Zep
Zero emissions platform

The Costs of CO_2 Transport

Post-demonstration CCS in the EU

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Zero emissions platform

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Executive Summary

Founded in 2005 on the initiative of the European Commission, the European Technology Platform for Zero Emission Fossil Fuel Power Plants (known as the Zero Emissions Platform, or ZEP) represents a unique coalition of stakeholders united in their support for CO_2 Capture and Storage (CCS) as a critical solution for combating climate change. Indeed, it is not possible to achieve EU or global CO_2 reduction targets cost-effectively without CCS – providing 20% of the global cuts required by 2050.[1] Members include European utilities, oil and gas companies, equipment suppliers, national geological surveys, academic institutions and environmental NGOs. The goal: to make CCS commercially available by 2020 and accelerate wide-scale deployment.

ZEP is an advisor to the EU on the research, demonstration and deployment of CCS. Members of its Taskforce Technology have therefore now undertaken a study into the costs of complete CCS value chains – i.e. the capture, transport and storage of CO_2 – estimated for new-build coal- and natural gas-fired power plants, located at a generic site in Northern Europe from the early 2020s. Utilising new, in-house data provided by ZEP member organisations, it establishes a reference point for the costs of CCS, based on a "snapshot" in time (all investment costs are referenced to the second quarter of 2009).

Three Working Groups were tasked with analysing the costs related to CO_2 capture,[2] CO_2 transport and CO_2 storage[3] respectively. The resulting integrated CCS value chains, based on these three individual reports, are presented in a summary report.[4]

This report focuses on CO_2 transport.

- **The most complete analysis of CO_2 transport costs to date**

Initially, the intention was to build the report as a summary of existing studies. However, since these were found to be insufficient for the purpose, the bulk of cost data has been provided via member organisations and ZEP analysis, guided by the principle of consensus.

The approach has been to describe three methods of transportation and for each of these present detailed cost elements and key cost drivers. The three methods are:

1. Onshore pipeline transport
2. Offshore pipeline transport
3. Ship transport, including utilities.

Interface conditions such as pressure, temperature and flow rates have been agreed with the respective Working Groups for Capture and Storage; and much effort was invested in detailing the assumptions made for each of the transport methods. The CAPEX and OPEX of each method of transport have been estimated using internally available information.

Several likely real-life transport networks are described as they may evolve: network parameters were selected with an eye to real scenarios, such as clusters of CO_2 sources and storage sites. The cost models operate with three legs of transport: *feeders, spines* and *distribution*, each of which may be onshore pipeline, offshore pipeline or ship. The volumes of transported CO_2 include a typical demonstration scenario similar to

[1] International Energy Agency, World Energy Outlook, 2009
[2] www.zeroemissionsplatform.eu/library/publication/166-zep-cost-report-capture.html
[3] www.zeroemissionsplatform.eu/library/publication/168-zep-cost-report-storage.html
[4] www.zeroemissionsplatform.eu/library/publication/165-zep-cost-report-summary.html

a commercial natural gas-fired plant with CCS, but primarily volumes are as may apply in a commercial market in, say, 2030-2040. Compared to previous studies, this report has given more attention to scenarios with shorter distances and transport to offshore storage locations.

The issues of short- and long-term cost and currency developments have been simplified by indexing all estimates to one specific period – the second quarter of 2009. Any user of the cost data in this report is therefore advised to estimate and adjust for developments after this period. Cost estimates are displayed as capital expenditure (CAPEX) annualised at 8% interest rate and 40 years lifetime, and annual operating expenditure (OPEX). Total annual network costs and a cost per transported tonne CO_2 are also presented. The networks have been specified with different transportation distances. For some pipeline cases, CAPEX per tonne per km is also presented, which offers a very useful tool for comparison.

The data and results provided in this report should therefore assist in the evaluation of both the costs of CO_2 transport and optimal solutions for specific projects.

ZEP's target: +/- 30% accuracy

ZEP's target has been to obtain cost estimates which are accurate within a margin of ~30%. This is a strict requirement for a study that excludes front-end engineering. However, all the in-house cost data utilised are based on relevant experience, with pipelines and ships designed to carry hydrocarbons which, if anything, would have a tendency to overestimate costs.

The report accounts for costs in several sequential steps and specifies CAPEX and OPEX. This not only allows detailed scrutiny by the reader, but provides the opportunity to modify some of the assumptions. Indeed, these are specified as accurately as possible, giving the reader the chance to agree or disagree with their relevance. The impact of variations on the unit cost in a few key parameters is also provided (see Section 7.2.1, Key sensitivities, page 42).

Shipping investments are assumed to have residual value in hydrocarbon transportation, as well as other CO_2 projects, which may be considered in any evaluation of project risks. All cost estimates are based on custom design and new investment, i.e. no re-use of existing pipelines or existing semi-refrigerated LPG tonnage.

It is worth underlining that transport costs constitute only one of the three CCS cost components and that overall accuracy should ideally be determined on the aggregate CCS level.

• The results

For CCS demonstration projects (and commercial natural gas-fired plants with CCS), a typical capacity of 2.5 million tonnes per annum (Mtpa) and "point-to-point" connections are assumed. The following table shows the unit transportation cost (EUR/tonne) for such projects, depending on transport method and distance:

Distance km	*180*	*500*	*750*	*1500*
Onshore pipe	5.4	n. a.	n. a.	n. a.
Offshore pipe	9.3	20.4	28.7	51.7
Ship	8.2	9.5	10.6	14.5
Liquefaction (for ship transport)	5.3	5.3	5.3	5.3

Table 1: Cost estimates for CCS demonstration projects (and commercial natural gas-fired plants with CCS), 2.5 Mtpa (EUR/tonne CO_2)

As shown, pipeline costs are roughly proportional to distance, while shipping costs are only marginally influenced by distance. Pipeline costs consist mainly (normally more than 90%) of CAPEX, while shipping costs are less CAPEX-intense (normally less than 50% of total annual costs). If there is considered to be any technical or commercial risk, the construction of a "point-to-point" offshore pipeline for a single demonstration project is therefore less attractive than ship transportation for distances also under 500 km. (Pipeline costs here exclude any compression costs at the capture site, while the liquefaction cost required for ship transportation is specified.)

Once CCS becomes a commercially-driven reality, it is assumed that typical volumes are in the range of 10 Mtpa serving one large-scale power plant, or 20 Mtpa serving a cluster of CO_2 sources. The unit transportation cost of such a 20 Mtpa network with double feeders and double distribution pipelines is estimated to be as follows:

Spine Distance km	*180*	*500*	*750*	*1500*
Onshore pipe	1.5	3.7	5.3	n a
Offshore pipe	3.4	6.0	8.2	16.3
Ship (including liquefaction)	11.1	12.2	13.2	16.1

Table 2: Cost estimates for large-scale networks of 20 Mtpa (EUR/tonne CO_2). In addition to the spine distance, networks also include 10 km-long feeders (2*10 Mtpa) and distribution pipelines (2*10 Mtpa)

Table 2 illustrates how pipelines benefit significantly from scale when comparing costs with the 2.5 Mtpa "point-to-point" solutions in Table 1, whereas the scale effects on ship transport costs are less significant. (Shipping costs here include the costs for a stand-alone liquefaction unit, i.e. remote from the power plant.) These figures assume full capacity utilisation from day one, which may well prove to be unrealistic for a cluster scenario. If, for example, volumes are assumed to be linearly ramped-up over the first 10 years, this increases the unit cost of pipeline networks by ~35-50% depending on maximum flows. For ships, ramp-up is achieved by adding ships and utilities when required, resulting in only marginal unit cost increases.

The main aim of this report is to provide cost estimates for large-scale CCS, rather than to recommend generic modes of transport. However, assuming that high CAPEX and high risk are obstacles to rapid CCS deployment, one conclusion that could be drawn from the results is that combining ship and pipe transport in the development of clusters could provide cost-effective solutions – especially for volume ramp-up scenarios. To achieve lowest possible transport costs for CCS in a large-scale, commercial market, central planning is already required in the demonstration phase.

Key conclusions

- Pipeline costs are mainly determined by CAPEX (capital expenditure) and are roughly proportional to distance. They therefore benefit significantly from economies of scale and full capacity utilisation.
- Ship transport costs are less dependent on distance and on scale of transport. CAPEX is proportionally lower than for pipelines and ships have a residual value in hydrocarbon gas transportation which significantly reduces the financial risk.
- Combining pipes and ships for offshore networks could provide cost-effective and lower risk solutions, especially for the early developments of clusters.
- For large-scale transport infrastructure, long range and central planning can lead to significantly reduced long-term costs.

1 Study on CO_2 Transport Costs

1.1 Background

In 2006, ZEP launched its Strategic Deployment Document (SDD) and Strategic Research Agenda (SRA) for CO_2 Capture and Storage (CCS). The goal: to provide a clear strategy for accelerating its deployment as a critical technology for combating climate change. The conclusion: an integrated network of demonstration projects should be implemented urgently EU-wide in order to ensure CCS is commercially available by 2020.

In 2008, ZEP then carried out an in-depth study[5] into how such a demonstration programme could work in practice, from every perspective – technological, operational, geographical, political, economic and commercial. This approach was endorsed by both the European Commission and European Council; and by 2009, two key objectives had already been met – to establish funding for an EU CCS demonstration programme and a regulatory framework for CO_2 storage. An updated SDD followed in 2010.[6]

As importantly, ZEP has published its long-term R&D plan[7] for next-generation CCS technologies to ensure rapid deployment post-2020. Now, ZEP experts have identified the key cost elements and forecast the long-term cost of CO_2 transport – in the context of CO_2 capture and storage solutions. Indeed, this has been undertaken in parallel with similar work on capture and storage costs, and should be assessed in conjunction with these results.[8]

1.2 Use of new, in-house data

Cost forecasting work was organised into three Working Groups within ZEP's Taskforce Technology – for Capture, Transport and Storage, respectively.

The original intention of the Working Group on Transport was to extract comparable cost data from published reports, align with the assumptions made within the Working Group on Transport and present the results as a range of costs. However, as described below, existing literature does not readily lend itself to transport cost comparisons, either because of the lack of information on CAPEX and OPEX, or because the wide range of assumptions made is not consistently accounted for.

As a parallel activity, the development of a generic model for transport cost estimation was also considered, but it was concluded early on that the limited time and resources available for this task would not allow sufficient stringency and quality assurance. This approach would also have gone beyond the agreed task of presenting credible estimates for the costs of large-scale CO_2 transport in both the early demonstration phase and a commercial market.

Instead, the group decided to use its own detailed technical and economical knowledge of the various cost elements. Composed of members from organisations where substantial research and experimental work in the area of CO_2 transport costs has already been carried out, their extensive, cumulative experience has formed much of the basis of the cost estimates (see page 48 for a list of members).

The group then elaborated on what could be considered plausible transport networks, representative of a commercial-scale market for CO_2 transport in 2030. For each of these networks, assumptions, cost elements and cost numbers were applied in order to arrive at credible and documented cost estimates. As a result of the diverse representation within the group, and by using competent external parties for review, individual

[5] www.zeroemissionsplatform.eu/library/publication/2-eu-demonstration-programme-co-2-capture-storage.html
[6] www.zeroemissionsplatform.eu/library/publication/125-sdd.html
[7] www.zeroemissionsplatform.eu/library/publication/95-zep-report-on-long-term-ccs-rad.html
[8] www.zeroemissionsplatform.eu/library/publication/166-zep-cost-report-capture.html
www.zeroemissionsplatform.eu/library/publication/168-zep-cost-report-storage.html

statements, all data and assumptions have been challenged, vetted and verified in order to ensure quality control.

Indeed, the work has been guided by a principle of consensus. Ad hoc sub-groups were formed for specific tasks and consultations made with colleagues both from other working groups in Taskforce Technology and within the member organisations. Discussions were held in an atmosphere of openness and in areas with high uncertainties, numerous iterations were performed in order to find the most likely scenarios and best available consensus.

As importantly, considerable emphasis has been placed on explicitly detailing the assumptions used in order to make it possible to use and/or modify the estimates, according to the extent to which the assumptions employed are applicable to more specific projects.

N.B. Certain critical technology, cost data or references may be of a proprietary nature, such that it may not have been possible for the organisation or individual to disclose certain details for commercial reasons.

1.3 Literature and references

There are very few studies and reports focusing specifically on the cost of CO_2 transport in the context of CCS. Existing cost estimates may also vary widely, as shown by The Bellona Foundation,[9] who compared a cost report by McKinsey and Company with one by Statoil. However, some reports were particularly useful when comparing technical assumptions and, ultimately, in validating the results of ZEP's work.

Pipeline costs depend on several parameters, such as wall thickness (resulting from, for example, maximum pressure in the pipe and choice of installation method), choice of material and terrain factors such as urban zone, river or rail crossings [Usine Nouvelle 2009]. Vandeginste et al [2008] present a critical review of existing models used to determine the pipe diameter – the most important cost impact factor for pipelines. They point out that none of the reviewed models takes into account all the parameters impacting pipe diameter and propose a new correlation.

Even if ship transport of CO_2 is an obvious complement and alternative to pipelines, only very few studies include the economics of shipping: IEA/Mitsubishi [2005], Aspelund et al [2007], Svensson et al [2007], H.A. Haugen et al [2009]. Scenarios and assumptions are not sufficiently detailed to enable direct comparisons of cost data.

One report providing significant cost detail is published by the IEA. This dates back to 2005 and focuses on transport over long distances of up to 12,000 km, whereas European CCS projects discussed in this report are generally expected to transport CO_2 over distances shorter than 1,500 km. The cost data provided at the lower end of the IEA study's distance range do, however, correspond reasonably with the results presented in this report.

Greater efforts have been made to establish, by extrapolation, break-even distances for pipeline and ship costs for a given volume. Cost estimates are generally expressed per tonne of CO_2 with less breakdown on detail (either CAPEX or OPEX). Some authors based their estimates on physical or techno-economical correlations, including parameters such as the pipe diameter or the pressure drop – G. Heddle et al [2003]; V. Vandeginste, K. Piessens [2008]; CSA Group [2008]; J. Brac, G. Maisonnier [2009] and S. Decarre et al [2010].

Referenced literature listed on page 49 has therefore been used as a source of information for both the validation of assumptions and comparing the results of ZEP's cost estimates.

[9] www.bellona.org/ccs/ccs_blog/1239864580.29

1.4 Reader's guide to the report

N.B. For detailed cost estimates, please turn to Chapter 6.

Chapter 1 places the report in context, both in relation to parallel reports on the costs of Capture and Storage, and other ZEP work. Literature references are also provided, together with a description of data collected, the work process and methodology.

Chapter 2 describes the general assumptions in detail, including common specifications agreed with the Capture and Storage cost Working Groups. Boundary conditions are also described in order to clarify which types of costs are included in which report.

Chapter 3 describes the approach for categorising transport into four transport modules, followed by detailed insight into the components of each of the modules and detailed transport module costs.

Chapter 4 builds on the transport modules and cost element descriptions in Chapter 3, detailing specific assumptions for the transport networks. This gives readers the opportunity to calibrate background information in this report with real-life projects and other studies.

Chapter 5 aims to bring theory closer to reality and future practice, including a description of how transport infrastructure could develop over time and the possible large-scale networks necessary to provide sufficient transport capacity for CCS on a commercial scale. The combination of transport modules in building regional infrastructure is used to illustrate some typical network cases.

Chapter 6 details the components of each of the networks selected for cost assessment. Cost representations are made, building on the assumptions from Chapters 2 and 4, followed by a summary table with a useful overview of different networks and comparable cost data, expressed as EUR/tonne CO_2 transported.

Chapter 7 describes the cost uncertainties and key sensitivities – in particular, the load factor effect (capacity utilisation).

Chapter 8 discusses the risk of over- and/or understating cost estimates. Some tentative conclusions emerge, such as the need to recognise cluster developments and the use of ship logistics, especially in a volume build-up period. The chapter ends with a recommendation for further work on transport costs in Europe.

Chapter 9 provides details of individuals and organisations who have contributed to this report.

2 General CCS Assumptions

2.1 Production volumes

For consistency, a number of common assumptions were established and applied in all three Working Groups on the costs of CCS (capture, transport and storage). Those with the highest impact on transport cost estimates are reiterated below.

One of the most important assumptions is on production volumes and profiles. This report assumes three different annual volumes: 2.5 Mtpa for a typical demonstration project or a commercial natural-gas fired plant with CCS; 10 Mtpa for a full-scale, commercial coal-fired power plant with CCS; and 20 Mtpa for a typical full-scale, mature CCS project or a cluster of sources. The production profile is assumed to be linear, with equal hourly production rates of 333, 1,330 and 2,660 tonnes/hour respectively for 7,500 hours per year. All process and transport equipment is assumed to be able to achieve these hourly rates over prolonged periods of time.

2.2 Currency and interest rates

Costs refer to cost levels in the second quarter of 2009. It should be noted that this was a period with volatile prices in many markets. (This is discussed further in Chapter 7, Cost Estimate Ranges.) The currency exchange rates used are:

- 0.683 EUR/USD
- 1.258 EUR/GBP
- 0.111 EUR/NOK

The interest rate applied for both pipeline and ship investment is the same as for the other parts of the CCS chain: 8%. There are good reasons why the rate of return on investment could differ between pipelines and ships, since pipelines are likely to be public investments, while ships are likely to be provided by commercial players. For shipping, the rate of return is also normally differentiated between short- and long- term charters. However, for the sake of simplicity and comparison, the cost of capital for any investment has been fixed at one common rate.

2.3 Project lifetime

The agreed CCS project lifetime is 40 years. This has been incorporated into maintenance and overhaul costs relating to transport chain components.

2.4 Choice of material

Significant work is currently ongoing in demonstration projects and by R&D institutes to determine the limits for impurities in the CO_2 stream, related to both transport options and storage. The presence of water is the most critical impurity issue influencing the cost of transport since the risk of corrosion on pipes, tanks and process equipment directly affects the choice of material. For such transport systems, it is not realistic to assume the use of exotic materials which are resistant to a corrosive CO_2 composition, since this would increase costs by an order of magnitude. The cost estimates in this report are therefore based on the use of normal carbon steel, assuming the CO_2 for transport is sufficiently dry. It should be noted that the liquefaction process used for ship cargoes also requires low humidity.

2.5 Cost of energy

Both the compression of CO_2 for pipeline transport and its liquefaction for ship transport require large amounts of electrical energy. A stand-alone liquefaction process, in particular, needs to purchase large

quantities of electricity off the grid. It has therefore been important to establish a relevant, large consumer market price for electricity. Following an exchange with McKinsey and a study of European electricity market prices, an electricity price of €0.11/kWh was found to be representative.

Ships are assumed to be fuelled by either LNG (resulting in a significant reduction in greenhouse gas emissions), or conventional marine diesel oil. The cost of LNG fuel is generally anticipated to be equivalent to the cost of diesel oil, as a result of which a typical diesel oil price in Q2 2009 of 514 USD/tonne was applied.

2.6 Transport cost boundaries

The CO_2 is assumed to be delivered from the capture plant at 110 barg and ambient temperature. The feeder pipelines included in the cost estimates are therefore high pressure pipelines. It should be noted that feeder pipes or feeder networks may also be operated with the CO_2 in a gaseous phase at a lower pressure of, for example, 10 to 20 barg. This alternative is only possible when the compressor station is in relatively close proximity to the capture plant. Such a low pressure could also allow the use of plastic, as opposed to steel pipes, which under certain conditions could be highly advantageous. The option of lower pressure feeder pipelines has been considered but omitted here in order to use one, single interface condition between the capture and transport processes.

The transport process is assumed to deliver the CO_2 to the well-head at the storage site in the following condition:

- Temperature offshore: ambient seawater temperature 4 to 15°C
- Temperature onshore: ambient ground temperature approximately 10°C
- Pressure 60 barg.

This corresponds to the condition assumed for injection into a typical deep saline aquifer at approximately 1, 000 m depth. It should be noted that injection in depleted gas fields, as is likely in the southern North Sea, may take place at reservoir pressure not far above atmospheric at the start of injection.

Cost estimates for onshore pipelines assume that the pipeline terminates in a valve and a metering station, which constitute the simple interface to the storage process onshore. Both offshore pipeline and ship transport cost estimates include the cost of a subsea well-head template, whereas manifold costs are assumed to be included in storage costs with the drilling of injection wells.

The boundary towards the storage process is therefore at the sea bottom surface, below this template. For ship transport, this implies conditioning (pumping and heating to the required condition) onboard for “slow” discharge directly to the well(s) without the use of intermediate buffer storage. A consequential assumption is therefore that both the wells and the storage reservoir are capable of receiving injection interrupted by shorter or longer periods, waiting for the subsequent ship.

3 Transport Module Descriptions

For the purposes of this study, the logistic systems required for the large-scale transfer of CO_2 from sources to sinks are broken down into four discreet transport cost modules:

- Offshore pipelines
- Onshore pipelines
- Liquefaction
- Ship transport.

3.1 Pipeline transport of CO_2

High pressure pipeline transport is, for many purposes, a mature industry. In this context, the most relevant comparable examples are use of pipelines for transport of hydrocarbons, i.e. oil and gas. The characteristics of the substance transported inside the pipeline will affect the way the pipeline is designed and installed. In general, main attention needs to be given to the density of the transported medium, the flow pattern and the corrosivity as a function of the relationship between the selected pipeline material and the composition of the inventory of the pipeline.

A CO_2 transport pipeline can, to a large extent, be planned and constructed in the same way as natural gas transmission pipelines. This applies to both on- and offshore pipelines. As natural gas passes through the process chain after leaving the gas field, it is dried, compressed – in some cases, stored – and transported to the consumer. The energy industry has extensive experience with natural gas in all parts of the process chain. Captured CO_2 passes through similar process steps on its way from the source (e.g. power stations or other CO_2 emitters) to the storage site. A typical CO_2 process chain is shown below:

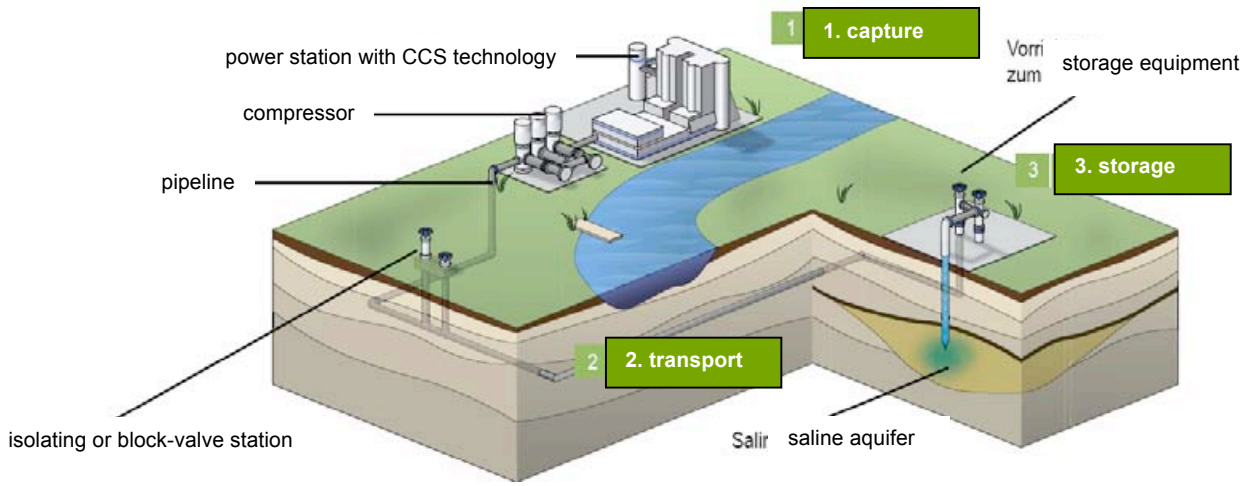


Figure 3-1 : CCS process chain: 1. capture, 2. transport and 3. storage [IZ Klima e. V., 2009]

However, CO_2 has different thermodynamic properties to natural gas along the process chain. For example, natural gas is always transported in its gaseous state in high-pressure pipelines. Design pressures of up to 100 barg are generally allowed for in onshore gas transmission systems, while offshore transmission pipelines may have an operational pressure up to, or even beyond, 200 barg. By contrast, when CO_2 is transported, the fact that the CO_2 may be in its gaseous, liquid or dense state – depending on the operating pressure – has to be taken into consideration. If pressure inside the pipeline is reduced, the liquid phase CO_2 will start to go into gaseous phase, resulting in mechanical challenges to the pipeline and reducing the

transport capacity. Thus, the transport pressure and temperature conditions need to be planned to ensure single (dense, liquid) phase transport from inlet to outlet of the pipeline.

In addition, presence of free water in the CO_2 stream will result in severe corrosion in a standard carbon steel pipeline, while other impurities may lead to a change in the phase diagram and may also cause complex corrosion mechanisms. R&D still needs to be performed to fully understand such mechanisms. Corrosion may be avoided either by ensuring that the transported medium is non-corrosive, or by using pipeline material resistant to corrosion. Efforts should therefore be made to define Europe-wide threshold values for entrained substances in CO_2 transportation. Until further knowledge is established, a conservative approach should be adapted with respect to the level of impurities in the CO_2 stream, including the presence of water. For long distance pipelines, corrosion resistant materials would increase the investment costs to an unacceptable level, thus implying that the only realistic alternative is to ensure that the transported medium is non-corrosive.

Standards and regulations for CO_2 transport also need to be developed, taking into account the properties of CO_2, e.g. risk and physical properties. For onshore pipeline transport of natural gas in continental Europe, requirements related to maximum operating pressure are normally defined – typically 80 barg – while for offshore pipelines such maximum levels are generally not defined. In the latter cases, design of the pipeline system then particularly needs to take into account both the probability of accidental events and consequences thereof to such extent that the overall risk is considered acceptable by the regulators. Thus, several offshore pipelines are in operation today with design pressure well above 200 barg.

Transport of large volumes of CO_2 needs to be performed in dense or liquid phase. In gaseous phase, the volume would require unrealistic pipeline dimensions, increasing costs by an order of magnitude. Then the pressure within the pipeline should be kept so that it is well above the "bubbling line". Looking at the phase diagram of CO_2 (Appendix 1), this means that the minimum operating pressure for onshore summer temperatures should be in the range of 70 barg for buried pipelines. For temperatures up to 31°C, CO_2 may exist in gaseous phase down to 73 barg. Thus, to avoid numerous compressor stations along the pipeline, the inlet pressure – also for onshore pipelines – probably needs to be higher than the existing maximum requirements for gas pipelines. However, this is a discussion that needs to be continued in close dialogue with relevant regulators.

3.2 Offshore pipelines

Assuming that the CO_2 stream inside the pipelines is non-corrosive, designing offshore pipelines are then, in principle, more or less similar to designing offshore pipelines for hydrocarbon transport. Planning such pipelines therefore needs to take into consideration standard issues such as:

- Selection of pipeline route along the seabed
- The relationship between desired transport capacity, pipeline dimensioning (diameter), inlet and outlet pressure, steel quality and pipeline wall thickness
- Stability of the pipeline on the seabed, e.g. impact by movements of the sea masses
- External corrosion protection
- Impact from third party, e.g. trawlers and sinking objects
- Installation method

The offshore CO_2 pipeline will, for the cases described in this report, terminate at a four-slot subsea template (see Figure 3-2) where the manifold and injection wells are located. For the 2.5 and 10 Mtpa volume scenarios, it is assumed that injection wells from one template will have the storage capacity for the CO_2 flow. For the 20 Mtpa scenarios, it is assumed that an additional template will be needed. In this case, a 10 km distribution pipeline from the first to the second template is assumed.

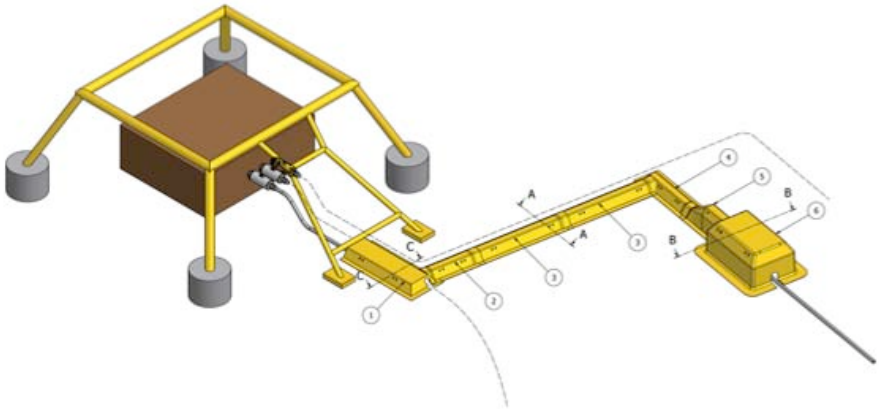


Figure 3-2: Schematic of a typical subsea template solution for CO_2 injection (Gassco)

3.3 Onshore pipelines

A high-pressure pipeline system is a safe and environmentally friendly way of transporting large volumes of CO_2 captured at CO_2 emitters ashore, to remote storage sites. The EGIG (2008) gas pipeline incident statistics in Europe demonstrate the high safety of the European pipeline system. More careful planning, higher-quality pipeline materials, improved construction methods, more intelligent monitoring, as well as the introduction of pipeline integrity management systems (PIMS), have led to even safer transport systems in recent years. Furthermore, the onshore transport of CO_2 through high-pressure pipelines has been proven practice for decades in the U.S. where CO_2 has long been injected into hydrocarbon deposits to boost the oil recovery rate.

A CO_2 onshore pipeline can, to a large extent, be planned and constructed in the same way as natural gas transmission pipelines. For both types of pipeline systems the following issues have to be considered:

- Routing
- Topography along the route (e.g. bedrock, flat or hilly terrain)
- Numbers of road and river crossings (e.g. micro tunnelling)
- The relationship between desired transport capacity, pipeline dimensioning (diameter), inlet and outlet pressure, steel quality and pipeline wall thickness
- Internal and external corrosion protection
- Compressors and/or pumps
- Rights of way (e.g. difference between agriculturally used area, sparsely populated or uninhabited areas and populated areas)
- Pigging.

Figure 3-3 shows the elevation along the pipeline length in a sample schematic diagram. It shows that the pipeline has to manage different slopes and height differences. Height differences in a short distance and frequency of the alternating gradient are the main construction cost impact factors.

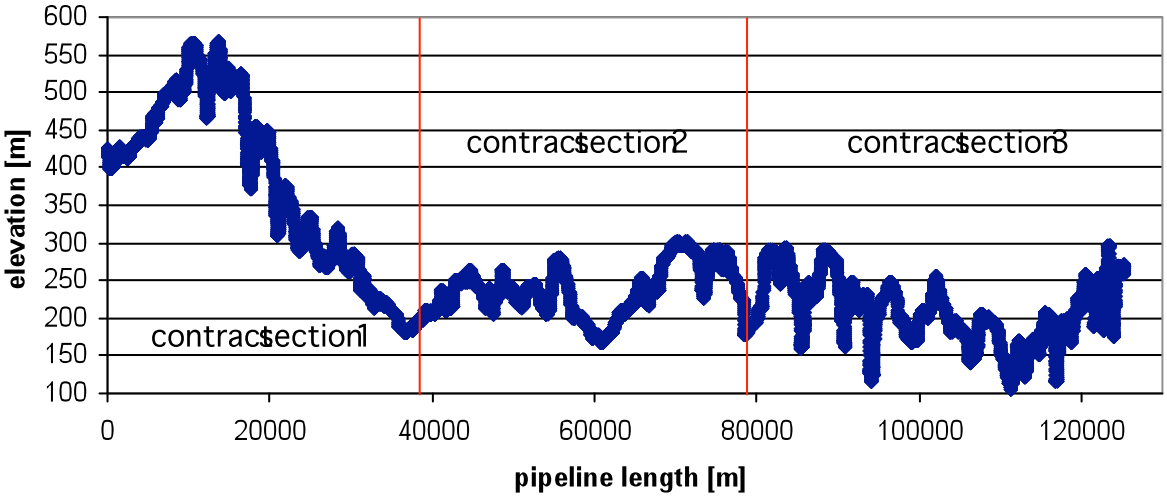


Figure 3-3: Schematic diagram of difference in elevation along the pipeline length

3.4 Ship transport

The practice of transporting liquefied and pressurised gases by ship dates back more than 70 years. Since then, ship transport of hydrocarbon gases has become a significant worldwide industry with gas carriers in regular traffic worldwide.

Gas carriers are separated into three main categories: Pressurised, Semi-Refrigerated (Semi-Ref) and Fully Refrigerated. They are also separated by the type of gas carried into three main categories: Liquid Petroleum Gas carriers (LPG) carrying mainly propane, butane and ammonia at temperatures down to –50°C; Ethylene carriers carrying ethylene and LPG cargoes at temperatures down to –104°C; and Liquefied Natural Gas Carriers (LNG) carrying natural gas consisting mainly of methane at temperatures down to –164°C. The design and operation of CO_2 carriers will be very similar to that of Semi-Refrigerated LPG carriers.

The industry has been regulated by a United Nations subsidiary, the International Maritime Organisation (IMO) since the 1960s. The regulations, known as the International Gas Code, or IGC, have worked well. In fact, the industry has had a literally unblemished safety record. Gas carriers are like other ships, exposed to the vagaries of the marine environment causing, for example, collisions and groundings, but there has never been any accident causing loss of cargo tank integrity with subsequent cargo release. The IGC code also covers the transportation of CO_2, allowing some minor relaxations due to the non-combustible nature of the CO_2 cargo, compared to hydrocarbon cargoes. International regulations for the transportation of CO_2 by ship are therefore well established.

Indeed, ship transportation of CO_2 has been taking place for nearly 20 years, although only in small parcels for industrial and alimentary purposes. The existing fleet of four CO_2 carriers are around 1,000 m^3 each. CO_2 has to be carried at above 5.2 bara to avoid solidification into dry ice. The existing ships carry the cargo at 15-20 bara and around –30°C. For the larger volumes required for CCS purposes it is likely that the CO_2 will be carried at 7-9 bara and down to around –55°C. This is practically the same cargo condition as that of the significant fleet of semi-ref LPG carriers currently in operation. In fact, six such LPG/ethylene carriers of 8-10,000 m^3 in the ownership of IM Skaugen of Norway are approved for the carriage of CO_2. The fleet of Semi-Ref carriers presently engaged in the transportation of hydrocarbon gases number more than 300, with a service record totalling more than 5,000 ship years.

During ship transport, heat leakage into the tanks will cause the cargo temperature to rise, increasing the cargo tank pressure from the ~7 bara at which the CO_2 will be loaded. For this reason, the delivery pressure from the ship is expected to be in the 8-9 bara range, depending primarily on the transportation distance.

A typical example of a 20,000 m^3 Semi-Ref ship intended for CO_2 transport is shown in Figure 3-4. It is anticipated that CO_2 carriers for CCS purposes are likely to be from 10,000 m^3 to a maximum of ~40,000 m^3, most typically in the 20-30,000 m^3 range.

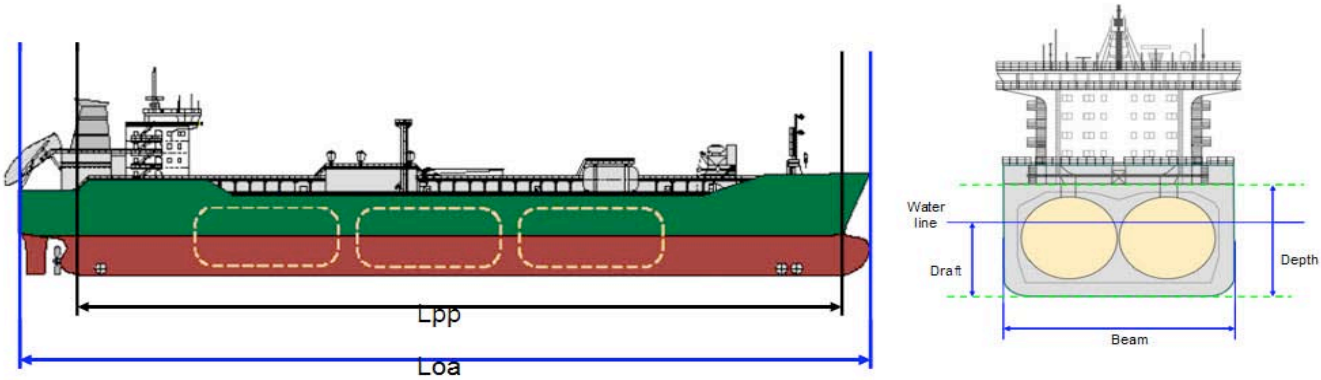


Figure 3-4: CO_2 ship design with 20,000m^3 cargo capacity, for port discharge

While CO_2 carriers will be designed to load and discharge in normal ports, they may also be equipped for discharging offshore. The technology will basically be the same as that utilised to load oil tankers from offshore platforms. Such operations are regularly carried out even in harsh weather areas such as the North Sea and the Norwegian Sea, and more than 20,000 such operations have already been carried out with an excellent safety and environmental record.

Ship transportation of CO_2 will therefore be carried out using established technologies and verified procedures with a good safety record. Offshore discharge is a new field of operation where technologies may need to be qualified, e.g. with regard to pressure issues and the potential formation of dry ice. An investigation of the influence of impurities on the triple point seems advisable in order to verify that the margin between the triple point pressure of 5.2 bara and the loading pressure of ~7 bara is adequate.

This record not only provides a confirmation of operational performance, it means there exists a shipbuilding industry which has extensive experience in the building of such Semi-Ref ships and a corresponding shipbuilding market ensuring the availability of CO_2 ships at commercially competitive prices from most of the major shipbuilding areas of the world. Furthermore, Semi-Ref CO_2 carriers can, at limited cost, be designed for subsequent conversion to the carriage of LPG. This means that should such a ship for any reason become redundant in CO_2 trade, it still has a residual value as an LPG carrier. The investment is thus not locked into a specific CCS project or even the CCS industry.

3.5 Conditioning for transport

CO_2 can be transported in gaseous, liquid or solid phase. Gas transported at close to atmospheric pressure occupies such a large volume that very large facilities are needed. Efficient transport of CO_2 via pipeline or ship therefore requires that the gas is compressed or cooled to the liquid stage (dense phase). Transport at lower densities (i.e. gaseous CO_2) is impractical due to the risk of two-phase flow. Pipeline transport demands that the CO_2 is compressed up to a pressure equal to the required outlet pressure, plus pressure loss along the pipeline. In any case, the pressure along the entire pipeline length should ensure that the CO_2 is in liquid/dense phase, i.e. above ~55-80 barg (including a safety margin), depending on the ambient temperature. For ship transport, the CO_2 has to be liquefied at a pressure of 7 bara and a temperature of -

50°C to avoid any risk of formation of dry ice. (Please refer to the CO_2 pressure-temperature diagram in Appendix 1.)

3.5.1 Conditioning for offshore pipeline transport

The pressure of the CO_2 in the pipeline is dependent on conditions in the geological storage site. In this study, the costs for the compression of the CO_2 up to 110 barg before transport are included in the cost of the capture plant. Offshore pipeline costs include pumping CO_2 from 110 barg to 200 barg before transport. Costs for the drying, purification and removal of impurities are included in the costs of the capture plants.

3.5.2 Conditioning for onshore pipeline transport

Onshore pipeline costs have been estimated at a maximum pressure of 100 barg and the compression up to 110 barg is included in the capture costs. This follows that no extra costs for the CO_2 compression are included in the onshore pipeline pre-treatment. Costs for the drying, purification and removal of impurities are also included in the costs of the capture plants.

3.5.3 Liquefaction for ship transport

In order to reduce the costs of ships and storage tanks (thickness of the tanks' walls), it is preferable to operate as close to the triple point of -56.6°C/5.2 bara as is practically feasible. Liquefaction of the CO_2 is achieved by condensing and depressurising. The temperature is controlled by the pressure. Between 20% and 40% of the CO_2 condensate/dense phase will flash off during depressurisation and has to be recompressed.

The liquefaction process is designed using commercially available simulation tools (HYSYS and ProVision). The liquefaction plant delivers CO_2 at 7 bara and -50°C to the storage tanks. To convert the CO_2 into a low pressure liquid, it is cooled through the expansion and recompression of gas. By "flashing" off 20 to 40% of the volume, temperature can be lowered to -50°C and the pressure to 7 bara. A simple diagram of the liquefaction plant is shown in Figure 3-6. The input parameters will be a pressure of 100 bar and a temperature of 20°C.

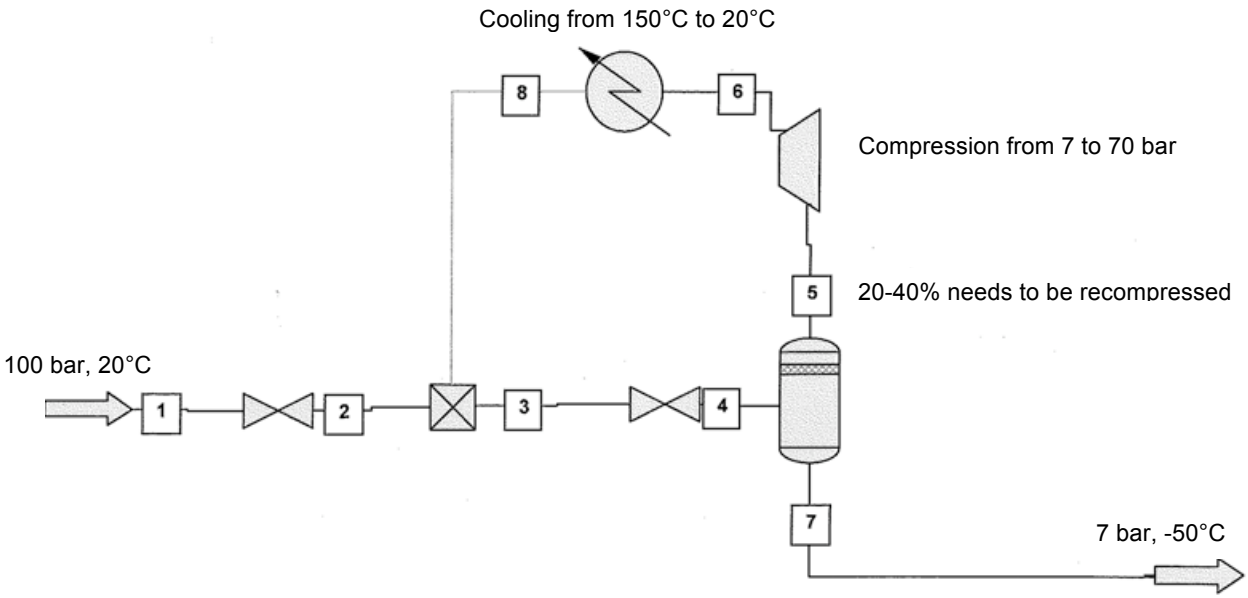


Figure 3-5: Outline of a liquefaction plant

Inlet condition: 100 barg, 20°C, pure CO_2
Outlet condition: 7 bara, -50°C, pure CO_2

The high inlet pressure is not optimal for the liquefaction process since pure CO_2 enters at stage 1 and the process starts by reducing the pressure from 100 barg to 70 barg.

3.6 Transport module cost estimates

Appendix 3 provides details of costs for each of the four transport modules described above. These data have been used as input in the compilation of the more complex transport network cost estimates described in Chapter 6.

4 Transport Specific Assumptions

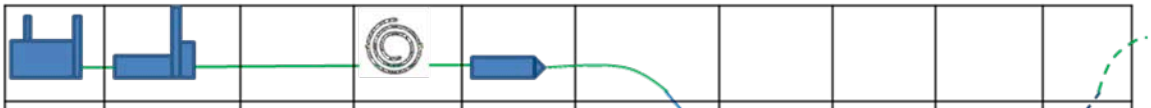
4.1 Pipelines

No phase change is allowed in the pipeline, i.e. the CO_2 must remain in a dense or liquid phase all along the pipe. This condition places specific requirements on the choice of pumps, pipeline diameter and linepipe wall thickness with a direct impact on cost. The outlet pressure is set to 60 barg offshore and 80 barg onshore.

The application of crack arrestors for onshore pipes has been investigated, but as no conclusive statements were made, the costs were not included. For offshore and onshore pipelines, the wall thickness provided by the pipeline pressure rating and the installation method is assumed to give the necessary resistance to longitudinal crack propagation. The estimates support a design with a maximum pressure of up to 250 barg offshore and 100 barg onshore.

4.2 Offshore pipelines

Developing a reliable generic model for establishing cost estimates for offshore pipelines is challenging, as assumptions related to the characteristics of each specific pipeline case may vary significantly. Such a generic model will become complex. For the results described in this report, a pipeline route is therefore defined with specific terrain characteristics. Cost estimates are then made for this route. By changing the terrain characteristics, these estimates for different lengths and volumes can also be the basis for preparing estimates for other routes.



	Source	Capture/ Compression	Onshore pipeline	Pump	Launcher/ Landfall	Offshore Pipeline	Template Storage	Offshore Pipeline	Template Storage	Control Cable
Length			10 km			180– 1,500 km		10 km		50 km
Pressure		110 barg	110→ 100 barg	100–> 200 barg	200 barg	200 → 60 barg	60 barg	60 barg	60 barg	
	A	B	C	D	E	F	G	H	I	J

Figure 4-1: Battery limits and cost zones for offshore pipelines

The chosen offshore route starts at the Belgian coast and ends at the Norwegian continental shelf. The starting point is close to heavily industrialised areas in Europe and the routing is in the proximity of several promising storage areas. Thus, the cases described through this route may be representative of possible future transport solutions.

Offshore CO_2 injection can either be performed from a platform or a subsea template. The estimates are based on a subsea template with a control cable to a platform. This is probably the most cost-effective alternative except in cases where existing installations may also be used for this service throughout the lifetime of the CO_2 storage activity.

To ensure single phase flow, the minimum internal pressure has been set to be 60 barg (including a safety margin towards a two-phase region). To obtain this minimum pressure at the end, the start pressure is set to be 200 barg, which is representative for offshore pipeline transport.[10] The diameter of the pipeline will vary from 12" for the 2.5 Mtpa volume and 180 km length, to 40" for the 20 Mtpa volume and 1,500 km length.

	Offshore Main Pipeline				Onshore Pipeline(s)	Offshore Branch Pipeline
CO_2 volume	180 km	500 km	750 km	1,500 km	10 km	10 km
2.5 Mtpa	12"	16"	16"	18"	(same size as offshore pipeline)	N/A
10 Mtpa	22"	26"	26"	30"	(same size as offshore pipeline)	N/A
20 Mtpa	26"	32"	34"	40"	2 x 10 km x 22"	(same size as offshore main line)

Table 4-1: Offshore pipeline dimensions as function of volume and distance

The offshore pipeline will terminate at a four-slot subsea template. The template costs, including costs for installation, are included in the cost estimates for the offshore pipeline. The costs of the manifold for the wells and drilling of the injection wells are not included in these costs, but are assumed to be part of the storage costs. Main assumptions for the cost estimates related to the offshore pipelines and templates are:

Design Factors

- 200 barg inlet pressure, 60 barg outlet pressure
- Design pressure: 250 barg
- Pipeline Internal friction: 50 µm
- Pipeline Material: Carbon Steel
- External Coating: 3 mm Polypropylene (PP)
- Concrete Coating (70 mm/ 2600 kg/m^3) to be used for pipelines exceeding 16". No concrete coating for pipelines below 16"

Environmental factors

- First 50 km shallow with sand waves with remaining route flat
- Burial requirements:
  - 100% burial for pipeline dimensions equal to, or below 16"
  - 100% burial in sand wave area for all sizes
  - Other areas no burial
- Landfall
  - 1.5 km in cofferdam trench
  - 2.0 km in near-shore trench (shallow water)

Market Factors

- Steel price
  - 16" : €160/metre
  - 40" : €700/metre

[10] Existing hydrocarbon pipelines are operated even above 200 barg, e.g. on the Norwegian Continental Shelf

- External coating (anti-corrosion/weight)
    - 16” : €90/metre
    - 40” : €200/metre
- Installation cost
    - Pipeline installation costs: €200-300/metre
    - Trenching costs: €20-400/metre

Contingency
- 20%

Based on this, cost estimates have been established for alternative pipeline lengths and transport capacity requirements with the following cost elements:
- Accumulated cost prior to execution
- Offshore Linepipe, Equipment and Materials
- Offshore Linepipe, Coating, Transport and Preparation
- Offshore Pipeline Installation
- Offshore Survey, Tie-ins and intervention
- Onshore Linepipe, Equipment and Materials
- Onshore Linepipe, Coating, Transport and Preparation
- Onshore, Civil Work and Pipeline Installation
- Template(s) and Control Cable(s)
- Project Management and Services
- Contractor Detail Engineering
- RFO (ready for operation) and Commissioning
- Insurance

4.3 Onshore pipelines

The calculation of the costs for the transmission lines was carried out using an Open Grid Europe GmbH software package, while Tel-Tek undertook pumping cost estimations. The calculation for the CO_2 pipeline is analogous to the calculation for natural gas transport pipeline. It should be noted that the costs for building a CO_2 transmission pipeline can differ greatly from those for the construction of a natural gas pipeline. This is mainly due to the higher wall thickness for the pipes at the specified pressure of 100 bar. The following items are included in the calculation:

- Pipework and construction costs
- Linepipe (including coating, delivery ex. works)
- Pumping
- Corridor compensation
- Engineering
- Building costs
- Rights of way
- Electrical installation
- Corrosion protection
- CO_2 measuring
- Installation and operation
- Archaeology

					
	Source	Capture/ Compression	Onshore pipeline	Pump	Sink
Length			X km		
Pressure		110 barg	Max 100 barg	Y –> Z barg	Z barg
	A	B	C	D	E

Figure 4-2 Battery limits and cost zones for onshore pipelines

Costs for the pipeline (including coating), pipework and installation are based on vendor offers. The following constraints and assumptions apply to the calculation of the total cost of a CO_2 transmission pipeline:

- Flat topography
- Simple soil conditions (e.g. no bedrock or costly drainage, etc.)
- Unobstructed right of way and permitting acquisition
- Project duration: 3.5 years
- No site roads
- Compression is not included
- No special structures (e.g. micro tunnelling, culverts etc.)
- Pipeline construction is from May to September
- Costs have an accuracy of +/– 30%
- Operating costs: €6,000/km

The diameter of the pipeline will vary from 12” for the 2.5 Mtpa volume and 10 km length, to 32” for the 20 Mtpa volume and 1,500 km length.

CO_2 volume	10 km	180 km	500 km	750 km	1,500 km
2.5 Mtpa	**12''**	**12''**	**---**	**---**	**---**
10 Mtpa	**20''**	**24''**	**24 ''**	**24''**	**24''**
20 Mtpa	**24''**	**32''**	**32''**	**32''**	**32''**

Table 4-2: Onshore pipeline dimensions as function of volume and distance

<u>Design Factors</u>

- Inlet pressure: 100 barg
- Minimum pressure: 80 barg
- Pipeline material: Carbon Steel

- Temperature of the CO_2: 50°C

The results are based on an onshore pipeline installed on a flat terrain (contingency 30%). In the case of difficult terrain (e.g. hilly, costly drainage, mountains, built-up areas), costs would increase. The basis for the calculations is national pipelines within Germany. For cross-border activities or other nations, the considerations have to be adjusted.

4.4 Ship transport

Ship transport costs have been estimated on the basis of the assumptions listed below.

Cost components/Battery limits	
Loading buffer storage	100% of ship size, at loading site. Cost of buffer storage estimated to be €1,000/m^3, based on utilising a floating storage barge permanently located between the ship and the quay. N.B. The floating buffer storage solution has been chosen as the likely least cost alternative wherever sufficient harbour space is available as such a solution will allow construction in a low-cost area. If sufficient harbour space is not available, costs for onshore storage are anticipated to be noticeably higher.
Port terminal	Loading equipment and functional quay facilities are assumed to be existent. The port terminal cost considered only covers the provision of a liquid loading arm on the quayside, but does not include the construction of quay or dredging of port etc. as this will be completely dependent on local conditions.
Ship	Size optimised to each transport assignment – see below.
Offshore terminal	Complete facilities for offshore discharge, with costs based on the use of high availability Submerged Turret offloading.

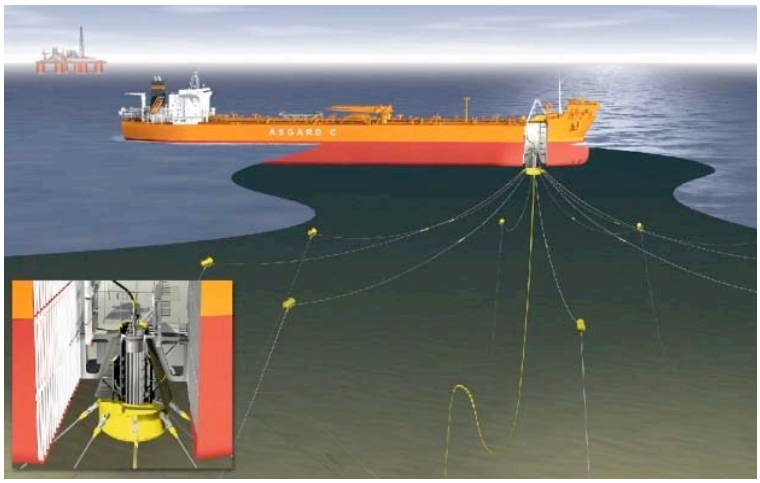


Figure 4-3: Illustration of Submerged Turret Offloading

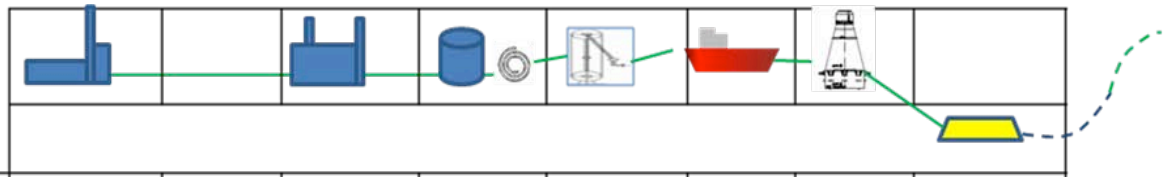
Gas conditioning	Heating is to ~0°C and compression to ~60 bar, assumed to be performed onboard ship prior to discharge. This means

discharge at above zero temperature which is advantageous for the discharge equipment. This does, however, imply that the necessary pumping and heating equipment must be installed onboard each ship. For the large volume, long distance scenarios requiring a large number of ships, it may be an attractive alternative solution to employ a pipeline on the seabed as a heat exchanger

During ship transport, the temperature of the CO_2 will rise, causing boil off and thereby, increasing the internal vessel pressure. As a result, the cargo tank pressure at the end of the loaded voyage will be 8-9 bara, depending on the transportation distance and resulting voyage duration.

CO_2 transported by ship for discharge offshore has to be pumped from 7 to 9 bara to an assumed 60 barg. Depending on the water depth, the liquid head will provide ~10 bara margin for pressure loss in offloading hose and pipeline. Furthermore, the CO_2 needs to be heated, a process which can be managed onboard the ship using onboard waste heat and seawater as cold sink. This solution is advantageous in that the discharge hoses and associated equipment will not be exposed to low temperature, freezing etc. Costs for pumping and heating equipment (including related energy consumption) are included in the ship's expenses. Offshore discharge of all ships, regardless of size, is assumed to be performed within a period of 36 hours.

No intermediate offshore storage is assumed to be necessary. This results in an intermittent injection into the wells. The 36 hours discharge assumed will, for the different transportation scenarios, be followed by a period of ~3 to 36 hours before the next cargo discharge starts. This must be taken into account in the design of the storage well. It should be noted that while such a procedure is assumed suitable for injection in deep saline aquifers, other solutions may be more advantageous in the case of, for example, depleted oil and gas fields. No such alternative solutions are covered in this report.



	Capture/ Compression	Onshore pipeline	Liquefaction	Buffer Storage/ Pump	Loading Equipment (quay side)	Ship/s/	Offshore Terminal (STL)	Template + Control Cable
Distance		10 km				180 – 1500 km		50 km
Pressure	110 barg	110 –> 100 barg	7 bara	7 bara -55°C	7 bara -55°C	7 bara -55°C	60 barg	
Cost zone	A	B	C	D	E	F	G	I

Figure 4-4: Battery limits and cost zones for ship transportation

Shipping in the Transport Networks

Ship transport is assumed to function as spine and feeder respectively, with offshore discharge, except in the case of feeders, when discharge into an onshore hub is foreseen for further transport in a pipeline spine.

Ship cost assumptions

- The size of ship is optimised to each transport assignment, with a maximum cargo capacity of 40,000 m^3 per ship
- For offshore discharge, ship costs include:
  - Dynamic positioning capabilities
  - Hull adaptation to submerged turret (un-)loading buoy
- Loading time constant, set at 12 hours, regardless of ship size
- Discharge time offshore constant, set at 36 hours
- Discharge time to onshore buffer storage constant, set at 12 hours
- CO_2 transport condition, up to 9 bara and a minimum temperature of -55°C
- No re-liquefaction unit required to handle boil-off as pressure increase during the round-trip is limited
- Ship speed in water is 14 knots (15 knots for the 1,500 km cases)
- Ships are manufactured in the Far East
- Cargo is distributed evenly on deployed ships

CAPEX calculations

- Project lifetime and depreciation period: 40 years
- Interest rate is 8%
- No residual value

OPEX calculations

Ship OPEX is based on actual operating cost experience, consisting of:

- Crew costs: Far East sourcing, same complement independent of ship size
- Maintenance: 2% of CAPEX
- Fuel costs are calculated based on ship size, speed and distances
- Fuel price is USD 514 per tonne marine diesel oil assumed equivalent to LNG price if LNG is used as fuel
- European size- and cargo related port fees are applied, including a “negotiation factor” for regular frequent service.

Other variable costs consisting of:

- Port terminal loading arm maintenance costs: 2% of CAPEX
- Offshore terminal, maintenance costs: 5% of CAPEX
- Subsea installations, maintenance costs: 5% of CAPEX
- Floating buffer storage, operation and maintenance costs: 5% of CAPEX

4.5 Conditioning for transport

General assumptions:

- Construction period: 1 year
- Operation period: 39 years

Liquefaction plant assumptions:

- Cooling water price: €0.13/m^3
- Cooling water consumption: 3.38 m^3/tonne CO_2
- Labour cost: €100 k/man-year

The cost estimation is performed using the factor estimation method and based on data from Eurostat. This data is based on general process equipment, with equipment cost calculated in Aspen Icarus Project Manager, generic cost (Rotterdam location).
It is assumed that the liquefaction plant is built in relation with existing industrial facilities and that all utilities (help functions and seawater supply) have sufficient capacity to supply the liquefaction plant. It is also

assumed that the existing operational organisation and control room crew operate the liquefaction plant, with the addition of one operator and one engineer.

The equipment is installed in a closed, not insulated building. No other buildings are included in CAPEX. It is assumed that many (>60) other similar plants have been built. The first plant of this kind will be more expensive (learning curve).

4.6 Construction period interest

The total construction time is a large cost component. Cost estimates therefore include interest on investment for the duration of the project. The following elaborates ZEP's views on the different project phases.

The aggregate time from the first identification of the need for an offshore pipeline to actual use could be approximately 4.5 to 6.5 years including planning, engineering and installation. Early phase planning (performing the first rough analyses and confirming technical feasibility of the system) normally takes 6 to 12 months. Alternative concepts are normally then evaluated and cost estimates matured to +/– 30% accuracy in a phase lasting around 8 to 12 months. A completed pre-engineering study for the different parts of the selected concept is a prerequisite for an invitation to tender. The outcome of this is a fairly accurate technical definition of the required pipeline system.

Based on the tenders, a cost estimate can typically be established within +/– 20%. The pre-engineering phase normally takes between 10 and 16 months and is the basis for an investment decision. The accumulated time for the project prior to sanction is thus normally in the range of two to three years and relatively independent of the length of the pipeline.

Following an investment decision, contracts for detailed engineering, manufacturing, installation and commissioning of the pipeline are signed. This period is defined as the execution period and starts with detailed engineering (between 12 and 24 months), followed by the installation period. Installation of offshore pipelines in northern waters is performed in the period April – September, due to weather conditions.

Normally, a pipeline with a total length up to approximately 300+ km may be installed during one season. If the pipeline is significantly longer, the installation period must be distributed over more than one season or more than one installation vessel will need to be used. In total, the period for detailed engineering and pipeline installation may then be in the range of 2.5 to 3.5 years. Thus, the total time needed for an offshore pipeline project will be in the range of 4.5 years for a typical project, to 6.5 years for the super mega projects (e.g. the Langeled pipeline project in the North Sea – a 1,200 km 42"/44" pipeline).

For onshore pipelines, a typical complete project time would be four to six years following the same structure as above, but with a higher theoretical installation capacity (~500 to 750 km per year), projects could be somewhat shorter. It should be noted though that in practice very few, if any, onshore CO_2 pipelines longer than 500 km should be expected for the purposes of CCS. High uncertainty relates to the consenting process which in fact could prove to be more time-consuming (and costly) onshore than offshore, especially since it includes issues surrounding right of way and local public opinion.

Completing a logistic chain project based on shipping would probably be the fastest of the three transport modes. In a mature market situation with a certified ship design, a charterer could take delivery of vessel(s) within 24 months, a period which would probably also suffice for delivery of the other main chain components, liquefaction plant, buffer storage and offshore discharge. Taking into account time for the approval of plant installations in an industrial port area, it might be possible for a ship-based transport component of a demonstration project to be operable within two to three years.

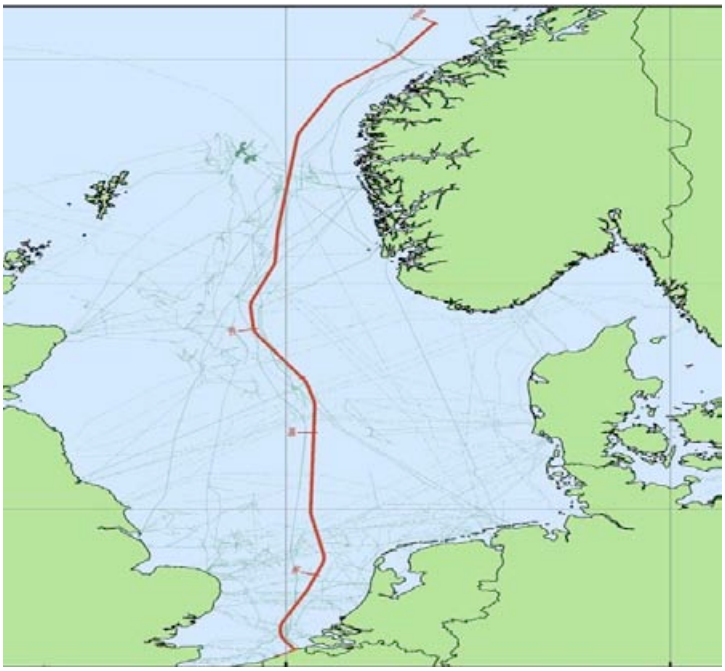
5 Transport Networks

5.1 Introduction

Ideally CO_2 would be stored where it is captured. The reality is that capture and ideal storage sites rarely co-exist, so the transport networks aim to fit between a range of capture and storage locations. Projects within the EU CCS demonstration programme are assumed to require "point-to-point" transport solutions at a scale of 2.5 Mtpa, similar to commercial-scale gas-fired plants with CCS. In other words, they are designed simply to meet the needs of one project without necessarily aiming to solve long- term transport requirements – hence possibly representing a higher, sub-optimised cost than would otherwise be the case. Indeed, the project location may be chosen for its ability to access sources or prove a storage site, or to simply minimise the proof of concept, knowing that the large-scale solution will be better located elsewhere. Consequently, the transport solution for early demonstration projects may be less than ideal, but overall this will be offset by other considerations.

Shipping is particularly relevant as it has the least chance of being a stranded asset if the project does not continue past the demonstration phase. If a location would never produce a peak capture rate of more than 2.5 Mtpa of CO_2 then the associated pipeline would be for that volume. However, if a pipeline is installed where there is greater capture potential, it is very unlikely that planning and environmental impact considerations would not look to have a design capacity to match future potential, as the marginal cost is small, say in the case of a 10 Mtpa (as in the base case for a capture location) pipeline compared to a 2.5 Mtpa pipeline. Pipelines may therefore be sized at greater capacity than the demonstration project requires.

In this report, both demonstration projects and large-scale networks use a minimum transport distance of 180 km. This was chosen to very roughly approximate non-trivial transport costs seen for onshore locations of 100 km or more (e.g. Campostilla, La Robla, Spain; Porto Tolle, Italy; east coast locations of the UK; and some onshore in Germany), though it is not specific to any one location. For offshore locations, 180 km is an arbitrary distance, but a starting point for costs to reach Dutch and UK southern North Sea locations; and UK, Norwegian and Danish central North Sea locations, although there is considerable variation. The trend in costs is therefore picked up in considering longer distances so interpolation of figures is possible.



The range of distances extends out to 1,500 km to overlap the base case costs and the network costs. At the extreme, 1,500 km covers longer-term access to the northern North Sea offshore storage locations via network solutions to CO_2 transport from continental Europe or the Baltic Sea states. The distances used are marked along a pipeline in the picture attached (courtesy of Gassco).

Figure 5-1: Distance examples illustrating scenario selection

This is not a "point-to-point" example, but illustrates the scale which may become necessary to store European CO_2 as we work towards large-scale CCS where networks arise and trunklines transport CO_2 from many sources to multiple storage sites. The need

and scale for CO_2 pipelines, particularly in the North Sea, has been discussed and reported for many years. The cost estimates in this report should be helpful in providing some comparative costs.

5.2 Demonstration phase

Ideally, CO_2 would be stored where captured, so as explained above, the transport networks aim to fit a range of capture and storage examples in order to illustrate transport costs. The demonstration projects are assumed to require "point-to-point" transport solutions at a scale of 2.5 Mtpa.

In order to represent the possible range of solutions for demonstration projects with an annual flow rate of 2.5 Mtpa over 7,500 hours, this translates into 333 tonnes per hour. Specific scenarios can be based on interpolating from costs of a 10 km onshore pipeline of 2.5 Mtpa, a 180 km pipeline onshore or offshore of 2.5 Mtpa and shipping options transporting over distances of 180 km, 500 km, 750 km and 1,500 km.

5.3 Base cases

The agreed base case for a long-term capture location is an annual flow rate of 10 Mtpa – a flow of 1,333 tonnes per hour. Specific scenarios can be based on interpolating from costs of a 10 km onshore pipeline of 10 Mtpa, a 180 km pipeline onshore, or offshore of 10 Mtpa, with pipeline options transporting over distances of 180 km, 500 km, 750 km and 1,500 km. Shipping options can also be computed for the same distances. For example, a 180 km onshore line can be added to a 180 km offshore case or a shipping case of 500 km. This is because the cost assumptions use consistent input and output pressures.

These are all "point-to-point" solutions, relevant to locations with major, single point cases such as Moneypoint in Ireland and Snøhvit in Norway, although these often store less than 10 Mtpa. However, if a "point-to-point" project did have a CCS transport solution, other emitters may add volume at a later date. The reason for the 10 km onshore pipeline is to pick up cases where there is very local storage or connection to an existing transport solution, or to move from an emitter site to a ship export point, or to a coastal location suitable for the landfall of an offshore pipeline.

5.4 Networks

Once a base case, "point-to-point" route for transport to a storage site is solved, the question of design capacity arises. This is because incremental capacity for a pipeline is a low marginal cost compared to adding a parallel pipeline later. Shipping is much more flexible in this respect, with little benefit in excess capacity investment. In Europe, there are considerable planning time delays.

Extra land use for additional pipelines adds huge costs, which is why over-sizing pipelines onshore seems even more attractive than for offshore pipelines. The extra capacity could be offered for greater CCS potential from the same site, sold to emitters on the same route, or the establishment of a network solution with a spine and feeder layout. Proponents of clusters also argue that the existence of a network with spare capacity will attract additional industrial development because it will offer the lowest risk transport and storage solution for future CCS.

At the storage end, networks offer risk reduction through the use of multiple sites. For large-scale storage, the capital investment in the capture plant and the pipeline are sunk costs, which means robust storage solutions are required. One solution is to have multiple independent storage sites, or separately licensed and operated sites. For low transport costs, storage sites would ideally be close together with short feeders, or on a daisy chain along a transport spine.

The agreed large-scale and long-term network is an annual flow rate of 20 Mtpa – a flow of 2,666 tonnes per hour from multiple sources to multiple storage locations.

All networks for which cost estimates are provided use a single spine route of 20 Mtpa capacity with feeder lines from emitters of 2.5 Mtpa or 10 Mtpa. In order to provide an indicative cost between a daisy chain of storage sites – each with 20 Mtpa capacity or a node with 20 Mtpa capacity and feeders to one, two or more storage sites – a flow to a node with two feeders of 10 Mtpa capacity has been cost estimated. Whilst this can be said to be a node with feeders to storage sites, it is simply an indicative cost of how actual transport costs may be incurred to provide robust storage in a range of scenarios – from one compartmentalised to three separately located storage sites.

The primary spine route can be made up of combinations of an onshore pipeline, offshore pipelines and shipping. 20 Mtpa is still a low volume compared to potential large cluster volumes of which the Ruhr is generally said to be 100 Mtpa and the Humber, 60 Mtpa. However, there are smaller clusters such as the Thames, where E.ON has proposed a 24 Mtpa capacity pipeline for their demonstration project and the suggested Netherlands network which for example, includes a 36“, 180 km trunk pipeline from Maasvlakte to the L10-A platform. In general, transport networks used in this report are more typical of those required for wide-scale deployment, especially when considering the entire future CCS market in Europe.

6 Results by Network

Note that CAPEX includes the interest on all construction expenses prior to start-up. All shipping costs include liquefaction as well as buffer storage costs.

6.1 Network 1

A "point-to-point" transport case, transporting 10 Mtpa CO_2 per year through a 10 km onshore feeder, followed by a 180 km onshore or offshore pipeline, i.e. a pipeline totalling 190 km from source to storage.

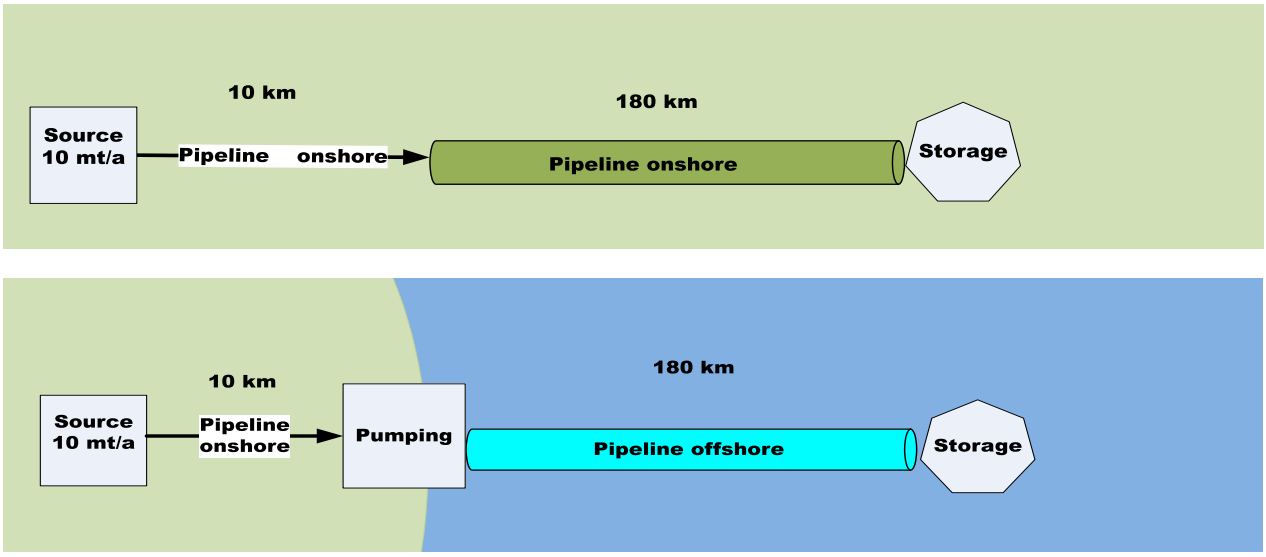


Figure 6-1: Network 1 illustration onshore (1a) and offshore (1b) spine

Network 1, 10 Mtpa CO_2, Pipeline spine	Cost item:	Feeder	Spine	Network cost
a. Pipe Base Case, 180 km onshore spine	*CAPEX (M€):*	*15.06*	*225.90*	
	Annuity (M€ p a):	1.26	18.94	
	OPEX (M€ p a):	0.06	1.08	
	Cost (M€ p a):	**1.32**	**20.02**	**21.35**
	Unit cost (€/T CO_2):			**2.13**
b. Pipe Base Case, 180 km offshore spine	*CAPEX (M€):*	*15.06*	*337.95*	
	Annuity (M€ p a):	1.26	28.34	
	OPEX (M€ p a):	0.06	4.76	
	Cost (M€ p a):	**1.32**	**33.10**	**34.42**
	Unit cost (€/T CO_2):			**3.44**

Table 6-1: Cost estimates for Network 1, onshore (1a) and offshore (1b)

6.2 Network 2

Another "point-to-point" transport case with 2.5 Mtpa CO_2 transported by a 10 km feeder to a port from where a ship transports it to storage sites located 180, 500, 750 or 1,500 km from shore.

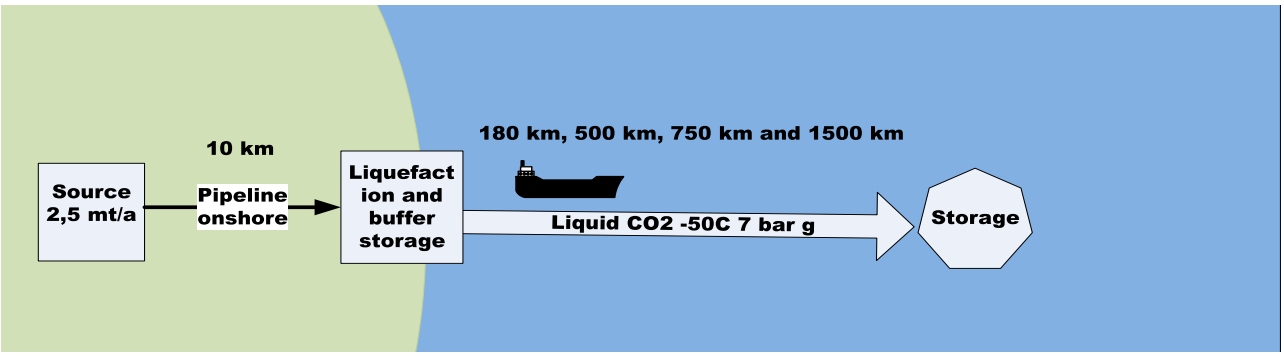


Figure 6-2: Network 2 illustration ship spine (2 a, b, c and d)

Network 2, 2,5 Mtpa CO_2, Ship spine	Cost item:	Feeder	Ship Spine	Network cost
a. Ship base case, 180 km spine	*CAPEX (m€):*	*11.55*	*138.87*	
	Annuity (m€ p a):	0.97	11.65	
	OPEX (m€ p a):	0.06	22.07	
	Cost (m€ p a):	**1.03**	**33.72**	**34.75**
	Unit cost (€/T CO_2):			***13.90***
b. Ship base case, 500 km spine	*CAPEX (m€):*	*11.55*	*157.15*	
	Annuity (m€ p a):	0.97	13.18	
	OPEX (m€ p a):	0.06	23.73	
	Cost (m€ p a):	**1.03**	**36.91**	**37.94**
	Unit cost (€/T CO_2):			***15.17***
c. Ship base case, 750 km spine	*CAPEX (m€):*	*11.55*	*174.56*	
	Annuity (m€ p a):	0.97	14.64	
	OPEX (m€ p a):	0.06	25.02	
	Cost (m€ p a):	1.03	39.66	**40.69**
	Unit cost (€/T CO_2):			***16.28***
d. Ship base case, 1500 km spine	*CAPEX (m€):*	*11.55*	*213.98*	
	Annuity (m€ p a):	0.97	17.94	
	OPEX (m€ p a):	0.06	31.60	
	Cost (m€ p a):	**1.03**	**49.55**	**50.58**
			Specific yearly cost (€/T CO_2):	***20.23***

Table 6-2: Cost estimates for Network 2, ship 180 (a), 500 (b), 750 (c) and 1,500 (d) km

6.3 Network 3

CO_2 from two point sources of 10 Mtpa each is transported by 10 km onshore feeders to a single 20 Mtpa CO_2 onshore spine pipeline. Near the storage location, the flow is split into two 10 km distribution pipelines supplying two separate storage sites.

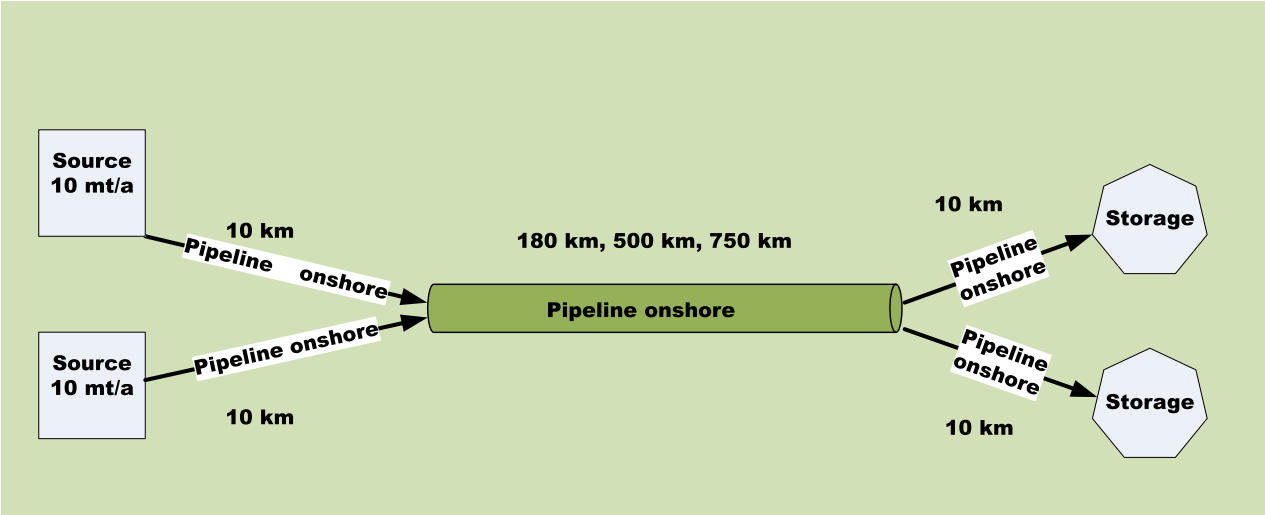


Figure 6-3: Network 3 illustration onshore pipeline spine 180 (a), 500 (b) and 750 (c) km

Networks 3, 20 Mtpa CO_2, Onshore	Cost item:	Feeders	Spine	Distribution	Network cost
a. Onshore network,180 km Spine	*CAPEX (M€):*	*30.12*	*287.14*	*30.12*	
	Annuity (M€ p a):	2.53	24.08	2.53	
	OPEX (M€ p a):	0.12	1.08	0.12	
	Cost (M€ p a):	**2.65**	**25.16**	**2.65**	**30.45**
				Unit cost (€/T CO_2):	**1.52**
b. Onshore network, 500 km spine	*CAPEX (M€):*	*30.12*	*774.08*	*30.12*	
	Annuity (M€ p a):	2.53	64.91	2.53	
	OPEX (M€ p a):	0.12	3.00	0.12	
	Cost (M€ p a):	**2.65**	**67.91**	**2.65**	**73.21**
				Unit cost (€/T CO_2):	**3.66**
c. Onshore Network, 750 km spine	*CAPEX (M€):*	*30.12*	*1148.58*	*30.12*	
	Annuity (M€ p a):	2.53	96.32	2.53	
	OPEX (M€ p a):	0.12	4.50	0.12	
	Cost (M€ p a):	**2.65**	**100.82**	**2.65**	**106.11**
				Unit cost (€/T CO_2):	**5.31**

Table 6-3: Cost estimates for Network 3, onshore pipeline spine 180 (a), 500 (b) and 750 (c) km

6.4 Network 4

Networks 4, 5 and 6 are variations of 20 Mtpa transport, with Network 4 consisting of two 10 km onshore feeder pipelines, transporting 10 Mtpa CO_2 each into an onshore pipeline spine of varying distances. The flow is split into two offshore distribution pipelines (10 km). Costs are shown in section 6.7.

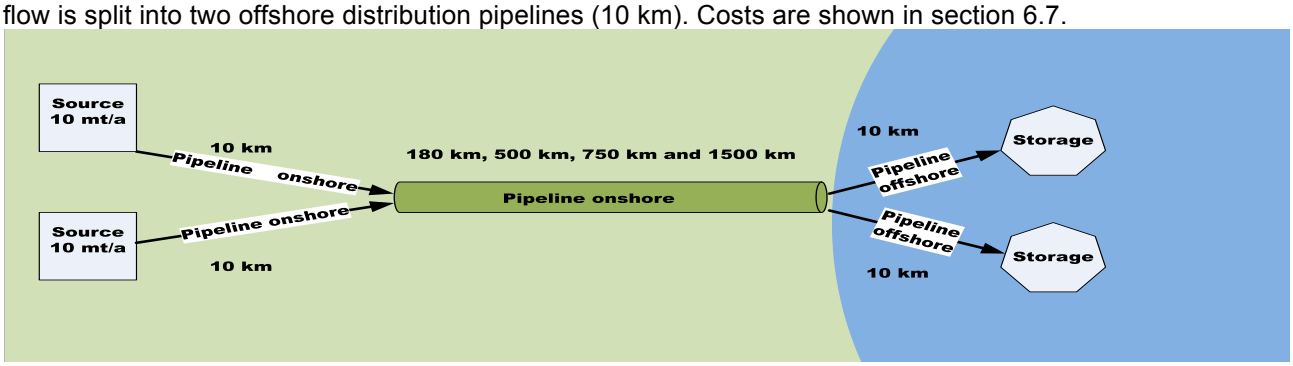


Figure 6-4: Network 4 illustration onshore pipeline spine 180 (a), 500 (b), 750 (c) and 1,500 (d) km

6.5 Network 5

Network 5 is similar to #4, but with an offshore pipeline spine. Costs are shown in section 6.7.

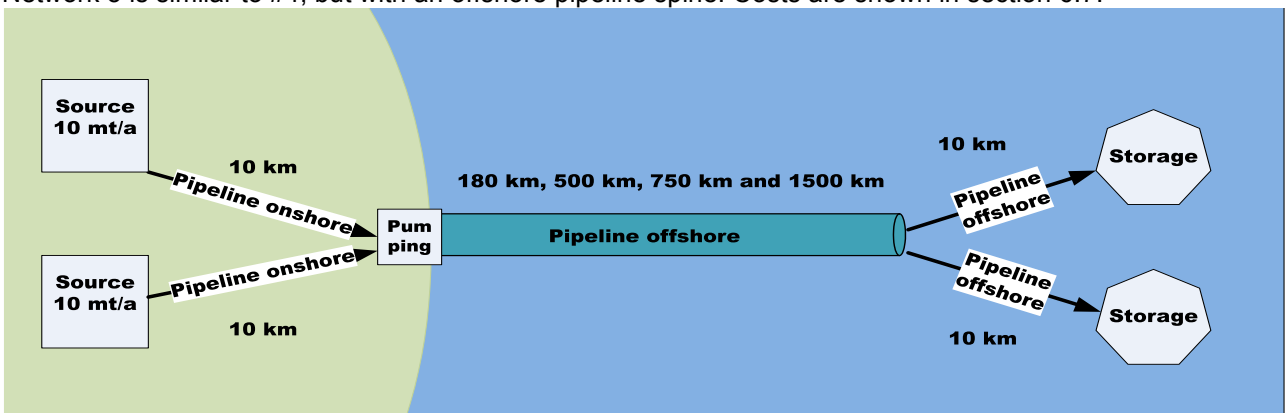


Figure 6-5: Network 5 illustration offshore pipeline spine 180 (a), 500 (b), 750 (c) and 1,500 (d) km

6.6 Network 6

Network 6 is similar to #4 and 5, but with a ship spine. Costs are shown in section 6.7.

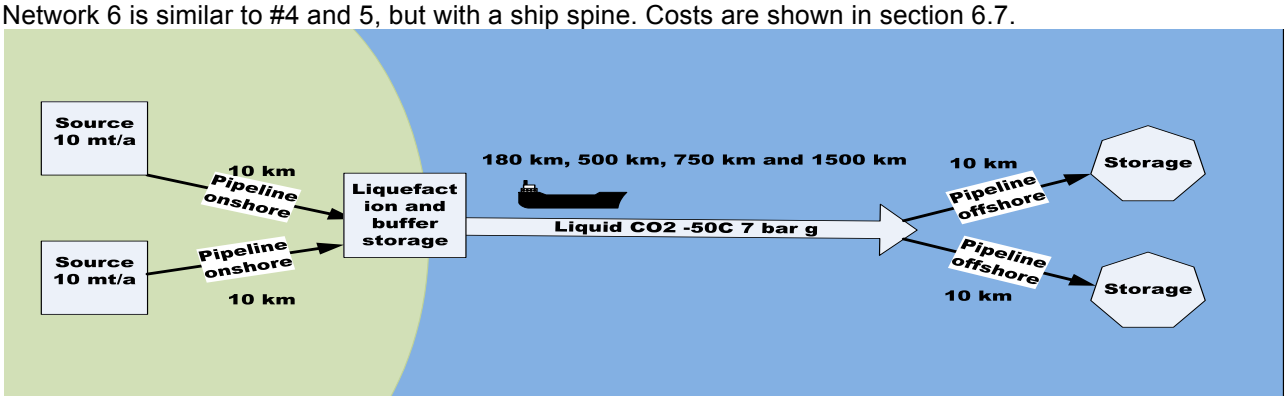


Figure 6-6: Network 5 illustration ship spine 180 (a), 500 (b), 750 (c) and 1,500 (d) km

6.7 Comparison of costs for Networks 4, 5 and 6

Networks 4, 5 and 6 in a summary and comparison table.

Network 4, 5 & 6 20 Mtpa CO_2		4. Onshore Spine				5. Offshore Spine				6. Ship Spine			
	Cost item:	Feeders	Spine	Distri-bution	Network cost	Feeders	Spine	Distri-bution	Network cost	Feeders	Spine	Distri-bution	Network cost
180 km spine	*CAPEX (M€):*	*30.12*	*287.14*	*152.16*		*30.12*	*423.78*	*152.16*		*30.12*	*642.04*	*152.16*	
	Annuity (M€ p a):	2.53	24.08	12.76		2.53	35.54	12.76		2.53	53.84	12.76	
	OPEX (M€ p a):	0.12	1.08	9.51		0.12	7.90	9.51		0.12	143.62	9.51	
	Cost (M€ p a):	**2.65**	**25.16**	**22.27**	**50.08**	**2.65**	**43.44**	**22.27**	**68.36**	**2.65**	**197.46**	**22.27**	**222.38**
	Unit cost (€/T CO_2):				**2.50**				**3.42**				**11.12**
500 km spine	*CAPEX (M€):*	*30.12*	*774.08*	*152.16*		*30.12*	*1035.41*	*152.16*		*30.12*	*756.35*	*152.16*	
	Annuity (M€ p a):	2.53	64.91	12.76		2.53	86.83	12.76		2.53	63.43	12.76	
	OPEX (M€ p a):	0.12	3.00	9.51		0.12	7.90	9.51		0.12	156.37	9.51	
	Cost (M€ p a):	**2.65**	**67.91**	**22.27**	**92.83**	**2.65**	**94.73**	**22.27**	**119.65**	**2.65**	**219.79**	**22.27**	**244.71**
	Unit cost (€/T CO_2):				**4.64**				**5.98**				**12.24**
750 km spine	*CAPEX (M€):*	*30.12*	1148.58	*152.16*		*30.12*	*1552.08*	*152.16*		*30.12*	*868.99*	*152.16*	
	Annuity (M€ p a):	2.53	96.32	12.76		2.53	130.16	12.76		2.53	72.87	12.76	
	OPEX (M€ p a):	0.12	4.50	9.51		0.12	7.90	9.51		0.12	167.10	9.51	
	Cost (M€ p a):	**2.65**	**100.82**	**22.27**	**125.74**	**2.65**	**138.06**	**22.27**	**162.98**	**2.65**	**239.97**	**22.27**	**264.89**
	Unit cost (€/T CO_2):				**6.29**				**8.15**				**13.24**
1500 km spine	*CAPEX (M€):*	*30.12*	*2283.10*	*152.16*		*30.12*	*3501.10*	*152.16*		*30.12*	*1120.69*	*152.16*	
	Annuity (M€ p a):	2.53	191.46	12.76		2.53	293.60	12.76		2.53	93.98	12.76	
	OPEX (M€ p a):	0.12	9.00	9.51		0.12	7.90	9.51		0.12	203.71	9.51	
	Cost (M€ p a):	**2.65**	**200.46**	**22.27**	**225.38**	**2.65**	**301.51**	**22.27**	**326.42**	**2.65**	**297.70**	**22.27**	**322.61**
	Unit cost (€/T CO_2):				**11.27**				**16.32**				**16.13**

Table 6-4: Cost estimates for Network 4, 5 and 6 in summary for spines of 180, 500, 750 and 1,500 km

6.8 Network 7

This 20 Mtpa CO_2 network comprises one 5 Mtpa point source at the collecting point, with 2.5 Mtpa transported to the collecting point by a10 km onshore pipeline; another 2.5 Mtpa CO_2 is transported 750 km by ship to the hub; and a final 10 Mtpa CO_2 is transported 180 km offshore by pipeline. From the hub, 20 Mtpa CO_2 is transported via an onshore pipeline – in a) the spine is 180 km, in (b) it is 500 km – and is finally distributed by two 10 km pipelines, carrying 10 Mtpa CO_2 each.

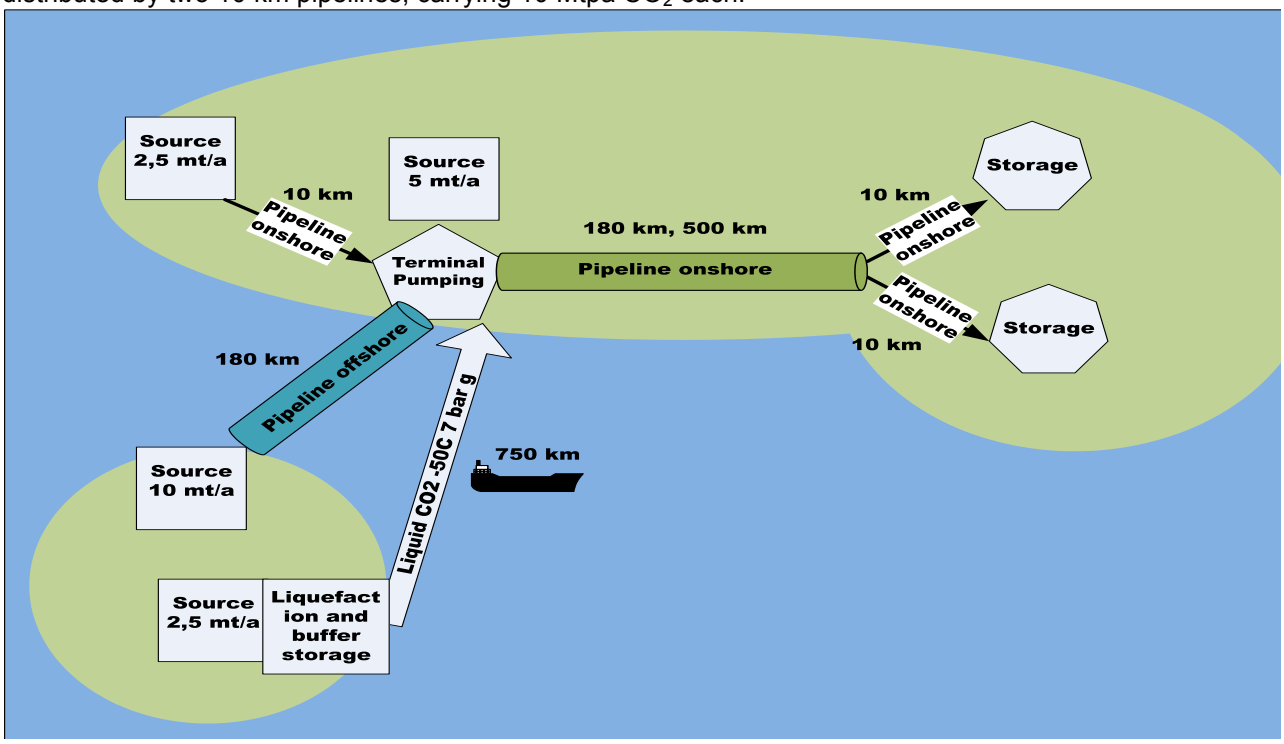


Figure 6-7: Network 7 illustration complex network with onshore pipeline spine of 180 km (a) and 500 km (b)

Network 7 20 Mtpa CO_2	Cost item:	Feeders	Spine	Distribution	Network cost
a. 180 km spine onshore	*CAPEX (M€):*	*524.06*	*287.14*	*30.12*	
	Annuity (M€ p a):	43.95	24.08	2.53	
	OPEX (M€ p a):	29.84	1.08	0.12	
	Cost (M€ p a):	**73.78**	**25.16**	**2.65**	**101.59**
				Unit cost (€/T CO_2):	**5.08**
b. 500 km spine onshore	*CAPEX (M€):*	*524.06*	*774.08*	*30.12*	
	Annuity (M€ p a):	43.95	64.91	2.53	
	OPEX (M€ p a):	29.84	3.00	0.12	
	Cost (M€ p a):	**73.78**	**67.91**	**2.65**	**144.35**
				Unit cost (€/T CO_2):	**7.22**

Table 6-5: Cost estimates for Network 7, complex network with onshore pipeline spine of 180 km (a), 500 km (b)

6.9 Network 8

This 20 Mtpa CO_2 network comprises one 5 Mtpa point source at the collecting point, with 2.5 Mtpa transported to the collecting point by a 10 km onshore pipeline; another 2.5 Mtpa CO_2 is transported 750 km by ship to the hub; and a final 10 Mtpa CO_2 is transported 180 km offshore by pipeline. From the hub, 20 Mtpa CO_2 is transported via an offshore pipeline – (a) 180 km and (b) 500 km – with the flow finally distributed by two 10 km pipelines, carrying 10 Mtpa CO_2 each.

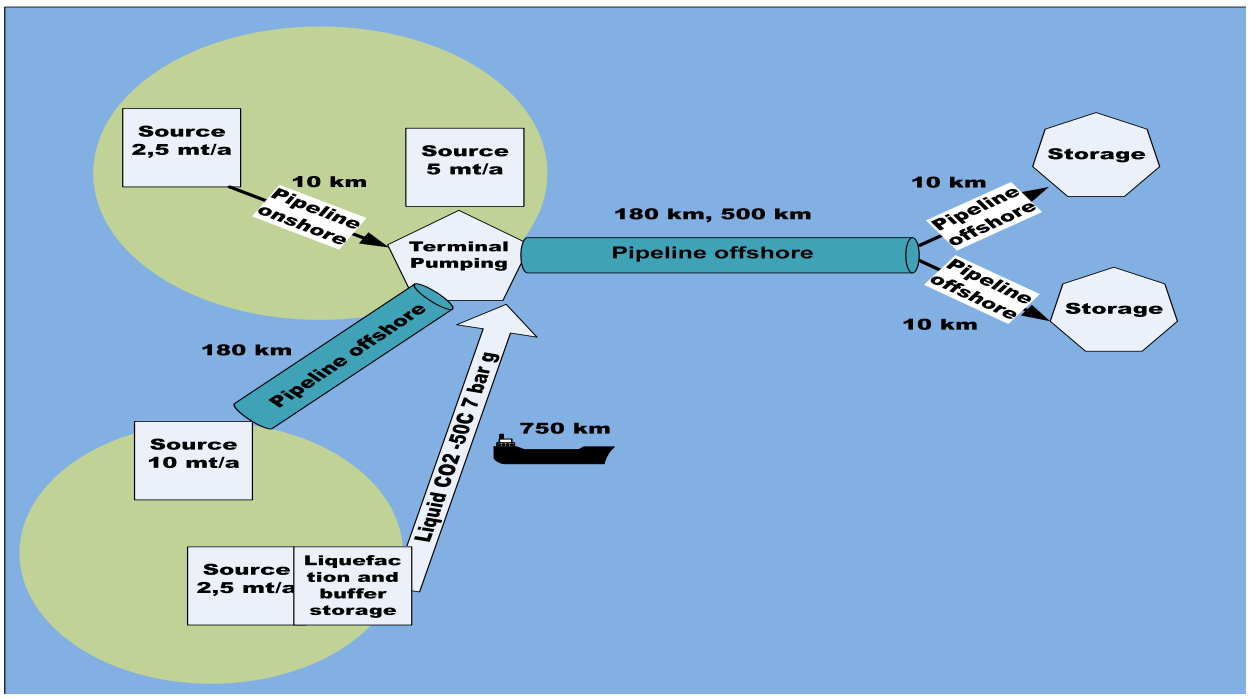


Figure 6-8: Network 8 illustration complex network with offshore pipeline spine of 180 km (a) and 500 km (b)

Network 8 20 Mtpa CO_2	Cost item:	Feeders	Spine	Distribution	Network cost
a. 180 km spine offshore	*CAPEX (M€):*	*524.06*	*423.78*	*152.16*	
	Annuity (M€ p a):	43.95	35.54	12.76	
	OPEX (M€ p a):	29.84	7.90	9.51	
	Cost (M€ p a):	**73.78**	**43.44**	**22.27**	**139.50**
				Unit cost (€/T CO_2):	**6.97**
b. 500 km spine offshore	*CAPEX (M€):*	*524.06*	*1035.41*	*152.16*	
	Annuity (M€ p a):	43.95	86.83	12.76	
	OPEX (M€ p a):	29.84	7.90	9.51	
	Cost (M€ p a):	**73.78**	**94.73**	**22.27**	**190.79**
				Unit cost (€/T CO_2):	**9.54**

Table 6-6: Cost estimates for Network 8, complex network with offshore pipeline spine of 180 km (a), 500 km (b)

6.10 Network cost overview

Net work	Volume	Source/s/	Transport						Store/s/	Cost
	Total		Feeder/s/		Spine		Distribution			
	(Mtpa)	(#*Mtpa)	(km)	Type	(km)	Type	(km)	Type	(#)	(EUR/t)
1 a	10	1*10	10	Onshore	180	Onshore	0	-	1	**2.1**
1 b	10	1*10	10	Onshore	180	Offshore	0	-	1	**3.4**
2 a	2.5	1*2.5	10	Onshore	180	Ship	0	-	1	**13.9**
2 b	2.5	1*2.5	10	Onshore	500	Ship	0	-	1	**15.2**
2 c	2.5	1*2.5	10	Onshore	750	Ship	0	-	1	**16.3**
2 d	2.5	1*2.5	10	Onshore	1,500	Ship	0	-	1	**20.2**
3 a	20	2*10	2*10	Onshore	180	Onshore	2*10	Onshore	2	**1.5**
3 b	20	2*10	2*10	Onshore	500	Onshore	2*10	Onshore	2	**3.7**
3 c	20	2*10	2*10	Onshore	750	Onshore	2*10	Offshore	2	**5.3**
4 a	20	2*10	2*10	Onshore	180	Onshore	2*10	Offshore	2	**2.5**
4 b	20	2*10	2*10	Onshore	500	Onshore	2*10	Offshore	2	**4.6**
4 c	20	2*10	2*10	Onshore	750	Onshore	2*10	Offshore	2	**6.3**
4 d	20	2*10	2*10	Onshore	1,500	Onshore	2*10	Offshore	2	**11.3**

Table 6-7 Complete network cost overview (1)

Net work	Volume	Source/s/	Transport						Store/s/	Cost
	Total		Feeder/s/		Spine		Distribution			
	(Mtpa)	(#*Mtpa)	(km)	Type	(km)	Type	(km)	Type	(#)	(EUR/t)
5 a	20	2*10	2*10	Onshore	180	Offshore	2*10	Offshore	2	**3.4**
5 b	20	2*10	2*10	Onshore	500	Offshore	2*10	Offshore	2	**6.0**
5 c	20	2*10	2*10	Onshore	750	Offshore	2*10	Offshore	2	**8.2**
5 d	20	2*10	2*10	Onshore	1,500	Offshore	2*10	Offshore	2	**16.3**
6 a	20	2*10	2*10	Onshore	180	Ship	2*10	Offshore	2	**11.1**
6 b	20	2*10	2*10	Onshore	500	Ship	2*10	Offshore	2	**12.2**
6 c	20	2*10	2*10	Onshore	750	Ship	2*10	Offshore	2	**13.2**
6 d	20	2*10	2*10	Onshore	1,500	Ship	2*10	Offshore	2	**16.1**
7		1*2.5	10	Onshore						
a	20	1*2.5	750	Ship	180	Onshore	2*10	Onshore	2	**5.1**
b		1*5	-	-	500	Onshore	2*10	Onshore	2	**7.2**
		1*10	180	Offshore						
8		1*2.5	10	Onshore						
a	20	1*2.5	750	Ship	180	Offshore	2*10	Offshore	2	**7.0**
b		1*5	-	-	500	Offshore	2*10	Offshore	2	**9.5**
		1*10	180	Offshore						

Table 6-7 Complete network cost overview (2)

7 Cost Estimate Ranges

7.1 Uncertainties

Any cost estimate not based on a supplier's fixed price contract is, by definition, uncertain; and even then it is subject to uncertainties during execution. As ZEP's cost estimates are not based on such contracts or basic engineering studies, a strict target of ~30% accuracy has been agreed. In general, the most important sources of cost estimate uncertainties are:

- Novelty of process, design and operation
- Cost level at the area of supply
- Timing and its influence on cost levels, currency exchange rates etc.
- The existence and efficiency of markets for the supplies sourced
- Financial market conditions
- Local conditions at the installation site

The *novelty aspect* applies the least to CO_2 pipelines, as a 6,000 km onshore network has already been established in the US over the last 30 years and experience in hydrocarbon transportation is also directly applicable. Offshore CO_2 pipelines represent a new field, but taking the necessary and reasonable assumption that the CO_2 is non-corrosive, their design and installation is, to a large extent, similar to that of hydrocarbon pipelines. The recent Snøhvit pipeline installation provides valuable experience already. With regard to shipping, the situation is even better, as CO_2 has been shipped regionally for over 20 years, while the differences between the design and operation of CO_2 Carriers and other Semi-Refrigerated Gas Carriers will be minimal. The uncertainty in estimating the costs of major CO_2 liquefaction plants lies in the fact that such plants have never been built on this scale. However, they consist of well-known processes and equipment utilised for the liquefaction of other, primarily hydrocarbon, gases. As a result, even the very first plants can be considered to be a significant way down the 'learning curve'.

With regard to *cost levels for supply and installation*, ZEP member organisations already have extensive experience in similar activities accessing supplies and performing installations in the European areas considered in this report. Ships and floating buffer storage are assumed to be supplied from the most cost-effective areas of supply available worldwide, in the same way as the hydrocarbon gas ships upon which current experience is based. The report aims to cover European site installation conditions, which means that some degree of generalisation has been applied since costs across Europe vary widely.

Timing is a critical uncertainty factor with a view to both source cost data and to the expected time of application. The three Working Groups in Taskforce Technology have agreed to use cost data and currency exchange rates consistently from the second quarter of 2009, with any deviations noted. Cost estimates therefore do not account for any inflationary or other market effects, e.g. variations in the steel price which is a key cost factor. The cost of electricity (for compression and liquefaction) also reflects prevailing market prices during this period.

There exist relatively *efficient markets* and market prices for the construction of both pipelines and ships. Prices fluctuate with demand and these variations were particularly volatile at the time of the current estimates. Before and after this period *price fluctuations* could be in the range of 25 to 30%, a fact which should be given due attention in any future use of the cost estimates in this report.

Local conditions could be a key factor. It is assumed here that sites are available without unusual local restrictions or particular local cost levels applying. Whether this is a reasonable assumption for specific future projects will have to be carefully considered in each case.

In summary, it is ZEP's view that the cost estimates may be considered accurate to around +/– 30%, subject to local conditions and developments subsequent to the second quarter of 2009.

7.2 Sensitivities

7.2.1 Key sensitivities

Cost estimates are based on certain assumptions which can cause some confusion regarding the meaning of the actual numbers presented. In order to clarify and challenge our estimates, some "*What if* " questions have therefore been asked. In doing so, possible areas for further analysis – both in the understanding of generic transport costs and their application to specific projects – are also highlighted. The following graphs illustrate the effects on the calculated transportation cost per tonne of CO_2 for 50% variations in each of the sensitivity factors below. For example: "*What if total capacity utilisation over the project lifetime is only 50%?*"

The key sensitivity factors identified and analysed were:

- Capacity utilisation
- Transport distance
- CAPEX (estimation error margin)
- OPEX (estimation error margin)

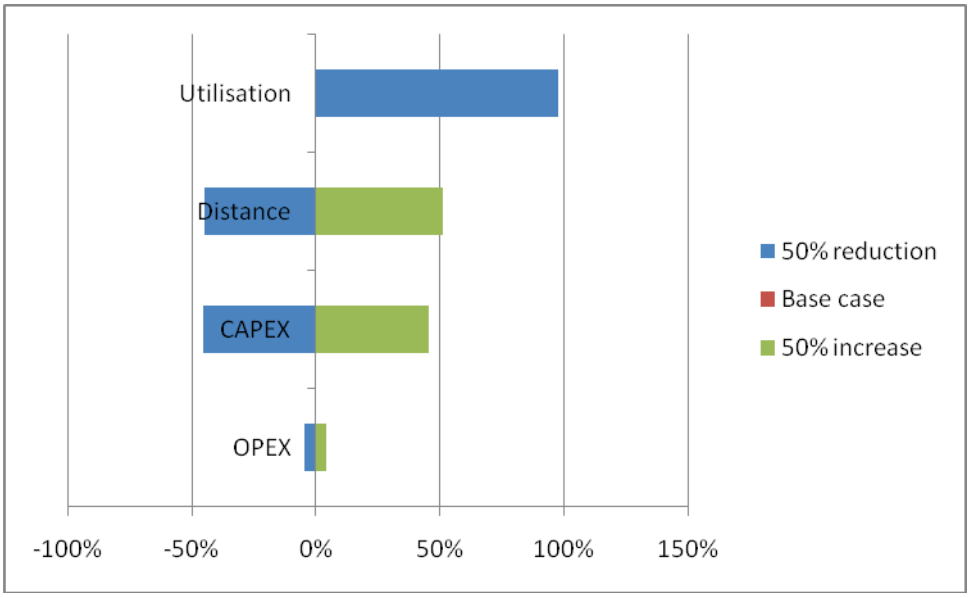


Figure 7-1: Sensitivities for offshore pipeline, 10 Mtpa and 500 km, expressed as EUR/tonne CO_2

The graph in Figure 7-1 illustrates that the EUR/tonne cost increases 98% from the base cost at full capacity. Alternatively, and maybe more likely, transporting that half volume in a smaller pipeline utilised at 100% is only 22% more expensive than the full capacity case for the full volume, as can be seen in Appendix 3. (N.B. In a real-life situation, the actual cost to the shipper will be more a function of the applied tariff policy.)

The four factors appear in order of sensitivity. For this example, the impact on cost is almost equal for onshore and offshore pipelines. Pipelines are capital intensive which causes high dependency on full utilisation. A 50% variation in distance (from 500 km to 750 km), or in actual CAPEX, causes a variation of 45 to 50%. On the other hand, operating expenses calculated as a function of CAPEX are low and nearly independent of flow, although in these estimates the energy used for compression up to 110 barg is not included as transport operating cost, but in the cost of capture.

Ship transport shows nearly the opposite sensitivity, which could in fact be beneficial when designing combined transport scenarios. Operating expense is the most sensitive cost factor where a 50% variation causes +/– 35% EUR/tonne cost impact. One key assumption has been to use international crew which for purely domestic routes may prove difficult. If applying European or national (UK, France, Norway etc) crew tariffs instead, this modification alone would increase cost per tonne by ~5%.

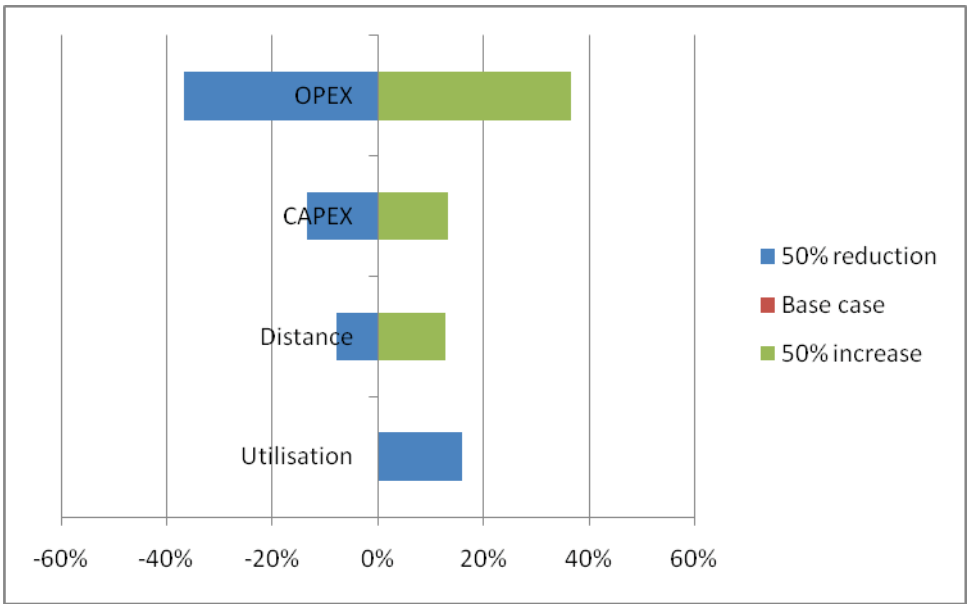


Figure 7-2: Sensitivities for ship transport, 10 Mtpa and 500 km, expressed as EUR/tonne CO_2

Transport costs presented in the main network table in 6.10 are based on 100% utilisation of capacity from day one of any given project lifetime, which for real-life situations may not be realistic. Using a Net Present Value method for assessing the average cost of transportation during the project lifetime, it is found that costs are greater if capacity utilisation is less than 100%, even if only early in the project, but the marginal cost of over-capacity is small compared to building more capacity later.

It is assumed that one single, larger pipeline has lower social and environmental impact (cost) compared to two smaller pipelines. With the assumptions of 8% interest rate and 40 years lifetime generally used in this study, a linear ramp-up from zero to 100% utilisation over 10 years results in a 35% increase in unit transportation cost. However, the cost of 2x10 Mtpa pipelines is ~55% more than a 20 Mtpa capacity pipeline and the unit cost of a 20 Mtpa pipeline at 50% capacity is only 22% more than a full 10 Mtpa pipeline.

Thus, for a specific case, the most optimal economic solution overall must be evaluated – either to pre-invest in a high-capacity transportation system with lower CAPEX per unit capacity available (but with higher initial costs due to lower utilisation), or to invest stepwise over time in more than one transportation system, resulting in higher CAPEX per unit capacity available. For ship transport, a corresponding analysis results in more marginal and stepwise increases, since it can be assumed that ships and utilities are built roughly to suit capacity demand at any time.

With capacity utilisation the critical factor for pipelines, a commercial-scale “point-to-point” transport scenario is described with cost as a function of distance. Ship transport capacity is assumed to be dynamically adjustable to demand and plotted for comparison. Reference is made to Appendix 3 where specific transport module costs at 100% utilisation are presented. In the end, such evaluations need to be made for specific projects, based on a more or less firm forecast of the anticipated transport demand over time.

Figure 7-3 illustrates the relationship between the transport distance and the cost of transporting one tonne of CO_2 over a distance of one km for systems with the capacity to transport 10 Mtpa and where this capacity is 50% utilised. This figure is then given for transportation systems of varying overall lengths. Three observations could be made from this graph. First, it seems for the offshore pipeline alternatives that (with the exception of short distance pipelines) the cost of transporting one tonne CO_2 the distance of one km is more or less independent of pipeline length.

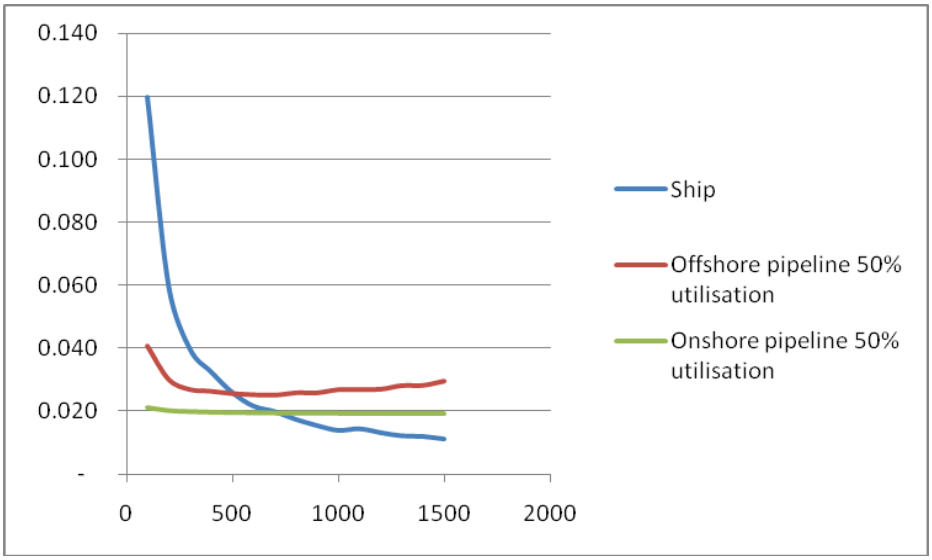


Figure 7-3: Cost expressed as EUR/tonne/km for pipelines at 50% capacity, 10 Mtpa (cost of fully utilised ship transport included for comparison)

The explanation is that additional length for the same volume will require only marginally larger pipeline dimensions to obtain the overall capacity – longer pipelines will result in larger internal friction inside the pipeline and thus larger diameter pipelines are needed to sustain the capacity. Normally this would result in an increasing unit cost per tonne and km, but since the inlet and outlet facilities of the pipeline – also representing a noticeable part of the overall costs – remain the same, this reduces the unit cost per tonne and km, so the overall effect is close to zero. As can also be seen from the illustration, this effect is somewhat different for short and very long pipelines, where the relative significance of these two effects no longer neutralises each other.

Secondly, it seems that this effect is also relevant for the longest onshore pipelines. The reason for this is that long onshore pipelines may be regarded as any given number of sections, where each section consists of inlet compression (taking the pressure at the outlet from the previous section up to the required inlet pressure of the current section) and a pipeline length. Any overall pipeline length then consists of a number of such sections, depending of the length of the system. Since the CO_2 is compressed up to the same pressure at the inlet of each section, long pipelines do not imply the need for pipelines with larger diameters – the unit cost per tonne CO_2 and km remains the same for any given length. As for the offshore pipelines, this is not valid for short transportation systems, where the costs of compression may have a relatively higher significance than the pipeline itself.

Thirdly, it seems that for ships, the unit cost per tonne CO_2 and km continues to be reduced, even for the longest transportation routes. The reason for this is that for any given volume of CO_2, longer transportation routes imply a more efficient use of the ships, in that a lesser proportion of the trip time is used for

loading/offloading and harbour maneuvering/waiting time, meaning that more of the gross time for one round trip will be used for transporting the CO_2.

7.2.2 Risk

There is a fundamental difference between pipes and ships in the sensitivity to technical and commercial risk. This is because pipes are highly capital intensive, with the annualised cost of capital forming more than 90% of the total cost. Ships are less capital intensive, with capital cost well below 50% of the total cost. Pipelines are also generally considered ”sunk cost” with no residual value, while CO_2 ships for one project are likely to have a residual value, either in other CCS schemes or in hydrocarbon transportation.
This perceived different risk sensitivity may impact the required interest rate applied for the different transport modes, but since the argumentation is highly speculative, the report does not include any quantitative estimates to this effect. Since the main report contains explicit information on the estimated, specific CAPEX, the reader can evaluate the financial consequences of any such risks.

7.2.3 Volume ramp-up sensitivity

The most likely scenario for under capacity utilisation is probably for a period of volume ramp-up. In the following this has been calculated as a linear volume increase from year 1 to year 10 for pipelines in a 20 Mtpa and 500 km “point-to-point” transport case. First, the CAPEX and OPEX profiles are illustrated by the following two graphs:

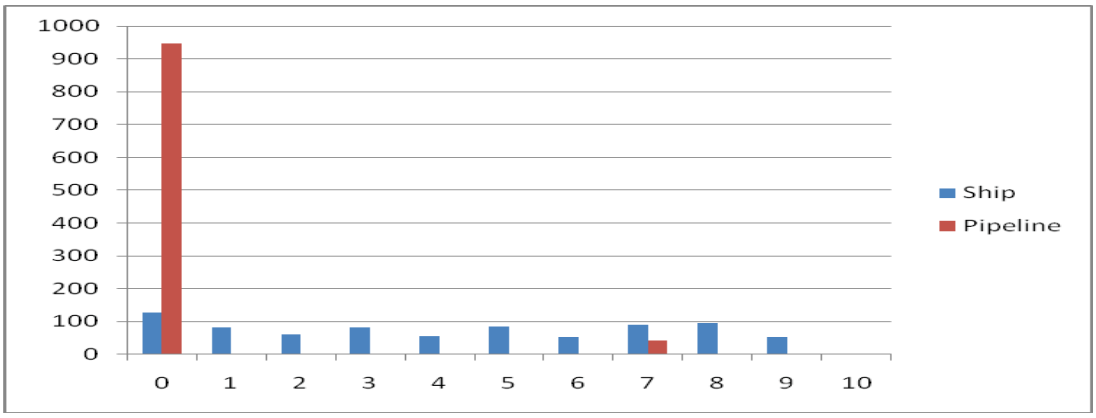


Figure 7-4: Investment, ramp-up case, 500 km and 20 Mtpa, expressed in M EUR/year

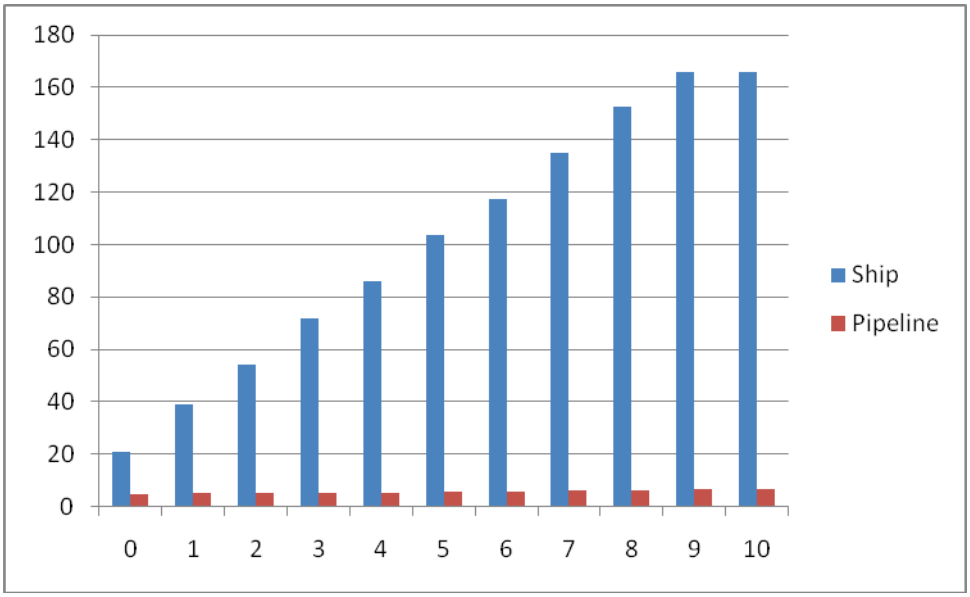


Figure 7-5: Operating expenses ramp-up case, expressed in M EUR/year

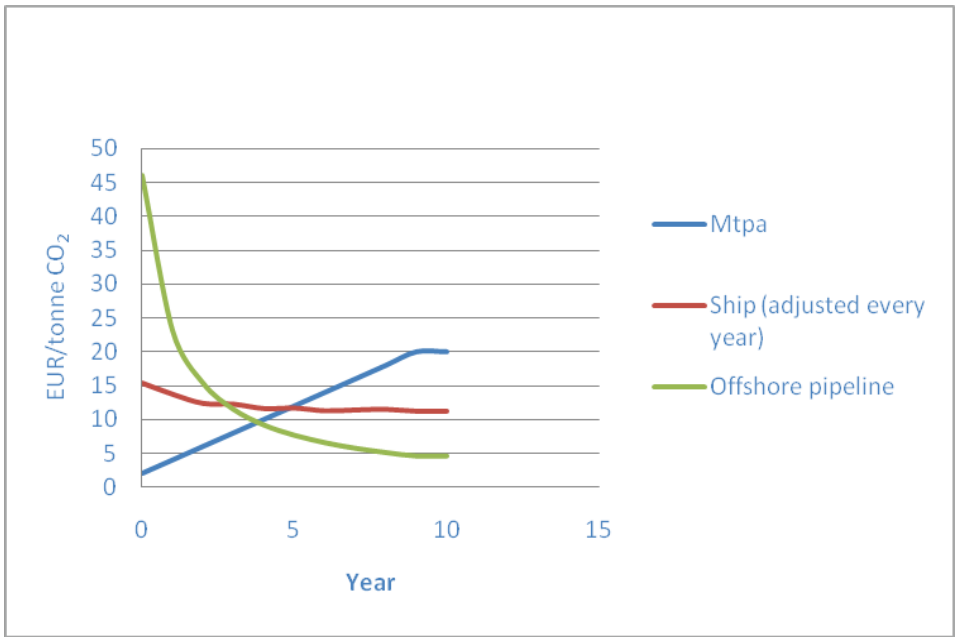


Figure 7-6: Transport cost EUR/tonne ramp-up case, 500 km and 20 Mtpa, volume increase 2 Mtpa

With the above criteria for capacity utilisation and the build-up of transported volumes to the maximum flow of 20 Mtpa, the cost in EUR/tonne is illustrated for the ramp-up period by Figure 7-6.

For the pipeline case, which is indeed affected by the linear build-up, the average cost per tonne transported CO_2 over the project lifetime of 40 years increases by approximately 48% – from €4.50/tonne to €6.50/tonne. In comparison, the shipping cost in this model remains basically unaltered at an average of €13.40/tonne.

8 Next Steps

The analysis in this report builds on empirical data, predominantly from extensive experience of product transport in the petroleum industry. This implies that the cost estimates include a certain element of hydrocarbon risk premium indicating a potential upside (inflated costs). This could be seen as a counterweight to the inherent risk of underestimating costs – mitigating and preventing risks and hazards in a novel field of operation. There has been no attempt to quantify the impact of these factors.

Development of highly efficient and large-scale pipeline infrastructure involves complex decision-making in a landscape where public and private interests meet. The cost estimates in this report point to the fact that ship logistic systems could play a more significant role, especially in the ramp-up period – starting with demonstration projects – than has previously been discussed in literature or in the public domain. The flexibility, scalability and low financial risk are arguments in favour of such conclusions.

The scale effect in pipeline costs supports the rapid development and early implementation of cluster developments in order to minimise long-term transport cost. The dynamics of capacity utilisation of logistic systems should be studied further in sensitivity analyses as this report has used only one flat rate capacity utilisation assumption.

Cost levels for the various transport networks can also be used as reference for other studies of CO_2 transport costs. Indeed, the aim has been to provide a transparent analysis – with the quantification of costs based on clear assumptions – which should then enable readers to compare with their own data or referenced literature. The selection of hypothetical networks should also mirror current views on how transport systems could look in a large-scale CCS market – from 2030 at the earliest and as such provide some degree of representation.

ZEP's unique ability to draw on live, in-house data produces both relevant and credible output. It is therefore our explicit recommendation to build on these conclusions as a basis for a European study – maintaining the neutral and cross-discipline approach, either as a consultancy or research assignment, authorised by the European Commission. The aim: to provide further input for political decisions in order to accelerate the wide deployment of CCS.

Indeed, for CCS to contribute significantly to EU emissions reduction targets requires the development of logistic systems on a scale matched only by the current hydrocarbon transport infrastructure. Efficient CO_2 transport must therefore be in place by 2030 at the latest, underlining the urgent need for sufficient comprehension of the scope and challenges involved.

9 Acknowledgements

The work described in this report has been possible solely due to the cooperation of participating ZEP members, resulting in a truly cross-border, cross-organisation product. Without their commitment, the challenging and constructive debate could not have been created, nor yielded such substantial results.

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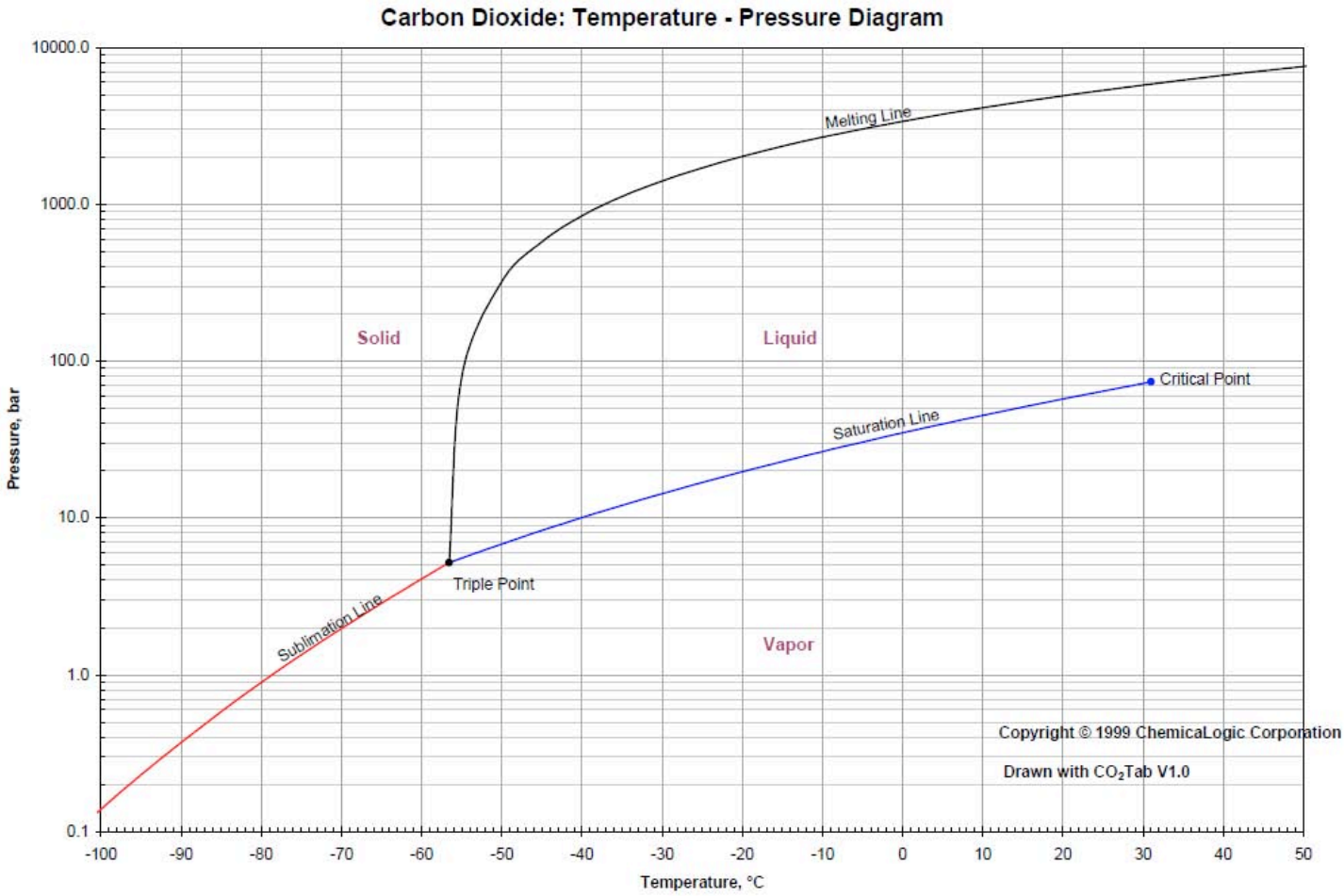
Glossary

bara	Absolute Pressure – used for applications where the pressure is sufficiently low to make the difference between bara and barg significant (see below)
barg	Bar gauge, equal to bara minus 1
bar	Used for pressures sufficiently high to make the difference between bara and barg insignificant
CAPEX	Capital expenditure or investment
CCS	CO_2 Capture and Storage
CO_2	Carbon dioxide
EU	European Union
EUR	Euro
GBP	Pound sterling
kWh	Kilowatt hour
km	Kilometre
LNG	Liquefied Natural Gas
LPG	Liquefied Petroleum Gas
M	Thousand
Mtpa	Million tonnes per annum
n.a.	Not applicable
NGO	Non-governmental organisation
NOK	Norwegian krone
OPEX	Annual operational expenditure
R&D	Research and development
T	Tonne
USD	United States dollar
ZEP	European Technology Platform for Zero Emission Fossil Fuel Power Plants (known as the Zero Emissions Platform)

Annex 1: CO_2 Phase Diagram



Annex 2: List of Tables and Figures

Annex 3: Transport Module Costs

Discount rate: 8%
No of years in operation: 40
Cost of transport chain Components

	Transport Mode:	Onshore					Offshore				
	Pipeline length in km:	10	180	500	750	1500	10	180	500	750	1500
	Pipeline diameter in inch:	12	12					12	16	16	18
2,5 MTPA CO_2	*CAPEX year 0 +construction interest (M€)*	*11.5*	*147.6*	*not relevant for onshore*			*not relevant*	*250.25*	*580.59*	*827.71*	*1513.96*
	Annuity (M€ p a)	0.97	12.38					20.99	48.69	69.41	126.96
	OPEX (M€ p a)	0.06	1.1					2.35	2.35	2.35	2.35
	Cost (M€ p a)	1.03	13.46					23.34	51.04	71.77	129.31
	Cost in € per tonne CO_2	*0.41*	*5.38*					*9.34*	*20.42*	*28.71*	*51.73*
	Annual pipeline cost in k€/inch/km	*8.57*	*6.23*					*10.81*	*6.38*	*5.98*	*4.79*

	Transport Mode:	Ship (including liquefaction)					Liquefaction
	Distance in km:	180	500	750	750*	1500	Mode 13
	Ship size in m^3:	22000	29300	36600	36600	25700	
	Number of ships	1	1	1	1	2	
2,5 MTPA CO_2	*CAPEX year 0 +construction interest (M€)*	*138.87*	*157.15*	*174.56*	*248.47*	*213.98*	*20.44*
	Annuity (M€ p a)	11.65	13.18	14.64	20.84	17.94	1.71
	OPEX (M€ p a)	22.07	23.73	25.02	22.15	31.60	11.57
	Cost (M€ p a)	33.72	36.91	39.66	42.99	49.55	13.28
	Cost in € per tonne CO_2	*13.49*	*14.76*	*15.86*	*17.20*	*19.82*	*5.31*

*=750 km for network 7 & 8 only

	Transport Mode:	Onshore					Offshore				
	Distance/length in km:	10	180	500	750	1500	10	180	500	750	1500
	Diameter in inch	20	24	24	24	24		22	26	26	30
10 MTPA CO_2	*CAPEX year 0 +construction interest (M€)*	*15*	*226*	*601*	*895*	*1778*	*76.08*	*337.95*	*780.85*	*1105.72*	*2360.08*
	Annuity (M€ p a)	1.26	18.94	50.43	75.02	149.11	6.38	28.34	65.48	92.73	197.92
	OPEX (M€ p a)	0.06	1.1	3.0	4.5	9.0	4.76	4.76	4.76	4.76	4.76
	Cost (M€ p a)	1.32	20.02	53.43	79.52	158.11	11.14	33.10	70.24	97.48	202.67
	Cost in € per tonne CO_2	*0.13*	*2.00*	*5.34*	*7.95*	*15.81*	*1.11*	*3.31*	*7.02*	*9.75*	*20.27*
	Annual pipeline cost in k€/inch/km	*6.61*	*4.64*	*4.45*	*4.42*	*4.39*		*8.36*	*5.40*	*5.00*	*4.50*

	Transport Mode:	Onshore					Offshore				
	Distance/length in km:	10	180	500	750	1500	10	180	500	750	1500
	Diameter in inch	24	32	32	32	32		26	32	34	40
20 MTPA CO_2	*CAPEX year 0 +construction interest (M€)*	*19*	*287*	*774*	*1149*	*2283*	*not relevant*	*423.78*	*1035.41*	*1552.08*	*3501.10*
	Annuity (M€ p a)	1.60	24.08	64.91	96.32	191.46		35.54	86.83	130.16	293.60
	OPEX (M€ p a)	0.06	1.1	3.0	4.5	9.0		7.90	7.90	7.90	7.90
	Cost (M€ p a)	1.66	25.16	67.91	100.82	200.46		43.44	94.73	138.06	301.51
	Cost in € per tonne CO_2	*0.08*	*1.26*	*3.40*	*5.04*	*10.02*		*2.17*	*4.74*	*6.90*	*15.08*
	Annual pipeline cost in k€/inch/km	*6.92*	*4.37*	*4.24*	*4.20*	*4.18*		*9.28*	*5.92*	*5.41*	*5.03*

	Transport Mode:	Ship (including liquefaction)				Liquefaction
	Distance in km:	180	500	750	1500	Mode 13
	Ship size in m^3:	35200	39100	41900	41000	
		5	6	7	10	
20 MTPA CO_2	*CAPEX year 0 +construction interest (M€)*	*642.04*	*756.35*	*868.99*	*1120.69*	*132.36*
	Annuity (M€ p a)	53.84	63.43	72.87	93.98	11.10
	OPEX (M€ p a)	143.62	156.37	167.10	203.71	86.28
	Cost (M€ p a)	197.46	219.79	239.97	297.70	97.38
	Cost in € per tonne CO_2	*9.87*	*10.99*	*12.00*	*14.88*	*4.87*