

A techno-economic case study of CO₂ capture, transport and storage chain from a cement plant in Norway

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Abstract

To make carbon capture and storage (CCS) happen, clever strategies are needed for robust decision-making under uncertainties. This paper investigates various alternatives for the application of CCS at a cement plant in Norway. A matrix consisting of nine CCS chain designs was analysed in order to quantify and compare alternatives designed to reveal important facts and relationships that would provide a sound knowledge foundation for project prioritization and decision-making. An in-house techno-economic assessment methodology and tool, iCCS, was used to evaluate and compare the costs of different technologies and estimate their cost-cutting potential. In particular, the paper discusses the effects of the choice of capture technology and transport solution, the potential of EOR as a market maker, the effect of the quota-price incentive, and the need for a long-term governmental strategy for CCS, focusing specifically on the need for public support of CCS from a cement plant. Finally, the importance of considering potential socio-economic benefits in analyses of CCS project viability is highlighted and developed.

Keywords: CCS; Cement industry; CO₂ capture; CO₂ transport; CO₂ storage; Techno-economic benchmarking.

Abbreviations: API, American Petroleum Institute; CAPEX, capital expenditure; CCS, carbon capture and storage; CEPCI, chemical engineering plant cost index; DOGF, depleted oil and gas field; EOR, enhanced oil recovery; FOB, free on board; FSC, fixed site carrier; GWP, global warming potential; MEA, mono-diethanolamine; NETL, National Energy Technology Laboratory; SA, saline aquifer; ZEP, zero emissions platform;

1. Introduction

There is currently a consensus about the role of carbon capture and storage (CCS) as a vital part of any greenhouse gas emission mitigation scenario [1] and the importance of CCS is widely acknowledged [2]. Furthermore, it has been shown that without CCS, reduction targets cannot be met and the costs of greenhouse gas emission mitigation measures would be more than doubled [3]. CCS technology is available and could be applied in the power generation sector as well as in industry. In spite of these positive developments with respect to global CCS attitude, the rate of CCS deployment has stalled, especially in Europe [2]. The deployment of planned CCS projects, in addition to the initiation of new ones, will require strong policy drivers.

Traditionally, the power generation industry was the most favoured candidate for CCS application. However, focus has recently also turned towards industrial sources of CO₂. Cement and steel production are examples of industrial processes that will always produce CO₂ as part of their production process. CO₂ emissions from the cement industry represent 5% of global anthropogenic CO₂ emissions [4]. In the case of cement production, CO₂ is an unavoidable by-product of the process and in order to significantly reduce the climate impact of cement production, CCS is unavoidable. Despite the moderate size of the CO₂ stream resulting from a typical size cement plant, cement is often considered as an attractive candidate for CCS due to the rather high CO₂ content of the flue gas, the stability of the stream over time and the availability of waste heat at the plant which could be utilized for CO₂ capture. For these reasons, CCS from the cement industry has gained interest in Norway and throughout Europe. The focus on CCS from cement in Norway centres on the Norcem Brevik plant, that produces approximately 1.2 million tons of cement and 0.925 million tons of CO₂ per year.

The Zero Emissions Platform (ZEP) [5] concludes that the major reason hindering deployment of the CCS technologies is the lack of business case. In simple terms, a viable business is characterised by a cumulative income that exceeds its cumulative costs. Many actors will be involved in CCS unless one company owns and operates the whole CCS chain. This means that there is a significant counterparty risk associated with CCS that will need to be dealt with. Furthermore, several factors that are principally different from each other will affect the technical feasibility of the chain and its financial viability. Examples of such factors are commercial technology availability, logistics and transport infrastructure, business economics, global market economics, socio-economics, environmental sustainability, risk and safety, public acceptance, national and international policies and regulatory frameworks. It is obvious that the complex set of factors and the involvement of several actors are associated with many uncertainties. Indeed, uncertainty seems to be the largest obstacle to the development of a business case for CCS and therefore a key barrier for CCS deployment, because investors need to be confident of generating income of sufficient size and duration [6]. Clever and creative solutions for CCS business cases are urgently needed in order to encourage commercial deployment of the technology.

In this paper, we investigate different alternative CCS chain designs suitable for application on a cement plant in Norway. We evaluate and compare the costs of different technologies and estimate their cost cutting potential. We also investigate the effects of various external parameters such as the CO₂ quota price on the commercial viability of the chains. We further study the effect of enhanced oil recovery (EOR) on the overall economic viability of the CCS chain, in order to verify or disprove its proclaimed role as CCS business-makers [7]. We also identify specific needs for public support of CCS from a cement plant with particular focus on the socio-economic benefits.

2. Case study design

To investigate the issues mentioned above, a case study was designed. A matrix of different case alternatives and parameter variations was analysed with in-house techno-economic assessment tool iCCS developed within the BIGCCS research centre [8]. With respect to the chain design, focus is set on capture technology choice, type of transport, and type of storage. In addition to the analysis of various chain designs, several parameter sensitivity studies are performed, varying the process performance characteristics and costs of capture, the transport distance and investment models for transport infrastructure, as well as fluctuations in global parameters such as CO₂ quota and oil price.

2.1 NORCEM Brevik cement plant [9]

Norcem AS develops, produces, markets and sells all types of cement to the civil engineering and oil and gas industries, especially in Norway. The company has around 500 employees and is part of the HeidelbergCement Group. Norcem, which is part of the HeidelbergCement Group, is the only cement producer in Norway, and operates two factories, Kjølsvik and Brevik. Norcem's main markets are in Norway, Scandinavia and the Baltic states, with smaller amounts exported to the USA and Russia.

The Norcem Brevik cement factory is located in the Porsgrunn municipality in Telemark. The factory has an annual production of approximately 1.2 million tonnes of cement. Norcem extracts limestone from a quarry and mine located near the production site. The Brevik site has two point sources, corresponding to the two clinker production trains, with combined emissions of approximately 925 kt/y of CO₂.

HeidelbergCement has expressed its aim to reduce its CO₂ emissions by 25% compared to 1990. The company's approach has been to invest in energy-efficient technologies and production processes, increase the use of composite cement and of alternative fuels, including biomass. So far, their progress is ahead of schedule. The Norcem factory in Breivik has been at the front of this activity by investigating the potential for CCS at the site, in addition to investing in energy-efficient technologies and fuel switching.

This led to a project testing three CO₂ capture technologies (solvent, membrane, and adsorption) under real flue-gas conditions [9] and is now regarded as one of the promising cases for implementation of Carbon Capture and Storage in Norway.

2.2 System characteristics

The Norcem Brevik cement plant emits a flue gas containing 17,8 % CO_{2,wet}, with a total yearly emissions of 925 ktCO₂/y [10]. In addition to the high CO₂ concentration in the flue gas, the cement plant also presents the advantage of having excess heat available, which could be used for the CO₂ capture unit. Finally, the plant is located by the fjord and already possesses a harbour facility to export the produced cement to customers by ship.

Regarding possible CO₂ storage locations, two options seem promising [11, 12], as shown in Figure 1:

- The Gassum formation, referred to as L1, which extends over large parts of the Skagerrak and south towards Denmark. While most aquifers and geological structures of the region have not been sufficiently qualified for CO₂ storage, depths and reservoir characteristics enable the Gassum formation to emerge as the most attractive storage option in the area. The Gassum formation has been identified as the most promising option for storage of CO₂ from point sources in eastern Norway. This storage site lies about 300 km from the Norcem cement plant and is therefore rather close; however, it is believed that this location would be suitable only for storage in an aquifer.
- The Johansen formation in the northern part of the North Sea, referred to as L2, is a water-filled reservoir located 500-600 meters deep, under which a porous reservoir produces oil and gas from the Troll field. While there has been an extensive debate on most suitable CO₂ storage sites between Johansen formation and the Utsira formation (south of Sleipner), especially for CO₂ emissions from Mongstad and Karstø, the Johansen formation is felt to be the most cost-efficient solution. This option is around 730 km from the Norcem plant and offers opportunities for both CO₂ storage only in an aquifer or combined with an Enhanced Oil Recovery project.

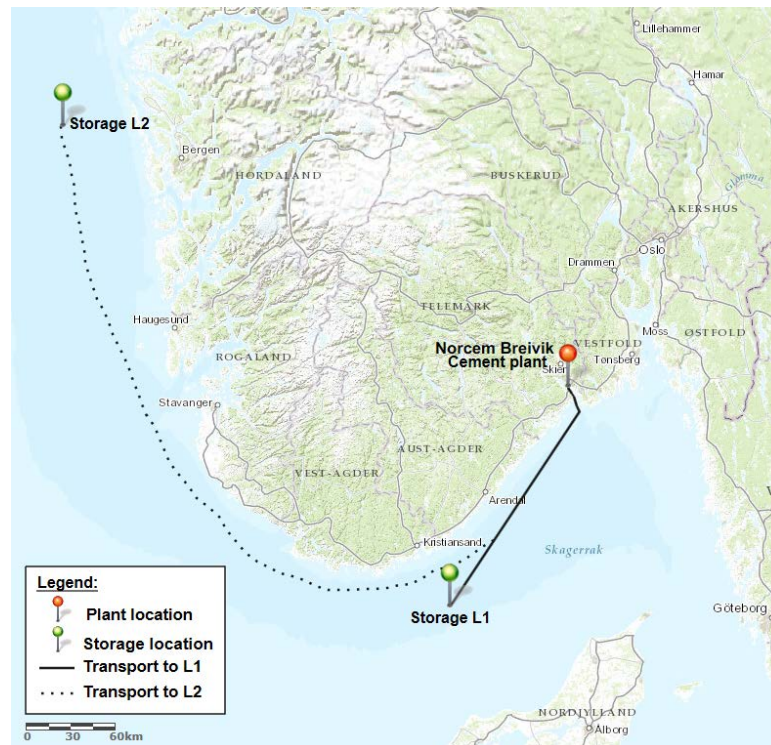


Figure 1: Locations of the cement plant and potential storage sites

2.3 Chain design alternatives

Nine alternative CCS chain designs are analysed in order to quantify and compare their potential benefits and costs. The complete case matrix is summarized in Table 1.

In the chain A, considered as base case, CO₂ emissions from the cement plant is captured using a MEA-based process. After the capture unit, the CO₂ is liquefied and transported via ship to a saline aquifer at the L1 storage location. In the base case as well as in chains B to H, a part-scale capture is considered where only 385 ktCO₂/y (~42% of the plant emissions) are captured from the cement plant. This part-scale capture is applied in order to use the 31 MW_{th} of waste heat available from the cement plant for the CO₂ regeneration and limit the need for supplementary steam production from a natural gas boiler and associated CO₂ emissions.

As CO₂ capture is a major component of the CCS chain costs, the first set of alternatives (chains B to D) investigates the potential benefits of a CO₂ capture systems based on advanced solvent or polymeric membranes. In chain B, the capture technology is a solvent-based process, just as in chain A, but the reboiler steam duty associated with the solvent regeneration is assumed to be 2.1 GJ/tCO₂ which is 33% lower than in the base case - chain A, assuming use of a novel less energy intensive solvent¹. The next two alternatives, chains C and D, are based on membrane-based capture. Two possible types of membranes are considered. The Polaris polymeric membrane developed by MTR [13] is believed to be at an advanced stage of development and testing [14] and is referred to as the reference membrane in several studies [15]. The Fixed Site Carrier (FSC) membrane was developed by NTNU [16] and has been tested at Norcem Brevik cement plant [17].

The set of chain options E and F investigate the potential of alternative transport technologies and transport distances. A stand-alone CO₂ pipeline transport and a shared pipeline transport

¹ In this case, the investment and operations costs of the advanced solvent system, apart from the steam consumption, are assumed to be the same as the MEA-based process.

leading to a shared saline aquifer for CO₂ storage are investigated in respectively cases E and F².

The chain alternatives G and H investigate the potential benefits of CO₂ EOR. In chain G, most of the CO₂ is used for EOR production over 25 years, while the excess CO₂ is stored in a nearby aquifer. In chain H, the CO₂ is used for EOR production over the first 10 years while the excess CO₂ and the CO₂ that is to be stored after 10 years is stored in a nearby aquifer. Due to the small volume of CO₂ considered, the EOR and saline aquifer storages are assumed to be shared in both G and H cases³.

Finally, as the base case and the alternative chains B to H are based on partial-scale capture, chain I is used to consider the implications of capturing at full-scale from the cement plant (i.e. 85% of plant yearly emissions).

Table 1: Summary of chain design options

Chain	Capture	Transport	Storage	Storage location
A	MEA-based capture	Shipping	Saline aquifer (SA)	L1
B	Advanced solvent-based capture	Shipping	Saline aquifer	L1
C	Membrane-based capture with high permeance membrane	Shipping	Saline aquifer	L1
D	Membrane-based capture with high selectivity membrane	Shipping	Saline aquifer	L1
E	MEA-based capture	Pipeline	Saline aquifer	L1
F	MEA-based capture	Shared pipeline	Shared saline aquifer	L1
G	MEA-based capture	Shipping	Shared EOR storage over 25 years with nearby shared SA for excess CO ₂	L2
H	MEA-based capture	Shipping	Shared EOR storage the first 10 years and shared SA for excess CO ₂ and after 10 years	L2
I	MEA-based capture at full scale	Shipping	Saline aquifer	L1

3. Methodology

3.1 Technical assessment

The following sections describe technical elements of the individual capture, transport and storage alternatives.

3.1.1 MEA-based CO₂ capture [18, 19]

In the MEA-based process, as shown in Figure 2, the flue gas is fed to the absorber after being cooled and pumped, using blowers to overcome the pressure drops in the columns. In the absorber, the flue gas comes into contact with a MEA-based solution containing 30%wt of MEA. After absorption, the CO₂ is recovered at the bottom of the column, chemically bound to the solvent, while the flue gas passes through a wash section to balance water and recover solvent carried out as droplets or vapour. The "CO₂ -rich" solvent is removed from the bottom of the absorber, pumped and enters a hot-cold heat exchanger to be preheated (to 120°C) by the regenerated lean solvent, before entering the top of the stripper. Significant amounts of heat are required at the stripper reboiler to break the chemical bond between CO₂ and the solvent, and

² In case F, the transport and storage costs are shared equally among three CO₂ sources of the same size.

³ The storage costs and revenues are shared equally among three CO₂ sources of the same size.

maintain regeneration conditions in the column. The vapourised water from the top of the column is recovered in the condenser and fed back to the column, while the purified CO₂ is sent through the conditioning process to reach the requirements for pipeline transport. The "lean" solvent recovered at the bottom of the column is pumped back to the top of the absorber through the hot-cold heat exchanger and a cooler is used to reach a lower solvent temperature that enhances the absorption process.

It is worth noting that 31 MW_{th} of waste heat is available at the cement plant and can be used to generate a significant proportion of the steam required by the stripper. Therefore it is assumed that stripper steam is produced from the available waste heat in priority, while a natural gas-fired boiler for additional steam requirement.

A summary of the solvent-based capture characteristics is presented in section 7.1.

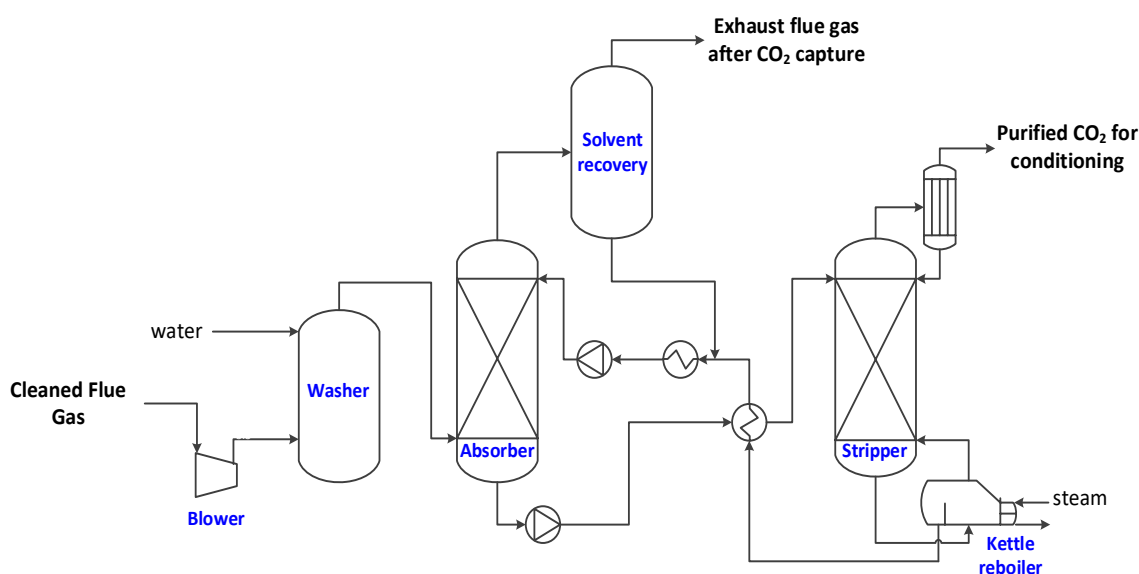


Figure 2: Schematic process flow diagram of the MEA-based capture process [18, 19]

3.1.2 Membrane based CO₂ capture [20-22]

A numerical version of the Attainable Region Approach developed and described in detail by SINTEF Energy Research [20-22] is used here. In practice, the numerical model optimises the membrane-based capture process, considering configurations of up to three stages, as shown in Figure 3, with the objective of minimising the overall investment and operating costs of the process.

Based on the membrane properties and the system conditions being considered, the numerical model first generates the attainable region diagrams in order to select the ranges of stage feed and permeate purities relevant for each stage of the different multi-stage membrane process configurations. Based on the selected ranges of permeate purity, the cost-optimal designs of the one-, two- and three-stage configurations are identified and compared in order to identify the overall cost-optimal membrane configuration and design. Once the cost-optimal design has been set, the actual operating conditions (feed pressure, permeate pressure and area) are calculated from the targeted stage purity using the membrane model.

A summary of the membrane-based capture characteristics is presented in section 7.1.

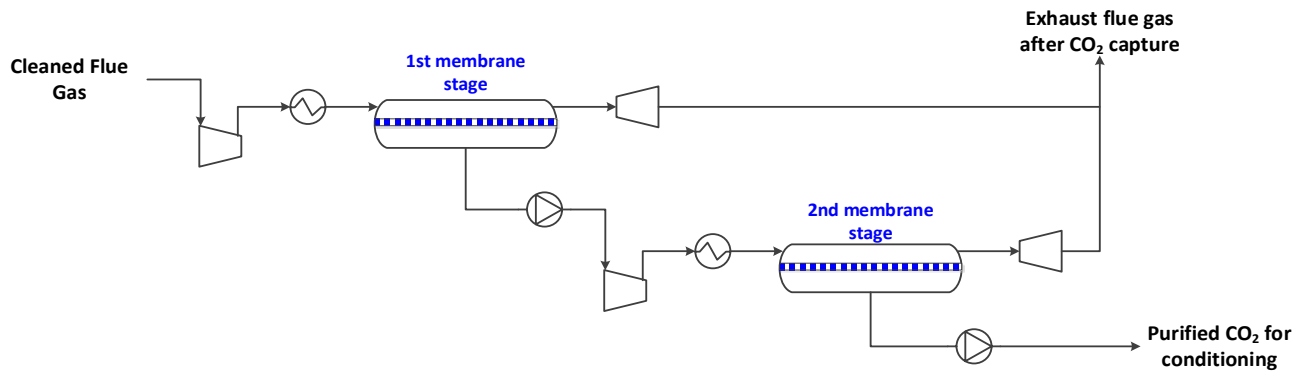


Figure 3: Schematic process flow diagram of the membrane-based capture process with a two stages configuration

The design methodology considers a membrane model for binary components, after Saltonstall [23], and a membrane unit in cross-flow configuration with plug flow on the feed side and no mixing with the bulk stream on the permeate side.

It is worth noting that this approach and the graphical solution generated are used to evaluate simple multi-stage configurations without advanced process features, such as retentate recycles or retentate heating before expansion.

3.1.3 CO₂ transport pipeline [24, 25]

To reach the pressure of 200 bar desired at the inlet of an offshore pipeline⁴, conditioning before pipeline transport is needed. This consists of compression stages and pumping, combined with the removal of unwanted components (dehydration)⁵. In order to assess the conditioning characteristics, simulations were performed under Aspen HYSYS[®] using the Peng-Robinson thermodynamic property package. The process was modelled into four compression stages with intercooling followed by a pumping stage to reach 200 bar and with the characteristics given in Table 10.

Before the offshore pipeline, a flexible riser transports the CO₂ from the shore to the seabed. Depending on the water depth, the liquid head provides a 10 bar safety margin for the pressure drops in the injection network.

Due to prohibitive subsea pumping costs, no reboosting is considered along the offshore pipeline, and the pressure drop must therefore be limited in order to maintain the outlet pressure above 60 bar [26], as shown in Figure 4. Here, 20 pipeline diameters ranging from 6 5/8" to 44" are considered. The offshore pipeline chain has different characteristics depending on the diameter: pressure drops, costs, etc. The pipeline designs are based on the minimum wall thickness required [27] and according to the American Petroleum Institute (API) specification 5L standard [28] with the characteristics shown in Table 10. The pressure drop is calculated using the Fanning equation, and does not take the effects of potential elevations into account [29].

A summary of the pipeline conditioning and transport chain design characteristics is presented in section 7.2.

⁴ Prohibitive subsea pumping costs make high pressures essential at offshore pipeline inlets.

⁵ The glycol dehydration unit is not included in the assessment.

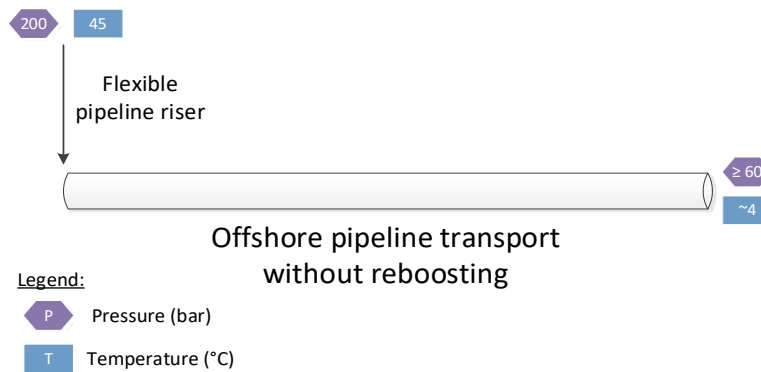


Figure 4: Schematic design of the pipeline export system [24]

3.1.4 CO₂ shipping [24, 25]

To obtain liquid CO₂ at 6.5 bar and -50 °C, conditioning before shipping transport is required, and this consists of compression stages followed by a liquefaction process using ammonia cooling cycles, combined with the removal of unwanted components (dehydration)⁶. In order to assess the characteristics of the conditioning process, simulations were performed using Aspen HYSYS[®] using the Peng-Robinson thermodynamic property package. The process was modelled as three compression stages followed by ammonia cooling, liquefaction by expansion and recycling of the remaining gaseous part of the stream [30] and with the characteristics given in Table 11.

After liquefaction, cryogenic buffer storage facilities are required, as shipping involves batch export, while liquefaction and injection are continuous processes, as shown in Figure 5. Depending on the size of the vessel involved, the shipping chain has different characteristics: number of ships in the fleet, buffer storage capacity, fuel consumption, costs, etc. Here three vessel sizes are considered with the associated characteristics given in Table 12. It is here assumed that the volume of the buffer storage before export is equal to the ship's cargo volume [26]. For each ship size, the fuel consumption is assumed to be proportional to the distance and transport volume, and estimates are based on the figures of Roussanaly et al. [31].

At the offshore field, a cryogenic buffer storage is also required to match the batch exports involved in shipping and the injection, which is a continuous process. It is here assumed that the buffer will be provided by a vessel with the same cargo volume as the others in the fleet [32]. The on-board reconditioning of CO₂ consists of repumping to 60 bar with heating, to ensure a temperature after reconditioning above 0°C. Even if frigoriferes have an economic value on an industrial site, there is here almost no integration possibility⁷, and reconditioning investments and operating costs must therefore also be included in the shipping chain values. Simulations are performed using Aspen HYSYS[®] to assess the characteristics of the on-ship reconditioning process. The electricity for on-ship reconditioning is produced by burning shipping fuel, with a conversion factor of 12,029 kWh/t_{fuel} [33].

Finally, a flexible riser transports the CO₂ from the ship to the seabed. Depending on the water depth, the liquid head will provide a 10 bar safety margin for pressure drops in the offloading hose and injection network.

A summary of the shipping conditioning and transport chain design characteristics is presented in section 7.3.

⁶ The glycol dehydration unit is not included in the assessment.

⁷ Except in cases in which there are opportunities for integration with natural gas liquefaction systems.

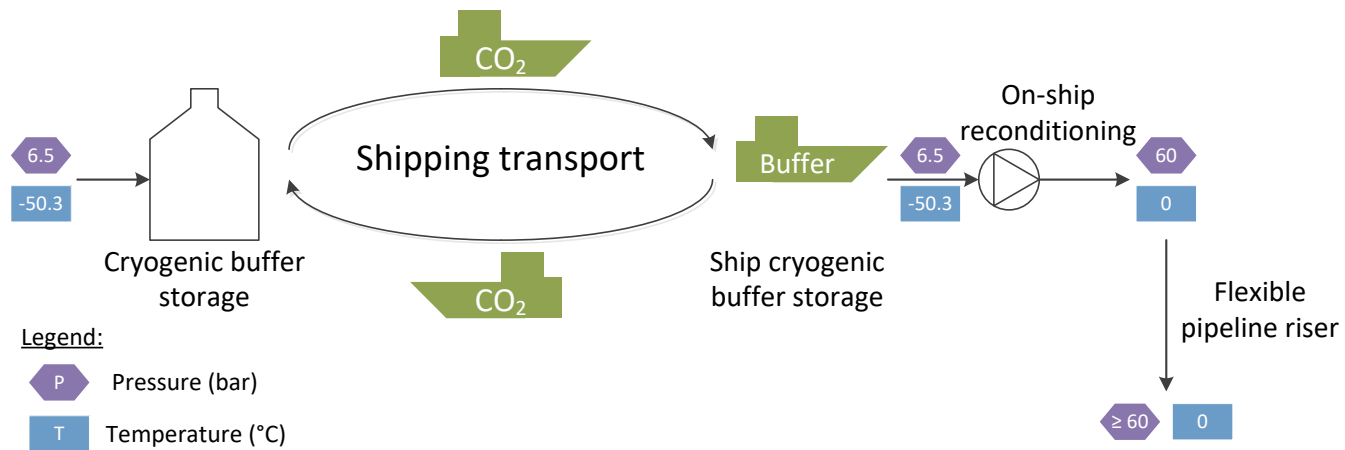


Figure 5: Schematic design of the shipping export system [25]

3.1.5 CO₂ storage

The evaluations of CO₂ storage are performed using the CO₂ storage module of the iCCS value chain tool [7, 8] based on the ZEP report on CO₂ storage of CO₂ storage in depleted oil and gas fields (DOGF) and deep saline aquifers (SA) [34] extended to include CO₂-Enhanced Oil Recovery (EOR) storage [7]. The module includes four offshore storage pre-set cases depending on the type of storage and the well legacy for DOGF (reuse or new wells) as shown in Table 2. Here, field characteristics of the ZEP medium cost scenario⁸ are considered, while other parameters such as well depth, economic and climate data can be modified. In the EOR case, a medium EOR scenario that takes an additional oil recovery of 7% into account [7], is included.

Table 2: CO₂ storage module pre-set storage cases

Case #	1	2	3	4
Location	Offshore	Offshore	Offshore	Offshore
Type of storage	DOGF	DOGF	SA	EOR
Legacy wells	Yes	No	No	Yes
Well depth [m]	2000	2000	2000	2000

3.2 Cost evaluation

This study attempts to include costs expected to be representative of a demonstration projects to be built in a near future even if the technology is not yet fully mature and demonstrated on the commercial scale level. Such estimates do not reflect the expected benefits of technological learning and therefore lead to costs higher than normally estimated in the literature which do not adequately take into account the greater costs that typically occur in the early stages of commercialisation [35].

Estimating cost data that are representative of demonstration projects has been, and remains, a challenging task. In this work, the increased investment costs associated with demonstration projects are performed in accordance with the National Energy Technology Laboratory (NETL) cost estimation guidelines [36, 37].

⁸ Which assume a well injection rate of 0.8 Mt_{CO2}/y/well and a liability transfer cost of 1 €/t_{CO2}.

3.2.1 Investment cost

Various investment cost estimation methods are used: a general method for the CO₂ capture processes and a more specific one for CO₂ transport and storage. Investment and operating costs are given in 2014 prices. Instances where cost data not available directly in 2014 prices are be updated using the Chemical Engineering Plant Cost Index (CEPCI) [38] for investment costs while the utilities costs are corrected considering a yearly inflation of 2% [39].

3.2.1.1 CO₂ capture processes

A factor estimation method is used to estimate the investment costs of the process equipment. In the approach, the direct costs of equipment in suitably selected materials are evaluated using the Aspen Process Economic Analyzer[®], based on simulations based on the solvent process flow diagram or the numerical membrane model. It is worth noting that as the membrane numerical model requires a cost model to optimise the membrane design, the direct cost function for each of the equipment in the membrane process has been regressed using the Aspen Process Economic Analyzer[®] and are presented in section 7.4.

The investment cost of a given item of equipment is then calculated by multiplying the component's specific direct cost by an overall indirect cost factor specific to include the indirect cost⁹, the demonstration cost, the location cost and retrofit cost as shown in

Table 3. It is important to note that MEA and membrane-based processes account for different levels of project contingencies due to differences in levels of maturity between the two technologies.

The total investment cost of the capture process is then determined by summing the estimated investment cost for all components within defined system boundaries (Equation 1).

$$\text{Total investment cost} = \sum(\text{Direct cost} \cdot \text{Indirect cost factor}) \quad (1)$$

Table 3: Overall indirect cost factor for the MEA- and membrane-based capture

Indirect factor component	Value (% of direct cost)	
	MEA-based capture	Membrane-based capture
Indirect cost factor [40]	31	31
FOAK cost factor including additional contingencies	25 [41]	50 [36, 37]
Specific location cost factor [42]	30	30
Retrofit cost factor	10	10
Overall indirect cost factor	96	121

3.2.1.2 CO₂ transport

For pipeline transport, the pipeline investment costs are determined assuming a CAPEX for offshore pipeline of 75,000 €₂₀₁₀/inch/km¹⁰ based on the EU FP7 CO₂Europipe project [43]. This cost, adapted to a North-West European concept, is based on a maximum operating pressure of 200 bar for offshore transport.

For the shipping transport, the process equipment costs are evaluated following the power plant and CO₂ capture cost methodology, while the ships' investment costs are determined directly,

⁹ Includes yard improvement, service facilities, engineering/consistency cost, building, miscellaneous, owner costs, and project contingencies.

¹⁰ 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.

using the total investment cost per ship [31], which is a function of its effective capacity, as shown in Table 4.

For both pipeline and ship transport, the cost of the pipeline riser is based on a reference cost of 8.5 M€₂₀₀₈¹¹ for a 1MtCO₂/y [44] and scaled up, assuming costs linear to the diameter¹².

Table 4: Ship investment and fixed operating cost [31, 45]

Ship size [tCO ₂]	Total investment cost [M€ ₂₀₀₉ /ship]	Annual ship fixed operating cost [M€ ₂₀₀₉ /y/ship]
25,000	40	2.0
35,000	47	2.3
45,000	54	2.4

3.2.1.3 CO₂ storage

The CO₂ storage costs consist of six components, which include all of the phases in the lifetime of the CO₂ storage project: 1) Pre-FID, 2) Platform, 3) Injection wells, 4) Operating, 5) Monitoring, Measurement and Verification (MMV) 6) Close-down. Based on the ZEP cost methodology [34] combined with data from Holt et al. [46] to represent the costs and benefits associated with the CO₂ EOR production, the CO₂ storage module evaluates the detailed costs of the six components and provides the unit storage costs, including investment and operating costs. The unitary storage costs of offshore storage are shown in Table 5 for the medium cost scenarios and the four types of offshore storage. For the base case scenario, the cost of an offshore DOGF for the medium cost scenario is considered.

Table 5: Offshore CO₂ storage cost (€₂₀₀₉/tCO₂) scenarios characteristics [7]

Type of storage	Location	Legacy wells	Medium
DOGF	Offshore	Yes	7.4
DOGF	Offshore	No	9.9
SA	Onshore	No	5.8
CO ₂ EOR	Offshore	No	13.1 ¹³

3.2.2 Operating costs

The operating costs are split into fixed and variable operating costs.

3.2.2.1 Fixed operating costs

The fixed operating cost depends on the investment cost and covers maintenance, insurance, and labour. The annual fixed operating cost is set at 6% of process units CAPEX [47]. The annual pipeline fixed operating costs are assumed to be a fixed yearly cost per kilometre, independent of the pipeline diameter and equal to 7,000 €₂₀₁₀/km/y [43]. The annual fixed operating cost per ship is a constant function of the ship size [31, 45], as shown in Table 4.

3.2.2.2 Variable operating costs and revenues

The variable operating costs of the power plant and CCS chain are a function of the amount of CO₂ captured, and cover consumption of utilities: electricity cost, steam, cooling water, MEA make-up, vessel fuel, and harbour fees. The annual variable operating costs are estimated using the utilities consumptions estimated by the iCCS tool and the utility costs given in Table 6.

¹¹ 900 M€₂₀₁₂, assuming a well-head depth 500 m below the surface.

¹² And therefore a 0.5 power factor on the capacity.

¹³ This number does not include any revenue associated with the additional oil recovery.

However, additional operating costs can also be expected in the first years of operation, especially for a demonstration project due to learning and training time, inefficiency, and so on. Utility consumption is therefore assumed to be 15% higher than the basis during the first three years of operation [22].

Table 6: Utility costs

Utilities	Reference costs	Cost Units	Reference year
Electricity	30 ¹⁴	€/MWh	2014
Steam available from the cement process	0	€/GJ	2014
Steam produced from Natural Gas [48]	9.1	€/GJ	2014
Cooling water [24]	0.035	€/m ³	2014
Shipping fuel cost [26]	370	€/t _{fuel}	2009
Harbour fees [25]	1	€/t _{CO2}	2009

As a principal purpose of this study is to calculate the cost of capturing, transporting and storing the CO₂ for each case, no CO₂ tax is taken into consideration.

In cases in which CO₂ EOR is a possibility, the revenues associated with the oil production are included in the valuation of the CCS chain. As shown previously by Roussanaly and Grimstad [7], oil price to be considered in the valuation of the project is dependent on the cost and production profile of alternative methods to CO₂ injection for EOR; two oil valuations¹⁵ are therefore taken into consideration. The first one, equal to 60 €/barrel [49, 50]¹⁶, is representative of cases in which alternative EOR methods rather than CO₂ are not viable options. The second one, equal to 31€/barrel [7], is representative of cases in which chemical EOR is a viable and competitive method.

3.3 Greenhouse Gas assessment

To evaluate the chain cost per ton of CO₂ avoided in a consistent way, it is necessary to include the carbon footprint of the chain. Here, only direct greenhouse gases emissions associated with the consumption of electricity, steam and shipping fuel are considered, as shown in Table 7. The GHG emissions are converted into CO₂ equivalents (CO₂e) according to the IPCC guidelines [51] and summed. This sum indicates the potential climate effect and is often referred to as the global warming potential (GWP).

Table 7: Global warming potential factor of electricity and heavy fuel oil burning

Physical processes related GHG emissions	GWP factor	Unit
Electricity consumption	170	kg _{CO2e} /MWh
Steam consumption produced from natural gas	56.1	kg _{CO2e} /GJ
Burning of heavy fuel oil in tanker [52]	3.11	kg _{CO2e} /kg _{oil}

¹⁴ Low electricity cost representative of the Norcem Brevik cement plant.

¹⁵ The oil valuation considered is the oil barrel FOB (Free On Board) price in Rotterdam minus costs that are not included in the EOR production costs, such as normal production costs as well as transport from the oil platform (in the North Sea) to Rotterdam.

¹⁶ Corresponding to the average price of oil 90\$₂₀₁₃/barrel minus a production cost of 12\$/barrel, which includes only the operating expenses associated with the oil production, as the investment part is normally covered by the normal production and the primary water injection recovery.

3.4 Key Performance Indicators for comparison of the options

The CO₂ avoided cost [53] is here used as Key Performance Indicator (KPI) in order to compare the different chains. The CO₂ avoided cost (€t_{CO₂,avoided}) approximates the average discounted CO₂ tax or quota over the duration of the project that would be required as income to match the net present value of additional capital and operating costs due to the CCS infrastructure. It is equal to the annualised costs divided by the annualised amount of CO₂ avoided, as shown in equation (2). The annualised amount of CO₂ avoided is defined as the amount of CO₂ captured minus the direct emissions associated with the CCS infrastructure. The CO₂ avoided cost is calculated assuming a real discount rate of 8%¹⁷, 7400 annual operating hours and an economic lifetime of 25 years [40]. In addition, investment costs consider that construction is shared over a three-year construction period [40].

$$\text{CO}_2 \text{ avoided cost} = \frac{\text{Annualized investment} + \text{Annual OPEX}}{\text{Annualised amount of CO}_2 \text{ avoided}} \quad (2)$$

4. Results

4.1 Overall results

This section provides a brief summary of the results of the techno-economic analysis of the various chain alternatives, while specific issues arising through the different case variations are discussed in the following section.

The CO₂ avoided cost of the nine considered chain alternatives are summarised in Figure 6 while the detailed cost breakdown is presented in section 0. The results show that the full-chain cost of the base case is estimated to be around 120 €t_{CO₂,avoided}, while the alternative chains lead to costs that lie between 100 and 150 €t_{CO₂,avoided}. Although these values may appear high compared to conventional figures available in the literature, it is important to remember that these numbers include additional costs representative of demonstration projects and the maturity of the current technology, the remote location of the plant, retrofit projects, and small CO₂ volumes (approximately 400 kt_{CO₂/y}).

In the base case, CO₂ capture and conditioning represent around half of the CO₂ avoided cost, while transport and storage respectively represent 25 and 20% of the cost. These proportions vary from case to case, depending on the characteristics of the chain considered.

These nine chains are used to discuss four topic of relevance to CCS deployment and the case under consideration:

- The potential costs and benefits from capture technology improvement and second-generation technologies through comparison of the chains "improved amine", "high permeance membrane", and "high selectivity membrane" with the base case;
- Opportunities for reduction of the transport cost through the comparison of the chains "stand-alone pipeline" and "shared pipeline" with the base case;
- The potential value creation benefit of combining the CCS chain with CO₂ EOR through comparison of the chains "EOR 25y" and "EOR 10y";
- The potential benefit of having a CCS project portfolio rather than a "full-scale" chain.

¹⁷ This real discount rate of 8 % corresponds to a nominal discount rate of around 10% if an inflation rate of 2% is considered.

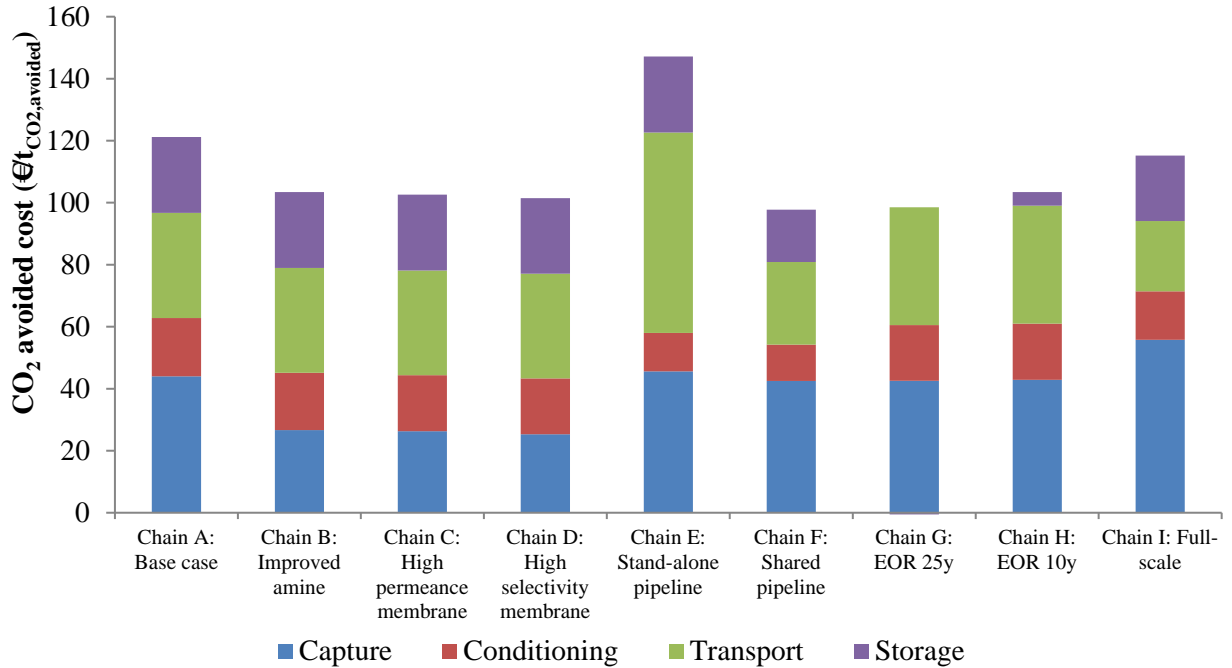


Figure 6: CO₂ avoided cost for the nine chains considered

4.2 Cost-reduction potential from capture technology improvement and second-generation technologies

CO₂ capture is a major cost component of the CCS chain, and the improvement of existing technologies and development of 2nd and 3rd generation of capture technologies has been focal points of research and development throughout the past 20 years [54-56]. Here, the potential of both of these cost-reduction approaches have been evaluated through three chain alternatives: 1) solvent-based capture with an improved amine decreasing the steam requirement by 33% compared to MEA 2) membrane-based capture based on the high-permeance developed by MTR [13] 3) membrane-based capture based on the high-selectivity membrane developed by NTNU [16].

The results presented in Figure 7 show that these three options have the potential to significantly reduce the cost of CO₂ capture from the cement plant. The solvent process based on improved amine with a steam requirement of 2.1 GJ/tCO₂ has the potential to reduce costs by 40% compared to the base case. This significant cost reduction is primarily due to the cost savings directly associated with reduced steam consumption. However, the reduction in the CO₂ emissions from steam consumption, which impacts both the capture costs and the overall chain costs, account for almost one fourth of the cost reduction.

In the case of the membrane-based capture processes, the potential cost reduction might be also 40% compared to the base case. This is mainly due to the low cost of electricity at the cement plant. However, there are rather significant uncertainties associated with the estimated costs of the membrane module, as the literature often assumes a unitary cost of 40 €/2014/m² irrespective of the properties of the membrane, and does not take the initial development cost into account [22]. Therefore subcases with membrane module cost of 80 €/2014/m² are also presented in Figure 7 for comparison. In these cases, the cost advantage of the membrane-based processes is reduced to 30% compared to the MEA process of the base case.

Both the improved amine-based and the membrane-based technology show a strong potential for reducing the cost of CO₂ capture from the cement factory. Membranes for post-combustion CO₂ separation are not yet commercially available and therefore represent a risk that is still too high in a short-term perspective, although it has great potential in the long run. On the other

hand, even though few improved solvents are commercially available, it is important to note that their performances are lower than the improved amine case considered here, and further development is also required to reach the full potential of improved amine-based capture.

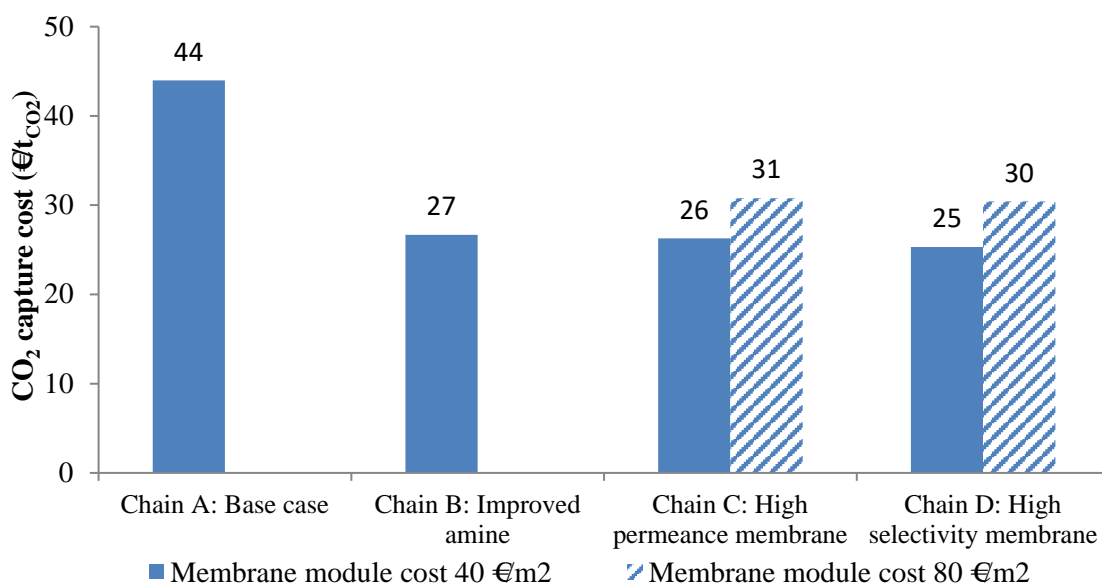


Figure 7: CO₂ captured costs for the base case and the capture technology alternatives

4.3 Opportunities for reduction in transport cost

Two alternatives are possible to transport CO₂ to an offshore location: pipeline and shipping. Offshore pipeline transport has often been regarded as the most advantageous, due to its cost-effectiveness for large volumes and as it has the advantage of being a continuous process with opportunities for automation, but it requires large initial investments. On the other hand, CO₂ shipping is less capital-intensive and more flexible. However, it is less cost-effective for short distances and large volumes.

While transport is often regarded as a minor cost component of the CCS chain, higher costs than expected are incurred in this case, due to the small volumes involved as shown in Figure 8. Therefore CO₂ shipping transport considered in the base case is compared to pipeline transport, both on a stand-alone basis and on a common shared infrastructure basis. Comparison of the stand-alone pipeline transport with the shipping base case indicates an increase of 45% in the cost of CO₂ conditioning and transport. Indeed, even if the conditioning costs are lower in the case of pipeline transport [31], pipeline CO₂ transport is an extremely cost-inefficient method for transport of small volumes over long distances, as shown in Figure 9 and as documented in the literature [25, 27]. However when considering a common pipeline infrastructure shared with two other actors of similar size to the cement plant base case, the costs of transport and conditioning allocated to the cement plant are reduced by 50% compared to the stand-alone case, and thus lead to conditioning and transport costs 30% lower than in the base case (i.e. using shipping).

These results show that a common pipeline infrastructure and, even more, a pipeline network have the potential to significantly lower the cost of CCS for CO₂ sources and sinks located in the Skagerrak region due to the small volumes involved. In theory, such an infrastructure could be beneficial for the Norcem case and could be possible as two other high-potential cases for Norwegian full-chain CCS demonstration (Yara's fertilizer production facility and Klemetsrud waste management and energy recovery plant) are located less than 200 km from the Norcem site. However, there are several significant obstacles to this solution, as it would require joint

interest in such an infrastructure, guaranties from several actors, deployment coordination, high investment and therefore investment risk. Without a strong involvement and national financial support, the deployment of such an infrastructure would be difficult to put in place [32, 57] and CO₂ transport via shipping seems to be a more realistic solution. In addition, shipping transport will become even more cost-effective than pipeline transport in the case of transport to CO₂ storage sites in the North Sea.

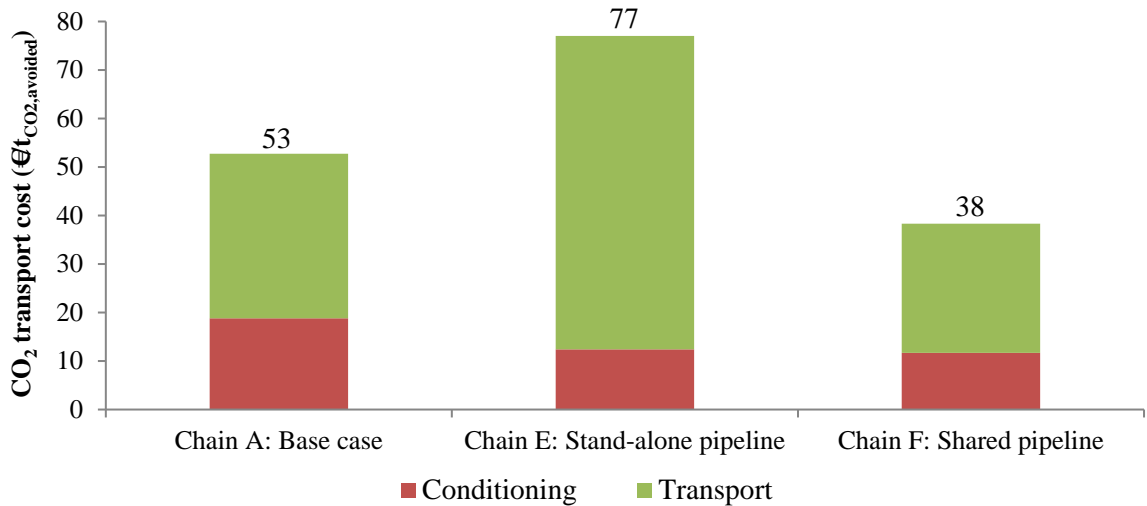


Figure 8: CO₂ conditioning and transport cost of the base case with shipping and the two pipeline transport alternative cases (stand-alone pipeline and shared pipeline)

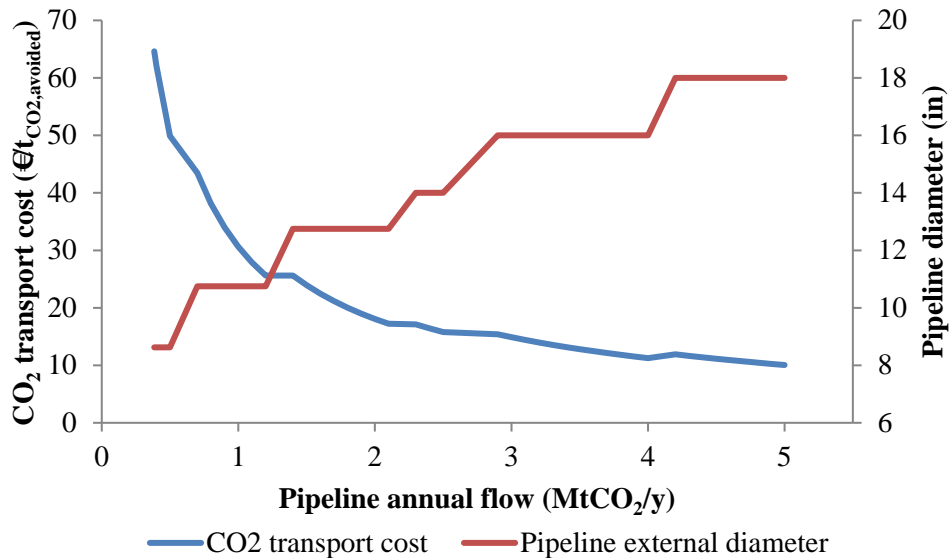


Figure 9: CO₂ transport cost per ton of CO₂ in function of the annual flow considered for the pipeline design for a 300km pipeline

4.4 CO₂ EOR an opportunity for CCS?

CO₂ capture, transport and storage in connection with Enhanced Oil Recovery (EOR) is often considered to be a promising way to ensure cost-efficient avoidance of CO₂ emissions to atmosphere [1].

The potential cost benefits of CO₂ storage associated with EOR are evaluated and compared to the base case. In the chains associated with EOR, the storage considered is located in the North Sea (Storage L2) instead of the Skagerak region (Storage L1) in the base case. In addition, as the CO₂ emissions of the cement on their own are regarded as small for a full CO₂ EOR project

(beyond testing), it is assumed that the CO₂ EOR storage is used for two other sources of the same size as the emissions stored from the cement plant. The costs of the two transport and storage cases in which the EOR storage can be used for respectively 25 and 10 years, while a saline aquifer is used for the excess CO₂, are assessed and compared in Figure 10. The results of the assessment show that significant cost reductions can be achieved if CCS projects can be coupled with CO₂ EOR storage under the oil prices considered. Indeed, the costs of CO₂ transport and storage can be reduced by 35 and 28% respectively in the cases of 25 and 10 years of EOR storage.

However, it is important to note that the viability of CO₂ EOR storage is highly dependent on the oil value considered. Indeed, as shown by Roussanaly and Grimstad [7], the oil value considered for the valuation of a CCS project with CO₂ EOR storage can be significantly lower than the oil price depending not only on production costs but also on the performances of alternative EOR methods for the oil field in question. As the oil value considered here takes in account both these issues, it is important to consider the influence of the oil price on the valuation of the CO₂ transport and storage cost of CCS chain with EOR considered. Therefore two additional sets of sub-cases with oil values of 66 and 14 €/bbl [58, 59]¹⁸ are presented in Figure 11.

The results show that, in both EOR cases, an oil value for the CCS project of 66 €/bbl would lead to halving the CO₂ transport and storage cost compared to the reference oil value. In this case, the CO₂ EOR part of the chain can fully overcome the storage costs and even halve the transport cost. However, at an oil value of 14 €/bbl, the transport and storage costs increase to 53 €/t_{CO₂,avoided} with both EOR chains. In this case, which reflects closely the low oil prices at the end of 2015 and beginning of 2016, CO₂ EOR storage leads to a very limited improvement in transport and storage costs compared to the base case in which CO₂ is only stored in a saline aquifer in the Skagerrak region.

These results confirm that CO₂ EOR has significant potential for reduction of the cost of CCS; however both the length of time period during which CO₂ can be injected in the EOR reservoir and the oil value have significant impacts on the profitability of this storage alternative.

¹⁸ Which corresponds to an oil price of 99 and 30 \$₂₀₁₄/bbl minus 12 \$₂₀₁₄/bbl of production cost for a field in which alternative EOR methods are not an option. The first oil prices correspond to the annual 2014 Brent average, while the second one, which is used to represent periods in which the oil prices are low, corresponds to the forecast value for February 2016.

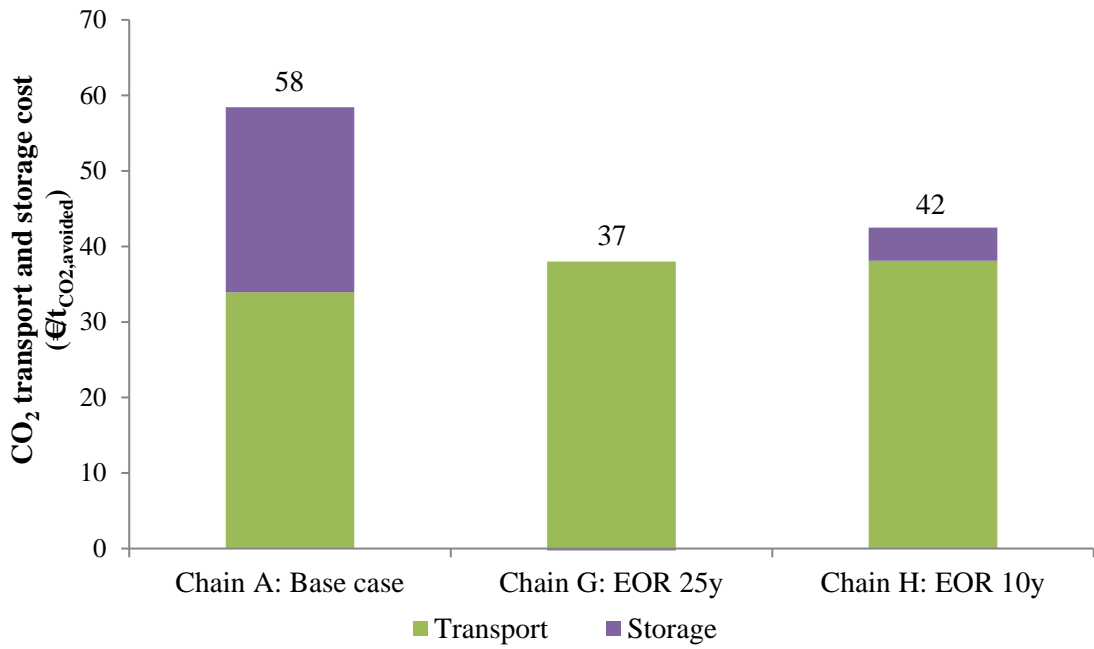


Figure 10: CO₂ transport and storage cost of the base case and the two storage alternatives (25 and 10 years EOR with an aquifer storage for the excess CO₂)

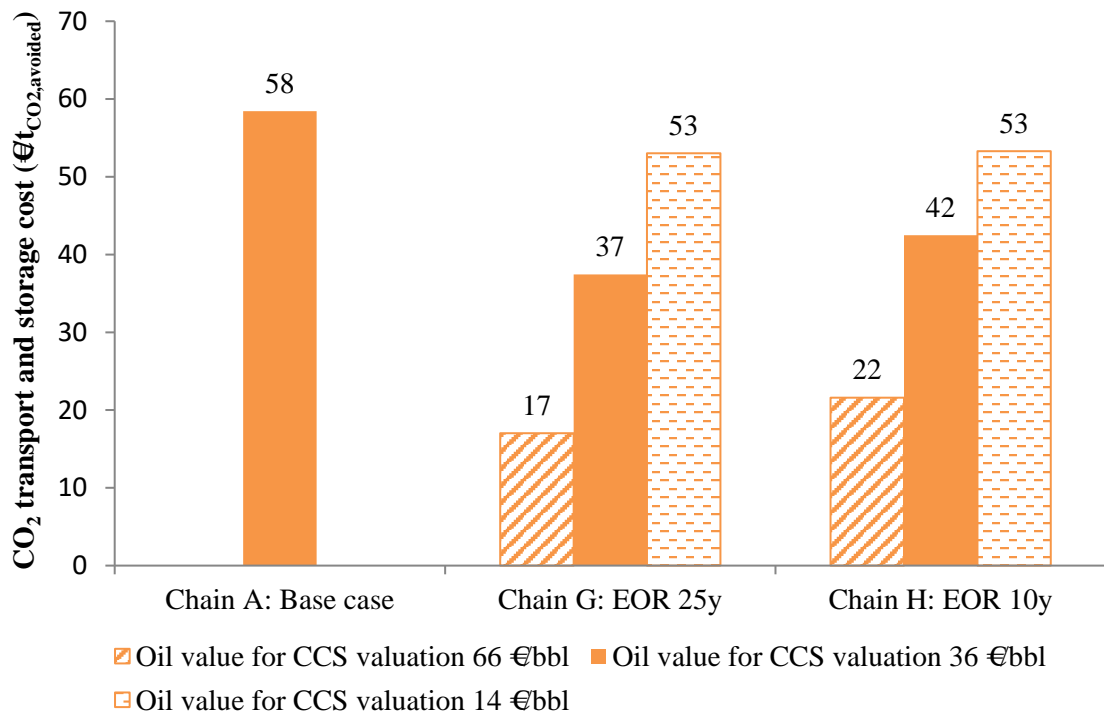


Figure 11: Influence of the oil value considered for the CCS valuation on the CO₂ transport and storage cost

5. Discussions

5.1 Quota price and CCS impact on the cost of cement

The need to develop an economic and financial framework to discourage high carbon options and reduce uncertainty is often highlighted by actors involved in enabling and implementing low carbon options [60].

This issue is of special importance here due to the high CO₂ avoidance cost obtained in all of the cases considered and more generally when considering the impact of CO₂ capture from a cement plant. This means that a high CO₂ tax/quota or a high level of public financial support is required to compensate for the additional costs associated with CO₂ capture, transport and storage. Indeed, as shown in Figure 12, cement is a rather cheap material to produce (around 50 €/t_{cement}¹⁹) with a large climate impact (0.66 tCO₂/t_{cement}) [61]. In practice, the inclusion of the CO₂ capture and conditioning cost in the cement production cost leads to an increase of 70% in the cost of cement production, in the base case, which would have a significant impact on the competitiveness of the cement produced at the Norcem plant. This increase, which does not take transport and storage costs into account, would exceed the producer's margin rendering the cement production with CCS unprofitable at the current market price [62] unless it is compensated for. If CCS is to be implemented at Norcem, public financial support will therefore be required to overcome the additional cost associated with the implementation of CO₂ capture and conditioning at the cement plant. This financial support required will depend on the capture technology employed, ranging from 40 €/tCO_{2,avoided} with the improved amine and membrane based capture to 60 €/tCO_{2,avoided} with the conventional MEA process.

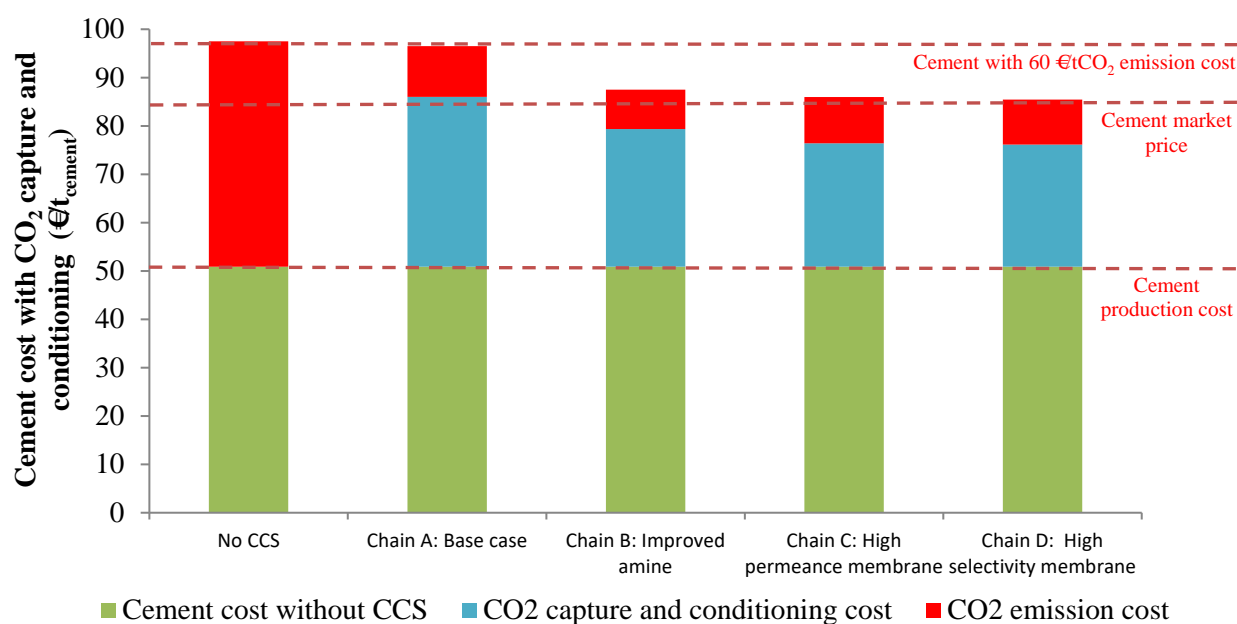


Figure 12: Cement cost with CO₂ capture and conditioning for the different capture alternative at a CO₂ emission cost of 60 €/tCO₂

5.2 Socioeconomic aspects

While full-scale CCS is often referred as the goal for demonstration and implementation of the CCS technology due to potential economies of scale, it might not be the most suitable target for all cases of demonstration or implementation. Indeed, as shown in **Figure 13**, in the case discussed here, a full-scale implementation might reduce the CO₂ avoided cost by only 6%

¹⁹ The cement cost used here is a generic European value and is not specific to the Norcem cement plant.

compared to the base case in which partial capture is considered. Even if the whole chain benefits from the economies of scales associated with the higher CCS capacity, the CO₂ capture cost increases significantly in the full-scale case. While a large proportion of the steam required by the capture unit can be produced at a low cost from the cement plant's waste heat in the base case, the capture cost increases in the full-scale case as the additional steam required will be produced by a natural gas boiler at full cost. This significantly offsets the economies of scale in the full-scale case.

This limited reduction in the CO₂ avoided cost, while the overall CCS cost increases from 450 to 830 M€ underlines the fact that full-scale implementation based on the solvent technology would not be suitable in this case, unless it was supported by significant financial incentives (CO₂ tax or quota, or public-sector financial support). If financial support from the government is available above the support required for the base case, support for further demonstration of other capture technologies, such as membrane, at the Norcem, site would be preferable to full-scale solvent based implementation. Alternatively, potential national CCS financial support available above the cost of Norcem base case, could also be used to support some of the other high potential cases for Norwegian full-chain CCS demonstration: the Klemetsrud waste management and energy recovery plant near Oslo, Yara's fertiliser production facility near Porsgrunn, and the Longyearbyen coal-fired power plant on Svalbard. In both cases, these potential "additional" available financial supports would help to demonstrate additional CCS technologies than in the Norcem base case and further qualify CCS as a safe and cost-effective option for reducing CO₂ emissions from industry and the electricity generation sector.

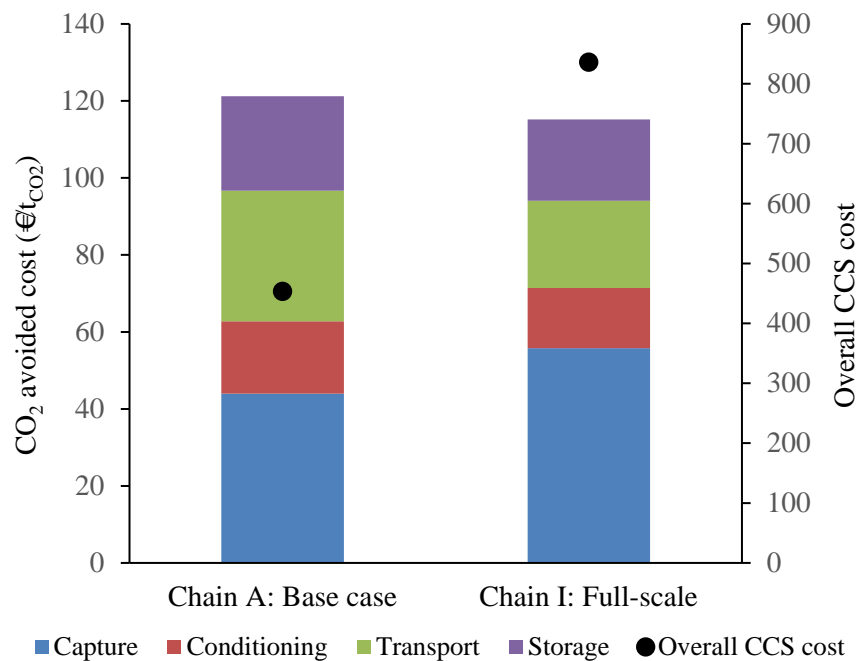


Figure 13: CO₂ avoided cost of the base case and the full-scale case

6. Conclusions

To make carbon capture and storage happen, clever strategies are needed for robust decision making under uncertainties. The iCCS methodology and tool were developed in order to reveal important facts and relationships that would provide a sound knowledge foundation for project prioritization and decision-making. The methodology and tool were applied to the NORCEM Brevik cement plant case study in order to assess and understand the following issues: effects of the choice of capture technology, the potential of EOR as a market maker, effect of the quota-

price incentive, and the need for a long-term governmental strategy for CCS. The conclusions drawn, based on the results obtained for the set of nine alternative chains analysed, can be summarized as follows:

- The assumed reduced energy demand for solvent regeneration by developing improved solvents has the potential to reduce the capture cost by 40%. However, there may be thermodynamic constraints that will not allow further significant energy reduction.
- Membranes appear to have great potential for capture cost reduction in the same range, but are currently associated with significant risks due to the lack of maturity and uncertainties regarding membrane properties and costs.
- EOR can improve the economics of the whole CCS chain but the cost versus revenues balance is very sensitive to the oil price and depends on the availability, efficiency, and cost of alternative EOR technologies.
- The CO₂ quota price level required to cover the cost of the CO₂ capture (not including transport and storage) implementation on the cement plant analysed here is around 60 €/tCO₂. A more stringent CO₂ quota policy is required. However, by itself, this is unlikely to be a sufficient measure to kick-start the implementation of CCS in the cement production industry. Additional incentives will also be required to ensure the viability of CCS from cement production:
 - Public investment in shared infrastructure and storage.
 - Rewarding mechanisms for first movers, CO₂ EOR, or other initiatives.
- The development of a long-term strategic vision for CCS financing based on socio-economic aspects and potential benefits might introduce new perspectives.
- Innovative business models on the crossroad between the public and private sectors will have to be developed in order to help close the cost gap and align commercial and societal interests across the CCS chain.

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7. Appendix A: Further data on CO₂ capture and transport modelling

7.1 CO₂ capture technologies

The characteristics of the solvent-based captures for chains A and B are presented in Table 8, while the characteristics of the membrane-based captures for chains C and D are presented in Table 9.

Table 8: Characteristics of the solvent-based captures in chains A and B

Utilities consumptions	Chain A	Chain C
Amine type	MEA	Advanced amine
Steam consumption (GJ/t _{CO₂,captured})	3.2	2.1
Electricity consumption (kWh/t _{CO₂,captured})	14.2	14.2
Cooling water (m ³ /t _{CO₂,captured})	30	30
Amine make-up (kg _{MEA} /t _{CO₂,captured})	0.8	0.8

Table 9: Characteristics of the membrane-based captures in chains C and D

Type of data	Characteristics	Chain C	Chain D
Membrane	Selectivity (-)	5.94	2
	Permeance (m ³ _(STP) /(m ² .h.bar)	50	135
Overall	Number of membrane stages (-)	3	2
First stage	Permeate purity after the 1 st stage (%)	59	84.1
	Inlet operating pressure of the membrane module (bar)	2.2	4.2
	Vacuum pumping pressure of the permeate (bar)	0.2	0.2
	Membrane area (m ²)	90 400	94 400
Second stage	Product purity (%)	92.1	99.1
	Inlet operating pressure of the membrane module (bar)	1.6	1
	Vacuum pumping pressure of the permeate (bar)	0.2	0.3
	Membrane area (m ²)	17 500	41 300
Third stage	Product purity (%)	99	-
	Inlet operating pressure of the membrane module (bar)	1	-
	Vacuum pumping pressure of the permeate (bar)	0.4	-
	Membrane area (m ²)	10 300	-

7.2 CO₂ pipeline transport

Table 10: Offshore pipeline conditioning and transport chain design characteristics [24]

	Parameter	Value	Unit
System	Inlet pressure	1	bar
	Inlet temperature	25	°C
	Pressure after conditioning	200	bar
	Temperature after conditioning	45	°C
	Wellhead pressure	≥60	bar
	Wellhead temperature	~4	°C
Conditioning	Number of compression stages	4	-
	Pressure ratio	~3	-
	Gas temperature after intermediate cooling	25	°C
	Compressor adiabatic efficiency	80	%
	Pump adiabatic efficiency	75	%
1 i	Range of pipeline diameter	8 5/8 to 44	in

Overlength factor ²⁰	10	%
Design pressure	250	bar
Minimum allowed pressure	60	bar
Average temperature ²¹	~4	°C
Well head depth	500	m
Flexible pipeline riser length	600	m

7.3 CO₂ shipping transport

Table 11: Shipping conditioning and transport chain design characteristics [25]

	Parameter	Value	Unit
System	Inlet pressure	1	bar
	Inlet temperature	25	°C
	Pressure after conditioning	6.5	bar
	Temperature after conditioning	-50.3	°C
	Pressure after reconditioning	60	bar
	Temperature after reconditioning	~4	°C
	Wellhead pressure	≥60	bar
	Wellhead temperature	~4	°C
Conditioning	Number of compression stages	3	-
	Pressure ratio	~3	-
	Gas temperature after intermediate cooling	25	°C
	Compressor efficiency	80	%
	Pump efficiency	75	%
Shipping	Shipping cycle duration excluding transport time ²²	24	h
	Shipping service speed ²³	14	knots
	Ship operating time ²⁴	350	d/y
Reconditioning and riser	Inlet seawater temperature	15	°C
	Outlet seawater temperature	13	°C
	Shipping fuel conversion factor	12,029	kWh/t _{fuel}
	On-board pump efficiency	75	[%]
	Unitary CO ₂ pump power	1,200	kW/pump
	Wellhead depth	500	m
	Flexible riser length	600	m

Table 12: Shipping characteristics depending on vessel size [31]

²⁰ In order to take into account the total length of the pipeline (including t-junctions, terrain factors, etc.), its length is assumed to be 10% longer than the transport distance.

²¹ As the pipeline is mainly located at the bottom of the sea where the water is at 4°C, the CO₂ will rapidly cool and will be more dense than at ambient temperature.

²² Assuming mooring/loading/departure and mooring/unloading/departure durations of 12 h each.

²³ Equivalent to 25.9 km/h.

²⁴ 360 h (15 days) per year are used for maintenance.

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

7.4 Cost methodology for membrane-based CO₂ capture process

A direct costs function for carbon steel equipment has been regressed for the membrane-based capture process using the Aspen Process Economic Analyzer[®] (see Table 13), based on simulations performed using the numerical membrane model. However, due to their specificity, the CO₂ membrane module and framework costs are estimated in a different way. The membrane module is estimated on the basis of the 50 \$₂₀₁₀/m² cost adopted by Zhai and Rubin [15]. The membrane framework is based on the cost function suggested by van der Sluijs et al. [63] for the framework of the membrane separation system in an ammonia plant of DSM, and modified by Roussanaly et al. [21] to take the influence of the design pressure of the module into account, as shown in equation 1 and Table 14²⁵.

$$\text{Direct cost}_{\text{membrane framework}} = \left(\frac{\text{Module area}}{2000} \right)^{0.7} \cdot \text{Reference module cost} \cdot \left(\frac{\text{Module pressure}}{55} \right)^{0.875} \quad (2)$$

Table 13: Direct cost of membrane module, rotating equipment and heat exchanger equipment costs

Type of equipment	Unitary cost	Unit
Membrane module [15]	40	€ ₂₀₁₄ /m ²
Compressor (First stage)	920	€ ₂₀₁₄ /kW
Compressor (Second stage)	510	€ ₂₀₁₄ /kW
Compressor (Third stage)	370	€ ₂₀₁₄ /kW
Expander	570	€ ₂₀₁₄ /kW
Vacuum pump	800	€ ₂₀₁₄ /kW
Cooler	370	€ ₂₀₁₄ /m ²

Table 14: Direct cost of the membrane framework

Type of equipment	Unitary cost	Unit	Reference
Reference module area	2 000	m ²	[63]
Reference pressure	55	bar	[63]
Reference module cost	286	k€ ₂₀₁₄	[63]

²⁵ It is worth noting that a limit of 25,000 m² of membrane area per module is used in order to avoid having unrealistically large modules.

8. Appendix B: Detailed cost breakdown of the chain alternatives

Table 15: CO₂ avoided cost (€t_{CO₂,avoided}) detailed breakdown of the chain alternatives

		Chain A	Chain B	Chain C	Chain D	Chain E	Chain F	Chain G	Chain H	Chain I
Capture	CAPEX	14.5	14.5	10.2	10.6	14.5	14.5	14.5	14.5	11.1
	Fixed OPEX	9.2	9.2	4.6	4.8	9.2	9.2	9.2	9.2	7.0
	Variable OPEX	12.8	2.7	7.6	6.6	12.8	12.8	12.8	12.8	23.3
	Climate impact	7.5	0.2	4.0	3.4	9.1	6.1	6.1	6.4	14.4
Conditioning	CAPEX	7.7	7.7	7.7	7.7	4.7	4.7	7.7	7.7	6.1
	Fixed OPEX	4.9	4.9	4.9	4.9	3.0	3.0	4.9	4.9	3.8
	Variable OPEX	4.2	4.2	3.7	3.7	2.6	2.6	3.7	3.7	3.7
	Climate impact	2.1	1.8	1.8	1.7	2.1	1.4	1.7	1.8	2.0
Transport	CAPEX	18.7	18.7	18.7	18.7	57.4	24.0	20.2	20.2	12.5
	Fixed OPEX	12.2	12.2	12.2	12.2	7.2	2.6	12.7	12.7	7.2
	Variable OPEX	2.0	2.0	2.0	2.0	0.0	0.0	3.2	3.2	2.0
	Climate impact	1.0	0.9	0.9	0.8	0.0	0.0	1.8	1.9	0.9
Storage	CAPEX	18.0	18.0	18.0	18.0	18.0	12.2	16.2	16.4	14.0
	Fixed OPEX	5.2	5.2	5.2	5.2	5.2	3.3	6.1	4.8	5.9
	Variable OPEX	1.1	1.1	1.1	1.1	1.1	1.1	1.1	1.0	1.1
	EOR revenues	0.0	0.0	0.0	0.0	0.0	0.0	-24.4	-18.3	0.0
	Climate impact	0.2	0.1	0.1	0.0	0.2	0.4	0.4	0.4	0.2