Transportation and unloading of CO_2 by ship - a comparative assessment

WP9 Final **Report**

Prepared by.
Robert de Kler (TNO),
Filip Neele (TNO)
Michiel Nienoord (TNO)
Peter Brownsort (SCCS, Edinburgh)
Joris Koornneef (Ecofys)
Stefan Belfroid (TNO)
Lies Peters (TNO)
Andries van Wijhe (TNO)
Daniël Loeve (TNO)

Reviewed by
Marco Linders (TNO)
Cor Hofstee (TNO)

Approved by
Jan Brouwer (CATO-2 Director)

Topsector	Energy
TKI	Gas
Program Line	CCUS (Carbon Capture Utilization & Storage)
Project manager	TNO R.C.F. de Kler Robert.dekler@tno.nl +31 (0)654398002

Contents

0 Summary

This report presents the results of a study into the functional requirements and optimisation of the CO_2 shipping chain, with a focus on the offshore offloading system. The goal is to evaluate the feasibility of a generic approach to the development of ship-based CO_2 transport and storage system in the North Sea, using a range of typical North Sea reservoirs (offshore saline formation or hydrocarbon fields).

- **A single ship design can be used for North Sea CO_2 storage reservoirs.** A single design for the ship and near-well installations could be used to develop CO_2 injection into a variety of fields in the North Sea. The list of fields analysed in this study includes depleted hydrocarbon fields and deep saline formations. This makes it possible to develop a uniform approach to storage in deep saline formations (which hold most of the storage capacity in the North Sea), oil fields (including the option to do enhanced oil recovery) and depleted gas fields. As storage reservoirs are filled to capacity, systems could be transferred to the next location, to be re-used. This will decease cost, enable cooperation among different nations and, hence, accelerate CCS development in Europe.
  The results from this study provide insight into the requirements for offshore offloading from a ship into an injection well, for a range of potential storage sites in the North Sea. The results of the analysis are presented in terms of pumping and heating requirements, to bring the CO_2 from the conditions in the ship to conditions acceptable for the injection well, the required investment cost and operational cost and the resulting cost of shipping CO_2. Offshore mooring options, offloading options and possible temporary storage need to be evaluated in relation to the storage well requirements.

- **The cost of ship-based transport of CO_2 is estimated to lie in the range of 13 – 33 €/t.** The cost of ship-based transport in the North Sea is in the range of 13 - 27 €/tCO_2, for a distance of 400 km, and increases to 20 – 33 €/tCO_2 for a distance of 1200 km. Unit cost is about 10 – 25 % higher in case of direct injection from the ship into the well, compared to injection from a platform (which can be a temporary platform).
  The transport capacity ranges from about 2 Mpta to almost 5 Mpta, for a single injection well. Injection scenarios were developed to result in continuous injection into the well. The table below shows two examples of scenarios considered in this report: injection into a saline formation at depths of 1 km or 4 km, for transport distances 400 km or 1200 km.

	Unit	Transport distance 400 km	Transport distance 1200 km
CO_2 transport cost	€/ton CO_2	13,6	27,8
Transport capacity	Mtpa	4.7	2.6
Ships required		2, ship size 50 kt	3, ship size 30 kt
Utilisation factor	%	82	76
Capex	M€	358	394
Reservoir		Saline formation at 1 km depth, permeability 1000 mD	Saline formation at 4 km depth, permeability 1000 mD

- **Direct injection from a CO_2 carrier into a range of typical injection wells is feasible.** The equipment for compressing and heating of the CO_2 prior to injection can be installed on the ship; power requirements are feasible. For a ship capacity of 10,000 t, offloading time is in the range of 24 – 36 hours, using a single injection well.

This conceptual study focussed on the CO_2 transported in liquid form by ship, followed by injection into different wells with varying depths. In one scenario the CO_2 is injected directly from the ship into a well. In a second scenario the CO_2 is pumped from a ship to a platform and from the platform into a well. The latter approach allows higher injection pressures than the former, as no high-pressure flexible hose is involved. The electrical and thermal power, necessary to prepare the CO_2 for injection, depend on the well type and the well depth. Heating CO_2 from approx. -50 ºC to injection temperatures of approx. 5 ºC is manageable and the required heating capacity could be provided through heating with sea water and surplus heat from the ship's engines.

- **Temporary near-well storage is the lowest-cost solution.** When temporary, near-well storage is used, ship-offloading times are shorter, even for larger size ships. As a result, the shipping fleet is used more efficiently and overall cost decreases, relative to direct injection from the ship into the well.

- **Platform modifications could be limited.** The results suggest that limited modifications to platforms are required to inject the CO_2, but this will need to be assessed for each specific injection location.

In summary, the results from this study suggest that ship transport of CO_2 to offshore storage locations is feasible from a technical point of view and that the cost is at the same level as that of pipeline transport. Hence, it is concluded that ship-based transport can provide the flexibility that will be needed during the start-up phase of large-scale CCS in those parts of Europe that will rely on offshore storage. Ship transport of CO_2 will provide the same flexibility to CO_2-EOR operations, thus providing opportunities of matching supply of and demand for CO_2.

1 Introduction

The North Sea contains the largest storage capacity for CO_2 in North West Europe (Vangkilde-Pedersen *et al.,* 2009). However, a major hurdle is the development of long-distance transport systems. Transport by ship is an attractive option because of its inherent flexibility in combining CO_2 from several sources at different flow rates to one or more storage locations. Nevertheless the technical design of CO_2 shipping infrastructure is subject to the process conditions (requirements) at the wellhead of the respective storage site. The feasibility of ship-based transport could well depend on the possibility of using a generic transport chain design for North Sea storage sites.

Transport of CO_2 by ship from port to port has already been practised for a long period with relatively small volumes (up to 1500 m^3). Larger ships from 40,000 to 100,000 m^3 for CO_2 transport have been proposed, even with high-pressure tanks on board. None of these larger ships have been built or tested yet. In contrast, multi-purpose ships are in use today: six LPG/ethylene carriers of 8-10,000 m^3 in the ownership of IM Skaugen of Norway have already been approved for the carriage of CO_2 (Skaugen, 2014).

The aim of this report is to arrive at a high-level (functional) description of the elements of the CO_2 shipping chain, with an emphasis on offshore offloading. The report does not deal with the detailed design of the CO_2 carrier, or the onshore loading systems.

The technical design of ship transport systems, which include the shore loading installation, the ship itself and the offshore offloading installation, have been studied and described in recent publications. The infrastructural design of ship transport systems has been described in detail, but questions remain about the functional requirements for heating and compression and the location of such systems on the ship or offloading platform. This reports presents a description of the functional requirements of the CO_2 ship transport chain. Based on a characterisation of the operational window of a range of typical, potential North Sea storage sites, several possible implementations of a generic offshore offloading system are presented and used in a cost analysis.

1.1 Setup of report

Literature survey and basis for analysis
As starting point a recent comprehensive literature survey has been used, updated with additional information. The survey is presented in Section 2.

Basis for analysis and assumptions
This study uses a set of hypothetical subsurface reservoirs that is typical for North Sea hydrocarbon fields and saline formations to assess the range in injection conditions. Section 3 describes the set of reservoirs, along with the assumptions regarding the design of the ship transport and injection chain.

Reservoir and well
In the second part the range of acceptable wellhead conditions for the CO_2 was established for a series of potential storage sites. These include deep saline formations and oil fields in end of field life production (assumed to be secondary recovery). The wellhead conditions are used to formulate functional requirements of the interface between ship and wellhead. The reservoir and the well together constrain the range of pressure, temperature and (maximum) flow rates (*[p, T, q]*) at the wellhead. Constraints originating from the reservoir arise from injection-induced pressure increase in

the reservoir and from thermal stresses in the reservoir due to injection of low-temperature CO_2. Constraints arise from freezing, hydrate formation and fracturing of the reservoir. Constraints originating from the injection well are due to the well completion, from stresses in the well, from erosion/corrosion and vibration effects. Further constraints that are closely related to the injection well, arise from start-up and shut-down operations. This part of the project in effect propagates the reservoir-related constraints to the wellhead, including the well-related limitations. The result is a description of the range of values for *[p, T, q]* at the wellhead that are acceptable to the combination of injection well and reservoir. These issues are the subject of Section 4.

Functional requirements and engineering options of the surface installations and ship
With a description of the boundary conditions at the wellhead, the interface between the ship and the wellhead can be defined in terms of functional requirements. These describe the compression and heating that is required to bring the CO_2 from ship transport conditions to well head conditions. Section 5 presents the functional requirements derived for the sites studied. Results were derived for a number of the typical offshore storage sites on the North Sea continental shelf, saline formations and oil fields that were defined in Section 4.

Cost assessment and cash flow analyses
The transport cost via CO_2-shipping is analysed based on cash flow models. The analyses combine the operational performance of reservoir options and an elaborated modelling of the logistical dispatch. This approach results in a detailed discounted cash flow (DCF) modelling which shows the cost of CO_2 shipping when varying different options such as ship sizes, infrastructural setup and reservoir characterisation (operating window) etc. These results are presented in Section 6.

Results
The results from the study are partly presented through the main parts of this report with some overall conclusions presented in Section 7. More detailed results for all selected storage sites and design cases are presented in three appendices:
- Appendix A: lists the operational windows for each of the potential storage sites considered;
- Appendix B: results from the cost engineering;
- Appendix C: detailed cash flow analyses for a range of ship transport scenarios.

2 Review of literature on ship transport of CO_2

The starting point is a literature survey of existing proposals and designs for shipping solutions, including onshore and offshore loading/unloading systems. These include the shipping solutions developed by:

- Tebodin (Vermeulen, 2011), Anthony Veder (2014) and Vopak.
- Studies published by SINTEF (Aspelund *et al.,* 2006), IFPEN (Roussanaly *et al,.* 2013abc, 2014) and Chiyoda Corp. (Omata 2011, 2012ab).
- Knutsen OAS Shipping has filed a number of patents for ship CO_2 transportation at high pressure levels; high pressures would be favourable for offshore unloading (Knutsen OAS, 2013).

This literature review follows that of Brownsort (2015). Furthermore, work was reviewed that has been done in the Dutch national research programme CATO and in recent European projects concerning offshore CO_2 storage, such as the FP7 projects CO2Europipe and COCATE. Also the large-scale demonstration projects have been scrutinized for system design studies and CO_2 ship transport concepts.

2.1 Overview of literature

Three instruments have been used for the literature search on CO_2 transport by ship. These instruments are:

- Google search,
- Science Direct, and
- Scopus.

A recent published literature review of Brownsort (2015) was used. This comprehensive report provides an overview of references until 2014. Therefore, Science Direct and Scopus were used to search only the year from 2013 until 2015. Furthermore, we were pointed to a confidential study of Bluewater from 2009 about a project: “North Sea CO_2 Injection - CO_2 transfer options; Technical Feasibility Screening Study”. In this study several options for off-loading CO_2 from a ship to a specific well in the North Sea are evaluated.

The Scopus search provided only one new conference paper about corrosion behaviour of pipeline steel under CCS conditions (Bohraus *et al.* 2013)
The literature found with Science Direct mainly focuses on:

- policy making: Neele *et al.* (2014),
- economic/cost modelling:
  - Mendelevitch (2014),
  - Roussanaly & Grimstad (2014),
  - Kemp & Kasim (2013) ,
  - Roussanaly *et al*. (2014),
  - Geske *et al*. (2015),
  - Weihs *et al*. (2014),
  - Seo *et al*. (2015),
- Corrosion:
  - Dugstad *et al*. (2013),
  - Sim *et al.* (2014),
  - Yevtushenko *et al*. (2014)

- Interim storage: Farhat & Benson (2013)
- Material properties: Capelle *et al*. (2013) .

Although no searches have been done in the patent literature, most of the patents of Knutsen OAS Shipping have been collected (Koers & De Looij 2011). A patent of Stamicarbon (2012) about a shipping method for CO_2 storage and import of CNG has been found via Google.

2.2 Key publications

For the assessment of available technical design a summary is given of key publications.

The Pressure-Temperature diagram of pure CO_2 is given in Figure 2-1; the areas of operation for pipeline transport and ship transport of CO_2 are indicated. Figure 2-1 gives a picture of the dilemma: for ship transport, one likes to have a high density and a low pressure; on the other hand, one may need a higher pressure for well injection.

The key publications for CO_2 shipping are considered to be the following.

MITSUBISHI HEAVY INDUSTRIES LTD. (2004).

> *Based on the idea of a Mitsubishi patent to use LPG ships for both LPG and CO_2 transport, a feasibility study has been done for the IEAGHG R&D Programme about ship transport of liquid CO_2. The ship transport has been compared with pipeline transport.*

SVENSSON *et al*. (2004a -b).

> *A cost comparison is given of CO_2 transport by rail, ship and pipeline for the European situation. No costs are included for compression or liquefaction.*

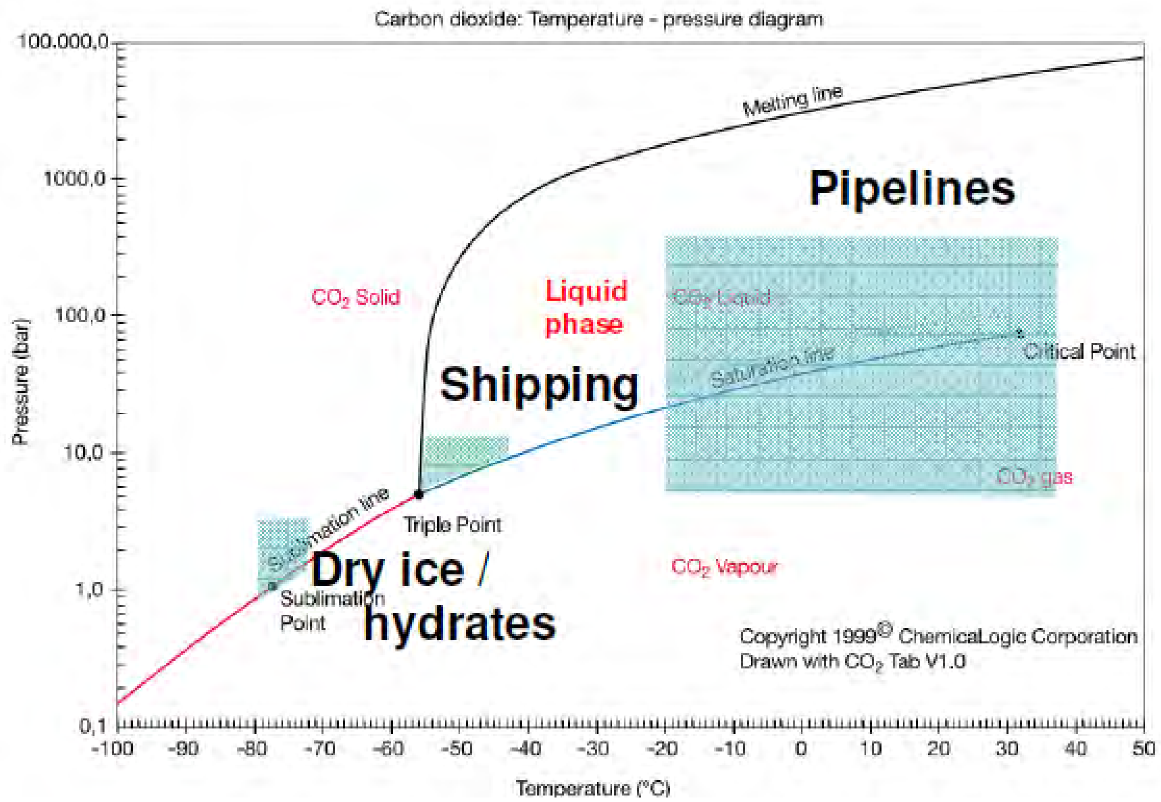


Figure 2-1: Phase diagram CO_2 (Martynov *et al*. 2012)

HEGERLAND *et al*. (2004).

Based on Yara's experience with ship transport of CO_2, the use of CO_2 for EOR is worked out. The need for a CO_2 buffer storage is suggested at the receiving point.

DOCTOR *et al*. (2005).

This chapter treats the transport of CO_2 via land and underwater pipeline and ship. Costs are compared and risks are reviewed. CO_2 transport via land pipeline in the USA is quite common for EOR application.

Global CCS Institute and Worley Parsons (2009).

In this world wide strategic analysis of CO_2 capture and storage, transport of CO_2 is treated in appendix C. Transport via pipeline, truck and ship tanker are mentioned. The risks are compared with transportation risks of LPG and LNG. Design considerations are given.

Bluewater project (2009).

A confidential, feasibility screening study of the ship transport of CO_2 to a well in the North Sea with mooring options and unloading options.

ASPELUND *et al*. (2004 through 2010).

Several publications about CO_2 transport by ship for storage into sub-sea wells.

OMATA (2011 - 2012).

Japanese publications about the feasibility of CO_2 transport to sub-sea wells. A carrier ship with injection equipment on board is described.

VERMEULEN (2011).

A detailed report from Dutch consultants Tebodin for the tank storage company Vopak and shipping company Anthony Veder. The report describes in detail the liquid, ship-based transport of CO_2. More development is suggested for offshore offloading systems. Safety aspects are published in (Ter Mors 2011) and (Koers. & de Looij 2011). A business model is described in (Tetteroo & van der Ben 2011)

ZEP (2011).

The report describes the costs of CO_2 transport based on members' data and claims an accuracy of ± 30%.

GILES (2012).

This report is focuses on the receipt of CO_2 into the port of Peterhead or direct transport to offshore. Costs for offshore elements are mentioned.

ROUSSANALY *et al*. (2013abc)

The data for this publication comes from the COCATE project about CO_2 collection in the Le Havre area; see also Decarre et al. (2010), Roussanaly et al. (2013 - 2014). Costs of CO_2 transport between Le Havre and Rotterdam and onwards via pipeline and ship are compared.

YOO *et al*. (2013).

The concept of CO2 transport by ship is extended to CO_2 carriers of 100,000 m^3 in order to make it competitive with pipeline transport for the Korean situation; see also (ZEP 2011).

WHITTAKER *et al*. (2013),

This contribution is mainly directed to the use of CO_2 for EOR and suggests CO_2 demand profiles.

SKAGESTAD *et al.* (2014).

This report provides an overview of the current status of CO_2 transport by ship, and gives a description of identified gaps that need to be closed to bring CCS chains up and running. There are a few CO_2 ships in daily use for food industry, but no CO_2 is shipped today for storage purposes. The project has uncovered gaps in all parts of the chain from preparation for transport, via loading, shipping and unloading, to injection. For the studied case a way forward with the aim to close these gaps is suggested. If the gaps are closed, the studied scenario can probably be feasible, but should also be compared to alternative cases.

The largest capital expenditures are the ship itself and the liquefaction. Operational cost (energy, crew) constitutes the most significant part of total cost per ton. The project also points to barges as an alternative, not only to ships with tanks on board, but to fixed onshore installations. Likewise, the cold of liquefied CO_2 may in itself represent a possibility for energy saving if it can somehow be re-used. Both these ideas should be investigated further.
Compared to pipeline transportation, ships/vessels have advantages when distances increase and volumes are not too high. Ships also constitute a way to start CO_2 transportation at an earlier stage as compared to pipelines because of their flexibility and relatively low up-front investment cost.

NØKLEBY (2015).
A conference presentation about CO_2 for EOR, which gives the potential of CO_2 EOR, the challenges, a feasibility, results of reservoir simulations with different flooding schemes and proposed (subsea) separation and reinjection processes.

Brochures about CO_2 transport and storage have been found: A brochure about CO_2 transport and storage of Moller-Maersk mentions:
Maersk Tankers' CO_2 footprint would be less than 1% of transported CO_2.
Maersk Tankers aims for ship sizes up to 35,000 m^3, allowing for up to 40,000 tonnes CO_2 per voyage. Delivery time of ships from order is 2 years. Semi-pressurized/semi-refrigerated CO_2 is approximately minus 55°C and 6.5 bar. CO_2 ships can discharge offshore using the same principles as oil and gas shuttle tankers that are loaded offshore. Offshore discharge requires heating and compression equipment on ship or offshore platform prior to storage. Ships and pipelines can support each other in future large-scale hub logistics.

Another brochure of Scottish Enterprise (2011) mentions that:
Ship transportation of CO_2 has been taking place for nearly 20 years, although only in small parcels for industrial or food and beverage purposes. The existing fleet of four vessels currently dedicated to transporting CO_2 are around 1,000 m^3 each.
For the larger volumes required for CCS purposes it is likely that the CO_2 will be carried at 7-9 bara and down to around –55°C. This is practically the same cargo condition as that of the significant fleet of semi-refrigerated LPG carriers currently in operation.
Six such LPG/ethylene carriers of 8-10,000 m^3 in the ownership of IM Skaugen of Norway are already approved for the carriage of CO_2.
It is anticipated that CO_2 carriers for CCS purposes are likely to range from 10,000 m^3 to ~40,000 m^3, most typically in the 20-30,000 m^3 range.

2.3 Key demonstration projects dissemination reports

According to the latest annual status update extracted from the Global CCS Institute website (GCCSI website 2014) there are 13 large-scale CCS projects in operation and 9 projects are in construction. The total CO_2 capture capacity is around 40 million tonnes per annum when all 22 projects are in operation.

Large-scale CCS projects in the power sector, in operation or construction phase:
- the Boundary Dam Integrated Carbon Capture and Sequestration Demonstration Project in Canada (CO_2 capture capacity of 1 Mtpa) EOR pipeline CO_2 transportation,
- the Kemper County Energy Facility a new-build 582 MW power plant in US (CO_2 capture capacity of 3 Mtpa) with CO_2 capture envisaged to commence in the first half of 2016, EOR pipeline CO_2 transportation,
- the Petra Nova Carbon Capture Project at the W.A. Parish power plant near Houston, Texas US (CO_2 capture capacity of 1.4 Mtpa) in construction phase, with CO_2 capture expected by the end of 2016, EOR pipeline CO_2 transportation.

The European CCS Demonstration Projects, all projects envisage CO_2 transport by pipeline:

- Norway: Sleipner and Snøhvit CO_2 Storage Projects;
- UK: Don Valley, White Rose, Peterhead, Caledonia and C.GEN North Killingholme projects;
- Netherlands: Rotterdam Opslag en Afvang Demonstratieproject (ROAD).

Worldwide, there are currently no demonstration projects that plan to use shipping for transport of CO_2.

2.4 Summary

The literature cited above and the list of existing and planned projects can be summarised as follows, focusing on transport of CO_2 by ship.

- CO_2 transport ships exist and are in use, but their capacity is not yet relevant for large-scale CO_2 transport. Combining CO_2 transport with LNG or ethylene appears feasible and may well be the route towards cost-efficient ship transport.
- Several authors recognise the potential of ship transport to enable large-scale CO_2 capture, transport and storage in the North Sea region, by providing flexible transport from early, low-volume capture locations to storage or EOR fields.
- While all technology that is needed for ship transport of CO_2 is available, the offshore offloading interface between ship and well is likely to be the key towards cost efficient transport by ship.

3 Data and assumptions

This section presents the data used in the assessment of the injection conditions leading to well head requirements (Section 3.1, data used in Section 4), the functional requirements of the offshore offloading system (Section 3.2, used in 5) and the unit cost of ship based transport (Section 0, used in Section 6).

3.1 Subsurface reservoirs

To characterise the subsurface conditions, sixteen different hypothetical storage reservoirs were defined. At four depth levels, the analysis considers two saline aquifers and two depleted gas fields. Together, these storage reservoirs cover the typical potential CO_2 storage sites in the North Sea region. It is assumed that the saline formations can be used to represent oil fields. The reservoirs are coded 1a through 4d; these codes are used in the remainder of the document.

In addition to the properties as listed in Table 3.1, the following input was used for the analysis of the injection requirements presented in Section 4:

- All saline formations are initially (before injection) at hydrostatic pressure with a pressure gradient of 0.1 bar/m.
- All gas reservoirs are at a depletion of 80% or 50% at the start of injection. The pressure at the start of CO_2 injection is then 20% or 50% of the initial pressure, respectively,
- Reservoir thickness is 100 m.
- Reservoir temperature depends only on depth and is based on a thermal gradient of 31 °C/km.
- The maximum injection rate is calculated for an injection temperature of 15, 25 and 35 °C.
- The calculation of the minimum horizontal stress before the start of injection is:

$$S_{hmin} = 0.6G_L D - DC(P_{ini} - P_r)$$

Table 3.1: Subsurface conditions of the relevant scenarios, giving well depth (true vertical depth, TVD), initial reservoir pressure and temperature p_{res} and T_{res}, permeability *k* and allowable pressure increase *dP*.

Case	Field	TVD [m]	P_{res} [bar]	T_{res} [°C]	k [mD]	dP [bar] @100 kg/s
1a 1b 1c 1d	Saline formation, 100 mD	1000 2000 3000 4000	101 201 301 401	43 74 105 136	100	3.96 4.20 4.33 4.46
2a 2b 2c 2d	Saline formation, 1000 mD	1000 2000 3000 4000	101 201 301 401	43 74 105 136	1000	0.40 0.42 0.43 0.45
3a 3b 3c 3d	Gas well 20% of hydrostatic pressure	1000 2000 3000 4000	20.2 40.2 60.2 80.2	43 74 105 136	100	23.05 13.56 10.76 9.59
4a 4b 4c 4d	Gas well 50% of hydrostatic pressure	1000 2000 3000 4000	50.5 100.5 150.5 200.5	43 74 105 136	100	8.15 4.98 4.98 4.58

where 0.6 is an empirical constant which defines the ratio between the minimum horizontal stress and the overburden pressure, G_L is the lithostatic gradient (0.23 bar/m), *D* is depth (m), *DC* is the depletion constant (as mentioned above, for gas fields either 80% or 50%; for saline formation DC is zero), P_{ini} is the initial reservoir pressure (bar), P_r is the reservoir pressure at the start of injection (bar).

- No distinction has been made between saline aquifers and oil reservoirs, because it has been assumed that oil reservoirs are still close to initial pressure. When that is the case, the difference in minimum horizontal stress between oil reservoirs and saline aquifers is minimal.
- The permeability in Table 3.1 is the effective permeability for the CO_2 injection.

Many of the parameters that are assumed constant are highly variable in nature. To account for some of that variability, low-mid-high values are used for some parameters rather than a single value. The choice for the variables was based on a sensitivity analyses. The results (i.e. maximum injection rates) are expressed as ranges instead of single values per scenario. The parameters varied include the thermo-elastic constant, the depletion (for the gas fields) and the injection rates.

- Thermo-elastic constant: The thermo-elastic constant describes the relation between temperature change and reduction of minimum horizontal stress:

$$A_t = \frac{E\alpha_t}{1-v}$$

  where α is the linear thermo-elastic constant (a value of $1{\cdot}10^{-5}$ °C is used), *E* is Young's modulus (the values used are 1, 4.5 and 9 GPa), *v* is the Poisson ratio (the values used are 0.2, 0.25 and 0.3.

  The thermo-elastic constant is varied according to the values of Young's modulus and the Poisson ratio.
- Also the injection rates are varied to check that the injection rate does not influence the minimum horizontal stress too much.

3.2 Ship and offshore offloading design options

As presented in Figure 3-1, CO_2 will be transported at refrigerated conditions and needs to be conditioned before it can injected into a reservoir. The CO_2 conditioning system will be different for each offshore CO_2 handling option considered. Available options for a liquid carbon dioxide (CO_2) handling and transport system, using shipping as one principal transport element, are divided into three categories:

- Direct injection from the ship into the injection well; conditioning of the CO_2 takes place on the ship (Section 3.2.1).
- Injection takes place from an offshore platform; installations to condition the CO_2 are located both on the ship and on the platform (Section 0).
- The ship offloads into a temporary storage that is moored near the injection platform. No conditioning of the CO_2 on the ship (Section 3.2.3).
- The total capacity, in terms of yearly injected volumes, follows from the injection capacity of the (single) injection well and is an outcome of the analysis, rather than a design parameter. The yearly volumes are in the range of 2 – 5 Mpta.

The different design options considered in this study are presented in Figure 3-2, Figure 3-3 and Figure 3-4. System boundaries for the design are set upstream between the onshore CO_2 storage plant and the ship, and downstream at a CO_2 injection wellhead offshore. The outline of available design options aims to identify the main process equipment with an indication of their siting and process conditions; some indicative operational data such as maximum allowable design pressures is provided where possible. It is most likely that CO_2 will be carried at refrigerated conditions of approx. -55 °C and a pressure of 7-9 bar.

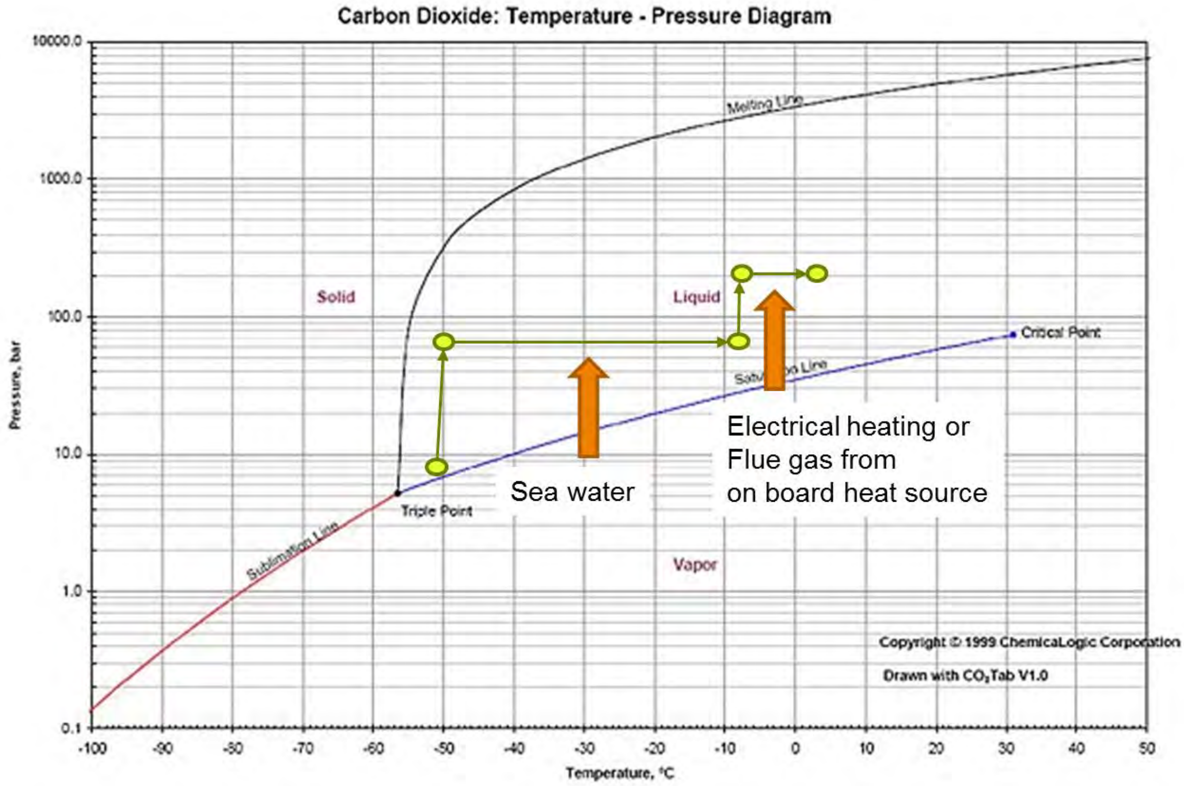


Figure 3-1: CO_2 pumping and heating in two steps from the conditions in the ship to well head conditions. The yellow point at about -50 °C and 7-8 bar represents the conditions of the CO_2 in the ship; the yellow point at just above zero degrees centigrade and 200 bar represents an example well head condition.

Before CO_2 can be injected into the reservoir it requires heating and pressurisation as shown in Figure 3-1. Subject to the outline of the CO_2 transportation process, equipment and infrastructure will be located on the CO_2 shuttle carrier, on the offshore platform, on a moored processing and storage vessel, or spread across these options.

3.2.1 Direct injection from the ship

The first option is the direct injection into the reservoir from the shuttle carrier as presented in Figure 3-2. This option has a design limitation, arising from the flexible hose that connects the ship to the mooring system. This hose is assumed to be limited to a pressure of 200 bar (an assumption confirmed by several EPC contractors.

For the analyses it is assumed that a spare ship will be required for continuous shipping operation.

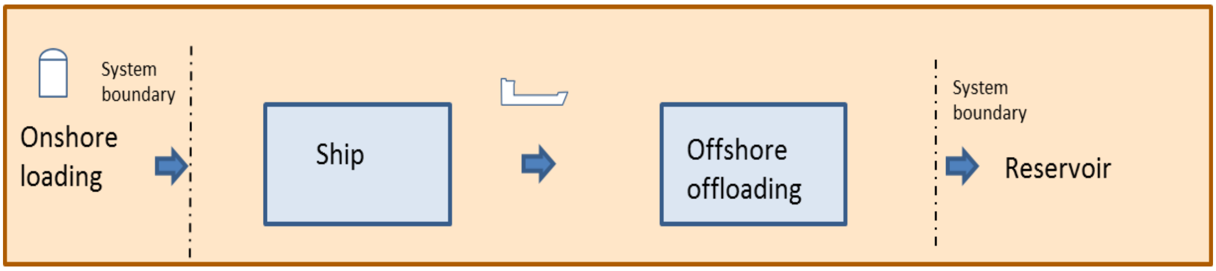


Figure 3-2: First design option: CO_2 shipping to an offshore offloading point close to the injection site and direct injection from the ship. CO_2 processing takes place on the ship.

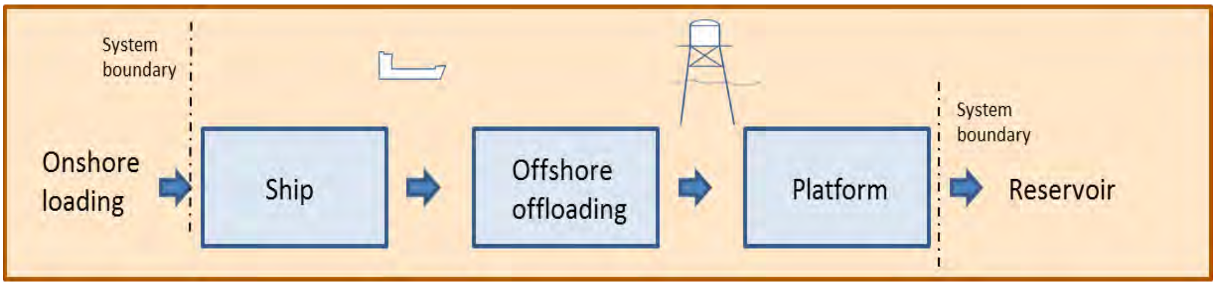


Figure 3-3: Second design option: CO_2 shipping to an offshore offloading point close to the injection site and injection from the platform. No intermediate offshore storage. CO_2 processing both on the ship and platform.

3.2.2 Injection from a platform

The second option is CO_2 shipping to the injection site, then injection from the platform; conditioning of the CO_2 is performed partly on the ship and partly on the platform. There is no temporary storage near the injection site. For this option the maximum injection pressure at the well head is assumed to be 300 bar (see Figure 3-3).

Also in this case, it is assumed that a spare ship will be required for uninterrupted shipping operation.

3.2.3 Injection from a platform or, temporary storage

The third option includes temporary storage near the injection site. The conditioning of CO_2 can be located on the temporary storage facility or on the platform, subject to the specific local conditions For the offshore offloading CO_2 will be discharged directly from the CO_2 shuttle carrier at refrigerated conditions (7 bar, -55 °C) to temporary storage, the maximum injection pressure at the well head is also 300 bar (see Figure 3-4). As such the maximum wellhead injection pressure for the CO_2 injection will be identical to the injection pressures from a platform discussed in Section 0, therefore the functional requirements in 5 consist of two main cases. The advantage of a temporary storage facility is the fast offshore offloading of CO_2 (assumed to take 15 hours). This will reduce offshore time and as a result the shuttle carriers will be more effectively used.

Due to the rapid offshore offloading into the temporary storage facility, no spare ship is required.

3.2.4 General inputs

After the sea voyage, CO_2 in the tanks of the ship is assumed to be at 10 bar and -50°C. The assumed composition of the CO_2 is given in Table 3.2.

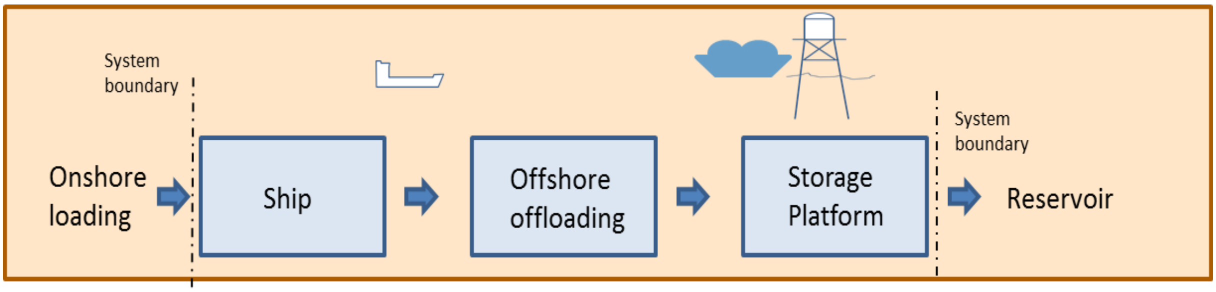


Figure 3-4: Third storage option: shipping to an offshore offloading point close to the injection site, with temporary storage and injection from the platform. Processing of the CO_2 takes place on the storage vessel or the platform.

Table 3.2: Composition of CO_2

Component	Mass fraction
CO_2	99,972%
N_2	0,019%
O_2	0,007%
H_2O	0,002%

One of the heat sources for raising the temperature of CO_2 is seawater. Seawater composition is simplified to water with 3.5 wt% NaCl in Aspen Plus. The seawater inlet temperature is 5 °C, the seawater outlet temperature is 0 °C. Because ice formation will occur in seawater, when heating liquid CO_2 directly, a secondary heating fluid is required. For this, methanol is chosen with inlet temperature of 0 °C and an outlet temperature of -25 °C.

For pressure drop calculations in pipelines, a default pipe roughness (46 μm) is used and a liquid velocity in the pipe of 1.5 m/s. For the case of ship to wellhead on the platform, a pipe length of 1150 m is assumed.

The thermodynamic property model of Peng-Robinson is used for description of the behaviour of CO_2. In some cases additional heat is required to be able to heat the CO_2 to the required temperature. A source for this heat may be waste heat from the ship's engine, electricity or any other source. Pump efficiency is set at 88% (volumetric) and 95% (mechanical) for the pump drive.

The maximum CO_2 pressure for the direct injection from the ship cases is limited to 200 bar, which is the maximum allowed pressure for flexible off-loading tubing. To avoid damage from brittle behaviour of the flexible off-loading tube, the minimum temperature for CO_2 off-loading from the ship is set to 0 °C.

3.3 Ship transport scenario parameters

The CO_2 shipping cost assessment, presented in Section 6, has been carried out for each reservoir type comprise the following cases (see Table 3.3):

- Ship size: 10, 20, 30 and 50 kilotonne (kt);
- Travel distance: 400, 800 and 1200 km, see Figure 3-5 for the range;
- Three offshore offloading and injection options, as described in Section 3.2:

1. Conditioning of the CO_2 on the ship and injection from ship directly into the well;
2. Injection from a platform; conditioning of the CO_2 on the ship and the platform;
3. Fast offloading of the ship into a temporary store near the platform; conditioning and injection on the platform.

Table 3.3: Main input sheet for the different options.

Parameter	Range
Ship size	10 kt, 20 kt, 30 kt, 50 kt
Route length	400, 800, 1200 km
Offshore ship offloading options	1. Direct injection from the ship 2. Injection from the platform; CO_2 conditioning on ship and platform 3. Fast ship offloading into temporary storage near platform; injection from the platform; CO_2 conditioning on platform
IRR	8%

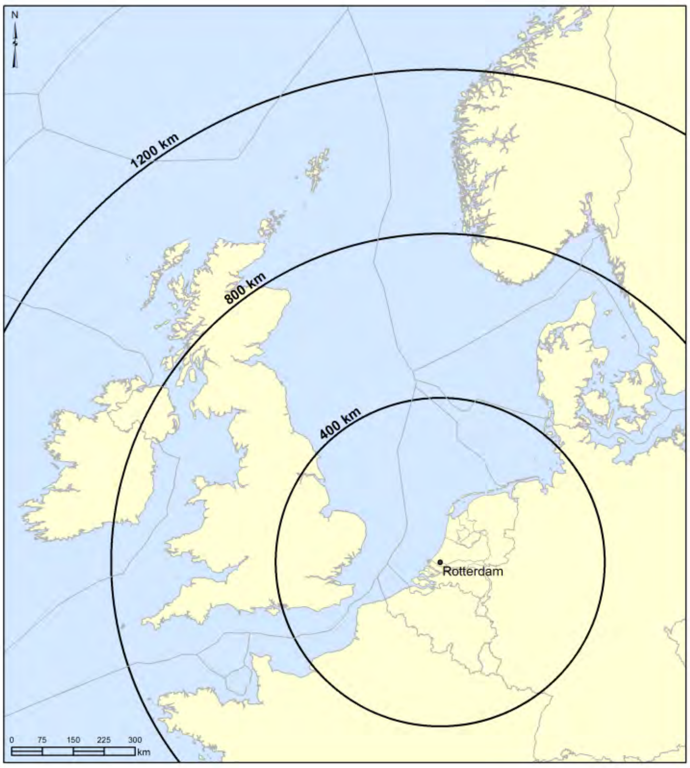
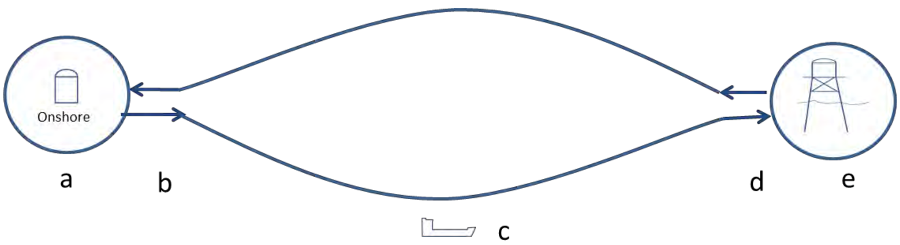


Figure 3-5: CO_2 shipping distance from Rotterdam.



CO2 shipping duration for the different design options (hr)			
	Option 1	Option 2	Option 3
a = ship loading at port	15	15	15
b = from/to harbor	2	2	2
c = cruising speed	ship size and distance (calculated)		
d = from/to offshore mooring	2	2	2
e = offshore offloading	injection rate calculated	injection rate calculated	15

Figure 3-6: Overview of the different time elements of CO_2 shipping.

Figure 3-6 illustrates the duration of the shipping elements for the different design options. The travel time depends on the cruising speed of the CO_2 shuttle carrier and travel distance. The timespan for offshore offloading for the direct injection (option 1) and injection from the platform (option 2) is subject to the maximum allowable injection flow rate, which is determined based on the reservoir characterisation operating envelopes and the CO_2 shuttle carrier size. For the temporary storage option (option 3) the offloading will take place at refrigerated liquid conditions and is assumed to take 15 hr, for all carrier capacities (this is achieved by choosing different sized pumps).

In each case, scenarios were developed with the requirement of maintaining a constant inflow into the injection well.

4 Characterisation of typical North Sea storage options

4.1 Approach

A range of typical, potential CO_2 storage sites in the North Sea was set up to be able to study the range of injection characteristics that can be expected in the North Sea (see Section 3.1). At reservoir level, two criteria have been used to determine maximum injection rate: the minimum bottom hole injection temperature (BHT) and maximum bottom hole pressure (BHP). Section 4.2 describes the derivation of limitations to injection rates and conditions arising from the reservoir.

After the analysis of reservoir-linked limitations, the operational requirements from the perspective of the well are evaluated. Potential limiting factors which are taken into account are erosion, tubing fatigue induced by vibration, pump (pressure) limitations and hydrate forming in the near-wellbore. The calculated results are presented as a working envelope. Section 4.3 describes the limitations to injection rates and conditions related to the injection well.

4.2 Reservoir

At reservoir level two criteria were used to determine maximum injection rate: the minimum bottom hole injection temperature (BHT) and maximum bottom hole pressure (BHP).
These criteria relate to avoidance of the following issues respectively:

- Formation of gas hydrates, and
- Formation of hydraulic fractures.

4.2.1 Gas hydrates

At sufficiently low temperatures, CO_2 injection can induce the formation of gas hydrates, also called clathrates, with the pore water. The background of clathrate formation was reviewed by Goel (2006). CO_2 and CH_4 clathrates are formed below approximately 10°C and 13°C, respectively (see the hatched zone of (Figure 4-1). The hydrates are crystalline inclusion compounds in which gas molecules are trapped in a host water lattice. An unwanted effect of CO_2 clathrate formation is that the clathrates will hamper the injection due to reduced injectivity resulting from pore neck plugging (Oldenburg, 2006).

In the pressure range of the reservoirs (>20 bar or 2 MPa) the threshold for hydrate formation ranges from 5 to 13°C. We used a safety margin of 2 °C and set the lower limit in this study at 15 °C. The safety margin takes into account effects like Joule-Thomson cooling and cooling due to evaporation of connate water (Loeve *et al*., 2014).

4.2.2 Fracture development

The risk associated with hydraulic and thermal fracturing of the reservoir rock is related to possible fracture forming in the top seal. These fractures could allow vertical migration of the injected CO_2. The threshold used in this study for safe CO_2 injection is that no fracture is allowed to develop, so the BHP in the injection well is not allowed to exceed the minimum horizontal stress. The BHP and horizontal stress are both dynamic and depend on injection rate, reservoir pressure, injection temperature and properties of the specific reservoir (e.g. depletion factor, permeability, reservoir temperature).

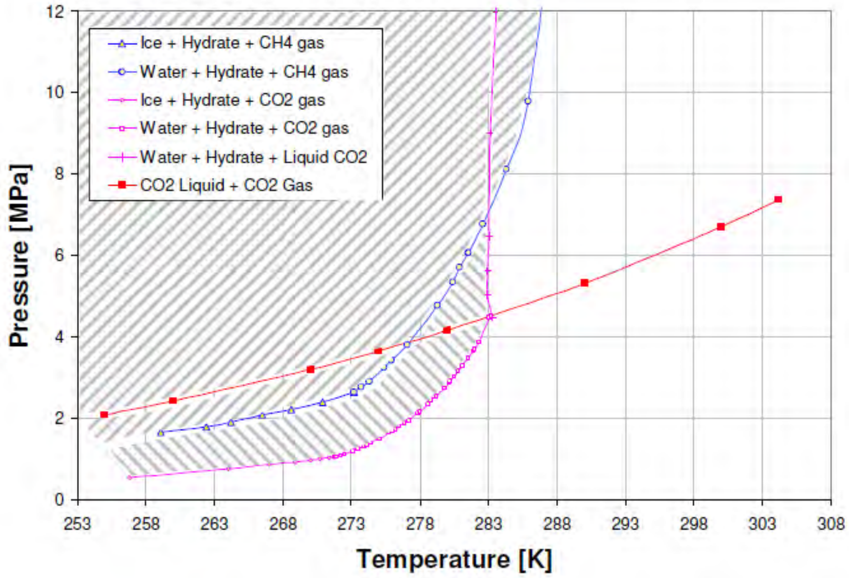


Figure 4-1: Hydrate forming conditions (p and T) of CO_2 and CH_4. The hatched areas show the CO_2 and CH_4 hydrate equilibrium pT-zones. The lower hatched area indicates the CH_4 / CO_2 exchange pT-zone. Figure based on Goel (2006). To avoid hydrate formation in the reservoir, a minimum injection temperature of 15 °C (288 K) was chosen.

The approach followed to estimate fracture initiation and fracture growth in a reservoir is that proposed by Perkins & Gonzalez (1985), who describe a simple analytical fracture propagation model. The most important assumptions of this approach are that the reservoir is homogeneous and that there is piston-like displacement of the fluid front and cold front (see Figure 4-2), which here is assumed to be true in the near-well area. From a geomechanical point of view it is assumed that the reservoir rock has no fractures, or faults close to the wellbore area that can be re-activated.

A fracture will develop when the pressure in the reservoir due to injection is larger than the minimum horizontal stress (S_{hmin}). The minimum horizontal stress is affected by poro-elastic and thermo-elastic stress changes due to the injection of cold CO_2 (Perkins & Gonzalez, 1985). The injection of cold CO_2 increases the pressure near the well, which increases the in-situ minimum horizontal stress. The cooling effect of the cold CO_2 injection reduces the minimum horizontal stress, which means that for cold injection a fracture develops more easily than for warm injection.

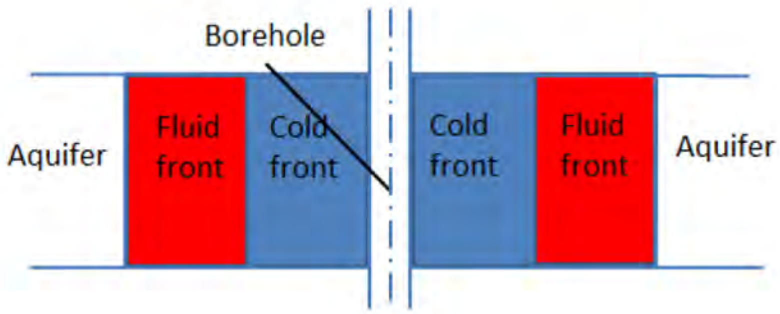


Figure 4-2: Piston-like displacement of the fluid fronts (side view).

Furthermore, the pressure reduction due to production of an oil/gas field will also reduce the minimum horizontal stress according to a depletion constant (*DC*, $DC=\Delta S_{hmin}/\Delta p$), which has a value in the range 0.4-0.8 (Zoback, 2007).

4.3 Injection well

The next step, after the analysis of reservoir-linked limitations, is to evaluate the operational requirements from the perspective of the well. Potential limiting factors which are taken into account are erosion, tubing fatigue induced by vibration, pump (pressure) limitations and hydrate forming in the near-wellbore.

4.3.1 Erosion and vibration

During normal operation erosion is not considered to be an issue assuming that the shipped CO_2 is free of solids. During shut-in, backflow at the bottom hole end of the pipe should be avoided. Solids from the reservoir could erode the piping and saline water from the reservoir could corrode the piping.

Turbulent flow causes a wideband noise with the majority of the energy at frequencies below 100 Hz. The fluids within the piping can also be subjected to flow induced pulsations, which are also typically less than 100 Hz. These low frequencies can excite the mode shapes (eigenfrequencies) of piping and cause fatigue. A more detailed explanation can be found in the guidelines of the Energy Institute (EI, 2008). These guidelines use the quantity ρv^2 (density times velocity squared) to determine if further analysis is required.

A value for $\rho v2$ below 5000 (with ρ in kg/m^3 and v in m/s) for a certain operating point indicates a low risk, a value for $\rho v2$ above 20000 indicates a high risk for fatigue. Note that this does not mean that the operating point is not feasible, but it needs a more detailed analysis. This is illustrated in Figure 4-3.

A free-hanging pipe section will start to vibrate due to flow out of this pipe. The critical flow rate is dependent on the length of the pipe and pipe material and geometry. For a hanging pipe the critical rate (i.e., the flow rate above which vibration is to be avoided through tail pipe design) is given by:

$$\dot{m} \approx 4\frac{\sqrt{MEI}}{L}$$

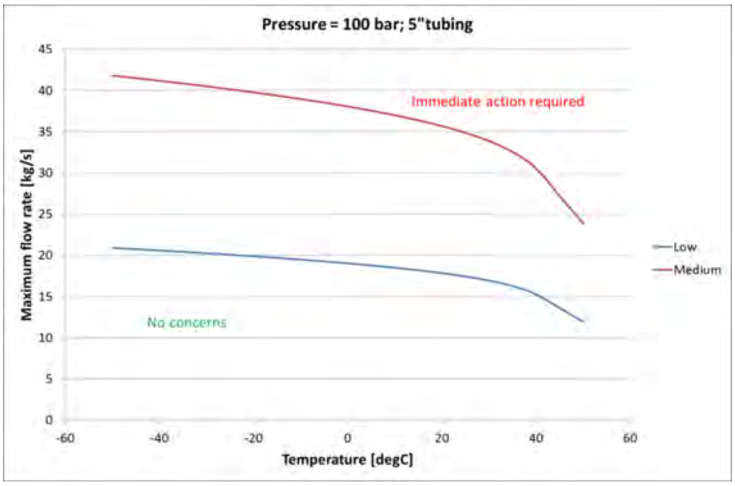


Figure 4-3: Fluid flow risk level as a function of temperature and flow rate for liquid CO_2 flow in a 5” tubing. Curves are shown for the quantity ρv^2. Blue line: ρv^2=5000, Red line: ρv^2=20000. The quantity ρv^2 is to be evaluated in SI units.

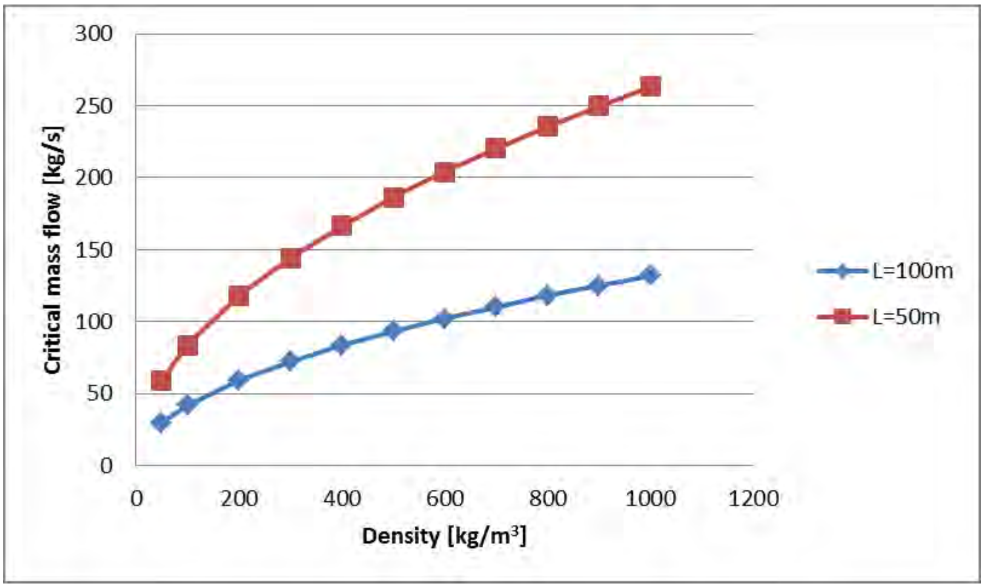


Figure 4-4: Critical mass flows for unsupported pipe end vibrations for two unsupported pipe ending lengths with 5" diameter and 10 mm wall thickness.

where *L* is pipe length [m], *M* is mass of fluid per unit length, *E* is Young's modulus, *I* is pipe area moment of inertia (Paidousis 1986, 1998; Paidousis & Semler 1993). Figure 4-4 shows the relation between density, mass flow and end pipe length.

4.3.2 Steady state OLGA simulations

Steady-state injection of the wells can be simulated with OLGA[1], a modelling tool for multiphase pipeline flow. This model is developed for the oil and gas industry but it also has an implementation for single component CO_2 that uses the Span & Wagner equation of state, which is accurate for pressures and temperatures above the triple point (5.2 bar, 216.6 K) [2].

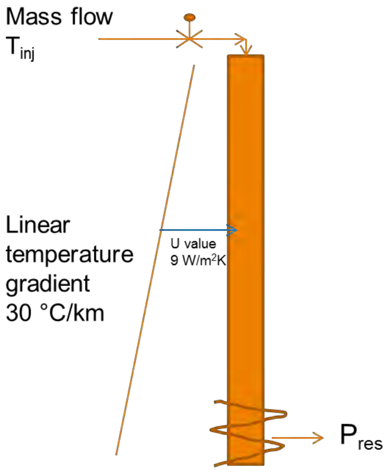


Figure 4-5: The well from the model perspective, imposed mass flow at the wellhead, fixed reservoir pressure and heat transfer from surrounding, using a linear temperature gradient.

1 https://www.software.slb.com/products/olga.
2 http://www.software.slb.com/store/_layouts/SLB/Pages/ProductDetailPage.aspx?pid=ASCP-M1.

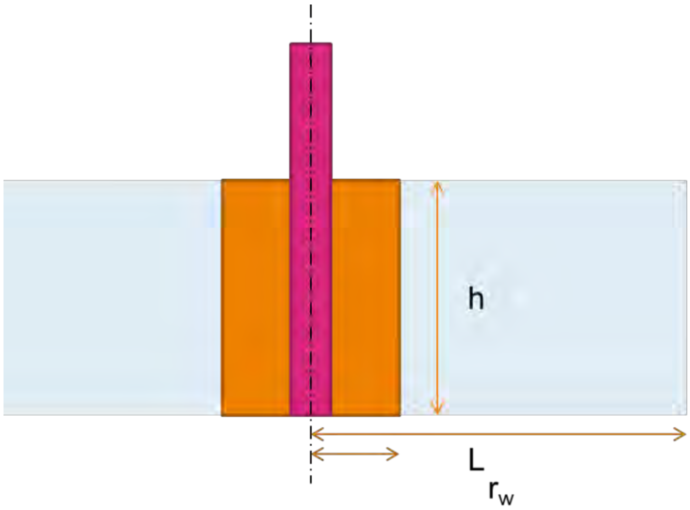


Figure 4-6: Schematic of the reservoir model used to determine the productivity index (see text).

The assumptions for the OLGA modelling are: 1D pipeline discretization, single inner diameter, linear temperature gradient with fixed heat transfer (9 W/m^{2}K) coefficient and a linear *PI* (Productivity Index); see also Figure 4-5.

The *PI* [kg/s/Pa] is determined from the reservoir properties with the following equation:

$$q\left[\frac{kg}{s}\right] = \Delta P \underbrace{\overbrace{\boxed{\frac{\rho(P)}{\mu(P)}}}^{\text{p, T dependent}} \frac{2\pi k h}{(ln(L/r_w)+s)}}_{=\text{PI [kg/s/Pa]}}$$

Where *q* is mass flow rate [kg/s], *ΔP* is pressure drop between bottom hole and reservoir [Pa], *k* is permeability [m^2], *h* is height [m], *L* is radius of control volume, r_w is radius of well, *s* is skin factor, *ρ* is density [kg/m^3] and *μ* is viscosity [Pa s]. See also Figure 4-6 for a sketch of the simulation geometry.

Note that this equation assumes a fixed fluid density and viscosity, which are pressure and temperature dependent, and thus dependent on the flowrate. The pressure used to calculate the fluid properties are that of the reservoir condition, which makes it flow independent. The bottom hole pressure is (via the *PI*) dependent on the flowrate, which induces an error in the *PI* calculation.

With the values of *PI* and flowrate used, the pressure drop over the reservoir is not significant in most cases, which can be seen in the last column of Table 3.1.

The wells are all assumed to be vertical; a horizontal section of 10 m is added with a wellhead choke (2-phase model with C_D =0.84). The bottom hole boundary condition is a well with a fixed *PI* and reservoir pressure. The wellhead boundary condition is either a mass flow or a pressure boundary condition.

Steady-state analysis of CO_2 injection was used to determine the wellhead pressure and bottom hole temperature. A transient OLGA model was used to determine these with a stepwise increase of mass flow, since the single component model in OLGA does not support steady-state calculations. The input data is listed in Table 3.1.

A parameter study was done for each field/pressure combination to evaluate the operation window. The mass flows used are 10, 20, 30, 40, 50, 60, 70, 80, 90, 100, 125 and 150 kg/s, the injection temperatures used ranged from -30 °C to 30 °C with steps of 10 °C.

4.4 Reservoir and well

4.4.1 Bottom hole conditions

For each of the 16 scenarios defined in Table 3.1, the maximum safe injection rate for which no fracturing occurs for a bottom hole temperature (BHT) of 15, 25 and 35 °C was calculated. For each of the 16 storage sites a figure similar to Figure 4-7 was produced, which shows the range in maximum safe injection rate calculation with different settings. For each temperature, a boxplot indicating minimum, p25 (25% percentile), p50 (median), p75 (75% percentile) and maximum is presented. From the figure it is clear that the ranges are quite large and that the maximum injection rate is highly case dependent. However, it is also clear that for increasing injection temperature a higher rate can be achieved. For reference, a rate of 50 kg/s is about 1.5 Mtpa (million tonnes per year).

An overview of the results for all aquifer scenarios (which are also representative for oil fields) is presented in Figure 4-8. For the depleted gas fields the results are shown in Figure 4-9. The value shown for each scenario is the most cautious value, namely the minimum from the range of injection rates, thus allowing for uncertainties in the calculation. For most scenarios, this value is large (> 150 kg/s). The type of reservoirs which are most sensitive for the development of fractures are shallow, low-permeable aquifers. These reservoirs have the smallest difference between the reservoir pressure and the minimum horizontal stress (S_{hmin}) (see Figure 4-10). This pressure difference determines the pressure increase that is possible due to injection. Low permeable reservoirs are more sensitive to fracturing because the required injection pressure is higher for the same amount of injected fluid. Thus for shallow, low-permeable cases, a case-specific study should be done since the ranges (see Figure 4-7) are large.

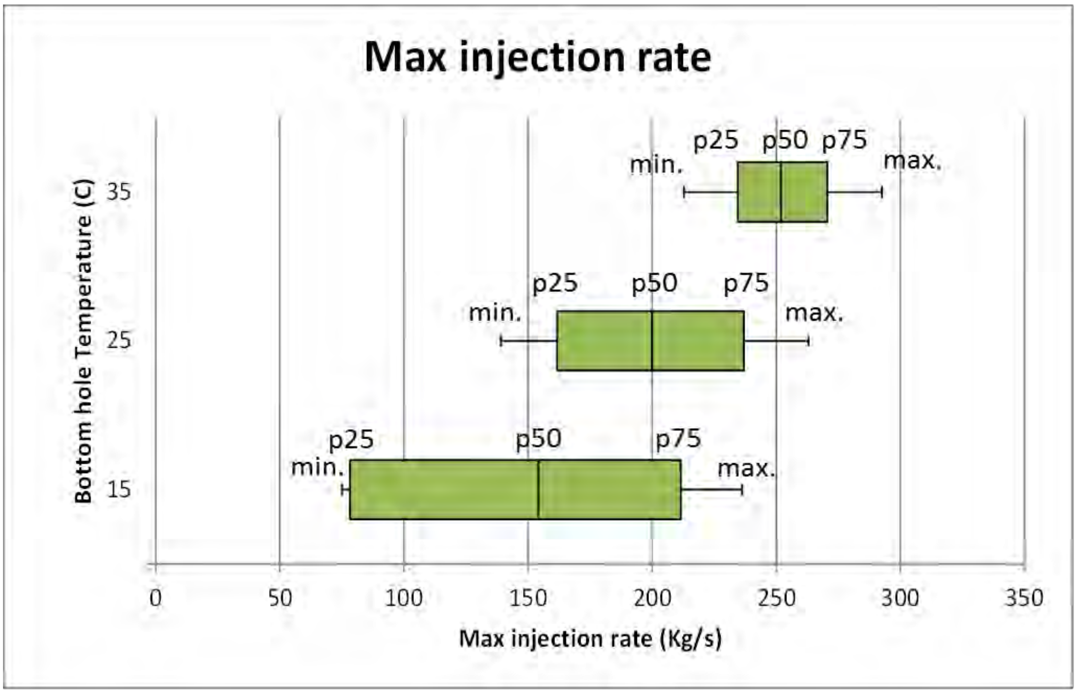


Figure 4-7: Example of the output that is obtained for each of the scenarios. Output shown here is for an aquifer with k = 100mD, at a depth of 1 km. CO_2 is injected at a temperature, at bottom hole, of 15, 25 or 35 °C.

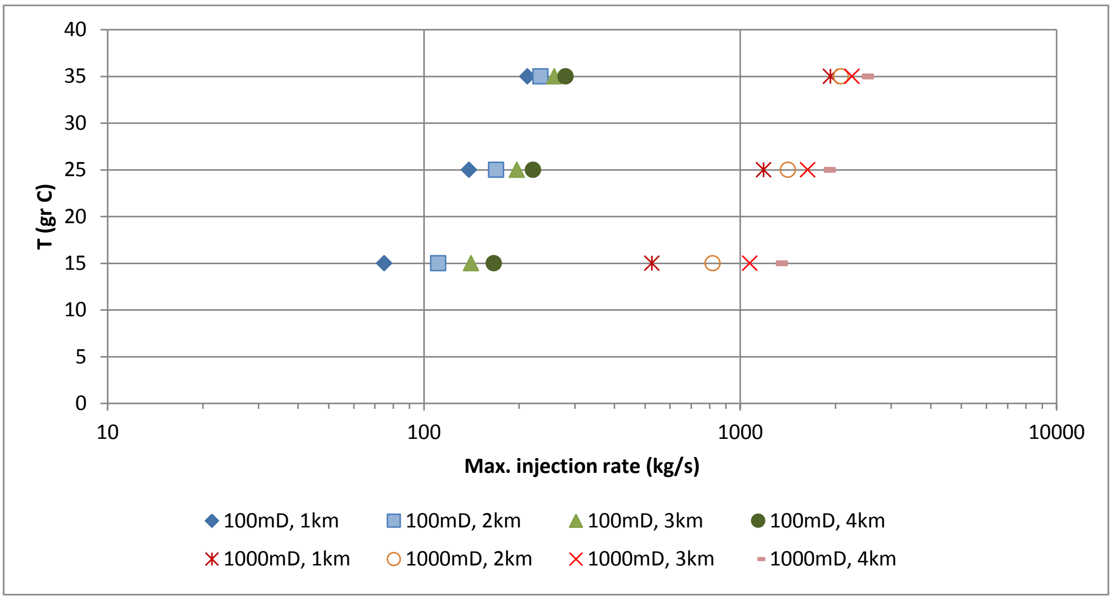


Figure 4-8: Overview of the maximum injection rate for all 8 aquifer scenarios, and three values for the temperature Shown are minimum rates (see Figure 4-7).

Depleted gas fields are less sensitive to fracturing because the decrease in S_{hmin} is less than the decrease in pressure (see Figure 4-10), which increases the pressure difference between S_{hmin} and the reservoir pressure. Because of the low pressure in these reservoirs, injection can be done at a lower temperature from the point of hydrate formation (Figure 4-1). However, this requires detailed simulation to take account of the effects of evaporation and Joule-Thomson cooling, which is particularly challenging due to the occurrence of phase transitions and two-phase flow.

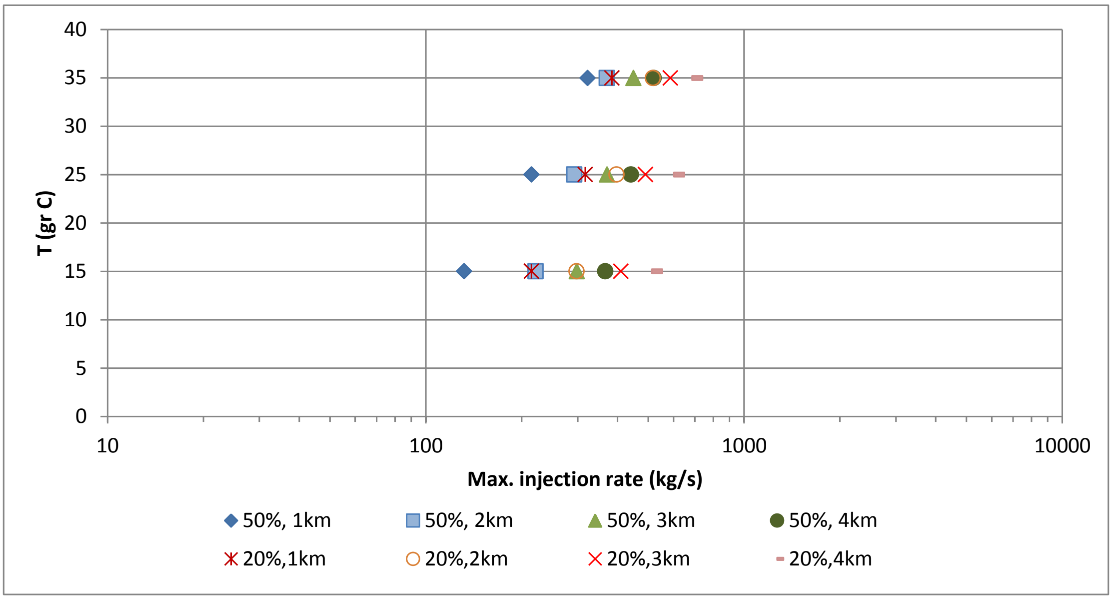


Figure 4-9: Overview of the maximum injection rate for all 8 depleted gas field scenarios. '50%' is 50% of original, hydrostatic pressure, '20%' is 20% of the original pressure.

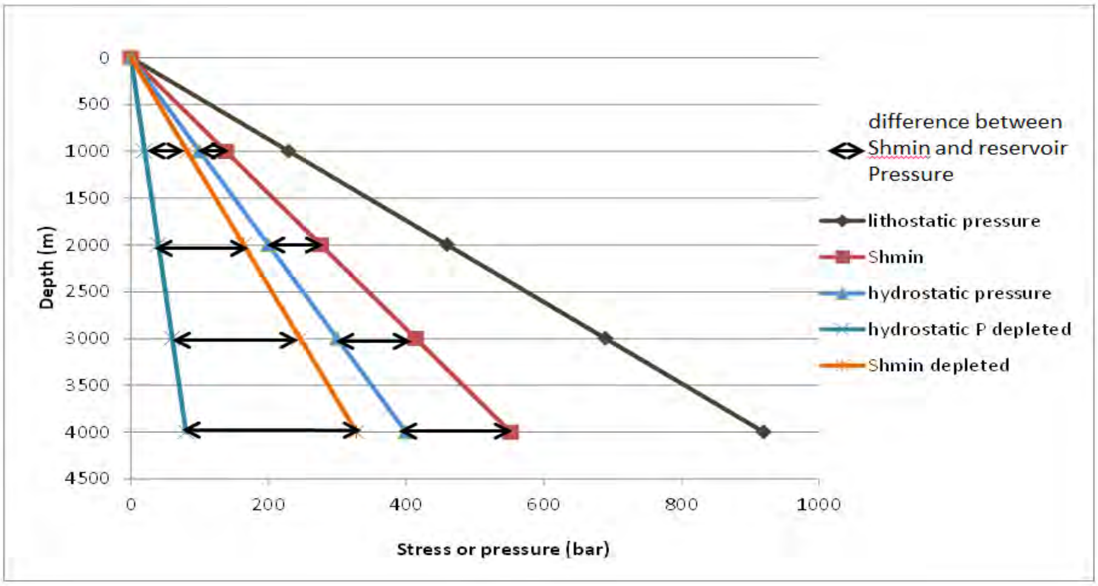


Figure 4-10: Illustration of the relevant stresses and pressure as a function of depth.

4.5 Well head conditions

4.5.1 Operational window of injections

From the OLGA simulation results, two limiting factors are used to determine the operation point, the wellhead pressure (<300bar) and the bottom hole temperature (>15°C). These are determined for all fields considered. Examples for an aquifer case with two permeabilities and two gas field cases are shown here. The results for all the considered wells are found in appendix A.

4.5.2 Saline formations

The first example given is for an aquifer at a depth of 2000 m, case 1b (Figure 4-11). For injection rates below ~35 kg/s the wellhead is in gas-liquid equilibrium at which the injection pressure is dictated by the injection temperature via the saturation line of CO_2. As a result of this an increase in the flowrate does not lead to an increase in the wellhead pressure. For flowrates higher than ~35 kg/s the flow is entirely liquid which leads to an increasing wellhead pressure with flowrate.

The permeability was also varied (100 mD and 1000 mD: cases 1 and 2, respectively), which results in a difference in pressure drop over the reservoir. For the 100 mD aquifer cases the pressure drop is 3.9-4.5 bar at 100 kg/s injection and for the 1000 mD aquifer this pressure drop is 0.4-0.5 bar. The difference between the cases is thus not significant from the well perspective if compared to the pressure drop over the well itself. But the difference in permeability is relevant for the reservoir in terms of fracturing which can mean that different permeabilities lead to different operation windows.

The mass flow rate limitation due to fracture propagation is also taken into account when defining the operational window of injection. It is obtained from the reservoir calculations. An example is shown in Figure 4-11. For all the other cases the plots are shown in appendix A. If the mass flow limitation due to fracture propagation is above 150 kg/s, it is not plotted.

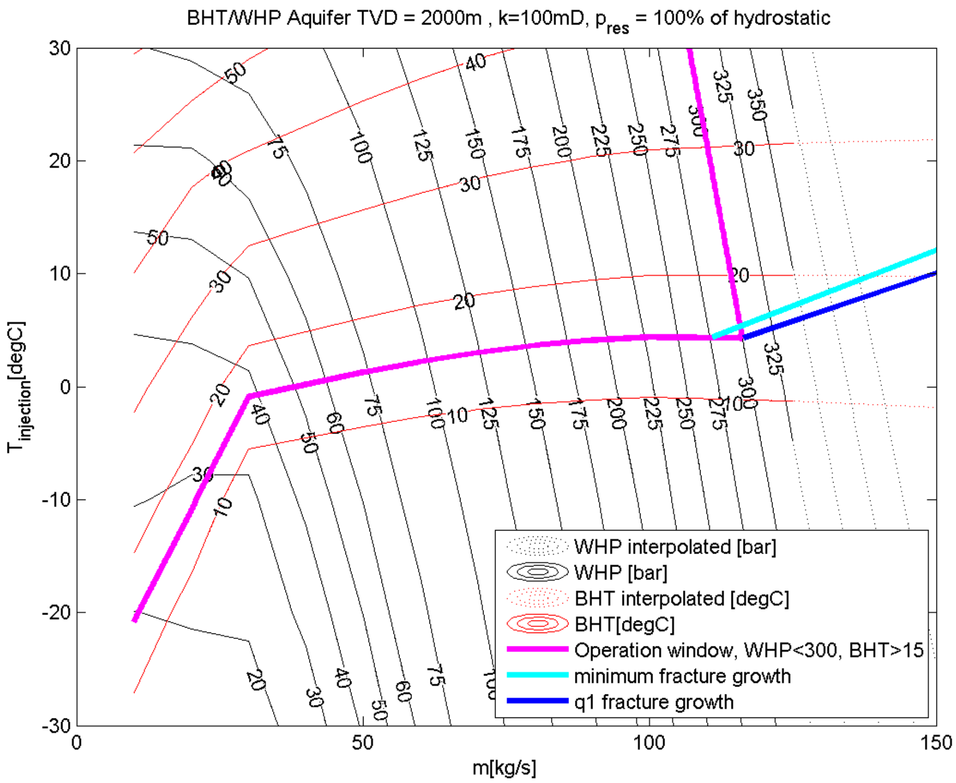


Figure 4-11: Plot showing the operation window of an injection well in storage reservoir (case 1b, see Table 3.1). On the horizontal axis is the mass flow rate, on the vertical axis is the temperature of the injected CO_2 at the wellhead. The black lines are isolines for the required wellhead pressure (WHP) for this injection. The red lines are the bottom hole temperatures (BHT) of the CO_2. The magenta curves define the boundary of the operational window in terms of BHT and WHP. Safe CO_2 injection is possible for combinations of flow rate and wellhead temperature that lie inside the magenta curves (i.e., in the upper left quadrant in the figure). The cyan and blue lines are operating limits due to fracture propagation in the reservoir; note that these limits are not calculated for bottom hole temperatures below 15°C since this is already outside the operation window due to hydrate forming in the reservoir. Also note that fracture generation in this case only slightly reduces the operational window of injection.

4.5.3 Gas fields

CO_2 could be stored in gas fields that are at the end of field life. This means that the reservoir pressure is often below the hydrostatic pressure. The analysis has been performed for reservoir pressures that are 20% and 50% of the hydrostatic pressure for the different depths (cases 3 and 4 in Table 3.1).

The decrease in pressure has a significant effect on the operational window. The lower reservoir pressure results in a lower bottom hole pressure. If the bottom hole pressure is below the saturation pressure, gas and liquid coexist. And thus the temperature is equal to the saturation temperature at the bottom hole pressure. This means that if the bottom hole is at the phase equilibrium the pressure should not be below 50.9 bar, which is the saturation pressure at 15 °C, and this temperature of 15 °C should be exceeded to avoid hydrate formation. This is illustrated in Figure 4-12 for case 3b.

From Table 3.1 it can be deduced that the bottom hole pressure as a function of the mass flow rate is:

$$BHP = 40.2 + 0.136\dot{m}$$

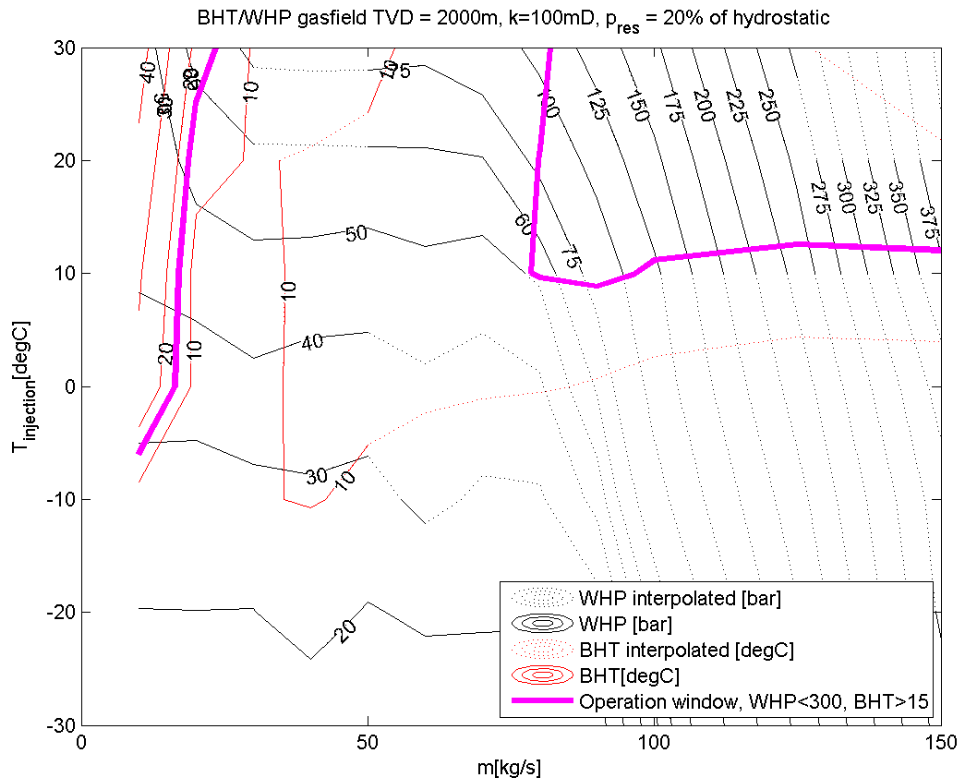


Figure 4-12: As Figure 4-11, now for a depleted gas field (case 3b, see Table 3.1). The operation window is limited to two sections in the upper left and upper right corner. The isolines are dashed for operating points that are not covered by the OLGA simulation, but are interpolated from nearby values.

This means that for mass flow rates below 78.5 kg/s the bottom hole pressure is below the saturation pressure at 15 °C. From the graph it becomes clear that below this point there is no possible operation window due to the bottom hole temperature. If the flow rate (and thus pressure) is decreased further, all the liquid CO_2 evaporates. The CO_2 is in the gas phase which means the pressure decreases with decreasing mass flow rate and the temperature can also increase again. Note that this problem is only relevant for gas wells with reservoir pressures below 50.9 bar. This is shown Figure 4-13 for case 3c, which is a depleted reservoir at a pressure of 60.2 bar.

4.5.4 All storage sites

As mentioned above, operational windows of the CO_2 injection are shown in Appendix A for all sixteen hypothetical storage sites. The results, maximum allowable flow rates and injection pressures, temperatures, has been used for section 5, see table 5.1.

4.6 Summary

The resulting characteristics of the operational window illustrated some ‘sweet spot’ in many of the cases, but others have limited scope for operation. This means that the injection flow rates and process conditions are more restricted. That does not directly mean these reservoirs are unattractive. In many case the flow rates and process conditions will differ and it will be crucial to define a generic design for the CO_2 injection infrastructure.

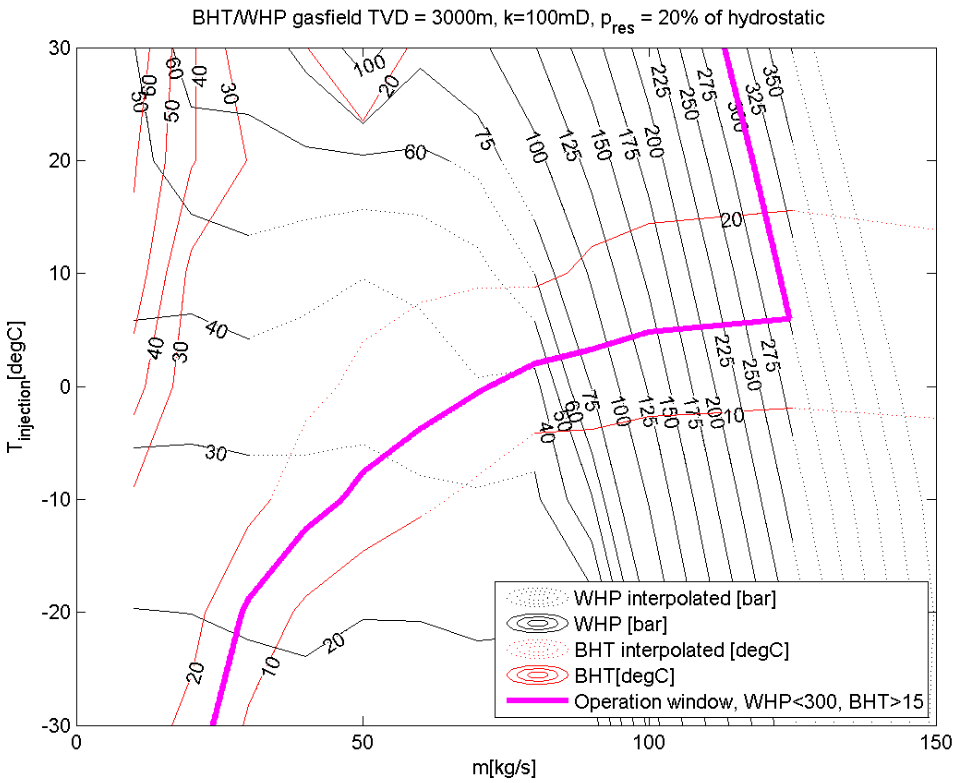


Figure 4-13: As Figure 4-12, now for a depleted gas field at a depth of 3 km (case 3c, see Table 3.1). The liquid, two-phase and gas in the wellhead can be recognized by the gradient of the WHP lines (see text).

5 Functional requirements and engineering CO_2 shipping

5.1 Introduction

The operational windows for the sixteen hypothetical storage sites presented in Section 4 define the range of acceptable injection conditions. Limiting conditions include a wellhead pressure that has a maximum of 300 bar and a bottom hole temperature that should be above 15 °C, in order to avoid fracture formation in the reservoir, as explained in the previous section.

As the CO_2 transported by ship arrives at the offloading point at about -50 °C and 10 bar, the temperature and pressure of the CO_2 have to be raised for injection conditions. This section presents the results of a conceptual design study of the interface between ship and injection well. The purpose was to get an impression of the compression, pumping and heating duties needed to prepare the CO_2 for well injection and a cost estimate of the equipment involved.

Two scenarios have been studied. In the first scenario CO_2 is injected directly from the ship into a well. In the second scenario the CO_2 is pumped to a platform and injected from the platform into a well. In the latter case, two implementations are considered: with and without temporary storage near the platform. Both implementations are fundamentally the same.

It is noted here that the term ‘platform’ does not necessarily refer to an existing offshore platform. In the case of temporary storage near the injection well, processing equipment could be located on the temporary storage construction, subject to local conditions.

Sections 3.2.4 and 5.2 outline the assumptions for the study. Next the results of the calculations are reported; the necessary duties are calculated using Aspen Plus V8.6 for solving the energy and mass balances (Section 5.3). Finally cost estimates are presented for the equipment, necessary to bring the CO_2 to well injection conditions (Section 5.4). The cost estimates are made for a minimum duty case and a maximum duty case for both ship-to-well and ship-to-platform situations. Five (including spares) CO_2 pumps are accounted for in the investment estimate. For the other pumps, spares are accounted for. The Aspen Capital Cost Estimator V8.6 is used for the cost estimation. The cost basis is first quarter of 2013.

5.2 General flow sheets

5.2.1 Ship to well case

The equipment for preparing the CO_2 on board of a ship for well injection is presented in Figure 5-1. The description of the process is as follows. Pump P-1brings the CO_2 from the CO_2 tanks to the deck of the ship. The CO_2 is heated in heat exchanger HEX-HTF with a heat transfer fluid. The cooled heat transfer fluid is re-heated with sea water in heat exchanger HEX-SEAW. The sea water is pumped with pump P-3 from the sea through the heat exchanger HEX-SEAW. The CO_2 is brought to 200 bar with pump P-2. When necessary, the CO_2 temperature can be adjusted with an auxiliary heat exchanger HEX-AUX to the proper temperature.

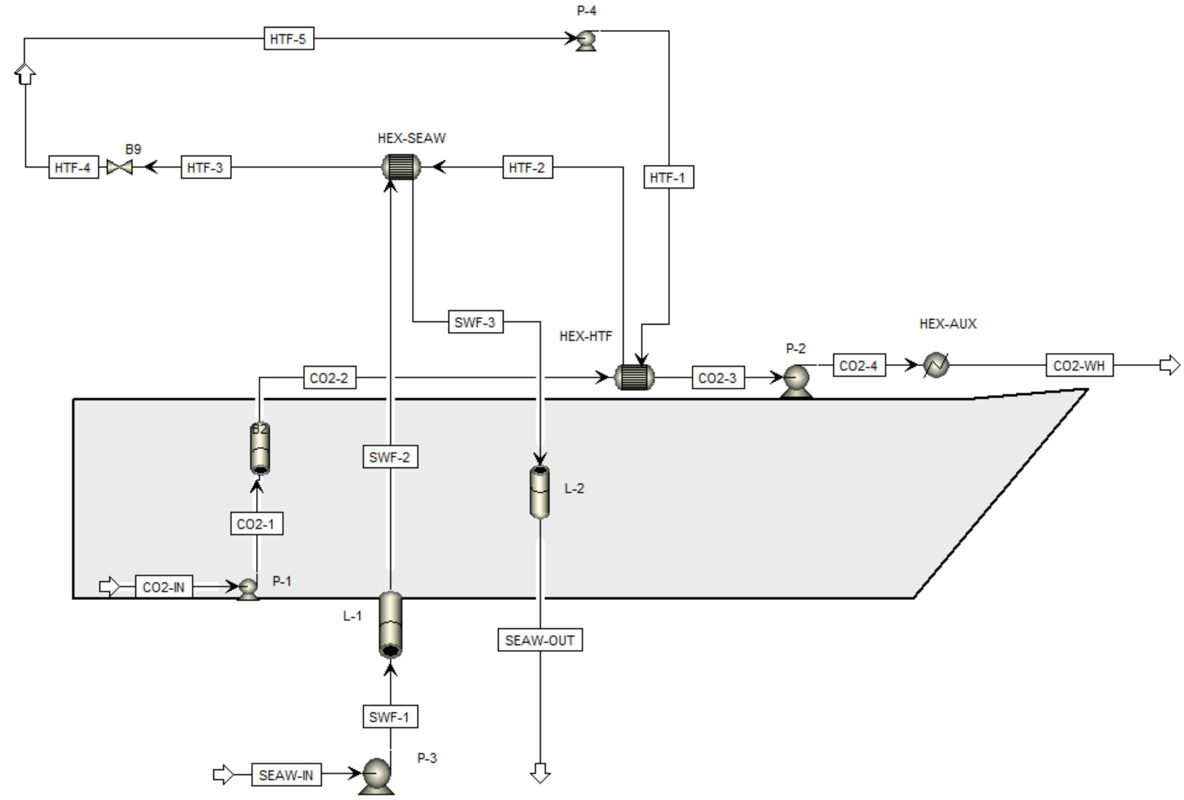


Figure 5-1: Flow sheet for equipment to prepare CO_2 for direct injection from the ship into the well.

5.2.2 Injection from the platform

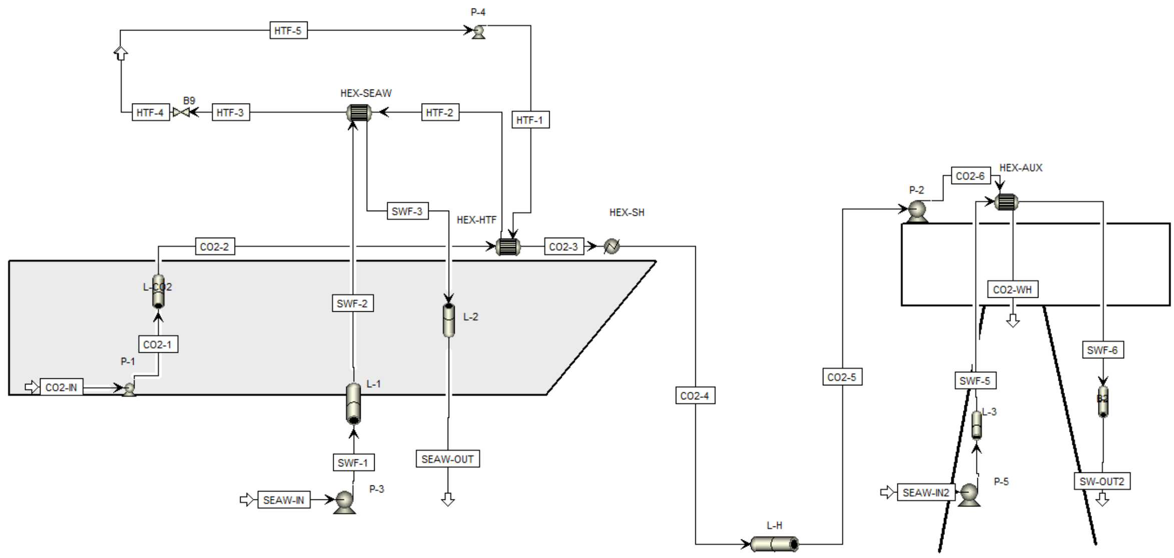


Figure 5-2: Flow sheet for equipment to prepare CO_2 for injection from the platform.

The equipment for preparing the CO_2 on board of a ship for transportation to a platform and further preparation on a platform for well injection is presented in Figure 5-2. The equipment on board of the ship is the same as in Figure 5-1. The auxiliary heat exchanger on board of the ship is now called HEX-SH. Pump P-2 and the auxiliary heat exchanger are now placed on the platform, the CO_2 flow is brought to a maximum pressure of 300 bar. Additional heating is necessary on the platform for shallower wells. However, for deeper wells, it is favourable to have CO_2 cooling on the platform, using the auxiliary heat exchanger. Due to the chosen pump efficiency, the CO_2 temperature can become higher than the temperature for maximum injection rate. Therefore, the auxiliary heat exchanger is now used to cool the CO_2 with seawater in order to get a higher allowed injection rate. A temperature of 10 °C for CO_2 injection is aimed for.

5.3 Results for mass flow injections and duties

5.3.1 Ship to well

The results for the ship to well cases are given in Table 5.1. It concerns 4 well types and four well depths, 16 cases in total. It can be seen from Table 5.1 that auxiliary heating is necessary for the shallow wells. No auxiliary heating is necessary for wells, deeper than 3000 m. Total injected volumes are in the range of 2 – 4 Mtpa. As noted in Section , the ship transport scenarios are designed to maintain a constant injection rate, at the maximum rate feasible.

5.3.2 Injection from the platform

The results of the 16 cases for injection from the platform are given in Table 5.2. It follows from Table 5.2 that a CO_2 pressure of 300 bar is not feasible, within this analysis, for shallow wells (1000 m) and for a low pressure gas well with a depth of 4000 m. It is noted that the two cases of injection from the platform are both represented by Table 5.2.

Auxiliary heating on the ship is required in all cases, while additional auxiliary heating on board of the platform is only necessary for the 1000 m depth wells. CO_2 cooling with seawater on board of the platform is applied in all cases with wells deeper than 2000 m.

Total injected volumes are in the range of 2.6 – 4.7 Mtpa, slightly higher than in the case of direct injection from the ship into the well.

5.4 Results cost estimations process equipment

The costs for equipment have been estimated for four cases. These cases are both a minimum and a maximum case for direction injection from the ship and for ship to platform and injection. For the case of direct injection from the ship, a maximum and a minimum duty case have been determined from Table 5.1. The same has been done from Table 5.2 for the ship to platform case. Stainless steel 316L has been chosen for the seawater heat exchanger and 304 LW for the other exchangers.

5.4.1 Direct injection from the ship

The duties for the minimum and maximum cases, used for the costs estimations, are given in Table 5.3, for the case of direct injection from the ship.
The maximum and minimum costs for equipment to be installed on board of a ship for CO_2 preparation for well injection are given in Table 5.4. The breakdown of the costs in Table 5.4 can be reviewed at Appendix C.

Table 5.1: Direct injection from ship to well, for all cases listed in Table 3.1.

	Case	1a	2a	3a	4a
Depth [m]	P reservoir (bar)	100	100	20	50
1000	Permeability (mD)	100	1000	100	100
	Type	Saline/oil	Saline/oil	Gas	Gas
Injection pressure	bar	200	200	200	200
Injection temperature	°C	23,7	15	23	28,6
Flow rate	kg/s	122	128	137	133
	Mtpa	3.8	4.0	4.3	4.2
Pump capacity	MW	2,98	3,12	3,34	3,24
Seawater heating	MWth	10,82	11,35	12,15	11,80
Auxilary heating	MWth	4,37	2,18	4,69	6,22
Total heating duty	MWth	15,19	13,53	16,84	18,02
	Case	**1b**	**2b**	**3b**	**4b**
Depth [m]	P reservoir (bar)	200	200	40	100
2000	Permeability (mD)	100	1000	100	100
	Type	Saline/oil	Saline/oil	Gas	Gas
Injection pressure	Bar	200	200	200	200
Injection temperature	°C	5,2	5,2	12,5	7,4
Flow rate	kg/s	93	94	117	112
	Mtpa	2.9	3.0	3.7	3.5
Pump capacity	MW	2,25	2,27	2,85	2,72
Seawater heating	MWth	7,96	8,05	10,38	9,90
Auxilary heating	MWth	0	0	1,38	0,14
Total heating duty	MWth	7,96	8,05	11,76	10,04
	Case	**1c**	**2c**	**3c**	**4c**
Depth [m]	P reservoir (bar)	300	300	60	150
3000	Permeability (mD)	100	1000	100	100
	Type	Saline/oil	Saline/oil	Gas	Gas
Injection pressure	bar	200	200	200	200
Injection temperature	°C	0	0	5,5	0
Flow rate	kg/s	78	79	109	102
	Mtpa	2.5	2.5	3.4	3.2
Pump capacity	MW	1,85	1,87	2,64	2,41
Seawater heating	MWth	5,90	5,98	9,40	7,72
Auxilary heating	MWth	0,00	0,00	0,00	0,00
Total heating duty	MWth	5,90	5,98	9,40	7,72
	Case	**1d**	**2d**	**3d**	**4d**
Depth [m]	P reservoir (bar)	400	400	80	200
4000	Permeability (mD)	100	1000	100	100
	Type	Saline/oil	Saline/oil	Gas	Gas
Injection pressure	bar	200	200	200	200
Injection temperature	°C	0	0	0	0
Flow rate	kg/s	68	68	105	94
	Mtpa	2.1	2.1	3.3	3.0
Pump capacity	MW	1,62	1,62	2,48	2,22
Seawater heating	MWth	5,17	5,17	7,94	7,11
Auxilary heating	MWth	0,00	0,00	0,00	0,00
Total heating duty	MWth	5,17	5,17	7,94	7,11

Table 5.2: Ship to platform and injection from platform, for all cases listed in Table 3.1.

	Case	1a	2a	3a	4a
Depth [m]	P reservoir (bar)	100	100	20	50
1000	Permeability (mD)	100	1000	100	100
	Type	Saline/oil	Saline/oil	Gas	Gas
Injection pressure	bar	275	275	238	250
Injection temperature	°C	30	22	23	28
Flow rate	kg/s	143	150	150	150
	Mtpa	4.5	4.7	4.7	4.7
Pump capacity	MW	5,07	5,33	4,61	4,84
Seawater heating	MWth	12,68	13,30	13,30	13,30
Auxilary heating Ship	MWth	1,78	1,87	1,87	1,87
Auxilary heating Platform	MWth	2,82	0,53	1,79	3,01
Total heating duty	MWth	17,28	15,70	16,96	18,18
	Case	**1b**	**2b**	**3b**	**4b**
Depth [m]	P reservoir (bar)	200	200	40	100
2000	Permeability (mD)	100	1000	100	100
	Type	Saline/oil	Saline/oil	Gas	Gas
Injection pressure	bar	300	300	300	300
Injection temperature	°C	10	10	12,5	10
Flow rate	kg/s	115	115	136	132
	Mtpa	3.6	3.6	4.3	4.2
Pump capacity	MW	4,52	4,52	5,45	5,28
Seawater heating	MWth	10,20	10,20	12,06	11,71
Auxilary heating Ship	MWth	1,43	1,43	1,69	1,64
Total heating duty	MWth	11,63	11,63	13,75	13,35
Seawater cooling platform	MWth	2,68	2,68	2,80	3,31
	Case	**1c**	**2c**	**3c**	**4c**
Depth [m]	P reservoir (bar)	300	300	60	150
3000	Permeability (mD)	100	1000	100	100
	Type	Saline/oil	Saline/oil	Gas	Gas
Injection pressure	bar	300	300	300	300
Injection temperature	°C	10	10	10	10
Flow rate	kg/s	94	94	122	111
	Mtpa	3.0	3.0	3.8	3.5
Pump capacity	MW	3,65	3,65	4,86	4,36
Seawater heating	MWth	8,34	8,34	10,82	9,85
Auxilary heating Ship	MWth	1,17	1,17	1,52	1,38
Total heating duty	MWth	9,51	9,51	12,34	11,23
Seawater cooling platform	MWth	2,07	2,07	2,992	2,576
	Case	**1d**	**2d**	**3d**	**4d**
Depth [m]	P reservoir (bar)	400	400	80	200
4000	Permeability (mD)	100	1000	100	100
	Type	Saline/oil	Saline/oil	Gas	Gas
Injection pressure	bar	300	300	250	300
Injection temperature	°C	10	10	10	10
Flow rate	kg/s	82	82	106	104
	Mtpa	2.6	2.6	3.3	3.3
Pump capacity	MW	3,18	3,18	3,45	4,06
Seawater heating	MWth	7,27	7,27	9,40	9,23
Auxilary heating Ship	MWth	1,02	1,02	1,32	1,30
Total heating duty	MWth	8,29	8,29	10,72	10,52
Seawater cooling platform	MWth	1,79	1,79	1,65	2,35

Table 5.3: Maximum and minimum duties for direct injection from the ship.

Duty	Unit	Maximum	Minimum
Pump capacity	MW	3,34	1,62
Seawater heating	MWth	12,15	5,17
Auxilary heating Ship	MWth	6,22	0,00
Total heating duty	MWth	18,37	5,17

Table 5.4: Maximum and minimum investment for CO_2 preparation for well injection on the ship.

	M€	
Project Total Costs	Maximum	Minimum
On Ship	18,58	14,22

5.4.2 Injection from the platform

The duties for the minimum and maximum cases, used for the costs estimations, are given in Table 5.5, for the case of injection from the platform. The maximum and minimum costs for equipment to be installed on board of a ship and on board of a platform for CO_2 preparation for well injection are given in Table 5.6. One should remember (see Table 5.2) that for shallow wells to a depth of 1000 m auxiliary heating on the platform is needed, while for wells deeper than 2000 m sea water cooling of the CO_2 is preferred. The breakdown of the costs in Table 5.6 is given in appendix C.

The resulting conceptual design provides a sound basis for a generic process design for the process equipment for CO_2 transported in liquid form by ship and injection into different reservoirs at varying depths. As such the engineering data of the process equipment show that with a single generic design for a typical North Sea fields can be accomplished. It is worth noting that the electrical and thermal power necessary to prepare the CO_2 for injection depends on the well type and the well depth.

Table 5.5: Maximum and minimum duties for the case of injection from the platform. In these cases CO_2 conditioning takes place both on the ship and on the platform.

Duty	Unit	Maximum	Minimum
Pump capacity	MW	5,45	3,18
Seawater heating	MWth	13,30	7,27
Auxiliary heating Ship	MWth	1,87	1,02
Auxiliary heating Platform	MWth	3,01	0,53
Total heating duty	MWth	18,18	8,29
Seawater cooling platform	MWth	3,31	1,65

Table 5.6: Maximum and minimum investment on board of ship and on platform for CO_2 preparation for well injection

	M €	
Project Total Costs	Maximum	Minimum
On ship	7,63	5,41
On platform	24,93	21,45

6 CO_2 shipping cost assessment

6.1 CO_2 shipping cost estimates

6.1.1 Ships

Ship transport will be performed in semi-pressurized carriers. According to Aspelund *et al.* (2006) semi-pressurized ships are typically designed for a working pressure of 5 to 7 bar with low operational temperatures (e.g. -48°C for LPG, -104°C for ethylene). Ships of this type are very common for LPG transport at up to nearly 40000 m^3 of carrier total capacity.

In this research only dedicated CO_2 carriers have been assessed because of limited information about requirements and costs of combined carriers; these carriers at the moment are only concepts and no information is available in the open literature.

Generally, for dedicated CO_2 carriers the main requirements are:

- Equipment to load/unload liquid CO_2;
- Suitable tanks for stable storage of liquid CO_2;
- A re-condensation unit (optional, for long trip).

Only the total capacity of the ship has been assessed in this study. Numbers of tanks and tank capacities have not been evaluated since the detailed designing phase of CO_2 carrier is beyond the purposes of the research.
Data on ship cost estimates have been based mainly on work performed by Nardon (Anthony Veder 2014) gathered through interviews with different companies. The firms that collaborated in the research were:

- Maersk Tankers
- IM Skaugen
- Rotterdam Climate Initiative, Antony Verder and Vopak
- Finncap
- Bluewater
- IEAGHG

For this project the shipping cost estimates have been reviewed externally using the shipbuilding expertise of DSME[3]. Variable operational cost includes mainly fuel costs. A calculation module is included in the spread sheet model to calculate annual fuel costs depending on speed, energy use during hoteling (waiting time) and manoeuvring and fuel cost for on-board process equipment. The cost estimation does not include liquefaction and shore storage. The calculation model used the mid-point values of the cost estimates of CO_2 carriers of Table 6.1 and Table 6.2. The cost estimates do not include discharge and injection equipment, but include dynamic positioning systems.

Table 6.1: Capex estimates for CO_2 shipping.

CAPEX					
Category	**Variant**	**Unit**	**Low**	**High**	**Mid-point**
Ship	10 kt CO_2	M€	50	60	55
	20 kt CO_2	M€	63	73	68
	30 kt CO_2	M€	75	85	80
	50 kt CO_2	M€	100	110	105

3 The general comment received on the cost elements presented in this section was that the cost estimates were high by about 30%.

Table 6.2: Opex estimates for CO_2 shipping. Fixed OPEX is assumed to be 3% of initial investment. Harbour fee at 1.3 €/t CO_2 is not included in fixed O&M cost.

Fixed OPEX**					
Category	**Variant**	**Unit**	**Low**	**High**	**Mid-point**
Ship	10 kt CO_2	M€	0.9	1.2	1.1
	20 kt CO_2	M€	1.5	1.8	1.7
	30 kt CO_2	M€	1.9	2.2	2.0
	50 kt CO_2	M€	2.3	2.6	2.4

Table 6.3: Variable operational cost estimates for CO_2 shipping.

Variable Operational cost module for shipping - trip costs			
Item	**Value**	**Unit**	**Source**
Ship fuel cost (HFO)	350	€/t	http://shipandbunker.com/prices
Main Engine fuel use	0.21	kg/kWh	Nardon, 2010
Auxiliary Engine fuel use	*0.175*	kg/kWh	[Nardon, 2010
Hoteling (loading and unloading)	5%	of main engine power	Nardon 2010
Manoeuvring	40%	of main engine power	Nardon, 2010
Cruise	75%	of main engine power	Nardon, 2010
Deadweight of ship	30.61	kt	Nardon, 2010
Main engine power	7,669	kW	Nardon, 2010
Loading time	15	hrs, dummy	Zep. 2011
Unloading time offshore	36	hrs, dummy	Zep, 2011
Manoeuvring time	16	hrs, dummy	Nardon, 2010

6.1.2 Offloading and intermediate storage

Several offshore unloading concepts are currently being used in the oil and gas industry and may also be used for CO_2 ships, these include: Catenary Anchor Leg Mooring (CALM); Single Anchor Leg Mooring (SALM); Tower Mooring System (TMS) and Submerged Turret loading system (STL). These concepts are shown in Figure 6-1.

The STL variant is the most advantageous transfer system in terms of adaptability for different offshore installations. The choice for one of these concepts depends on the average weather conditions (i.e. wave height) at the injection site. Cost considerations and design specifications for the ship are also important elements in decision making. The TMS system does not use a buoy system, but a fixed rotating installation and the hoses are always kept out of the water. STL tends to have fewer problems due to weather exposure/swell but higher installation costs. In contrast, SALM has higher weather exposure but lower installation costs. The TMS system has higher capital costs compared to the others but permits higher waves and thus higher availability. The system allows for additional space for the machinery required for unloading (compressors, pump and heaters) and has in general less operation and maintenance costs. In all concepts the CO_2 is transferred via a flexible hose, either submerged or not. The hose and mechanical equipment should be able to cope with low temperature CO_2 if the CO_2 is not heated at the ship side of the transfer system. (After Hendriks et al., 2011).

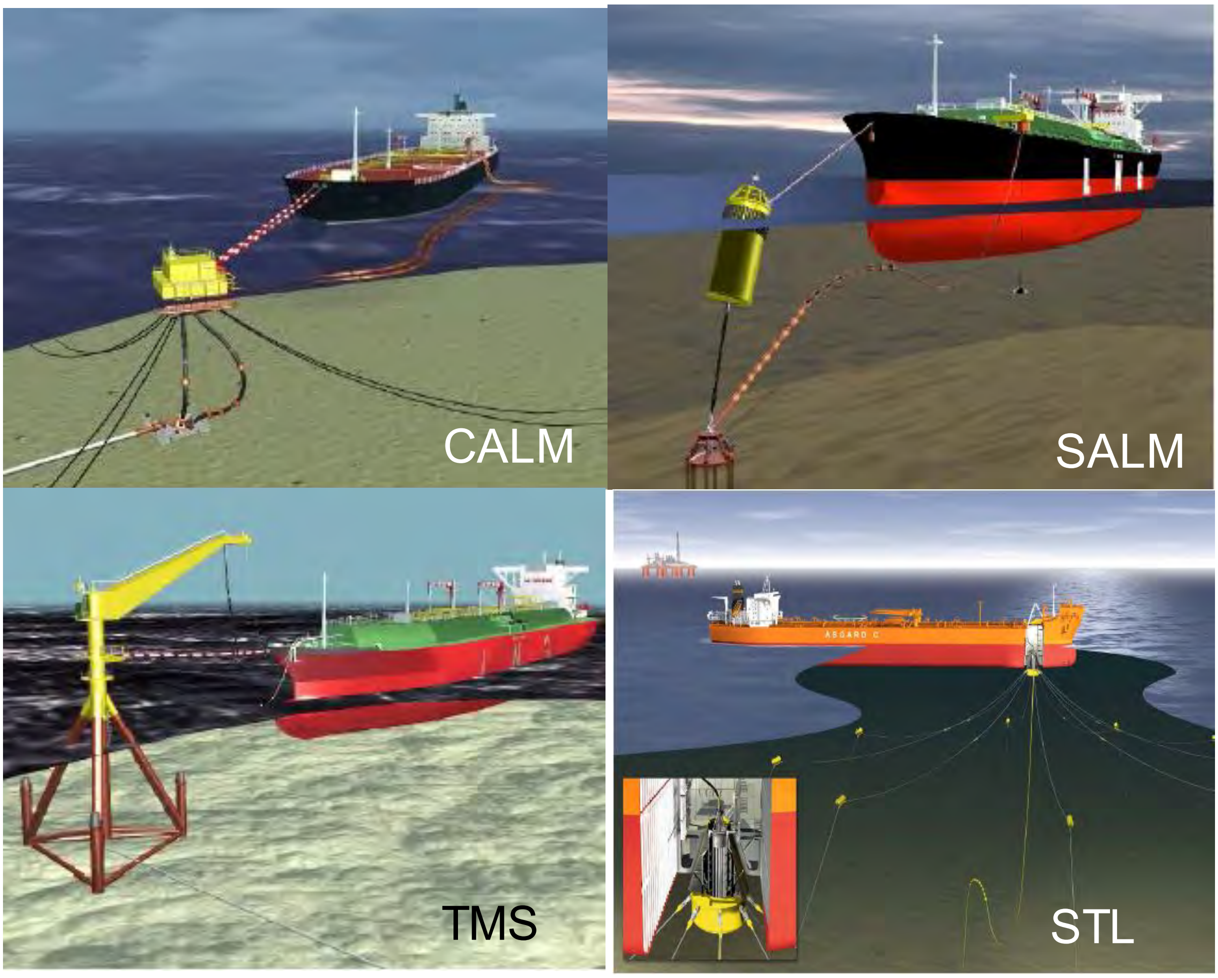


Figure 6-1; Offshore mooring and offloading concepts (Bluewater Energy Services 2009). These include: Catenary Anchor Leg Mooring (CALM); Single Anchor Leg Mooring (SALM); Tower Mooring System (TMS) and Submerged Turret loading system (STL).

In this study the capital cost estimates are provided for the SALM and TMS variant. The SALM option can only be used in combination with a ship with all process equipment on-board. The third option for offloading is through an offshore platform combined with offshore buffer storage of CO_2. One might consider to use a CO_2 carrier as offshore platform although the connection towards the wellhead requires special attention as mentioned in section 3.2.3. The total cost of such a platform is roughly estimated at 100 M€ (only the storage), as outlined below by comparison with other estimates:

1) a standard offshore platform requires about 40 M€ in the North Sea area (Noothout & Berghout, 2010);
2) a ship of 40 kt without process equipment and positioning system requires about 70 million of investment;
3) onshore storage of semi-pressurised CO_2 of 40kt would require <50 M€ (Nardon, 2010);
4) offshore installation and transport of the facility would require about 30 M€[4]. This excludes on-board process equipment.

[4] Quote by anonymous O&G equipment supplier 2015

Table 6.4: CAPEX estimates for offshore infrastructure.

CAPEX						
Category	**Variant**	**Sub-item**	**Unit**	**Low**	**High**	**Mid-point**
Mooring system / offshore connection system	Single Anchor Leg Mooring	hardware	M€	14	20	15
	Single Anchor Leg Mooring	installation costs	M€	2.5	7.5	5
	Single Anchor Leg Mooring	total	M€	16	27	20
	Tower Mooring System	hardware	M€	36	52	40
	Tower Mooring System	installation costs	M€	2.5	7.5	5
	Tower Mooring System	total	M€	39	60	45
Offshore platform incl. storage, incl offshore transport and installation	40 kt CO_2, 50 bar, 0 C°	platform only and storage	M€		150	110

Yoo *et al.* (2013) also suggest that a floating platform can be an option and the most cost-effective and safe solution should be selected based on accurate data of injection site and project conditions. Accurate cost estimates seem however not to be available in public literature.

Based on literature estimates of offshore O&M costs for platforms (ZEP, 2011) fixed OPEX is assumed to be 5% of initial investment, giving values shown in Table 6.5.

6.2 Method

The transport cost via CO_2-shipping is calculated based on a cash flow model from the shipper perspective (revenue and cost numbers). The assessment combines a sophisticated modelling of the operational performance of options with an elaborated modelling of the logistical dispatch. This approach results in a detailed DCF modelling which provides the ability to study the cost of CO_2 shipping by varying different options such as ship sizes, infrastructural setup and reservoir characterisation (operating window) etc. The cash flow model will change the CO_2 shipping fee to achieve a project return of (IRR) of 8%. The CO_2 shipping costs are determined in €/ton CO_2.

The model uses the results of characterisation of the reservoir and technical process functional requirements (as presented in Table 5.1 and Table 5.2 as well as the CAPEX/OPEX cost figures as discussed in Section 6.1. See table 6.6 how the data is lumped together per case for the different infrastructural setup resulting maximum injection pressures.

6.3 Results CO_2 shipping costs

As an example for a typical case, results of the model are presented in Table 6.7, Table 6.8 and Table 6.9, for case 1a (see Table 3.1): a saline formation at a depth of 1000 m. The reservoir data that has been used is presented in Table 6.6. All results for the shipping cash flow analyses are given at appendix C.

Table 6.5: OPEX estimates for offshore infrastructure

Fixed OPEX						
Category	**Variant**	**sub-item**	**unit**	**low**	**High**	**Mid-point**
Mooring system / offshore connection system	Single Anchor Leg Mooring	total	M€/yr	0.8	1.4	1.0
	Tower Mooring System	total	M€/yr	1.9	3.0	2.3
Offshore platform incl. storage		total	M€/yr		7.5	5

Table 6.6: Example input data for Case 1a (in Table 3.1): data for a storage reservoir (saline formation) at a depth of 1000 m and a permeability of 100 mD at different injection pressures.

Parameter	Value		Unit
Reservoir pressure		100	bar
Reservoir permeability		100	mD
Reservoir type	Saline formation / oil field		
Reservoir depth		1000	m
Injection pressure (well head), min – max	200	275	bar
Injection temperature (well head), min – max	23,7	30	°C
Maximum flow rate, min – max	122 3.8	143 4.5	kg/s Mtpa
Pump capacity, min – max	2,98	5,07	MW
Seawater heating, min – max	10,82	12,68	MWth
Auxiliary heating on ship, min – max	4,37	1,78	MWth
Auxiliary heating on platform, min – max	-	2,82	MWth
Total heating duty, min – max	15,19	17,28	MWth

Table 6.7: High-level results CO_2 shipping for a distance of 400 km and Case 1a.

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to well	size 10.000 ton	14,8	5	75%	-314,5
	size 20.000 ton	17,6	4	58%	-368
	size 30.000 ton	15,3	3	63%	-317,5
	size 50.000 ton	18,6	3	52%	-392,5
Ship to platform to well	size 10.000 ton	14,7	6	70%	-355,5
	size 20.000 ton	15,7	4	63%	-372,3
	size 30.000 ton	17,4	4	51%	-420,3
	size 50.000 ton	16,8	3	55%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	14,7	5	84%	-364,9
	size 20.000 ton	14,6	3	85%	-357,7
	size 30.000 ton	15,9	3	68%	-393,7
	size 50.000 ton	14,3	2	83%	-358,1

Table 6.8: High-level results CO_2 shipping for a distance of 800 km and Case 1a.

Distance 800 km						
Off-shore infrastructure	Ship size	Transport costs	nr ships	Utilization	capex
Direct from ship to well	size 10.000 ton	20,7	7	75%	-431,5
	size 20.000 ton	22,1	5	61%	-454,5
	size 30.000 ton	20,2	4	60%	-416
	size 50.000 ton	18,9	3	62%	-392,5
Ship to platform to well	size 10.000 ton	17,6	7	85%	-403,1
	size 20.000 ton	19,3	5	68%	-447,9
	size 30.000 ton	17,9	4	65%	-420,3
	size 50.000 ton	17,1	3	66%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	17,4	6	99%	-410,5
	size 20.000 ton	18,1	4	84%	-431,3
	size 30.000 ton	16,3	3	87%	-393,7
	size 50.000 ton	14,6	2	99%	-358,1

Table 6.9: High-level results CO_2 shipping for a distance of 1200 km and Case 1a.

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs	nr ships	Utilization	capex
Direct from ship to well	size 10.000 ton	24,2	8	84%	-490
	size 20.000 ton	22,8	5	75%	-454,5
	size 30.000 ton	20,7	4	71%	-416
	size 50.000 ton	24,8	4	54%	-516
Ship to platform to well	size 10.000 ton	22,1	9	86%	-498,3
	size 20.000 ton	22,8	6	70%	-523,5
	size 30.000 ton	21,8	5	63%	-507,9
	size 50.000 ton	21,9	4	58%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	21,9	8	96%	-501,7
	size 20.000 ton	21,6	5	84%	-504,9
	size 30.000 ton	20,2	4	79%	-479,3
	size 50.000 ton	19,3	3	78%	-468,7

Figure 6-2: CO_2 transportation cost for the different reservoir cases at a shipping distance of 400 km.

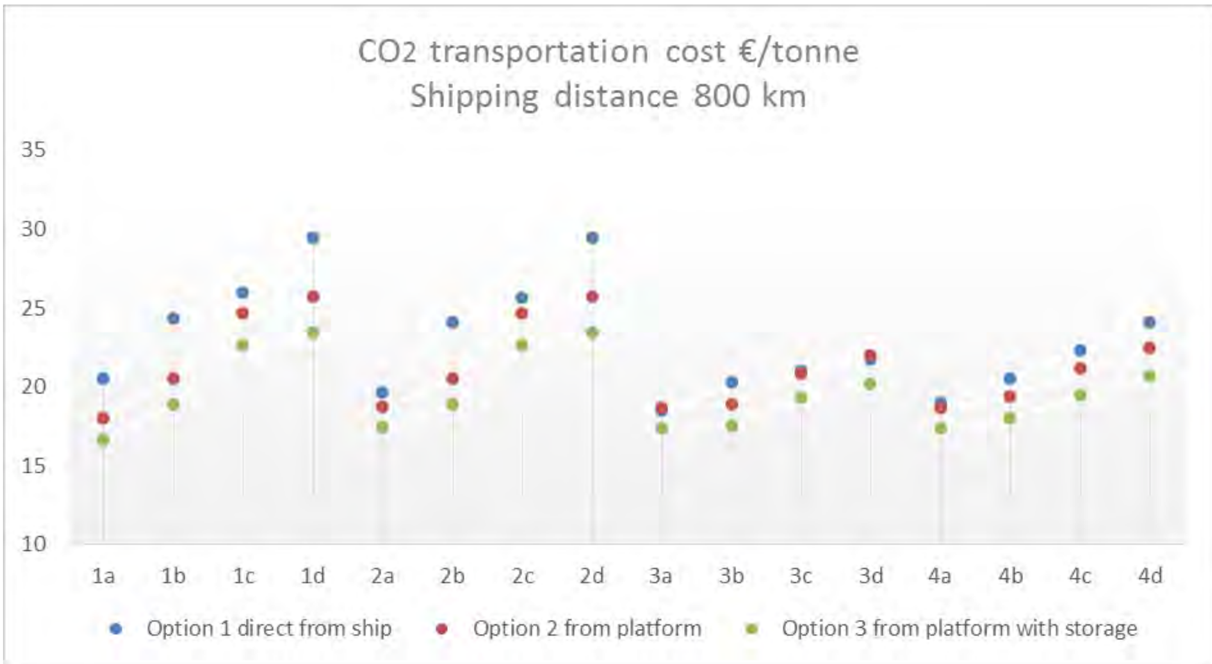


Figure 6-3: CO_2 transportation cost for the different reservoir cases at a shipping distance of 800 km

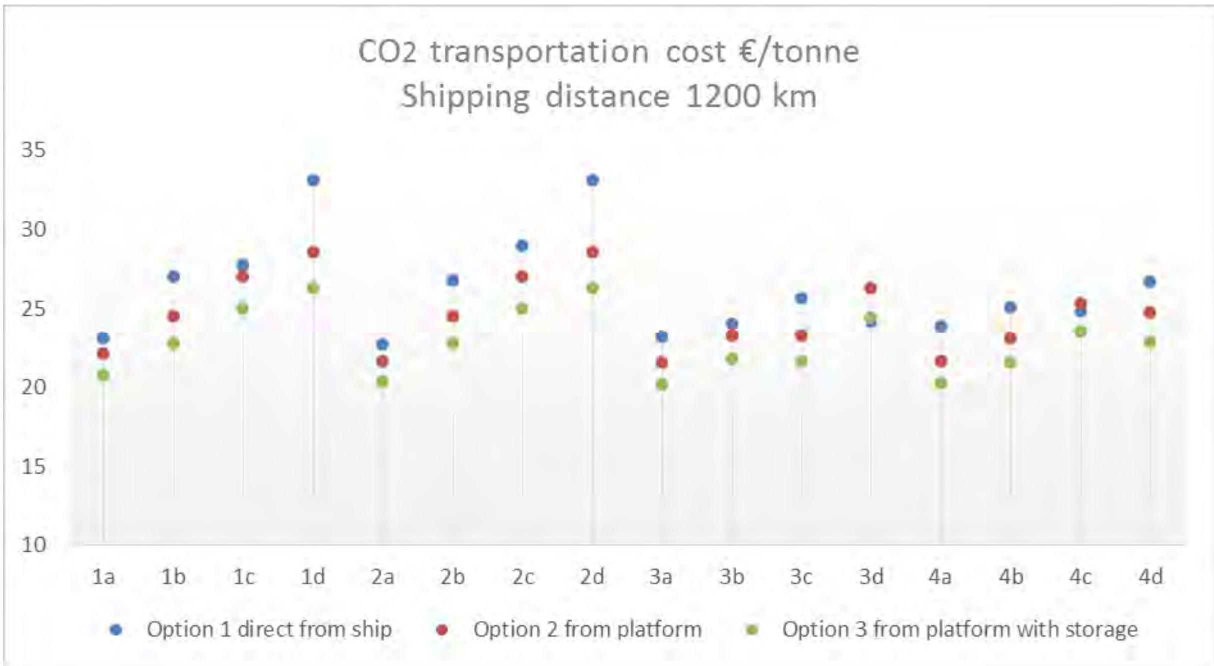


Figure 6-4: CO_2 transportation cost for the different reservoir cases at a shipping distance of 1200 km

Figure 6-2, Figure 6-3 and Figure 6-4 illustrate the CO_2 transportation cost of the different offshore design options as discussed in Section 4, for the different reservoir cases. Each data point in the graphs represents the scenario at maximum allowable flow rate case and optimised logistical scenario.

The results suggest that the use of an offshore platform (option 3) produces the lowest CO_2 transportation cost. This is mainly due to the more efficient use of the shipping fleet. The capital invetstment 110 M€ for the platform sensitivity is reflected in Figure 6-5.

A high-level overview of the results of extreme cases for the different offshore options for different type of reservoirs is presented in the tables below for the three options of offshore offloading. For the direct shipping option (1) key performance figures are presented in Table 6.10; for the direct platform option (2) and the option with offshore storage (3), the key performance figures are presented in

Table 6.11 and Table 6.12 respectively.

Table 6.10: Results of the direct shipping option (1)

	Unit	Min	Max
CO_2 transport cost	€/ton CO_2	13,7	35,4
Transport capacity	Mtpa	4.2	2.1
Ships required	-	5 (size 10kt)	4 (size 30kt)
Utilisation factor	%	75	52
Capex	M€	314	416
Reservoir nr	-	4a (50% depleted gas field, 1 km depth)	2d (saline formation, 4 km depth)
Travel distance	km	400	1200

Table 6.11: Results of the platform option (2)

	Unit	Min	Max
CO_2 transport cost	€/ton CO_2	14,1	30,6
Transport capacity	Mtpa	4.7	2.6
Ships required	-	6 (size 10kt)	4 (size 30kt)
Utilisation factor	%	72	57
Capex	M€	355	420
Reservoir nr	-	4a (50% depleted gas field, 1 km depth)	2d (saline formation, 4 km depth)
Travel distance	km	400	1200

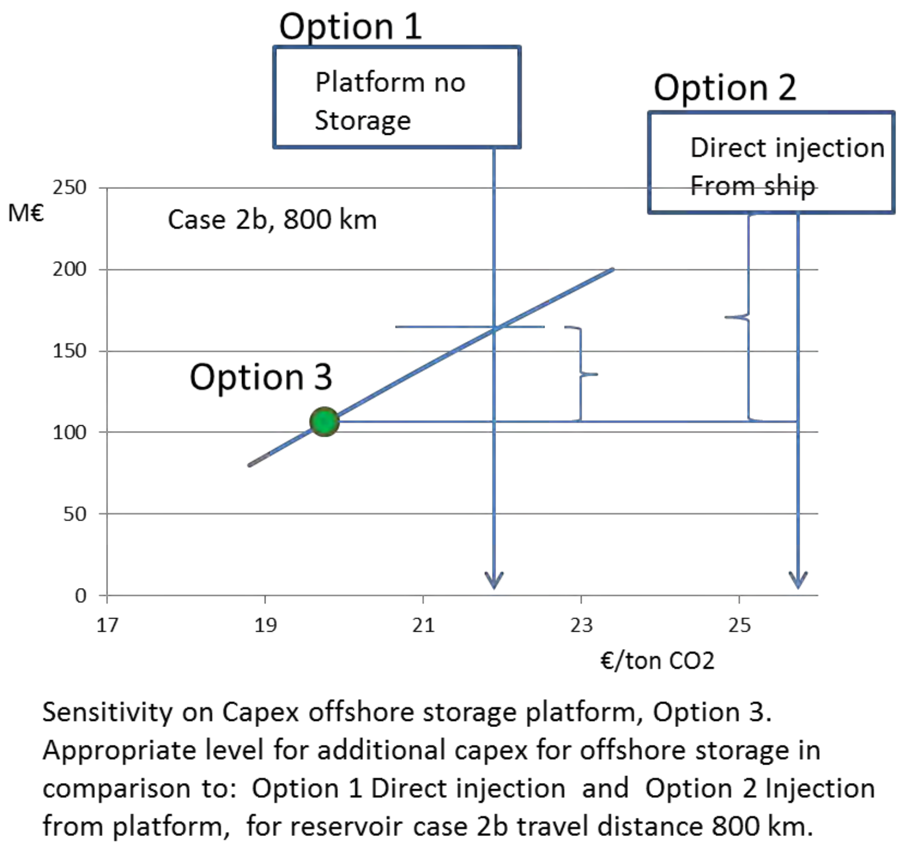


Figure 6-5: Offshore floating storage, the sensitive for capital investment levels.

Table 6.12: Results of the platform including storage option (3)

	Unit	Min	max
CO_2 transport cost	€/ton CO_2	13,6	27,8
Transport capacity	Mtpa	4.7	2.6
Ships required	-	2 (size 50kt)	3 (size 30kt)
Utilisation factor	%	82	76
Capex	M€	358	394

Reservoir nr	-	2a (saline formation, 1 km depth)	2d (saline formation, 4 km depth)
Travel distance	km	400	1200

The results of this study have been compared with the results from the ZEP transport study (ZEP, 2011), the ZEP study includes the capital investment costs for liquefaction, the comparison should be corrected for this cost element. Figure 6-6 illustrates the relationship between the transport distance and the cost of transporting one tone of CO_2 over a distance of one km. While the ZEP study assumes a capacity of 10 Mtpa (ZEP, 2011), in this study the capacity is in the range of 2 to 5 Mtpa, depending on the capacity of the injection well.

The transport costs are in the same range as results from other studies. It seems that for the three design cases for CO_2 shipping that ship transport may be cost-competitive compared to offshore pipelines at a transport distance of more than 700 km.

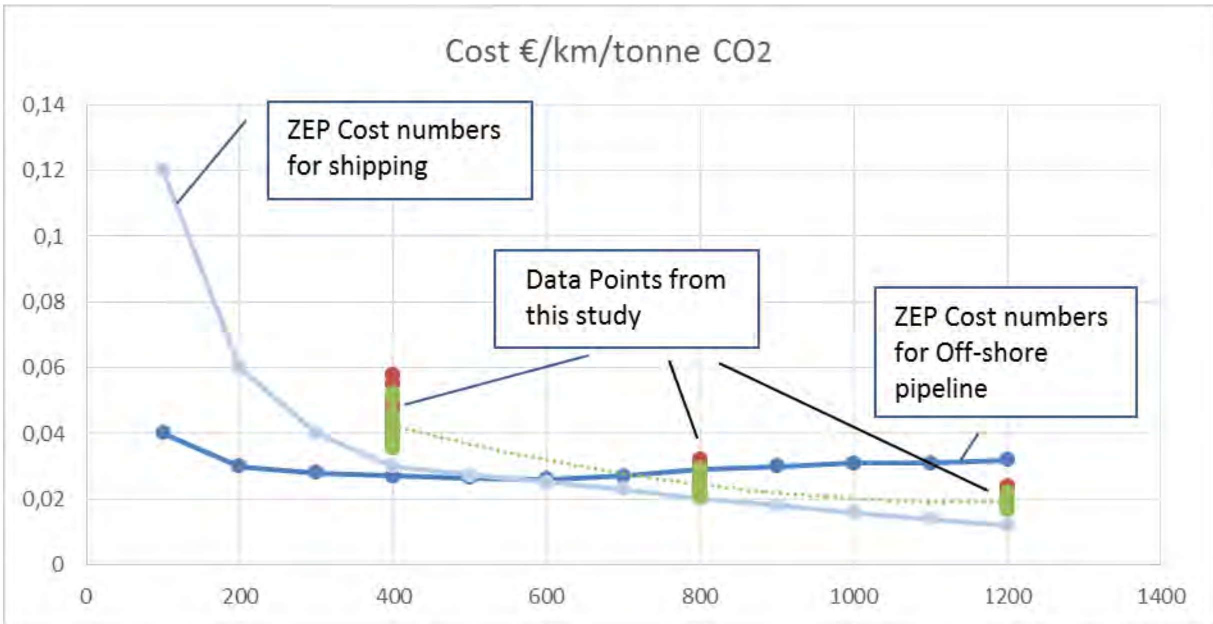


Figure 6-6: Cost expressed as €/tonne/km for the different shipping cases compared to ZEP resulting cost numbers for shipping and offshore pipeline transport (ZEP, 2011).

Figure 6-7, Figure 6-8 and Figure 6-9 illustrate the breakdown of total cost, by CAPEX, fuel costs and other OPEX, for the shipping design option 1 (direct injection from ship) and the reservoir case 1a (saline formation, permeability 100 mD, at a depth of 1000 m) at different shipping distances. Fuel cost will increase in ratio with the shipping distance as presented in the figures below.

From a total cost of ownership perspective offshore floating storage near the reservoir and injection direct from the platform, or floating storage and processing vessel, seems to be most attractive (see Figure 6-2, Figure 6-3 and Figure 6-4). The CO_2 shipping cost might be further reduced subject to the specific design conditions.

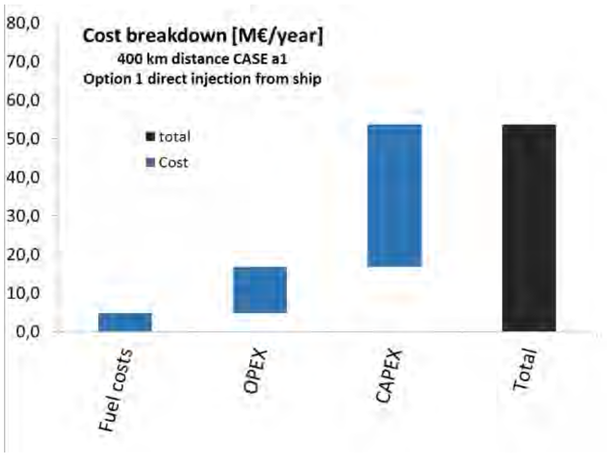


Figure 6-7: Cost breakdown for the shipping design option 1 (direct injection from ship) and reservoir case 1a (saline formation, permeability 100 mD, depth 1000 m) at 400 km shipping distance. The transport capacity for this scenario is 3.8 Mtpa.

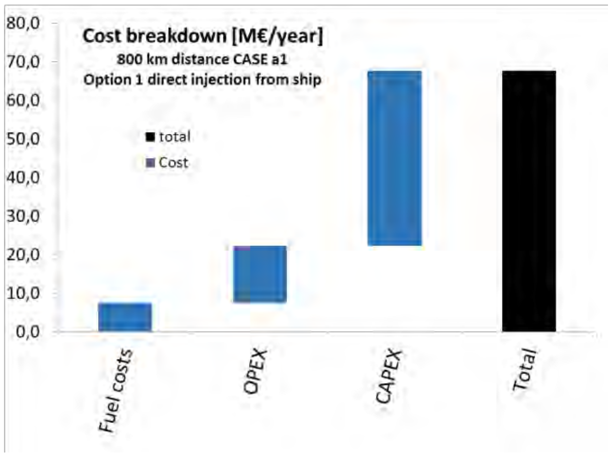


Figure 6-8: Cost breakdown for the shipping design option 1 (direct injection from ship) and reservoir case 1a (saline formation, permeability 100 mD, depth 1000 m) at 800 km shipping distance. The transport capacity for this scenario is 3.8 Mtpa.

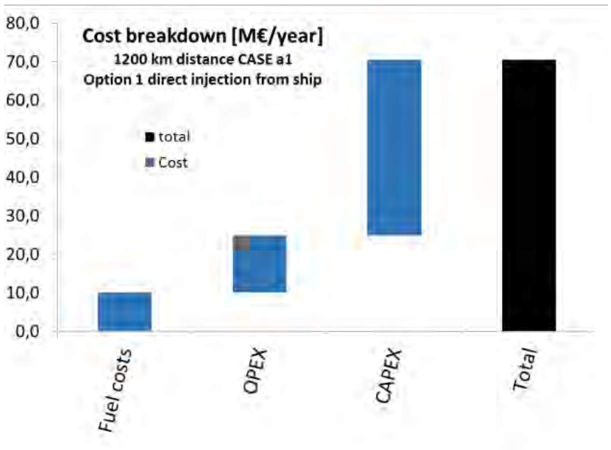


Figure 6-9: Cost breakdown for the shipping design option 1 (direct injection from ship) and reservoir case 1a (saline formation, permeability 100 mD, depth 1000 m) at 1200 km shipping distance. The transport capacity for this scenario is 3.8 Mtpa.

7 Conclusions

This report presents an analysis of the functional requirements of the CO_2 ship transport chain, focussing on offshore offloading near the storage site. Starting from the subsurface storage reservoir and a typical injection well, the operational window of injection is presented, in terms of pressure, temperature and mass flow rate of the CO_2 at the wellhead that are acceptable for safe and secure operations and storage. Based on a range of realistic storage reservoirs, including both saline formations and depleted hydrocarbon fields, these results show the variation in injection conditions that can be expected in the North Sea.

Functional requirements for the offshore offloading installations are derived from the difference between the conditions of the CO_2 in the ship with those at the wellhead, along with a number of assumed operational requirements, such as offloading time.

The functional requirements and engineering of the CO_2 shipping infrastructure must be matched to the characteristics of the well in terms of the required and allowable injection process conditions at the wellhead, to secure safe and reliable operations. Therefore it can be concluded that offshore mooring options, offloading options and possible intermittent storage all need to be evaluated in relation to the storage well characteristics.

The conceptual design of this study provides a sound basis for a generic process design for the process equipment for CO_2 transported in liquid form by ship and injection into different wells with varying depths. As such, the engineering data of the process equipment show that a single generic design for a typical North Sea fields can be defined. It is worth noting that the electrical and thermal power necessary to prepare the CO_2 for injection depends on the well type and the well depth.

The capital investment for CO_2 conditioning on board a ship for well injection ranges from 14,22 to 18,5 M€. The electrical duty is in the range 1,6 – 3,3 MWe and the thermal heating duty ranges from 5,2 to 18,4 MWth.

When the CO_2 is unloaded as a refrigerated liquid from a ship to a platform for conditioning and well injection, the investment for CO_2 equipment on board a ship ranges from 5,4 to 7,6 M€ and on board the platform from 21,45 to 24,9 M€. The electrical duty ranges from 3,2 to 5,5 MWe. Depending on the depth of the well, the thermal duty for heating ranges from 8,3 to 15,2 MWth, while a seawater cooling duty from 1,65 to 3,3 MWth may be required.

Estimates of the total investment costs for CO_2 transport infrastructure, including shuttle carriers but excluding liquefaction and shore storage, range from 310 to 420 M€ for a shipping distance of 400 km, up to 450 to 550 M€ for a 1200 km distance.

The results presented here suggest that all design options reviewed are feasible from a technical perspective, although for the direct injection option from a CO_2 carrier, the storage reservoir must be able to handle a distinctly intermittent injection process.

The duration of CO_2 injection is dependent on the maximum safe injection flow rate, which is determined by the reservoir characteristics; injection duration ranges between 30 and 50 h in this study. For the design cases without storage near the injection well (Cases 1 and 2) this requires the CO_2 carrier to remain at the offloading point for this time. When temporary offshore storage is available (Case 3) offloading time can be much shorter (15 h) allowing more efficient use of the shipping fleet with lesser requirement for spare shipping capacity and lower resulting transport costs.

In this this study the cases with temporary offshore storage had total CO_2 transport costs from 13 to 28 €/t (CAPEX and OPEX, excluding liquefaction and shore storage); the uncertainty in these cost estimates is of the order of 30 – 50%, given the high level of the current study.

The reservoir characteristics described in this report cover a range of realistic injection flow rates into the example reservoirs. For design cases without temporary offshore storage the flow rates have a direct impact on the offshore time of the CO_2 shuttle carrier and so on the operational costs. Therefore compared to other CO_2 shipping studies, the cost numbers of CO_2 shipping in this report are slightly higher. Other studies have generally assumed a certain flow rate derived from overall project scale and do not consider the reservoir constraints.

It is recommended to extend this study to two or three realistic storage options for the North Sea and refine the technical design of the CO_2 shipping infrastructure, with special focus on use of temporary storage near the injection well.

8 References

8.1 Literature

ASPELUND, A. & GUNDERSEN, T. (2009a). A liquefied energy chain for transport and utilization of natural gas for power production with CO_2 capture and storage – Part 1. *Applied Energy.* 86(6): 781-792.

ASPELUND, A. & GUNDERSEN, T. (2009b). A liquefied energy chain for transport and utilization of natural gas for power production with CO_2 capture and storage – Part 2: The offshore and the onshore processes. *Applied Energy.* 86(6): 793-804.

ASPELUND, A. & GUNDERSEN, T. (2009c). A liquefied energy chain for transport and utilization of natural gas for power production with CO_2 capture and storage – Part 4: Sensitivity analysis of transport pressures and benchmarking with conventional technology for gas transport. *Applied Energy.* 86(6): 815-825.

ASPELUND, A. & JORDAL, K. (2007). Gas conditioning – The interface between CO_2 capture and transport. *International Journal of Greenhouse Gas Control.* 1(3): 343-354.

ASPELUND, A. (2010). Gas purification, compression and liquefaction processes and technology for carbon dioxide (CO_2) transport. IN: MAROTO-VALER, M. M. (Ed) *Developments and innovation in CCS technology*, Cambridge, Woodhead Publishing Ltd. pp. 383-407.

ASPELUND, A., KROGSTAD, H., SANDVIK, T. E., (2008). US Patent Application US20080156035, Liquefaction.

ASPELUND, A., KROGSTAD, H., SANDVIK, T. E., FIVELSTAD, J., HENNINGSEN, R., WONGRAVEN, L. R., HILDEN, T. & OMA, N. (2008). US Patent Application US20080256959, Vessel.

ASPELUND, A., MØLNVIK, M. J. & DE KOEIJER, G. (2006). Ship Transport of CO_2. *Chemical Engineering Research and Design.* 84(9): 847-855.

ASPELUND, A., SANDVIK, T. E., KROGSTAD, H. & DE KOEIJER, G. (2004a). Liquefaction of captured CO_2 for ship-based transport. IN: WILSON, M., MORRIS, T., GALE, J. & THAMBIMUTHU, K. (Eds.) *7th International Conference on Greenhouse Gas Control Technologies, 2004, Vancouver*, Elsevier Ltd.

ASPELUND, A., TVEIT, S. P. & GUNDERSEN, T. (2009). A liquefied energy chain for transport and utilization of natural gas for power production with CO_2 capture and storage – Part 3: The combined carrier and onshore storage. *Applied Energy.* 86(6): 805-814.

ASPELUND, A., WEYDAHL, T., SANDVIK, T. E., KROGSTAD, H.L., WONGRAVEN, R., HENNINGSEN, R., FIVELSTAD, J., OMA N. & HILDEN T. (2004b). Offshore unloading of semi-pressurised CO_2 to an oilfield. IN: WILSON, M., MORRIS, T., GALE, J. & THAMBIMUTHU, K. (Eds.) *7th International Conference on Greenhouse Gas Control Technologies, 2004, Vancouver,* Elsevier Ltd.

BLUEWATER (2009). *North Sea CO_2 Injection - CO_2 transfer options; Technical Feasibility Screening Study*, Confidential.

BOHRAUS, S., BETTGE, D., KRANZMANN, A., (2013) Corrosion behaviour of a Pipeline Steel under CCS-Transport Conditions EUROCORR 2013 - European Corrosion Congress

BROWNSORT, P.A., Scottish Carbon Capture & Storage, Ship transport of CO2 for Enhanced Oil Recovery – Literature Survey. Jan. (2015), http://www.sccs.org.uk/images/expertise/reports/co2-eor-jip/SCCS-CO2-EOR-JIP-WP15-Shipping.pdf

CAPELLE, J., FURTADO, J., AZARI, Z., JALLAIS, S. & PLUVINAGE, G. (2013). Design based on ductile–brittle transition temperature for API 5L X65 steel used for dense CO2 transport, Engineering Fracture Mechanics, 110, 270 - 280

DECARRE, S., BERTHIAUD, J., BUTIN, N. & GUILLAUME-COMBECAVE, J.-L. (2010). CO_2 maritime transportation. *International Journal of Greenhouse Gas Control.* 4(5): 857-864.

DOCTOR, R., PALMER, A., COLEMAN, D. L., DAVISON, J., HENDRIKS, C., KAARSTAD, O., OZAKI, M. & AUSTELL, M. (2005). Transport of CO_2. IN: PICHS-MADRUGA, R. & TIMASHEV, S. (Eds.) *IPPC Special Report on Carbon dioxide Capture and Storage.* IPCC. pp 179-193.

DUGSTAD, A., HALSEID, M., MORLAND, B. & SIVERTSEN, A. O. (2013). Corrosion in Dense Phase CO2 – the Impact of Depressurisation and Accumulation of Impurities, Energy Procedia, 37, 3057 - 3067

EI (Energy Institute) (2008), Guidelines for the avoidance of vibration induced fatigue failure in process pipework, Energy Institute, UK, http://www.energypublishing.org/publication/ei-technical-publications/installation-integrity/guidelines-for-the-avoidance-of-vibration-induced-fatigue-failure-in-process-pipework.

FARHAT, K. & BENSON, S. M. (2013). A technical assessment of CO2 Interim Storage in deep saline aquifers, International Journal of Greenhouse Gas Control, 15 200 - 212

GESKE, J., BERGHOUT, N. & BROEK, M.V.D. (2015). Cost-effective balance between CO2 vessel and pipeline transport: Part II – Design of multimodal CO2 transport: The case of the West Mediterranean region, International Journal of Greenhouse Gas Control, 33, 122- 134

GILES, C. (2012). *Peterhead CO_2 importation feasibility study.* Petrofac Engineering Ltd. Report number: JU-12966A-REP-A-0001.

Global CCS Institute and Worley Parsons, Strategic Analysis of the Global Status of Carbon Capture and Storage, appendix C (2009). http://www.globalccsinstitute.com/sites/www.globalccsinstitute.com/files/publications/5751/report-1-status-carbon-capture-and-storage-projects-globally.pdf

GOEL, N. (2006). In situ methane hydrate dissociation with carbon dioxide sequestration: Current knowledge and issues. Journal of Petroleum Science and Engineering 51, 169-184.

HEGERLAND, G., JORGNSEN, T. & PANDE, J.O. (2004). Liquefaction and handling of large amounts of CO_2 for EOR. IN: WILSON, M., MORRIS, T., GALE, J. & THAMBIMUTHU, K. (Eds.) *7th International Conference on Greenhouse Gas Control Technologies, 2004, Vancouver,* Elsevier Ltd.

HENDRIKS. C.A., de VISSER, E. & KOORNNEEF, J.M. (2011). CO_2 Transport – The Missing Link for CCS, in STOLTEN, D. & SCHERER, V. (Eds.) *'Efficient Carbon Capture for Coal Power Plants'*, Wiley.

KEMP, A,G., KASIM, S. (2013). The economics of CO2-EOR cluster developments in the UK Central North Sea Energy Policy, 62, 1344 - 1355

KNUTSEN OAS Shipping, Patents: NO20084170 A, NO20074154 A, US200823484 A1, US2007068860 A1, US2005257728 A1, US2006005757 A1, US2005166982 A1, US2004194844 A1, US2004074430 A1, NO20010778 A, NO20010728 A, WO03047959 A1, WO2008097099 A1

KOERS, P. & DE LOOIJ, M. (2011). *Safety study for Liquid Logistics Shipping Concept*. Rotterdam, Det Norske Veritas BV. Report number: 12TUIBY-3

MARTYNOV S., MAHGEREFTEH H., BROWN S., University College London, UK, CCSC Winter School, University of Cambridge, 9th-12th January (2012), http://www.co2pipehaz.eu/

MENDELEVITCH, R. (2014). The role of CO2-EOR for the development of a CCTS infrastructure in the North Sea Region: A techno-economic model and applications, International Journal of Greenhouse Gas Control, 20, 132-159.

MITSUBISHI HEAVY INDUSTRIES LTD. (2004). *Ship Transport of CO_2*. Cheltenham, IEA-GHG. Report number: PH4/30.

NARDON, 2010, Techno-economic assessment of CO2 transport by ship. A case study for the Netherlands. CATO2 - WP 2.2.1 Logistics CCS transport of the CATO2 programme.

NEELE, F, HAUGEN, H.A.,SKAGESTAD, R. (2014). Ship transport of CO_2 – breaking the CO_2-EOR deadlock, Energy Procedia, 63.

NØKLEBY, P.H. (2015) Aker Solutions, Creating value based on offshore CO2 EOR, Tekna CO_2 Conference, Trondheim January 9.

OLDENBURG, C.M. (2006). Joule-Thomson cooling due to CO2 injection into natural gas reservoirs. TOUGH Symposium 2006. Lawrence Berkeley National Laboratory, California, U.S.A. Paper LBNL-60158.

OMATA, A. (2011). *Preliminary Feasibility Study on CO2 Carrier for Ship-based CCS*. Chiyoda Corporation and GCCSI. Report number: CCSC-RPT-10-002.

OMATA, A. (2012a). *Phase 2 – unmanned offshore facility. Preliminary Feasibility Study on CO_2 Carrier for Ship-based CCS*. Chiyoda Corporation and GCCSI. Report number: CCSC-RPT-00-002

OMATA, A. (2012b). *Storage Site Identification beyond the Japanese Continental Shelf. Preliminary Feasibility Study on CO_2 Carrier for Ship-based CCS.* Chiyoda Corporation and GCCSI. Report number: CCSC-RPT-00-003

PAIDOUSSIS, M.P. (1986). Dynamics of finite-length tubular beams conveying fluid, J. Sound and Vibration, 106, 311-331.

PAIDOUSSIS, M.P. (1998). Fluid-structure interactions, Volume 1: Slender structures and axial flow, Academic Press, 1998.

PAIDOUSSIS, M.P. & SEMLER, C. (1993). Non-linear dynamics of a fluid-conveying cantilevered pipe with a small mass attached at the free end, Int. J. Non-Linear Mechanics, 33, 15-32.

PERKINS, T.K. & GONZALEZ J.A. (1985). The effect of thermo-elastic stresses on injection well fracturing, SPE journal.

ROUSSANALY, S., BUREAU-CAUCHOIS, G. & HUSEBYE, J. (2013a). Costs benchmark of CO_2 transport technologies for a group of various size industries. *International Journal of Greenhouse Gas Control.* 12: 341-350.

ROUSSANALY, S., HOGNES, E.S. & JAKOBSEN, J.P. (2013b). Multi-criteria analysis of two CO_2 transport technologies. IN: DIXON, T. (Ed.) *11th International Conference on Greenhouse Gas Control Technologies, 2013, Kyoto. Energy Procedia,* 37: 2981-2988. Elsevier Ltd.

ROUSSANALY, S., JAKOBSEN, J.P., HOGNES, E.H. & BRUNSVOLD, A.L. (2013c). Benchmarking of CO_2 transport technologies: Part I—Onshore pipeline and shipping between two onshore areas. *International Journal of Greenhouse Gas Control.* 19: 584-594.

ROUSSANALY, S., BRUNSVOLD, A.L. & HOGNES, E.S. (2014). Benchmarking of CO2 transport technologies: Part II Offshore pipeline and shipping to an offshore site, International Journal of Greenhouse Gas Control, 28, 283 – 299.

ROUSSANALY, S., GRIMSTAD, A., The Economic Value of CO_2 for EOR Applications, Energy Procedia 63 (2014) 7836 – 7843.

SEO, Y.,YOU, H., LEE, S., HUH, C., CHANG, D. (2015). Evaluation of CO2 liquefaction processes for ship-based carbon capture and storage (CCS) in terms of life cycle cost (LCC) considering availability, International Journal of Greenhouse Gas Control, 35, 1 - 12

SIM, S., COLE, I.S., CHOI, Y.S., BIRBILLS, N. (2014). A review of the protection strategies against internal corrosion for the safe transport of supercritical CO2 via steel pipelines for CCS purposes, International Journal of Greenhouse Gas Control, 29, 185 - 199

SKAGESTAD, R., ELDRUP, N., HANSEN, H., BELFROID, R., MATHISEN, S., LACH. A. & HAUGEN, H.A. (2014). Ship transport of CO2, Status and Technology Gaps, Gassnova, Tel-Tek report no. [2214090].

Stamicarbon patent WO2013025108 A1, 17 Aug. 2012, Shipping method for CO2 storage and import of cng

SVENSSON, R., ODENBERGER, M., JOHNSSON, F. & STRÖMBERG, L. (2004a). Transportation systems for CO_2 – application to carbon capture and storage. *Energy Conversion and Management.* 45(15-16): 2343-2353.

SVENSSON, R., ODENBERGER, M., JOHNSSON, F. & STRÖMBERG, L. (2004b). Transportation Infrastructure for CCS - Experiences and Expected Development. IN: WILSON, M., MORRIS, T., GALE, J. & THAMBIMUTHU, K. (Eds.) *7th International Conference on Greenhouse Gas Control Technologies, 2004, Vancouver,* Elsevier Ltd.

TER MORS, Y. (2011). *Safety, Health and Environment (SHE) Report. CO_2 Liquid Logistics Shipping Concept.* Tebodin Netherlands BV, Vopak, Anthony Veder and GCCSI. Report number: 3112003.

TETTEROO, M. & VAN DER BEN, C. (2011). *CINTRA Business Model. CO_2 Liquid Logistics Shipping Concept.* Vopak, Anthony Veder and GCCSI.

VANGKILDE PEDERSEN, T., KIRK, K., SMITH, N., MAURAND, N., WOJCICKI, A., NEELE, F., HENDRIKS, C., LE NINDRE, Y.M. & LYNG ANTHONSEN, K. (2009).Geocapacity final report, Geocapacity report D42, 2009 (http://www.geology.cz/geocapacity/publications/D42%20GeoCapacity%20Final%20Report-red.pdf).

VERMEULEN, T. N. (2011). *Overall Supply Chain Optimization. CO_2 Liquid Logistics Shipping Concept.* Tebodin Netherlands BV, Vopak, Anthony Veder and GCCSI. Report number: 3112001.

WEIHS, G.A., FIMBRES, KUMAR, K. & WILEY, D.E. (2014). Understanding the Economic Feasibility of Ship Transport of CO2 within the CCS Chain, Energy Procedia, 63, 2630 - 2637

WHITTAKER, S. & PERKINS, E. (2013). *Technical aspects of CO_2 enhanced oil recovery and associated carbon storage.* GCCSI.

WILDBOLZ, C. (2007). *Life Cycle Assessment of Selected Technologies for CO_2 Transport and Sequestration.* Thesis, (Diploma). Swiss Federal Institute of Technology.

YEVTUSHENKO, O., BETTGE, D., BOHRAUS, S., BÄßLER, R., PFENNIG, A. & KRANZMANN, A. (2014). Corrosion behavior of steels for CO2 injection, Process Safety and Environmental Protection,92, 108 – 118.

YOO, B.Y., CHOI, D.K., KIM, H. J., MOON, Y.S., NA, H.S. & LEE, S.G. (2013). Development of CO_2 terminal and CO_2 carrier for future commercialized CCS market. *International Journal of Greenhouse Gas Control.* 12: 323-332.

ZEP (2011). *The Costs of CO_2 Transport.* Brussels, European Technology Platform for Zero Emission Fossil Fuel Power Plants.

ZOBACK, M.D. (2007). Reservoir Geomechanics, Cambridge University Press.

8.2 Websites and other sources

ANTHONY VEDER, (2014). Company website, accessed 01/08/2014: http://www.anthonyveder.com/fleet/coral-carbonic/

GCCSI website http://www.globalccsinstitute.com/publications/global-status-ccs-2014

HEUCKE, U. (2014). Personal communication via Gordon Sim, SCCS from Ulrich Heucke, Linde AG.

HSE, (2014). Health and Safety Executive website, accessed 22/08/2014: http://www.hse.gov.uk/carboncapture/carbondioxide.htm

IMO, (2014). International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code). International Maritime Organisation web page, accessed 29/08/2014: http://www.imo.org/OurWork/Environment/PollutionPrevention/ChemicalPollution/Pages/IGCCode.aspx

MITSUBISHI JUKOGYO KK (2002). Japanese Patent JP2004125039-A; *Carbon dioxide handling involves using liquefied petroleum gas ship for conveying carbon dioxide*, Mitsubishi Jukogyo KK (Mito-C).

MOLLER – MEARSK brochure: CO2 Transportation and Storage, http://www.maersktankers.com/Documents/CO2%20transportation%20and%20storage%20folder.pdf

SCOTTISH ENTERPRISE, CarbonCapture and Storage, CO_2 transport options for Scotland, Sept. (2011), http://www.scottish-enterprise.presscentre.com/Multimedia-library/CO2-Transport-Options-for-Scotland-study-front-cover-pic-2e8.aspx

SKAUGEN, (2104). Article on company website, accessed 30/07/2014: http://www.skaugen.com/index.php?option=com_content&view=article&id=139:main-article-history&catid=49:history&Itemid=134

LARVIK, (2014). Company website, accessed 30/07/2104: http://www.larvik-shipping.no/

NOV/APL, 2014. Company website, accessed 31/07/2014: http://fps.nov.com/subsea/mooring-systems/submerged-turret-loading

IAEGHG, CO_2 Transport via Pipeline and Ship, IEA Greenhouse Gas R&D Programme Cheltenham, UK, March 30,(2012,) http://ieaghg.org/docs/General_Docs/IEAGHG_Presentations/3._CO2_Transport_Overview_-_S._Santos_IEAGHG.pdf

YARA, (2013). Press release on company website, accessed 30/07/2014: http://www.yara.com/media/news_archive/Yara_co2_ships.aspx

8.3 Further reading

BAKKEN, B. H. & VON STRENG VELKEN, I. (2008). Linear models for optimization of infrastructure for CO_2 capture and storage. *Transactions of Energy Conversion.* 23(3).

BARRIO, M., ASPELUND, A., WEYDAHL, T., SANDVIK, T. E., WONGRAVEN, L. R., KROGSTAD, H., HENNINGSEN, R. M., MØLNVIK, J. & EIDE, S. I. (2004). Ship-based transport of CO_2. IN: WILSON, M., MORRIS, T., GALE, J. & THAMBIMUTHU, K. (Eds.) *7th International Conference on Greenhouse Gas Control Technologies, 2004, Vancouver*, Elsevier Ltd.

BERGER, B., KAARSTAD, O. & HAUGEN, H. A. (2004). Creating a large-scale infrastructure for EOR. IN: WILSON, M., MORRIS, T., GALE, J. & THAMBIMUTHU, K. (Eds.) *7th International Conference on Greenhouse Gas Control Technologies, 2004, Vancouver*, Elsevier Ltd.

CHU, B., CHANG, D. & CHUNG, H. (2012). Optimum liquefaction fraction for boil-off gas reliquefaction system of semi-pressurized liquid CO_2 carriers based on economic evaluation. *International Journal of Greenhouse Gas Control.* 10: 46-55.

CHU, B., YANG, K. W. & CHANG, D. (2011). Controlled cargo handling with piston fluid for pressurized liquid CO_2 Carrier. IN: GALE, J., HENDRIKS, C. & TURKENBERG, W. (Eds.) *10th International Conference on Greenhouse Gas Control Technologies, 2011, Amsterdam. Energy Procedia,* 4: 3048-3055. Elsevier Science BV.

HAUGEN, H.A., ELDRUP, N., BERNSTONE, C., LILJEMARK, S., PETTERSSON, H., NOER, M., HOLLAND, J., NILSSON, P.A., HEGERLAND, G. & PANDE, J.O. (2009). Options for transporting CO_2 from coal fired power plants Case Denmark. IN: BRAITSCH, J. (Ed.) *9th International Conference on Greenhouse Gas Control Technologies, 2009, Washington DC. Energy Procedia,* 1: 1665-1672. Elsevier Science BV.

ISO-TRYYKÄRI, M., RAURAMO, J. & PEKKANEN, E. (2011). FINNCAP - Meri-Pori CCS demonstration project. IN: GALE, J., HENDRIKS, C. & TURKENBURG, W. (Eds.) *10th International Conference on Greenhouse Gas Control Technologies, 2011, Amsterdam. Energy Procedia,* 4: 5599-5606. Elsevier Science BV.

JUNG, J.Y., HUH, C., KANG, S.G., SEO, Y. & CHANG, D. (2013). CO_2 transport strategy and its cost estimation for the offshore CCS in Korea. *Applied Energy.* 111: 1054-1060.

JUNG, J.Y., HUH, C., KANG, S.G., SEO, Y. & CHANG, D. (2013). CO_2 Transport Strategy for the Offshore CCS in Korea. IN: DIXON, T. (Ed.) *11th International Conference on Greenhouse Gas Control Technologies, 2013, Kyoto. Energy Procedia,* 37: 3242-3249. Elsevier Ltd.

KOKUBUN N., KO K., OZAKI, M. (2013). Cargo conditions of CO2 in shuttle transport by ship, Energy Procedia 37, 3160 – 3167

KROGH, E., NILSEN, R. & HENNINGSEN, R. (2012). Liquefied CO_2 Injection Modelling. IN: *6th Trondheim CCS Conference, 2012, Trondheim. Energy Procedia,* 23: 527-555. Elsevier Ltd.

KUJANPÄÄ, L., RAURAMO, J. & ARASTO, A. (2011). Cross-border CO_2 infrastructure options for a CCS demonstration in Finland. IN: GALE, J., HENDRIKS, C. & TURKENBURG, W. (Eds.) *10th International Conference on Greenhouse Gas Control Technologies, 2011, Amsterdam. Energy Procedia,* 4: 2425-2431. Elsevier Science BV.

LEE, S.G., CHOI, G.B., YOON, E.S., HAN, C. & LEE, J.M. (2012). Modeling and Simulation of Ship Transport of CO_2. IN: DIXON, T. (Ed.) *11th International Conference on Greenhouse Gas Control Technologies, 2013, Kyoto. Energy Procedia,* 31: 785-789. Elsevier BV.

LEE, U., LIM, Y., LEE, S., JUNG, J. & HAN, C. (2012). CO_2 Storage Terminal for Ship Transportation. *Industrial & Engineering Chemistry Research.* 51(1): 389-397.

LEE, U., YANG, S., JEONG, Y.S., LIM, Y., LEE, C.S. & HAN, C. (2012). Carbon Dioxide Liquefaction Process for Ship Transportation. *Industrial & Engineering Chemistry Research.* 51(46): 15122-15131.

LOEVE, D., HOFSTEE C., MAAS, J.G. (2014) Thermal effects in a depleted gas field by cold CO_2 injection in the presence of methane, Energy Procedia; 63, 5378-5393.

MIKUNDA, T., VAN DEURZEN, J., SEEBREGTS, A., KERSSEMAKERS, K., TETTEROO, M. & BUIT, L. (2011). Towards a CO_2 infrastructure in North-Western Europe: Legalities, costs and organizational aspects. IN: GALE, J., HENDRIKS, C. & TURKENBERG, W. (Eds.) *10th International Conference on Greenhouse Gas Control Technologies, 2011, Amsterdam. Energy Procedia,* 4: 2409-2416. Elsevier Science BV.

NAM, H., LEE, T., LEE, J., LEE, J. & CHUNG, H. (2013). Design of carrier-based offshore CCS system: Plant location and fleet assignment. *International Journal of Greenhouse Gas Control.* 12: 220-230.

NOOTHOUT, P., & BERGHOUT, N. (2010). First assessment of the cost and logistics of reusing existing infrastructure: Use or reuse of platforms or subsea completion for offshore storage of CO2. CATO2-2.2 Techno-economic chain analysis. Ecofys & Utrecht University.

ECOFYS, Utrecht University. 2.2 Techno-economic chain analysis.

OGDEN, J. & JOHNSON, N. (2010). Techno-economic analysis and modeling of carbon dioxide (CO_2) capture and storage (CCS) technologies. IN: MAROTO-VALER, M. M. (Ed) *Developments and innovation in CCS technology*, Cambridge, Woodhead Publishing Ltd. pp. 27-63.

OZAKI, M. & OHSUMI, T. (2011). CCS from multiple sources to offshore storage site complex *via* ship transport. IN: GALE, J., HENDRIKS, C. & TURKENBERG, W. (Eds.) *10th International Conference on Greenhouse Gas Control Technologies, 2011, Amsterdam. Energy Procedia,* 4: 2992-2999. Elsevier Science BV.

OZAKI, M., DAVISON, J. & MINAMIURA, J. (2004). Marine Transportation of CO_2. IN: WILSON, M., MORRIS, T., GALE, J. & THAMBIMUTHU, K. (Eds.) *7th International Conference on Greenhouse Gas Control Technologies, 2004, Vancouver,* Elsevier Ltd.

OZAKI, M., OHSUMI, T. & KAJIYAMA, R. (2013). Ship-based Offshore CCS Featuring CO_2 Shuttle Ships Equipped with Injection Facilities. IN: DIXON, T. (Ed.) *11th International Conference on Greenhouse Gas Control Technologies, 2013, Kyoto. Energy Procedia,* 37: 3184-3190. Elsevier Ltd.

SANTARELLI, F.J., HAVMØLLER, O., NAUMANN, M. (2008). Geomechanical aspects of 15 years water injection on a field complex: An analysis of the past to plan the future, SPE112944.

SEO, Y., CHANG, D., JUNG, J.Y., HUH, C. & KANG, S.G. (2013). Economic Evaluation of Ship-based CCS with Availability. IN: DIXON, T. (Ed.) *11th International Conference on Greenhouse Gas Control Technologies, 2013, Kyoto. Energy Procedia,* 37: 2511-2518. Elsevier Ltd.

SINGH, V., CAVANAGH, A., HANSEN, H., NAZARIAN, B., IDING, M. & RINGROSE, P. (2010), Reservoir modeling of CO_2 plume behavior calibrated against monitoring data from Sleipner, Norway, SPE134891. Presented at SPE ATCE, Florence, Italy.

SKAGESTAD, R., MATHISEN, A., ELDRUP, N.H. & HAUGEN, H.A. (2011). CO_2 transport from sources to storage in the Skagerrak/Kattegat region. IN: GALE, J., HENDRIKS, C. & TURKENBERG, W. (Eds.) *10th International Conference on Greenhouse Gas Control Technologies, 2011, Amsterdam. Energy Procedia,* 4: 3016-3023. Elsevier Science BV.

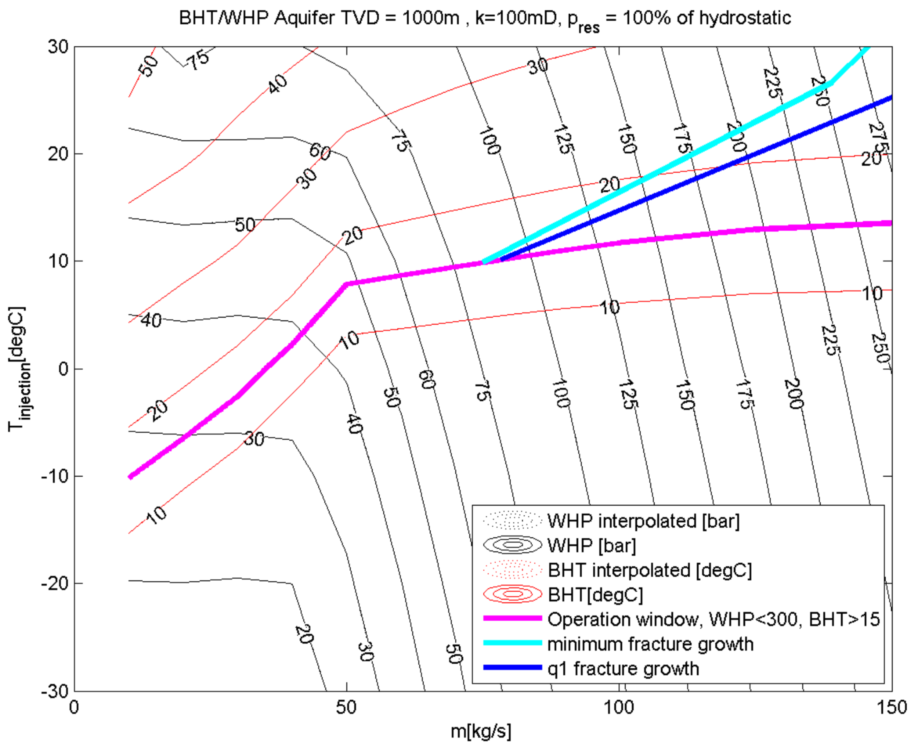
YOO, B.Y., LEE, S.G., RHEE, K.P., NA, H.S. & PARK, J.M. (2011). New CCS system integration with CO_2 carrier and liquefaction process. IN: GALE, J., HENDRIKS, C. & TURKENBERG, W. (Eds.) *10th International Conference on Greenhouse Gas Control Technologies, 2011, Amsterdam. Energy Procedia,* 4: 2308-2314. Elsevier Science BV.

Appendix A: Operational windows

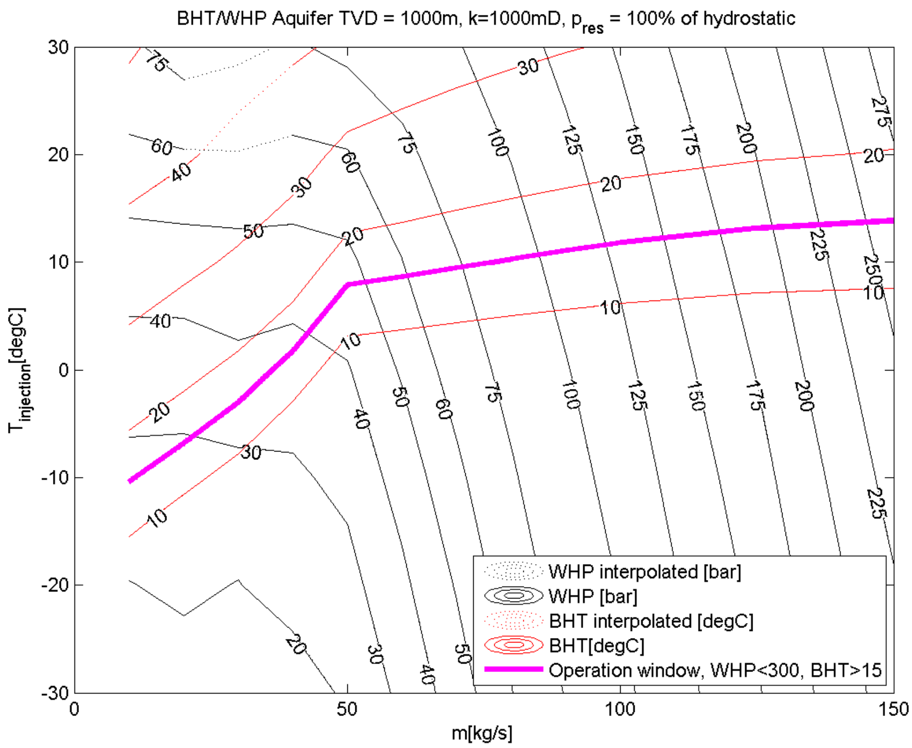
Operational windows of injection, in terms of mass flow rate and wellhead temperature, are shown below for all sixteen hypothetical storage site defined in Table 3.1.

In each plot, the horizontal axis is the mass flow rate; the vertical axis is the temperature of the injected CO_2 at the wellhead. Black lines are isolines for the required wellhead pressure (WHP) for this injection. Red lines are the bottom hole temperatures (BHT) of the CO_2. The magenta curves define the boundary of the operational window in terms of BHT and WHP. Safe CO_2 injection is possible for combinations of flow rate and wellhead temperature that lie inside the magenta curves (in most cases, this is the upper left part of the range in flow rate and temperature represented in the figure). Cyan and blue lines represent operating limits due to fracture propagation in the reservoir; note that these limits are not calculated for bottom hole temperatures below 15°C since this is already outside the operation window due to hydrate forming in the reservoir. In cases where the blue or cyan curves fall within the 'magenta' operational window, fracture growth represents a further limitation of injection rate and injection temperature.

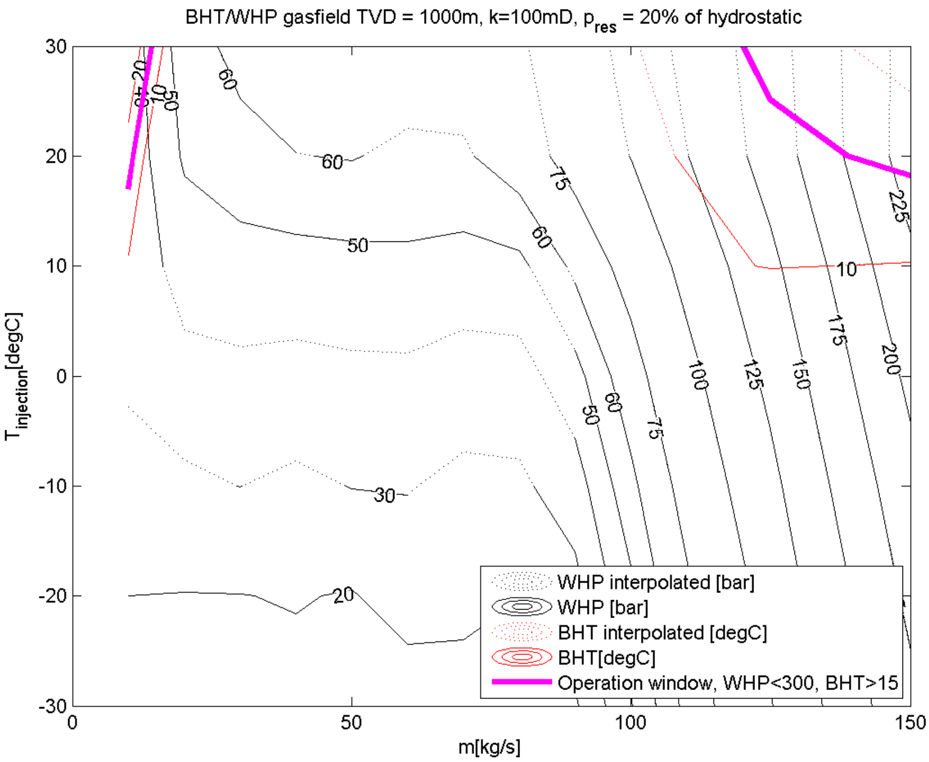
1000 m depth



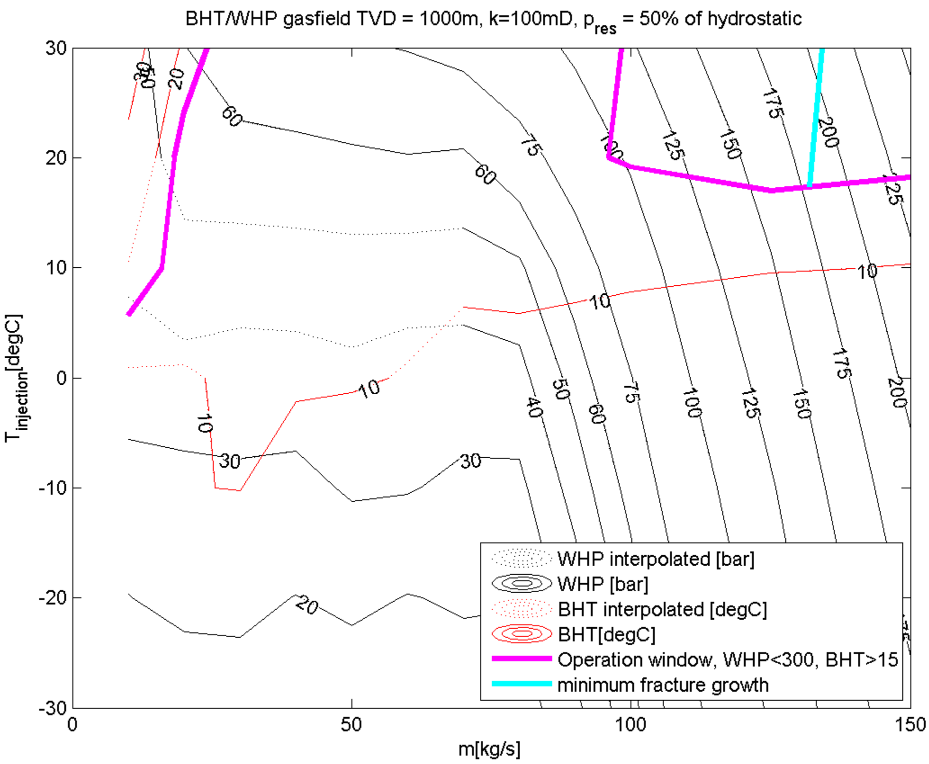
Case 1a



Case 2a

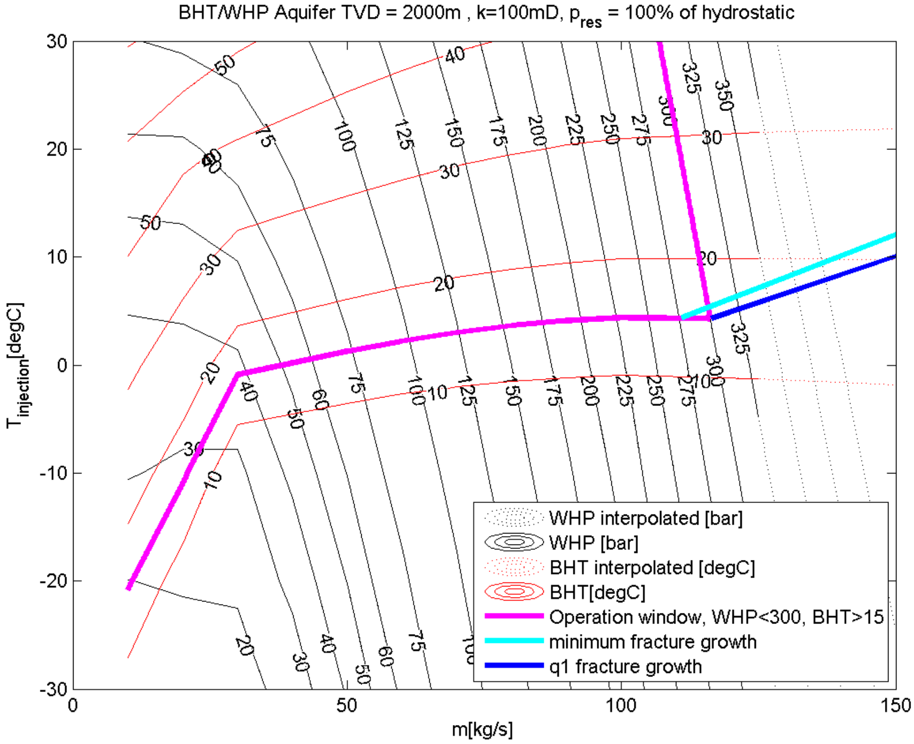


Case 3a

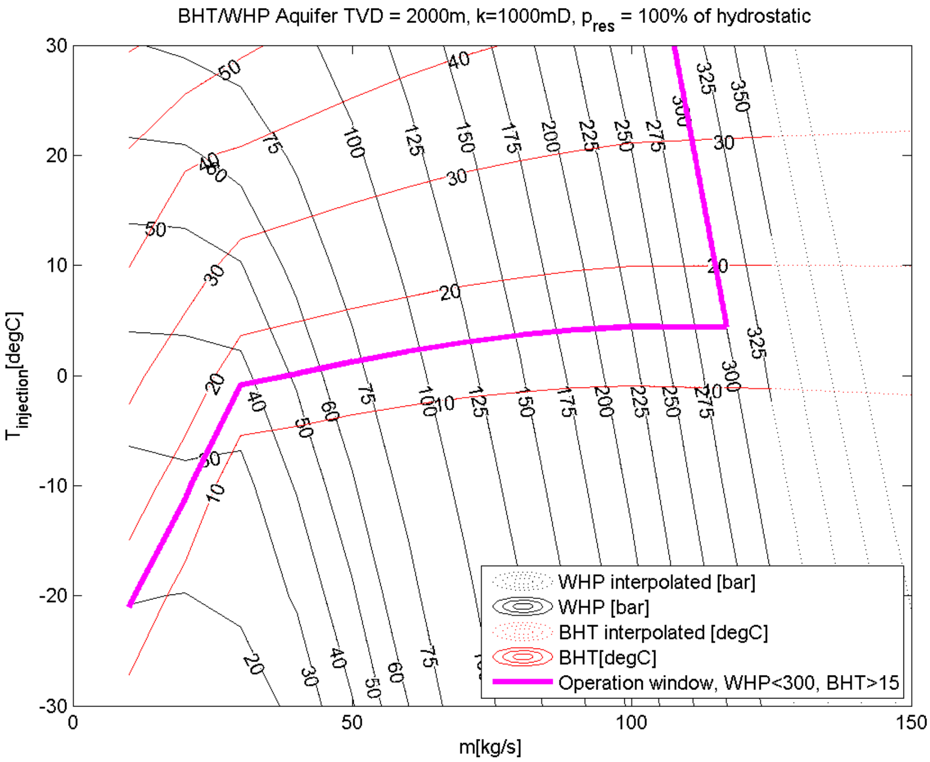


Case 4a

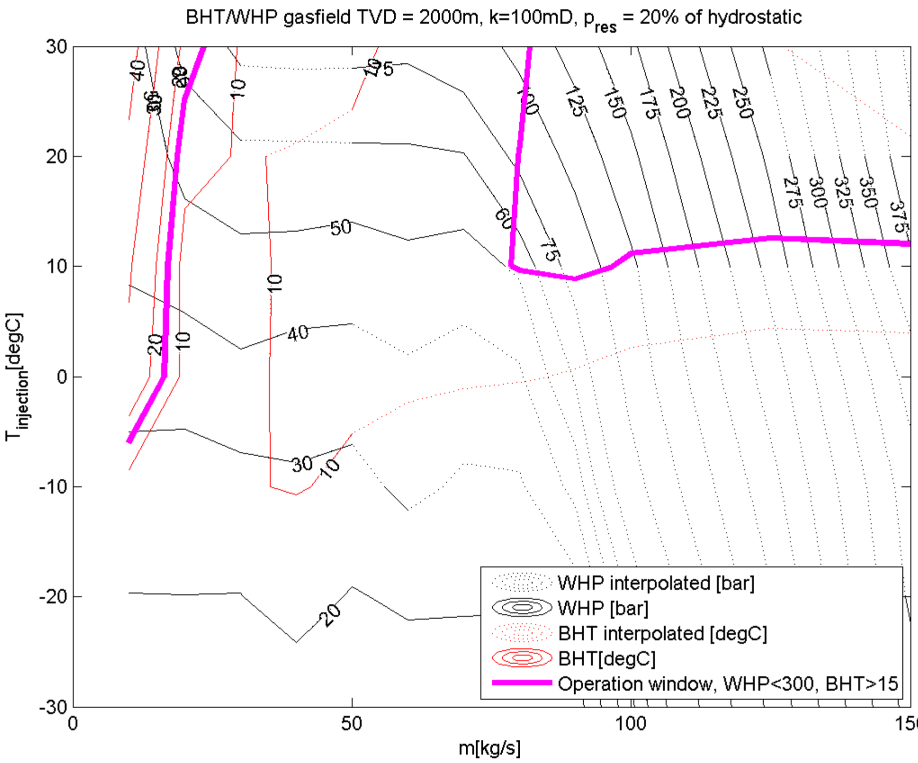
2000 m depth



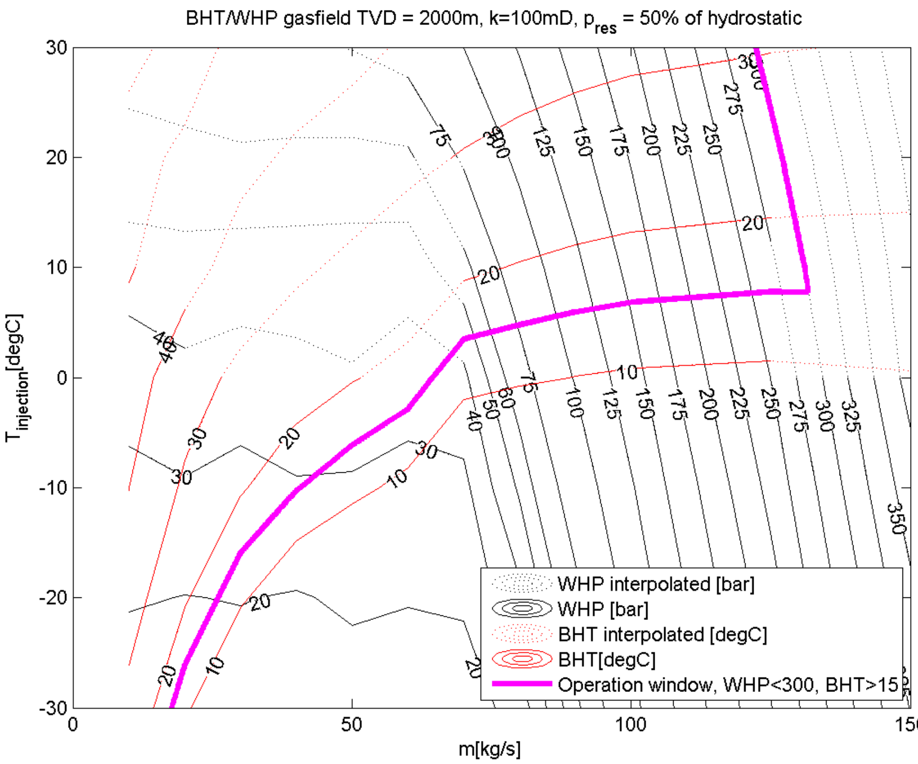
Case 1b



Case 2b

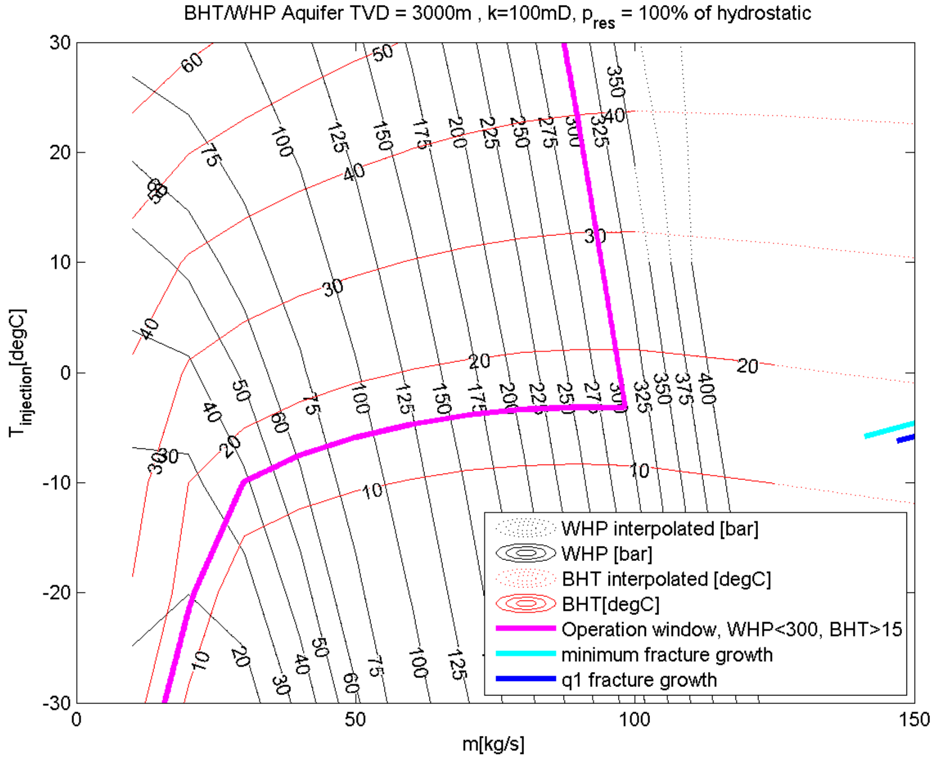


Case 3b

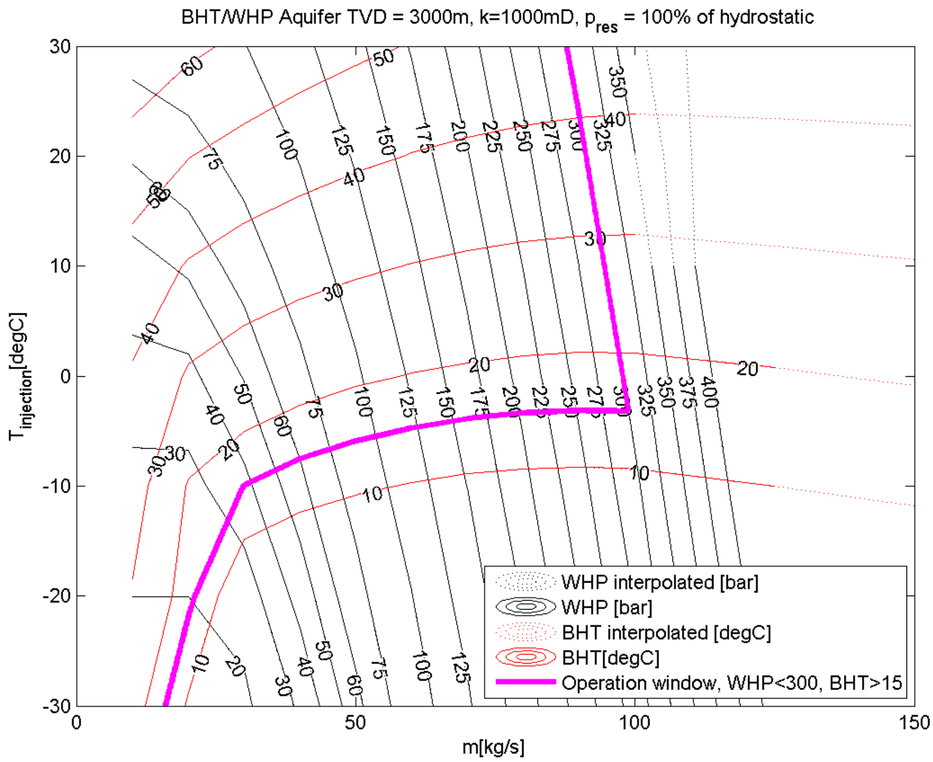


Case 4b

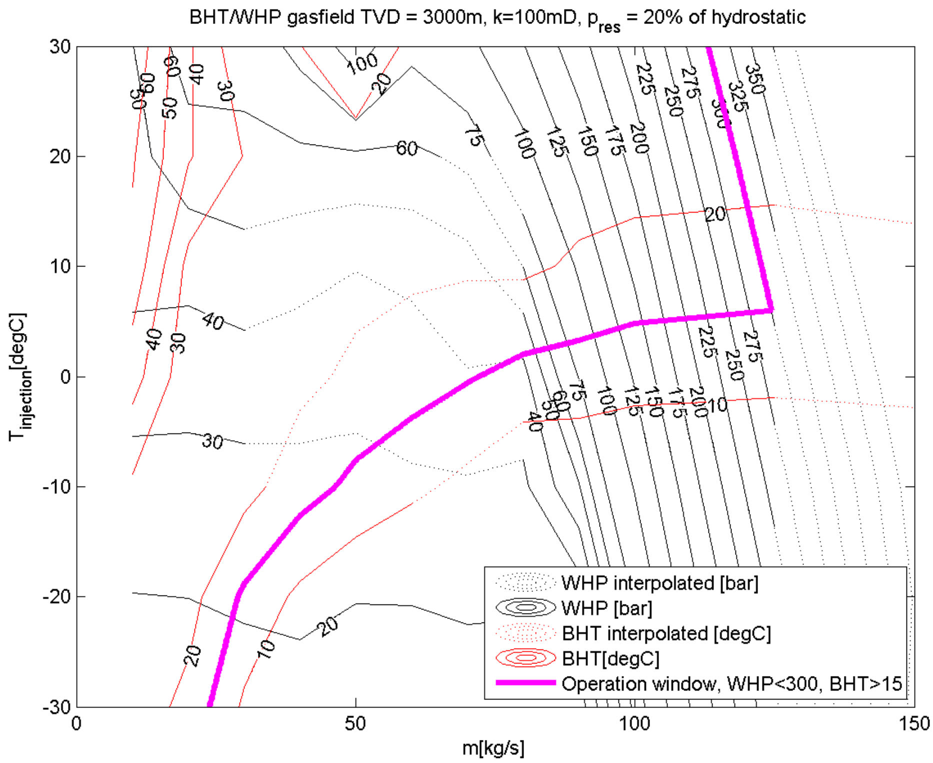
3000 m depth



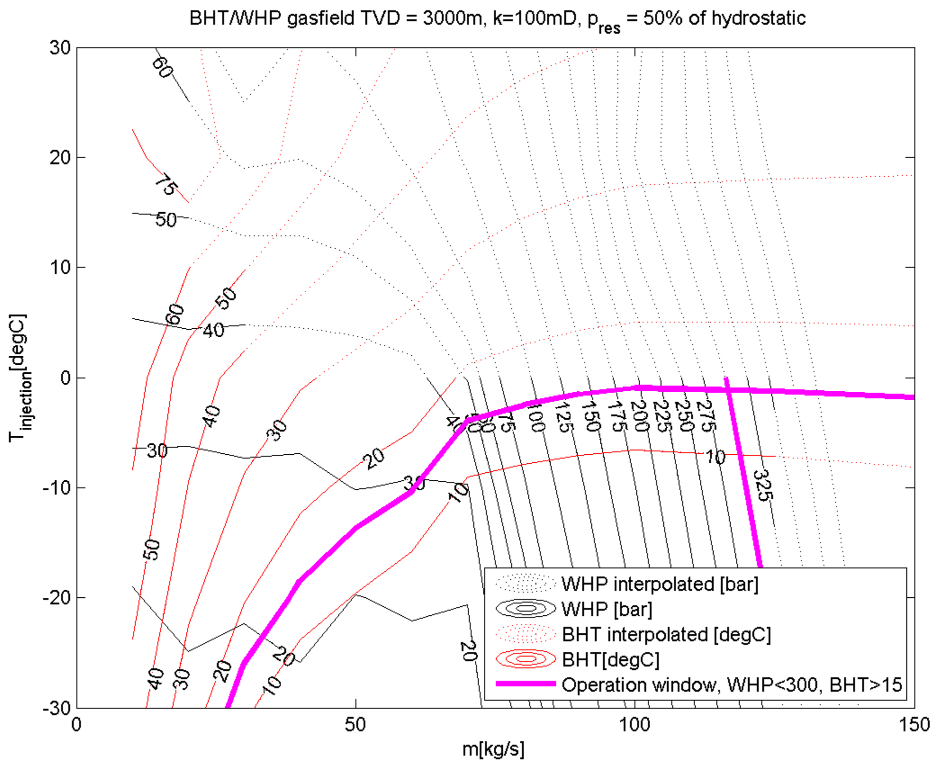
Case 1c



Case 2c

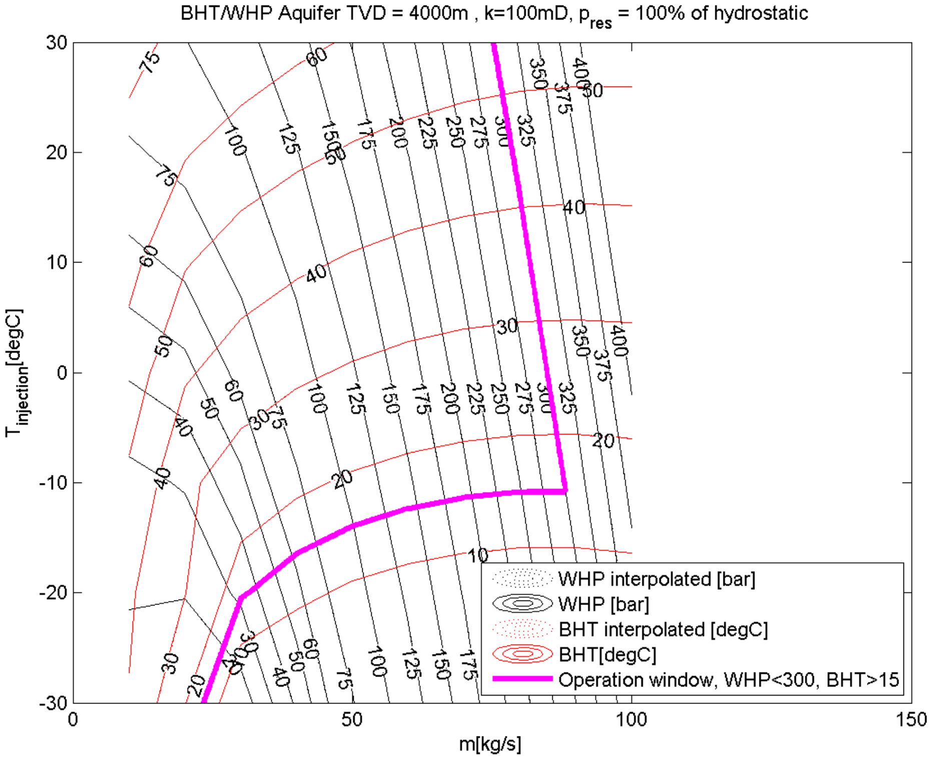


Case 3c

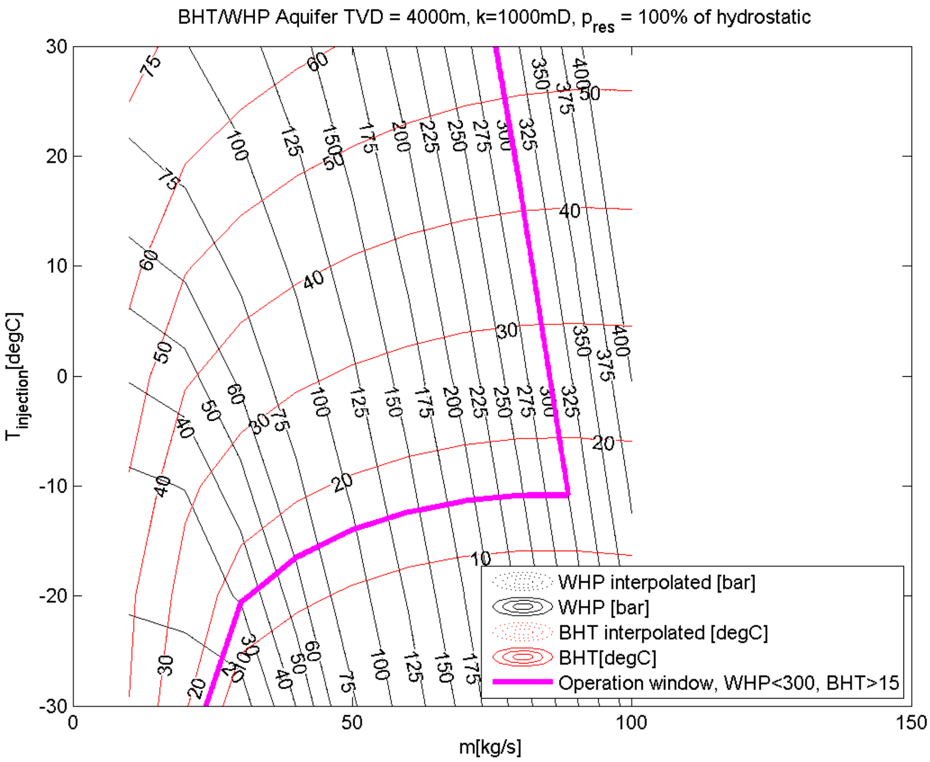


Case 4c

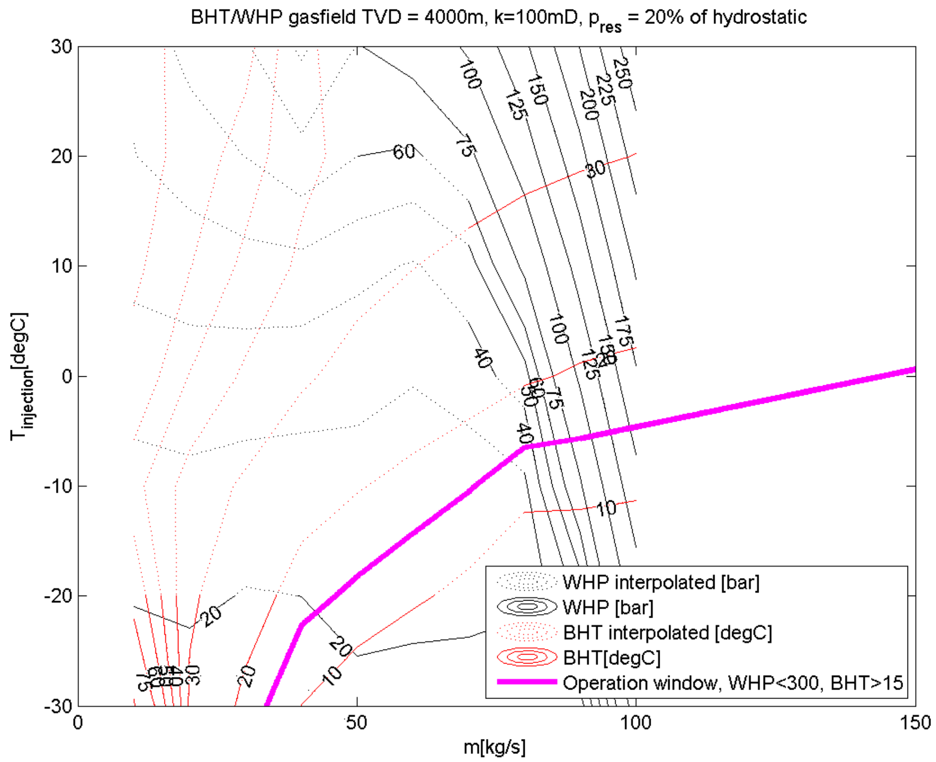
4000 m depth



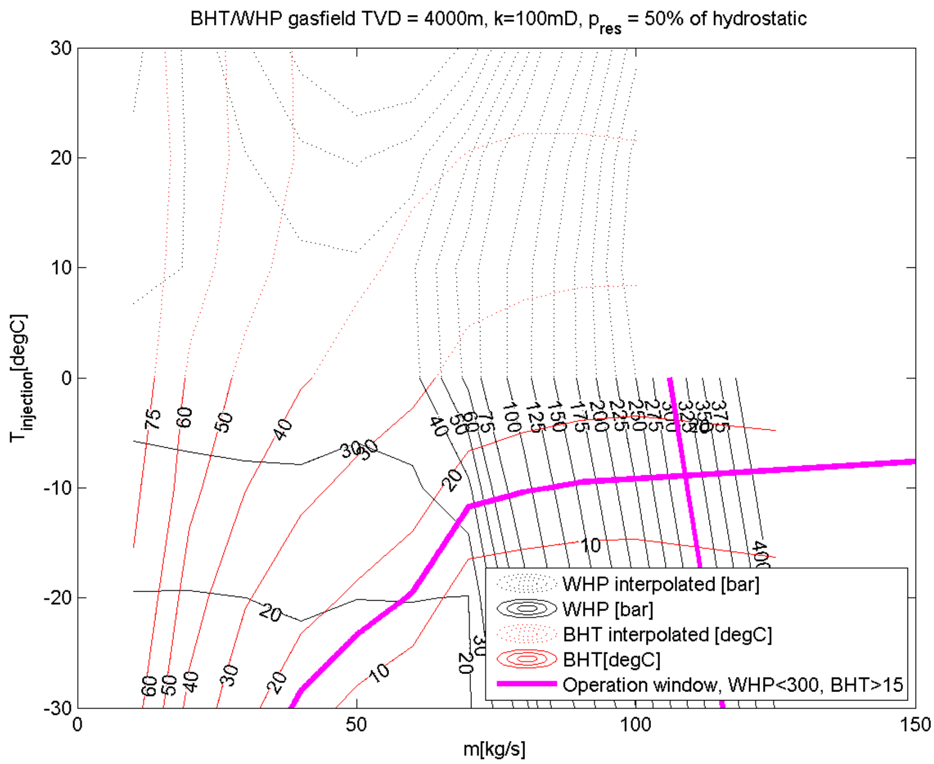
Case 1d



Case 2d



Case 3d



Case 4d

Appendix B: Cost engineering results

Ship to well total equipment cost – Maximum case (direct injection – option 1)

SHIP to WELL: Maximum						
Tag	**item**	**cost per item**		**Number**	**Total**	
	(105) Misc. Item Allowance	€	88.100	-	€	88.100
	(107) Warehouse Spares	€	127.800	-	€	127.800
HEX-AUX	(261) Shell & Tube Exchangers	€	65.233	1	€	65.233
HEX-HTF	(261) Shell & Tube Exchangers	€	757.851	1	€	757.851
HEX-SEAW	(266) Misc. Heat Exchangers	€	292.232	1	€	292.232
P-1	(161) Centrifugal Pumps	€	344.298	5	€	1.721.490
P-2	(161) Centrifugal Pumps	€	1.336.992	2	€	2.673.985
P-3	(161) Centrifugal Pumps	€	148.909	2	€	297.818
P-4	(161) Centrifugal Pumps	€	24.532	2	€	49.063
	(2) Equipment				**€**	**6.073.571**
	(3) Piping				€	2.440.542
	(4) Civil				€	190.172
	(6) Instruments				€	1.069.744
	(7) Electrical				€	1.856.810
	(8) Insulation				€	107.816
	(9) Paint				€	48.560
	Total Direct Field Costs				**€**	**11.787.214**
	Indirect Field Costs				**€**	**1.257.696**
	Total Field Costs				**€**	**13.044.910**
	Freight				€	110.800
	Taxes and Permits					
	Engineering and HO				€	1.497.830
	Other Project Costs				€	1.092.606
	Contingency				€	2.834.286
	Total Non-Field Costs				**€**	**5.535.521**
	Project Total Costs				**€**	**18.580.323**

Ship to well total equipment cost – Minimum case (direct injection – option 1)

SHIP to WELL: Minimum						
Tag	**item**	**cost per item**		**Number**	**Total**	
	(105) Misc. Item Allowance	€	52.700	-	€	52.700
	(107) Warehouse Spares	€	94.900	-	€	94.900
HEX-AUX	(261) Shell & Tube Exchangers	€	-	1	€	-
HEX-HTF	(261) Shell & Tube Exchangers	€	273.633	1	€	273.633
HEX-SEAW	(266) Misc. Heat Exchangers	€	127.985	1	€	127.985
P-1	(161) Centrifugal Pumps	€	239.189	5	€	1.195.945
P-2	(161) Centrifugal Pumps	€	1.061.231	2	€	2.122.462
P-3	(161) Centrifugal Pumps	€	58.805	2	€	117.610
P-4	(161) Centrifugal Pumps	€	18.258	2	€	36.516
	(2) Equipment				**€**	**4.021.751**
	(3) Piping				€	1.618.922
	(4) Civil				€	123.479
	(6) Instruments				€	1.090.438
	(7) Electrical				€	1.725.914
	(8) Insulation				€	87.000
	(9) Paint				€	32.106
	Total Direct Field Costs				**€**	**8.699.609**
	Indirect Field Costs				**€**	**1.035.253**
	Total Field Costs				**€**	**9.734.862**
	Freight				€	80.906
	Taxes and Permits					
	Engineering and HO				€	1.334.383
	Other Project Costs				€	892.746
	Contingency				€	2.168.414
	Total Non-Field Costs				**€**	**4.476.449**
	Project Total Costs				**€**	**14.215.161**

Ship to platform total equipment costs
MAXIMUM CASE (platform and offshore storage case)

Equipment SHIP

Tag	item	cost per item	Number	Total
	(105) Misc. Item Allowance	€ 49.899	-	€ 49.899
	(107) Warehouse Spares	€ 80.315	-	€ 80.315
HEX-SF	(261) Shell & Tube Exchangers	€ 18.233	1	€ 18.233
HEX-HTF	(261) Shell & Tube Exchangers	€ 820.151	1	€ 820.151
HEX-SEAW	(266) Misc. Heat Exchangers	€ 319.397	1	€ 319.397
P-1	(161) Centrifugal Pumps	€ 343.653	5	€ 1.718.265
P-3	(161) Centrifugal Pumps	€ 147.809	2	€ 295.618
P-4	(161) Centrifugal Pumps	€ 24.432	2	€ 48.864
	(2) Equipment			**€ 3.350.742**
	(3) Piping			€ 922.743
	(4) Civil			€ 61.860
	(6) Instruments			€ 252.594
	(7) Electrical			€ 443.329
	(8) Insulation			€ 113.410
	(9) Paint			€ 10.310
	Total Direct Field Costs			**€ 5.154.987**
	Indirect Field Costs			**€ 457.763**
	Total Field Costs			**€ 5.612.750**
	Freight			€ 48.612
	Taxes and Permits			
	Engineering and HO			€ 385.158
	Other Project Costs			€ 420.793
	Contingency			€ 1.164.107
	Total Non-Field Costs			**€ 2.018.670**
	Project Total Costs			**€ 7.631.368**

Equipment PLATFORM

Tag	item	cost per item	Number	Total
	(105) Misc. Item Allowance	€ 173.699	-	€ 173.699
	(107) Warehouse Spares	€ 279.581	-	€ 279.581
HEX-AUX	(261) Shell & Tube Exchangers	€ 1.158.110	1	€ 1.158.110
P-2	(161) Centrifugal Pumps	€ 4.623.209	2	€ 9.246.418
P-5	(161) Centrifugal Pumps	€ 44.821	2	€ 89.642
	(2) Equipment			**€ 10.947.450**
	(3) Piping			€ 3.014.759
	(4) Civil			€ 202.107
	(6) Instruments			€ 825.269
	(7) Electrical			€ 1.448.432
	(8) Insulation			€ 370.529
	(9) Paint			€ 33.684
	Total Direct Field Costs			**€ 16.842.231**
	Indirect Field Costs			**€ 1.495.590**
	Total Field Costs			**€ 18.337.821**
	Freight			€ 158.822
	Taxes and Permits			
	Engineering and HO			€ 1.258.051
	Other Project Costs			€ 1.374.444
	Contingency			€ 3.802.348
	Total Non-Field Costs			**€ 6.593.689**
	Project Total Costs			**€ 24.926.502**

Ship to platform total equipment costs
MINIMUM CASE (platform and offshore storage case)

Equipment SHIP

Tag	item	cost per item	Number	Total
	(105) Misc. Item Allowance	€ 30.822	-	€ 30.822
	(107) Warehouse Spares	€ 57.171	-	€ 57.171
HEX-SF	(261) Shell & Tube Exchangers	€ 14.533	1	€ 14.533
HEX-HTF	(261) Shell & Tube Exchangers	€ 477.582	1	€ 477.582
HEX-SEAW	(266) Misc. Heat Exchangers	€ 177.790	1	€ 177.790
P-1	(161) Centrifugal Pumps	€ 260.483	5	€ 1.302.413
P-3	(161) Centrifugal Pumps	€ 88.921	2	€ 177.841
P-4	(161) Centrifugal Pumps	€ 15.558	2	€ 31.116
	(2) Equipment			**€ 2.269.268**
	(3) Piping			€ 668.470
	(4) Civil			€ 41.460
	(6) Instruments			€ 225.797
	(7) Electrical			€ 351.358
	(8) Insulation			€ 22.970
	(9) Paint			€ 12.776
	Total Direct Field Costs			**€ 3.592.099**
	Indirect Field Costs			**€ 335.261**
	Total Field Costs			**€ 3.927.360**
	Freight			€ 33.826
	Taxes and Permits			
	Engineering and HO			€ 319.960
	Other Project Costs			€ 302.510
	Contingency			€ 825.058
	Total Non-Field Costs			**€ 1.481.355**
	Project Total Costs			**€ 5.408.715**

Equipment PLATFORM

Tag	item	cost per item	Number	Total
	(105) Misc. Item Allowance	€ 135.278	-	€ 135.278
	(107) Warehouse Spares	€ 250.929	-	€ 250.929
HEX-AUX	(261) Shell & Tube Exchangers	€ 469.875	1	€ 469.875
P-2	(161) Centrifugal Pumps	€ 4.027.427	2	€ 8.054.853
P-5	(161) Centrifugal Pumps	€ 44.821	2	€ 89.642
	(2) Equipment			**€ 9.000.578**
	(3) Piping			€ 2.651.348
	(4) Civil			€ 164.443
	(6) Instruments			€ 895.577
	(7) Electrical			€ 1.393.589
	(8) Insulation			€ 91.104
	(9) Paint			€ 50.672
	Total Direct Field Costs			**€ 14.247.312**
	Indirect Field Costs			**€ 1.329.741**
	Total Field Costs			**€ 15.577.054**
	Freight			€ 134.164
	Taxes and Permits			
	Engineering and HO			€ 1.269.055
	Other Project Costs			€ 1.199.845
	Contingency			€ 3.272.421
	Total Non-Field Costs			**€ 5.875.484**
	Project Total Costs			**€ 21.452.538**

Appendix C: Cash flow analyses

The tables in this Appendix show cost estimates for all combinations of:

- reservoir type (the sixteen cases shown in Table 3.1);
- the three scenarios of offshore offloading (described in Section 3.2);
- and the three distances (400 km, 800 km, 1200 km).

Each table presents results for the three offshore offloading scenarios for the case of one reservoir type and one transport distance; a parameter table that summarises the reservoir type, the transport distance and the transport capacity of the cases shown (in units of Mtpa) is given with each results table.

Parameter	Description	Value
Storage reservoir	Case 1a	saline formation, depth 1000 m, permeability 100 mD (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.8 Mtpa (Table 5.1) 4.5 Mtpa (Table 5.2) 4.5 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to well	size 10.000 ton	14,8	5	75%	-314,5
	size 20.000 ton	17,6	4	58%	-368
	size 30.000 ton	15,3	3	63%	-317,5
	size 50.000 ton	18,6	3	52%	-392,5
Ship to platform to well	size 10.000 ton	14,7	6	70%	-355,5
	size 20.000 ton	15,7	4	63%	-372,3
	size 30.000 ton	17,4	4	51%	-420,3
	size 50.000 ton	16,8	3	55%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	14,7	5	84%	-364,9
	size 20.000 ton	14,6	3	85%	-357,7
	size 30.000 ton	15,9	3	68%	-393,7
	size 50.000 ton	14,3	2	83%	-358,1

Parameter	Description	Value
Storage reservoir	Case 1a	saline formation, depth 1000 m, permeability 100 mD (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.8 Mtpa (Table 5.1) 4.5 Mtpa (Table 5.2) 4.5 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs	nr ships	Utilization	capex
Direct from ship to well	size 10.000 ton	20,7	7	75%	-431,5
	size 20.000 ton	22,1	5	61%	-454,5
	size 30.000 ton	20,2	4	60%	-416
	size 50.000 ton	18,9	3	62%	-392,5
Ship to platform to well	size 10.000 ton	17,6	7	85%	-403,1
	size 20.000 ton	19,3	5	68%	-447,9
	size 30.000 ton	17,9	4	65%	-420,3
	size 50.000 ton	17,1	3	66%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	17,4	6	99%	-410,5
	size 20.000 ton	18,1	4	84%	-431,3
	size 30.000 ton	16,3	3	87%	-393,7
	size 50.000 ton	14,6	2	99%	-358,1

Parameter	Description	Value
Storage reservoir	Case 1a	saline formation, depth 1000 m, permeability 100 mD (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.8 Mtpa (Table 5.1) 4.5 Mtpa (Table 5.2) 4.5 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs	nr ships	Utilization	capex
Direct from ship to well	size 10.000 ton	24,2	8	84%	-490
	size 20.000 ton	22,8	5	75%	-454,5
	size 30.000 ton	20,7	4	71%	-416
	size 50.000 ton	24,8	4	54%	-516
Ship to platform to well	size 10.000 ton	22,1	9	86%	-498,3
	size 20.000 ton	22,8	6	70%	-523,5
	size 30.000 ton	21,8	5	63%	-507,9
	size 50.000 ton	21,9	4	58%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	21,9	8	96%	-501,7
	size 20.000 ton	21,6	5	84%	-504,9
	size 30.000 ton	20,2	4	79%	-479,3
	size 50.000 ton	19,3	3	78%	-468,7

Parameter	Description	Value
Storage reservoir	Case 1b	saline formation, depth 2000 m, permeability 100 mD (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.9 Mtpa (Table 5.1) 3.6 Mtpa (Table 5.2) 3.6 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	18,9	5	62%	-314,5
	size 20.000 ton	22,8	4	51%	-368
	size 30.000 ton	19,8	3	57%	-317,5
	size 50.000 ton	24,2	3	48%	-392,5
Ship to platform to well	size 10.000 ton	15,8	5	72%	-307,9
	size 20.000 ton	19,3	4	56%	-372,3
	size 30.000 ton	17,2	3	62%	-332,7
	size 50.000 ton	20,8	3	51%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	15,8	4	90%	-319,3
	size 20.000 ton	17,9	3	75%	-357,7
	size 30.000 ton	15,4	2	93%	-308,1
	size 50.000 ton	17,6	2	77%	-358,1

Parameter	Description	Value
Storage reservoir	Case 1b	saline formation, depth 2000 m, permeability 100 mD (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.9 Mtpa (Table 5.1) 3.6 Mtpa (Table 5.2) 3.6 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	23,2	6	71%	-373
	size 20.000 ton	23,4	4	64%	-368
	size 30.000 ton	26,0	4	52%	-416
	size 50.000 ton	24,5	3	56%	-392,5
Ship to platform to well	size 10.000 ton	19,0	6	83%	-355,5
	size 20.000 ton	19,9	4	73%	-372,3
	size 30.000 ton	21,9	4	58%	-420,3
	size 50.000 ton	21,1	3	60%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	19,0	5	100%	-364,9
	size 20.000 ton	18,6	3	98%	-357,7
	size 30.000 ton	20,0	3	77%	-393,7
	size 50.000 ton	18,0	2	90%	-358,1

Parameter	Description	Value
Storage reservoir	Case 1b	saline formation, depth 2000 m, permeability 100 mD (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.9 Mtpa (Table 5.1) 3.6 Mtpa (Table 5.2) 3.6 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	27,4	7	77%	-431,5
	size 20.000 ton	29,1	5	62%	-454,5
	size 30.000 ton	26,5	4	61%	-416
	size 50.000 ton	24,8	3	63%	-392,5
Ship to platform to well	size 10.000 ton	24,5	8	80%	-450,7
	size 20.000 ton	24,2	5	72%	-447,9
	size 30.000 ton	22,4	4	69%	-420,3
	size 50.000 ton	26,9	4	52%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	24,2	7	92%	-456,1
	size 20.000 ton	22,8	4	90%	-431,3
	size 30.000 ton	20,5	3	92%	-393,7
	size 50.000 ton	23,7	3	69%	-468,7

Parameter	Description	Value
Storage reservoir	Case 1c	saline formation, depth 3000 m, permeability 100 mD (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.5 Mtpa (Table 5.1) 3.0 Mtpa (Table 5.2) 3.0 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	18,5	4	70%	-256
	size 20.000 ton	20,9	3	62%	-281,5
	size 30.000 ton	23,4	3	53%	-317,5
	size 50.000 ton	28,7	3	46%	-392,5
Ship to platform to well	size 10.000 ton	18,9	5	63%	-307,9
	size 20.000 ton	23,2	4	51%	-372,3
	size 30.000 ton	20,8	3	57%	-332,7
	size 50.000 ton	25,2	3	48%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	18,9	4	78%	-319,3
	size 20.000 ton	21,6	3	68%	-357,7
	size 30.000 ton	18,5	2	85%	-308,1
	size 50.000 ton	21,3	2	73%	-358,1

Parameter	Description	Value
Storage reservoir	Case 1c	saline formation, depth 3000 m, permeability 100 mD (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.5 Mtpa (Table 5.1) 3.0 Mtpa (Table 5.2) 3.0 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	23,3	5	75%	-314,5
	size 20.000 ton	27,6	4	58%	-368
	size 30.000 ton	23,9	3	64%	-317,5
	size 50.000 ton	29,0	3	52%	-392,5
Ship to platform to well	size 10.000 ton	22,7	6	71%	-355,5
	size 20.000 ton	23,9	4	65%	-372,3
	size 30.000 ton	26,5	4	52%	-420,3
	size 50.000 ton	25,5	3	56%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	22,5	5	86%	-364,9
	size 20.000 ton	22,3	3	86%	-357,7
	size 30.000 ton	24,1	3	69%	-393,7
	size 50.000 ton	21,7	2	84%	-358,1

Parameter	Description	Value
Storage reservoir	Case 1c	saline formation, depth 3000 m, permeability 100 mD (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.5 Mtpa (Table 5.1) 3.0 Mtpa (Table 5.2) 3.0 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	22,0	6	78%	-373
	size 20.000 ton	28,2	4	70%	-368
	size 30.000 ton	31,2	4	55%	-416
	size 50.000 ton	29,3	3	58%	-392,5
Ship to platform to well	size 10.000 ton	26,4	7	78%	-403,1
	size 20.000 ton	29,0	5	63%	-447,9
	size 30.000 ton	26,9	4	61%	-420,3
	size 50.000 ton	25,8	3	63%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	26,2	6	91%	-410,5
	size 20.000 ton	27,3	4	78%	-431,3
	size 30.000 ton	24,5	3	82%	-393,7
	size 50.000 ton	22,0	2	95%	-358,1

Parameter	Description	Value
Storage reservoir	Case 1d	saline formation, depth 4000 m, permeability 100 mD (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.1 Mtpa (Table 5.1) 2.6 Mtpa (Table 5.2) 2.6 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	20,9	4	65%	-256
	size 20.000 ton	23,8	3	59%	-281,5
	size 30.000 ton	26,6	3	51%	-317,5
	size 50.000 ton	32,7	3	45%	-392,5
Ship to platform to well	size 10.000 ton	18,4	4	72%	-260,3
	size 20.000 ton	21,3	3	64%	-296,7
	size 30.000 ton	23,7	3	54%	-332,7
	size 50.000 ton	28,7	3	47%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	18,5	3	96%	-273,7
	size 20.000 ton	19,6	2	95%	-284,1
	size 30.000 ton	21,0	2	81%	-308,1
	size 50.000 ton	24,3	2	70%	-358,1

Parameter	Description	Value
Storage reservoir	Case 1d	saline formation, depth 4000 m, permeability 100 mD (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.1 Mtpa (Table 5.1) 2.6 Mtpa (Table 5.2) 2.6 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	26,3	5	68%	-314,5
	size 20.000 ton	31,3	4	54%	-368
	size 30.000 ton	27,1	3	60%	-317,5
	size 50.000 ton	33,0	3	50%	-392,5
Ship to platform to well	size 10.000 ton	22,5	5	78%	-307,9
	size 20.000 ton	27,1	4	60%	-372,3
	size 30.000 ton	24,1	3	65%	-332,7
	size 50.000 ton	29,0	3	53%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	22,5	4	97%	-319,3
	size 20.000 ton	25,2	3	80%	-357,7
	size 30.000 ton	21,5	2	97%	-308,1
	size 50.000 ton	24,6	2	80%	-358,1

Parameter	Description	Value
Storage reservoir	Case 1d	saline formation, depth 4000 m, permeability 100 mD (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.1 Mtpa (Table 5.1) 2.6 Mtpa (Table 5.2) 2.6 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	31,7	6	71%	-373
	size 20.000 ton	31,9	4	64%	-368
	size 30.000 ton	35,4	4	52%	-416
	size 50.000 ton	33,3	3	56%	-392,5
Ship to platform to well	size 10.000 ton	26,6	6	82%	-355,5
	size 20.000 ton	27,8	4	72%	-372,3
	size 30.000 ton	30,6	4	57%	-420,3
	size 50.000 ton	29,3	3	60%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	26,5	5	98%	-364,9
	size 20.000 ton	25,9	3	96%	-357,7
	size 30.000 ton	27,8	3	76%	-393,7
	size 50.000 ton	24,9	2	89%	-358,1

Parameter	Description	Value
Storage reservoir	Case 2a	Saline formation, depth 1000 m, permeability 1000 mD (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	4.0 Mtpa (Table 5.1) 4.7 Mtpa (Table 5.2) 4.7 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	14,2	5	77%	-314,5
	size 20.000 ton	16,9	4	60%	-368
	size 30.000 ton	14,6	3	65%	-317,5
	size 50.000 ton	17,8	3	53%	-392,5
Ship to platform to well	size 10.000 ton	14,1	6	72%	-355,5
	size 20.000 ton	15,0	4	65%	-372,3
	size 30.000 ton	16,7	4	52%	-420,3
	size 50.000 ton	16,1	3	56%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	14,1	5	87%	-364,9
	size 20.000 ton	14,0	3	87%	-357,7
	size 30.000 ton	15,2	3	70%	-393,7
	size 50.000 ton	13,7	2	84%	-358,1

Parameter	Description	Value
Storage reservoir	Case 2a	Saline formation, depth 1000 m, permeability 1000 mD (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	4.0 Mtpa (Table 5.1) 4.7 Mtpa (Table 5.2) 4.7 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	19,9	7	78%	-431,5
	size 20.000 ton	21,2	5	63%	-454,5
	size 30.000 ton	19,3	4	61%	-416
	size 50.000 ton	18,1	3	63%	-392,5
Ship to platform to well	size 10.000 ton	18,5	8	77%	-450,7
	size 20.000 ton	18,5	5	70%	-447,9
	size 30.000 ton	17,1	4	67%	-420,3
	size 50.000 ton	20,6	4	51%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	18,4	7	88%	-456,1
	size 20.000 ton	17,4	4	87%	-431,3
	size 30.000 ton	15,7	3	89%	-393,7
	size 50.000 ton	18,1	3	68%	-468,7

Parameter	Description	Value
Storage reservoir	Case 2a	Saline formation, depth 1000 m, permeability 1000 mD (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	4.0 Mtpa (Table 5.1) 4.7 Mtpa (Table 5.2) 4.7 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	25,6	9	78%	-548,5
	size 20.000 ton	21,8	5	78%	-454,5
	size 30.000 ton	19,8	4	74%	-416
	size 50.000 ton	23,7	4	55%	-516
Ship to platform to well	size 10.000 ton	22,9	10	80%	-545,9
	size 20.000 ton	21,9	6	73%	-523,5
	size 30.000 ton	20,9	5	65%	-507,9
	size 50.000 ton	20,9	4	60%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	22,7	9	89%	-547,3
	size 20.000 ton	20,8	5	88%	-504,9
	size 30.000 ton	19,3	4	82%	-479,3
	size 50.000 ton	18,5	3	80%	-468,7

Parameter	Description	Value
Storage reservoir	Case 2b	Saline formation, depth 2000 m, permeability 1000 mD (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.0 Mtpa (Table 5.1) 3.6 Mtpa (Table 5.2) 3.6 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	18,7	5	63%	-314,5
	size 20.000 ton	22,6	4	51%	-368
	size 30.000 ton	19,6	3	57%	-317,5
	size 50.000 ton	24,0	3	48%	-392,5
Ship to platform to well	size 10.000 ton	15,8	5	72%	-307,9
	size 20.000 ton	19,3	4	56%	-372,3
	size 30.000 ton	17,2	3	62%	-332,7
	size 50.000 ton	20,8	3	51%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	15,8	4	90%	-319,3
	size 20.000 ton	17,9	3	75%	-357,7
	size 30.000 ton	15,4	2	93%	-308,1
	size 50.000 ton	17,6	2	77%	-358,1

Parameter	Description	Value
Storage reservoir	Case 2b	Saline formation, depth 2000 m, permeability 1000 mD (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.0 Mtpa (Table 5.1) 3.6 Mtpa (Table 5.2) 3.6 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	23,0	6	71%	-373
	size 20.000 ton	23,2	4	65%	-368
	size 30.000 ton	25,8	4	52%	-416
	size 50.000 ton	24,3	3	56%	-392,5
Ship to platform to well	size 10.000 ton	19,0	6	83%	-355,5
	size 20.000 ton	19,9	4	73%	-372,3
	size 30.000 ton	21,9	4	58%	-420,3
	size 50.000 ton	21,1	3	60%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	19,0	5	100%	-364,9
	size 20.000 ton	18,6	3	98%	-357,7
	size 30.000 ton	20,0	3	77%	-393,7
	size 50.000 ton	18,0	2	90%	-358,1

Parameter	Description	Value
Storage reservoir	Case 2b	Saline formation, depth 2000 m, permeability 1000 mD (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.0 Mtpa (Table 5.1) 3.6 Mtpa (Table 5.2) 3.6 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	27,2	7	78%	-431,5
	size 20.000 ton	28,8	5	63%	-454,5
	size 30.000 ton	26,2	4	61%	-416
	size 50.000 ton	24,6	3	63%	-392,5
Ship to platform to well	size 10.000 ton	24,5	8	80%	-450,7
	size 20.000 ton	24,2	5	72%	-447,9
	size 30.000 ton	22,4	4	69%	-420,3
	size 50.000 ton	26,9	4	52%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	24,2	7	92%	-456,1
	size 20.000 ton	22,8	4	90%	-431,3
	size 30.000 ton	20,5	3	92%	-393,7
	size 50.000 ton	23,7	3	69%	-468,7

Parameter	Description	Value
Storage reservoir	Case 2c	Saline formation, depth 3000 m, permeability 1000 mD (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.5 Mtpa (Table 5.1) 3.0 Mtpa (Table 5.2) 3.0 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	18,3	4	70%	-256
	size 20.000 ton	20,7	3	63%	-281,5
	size 30.000 ton	23,1	3	54%	-317,5
	size 50.000 ton	28,3	3	46%	-392,5
Ship to platform to well	size 10.000 ton	18,9	5	63%	-307,9
	size 20.000 ton	23,2	4	51%	-372,3
	size 30.000 ton	20,8	3	57%	-332,7
	size 50.000 ton	25,2	3	48%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	18,9	4	78%	-319,3
	size 20.000 ton	21,6	3	68%	-357,7
	size 30.000 ton	18,5	2	85%	-308,1
	size 50.000 ton	21,3	2	73%	-358,1

Parameter	Description	Value
Storage reservoir	Case 2c	Saline formation, depth 3000 m, permeability 1000 mD (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.5 Mtpa (Table 5.1) 3.0 Mtpa (Table 5.2) 3.0 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	23,1	5	76%	-314,5
	size 20.000 ton	27,3	4	59%	-368
	size 30.000 ton	23,6	3	64%	-317,5
	size 50.000 ton	28,7	3	53%	-392,5
Ship to platform to well	size 10.000 ton	22,7	6	71%	-355,5
	size 20.000 ton	23,9	4	65%	-372,3
	size 30.000 ton	26,5	4	52%	-420,3
	size 50.000 ton	25,5	3	56%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	22,5	5	86%	-364,9
	size 20.000 ton	22,3	3	86%	-357,7
	size 30.000 ton	24,1	3	69%	-393,7
	size 50.000 ton	21,7	2	84%	-358,1

Parameter	Description	Value
Storage reservoir	Case 2c	Saline formation, depth 3000 m, permeability 1000 mD (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.5 Mtpa (Table 5.1) 3.0 Mtpa (Table 5.2) 3.0 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	27,9	6	79%	-373
	size 20.000 ton	27,9	4	70%	-368
	size 30.000 ton	30,9	4	56%	-416
	size 50.000 ton	29,0	3	59%	-392,5
Ship to platform to well	size 10.000 ton	26,4	7	78%	-403,1
	size 20.000 ton	29,0	5	63%	-447,9
	size 30.000 ton	26,9	4	61%	-420,3
	size 50.000 ton	25,8	3	63%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	26,2	6	91%	-410,5
	size 20.000 ton	27,3	4	78%	-431,3
	size 30.000 ton	24,5	3	82%	-393,7
	size 50.000 ton	22,0	2	95%	-358,1

Parameter	Description	Value
Storage reservoir	Case 2d	Saline formation, depth 4000 m, permeability 1000 mD (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.1 Mtpa (Table 5.1) 2.6 Mtpa (Table 5.2) 2.6 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	20,9	4	65%	-256
	size 20.000 ton	23,8	3	59%	-281,5
	size 30.000 ton	26,6	3	51%	-317,5
	size 50.000 ton	32,7	3	45%	-392,5
Ship to platform to well	size 10.000 ton	18,4	4	72%	-260,3
	size 20.000 ton	21,3	3	64%	-296,7
	size 30.000 ton	23,7	3	54%	-332,7
	size 50.000 ton	28,7	3	47%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	18,5	3	96%	-273,7
	size 20.000 ton	19,6	2	95%	-284,1
	size 30.000 ton	21,0	2	81%	-308,1
	size 50.000 ton	24,3	2	70%	-358,1

Parameter	Description	Value
Storage reservoir	Case 2d	Saline formation, depth 4000 m, permeability 1000 mD (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.1 Mtpa (Table 5.1) 2.6 Mtpa (Table 5.2) 2.6 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	26,3	5	68%	-314,5
	size 20.000 ton	31,3	4	54%	-368
	size 30.000 ton	27,1	3	60%	-317,5
	size 50.000 ton	33,0	3	50%	-392,5
Ship to platform to well	size 10.000 ton	22,5	5	78%	-307,9
	size 20.000 ton	27,1	4	60%	-372,3
	size 30.000 ton	24,1	3	65%	-332,7
	size 50.000 ton	29,0	3	53%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	22,5	4	97%	-319,3
	size 20.000 ton	25,2	3	80%	-357,7
	size 30.000 ton	21,5	2	97%	-308,1
	size 50.000 ton	24,6	2	80%	-358,1

Parameter	Description	Value
Storage reservoir	Case 2d	Saline formation, depth 4000 m, permeability 1000 mD (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	2.1 Mtpa (Table 5.1) 2.6 Mtpa (Table 5.2) 2.6 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	31,7	6	71%	-373
	size 20.000 ton	31,9	4	64%	-368
	size 30.000 ton	35,4	4	52%	-416
	size 50.000 ton	33,3	3	56%	-392,5
Ship to platform to well	size 10.000 ton	26,6	6	82%	-355,5
	size 20.000 ton	27,8	4	72%	-372,3
	size 30.000 ton	30,6	4	57%	-420,3
	size 50.000 ton	29,3	3	60%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	26,5	5	98%	-364,9
	size 20.000 ton	25,9	3	96%	-357,7
	size 30.000 ton	27,8	3	76%	-393,7
	size 50.000 ton	24,9	2	89%	-358,1

Parameter	Description	Value
Storage reservoir	Case 3a	Gas field, 80% depleted, depth 1000 m (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	4.3 Mtpa (Table 5.1) 4.7 Mtpa (Table 5.2) 4.7 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	15,5	6	68%	-373
	size 20.000 ton	15,8	4	62%	-368
	size 30.000 ton	17,6	4	50%	-416
	size 50.000 ton	16,7	3	54%	-392,5
Ship to platform to well	size 10.000 ton	14,0	6	72%	-355,5
	size 20.000 ton	14,9	4	65%	-372,3
	size 30.000 ton	16,6	4	52%	-420,3
	size 50.000 ton	16,0	3	56%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	14,0	5	87%	-364,9
	size 20.000 ton	13,9	3	87%	-357,7
	size 30.000 ton	15,1	3	70%	-393,7
	size 50.000 ton	13,6	2	84%	-358,1

Parameter	Description	Value
Storage reservoir	Case 3a	Gas field, 80% depleted, depth 1000 m (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	4.3 Mtpa (Table 5.1) 4.7 Mtpa (Table 5.2) 4.7 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	18,7	7	82%	-431,5
	size 20.000 ton	19,9	5	66%	-454,5
	size 30.000 ton	18,1	4	64%	-416
	size 50.000 ton	17,0	3	65%	-392,5
Ship to platform to well	size 10.000 ton	18,4	8	77%	-450,7
	size 20.000 ton	18,4	5	70%	-447,9
	size 30.000 ton	17,1	4	67%	-420,3
	size 50.000 ton	20,5	4	51%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	18,3	7	88%	-456,1
	size 20.000 ton	17,3	4	87%	-431,3
	size 30.000 ton	15,6	3	89%	-393,7
	size 50.000 ton	18,1	3	68%	-468,7

Parameter	Description	Value
Storage reservoir	Case 3a	Gas field, 80% depleted, depth 1000 m (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	4.3 Mtpa (Table 5.1) 4.7 Mtpa (Table 5.2) 4.7 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	24,1	9	83%	-548,5
	size 20.000 ton	23,9	6	68%	-541
	size 30.000 ton	22,5	5	62%	-514,5
	size 50.000 ton	22,2	4	57%	-516
Ship to platform to well	size 10.000 ton	22,8	10	80%	-545,9
	size 20.000 ton	21,8	6	73%	-523,5
	size 30.000 ton	20,8	5	65%	-507,9
	size 50.000 ton	20,8	4	60%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	22,6	9	89%	-547,3
	size 20.000 ton	20,7	5	88%	-504,9
	size 30.000 ton	19,2	4	82%	-479,3
	size 50.000 ton	18,4	3	80%	-468,7

Parameter	Description	Value
Storage reservoir	Case 3b	Gas field, 80% depleted, depth 2000 m (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.7 Mtpa (Table 5.1) 4.3 Mtpa (Table 5.2) 4.3 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	15,4	5	73%	-314,5
	size 20.000 ton	18,3	4	57%	-368
	size 30.000 ton	15,9	3	62%	-317,5
	size 50.000 ton	19,4	3	52%	-392,5
Ship to platform to well	size 10.000 ton	15,5	6	67%	-355,5
	size 20.000 ton	16,5	4	62%	-372,3
	size 30.000 ton	14,8	3	67%	-332,7
	size 50.000 ton	17,7	3	54%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	15,4	5	81%	-364,9
	size 20.000 ton	15,4	3	82%	-357,7
	size 30.000 ton	13,2	2	100%	-308,1
	size 50.000 ton	15,1	2	81%	-358,1

Parameter	Description	Value
Storage reservoir	Case 3b	Gas field, 80% depleted, depth 2000 m (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.7 Mtpa (Table 5.1) 4.3 Mtpa (Table 5.2) 4.3 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	21,5	7	72%	-431,5
	size 20.000 ton	19,0	4	74%	-368
	size 30.000 ton	21,0	4	58%	-416
	size 50.000 ton	19,7	3	61%	-392,5
Ship to platform to well	size 10.000 ton	18,4	7	82%	-403,1
	size 20.000 ton	20,2	5	65%	-447,9
	size 30.000 ton	18,8	4	63%	-420,3
	size 50.000 ton	18,0	3	65%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	18,3	6	95%	-410,5
	size 20.000 ton	19,0	4	82%	-431,3
	size 30.000 ton	17,2	3	84%	-393,7
	size 50.000 ton	15,4	2	97%	-358,1

Parameter	Description	Value
Storage reservoir	Case 3b	Gas field, 80% depleted, depth 2000 m (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.7 Mtpa (Table 5.1) 4.3 Mtpa (Table 5.2) 4.3 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	25,1	8	81%	-490
	size 20.000 ton	23,6	5	73%	-454,5
	size 30.000 ton	21,5	4	70%	-416
	size 50.000 ton	25,8	4	52%	-516
Ship to platform to well	size 10.000 ton	23,1	9	82%	-498,3
	size 20.000 ton	24,0	6	68%	-523,5
	size 30.000 ton	22,9	5	61%	-507,9
	size 50.000 ton	23,0	4	57%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	22,9	8	92%	-501,7
	size 20.000 ton	22,7	5	81%	-504,9
	size 30.000 ton	21,2	4	77%	-479,3
	size 50.000 ton	20,3	3	75%	-468,7

Parameter	Description	Value
Storage reservoir	Case 3c	Gas field, 80% depleted, depth 3000 m (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.4 Mtpa (Table 5.1) 3.8 Mtpa (Table 5.2) 3.8 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	16,4	5	69%	-314,5
	size 20.000 ton	19,6	4	55%	-368
	size 30.000 ton	17,0	3	60%	-317,5
	size 50.000 ton	20,8	3	50%	-392,5
Ship to platform to well	size 10.000 ton	15,0	5	75%	-307,9
	size 20.000 ton	18,2	4	58%	-372,3
	size 30.000 ton	16,3	3	63%	-332,7
	size 50.000 ton	19,6	3	52%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	15,0	4	93%	-319,3
	size 20.000 ton	17,0	3	77%	-357,7
	size 30.000 ton	14,6	2	95%	-308,1
	size 50.000 ton	16,7	2	78%	-358,1

Parameter	Description	Value
Storage reservoir	Case 3c	Gas field, 80% depleted, depth 3000 m (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.4 Mtpa (Table 5.1) 3.8 Mtpa (Table 5.2) 3.8 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	20,2	6	80%	-373
	size 20.000 ton	20,3	4	71%	-368
	size 30.000 ton	22,4	4	56%	-416
	size 50.000 ton	21,1	3	59%	-392,5
Ship to platform to well	size 10.000 ton	20,2	7	75%	-403,1
	size 20.000 ton	22,3	5	61%	-447,9
	size 30.000 ton	20,8	4	60%	-420,3
	size 50.000 ton	20,0	3	62%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	20,0	6	87%	-410,5
	size 20.000 ton	21,0	4	76%	-431,3
	size 30.000 ton	18,9	3	79%	-393,7
	size 50.000 ton	17,0	2	93%	-358,1

Parameter	Description	Value
Storage reservoir	Case 3c	Gas field, 80% depleted, depth 3000 m (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.4 Mtpa (Table 5.1) 3.8 Mtpa (Table 5.2) 3.8 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	26,7	8	77%	-490
	size 20.000 ton	25,2	5	69%	-454,5
	size 30.000 ton	22,9	4	67%	-416
	size 50.000 ton	27,6	4	51%	-516
Ship to platform to well	size 10.000 ton	23,3	8	84%	-450,7
	size 20.000 ton	23,0	5	75%	-447,9
	size 30.000 ton	21,3	4	71%	-420,3
	size 50.000 ton	25,4	4	54%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	23,1	7	96%	-456,1
	size 20.000 ton	21,6	4	94%	-431,3
	size 30.000 ton	19,4	3	95%	-393,7
	size 50.000 ton	22,4	3	71%	-468,7

Parameter	Description	Value
Storage reservoir	Case 3d	Gas field, 80% depleted, depth 4000 m (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.3 Mtpa (Table 5.1) 3.3 Mtpa (Table 5.2) 3.3 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	16,9	5	67%	-314,5
	size 20.000 ton	20,3	4	54%	-368
	size 30.000 ton	17,6	3	59%	-317,5
	size 50.000 ton	21,5	3	50%	-392,5
Ship to platform to well	size 10.000 ton	16,9	5	68%	-307,9
	size 20.000 ton	20,7	4	54%	-372,3
	size 30.000 ton	18,5	3	60%	-332,7
	size 50.000 ton	22,3	3	50%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	16,9	4	85%	-319,3
	size 20.000 ton	19,2	3	72%	-357,7
	size 30.000 ton	16,4	2	90%	-308,1
	size 50.000 ton	18,9	2	75%	-358,1

Parameter	Description	Value
Storage reservoir	Case 3d	Gas field, 80% depleted, depth 4000 m (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.3 Mtpa (Table 5.1) 3.3 Mtpa (Table 5.2) 3.3 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	20,8	6	78%	-373
	size 20.000 ton	20,9	4	69%	-368
	size 30.000 ton	23,2	4	55%	-416
	size 50.000 ton	21,8	3	58%	-392,5
Ship to platform to well	size 10.000 ton	20,3	6	78%	-355,5
	size 20.000 ton	21,3	4	69%	-372,3
	size 30.000 ton	23,5	4	55%	-420,3
	size 50.000 ton	22,6	3	58%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	20,2	5	94%	-364,9
	size 20.000 ton	19,8	3	93%	-357,7
	size 30.000 ton	21,4	3	74%	-393,7
	size 50.000 ton	19,2	2	88%	-358,1

Parameter	Description	Value
Storage reservoir	Case 3d	Gas field, 80% depleted, depth 4000 m (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.3 Mtpa (Table 5.1) 3.3 Mtpa (Table 5.2) 3.3 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	24,7	7	85%	-431,5
	size 20.000 ton	26,1	5	68%	-454,5
	size 30.000 ton	23,7	4	65%	-416
	size 50.000 ton	22,1	3	66%	-392,5
Ship to platform to well	size 10.000 ton	26,1	8	75%	-450,7
	size 20.000 ton	25,9	5	68%	-447,9
	size 30.000 ton	24,0	4	66%	-420,3
	size 50.000 ton	28,9	4	50%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	25,8	7	86%	-456,1
	size 20.000 ton	24,4	4	85%	-431,3
	size 30.000 ton	21,9	3	87%	-393,7
	size 50.000 ton	25,4	3	67%	-468,7

Parameter	Description	Value
Storage reservoir	Case 4a	Gas field, 50% depleted, depth 1000 m (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	4.2 Mtpa (Table 5.1) 4.7 Mtpa (Table 5.2) 4.7 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	13,7	5	79%	-314,5
	size 20.000 ton	16,3	4	61%	-368
	size 30.000 ton	14,1	3	66%	-317,5
	size 50.000 ton	17,2	3	54%	-392,5
Ship to platform to well	size 10.000 ton	14,1	6	72%	-355,5
	size 20.000 ton	15,0	4	65%	-372,3
	size 30.000 ton	16,6	4	52%	-420,3
	size 50.000 ton	16,0	3	56%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	14,0	5	87%	-364,9
	size 20.000 ton	13,9	3	87%	-357,7
	size 30.000 ton	15,1	3	70%	-393,7
	size 50.000 ton	13,6	2	84%	-358,1

Parameter	Description	Value
Storage reservoir	Case 4a	Gas field, 50% depleted, depth 1000 m (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	4.2 Mtpa (Table 5.1) 4.7 Mtpa (Table 5.2) 4.7 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	19,2	7	80%	-431,5
	size 20.000 ton	20,4	5	64%	-454,5
	size 30.000 ton	18,6	4	62%	-416
	size 50.000 ton	17,5	3	64%	-392,5
Ship to platform to well	size 10.000 ton	18,5	8	77%	-450,7
	size 20.000 ton	18,4	5	70%	-447,9
	size 30.000 ton	17,1	4	67%	-420,3
	size 50.000 ton	20,5	4	51%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	18,3	7	88%	-456,1
	size 20.000 ton	17,3	4	87%	-431,3
	size 30.000 ton	15,6	3	89%	-393,7
	size 50.000 ton	18,1	3	68%	-468,7

Parameter	Description	Value
Storage reservoir	Case 4a	Gas field, 50% depleted, depth 1000 m (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	4.2 Mtpa (Table 5.1) 4.7 Mtpa (Table 5.2) 4.7 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	24,8	9	81%	-548,5
	size 20.000 ton	24,6	6	67%	-541
	size 30.000 ton	23,1	5	60%	-514,5
	size 50.000 ton	22,9	4	56%	-516
Ship to platform to well	size 10.000 ton	22,9	10	80%	-545,9
	size 20.000 ton	21,8	6	73%	-523,5
	size 30.000 ton	20,8	5	65%	-507,9
	size 50.000 ton	20,9	4	60%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	22,6	9	89%	-547,3
	size 20.000 ton	20,7	5	88%	-504,9
	size 30.000 ton	19,3	4	82%	-479,3
	size 50.000 ton	18,4	3	80%	-468,7

Parameter	Description	Value
Storage reservoir	Case 4b	Gas field, 50% depleted, depth 2000 m (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.5 Mtpa (Table 5.1) 4.2 Mtpa (Table 5.2) 4.2 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	16,0	5	70%	-314,5
	size 20.000 ton	19,2	4	55%	-368
	size 30.000 ton	16,6	3	61%	-317,5
	size 50.000 ton	20,3	3	51%	-392,5
Ship to platform to well	size 10.000 ton	14,0	5	79%	-307,9
	size 20.000 ton	17,0	4	61%	-372,3
	size 30.000 ton	15,2	3	66%	-332,7
	size 50.000 ton	18,2	3	54%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	14,0	4	99%	-319,3
	size 20.000 ton	15,8	3	81%	-357,7
	size 30.000 ton	13,5	2	98%	-308,1
	size 50.000 ton	15,5	2	80%	-358,1

Parameter	Description	Value
Storage reservoir	Case 4b	Gas field, 50% depleted, depth 2000 m (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.5 Mtpa (Table 5.1) 4.2 Mtpa (Table 5.2) 4.2 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	19,8	6	81%	-373
	size 20.000 ton	19,8	4	72%	-368
	size 30.000 ton	21,9	4	57%	-416
	size 50.000 ton	20,6	3	60%	-392,5
Ship to platform to well	size 10.000 ton	18,9	7	80%	-403,1
	size 20.000 ton	20,8	5	64%	-447,9
	size 30.000 ton	19,3	4	62%	-420,3
	size 50.000 ton	18,5	3	64%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	18,7	6	93%	-410,5
	size 20.000 ton	19,6	4	80%	-431,3
	size 30.000 ton	17,6	3	83%	-393,7
	size 50.000 ton	15,8	2	96%	-358,1

Parameter	Description	Value
Storage reservoir	Case 4b	Gas field, 50% depleted, depth 2000 m (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.5 Mtpa (Table 5.1) 4.2 Mtpa (Table 5.2) 4.2 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	26,1	8	78%	-490
	size 20.000 ton	24,7	5	71%	-454,5
	size 30.000 ton	22,4	4	68%	-416
	size 50.000 ton	27,0	4	51%	-516
Ship to platform to well	size 10.000 ton	23,7	9	80%	-498,3
	size 20.000 ton	21,4	5	80%	-447,9
	size 30.000 ton	23,5	5	60%	-507,9
	size 50.000 ton	23,6	4	56%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	23,5	8	90%	-501,7
	size 20.000 ton	20,2	4	99%	-431,3
	size 30.000 ton	21,7	4	75%	-479,3
	size 50.000 ton	20,8	3	74%	-468,7

Parameter	Description	Value
Storage reservoir	Case 4c	Gas field, 50% depleted, depth 3000 m (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.2 Mtpa (Table 5.1) 3.5 Mtpa (Table 5.2) 3.5 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	17,4	5	66%	-314,5
	size 20.000 ton	20,9	4	53%	-368
	size 30.000 ton	18,1	3	59%	-317,5
	size 50.000 ton	22,1	3	49%	-392,5
Ship to platform to well	size 10.000 ton	16,3	5	70%	-307,9
	size 20.000 ton	19,9	4	55%	-372,3
	size 30.000 ton	17,8	3	61%	-332,7
	size 50.000 ton	21,5	3	51%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	16,3	4	87%	-319,3
	size 20.000 ton	18,5	3	74%	-357,7
	size 30.000 ton	15,9	2	91%	-308,1
	size 50.000 ton	18,2	2	76%	-358,1

Parameter	Description	Value
Storage reservoir	Case 4c	Gas field, 50% depleted, depth 3000 m (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.2 Mtpa (Table 5.1) 3.5 Mtpa (Table 5.2) 3.5 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	21,4	6	76%	-373
	size 20.000 ton	21,5	4	68%	-368
	size 30.000 ton	23,8	4	54%	-416
	size 50.000 ton	22,4	3	57%	-392,5
Ship to platform to well	size 10.000 ton	19,6	6	81%	-355,5
	size 20.000 ton	20,6	4	72%	-372,3
	size 30.000 ton	22,7	4	57%	-420,3
	size 50.000 ton	21,8	3	59%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	19,5	5	97%	-364,9
	size 20.000 ton	19,2	3	95%	-357,7
	size 30.000 ton	20,6	3	75%	-393,7
	size 50.000 ton	18,6	2	89%	-358,1

Parameter	Description	Value
Storage reservoir	Case 4c	Gas field, 50% depleted, depth 3000 m (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.2 Mtpa (Table 5.1) 3.5 Mtpa (Table 5.2) 3.5 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	25,3	7	83%	-431,5
	size 20.000 ton	26,7	5	66%	-454,5
	size 30.000 ton	24,3	4	64%	-416
	size 50.000 ton	22,7	3	65%	-392,5
Ship to platform to well	size 10.000 ton	25,2	8	78%	-450,7
	size 20.000 ton	25,0	5	70%	-447,9
	size 30.000 ton	23,1	4	67%	-420,3
	size 50.000 ton	27,8	4	51%	-520,3
From ship to offshore storage (50kton)	size 10.000 ton	25,0	7	89%	-456,1
	size 20.000 ton	23,5	4	88%	-431,3
	size 30.000 ton	21,1	3	90%	-393,7
	size 50.000 ton	24,4	3	68%	-468,7

Parameter	Description	Value
Storage reservoir	Case 4d	Gas field, 50% depleted, depth 4000 m (Table 3.1)
Transport distance		400 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.0 Mtpa (Table 5.1) 3.3 Mtpa (Table 5.2) 3.3 Mtpa (Table 5.2)

Distance 400 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	18,7	5	63%	-314,5
	size 20.000 ton	22,5	4	51%	-368
	size 30.000 ton	19,6	3	57%	-317,5
	size 50.000 ton	23,9	3	48%	-392,5
Ship to platform to well	size 10.000 ton	17,3	5	67%	-307,9
	size 20.000 ton	21,1	4	53%	-372,3
	size 30.000 ton	18,9	3	59%	-332,7
	size 50.000 ton	22,8	3	50%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	17,3	4	84%	-319,3
	size 20.000 ton	19,7	3	71%	-357,7
	size 30.000 ton	16,8	2	89%	-308,1
	size 50.000 ton	19,4	2	75%	-358,1

Parameter	Description	Value
Storage reservoir	Case 4d	Gas field, 50% depleted, depth 4000 m (Table 3.1)
Transport distance		800 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.0 Mtpa (Table 5.1) 3.3 Mtpa (Table 5.2) 3.3 Mtpa (Table 5.2)

Distance 800 km					
Off-shore infrastructure	Ship size	Transport costs €/ton Co2	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	23,0	6	71%	-373
	size 20.000 ton	23,2	4	65%	-368
	size 30.000 ton	25,8	4	52%	-416
	size 50.000 ton	24,3	3	56%	-392,5
Ship to platform to well	size 10.000 ton	20,8	6	77%	-355,5
	size 20.000 ton	21,8	4	69%	-372,3
	size 30.000 ton	24,1	4	55%	-420,3
	size 50.000 ton	23,2	3	58%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	20,7	5	93%	-364,9
	size 20.000 ton	20,3	3	92%	-357,7
	size 30.000 ton	21,9	3	73%	-393,7
	size 50.000 ton	19,7	2	87%	-358,1

Parameter	Description	Value
Storage reservoir	Case 4d	Gas field, 50% depleted, depth 4000 m (Table 3.1)
Transport distance		1200 km
Transport capacity	Direct from ship to well Ship to platform to well From ship to offshore storage	3.0 Mtpa (Table 5.1) 3.3 Mtpa (Table 5.2) 3.3 Mtpa (Table 5.2)

Distance 1200 km					
Off-shore infrastructure	Ship size	Transport costs €/ton	nr ships	Utilization	capex
Direct from ship to wel	size 10.000 ton	27,2	7	78%	-431,5
	size 20.000 ton	28,8	5	63%	-454,5
	size 30.000 ton	26,2	4	61%	-416
	size 50.000 ton	24,6	3	63%	-392,5
Ship to platform to well	size 10.000 ton	24,2	7	84%	-403,1
	size 20.000 ton	26,5	5	67%	-447,9
	size 30.000 ton	24,6	4	65%	-420,3
	size 50.000 ton	23,5	3	66%	-407,7
From ship to offshore storage (50kton)	size 10.000 ton	24,1	6	98%	-410,5
	size 20.000 ton	24,9	4	84%	-431,3
	size 30.000 ton	22,4	3	86%	-393,7
	size 50.000 ton	20,0	2	99%	-358,1