Benchmarking of CO_2 transport technologies: Part II – Offshore pipeline and shipping to an offshore site

Simon Roussanaly[a,*], Amy L. Brunsvold[a] and Erik S. Hognes[b]

[a]*SINTEF Energy Research, Sem Sælandsvei 11, NO-7465 Trondheim, Norway*
[b]*SINTEF Fisheries and Aquaculture, SINTEF SeaLab, Brattorkaia 17, NO-7465 Trondheim, Norway*

* Corresponding author. Tel.: +47 474 41 763; fax: +47 735 97 250; E-mail address: simon.roussanaly@sintef.no

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Abstract

This paper continues the illustration of the methodology and the functionality of the CCS value chain tool developed within the BIGCCS Research Centre through the use of two new transport assessment modules for offshore pipeline and shipping to an offshore site. Technical, costs, and climate impact characteristics of each transport infrastructure are assessed and used to benchmark offshore pipeline and CO_2 shipping to an offshore site transports in a base case for a range of distances and capacities. As expected, the base case illustrates that short distances and large capacities favour pipeline transport while ship transport is favoured by long distances and small capacities. The results show that the distance effect is stronger in the case of transport to an offshore site than in the case of transport between harbours, due to both higher pipeline investment costs and the pipeline pressure drop limitation for offshore. The base case is used to draw conclusions regarding specific case studies under the hypotheses described in this paper. Our methodology also appears to lead to results consistent with cases available in the literature when the same cost hypotheses are taken into consideration.
Sensitivity analyses are used to quantify the impact of several important parameters and show that the four most influential parameters regarding the transport technology selection are: 1) the geographical context through the distance ratio 2) the regional effect of pipeline costs and uncertainties in pipeline investment costs through the pipeline investment costs 3) the project ownership effect through the discount rate 4) the First Of A Kind effect and uncertainties on investments through the overall investment costs.
The CO_2 avoided transport costs of the two transport technologies are illustrated in order to emphasise the importance of selecting the most efficient transport technology. The evaluation of costs underlines the fact that knowing the actual costs and limiting uncertainties is very important for the selection of the cost-optimal technology, to avoid cost overruns, and limit financial risks. The cost evaluation is also used to demonstrate the impact of limiting transport cost on the conditions in which CO_2 transport is economically viable. The results demonstrate that the stronger the cost constraint, the more "long" distances and "small" capacities should be ruled out.
The methodology and results are also used to illustrate how constraint on initial investment, in order to limit financial exposure, is to the disadvantage of pipeline transport due to the large investments required for transport via pipeline.

Keywords: Carbon Capture and Storage (CCS); Benchmark; Transport; Offshore pipeline; Shipping to an offshore site; Techno-economic assessment; Greenhouse gases (GHG) assessment.

Abbreviations: API, American Petroleum Institute; CAPEX, capital expenditures; CCS, carbon capture and storage; CEPCI, chemical engineering plant cost index; FOAK, first of a kind; GHG, greenhouse gas; GWP, global warming potential; IGCC, integrated gasification combined cycle; LCA, life cycle assessment; NOAK, n^{th} of a kind; OPEX, operating expenditures; ZEP, Zero Emission Platform.

1 Introduction

Carbon Capture and Storage (CCS) is regarded as one of the most promising technologies for reducing man-made carbon atmospheric emissions, and is projected to provide 14% of the reduction in man-made greenhouse gas (GHG) emissions by 2050 (International Energy Agency, 2013). To bring CCS closer to commercial realization, the techno-economic viability of CCS value chains must be explored, including both costs and environmental effects. A consistent and transparent methodology was developed to ensure the critical evaluation of the viability of a CCS chain with respect to multiple criteria (technical, economic and environmental) (Jakobsen et al., 2011; Jakobsen et al., 2013). The value of such a methodology lies in the support it provides to decision-makers to select the best alternatives for CCS chains.

To cut the cost of CCS, three main ways can be investigated: 1) Technology improvement (e.g. improved solvents (Knudsen et al., 2011), improved membranes (Tomé et al., 2013; Yngve et al., 2012)) 2) Development of new and innovative technologies (e.g. carbonate looping (Berstad et al., 2012; Ströhle et al., 2014), low-temperature CO_2 capture (Berstad et al., 2013)) 3) Smart design and operation of CCS chains (e.g. selection of cost-optimal capture capacity (Anantharaman et al., 2013), selection of cost-optimal technology (European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011a; Ho et al., 2011; Roussanaly et al., 2013d)).

A value chain methodology and tool for multi-criteria assessment of CCS chains are being developed within the BIGCCS Research Centre (Mølnvik et al., 2011) in order to provide support for technology selection as well as the smart design and operation of CCS chains. The approach is flexible and modular, as shown in Fig. 1, and the assessment modules which are being developed for capture, transport, and storage can be used as basic building blocks and interconnected freely to create a range of potential chain designs.

The modules already developed include those for CO_2 capture technologies (amine post-combustion capture, CO_2 membrane separation...), CO_2 transport technologies (pipeline onshore and offshore, as well as shipping between harbours and to an offshore site), CO_2 storage options (depleted, saline aquifer, and EOR storage) combining technical, cost and climate impact assessments, and considering a wide range of variables and parameters such as flow rates, capacities, CO_2 concentration in the flue gas, cost data, and climate impact data and so on.

In addition to its flexibility, and even if the quality of the results are of course dependent on the quality of the input data, the method is consistent and transparent. The modules can evaluate a range of techno-economic and environmental criteria of CCS chains, and enable developers to simulate a large number of CCS chains in a relatively short calculation time[1]. The methodology will help to provide the necessary knowledge for the design of efficient CCS chains, and will help to provide efficient policy tools and measures to promote the development of CCS.

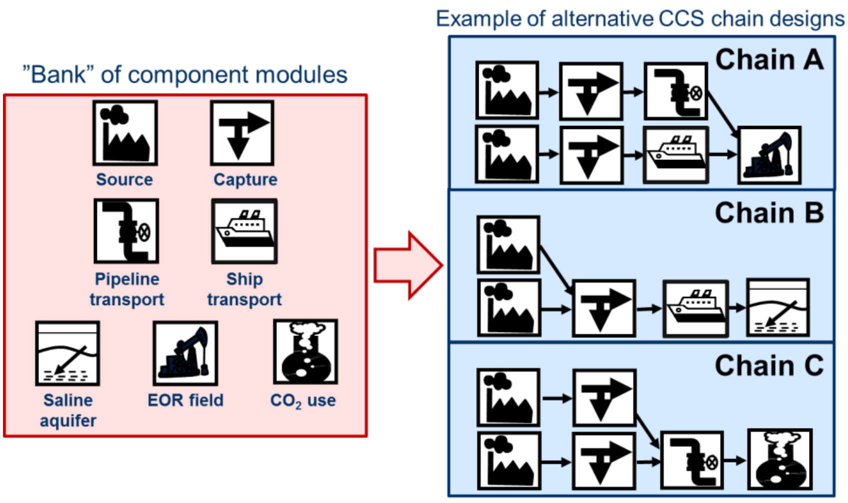

Fig. 1: Modular concept (Jakobsen et al., 2013)

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[1] As an example, by combining different distances, capacities, pipeline diameters, ship sizes, and input parameters, more than 800,000 CCS transport chains have been calculated for parts I and II of this paper.

Several report and studies have looked into the cost of transporting CO_2 by onshore pipeline, offshore pipeline and shipping, as well as the selection of the cost-optimal transport technology. The IPCC report (Metz et al., 2005) has compared the cost of CO_2 transport by onshore pipeline, offshore pipeline and CO_2 shipping for a capacity of 6 $MtCO_2$/y and found that pipelines should be used for distances below 1000 km and 1700 km for onshore and offshore transport respectively, while shipping should be used for larger transport distances. The ZEP report (European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b) on CO_2 transport compared the cost of CO_2 transporting 20 $MtCO_2$/y by offshore pipeline and CO_2 shipping for distances of 180, 500, 750 and 1500 km, and concluded that offshore pipeline will be used in the three first cases while shipping will be the last one. Coussy et al. (Coussy et al., 2013) and Roussanaly et al. (Roussanaly et al., 2013b) illustrates that in the case of the EU project COCATE, onshore pipeline was the cost-optimal technology to transport 13.1 $MtCO_2$/ from Le Havre (France) to Rotterdam (Netherlands)[2]. Mallon et al. (Mallon et al., 2013) evaluated that offshore pipelines would be used for distances below 500 km for an installed transport capacity of 10 $MtCO_2$/y used at 50% while shipping will be used for larger distances. However general conclusions on the selection of the cost-optimal transport technology are hard to draw as these studies consider different case study characteristics (transport distance and capacities), and consider different assumptions (pipeline cost, project duration, utilization rate...).
In order to draw general conclusions on conditions in which pipeline and shipping are respectively the cost-optimal technology, a case study benchmarking onshore pipeline and shipping between harbours was performed, based on the cost of the transport options calculated by the transport modules, and was presented in the first part of this paper (Roussanaly et al., 2013d). Unlike previous studies, this work did not focus only on a fixed capacity (Metz et al., 2005) nor a specific case (Coussy et al., 2013; European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b; Roussanaly et al., 2013b; Roussanaly et al., 2013c), but considered two initial variables: transport distance and transport capacity.
Part II of this paper focuses on the selection of the cost-optimal technology, either offshore pipeline or shipping, to transport CO_2 to an offshore site, based on the cost of the transport options calculated by the transport modules. In addition to a base case benchmark, sensitivity analyses are performed in order to quantify the impact of important parameters on technology choice. Finally, comparison of results with literature, cost of CO_2 transport, financial risks and implementation strategies are discussed.

2 Methodology

Offshore pipelines and CO_2 shipping to an offshore site are compared for distances from 200 to 2000 km and transport capacities from 2 to 20 Mt_{CO2}/y. The flowchart illustrated in Fig. 2 is used to identify in under which conditions (capacity and distance) are pipeline and shipping respectively the cost-optimal CO_2 transport technologies. As, several options (diameter or ship size) are possible for each technology, the optimal options of each transport options should first be identified before the two cost-optimized supply chains are compared.
The following sections illustrate the structure of both pipeline and shipping transport chains, and present the characteristics considered for the technical, cost and climate assessments.

[2] Considering an onshore pipeline of 620 km and a shipping distance of 480 km.

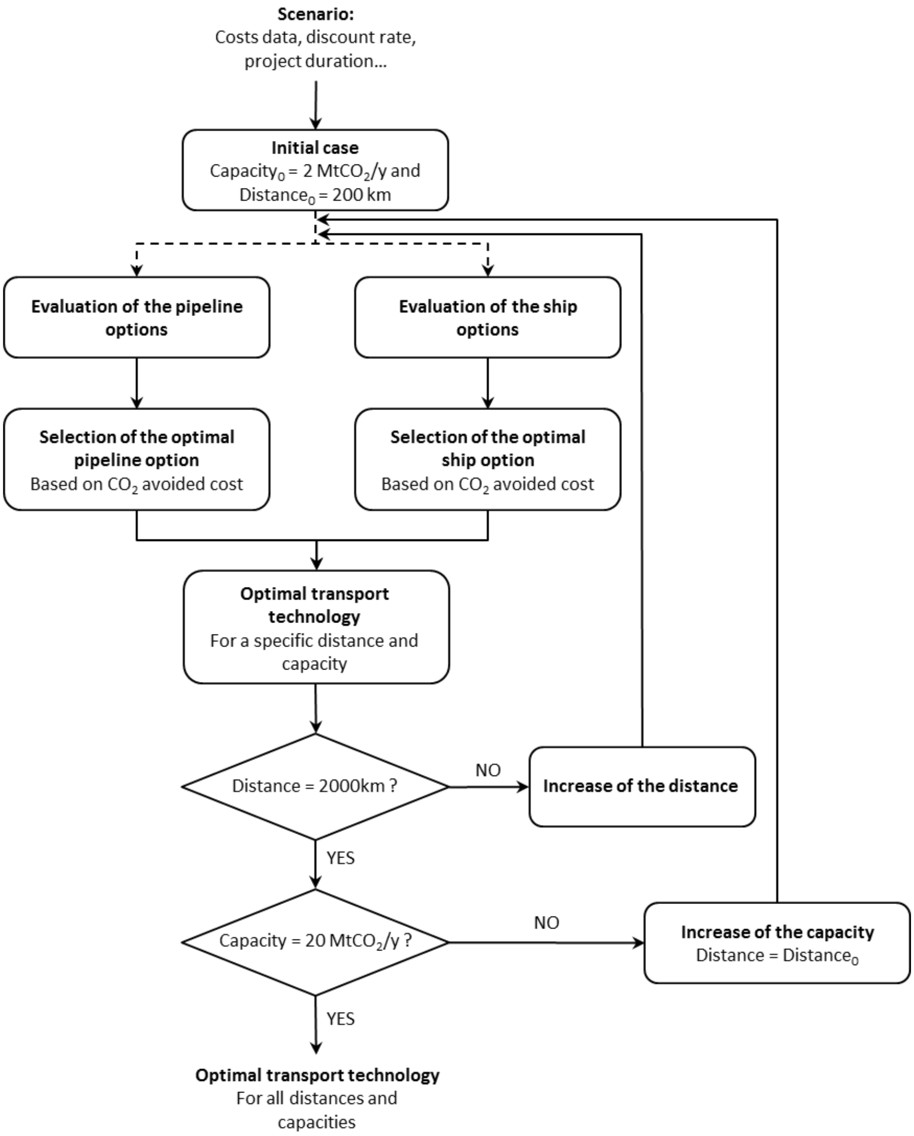


Fig. 2: Flowchart illustrating the process used to determine the optimal technology for all distances and capacities

2.1 Technical assessment

Both transport systems consider CO_2 streams assumed to be collected after CO_2 capture and regeneration[3] at atmospheric pressure (Husebye et al., 2012; Roussanaly et al., 2013a) and delivered at the offshore storage facility at a pressure assumed to be superior to 60 bar which correspond to the inlet pressure of an injection well head (European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b). Each of the two transport systems is therefore composed of a conditioning process followed by the export system and if necessary a reconditioning step.

2.1.1 Offshore pipeline

To reach a pressure of 200 bar, desired at the inlet of an offshore pipeline[4], conditioning before pipeline transport is therefore needed, and consists of compression stages and pumping, combined with the removal of unwanted components (dehydration)[5]. In order to assess the conditioning characteristics, simulations are performed under Aspen HYSYS® v7.2 using the Peng-Robinson thermodynamic property package. The process was modelled into four compression stages with intercooling followed by

[3] The CO_2 stream is assumed to be composed of only CO_2 (96.7 $\%_{mass}$) and water (3.3 $\%_{mass}$). In practice, depending on the source characteristics, NO_X, SO_X and non-condensibles will also have to be removed.
[4] Prohibitive subsea pumping costs make high pressures essential at offshore pipeline inlets.
[5] The glycol dehydration unit is not included in the assessment.

a pumping stage to reach 200 bar (Romeo et al., 2009), as shown in Fig. 3 and with the characteristics given in Table 1. The conditioning before pipeline export is assessed on a 10 $MtCO_2/y$ annual capacity basis, while subsequent cost scaling for the range of capacities considered is performed using the methodology presented in 2.2.1.

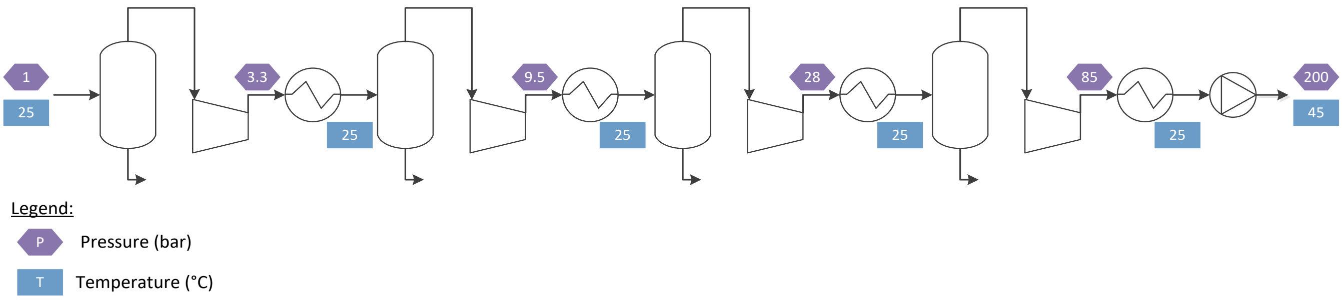


Fig. 3: Conditioning to pipeline export process flow diagram

Table 1: Offshore pipeline transport characteristics

	Parameter	Value	Unit	Reference
System	Inlet pressure	1	bar	(Husebye et al., 2012)
	Inlet temperature	25	°C	(Husebye et al., 2012)
	Pressure after conditioning	200	bar	(Mikunda et al., 2011)
	Temperature after conditioning	45	°C	HYSYS process simulation
	Wellhead pressure	≥60	bar	(European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b)
	Wellhead temperature	~4	°C	(Vermeulen, 2011)
Conditioning	Number of compression stages	4	-	(Romeo et al., 2009)
	Pressure ratio	~3	-	(Romeo et al., 2009)
	Gas temperature after intermediary cooling	25	°C	(Romeo et al., 2009)
	Inlet cooling water temperature	15	°C	(Haugen et al., 2009)
	Compressor adiabatic efficiency	90	%	(Muto and Kato, 2007; Ramgen Power Systems, 2014)
	Pump adiabatic efficiency	75	%	(Knoope et al., 2014)
	CO_2 purity after conditioning	99.93	%mass	HYSYS process simulation
	Water content after conditioning	0.07	%mass	HYSYS process simulation
Export pipeline and riser	Range of pipeline diameter	12¾ to 44	in	(American Petroleum Institute, 1990)
	Over length factor[6]	10	%	
	Design pressure	250	bar	(European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b)
	Minimum allowed pressure	60	bar	(European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b)
	Average temperature[7]	~4	°C	(Bureau-Cauchois et al., 2011b)
	Well head depth	500	m	(Chiyoda Corporation, 2013)
	Flexible pipeline riser length	600	m	

Before the offshore pipeline, a flexible pipeline riser is used to transport the CO_2 from the shore to the seabed. Depending on the water depth, the liquid head provides an approximately 10 bar safety margin for the pressure drops in the injection network.
Due to the prohibitive cost of subsea pumping, no reboosting is considered along the offshore pipeline, and therefore the pressure drop must therefore be limited in order to keep the outlet pressure above 60 bar, as shown in Fig. 4. Here, 17 pipeline diameters ranging from 12.75" to 44" were considered. Depending on the diameter, the offshore pipeline chain has different characteristics: pressure drops, costs, etc. The pipeline designs are based on minimal wall thickness required calculations (McCoy,

[6] The overall pipeline length is assumed to be 10% longer than the transport distance in order to take into account tee junctions, terrain factors, etc.
[7] As the pipeline is mainly located at the bottom of the sea where the water is at 4°C, the CO_2 will rapidly get cold and be more dense that at ambient temperature

2009) with the characteristics given in Table 1and following the API specification 5L standard (American Petroleum Institute, 1990). The pressure drops are calculated using the Fanning equation, considering no elevation effect (Serpa et al., 2011). For each capacity and distance, the cost-optimal diameter and associated characteristics (cost, climate impact...) are determined following the flowchart given in Fig. 5. It is worth noting that for offshore pipelines the smallest diameter which ensures that pressure drops are lower than the maximum allowable pressure is the cost-optimal diameter as pipeline investments increase with the diameter and that there is no subsea reboosting possible.

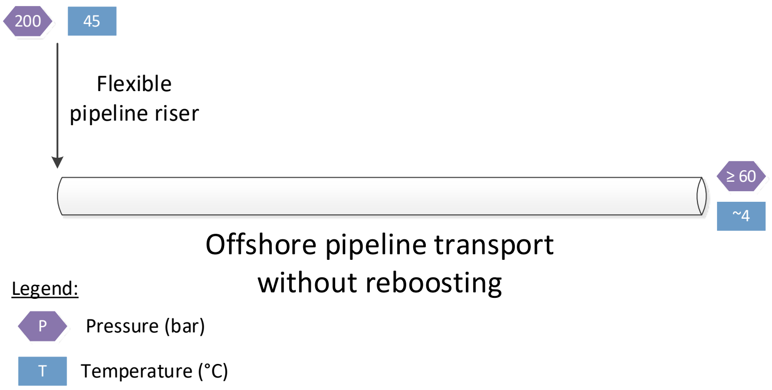


Fig. 4: Schematic design of the offshore pipeline export system

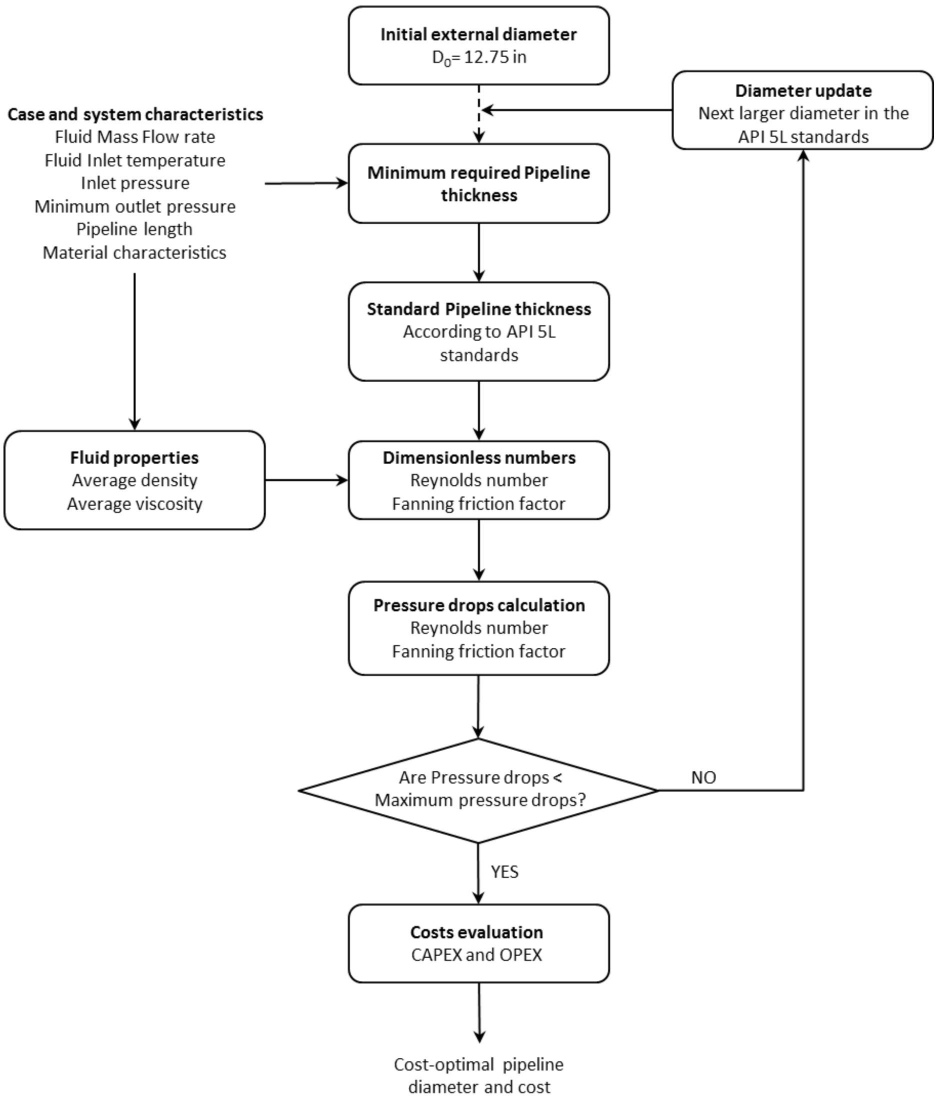


Fig. 5: Flowchart illustrating the method used to determine the optimal pipeline diameter and cost for a fixed distance and capacity

2.1.2 Shipping to an offshore site

To obtain liquid CO_2 at 6.5 bar and -50 °C (Aspelund et al., 2005), conditioning before shipping transport is therefore required, and consists of compression stages followed by a liquefaction process using ammonia cooling cycles, combined with the removal of unwanted components (dehydration)[8]. In order to assess the characteristics of the conditioning process, simulations are performed using Aspen HYSYS® v7.2 using the Peng-Robinson thermodynamic property package. The process was modelled into three compression stages followed by ammonia cooling, liquefaction by expansion and recycling of the remaining gaseous part of the stream (Alabdulkarem et al., 2012) as shown in Fig. 6 and with the characteristics given in Table 2. Conditioning before shipping export is assessed on a 10 $MtCO_2/y$ annual capacity basis, while subsequent cost scaling for the range of capacities considered is performed using the methodology presented in 2.2.1

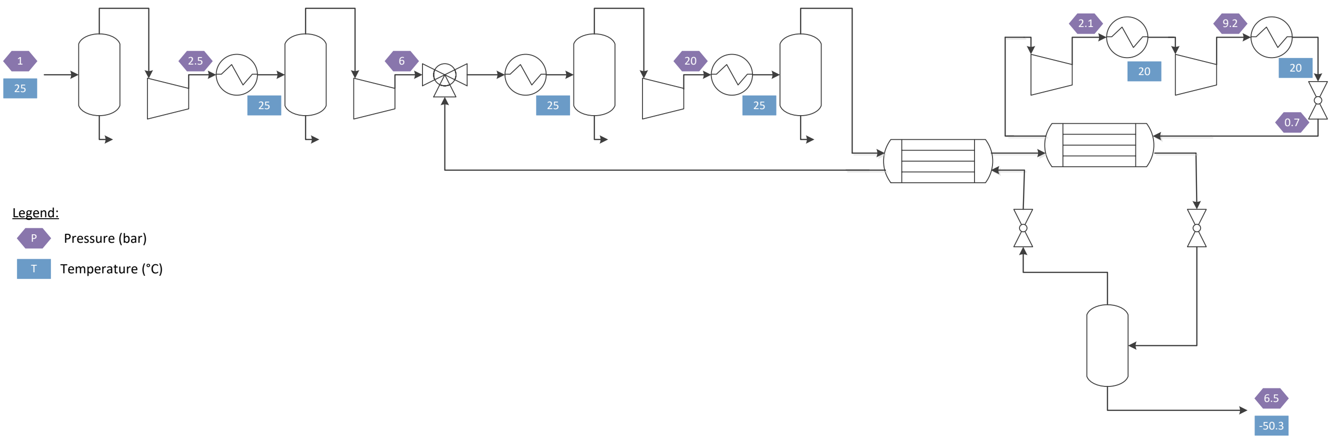


Fig. 6: Conditioning to shipping export process flow diagram

While liquefaction is a continuous process, shipping involves batch exports, and cryogenic buffer storages are therefore required after liquefaction as shown in Fig. 7. Depending on the ship size considered, the shipping chain has different characteristics: the fleet size, cryogenic buffer storage capacity, fuel consumption, associated costs, etc. Three ship sizes are considered here with the associated characteristics given in Table 3. The volume of the cryogenic buffer storage before export is considered to be equal to the ship's cargo volume (European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b). For each ship size, the fuel consumption is assumed to be proportional to the distance and transported volume; however it is worth noting that larger ship sizes lead to lower fuel consumption as shown in Table 3. Fuel consumption estimates are based on Roussanaly et al. figures (Roussanaly et al., 2013b).

At the offshore site, a cryogenic buffer storage is also required to ensure a continuous injection. It is considered that this buffer will be ensured by a ship of the same volume than the others of the supply fleet (European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b). The on-board reconditioning of CO_2 involves repumping to 60 bar followed by heating using sea water to ensure a temperature after reconditioning above 0°C, as shown in Fig. 8. Simulations are performed using Aspen HYSYS® v7.2 to assess the characteristics of the on-board reconditioning process for an annual capacity of 10 $MtCO_2/y$, while subsequent cost scaling is performed for a range of capacities. The electricity for on-board reconditioning is generated by burning bunkers fuel with a conversion factor of 12029 kWh/t_{fuel} (Carbon trust, 2011).

Finally, a flexible pipeline riser is used to transport the CO_2 from the ship to the seabed. Depending on the water depth, the liquid head will provide an approximately 10 bar safety margin for the pressure drops in the offloading hose and injection network.

[8] The glycol dehydration unit is not included in the assessment.

Table 2: Shipping transport characteristics

	Parameter	Value	Unit	Reference
System	Inlet pressure	1	bar	(Husebye et al., 2012)
	Inlet temperature	25	°C	(Husebye et al., 2012)
	Pressure after conditioning	6.5	bar	(Alabdulkarem et al., 2012)
	Temperature after conditioning	-50.3	°C	(Alabdulkarem et al., 2012)
	Pressure after reconditioning	60	bar	(Vermeulen, 2011)
	Temperature after reconditioning	~0	°C	(Vermeulen, 2011)
	Wellhead pressure	≥60	bar	(European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b)
	Wellhead temperature	~4	°C	(Vermeulen, 2011)
Conditioning	Number of compression stages	3	-	(Romeo et al., 2009)
	Pressure ratio	~3	-	(Romeo et al., 2009)
	Gas temperature after intermediary cooling	25	°C	(Romeo et al., 2009)
	Inlet cooling water temperature	15	°C	(Haugen et al., 2009)
	Compressor efficiency	90	%	(Muto and Kato, 2007; Ramgen Power Systems, 2014)
	Pump efficiency	75	%	(Knoope et al., 2014)
	CO_2 purity after conditioning	99.92	%mass	HYSYS process simulation
	Water content after conditioning	0.08	%mass	HYSYS process simulation
Shipping	Shipping cycle duration without the transport time[9]	24	h	(European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b)
	Shipping service speed[10]	14	knots	(European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b)
	Ship operating time[11]	350	d/y	(Roussanaly et al., 2013b)
Reconditioning and riser	Inlet sea water temperature	15	°C	(Vermeulen, 2011)
	Outlet sea water temperature	13	°C	(Vermeulen, 2011)
	Shipping fuel conversion factor	12,029	kWh/t_{fuel}	(Carbon trust, 2011)
	On-ship pumps efficiency	75	[%]	(Knoope et al., 2014)
	Unitary CO_2 pump power	1,200	kW/pump	Vendors contact
	Well head depth	500	m	(Chiyoda Corporation, 2013)
	Flexible pipeline riser length	600	m	

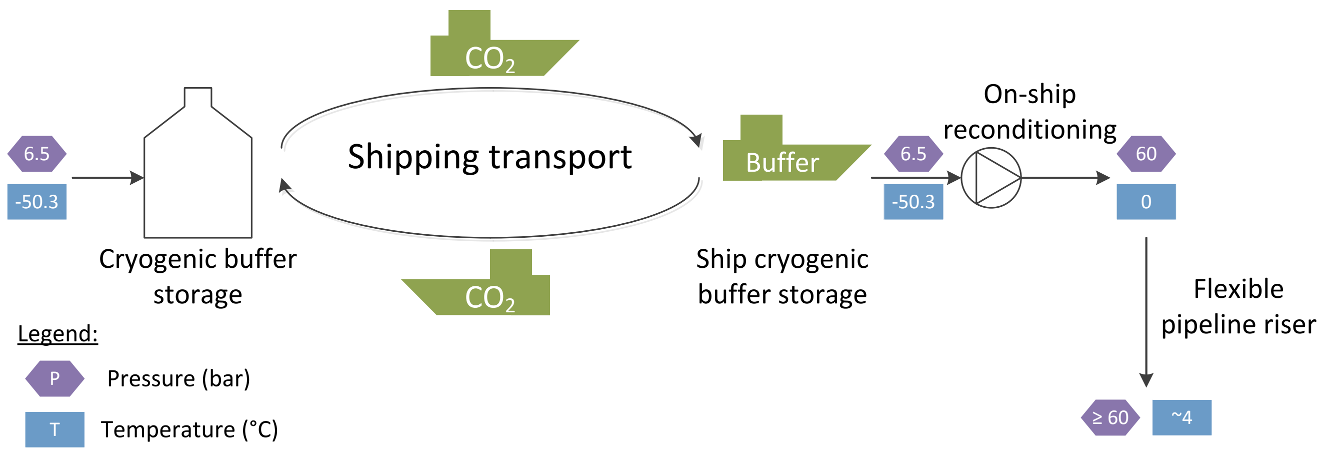


Fig. 7: Schematic design of the shipping export system

[9] Assuming mooring/loading/departure and mooring/unloading/departure durations of 12 h each.
[10] Corresponding to 25.9 km/h.
[11] 360 h (15 days) per year are used for maintenance.

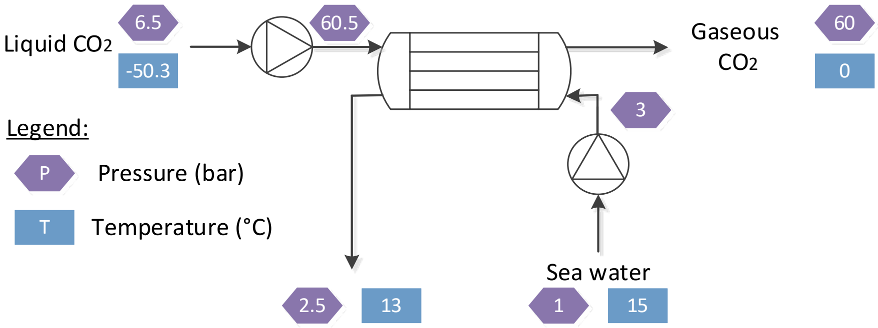


Fig. 8: Schematic design of the on-ship reconditioning (Vermeulen, 2011)

Table 3: Shipping characteristics depending on the ship size (Roussanaly et al., 2013b)

Ship size [t_{CO2}]	Cryogenic buffer storage [t_{CO2}]	Unitary fuel consumption [g_{fuel}/t_{CO2}/km]	Ship cryogenic buffer storage [t_{CO2}]
25,000	25,000	6.20	25,000
35,000	35,000	5.73	35,000
45,000	45,000	5.41	45,000

2.2 Cost evaluation

2.2.1 Investment costs

This study assumes costs of a "NOAK" (Nth Of A Kind) transport system to be built at some time in the future, when the technology is mature. NOAK cost estimates reflect the expected benefits of technological learning, but they may not adequately take into account the increased costs that typically occur in the early stages of commercialization (Metz et al., 2005). In practice, "FOAK" (First Of A Kind) systems can lead to higher investment costs than NOAK due to, for example, sub-optimal design, additional construction costs due to retrofitting, higher margin from contractors to face the risk of cost overrun, delays in construction, additional safety measures, etc.
Two investment costs estimation methods are used: a general method for process units and a more specific one for pipelines. Investment costs are given in 2009 prices or reported using the CEPCI Index (Chemical Engineering, 2016). However in the cash flow profile, the investment costs are reported as an overnight cost assuming an equally-shared investment over the construction time. For instance, process plants, ships and offshore pipeline are assumed to be built over three years (Schach et al., 2010).

- Factor methodology

A factor estimation method is used in order to estimate investment costs of the process equipment for the design capacity (10 MtCO_2/y), where the estimated equipment costs are multiplied by direct[12] and indirect[13] cost factors to obtain the investment costs. European-based equipment costs and direct costs (€$_{2009}$) of carbon steel equipment are estimated using Aspen Process Economic Analyzer® v7.2, based on results from the process simulations in Aspen HYSYS®. Based on the cost evaluations of the 10 MtCO_2/y process equipment, the subsequent scaling for capacities from 1 to 20 MtCO_2/y uses the equipment cost power law (Equation 1) and installation factors, where EC_0 is the equipment cost of a unit of size S_0, while EC_1 is the equipment cost of a unit of size S_1. The exponential coefficient "n" depends on the equipment as shown in Table 4 (Chauvel, 2003).

$$EC_1 = EC_0 \cdot \left(\frac{S_1}{S_0}\right)^n \qquad (1)$$

[12] Which includes the costs of erection, secondary equipment, piping, insulation, and civil work.
[13] Which includes the costs associated with engineering, commissioning, administration, and contingencies.

Table 4: Exponential coefficient (Chauvel, 2003) and equipment correction factor[14] as function of the equipment type

Equipment	Exponential coefficient	Equipment correction factor
Compressor	0.825	0.57
Heat exchanger	0.65	0.55
Separator	0.65	0.95

The direct cost of a given item of equipment is then calculated by multiplying the component-specific equipment cost by the appropriate direct cost factor (see Table 5) and equipment correction factor[15] (see Table 4).Equipment and direct costs of carbon steel components are adjusted to reflect the cost of stainless steel. This is adjusted by multiplying direct costs by a material factor of 1.3 for machined equipment (pumps and blowers) and 1.75 for welded equipment (columns and heat exchangers) (Eldrup, 2009). The investment cost of a given equipment is then calculated by multiplying the component's specific direct cost by the appropriate indirect cost factor (see Table 6).

Table 5: Direct cost factor as function of equipment cost (Eldrup, 2009)

Equipment cost lower limit (k€)	0	2	12	60	119	239	597	> 1,792
Equipment cost higher limit (k€)	2	12	60	119	239	597	1,792	
Direct cost factor	10.26	6.32	4.29	3.53	3.07	2.61	2.39	2.02

Table 6: Indirect cost factor as function of direct cost (Eldrup, 2009)

Direct cost lower limit (k€)	0	15	51	211	367	624	1,428	> 3,620
Direct cost higher limit (k€)	15	51	211	367	624	1,428	3,620	
Indirect cost factor	2.23	1.86	1.71	1.65	1.63	1.59	1.58	1.50

The total investment cost in €$_{2009}$ is then determined by summarizing the estimated investment cost for all components within defined system boundaries (Equation 2).

$$\text{Total investment cost} = \sum (\text{Equipment cost} \cdot \text{Direct cost factor} \cdot \text{Equipment correction factor} \cdot \text{Material factor} \cdot \text{Indirect cost factor}) \quad (2)$$

However due to their specificity, CO_2 pumps (before pipeline export and for the on-ship reconditioning) and CO_2 carriers are estimated differently. The installed cost of pumps has been estimated to 1.66 M€ per pump of 1,200 kW based on vendor contacts. Ships investment cost is determined using the total investment cost per ship (Roussanaly et al., 2013b), which is a function of its effective capacity as shown in Table 7 while investments for loading and unloading are included in harbour fees.

Table 7: Ship investment and fixed operating costs (Drewry, 2009; Roussanaly et al., 2013b)

Ship size [tCO_2]	Total investment cost [M€/ship]	Annual ship fixed operating cost [M€/y/ship]
25,000	40	2.0
35,000	47	2.3
45,000	54	2.4

[14] Developed based on equipment and direct costs evaluation using Aspen Process Economic Analyzer® for a range of equipment costs and each type of equipment.
[15] The direct cost factor methodology is representative of the global relationship between the equipment cost and direct cost. However, based on evaluations made using the Aspen Process Economic Analyzer®, an adaptation was deemed necessary to model the specificity of each equipment. Correction factors have therefore been developed to evaluate with a higher accuracy the direct cost considering the type of equipment.

- Pipeline methodology

The offshore pipeline investment costs are determined assuming an installed cost of 71,065 $€_{2009}$/"/km[16] based on the EU FP7 CO2Europipe project (Mikunda et al., 2011). This cost, adapted to a North-West European concept, is based on a maximum operating pressure of 200 bar for offshore transport.
The cost of the pipeline riser is based on a reference cost of 7.7M€[17] for a 1 $MtCO_2$/y (Chiyoda Corporation, 2013) and scaled up assuming costs linear to the diameter[18].

2.2.2 Maintenance and operating costs

2.2.2.1 Fixed operating costs

Fixed operating costs cover maintenance, insurance, and labour costs. The annual fixed operating cost is set to 6% of investment costs for process units (Chauvel, 2003) while a fixed yearly kilometric cost of 6,633 €/km/y is assumed for pipelines (Mikunda et al., 2011). The annual fixed operating cost of ships is a calculated based on the annual fixed operating cost per ship (Drewry, 2009; Roussanaly et al., 2013b) presented in Table 7.

2.2.2.2 Variable operating costs

Variable operating costs are a function of the amount of CO_2 captured, and cover the consumption of utilities: electricity, steam, cooling water, ships' fuel and harbour fees at the initial harbour. Annual variable operating costs are assessed based on the utilities consumptions estimated in the technical assessment, utility costs and fees shown in Table 8. It is worth noting that harbour fees are halved compared to the transport between harbours presented in our previous work (Roussanaly et al., 2013d) as shipping to an offshore field implies only one harbour.

Table 8: Utility costs and harbour fees

Utilities	Costs	Units	Reference
Electricity	55.5	€/MWh	(The Europe's Energy Portal, 2011)
Cooling water	0.025	€/m^3	(Eldrup, 2009)
Fuel cost	370	€/t_{fuel}	(European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b)
Harbour fees	1	€/t_{CO2}	(Roussanaly et al., 2013b)

2.3 Greenhouse Gases assessment

The GHG emissions caused by the activities associated with the CO_2 transport systems are evaluated via a hybrid-LCA approach. Hybrid-LCA assessments combine physical process data with economic data (Strømman and Solli, 2008), and enable the inclusion of emissions that would have been lost if only physical process data were considered (Suh, 2004).
GHG emissions from material and energy flows are modelled using European-based data (Table 9) from Ecoinvent v2.2 (EcoInvent, 2012), while GHG emissions associated with capital and operating expenses are modelled using data (Table 10) from the Carnegie Mellon University Economic Input-Output Life Cycle Assessment method (EIO-LCA) (Carnegie Mellon University - Green Design Institute, 2008), which is based on economic and environmental data from the US economy in 2002[19].

[16] 75,000 $€_{2010}$/"/km. As an indication, the pipeline investment cost given by the EU FP7 CO2Europipe project shows that an offshore pipeline will be 50% more expensive than an onshore pipeline of the same length and diameter.
[17] 900 $M¥_{2012}$ assuming a well head depth is 500 m below the sea surface.
[18] And therefore a 0.5 power factor on the capacity.
[19] The IO data refer to the U.S. economy in 2002, and to convert it into 2009 equivalents in euros, a conversion factor of 0.74 EUR_{2009}/USD_{2002} was used for capital investments based on the CEPCI and exchange rate, and 0.92 EUR_{2009}/USD_{2002} for operating expenses based on inflation and exchange rate.

Table 9: Overview of Ecoinvent process used to model the physical flows (EcoInvent, 2012)

Physical processes related GHG emissions	GWP factor	Unit
Carbon Steel at factory	1.45	kg CO_2e / kg steel
Drawing of steel pipes	0.43	kg CO_2e / kg steel
Electricity, medium voltage at grid, European mix	0.50	kg CO_2e / kWh
Heavy fuel oil, at regional storage/RER U	0.45	kg CO_2e / kg oil
Burning of heavy fuel oil in tanker	3.11	kg CO_2e / kg oil

Table 10: Overview of entries in used to model the monetary flows (Carnegie Mellon University - Green Design Institute, 2008)

Expenses related GHG emissions	GWP factor	Unit
Pump and pumping equipment manufacturing	0.56	kg CO_2e / $\$_{2002}$
Non-residential maintenance and repair	0.62	kg CO_2e / $\$_{2002}$
Non-residential manufacturing structures	0.44	kg CO_2e / $\$_{2002}$
Air and gas compressor manufacturing	0.56	kg CO_2e / $\$_{2002}$
Ship building and repairing	0.73	kg CO_2e / $\$_{2002}$
Scenic and sightseeing transportation and support activities for transportation	0.50	kg CO_2e / $\$_{2002}$
Pipeline riser[20]	1.16	kg CO_2e / $\$_{2002}$

The GHG emissions are converted into CO_2 equivalents (CO_2e) according to the IPCC guidelines (Solomon et al., 2007) and their sum indicates the potential climate effect and is often referred to as the global warming potential (GWP).
The availability of cost-related climate impact factors dedicated to CCS in a European context is very limited. It is therefore difficult to evaluate the quality of the data from Carnegie Mellon University Economic Input-Output Life Cycle Assessment database, and whether they are representative of European conditions. Data such as these are under continuous development (Hertwich and Peters, 2009) and are expected to increase in availability and quality (Tukker et al., 2009). Modules already developed will therefore be updated as better databases become available.
The GHG assessment of the offshore pipeline is based on the same parameters as the onshore pipeline. The GHG emissions of an offshore pipeline would however be higher than for an onshore pipeline as offshore pipeline require more materials, construction work, operational inputs, and will therefore lead to more greenhouse gases emissions.
As for the onshore transport (Roussanaly et al., 2013d), the amount of CO_2e emitted by the CO_2 transport is rather small compared to the amount transported[21], around 0.9 and 1.7% for pipeline and shipping transport respectively, at the distances where the cost-optimal technology passes from one to the other. However, it is important to include it in order to perform a full and consistent assessment of the chains.

2.4 Comparison of the two transport technologies

Offshore pipeline and CO_2 shipping to an offshore site are compared for various distances and capacities. For each technology several options are possible (pipeline diameter and shipping size), the optimal options of each transport options should be selected before the two cost-optimized supply chains are compared as shown in Fig. 2.
The CO_2 avoided transport cost [€/t] is used here as a key performance indicator to compare the two transport technologies, including their greenhouse gases emissions (Ho et al., 2011) through the annualized amount of CO_2 equivalent emitted. The CO_2 avoided transport cost approximates the

[20] The GWP factor for riser pipeline is not available in any of the database. To be consistent with the methodology, it was calculated using the transport module to assess the average climate impact of a 500m pipeline, considering an over-length of 20%, for different capacities and associated costs.

[21] Most of the difference between CO_2 captured and avoided by a CCS chain is due to the capture part of the chain.

average discounted carbon credit per tonne transported over the project duration that would be required as income to match the net present value of capital and operating costs for the project. It is equal to the annualized costs divided by the annual amount of CO_2 transported, less the annualized amount of CO_2 equivalent emitted obtained through the greenhouse gases assessment, as shown in Equation 3. It is estimated on the basis of the methodologies described above, and assuming a base case with a utilization rate of 85%[22] of the designed capacity, a project duration of 30 years, and a real discount rate of 8%[23].

$$CO_2 \text{ avoided transport cost } [€/t] = \frac{\text{Annualized investment + Annual OPEX}}{\text{Annual } CO_2 \text{ transported - Annualized } CO_{2,equivalent} \text{ emitted}} \quad (3)$$

Sensitivity analyses are then performed in order to address and quantify the impact of a range of important issues on the choice of the optimal technology:

- The First Of A Kind effect and the uncertainties in investment costs through the overall investment costs;
- The regional effect of pipeline costs and uncertainties in pipeline investment costs through the pipeline investment costs;
- The project ownership effect through the project discount rate;
- The geographical context through the ratio between the pipeline and shipping distances;
- The effect of fluctuations and storage availability through the utilization rate;
- Uncertainties regarding the future of CCS and financial risks through the project duration;
- Future energy prices through the electricity and ship fuel costs.

3 Results

3.1 Base Case

The results of the comparison of offshore pipeline and shipping to an offshore site based on CO_2 avoided transport cost are illustrated in Fig. 9 for various distances and annual capacities while the corresponding CO_2 avoided transport costs of both technologies are detailed in Tables 12 and 13. As for the onshore case (Roussanaly et al., 2013d), for a fixed capacity, the offshore pipeline transport is the most cost-efficient option for "short" distances while shipping to an offshore site shall be used for longer distances. Regarding the impact of the capacity, Fig. 9 shows that higher capacities benefit to offshore pipeline transport as the switching distance between the transport technologies increase. The switching distance between the two transport technologies rises from around 225 to around 625 km when the annual capacity increases from 2 to 20 $MtCO_2/y$. Indeed, as illustrated in the pipeline literature (Chandel et al., 2010; McCoy, 2009; Metz et al., 2005), the high transport capacity lead to significant economy of scale for pipeline which are less important for the case of CO_2 shipping.

Fig. 9 can also be used as a guide to draw conclusions on specific cases under the hypotheses presented in this paper. As an example of how Fig. 9 can be used, one may conclude that a stand-alone project considering a coal-fired power plant with CO_2 capture transport and storage, capturing 4 $MtCO_2/y$ [24] will use an offshore pipeline to transport its emissions if the transport distance is lower than 325 km. However, if the coal-fired power plant combines the transport of its emissions with those of possible nearby industries to reach 8 or 12 $MtCO_2/y$, the switching distance between offshore pipeline and CO_2 shipping to an offshore site increases respectively to around 375 and 475 km.

As a consequence, offshore CO_2 pipelines appears as the cost-optimal technology to transport CO_2, for example, from the Netherland coast to the Netherland part of the North Sea, from British coast to the British part of the North Sea, and from the Norwegian coast to the Norwegian part of the North Sea. On the other hand, when considering transport of CO_2 from a country coast to outside of its national sea, shipping can become a more cost-attractive option than offshore pipeline for example in the case of

[22] The yearly profile is here regarded as being divided into two periods of equal duration. The first period operates at full capacity while the infrastructure operates at a constant flow equal to 70% of the designed capacity during the second period, which leads to an average annual utilisation rate of 85%.

[23] A real discount rate of 8% corresponds to a nominal discount rate around 10% when considering an inflation rate of 2%.

[24] Corresponding to the annual emissions of a coal-fired power plant producing 1GWe.

transport of CO_2 from Netherland to the Norwegian part of the North Sea. However these results may lead to different conclusions in the case of network deployment and when considering the financial risks associated with offshore pipeline investments.
It is worth noting that this "optimisation" problem is discontinuous and that here the switching distances between the two transport technologies is therefore approximated by a continuous delimitation, as shown in Fig. 9.

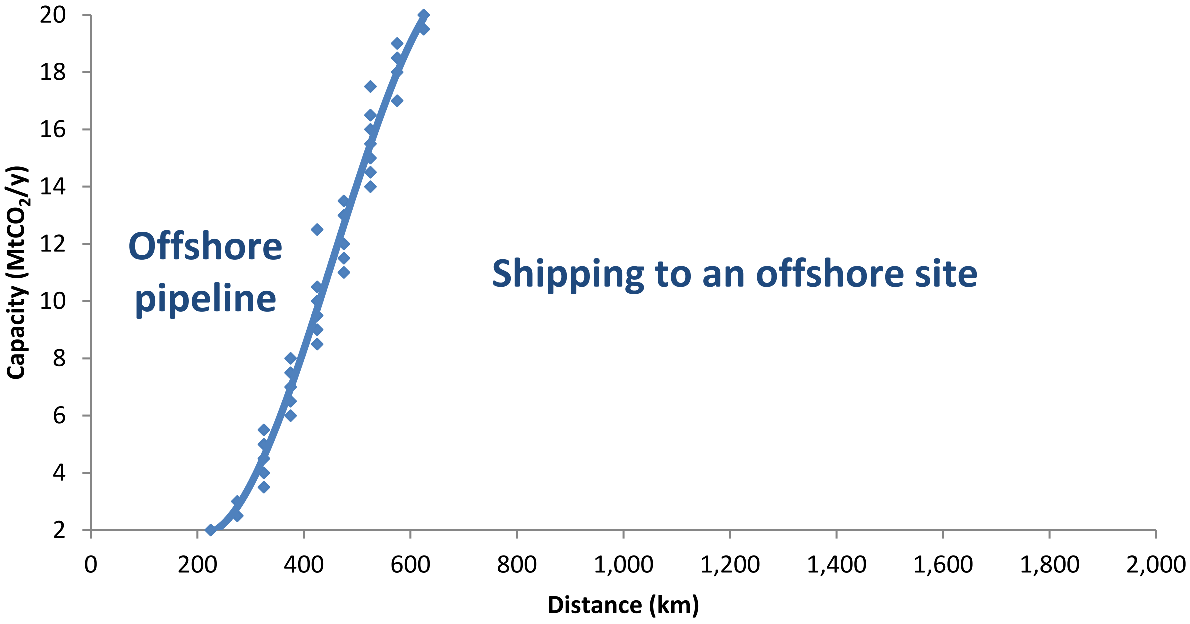


Fig. 9: Benchmark between offshore pipeline and shipping to an offshore site

3.2 Sensitivity analyses

3.2.1 Overall CAPEX: The First Of A Kind (FOAK) effect and uncertainties on investments

Cost estimates available in the literature and cost estimation tools often refer to Nth Of A Kind (NOAK) transport system to be built sometime in the future when the technology is mature, which reflects the expected benefits of technological learning. However, the FOAK issue and the increased costs that typically occur in the early stages of commercialization (Eldrup and Røkke, 2011; Metz et al., 2005) are often left untreated. In practice, the different parts of the transport system may lead to higher investment costs due to for example sub-optimal design, additional construction costs due to retrofitting, higher margin from contractors to face the risk of cost overrun, delays in construction, additional safety measures while operating costs are impacted to a smaller extent (Al-Juaied and Whitmore, 2009; Bonsu et al., 2006; Eldrup and Røkke, 2011; Mississippi Power, 2009; Montel Powernews, 2008). As an example, in the case of an IGCC plant with CO_2 capture, Al-Juaied and Whitmore (Al-Juaied and Whitmore, 2009) estimate the increase in capital costs to 25% based on different project descriptions (Bonsu et al., 2006; Mississippi Power, 2009; Montel Powernews, 2008). The impact of the FOAK issue on the optimal technology is addressed here, considering that the first CCS infrastructures to be built will require higher investment costs.
As Fig. 10 shows, the FOAK effect and cases with higher investments that the base case will increase the range within which shipping is the preferred technology, as pipeline transport has higher investment costs.
On the other hand, if in the future CCS transport technologies advance more rapidly than currently expected and in cases with lower investments than the base case will therefore benefit pipeline transport as shown in Fig. 10.

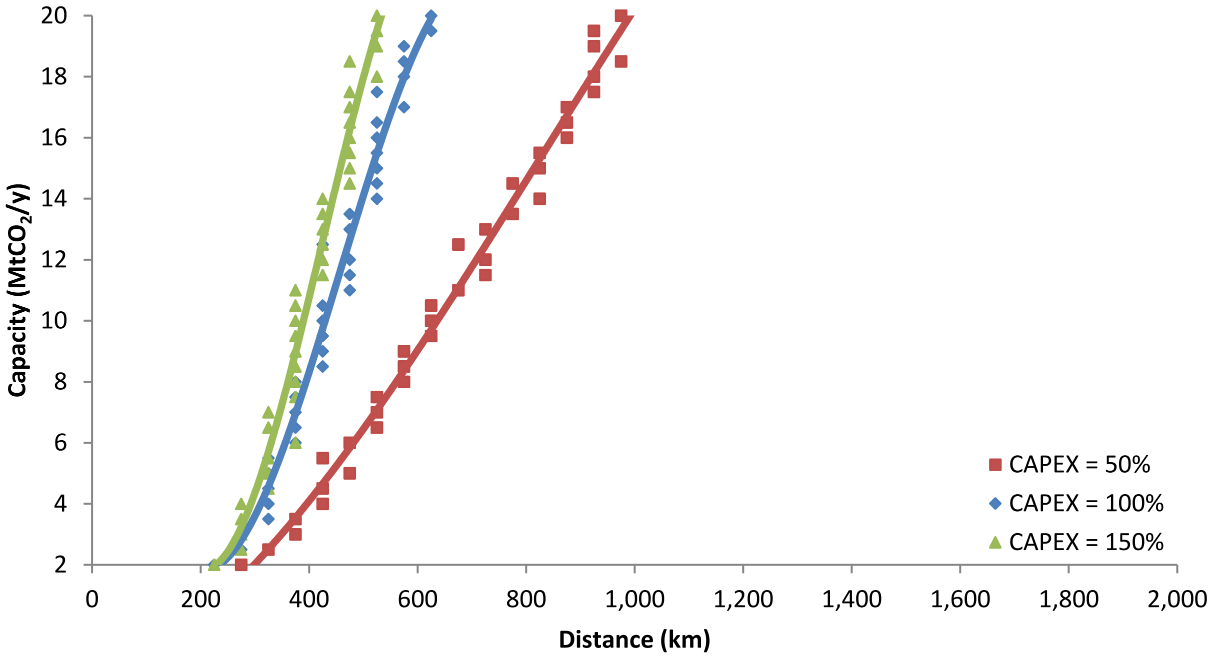


Fig. 10: Impact of overall CAPEX on the benchmark between offshore pipeline and shipping to an offshore site

3.2.2 Pipeline investment costs: The regional effect of pipeline costs and uncertainties in pipeline investment costs

As illustrated by Knoope et al. (Knoope et al., 2013), several costs models for onshore and offshore CO_2 pipeline transports have been published over the last ten years (ElementEnergy, 2010; Heddle et al., 2003; International Energy Agency GreenHouse Gas R&D Program (IEAGHG), 2005; Mikunda et al., 2011), with important discrepancies among them. Due to the lack of publicly available industrial cost data and the cost diversity in the literature, it is much more difficult to evaluate offshore CO_2 pipeline investment costs. For instance, pipelines in North American based models have significantly lower investment costs than the recent European models due to, for example, lower material costs and right-of-ways. For example, the MIT cost model representative for North-American based CO_2 pipeline (Heddle et al., 2003) lead to investment costs that are 40% lower than the model suggested by Mikunda et al. (Mikunda et al., 2011) representative for North-Western Europe based CO_2 pipeline.

Based on this, everything else remaining equal, pipeline transport of CO_2 will therefore tend to be more attractive in North America than in North-Western Europe as shown in Fig. 11.

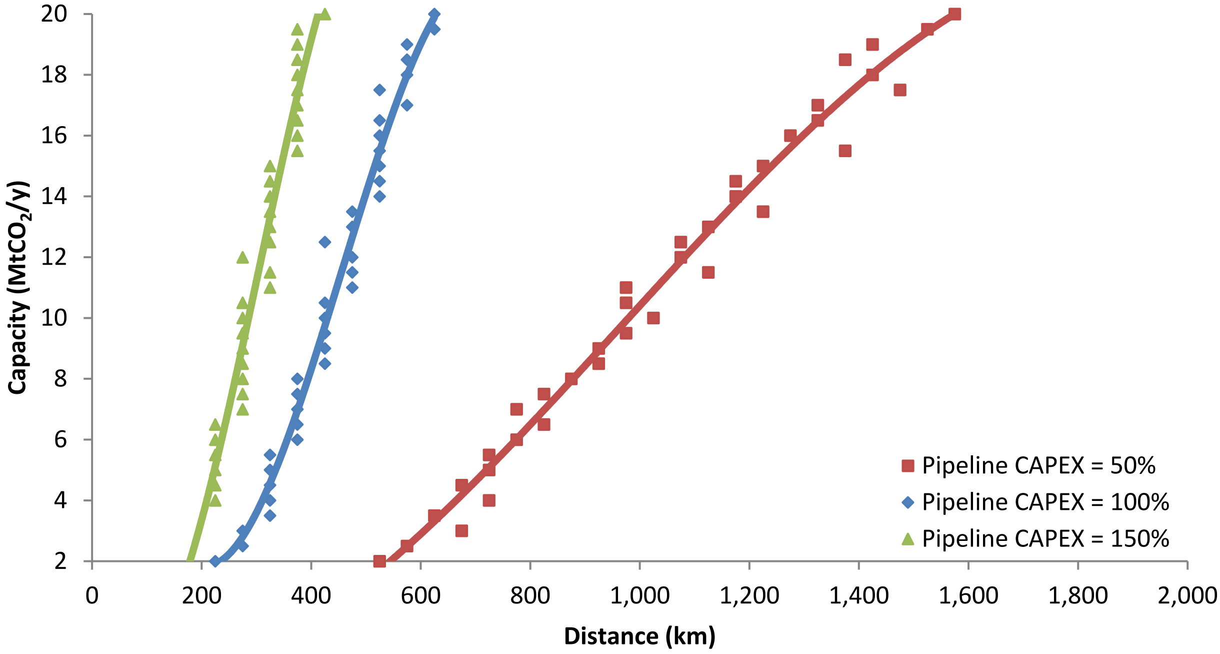


Fig. 11: Impact of the pipeline investment costs on the benchmark between offshore pipeline and shipping to an offshore site

3.2.3 Real discount rate: The project ownership effect

Depending on the project investors, the joint venture will lead to different discount rates and therefore different net present values for the same project costs and revenues. As a consequence, the project ownership can have a significant impact on the technology selection. For example, national authorities use a lower discount rate than average companies, while oil and gas companies and companies dealing with risks use a higher discount rate and risk premium.

As the total amount of CO_2 transported and OPEX are constant throughout the project duration, the discount rate only impacts the CAPEX annuity. The more the discount rate rises, the more important the CAPEX annuity increases, and this will weigh on the CO_2 avoided transport cost. Thus, when the discount rate increases, marine transport becomes more cost-effective, while the pipeline becomes less so, as shown in Fig. 12.

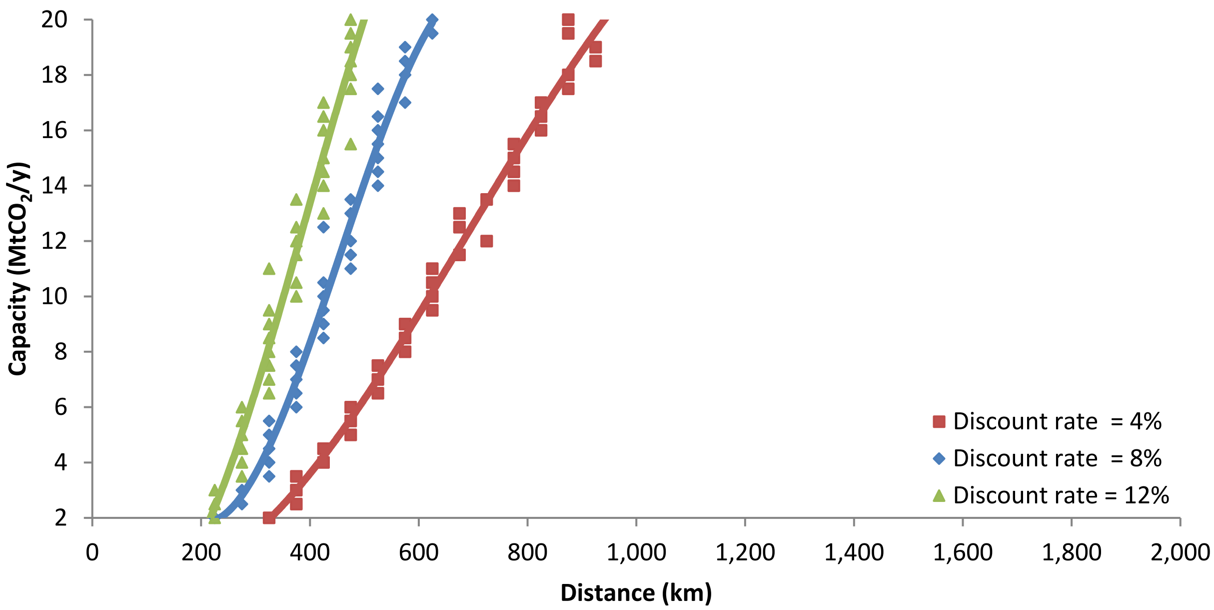


Fig. 12: Impact of the real discount rate on the benchmark between offshore pipeline and shipping to an offshore site

3.2.4 The ratio between the pipeline and shipping distances: The geographical context

The relative distances involved between the pipeline and shipping options are also an important issue for the choice of transport technology. The geographical context may favour either technology. For example, the seabed relief may require detours that increase the overall offshore pipeline length. On the other hand, ships must follow shipping channels, which can also increase the shipping distance.

Fig. 13 highlights the critical importance of the geographical context for the choice of transport technology. Indeed, distance play a major role in transport costs, and therefore in comparing the two technologies. However both transport technologies are impacted in different ways by the transport distance (Metz et al., 2005). As a consequence, a shorter pipeline distance ratio increases the range of conditions favourable to offshore pipeline significantly more than a longer distance decreases it, as illustrated in Fig. 13.

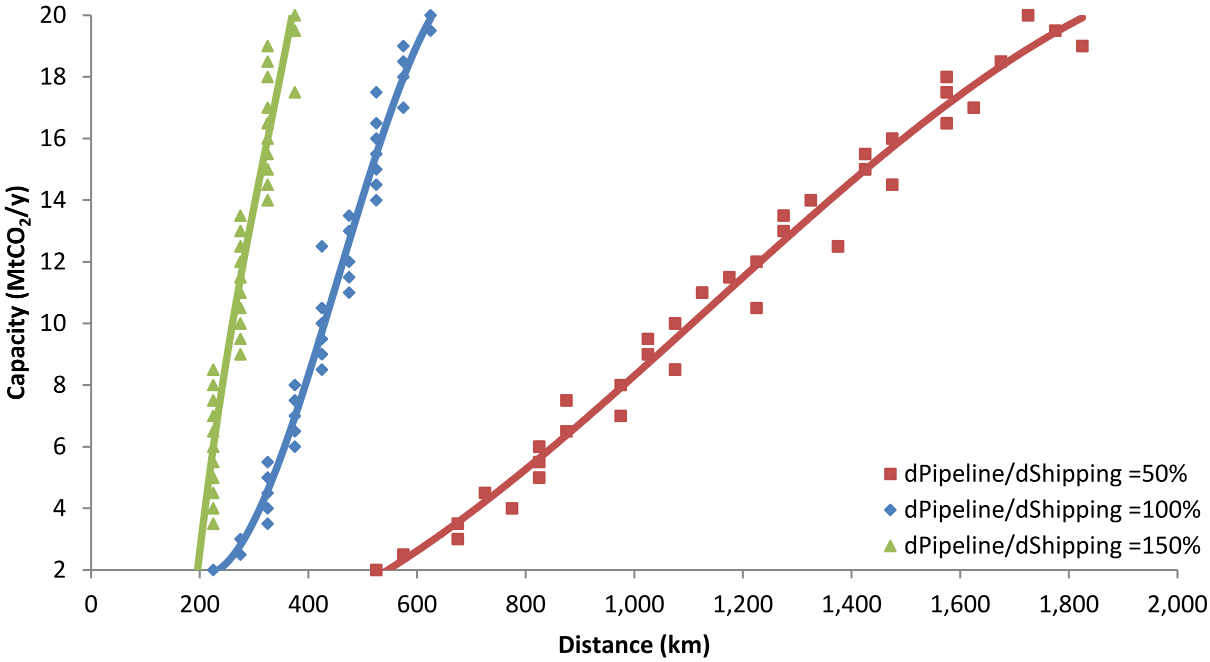


Fig. 13: Impact of the ratio between the pipeline and shipping distances on the benchmark between offshore pipeline and shipping to an offshore site

3.2.5 Utilization rate: The CO_2 fluctuation effect and storage availability

A fundamental difference between pipeline and shipping is the chain flexibility and their differences in response to fluctuations in the volume of CO_2 transported which can be due to fluctuations in the capture profile (Anantharaman et al., 2013) or, for example, storage availability issues (Wang et al., 2012). While fluctuations have a rather limited impact on shipping costs, the optimal pipeline diameter depends on the flow profile due to the non-linear relationship between pressure drops and mass flow. Fluctuations thus increase the cost of pipeline transport and therefore narrow the range in which pipeline is the optimal transport technology, as illustrated in Fig. 14[25].

[25] The yearly profile is here regarded as being divided into two periods of equal duration. The first period operates at full capacity while the infrastructure operates at a constant flow equal to 70% of the designed capacity during the second period, which leads to an average annual utilisation rate of 85%.

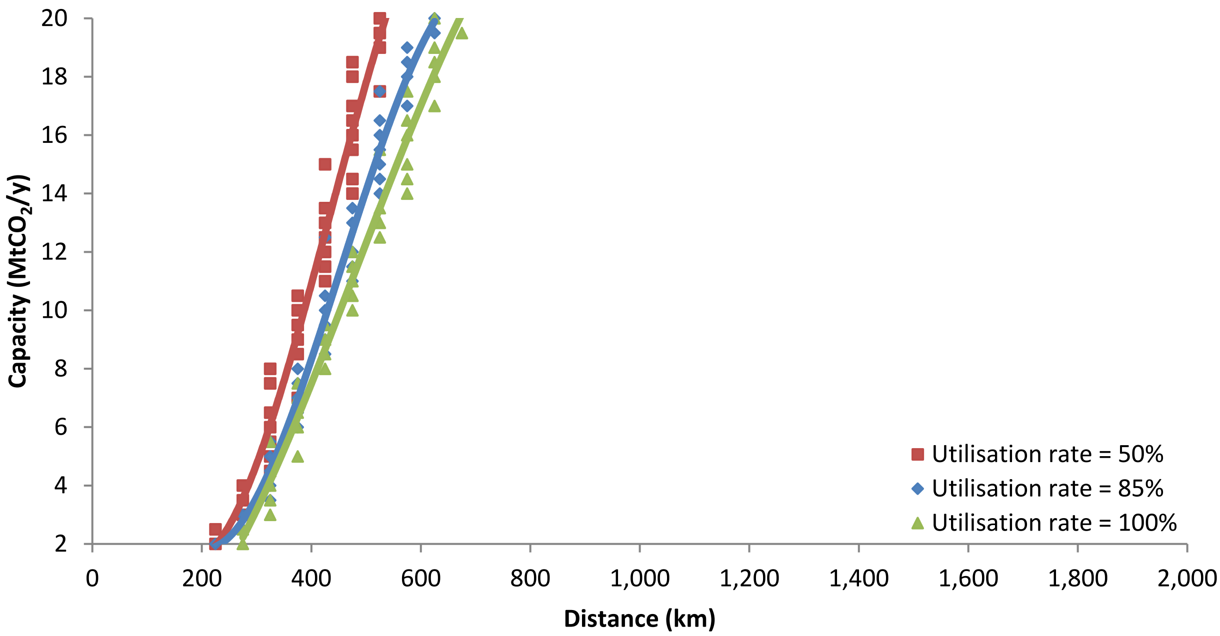


Fig. 14: Impact of the utilization rate on the benchmark between offshore pipeline and shipping to an offshore site

3.2.6 Project duration: Uncertainties on the future of CCS and financial risks

While Roussanaly et al. (Roussanaly et al., 2013b) illustrated the limited influence of the infrastructure lifetime difference between pipeline and shipping on technology selection, one of the major issues before large-scale CCS can be deployed concerns uncertainties regarding the evolution of the carbon credit (quota or tax) and the financial risks it will involve. The importance of this issue is quantified here in terms of the impact of the project duration on the technology selection. As CO_2 pipeline transport is more capital-intensive than shipping, a shorter project duration will increase the CO_2 avoided transport cost of shipping less than pipeline. Fig. 15 illustrates that uncertainties regarding the future of CCS could lead to the selection shipping due to the high investment costs of pipeline transport[26].

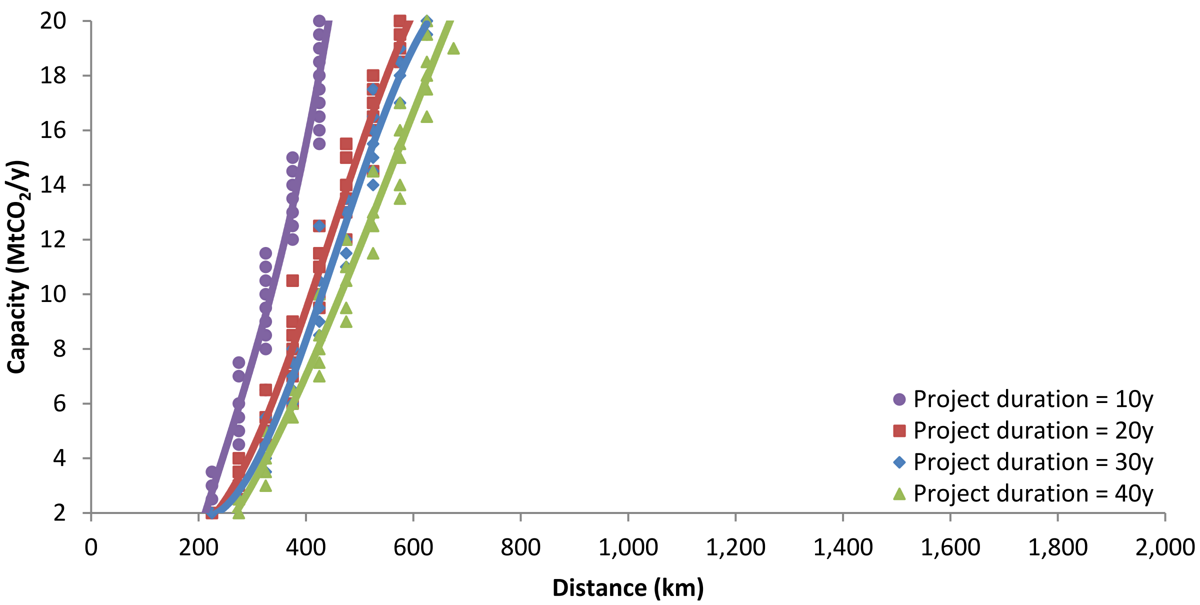


Fig. 15: Impact of the project duration on the benchmark between offshore pipeline and shipping to an offshore site

[26] No future revenues for sales of ships have been taken into account. However, if these are taken into account they will also benefit the selection of shipping.

3.2.7 Energy costs: Future energy prices

Future energy prices[27] represent an important uncertainty for transport costs and therefore the optimal technology selection, as energy costs are not identical for both transport systems. Indeed, as Fig. 16 shows, offshore pipeline transport is a better candidate for a wider range of transport distances and capacities when the electricity price increases due to higher electricity consumption for CO_2 liquefaction than CO_2 compression, while the shipping option would be favoured by an electricity price decrease.

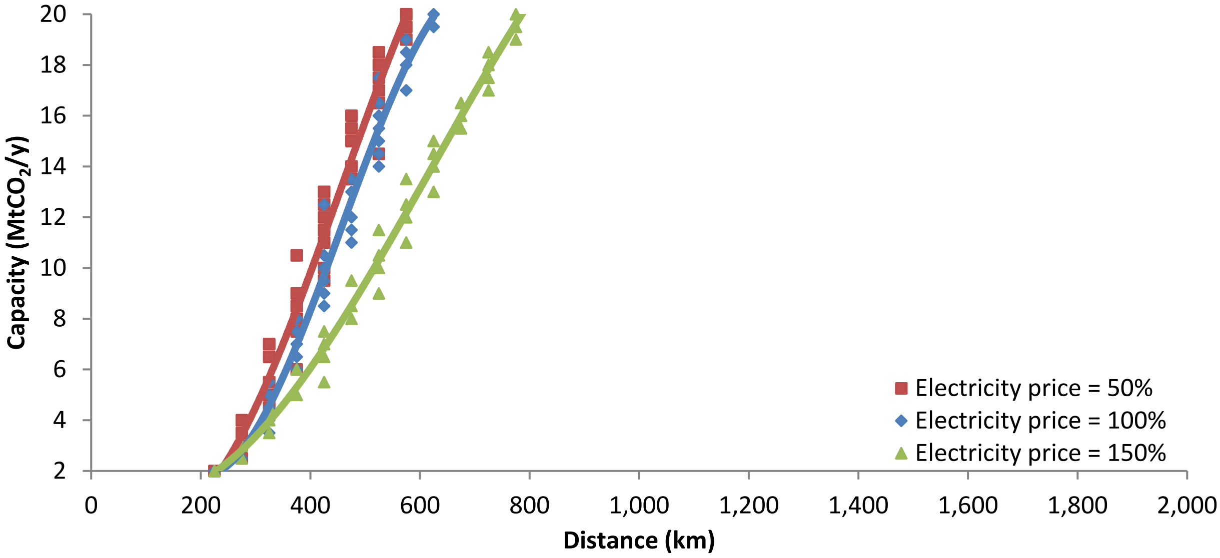
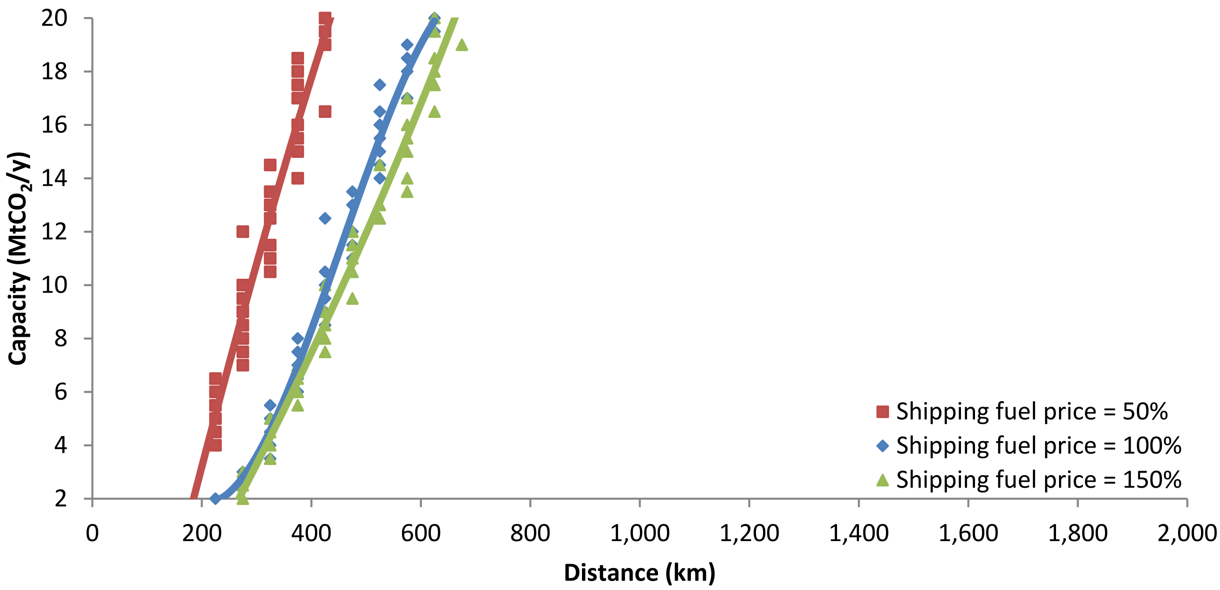


Fig. 16: Impact of future electricity prices on the benchmark between offshore pipeline and shipping to an offshore site

Another cost uncertainty for CO_2 shipping is the shipping fuel cost. In addition to uncertainty regarding the evolution of the price of shipping fuel, certain marine areas, such as the North Sea, are or will be designated Sulphur Emission Controlled Areas in a near future. It is therefore likely that from 2020, ships navigating in these areas will be required to run on low-sulphur fuels which are more expensive than those in current use (International Maritime Organization, 2009; Matthias et al., 2010). Fig. 17 shows that, as expected, a rise in fuel prices favours pipeline transport, while the range within which shipping is the most cost-efficient option increases at lower fuel prices.



[27] As shipping transport does not consume only electricity but also fuel, sensitivity analyses are performed on both electricity and fuel prices.

Fig. 17: Impact of future shipping fuel prices on the benchmark between offshore pipeline and shipping to an offshore site

4 Discussions

4.1 Relative importance of parameters

The impact of each parameter described in section 3.1.2, is measured as the average ratio between the switching distances. The influences of the individual parameters are then ranked based on their importance on the decision regarding which technology should be employed to transport CO_2 to an offshore site. As in the case of transport between two onshore harbours (Roussanaly et al., 2013d), the results of the sensitivity analyses illustrates that the four most influential parameters on the technology choice are: 1) the ratio between the pipeline and shipping distances (i.e. the geographical context) 2) the pipeline investment costs (i.e. the regional effect of pipeline costs and uncertainties in pipeline investment costs) 3) the real discount rate (i.e. the project ownership effect) 4)the overall investments (i.e. the First Of A Kind effect and uncertainties on investments) as shown in Fig. 18. The comparison also shows that halving any of these four parameters will increase the average switching distance between offshore pipeline and shipping by between 45 and 160 %, and therefore significantly favour pipeline transport. Fig. 18 also highlights conditions that favour respectively shipping to an offshore site and offshore pipeline transports, as well as their relative importance.

Knowing the relative importance of these parameters will be of importance for CCS investors, policy-makers, and researchers, as they provide decision-makers with indications regarding important parameters that should be borne in mind to promote cost-efficient deployment of CCS chains and selection of optimal transport technologies. They can also be used by policy-makers in order to provide support in the development of efficient tools to promote early deployment of carbon capture and storage infrastructures. As an example, the results obtained could help to identify potential first projects and contribute to their implementation strategies. The results presented here could also be used to give indications regarding the impact of more complex questions such as the impact of impurities which would simultaneously affect, for example, pipeline investment cost, infrastructure lifetime and pumping cost.

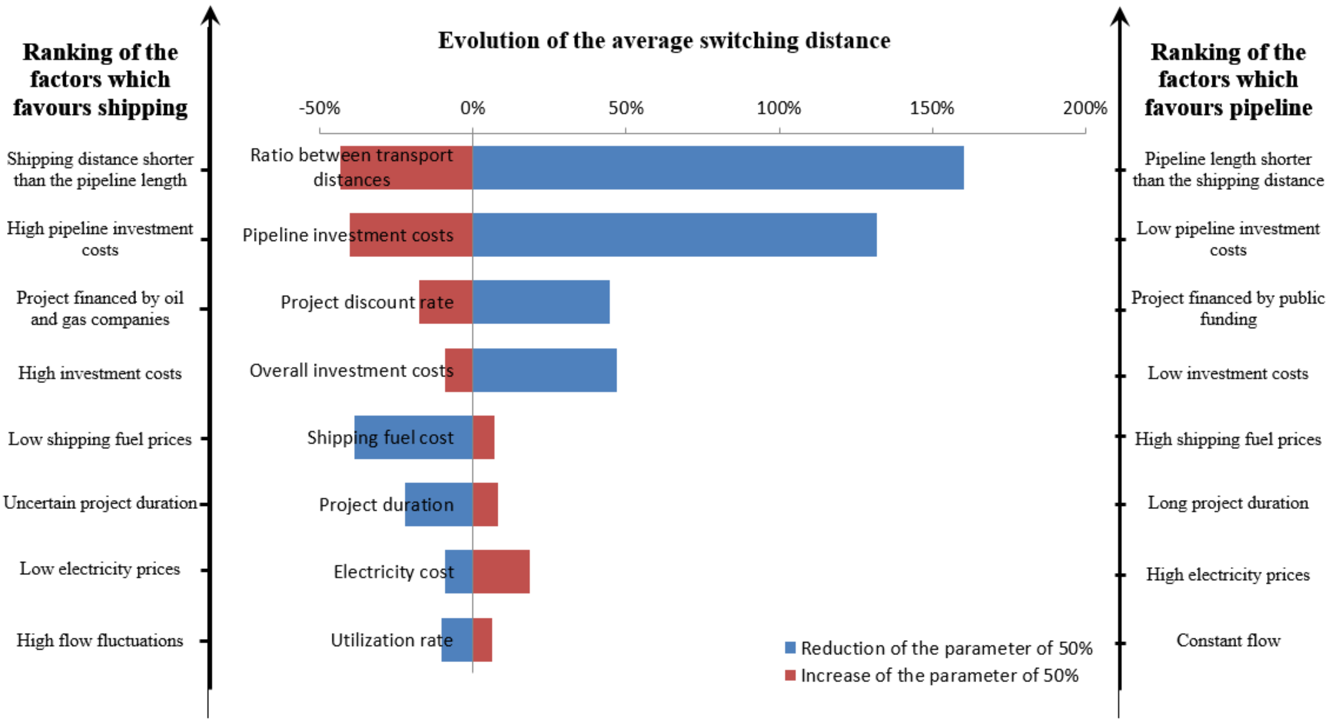


Fig. 18: Ranking of the impact of the different parameters on the switching distance

4.2 Comparisons with the literature

4.2.1 Literature on offshore transport

The results available in the literature (European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b) cannot be directly compared to those presented in this paper. The comparison between offshore pipeline and shipping transport is therefore performed using the BIGCSS modules, and including the following assumptions in order to be consistent with the ZEP assessment:

- A project duration of 40 years;
- A construction period of one year for the CO_2 conditioning plant;
- The cost of liquefaction is increased by 18% (Bureau-Cauchois et al., 2011a)[28] in order to match the CO_2 liquefaction cost of the ZEP report, which considered the liquefaction of CO_2 by expansion, while liquefaction using ammonia cycles has recently been shown to be more energy-efficient (Alabdulkarem et al., 2012) and cost-efficient (Bureau-Cauchois et al., 2011a);
- The investment cost of pipelines are reduced by 25%[29] in order to match the pipeline cost model in the ZEP report;
- No terrain factor is included to evaluate the pipeline;
- No life cycle assessment is included in the calculation of the transport cost.

When these six assumptions are taken into account, the benchmark shows that for 20 $MtCO_2$/y transported, the switch between the two technologies is located around 1325 km with our model as shown in Fig. 19. This is therefore consistent with the values presented by the ZEP, which indicates a switch from offshore pipeline to shipping transport for a distance between 750 and 1500 km, as shown in Table 11, and which would be close to 1500 km according to the small difference between the two transport technology costs at 1500 km.

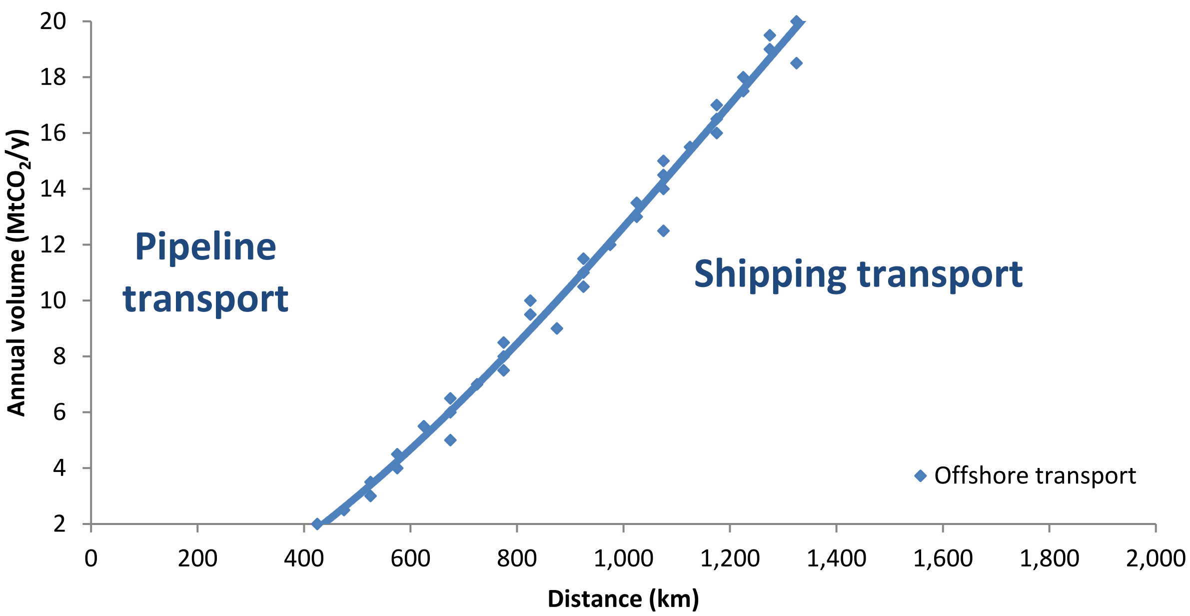


Fig. 19: Benchmark between offshore pipeline and shipping to an offshore site considering the ZEP assumptions

Table 11: ZEP cost evaluations for the transport of 20$MtCO_2$/y using offshore pipeline and shipping

Distances (km)	500	750	1500
Offshore pipeline cost (M€ per a)	94.7	138.1	301.5
Shipping to an offshore site cost (M€ per a)	219.8	240	297.7
Optimal transport technology according to ZEP	Pipeline	Pipeline	Shipping

[28] This value was obtained by comparing the two processes for an annual volume of 13.1 $MtCO_2$/y.
[29] This value is obtained by comparing the pipeline investment cost of the ZEP report (in €/t/in.) for 500, 750 and 1500 km with the model by Mikunda et al. considered in the present paper.

4.2.2 Comparison with the previous results for transport between onshore harbours

Besides comparing the results presented here with the available literature on offshore transport, it is also important to compare them to the results previously presented for the benchmarking of CO_2 transport between onshore harbours (Roussanaly et al., 2013d). For the base case considered, the evaluation shows that the switching distance is in average 40% higher for onshore transport than for offshore transport, as shown in Fig. 20. The main reasons for this difference are both the higher offshore pipeline costs compared to onshore, and the pipeline pressure drops limitation for offshore applications. However this ratio ranges from 20% for low capacities to 50% for high capacities, as at the switching distances for high capacities, the investments required are higher.

Regarding the sensitivity analyses, it is also important to note that even if the trend and the importance of the parameters are generally similar, differences exist between the onshore and the offshore comparisons. For example, the ownership effect in the offshore transport is more important than the First Of A Kind issue. In addition, the cost of the shipping fuel assumes greater importance in the decision for offshore transport and is the fifth most important parameter.

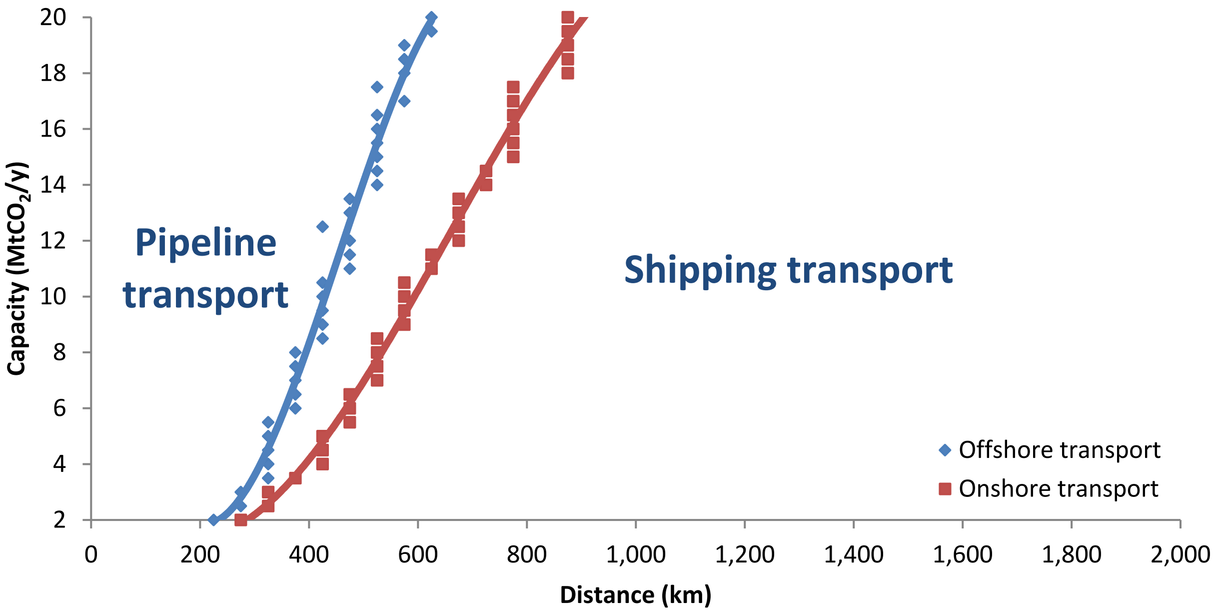


Fig. 20: Comparison of the onshore and offshore benchmarks

4.3 Further discussions

4.3.1 Transport costs

An important issue in any discussion of CO_2 transport and Carbon Capture and Storage is cost. Being able to model the cost of CO_2 transport and understand trends is therefore a very important aspect of selecting the optimal transport technology and lowering the total cost of CCS.

Depending on capacity and distance, the two transport technologies can have very different costs. For distances below the switching distances, the two costs remain similar even if shipping becomes more and more expensive compared to pipeline as the transport distance lessens and capacity increases, as shown in Fig. 21. On the other hand, above the switching distances, the more the distance increases and the capacity decreases, the higher becomes the discrepancy between pipeline and shipping transport costs.

Fig. 21 illustrates the cost of the optimal transport technologies under the different transport conditions. The cost evaluation also underlines the potential impact of selecting a non cost-optimal transport technology on the transport cost. This is especially important in cases in which the technology is chosen on the basis of faulty hypotheses or under uncertainties (for example regarding pipeline investment costs). Knowing the actual costs and limiting uncertainties will therefore be critical in selecting the cost optimal technology, avoiding cost overruns and limiting financial risks.

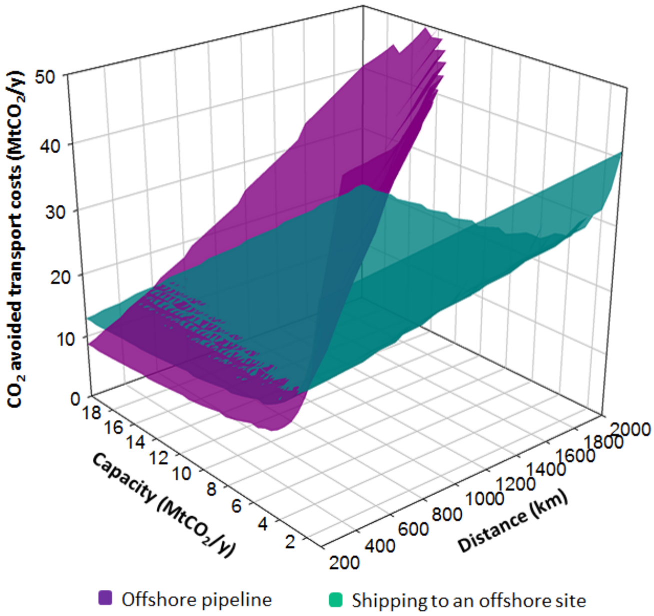


Fig. 21: CO_2 avoided transport cost of offshore pipeline and shipping to an offshore site

Another important factor is the cost of the whole chain (capture, transport and storage) and how it relates to the carbon credit (quota price or tax). Depending on the carbon credit, the cases to be considered may have different constraints regarding capacity, CO_2 concentration in the flue gas, transport distances and so on, due to the cost constraints required to make CCS economic. For transport, this might result in the limitation of the part of the CCS cost which can be allocated to the transport segment, and therefore on the conditions under which the transport leads to an economically feasible CCS chains.

Fig. 22 illustrates the impact of a transport[30] cost limitation on the conditions under which transport is economically feasible. The stronger the cost constraint, the more "long" distances and "small" capacities are ruled out, to the point that for 15€/tCO_2 shipping is almost out of the region of economically feasible transport.

However, it is important to understand that different CCS chains could require different limitations on transport costs. For example, a CCS chain with very cost-effective capture could afford a CO_2 storage site located significantly farther away and still be below the carbon credit price.

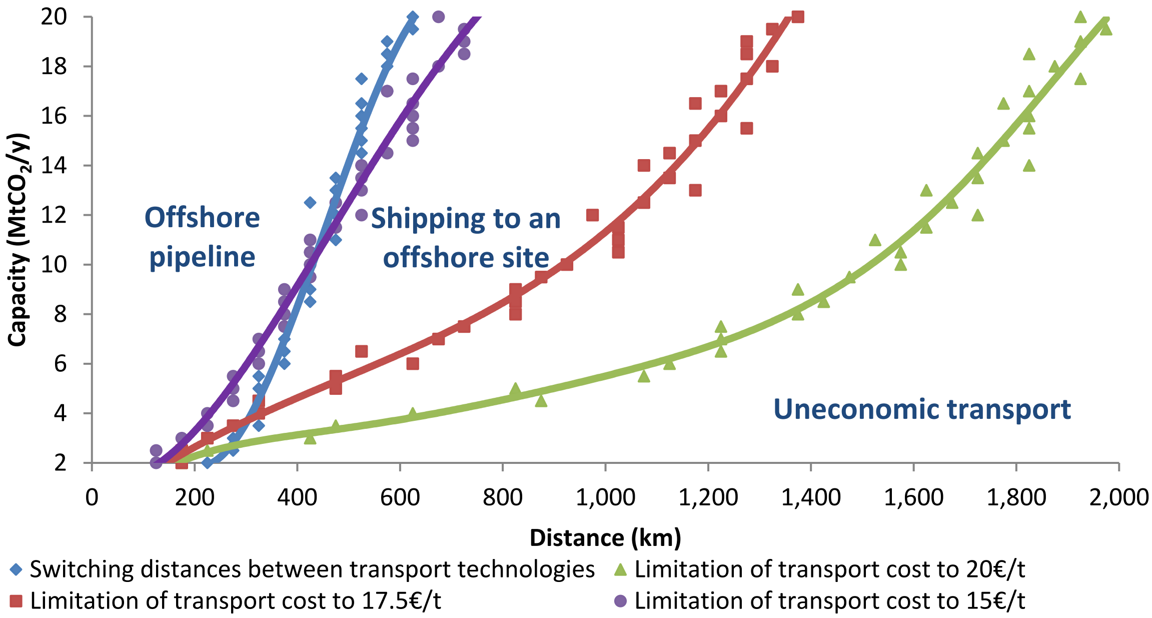


Fig. 22: Limitation of the CO_2 transport cost

[30] Including conditioning before transport from 1 bar and transport itself.

4.3.2 Limiting financial risks and implementation strategies

The evaluation and benchmark performed in this article are based solely on the avoided transport cost. However in practice other parameters such as initial investment and implementation strategies can play important roles in the choice of technology and even lead the selection of the non-cost-optimal transport option.

Particularly when the first CCS chains will be implemented, the initial investment and financial exposure will represent important criteria in the comparison of systems and technologies, and may in certain cases lead to the selection of non-cost-optimal technologies. Fig. 23 illustrates the impact of limiting the investment share defined as the ratio between overnighted investments over the sum of discounted project costs. Due to its high investment share, pipeline transport is disadvantaged by limitations on investment share, as illustrated in Fig. 23[31]. In consequence, in the first steps of CCS, pipeline transport might be used in a more restricted domain than the cost-optimal one in order to limit sunk costs and therefore financial risks. It is also worth noting that limiting investment share to 80% and above does not influence the choice of transport technology.

In the case of infrastructure implementation or network deployment, it is much more difficult to obtain general rules regarding the cost-optimal technology in function of the individual variables involved (distance, capacity required over time, timing of implementation), as well as when less cost-effective technologies would be selected depending on uncertain parameters (reliability of forecast and aversion to investment). In the first situation, a case-specific approach would provide useful information for comparing the available options based on the project-specific trade-off between cost-optimal technology and aversion to investment (Roussanaly et al., 2012). In the second situation, in which uncertainties could play a significant role in costs and the choice of technology, a probabilistic view of the problem could be used by coupling, for example, the BIGCCS value chain tool with a Monte Carlo simulation system to obtain NPV probabilities based on uncertainties in profile, costs and scenarios (Di Lorenzo et al., 2012).

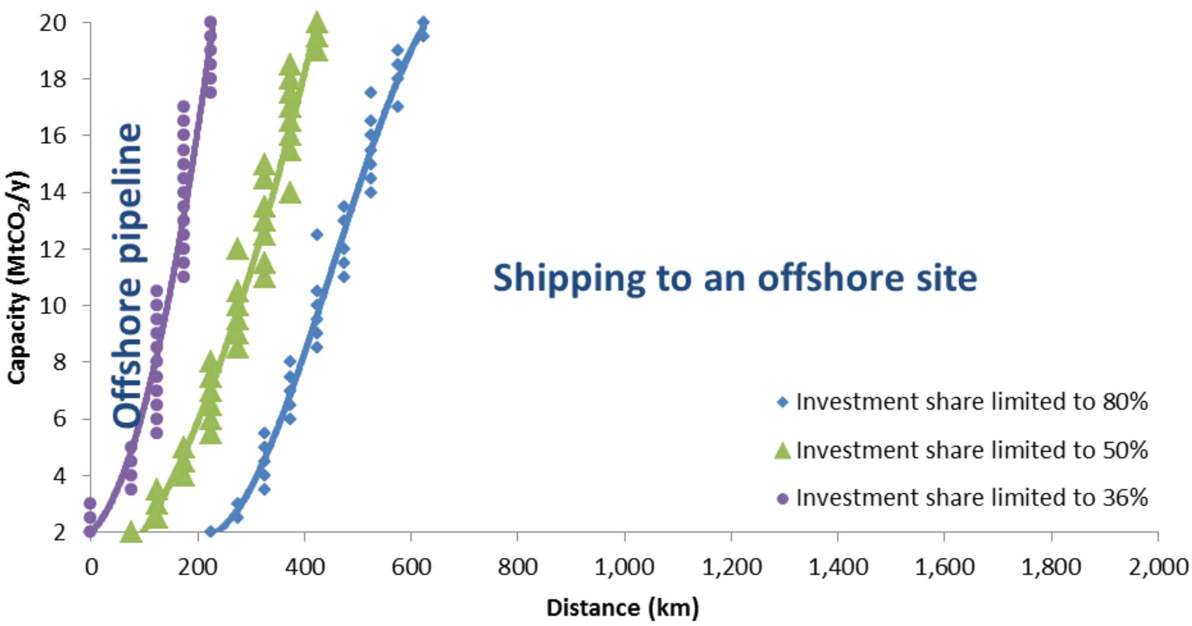


Fig. 23: Impact of the investment ratio limitation on the benchmark between offshore pipeline and shipping to an offshore site

[31] In cases in which both pipeline and ship transports are below the investment share, shipping is selected due to its typically lower investment costs and its flexibility.

5 Conclusions

This paper focuses on benchmarking CO_2 transport technologies for transport to an offshore site, using the value chain methodology and two new transport modules developed within the BIGCCS Research Centre (Mølnvik et al., 2011). The technical, cost, and climate impact characteristics of transport infrastructures are assessed and used to compare offshore pipeline and CO_2 shipping to an offshore site in a base case involving a range of distances and capacities. Unlike previous studies, this paper does not focus on a specific case (Coussy et al., 2013; European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b; Roussanaly et al., 2013b; Roussanaly et al., 2013c) nor a given capacity (Metz et al., 2005), but considers two initial variables: transport distance and capacity. As in the onshore benchmark study performed in the first part of our work, the base case demonstrates that short distances and large capacities favour pipeline transport. However, the distance effect in this case is stronger than in the onshore transport case, due to both higher pipeline investment costs and the limitation on pipeline pressure drops for offshore transport. The base case is used to draw conclusions regarding specific case studies under the hypotheses described in this paper. Our methodology also appears to lead to results consistent with cases available in the literature (European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011b) when the same cost hypotheses are taken into consideration.

Sensitivity analyses are used to quantify the impact of several important parameters and show that the four most influential parameters on the technology selection are: 1) the geographical context through the distance ratio 2) the regional effect of pipeline costs and uncertainties in pipeline investment costs through the pipeline investment costs 3) the project ownership effect through the discount rate 4) the First Of A Kind effect and uncertainties on investments through the overall investment costs.

The costs of the two transport technologies are also illustrated in order to bring out the importance of selecting the cost-effective transport technology, and discuss economically feasible CO_2 transport and CCS chains. The evaluation of costs underlines the potential financial impact of selecting a non-cost-optimal transport technology. Therefore understanding the range of cost uncertainties and their impact on the system design and cost is a very important aspect of selecting the cost-optimal technology, avoiding cost overruns and limiting financial risks. The cost evaluation is also used to show the impact of transport cost limitations on the conditions in which CO_2 transport is economically feasible. The stronger this cost constraint, the more "long" distances and "small" capacities are ruled out.

The methodology and results are also used to illustrate how constraints on initial investment, in order to limit financial exposure, disadvantage pipeline transport due to the large investment required for pipeline export. Finally, the potential integration of the BIGCCS value chain modules and tool with a Monte Carlo simulation system in order to tackle the impact of uncertainties in inputs parameters on Net Present Value of costs and technology selection from probabilistic perspective are discussed.

It should be borne in mind that this study, like the previous one, does not look into the deployment of a network whose total costs might lead to a different technology choice at the infrastructure level. Furthermore, in certain cases, one of the two transport technologies discussed here might be favoured by the capture technology considered in the context of the entire chain assessment (capture, transport and storage). For example, CO_2 capture by liquefaction has been identified as a very cost-effective technology for capture from an IGCC power plant, and offers the possibility to deliver liquid CO_2 instead of supercritical at very low additional costs, which could therefore significantly favour CO_2 shipping in this case (Anantharaman et al., 2017; Roussanaly et al., 2014).

Future studies will therefore include the use of BIGCCS transport modules to consider transport network deployments, as well as integration with existing and future CO_2 capture and storage modules, in order to compare different CCS chain options in a range of case studies.

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Appendix A

The CO_2 avoided transport costs (€/t$CO_{2,avoided}$) of the base case scenario at different capacities and distances are given in Table 12 for the offshore pipeline transport and respectively in Table 13 for the shipping transport to an offshore site.

Table 12: CO_2 avoided transport cost (€/$t_{CO2,avoided}$) for offshore pipeline transport at different capacities and distances for the base case

Capacity	Distance (km)									
($MtCO_2$/y)	200	400	600	800	1000	1200	1400	1600	1800	2000
2	20.6	33.2	46.0	59.0	78.4	93.3	108.5	141.5	160.0	179.0
4	13.6	20.9	30.5	42.1	51.1	60.2	76.4	86.8	97.5	108.3
6	12.2	18.5	24.2	32.5	39.0	49.4	56.7	64.1	77.6	86.0
8	10.7	16.3	21.1	27.7	33.0	41.2	47.1	56.9	63.5	70.1
10	10.2	14.3	19.2	24.8	29.4	36.3	41.4	49.5	55.1	60.7
12	9.8	13.5	17.9	22.9	27.0	33.1	37.6	44.7	49.6	54.5
14	9.3	13.0	17.0	20.5	25.3	30.7	34.8	39.0	45.6	50.1
16	9.1	12.1	15.6	19.6	24.0	27.6	32.8	36.7	42.7	46.9
18	8.8	11.8	15.1	18.9	22.0	26.4	29.8	34.9	38.5	44.3
20	8.7	11.3	14.2	17.6	21.3	25.4	28.7	33.4	36.9	40.4

Table 13: CO_2 avoided transport cost (€/$t_{CO2,avoided}$) for shipping to an offshore site at different capacities and distances for the base case

Capacity	Distance (km)									
($MtCO_2$/y)	200	400	600	800	1000	1200	1400	1600	1800	2000
2	23.3	23.9	24.4	25.0	25.6	27.9	28.4	29.0	31.0	31.6
4	17.4	18.8	19.3	20.5	21.2	22.8	23.3	23.9	25.2	25.7
6	15.9	16.9	17.5	18.7	19.7	20.2	21.5	22.0	23.1	23.7
8	15.0	16.1	16.6	17.5	18.5	19.5	20.0	21.1	22.1	22.6
10	14.2	15.1	15.9	16.8	17.7	18.6	19.5	20.0	21.4	21.9
12	13.9	14.7	15.6	16.4	17.5	18.0	19.2	19.7	20.9	21.4
14	13.5	14.5	15.2	16.3	16.8	17.9	18.3	19.4	19.9	21.1
16	13.2	14.0	14.7	15.7	16.7	17.2	18.2	19.2	19.7	20.8
18	13.0	13.9	14.8	15.8	16.2	17.2	18.1	18.6	19.6	20.6
20	12.9	13.6	14.5	15.3	16.2	17.1	17.6	18.5	19.4	20.4

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