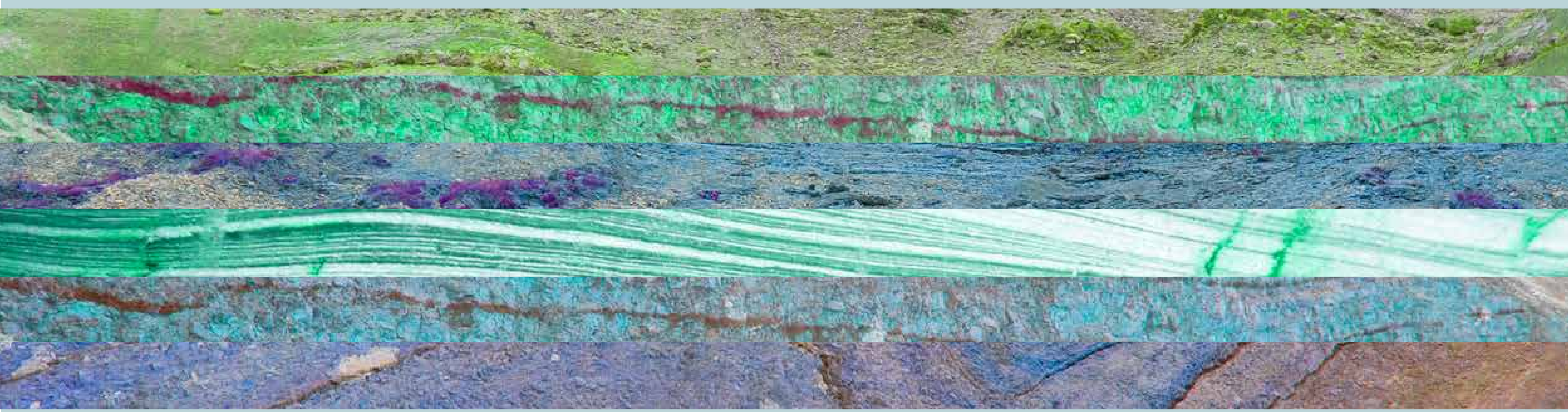
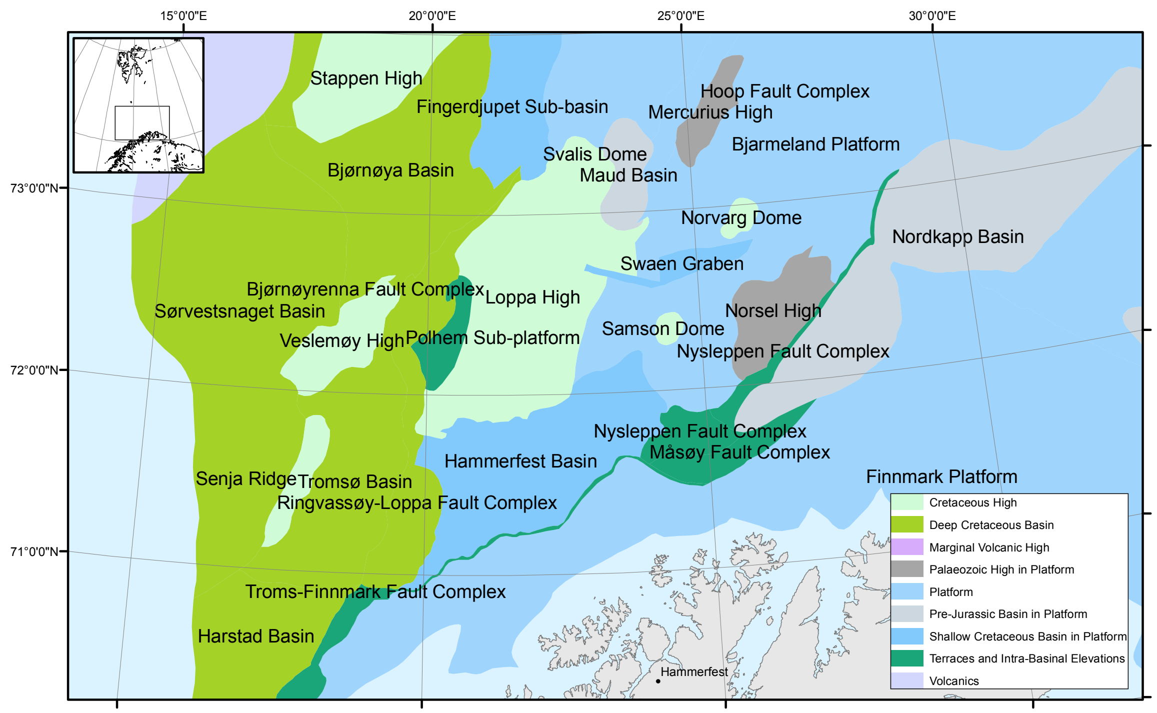
6. The Barents Sea

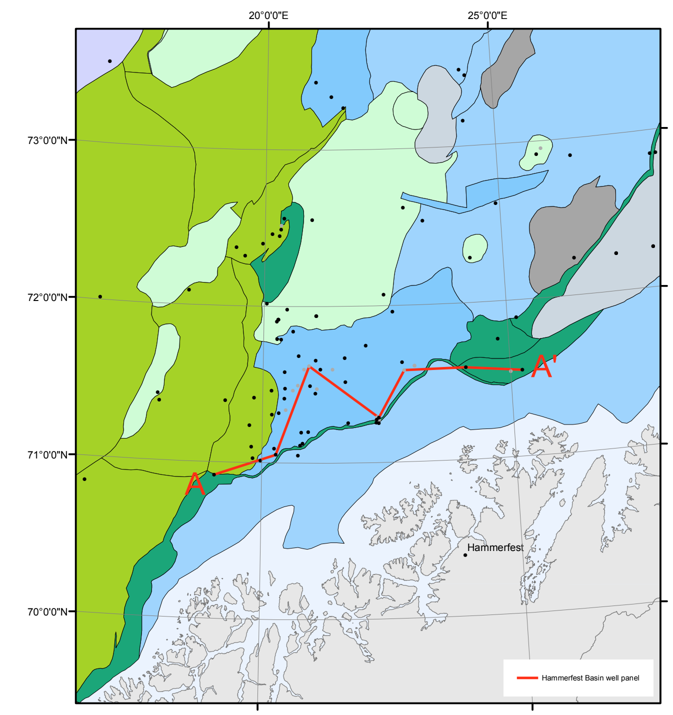


Eva K. Halland (Project Leader), Andreas Bjørnestad, Ine Tørneng Gjeldvik, Maren Bjørheim, Christian Magnus, Ida Margrete Meling, Jasminka Mujezinović, Fridtjof Riis, Rita Sande Rød, Van T. H. Pham, Inge Tappel

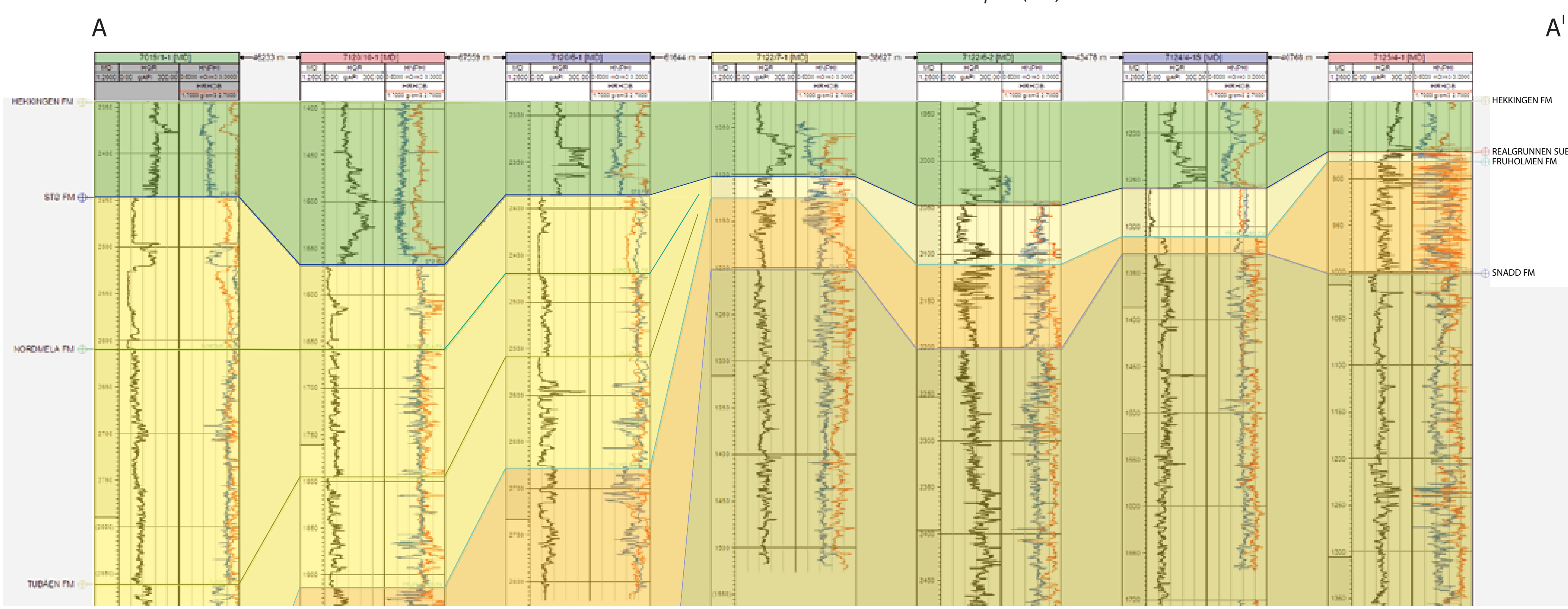
6.1 Geology of the Barents Sea



Structural elements of the Southern Barents Sea.

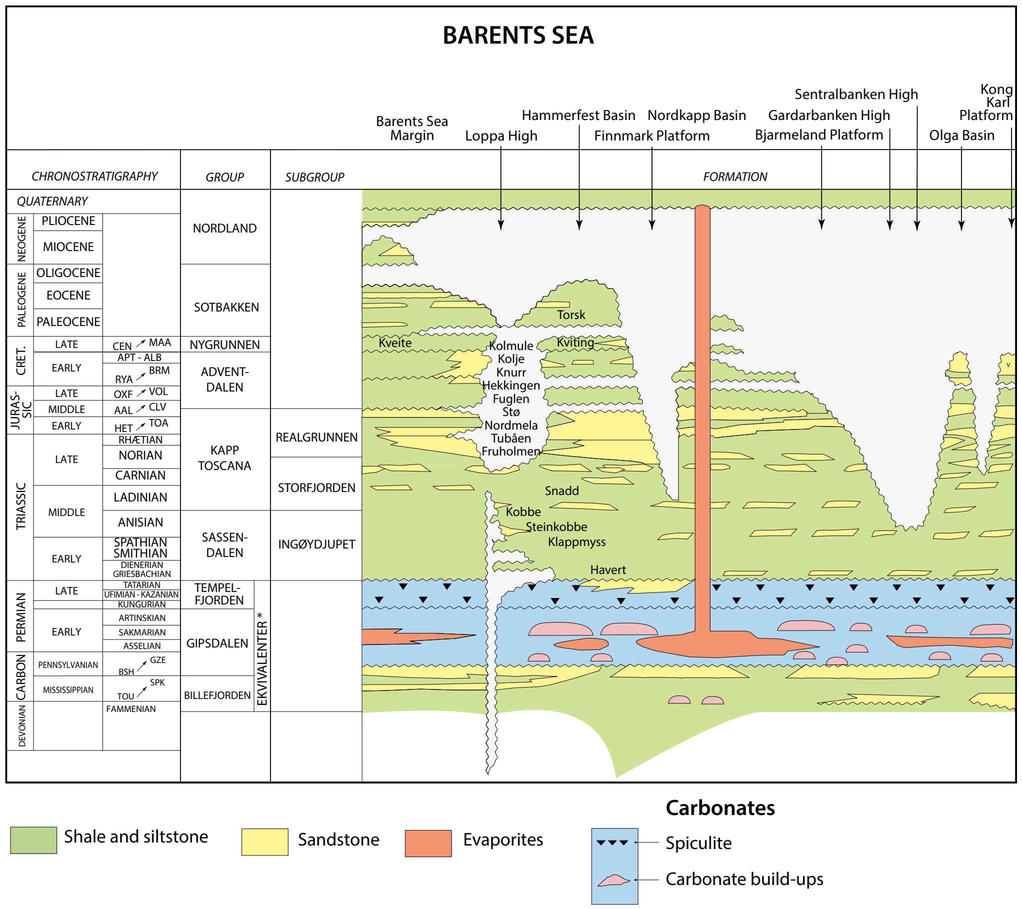


Transect from the Harstad Basin to the Måsøy Fault Complex (AA`).

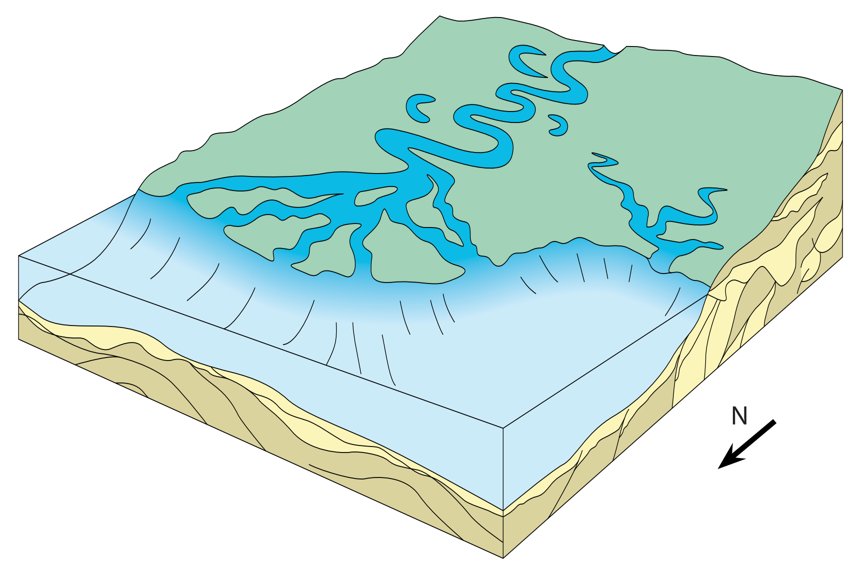


Well section panels (AA`) showing gamma and neutron/density logs reflecting thickness variations of the different formations.

6.1 Geology of the Barents Sea



* Lithostratigraphic nomenclature for The Barents Sea Paleozoic (NPD).



Conceptual sketch of an early stage in the development of the Stø formation in the southern parts of the Barents Sea.

Lithostratigraphic nomenclature

The lithostratigraphic nomenclature for the post-Caledonian successions of the southern Barents Sea has been a matter of 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.

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

The official stratigraphic nomenclature for the Barents Sea is as follows:

The CO_2 Storage Atlas for the Norwegian Continental Shelf has followed the definitions from Dallmann et.al (1999) and suggested a revised lithostratigraphic scheme for the Mesozoic. For the Upper Paleozoic successions, the official nomenclature from NPD Bulletin No 9 (Larssen et.al 2002) has been used. For the Cenozoic, we follow NPD Bulletin No 4.

6.1 Geology 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 very active 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.

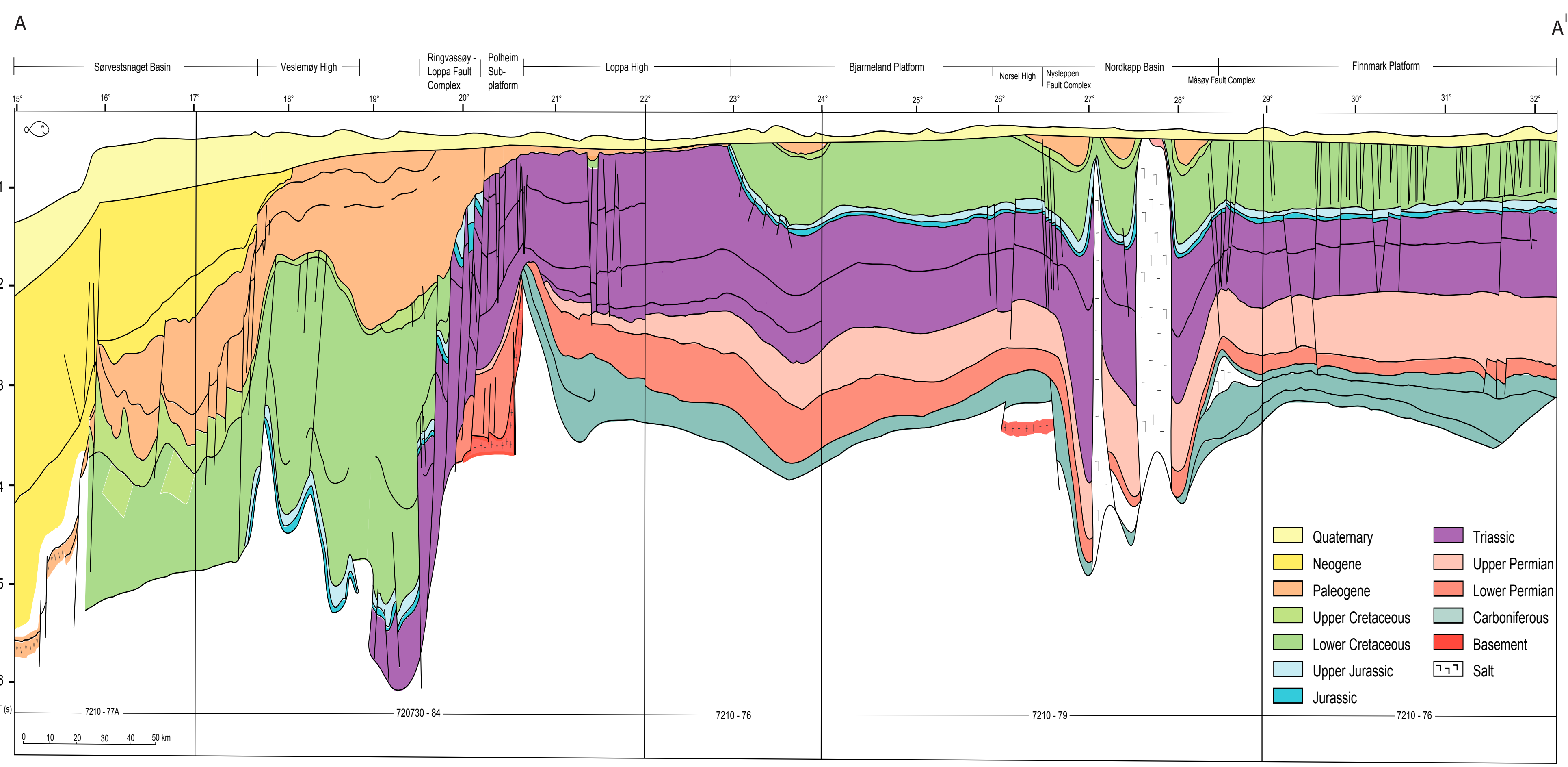
The area evaluated for CO_2 storage is defined to the west by the N-S to NNE-SSW trending Ringvassøy-Loppa and Bjørnøyrenna Fault Complexes, to the south/southeast by the Troms-Finnmark Fault Complex and the Finnmark Platform, to the north by an east-west line approximately along the 73^{O} N parallel,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

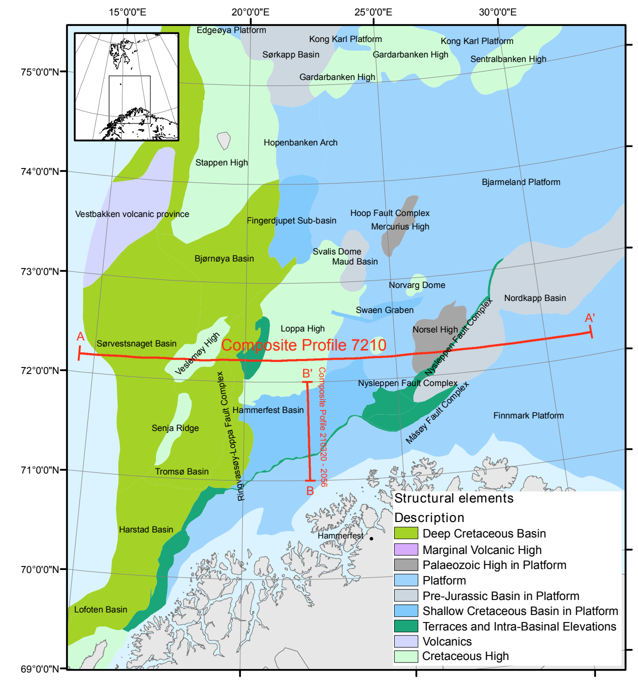
During the Late Paleozoic (Late Carboniferous to Early Permian), thick sequences of halite were deposited (Gipsdalen Gp) giving rise to pronounced salt diapirism, beginning in the Early Triassic. The basin is dominated by thick Mesozoic, mainly Triassic successions, with a significant thickness of Upper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

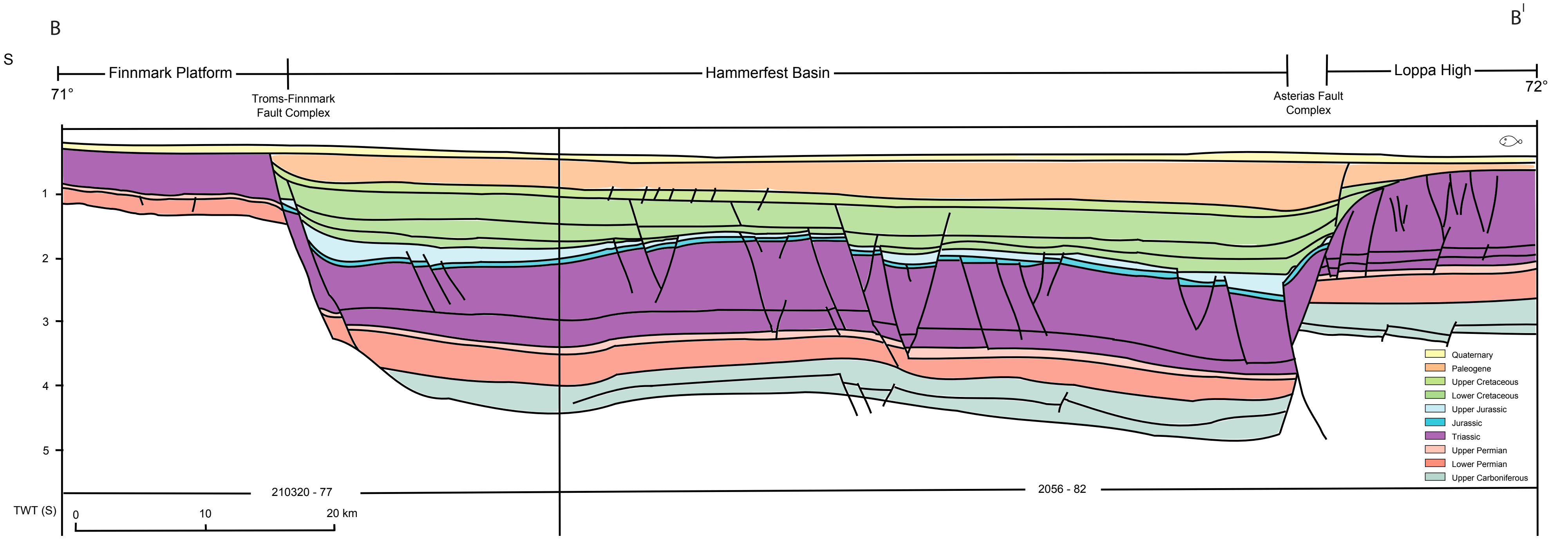
The central part of the Troms-Finnmark Platform in the Norwegian sector shows a rift topography with half-grabens containing siliciclastic rocks of Early Carboniferous age (Billefjorden Gp). During the Permian, the stable western part of the platform was transgressed. Late Permian and Late Jurassic movements 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.

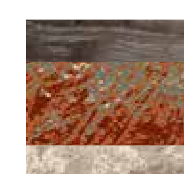
The Bjarmeland Platform is part of an extensive platform area east of the Loppa High and north of the Nordkapp Basin. The platform was established in the Late Carboniferous and Permian, but subsequent Paleogenetectonism tilted the Paleozoic and Mesozoic sequences towards the south, so that presently 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).

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



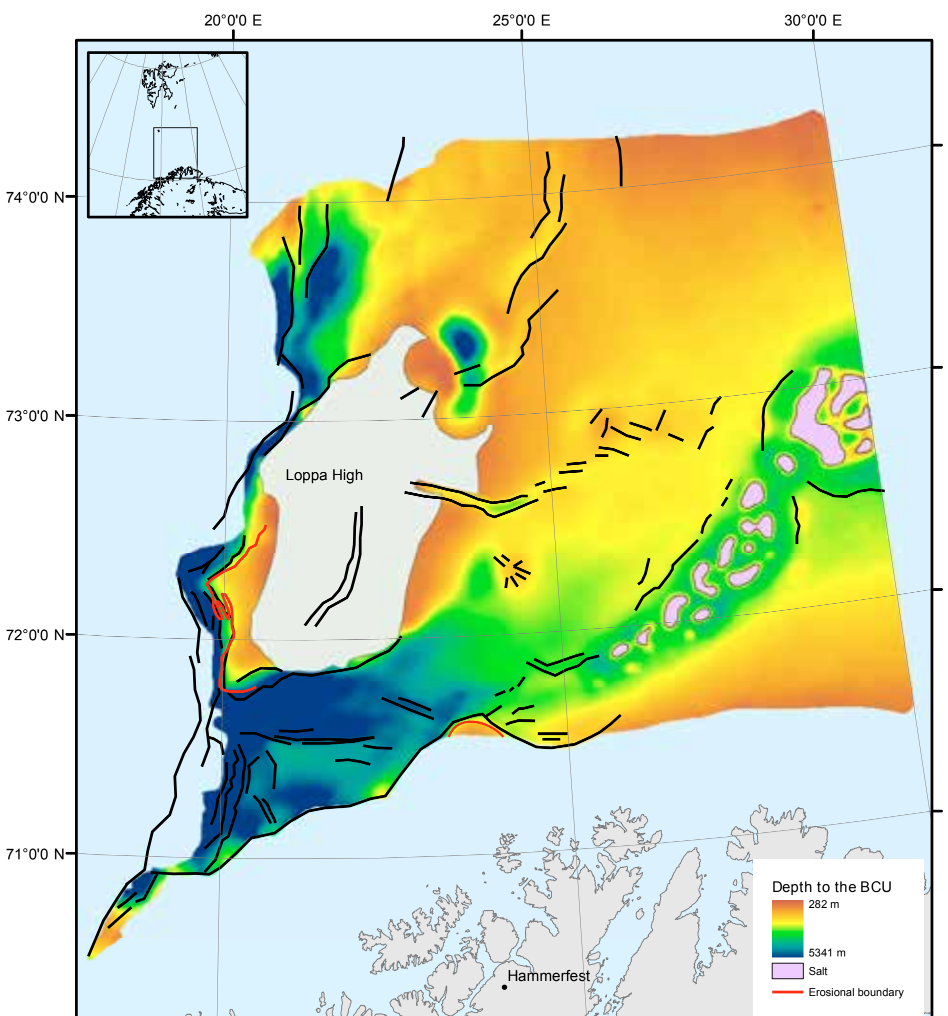
Transects of the geosections from the western part of the Sørvestsnaget Basin to the eastern part of the Finmark Platform (AA`) and from the Finmark Platform across the Hammerfest Basin to the Loppa High (BB`). Gabrielsen et al. 1990.



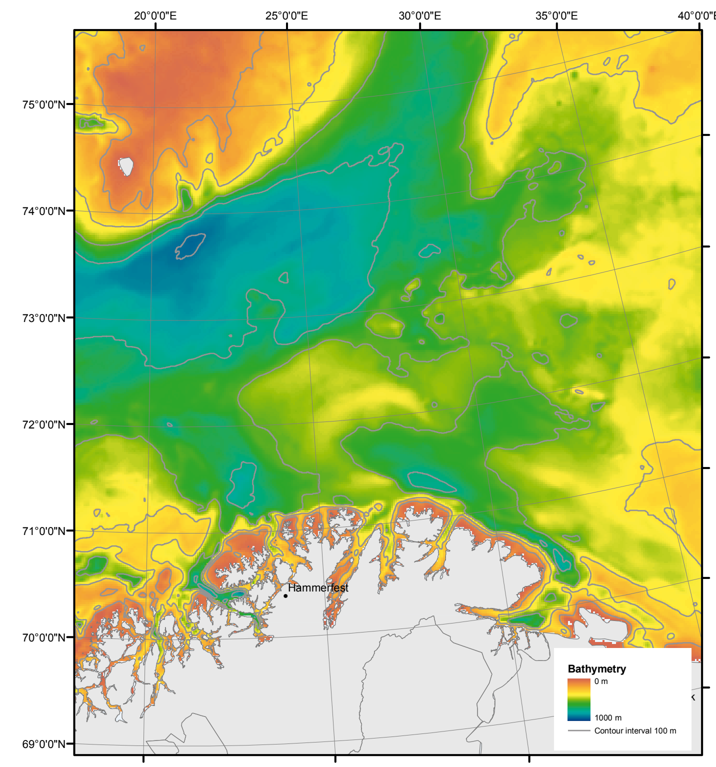


6.1 Geology of the Barents Sea

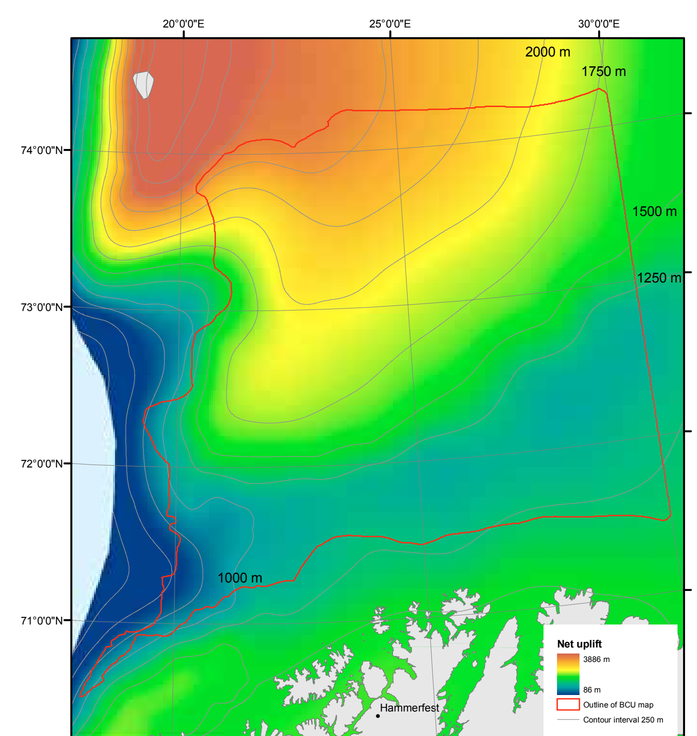
The Loppa High is a marked (N-S) trending structural feature, separated from the Hammerfest Basin in the south by the E-W trending Asterias Fault Complex. To the west it is separated from the Tromsø and Bjørnøya Basins by the Ringvassøy-Loppa and Bjørnøyrenna Fault Complexes. To the east it grades into the Bjarmeland Platform. The Loppa High has a complex geological history with several phases of uplift/subsidence followed by tilting and erosion. Late Carboniferous rift



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.

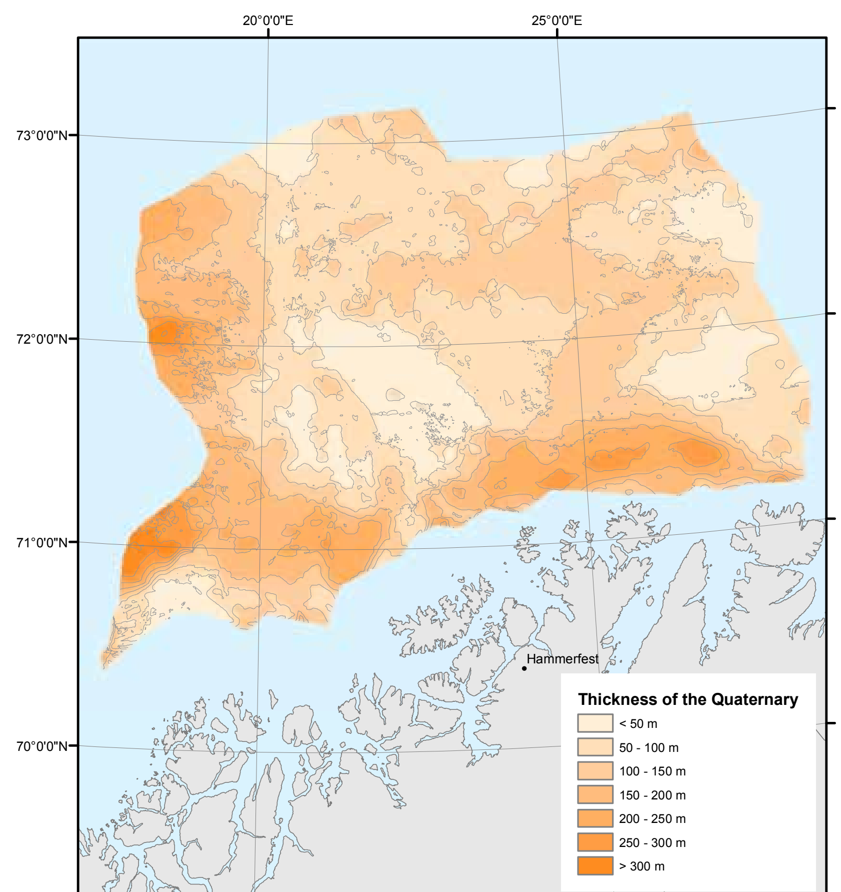


Map showing Cenozoic and Quaternary erosion of the Barents Sea. Modified from Henriksen et al. 2011.

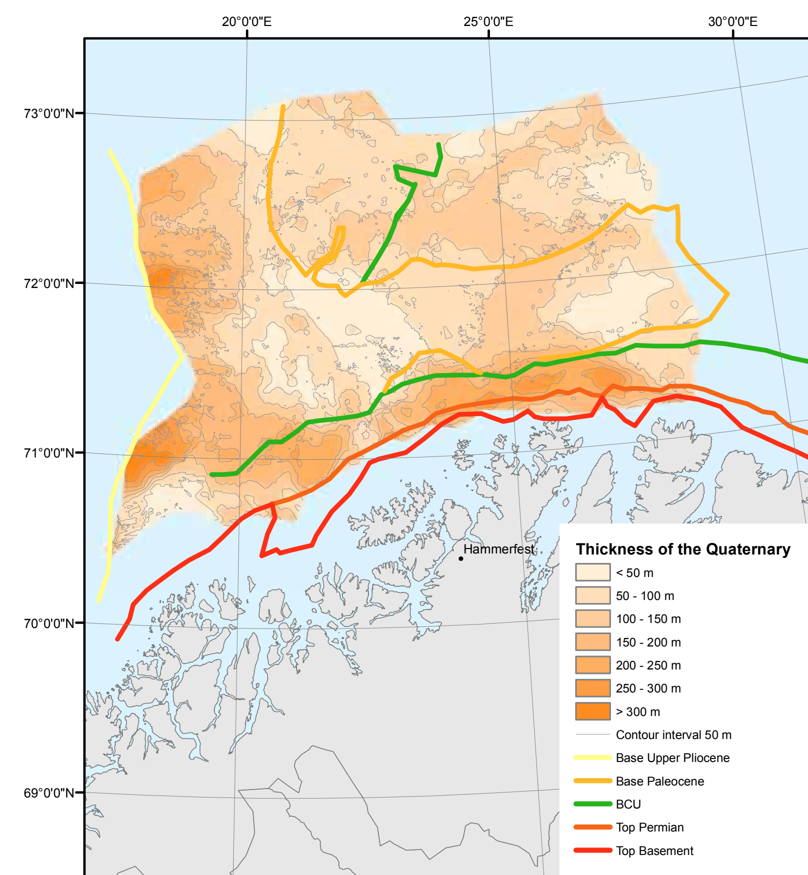
6.1 Geology of the Barents Sea

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 greatest 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.



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.



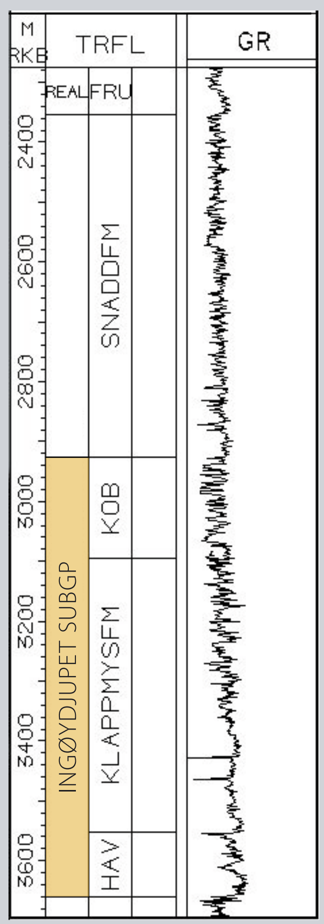
Thickness map of Quaternary sediments including subcrop lines of basement, top Permian, BCU, base Paleocene and base upper Pliocene

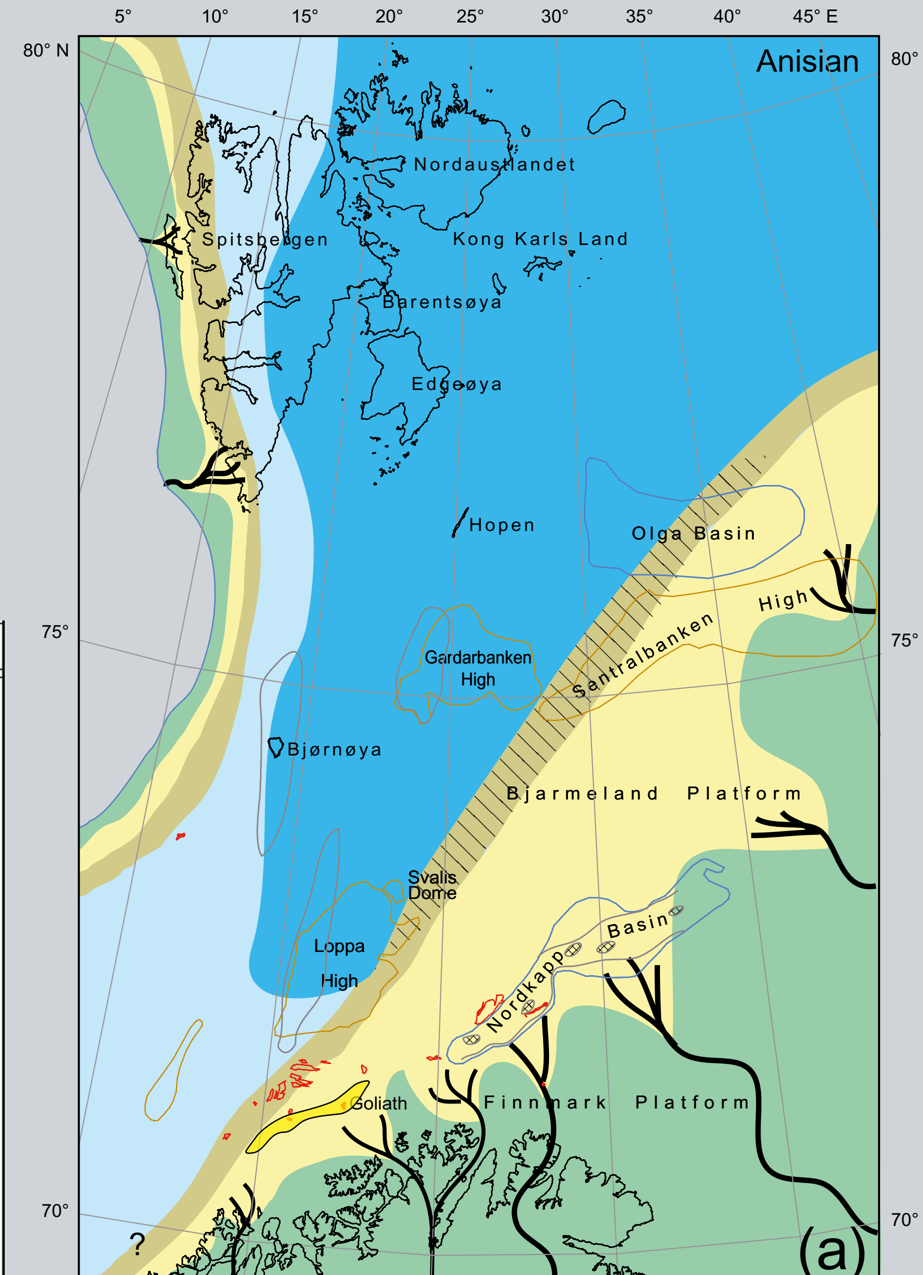
The Sassendalen Group

Lower and Middle Triassic
(Induan to Anisian)

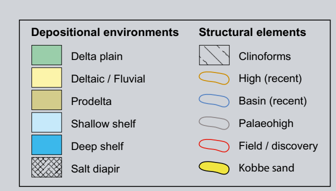
The Sassendalen Group on the Barents Sea shelf is divided into the **Ingøydjupet Subgroup** which consists of three formations: Havert, Klappmyss and Kobbe. The lower boundary is defined towards the Upper Paleozoic by mixed siliciclastic and carbonate sequences, while the upper boundary is marked by a shale interval at the base of the Fruholmen Formation (Realgrunnen Subgroup). This represents an important transgressive event which formed a traceable sequence boundary throughout most of the Arctic from the Barents Sea to the Sverdrup Basin. The type and reference area for the Ingøydjupet Subgroup is represented in 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 subgroup is thick throughout the Hammerfest Basin, where the lower part is 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 dominant lithology of the Ingøydjupet Subgroup is black shale and claystone with thin grey silt- and sandstones, occurring particularly in the upper parts. Minor carbonate and coal interbeds are also present. Marine environments encountered by wells in the lower parts of the subgroup, 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 subgroup reflect northwestward outbuilding of deltaic sequences over an extensive, low relief depositional basin.

INGØYDJUPET SUB GP
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)

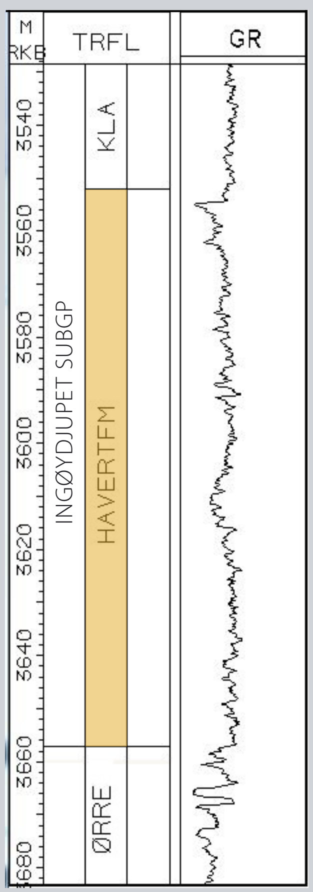


The Sassendalen Group

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 105m. 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, dominated by silt and claystone with subordinate sandstone lithologies. On the Finnmark Platform a thickness of 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 to open marine setting with coastal environments to the south and southeast

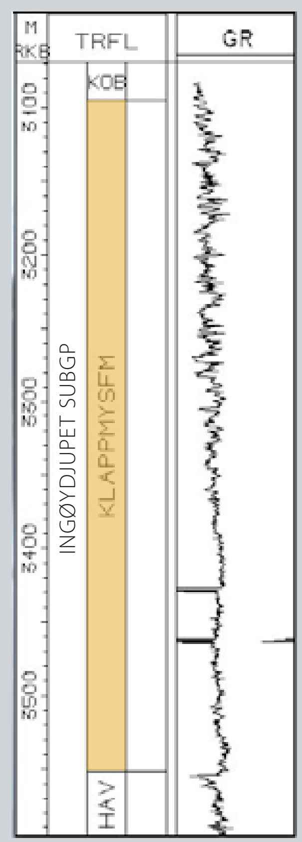
The Klappmyss Formation (Olenekian)
In the type well (7120/12-2) in the Hammerfest Basin, the formation consists of medium to dark grey shale passing upwards into siltstones and sandstones. The reference well (7120/9-2) shows a similar trend, but with higher content of shale. The thickness is 457m in the type well and 561m in the reference well. Thicknesses as high as 600m have been reported from the Bjarmeland Platform (well 7226/2-1) and the Norsel High (well 7226/11-1). On the central Finnmark Platform (well 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 a 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

The Kapp Toscana Group

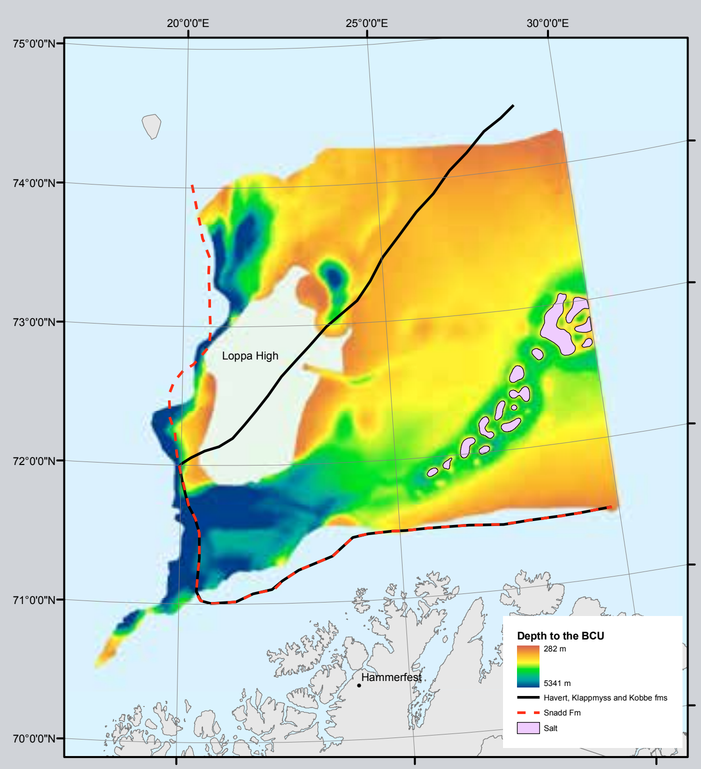
Lower Triassic and Middle Jurassic
(Ladinian-Bathonian)

The Kapp Toscana Group on the Barents Sea shelf is divided into two subgroups: the Storfjorden (Ladinian to Norian) and Realgrunnen (Early Norian to Bathonian).

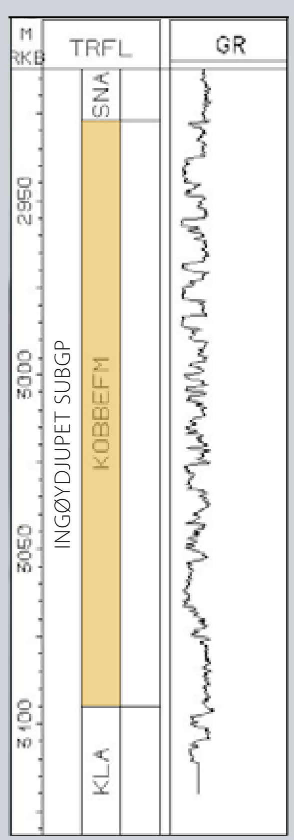
The Storfjorden Subgroup
(Ladinian to Norian)

The Storfjorden Subgroup consists of the **Snadd Formation** and 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 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 parts of the unit, calcareous layers are relatively common, with thin coaly lenses occurring in the upper part. 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 upper part of the Storfjorden Subgroup 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).

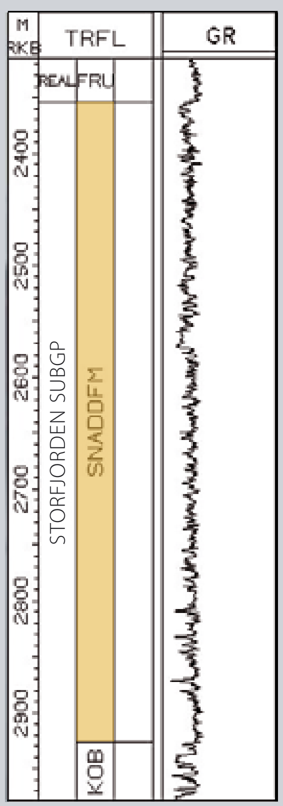


WELL LOG 7120/12-2



7120/12-1
KOBBE, 3521-3524 m

WELL LOG 7120/12-2

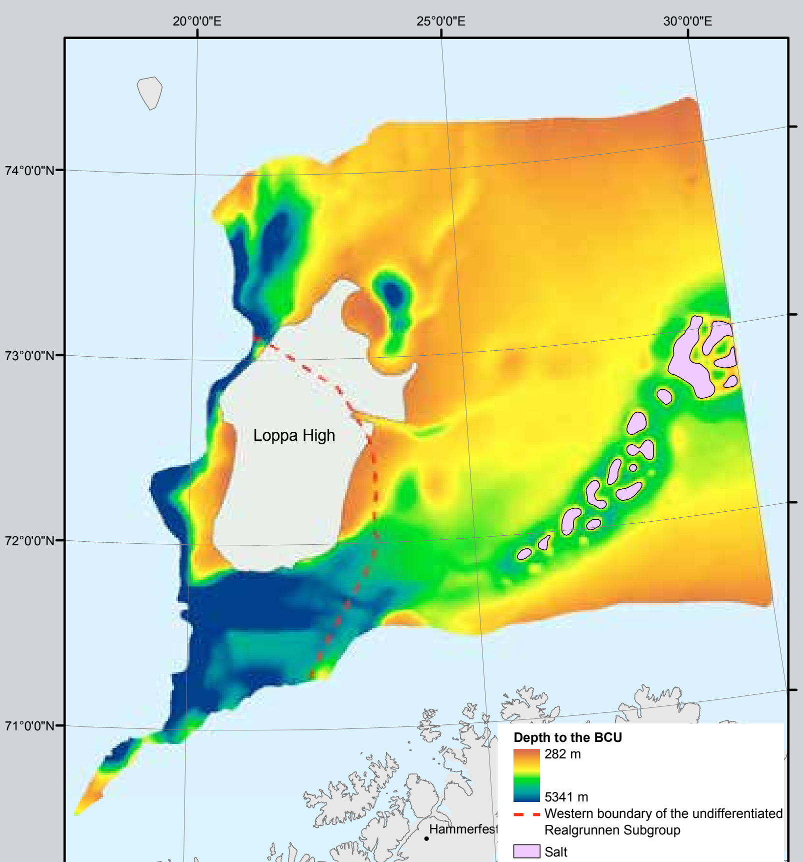


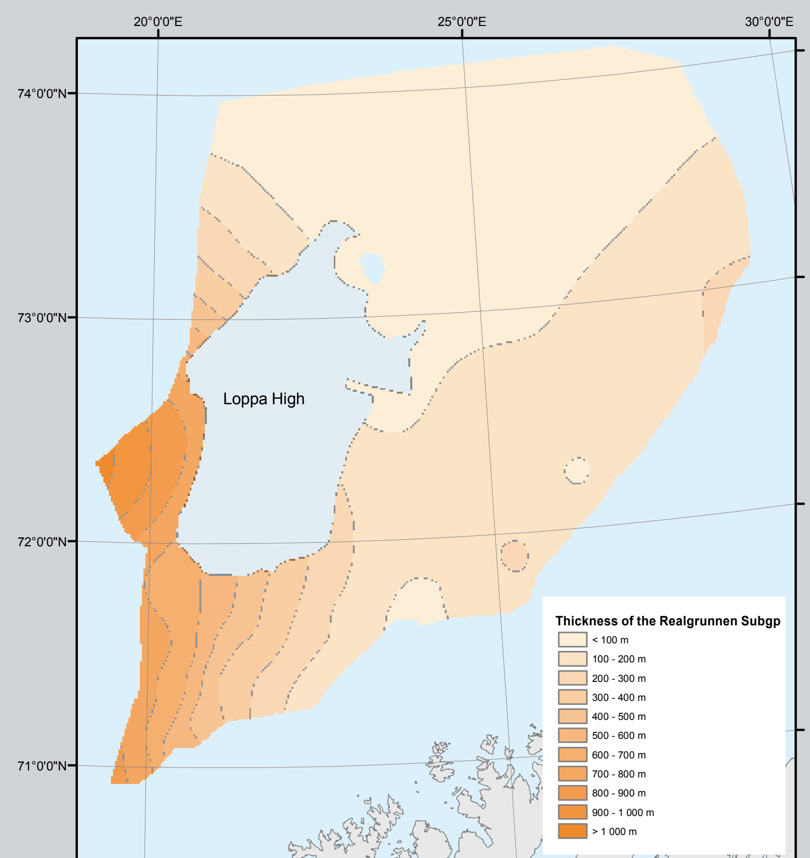
7121/5-1 - SNADD, 3088-3094 m

The Kapp Toscana Group - Realgrunnen Subgroup

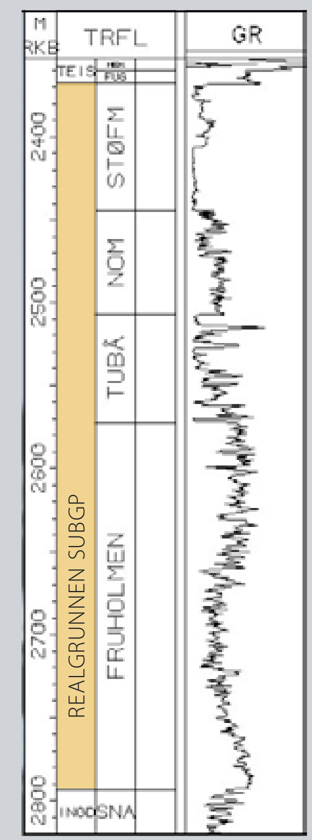
Early Norian to Bathonian

The Realgrunnen Subgroup was originally defined in the west central Hammerfest Basin with its type area in block 7121/5. It is subdivided into four formations; Fruholmen, Tubåen, Nordmela and Stø. 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 subgroup is thinly developed on the Bjarmeland Platform, and the definition of various formations is therefore unclear. The subgroup 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. Sediments of the Realgrunnen Subgroup have been deposited in general near-shore deltaic environments, characterized by shallow marine and coastal reworking of deltaic and fluviodeltaic deposits.



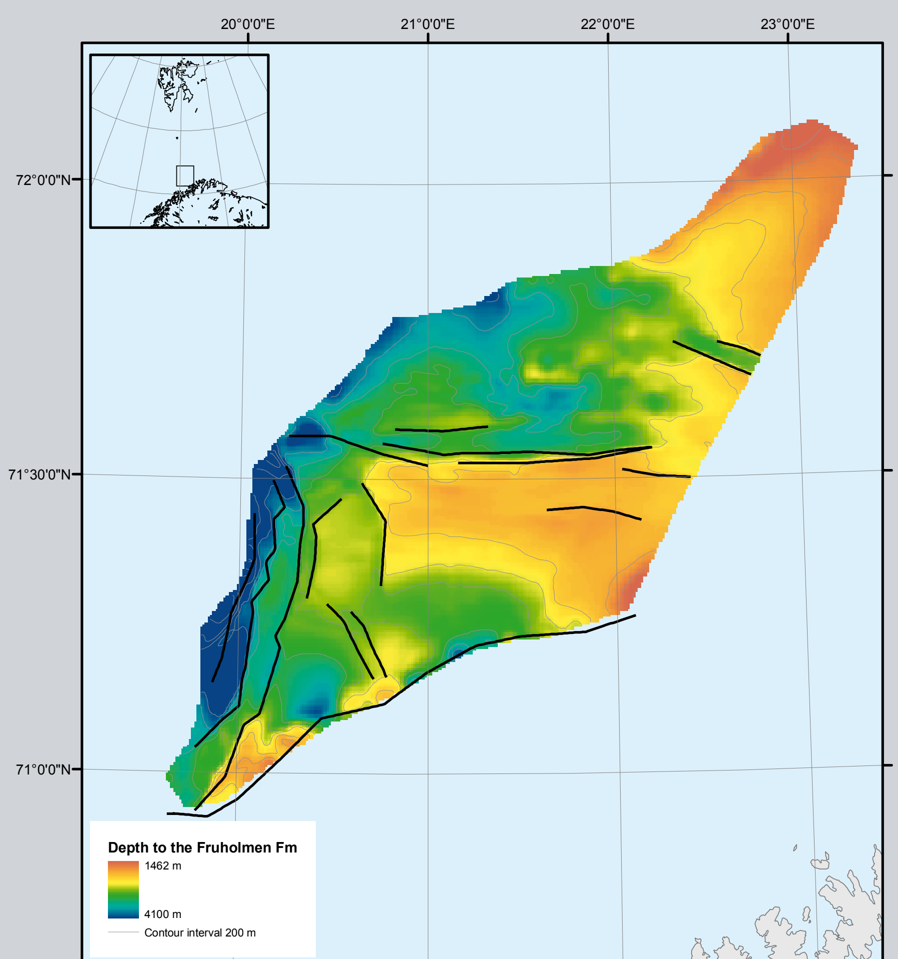


REALGRUNNEN
WELL LOG 7121/5-1

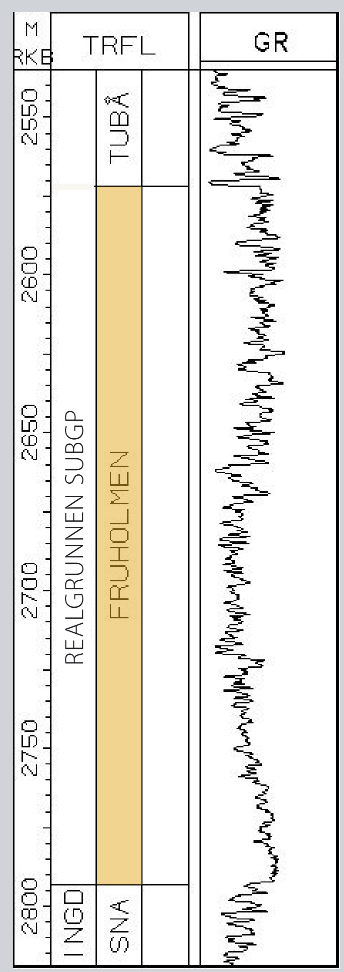


The Kapp Toscana Group - Realgrunnen Subgroup

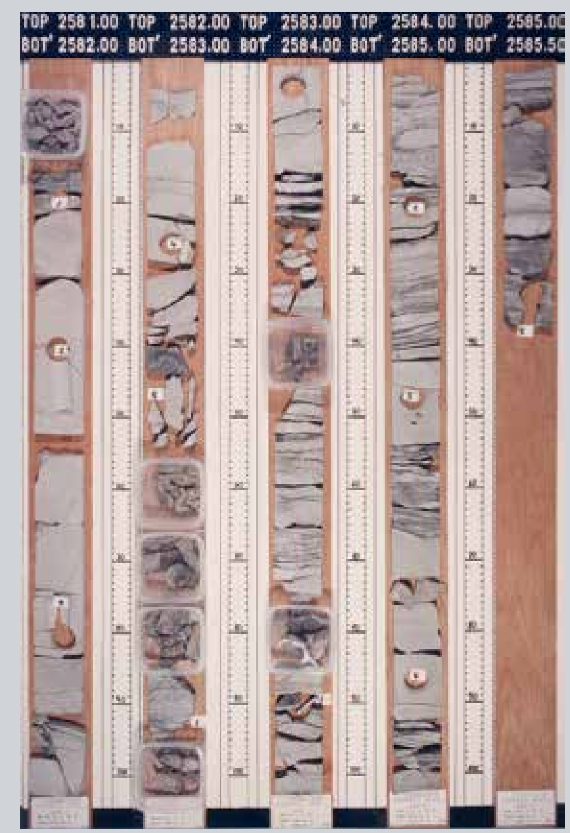
The Fruholmen Formation
(Norian to Rhaetian) consists of grey to dark shale passing upwards into interbedded sandstone, shale and coals. Sandstone dominates in the middle part of the formation, while the upper part is dominated by shales. This lithological development has resulted in a threefold subdivision of the formation with the shale-dominated Akkar Member at the base, overlain by the more sandy Reke Member which in turn is 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

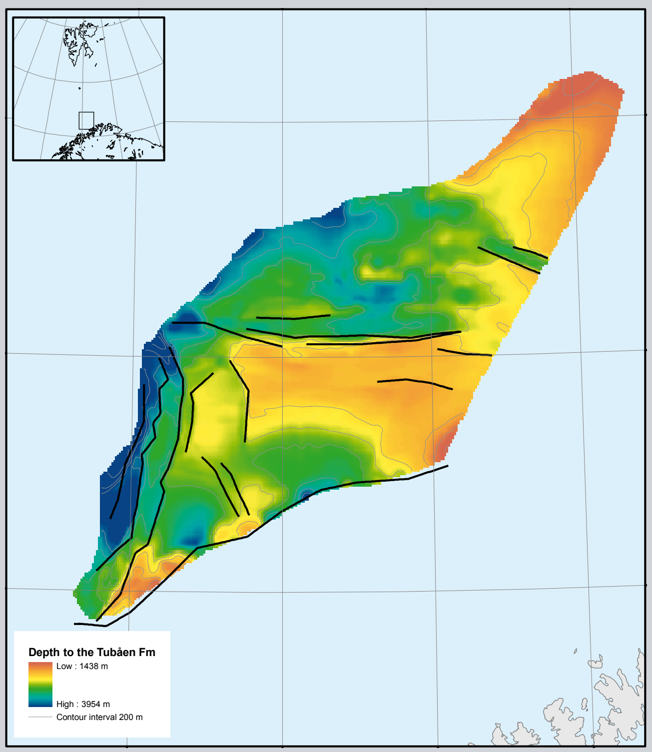


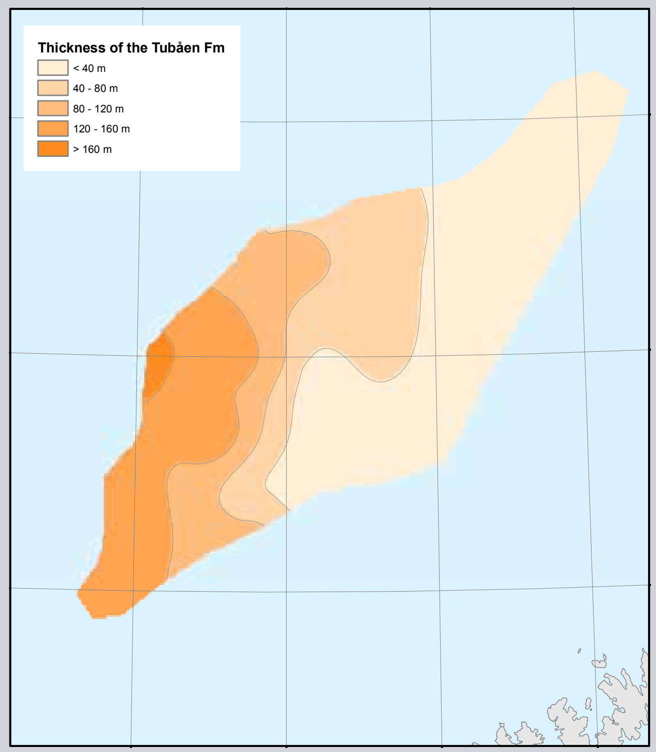
7120/1-2 - FRUHOLMEN, 2581-2585 m



The Kapp Toscana Group - Realgrunnen Subgroup

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 fade 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 Fm is 65m, and in the reference well (7120/12-1) it is 85m with a maximum thickness of 261m (well 7120/6-1) in 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.





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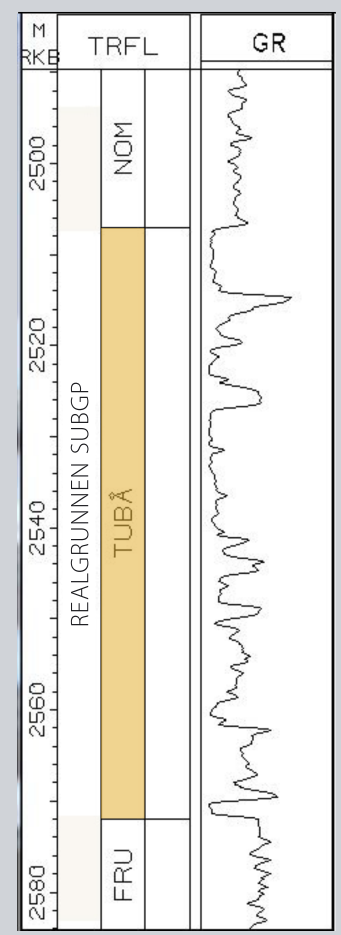
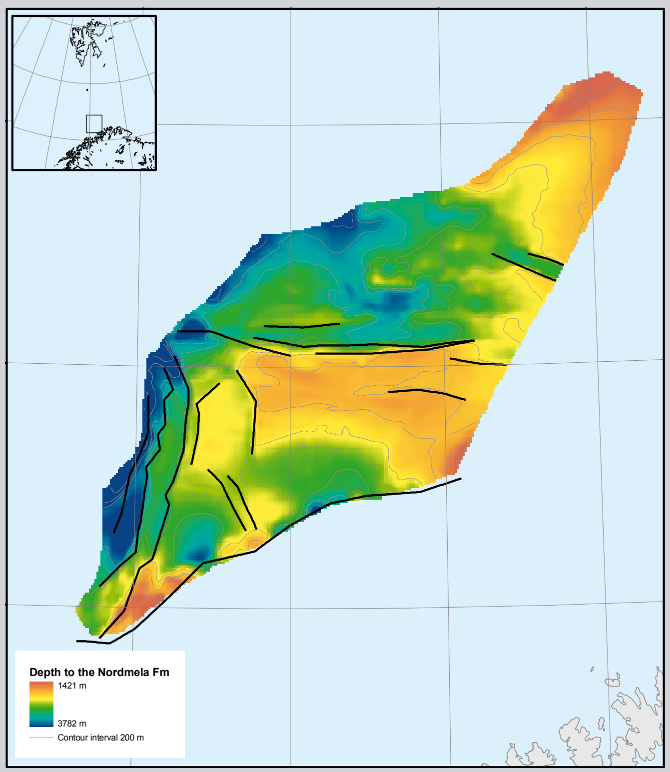
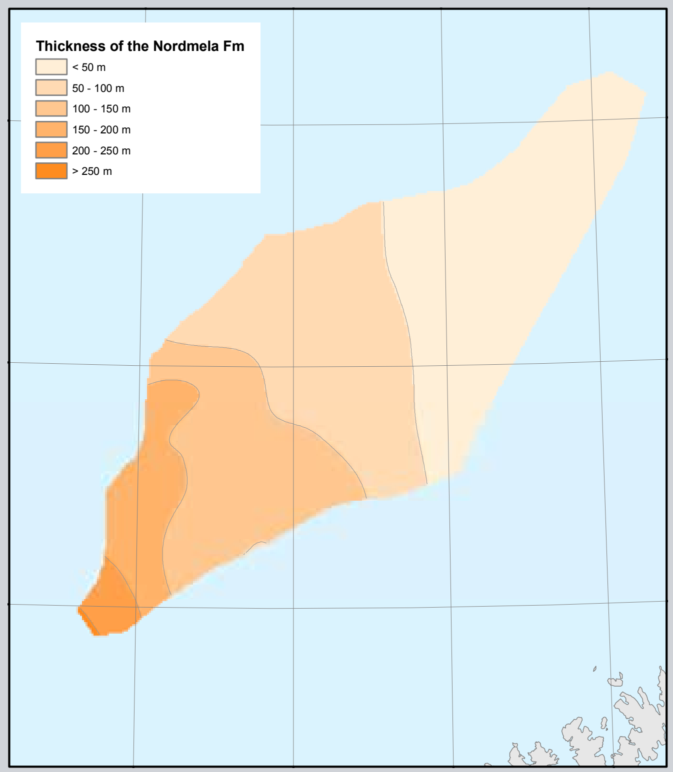


7121/5-1 - TUBÅEN, 2519-2524 m

The Kapp Toscana Group - Realgrunnen Subgroup

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 west-southwest thickening wedge, similar to the underlying Tubåen Fm. It may be diachronous, becoming younger 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 oriented thickening wedge. Westward thickening is characteristic for all the three Lower and Middle Jurassic formations and may be the result of early Kimmerian subsidence and tilting towards the Tromsø and Bjørnøya Basins.





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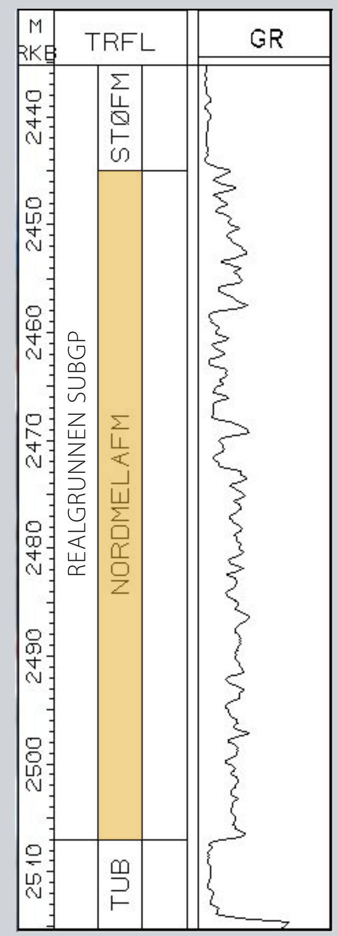
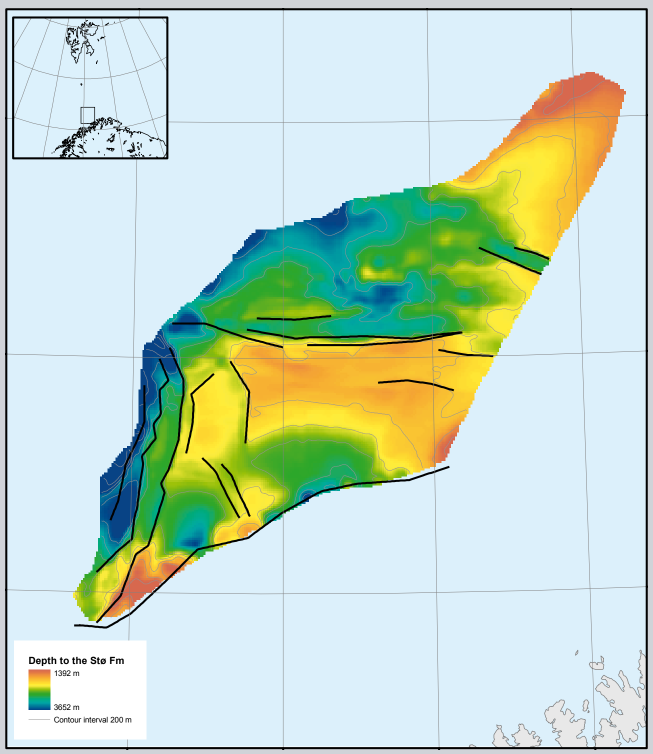
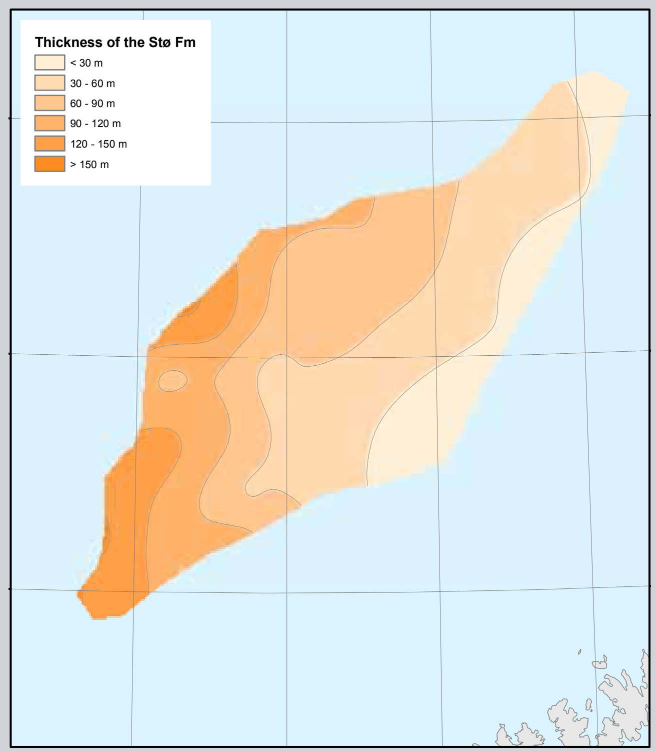


7121/5-1 - NORDMELA, 2503-2506 m

The Kapp Toscana Group - Realgrunnen Subgroup

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 mineralogically mature and well sorted sandstone. Thin units of shale and siltstone represent regional markers. Especially in the upper part of the Stø Fm, 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 Fm 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 as well as 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 and siltstone intervals represent regional transgressive pulses in the late Toarcian and late Aalenian.





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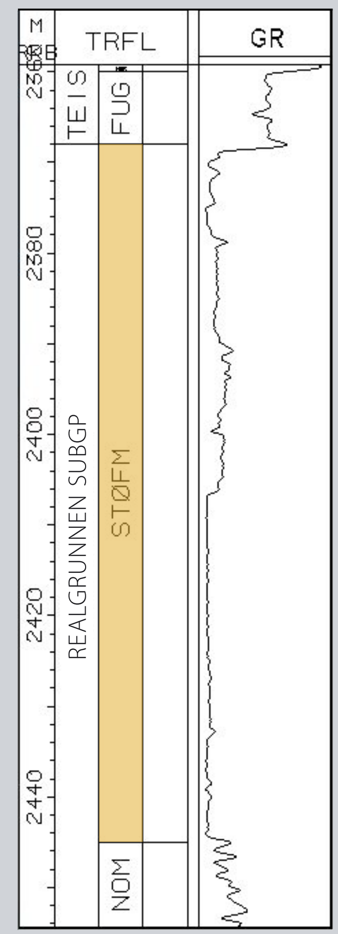


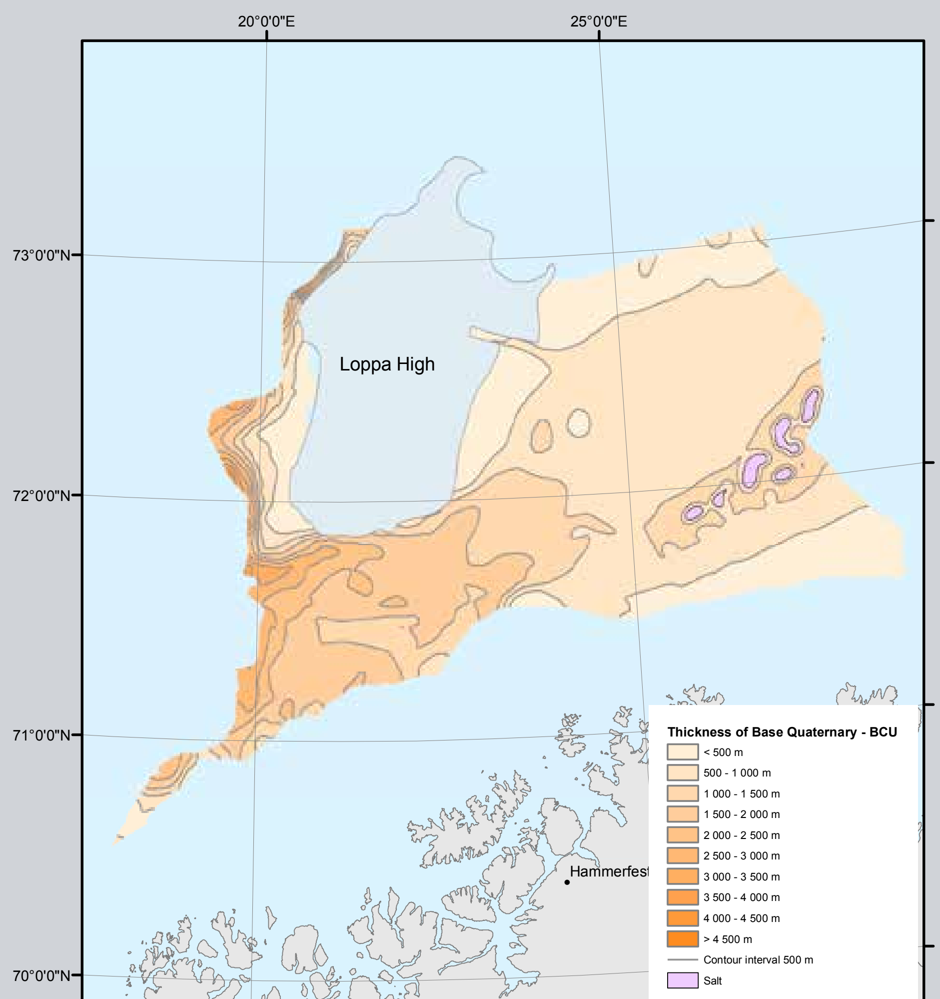
7121/5-1 - STØ, 2400-2405 m

The Adventdalen Group

Middle Jurassic to Lower Cretaceous (Bathonian to Cenomanian)

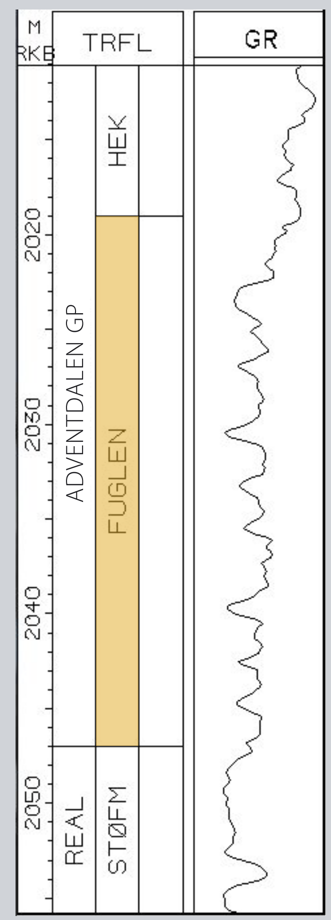
The Adventdalen Group is subdivided into the Fuglen, Hekkingen, Knurr, Kolje and Kolmule formations, with its type area in the northern part of block 7120/12 in the Hammerfest Basin and in 7119/12 in the eastern part of the Ringvassøy-Loppa Fault Complex. The thickness varies from more than 900m in the Bjørnøyrenna Fault Complex (7219/8-1S) to 300m north of the Troms-Finnmark Fault Complex. Nevertheless, the thickness decreases to approximately 60m or less on structural highs in the centre 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 Formation is an important hydrocarbon source rock. Both the Fuglen and Hekkingen formations constitute good cap rocks. The Hekkingen Fm (Upper Oxfordian–Tithonian) has been drilled in the Hammerfest Basin, the eastern part of the Bjørnøya Basin (Fingerdjupet Sub-basin) and the Bjarmeland Platform. The lower boundary is defined by the transition from carbonate cemented and pyritic mudstone to poorly con-



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

WELL LOG 7120/12-1

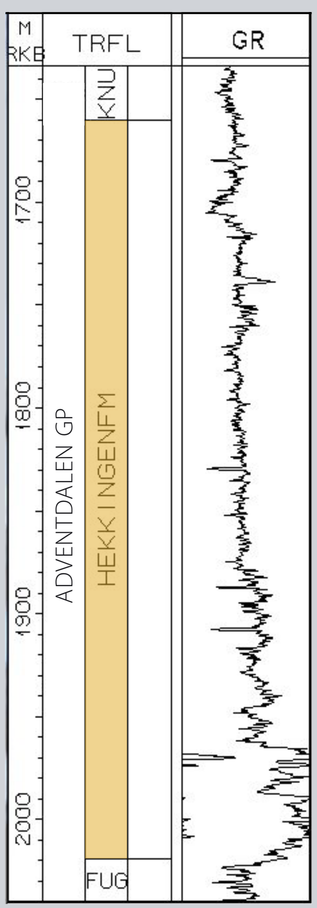


7120/12-1 - FUGLEN, 2044-2047 m

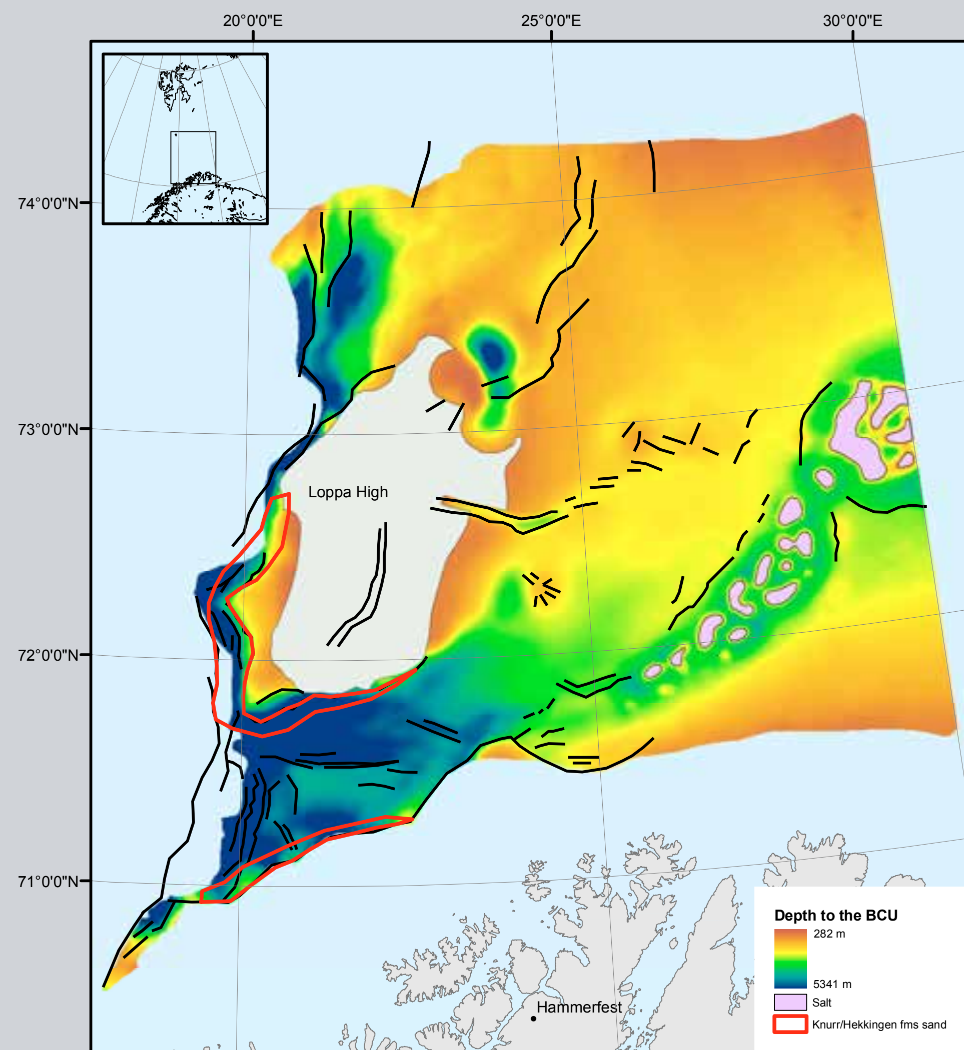
The Adventdalen Group

solidated shale in the Fuglen Formation. The upper boundary in the reference well (7120/12-1) is defined towards the 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 seen 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.

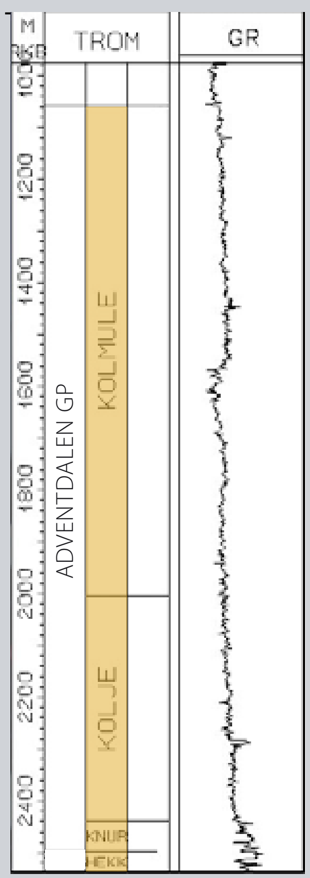
The Adventdalen Group

Createceous
Berriasian to Cenomanian

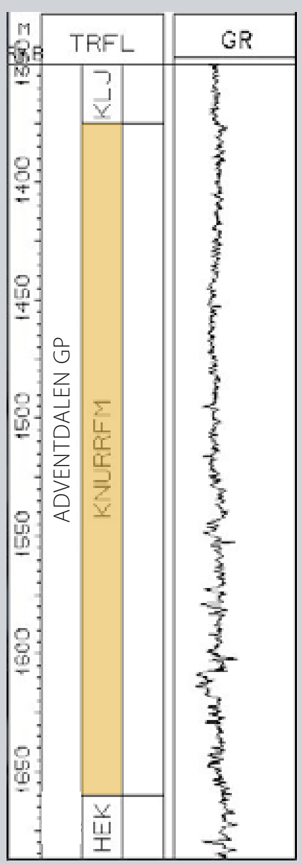
The Cretaceous sucsession is subdivided into three formations: The Knurr, Kolje, and Kolmule Formations. The dominant lithology of the Knurr, Kolje and Kolmule formations is dark to grey-brown shale with thin interbeds of siltstone, limestone, dolomite and local sandstone. The thickness is in the order of 1000-1400m in the type area (blocks 7119/12 and 7120/12). Thicknesses within the Hammerfest Basin are closely related to Upper Jurassic structural development. The formations are thickest along basin margins and thin towards the central part of the Hammerfest Basin. In our study we have focused 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 285m 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 Veslemøy High. The base is defined by a thin sandy limestone overlying the Hekkingen Formation, and the upper boundary is defined with a presence 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 and generally distal marine environment with local restricted bottom conditions.

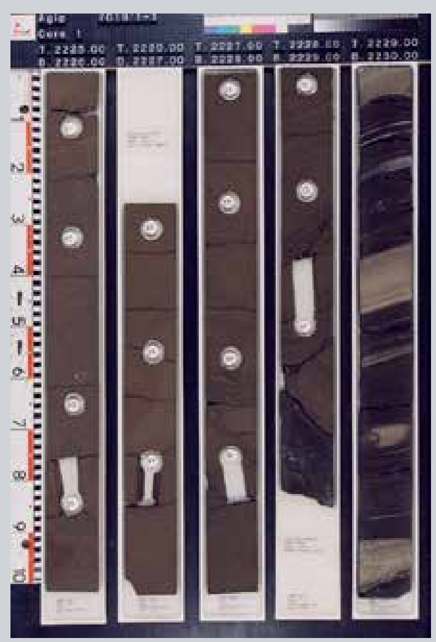
ADVENTDALEN
WELL LOG 7119/12-1

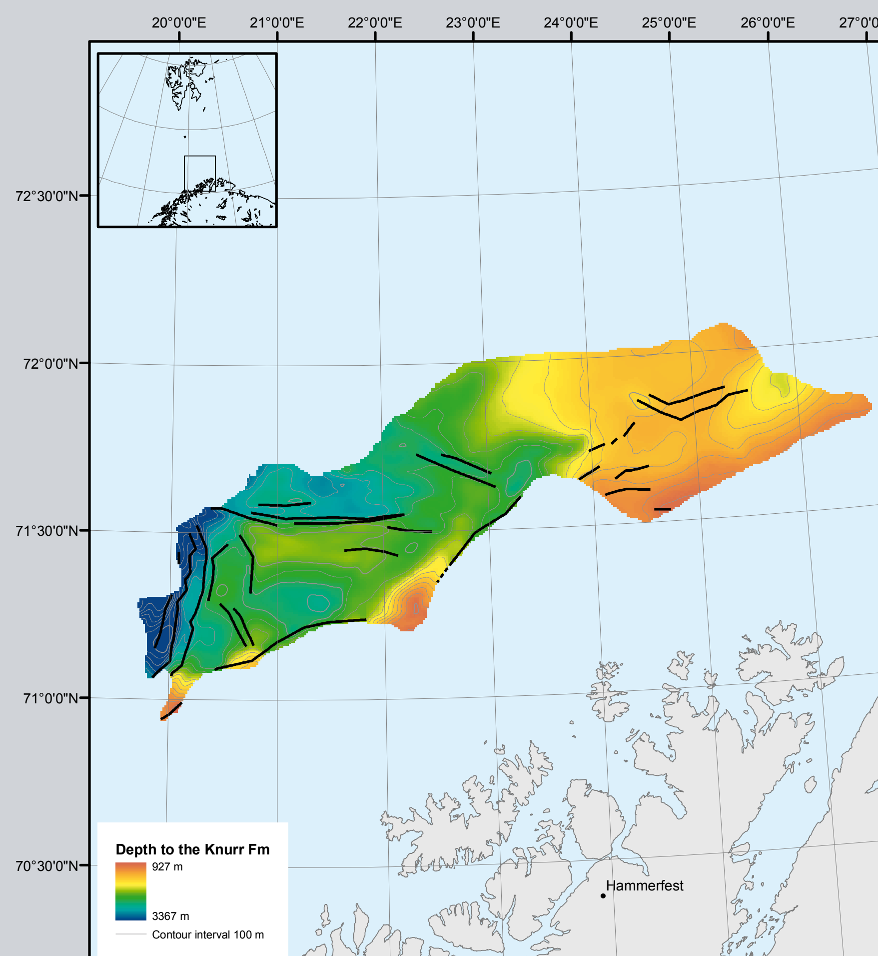


WELL LOG 7120-12-1



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. Photo: NPD.

Introduction

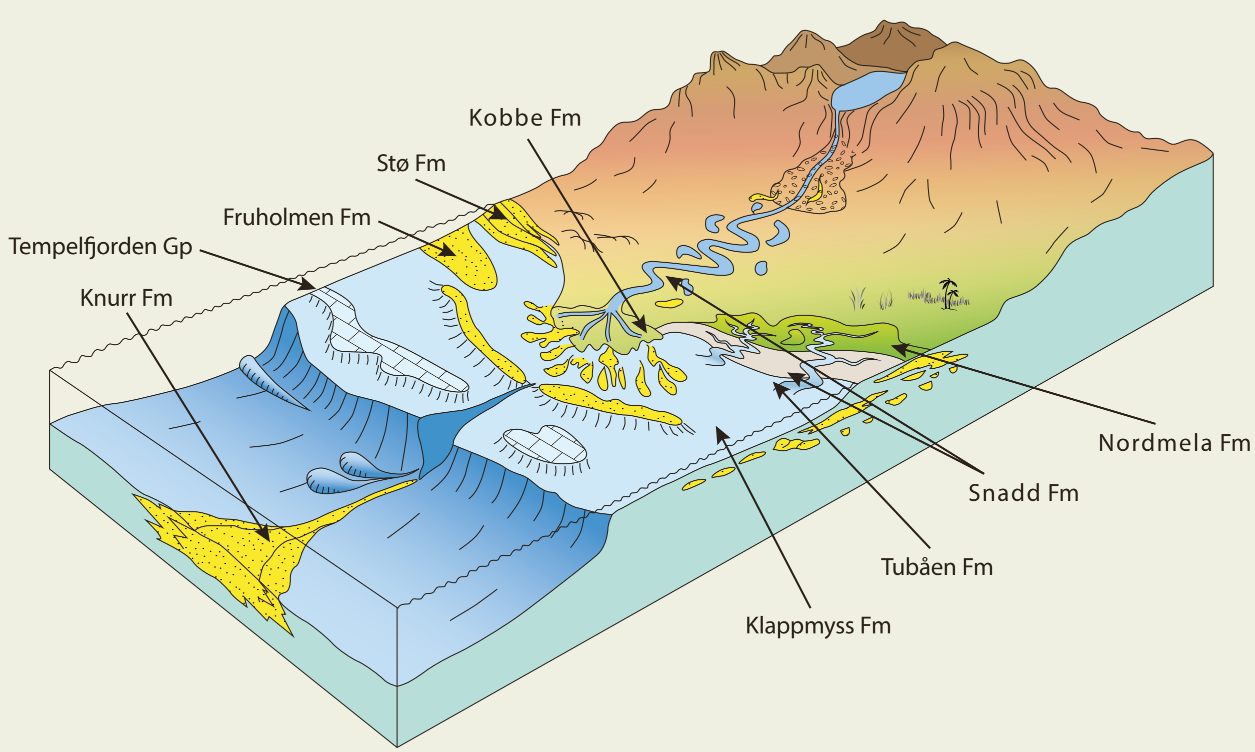
The parts of northern Fennoscandia adjacent to the Norwegian sector of the Barents Sea are sparsely populated, and the industrial activity generates only small amounts of CO_2 emissions. CO_2 associated with the production of natural gas in the Snøhvit Field is extracted at Melkøya, Hammerfest, and injected 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 eliminated. The areas north of 74° were excluded because they were considered too remote and because the good Jurassic aquifers are generally thin and poorly sealed due to a shallow overburden. The Finnmark Platform east of 29° was eliminated because there is limited infrastructure and industrial activity in this area, and the main aquifers of interest are poorly structured and generally 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 are 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 accordance 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, one might consider using CO_2 injection to recover some of these oil resources (CCUS).

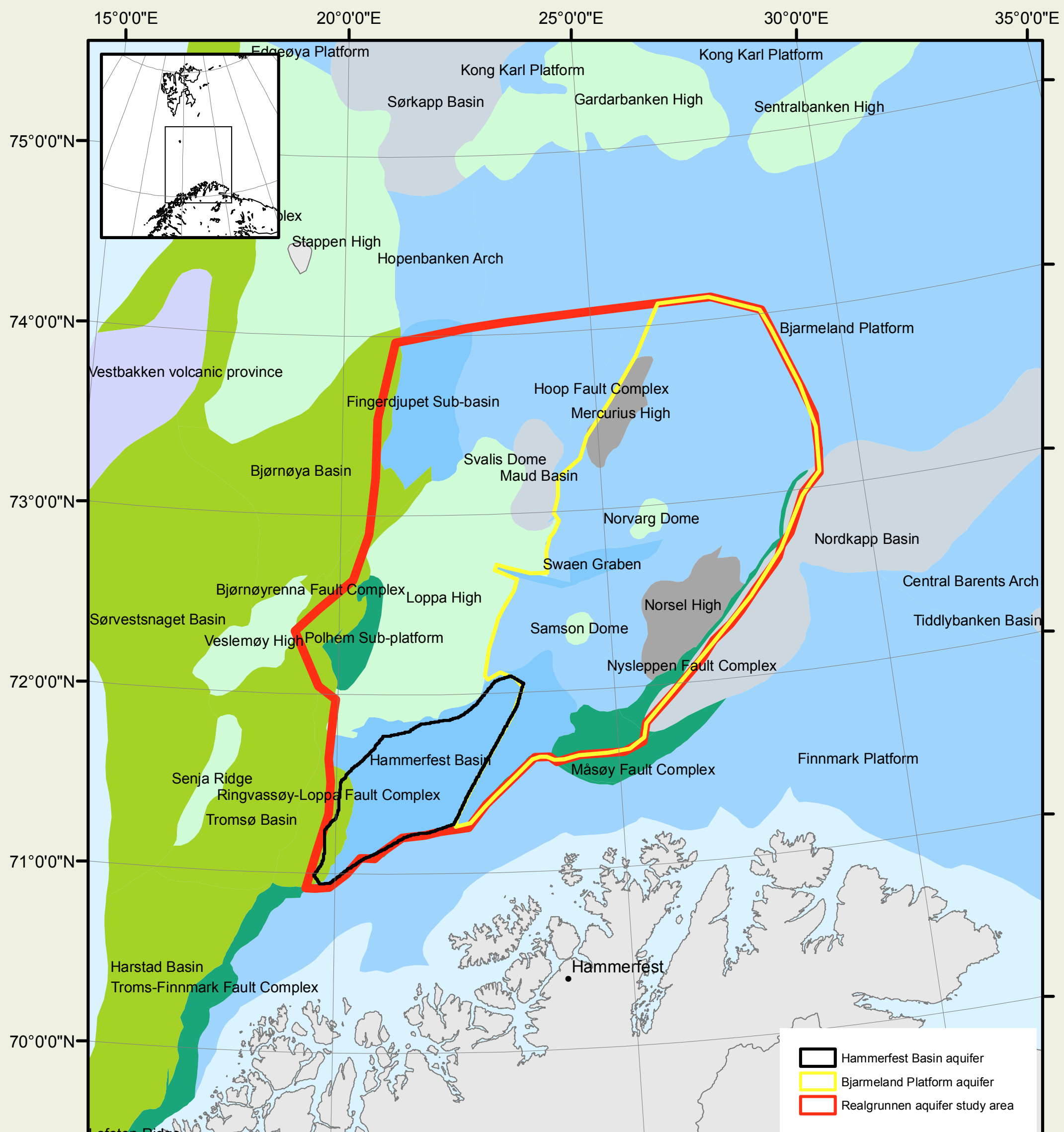
The main aquifer system in the study area consists of Lower and Middle Jurassic sandstones belonging to the Realgrunnen Subgroup. This aquifer system can be defined in three distinct geographical areas which are described in the following section. Hydrocarbons have been encountered in several reservoir levels pre-dating the Jurassic, notably in the



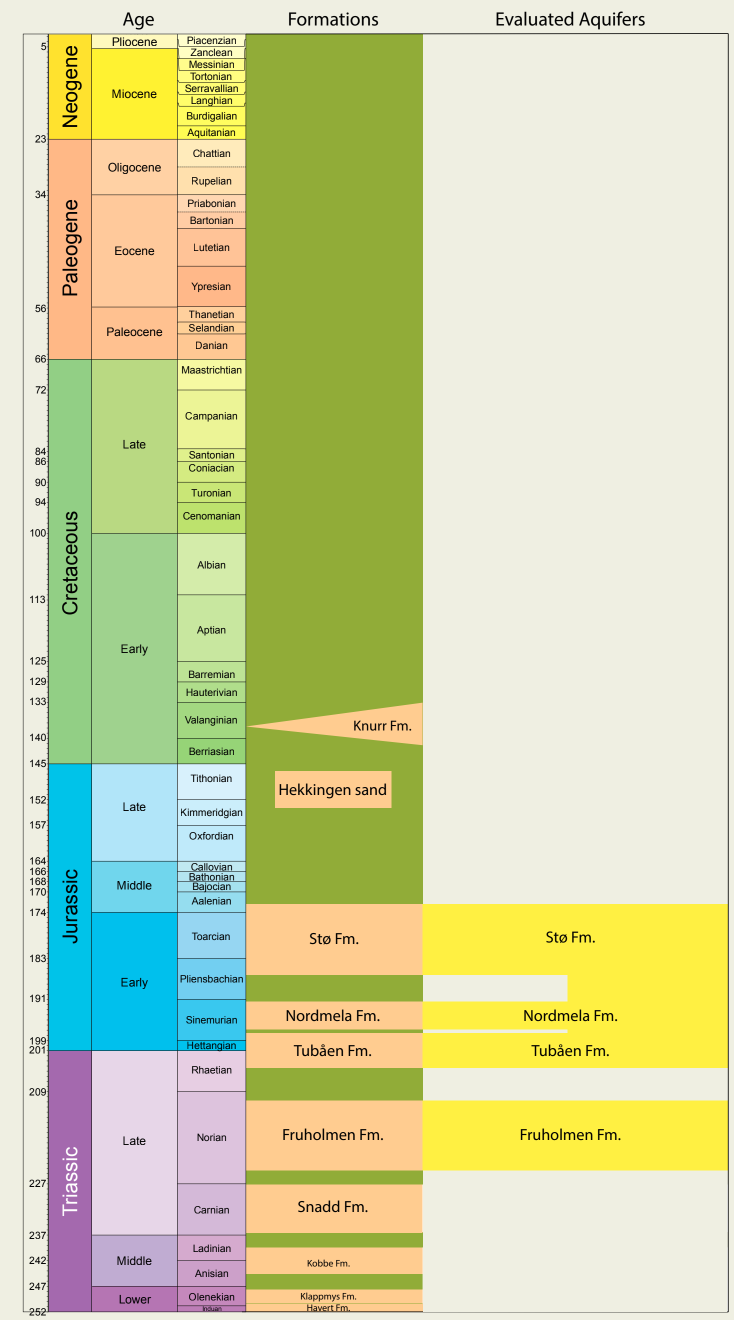
Conceptual sketch showing the depositional environments of the different aquifers.

Introduction

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 only briefly discussed. 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 they are not considered for this study.



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



Evaluated geological formations, and aquifers.

6.2.1 Saline aquifers

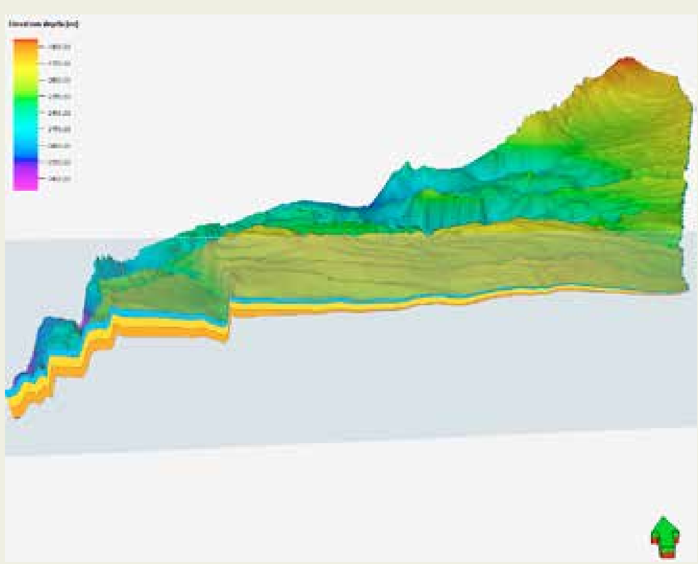
Hammerfest Basin

In the Hammerfest Basin, the Jurassic Tubåen, Nordmela and Stø Formations increase in thickness towards the 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 the northeast, 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 the Nordmela and Tubåen Formations. Paleofluid contacts indicate that the faults are open where there is sand-sand contact.

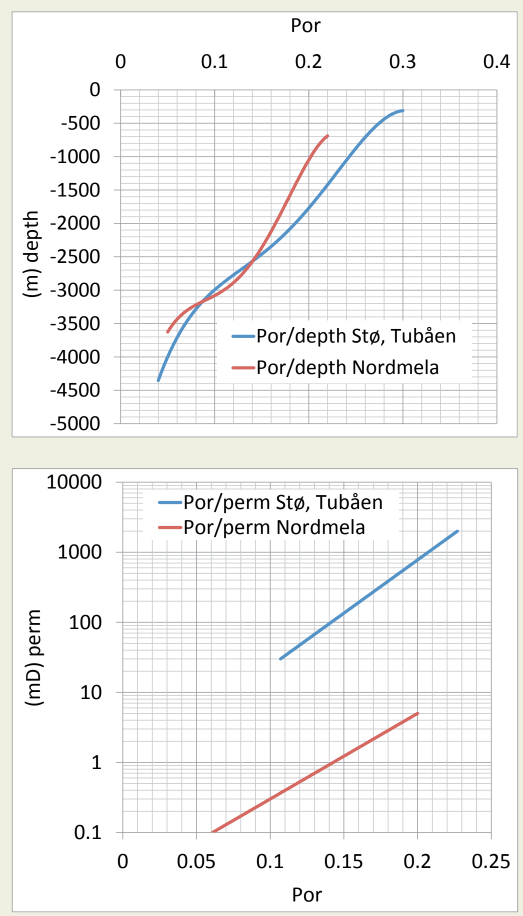
Pressure data from exploration wells show that the Jurassic formations are hydrostatically pressured at depths shallower than 2600 m. The data indicates that the pore pressure has equilibrated between the three formations. The most important regional stratigraphic barrier in the succession is considered 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. Experience from 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.



W–E cross section through the Hammerfest Basin 3D geological model, showing the Stø, Nordmela and Tubåen aquifers in blue, yellow and orange respectively.



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

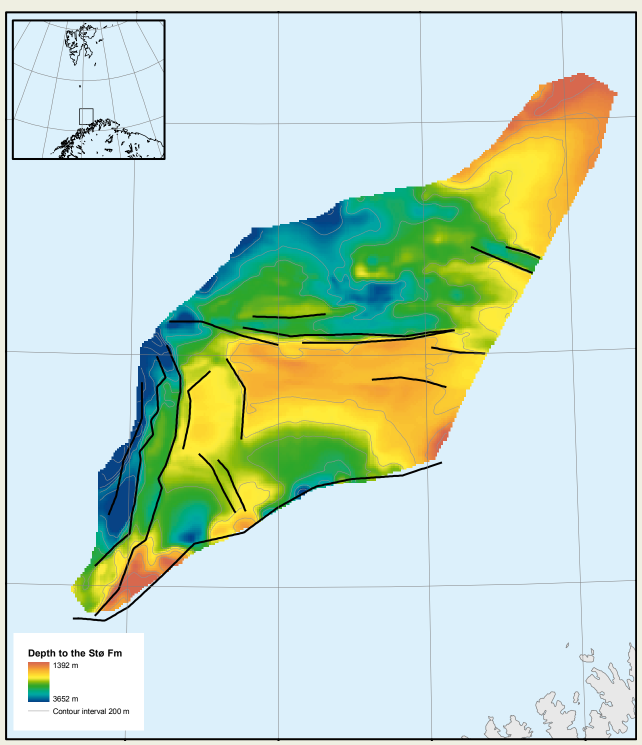
Hammerfest Basin aquifer	Summary
Storage system	Half open
Rock Volume	1200 Gm^3
Net volume	790 Gm^3
Pore volume	120 Gm^3
Average depth	2400 m
Average net/gross	0,65
Average porosity	0,15
Average permeability	1-500 mD
Storage effeciency	3 %
Storage capacity aquifer	2500 Mt
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	

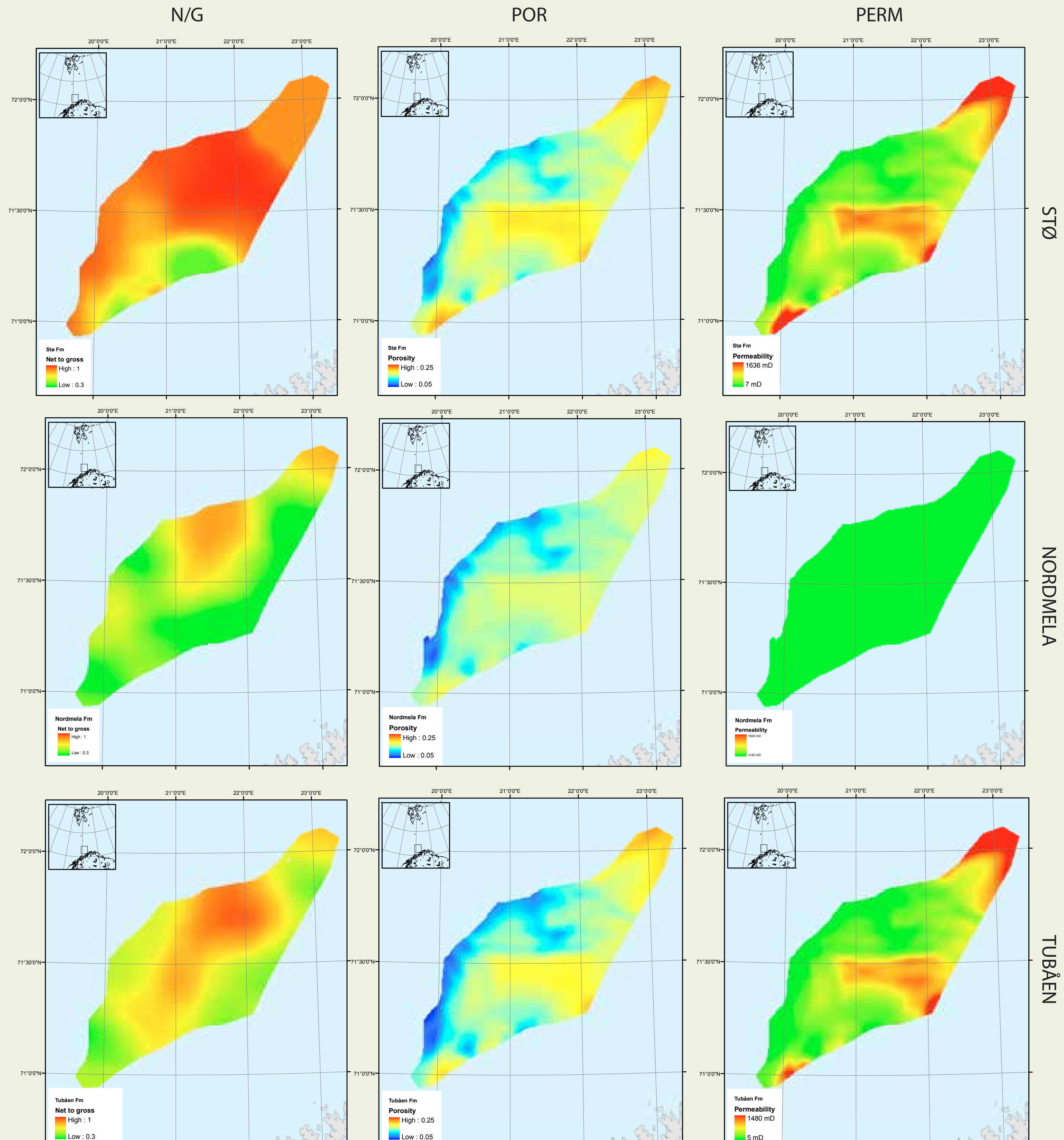
6.2.1 Saline aquifers

Hammerfest Basin

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 mega-structures 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.





Depth and property maps of the Stø Fm in the Hammerfest Basin.

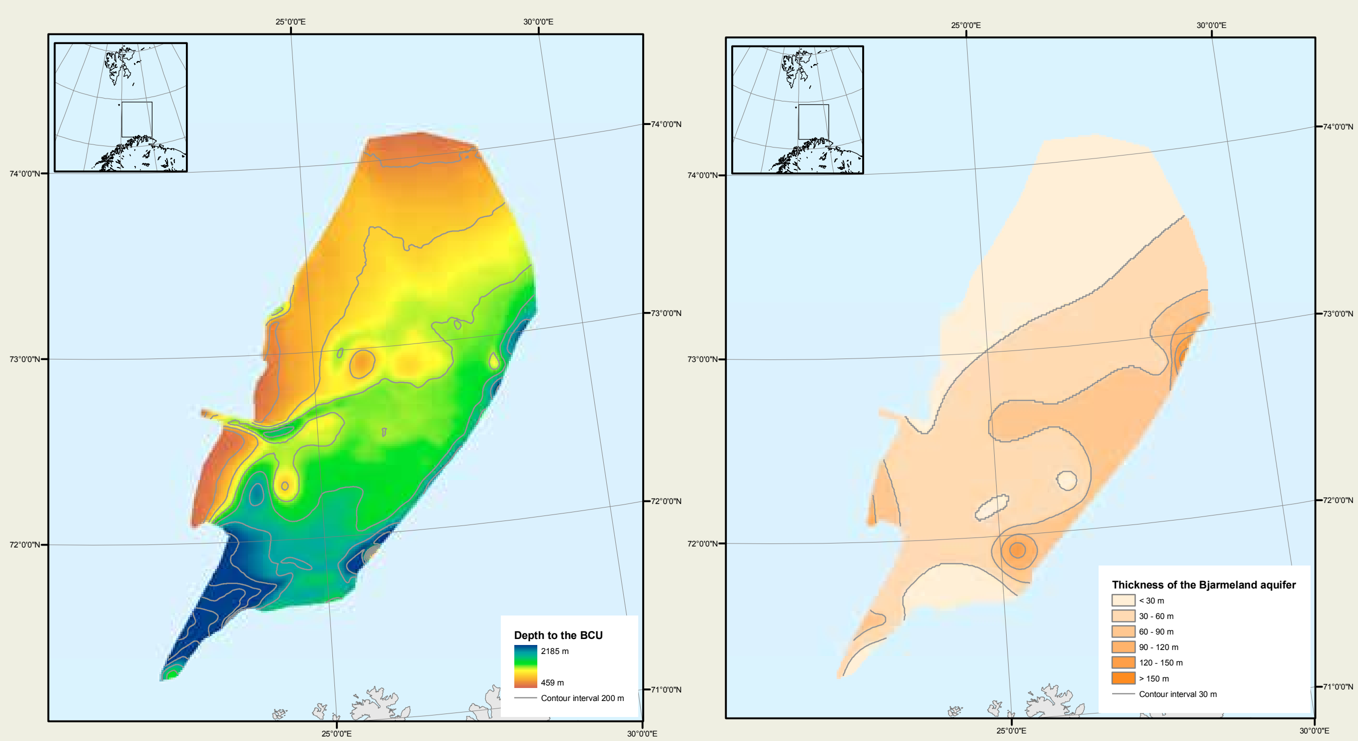
Bjarmeland Platform

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

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 Subgroup decreases from around 100 m in the south to a few tens of metres in the north. The sedimentary facies are similar to the Tubåen, Nordmela 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 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 the Loppa High and the Svalis Dome in the west, the Jurassic strata are eroded and Triassic sedimentary rocks outcrop at the seabed. 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 upper part of the Hammerfest Basin aquifer (Stø Formation), due to reduced thickness and more heterolithic facies.



Depth map and thickness map of the Bjarmeland Platform aquifer which consists of the Realgrunnen Subgroup.

Bjarmeland Platform aquifer	Summary
Storage system	Half open
Rock Volume	1500 Gm^3
Net volume	1100 Gm^3
Pore volume	250 Gm^3
Average depth	1100 m
Average net/gross	0,72
Average porosity	0,23
Average permeability, mD	5-1000 mD
Storage effeciency	3 %
Storage capacity aquifer	4800 Mt
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	

Additional aquifers and Seal Capacity

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

Snadd Formation
The sandstones in the Snadd Formation are 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 on 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, due to 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 6.1. 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.

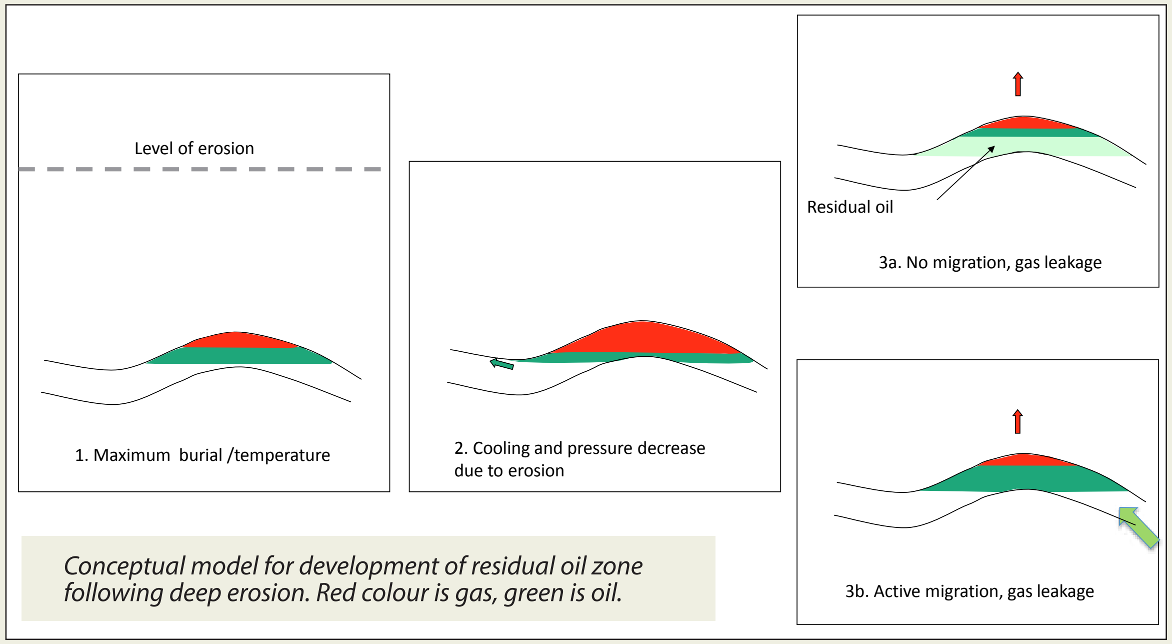
Late Paleozoic reservoirs
Late Paleozoic sandstones and carbonates and Early Triassic sandstones outcrop along the coast of Troms and Finnmark south of the evaluated area. Reservoir properties have been proved by a few exploration wells and stratigraphic cores. Because of limited seismic and well data 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. There are two important questions:

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 NCS, in particular in areas of active hydrocarbon generation. In the studied area, gas chimneys and shallow gas are 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 the Bjørnøyrenna Fault Complex. Here, the source rocks generate hydrocarbons, and several traps are filled to spill point. This indicates that the rate of gas seepage is slower than, 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 well 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 one can use the same guidelines for the Barents Sea as 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, and consequently have a reduced sealing capacity.



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

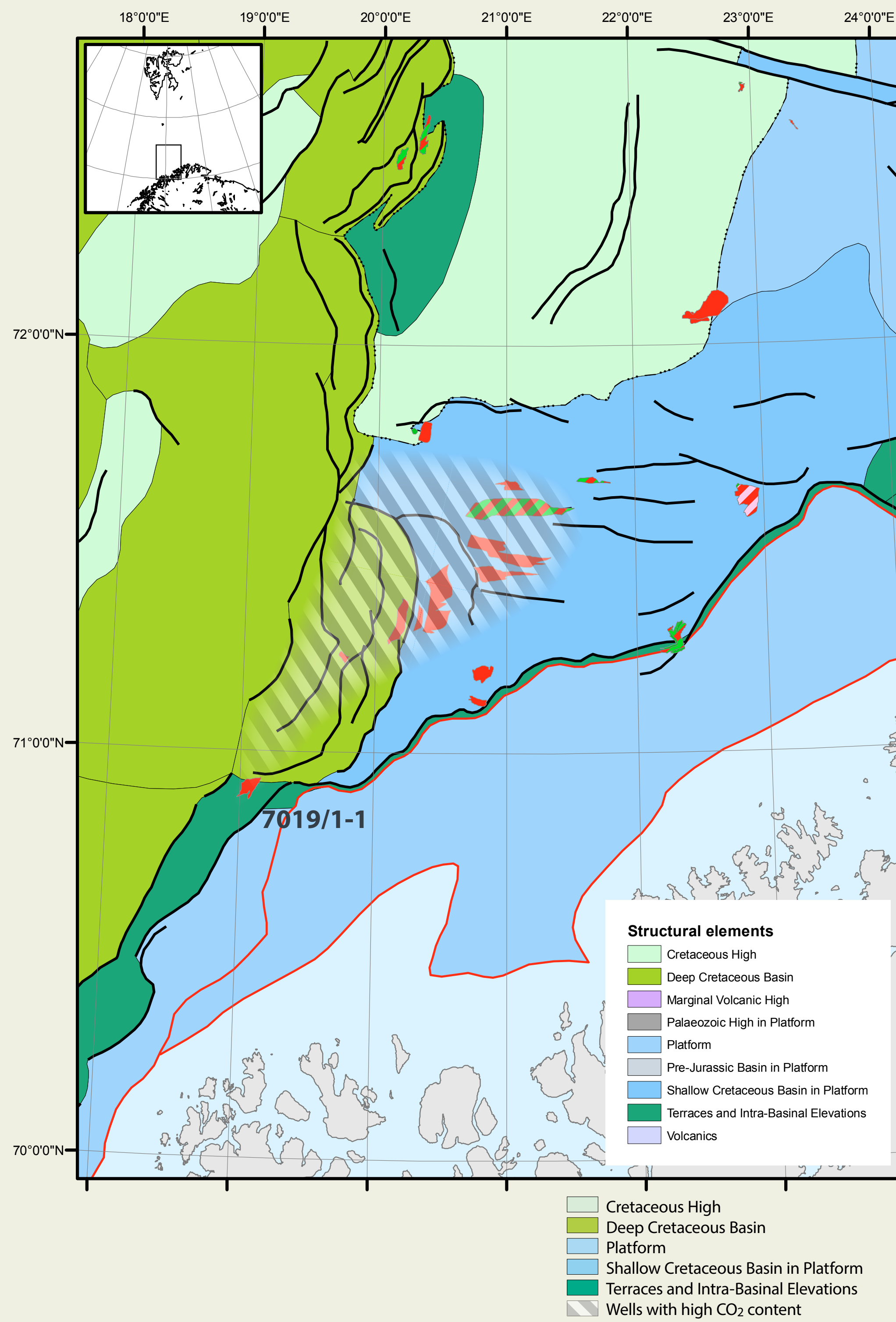
7019/1-1 discovery

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 606,000 m^3 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 content.

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.

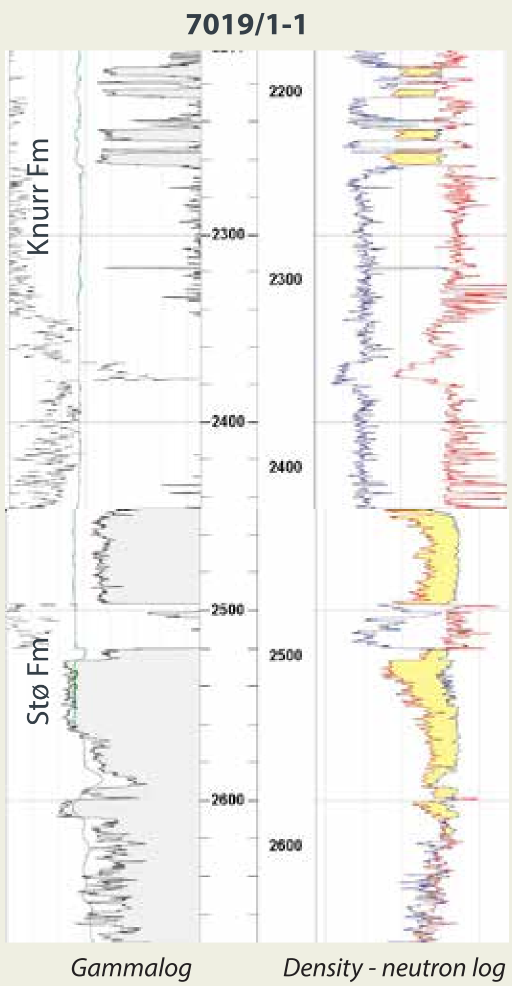
The pressure data show that the Upper Jurassic shale between the two reservoirs has good sealing properties. A large difference in CO_2 concentration between the two reservoirs implies that the Upper Jurassic seal is capable

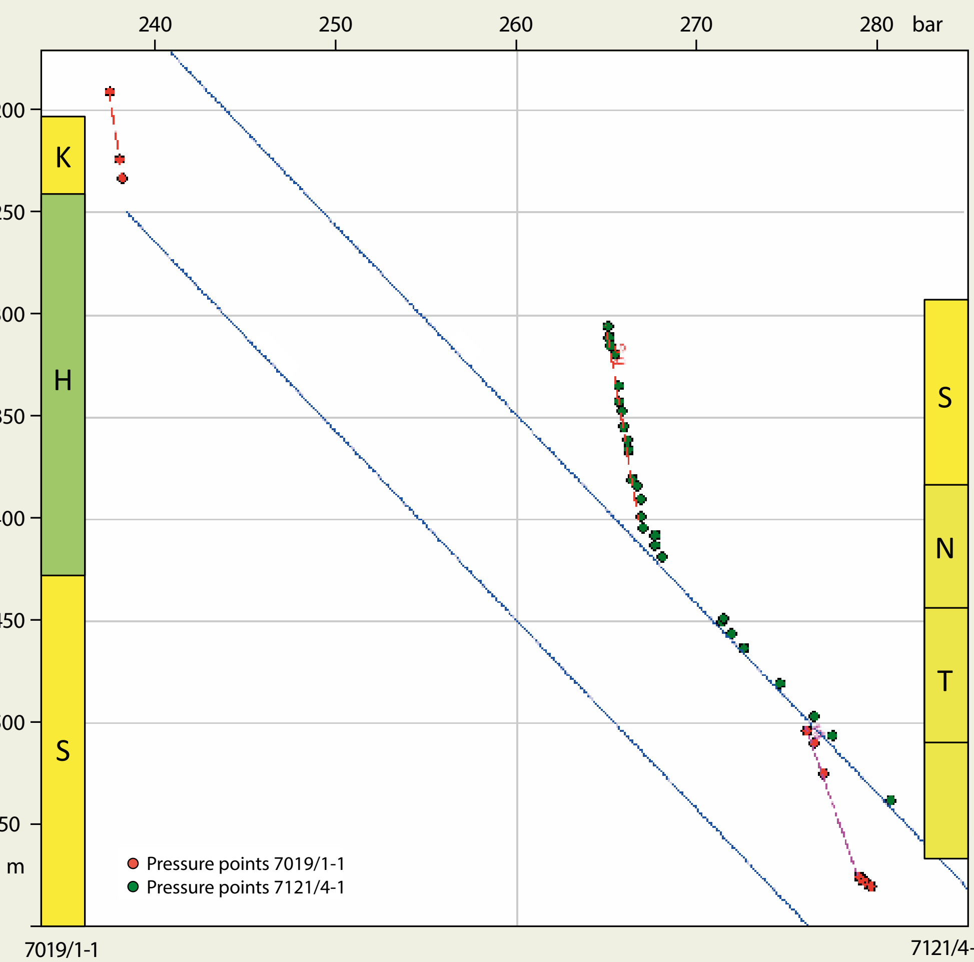


Seal capacity

of containing CO_2 for a long period (geological time scale). The sealing capacity of the Upper Jurassic cap rock in the Barents Sea has been debated, because many wells in areas with net uplift show evidence that methane gas has leaked from the reservoirs. The amount of erosion of the overburden in the typical Hammerfest Basin wells is estimated to be less than in 7019/1-1. Consequently, other factors than net uplift are also considered important for the evaluation of seal capacity.

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 Formations. Vertical scale: Depth below sea level.

6.2.1 Saline aquifers

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 330 m, and the reservoirs are found in the Stø and Nordmela Formations (Early and Middle Jurassic age), at depths of approximately 2300 m. The hydrocarbon phase in the Snøhvit main field is largely gas with minor condensate with 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 depth, resulting in massive quartz cementation of the sandstones and a poorer 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. 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.

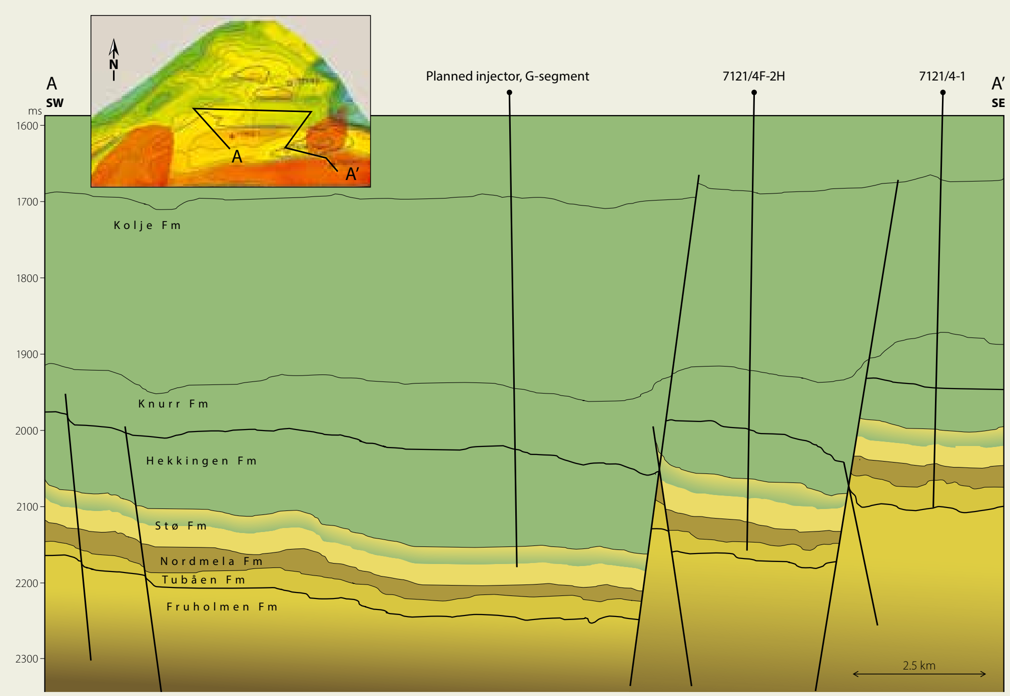
CO_2 storage at the Snøhvit Field started in 2008, and CO_2 was until April 2011 injected in well 7121/4F-2H in the Tubåen Fm, which is dominated by fluvial sandstone. After a while the pressure built up faster than expected, and an intervention was performed to avoid fracturing of the seal. In 2011, 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 Mton 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 build-up 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 the 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, the minimum and maximum pore volumes with good communication to the planned well area have been estimated. The maximum connected pore volume, "Snøhvit 2800", represents the pore volume of the water zone in the Stø, Nordmela and Tubåen Formations in the Snøhvit and Snøhvit north area down to 2800 m.

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.

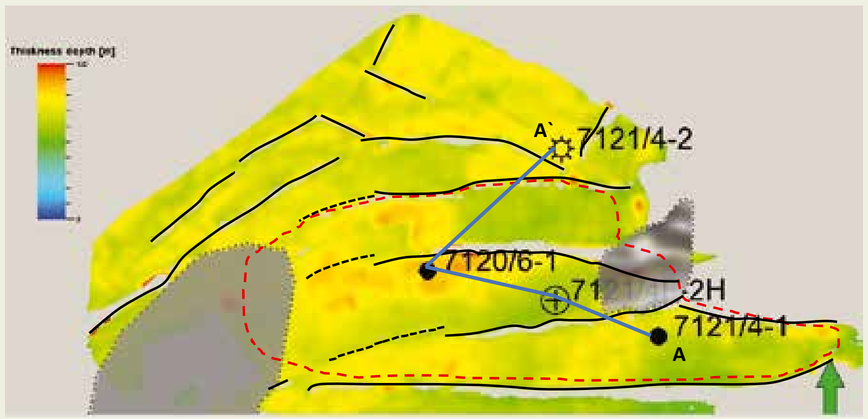


SW-SE profile showing the geometry and thickness –variations in the Snøhvit area. Location of CO_2 injection is illustrated. Sealing formations indicated in green color. 7121/4F-2H is the current CO_2 injector.

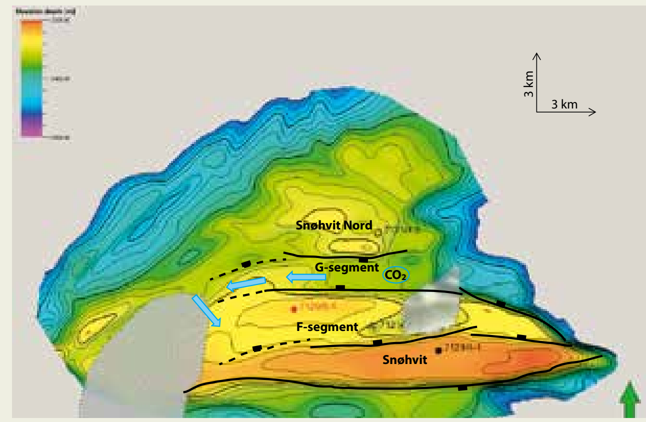
Storage capacity Snøhvit area

2800 m was selected because permeability deteriorates below this depth. The minimum pore volume, “Snøhvit central Stø”, was calculated as the pore volume of the Stø Formation in the areas surrounding the G segment. This is interpreted to represent a water volume where good 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 this minimum case, structural ramps create corridors of communication within the Stø Formation.

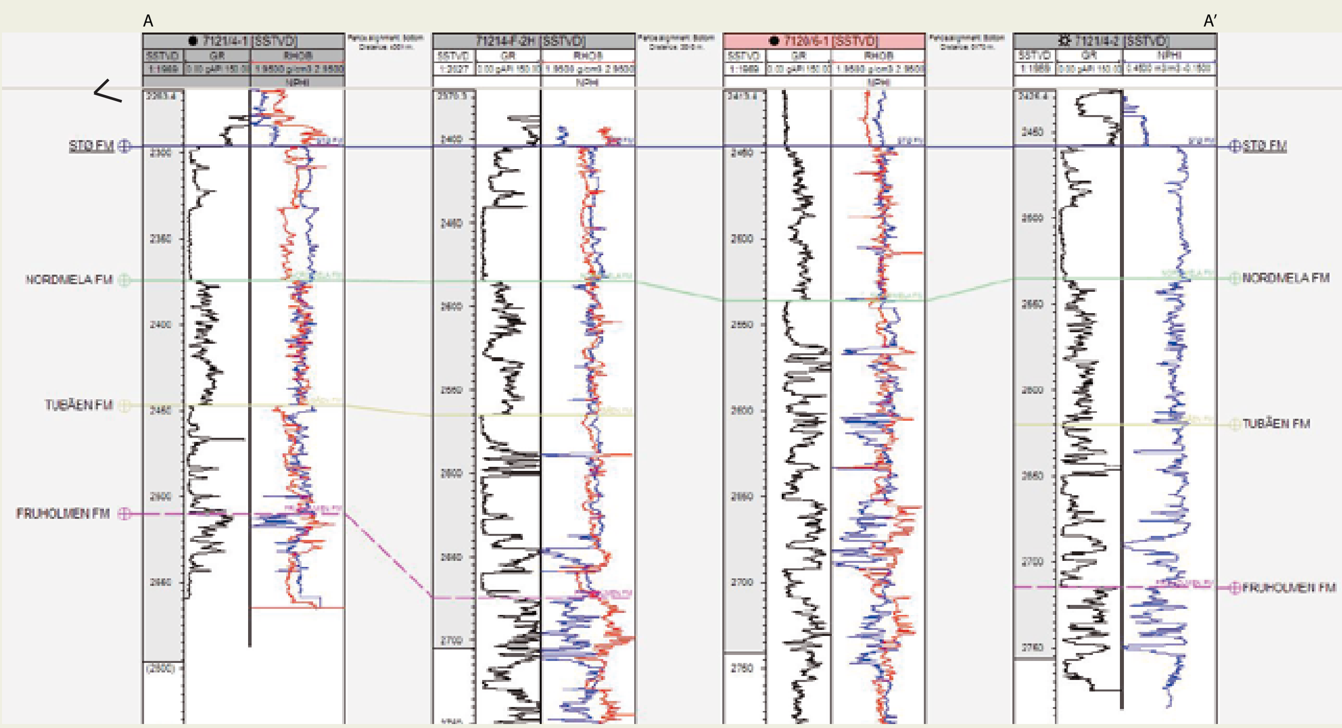
The calculation of maximum and minimum pore volumes resulted in 6400 Mm^3 for the “Snøhvit 2800” case and 680 Mm^3 for Snøhvit central Stø. These pore volumes indicate that there are sufficient aquifer volumes available to support the planned CO_2 injection in the Stø Formation at Snøhvit.



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



Stø depth map where blue arrows illustrate a possible CO_2 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.grey polygons shows location of shallow gas.



Log correlation panel with gamma and neutron/density, flattened on the Stø Fm. Location of profile is shown in the Stø Fm thickness map.

Snøhvit Central Stø	Summary
Storage system	Half open
Rock Volume	6.1 Gm^3
Net volume	4.8 Gm^3
Pore volume	680 Gm^3
Average depth	2320-2400m
Average net/gross	0,8
Average porosity	0,14
Average permeability	300 mD
Storage effeciency	5 %
Storage capacity aquifer	24 Mt
Reservoir quality	
capacity	3
injectivity	2
Seal quality	
seal	3
fractured seal	3
wells	2
Data quality	
Maturation	

6.2.1 Saline aquifers

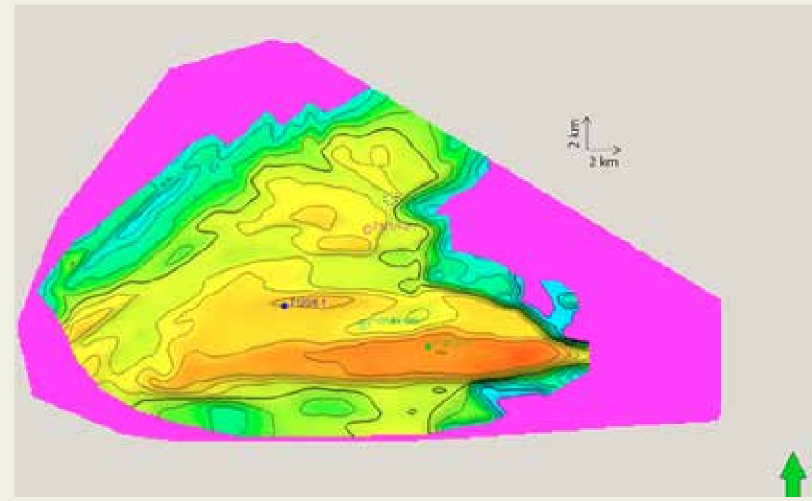
Storage capacity Snøhvit area

The expected flow direction for the injected CO_2 will be towards the west. As seen in the well section profile, thick packages of shale seal the Stø Formation and are expected to 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 9) will be important to control the injection and the movement of the CO_2 through time. Data quality in the area is good, except in the areas with gas clouds. There is sufficient experience with injection in the Stø Formation 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, interpretation and calculations were performed to evaluate the storage potential in the Snøhvit Jurassic aquifer consisting of the Stø, Nordmela and Tubåen Formations above the spill point for the main Snøhvit Field. This pore volume case is called the Greater Snøhvit area. It may represent the pore volume which has been filled with hydrocarbons in geological history and is analogous to the Greater Albatross and the Greater Askeladd areas. The results show a pore volume of 4100 Mm^3.

All parameters used in the calculations and presented in the table, are 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 "Snøhvit 2800" case. 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 indicated in the table. 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 the Stø Fm, where the pink surface at 2800 m represent the base of the Jurassic aquifer.

Snøhvit 2800m	
Storage system	Half open
Rock Volume	89 Gm^3
Net volume	54 Gm^3
Pore volume	6.4 Gm^3
Average depth	2404-2800m
Average net/gross	0,6
Average porosity	0,12
Average permeability	150 mD
Storage effeciency	2 %
Storage capacity aquifer	90 Mt
Reservoir quality	
capacity	3
injectivity	2
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	

Storage in depleted and abandoned fields

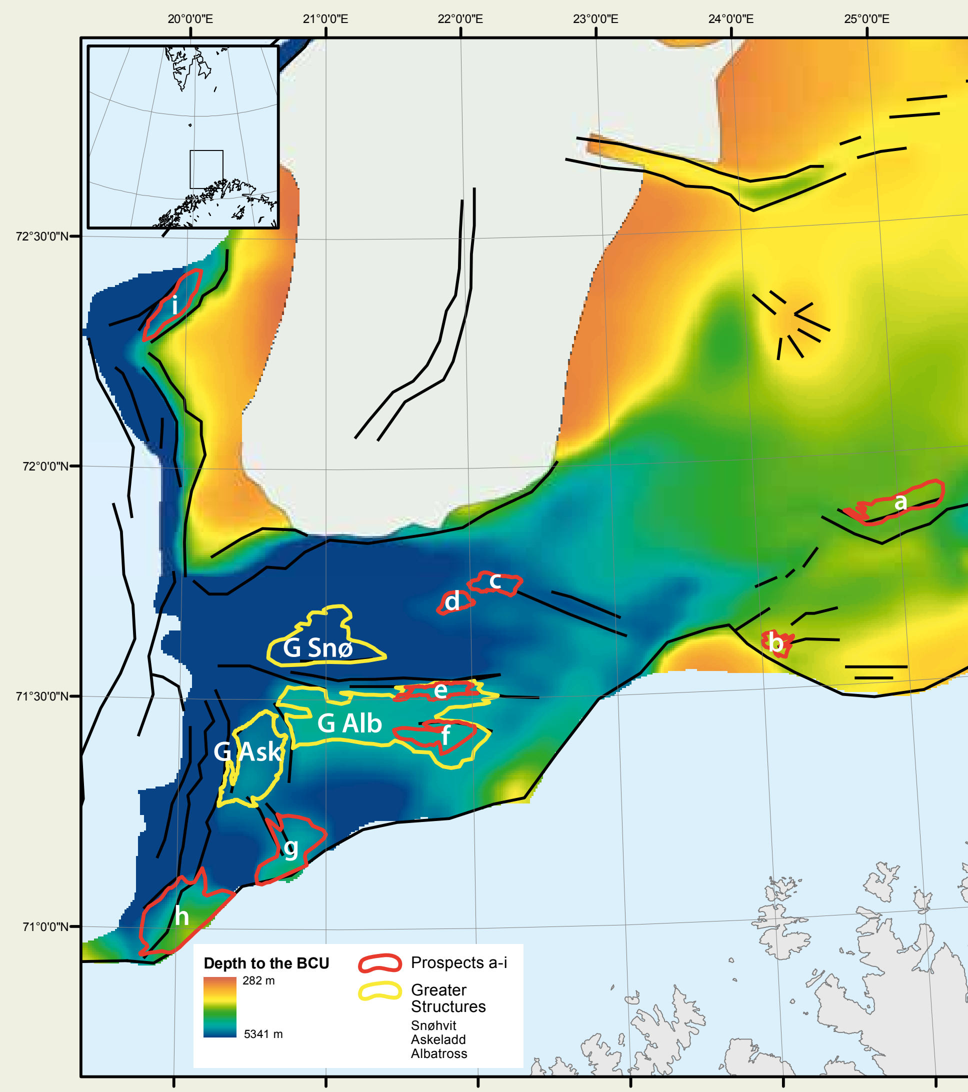
The Snøhvit development includes several gas discoveries within the greater Snøhvit, Askeladd and Albatross structures. The potential of CO_2 storage after abandonment of the smaller of these discoveries was calculated from the pore volume of their gas zones. It was assumed that after production there 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.

6.2.2 Prospects

Introduction

The preferred locations for CO_2 sequestration in the Barents Sea are structural traps which have been 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 prospects A to I) within the aquifer systems of the Realgrunnen Subgroup have been mapped and characterized by their storage capacity, injectivity and seal quality. The storage capacity of a structural trap can be limited by the pore volume of the structural closure and by the pore volume and permeability of the connected aquifer. The evaluation of Prospect A is based on a simulation model that takes these factors into account. Evaluation of the other prospects is based on pore volumes 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. For the reservoirs in the Hammerfest Basin, average permeability is indicated in the tables for the Nordmela Formation (low values) and Stø Formation (high values). Provided that the 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 the thickness of the primary seal (the 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. A 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 considered to be low (blue colour). Prospects which have been drilled and that proved only brine or brine and residual oil, are considered more mature (green colour). The yellow colour is applied to prospects which are approaching a development plan, such as in the Snøhvit area. These prospects require more in-depth studies than what was possible in this study. In addition to the prospects, the Greater Snøhvit, Greater Askeladd and Greater Albatross areas 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.

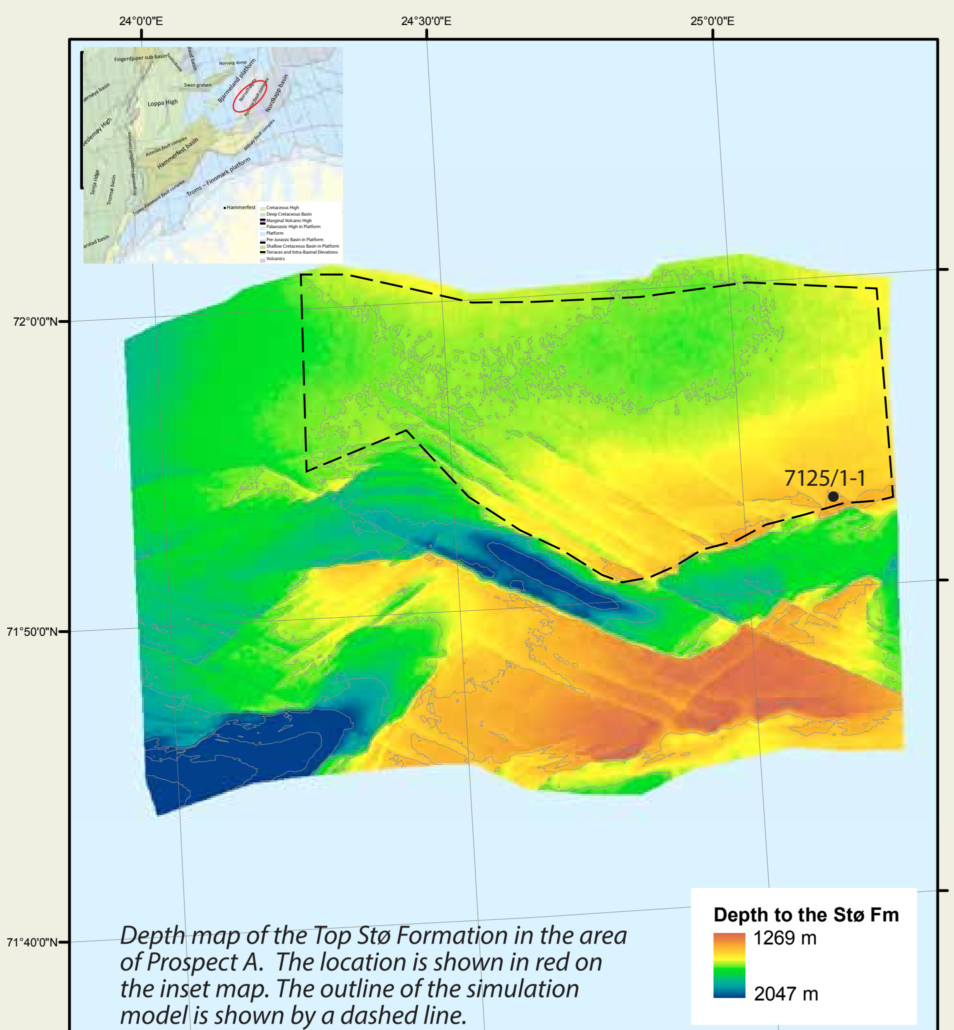


Location of evaluated prospects (red) and large structural closures (yellow).

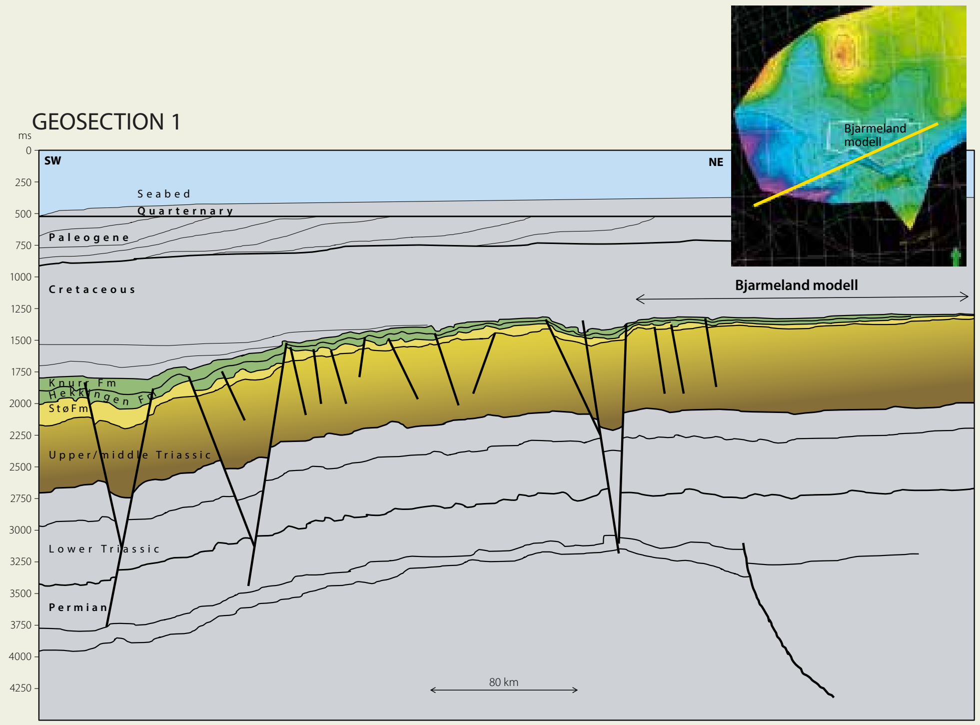
6.2.2 Prospects

Bjarmeland Platform prospects

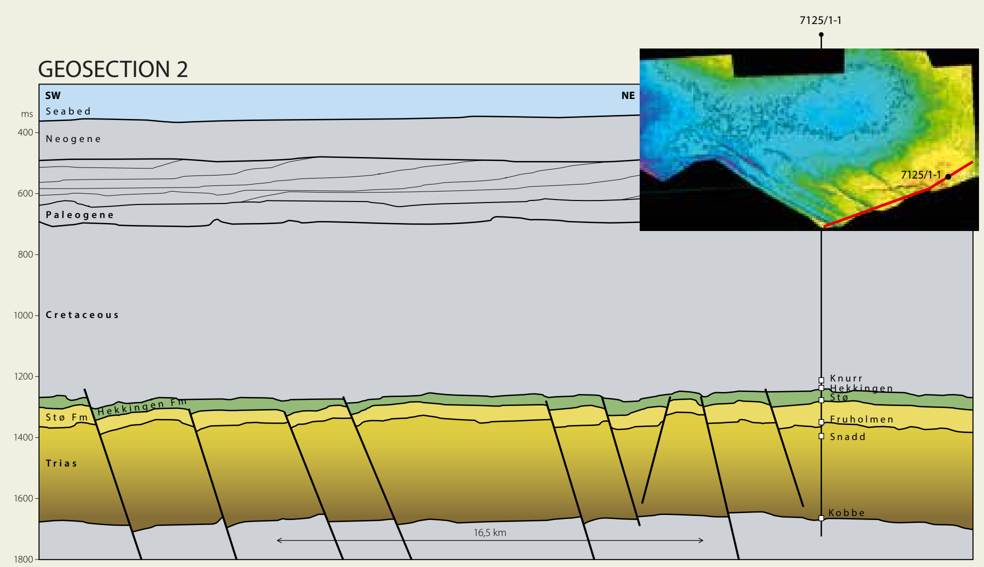
Prospect A is defined as a closed structure located east of the Loppa High in the southernmost part of the Bjarmeland Platform, west of the Nysleppen Fault Complex. The structure is drilled by the7125/1-1 well. 1 m oil saturation was encountered in the top of the main reservoir, with a residual oil zone below. The main reservoir zone evaluated for CO_2 storage is the Stø Formation with a thickness of 130 m in well 7125/1-1. The Stø Formation is part of the Realgrunnen Subgroup, which thickens westwards into the Hammerfest Basin. Depth to top of the interpreted structure is about 1400 m. The Stø Formation overlies a thick Triassic succession of the Ingøydjupet Subgroup. 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 section 6.2.1, this seepage is believed to be a slow process, and the seal risk is characterized as relatively low. The geomodel of the Realgrunnen Subgroup is based on interpretation of 3D seismic data and data from the exploration well. The geomodel is developed into a reservoir simulation model in order to study the behaviour 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 in red on 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.

6.2.2 Prospects

Bjarmeland Platform prospects

The simulated CO_2 injection well is located down dip 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 a free, movable state. Migration stops when CO_2 is permanently trapped, by going into a solution with the formation water or by being residually or structurally trapped (mineralogical trapping is not considered here).

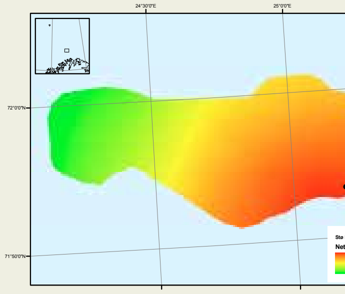
Confinement of CO_2 requires prevention of migration of the CO_2 plume to potential leakage areas. For Prospect A, the fault/graben system to the west and south will seal the structure in that direction. The structurally highest point on the Bjarmeland structure is located along this fault.

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 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 75 bar could be applied at that depth. However, as discussed in section 6.2.1, 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 the thick Stø Formation and has excellent reservoir properties. Further north in the Bjarmeland Platform, the Realgrunnen Subgroup is thinning, but good porosity and permeability is developed in a large area.

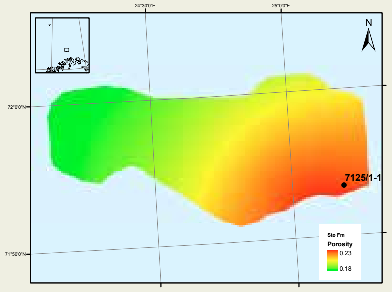
The volume of the active aquifer system is conservatively estimated to be 25 times the volume of the geological model, and this volume is added to the simulation model volume.

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.

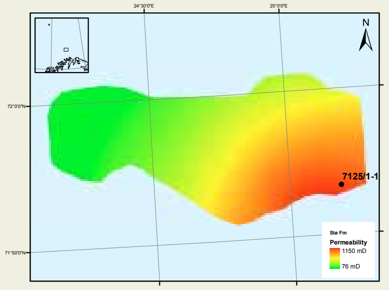
Prospect A	
Storage system	Open
Rock Volume	55 Gm^3
Net volume	52 Gm^3
Pore volume	10 Gm^3
Average depth	1525 m
Average net/gross	0,94
Average porosity	0,20
Average permeability	500 mD
Storage effeciency	2.5 %
Storage capacity aquifer	176 Mt
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	



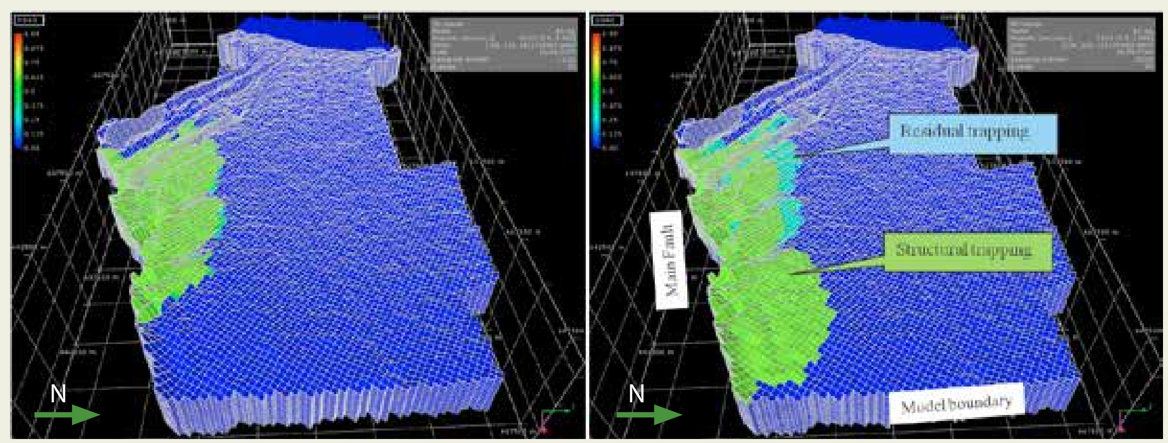
Net/Gross values from 0,97-0,92



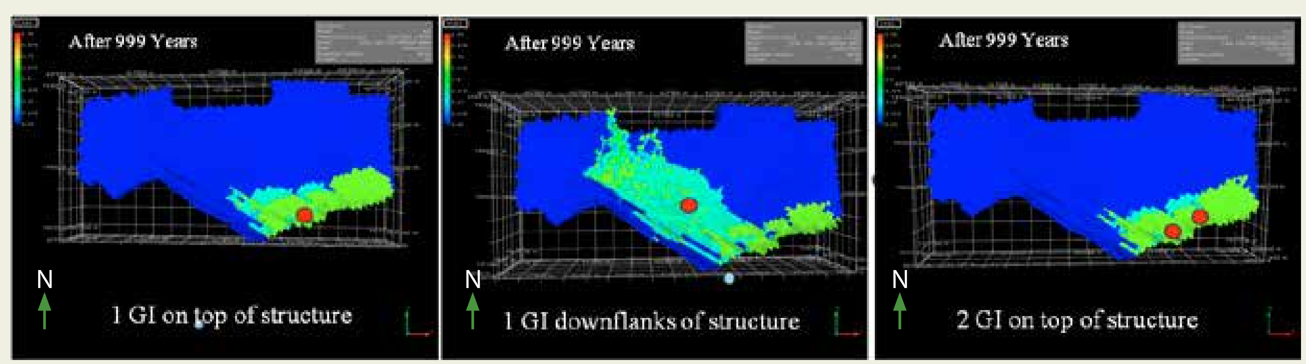
Porosity varies from 20-24 %



Permeability is 1000 mD 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.

6.2.2 Prospects

Bjarmeland Platform prospects

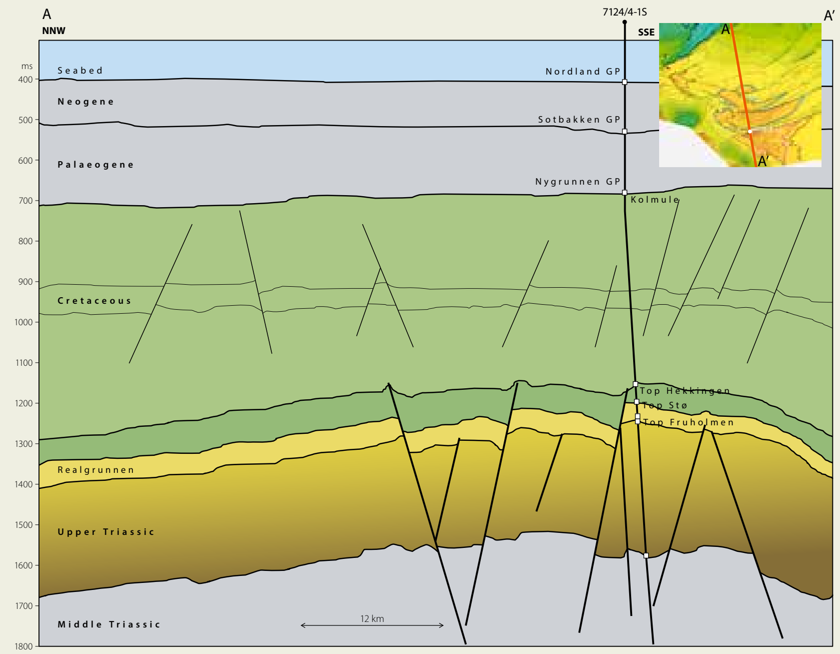
Prospect B is located in the transition zone between the Hammerfest and the Nordkapp Basins, about 70 km north-east of the Goliat Field. It is defined at a NW-SE trending fault block with a structural closure. The main reservoir is in the Stø Formation (Realgrunnen Subgroup). The structure has been drilled by the well 7124/4-1 S, where the Stø Formation was encountered at a depth between 1259 and 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 data and data from the 7124/4-1S well. The 3D seismic data set does 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). The primary seal is the Hekkingen Formation, and 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. The structure is segmented by several smaller WSW-ENE trending faults.

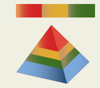
Approximately 50 metres of Hekkingen shale overlie the sand-rich Stø Formation. The faults cutting through the Stø Formation seem to terminate in the Hekkingen shale, hence the seal risk is considered to be relatively low.

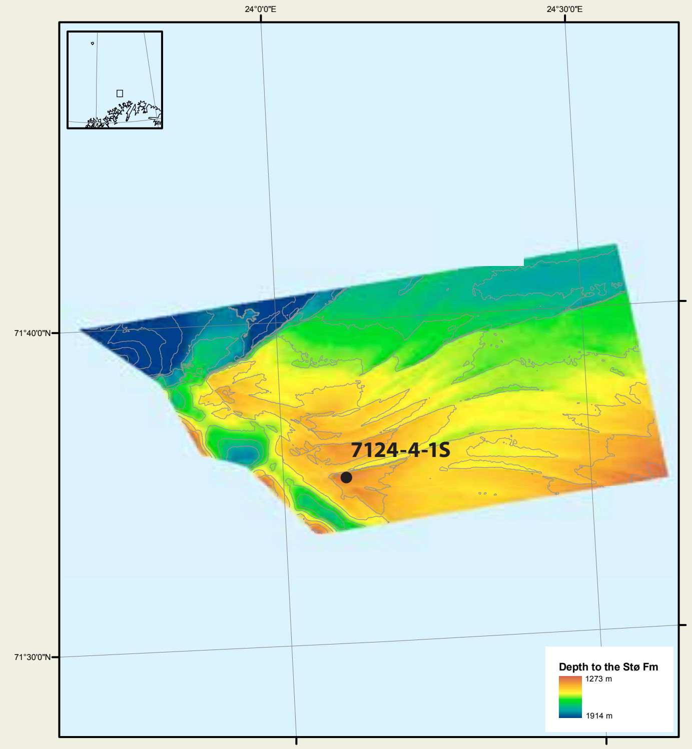
The structure consists of two main segments. If a CO_2 injector is placed in the northern segment, the CO_2 plume can migrate and spill into the structurally higher segment to the south. The calculated CO_2 storage capacity for both segments is 19 Mt based on a constant thickness of the Stø Formation.



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

Prospect B	
Storage system	Half open
Rock Volume	4.0 Gm^3
Net volume	3.9 Gm^3
Pore volume	900 Mm^3
Average depth	1260 m
Average net/gross	0,98
Average porosity	0,23
Average permeability	500 mD
Storage effeciency	3 %
Storage capacity aquifer	19 Mt
Reservoir quality	
capacity	3
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	



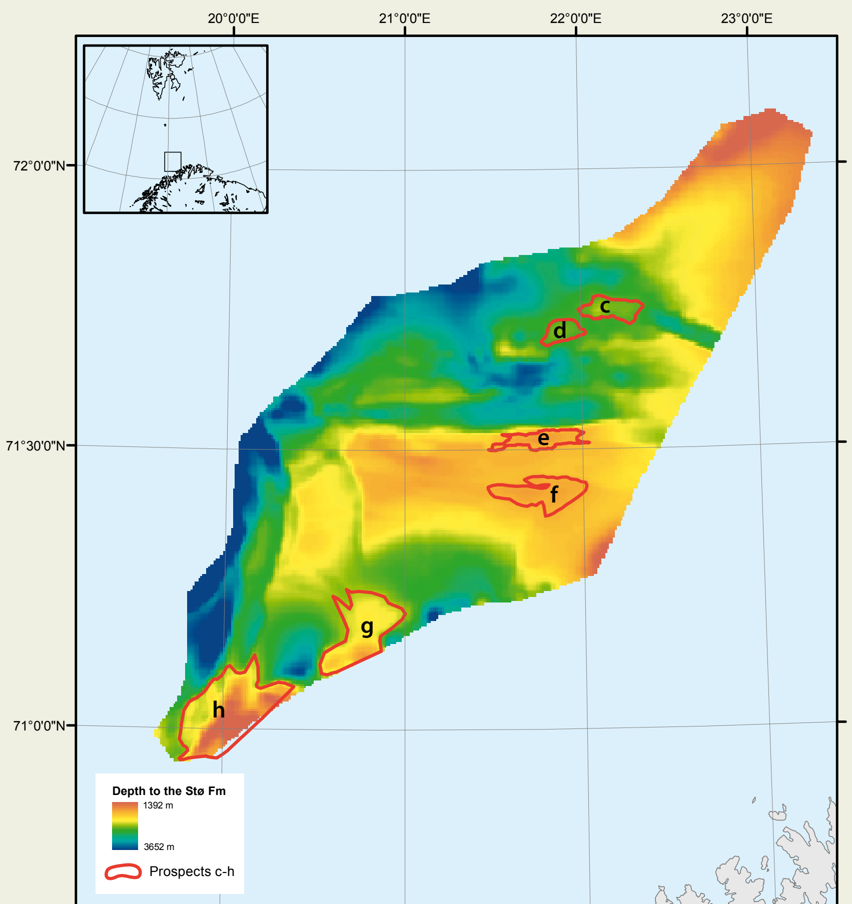


Hammerfest Basin prospects

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 in 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.

Prospects C and D

Prospects C and D are structurally defined traps with 4-way closures. 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 closures are uncertain. Prospect C has several minor faults cutting through the reservoir. The faults are not believed to offset the primary seal completely, but a lower fractured seal quality is indicated. Well 7122/4-1 was drilled on prospect C and proved a brine filled structure with hydrocarbon shows.

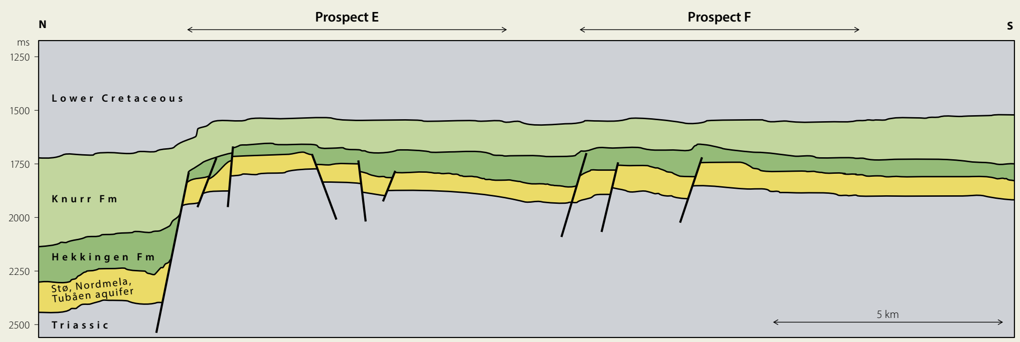


Prospect C	
Storage system	Open
Rock Volume	1.94 Gm^3
Net volume	1.79 Gm^3
Pore volume	280 Mm^3
Average depth	2400 m
Average net/gross	0,92
Average porosity	0,15
Average permeability	1-170 mD
Storage effeciency	10 %
Storage capacity aquifer	19 Mt
Reservoir quality	
capacity	1
injectivity	3
Seal quality	
seal	3
fractured seal	2
wells	3
Data quality	
Maturation	

Prospect D	
Storage system	Open
Rock Volume	1.18 Gm^3
Net volume	1.25 Gm^3
Pore volume	180 Mm^3
Average depth	2400 m
Average net/gross	0,97
Average porosity	0,15
Average permeability	1-150 mD
Storage effeciency	10 %
Storage capacity aquifer	12 Mt
Reservoir quality	
capacity	1
injectivity	3
Seal quality	
seal	3
fractured seal	3
wells	3
Data quality	
Maturation	

Hammerfest Basin prospects

Prospects E and F
Prospects E and F are interpreted 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 neighbouring structure, prospect F. Prospect E was drilled by 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. Prospects E and F are located between Snøhvit and Melkøya, only a few km away from the pipeline.



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 must not interfere with the accumulations of natural gas.

Prospect H
Prospect H is a complex structure with many fault blocks, bounded to the south by the Troms-Finnmark Fault Complex. The volume of the structure is calculated based on 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 Upper Triassic.

Prospect E	
Storage system	Open
Rock Volume	1.9 Gm^3
Net volume	1.7 Gm^3
Pore volume	290 Mm^3
Average depth	1900 m
Average net/gross	0,86
Average porosity	0,18
Average permeability	2-500 mD
Storage effeciency	10 %
Storage capacity aquifer	20 Mt
Reservoir quality	
capacity	2
injectivity	3
Seal quality	
seal	2
fractured seal	2
wells	3
Data quality	
Maturation	

Prospect F	
Storage system	Open
Rock Volume	2.3 Gm^3
Net volume	1.9 Gm^3
Pore volume	350 Mm^3
Average depth	1900 m
Average net/gross	0,79
Average porosity	0,19
Average permeability	2-550 mD
Storage effeciency	10 %
Storage capacity aquifer	24 Mt
Reservoir quality	
capacity	2
injectivity	3
Seal quality	
seal	3
fractured seal	3
wells	3
Data quality	
Maturation	

Prospect G	
Storage system	Half open
Rock Volume	17 Gm^3
Net volume	9.9 Gm^3
Pore volume	16 Gm^3
Average depth	2200 m
Average net/gross	0,57
Average porosity	0,17
Average permeability	1-300 mD
Storage effeciency	5 %
Storage capacity aquifer	57 Mt
Reservoir quality	
capacity	2
injectivity	2
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	

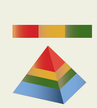
Prospect H	
Storage system	Half open
Rock Volume	58 Gm^3
Net volume	29 Gm^3
Pore volume	5.2 Gm^3
Average depth	2100 m
Average net/gross	0,5
Average porosity	0,18
Average permeability	1-600 mD
Storage effeciency	5 %
Storage capacity aquifer	180 Mt
Reservoir quality	
capacity	2
injectivity	2
Seal quality	
seal	2
fractured seal	2
wells	2
Data quality	
Maturation	

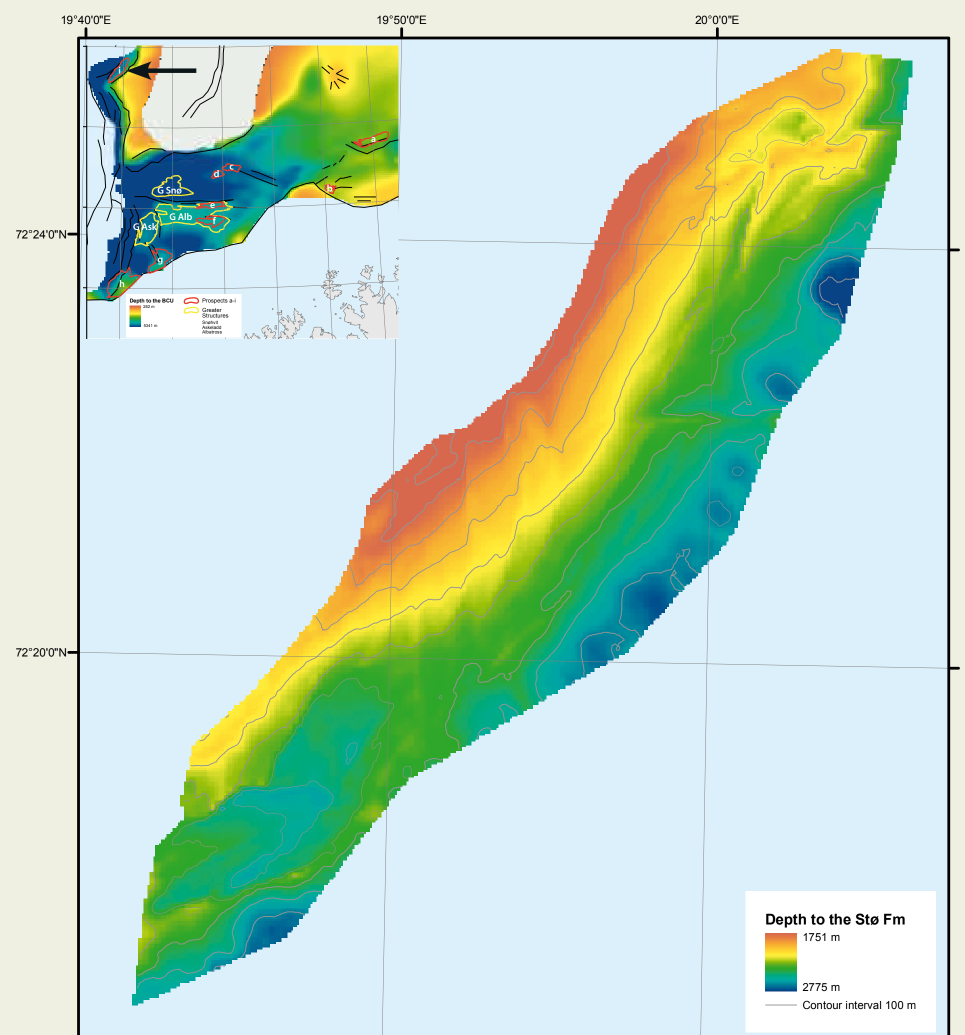
Bjørnøyrenna Fault Complex prospect

The Jurassic aquifer in the Bjørnøyrenna Fault Complex is separated from the Hammerfest Basin by the eroded Loppa High and faults with large throws 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 have developed in some of the fault blocks and communication between segments is possible. 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 the 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	
Storage system	closed
Rock Volume	7.7 Gm^3
Net volume	6.9 Gm^3
Pore volume	1.3 Gm^3
Average depth	2100 m
Average net/gross	0,9
Average porosity	0,18
Average permeability	400 mD
Storage effeciency	1 %
Storage capacity aquifer	9 Mt
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.

6.2.3 Summary

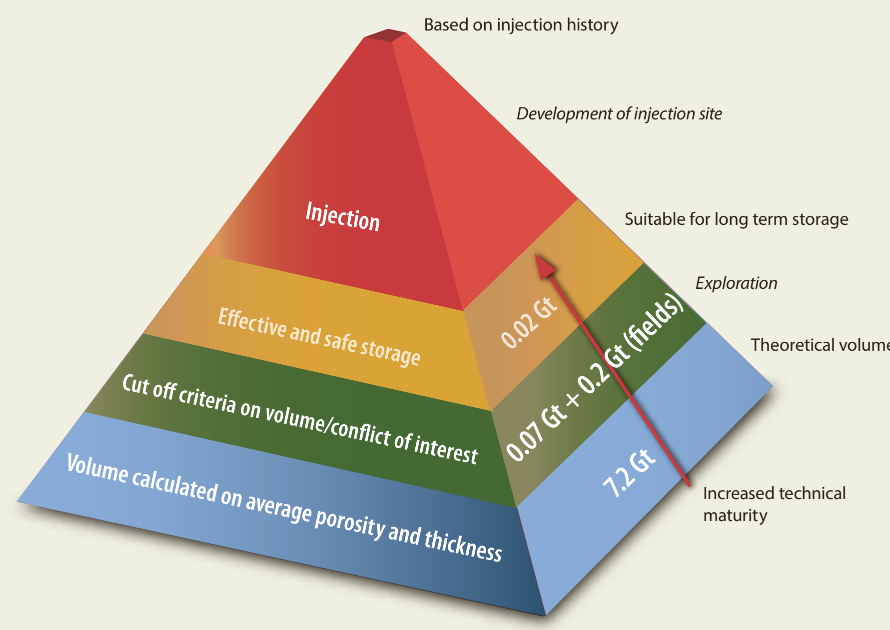
The main results of this study are displayed in the table below and illustrated by the maturation pyramid. The aquifers in the Jurassic Realgrunnen Subgroup are well suited for sequestration, and their storage potential has been quantified. Additional storage in other aquifers is possible. A theoretical 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 such 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 relate to the quality of the seal and to the possibility of encountering hydrocarbons in the traps.

CO_2 injection can be used to mobilize residual oil, which is abundant in the Realgrunnen Subgroup. 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 for development as storage sites. A simple calculation revealed a potential of around 200 Mt in four of these structures.

Prospects in structural traps	Avg depth	Bulk volume	Pore volume	Avg K	Open/closed	Storage eff	CO_2 density in reservoir	Storage capacity	Maturity
Unit	*m*	*Gm³*	*Gm³*	*mD*		*%*	*kg/m³*	*Mt*	
BP Aquifer									
A	1525	55	10	500	open	2.50	650	176	
B	1260	4	0.9	500	half open	3	650	19	
HB Aquifer									
C	2400	1.9	0.28	1-170	open	10	700	19	
D	2400	1.2	0.18	1-150	open	10	700	12	
E	1900	1.9	0.29	2-500	open	10	700	20	
F	1900	2.3	0.35	2-550	open	10	700	24	
G	2200	17	1.6	1-300	half open	5	700	57	
H	2100	58	5.2	1-600	open	5	700	183	
BFC Prospect									
I	2100	7.7	1.3	400	closed	1	700	9	
Storage in abandoned fields									
Fields in production								200	
Aquifer volumes									
BP Aquifer	1100	1480	245	5-1000	half open	3	650	4800	
HB Aquifer	2400	1230	120	1-500	half open	3	700	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	700	90	
Snøhvit central Stø	2404-2800	6.1	0.68					24	



The UNIS CO_2 well site in Longyearbyen, Svalbard. Photo: Sebastian Sikora.