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Kårstø CO_2 Pipeline Project: Extension to a European Case

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Abstract

This report describes a case study where the "point to point" system in the Kårstø case study described in deliverable 4.3.1 is extended to a small network consisting of additional CO_2 pipelines from Rotterdam (the Netherlands) and Teesside (UK) entering the same storage location in the Utsira formation on the Norwegian Continental Shelf. In addition, a ship transport chain is described as part of the sources for CO_2 at Teesside, i.e. that CO_2 is transported from a different location to Teesside by ship, for injection into the pipeline system to Utsira. In addition to the technical description, cost estimates are given for the transport system.

EXECUTIVE SUMMARY

This report describes a specific case study related to transport of CO_2 from Kårstø in Norway, Kingsnorth and Teesside in UK and Rotterdam in the Netherlands. The case is used to illustrate technical solutions and associated CO_2 transportation costs.

Both transportation through high pressure subsea pipeline and as liquid CO_2 onboard special vessels are evaluated in the case study. Both concepts are assumed technical feasible for its purpose, but some issues remain subject to technology qualification processes, either as part of future projects, or as part of currently ongoing CCS related R&D activities. With respect to offshore pipeline transportation, this is in particular related to noise reduction during depressurisation, corrosion effect of impurities in the CO_2 stream and the risk of propagating longitudinal fractures.

All of these issues are assumed to be manageable, and do not represent potential showstoppers for transport of CO_2.

Transport of CO_2 will to a large extent be performed in systems similar to those in use for transportation of natural gas and petroleum product. CO_2 transport requires strict control of water and impurities as otherwise the mix of CO_2 and free water will form carbon acid that will have a corrosive effect on the carbon steel materials within short time. Corrosion resistant materials are generally not considered necessary.

Ship transport of CO_2 is a mature business, which have been operated for nearly 20 years on a smaller scale to the food industry. Technology for scaling up to large scale transport vessels is considered available.

Maturing of storage and CO_2 capture facilities require transportation of CO_2 from capture locations to storage location(s) in the North Sea. Development of such transportation infrastructure could be organised similar to established regimes for upstream infrastructure for gas and petroleum products, and each of the applicable EU Member States (and Norway) have developed such regimes that are recognised by the industry.

Development of a commercial CO_2 transportation infrastructure will require owners of CO_2 to undertake payment commitment for a period of time sufficient to make a financial recovery of the investment at a reasonable rate of return. If such payment obligation is secured, the organisation of the ownership and operation could follow the model from the petroleum transportation business. A joint venture of owners (with or without state participation) could be formed, and an independent operator could also be appointed.

Cross-border infrastructure for CO_2 transportation raise issues of pipeline jurisdiction including inter alia questions of safety regulation, metering and third party access. As regards the third party access rules, it is important that rules pertaining to the storage site and the pipeline(s) are aligned, as the latter is dependent on the former. Such issues can be dealt with in bi- or multilateral instruments such as treaties.

The Norwegian Ministry of Petroleum and Energy (MPE) is coordinating the work of developing a regulatory framework for CO_2-storage on the Norwegian Continental Shelf

(NCS). Draft regulations are expected late 2011. The MPE has also given the Norwegian Petroleum Directorate (NPD) the responsibility of gathering information and to establish the Norwegian CO_2-Atlas detailing the CO_2-storage potential in the NCS. Based on the ongoing work undertaken by the Norwegian authorities to mature regulations and storage sites on the NCS, it is expected that qualification and development programs of CO2-storage will be established in due time for any decisions to install relevant carbon capture facilities.

Design of offshore high pressure pipelines are based on mature and proven technology. There are technical issues also for offshore pipelines needing qualification programmes and one of the more critical is related to noise levels for shut downs or failures leading to pressure relief through safety vents. Establishing acceptance levels for impurities is another area. The offshore systems including onshore pressurisation is however assumed sufficient matured to be regarded as feasible and realistic cost estimates are available for the CO_2 transportation chain.

The cost summary for the cases described in this report are given in the below figures, and described in detail hereinafter.

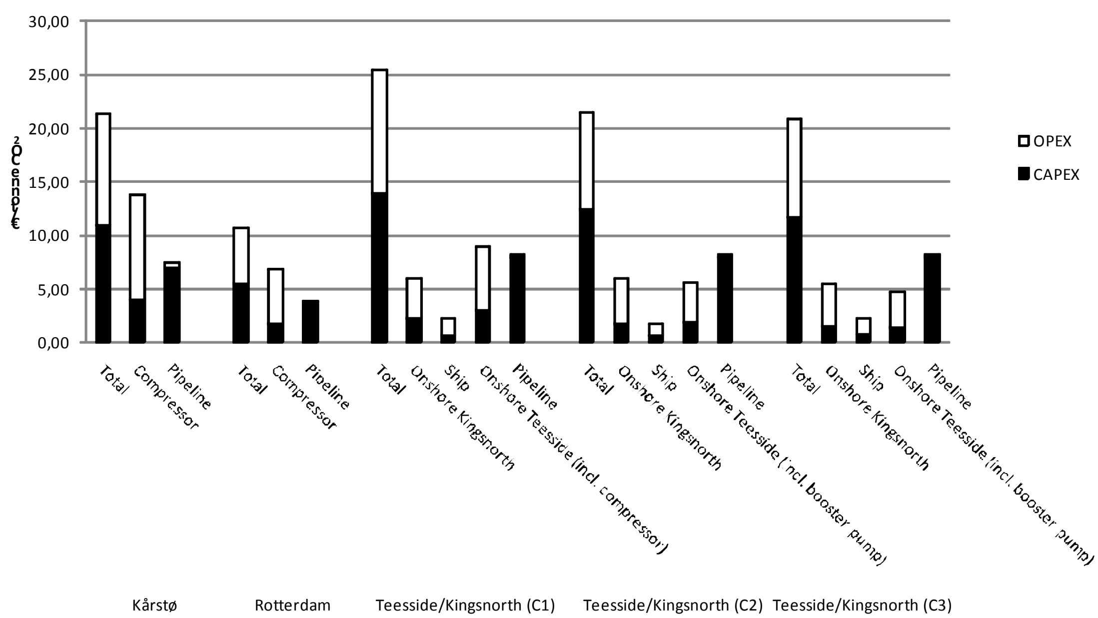

Figure 0-1 *NPV unit cost illustration for the European case. OPEX for the pipelines are small compared to the overall costs and thus barely visible*

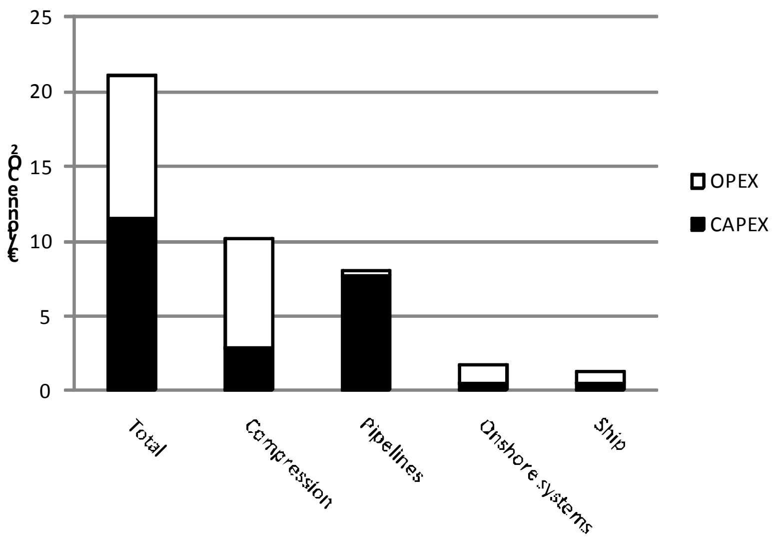

Figure 0-2 Total network NVP unit costs, assuming ship concept C3

PROJECT SUMMARY

The CO2EuroPipe project aims at paving the road towards large-scale, Europe-wide infrastructure for the transport and injection of CO_2 captured from industrial sources and low-emission power plants. The project, in which key stakeholders in the field of carbon capture, transport and storage (CCTS) participate, will prepare for the optimum transition from initially small-scale, local initiatives starting around 2010 towards the large-scale CO_2 transport and storage that must be prepared to commence from 2015 to 2020, if near- to medium-term CCS is to be effectively realized. This transition, as well as the development of large-scale CO_2 infrastructure, will be studied by developing the business case using a number of realistic scenarios. Business cases include the Rotterdam region, the Rhine-Ruhr region, an offshore pipeline from the Norwegian coast and the development of CCS in the Czech Republic and Poland.

The project has the following objectives:
1. describe the infrastructure required for large-scale transport of CO_2, including the injection facilities at the storage sites;
2. describe the options for re-use of existing infrastructure for the transport of natural gas, that is expected to be slowly phased out in the next few decades;
3. provide advice on how to remove any organizational, financial, legal, environmental and societal hurdles to the realization of large-scale CO_2 infrastructure;
4. develop business case for a series of realistic scenarios, to study both initial CCS projects and their coalescence into larger-scale CCS infrastructure;
5. demonstrate, through the development of the business cases listed above, the need for international cooperation on CCS;
6. summarise all findings in terms of actions to be taken by EU and national governments to facilitate and optimize the development of large-scale, European CCS infrastructure.

The present report describes a case study of a small network, where CO_2 from sources in UK, continental Europe and Norway are transported and stored in a common storage in the Norwegian Continental Shelf, providing insight into how a small network in a demonstration (or early implementation) phase of the CCS industry may be installed and operated.

Project partners

Nederlandse Organisatie voor Toegepast Natuurwetenschappelijk Onderzoek- TNO	Netherlands
Stichting Energieonderzoek Centrum Nederland	Netherlands
Etudes et Productions Schlumberger	France
Vattenfall Research & Development AB	Sweden
NV Nederlandse Gasunie	Netherlands
Linde Gas Benelux BV	Netherlands
Siemens AG	Germany
RWE DEA AG	Germany
E.ON Benelux NV	Netherlands, Belgium, Luxemburg
PGE Polska Gruppa Energetyczna SA	Poland
CEZ AS	Czech Republic
Shell Downstream Services International BV	Netherlands, United Kingdom
CO2-Net BV	Netherlands
CO2-Global AS	Norway
Nacap Benelux BV	Netherlands
Gassco AS	Norway
Anthony Veder CO_2 Shipping BV	Netherlands
E.ON New Build and Technology Ltd	United Kingdom
Stedin BV	Netherlands

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1 INTRODUCTION

The purpose of this report is to describe the results from the work performed for the European case in the Work Package 4.3 (WP4.3) within the CO_2EuroPipe project. The report stands on its own when it comes to describe the case study in terms of technical solutions and cost estimates, but should also be looked at in the context of the Kårstø case when it comes to an elaboration on general assumptions related to CO_2 transport systems.

1.1 Background

CO2EuroPipe is a defined project within EU's 7th framework program supported and partly funded by the European Commission. This project aims at paving the road towards a large-scale, pan-European infrastructure for the transport and injection of CO_2. The project will identify barriers and present scenarios for the optimum transition from initial small-scale, local initiatives towards large-scale CO_2 transport and storage that is proposed to start around 2020, with key stakeholders in the field of carbon capture, transport and storage. This transition, as well as development of the CO_2 infrastructure is being studied by identifying the business cases in a number of realistic scenarios. The project will result in a roadmap for CO_2 transportation, with 2020 as the target year for start of large-scale CCS in Europe. The roadmap will be defined for multiple levels considered in the project, ranging from technical to organizational, financial and societal. A combination of both pipeline and ship transportation is considered.

One of the work packages (WP4.3) of the CO2EuroPipe project has as an objective the task of describing transport systems for 2 cases;

- A technical solution for long-length (i.e. more than 200 km) subsea pipeline transport of CO_2 (for 1 to 5 Mt/yr) from source to geological permanent storage, with focus on:
  - Differences between gas and CO_2 transport, e.g. related to hydraulic flow calculations, stability analysis and temperature effects.
  - Analysis of relationship between costs and capacity effects from alternative pipeline dimensions.
- A technical case for a transport system for larger volumes (typically 20 Mt/yr) from Continental Europe, UK and Norway to underground storage in the Utsira saline aquifer formation, with focus on:
  - Optimisation of system configuration – which principles should be used for development of such a system, taking into consideration:
    - Need for long term optimal solutions both with respect to technical configuration and overall costs
    - Likely development of such a system over time, i.e. it is not likely that the overall system will be implemented in one go, but will develop over time

- Technical challenges related to pipeline transport of larger volumes of CO_2 over longer distances (500+ km).

This document is related to the second case, i.e. what is defined as the "European case". The starting point for the development of the case is one of the alternative CO_2 pipelines developed for the Kårstø case. In deliverable D4.3.1, three alternative pipelines from Kårstø to Utsira are described, having annual transport capacity of 1, 3 and 5 Mt/yr, respectively. For the European case, the 12" pipeline having a capacity of 3 Mt/yr has been selected as the starting point for development of a network within this case study.

This pipeline system is then developed into a small network;

- At the same time as the Kårstø - Utsira pipeline is installed, it is assumed that the CO_2 pipeline from Rotterdam described in the report from CO2Europipe work package 4.1 [*D4.1.1*] is installed. This pipeline will transport CO_2 for storage in depleted gas fields in the Dutch Continental Shelf (DCS). After 20 years, when it is assumed that the capacity of suitable depleted gas fields in the DCS have been utilised, the pipeline will be extended to the storage location in the Utsira formation. Depending on the future investment appetite of oil companies and operators in the North Sea for CO_2-EOR the pipeline extension beyond the DCS may happen much earlier to supply CO_2 to either English, Danish or Norwegian oil fields in which case the forecasted CO_2 supply to the Utsira formation will be smaller than 20 million ton CO_2 per year after 2036 or even start earlier than 2036 if Utsira proves to be a good buffer.
- Tree years after the Kårstø - Utsira pipeline is installed, a pipeline is installed from Teesside in UK, transporting up to 7 Mt/yr CO_2. Out of these 7 Mt/yr, 3 Mt/yr are transported from Kingsnorth, also in UK, to Teesside. The remaining 4 Mt/yr is assumed to come from sources in the Teesside region.

All three pipelines are routed to the storage location described for the Kårstø case study. This implies that the storage location should have the capacity of storing up to 30 Mt/yr over the lifetime of the CCS system, except for the first 20 years (when the CO_2 from the Rotterdam area is stored in depleted gas fields in the DCS), where the storage capacity needs to be at least 10 Mt/yr.

The selection of starting points for the CO_2 transport system, i.e. Kårstø, Rotterdam, Kingsnorth and Teesside, is selected based on the fact that CCS systems are, or have been, under evaluation with sources in those regions. The results from the current case study could, however, be equally valid for transport of CO_2 from other sources, where distance from source to sink and topography along the pipeline route is similar to what is described in the European case.

For the remainder of this report, the "Kårstø report" and the "Kårstø case" shall mean the reference to deliverable D4.3.1 within the CO2EuroPipe project.

1.2 Objectives

As for the Kårstø case, the resources allocated for the European case does not allow for any specific engineering of the technical solutions included in the network. Inside the organisations contributing to the work there exists, however, a significant amount of experience data from other, similar or related projects, which have been utilised for the evaluation of the European case.

In the Kårstø report, the technical solution for the pipeline alternative was extensively described. In the current report, a similar focus will be put on description of the part of the system implying ship transport. This description includes all necessary systems, including onshore systems (liquefaction, intermediate storage and loading/offloading systems) and an analysis of how three alternative logistic models may impact the need for such capital intensive onshore systems.

Thus, the totality of the current report and the report describing the Kårstø case should give a significant insight in both pipeline and ship transport for cases similar to the ones described in the reports.

1.3 Abbreviations

The following abbreviations are used throughout this document:

CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
DCS	Dutch Continental Shelf
DP	Dynamic Positioning
EUR	Euro (€)
HSE	Health, Safety and Environment
ID	Inner diameter
KP	Kilometre post
Kts	Nautical knots (1 852 meter)
MDO	Marine Diesel Oil
MPE	Norwegian Ministry of Petroleum and Energy
MSL	Mean Sea Level
MSm^3/d	Million standard cubic metres per day
Mt/yr	Million tonnes per year
NCS	Norwegian Continental Shelf
NM	Nautical mile (1852 m)
NPD	Norwegian Petroleum Directorate
O&M	Operations and maintenance
OD	Outer diameter
P	Pressure
R&D	Research and Development
RFO	Ready For Operation
T/C	Time Charter
WHD	Well head

2 BASIS FOR THE WORK

In this section, a description is given of the elements and assumptions used to establish cost estimates for the alternative systems.

2.1 Sources for CO_2

Sources for CO_2 throughout Europe are evaluated in a previous CO2Europipe report [*D2.2.1*]. In this case study three of the relevant areas for CO_2 capture have been used as a starting point, namely Kårstø in the western Norway, Teesside on the east coast of UK, and Rotterdam in the Netherlands.

Kårstø

Kårstø is located on the western part of Norway, approximately mid-way between Stavanger and Bergen. Since 1985, one of the world's most complex processing plants for treatment of rich gas has been situated here. Gassco is the Operator of the plant, which alone supplies Europe with up to ~70 MSm^3/d dry gas, which e.g. corresponds to 40% of the average gas consumption in France. Located at the same area is also Norway's only commercial gas fired power plant, operated by Naturkraft, see the below figure.

Figure 2-1 Kårstø processing plant and Naturkraft gas fired power plant (right-most in the picture). Source: Gassco

Under continuous and normal operations, a total of approximately 2,4 Mt/yr of CO_2 is emitted from Kårstø, distributed approximately equally between the gas fired power plant and the gas terminal, respectively.

In the Kårstø case report, three alternative capacities, i.e. 1, 3 and 5 Mt/yr was described for transport of CO_2 to the Utsira saline aquifer. In the current report, the 3 Mt/yr alternative will be used in the European case.

Teesside
Teesside is located in the north-east of England, and has been an area for heavy industry since development of iron and steel plants in the 19th century. Today, the emissions from the Teesside region is approximately 13 Mt/yr CO_2. The Teesside Project being developed by Progressive Energy and a consortium of industrial and utility players is planning to capture approximately 5 Mt/yr by 2020. A second project under development by Progressive may also capture 5 Mt/yr in the same time frame from an area north of Teesside (closer to Blythe). In addition, other plans exist to capture additional ~5 Mt/yr.

Rotterdam
The Rotterdam area contains sources from industry comprising more than 25 Mt/yr CO_2 emissions. Two demo projects have been initiated;

- EERP funded project of a 50/50 JV of E.ON Benelux and Electrabel/Suez called ROAD that will transport CO_2 from the EON coal fired power plant (in construction) to an offshore depleted gas field.
- NER 300 project of Air Liquide in cooperation with CINTRA and Maersk to transport CO_2 from a hydrogen plant to an offshore oil field.

Besides these 2 demo projects (to be operational in 2015) Rotterdam aspires to become a large CO_2-hub (a logistic centre with a collection network, CO_2 capture, CO_2 import, compression and offshore transport). These demo projects are described in more detail in the Rotterdam case study report [*D4.1.1*].

Kingsnorth
In the European case, it is assumed that 3 Mt/yr CO_2 is transported from Kingsnorth to Teesside by ship, before it is entering the CO_2 pipeline from Teesside to the Utsira formation. Kingsnorth is located in the south-east England, and for the current case study, it is assumed that the source of the CO_2 will be the (postponed) Eon Kingsnorth (UK) CCS project.

2.2 Design basis

The design basis for the European case is given in Section A1. The CO_2 stream is assumed to enter the transportation system (both the ship and the pipeline parts of the system) at 1 bara and at a maximum temperature of 50ºC. At the storage site, the CO_2 is assumed to exit the transportation system at the inlet of a subsea template structure facilitating the manifold system for the injection wells into the geological structure, see the below figure for a typical configuration.

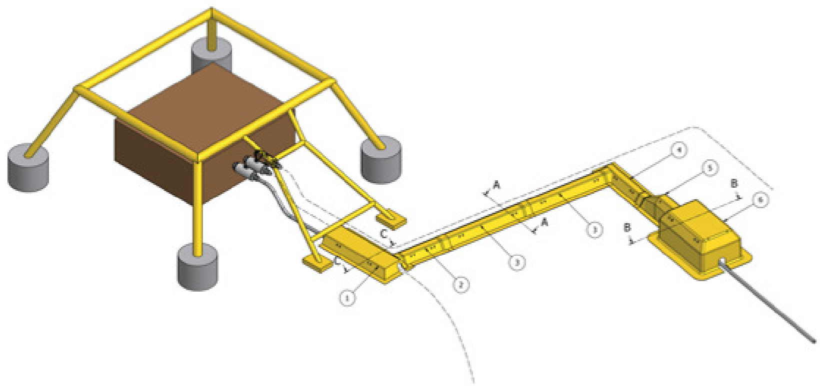

Figure 2-2 Schematic of a typical subsea template solution for CO_2 injection. Source: Gassco

Between these battery limits, CO_2 will be transported by ship from Kingsnorth to Teesside, and by pipeline systems from Kårstø, Rotterdam and Teesside to the location for geological storage. The CO_2 will be compressed onshore to inlet pressures in the pipelines necessary for obtaining the required flow rate and minimum outlet pressure at the subsea template. For the ship transport to Teesside, alternative concepts, including alternative transport pressures and logistic models are presented and discussed.

Maximum flow rates for the system will be,

- Ship transport from Kingsnorth to Teesside: 3 Mt/yr = 375 t/hr
- Pipeline transport from Teesside to the Utsira formation: 7 Mt/yr = 875 t/hr (including 3 Mt/yr shipped from Kingsnorth)
- Pipeline transport from Rotterdam to the Utsira formation: 20 Mt/yr = 2500 t/hr
- Pipeline transport from Kårstø to the Utsira formation: 3 Mt/yr = 375 t/hr

Thus, the total maximum flow rate for the transportation network is 30 Mt/yr = 3750 t/hr.

Although it is not fully defined which sources for CO_2 are included in the European case, it can be expected that variations in flow rate will be part of the normal operating pattern of the network. Thus, design and operational flexibility needs to take into account that such variations can be handled on a continuous basis.

The CO_2 stream entering the transport alternatives shall be non-corrosive. After compression (pipeline part of the network) and following liquefaction (ship transport to Teesside) the CO_2 shall remain in dense or liquid state until entering the subsea template at the storage location.

2.3 Pipeline transport

In this section, the basis for the pipeline part of the CO_2 network is described. For the Kårstø pipeline, the results are based on the Kårstø case report. For the Teesside and

Rotterdam pipelines, the results are based on results from relevant projects performed within Gassco. Data related to design and functional solutions are, however, based on hydraulic simulations performed specifically for the European case, and the technical and economical results should be relevant for the current work. Cost estimates are based on results from similar systems developed during 2008 and 2009, and adjusted to 2011 market conditions.

Technical aspects related to pipeline transport are briefly discussed in this case report, and are presented in more detail in other CO2Europipe reports [*D3.1.1*, *D3.1.2*].

2.3.1 Pipeline routing

Onshore sections
Both for Teesside and Rotterdam it is assumed that the compressor station is located in the vicinity of the landfall area, i.e. that the onshore section of the pipeline system is only a few hundred meters. This corresponds to the solution described in the Kårstø report.

No specific engineering evaluations have been made within the European case to evaluate suitable landfall areas at Teesside, but assumptions related to characteristics of typical near shore and landfall conditions in the Teesside area have been made. For the Rotterdam pipeline, the European case pipeline will be a continuation of the pipeline described as part of the Rotterdam CCS development [*D4.1.1*], and the current report will use the same assumptions as have been used there.

Offshore sections
The offshore section for the Kårstø pipeline is extensively described in the Kårstø report [*D4.3.1*], and will not be repeated here.

For the Teesside pipeline, it is assumed a route that follows a straight line from Teesside to the storage location in the Utsira formation, which is 7 km west of the Draupner S/E platforms, approximately 240 km west of Kårstø.

Figure 2-3 Offshore pipeline route. Source: Google Earth

The Rotterdam pipeline is assumed to follow a straight line from the location of the depleted gas field furthest away from shore (J06A) in the Rotterdam case, to Utsira.

Normally, a straight line route would be the starting point for any pipeline project, implying the shortest distance from start to end of the pipeline. In general, factors that may imply the need for deviating from such route could be;

- Topography, i.e. the terrain on the seabed. Islands, shallow water areas, areas with uneven bottom conditions or with soil conditions not suitable for pipelines (e.g. related to the need for stability)
- Areas with higher risk to the pipeline system, e.g. as result of extensive ship traffic, trawling activities or military activities
- Environmental vulnerable areas
- Areas that for other regulatory reasons are not available (e.g. reserved for other activities)
- Existing installations along the route

For the European case, the topography have been evaluated based on available information (sea bed charts), but no specific in-depth mapping of the route have been made. Based on the evaluation, the initial assumption of straight line routes seems reasonable.

The length of the Teesside pipeline is approximately 450 km. The total length of the Rotterdam pipeline is approximately 700 km, whereof 270 km is the distance between Rotterdam and the depleted gas field furthest away from Rotterdam (see *D4.1.1*). Thus, the “new” section of the Rotterdam pipeline from this gas field to the Utsira storage location is approximately 430 km.

2.3.2 Hydraulic analyses and pipeline dimensioning

Simulation of the behaviour of the CO_2 stream in the pipeline should be performed to evaluate:

- The relationship between pipeline dimension, inlet pressure and transport capacity as a results of relevant pipeline characteristics (e.g. pipeline topography profile and surface roughness of the pipeline material)
- Temperature effects along the pipeline route
- Alternative operating modes, both steady state transport and transitions between alternative operating modes (including the “no flow” mode)
- Leakage situations with respect to flow rates and duration of an accidental event
- Planned blow down of the pipeline (venting of CO_2 to the atmosphere)

As described in the Kårstø report, particular focus should be put on the effects of burial of the pipeline, in particular during the first kilometres of the pipeline route, since this will have a significant impact on the density profile along the pipeline route, and thus also capacity of the pipeline itself. See the Kårstø report for a further description of this. For the European case, it is assumed that the pipeline is buried for the first 30 km, mainly due to need for protection of the pipeline in shallow areas where moving sand on the seabed may result in unstable support of the pipeline on the seabed. In addition, it is assumed that the pipeline is buried an additional 70 km in total (in shorter sections along the route) due to requirements in areas with heavy ship traffic (shipping lanes).

Based on the assumptions given in the design basis in Section A1 and for the selected pipeline route/profile, hydraulic analyses have been performed for the alternative maximum volume scenarios in order to defined necessary pipeline dimensioning and pressure requirements, see the below table.

Table 2-1 Key results from the hydraulic simulations

	Pipeline length km	OD inch	Inlet pressure Barg	Outlet pressure Barg
Kårstø	240	12	199	53
Teesside	450	20	190	53
Rotterdam	700	30	227	53

To understand the effect of variations in flow rates on compressor requirements, simulations have also been performed for other flow rates for the Rotterdam and Teesside pipelines. The results are given in the below table.

Table 2-2 Inlet pressure requirements as function of flow rates lower than maximum flow rates

	Flow rate - Teesside Mt/yr			Flow rate - Rotterdam Mt/yr		
	1	**3**	**5**	**5**	**10**	**15**
Inlet pressure Barg	70[1]	76	122	75	95	151

This means that the compressors need to handle alternative combinations of flow and pressure than what is defined as the maximum flow rate mode.

2.3.3 Flow assurance

The simulation models described in the above section can also be used to analyse pressure, temperature and density profiles along the pipeline routes. Such profiles are normally used in design of the pipeline and to understand conditions for flow which may affect operating principles. In particular issues related to transient situations, i.e. situations where flow in the pipeline vary with time (e.g. during start-up after a shut-down period, or as a result of variations in flow rates), are interesting. Changes in the operating pattern may result in a condition of the CO_2 inside the pipeline that are unacceptable. e.g. that the combination of pressure and temperature in parts of the pipeline results in to phase flow (low pressure or high temperature, or a combination.

A full flow assurance analysis has not been performed for the pipeline system described in this report, but a few flow cases have been simulated. In the below figures, some example results from these simulations are given for illustrative purposes. The results are related to the Teesside and Kårstø pipeline only. In this example it is assumed that the Kårstø and Teesside pipeline is entering the same subsea template (see the Kårstø report for a description of such template), and that the CO_2 from Rotterdam is injected into a separate template, see the below figure.

[1] To obtain the required outlet pressure at the wellhead (53 barg) under such low flow rates, a choke needs to be installed at the wellhead, alternatively in the well itself. Without this choke, the unrestricted flow will result in a wellhead pressure below 53 barg.

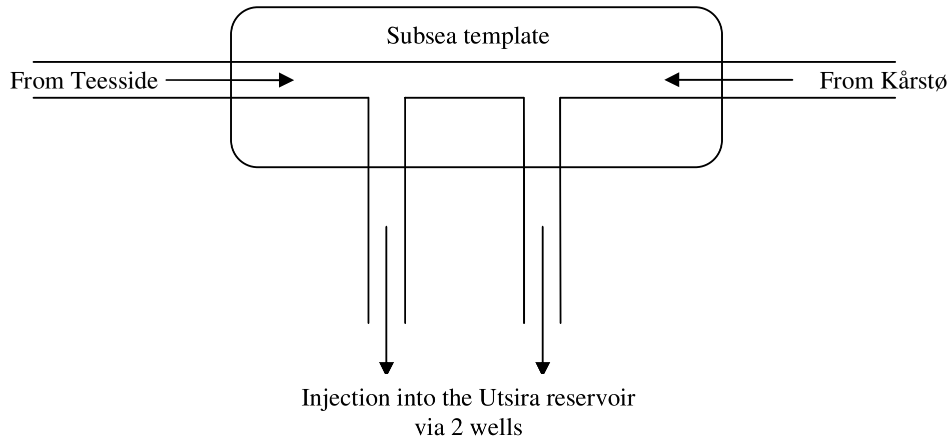

Figure 2-4 *Simple system sketch of simulation assumptions used for injection*

Steady state operation, full flow from Teesside, reduced flow from Kårstø

In the below figures, a steady state operating pattern is assumed, i.e. a constant CO_2 export from Kårstø and Teesside of 1 and 7 Mt/yr, respectively. This case, where the flow rate is reduced, is interesting with respect to unwanted effects of the significant differences in flow rates from the two sources. To estimate pressure profile along the pipeline, simulation tools may be used. Inlet parameters to the simulation tools are the flow parameters, in this case the fixed flow rate, pipeline elevation profile (height of the pipeline compared to mean sea level along the pipeline route), and assumptions related to sea temperature. The simulation tool will then start calculating the pressure at any selected point along the pipeline route.

In the below figure, the results from the calculations related to the inlet pressure at Kårstø for the above case is illustrated. Depending on the starting conditions for the simulated system, it will take some time before such a simulated system obtain stable steady-state flow conditions, and in this case such steady-state is obtained after approximately 175 000 seconds, i.e. after approximately 2 days of simulated flow (red circle).

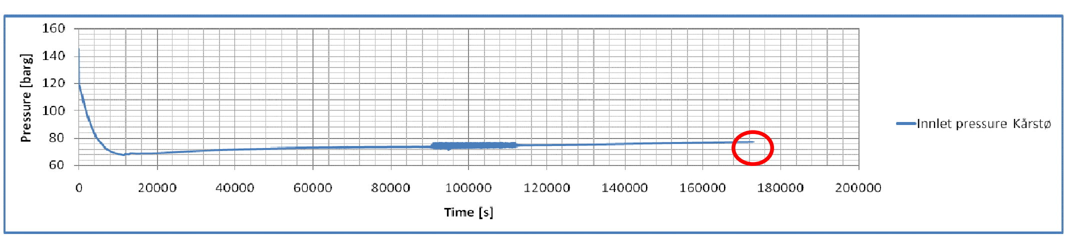

Figure 2-5 *Results from simulation of pressure at the Kårstø inlet. Flow from Kårstø and Teesside is 1 and 7 Mt/yr steady state respectively. The figure gives the inlet pressure at Kårstø.*

It can be seen that for this flow situation (flow rate from Kårstø at 1 Mt/yr), the inlet pressure at Kårstø will be approximately 77 barg. This is a rather low pressure, and it may be interesting to see what the resulting pressure at the wellhead will be. This is illustrated in the following figure.

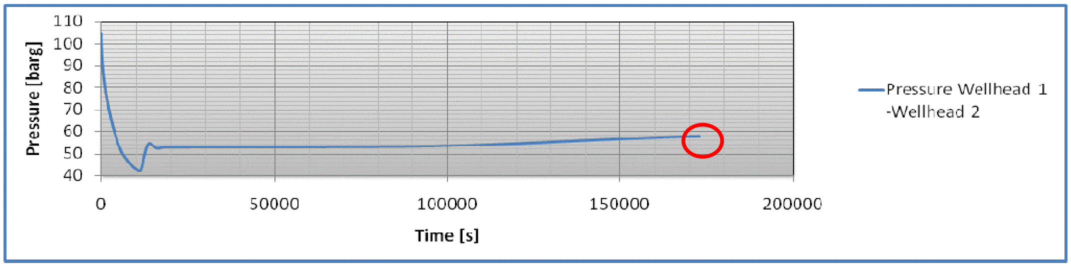

Figure 2-6 *Results from simulation of pressure at the Kårstø inlet. Flow from Kårstø and Teesside is 1 and 7 Mt/yr steady state respectively. The figure gives the outlet pressure at the template.*

The figure shows that the outlet pressure at the template will be ~58 barg. Considering the permanent low ambient temperature, around 7°C, this is well above a pressure that will result in two phase flow, and is acceptable.

<u>Transient state operation, full flow from Kårstø, flow from Teesside reduced from 7 to 0 Mt/yr</u>

In this case, the flow from Kårstø is maintained constant at 3 Mt/yr, while the flow from Teesside is reduced from 7 to 0 Mt/yr. This could typical for an emergency situation, where the flow is stopped by an emergency shutdown valve, or for a situation where the flow is gradually reduced over time, to allow for planned maintenance.

In the below figures, it is assumed that the flow from Teesside is gradually reduced from 7 to 0 Mt/yr over 4 days.

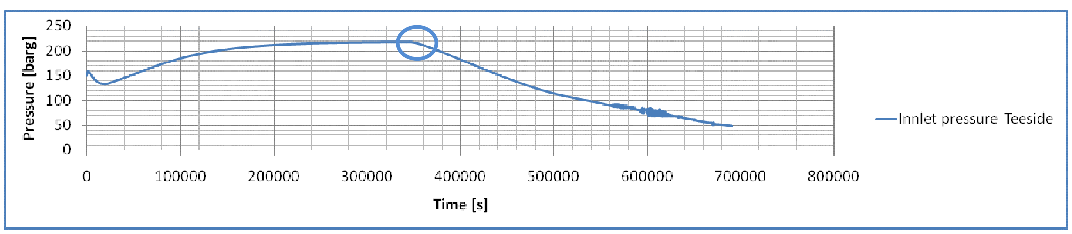

Figure 2-7 *Results from simulations at the Teesside inlet, where the flow is reduced from 7 to 0 Mt/yr over 4 days. The figure shows the pressure reduction as function of time.*

In the above figure, the simulation tool is allowed to obtain steady state conditions at a flow rate of 7 Mt/yr from Teesside (blue circle). Then the flow rate is reduced at a constant rate to zero over 4 days, and the pressure is reduced accordingly.

Reducing the flow rate from Teesside will have an effect of the pressure at the wellhead, and thus also on the inlet pressure at Kårstø. In the below figure, the pressure as function of time is given. Again, the blue circle indicates the time when the flow rates from Teesside starts to be reduced.

In the above figure, it can be seen that the pressure at the wellhead is gradually getting closer to two phase flow. Such two phase flow will occur at ~44 barg at sea bed conditions relevant in this case, which means that there still is a margin up to the ~50 barg shown in the figure. However, a safety margin should always be applied to avoid local two-phase flow in parts of the pipeline with unfavourable conditions (e.g. with higher water temperature, or if the pipeline is situated in shallow areas close to the wellhead), and in this case a safety margin of 6 bar could be evaluated as insufficient. If so, choke valves should be initiated at the wellhead (or in the well) having the effect of increasing the pressure at the wellhead, and thus reducing the risk of two-phase flow.

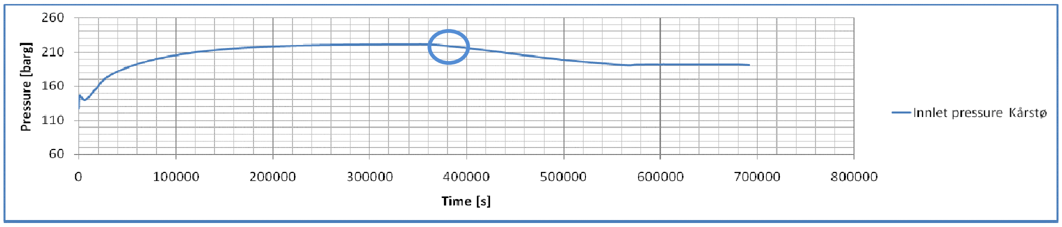

Figure 2-8 Results from simulations at the Kårstø inlet, resulting from reduced flow rates at the Teesside inlet, where the flow is reduced from 7 to 0 Mt/yr over 4 days. The figure shows the pressure reduction at the Kårstø inlet as function of time.

2.3.4 Other issues related to pipeline installation

In addition to the issues described above, the following issues needs to be taken into account when designing, installing and operating a subsea pipeline;

- pipeline mechanical design (on-bottom stability, cathodic protection, buckle and fracture arrestors, trawl impact and pipeline expansion)
- tie-in design
- template functional requirements
- pipeline installation
- seabed intervention
- landfall design
- onshore piping design
- RFO (Ready For Operation)
- Blow down philosophy and design
- Technical and operational requirements
- Health, safety and Environmental requirements

General requirements concerning these issues are described in the Kårstø report and is not repeated in the current report. For the cost estimates, general assumptions have been made of the impact from these issues, based on experience data from similar projects.

This is the normal approach to handling such issues when establishing unclassified cost estimates, which is the accuracy level in this report.

2.3.5 Compression

In the current section, compressor solutions are described for;

- Compression of 3 Mt/yr CO_2 from Kårstø
- Compression of 3 Mt/yr CO_2 at Kingsnorth as part of preparations to the liquefaction and ship transport to Teesside
- Compression of 4 Mt/yr CO_2 at Teesside prior to mixing the CO_2 with CO_2 from Kingsnorth
- Compression of 20 Mt/yr CO_2 from Rotterdam, assuming that a new compressor package is replacing the original compressor solution described as part of the Rotterdam transport system [*D4.1.1*]

The compressor design for the 3 Mt/yr pipeline from Kårstø have been established in the Kårstø report, and will be used in the current report. For the Rotterdam and Teesside pipelines, new compressor designs have been established by Siemens. The inlet conditions for all cases are 1 bara and 20°C, as described in Section A1. The inlet stream consist of CO_2 saturated with water. In all cases the outlet conditions are set at 50°C and a water content of 50ppm(wt).

<u>Kårstø - 3 Mt/yr:</u>
A double train of 2 x 50% is chosen. An eight stage integrally geared compressor of type STC-GV(80-8) is recommended, see the below figure. With full flow rate, the total power requirement is 2 * 20.6 MW.

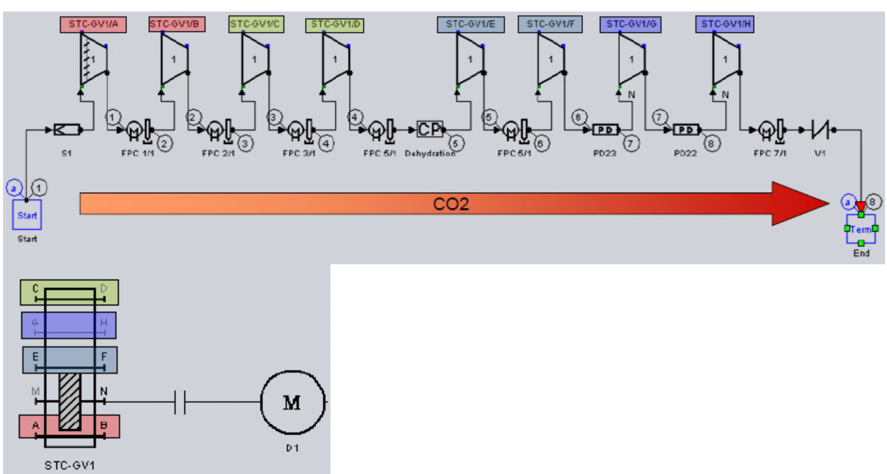

Figure 2-9 Design setup of compressor system for the 3 Mt/yr case. Source: Siemens

Kingsnorth - 3 Mt/yr:
At Kingsnorth, the CO_2 from the local source is compressed to 75 barg before entering the liquefaction system. A seven stage integrally geared compressor of type STC-GV(125-7) is selected. With full flow rate, the total power requirement is 24.2 MW.

Teesside - 4 Mt/yr, ship concept C1[2]:
At Kingsnorth, the CO_2 from the local source is being compressed to the pressure in the intermediate storage system for the CO_2 from Kingsnorth, mixed with the CO_2 in the intermediate storage tanks and further compressed to the pipeline export pressure. Two parallel compressors of type STC-GV(160-8) are used to compress the CO_2 up to 160 barg, while one single shaft compressor of type STC-SV(06-1-A) is used to further compress the CO_2 to pipeline export pressure.

Teesside - 4 Mt/yr, ship concepts C2, C3:
At Kingsnorth, the CO_2 from the local source is compressed to 75 barg before being mixed with the CO_2 from Kingsnorth. A seven stage integrally geared compressor of type STC-GV(160-7) is selected. With full flow rate, the total power requirement is 32.7 MW.

Pumping from 7 barg to 75 barg, as described in the figure in Section 2.4.3 below, is included in the ship transport system costs generally described in Section 2.4.

Rotterdam - 20 Mt/yr:
Compressor facilities are assumed installed as part of the Rotterdam case. However, since there are major differences in transport distances and thus also pressure requirements when transporting and injecting at Utsira (700 km) compared to injecting in a depleted gas field in the Dutch sector (270 km), a choice must be made;

- A compressor solution may be installed for the 270 km requirement only. Then, after 20 years, when the CO_2 is to be transported for 700 km, the compressor system is replaced or upgraded.
- A compressor solution is installed that may handle both alternatives (both 270 and 700 km).

Since there will be 20 years after installing the first compressor configuration before the 700 km transportation requirements is relevant, it is in this case study assumed that the full compressor solution is replaced when the 700 km transport requirement becomes relevant.

In the current report, only the compressor solution installed after 20 years of operation is described and included in the cost estimates. The compressor solution necessary for injecting into the depleted gas field on the Dutch sector is described in *D4.1.1*.

[2] C1, C2 and C3 refers to three alternative ship concepts described in Section 2.4

Then, for the European case, five parallel compressors of type DSTC-GV (160-8) are installed. The total power requirement for these compressors are 5 x 38 MW. The five parallel compressors will bring the pressure of the CO_2 up to 160 bara. To further increase the pressure to the required inlet pressure of the pipeline, a single shaft machine of type STC-SV(6-1-A) is installed. The power requirement for this machine is 7.7 MW.

Further information about the Siemens compressors may be found in the Kårstø report.

2.3.6 Authority requirements

The transport system described in the Kårstø report is entirely located on the Norwegian Continental Shelf, having the natural consequence that the system is subject to Norwegian regulations. For the European case, two cross-border pipelines are added to the transport network from UK and the Netherlands, respectively. Then, a clarification of regulations, including regulations related to safety and fiscal regime needs to be made.

It is not the intention of this report to conclude on which agreement will or should be made between the countries involved. However, one alternative could be to follow principles implemented for some of the offshore cross-border transport systems for natural gas, where a treaty is established between the countries involved, specifying overall principles for relevant regulations. Examples shows that in some cases, the authorities have agreed that the technical system is defined under one of the involved countries' jurisdiction, including the parts of the technical system that is outside the border of this country. Agreements are then made (e.g. a "Memorandum of Understanding") between regulatory bodies representing the relevant areas of responsibility in different countries, e.g. related to safety and fiscal metering. Such agreements normally includes handling of issues related to permits, audits and inspections and incidents/accidents.

2.4 Ship transport

In this section, three alternative concepts for ship transport are presented. The concept C1 describes a ship transport alternative similar to the Kårstø case, i.e. that CO_2 is entering the liquefaction systems at 1 bara, and where compression and liquefaction is performed as an integrated system. The concepts C2 and C3 describes system where the CO_2 first is compressed to 75 barg before entering the liquefaction plant. To evaluate how the number of ships may affect the need for onshore systems (in particular cost intensive intermediate storage), a 1 ship (concept C2) and 2 ship (concept C3) alternative is presented.

Also for ship transport, some relevant technical aspects related to ship transport are discussed in the current report, and further presented and discussed in *D3.1.1*.

2.4.1 Introduction

The intention with the following analysis is to provide an example of how a ship transport could fit into a larger network of CO_2 transportation using pipelines. As an example a transport on the UK coast between the EON Kingsnorth power plant in the Medway estuary, and the Port of Seal Sands at Teesside has been chosen. An assumed volume of 3 Mt/yr transported over this route will then be added to a locally captured 4Mt/yr and piped to Utsira.

In the following paragraphs the case at hand, the transportation chain, and its logistical and economic considerations are described.

2.4.2 Case description

In the original Kingsnorth project[3] the CO_2 flow was to be transported to the Hewett field (a depleted southern North-sea gas field) via an offshore pipeline. In this case these volumes are assumed to be transported by ship from Kingsnorth to Teesside. The figure below shows the 270NM/500 km shipping route.

Figure 2-10 Route Additional CO_2 source Kingsnorth - Seal Sands (Teesside)

The components of a CO_2 shipping chain in this case differs from the Kårstø case in that this is a port to port solution whilst in the Kårstø case, onboard offshore conditioning and injection was required parallel to vessel adaptations to accommodate the offshore infrastructure connection. In the below overview the different steps/components are given of a typical port to port solution. The capture and storage side of the chain are not covered.

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[3] *http://www.ccsassociation.org.uk/ccs_projects/uk_projects.html*

In the next two figures the site facility of the Kingsnorth site and a high level picture of the Seal Sands port area in Teesside is given for illustrational purposes.

Figure 2-11 Kingsnorth EON facilities Source: Google Maps

Figure 2-12 Destination Teesside, Port of Seal Sands

2.4.3 Scope and battery limits, concept C1

In the below figure, the scope and battery limits for concept C1 is described.

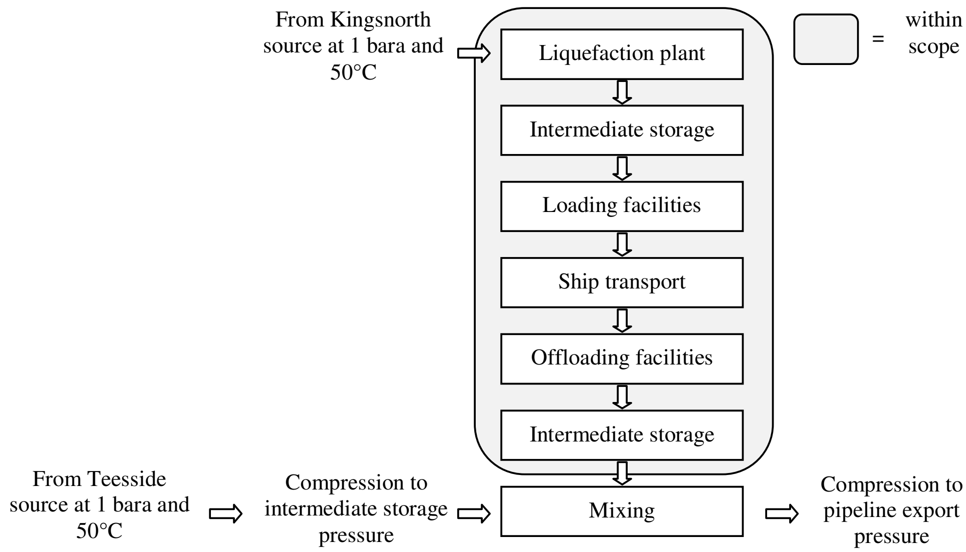

Figure 2-13 Scope and battery limits for the ship concept C1 described in this section

The concept C1 is, for the onshore systems at Kingsnorth, similar to the concept described in the Kårstø case report.

Liquefaction plant. CO_2 has significant volumetric transportation efficiency when transported in liquid phase. The weight / volume ratio of the liquid CO_2 is more suited for transportation in a ship, then in gaseous phase. The captured CO_2 will be liquefied, which means that a liquefaction plant is required at the capture site.

Technologies for liquefaction of CO_2 vary, but it is (process) industry practice to perform a dehydration step of the captured CO_2 prior to liquefaction. The reason for the dehydration is to avoid ice formation in the liquefaction process and the risk of carbonic acid formation (in later phase changes), which is highly undesirable in a metallurgic environment. The liquefaction process itself will then knock out most of the impurities. Since the CO_2 is relative dry and pure, existing thermodynamic knowledge of CO_2 can be used in simulation models. The conditions of the CO_2 after liquefaction are assumed to be -55 °C and 7 barg. It is assumed that the CO_2 stream in the shipping transportation chain is non-corrosive.

Intermediate storage. After liquefaction, intermediate storage is required at the capture site due to the batch wise nature of seagoing transportation therefore allowing for time efficient (in other words fast) loading of the CO_2 carrier.

Loading facilities. Preferably near the capture and intermediate storage location the jetty with the loading facilities: at least 2 loading arms are required (1 for cargo flow, 1 for the vapour return).

Ship transport. Vessel transportation of CO_2 in cargo containment system onboard a (seagoing) vessel from port to port.

Offloading facilities. Upon arrival at the destination port the vessel will be discharged via means of 2 loading arms (1 for cargo flow, 1 for the vapour return).

Intermediate storage. Intermediate storage is needed here to allow, again, for efficient offloading of the vessel that can return to the loading port for the next roundtrip.

Mixing with CO_2 from Teesside. From the intermediate storage, the liquid CO_2 needs to be either gasified prior to entering the pipeline flow or as in the Kårstø case, these volumes could be used as a coolant in the different compression stages needed prior to sending off the CO_2 via the pipeline to the Utsira formation

Step 7 is dependant of how the tie in of the shipping volumes into the pipeline flow is performed, in the Kårstø case TNO made an analysis of the flows that were to be combined from the incoming shipping flows and those captured at the Kårstø site. It proved feasible to use the shipping volume flow for cooling purposes in the different compression stages prior to sending out the CO_2 to the Utsira formation.

2.4.4 Logistical description, concept C1

In this paragraph the logistical assumptions and calculations are given that led to the choice of a 35,000 m³ vessel.

This vessel is assumed to sail at 16kts and have a loading and discharge rate of 2,000t/hr, a voyage related spare day is included here to allow for waiting times at the port (pilot, tug assistance, etc). A roundtrip will take approximately 4.0 days, the utilisation of the vessel is taken at approximately 85% which is conservative.

In line with the previous Kårstø case a multiple of 1.5X was used to set the storage size capacity – this is a conservative approach but given the high level of this study this is deemed appropriate. With a storage capacity of 52,500 m³ the voyage could be delayed (bad weather, strikes, unforeseen downtime etc) by 3.2 days before the liquefaction and capture process must be stopped given a full intermediate storage.

Table 2-3 Roundtrip calculation overview

Roundtrip calculation	**35 000 m³**	
Volume [MTA]	3	
Distance [NM]	270	
Speed [kts]	16	
Voyage related spare [d]	1.0	
Sailing time roundtrip [d]	1.4	
Loading and discharge [d]	1.6	
Roundtrip duration [d]	4.0	
Number of roundtrips/year [-]	77.0	
Utilisation [%]	84%	
Production per day [m³]	7246	
Production during roundtrip [m³]	29346	
Storage capacity [m³]	52500	-/- (1.5 multiple ship size)
Buffer capacity [m³]	23153	
Buffer [d]	3.2	

2.4.5 Liquefaction, concept C1

Several liquefaction technology providers exist using different coolants and processes, and one example is illustrated in the below figure;

- The CO_2 from the capture plant, assuming to be at 1 bara and 40-50°C, is cooled down to approx 11°C, using sea water heat exchangers. A separator is used to remove condensed water.
- The CO_2 is compressed to approx. 5.5 bara, and further cooled to approx. 11°C again, also this time using sea water heat exchangers. Again, a separator is used to remove condensed water.
- The CO_2 is compressed to approx. 20 bara, and further cooled to approx. 11°C a third time with same type of equipment, followed by water removal in a third separator.
- The CO_2 is led through a molecular sieve to remove the remaining water down to the requirement of 50 ppm(wt).
- The CO_2 is compressed to 60 bara and cooled/condensed. CO_2 in liquid phase is led to a system for nitrogen removal.
- The CO_2 is choked to approx. 20 bara, where some 1/3 of the CO_2 will enter gas phase. This CO_2 is heated and rerouted back to one of the above described compression steps.
- The remaining liquid CO_2 is cooled and choked to approx. 8 bara. Again, some of the CO_2 will enter gas phase and rerouted back for recompression.

- The conditions of the CO_2 after liquefaction are assumed to be -55 to -50°C and 7-8 barg. It is assumed that the CO_2 stream in the shipping transportation chain is non-corrosive.

In this integrated system, use of heat exchangers and economisers are used to optimise exchange of heat energy through the required heating/cooling requirements.

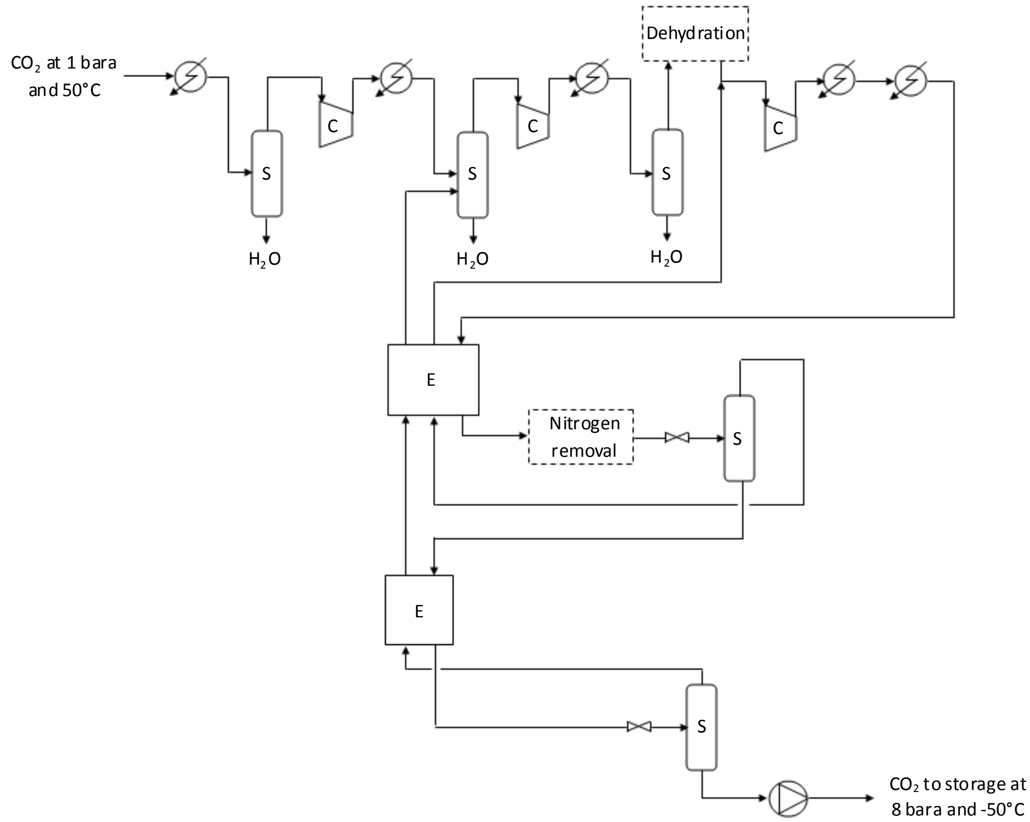

Figure 2-14 Typical system for liquefaction of CO_2 to be stored onshore (for ship transport). Use of compressors (C), separators (S) and economisers (E) indicated in the illustration. Source: Gassco

Power need for this example system is 15.4 MW, corresponding to 111 kWh per tonne CO_2 liquefied. A specific design have not been developed for this case, but the cost estimates are based on this unit power requirement.

2.4.6 Intermediate Storage, concept C1

From previous Gassco projects the following intermediate storage solutions came forward. The study considered two different modular single-walled storage concepts.

The storage concept is named InnoCell. The InnoCell system allows easy manufacturing and testing, transport and installation of tanks of 535 m^3 in cell structures. Two different insulation concepts are studied for this concept. This study compares cost, performance, flexibility in operation, and ease of installation for the two concepts.

Large cylindrical horizontal aligned tanks of 3000 m^3, as proposed in previous studies for Gassco, are not considered due to significantly higher costs, high weight, the resulting tank wall thickness, and requirements for large foundations and support. Moreover, large spherical site-built tanks are not investigated in this project due to the high manufacturing cost in Norway.

Each InnoCell will appear as a single tank system, but comprises multiple tanks. A 9-unit cell will have one common 14" feed line, and one 14" delivery line to either injection pipe or ship-loading facility (hub, source). All tanks in a cell will maintain the same pressure. This simplifies monitoring, installation and operation. Any individual tank in the cell can be insulated from the storage cell for maintenance etc.

Other features are pressure safety valves (PSV) on all blocked interconnections, and there will be a venting line through the vent stack on top of the InnoCell to allow for pressure relief. There will be a top-spray system in each tank. There will be either 5 or 6 nozzles on each individual tank, including the vent line, spray-line, top- and bottom filling. The feed lines to the individual tanks in the cell would be 6". The 14" line is connected to the 6" feed and delivery lines via a valve assembly with actuated controls.

The InnoCell CO_2 tanks are either made of P355NL2 or P420NL2 carbon steels. See Table 5 1 P355. The number denotes yield strength in N/mm^2. NL2 is a special low temperature quality normalised rolled carbon steel, the lowest testing temperature for impact toughness is at -50 degC.

Table 2-4 InnoCell CO_2 tank specification

MAIN TANK SPECIFICATIONS		
Gross volume per unit	[m3]	535
Number of units per cell	[#]	9
Gross cell volume	[m3]	4815
Tank length over all incl. skirts	[m]	34.5
Cylindrical length	[m]	28
Diameter	[m]	4.8
Design pressure	[bara]	11
Max. working pressure	[bara]	7.95
Material type 1 P355NL2		
Mat. Thickness 1 *	[mm]	13
Dish end thickness 1	[mm]	17
Weight per unit 1	[tonnes]	57.0
Material type 2 P420NL2		
Mat. Thickness 2 *	[mm]	11
Dish end thickness 2	[mm]	15
Weight per unit 2	[tonnes]	50.0
*2 mm steel for outer corrosion according to EN-standard.		

In an InnoCell cold box, a number of vertical CO_2 tanks will be arranged inside an enclosure, with outer walls supported by a steel structure, insulated with polyurethane plates and outside walls covered with building plates. The CO_2 tanks are single-layer and primed with polyurethane paint. There is no insulation around the individual tanks within the cell.

To simplify installation, all tank interconnections are bolted. No welding of tank interconnections will be required on site. The piping system is designed for block and bleed. There will be either 5 or 6 nozzles on each individual tank. The CO_2 tanks are equipped with skirts, and can be easily installed into its position on the concrete foundation.

In order to avoid icing, a gauge pressure system must be installed. This is to avoid oxygen presence within the cell. If oxygen is present in the atmosphere, icing will occur, and insulation performance will be reduced over time. The gauge pressure will be 0.05-0.1 bar. If the medium is nitrogen, a simple compressor system is required to maintain the pressure.

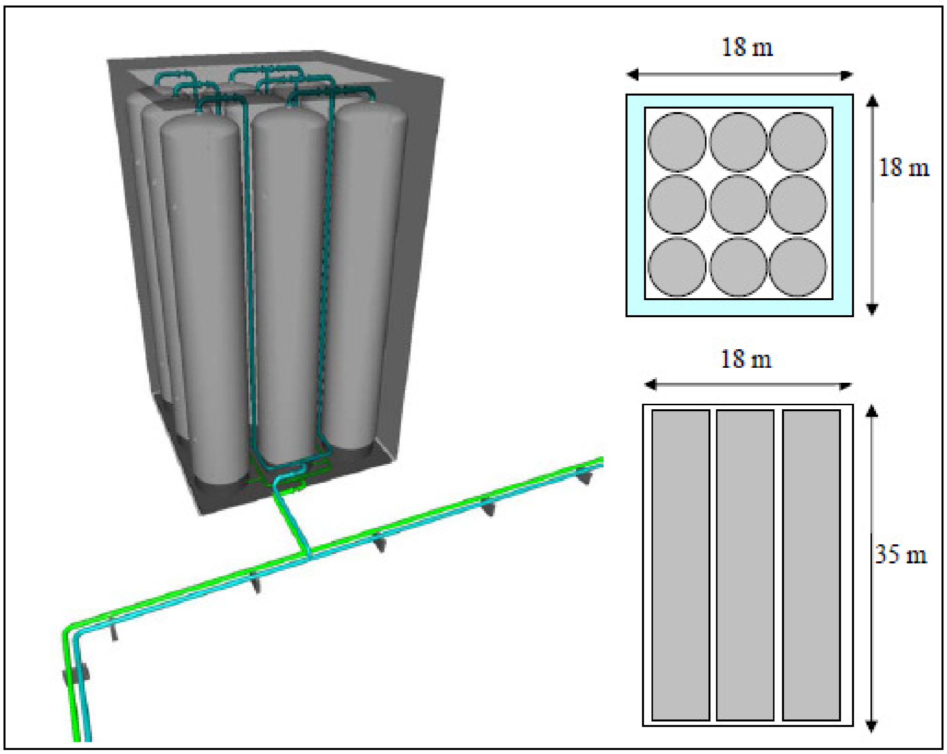

Figure 2-15 Cold-box system, with top- and side-view of 9 x 535 m3 tanks

<u>InnoCell Insulated Tanks</u>
An alternative to the cold-box design is to insulate the CO_2 tanks in manufacturing. This simplifies the installation process, as there would be no need for a cold-box system. The

CO_2 tanks are identical to the specification given in the above table, but each tank would require an insulation layer.

The tanks are single-layer and primed with polyurethane paint. The tanks are covered with a thin layer aluminium foil, and a 6 mm aerogel1 blanket with 1 mm aluminium or stainless cladding for protection of the insulation. All interconnections are bolted. No welding of tank interconnections will be done on site. The piping system is designed for block and bleed. There will be either 5 or 6 nozzles on each individual tank. The CO_2 tanks are equipped with skirts, and can easily be installed into its position on a concrete foundation.

Preinsulated InnoCells could be organised in a hexagonal shaped form to minimise boil-off from the system. See Figure 5 2 for illustration. Each cell could comprise 7 or 9 tanks.

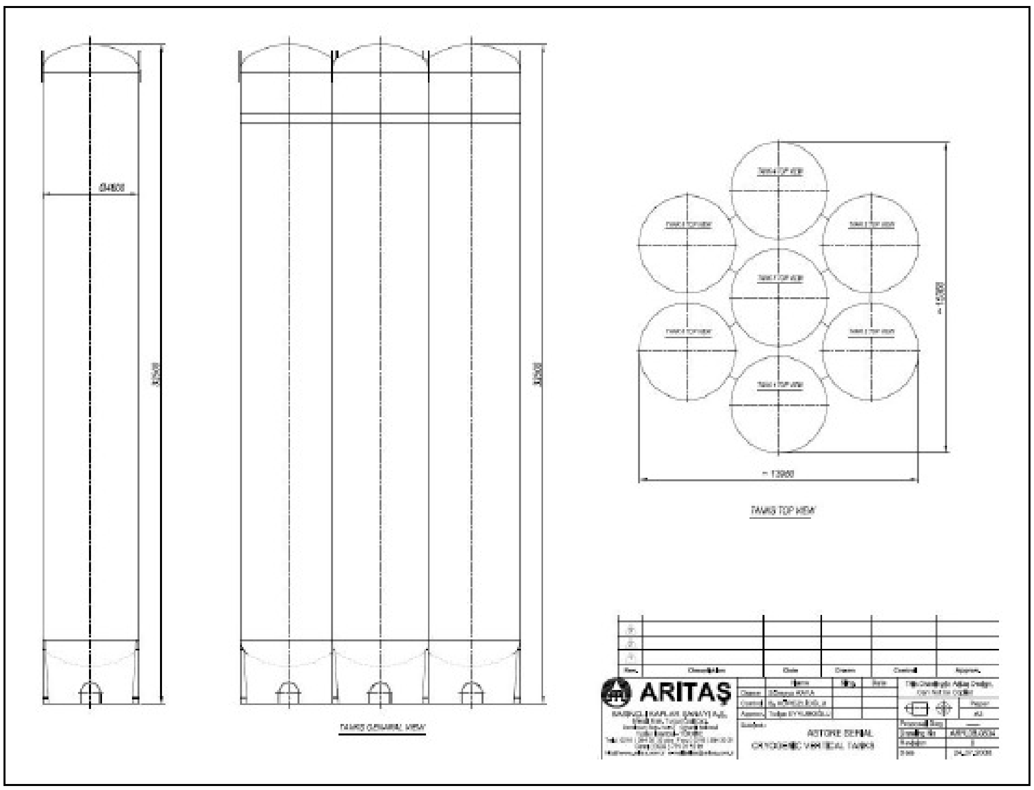

Figure 2-16 Aerogel insulated InnoCell in hexagonal organization

<u>Insulation materials</u>

Polyurethane: The InnoCell cold-box design utilizes insulation mats made of polyurethane. Polyurethanes are widely used rigid foam insulation panels. It is estimated that 60-80 mm insulation panels will provide sufficient insulation for the enclosed cold-box design.

Aerogel: The pre-insulated InnoCell tanks minimises insulation work in manufacturing and tank thickness and allows for easy transport and handling by use of a silica-based Aerogel insulation system consisting of thin insulating mats. Aerogels comprise a group of nano-materials that are good thermal insulators because they almost nullify three methods of heat transfer (convection, conduction and radiation). They are good convective inhibitors because air cannot circulate throughout the lattice. Silica Aerogel is an especially good conductive insulator because silica is a poor conductor of heat.

Aspen's Spaceloft Aerogel (www.aerogel.com) is a silica-based substance, derived from silica-gel. It has remarkable thermal isolative properties, having an extremely low thermal conductivity at around 0.01 W/m*K.

Evaluation of Storage Concepts

A qualitative assessment of the two InnoCell concepts reveals that use of pre-insulated tanks should be preferred with respect to costs, operation and flexibility. The cold box design has its advantage in more easy transport from manufacturing to installation site.

Table 2-5 Qualitative performance comparison of InnoCell storage designs

PARAMETER	COLDBOX DESIGN	INSULATED TANKS
Installed cost	**	***
Operational requirements	** [Gauge pressure/ purging system required]	***
Ease of installation	**	***
Ease of transport	***	**
Flexibility (accessibility of system for maintenance, replacement, or in case of leakage)	**	***
Operational performance	**	***
Zero emission philosophy	***	***
* Low ** Good *** Outstanding		

Recondensation system

During transport and storage there will be a heat leak from the ambient to the liquid CO_2. Also, when loading and unloading, heat will be transferred to the CO_2 due to e. g. cooling of the on-site piping and distribution system. A heat leak to the system will cause the pressure to increase. In order to maintain the pressure, some CO_2 must be purged, or re-liquefied. The total installed power for the re-condensation unit will be approximately the same as the heat leak to the tanks. E. g. a heat leak of 1 MW will require a 1 MW re-condensation unit. The required power will be lower, as the re-condensation unit will not continuously run at full capacity.

Even if the liquid CO_2 contains very small amounts of volatiles such as nitrogen (up to 0.4 mole%), the gas to be re-liquefied will contain a significant fraction of volatiles. The reason for this is twofold. First, at equilibrium the partial vapour pressure will be higher, giving a higher concentration of volatiles in the gas, than in the liquid. Second, the tank will not be in equilibrium and the volatiles will have a tendency to accumulate in the gas. Hence, in order to avoid purging of CO_2, the re-condensation unit must be capable of re-liquefying a CO_2 gas that is richer in nitrogen than the specification from liquefaction.

A typical re-condensation unit is shown in Figure 6 1. Flash gas from the storage tank at 8 bara is compressed in two stages to a high pressure e.g. 65 bara, before it is cooled to -30°C by an ammonia refrigeration unit. The CO_2 is then expanded to a pressure of e.g. 40 bara. If large amounts of nitrogen (>10 mole %) is present in the gas, some gas must be purged. The purge gas will consist of approximately 60-70% nitrogen and 30-40% CO_2. The liquid is then expanded to tank pressure and sent back to the storage tank.

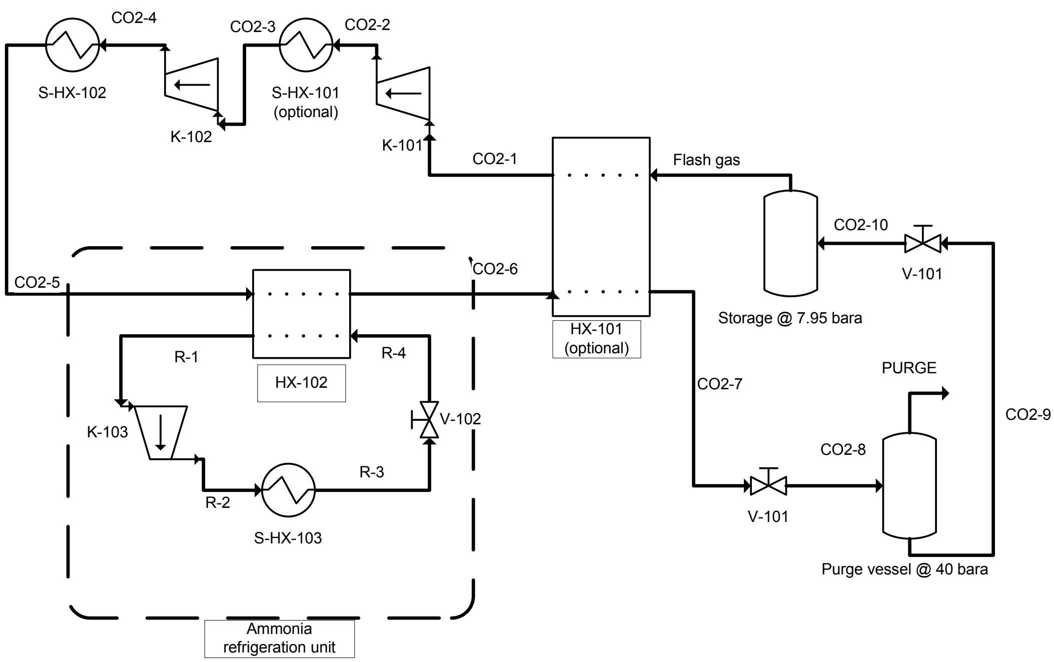

Figure 2-17 Typical design of the re-condensation system with ammonia refrigeration unit. Source: Gassco

The above figure shows the total loss and the loss of nitrogen and CO_2 as a function of nitrogen concentration in the flash gas for the proposed re-condensation unit. From the figure we see that small amounts of nitrogen and CO_2 needs to be purged already for nitrogen concentrations of 5%. If the nitrogen content is 20%, about 25% of the flash gas will be purged; at 50% as much of 65% of the gas will be purged.

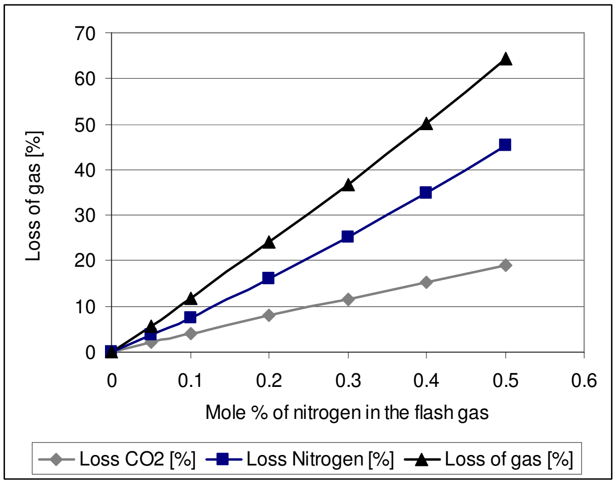

Figure 2-18 Loss of nitrogen and CO_2 as a function of nitrogen concentration in the flash gas

The concentration of nitrogen in the flash gas will decrease rapidly after start-up of the re-condensation unit. Hence, nitrogen and CO_2 will only be purged in the beginning. It should be noticed that the amount that will be purged is negligible and that there will be marginal changes in the gas composition. Furthermore, since nitrogen is purged, the quality of the CO_2 will increase.

The nitrogen content in the flash gas and the pressure increase in the tank system will be reduced given a "spray system" is installed at the top of the tanks.

Figure 2-19 Example of small CO_2 condensation system

During ship-loading at the CO_2 sources, the storage will unload continuously to the ship-export pipeline. This will decrease the pressure in the tank. A trim heater may be required to maintain the pressure.

For the proposed solution the installed power of the re-condensation unit will be approximately the same as the heat duty. The actual power consumption will depend on the flash gas composition.

2.4.7 Jetties and onshore (un)loading facilities, concept C1

Kingsnorth

The Kinsnorth site is today already used for coal supply of the existing power plant, a jetty is in place though only equipped for bulk (i.e. coal) offloading. It could be envisaged that part of the jetty is usable for the berthing of a CO_2 carrier though this must be further investigated. Currently multiple usage of a jetty that has a dry bulk function for say gas transfer is unlikely to be conceivable. Though given the non flammability of CO_2, this might be, subject to further study, a possibility. Furthermore tidal restrictions might apply which could mean that dredging is needed to allow for ease of access. Given the large quantities of coal that must be supplied it is assumed here that only new CO_2 loading arms and related equipment must be installed.

As mentioned before two loading arms are needed to allow for the cargo flow and the vapour return whilst loading/unloading the vessel. Due to the fact that CO_2 on and offloading at Kingsnorth is a novelty a detailed HAZOP analysis must be performed (though based on existing procedures for existing CO_2 carrying vessels) parallel to a full risk assessment as will be required by the facility operator and regulatory framework (both national and international).

Seal Sands – Teesside

The Seal Sands port area has various functions, container, oil and various other goods that can be shipped into this area. It is therefore assumed that building a CO_2 offloading facility is feasible though subject to further research (available land plots, permitting, safety studies etc). Again here a discharging jetty/quay must be equipped with two loading arms to allow for the cargo flow and the vapour return whilst loading/unloading the vessel. Also here, due to the fact that CO_2 on and offloading at Seal Sands is a novelty a detailed HAZOP analysis must be performed (though based on existing procedures for existing CO_2 carrying vessels) parallel to a full risk assessment as will be required by the facility operator and regulatory framework (both national and international).

2.4.8 Vessel, concept C1

A combined CO_2/LPG carrier mitigates the investment risks since an alternative trade service capability is available. Consequently preventing the obsolesce of the CO_2 carrier in the event the CCS project is cancelled after the pilot phase or when unforeseen longer term downtime occurs. Based on the required carrying capacity, typical dimensions of the needed vessel are given below.

Table 2-6 Typical vessel dimensions

VESSEL	35,000 m³ (port to port)
LOA (Length Over All), m	227
B (Beam), m	33
D (Depth), m	18.5
T (Draft), m	11.9
DWT (Dead Weight Tonnes), t	43,210
Speed, kts	16

Cargo containment will be provided by independent Type C (IGC-Code) tanks, the exact number and sizing of these pressure vessels is subject to further engineering. The tanks will allow for certain pressure and temperature conditions, designed as pressure vessels and insulated to reduce heat ingress.

2.4.9 Economic considerations, concept C1

In this section, the cost build up (investment and operational) for the ship alternative is given.

Depreciation mechanism for combined Carriers

The value of a combined tanker in LPG mode is determined by the price (on the market) of an LPG carrier of similar tank type, size (m³) and age (see Figure 9.1 1). The figure shows that during CO_2 transport the ships' value depreciates much faster against regular LPG transport.

Higher depreciation during CO_2 trade is caused by the requirement to depreciate CO_2 related investments during the CO_2 service contract lifetime. CO_2 related investments are for example DP systems and CO_2 onboard conditioning equipment and offshore discharge installations that allow for connection to the offshore infrastructures. In this Europe case for WP4.3 these offshore costs are excluded given the port to port nature of the chain.

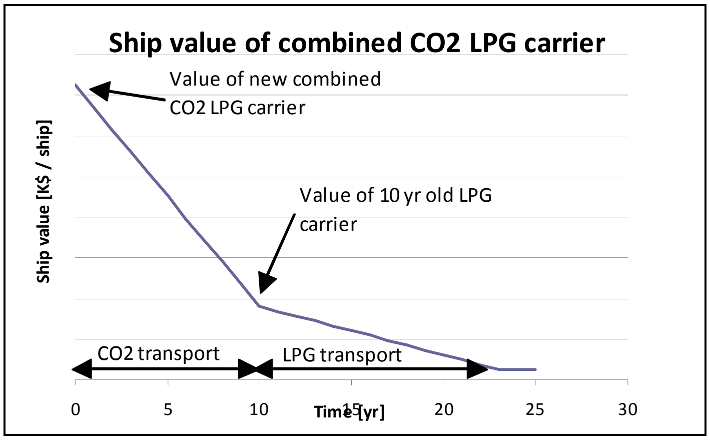

Figure 2-20 *Graphical representation of the ships' value in time for a combined CO_2/LPG carrier, which is utilized for CO_2 transport for the first 10 years and for LPG transport after 10 years.*

2.4.10 Cost estimates, ship transport concept C1

<u>Capital related expenses (CAPEX)</u>
Capex includes the vessel and its onboard conditioning equipment (for cold transfer and in transit needed equipment), a Weighted Average Cost of Capital (WACC) of 10% is used in the annuity based repayment profile for the asset financing. Building interest is assumed to be 5% of the total investment. The economic lifetime of the vessels is set at 25 years. Construction costs are based on 2010 price levels.

<u>Operational expenses (OPEX)</u>
Fixed OPEX: The fixed operational expenditures consist of crewing, maintenance, management, insurance and dry docking (bi annual surveys and dry docking every other 2-2.5 years is common market practice) costs. All costs are based on 2010 price levels.

Variable OPEX: The variable OPEX depends on fuel, port, other transit costs and the costs of consumables. It is mainly driven by the fuel consumption of the ship for propulsion. All costs are based on 2010 price levels.

In the following table one can deduce the costs of shipping CO_2 to and from the described locations.

Table 2-7 *Cost summary on a Euro per ton basis*

	35,000 m³
Annual Volumes [mmtpa]	3.0
Investments [Mill. EUR]	65
OPEX Fixed [EUR/t]	0.85
OPEX Var [EUR/t]	3.40
Total OPEX cost [EUR/t]	4.25

Fuel used here is HFO (USD550/t); given strict emission rules in reality fuels used will be either MDO or even LNG. EUR to USD conversion is taken at 1.35.

2.4.11 Onshore cost estimates, concept C1

Assuming the liquefaction, intermediate storage and loading/offloading alternatives described above, cost estimates for the onshore systems are given in the below tables. OPEX in the current section and for the remainder of this report is based on the power price defined in Section 3.2.

Table 2-8 Liquefaction costs at Kingsnorth

Volume (Mt/yr)	CAPEX (M€)	OPEX (M€/yr)
3	91	28.3

Onshore storage at Kingsnorth is given as 1,5 X ship capacity, i.e. 52,500 m^3.

Table 2-9 Cost estimates for onshore storage facilities at Kingsnorth, including recondensating system

Storage capacity (m^3)	CAPEX (M€)	OPEX (M€/yr)
52500	112	2.5

Estimates for loading and offloading equipment at Kingsnorth and Teesside are assumed to be equal for all storage capacity alternatives, and set to:

- Capex: 9.5 M€
- Opex: 2% of Capex, i.e. 0.2 M€

Also at Teesside, intermediate storage facilities are necessary to allow for the relatively short discharge time. Buffer capacity is, however, not assumed necessary in this end of the ship transport chain, and the intermediate storage capacity is set equal to the ship capacity.

Table 2-10 Cost estimates for onshore storage facilities at Teesside, including recondensating system

Storage capacity (m^3)	CAPEX (M€)	OPEX (M€/yr)
35000	84	1.6

2.4.12 Scope and battery limits, concepts C2, C3

The scope for the description of the ship part of the transport chain described in this section is illustrated in the below figure. Compression to 75 barg at Teesside and Kingsnorth is described in Section 2.3.5.

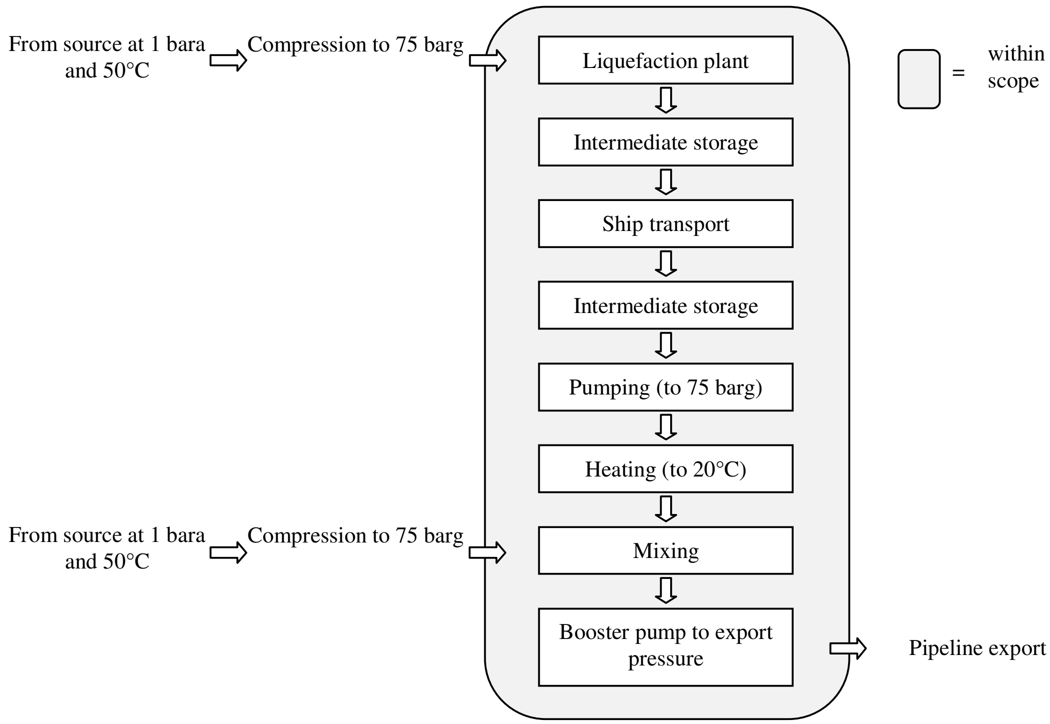

Figure 2-21 Definition of scope for the ship transport system described in this section

2.4.13 Logistical solutions, concepts C2, C3

CO_2 is most effectively transported by ship as a liquid at a temperature of about -50°C where it has a density of 1.15 t/m^3. The pressure has to be above the triple point pressure of 5.2 bara as the CO_2 will otherwise solidify at this temperature. In order to afford some margin against it (partly) solidifying, the actual transport pressure foreseen will be 7-8 bara. Such a condition is typical for the Semi-Refrigerated (Semi-Ref) hydrocarbon gas carriers which exist in large quantities. This means that the CO_2 carriers can (and likely will) be designed as combined CO_2 and Hydrocarbon gas carriers built in a competitive shipbuilding market. It can also provide the ships with a second hand value in case of an intended or unanticipated end of CO_2 utilization prior to the end of their life expectancy.

It should be noted that CO_2 can also be transported as a compressed gas. The advantage is that the energy consumption and cost of compression is significantly less than the cost of liquefaction. The weight of the pressure vessels required is however large, while the specific weight of the compressed gas is low, making this a solution that is advantageous only for distances significantly shorter than the 500 km considered here.

Ship transportation has a considerable benefit of size and it is obvious that the use of one ship large enough to handle the whole transport volume will be a basic alternative. The ship transport chain does however as shown above consist of not only the ships but also expensive intermediate storage, at least in the loading port and basically also in the discharge port. It is however possible to mix the cold liquid into the locally collected CO_2 gas stream during its compression. If the cold ship liquid could be delivered ashore more or less continuously it would be possible for the (valuable) cold to be economically utilized in the compression process, and to avoid or limit the discharge port intermediate storage facility. We have thus added a second logistic alternative using two ships where one ship performs a slow discharge until a short time before the second ship arrives.

The 3 Mt/yr is assumed transported during 350 days per year giving a daily production of 8571 t and an hourly production of 357 t.

All the ships are assumed to serve with a speed of 15 knots as the relatively short distance gives little benefit to a faster speed, but increases fuel consumption noticeably. They are however likely to be designed for a higher service speed of 16 knots or more for longer distance Hydrocarbon service.

The Teesside area has deep water with no tidal entry restrictions foreseen for this size of ship. The Medway estuary is however too shallow to allow entry at low tide. With a depth at low tide of about 7m, both ship sizes, (drawing as will be shown subsequently about 11.5 and 9 m respectively) and particularly the larger ship, will be forced to wait for favourable tide during some of the voyages.

The round trip calculation and resulting ship sizes are shown in the below table.

Table 2-11 Round-trip assumptions for two logistic alternatives C2 and C3

Alternative	C2	C3
No of ships	1	2
Offloading	Fast	Slow
Service Speed, kn	15	15
Voyage duration, h	2x18	2x18
Loading time, h	16	10
Discharge time, h	16	36
Port Manoeuvring per R/T	14	10
Idle time reserve, h	14	4
Total Round-trip, days	4	4
Ship size, m^3	32000	16000

The ship size given is gross tank volume with 98% maximum allowable filling. A 5% ship size margin has been added as a reserve. As shown the one-ship alternative (C1) has a larger idle time margin that the 2 ship one but for the type of regular voyage foreseen, whole day round-trips are considered to have significant advantages. Additional reserves in case of weather or other interruptions exist for both ship sizes in the potential to increase speed up to the design limit.

For the one-ship alternative there will be a need for storage capacity more or less equivalent to ship capacity in both ports. For the slow discharge two ship alternative (C2) a much reduced storage capacity covering in principle the 12 hours assumed from the time of one ship leaving to the time of the next ship arriving will be sufficient.

2.4.14 Liquefaction and storage in loading port, concepts C2, C3

Liquefaction of the CO_2 is assumed accomplished by a simple process of pressurizing, condensing and depressurizing. The temperature is controlled by the pressure. Between 20 and 40% of the CO_2 condensate/dense phase will flash during depressurization and has to be recompressed. The process is shown in the below figure.

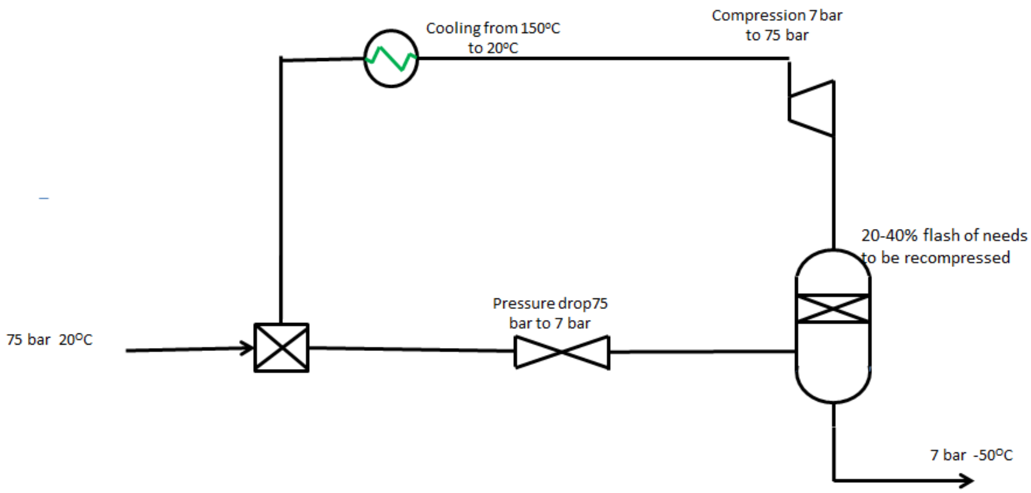

Figure 2-22 Principle of liquefaction process

The liquefaction process is designed using commercially available simulation tools (HYSYS and ProVision). The liquefaction plant delivers CO_2 at 7 bara and -50°C to the storage tanks. The input parameters are assumed to be a pressure of 75 bar and a temperature of 20°C. The water content should be lower than 50 ppm before liquefaction.

Power need for this example system is 42 kWh per ton CO_2.

The liquid CO_2 will be produced to storage tanks awaiting ship arrival. In principle a storage volume of about the same size as the ship has been assumed. Storage tanks are assumed to be located onshore. It should be mentioned that storage tanks situated on a floating barge may be a cost effective solution, however this very much depends on local conditions and have not been further considered here.

During previous studies the optimal size of storage tank was found to be approximately 5 000 m^3, see the figure below.

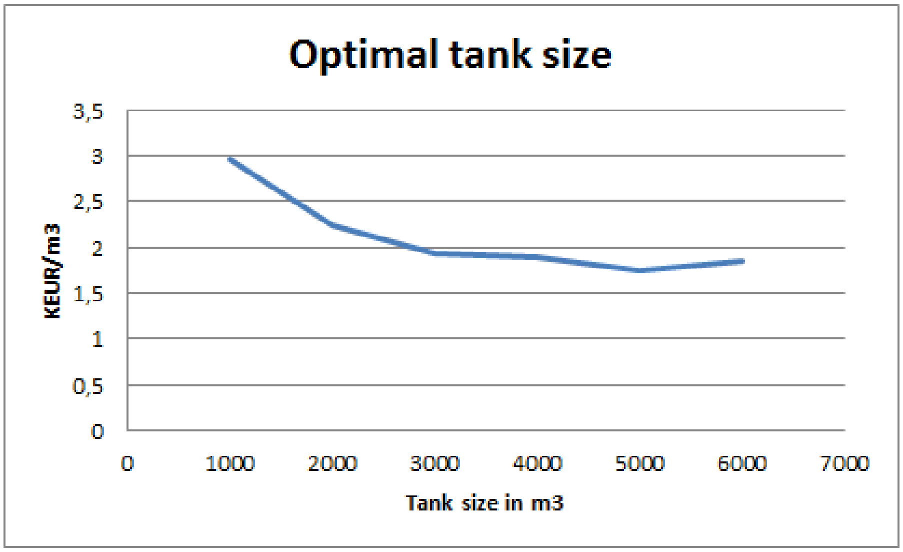

Figure 2-23 Optimal tank size

The equipment cost has been calculated in Aspen Icarus PM and multiplied with an installation factor. The horizontal 5000 m^3 tanks have 10.5 meter diameter and are 60 meters long. The tanks are insulated.

The ships(s) will be loaded and discharged via fixed loading/discharge arms of the Chicksan type. There will be two pipelines; a liquid line and a vapour return line. It is assumed that these are arranged 'piggy-back' on one loading arm.

2.4.15 Ship design and operation, concepts C2, C3

Semi-Ref ships are equipped with horizontal pressure vessel type cylindrical tanks. The tanks will be designed for -55°C and a pressure of about 8 barg. The cargo is assumed to be loaded at maximum 6 barg and transported at a pressure up to 7 barg. The tanks will be insulated sufficiently to reduce the heat ingress to a level where the heat leak causes only a minor increase in pressure over the duration of the voyage. A pressure increase of about 1 bar is likely to allow operation for 7 to 10 days without the need to release any CO_2. (It should be noted that in case of accidental voyage interruptions causing the cargo to remain onboard over a period longer than this, the only issue is the cost of the emission of a limited volume of gaseous CO_2 until the cargo can be discharged as intended). It is thus not foreseen to be necessary to equip the ships with a recondensation plant. They should however be designed with space available for retrofitting of such a plant in case of conversion to carriage of hydro-carbon gases.

The design of semi-ref ships is primarily determined by the need to accommodate the cylindrical tanks. These will normally be arranged in two rows, and the ship designs are foreseen to be approximately as shown in the following table.

Alternative	C2	C3
Ship size, m^3	32000	16000
LOA (Length Over All), m	220	168
B (Beam), m	33	29
D (Depth), m	18.5	15
T (Draft), m	11.5	8.5
DWT (Dead Weigth Tonnes), t	39000	19500

Figure 2-24 Approximate main dimensions of ship size alternatives considered

The ships will be equipped with both a liquid loading/unloading line and a vapour return line. The first voyage will start by loading a small amount of liquid and spraying it into the tank atmosphere for a controlled cool-down of the tanks. Initially the vaporized CO_2 will have to be released to the atmosphere, after the tank atmosphere is sufficiently low on other gases the vapour will be returned ashore to the liquefaction plant. During unloading the emptied tank volume will be filled up as far as required to keep the pressure, from ashore through the vapour return line. During the return voyage a small quantity of liquid cargo (heel) will be kept in order to limit the temperature and pressure increase and if necessary cool down the tanks prior to arrival in loading port in order to resume next loading. The cooling process will thus only be required whenever the tank atmosphere has been purged for inspection or repair, normally only in connection with dry-docking every 2.5 years. A detailed estimate of heat leak, pressure and temperature increase during loaded voyage as well as return voyage and the amount of cargo heel required for temperature control will be performed at the ship design stage.

It should be noted that some potential impurities in the liquid gas loaded, such as by nitrogen, will tend to vaporize faster than the CO_2 itself, causing over time an enrichment of impurity in the vapour phase. This may be sufficient to require the release into the atmosphere of an amount of impurity-rich CO_2 gas from the tank atmosphere at regular intervals. The quantities released will completely depend on the purity of the gas loaded but are assumed to be limited. Anyway the main consequence will be the cost of the resulting CO_2 emission.

2.4.16 Storage and unloading facilities at Teesside, concepts C2, C3

The two logistic alternatives have significantly different requirements for intermediate storage at Teesside. For the large ship with fast discharge, storage capacity equivalent to ship size or more is required. For the smaller ships storage for 12 hours production is in principle sufficient.

The process in the discharge port consists primarily of pumping the liquid up to about 75 bar, i.e. above the critical pressure of the CO_2. At this stage it is in the dense phase and can be mixed with the locally sourced CO_2 at a suitable compression stage. Mixing of 357 t/hr cold CO_2 at 75 bar and at -49°C, with 476 t/hr gaseous CO_2 at about 75 bar and more than 100°C, gives a mixed temperature of about 30°C, which should be suitable for further compression (pumping dense phase) to pipeline pressure. The main process facilities for the two alternatives are shown in the figures below.

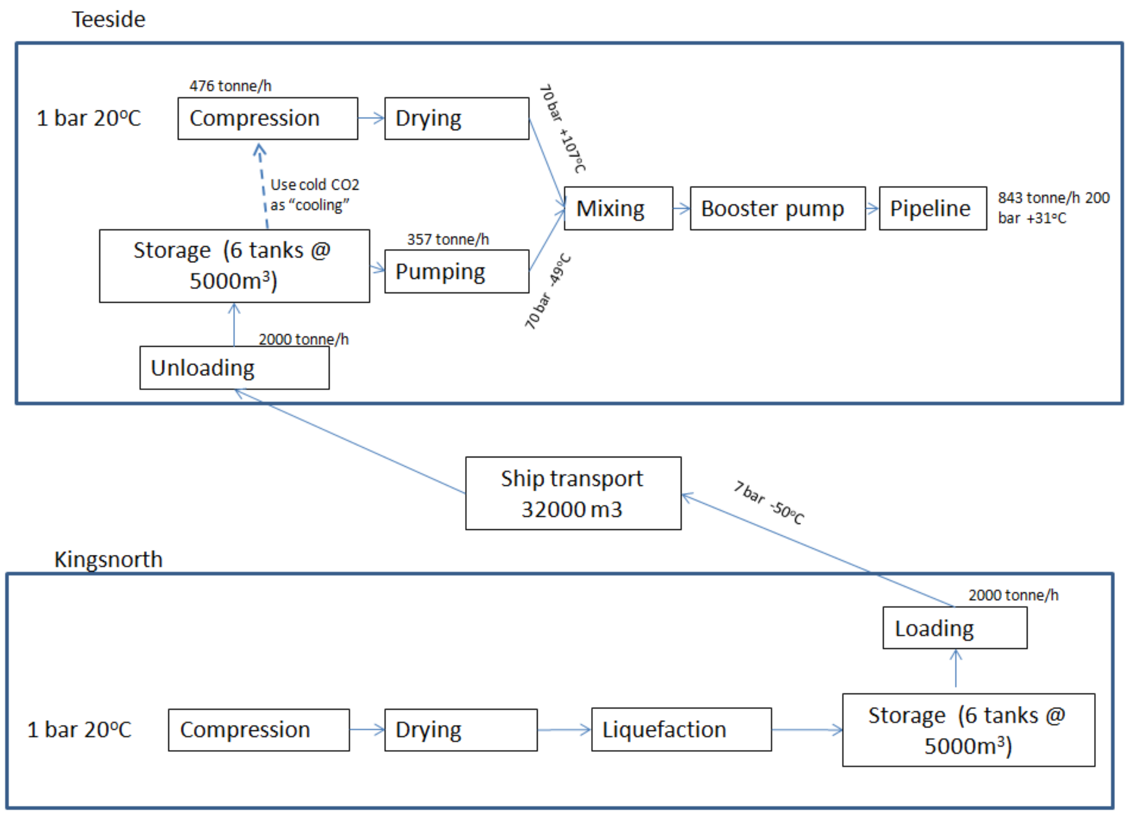

Figure 2-25 Facilities required for one large ship

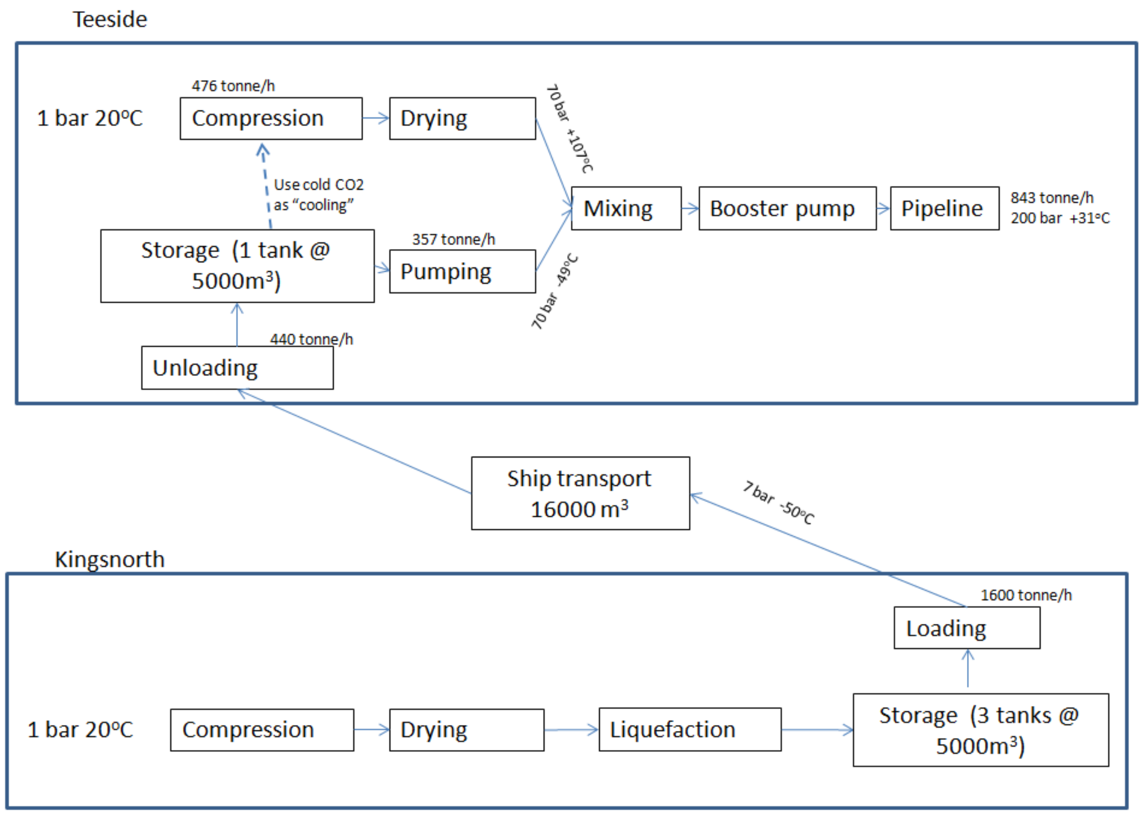

Figure 2-26 Facilities required for 2 smaller ships

In the below tables are specifications for these facilities given.

Table 2-12 Specifications for the onshore storage facilities in Kingsnorth and Teesside

In Kingsnorth	**One big ship**	**Two small ships**
Minimum storage (ship size)	32000	16000
Storage on ship (during loading)	5712	3570
No of tanks	6	3
Total storage (in tanks)	30000	15000
Total storage	35712	18570
Storage factor (ship size/total storage)	1.12	1.16

In Teesside	**One big ship**	**Two small ships**
Exported during unloading	5712	12852
Storage needed	26288	3148
No of tanks	6	1
Volume storage	30000	5000
Total storage (ship + tanks)	35712	17852
Storage factor (ship size/total storage)	1.116	1.116

Total (Kingsnorth and Teesside)	One big ship	Two small ships
Total no of storage tanks	12	4
Cost of each storage tank k€	8 706	8 706
Total storage cost k€	104 476	34 825

Combining the cold CO_2 with the cooling demand in the CO_2 compression

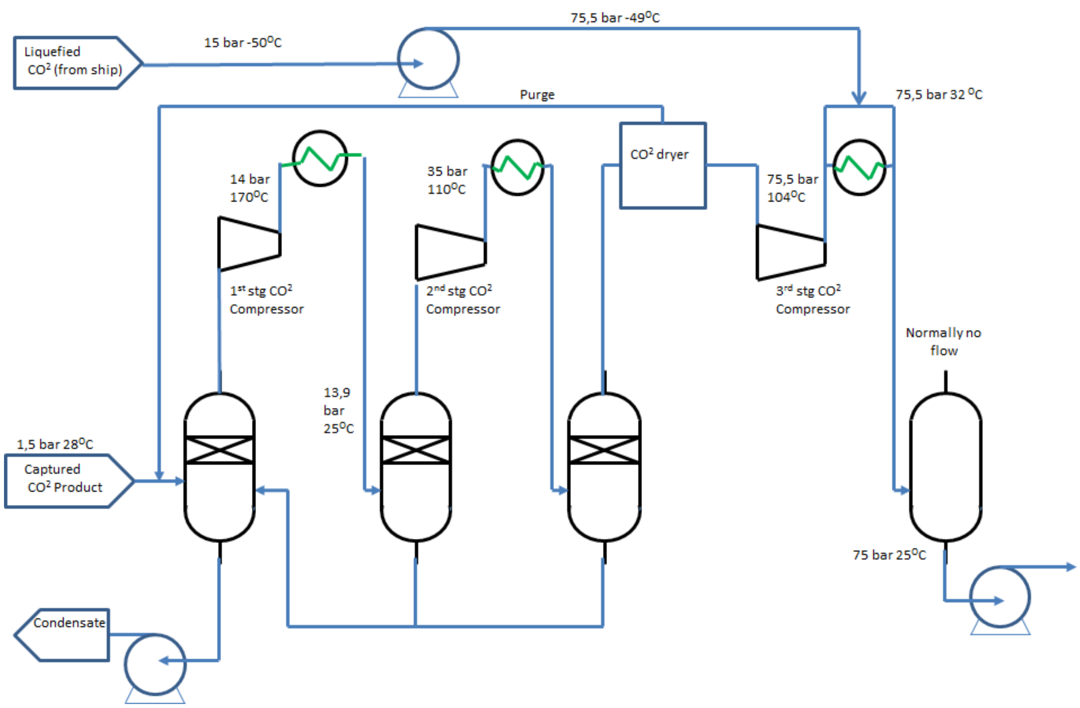

Figure 2-27 Process diagram showing the pumping of Liquid CO_2 and the mixing with gaseous CO_2 being compressed to pipeline pressure

This above figure describes how liquefied CO_2 can be most effectively introduced into the compression train in Teesside. The cold CO_2 is used for inter-stage cooling during compression of the local CO_2, improving the efficiency of this process. It also removes any need for heating the cold CO_2 before injecting it into the export pipeline.

2.4.17 Cost summary ship concepts C2, C3

General assumptions
The cost figures are intended to reflect 2010 prices. For resources likely to be sourced in USD, a conversion rate of 1.4 USD/EUR is assumed.

For the purpose of obtaining annual as well as per ton costs all capital expenditures are converted to an annual cost or annuity based on a weighted average cost of capital of 8%, and an investment lifetime of 40 years. 40 years may seem high but the type of facilities covered here, including the ships, may well be operated safely and effectively for a period of 40 years as long as this is considered both in their design and in the maintenance decisions taken during their lifetime.

Liquefaction
The liquefaction process costs include all equipment, installation and required building space but no ground purchase cost.

The operating expense includes a provision for purchase of electricity at a rate of 0.085 €/kWh, assumed to be a typical off the net price. In this case the electricity would however be obtained directly from the power station at what could be assumed to be a lower price. OPEX also includes operators, maintenance and cooling water.

Table 2-13 Cost estimates for liquefaction, concepts C2, C3

	Alt C2	**Alt C3**
CAPEX M€	38.1	38.1
OPEX M€/yr	15.0	15.0

A table showing the main cost items considered is found in Section A2.

Intermediate storage and equipment in loading port
The size of storage required is described above. Costs include both Capex and OPEX. Ground purchase costs are not included.

The availability of quay space is assumed covered by the port costs included in the OPEX. A Chicksan loading arm with installation and piping ashore has been included in the cost estimate.

Table 2-14 Cost estimates for intermediate storage and equipment in loading port

	Alt C2	**Alt C3**
CAPEX MEUR	53.7	27.6
OPEX MEUR/year	2.1	1.1

Ship(s)
The ships are assumed to be ordered in the competitive international shipbuilding market which makes it likely that they end up being built in the Far East. For political reasons it may be decided to build in Europe which would likely increase costs above those given here. In addition to shipbuilding contract prices the CAPEX given includes provisions for pre-delivery capital and design/inspection expenses. It should be noted that CCS operators are likely not to invest in any ships themselves, but to hire them from ship-owning companies on long term Time/Charters (T/C). Long term T/C's with highly bankable entities such as public utilities are likely to obtain very competitive offers from ship-owners.

The fuel consumption given is based on general estimates of likely consumption for propulsion as well as for pumping and general electric load onboard. It is assumed that ship transport in the EU area is likely to be required to use either Marine Diesel Oil (MDO) or LNG at the time any such project materializes. The fuel price used here is a typical present price MDO of 750 USD/t which is if anything likely to be low in the long term. LNG may have a similar or lower price per calorie but will entail noticeable extra investments not considered here.

The remaining Operation and Maintenance expenses consist of 3 major parts: Port costs, Crew costs and other O&M expenses.

Port Expenses are based on typical port expenses in European ports. Standard rates are assumed negotiated down due to the regular and very frequent nature of the service. Port costs are assumed to cover the provision of quays, mooring dolphins, and any required dredging which is thus not covered in intermediate storage and equipment costs in loading port (described above) and discharge port (described below).

Crew costs are based on international crews of 14-16 people. Local or EU crews are likely to be more expensive but for the regular service foreseen it might be possible to find alternative solutions with smaller local crews alternating frequently and backed by shore maintenance resources that have a competitive cost.

The remaining O&M expenses, often known as Fleet management costs, include insurance, victualing, repairs and drydocking, spare parts and all consumables other than fuel.

Table 2-15 Cost estimates for ship(s) concepts C2, C3

	Alt C2	**Alt C3**
CAPEX MEUR	62.0	78.0
OPEX MEUR/year	9.2	12.3

Intermediate storage and equipment in discharge port

The storage capacity required varies as shown previously very much dependent on the choice of one or two ships. As shown in the cost summary this difference is sufficient to result in the two ship alternative being the totally most cost effective solution.

The process includes the total compression/pumping of the ship transported volume up to an assumed pipeline pressure of about 200 bar. It is likely possible to combine the equipment required for this with the equipment intended for the gas compression in such a way that the total expense is reduced somewhat.

Table 2-16 Installations onshore handling CO_2 from Kingsnorth, concepts C2, C3

	Alt C2	**Alt C3**
CAPEX MEUR	78.4	26.2
OPEX MEUR/year	3.6	1.6

After mixing the two streams, the total flow (843 t/hr) has to be pumped (dense phase) from 75 bar to pipeline export pressure.

Table 2-17 Cost estimates for booster pumps from 75 bar to export pressure

	Alt C2	Alt C3
CAPEX MEUR	19.6	19.6
OPEX MEUR/year	3.3	3.3

2.4.18 Cost summary tables, ship concepts

Liquifaction	Alt C2	Alt C3
CAPEX M€	38	38
Annuity k€/yr	3 209	3 209
Energy Price €/kWh	0.085	0.085
Energy consumption kWh/yr	130 605 242	130 605 242
Energy cost k€/yr	11 101	11 101
Other OPEX k€/yr	3 902	3 902
Annual cost k€/yr	18 213	18 213

Storage and port facilities Kingsnorth	Alt C2	Alt C3
CAPEX M€	54	28
Annuity k€/yr	4 524	2 325
Energy Price €/kWh	0.085	0.085
Energy consumption kWh/yr	0	0
Energy cost k€/yr	0	0
Other OPEX k€/yr	2 149	1 105
Annual cost k€/yr	6 673	3 430

ShipTransport	Alt C2	Alt C3
CAPEX M€	62	78
Annuity k€/yr	5 219	6 566
Fuel Price €/t	535	535
Fuel consumption kt/yr	8,6	11
Energy cost k€/yr	4601	5885
Other OPEX k€/yr	4 608	6 427
Annual cost k€/yr	14 428	18 878

Storage and port facilities Teesside	Alt C2	Alt C3
CAPEX M€	78	26
Annuity k€/yr	6 597	2 207
Energy Price €/kWh	0.085	0.085
Energy consumption kWh/yr	5 915 234	5 915 234
Energy cost k€/yr	503	503
Other OPEX k€/yr	3 135	1 048
Annual cost k€/yr	10 234	3 758

CO_2 booster pump	Alt C2	Alt C3
CAPEX M€	20	20
Annuity k€/yr	1 652	1 652
Energy Price €/kWh	0.085	0.085
Energy consumption kWh/yr	29 241 975	29 241 975
Energy cost k€/yr	2 486	2 486
Other OPEX k€/yr	785	785
Annual cost k€/yr	4 922	4 922

Total	Alt C2	Alt C3
Total CAPEX (M€)	252	190
Total Annuity k€/yr	21 201	15 959
Total Energy cost	18 691	19 975
Total other OPEX k€/yr	14 579	13 267
Total annual cost k€/yr	54 471	49 201
€/tonne CO_2	17.2	15.5

As shown above the two ship alternative appears to be the most cost-advantageous solution. With total costs about 10% lower than the one ship alternative the difference is considered to be quite significant.

As mentioned previously it may be possible to use barge mounted storage facilities which would enable complete fabrication in low cost areas and hopefully lower total installed cost. It is not considered likely that this will remove the cost advantage of the two ship solution.

It should also be noted that the ships fuel consumption will produce CO_2. The amount produced is however not corresponding to more than about 1 % of the CO_2 transported, and thus not significant in evaluating overall capture efficiency. The environmental footprint of the electricity consumed depends completely on how that electricity is produced.

3 ECONOMIC EVALUATIONS

In the current section, the economic analyses for the transport system in the European case is evaluated.

Being a case study, cost estimates should be as representative for the actual technical solution as possible. Within the budgets and resources allocated for the CO2EuroPipe project, specific engineering is, however, not possible. Thus, the cost estimates are derived from relevant similar studies performed by the participants within WP4.3. Simulations and evaluations with respect to obtaining as relevant technical and cost data have to some extent been performed and according to the evaluation of the participating companies within WP4.3, such data are to a large degree relevant, thus in a good way making the below cost estimates relevant for the case described in this report.

3.1 Pipeline systems

3.1.1 Cost estimate assumptions

The following definitions and/or assumptions have been adopted in establishing the CAPEX costs for the pipeline systems:

- Total technical cost includes technical allowance, pre, detail & follow on engineering
- Contractor Management & Administration is taken as 3% of the total technical cost
- Commissioning is taken as 2,5% of the total technical cost
- Third Party Verification and Studies is taken as 2% of the total technical cost
- Operator Project Team & PSC Management is taken as 4% of the total technical cost
- Insurance assumed to be 3,5% of total technical cost
- Contingency is taken as 25% of all costs
- No modifications at the platform in the Dutch sector are included
- Template & control umbilical are not included
- Landfall includes onshore facilities within 200mts of landfall, CO_2 vent tower & vent piping (400m) and utilities to edge of onshore facilities plot
- All cost are based on S-lay pipeline installation methods
- All pipelines require concrete coating
- All estimates are based on mid 2010 prices

3.1.2 Cost estimates, pipelines and compressors

Cost estimates for the Rotterdam and Teesside pipelines are given in the below table. All costs are given in 2011 currency. The costs related to the Rotterdam pipeline does not include installation of the pipeline section from shore in Rotterdam to the depleted gas field at the end of this pipeline that is installed 20 years before the pipeline is extended to the Utsira storage location.

Description	Teesside pipeline [M€]	Rotterdam pipeline[4] [M€]
1. Contractor Management & Administration	16	20
2. Pipeline Material & Installation	483	644
3. Structures, Spools & Onshore - Material & Installation	33	7
4. RFO & Commissioning	13	16
5. Third Party Verification & Studies	10	13
6. Operator Project Team & PSC Management	21	26
7. Insurance	18	23
Sub Total	**594**	**749**
8. Contingency	149	187
Total Project Costs	**743**	**936**

Figure 3-1 CAPEX cost estimates for the Teesside and Rotterdam pipelines

Investment costs for the compressor alternatives are given in the below table. As it can be seen from the table, installation costs are the most significant part of the investment. Here it is assumed that the compressors are installed outside the areas requiring the most significant safety precautions with respect to installation methods.

Table 3-1 CAPEX for the compressor system in the pipeline alternatives. C1, C2 and C3 refers to the alternative ship concepts described in the above sections

	Required power [MW]	Capex [M€]	Installation[5] [M€]
Kingsnorth C2, C3	24.2	18.3	54.9
Teesside C2, C3	32.7	20.9	62.7
Teesside C1	67.8	46.4	139
Kårstø	41.1	24.0	129
Rotterdam	197.7	108	324

3.1.3 Investment profile and operating costs, pipeline

An offshore pipeline project in northern waters needs to be planned so that installation of the pipeline is performed between April and September ("lay season"). In addition, for long pipelines, it needs to be evaluated if the pipeline can be installed during one lay season, or if the installation work needs to be performed over two or more seasons. If the pipeline is not possible to install during one lay season using one lay vessel, an

[4] Includes only the pipeline segment from the end of the pipeline described in WP4.1 (i.e. from the location of the "furthest away" depleted gas field on the DCS used for CO_2 storage) to the Utsira storage location.

[5] A factor of 3 is used to estimate installation costs for the compressors at Kingsnorth, Teesside and Rotterdam. This is lower than used for Kårstø, where high installation costs are expected due to the location within/adjacent to the gas processing plant area.

alternative approach may be to engage more than one lay vessel, implying that sections of the pipeline may be installed in parallel.

As a reference, it can be mentioned that the Langeled pipeline from western Norway to UK, which (at the time) was the longest large dimensioning offshore pipeline installed with a length of 1200 km and a dimension of 42” and 44” for the north-east and south-west sections of the pipeline respectively, was installed during two lay seasons. This was obtained using more than one lay vessel in parallel.

For the Teesside and Rotterdam pipelines described above, it is assumed that the pipelines may be installed during one lay season.

For the dimensions relevant in this case study (20” and 30”) only the S-lay method is applicable (see the Kårstø report for a further description of lay methods). That implies that a typical investment profile for an S-lay pipeline project can be used, and for the European case such a profile is given in the below table.

Table 3-2 Typical investment profile for a S-lay pipeline project

General investment profile (% each year)	IY minus 2 years	IY minus 1 year	Investment year (IY)
	13 %	31 %	56 %

If we assume that the Kårstø pipeline was to be installed in the lay season of 2016, i.e. ready for operations in October 2016, the Teesside pipeline will, according to the design basis assumptions in section A1.1, be installed in lay season 2019, i.e. ready for operation in October 2019. It is also defined that start of CO_2 injection in the depleted gas fields on the DCS will start the same year as the Kårstø pipeline is in operation, i.e. in year 2016, and that the extension of this pipeline up to Utsira will commence 20 years thereafter, i.e. in year 2036. This will result in the investment profile given in the below table.

Table 3-3 Example: Investments for the pipelines in the European case. Investment year is specified in brackets after each figure

	Pipeline cost (M€)	Investment profile (M€)		
		Year 1	Year 2	Year 3
Kårstø	269	35 (2014)	83 (2015)	151 (2016)
Rotterdam	936	122 (2034)	290 (2035)	524 (2036)
Teesside	743	97 (2017)	230 (2018)	416 (2019)

Pre-operational costs

It may be expected that operation of CO_2 pipeline systems may be integrated into organisations already responsible for similar infrastructure operations, e.g. like oil or gas pipelines. Then, in addition to project activities associated with procurement and installation of the pipeline system itself, the organisation responsible for the operations of a CO_2 pipeline will need to establish procedures and systems to integrate this into its other activities. Such activities will include:

- Integration of the CO_2 pipeline system into existing control room systems related to monitoring and control of the pipeline, including development of pipeline modelling and simulation tools
- Spare parts administration and implementation of a repair philosophy
- Establishment of maintenance programmes
- Prepare the inclusion of the CO_2 Transport pipeline into existing HSE-related documentation, such as the Emergency Response Plan.
- Development of communication systems and procedures

Costs for such pre-operational preparations are to a large extent independent of the investment levels for the pipeline itself, as the same systems are necessary for any pipeline, regardless of length or diameter. The costs are to some extent dependent of the requirements relevant within the operating organisation, and also to the degree of already implemented systems for similar operations (e.g. systems already installed for control and monitoring of oil and gas pipelines).

Assuming that the CO_2 pipeline is to be technically operated from a control room already prepared for operating oil or gas pipelines, typical pre-operational costs will be in the range of 2 to 4 M€, and can be assumed to incur in the final investment year (~75%) and the year before (~25%).

Operational costs
Operational costs for a CO_2 pipeline includes:

- Daily operations related to monitoring and control of the CO_2 flow in the pipeline
- Regular activities related to monitoring and control of the physical condition of the onshore pipeline, both externally and internally
- Performing analyses, planning of operational and other activities, administration and evaluating technology issues

Monitoring of the physical condition of the pipeline is typically performed in regular intervals, e.g. external monitoring of the onshore pipeline several times during the year, and internal monitoring of the offshore pipeline once every 5 to 10 years.

Assuming that the CO_2 pipeline is operated as an integrated part of several pipelines (CO_2, oil, gas), the OPEX for a pipeline as in the European case will be ~1.25 M€ every year, except for every 5 to 10 years, when an internal inspection is to be performed, for which the OPEX will be ~5 M€. In the calculations performed in Section 3.2 an average annual OPEX of 1,6 M€ is assumed. Annual OPEX for the alternative pipeline in this report will be the same, independent of diameter.

3.2 Cost estimates summary

In addition to the specific assumptions given in the above sections, the following assumptions are basis for the cost summary:

- No escalation is defined for the cost estimates, and all costs are given as Q3/2010, real currency.
- Annual discount rate is set to 7% for the Kårstø pipeline, and 8% for the other transport systems.
- Operating period for the transport system is up to, and including 2056. The remaining value of the transport system after 40 years is set to 0.
- The unit cost is given as the NPV(total costs over years up to 2056) divided by NPV(total volume over years up to 2056).

The discount rate for the Kårstø pipeline is based on the assumption that unit costs for using the transport system should reflect a risk similar to the one relevant for Norwegian gas transport systems. In these gas transport systems, the transport tariffs are based on a Weighted Average Cost of Capital (WACC) of 7% pre tax. Such level would normally reflect that there is assumed to be a confirmed income of the lifetime of the project. For the other pipelines, the 8% discount rate reflects similar rates that are used throughout the CO2EuroPipe project, and discussed within other reports.

The CO_2 transport network will have a high and continuous power demand. An appropriate power reference price is very important as the energy based compression costs make up a large percentage of the total costs for CO_2 transport through the network. In an assessment by ECN in The Netherlands [*ECN*] a power price scenario has been evaluated for different industry sectors. The power prices are based on Euros in the year 2000 ($€_{2000}$) and include energy tax but no VAT. Industry sectors as iron and steel, aluminium, base chemicals are most appropriate as a reference because of similar high demand and base load requirement. ECN arrives at 70 $€_{2020}$/MWh. Note that large power purchasers pay relatively little energy tax as a % of the power price in The Netherlands. Also, the transport costs, paid to the power grid operator, are relatively low. Inflation in The Netherlands between 2000 and 2010 was 23%[6]. Thus the 2020 power price based on 2010 Euros equals 86 $€_{2010}$/MWh. Note that D4.1.1. assumes 85 $€_{2010}$/MWh as reference power price, and for consistency this will also be used in the current report.

It is expected that the power price expectation for The Netherlands in 2020 will be close to the power prices in countries like the UK, Norway and Germany as power prices in NW-Europe will converge due to foreseen power infrastructure investments that increase the connectivity between countries (reference EC (2010b): Energy infrastructure priorities for 2020 and beyond - A Blueprint for an integrated European energy network, Communication from the Commission to the European Parliament, The

[6] http://statline.CBS.nl selection prijzen > consumenten prijzen

Council, The European Economic and Social Committee and the Committee of the Regions, Brussels, November 2010).

The cost summary for the network parts of the European case are given in the below table.

Table 3-4 NPV unit cost summary for the European case

		CAPEX	OPEX
Kårstø	Total	10.98	10.36
	Compressor	3.98	9.83
	Pipeline	7.00	0.53
Rotterdam	Total	5.45	5.25
	Compressor	1.72	5.19
	Pipeline	3.73	0.06
Teesside/Kingsnorth (C1)	Total	13.92	11.53
	Onshore Kingsnorth	2.26	3.76
	Ship	0.69	1.55
	Onshore Teesside (incl. booster pump)	2.96	6.03
	Pipeline	8.01	0.19
Teesside/Kingsnorth (C2)	Total	12.41	9.10
	Onshore Kingsnorth	1.78	4.16
	Ship	0.67	1.12
	Onshore Teesside (incl. booster pump)	1.96	3.64
	Pipeline	8.01	0.19
Teesside/Kingsnorth (C3)	Total	11.74	9.12
	Onshore Kingsnorth	1.50	4.04
	Ship	0.84	1.49
	Onshore Teesside (incl. booster pump)	1.39	3.39
	Pipeline	8.01	0.19

The NPV unit costs are further illustrated in the below figure.

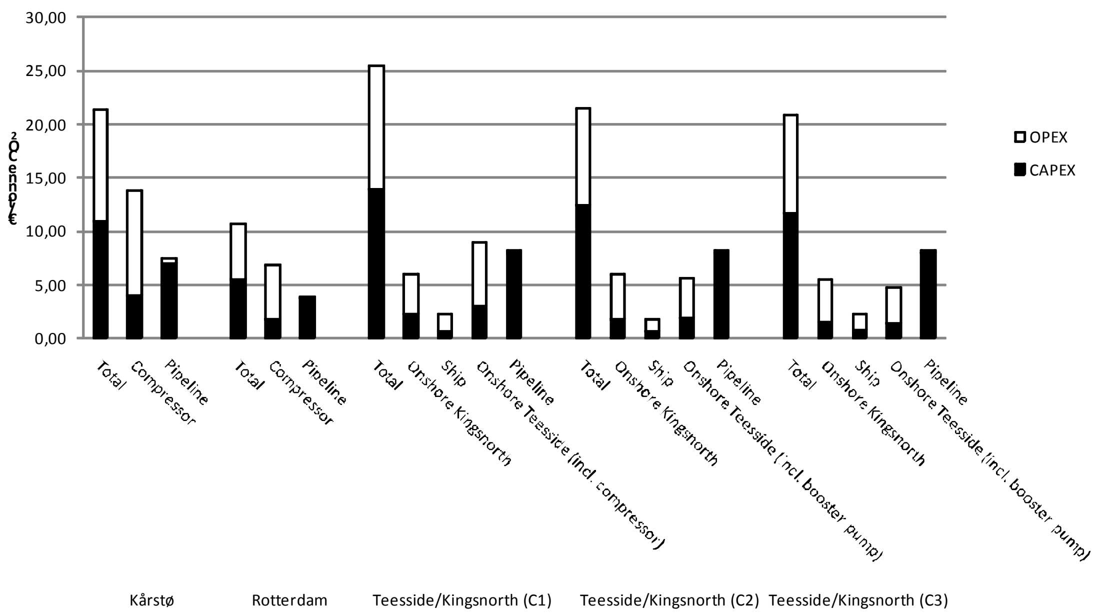

Figure 3-2 *NPV unit cost illustration for the European case. OPEX for the pipelines are small compared to the overall costs and thus barely visible*

If the network was considered as one integrated network with respect to unit costs, the total NPV for the network within the battery limits described in Section A1.2 is given in the below table and figure. In this case, ship concept C3 is assumed.

Table 3-5 *Total network NPV unit costs, assuming ship concept C3*

	CAPEX	**OPEX**
Total	11.54	9.55
Compression	2.82	7.33
Pipelines	7.74	0.26
Onshore systems	0.53	1.15
Ship	0.45	0.80

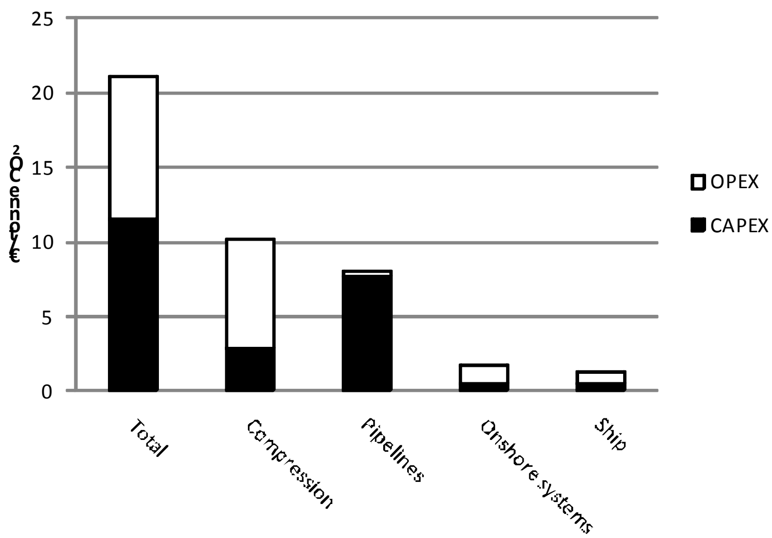

Figure 3-3 Total network NVP unit costs, assuming ship concept C3

4 COMMERCIAL ISSUES

The European case is defined as three CO_2 transportation projects from three different countries, all connected to a reservoir in the Utsira formation on the Norwegian continental shelf. The transportation systems are installed and will start operation independently. It is assumed that the onshore compression and conditioning facilities and pipelines will be owned and operated independently from each other.

It is recognised that the overall CCS chain comprises of far more costly and complex facilities than the transportation system. Neither the capture facilities nor storage are part of the scope for the present study. Hence the transportation system is based on a number of sources of CO_2 together with qualified storage facilities, with the latter being assumed to be at a location in the Utsira formation on the Norwegian continental shelf.

Legal, financial, organisational and commercial issues are further discussed on a general basis in a separate CO2Europipe report [*D3.3.1*].

4.1 The Kårstø case

In 2008 Gassco carried out an open season process to identify other CO_2 sources that might feed into the planned CO_2 pipeline from Kårstø. A group of nine private companies financed a mapping study of possible CO_2 transportation to develop Kårstø as a hub to feed into a CO_2 pipeline. Both pipeline and ship transportation were studied. None of the identified sources for CO_2 have matured carbon capture further, and there is currently no business driver for continuing this work.

Subsequently, the work towards an investment decision for the Kårstø project has been funded by the Norwegian Government.

The Kårstø project is based on qualification and development of an aquifer suitable for safe storage of CO_2 from the Kårstø project for at least 50 years. The Utsira formation has been identified and is being evaluated by the Norwegian authorities for such service. It is for the present European case study assumed that the aquifer is also suitable for storing all the anticipated CO_2 from the Rotterdam and Teesside projects in addition to the Kårstø projects, albeit the number of wells needed to inject the increased volume scenarios will be greater.

4.2 Commercial model for the execution of the Kårstø project

Provided both CO_2 capture for the Kårstø project is realised and other sources in the region are developing capture facilities, then an open season could be undertaken by an appointed operator of the CO_2 transportation system to attract users with a need for transportation of CO_2 to a qualified CO_2-storage site. If "owners" of CO_2 reserve and commit to pay for (on a "ship or pay" basis) sufficient capacity, a tariff could be calculated giving pipeline investors a defined return on their investment. This could be based on regulations enforced by the authorities, i.e. regulated third party access. The investment risk will thus to a large extent remain with the owners of CO_2.

The CO_2 owners could be the emitters of CO_2 and the Norwegian government for the Kårstø project or any combination thereof. Subsequent need for transportation will be handled in compliance with third party access rules in accordance with EU and national legislation. To what extent the Norwegian State will need or want to be an investor in transportation infrastructure remains open. It is assumed that an independent operator will be appointed and such operator will have the responsibility to operate and maintain the CO_2 transportation and storage facilities. Access to the transportation system will also require access to the storage so that one body managing both facilities may ease the access to storage for the owners of CO_2.

4.3 Commercial models for execution of the Teesside project

The Teesside project is for the export pipeline part of the project from Teesside to the Utsira formation similar to the Kårstø case, although the initial capacity is approximately double that of the Kårstø case, and the pipeline length is significantly longer. In all other terms the compression, transportation and injection are comparable and hence this aspect is not further described here.

The special features of the Teesside project is to collect and transport part of the CO_2 from other regions in the UK by ship. The shipping arrangements would also require storage and liquefaction for transportation in chilled and low pressure conditions before ship transport.

Organisationally shipping logistics is traditionally managed and operated by ship owners, whom undertake long term obligations with the product owners. Several commercial models are known to the industry and it is not anticipated that shipping CO_2 in large volumes (e.g. 3 million tonnes per annum in the Teesside case) requires any special arrangements. The CCS chain from capture by the industrial emitters at Kingsnorth will consist of the following: a local hub downstream of the capture facilities; liquefaction and storage facilities; offloading and metering facilities; special vessels, receiving and storage facilities at Teesside; compression, high pressure offshore pipeline system and finally storage reservoir at the Utsira formation. The CO2EuroPipe European case report covers the chain from the local hub in the Kingsnorth area through to the subsea injection template at the Utsira formation.

The emitters will seek to be relieved from their responsibility for the CO_2 emissions and collect the carbon credits as far up the CCS chain as possible. It is however not likely that the ship owners will be undertaking major risks and liabilities in the CCS chain, hence it would be likely that the emitters will have emission liabilities until the CO_2 is delivered at the receiving facilities at Teesside. Ship transportation of CO_2 will presumably only be competitive for transporting limited volumes of CO_2 into receiving hubs for injection into offshore storage through high pressure pipelines. The commercial arrangements could follow similar transportation models for petroleum products involving storage and shipping onboard special vessels. The challenges related to ship transport is not considered to be any more complex than the pipeline transport and the ship transport may be privately owned and operated based on similar arrangements as is practised for transporting petroleum products on ships. Traditionally that would mean the product owner holds the liability for any pollution as long as the product in onboard the ship. It is however challenging to envisage a CO_2 transportation system including shipping by special vessels based on fully governmental ownership or operations.

4.4 Commercial model for the execution of the Rotterdam project

The Rotterdam project is based on collecting European CO_2 in the Rotterdam area and ship CO_2 in high pressure pipelines initially to depleted gas reservoirs on the Dutch continental shelf for later to expand the network to the Utsira aquifer when the Dutch reservoirs are filled up. This is anticipated after twenty years of injecting into the depleted gas reservoirs.

The first phase is covered by the Rotterdam case study [*D4.1.1*]. The injection and storage service are in this phase assumed into depleted gas fields on the Dutch sector and the transportation system would consist of compression facilities in Rotterdam and high pressure pipelines to the applicable depleted gas fields and oil fields that benefit from CO_2 for EOR. These oil fields lay outside the DCS but along the pipeline trajectory from Rotterdam to the Utsira formation. Phasing in time of CO_2 storage in depleted gas fields versus CO_2-EOR in pressurized oilfields at large scale will depend more on economics and required timing (related to abandonment of gas fields and productive oil field life) than proximity of field location to Rotterdam.

The compression and transportation system would be developed and installed in two or more phases. The owners of the pipeline system could be state owned or held by private entities provided the investments are secured with sufficient commitments by the users (and the authorities).

The first 20 year period is regarded as a separate system and is described in the Rotterdam case study [*D4.1.1*]. The extension to the European case connecting to the CO_2 storage will be based on the transportation system developed for the initial phase including compression facilities and pipelines to the extent they are suitable. Extending the CO_2 transportation system to the aquifers on the Norwegian continental shelf will include upgrading or new installation of compressor facilities at Rotterdam, installing pipeline from the sink and subsea connections to the existing CO_2 pipelines on the Dutch sector. All costs associated therewith needs to be recovered through the tariff system ensuring a reasonable return on investments.

The transportation could be organised in line with the existing Dutch natural gas grid as a regulated and currently state owned service, or another suitable model based on similar transportation of natural gas and petroleum products in pipelines.

Gas Transport Services B.V. (GTS) is the independent operator of the national gas transmission system in the Netherlands. GTS is a subsidiary of the Dutch Gasunie, a wholly state owned enterprise, and is responsible for management, operation and the development of the national transmission grid.

Installation and operations of the transportation system from Rotterdam in the Netherlands to the Utsira formation on the Norwegian continental shelf requires cross border regulations to be in place. The natural gas pipeline from Norway to Europe crosses several member states' continental shelves and the responsibilities between the countries are regulated in a treaty for each pipeline. Such arrangements would also be envisaged for the CO_2 transportation pipelines. The regulation between the EU member states utilising the aquifers on the Norwegian shelf and Norway as the host state for deposits of CO_2 is an issue that will need regulations related to the future liabilities for CO_2 deposited in the subsea reservoirs. The scope of work for CO2EuroPipe with a focus on the transportation issues means that the commercial requirements related to storage is not covered in this study.

CO_2 shipping using special vessels may play a significant role in early development or feasibility testing of CO_2 injection for EOR and CO_2 storage purposes. A field may start testing injection by shipping CO_2 to a temporary injection point and allow early production and full scale testing prior to developing pipeline systems to certain fields at a distance from existing CO_2 infrastructure.

4.5 CO_2 for enhanced oil recovery purpose

Developing a network like the European case for CCS purposes will also make CO_2 available for enhanced oil recovery (EOR) by CO_2 injection in oil producing reservoirs. Hence a market for CO_2 injection may emerge on the Dutch, British and Norwegian sector. The scope of work for the CO2EuroPipe project does not include assessing the potential values and associated risks in developing existing or depleted oil fields for EOR by CO_2 injection. There are however other studies ongoing (the ECCO project) covering such issues. ECCO and CO2EuroPipe work together in the Rotterdam test case to quantify the synergy between CCS and CO2-EOR.

Development of CCS on the scale identified in the CO2EuroPipe project will make CO_2 available in larger volumes than previously envisaged, hence the EOR potential may be underestimated. Previous studies on the Norwegian sector have however concluded that the costs for modifying existing platforms to handle CO_2 is a major issue when introducing EOR based on CO_2 injection to existing fields. Development of new fields or installations to redevelop abandoned fields are other issues which could increase oil recovery and bring incremental value to subsea developments. This report does not describe the potential further as the issue is outside the scope of the CO2EuroPipe project members.

Any use of CO_2 for EOR could introduce significant values and might require other commercial models than described herein to equitable distribute the generated values between the oil producers and the investors in the CCS chain.

5 CONCLUSIONS AND RECOMMENDATIONS

This report describes a case related to transport of CO_2 from Kårstø in Norway, Kingsnorth and Teesside in UK and Rotterdam in the Netherlands. The case is used to illustrate technical solutions and associated CO_2 transportation costs. The results from the studies are valid for this specific study, but may also give a good indication of how logistics and costs can be for comparative systems.

Both transportation through high pressure subsea pipeline and as liquid CO_2 onboard special vessels are evaluated in the case study. Both concepts are assumed technically feasible for its purpose, but some issues remain subject to technology qualification processes, either as part of future projects, or as part of the R&D activities currently ongoing for CCS. With respect to offshore pipeline transportation, this is in particular related to noise reduction during depressurisation, corrosion effect of impurities in the CO_2 stream and the risk of propagating longitudinal fractures.

All of these issues are considered to be manageable through qualified engineering, and therefore do not represent potential showstoppers for the transportation of CO_2, and construction of CO_2 pipeline and ship transport systems as described in this report are considered feasible today, assuming some conservative assumptions related to these issues.

Transport of CO_2 will to a large extent be performed in systems similar to those used for existing transportation of natural gas and petroleum product. CO_2 transportation requires stricter control of water and impurities as otherwise the mix of CO_2 and free water will form carbonic acid that will have a corrosive effect on the carbon steel materials within short time. However using corrosion resistant materials is generally not considered to be necessary for the pipeline infrastructure although control of the level of water and other impurities is essential.

Ship transport of CO_2 is a mature business, which has been operated for nearly 20 years on a small scale in the food industry. Technology for scaling up to a large scale transport vessels is considered available.

It should be noted that liquefaction and compression is included in the transport cost estimates in this report.

Maturing of storage and CO_2 capture facilities require transportation of CO_2 from capture locations to storage location(s) in the North Sea. Development of such transportation infrastructure could be organised similar to established regimes for upstream infrastructure for gas and petroleum products, and each of the applicable EU Member States (and Norway) has developed such regimes that are recognised by the industry.

Development of a commercial CO_2 transportation infrastructure will require owners of CO_2 undertaking payment commitment for a period of time sufficient to make a financial recovery of the investment at a reasonable rate of return. If such a payment obligation is secured, the organisation of the ownership and operation could follow the model from the petroleum transportation business. A joint venture of owners (with or without state participation) could be formed, and an independent operator could also be appointed.

Cross-border infrastructure for CO_2 transportation raises issues of pipeline jurisdiction including questions of safety regulation, metering and third party access. As regards the third party access rules, it is important that rules pertaining to the storage site and the pipeline(s) are aligned, because the latter is dependent on the former. Such issues can be dealt with in bi- or multilateral instruments such as treaties.

Design of offshore high pressure pipelines is based on mature and proven technology. There are certain technical issues for offshore CO_2 pipelines that need qualification programmes. One of the more critical issues is related to noise levels for shut downs or failures leading to pressure relief through safety vents. A second area is defining acceptance levels for impurities. The offshore systems including onshore pressurisation is however assumed sufficiently matured to be regarded as feasible and realistic cost estimates are available for the CO_2 transportation chain.

The cost summary for the cases described in this report are given in the below figures.

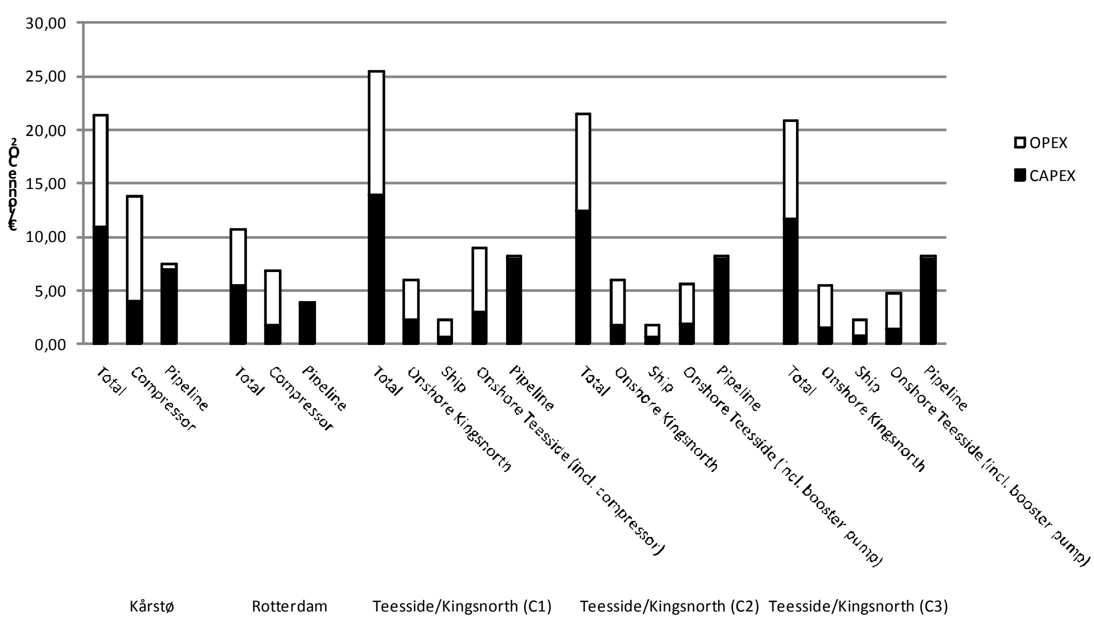

Figure 5-1 *NPV unit cost illustration for the European case. OPEX for the pipelines are small compared to the overall costs and thus barely visible*

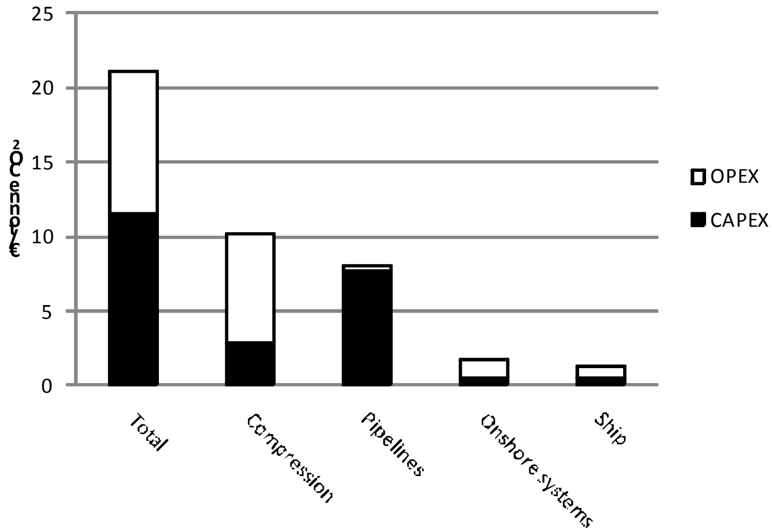

Figure 5-2 Total network NVP unit costs, assuming ship concept C3

6 REFERENCES

[D2.2.1] CO2Europipe, *Development of a large-scale CO_2 transport infrastructure in Europe: matching captured volumes and storage availability*, CO2Europipe consortium, April 2011.

[D3.1.1] CO2Europipe, *Transport network design and CO_2 management*, CO2Europipe consortium, July 2011.

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[D4.1.1] CO2Europipe, *Development of CCS in Rotterdam*, CO2Europipe consortium, August 2011.

[D4.3.1] CO2Europipe, *Kårstø Case*, CO2Europipe consortium, May 2011.

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A1 DESIGN BASIS, FUNCTIONAL AND OPERATIONAL REQUIREMENTS FOR THE EUROPEAN CASE

This section defines the design basis as well as the functional and operational requirements for the European case (the CO_2 transportation system from Kårstø, Teesside/Kingsnorth and Rotterdam to the storage site) in WP4.3 in the CO2EuroPipe project.

A1.1 Project schedule

For the European case the following dates are assumed for start-up of operations;

- Kårstø pipeline: 1 Oct. 2016
- Teesside pipeline: 1 Oct. 2019
- Kingsnorth ship transport: 1 Oct. 2019
- Rotterdam extended pipeline: 1 Oct. 2036

A1.2 Battery limits

Battery limits are defined upstream and downstream of the transportation system, i.e. at Kårstø, Teesside/Kingsnorth, Rotterdam and at the Utsira formation.

A1.2.1 Kårstø

The battery limit between the upstream facilities and transport facilities at Kårstø is at the flange downstream of a metering system and shutdown valve at the source of the CO_2. Pipeline equipment (pig launcher, emergency shut-down valve, vent line, monitoring and control facilities, etc) is part of the CO_2 pipeline system.

A1.2.2 Rotterdam

For the European case in WP4.3 it is assumed that the CO2 pipeline system from Rotterdam to several depleted gas fields on the DCS described in *D4.1.1* is already installed (at the same time as the Kårstø pipeline is installed). Then, after 20 years of operation, it is assumed that the CO2 storage capacity of these gas fields have been utilised, and the pipeline is the extended from the end of the assumed existing pipeline (at the depleted gas field furthest away from Rotterdam). The upstream battery limit between the pipeline from Rotterdam and the extended pipeline to the Utsira storage location is defined as the subsea weld between the assumed existing pipeline and the extended pipeline to Utsira.

A1.2.3 Teesside/Kingsnorth

It is assumed that 3 Mt/yr CO2 is transported by ship from Kingsnorth to Teesside. The upstream battery limit at Kingsnorth is assumed to be at the inlet to the compressors taking the pressure from ambient pressure to 75 barg, see the figure in Section 2.4.3.

At Teesside, CO2 from local sources is included in the volume basis for the system, and it is assumed that the upstream battery limit for this CO2 also is at the inlet to the compressors taking the pressure from ambient pressure to 75 barg.

A1.2.4 CO_2 storage location at Utsira

The exact coordinates for the location used in the Kårstø project by MPE are confidential. However, for the CO2EuroPipe Kårstø case, it is assumed to be in the region 7 km west of the Draupner S/E platforms, approximately 240 km west of Kårstø.

The battery limit between the transportation facilities and the storage/injection facilities at the template is at the weld between the pipeline tie in spool and the upstream connector hub at the template as shown in the below figure. Functional requirements to pipeline related facilities/equipment downstream of the battery limit are described in Section A1.4.2 below.

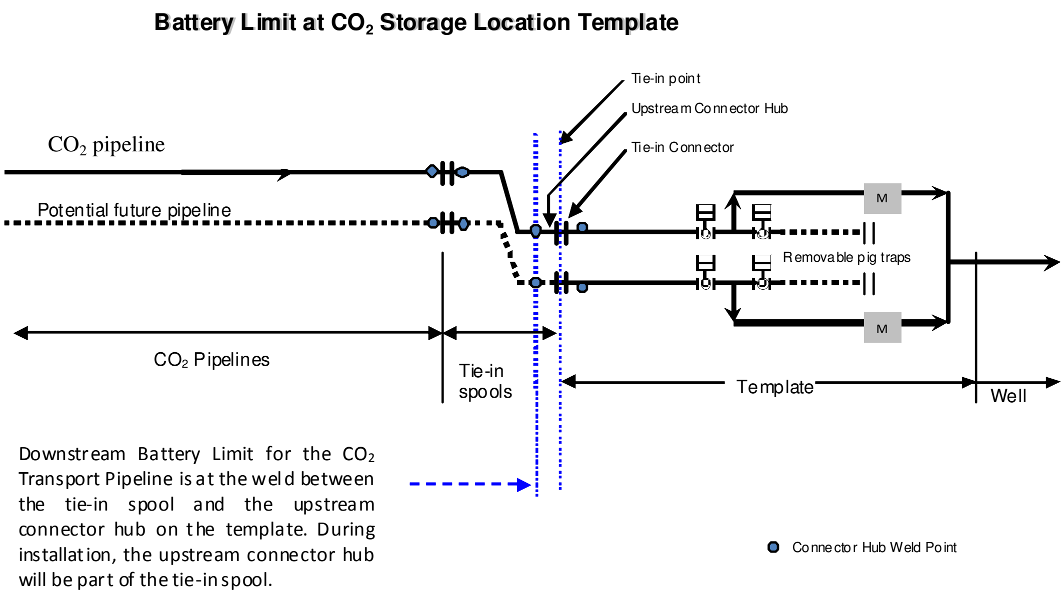

Figure A-1-1 Battery limit at the Utsira template

A study of the storage location and configuration of storage templates and injection well is not included in this report. It is, however, assumed that each template will have a capacity of a maximum of 4 slots for injection wells, and that each injection well may have a capacity of up to 5 Mt/yr, assuming a steady injection rate. Thus, as a basis for the transport study, it is assumed a maximum throughput capacity of 20 Mt/yr for each subsea template.

A1.3 Design premises

A1.3.1 Design flow rate

CO_2 design flow rates are:

- Kårstø: 3 Mt/yr à 375 t/hr
- Kingsnorth : 3 Mt/yr à 375 t/hr
- Teesside[7]: 4 Mt/yr à 500 t/hr
- Rotterdam: 20 Mt/yr à 2 500 t/hr

It is assumed that the period of use for the pipelines will be 8000 hr/year.

A1.3.2 CO_2 Product and transport specifications

The CO_2 quality design transport specification, i.e. the composition of the CO_2 stream, is developed as part of other parts of the CO2Europipe project [*D3.1*.2]. Functional requirements related to this specification are:

- Impurities shall be dissolved in the CO_2 at all pressures and temperatures within the pipeline
- The combinations of CO_2 and impurities in the comingled stream shall be non-corrosive for all possible operating conditions of the CO_2 in the pipeline.

This also means that the content of H_2O in the CO_2 stream should be such that free water is not allowed to form, even under blow down conditions, where low pressure and temperature may be present.

The integrity of the pipeline may be at risk (such as severe corrosion attack) if sustained operations are carried out with some components at a higher level than specified, such as water or oxygen.

In addition, impurities can have a negative impact on transport capacity and can also significantly change the phase diagram for the transport medium, which should be taken into account for flow analyses.

A real time monitoring system for product quality shall be provided, linked to alarm and manual and/or automatic shut-in of the pipeline as required preventing off-spec CO_2 to enter the pipeline.

A1.3.3 Design temperature and pressure

The design temperatures (min /max for normal operations) are given as -20/+50°C. This corresponds to requirements e.g. for a typical gas pipeline. Design pressure is given as max 250 barg at MSL.

[7] Export from Teesside includes both CO2 from Kingsnorth (3 Mt/yr) and from local sources at Teesside (4 Mt/yr), i.e. a total of 7 Mt/yr.

Definition of design pressure is normally the result of a cost benefit analysis, where the cost of increased steel quantities as a result of higher wall thickness is compared towards the decreased steel quantities as a result of reduced pipeline diameter is evaluated for higher design pressure alternatives. In this case, an extensive cost benefit analysis has not been performed, but experiences from similar projects have been used to arrive at a likely beneficial pressure rating of the pipeline.

The maximum operational pressure is defined as the design pressure less a minor margin.

A 10 bar margin to two phase flow is to be maintained at all times and locations during normal operating conditions. According to the thermo-hydraulic analysis this is ensured by fixing the well head pressure at 53 barg (or above) at Utsira. Low flow rates may result in a lower injection pressure (due to the good injectivity of the reservoir) than 53 barg. In such cases a down-hole choke will be assumed installed to increase the wellhead pressure at the template.

A1.4 Functional requirements

The function of the CO_2 transport pipeline is to transport CO_2 from Kårstø, Rotterdam and Teesside/Kingsnorth to a sub-sea template for injection and storage.

Normal operation is defined as all operating conditions when CO_2 is transported from the source to the storage site according to the needs for transportation, all operating conditions when the flow has been stopped for reasons not related to the pipeline and the pipeline is ready to resume operation (e.g. shutdown of power plant/capture plant), and all transient conditions between these different flow conditions. It is required that the CO_2 shall be maintained in single (dense or liquid) phase throughout the pipeline in all normal operating conditions.

The pipelines shall be designed to withstand all foreseeable conditions during normal operation, including low temperature effects.

Abnormal operating conditions shall also be addressed; such as blow-down and leak/rupture conditions. While some un-normal operating conditions, such as a large leak, may result in effects which are outside the basis for normal operation, it is required that un-normal operations which can be controlled, such as blow-down for release of the pipeline contents to the atmosphere, shall be controlled by procedures to be developed to prevent exposure of the pipeline to unacceptable conditions.

The pipelines and pipeline facilities shall be designed for reliable and safe operation over the lifetime, and protection of the public, the environment and commercial values against effects of possible incidents.

Coordination of operations at the sources and Utsira is necessary to ensure appropriate pipeline safety. Such coordination shall be performed from a central control centre.

A1.4.1 Upstream pipeline facilities

The facilities at the Kårstø, Rotterdam and Teesside end shall include:

- Permanent pig launcher and receiver facilities for RFO and inspection
- Emergency Shut-down (ESD) system, primarily to isolate the subsea pipeline from the onshore facilities. Location either near the pigging facilities or at the landfall.
- Blow down system to safely evacuate the contents of the pipeline. Shall be operational for the offshore pipeline also if the ESD valve is closed. Possibly a separate blow-down system for the onshore pipeline (if ESD valve at the landfall)
- Control equipment for normal pipeline operation, such as block valve to trap contents in shut-in situations and control valve for re-start from shut-in conditions.
- Instrumentation for monitoring of pressure, temperature and for leak detection, linked to the pipeline control centre.
- A real time monitoring system for product quality, linked to alarm and manual or automatic blocking of flow into the pipeline in off-spec situations.
- Utilities as required to serve the above functions

Facilities for metering as part of leak detection and monitoring of product quality are included as part of the relevant capture plant(s) system to ensure production of CO_2 according to required specifications.

A1.4.2 Downstream pipeline facilities

The facilities at the downstream end (on the sub-sea template at Utsira) shall include:

- Removable (for template) pig launcher and receiver facilities for RFO and inspection.
- Emergency Shut-down (ESD) system, primarily to isolate the sub-sea pipeline from the downstream facilities.
- Control equipment for normal pipeline operation, such as block valve to trap contents and control valve in shut-in conditions for re-start from shut-in conditions
- Instrumentation for monitoring of pressure, temperature and for leak detection, linked to the pipeline control centre. May be combined with well control instrumentation.
- Utilities as required to serve the above functions

All facilities are downstream of the pipeline battery limit, and will for the sub-sea template alternative be integrated on the template with facilities for well operation and control. Functional requirements for the pipeline related facilities shall be established for as part of Utsira template and well engineering, ref. battery limits in the above figure.

A1.4.3 Regularity

Terms and definitions used to measure regularity should be based on the NORSOK standard[8].

The regularity evaluations shall provide estimates for the regularity of the respective options. No specific target is set. However, the pipeline system (export facilities and transport pipeline) should not be a major contributor to reduced regularity for the CO_2 capture and deposit chain.

The requirement/target for the export, transport and injection chain should reflect the actual importance of high regularity for handling of the CO_2 captured.

A1.4.4 Design life

The design life of the pipelines, tie-in spools and subsea structures shall be 50 years from installation.

A1.5 Operational requirements

A1.5.1 Health, Safety, Security and Quality

General
Safety of personnel and equipment and the protection of the environment are of paramount importance in all aspects of operation of the systems. Accordingly, health, environment, safety and security (HSE) requirements will be implemented at all operated facilities and will be managed via requirements as laid down in relevant management system.

A total risk analysis for the systems shall be available. It should be updated according to established requirements.

HES & Q management system
The CO_2 pipeline will satisfy the requirements of the relevant management system concerning HSE during design, construction, commissioning and start-up, and eventually in operation. These requirements will include, but shall not be limited to safe and reliable operation, permit to work, quantitative risk assessments and individual risk analysis for the wide range of tasks and procedures for operations shall reflect best industry practises.

Emergency Procedures
Emergency procedures shall be readily available and shall cover all aspects of emergency shutdowns, power and services failure, fire, explosion and catastrophic failure (e.g. pipe rupture, loss of containment).

[8] NORSOK, *Regularity management & reliability technology*, NORSOK Standard Z-016 Rev. 1, December 1998

A1.5.2 Environment

All the facilities included in the CO_2 Transportation Network will comply with all statutory directives related to emissions and discharge(s) and solid waste handling/intermediate storage notification schemes.

Any potential for release of hazardous (or toxic) gases will be strictly controlled during any transportation (and maintenance) operations by use of controlled operational procedures.

A1.5.3 Operations

Operating Guidelines for the CO_2 Transportation Network
This section gives a brief overview of the operating guidelines for the transportation system. Quantity and quality received by and injected from the CO_2 Transportation Network shall be within transport specifications.

Normal operating procedures are derived from the following priorities (not in hierarchical order):

- The integrity of the pipeline shall never be jeopardized.
- Venting must be minimized (environmental pollution).
- Smooth operation should be maintained at both the Capture Plant(s) and the CO_2 Transportation Network.

Taking into account these priorities, the CO_2 Transportation Network undertake to receive the CO_2, transport and deliver it to Storage.

The operation of the CO_2 Transportation Network will be monitored and controlled from a Transport Control Center. The monitoring will be according to operating procedures, which will be developed in cooperation with the Capture Plant(s) and storage Operators.

These procedures shall comprise operating conditions for the pressure, temperature, flow, composition, content of H_2S, O_2 and other impurities and the Capture Plant(s) must include defined controllable margins to the CO_2 Transport specification values.

The CO_2 Transportation Network will at all times be operated in such a way that two-phase flow in any part of the system will be avoided.

Flow variations resulting from variations in output from the CO_2 source(s), including no flow, are considered normal operating modes, and the transport system should be designed to handle such operating modes.

Methods controlling and monitoring of well flows must be implemented to avoid CO_2 flowing back from the well to the pipeline.

To perform leak detection of the pipeline system, a computerised online leak detection model will be established and will use above mentioned monitored data from all relevant sites as input.

Operating Procedures
The CO_2 Transportation Network Operator shall operate the CO_2 Transportation Network with due regard to operational tolerances and sufficient working quantity of CO_2 in the pipeline. The CO_2 Transportation Network Operator will in cooperation with all interface parties develop interface- and operational procedures/agreements.

This will include:

- Planning, dispatching and reporting
- Capacity reservation rules, if tie-in of potential future 3rd party access
- Variation in flow rates
- Survival time in case of unplanned events at the Capture Plant(s) or the Storage
- Right quality
- Metering/metering deviations
- Unplanned maintenance in the CO_2 Transportation Network and/or adjacent systems
- Yearly planned maintenance programme/unplanned maintenance
- Pipeline start-up, normal operation and shutdown situations
- Capacity tests
- Energy optimisation
- Emergency conditions/leak detection
- Blow down of pipeline
- Loss of communications
- Special coordination procedures
- Pigging operations

Product specification quality control
The CO_2 specifications shall include the required product specifications this is to be continuously monitored by means of permanently installed gas analysis equipment. Spot-check CO_2 sample testing may also be required to verify the on-line equipment.

The principle for instruments and analysers are duplicated equipment.

Metering stations
The metering and the analysis of the CO_2 being sent in the pipeline shall meet the requirements outlined in the EU legislation for carbon capture and storage. This requires an analysis of the composition, including corrosive substances. As of today there is only a provisional edition, and the associated guidelines are not written yet. Therefore the

uncertainty requirements as detailed by EU[9,10] for gas emissions are temporarily used as requirements. As the expected quantities is rather pure CO_2 (99.6%), these documents specify that the total maximum uncertainty of CO_2 determination in mass shall be less than +/- 1.5 %.

A1.5.4 Maintenance

The CO_2 Transportation Network Pipeline is designed to facilitate no maintenance on a regulate basis. If conditions' necessitating repairs or the need for other intervention work is discovered, the appropriate authorities will be informed of the finding and of the proposed remedial work. This will include stationing a guard vessel in the area if this is considered necessary.

Pipeline integrity management.
The Pipeline integrity management system for the CO_2 Transportation Network shall have focus on the following key integrity areas:

- Pipeline safety systems and operation
- Pipeline external inspection
- Corrosion management
- Modification and repair management.

The work process shall follow the four phases plan, do, check and improve as outlined in relevant standards.

Pigging
The CO_2 Transportation Network pipeline will be designed to cater for maintenance and inspection pigging from Kårstø to storage site.

The need for and the frequency of cleaning pigs shall be based upon the operating conditions of the pipeline. Increased pressure drop, potential accumulation of liquids / debris together with the handling capability at the receiving end shall be used to decide if it is necessary to send cleaning pigs. These parameters shall be carefully monitored especially after connecting branch lines to existing pipelines, after significant changes in supply operations and when taking potential new lines into operation.

[9] DIRECTIVE 2003/87/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL, of 13 October 2003, establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC

[10] COMMISSION DECISION, of 18 July 2007, establishing guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council

A1.6 Study assumptions

A1.6.1 Design parameters for hydraulic pipeline calculations

CO_2 density is assumed minimum 750 kg/m³ and maximum 1050 kg/m³. CO_2 dense phase flow is to be maintained under all normal operating conditions, i.e., two phase flow must be avoided. The calculation method must be able to determine two-phase flow conditions. Overall heat transfer coefficient offshore pipeline must be calculated. Parameters for hydraulic calculations are given in the below table.

Table A-1-1 Parameters for hydraulic calculations

Description	Value	Unit
Ambient seabed mean temperature	7	°C
Highest monthly mean seabed temperature	11	°C
Lowest monthly mean seabed temperature	4	°C
Pipeline internal roughness	50 [11]	µm
Reservoir pressure for Utsira	95 [12]	bara

A1.6.2 Pipeline and coating details

The CO_2 pipeline shall be externally coated to prevent external corrosion. The proposed pipeline coating data is shown in the below table.

Table A-1-2 External pipeline coating

Description	Layer Thickness [mm]	Density [kg/m³]	Thermal Conductivity [W/mK]
FBE	0.3	1450	0.3
PP adhesive and shield [13]	2.7	900	0.23

The pipeline shall ideally be coated internally to provide corrosion protection prior to installation and allow for flow improvement. However, such a flow coating needs to be qualified for the CO_2 service and resistance to wear by pigging. In a recommended practise for CO_2 transport, DNV does not recommend using internal coating due to possible detachment during depressurisation, see DNV (III)[14]. Thus, based upon our current knowledge flow coating is not recommended to be used inside the pipeline.

A1.6.3 Spool piece bends

Bend radii are shown in the below table.

[11] With no internal coating an internal roughness of 50 µm should be applied.

[12] Depth of well below MSL: 958 m and reservoir temperature 35 °C

[13] If PP does not satisfy low operating temperatures other alternatives might be considered e.g. PE

[14] DNV (III), *Project Specific Guideline for Safe, Reliable and Cost-effective Transmission of CO_2 in Pipelines*, August 2009

Table A-1-3 Bend radiuses

Min 5D bends
Min 2D straight run between 90 deg bends in one plane
Min 3D straight run between bends in two planes
Min 3D straight run between barred Tee and bend

The bend radii shall be measured at the centre line of the bend. Tangent length is required at each end of the bend. The required bend wall thickness is the wall thickness after the pipe is bended, i.e. bend mother pipe wall thickness has to be greater than the required bend wall thickness.

A1.6.4 Valves and branches

All block valves shall be full bore valves and branches larger than 40% ID shall be barred. Water hammering is not expected as compressibility is high.

A1.6.5 Pipeline material selection

Base case pipeline material is seamless carbon steel SML 450 I SFPD. If this design result in a hoop stress capability exceeding 250 barg design pressure, lower yield material or higher design pressure shall be considered. Line pipe specification shall take into account possible low operating temperatures and other effects of CO_2.

A1.6.6 Special design requirements for CO_2 service

Fracture properties:
The pipeline design should account for the special properties of CO_2 with respect to the susceptibility to running ductile fractures. In case engineering analysis demonstrates unacceptable risk related to fracture properties, crack arresters or other measures shall be incorporated into the design.

Material choice:
All materials and equipment must be capable of handling dense phase CO_2. Special care must be taken that lubricants, gaskets and sealants in the equipment are resistant over time. Resilient material shall be resistant to explosive decompression.

Line segments and pipeline components may during normal or certain un-normal operating conditions locally reach particularly low temperatures. In such cases (not including large leak/rupture) it shall be considered to specify a lower design temperature for these segments or components than for the rest of the pipeline.

Block valves: maximum opening and closing times must be specified.

Depressurization and venting:
Facilities must be included in the pipeline design to allow for safe venting and depressurization of the pipeline. The blow down/venting facilities need to be at a safe location. Monitoring equipment need to be included to warrant safe depressurization of the pipeline, including temperature monitoring and control of pipeline components and local ambient CO_2 concentrations.

Noise control during venting must be implemented to allow safe venting without the risk of hearing damage.

Pigging:
Pigging facilities must be included to allow for dewatering and inspection pigging. This includes an onshore upstream pig launcher\receiver and downstream subsea pig launcher\receiver for the Utsira. The low lubricate properties of CO_2 should be accounted for in the design of pigging equipment as well as the requirements of material compatibility with dense phase CO_2.

Monitoring and control:
At the entry to the pipeline a monitoring system must be included comprising compositional and water contents measurement of the CO_2 entering the pipeline. This has to be part of a control system incorporating a block valve at the battery limit isolating the pipeline from the capturing facilities when the fluid specification for the CO_2 is exceeded.

A1.6.7 Corrosion allowance

No corrosion allowance is included in pipeline design. The rationale for this is that it is critical that the CO_2 stream under any circumstances is non-corrosive, and that strict measures are implemented to ensure this. If the stream becomes corrosive, corrosive rates for a CO_2 stream will be so high that any normal corrosion allowance (e.g. 3 to 5 mm extra wall thickness) will not be sufficient to prevent fatal damage over the lifetime of the pipeline.

A1.6.8 Installation methods

The design shall provide flexibility with respect to installation methods where applicable, and in particular allow methods based on reverse plastic bending of the pipe during installation for pipeline diameters allowing this installation method.

A1.6.9 Protection requirements

The pipeline shall be protected against third party loads in all areas where such loads otherwise would pose an unacceptable risk i.e. trenching and possibly backfilling in trawling areas and other protection such as gravel dump, protection covers, mattresses, to be used as required.

Protection against environmental loads as required.

A1.7 CO_2 transport by vessel

A1.7.1 Scope specification

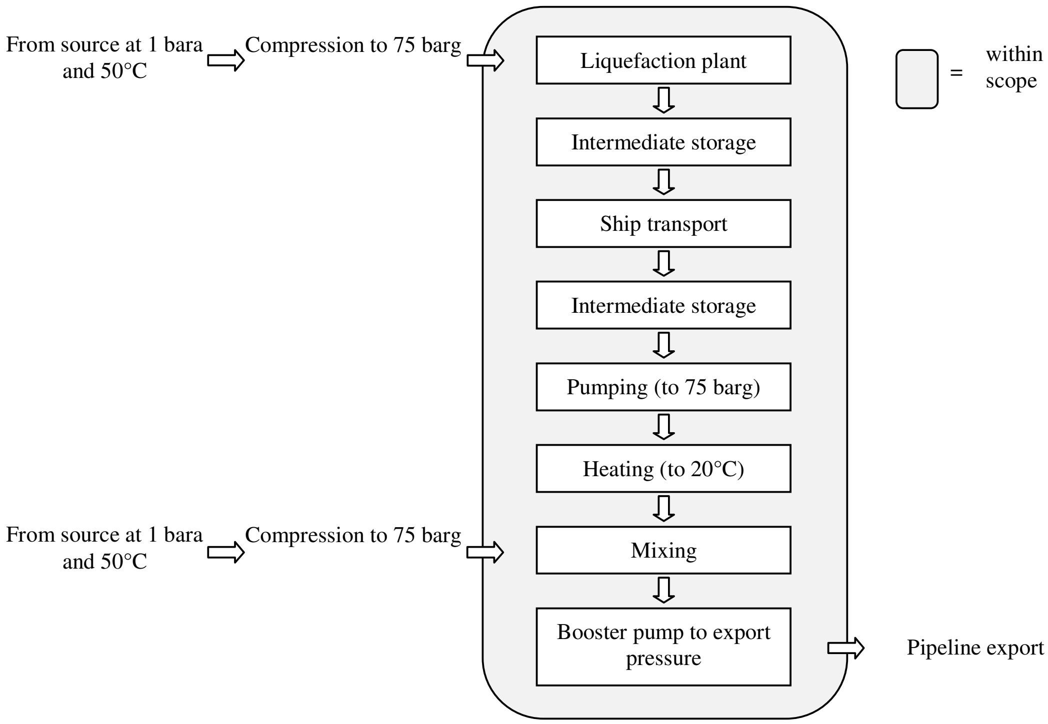

Figure 1-2 Scope definition for the ship transport assumptions

The shipping scope consists of 6 steps prior to mixing with CO2 captured locally at Teesside, see the above figure.

A1.8 References in Appendix A1

NORSOK, *Regularity management & reliability technology*, NORSOK Standard Z-016 Rev. 1, December 1998

DNV (III), *Project Specific Guideline for Safe, Reliable and Cost-effective Transmission of CO_2 in Pipelines*, August 2009

DIRECTIVE 2003/87/EC OF THE EUROPEAN PARLIAMENT AND OF THE COUNCIL, of 13 October 2003, establishing a scheme for greenhouse gas emission allowance trading within the Community and amending Council Directive 96/61/EC

COMMISSION DECISION, of 18 July 2007, establishing guidelines for the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council

A2 DETAILS OF LIQUEFACTION EQUIPMENT AND ASSOCIATED COSTS

Cost estimate					
	IBL Equipment	IBL Bulk materiel	IBL Hour Cost	OBL	Sum
	kEUR	kEUR	kEUR	kEUR	kEUR
Equipment costs	10 204	0	0	0	10 204
Erection cost		0	809	0	809
Piping incl. Erection		2 132	2 055	0	4 187
Electro (equip & erection)		1 155	1 320	0	2 474
Instrument (equip. & erection)		959	1 644	0	2 602
Ground work		230	614	0	844
Steel & concrete		1 168	1 335	0	2 504
Insulation		179	205	0	383
Direct costs	**10 204**	**5 823**	**7 980**	**0**	**24 007**
Engineering process			652	0	652
Engineering mechanical			285	0	285
Engineering piping			1 186	0	1 186
Engineering el.			647	0	647
Engineering instr.			803	0	803
Engineering ground			132	0	132
Engineering steel & concrete			391	0	391
Engineering insulation			62	0	62
Engineering			**4 158**	**0**	**4 158**
Procurement			227	0	227
Project control			229	0	229
Site management			1 392	0	1 392
Project management			1 286	0	1 286
Administration			**3 134**	**0**	**3 134**
Commissioning			468	0	468
Identified costs			**31 767**	**0**	**31 767**
Contingency			**6 353**	**0**	**6 353**
Total costs 2010			**38 121**	**0**	**38 121**

IBl: Inside battery Limit
OBL: Outside Battery Limit

Equipment list for liquefaction (3 trains)

Equipment description	Size	Unit	Material	Equipment Cost KEUR	Installed cost kEUR
CO2 condenser	1 285	m2	CS	308	1 561
CO2 cooler	685	m2	SS316 welded	408	1 605
CO2 condenser	154	m2	CS	41	355
CO2 Compressor	4 970	kW	CS	2 548	8 413
CO2 catchpot	3	m3	CS	36	311
CO2 catchpot	7	m3	CS	60	461
CO2 condenser	1 285	m2	CS	308	1 561
CO2 cooler	685	m2	SS316 welded	408	1 605
CO2 condenser	154	m2	CS	41	355
CO2 Compressor	4 970	kW	CS	2 548	8 413
CO2 catchpot	3	m3	CS	36	311
CO2 catchpot	7	m3	CS	60	461
CO2 condenser	1 285	m2	CS	308	1 561
CO2 cooler	685	m2	SS316 welded	408	1 605
CO2 condenser	154	m2	CS	41	355
CO2 Compressor	4 970	kW	CS	2 548	8 413
CO2 catchpot	3	m3	CS	36	311
CO2 catchpot	7	m3	CS	60	461