CO₂ STORAGE ATLAS
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Norway’s (Scandinavia’s) first resource map, Olaus Magnus, 1539

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1. Introduction

The CO2 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 CO2 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 CO2 storage projects on NCS Skagerrak 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 CO2 storage potential in relevant dry-drilled structures and mapped structures in the area is provided. CO2 storage in enhanced oil recovery projects is also discussed and a new study of CO2 for EOR and CO2 injected in residual oil zones has been included.

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 CO2 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 CO2 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.
1. Introduction

There is significant technical potential for storing CO₂ 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 CO₂.

Environmental sound storage of CO₂ is a pre-condition 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 CO₂. It is important to have the best possible understanding of what can be the CO₂ storage potential.

These factors necessitate an enhanced effort within the mapping and investigation of CO₂ storage sites. The production of this CO₂ storage atlas is at the very centre of this effort. Various Norwegian research institutions and commercial enterprises have extensive experience and competence within CO₂ storage.

For investment in CO₂ storage, the following main objectives have been identified:

- Develop and verify the knowledge and technology for safe and cost-effective storage and monitoring of CO₂
- Help develop and verify commercially viable methods, service concepts and technologies.
- Contribute to increased knowledge on geological storage

By supporting testing and demonstration projects, Gassnova will contribute to the development of cost-effective and innovative technology concepts for CO₂ capture. This includes knowledge and solutions for:

- CO₂ capture before, during or after power production
- Compression and handling of CO₂
- Transport of CO₂
- Long-term storage of CO₂ in terms of injection, storage or other application areas

Gassnova will focus on on-shore developments 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.clim.nu.

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- Develop and verify the knowledge and technology for safe and cost-effective storage and monitoring of CO₂
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- Contribute to increased knowledge on geological storage

The primary focus for the work on CO₂ storage is to support the development of geological storage of CO₂. This involves storing in water-bearing formations located deep enough to keep the CO₂ in a dense phase.

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 commercialisation of CO₂ utilisation 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.
2. Petroleum activity in the Barents Sea
With the discovery of the Draugen field in 1985, 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, and the petroleum activity gradually expanded northwards. In May 1983, 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 Borkheia, 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 since December 2012. However, there are development plans for some of these abandoned fields.

Production on the NCS is still high. In 2012, Norway was the seventh largest exporter of oil and the third largest exporter of natural gas (2011). Oil production has been slightly above 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 a mature 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 (Bjørnøya 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 consent rounds and awards in predefined areas (MAW) 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 bbls/adjacent unit resulted in around 35 discoveries. It has been proven roughly 1.3 billion sm³ of gas and 2.4 billion sm³ 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, 7125-K-1 Snøhvit. The biggest gas discovery is 7124-1/4 Snøhvit drilled in 1984. The Snøhvit gas field also comprises four discoveries made prior to 7124-1/4 Snøhvit and the development comprise 4 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 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 activity in the Barents Sea was temporarily suspended for a couple of years soon after 2000.

Little-exploitation 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 7125-3/1 (Norway) as the largest. The first well to test the play was drilled in 1982, and the next few wells were dry. A couple of discoveries were significantly smaller than expected. The gas discovery 7225-3/3 (Norway) is encouraging, and the estimate of undiscovered resources shows the potential remains large.

The Upper Triassic to Lower Cretaceous plays along the Ringvassøy-Loppa and Bjørnøya 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 has been followed by three other wells. This well discovered gas with a very high CO₂ content. Finding oil in Johan Castberg (7225-8/1) Skrugard and 7225-7/1 Hauk 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 oil are developing the Goliat oil field. The gas from Snøhvit is transported to a land terminal at Meløyhamn and forwarded as LNG (liquefied natural gas) by ship. The CO₂ is separated from the gas stream onshore on Meløyhamn terminal and transported by a 300 km pipeline offshore and injected into the Sta-helesta geological formation in the Snøhvit field.

Oil and gas discoveries in the Barents Sea have been made since the 1980`s, and the exploration has been more frequent in the last decade. Since 2000, there have been periods with several discoveries in the Barents Sea. The recent increase is associated with the increased interest in the area and the increased activity in the NCS.
3. Methodology
To be suitable for CO2 storage, saline formations need to have sufficient porosity and permeability to allow large volumes of CO2 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 CO2 migration into other formations or to sea. CO2 is held in place by the storage formation that is generally contained in a storage reservoir. The reservoir is the part of the 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 seal is the main part of the storage system that is generally contained within a structural or stratigraphic closure, 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 CO2 storage, as they have held oil 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.

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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 subsurface 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 1996), 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 overview and analyses make up an important fact base 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 core 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:

3. Methodology

3.3 Workflow and characterization

Characterization

Aquifers and structures have been evaluated in terms of capacity and safe storage of CO2. 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 CO2 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

<table>
<thead>
<tr>
<th>Criteria</th>
<th>Definitions, comments</th>
</tr>
</thead>
<tbody>
<tr>
<td>Reservoir quality</td>
<td>Capacity, communicating volumes</td>
</tr>
<tr>
<td></td>
<td>Large calculated volume, dominant high scores in checklist</td>
</tr>
<tr>
<td></td>
<td>Medium-low estimated volume, low score in some factors</td>
</tr>
<tr>
<td></td>
<td>Dominant low volume, or at least one score close to unacceptable</td>
</tr>
<tr>
<td></td>
<td>High value for permeability * thickness (k*h)</td>
</tr>
<tr>
<td></td>
<td>Medium k*h</td>
</tr>
<tr>
<td></td>
<td>Low k*h</td>
</tr>
<tr>
<td>Injectivity</td>
<td>High value for permeability * thickness (k*h)</td>
</tr>
<tr>
<td></td>
<td>Medium k*h</td>
</tr>
<tr>
<td></td>
<td>Low k*h</td>
</tr>
<tr>
<td>Sealing quality</td>
<td>Seal</td>
</tr>
<tr>
<td></td>
<td>At least one sealing layer with acceptable properties</td>
</tr>
<tr>
<td></td>
<td>Sealing layer with uncertain properties, low scores in checklist</td>
</tr>
<tr>
<td></td>
<td>Dominant high scores in checklist</td>
</tr>
<tr>
<td></td>
<td>Medium</td>
</tr>
<tr>
<td>Fracture of seal</td>
<td>No previous drilling in the reservoir / safe plugging of wells</td>
</tr>
<tr>
<td></td>
<td>Wells penetrating seal, no leakage documented</td>
</tr>
<tr>
<td></td>
<td>Low scores in checklist</td>
</tr>
<tr>
<td>Other leak risk</td>
<td>Wells</td>
</tr>
<tr>
<td></td>
<td>No fracture</td>
</tr>
<tr>
<td></td>
<td>Sand injections, slumps</td>
</tr>
<tr>
<td></td>
<td>Active chimneys with gas leakage</td>
</tr>
<tr>
<td></td>
<td>High number of wells</td>
</tr>
<tr>
<td>Data coverage</td>
<td>Good data coverage</td>
</tr>
<tr>
<td></td>
<td>Limited data coverage</td>
</tr>
<tr>
<td></td>
<td>Poor data coverage</td>
</tr>
</tbody>
</table>

### CHECKLIST FOR RESERVOIR PROPERTIES

<table>
<thead>
<tr>
<th>Reservoir Properties</th>
<th>Typical high and low scores</th>
</tr>
</thead>
<tbody>
<tr>
<td>Sealing Properties</td>
<td>High</td>
</tr>
<tr>
<td>Sealing layer</td>
<td>More than one seal</td>
</tr>
<tr>
<td>Properties of seal</td>
<td>Proven pressure barrier &gt; 1000 mTorr</td>
</tr>
<tr>
<td>Composition of seal</td>
<td>High clay content, homogeneous</td>
</tr>
<tr>
<td>Faults</td>
<td>No faulting of the seal</td>
</tr>
<tr>
<td>Other breaks through seal</td>
<td>No fracture</td>
</tr>
<tr>
<td>Wells (exploration/ production)</td>
<td>No drilling through seal</td>
</tr>
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For Sealing Properties

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3. Methodology

3.3 Workflow and characterization

Workflow

RPOC approach for assessing the suitability of the geological formations for CO2 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 CO2.

In subsequent steps in the workflow, each potential reservoir and seal identified, are evaluated and characterized for their CO2 storage potential. 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. The evaluation does not provide an economic assessment of the storage sites.

3.4 Estimation of storage capacity

CO2 can be stored in produced oil and gas fields, or in saline aquifers. In a producing field, CO2 can be used to enhance recovery before it is stored. A depleted gas field can be used for CO2 storage by increasing the pressure in the reservoir. Some of the remaining gas can be recovered during the CO2 injection. Even if the field is not put to purpose, oil and gas fields can be used as storage for CO2 by increasing the pressure in the reservoir.

Storage capacity depends on several factors, primarily the poro-volume, and how much the reservoir can be pressure-saturated. 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 saturation 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 CO2 in the different phases will also play a part.

CO2 will preferably be stored in a supercritical phase to inject the least possible volume in the reservoir. For saline aquifers, the amount of CO2 to be stored can be determined using the following formula:

\[ \text{MCO}_2 = \rho \times \text{g} \times \text{h} \times \text{e} \times \text{v} \times \text{p} \times \text{t} \times \text{Seff} \]

Where:

- \( \rho \) = CO2 density at reservoir conditions
- \( \text{g} \) = gravity
- \( \text{h} \) = formation thickness
- \( \text{e} \) = effective porosity
- \( \text{v} \) = density of CO2 in reservoir conditions
- \( \text{p} \) = storage capacity factor
- \( \text{Seff} \) = storage efficiency factor

Self is calculated as the fraction of stored CO2 relative to the pore volume. The CO2 in the pore volume will appear as a mobile or immobile phase (trapped). Most of the CO2 will be in a mobile phase. Some CO2 will be dissolved in the water and simulations show that approximately 10-20% of the CO2 will be dissolved in the water. When injection stops, the CO2 will continue to migrate upward in the reservoir, and the water will follow, trapping some of the CO2 behind the water.

The trapped gas saturation can range from 30% to 300% depending on how long the migration continues. The diffusion of CO2 into the reservoir 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 CO2 will depend on the size of the reservoir and the injectivity.

For a homogeneous reservoir with a permeability of 200 mD and reservoir thickness of 100 m, 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 reasonable for reservoirs between 1000 and 3000 m, 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 CO2 injection, as the water will be pushed beyond the boundaries of the reservoir. The CO2 stored will be the amount injected until it reaches the boundaries. The efficiency will be ~5% or less, depending primarily on the relationship between the vertical and horizontal permeability. A how-vertical to horizontal permeability ratio will reflect the possibility to store the CO2 better over the reservoir than a high ratio.

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

A cross-section of a flat reservoir with injection for 55 years is shown below.
4. Geological description of the Barents Sea
4. Geological description of the Barents Sea

4.1 Geological development of the Barents Sea

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. Dalland et al. (1990) suggested a revised lithostratigraphic scheme for the Upper Palaeozoic, Mesozoic and Cenozoic successions from the Southard area including the southern Barents Sea.

In NPD Bulletin No 9 (Larssen et al. 2002), a formalized Upper Palaeozoic lithostratigraphy for the southern Norwegian-Barents Sea area is presented. In the 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 northern Barents Sea. For the Upper Palaeozoic successions we use the official nomenclature from NPD Bulletin No 9 (Larssen et al. 2002).

Lithostratigraphic nomenclature

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4. Geological description of the Barents Sea

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 related 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-SW trending Ringvassøy-Loppa and Bjørnøya Fault Complexes. The area to the west of this boundary was tectonically active throughout Late Mesozoic and Cenozoic times, with deposition of available thicknesses of Cretaceous, Paleogene and Neogene sediments in the Marsted, Tromsø and Bjørnøya Basins. NNE-WSW and locally N-S trending faults dominate in this western part of the southeastern Barents Sea is dominated by thick Upper Paleozoic and Mesozoic sequences, whereas E-W, WNW-ESE to ENE-SSW trending faults dominate.

The area evaluated for CO₂ storage is defined to dominate. In contrast the southeastern Barents Sea is dominated by N-S trending faults in this western part of the Platform. The southeastern Barents Sea Shelf is divided into several main structural elements. The most important are: The Hammerfest and Nordkapp Basins, the Finnmark and Bjørnøya Platforms and the Loppa High. There are also several smaller structural elements, like the Polheim Sub-platform, Senja Ridge, Vestkney, Norsel High. Bordering and partly defining the main structural elements are a series of complex fault zones: Troms–Finnmark, Ringvassøy-Loppa, Bjørnøya, Mäzøy, Nyksløppen and Asturia 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 (Anteros Fault Complex) and the Bjørnøya Platform. Internally E-W to WNW ESE trending faults dominate.

The basin was probably established by Early to Late Carboniferous rifting. Two wells have penetrated the Upper Paleozoic succession. Well 7120/1-2, drilled in the southern margin, penetrated a 1000m thick Upper Permian sequence overlying Lower Permian dolomitic limestone and red beds resting on Precambrian/Caledonian basement. Well 71/20-2 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 Paleogene 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 episodes.

The Nordkapp Basin in fault controlled and located along a NNE trending Upper Paleozoic rift. It is bounded by the Bjørnøya Platform to the northwest and the Finnmark Platform to the southeast. The northern boundary is defined by the Nyksløppen Fault Complex and the southeastern boundary is defined by the Mäzøy Fault Complex.

During the Late Paleozoic, the most important tectonics were related to the Late Permian and Early Triassic. The basin is dominated by thick Mesozoic, mainly Triassic successions, with a significant thickness of Upper Paleozoic rocks.

The Hammerfest 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 Palaeogene tectonics resulted in a gentle northeast tilt of the Platform. In the northeastern part of the Platform thick sequences of Mesozoic, mainly Triassic rocks have been drilled.

The Bjørnøya 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 Palaeogene tectonics tilted the platform. The Bjørnøya Platform is fault controlled and located along a NNE trending Upper Paleozoic rift. It is bounded by the Bjørnøya Platform to the northwest and the Finnmark Platform to the southeast. The northern boundary is defined by the Nyksløppen Fault Complex and the southern boundary is defined by the Mäzøy Fault Complex.

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

The Loppa High is a marked (N-S) trending structural feature separated from the Hamnøyfjord 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 Bjørnøya fault Complexes. To the east it grades into the Bjørnøya 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 sediments, evaporites and carbonates. 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 3000 m), 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.

4.1 Geological description of the Barents Sea

The thickness map of Quaternary sediments including subcrop lines of basement, top Permian, BCU, base Paleocene and base upper Pliocene.
The Ingøydjupet Group

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 Frøholmen Formation of the Raudafjellet Facies. This represents an important transition which produced a sequence boundary transecting throughout most of the Arctic from the Barents Sea to the Seedup Basin.

The type and reference area for the Ingøydjupet Group is blocks 7120/9 in the western part of the Hammerfest Basin. In the type well the thickness is approximately 1700m thickening northwards towards the reference area to 2460m (well 7120/12-2). 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 southwestern margin of the Nordkapp Basin. The upper part of the group (Snadd Formation) has been eroded found to the east on the Bjarmeland Platform, Norsel High, thicknesses in the order of 100m have been reported. Here the dominant facies is silt and claystone with subordinate sandstone. On the Firemark 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 (Gleinkian)

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-upward sequences. The thickness in the type well is 105 m. Further to the north the reference well (7120/12-1) has a thickness of 150 m with a more monotonous silt and shale sequence. Further to the east, on the Bjarmeland Platform and Norsel High, thicknesses in the order of 100m have been reported. Here the dominant facies is silt and claystone with subordinate sandstone. On the Firemark 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.

Generally the formation thins 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 northerly to northwestern coastal progradation.
Lower and Middle Triassic

The base of the formation is a distinct regional marker, which on Svalbard marks the onset of deposition of phosphoria- tic organic-rich mudstones (Botneheia Formation). On the Svalbard shelf, similar lithologies are found in the Snadd Formation. The oldest sediments of the Steinkobbe Formation are older than the Botneheia Formation. In the reference wells (7120/12-1 and 7120/12-2), the thickness is 944m and 1404m, respectively, while in the type well (7120/12-1), the thickness is only 775m due to thinning out of 400m of the middle and upper part of the unit. On the Loppa High, thicknesses are in the order of 500–1600m. On the Nykkopen and Nallyfjell, the thickness is between 300 and 500m. The Bjarmeland Platform has thicker sections in the order of 800 to 850m. The basal grey-shale coarsens up into marine sandstones. In the middle and upper parts of the unit, calcareous layers are relatively common with thin coaly lenses further upwards.

Thicknesses in the order of 600 to 850m. 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. The Raalgrunnen 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 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 Raalgrunnen Group

The Raalgrunnen Group 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). The Raalgrunnen Group is subdivided into four formations: the Botneheia, Steinkobbe, Fruholmen, and Tubåen Formations. The group is defined by the onset of deposition of phosphatic organic-rich mudstones from the Tschermakfjellet and De Geerdalen Formations. The Raalgrunnen Group is defined by the Raalgrunnen Formation, which is the lower boundary of the group.

The thickness is 168m in the type well and 283m in the reference well. This formation is one of the major petroleum plays in the area, with significant oil and gas accumulations. The thickness of the formation increases from the south/southeastern coastal areas and fining towards the basin axis. The southern margin of the Hammerfest Basin is characterized by 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 Botneheia Formation. The Raalgrunnen Group is defined by the Raalgrunnen Formation, which is the lower boundary of the group.
4. Geological description of the Barents Sea

4.2 Geological description

The Fruholmen Formation (Rhaetian-Rhaetian) consists of grey to dark shale passing upwards into interbedded sandstone, shale and coal. 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 is overlain by the more shale-rich Krabb Member. Depositionally, this has been interpreted in terms of open marine shale (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 floodplain deposition, with more marine environments to the north (Krabbe Member). The sandstone thickness 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.

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 basin 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 65m 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 northeast, while coals in the southeast were deposited in protected backbarrier lagoonal environments.
The Nordmela Formation (Sinemurian-Late Pliensbachian) consists of interbedded siltstones, sandstones, shale and mudstones with minor coal. 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 discontinuous, younging southeastwards.

The formation represents deposits in a tidal flat to floodplain environment. Individual sandstones represent estuarine and tidal channels. In the type well (7215/5-1) the thickness is 62m and in the reference well (7119/12-1) it is 256m. The thickness variation between the type well and reference well clearly illustrates a southwestward-thickening wedge. Westward thinning is characteristic for all the three Lower and Middle Jurassic formations and may be the result of early Kimmeridgian subsidence and tilting towards the Troms and Bjoernoya Basins.

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 (7215/5-1) 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.

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Teistengrunnen Group  
[Balthorian 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 Bjarmyrenna Fault complex (7120/12-1) to 300m just north of the Troms-Norway 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 carbonates. The Hekkingen Formations is an important hydrocarbon source rock. Both the Fuglen and Hekkingen Formation constitute good cap rocks.

The Hekkingen Formation (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 Flottvatn Basin and Bjarmyras Basin, as shown in well 7219/8-1 in the southern part of the Bjarmyrenna 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.

Areas where Knurr and/or Hekkingen sandy deposits occur are outlined.
4. Geological description of the Barents Sea

4.2 Geological description

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, limestones, dolomites 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 Bjørnøya 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 Bjørnøya 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 Kolmule Formation.

Although the formation shows similar lithology at 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 genetically distal marine environment with local restricted bottom conditions.

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 Introduction

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 CO₂ emissions. CO₂ associated with the production of natural gas in the Snøhvit Field is sequestered at Melkøya, Hammerfest, and injected into the aquifer of the field. CO₂ associated with gas production is separated at Melkøya, Hammerfest, and injected into the production of natural gas in the Snøhvit Field. CO₂ storage and EOR in the near future. In a more distant future, storage of anthropogenic CO₂ 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° 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 water depth. The Finnmark Platform east of 29° was screened out because there is limited infrastructure and industrial activity in this area, and the main aquifers of interest are poorly structurally and generally monokrally 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 Palaeozoic sections. Because of Cenozoic tectonic 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 extensional erosion, good reservoir quality is encountered only at shallower depth than what is found in the North Sea and Norwegian Sea. Below 1000 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 areas. 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 CO₂ storage will also be subject to further exploration and exploitation by the petroleum industry. Consequently, storage of CO₂ 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 CO₂ and it may be considered to use CO₂ 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.
CO2 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 0.5% CO2. Some of our producing gas fields have higher CO2 content which require dilution with gas having low CO2 content or CO2 has to be separated from the gas stream and injected into saline aquifers.

Gas from the Sleipner field and the Skirpavik field have high CO2 concentrations that require CO2 capture and storage. Some of the discoveries in the Norwegian Sea offshore Nordland also have a high CO2 content that will require capture and storage of CO2 if the gas is produced. CO2-rich gas occurs in the western parts of the Hallen- and Donna terraces. In the western part of the Voring area, one well showed a CO2 content of 9%. Other gas discoveries in the deeper parts of the Møre- and Vøring Basins do have more than 2.5% CO2. Some of our producing gas fields have higher CO2 content which require dilution with gas having low CO2 content or CO2 has to be separated from the gas stream and injected into saline aquifers.

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In general, in the Norwegian shelf, the percentage of CO2 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, CO2-rich gas has been encountered along the margins of the deep Harstad, Tromsø and Bjørnøya basins. One accumulation of gas with a CO2 content in the order of 50% was found in well 7019/1-1 (NPD web site), while an earlier discovery in the eastern Barents Sea, the percentage of CO2 typically does not exceed 10. Further tests, the CO2 content appears to be lower. The reason for the increased CO2 content in those areas is not clear, although the low vicinity to Paleogene volcanic sill intrusions may explain a lot of the natural CO2 in 7019/1-1. Both organic processes and degassing of metamorphic and overheated sedimentary rocks may contribute to the CO2 generation.
In the Hammerfest Basin, the Jurassic Tabåen, Nordmela and Ste 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 aquifers 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 thruster formations in the Barents Sea Platform aquifer. Faults within the basin commonly juxtapose Stø towards Nordmela and Tabåen Formations. Paleo fluid contacts indicate that the faults are open where there is sand-sand contact. Pressure data from exploration wells show that the pore pressure has equilibrated between the formations at depths shallower than 2600 m. The data indicates that the thin shaly continuous barrier in the succession is considered to be the shaly lower part of the Nordmela Formation. The calculations of storage capacity in structures are based on injection and storage in the Stø Formation. Faults within the basin contribute to stratigraphic barriers which may allow gas to accumulate connected laterally. The underlying heterolithic formations 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 Ste, Nordmela and Tabåen Formations as one single aquifer system. The geological data show that the Ste 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 Snøhvit CO2 injection showed that CO2 was contained within the Tabåen Formation with no upwards migration into the Nordmela and Ste Formations. Another effect of salinity is that CO2 is less soluble in high salinity brines than in sea water, the amount of CO2 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. The experience from the Snøhvit CO2 injection due to salt precipitation near the wells. High salinity may cause problems for CO2 discovery and in some wells in the southwestern part. Another effect of salinity is that CO2 is less soluble in high salinity brines than in sea water, the amount of CO2 trapped by dissolution can then be relatively small.

Porosity depth and porosity permeability plots based on core and log data from the Hammerfest Basin.
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 2018. A condensed Lower and Middle Jurassic section is developed in large areas in the central Barents Sea and Seaibard. In the Bjarmeland Platform the thickness of the Reongrønne Group decreases from around 100 m in south to a few tens of meters in the north. The sedimentary facies are similar to the Tublian, Fruholmen and Ste Formations in the Hammerfest Basin. The boundary between the Hammerfest Basin aquifer and the Bjarmeland 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 thickness 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 Svalbard Dome in the west, the Jurassic strata are eroded and Triassic sedimentary rocks outcrop at the seafloor. 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 within the Ste aquifer in the Hammerfest Basin due to reduced thickness and more heterogeneous facies. Fruholmen Formation The sandy parts of the Fruholmen Formation were deposited in large parts of the evaluated area in a fluvo-deltaic environment. Channelized sandstones have good reservoir properties along the margin whereas they are not as good deep and they have mapped up in the Gullfaks Field and in the 7521/1-1 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 Reongrønne 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 widespread around the Seaibard Embayment, and can be mapped in 3D seismic data. Gas accumulations are attached to both the oil and gas fields. The Snadd Formation has not been evaluated for large scale CO2 injection, because of poor lateral connectivity and because of several of the channelized sandstone sandstone may have a potential for hydrocarbons. Kobbek Formation The Kobbek Formation consists of marine shales, silts and debris sands, mainly to the middle Cretaceous. The formation is developed as reservoir sandstones along the Fennoscandian margin as seen on seismic data in the section 4. The Kobbek Formation constitutes the main reservoir in the Goliat Field. It has not been evaluated for large scale CO2 injection because only a limited volume of the aquifer is formed at sufficiently shallow depth to maintain high porosity and permeability. Late Palaeozoic reservoirs Late Palaeozoic sandstones and carbonates and Early Triassic sandstone outcrop along the coast of Troms and Finnmark south of the evaluated area. Reservoir properties are proxied by a few stratigraphic sections. Increase in basin of limited seismic and well data coverage close to the coast, there is however no suitable prospect for CO2 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 source sands 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 structure, 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 1.
2. What will be the fraction of seepage from a plume of CO2 in decay phase compared with a methane seepage 1

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 seepage and the position of gas seepage is seen on seismic data in the Bjernya Basin and the western part of the Hammerfest Basin. In the Bjernya Basin, gas seepage is commonly capped by gas hydrates and associated gas flares (Chand et al. 2012). This shows that gas seepage is active today. The most active seepage takes place in the Bjernya Basin and Bjarnemyna Gas Field. Here, the source rocks generate hydrocarbons and several gas fields are filled at spill point. This indicates that the rate of gas seepage is low in comparison 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 CO2 sequestration. Concerning the sealing capacity for CO2 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% CO2/methane mixture in the Jurassic reservoir and the methane with 10-15% CO2 in the Cretaceous reservoir. Our interpretation is that in this well, the rate of seepage of CO2 is significantly less than for methane. 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. This is however a concern since 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.
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 Snøhvit Central Structure (Middle Jurassic age), at depths of approximately 2300 m. The hydrocarbon production in the Snøhvit Field is from the Stø and Nordmela Formation (Early and Middle Jurassic age), at depths of 2200-2300 m and the reservoirs are found in the central part of the Hammerfest Basin.

The Stø Formation is mainly gas with minor condensate and a 10-15 m thick oil leg. The CO2 is separated from the gas in Melkøya in an amine process. Compressed CO2 in liquid phase is returned to the field in a 153 km long pipeline to be stored 2500 m below sea level. CO2 storage at the Snøhvit Field started in 2006, and CO2 was until April 2011 injected in well 7121/4F-1H in the Tubåen Fm which is dominated by fluvial sandstones. 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 performed as the new storage formation for CO2.

After the intervention in 2011 all CO2 from the Snøhvit Field has been injected in the water zone of the Stø Formation. Until 2017 a total of 1,1 Mton CO2 has been injected in the Tubåen Fm and Stø Mtn in the Stø Formation.

In contrast to the Tubåen Formation, the Stø Formation is in pressure communication with the gas producers on the Snøhvit and no significant pressure buildup is expected in the injection site. However, a new injection well for CO2 in the Stø Formation is in pressure communication with the gas producers on 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, 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 depth. The minimum aquifer zone, Snøhvit central, 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, communication is interpreted.

The calculation of pore volumes for the two aquifers resulted in 6420 Mrm3 for the Snøhvit 2800 case and 660 Mrm3 for the Snøhvit central case. These aquifer volumes indicate that there are sufficient water volumes available to support the planned CO2 injection in the Stø Formation at Snøhvit.

The CO2 storage aquifer is interpreted to represent a water volume of 30-35 Mm3 for the water zone in the Stø Formation. The CO2 storage aquifer is the Melkøya terminal. Blue circle indicates main study area for CO2 storage at the Snøhvit Field.

Storage capacity Snøhvit area

Storage options

5.2 Saline aquifers

5. Storage options

5.2 Saline aquifers

Storage capacity Snøhvit area

Major faults are not expected where the throw is larger than the thickness of the Stø Formation, but in the minimum aquifer, communication is interpreted.

The calculation of pore volumes for the two aquifers resulted in 6420 Mm3 for the Snøhvit 2800 case and 660 Mm3 for the Snøhvit central case. These aquifer volumes indicate that there are sufficient water volumes available to support the planned CO2 injection in the Stø Formation at Snøhvit.
5.2 Saline aquifers

The expected flow direction for the injected CO\textsubscript{2} will be towards the west. As seen in the profile, thick packages of shale seal the Ste Fm, and prevent vertical leakage of CO\textsubscript{2}. Seepage of gas along the faults is regarded as a risk, in particular in the areas with shallow gas clouds. Monitoring of the seepage (section 6) will be important to control the injection and the movement of CO\textsubscript{2} through time. Data quality in the area is good, except in the areas with gas clouds. The experience with injection in the Ste Fm is sufficient to conclude that the area has been matured as a storage site.

In addition to the CO\textsubscript{2} storage potential related to the ongoing injection in the Ste Fm (G-segment), interpretation and calculations were performed to evaluate the storage potential in the Snøhvit Jurassic aquifer consisting of Ste, Hekkingen, and T tabindex. Integration shows the trend towards the Western part of the Ste Fm, but more shaly zones in the middle part of the formation most likely act as an internal barrier or baffle for injected CO\textsubscript{2}.

Data quality is good as previously mentioned, but due to possible conflicts with the petroleum activity, evaluation is shown in blue colour. This represents a theoretical volume of the CO\textsubscript{2} storage potential calculated for the Jurassic aquifer. Uncertainty in the calculation is mostly related to the structural closures and a simplified approach to the distribution of the aquifer.

Storage in depleted and abandoned fields

The Snøhvit development includes several gas discoveries within the greater Snøhvit, Askledal, and Albatross structures. The potential of CO\textsubscript{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\textsubscript{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.

<table>
<thead>
<tr>
<th>Storage capacity Snøhvit area</th>
<th>Summary</th>
</tr>
</thead>
<tbody>
<tr>
<td>Storage system</td>
<td>Full open</td>
</tr>
<tr>
<td>Rock Volume, m\textsuperscript{3}</td>
<td>8,6E+10</td>
</tr>
<tr>
<td>Net volume, m\textsuperscript{3}</td>
<td>5,3E+10</td>
</tr>
<tr>
<td>Pore volume, m\textsuperscript{3}</td>
<td>6,4E+09</td>
</tr>
<tr>
<td>Average depth, m</td>
<td>2404-2800</td>
</tr>
<tr>
<td>Average net/gross</td>
<td>0.0</td>
</tr>
<tr>
<td>Average porosity</td>
<td>0.12</td>
</tr>
<tr>
<td>Average permeability, mD</td>
<td>110</td>
</tr>
<tr>
<td>Storage efficiency, %</td>
<td>2</td>
</tr>
<tr>
<td>Storage capacity aquifer</td>
<td>80 Mtons</td>
</tr>
<tr>
<td>Reservoir quality</td>
<td>3</td>
</tr>
<tr>
<td>injectivity</td>
<td>2</td>
</tr>
<tr>
<td>Seal quality</td>
<td>2</td>
</tr>
<tr>
<td>Residual seal</td>
<td>2</td>
</tr>
<tr>
<td>Enclosed seal wells</td>
<td>2</td>
</tr>
<tr>
<td>Data quality</td>
<td>Maturation</td>
</tr>
</tbody>
</table>

As discussed in 5.2, the preferred locations for CO\textsubscript{2} sequestration in the Barents Sea are structural traps which are proved to contain brine and 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 porosity of the structural closure and the connectivity and permeability of the connected aquifer. The evaluation of the prospects is based on a simulation model taking these factors into account. Evaluation of the other prospect aquifers is a combination of 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 presented here. For the reservoirs in the Hammerfest Basin average permeability is calculated based on the Ste Fm, the Nordhelle formation (low values) and Ste Fm formation (high values). Provided that CO\textsubscript{2} will be injected at a high rate, injectivity is considered to be medium to high in most prospects. The seal quality is characterized by the thickness of the primary seal (Hekkingen and Fujigen formations) and the faulting integrity 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. Pressure simulation was run with a maximum pressure build-up of 30 bar. Maturity of prospects which may be of interest for petroleum exploration is evaluated as low (blue colour). Prospects which have been drilled and proved only brine or residual oil are indicated to be more mature (green colour). The yellow colour is applied to prospects which are approaching a PDO, such as the Snøhvit area. These require more investigation before they can be considered for CO\textsubscript{2} sequestration in this study. In addition to the prospects, the areas Greater Snøhvit, Greater Askledal and Greater Albatross are defined. These areas represent structural closures with some culminations. Some of the culminations are hydrocarbon filled, and some of them have only residual hydrocarbons. These are indicators in the wells that these greater structural closures have been filled with hydrocarbons at the time of maximum burial. CO\textsubscript{2} injected in these is not likely to migrate out.
The simulated CO₂ injection well is located down-dip with plume migration towards south-southwest, 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 CO₂ migration effects. CO₂ will continue to migrate upwards as long as it is free, movable state. Migration of the CO₂ plume is permanently trapped, by going into solution with the formation water or by being trapped interstitially (pore trapping is not considered here).

Confinement of CO₂ requires prevention of migration of the CO₂ plume to potential leakage areas. For Prospect A, the fault/gap system in the west and south will seal the structure in that direction. The structurally highest point on the Bjarmeland structure is located along the fault.

To obtain confinement of CO₂, 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 CO₂ plume migration during the period of injection (400m). The structure is hydrostatically pressured. Fracture gaps 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 explored regions of the Barents Sea could be lower, and the effects of a maximum pressure of 10 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 Raukgrunnen 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.

Prospect A, Bjarmeland Platform

The simulated CO₂ injection well is located down-dip with plume migration towards south-southwest, 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 CO₂ migration effects. CO₂ will continue to migrate upwards as long as it is free, movable state. Migration of the CO₂ plume is permanently trapped, by going into solution with the formation water or by being trapped interstitially (pore trapping is not considered here).

Confinement of CO₂ requires prevention of migration of the CO₂ plume to potential leakage areas. For Prospect A, the fault/gap system in the west and south will seal the structure in that direction. The structurally highest point on the Bjarmeland structure is located along the fault.

To obtain confinement of CO₂, 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 CO₂ plume migration during the period of injection (400m). The structure is hydrostatically pressured. Fracture gaps 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 explored regions of the Barents Sea could be lower, and the effects of a maximum pressure of 10 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 Raukgrunnen 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.
Prospect B is located in the transition zone between the Hammerfest and the Nordcapp basins, about 70 km northwest from the Goliat field. It is defined by 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, where the Stø Formation was encountered at a depth between 1293-1312 m. The formation consists of a 52 m 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 7124-1 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 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 7124/4-1 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 gigantic structure west of the fault. The structure is segmented by several smaller WSW-ENE trending faults.

### Prospect B Summary

- **Storage capacity**: Half open
- **Rock Volume, m³**: 4.60E+08
- **Net volume, m³**: 3.90E+08
- **Pore volume, m³**: 9.00E+07
- **Average depth, m**: 1260
- **Average net/gross**: 0.98
- **Average porosity**: 0.18
- **Average permeability**: 0.21 M.D
- **Storage capacity aquifer**: 19 Mtons
- **Reservoir quality**: Capacity 3
- **Injectivity**: 3
- **Seal quality**: Good
- **Data quality**: Relatively good.

### Storage Options

- **Storage options**: Open
- **Rock volume, m³**: 1.90E+09
- **Net volume, m³**: 2.18E+09
- **Average depth, m**: 1240
- **Average net/gross**: 0.83
- **Average porosity**: 0.17
- **Average permeability**: 0.01
- **Storage efficiency, %**: 17
- **Stoarge capacity aquifer**: 12 Mtons
- **Reservoir quality**: Capacity 4
- **Injectivity**: 3
- **Capacitiy**: Good
- **Stoarage capacity aquifer**: 12 Mtons
- **Reservoir quality**: Capacity 4
- **Injectivity**: 3
- **Capacitiy**: Good

### Well 7124/4-1 S

The well was drilled on prospect B and proved a brine filled structure with hydrocarbon shows. No major faults and no signs of gas leakage were observed. The interpretation is based on the well data with poor coverage, consequently the geometry and size of the structural seal 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 7124/4-1 was drilled on prospect C and proved a breccia filled structure with hydrocarbon shows.
5. Storage options

5.3 Prospects

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 and the fault is larger than the thickness of the primary seal. The seal quality is rated lower than the neighboring structure, prospect F. Prospect F was drilled by the well 7220/5-5 which encountered brine with hydrogen sulfide shows in the Stø and Tubaen formations. Prospect F has not been drilled and is regarded as a hydrocarbon prospect. The closure is partly bounded by faults with small closures. No gas clouds or other sign of gas leakage have been observed in the seismic data. Prospect F can be an interesting candidate for CO2 storage, especially in the southern part of the structure, 7220/5-5 was a gas discovery in the Tubaen Formation. South of the structure, 7220/12-1 encountered brine with hydrogen sulfide shows, and 7220/12-2 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 CO2 plumes should not interfere with the accumulations of natural gas.

Prospect G

Prospect G is defined as a large structural closure with several carbonate reservoirs. The structure is the southern boundary of the Troma-Finnmark Fault Complex, and a deep spill point exists on the fault seal towards the Trassic rocks in the Troma-Finnmark Platform. Two wells have been drilled within the volume above spill point. The prospects E and F are located between Snøhvit and Melkøya, only a few km away from the pipeline. The Jurassic aquifer in the Bjørnøyrenna Fault Complex is separate from the Hammerfest Basin by the eroded Loppa High and faults with large fault gouge. The volume of the trap is calculated to a deep spill point which depends on fault seal quality. 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. 7119/14-1 and 7120/10-1 were dry while shows were observed in 7119/12-3. The spatial distribution of the organic matter in the prospect is controlled by the structural closure, 7120/12-5 was dry, 7120/12-3 was a gas discovery in the Stø Formation. South of the structure, 7220/12-1 encountered brine with hydrogen sulfide shows, and 7220/12-2 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 CO2 plumes should not interfere with the accumulations of natural gas.

Prospect H

Prospect H is a complex structure with many fault blocks, it is bounded to the south by the Troma-Finnmark fault complex. The closure of Prospect H is a complex structure which depends on fault seal quality and is of interest for CO2 storage if water filled. The storage capacity aquifer is 67 Mtons with a storage efficiency of 10%. The reservoir volume is 2,06E+09 m³ with a high permeability of 2-550 mD.

Prospect I

Prospect I is located at a closed fault block. One water bearing closure was selected as a candidate for CO2 storage. 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 from 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 high. The lithologies and the degree of communication within the trap is based on the volume of the fault blocks and is considered to be due to the seal quality, which can account for communication between segments. One water bearing closure has been selected as a candidate for CO2 storage. Prospects H located at a closed structure drilled by well 7229/9-1.

The Jurassic aquifer in the Bjørnøyrenna Fault Complex is separated from the Hammerfest Basin by the eroded Loppa High and faults with large fault gouge. The volume of the trap is calculated to a deep spill point which depends on fault seal quality. 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. 7119/14-1 and 7120/10-1 were dry while shows were observed in 7119/12-3. The spatial distribution of the organic matter in the prospect is controlled by the structural closure, 7120/12-5 was dry, 7120/12-3 was a gas discovery in the Stø Formation. South of the structure, 7220/12-1 encountered brine with hydrogen sulfide shows, and 7220/12-2 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 CO2 plumes should not interfere with the accumulations of natural gas.

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5.4 Storage options with EOR

Study of enhanced oil recovery (EOR) from an oil zone with an underlying residual oil zone in the prospect A. CO2 has shown to be a very efficient agent to recover oil, especially residual oil. When the CO2 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 CO2 is stored at the end of the injection period after the oil and water has been displaced. CO2 is widely used in the USA where CO2 is a natural resource. In Europe there is only small amount of CO2 available, therefore this method is presently not used. However, there is a big potential if anthropogenic CO2 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 CO2 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 CO2 injection was applied. The oil in the simulation model was produced (well OP) from the main oil zone while CO2 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. However, the oil production will increase when CO2 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 Sm3, of which 2.5 mill Sm3 comes from the main oil zone and 3.8 mill Sm3 from the residual zone. 43 mill tons of CO2 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.

### Input data and results

- **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
- **CO2 injection rate:** 1.5 MSm3/d
- **OP and CO2 inj. Start:** 01.01.2015
- **Oil in-place, main structure:** 23 MSm3
- **Res. oil in-place, main structure:** 49 MSm3
- **Oil in-place, sector model:** 9.7 MSm3
- **Res.oil in-place, sector model:** 25.3 MSm3

### Results

- **Oil produced, sector main zone:** 2.5 MSm3
- **Oil produced, sector residual:** 3.8 MSm3
- **Recovery factor, main zone:** 46%
- **Recovery factor, residual zone:** 15%
- **CO2 stored:** 43 Mtons
5. Storage options

5.5 Summary of storage evaluation

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 sequential injection and the 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 CO2 available for injection in the Barents Sea is likely to come from natural sources as CO2 associated with methane in the gas fields. The evaluation indicates that there is a potential for safe storage of more than 500 Mt CO2 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. CO2 injection can be used to mobilize residual oil, which is abundant in the Realgrunnen Group. The potential for such utilization of CO2 is shown by a simulation study of prospect A. The results indicate that large amounts of CO2 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.
Gas hydrates in the Barents Sea

Natural gas hydrates are a relatively new source of gas in浅水, high pressure 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 GHSz defined by the phase diagram. The limits of the stability zone are determined by bottom water temperature, sea level, geothermal gradient, and the ocean's depth. Gas hydrates can form in areas where there is sufficient flux of thermogenic methane or deposits of biogenic methane. In the southern Barents Sea, the thickest GHSz generally coincides 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 Tjøtvena Basin.

CDI, Storage in Hydrates

CDI may be stored in gas hydrates. Depositing methane hydrate to CO2 will cause a solid exchange of CO2 and CH4 in guest molecules within the hydrate, an exchange caused by the fact that it is thermodynamically more favorable for water to form hydrate with CO2 compared to methane. CO2 sequestration in hydrates is a win-win process since associated natural gas will be produced as CO2 is replaced by the more thermodynamically stable hydrate; thus the replacement of natural gas hydrate with CO2 hydrate will increase the stability of hydrate formations.

CO2 storage in hydrate formations, as demonstrated in the Alaskan injection test by ConocoPhillips and USDOE in 2012 concluded that CO2 was stored and methane successfully produced during a huff and puff operation injecting 200,000 scf of CO2 and nitrogen. Storage of CO2 as hydrate 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 source of CO2 will be trapped as hydrate before reaching the sea floor.

5.6 Gas Hydrates

Freeze gas hydrate

Methane hydrates well

CO2 hydrate released

Stable CO2 hydrate

Stable CO2 and CH4 hydrate

Stable CO2 hydrate

Gas hydrate stability zone

Phase diagram for water, methane and CO2

Reservoirs

Reserves growth & undiscovered

Remaining unrecoverable

Non-sandstone marine reservoirs with permeability (unknown)

Arctic sandstones away from infrastructure (~10's of Tcf in place)

Deep-water sandstones (~100s of Tcf in place)

Massive superficial and shallow nodular hydrate (unknown)

Reserves (200 Tcf)

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

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

5. Storage options

5.5 Gas Hydrates

5.6 Gas Hydrates

5. Storage options

by Rune Mattingdal, Alexey Deryabin (NPD) and professor Arne Graue (UiB)
The Longyearbyen CO2 Lab in Svalbard, Norway, is one of the demonstration projects currently carried out worldwide. The purpose is to learn more about the CO2 behavior 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 CO2 sequestration.

5. Storage options
5.7 Longyearbyen CO2 Lab

By Alvar Braathen and coworkers

The Longyearbyen CO2 Lab in Svalbard, Norway, is one of the demonstration projects currently carried out worldwide. The purpose is to learn more about the CO2 behavior 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 CO2 sequestration.

Longyearbyen has a population of around 2,000 and is located in the polar wilderness of central Svalbard. 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 CO2 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 CO2. 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 successions rise 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 (700–875 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 CO2 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 CO2 Lab.
Monitoring of injected CO₂ in a storage site is important for two main reasons: 
Firstly, to see that the CO₂ is contained in the reservoir according to plans and 
secondly, to detect any abnormal behavior of the reservoir that may affect the 
storage formation induced by the injection process, and 2-dimensional 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 can be a result of natural processes, for example in active geothermal systems. 
Most research is focused on the impact of caprocks on the integrity of the storage 
reservoir, giving data on pressure build-up and CO₂ breakthrough. This is 
important as CO₂ is toxic and it needs to be stored safely. A number of surface 
monitoring techniques can be applied. 4-D seismic has proven most successful on the industry-scale 
offshore projects of Sleipner and Snadrød, yielding the geometry of the CO₂ plume with high resolution, while geomechanics has given complementary information on CO₂ in-situ density and dissolution rates in the formation water. Downhole, 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. Equip-
ment reliability and a system of documentation which works over a few spans of 
generations are also important for a monitoring program. With a proper moni-
A 4-D seismic survey is shown in the figure. Right: A 4-D seismic amplitude slice that shows the development through time of cumulative amplitude for all wells. 80% of the area of the CO₂ plume was about 3 km², and it was slowly growing.
A leakage of CO2 from a storage reservoir can result in a failure during injection or due to a natural leakage of CO2 from the seabed or along unforeseen pathways for fluid flow. Whereas the first would be detected by instrumentation at the injection sites, monitoring the latter is much more difficult.

The flow of fluids from the subsurface, across the seafloor and into the water column is strongly influenced by the behaviour of microbial colonies and the seafloor biota. AUVs and ROVs may also carry sensors that directly measure dissolved CO2 and CH4 in the water just above the seafloor. At present, these sensors lack the sensitivity as well as the 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 tools 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 CO2 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 CO2 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 CO2 storage reservoir rather than natural variations.

Seafloor monitoring programs are now being designed to detect CO2 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 high-resolution to detect topographic changes that might reveal the formation of new fluid escape pathways; 3) imaging of bacterial mats and fauna at seafloor sites to document environmental changes related to fluid flow across the seabed; and 4) high-definition camera systems to monitor the flux of gases into the water column.

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6. Monitoring

Wells

By: The Petroleum Safety Authority Norway

- A potential CO2 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 CO2. These wells can be abandoned wells as well as production, injection and disposal wells.
- Adjacent wells can have well integrity issues that might allow CO2 to leak into the surroundings.

There are challenges concerning the design of these adjacent wells, since they were not planned to withstand CO2. 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 CO2 injection wells is related to design of CO2 injection wells. This includes considerations related to CO2 resistant cement, casing, tubing, packers and other exposed downhole and surface equipment.

A common industry practice is abandoned CO2 injection wells and adjacent wells.

- Proposed ISO standard related to CO2 injection well design and operation.
- DNV “Guideline for risk management of existing wells at CO2 geological storage sites” (CO2WELLS)
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