Benchmarking of CO_2 transport technologies: Part I – Onshore pipeline and shipping between two onshore areas

Simon Roussanaly[a,*], Jana P. Jakobsen[a], Erik H. Hognes[b] and Amy L. Brunsvold[a]

[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.: +47 735 93 767; fax: +47 735 97 250; E-mail address: simon.roussanaly@sintef.no

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Abstract

This paper focuses on illustrating the CCS chain methodology and the functionality of two transport assessment modules developed within the BIGCCS Research Centre for onshore pipeline and shipping between onshore areas. On the basis of these two modules, technical, costs and climate impact assessments of transport infrastructure and conditioning processes were assessed and compared for a base case. In this case study, onshore pipeline and CO_2 shipping between two onshore harbours are compared for different distances and capacities. As expected, for a given annual capacity, onshore pipeline transport should be used for "short" distances, while shipping between harbours is employed for longer distances. Regarding the distance at which the cost-optimal technology switches between the two options, the results show that higher annual capacity and volume would lead to a preference for onshore pipeline transport. The base case can be use as a guide to draw conclusions on particular case studies under the hypotheses presented in this paper. The results also appear to be consistent with the few papers that have compared onshore pipeline and shipping between harbours.
Sensitivity analyses were used to address and quantify the impact of several important parameters on the choice of technology. The influences of the individual parameters were then ranked showing that the four most influent parameters on the technology choice are the geographical context, the regional effect of pipeline costs, the First-Of-A-Kind effect, and the ownership effect.
Additional work that focuses on transport between a coastal area and an offshore site using either an offshore pipeline or shipping will be presented in Part II of this paper.

Keywords: Carbon Capture and Storage (CCS); Benchmark; Transport; Onshore pipeline; Shipping between harbour; 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; 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 anthropogenic greenhouse gas emissions (Rochelle, 2009). To bring CCS closer to commercial realization, the viability of CCS value chains must be explored. For a commercial CCS chain to be successful, it must be sustainable, and therefore take into account both costs and environmental effects. To ensure the critical evaluation of the viability of a CCS chain with respect to multiple criteria, we have developed a consistent and transparent methodology (Jakobsen et al., 2011; Jakobsen et al., 2012). The value of such a methodology lies in the support it provides to decision-makers to select the best alternatives for CCS chains.

The studies performed in the BIGCCS Research Centre (Aarlien, 2009; Mølnvik et al., 2011) are contributing to the development of a methodology for a multi-criteria assessment of CCS chains. The approach is considered to be flexible and modular as shown in Fig. 1, and the assessment modules which will be developed for capture, transport, and storage can be used as basic building blocks and interconnected freely to create a range of chain designs. 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. In addition to its flexibility, and even if the results are very dependent on the input data, the method is consistent and transparent. The modules can evaluate a range of techno-economic and environmental criteria of a CCS chain, and will enable developers to simulate a large number of CCS chains within a relatively short calculation time[1].

Among others, the modules already developed include those for two CO_2 transport technologies (onshore pipeline and shipping between onshore areas), combining technical, costs and climate impact assessments, and considering a wide range of variables and parameters such as flow rates, capacities, pipeline diameter, ship size, transport distances, costs data, and climate impact data.

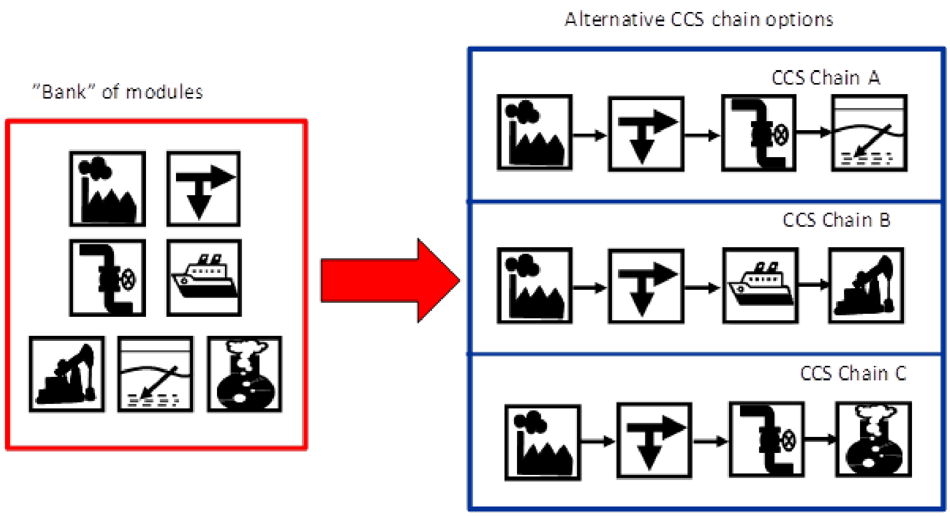

Fig. 1: Modular concept (Jakobsen et al., 2012)

In order to illustrate the methodology and the functionality of the two transport modules, a case study that benchmark two CO_2 transport technologies was performed. The study compares onshore pipeline and CO_2 shipping between two onshore harbours for different distances and capacities. Based on the cost of the transport options calculated by the modules, the conditions under which onshore pipeline or shipping is the most cost-efficient option can be identified as shown in Fig. 2. Unlike previously published studies, the work presented here does not focus only on a fixed capacity, for example, as shown by the red line in Fig. 2 that represents the IPCC case (Metz et al., 2005), or a specific case for a given distance and capacity (Coussy et al., 2012; European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011; Roussanaly et al., 2013b; Roussanaly et al., 2013c) which would then represent a single point in Fig. 2, but considered two variables: transport distance and transport capacity. Sensitivity analyses then address and quantify the impact of several important parameters

[1] As an example, by combination of different distances, capacities, pipeline diameters, ship sizes and inputs parameters more than 400,000 CCS transport chains have been calculated for this paper.

(regional effect of pipeline costs, ownership of the infrastructure, uncertainties regarding project duration, etc.) on the choice of the optimal technology.

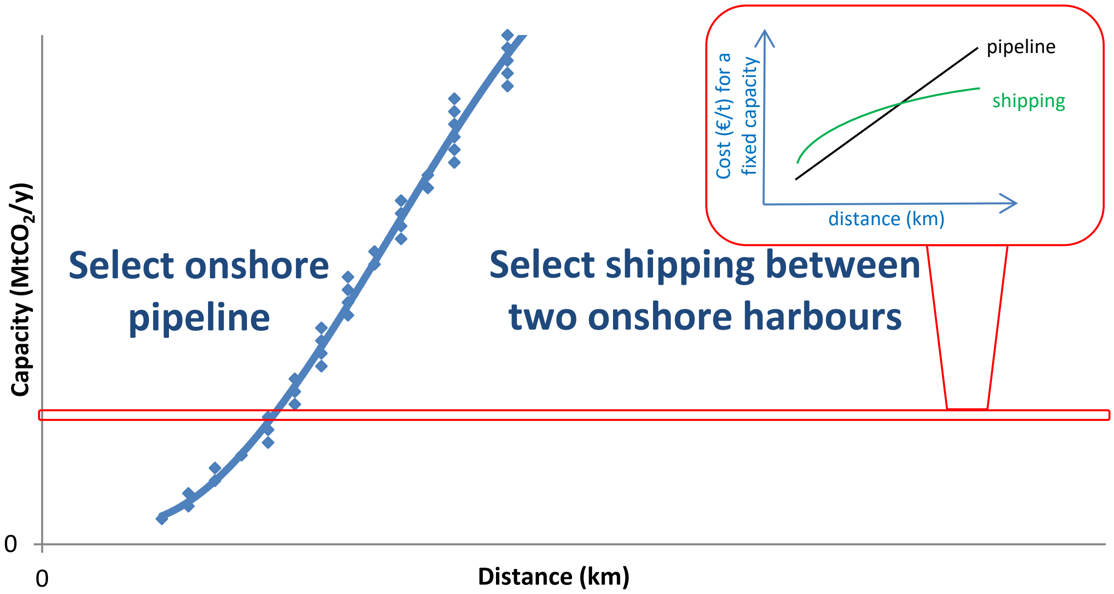

Fig 2: Benchmark between onshore pipeline and shipping between two onshore harbours

This paper focuses on comparing transport between two onshore areas, using either an onshore pipeline or shipping between harbours. Additional work focusing on the transport between a coastal area and an offshore site using either an offshore pipeline or shipping will be presented in Part II of this paper.

2 Methodology

This section describes the methodologies used to evaluate technical, costs, and climate impact assessments for both onshore pipeline and shipping between two onshore harbours. Both chains, receiving and delivering CO_2 under the same conditions, include conditioning before export, and the export system itself. In order to gain more insight in the transport technologies, simulations were carried out under Aspen HYSYS® for the conditionings, while the export system designs were performed on the basis of correlations from the literature (American Petroleum Institute, 1990; European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011; McCoy, 2009; Roussanaly et al., 2013b) in order to obtain their consumption of utilities and the characteristics of their components.
On the basis of the following assessment methodologies, the modules developed assess the costs and the climate impact of both transport chains for capacities ranging from 2 to 20 $MtCO_2$/y and transport distances from 200 to 2,000 km. The overall costs of the two transport technologies, including environmental costs, are then compared to produce charts similar to Fig. 2.

2.1 Technical assessment

2.1.1 Onshore pipeline

2.1.1.1 Conditioning before export

At the inlet of an onshore pipeline, dense CO_2 at 150 bar and ambient temperature is desired (Aspelund and Jordal, 2007), while CO_2 is delivered at 1 atm and 25 °C after CO_2 capture and regeneration[2] (Husebye et al., 2012; Roussanaly et al., 2013a). Conditioning before pipeline transport is therefore needed, and consists of compression stages and pumping, combined with the removal of unwanted components (dehydration)[3]. In order to assess the conditioning characteristics, simulations are performed under Aspen HYSYS®. The process was modelled into four compression stages followed by

[2] The CO_2 stream contains 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.
[3] The TEG dehydration unit is not included in the assessment.

pumping (Romeo et al., 2009), as shown in Fig. 3. A pressure ratio close to three is used for each compression stage, while compressors and pump efficiencies are assumed to be 90% and 75% respectively. Between the compression stages, the gas is cooled to 25 °C and removal of the water content is performed. The conditioning for pipeline export is assessed on the basis of an annual capacity of 10 $MtCO_2$/y, while subsequent cost scaling is performed for several different capacities.

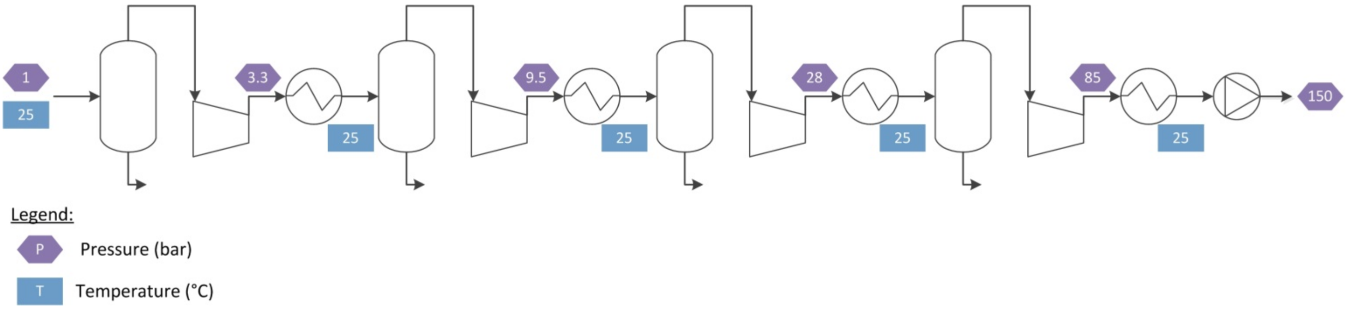

Fig. 3: Conditioning to pipeline export process flow diagram

2.1.1.2 Onshore pipeline export

At the inlet of an onshore pipeline, dense CO_2 at 150 bar and ambient temperature is desired (Aspelund and Jordal, 2007), while CO_2 is delivered, after reconditioning as shown in Fig. 4, at the outlet of the onshore pipeline at 200 bar, corresponding to the inlet pressure of an offshore pipeline[4] to store the CO_2 offshore[5] (Roussanaly et al., 2013b). The onshore pipeline chain has different characteristics depending on its diameter: pressure drop, number of pumps, energy consumption, costs, etc. Here, 17 pipeline diameters ranging from 12.75" to 44" were considered. In order to take into account the overall length of the pipeline (including tee junctions, terrain factors, etc.), its length is assumed to be 10% longer than the transport distance. The pipeline designs are based on the minimal wall thickness required (McCoy, 2009) and according to the API specification 5L standard (American Petroleum Institute, 1990) and a maximum operating pressure of 150 bar. The pressure drop is calculated using the Fanning equation, considering no elevation effect (Serpa et al., 2011), while the power required for pipeline pumping is obtained using Aspen HYSYS®. The number of pumps is estimated on the assumption that the pressure in the pipeline must not fall below 90 bar (i.e. it should stay above the critical pressure), and a capacity of 2 $MtCO_2$/y per pump.

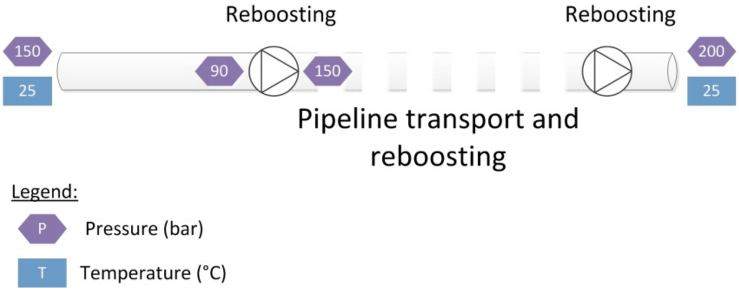

Fig. 4: Schematic design of the pipeline export system

2.1.2 Shipping between two onshore harbour

2.1.2.1 Conditioning before export using ammonia liquefaction

At the inlet of a shipping export, liquid CO_2 at 6.5 bar and -50 °C is desired (Aspelund and Jordal, 2007; Roussanaly et al., 2013b), while CO_2 is delivered at 1 atm and 25 °C after CO_2 capture and regeneration[6] (Roussanaly et al., 2013a). Conditioning before pipeline transport is therefore needed, and

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[4] Due to prohibitive subsea pumping costs, high pressures are desired at the inlet of offshore pipelines.
[5] Costs of transport to the offshore field and storage costs were not evaluated in this study.
[6] The CO_2 stream, contains 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.

consists of compression stages followed by a liquefaction process using ammonia cooling cycles (Aspelund et al., 2005), combined with the removal of unwanted components (dehydration)[7]. In order to assess the characteristics of the conditioning process, simulations are performed using Aspen HYSYS®. The process was modelled into three compression stages followed by ammonia cooling and expansion (Alabdulkarem et al., 2012; Romeo et al., 2009) as shown in Fig. 5. A pressure ratio close to three is used for each compression stage, while compressors and pump efficiencies are assumed to be 90% and 75% respectively. Between the compression stages, the gas was cooled to 25 °C and removal of the water content is performed. Conditioning for shipping export is based on an annual capacity of 10 $MtCO_2$/y, while subsequent cost scaling is performed for a range of different capacities.

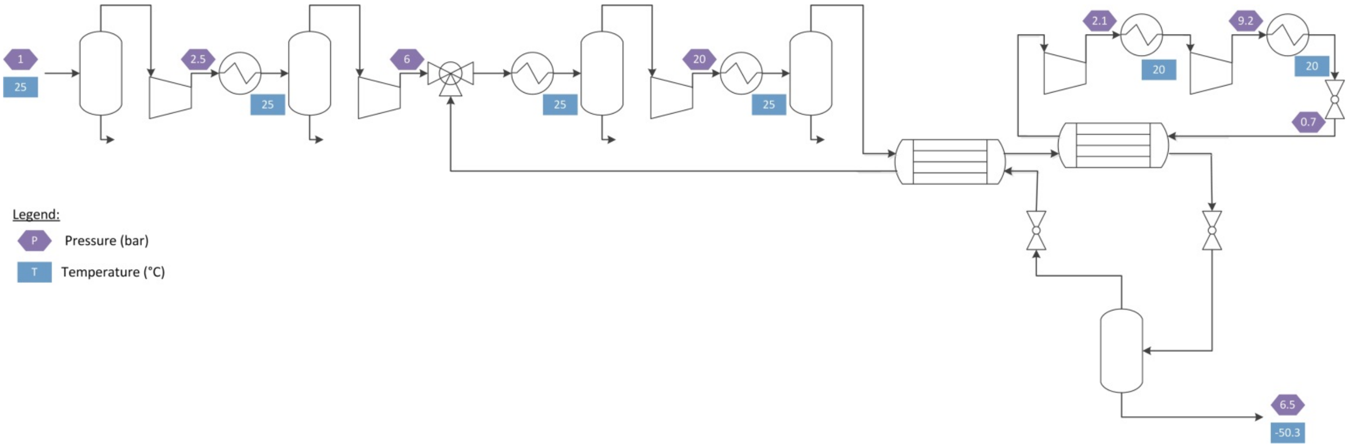

Fig. 5: Conditioning to shipping export process flow diagram

2.1.2.2 Shipping export

For shipping export, liquid CO_2 at 6.5 bar and -50°C is desired (Aspelund and Jordal, 2007; Roussanaly et al., 2013b) while CO_2 is delivered, after reconditioning as shown in Fig. 6, at 200 bar which corresponds to the inlet pressure of an offshore pipeline[8] to store the CO_2 offshore[9] (Roussanaly et al., 2013b). The shipping chain has different characteristics that depend on the size of the ship: the number of ships in the fleet, buffer storages capacity, fuel and electricity consumption, costs, etc. Here three ship sizes (25,000 t_{CO2}, 35,000 t_{CO2}, 45,000 t_{CO2}) were considered (Roussanaly et al., 2013b). After liquefaction and before reconditioning, cryogenic buffer storages are required, as shipping involves batch export, while liquefaction and injection are continuous processes. It is here considered that the volume of each of these buffer storages is equal to the ship's cargo volume (European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011). The shipping transport cycle is calculated as function of the distance assuming mooring, loading, departure and mooring, unloading, departure of 12 h each and a service speed of 14 knots (25.9 km/h) (European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011) while ships are considered to operate 350 days per year[10]. For each ship size, the fuel consumption is assumed to be proportional to the distance and transport volume, and estimates are based on Roussanaly et al. figures (Roussanaly et al., 2013b). Post-shipping reconditioning of CO_2 consists of repumping to 200 bar, followed by heating to ambient temperature. As frigories have an economic value at an onshore industrial site, the investment and operating costs of heating during reconditioning are not taken into account here. The number of pumps is estimated on the assumption of a capacity of 2 $MtCO_2$/y per pump, while the power requirements are obtained using Aspen HYSYS®.

[7] The dehydration unit is not included in the assessment.
[8] Due to prohibitive subsea pumping costs, high pressures are desired at the offshore pipeline inlet.
[9] Neither transport to the offshore field nor storage there were evaluated in this study.
[10] 360 h (15 days) per year are used for maintenance.

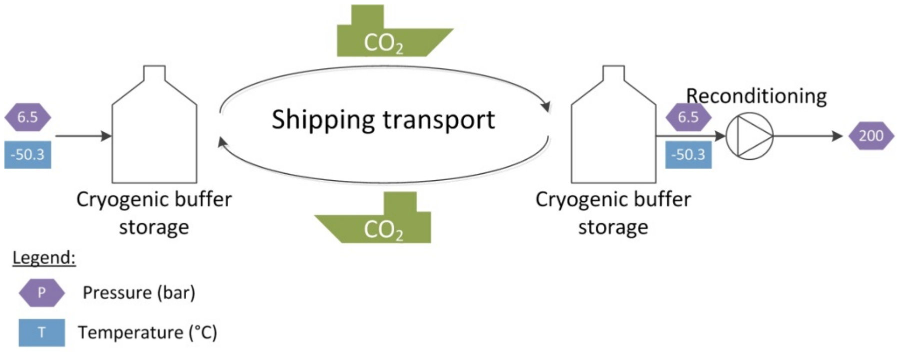

Fig. 6: Schematic design of the shipping export system

2.2 Cost evaluation

2.2.1 Investment costs

This study assumes costs of a "NOAK" (Nth Of A Kind) plant to be built at some time in the future, when the technology is mature. Such 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).
Different investment costs estimation methods are used: a specific one for pipelines and a more general method for process units. Investment costs are given in 2009 prices or reported using the CEPCI Index (Chemical Engineering, 2011). 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 and ships are assumed to be built over three years (Schach et al., 2010), while onshore pipelines are assumed to have a laying time of five years.

- Pipeline methodology

The pipeline investment costs are determined assuming a CAPEX for onshore pipeline of 47,377 €$_{2009}$/"/km[11] 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 150 bar for onshore transport.

- Factor methodology

A factor estimation method is used in order to estimate investment costs of the process equipments for the design capacity (10MtCO_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®, 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 C_0 is the equipment cost of a unit of size S_0, while C_1 is the equipment cost of a unit of size S_1. The exponential coefficient "n" depends on the equipment as shown in Table 1 (Chauvel, 2003). 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 2) and equipment correction factor[14] (see Table 1).

[11] 50,000 €$_{2010}$/"/km.
[12] Which includes erection, piping, secondary equipment, civil work, insulation, steel and concrete costs.
[13] Which includes engineering, administration, commissioning and contingencies costs
[14] The direct cost factor methodology is representative of the global relationship between the equipment cost and direct cost. However, an adaptation is necessary to model the direct costs of different equipments. Based on evaluations made using the Aspen Process Economic Analyzer®, correction factors have been developed to evaluate with higher accuracy the direct cost depending on the type of equipment.

$$C_1 = C_0 \cdot \left(\frac{S_1}{S_0}\right)^n \qquad (1)$$

Table 1: Exponential coefficient (Chauvel, 2003) and equipment correction factor[15] 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

Table 2: 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 3: 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

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 3).
The total investment cost in $€_{2009}$ is then determined by summarizing the estimated investment cost for all components within defined system boundaries.

However due to their specificity, CO_2 pumps and CO_2 carriers are estimated differently. The equipment cost of pumps has been estimated to 0.76 M€ per pump of 2 $MtCO_2$/y, following contacts with vendors, which leads to 1.66 M€/pump once direct and indirect costs are included. The ships investment costs are determined directly, using the total investment cost per ship (Roussanaly et al., 2013b), which is a function of its effective capacity as shown in Table 4.

Table 4: Ship investment costs

Ship size [t_{CO2}]	Total investment cost [M€/ship]
25,000	40
35,000	47
45,000	54

2.2.2 Maintenance and operating costs

2.2.2.1 Fixed operating costs

The fixed operating cost depends on the investment cost and covers maintenance, insurance, and labour costs. The annual fixed operating cost is set to 6% of investment costs for process units (Chauvel, 2003). The annual fixed operating costs are assumed to be a fixed yearly kilometric cost independent of the pipeline diameter and equal to 6,633 €/km/y (Mikunda et al., 2011). The annual fixed operating cost per ship is a constant function of the ship size (Drewry, 2009; Roussanaly et al., 2013b) as presented in Table 5.

[15] Estimated using Aspen Process Economic Analyzer® for the considered equipment cost range.

Table 5: Ships fixed operating cost (Drewry, 2009; Roussanaly et al., 2013b)

Ship size [t_{CO2}]	Annual ship fixed operating cost [M€/y/ship]
25,000	2.0
35,000	2.3
45,000	2.4

2.2.2.2 Variable operating costs

The variable operating cost, which is a function of the amount of CO_2 captured, covers the consumption of utilities: electricity, steam, cooling water, ships' fuel and harbours fees. The annual variable operating costs are estimated using the utilities consumptions given by the technical design, utility costs and fees as shown in Table 6.

Table 6: Utility costs

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, 2011)
Harbour fees	2	€/t_{CO2}	(Roussanaly et al., 2013b)

2.3 Climate Impact evaluation

The GHG emissions caused by the transport systems, and their associated energy, materials and services are assessed by a hybrid-LCA approach. Hybrid-LCA combines physical processes data with economic data (Strømman and Solli, 2008). This combination enables the assessment to cover emissions that would usually be lost if only physical process data were used (Suh, 2004). The use of economic data from the techno-economic assessment also ensures consistency between the climate and economic results.

GHG emissions from physical and energy flows data are modelled with European-based data (Table 7) from Ecoinvent 2.2 (EcoInvent, 2012). On the other hand, the GHG emissions from capital and operating expenses are modelled using data (Table 8) from the Carnegie Mellon University Economic Input-Output life cycle Assessment method (EIO-LCA Method) (Carnegie Mellon University - Green Design Institute, 2008), which is a database of environmentally extended input-output data from the US economy from 2002[16].

Table 7: 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 CO2e / kg oil
Burning of heavy fuel oil in tanker	3.11	kg CO2e / kg oil

[16] 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 and 0.92 EUR_{2009}/USD_{2002} for operational expenses.

Table 8: Overview of entries in the EIO-LCA Method 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 / $\$_{2002}$

The GHG emissions are converted into CO_2 equivalents (CO_2e) according to the IPCC guidelines (Solomon et al., 2007) and summed. This sum indicates the potential climate effect and is often referred to as the global warming potential (GWP).
The availability of environmentally extended input-output data is very limited. It is therefore difficult to evaluate the quality of these data 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. Modules developed will therefore be updated when better databases become available.
The amount of CO_2e emitted by the CO_2 transport is rather small compared to the amount transported[17], around 0.9 and 1.6% 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. Moreover, even if the climate impact does not modify the cost-optimal transport technology, the difference between the two transport technologies' emissions may be of importance in a global perspective.

2.4 Comparison between the two transport technologies

Onshore pipeline and CO_2 shipping between harbours are compared for various distances and capacities, in order to obtain a chart similar to Fig. 2. As 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.
The CO_2 avoided transport cost [€/t] is used here as a key performance indicator to compare the two transport technologies, including their environmental impact (Ho et al., 2011) through the annualized amount of CO_2 equivalent emitted. The CO_2 avoided transport cost approximates the 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[18], as shown in Equation 2. It is estimated on the basis of the methodologies described above, and assuming a base case with a utilization rate of 85%[19], a project duration of 30 years, and a real discount rate of 8%[20].

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

Sensitivity analyses are then performed to address and quantify the impact of several important parameters (e.g. regional effect of pipeline costs, ownership of the infrastructure, uncertainties regarding project duration, etc.) on the choice of the optimal transport technology.

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[17] Most of the difference between CO_2 captured and avoided by a CCS chain is due to the capture part of the chain.
[18] Calculated by the hybrid-LCA assessment.
[19] The yearly profile is here regarded as being divided into two equal periods. The first period operates at full capacity while the infrastructure operates at a constant flow during the second period, which leads to the average annual utilisation rate.
[20] This real discount rate of 8% corresponds to a nominal discount rate around 10% if an inflation rate of 2% is assumed.

A detailed cost breakdown of the pipeline and shipping transport of 10 $MtCO_2$/y over 500 km, using BIGCCS transport modules, can be found in Roussanaly et al. (Roussanaly et al., 2013c).

3 Results and discussions

3.1 Base case

3.1.1 Results

The results of the CO_2 avoided transport cost comparison of the two technologies for various distances and annual capacities are illustrated in Fig. 7. As expected, for a fixed annual capacity, the onshore pipeline transport should be used for "short" distances while shipping between two harbours is employed for longer distances. Regarding the switching distance between the two technologies, Fig. 7 shows that higher annual capacity and volume benefit the onshore pipeline transport as the switching distance rises. For the range of annual capacities considered, i.e. from 2 to 20 $MtCO_2$/y, the switching distance between the two technologies increases from around 275 to around 875 km.

Fig. 7 also can be used as a guide to drawing conclusions regarding particular cases under the hypotheses described above. On the basis of Fig. 7, one may conclude that a coal-fired power plant with CCS, capturing 4 $MtCO_2$/y [21], will use an onshore pipeline to transport its emissions if the transport distance is less than 400 km. However, if the coal-fired power plant combines the transport of its emissions with those of nearby industries to reach 8 or 12 $MtCO_2$/y, the switching distance shifts to around 575 and 675 km respectively for an onshore pipeline and CO_2 shipping between two harbours.

It is worth nothing that this "optimisation" problem is discontinuous and that therefore the switching distances between the two transports correspond to a group of distances which can be approximated by a continuous delimitation, as shown in Fig. 7.

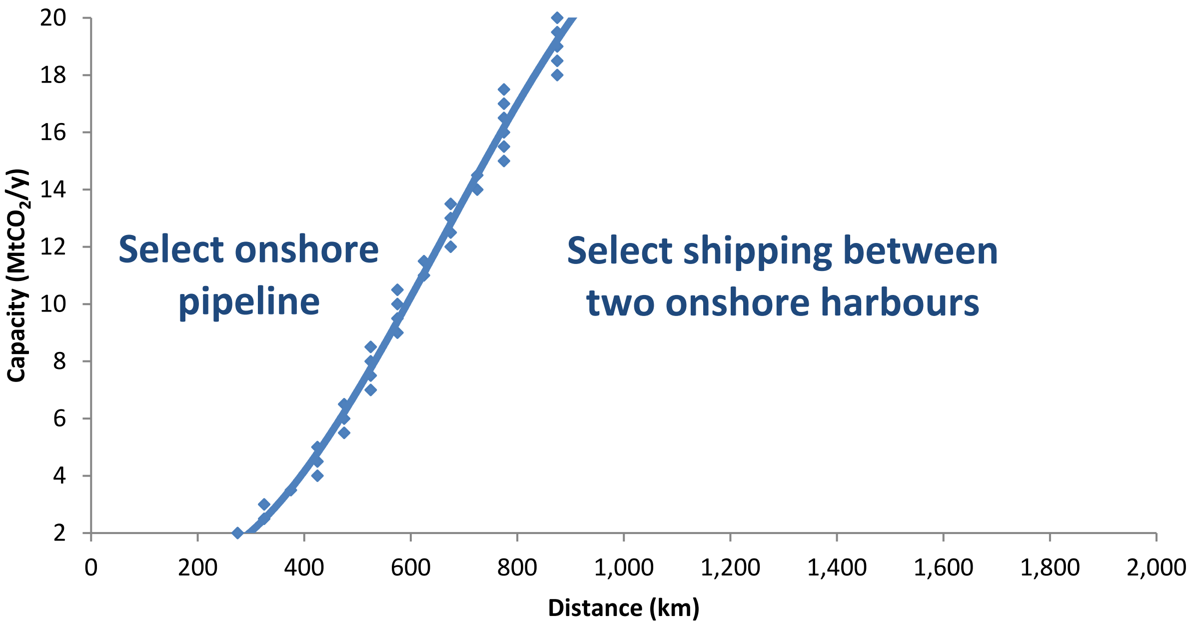

Fig. 7: Benchmark between onshore pipeline and shipping between two onshore harbours

3.1.2 Comparison with the literature

To compare the results presented in this paper to the literature on this topic is not a simple task. In most cases, the costs of pipeline and shipping transport are compared for an offshore application (European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011; Metz et al., 2005). The only study that was found on the comparison between onshore pipeline and shipping between two onshore harbours is part of the COCATE EU project (Roussanaly et al., 2013b).

Roussanaly et al. (Coussy et al., 2012; Roussanaly et al., 2013b) compared onshore pipeline transport and shipping between two onshore harbours where 13.1 $MtCO_2$/y are transported from Le Havre to

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

Rotterdam[22] for 30 years. The article shows that, in the case considered, an onshore pipeline would be the most cost-efficient way of transporting CO_2, leading therefore to conclusions consistent with Fig. 7.

Other studies, such as the ZEP report (European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011), the IPCC special report (Metz et al., 2005) and the EU FP7 CO2Europipe project (Mikunda et al., 2011) have estimated the cost of onshore pipeline, offshore pipeline and shipping to an offshore field. However the comparison between an onshore pipeline and shipping to an offshore field, instead of the comparison with the shipping between two onshore harbours, cannot directly be compared be compared to our results. Indeed, as transport to an offshore field is considered, shipping has higher costs of offloading and reconditioning. In addition, these studies include other hypotheses, which could be regarded as favouring pipeline transport:

- Lower pipeline cost: The IPCC estimates were performed in the United States and therefore the pipeline costs are significantly lower than for example in North-West Europe;
- Project duration of 40 years: Project durations longer than 30 years benefit the pipeline slightly more, as the lifetime of a pipeline is longer than the one of a ship.
- Overestimation of liquefaction costs: These reports assumed the liquefaction of CO_2 by expansion, while liquefaction using ammonia cycles has recently been shown to be more energy- (Alabdulkarem et al., 2012) and cost-efficient. However liquefaction by expansion is less capital-intensive and therefore limits the financial risks involved.
- Harbour fees: The harbour fees assumed in the two models are not reported and might be a disadvantage for shipping.

3.2 Sensitivity analyses

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

- The regional effect of pipeline costs;
- The First Of A Kind effect;
- The ownership effect;
- The geographical context;
- The effect of fluctuations;
- Uncertainties regarding the future of CCS and financial risks;
- Future energy prices.

3.2.1 Pipeline investment costs: The regional effect of pipeline costs

Several pipeline costs models for CO_2 have been published in the course of the past ten years (Chandel et al., 2010; Heddle et al., 2003; International Energy Agency GreenHouse Gas R&D Program (IEAGHG), 2005; McCoy, 2009; Mikunda et al., 2011; Parker, 2004; Serpa et al., 2011), with important discrepancies among them. Some of the models are only based on a gas pipeline cost model and do not take into account the lineic mass differences, or are not based on the same geographical region. For instance, pipelines have significantly lower investment costs in North American models than North-West European models. As an example, the NETL cost model developed by the University of California (Parker, 2004) led to investment costs that were 40% lower on average than the model suggested by Mikunda et al. (Mikunda et al., 2011) for North-Western Europe.

Other things remaining equal, pipeline transport of CO_2 will therefore tend to be more attractive in North America than in North-Western Europe. The regional effect of pipeline costs will significantly influence the optimal transport technology as shown in Fig. 8.

[22] The onshore pipeline length being 620 km, while the shipping distance has been estimated to 480 km.

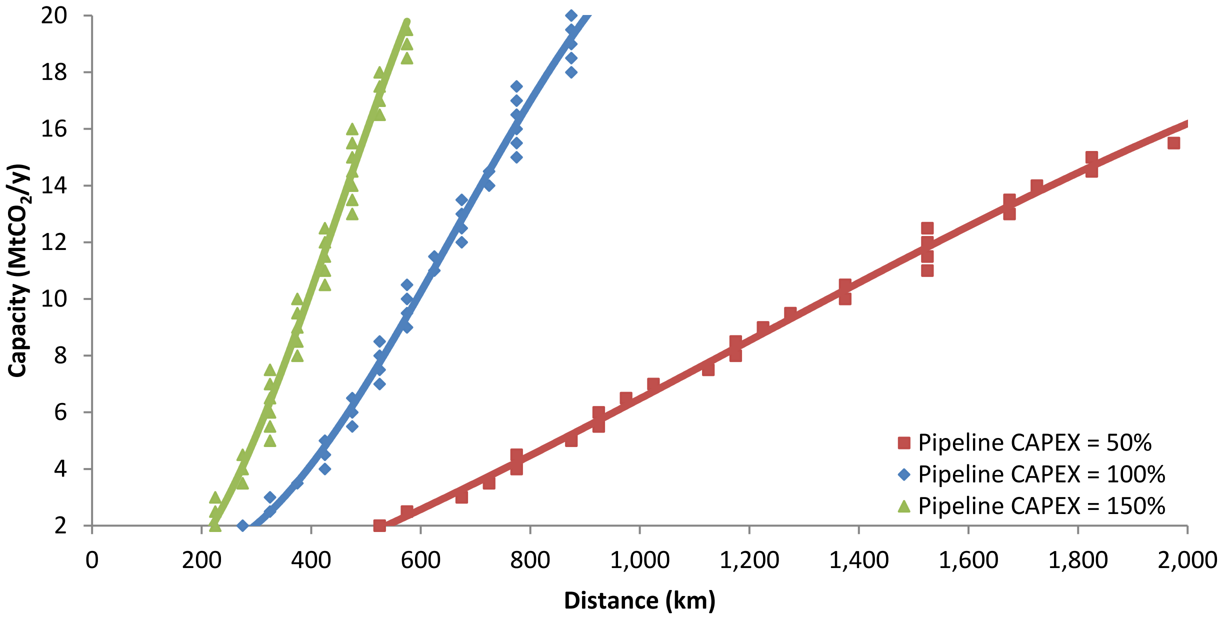

Fig. 8: Impact of the pipeline investment costs on the benchmark between onshore pipeline and shipping between two onshore harbours

3.2.2 Overall CAPEX: The First Of A Kind (FOAK) effect

The costs available in the literature often refer to Nth Of A Kind (NOAK) plants to be built sometime in the future when the technology is mature, which reflects the expected benefits of technological learning. However the FOAK question 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. This issue and its impact on the optimal technology are addressed here considering that the first CCS infrastructures will require higher investment costs. As Fig. 9 shows, the FOAK effect will increase the range within which shipping is the preferred technology, given that pipeline transport has higher investment costs. In addition, even if pipelines are technologically more mature than shipping, one might expect that the first large-scale CO_2 onshore pipeline could lead to resistance from the general public and that substantial additional safety and communication costs would be incurred.

On the contrary, if in the future, CCS transport technologies are more advanced than expected, investment costs will probably be lower and will therefore benefit pipeline transport as shown in Fig. 9.

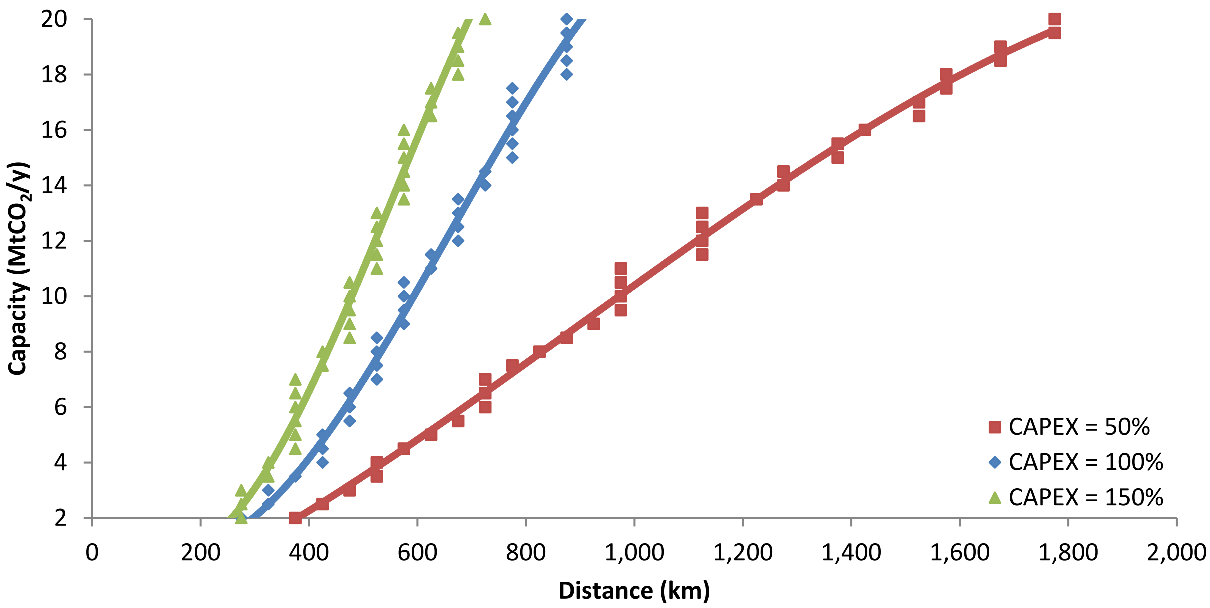

Fig. 9: Impact of overall CAPEX on the benchmark between onshore pipeline and shipping between two onshore harbours

3.2.3 Real discount rate: The ownership effect

Another important issue is project ownership. Depending on the investors, projects will have different discount rates and therefore different valuations of future revenues and costs. For example, the State uses a lower discount rate than average companies, while Oil & Gas companies and companies dealing with risk use a higher discount rate.

Since the total amount of CO_2 transported and OPEX are constant throughout the project duration, the discount rate mainly impacts the CAPEX annuity. The more the discount rate rises, the more important the CAPEX annuity becomes, and this will weigh on the CO_2 avoided transport cost. Thus, when the discount rate increases, ship transport becomes more cost-effective while the pipeline becomes less so, as shown in Fig. 10.

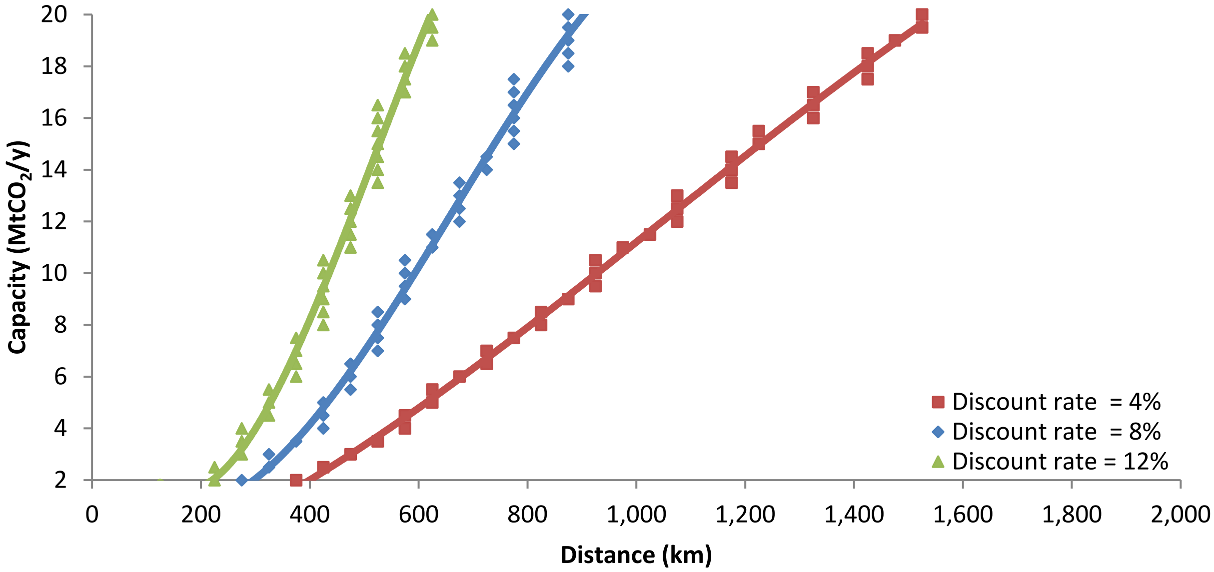

Fig. 10: Impact of the real discount rate on the benchmark between onshore pipeline and shipping between two onshore harbours

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

Another important issue for the transport technology selection is the relative pipeline and shipping distances. The geographical context can lead to either an advantage or a disadvantage of one or other technology. For example, mountains or urban areas may require deviations and increase the total pipeline transport distance, while ships must follow shipping channels which can also increase the shipping distance.

The sensitivity of this parameter, as shown in Fig. 11, highlights the critical importance of the ratio between the pipeline and shipping distances for the transport technology selection. The transport distance is an important factor in determining transport costs, and therefore in comparing the two technologies. It is also worth noting that the technologies are impacted in different ways by distance. Fig. 11 shows that a shorter pipeline distance ratio increases the range within which an onshore pipeline would be chosen significantly more than a longer distance decreases it.

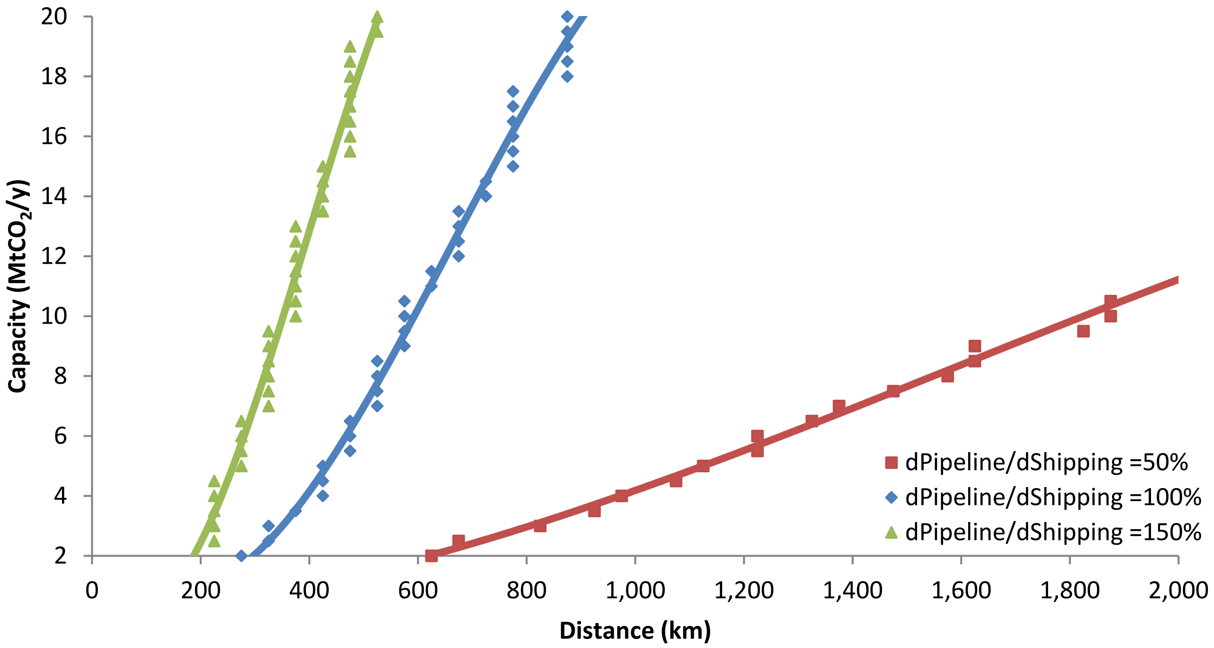

Fig. 11: Impact of the ratio between the pipeline and shipping distances on the benchmark between onshore pipeline and shipping between two onshore harbours

3.2.5 Utilization rate: The effect of fluctuations

An important difference between a pipeline and shipping is the difference in flexibility of the two chains and their responses to fluctuations in the volume of CO_2 transported. While shipping costs are fairly insensitive to fluctuations, both pipeline operating costs and the optimal diameter depend on the flow profile. Fluctuations thus increase the cost of the pipeline transport and increase the range within which shipping is the optimal transport technology as shown in Fig. 12[23].

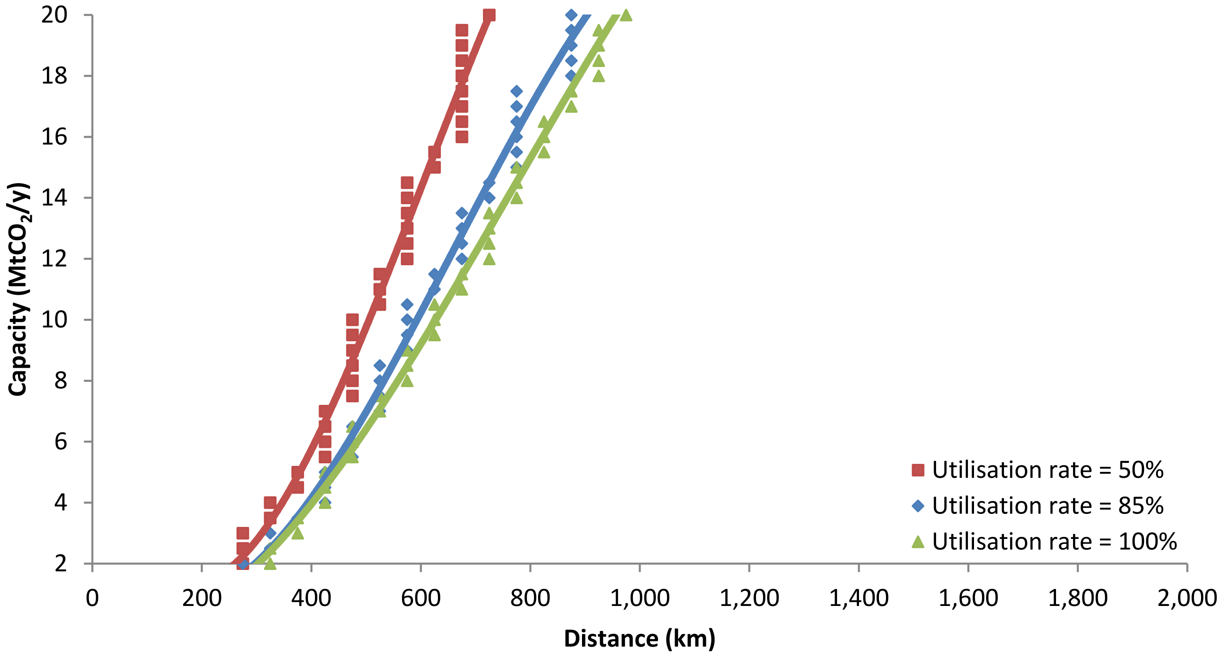

Fig. 12: Impact of the utilization rate on the benchmark between onshore pipeline and shipping between two onshore harbours

[23] The yearly profile is here divided in two equal periods. The first period operates at full capacity while the infrastructures operate at a constant flow during the second period. Together, these give the average annual utilisation rate.

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

Roussanaly et al. (Roussanaly et al., 2013b) showed that the difference between the lifetimes of pipeline and shipping infrastructures does not have a significant impact on technology choice and costs. However, when the uncertainties on the future of CCS or the financial risks due to reductions of the project duration are taken into account, there is a significant impact on the selection of the optimal technology. As CO_2 pipeline transport is more capital-intensive than shipping, shorter project duration will lower the project costs of shipping more than the pipeline costs. As Fig. 13 shows, uncertainties on the future of CCS could therefore lead to choosing shipping due to the high investments of pipeline transport[24].

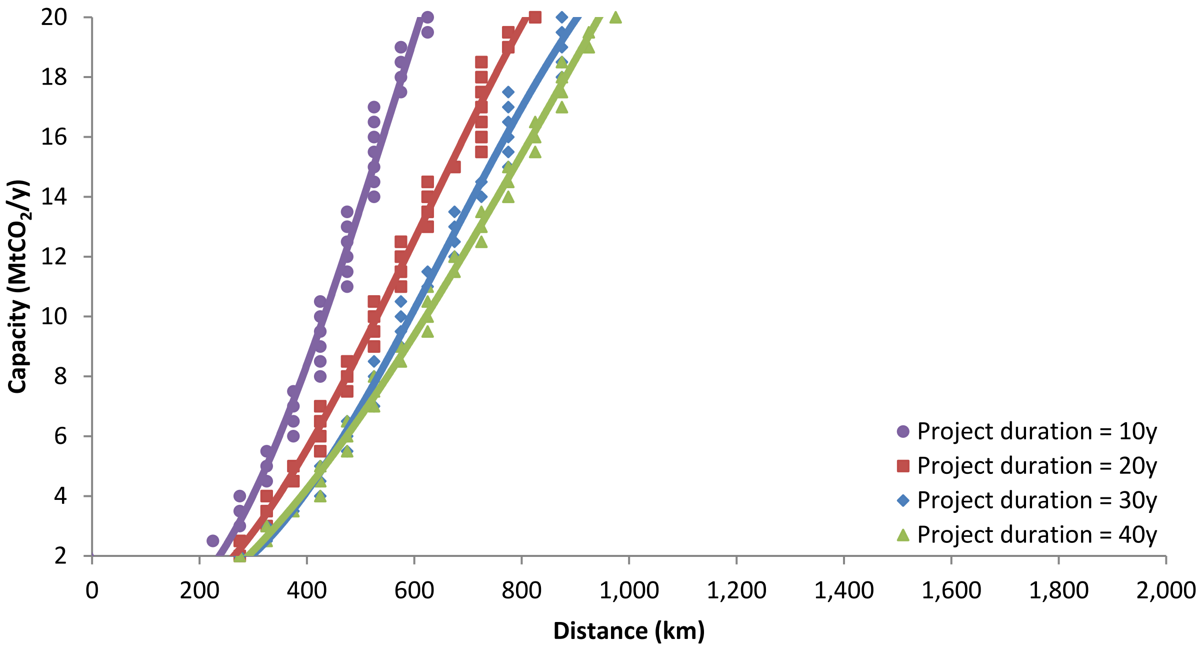

Fig. 13: Impact of the project duration on the benchmark between onshore pipeline and shipping between two onshore harbours

3.2.7 Energy costs: Future energy prices

Future energy prices[25] represent an important uncertainty for both costs and optimal technology selection, as energy costs are not identical for the two transport systems. Fig. 14 shows that as the price of electricity increases, transport via pipeline becomes the better candidate for a greater range of transport distances and CO_2 capacities, while the shipping option would be favoured by an electricity price decrease.

[24] 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.

[25] As shipping transport does not consume only electricity but also fuel, sensitivity analyses are performed on both electricity and fuel prices. The energy prices considered here already include the CO_2 emissions contribution as costs per tonne of CO_2 avoided.

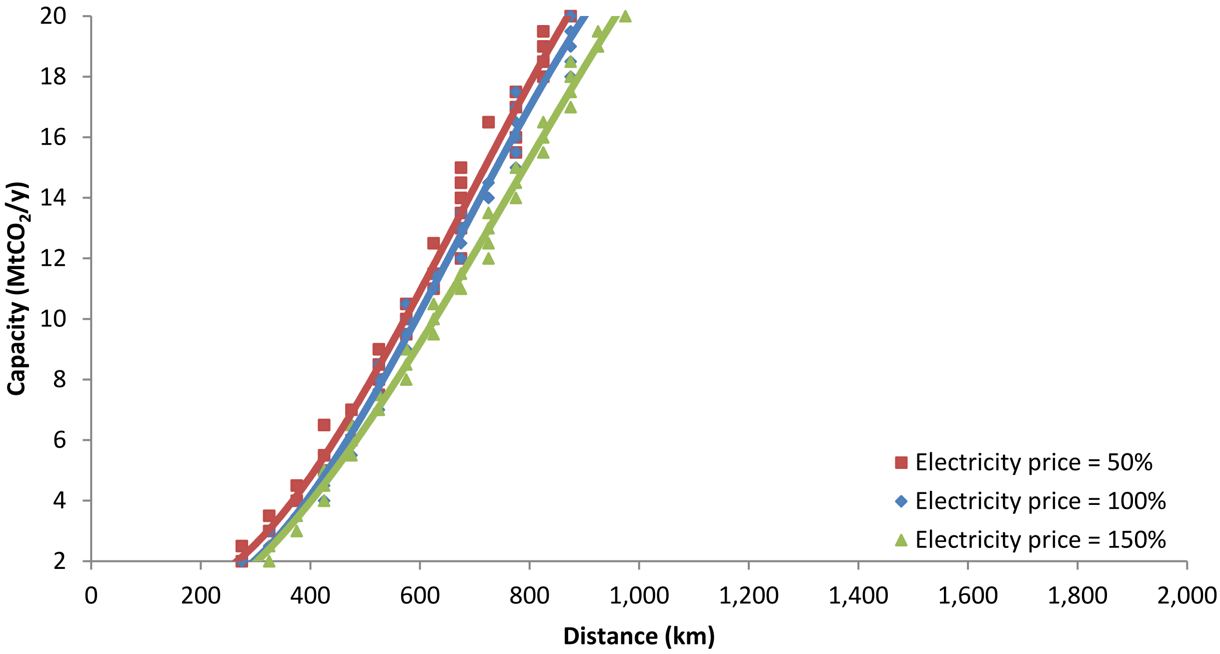

Fig. 14: Impact of future electricity prices on the benchmark between onshore pipeline and shipping between two onshore harbours

Another cost uncertainty for CO_2 transport by ships is the cost of fuel. In addition to uncertainty regarding the evolution of the price of oil and its derivatives, certain areas, such as the North Sea, are or will be designated Sulphur Emission Controlled Areas. It is therefore likely that from 2020, ships operating within these areas will have to run on low-sulphur fuels which are more expensive than those in current use (International Maritime Organization, 2009; Matthias et al., 2010). Fig. 15 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.

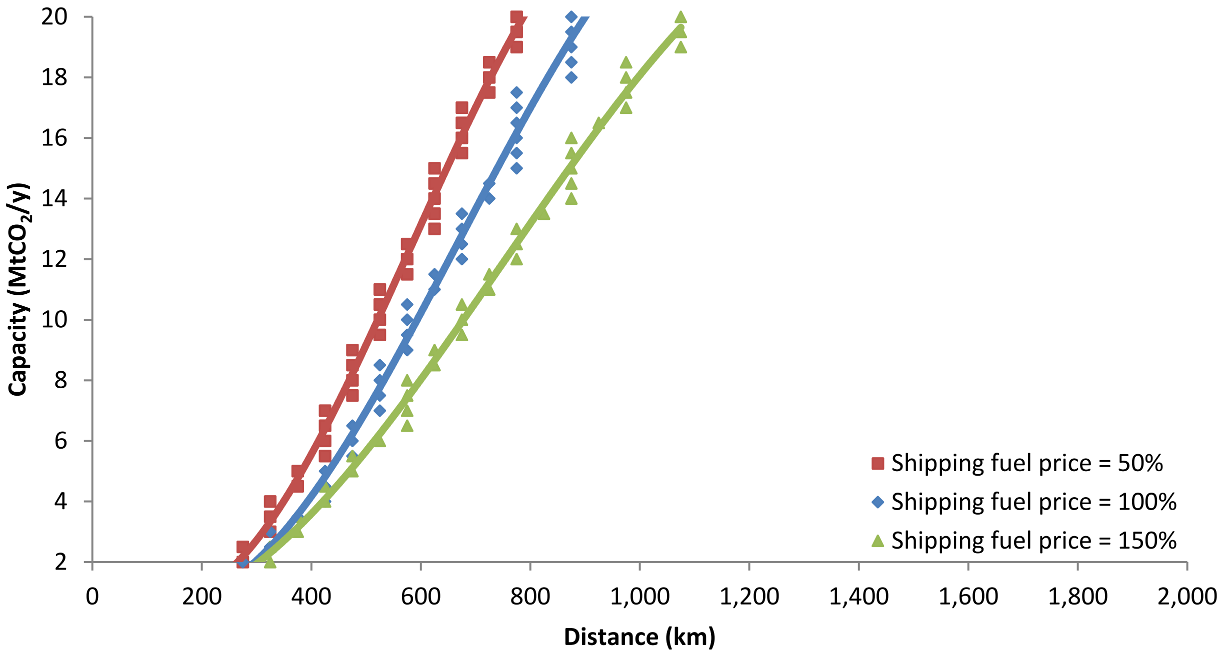

Fig. 15: Impact of future shipping fuel prices on the benchmark between onshore pipeline and shipping between two onshore harbours

3.2.8 Relative importance of parameters

For each parameter described in the previous sub-sections of section 3.2, the impact of the parameter is measured by the average ratio between the switching distances. The influences of these different parameters are then ranked to identify the most important parameters for the decision regarding the transport infrastructure. As Fig. 16 shows, the sensitivity analyses indicate that the four most influential parameters on the technology choice are the geographical context (i.e. the ratio of pipeline distance to shipping distance), the regional effect of pipeline costs (i.e. the pipeline investment costs considered), the First Of A Kind effect (i.e. the overall investment costs), and the ownership effect (discount rate). The comparison also shows that a reduction in any of these four parameters tends to favour pipeline transport significantly. Halving any of these four parameters will increase the average switching distance between pipeline and shipping by between 50 and 200 %. Fig. 16 also emphasizes conditions which favour shipping and pipeline transport respectively, as well as their relative importance.

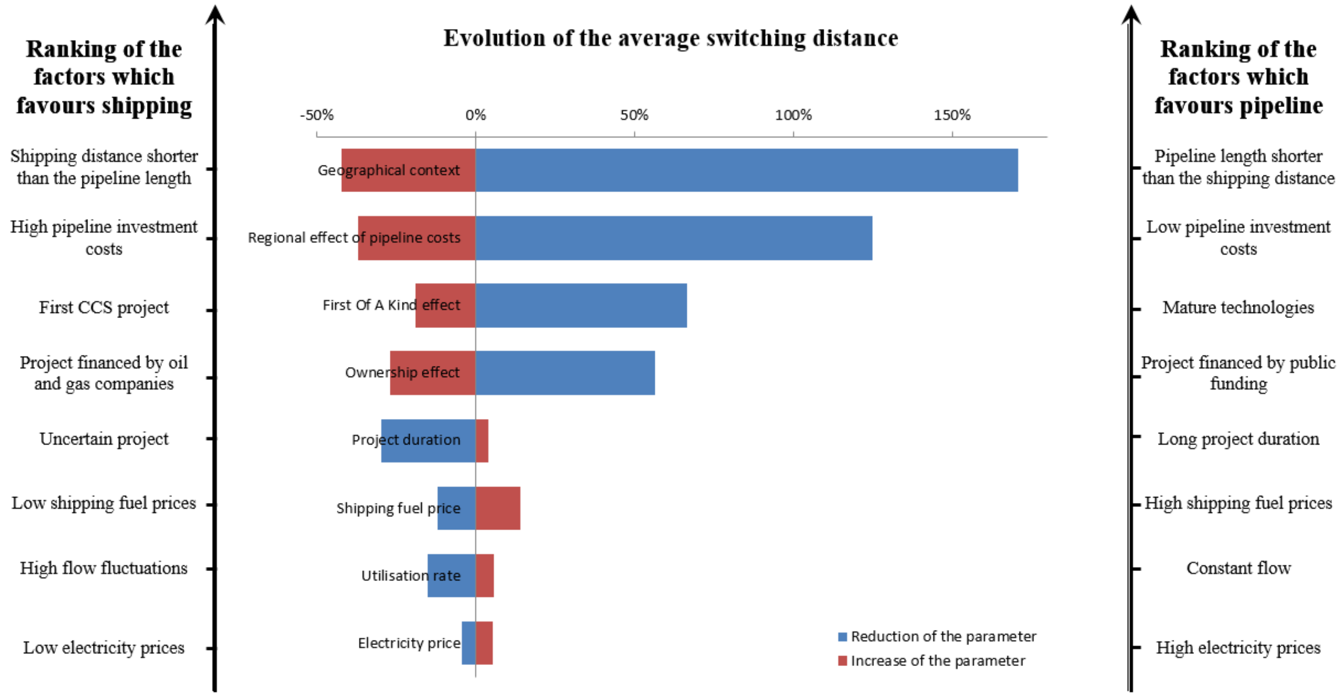

Fig. 16: Ranking of the impact of the different parameters on the switching distance

Knowing the relative importance of these parameters can be very important for CCS investors, policy-makers, and researchers, as they provide decision-makers with indications regarding important parameters that should be borne in mind when selecting CCS chains and transport technologies. They can also help policy-makers to develop efficient tools to promote efficient deployment of carbon capture and storage infrastructures. As an example, the idea of a European CO_2 pipeline network has often been raised in connection with a number of associated issues: overall costs, the first projects to be realized, implementation strategies, financial support from governments, etc. The indications obtained here could help to identify potential first projects and contribute to implementation strategies.

It is worth noting that this ranking of parameters does not quantify the impact of these different parameters on the transport cost. In addition, even though parameters such as project duration, energy costs and utilisation rate have a smaller influence on the switching distance, they do not have a more significant impact on the transport cost.

4 Conclusion

This paper focuses on illustrating the methodology and the functionality of two transport modules, developed within the BIGCCS Research Centre (Aarlien, 2009; Mølnvik et al., 2011), for an onshore pipeline and shipping between onshore areas. Technical, costs, and climate impact assessments of transport infrastructure are assessed and compared for a base case in which onshore pipeline and CO_2 shipping between two onshore harbours are compared for a range of distances and capacities. Unlike previous studies, our efforts focus not only on a given capacity (Metz et al., 2005) or a specific case (Coussy et al., 2012; European Technology Platform for Zero Emission Fossil Fuel Power Plants (ZEP), 2011; Roussanaly et al., 2013b; Roussanaly et al., 2013c), but considers two variables: transport distance and transport capacity. As expected, for a fixed annual capacity, onshore pipeline transport should be used for "shorter" distances while shipping between two onshore harbours is a better choice for higher distances. Regarding the switching distance between the two technologies, the results show that a greater capacity and volume tend to favour the onshore pipeline transport choice. The base case can be used to draw conclusions about specific cases under the hypotheses described above. Our results also appear to be consistent with the few papers which have focused on comparing onshore pipelines and shipping between harbours in specific cases.

The sensitivity analyses performed quantify the impact of several important parameters (regional effect of cost of pipeline, ownership of the infrastructure, uncertainties regarding project duration, etc.) on the choice of the optimal technology. These different parameters were ranked, and show that the four most influential parameters on the choice of technology are the geographical context, the regional effect of pipeline costs, the First Of A Kind effect, and the ownership effect.

It should be borne in mind that this study takes into account only the case of a unique infrastructure rather than the deployment of a network, the total costs of which might well lead to different technology choice at infrastructure level. Nor have implementation issues been directly considered. It is likely that if CCS starts, large CCS infrastructures would be deployed step by step, in which case CO_2 shipping could be used in the beginning while pipeline networks would be deployed later as the projects develop. This deployment strategy is interesting as it would limit initial investments and financial risks, the uncertainties on volumes of CO_2 to be transported in the future (Roussanaly et al.), and increase the potential for subsequent expansion of a pipeline network.

We have focused here on comparing transport between two onshore areas using onshore pipeline or shipping between harbours. Part II of this paper will compare transport technologies, and focus on transport between a coastal area and an offshore site using offshore pipeline or shipping solutions.

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