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Independent assessment of high-capacity offshore CO2 storage options

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Executive Summary

Title :	Independent assessment of high-capacity offshore CO_2 storage options
Author(s) :	Filip Neele, Johan ten Veen, Frank Wilschut, Cor Hofstee
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In 2010, the Rotterdam Climate Initiative (RCI) contracted TNO Built Environment and Geosciences (TNO) to conduct an Independent CO_2 Storage Assessment (ISA) of offshore CO_2 storage sites under the Dutch North Sea. The aim of the ISA was to provide CCS project developers with greater certainty over the availability, technical viability, capacity and cost of utilizing prospective CO_2 storage sites. ISA Phase 1 screened for CO_2 storage in depleted offshore gas fields close to Rotterdam that might be available between 2015-2020, so as to support early CCS projects and to ensure that no good short-term options were overlooked. ISA Phase 2 then studied the best options in more detail. ISA Phase 3, the subject of the current report, extended this analysis to provide a comprehensive view of Dutch high-capacity offshore CO_2 storage.

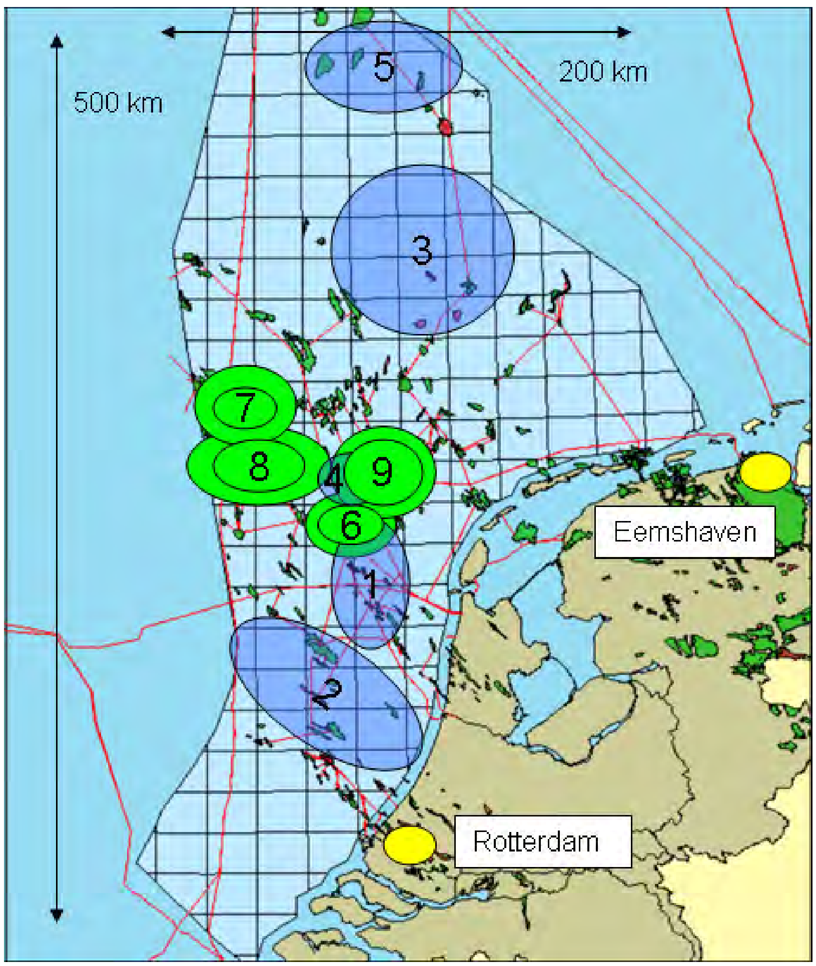
Objectives: the need for high-capacity CO_2 *storage*
One of the key findings of ISA Phases 1 and 2, as well as of previous studies of Dutch offshore CO_2 storage options, was that while a number of good short-term prospects exist, few have large enough storage capacities to accommodate the high CO_2 volumes envisioned for The Netherlands with the commercialization of CCS. ISA Phase 3 aims to provide greater certainty about the availability of high-capacity offshore storage to support the large-scale deployment of CCS on a commercial basis and to provide potential CCS project developers with greater confidence in the long-term viability of any projects they might pursue. These objectives gained even more importance with the delay of onshore CO_2 storage by the Dutch Government.

In doing so, ISA Phase 3 builds on previous studies, such as those by NOGEPA (2008, 2009) and by EBN – Gasunie (2010), in three key ways:

- Comprehensiveness: ISA Phase 3 extended existing data sets and its assessments to all potential storage options, including saline formations, gas fields and gas field cluster strategies, and oil fields and enhanced oil recovery (EOR) strategies. Special emphasis was placed on analysis of saline formations so as to find large connected volumes capable of storing CO_2, where previous studies only searched for structural traps for CO_2.
- Geological focus: ISA Phase 3 had a pure geological focus, meaning that results are independent of any constraints regarding location, timing of availability or the ability to re-use existing oil & gas infrastructure, further ensuring comprehensiveness and that no attractive option has been overlooked.
- Capacity focus: ISA Phase 3 focused on locating storage sites with potential capacities above 50Mt for saline formations and 40Mt for oil & gas fields, so as to identify new options attractive for medium and long-term use and to avoid reliance on complex strategies combining numerous small sites.

Key findings: a comprehensive view of offshore Dutch high-capacity CO_2 *storage*
In conducting ISA Phase 3, potential storage compartments were identified by combining data of subsurface faults, reservoir formation extension and thickness, and porosity maps with its knowledge of the geology of the Dutch Continental Shelf (DCS) for all relevant reservoir formations with good quality (i.e. good permeability) and an appropriate sealing layer on top. A database containing all sources of information used in ISA Phase 3, organised by site, can be made available to future investigations

This ISA Phase 3 report is an assessment of the best high-capacity storage sites for CO_2, as captured in the shortlist in the following table and as pictured in the following map. It is to be emphasised that the capacity and injectivity estimates for saline formations are far more uncertain than those for oil & gas fields, due to a much more limited amount of data, with one exception. Due to oil & gas production in the area and previous study in ISA Phases 1 and 2, estimates for the saline formation that contains the oil fields in the K18 – L16 – Q1 blocks are to a similar level of certainty as those for gas fields and gas field cluster.



Map showing the high-capacity offshore storage options identified in this study. The numbers correspond to the numbers in the table below (first column of table). Blue: saline formations; green: depleted gas fields. Larger green discs represent clusters of gas fields. Indicated on the map are the industrial areas Eemshaven and Rotterdam, where CCS is likely to start.

	Attractiveness				***Urgency***	
Field	**Capacity (Mt)**	**Plateau injection rates ($MtCO_2/yr$)**	**Distance from Den Helder (km)**	**Overall Complexity and Risk**	**Minimum Development Time**	**Next step to decrease uncertainty**
K14/15 (#6)	165 (54 for K15-FB)	3 [15-20 yrs] 6 [5-10 yrs] 9 [5 yrs]	60	Low – multiple fields and aging infrastructure, but low well integrity risks; single operator and well-known geology	6 years	Feasibility study
K04/05 (#7)	140 (40 for K05a-A)	2 [19 yr] 3 [12 yr] 5 [6 yr]	120	Low – Although multiple fields relatively modern infrastructure; late availability allows learning from earlier projects	6 years	Use best practices other projects (fields available well after other CCS projects assumed to be operational)
K07/08/10 (#8)	195 (130 for K08-FA)	3-6 [20+ yrs] 6-12 [10+ yrs] 9-18 [5+ yrs]	100	Moderate – multiple fields and ageing infrastructure, but relatively few blocks account for most capacity; several old, abandoned wells	6 years	Feasibility study, focus on abandoned wells
L10/K12 (#9)	175 (125 for L10-CD)	6 [17 yrs] 9 [10 yrs] 12 [4 yrs]	50	High – several risk factors identified	> 6 years	Feasibility study; immediate negotiations with operator (several fields close to end of production)

	Attractiveness					***Urgency***	
Saline formation	**Capacity (Mt)**	**First-order estimate injectivity**	**Overall uncertainty**	**Distance froms Den Helder (km)**	**Issues**	**Minimum Development Time**	**Next step to decrease uncertainty**
Q1 - Lower Cretaceous (#1)	110 - 225	Good: up to 10 Mt/yr	Medium (B/A)	40 km	Well integrity; possible re-use	5 years	Feasibility study of combination with EOR (Q1 and P9)
P, Q - Lower Cretaceous (#2)	360	Good: up to 10 Mt/yr	High (B)	60 km	Interference with h/c production.	6-7 years	Feasibility study (1 - 4 M€)
F15, F18 – Triassic (#3)	650	1-3 Mt/yr	High (B)	150 km	Interference with h/c production.; overpressure; low permeability	6-7 years	Feasibility study (1 - 4 M€)
L10, L13 – Upper Rotliegend (#4)	60	5 Mt/yt	High (B)	50 km	Interference with h/c production.	6-7 years	Feasibility study (1 - 4 M€)
Step graben – Triassic (#5)	190	1-3 Mt/yr	High (B)	200 km	Interference with h/c production.; low permeability	6-7 years	Feasibility study (1 - 4 M€)

Next Steps: ensuring adequate CO_2 storage to underpin CCS commercialization
As can be seen in the preceding table, there are several attractive high-capacity storage options for CO_2 on the DCS, including several saline formations that had not previously been identified. While this should be encouraging to CCS project developers and other stakeholders, it is important to note that the estimates for the saline formations are particularly uncertain due to data limitations and thus prone to downward revision with further study.

Nonetheless, it is worth pursuing a number of these options due to their high strategic value and attractive initial assessments. Furthermore, near-term action will be required to ensure the possibility of some or all of them being available to future CCS projects, a particularly important consideration for saline formations. The low amount of geological data currently available for saline formations and their lack of existing infrastructure means that realistically, most of them could take at least 6-7 years to develop to the point at which CO_2 injection would be possible and that data acquisition needs to begin now if they are to be viable by 2020 - 2025.

With this in mind, it is recommended, based on the conclusions of ISA Phase 3, to define a set of actions, to leverage the results of the ISA. This should be done together with the ISA Steering Group, which is composed of the seven large Netherlands-based emitters most advanced in their thinking about potential CO_2 capture projects. Relevant criteria include:
- Relative attractiveness of potential storage sites, taking into consideration location, potential capacity and injectivity, and site-specific risks;
- Urgency of next steps, taking into consideration the current levels of data (and in the case of oil & gas fields future levels of data) and the implications of realistic development timelines for what impact current actions will have on the future availability of specific sites; and
- Returns on investment, taking into consideration what the next step for each site would cost versus the contribution each next step would make to the current understanding and future availability of each site.

The database developed for the ISA studies will be available to future CO_2 storage feasibility assessment work, subject to confidentiality requirements associated with elements of the database.

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Appendices

A Site development
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1 Introduction

In early 2010, the Rotterdam Climate Initiative (RCI) contracted TNO Built Environment and Geosciences (TNO) to conduct an Independent CO_2 Storage Assessment (ISA) of offshore CO_2 storage sites under the Dutch North Sea, so as to support the early deployment of carbon capture and storage (CCS) in the Netherlands. The ISA was conducted in three phases, with this report summarizing Phase 3. Phases 1 and 2 are covered in two previous reports, one detailing the methodology employed (*Neele et al., 2011a*) and one presenting the results (*Neele et al., 2011b*).

As a whole, the ISA studies are intended to provide a comprehensive view of potential offshore CO_2 storage, with the specific goals of:

- ensuring that planning for CO_2 storage does not lag planning of other portions of the CCS value chain;
- identifying and progressing work on several potential CO_2 storage sites, to provide sufficient alternatives should individual sites prove to be unavailable on desired timelines or prove less attractive during later stage work;
- providing greater certainty among emitters regarding storage availability and capacity, enhancing their confidence in planning CO_2 capture projects; and
- providing good, harmonized data for emitters to use in their planning and in applying for funding for CCS projects.

ISA Phases 1 and 2 sought to support first-mover CCS projects by providing detailed assessment of the most promising prospective CO_2 storage sites available between 2015-2020. In doing so, Phase 1 screened the P and Q bocks close to Rotterdam to identify the most attractive options and to ensure that no good short-term prospects had been overlooked. Phase 2 then characterized the four most attractive prospects in greater detail, including feasibility-level analysis of their technical viability, capacity, availability and cost, as well as key actions and risks to bring each site operation.

ISA Phase 3 broadens Phase 1 and 2 screening to underpin longer-term CCS deployment, seeking to identify high-capacity CO_2 storage sites throughout the entire Dutch Continental Shelf, irrespective of their location and of the timing of their availability. High-capacity sites were targeted because, while ISA Phases 1 and 2 successfully identified several near-term prospects, these sites do not represent sufficient CO_2 storage capacity for the volume of CO_2 capture anticipated with the commercialization of CCS, a concern that has grown in strategic importance for emitters throughout the Netherlands with the Dutch Government's prohibition of onshore CO_2 storage.

Specific objectives of ISA Phase 3 were to:

- screen for and identify high-capacity CO_2 storage sites in the Dutch North Sea that could accommodate increasing volumes of CO_2 from early demonstration projects and the long-term needs of commercial CCS in the Netherlands;
- consider all potential structures, including depleted hydrocarbon fields and saline formations, purely from a geological perspective;
- develop a comprehensive and quality set of data for use in future analysis, commercial planning and strategy formulation;

- identify data gaps, constraints and other areas for further investigation; and
- find ways to circumvent data availability barriers and infrastructure assumptions that constrained previous studies.

Special emphasis was placed the comprehensiveness of Phase 3, particularly in assessing potential to store CO_2 in saline formations, which had not been covered thoroughly in studies prior to the ISA, due to gaps in available data.

What follows is a more detailed discussion of these findings.
- Section 2 describes the general approach used in ISA Phase 3.
- Section 3 gives a brief overview of the geology of the Dutch Continental Shelf (DCS).
- Section 4 describes the offshore deep saline formation CO_2 storage options.
- Section 5 describes offshore gas field CO_2 storage options.
- Section 6 describes the potential for CO_2-EOR in the Netherlands.
- Finally, Section 7 pulls the results of the preceding sections together to assess the best high-capacity offshore storage options in the Netherlands and make recommendations for next steps based on these findings.

The development of a saline formation for injection and storage of CO_2 is described in Appendix A; a comparison is made with the steps required to convert (the installations of) a depleted gas field for CO_2 storage. The data used in this study, which together form the data mentioned above for use in future analysis, are described in Appendix B.

2 Screening study criteria and approach

2.1 Screening criteria

As stated in the Introduction, the key objective of ISA Phase 3 is to screen for high-capacity, offshore CO_2 storage options, to accommodate increasing volumes of CO_2 from early demonstration projects and support the long-term needs of CCS deployment in The Netherlands. In doing so, Phase 3 screened all potential geological structures, including saline formations and depleting hydrocarbon fields in the entire Dutch Continental Shelf as indicated in Figure 2-1.

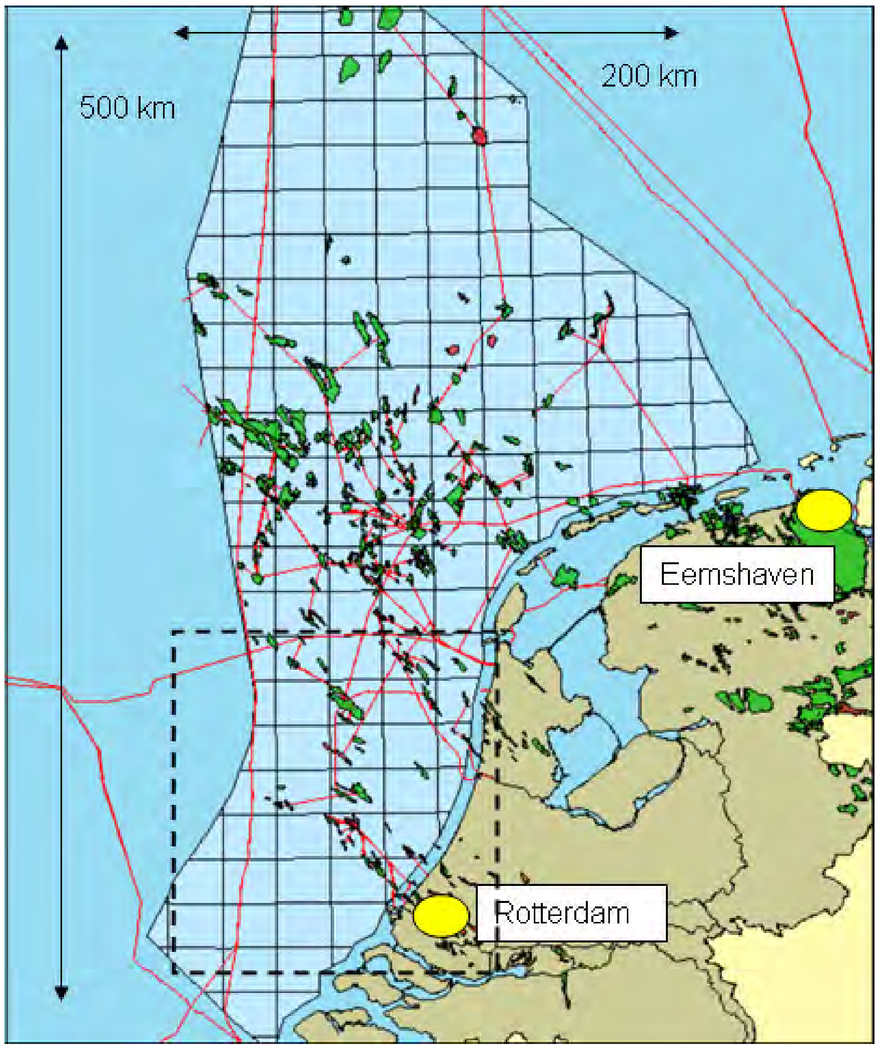

Figure 2-1 Map of the Dutch Continental Shelf (DCS), with gas fields indicated in green and oil fields in red. The yellow circles show the location of Rotterdam and Eemshaven; the dashed box indicates the area covered by ISA Phases 1 and 2 (the P and Q blocks).

To narrow the focus of the screening process on high-capacity sites, lower CO_2 storage capacity thresholds were set at 50 Mt for saline formations and 40 Mt for gas fields. These arbitrary limits were selected based on a review of existing storage capacity rankings of gas fields on the DCS by size. While there are very many gas fields on the DCS, only a handful have a storage capacity larger than 40 Mt, so anything in excess of this was considered relatively interesting. No capacity threshold was set for the screening of oil fields, because there are very few in the entire DCS.

A short discussion of the general approach taken follows. A more detailed discussion of methodology can be found in the relevant sections of this report: Section 4.2 for saline formations, Section 0 for gas fields, and Section 6.2 for oil fields.

2.2 Approach

2.2.1 Saline formations

The approach taken in the screening for saline formations suitable for CO_2 storage is different from that used in previous studies. While a previous study of the same region screened for structurally favourable (parts of) saline formations, such as local anticlines (dome structures), that would trap the CO_2 (*TNO, 2007*), in the present study the intention was to identify large, connected volumes (compartments) of saline formations.

To find these volumes and to assess the feasibility of storage, a number of elements were combined:

- Structural models of the deep geology, revealing the occurrence and extent of potential reservoir formations (see Section 3 for a description of these formations);
- Maps of faults intersecting the reservoir formations, which define compartment size;
- Knowledge of the behaviour of gas fields located in these formations, as an independent indicator of the size of compartments;
- Knowledge of the geological history of the area, providing information on reservoir quality (which defines the storage rates, in Mt/yr).

The result from this approach is a number of compartments within the potential storage formations that could be used for CO_2 storage. Possible migration of the CO_2 within a storage compartment is to be addressed as part of a more detailed analysis of each compartment. Given the large size of the compartments screened for here, it is considered likely that a structurally favourable location can be found in each compartment. Such locations include, for example, dome structures, as mentioned above, locally elevated reservoir formation bounded by (impermeable) faults or by salt domes. It is understood that any such location should be at a depth of about 1000 m or more, to ensure efficient storage of CO_2 in a dense phase.

It is noted that the injection into the Utsira formation (the Sleipner project) takes place in a formation that is almost horizontal. A good seal is present over almost the entire formation. A similar situation, regarding the seal, exists for the reservoir formation below the thick salt deposits in the central part of the offshore. This reservoir formation contains most of the offshore gas fields.
Although this formation is strongly compartmentalised, the presence of the sealing salt layer suggests that injection into a nearly horizontal layer might be done in the

DCS as well. This study screens for such options in the DCS, not only in the sub-salt layers, but also in other potential reservoir formations.

The implicit assumption in the present study is that storage capacity is created by increasing the pressure in the formation and using the compressibility of the reservoir system. As a result, due to the limited compressibility of reservoir rock and fluids, [structurally] large compartments are required to meet the lower screening threshold of this study An alternative approach would be to assume the production (extraction) of the saline formation fluids to be replaced with CO_2. This has the advantage that even a relatively small compartment can provide a large storage capacity. However, it is currently not clear whether this assumption is realistic and feasible as the ease with which the formation fluids can be disposed of will, inter alia, depend on their [particular] composition. The capacity figures reported here can therefore be seen as conservative estimates; higher storage capacities can be reached, but only when formation water production is feasible.

2.2.2 Depleted gas fields

The gas fields in the DCS have been well documented in previous studies, including in previous phases of the ISA. With the exception of setting a minimum storage capacity threshold of 40 Mt, the approach taken in ISA Phase 3 is identical to that taken in ISA Phase 1 and is described in detail in *Neele et al.* (2011a).

2.2.3 Oil fields

Finally, a brief review of options for CO_2-EOR in offshore oil fields was made, focusing on potential combinations of EOR with CO_2 storage options. The suitability of the individual oil fields for EOR, for which guidelines were set out Chapter 5 of the IPCC Special Report on Carbon Capture and Storage[1] (IPCC, 2005), was not investigated.

3 Saline formations in the Dutch subsurface

3.1 Introduction

Saline formations[1] are deep underground rock formations that consist of porous materials which are permeable and contain highly saline fluids, and are potential host sites for gas. However, only small parts of these saline formations contain natural gas and potentially the storage capacity for CO_2 reaches beyond the capacity of the depleted gas fields. Nonetheless, saline formations have to date been studied in significantly less detail relative to gas and oil reservoirs and there continues to be major uncertainties concerning all of their properties and suitability for CO_2 storage.

3.2 Geological background

A great variety of proven hydrocarbon plays and trap styles are present in the middle Paleozoic to Quaternary sedimentary succession of the Netherlands. This succession has been deformed during several periods of tectonic activity. This tectonism led to a structuration into numerous structural elements. Here the term 'structural element' is assigned to regional structures with a uniform deformation history in terms of subsidence, faulting, uplift and erosion during a specific time interval. A first order classification of these elements distinguishes between highs, platforms and basins. A *high* is defined as an area with significant non-deposition and erosion down to Carboniferous or Permian strata (Rotliegend and/or Zechstein). A *platform* is characterized by the absence of Lower and Upper Jurassic strata due to Late Jurassic erosion down to the Triassic. The term *graben* is used for basins that are clearly delineated by major faults and where, in general, Jurassic sediments are preserved. For both platforms and basins, a further subdivision has been made. Platforms may represent 1) areas where Cretaceous rocks overlie Triassic rocks or 2) areas where Cretaceous rocks lie directly on top of Permian sediments. Structural elements are often bounded by fault zones/systems. Therefore the main fault systems are included in the structural elements (Figure 3.1). In this section reference is made to these structural elements.

Most hydrocarbon discoveries in the Mesozoic sequence overlying the Permian Zechstein Group (ZE, Figure 3.2) , are located in structural traps that have been formed in response to salt tectonics (Remmelts, 1996). Either the traps are formed adjacent to salt structures, are fault-bounded, or a combination of both. Below the Zechstein Group, the largest Dutch natural gas occurrences reside in Rotliegend reservoirs, which are located in structural traps that consist of tilt-block geometries commonly sealed by Zechstein salt. Thus sub- and supra salt faults and salt structures play an essential role in the formation of confined reservoirs or aquifers. The Zechstein salt plays a key role in the structural style of the subsurface. Where the original salt thickness exceeds ~300 m (ten Veen et al., 2012 *in prep.*), the salt it acts as a decollement level, meaning that faults generally do not penetrate the salt. For this reason the subsurface can be broadly divided in northern- and southern offshore domains, which are generalized in N-S cross-section through the Dutch offshore (see Figure 3-3 and Figure 3-3).

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[1] In literature saline formations are also referred to as saline aquifers or just aquifers

This subdivision also coincides with the distribution of the major sub salt Rotliegend reservoirs, which are importantly linked to the presence of a thick and unfaulted salt seal.

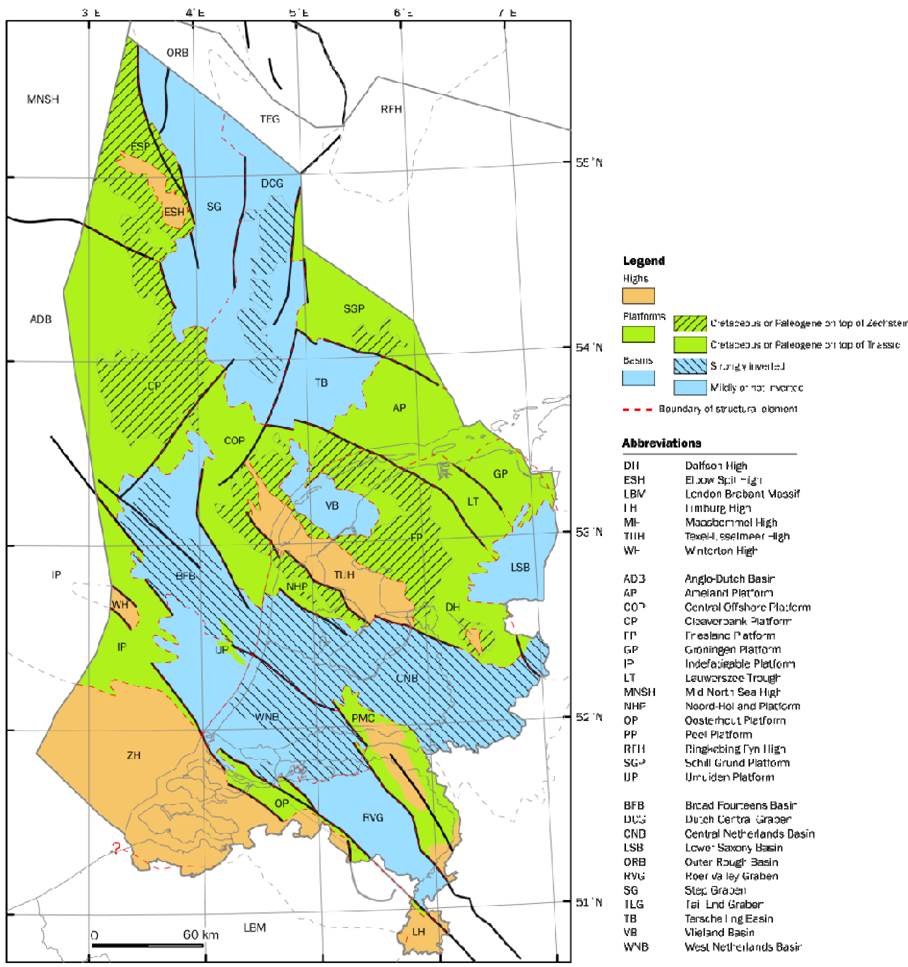


Figure 3-1 Structural elements in the Netherlands.

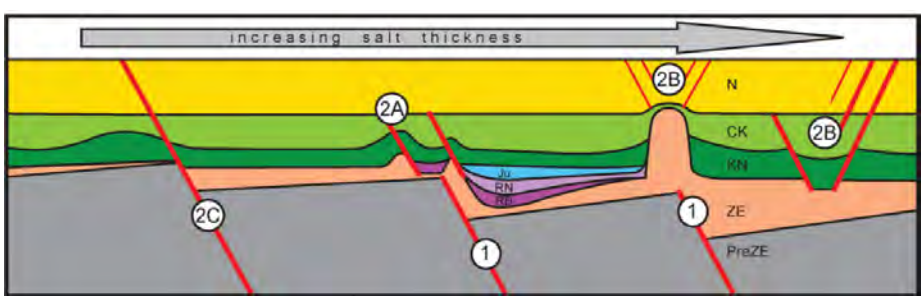


Figure 3-2 Illustration showing a general N-S section through the Dutch North Sea. From S (left) to N (right) original salt thickness and salt structure height increases. Adapted from Ten Veen et al. (2012, in press).

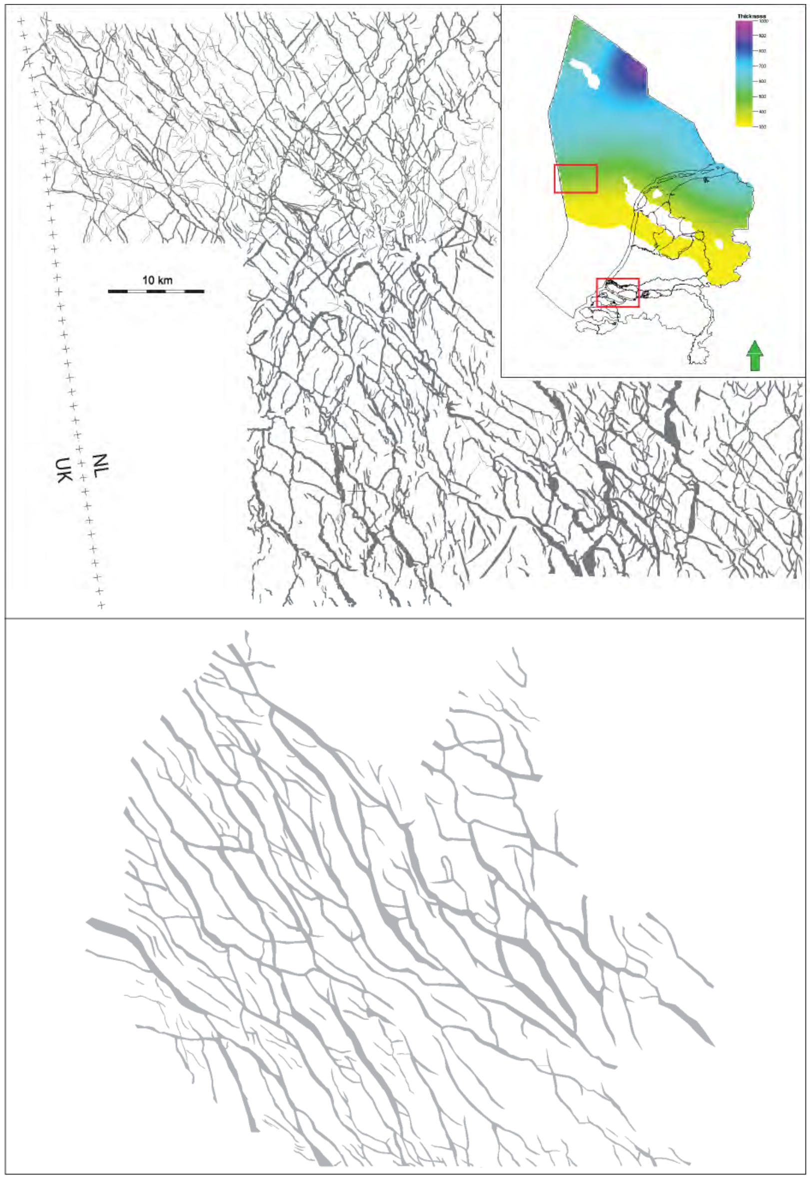


Figure 3-3 Examples of fault styles in areas with (upper)- and without (lower) thick (>300 m) Zechstein salt in the northern and southern offshore, respectively (see inset for thickness distribution; after Ten Veen et al., 2012). The northern offshore is characterized by a rhomboid fault pattern, whereas the southern offshore shows an anastomosing fault arrangement (modified from De Jager, 2007).

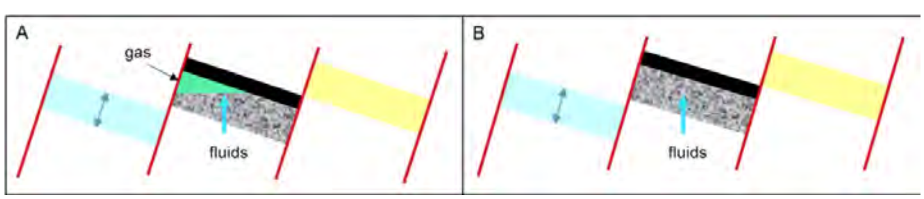


Figure 3-4 A) Gas reservoirs ("proven aquifers") indicated by gas accumulation (green) vs. B) saline formations. Both proven aquifers and saline formations need to be vertically sealed (black layer) and laterally confined.

3.2.1 Northern offshore domain

Below the Zechstein salt, at the level of the Rotliegend, many structural elements show a characteristic rhomboid pattern of intersecting fault trends. The dominant family of faults trends NW-SE; the second most common fault trend is aligned NESW to ENE-WSW. Both trends were already in place prior to Rotliegend and Zechstein deposition (Ziegler, 1988, 1990) and their presence in younger intervals results from fault reactivation. The fault intersections generally do not indicate consistent offset geometries, and it is likely that both trends were reactivated several times more or less simultaneously. In the northern offshore, the NW-SE fault trend becomes less important and N-S faults paralleling the Dutch Central Graben (DCG) and Step Graben (SG) dominate. In the northern sector of the Broad Fourteens Basin (BFB[2]) and on adjacent platform areas, 3D seismic data clearly show NW-SE and NE-SW fault trends at Rotliegend level, with secondary faults trending WNW-ESE and N-S. Apart from the better imaging of these faults on the platforms (which are located at shallower depth), there presumably is no significant difference between the basin and the platforms in the directions and spacing of faults.

3.2.2 Southern offshore domain

The structural style in the southern domain is well studied in the West Netherlands Basin and to a lesser extent in the BFB basin. Faults commonly penetrate the entire Rotliegend to Cretaceous sequence and show a characteristic anastomosing pattern of dominant WNW-ESE and NNW-SSE, and secondary N-S and E-W directions. Many of the structures are inverted in complex fault patterns. Since the Zechstein salt is absent, gas could have migrated into stratigraphically younger aquifers.

3.2.3 Gas fields vs saline formations

Judgments about storage potential of saline formations are mainly based on knowledge of “proven” aquifers, most of which contain hydrocarbon accumulations and few are water producing only. All the hydrocarbon-bearing aquifers (“reservoirs”) share the property that they are vertically (or laterally) sealed by impermeable layers, such as salt or clay and are laterally confined by faults or folds (Figure 3-4). Since, these rules for vertical and lateral confinement apply to CO_2 storage as well, in this screening only those formations are considered.

Although most gas in the Netherlands is contained in the Permian, Upper Rotliegend sandstones, other hydrocarbon plays, ranging from Carboniferous to Quaternary, are present as well (Figure 3-5). Triassic plays are second in importance with respect to proven gas volumes. Additional gas reserves are in Permian Zechstein carbonates, Jurassic and Cretaceous sandstones as well as in shallow unconsolidated sands of Tertiary and Quaternary age. Producible oil occurs within the Late Jurassic and Early Cretaceous rift basins (“grabens”) in a variety of sandstone reservoirs and trap styles. Only minor amounts of oil have so far been found in the Upper Cretaceous chalk (Figure 3-5).

In this screening the Carboniferous reservoirs are not considered, because the knowledge on their distribution is too scarce. These reservoirs generally occur at greater depths and are poorly imaged in seismic data. The Zechstein reservoirs

[2] Figure 3-1 contains a table with abbreviations for the different structural elements that are identified in the DCS.

(predominantly Z3 carbonates) units (almost) exclusively occur onshore the Netherlands and are therefore not considered herein.

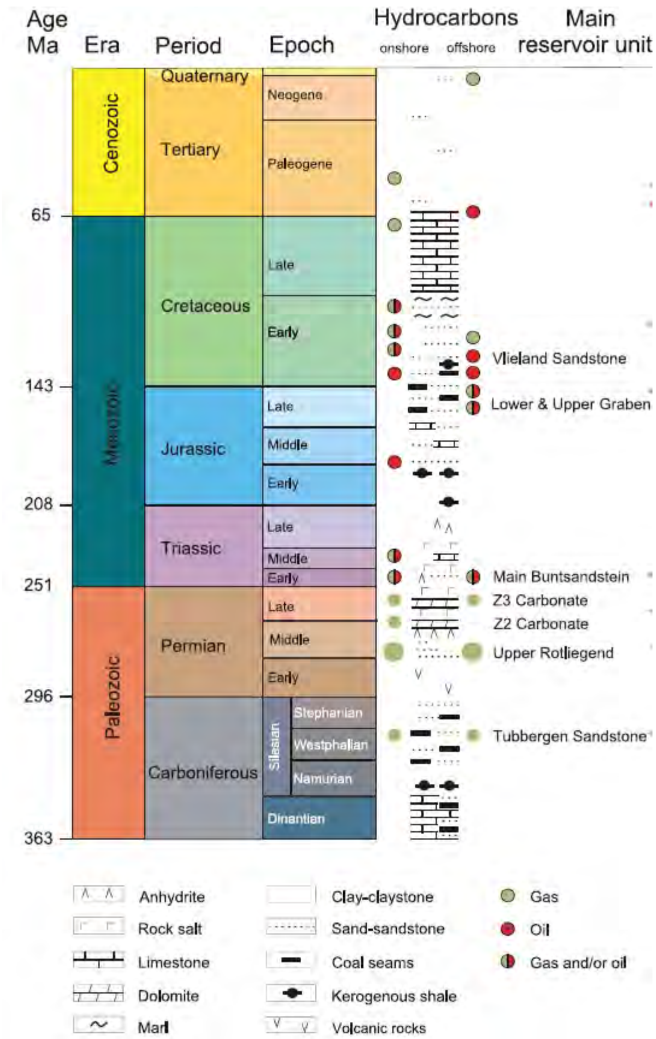


Figure 3-5 Reservoir units in the Dutch subsurface (modified from de Jager & Geluk, 2007).

3.3 Saline formations

3.3.1 Rotliegend

Characteristics (Figure 3-6):

- Includes Lower and Upper Slochteren sandstones formations with different areal extent. In the north the two are separated by the Silverpit Claystone, whereas in the south the Slochteren sandstones are continuous.
- Porosity is strongly coupled to distribution of sedimentary facies
- Top is the base of the Zechstein (red line) in Figure 3-6
- Where the Ten Boer Claystone (uppermost part Rotliegend) is sufficiently shaly, it provides a seal in fault juxtaposition increasing potential aquifer size.
- Most faults cutting the Rotliegend sand are sealing.

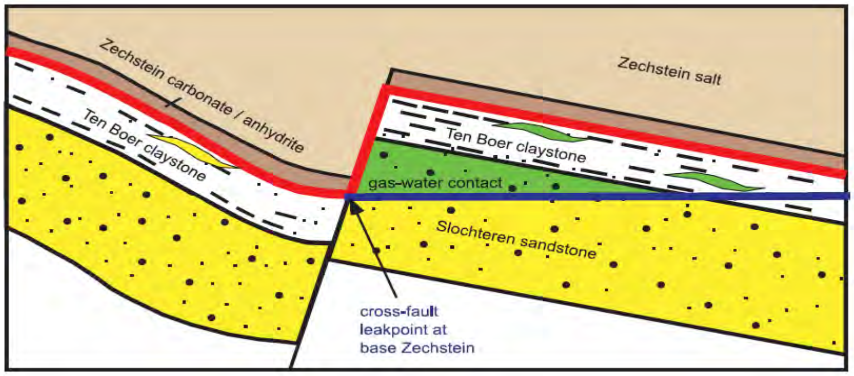


Figure 3-6 Typical reservoir in the (Rotliegend) Slochteren sandstone Formation with Zechstein top seal.

3.3.2 Triassic

Characteristics southern offshore:

- The Main Buntsandstein reservoir (Figure 3-7A) consists of a series of stacked reservoirs and includes the Lower and Upper Volpriehausen and the Lower and Upper Detfurth Formations that are commonly in vertical communication.
- Compartments are confined by faults

Characteristics northern offshore:

- The Main Buntsandstein reservoir (Figure 3-7B) consists of a series of stacked reservoirs and include the Volpriehausen sandstones, which is commonly in communication with a Middle Triassic sandstone, the Basal Solling that only locally exceeds 10 m in thickness.
- Gas is trapped in four-way dip-closed structures above salt swells or in turtle-back structures. Where the Triassic is truncated at the Base Cretaceous Unconformity, Lower Cretaceous marine shales may provide the seal.

3.3.3 Upper Jurassic – lower Cretaseous

Characteristics southern offshore:

- Several aquifer units are in communication (Figure 3-8) and can be considered as one continuous stacked unit
- The Upper Jurassic and Lower Cretaceous oil and gas plays of the Broad Fourteens Basin are essentially the same as in the West Netherlands Basin, with the same source rocks and reservoir sandstones

Characteristics northern offshore:

- Traps in the graben occur as four-way dip-closures in turtle-back structures (Figure 3-8B) and as tilted fault blocks. The southern sector of the graben has been more strongly inverted, resulting in greater structural complexity and compartmentalisation of the traps.
- Apart from structural characteristics, reservoir distribution is another important factor in these syn-tectonic sequences that have been deposited in fluvial, deltaic and lagoonal environments.
  This is in particular the case in the south of the DCG, where there are great variations in sand to shale ratios, and where individual sands seem to have a limited lateral extent.

- In the Waddenzee area of the Vlieland Basin, the Zuidwal field produces gas from the Vlieland Sandstone Formation in a drape structure over an Upper Jurassic volcanic complex (Perrot & Van der Poel, 1987; Herngreen et al., 1991).
- Generally, it can be stated that reservoirs are not in communication and have separate hydrocarbon-water contacts.

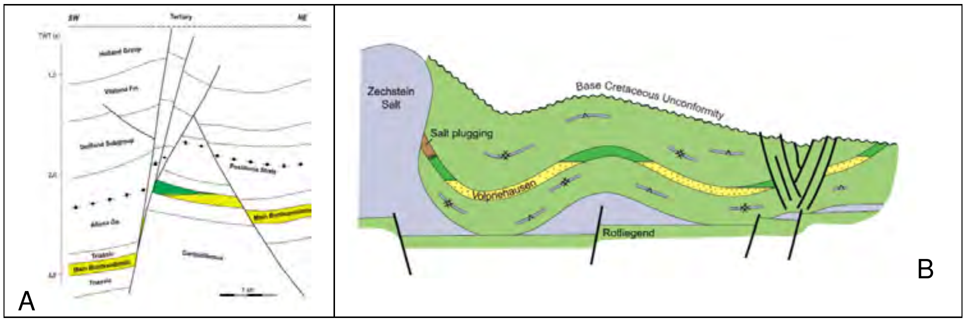


Figure 3-7 Aquifer styles in the Triasic of A) the southern offshore (example from West Netherlands Basin) and B) the Dutch central Graben in the northern offshore (based on De Jager en Geluk, 2007).

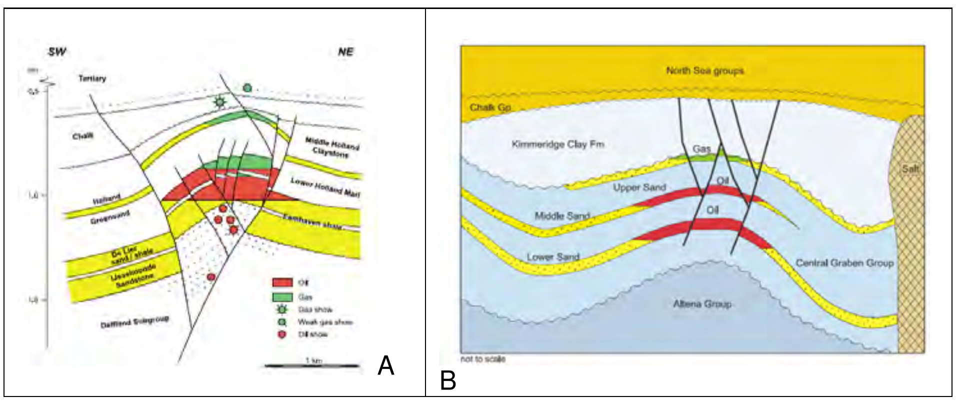


Figure 3-8 Aquifer styles of the Upper Jurassic – Lower Cretaceous reservoirs. A) the southern offshore - example of a trap in the Upper Jurassic and Lower Cretaceous in the West Netherlands Basin (IJsselmonde-Ridderkerk field). Several stacked reservoirs are present. B) the northern offshore – example of the F3-FB field in the north of the Dutch Central.Graben. Three main Upper Jurassic sandstone reservoirs are present in a faulted four-way dip-closed turtle-back structure (based on De Jager en Geluk, 2007).

4 Storage capacity in saline formations

4.1 Introduction

This section presents a screening of all confined saline formations in the Dutch part of the North Sea such as defined in chapter 3. Other than estimated CO_2 storage capacity, the selection criteria applied for saline formations in this study are mainly based on the extent and thickness of the formations, their average porosity, and the nature of the confinements. This information is enhanced with knowledge on offshore gas field properties to reduce the wide range of uncertainties that are relevant for the screening process. Consequently, in addition to the methodology and data sources, special attention will be paid to these uncertainties and how they affect the screening result and the estimated timeline for further characterisation of the aquifer before CCS development can take place.

As mentioned in Section 2.2.1, the approach taken here is to search for large, connected volumes (compartments) of saline formations, rather than for structural or stratigraphic traps for the CO_2 plume. The result from this approach is a number of compartments within the potential storage formations that could be used for CO_2 storage. The issue of migration of the CO_2 within a compartment is left to be addressed later, as part of a more detailed analysis of each compartment. Given the large size of the compartments presented here, it is considered likely that a structurally favourable location can be found in each compartment, where the CO_2 plume will migrate after injection. Given the experience at the Sleipner site, with injection in the horizontal Utsira formation, the approach used here will result in a more complete inventory of potential storage structures, compared to the approach that just looks for structural traps.

4.2 Storage capacity estimation method

Storage capacity (in Mt) is defined by:

$$SC = 10^{-9}\, h\, A\, \square\square\, e\, \square CO_2$$

in which:

SC storage capacity (Mton)
h height (m)
A area (m²)
□ porosity (net to gross is also represented in the total porosity)
e storage efficiency, here considered 2%, based on Vangkilde-Pedersen et al. (2009).
$\square CO_2$ density of CO_2 at supercritical (reservoir) conditions (for simplicity taken constant here at 700 kg m^{-3})

In this screening study *e,*□□□ and $\square CO_2$ are considered constant and thus the storage capacity is solely influenced by the volume of the confined aquifer compartments. The storage efficiency also incorporates aquifer heterogeneities.

The value of 2% for the storage efficiency is an approximation of the storage space that can be created by increasing the pressure in the formation, using the compressibility of the reservoir and fluids. This value of 2% has been used in compiling a database of saline formation storage capacity options in Europe (Vangkilde-Pedersen et al., 2009) and is compatible with (if at the lower end of) the range of storage efficiency factor used for the offshore saline formations in the storage atlas of the Norwegian continental shelf (NPD, 2011).

4.2.1 Aquifer connectivity across faults

In the screening process it is assumed that aquifers are delineated either by faults or by their natural (depositional) distribution. The scope of this study is confined to the Dutch,subsurface and as such, any aquifer units that extent beyond the Dutch sector of the North Sea continental shelf, have been altogether excluded from this assessment as there is currently no information available to TNO on the conditions across the border(s).

In order to screen the aquifer connectivity across faults, the juxtaposition relationships between aquifer compartments is evaluated (for those faults present at the level of the aquifer considered). The following assumptions are made:

- Only simple and single fault planes exist
- Potential seal attributes (smear, cataclasis, and cementation) are not taken into account. However, for the Rotliegend aquifers it is known that many if not all faults are sealing due to cataclasis.
- Stacked aquifers (see previous section) are added up, so that the possibility of connectivity between individual aquifer layers is honoured.

The following five (Figure 4-1) connectivity classes are discerned for saline formations other than the Rotliegend, i.e. for those formations where faults are non-sealing due to cataclasis and across which juxtaposed compartments are likely in communication:
0 = not faulted (undefined)
1 = partially connected
2 = fully (100%) connected (no fault throw, though faulted)
3 = fully unconnected (juxtaposition seal)
4 = stacked reservoir connectivity
Faults can be displayed according their juxtaposition style as shown in Figure 4-2.

In hydrocarbon exploration, the reservoir capacity in tilted fault-blocks is determined by the structural spill point, which in case of juxtaposition fault seal (see Figure 4-1) is at the structural lowest point of the aquifer. This means, that if the aquifer is sealed across the fault, theoretically the entire aquifer pore volume can be regarded as storage capacity. Here, CO_2 injection cannot occur below the spill point. In more complex structures where folds and faults are combined or where aquifers are partially juxtaposing (and faults are not sealing), the structural spill point may be higher. CO_2 injection below spill point would then result in flow across communicating compartments. This connectivity is directly related to the connectivity class assigned to the fault.

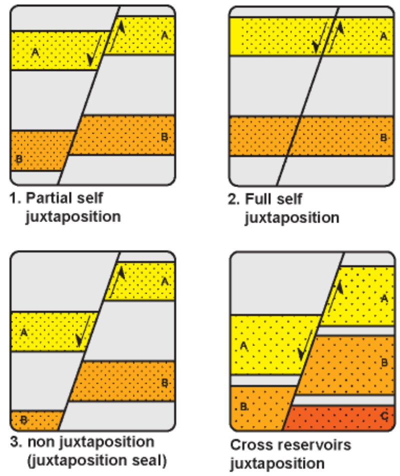


Figure 4-1 *Juxtaposition styles*

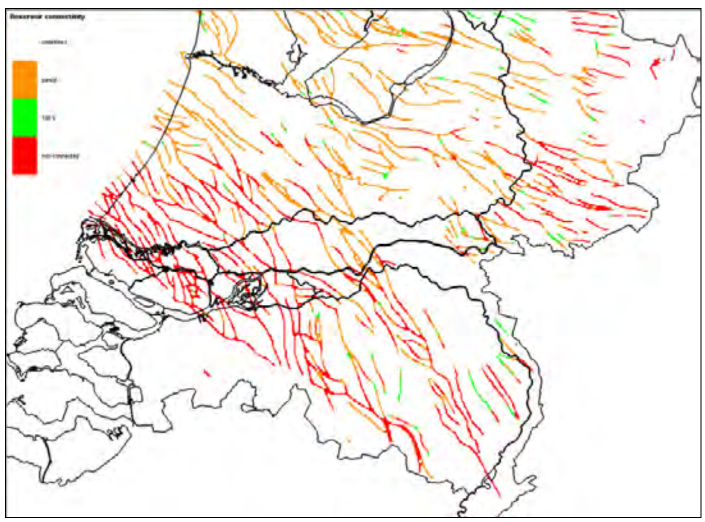


Figure 4-2 Fault map with juxtaposition attribute indicated by different color-coding. (example of the Rotliegend Upper Slochteren Fm.- onshore)

Figure 4-3 Connected reservoirs for the the Rotliegend Upper Slochteren Fm – onshore example

4.2.2 Aquifer compartments identification and classification

Based on the juxtaposition styles determined, the connectivity of compartments on either side of the fault can be evaluated. If faults are assumed to be sealing, as would be the case for most sub Zechstein salt, most compartments are delineated by the observed faults. The connected volume method (functionality of Petrel©) “traces” the extent of a compartment until is hits a fault or its outer limits. Each connected volume is given a different colour and is ranked numerically based on its volume (Figure 4-3), which is given as output parameter. These compartment volumes are input to the storage capacity equation given in Section 4.2.

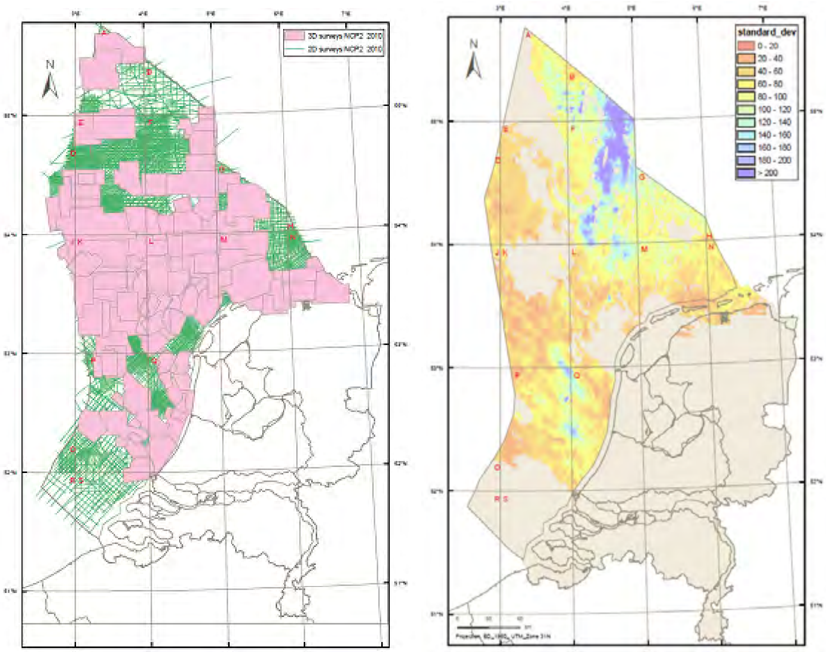
4.3 Data used

The following sections describe the data used in the screening for candidate reservoirs for CO_2 storage; Appendix B provides a summary of the data.

4.3.1 Reservoirs/aquifers

For the Dutch offshore, the distribution of those aquifers that are potential hydrocarbon reservoir are taken from the NCP2 mapping program (see www.nlog.nl). For this regional mapping project all available non-confidential 3D seismic surveys have been used to interpret the boundaries of ten major stratigraphic units, from the Late Permian Upper Rotliegend Group up to the Neogene Upper North Sea Group. Areas not covered by 3D seismic surveys are filled with interpretations from 2D seismic surveys (Figure 4-4A). In general, every 10th to 20th inline and crossline has been interpreted in the 3D surveys, corresponding to a 250 m resolution. The workflow is common practice in oil and gas exploration and includes the interpretation of horizons and faults from 3D and 2D seismic data in time domain (two-way traveltime) and the subsequent conversion to the depth domain using a velocity model built from well log and check-shot data.

Many aquifers units can be thin (less than about 10 m) and deriving their thickness from seismic data may be difficult, due to limited resolution in these data. Therefore, depth and thickness maps have been constructed for the most important aquifer horizons in the offshore by integrating stratigraphic well log, seismic and fault interpretations. The first step in this process is to select the appropriate wells to calculate the (true vertical) thickness of the aquifer horizon. The second step includes plotting of the wells in map view. When both the wells where the aquifer is present and absent are displayed, the areas where the reservoir is present can be delineated. Based on this information, polygons have been constructed within which the interpolation (aquifer depth and thickness) is performed. Major faults have been used to delineate the polygons. The third step involves a further selection of wells where the aquifer is presumed present. If the base of the aquifer is also the base of the mapped horizon the latter has been taken as the base of the aquifer to keep the model consistent. The same applies to aquifers that occur on top of each other, for example the Triassic sandstones of the Lower and Upper Volpriehausen sandstones. When modelled separately, the top and the base of respectively the Lower Volpriehausen and Upper Volpriehausen might intersect. Since the model has to be geometrically correct (no overlapping boundaries are permitted), the base of the upper aquifer is maintained and used as the top of the underlying one.



A B

Figure 4-4 A) Distribution of public 2D (lines) and 3D (cubes) seismic data, B) Uncertainty (Standard deviation) of the depth of the base of the Lower Germanic Trias Group

4.3.2 Faults

The NCP mapping program focussed on mapping of significant faults as well. Significant faults are those faults that have a visible offset of the interpreted seismic horizons, which are traceable over a certain distance, and which are important in terms of structuration. For the offshore area around 3800 faults were interpreted, depth converted and stored in a fault database. The offshore of the Netherlands has been subdivided in 7 smaller subareas (NCP-2A-G). Fault models were built for each of these subarea sand resulting grids and fault lines are published on NLOG (www.nlog.nl). In total a selection of about 2500 faults were incorporated in the models.

4.3.3 Approach to porosity, permeability

Estimating aquifer storage potential (see section 4.2.) requires information on the aquifer porosity. Due to variations in grain size, sediment composition (clay content), depth (and thus compaction) the porosity may vary considerable. For both the Rotliegend and Triassic aquifers porosity distribution maps are available. For other aquifer levels, average porosity values are used. These porosities vary within the range of 10-30% and volumetric errors imposed by adopting an average porosity can amount to 50%.
Permeability (k) is a measure of the ability of rocks to transmit fluids. Variations of permeability are not explicitly taken into account, but taken are incorporated in the storage efficiency factor.

4.3.4 Additional data and knowledge on offshore gas fields properties

In general, it can be stated that the more data on the described building blocks are available, the better the storage feasibility assessment can be performed. Thus, any data that can contribute to improvement of the assessment should be used. For this study these include:

- In-house knowledge on production issue in proven aquifers;
- Pressure / overpressure conditions of aquifers;

Where applicable this information is presented in the sections on the screening of saline formations.

4.4 Uncertainties, limits

The thickness and distribution of the aquifer units are uncertain to some extent, as are the number and extent of faults cutting the aquifers, and the continuity of seals. Propagation of these uncertainties may results in errors that are difficult to quantify but which will be addresses in the aquifer screening results.

4.4.1 Reservoir thickness and distributions

The methodology described above concerns a deterministic mapping workflow. It produces best estimates of depth/thickness based on the interpreter's insight of where data is available. In areas without data the depths are estimated using standard interpolation algorithms. This method produces geologically sound maps but does not provide information concerning the reliability of the obtained depths and thicknesses.

Four sources of error exist:

1) *Data error* - This error takes into account any error related to the picking of a horizon within a seismic dataset including processing errors, vertical shifting errors and resolution errors (see example in Figure 4-4B). A larger error is assumed for picks traced from 2D seismic than from 3D seismic. Below seismic resolution, reflections from the sand top and base maintain a constant temporal separation which is unrelated to the true thickness. This separation is called the tuning thickness, i.e., the bed thickness at which two events become indistinguishable in time. The tuning thickness is equal to 1/4 of the wavelength and depends on the seismic frequency and interval velocity of the formation. The publically available seismic data used for the NCP2 mapping program generally has a frequency of 60 Hz, which means that with average interval velocities for sandy formations (2500 ms^{-1}) formations with a thickness of less than about 15 m are not properly distinguishable. Tuning thicknesses commonly increase with depth, since interval velocities tend to be higher at greater depths, i.e. influencing the wavelength.

2) *Structural error* - This error is associated with the interpolation of the time maps aquifer thickness from well data. Areas characterized by low structural complexity and gentle features (e.g. platforms and highs) will produce small errors with interpolation, while in structurally complex areas (e.g. large fault offsets, salt doming) a significant error is introduced when large gaps exist between data points.

3) *Velocity model error* - The conversion from time domain to depth domain is based on a velocity models that include a large uncertainty as they are based on a relatively sparse borehole data set and the determination of acoustic velocities in itself often incorporates a lot of uncertainties. This uncertainty does not pertain to well log data, which are measured in depth and do not need a time-depth conversion

4) *Distribution errors* – Delineation of the aquifers is based on well information (present/not present) constrained by knowledge on presence of proven aquifers (hydrocarbon fields). Especially when hydrocarbon fields occur within the area to be mapped, many wells plot in clusters while the density of wells in between these clusters is much less. This unequal distribution causes an irregular surface when processed. The outline of aquifer units is a best-fit polygon that includes all wells that contain the unit concerned.

4.4.2 Fault uncertainty

In seismic data small-scale faults with offsets smaller than ~10 m are not detectable due to the resolution limits of the seismic data. Such faults are called “sub-seismic” faults (Figure 4-5). Even where there is no real fault offset, many faults have a fractured zone at their fault tip. This so-called “process zone” may either enhance connectivity when it forms a flow baffle, or inhibit fluid flow when it is impermeable due to cataclasis. The faults used in this screening study represent faults with “visible” offset only. Consequently, uncertainties in fault presence and continuation leads to different interpretations that have different implications for fluid communication between structures and thus affect calculated capacity volumes.

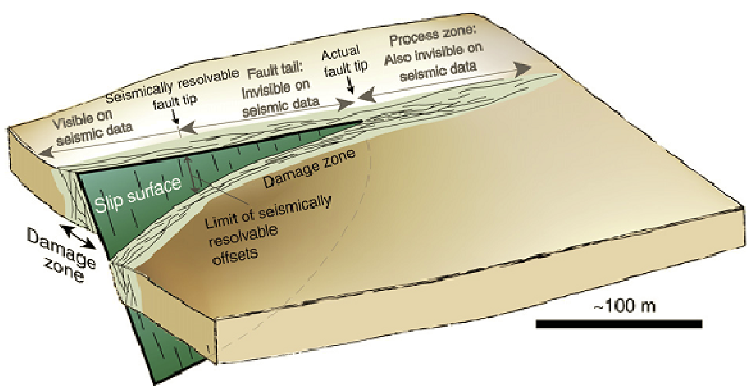


Figure 4-5 The length of faults is commonly underestimated in seismic data interpretation. From Rotevatn & Fossen (2011).

4.4.3 Seals

Also the distribution of seals is based on the NCP2 regional mapping of the Dutch subsurface and therefore generalized for that purpose. Local presence of permeable streaks within these seals may have local effects on sealing capacity (e.g. inter Zechstein carbonates and sands, Ten Boer sand lenses, etc.), but are not accounted for.

4.4.4 Porosity, permeability

To date, no porosity (and permeability) maps for individual aquifer units exist for all aquifer levels in the Dutch offshore. These maps, including their uncertainty assessment, do exist for the onshore as part of the ThermoGis© application (www.thermogis.nl). The availability of such maps would reduce the uncertainty associated with porosity and estimated capacity. However, with every map that is based on available well data, it should be kept in mind that most wells in the Netherlands were drilled for exploration purposes, i.e. targeted at those parts of the aquifer that are hydrocarbon bearing (reservoirs). Extrapolation of reservoir properties in areas were well coverage is low, may introduce another source of uncertainty.

4.5 Classification of options

The storage options are organised according to the analysis by TNO whether the location provides sound storage, based on the availability of data which results in a level of certainty. This allows the different options to be compared. The aquifer compartments are categorized as follows:

A) "Good Option / High certainty": structures which are suitable for CO_2 storage, based on good existing information
B) "Good option / Low Certainty": structures which are likely to be appropriate for CO_2 storage, but data is currently insufficient or low quality
C) "Poor Option / Low Certainty": structures which are unlikely to be appropriate for CO_2 storage, but based on insufficient or low quality data
D) "Poor Option / High certainty": structures which are not appropriate for CO_2 storage, based on good existing information

Options classified as 'A' or 'B' are considered options that should be looked at in more detail in future studies. The storage potential of options that are marked 'C' or 'D' is considered too low to warrant a further, detailed study. By acquiring better information in the future, a site classification can potentially change.

On the basis of the data used in this study, which is mainly data on a regional scale, saline formations are marked with a 'B' as a maximum. The regional data is too coarse to result in high-certainty options. As will be clear in the following sections, one saline formation structure is marked with a 'A'. This formation is associated with hydrocarbon production and much more information on its properties is available. In addition, the structure has been identified in previous studies.

As mentioned in Section 2.2.1, the screening for storage options in saline formations assumes that storage capacity is created by utilising the compressibility of the storage system. The storage efficiency of 2% is used as an indication of the capacity that can be created. However, when formation fluids are extracted and replaced by CO_2, a potentially much larger storage capacity can be created. In that case, the size of the compartments required for a minimum storage capacity of 50 Mt depends on the fraction of fluids extracted, rather than the total connected volume. If a larger part of the formation water can be extracted, larger storage capacity can be created. It follows that in such case the classification scheme should be changed and an option that is labelled as 'C' could be upgraded to a 'B' (more attractive option, maintaining same low uncertainty).
In summary, if formation water production to create storage capacity for CO_2 becomes a real option, the screening presented here should be revisited, with the data that form the basis for the present study.

4.6 Rotliegend - Lower Slochteren (ROSSL)

4.6.1 Description of Compartments (Figure 4-6)

- The Permian Lower Slochteren aquifers exclusively occur in the northern offshore.
- Aquifers are sealed by Zechstein (ZE) salt.
- Especially the area where the ROSSL is at a structural shallow depth (Cleaverbank and Central offshore Platforms), many small compartments are revealed by the connectivity analysis.
- Larger compartments occur in basin areas, such as the Dutch Central Graben (DCG; 2) and the connection between the DCG and the Broad Fourteens Basin (BFB; 3).
- Pore volume (and thus storage capacity) decreases from ~20% in the south to ~0% in the north of the distribution area, reflecting the general S-N fining trend and interfingering with the Silverpit fine-grained deposits.

4.6.2 Capacity

The following aquifers with capacity > 50 Mt are identified (Figure 4-7):

1. Compartment covering E to L blocks (145 Mt).
2. Compartment around K9-K12 (65 Mt) in the northwestern most part of the BFB basin.

4.6.3 Discussion

There is large variation over the extent of the Lower Slochteren in mapped fault density due to sub-salt imaging issues in seismic data. The high amount of identified small compartments in the K and L may be due to the shallower depth of the ROSSL formation. In these so-called platform areas, thee faults are more easily interpret than in the deeper basin areas. In the latter the ROSSL occurs at depths where seismic resolution is often too low to readily identify faults. The absence of mapped faults overestimates the aquifer volume; this is most probably the case for compartments 1 and 2. Most likely, the fault density observed on the platforms is present in the basins as well (De Jager, 2007) and more detailed mapping, using higher resolution data, will likely result in the recognition of smaller compartments and lower storage potential in the basins as well.

4.6.4 Recommendation

All identified compartments are categorized as B because of uncertainties related to data quality and availability, as well as the high likelihood that the actual compartments in reality are too small.

In conclusion, the ROSSL formation does not provide high-capacity options for CO_2 storage.

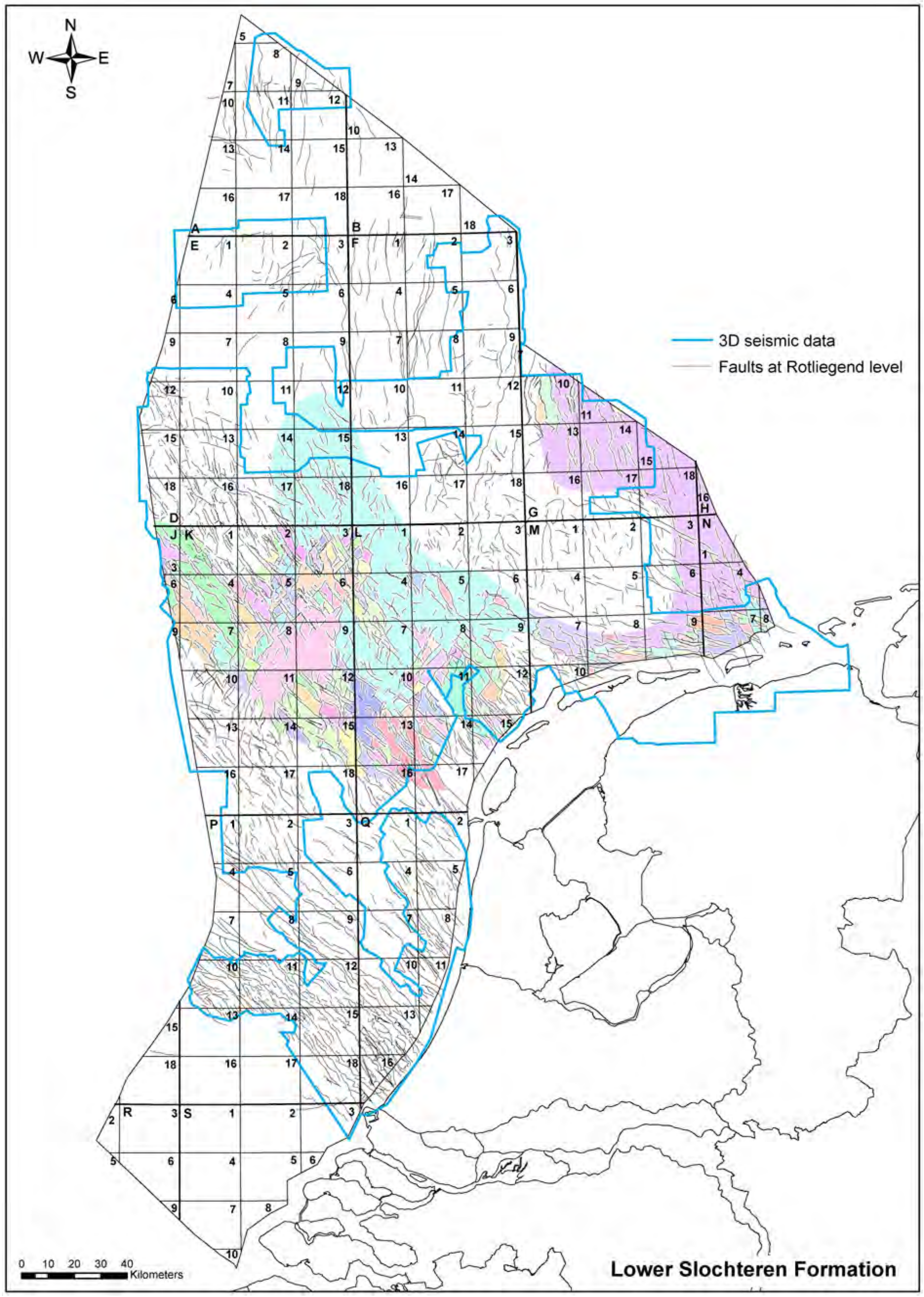


Figure 4-6 Saline formation compartments in the Lower Slochteren Formation (ROSLL). Colours are randomly chosen, such that individual compartments are highlighted

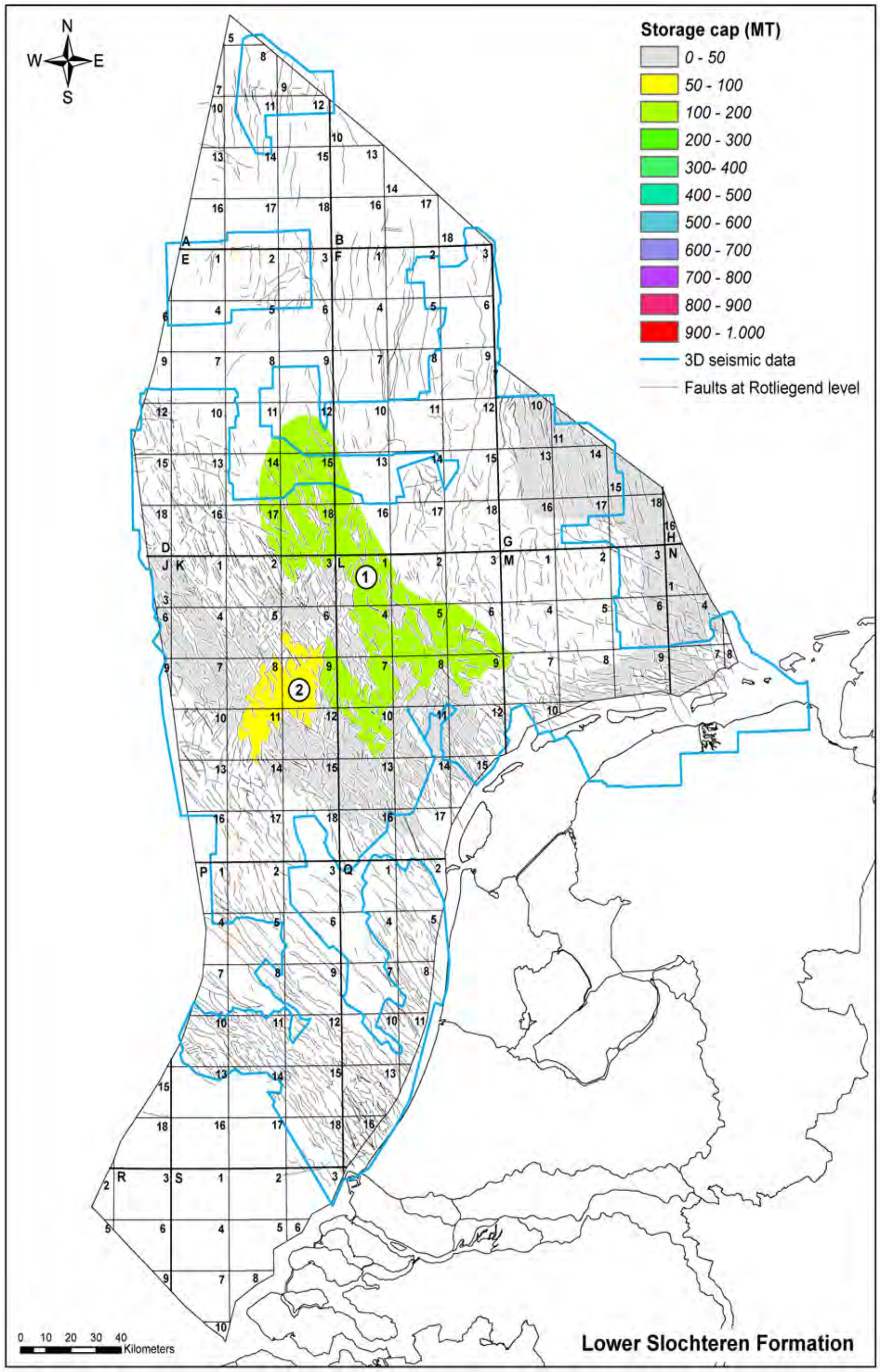


Figure 4-7 Lower Slochteren (Rotliegend) saline formation compartments with storage capacity >50 Mt (se colour scale). Numbers refer to description in text.

4.7 Rotliegend – Upper Slochteren (ROSLU)

4.7.1 Description of Compartments (Figure 4-8)

- The Permian Lower Slochteren aquifers exclusively occur in the southern offshore
- Aquifers are sealed by ZE salt only in the K,L blocks
- Large compartments in the central Broadfourteens Basin (BFB) in an area covered by either 2D seismic data or where the ROSLU is deeply buried (or both)
- Higher potential in K, L blocks
- The P and Q blocks in the West Netherlands Basin (WNB) show many small compartments
- Southernmost compartment (S blocks) lies outside the 3D data contour.
- Pore volume (porosity) shows less of a trend compared to the Lower Slochteren aquifers. In the offshore, only small and local deviations from the average 14% porosity occur, which are attributed to the distribution of aeolian and fluvial sands.

4.7.2 Capacity

The following aquifers with capacity > 50 Mt are identified (Figure 4-9):

1. A large compartment (80 Mt) around K9-K11 in the northwesternmost part of the BFB basin (same area identified for the ROSSL)
2. Compartment covering L10-L13 (60 Mt) in the Central offshore platform
3. Compartment covering the BFB basin (2100 Mt)
4. Compartment in S blocks (140 Mt)

4.7.3 Reservoir quality

The quality of the ROSLU formation determines the injection rates that can be reached with a single platform (with one or more injection wells). The quality is described by the permeability of the reservoir (a measure of the connectivity between the pores in the sandstone). Available data indicate that permeability is in the range of several hundred milliDarcy (mD), which classifies the formation as a good to very good reservoir. From a single injection site, a rate of 5 Mt/yr[3] can be easily maintained.

4.7.4 Discussion

Especially in the area where the ROSLU is at a structural shallower depth (Cleaverbank and Central offshore Platforms), or where the Zechstein salt is absent (WNB) many small compartments are revealed by the connectivity analysis.

The same large variation in mapped fault density due to sub-salt imaging issues in seismic data as observed for the Lower Slochteren is observed here. The enormous compartment (3) in the BFB basin is related to the small amount of mapped faults and should be treated with care. Also the K9-K11 compartment (1) lies relatively deep and may also suffer from underestimation of the fault density. Compartment 4 lies with in an area with 2D data coverage only and should be discarded at this point.

[3] A rate of 5 Mt/yr is the order of magnitude of CO_2 captured from a single, large fossil-fuelled power plant.

Only the L10-L13 block seems to be a reliable candidate since the aquifers are not too deeply buried, i.e. seismic resolution is fair in the platform areas. Ongoing in-house studies at TNO (L. Peters, pers. Comm.) reveal that communication of reservoir compartments based on pressure differences, does not completely fit the observed fault structure. Most probably the structure is more complex.

4.7.5 Recommendation

Most identified compartments are categorized as type ‘C’ (Poor Option / Low Certainty) because of uncertainties related to data quality and availability. Compartment 2 in the L10-L13 blocks (60 Mt) seems a more reliable candidate for CO_2 storage. Furthermore, this aquifer compartment is in very close vicinity of the L10 infrastructure (Figure 4-10). However, awaiting the result of the ongoing study mentioned above that also includes detailed fault mapping, a proper recommendation concerning the potential of this structure cannot (yet) be made. Therefore it is categorized as type ‘B’ (Good Option / Low Certainty). Considering that the estimated storage potential of 60 Mt is very close the lower threshold value of 50 Mt, a more detailed fault structure could decrease compartment size to below this value.

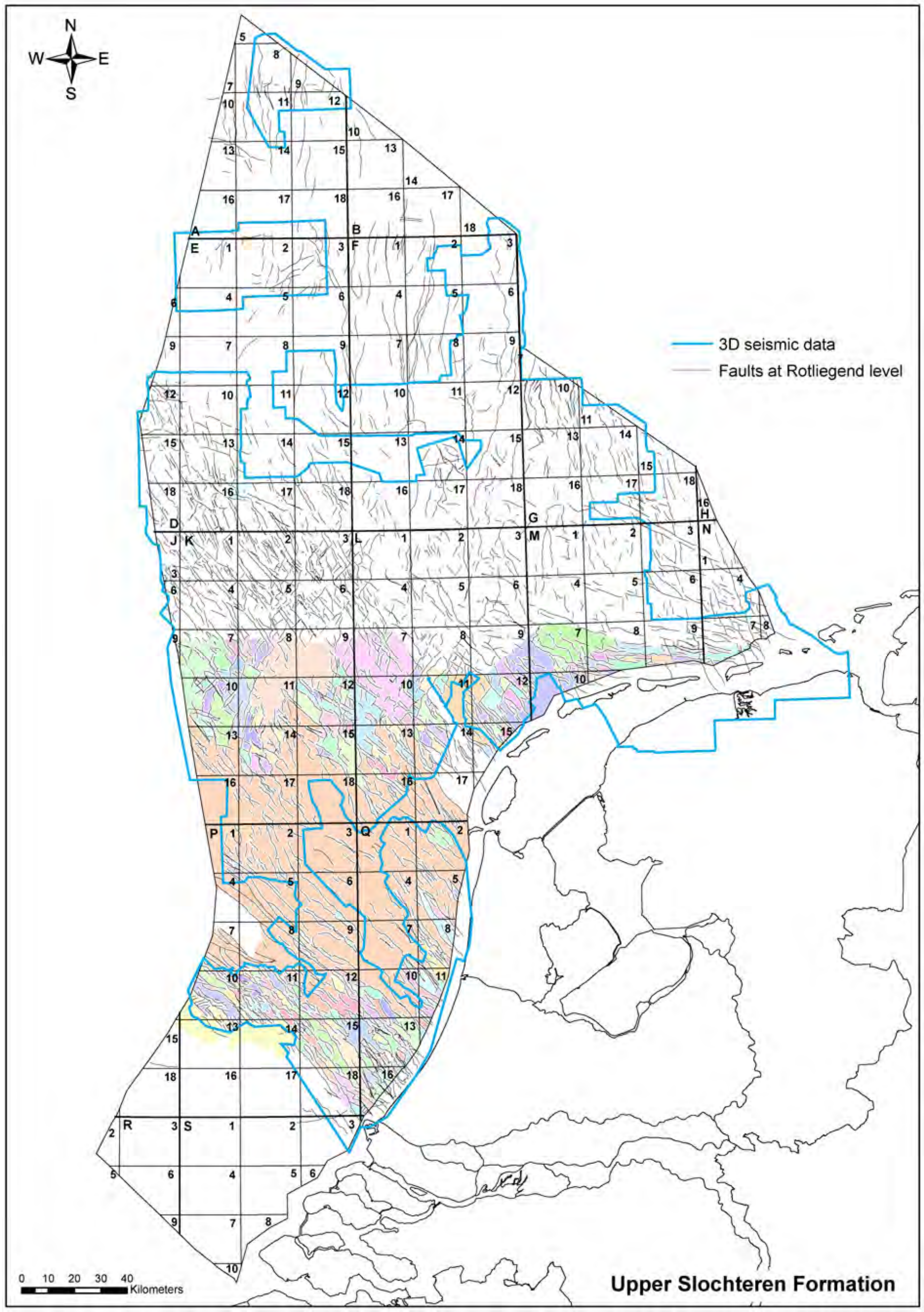


Figure 4-8 Saline formation compartments in the Upper Slochteren Formation (ROSLU). Colours are randomly chosen, such that individual compartments are highlited

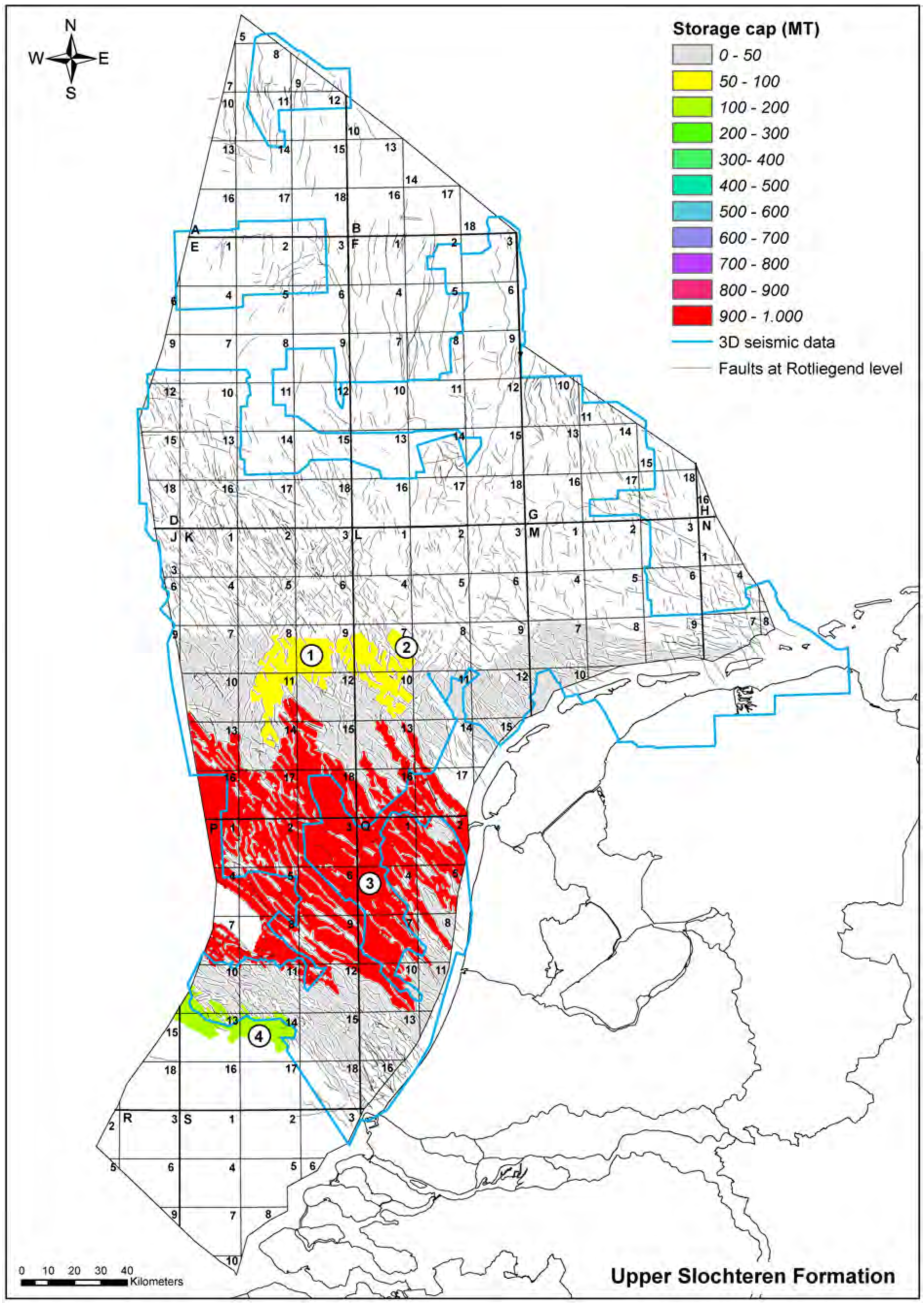


Figure 4-9 Upper Slochteren (Rotliegend) saline formation compartments with storage capacity >50 Mt (see colour scale). Numbers refer to description in text.

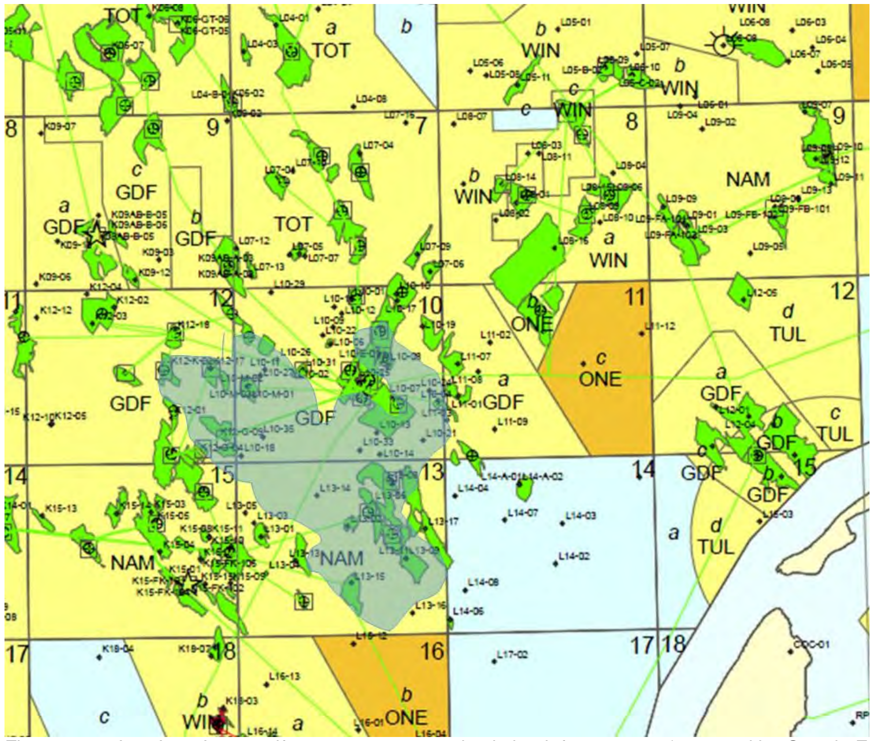


Figure 4-10 L10-L12_L13 aquifer compartment and existing infrastructure (operated by Gaz de France).

4.8 Triassic (Main Buntsandstein stacked aquifers)

4.8.1 Description Compartments (Figure 4-11)

- P and Q blocks are highly fragmented and porosities are very low
- Connectivity between BFB – DCG and Terschelling Basin (TB) due to absence of mapped supra-Zechstein faults, highly unlikely that entire area is in communication
- In North Triassic aquifers are surrounded by salt diapirs (potential compartmentalisation).
- Along the border with the UK, GE aquifers exist with unknown extent
- Large compartment in S block due to absence of fault information
- Good seals are Upper Triassic salt and Jurassic clays
- Average porosity is 12%, but varies significantly depending on both facies distribution (westward fining) and depth of burial, with lowest values (~1 %) in the West Netherlands Basin, Broadfourteens Basin and Dutch Central Graben. High values, up to ~30%, occur on structural highs, where the sandstone has been less compacted. In spite of this general knowledge, no porosity maps are available yet.

4.8.2 Capacity

The following aquifers with a capacity of more than 50 Mt are identified (Figure 4-12):

1. 1300 Mt compartment covering the BFB Basin, the DCG and the TB. The potential of 1300 Mt is the total volume; compartments with a storage capacity larger than 50 Mt are expected to be found here. The area can be split into a southern part (1a) and northern part (1b), based on the absence (southern part) or presence (northern part) of structured salt in the subsurface. The storage capacity in the two parts (1a) and (1b) is about 650 Mt each.
2. 190 Mt compartment in the Step Graben. The absence of faults in this area is rather suspicious, although the area is bounded to the west by a major fault zone delineating the Elbow Spit High. The eastern boundary is formed by salt ridges.
3. 100 Mt on Silverpit Platform, western boundary is fault controlled; eastern limit is erosional contact against slightly higher-elevated Cleaverbank Platform
4. 50 Mt on Silverpit Platform, eastern boundary is fault controlled, but extent to the west (UK) is unknown, but considerable
5. Compartment in S blocks (80 Mt); area lies outside the 3D data contour
6. Potential in overpressured compartments in northern salt province (example = ~ 75 Mt; see Figure 4-13)

As can be seen in Figure 4-11, the northern offshore region comprises many elongated salt ridges that delineate the structures associated with the Dutch Central Graben. Several basement faults and salt structures tend to cross the general N-S graben structure, suggesting that compartments may exist. Overpressures in the Triassic aquifers suggest that compartments are sealed laterally by the salt as well (see also Figure 3-7B). Only one example of such a salt-bounded compartment is given here; it is noted that this particular compartment is likely to be present, but its presence remains to be proven. The example presented here, encompasses the F15, F18 and K02-03 blocks and has easy connection via the infrastructure of the K2 and F16 platforms (gas pipeline NGT noordwest; expected availability 2023).

4.8.3 Reservoir quality

The quality (permeability) of the Triassic sandstones is variable. Available data suggest that permeability in the gas fields in the F blocks is generally below 15 – 20 mD, which, in terms of CO_2 storage would classify the potential reservoirs as medium at best. However, it should be noted that gas fields are located close to the salt domes, where salt precipitation has reduced porosity and permeability. Reservoir quality is expected to improve the further away from the salt domes. Unfortunately, data is available only from hydrocarbon exploration wells, which were drilled close to the salt. Gas fields with good to very good reservoir quality exist in the L blocks. A detailed mapping of permeability in the Trias in the northern offshore is required.

Injection rates for the low permeability values (in the range of a few to up to 20 mD) are low. To reach an injection rate of 5 $MtCO_2$/yr more than one injection location may have to be developed.

4.8.4 Discussion

In (1a) the absence of salt would suggest that many basement faults will penetrate the Triassic rock sequence. The small number of observed faults, however, suggests otherwise. Most probably the fault density and fault continuation is underestimated and therefore aquifer connectivity is overestimated.

Pressures are an excellent tool to test the connectivity of a reservoir between well locations. Overpressures in the northern offshore are caused by the thick Tertiary cover and slow dewatering towards the south and up section (see Figure 4-13 and Figure 4-14). In addition, the shaly facies of the Triassic in the northern sector of the Dutch subsurface and sealing faults and salt contribute to the pressure build up. Although the pressure data suggest that compartments do exist, the pressures of more than 400 bar (40 Mpa) in the southern Dutch Central Graben also flag an issue for CO_2 injection. High overpressures may cause very serious drilling hazards and traps to be breached.

4.8.5 Recommendation

The salt-enclosed area (1b) with the indicated typical compartment size (6) is classified as B (Good Option / Low Certainty), as it is expected that such compartments with good seals exist. The southern half (1a) should be classified as type C (Poor Option / Low Certainty), since many uncertainties exist related to data quality and availability.

For the larger compartments 2, also fault density is underestimated, but the salt control is stronger and it is expected to be less faulted, i.e. compartments are expected to be bigger (as is the case for aquifer 6 (see below). Therefore it is categorized as type B (Good option / Low certainty). Compartment 5 should be discarded at this point since it is categorized as a type C (Poor Option / Low Certainty). For compartments 3 and 4 a more detailed mapping of the fault structure is required to ensure that aquifers are not more intensively fractured than currently estimated. If so, the resulting compartments are likely to have storage capacity below 50 Mt (they are classified as type C (Poor Option / Low Certainty)).

The timeline for compartment characterisation of each structure is estimated at 3-4 yrs of the total 6-7 yrs estimated for development for use in CCS, following the steps described in Section A.1.

Another, potential region that needs more research (type B: Good Option / Low Certainty) can be found in Triassic aquifers that are enclosed by salt structures delineating and transecting the Dutch Central Graben area (1b). Note that only one example (6) of compartment size is given and that more detailed work is required to see if more of these structures exist and if overpressure conditions are not too severe. The overpressure element applies mainly to (6); it is expected that compartments such as indicated in green in Figure 4-12 can be found elsewhere in (1b) as well. Figure 4-13 shows the location of the (hypothetical, but realistic) compartment (6) in close up. If this compartment is real, its location suggests that options for re-using existing installations (platforms) exist. The gas fields indicated in the figure are located at greater depth than the Triassic reservoirs, so also the wells could be re-used. If the Trias reservoirs prove to be a real option for CO_2 storage, the option of re-using existing hydrocarbon production installations and wells should be considered.

The timeline for compartment characterisation of this structure is estimated at 3-4 yrs of the total 6-7 yrs estimated for development for use in CCS, following the steps described in Section A.1.

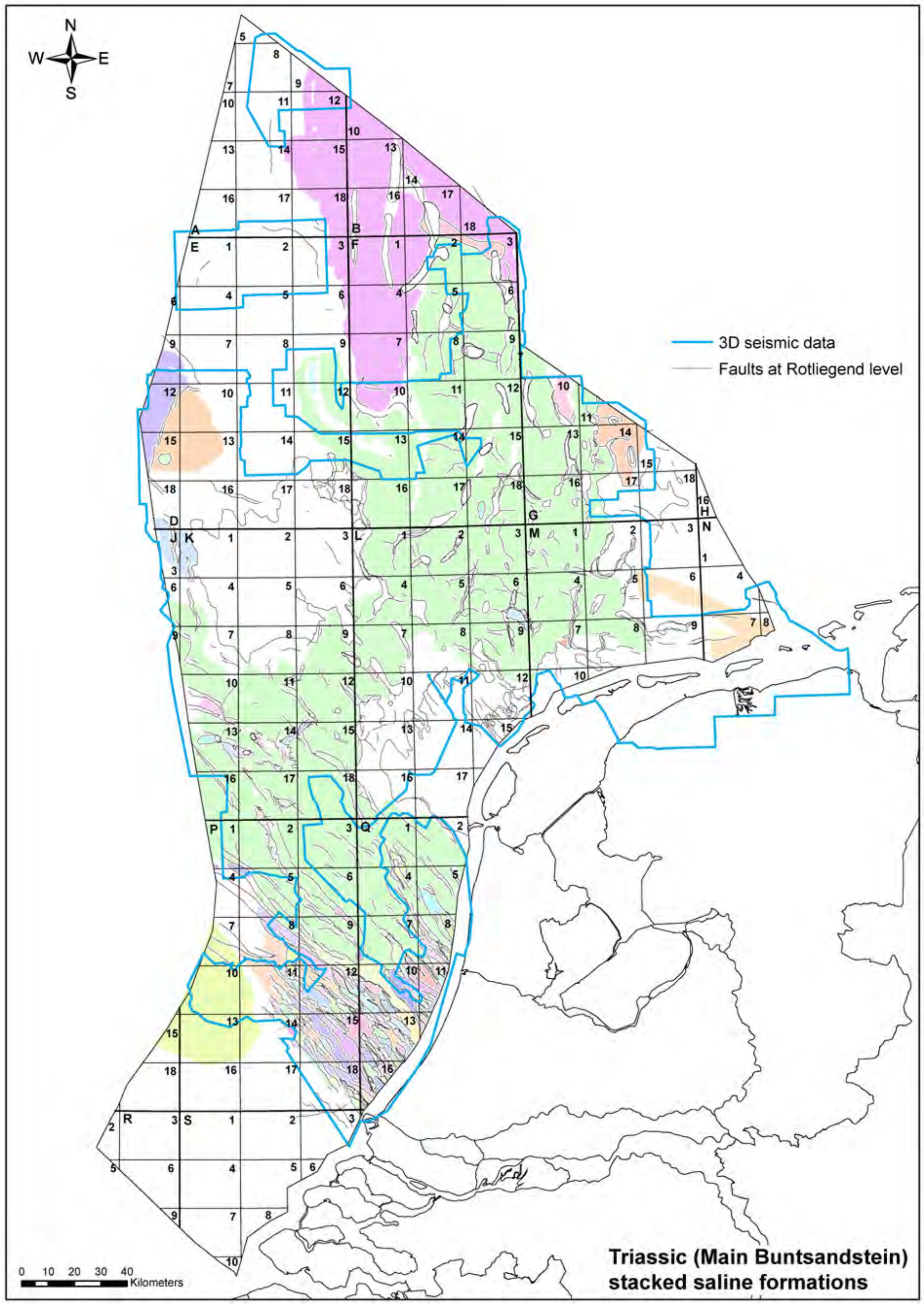


Figure 4-11 Saline formation compartments in the Triassic (Main Buntsandstein). Colours are randomly chosen, such that individual compartments are highlighted

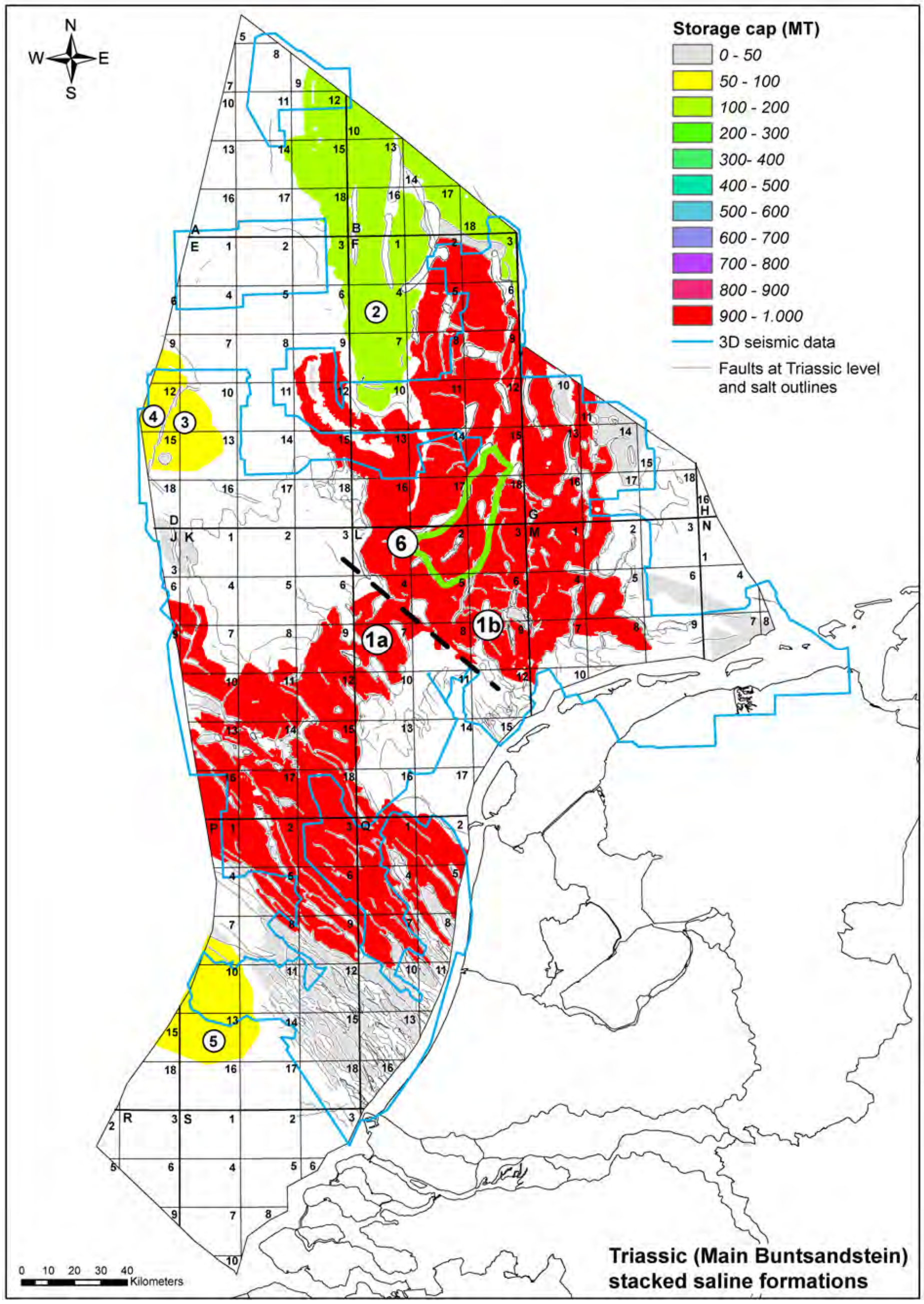


Figure 4-12 Saline formation compartments of the Triassic (Main Buntsandstein) with storage capacity >50 Mt (see colour scale). Numbers refer to description in text. Elongated salt ridges are in white.

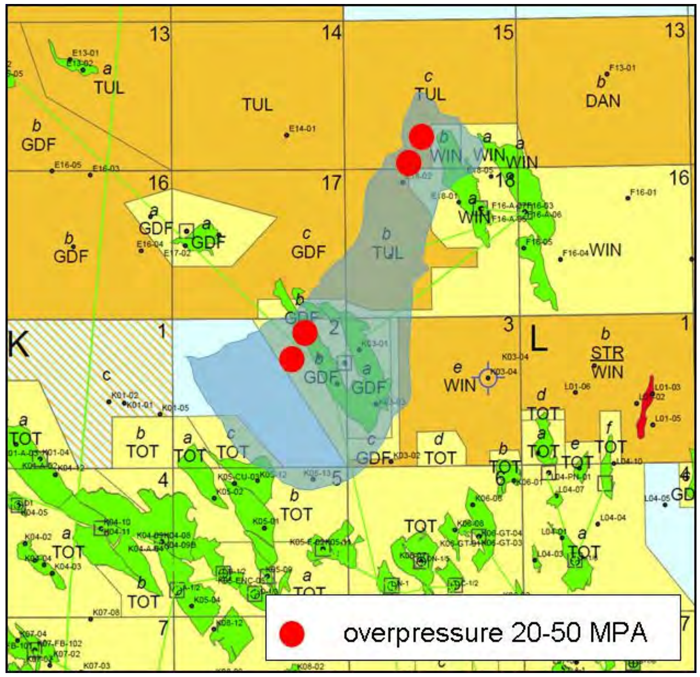


Figure 4-13 Salt enclosed, over-pressured aquifers in E15-E18 and K02-K03 and existing infrastructure.

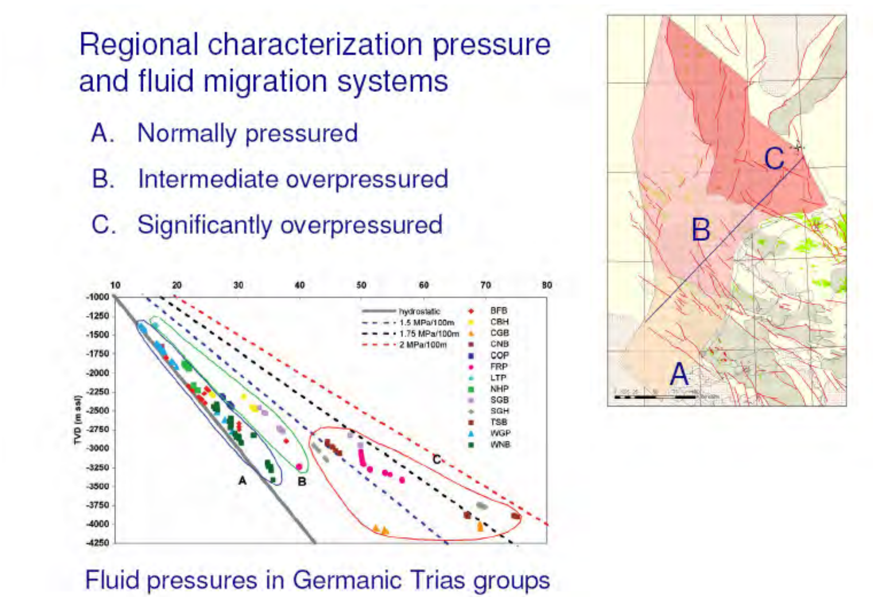


Figure 4-14 Overview of overpressures in the Triassic aquifers. Note that the selected example area is within area C. (from Simmelink et al., 2004).

4.9 Upper Jurassic – Lower Cretaceous (stacked aquifers)

4.9.1 Description of Compartments (Figure 4-15)

- P and Q blocks are highly fragmented with many small (< 50 Mt capacity) aquifers
- Several large compartments that may be structurally more complex throughout the offshore
- Good seals by Vlieland clay or Holland Formation
- In the absence of porosity maps, an average porosity of 20 % is adopted
- Main aquifer layer is the Cretaceous Vlieland sandstone, which is mostly less than 20 m thick.

4.9.2 Capacity

The following aquifers with capacity > 50 Mt are identified (Figure 4-16):

<u>Several large aquifers with suspiciously small amount of faults, including the following compartments:</u>

1. K04, K05: 100 Mt. Existing data for this aquifer shows a suspiciously low amount of faults and has a thickness that barely exceeds 10 m.
2. L09, L12, L15: 125 Mt. This aquifer shows a suspiciously low amount of faults.
3. PQ blocks: 360 Mt. Appears as a very large compartment in existing data, probably due to the absence of mapped faults across the deeper parts of the West Netherlands Basin (WNB).

<u>Aquifers compartments that need special attention:</u>

4. L13, K12, L16, P03, Q1 with a capacity of 110 Mt

Note that for the under-pressurized Q1 Helder & Helm oil fields (Chevron) TNO, had previously conducted a storage potential screening study that revealed:

- The geology at Q1 seems very suitable for 10^{-9} storage
- High porosity and high permeability sandstone reservoir.
- Oil production and adjacent water injection at the site have already proven the capabilities of this complex, e.g. reservoir and seal.
- Storage Capacity: 115 Mt.

It should be stressed, however, that the Q1 oil field is water producing and should therefore have a higher than 2% storage efficiency assumed in this study. This explains why the aquifer that surrounds the Q1 oil field has an estimated storage capacity of only 110 Mt. This number should thus be regarded as minimum potential. The well density in the oil fields of the Q1 block is high compared to conventional gas reservoirs and gas infrastructure is available (Figure 4-17; Q1, Chevron). More realistic capacity estimates are likely in the range of 225 Mt (i.e.: additional 100 Mt capacity).

4.9.3 Reservoir quality

The permeability of the formations associated with the Q1 oil fields is high, up to 6000 mD reported. Available data for the formations in the PQ blocks (structure (3) in the above list) suggest that permeability values up to 200 mD exist, which classifies these formations as good reservoirs.

In both cases, an injection rate of 5 $MtCO_2$/yr can be maintained from a single injection location.

4.9.4 Discussion

Mapped faults underestimate the complexity of the structure mainly due to absence of mapped supra Zechstein faults, i.e., in reality compartments may be smaller. Furthermore, regionally mapped faults in the West Netherlands Basin (WNB) tend to underestimate the complexity of the structure, i.e. compartments may be smaller here as well (see Figure 4-18). Considering that this screening identified less than 50 $MtCO_2$ storage capacity, any further research would likely decrease this estimate further.

Although the Q1 surrounding aquifer offers great potential for CO_2 storage, it is noted that the conditions of the aquifer are different from those of the reservoir. These conditions and reservoir properties cannot directly be extrapolated beyond the limits of the oil field, because:

- Q1 field has a strong water drive;
- It produces water at present;
- And therefore has storage efficiency much larger than 2%.

This explains why the aquifer that surrounds and included the Q1 oil field has an estimated 110 Mt of storage capacity only. This number should thus be regarded as minimum potential. To elucidate on the potential of the surrounding aquifer the detail of the fault network needs improvement.

4.9.5 Recommendation

The compartments 1 (K04, K05 blocks) and 2 (L09, L12, L15) both show good storage potential, but suffer from the lack of reliable fault data. Reinterpretation would most probably result in compartments with storage capacities <50 Mt, therefore these are categorized a type C. The timeline for compartment characterisation of this structure is estimated at 3-4 yrs of the total 6-7 yrs estimated for development for use in CCS, following the steps described in Section A.1.

The large compartment in the PQ blocks (3) is categorized as type B; it also misses a detailed fault interpretation but, after reinterpretation, could result in several compartments that are likely to have storage capacities that are still above 50 Mt. Considering, the large size of the compartment and the large number of faults it is estimated that the required time for compartment characterisation of this structure is twice that of the average 3-4 yrs, i.e. 6-8 yrs. Also more than 2 wells would be required. The total timeline for full development of storage sites in this compartment would therefore require 9-11 yrs, following the steps described in Section A.1.

The Q1 and Q1- surrounding aquifer (4) has potential for CO_2 storage of up to 225 Mt and should be categorized as type B/A. Although further research is needed aimed at refining the fault network and obtaining non-reservoir properties, the timeline for compartment characterisation of this structure can be slightly shorter that the average 3-4 yrs. Estimated time for development for use in CCS, following the steps described in Section A.1., is 6 yrs at maximum.

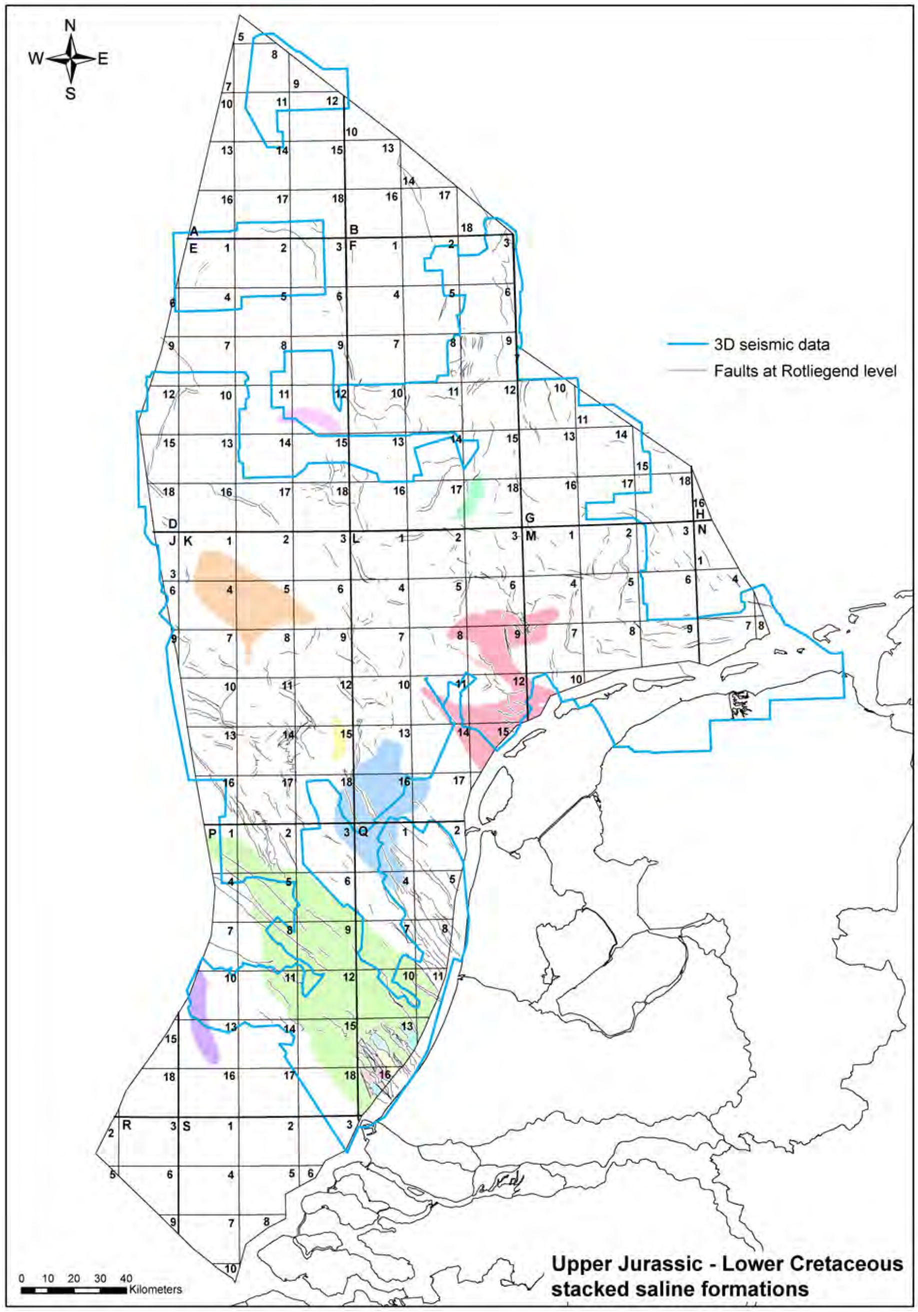


Figure 4-15 Saline formation compartments in the Upper Jurassic – Lower Cretacesou stacked aquifers. Colours are randomly chosen, such that individual compartments are highlighted.

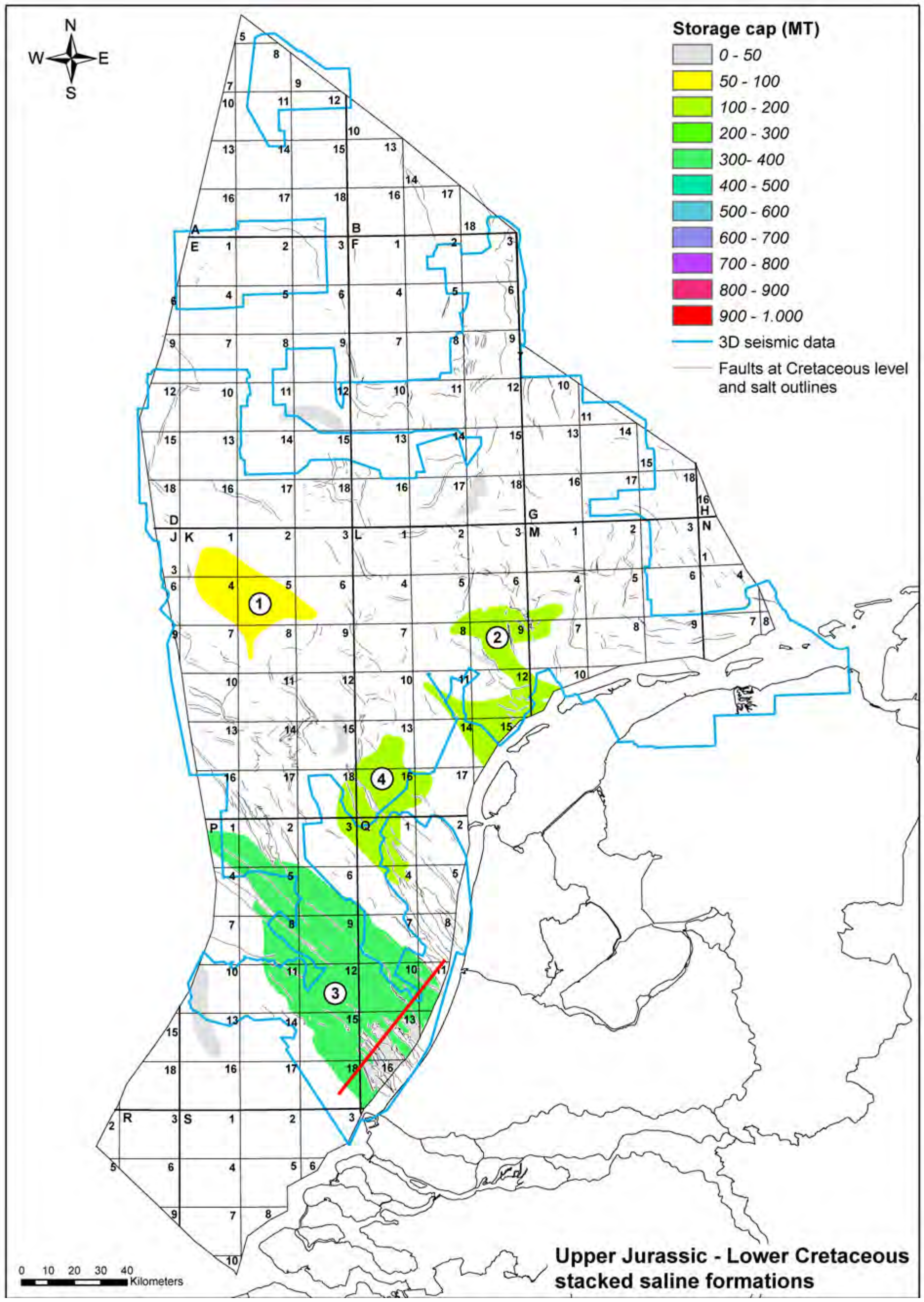
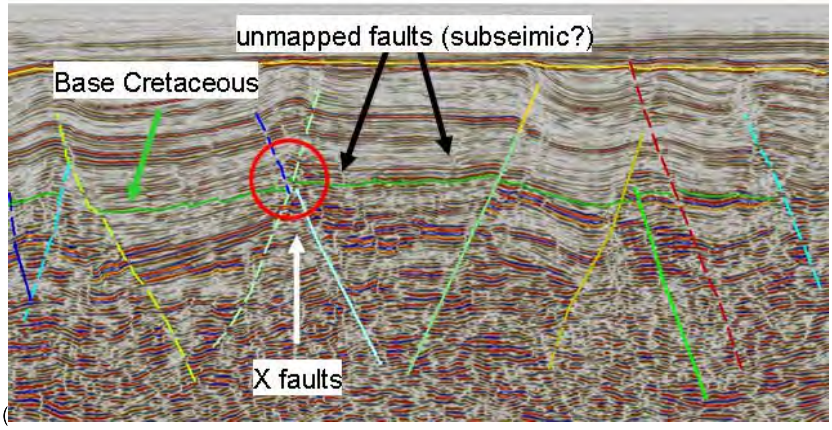


Figure 4-16 Upper Jurassic – Lower Cretaceous saline formation compartments with storage capacity >50 Mt (see colour scale). Numbers refer to description in text. Red line indicate seismic section through

the West Netherlands Basin



(Figure 4-18).

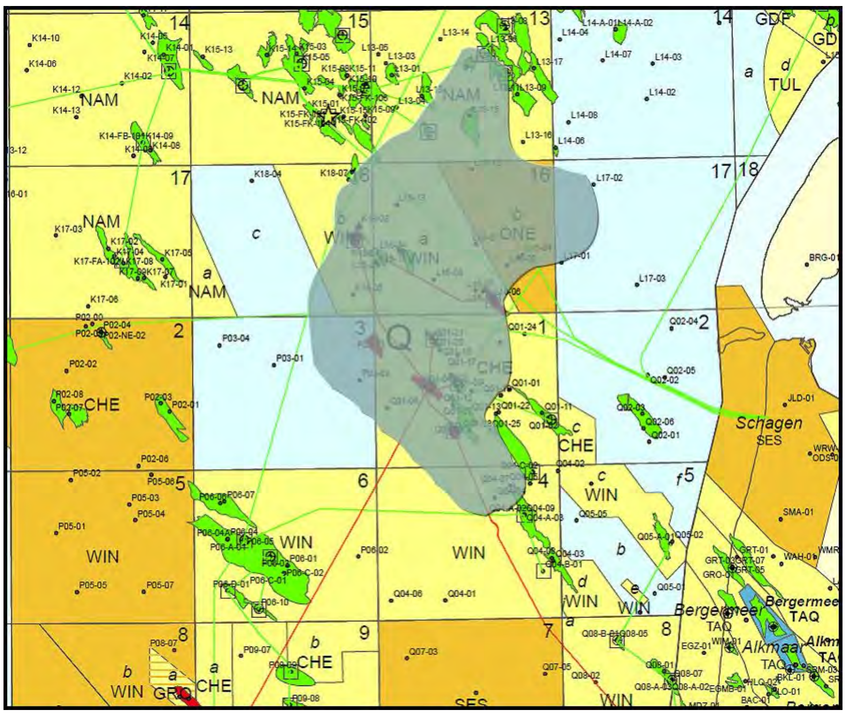


Figure 4-17 Potential storage aquifer surrounding the Q1 block and existing infrastructure.

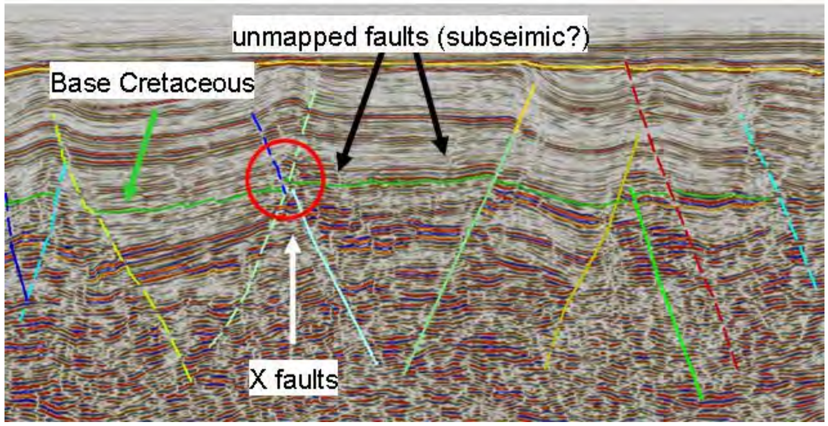


Figure 4-18 Seismic section through WNB illustrating that the structure is more complex that assumed based on the mapped faults.

4.10 Summary and recommendations - potential aquifers

Unit	Blocks / element					Category	estimated SC (Mt)	Characterisation time (yrs)
Low. Cret	L13	L16	K12	P03	Q1	B/A	115 (Q1) + 110 (aquifer) = 225 (**)	5 - 6
Low. Cret.	P	Q				B	360	6 – 7
Triassic	Step Graben					B	190	6 – 7
Triassic	F15	F18	K02	K03		B	650 (>75(*))	6 – 7
ROSLU	L10	L13				B	60	6 – 7
ROSLU	BFB					C	2138	-
Triassic	BFB, DCG, TB					C	650	-
ROSLU	S blocks					C	143	-
ROSLL	E to L blocks					C	145	-
Low. Cret	L09	L12	L15			C	124	-
Low. Cret	K04	K05				C	99	-
Triassic	Silverpit Platform					C	98	-
Triassic	S blocks					C	78	-
ROSLU	K9	K11				C	78	-
ROSLL	K9	K12				C	65	-
Triassic	Silverpit Platform					C	52	-

Table 4-1 Summary of aquifers with storage capacities of more than 50 Mt. For location of structural elements and abbreviations see the sections on the respective formations. More information on the storage options labelled 'A/B' and 'B' is given in Section 7 (Table 7-1).

Table 4-1 shows the best options for offshore saline formation storage of CO_2.

(*) The storage capacity in the Triassic formations in the F and K blocks is given as 650 Mt. The expected typical storage capacity of a single compartment is about 75 Mt. Current data do not allow the identification of individual compartments, but multiple compartments of that typical size are likely to be found in that formation.

(**) The storage capacity of the Lower Cretaceous unit (the Q1 block) is given as 115 Mt (representing the storage capacity in the void space created by oil and water production activities) and 110 Mt in the entire aquifer, but under different conditions of storage efficiency (representing the storage capacity created by elevating the pressure in the formation).

It should be stressed once more that for the selected high-potential storage aquifers, a first priority should be given to obtaining more detailed fault networks that will incorporate the internal structure of compartments more realistically. This can be done by acquiring high-quality 3D seismic data, or, if possible, by re-processing existing 3D seismic data. Secondly, since the accessible volume and permeability and thickness of the aquifer is key in estimating storage potential, better information on thickness distribution and porosities is required.

As mentioned in section 4.8.5, the existence of re-using hydrocarbon production infrastructure in saline formation storage projects should be considered. Most of the options for saline formation storage overlap with gas fields. The presence of gas or oil fields can also lead to conflicts of interest, especially when storage is to take place in the same formation(s) as production. In case of the Lower Cretaceous Formation compartment in the L13 – L16 – K12 – P3 – Q1 blocks, the combination of activities could be used to advantage (see section 6).

5 Gas field screening

5.1 Introduction and chapter setup

Developed and depleted hydrocarbon fields offer natural possibilities for CO_2 storage (see also section 3.2.3). The extensive hydrocarbon production in the Dutch Continental Shelf (DCS) since 1968, suggests that there may be a sizeable portfolio of attractive storage sites. Indeed, to date, a total of 248 gas accumulations have been discovered and a total of 137 have been developed. Of these, 44 fields have already ceased production (Natural resources and geothermal energy of the Netherlands – Annual Review 2010) and may serve as suitable sites for CO_2 storage.

The CO_2 storage capacity of gas fields in the DCS has been assessed by TNO in different studies at various levels of aggregation and detail, for example for specific quadrants (Phase 2 ISA, Neele et al., 2011a, 2011b) individual fields (NOGEPA, 2008), clusters connected to main platforms (EBN-Gasunie, 2010) and broader offshore areas (NOGEPA, 2008; see Figure 5-1). Unlike these previous studies however, this report aims to provide a more comprehensive assessment of the possibilities for CO_2 storage in high capacity gas fields in the *entire* DCS as well as an alternative view on storage in gas field clusters.

It is nonetheless worth noting that previous assessments concluded that the Central part of the offshore (K- and L- quadrants) offers the greatest potential for CO_2 storage (with total effective capacity of roughly 780Mt[4]), while the fewer fields in the remote Northern and Eastern areas offer far less capacity (total 70Mt and 40Mt, respectively). The P- and Q- quadrants of the Southern area were screened in more detail in Phase 1 and 2 of the Independent Storage Assessment (see Neele et al., 2011a, 2011b), due to their proximity to onshore industrial clusters in Rotterdam and Amsterdam and likely role in early mover CCS projects in those areas.

The storage capacity of a depleted gas field is not necessarily proportional to its areal extent (cf. Figure 5-1) and will depend on the particular geological setting of individual fields, which in the case of the DCS can be summarized as below. See chapter 3 for a more extensive discussion.

- The storage potential in the K- and L- quadrants of the Central area is dominated by <u>Rotliegendes</u> reservoirs, which are determined by the gas column height. This is likely to be 100+ meters in Rotliegendes reservoirs in the southern K- and L-blocks, but reduced to only a few meters in the Rotliegends reservoirs in the northern edge of the K- and L- blocks, due to wedging out. Indeed, the stratigraphic net thickness in the northern edge of the K- and L- blocks becomes the determining factor for the gas column height.
- The storage potential in the Southern and Eastern areas is dominated by <u>Triassic</u> reservoirs. As a rule the net gas column of these reservoirs is in the order of tens of meters. Stratigraphic thickness is fairly constant over these

[4] The effective storage capacity is the sum of the theoretical capacities (calculated assuming CO_2 can replace produced natural gas) for all fields that are not abandoned, have an injectivity (the product of permeability and thickness) larger than 0.25 Dm and a minimum storage capacity of 2.5 $MtCO_2$.

areas, but the net-to-gross ratio (determining available pore volume and quality for injection) may vary considerably per reservoir unit.

- The so-called shallow gas fields in the northernmost A- and B-quadrants have a relatively small gas column because of the low structural relief of these fields.

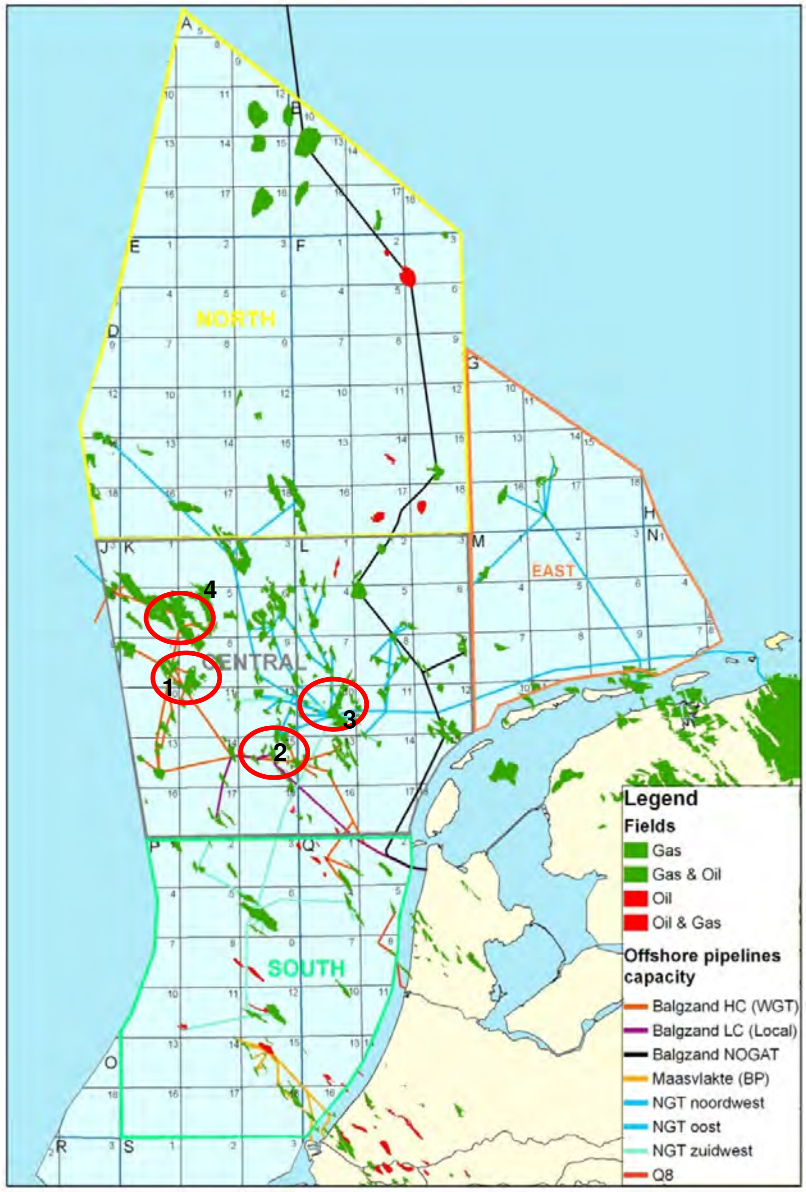


Figure 5-1 Overview map (including zonation) of the Dutch continental shelf (DCS). Source: NOGEPA (2008). The gas fields included in the current phase of the Independent Storage Assessment are indicated. The numbers correspond to the fields listed in Section 5.2.1.

CO_2 storage capacity per unit pore volume is only mildly dependent on depth at the depth range in which the Dutch offshore gas fields are located (2-5 km). This is due to the peculiar pressure-volume-temperature (PVT) relationship for CO_2 (which strongly deviates from that of a normal natural gas), combined with the normal hydrostatic pressure-depth trend. These same relationships do not allow CO_2 to reach the so called “dense phase” at depths shallower than 800-1000 meters and therefore any reservoirs at those depths offer little or no effective storage capacity. The shallow gas fields in the northernmost A- and B- quadrants mentioned above would fall into this category.

Further background information on the geological development of the Dutch offshore can be found in, for example, chapter 3 of this report, in Geluk (2005) and in the South Permian Basin Atlas (Doornenbal & Stevenson, 2010).

Because depleted gas fields have a proven seal capacity and often reliable capacity estimated, based on data available from the production phase, the focus in this chapter is on risks and re-usability of existing infrastructure. The chapter is setup as follows. The selection criteria for individual fields and clusters are described in Section 5.2. The methodology and sources of information are described in Section 0, while a general site development plan, followed by specific descriptions of the individual fields and clusters is presented in Section 5.4 .

5.2 Scope of fields and clusters

5.2.1 Selection of individual depleted gas fields

As mentioned above, the objective of this study has been to screen for and identify high capacity CO_2 storage sites in the entire DCS to accommodate increasing volumes of CO_2 from early demonstration projects in the Netherlands. As such the key criteria applied in the screening process to filter the gas fields in the DCS has been:

- Capacity: individual fields with initial estimated storage capacity of at least 40 $MtCO_2$[5], based on existing public information or confidential information provided to TNO. The rationale is that any sites with initial estimates below 40$MtCO_2$ are unlikely to accommodate the long term needs of commercial CCS.
- Depth: fields located at depths shallower than 1000 meters have been excluded, as the low density of CO_2 at those depths renders storage inefficient[6].

These criteria have limited the number of individual fields to be investigated in this study to the following four (the numbers correspond to the numbers in Figure 5-1):

1. K08-FA (130 $MtCO_2$, operated by NAM);
2. K15-FB (54 $MtCO_2$, operated by NAM);
3. L10-CD (125 $MtCO_2$, operated by Gaz de France Suez);
4. K05a-A (40 $MtCO_2$, operated by Total);

[5] In an earlier study, an overview has been made of all depleted gas fields in the Dutch offshore, for which the storage capacity has been categorized (NOGEPA, 2008). Two fields (K08-FA, L10-CD) are in the highest category (storage capacity >50 $MtCO_2$). Both are included in this study. Two fields in the category 20-50 $MtCO_2$ category (K15-FB and K05a-A) have also been included. In this study, it has been estimated that the storage capacity of K15-FB is 54 $MtCO_2$ (under the assumptions specified in this report), while the storage capacity for K05a-A is close to 40 $MtCO_2$.

[6] The depth threshold depends on local temperature and pressure, but is generally between 800 m and 1000 m. In this depth range, the density of CO_2 increases dramatically, as CO_2 crosses a phase transition from gas phase to dense phase.

In the description of these four fields, additional storage options in nearby fields, such as those operated by the same operator from the same platform, have also been identified. However, they do not qualify for independent assessment due to their low storage capacity.

Among the excluded fields are:

- K02-FA (operated by Gaz de France Suez); in spite of its large appearance on the map (see Figure 5-1), this field has a total capacity well below 40 $MtCO_2$.
- Fields in the A- and B-quadrants, operated by Chevron. These fields are too shallow for efficient CO_2 injection.

5.2.2 Clusters of gas fields

From the analysis of the individual depleted gas fields, it becomes apparent that no single field in the DCS has sufficiently high storage capacity to support the long term needs of CCS deployment in the Netherlands. Considering a scenario of up to 5 $MtCO_2$ captured per year over a period of 40 years (the life time of a typical coal fired power plant), it is clear that storage sites with a capacity of at least 200 $MtCO_2$ would be required and it may be worth exploring the possibility of aggregating storage in gas field clusters.

In our view, in order for CO_2 storage in clusters to make economic sense, they should contain at least one or a few ‘core’ fields, such as the four fields identified above, that can maintain a certain injection rate over a large period of time. The resulting clusters analyzed in this study coincide with those identified in the earlier NOGEPA study referred to above (see Figure 5-2.).

One exception to this configuration would be a cluster consisting of the numerous smaller fields in the K04- and K05-blocks, with total storage capacity estimated by NOGEPA in its earlier study at 190 $MtCO_2$. While there would be no ‘core’ field in this cluster, section 4.8 of this report, presents the possible injection rates for the largest field (K05a-A).

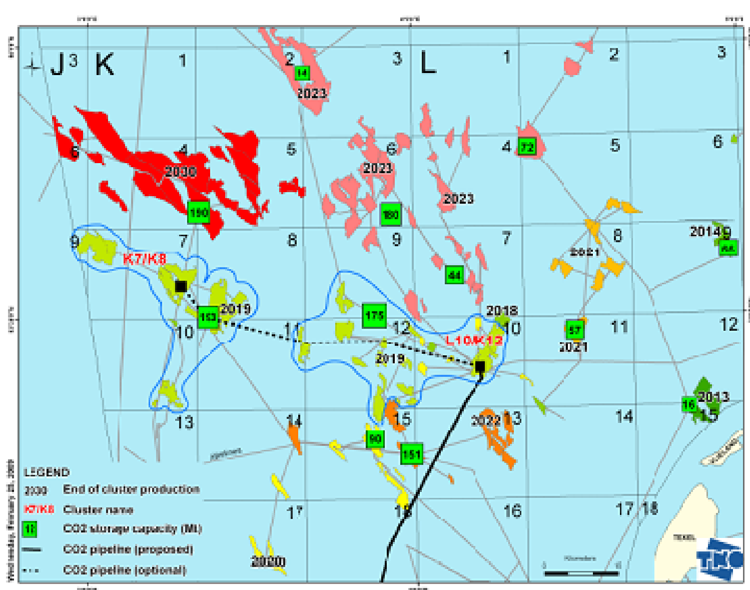


Figure 5-2 Possible clusters in the Dutch Offshore. Source: NOGEPA (2008).

In all cases, a description of the setting and infrastructure, as well as an estimate of the storage capacity are provided for the cluster and the key technical risks and timing considerations for the development are discussed.

5.3 Methodology

5.3.1 Setting and infrastructure

For all individual fields, the geological setting and existing infrastructure are described. With regards to geology, the fields described in this report are all Rotliegendes sandstones reservoirs sealed by Zechstein salt layers, which ensure safe and secure storage. The review of existing infrastructure refers to platforms, wells and pipelines currently used for the production of the fields.

This information has been sourced primarily from the production plans that operators are required to submit in their application for a production license, which are publicly available at www.nlog.nl.

5.3.2 Calculation of injection capacity and rates

The total field storage capacity is calculated using a material balance equation. The pressure build-up in the reservoir, starting from the abandonment pressure of the gas production phase, is calculated for increasing volumes of injected CO_2, taking into account the pressure and temperature dependent CO_2 density. It is assumed that CO_2 can be injected until the reservoir reaches its initial pressure (at the start of production).

The initial volume of gas, the initial pressure and abandonment pressures of the reservoirs are provided by the operators. The temperature of the reservoir is either provided by the operator or estimated from the depth of the reservoir.

The estimation of the injection rates that can be maintained over relevant time horizons is derived by the same model as described in phase 1 and 2 of this assessment (see Neele et al., 2011a). The model is governed by material balance equations (for the pressure build-up in the reservoir) and well inflow equations based on the difference between the flowing bottom hole pressure in the well and the average reservoir pressure at any point in time.

The most important input variables of the model for each reservoir are depth, thickness, temperature, initial pressure, abandonment pressure, permeability and initial gas volume. The operators also provide information about the number of wells available for injection.

For each field, alternative injection scenarios have been modeled and our analysis estimates the possible plateau injection rates and the period over which these rates can be maintained, based on the following assumptions:

- Injection starts from one well. Any additional available wells are used to maintain injection at the target plateau rate. The plateau rates is assumed to be achieved in 3 years from start of injection;
- The maximum number of wells is the number of currently active production wells, based on information provided by the operator;
- No new wells are drilled;
- There is no constraint on the trunk line capacity;

- The pressure and temperature at the well head are 80 bar and 10 °C respectively; the flowing bottom hole pressure is a (constant) function of the well head pressure, the depth of the wells and the mean density of CO_2 over the length of the well;
- Other than the utilization solely of existing (re-worked) wells, no other economic considerations have been taken into account

5.3.3 Identification of possible risks

Depleted gas field have a proven seal quality and often reliable capacity estimates, based on data available from the gas production phase. From this perspective, depleted gas fields represent attractive possibilities for CO_2 storage. Nonetheless, there are a number of risks factors that need to be taken into account.

Abandoned wells impose a risk for damage of the seal or leakage along the well path, especially if the abandonment has not been done properly. Given a large number of identified fields were developed and abandoned decades ago, there is a risk that production wells were abandoned before 1976 when relevant stricter regulation came into force or with no consideration of possible future re-use of the reservoir. As such, this study identifies the number of any abandoned wells in the field (and, if so, the year of abandonment[7]) and provides an assessment of the integrity of the non-abandoned wells, based on information provided by the operators.

Faults impose a risk for CO_2 injection, because of possible induced seismicity during storage (re-pressurization of the reservoir) and leakage to other reservoirs or aquifers. Furthermore, thermal stresses resulting from the injection of CO_2 at much lower temperatures than the reservoir temperatures might result in fracturing of the reservoir rock. Investigation of fault integrity and possible thermal fracturing always implies a detailed study of the geomechanical behavior of the reservoir and is beyond the scope of this assessment. With respect to geomechanical risks, information about seismicity is provided where available.

A possible injection problem is hydrate formation when the injected CO_2 enters the reservoir at a temperature lower than 12°C. Hydrate formation can seriously decrease injection rates. Heating of the CO_2, prior to injection is an option, but expensive. A detailed reservoir simulation study including different injection profiles should always be part of the technical feasibility study.

5.4 Site development plan

The site development plan outlined in Appendix A, Section A.1 applies to the fields and clusters discussed below. That section also gives cost figures, as a base for cost estimates given below.

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[7] Wells have been abandoned according to regulations at the time of abandonment. In 1976 the regulations for abandoning wells were made stricter. The integrity of wells abandoned before that time should be checked closely.

5.5 Assessment of K08-FA (NAM)

5.5.1 Setting and infrastructure

The K08-FA field operated by NAM, is situated in a complex structure of several fields and compartments separated by faults, located about 100 km northwest of Den Helder. It has an estimated storage capacity of 130 $MtCO_2$.

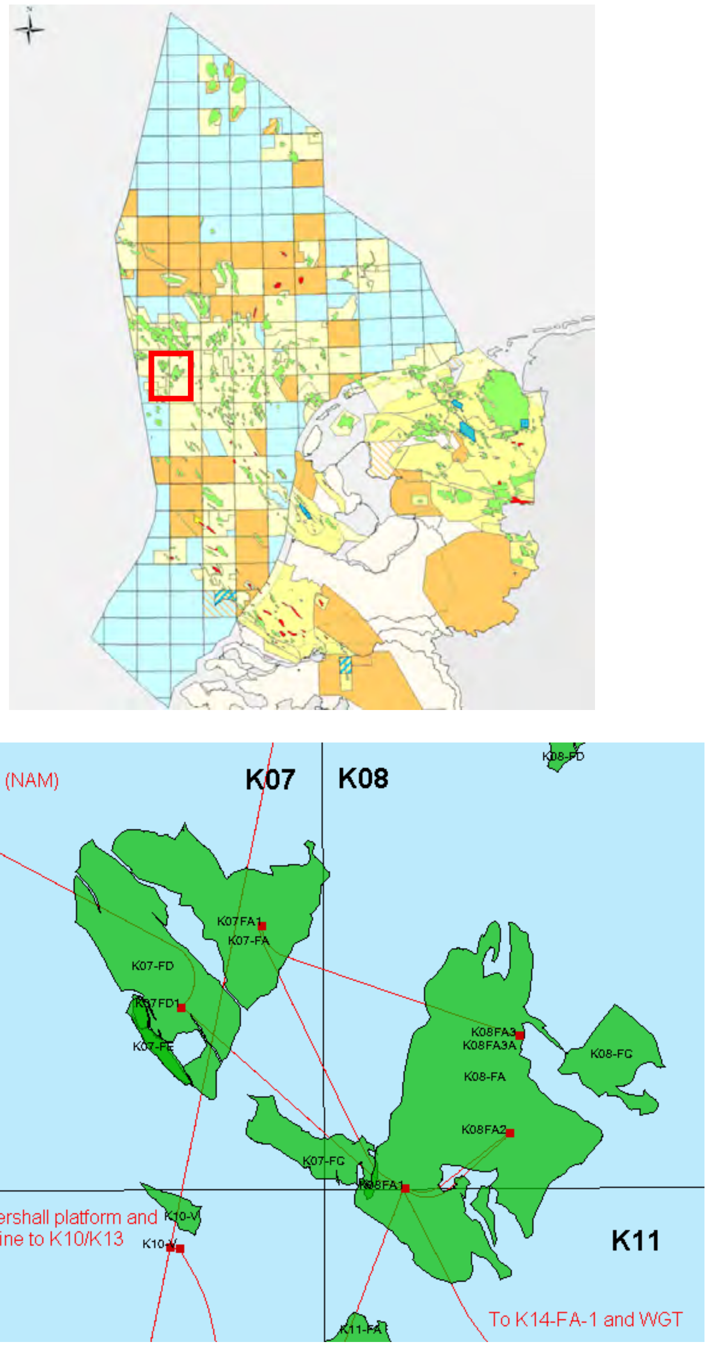


Figure 5-3 Map of the K08-FA field, its platforms and neighbouring accumulations.

The K08-FA field consists of four blocks, of which the Northern, Central and Southern blocks are the largest. The fourth and smaller compartment is identified as block 2B. All blocks are produced from three platforms (K08-FA-1, K08-FA-2 and K08-FA-3), from which the K07-FC accumulation is also produced. The wet gas is collected and processed at platform K08-FA-1, to which a fourth platform (K07-FD-1) is also connected. From this platform the K07-FD and K07-FE accumulations are produced. With regards to wells that may be available for injection once production has ceased, the operator has stated that in the Southern block there are three, in the Central block there are five, while in the Northern block there are three (all in 2019). Apart from a collapsed casing at the surface of one of the producing wells in the Southern block, there are no indications of problems with the available injection wells. However, well integrity is an issue that must be considered (see section 5.3.3).

The fields and platforms mentioned above are part of a larger systems of fields and platforms called the HiCal system. Gas produced in this system is gathered at a platform in the K14-block, compressed and sent to Den Helder through the West Gas Trunk (WGT) pipeline.

The accumulations in the K08-FA and K07-FC/FD/FE fields are covered by the same production license of NAM. NAM also holds a license to produce the nearby fields K07-FA (North of K07-FD), K07-FB (West of K07-FD) and K08-FC (East of K08-FA). All these accumulations are small compared to the large blocks in the K08-FA field. However, since infrastructure is shared, it is recommended to include at least K07-FA and K07-FC in a more detailed study. Both add about 10 $MtCO_2$ to the total storage capacity. See also the clustering options below. Figure 5-3 gives an overview of the different accumulations and platforms.

All gas accumulations are in Rotliegendes sandstones, alternated by shale layers. The seals of the reservoirs are predominantly Zechstein salts and anhydrites. The accumulations are located at a depth of about 3200 m. For this assessment, the storage capacity of the three largest blocks in the K08-FA field is calculated individually.

5.5.2 Storage capacity and feasibility rates

Table 5-1 gives an overview of the estimated storage capacity and plateau injection rates, including the period over which these rates can be maintained, for the individual blocks in the K08-FA field. Note that it is assumed that there is no communication between the different blocks. While this can easily be confirmed using production data, it falls outside the scope of this study due to confidentiality considerations of the underlying data.

Table 5-1Storage capacity and possible plateau injection rates and duration for the different blocks of the K08-FA field.

Block	**Capacity ($MtCO_2$)**	**Plateau Injection rates and duration ($MtCO_2$/yr [duration])**		
K08-FA-North	15	1.0 [14 yr]	2.0 [6 yr]	3.0 [4 yr]
K08-FA-Central	84	3.0 [26 yr]	6.0 [12 yr]	9.0 [7 yr]
K08-FA-South	31	2.0 [14 yr]	4.0 [6 yr]	6.0 [3 yr]
Total	**130**			

5.5.3 Key technical/geological risks and uncertainties

Well integrity for the K08-FA field is an issue that must be considered. In total, 30 wells have been drilled penetrating the seal and/or the reservoir. Five of these were abandoned before 1976, when the stricter regulations came into force, and impose a possible higher risk for CO_2 injection. Six wells were abandoned at a later stage. For one of the operational wells in the K08-FA field, located in the Southern block, NAM has reported a collapsed casing at the surface. However, the well is still producing.

Two of the production platforms (K08-FA-1 and K08-FA-2) were installed in 1977 and it is likely that they have to be replaced if the site is to continue to be used for a long period of CO_2 injection. Also, the satellite platform K08-FA-3 was installed in 1984, more than 25 years ago.

Faults always impose a risk to CO_2 storage because of induced seismicity and possible leakage to other reservoirs. In this case, there is no indication of natural unstable faults. Information about induced seismicity during the gas production is not available.
Detailed geological and reservoir modeling in the feasibility study will yield further information on the connectivity of the different blocks in the K08-FA field.

5.5.4 Clustering options and timing

The K08-FA field can be seen as the central field in a cluster also containing the fields in the K07-block and the K10-FB field operated by Wintershall (see Figure 5-4). Below, the timing of availability of platforms and expected years of end of field production are presented (Table 5-2). Note that the different platforms of the K08-FA field are not foreseen to be available at the same time (production from the satellite platforms K08-FA-2 and K08-FA-3 stops earlier than the availability of the main platform). The main platform becomes available a few years after the expected end of production of the entire field. As such, the K08-FA field alone may require mothballing for a period of 5-10 years, while the development of the entire cluster, may require mothballing of some platform for an extended period of time.

Table 5-3 gives an overview of the storage capacity in the entire cluster, including the availability of the main platform for each field (as reported by the operator) and its age. Depending on their design and state at the end of production, it is possible that older platforms may not be re-used and may have to be replaced if the fields are to be used for CO_2 storage. A typical life time for platforms is assumed to be 40 years.

Table 5-2Platform availability for injection in the K08-FA fields (and nearby accumulations).

Platform	**Year available**	**Field**	**Year available**
K08-FA-1	2023	K08-FA	2019
		K07-FC	2015
K08-FA-2	2018	K08-FA	2019
K08-FA-3	2018	K08-FA	2019
		K08-FC	production stopped
K14-FA-1	2023	[> WGT]	

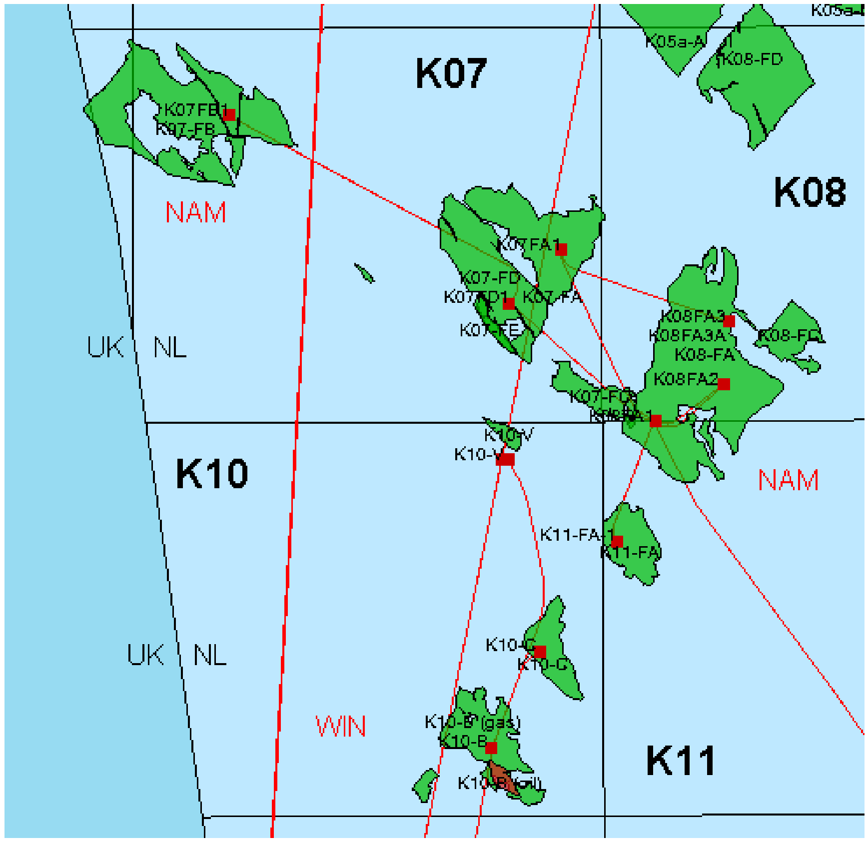


Figure 5-4 Overview map of the K7/K8/K10 cluster.

Table 5-3Storage capacity and platform availability for the K7/K8/K10 cluster.

Field (operator)	**Capacity ($MtCO_2$)**	**Platform year of availability**	**Platform year of installation**
K07-FA (NAM)	≈ 10	2018	1980
K07-FB (NAM)	< 5	2017	2003
K07-FC (NAM)	≈ 10	2023	1977
K07-FD (NAM)	< 5	2017	1988
K07-FE (NAM)	< 5	2017	1988
K08-FA (NAM)	130	2023	1977
K10-B (WIN)	≈ 35	not reported	1981
Total	**195**		

5.6 Assessment of K15-FB (NAM)

5.6.1 Setting and infrastructure

The K15-FB field operated by NAM, is part of a system of fields that is referred to as the LoCal system, located about 60 km North West of Den Helder. The field has an estimated storage capacity of 54 MtCO_2.

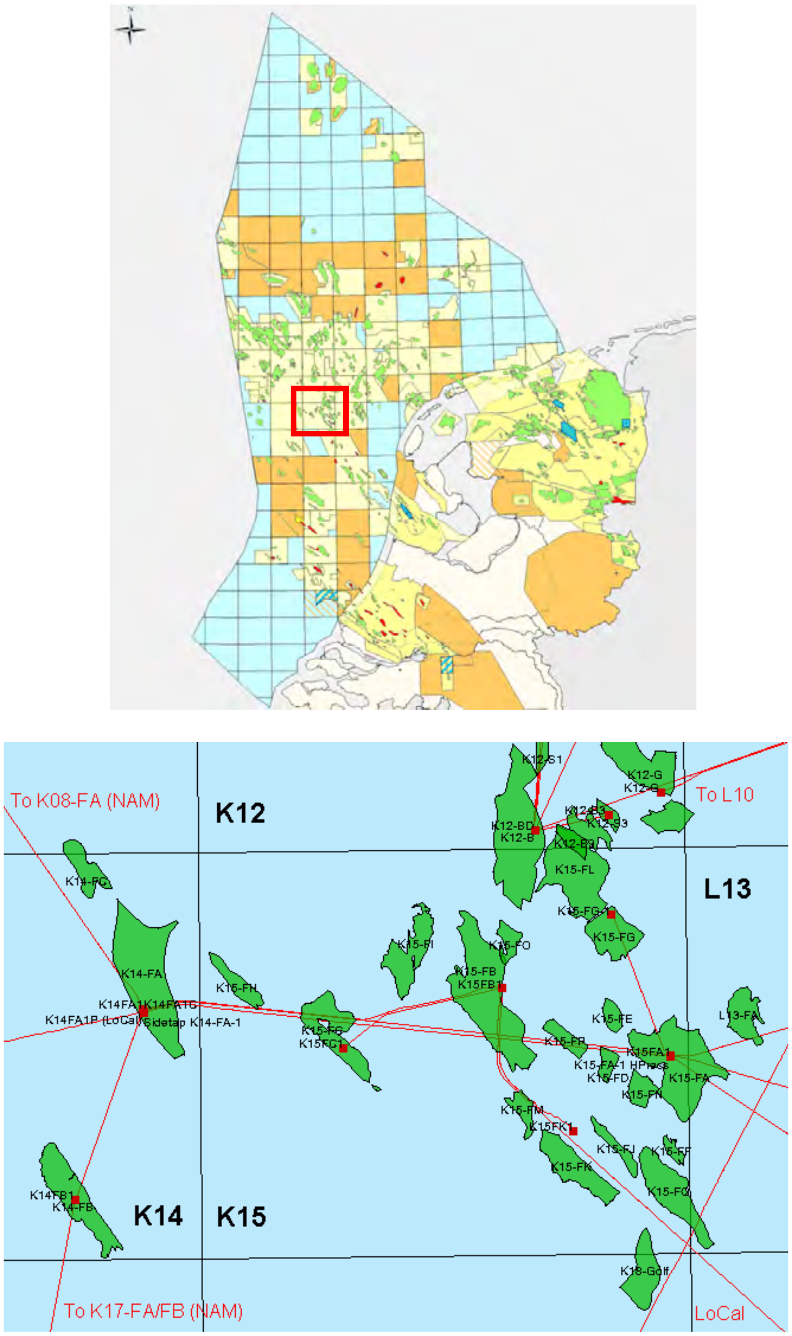


Figure 5-5 Overview map of the K15-FB and neighbouring fields.

Table 5-4Storage capacity and possible plateau injection rates and duration for the different blocks of the K15-FB field.

Field	**Capacity ($MtCO_2$)**	**Plateau inj. rates and duration ($MtCO_2$/yr [duration])**		
K15-FB	54	3.0 [18 yr]	6.0 [8 yr]	9.0 [5 yr]

The LoCal system also comprises the K14-FB, K15-FC and K14-FK fields. The gas is transported from one of the platforms to Den Helder by a dedicated pipeline. The K15-FB field consists of two parts, both with an anticlinal structure at a depth of over 3500 meters. The reservoir consists of Rotliegend sandstones, alternated by shale layers. The seal consists of Zechstein chalk, salt and anhydrite layers.

The K15-FB field is produced from one platform by six wells, all of which are available for CO_2 injection. Figure 5-5 gives an overview of the K15-FB and nearby fields as well as the production platforms. As is apparent from Figure 5-5, there are many small fields in the K15 block that can provide additional storage capacity in a cluster (see options below).

5.6.2 Storage capacity and feasible rates

Table 5-4 gives an overview of the estimated storage capacity for the K15-FB field and plateau injection, including the period over which these rates can be maintained.

5.6.3 Key technical/geological risks and uncertainties

The risk with respect to well integrity for the K15-FB field can be qualified as limited. In five of the six production wells, side tracks have been drilled because the mother well was either dry (no connection to hydrocarbon filled layers) or technically failed. In one of these wells, also the side tracks were dry and/or failed. However, no possible show stoppers concerning the wells have been reported by the operator. Only 4 wells in the reservoir have been abandoned, none of which more than 35 years ago.

The platform from which the field is produced was installed in 1978 and might be replaced if this field will be used for CO_2 storage.

5.6.4 Clustering options and timing

Production of the K15-FB field was expected to end in 2011, however, it is currently estimated to continue for at least 5 years. NAM, the operator, has reported that the platform will be available for CO_2 injection from 2023 onwards.

Table 5-5Storage capacity and platform availability for the K14/K15 cluster.

Field	**Capacity ($MtCO_2$)**	**Platform year of availability**	**Platform year of installation**
K14-FA	≈ 35	2023	1975
K14-FB	≈ 15	2023	1997
K15-FG	≈ 15	2022	1990
K15-FB	54	2023	1978
K15-FA	≈ 30	2022	1977
K15-FK	≈ 15	2023	2002
Total	165		

The K15-FB field can be considered as the core field of a cluster of fields in the K14- and K15-blocks. Figure 5-6 gives an overview of this cluster. For all these fields, the operator has reported the platform availability. An overview is given in Table 5-5. It should be noted that production from the field is expected to end earlier than the platform availability.

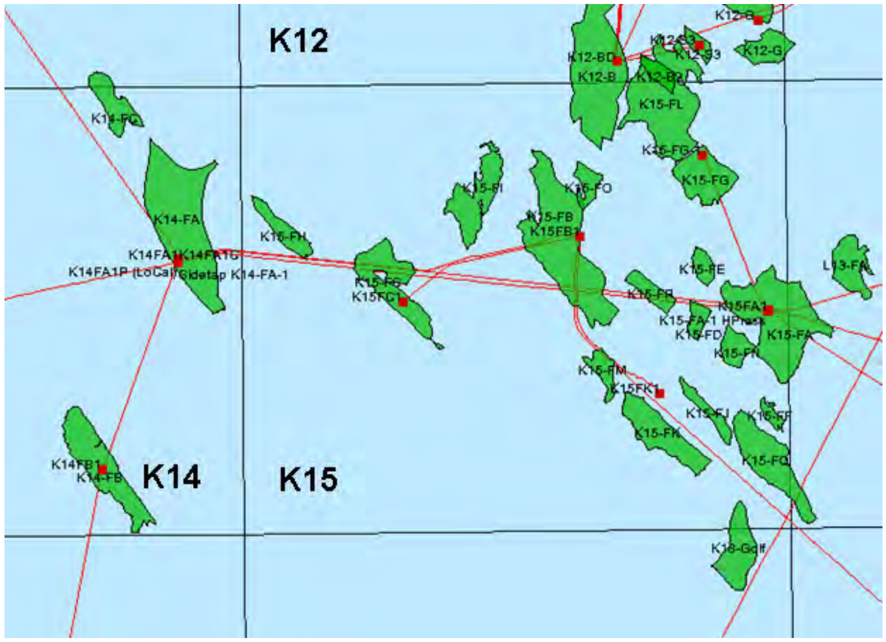


Figure 5-6 Overview map of the fields in the K14/K15 cluster.

5.7 Assessment of L10-CD (Gaz de France Suez)

5.7.1 Setting and infrastructure

The production license of L10-Central Development Area (L10-CD) covers the production of gas in many accumulations in the L10 block. The estimated storage capacity for L10-CD is 125 MtCO_2.

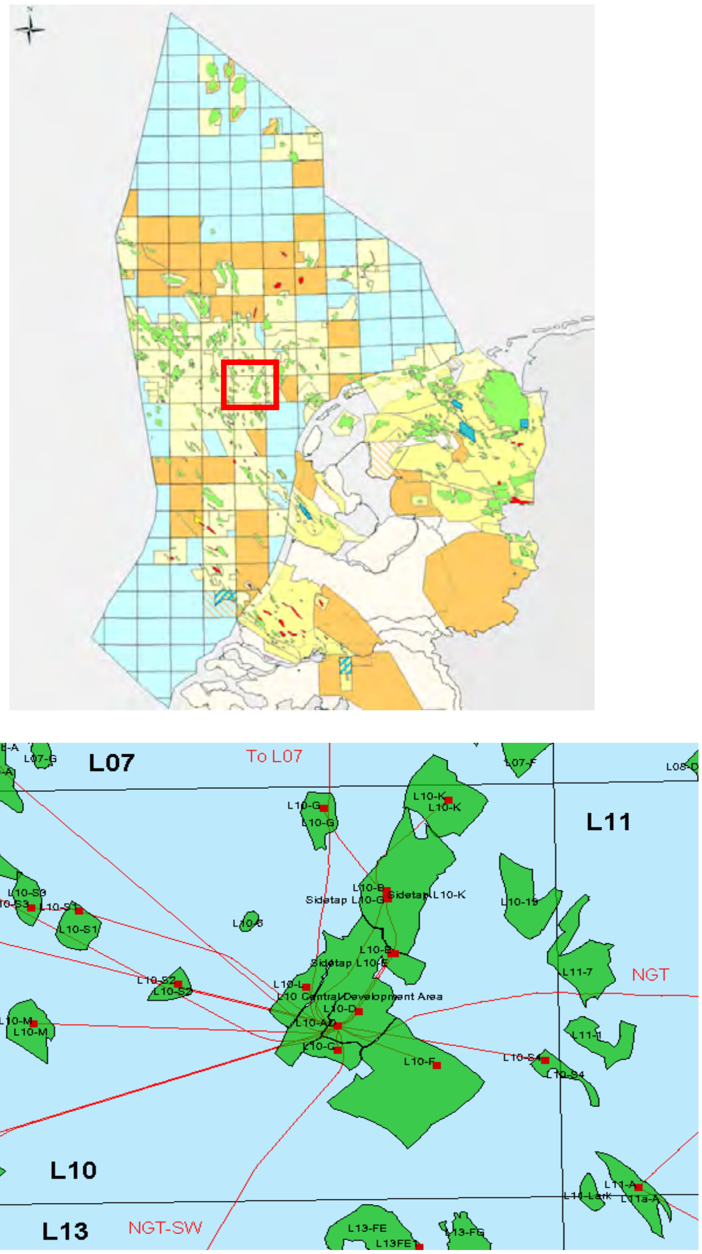


Figure 5-7 Map of the L10-CD field and neighboring accumulations.

The accumulations that are part of the L10-CD field are the A-, B-, C-, D-, E-, F- and L-parts. The S-, G- and K-parts do not belong to the L10-CD field (see Figure 5-7). The L10-block is located about 60 km from Den Helder, but the platforms connect to the NGT pipeline which transports the produced gas to Uithuizen. The main platform is the L10-A platform. In addition, there are 7 satellite platforms and 4 subsea completions. A total of 53 wells have been used to produce the different accumulations. On January 1, 2010, 34 of these wells were still producing (according to the publicly available production plan). The accumulations are all in Rotliegend sandstones at a depth of about 4000 meters. Zechstein salt layers form the sealing layers.

Figure 4-13 gives an overview of the accumulations in the L10-L11 area.

5.7.2 Storage capacity and feasible injection rates

The L10-CD field has a total storage capacity of 125 $MtCO_2$. However, as reported figures by the operator, GdF Suez, are aggregated at field-level, no estimate can be made for the individual parts of the reservoir. There is significant uncertainty with respect to the suitability of the wells for CO_2 injection (see also below). For this reason, no accurate estimate can be made with respect to the possible injection rates in the different parts of the field.

It is not expected that high injection rates in the L10-CD reservoir are possible. The reservoir quality is poor; the permeability is low. This is most likely one of the reasons that the reservoir is currently produced using a large number of wells and it is expected that a large number of wells will also be required for CO_2 injection.

A first order estimate of possible injection rates has been made for a part of the reservoir of approximately one third of the size (representing a larger compartment such as the F-compartment, see Figure 5-7), assuming one well immediately available for injection and three potential new ones. It would be possible in such a compartment to maintain an injection rate of 2 $MtCO_2$/yr for 17 years. However, a rate of 4 $MtCO_2$/yr can not be maintained longer than 4 years, due to the low permeability of the field.

5.7.3 Key technical/geological risks and uncertainties

The risk with respect to well integrity in this field can be classified as very serious. The operator has not reported the total number of wells that are available for injection. In total, the status of 39 wells has been reported in the L10-CD field, and 32 of these are classified as producing. For 15 wells, production problems have been reported, ranging from collapsed casings, sand production, serious liquid loading and problems with the perforation gun. These problems will at a minimum affect the operation of the corresponding wells or even render them unsuitable for conversion into CO_2 injection wells. For example, sand production may have affected the integrity of the well because of erosion of the casing. Three of the non-producing wells have been abandoned. The 39 wells in the status report do not include 4 wells that were abandoned before 1976 and 12 wells abandoned more recently.

The main platform from which the field has been produced was installed in 1974 and probably needs to be replaced if this field is to be used for CO_2 storage. It is unlikely that one platform will be sufficient to develop the site for large scale CO_2 injection.
With respect to seismicity, the field is naturally stable, but no information is available about possible induced seismicity during the production process.

In the feasibility study, connectivity between the different compartments in the reservoir is an important aspect of the geological and reservoir modeling. As mentioned above, the poor reservoir quality is another issue that needs to be addressed.

5.7.4 Clustering options and timing

The expected end year of production for the accumulations in the L10 area is 2022. However, it should be noted that different platforms are foreseen to be abandoned well before then. The operator has reported years of platform availability starting in 2007 (L10-C and L10-D). The current state of these platforms needs to be verified, as is also the case for platform L10-E (reported to be available in 2010), L10-B (2011) and L10-L (2011).

Although the L10-CD field can be considered as a cluster by itself, it can also serve as the core field of a cluster also containing fields in the K12-block (see Figure 5-8). Table 5-6 gives an overview of the storage capacities of the different fields in this cluster, as well as information about the year of installation and availability of the different platforms.

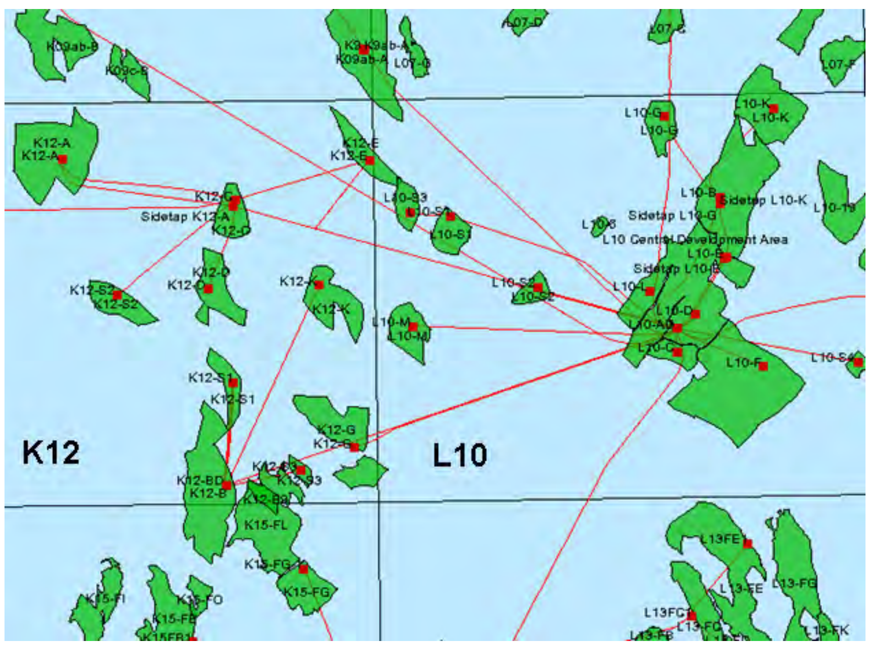


Figure 5-8 Overview map of the fields in the L10/K12 cluster.

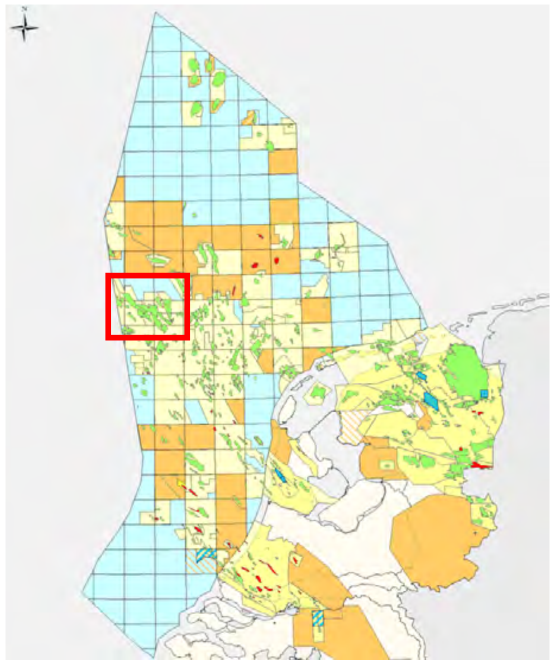
Table 5-6Storage capacity and platform availability for the L10/K12 cluster.

Field	**Capacity ($MtCO_2$)**	**Platform availability**	**Platform year installation**
L10-CD	125	2019	1974
K12-B	≈ 30	2017	1987
K12-D	< 5	2010?	1985
K12-G	≈ 15	2019	2001
K12-S3	< 5	2012	2003 (subsea)
Total	**175**		

5.8 Assessment of K04- and K05-blocks, including K05a-A (Total)

5.8.1 Setting and infrastructure

Total operates a number of fields in the K04- and K05-block, located about 120 km northwest of Den Helder. A cluster of these fields has an estimated storage capacity of 140 $MtCO_2$[8].



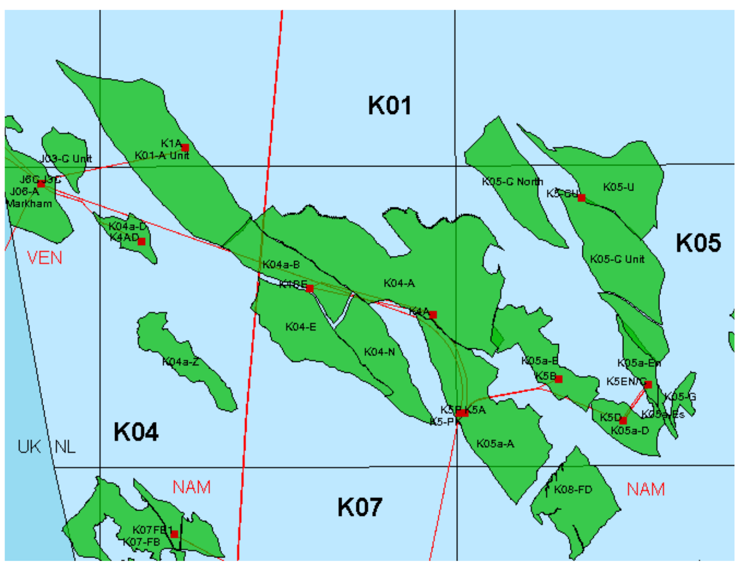


Figure 5-9 Map of the fields in the K04- and K05-blocks.

The fields in the K04- and K05-blocks are formed by Rotliegendes sandstones at a depth between 3500 and 4000 meters. The reservoirs are sealed predominantly by

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[8] The capacity is listed in Section 4.2.2 as 190 Mt. The difference lies in the fields in the J-blocks, that were not included here.

Zechstein salt layers. The largest field in the cluster is the K05a-A field, which a capacity close to 40 $MtCO_2$. For this field, possible injection rates are calculated (see below).

Three connected platforms (PE-K5-PP, PE-K5-PK and PE-K5-PA) form the so called K5 Central Complex (K5CC) from which some of the fields, including K05a-A, are produced. For other fields, K5CC is the riser platform and the platform where the produced gas is treated. From K5CC, gas is transported to the shore through the WGT trunk line. Figure 5-9 gives an overview of the different fields and platforms in the K04- and K05-blocks.

It should be noted that the fields in the K04- and K05-blocks were discovered later than many of the other fields in the DCS. For this reason, the platforms were installed more recently and it is expected that their current state is better than for the other fields described in this assessment. On the other hand, the fields do not become available for injection in the next 15-20 years.

5.8.2 Key technical/geological risks and uncertainties

The risk with respect to the well integrity in the fields in the K04- and K05-blocks can be considered as limited. The operator has reported the status of 29 non-abandoned wells, 3 of which are no longer producing and may be abandoned in the (near) future. For the other wells, no problems are reported that are considered show stoppers for CO_2 injection. A further 11 wells in the cluster have already been abandoned, only one of which before 1976 when the stricter regulations came into force.

The current platforms are rather new, with the earliest platform installed in 1994. However, CO_2 injection is unlikely to start for another 15-20 years, as the reservoirs are still producing. This cluster can benefit from experiences with CO_2 storage in other clusters, including best practices for renewal or replacement of the installation.

There is no indication that fault integrity or induced seismicity is a risk for the fields in the K04-05 cluster.

5.8.3 Storage capacity, possible rates and timing

The largest field in the K04-05 cluster, K05a-A, has a storage capacity close to the lower threshold determined for this assessment and the plateau injection rates, including the period over which these rates can be maintained are presented in the table below:

Table 5-8 gives and overview of the storage capacity and the availability of the platform for the fields in the K04- and K05-blocks. Note that two fields in the western part of the cluster (K04a-D and K04a-Z) are not included because of their very limited storage capacity. The fields K05a-C en K05a-E are produced from the same platform and are combined in the overview.

Table 5-7Storage capacity and possible plateau injecttion rates and duration for the K05a-A field.

Field	**Capacity ($MtCO_2$)**	**Plateau inj. rates and duration ($MtCO_2$/yr [duration])**		
K05a-A	40	2.0 [19 yr]	3.0 [12 yr]	5.0 [6 yr]

Except for the K05a-D field, none of the fields in the cluster will become available before 2020. In addition, if the K05a-C and K05a-E fields, whose platforms are expected to become available 2–6 years earlier than the rest, are disregarded due to their small size, there will only be a limited (if any) mothballing period for this cluster. The fields in the K04- and K05-blocks are among the latest connected to the WGT trunk pipeline to the Dutch shore. Therefore, there is a possibility that this pipeline can be re-used for CO_2 transport to the storage site. Another advantage of the late availability is the opportunity to learn from experiences from other clusters (with respect to re-use of infrastructure, timing to bring sites to operation, et cetera).

Table 5-8Storage capacity and platform availability for the K04-K05 cluster.

Field	**Capacity (MtCO_2)**	**Platform availability**	**Platform year installation**
K01-A-Unit	≈ 25	2028	2001
K05a-A	35-40	2028	1994
K05a-B	≈ 10	2024	1995
K05a-C/E	5-10	2022	1997
K05a-D	10-15	2015	1994
K04a-B	5-10	2028	2000
K04-E	≈ 10	2028	2000
K04-N	10-15	2028	2000
K04-A	15-20	2028	1998
Total	**140**		

5.9 Summary

Depleted gas fields offer attractive potential for CO_2 storage. Their capacities and geological settings, including sealing layers, are relatively well known and existing production infrastructure may be re-used for injection.

Technical risks associated with storage in depleted gas fields can be summarized as:

- Integrity risks, for example due to improper abandonment of wells;
- Geomechanical risks, such as fault reactivation;
- Injectivity problems, for example due to poor reservoir quality or problems with re-used wells.

In addition to the technical risks, commercial or contractual issues are very important.

- Required and available storage capacity needs to be matched in time in agreement between emitters and operators.
- From the operator's perspective, matching supply and demand of capacity may involve mothballing infrastructure. For some fields, immediate action is required to prevent loss of storage capacity.
- From the emitter's perspective, capture and transport options needs to be aligned with the timing of capacity availability.

Table 5-9Summary depleted gas fields

Field (operator)	Capacity ($MtCO_2$)	Cluster capacity ($MtCO_2$)	Timing considerations	Overall complexity, risk level	Next steps
K08-FA (NAM)	130	195	Available 2023. Mothballing required for both field and cluster.	Moderate: multiple fields, aging infrastructure; high risk well integrity.	Feasibility study.
K05a-A (Total)	40	140	Available 2028. Mothballing not a serious issue. Benefit from experiences pilot projects.	Low: relatively modern infra-structure; moderate risk well integrity.	Best practices other projects.
K15-FB (NAM)	54	165	Available 2023. Mothballing not a serious issue.	Low: multiple fields, aging infrastructure; low risk well integrity.	Feasibility study.
L10-CD (GdF Suez)	125	175	Immediate actions required. Mothballing serious issue.	High: multiple fields, poor reservoir quality, high risk well integrity	Immediate action, feasibility study.

Clustering depleted gas fields is the only way to develop storage sites with capacities in the order of 150-200 $MtCO_2$. A field that has too low a storage capacity by itself for cost-efficient storage of CO_2 may be attractive when included in a cluster with shared infrastructure.

In this study, four fields are studied in detail, all of which can be considered as an important field in a cluster. Table 5-9 summarizes their individual and cluster storage capacity, timing considerations, overall complexity and next steps (see also appendix A). An overview with more information on each of the fields is given in Section 7 (Table 7-2).

6 Storage in offshore oil fields

6.1 Introduction

For purposes of completeness, this study also assessed the suitability of the limited oil fields in the Dutch Continental Shelf for enhanced oil recovery (EOR), as a means to absorb further CO_2 volumes from CCS projects in the Netherlands. It is noted that the development of EOR in connection with CCS is currently being considered in the large oil fields in the Norwegian and UK sectors of the North Sea, representing a theoretical demand of up to tens of millions of tons of CO_2 per year and significant additional oil revenues that could potentially finance part of the CCS infrastructure.

A recent study by NOGEPA investigated the theoretical CO_2 storage capacity of offshore oil fields (NOGEPA, 2010) and provided a detailed worked example of storage capacity in the oil fields in the Q1 area. As mentioned in the previous section, the larger part of the storage capacity in the Q1 structure is located in the saline formation, rather than in the oil fields. The storage capacity in oil fields in the entire DCS was estimated to be of the order of hundreds of millions of tons. However, storage capacity due to water extraction from the associated saline formations represents the larger part of this capacity.

This section outlines the potential for enhanced oil recovery in oil fields across the entire DCS and estimates both the volume of additional oil produced through CO_2 injection and the amount of CO_2 that can be stored in these fields, assuming that CO_2 replaces any incremental oil produced. In addition to this theoretical exercise, operators were contacted for their view on EOR with CO_2 in their field(s). Special focus is put on the combination with potential CO_2 storage activities elsewhere in the DCS.

6.2 Potential CO_2 demand for CO_2-EOR

The criteria to assess whether the Dutch offshore oil fields are suitable for the use of CO_2 for EOR purposes are as described in Chapter 5 of the IPCC Special Report on Carbon Capture and Storage[1] (IPCC, 2005). The report does not mention excluding aspects of oil fields for the use of CO_2-EOR. However, based on the composition of the oil (as expressed in degrees API, which ranks the oil from light (low degree API) to heavy oil (high degree API)), a distinction is made between:
a) immiscible flooding (API 12-25);
b) miscible flooding (API 24-48, pressure above 10-15 MPa).

Generally, immiscible flooding tends to be applicable for the heavier oils, while lighter oils tend to be more suitable for miscible flooding. Miscible flooding required a so-called minimum miscibility pressure (MMP), which stands for the minimum pressure at which full miscibility occurs. The IPCC report assumes values in the range of 1-15 MPA. It should be noted that the actual MMP depends on a number of factors including the composition of the oil, reservoir temperature and the composition of the injected CO_2. For the current inventory, a minimum pressure of 10 MPa for miscible pressure has been used.

Given the rather general criteria, almost all Dutch oil fields, in principle, are suitable for CO_2-EOR. A minimum increased recovery of 1.0 Mm^3 was applied to exclude the smallest fields. This corresponds to a minimum (theoretical) storage capacity for CO_2 of about 0.7 $MtCO_2$ (assuming a density, at reservoir conditions, of the order of 700 kg/m^3).

Besides the general criteria, there are also reservoir specific conditions. Excluded from this screening study were fields with a gas cap (as the CO_2 would migrate into the gas cap), gas fields containing an oil rim (quantity of oil too small) and carbonate fields (possible reactivity between CO_2 and reservoir); other factors, such as aquifer activity or slope of the reservoir, were not considered.

Figure 6.1 shows the offshore areas in which clusters of oil reservoirs are located. The individual structures are small, with respect to CO_2 storage. Furthermore, the ultimate recovery of an oil field is typically only about 40% and the additional production of oil as a result of CO_2 injection is of the order of 10% at most.

The net use of CO_2 is reported to be around 1.2 tCO_2/m^3 for immiscible flooding and 2.4 tCO_2/m^3 for miscible flooding, respectively. The estimated increase of oil production is 3.8 Mm^3 (23.4 Mbbl[9]), for which the net CO_2 consumption ranges from 4.5 to 9 Mt, again depending on the type of EOR (miscible or immiscible). This range represents the total CO_2 stored, as a result of EOR. This volume is distributed over the areas indicated in Figure 6.1, i.e., over almost the entire DCS, as well as over the lifetime of each separate CO_2-EOR project. Resulting yearly volumes of CO_2 needed on a field basis are likely to be of the order of 0.1 Mt/yr resulting in an extra oil production of between 0.3 and 0.5 Mbbl/yr. Table 6-1 lists the results for the clusters shown in Figure 6.1, using an average net consumption of 1.8 tCO_2/m^3 (the average value for miscible and immiscible flooding). It is noted that the volumes reported here do not include storage capacity created by producing water from the saline formation associated with the oil fields. This case, relevant for the oil fields in the K18 – L16 – Q1 blocks, is discussed in Section 4.9.

Table 6-1Summary of oil field clusters. Figure 6.1 shows the location of the clusters. *: the net CO_2 consumption is based on an assumed value of 1.8 tCO_2/m^3 increased oil production (see text).

Cluster	Incremental oil production (Mm^3)	Incremental oil production (Mbbl)	Field status	Estimated end of production	Net CO_2 consumption* (Mt)
North: F02, F03	1.2	7.4	producing	2012	2.2
Central: K18, L16, Q1	1.2	7.4	producing	2012	2.2
South; P9, P15	1.4	8.6	producing	2013 , 2020	1.4

[9] The abbreviation bbl stands for barrel.

6.3 Feasibility of CO_2-EOR in DCS oil fields

The volumes of CO_2 likely to be absorbed in any EOR activities in the DCS are too small to drive CCS development in the short or long term (Table 6-1). In addition, it must be noted that the feasibility of EOR has not yet been established for each field.

Nonetheless, there may be field specific opportunities for use of CO_2 in EOR and some operators in the DCS are currently considering this potential.

For example, the oil fields in the F02 and F03 blocks, located c.150km and 400km from Eemshaven and Rotterdam respectively, (in the northern circle in Figure 6.1) are currently producing and are estimated to continue to around 2018. DANA, the operator has just concluded a screening study for alternative EOR solutions and at this moment, the use of CO_2 is not the first choice.

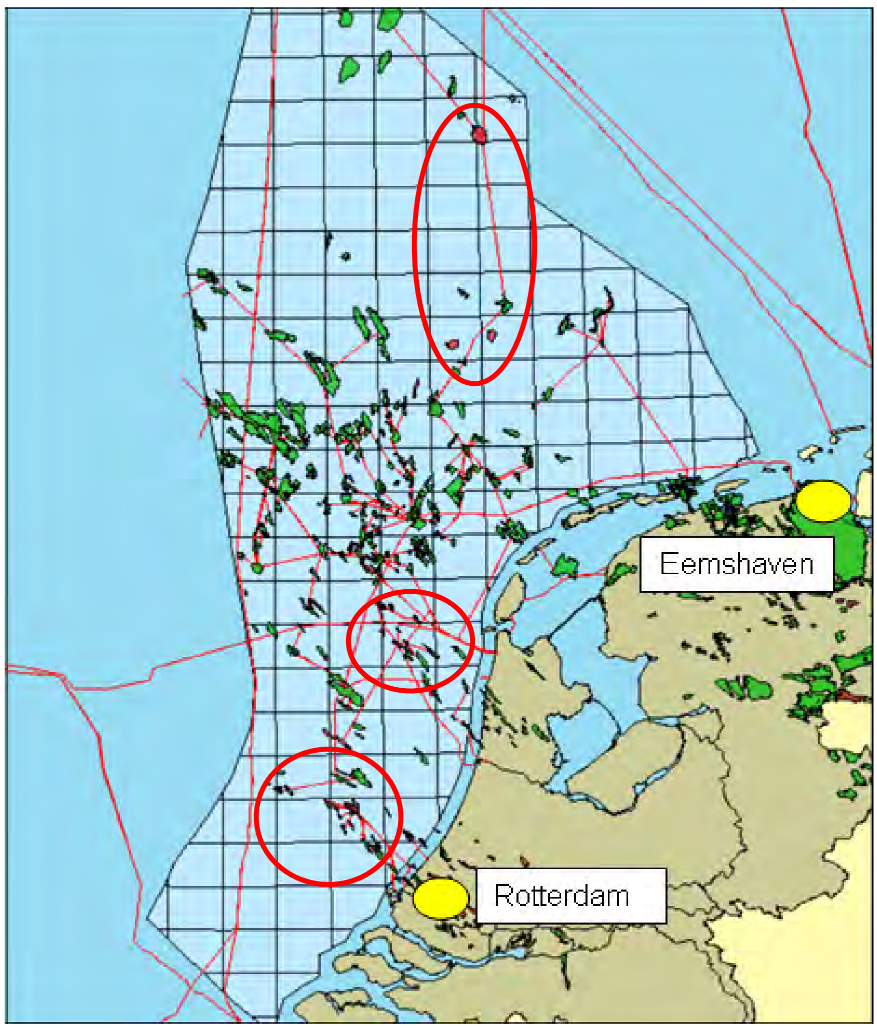

Figure 6.1 Location of the off-shore oil fields (red spots; green indicates gas fields). The circles indicate the location of three clusters of oil fields and are discussed in Table 6-1.

The type of field (chalk) requires laboratory testing to establish the level of interaction between CO_2 and the reservoir formation, but no reservoir samples are available, only small cuttings.

The oil fields in the F14, F17, F18 and L1 blocks (in the lower part of the northern circle in Figure 6.1) are currently not producing and as yet there is no infrastructure in place to produce and transport the oil. The horizon for CO_2-EOR, if any, lies at least 10 – 15 years away. The fields are located outside the cluster of gas fields in the K and L blocks, at about 80 km from L10 field. Once CO_2 is available in that area, transport distances to these fields will still be significant.

The fields in the Q1 area, in the central circle in Figure 6.1 and operated by Chevron and Wintershall, are close to the end of production. The quality of the reservoirs is high: a large percentage of the oil in place is produced, currently using water injection to sustain reservoir pressure. The operator is currently investigating the option of combining CO_2 storage in the saline formation (outside the oil fields) associated with the oil fields with EOR, in two ways. Firstly, CO_2 injection in the saline formation will increase the pressure in the formation, which will provide additional pressure support in the oil fields, which will lead to increased oil production. This approach could be regarded as indirect CO_2-EOR. Secondly, the availability of CO_2 in the Q1 area can help develop CO_2-EOR in the P9 oil field, which is located in the southern circle in Figure 6.1. The oil pipeline that connects the P09 field with the Q1 area can be used to transport the CO_2. The technical feasibility study for the latter field is ongoing and will be followed by an economic analysis. Connecting with the P8 oil field could help improve the business case. It is possible that in these two ways, CO_2-EOR and CO_2 storage can mutually benefit.

The P15-Rijn oil field, located in the southern circle in Figure 6.1 and operated by TAQA, is located close to the P18 field, which is the target storage site for the CO_2 from the ROAD project. Once storage is ongoing at P18 and is possibly continued in the P15 field, CO_2 would be available on the doorstep of the P15 Rijn field. However, although the operator is currently investigating EOR in that field, the use of CO_2 is not the option of first choice, due to well integrity issues.

6.4 Summary

From the point of view of climate mitigation, the results show that CO_2 storage in the Dutch offshore oil fields is insignificant, compared to other subsurface options. For comparison, the Rotterdam Climate Initiative uses CO_2 capture scenarios that grow from volumes of the order of 5 Mt/yr by 2020 to several tens of million tons by 2050. The volumes associated with CO_2-EOR are too small to expect such projects to contribute to major developments in offshore CCS infrastructure.

It should be emphasized that this conclusion does not rule out the existence of unique opportunities (in terms of CO_2 availability) in connection with individual fields, in which the primary objective is oil production optimization rather than climate mitigation. The previous section illustrates that several offshore oil field operators are considering CO_2-EOR as one of the options for their fields. For various reasons, CO_2-EOR is not the option of first choice in most cases.

The option that is most attractive is the combination of CO_2 storage in the saline formation that contains the oil fields in the K18 – L16 – Q1 blocks, with enhanced production in these oil fields, as well as with CO_2-EOR in the P09 oil field.

7 Discussion

7.1 Best high-capacity options

The high-capacity storage options in the DCS are shown in Figure 7-1, colour coded for the type of structure (green: gas field, blue: saline formation). The size of the circle is a measure of the estimated storage capacity. Table 7-1 and Table 7-2 give an overview of the properties of each option shown in the figure, for saline formations and gas fields, respectively.

Saline formations. As discussed in Section 4, all saline formation options listed in Table 7-1 are in the 'B' category, representing good options, but low certainty. The exception is option 1, which is a saline formation associated with the K18 – L16 – Q1 oil fields. Due to the lack of detailed data on the properties of the structures, the result of the analyses is an estimate of the likelihood that a particular option will prove to be successful. The formation in the K18 – L16 – Q1 offshore blocks has the lowest uncertainty. Due to the production of the oil fields, the level of knowledge on this structure is comparable to that of gas fields; in Phase 2 of the Study a detailed characterisation study was performed.

Gas fields. The results given in this report can be used to give a first-order estimate of the risk level for developing the fields for storage of CO_2. It should be emphasised that the risks listed in Table 7-2, ranging from 'Low' to 'High', are not to be interpreted as quantitative risks associated with these fields; that can only be obtained with a detailed site qualification study.

It is to be emphasised that the options shown in the figure are quite dissimilar. The options for storage in gas fields are listed separately in the table, as these can be compared. The amount of data used for the analysis of the gas fields, even in this high-level screening study, is much larger than that available for the saline formations also shown in the figure. The results for the saline formations cannot be compared to those for the gas fields.

7.2 CCS Development

The suitability of the options identified depends on many factors, of which availability, capacity and feasible storage rates are addressed in this study. Figure 7-2 shows a timeline extending from 2011 to 2045, with the possible injection periods and storage rates for each of the storage options. The P18 gas field, which is currently being developed for CO_2 storage as part of the ROAD project, is shown in the figure, at first for the rate relevant for the demonstration project (about 1 Mt/yr), later at a higher, post-demo phase rate. The P15 gas field, located close to the P18 field, is a candidate site for storage when CO_2 volumes exceed the capability of the P18 field. These two sites are included in the figure, to sketch the capacity and likely storage rates in the short term.

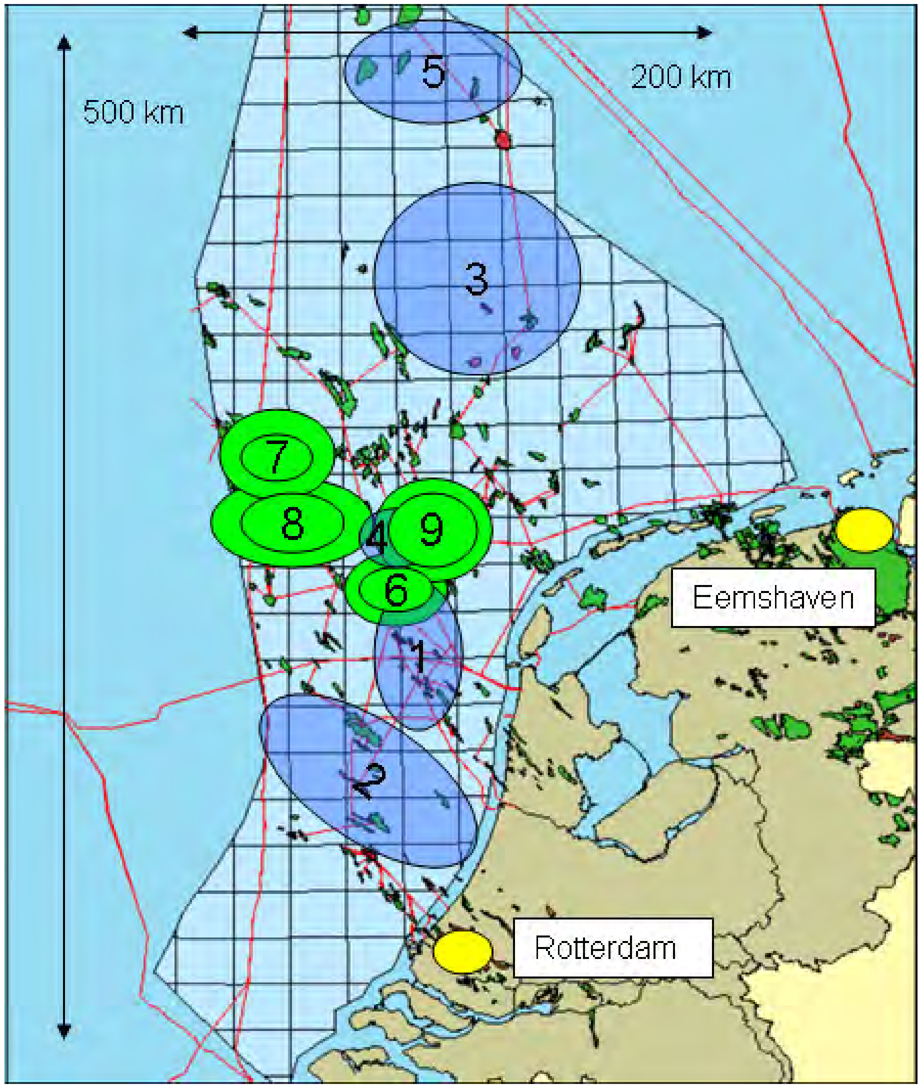

Figure 7-1 Location and (approximate) size of high-capacity offshore storage options for CO_2. Green: gas fields (the larger green discs represent the gas field clusters associated with the large gas fields studied here); blue: saline formations. Table 7-1 and Table 7-2 list relevant properties of the sites shown. Figure 7-2 shows the timing (availability) of the options.

The currently estimated availability of the gas fields, as it is given by the operators, is used to place the gas fields in the figure. The medium storage rate (see Table 7-2) is used to give an indication of the duration of injection (grey bars in Figure 7-2). The figure shows that, using the data available in this study and assuming that delaying the start of injection is possible, a total storage rate in the gas fields in the range of 20 - 30 Mt/yr is feasible. Utilising this potential involves constructing a pipeline to the K and L blocks (approximately 150 km from Rotterdam, up to 200 km from Eemshaven).

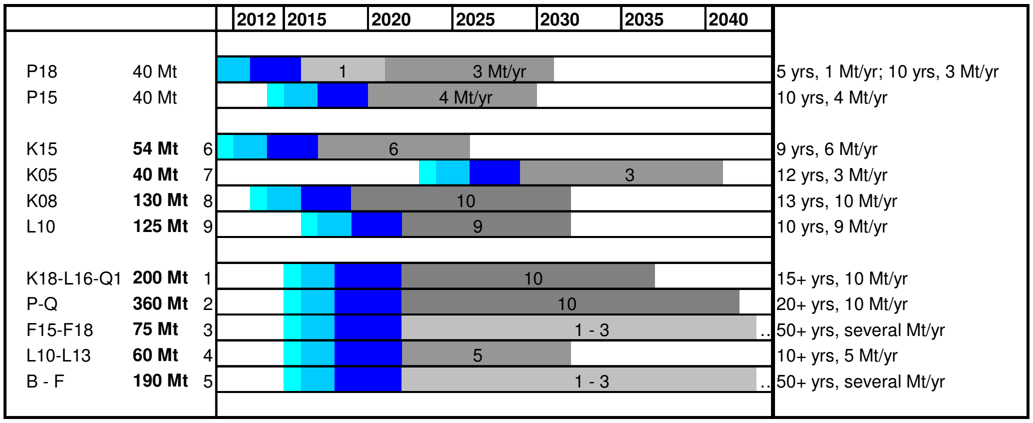

Figure 7-2 Timing and approximate storage rate and duration of the different options for offshore storage. The P18 gas field (top) is being developed within the ROAD project; the P15 gas field (second row) is a possible candidate for storage after P18. The major gas fields are shown in rows 3 – 6; the saline formations are in rows 7 – 11. The numbers correspond to the numbers in Figure 7-1. For each storage option, the storage period is indicated by a grey bar, with different shades of grey depending on approximate storage rate. The blue bars represent the development time line; see Appendix A for details. The start time of the saline formations was arbitrarily set in the period 2020 – 2025. Table 7-1 and Table 7-2 list relevant properties of the storage options.

For the saline formations it is assumed that injection starts in the period 2020 – 2025. If all five structures are developed to start simultaneously, a similar total injection rate (20 – 30 Mt/yr) should be feasible. However, these options are distributed all over the DCS and utilizing their full potential involves several long pipelines (or ship transport). Two storage options are located close to Rotterdam, in the lower Cretaceous in the P and Q blocks. With a total estimated storage capacity is about 500 Mt and total storage rates of the order of 10 – 20 Mt/yr, these two options can provide a solution for commercial-scale CCS for a considerable period of time.

7.3 Developing the options

The actions needed for developing the high-capacity storage options have been explained in the previous sections.

Gas fields. The steps involved in developing the gas fields for CO_2 storage are listed in Appendix A. The associated timeline is 5 – 6 years (minimum), depending on the size of the field and the complexity of the workover required on existing installations (wells, platforms, pipelines). This period is measured from the start of the detailed site characterisation to the start of injection; it is indicated in Figure 7-2 by the blue bars. Most of this work can be done during the last phase of production, to optimise the conversion from production to storage and to minimise any idle time of fields and installations. As discussed previously, at present it is not clear whether injection into depleted gas fields can be done with a subsea installation, or whether a (small) platform is required for processing of the CO_2 prior to injection. The former obviously results in lower complexity, lower costs and, likely greater flexibility in mothballing fields.

Saline formations. The steps towards the development of saline formations for CO_2 storage differ between the Q1 formation and the other options. As the Q1 formation is associated with the oil production from the K18 – L16 – Q1 oil fields, its status in terms of data availability is comparable to that of a depleted gas field and the situation described above applies. In addition, studies are already being undertaken by the operator. For the other saline formations, the next steps in essence involve an exploration effort quite similar to, but different in emphasis and details from that for a hydrocarbon field. The effort is similar in the sense that the same type of data is collected. The effort is different in the sense that in this case the search is for saline formation *without* gas or oil, but with a solid seal. In addition, the volume studied in detail is larger than that of a single oil or gas field. The steps are explained in Appendix A. The total timeline for virgin saline formations is 6 – 7 years, as a minimum; it is also indicated in Figure 7-2.

7.4 Next steps

Apart from the steps involved in developing each storage option separately, the results presented here provide a good basis for defining next steps in the development of offshore CCS in and outside the DCS. For these first actions participation by the national government is necessary.

1. All participants (businesses and governmental organizations) should work together to investigate the storage opportunities in the DCS more and to bring the level of reliability in the data between hydrocarbon fields and saline formations to the same level. This step needs to be taken in the immediate future because of the long lead times for this kind of research (this includes drilling one or more exploration wells).
Actor: business and national government
Timeline: 2012 - 2013
2. Develop a long-term road map (or Master Plan) for the development of CCS, covering transport and storage and based on a shared insight on the possible quantities of CO_2 to be collected. This plan should lay out the national ambition regarding emission reduction and the expected contribution from CO_2 capture. The plan should also define the involvement of businesses and the national government in participating into this development.
Actor: business and national government
Timeline: 2012 - 2014

3. The development of the most attractive option(s) for commercial-scale CCS is to be started. The timing of the start of development depends on the expected growth in CO_2 capture efforts; the long lead time to the start of injection must be taken into account.
Actor: future CCS operators as well as national government
Timeline: 2015, assuming start of injection in the period 2020 – 2025

Other necessary actions, not directly related to well development:

4. With the long-term ambitions and the role of the national government defined in the Master Plan, the associated regulatory environment should be put in place. This will support CCS industry by providing the stable long-term environment that allows long-term investments to be made
Actor: national government, advised by CCS stakeholders
Timeline: 2014 – 2016

5. Much is uncertain on the cost of transport and storage off the fence from an emitter. To enhance insight in this subject there is a need for a cost-calculation tool based on real figures that now come available. Preferably this tool is available before the entries for the second round of NER 300 have to be ready.
Actor: future CCS project developers with the RCI
Timeline: 2012

7.5 Concluding remarks

This study shows that there are several high-capacity storage options for CO_2 in the DCS. The largest gas fields have a storage capacity of the order of 100 Mt and are available around 2020. The time needed to develop these fields for CO_2 storage of is estimated to be in the range of 5 – 10 years. The cost involved for these fields strongly depends on the results of the first demonstration projects, which will show which installations are required for injection into depleted gas fields.

A number of high-capacity saline formations favourable for CO_2 storage have been found. With one exception, the options are at a different point in the development towards CO_2 storage, compared to depleted gas fields. While gas exploration and production efforts have resulted in a high level of knowledge on gas fields, only little detailed information is available for these saline formations. A full-scale exploration effort is required to obtain the information for a thorough risk analysis of these options.

The total storage capacity represented by the saline formations identified in this report is about 1.5 Gt. In the CSLF storage pyramid, this storage potential falls in the lowest, most uncertain, part of the pyramid.

The gas field storage potential, represented by the largest gas fields considered in this report, is about 350 Mt, while the potential in the gas field clusters associated with these fields is about 675 Mt. The total offshore storage capacity has been estimated at about 800 Mt (*NOGEPA, 2008*).

The storage capacity in the offshore oil fields is, compared to the potential for CO_2 storage in the saline formations and gas fields, negligible, amounting to several megatonnes of CO_2 only. However, there is an interesting option of combining CO_2 storage in the K18 – L16 – Q1 saline formation with enhanced oil recovery in the associated oil fields, as well as with oil fields in the P9 block. This combination could produce mutual benefits for CO_2 storage and oil production. It is currently being investigated by the operator (Chevron).

Table 7-1Summary of results for the saline formations analysed in this study. The numbers in the first column correspond to the numbers in Figure 7-1.

Structure	Type of structure	Estimated availability	Operator(s)	Capacity ($MtCO_2$)	Permeability (mD)	Injection locations required for Injection rate of ~ 5 Mt/yr	Transport Distance (km) from Den Helder	Current Level of Knowledge
(1) Q1 - Lower Cretaceous	Saline formation, contains oil fields	2015 - 2020	Chevron (oil fields)	110 - 225	500 – 6000	1	40 km	A/B – Good option, good data
(2) P, Q - Lower Cretaceous	Saline formation	post 2025	None	360	200	1	60 km	B – good option, reasonable data
(3) F15, F18 – Triassic	Saline formation	post 2025	None	650	Up to 15 (in gas fields)	2 (for permeability of 15 mD; more for lower permeability)	150 km	B – good option, reasonable data
(4) L10, L13 – Upper Rotliegend	Saline formation	post 2025	None	60	Up to 1000	1	50 km	B – good option, reasonable data
(5) Step graben - Triassic	Saline formation	post 2025	None	190	Up to 20 (in gas fields)	1 (for permeability of 20 mD; more for lower permeability)	200 km	B – good option, reasonable data
Structure	Geological Risk	Well Integrity Risk	Infrastructure Risk	Timing Considerations		Overall Complexity	Minimum Development Time	Next Step; First-Order Cost Estimate for Full Development
(1) Q1 - Lower Cretaceous	Low	Moderate – many wells in oil fields K18 – L16 – Q1	Oil field infrastructure may be re-used	Oil fields close to end of production		Complex: many wells, several existing platforms	5 years	Feasibility study of combination with EOR (Q1 and P9)
(2) P, Q - Lower Cretaceous	Medium	-	Interference with hydrocarbon fields to be investigated	-		New development	6-7 years	Detailed modeling, pilot injection; 110 M€ (one injection location)
(3) F15, F18 - Triassic	Medium	-	Interference with hydrocarbon fields to be investigated	-		New development	6-7 years	Detailed modeling, pilot injection; 110 M€ (one injection location)
(4) L10, L13 – Upper Rotliegend	Medium	-	Interference with hydrocarbon fields to be investigated	-		New development	6-7 years	Detailed modeling, pilot injection; 110 M€ (one injection location)
(5) Step graben - Triassic	Medium	-	Interference with hydrocarbon fields to be investigated	-		New development	6-7 years	Detailed modeling, pilot injection; 110 M€ (one injection location)

Table 7-2Summary of results for the gas fields and clusters analysed in this study. The numbers in the first column correspond to the numbers in Figure 7-1).

Field	Type	Estimated availability	Operator(s)	Capacity ($MtCO_2$)	Plateau injection rates ($MtCO_2$/yr) [duration of plateau in years] Low	Medium	High	Transport Distance (km)	Current Level of risk
(6) K14/15	Depleted Gas Field Cluster (35% of capacity in anchor field: K15-FB)	2023 at the earliest (still producing)	NAM (sole operator)	165 (54 for K15-FB)	3 [15-20 yrs] (K15-FB)	6 [5-10 yrs] (K15-FB)	9 [5 yrs] (K15-FB)	60 km from Den Helder (WGT trunk can not be re-used; interfield pipe lines probably re-usable and with sufficient capacity)	High – integrity of limited number of abandoned wells to be checked; ageing platforms
(7) K04/05	Depleted Gas Field Cluster	2028 at the earliest (still producing)	Total (sole operator)	140 (40 for K05a-A)	2 [19 yr] (K05a-A)	3 [12 yr] (K05a-A)	5 [6 yr] (K05a-A)	120 km from Den Helder (both trunk and interfield pipe lines possibly re-usable and with sufficient capacity)	High – integrity of several abandoned wells to be checked
(8) K07/08/10	Depleted Gas Field Cluster (67% of capacity in anchor field: K08-FA)	2023 at the earliest (still producing)	NAM (all but one field incl. anchor field), Wintershall (K10-B)	195 (130 for K08-FA)	3-6 [20+ yrs] (K08-FA)	6-12 [10+ yrs] (K08-FA)	9-18 [5+ yrs] (K08-FA)	100 km from Den Helder (WGT trunk can not be re-used; interfield pipe lines probably re-usable and with sufficient capacity)	Moderate -- flow connection between blocks is uncertain but can easily be confirmed using additional (confidential) production data; integrity abandoned wells to be checked
(9) L10/K12	Depleted Gas Field Cluster	immediate action required for some of the fields in the cluster	Gaz de France Suez (sole operator)	175 (125 for L10-CD)	6 [17 yrs]	9 [10 yrs]	12 [4 yrs]	50 km from Den Helder (WGT trunk can not be re-used; interfield pipe lines probably re-usable and with sufficient capacity)	High -- many different blocks, connectivity unknown; many abandoned wells; ageing platforms; timing issues of fields in cluster

Field	Geological Risk	Well Integrity Risk	Infrastructure Risk	Timing Considerations	Overall Complexity and Risk	Minimum Development Time	Next Step
(6) K14/15	Low	Low: limited number of abandoned wells, no reported problems	High -- old platforms	Multiple fields still producing & using shared infrastructure; mothballing not a serious issue	Low – multiple fields and aging infrastructure, but low well integrity risks; single operator and well-known geology	6 years	Feasibility study
(7) K04/05	Low	Moderate: 11 abandoned wells, 1 before 1976	Low -- relatively modern	About 80% of storage potential estimated to be available in same year (mothballing not a serious issue)	Low – Although multiple fields relatively modern infrastructure; late availability allows learning from earlier projects	6 years	Use best practices other projects (fields available well after other CCS projects assumed to be operational)
(8) K07/08/10	Low	High: 11 abandoned wells, 5 before 1976	High -- old platforms	Multiple fields still producing, using shared infrastructure; mothballing required, already for anchor field itself	Moderate – multiple fields and ageing infrastructure, but relatively few blocks account for most capacity; several old, abandoned wells; single operator and well-known geology	More than 6 years (due to high well integrity risks, old platforms)	Feasibility study, focus on abandoned wells
(9) L10/K12	Moderate -- see field information	High: large number of abandoned wells; problems reported for producing wells	High -- old platforms	Multiple fields still producing, using shared infrastructure; mothballing required, already for anchor field	High – All traffic lights are red	More than 6 years (many abandoned wells, old platforms)	Feasibility study; immediate negotiations with operator (several fields close to end of production)

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9 Signature

Utrecht, March 2012

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A Site development

The discussion of feasibility of storing CO_2 in saline formations or depleted gas fields, presented in Sections 4 and 5, includes a brief description of the work to be done, an estimate of the timeline and of the costs. As these partly overlap, the sections below discuss the timeline, cost and activities for saline formations (Section A.1) and describe the work, time and cost listed in previous reports from the Study for depleted gas fields (Section A.2).

A.1 Site development – virgin saline formations

The saline formations studied in this report are all virgin formations (the Q1 formation being the exception), which means that the formations have not been used for or associated with previous hydrocarbon production activities. Although gas fields occur throughout the DCS, they occur only in a small number of formations (see Section 3), mostly concentrated regionally. It is important to note that in a screening study such as this, in which both saline formations and depleted gas fields are considered, the starting point for (virgin) saline formations is significantly different from that for depleted gas fields. For the latter, the exploration and production of hydrocarbons has resulted in a detailed knowledge of the reservoir (gas field) and the feasibility of CO_2 storage can be established with available data. For virgin saline formations, the starting point can be described as an almost total lack of data (apart from regional geological models derived from seismic data). To arrive at a similar, but not the same, position regarding knowledge on the potential reservoir, a full exploration effort must be performed, including the drilling of one or more exploration wells.

A.1.1 Workflow

The following general workflow including timeline given in Table A-1 sketches the steps towards developing a virgin saline formation from first identification (as in this report) to start of injection. The timeline assumes that several of the activities can be performed in parallel.

The site development is broken up into three phases. The decision gates associated with these phases involve increasingly higher budgets. At each decision gate, the level of knowledge about the risks associated with the storage system is improved and the uncertainties are smaller.

- DG0. This is the decision to start a feasibility study, following selection of the site after a screening study. The budget to be decided on is up to about 4 M€, in case no seismic data is available, or up to about 1 M€, in case existing seismic data is to be re-interpreted.
- Phase 1. The first phase typically takes about 2 years (if a seismic survey is included), or about 1 year (if existing data are used).
- DG1. This decision concerns the drilling of an exploration well. The budget involved is about 20 M€.
- Phase 2. The second phase takes typically 2.5 years.
- DG2. The results from the exploration well are used to decide on the development of the site: platform, pipelines. The budget involved is of the order of 85 M€.
- Phase 3. The third phase is the phase with longest duration, at least 3 – 4 years.

Table A-1 General steps in a site development plan for a virgin saline formation. The estimate for the budget associated with each decision gate was obtained assuming 2 wells to be drilled and a single platform to be constructed.

	Activity	*Time needed (includes lead times, if any)*	*Cost estimate*	*Comment*
	Decision gate DG0: 1 – 4 M€			
Phase 1	1. Acquisition of high resolution seismic data, or re-processing of existing 3D data	1 yr	1 M€	Specialised contractor: €15-20 k€/ km². Re-processing 3D data: €1.5k / km² Area assumed: 20x20 km
Phase 1	2. Processing of seismic data	0.5 yrs	1 – 2 M€	Specialised contractor
Phase 1	3. Seismic interpretation, building of sophisticated fault models and constructing of geological models (i.e., site characterisation study)	0.5 – 1 yrs	0.5 – 1 M€	Typical size of area covered: 6 offshore blocks
	Decision gate DG1: 20 M€			
Phase 2	4. Drilling of exploration well, logging, coring and injection testing	2 yrs	20 M€	Includes lead time for exploration license application; cost is for one well, includes hook-up
Phase 2	5. Update geological model and feasibility of storing CO_2	0.5 yrs	0.5 M€	Use data obtained from well
	Decision gate DG2: 85 M€			
Phase 3	6. File license application for storage; complete environmental impact assessment	1 yr	0.5 M€	License approval takes 1 – 2 yrs; activities can continue in parallel
Phase 3	7. Design, procurement and construction of injection facilities	2 yrs	60 M€	In parallel with license application procedure
Phase 3	8. Drilling additional well(s)	1 yr	20 M€	Parallel to previous item
Phase 3	9. Pipeline construction	1 yr	2 M€ / km	Costs for high-pressure CO_2 pipeline; in parallel to other construction
	Total	**6-7 yrs**	**110 M€**	Small platform, 2 wells, no compression on platform; pipeline costs not included

A.1.2 Site (field or cluster) feasibility study

The data required for a rigorous feasibility study, steps 3 and 5 in Table A-1, is usually available for a depleted gas field (although perhaps not all in the public domain), but not for a saline formation. For the latter, data is collected in two steps: from regional models of the subsurface, with additional data from nearby hydrocarbon exploration and production activities (if any), in step 3, plus data obtained from an exploration well (step 5).

The feasibility study should contain the following components:

- Geological modeling
- Reservoir modeling (including injection scenarios)

- Geomechanical assessment
- Geochemical assessment
- Assessment well integrity and risks
- Assessment of facilities (wells, platforms, pipelines)
- Integral risks assessment
- Initial monitoring plan

A.1.3 Costs

The costs given in the above workflow strongly depend on the area covered. Exploration for and a qualification of a saline formation for CO_2 storage generally deals with (very) large areas and subsurface volumes. The time needed to complete the seismic surveys, to process the seismic data and to perform a site qualification study is longer than similar activities dealing with gas fields. This explains the range in the time needed listed for each step. A similar uncertainty is associated with the estimate of the costs of development. The data given in Section A2.4 was used. The cost given represents only the up-front investment cost; operational expenditures during the project are not given.

This list results in a total cost of developing a virgin saline formation (i.e., not previously associated with hydrocarbon production) for injection of CO_2, at a single injection location. The major cost elements are the new wells, the construction of a platform and the pipeline. In this example two new wells are drilled; in some cases in hydrocarbon exploration and production the exploration well can be used for production, which in this case would reduce the costs by about 20 M€.

If existing installations can be re-used, significant cost savings can be reached. However, this depends strongly on the local situation, the state of the installations, as discussed in Section 4. Installations from oil production exist in the Q1 block, rendering re-use a possibility, but for the other options re-use is less likely.

A.1.4 Single site or multiple sites?

It should be emphasised here that if multiple injection sites are required, for example to increase injection rates, the cost is multiplied by the number of locations. If the injection rates obtained with a single injection site are insufficient, for example due to increasing demands, an additional well at the same site is likely not to increase the maximum rate. This is due to the fact that rates are limited by the allowed local pressure increase, not by the number of wells. The combination of reservoir thickness, reservoir permeability and pressure limit largely determines the maximum injection rate[10]. Adding an injection well from the same platform does not necessarily increase this rate.

Higher rates can then only be reached by adding an injection point, far from the first site. Here, ‘far’ is defined in the context of the pressure field in the saline formation. The extent of the pressure footprint of an injection site depends on the properties of the reservoir (such as thickness, permeability, connectivity) and can be estimated with reservoir models. The fact that an additional injection location must be ‘far’ from existing injection locations implies that new sites are to be developed. Given the dimensions of typical saline formations for CO_2 storage, many tens of kilometres across, combining installations between sites is probably limited.

[10] There are other relevant parameters, related to the tubing size in the well, whether or not the well is partly horizontal, the density of the CO_2, etc.

For more information, a more detailed explanation of pressure-limited injection rates and an illustration of the pressure footprint of an injection well, the reader is referred to *Van der Meer & Egberts* (2008ab).

A.2 Site development plan

A general site development plan for depleted gas fields is presented here, following recommendations done in an earlier phase of this study (*Neele et al., 2011a*). Additional recommendations are given with respect to clusters.

Table A-2 General steps in a site development plan for a (depleted) gas field. It is assumed that existing installations are re-used; the budget associated with each decision gate strongly depends on the size of the field and the required modifications.

	Activity	*Time needed (includes lead times, if any)*	*Cost estimate*	*Comment*
	Decision gate DG0: 0.5 – 1 M€			
Phase 1	1. Site characterisation study	0.5 – 1 yrs	0.5 – 1 M€	Time and budget depend on size of field Cost estimate ±40-50%
	Decision gate DG1: 1 – 2 M€			
Phase 2	2. EIA	1 yrs	0.5 – 1 M€	More detailed cost estimate, using results from feasibility study Cost estimate ±20%
Phase 2	3. Pre-FEED	1 yrs	0.5 – 1 M€	Cost estimate ±15%
	Decision gate DG2: tens of millions of €			
Phase 3	4. FEED	1 yr	0.5 M€	License approval takes 1 – 2 yrs; activities can continue in parallel
Phase 3	5. Well workovers	1 – 2 yrs	10 – 50 M€	In parallel with license application procedure
Phase 3	6. Platform modifications	1 – 2 yr	10 – 50 M€	Parallel to previous item
Phase 3	7. Pipeline construction	1 yr	2 M€ / km	Costs for high-pressure CO_2 pipeline; in parallel to other construction
	Total	**6 yrs**	**Varies; tens of M€**	Small platform, 2 wells, no compression on platform; pipeline costs not included

A.2.1 Workflow

The following general workflow including timeline given in Table A-3 sketches the steps towards developing a depleted gas field from several year prior to the end of production to start of injection. The timeline assumes that several of the activities can be performed in parallel. The workflow assumes that the existing installations can be re-used and / or converted from production to injection.
The site development is broken up into three phases. The decision gates associated with these phases involve increasingly higher budgets. At each decision

gate, the level of knowledge about the risks associated with re-use and conversion is improved and the uncertainties are smaller.

DG0. This is the decision to start a feasibility study, following selection of the site after a screening study (a study similar to Phase 1 of the ISA). The budget to be decided on is about 1 M€.

Phase 1. The first phase typically takes one half to one full year, depending on the size of the field.

DG1. This decision concerns the start of the pre-FEED phase. The budget to be decided on is in the range of 1 – 2 M€.

Phase 2. The second phase takes typically about two years and contains the pre-FEED phase, an environmental impact assessment and license applications.

DG2. A second decision gate occurs when a detailed cost and timing estimate of the site (re-)development is available. The budget to be decided is of the order of several tens of million euros.

Phase 3. The third phase concerns detailed engineering, procurement and construction and takes several years. An additional decision gate was introduced between the pre-FEED and FEED phases in (*Neele et al., 2011a*); for simplicity, it has been omitted here.

A.2.2 Comparisons with saline formations

The workflows for saline formations and depleted gas fields are similar. Where the starting point for saline formations can be characterized by large uncertainties about the quality of the storage site and a general lack of site and reservoir specific data, the production history of the gas field has resulted in a good knowledge of the reservoir. A large part of the workflow for saline formations is aimed at reaching the level of knowledge and confidence comparable to that for gas fields. The most important data are obtained from the exploratory well and subsequent pilot injection test that occurs in the second phase of the workflow for a saline formation (Table A-1).

Once these data are obtained, the state of knowledge, the assessment of risk and the level of confidence on the performance of the storage complex for a saline formation is comparable to that for a depleted gas field, after the feasibility study.

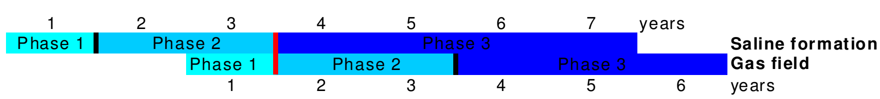

Figure A-1 Comparison between development timelines for saline formations (top) and gas field (bottom). The solid vertical lines represent decision gates between the different phases; the phases are explained in Table A-1 and Table A-2. A comparable level of knowledge about the storage complex and certainty about safety and security of storage exists after Phase 2 in the development of a saline formation and Phase 1 in that of a gas field (vertical red line).

Figure A-1 illustrates this, by aligning the development timelines for saline formations and gas fields. It is assumed that 7 years is required for a saline formation and 6 years for a gas field. The three phases in the workflow are indicated by the different shades of blue; the decision gates are represented by vertical black lines. The heavy red vertical line represents the second decision gate in the saline formation study, and the first decision gate in the gas field study. At these milestones in the development, the results for the saline formation can be compared with those for the depleted gas field. In other words, when a proper comparison is to be made between storage in saline formations and in depleted gas fields, the studies must (at least) be at these milestones.

A.2.3 *Clusters*

In the development of storage clusters of gas fields, timing is of even larger importance, because different fields or facilities are generally not available at the same time. Therefore, 'mothballing' facilities (wells and platforms) might be required, so that they can re-used for CO_2 storage at a later stage. At the moment, the OSPAR convention requires offshore facilities to be abandoned within two years after production has ceased. It seems to be most practical from a technical perspective and most cost effective to invest only in larger fields for mothballing. In the NOGEPA study, it is suggested that stakeholders cooperate in defining possible storage clusters in a Masterplan (as presented at the 23rd World Gas Conference in Amsterdam, 2006). The final decision to abandon a field or to invest in mothballing is made by the operator.

In some cases, mothballing can not prevent that field become unusable for CO_2 storage, especially if the period for mothballing is longer. A technical limit for the duration of the mothballing period is difficult to predict. In an example presented recently, a maximum duration of 10 years is assumed (*EBN-Gasunie, 2010*).

As an alternative for mothballing, CO_2 can be stored directly after the end of production, transporting the CO_2 by ships instead of pipelines. For smaller fields, this might be a cost effective option. The option of ship transport is currently being developed, in the framework of one of the NER-300 proposals in Rotterdam.

A.2.4 *Re-use versus new build*

The possibility to re-use facilities is an important aspect in site development, both from a technical and from a financial point of view. Experiences and/or best practices in future projects, for example in the P18-block, should shape the options with respect to the facilities.

One of the possible scenarios is to maintain only the main platform for a field or cluster of fields and service all other fields in the cluster or compartments in the field with new subsea completions. The first series of demonstration projects should provide the data and experience to decide on the required installations for injection in depleted gas fields.

Table A-3 gives and indications of costs involved, comparing re-using existing and building new installations. In each case, the condition of the main platform needs to be assessed. One of the requirements is that it must have enough space for CO_2 processing equipment (compressors, heaters and other equipment, depending on the injection scenarios).

A.2.5 *Transport*

Transport of produced natural gas to the onshore processing facilities will continue until production has ceased in the last fields (2030 or later). Therefore, it cannot be expected that the back bones of the natural gas transport infrastructure (the trunk lines) can be re-used for transport of CO_2; new dedicated pipelines need to be constructed. Inter-field pipelines between different production platform can possibly be re-used, although assessment on individual basis is required. These inter-field pipelines were designed for the initial gas field pressure, which is likely to be in the range of dense-phase CO_2, which is the likely transport mode for large-scale CO_2 transport.

A.2.6 Concept selection and first decision gate

The concept selection concludes the first technical assessment. Besides the feasibility of storage, also capture, transport and injection need to be assessed. At the end of the concept selection, there is a decision gate. The commencement of next step and further investments is at stake at this point. Decisions should be made on all technical grounds, taking into account also costs, public perception and HSE (health, safety, environment) aspects for all stakeholders.

Table A-3 Cost data for storage of CO_2 in offshore depleted gas fields. All CAPEX figures are expressed in M€; OPEX is given in M€/yr. Data taken from TEBODIN (2009).

Cost element	Mothballing		Construction / modification and operation		Abandonment	Monitoring	
	CAPEX	OPEX	CAPEX	OPEX		CAPEX	OPEX
Export platform, new	-	-	60[11]	6.2	20.5	2.8	2.8
Export platform, re-use	4.5	1.5	20.8	16.4	31.5	4.3	4.3
Satellite platform, new	-	-	60	6.2	20.5	2.8	2.8
Satellite platform, re-use	2.6	0.7	13.2	6.4	20.5	2.8	2.8
Subsea completion, new	-	-	4.3	-	10	2.8	2.8
Subsea completion, re-use	-	-	1.8	3	10	2.8	2.8
New well	-	-	20[12]	-			

[11] The cost of a new platform is given as 39.5 M€ by TEBODIN [2009], but listed here as 60 M€, following information provided by EBN.
[12] The cost of a new well is given as 30 M€, but listed here as 20 M€, following information provided by EBN.

B Data used

B.1 Data used - saline formations

The screening for high-capacity offshore storage options in saline formations was performed by combining a number of data sets. Table B-4 describes these data briefly. The source, location and availability of the data is listed. The NLOG site (www.nlog.nl) is the site where all publicly available data on the Netherlands subsurface can be found.

Table B-4 Data used for the screening for CO_2 storage options in saline formations.

Data type	*Source / location*	*Availability*	*Comment*
Aquifer distribution maps with bottom/top and thickness	NLOG (www.nlog.nl)	Public	Available for all aquifers, thicknesses are added for stacked reservoirs. The resolution of the model is 250×250 m.
Fault data	TNO fault data base. Will be available through DINO or NLOG (2012)	Public	Contains all seismically mapped faults in Dutch subsurface.
Porosity data	Work in progress, will be available through NLOG (2012)	Public	Not available for Cretaceous aquifers yet

B.2 Data used – depleted gas fields

Table B-5 lists the data used in the CO_2 storage feasibility assessment of depleted gas fields. Additional data on the offshore gas fields is present in a confidential database maintained at TNO. This database contains the production history of the fields, pressure data, which will be needed in a detailed analysis of the feasibility of storing CO_2 in any field.

Table B-5 Data used for the assessment of feasibility of CO_2 storage in depleted gas fields.

Data type	*Source / location*	*Availability*	*Comment*
Geological setting of fields and clusters	Production plans at NLOG	Public	Level of detail varies per operator
Current infrastructure	Production plans at NLOG	Public	Level of detail varies per operator
Number of (abandoned) wells	NLOG	Public	
Wells available for injection and possible problems	Operator overview NOGEPA	Confidential	Use of data approved by operator
Critical field properties (depth, pressures, permeability, volume, etc.)	Operator overview NOGEPA	Confidential	Use of data approved by operator; some information can also be found in public Production plan at NLOG
Other field properties (temperature, well locations, area)	Estimated	--	See phase 1 model description
Field and platform availability	Operator overview NOGEPA	Confidential	Use of data approved by operator
Platform age (year of installation)	Annual report Netherlands natural resources 2010	Public	