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CO_2 transport by ship: the way forward in Europe

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Abstract

This paper presents the results of a study into the functional requirements and optimisation of the CO_2 shipping chain, with a focus on the offshore offloading system. The goal was to evaluate the feasibility of a generic approach to the development of ship-based CO_2 transport and storage systems in the North Sea, using a range of typical North Sea reservoirs (saline formations or depleted hydrocarbon fields). The feasibility of such a generic approach would help develop the ship transport option that is widely regarded as an important option for developing offshore CO_2 storage (or enhanced recovery with CO_2). This will be especially true in the first phase of CCS, when capture locations are few and at large distance from each other. In this phase ship transport is the best option to collect the captured CO_2 and to deliver to one or two storage or enhanced recovery sites. The results provide insight into the requirements for offshore offloading from a ship into an injection well for a range of potential North Sea storage reservoirs. The results of the analysis are presented in terms of pumping and heating requirements (to bring the CO_2 from the conditions in the ship to conditions acceptable for the injection well) and the required investment cost and operational cost of shipping CO_2.

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Keywords: CO_2 ship transport; ship design; injection conditions

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1. Introduction

The North Sea contains the largest storage capacity for CO_2 in North West Europe [1]. Transporting CO_2 captured onshore to offshore storage locations is a challenge, especially during the early phases of the development large-scale CO_2 capture. Transport by ship is an attractive option because of its inherent flexibility in combining CO_2 from several sources at different flow rates to one or more storage locations. The technical design of CO_2 shipping infrastructure is subject to the process conditions (requirements) at the wellhead of the respective storage site. The feasibility of ship-based transport could well depend on the possibility of using a generic transport chain design for North Sea storage sites.

Transport of CO_2 by ship from port to port has already been practised for a long period with relatively small volumes (up to 1500 m^3). Details on the current CO_2 fleet are provided in [2]. Larger ships from 40,000 to 100,000 m^3 for CO_2 transport have been proposed, even with high-pressure tanks on board, but none of these larger ships have been built or tested yet. The technical design of ship transport systems, which include the shore loading installation, the ship itself and the offshore offloading installation, has been studied and described in recent publications (see, e.g., [3][4][5]); an overview is given by Brownsort [2]. Questions remain about the requirements for heating and compression of the CO_2 prior to injection and the location of the facilities on the ship or offloading platform [5].

The aim of the present report is to derive a high-level (functional) description of the elements of the CO_2 shipping chain, with an emphasis on offshore offloading. The report does not deal with the detailed design of the CO2 carrier, or of the onshore loading systems. Starting from a characterisation of the operational window of a range of typical, potential North Sea storage sites, several possible implementations of a generic offshore offloading system are presented and used in a cost analysis.

2. Method

2.1. Subsurface CO_2 storage reservoirs

The starting point of the study was the injection wellhead, as the reservoir and the well together constrain the acceptable combinations of pressure, temperature and (maximum) flow rates ([p, T, q]) at the wellhead. The study used a set of hypothetical subsurface reservoirs (based on experience within the project team) typical for typical for North Sea hydrocarbon fields and saline aquifers.

Sixteen different hypothetical storage reservoirs were defined (Table 1). The analysis considers two saline aquifers and two depleted gas fields, each at four different depths. Together, these storage reservoirs cover the typical potential CO_2 storage sites in the North Sea region. It is assumed that the saline aquifers can also be used to represent oil fields. The reservoirs are coded 1a through 4d; these codes are used in the remainder of the paper.

Constraints originating from the reservoir arise from injection-induced pressure increase in the reservoir and from thermal stresses in the reservoir due to injection of low-temperature CO_2. Wellhead conditions are further constrained by freezing, hydrate formation and fracturing of the reservoir. Constraints originating from the injection well are due to the well completion, to stresses in the well, to erosion/corrosion, and to vibration effects. Further constraints that are closely related to the injection well arise from start-up and shut-down operations. Combining reservoir-related and well-related limits results in the range of values for pressure, temperature and flow rate ([p, T, q]) at the wellhead that are acceptable to the combination of injection well and reservoir.

In addition to the properties as listed in Table 1, the following input was used for the analysis of the limitations to [p, T, q].

- Saline aquifers are initially (before injection) at hydrostatic pressure with a pressure gradient of 0.1 bar/m.
- Gas reservoirs are at a depletion of 80% (cases 3, see Table 1) or 50% (cases 4) at the start of injection. The pressure at the start of CO_2 injection is then 20% or 50% of the initial pressure, respectively,
- Reservoir thickness is 100 m.
- Reservoir temperature depends only on depth and is based on a thermal gradient of 31 °C/km.
- The maximum injection rate is calculated for an injection temperature of 15, 25 and 35 °C.

- The calculation of the minimum horizontal stress before the start of injection is:
$$S_{hmin} = 0.6G_L D - DC(P_{ini} - P_r)$$
where 0.6 is an empirical constant which defines the ratio between the minimum horizontal stress and the overburden pressure, G_L is the lithostatic gradient (0.23 bar/m), D is depth (m), DC is the depletion constant (as mentioned above, for gas fields either 80% or 50%; for saline aquifers DC is zero), P_{ini} is the initial reservoir pressure (bar), P_r is the reservoir pressure at the start of injection (bar).
- No distinction has been made between saline aquifers and oil reservoirs, because it has been assumed that oil reservoirs are still close to initial pressure. When that is the case, the difference in minimum horizontal stress between oil reservoirs and saline aquifers is minimal.
- The permeability in Table 1 is the effective permeability for the CO_2 injection.

Table 1: Subsurface conditions of the relevant scenarios, giving well depth (true vertical depth, TVD), initial reservoir pressure and temperature p_{res} and T_{res}, permeability k.

Case	Field	TVD [m]	P_{res} [bar]	T_{res} [°C]	k [mD]
1a	Saline aquifer,	1000	101	43	100
1b	100 mD	2000	201	74	100
1c		3000	301	105	100
1d		4000	401	136	100
2a	Saline aquifer,	1000	101	43	1000
2b	1000 mD	2000	201	74	1000
2c		3000	301	105	1000
2d		4000	401	136	1000
3a	Gas field, 20% of	1000	20.2	43	100
3b	hydrostatic	2000	40.2	74	100
3c	pressure	3000	60.2	105	100
3d		4000	80.2	136	100
4a	Gas field, 50% of	1000	50.5	43	100
4b	hydrostatic	2000	100.5	74	100
4c	pressure	3000	150.5	105	100
4d		4000	200.5	136	100

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

- Thermo-elastic constant: the thermo-elastic constant describes the relation between temperature change and horizontal stress. The thermo-elastic constant is varied according to the values of Young's modulus and the Poisson ratio (see [6] for details).
- Also the injection rates are varied to check that the injection rate does not influence the minimum horizontal stress too much.

2.2. Ship and offshore offloading design options

It is most likely that CO_2 will be carried at refrigerated conditions of approx. -55°C and a pressure of 7-9 bar [3][5]. Following refrigerated transport the CO_2 needs to be conditioned before it can injected into a reservoir. The CO_2 conditioning system will be different for each offshore CO_2 handling option considered. Available options for a liquid carbon dioxide (CO_2) handling and transport system, using shipping as one principal transport element, are divided into three categories:

- Option 1. direct injection from the ship into the injection well; conditioning of the CO_2 takes place on the ship
- Option 2. injection takes place from an offshore platform; installations to condition the CO_2 are located both on the ship and on the platform.
- Option 3. the ship offloads into a temporary storage that is moored near the injection platform. The temporary storage is envisaged as a floating storage and processing vessel suitable for receiving and storing refrigerated liquid CO_2, conditioning it for injection and either injecting it directly from the vessel, or transferring it to a fixed platform for injection. In option 3, there is no conditioning of the CO_2 on the ship.

The total capacity, in terms of yearly injected volume, follows from the injection capacity of the (single) injection well and is an outcome of the analysis, rather than a design parameter. The yearly volumes that can be injected are in the range of 2 – 5 Mpta.

System boundaries for the design are set upstream between the onshore liquid CO_2 storage plant and the ship, and downstream at a CO_2 injection wellhead offshore. The outline of available design options aims to identify the main process equipment with an indication of their siting and process conditions.

2.3. Conditioning the CO_2 for injection

After the sea voyage, CO_2 in the tanks of the ship is assumed to be at 10 bar and -50°C. One of the heat sources for raising the temperature of CO_2 is seawater. To avoid ice formation in sea water a secondary heating fluid is required. For this, methanol is chosen with inlet temperature of 0 °C and an outlet temperature of -25 °C. This allows the sea water to be used with inlet temperature 5 °C and outlet temperature 0 °C. For pressure drop calculations in pipelines, a default pipe roughness (46 µm) is used and a liquid velocity in the pipe of 1.5 m/s. For the case of ship to wellhead on the platform, a pipe length of 1150 m is assumed.

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

The maximum CO_2 pressure for the direct injection from the ship cases is limited at 200 bar, which is the maximum allowed pressure for flexible off-loading tubing that connects the ship to the mooring system (this value of 200 bar was confirmed by several EPC contractors). To avoid damage from brittle behaviour of the flexible off-loading tube, the minimum temperature for CO_2 off-loading from the ship is set to 0 °C.

2.4. Ship transport scenario parameters

The CO_2 shipping cost assessment was carried out for each reservoir type and comprises the cases set out in Table 2. Table 3 lists the duration of various elements of a CO_2 shipping route. The ship transport scenarios are designed to maintain a constant injection rate, at the maximum rate feasible.

Table 2: Main input sheet for the different options.

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

Table 3: Overview of the different time elements of CO_2 shipping. Unit is hours.

Parameter	Option 1 Direction inj. from ship	Option 2 Ship to platform to well	Option 3 Ship to buffer to platform to well
Ship loading at port	15	15	15
Slow passage into / out of port	2	2	2
Cruising speed	Depends on ship size and distance (calculated)		
Slow passage to / from offshore mooring	2	2	2
Offshore offloading	Depends on ship size and injection rate (calculated)		15

2.5. Cost assessment and cash flow analyses

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

3. Well head operational window

3.1. Saline aquifers

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

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

The mass flow rate limitation due to fracture propagation is also taken into account when defining the operational window of injection. It is obtained from the reservoir calculations and shown in Figure 1 (cyan and blue curves).

3.2. Depleted fields

CO_2 could be stored in gas fields that are at the end of field life. This means that the reservoir pressure is often below the hydrostatic pressure. The analysis has been performed for reservoir pressures that are at 20% and 50% of the hydrostatic pressure for the different depths (cases 3 and 4 in Table 1).

The decrease in pressure in depleted gas fields (cases 3 and 4 in Table 1) has a significant effect on the operational window. The lower reservoir pressure results in a lower bottom hole pressure. If the bottom hole pressure is below the saturation pressure, gas and liquid coexist and the temperature is equal to the saturation temperature at the bottom hole pressure. This means that if the bottom hole is at the phase equilibrium the pressure should not be below 50.9 bar, which is the saturation pressure at 15 °C; this temperature of 15 °C should always be exceeded to avoid hydrate formation. Examples given in [6] show that this causes severe limitations to the operational window, especially for depleted fields at low pressure (< 50 bar).

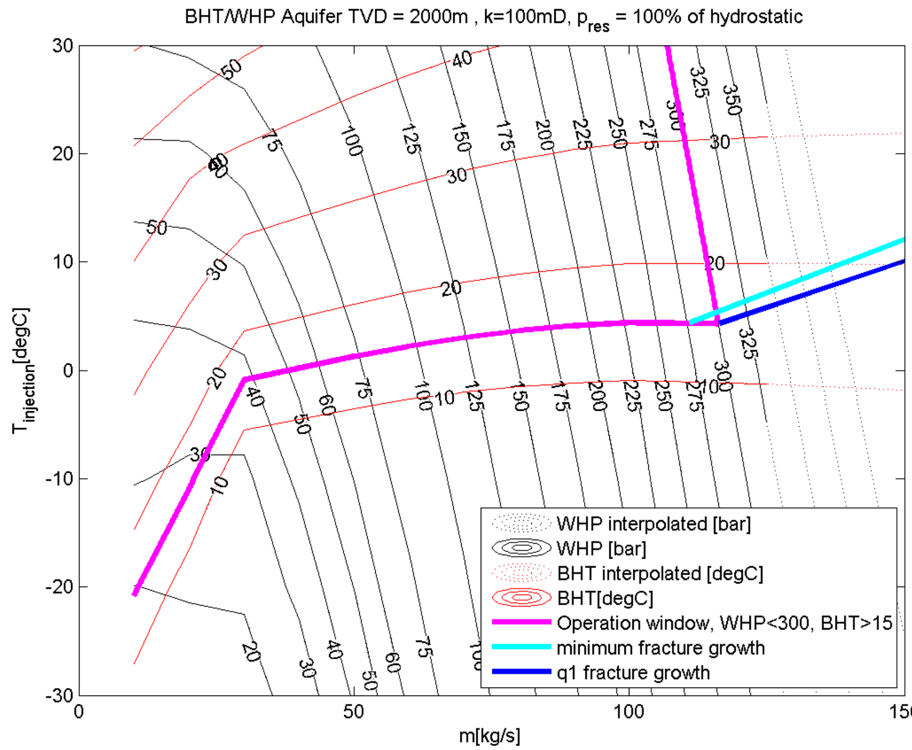

Figure 1: Plot showing the operational window of an injection well in storage reservoir (case 1b, see Table 1). On the horizontal axis is the mass flow rate; on the vertical axis is the temperature of the injected CO_2 at the wellhead. The black lines are isolines for the required wellhead pressure (WHP) for this injection. The red lines are the bottom hole temperatures (BHT) of the CO_2. The magenta curves define the boundary of the operational window in terms of BHT and WHP. An upper limit off 300 bar for the injection pressure was assumed. Safe CO_2 injection is possible for combinations of flow rate and wellhead temperature that lie inside the magenta curves (i.e., in the upper left quadrant in the figure). The cyan and blue lines are operating limits due to fracture propagation in the reservoir; these limits are not calculated for bottom hole temperatures below 15°C since this is already outside the operation window due to hydrate forming in the reservoir. Fracture generation in this case only slightly reduces the operational window of injection.

4. Functional requirements and engineering for CO_2 shipping

With a description of the boundary conditions at the wellhead, the interface between the ship and the wellhead can be defined in terms of functional requirements. These describe the compression and heating that is required to bring the CO_2 from ship transport conditions to well head conditions. This section presents the functional requirements derived for the sites studied.

The results for the direct injection from the ship (option 1 in Section 2.2) are given in Table 4. Results are shown for lower-permeable saline aquifers and depleted fields (cases 1 and 3 in Table 1). Table 4 shows that auxiliary heating is necessary for the shallow wells. No auxiliary heating is necessary for wells deeper than about 3000 m. Maximum injection rates are in the range of 2.1 – 4.3 Mtpa, where the flexible hose limits pressure to 200 bar.

Table 4 also shows the results for injection from the platform (options 2 and 3 in Section 2.2). The results show that a well head pressure of 300 bar is not feasible for shallow wells (1000 m) or for low-pressure gas wells at depths of 4000 m. Auxiliary heating on the ship is required in all cases, while additional auxiliary heating on board of the platform is only necessary for the 1000 m depth wells. CO_2 cooling with seawater on board of the platform is applied in all cases with wells deeper than 2000 m. Due to the chosen pump efficiency, the CO_2 temperature can become higher than the temperature for maximum injection rate for these deeper wells. In those cases, the auxiliary heat exchanger is used to cool the CO_2 with seawater in order to get a higher allowed injection rate. A temperature of 10 °C for CO_2 injection is aimed for. Maximum injection rates are in the range of 2.6 – 4.7 Mtpa, about 10-20% higher than in the case of direct injection from the ship into the well.

Table 4: Direct injection from ship to well. 'Case' refers to typical storage reservoirs listed in Table 1; results are shown for saline aquifers with a permeability of 100 mD (cases 1) and depleted gas fields (cases 3), at depths of 1000, 2000, 3000 and 4000 m. Section 2.2 describes options 1, 2 and 3.

		Direct injection from ship (option 1)		Ship to platform to reservoir (options 2 and 3)	
	Case	1	3	1	3
Depth 1000 m					
Injection pressure	bar	200	200	275	238
Injection temperature	°C	23.7	23	30	23
Flow rate	kg/s (Mtpa)	122 (3.8)	137 (4.3)	143 (4.5)	150 (4.7)
Pump capacity	MW	2.98	3.34	5.07	4.61
Seawater heating	MWth	10.82	12.15	12.68	13.30
Auxilary heating ship	MWth	4.37	4.69	1.78	1.87
Auxiliary heating platform	MWth	-	-	2.82	1.79
Total heating duty	MWth	15.19	16.84	17.28	16.96
Depth 2000 m					
Injection pressure	bar	200	200	300	300
Injection temperature	°C	5.2	12.5	10	12.5
Flow rate	kg/s (Mtpa)	93 (2.9)	117 (3.7)	115 (3.6)	136 (4.3)
Pump capacity	MW	2.25	2.85	4.52	5.45
Seawater heating	MWth	7.96	10.38	10.20	12.06
Auxilary heating ship	MWth	0	1.38	1.43	1.69
Total heating duty	MWth	7.96	11.76	11.63	13.75
Seawater cooling platform	MWth	-	-	2.68	2.80
Depth 3000 m					
Injection pressure	bar	200	200	300	300
Injection temperature	°C	0	5.5	10	10
Flow rate	kg/s (Mtpa)	78 (2.5)	109 (3.4)	94 (3.0)	122 (3.8)
Pump capacity	MW	1.85	2.64	3.65	4.86
Seawater heating	MWth	5.90	9.40	8.34	10.82
Auxilary heating ship	MWth	0.00	0.00	1.17	1.52
Total heating duty	MWth	5.90	9.40	9.51	12.34
Seawater cooling platform	MWth	-	-	2.07	2.92
Depth 4000 m					
Injection pressure	bar	200	200	300	250
Injection temperature	°C	0	0	10	10
Flow rate	kg/s (Mtpa)	68 (2.1)	105 (3.3)	82 (2.6)	106 (3.3)
Pump capacity	MW	1.62	2.48	3.18	3.45
Seawater heating	MWth	5.17	7.94	7.27	9.40
Auxilary heating ship	MWth	0.00	0.00	1.02	1.32
Total heating duty	MWth	5.17	7.94	8.29	10.72
Seawater cooling platform	MWth	-	-	1.79	1.65

The duties for the minimum and maximum cases, derived for all storage cases in Table 1 and used for the costs estimations, are given in Table 5. The minimum and maximum costs for equipment to be installed on board a ship for CO_2 preparation for well injection range for option 1 from 14 to 19 M€ with all facilities installed on the ship. For option 2, costs are in the range 5.4 - 7.6 M€ for ship-based facilities, with a further 21 – 25 M€ for platform-based facilities. For shallow wells to a depth of about 1000 m auxiliary heating on the platform is needed, while for wells deeper than 2000 m seawater cooling of the CO_2 is preferred.

The resulting conceptual design provides the basis for a generic design for the process equipment for CO_2 transported in liquid form by ship and injection into different reservoirs at varying depths.

5. CO_2 shipping cost assessment

Generally, for dedicated CO_2 carriers the main requirements are:

- Equipment to load/unload liquid CO_2;

- Suitable tanks for stable storage of liquid CO_2;
- A re-condensation unit (optional, for long trip), to avoid releasing boil-off gas to the atmosphere [5].

Only the total capacity of the ship has been assessed in this study. Numbers of tanks and tank capacities have not been evaluated. Data on ship cost estimates (various operational cost items, such as those related to fuel use, engine power, and loading and unloading times) were based mainly on work performed previously [7][8] and are shown in Table 6. Table 7 gives the cost (CAPEX) of offshore offloading infrastructure; OPEX is assumed to be 5% of the investment costs.

Table 5: Minimum and maximum duties for the case of injection from the platform (options 2 and 3). In these cases CO_2 conditioning takes place both on the ship and on the platform.

Duty	Unit	Injection from ship		Injection from platform	
Duty	Unit	Minimum	Maximum	Minimum	Maximum
Pump capacity	MW	1,62	3,34	3,18	5,45
Seawater heating	MWth	5,17	12,15	7,27	13,30
Auxiliary heating Ship	MWth	0,00	6,22	1,02	1,87
Auxiliary heating Platform	MWth	-	-	0,53	3,01
Total heating duty	MWth	5,17	18,37	8,29	18,18
Seawater cooling platform	MWth	-	-	1,65	3,31

Table 6: CAPEX and OPEXestimates for CO_2 shipping. Units in the table are million € (Capex), or million €/ tCO_2/yr. Fixed OPEX is assumed to be 3% of initial investment. Harbour fee at 1.3 €/t CO_2 is not included in fixed OPEX cost.

	CAPEX (M€)			Fixed OPEX (M€/yr)		
Capacity	Low	High	Mid-point	Low	High	Mid-point
10 kt CO_2	50	60	55	0.9	1.2	1.1
20 kt CO_2	63	73	68	1.5	1.8	1.7
30 kt CO_2	75	85	80	1.9	2.2	2.0
50 kt CO_2	100	110	105	2.3	2.6	2.4

Table 7: CAPEX estimates for offshore infrastructure. OPEX is assumed to be 5% of CAPEX.

Category	Variant	Sub-item	Unit	Low	High	Mid-point
Mooring system / offshore connection system	Single Anchor Leg Mooring	Option 1	M€	16	27	20
	Tower Mooring System	Option 2	M€	39	60	45
Offshore platform incl. storage, incl. offshore transport and installation	Floating storage vessel: 40 kt CO_2	Option 3	M€	70	150	110

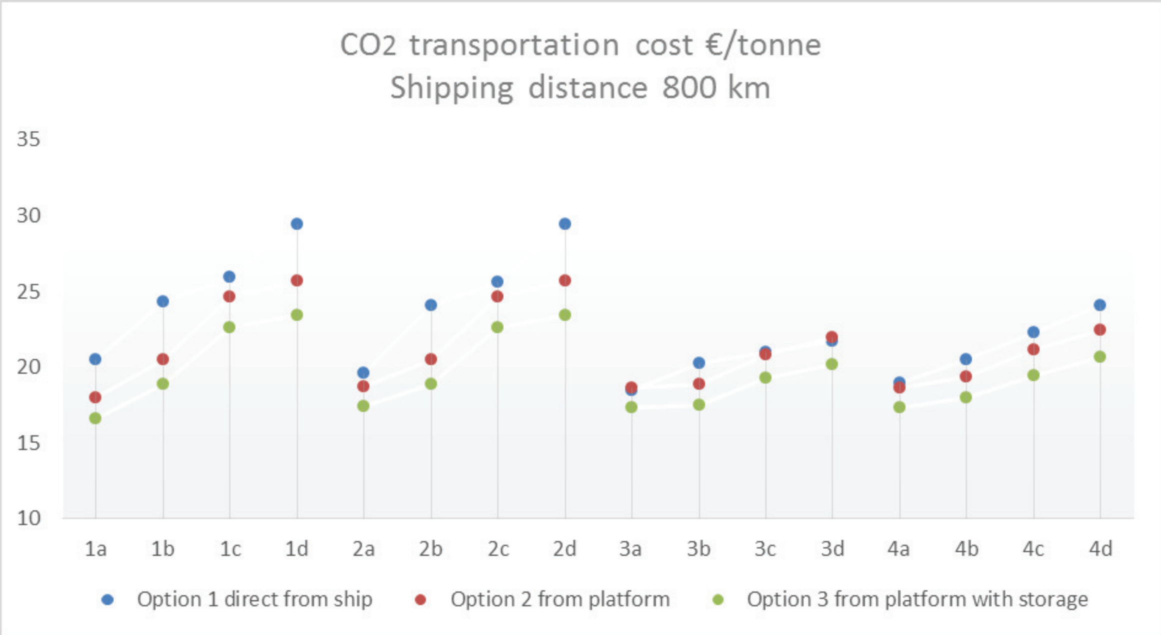

Figure 2: CO_2 transportation cost for the different reservoir cases at a shipping distance of 800 km

Figure 2 illustrates the CO_2 transportation cost of the different offshore design options as discussed in Section 4, for the different reservoir cases (see Table 1) and a distance of 800 km. Each data point in the figure represents the scenario at maximum allowable flow rate case and optimised logistical scenario.

The results suggest that the use of an offshore platform with storage (option 3) produces the lowest CO_2 transportation cost. This is mainly due to the more efficient use of the shipping fleet; added benefits are that ship design is less complex (no need for conditioning equipment on each ship) and that injection can be continuous with discrete ship deliveries.

Table 8: Results for the design option of direct injection from the ship (option 1).

	Unit	Lowest cost	Highest cost
CO_2 transport cost	€/ton CO_2	13.7	35.4
Transport capacity	Mtpa	4.2	2.1
Ships required	-	5 (ship size 10 kt)	4 (ship size 30 kt)
Utilisation factor	%	75	52
Capex	M€	314	416
Storage case	-	4a (50% depleted gas field, 1 km depth)	2d (saline aquifer, 4 km depth)
Travel distance	km	400	1200

Table 9: Results for the design option of injection from a platform, without buffer storage (option 2).

	Unit	Lowest cost	Highest cost
CO_2 transport cost	€/ton CO_2	14.1	30.6
Transport capacity	Mtpa	4.7	2.6
Ships required	-	6 (ship size 10kt)	4 (ship size 30kt)
Utilisation factor	%	72	57
Capex	M€	355	420
Storage case	-	4a (50% depleted gas field, 1 km depth)	2d (saline aquifer, 4 km depth)
Travel distance	km	400	1200

Table 10: Results for the design option to offload into a buffer storage and injection from a platform (option 3).

	Unit	Lowest cost	Highest cost
CO_2 transport cost	€/ton CO_2	13.6	27.8
Transport capacity	Mtpa	4.7	2.6
Ships required	-	2 (ship size 50kt)	3 (ship size 30kt)
Utilisation factor	%	82	76
Capex	M€	358	394
Storage case	-	2a (saline aquifer, 1 km depth)	2d (saline aquifer, 4 km depth)
Travel distance	km	400	1200

A high-level overview of the results of extreme cases for the different offshore options for different type of reservoirs is presented in the tables below for the three options of offshore offloading. The results for the three design options (Section 2.2) are given in Table 8; Table 9 and Table 10 respectively.

The results of this study have been compared with the results from the ZEP transport study (ZEP, 2011); the ZEP study includes the capital investment costs for liquefaction, these have not been included in the present work. Figure 3 illustrates the relationship between the transport distance and the cost of transporting one tone of CO_2 over a distance of one km. While the ZEP study assumes a capacity of 10 Mtpa (ZEP, 2011), in this study the capacity is in the range of 2 to 5 Mtpa, depending on the capacity of the injection well.

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

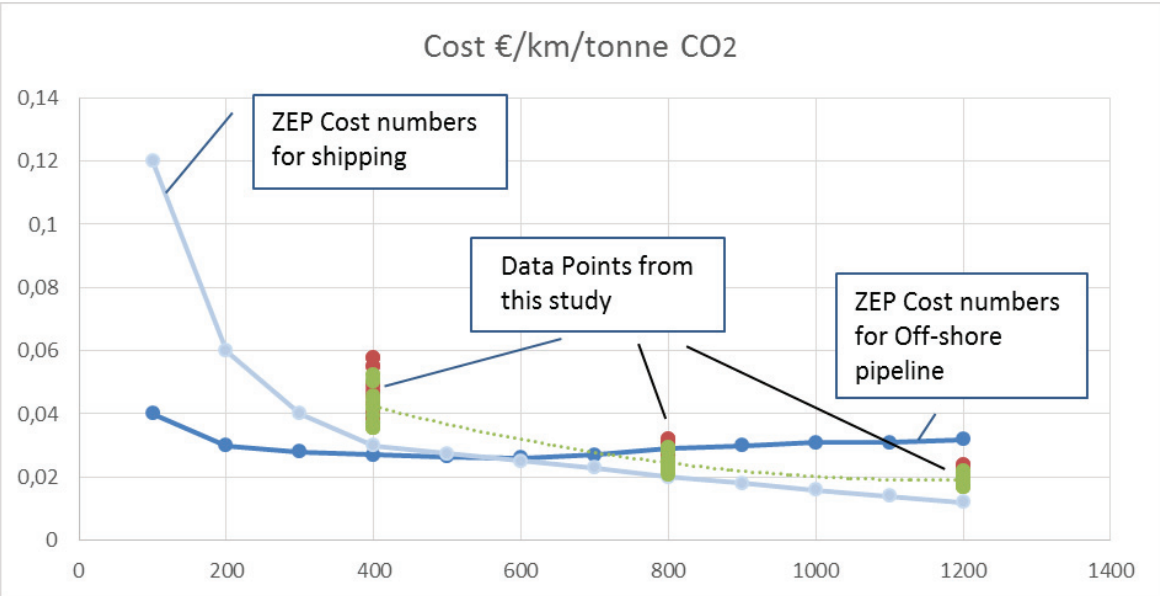

Figure 3: Cost expressed as €/tonne/km (vertical axis) for the different shipping cases (green and red data points), as a function of transport distance (horizontal axis), compared to ZEP resulting cost numbers for shipping and offshore pipeline transport [7].

6. Conclusion

Reservoir properties, well completion and well depth determine the electrical and thermal power necessary to prepare the CO_2 for injection. Direct injection from a CO_2 carrier is feasible for a range of typical injection wells, with high rates (several megatonnes per annum) feasible in many cases (exceptions include shallow depleted reservoirs). Power requirements allow equipment for compressing and heating the CO_2 prior to injection to be installed on the ship; the required heating capacity can be provided through heating with seawater and surplus heat from the ship's engines.

For a ship capacity of 10,000 tonnes, offloading time is in the range of 24 – 36 hours, using a single injection well. With temporary, near-well storage, ship-offloading times are shorter, even for larger size ships, allowing for a more efficient use of the shipping fleet. This results in lower overall cost, relative to direct injection from the ship into the well.

The cost of ship-based transport in the North Sea is estimated to be in the range of 13 - 27 €/tCO_2, for a distance of 400 km, 17 – 30 €/tCO_2 for a distance of 800 km and increases to 20 – 33 €/tCO_2 for a distance of 1200 km. Unit cost is about 10 – 25 % higher in case of direct injection from the ship into the well, compared to injection from a platform (which can be a temporary platform).

A single design for the ship and near-well installations could be used to develop CO_2 injection into a variety of fields in the North Sea. This makes it possible to develop a uniform approach to storage in deep saline aquifers (which hold most of the storage capacity in the North Sea), oil fields (including the option to do enhanced oil recovery) and depleted gas fields. When a storage reservoir is filled to capacity, the storage related systems can be transferred to the next location, to be re-used. This will decease cost, enable cooperation among different nations and, hence, accelerate CCS development in Europe.

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