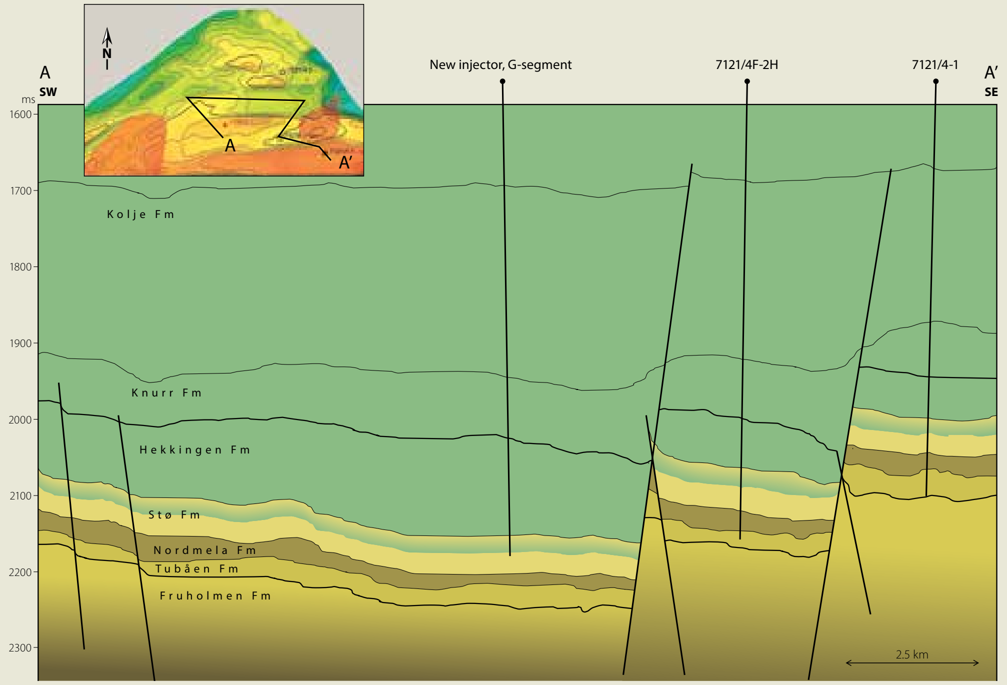
CO_2 storage at the Snøhvit Field started in 2008, and CO2 was until April 2011 injected in well 7121/4F-2H in the Tubåen Fm which is dominated by fluvial sandstone. After a while the pressure built up faster than expected, and an intervention was performed to avoid fracturing the seal. In 2011, the injection in the Tubåen formation was stopped, and the shallower Stø formation was perforated as the new storage formation for CO_2.

After the intervention in 2011 all CO_2 from the Snøhvit Field has been injected in the water zone of the Stø Formation. Until 2013 a total of 1, 1 M ton CO_2 has been injected in the Tubåen Fm and 0,8 Mton in the Stø Formation.

In contrast to the Tubåen Formation, the Stø Formation is in pressure communication with the gas producers on Snøhvit and no significant pressure buildup is expected in the injection site. However, a new injection well for CO_2 is considered in segment G (SW-SE profile) to prevent future migration of injected CO_2 into the natural gas of the main Snøhvit Field. This segment is located between Snøhvit main structure and Snøhvit North.

The new well will inject into the Stø Formation. In order to investigate the storage potential for the new well, a minimum and a maximum aquifer zone was defined. The maximum aquifer, Snøhvit 2800, represents the pore volume in the water zone in Stø, Nordmela and Tubåen Formations in the Snøhvit and Snøhvit north area down to 2800 m. 2800 m was selected because the permeability deteriorates below this

Map showing the location of the Snøhvit Field, the pipeline and the Melkøya terminal. Blue circle indicates main study area for the CO_2 storage aquifer.

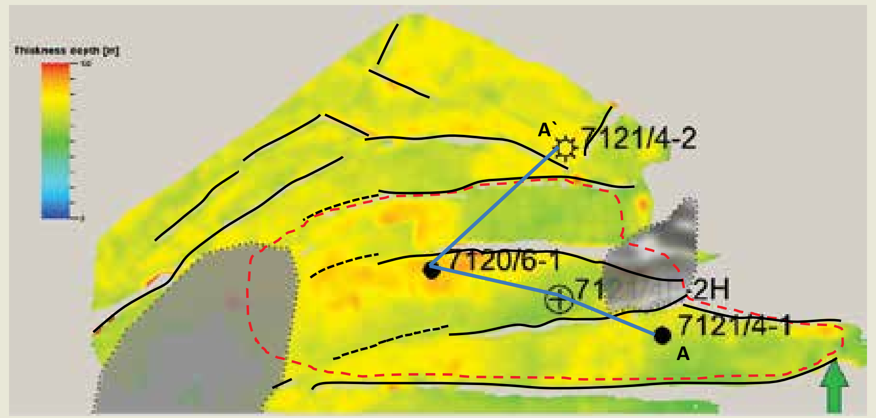


SW-SE profile showing the geometry and thickness –variations in the Snøhvit area. Location of CO_2 injection is illustrated. Sealing formations indicated in green color. 7121/4F-2H is the CO_2 injector.

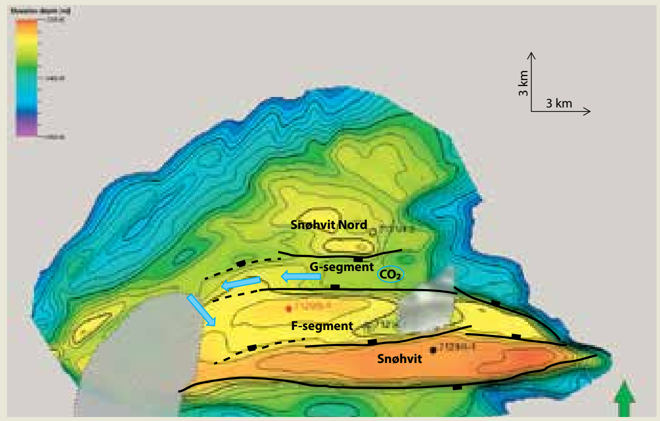
Storage capacity Snøhvit area

depth. The minimum aquifer zone, Snøhvit central Stø, covers only the Stø Formation in the areas surrounding the G segment and is interpreted to represent a water volume where communication to the new injection site is very likely. Communication through major faults is not expected where the throw is larger than the thickness of the Stø Formation, but in the minimum aquifer, corridors of communication are interpreted.

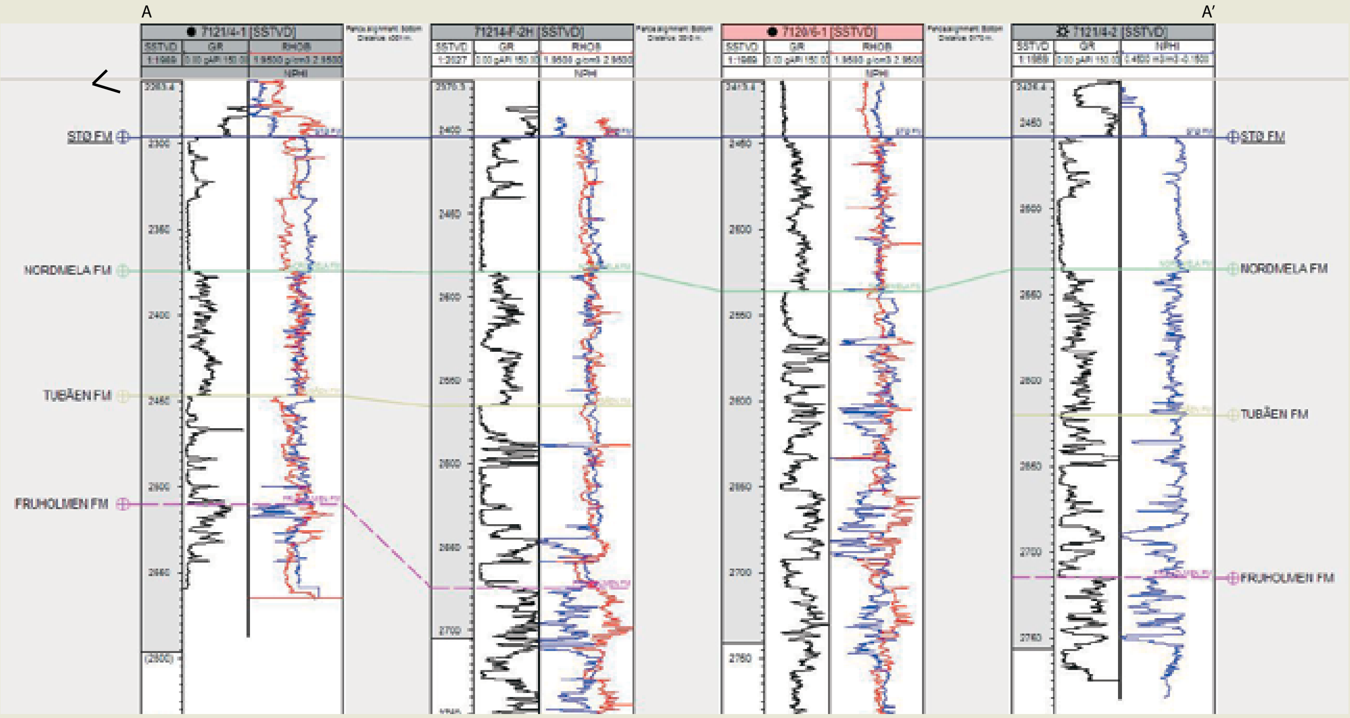
The calculation of pore volumes for the two aquifers resulted in 6400 Mm3 for the Snøhvit 2800 case and 680 Mm3 for the Snøhvit central Stø. These aquifer volumes indicate that there are sufficient water volumes available to support the planned CO_2 injection in the Stø Formation at Snøhvit.



Stø Fm thickness map. Gray areas indicate shallow gas. AA' shows the location of the log correlation profile.



Stø depth map where blue arrows illustrate CO2 migration after injection in the G segment. Black solid lines illustrate faults with big throw, while black dotted lines indicate where the throw dies out. gray polygons shows location of shallow gas.



Log correlation panel with gamma and porosity density, flatten on Stø Fm. Layout showed in Stø thickness map.

Snøhvit Central Stø	Summary
Storage system	Half open
Rock Volume, m^3	6,05E+09
Net volume, m^3	4,84E+09
Pore volume, m^3	6,77E+08
Average depth, m	2320-2400
Average net/gross	0,8
Average porosity	0,14
Average permeability, mD	300
Storage effeciency, %	5
Storage capacity aquifer	24 Mtons
Reservoir quality	
capacity	3
injectivity	2
Seal quality	
seal	3
fractured seal	3
wells	2
Data quality	
Maturation	

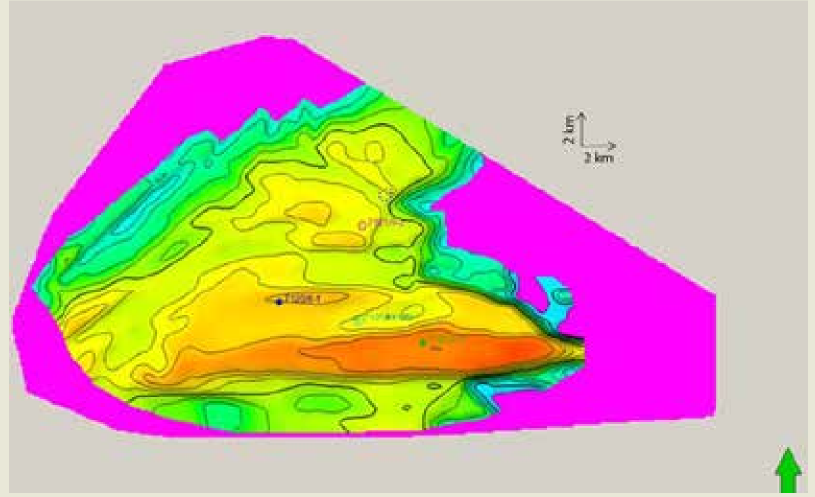
Storage capacity Snøhvit area

The expected flow direction for the injected CO_2 will be towards the west. As seen in the profile, thick packages of shale seal the Stø Formation and prevent vertical leakage of CO_2. Seepage of gas along the faults is regarded as a risk, in particular in the areas with shallow gas clouds. Monitoring of the injection (section 6) will be important to control the injection and the movement of CO_2 through time. Data quality in the area is good, except in the areas with gas clouds. The experience with injection in the Stø Formation is sufficient to conclude that the area has been matured as a storage site.

In addition to the CO_2 storage potential related to the ongoing injection in the Stø Fm (G-segment), interpretation and calculations were performed to evaluate the storage potential in the Snøhvit Jurassic aquifer consisting of Stø, Nordmela and Tubåen Formation above the spill point for the main Snøhvit Field. This aquifer case is called the Greater Snøhvit Aquifer. It may represent the volume which has been filled with hydrocarbons in geological history and is analogous to the Greater Albatross and the Greater Askeladd aquifers. The results show a pore volume of 4100 Mm3.

All parameters used in the calculations and presented in the table, is based on well information. Key wells are 7121/4-1, 7121/4-2, 7120/6-1 and 7121/4F-2H. Porosity and permeability trends and input to depth conversion were derived from several wells in the area. The reservoir quality varies in the different formations in the aquifer. The best quality is seen in the lowermost part of the Stø Fm, but more shaly zones in the middle part of the formation most likely act as an internal barrier or baffle for injected CO_2.

Data quality is good as previously mentioned, but due to possible conflicts with the petroleum activity, maturation is shown in blue colour. This represents a theoretical volume of the CO_2 storage potential calculated for the Jurassic aquifer. Uncertainty in the calculation is mostly related to interpretation, depth conversion and a simplified approach to the distribution of the aquifer.



Depth map of Stø Fm, where pink surface at 2800 m represent the base of the Jurassic aquifer.

Snøhvit 2800m aquifer	Summary
Storage system	Half open
Rock Volume, m³	8,92E+10
Net volume, m³	5,35E+10
Pore volume, m³	6,4E+09
Average depth, m	2404-2800
Average net/gross	0,6
Average porosity	0,12
Average permeability, mD	150
Storage effeciency, %	2
Storage capacity aquifer	90 Mtons
Reservoir quality	
capacity	3
injectivity	2
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	

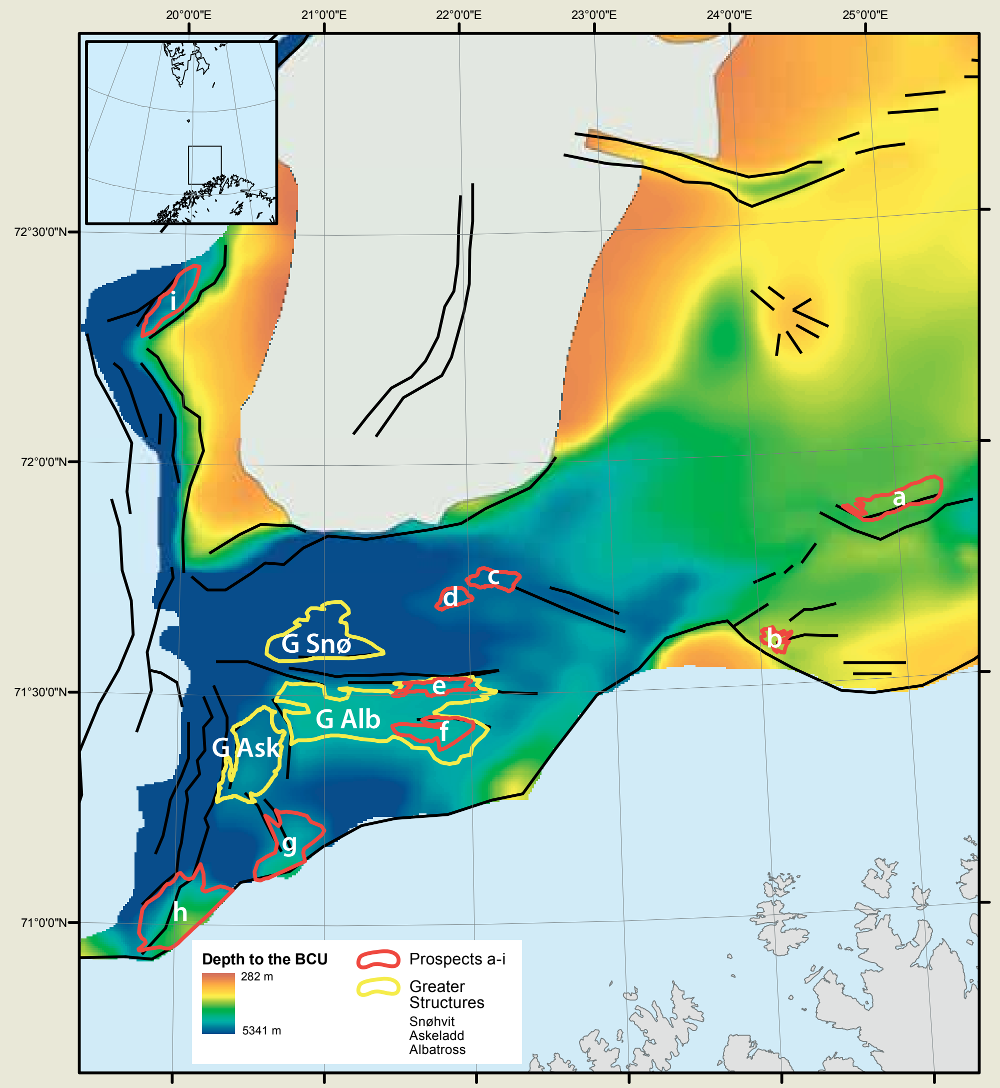
Storage in depleted and abandoned fields

The Snøhvit development includes several gas discoveries within the greater Snøhvit, Askeladd and Albatross structures. The potential of CO_2 storage after abandonment of the smaller of these discoveries was calculated from the pore volume of their gas zones. It was assumed that after production there will remain residual gas and minor amounts of free gas and that injected CO_2 can occupy 40 % of the initial pore volume. Based on this assumption, which is regarded as conservative, the storage capacity of the abandoned field is 200 Mtons.

Introduction

As discussed in 5.2, the preferred locations for CO_2 sequestration in the Barents Sea are structural traps which are proved to contain brine and no moveable hydrocarbons. In the future, depleted and abandoned gas fields can also be developed as storage sites.

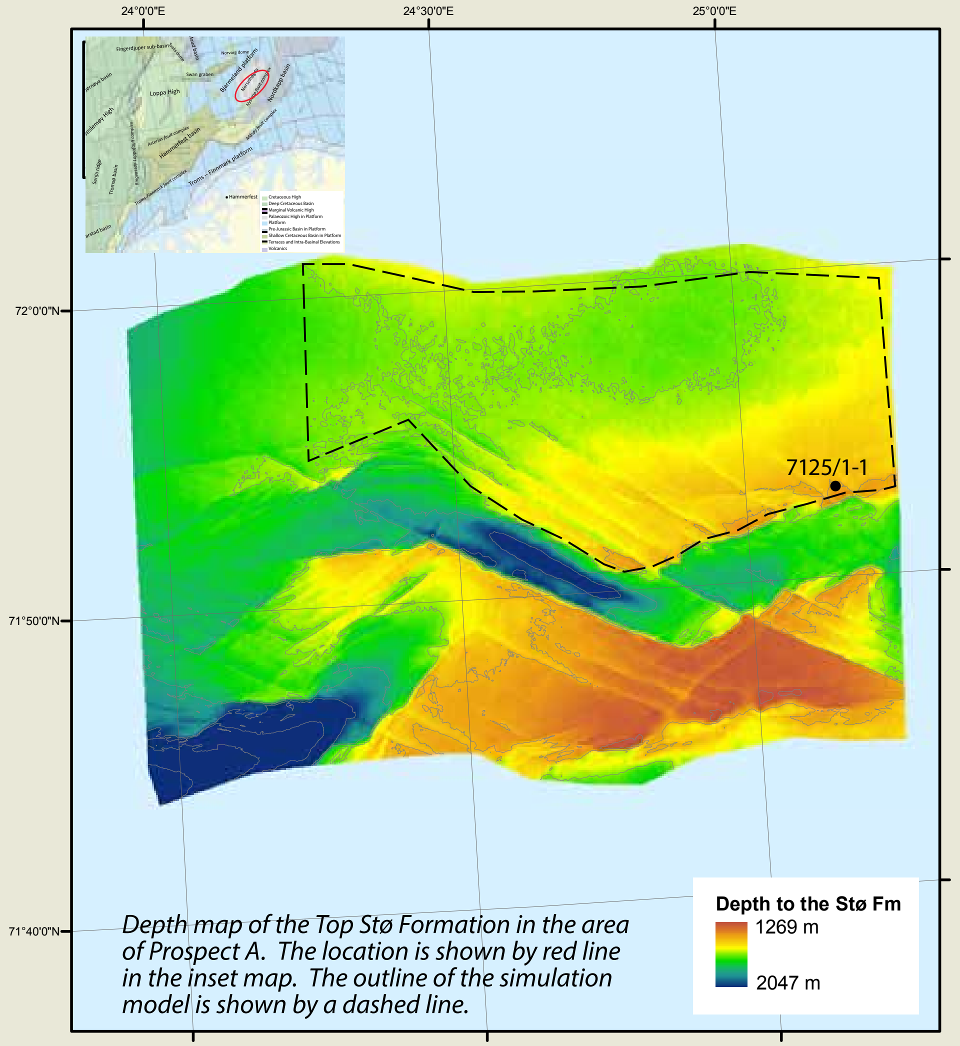
Nine structures (named prospect A to I) within the aquifer systems of the Realgrunnen Group have been mapped and characterized by their storage capacity, injectivity and seal quality. The storage capacity of a structural trap can be limited by porevolume of the structural closure and by the porevolume and permeability of the connected aquifer. The evaluation of Prospect A is based on a simulation model taking these factors into account. Evaluation of the other prospects is based on porevolumes of the structural closures and a storage efficiency factor based on the geological conditions for each prospect. Pore volumes are calculated based on mapped surfaces, porosity and net/gross maps presented here. For the reservoirs in the Hammerfest Basin average permeability is indicated for Nordmela Formation (low values) and Stø Formation (high values). Provided that CO_2 will be injected in the Stø Formation, injectivity is considered to be medium to high in most prospects. The seal quality is characterized by thickness of the primary seal (Hekkingen and Fuglen Formations) and the faulting intensity of the reservoir. Seismic anomalies indicating shallow gas were also taken into account. Leak-off tests indicate that the typical fracturing pressures in the Barents Sea are somewhat lower than in the North Sea and the Norwegian Sea. Prospect simulation was run with a maximum pressure build-up of 30 bar. Maturation of prospects which may be of interest for petroleum exploration is evaluated to be low (blue colour). Prospects which have been drilled and proved only brine or brine and residual oil are considered to be more mature (green colour). The yellow colour is applied to prospects which are approaching a PDO, such as in the Snøhvit area. These requires more in-depth studies than what was possible in this study. In addition to the prospects, the areas Greater Snøhvit, Greater Askeladd and Greater Albatross are defined. These areas represent structural closures with several culminations. Some of the culminations are hydrocarbon filled, and some of them have only residual hydrocarbons. There are indications in the wells that these greater structural closures have been filled with hydrocarbons at the time of maximum burial. CO_2 injected in these is not likely to migrate out.



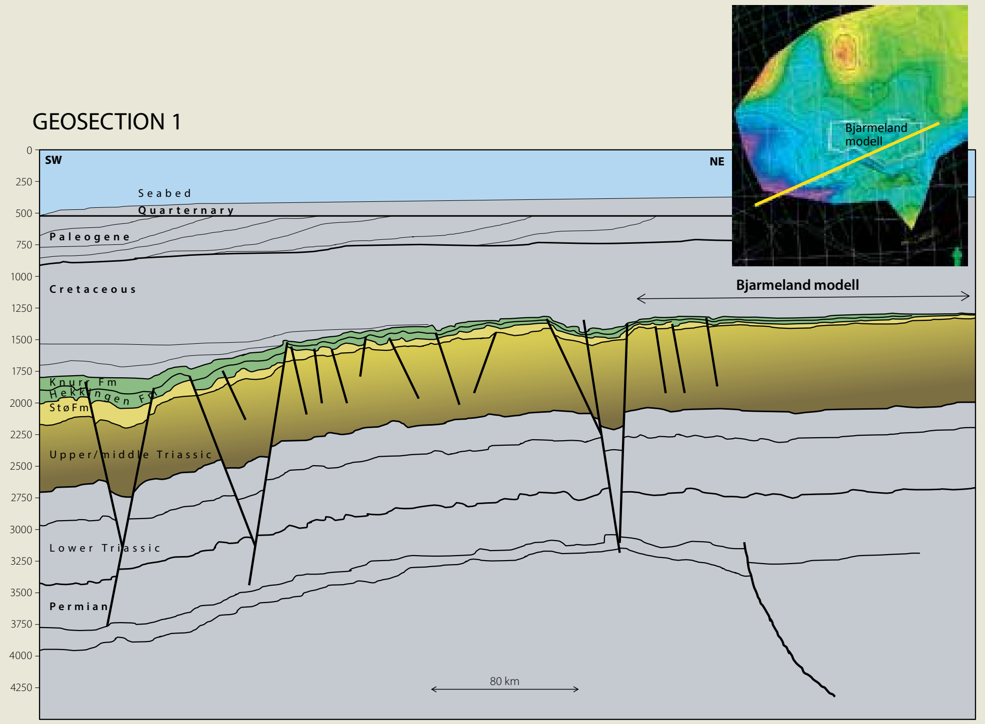
Location of evaluated prospects (red) and large structural closures (yellow).

Prospect A, Bjarmeland Platform

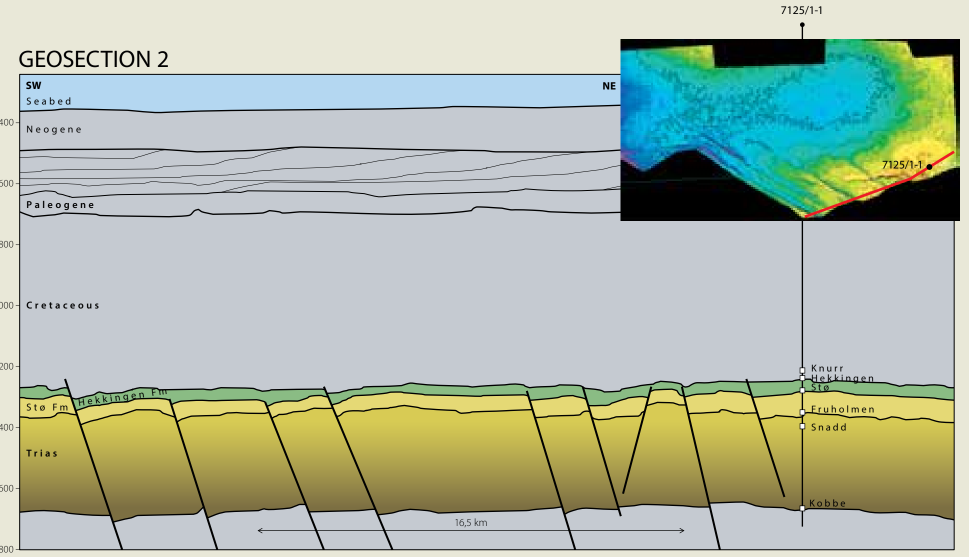
Prospect A is defined at a closed structure located east of the Loppa High in the southernmost part of the Bjarmeland Platform, west of the Nysleppen Fault Complex. The structure is drilled by well 7125/1-1. 1 m of high oil saturation was encountered in top of the main reservoir and with a residual oil zone below. The main reservoir zone evaluated for CO_2 storage is Stø Formation with a thickness of 130 m in well 7125/1-1. The Stø Formation is part of the Realgrunnen Group which thickens westwards into the Hammerfest Basin. Depth to top of the interpreted structure is about 1400 m. The structure has retained a more or less complete sedimentary succession from the Permian to the Upper Jurassic. No shallow gas indications have been observed along the boundary faults to the south. However, the residual oil observed in the exploration well 7125/1-1 indicates that leakage or seepage has taken place. As discussed in 5.2, this seepage is believed to be a slow process, and the seal risk is characterized as relatively low. The geomodel of Realgrunnen Group is based on interpretation of 3D seismic and data from the exploration well. The geomodel is developed into a reservoir simulation model in order to study the behavior of CO_2 injection in this reservoir with brine and residual oil.



Depth map of the Top Stø Formation in the area of Prospect A. The location is shown by red line in the inset map. The outline of the simulation model is shown by a dashed line.



Structural setting of prospect A.



The Realgrunnen aquifer is shown as a thin yellow layer below the green primary seal of the Hekkingen formation.

Prospect A, Bjarmeland Platform

The simulated CO_2 injection well is located downdip with plume migration towards south-southeast, but alternative locations with different injection rates have been simulated.

The injection period is 50 years, and simulation continues for 1000 years to follow the long term CO_2 migration effects. CO_2 will continue to migrate upwards as long as it is in free, movable state. Migration stops when CO_2 is permanently trapped, by going into solution with the formation water or by being residually or structurally trapped (mineralogical trapping is not considered here).

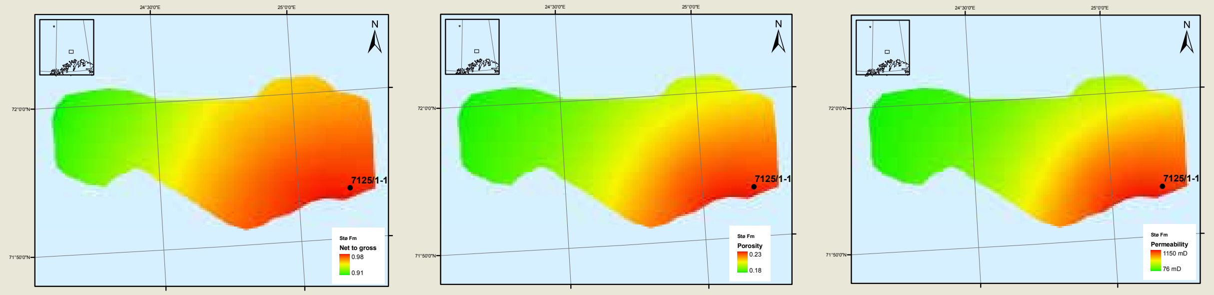
Confinement of CO_2 requires prevention of migration of the CO_2 plume to potential leakage areas. For Prospect A, the fault/graben system to the west and south will seal the structure in that direction. The structurally highest point on the Bjarmeland structure is located along this fault.

To obtain confinement of CO_2, the injection pressure must not exceed fracturing pressure. The fracturing pressure increases with depth. The depth of the maximum acceptable pressure increase was calculated for the shallowest point of the CO_2 plume migration during the period of injection (1400m). The structure is hydrostatically pressured. Fracture gradients established from the North Sea and Norwegian Sea indicate that a maximum acceptable pressure increase of 75bar could be applied at that depth. However, as discussed in 5.2, the fracture gradients in the eroded regions of the Barents Sea could be lower, and the effects of a maximum pressure of 30 bar were also investigated. The pressure build-up depends on the volume and connectivity of the surrounding aquifer. The aquifer used for modelling covers the area of thick Stø Formation with excellent reservoir properties. Further north in the Bjarmeland Platform, the Realgrunnen Group is thinning, but good porosity and permeability is developed in a large area.

Most probably, the volume of the active aquifer system is 25 times the volume of the geological model and this volume is added to the simulation model volume.

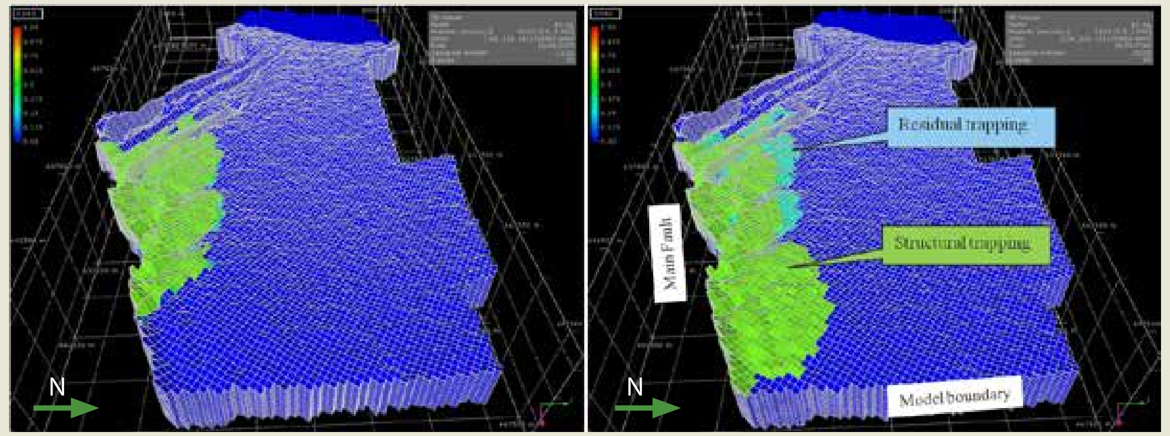
In the simulation model, CO_2 injection was stopped when the plume reached the eastern boundary of the model. This boundary was regarded as the spill point of the structure. East of this boundary there is only seismic coverage by 2D lines, and the spill point is regarded as conservative.

Prospect A	Summary
Storage system	Open
Rock Volume, m^3	5,50E+10
Net volume, m^3	5,17E+10
Pore volume, m^3	1,03E+10
Average depth, m	1525,00
Average net/gross	0,94
Average porosity	0,20
Average permeability, mD	500,00
Storage effeciency, %	2,50
Storage capacity aquifer	176 Mtons
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	

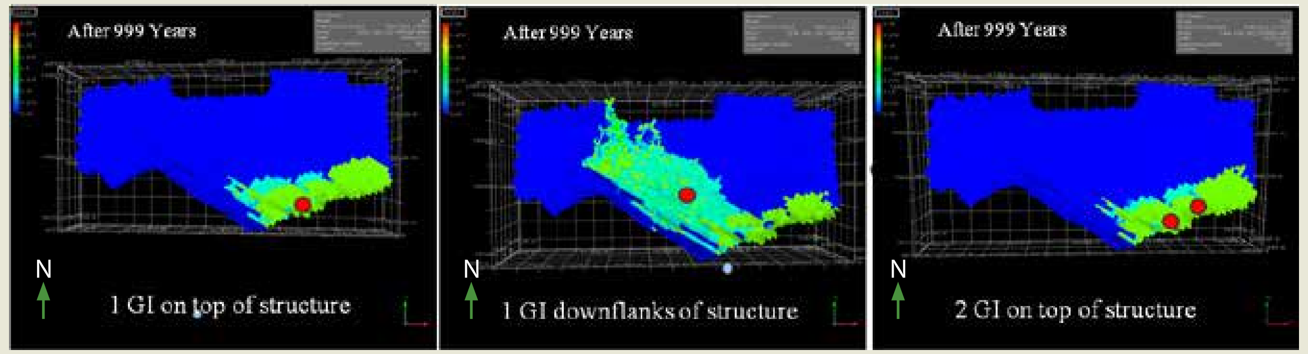

Net/Gross values from 0,97-0,92

Porosity varies from 20-24 %

Permeability is 1000mD in the well



Distribution of injected gas (green) after end of injection (50 years), and after 1000 years of storage. North to the right.



Distribution of injected gas (green) after 1000 years of storage, depending on location of injector well.

Prospect B, Bjarmeland Platform

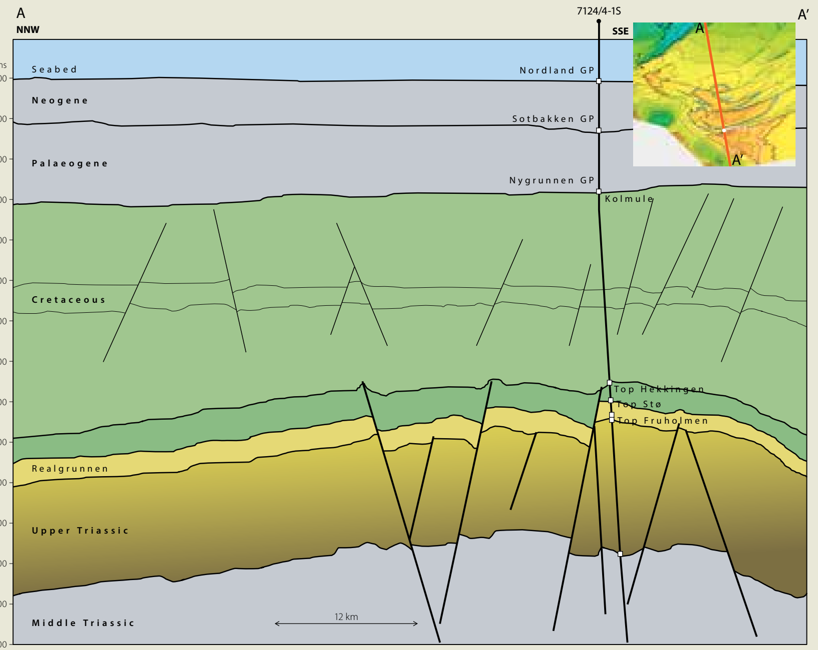
Prospect B is located in the transition zone between the Hammerfest and the Nordkapp Basins, about 70 km northeast from the Goliat Field. It is defined at a NW-SE trending fault block with a structural closure. Main reservoir is in the Stø Formation (Realgrunnen Group). The structure has been drilled by the well 7124/4-1 S, where the Stø Formation was encountered at a depth between 1259-1312m. The formation consists of a 52m thick homogeneous unit of mainly fine to medium grained sandstone with good reservoir properties. The well was water bearing and there are no indications of hydrocarbons. Interpretation of the prospect is based on good 3D seismic and the 7124/4-1S well. The 3D cube may not cover the spill point SE of the structure, which means that the calculated volume is conservative.

The geosection illustrates the geometry of aquifers (yellow) and sealing formations (green). Faults cutting through the Stø Formation seem to terminate within the primary seal constituted by the Hekkingen Formation. Thick Cretaceous shaly sediments act as a secondary sealing layer.

The reservoir quality and storage capacity is summarized and illustrated in the table below. The reservoir properties used in the evaluation are based on the 7124/4-1S well. Prospect B is defined as a half open structure, where the boundary towards the west is structurally closed by a major fault and a graben structure west of the fault. The structure is segmented by several smaller WSW-ENE trending faults.

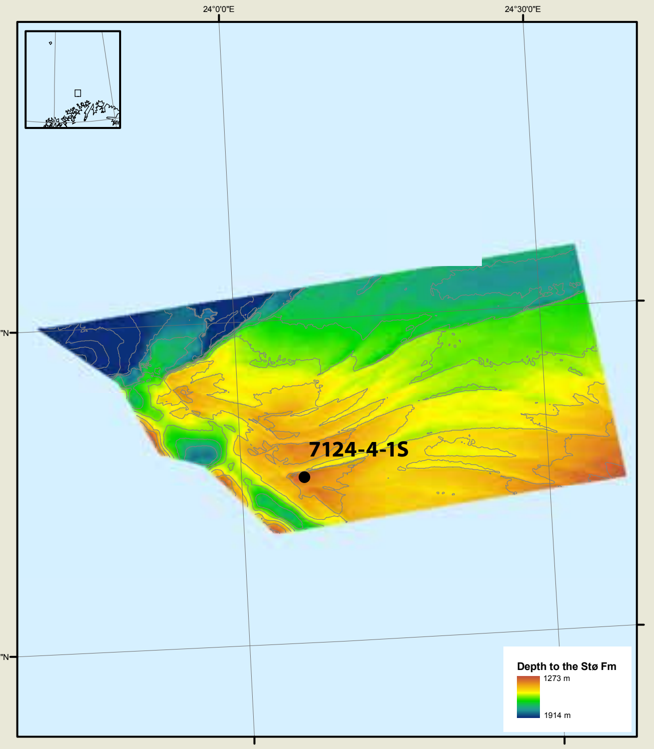
Approximately 50 meters of Hekkingen shale overlie the sand rich Stø Formation. The segmenting faults cutting through the Stø Formation seem to terminate in the Hekkingen shale, and the seal risk is considered to be relatively low.

The structure consists of two main segments. If a CO_2 injector is placed in the northern segment, the CO_2 plume can migrate and spill into the structurally higher segment to the south. The calculated CO_2 storage capacity for both segments is 19 million tons based on a constant thickness of the Stø Formation.



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

Prospect B	Summary
Storage system	Half open
Rock Volume, m^3	4,00E+09
Net volume, m^3	3,90E+09
Pore volume, m^3	9,00E+08
Average depth m	1260
Average net/gross	0,98
Average porosity	0,23
Average permeability, mD	500
Storage effeciency,%	3
Storage capacity aquifer	19 Mtons
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	

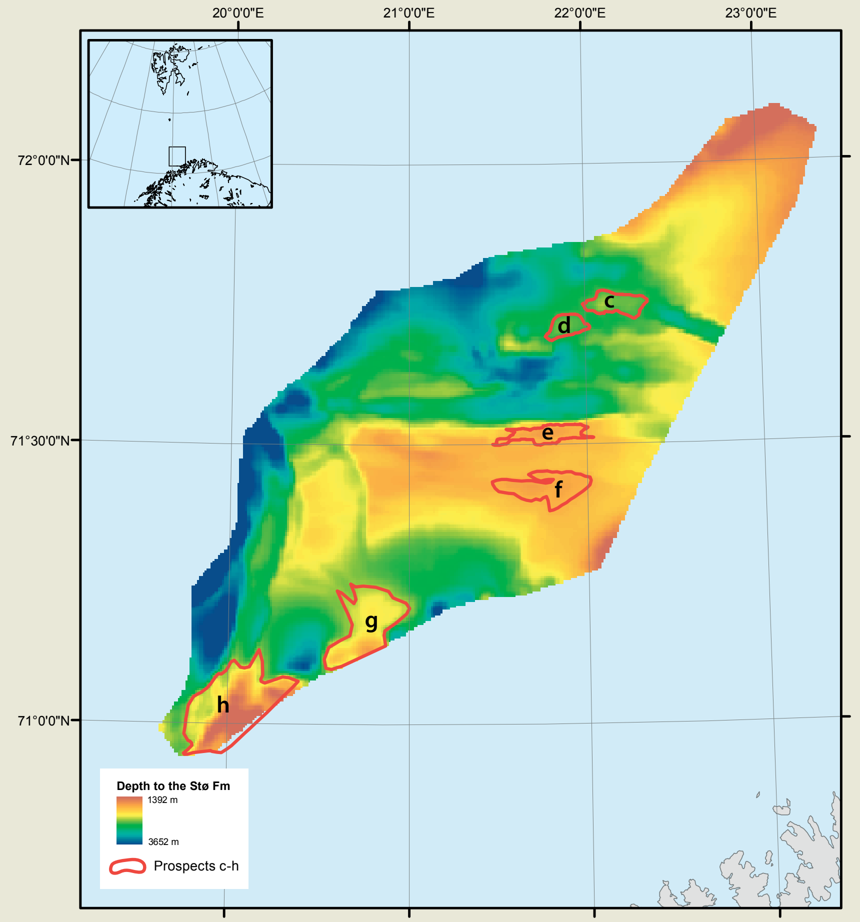


Hammerfest Basin prospects

The Hammerfest Basin aquifer is classified as a half open aquifer, comprising the Tubåen, Nordmela and Stø Formations. The aquifer is bounded by the Troms-Finnmark and Ringvassøy-Loppa fault complexes in the south and west, and by the Asterias Fault Complex towards the Loppa High. The permeability is highest in the Stø Formation and lowest in the Nordmela Fm, as reflected in the permeability range in the table. The total aquifer volume is significantly higher than the volume of separate prospects, and the lateral connectivity in the Stø Formation is good. Consequently, the calculation of storage capacity of the Stø Formation in the prospects is in most cases based on the assumption that the pore volume of the trap is the limiting factor.

Prospect C and D

Prospect C and D are structurally defined traps with 4-way closure. No major faults and no signs of gas leakage were observed. The interpretation is based on 2D seismic data with poor coverage, consequently the geometry and size of the structural closure is uncertain. Prospect C has several minor faults cutting through the reservoir. The faults are not believed to offset the primary seal completely, but a lowered fractured seal quality is indicated. Well 7122/4-1 was drilled on prospect C and proved a brine filled structure with hydrocarbon shows.

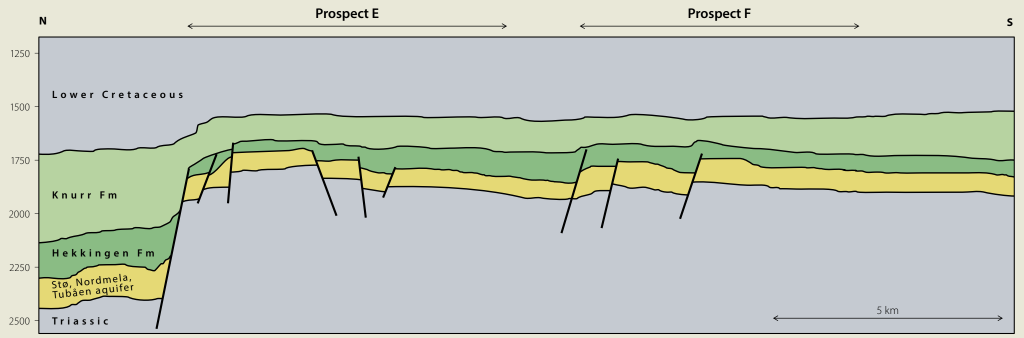


Prospect C	Summary
Storage system	Open
Rock Volume, m^3	1,94E+09
Net volume, m^3	1,79E+09
Pore volume, m^3	2,8E+08
Average depth, m	2400
Average net/gross	0,92
Average porosity	0,15
Average permeability, mD	1-170
Storage effeciency, %	10
Storage capacity aquifer	19 Mtons
Reservoir quality	
capacity	1
injectivity	3
Seal quality	
seal	3
fractured seal	2
wells	3
Data quality	
Maturation	

Prospect D	Summary
Storage system	Open
Rock Volume, m^3	1,18E+09
Net volume, m^3	1,15E+09
Pore volume, m^3	1,8E+08
Average depth, m	2400
Average net/gross	0,97
Average porosity	0,15
Average permeability, mD	1-150
Storage effeciency, %	10
Storage capacity aquifer	12 Mtons
Reservoir quality	
capacity	1
injectivity	3
Seal quality	
seal	3
fractured seal	3
wells	3
Data quality	
Maturation	

Hammerfest Basin prospects

Prospect E and F
Prospect E and F are structurally defined with 3D seismic data as 4-way closures within the greater Albatross area. The closure of prospect E is fault bounded to the north. The throw of the fault is larger than the thickness of the primary seal, hence the seal quality is rated lower than the neighboring structure, prospect F. Prospect E was drilled by the well 7221/5-3 which encountered brine with hydrocarbon shows in the Stø and Tubåen Formations. Prospect F has not been drilled and is regarded as a hydrocarbon prospect. The closure is partly bounded by faults with small throws. No gas clouds or other signs of gas leakage have been observed in the seismic data. Prospect F can be an interesting candidate for CO_2 storage if water filled. The storage capacities are based on the volume above spill point. The prospects E and F are located between Snøhvit and Melkøya, only a few km away from the pipeline.



Prospect E	Summary
Storage system	Open
Rock Volume, m³	1,87E+09
Net volume, m³	1,68E+09
Pore volume, m³	2,9E+08
Average depth, m	1900
Average net/gross	0,86
Average porosity	0,18
Average permeability, mD	2-500
Storage effeciency, %	10
Storage capacity aquifer	20 Mtons
Reservoir quality	
capacity	2
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	

Prospect F	Summary
Storage system	Open
Rock Volume, m³	2,34E+09
Net volume, m³	1,85E+09
Pore volume, m³	3,5E+08
Average depth, m	1900
Average net/gross	0,79
Average porosity	0,19
Average permeability, mD	2-550
Storage effeciency, %	10
Storage capacity aquifer	24 Mtons
Reservoir quality	
capacity	2
injectivity	3
Seal quality	
seal	3
fractured seal	3
wells	3
Data quality	
Maturation	

Prospect G
Prospect G is defined as a large structural closure with several culminations. The structure is bounded by the Troms-Finnmark Fault Complex, and a deep spill point depends on a fault seal towards the Triassic rocks in the Troms-Finnmark Platform. Two wells have been drilled within the structural closure, 7120/12-5 was dry, 7120/12-3 was a gas discovery in the Stø Formation. South of the structure 7120/12-1 encountered brine with hydrocarbon shows, and 7120/12-2 proved gas/condensate. The capacity of the trap is based on the volume above the spill point, but with a low storage efficiency because injected CO_2 plumes should not interfere with the accumulations of natural gas.

Prospect G	Summary
Storage system	Half open
Rock Volume, m³	1,73E+10
Net volume, m³	9,87E+09
Pore volume, m³	1,6E+09
Average depth, m	2200
Average net/gross	0,57
Average porosity	0,17
Average permeability, mD	1-300
Storage effeciency, %	5
Storage capacity aquifer	57 Mtons
Reservoir quality	
capacity	2
injectivity	2
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	

Prospect H
Prospect H is a complex structure with many fault blocks, it is bounded to the south by the Troms-Finnmark fault complex. The volume of the structure is calculated to a deep spill point which depends on fault seal. The prospect is covered by 3D seismic data, but the seismic data quality is low in large areas due to gas clouds and shallow gas. Within the structure, three wells have been drilled without encountering movable hydrocarbons. 7119/12-4 and 7120/10-1 were dry while shows were observed in 7119/12-2 throughout the Middle Jurassic to Late Triassic.

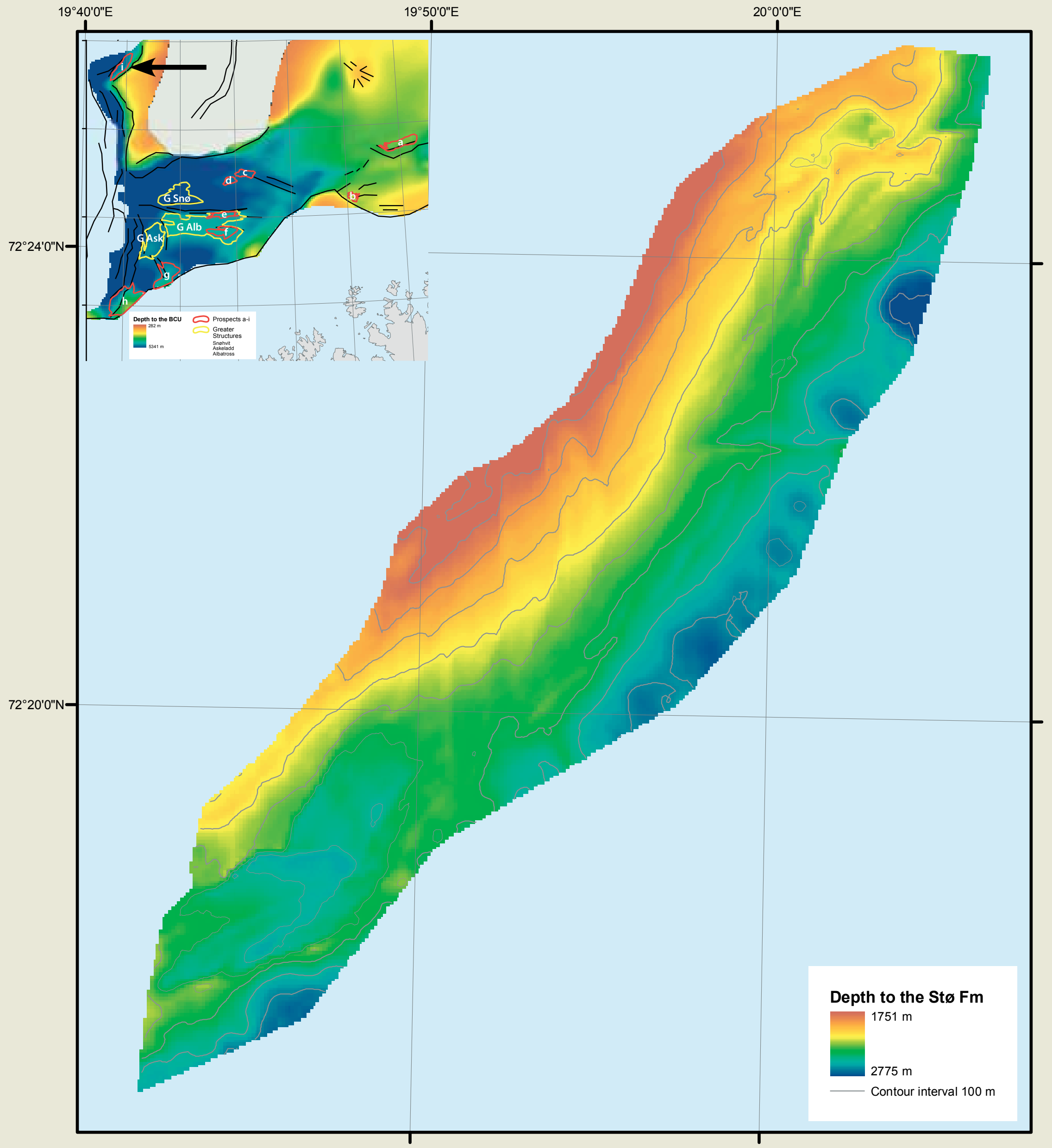
Prospect H	Summary
Storage system	Half open
Rock Volume, m³	5,81E+10
Net volume, m³	2,91E+10
Pore volume, m³	5,2E+09
Average depth, m	2100
Average net/gross	0,5
Average porosity	0,18
Average permeability, mD	1-600
Storage effeciency, %	5
Storage capacity aquifer	180 Mtons
Reservoir quality	
capacity	2
injectivity	2
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	

Bjørnøyrenna Fault Complex prospect

The Jurassic aquifer in the Bjørnøyrenna Fault Complex is separated from the Hammerfest Basin by the eroded Loppa High and faults with large troughs south of the high. The lithologies and the properties of the formations are similar to the Hammerfest Basin. The area west of the Loppa High is an active petroleum province with several gas clouds, seeps to the sea floor, gas hydrates and recent discoveries of oil and gas. The area is strongly segmented by large faults, and the degree of communication between the rotated fault blocks is not known. Lower Cretaceous sands are developed in some of the fault blocks and could account for communication between segments. One water bearing closure has been selected as a candidate for CO_2 storage.

Prospect I is located at a closed structure drilled by well 7219/9-1. The geometry of the trap is mapped using 3D seismic data of good quality. The prospect belongs to a fault segment within the Bjørnøyrenna Fault Complex. The Jurassic aquifer formations proved to have good reservoir properties and were water filled. Shows of residual oil in the well are interpreted as remnants of oil resulting from natural leakage or water sweep of a hydrocarbon accumulation. There are indications of gas brightening in the fault zone above the crest of the structure. The Fuglen and Hekkingen Formations are eroded at the top of the structure. The main risk for this prospect is considered to be the sealing properties of the cap rock, including the fault and the overlying Lower Cretaceous sedimentary rocks.

Prospect I	Summary
Storage system	closed
Rock Volume, m³	7,70E+09
Net volume, m³	6,93E+09
Pore volume, m³	1,25E+09
Average depth, m	2100
Average net/gross	0,9
Average porosity	0,18
Average permeability, mD	400mD
Storage effeciency, %	1
Storage capacity aquifer	9 Mtons
Reservoir quality	
capacity	2
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	



The location of prospect I is shown by the black arrow in the inset map.

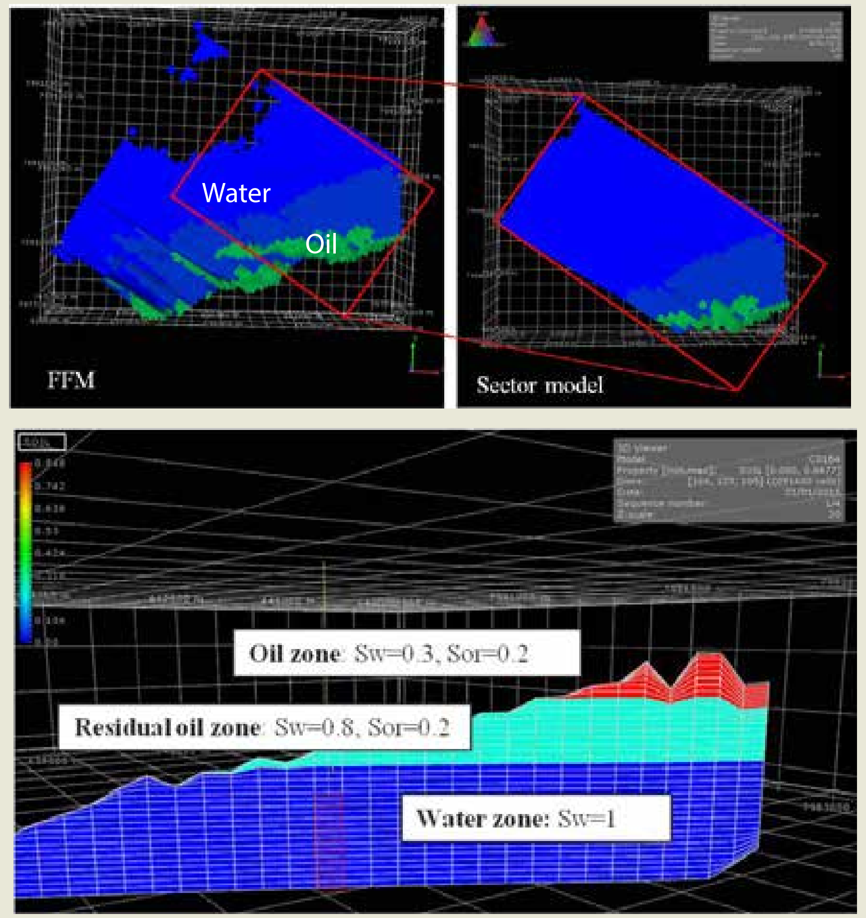
Case study: Prospect A, evaluation of residual oil zone

Study of enhanced oil recovery (EOR) from an oil zone with an underlying residual oil zone in the prospect A

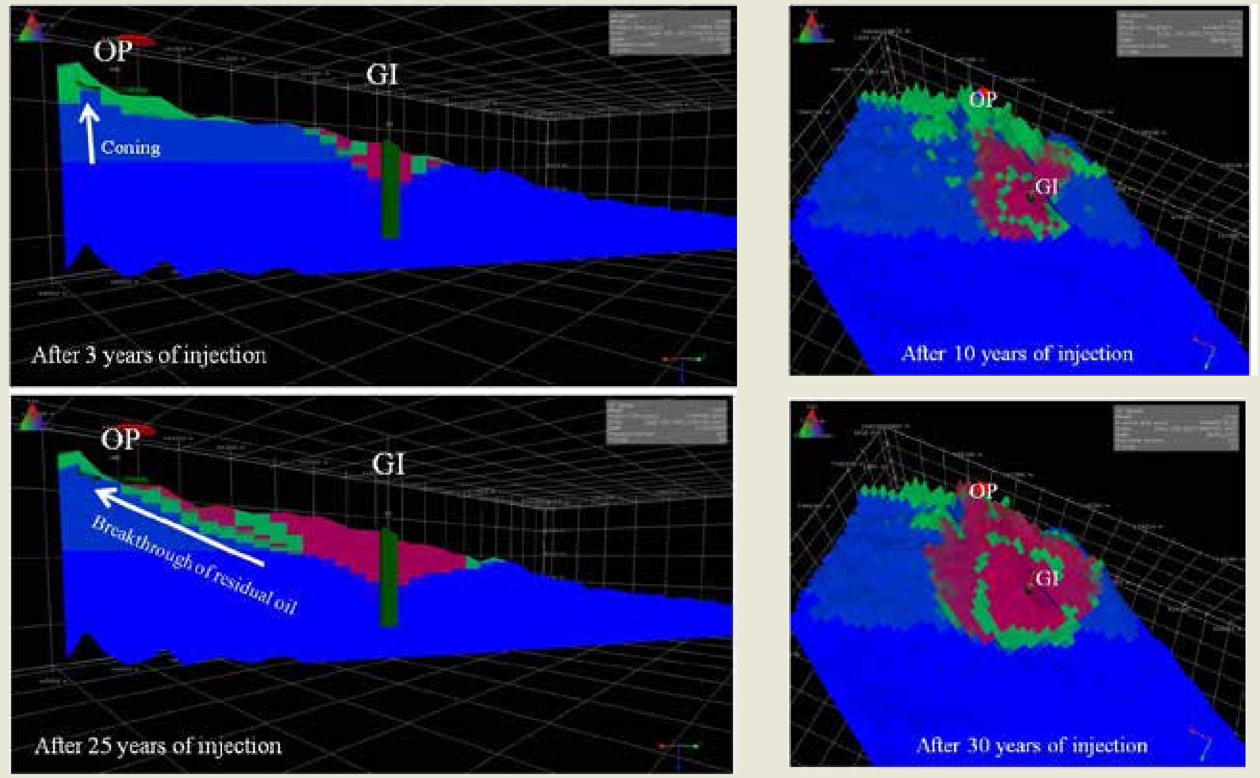
CO_2 has shown to be a very efficient agent to recover oil, especially residual oil. When the CO_2 is mixable with oil, the oil will get less viscous, swell and will be easier to produce. It can also vaporize and pull out intermediate components in the oil. During this process significant amount of CO_2 is stored at the end of the injection period after the oil and water has been displaced. CO_2 is widely used in the USA where CO_2 is a natural resource. In Europe there is only small amount of CO_2 available, therefore this method is presently not used. However, there is a big potential if anthropogenic CO_2 is captured and made available for injection.

A technical oil discovery was made in the Stø Fm in well 7125/1-1 located east of the Loppa High on the southern part of the Bjarmeland Platform. The discovery well identified a thin oil zone of 1-1.5 m with high oil saturation overlying a residual oil zone of 32.5 m. The well encountered the contact between oil and the water with residual oil. If the oil water contact is horizontal, the thickness of the oil zone is thicker at the crest of the structure. The potential oil recovery with CO_2 injection was investigated in the simulation model described in 5.3 (sector model). The structure was filled with oil according to the OWC in well 7125/1-1 and CO_2 injection was applied.

The oil in the simulation model was produced (well OP) from the main oil zone while CO_2 was injected down flank in the residual oil zone (GI) with an injection period of 30 years. Results from the simulation model show reduced oil production when water coned into the producer.



Setup of simulation model, showing the location of the sector model and the distribution of oil and residual oil.

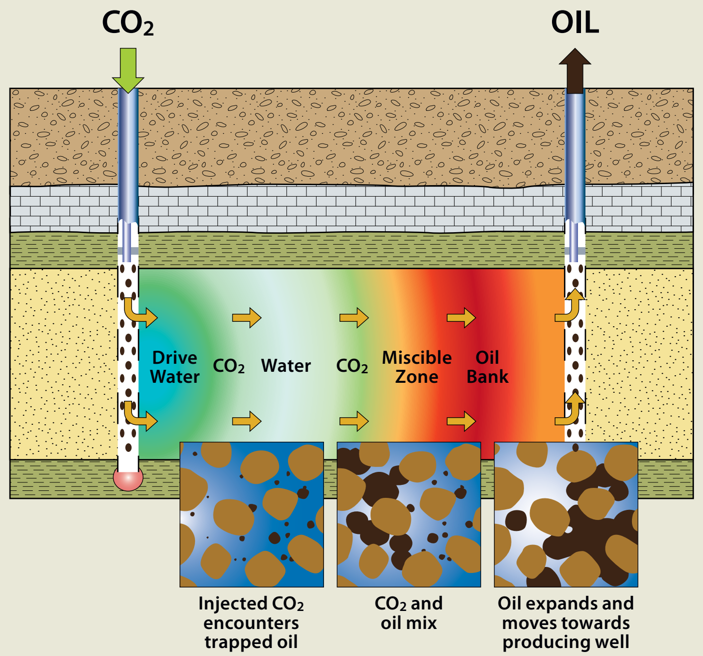


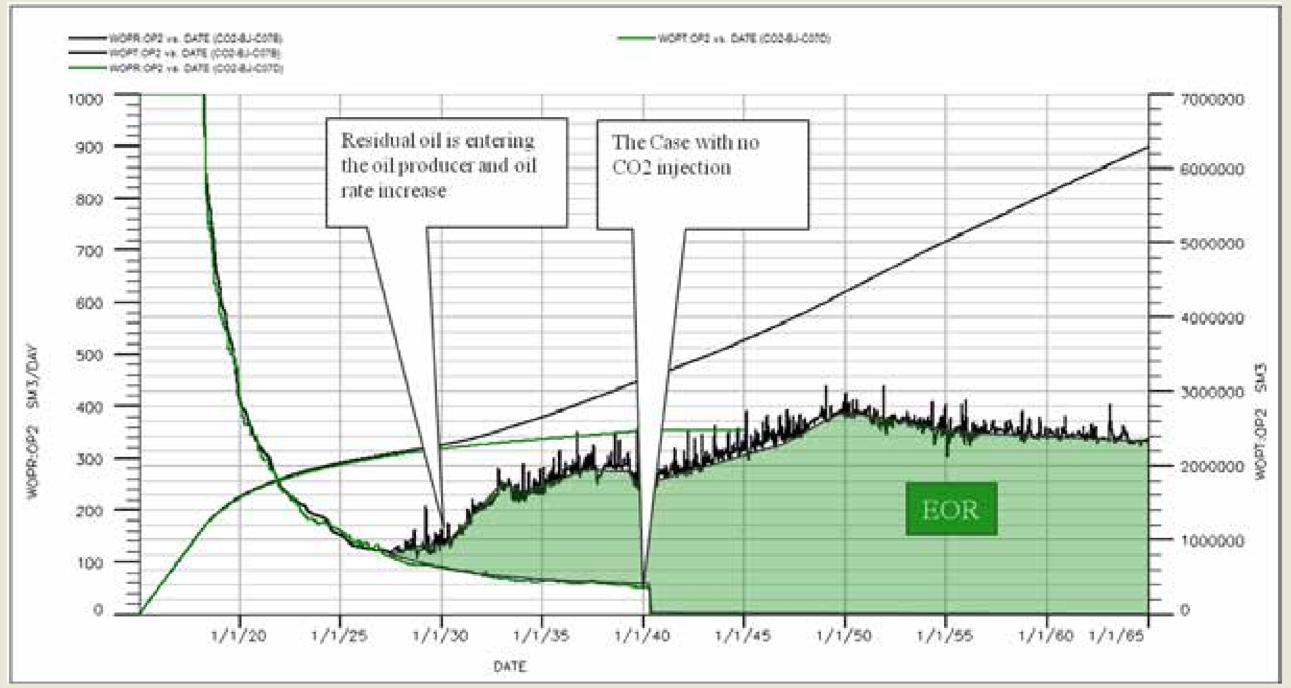
Profiles through the CO_2 injector (GI) and the oil producer (OP), showing distribution of gas (red), oil (green) and water (blue) 3 and 25 years after the injection start. The maps to the right show the distribution of the gas plume. North is down to the left.

Case study: Prospect A, evaluation of residual oil zone

However, the oil production will increase when CO_2 enters the residual oil zone. A combination of oil production from an oil zone and a residual zone has a beneficial effect on the economy as the oil production starts immediately after injection.

The input data and the results are given in the table below. Based on the sector model a total production of oil will be 6.3 mill Sm^3, of which 2.5 mill Sm^3 comes from the main oil zone and 3.8 mill Sm^3 from the residual zone. This gives a recovery factor of 26 % from the main zone and 15 % from the residual zone. 43 mill tons of CO_2 is stored in the reservoir during the injection and production period. The profile below is showing the daily and the cumulative oil production for the main oil zone and the residual zone.





Profile of oil production showing one case with no injection and the additional oil recovered by CO_2 injection.

Porosity:	22 %
Horizontal Permeability:	900 mD
Kv/Kh :	0.5
N/G:	0.94
So oil zone:	75 %
Sor residual zone:	20 %
Oil density:	0.80
GOR:	66
Max injection pressure:	225 bar
CO_2 injection rate:	1.5 MSm^3/d
OP and CO_2 inj. Start:	01.01.2015
Oil in-place, main structure:	23 MSm^3
Res. oil in-place, main structure:	49 MSm^3
Oil in-place, sector model:	9.7 MSm^3
Res.oil in-place, sector model:	25.3 MSm^3
Results:	
Oil produced, sector main zone:	2.5 MSm^3
Oil produced, sector residual:	3.8 MSm^3
Recovery factor, main oil zone:	26 %
Recovery factor, residual zone:	15 %
CO2 stored	43 Mtons

Input data and results.

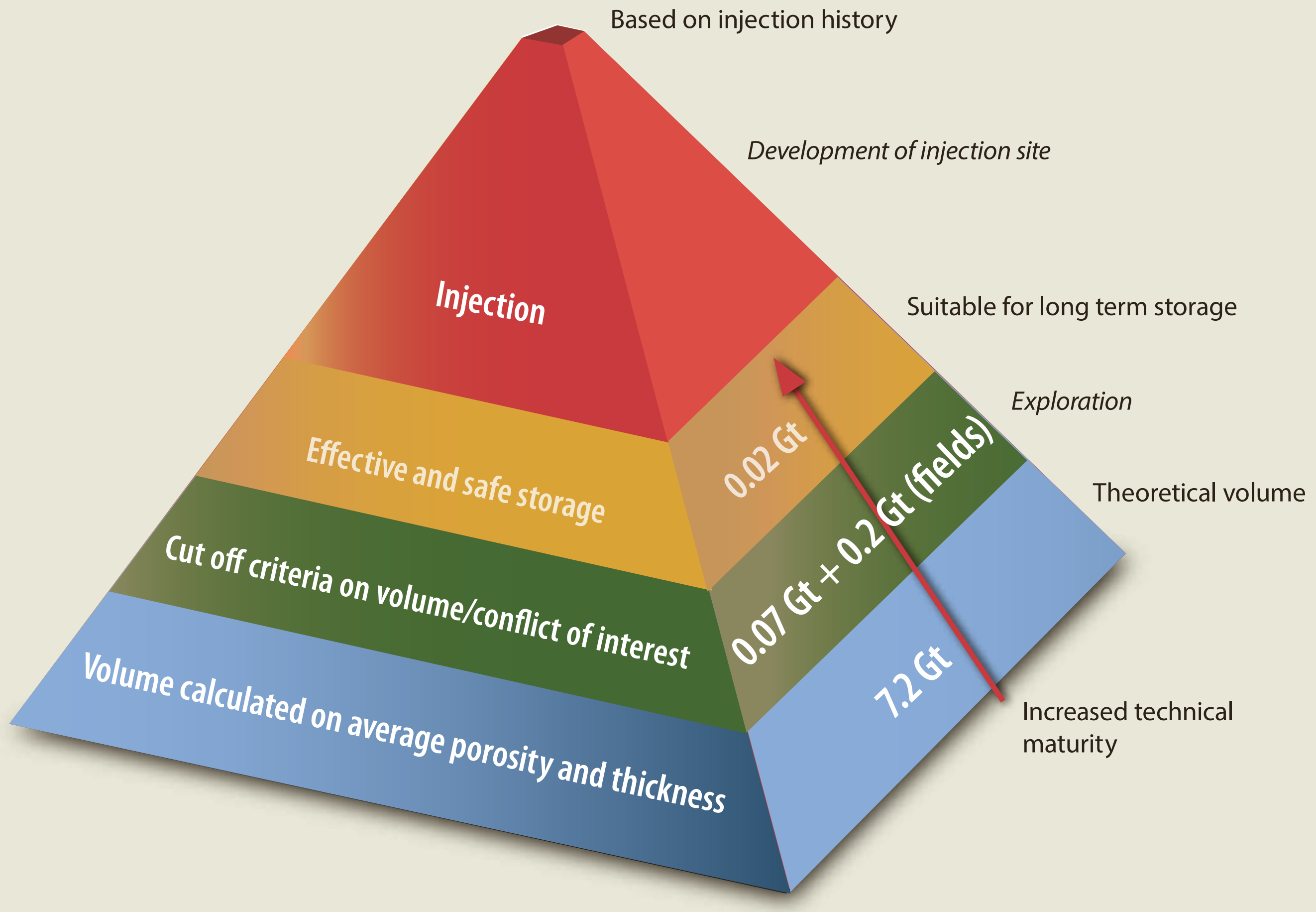
The main results of this study are displayed in the tables and illustrated by the maturation pyramid. The aquifers in the Jurassic Realgrunnen Group are well suited for sequestration, and their storage potential has been quantified. Additional storage in other aquifers is possible. A theoretical storage potential of 7.2 Gt is identified in the regional aquifers. Since some of these areas may have a potential for petroleum exploration and exploitation, the storage potential in the aquifer is classified as immature.

In the near future the CO_2 available for injection in the Barents Sea is likely to come from natural sources as CO_2 associated with methane in the gas fields. The evaluation indicates that there is a potential for safe storage of more than 500 Mt CO_2 in structural traps in the southern Barents Sea. Some of these traps are close to the areas of field development and production. The main uncertainties are related to the quality of the seal and to the possibility of encountering hydrocarbon in the traps.

CO_2 injection can be used to mobilize residual oil, which is abundant in the Realgrunnen Group. The potential for such utilization of CO_2 is shown by a simulation study of prospect A. The results indicate that large amounts of CO_2 which can be safely stored in prospects could be dedicated to oil recovery from residual oil and thin oil zones. Analysis of this potential is beyond the scope of this atlas.

Gas production started in the southern Barents Sea in 2007. In the future, when gas bearing structures are depleted and abandoned, they will have a potential to be developed as storage sites. A simple calculation revealed a potential of around 200 Mt in four of these structures.

Prospects in structural traps	Avg depth	10^9m^3 Bulk volume	10^6m^3 Pore volume	Avg K	Open/closed	Storage eff	CO_2 Density	Storage capacity	Maturity
Unit	*m*	*Rm^3*	*Rm^3*	*mD*		*%*	*tons/Rm^3*	*Mtons*	
BP Aquifer									
A	1525	55	10000	500	open	2.50	0.65	176	
B	1260	4	900	500	half open	3	0.65	19	
HB Aquifer									
C	2400	1.9	280	1-170	open	10	0.7	19	
D	2400	1.2	180	1-150	open	10	0.7	12	
E	1900	1.9	290	2-500	open	10	0.7	20	
F	1900	2.3	350	2-550	open	10	0.7	24	
G	2200	17	1600	1-300	half open	5	0.7	57	
H	2100	58	5200	1-600	open	5	0.7	183	
BFC Prospect									
I	2100	7.7	1250	400	closed	1	0.7	9	
Storage in abandoned fields									
Fields in production								200	
Aquifer volumes		10^9m^3	10^9m^3						
BP Aquifer	1100	1480	245	5-1000	half open	3	0.65	4800	
HB Aquifer	2400	1230	120	1-500	half open	3	0.7	2500	
Greater Snøhvit			4.1						
Greater Askeladd			2.3						
Greater Albatross			5.4						
Snøhvit CO_2 injection									
Snøhvit aquifer 2800	2404-2800	89	6.4	150	half open	2	0.7	90	
Snøhvit central Stø	2404-2800	6.1	0.68					24	



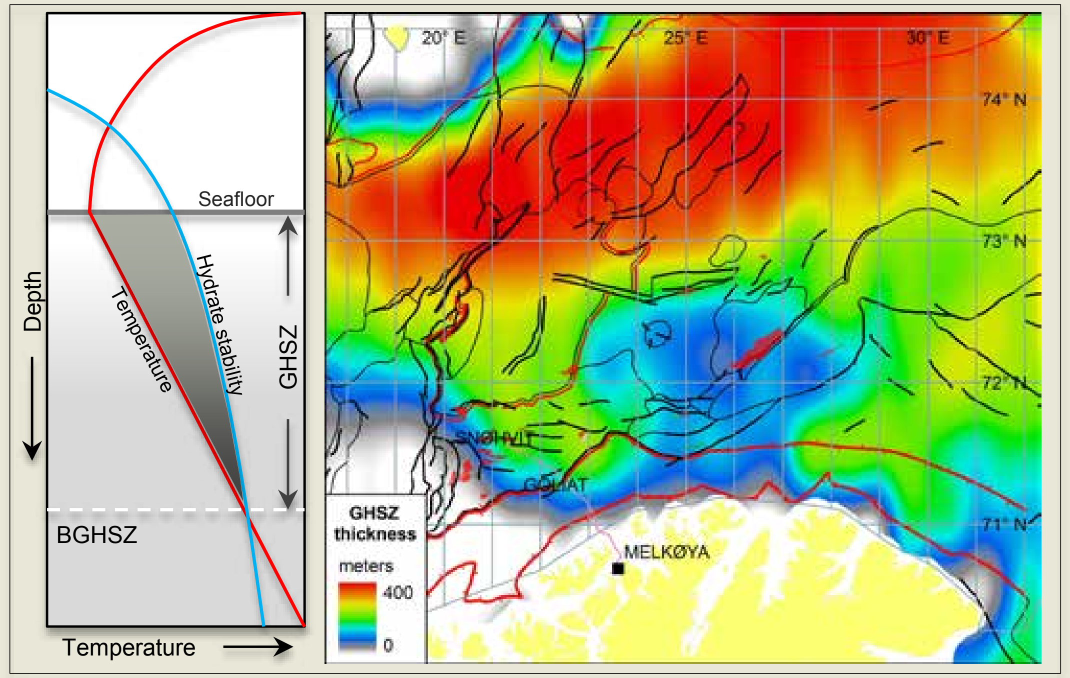
5.6 Gas Hydrates

by Rune Mattingsdal, Alexey Deryabin (NPD) and professor Arne Graue (UiB)

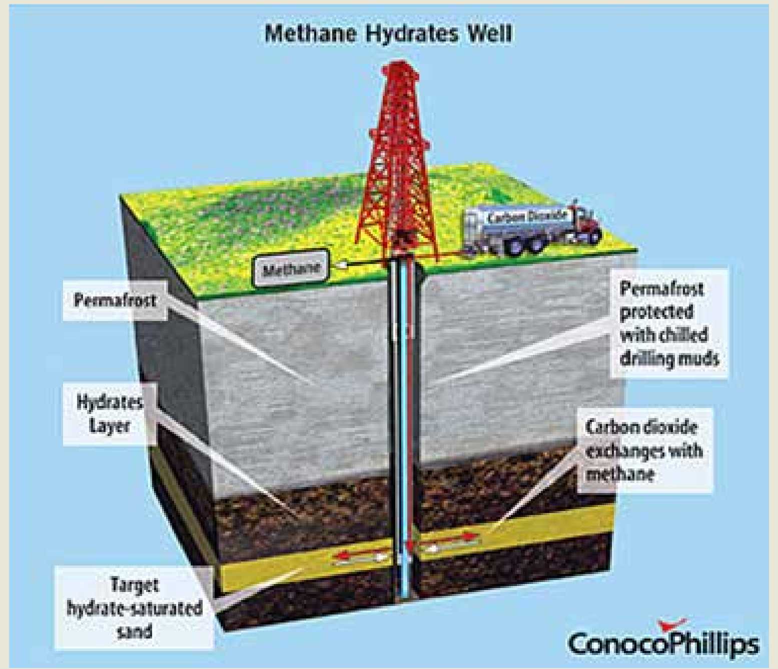
Gas hydrates in the Barents Sea
Natural gas hydrate is a solid consisting mostly of methane and water. It form crystals where gas molecules are trapped in cage-like structures formed by water molecules. Gas hydrates can be found in Arctic regions below permafrost and in marine subsurface at deep water, high pressure conditions and low temperatures (typically above 60 bar and below 100C). Hydrate is a highly condensed form of natural gas bound with water; one cubic meter of hydrate corresponds to ca. 160 cubic meter of natural gas at atmospheric conditions. The zone where gas hydrates can form is referred to as the gas hydrate stability zone (GHSZ). In the marine environment, the GHSZ is located between the sea floor and the base of the stability zone defined by the phase diagram The limits of the stability zone are determined by bottom water temperature, sea level, geothermal gradient, gas composition and pore water salinity.

The Barents Sea is a relative deep continental shelf with water depths of up to 500 meters, mainly due to several episodes of glacial erosion. This, combined with bottom water temperatures that can be as low as 0^{0}C or less, results in a GHSZ thickness which might vary from tens of meters to 400 meters, depending on gas composition and geothermal gradient (Chand et al, 2008). Figure below shows a modeled GHSZ thickness map. Within this zone, gas hydrates can form in areas where there is sufficient flux of thermogenic methane or deposits of biogenic methane. In the southwestern Barents Sea, the thickest GHSZ generally coincide with the deeper parts of the shelf. Here gas hydrates might in theory act as a seal for hydrocarbons in shallow reservoirs. In the Barents Sea gas hydrates have been drilled in the Vestnesa area west of Spitsbergen, and there are good geophysical indications of gas hydrates in the Bjørnøya Basin.

CO_2 Storage in Hydrates
CO_2 may be stored in gas hydrates. Exposing methane hydrate to CO_2 will cause a solid exchange of CO_2 and CH4 as guest molecules within the hydrate; an exchange caused by the fact that it is thermodynamically more favorable for water to form hydrate with CO_2 compared to methane. CO_2 sequestration in hydrates is a win-win process since associated natural gas will be produced as CO_2 is sequestered in the form of CO_2 hydrate. The regenerated CO_2 hydrate is thermodynamically more stable than the methane hydrate; thus the replacement of natural gas hydrate with CO_2 hydrate will increase the stability of hydrate formations.



Left: Conceptual model of the gas hydrate stability zone (GHSZ) for a marine setting. BGHSZ is the bottom of the GHSZ. Right: GHSZ thickness map calculated assuming 96% methane + 3% ethane + 1% propane and sea water with a geothermal gradient of 31 °C/km, adapted from Chand et al. (2008). Fields, discoveries, faults and boundaries are indicated.



CO_2 storage in hydrate formations, as demonstrated in the Alaskan Injection test by ConocoPhillips and USDOE (Courtesy ConocoPhillips)

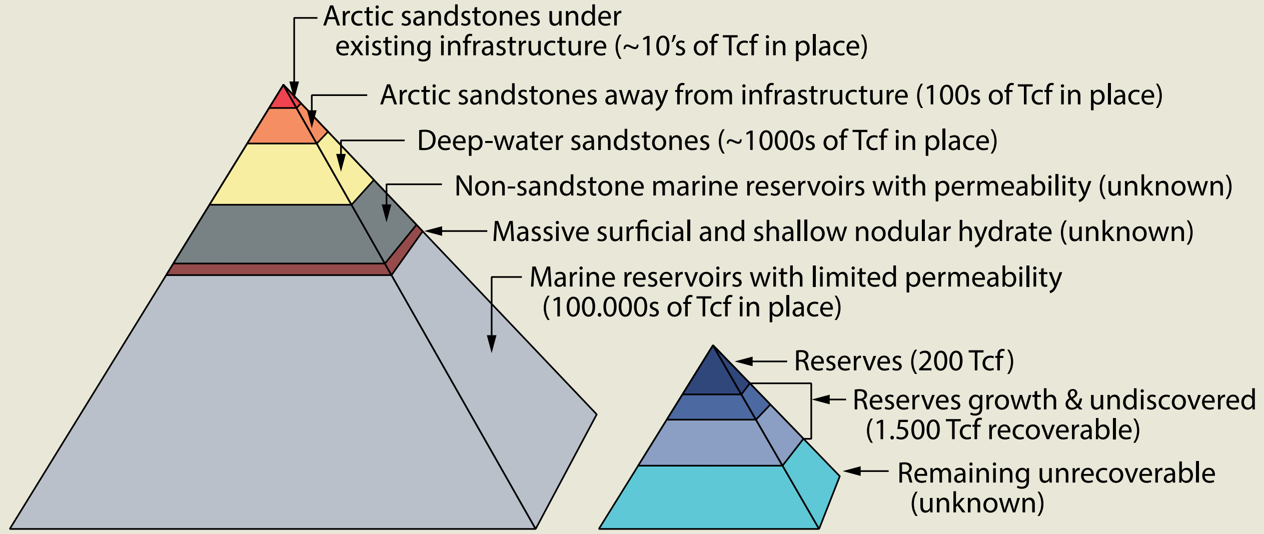
5. Storage options

5.6 Gas Hydrates

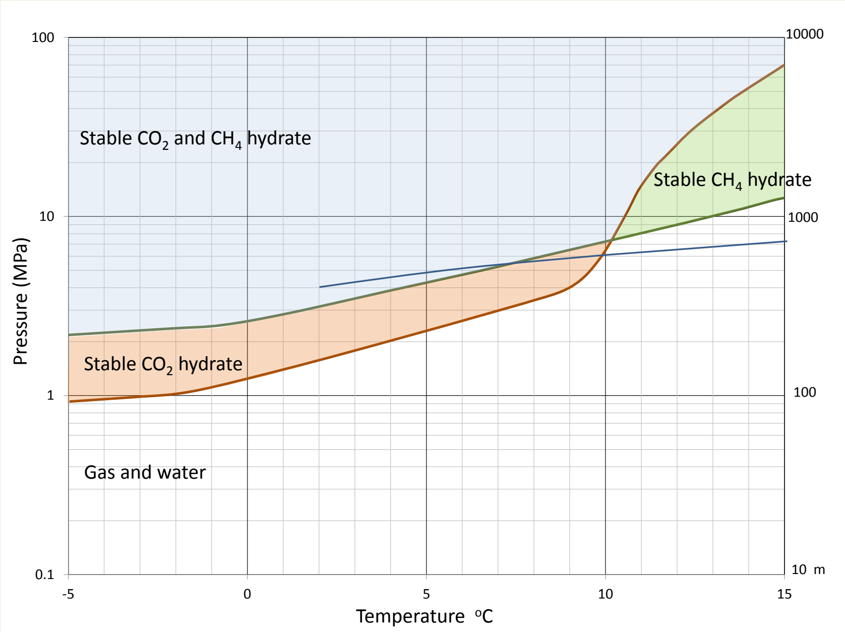
by Rune Mattingsdal, Alexey Deryabin (NPD) and professor Arne Graue (UiB)

From an energy perspective natural gas hydrates may represent an enormous energy potential (Boswell and Collett 2006). Some authors claim that the total energy corresponding to natural gas entrapped in hydrate reservoirs worldwide might be more than twice the energy of all known energy sources of coal, oil and gas. Storage of CO_2 in natural gas hydrate reservoirs by replacing the CH4 in the hydrate with CO_2 may have some significant attractive potential compared to other natural gas production methods from hydrates. Besides the CO_2 storage potential, this method benefits from little or no associated brine production, which has been a severe limitation in previous attempts to produce natural gas from hydrates by depressurization and heat injection, and the capability of maintaining the geomechanical stability to avoid formation collapse or subsidence. A field pilot in Alaska performed by ConocoPhillips and US DOE in 2012 concluded that CO_2 was stored and methane successfully produced during a huff and puff operation injecting 200 000 scf of CO_2 and nitrogen.

Storage of CO_2 as hydrates below the sea floor is a possible trapping mechanism, but has not been considered here because the long term behavior of such hydrate in shallow sediments is not well known. It should be noted that within the gas hydrate stability zone, a seepage of CO_2 will be trapped as hydrate before reaching the sea floor.



Boswell, R. and Collett, T.S.: "The gas hydrate resource pyramid", Fire in the ice, Netl fall newsletter, 5-7, 2006



Phase diagram for water, methane and CO2. The scale to the right shows approximate water depth converted from the pressure scale. CO2 hydrate is more stable than methane hydrate at depths shallower than 700 m. The blue line shows pressure and temperature below the sea bed assuming a sea water temperature of 2 oC and a gradient of 40 oC/km.

Natural Gas Hydrate on Fire; "Fiery Ice" (Courtesy USGS)

5.7 Longyearbyen CO_2 Lab

By Alvar Braathen and coworkers

The Longyearbyen CO_2 Lab in Svalbard, Norway, is one of the demonstration projects currently carried out worldwide. The purpose is to learn more about the CO_2 behaviour in high-pressure conditions and to assess the storage and sealing capacity of local subsurface rock successions.

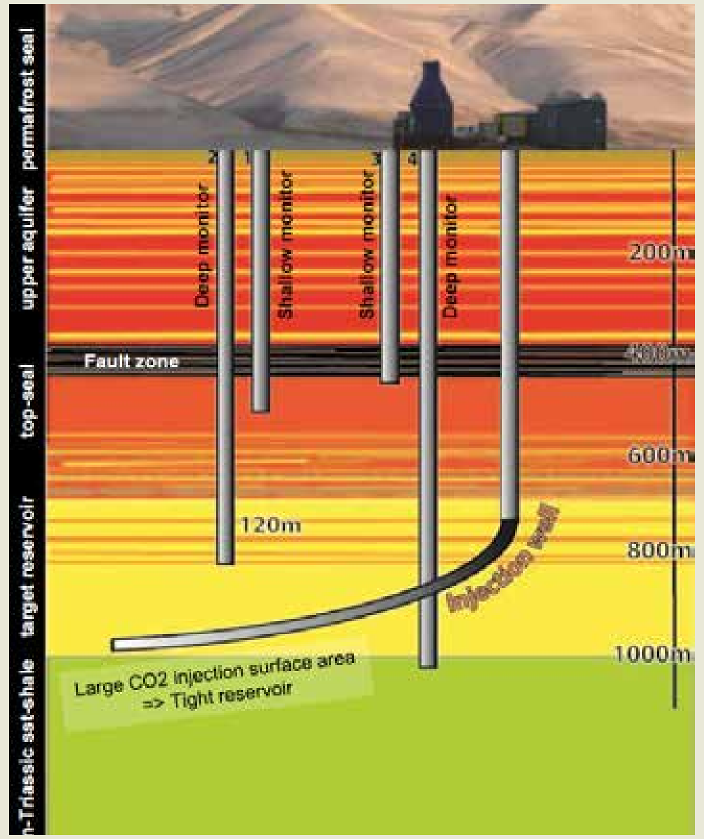
These pilot projects are meant to provide a foundation for worldwide commercial ventures of CO_2 sequestration.

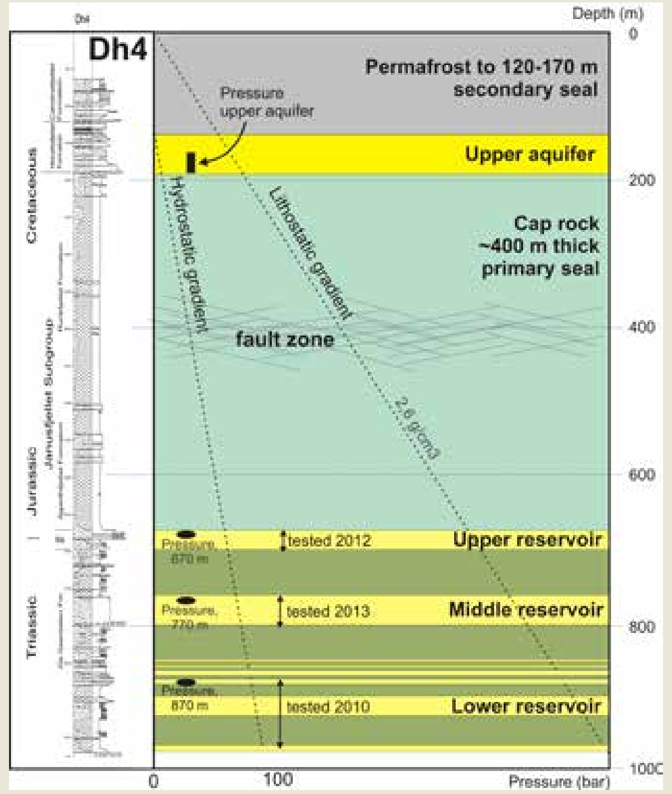
Longyearbyen has a population of around 2000, and is located in the polar wilderness of central Spitsbergen.

A coal-burning, single power plant in Longyearbyen provides both electricity and hot water, and supports the city's entire house-warming system of radiators. One objective of the demonstration project is to investigate if there is sufficient storage capacity close to Longyearbyen to capture the CO_2 which can be sequestered from the power plant – a maximum of 60,000 tons /annually.

The aim of the project has been to evaluate local geological conditions for subsurface storage of the greenhouse gas CO_2. Project activity included drilling and logging of slim-hole cored wells, acquisition of seismic sections with snow streamer and a wide range of laboratory and field studies. The targeted reservoir is a paralic sandstone succession of the Upper Triassic–Middle Jurassic Kapp Toscana Group at ≥670 m depth. This is overlain by thick Upper Jurassic shales and younger shale-rich formations. The reservoir has a sandstone net gross ratio of 25–30% and is intruded by thin dolerite sills and dykes. The reservoir and cap-rock succession rises at 1–3° towards the surface and crops out 14–20 km to the northeast of Longyearbyen. Near the surface, all units are seemingly sealed by permafrost. The reservoir is compartmentalized and shows considerable underpressure, in the lower part equal to 30% of hydrostatic pressure, which indicates good initial sealing conditions. Core samples indicate a reservoir with sandstones of moderate porosity (5–18%) and low permeability (max. 1–2 mD). Rock fractures are therefore important for fluid flow.

Water injection tests have indicated good injectivity in the lower part of the reservoir succession (870–970 m depth). The relatively more porous and permeable upper part (670–870 m depth) has only been partly tested. The injectivity increases with increasing pressure, suggesting that the fractures gradually open and grow under injection. Reservoir pressure compartments indicate bedding-parallel permeability barriers, although these may gradually yield under a growing cumulative pressure. The reservoir storage capacity and its apparent connection with the surface remain to be fully evaluated. However, the lateral expansion of the injected CO_2 plume in this large reservoir over a distance of 14 km to the outcrops is projected to take thousands of years.





Results from Drillhole 4 in the Longyearbyen CO_2 Lab.

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).

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

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

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

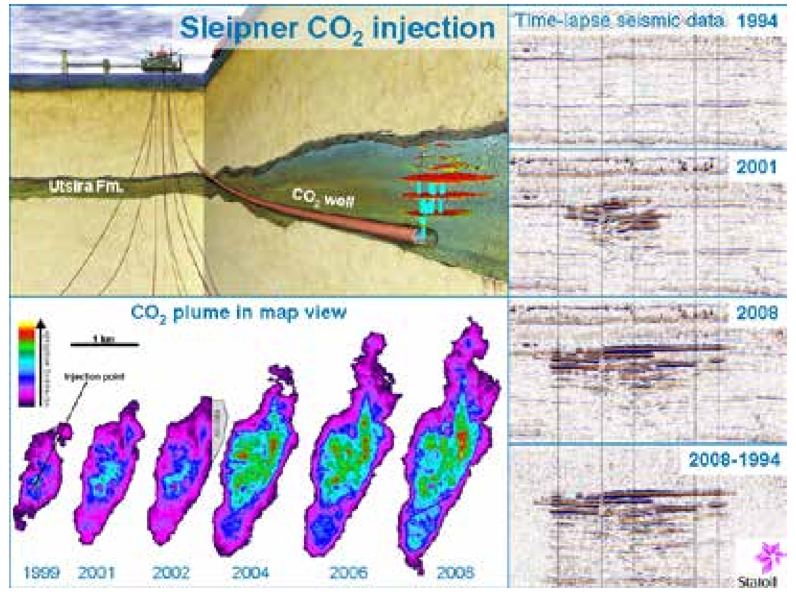


Figure of the Sleipner CO_2 *injection 4-D seismic monitoring. Upper left: sketch of the injection well and storage reservoir. To the right is a seismic section along the long axis of the plume (south-west to north-east) for different vintages and for a time-lapse difference. Note the lack of reflectivity on the seismic difference above the storage formation, showing no signs of leakage. Lower left: Maps of the development through time of cumulative amplitudes for all layers.*
By 2008 the area of the CO_2 *plume was about 3 km², and it was steadily growing.*

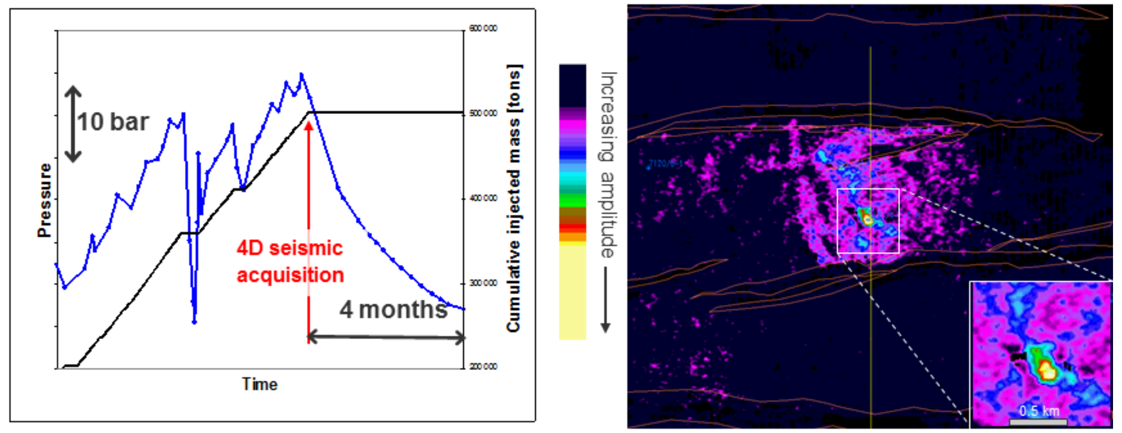


Figure from the Snøhvit CO_2 *injection. Left: Cumulative injection (black line) and estimated bottom-hole pressure (blue line) spanning year 2009, showing pressure increase during periods of injection and pressure fall-off during stops. The timing of a 4-D seismic survey is shown in the figure. Right: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

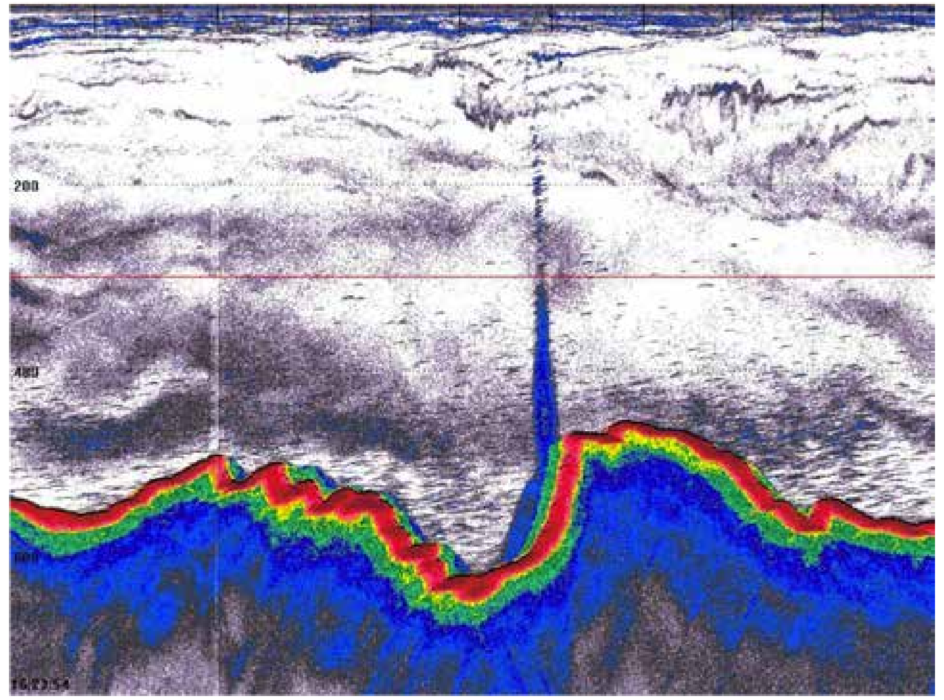
Seafloor monitoring programs are now being designed to detect CO_2 leakages and such early warnings. These schemes include: 1) scanning of the water column with acoustic systems to reveal any changes in the release of gas bubbles from the seafloor; 2) acoustic imaging of the seafloor at ultrahigh resolution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

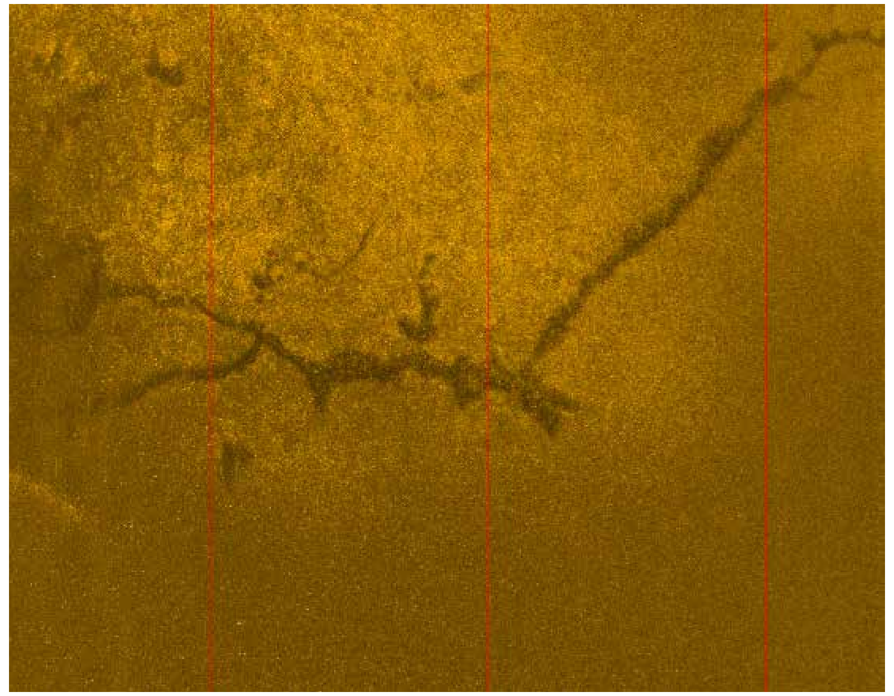


Detection of gas bubbles by echo sounder systems. The figure shows the acoustic signature generated by CO_2 bubbles being naturally released from the Jan Mayen vent fields. The CO2 bubbles are here seen as a blue flare that rises around 500 metres from the seafloor through "clouds" of plankton in the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

Wells

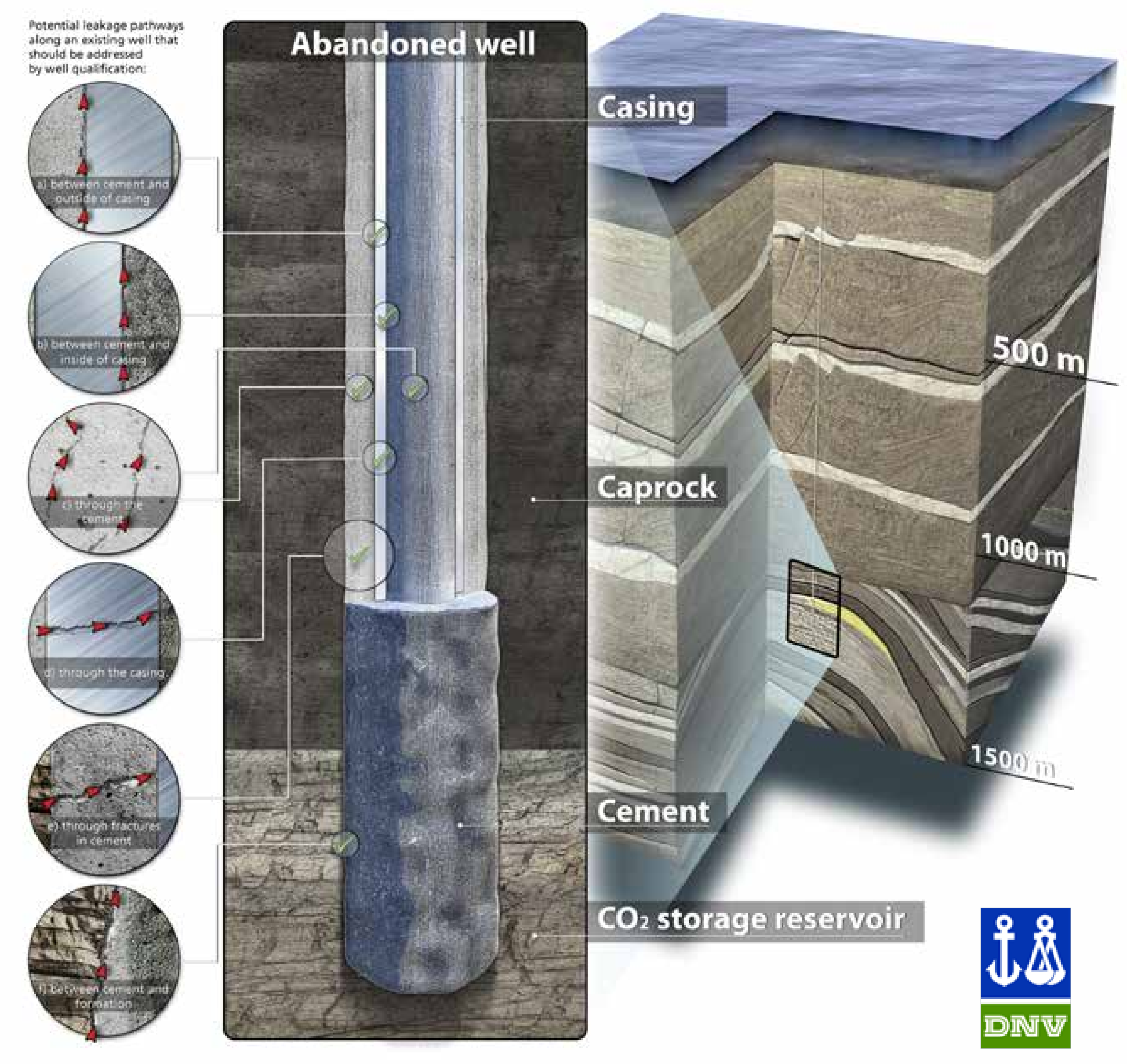
By: The Petroleum Safety Authority Norway

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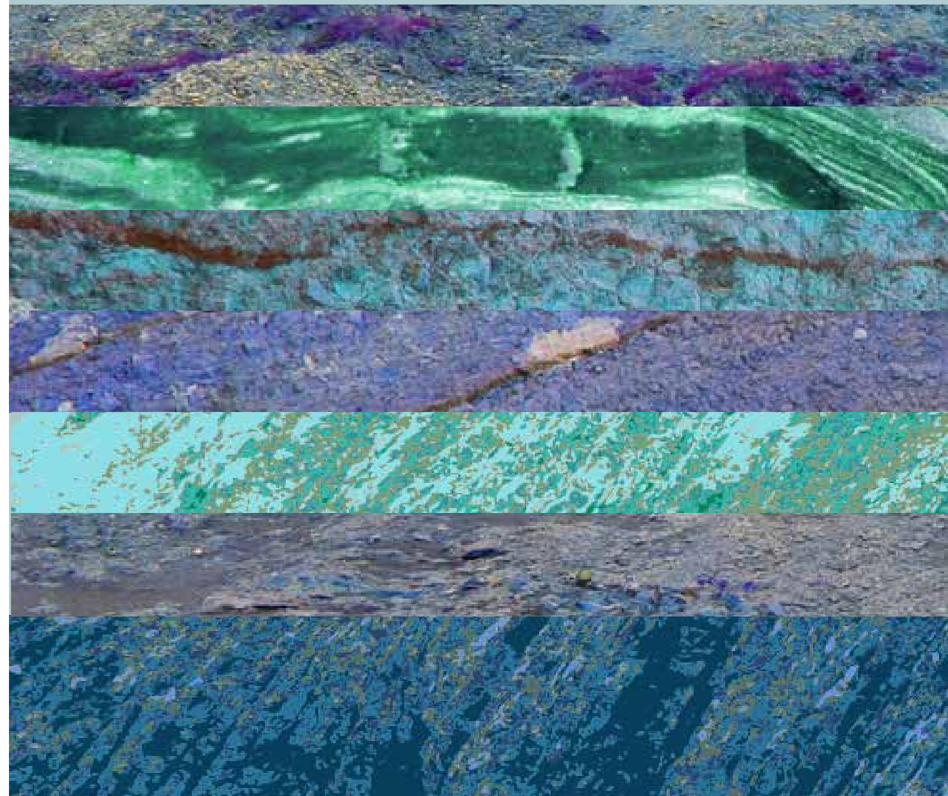
Geocapacity: *http://www.geology.cz/geocapacity*



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