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Abstract

Major changes are foreseen in the coming decades to reduce CO_2 emissions from all sectors of the Dutch economy, pursuing the goals of the Paris Climate Agreement. Carbon Capture and Storage (CCS) technology is complimentary to the deployment of renewable energy sources, coupled with flexible power generation.

CCS is seen as the most promising solution to rapidly decarbonize energy intensive industries such as oil refining and the production of chemicals, steel, cement and ammonia. Adding CCS to the toolbox reduces overall decarbonization costs by extending the lifetime of existing multi-billion-dollar industrial assets, and by prolonging the use of low-cost energy sources.

This report presents cost estimates and technical considerations for the links of a CO_2 transport and storage chain. The focus is on the Dutch case for emitters (e.g. industrial sites in the Port of Rotterdam) as well as CO_2 storage locations. Sources and sinks in nearby countries are also discussed in the context of possible connections with a Dutch CCS grid. Related topics such as available storage, capture technology and transport infrastructure costs have been studied extensively and ample data is available in reports from various companies and institutions, as well as in scientific literature.

The intention of this report therefore was to make best use of the work that has already been done and to provide an overview of the relevant information for developing a CCS network in The Netherlands, mainly intended for industrial decarbonization. Several reports that were issued as part of the CATO-2 research program were consulted. Based on preliminary estimates, very significant cost-savings can be achieved for the transport and storage of CO_2 by using large scale CCS networks, instead of individual source-to-sink projects. However, networks pose specific challenges that require detailed planning and good coordination between the parties involved.

Industrial emissions in The Netherlands are concentrated at a few locations, and so are the known offshore storage locations (onshore storage of CO_2 is currently not seen as an option). Transport distances both onshore and offshore are relatively short, and there is existing offshore infrastructure that can be potentially adapted and reused for CO_2 storage. For these reasons, the country has excellent conditions for a large-scale CCS network to help reach decarbonization ambitions. Developing a Dutch CCS grid could also support similar efforts in nearby countries, for instance by facilitating the export of CO_2 by ship from Germany to distant offshore storage locations in the North Sea, near the UK or Norway.

Just like there are no silver bullets with regard to decarbonization, there are also no magic numbers with regard to CCS infrastructure costs. Several cost estimates are presented in this report, with ranges whenever available, but accurate cost estimates cannot be made without knowing the specific details of a proposed project. Besides the volume of CO_2 captured and the transport distances, other important cost factors are the type of process that is emitting CO_2, the characteristics of the storage reservoir and the availability of existing offshore infrastructure.

For a standalone CCS project in The Netherlands with a capacity of up to 2.5 Mt CO_2/year captured, overall transport and storage costs are expected to be in the range of 30-40 €/ton of CO_2, possibly higher. These estimates assume offshore storage in the Dutch Continental Shelf of the North sea and the costs would increase if the CO_2 is transported for final storage near Norway or the UK. Overall CO_2 avoidance costs (for the integrated chain) would be considerably higher, depending on how much extra energy input is required for capturing CO_2.

A more optimistic cost estimate can be made if rapid deployment of a large scale CCS network to capture 14 to 30 Mt CO_2 / year is assumed. With perfect planning/timing and best use of existing offshore infrastructure, current estimates indicate that transporting and injecting CO_2 in depleted gas fields in the North Sea could cost as little as 9€ per ton of CO_2 sequestered, including onshore transport costs.

ETS CO_2 prices have risen above 20€/ton this year and could reach 50€/ton or more as early as 2030. If a large scale CCS network is developed and improvements in CO_2 capture technology bring the cost down to ~40€/ton or less, then CCS could be carried out without industrial emitters incurring additional financial penalties. There is also potential to further improve project economics by (partially) converting captured CO_2 into valuable fuels or chemicals, but cost-effective technologies are under development. Furthermore, the potential market for products obtained using CO_2 as feedstock is small when compared to the scale of global emissions. Additionally, only a handful of the identified products appear feasible, because of the high energy input required to convert CO_2.

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List of abbreviations

2DS	Two Degree Scenario → a 2°C increase in average global temperature
ABEX	Abandonment Expenditure
ATR	Auto-Thermal Reforming
BECCS	Biomass to Energy with CCS
CAPEX	Capital Expenditure
CATO	CO_2 Afvang, Transport en Opslag (CO_2 capture, transport and storage)
CEMCAP	CO2 Capture from Cement Production (H2020 project)
CCS	Carbon Capture and Storage
CCU	Carbon Capture and Utilization
DCS	Dutch Continental Shelf
DDP	Deep Decarbonization Pathways
DOGF	Depleted Oil and Gas Fields
EBN	Energie Beheer Nederland
EOR	Enhanced Oil Recovery
ETS	Emissions Trading System
FID	Final Investment Decision
GHG	Greenhouse Gas
HIC	Harbor and Industry Complex (part of the Port of Rotterdam)
IEA	International Energy Agency
IEAGHG	IEA's Greenhouse Gas R&D Program
IPCC	Intergovernmental Panel on Climate Change
LCOE	Levelized Cost of Electricity
OECD	Organization for Economic Cooperation and Development
OPEX	Operational Expenditure
MLO	Moerdijk Lower Olefins
MMV	Monitoring, Measurements and Verification
Mtpa	Million tons per annum
NG	Natural Gas
NRW	North Rhine Westphalia
RED	Renewable Energy Directive
SA	Saline Aquifers
SMR	Steam Methane Reforming
UTC	Unit Technical Cost
ZEP	Zero Emissions Platform

1 INTRODUCTION AND OUTLINE

1.1 Rationale for CCS in The Netherlands

2018 in Europe has been a year marked by unusually long heat waves, droughts and forest fires. There's overwhelming evidence that greenhouse gas (GHG) emissions are affecting the climate and there is a clear link between anthropogenic activities and the frequency and intensity of extreme weather events.[1]

Recent years have seen a much needed boost in awareness of the general public and also the political will to implement measures that will reduce emissions that are impacting the climate. Yet CO_2 emissions have continued to increase on average by 1.3% per year in the last ten years and, earlier this year, the measured concentration of CO_2 in the atmosphere has reached 410ppm. "This was the highest monthly average in recorded history, and in fact according to ice core records it is the highest value in at least 800,000 years."[2]

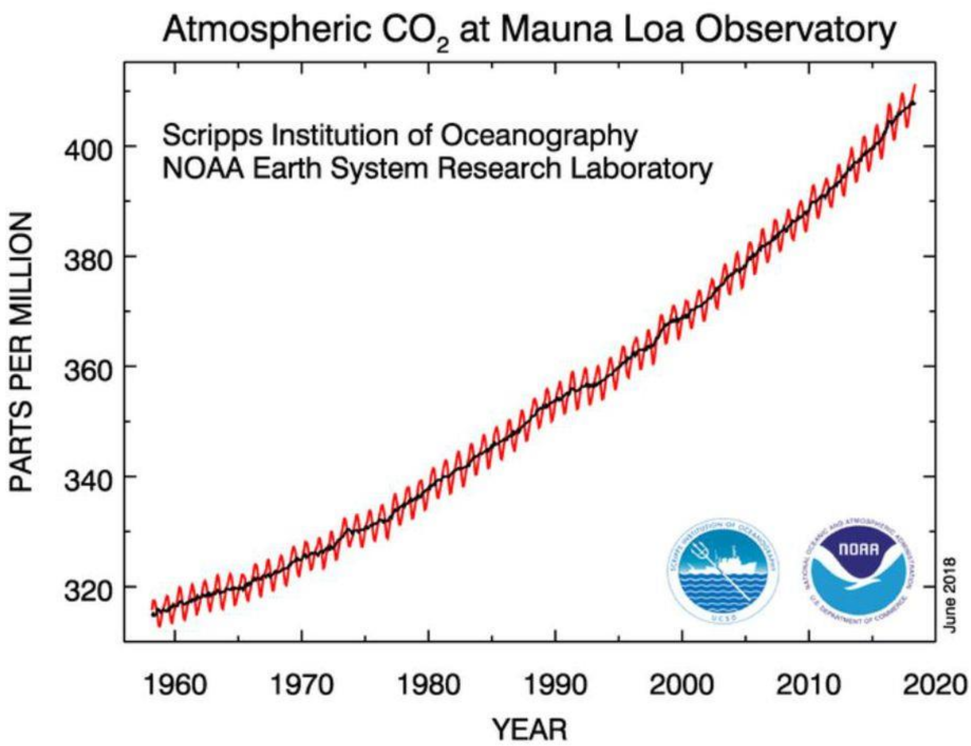


Figure 1. Full Mauna Loa CO_2 record,
Source: US NATIONAL OCEANIC AND ATMOSPHERIC ADMINISTRATION

[1] https://www.nature.com/articles/d41586-018-05849-9 (accessed 21.08.2018)

[2] https://www.forbes.com/sites/rrapier/2018/06/29/global-carbon-dioxide-emissions-set-new-record/ (accessed 20.08.2018)

Major national and international research centers and think tanks stress that reversing this trend and achieving Paris agreement targets will not be possible without the widespread implementation of Carbon Capture and Sequestration (CCS) technology.

Renewable sources of energy, excluding hydroelectric power, have grown by 17% in 2017 versus 2016. Despite having the highest growth in the energy sector, renewables currently account for just 3.4% of primary energy consumption. Oil, coal and natural gas retain the lion's share – fossil fuels still account for about 85% of primary energy consumption. (BP, 2018)

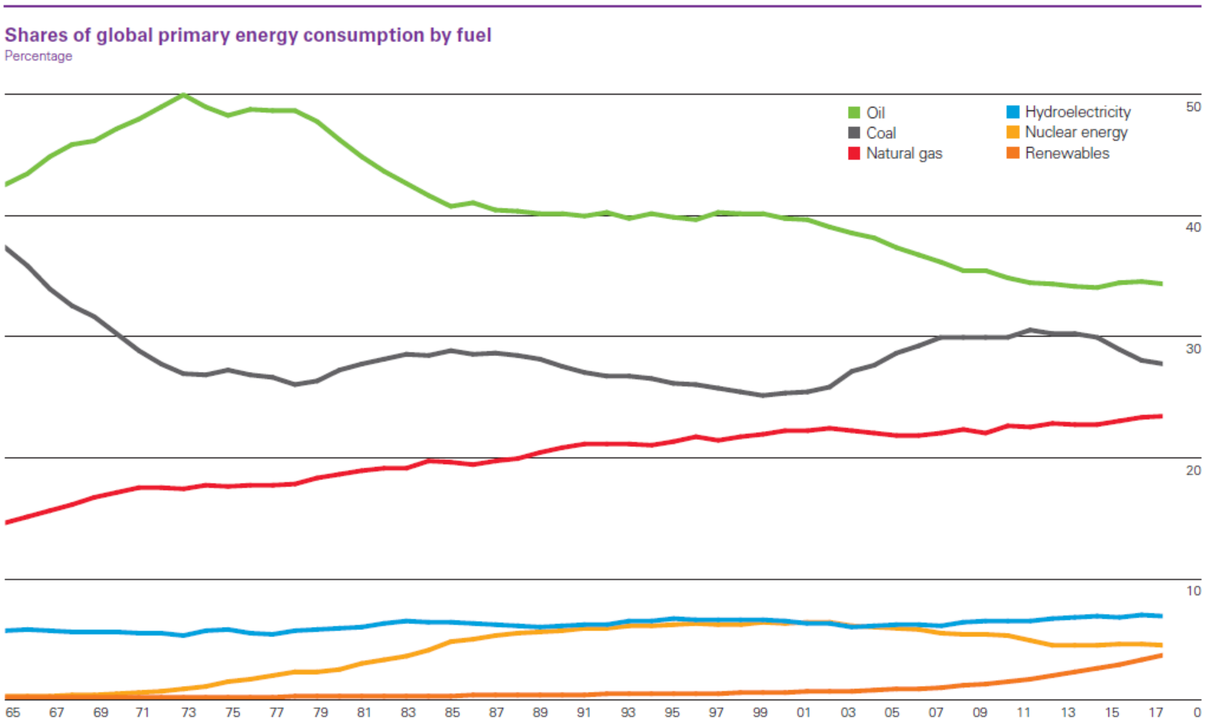


Figure 2. Source: BP Statistical Review of World Energy (2018)

The IPCC has published estimated "carbon budgets", i.e. cumulative CO_2 emissions that can be emitted corresponding to various global warming scenarios. (IPCC, 2014) Achieving the drastic reduction in CO_2 emissions that is required by 2050 to remain within the 2DS carbon budget (the scenario in which the average global temperature increases by no more than 2°C) relies on "massive deployment of various clean energy technologies, including renewable energy, nuclear energy, cleaner transport technologies, energy efficiency, and carbon capture and storage." (IEA, 2013)

CCS is needed because renewables and nuclear are not projected to supply sufficient power to balance demand, which is foreseen to increase due to electrification in the transport sector, industry, and the built environment. In The Netherlands specifically, the need for base load power capacity could strongly decrease, as a result of the projected increase in offshore wind capacity in the North Sea (see *Figure 3* on the next page). Unless large scale energy storage solutions become available, a large amount of flexible and carbon-free power generation will be required to balance the grid on days with no or too little wind power. Emissions from flexible power units such as gas turbines can be reduced by more than 90% with post-combustion CCS or by using H_2 as fuel, with the pre-combustion CO_2 capture at the H_2 production site (also known as "blue" hydrogen). Other large scale power generation options are difficult to operate flexibly in switch-on / switch-off mode.

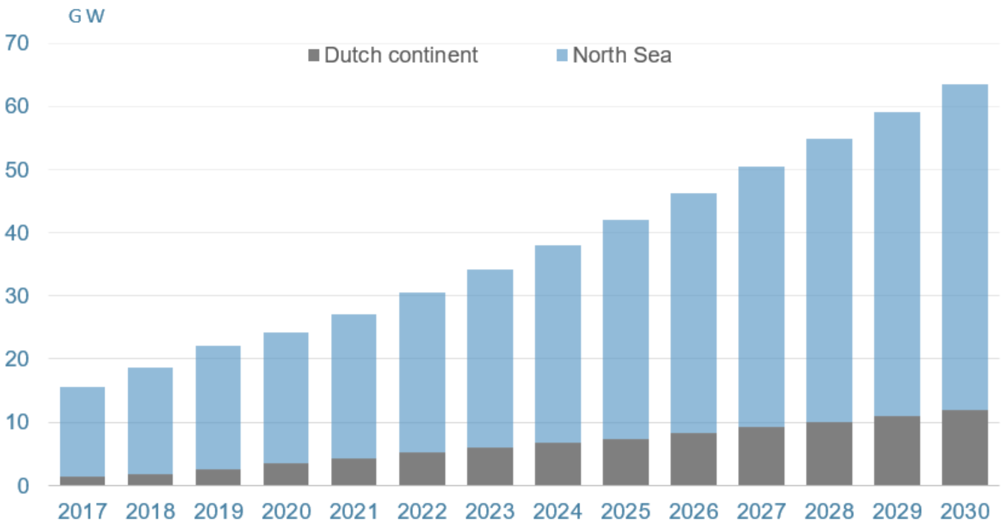


Figure 3. Projected growth of offshore wind capacity in the North Sea. Data source: (Wind Europe, 2017)

Beyond electricity generation, CCS is a crucial technology to decarbonize energy intensive industry. Steel and cement manufacturing account for ~40% of global industrial GHG emissions, together responsible for nearly 6 Gton CO_2 emitted in 2015. (McKinsey & Company, 2018)

McKinsey published an extensive report on the possible ways of decarbonizing the cement, steel, ammonia and ethylene industries. According to this study, CCS/CCU has the largest potential to reduce emissions, even if the average price of zero-carbon electricity (assumed to be available at sufficient capacity and able to sustain 24/7 industrial demand) drops below 20$/MWh:

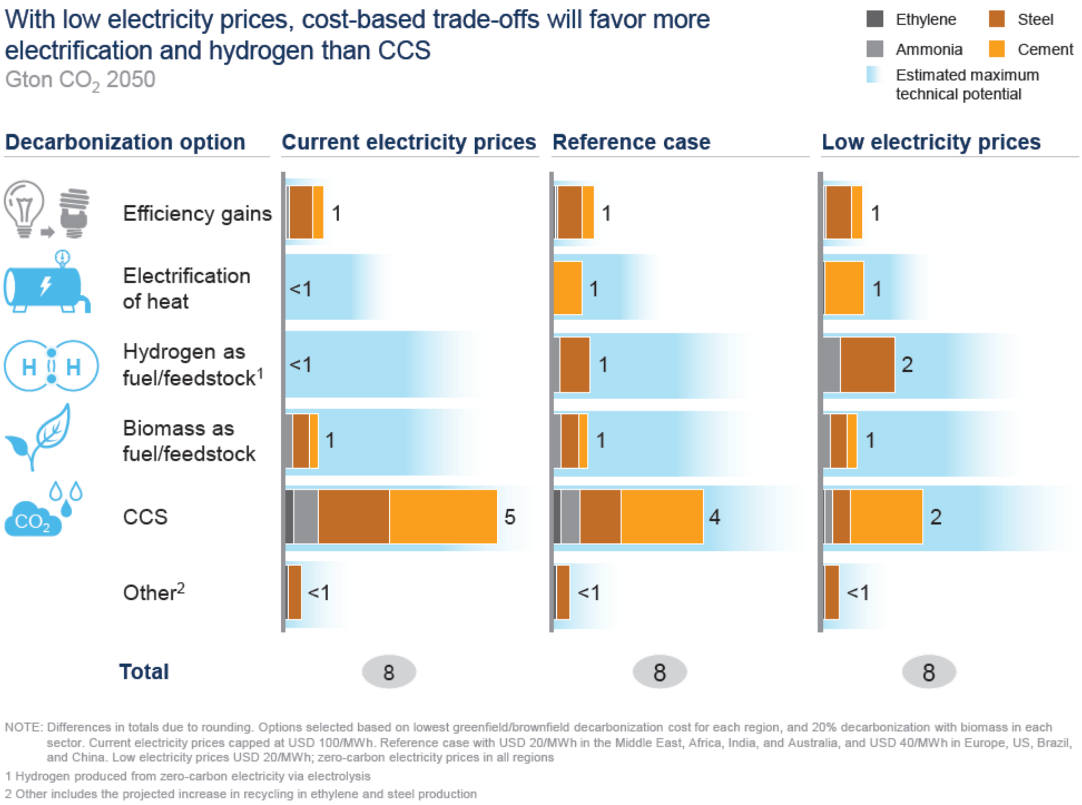


Figure 4. Source: McKinsey - Decarbonization of Industrial Sectors: The Next Frontier (2018)

The IEA has also set highly ambitious targets for CCS, for power generation as well as industry:

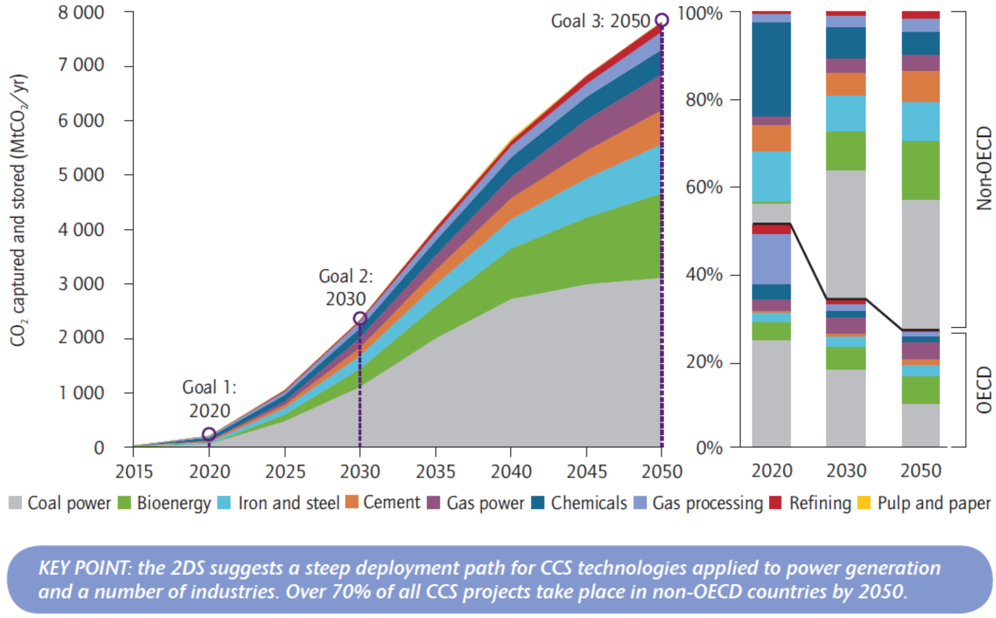


Figure 5. Source: IEA - Technology Roadmap Carbon Capture and Storage (2013)

Besides decarbonizing energy intensive industrial sectors, CCS networks are an enabler for biomass to energy with CO_2 capture and storage (BECCS), an energy chain with overall negative CO_2 emissions. As emissions continue to increase year-on-year, more of the 2DS carbon budget is being spent so it will be necessary to go beyond reducing emissions in order not to exceed it. "[…] in the latest Intergovernmental Panel on Climate Change assessment report published in 2014, 101 of the 116 scenarios that achieved a "likely" chance of staying below 2°C relied on BECCS."[3]

There is vast capacity for permanent CO_2 storage globally (see *Figure 6* below). Some of the major emitters such as China and the US have sufficient capacity within their borders. That is not the case for most European countries, as most proven CCS capacity is concentrated in the North Sea area.

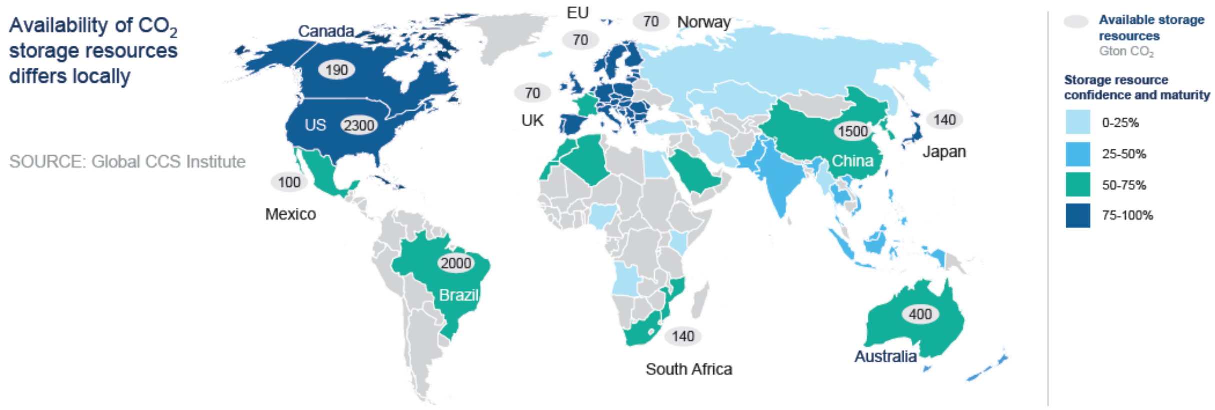


Figure 6. Source: McKinsey - Decarbonization of Industrial Sectors: The Next Frontier (2018)

[3] https://www.carbonbrief.org/explainer-10-ways-negative-emissions-could-slow-climate-change - the article also indicates other options to achieve negative CO_2 emissions. (accessed 14.08.2018)

The Netherlands is one of the European countries that has access to large CO_2 storage potential, of which roughly 65% is offshore and the rest in onshore formations. Onshore CO_2 storage has been opposed by the public in the past though, due to the risks of seismic activity possibly triggered by the injection of CO_2 and the fear of leakages in the future, and for now it is not seen as a viable option. Nevertheless, there is still sufficient storage capacity available in offshore depleted oil & gas fields and saline aquifers to capture and store a large fraction of industrial CO_2 emissions. Based on current estimates, some 34Mt of CO_2 could be stored annually over a period of 50 years, mitigating climate change and supporting the transition to a carbon-free economy.

All the steps required for CCS have been demonstrated at commercial scale, so this technology can be deployed rapidly. The Netherlands has a well-established offshore oil & gas sector and there is potential for cost savings by reusing existing infrastructure to inject CO_2 in offshore reservoirs. Among the options at hand, CCS appears to be the most cost-effective way to begin reducing emissions at scale, especially from industry.

For other countries such as Germany, making use of CCS technology would likely require exporting part of the captured CO_2 to a neighboring country with larger capacity for permanent storage, for instance Norway or the UK. If Rotterdam becomes a hub for CCS, with a large scale CO_2 transport network and facilities for export, CO_2 captured at a German site near the border could be routed via Rotterdam towards the final storage destination. Similarly, there is potential for synergy with decarbonization projects in the nearby port of Antwerp. Developing CCS capabilities in The Netherlands would therefore not only support the decarbonization of the Dutch energy intensive industry, but could also support the reduction of CO_2 emissions from other EU countries.

An integrated network for CO_2 transport, using long trunklines and shorter from-source and to-sink branches, also benefits from economy of scale and would lower overall costs compared to the use of point-to-point pipelines for each CCS project. Cost savings at larger scales result from the fact that CAPEX for pipeline and compression is not a linear function of CO_2 transport capacity.

Such an integrated CO_2 transport infrastructure implies long term and coordinated planning between the different parties involved. This is not trivial, considering the long distances between the various sources and sinks, as well as the different timing and uncertainties of CCS projects.

1.2 Experience with CCS to date

Carbon capture and storage is a mature technology – the first large scale projects started up in the 70's and 80's. Total global capacity, including four projects that are under construction and were scheduled to be commissioned this year, is 37 Mt CO_2 / year. (Global CCS Institute, 2017) It's estimated that approximately 220 Mt of CO_2 in total have been captured and sequestered to date as a result of CCS these projects, most of which has been used for EOR:

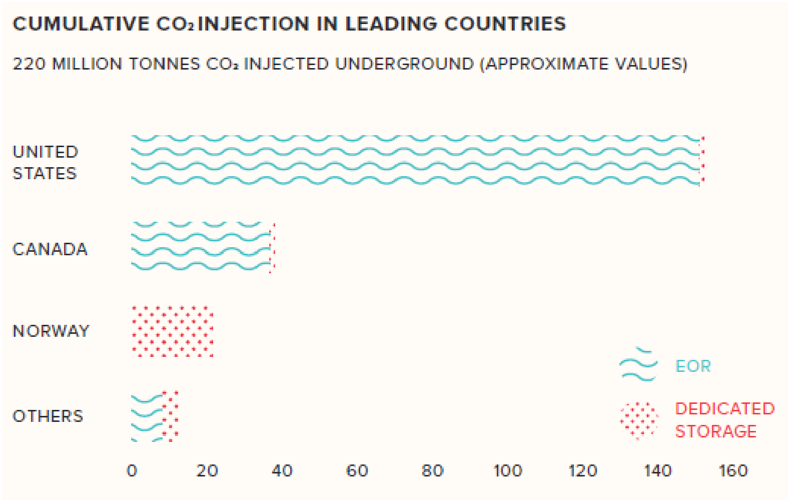


Figure 7. Source: Global CCS Institute - The Global Status of CCS: 2017

Figure 8 below presents large-scale CO_2 capture projects in operation, under construction or at an advanced stage of planning as of end-2012, by sector, storage type, capture potential and start date:

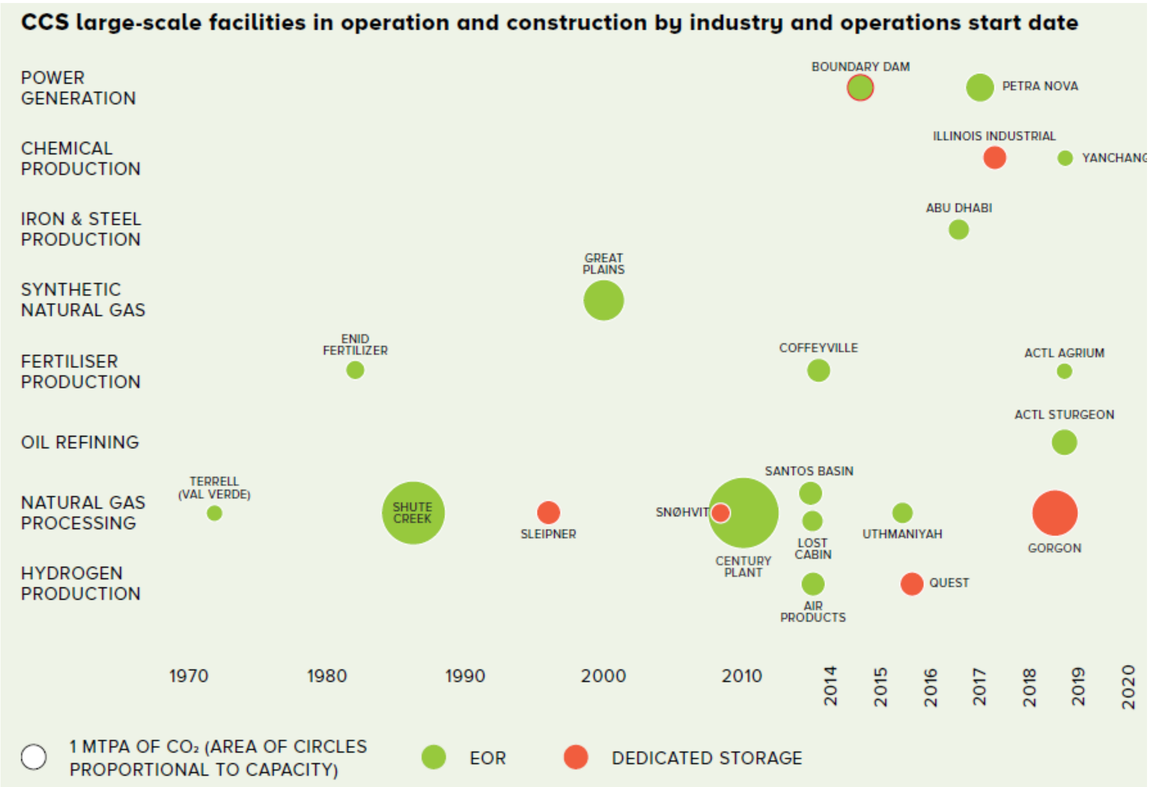


Figure 8. Source: Global CCS Institute - The Global Status of CCS: 2017

There are 16 more large-scale CCS projects under early or advanced development. The Global CCS Institute maintains an up-to-date list of large-scale CCS facilities around the world.[4] Large scale in this case being defined as:

- at least 800,000 tons of CO_2 annually for a coal–based power plant, or
- at least 400,000 tons of CO_2 annually for other emissions–intensive industrial facilities (including natural gas–based power generation).

1.3 Outline of this report

Following up on previous work done within the Horizon 2020 Elegancy program, this report presents cost estimates and technical considerations for transporting and storing CO_2 captured at industrial sites from the Port of Rotterdam, as well as other industrial sources.

Chapter 2 provides an overview of major CO_2 sources with potential for CCS within The Netherlands, and neighboring areas that could be connected to a future Dutch CCS network. Several studies have been published in recent years evaluating the potential capacity for storing CO_2 in the Dutch Continental Shelf and other areas of the North Sea. Based on this work, chapter 3 and Appendix A contain a list of promising depleted gas fields and saline aquifers, indicating estimated capacities along with other relevant aspects CO_2 storage.

Chapter 4 covers the costs of a CCS chain, broken down per subchapter into capture, transport costs and injection costs, using data from previously published reports. Combining individual costs and their uncertainties results in ranges for transport and storage chains, which are presented in chapter 4.4.

CO_2 can also be potentially used as a feedstock, either as an alternative to or complementary to CCS. This is known as carbon capture and utilization (CCU) and is discussed in chapter 5. Finally, a series of conclusions can be drawn and are presented in chapter 6, together with a series of recommendations for future work on establishing an effective CCS network.

There are of course other important aspects of CCS projects, for instance public engagement or safety considerations specific to CO_2, which are not covered in this report. These topics have been however covered extensively in previous publications, such as the overview report of the CATO-2 research program "CATO-2 – Linking the Chain". (Vos, 2014) Safety concerns and public engagement are also addressed in the "CO_2 Pipeline Infrastructure" reference manual compiled by Ecofys and SNC-Lavalin. (IEAGHG, 2014)

[4] https://www.globalccsinstitute.com/projects/large-scale-ccs-projects (accessed 22.08.2018)

2 CO_2 SOURCES

2.1 The Netherlands

CCS is an attractive option for reducing CO_2 emissions in The Netherlands because the largest emitters are concentrated in areas that are relatively close to the available offshore CO_2 storage sites. This holds for all industrial clusters with the exception of Geleen. 10% of the industrial actors are accountable for 85% of ETS CO_2 emissions:

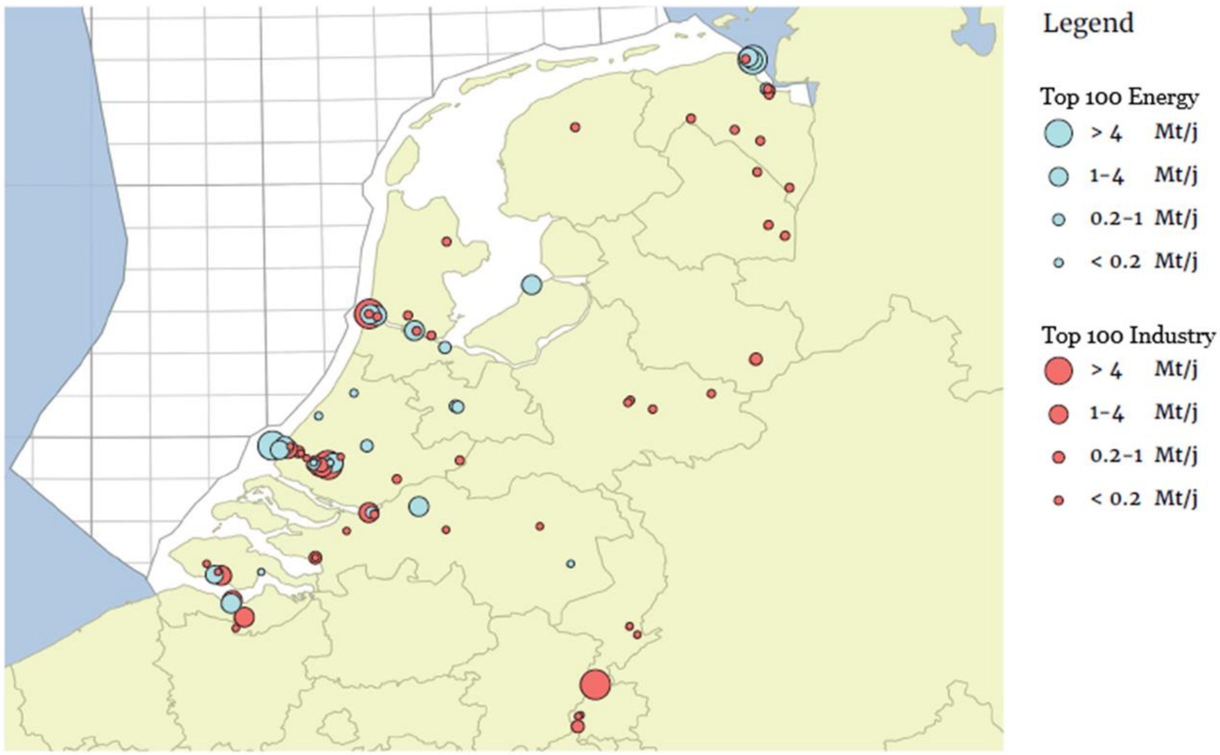


Figure 9. Location of major (>0.1 Mt CO_2/year) emitters in The Netherlands. (EBN, Gasunie, 2017)

It's important to note that the current climate strategy of The Netherlands implies shutting down all coal-fired power generation (large light blue bubbles in *Figure 9*) by 2030. As such, these sites will not be candidates for CCS, unless importing biomass to replace coal or implementing pre- or post-combustion CCS would be politically acceptable and economically feasible options to continue operating these assets.

The most promising areas for the first phase of the Dutch CCS network are the industrial hubs in the ports of Amsterdam and Rotterdam. These are home to major emitters such as Tata Steel in Ijmuiden, the Uniper and Engie power plants at Maasvlaakte, and the BP, Exxon and Shell refineries near Rotterdam. These emitters are also located close to the coast, which reduces infrastructure and compression costs for offshore storage of CO_2.

An inventory of CO_2 sources in the Rotterdam Harbor and Industry Complex (HIC) was reported in a previous deliverable, as part of the Elegancy program. (TNO, 2018) The refining and petrochemicals sectors alone in the Rotterdam HIC, including the Shell Moerdijk site and off-plot hydrogen production, account for over 13 Mtpa of CO_2 emissions. See *Figure 10* on the following page for a breakdown of the processes responsible for these emissions.

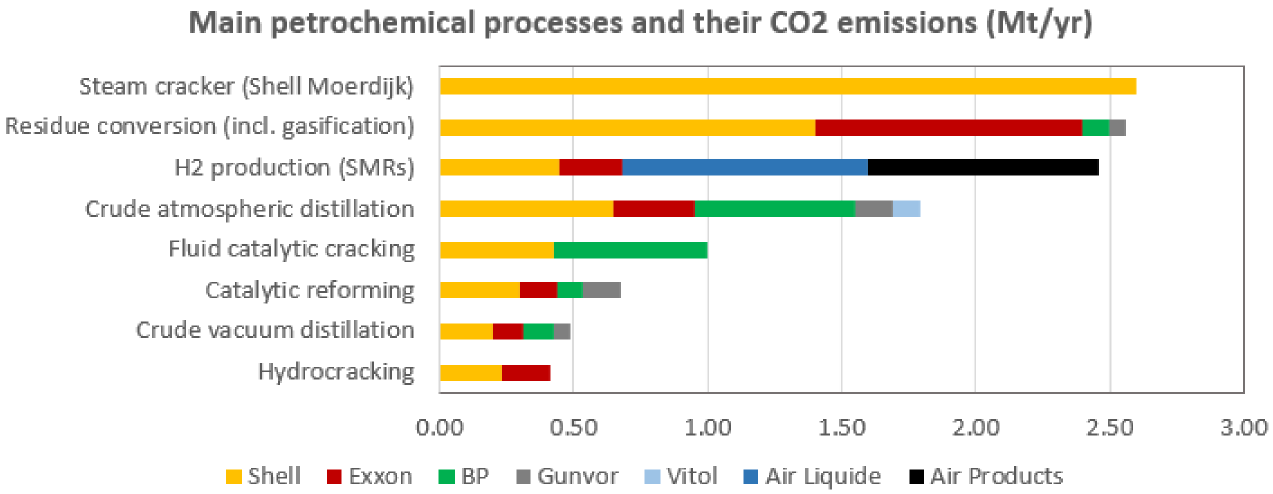


Figure 10. Major petrochemical processes responsible for CO_2 emissions in the Rotterdam HIC
TNO estimates based on CBS statistics, typical refinery emissions profiles and feedback from industrial partners

Nearly all of these CO_2 emissions are generated by burning natural gas or refinery gases in high temperature furnaces, to heat up various process streams. There are three main options to reduce CO_2 emissions from these furnaces, each with advantages and disadvantages:

1) **Electrification** – implement novel technologies (e.g. electrical resistance furnaces or microwave heating) to heat up the process streams using electricity instead of fuels.

   Electrification would be very effective in reducing CO_2 emissions, if the electricity mix is low-carbon. Electrifying industrial furnaces will increase electricity demand from the grid and supplying that with renewables would be a challenging balancing act. The technology maturity level is low, and many hardware modifications will be required.

2) **H_2 as fuel (pre-combustion CO_2 capture)** – decarbonize the fuel by replacing methane and other light hydrocarbons with H_2.

   The technology to convert methane to H_2, and capture the associated CO_2, is commercially available. Large volumes of H_2 can be produced centrally to benefit from economy of scale. However, most of the furnace duty required at refineries is covered by refinery fuel gas, a mix of secondary streams supplied by various process units. Converting this stream to H_2 poses additional challenges compared to natural gas.

   Another important consideration is that existing fuel gas distribution networks (pipes/fittings, valves, instruments, safeguarding and control systems) would need to be upgraded to cope with the high percentage of H_2 in the fuel mix.

3) **Post-combustion CO_2 capture** – install CO_2 capture equipment (e.g. amine scrubbers) at furnace stacks to remove CO_2 from flue gases.

   This is a straightforward solution, requiring well known and commercially available technology. Capturing CO_2 from these streams is hampered though by the low pressure of flue gases and the low CO_2 concentration. It’s not cost-effective to have an array of small scale capture units for individual stacks, so the flue gases would have to be rerouted to larger capture units. There might also not be sufficient plot space available to install CO_2 capture equipment at existing refineries.

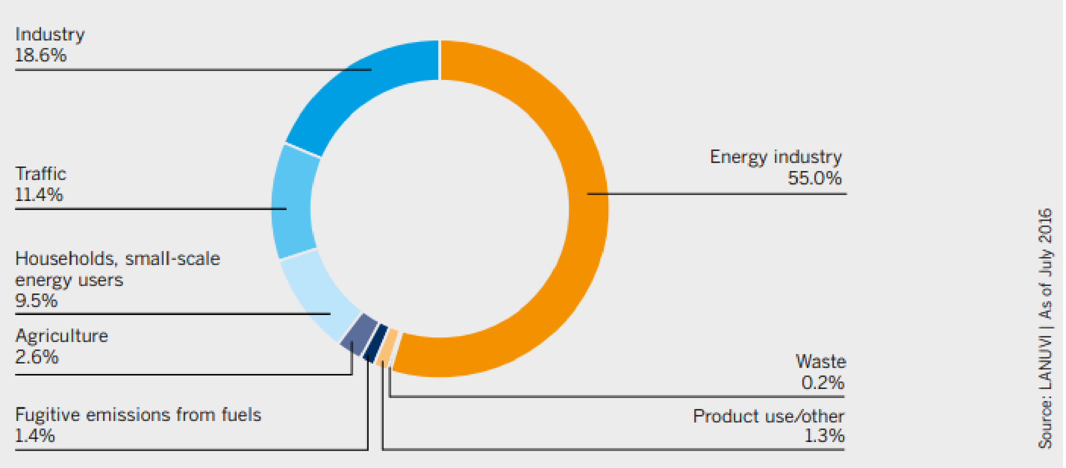
2.2 Neighboring countries

To the east of The Netherlands lies Germany's powerhouse, the industrial area of the state of North Rhine Westphalia (NRW). Much of the country's heavy industry is located in this area and has traditionally relied on coal for power generation. Roughly one third of Germany's power capacity is located in the state of NRW. Some of the units are very old though, with three of the coal-fired power plants in this region listed in the top 10 in *"Europe's Dirty 30"* list (Climate Action Network, 2014), at numbers 2, 3 and 7:

Power Station, Location	Country	2013 emissions ($MtCO_2$)
Bełchatów Power Station, Bełchatów	Poland	37.18
Neurath Power Station, Grevenbroich	Germany	33.28
Niederaussem Power Station, Niederaussem	Germany	29.58
Jänschwalde Power Station, Jänschwalde	Germany	25.40
Boxberg Power Station, Boxberg, Saxony	Germany	21.89
Drax Power Station	United Kingdom	20.32
Weisweiler Power Station, Eschweiler	Germany	18.66
Agios Dimitrios Power Station, Agios Dimitrios, Kozani	Greece	13.11
Brindisi Sud Power Station	Italy	11.81
Lippendorf Power Station, Lippendorf	Germany	11.73

Figure 11. Top 10 "dirty" coal-fired power plants in the EU according to (Climate Action Network, 2014)

Due to relatively old technology and the burning of low quality coal (lignite, aka brown coal), resulting in high emissions per unit of energy produced, these three power plants alone accounted for combined CO_2 emissions of ~82 Mtpa in 2013. In total, the power sector was responsible for 55% of all CO_2 emissions in NRW in 2014:



The energy sector – lignite and coal-based power generation in particular – has consistently been one of the major sources of greenhouse gas emissions. In 2014, 55% of the state's emissions came from this sector; it is the only sector in which emissions have not dropped below 1990 levels (there are currently 1.5 million metric tons or roughly 1% more emissions than in 1990). Other significant sectors in 2013 were industry with around 18%, traffic with around 11% and households and small-scale consumers with around 10% of total emissions. Agriculture was responsible for 2.6% of local greenhouse gas emissions. Fugitive emissions from fuels, for example, from coal mines and the oil and gas industries, accounted for 1.4% of emissions. The use of products such as the refrigerants in air-conditioning units generated about 1.3% of emissions, while waste only had a share of 0.2%.

Figure 12. Distribution of GHG emissions in NRW in 2014 (Ministry for Climate Protection, Environment, Agriculture, Conservation and Consumer Protection of the State of North Rhine-Westphalia, 2016)

The GHG emissions from power generation and other industrial activities in the state of North Rhine Westphalia exceed the total GHG emissions from The Netherlands. Pre- and post-combustion CCS could help mitigate these CO_2 emissions, possibly making use of future Dutch CO_2 transport infrastructure. However, known storage capacity in the Dutch Continental Shelf is not available on large enough scale to absorb a significant part (i.e. more than 10%) of the annual industrial emissions from NRW. See Chapter 3 for details on available offshore storage capacity.

Export of liquified CO_2 for offshore storage near the UK or Norway is an option, albeit at a higher overall cost. Dutch infrastructure could play a role if the offloading terminal is located in Rotterdam or Eemshaven. Sharing transport infrastructure between several projects is expected to lead to large cost savings per ton of CO_2 transported. This is further discussed in Chapter 4.

A more likely candidate for integration in terms of CO_2 infrastructure is the industrial region in the port of Antwerp. Large scale emitters from this area are located at a distance of about 120 km from the expected take-off location (Maasvlakte / Hoek van Holland) for CO_2 injection in offshore fields nearby Rotterdam. Transporting CO_2 onshore over such a distance is a marginal addition to the overall costs of a CCS project.

Like Rotterdam, GHG emissions in the port of Antwerp are predominantly related to power generation and refining/chemicals so a similar decarbonization strategy could be implemented. A breakdown of GHG emissions in the port of Antwerp is shown in the chart below (CO_2 is about 80% of the total):

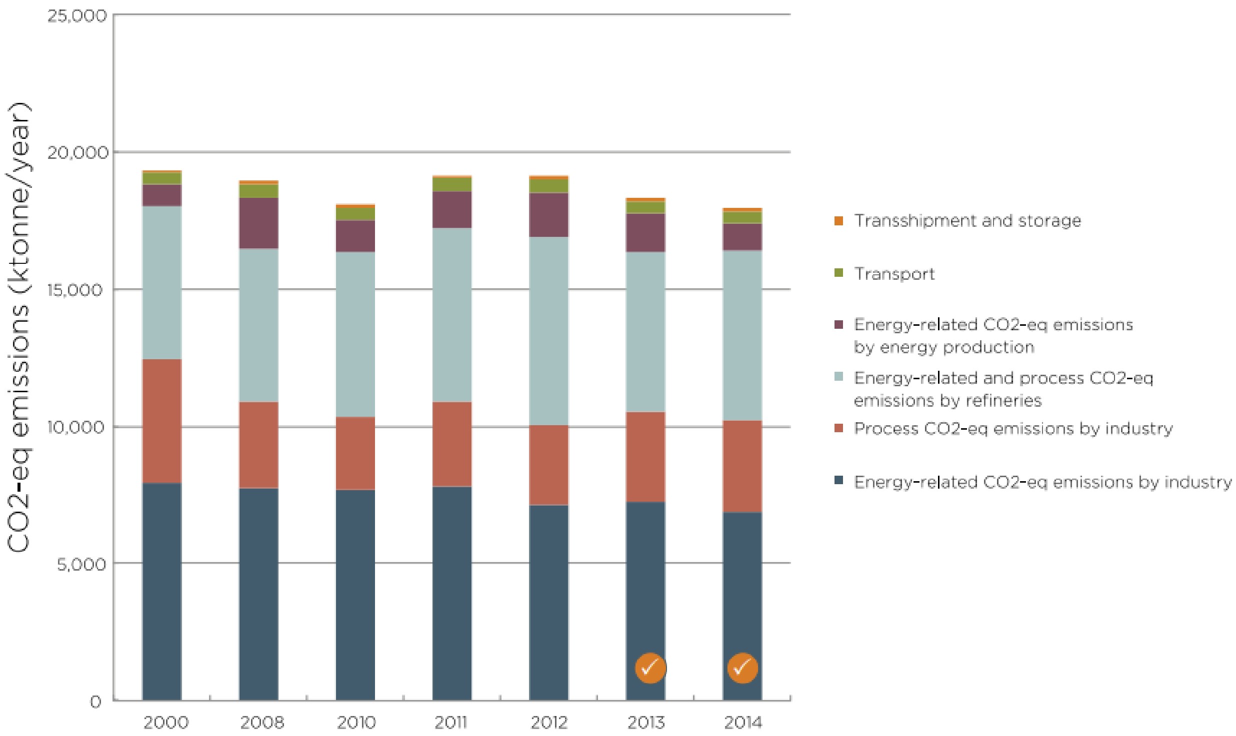


Figure 13. Emissions of CO_2, CH_4 and N_2O (based on emission factors and Global Warming Potential as per IPCC 1996) by different sectors in the Antwerp port area. Source: (Port of Antwerp, 2017)

3 AVAILABLE STORAGE CAPACITY

3.1 The Netherlands

The total offshore storage capacity, within the Dutch Continental Shelf (DCS), is approximately 1700 Mt CO_2. (EBN, Gasunie, 2017) It's important to note that this capacity is concentrated, i.e. 25% of the offshore fields hold about 65% of the total capacity. In the context of CCS this is very advantageous, because it reduces the complexity of the delivery infrastructure. In addition to the available offshore capacity there is also ample storage capacity onshore, estimated at 1100 Mt CO_2. Onshore storage locations are generally not being considered anymore, as previous projects have been met with very strong opposition (for example the CCS project in Barendrecht[5]).

A detailed evaluation of potential CO_2 storage sites in the DCS was also published by TNO in 2012 ("Independent assessment of high-capacity offshore CO2 storage options"). This resulted in a selection of four partially depleted gas fields with a potential capacity of >40 Mt CO_2 each, and five saline aquifers with a potential capacity of >50 Mt CO_2 each (see Figure 14 below). These CO_2 sinks are characterized well enough to represent reliable capacity for CCS, and they can sustain high CO_2 injection rates. Aquifers 1 and 2 for example, both located close to Rotterdam, could support combined injection rates of 10-20 Mtpa, which is enough to cover the forecasted CCS requirements of industry in the HIC area and could also enable storing CO_2 imported from Belgium or Germany.

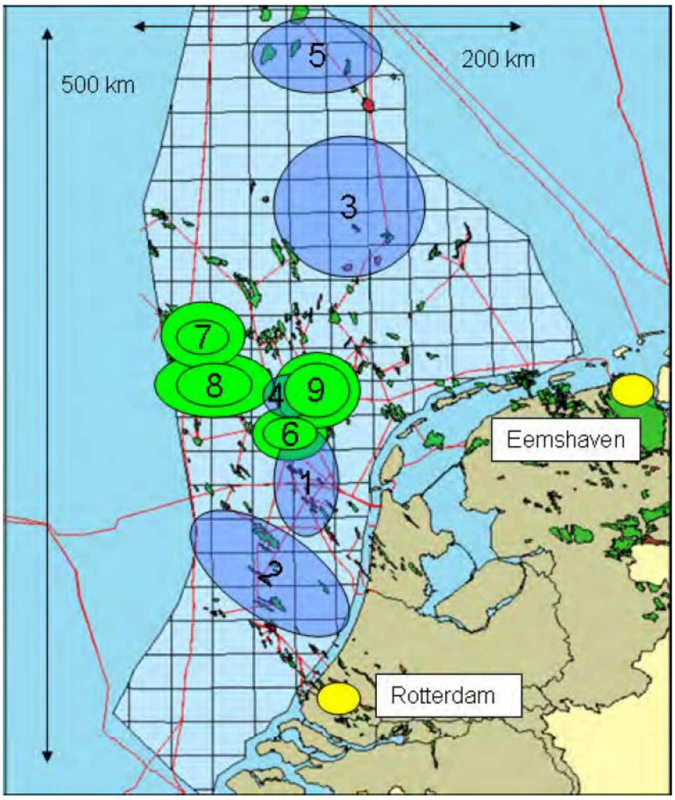


Figure 14. Location and (approximate) size of high-capacity offshore storage options for CO2. Green: gas fields and gas field clusters. Blue: saline formations. Source: (TNO, 2012)

[5] https://www.globalccsinstitute.com/publications/what-happened-barendrecht (accessed 18.09.2018)

Table 1 Overview of evaluated CO_2 storage sites in the DCS (TNO, 2012)

Depleted gas fields						
Field	**Capacity (Mt)**	**Plateau injection rate (Mtpa CO_2)**		**Distance from Den Helder (km)**	**Overall complexity and risk**	**Minimum development time**
K14/15 (#6)	165 (54 for K15-FB)	3 [15-20 years] 6 [5-10 years] 9 [5 years]		60	Low – multiple fields and aging infrastructure, but low well integrity risks; single operator and well-known geology	6 years
K04/05 (#7)	140 (40 for K05a-A)	2 [19 years] 3 [12 years] 5 [6 years]		120	Low – Although multiple fields relatively modern infrastructure; late availability allows learning from earlier projects	6 years
K07/08/10 (#8)	195 (130 for K08-FA)	3-6 [20+ years] 6-12 [10+ years] 9-18 [5+ years]		100	Moderate – multiple fields and ageing infrastructure, but relatively few blocks account for most capacity; several old, abandoned wells	6 years
L10/K12 (#9)	175 (125 for L10-CD)	6 [17 years] 9 [10 years] 12 [4 years]		50	High – several risk factors identified	> 6 years
Saline aquifers						
Saline formation	**Capacity (Mt)**	**Injectivity estimate (Mtpa CO_2)**	**Overall uncertainty**	**Distance from Den Helder (km)**	**Identified issues**	**Minimum development time**
Q1 - Lower Cretaceous (#1)	110 - 225	up to 10 Mtpa	Medium (A/B)	40	Well integrity; possible re-use	5 years
P, Q - Lower Cretaceous (#2)	360	up to 10 Mtpa	High (B)	60	Interference with hydrocarbon production	6-7 years
F15, F18 – Triassic (#3)	650	1-3	High (B)	150	Interference with hydrocarbon production; overpressure; low permeability	6-7 years
L10, L13 – Upper Rotliegend (#4)	60	5	High (B)	50	Interference with hydrocarbon production	6-7 years
Step graben – Triassic (#5)	190	1-3	High (B)	200	Interference with hydrocarbon production; low permeability	6-7 years

Minimum development times were estimated on the basis of a preliminary site development plan, taking into account the required steps (pilot wells, injectivity tests etc.) that need to be taken to go from a feasibility study to installing the required facilities and injecting CO_2 into the formation.

For more details on the outcome of the TNO review from 2012 see Appendix A.

3.2 Neighboring countries

Projected cumulative CO_2 emissions over 40 years from large point sources (suitable for CCS) were compared in a 2011 study with conservative estimates for the CO_2 storage capacity of Germany and several of its neighboring countries (Samuel Höller, 2011). Based on the currently available information on saline aquifer formations, and the conservative assumptions used for these estimates, Norway clearly stands out as having the largest potential for CO_2 import, followed by the UK.

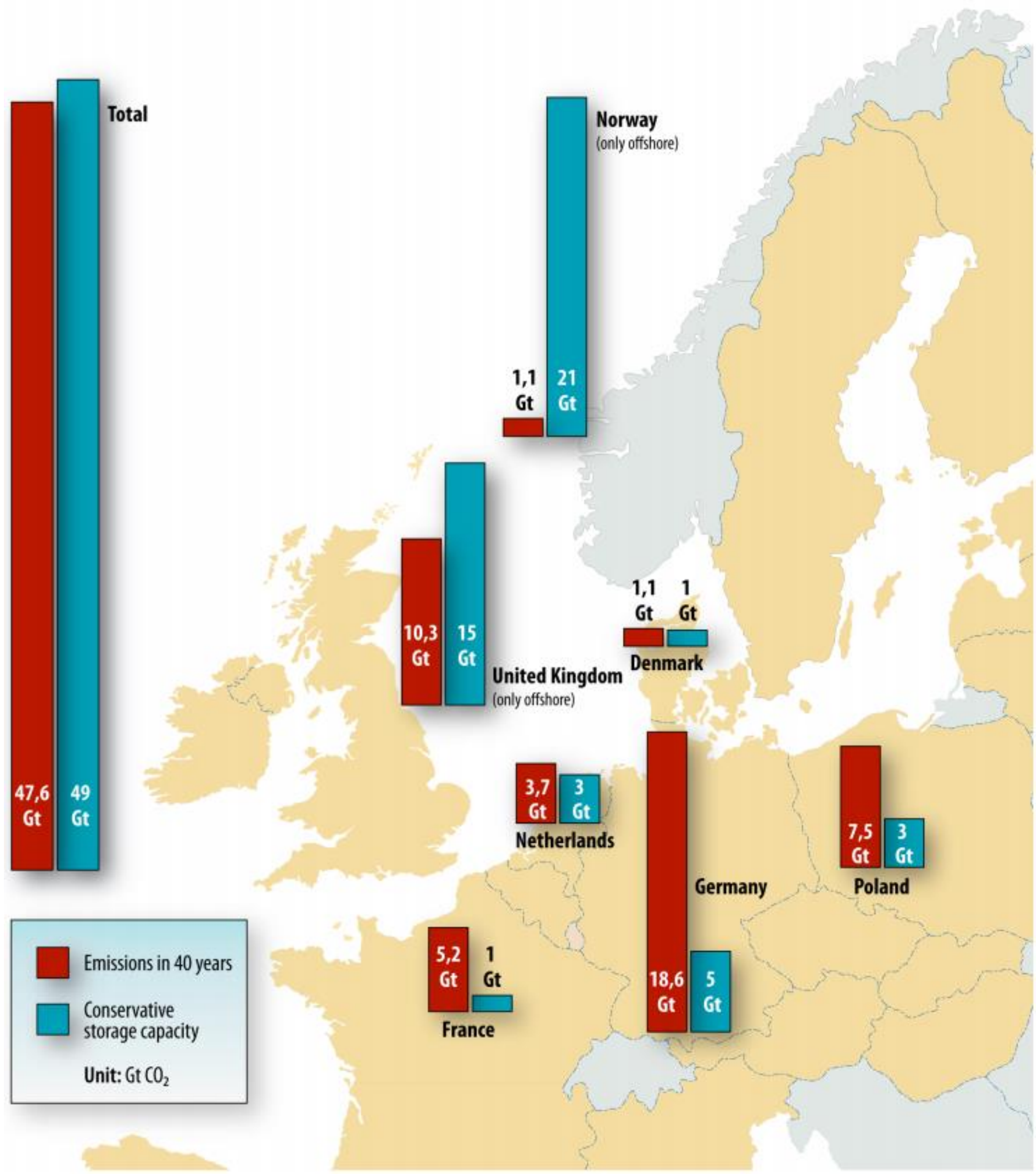


Figure 15. Overview of conservative capacity estimates for CO_2 storage in Germany and neighboring countries, compared with 40 years emissions from large point sources. Source: (Samuel Höller, 2011)

The authors used the following volumetric approach for estimating CO_2 sequestration capacity in saline aquifers:

$$m_{CO_2,effective} = V_b \cdot n/g \cdot \phi \cdot traps\% \cdot \rho_{CO_2} \cdot E$$

Where

m_{CO_2}	gravimetric storage capacity, theoretical or effective, [kg]
V_b	bulk volume of the potential formation, [m^3]
Φ	porosity, [%]
n/g	proportion of sediment structures with porosity and permeability suitable for absorbing CO_2 (net-to-gross ratio), [%]
traps%	proportion of traps in the total volume, [%]
ρ_{CO_2}	density of the CO_2, [kg/m^3]
E	efficiency factor, [%]

The efficiency factor *E* takes into account the effect of water displacement and compressibility, because the available pore volume is water-saturated so only a small percentage can be filled with CO_2. These estimates are conservative with regard to the assumptions made for estimating the efficiency factor – the authors used 0.01%, 0.1% and 1% for the min/base/max estimates. The results are compared with previously published estimates in the figure below:

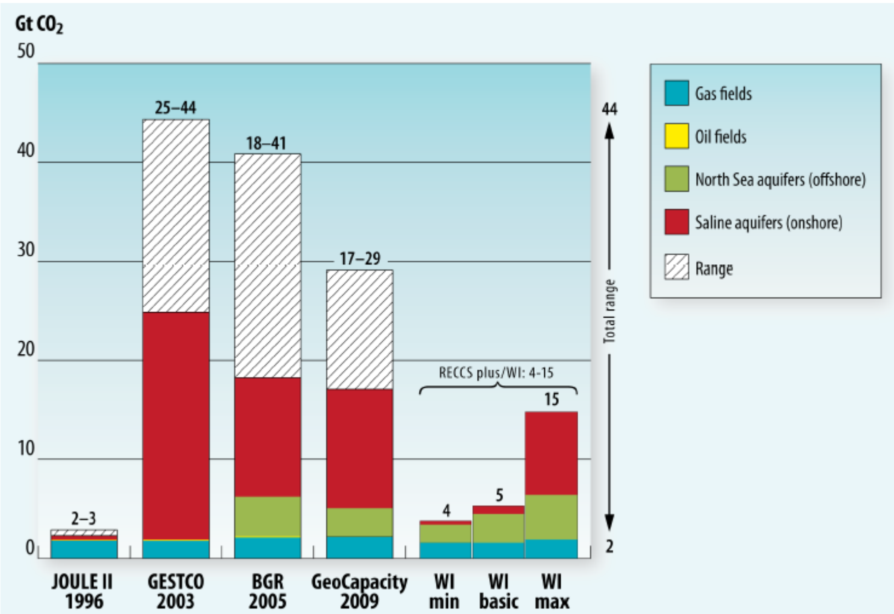


Figure 16. Overview of different CO_2 storage estimates for Germany. Source: (Samuel Höller, 2011)

Depleted oil & gas fields are well characterized and allow for accurate estimates of potential CO_2 storage capacity. For saline aquifers the ranges of capacity estimates can be very broad and more practical experience with CO_2 injection is needed to reduce uncertainty.

4 CCS COSTS AND CONSIDERATIONS

4.1 CO_2 capture

Estimating CO_2 capture costs is not part of the scope of this deliverable. A cost estimate from literature for CO_2 capture costs is included for the sake of comparing the different cost components in the overall CCS chain. A study from 2011 by the Zero Emissions Platform (ZEP) evaluated CO_2 capture costs for coal-fired power plants, for the three different options:

- Post-combustion CO_2 capture
- Integrated gasification combined cycle (IGCC) with CO_2 capture
- Oxy-fuel firing with CO_2 capture

According to this study, CO_2 capture costs are in the range of 35-60 €/ton of CO_2 captured for existing technology and could decrease to 30-35 €/ton for configurations optimized for CCS:

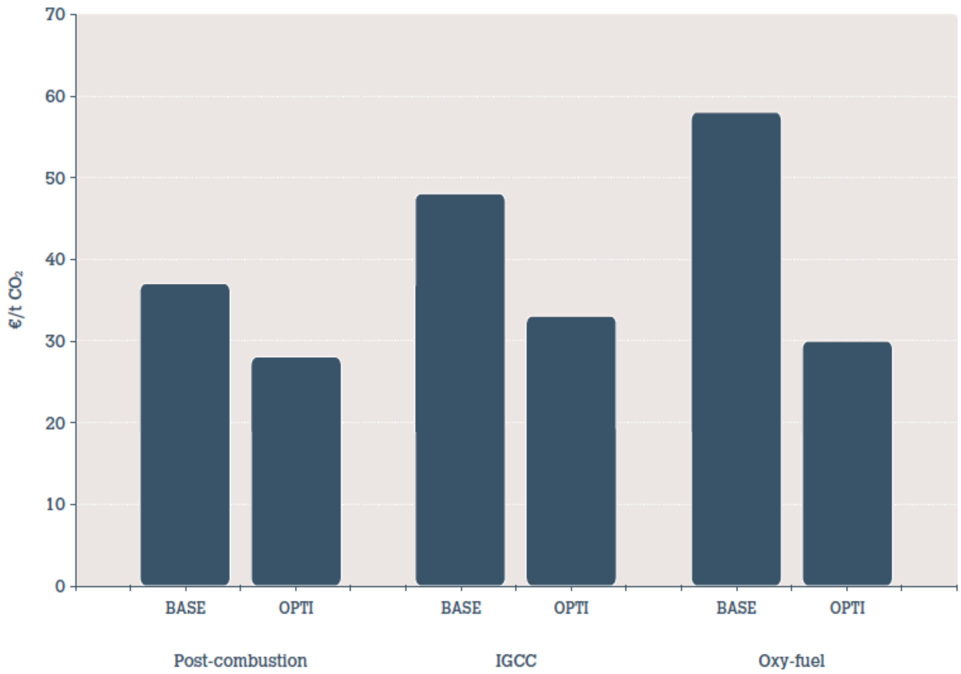


Figure 17. Estimated CO_2 capture costs for a coal-fired power plant, comparing current technology with future configurations optimized for CCS. Source: (ZEP, 2011)

Capturing CO_2 from coal fired and natural gas-fired power plants can remain a viable strategy for the energy transition if the levelized cost of electricity (LCOE) of these units, including CCS, can be reduced to remain competitive on the electricity market. Overall costs could rapidly decrease according to the 2011 report published by ZEP, under the assumption that implementing CCS projects will decrease costs as a result of technology maturation (see *Figure 18*). In The Netherlands, coal-fired power plants are scheduled to be shut down between 2024 and 2030 but CO_2 captured from a power plant in Germany or Belgium could be transported and sequestered via the Dutch CCS network. Natural gas-fired power plants are expected to remain operational, albeit mainly for peak-power production and to compensate when renewable generation doesn't match demand. This poses a challenge, as the LCOE and cost of CO_2 abatement both increase with decreasing operating hours.

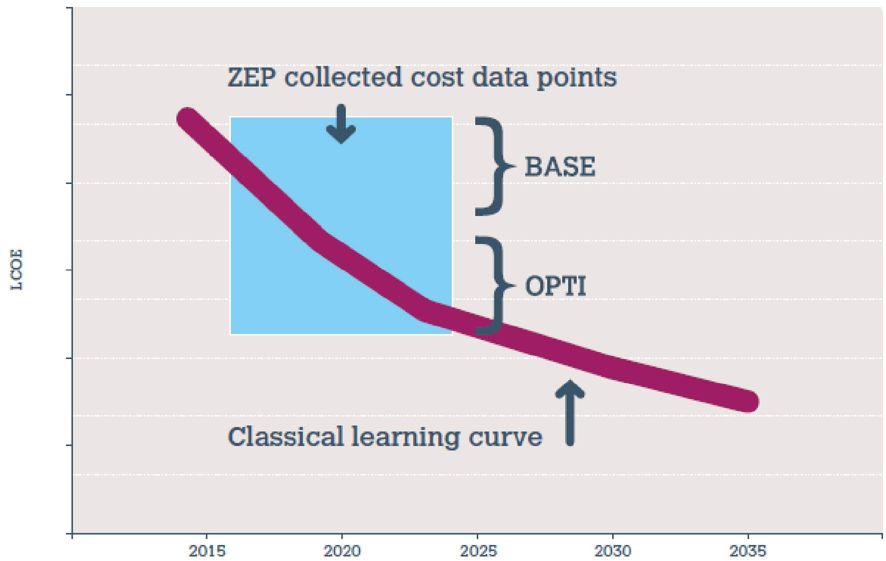


Figure 18. The LCOE of coal and NG power plants with CCS is expected to decrease, based on ZEP data collected for base case (BASE) and CCS optimized (OPTI) power plants with CO_2 capture. Source: (ZEP, 2011)

4.2 CO_2 transport

Transporting CO_2 by pipeline is the most technically mature step in the CCS chain. The IEAGHG commissioned Ecofys and SNC Lavalin to establish a reference manual for CO_2 pipeline infrastructure. (IEAGHG, 2014) For the design and operation of CO_2 pipelines DNV issued a dedicated technical standard (DNV, 2010), that supplements existing technical standards for pipeline transport of fluids (*e.g.* ISO 13623 and ASME B31.4).

From an infrastructure point of view, CO_2 pipeline transport is in most aspects comparable to natural gas networks. Overall costs are typically higher for CO_2 compared to natural gas though, due to the following technical requirements (IEAGHG, 2014):

- CO_2 depressurization characteristics dictate the use of crack arrestors
- The carbon steel grade needs to be resistant towards brittle fracture because CO_2 can reach very low temperatures when expanded
- CO_2 suppliers have to deliver at specified conditions which are in general:
  - 95% purity
  - water content between 50-840 ppmv, depending on region
  - temperature and pressure according to single dense phase transport (liquid or supercritical)
- Installation of ESD (emergency shut-down) valves is required to limit CO_2 release in case of leakage
- Venting procedures need to include provisions for lofting and dispersing released CO_2
- Gaskets and other non-ferrous materials must be resistant to deterioration in presence of CO_2

On land and over short distances, CO_2 can be transported in gas phase. For example, for the OCAP project near Rotterdam that delivered CO_2 captured from industrial sources to nearby greenhouses, a gas phase pipeline with a starting pressure of ~20 bar is used. (EBN, Gasunie, 2017) For offshore pipelines and over long distances, it is much more effective to transport CO_2 in single dense phase, and a safety margin is used to avoid partial vaporization and two-phase flow conditions:

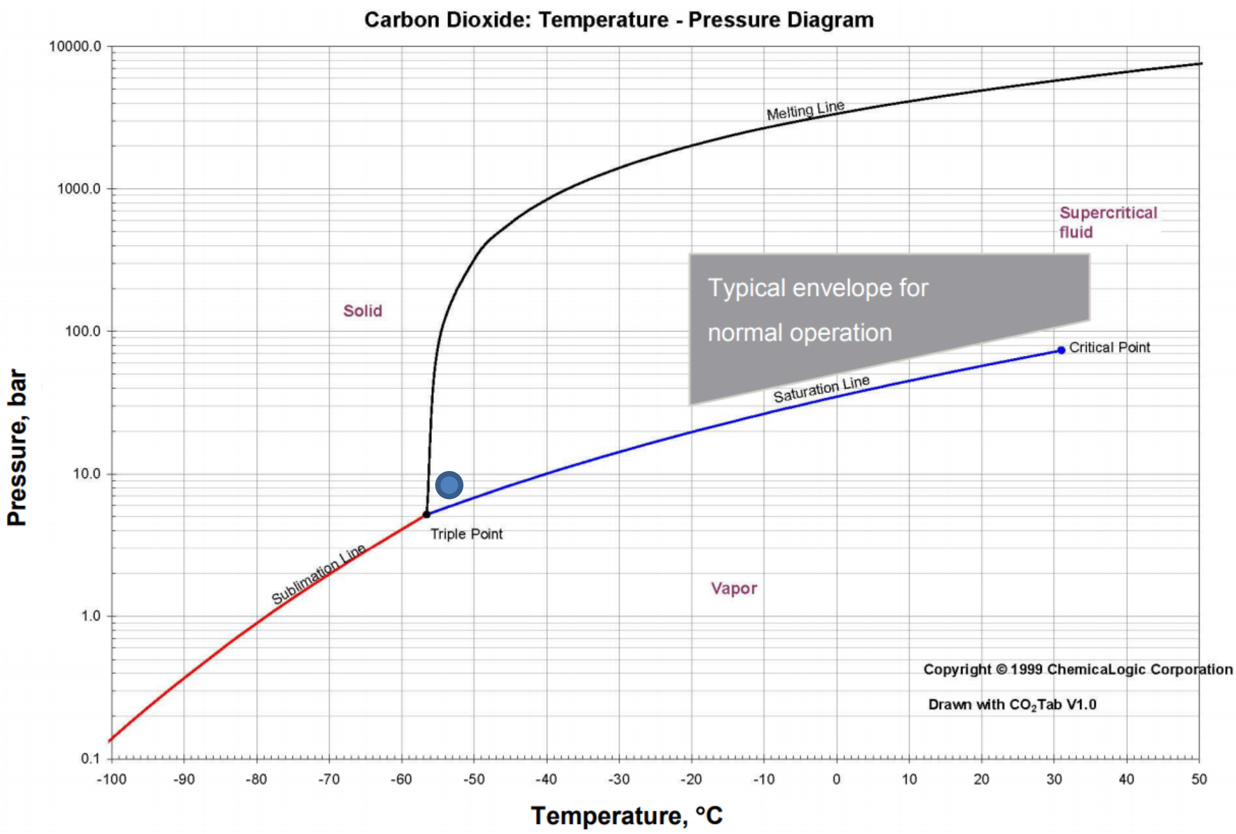


Figure 19. Phase diagram of CO_2 and typical operating region for long distance transport. Source: (DNV, 2010) Expected conditions for CO_2 transport by ship (marked in blue) are < -50°C at a pressure of 7-9 bar (TNO, 2016)

Cost optimization is required for long-distance CO_2 transport pipelines to find the right compromise between pipeline diameter (affecting pipeline cost and pressure drop per km) and the cost of pumping or recompression stations. The optimal pressure drop for liquid CO_2 transport is roughly 0.15-0.45 bar/km for mass flows of 100 kg/s (~3.15 Mtpa) or larger. (Knoope, 2015)

A table is given in the recent EBN & Gasunie report as an indication for the required diameter, aiming for a low average pressure drop of 0.1 bar/km, for different capacities of offshore pipelines:

Table 2 Example diameters required for large capacity long distance pipelines (EBN, Gasunie, 2017)

Pipeline capacity, distance of >100 km	Mass flow rate [kg/s]	Diameter [inch]	Average velocity [m/s]	Average pressure drop [bar / km]
5Mtpa, long distance	159	18	1	0.1
10Mtpa, long distance	317	24	1.1	0.1
20Mtpa, long distance	634	32	1.3	0.1
30Mtpa, long distance	951	36	1.5	0.1

CO_2 transport for CCS is the main subject of the PhD thesis of M. Knoope – *"Costs, safety and uncertainties of CO2 infrastructure development"*, published as part of the CATO-2 research program. The thesis thoroughly addresses the techno-economical aspects of CO_2 transport by pipeline and ship, together with risk mitigation for potential CO_2 releases and broader considerations for CO_2 infrastructure. The author presents a detailed review of existing models for estimating CO_2 pipeline costs and proposes a new cost model (see Chapter 3 of the thesis). Results for the estimated investment cost per km of pipeline as a function of pipeline diameter are shown in *Figure 20*.

This trend gives a first indication of onshore pipeline costs, for a typical grade of steel and standard terrain, over a sparsely populated area. The tool developed by Knoope has broader scope and can be used to determine cost-effective configurations by optimizing for inlet pressure, pipe diameter, steel grade / pipe thickness and number of pumping stations.

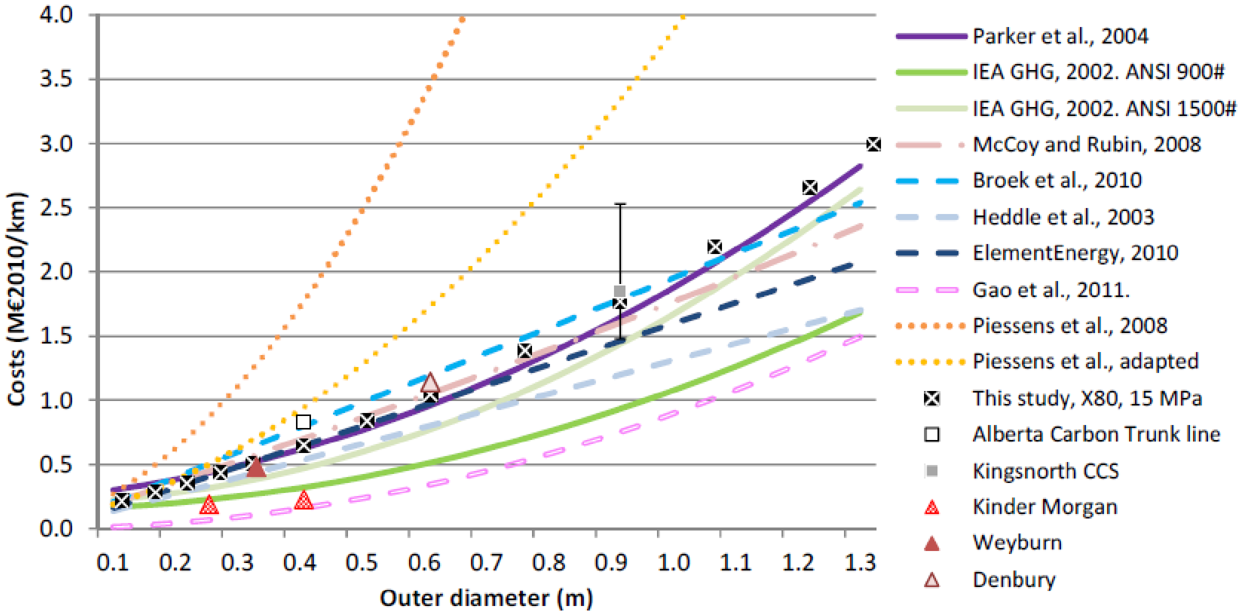


Figure 20. Comparison of the new pipeline cost model with cost models given in literature and cost estimations for planned and existing CO2 pipelines (Knoope, 2015)

Other ways of transporting large volumes of CO_2 (for CCS purposes) on land, by truck or rail for example, are not cost-effective. For offshore transport on the other hand, using ships is a viable alternative. Shipping costs are far lower than road/rail and offshore pipeline costs can be a factor 5 or more higher than onshore pipeline costs, depending on water depth and seabed topography.

CO_2 transport by ship is already used commercially for the food industry. Transporting CO_2 by ship for offshore CCS is technically feasible, but the offshore offloading interface between ship and injection well is seen as the key towards a cost-effective chain. (TNO, 2016) Shipping is expected to be more cost effective compared to offshore pipelines if the storage location is far away from shore, even more so if the seafloor topography is very rough. Transporting CO_2 by ship can also be an enabler of early large-scale CO_2 capture projects by providing flexible transport from dispersed and relatively low volume CO_2 sources to a distant oil field (if used for EOR), a depleted gas field or saline aquifer for sequestration. Another possible advantage is that ships do not lock in capital for a project in the way dedicated pipelines do – if a field is saturated or an emitter shuts down, the ships can be re-used to transport CO_2 for other projects.

Transporting CO_2 by ship for offshore storage is addressed in the TNO report *"Transportation and unloading of CO_2 by ship - a comparative assessment"*, published in 2016 within the CATO-2 program. Sixteen scenarios with different reservoir characteristics were used for the techno-economical evaluation, covering the range of possible North Sea storage locations:

Table 3 Subsurface conditions of the relevant scenarios, giving well depth (true vertical depth, TVD), initial reservoir pressure and temperature P_{res} and T_{res}, permeability k and allowable pressure increase dP. Source: (TNO, 2016)

Case	Field	TVD [m]	P_{res} [bar]	T_{res} [°C]	k [mD]	dP [bar] @100 kg/s
1a 1b 1c 1d	Saline formation, 100 mD	1000 2000 3000 4000	101 201 301 401	43 74 105 136	100	3.96 4.20 4.33 4.46
2a 2b 2c 2d	Saline formation, 1000 mD	1000 2000 3000 4000	101 201 301 401	43 74 105 136	1000	0.40 0.42 0.43 0.45
3a 3b 3c 3d	Gas well 20% of hydrostatic pressure	1000 2000 3000 4000	20.2 40.2 60.2 80.2	43 74 105 136	100	23.05 13.56 10.76 9.59
4a 4b 4c 4d	Gas well 50% of hydrostatic pressure	1000 2000 3000 4000	50.5 100.5 150.5 200.5	43 74 105 136	100	8.15 4.98 4.98 4.58

Reservoir characteristics affect the pressure and temperature at which CO_2 injection is carried out, therefore also the required equipment and corresponding duties. Different configurations were evaluated to compare direct injection from the ships with injection from a dedicated platform. Liquefaction costs upstream of the ship loading facility were not taken into account.

For CO_2 shipping the primary CAPEX component are the ships themselves. Based on available information on commercial shipping, data from literature and interviews with industry stakeholders, the following conservative estimates were used in the above-mentioned study for ships with different capacities (all using cryogenic tanks at 7-9 bar pressure, similar to LPG transport):

Table 4 CAPEX estimates for CO_2 transport ships. Source: (TNO, 2016)

CAPEX					
Category	**Variant**	**Unit**	**Low**	**High**	**Mid-point**
Ship	10 kt CO_2	M€	50	60	55
	20 kt CO_2	M€	63	73	68
	30 kt CO_2	M€	75	85	80
	50 kt CO_2	M€	100	110	105

These values do not include the additional equipment items required on board to condition and pressurize the CO_2, in the case of direct injection from ship to well. The other major CAPEX component is the infrastructure required at the offloading and injection site: a suitable mooring system and an offshore platform if used, with or without temporary storage.

Three shipping distances were used to calculate transport costs – 400km (covering the entire DCS area), 800km and 1200km (enough to reach saline aquifers off the coast of the UK and Norway):

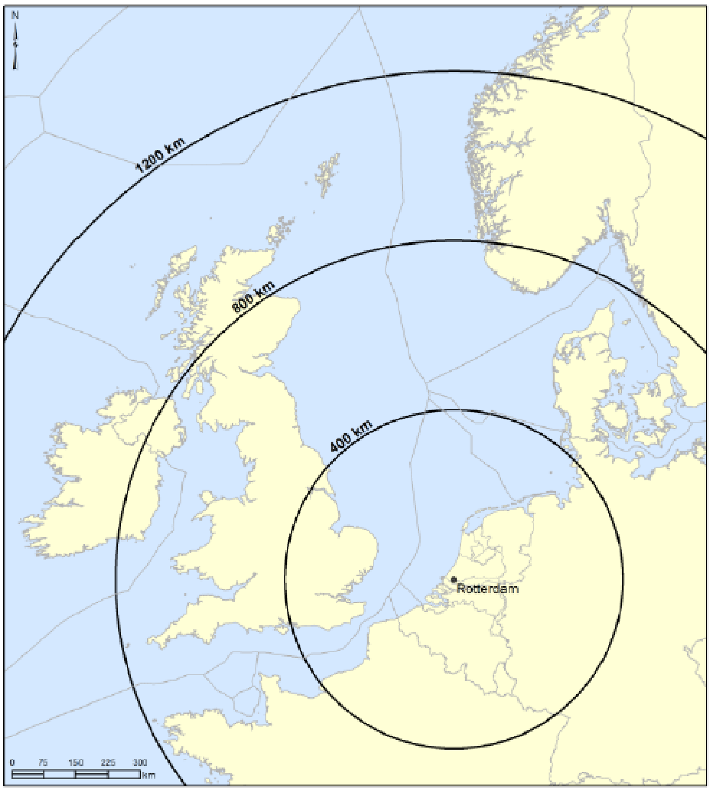


Figure 21. (CO_2) shipping distance from Rotterdam – 400, 800 and 1200 km radii. Source: (TNO, 2016)

The cost of long offshore pipelines varies almost linearly with distance (assuming uniform seabed topography), whereas for shipping the impact of distance on CAPEX is far smaller. For small scale projects and long distances, transporting CO_2 by ship is expected to be more cost-effective:

Distance km	180	500	750	1500
Onshore pipeline	5.4	n. a.	n. a.	n. a.
Offshore pipeline	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

Figure 22. Cost estimates (€/ton of CO_2 transported) for CCS projects with a 2.5 Mtpa capacity (ZEP, 2011)

According to the TNO study, increasing the shipping distance from 400km to 1200km only increases the overall unit costs (€/ton of CO_2) by 20-35%, depending on the other characteristics of each case. A similar relation between distance and cost can be seen in the results of the ZEP study.

As economy of scale has a stronger influence on transport costs for pipelines than for ships, for large scale projects shipping is only expected to be competitive at very long transport distances:

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

Figure 23. Cost estimates (€/ton of CO_2 transported) for a large scale CCS network with 20 Mtpa capacity (ZEP, 2011)

Besides capacity, reservoir characteristics and distance, overall transport costs by ship are also affected by the offloading and injection system. Three main options were considered:

1. Direct injection from the ships

   This option reduces the CAPEX required for offshore infrastructure but was found to be overall the least cost-effective option in nearly all the scenarios that were evaluated.

   Another disadvantage of direct injection from ships are risks associated with transient well conditions, caused by frequently interrupting and restarting the flow of CO_2 towards the reservoir. In this respect, injection from a platform with temporary storage is preferred as it offers the most stable operating conditions.

   Each ship would have to be fitted with CO_2 conditioning and injection equipment. The maximum injection rate is limited to 200 bar (upper limit for flexible transfer hoses).

2. Injection from a platform

   CAPEX for offshore infrastructure will be higher but this configuration allows for a higher injection rate. Also, less equipment is required on individual vessels because conditioning and injection equipment will be on the platform.

3. Injection from a platform, with dedicated storage

   Having dedicated CO_2 storage available reduces offloading time and therefore also reduces the total number of ships required.

Figure 24 on the following page summarizes the results of the study, for the 16 reservoir cases, three different injection options and the three transport distances that were considered.

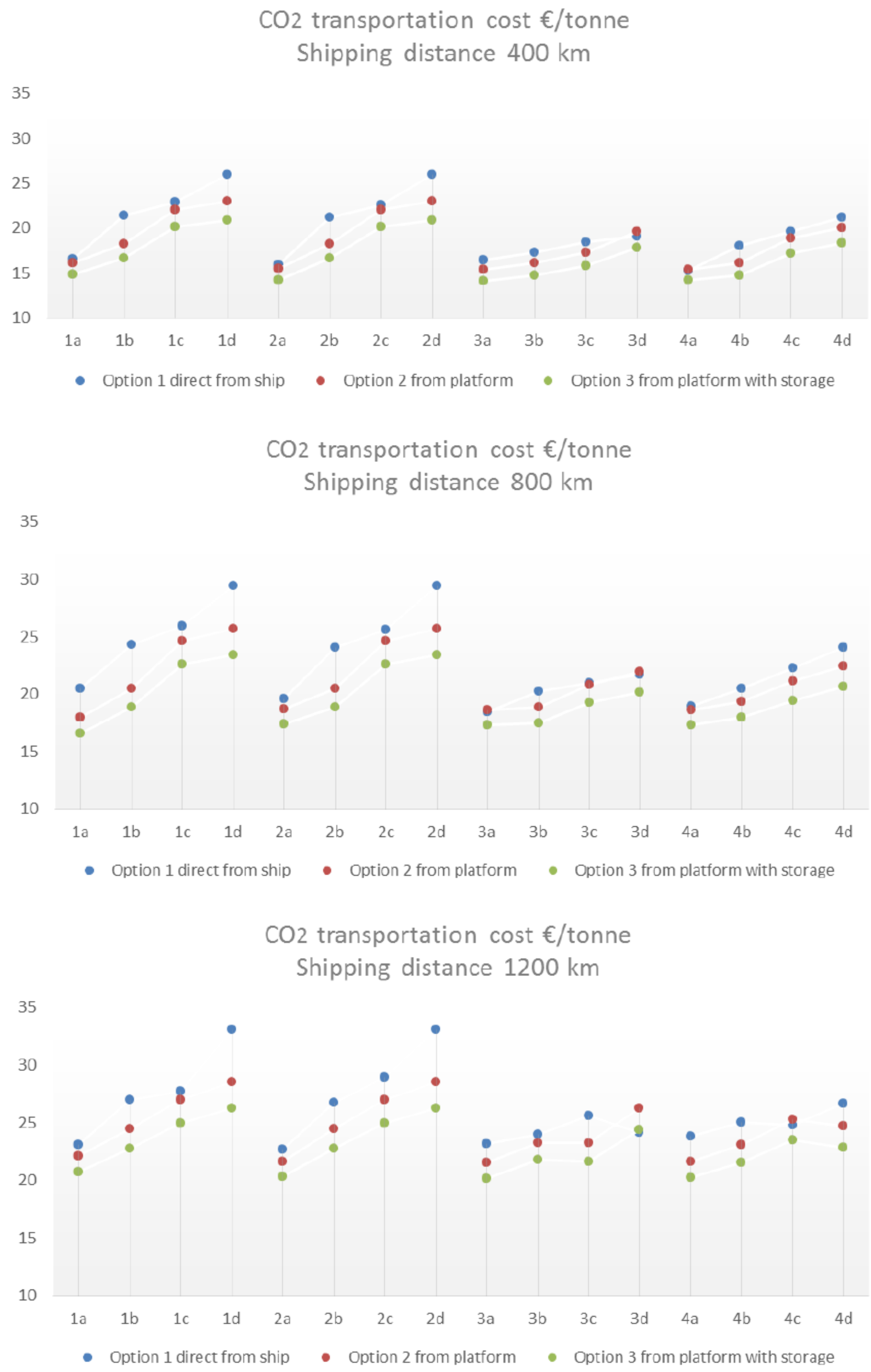


Figure 24. CO_2 transport cost for the different reservoir cases and shipping distances. Source: (TNO, 2016)

The estimated costs per ton of CO_2 transported are higher compared to the 2010 ZEP study. The calculations were based on a single injection well, with the annual amount of CO_2 transported and stored determined by the theoretical maximum injection rate (the estimates range from 2 to 5 Mtpa, higher compared to the 0.8 to 2.5 Mtpa range used in the 2010 ZEP study). This depends on reservoir characteristics and the design margins required to avoid hydrate formation and fractures in the reservoir. In practice, multiple injection wells can be drilled into the same formation, which would increase the maximum injection rates per reservoir and result in lower costs per ton of CO_2.

Also, the CAPEX estimates used in the TNO study are 60-90% higher compared to literature references (see *Figure 21* below), which could in turn be too optimistic. More accurate cost estimates will be available once larger liquid CO_2 transport ships are built or converted from LPG carriers.

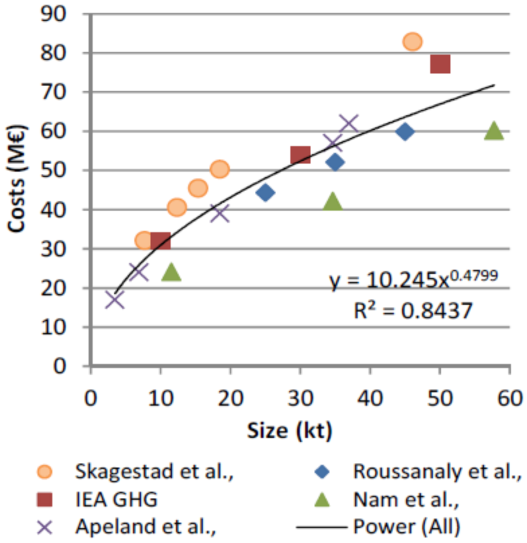


Figure 25. Literature references for CAPEX of CO_2 transport ships (Knoope, 2015)

Apart from CAPEX and OPEX, ABEX (abandonment expenditure) should also be estimated for a thorough comparison of transporting CO_2 by ship versus offshore pipelines are listed below:

Table 5 CAPEX, OPEX and ABEX elements for CO_2 pipelines and ships (Knoope, 2015)

	CAPEX	OPEX	ABEX[a]
Pipeline	- Capture and compression - Pumping station - Offshore pipeline - Platform	- Fixed operation and maintenance (O&M) costs capture plant - Variable capture costs - Electricity (pumps) - O&M costs pipeline - O&M costs platform	- Capture and compression plant - Pumping station - Offshore pipeline - Platform
Ship	- Capture and compression - Liquefaction unit - Temporal storage - (Un)loading equipment - Ship including cargo pumps - Floating vessel with conditioning equipment	- Fixed O&M costs capture plant - Variable capture costs - Electricity (liquefaction) - O&M costs ship - Fuel oil for ship - O&M costs floating vessel and conditioning equipment - Conditioning energy	- Capture and compression plant - Liquefaction unit - Temporal storage - (Un)loading equipment - Ship - Floating vessel with conditioning equipment

a) ABEX can be negative if the residual value is higher than the costs of decommissioning.

Starting from the set of assumptions listed in Chapter 5 of her PhD thesis, M. Knoope reached similar conclusions, namely that transporting CO_2 by ship is expected to be more cost effective compared to offshore pipelines for small projects. The overall estimated transport and storage costs are comparable to those obtained in the 2010 ZEP study and the 2016 TNO study:

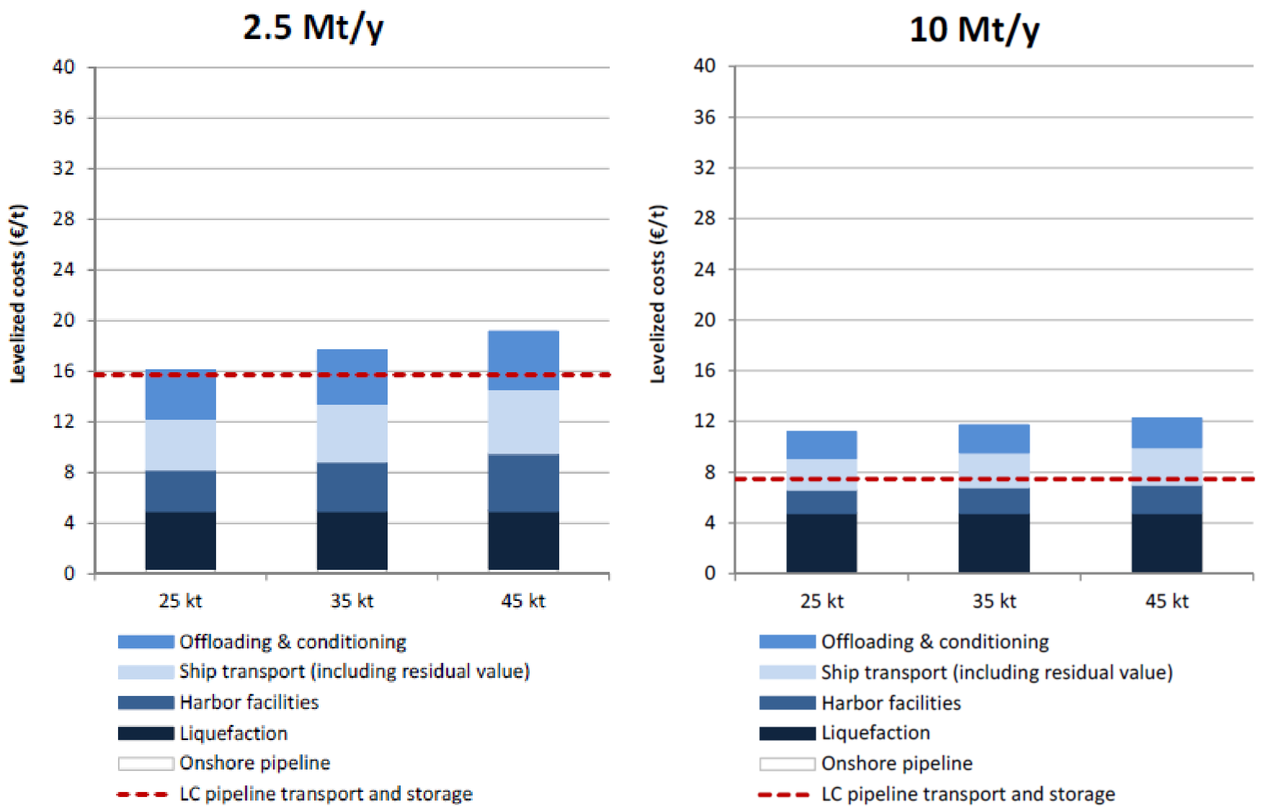


Figure 26. Estimated levelized cost of CO_2 transport and storage, comparing offshore pipelines (dotted line) with ship transport (bars), for a distance of 250km and two cases: 2.5Mt/y and 10Mt/y (Knoope, 2015)

Reviewing the cost estimates from the studies mentioned in this chapter shows how much variability can be expected in the unit cost of CO_2 transport. Distance and overall capacity are the most important factors affecting costs. It's also important to note that the costs presented here are based on discounted cash flow calculations over the entire lifetime of a project, so the overall discount rate resulting from the economic assumptions that are made will also strongly affect the unit cost.

For a single project with a capacity of 2.5 Mtpa CO_2 and short onshore/offshore transport distances (<250km), transport costs are expected to be about **15-20 €/ton of CO_2**. If the CO_2 is transported by ship to a remote (>1000 km away) offshore location, the costs are expected to increase to **25-30 €/ton of CO_2**. These estimates exclude CO_2 capture and offshore injection costs.

If large scale CCS projects are implemented for storage in the North Sea area, it's likely that a combination of pipelines and transport by ship will be used. Networks connecting various sources to a single or multiple sinks are an additional layer to the optimization problem, offering cost-saving opportunities versus point-to-point transport per project. This holds for long distance transport, due to economy of scale for trunklines and pumping stations, but either a single sink with a very large capacity or a network of sinks that are close to each other would be needed for storage. An onshore trunkline could also end at a ship loading point that connects multiple CO_2 sources to a distant offshore storage location.

Figure 27 below illustrates a possible CCS network, comprised of four source clusters and two large sinks. In this conceptual example, 10 Mtpa CO_2 are captured from a coal-fired power plant (with two units), 5 Mtpa CO_2 from a second coal-fired power plant with a single unit, and the remainder from natural gas-fired plants. All transport options listed previously (onshore/offshore pipelines and ships) are used to bring the captured CO_2 to a central collection point, from where a major offshore trunkline transports it to the final offshore storage location:

Figure 27. Possible configuration of a large scale (20Mtpa) CCS cluster (ZEP, 2011)

For the coal-fired and gas-fired power plants that are near the offtake location of the offshore pipeline in this example, estimated overall transport costs could be as low as **7-8 €/ton of CO_2** (based on the ZEP estimate for a 500km offshore pipeline + 1-2 €/ton of CO_2 for the 10km onshore/offshore connecting lines).

4.3 CO_2 sequestration

Depending on the selected reservoir and infrastructure configuration, offshore injection at the final destination can also be a large cost element. (see also 4.4 Overall costs) There is potential for significant savings by making use of existing offshore infrastructure, for instance retrofitting existing platforms above depleted gas fields with the equipment required for CO_2 injection.

However, most of the existing offshore infrastructure (platforms and wells) is scheduled to be decommissioned in the next two decades, as production from the corresponding fields declines and is halted. A masterplan was proposed by EBN for a coordinated effort to manage and reduce the costs of decommissioning activities. (EBN, 2016) There is an opportunity to save costs on both ends, by extending the lifetime of existing assets and retrofitting offshore installations for CO_2 injection in depleted gas fields. There is a time gap however between platforms becoming available for other possible uses and the start of large scale offshore CO_2 injection. To bridge this gap, agreements have to be made early on with the relevant exploration & production companies, and other relevant stakeholders such as permit authorities. Offshore infrastructure would need to be adapted, reconditioned / recertified and in several cases temporarily preserved ('mothballed').

The cost reduction obtained by reusing existing assets was evaluated in a 2010 study by the Zero Emissions Platform. In addition to infrastructure savings, using legacy oil & gas assets can in principle eliminate costs related to characterizing the storage reservoir (modeling/logging, seismic surveys, injection testing, exploration wells and permitting). This is reflected in the cost breakdown shown below, made for a medium case CO_2 storage scenario (66 Mt CO_2 stored in total – an average of 1.65 Mt CO_2 injected annually over a period of 40 years):

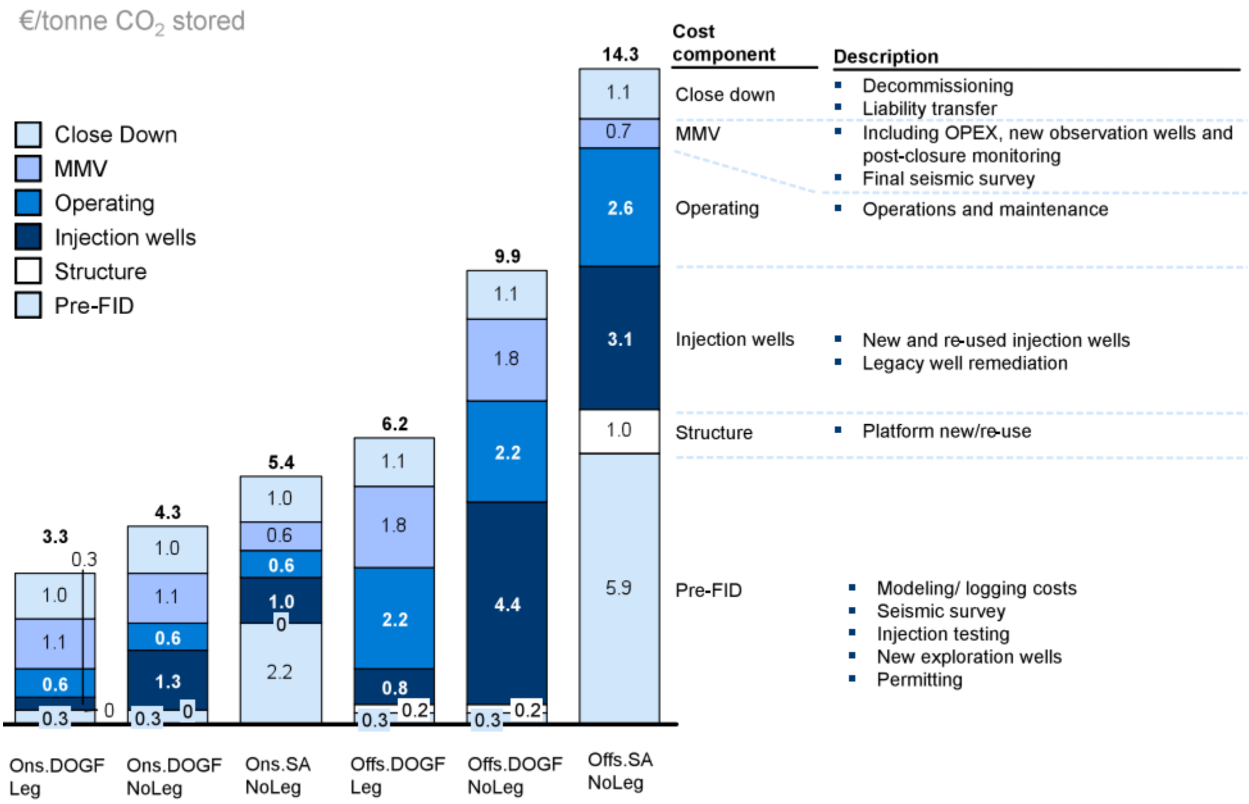


Figure 28. Breakdown of cost components for different storage options – medium cost scenario (ZEP, 2010)

A Low cost case (200 Mt CO_2, high well injectivity, low liability costs) and a High cost case (40 Mt CO_2, low well injectivity, high liability costs) were also estimated and are summarized below for the six storage options considered:

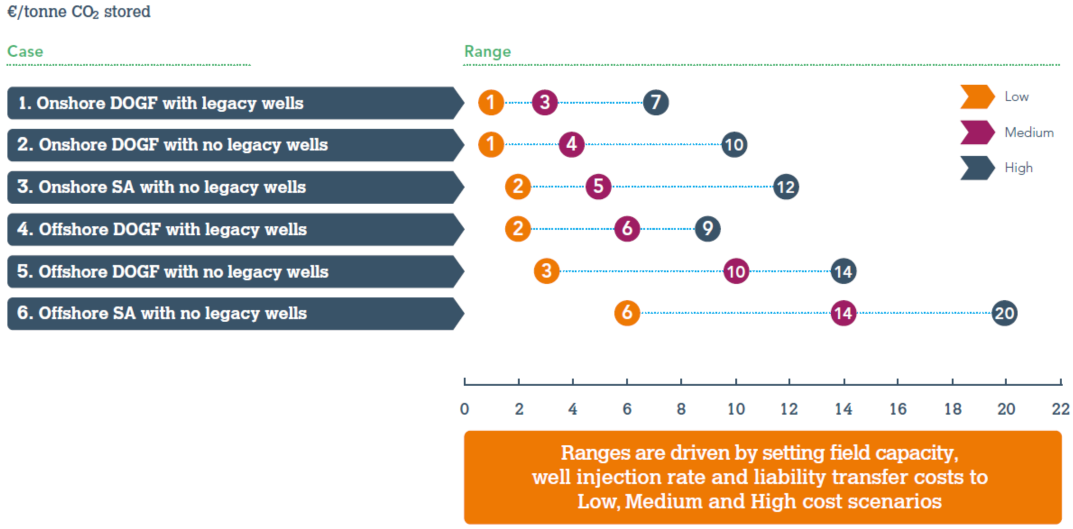


Figure 29. Storage cost per case, with uncertainty ranges; purple dots correspond to base assumptions (ZEP, 2011)

The sensitivity calculations performed as part of this study indicate that, within the project boundaries and assumptions that were made, the three most important factors for storage costs per ton of CO_2 are field capacity, well injection rate and field depth:

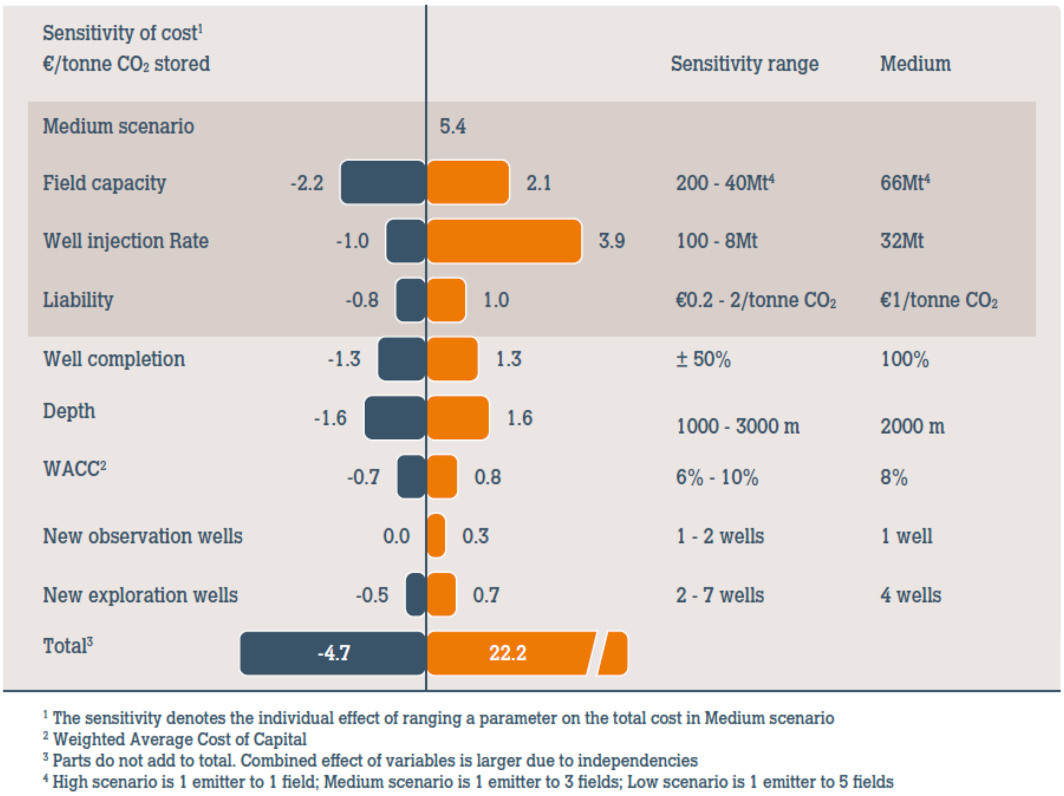


Figure 30. Illustration of sensitivities in the storage cost calculations for one storage case (ZEP, 2011)
The Well Injection Rate is expressed as total CO_2 injected over the entire period of 40 years, per well.

4.4 Combined transport and storage costs for integrated projects

A recent study by EBN and Gasunie (EBN, Gasunie, 2017) estimated overall CO_2 transport and storage costs, covering four different scenarios: Low (14 Mtpa), Mid (20 Mtpa) and High (30 Mtpa) cases with maximum reuse of existing infrastructure, and one more Mid case scenario (20 Mtpa) with greater investments in new offshore infrastructure. See *Table 6* below for details. In all scenarios, 5 Mtpa is already reached by 2023 with the remaining capture and storage capacity soon following and on stream by 2031-2032. Considering where the biggest emitters are concentrated, CO_2 in the Low and Mid scenarios is captured from large emitters in the Rotterdam, Zeeland and Ijmuiden areas, with collection points at Maasvlakte and Ijmuiden. For the High scenario a capture cluster for power generation at Eemshaven is added. The duration is 40 years, starting from 2019, and the costs per ton of CO_2 sequestered result from a discounted cash flow calculation for the overall project.

According to this study, the estimated overall CCS costs for CO2 that's locally emitted (within the territory of The Netherlands, concentrated in the Rotterdam HIC area) range between 8.9-11.4 € / ton CO_2 sequestered:

Table 6 Cost breakdown per scenario (EBN, Gasunie, 2017)

Costs, in M€	Reuse of existing infrastructure			Mid case 20 Mtpa (new infra)
	Low 14 Mtpa	Mid 20 Mtpa	High 30 Mtpa	
Mothballing	133	216	474	120
Injection	1499	2740	3382	4154
Offshore transport	740	764	1.404	764
Onshore transport	366	366	376	366
Onshore compression	1490	2072	3072	2072
Total costs	4229	6158	8707	7477
Mt CO_2 sequestered	476	654	964	654
UTC (€/ton CO_2)	**8.9**	**9.4**	**9**	**11.4**

These estimates support the conclusion also drawn in the ZEP study that deploying large scale CCS networks greatly reduces the unit cost per ton of CO_2 stored, compared to small scale source-to-sink connections.

The scenarios paint a perfect picture though: the entire network is evaluated at cost as a single project and different sources and sinks are connected at the right time to the newly built transport grid. In practice, planning and coordination on such a scale between the various parties involved could prove very challenging. The trunklines must be in operation to complete any of connections in the grid. If the biggest sources and sinks are not on stream first, because of poor planning or project delays, trunklines will be underutilized resulting in a much bigger transport cost per ton of CO_2.

To illustrate the complexity of this decision-making process, *Figure 31* on the next page shows the approach proposed by M. Knoope in her PhD thesis to determine an optimal configuration for connecting multiple sources and sinks in a CCS network.

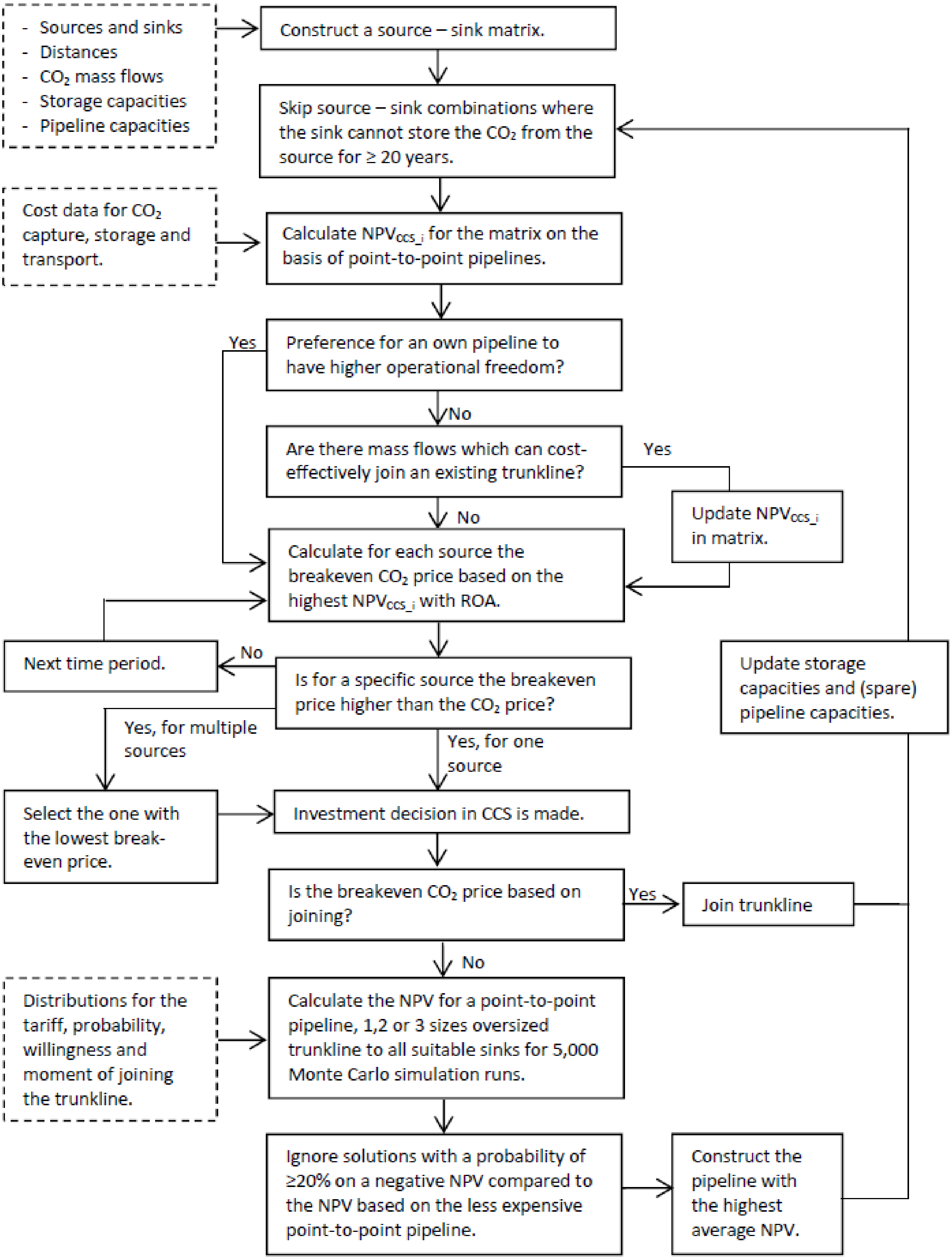


Figure 31. Flow diagram for selecting an optimal CCS configuration (Knoope, 2015)

The ZEP study also included a simple sensitivity check for offshore CO_2 transport pipelines, highlighting the importance of good planning for trunklines. Distance and CAPEX have a similar and almost directly proportional influence on the unit transport cost, but a reduction in pipeline utilization has a stronger effect. This factor is part of the denominator, so if a pipeline is used at 80% of nominal capacity, the corresponding cost per unit transported will be 25% higher. At 50% utilization the cost doubles and at a low utilization of just 20% the cost will be 5 times higher, and so on.

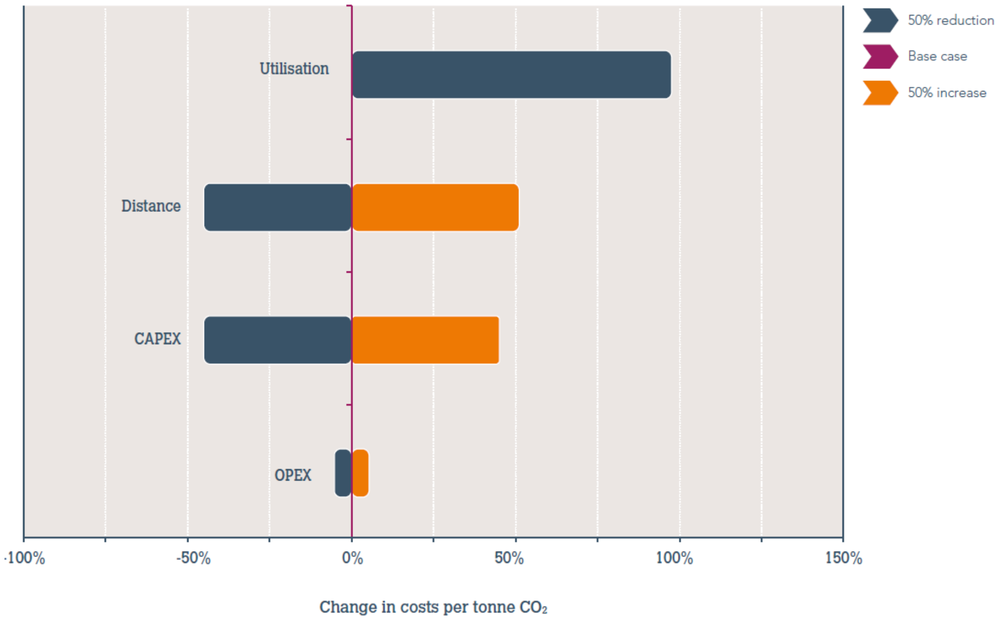


Figure 32. Sensitivity of four key factors on offshore pipeline costs, 10 Mtpa and 500 km (ZEP, 2011)

Despite all the challenges, developing large scale infrastructure appears to be the best way forward, considering all the topics addressed up to this point but primarily in terms of cost savings. With political and public support, and if planning and coordination difficulties can be overcome, the estimated cost savings are massive.

Adding up the previously mentioned estimates for transport and storage, the overall costs are expected to be in the range of 30-40 €/ton of CO_2 but can easily exceed 40 €/ton of CO_2 for a small scale project (2.5 Mtpa CO_2 or smaller). Combined with CO_2 capture costs at the source, the economic penalty for reducing CO_2 emissions is very large. Without significant political or market pressure, it seems highly unlikely that any of the major emitters would independently decide to invest in CCS under these conditions.

If developing a large scale CCS network in The Netherlands could indeed bring the transport and storage costs down to ~10 €/ton of CO_2, this option of reducing emissions becomes far more attractive. Cost reductions could also be achieved if joint compression stations are built to service multiple sources (for instance in the Rotterdam HIC area), and by dividing infrastructure maintenance and personnel costs between the parties involved.

Lastly, it's relevant to compare the overall costs of CCS with the price that emitters currently have to pay under the EU's Emissions Trading System (ETS) policy. The ETS was reformed in 2017[6], and this seems to have already impacted CO_2 prices - see *Figure 33* below for the long term trend:

Figure 33. Long term trend showing the recent increase in trading value for ETS (€/tonCO_2).

Source: ICE EUA futures via [Sandbag] and [Quandl]. Chart by Sandbag using [Highcharts]

CO_2 credits were trading below 10 €/ton for several years, mainly due to oversupply in the market. At an ETS price of emitted CO_2 above 20 €/ton, the trading scheme applies more pressure for coal-fired power generation and will stimulate energy efficiency measures in industry.

The current value is not high enough to incentivize decarbonization using CCS yet, but the price per ton of CO_2 emitted is projected to continue increasing. According to a recent study by Carbon Tracker published indicates the price could be even higher as 55 €/ton CO_2 by 2030.[7] CCS could then be an effective decarbonization option, if integrated large scale networks can be deployed and the costs of CO_2 capture decrease as a result of a learning curve from industrial projects. This concept is illustrated in the figure below, taken from the IEA's technology roadmap for CCS:

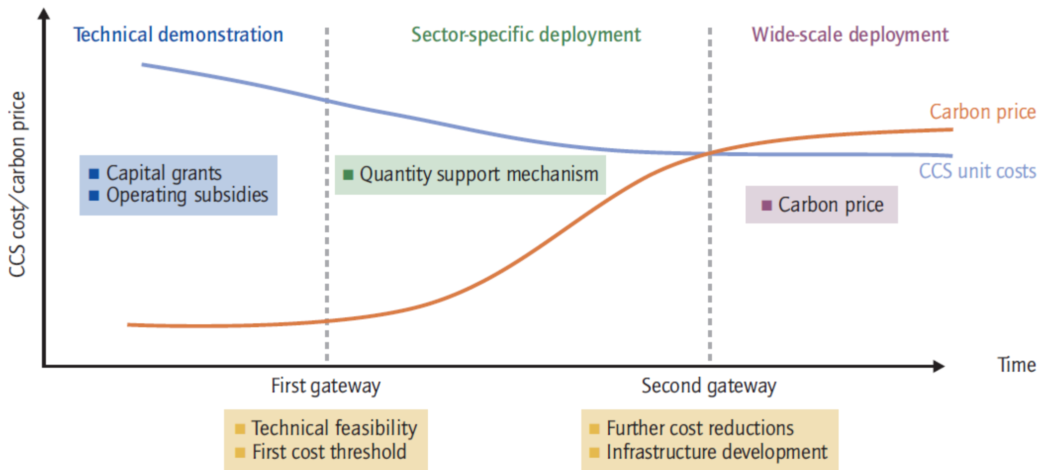


Figure 34. Policy gateways within a CCS policy framework. Source: (IEA, 2013)

[6] See https://www.carbonbrief.org/qa-will-reformed-eu-emissions-trading-system-raise-carbon-prices for a detailed coverage of changes made to the ETS (accessed on 21.09.2018)

[7] https://www.carbontracker.org/eu-carbon-prices-could-double-by-2021-and-quadruple-by-2030/ (accessed on 14.08.2018)

5 CO_2 UTILIZATION

This report focuses on CO_2 geological sequestration as the primary option to reduce CO_2 emissions resulting from industrial activity. In and of itself CCS does not generate economic value – rather it can be seen as a penalty imposed for instance on carbon-intense industry to mitigate the adverse impacts of climate change. A more elegant solution is to use the captured CO_2 as feedstock for valuable products, what is known as carbon capture and utilization (CCU). But this requires a large energy input, and viable applications are typically not in the same order of magnitude as that of CO_2 generation. If captured CO_2 can be partially used to make a high-margin product, smaller scale applications could still greatly improve the overall economics of a CCS project.

Some of the most promising products for which CO_2 is a potential feedstock are shown below in *Figure 35*, indicating the oxidation state of the carbon atom and the types of bonds that need to be formed. The carbon atom in CO_2 is in its highest oxidation state (+4), which is a very stable and low energy state. Converting the CO_2 to other molecules implies reducing the carbon atom to lower oxidation states, with the exception of carbonates and urea. As a result, most of the processes that use CO_2 as feedstock are intrinsically highly energy intensive.

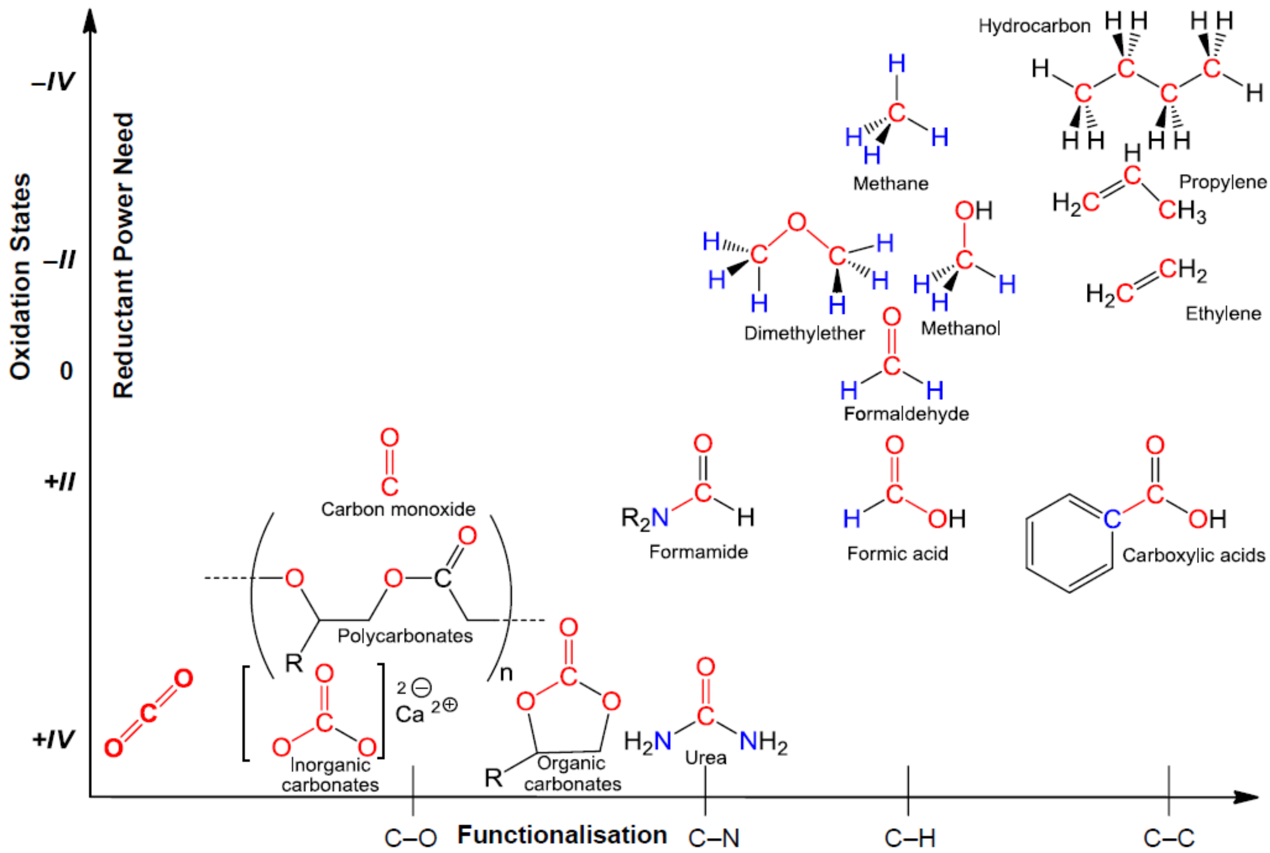


Figure 35. Products obtainable from CO_2 utilization reactions. Source: (E. A. Quadrelli, 2015)

Thoroughly reviewing CO_2 utilization is beyond the scope of this report, but it is important to address it because of the attention the topic is receiving, as well as its potential to improve the economics of CCS projects. CCU could support decarbonizing transport and industry on the long term, through the use of renewable energy to convert captured CO_2 into valuable fuels and chemicals. However, doing this will be hampered by the time and effort required to develop CCU technologies at industrial scale. This topic is widely researched within TNO and other institutes, and supported by EU research funding programs.

A recent TNO publication (TNO, 2018) describes in detail possible pathways for using CO_2 captured from cement manufacturing, for a range of products from the following five categories:

- Inorganic carbonates, such as calcium and potassium carbonates;
- Fuels, such as hydrocarbons, biodiesel, methanol and DME (dimethyl ether);
- Polymers, such as polycarbonates and polyurethanes;
- Chemicals, including both specialties such as organic carbamates, and bulk such as ethylene; and
- CO_2 as a product on its own, for greenhouses[8] or as food-grade CO_2.

For most of these utilization routes the source is not relevant, and the CO_2 could just as well be captured from a petrochemical process. To evaluate and compare the potential for each production route, the following criteria were used:

Table 7. Definition of CEMCAP metrics for evaluating CCU products (TNO, 2018)

Metric	Icon	Bad	Intermediate	Good
Product Market		Below 10 Mt/year	10-100 Mt/year	Above 100 Mt/year
Energy demand		Carbon oxidation state above 2	Carbon oxidation state between 0 and 2	Carbon oxidation state below 0
Technology Maturity		TRL < 5	5 ≤ TRL ≤ 7	TRL >7
Product price		Below 200 €/ton	200-500 €/ton	Above 500 €/ton

The outcome of the evaluation is summarized in *Table 8* on the following page.

[8] It should be noted that supplying captured CO_2 to greenhouses only leads to a partial reduction of emissions, since plants will only absorb a fraction of the CO_2 that is supplied to the greenhouse, and the rest is still emitted to atmosphere. However, emissions from burning natural gas to increase the CO_2 concentration inside greenhouses would be abated by using captured CO_2 instead.

Table 8. Overview of possible CCU products, evaluated in CEMCAP (TNO, 2018)

Product	Market	Energy demand	Maturity	Price
$CaCO_3$ (GCC)				
$CaCO_3$ (PCC)				
Aggregates				
Carbonated concrete				
Methanol				
DME				
Methane				
Ethanol				
Isopropanol				
Biodiesel from microalgae				
PPC				
Polyols				
Cyclic carbonates				
Formic acid				
CO_2 (food-grade)				
CO_2 (greenhouses, NL)				

A report published this year by SAPEA evaluates CCU technologies from the perspective of climate change mitigation. (SAPEA, 2018) Several frameworks are proposed to correctly assess the overall efficiency and impact of various CCU chains. The report acknowledges the potential that CCU has for the production of certain molecules, such as urea, salicylic acid and carbonates. However, the authors stress the importance of carefully evaluating each step in the chain (see *Figure 36* below), to account for all the energy input that's required per ton of CO_2-based product, and to consider the environmental impact of product utilization and waste disposal.

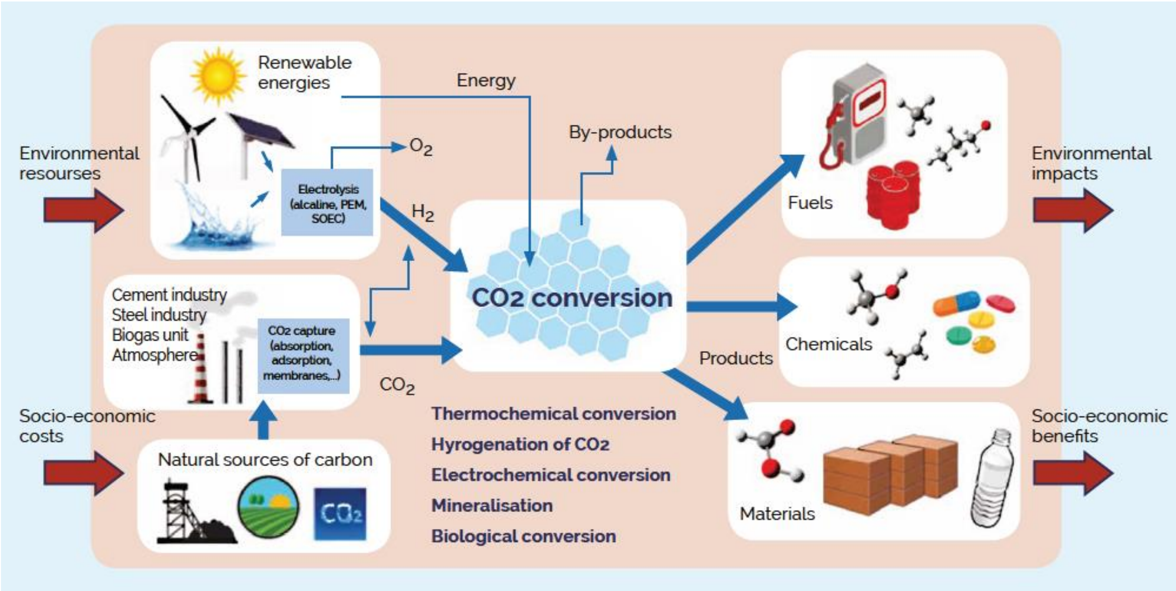


Figure 36. A systems approach to considering life cycle environmental and socio-economic sustainability of CCU systems. (SAPEA, 2018)

The potential of CCU to reduce CO_2 emissions is considered to be very limited if fuels or short-lifespan molecules are produced. For some sectors CCU could still be the best available option in the coming decades though, with aviation and long haul shipping often given as examples. An example of a CCU system for producing fuels is shown below, compared to the current fossil based reference:

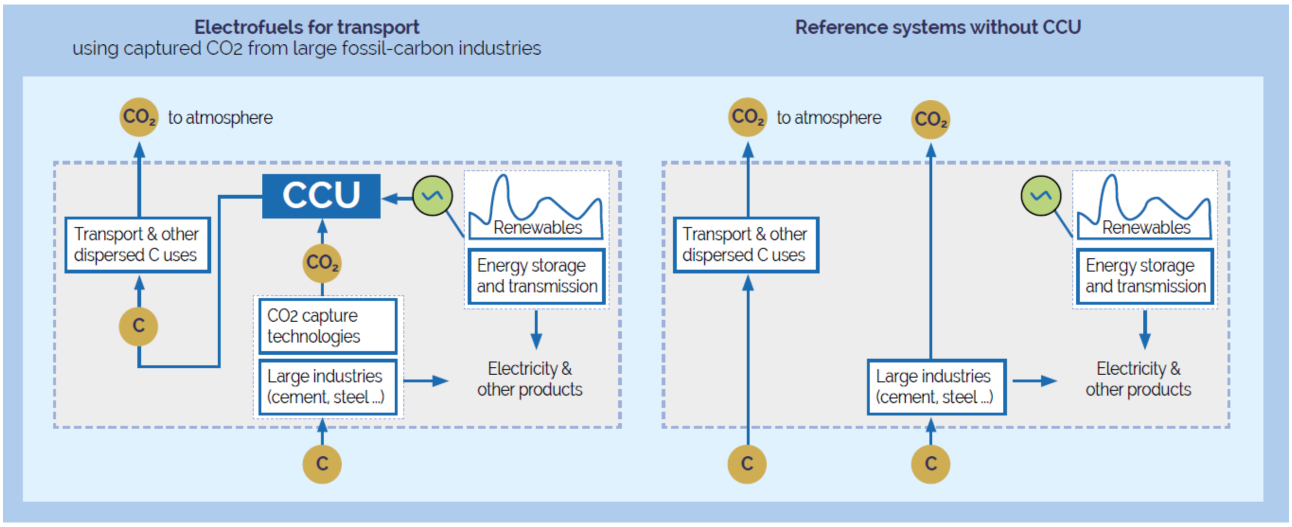


Figure 37. Carbon reduction potential of a CCU system in comparison with a reference system. (SAPEA, 2018)

Aviation and long haul shipping require fuels with high energy density, and electrification of these sectors is far more challenging compared to road transport. Full decarbonization is currently not within reach, and CCU could at least provide partial abatement of emissions. For linear CCU systems using fossil sources of CO_2, the theoretical maximum for emissions reduction is 50% compared to current fossil fuel chains. The actual potential to reduce emissions is lower, because CO_2 emissions related to developing the new system have to be accounted for, as well as emissions related to the energy input required to capture CO_2 and convert it to fuels. These are partially compensated by the fact that current emissions from oil & gas exploration and refining would be avoided. Achieving CO_2 abatement percentages above 50% is possible, but that requires somehow closing the carbon loop, either by direct air capture or by using biogas or biomass as a fuel (and source of carbon) for the industries from which CO_2 is captured to produce fuels.

Furthermore, it is equally important to take technology development challenges into account when estimating the potential of CCU to substantially reduce emissions by 2030-2050. A realistic view must be maintained about the scale at which these technologies could potentially be deployed. To illustrate, we can assume a hypothetical scenario in which 100% of the current urea, 20% of specific chemicals, 30% of solid waste mineralization, 20% of specific polymers, 5% of diesel and aviation fuel, and 10% of methane are produced using captured CO_2 by 2030.[9] In this highly optimistic scenario, an estimated 1.34 Gt of CO_2/year would be utilized, which is roughly 3% of the estimated global emissions in 2030. The amount of CO_2 effectively sequestered is lower than this estimate, and in any case it is not realistic to assume that the technology could be used at such large scale within a little more than a decade.

To illustrate the challenges of large scale technology deployment, the SAPEA report references the development of Shell's gas-to-liquids (GTL) process. The foundation of Fischer-Tropsch technology had already been laid in the 1920's and by the 1970's market conditions were favorable for large scale implementation. It took however nearly thirty years between commissioning a demonstration plant in Amsterdam in 1983 and the start-up of a world-scale GTL plant in Qatar in 2011. Shell's Pearl GTL plant was the largest oil and gas project of its time and the plant has a nameplate capacity of 120,000 bbl/day of synthetic fuels. This is however only about 0.15% of the global conventional oil refinery capacity of ~82 Mbbl/day (BP, 2018).

Despite the decades of development and tens of billions of dollars invested, GTL technology does not have a large contribution in the fuels market yet. By analogy, it is highly unlikely that CCU will be deployed rapidly enough to result in a large scale reduction of CO_2 emissions before 2050.

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[9] https://www.frontiersin.org/articles/10.3389/fenrg.2015.00008/full (accessed 09.11.2018)

6 CONCLUSIONS AND RECOMMENDATIONS

CCS is primarily a transition technology, a way to bridge the gap between the current situation and the envisioned future (reached by 2050-2100) in which emissions are drastically reduced as a result of energy efficiency measures, recycling of materials and various low-carbon technologies. For some industrial activities, which are very difficult to decarbonize but essential to society, CCS could be a longer term solution. Furthermore, adding CCS to a biomass-to-energy facility is one of the ways in which negative emissions can be achieved.

The Netherlands has almost ideal conditions for the development of a large CCS network:

- Highly concentrated sources (85% of industrial CO_2 emissions from 10% of the sites)
- Small country / short transport distances between sources and sinks
- Sufficient offshore storage capacity available to absorb a significant portion of industrial emissions, and also located relatively close to shore and in shallow waters
- Possibility to reduce costs by reusing existing offshore infrastructure
- Strong oil & gas sector – expertise available for the design, planning and management of CCS infrastructure

Under these conditions it would feasible to deploy CCS on large scale and achieve decarbonization targets, without undermining the competitiveness of Dutch industry or placing a heavy burden on tax payers. Over a period of 50 years, current known offshore storage capacity could absorb a maximum of 34 Mtpa CO_2. Depending on how much of that is reserved for local sources, there is potential to store some of the emissions from nearby countries (Belgium or Germany), but this is clearly limited. The Dutch CCS network could however facilitate capturing emissions from these countries in offshore fields near the UK or Norway, if CO_2 liquefaction and ship-loading facilities are developed, for example in Rotterdam or Eemshaven.

CCS costs per ton of CO_2 sequestered can vary greatly depending on project specifics. The main factors influencing costs are:

- The annual volume of CO_2 to be captured, as the costs of capture technology, pipelines, recompression stations and injection infrastructure depend very strongly on scale
- The type of process that is causing the emissions and the options available to integrate CO_2 capture on site
    - Source streams with a higher CO_2 concertation are preferred
    - Major cost-savings can be achieved if electricity / utilities are already available
- The characteristics of the storage reservoir (mainly capacity, depth and injectivity)
- The distance from source to sink, as well as the type of terrain crossed by the pipeline (for both onshore and offshore pipeline transport)
- The availability of offshore infrastructure that can be adapted and reused
- The approach chosen for post-storage monitoring, as well as liability transfer and insurance structures
- The lifespan of the project, capital allocation and corresponding discount rate

This list indicates that much of the variability in the overall costs of a CCS chain falls under the transport and storage components. Based on the estimates reviewed for this report, overall transport and storage costs for a single small scale project (up to 2.5 Mtpa) can easily exceed 40 €/ton of CO_2 captured. At the same time, it's technically feasible to develop a large scale (14-30 Mtpa) CCS network in The Netherlands. The main industrial sources of CO_2 emissions are clustered and offshore storage locations are available at relatively short transport distances.

If that is achieved and optimal use is made of existing offshore infrastructure and gas field developments, current estimates indicate the cost could be as low as 9 €/ton of CO_2 captured. In other words, economy of scale and infrastructure synergy are expected to reduce costs by more than 75% compared to individual projects! Using large CCS networks instead of source-to-sink connections is therefore expected to drastically reduce unit costs, and is the recommended way forward for cost-effective abatement. Careful planning and cooperation between the parties involved is required to optimally match sources and sinks, as well as to maximize the utilization of costly trunklines.

CO_2 utilization is a widely researched topic but there are few major commercial developments taking place. High margin products are the most promising, because processes starting with CO_2 as feedstock are energy-intensive, but the corresponding markets are not of a scale comparable with anthropogenic emissions. Nevertheless, partially converting captured CO_2 into valuable products can improve project economics for CCS so an integrated approach combining the two technologies can decrease the economic penalty of decarbonization.

In any case, from the perspective of CO_2 utilization establishing a CCS network is a low-regret decision because CO_2 capture costs dominate transport and storage costs. The capture, compression and onshore transport infrastructure could be fully reused for large scale CO_2 utilization, so the penalty of transitioning from sequestration to utilization at a later phase lies primarily with offshore development. This might be a differentiator to be taken into account when evaluating depleted gas fields (lower upfront CAPEX) vs saline aquifers and shipping vs offshore pipelines, since ships can be reused for a different project.

The cost of CO_2 transport and storage is an important element to consider in the business case for blue H_2 (produced via reforming or partial oxidation + CCS), either for flexible power generation or industrial decarbonization. The CO_2 avoidance cost of blue H_2 must be compared to alternatives pathways, such as electrolysis.

On the short to medium term, blue H_2 is seen as a cost-effective pathway to rapidly reduce CO_2 emissions in The Netherlands, and also an enabler for a future green H_2 (produced from renewable sources via electrolysis) based economy. In collaboration with Deltalinqs and more than ten industrial partners, TNO will conduct a feasibility review (the H-Vision project) in the coming months for the use of blue H_2 to reduce industrial emissions in the Rotterdam harbor.[10]

[10] https://www.deltalinqs.nl/nieuwsberichtendef/2018/openbaar/subsidie-h-vision (accessed 02.10.2018)

Last but not least, CCS projects should be accompanied by suitable public engagement efforts, considering the scale and costs of such projects, as well as the risks of opposition from the public and from NGOs, which could cause delays or even lead to project cancelation. In The Netherlands for example there is broad public support for energy transition initiatives, but the perception of CCS is often negative due to association with fossil fuels and the perceived risks of CO_2 storage.

The potential health and environmental risks associated with CO_2 leakages during transport or after storage have been studied extensively, together with the accompanying mitigation options, but are not well understood by the general public and sometimes exaggerated by NGOs that oppose CCS. These topics are covered in detail in various CATO-2 publications, summarized in the overview report *"CATO-2 – Linking the Chain"*. (Vos, 2014)

Safety concerns and public engagement are also addressed in the *"CO_2 Pipeline Infrastructure"* reference manual compiled by Ecofys and SNC-Lavalin. (IEAGHG, 2014) This publication should be consulted in the early phase of a project, as it summarizes the experience gathered from 29 CO_2 pipeline projects and covers all relevant aspects of CO_2 infrastructure:

- Pipelines and related equipment
- Regulation and permitting
- Pipeline project planning / phasing
- CO_2 pipeline cost estimates
- Guidelines for design studies
- Construction, operation, inspection & maintenance guidelines
- Decommissioning and abandonment considerations

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8 APPENDICES

A APPENDIX A – EVALUATION OF SALINE FORMATIONS AND GAS FIELDS (TNO, 2012)

Structure	Type of structure	Estimated availability	Operator(s)	Capacity ($MtCO_2$)	Permeability (mD)	Injection locations required for Injection rate of ~ 5 Mt/yr	Transport Distance (km) from Den Helder	Current Level of Knowledge
(1) Q1 - Lower Cretaceous	Saline formation, contains oil fields	2015 - 2020	Chevron (oil fields)	110 - 225	500 – 6000	1	40 km	A/B – Good option, good data
(2) P, Q - Lower Cretaceous	Saline formation	post 2025	None	360	200	1	60 km	B – good option, reasonable data
(3) F15, F18 – Triassic	Saline formation	post 2025	None	650	Up to 15 (in gas fields)	2 (for permeability of 15 mD; more for lower permeability)	150 km	B – good option, reasonable data
(4) L10, L13 – Upper Rotliegend	Saline formation	post 2025	None	60	Up to 1000	1	50 km	B – good option, reasonable data
(5) Step graben - Triassic	Saline formation	post 2025	None	190	Up to 20 (in gas fields)	1 (for permeability of 20 mD; more for lower permeability)	200 km	B – good option, reasonable data

Structure	Geological Risk	Well Integrity Risk	Infrastructure Risk	Timing Considerations	Overall Complexity	Minimum Development Time	Next Step; First-Order Cost Estimate for Full Development
(1) Q1 - Lower Cretaceous	Low	Moderate – many wells in oil fields K18 – L16 – Q1	Oil field infrastructure may be re-used	Oil fields close to end of production	Complex: many wells, several existing platforms	5 years	Feasibility study of combination with EOR (Q1 and P9)
(2) P, Q - Lower Cretaceous	Medium	-	Interference with hydrocarbon fields to be investigated	-	New development	6-7 years	Detailed modeling, pilot injection; 110 M€ (one injection location)
(3) F15, F18 - Triassic	Medium	-	Interference with hydrocarbon fields to be investigated	-	New development	6-7 years	Detailed modeling, pilot injection; 110 M€ (one injection location)
(4) L10, L13 – Upper Rotliegend	Medium	-	Interference with hydrocarbon fields to be investigated	-	New development	6-7 years	Detailed modeling, pilot injection; 110 M€ (one injection location)
(5) Step graben - Triassic	Medium	-	Interference with hydrocarbon fields to be investigated	-	New development	6-7 years	Detailed modeling, pilot injection; 110 M€ (one injection location)

Field	Type	Estimated availability	Operator(s)	Capacity ($MtCO_2$)	Plateau injection rates ($MtCO_2$/yr) [duration of plateau in years] Low	Medium	High	Transport Distance (km)	Current Level of risk
(6) K14/15	Depleted Gas Field Cluster (35% of capacity in anchor field: K15-FB)	2023 at the earliest (still producing)	NAM (sole operator)	165 (54 for K15-FB)	3 [15-20 yrs] (K15-FB)	6 [5-10 yrs] (K15-FB)	9 [5 yrs] (K15-FB)	60 km from Den Helder (WGT trunk can not be re-used; interfield pipe lines probably re-usable and with sufficient capacity)	High – integrity of limited number of abandoned wells to be checked; ageing platforms
(7) K04/05	Depleted Gas Field Cluster	2028 at the earliest (still producing)	Total (sole operator)	140 (40 for K05a-A)	2 [19 yr] (K05a-A)	3 [12 yr] (K05a-A)	5 [6 yr] (K05a-A)	120 km from Den Helder (both trunk and interfield pipe lines possibly re-usable and with sufficient capacity)	High – integrity of several abandoned wells to be checked
(8) K07/08/10	Depleted Gas Field Cluster (67% of capacity in anchor field: K08-FA)	2023 at the earliest (still producing)	NAM (all but one field incl. anchor field), Wintershall (K10-B)	195 (130 for K08-FA)	3-6 [20+ yrs] (K08-FA)	6-12 [10+ yrs] (K08-FA)	9-18 [5+ yrs] (K08-FA)	100 km from Den Helder (WGT trunk can not be re-used; interfield pipe lines probably re-usable and with sufficient capacity)	Moderate -- flow connection between blocks is uncertain but can easily be confirmed using additional (confidential) production data; integrity abandoned wells to be checked
(9) L10/K12	Depleted Gas Field Cluster	immediate action required for some of the fields in the cluster	Gaz de France Suez (sole operator)	175 (125 for L10-CD)	6 [17 yrs]	9 [10 yrs]	12 [4 yrs]	50 km from Den Helder (WGT trunk can not be re-used; interfield pipe lines probably re-usable and with sufficient capacity)	High -- many different blocks, connectivity unknown; many abandoned wells; ageing platforms; timing issues of fields in cluster

Field	Geological Risk	Well Integrity Risk	Infrastructure Risk	Timing Considerations	Overall Complexity and Risk	Minimum Development Time	Next Step
(6) K14/15	Low	Low: limited number of abandoned wells, no reported problems	High -- old platforms	Multiple fields still producing & using shared infrastructure; mothballing not a serious issue	Low – multiple fields and aging infrastructure, but low well integrity risks; single operator and well-known geology	6 years	Feasibility study
(7) K04/05	Low	Moderate: 11 abandoned wells, 1 before 1976	Low -- relatively modern	About 80% of storage potential estimated to be available in same year (mothballing not a serious issue)	Low – Although multiple fields relatively modern infrastructure; late availability allows learning from earlier projects	6 years	Use best practices other projects (fields available well after other CCS projects assumed to be operational)
(8) K07/08/10	Low	High: 11 abandoned wells, 5 before 1976	High -- old platforms	Multiple fields still producing, using shared infrastructure; mothballing required, already for anchor field itself	Moderate – multiple fields and ageing infrastructure, but relatively few blocks account for most capacity; several old, abandoned wells; single operator and well-known geology	More than 6 years (due to high well integrity risks, old platforms)	Feasibility study, focus on abandoned wells
(9) L10/K12	Moderate -- see field information	High: large number of abandoned wells; problems reported for producing wells	High -- old platforms	Multiple fields still producing, using shared infrastructure; mothballing required, already for anchor field	High – All traffic lights are red	More than 6 years (many abandoned wells, old platforms)	Feasibility study; immediate negotiations with operator (several fields close to end of production)