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Submitted (Author(s))	Michael Austell, Anton van der Burgt, Filip Neele, Michael Tetteroo, Menno Ros, Tom Mikunda, Meindertsma, Stijn Santen, Ad Seebregts	29-11-2011
Verified (WP-leader)	Stijn Santen	29-11-2011
Approved (SP-leader)	Filip Neele	29-11-2011

Author	Organization	Email
--------	--------------	-------

Michael Austell	CO ₂ -Global	jma@CO ₂ -global.com
Anton van der Burgt	Stedin	Anton.vanderBurgt@stedin.net
Wim Guijt	Shell	Wim.Guijt@Shell.com
Filip Neele	TNO	filip.neele@tno.nl
Wouter Meindertsma	TNO	wouter.meindertsma@tno.nl
Tom Mikunda	ECN	mikunda@ecn.nl
Menno Ros	E.On Benelux	menno.ros@road2020.nl
Stijn Santen	CO ₂ -Net	stijn.santen@CO ₂ -net.com
Ad Seebregts	ECN	seebregts@ecn.nl
Sarah Stiff	E.On UK	sarah.stiff@eon-uk.com

Abstract
Scenarios for future captured CO ₂ emissions for industry and power sector have been investigated together with models for CO ₂ storage planning in the North Sea and scenarios for enhanced oil recovery using CO ₂ . These scenarios and models have been applied to develop a set of measures and a transport network in the North sea that best serves the objectives of society (large cost-effective CO ₂ reductions) and industry/financers (a return on capital with acceptable risk profile that attracts private capital).

EXECUTIVE SUMMARY

The Rotterdam Climate Initiative was founded early 2007 to implement the vision of a prosperous industry with strongly decreased CO₂ emissions in the region, setting itself an ambitious goal of 50 % CO₂ reduction in 2025. This goal had to be achieved to large extent by CCS. Currently 2 demo CCS projects are in development in Rotterdam; The EERP funded ROAD project and NER 300 funded project by Air Liquide supported by the CINTRA consortium. These and many other demo projects serve to generate the operational, technical and organizational experience that is required to develop large scale CCS. This report has the focus on the development of a large scale CO₂ transport infrastructure in The North Sea in the post demo era starting around 2018 till 2050 when large scale CCS will be increasingly implemented assuming the demo projects have creating the essential learning and that a financial support mechanism for CCS will be in place. Rotterdam aspires to fulfill the role of CO₂-hub in this development connecting imported CO₂-streams and locally captured CO₂ streams with offshore storage reservoirs in one connected network. The desired conditions are analyzed and based on the criteria of lowest costs to society while providing a return on capital that invites private investors with an acceptable risk profile. A top down approach has been used to establish the desired conditions by investigating the following topics:

- Up to date scenarios to establish industrial CO₂ emissions over time in the Netherlands, Germany and Belgium that might be captured and supplied to the CO₂-hub
- Identification and routing to storage locations in the Dutch Continental Shelf
- Scenarios for CO₂ demand for enhanced oil recovery by CO₂-EOR estimating potential, timing and revenues
- Cost structure (fixed and variable), economy of scale and transport costs for combined transport by pipelines and ships for either CCS or CO₂-EOR
- Description of the 2 demo projects and the learning that can be applied for large scale CCS
- Technical feasibility and issues for a backbone pipelines connecting Rotterdam to the Utsira deep saline formation as well as storage in depleted gas fields
- Relation between transport costs for energy (natural gas and power) versus CO₂ to establish the impact on future locations for power plants in relation to CO₂-hubs and harbors

The results show that a system approach with common standards will better serve the objectives of society and project financiers and operators than individual isolated projects. The reasons are a strong economy of scale with transport and the necessity to solve many regulatory, organizational, and financial issues related to cross-boundary transport. Key conclusions derived from this study are listed below:

- 1) CO₂ transport costs in euro/ton CO₂ decrease strongly with higher volumes and pipeline diameters. This economy of scale benefit requires a large transport network yielding also flexibility benefits for intermittent CO₂ emitters like many power plants
- 2) Planning a transport network for the North Sea should focus on CO₂-EOR directly even if the suitable oil fields are much more distant from Rotterdam than depleted gas fields in The Dutch Continental Shelf on basis of financial, political, technical and strategic arguments
- 3) Shipping liquid CO₂ servicing several offshore CO₂-EOR amenable oil fields in succession might act as a catalyst for the development of a large scale pipeline infrastructure by de-risking the major offshore platform investments for EOR

- 4) Import of CO₂ streams to Rotterdam derived from the basis emissions scenario as developed by the PRIMES model is essential to deploy CCS and CO₂-EOR timely and cost-effectively. Lower captured volumes will make CCS more expensive and will reduce the opportunity value of CO₂-EOR
- 5) Investment planning of such a network requires a high level of political commitment and urgency of the various member states near the North Sea and the EU as well due to the cross-border legal and tax issues as well as the timing of storage availability, the EOR opportunity window in time and the investments at stake.
- 6) Transparency in the business model for a multi user offshore transport network is crucial for investors and all parties in the CCS and CO₂-EOR value chain to avoid sunk costs in separate infrastructure investments
- 7) Although large investments are needed, the transport costs at large scale are primarily determined by compression energy, hence power costs, with only a modest influence of capital cost (WACC)
- 8) Transport and storage costs are strongly influenced by the storage reservoir properties and the required compression power for large scale transport and injection. Hence a transport network design leading to the lowest overall costs will often not lead to the shortest distance between the Rotterdam CO₂-hub and storage locations
- 9) The focus on storage in depleted gas fields for demo projects is likely to shift in the near future to deep saline formations or EOR amenable oil fields for large scale CCS on basis of technical (risk of hydrate formation in reservoir) and financial arguments (EOR value and lower transport costs for dense phase high pressure CO₂)
- 10) The optimum location of a new power plant or other industrial plant does not have to change significantly by applying CCS as CO₂ transport costs are much smaller than power transport costs on an equal energy basis

The following key recommendations are made to solve these issues:

- Develop a master plan for the transport and storage network to coordinate the different plans and investment decisions and to optimize the system across the whole CCS value chain
- Start with a cross-boundary transport network in the North sea connecting Rotterdam with offshore CO₂ storage locations as well as other harbors and industrial clusters in Groningen Eemshaven, Teesside (UK), Germany (North German harbors as well as NRW region) for CCS as well as CO₂-EOR
- Set up an expert authority that coordinates essential regulatory, commercial and financial issues related to cross-boundary projects (investment decisions, tax revenues, liability issues, national differences in implementation CCS directive etc.)
- Integrate CCS and CO₂-EOR in to a common EU energy and climate policy with CO₂ transport networks as part of energy infrastructures investment planning
- Endorse the common carrier business model for CO₂ transport through the network as an analogue to gas- and power transport to attract sufficient private and public capital including government guarantees to mitigate the political risk

PROJECT SUMMARY

The CO₂Europipe project aims at paving the road towards large-scale, Europe-wide infrastructure for the transport and injection of CO₂ captured from industrial sources and low-emission power plants. The project, in which key stakeholders in the field of carbon capture, transport and storage (CCTS) participate, will prepare for the optimum transition from initially small-scale, local initiatives starting around 2010 towards the large-scale CO₂ transport and storage that must be prepared to commence from 2015 to 2020, if near- to medium-term CCS is to be effectively realized. This transition, as well as the development of large-scale CO₂ infrastructure, will be studied by developing the business case using a number of realistic scenarios. Business cases include the Rotterdam region, the Rhine-Ruhr region, an offshore pipeline from the Norwegian coast and the development of CCS in the Czech Republic and Poland.

The project has the following objectives:

1. describe the infrastructure required for large-scale transport of CO₂, including the injection facilities at the storage sites;
2. describe the options for re-use of existing infrastructure for the transport of natural gas, that is expected to be slowly phased out in the next few decades;
3. provide advice on how to remove any organizational, financial, legal, environmental and societal hurdles to the realization of large-scale CO₂ infrastructure;
4. develop business case for a series of realistic scenarios, to study both initial CCS projects and their coalescence into larger-scale CCS infrastructure;
5. demonstrate, through the development of the business cases listed above, the need for international cooperation on CCS;
6. summarize all findings in terms of actions to be taken by EU and national governments to facilitate and optimize the development of large-scale, European CCS infrastructure.

Project partners

Nederlandse Organisatie voor Toegepast Natuurwetenschappelijk Onderzoek- TNO	Netherlands
Stichting Energieonderzoek Centrum Nederland	Netherlands
Etudes et Productions Schlumberger	France
Vattenfall Research & Development AB	Sweden
NV Nederlandse Gasunie	Netherlands
Linde Gas Benelux BV	Netherlands
Siemens AG	Germany
RWE DEA AG	Germany
E.ON Benelux NV	Netherlands, Belgium, Luxemburg
PGE Polska Grupa Energetyczna SA	Poland
CEZ AS	Czech Republic
Shell Downstream Services International BV	Netherlands, United Kingdom
CO ₂ -Net BV	Netherlands
CO ₂ -Global AS	Norway
Nacap BV	Netherlands
Gassco AS	Norway
Anthony Velder CO ₂ Shipping BV	Netherlands
E.ON New Build and Technology Ltd	United Kingdom
Stedin BV	Netherlands

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1 INTRODUCTION

Europe’s industrial clusters, ports as well as inland clusters, based on fossil fuel production, processing and transport are vital for their local communities, home countries, and the EU economy as a whole. These clusters in the CO₂europipe consortium countries Netherlands (Rotterdam), Germany (NRW), Norway, Poland, and Czech Republic are strongly reliant on coal, gas or oil. The financial impact of these clusters is not restricted to revenues generated by the production, processing and distribution of fossil fuels but involves also the downstream industrial processes (chemicals and metals processing) that rely on heat (steam) and electricity generated by fossil fuel fired power plants. The concentration of high volume industrial CO₂ sources in these clusters makes them ideal candidates for application of large scale CCS as described in this report D 4.1.1 as well as in D 4.2.1, D 4.2.2, D 4.3.2 and D 4.4.3.

Given limitations on nuclear and renewable energy alternatives it is more and more apparent that CCS will become vital to maintain and grow the industrial based economy in the CO₂europipe countries; it will secure employment and economic competitiveness while enabling the high CO₂ reduction ambitions of the EU. The BLUE map scenario developed by the IEA and endorsed by the G8 at Gleneagles in 2005 shows that CCS can be the second largest contributor with 19 % (energy efficiency is the largest) towards the target of 80 % CO₂ reduction by 2050 as shown in the graph below.

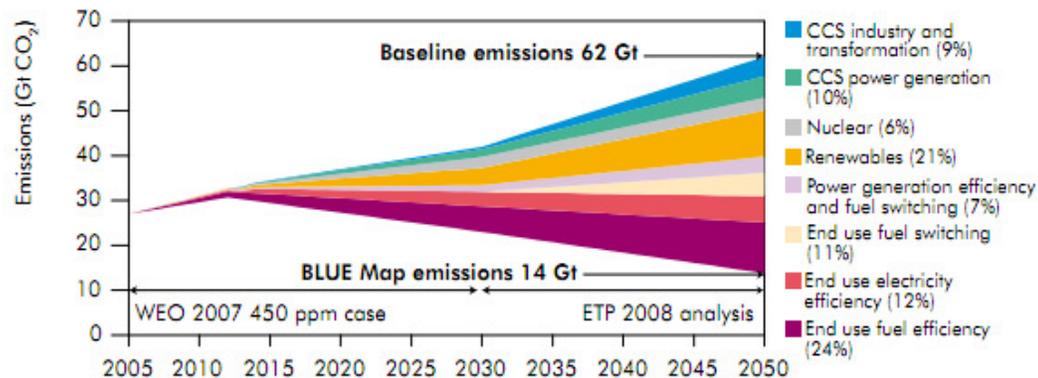


Figure 1.1 Blue map scenario (Source: IEA)

The Dutch economy is strongly dependent on fossil fuels as shown in the industrial harbor complex in Rotterdam which by its nature has a high concentration of CO₂ emissions. Therefore, several parties have set up the Rotterdam Climate Initiative (RCI) early 2007 to reduce the CO₂ emissions in the Rotterdam area by a portfolio of measures based on 3 pillars (CCS and CO₂ re-use, energy efficiency and biomass/sustainable energy) with the ambitious target of reaching 50 % CO₂ reduction

in 2025 based on 1990 reference level while on the other hand ensuring and increasing economic growth of the Rotterdam area. The founding fathers of the RCI are the Rotterdam port authority, the Environmental protection agency DCMR, the industry association Deltalinqs and the municipality of Rotterdam) and they coordinate strongly with industry and government. In order to meet these goals several activities need to be deployed that are shown in the picture below. (see Figure 1.2 [source RCI]).

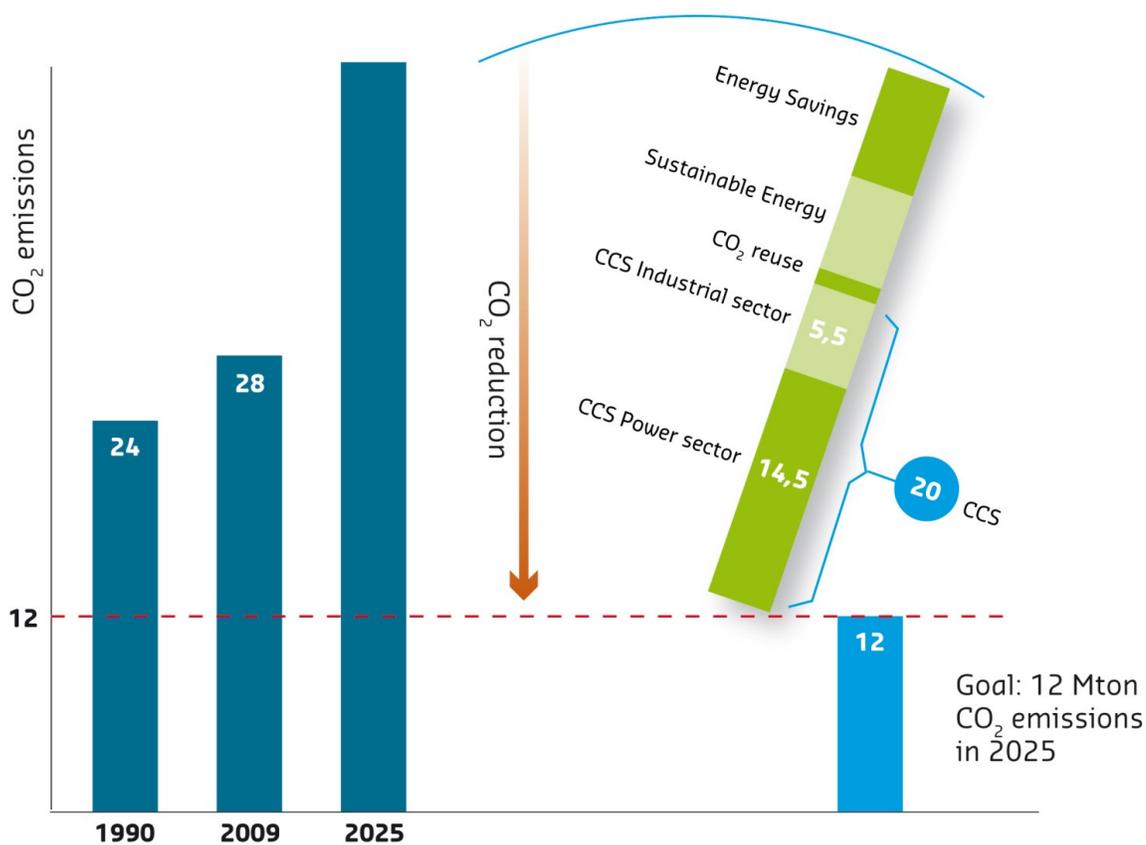


Figure 1.2 CO₂ emission reduction goals in Rotterdam (source: RCI).

The main contribution to reduce CO₂ and meet the emission reduction target in the Rotterdam area needs to come from CCS. The focus on CCS is a logical consequence of the presence of many power plants and energy intensive industries in the area as well as the proximity of nearby offshore CO₂ storage locations as depleting gas fields. According to the RCI CCS in the Rotterdam area can be deployed while increasing the strengths and opportunities of the region, for example because it can be deployed cost effectively due to the high concentration of the industry (many point sources) and possible synergies for collection and transport of CO₂. Together with industry the RCI

developed a vision and related steps to realize CCS. The long term vision of the RCI related to CCS in Rotterdam is to become a CO₂ hub where not only sources of CO₂ within the Rotterdam area are collected and transported, but also CO₂ from industrial areas nearby (Antwerp and the Ruhr area) will be transported via Rotterdam to several (offshore) storage sites using several transport modalities, i.e. by ship and pipeline.

To assess the requirements and feasibility of a CO₂-hub in Rotterdam in the time frame 2020 till 2050 (post demo phase) the capture potential and storage potential versus time are independently assessed. The capture potential is based on CO₂ emissions scenarios using the PRIMES model for The Netherlands as well as Belgium and Germany (with a partial CO₂ export to Rotterdam). The offshore storage potential versus time and associated storage costs is assessed for depleting gas fields in the Dutch Continental Shelf (DCS) based on capacity, production, and costs of abandonment. Subsequently, an optimal routing for transport to storage versus time is determined based on these criteria. Appropriate business models and the associated financing issues of the growing infrastructure are discussed using analogues and differences in the gas and power infrastructure.

Outside the DCS there is a significant potential CO₂ demand for enhanced oil recovery CO₂-EOR from major mature oil fields in the English, Danish and Norwegian offshore sector. The magnitude of CO₂ demand versus time for CO₂-EOR and its business drivers versus CCS is touched upon in the storage chapter and elaborated in the EOR chapter. This work has been carried out in cooperation with ECCO; a FP7 sponsored European project on CO₂-EOR.

The chapter of transport logistics planning (including pipelines and ships) describes the evolution of transport infrastructure over time for both CCS and CO₂-EOR. In order to make fundamental decisions on investments in transport infrastructure the potential financial synergy of a joined infrastructure for CCS and CO₂-EOR and the required timing is analyzed. Subsequently, in cooperation with D 4.3.2. An analysis has been made of the technical and financial issues of European CO₂ pipeline transport from Rotterdam (in conjunction with streams from Teesside and North Germany) to the Norwegian Utsira deep saline formation. The trajectory for this pipeline coincides roughly with the pipeline trajectories for CCS and CO₂-EOR in The North Sea as previously described.

This large infrastructural network will take shape from 2020 onwards. However, there are also shorter term CCS developments in Rotterdam via the demo CCS projects ROAD from E.On and Electrabel (EEPR funded) and the NER 300 funded Air Liquide project. The latter is the driver for the CINTRA consortium that aims to build and operate an infrastructure for both high pressure CO₂ transport per pipeline as well as liquid CO₂ transport per ship. These demo projects serve to generate know-how and experience in technical, operational and organizational issues that will enable large scale deployment of CCS via the CO₂-hub in Rotterdam.

In the last chapter CO₂ transport is compared with its alternatives natural gas transport and electricity transport to verify whether CCS for fossil fuel based power plants would lead to different locations for new built build power plants and to position CO₂ transport in the same framework as energy infrastructures.

2 CO₂ SUPPLY SCENARIOS FOR THE ROTTERDAM AREA

This chapter outlines the CO₂ supply (capture) scenarios for the Rotterdam case. The sources of CO₂ are from the Netherlands and imports from Germany and Belgium. To the extent possible, the CO₂ supply scenario made as part of CO₂Europipe WP2.2 (Neele et al, 2010) has been used as starting point. Section 2.1 first outlines the additional assumptions or corrections made in comparison to the WP2.2 scenario. Section 2.2 shows the two CO₂ supply scenarios for the Rotterdam CO₂ Hub. Besides a default case, it also shows a sensitivity case with only 50% of the default CO₂ supply. The CO₂ supply scenarios presented in this chapter can be compared to the CO₂ demand scenarios for EOR as outlined in Chapter 5.

Since publication of (Neele et al, 2010) additional scenarios from other studies than CO₂Europipe have been published. Therefore, Section 2.3 shows a comparison between the CO₂Europipe scenarios and these more recent scenarios. This provides an indication of the validity and plausibility of the original WP2.2 CO₂Europipe scenario.

2.1 Main assumptions

The CO₂ supply scenarios for the Rotterdam area will be based on the following assumptions:

1. Up to 2025 the CO₂ supply from the Rotterdam area itself is based on the most recent figures from the RCI Roadmap as outline in (RCI, 2011).
2. From 2025 to 2050, the CO₂ supply figures are mainly based on the CO₂Europipe WP2.2 CO₂ figures but with the following corrections:
 - a. The CO₂ captured in the Eemshaven area will be transported to Germany, and stored there or transported from Northern German harbours to offshore sinks in the North Sea connected to the backbone pipeline from Rotterdam to the Utsira deep saline formation.
 - b. The CO₂ captured in the Amsterdam area will be transported to Rotterdam.¹
 - c. Belgian CO₂ captured will be transported to Rotterdam, for 75 %.
 - d. Part of the German CO₂ captured (in the Rhine-Ruhr area) will be transported to the Rotterdam CO₂ Hub.

¹ Direct transport of CO₂ from Amsterdam area to tie-in directly to offshore storage is shorter and may therefore be more cost effective.

2.2 Results: two CO₂ paths

If the three CO₂ supply sources from within the Netherlands and the imported CO₂ from Germany and Belgium are combined, the total CO₂ supply is 105 Mton/year in 2030 and 180 Mton/year in 2050. As a sensitivity case, a 50% case from 2025 onward has been defined. The CO₂ supply paths are summarised in Figure 2-1.

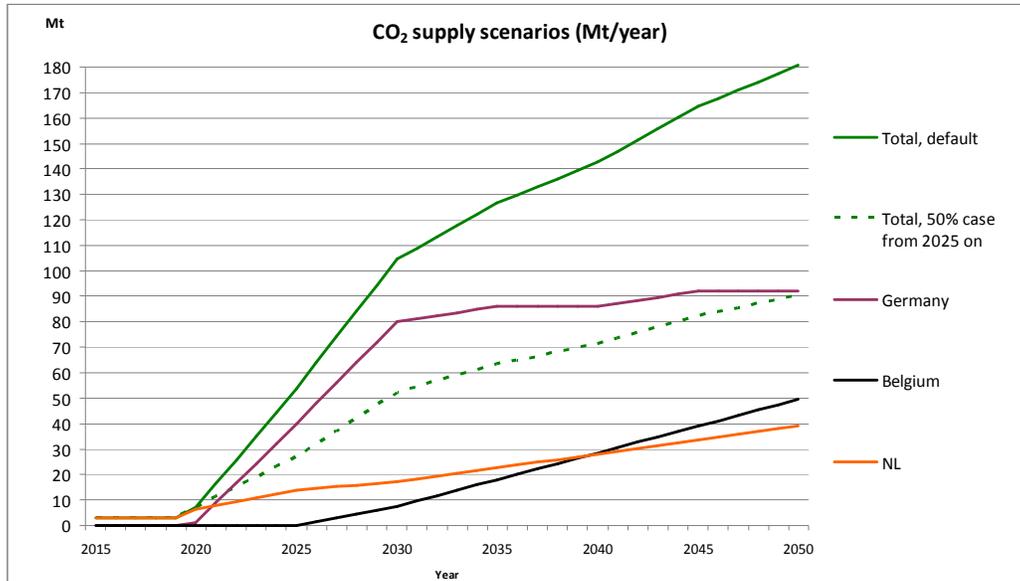


Figure 2-1 CO₂ Supply Scenarios to the Rotterdam area

2.2.1 The Netherlands

From 2015-2025 the CO₂ supply is largely based on the most recent RCI Roadmap (RCI, 2011). It includes 1 Mton of pure CO₂ streams plus the CO₂ captured from the two new coal power plants now under construction (E.ON and Electrabel). Around 2015 about 3 Mton is captured or produced. In 2020, this is doubled to more than 6 Mton/year. From 2030 onwards, new coal/biomass power plants are assumed to be built in the Rotterdam area, directly equipped with CO₂ capture. Together with CO₂ from other industry the CO₂ supply grows to 17 Mton/year in 2030. In 2050, the CO₂ supply is almost 40 Mton/year. Note that we assume that from 2030 on, also some CO₂ supply from the Amsterdam area is transported to the Rotterdam CO₂ hub. Direct transport of CO₂ from Amsterdam area to tie-in directly to offshore storage is shorter and may therefore be more cost effective.

2.2.2 Germany

The CO₂ supply from Germany to the Rotterdam area is based on the CO₂Europipe WP 2.2 scenario (Neele et al, 2010). That scenario is based on the three scenarios for WP 4.2 (Thielemann et al, 2011) with the choice made for scenario 3 (highest) from 2030 to 2050. Given the current political climate in Germany, for the period to 2025 a

more moderate path has been selected; the supply in 2025 is still based on scenario 2 from (CO₂Europipe reports D.4.2.1 and D4.2.2, Thielemann et al, 2011). Therefore, as part of WP 4.1, the CO₂Europipe partners decided to use this high path rather than the low path used later on in WP 4.2 (German case).

The German CO₂ capture path in D4.2.2 is the lowest path corresponding to the three NRW (Nord-Rhein-Westfalen) areas (including the Ruhr area). Scenario 3 is considered likely in the D 4.2.2 report because of the current local (i.e. German) political climate. For the purpose of WP 4.1, the partners decided that a higher CO₂ supply from NRW to Rotterdam will be used. It is more towards the highest path (scenario 1) and also more in agreement with the original CO₂Europipe WP 2.2 scenario (Neele et al, 2010). It should be noted that recent EC Baseline scenarios² (not available when doing the WP 2.2 work) also include higher figures for CO₂ captured in Germany than in WP 4.2.

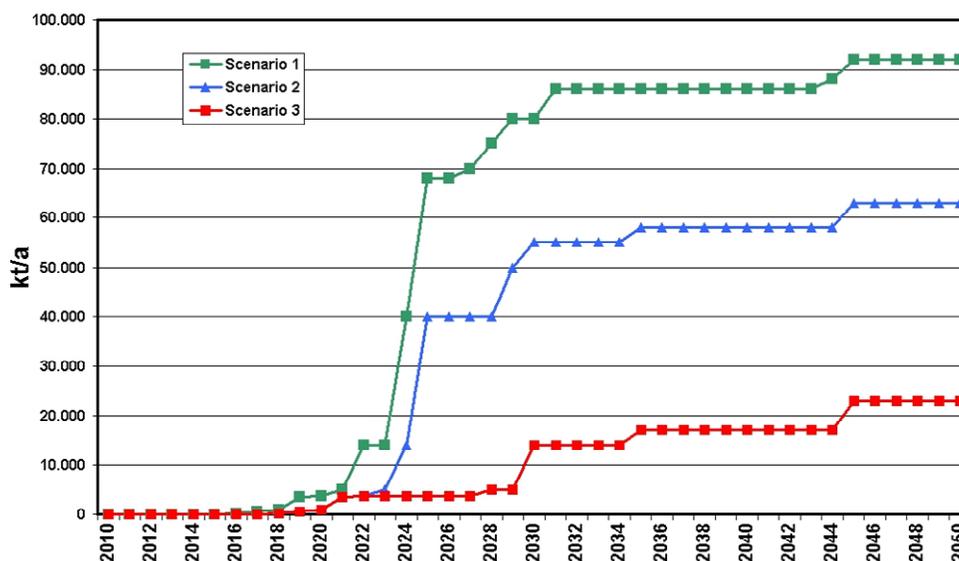


Figure .2-2 CO₂ Capture paths from NRW area Germany (Source: CO₂Europipe WP 4.2, RWE and Wuppertal Institute)

2.2.3 Belgium

The assumption is that 75% of CO₂ captured or produced in Belgium will be transported to Rotterdam. Most of the CO₂ will come from the industrial area of Antwerp. The CO₂ captured in Belgium is based on the CO₂Europipe WP 2.2 scenario

² EC, 2010: EU Energy Trends to 2030 – Update 2009, European Commission, September 2010.

Neele et al, 2010). It is relatively high because in the CO₂Europipe WP 2.2 scenario Belgium will phase out all of its nuclear power plants. That phase out is consistent with the 'EU Energy Trends to 2030 – Update 2009' scenario of (EC, 2010). These nuclear power plants are partly replaced by fossil fuelled power plants, directly equipped with CO₂ capture. Direct deployment of CCS on new coal and new (large) biomass power plants after 2025 is a general assumption in the WP 2.2 scenario.

Table 4.1 Summary of CO₂ captured (supply) path to Rotterdam area (default case), in Mton/year

	2015	2020	2025	2030	2035	2040	2045	2050	remarks
From NL	3.1	6.2	13.8	17.1	22.6	28.1	33.6	39.1	2030 and later: WP 2.2 corrected for Eemshaven
R'dam area	2.1	5.2	12.8	12.8	13.8	18.6	25.3	32.1	2 new coal (2012/2013), 2 pure CO ₂ streams, additional new coal/biomass from 2030 onwards
Amsterdam area (Tata Steel)	0	0	0	2	5	7	7	7	No new coal in A'dam area
From Germany, scenario 3 (based on highest), NRW area		1.0	40	80	86	86	92	92	2025, scenario 2; 2030-later: scenario 3
From Belgium, largely based on WP 2.2		0.0	0.0	7.5	18.0	28.5	39.0	49.5	75% of Belgium to R'dam (assumption)
CO ₂ Europipe									
Total, NL+BE+DLD (DEFAULT CASE)	3.1	7.2	53.8	104.6	126.6	142.6	164.6	180.6	
50% Case	3.1	7.2	26.9	52.3	63.3	71.3	82.3	90.3	from 2025 onward, 50% of default case

2.3 Comparison of WP 2.2 CO₂Europipe scenario with recent other scenarios, for NSBTF countries and EU-27

The CO₂Europipe WP 2.2 resulted in a CO₂ supply scenario for mainly Northwest European EU Member States and Norway (Neele et al, 2010). Other more recent scenarios include most of these countries too, or they include the EU-27 as a whole, or even a wider geographical scale ('OECD Europe').

Therefore, this section shows a comparison between the CO₂Europipe scenarios and these more recent scenarios. This provides an indication of the validity and plausibility of the original WP2.2 CO₂Europipe scenario.

The comparison is summarised in Table 4.2 that shows the amounts of CO₂ captured in the various scenarios and studies compared here.

2.4 Comparison at the regional and EU-27 level

The first comparison is between the CO₂Europipe WP 2.2 scenario with the One North Sea scenarios, and other scenarios that cover the EU-27 or 'OECD Europe'.

1. *One North Sea*: The CO₂Europipe WP 2.2 scenario, restricted to the North Sea Basin Task Force (NSBTF) countries is in between the High and Low '*One North Sea*' scenarios made for the NSBTF (One North Sea, 2010). The high One North Sea variants are in the same order of magnitude as WP 2.2 CO₂Europipe for those countries (Netherlands, Germany, United Kingdom, and Norway). The One North Sea scenarios and variants are important to compare with the WP2.2 CO₂Europipe scenario, as both scenarios focus on the countries in North-west Europe.
2. *IEA CCS Roadmap*: The CO₂Europipe WP 2.2 scenario is in good agreement with the IEA CCS Roadmap for the year 2030. For the year 2050 CO₂Europipe WP 2.2 scenario seems at the high end of the CCS potential.
3. *EU Energy Trends to 2030*: The CO₂Europipe WP 2.2 scenario is in good agreement with the year 2030 figures from the most recent EC Baseline 'EU Energy Trends to 2030 – Update 2009' (EC, 2010)
4. *Eurelectric Power Choices*: The Eurelectric Power Choices scenario (Eurelectric, 2010/2011) has no Member State or regional detail. It only provides figures for the EU-27 as a whole. Therefore it is of no use for the Rotterdam case. However, its long term view in 2050 is in large agreement with the WP 2.2 CO₂Europipe scenario with respect to the CO₂ captured in the power generation sector.

Figure 2-3 shows the power generation mix for the EU-27 based on the two previous scenarios.

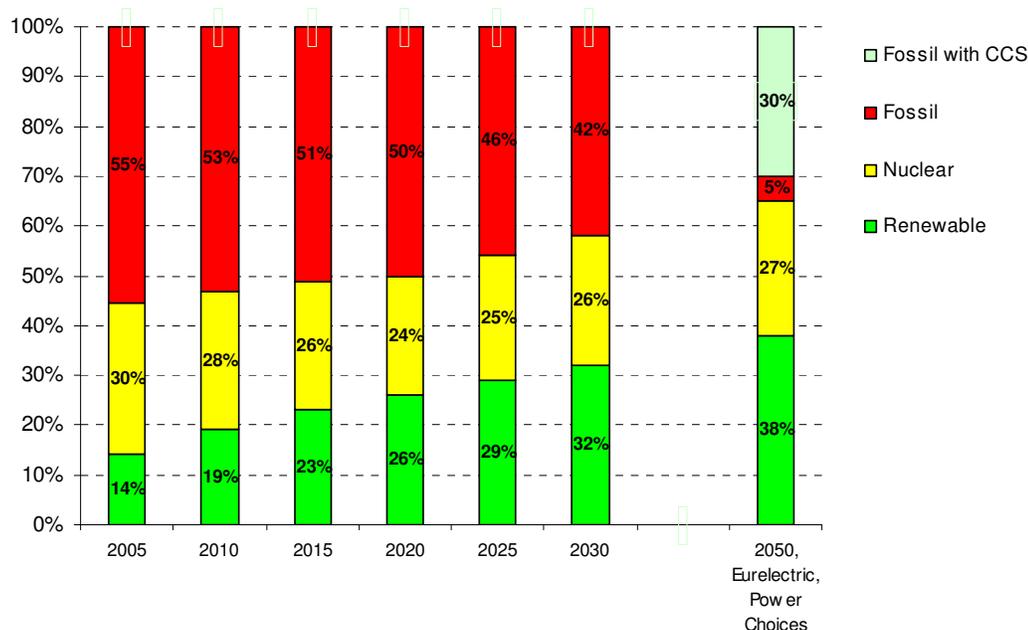


Figure .2-3 Production Mix for EU-27 Power Generation: EU Energy Trends to 2030 (2010-2030, no distinction made for fossil without and with CCS) versus Eurelectric's Power Choices scenario (2050).

2.5 The Netherlands and the Rotterdam area

The CO₂Europipe WP 2.2 scenario (Neele et al, 2010) is now on the high end (optimistic) for the CO₂ supply from the Netherlands, in the years 2020 and 2030. The main reasons are that construction of the WP2.2 scenario, some plans for new coal power plants in the Rotterdam have been cancelled (Autumn 2010). In addition, the CO₂ captured in the Eemshaven (North of the Netherlands) may face a serious delay now that the Dutch government has prohibited CO₂ storage onshore in the next years (decision made in March 2011). However, this issue could be solved by pipeline CO₂ transport from Eemshaven to nearby German harbors like Emden (20 to 30 km distance) from where it can be transported offshore to storage locations in the North Sea and connect to the backbone pipeline from Rotterdam.

The NL CO₂ supply path for the Rotterdam CO₂ Hub is taken equal to the WP2.2. CO₂Europipe scenario, corrected for the CO₂ captured in the Eemshaven area that is transported to Germany. That amount is about 1 Mton in the initial phase based on a 250 MW_e demo for the RWE/Essent new coal power plant (1560 MW_e net) currently under construction. In a later stage full scale CCS at this plant would lead to almost 7 Mton captured CO₂.

The Amsterdam area is responsible for a maximum 7 Mton of CO₂ (ECN, 2010, based on 'Updated Option Document CO₂ Reduction, Smekens et al, 2010). This amount is

totally based on CCS deployed on the Tata Steel plant in IJmuiden. No new coal power plants have been assumed for the Amsterdam area. Rotterdam and the Eemshaven are the preferred locations new coal power plants (with co-firing of biomass) in the Netherlands.

New gas fired power plants will not be equipped with CCS (in line with the CO₂Europipe WP 2.2 scenario).

Other NL CO₂ capture and CO₂ scenarios for the Netherlands

In 2009, McKinsey made two long term (2050) scenarios for the Netherlands specifically aimed to explore the need and extent of CCS deployment in the Netherlands (McKinsey, 2009). These two scenarios ('MK-NL' scenarios) are also used in the EBN/Gasunie 2010 report (EBN/Gasunie, 2010) but differ from more recent ECN/PBL reference scenarios made for the Dutch government (ECN/PBL, 2010). The high MK-NL scenario is based on a very high economic growth scenario (2.75%/year GDP growth) that does not take into account the recent financial and economic crisis. The ECN/PBL references take such developments into account. Energy demand development in the MK-NL scenario is therefore too high compared to both recent NL reference and EC Baseline scenarios like the EU Energy Trends to 2030 (EC, 2010). Consequently, the CCS deployment is too high. The other MK-NL low ('Green') scenario does not include co-firing of biomass in Dutch coal-power plants. In addition, it includes new nuclear power in the Netherlands.

The NL WP2.2 CO₂Europipe scenario is in agreement with the most recent Dutch reference scenarios (ECN/PBL, 2010). ECN used these reference scenarios as a basis for the WP 2.2 CO₂Europipe scenario. It has also been used in ECN CCS studies for the European Climate Foundation (Seebregts et al, 2010) and the Dutch CATO programme (Seebregts, 2010).

2.6 Recent scenario: CCS in the EC Roadmap to 2050

In March 2011, the EC published its 'A Roadmap for moving to a competitive low carbon economy in 2050' (EC, 2011). It reconfirms the strategic goal of at least 80% greenhouse gas reduction in 2050 (compared to 1990 levels) which formed the basis of the WP 2.2 CO₂Europipe scenario. In addition, the role of CCS is prominent in the Roadmap:

"The analysis also shows that a less ambitious pathway could result in higher carbon prices later on and significantly higher overall costs over the entire period. In addition, R&D, demonstration and early deployment of technologies, such as various forms of low carbon energy sources, carbon capture and storage, smart grids and hybrid and electric vehicle technology, are of paramount importance to ensure their cost-effective and large-scale penetration later on. Full implementation of the Strategic Energy Technology plan, requiring an additional investment in R&D and demonstration of € 50 billion over the next 10 years, is indispensable."

"In addition to the application of more advanced industrial processes and equipment, carbon capture and storage would also need to be deployed on a broad scale after

2035, notably to capture industrial process emissions (e.g. in the cement and steel sector). This would entail an annual investment of more than € 10 billion. In a world of global climate action, this would not raise competitiveness concerns. But if the EU's main competitors would not engage in a similar manner, the EU would need to consider how to further address the risks of carbon leakage due to these additional costs.”

“Various forms of low carbon energy sources, their supporting systems and infrastructure, including smart grids, passive housing, carbon capture and storage, advanced industrial processes and electrification of transport (including energy storage technologies) are key components which are starting to form the backbone of efficient, low carbon energy and transport systems after 2020. This will require major and sustained investment: on average over the coming 40 years, the increase in public and private investment is calculated to amount to around € 270 billion annually. This represents an additional investment of around 1.5% of EU GDP per annum on top of the overall current investment representing 19% of GDP in 2009.”

2.7 Conclusions

From the various CO₂ supply scenarios available and addressed here, it is concluded that:

- Domestic CO₂ supply from the Netherlands may benefit from import to build a cost-effective CO₂ infrastructure with Rotterdam as one of the major CO₂ hubs in Northwest Europe. Domestic CO₂ will mainly stem from the (south-) western part of the Netherlands centralized in Rotterdam. Import of CO₂ from Germany and Belgium can aid in economies of scale and provides more guarantee to arrive at a more optimal pan-European CO₂ infrastructure in the decades after 2020.
- CO₂ supply to the Rotterdam area from within the Netherlands plus imports of CO₂ from Germany and Belgium amount to about 105 Mton/year in 2030 and 180 Mton/year in 2050. These scenarios are largely based on the previous CO₂Europipe WP 2.2 scenario.

Table 4.2 Overview of CO₂ Capture (and Supply) scenarios

	2020	2025	2030	2
<u>EU-27 or OECD Europe</u>				
- IEA CCS Roadmap 2009, OECD Europe	37		300	
- EU 27, New baseline (EC, 2010), EU-27 Total	36	113	272	
-Eurelectric, Power Choices scenario, EU-27 (Eurelectric, 2010)				
- CO ₂ Europipe, WP 2.2 (Neele et al, 2010)	45		358	
<u>North Sea Basis Task Force Countries (NL, UK, D, DK, NO)</u>				
- CO ₂ Europipe, WP 2.2	41		145	
- One North Sea (2010)				
High			273	
Low			46	
- EU New baseline (Sep 2010), NSBTF , except Norway	25	84	169	

	2015	2020	2025	2030	2
<u>The Netherlands and R'dam</u>					
- NL total, CO ₂ Europipe, WP 2.2		7.6		22	
- EU New baseline (Sep 2010), NL only		4.2	5.8	6.9	
- Rotterdam area: ECN, study for DCMR (RCI partner), ECN-E-10-031, May 2010	1.5	1.5	4		
<i>NL Reference Projection 2010 (ECN, PBL, 2010) ROAD demo plus Barendrecht</i>	1.4	1.4	1.4	1.4	
<i>With additional CCS Policy in post-demo phase (only power generation), (Seebregts et al, 2010b)</i>					
Slow Coal					
All new coal power 2012-2013 equipped with CCS in 2030 (more than 3000 MW)	1.4	6.5	10.2	18.5	
Fast Coal					
2 demos in 2015; Additional New Coal after 2025 with CCS (+1000 MW)	2.8	10.8	24.4	28.4	
Fast Coal Gas					
2 demos in 2015; New Coal and New Gas after 2025 with CCS (+1000 MW new coal + 1000 MW new gas, directly with CCS)	2.8	10.8	24.1	29.6	

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3 FACILITATING EFFICIENT CO₂ TRANSPORTATION FROM ROTTERDAM TO OFFSHORE

The section introduces the main concepts of financing, contracts and risk management relating to the development of multi-user CO₂ transportation infrastructures. A conceptual financing model for a CO₂ pipeline is provided, highlighting the various key cost drivers and potential revenue streams. Options to stimulate the over-dimensioning in anticipation of additional capacity requirements are mentioned, including market initiated 'open seasons' and the use of various types of public funding.

3.1 Financing a multi-user CO₂ transportation system

One of the most prominent advantages foreseen in strategically grouping CCS installations, is the pooling of CO₂ source streams in order to reduce the number of pipelines needed to connect the capture points to the storage locations.

Specifically to the Rotterdam case and other existing industrial agglomerations, the establishment of a multi-user pipeline network in the area may facilitate the deployment of a greater number of CCS projects, as CO₂ emitters that lack the technical or financial capacity develop their own pipeline infrastructure will be able to gain access to the pipeline, presumably through a long-term contract and/or fixed transport tariff. In addition, the development of individual pipelines may be hindered due to space restrictions and the possibility of having to disrupt third-party operations during the construction phase.

Figure 3.1 depicts the relationship between the project financing, project revenue and project cost for a CO₂ transportation pipeline. The capital requirements and the expected project revenue will determine the financeability of the project in terms of access to various forms of lending and equity.

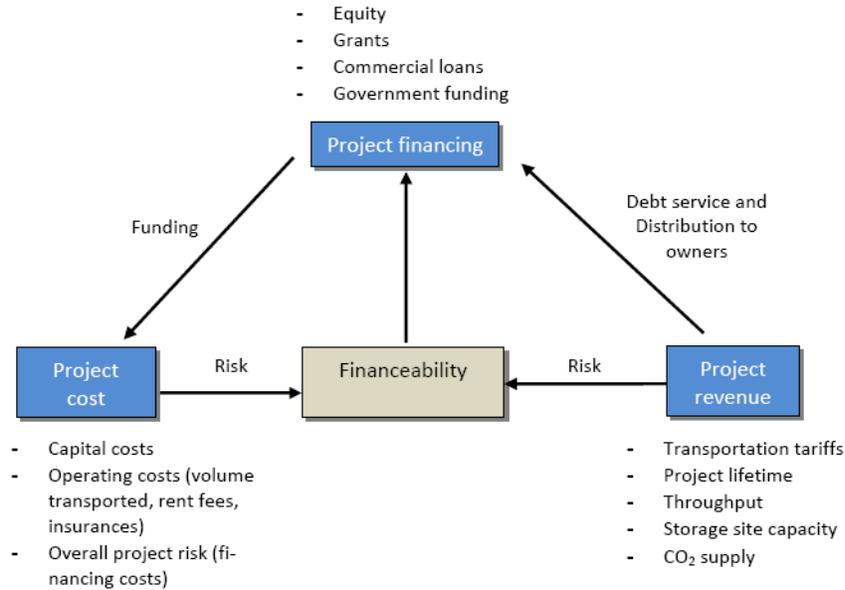


Figure 3.1 A conceptual financial model of a multi-user CO₂ pipeline

3.2 Financing over-dimensioning of CO₂ pipelines

Although in theory the advantages of over-dimensioning a pipeline are clear, there are a number of economic barriers in doing so. Firstly, the future demand for CO₂ transportation capacity will always entail a level of uncertainty. According to leading investment specialists in the Netherlands, approaching debt or equity markets in order to acquire capital for constructing any pipeline which will be initially under-utilised will be highly challenging, without a guarantee of a return on investment (E. Krijger, personal communication, 28th April, 2011). Looking at the natural gas transportation system, a final investment decision is only made and constructions starts once long-term capacity contracts are in place. For CCS, with the current low carbon prices (less than €15/tonCO₂) on the European Union Emissions Trading Scheme, transporting CO₂ cannot be compared with the established and steadily increasing demand for natural gas across Europe.

From interviews with finance specialists and potential users of CO₂ transport pipelines in the Netherlands, it can be said with confidence that without financial support from the public sector, significant³ oversizing of pipelines, compression units and/or liquefaction and intermediary storage facilities (in the case of shipping CO₂) will not occur (E. Krijger, personal communication, 28th April, 2011).

³ Significant in this case is defined as over-sizing that goes beyond the foreseen requirements of a single project, and would allow multiple large emitters to co-utilize the infrastructure in the long-term.

3.3 Achieving ‘coordinated capacity’

In light of the difficulties in acquiring investment in an underutilized pipeline, there is a risk that market parties restrict the development of transportation capacity to their own requirements. This could potentially increase the long-term overall cost of transporting CO₂, raising the costs of projects and consequently the cost of electricity generation or industrial production. There are a number of options which may encourage the investment in larger pipelines than initially necessary.

CO₂ pipeline developers can be obliged by the Member State to hold ‘open seasons’ which market test the potential for further capacity requirements in the future. However, the extent to which open seasons will facilitate over-dimensioning particularly in the demonstration phase of CCS is limited, due to the low probability of more than one CCS project coinciding with another within close proximity, both requiring capacity within a similar timeframe. Given a time lag between pipeline completion and capacity requirement, the project feasibility will thus be governed by a cost-benefit analysis between pipeline savings and the cost of temporarily unused assets

Public finances are often used in large infrastructure projects that are considered to be in the interest of society as a whole. It could be argued that public intervention through the co-investment in CO₂ transport infrastructure, is justified on the basis that taking advantage of economies of scale can reduce the overall cost to society of reducing greenhouse gas emissions through CCS.

There are a number of potential public funding options that could possibly be used for CO₂ transportation infrastructure (see Table 3.1).

Table 3.1 Sources of public funding for CCS transport projects (Chrysostomidis and Zakkour, 2008)

Public funding sources	
Loans	Governments can share the risk of an infrastructure project by providing loans through designated financial institutions such as multilateral agencies and development banks such as the European Investment Bank (EIB), the World Bank, the International Finance Corporation (IFC) and the European Bank for Reconstruction and Development.
Grants/subsidies	A subsidy is a form of financial assistance to be paid to a business or economic sector. The rationale for the disbursement of a subsidy can be that of national or supranational strategic interest. In Europe, an example of a subsidy is the New Entrants Reserve 300 (NER300), an EU subsidy programme that has 300 million EU ETS credits currently worth approximately €4,5 billion in order to co-fund up to 12 CCS projects.
Guarantees	Guarantees can be provided by multilateral agencies to help facilitate financing of a project by providing risk coverage. The provision of guarantees to large infrastructure projects helps to lower the risk and may help the network owner/operators raise long-term financing from lenders/equity institutions which in the absence of government guarantees would have not been willing to cooperate.

The type of public funding most suitable will be dependent on the interest of other entities in developing CO₂ transportation infrastructure. For example, if a CCS network owner/operator was planning on building a pipeline to meet the capacity requirements of a single project, the government may wish to provide a grant in order to finance the additional capacity. Although the level of public funding at the start of the pipeline project is likely to be high (when capacity utilization is low), it could be reduced as further parties require transport capacity and pay tariffs, the income of which can then be used to service the debt or dividend requirements of potential shareholders.

For the development of large-scale multi-user CO₂ transportation networks, with coordinated capacity to ensure sufficient capacity towards 2050, both government guarantees and supranational coordination is needed. Government guarantees are necessary to provide political risk coverage, acting as leverage for private capital investment and lending. In order to effectively manage the investments necessary to realize a cross-border CO₂ transport infrastructure, a supranational entity will be required to achieve the ‘coordinated capacity’ of pipelines. Tasks of the supranational entity would be to assess current and potential CO₂ stream sources, their quantity and timing, as well as monitoring the availability of sinks and removing barriers of organizational interoperability. This may be particularly important for the Rotterdam CO₂ Hub concept, which could accept CO₂ streams from other EU Member States.

3.4 A project financing model

The development of multi-user CO₂ transport infrastructure requires a long-term economic vision, entailing significant market and political risk. In the case of the Rotterdam CO₂ Hub, where large volumes of CO₂ from numerous sources are expected to emerge, substantial capital from a diverse range of investors including, equity from network owner/operators, commercial loans and other equity funds, in addition to public sector funds will be needed.

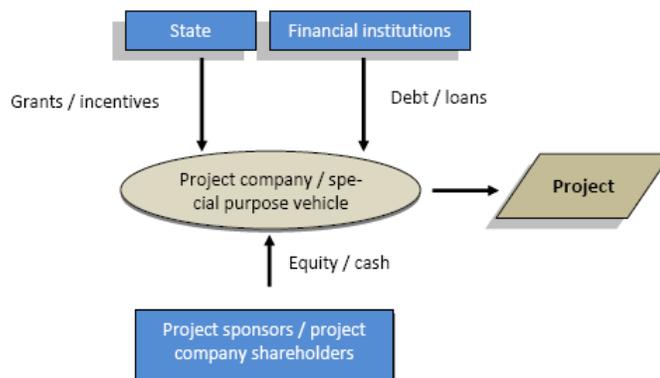


Figure 3.2 A basic project financing model

The project financing model with the establishment of a special purpose vehicle allows the financial risk of the project to be spread amongst a number of parties. Furthermore, a consortium of smaller companies may be able to raise additional capital from third-parties than if they acted alone. The use of government guarantees provides risk coverage, and will help to lever other sources of capital. Financing via a SPV is however more complex and more costly than via the balance sheet of a large integrated company which invests in the whole chain of capture, transport and storage as is the case in most demo projects.

3.5 Financial risk management throughout the CCS value chain

Two general areas of financial risk can be identified which investors may face when making investment decisions regarding multi-user CO₂ pipeline infrastructures. The first type of risks relates to the political risk that CCS as an abatement technology is no longer supported by the European Union. In this situation, the infrastructure built will not be utilized as expected. This financial risk could potentially be mitigated through the issuance of government guarantees as outlined above. The second type of financial risk is a commercial risk, whereby the revenue generated through the transport tariffs is not sufficient for the loan payments (interest and principal). This risk could be mitigated by coordinated investment plans that aim for optimum capacity utilization.

At closer examination of the entire CCS chain, the contractual structure across the CCS chain has an impact on the level of commercial risk that each entity (capture, transport and storage) is exposed to. The multiple components of the CCS chain also leads to interdependency between the parties responsible for each stage. For example, the downstream components will be reliant on the upstream capture components for revenue, while the capture entity is dependent on the downstream components of transport and storage to successfully abate the CO₂ generating the emission reduction credits. Therefore in a CCS operative chain involving multiple independent entities, the allocation of risk between the project partners must be clearly identified.

Houston and Pearce (2011), raise the point that the manner in which contracts are structured between the different entities of the CCS value chain will impact on each partners risk exposure and expected return. To demonstrate how investment risks may be spread amongst capture, transport and storage providers, Houston and Pearce (2011) model a scenario whereby the annual load factor of a power generating plant with CCS is reduced from base load to 50%. It was assumed that the power generator receives income from electricity generation and then distributes it to the other partners. Four contractual structures were investigated:

- **Fully integrated project** – all partners invest in a single entity or joint venture, and receive the same return on investment
- **Take or Pay (fixed price)** – where the contracts specify a fixed payment to both the transport and storage partner regardless of capacity utilisation
- **Market (variable price)** – where the contracts specify a price per unit of CO₂
- **50:50** – where 50% of the revenue is fixed and 50% of the revenue is variable

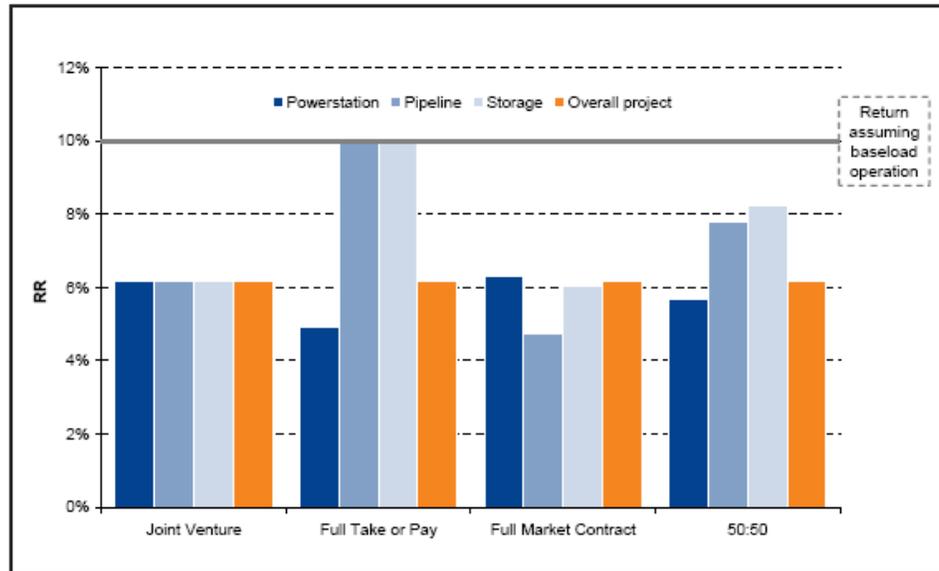


Figure 3.3 The spread of risks amongst different entities in the CCS value chain under 4 different contract structures, given a reduction in baseline power generation (Houston and Pearce, 2011).

For all four contractual structures, Figure 3.3 displays the impact of the 50% reduction in load factor on the Internal Rate of Return (IRR) for the investments made by the power station, transport and storage entity. Without the base load reduction, all the contractual structures achieve the same return on investment shown by the grey line (10% IRR). By reducing the base load of the power station highlights the different risks faced by each entity under each of the 4 contractual structures. Given a joint venture business model, all entities are exposed to the same level of risk and all experience an equal drop in return. In the Full Take or Pay model, the fixed payments contracts that the transport and storage entities hold with the power station mean that their IRR remain unaffected. The PowerStation’s IRR however, drops due to reduction in revenue and the contractual obligations to continue paying the transport and storage entities for unused capacity.

In the full market business model, all entities are exposed to the risk of the reduction in base load electricity generation. Due to the drop in generation, the power station experiences lower returns but the financial loss is minimized due to the fact that the unused capacity of the pipeline and storage does not have to be paid for. The pipeline however sees a significant drop in IRR as it relies on the revenue from the transportation to compensate for fixed capital investments common with pipeline projects. The storage entity also experiences a minor loss in revenue, however the IRR reduction is cushioned due to the fact that the storage process is dominated primarily through the variable costs of injection which can be downsized accordingly to meet demand. In the 50:50 style business model results in an intermediary result between the fixed and variable contracts.

Although the above example considers the risk to a CCS value chain due to a reduction in the electricity generation base load of a power-station. Similar risks can emerge due to a drop in the price of EU ETS credits, which dependent on the contractual arrangements of the CCS value chain could impact on the returns on all entities.

In the Rotterdam CO₂ Hub, an organization model for the development and operation of the transport infrastructure outlined in Figure 3.4 involves the formation of an independent transport and storage company. This company, the activities for which it is responsible highlighted in the area within the dashed line in Figure 3.4, is legally separated from both the production and trading of CO₂.

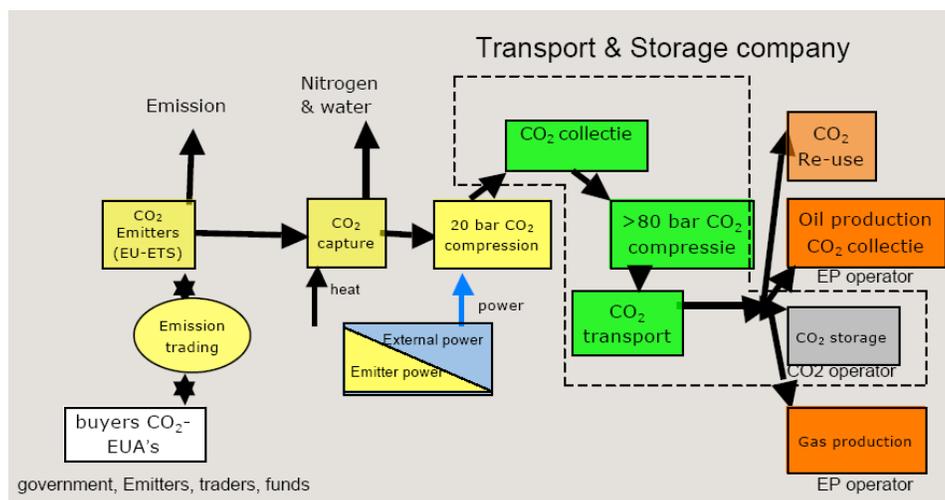


Figure 3.4 An organization model for the development and operation of the transport infrastructure of the Rotterdam CO₂ Hub (RCI, 2009)

The transport and storage company would be responsible for provide transport capacity to all capture installations using non-discriminatory tariffs. The foreseen advantages of this type of organization model are (RCI, 2009): -

- As the transport and storage company is isolated from activities of the CO₂ emitters and the potential volatility in EU ETS prices, this can lead to lower financing costs for the transport network as no risk premium is added.
- The CO₂ is transported by a gas transportation company, of whom the planning, construction and operation of gas transportation networks is a core competency.
- Standards on pressure and composition can be set in order to enable easy connection of additional CO₂ streams.

However, in addition to the transport and storage company being independent from CO₂ emitters and the EU ETS market, in order to secure the investment required, long-term contracts of 15 years or more will be needed. With regards to Figure 3.4, 'Full take or pay' contracts will be required to provide security to prospective investors that returns will be achieved through the consistent tariff payments from users, regardless of the pipeline capacity used. Furthermore, sufficient collateral will be required to secure the

necessary financing for the transport infrastructure, which can be achieved through a commitment by current and prospective project sponsors, network operators and the state government.

3.6 References

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4 OFFSHORE CO₂ STORAGE PLANNING

4.1 Approach

Recent inventories of offshore storage capacity for CO₂ in The Netherlands showed a theoretical storage capacity of about 1.5 Gton CO₂ [Vosbeek & Warmenhoven, 2007; Vangkilde-Pedersen et al, 2009]. The larger part of this storage capacity is in hydrocarbon fields (Figure 4.1). While this capacity is a theoretical capacity, assuming that all hydrocarbon fields can be re-used for CO₂ storage, recent, more detailed studies have shown that the application of thresholds on storage reservoir size and injection rate, where the latter was derived from natural gas production data, reduces the storage capacity in the Dutch continental shelf (DCS) by about 40%, to about 800 Mton in a number of gas field clusters in the central offshore [Van der Velde et al., 2008, 2009]. The latest study performed a study of individual storage locations (hydrocarbon fields), using (confidential) gas production data to estimate storage capacity and injection rates [EBN-Gasunie, 2010], to investigate the development of transport and storage until 2050.

These recent studies show that the total effective offshore storage capacity, in terms of the storage capacity pyramid from the Carbon Sequestration Leadership Forum (CSLF), is about 1 Gton. This is roughly the amount of CO₂ captured at four large coal-fired power plants in a period of 40 years. Storage capacity is present in a large number of relatively small gas fields, with the largest fields of the order of 100 Mton. Most of these are producing fields that are expected to reach their end of production between 2015 and 2025. Current legislation requires that infrastructure be abandoned shortly after the end of production. This infrastructure may well prove highly valuable for re-use during CO₂ injection. Given the large number of offshore gas and oil fields, the development of CCS must be planned, to identify the fields of key importance, to minimize expensive rebuilding of infrastructure and to avoid excessively long (and equally expensive) hibernation periods of hardware. This chapter models CO₂ storage on the DCS for two different scenarios and studies the effects of the timing and size of the CO₂ supply on the capacity and costs of CO₂ storage in the DCS.

This section describes the method used to model the development of offshore CO₂ storage in the Netherlands. The option of transporting part of the CO₂ available from the harbour area to oil fields in the North Sea for EOR purposes is included, to study the effect on the development and cost of domestic offshore CO₂ storage. The time horizon of the offshore development is 2080, to include in the results the time when the limits of the offshore storage capacity become apparent.

The present study stores the CO₂ captured in the industrial areas in the Netherlands, Belgium and Germany in offshore storage reservoirs (both depleted hydrocarbon fields and deep saline formations). The time of availability of the storage reservoirs is leading

in the decision which reservoirs are to be used, with the restriction that nearby reservoirs are used first.

The following sections describe the model that was used to match the captured volumes to storage reservoirs (section 4.2), the CO₂ supply scenarios (section 4.3.1) and the data of storage capacity and availability of the storage reservoirs (section 4.3.2), the pipeline network (section 4.3.3) and storage cost data (section 4.3.4), which also includes a small paragraph on general economic parameters used in the study.

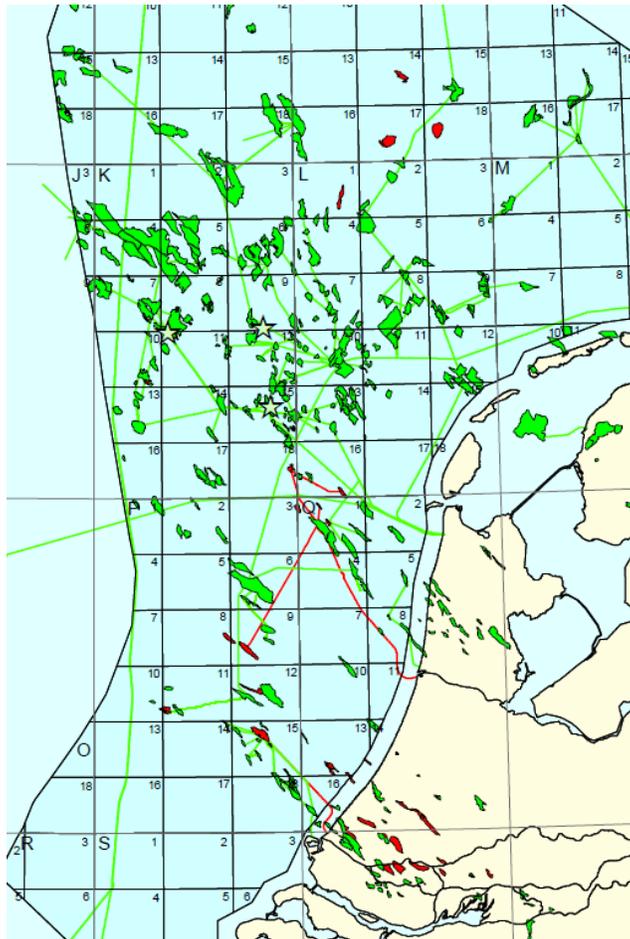


Figure 4.1 Hydrocarbon fields in the Netherlands offshore. Green: gas fields, red: oil fields. Not shown are offshore deep saline formations, with an estimated (but realistic) storage capacity of about 100 Mton. Figure taken from www.nlog.nl.

4.2 Model

A CCS decision support tool is used that was developed in the EU FP7 Geocapacity project. The model performs an economic analysis of CO₂ capture, transport and storage for multiple sources and sinks, connected by a pipeline network [Neele *et al.*, 2009,

2011]. This tool analyses the economics of the CCS chain stochastically, propagating into the key performance indicators the uncertainty in all input parameters, most notably those associated with the geological properties of the storage reservoirs. In the simulation of offshore CCS, new fields are developed (installations and wells reworked or new built) as previous fields reach their limit, with the choice for a new field depending on its distance from the source. Each time, the closest new field is selected from all available gas fields (i.e., fields that have reached their end of production and that are available for re-use as a CO₂ store) or saline formations.

The input to this model is, as far as storage capacity is concerned:

- the location in the network, relative to the source of CO₂, of all reservoirs;
- the storage capacity (in Mton), feasible injection rates (in Mton/yr/well), the number of wells;
- the first year that CO₂ storage is possible; this is assumed to be one year after the currently foreseen end of production.
- the type of platform on the reservoir (processing versus satellite platform)
- depth of the reservoir; this is used in the computation of the cost of new wells;

All of the above data, as well as the cost data described below, can be specified as stochastic data, i.e., the uncertainty in any of the data can be taken into account in the computations.

4.3 Data

4.3.1 CO₂ Supply Scenarios

The capture scenarios outlined in chapter 2 have been combined with the forecasts for CO₂ requirements for EOR in chapter 5 in order to create two scenarios for the previously described model. Chapter 9 provides more details on how these scenarios were created. The following two scenarios have been used for this study, based on the amount of CO₂ transported to the DCS:

- Scenario 1: scenario without EOR priority
- Scenario 2: 50% scenario with EOR priority

Scenario 1 is the regular scenario without a priority for EOR. This scenario results in large volumes of CO₂ being transported to the DCS. In scenario 2, however the CO₂ stream is reduced to 50% and a priority is put on EOR, resulting in much smaller quantities of CO₂ being transported to the DCS (See Figure 4.2).

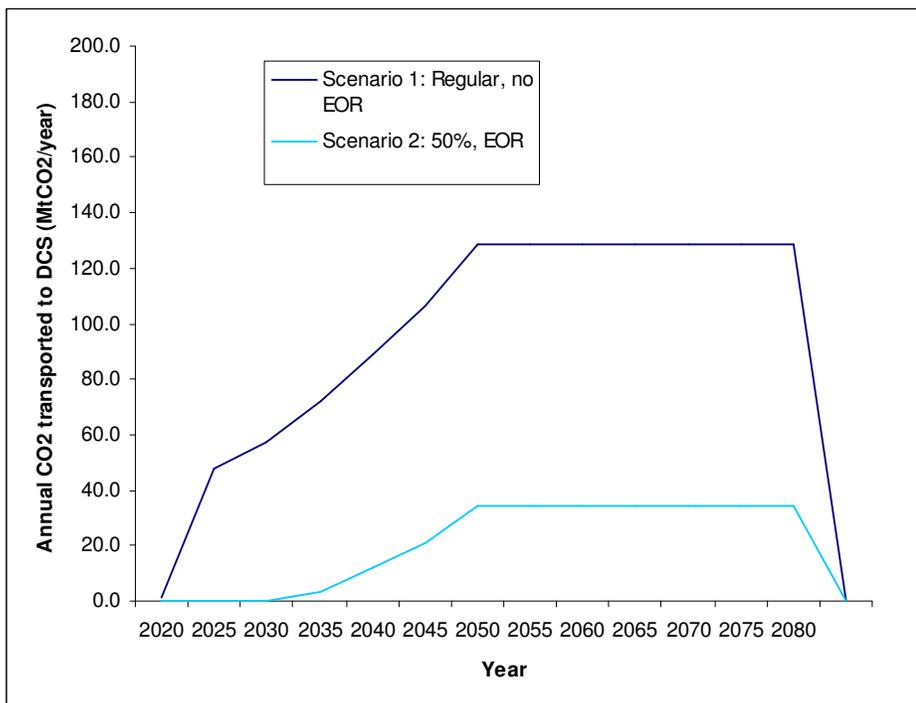


Figure 4.2 Scenarios for the CO₂ transported to the DCS. Scenario 1 (dark blue) is the scenario without EOR, which results in a large CO₂ stream to the DCS and scenario 2 (light blue), is the 50% scenario with a priority for EOR, which results in a smaller stream of CO₂ to the DCS.

In this study, the period considered is 2015 – 2080, to include the full economic lifetime of all capture installations that together produce the captured volumes. The captured volumes from these installations decrease to zero after about 2080, to emphasize the temporary nature of CCS. While this may underestimate captured volumes beyond 2050, the results will show whether the DCS can fully store CO₂ captured at installations built until about 2050.

4.3.2 Storage capacity data

Data on the storage reservoirs are taken from public repositories⁴ and recent reports on CCS in the DCS [Van der Velde et al., 2008, 2009]. The data include the end year of production, storage capacity, the number of wells and well injection rate. All of these data are uncertain (e.g., the end year of production strongly depends on the gas price) or confidential and must be estimated. Uncertainty ranges were specified and used in the modeling. The number of wells was taken from the distribution of existing wells in the field. In a field with closely spaced wells, re-use of wells is assumed to result in a single injection well, while multiple injection wells are assumed possible if existing wells are located far apart. In the absence of reliable public data on well injection rates, each well

⁴ Data available at www.nlog.nl

was assumed to have a maximum injection rate between 1 Mton/yr and 1.5 Mton/yr. In the stochastic analysis of the Geocapacity tool, both storage capacity and well injection rate were randomly varied. Table 4.1 shows the size distribution of offshore storage capacity. This also includes the Q1-Saline deep saline formation, which is considered suitable for CO₂ injection and has a large capacity. The initial technical total storage capacity of over 1 Gton is distributed over a large number of relatively small fields.

Although the technical capacity of the individual fields is of crucial importance for determining the total storage capacity of the Dutch offshore, economic factors also play a large part. The main characteristics of the fields which influence its economic feasibility are the size of the fields and the distance of the fields from the main trunk line. Whether or not it is possible to re-use existing infrastructure also affects the economic attractiveness of a field, but it is outside the scope of this paper to assess this for each of the fields on an individual basis.

The CAPEX of small fields is similar to the CAPEX of larger fields. This means that investments in small fields are relatively large compared to their storage capacity. As such smaller fields are less likely to be economically feasible. For this study, a cut-off point of 5 Mton has been selected, following the approach of *Van der Velde et al. [2008, 2009]*. This means that all fields which have a storage capacity of less than 5 Mton are excluded from the analysis.

Table 4-1 *Distribution of DCS gas fields and the Q1 saline deep saline formation, taking the cut-off points for capacity and distance from main trunk line into account.*

Capacity range (Mton)	Number of fields	Total capacity (Mton)
5 – 10	5	40
10 – 20	8	123.25
20 – 50	11	415
> 50	2	136.25
deep saline formations	1	110
	27	824.5

In addition to the size of the field, the distance of the field to the main trunk line also affects its economic storage potential. Faraway fields require large investments in pipelines and compressors as compared to closer fields. In order for it to be worthwhile to make large investments in faraway fields, the fields should be able to accommodate large quantities of CO₂. For this study, an arbitrary chosen cut-off point of 1 Mton per 2 km distance from the main trunk line is used. This means that for each two kilometers of distance from the main trunk line, the field should have at least 1 Mton of storage capacity.⁵ If this is not the case, the field is excluded from the study. At a cut-off point of 1 Mton per 2 km results in an estimated decrease in storage capacity from around 1100 Mton to around 825 Mton, e.g. a reduction of close to 275 Mton.

⁵ This means that the distance from the main trunk line divided 2 should be larger than the storage capacity of the field.

4.3.3 Pipeline network

The production, especially in the central part of the Netherlands offshore, is organized around large platforms that process the gas produced by a cluster of smaller platforms (and fields). Pipeline and platform availability is determined by the last producing field in a cluster; the dates of availability of fields in such a cluster were adjusted accordingly. It is assumed that any new CO₂ pipelines will be laid along existing pipelines. Pipeline re-use is likely to be an option only for satellite lines leading from central processing platforms to satellite platforms. The main gas trunk lines will be used for natural gas at least until the last of the gas fields is taken out of production. The existing network of satellite lines was represented in the Geocapacity model, with new CO₂ trunk lines leading out of Rotterdam and Amsterdam into the offshore area (see Figure 4.4 (below), the new CO₂ trunk lines are indicated in red, while the existing pipeline grid is shown in black), similar to the approach used previously [Van der Velde *et al.*, 2008, 2009; EBN-Gasunie, 2010]. The feasibility of re-using existing pipelines is not considered here.

The costs used for calculating the required investments for deploying the new pipelines are based on figures from ZEP and Gassco. After correcting for the lack of onshore pipelines and subsea platforms in our test case, the following formula was used for the model:

The cost C of constructing offshore pipelines, in M€, is given by the following relation

$$C = 35 + 0.065DL$$

Equation 1: Costs for offshore pipelines

D is the pipeline diameter (inch) and L the pipeline length (km). Mobilization/demobilization costs and landfall and riser installation costs are included in the fixed cost of 35 M€.

4.3.4 Storage cost data

A recent study addressed the cost of building new offshore installations or converting existing offshore production platforms [TEBODIN, 2009]. This study provides the data to assess the cost of developing CCS in the DCS. The options are, for each field, to either use new wells and platforms, or to re-use and convert existing production installations. The cost data used are shown in Table 4-2.

The cost elements taken into account include:

- *Hibernation, re-use and new build.* CO₂ injection may not always follow smoothly on the end of gas production. When this transition time is limited, the installations can be prepared for an idle time and maintained with a minimum of maintenance. A recent study showed that this can be more cost efficient than rebuilding platform and equipment and drilling new wells, if the idle period is shorter than about 10 years [EBN-Gasunie, 2010]. The feasibility and cost of hibernation should be assessed for each platform separately, as re-using the

installations for the duration of CO₂ storage implies using them well beyond their design lifetime. For this modeling exercise, it is assumed that when the delay between the end of production and the start of CO₂ injection is longer than 10 years, installations are abandoned and assumed to be built new when required. Otherwise, installations are converted and re-used after an optional period of mothballing.

- *Abandonment.* The cost for abandonment is taken into account for the different platform types (satellite platform, processing platforms, subsea completions), but only in case new platforms are constructed. If hydrocarbon production installations are re-used, it is assumed that the abandonment budget provided by the production operator is transferred to the CO₂ injection operator.
- *Monitoring.* Estimates for the cost of monitoring, as given TEBODIN [2009] are included in the unit cost of storage. Monitoring is assumed to continue until 10 years after the end of injection.

Table 4-2 Cost data for storage of CO₂ in offshore depleted gas fields. All figures are expressed in million Euros. OPEX is provided in years. Data taken from TEBODIN [2009].

Cost element	Mothballing		Construction modification / operation and		Abandonment	Monitoring	
	CAPEX	OPEX	CAPEX	OPEX		CAPEX	OPEX
Export platform, new	-	-	39.5	6.2	20.5	2.8	2.8
Export platform, re-use	4.5	1.5	20.8	16.4	31.5	4.3	4.3
Satellite platform, new	-	-	39.5	6.2	20.5	2.8	2.8
Satellite platform, re-use	2.6	0.7	13.2	6.4	20.5	2.8	2.8
Subsea completion, new	-	-	4.3	-	10	2.8	2.8
Subsea completion, re-use	-	-	1.8	3	10	2.8	2.8
New well	30 M€						

4.3.5 General economic data

Economic parameters, such as inflation and tax rate are mostly based on estimates which are taken from chapter 9. The depreciation period was set to 25 years and a WACC of 10 is used in all calculations. The discount rate has been set to 10%.

4.4 Results

4.4.1 Development of offshore CCS

Maximum annual injection rate and peak of annual injection rate

The maximum feasible injection rate and peak of the annual storage rate were computed, using the CO₂ streams from the two different scenarios. Figure 4.3 shows the yearly total injected volume for both scenarios. Given the assumed well injection rate of between 1 Mton/yr and 1.5 Mton/yr per well, maximum storage rates are of the order of 40 Mton CO₂/yr for scenario 1 and 35 Mton CO₂/yr for scenario 2, although in both cases these injection rates drop steeply after peaking.

It shows that for scenario 1, the yearly injected volume peaks early, a couple of years already after injection started. For scenario 2, where the CO₂ stream is much smaller and starts a lot later, the yearly injected volume peaks a little bit later. This is because injection is started a later period and smaller quantities are used.

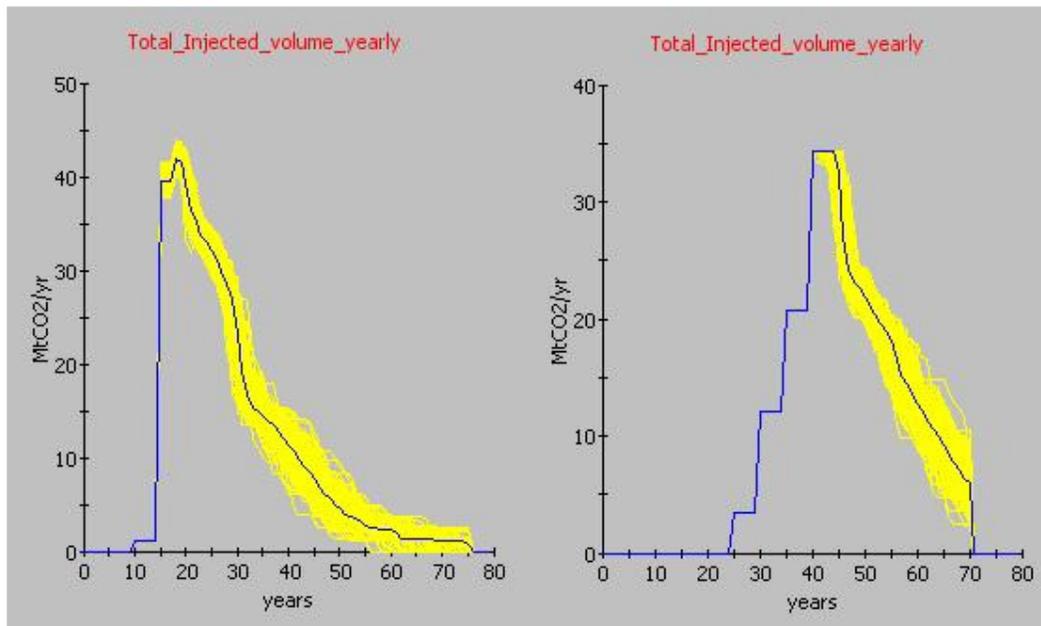


Figure 4.3 Total injected volumes yearly for scenario 1 (left side of graph) and scenario 2 (right side of graph).

Development of storage network and idle times

By using the scenarios from Figure 4.2 in the model, the start year of injection for each field can be determined. Using the year the field becomes available for injection and the start year of injection, the idle time can be calculated for each field. The results have been mapped and are shown in Figure 4.4 and Figure 4.5. The results suggest that CCS can develop, starting in the reservoirs close to Rotterdam and gradually expanding and developing the more distant sites, based on how fast the existing storage capacity is filling up. The fields which have long idle times (longer than about 10 years) are likely to be located further away from the main trunk line. For several fields, idle times up to 20 years are computed. For these fields, hibernation costs may be prohibitive and the field can be expected to have been abandoned by the time CO₂ arrives in the area. New installations and wells are then required for the field to be used for storing CO₂. As can be seen, for scenario 2 (Figure 4.5) the lower CO₂ streams lead to longer idle times as compare to scenario 1 (Figure 4.4).

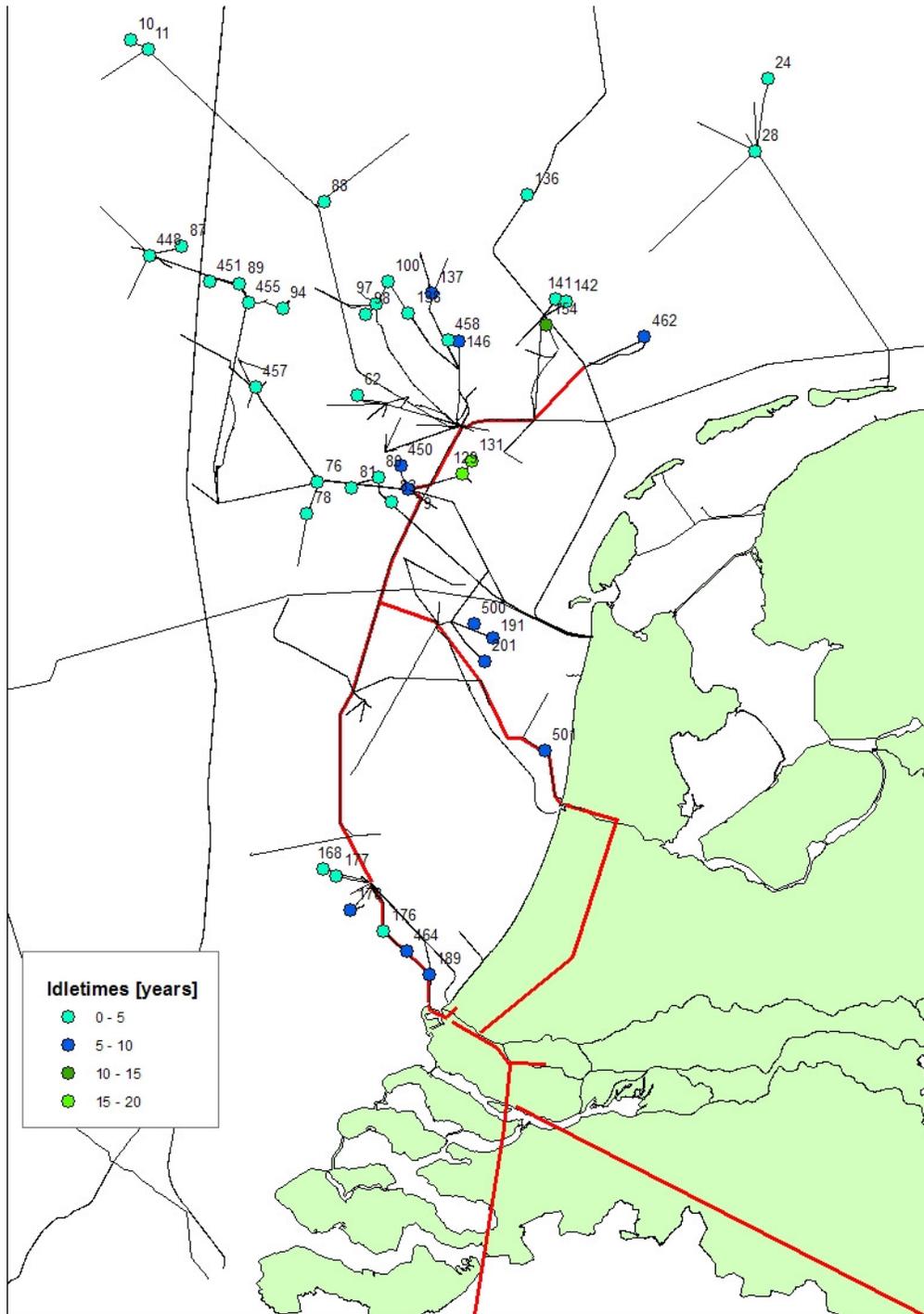


Figure 4.4 Map of the idle times for gas fields in the Netherlands offshore, using supply scenario 1 shown in Figure 4.2, which delivers a large stream of CO₂ to the DCS. The red lines represent new CO₂ trunk lines leading to the large processing platforms in the central offshore; thin black lines represent existing hydrocarbon pipelines.

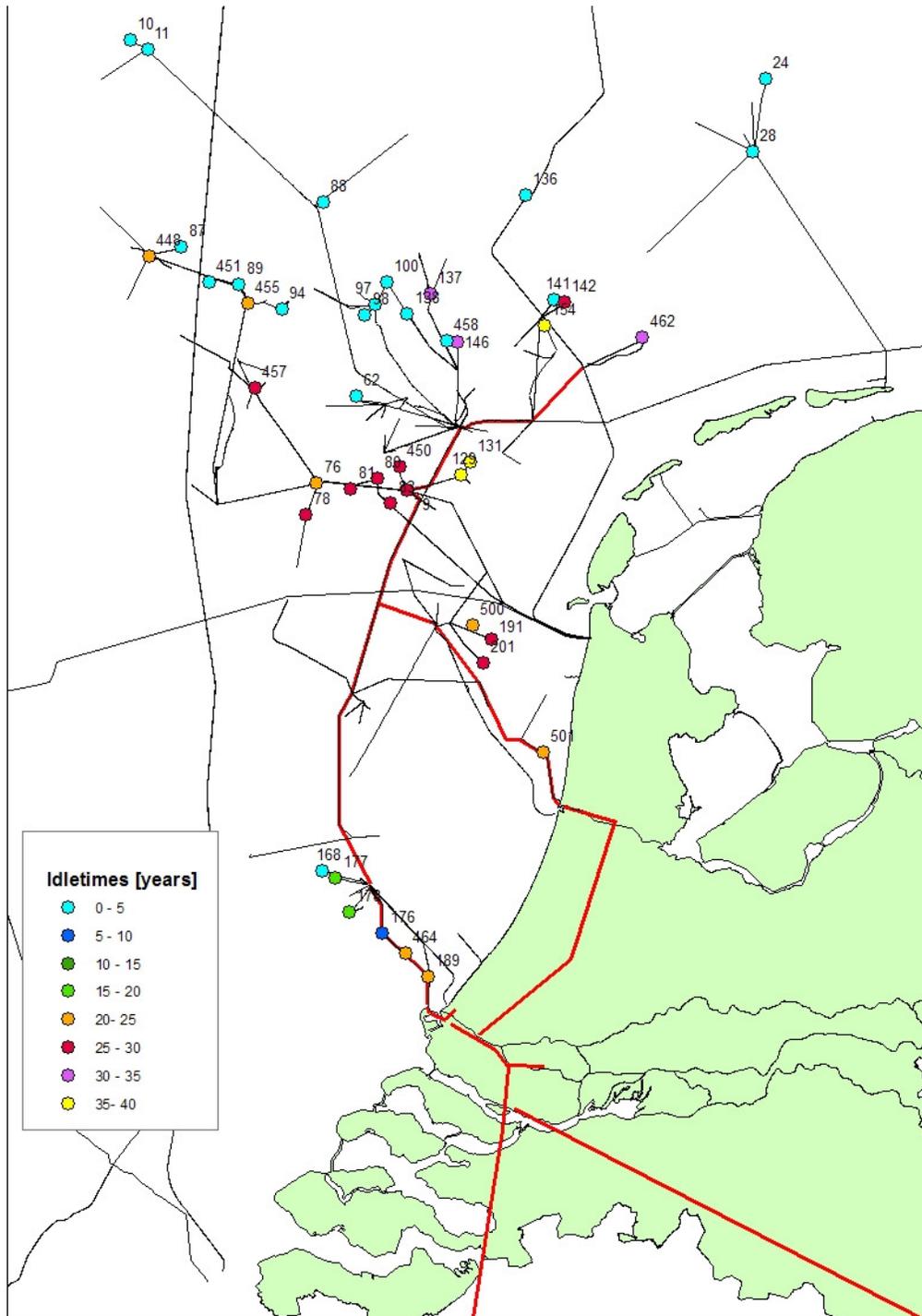


Figure 4.5 Map of the idle times for gas fields in the Netherlands offshore, using supply scenario 2 shown in Figure 4.2, which delivers a smaller stream of CO₂ to the DCS. The red lines represent new CO₂ trunk lines leading to the large processing platforms in the central offshore; thin black lines represent existing hydrocarbon pipelines.

4.4.2 First-order cost estimates of offshore CCS

Running the model with the previously described technical and economical input provides output regarding the costs associated with transporting CO₂ from Rotterdam to the offshore gas fields. For both scenarios, the capital costs for transport lie in the range of 2 to 3 euro per ton CO₂. This means that the amount of CO₂ does not influence transport costs very much. Regardless of the scenario, the pipelines are constructed and the fields are filled up and the costs for pipelines divided by the amount of CO₂ stays the same

It should be noted that hibernation costs and construction costs of platforms are not considered a part of the transport infrastructure and hence not represented in transport costs.

4.5 Discussion and recommendations

4.5.1 Timeline of CCS development

A large supply of CO₂ to the DCS means that all fields that become available for storage can be utilized right away. This means that most platforms can be reused immediately and costs for constructing new platforms are minimal. In addition, no costs have to be made for mothballing.

However, when large quantities of CO₂ are directed to the DCS, for instance from Belgium and Germany, the yearly storage capacity peaks quickly and storage capacity is exhausted rapidly.

4.5.2 Pipelines construction planning

Due to the large initial investment costs of pipeline construction (Table 4-2), it is worthwhile to group the construction of several small sections of pipelines together. This means some stretches of pipeline have to be constructed in advance, which leads to additional OPEX and making costs up front, which is unattractive from a financial perspective. When constructing pipelines, this has to be balanced with the advantage of lower fixed costs.

4.5.3 Third Party Access

Third party access to infrastructure, as mentioned in the EU CCS Directive, is a hotly debated topic in the CCS world. Recent developments in the UK suggest that it might be possible for operators in the future to make use of spare capacity on the platforms of other operators.⁶ How this will develop in the Netherlands is yet still unclear. It could, however, influence the availability of platforms and reduce the need for constructing new platforms. This can influence the economic attractiveness of CO₂ storage.

⁶ <http://www.carboncapturejournal.com/displaynews.php?NewsID=792>

4.5.4 CO₂-EOR: cost and benefits for NL offshore CCS development

The use of CO₂ for EOR limits the amount of CO₂ which should be stored at the DCS. A smaller volume of CO₂ which has to be stored at the DCS means that the capacity of the DCS will run out later and there is more time to look for alternative storage locations.

It can also mean that less CO₂ is available to fill the fields that become available right away, thus leading to higher idle times. High idle times can make mothballing platforms economically unattractive and favor the new construction of platform for injection, thus in turn driving up storage costs.

4.6 Conclusions

The size of the individual depleted hydrocarbon fields and their position in relation to the backbone has an influence on their economic attractiveness. The quantity and timing of the CO₂ stream which is directed to the DCS determines when the amount of CO₂ stored yearly peaks and when the storage capacity fills up.

A small CO₂ stream also affects the costs of storage because it leads to longer idle times and as such higher costs for mothballing and construction of injection platforms. The size of the CO₂ stream does not influence the transport capital costs, because the total pipeline CAPEX and amount of CO₂ injected stays the same.

4.7 References

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5 POTENTIAL DEMAND FOR CO₂ FOR EOR FROM STRATEGIC FIELDS IN THE NORTH SEA

5.1 Introduction

The use of CO₂ for Enhanced Oil Recovery (EOR) is a proven method for both increasing oil production from depleting oil fields and storing CO₂ in the geological formation in the process. The process has been in wide use in the US and Canada since the 1970's and is currently responsible for the production of approximately 250,000 barrels of oil per day. The financial benefit of the oil produced, together with strong tax breaks introduced by the US government, has encouraged the development of 2600 km of high pressure onshore CO₂ pipelines as seen in Figure 5.1 for the distribution of the CO₂ from both natural and anthropogenic CO₂ sources.

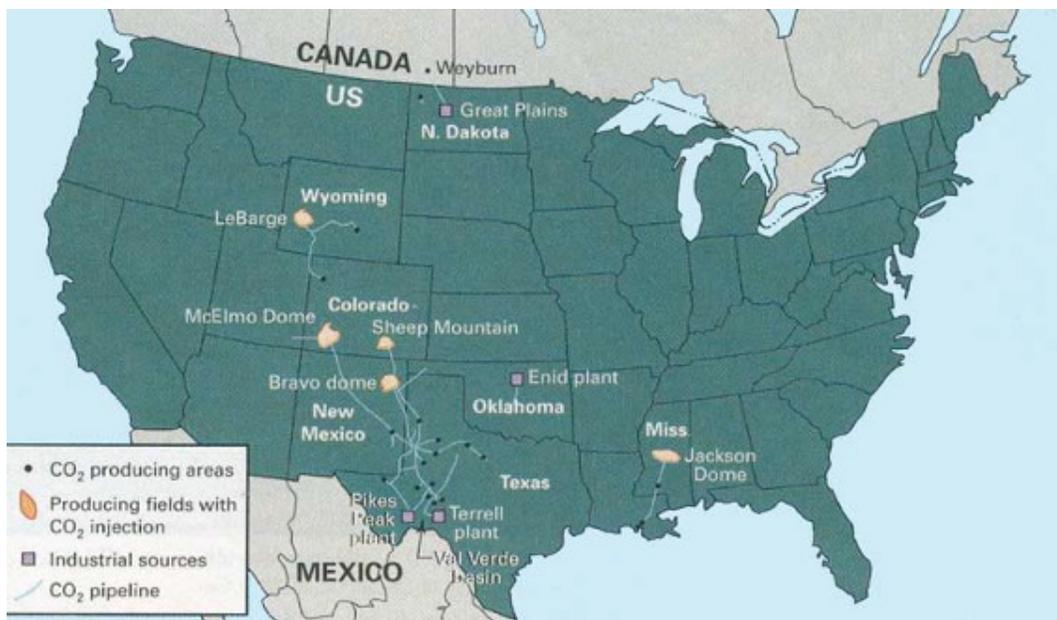


Figure 5.1 CO₂ pipelines in North America. (Courtesy of Oil and Gas Journal)..

CO₂ under the pressure and temperature conditions of many of the oil fields in the North Sea is miscible to the oil in place. Simply stated, CO₂ is injected directly into the oil field where it dissolves into the oil swelling the oil and reducing its viscosity so that the oil becomes more mobile. Depending on the design of the CO₂ flood, water may then be injected behind the CO₂ to help push the oil with dissolved CO₂ toward the producing wells. Figure 5.2 depicts how this type of flood works.

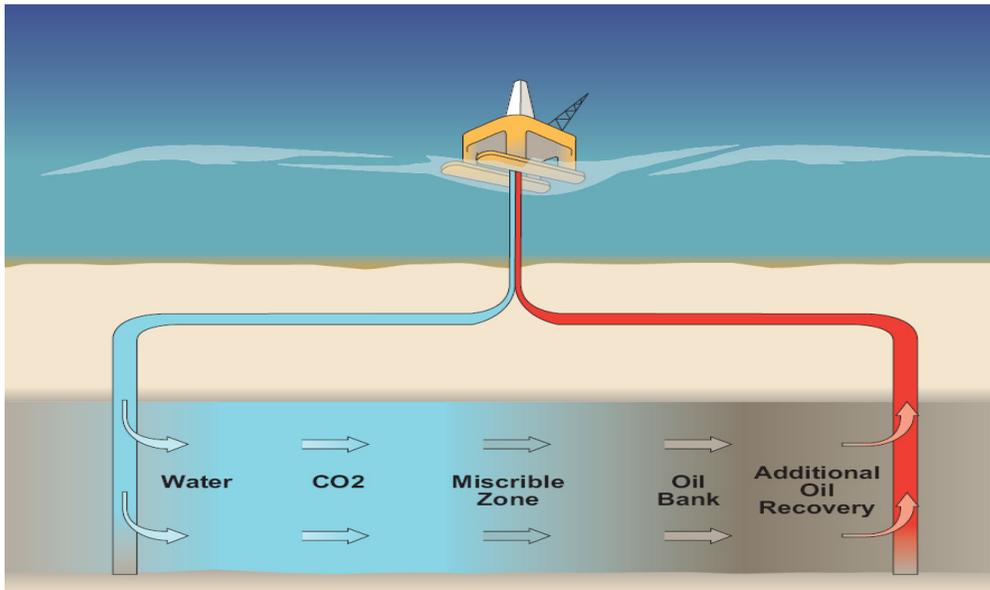


Figure 5.2 CO₂ EOR schematic for an offshore application. Courtesy of Statoil SA.

Approximately 50% of the CO₂ injected stays in the oil field permanently while the remainder is produced with the oil. The CO₂ produced with the oil must then be separated from the oil, dehydrated and recompressed to put back down into the oil field with additional CO₂ until the tertiary oil recovery is completed and all the CO₂ is stored in the geological formation of the depleted oil field.

Like in the US experience, the economic benefits of CO₂ for EOR may assist in the build out of infrastructure in the North Sea for CO₂ storage. The EU NER 300 CO₂ Capture and Storage demonstration projects should prove the availability of anthropogenic CO₂ while using the nearby offshore CO₂ storage opportunities such as depleted gas fields and saline deep saline formation formations. Oil field operators then will be able to make an assessment of whether there is or will be sufficient supply for future EOR projects and to assess the economics of EOR and whether they are willing to assist in the funding of pipelines to reach the EOR/Storage prospects that are much further away than the depleted gas fields and deep saline formations.

There also is a substantial benefit if the governments are supportive of CO₂ for EOR, like the US government in the seventies of last century, and the build out of infrastructure since the costs of decommissioning of oil field platforms in the UK and Norwegian sectors are shared between the offshore operators and their respective government treasuries. With oil prices exceeding \$75 per barrel, tax rates are from 62% to 78% on oil production and there is a potential to produce 8-20% of the original oil in place through CO₂ EOR in a given field. With these numbers the economics of CO₂ for EOR should be favourable to all the parties. Subsequently, a mutually beneficial

programme is required to delay decommissioning, build out CO₂ pipeline infrastructure and supply CO₂ for EOR and permanent storage.

5.2 Potential Demand for CO₂ in the North Sea

The European CO₂ Value Chain Project known as the ECCO Project under the EU FP7 Programme completed an analysis of the oil fields throughout the North Sea with respect to their CO₂ storage potential and their use of CO₂ for EOR. ECCO has also developed a more specific list of strategic oil fields that have been assessed with respect to the amount of CO₂ that might be stored through the process of Enhanced Oil Recovery as a means of developing a demand for CO₂ that could help finance infrastructure for delivering captured CO₂ to the North Sea. This is not an evaluation based on rigorous individual field analyses but one that relies on usage factors for CO₂ and anticipated periods when CO₂ EOR would most likely be considered as part of the solution for tail end or tertiary recovery for individual fields.

The assessed demands are grouped by sub regions of the North Sea in which a hub or pipeline interconnection may enable a point for distribution of large volumes of CO₂. The sub regions are:

The Southern Norwegian Sector (including fields like Ekofisk, Eldfisk, Embla, Tor, Valhall, Gyda and Ula)

The UK southern portion of the Central North Sea (including fields like Auk, Fulmer and Clyde)

The UK central portion of the CNS (including fields like Gannet, Nelson, Forties, Elgin, Andrew and Arbroath)

The UK northern portion of the CNS (including fields like Brae, Piper, Scott, Claymore and Buzzard)

The UK and Norwegian NNS (including fields like Beryl, Dunlin, NW Hutton, Ninian, Gullfaks, Statfjord, Oseberg) Some of these fields will require significant delays to decommissioning or re-commissioning but the prize at each should be significant.

The first four sub regions have been identified because with respect to the Rotterdam project, these are the sub regions easily reached and serviced by one or possibly two substantial CO₂ Europipe pipelines. The fields of the UK portion of the Northern North Sea and the Norwegian Tampen Region are not included initially as these would require a further set of parallel pipelines from the Netherlands or Northern Germany to supply sufficient CO₂. These lines will most likely be required to completely supply the Danish Sector, the Southern Norwegian Sector, the UK NNS and the Norwegian Tampen Region.

5.3 Demand and Build Out Strategy

The Build Out Strategy put forward for the Rotterdam Case is based on an initial proof of available CO₂ supplies from the EU NER 300 and EU EPR programmes. The ECCO analysis predicts a substantial CO₂ EOR demand in the Southern Norwegian Sector and the southern portion of the UK CNS to justify the CO₂ pipeline extensions into the region branching at a hub inside UK waters to reach both of these sectors in a

first phase of CO₂ Storage and EOR activity shown in Figure 5.3 and Figure 5.4. The second phase would extend the UK branch up to the Gannet Tee of the proposed COOTS Ltd pipeline coming from Teesside in the UK to the CNS fields from Gannet to Brae enabling access to the proposed branch lines for all the fields within the central portion of the UK CNS shown in Figure 5.5. The third phase would probably require a second parallel pipeline from the Netherlands to the branch hub in the UK waters and an extension of the Norwegian branch northward to tie into the COOTS line at or around the Brae field shown in Figure 5.6. By then, it is proposed that the old Miller gas line from the Miller field to St Fergus would be converted to a CO₂ line and that CO₂ from Scotland and CO₂ from the COOTS line and the CO₂Europipe line would supply CO₂ to the oil fields of the UK NNS sector post 2026 as shown in Figure 5.7, unless oilfield operators were willing to pay for earlier deliveries and supplies could be developed.

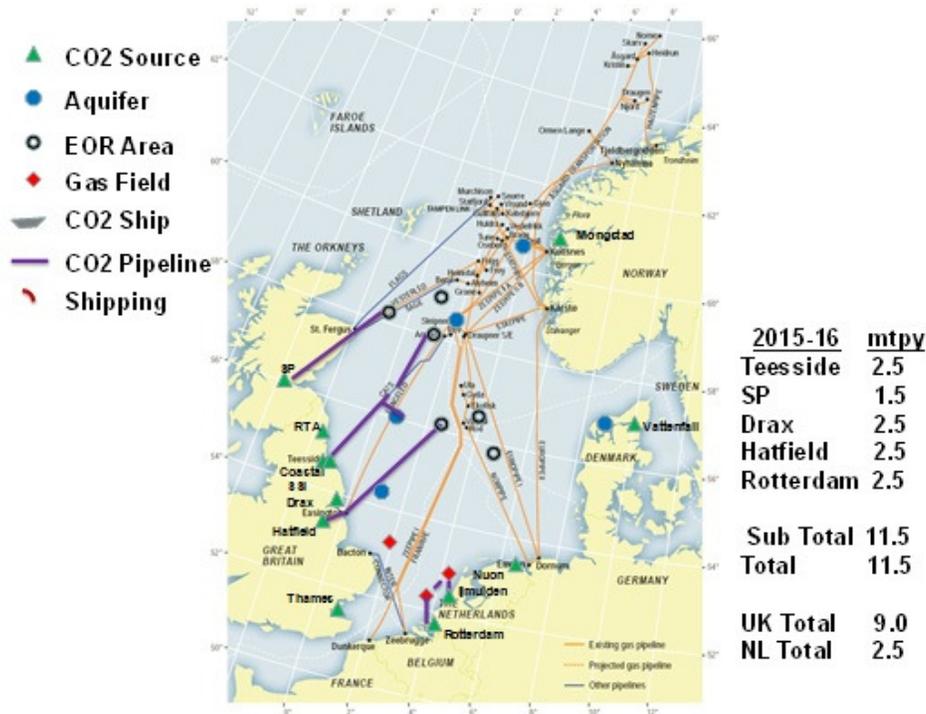


Figure 5.3 Potential 1st Phase A CO₂ Storage and EOR Infrastructure Projects (2015-16)

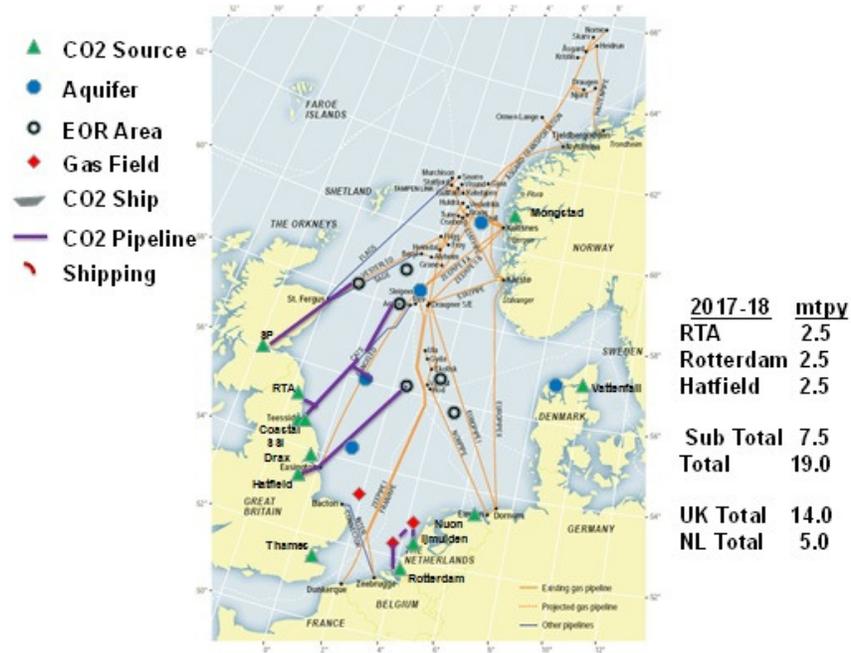


Figure 5.4 Potential 1st Phase B CO₂ Storage and EOR Infrastructure Projects (2017-18)

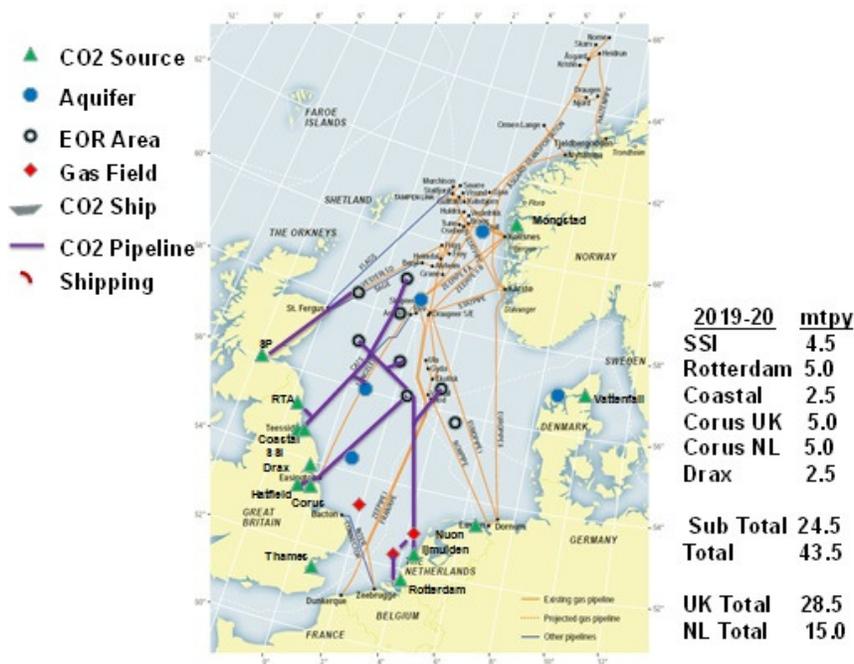


Figure 5.5 Potential 2nd Phase CO₂ Storage and EOR Infrastructure Projects (2019-20)

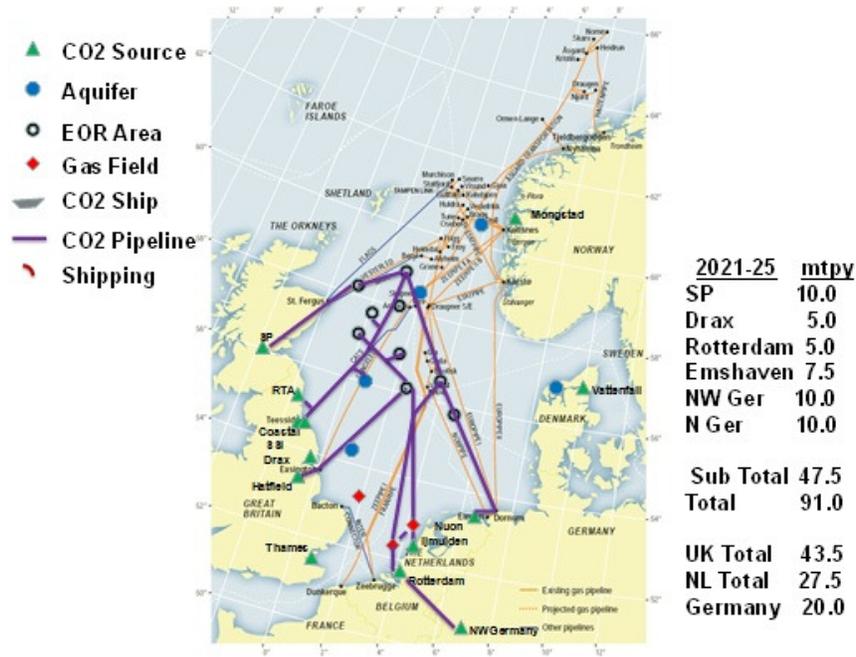


Figure 5.6 Potential 3rd Phase CO₂ Storage and EOR Infrastructure Projects (2021-25)

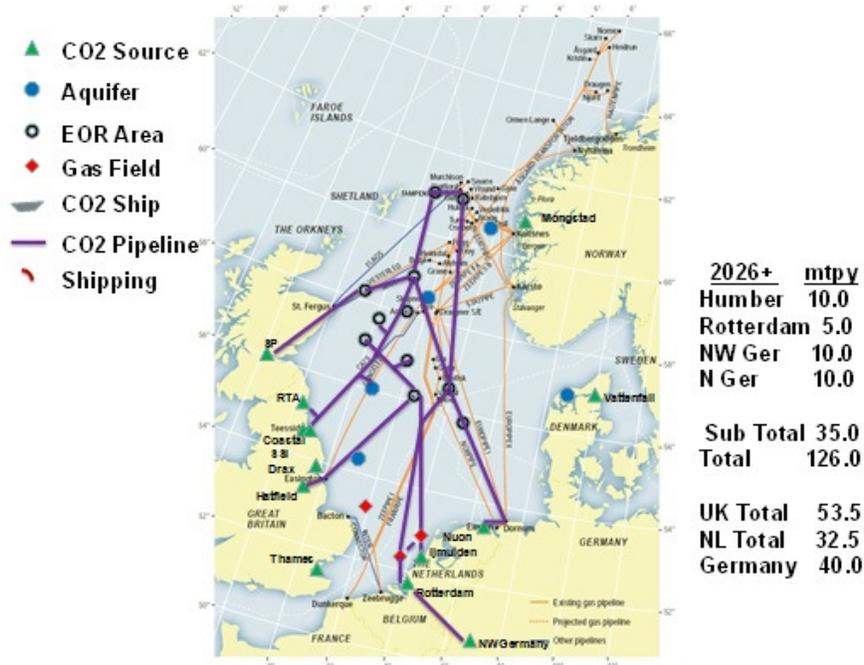


Figure 5.7 Potential 4th Phase CO₂ Storage and EOR Infrastructure Projects (2026+)

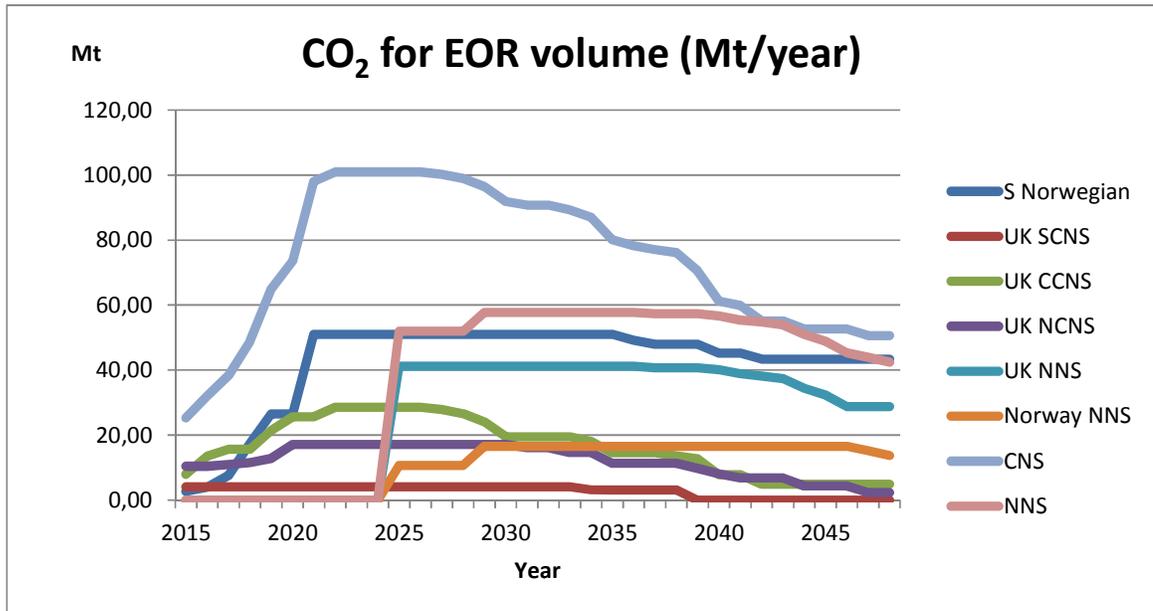


Figure 5.8 Potential Demand for CO₂ for EOR from all clusters in the different regions in the North Sea

Based on the above build out concept, the potential demands for CO₂ for EOR for specific strategic fields were assessed based on a start date of 2016 and the year when the fields would significantly benefit from CO₂ EOR without interfering too much with the production of the remaining secondary oil capacity. In some cases, to minimize disruption of existing production, new platforms designed for reprocessing CO₂ laden produced fluids will be built, located and connected up to existing facilities at the fields. This has the added benefit of minimising the amount of expensive conversion work done on old existing platforms while de-loading these same platforms as a means of extending their useful life as infrastructure for power generation, export of hydrocarbons, habitation, control and communication.

In addition to the proposed COOTS Ltd pipeline, another pipeline is also proposed from the Humberside region and it may eventually extend to the same area of the southern portion of the UK CNS. However, the analysis indicates the need for CO₂ in these four regions far outstrips the available CO₂ for many years to come and when the supply exceeds this demand and the demand that may come from other fields in the four regions, it will be time to extend the pipelines to the UK NNS and the Norwegian Tampen Region in conjunction with other lines from Europe. Figure 5.8 indicates the total annual CO₂ demand for the different sectors in The North Sea as well as the total cumulative demand from 2015 till 2050. Additionally, the demands for CO₂ included in Figure 5.8 are not necessarily the optimised distributions for field demands but are more levelled demands reflecting a constrained supply of CO₂. Larger earlier supplies may be more optimum for EOR and more economically advantageous for building out the infrastructure but the amounts listed are a first cut on CO₂ demand. Note also the deep saline formations in the regions will also provide significantly larger volumes for CO₂

storage once the pipeline infrastructure is built out and funded by the demand for CO₂ for EOR.

The demand for CO₂ starts in 2016 but may not be large enough to justify the installation of a large pipeline until 2019. This is also consistent with a perceived need of proof of CO₂ availability prior to oil field operators seriously considering the investment in platform modifications or consideration of supporting the installation of a purpose built CO₂ pipeline into the region. The EU NER 300 programme can begin establishing the availability of CO₂ from Rotterdam where it may be stored in a depleted gas field until larger supplies are developed and a regional pipeline is installed. Note based on supplies indicated in figures above, the demand exceeds the supply for decades. However, if supplies are not made available in the near future, there is a greater risk that oil field infrastructure will be decommissioned and opportunities for EOR will be lost.

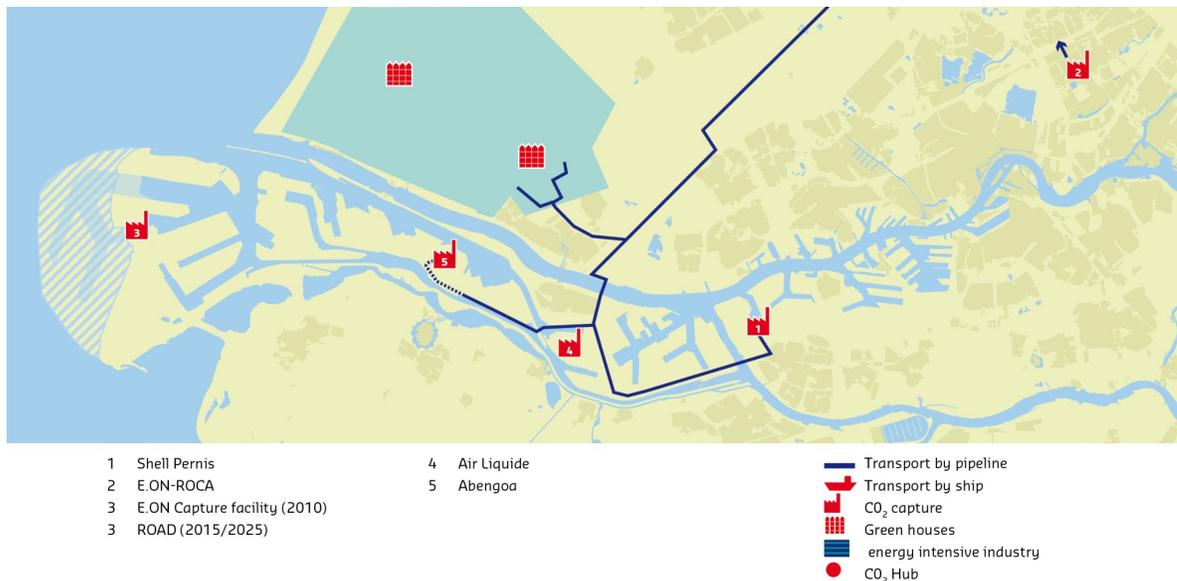
5.4 Conclusions

- The economic benefits of CO₂ for EOR may offer an opportunity to assist in the funding of the build out of the CO₂ pipeline infrastructure needed to get to large depleted oil fields and deep saline formations in the Central and Northern North Sea.
- The EU NER 300 and EU EPR funding programs will help demonstrate the availability of CO₂ for EOR but much greater supplies of CO₂ are needed to fully realize the potential of CO₂ for EOR.
- Offshore EOR requires high investments by oil field operators that require timely design and construction of a large CO₂ backbone to the oilfields to connect to large scale onshore capture units.
- There is an opportunity window in time for CO₂-EOR which requires timely design and construction of transport infrastructure in order to prevent early decommissioning of oil fields before sufficient CO₂ supplies are developed
- North Sea rim governments should assess the potential for delaying decommissioning in order to maintain the infrastructure for CO₂ EOR and storage.
- CO₂ for EOR could be the mechanism for delaying costly decommissioning of oil field infrastructure, extracting more needed oil, financing the CO₂ pipeline infrastructure, producing more tax revenues, creating more jobs and opening up distant, large geological formations for the storage of CO₂.

6 START OF ROTTERDAM CCS HUB: THE ROAD PROJECT

6.1 Current situation

At the moment there is an existing CO₂ pipeline (the OCAP pipeline) delivering CO₂ from the Shell Pernis refinery and Abengoa to the greenhouses, as well as another pipeline from the E.ON power plant delivering CO₂ to greenhouses in another area near Rotterdam. These pipelines and volumes are relatively small compared to full scale CCS, but can provide a spring board for further development of a local collection network.



The first integrated CO₂ capture transport and storage project which can act as an anchor project for further developments in Rotterdam is the ROAD project. ROAD stands for ‘Rotterdam Opslag en Afvang Demonstratieproject’ (Rotterdam Capture and Storage Demonstration Project) and is one of the largest integrated demonstration projects in the world for the capture and storage of CO₂.

The initiating parties of the ROAD project are E.ON Benelux and Electrabel, GDF SUEZ Group. Together they constitute the Maasvlakte CCS Project C.V. joint venture. The joint venture aims to collaborate with intended partners GDF-SUEZ E&P Nederland B.V. for the transport of CO₂ and TAQA Energy B.V. for the CO₂-injection and permanent storage under the seabed of the North Sea. The ROAD project is co-financed by the Government of the Netherlands and the European Commission within the framework of the European Energy Programme for Recovery (EPR).

Starting in 2015, approximately 1.1 megatons of CO₂ on average per year will be captured, transported and stored in depleted gas reservoirs under the North Sea. ROAD is a demonstration project aimed at facilitating an integrated CO₂ capture, transport and storage chain - Carbon Capture and Storage (CCS) - on an industrial scale. It will scale up existing CCS technologies which now need to be applied and integrated on a larger scale. ROAD is a unique project due to its industrial and fully integrated CCS chain.

6.2 Challenges

There are several challenges for the ROAD project on different aspects, like technical, legal, economic, organizational and social. For example, one of the challenges is new legislation being implemented (CCS Directive) into national legislation. This causes the storage permit process and content to be new to applicants and the competent authorities. Main points of attention coming with this new regulation are the monitoring requirements, financial contribution and handover regime. If there is uncertainty around these issues for companies involved in the chain it is difficult to determine the cost of storage and associated (financial) risks.

A challenge of a different kind comes with public funding. The ROAD project is seen as an anchor project for starting CCS in the Rotterdam region. Building a future proof transport system, e.g. oversizing the pipeline for what the ROAD project would need and therewith creating a backbone for CO₂ from Rotterdam to the Dutch offshore, would help the future development of CCS in the Rotterdam area. However, public funding does not allow the ROAD project to oversize, due to state aid regulation. Other investors are allowed to pay for oversizing of the pipeline, but may feel reluctant to do so, since the market developments are uncertain and there is now only one source and one sink going to be connected. This could mean that when CCS will take of the pipeline could be full rather soon.

6.3 The ROAD pipeline

The ROAD is designing to transport the captured CO₂ from the E.ON power plant to the TAQA operated offshore gas fields. Initially the pipeline will transport the CO₂ in gas phase, due to the low pressure in the reservoirs and there will be no additional transport capacity available. In time when pressure in the reservoir increases CO₂ will be transported in dense phase. The transport capacity in that case would be 5 Mton/year.

The pipeline route provides some challenges. The pipeline has to cross the Yankze harbor and the shipping lane. Two HDDs (Horizontal Directional Drillings) are needed to overcome these challenges. Keep in mind though for future developments there are a limited number of pipeline slots available under the Yankze harbor. Oversizing should therefore be considered or slots should be held available for future pipelines, unless they are going to be re-routed over the Maasvlakte 2.

In order to facilitate 3rd parties CO₂ to be transported via the ROAD pipeline tie-ins are foreseen to be built into the pipeline. Tie-in possibilities for the pipeline will be near the E.ON site (before the Yankze harbor crossing) and before the pipeline goes offshore,

i.e. before the shipping lane. Provisions will also be made to extend the pipeline offshore, so when other sinks will become available the pipeline can be extended. So, technically the pipeline can function as a starting point of a CO₂ transport system.

The funders of the ROAD project (The Dutch and EU government) require there needs to be Third Party Access. This means if there is transport capacity available and there is a third party wanting to make use of the pipeline, access needs to be provided. The business model is being set up to be able to facilitate this arrangement.

6.4 The ROAD transport pipeline business model

The operator of the ROAD pipeline will be GDF-SUEZ E&P Nederland B.V. The operator will be responsible for the utilization, operation and maintenance and other services required to operate the pipeline according to best industry practice.

The operator will be responsible to sign, on behalf of the investing shareholder(s) of the pipeline, transportation agreements with multiple customers. The transportation agreement aims at being transparent, non-discriminatory and at reflecting the risks being born by the investing shareholder(s) of the ROAD pipeline. The risks mainly being financial risk of amongst others the initial investment and the operating cost.

The transportation agreement will govern the capacity reservation, nomination and allocation between the customer and the pipeline operator as well as describe the tariff structure.

Capacity reservation:

In short, all customers will nominate a firm reserved capacity profile corresponding to their expected usage of pipeline capacity. On a regular basis, customers may revise the reserved capacity profile. As such, a reserved capacity profile is a firm commitment from the customer. Based on the firm commitments the pipeline operator knows if there is pipeline capacity to be marketed or if all capacity in the pipeline is booked.

Tariff structure:

The transportation tariff will be based on two different tariff items:

- a capital item covering the (initial and future) investment(s) and
- an operational item covering operation and maintenance costs.

The capital item of the transportation tariff will be calculated such that the investors achieve a fixed rate of return on their investment. The capital item of the transportation tariff is therefore ‘take or pay’ and based upon the reserved capacity of a customer.

The capital item of the transportation tariff is a function of the total capital investment costs (depreciated over at least 20 years) and the revenues (based on a low rate of return) from total reserved capacity commitments. The capital investment costs include

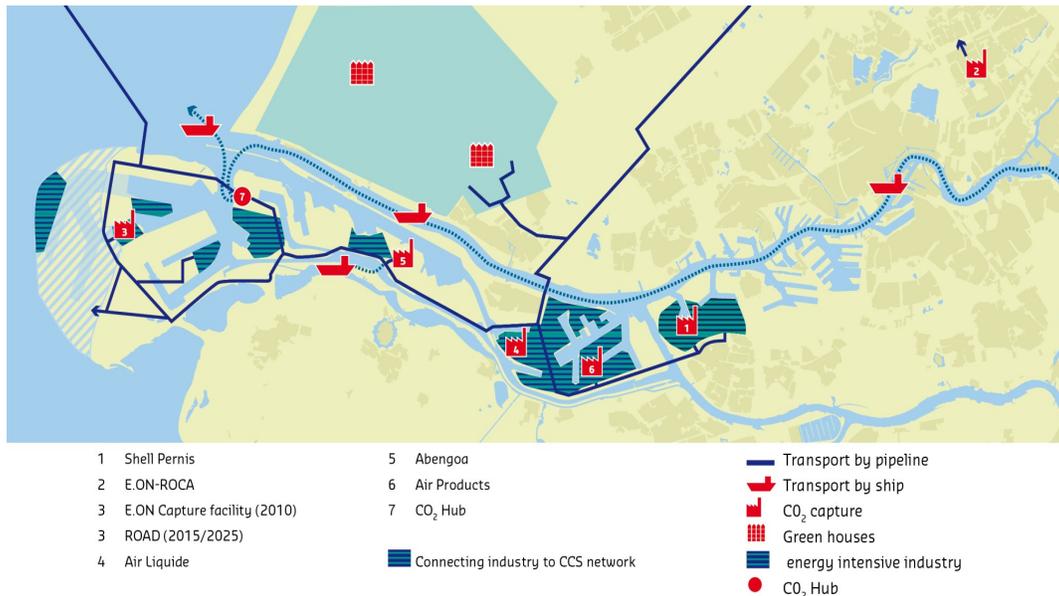
the incurred capex and any potential forecasted remaining capex escalated for inflation. The revenues include the historical payments received from customers for reserved capacity as well as the expected future reserved capacity payments. The capital item of the transportation tariff will be escalated every year with inflation. Customers will be charged based on the reserved capacity profile times the capital item of the transportation tariff, regardless of actual usage.

The operational item of the transportation tariff will be charged to the users of the pipeline based upon actual usage i.e. throughput on a yearly basis. The operation costs consist of all direct and indirect costs incurred by the operator for the operation, maintenance, repair and survey of the pipeline. The total operational costs will be divided among users proportionally to their respective actual usage. At the beginning of any calendar year, the operational item of the tariff for each customer will be estimated based on budgeted costs and reserved transportation capacity. At the end of any calendar year, an adjustment will be realized using the final operational costs incurred and the actual throughput volumes of the customer.

Title of the CO₂:

The title of the CO₂ will remain with the emitter. The pipeline operator is merely a shipper. This means the operator/owner(s) of the pipeline will not buy EUA's in case there is leakage.

6.5 Future outlook



The ROAD pipeline can be a stepping stone for the Rotterdam area, but since the Rotterdam region has a high concentration of industrial emissions it is questionable for how long. If CCS takes off in the future the capacity of the ROAD pipeline is quite

limited, but could serve several smaller and/or seasonal CO₂ volumes. In order to facilitate bigger volumes (>5 Mton) a bigger pipeline and/or a shipping route need to be developed.

In time both options will arise due to the need for transport capacity and diversity of the sinks in size and location. By connecting these two transport outlets synergies can be created, for example when one sink or transport mode is out of operation the other can serve as a backup so emitters can still store their CO₂. Another advantage especially in case an EOR sink is connected having multiple outlets allows emitters to pool with their CO₂, so the operator of the EOR sink would be more certain of CO₂ being supplied, since this is required for the EOR purpose.

7 ROTTERDAM CO₂ HUB: THE ROLE OF CINTRA

7.1 CO₂ Hub concept

In the oil and gas industry the combining of flows at strategic terminal locations such as main seaports was driven by the fact that combining flows allow for economies of scale and a level of logistical flexibility compared to point to point volume flows.

The main topic in the CO₂Europipe project, transportation, implies the need for logistical solutions that are optimal from a logistical, technological and economical perspective. The projected CO₂ volumes that need to be captured, transported and stored into permanent storage locations to achieve the targets set in the EU (and on a bigger level in the IEA) 'Blue' scenario are of such scale that point to point solutions in a post CCS demo phase would be highly inefficient and costly. Therefore the base principle of Oil and Gas terminaling should be applied to the CO₂ logistical challenge that these volumes create.

7.2 Core principles of the CO₂ hub

- Gather from multiple sources and distribute to multiple offshore sinks
- Provide independent custody transfer metering (for ETS)
- Network building blocks (at rivers and coast lines)
- Allow for different transportation modalities to feed captured CO₂ from multiple emitter sites to the CO₂ hub location by
 - Onshore pipeline transportation (gas phase)
 - Inland barge transportation (liquid phase)
- Export to different offshore storage locations (depleted gas fields, deep saline formations and producing oil and gas fields for EOR and EGR purposes) via different modalities
 - Offshore pipeline transportation (gas phase)
 - Deep-sea ship transportation (liquid phase)

The CO₂ hub is to be located on the seashore side in a preferably easy access, high traffic and high volume throughput seaport with Hinterland access. As this would create a precedent to accommodate the (large) CO₂ volume flows in surroundings (e.g. port authorities) that are accustomed to handling these intense traffic and volume flows.

Schematically the hub functionality can be summarized as depicted below:

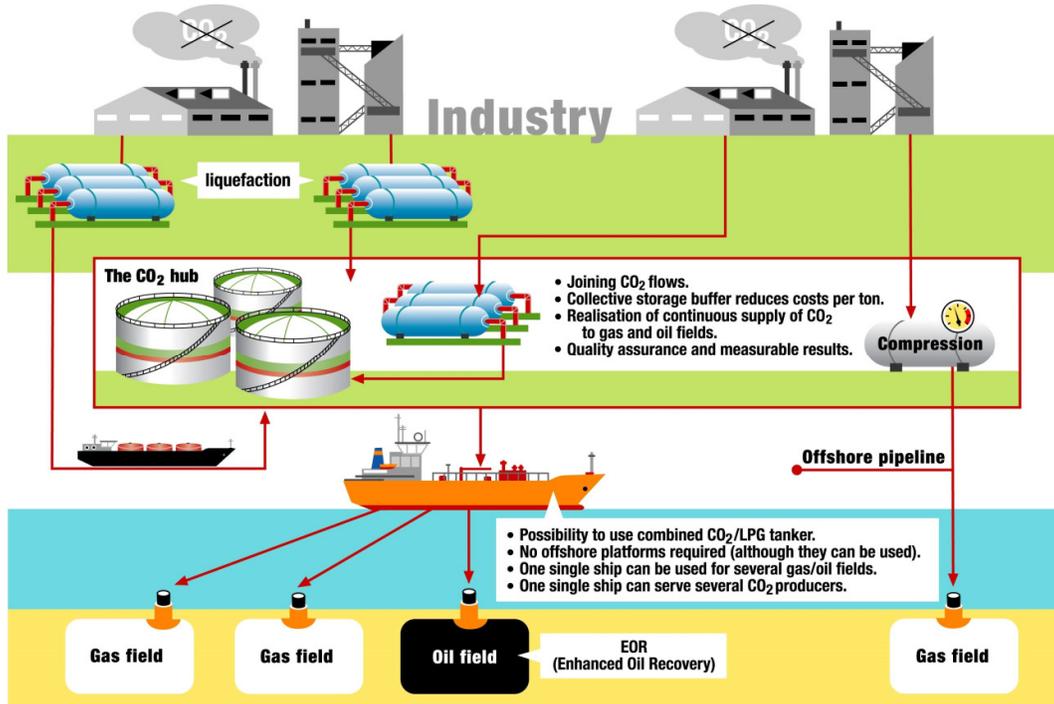


Figure 7-1 CO₂ hub functionality (source: Rotterdam Climate Initiative)

The main advantage of hub solution is that multiple customers (emitters and field owners) can be served offering one another system flexibility and reliability through the shared facilities. For example if emitter A has a contract to deliver a fixed volume to field owner A and due to maintenance requirements or other unforeseen outages of the capture facility, emitter A can't fulfill its contractual obligations, then the pooled CO₂ volume that come into the terminal from an emitter B could be diverted to field owner A. Avoiding injection shutdowns/hick ups and as such contractual liabilities. This also works the other way around, having multiple field owners creates alternative storage locations if one of the fields goes offline.

In the terminalling business it is common market practice to use the above system though it must be noted here that sufficient emitters and field owners must be connected to the CO₂ hub to enable similar functioning. Nevertheless, even in the demonstration phase, advantages of the CO₂ hub are clearly present: having the option to divert captured flows to other storage locations.

As outlined above an advantage of a CO₂ hub located in a seaport will allow for the usage of the flexibility that a CO₂ carrier (rather than a pipeline) can offer to serve a multitude of fields

- (i) that are small in storage capacity (and therefore not worthwhile to serve via pipeline)
- (ii) and remotely located demising the economics of a pipeline installation.

Located at a seaport, that by nature has a link to the Hinterland will allow for further sourcing of CO₂ to the CO₂ hub location. The port of Rotterdam is a perfect example: the Rhine is considered to be an important cargo flow to the Rotterdam port region from the German and Eastern European hinterland. As described in WP4.2, significant CO₂ volumes can be transported over inland waterways, which avoids construction of pipelines through sometimes densely populated areas. The latter is a lengthy process from construction and permitting point of view, even more so given the novelty of CO₂ transportation by pipeline in the EU.

The CO₂ hub is technically only possible if the process facilities in place allow for the working envelope of the different CO₂ phases that are encountered at both inlet and outlet of the port. Below the phase diagram of CO₂ with the typical CO₂ phases for shipping and pipeline transport is plotted. The CO₂ Hub will allow for the phase changes between the transportation modalities (i.e. from liquid to gas and vice versa) and as such link the different modes of transportation (from barge and shipping to pipe and vice versa).

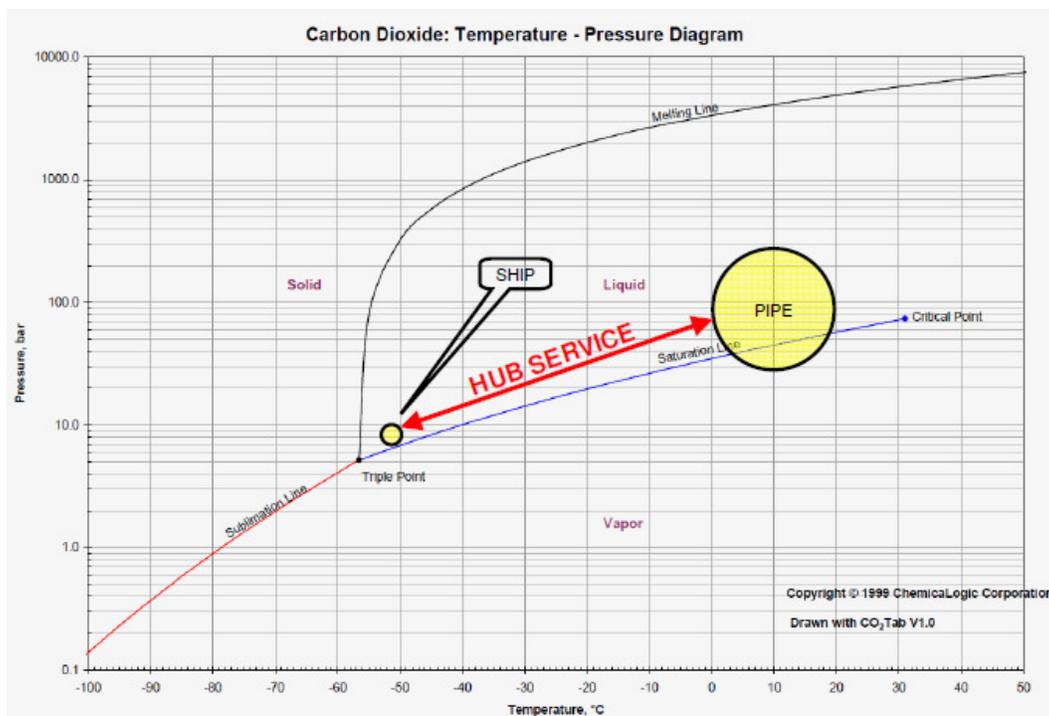


Figure 7-2 CO₂ hub phase functionality (courtesy of ChemicaLogic Corporation and Vopak LNG)

Below a list of process facilities and other equipment that must be present to facilitate the envisaged service:

- **Intermediate storage facilities:** to allow for (i) fast offloading and loading of the barges and ships, and (ii) facilitate a buffer capacity that avoids forced capture shut downs due to downstream hick ups. The storage facilities envisaged in the Rotterdam CO₂ hub concept are cylindrical pressurized tanks; ease of

production and cost considerations have led to this choice. Usage of tanks will allow for further capacity expansion by simply adding tank(s) to the CO₂ hub location.

- **Liquefaction** to allow (iii) for the incoming gaseous CO₂ to be liquefied and shipped out, (iv) reliquefy boil of gas coming from the intermediate storage and liquid CO₂ handling
- **Regasification/vaporization** of the incoming liquid CO₂ or already present intermediately stored liquid CO₂ to allow for pipeline export
- **Compression** facilities to send out the gaseous CO₂ via offshore pipe line
- **Loading and offloading** facilities and jetties/quays for the barges and ships

The (Rotterdam) CO₂ hub concept came to (public) life early 2010, when the companies Air Liquide, Anthony Veder, Gasunie and Vopak signed a letter of cooperation with the city of Rotterdam and the Rotterdam Climate Initiative to create a CO₂ hub in the Rotterdam port area using the four companies' core competencies required as described above⁷. CINTRA (Carbon In Transport, joint venture of aforementioned companies) is the party that will offer the one stop for both emitters in the Rotterdam area (and the Hinterland) and storage providers offshore as operator of the CO₂ Hub. Under the umbrella of the Rotterdam Climate Initiative these parties and local (both small and large scale, power plant and industrial) emitters had a platform to come together and transform the Rotterdam port area to a CO₂ hub location. In contrast to other demonstration projects worldwide that are using or envisage using point to point connections, the linking pin of a CO₂ hub will allow the flexibility of having multiple emitters and offshore storage locations linked together. Hence creating a more reliable CCS chain.

⁷ Press release 17/3/2010 Rotterdam Climate Initiative

8 EUROPEAN CO₂ TRANSPORT INFRASTRUCTURE ROTTERDAM TO UTSIRA

8.1 Introduction

The D 2.2 report concludes that from 2020 onwards, when CCS will be deployed on very large scale, a large Pan-European network will be necessary as not every region will have sources and sinks in close proximity. Even in Rotterdam, the depleted gas fields in the Dutch continental shelf might offer insufficient storage capacity in time for the large CO₂ supply based on local CO₂ capture and large CO₂ import streams. Therefore, a joint effort between D 4.1.1 with the European/Norwegian test case (D 4.3.2) using data from Gassco and Siemens has evaluated the potential and technical feasibility of CO₂ transport from the Dutch continental shelf to the Norwegian Utsira deep saline formation. This effort is carried out in parallel with the ECCO project for CO₂ storage related to CO₂-EOR outside the DCS as described in chapter 5 and 9.

8.2 Assumptions

- maximum CO₂ injection from Rotterdam in Utsira is 20 million ton CO₂/year
- the pipeline from Rotterdam to Utsira follows a straight line (the deviation in pipeline length is small when connection to EOR fields are considered) and its size is 30 inch internal diameter and roughly 700 km long
- The maximum CO₂ inlet temperature for the pipeline in Rotterdam is 50 degrees C.
- The wellhead pressure of 90 bar at the most faraway Dutch field (J06A with 35 meter seabed depth) at 267 km North-West from Rotterdam is sufficient for the designed injection throughput
- No booster stations are required for intermediate compression
- Throughputs are based on 8000 run hours per year

The calculations are carried out with OLGA software that takes into account the non-ideal behavior of dense phase CO₂.

8.3 Results

Table 8-1 lists the required compressor discharge pressure (in the 2nd column) to achieve the required injection throughput (in million ton CO₂/year) at the Dutch depleted gas fields J06A (upper Northwest part of the Dutch continental shelf). Subsequently the compressor discharge pressure is listed for the same throughput range in the Utsira deep saline formation (in the 3rd column). It seems odd that at low throughput the required compressor pressure is lower for the Utsira deep saline formation (roughly 600 km from Rotterdam) than for the J06A which is (only) 267 km from Rotterdam. The reason is the much lower required wellhead pressure for the

Utsira deep saline formation (54 barg) than for J06A (80 barg). This implies that a choke may be required at the wellhead for the Utsira deep saline formation at low throughput. As the Utsira deep saline formation is very large and has a very high permeability it is expected that the wellhead pressure will rise only slightly over the years with a maximum pressure increase of 20 till 30 bar (reference: Sigve Apeland, Gassco).

Table 8-1 Required compressor discharge pressure for different throughputs, for a pipeline from Rotterdam to depleted gas fields in the most distant parts of the Dutch continental shelf.

Throughput	Pressure (J06A)	Pressure (Utsira)
5	92	80
10	105	95
15	127	151
20	157	227

The timing for construction of the pipeline extension and the high pressure compression stages will depend on many factors. Thus, one can start with a compressor station that delivers up to 100 bar and later expand the station with high compression stages above 200 bar. CO₂ demand for EOR might start earlier than available large scale storage in the Dutch continental shelf. This case would incentive initial investment and construction in a large backbone pipeline from Rotterdam to the EOR fields with tie-ins for the nearby depleted gas fields that would follow the trajectory to Utsira. In the following graphs temperature and density of the pipeline CO₂ is presented as a function of distance from the Rotterdam compression station near shore for throughput increasing from 5 till 20 million ton CO₂/yr. The warm CO₂ is gradually cooling down due to the cold seawater. The density increases strongly when the temperature decreases below the critical temperature (30 degrees C.) when CO₂ transport switches from supercritical to liquid phase transport.

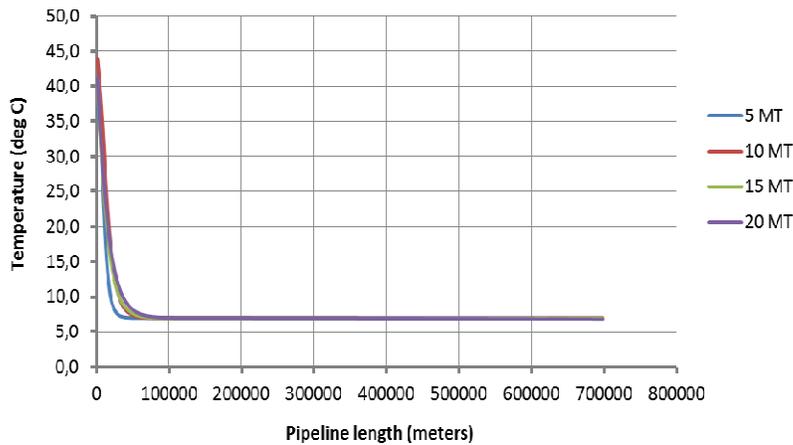


Figure 8.1 CO₂ temperature in CO₂ backbone pipeline from Rotterdam to Utsira

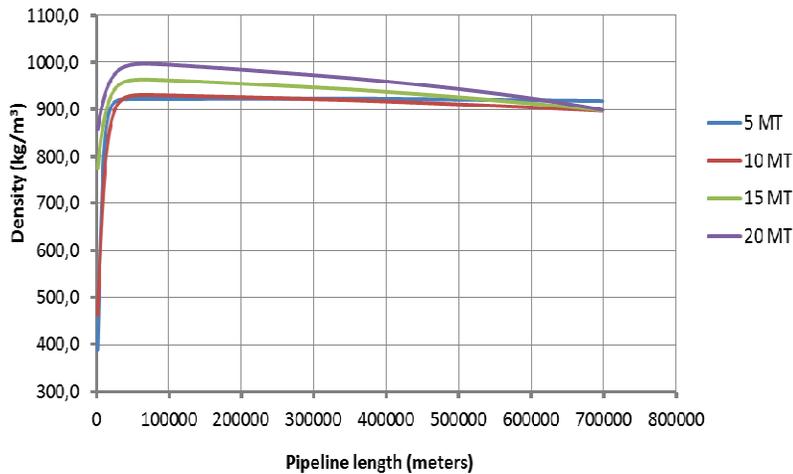


Figure 8.2 CO₂ density in CO₂ backbone pipeline from Rotterdam to Utsira

For the lowest throughput of 5 million ton CO₂/year thermal equilibrium is already achieved within 25 km from the coast at roughly 7 °C. At maximum throughput of 20 million ton CO₂/yr roughly 50 km is needed. In all cases temperature drops within a few

kilometers below the critical point of 30 °C. Thus, even for nearby storage locations density will be high enough to reach high injectivity.

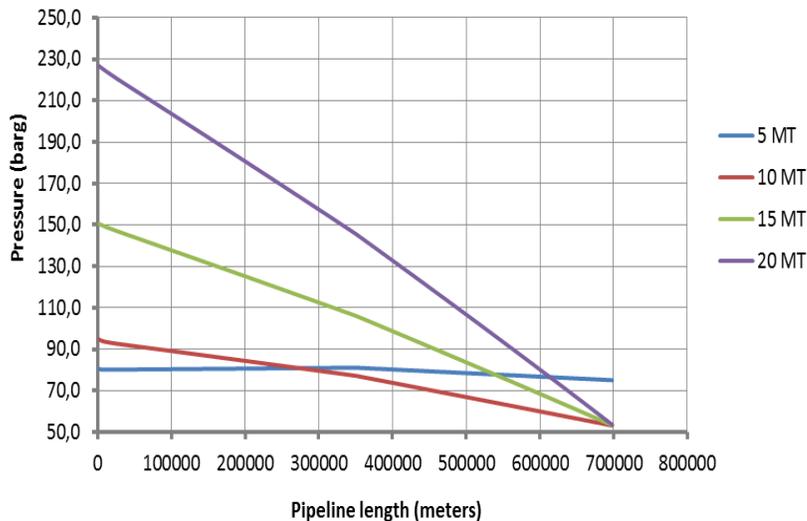


Figure 8-3 CO₂ pressure in CO₂ backbone pipeline from Rotterdam to Utsira

The Utsira deep saline formation requires only a wellhead pressure of roughly 53 bar to achieve the injection rates compatible with the throughput up to 20 million ton CO₂/year. At throughputs below 10 million ton CO₂/yr a maximum compression pressure in Rotterdam of 100 bar would be sufficient. However, if CO₂ is stored first stored in more nearby pressurized oil fields for EOR over time a higher injection pressure is needed. A wellhead pressure of at least 90 bar is necessary (as explained in the chapter storage planning). This implies that a higher compression pressure is needed to achieve the required injectivity in pressurized fields. For the maximum throughput a range of 550 km is feasible with a compression pressure of 227 bar reaching still a wellhead pressure of at least 90 bar.

8.4 Transport conditions versus storage conditions

In the proposed transport infrastructure with a backbone pipeline from Rotterdam with Utsira as end destination, the low wellhead pressure at Utsira fits well with storage of CO₂ in high pressure oil fields or deep saline formations relatively close to the Rotterdam CO₂-hub where pressures are still high. The main question to be answered is how depleted gas fields (with a low reservoir pressure) in the Dutch Continental Shelf would respond to injection of pressurized cold and dense phase CO₂ when using the

same pipeline. To answer this question several simulations have been carried out with OLGA software (ref. Gassco, Sigve Apeland) that model temperature, pressure and density behavior of injected CO₂ along a deep completely vertical well of a typical (virtual) depleted gas field situated close to the J06A location. Adiabatic flow conditions are assumed in the well

Specifications reservoir:

Depth: 3500 m, Temperature: 100 degrees C. and pressure 30 barg (initial)

Specifications well:

Internal diameter 6 inch for the first 3200 m from the wellhead, than 4,5 inch for the subsequent 100 m and 3,8 inch for the last 200 m.

The following cases are analyzed that describe the progressive pressure build up in the reservoir upon years of injection of large CO₂ flows.

1. Offshore pipeline with 16 inch internal diameter with a throughput of 1,5 million ton CO₂/year (8000 run hours per year) assuming wellhead conditions of 60 degrees C. Compressor discharge temperature in Rotterdam is 80 degrees C. This simulates gas phase transport & injection
2. Liquid phase transport using same pipeline diameter and throughput but compressor discharge temperature of 30 degrees C.
3. Maximum throughput using a compressor discharge pressure of 227 barg.
4. Reservoir nearly filled with Utsira like characteristics

Analysis case 1.

These conditions can only realized when using a very well thermally insulated pipeline (extremely low heat transfer coefficient 0,021 W/m²*K). Compressor discharge pressure is 110 barg. Wellhead pressure is 85 barg. The CO₂ temperature reaches a minimum of 35 degrees C. down hole in the reservoir due to Joule-Thomson cooling. These conditions are safe; there is no risk of freezing and possible fracturing due to low temperatures. However, a high price is paid for the gaseous transport in terms of high pipeline CAPEX due to the thermal insulation and the lower (transport and injection) capacity compared to dense phase transport.

Analysis case 2.

The pipeline is again buried but not insulated and the transported CO₂ will approach seawater temperature in roughly 50 km (7 degrees C.) . Compressor discharge pressure is 134 barg and wellhead pressure is 130 barg. The pressure drop over the pipeline is thus very low due to dense phase transport of the CO₂ and will mainly occur over the last phase of the well where it narrows down till 3.8 inch. In the first 2900 m of the well the pressure builds up in the well due to hydrostatic pressure (up to 400 barg). In this (extreme) case the temperature drop to 5 degrees C. after the first choke (6 to 4,5 inch) and to 0 degrees C. after the 2nd choke (4.5 to 3.8 inch) by the Joule-Thomson effect. To maintain the 130 barg wellhead pressure a down hole choke valve is needed. In this case there might be mechanical stress in the casing due to the low temperature near the reservoir. Frozen hydrates and more mechanical stress might occur if water would be present in the reservoir.

Analysis case 3

The wellhead pressure is again chosen at 130 barg. The throughput can be increased with a factor 5 from 1,5 till 7.5 million ton CO₂/year due to the higher compressor discharge pressure of 227 barg. The temperature decrease of the CO₂ in the last phase of well is less due to the higher frictional loss over the well and ends at 11 degrees C. near the well outlet. This is very close to the minimum temperature of hydrate formation (12 degrees C.) but safe if no water is present. It is still necessary to choke the flow in order to maintain the wellhead pressure.

Analysis case 4

The wellhead pressure is chosen at 60 barg combined with low throughput (1.5 million ton CO₂/year) in dense phase (30 °C. compressor discharge temperature) through a buried but not insulated pipeline. Compressor discharge pressure reaches now 66.4 barg. Although the wellhead pressure is much lower than in the other cases there is still a large temperature drop down in the well leading to 5 °C. at the first narrowing at 2 degrees C. at the last choke. Even at this low wellhead pressure it is necessary to throttle the flow through the well. Also here is the risk of mechanical stress and additionally hydrate formation in the presence of water.

Apparently, only gaseous phase CO₂ transport and injection can avoid low temperatures (below 12 °C.) that cause mechanical stress, ice and hydrate formation. Gaseous CO₂ transport is however much more costly than dense phase CO₂ transport due to lower pipeline capacity and the additional cost of pipeline insulation. The combination of cold dense phase CO₂ transport with injection in a deep low pressure reservoir with narrowed tubing will nearly always lead to unacceptable low temperatures in the other 3 cases even at relatively low wellhead pressures (60 barg) or high throughput. To maintain a high pressure in a dense phase CO₂ pipeline network it is therefore recommended to take the following steps:

- select only high permeable depleted gas fields with either have a narrow tubing (< 6 inch diameter) and which are not deep (< 2500 m) and use high throughput (> 5 million ton CO₂/year)
- use heating at the platform during the period reservoir pressure is still low (below 70 bar) to heat from 7 degrees C. till 60 °C. (likely a minimum temperature of 40 °C.)

A downhole choke valve can maintain the wellhead pressure but but has the disadvantage of limiting the throughput at the stage when reservoir pressure is high enough to avoid Joule-Thompson cooling while in the initial phase it does not prevent cooling.

8.5 Conclusions and recommendations

The design for the compressor station in Rotterdam will be based on a maximum discharge pressure of 250 bar. This is above 227 bar to accommodate for a margin due to impurities in the dense phase CO₂ like nitrogen and hydrogen that might lead to a lower density. This is also a conservative design basis as a large portion of the transported dense phase CO₂ will be injected in Dutch fields. As a consequence the

pressure drop for the remaining throughput from J06A to Utsira will be smaller than calculated on basis of the full flow. We therefore assume that this extra transport capacity can be used to transport dense phase CO₂ imported from one of the North German harbors (e.g. Emden) or Groningen Eemshaven to serve oil fields for EOR and/or storage in Utsira. A tie-in will therefore be required roughly halfway the Rotterdam-Utsira backbone (at roughly 300 km from Rotterdam). The transport capacity from this tie-in up north will be 20 Million ton CO₂/year assuming that 20 million ton CO₂/year from Rotterdam will be stored in fields located near the first 300 km backbone pipeline from Rotterdam. The design pressure in the Northern German CO₂-hub should then also be 250 bar. By doing so, the transport capacity of the 30 inch pipeline is effectively doubled to 40 million ton CO₂/year.

It can be concluded that on this design basis the compressor station in Rotterdam and the design of the backbone pipeline are sufficient to store the required CO₂ supply in the Dutch continental shelf, to serve part of the demand of the EOR fields and finally store remaining CO₂ in the Utsira deep saline formation.

The interplay in pressure, throughput, density and temperature in the different storage locations can vary widely. It is therefore recommended to take reservoir characteristics into account when designing a transport network for the North Sea.

9 TRANSPORT LOGISTIC PLANNING

9.1 Introduction

The future CO₂ transport infrastructure development is influenced by

- the amounts and locations where CO₂ is captured and collected,
- the locations where the CO₂ can be injected and stored, and their capacity in terms of storage and injectivity and,
- the timing/availability of the captured CO₂ sources and the timing/availability of the storage sinks.

In this chapter it is assumed that there will be a EU wide coordination of CO₂ transport infrastructure, as an important component within a EU wide energy policy as described by the 2010 report “Energy infrastructure, priorities for 2020 and beyond” by the EU DG for Energy. It is also assumed that that large scale CCS will be deployed at least until 2050, and that EU policy enables the total economic optimization of the CCS transport and storage infrastructure within the EU will be optimized.

As part of the case study for Rotterdam, the potential of CO₂ hub location(s) to off-shore storage locations has been analysed. The Rotterdam area itself offers excellent opportunities for a CO₂ hub, since there are various large CO₂ emitters clustered in the area. Next to Rotterdam area’s own emissions is the geographic position of Rotterdam. Rotterdam developed to one of the world’s biggest harbours, because of its position opening to the German Ruhr area, one of the world’s biggest industrial areas. Rotterdam is relatively close to Antwerp, where the majority of Belgium’s industry is concentrated.

In this chapter the infrastructural development in the pre-commercial and commercial stage will be analysed with a financial model, in which the real growth in captured CO₂ volume starts (around 2020) and then grows fast in the decades afterwards.

9.1.1 Comparisons with Other Studies on Assumptions (Zero Emissions Program) (ZEP)

In 2011, the Zero emission platform published its reports about CCS costs, an overall chain report, and individual reports for costs of capturing, transport and storage⁸. Most of the cost estimates made in this report are very similar, or re-use findings of the ZEP studies.

The costs of the feeders (the term used in the ZEP reports for the infrastructure between individual CO₂ sources and the transport network) have not been included in the D

⁸ Cost of CO₂ capture, transport and storage- by European Technology platform for Zero Emission Fossil Fuel Power Plants - 2011

4.1.1. model as these costs are constant for all scenarios investigated in this report and therefore not relevant in the cost comparison.

The ZEP report uses a WACC (Weight Averaged Capital Cost) of 8% with a depreciation period of 40 years. In this report the WACC is set at 7 % at a depreciation period of 20 years. To assess the sensitivity of transport costs versus WACC a value of 15 % has also been investigated. Note that yearly capital cost and amortization for the ZEP case (8 % WACC at 40 years depreciation) equal 7 % WACC and 24 years depreciation.

The ZEP report assumes point to point connections this report evaluates a transport system connecting several sources and sinks.

The ZEP report assumes electricity price of €110/MWh where the D 4.1.1. model assumes €85/MWh in 2010 and an inflation rate of 2%.

The ZEP report assumes that the emitter will compress the CO₂ to 30 Bar. Most of the available cost reports assume that at least a part or the complete compression is included in the “capturing costs”. The ZEP report assumes an outlet pressure of 60 Bar. This is a fair value for injection into depleted gas field and very permeable deep saline formations but likely too low when the CO₂ needs to be injected for EOR. The D 4.1.1 model uses an outlet pressure of 85 Bar as this is required for EOR based CO₂ storage, to avoid that additional compression is needed on the platforms.

9.1.2 North Sea Basin Task Force

The 2007 BERR Report⁹ compares various CO₂ transport infrastructural options, starting from a few known CO₂ emission clusters to a range of potential storage locations, including North Sea storage locations where CO₂ is used for EOR.

The BERR report considered emission clusters in the UK and Norway, while CO₂Europipe considers emissions from Belgium, the Netherlands and Germany. The BERR report explicitly suggests that the use of Dutch and German CO₂ may be competitive to the use of UK sourced CO₂.

The expected demand for CO₂ by the oil operators has highly increased since 2007. The value of oil/barrel has increased substantially; and therefore the attractiveness of using CO₂ for CO₂-EOR. Therefore, there will rather be shortage of CO₂ in the North Sea for CO₂-EOR than a competition between CO₂ streams of different countries.

Compression can be provided by various organisational entities, the emitters, the transporters or the storage providers. At large scale compression costs are dominant and the optimum network configuration is strongly influenced by incorporating compression costs. Therefore, in the current model CO₂ compression costs are included in the transport scenarios (both capital and energy costs).

⁹ Development of a CO₂ Transport and storage network in the North Sea – Department for Business Enterprise & Regulatory Reform – report to the North Sea Basin Task Force - 2007

Often the initial part of the compression costs are included in the capture costs and provided by the CO₂ producer. There may even be a separate organisational entity for the local collection network.

As compression is done in order to transport the CO₂, CO₂Europipe has chosen to add the initial compression costs to the transport costs, since this compression (often provided by the emitters) will be used by the transporter and it will influence the network design as well.

Part of the compression provided by the transporter can be (re)used at the injection stage and may it often be more cost effective to compress to high pressure onshore than to recompress at the offshore platform. From a contractual perspective, the compression needed for injection may be part of the storage organisational entity. But in this chapter the transport and compression costs are all allocated to the transport function in the CCS value chain to ensure optimum usage of compression energy over the whole value chain.

D4.1.1 uses the costs for shipping and conditioning of CO₂ (providing the CO₂ at the requested pressure and temperature for injection) on confidential industrial data. To make “shipping” options comparable with pipeline options, liquefaction costs and costs for intermediate “buffering” are included. Buffering in terminals is required to facilitate the batch wise nature of shipping.

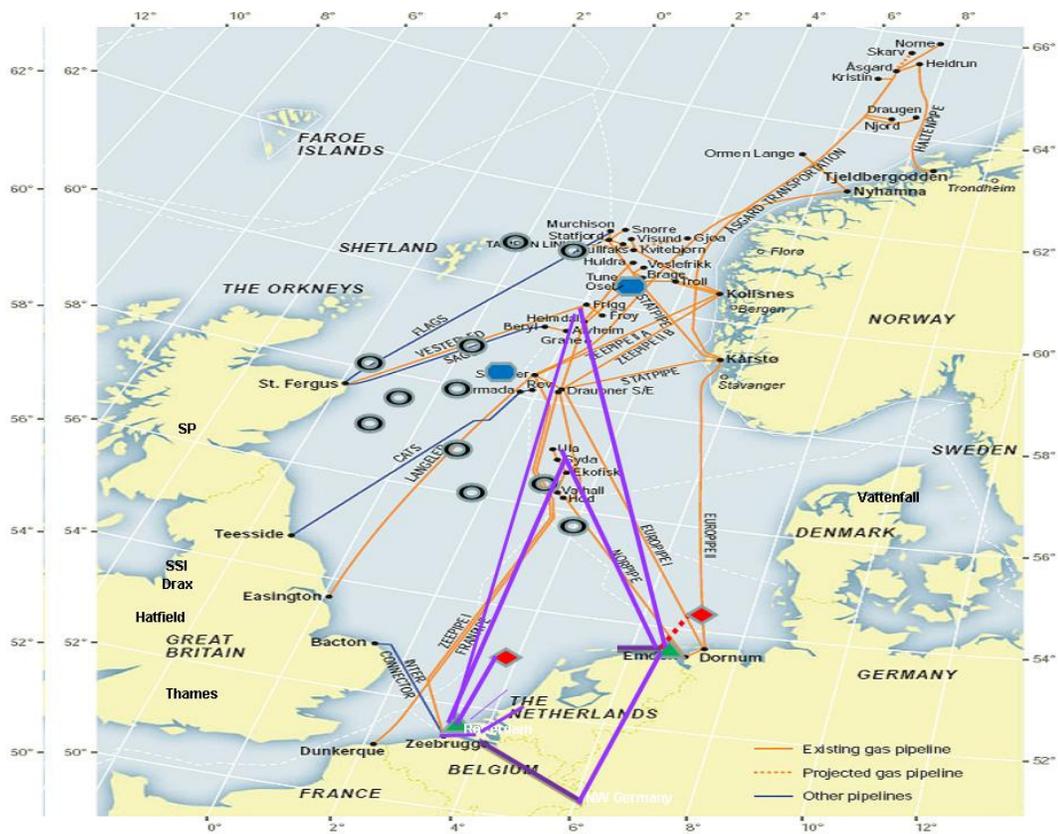


Figure 9-1 Main potential transport routes for CCS

The bold purple lines in the drawing above sketches the main transport corridors we have considered. As explained this reports excludes the emissions from the UK and the storage into UK fields.

9.2 Amounts, locations and timing

The amounts and locations where captured CO₂ becomes available develop over time. But the storage potential is also closely related to timing. As stated in the EBN / Gasunie report¹⁰, storage in depleted fields is very dependent on the right timing: many of the depleted gas fields in the Dutch continental shelf need to be re-used shortly after the fields are abandoned; otherwise substantial mothballing costs will occur. The EBN / Gasunie report assumes reuse of existing fields is only efficient within 10 years after (partial) abandonment.

The same fundamental timing issue (probably even more sensitive) can be observed for EOR based storage, fields should deploy EOR techniques timely, otherwise the window of opportunity is closed, and potential recoverable oil is lost or higher additional costs need to be made.

9.3 Two different emission scenarios

We base expected captured CO₂ volumes on two different growth forecasts, as explained in chapter 2 – “CO₂ Supply Scenarios”, the first based on the national emission forecasts and the numbers provided by WP 2.2 (baseline scenario) and the second more conservative scenario using only 50 % of these volumes (minimal scenario).

9.4 Storage capacity information base

In the calculation of CO₂ storage, both field injectivity and field storage capacity were taken into account.

- The offshore storage capacity is based on the information detailed in chapter - “Storage Planning” which describes the storage capacity in the Dutch continental shelf.
- The offshore storage capacity for EOR is based on the information from chapter 5 “Potential Demand from CO₂ for EOR.”
- For Dutch onshore storage capacity, the source is the Gasunie / EBN report of 2008, which calculates that large storage fields are available in the North of the Netherlands. (approx. 800 Mton).

¹⁰ CO₂ transport en opslag strategie EBN Gasunie, April 2010

Offshore storage potential in the German continental shelf is generally assumed to be substantially less than the capacity of the Dutch continental shelf. The costs of injection in the German continental shelf are assumed to be similar to the costs in the Dutch continental shelf (see D 4.1 storage planning chapter TNO). German storage potential in onshore deep saline formations has not been included in this report. The German onshore storage scenario is sufficiently described the Wuppertal Institute report.¹¹

9.5 Main routes, hubs and clusters

The two CO₂ supply scenarios from D 4.1.1 are used to analyse the following choices:

- i. nearby storage fields and the timely usage of these fields in the continental shelf (optimizing the available capacities in the continental shelf)
- ii. onshore storage (only depleted fields are considered, not the potential of storage in German deep saline formations- see reference to Wuppertal Institute report above)
- iii. storage combined with EOR in Norwegian fields outside the Dutch continental shelf. We have assumed the UK fields to be filled by UK CO₂ and Norwegian fields by continental CO₂. The focus will therefore be on the use of continental CO₂.

9.5.1 Rotterdam

The concept of a CO₂ hub is described in chapters 2 and 3.

Major amounts of CO₂, once in a Rotterdam hub, can go out towards ultimate storage following four possible routes:

1. Directly to the best possible reservoirs in the Dutch continental shelf (as described in Chapter 5 - “Storage Planning”). Transport is possible via pipelines or ships, we will investigate both options. Pipeline based transport would assume a backbone pipeline through the continental shelf, extended at various points to reach the specific storage field.
2. When the capacity in the Dutch continental shelf fields is not sufficient, this backbone pipeline through the Dutch shelf could be extended into the Norwegian Utsira reservoir.
3. Directly to the major onshore storage fields in Groningen in the north of the Netherlands. Similar to the EBN / Gasunie report we will assume 850 Mton of storage capacity. When Rotterdam CO₂ would be stored onshore in Groningen, it would certainly imply that also the Eemshaven region emissions would be stored in

¹¹ Energiewirtschaftliche, strukturelle und industriepolitische Analyse der Nachrüstung von Kohlekraftwerken mit einer CO₂-Rückhaltung in NRW“ by the Wuppertal Institut. (Abschlussbericht 132/41808012)

the Groningen onshore fields. We assumed onshore pipeline line systems from both regions.

4. Directly to a cluster of EOR oil fields. Transport is possible via pipelines or ships. Only few clusters of EOR fields require large amounts of CO₂ over a long period¹²
5. Therefore the focus will be on the two best candidates for CO₂-EOR from the Rotterdam Hub,
 - the southern Norwegian fields
 - the northern Norwegian fields.

9.5.2 Amsterdam and Antwerp

For the amounts of CO₂, collected in the Antwerp and Amsterdam regions, there are three possible routes,

1. directly to offshore fields in the continental shelf, via pipelines or ships. For example to the nearby Q1 former Chevron field for Amsterdam sourced CO₂ (110 Mton)
2. to EOR fields, via shipping or pipelines
3. via Rotterdam.

RCI performed a detailed feasibility study, explaining the likelihood of CO₂ transport and storage of Belgium and Amsterdam CO₂ via Rotterdam¹³. Since the distances to offshore fields are longer than the distances to Rotterdam, it is assumed that for all transport scalability and flexibility benefits from the combination of infrastructures; CO₂ collected in Antwerp and Amsterdam will go via Rotterdam.

9.5.3 Eemshaven

Furthermore it is assumed that the same logic can be applied to the combination of the Eemshaven region and the Hamburg/Emden North German region. There will be one central CO₂ hub for both regions, and that this CO₂ hub, (we will call it Hamburg – see below) similar to the CO₂ hub in Rotterdam, will also service regions in-land to transport these CO₂ volumes offshore potentially connecting to the backbone to Utsira.

9.5.4 Hamburg

CO₂ collected at the North German CO₂ hub can be transported to ultimate storage via following possible routes

1. offshore to nearby German or Danish continental shelf fields
2. offshore to EOR fields. As explained above, there are only few EOR clusters that require substantial CO₂ volumes over a longer period. We assume UK fields to be filled by UK CO₂. The two very interesting clusters remaining are
 - southern Norwegian fields
 - northern Norwegian fields

¹² see D4.1.1 chapter Mike Austell

¹³ CO₂ capture and storage in Rotterdam, a network approach RCI 2009

9.5.5 Ruhr area

The CO₂ collected in the German Ruhr area provides the biggest share of the CO₂ emissions considered in this study. In D 4.2.1 and D 4.2.2, various specific aspects of this area are discussed in detail, such as the local clustering. It is assumed there will be a collection network in the Ruhr area, collecting the emissions of these four major emission clusters.

9.6 Infrastructure over dimensioning

It may be more cost effective to size the pipelines on the higher CO₂ transport volumes in the future, and take a lower utilisation into account for a number of years, instead of constructing additional pipelines later. The cost of capital is a very important parameter in this decision.

For individual project planning, individual business cases will be made to judge how to deal with over dimensioning. As explained in WP 3.3, over dimensioning decisions can only be made with sufficient foresight when they are based on strong public and politically supported and enforced commitments to CO₂ reduction.

Between 1970 and 2000 the construction price of pipelines was very stable. The costs of pipelines in the last decade have almost doubled. This is due to rapidly rising costs of steel, but also due to growing complexity, increased safety requirements, increased environmental protection measures and longer lead times for permits. See also WP 3.1 construction capacity restrictions. Costs drivers like increasing stakeholder influence and environmental protection measures are unlikely to disappear, so there is a high probability that the cost increase will be higher than the average cost/price inflation. We have used a small extra inflation percentage of 20% every decade for pipeline costs to take into account these factors.

To judge how to dimension transport pipelines as capacity requirements gradually increase, the industry has defined a “no-regret period”. The no-regret period is the maximum time over which capacity requirements can be extrapolated to dimension the transport pipeline, to get the best economic performance. In the model calculations a no regret period for pipelines of 10 years is assumed.

9.7 Financial estimations

For all calculations the same values for the parameters has been used in other CO₂ Europipe work packages, i.e. the pipeline construction costs in all scenarios are all based on the cost indications given in WP 3.1 and 3.3 for onshore and offshore pipeline construction.

In all cost indications, we use the same compression equipment pricelists, and the same costs of energy. We separate compression onshore, (to get CO₂ from the emission

location to the CO₂ hub or to the onshore storage facility) versus the costs of boosting /pumping equipment at the CO₂ hub in order to go offshore.

The emission forecast is based on 5 year periods. All investments needed to meet the captured emissions in the coming period are accounted in the first year of the 5 year period before this emission level is reached (e.g. to meet the emission levels of 2025, the investments in the infrastructure are booked in 2021). The operational costs within a period are based on the volume of this first year. So the annual compression energy costs between 2021 and 2025 are based on the volume levels of 2021.¹⁴

9.7.1 Compression

- The cost assumptions start at the point immediately after the capture installation, where CO₂ is available according to the specifications at a pressure of around 1 bar. This needs to be noted when costs are compared with other reported cost estimates, in which the costs of compression are often added to the costs of capture.
- The compression costs needed for injection (e.g. for injection in EOR fields, assume CO₂ needs to be delivered at the fields' location with a remaining pressure of approx. 90 bar. The costs of storage in the continental depleted field also include the compression required of injection at the field location).
- CO₂ for offshore storage is compressed sufficiently by pumps installed onshore to cover both the compression losses in the pipeline and the compression needs for injection, so no additional compression equipment is needed on the injection platforms, and the offshore pipelines are designed for higher pressures to deliver sufficient injection pressures at the end point. Onshore pipelines are designed for 150 bar, and offshore pipelines are designed for 250 bar.
- Compression CAPEX costs are calculated based on the equipment price and capacity. We will assume no initial price discount, but equipment prices stay stable over the years (as improving technology will compensate for inflation).
- Compression OPEX is based on regular maintenance contracts (5 % of equipment value) and the power utilisation list of a major vendor of compression equipment.
- Initial wholesale electricity wholesale price is 85 Euro/MWh, similar for all locations in the infrastructure where electricity is consumed.

9.7.2 Scope of distances and network

This model does NOT include costs for the feeders, the local tail connections, or local collection networks. All mentioned locations are assumed to be a POINT location.

¹⁴ CO₂ Europipe is aware of these inaccuracies. Therefore the results should NOT be quoted as estimated cost figures without giving all the abstractions of the calculation model. The numbers calculated in this chapter are there to compare the efficiency of the various sketched scenarios.

Distances are based on a combination of straight line distances between the cluster central points and an average percentage of deviation, due to the practical/technical feasibility of the pipeline routing (10 % for offshore, 20% for onshore).

9.7.3 Pipelines or shipping

Whenever available, we will compare pipeline based transport versus ship based transport. Where pipeline transport is assumed, the required compression is included in the calculation of this stream. Wherever shipping is assumed, the required liquefaction and intermediate “buffering” is included as well as to the on-board offshore conditioning costs prior to field injection.

9.7.4 Shipping assumptions

Calculations were done based on 2010 cost figures, Heavy Fuel Oil (HFO) was taken at USD550/t, offshore discharge conditions were set at 180 bar, 7 deg C (REFERENCE). The cost figures include crewing, maintenance and repair, insurance, port, dry docking costs but exclude offshore infrastructure (Single Point Moorings) as these are designed on a case specific basis (In line with pipeline costs where PLEM’s and Xmas trees aren’t taken into account either). The maximum ship size used is 35,000 cbm and it is assumed that several injection locations exist to accommodate large number of vessels and the respective injection/discharge rates. Preheating costs for liquid CO₂ near the field for shipping are not included.

9.7.5 Price paid for CO₂ by E&P Operators in EOR.

Detailed studies have been made on the subject of enhancing oil recovery. CO₂ is a very effective medium for EOR, and therefore quite attractive for E&P operators in the EOR market as the CO₂ EOR industry in the USA has proven over the past 4 decades.

In the EOR Chapter estimates were made around the amount of CO₂ desired by these operators to optimize EOR in the most attractive oil fields of the North Sea.

A detailed assessment was done on CO₂ based EOR in the European situation in EUR 21895.¹⁵

In this assessment 81 active fields in UK, Norwegian and Danish sectors were analysed. The UK potential was estimated at 2.7 billion barrels, Norwegian potential at 4.2 billion barrels and the Danish potential at 0.4 billion barrels. Fifteen oilfields which are more than 80 % depleted were selected for an economic evaluation. It was estimated that with a value of 35 USD per barrel, and 25 Euro per tonne CO₂ all fields studied could be profitable for CO₂ EOR operations.

The report states that standard EOR practices, used as basis for the report, imply the minimisation of CO₂ usage, however if CO₂ storage had a commercial value, the operations could be designed to maximize the storage.

¹⁵ Enhanced oil recovery using carbon dioxide in the European energy system –Report 21895 EN, by DG JRC, Institute for Energy, Petten, Netherlands, Joint Research Centre, December 2005

Oil producers currently aim at maximising oil recovery and at minimising of CO₂ consumption, and that optimisation of CO₂ storage will be field specific. Principal barriers, next to technical geological characteristics, would be mainly economical: the cost of CO₂ supply, lack of financial incentives for CO₂ storage and modification to infrastructure.

The report further describes the differences between the investigated European North Sea potential and the already exploited fields in the US as merely a gradual difference in efficiency.

The 2010 white paper of ARI about the CO₂ - EOR potential in the US ¹⁶adds important new findings. It studies the EOR based on optimised CO₂ storage. This optimisation requires improved operations of EOR, based on increased CO₂ volumes injected, optimising well design and placement, improving the mobility ratio between the injected water and CO₂ and the residual oil and extending the miscibility range. These ‘next generation’ operations will increase the incremental technically recoverable oil (incremental in this context defined as on top of the already subtracted oil being developed by the current CO₂-EOR in the US) by more than 35 %. It also calculates the overall incremental economically recoverable oil, and finds 55 % of all technically recoverable oil to be economically feasible assuming an oil price of 70 USD/barrel and a CO₂ cost of 45 USD per tonne. The report takes into account that the vast majority of power plants to be equipped with CCS would be within 700 miles (1120 km) of oil basins with significant CO₂- EOR potential.

The costs for adaptation of existing platforms to facilitate CO₂ based EOR are different on a case by case basis.

Deploying large scale offshore CO₂-EOR results in the following implications:

- Oil produced within the EU will become a priority for the EU energy policy, since it will result in lower crude oil imports, enhanced EU energy security and significant economic benefits (tax income).
- This policy will enable an increasing number of specialized EOR operators for the most suitable EOR fields in the North Sea.
- E&P operators will adapt and or enhance their current equipment and infrastructure for the use of EOR in the fields that require substantial volumes of CO₂ and result in sufficient enhanced oil production.
- E&P operators will monitor the usage of CO₂ in the injection process and report only truly stored CO₂ amounts
- E&P operators will distribute CO₂ over a cluster of wells/fields according to their requirements.

¹⁶ US oil production potential from accelerated deployment of carbon capture and storage – by Advanced Resources International, Inc. Arlington VA USA, March 10, 2010

Resulting, E&P operators may be willing to pay a price per tonne CO₂, delivered at the right location above 85 bar (sufficient for injection without needing local compression). This pressure of 85 bar is an assumed average, because the specific required injection pressure will vary per field.

Because of the high volume demand of CO₂ by EOR, there may be additional competition between operators to “win” the available CO₂.

The infrastructure development scenarios are analysed against various CO₂ prices (at 10, 15 and 20 Euros) to evaluate costs versus revenues.

Distances for transport will be calculated to a point in the middle of cluster of oilfields for EOR¹⁷. Clustering is based on the same information base as the amounts of CO₂ required in specific years.

9.8 Scenario definitions and analysis

The storage locations were retrieved from the Geocapacity database.

For forecasted emissions from Netherlands, Belgium and Germany, a financial model was developed to compare the resulting transport costs per ton CO₂ versus different emission forecasts, different storage locations, different cost of capital and transport routing scenarios.

In total over 30 different combinations were compared, including all the most important cost drivers (capital and operational costs of both transport and compression infrastructure). This resulted in the following possibilities and scenarios:

- The emission baseline forecast and the minimal capture forecast
- CO₂ collected in the Ruhr area (Nord Rhein Westphalia) is routed either
 - via Hamburg (100%)
 - via Rotterdam (100%)
 - via a mix of both Rotterdam and Hamburg pipelines – in this case diversity is preferred – for example in the scenarios 1 and 31 the first 40 Mton/ annum are routed via Rotterdam and the remaining emissions are routed via Hamburg or in scenario 2 and 32 the first 20 Mton / annum are routed via Rotterdam and the remaining emissions are routed via Hamburg
- CO₂ collected at the CO₂ hubs in Rotterdam and Hamburg is transported to
 - the nearest available field in the continental shelf (cheapest transport option to available offshore storage) or
 - preference is given to EOR based CO₂ storage or
 - onshore storage is used.

9.8.1 Developing the scenarios

The complete list of investigated scenarios can be found at the end of this chapter.

¹⁷ “local” distribution is excluded, see also our earlier explanation on local tails and collection networks.

The following description explains the development and the types of differences considered in the various calculated scenarios.

The Rotterdam hub becomes the central point for offshore transport for the regions around Rotterdam, Antwerp, and Amsterdam. Therefore the pipeline connections from Antwerp to Rotterdam and from Amsterdam to Rotterdam only depend on the emission forecasts in these regions.

Similarly, there will be ONE central hub northbound into the North Sea, this location is named “Hamburg”, although this exact location is still not decided. Emissions from the Hamburg area and the Eemshaven area will be routed to this hub.

In the base emission forecast, in 2030 Amsterdam emissions are around 2 Mton/year rapidly growing to 7 Mton/year within 10 years and then remaining stable over 15 years or more.

Based on the agreed no-regret period of 10 years, it was decided to put in a pipeline supporting the 7 Mton/year starting operation in 2030.

The Antwerp emissions grow rapidly, from 7,5 to 28,5 Mton/year between 2030 and 2040, growing to almost 50 Mton/year in 2050. We decided to use a first pipeline from Antwerp to Rotterdam until 2040 for the first 30 Mton/year, and construct a second pipeline around 2040 for the remaining 20 MTON/YEAR in the years after.

The investment decision points have also been reviewed for the minimal emission forecast, based on the same dimensioning criteria. For this case, the same pipelines are built, but the diameters of the pipelines are smaller, and the timing for the second pipeline is 5 years later to accommodate the lower volumes. Next, major decisions have to be made in the routing of the Ruhr area CO₂, and the routing of the collected CO₂ at the hub locations to the final storage locations.

Amounts of CO₂ collected in Rotterdam around 2025 require large CO₂ flows from Germany (e.g. Ruhr area) to enable large scale CO₂-EOR for distant fields in the Norwegian shelf.

Therefore the decision to route all Ruhr area CO₂ via Hamburg limits the choice of storage locations in Rotterdam, it can only go to the nearest fields in the Dutch continental shelf, or to onshore storage (onshore storage would make transport from Amsterdam to the Rotterdam unlikely, it would probably be transported directly to onshore storage capacity in West Netherlands (110 Mton capacity available)).

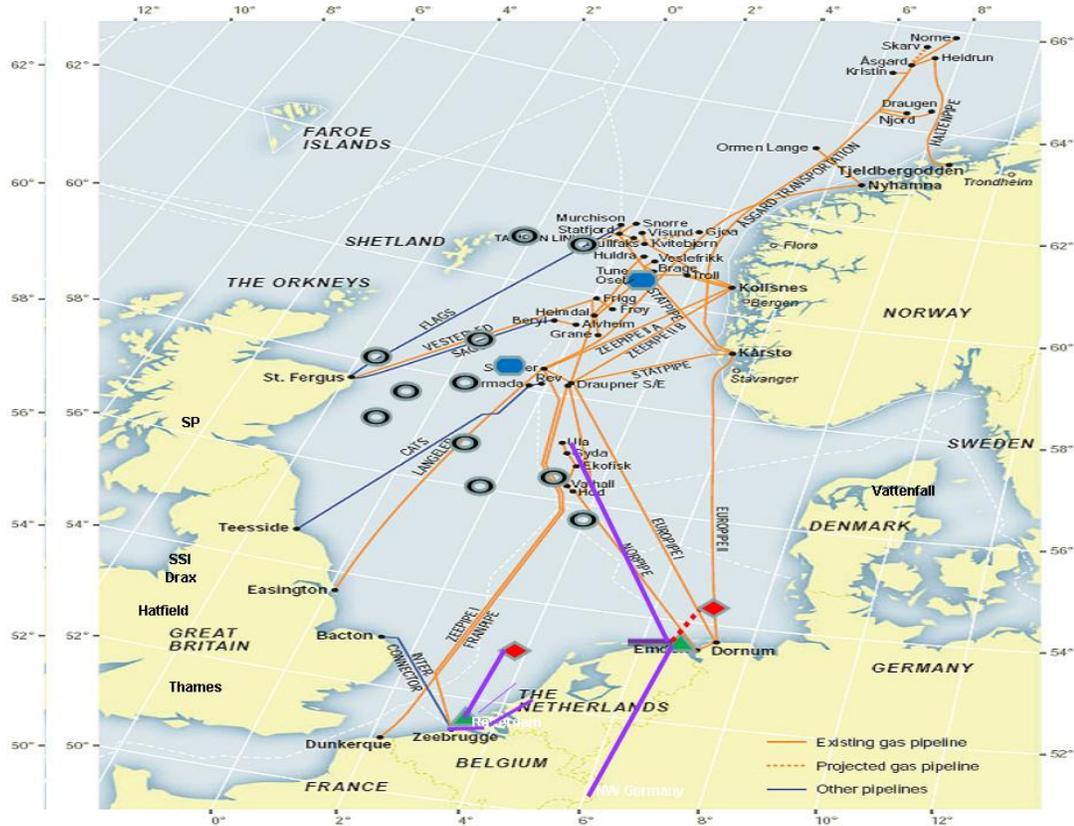


Figure 9-2 Only few of all possible transport routes are actually used, when the minimal emission forecast is applied and when NRW emissions are all routed via Hamburg.

The above map shows the proposed pipelines around 2025, assuming the decision to route CO₂ from the Ruhr area to Hamburg.

The remaining CO₂ volumes transported via Rotterdam do not justify the costs of a very long distance pipeline from Rotterdam to the EOR fields. From the Rotterdam Hub, therefore, only storage in the Dutch continental shelf is likely (a backbone trunk through the various fields is shown).¹⁸

From Hamburg, all German CO₂ is transported offshore. Therefore there would be two options, either storage in the nearby German continental shelf or long distance transport to the southern Norwegian EOR fields. These fields will already require substantial volumes of CO₂ (above 20 Mton/year) around 2025. D 4.2.2. presents an overview of the onshore storage potential in Germany.

¹⁸ The thin line on the drawing shows the potentially already available pipeline to the Taqa field, built for the demonstration pilot project of EON- Electrabel before 2015.

An alternative scenario would be based on the decision to route the Ruhr area CO₂ via Rotterdam.

This decision would result in a choice at the Rotterdam hub to consider long distance transport to EOR fields. This is visualised in the following map. In the calculation, network is “designed” assuming that required streams are translated to needed pipeline diameters, and based on the maximal 10 year no-regret period.

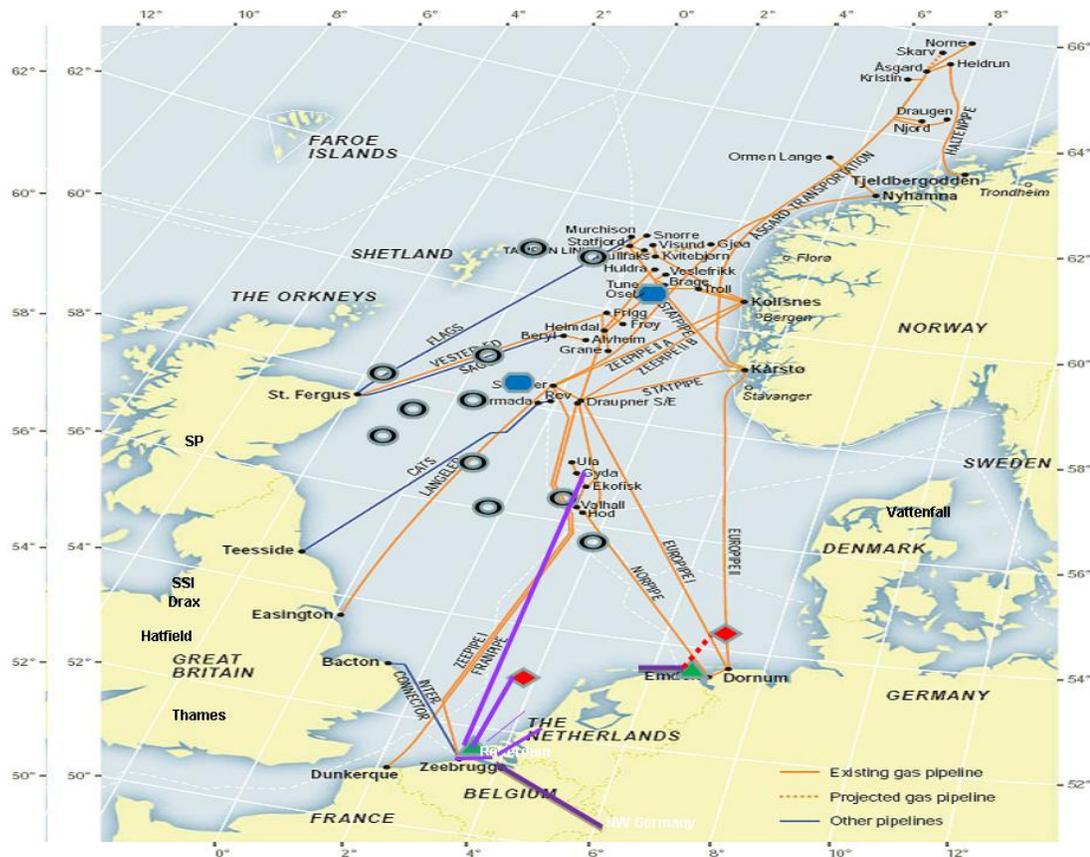


Figure 9-3 Assuming the minimal emission forecast, and NRW emissions routed via Rotterdam, another subset of all possible transport routes are actually used. Now the emissions gathered in Hamburg have a too low volume to justify long distance transport to the EOR fields.

In 2030 the volumes of emitted CO₂ in the Ruhr area according to the base scenario require additional pipeline capacity. The decision could be either to use the same route, or to prefer route diversity for the second pipeline.

Assuming the first 2025 pipeline would have gone via Hamburg, and Hamburg has made the decision to feed the CO₂ to the southern Norwegian fields. In 2030 the collected amounts of CO₂ surpass the required CO₂ in the southern Norwegian fields. So CO₂ from the second pipeline from the Ruhr area needs to go to another destination.

The below map shows the infrastructure when the second pipeline is routed via Rotterdam, and Rotterdam decides to feed this CO₂ to the Northern Norwegian fields. The CO₂ capacity of the second pipeline will not be sufficient for the full amount of available CO₂ in Rotterdam; therefore the overflow would be stored in the Dutch continental shelf.

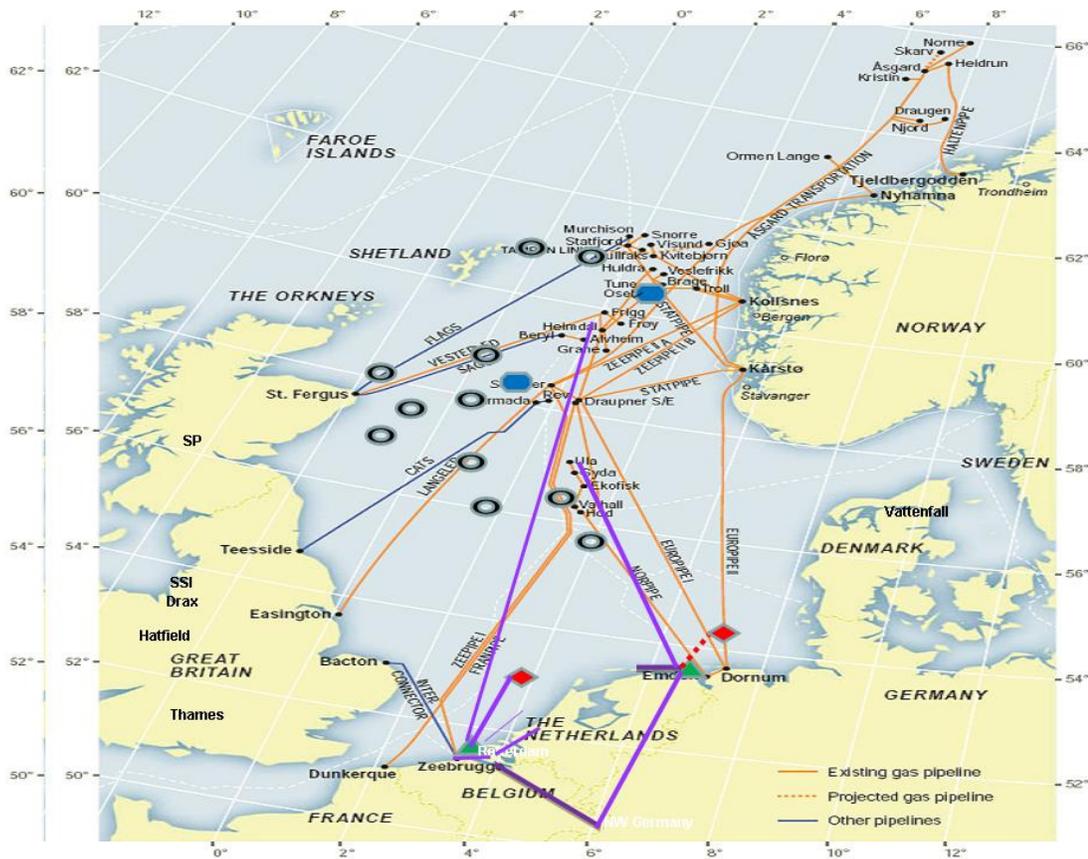


Figure 9-4 When the regular emission forecast is used, volumes from NRW can be used to both feed the northern EOR fields and the southern EOR fields. In the map above, the NRW emission route is diversified, approximately half via Rotterdam, and the other half via Hamburg. The Rotterdam volumes feed the northern Norwegian fields. The Hamburg volumes feed the southern Norwegian fields.

Apparently, the regular emission supply scenario (shown in Figure 9-4) is required to achieve large scale CCS from the Rotterdam hub and the “Groningen/Hamburg” hub and to realize the large scale potential of offshore CO₂-EOR.

Recent pipeline projects for natural gas or petrochemical products have been successfully completed; however there may be less social acceptance for onshore CO₂ pipelines. An alternative transport method using barges is investigated in D 4.2.2. The current cargo capacity of the Rhine can be increased by a factor of 700% before full capacity is reached, offering ample transportation capacity to accommodate larger volumes of CO₂. The economic feasibility of barges has not been evaluated in CO₂europipe.

9.9 Overview of scenarios and their results

In Table 9-1, the first column represents the number of the specific transport scenario, followed by the resulting “average transport costs per ton” assuming CO₂ used by EOR would be valued at 20 Euro, with a WACC of 7 % for all required transportation infrastructure investments. The third shows the costs with the same parameters but with a WACC of 15 %. The fourth and fifth column show the results when CO₂ for EOR is valued at 10 Euro/ton.

The various scenarios were based on choices between

- baseline or minimal emission forecasts (column 6),
- a priority policy focused at enabling EOR or a policy focused on cheap/nearby storage without taking potential EOR revenues in consideration (column 7)
- a routing of the Ruhr area emissions (NRW means Nord Rhein Westphalia) to offshore storage via Rotterdam, or via Hamburg, or a mix of both (column 8)
- in Rotterdam the first 5 Mton/year are realized either via shipping or via an EERP¹⁹ funded demo project with a pipeline from the EON power plant (column 9).
- Various dedicated parts of the infrastructure done with shipping (column 10)

¹⁹ European Economic Recovery Plan

Table 9-1

EOR €/tonne	20	20	10	10	Emissions Forecast	Priority	NRW emissions routed via	NRW to hub via	Variation
	7%	15%	7%	15%					
1	3,72	5,97	7,06	9,62	regular	eor	mix	ship	
2	4,55	7,82	7,98	11,44	minimal	eor	mix	ship	
3	2,55	4,33	6,12	8,18	regular	eor	rott	ship	
4	3,47	6,78	7,07	10,53	minimal	eor	rott	ship	
5	4,24	6,76	7,53	10,32	regular	eor	hamb	ship	
6	4,46	7,8	7,87	11,4	minimal	eor	hamb	ship	
7	2,95	6,43	6,36	10,03	minimal	eor	hamb	Na	nl onshore
8	10,15	13,3	10,15	13,3	minimal	no eor	hamb	Na	nl onshore
9	10,37	12,33	10,37	12,33	regular	no eor	mix	ship	
10	11,18	13,81	11,18	13,81	regular	no eor	na	ship	nrw exclude
11	4,01	6,09	7,35	9,74	regular	eor	mix	pipe	r-seor ship
12	3,63	5,39	6,96	9,04	regular	eor	mix	pipe	r-ncp ship
13	4,03	5,98	7,37	9,63	regular	eor	mix	pipe	h-gcp ship
14	4,29	8,31	8,41	12,46	minimal	eor	mix	pipe	r-seor ship
15	3,44	6,93	7,56	11,08	minimal	eor	mix	pipe	h-seor ship
16	3,02	6,63	7,14	10,78	minimal	eor	mix	pipe	h-gcp ship
17	3,62	5,5	7,19	9,36	regular	eor	rott	pipe	r-seor ship
18	3,15	5,07	6,72	8,92	regular	eor	rott	pipe	h-gcp ship
19	5,35	9,13	8,94	12,87	minimal	eor	rott	pipe	r-seor ship
20	4,57	8,01	8,16	11,76	minimal	eor	rott	pipe	h-gcp ship
21	3,97	5,74	7,27	9,3	regular	eor	hamb	pipe	h-seor ship
22	0,53	3,75	5,22	8,55	minimal	eor	hamb	na	nl and be eor
23	3,82	6,03	7,16	9,68	regular	eor	mix	ship	5 years no regret
24	10,88	14,28	10,88	14,28	minimal	no eor	hamb	na	nl onsh 5 yr noregret
31	3,5	5,49	6,84	9,14	regular	eor	Mix	pipe	
32	2,59	6,02	6,71	10,17	minimal	eor	Mix	pipe	
33	2,34	3,89	5,9	7,74	regular	eor	Rott	pipe	
34	2,81	5,52	6,41	9,27	minimal	eor	Rott	pipe	
35	3,62	5,86	6,91	9,43	regular	eor	Hamb	pipe	
36	3,3	6,03	6,72	9,65	minimal	eor	Hamb	pipe	
37	3,09	5,44	6,51	9,07	minimal	eor	Hamb	na	start 2025
38	10,19	11,79	10,19	11,79	minimal	no eor	Na	na	only NL and Be CO ₂
39	10,01	11,84	10,01	11,84	regular	no eor	Mix	pipe	

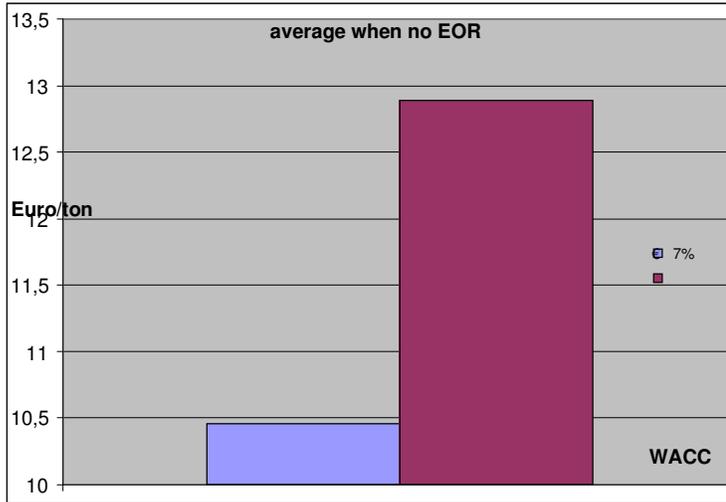


Figure 9.5

Figure 9.5 shows the average transport costs per ton for all scenarios not considering EOR based CO₂ storage.

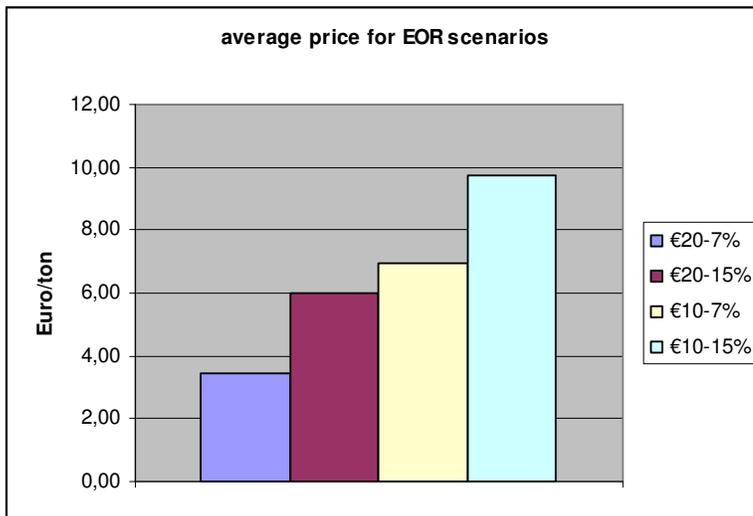


Figure 9.6

Figure 9.6 shows the average transport costs for all scenarios prioritizing EOR, when the sales value of the CO₂ for EOR is calculated as revenue subtracted from the transport cost..

For all scenarios with a fixed WACC and CO₂ sales price the transport costs minus the EOR revenues vary with in a range of only 2 euro per ton CO₂ as shown in figure 9.7. The impact of the CO₂ sales price of €10 till €20 per ton for EOR is substantial especially at the 7 % WACC value. Thus, it can be concluded that CO₂ sales revenues for EOR have a strong positive impact on the business case for the CO₂ transport infrastructure for CCS –EOR. Naturally, this assumes that the business case for CO₂-EOR investments, with the CO₂ supplied, at the platform is attractive.

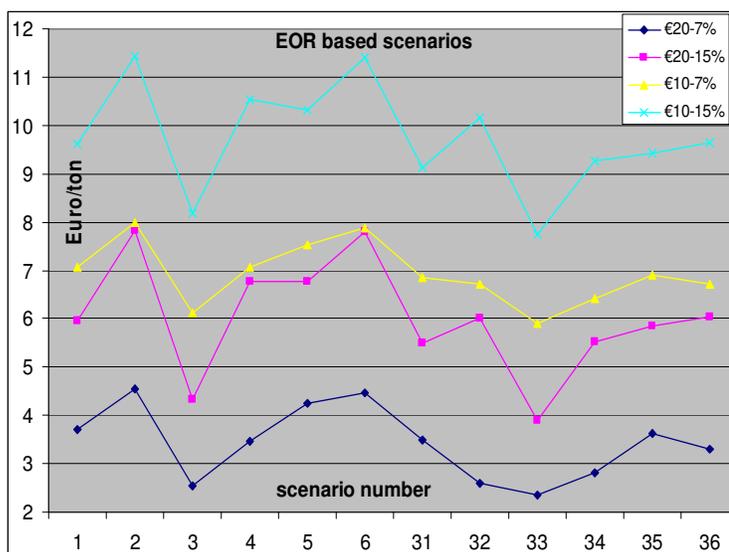


Figure 9.7 The costs of transport minus the CO₂ sales revenues per ton CO₂

For six different scenarios in Rotterdam, the prices were compared either using shipping for the first 5 Mton/year or using a pipeline. Figure 9. shows the average difference in price. In the model used, the average difference in price is not dependent on the price paid for CO₂ reused in EOR, but only on the required WACC. The results show that shipping transport in these six scenarios is more expensive in the long run. The distance from Rotterdam to the nearest storage field for the first 5 Mton/year is however very short (only 20 km). The difference in price between shipping and pipelines becomes smaller when distances increase. But the difference is overall small and less than 10 %. Note that the shipping cost we calculate in this chapter applies for offshore shipping using sea vessels, and does not include cost assumptions for shipping over rivers using barges. Costs for pre-heating the cold liquefied CO₂ from the ships to suitable reservoir injection conditions are also not included.

For modelling simplicity vessels were kept in service over their lifetime on the same route, whilst in reality initial volumes could be shipped and upon volume growth a pipeline may come online allowing for the ship to be redeployed in another ‘new’ trade. This flexibility is neglected here.



Figure 9.8

There are scenarios in which part of the volumes were transported by ships, resulting in a lower overall cost.

Figure 9. shows that the scenario 12 (where additional shipping is calculated between Rotterdam and the Dutch continental platform) is cheaper than scenario 31 (and its construction and regular upgrading of the pipeline for this stream) when calculated with a 15 % WACC.

This cost advantage can be explained by looking at the distance, the average distance between Rotterdam and the fields in the Dutch continental platform used in the calculations is 180 km. As explained above, shipping becomes relatively lower in cost when distances increase.

Differences between base emission forecast and minimal emission forecast

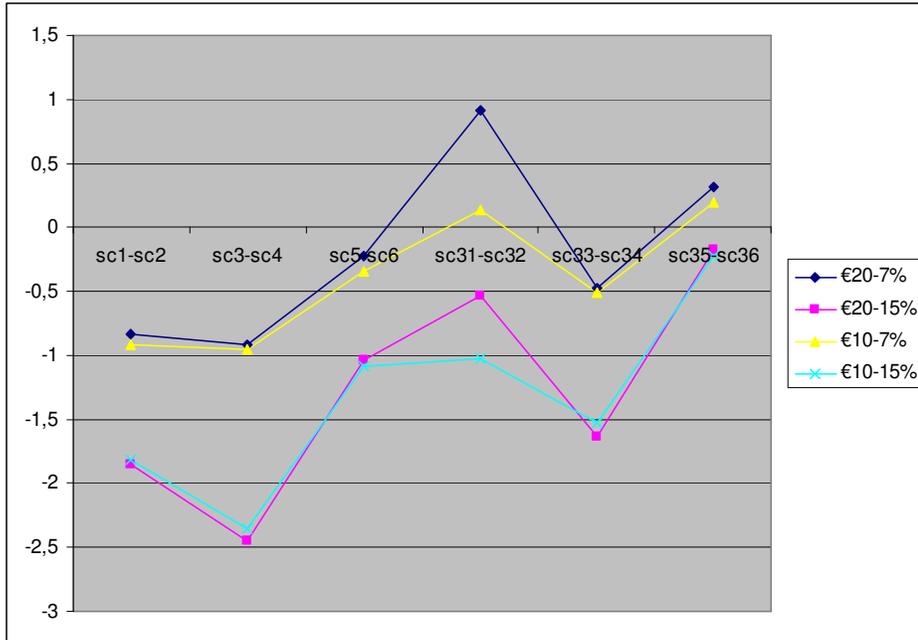


Figure 9.9

For 6 transport scenarios, both the base emission amounts and the minimal emission amounts were calculated. Figure 9. shows the differences between the base emission forecast and the minimal emission forecast for these scenarios. Scenarios based on the smaller emission clusters often result in slightly higher transport and compression costs. With 7 % WACC the difference is less than 1 Euro. When calculating with 15% WACC, the difference increases to a maximum of 2,5 Euro.

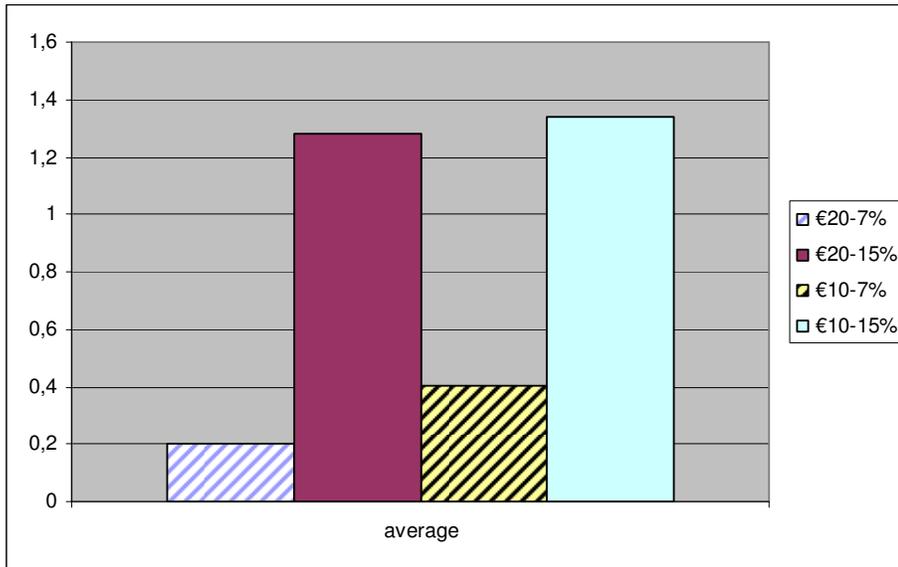


Figure 9.8

At a 15 % WACC rate, transport costs increase in average with 1,4 €/t in the minimal emission scenario, compared to the base emission scenario, as shown in figure Figure 9.9.²⁰

The required transport and compression average costs per tonne of CO₂ in the emission base scenario are lower than in the minimal emission scenario, again demonstrating the economy of scale. With a WACC of around 7 %, the difference is almost half of the difference in price with 15 %. Slower growth requires fewer investments in over dimensioned capacity. The fact that overall costs figures are dominated by compression energy also supports this finding.

Lowest costs, highest costs scenarios

Scenario 22 in which only the biggest clusters (NRW) are considered, results in the lowest costs (with the EOR price set on € 20, and WACC of 7 % the resulting transport/compression costs are only € 0,53/t) Scenarios such as 38 and 39, excluding the NRW streams are the most expensive.

²⁰ Note that compression operational costs are mainly energy costs to compress the CO₂, and are not influenced by scale, i.e. compression energy costs can not be reduced through economies of scale. Therefore the 1,5 €/t difference because of higher emission estimates was only achieved in the scalability of transport pipelines.

Although it should be noted that the calculations did not include the costs of local connections/collections, it shows that a transport infrastructures that bundles streams, may result in substantial economies of scale as shown by the scenarios 38, 39 versus 22.

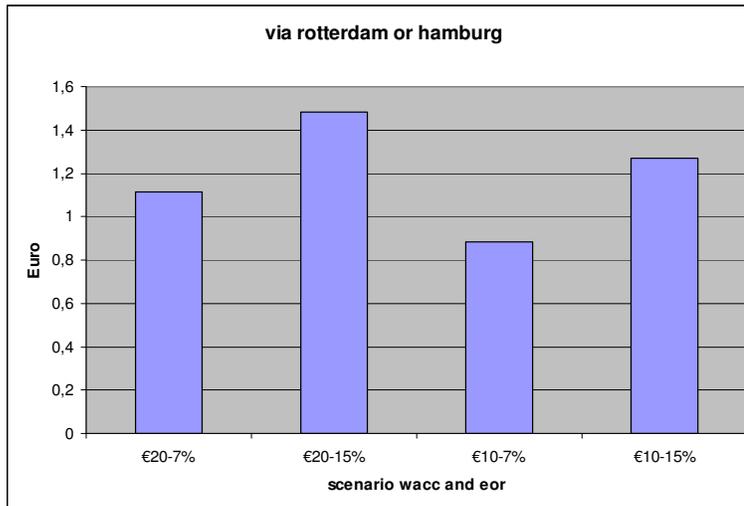


Figure 9.9

Figure 9.9 shows the difference in average costs, when NRW emissions are routed via Rotterdam versus via Hamburg. When all emission clusters are considered, the EOR options via Rotterdam are the lowest in cost, however the difference between transport of the NRW emissions via Rotterdam or via Hamburg is small. This could partly be due to the very detailed information available about the Dutch continental platform storage capacity, and the less detailed information for the German and Danish continental platform storage.

Moving from a no-regret period of 10 years to a period of 5 years has very little impact on the resulting overall costs in scenarios where the EOR return is priority. Storage in the nearest available fields in the continental shelf results in transport fees of 8,5 to 9,5 €/t (WACC 7 %) or between 10 and 11 €/t (WACC above 15%).

When 20 €/t CO₂ is paid for the EOR usage, sales revenues compensate nearly 30 % of the transport costs (WACC 7%). On top of the commercial advantages of extra revenues, there are substantial (financial and political) advantages of extra oil recovery in Europe and the EU.

In accordance with the ARI report about the infrastructure needs for EOR based CO₂ storage, pipeline based transport of distances up to 700 miles (1120 km) seems feasible and economic.

The most important reason why transport fees based on EOR CO₂ cannot be completely compensated by the CO₂ sales revenues from the EOR operator's lies within the huge

forecasted emissions to be captured after 2040. These emissions cannot be fully absorbed by the currently know EOR requirements, and therefore result in a substantial additional investment in infrastructure.

Onshore storage combined with CO₂ hubs and large scale infrastructures do not match easily. When CO₂ of Germany is routed to the Netherlands, even the largest onshore fields do not suffice. The scenario in which only the Dutch and Belgium CO₂ is stored in the onshore fields in the Netherlands, and all German CO₂ is transported via Hamburg to EOR-fields results in a comparable price. The cheaper onshore storage results in transport rates around 6 €/t (WACC 7 %).

9.10 Conclusions

Pipeline and ship transport is perceived as very capital intensive. However, the model simulations show the importance of the operational costs (continuous expenses of energy for compression, cooling and heating) are far higher. In average, operating expenses over the total lifecycle from 2020 to 2055 are more than four times the capital expenses (for the investments in pipelines, compressors/pumps, ships, storage). The overall operational cost figures are dominated by the compression energy costs (more than 70 % of the total operational costs). Therefore an increased capital cost assumption (e.g. 15 % instead of 7 %) has only a small impact on the calculated transport cost per ton CO₂.

The choice between the nearest storage fields (CCS only) in the Dutch continental shelf versus the distant oil fields (CO₂-EOR and storage) leads to the following economics. Prioritizing nearby storage would result in a required cost of € 11,80 per ton. Prioritizing EOR storage would result in € 13,- per ton; approximately 10% more expensive.

Cumulative costs regular emission scenario CO₂ transported from Rotterdam and stored in depleted gas fields DCS: € 67.000 Million.

Cumulative costs regular emission scenario CO₂ transported from Rotterdam and stored in oil fields outside the DCS: € 76.000 Million. This option however also generates € 49.000 Million revenues by sales of CO₂ for EOR purposes (when € 20 is paid per ton of CO₂ for EOR).

Thus, the cumulative revenues are 5 times the cumulative incremental transport costs of € 9000 M . In this regular emission scenario CO₂ is imported from Belgium and NRW (20 million ton/year from Germany) to Rotterdam. As the capital costs are less than 25 % of the transport costs, this implies than the cumulative revenues are more than 20 times larger than the cumulative transport costs and thus providing a good return on the expansion to the CO₂-EOR oil fields.

The net advantages for CO₂-EOR for the total EU community would even be bigger, because the extra tax income from the enhanced recovered oil. It can be concluded that a common transport infrastructure for CCS and CO₂-EOR directed first to the distant oil

fields is the preferred choice from the perspective of the E&P operators and investors, as well as governments and taxpayers. Naturally, this implies that the offshore investments at the oil fields to enable CO₂-EOR and storage provide an adequate return on capital using the CO₂ flows for decades to come. Secondly, the business model for the transport investments must be able to absorb the initial higher investment risk. Hence, EU coordination and support for these transport investments are crucial.

The ratio of cumulative CO₂ sales revenues and cumulative transport costs are roughly 5 for all different scenarios (low emission versus high emission scenario, and Rotterdam hub versus North German hub). Also changing the no-regret period of 10 years to a period of 5 years has very little impact on the resulting overall costs in scenarios where the EOR return is priority. Onshore storage for small emission clusters is clearly the most economic option (when potential EOR revenues are not considered). However, when considering storing emissions until 2050, very few of the largest onshore fields have sufficient capacity.

For the storage in the nearby fields in the DCS the transport costs for pipelines and ships are roughly the same. The average distance between Rotterdam and the fields in the DCS as used in the calculations is 180 km. Shipping becomes relatively lower in cost for larger distances and small volumes. As such the main advantage of shipping is de-risking the large investments needed at distant oil fields for enabling them for CO₂-EOR. When CO₂-EOR shows successful based on a testing period with CO₂ supplied by ships, an investment decision can be taken for a large pipeline. The ship can then be used for another oil field on a similar or different route. In this manner shipping acts as the catalyst for the deployment of the large scale CCS network in The North Sea.

Note that a large part of the CCS costs are within storage when CO₂-EOR is applied. In general the storage costs depend strongly on reservoir characteristics and a pre-treatment may be necessary to heat up the cold pressurized CO₂ in order to avoid hydrate formation in the reservoir. These costs have not been taking into account. It is therefore crucial to develop a future network based on integral costs for transport and storage. This is less applicable to capture as it has less economy of scale (beyond commercial size) and is less location dependent.

10 CO₂ TRANSPORT VERSUS NATURAL GAS AND POWER TRANSPORT

10.1 Introduction

The analysis of CCS and CO₂-EOR possibilities in the North Sea in this report has shown that the CO₂-EOR demand is far higher than the forecasted CO₂ emission scenarios for The Netherlands available for CCS offshore. This analysis, in addition of the economy of scale advantage of large offshore pipeline transport, underpins the logic of Rotterdam as CO₂-hub with import of large CO₂ streams via pipeline of relatively nearby large industry clusters as Antwerp (at roughly 130 km) and The Ruhr gebied in Germany (at roughly 300 km distance).

One could argue that it is possibly more cost-effective to locate new build large CO₂-emitters, as coal fired power plants, at the location of the Rotterdam CO₂-hub and export the resulting electricity instead of importing the CO₂. This analysis will be made in this chapter on basis of a financial comparison between power and CO₂-transport.

10.2 Assumptions

- Electricity and natural gas transport cost are compared on basis of 2 large projects executed in the same timeframe (BBL and Britned) and public references from literature
- Natural gas transport costs and CO₂ transport costs are compared on basis of the thermodynamic difference between high pressure CO₂ and high pressure natural gas and the Gassco simulations with OLGA software
- There is no limitation in the coal import infrastructure at the EMO terminal at Rotterdam Maasvlakte for a large growth in coal consumption in Rotterdam

10.3 Analysis power and gas transport

BBL is a consortium that transports high pressure natural gas by offshore pipeline from the Netherlands (Balgzand) to the UK (Bacton). The BBL company is a JV with 3 partners with the following ownership: GasUnie BBL B.V. (60 %), E.On Ruhrgas BBL B.V. (20 %) and Fluxys BBL B.V. (20 %). The following data are derived from their website www.bblcompany.com ;

- Gas transport capacity: 16,5 BCM (equivalent to 20,6 GW energy)
- Pipeline diameter: 36 inch (90 cm)
- Compressor station: 2 operational units combined 45 MW with one spare unit
- Pipeline length: 230 km
- CAPEX estimate: 500 million euro (dated from 26 April 2004)
- Britned is a consortium that transports power via a High Voltage Direct Current (HVDC) cable between The Netherlands (Maasvlakte) and the UK (the Isle of

Grain). The Britned company is a JV with 2 shareholders: National Grid and Tennet. The following data are derived from their website www.britned.com ;

- Power transport capacity: 1000 MW (1 GW)
- Cable length: 260 km
- Transmission loss: max. 5 % (estimated on basis of Norned data), thus 50 MW
- CAPEX estimate: 600 million euro (2008)

The distances are very similar and investments are also in the same range, however BBL might have become more expensive as the CAPEX quote is from 2004 when EPC prices were still relatively low. With HVDC power transport a large part of the investment and the transmission loss is due to the conversion from alternating current to direct current and vice versa. For longer distances one might expect the HVDC cable relatively less expensive as the cost of the convertor stations will remain the same. In a state-of-the-art gas fired power plant electrical efficiency is 59 %. Therefore one might state that the Britned cable has a transport capacity of $1000 \text{ MW} / 0,59 = 1700 \text{ MW}$ in primary energy terms. This is still relatively small compared to the BBL pipeline which has in absolute terms roughly the same transmission loss (45 MW) but has a transport capacity (for roughly the same CAPEX) which is more than 10 times higher. Therefore one can conclude that it is more cost-effective to transport the same amount of energy by gas than by power. This conclusion is confirmed by several publications:

- http://www.chpcenternw.org/NwChpDocs/Transmission_and_N_Gas_Comparing_Pipes_and_Wires_032304.pdf
- http://wpweb2.tepper.cmu.edu/ceic/pdfs/CEIC_03_04.pdf
- Superconducting power cables, currently only used in small demo projects, might change the game in the future when they would be applied at commercial scale.
- <http://www.w2agz.com/Library/Superconductivity/e-pipe.pdf>

Naturally, there are different reasons to transport high voltage power compared to high pressure natural gas than transport costs alone. Britned lists the following benefits:

- Security of supply for north-western European countries
- Open access for all market participants through explicit and implicit auctions
- Significant contribution to the diversity of electricity supply both in Great Britain and the Netherlands
- Market advantages such as price leveling

Similar benefits are likely present for gas transport with BBL. Both consortia are operated by commercial management and whose activities are to some extent exempt from regulation. The activities are therefore legally separated from the regulated activities in the holding companies.

10.4 Analysis CO₂ and natural gas transport

Offshore pipeline transport of CO₂ and natural gas at high pressure will show a very different behavior due to the difference in thermodynamics. Under offshore conditions CO₂ will have a high density and behave like a liquid. The Gassco simulations in the

chapter on EU infrastructure show CO₂ behaves as a slightly compressible liquid when it has approached the seawater temperature of 7 degrees C. 50 km outside the coast the density varies only in a narrow range between 900 and 1000 kg/m³ while the pressure varies across a wide range (between 53 and 227 bar). Natural gas (Groningen gas composition) has a density of roughly 250 kg/m³ at the same conditions close to the coast of 220 bar and 7 degrees C. based on extrapolation of Groningen gas compressibility from 80 bar till 220 bar (ref. KEMA, Luuk Buit). This density is nearly 4 times lower than CO₂ at the same pressure and temperature conditions. Therefore the frictional loss in pressure drop (equivalent to variable costs) for transport is also at least 4 times lower for CO₂ compared to natural gas. In reality the ratio will be higher than 4 as cold CO₂ stays will decrease only slightly in density when pressure decreases while natural gas will show a stronger decreasing density with decreasing pressure leading to a higher pressure drop. For the same reason compression of CO₂ will require less energy than for natural gas to reach the same pressure and temperature.

It can be concluded that under highly turbulent flow conditions (as encountered here for both large scale CO₂ and natural gas transport) the transmission losses for CO₂ are at least 4 times lower than for natural gas on basis of equal mass throughput.

In order to compare the transmission loss for natural gas and CO₂ we should compare on an energy basis and not a mass flow basis. When burned 1 M³ gas is converted in 1 M³ CO₂ which is 2.75 times heavier (the ratio of molar mass of CO₂ versus methane). Thus on an energy flow basis CO₂ transport is still at least 4/2.75 thus 45 % more efficient than gas transport. Therefore it makes more sense from a transport cost perspective to invest in CO₂ pipelines for CO₂ import than to invest in natural gas pipelines or HVDC cables for power export (everything else being equal).

Current or planned investments in a further integrated NW European high voltage power network, to increase market connectivity or energy supply security are currently foreseen by the EU (reference from DG-energy: energy infrastructures till 2020). This might then change the overall picture as the financing of high voltage power network will likely be more easily arranged as the infrastructure for large scale CO₂ import due to the additional commercial drivers.

10.5 Conclusions

High pressure natural gas transport by offshore pipelines is, for the same transport in primary energy, lower in cost than high Voltage Direct Current transport by offshore cables. This is valid for the investment (CAPEX/MWh transported) as well as the transmission losses (OPEX/MWh transported). High pressure CO₂ transport by offshore pipelines is again much lower in cost than high pressure natural gas offshore pipeline transport, when compared on an equal primary energy basis. Therefore, it can be concluded that CO₂ import is lower in cost than electrical power export on an equal primary energy basis.

However, there are other drivers to expand the current high voltage network in Europe that warrants investments. Connecting more power plants and power users via a large

network leads to a greater diversity in power supply and thereby a greater energy supply security as well as market advantages for producers and consumers. Fortunately, the location for investments in CO₂-hubs as well as power generation- and transmission installations are often large industrial and logistics centers located at ports. Thus, there will be a strong synergy in investments for CO₂ transport infrastructure as well as power transport infrastructure. The latter enables more power plant investments which create the critical mass for CO₂ supply to enable large scale transport for CO₂ storage and CO₂-EOR. The planning of such networks should, due to their interdependence, be made in a coordinated fashion. Generally, it can be concluded that the location factors that determine new power plant locations do not change significantly by introduction of CCS.

11 CONCLUSIONS AND RECOMMENDATIONS

The conclusions and recommendations of D 4.1 are classified below in 9 different recommendations with their underlying arguments both in a technical/operational, regulatory, commercial or financial sense. Many recommendations require EU wide coordination with a strong role for the energy directorate DG-Energy as CO₂ transport infrastructure naturally belongs to the same category as infrastructure for power or gas. It seems logical that the North Sea and its surrounding countries (The Netherlands, Germany, UK, Norway, Denmark and Belgium) will be the nucleus where large scale CCS will start and develop further because these countries have the proximity to large scale storage locations as well as industrial centers that emit large CO₂-streams. The North Sea basin Taskforce would be the forum to discuss the regulatory issues between the North Sea countries. When operational experience from the demo projects becomes available and when plans for large scale CCS deployment further matures this area might likely be the CCS incubator for Europe and also host the final large scale offshore transport and storage network in the timeframe 2020 till 2050.

Rotterdam is well positioned as a leading CO₂-hub in this region because of its wide industry presence, the 2 ongoing demo projects, and commitments from the Rotterdam Climate Initiative. However, Rotterdam is only able to fulfill this role when neighboring countries, specifically Germany, take an active role towards CCS and supply CO₂ to the large scale network. Specifically CO₂-EOR requires such a huge CO₂ supply (60 million ton CO₂/year during at least 2 decades and peaking at 100 million ton CO₂/year) that the large scale CO₂-EOR option will only mature when the North Sea countries will actively deploy large scale CO₂ capture and transport for The North Sea. In this context CCS is not only a cost effective CO₂-reduction option but the crucial enabler for profitable fossil fuel based energy security in Europe.

- 1) Beyond the initial EU CCS demonstration projects, a large offshore transport network connecting multiple sources and sinks should be designed and build to start operationally in 2020 and onwards, on the basis of the large CO₂ supplies to be stored for CCS and/or CO₂-EOR in The North Sea (like Rotterdam, Groningen Eemshaven, North German harbors, Teesside)
 - a. Large CO₂ volumes require large diameter pipelines that result in much lower CAPEX cost/ton CO₂ than multiple small diameter pipelines
 - b. A multiple source–sink network including buffers leads to a higher stability in view of intermittent CO₂ supply from power plants
 - c. Easier and faster permitting for offshore transport and storage
 - d. Higher political and public acceptance at regional level, national and EU level for onshore storage when offshore storage has been successfully demonstrated first in The North Sea

- e. Phasing investments over a long time period might lead to higher CAPEX due to expect high inflation for steel and EPC costs and this has to be balanced against the capital cost in order to judge the timing of investments
- 2) Transport infrastructure like pipelines should be organized using a common carrier business model with 3rd party access based on long term inflation linked capacity based contracts with tariffs unrelated to the EU-ETS prices leading to a fixed return for infrastructure owners. Infrastructure ownership should be organized such that sufficient capital is attracted for all investments.
 - a. These rules allow a variety of owners for the transport infrastructure (pipeline network, terminal and compressor stations); e.g. a consortium with both companies and governments
 - b. Activities in CO₂ generation, CO₂ capture and CO₂ trading are legally separated from the pipeline consortium (similar to unbundling in gas and power)
 - c. The transport tariffs are initially set to a level that allows the consortium to achieve a reasonable return while incentivizing maximum capacity utilization by contracting more customers and CO₂ volume over time
 - d. Exemption from regulated returns should be allowed if this is required to attract enough capital (similar to the Britned en BBLcompany consortium)
 - 3) In view of economy of scale transport infrastructure like pipelines should be dimensioned in coordination with the users of different CO₂-hub locations using government guarantees for financing to eliminate the political risk that can't be insured.
 - a. Designing on large CO₂ volume demonstrates political commitment to CO₂ reduction ambitions and energy policy at EU level while attracting economic activity to the region of the CO₂-hub
 - b. Government guarantees enable private institutions like banks to finance part of the investment with debt and thereby incentivizing equity investors to participate/invest leading to reasonable returns at low risk
 - c. Operating large capacity infrastructure leads to lower CAPEX per ton CO₂ at high utilization and also a lower capital cost as % of total cost leading to lower revenue risk as a function of utilization
 - d. The EU should allow governments to reserve capital for government guarantees to be paid out to the financiers of the transport infrastructure in case the political commitment for CCS disappears
 - e. The development of future transport infrastructure could be accelerated when future EOR-oil tax revenues would be earmarked for the guarantees

- 4) The offshore pipeline trajectory should be designed to enable CO₂ transport to fields for CO₂ storage (depleted gas fields and deep saline formations) as well as oilfields for EOR and will therefor cross various national borders in the North Sea. This requires EU wide harmonization of rules for CO₂ transport and monetization of CCS and CO₂-EOR. The CCS directive for instance is not yet implemented at state level for all involved countries around the North Sea. Also the London protocol has not yet been ratified by all involved countries.
 - a. Combining CCS and EOR leads to revenues from EU-ETS and increased oil production, as well as diversifying risks and thereby lower financing costs/higher return on investment
 - b. Combining CCS and EOR supports both EU's climate objectives (CO₂ reduction) as well as EU's energy security objectives (increasing EU's energy production)

- 5) The most optimal routing of the offshore pipeline trajectory depends on the availability and suitability of the potential CO₂ storage locations. Both emitters and potential CO₂ storage operators need to be able to access relevant data (seismic data, reservoir model, platform data and well locations) from current EP operators at least 2 years before end of production. This requirement for EP operators should be valid for all North Sea countries to the same extent.
 - a. Depleted gas fields and oil fields in different regions from different operators might then be compared at the same level leading to higher quality cost estimates
 - b. Planning for future transport capacity and investments is facilitated

- 6) Liquid CO₂ shipping should be part of the transport infrastructure as its flexibility in routing is an enabler for EERP and NER 300 demo projects in offshore CO₂ storage and EOR and their transition to large scale offshore EOR as well. Shipping is an integral part of CO₂ transport and complementary to pipelines.
 - a. Early injection in mature oilfields with CO₂ from ships enables demo scale testing (1-2 million ton CO₂/year) of large oilfields on their CO₂-EOR suitability
 - b. Demo scale testing leads to de-risking of future large scale EOR pipeline investments for throughputs of 10 to 40 million ton CO₂/year and thereby lower financing costs

- 7) Deployment of large scale CCS in Europe requires an independent expert authority for high level coordination across the entire CCS chain to ensure the development of the transport network. Also a tax treaty needs to be developed to ensure a fair distribution of EOR oil tax revenues to countries that invest in

- capture, transport and storage facilities (e.g. UK, Denmark, The Netherlands, Germany, Norway, Belgium)
- a. Investment planning for transport, storage, CO₂-EOR and capture plants needs to be harmonized in time
 - b. The license and permit policy for transport and storage operations in different countries needs to be harmonized
 - c. A system approach is more cost effective than independent isolated projects and therefore requires coordination
 - d. Without central coordination CO₂ reduction objectives will likely not be met on time
- 8) Current regulation requires offshore oil field operators to abandon their platforms and associated infrastructure within 2 years (in UK) after production has ceased. This regulation should be modified and harmonized for all North-sea neighboring countries to enable cost-effective re-use in time of infrastructure for CO₂ storage and/or EOR.
- a. EOR provides an opportunity to develop a more extensive CO₂ pipeline network, delay high decommissioning costs of platforms, extract needed oil supplies and reach future storage capacity in large deep saline formations.
 - b. Offshore EOR requires high investments by oil field operators that requires timely design and construction of a large CO₂ backbone to the oilfields connect to large scale onshore capture units.
 - c. It is anticipated that the demand for CO₂ for EOR will be greater than supply for decades and without access to CO₂ many fields will be decommissioned at significant costs to the operators and governments.
- 9) There is a high urgency to implement all these recommendations in time which requires the development of a transport and storage network master plan starting in 2012
- a. The development of a large pipeline infrastructure can take up to 8 years from initial feasibility till operation
 - b. The opportunity window in time for CO₂ storage in depleted gas fields is different from that of CO₂-EOR but both requires investment decisions before 2020 to avoid lost revenue, high mothballing and decommissioning costs as well as too little CO₂ reductions
 - c. The characterization of storage locations (especially deep saline formations) require a lot of time
 - d. The optimal transport network is strongly dependent on the characteristics of the storage locations (pressurized oil fields versus depleted gas fields and deep saline formations)

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- e. The master plan should take into account the different interest from stakeholders like governments/citizens (lowest socio-economic costs) as well as industry and investors (good return to investors)

 - 10) Set up an expert authority, initially focused on storage in the North Sea that coordinates cross-border transport and storage infrastructure investment plans and their associated investment decisions to ensure high infrastructure capacity utilization.