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# Pathways towards large-scale implementation of $CO_2$ capture and storage: A case study for the Netherlands

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ABSTRACT

We sketch four possible pathways how carbon dioxide capture and storage (CCS) (r)evolution may occur in the Netherlands, after which the implications in terms of $CO_2$ stored and avoided, costs and infrastructural requirements are quantified. CCS may play a significant role in decarbonising the Dutch energy and industrial sector, which currently emits nearly 100 Mt $CO_2$/year. We found that 15 Mt $CO_2$ could be avoided annually by 2020, provided some of the larger gas fields that become available the coming decade could be used for $CO_2$ storage. Halfway this century, the mitigation potential of CCS in the power sector, industry and transport fuel production is estimated at maximally 80–110 Mt $CO_2$/year, of which 60–80 Mt $CO_2$/year may be avoided at costs between 15 and 40 €/t $CO_2$, including transport and storage. Avoiding 30–60 Mt $CO_2$/year by means of CCS is considered realistic given the storage potential represented by Dutch gas fields, although it requires planning to assure that domestic storage capacity could be used for $CO_2$ storage. In an aggressive climate policy, avoiding another 50 Mt $CO_2$/year may be possible provided that nearly all capture opportunities that occur are taken. Storing such large amounts of $CO_2$ would only be possible if the Groningen gas field or large reservoirs in the British or Norwegian part of the North Sea will become available.



## 1. Introduction

Carbon dioxide capture and storage (CCS) is expected to become a serious $CO_2$ emission reduction technology in the Netherlands. The annual Dutch $CO_2$ emission is nearly 180 Mt $CO_2$ at present, of which approximately 100 Mt $CO_2$/year emitted by the energy and manufacturing industry (Klein Goldewijk et al., 2005). As we are on the threshold of its introduction, it is about time to come up with strategies for large-scale CCS deployment as part of the transition towards a more sustainable energy system. For this purpose, we need insights into the way CCS may evolve and what its role in reducing greenhouse gasses (GHG) could be. More specifically, the capture potential in time, and the extent and pace at which this could be deployed given available storage capacity, needs to be studied in more detail.

Recently, the contribution of CCS in reducing Dutch GHG emissions has been forecasted at 0–15 Mt $CO_2$/year avoided in 2020, depending on the emission reduction target set (Daniëls and Farla, 2006). Crucial in this analysis was the assumption on the maximal CCS contribution, which was loosely based on the expected storage capacity that could be operational in 2020. Although useful in comparing different GHG options to compose a technology portfolio, the analysis does not shed light on the road towards that 15 Mt $CO_2$ emission reduction in 2020, nor does it consider the road

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ahead. As most scenario studies indicate that CCS deployment really takes off beyond 2020 if a climate policy is in place (IEA, 2004; McFarland et al., 2003; Wise et al., submitted for publication), the analysis should at least cover the period up to 2050 to understand the potential development of CCS.

Rather than studying the competition between CCS and alternative GHG mitigation options as performed in Daniëls and Farla (2006) and as investigated in more detail for the power sector in concurrent research (van den Broek et al., 2008), we will focus on the prerequisites, bottlenecks and consequences of different CCS pathways for the Netherlands. The former approach would answer the question how much CCS can be expected in a portfolio of GHG mitigation options. Our analysis tries to answer the question how different futures for CCS deployment may look like. The main objective of this study is to set up CCS pathways that may unfold and assess the implications in terms of $CO_2$ avoided and stored, costs and infrastructural requirements. We cover a potentially wide range of CCS implementation and timing, as many of the factors determining the CCS potential are uncertain. The pathways are created by combining information on $CO_2$ capture potential in different sectors and the capacity and availability of geological reservoirs. The *temporal* and *spatial* aspects of the energy system and geological reservoirs are explicitly addressed in this analysis. So far studies have focussed either on the dynamics in the power sector (e.g. Johnson and Keith, 2004; Wise and Dooley, 2005) or the spatial matching of existing sources and sinks (i.e. geological reservoirs) (IEA GHG, 2005a,b). The timeframes in which hydrocarbon reservoirs become available are generally not considered. Source–sink matching has been performed for current Dutch sources (Wildenborg et al., 1999), but the developments and capital stock turnover in the energy sector and availability of sinks in time was not incorporated. The Netherlands may become an electricity exporting country, considering its strategic location on the sea (coal logistics, cooling water) and good infrastructure (natural gas and electricity transmission lines). An additional reason that may become important is the ample storage options in the Netherlands and the North Sea, and the limited storage capacity in neighbouring countries such as Belgium, Germany and France (Christensen and Holloway, 2003).

Composing CCS pathways serves multiple purposes. First, they illustrate how much $CO_2$ could and may be avoided in time, at what costs, and for how long we could continue relying on this option. This is valuable information for decision makers who need to develop strategies to reduce GHG emissions. Second, analysing the requirements and bottlenecks of possible CCS futures could also make clear what short-term actions may be needed to realise long-term goals. Third, an integrated assessment of this kind may reveal synergies in the form of common infrastructure to transport $CO_2$ from various sources.

The analysis we present is techno-economic by nature, as it deals with power and industrial plants, infrastructure and reservoirs, with a focus on the medium to longer term. We do not explicitly investigate actions to set off CCS the coming years. Neither do we study institutional, legal and social barriers that may inhibit its deployment.

## 2. Methodology

In setting up different pathways, we consider the following factors as being the most decisive for the future of CCS. The $CO_2$ infrastructure is not considered as driving factor for the deployment of CCS, but as an outcome.

- *Climate policy scenario*. The $CO_2$ reduction aimed for as function of time is a crucial factor in the role of CCS, as was demonstrated in Daniëls and Farla (2006). The pathways studied here differ in the reduction targets set for different timeframes (2020 and 2050).
- *Baseline scenario*. The $CO_2$ capture potential is determined by the development in energy and material demand and technological characteristics and dynamics in the energy and industrial sector (vintage structure, fuel mix, etc.).
- *Capacity and availability of $CO_2$ storage reservoirs*. The geological capacity available for $CO_2$ storage is rather uncertain due to geotechnical issues and competition with other applications such as underground gas storage (UGS). The storage capacity and availability is therefore varied among different pathways.
- *$CO_2$ capture options and costs*. $CO_2$ capture can be realised in different sectors by retrofitting plants or by installing completely new units with integrated capture technology. Progress in capture and conversion technologies is accounted for by differentiating between state-of-the-art technologies and more advanced technologies that are expected to become available in the longer term.

We set emission reduction targets (climate policy scenarios) versus baseline scenarios and translate the potential role of CCS into pathways. Each pathway represents a so-called 'wedge' (as proposed in Pacala and Socolow, 2004) in filling the gap between baseline and climate policy scenario. This methodology is in many aspects similar to a scenario analysis performed for the UK (Gough and Shackley, 2006). The difference lies in the assessment of the future role of CCS; in the UK study a varying share of CCS is assumed, after which each scenario is qualitatively evaluated by means of a multi criteria analysis. In our analysis, the potential for $CO_2$ capture and storage are used to estimate the role of CCS, after which infrastructural requirements and costs of different pathways are computed using a spreadsheet model. We distinguish the steps described below in setting up CCS pathways (see also Fig. 1). Steps 1–3 form the basis of the CCS pathways, whereas the actual synthesis is done in steps 4–6.

1. *Choosing baseline scenarios and climate policy scenarios*. Climate policy scenarios consist of emission reduction targets and trajectories towards these targets (gradual versus instantaneous). We select four combinations of baseline and climate policy scenarios, each representing a specific pathway.

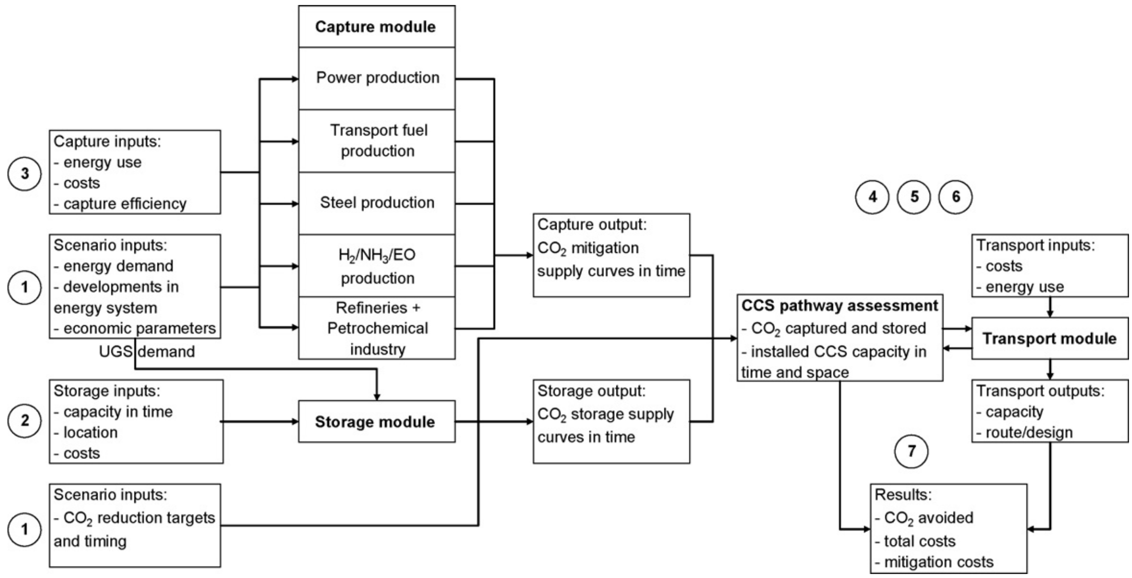


**Fig. 1 – Sequence of and relations between different modules in estimating the role of CCS.**

2. *Evaluating geological storage capacity* that becomes available in time, which set the physical boundaries for CCS. On that basis, storage supply curves are created, expressing storage potential versus storage costs, accounting for the availability of different reservoir types in different timeframes.
3. *Assessing $CO_2$ capture potential* in different sectors, which is mainly determined by the developments in the baseline scenario (energy demand, capital stock turnover, etc.). $CO_2$ mitigation supply curves are composed for each decade showing the $CO_2$ capture potential versus costs in time.
4. *Deriving CCS contributions* (in terms of $CO_2$ avoided) by combining steps 1–3. In this assessment, three situations can be distinguished:
   a. *Storage limitation*: the CCS wedge is limited by the geological storage capacity and/or availability.
   b. *Capture limitation*: in a scenario where practically the entire technical $CO_2$ storage potential would be available, CCS penetration is limited by the opportunities for $CO_2$ capture in the different sectors.
   c. *No limitation*: when both the capture and storage potential are larger than the required emission reduction, we assume a maximum CCS contribution. This value can either be based on other limitations (e.g. rate at which new infrastructure can be realised), or be a fixed value (a maximum of 50% of the gap) when there are practically no limits conceivable.
5. *Matching sources and sinks* given their spatial distribution and temporal availability. For this aim, we compose a supply curve, in which $CO_2$ transport and storage costs are calculated for each $CO_2$ source following the $CO_2$ mitigation supply curve from step 3, up to the CCS contribution assessed in step 4.
6. *Composing CCS pathways*. Steps 4 and 5 are repeated for each decade, accounting for the storage capacity being reduced by the extent at which CCS has been applied in previous time periods. In this iterative process, we incorporate future developments in $CO_2$ capture capacity with a perfect foresight of 25 years in deciding on storage capacity to be exploited and infrastructure to be constructed.
7. *Calculating the implications*. Finally, the amount of $CO_2$ stored and avoided in time, investment costs of the entire system and $CO_2$ mitigation costs are calculated for the various pathways. We use the present value method to calculate the economic performance of the CCS systems, as fuel prices, electricity production and hence $CO_2$ production vary in time and investments of the CCS system are incurred at different timeframes. For electricity and fuel production and use, we use Eqs. (1) and (2), as the reference system may be a different technology.[1] For industrial processes, where the reference system is simply the plant without capture, we use Eq. (3).

$$\mathrm{COE} = \frac{\sum_{t=0}^{T} C_t/(1+r)^t}{\sum_{t=0}^{T} E_t/(1+r)^t} \tag{1}$$

$$\mathrm{MC} = \frac{(\mathrm{COE}/\eta_{\text{end-use}} + C_{\text{end-use}})_{\mathrm{CCS}} - (\mathrm{COE}/\eta_{\text{end-use}} + C_{\text{end-use}})_{\mathrm{ref}}}{(m_{\mathrm{CO_2}}/\eta_{\text{end-use}})_{\mathrm{ref}} - (m_{\mathrm{CO_2}}/\eta_{\text{end-use}})_{\mathrm{CCS}}} \tag{2}$$

$$\mathrm{MC} = \frac{\sum_{t=0}^{T} C_{t,\mathrm{CCS}}/(1+r)^t}{\sum_{t=0}^{T} M_{t,\mathrm{avoided}}/(1+r)^t} \tag{3}$$

where COE is the production cost of energy carrier (€/GJ), $C_t$ the costs in year $t$ (€), $E_t$ the energy production in year $t$ (GJ), $T$ the project lifetime (year), $r$ the discount rate, MC the mitigation costs (€/t $CO_2$), $\eta_{\text{end-use}}$ the end-use efficiency (functional unit/

[1] An IGCC with $CO_2$ capture may replace a PC unit without capture. In the transport sector, hydrogen could replace gasoline, which involves different vehicle costs and tank-to-wheel efficiencies.

**Table 1 – Pathways for different $CO_2$ emission reduction scenarios. Values in parentheses are cumulative reductions.**

| Pathway | Baseline | Emission reduction 2020 | $CO_2$ reduction 2020 | Emission reduction 2050 | $CO_2$ reduction 2050 |
|---|---|---|---|---|---|
| 1 'deep reduction' | GE | 30% reduction versus 1990 | 95 Mt $CO_2$/year[a] (740 Mt) | 80% reduction versus 1990 | 300 Mt $CO_2$/year (6800 Mt) |
| 2 'postponed action' | GE | No action | 0 Mt $CO_2$/year (0 Mt) | 50% reduction versus 1990 | 250 Mt $CO_2$/year (2600 Mt) |
| 3 'action abroad' | TM | Stabilisation 2010 | 20 Mt $CO_2$/year (110 Mt) | Stabilisation versus 2010 | 65 Mt $CO_2$/year (1500 Mt) |
| 4 'ambitious' | TM | 15% reduction versus 1990 | 65 Mt $CO_2$/year (500 Mt) | 50% reduction versus 1990 | 165 Mt $CO_2$/year (4100 Mt) |

[a] This would imply realisation of the complete technical reduction potential (Daniëls and Farla, 2006).

GJ), $C_{end\text{-}use}$ the end-use costs (€/functional unit), $m$ the $CO_2$ emission factor (kg/kWh) of CCS chain and reference chain, and $M_{t,avoided}$ is the avoided $CO_2$ emission in year $t$ (t $CO_2$).

## 3. Developing CCS pathways

### 3.1. *Baseline and climate policy scenarios*

The four combinations of baseline and climate policy scenarios, each representing a specific pathway, are summarised and depicted in Table 1 and Fig. 2. The emission reductions levels are based upon ambitions formulated by the European Union, which are between 15–30% by 2020 and as much as 50–80% by 2050 in comparison to the 1990 level (CEU, 2005, 2006). Pathway 1 strives for an extreme cut in emission reduction starting right away. In the second pathway, $CO_2$ reduction is postponed to the period beyond 2030, after which we need to accelerate $CO_2$ emission reductions to achieve the targets set for 2050. In pathway 3, $CO_2$ emissions are to be stabilised at the 2010 level by means of national actions, assuming a large share of emission reduction is achieved by investments abroad. Pathway 4 is a more average and gradual, but still ambitious, scenario.

For the baselines, we adopt the Global Economy (GE) scenario and the Transatlantic Market (TM) scenarios. These scenarios have been composed by various Dutch planning agencies to study the impact of various trends in the Netherlands on the physical environment up to 2040 (Bollen et al., 2004; Farla et al., 2006). GE is characterised by global free trade and a strong orientation towards private responsibility, resulting in a relatively high economic growth of 2.6% annually up to 2040. The TM scenario has a somewhat lower economic growth (1.9% per year). EU member states focus on national interest (instead of international cooperation as in GE) and current trade blocks are maintained.

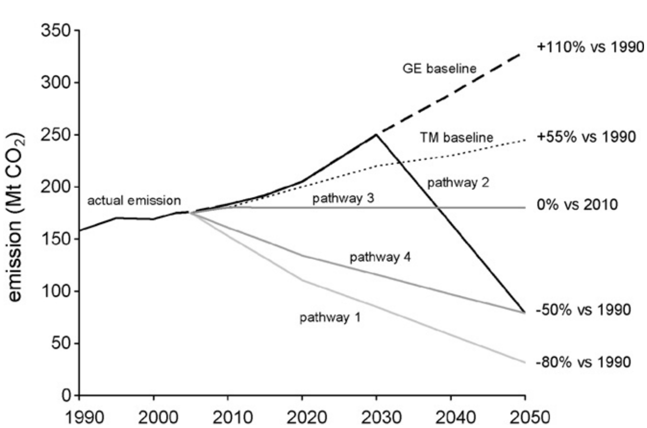


**Fig. 2 – Emission reduction pathways investigated in this study versus baseline scenarios developed for the Netherlands in Farla et al. (2006).**

### 3.2. $CO_2$ *storage*

#### 3.2.1. *Reservoir potential, availability and location*

Table 2 shows the technical capacity[2] for $CO_2$ storage in the Netherlands and the continental shelf. Gas fields represent the major storage potential. The Dutch oil fields represent a relatively low storage potential and, therefore, not further considered. Aquifers and coal seams are not that well studied and characterised as hydrocarbon structures, which causes a relatively large uncertainty in the capacity figures. In Table 2 only aquifer traps are included. Possibly other parts of the water bearing layers may be used for $CO_2$ storage as well. The gross storage potential of the entire Dutch aquifer formations, assuming 2% storage efficiency, is estimated at roughly 10 and 6 Gt $CO_2$ for onshore and offshore formations, respectively (Wildenborg et al., 2003, 1998).

A variety of technical, legal, social and/or economic reasons may reduce the capacity available for $CO_2$ storage. Apart from those reservoirs that may simply not be suited due to unfavourable characteristics (e.g. low permeability, doubtful seal quality, geomechanical effects, complex reservoirs such as the limestone formations in the eastern part of the Netherlands (Van der Krogt et al., 2006)), a number of factors that may inhibit the $CO_2$ storage can be distinguished:

- *Size constraints*. Small reservoirs are not preferred from an economic point of view. Generally, the lower limit is set around a few up to 10 Mt $CO_2$ (IEA GHG, 2005a,b; Wildenborg et al., 1998). Reservoirs should preferably offer sufficient

[2] Bradshaw et al. (2006) define three categories, being theoretical, realistic and viable capacity. The theoretical capacity assumes that the entire reservoir formation (pore volumes, water) is accessible to store $CO_2$. The realistic capacity applies a range of technical cut-off limits such as quality of the reservoir and seal, and whether there may be other competing interests that could be compromised by injection of $CO_2$. Finally, the viable capacity also considers economic, legal and regulatory barriers to $CO_2$ geological storage. The figures used in our report are somewhere in between the theoretical and realistic capacity and are hereby referred to as technical storage capacity.

**Table 2 – Technical $CO_2$ storage potential in the Netherlands.**

| Reservoir | Storage capacity ($Mt\ CO_2$) | Source |
|---|---|---|
| Gas fields[a] | | |
| Groningen gas field | 7350 | TNO (2007) |
| Other gas fields onshore | 1600 | TNO (2007) + confidential data |
| Other gas fields offshore | 1150 | TNO (2007) |
| Oil fields | 40 | TNO (2007) |
| Coal seams[b] | 170 (40–600) | Van Bergen and Wildenborg (2002) |
| Aquifer trap prospects | | |
| Onshore[c] | 400 | TNO (2007) |
| Offshore[d] | 350 (90–1100) | Wildenborg et al. (1998) |

[a] The figures in TNO (2007) refer to reserves with a storage capacity larger than 4 Mt $CO_2$, assuming 100% of the volume recoverable hydrocarbons could be replaced with $CO_2$ up to hydrostatic pressure. Undiscovered fields are estimated to add another 50 bcm the coming 10 years. The expectation is that future discoveries, given the mature stage of exploration in the Netherlands, will generally be smaller structures on average (Breunese, 2006). As small fields are less suitable for CCS, we do not make a large error by excluding them. The uncertainty margin in the estimation of the onshore gas fields is ±20%.

[b] Represents coal seams above 1500 m depth. Between 1500 and 2000 m, there is another 260–2260 Mt storage capacity, but the exploitation of coal seams in this interval is currently technically and economically questionable (Van Bergen and Wildenborg, 2002).

[c] Total onshore capacity including traps with a storage capacity larger than 5 Mt $CO_2$ identified in Permian, Triassic, Late Jurassic/Early Cretaceous and Tertiary aquifers.

[d] The range represents uncertainty in trap-density (1–10%) and storage efficiency (2–6%).

potential to store the captured $CO_2$ of one plant over its operational lifetime. Most of the Dutch gas fields are rather small (below 5 bcm, equivalent to roughly 10 Mt $CO_2$).

- *Timing*. Fig. 3 shows that most gas fields become available gradually in the coming two decades. Possibly, the lifetime of gas fields may be extended a few years with rising gas prices. The Groningen gas field is not expected to become available before 2040, and possibly (far) beyond 2050, provided that significant investments are made (TNO-NITG, 2006). The pattern at which gas fields become available dictates the 'window of opportunity' for $CO_2$ storage. Ideally, $CO_2$ injection into gas reservoirs starts immediately after the production of gas has ceased, in order to subdue changes in reservoir features, minimise water influx and allow for possible reuse of infrastructure (wells, pipelines, and platforms[3]) and knowledge of the reservoir. Possibly, $CO_2$ injection may even start in the tail of the gas production curve.[4] Reservoirs that were abandoned earlier may be taken into use again for $CO_2$ storage, but at higher costs in comparison to immediate reuse.

  Aquifer traps are not characterised sufficiently yet. Therefore, it is assumed that these formations may be used for $CO_2$ storage beyond 2010. Large-scale storage in coal seams is not expected to be feasible before 2020.

- *Alternative applications*. Reservoirs may be reserved for other functions such as underground natural gas storage, geothermal energy (aquifers) or possibly hydrogen storage in the longer term. In addition, plans may exist to construct new buildings or infrastructure on onshore fields. An extension of current UGS capacity can be expected due to declining and less flexible domestic gas supplies and increased reliance on inflexible gas import. With the decreasing pressure of the Groningen gas field, it will become more difficult to match supply and demand, which enhances the demand for UGS to cover demand fluctuations and provide seasonal flexibility (Van Dril and Elzenga, 2005). Gas fields are the most cost-effective reservoirs for this purpose (CIEP, 2006). The Netherlands, with its abundance of gas fields, may possibly serve as a gas hub, providing storage facilities for surrounding countries with a lack of (suitable) gas reservoirs. If the Netherlands will develop itself as a gas hub, the role of the Groningen gas field as seasonal balancer must be taken over by additional UGS capacity. In such a scenario, we estimate an additional 100–150 bcm (total gas volume) may be required the next 20 years, based on storage requirements forecasted in Breunese (2006) and CIEP (2006). This corresponds to 13–20% of the UR of all onshore gas fields minus the Groningen gas field. Fields of at least 10 bcm are preferable for both UGS (seasonal storage, not peak shaving facilities) and CCS, for which only a limited number (~30) are available (Breunese, 2006).

Fig. 4 illustrates the spatial mismatch between (current) $CO_2$ sources and sinks. The majority of the gas fields are located in the northern part of the country and the continental shelf, whereas most large $CO_2$ sources are located in the western part of the country. The coal seams are predominantly located in the southern and eastern part of the country, whereas the aquifers are distributed more homogeneously.

Although the Dutch reservoirs offer a large technical storage potential, the limiting factors mentioned above may force us to look beyond national boundaries. There are a number of very large structures located in the North Sea, which may be preferred above the relatively smaller fields located in the Netherlands. The southern North Sea basin of the UK offers over 14 Gt $CO_2$ of storage capacity in closed structures in aquifers and nearly 3 Gt of $CO_2$ in gas fields (Bentham, 2006). The Utsira formation in the Norwegian part of the North Sea, in which $CO_2$ from the Sleipner platform is

[3] Production wells are generally designed for lifetime of oil or gas production. When using these wells for $CO_2$ storage, possibly parts of the well have to be replaced in order to make these elements resistant to corrosion and high injection pressures. Platforms may be reused when they are large enough and the costs to maintain them are not prohibitive. In this analysis, reuse of wells and production platforms is not further considered.

[4] $CO_2$ injected into a producing field may mix with the gas and may cause breakthrough at the producing wells, thereby degenerating the natural gas resources. On the other hand, the recovery of gas may be enhanced by $CO_2$ injection, although this technique is not proven yet (Breunese, 2006).

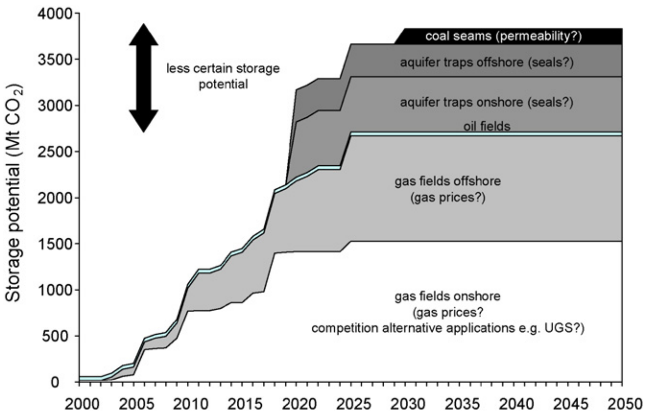


**Fig. 3 – Storage availability in time (excluding current UGS reservoirs and Groningen gas field). The time line for the gas fields is derived from publicly available figures (TNO, 2007). With less certain storage capacity, we refer to uncertainty in reservoir capacity, storage security and technical feasibility.**

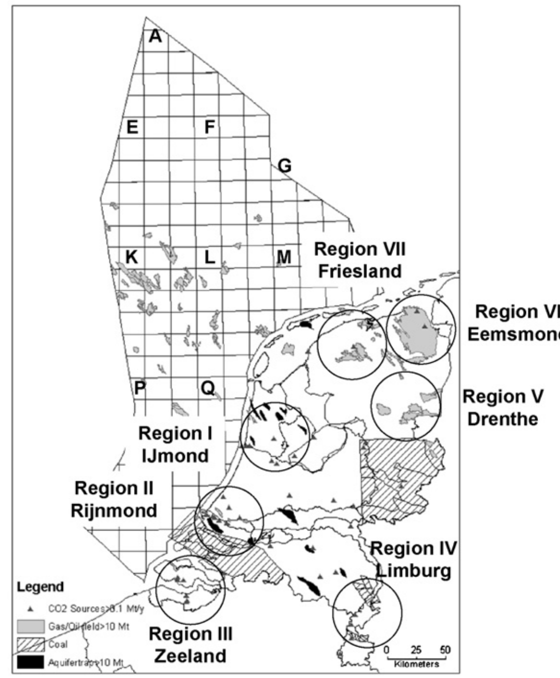


**Fig. 4 – Location of geological reservoirs and large $CO_2$ sources in the Netherlands (derived from data of TNO-NITG). The Groningen field is the enormous structure in region VI. Note that this map is a snapshot; future $CO_2$ sources that will be equipped with $CO_2$ capture may be located in areas where few emissions are occurring now.**

injected, is of such dimensions that it could theoretically store 42 Gt $CO_2$, of which 850 Mt in traps (Bøe et al., 2002).

Another interesting opportunity is enhanced oil recovery using $CO_2$ ($CO_2$-EOR) for nearly depleted oil fields in the North Sea. Given the location of these reservoirs, sources in the UK and the few sources in Norway are most likely targets to provide $CO_2$. Therefore, the North Sea EOR opportunities are not incorporated in this analysis.

In conclusion, the deployment of storage capacity depends on a number of uncertainties, which we captured in the form of scenarios:

- Availability of the Groningen gas field. Assuming this reservoir becomes available for $CO_2$ storage, it is the question when injection could be started. In a risk-averse strategy, injection is started after depletion.
- Availability of the UK offshore gas fields. There are various UK power plants in the regions around the southern North Sea sector that may become future $CO_2$ suppliers. Hence only a fraction of the UK reservoirs may become available for $CO_2$ produced in the Netherlands.
- A third, more remote reservoir is the Utsira formation in Norway, which might become a central storage hub for Northwest European $CO_2$. This option would only make sense if a large-scale infrastructure is being constructed.
- Competition with alternative applications, most importantly UGS. In the GE scenario, the Netherlands may develop itself as international gas hub, 'confiscating' many onshore gas fields for UGS.
- In a scenario where emphasis is put on risk minimisation, storage is most likely to occur in (offshore) gas fields.
- Profitability of enhanced hydrocarbon recovery. In a scenario with high energy prices and/or where energy security is one of the main priorities in energy policy, $CO_2$ storage with oil/gas revenues generated by EOR, EGR or ECBM may be the preferred option for storage. However, ECBM still requires significant development and must be considered as an uncertain storage option at this moment. EGR is not considered due to the uncertainty about its feasibility.

**Table 3 – Storage deployment in different pathways.**

| | Pathway | | | |
|---|---|---|---|---|
| | 1 'deep reduction' | 2 'postponed action' | 3 'action abroad' | 4 'ambitious' |
| Spatial constraints | Onshore + offshore NL, UK | Onshore + offshore NL, UK, NO | Offshore NL, UK | Onshore + offshore North Sea NL |
| 2010–2020 | Gas fields Aquifer traps | – | Offshore gas fields | Aquifer traps |
| 2020–2030 | Gas fields Aquifer (traps) | – | Offshore gas fields | Gas fields Aquifer (traps) |
| 2030–2040 | Gas fields Groningen field Aquifer (traps) | Aquifer (traps) | Offshore gas fields | Gas fields Coal seams Aquifer (traps) |
| 2040–2050 | Groningen field Aquifer (traps) | Aquifer (traps) | Offshore gas fields | Coal seams Aquifer (traps) |

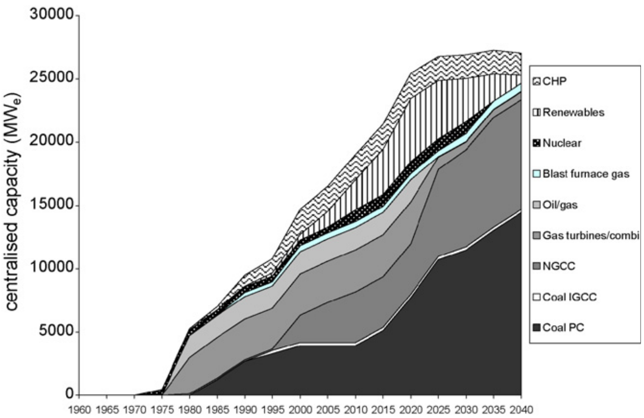


**Fig. 5 – Electric generation capacity in the GE baseline scenario derived from Farla et al. (2006) (excluding decentralised CHP units, which represent approximately 25% of the current installed capacity).**

Table 3 gives an overview of the reservoirs we consider to be available for $CO_2$ storage in different pathways and periods. In pathway 1, basically all Dutch reservoirs and a share of UK offshore reservoirs are available, apart from some gas fields deployed for UGS. We assume $CO_2$ injection into the Groningen field could be initiated in the tail of production curve around 2030. In pathway 2, the window-of-opportunity for hydrocarbon fields has closed and/or reservoirs are being deployed for UGS, hence only aquifers are available. Energy security and risk minimisation are the key drivers in pathway 3. This will induce storage in offshore depleted hydrocarbon reservoirs, as gas fields not yet fully depleted are considered valuable assets (not to be 'polluted' with $CO_2$) and the risks of leakage at onshore fields may be considered unacceptably high. In this scenario, storage in aquifer traps is no option due to concerns about leakage. In pathway 4, $CO_2$ storage is restricted to reservoirs located in the Dutch onshore region and the Dutch part of continental shelf. Such a scenario could occur when all interesting UK offshore gas fields are used to store $CO_2$ produced in the UK. We assume that the high gas prices in this scenario cause the lifetime of gas fields to be extended by 5–10 years and induce $CO_2$ storage in the Dutch coal seams in a later stage.

### 3.3. *$CO_2$ capture in different sectors*

Apart from the power sector, a number of industrial $CO_2$ sources and future transport fuel production are included in this analysis. Only sources emitting more than 0.1 Mt $CO_2$/year are accounted for. We do not include $CO_2$ capture from industrial CHP units, as the majority are decentralised sources emitting only a few kt/year.

#### 3.3.1. *Power sector*

The coming 5 years approximately 9 $GW_e$ of capacity may be commissioned, consisting mainly of large coal and gas-fired units. Up to 2020, the development of electricity supply in the GE and TM scenarios is nearly identical; coal, renewables and also decentralised CHP are the main grow markets. Beyond 2020, the baselines diverge. In GE mainly coal and gas-fired capacity is installed and also the share of decentralised CHP is increasing (see Fig. 5). In TM, 6 $GW_e$ of nuclear capacity is installed in addition to coal-fired capacity. Electricity production by means of decentralised CHP is decreasing due to unfavourable electricity and gas prices. The market for renewable energy collapses after 2020 in both GE and TM, as climate policy is not continued and incentives for green electricity are abolished (Farla et al., 2006).

In studying $CO_2$ capture in the power sector, it may be useful to distinguish capture at existing plants, plants built in the short term (2007–2015) and plants that will be built in the longer term (beyond 2015).

Existing plants could be retrofitted with $CO_2$ capture technology. Retrofitting may become necessary when deep emission reductions are required, given the current trend for lifetime extension of existing assets, especially coal-fired units. There are several drawbacks and barriers that might inhibit retrofitting, among which the strong increase in electricity production costs and reduction in power output, which has to be compensated by additional capacity.[5] Moreover, at many power plant locations there may not be enough space for absorption and regeneration columns, compressors and eventually cooling towers. In our study, it is assumed that retrofitting existing PC units is possible in pathway 1.

Plants that are built in the short term should be flexible in reducing their $CO_2$ output in order to anticipate uncertain climate policy. For coal-fired units that may be constructed the coming years, strategies are being considered to enable $CO_2$ emission reduction by either making the units 'capture ready'; i.e. designing the plants in a way that allows for cost-effective add-on of $CO_2$ capture later on. In practice, this means that additional space is reserved for $CO_2$ capture components, compression and cooling capacity. Also the vicinity of storage reservoirs may be considered in plant siting (Gibbins et al., 2006). As the need for $CO_2$ capture is uncertain, and also the development in capture technologies cannot be foreseen, pre-investments are expected to be modest (Bohm et al., 2006).

Fossil power plants that will be built in the longer term are assumed to be equipped with $CO_2$ capture, provided that more stringent climate policy has solidified, and sufficient certainty has been created to enable such large investments. Table 4 contains the main input parameters for the selection of technologies considered in this analysis.

Ideally, an electricity market dispatch model should be applied to study the penetration of CCS in the power sector as such models can incorporate the effects and dynamics of $CO_2$/fuel prices, sunk capital and plant dispatch (Johnson and Keith, 2004). Such an analysis is currently being performed for the Netherlands by van den Broek et al. (2008). Instead, we adopt a more heuristic approach to forecast the potential role of CCS in the power sector, making use of insights generated by such studies. We compose $CO_2$ mitigation supply curves by means of a simple plant-level analysis,[6] assuming the power

[5] We assume additional IGCC capacity with $CO_2$ capture is constructed to compensate for the loss in power output.

[6] For each plant that will be constructed in the baseline, we calculate the mitigation costs to install a plant with $CO_2$ capture instead. Likewise, retrofit costs for existing units are computed.

**Table 4 – Forecasts of electric efficiency and capital costs (€2000, year 0 in the model) of power plants in time.**

| Technology[a] | 2010–2020 | | 2020–2030 | | 2030–2050 | |
|---|---|---|---|---|---|---|
| | $\eta_e$ (LHV) | TCR (€/kW$_e$) | $\eta_e$ (%$_{LHV}$) | TCR (€/kW$_e$) | $\eta_e$ (%$_{LHV}$) | TCR (€/kW$_e$) |
| PC | 46% | 1200 | 49% | 1100 | 52% | 1050 |
| IGCC | 46% | 1500 | 50% | 1300 | 54% | 1200 |
| NGCC | 58% | 500 | 60% | 450 | 63% | 450 |
| PC + CCS[b] | 36% | 1800 | 40% | 1600 | 44% | 1500 |
| IGCC + CCS[c] | 38% | 1900 | 43% | 1600 | 48% | 1400 |
| NGCC + CCS[d] | 49% | 850 | 52% | 700 | 56% | 650 |
| PC capture ready retrofit[e] | 36% | 700 | 37% | 700 | 38% | 700 |
| IGCC capture ready retrofit[f] | 38% | 500 | 39% | 500 | 40% | 500 |
| PC retrofit 1[g] | 29% | 900 | 30% | 900 | Na | Na |
| PC retrofit 2[h] | 32% | 850 | 33% | 850 | Na | Na |

[a] Figures are derived from Damen et al. (2006), De Coninck et al. (2005), Gibbins et al. (2005), Hendriks et al. (2004), Menkveld (2004), and Panesar et al. (2006). All plants with $CO_2$ capture include compression to 110 bar. O&M costs are set at 4% of TCR for all configurations except for PC + CCS and PC retrofit at 5%. Lifetime of coal and gas-fired power plants is 45 and 30 years, respectively. Costs of retrofitting represent additional costs per kW$_e$ after retrofitting. Downtime due to retrofitting is not taken into account.
[b] Advanced supercritical PC + post-combustion capture (90% $CO_2$ capture efficiency).
[c] Dry-feed gasifier + pre-combustion capture (90% $CO_2$ capture efficiency).
[d] Brayton cycle + post-combustion capture (90% $CO_2$ capture efficiency).
[e] Advanced supercritical PC + post-combustion capture add-on (90% $CO_2$ capture efficiency).
[f] Dry feed gasifier + pre-combustion capture add-on (90% $CO_2$ capture efficiency).
[g] Subcritical PC + post-combustion capture add-on (90% capture efficiency), including refurbishment costs of 150 €/kW$_e$ to extend the plant lifetime by 20 years (Gibbins et al., 2005). Repowering to advanced supercritical conditions reduces the energy penalty and additional costs (Gibbins et al., 2005; Panesar et al., 2006), but this option is not considered here.
[h] Supercritical PC + post-combustion capture add-on (90% $CO_2$ capture efficiency).

plants with capture in the climate policy scenarios operate in the same load as the plants they replace in the baseline scenario. For the gas prices prevailing in the GE and TM baseline, an IGCC with $CO_2$ capture would be the most cost-effective mitigation option to replace PC units, representing the majority of new installed capacity in the baseline scenarios. NGCC with CCS may be deployed in intermediate load at sufficiently high $CO_2$ prices, which may occur in scenarios in which large emission reductions are required. As coal-fired plants are replaced for coal-fired plants with CCS and ditto for gas-fired plants, the ratio coal to gas does not change significantly over time. In reality, a switch to more gas-fired capacity without $CO_2$ capture may occur in some pathways. Fig. 6 shows NGCC without $CO_2$ capture would be most economic for gas prices below 5.5–7 €/GJ and $CO_2$ prices up to 40–55 €/t $CO_2$. Dispatch models indeed show that with rising $CO_2$ prices, NGCC will be dispatched more often and new capacity will be predominantly NGCC (Wise et al., submitted for publication; Johnson and Keith, 2004). At a certain $CO_2$ price, coal-fired units with CCS become the preferable option for base load generation above NGCC. This would imply that the opportunities for CCS are postponed. We ignore this temporary gas 'revival' and assume utilities invest in IGCC with CSS straight away. The possible early retirement of capital stock, which may occur under very stringent emission reduction pathways, is not accounted for.

Locations where old plants are being decommissioned will be used for new plants, as the construction of (especially coal-fired) power plants is to be preferred at existing sites due to legislation, social acceptance, logistics and available infrastructure. Locations being considered for new large power plants are Eemshaven, the Rijnmond area, the Vlissingen area in Zeeland and the IJmond region.

### 3.3.2. *Industrial sources*

We consider industrial processes that generate relatively small quantities of pure $CO_2$, the early opportunities, and processes generating large quantities of $CO_2$ concentrated at a single site as occur in the steel industry, petrochemical

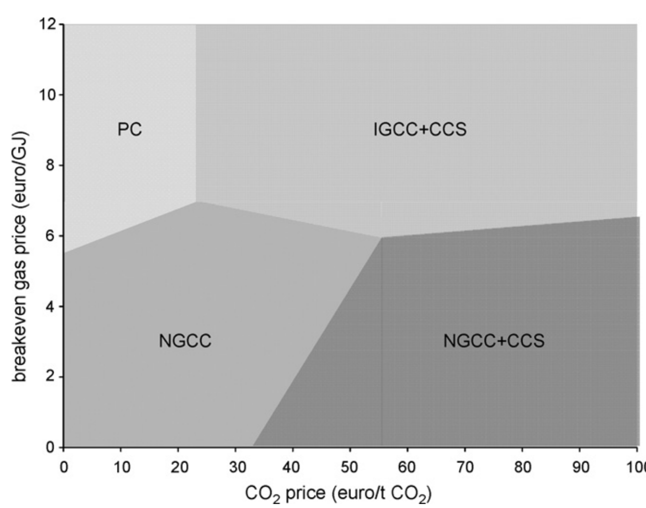


**Fig. 6 – Competition between coal and gas-fired technologies as a function of gas and $CO_2$ price, assuming a coal price of 1.7 €/GJ. The breakeven gas price is defined as the gas price where the electricity production costs of two competing options are equal. Values include compression, 100 km transport and storage in an onshore gas field. We consider PC as the preferred technology in a world without climate policy, whereas IGCC with CCS is considered to be the preferred technology in a carbon constrained world.**

**Table 5 – Overview industrial $CO_2$ sources, including capture costs and energy use (Wildenborg et al., 1999; Grootveld, 2006; IEA GHG, 2002; Rijksen, 2005; Van der Meer et al., 2005).**

| Source | Region | $CO_2$ emission (Mt/year)[a] | $CO_2$ purity | TCR (M€/kg $CO_2$/s)[b] | Heat requirements (kJ/kg $CO_2$) | Electricity requirements (kJ$_e$/kg $CO_2$)[b] |
|---|---|---|---|---|---|---|
| Ammonia plant 1 | IV | 0.5 | ~100% | 1.3 | 0 | 410 |
| Ammonia plant 2 | III | 0.8 | ~100% | 1 | 0 | 410 |
| Hydrogen plant 1 | II | 0.6 | ~100% | 1.2 | 0 | 410 |
| Hydrogen plant 2 | II | 0.1 | ~100% | 3 | 0 | 410 |
| Ethylene oxide plant 1 | II | 0.13 | ~100% | 2.6 | 0 | 410 |
| Ethylene oxide plant 2 | III | 0.06 | ~100% | 4 | 0 | 410 |
| Gas processing plant 1 | K | 0.4 | ~100% | 1.4 | 0 | 410 |
| Ethylene plant 1 | II | 1.4 | ~12% | 5 | 3000 | 470 |
| Ethylene plant 2 | III | 2.7 | ~12% | 3.1 | 3000 | 470 |
| Ethylene plant 3 | IV | 1.7 | ~12% | 4.2 | 3000 | 470 |
| Steel plant 1 | I | 3.7[c] | ~20% | 0.7 | 0 | 620 |
| Refineries 1–4 | II | 6.6[d] | 7–13% | 3.6-8.6 | 3200 | 480 |
| Refinery 5 | III | 1.0 | 7–13% | 6.7 | 3200 | 480 |

[a] Estimated $CO_2$ emission available for storage.
[b] Includes capture and compression to 110 bar.
[c] Only $CO_2$ produced in blast furnaces, i.e. the carbon input minus carbon incorporated in pig iron (~4%), is considered for capture (Klein Goldewijk et al., 2005).
[d] Estimated emissions from boilers and heaters, derived from the Dutch energy balances (CBS, 2003). $CO_2$ emissions are allocated to individual refineries on the basis of crude oil throughput.

industry and refineries (see Table 5). $CO_2$ emissions from those industrial sources are set constant within the time period considered, assuming the market for these products remains stable or the growth is offset by energy efficiency measures.

We adopt the relations between costs and energy use of post-combustion $CO_2$ capture and $CO_2$ flow and concentration as applied in Egberts et al. (2003), for all sectors except iron and steel production. The high partial pressure of CO and $CO_2$ in blast furnace gas makes pre-combustion capture (after CO shift) more cost-effective than post-combustion capture. We use the costs and energy use quoted in Gielen (2003).

### 3.3.3. *Production of alternative fuels*

In the longer term, new opportunities for CCS may arise when a market evolves for alternative fuels for the transport, residential and commercial sector. These sectors could be decarbonised by application of hydrogen or synfuels (Fischer–Tropsch diesel, methanol, DME) produced from coal (CTL), gas (GTL) and biomass (BTL) with CCS. Alternatively, cars may be driven electrically (using electricity produced with CCS), but this option is not considered here.

As the future of hydrogen is very much depending on the successful introduction of fuel cells, which is uncertain,[7] we incorporate a $H_2$ scenario in pathway 2 only. In the other pathways, we consider F–T diesel produced by gasification of coal and biomass with CCS as nearly climate-neutral alternative to clean hydrogen.[8] In contrast to hydrogen, the successful introduction of F–T diesel is not determined by the progress in immature technologies, as the fuel is compatible with existing vehicles and infrastructure. Its success will primarily be driven by oil prices, and the creation of large biomass markets and supply chains in case of BTL. F–T diesel produced from coal/biomass will become competitive with conventional diesel somewhere at 65–70 $/bbl at zero carbon prices, and around 45 $/bbl at carbon prices near 30 $/t $CO_2$ (Van Vliet et al., submitted for publication; Williams et al., 2006). In absence of scenario studies on F–T diesel penetration in time, we assume half the current diesel market could be replaced by synthetic diesel halfway this century.

In the $H_2$ variant, the demand is computed as a function of FCV penetration, for which we adopt the values proposed in the Hyways study (L-B-Systemtechnik, 2006). In the first years, when the demand is still small, the general consensus is that $H_2$ will be produced predominantly by distributed SMR units and/or truck delivery of merchant $H_2$. At a certain moment in time, the demand is sufficiently high to make a transition towards centralised hydrogen production with CCS. Combining the insights on transition dynamics published by Yang and Ogden (2005) and the adopted hydrogen demand scenario (L-B-Systemtechnik, 2006) for the Dutch context suggests that the optimal transition year towards large-scale production may be around 2030. We assume reformers are installed to cover the growth in $H_2$ demand around 2030, after which coal gasification units are installed and operated in base load (see Table 6).

### 3.3.4. *$CO_2$ mitigation supply curves*

Figs. 7 and 8 show the mitigation potential for $CO_2$ capture in different sectors in time. Note that the curves for each timeframe include plants equipped with $CO_2$ capture in earlier timeframes that are still operative. In all pathways, the bulk of $CO_2$ emissions in the power and industrial sector could be captured at costs below 50 €/t $CO_2$ avoided. In 2050, roughly 60–80 Mt could be reduced at costs below 20 €/t $CO_2$ avoided,

[7] In the energy futures sketched for the Netherlands up to 2040, the use of hydrogen is not accounted for due to large uncertainties in technological breakthrough of fuel cell technology (Bollen et al., 2004).

[8] F–T diesel production by coal gasification with CCS, but without biomass co-gasification, has well-to-wheel carbon emissions close to oil-derived diesel (Van Vliet et al., submitted for publication; Williams et al., 2006) and is therefore not considered.

**Table 6 – Efficiencies and costs of transport fuel production and use, derived from Damen et al. (2006), Van Vliet et al. (submitted for publication) and Edwards et al. (2006).**

| Fuel | $H_2$ | $H_2$ | F–T diesel |
|---|---|---|---|
| Technology | SMR + CCS | CG + CCS | CBTL + CCS |
| Capacity ($MW_{fuel}$) | 1000 | 1000 | 1000 |
| Efficiency ($GJ_{fuel}/GJ_{input}$) | 73% | 57% | 55% |
| Electricity output ($GJ_e/GJ_{fuel}$) | 0 | 0.04 | 0.09 |
| TCR (€/$kW_{fuel}$) | 550 | 840 | 1113 |
| O&M (% TCR/year) | 4 | 4 | 4 |
| Car[a] | | FCV | Hybrid DICI |
| Fuel economy (MJ/km) | | 0.94 | 1.66 |
| Costs (€/km) | | 0.32 | 0.28 |
| Direct $CO_2$ emissions (g $CO_2$/km) | | 0 | 100 |

[a] Reference system for $H_2$ and F–T diesel cars is a hybrid ICEV on gasoline and diesel, respectively, with fuel economy of 1.63 and 1.46 MJ/km and costs of 0.19 and 0.20 €/km.

primarily from coal gasification systems to produce electricity or synthetic fuels, and from blast furnaces. In pathway 1, there is a substantially higher capture potential in comparison to pathways 3 and 4. This can be attributed to retrofit options and the fact that more opportunities arise for $CO_2$ capture at coal-fired and to a smaller extent gas-fired capacity. The costs to retrofit existing PC units vary between 35 and 100 €/t $CO_2$, depending strongly on the age of the unit and the year of retrofitting. Pathway 2 is nearly identical to pathway 1 (and therefore not represented), with the exception that the retrofit option for existing plants has passed. In pathways 3 and 4, the installation of new nuclear capacity limits the application of CCS. As a consequence of nuclear capacity that becomes operative after 2030, several coal-fired plants are operated in intermediate load, driving mitigation costs up. However, the general trend is that costs to capture $CO_2$ decreases in time due to the application of improved technologies.

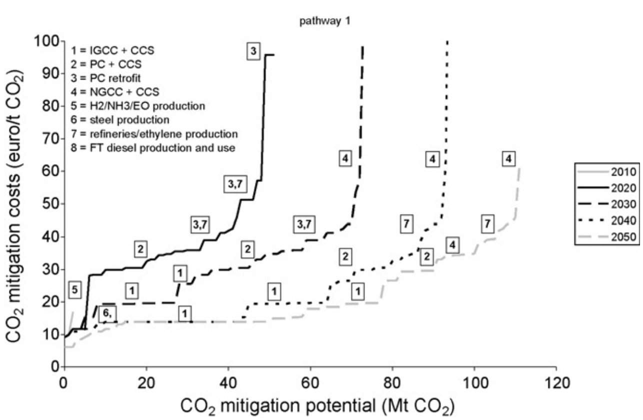


**Fig. 7 – $CO_2$ mitigation supply curve for pathway 1 as function of time, excluding transport and storage costs.**

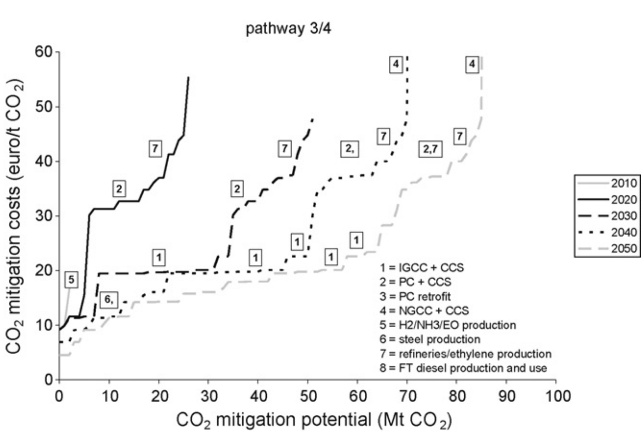


**Fig. 8 – $CO_2$ mitigation supply curve for pathways 3 and 4 as function of time, excluding transport and storage costs.**

### 3.4. $CO_2$ transport

$CO_2$ infrastructure could consist of direct source–sink pipelines or a $CO_2$ network (see Fig. 9). A network, connecting multiple sources with multiple sinks or multiple sources with one sink and vice versa, may be suitable when there are no sufficiently large structures nearby sources. In pathways with clear and ambitious long-term emission reduction targets, in which CCS is most likely to contribute substantially, the construction of a $CO_2$ network connecting various (future) sources and sinks may be preferable above dedicated lines. In less ambitious futures with regard to CCS deployment, the gradual build up of capacity is more likely, in which individual plants are directly connected to (nearby) sinks. In some regions, the challenge lies in connecting clusters of small and medium-sized fields. Alternatively, an export terminal could be constructed, from where $CO_2$ is transported via a large trunk line to one of the large structures in the North Sea. Although not explicitly considered in this study, parts of the existing offshore natural gas infrastructure may be reused for $CO_2$ transport and injection.

### 3.5. *Assessing CCS contribution in different pathways*

Now that we have insight into the storage capacity and the capture potential up to 2050, we combine those pieces of information to compose different CCS pathways,[9] the results of which are summarised in Table 7. The table shows the

[9] Note that the transport and storage costs, which are computed for each source as will be explained in the next section, also determine CCS deployment.

**Table 7 – Total annual $CO_2$ emission reductions and CCS contribution in parentheses (Mt $CO_2$) in different pathways.**

| Pathway | 2020 | | 2050 | |
|---|---|---|---|---|
| | Reduction | $CO_2$ capture at | Reduction | $CO_2$ capture at |
| 1 'deep reduction' | 95 (31) | Power plants (new-built PC + IGCC, retrofit existing PC)<br>Blast furnaces<br>$H_2$ plant (refinery)<br>$NH_3$ plants | 300 (112) | Power plants (new built IGCC + NGCC)<br>Blast furnaces<br>Refineries<br>Steam crackers<br>F–T diesel plants |
| 2 'postponed action' | 0 (0) | NA | 250 (108) | Power plants (new-built IGCC + NGCC, retrofit PC)<br>Blast furnaces<br>Refineries<br>Steam crackers<br>$H_2$ plants (transport fuel) |
| 3 'action abroad' | 20 (3) | Blast furnaces | 65 (27) | Power plants (new-built IGCC)<br>Blast furnaces |
| 4 'ambitious' | 65 (15) | Power plants (new-built PC + IGCC)<br>Blast furnaces<br>$H_2$ plant (refinery) | 165 (68) | Power plants (new-built IGCC)<br>Blast furnaces<br>Refineries<br>Steam crackers<br>F–T diesel plants |

potential contribution of CCS to achieve the emission reduction targets specified in the different pathways. In order to realise the deep emission reduction in pathway 1, all coal-fired power plants to be constructed in the future are equipped with $CO_2$ capture. In addition, the most efficient and youngest existing PC units are retrofitted prior to 2020 to achieve the target of 30% reduction versus the 1990 level. Beyond 2020, CCS is also implemented in NGCC units operating in intermediate load and in other sectors (industry and transport), in order to contribute maximally to the 80% emission reduction target in 2050. Still, a large share of the required reductions has to be realised by alternative GHG mitigation options. In pathway 2, the opportunity to retrofit existing PC units is missed. In addition to new-built CCS plants, power plants constructed before 2030 are retrofitted in order to realise the aggressive pathway beyond 2030. By taking nearly all capture opportunities in pathways 1 and 2, roughly 40% of the required emission reduction could be achieved by means of CCS by 2050. In absolute terms, no large CCS penetration occurs in pathway 3, due to the relatively low emission reduction required (domestically), and the fact that only offshore gas fields are available. Only the least costly mitigation options, as

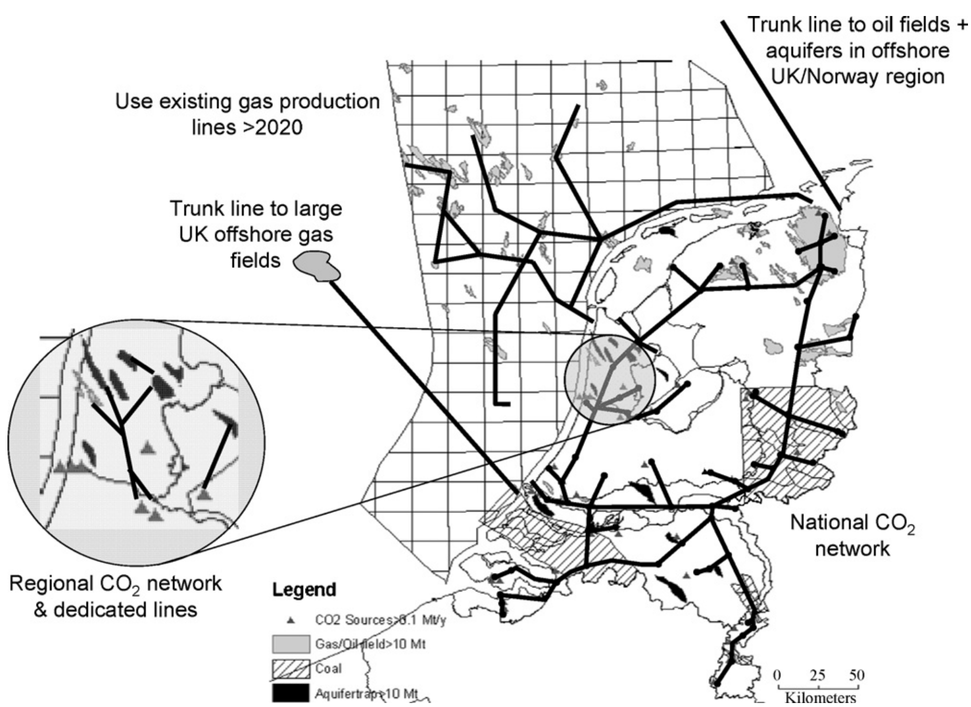


**Fig. 9 – Conceptual $CO_2$ transport configurations.**

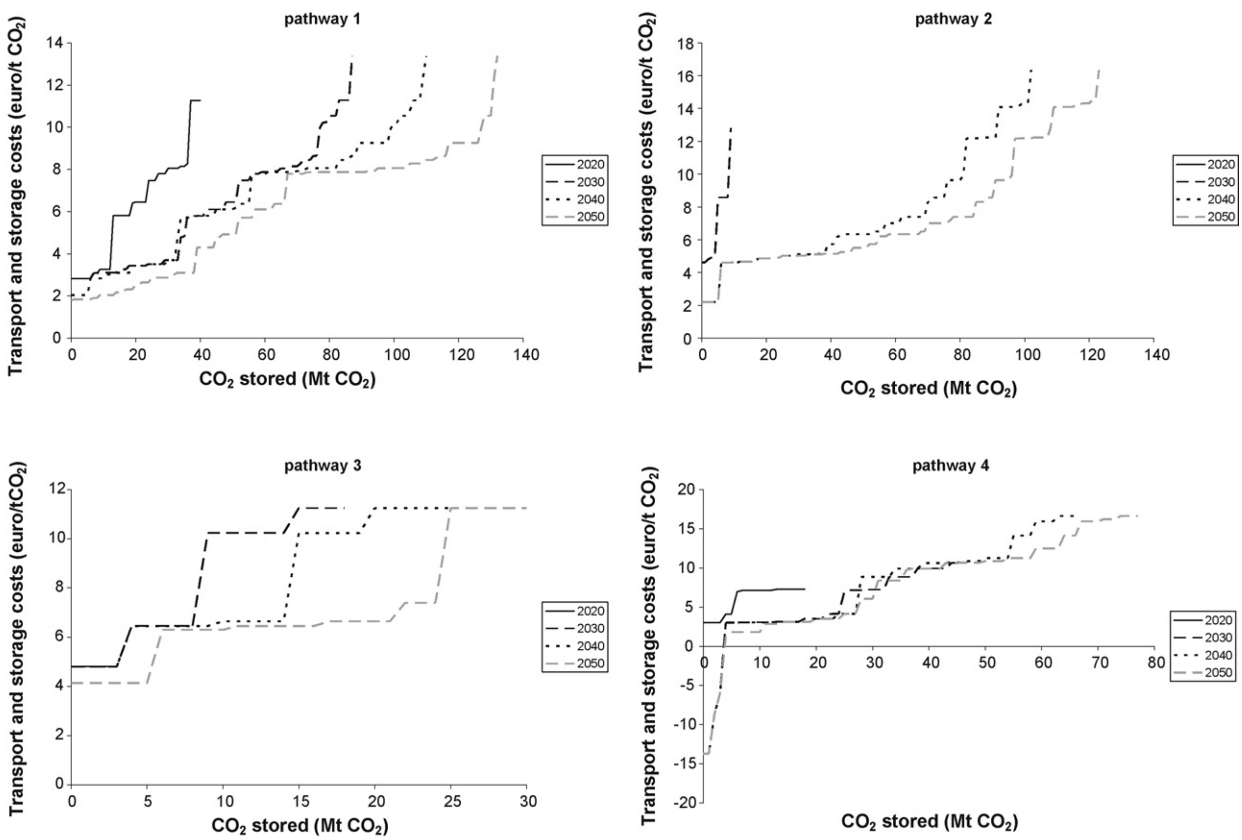


**Fig. 10 – $CO_2$ transport and storage costs in different timeframes.**

occur in blast furnaces and IGCC units dispatched at full load that are located in coastal regions and can be linked to relatively large reservoirs, are implemented. Pathway 4 is in many aspects similar to pathway 1, though existing PC plants are not retrofitted, CCS is implemented less rigorously, and fewer reservoirs are available. Occasionally, plants are faced with a lack of storage capacity, causing some missed opportunities or delay of $CO_2$ capture.

### 3.6. *Composing $CO_2$ transport and storage supply curves: source–sink matching*

Source–sink matching is performed by means of an economic optimisation procedure, in which the costs of transport and storage are computed for specific source–sink combinations. Each source is connected to the reservoir for which the total costs of transport and storage are minimal, following the 'who first comes, first gets' principle. A reservoir should in principle have sufficient capacity to store the plant emission for at least 25 years. After this period, the remaining capacity is calculated to decide on the storage strategy for the next period. As the storage capacity of many gas fields and aquifers is lower than 25 years of $CO_2$ production of large industrial or power plants, we also consider clusters of fields.

For each reservoir (cluster), the number of wells and investment costs (wells, site development, surface facilities and monitoring equipment) are computed using data from (IEA GHG, 2005a). Pipeline dimensions are calculated according the method described in Damen et al. (in press). For pipeline costs, we use figures presented in IEA GHG (2005a). Onshore pipeline costs are multiplied with a factor 3 due to the fact that pipeline installation is relatively costly in the densely populated urban areas of the Netherlands with many infrastructural barriers to cross. The choice between a dedicated source–sink line and a trunk line connecting various sinks and sources is based upon NPV minimisation computations. The results of the source–sink matching are summarised in the $CO_2$ transport and storage supply curves in Fig. 10.

Despite the large specific transport costs for the Dutch onshore region, transport costs are modest in most pathways, which can be explained by relatively small transport distances, large $CO_2$ flows and the scale advantage of trunk lines. For most plants, transport costs add a few €/t $CO_2$, with a maximum of nearly 10 €/t $CO_2$. The need to retrofit PC units and the construction of new power plants with $CO_2$ capture in the Rijnmond area around 2020 in pathway 1, in combination with the lack of regional storage capacity, makes it attractive to construct a large trunk line to offshore reservoirs. Ten years later, a trunk line of similar dimensions as current gas transmission lines is constructed to transport $CO_2$ from sources located in the southwest to the Groningen gas field. Similarly, the clear turning point in climate policy in pathway 2 causes many plants to be retrofitted in a short period. Together with the lack of large aquifer traps onshore, this opens up possibilities for 'joint' transport. Two large trunk lines are constructed to large offshore structures. One connects the sources in the Rijnmond area to the Bunter

Sandstone traps in the UK sector of the North Sea (to which also traps in Dutch part of the North Sea can be connected). The second line transports $CO_2$ from the Eemshaven region to the Utsira formation. As the construction of these trunk lines takes several years, many plants will go on stream somewhere between 2032 and 2035. In pathways 3 and 4, high transport and storage costs and the lack of regional storage availability, respectively, prevent or postpone the application of CCS at several, notably small, sources. In spite of the pure $CO_2$ available at early opportunities, transport and storage costs make overall costs too high. Possibly, synergy could be found in transporting $CO_2$ from the early opportunities and the steam crackers to aquifer traps in Brabant or the Rijnmond. In pathway 4, we observe that various plants store $CO_2$ in a cluster of offshore depleted gas fields using a dedicated line, which results in relatively high costs. Around 2030, plants will compete for storage in the coal seams in Limburg and eastern part of the country. Transport and storage costs may become negative when storing in coal seams, because gas prices (and hence coal bed methane revenues) prevailing in this scenario increase strongly beyond 2020.

## 4. Results

Combining the information generated in the previous sections enables us to present the quantities of $CO_2$ stored and avoided in time for the different pathways, as illustrated in Fig. 11.

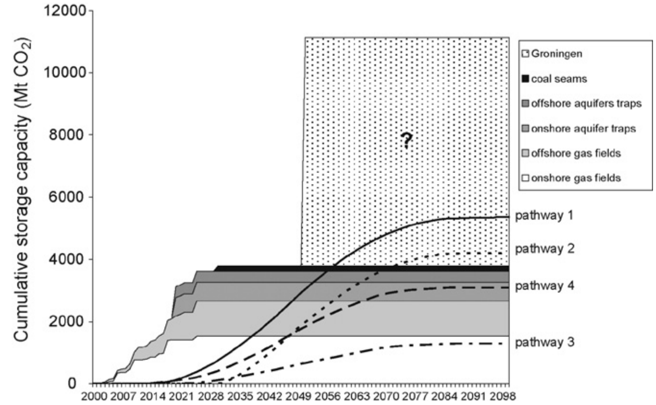


**Fig. 12 – Storage availability in time versus cumulative $CO_2$ storage.**

In pathway 1, representing the most ambitious CCS scenario, nearly 3 Gt $CO_2$ is stored by 2050. The cumulative $CO_2$ production of all sources that go on stream before 2050 equals nearly 40% of the Dutch technical storage potential. Fig. 12 shows that if all $CO_2$ would be stored in Dutch reservoirs that become available between 2005 and 2030, assuming every gas field and aquifer trap will be available and suitable for $CO_2$ storage, injection could be continued to roughly 2050. As this condition is unlikely to be met, we can conclude that such a scenario would only be possible if one of the mega structures,

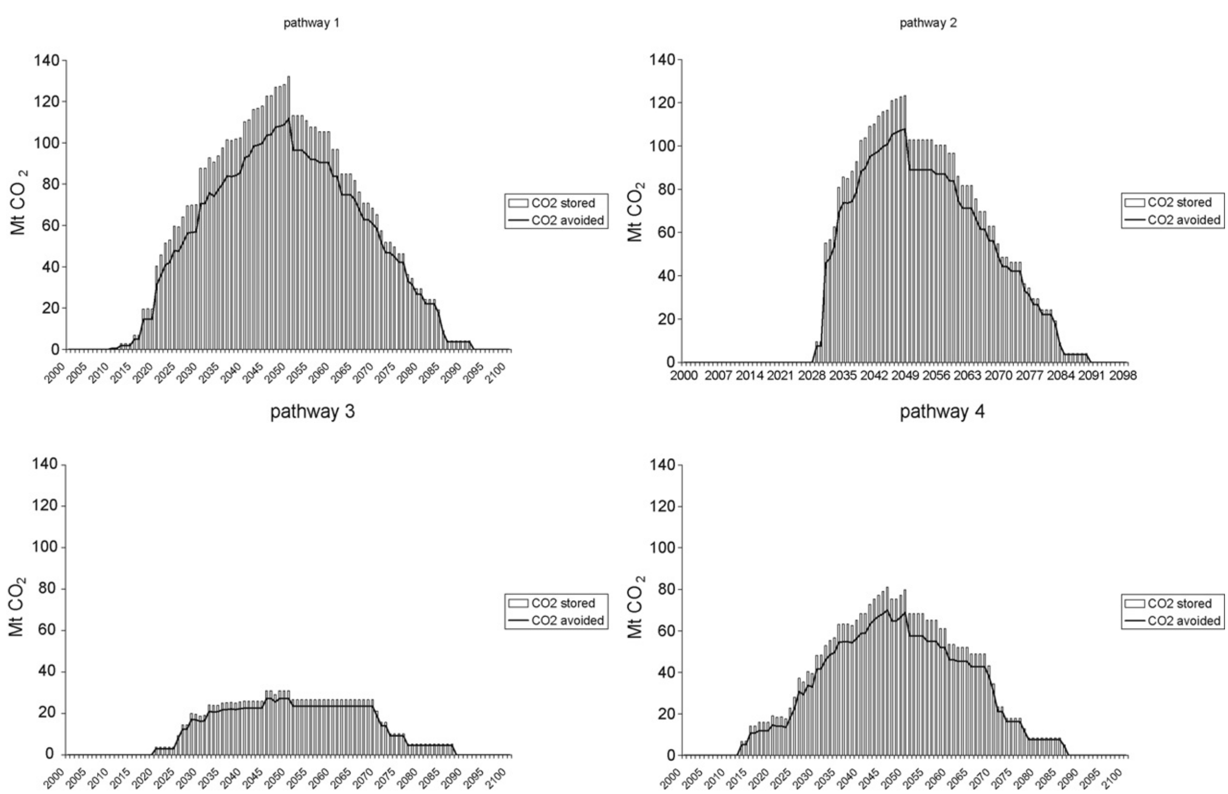


**Fig. 11 – Annual quantities of $CO_2$ stored and avoided in time, including all plants equipped with CCS constructed prior to 2050. Beyond 2050, there are still a number of (mainly coal-fired) plants in operation for a few decades due to the long lifetime of these units.**

in this case the Groningen gas field, becomes available prior to 2050. In pathway 2, the Groningen gas field and other gas fields are not available, enforcing $CO_2$ storage in aquifers. Roughly 96% of the nearly 2 Gt $CO_2$ captured between 2030 and 2050 is stored in the rich Bunter Sandstone formation in the UK part of the North Sea and the vastness of the Utsira formation. This illustrates the need to look beyond the national borders when large CCS deployment rates are strived for and gas fields are not available in such high numbers as in pathway 1. In pathway 4, about 1.7 Gt is stored more homogeneously in Dutch reservoirs up to 2050, requiring about 73% of the total storage potential (excluding the Groningen gas field).

The model runs up to 2050, which explains the peak in the figure. It could be argued whether the peak of CCS will occur in 2050. Given fossil fuel reserves, the peak may be extended some decades, which is also observed in certain scenarios presented in IPCC (2005). If we assume that the storage rates in 2050 are maintained up to 2100, the cumulative storage would lie between 2.2 and nearly 10 Gt by that time, representing roughly 20–85% of the entire Dutch technical storage potential, including Groningen. Excluding Groningen and reservoirs abroad, we would run out of technical storage capacity somewhere between 2050 and 2075 if storage rates above 80 Mt/year are continued beyond 2050. In a more modest scenario where storage rates are gradually increased and then kept constant at 30 Mt/year, we could continue storing $CO_2$ to at least 2100.

The realised CCS potential and the overall $CO_2$ mitigation costs, including transport and storage, are given in Fig. 13. By 2020, up to 30 Mt $CO_2$ could be reduced at marginal costs of roughly 50 €/t $CO_2$ in a scenario where retrofitting the most efficient PC units would be feasible and a part of the storage capacity in the British part of the North Sea is available. Excluding the retrofit options, 15 Mt $CO_2$ could be avoided at costs below 40 €/t $CO_2$ by capturing $CO_2$ from blast furnaces and new-built coal-fired power plants and storing it in Dutch gas fields and aquifer traps. Halfway this century, about 60 Mt $CO_2$ can be reduced at costs below 40 €/t $CO_2$, and in pathways 1 and 2 even below 25 €/t $CO_2$. The majority of this potential is represented by the many new coal-fired power plants to be installed. By 2020, electricity production from plants equipped with $CO_2$ capture lies between 0% and 35% of total electricity supply. Thirty years later, this number has increased to 20% in pathway 3 up to 70% in pathway 1. Note that the costs to avoid the first 20 Mt in pathway 2 are somewhat lower in comparison to pathway 1 as the costs to retrofit new-built plants in a later stage are lower than constructing a plant with $CO_2$ capture right away. This is due to the fact that investments in capture equipment are postponed and hence the additional costs of retrofitting are modest in real terms. On the other hand, costs in pathway 2 are expected to be higher in comparison to pathway 1, where cost reductions could be realised in the period between 2010 and 2030.

In the course of time, costs are reduced because of advances in more efficient capture and conversion technologies. In pathway 4, however, the cost reduction of $CO_2$ capture in time is partly outweighed by the combined effect of lower dispatch and the increased costs to transport and store $CO_2$ in relatively smaller reservoirs.

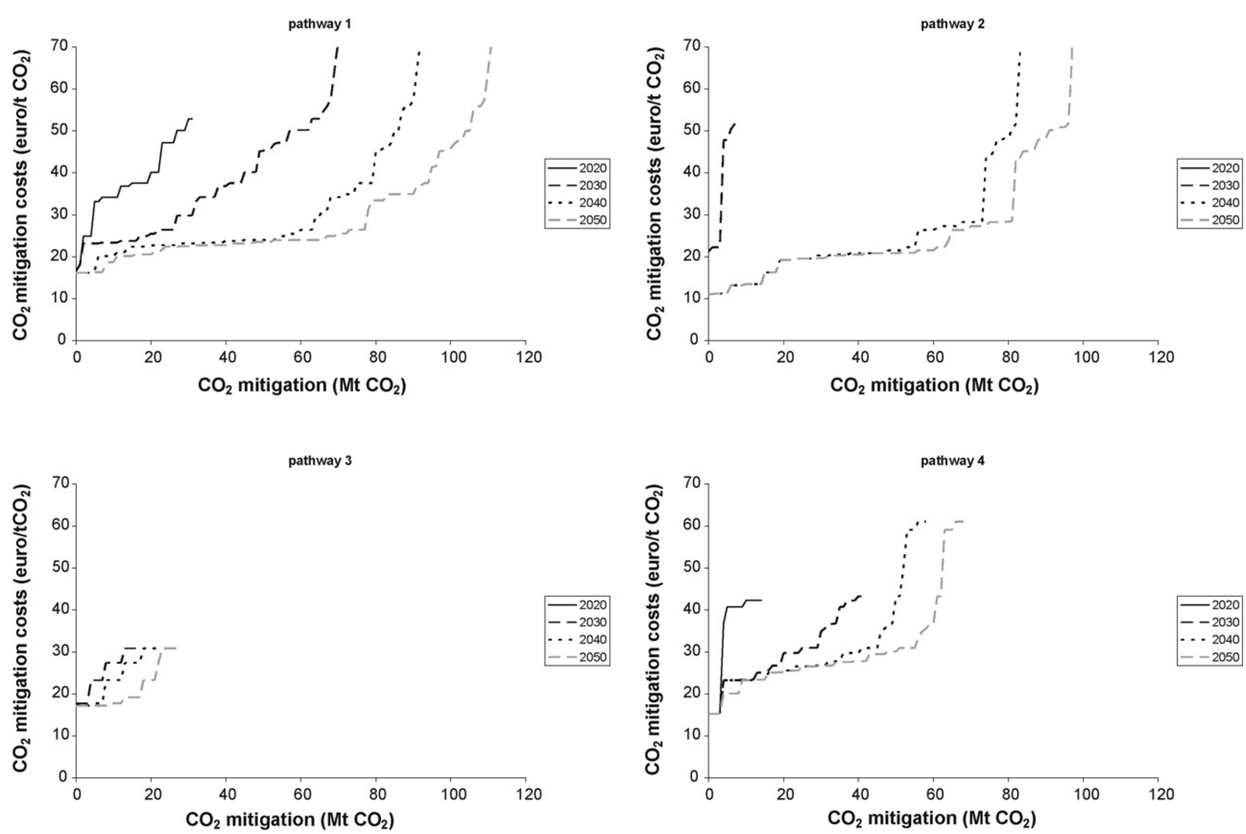


**Fig. 13 – $CO_2$ mitigation costs of realised $CO_2$ reductions in time, including $CO_2$ transport and storage.**

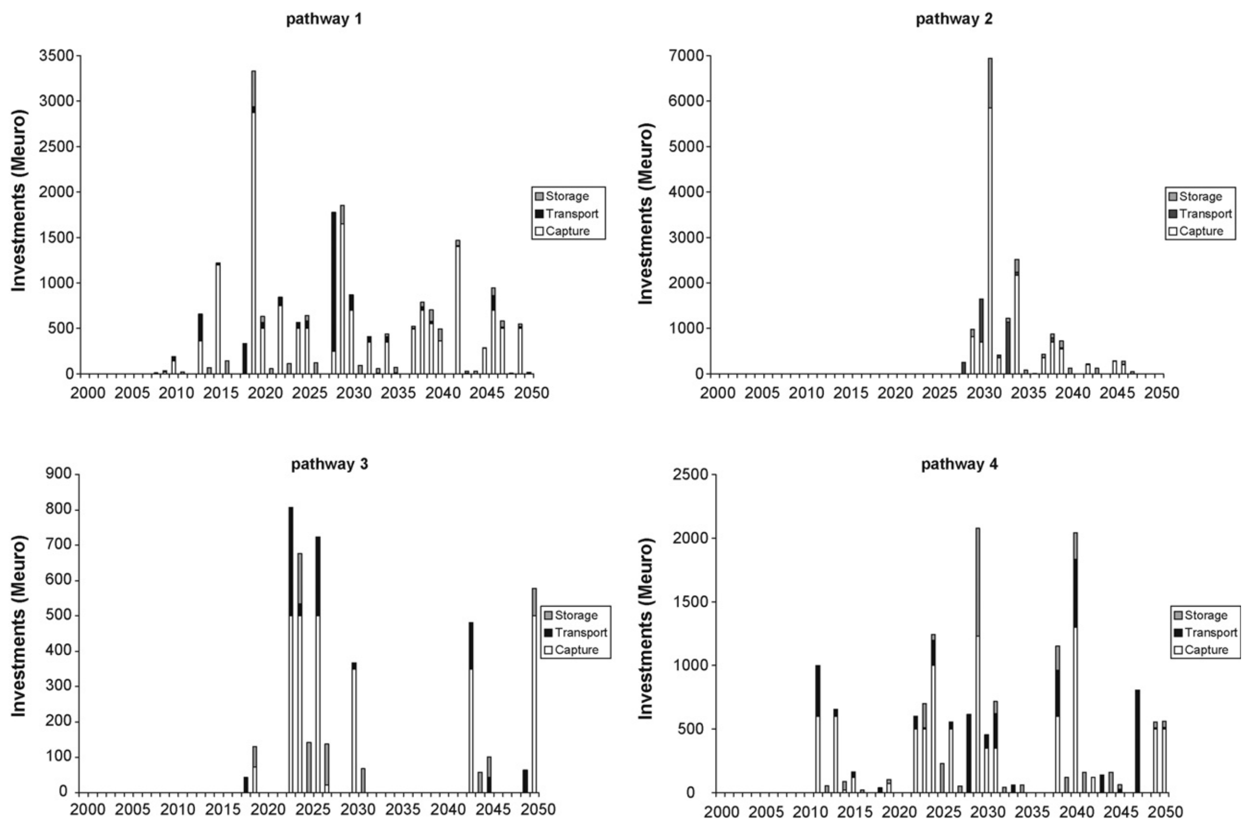


**Fig. 14 – Investments patterns of $CO_2$ capture (excluding power plants), transport and storage ($Euro_{2000}$).**

In the upper regions of the chart, above 40 €/t $CO_2$, we encounter new-built PC and NGCC units with CCS operated in intermediate load, and boilers, heaters (at refineries) and steam crackers retrofitted with a post-combustion capture unit. In pathway 2, the marginal costs may rise up to 300 €/t $CO_2$ for the last mega tonnes avoided in the transport sector by the application of clean hydrogen.

In order to understand what such CCS deployment rates means financially, the additional investments in capture and compression units, pipelines and storage facilities over time are presented in Fig. 14. In overall terms, total CCS investments up to 2050 have been framed at 6–23 billion Euros. The share among capture, transport and storage varies between 78%, 13% and 9% for pathway 1 and 62%, 22% and 16% in pathway 4, respectively. Not surprisingly, the investment pattern is quite diverse; in pathway 1, a relatively homogenous distribution is observed, with an occasional peak due to massive retrofitting (2020) or the construction of a trunk line. Pathway 2 shows a concentration of investments around 2030, also due to retrofits and trunk line investments. Pathway 4 is characterised by a peak in investments in 2030, which can be explained by the numerous wells that need to be drilled to inject $CO_2$ into the coal seams. Both pathways 3 and 4 have in common that there are periods of a few years up to 10 years in which hardly any investment occur. This feature can be explained by the vintage structure of the power plants, assumed lifetimes and growth in energy demand in the TM baseline.

A trunk line is attractive when several plants in a specific region go on stream in the same period and the storage capacity in vicinity is limited. The vintage structure and the locations of new plants are decisive, as well as the timing and extent of emission reduction. The ambitious goals in pathway 1, the sudden need for action in pathway 2 in combination with a lack of storage capacity onshore, and the need to go offshore in pathway 3 make the construction of trunk lines attractive. In pathways 1 and 4, a 250 km trunk line is constructed between the Rijnmond area and the gas fields in the northern provinces with a diameter of at least 40 in. and estimated costs over 1 billion Euros. A 250 km trunk line to the southern North Sea basin of the UK (via the reservoirs in the Dutch part of the continental shelf) is another interesting trajectory, as the power stations in the Rijnmond area that are constructed and/or retrofitted the next decade will begin producing $CO_2$ when the bulk of the gas fields in that region are not yet available. The capacity we forecasted is between 10 and 20 Mt/year (26–36 in.), depending on the need to retrofit PC units. A pipeline of such dimensions is framed at roughly 200–300 M€. In pathway 2, a 750 km 42 in. trunk line is constructed to transport over 20 Mt $CO_2$ from the Eemshaven region to the Utsira formation, costing over 1 billion Euros. This option should be considered if ambitious $CO_2$ emission reduction targets are strived for, while the storage potential in gas fields is scarcely available for CCS. As the marginal transport costs per tonne of $CO_2$ are modest beyond such scale, it may be beneficial to construct a larger pipeline that also allows power plants in Northwest Germany to make use of it.

**Table 8 – Impacts of assumptions and uncertainties on capture potential. The quantified impacts represent upper boundaries.**

| Assumption/uncertainty | Timing impact | Indicative impact on capture potential |
|---|---|---|
| Factors that decrease $CO_2$ capture potential | | |
| Neglecting the potential of renewables[a] | Beyond 2020 | 5–20 Mt $CO_2$/year |
| Assuming activity level in the carbon-constrained scenarios is equal to that in the baseline scenarios[b] | Short + long term | Potentially large |
| Ignoring coal to gas of switching[c] | Short–medium term (postponing CCS) | 5–25 Mt $CO_2$/year on average |
| Factors that increase $CO_2$ capture potential | | |
| Fix $CO_2$ emissions refineries industry in time[d] | Short + long term | 2–8 Mt $CO_2$/year |
| Fix $CO_2$ emissions petrochemical industry in time[e] | Short + long term | 10–18 Mt $CO_2$/year by 2050 |
| Fix $CO_2$ emissions iron and steel production in time[f] | Short + long term | 10 Mt $CO_2$/year by 2050 |
| Retirement of inefficient PC units[g] | Short–medium term (<2030) | 9 Mt $CO_2$/year |
| Capture potential alternative fuel production[h] | Short + long term | Unknown |

[a] The baseline scenarios we adopted are characterised by a gradual phase-out of renewables as incentives are abolished; by 2020, 30 TWh is produced from renewable resources, which is reduced to 3 TWh in 2050 (Farla et al., 2006). However, the competitiveness of renewable energy technologies depends on the assumed learning rate (see e.g. Uyterlinde et al., 2007), feedstock prices in case of biomass and oil prices, which are relatively low in the GE/TM baseline scenarios (20–30 $/bbl). Assuming high learning rates and currently prevailing oil prices will be structural, some renewable energy sources may be competitive with fossil energy. As a minimum, we assume the current onshore wind capacity is maintained and as maximum, the forecasted production from renewables in 2020 in the GE scenario is maintained.
[b] By implementing climate policy, the starting points of the baseline scenario will actually change, e.g. the demand for energy is likely to decrease due to efficiency measures and consumption patterns, thereby reducing CCS potential.
[c] Johnson and Keith (2004) calculate that approximately 20% of the emissions are reduced by carbon-ordered dispatch and increased use of gas-fired capacity for gas prices starting at 4.2 $/GJ (comparable to prices in GE/TM) before CCS enters the market. This corresponds to a cumulative reduction up to 2050 of 300 up to 1000 Mt $CO_2$. It is the question though whether utilities will choose for more gas-fired capacity given the risk of increasing gas prices and the possibility that a strict climate policy is implemented, which would result in a high-cost technology path (Johnson and Keith, 2004). In addition, the Dutch power sector is already relying heavily upon natural gas.
[d] The crude oil throughput grows from approximately 55 Mt now to 93 Mt in GE and 70 Mt in TM by 2040 (Farla et al., 2006). Current emissions are approximately 11 Mt $CO_2$ (Klein Goldewijk et al., 2005).
[e] In GE and TM the (physical) growth in the chemical industry is 2.5% $year^{-1}$ (Farla et al., 2006). We assume no efficiency improvements, a current ethylene and ammonia production of 3.7 and 2.7 Mt/year estimated from current production capacities and a $CO_2$ emission factor of 1.7 t $CO_2$/t ethylene and 1 t (net) $CO_2$/t $NH_3$ (Neelis et al., 2005). Note that ammonia plants might be operated in lower load or even shutdown in the longer term due to increasing natural gas prices, which represents the lower value presented in the table.
[f] In GE and TM the (physical) growth in the iron and steel industry is 1.3–1.4% $year^{-1}$ (Farla et al., 2006). We assume no efficiency improvement, a current steel production of 6.6 Mt/year and a $CO_2$ emission factor of 1.7 $CO_2$/t steel (Klein Goldewijk et al., 2005). Note that we restricted our analysis to blast furnace gas used on-site. Roughly 10 Mt $CO_2$ is produced in the blast furnaces and basic oxygen furnace, of which 5.5 Mt is emitted in the nearby located power plants, the rest being emitted within the boundaries of the steel plant. As $CO_2$ is present at high partial pressure and produced on a single site, these streams appear interesting targets for low-cost $CO_2$ capture by means of water–gas shift and physical absorption.
[g] Assuming the least three inefficient PC units would be retired. Wise and Dooley (2005) illustrate that a cut to one-third of current emissions by 2050 induces the retirement of the least efficient coal capacity by 65%. These units would mainly be replaced by IGCC with CCS. Note that the PC units considered in Wise and Dooley (2005) are less efficient than the least efficient PC units in the Netherlands.
[h] Currently prevailing oil prices, which varied between 55 and 70 $/bbl when this research was performed, are structurally higher than forecasted oil prices in the GE and TM scenarios used in this analysis. In scenarios with structural oil prices of 60–70 $/bbl, F–T diesel produced from coal and biomass with CCS is calculated to be nearly competitive with fossil diesel even without a carbon price (Van Vliet et al., submitted for publication).

## 5. Discussion

In this section, we will elaborate on the findings produced in the different pathways and the uncertainties that we need to face in developing strategies for CCS deployment. Some critical remarks are justified on the cost figures in this analysis, both on the values and on their interpretation.

### 5.1. *$CO_2$ capture potential and deployment*

There are various factors we did not accounted for that may alter, either positively or negatively, the capture potential we have reported (see Table 8).

With the exception of pathway 3, the CCS pathways in this analysis represent radical scenarios (that we created on purpose to investigate the boundaries of CCS). According to the IEA World Energy Outlook, CCS will start playing a role in their most ambitious scenario to cap $CO_2$ emissions in 2030 at today's level (identical to pathway 3) (IEA, 2006).

As noted in the introduction, an analysis on options to reduce Dutch GHG emissions by 2020 (Daniëls and Farla, 2006) forecasted a maximum CCS contribution of 15 Mt, of which approximately 5 Mt from industrial processes emitting pure $CO_2$ and 10 Mt from large-scale industrial CHP units. We estimate approximately 2.5 Mt $CO_2$/year could be avoided by CCS at pure sources. However, there are no proven reservoirs in vicinity of the ammonia plants and transport and storage costs to more remote reservoirs are relatively high as volumes are modest. In addition, we doubt that CHP units are the first targets for CCS; all signs indicate that the deployment is foreseen at coal-fired power plants first.

For the year 2050, the Dutch emission reduction potential of CCS has been estimated for the Energy Transition Task Force at 25–30 Mt $CO_2$ in energy production, 4–8 Mt in the transport sector and 0(!) Mt in industry (Task Force Energietransitie, 2006). The figures we produced indicate that the potential in the power sector and industry is probably much higher.

### 5.2. Transport costs

Recently, industry has experienced a strong increase in steel and labour/contracting costs, which will certainly affect the costs of pipelines and wells. These factors may add significantly to transport costs and need to be investigated. On the other hand, transport (and storage) costs may be reduced, either by optimising the spatial planning of new power plants or by reusing infrastructure. The Eemshaven region is an interesting new location for power plants due to the vicinity of many gas fields, among which a few relatively large reservoirs. Obviously, installing plants in the north will sooner or later require investments in power transmission capacity, although another 2 $GW_e$ can be connected to the transmission grid in the northern provinces at present (Bergsma et al., 2006). We identified some sink–source combinations in which reuse may be worthwhile considering, such as the steel plant in the IJmond region storing $CO_2$ in one of the gas fields in the P or K quadrant. Possibly also smaller pipelines may be reused in the concept where gas fields are used as buffer, as ‘branches’ of the main trunk line heading for the oil fields up north.

### 5.3. Capture costs

Capture costs should be considered as indicative figures, as we could not account for the specific conditions of individual plants. To take the example of refineries, $CO_2$ has to be captured from flue gas of various boilers fired with different fuels. As no data on the individual sources were available, we estimated $CO_2$ emissions for the entire refinery and used generic or average figures on flue gas concentration and waste heat availability. The latter is an important factor for the economic feasibility of post-combustion capture in the industrial sector; mitigation costs may increase with more than 10 €/t $CO_2$ when no waste heat is available. Shell has calculated that the costs to avoid 1 Mt of $CO_2$ by means of capture from a stack at their refinery in Pernis, assuming all energy required for the reboiler is produced in a gas-fired boiler, would be 70 €/t $CO_2$ (Shell Global Solutions, 2006). Mitigation costs we calculated for similar conditions are approximately 60 €/t $CO_2$, indicating costs may have been underestimated in some specific cases.

In general, the recent increase in steel, labour and contracting costs will affect the capture costs strongly. Capture costs at IGCC units are relatively low. In the scenarios we considered, many IGCC units (with $CO_2$ capture) have a load factor near 90%, a value that is still not realised with today’s IGCC unit in Buggenum (without capture) (Vroonhof et al., 2006). It can therefore be argued that such high loads in combination with high efficiencies are somewhat optimistic considering their operational characteristics. As we have seen in the TM scenario, several coal-fired power plants will be dispatched less often when nuclear comes in and the role of natural gas is diminishing. Therefore, the flexibility in changing load factor at IGCC units and the impact of $CO_2$ capture in this should be analysed in more detail.

### 5.4. Overall mitigation costs

In conclusion, the costs associated with all elements from the CCS chain may well be optimistic. A comparison with values reported in literature seems to support this notification; costs are on the low side of the range reported in the IPCC special report on CCS (IPCC, 2005). This is mainly due to future performance and cost figures of capture installations we assumed.

The trend in mitigation costs as can be seen in Fig. 13 illustrates that the costs will decrease in time due to the fact that more efficient and less costly technologies will be installed by then, which might be interpreted as a plea for a wait-and-see policy. This would, however, be a wrong interpretation of the results, as costs reductions need to be achieved partly by learning-by-doing. In order to reach the long-term costs as shown in the figure, CCS capacity should be installed the coming decades to gain operational experience and enable cost reduction. We have not specifically accounted for the effect of learning as a function of installed capacity, as this would require an estimation of worldwide installed CCS capacity.

## 6. Conclusion

CCS has the potential to become an important mitigation option in curbing Dutch $CO_2$ emissions, which currently approach 180 Mt $CO_2$/year. This study shows what the role of CCS could be in time given the $CO_2$ capture and storage potential, and uncertainties involved. We found that maximally 50 Mt $CO_2$/year could be avoided in 2020 by capturing $CO_2$ from various sources at costs between 10 and 100 €/t $CO_2$ (excluding transport and storage), versus a baseline scenario characterised by relatively large economic growth and strong increase in energy demand. Only sources emitting at least 0.1 Mt $CO_2$/year were included in the analysis, being power plants, blast furnaces, boilers and heaters in refineries, steam crackers, reformers and gasifiers. The potential includes about 20 Mt $CO_2$/year that may be avoided by retrofitting existing PC units, which may be an important back-stop option to achieve a target of 30% $CO_2$ reduction in 2020 versus 1990. However, there are some technical drawbacks (e.g. lack of space, reduction in power output) and costs are rather high: 40–50 €/t $CO_2$ avoided for the most efficient PC units. By 2050, the forecasted capture potential is 80–110 Mt $CO_2$ avoided/year, of which 60–80 Mt $CO_2$/year may be realised below 20 €/t $CO_2$ (excluding transport and storage). From the different sectors contributing to this potential, the power sector offers the biggest opportunities for $CO_2$ capture. The mitigation potential is estimated at 11–14 Mt $CO_2$/year by 2020 (excluding retrofit) and 60–84 Mt $CO_2$/year by 2050, assuming electricity supply increases from 95 TWh in 2005 up to 210 TWh in 2050. Industrial sources add another 16 Mt $CO_2$/year, of which

2.5 Mt/year in pure $CO_2$ sources, at least 3 Mt/year in steel production, 4.5 Mt/year in ethylene production and 6 Mt/year in boilers and heaters at refineries. The development of a market for alternative fuels produced via syngas production with CCS creates an opportunity to decarbonise the transport sector. The reduction potential for F–T diesel and $H_2$ has been estimated very roughly at 10 Mt $CO_2$. Most economic capture options exist in the production of power by means of IGCC, the production of hydrogen, ammonia, ethylene oxide, steel and F–T diesel, and gas processing.

In our analysis, the actual deployment of the capture potential is determined by the emission reduction targets and the geological capacity available for $CO_2$ storage (the competition with alternative mitigation options has not been considered). The uncertainty in these two decisive factors has been dealt with by performing scenario analyses. We sketched four CCS deployment pathways that allow us to get an idea on what emission reductions are reasonably achievable by means of CCS, and what may be possible if we 'pull out all the stops'. We found that 15 Mt $CO_2$ could be avoided annually by 2020 when some of the larger Dutch gas fields that are forecasted to become available the coming decade could be used for $CO_2$ storage. If, in addition, part of the existing PC units or large industrial boilers and furnaces is retrofitted with $CO_2$ capture, we may have to rely on the large reservoirs in the UK part of the North Sea. Alternatively, clusters of relatively small gas fields could be used, which could add more than 15 €/t $CO_2$ for transport and storage.

If the Netherlands focuses on national opportunities and does not consider storage options abroad, 30 Mt $CO_2$/year could be avoided by 2050 with relatively small efforts. Provided a good planning is being set up to ensure the domestic storage potential that will become available could be used for $CO_2$ storage, we may even avoid up to 60 Mt $CO_2$/year in 2050. In aggressive climate policies aiming for 50–80% reduction in $CO_2$ emissions by 2050 versus 1990, avoiding another 50 Mt $CO_2$/year may be possible provided that nearly all capture opportunities that occur are taken. Storing such large amounts of $CO_2$ would, however, only be possible if one of the mega structures, either the Groningen gas field, large reservoirs in the Bunter Sandstone formation or the Utsira formation in the North Sea, would become available. Another option could be to store $CO_2$ in aquifer formations that are not structurally trapped. However, the availability of Groningen is highly uncertain, the availability of the UK reservoirs is depending on the application of CCS in the UK and exploiting Utsira requires a costly offshore $CO_2$ infrastructure. Excluding Groningen, the reservoirs abroad and factors limiting the storage potential, the Netherlands would run out of storage capacity sometime between 2050 and 2075 for storage rates above 80 Mt/year. For more modest storage rates of 30 Mt $CO_2$/year, we could continue storing up to the year 2100.

Gas fields seem the most appropriate candidates for $CO_2$ storage given their large and, generally, secure capacity. Over 70% of the potential in gas fields is represented by the Groningen gas field, which will not be available prior to 2040 and possibly (far) beyond 2050. Insight into the feasibility of different applications and injection strategies prior to depletion are indispensable in judging what the large storage capacity of Groningen could mean for the future of CCS. The remaining 30% is represented by average and small-sized fields. Not all of these reservoirs will be available due to competition with alternative applications, most notably UGS, and due to geological conditions that complicate storage or imply a high risk of leakage. Many gas fields will be abandoned before 2025 given current production projections, followed by a gap of at least two decades before the Groningen field might become available for $CO_2$ storage. Large-scale deployment of CCS is not due to start before 2012. A future is conceivable in which plant owners will face a lack of suitable storage reservoirs in vicinity because the reservoir used in the first half of the plant lifetime is abandoned and/or because competitors who started CCS earlier have exploited all storage capacity. In the best case, several small structures or more remote traps will have to be exploited, resulting in higher transport and storage costs. In the worst case, plants will have to be operated without capture. In order to guarantee sufficient storage capacity in the spring of a potential CCS era – sometime between 2020 and 2040 – a strategy must be developed to bridge this gap and assure the possibility of $CO_2$ storage in a later stage.

In conclusion, the challenge for the coming years is to find suitable (clusters of) reservoirs that will become available at the right time, have sufficient storage capacity and will not be used for other purposes. If it appears that natural gas reservoirs cannot provide sufficient storage potential (at the right time), the Netherlands may have to rely on aquifers and, possibly, coal seams. However, the uncertainty in capacity and the technical/economic feasibility of $CO_2$ storage do not make these options a very safe bet for large-scale CCS deployment. Therefore, more work is required in geological characterisation and mapping of aquifers and their traps, and demonstrating ECBM.

Throughout this article we have mainly discussed $CO_2$ capture and storage potentials. The actual deployment for CCS, however, is to a large extent driven by national and international policy choices, and competition with alternative GHG mitigation options. When the EU and the Netherlands postpone climate policy and the need for far-reaching mitigation will become apparent in a few decades, overall costs may increase as the opportunities of technological learning, $CO_2$-EOR at the North Sea and infrastructure reuse are missed, and possibly more expensive reservoirs will have to be used. In a future where the concerns about climate change force us to do everything we possibly can beyond 2010, we probably have to transport $CO_2$ beyond the Dutch part of the continental shelf. This would require an internationally coordinated action to plan the $CO_2$ streams and realise the construction of an offshore $CO_2$ infrastructure. As neighbouring countries with a lack of storage capacity will have to rely on reservoirs located at the Dutch shore and North Sea, we need to extend our view beyond national borders and think within a Northwest European context.

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