INTERNATIONAL JOURNAL OF GREENHOUSE GAS CONTROL 2 (2008) 105–129

available at www.sciencedirect.com

ScienceDirect

journal homepage: www.elsevier.com/locate/ijggc

Planning for an electricity sector with carbon capture and storage
Case of the Netherlands

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ARTICLE INFO

Article history:
Received 5 July 2007
Received in revised form
20 September 2007
Accepted 20 September 2007
Published on line 8 November 2007

Keywords:
CO_2 capture and storage
Energy bottom-up model
Linear optimisation

ABSTRACT

Before energy companies will invest in power plants with CCS, appropriate climate policy should be in place, a need for new power plants must exist, CCS technology should be cost-effective, and CO_2 transport infrastructure and CO_2 sinks must be available. In order to get more grip on planning, we carried out a quantitative scenario study for the electricity and cogeneration sector in the Netherlands using the energy bottom-up model generated with MARKAL. We analysed strategies to realise a 15% and 50% reduction of CO_2 emissions in respectively, 2020 and 2050 compared to the 1990 level. We found that, if nuclear energy is excluded as a mitigation option, CCS can be sufficiently cost-effective in 2020 to avoid 29 Mt per year in 2020 in the Dutch electricity sector (which is half of the CO_2 emission abatement necessary in this year). We identified the following important factors for planning. In a postponement strategy in which CO_2 is reduced from 2020, CO_2 can be abated at less than 30 €/t up to 2020. A gradual reduction of 2.5% annually from 2010, asks for a climate policy that makes expenditures possible of 50 €/t CO_2 before 2015. Construction of coal-fired power plants without CCS are preferably not built or, in the postponement strategy, only to a limited extent. Finally, early planning is required to realise the construction of a transport infrastructure with a length of around 450 km before 2020.

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Abbreviations: CBS, Statistics Netherlands; CCS, carbon dioxide capture and storage; CHP, combined heat and power production; COE, cost of electricity; CPB, Netherlands Bureau for Economic Policy Analysis; CRRF, capture ready retrofit; ECBM, enhanced coalbed methane recovery; ETS, emission trading scheme; GHG, greenhouse Gas; IEA, International Energy Agency; IGCC, integrated gasification combined cycle power plant on coal and biomass; IPCC, Intergovernmental Panel on Climate Change; LWR, light water reactor; MARKAL, (acronym for Market Allocation); a linear optimisation energy bottom-up model; NGCC, natural gas combined cycle power plant; NL, the Netherlands; NPV, net present value; O&M, operating and maintenance; PC, ultra supercritical pulverised coal/biomass fired power plant; PV, photovoltaic; RES, reference energy system; RF, retrofit; SE, Strong Europe scenario; TCR, total capital requirement; WEO, World Energy Outlook published by IEA; WLO, Welfare and Environmental Quality report published by ECN.

1750-5836/$ – see front matter
doi:10.1016/S1750-5836(07)00113-2

1. Introduction

Most scientists agree that CO_2 emissions need to be reduced worldwide by 30–60% in 2050 compared to 2000 in order to keep CO_2 concentration in the atmosphere below 450 parts per million by volume. This would keep temperature raise between 2.4° and 2.8 °C compared to pre-industrialised levels (IPCC, 2007). Currently, the Kyoto Protocol states that the European Union (EU) should reduce its greenhouse gas (GHG) emissions by 8% in 2012 compared to 1990 level (UNFCCC, 1997). The EU considers a follow-up necessary and states that developed countries need to reduce greenhouse gas emissions by 30% in 2020 and 60–80% in 2050 compared to 1990. The EU is willing to commit to 30% reduction in 2020 if other developed countries also commit themselves to comparable emission reductions, and makes a firm independent commitment to achieve at least a 20% reduction compared to 1990 (EU, 2007a).

Carbon dioxide capture and storage (CCS) is a CO_2 abatement option that can contribute substantially to these ambitious targets. Especially the electricity sector, with large point sources of CO_2, offers opportunities to apply CCS at a large scale (IPCC, 2005). However, in the development towards an electricity sector with CCS, planning may be important. For example, an investment decision for a power plant with CCS will probably only be made if the following events coincide:

- new power plants are needed, because old power plants are dismantled or due to growth in electricity demand,
- climate policy which imposes restrictions on CO_2 emissions of power plants for at least the next decade, is in place,
- CCS is competitive (with or without external financial support) compared to other mitigation options,
- CO_2 transport infrastructure is available or construction of such an infrastructure can be built within the foreseeable future, and
- sinks in which the CO_2 can be stored are available.

In earlier studies, estimates have been made about the extent to which CCS can contribute to a worldwide CO_2 reduction in certain regions and periods. For example, IPCC has shown that the economic global reduction potential of CCS may vary between 0 and 70 Gt CO_2 per year in 2050[1] (IPCC, 2005). The IEA expects this potential to be between 8 and 25 Gt CO_2 per year in 2050 (IEA, 2004). These worldwide studies cannot address specific planning issues with respect to the energy infrastructure, because data are dealt with at a low spatial resolution. However, studies at the national level also do not deal with planning sufficiently. The Department of Trade and Industry in the UK calculated the British CCS economic reduction potential to be between 50 and 180 Mt CO_2 per year for the period 2040–2050 (Marsh et al., 2005).[2] The Energy research centre of the Netherlands (ECN) estimated this potential to be between 12 and 15 Mt in 2020 in the Dutch electricity sector (Daniëls et al., 2006). Another ECN study reports a technical potential of 46 Mt in 2050 in this sector (Menkveld, 2004).[3] These national studies did not analyse how above described events can coincide, and thus do not provide insight whether it is difficult to realise these figures. And even when the studies show a growth pathway of the CCS potential, they do not investigate whether this potential matches the availability of sinks over time or how climate policy should evolve. The interaction between the dynamic factors that play an important role in CCS development remains obscure. Consequently, planning a CCS trajectory is not a straightforward task. To overcome this gap of knowledge, we, therefore, investigate the following research question: *How may a trajectory towards an electricity sector with CCS look like, and how does it depend on the events described above?* Answering this question may help to know to what extent planning is necessary and possible.

For this purpose, we carry out a scenario study in which we integrate and vary dynamic data on:

- Electricity demand development
- Data on costs and efficiencies of different CCS technologies and developments in these parameters
- Data on costs of transport and storage of CO_2
- The vintage structure of the electricity park
- The CO_2 storage potential and the timing when storage sites become available
- Climate policy reduction targets

We study the influence of dynamic data within a scenario that is characterised by international cooperation and social motivations. Scenario variants have been studied by building and running a model of the electricity and cogeneration supply sector of the Netherlands generated with MARKAL (MARKAL-NL-UU). This is an interesting sector for CCS deployment because the Netherlands has good CO_2 storage possibilities, and relatively short distances between large point sources and potential sinks for CO_2. Furthermore, because the Netherlands is a small country, it is considered a suitable region to study timing aspects in detail. In 2005, the Dutch electricity park had a total installed capacity of around 21.8 GWe consisting of 19% coal-fired plants, 47% central gas-fired, 2% nuclear, 23% gas-fired cogeneration, and 8% other (solar, wind, biomass-only, waste incineration). See for more details on the vintage structure Section 3.5.

The structure of this paper is as follows. Details about the adopted methodology can be found in Section 2. Section 3 deals with the input data. Results and discussion are presented in Sections 4 and 5. Finally, in the last section conclusions are drawn with respect to CCS implementation trajectories. In this study, the costs are discounted back to the year 2000 with a discount rate of 5%, prices are given in

[1] The wide range is a consequence of using different scenarios and different models.

[2] This UK study used a detailed MARKAL model to estimate the CCS potential. It studied the consequences of timing on the development of CCS trajectories. However, it did not look at the consequences of timing of events such as sinks becoming available or decommissioning of existing power plants.

[3] CO_2 emissions from the Dutch public electricity and heat sector amounted to circa 55 Mt in 2003 (Klein Goldewijk et al., 2005).

€$_{2000}$ unless otherwise stated, and Mt always refers to Mt CO_2.

2. Methodology

2.1. Overview

In order to investigate CCS implementation trajectories, a quantitative analysis of a specific scenario for the electricity sector in the Netherlands is carried out. The focus of this study is on large-scale production of electricity. We choose the scenario Strong Europe (SE) to investigate CCS trajectories. SE is one of the four scenarios recently developed by the Netherlands Bureau for Economic Policy Analysis (CPB).[4] CPB formulated four qualitative storylines for Europe by highlighting two characteristics of the world.[5] The first characteristic deals with the extent to which international cooperation exists in the world versus a regional focus. The second characteristic makes a distinction between a social versus an individualistic-driven world. This resulted in four views of Europe, called Global Economy, Strong Europe, Transatlantic Markets, and Regional Communities. SE is based on prevalence of international cooperation and social motivations (Mooij and Tang, 2003). SE creates an environment in which it is likely that international agreements regarding climate change are made. Since large-scale implementation of CCS is likely to happen in this scenario, it is regarded as an appropriate scenario to work with in this study (see Section 3.1 for relevant figures on SE).

We specify different variants of the SE scenario in order to explore the influence of two dynamic factors. First, since CCS is not a cost-effective technology without a climate policy being in place, we aim to study different emission reduction pathways in detail: a non-reduction variant, a *DirectAction* variant with CO_2 reduction targets from 2010 onwards, and a *PostponedAction* variant with targets from 2020 onwards. In this study, we set a cap on the CO_2 emissions from electricity generation and cogeneration units.[6] We choose this sector cap so that the emissions will be reduced at a slightly more lenient rate (15% in 2020, 50% in 2050 compared to 1990) than the EU reduction ambition (20% in 2020, 60% in 2050 compared to 1990), because we consider the possibility that part of the emission reduction will take place abroad.[7] Secondly, the lifetime of power plants is varied from 30 years for power plants to 40 and 50 years for respectively, gas- and coal-fired power plants. Lifetime is an important issue, because it may turn out to be much longer than is generally assumed, as is demonstrated in the liberalised energy markets in the United States (IEA, 2004). Thus, with the energy markets being liberalised in Europe, longer life spans should be taken into account.[8] The variation of these two factors results in six main variants (see Table 1).

We use the MARKAL-NL-UU technical economic model of the Dutch electricity and cogeneration supply sub-system to find the CCS deployment trajectory of each variant for the period 2000–2050. In this period CCS can develop from the research phase to a well-established commercial technology. The analysis is done at the 2050 time horizon with 11 5-year time step to provide sufficient insight into possible implementation trajectories of CCS. Apart from studying the effect of the CO_2 reduction targets and the lifetime of power plants, we also explore the influence of the following factors in a sensitivity analysis: energy prices, potential of competing technologies (cogeneration and nuclear), development rate of CCS technology, discount rate, and the strictness of climate reduction targets (see Section 2.6).

2.2. The MARKAL-NL-UU model

The MARKAL (an acronym for MARKet ALlocation) methodology provides a technology-rich basis for estimating energy dynamics over a multi-interval period (Loulou et al., 2004). It is an international recognised model generator that has been used in numerous studies. Typical examples are a study on energy technology strategies in China (Larson et al., 2003), a world-wide study on the potential of key energy technologies (IEA, 2006a), and a study on UK 60% CO_2 abatement scenarios (Strachan et al., 2007).

MARKAL generates economic equilibrium models formulated as linear (or non linear) mathematical programming problems. It calculates the technological configuration of an energy system by minimising the net present value of all energy system costs. Linear programming bases its decisions on 'perfect foresight', which means that the model can 'look ahead' to the end of the model period to find the least-cost energy configuration over the whole period. The energy system in MARKAL consists of two building elements:

[4] These scenarios were further quantified by CPB for Europe (Lejour, 2003), by CBS and RIVM-MNP for the Dutch demographic developments (Jong and Hilderink, 2004) and by CPB for the Dutch economy (Huizinga and Smid, 2004). In addition, the Strong Europe and Global Economy scenario were translated to energy scenarios for the Netherlands in Reference projections for 2005–2020 (Dril et al., 2005). In the Welfare and Environmental Quality report (Janssen et al., 2006), energy scenarios for 2000–2040 were constructed for all four scenarios.

[5] This is analogue to the way IPCC had developed its scenarios in the Special Report on Emission scenarios (IPCC, 2000).

[6] i.e. units in the public electricity and heat sector (including cogeneration units that are joint-ventures of public electricity companies and private industrial companies) and cogeneration units in other sectors (industry, commercial, and agricultural sector).

[7] Under the Kyoto protocol CO2 reductions in the Netherlands will be mainly realised by acquiring CO2 rights abroad: in developing countries with Clean development mechanism projects and in central and eastern European countries with Joint implementation projects. This way, although the Dutch GHG emissions have to be reduced with 6% on average in the target period 2008–2012, the Dutch allocation plan allows a CO2 emission increase from 158 Mt in 1990 to 186 Mt in the target period (VROM, 2004). Note that we also assume that the CO2 reduction target will be evenly distributed over all sectors.

[8] Already the trend to extend the lifetime of power plants has started. The 11 large electricity producing units (>200 MWe) that have been decommissioned until now in the Netherlands had been operating during 24 years on average, while current units will probably operate for 32 years on average.

Table 1 – Main characteristics of the variants of the SE scenario

Name	Vintage structure	Upper limit of CO_2 emissions in the power and heat sector compared to 1990[a] (in %)		
		2010	2020	2050
BAU NV	Power plants have a lifetime according to the plans[b] of utility companies or if plans are unknown lifetime is assumed to be 30 years (*Normal Vintage*)[c]	–	0	0
DirectAction NV		+9[d]	−15	−50
PostponedAction NV		–	−15	−50
BAU EV	Coal-fired power plants have a lifetime of 50 years and the gas-fired power plants of 40 years (*Extended Vintage*)[e]	–	0	0
DirectAction EV		+9[d]	−15	−50
PostponedAction EV		–	−15	−50

[a] From the national greenhouse gas inventory report (Klein Goldewijk et al., 2005), we deduced that around 54 Mt of CO_2 was emitted from electricity generation and cogeneration units in 1990 (corresponding to 34% of the total national CO_2 emissions). This figure was not reported as a separate entity, but is the sum of 39.8 Mt (Public electricity and heat sector), 13 Mt (cogeneration industry), 0.4 Mt (cogeneration commercial sector), and 0.6 Mt (cogeneration agricultural sector).
[b] The average lifetime of the 20 current large units in the Dutch electricity park of which utility plans are known, will be on average 32 years (excluding the nuclear power plant).
[c] 1.1 GW of the capacity existing today will still be in place in 2035. In 2035, all existing power plants have been replaced.
[d] Emissions in the Dutch power and heat sector have increased by 24% in 2005 compared to 1990 due to the growth in electricity demand. Thus, an increase of +9% in 2010 compared to 1990 already requires an annual reduction of 2.5% from 2005.
[e] 6.7 GW of the capacity existing today will still be in place in 2035.

technologies and commodities. Commodities are energy carriers or materials. Technologies convert commodities into other commodities. Commodities flow from one technology to another thus creating a network structure. The resulting Reference Energy System (RES) can be depicted as a network diagram. In this study, we use technologies that convert primary energy carriers (e.g. coal or gas) into final energy carriers (electricity and heat), and we modelled CO_2 transport and sink technologies.[9] The cost and performance characteristics of the technologies need to be specified as well as the costs and availability of primary energy resources. Values for these parameters should be given for each 5-year time step in the model period. The energy system is optimised so that it can satisfy the annual energy demand (also an average figure for a 5-year time interval) against the least cost.

Our MARKAL-NL-UU model of the Dutch electricity sector builds on the West European (WEU) MARKAL model developed by ECN (Smekens, 2005). This model deals with the pre-2004 EU-15 countries plus Norway, Iceland and Switzerland. This ECN model provides the RES as well as data on costs and performance of energy conversion and demand technologies.[10] In our model, all relevant data have been updated. This concerns data on large-scale conversion technologies in the electricity sector, and CO_2 capture, transport, and storage technologies. Furthermore, the vintage structure of the Dutch electricity park, and the Dutch electricity and heat demand were specified.

The WEU MARKAL model can deal with endogenous learning (Seebregts et al., 2000). However, learning in energy technologies mostly takes place at world level whereas we focus on the Netherlands only. Therefore, our MARKAL-NL-UU model does not run with endogenous learning. Instead technology development is an exogenous input based on projections from literature. The improvement in cost and performance of technologies is implemented by specifying several variants of power plants for different points in time (2010, 2020, 2030, and 2040).

2.3. *Scenario-driven parameters*

The total Dutch final demand for electricity as well as heat from cogeneration is the driving force in the model and is based on the SE scenario.[11] This demand includes the heat and electricity generated by decentralised cogeneration units and used at location. The final electricity and heat demand excludes transport losses. These losses are modelled separately for the centralised power plants.

In MARKAL, the energy carriers, *electricity* and *heat*, are treated in a special way, since they are not easily stored. These energy carriers are tracked for different time-slices. Electricity demand is differentiated for the following six time-slices: day and night for summer, winter, and the intermediate period.[12] A reserve factor is used to take care that enough capacity is available to fulfil the peak demand. This reserve factor is also used to insure against possible electricity shortfalls due to

[9] Technologies that convert final energy carriers to energy services (e.g. the demand for lighting, cooling, or transport) can also be modelled in MARKAL. However, in this study we do not use this feature. Also technologies that convert energy carriers into materials or vice versa can be defined. We used this feature to model capture, transport, and storage of CO_2.

[10] The base data in the model is described in several publications of ECN: data on power plants can be found in (Lako and Seebregts, 1998), data on the use of biomass for energy in (Feber and Gielen, 1999), data on CCS in (Smekens, 2005).

[11] It is outside the scope of this study to analyse whether the factors that influence the energy demand (e.g. economic or population growth) will change due to the CO_2 cap we introduce into the SE scenario.

[12] Summer goes from 1st of June to 1st of September, winter from 1st of December to 1st of March. Intermediate period is the remaining part of the year. The day-period covers the period from 7 to 23 h and the night-period from 23 to 7 h.

uncertainties such as unplanned down time of equipment. Heat demand is differentiated for three time-slices: winter, summer, and the intermediate period.

2.4. Power plant technologies

2.4.1. Selection of technologies

A portfolio of power plant technologies is included in the model. A wide range of possible technologies is represented in the model by considering the following aspects:

- Fuel type: coal, gas, coal/biomass, biomass, solar, wind, and nuclear.
- State-of-the-art technologies and a diverse range of advanced technologies which are available from 2020, 2030, and 2040 onwards.
- With and without CO_2 capture technologies. CO_2 capture technologies which we include are post-combustion capture, pre-combustion capture, and retrofit of existing and new (capture-ready) power plants.[13]

2.4.2. Cost parameters

In order to make a fair comparison in the optimisation process, it is very important that the technology cost data in MARKAL refer to similar expenses (see Appendix A for a description of the cost composition). Based on literature search, we specified for each technology the investment costs (€/kW), the fixed operating and maintenance (O&M) costs (€/kW), and the variable O&M costs without fuel expenses (€/kWh).

2.4.3. Lifetime of power plants

In MARKAL, only one lifetime per technology can be specified. This lifetime represents both the economic and the technical lifetime. The economic lifetime determines over how many years the investment costs are spread. In the EV variants, O&M costs are probably too low for old power plants, because MARKAL does not provide any feature to increase O&M costs with aging of power plants. However, with longer life times we simulate more according to reality when there are opportunities to invest in a completely new power plant.

2.4.4. Base load and flexible power plants

In MARKAL, the operation pattern of power plants can be determined during a model-run, or it is indicated beforehand whether a power plant can provide base load power and/or peak load power. To overcome the limitation of six time-slices, we assume that all nuclear and coal/biomass-fired power plants (pulverised coal-fired power plants, PCs, as well as integrated coal-gasification combined cycle power plants, IGCCs) are operated in base load mode.[14] However, because coal-fired power plants could also be operated in a more flexible way, a sensitivity analysis is carried out on this input parameter (see Section 2.6). Furthermore, the availability of renewable energy technologies (onshore and offshore wind turbines, and solar energy) needs to be specified per time-slice.

2.4.5. Deployment of competing CO_2 reduction technologies

The extent to which CCS competes with other technologies to reduce CO_2 emissions (such as cogeneration, nuclear and renewable energy) is analysed in broad outlines. In the main variants, the deployment of these competing technologies is based on data reported for the SE scenario in the study 'Welfare and Environmental Quality, a scenario study for the Netherlands in 2040' (WLO) (Janssen et al., 2006). In the sensitivity analysis, it was explored to what extent these bounds on competing technologies influence the results (see Section 2.6).

2.5. Transport of CO_2

CO_2 transport cost data depend on the length and diameter of the pipeline (IEA-GHG, 2005b) (IPCC, 2005). The diameter depends on the desired flow rate of CO_2. Furthermore, also type of terrain matters, i.e. onshore transport is usually cheaper than offshore (IPCC, 2005). We explicitly model two transport alternatives:

- CO_2 is transported from a power plant to the vicinity of onshore or offshore reservoir(s) through a dedicated pipeline and then via a satellite line to a reservoir.
- It is transported from a power plant via a short connector pipeline to an onshore or offshore trunk line and then via a satellite line to a reservoir.

In this study, choices had to be made with respect to distances and CO_2 flow rates that are appropriate for the Dutch situation. In a study about CO_2 transport in the vast US, booster stations were not considered necessary (IEA-GHG, 2005b). Following this example, we also assume that these will not be required in the Dutch situation, and are thus not included in the model. Because in the Netherlands onshore CO_2 transport may be rather expensive due to the large number of obstacles that may be encountered (Warmenhoven, 2006), a sensitivity analysis is done on the onshore transport costs (see Section 2.6).

[13] We assume that all new coal-fired power plants are built capture-ready. We define capture ready power plants as power plants for which small adaptations have taken place in the design and construction phase (without additional investment costs) to make it easier to add a capture unit later on. To model retrofit of power plants in MARKAL, two technologies need to be specified: a power plant technology plus a capture technology. A user-constraint is added to assure that the capture technology only operates when the base plant is being operated.

[14] Coal fired power plants in the Netherlands used to operate in a flexible mode, even with a turn-down ratio of 20%. Due to low natural gas prices in the latest decennia, the natural gas combined cycle power plant power plants (NGCCs) were deployed in full load. However, with current high gas prices coal-fired power plants will preferably be operated in base load mode. Also power plants with CCS most likely provide base load power, because then the CO_2 emissions will be reduced to the highest degree. Furthermore, if a CCS plant with post combustion is turned down, the lower pressure may become too low for the regeneration of amines (Ploumen, 2006a).

2.6. Storage of CO_2

In MARKAL-NL-UU, we model five Dutch storage types: onshore and offshore empty gas/oil fields, onshore aquifers,[15] and coal fields combined with enhanced coal bed methane production (ECBM). Most storage sites in the Netherlands do not have the potential to store the total emissions of a power plant over its whole lifetime[16] and are small compared to some saline aquifers abroad.[17] Therefore, we also include the Norwegian Utsira aquifer as storage option in our model. For each Dutch storage type, we model an average sink technology (with an average size,[18] average lifetime, average number of wells, average costs, etc.). We assume that reservoirs will be filled at maximum rate (limited by the number of wells and the maximum injection rate per well) and will thus be full after a limited number of years (we use this number as the lifetime of the storage type in MARKAL-NL-UU). Then a switch needs to be made to new reservoirs. Consequently, investments in new storage capacity will be a continuous process during the life of a power plant.

We assume that 80% of the Dutch storage potential in the five storage types will be available for CO_2 storage. This way we take into account amongst others competing storage options such as natural gas storage[19] or the possibility that fields will not be fit for CO_2 storage due to safety risks. From the MARKAL-NL-UU model runs, we acquire information on the required size and the type of CO_2 storage reservoirs over time. Next, if the model has chosen to store the CO_2 in gas fields, we verify whether these reservoirs are actually available at the right time. This verification step is not necessary when the CO_2 is stored in aquifers or coal bed layers, because they are available from the start. Finally, in the sensitivity analysis we analyse how important the availability of CO_2 storage in the Netherlands is for the competitiveness of CCS. For this purpose, we do a model run in which CO_2 can only be stored in an aquifer abroad.

2.7. Sensitivity analysis

A sensitivity analysis is carried out on one of the main reduction variants. For this purpose, we choose the *DirectAction EV* variant (see Table 1) with extended vintage and climate policy starting from 2010.[20] In the sensitivity analysis, we are interested in the influence of two types of parameters. First, parameters which we expect to have a crucial role (such as energy prices, climate policy targets, and cost developments of competing technologies). Secondly, parameters that are relevant specifically for CCS (e.g. CCS development rate, transport costs, sink availability) in order to get more insight into important bottlenecks or stimuli in a CCS development trajectory.

Table 2 lists all sensitivity variants that are run with MARKAL-NL-UU. We look at two periods: the first period (2015–2030[21]) in which CCS could play an important role in the energy system (medium term) and the period (2035–2050) in which CCS could have settled as a mature technology in the energy system (the long term). We assess how the following three aspects differed from *DirectAction EV*:

- The three power plant technologies that produce the most electricity (on average) in the medium and long term. In this way, we get insights whether the configuration of the electricity park really looks different.
- The average yearly amount of CO_2 stored in the medium and long term. This way we could verify how robust a CCS strategy might be.
- The objective function in order to asses to what extent the parameters influence the costs.

3. Data

3.1. Scenario-driven parameters

This section describes all scenario related inputs (see Table 4 for a summary).

3.1.1. Development of the final electricity demand

The demand for electricity and heat from 2000 to 2050 has to be determined outside the model and is based on GDP and demographic developments. For the SE scenario CPB projected that the Dutch economy would annually grow with 1.6% on average (Huizinga and Smid, 2004). Statistics Netherlands (CBS) and the Netherlands Environmental Assessment Agency (MNP) expect that in this scenario, the Dutch population will grow from 16.3 million people to 19.2 million in 2050 (Jong and Hilderink, 2004). The projected electricity demand for SE can be obtained from the WLO study (Janssen et al., 2006). This study assumes annual growth rates of 1.5% until 2020, and 0.8% until 2040. Next, the demand growth is extrapolated with 0.8% until 2050, resulting in an electricity demand of 175 TWh in the year 2050. The scenario characteristics are presented in Table 3 in relation to their historic developments.

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[15] We do not consider offshore aquifer traps (TNO, 2007), because very little is known about these. This option will be interesting if one or more large offshore aquifers will be found.

[16] For example, you need more than 100 Mt CO_2 storage capacity for a 1000 MW coal-fired power plant with a lifetime of 30 years. Only one offshore and 6 onshore fields (including the Groningen gas field) have over 100 Mt of storage capacity.

[17] e.g. aquifers in the Bunter sandstone formation or in the Utsira formation in respectively, the UK and the Norwegian part of the North Sea (Bentham, 2006).

[18] The average size per storage option is based on the total storage capacity divided by the number of reservoirs of this option.

[19] In the WLO report it is foreseen that around 2.7 billion m^3 per year of natural gas will be stored underground (Janssen et al., 2006).

[20] We choose this *DirectAction* variant, because the EU aims for a post-2012 climate regime (EU, 2007b). Thus it is likely that there will be new CO_2 reduction targets from 2012 onwards.

[21] When we mention a specific year like 2030 in relation to input or result data of the MARKAL model, we usually refer to the five-year time step '2030' starting halfway 2027 and ending halfway 2032. An input or result data for the year 2030 can be considered as an average figure for the five-year time step '2030'.

Table 2 – List of categories and variants used in the sensitivity analysis

Category	Variant	Why
Capture of CO_2	Flexible-load operation	To asses to what extent more CCS would be deployed, if it can also be operated in a flexible mode.
	Slow development of CCS	CCS is not in a mature phase yet. The speed at which CCS develops with respect to costs and performance can be a determining factor
Transport and storage	CO_2storage in the Netherlands fall short, but storage abroad is available.	It might be possible that many Dutch sinks are not available for storage, but storage abroad is available. We explored the consequences.
	Higher onshore transport costs	Onshore transport costs can be much higher than the default values because of art works.
Short-term strategy of utilities	Almost half of the plans to build PCs and the IGCC plan are realised before 2012	Currently many plans exist to build coal-fired power plants. It is interesting to evaluate how much the results of the analysis change when these plans are actually realized
	Almost half of PC plans and the IGCC are realised before 2012, but with capture units.	It can be investigated how the results change when the new PCs will be immediately equipped with CCS.
Competition	Nuclear is allowed	It is important to explore to what extent nuclear competes with CCS.
	Nuclear is allowed, but with high waste fee	It is important to explore to what extent nuclear competes with CCS.
	Slow development of CCS plus nuclear	If the development of CCS is not as described in the base variant, it is especially interesting to analyse to what extent nuclear competes with CCS.
	Cogeneration may increase	It is important to explore to what extent cogeneration (without CCS) competes with CCS
	Higher onshore transport costs plus nuclear	If onshore transport costs are much higher, it is interesting to assess what happens when nuclear bound is released.
	Biomass remains high	In the SE scenario the increasing demand for biomass may keep the biomass price high.
CO_2 targets	Very strict climate policy	Since the EU opts for GHG reduction of 30% in 2030 and 80% in 2050 compared to 1990, we assess the consequences of such high CO_2 reduction targets.
Economic	High discount rate	Studies have published evidence arguing that the discount rate is a very determinant factor (reference).
	Coal price higher	In the main variants, especially IGCC-CCS power plants are used as a mitigation option. It is important to know how much this depends on the coal price.
	Gas and coal price higher	In the main variants, prices of natural gas and coal are lower than current prices. Therefore, also a variant is run with overall high energy prices.

Table 3 – Characteristics of the Strong Europe scenario in the Netherlands

Population growth per year (%)		GDP growth per year (%)		Projected: final electricity growth per year (%)
Projected	Historic	Projected	Historic	
0.4 (2005–2050)	0.6 (1980–2000)	1.6	2.6 (1971–2001)	1.5 (2005–2020) 0.8 (2020–2050)

3.1.2. *Load curve of the electricity demand*

Although the load duration curve could change over time, we assume in this paper that it will not.[22] Therefore, we use data for the years 2005–2006 (Tennet, 2006b) to generate the load duration curve for the whole study period (2000–2050). Because TENNET provides data at a rather detailed level (for each quarter of an hour), and we only have six time-slices in our model, aggregation was necessary. Fig. 1 presents the load duration curve per quarter-hourly and per MARKAL time-slice. The step downwards just before 6000 h in the right picture is caused by the difference in average daily and nightly load. Because we use the aggregated load duration curve, we use the reserve factor to take care that an extra 20% of capacity will be built to address the peak demand.[23] Furthermore, in the Netherlands, usually a reserve capacity above the maximum peak load of around 20% is used to meet contingencies

[22] In 1990, van Wijk also presented a load duration curve for the Netherlands based on 1987 data (Wijk, 1990). This curve looks quite similar as the load duration curve based on 2006 data. We consider, therefore, a reasonable assumption that the curve does not change over time.

[23] We deduce this value of 20% from the difference between the maxima in the aggregated and the detailed load duration curves.

Table 4 – Summary of scenario specific input data in MARKAL

Description	Units	Years					
		2000	2010	2020	2030	2040	2050
Electricity demand[a]	TWh	101	119	138	149	162	175
Decentral cogeneration upper bound[a]	GWe	5.0	5.8	7.0	7.5	8.1	8.7
Onshore wind upper bound[a]	GW	0.5	1.4	1.9	2.0	2.0	2.1
Offshore wind upper bound[a]	GW	–	0.7	3.0	6.5	10.0	12.0
Nuclear energy[a]	GW	0.45	0.45	0.45	0.45	0[b]	0
Uranium oxide	€/GJe	1.25	1.25	1.28	1.34	1.41	1.48
Gas price	€/GJ	2.1	4.0[c]	4.0	4.4	5.0	5.6
Coal price	€/GJ	0.9	1.3	1.4	1.5	1.6	1.7
Biomass price	€/GJ	6.0	6.0	5.5	4.5	4.0	4.0
Net import electricity	TWh	19	23	0	0	0	0

[a] SE WLO + extrapolation to 2050 (Janssen et al., 2006).
[b] From 2035.
[c] 3.8 in 2015.

(Scheepers et al., 2004). By adding these two elements, we arrive at a reserve factor of 40%.

3.1.3. *Final heat demand (from cogeneration) development*

CBS reports that in the year 2000 the heat production by cogeneration was 220 PJ. Of this heat, households consumed 16 PJ and the commercial sector 49 PJ. The remaining 155 PJ was consumed by the industry including the oil refineries and agriculture sector. 33 PJ of the heat was produced by central cogeneration units which include the district heating power plants, and the remaining by decentral units.

According to the WLO report (Janssen et al., 2006), growth of the electricity production by cogeneration units in the SE scenario is expected to increase from 37 TWh (133 PJ) in 2000 to around 51 TWh in 2040 (of which 44 TWh produced by decentral units and 7 TWh by centralised units). However, the heat from cogeneration is expected to grow at a lower pace or not at all, because it is assumed that the heat/power ratio of decentral cogeneration units will decrease from around 2/1 to around 1/1 (Dril et al., 2005). Because an in-depth analysis of the development of cogeneration is outside the scope of this study, the heat produced by cogeneration has been kept constant over time. Additionally, it is assumed that the division between heat from decentral and central cogeneration is kept constant.

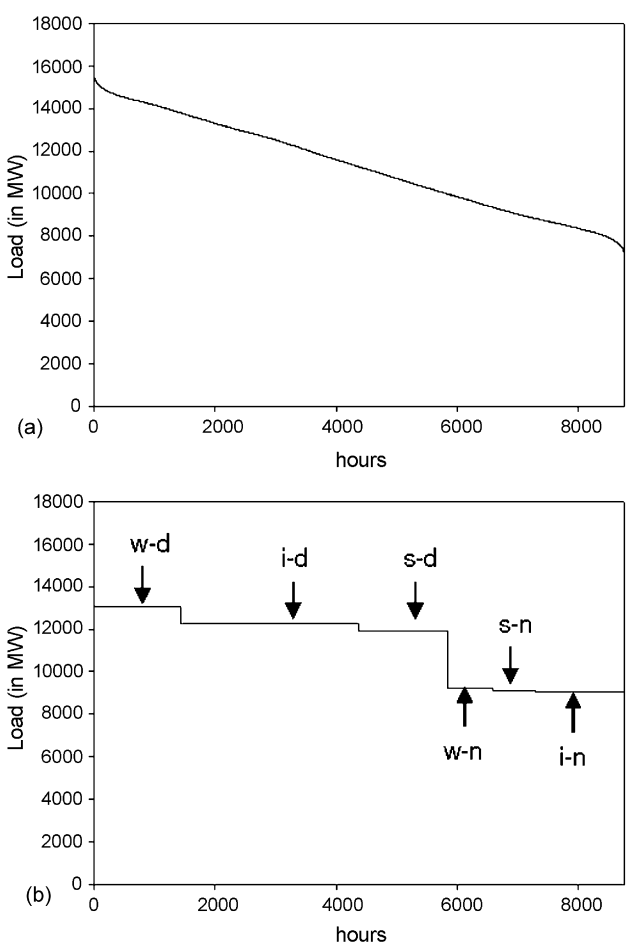

Fig. 1 – Yearly load duration curve sampled per 15 min (a) and per MARKAL time-slice (b) i, intermediate (fall + spring); s, summer; w, winter; d, day; n, night.

3.1.4. *Influence of cross-boundary electricity transport*

A determining factor for the development of the Dutch electricity park is whether the Netherlands will be a net-importer or exporter of electricity and to what extent. In the last decades, the Netherlands has been a net importer of electricity. In 2000, 18 TWh of electricity were imported, about 18% of the final electricity use (KEMA, 2002). It is expected that in the short term the Netherlands will import more, because in Europe still an overcapacity of power plants exists. In the long term, due to liberalisation and the closing of nuclear power plants, this overcapacity will decrease. In 2002, KEMA presented scenarios in which the Netherlands will remain an importer, but also one where it becomes a net exporter (KEMA, 2002). The authors of the WLO report (Janssen et al., 2006) assume an export of electricity in the Strong Europe scenario. In an electricity park with hardly any nuclear power and with a stringent climate policy, we consider this assumption rather unlikely. Therefore, we keep the net import at 0 TWh from 2020 onwards.

3.1.5. *Energy prices*

We use the latest available energy price projections of the reference scenario in the World Energy Outlook (WEO)

2006 (IEA, 2006b).[24] In this scenario, it is assumed that oil prices remain high (47 $\$_{2005}$/barrel in 2012 and 55 $\$_{2005}$ in 2030)[25] compared to the figures for the year 2000. We assume that oil prices will continue to increase up to 70 $\$_{2005}$/barrel in 2050. Gas prices will follow the oil price, because of inter-fuel competition and the widespread oil-price indexation in long-term gas-supply contracts, and analogue to WEO 2006 we set the gas price at 3.9 €/GJ in 2005 up to 4.4 €/GJ in 2030.[26] After 2030, it increases at a similar rate as the oil price to 5.6 €/GJ in 2050. Spot prices of coal were 2.4 €/GJ in 2004. However, the WEO 2006 expects that coal prices will decrease again to 1.3 €/GJ in 2010 and then slightly increase to 1.5 €/GJ in 2030. We adopt this coal price scenario and let the price gradually increase up to 1.7 €/GJ from 2030 to 2050.

We base the biomass price on the wood pellet price. Although pellets are more expensive than other biomass fuel input, they do not require extra investment or O&M costs when used for co-firing in coal-fired power generating units. Thus, these cost factors compensate each other (Sambeek et al., 2004). In our MARKAL-NL-UU model, we apply, therefore, no extra investment or O&M costs on the biomass-co-firing technologies. Wood pellets were 7–7.5 $€_{2004}$/GJ at the gate of the power plant in 2004 and the price is estimated to stabilise between 5.6 and 6.4 $€_{2004}$/GJ in the mid term (Sambeek et al., 2004). We assume that due to cost reductions in production, transport, and pre-treatment, prices will decrease over time to 4 €/GJ.[27]

As in the studies (Tolley and Jones, 2004; IEA, 2006a), we took the uranium oxide price to be 1.25 €/GJe (5.6 $\$_{2003}$/MWhe) including a nuclear waste fee of 0.24 €/GJ. This price increases slightly to 1.5 €/GJe in 2050. In the sensitivity analysis, we analyse the consequence of using advanced nuclear fuel cycles for an additional 10 €/MWhe[28] in order to reduce the amount and the radioactive lifetime of the nuclear waste.

[24] Although specific oil and gas prices (3.4 $€_{2000}$/GJ in 2030) are given for the SE in the WLO publication, we choose to use the more recent WEO projections. The SE prices in the WLO publication were lower, because of declining energy demand due to climate policy. However, the IEA used the same prices in the reference scenario as well as the alternative scenario with climate policy. They argue that the effect of declining energy demand on energy prices cannot be estimated.

[25] This high oil price scenario seems reasonable. Prices have already been for 2 years above $35/barrel and even reached levels of about $70/barrel (=8 $€_{2000}$/GJ). Also, prices in the Annual energy outlook 2006 of EIA-DOE are high: oil prices are projected to increase from 40$\$_{2004}$/barrel (=4.8 $€_{2000}$/GJ) in 2004 to 57$\$_{2004}$/barrel (=6.9 $€_{2000}$/GJ) in 2030 (EIA-DOE, 2006).

[26] These prices seems relatively low if compared to the oil price of 6.5 €/GJ and the gas price of 5 €/GJ (=22 ct_{2006}/m^3) in 2006 (Gasunie, 2006). Therefore, we do a sensitivity run with a 25% higher gas price than in the base variants.

[27] The report 'Pre-treatment technologies, and their effects on the international bioenergy supply chain logistics' declares that pellet costs delivered to Europe can be 3.6 €/GJ (for torrified pellets) and 4.9 €/GJ for normal pellets (Uslu et al., 2006).

[28] Additional costs of different advanced nuclear cycles (e.g. with transuranic waste burning in a fast reactor or accelerator driven systems) are estimated to be between 4 and 16 euro/MWh (OECD-NEA, 2002).

3.1.6. Deployment of competing CO_2 reduction technologies

In the WLO report, it was assumed that in SE subsidies for wind energy will continue up to 2040, and that consequently, 10 GW offshore and 2.0 GW onshore wind energy will be installed by the year 2040. In our study, we consider these capacities to be the maximum amount that can be installed, and we extapolate this upper bound to respectively, 12 GW and 2.1 GW in 2050. The model decides to which extent these potentials will be used. With respect to cogeneration, WLO assumes that electricity production from decentral units will be 44 TWh in 2040 which agrees with 8.1 GW of installed capacity with a capacity factor of 62%.[29] Again we adopted this capacity as upper bound for decentral cogeneration. Central cogeneration is constrained by the limited demand for district heating. According to WLO, the capacity of photovoltaic cells (PV) will grow to 3 GW in 2040. However, we just let the model decide on the deployment of PV based on its cost-effectiveness.

3.2. Technology data

3.2.1. Cost and performance

Data for the most important power plant technologies are presented in Table 5. We adopt the data for new and advanced gas- and coal-fired power plant technologies (with and without CCS) from two studies of Damen et al. (Damen et al., 2006, 2007), because the authors have collected cost and performance data in a consistent manner. We derive the data which are needed to split the O&M costs into a variable and a fixed cost part, from the original references. For NGCC and IGCC from (IEA-GHG, 2003), for PC from (IEA-GHG, 2004). To assure the quality of data, we verify the data against data from various other studies (Hendriks et al., 2004; Menkveld, 2004; IPCC, 2005; Peeters et al., 2007). All coal-fired power plants have a flexible input of either coal or biomass.[30] The WLO study assumes that in all coal-fired power plants 20% co-firing of biomass is happening in SE. We let the model free to decide to what extent it will use biomass for mitigation purposes. Data for PV are derived from (EU-PV-Technology-Platform, 2007), for wind from the CPB study Wind energy on the North Sea, the Fact sheets report presented by ECN in 2004, and Junginger's article about the global experience curves for wind farms (Menkveld, 2004; Junginger et al., 2005; Verrips et al., 2005). For the nuclear power plant, we take data from the study The economic future of nuclear power (Tolley and Jones, 2004; IEA, 2006a).[31]

[29] With CBS statistics data we calculate that decentral cogeneration units are operated with a capacity factor of 62% on average (CBS, 2006).

[30] Because it was outside the scope of this paper to analyse biomass co-firing in detail, we did not adjust the efficiency or other cost and performance data of the power plants with biomass co-firing, but used the more expensive wood pellets as input (see also section 3.1). However, costs and performance will change with other biomass input. For example, a biomass-fired IGCC has a somewhat lower efficiency (1% point) than an IGCC, because of moisture and larger volumes (lower energy density) (Hendriks et al., 2004).

[31] The nuclear power plant Borssele is a Pressurised light water reactor plant. A new power plant in the Netherlands will probably be of the same type, i.e. the EPR (European Pressurised light water Reactor) (Menkveld, 2004).

Table 5 – Technology cost and performance data

Technology[a]	2010	2020	2030	2040
Efficiency (in %)				
NGCC (%)	58	60	63	64
PC (%)	46	49	52	53
IGCC (%)	46	50	54	56
NGCC-CCS (%)	49	52	56	58
PC-CCS (%)	36	40	44	47
IGCC-CCS (%)	38	44	48	50
PC-RF (%)	28	29	29	29
PC-CRRF (%)	36	37	37	37
IGCC-CRRF (%)	38	39	39	39
Investment costs (in €/kW)				
NGCC	500	450	450	450
PC	1182	1100	1053	1000
IGCC	1457	1330	1229	1125
NGCC-CCS	848	750	693	620
PC-CCS	1851	1701	1550	1400
IGCC-CCS	1900	1600	1400	1300
PC-RF	850	850	850	850
PC-CRRF	700	700	700	700
IGCC-CRRF	500	500	500	500
Wind onshore	908	795	714	641
Wind offshore	1800	1500	1420	1400
Nuclear	1961	1961	1961	1961
PV	3200	2000	1000	700
Fixed O&M costs (in €/kW)				
NGCC	15	13	13	13
PC	61	57	52	48
IGCC	56	52	47	42
NGCC-CCS	26	19	17	15
PC-CCS	75	64	59	54
IGCC-CCS	73	60	55	50
PC-RF	11	11	11	11
PC-CRRF	15	15	15	15
IGCC-CRRF	17	17	17	17
Wind onshore	25	20	18	16
Wind offshore	76	72	68	64
Nuclear	52	52	52	52
PV	32	20	10	7
Variable O&M costs (in €/GJ)				
NGCC	0.01	0.01	0.01	0.01
PC	0.26	0.26	0.25	0.25
IGCC	0.22	0.18	0.15	0.14
NGCC-CCS	0.30	0.30	0.27	0.26
PC-CCS	0.96	0.92	0.80	0.70
IGCC-CCS	0.38	0.30	0.20	0.20
PC-RF	0.69	0.69	0.69	0.69
PC-CRRF	0.69	0.69	0.69	0.69
IGCC-CRRF	0.16	0.16	0.16	0.16
Nuclear	0.51	0.51	0.51	0.51
Availability (in %)				
All conventional plants	89	89	89	89
All CCS plants	85	85	85	85
Wind onshore	26	26	26	26
Wind offshore	40	40	40	40
Nuclear	90	90	90	90
PV	9	9	10	10
Capture ratio (%)	85	90	90	90

[a] Integrated gasification combined cycle power plant (IGCC), natural gas combined cycle power plant (NGCC), pulverised coal-fired power plant (PC), photovoltaic power (PV), retrofit (RF), capture ready retrofit (CRRF).

We used the same dataset for the *DirectAction* and *PostponedAction* variants. Although, for the *PostponedAction* variants, it is the question, if also in the rest of the world action is postponed and thus experience with large scale CCS is lacking, whether the technologies advance at similar rates.[32]

3.2.2. *Lifetime*

A lifetime of 30 years is chosen for coal-fired and gas-fired power plants, 20 years for wind turbines, 20 years for PV, and 40 years for nuclear power plants in the normal vintage variants.[33] In the EV variants, we prolong the life times to 40 years for gas-fired, 50 years for coal-fired, and 60 years for nuclear power plants.

3.2.3. *Availability factor*

The availability factor is the difference between the actual capacity and the available capacity. Usually, the difference is caused amongst others by environmental conditions, technical defects, maintenance, fulfillment of environmental permits, and disposal of heat (Tennet, 2006a). The availability factor does not equal the capacity factor. This latter factor is an output of the MARKAL model and depends on the load duration curve of the electricity demand. TENNET data show that in the Netherlands availability is on average 89% for the power plants and 90% for the nuclear power plant (Tennet, 2006a). We adopt these figures. Furthermore, we expect that the availability of a power plant with capture is a little lower (85% at most) because of increased complexity of the power plant. Finally, we assume an average yearly capacity factor for wind onshore, offshore and PV of respectively, 25%, 38%, and 10%.[34] In the model, the availability of the renewable technologies are differentiated per time-slice.

3.2.4. *Summary*

In order to put the cost and performance data of the different technologies into perspective, we present three technology indicators in Table 6: the specific CO_2 emissions (in kg/kWh), the cost of electricity (COE), and the CO_2 avoidance costs compared to a reference technology. Note, that in the MARKAL model runs the actual values will deviate from these figures.

[32] Empirically it is shown that there is a relation between the cumulative capacity of a technology and costs of the technology: unit costs decrease with increasing experience. This can be referred to as learning by doing (McDonald and Schrattenholzer, 2001).

[33] In current energy markets these life times seem relatively short. However, many MARKAL studies still use lifetimes between 25 and 30 years for fossil-fuelled power plants because MARKAL does not make a distinction between the economic and technical lifetime, and because it is not possible to increase the operating and maintenance costs with aging of a power plant.

[34] Capacity factor of onshore wind is derived from the website of Wind Service Holland (Holland, 2007). Capacity factor of offshore wind increases from 38% in 2000 to 40% in 2010 (Verrips et al., 2005). Capacity factor of PV increases from 8.6% in 2000 to 10.3% in 2050 (Holland-Solar, 2005).

Table 6 – Technology indicators

			2010	2020	2030	2040
Specific CO_2 emissions (in kg/kWh)	NGCC		0.348	0.337	0.321	0.316
	PC		0.740	0.699	0.655	0.643
	IGCC		0.740	0.681	0.631	0.608
	NGCC-CCS		0.062	0.058	0.036	0.035
	PC-CCS		0.142	0.127	0.077	0.072
	IGCC-CCS		0.134	0.077	0.071	0.068
	PC-RF		0.122	0.117	0.117	0.117
	PC-CRRF		0.095	0.092	0.092	0.092
	IGCC-CRRF		0.090	0.087	0.087	0.087
	Wind onshore		0	0	0	0
	Wind offshore		0	0	0	0
	Nuclear		0	0	0	0
	PV		0	0	0	0
COE[a] (in €/MWh)	NGCC		31	29	31	34
	PC		29	28	26	26
	IGCC		31	28	27	25
	NGCC-CCS		42	38	38	39
	PC-CCS		43	39	36	34
	IGCC-CCS		40	34	31	30
	PC-RF		52	52	52	54
	PC-CRRF		45	45	46	47
	IGCC-CRRF		42	42	43	44
	Wind onshore		43	37	33	30
	Wind offshore		63	55	52	50
	Nuclear		27	28	28	28
	PV		324	196	95	65
CO_2 avoidance costs[b] (in €/t)	Compared to					
	NGCC	NGCC-CCS	36	30	25	21
	PC	PC-CCS	23	20	17	14
	IGCC	IGCC-CCS	16	10	8	9
	PC-2000	PC-RF	37	39	44	48
	PC-2010	PC-CRRF	24	26	30	32
	IGCC-2010	IGCC-CRRF	17	19	22	25
	PC	NGCC	5	5	13	23
	PC	IGCC-CCS	19	11	8	7
	PC	Wind onshore	19	13	10	6
	PC	Wind offshore	46	39	39	38
	PC	Nuclear	−2	0	2	3
	PC	PV	398	241	105	60
	NGCC	PC-CCS	58	46	22	2
	NGCC	PC-RF	90	101	107	103

[a] These values must be considered as an indication for the cost of electricity (COE). In the calculation of these COEs, we assume that capacity is utilised to the maximum extent, that only coal is burned in PC and IGCC plants, and that energy prices remain constant over the lifetime of the technologies (for example the COE of a PC built in 2040 is based on coal prices in 2040). In the MARKAL model runs, these conditions will be different.

[b] The costs of CO_2 avoidance can only be determined in comparison to costs and emissions of a reference technology. In most cases PC is taken as the reference technology. Also the CO_2 avoidance costs are just an indication for the same reasons as for the COE.

3.3. *Storage data*

Table 7 presents the MARKAL-NL-UU inputs for CO_2 storage and the data on which these values are based. Cost data were taken from the IEA report 'Building the cost curves for CO_2 storage: European sector' (IEA-GHG, 2005a). This report presents distinct data for investment and O&M costs. The base data to calculate the average reservoir size is derived from (TNO, 2007) and is for onshore and offshore fields, respectively, 39 and 23 Mt. When two wells per reservoir are drilled and the full injection rate of 1.25 Mt per year per well is used,[35] these will be filled in respectively, 16 and 9 years. [36] We only consider the 10 onshore aquifers with a

[35] To capture all CO_2 emissions of a coal-fired power plant, injection will need to take place in two to three reservoirs at once.

[36] Using two wells and filling the offshore reservoir in 9 years is cheaper per tonne CO_2 (4.7 €/t CO_2) than filling the reservoir with only one well in 18 years (5.9 €/t CO_2). For storage onshore it doe not matter whether the reservoir is filled with one well in 32 years or two wells in 16 years (1.1 €/t). The difference is due to the fact that O&M costs are more expensive offshore than onshore.

Table 7 – Data overview of CO_2 storage options in the Netherlands

Unit		Gas fields onshore	Gas fields offshore	Aquifers onshore	ECBM
Cumulative Storage potential[a]		1421	863	440	172
Timing: how much storage capacity gets depleted around					
2010	Mt CO_2	491	137	Available from start	Available from 2020
2015		439	170		
2020			550		
2025		478	336		
Average reservoir characteristics					
Reservoir depth[b]	km	2.6	3.5	2	1
Reservoir thickness[c]	m	125	125	125	200
Well capacity[c]	Mt CO_2 per year	1.25	1.25	1	0.01
number of wells[c]		2	2	2	6
Horizontal drilling[c]	m	1000	1000	1000	800
average lifetime storage option		16	9	22	20
CO_2 storage capacity over lifetime	Mt CO_2	39	23	44	1.2
Average investment costs[c]					
Site development costs	m€	1.6	1.8	1.6	0.18
Drilling costs per meter 2000	€/m	1750	2500	1750	500
Drilling costs per meter 2020	€/m	1200	1750	1200	350
Surface facilities	m€	0.4	25	0.4	0.4
Monitoring investments	m€	0.2	0	2	2
Total investment costs	m€	17	52	18	11
O&M (as share of investment costs)[c]	%	7%	8%	7%	7%
MARKAL input[d]					
Investment costs 2000–2020	m€ per Mt CO_2 per year	7.6	22	9.2	183[d]
Investment costs 2020–2050	m€ per Mt CO_2 per year	5.5	19	7	141[d]
Fixed costs 2000–2020	m€ per Mt CO_2 per year	0.5	1.8	0.6	12.8
Fixed costs 2020–2050	m€ per Mt CO_2 per year	0.4	1.5	0.5	9.9
Costs per tonne CO_2 2000–2020[e]	€/t CO_2	1.5	5.6	1.7	34
Costs per tonne CO_2 2020–2050[e]	€/t CO_2	1.1	4.7	1.3	26

[a] Storage potentials for the gas fields and aquifers are from (TNO, 2007) and includes gas fields of >10 Mt and ten aquifer traps of >10 Mt. The conservative estimates of (Hamelinck et al., 2001) were used in which ECBM recovery is limited to a depth range of 500–1500. In the MARKAL model we take 80% of these storage potential figures.
[b] Average depth of gas fields and aquifers is based on TNO study (TNO, 2007).
[c] Data taken from (IEA-GHG, 2005a). Possible cost reductions when sinks are close to each other have not been considered.
[c]Values relate to storage facilities that can store 1 Mt CO_2 per year.
[d] Investment costs per Mt CO_2 per year are very high because of low injection rate. However, these costs will partly be offset by the yield of methane. It is assumed that 2 molecules of CO_2 replace one molecule of CH_4 (IEA-GHG, 2005a).
[e] Costs per tonne CO_2 in case the sink is used to its maximum. However, the MARKAL model decides itself to which extent the reservoir will be used.

storage capacity >10 Mt. These aquifers have an average storage capacity of 44 Mt, a filling capacity of 2 Mt per year (with two wells and a well capacity of 1 Mt per year), and are thus filled in 22 years. An ECBM site has six wells and a lifetime of 20 years.

3.4. *Transport data*

CO_2 transport cost data are derived from (IEA-GHG, 2002) and (Hendriks et al., 2003). These studies have been used to sketch the range in transport cost data in the IPCC special report on Carbon Dioxide Capture and Storage (IPCC, 2005).

Table 8 presents the data used in our MARKAL-NL-UU model. They represent different CO_2 transport pipelines in the Dutch situation. The distances are based on measurements between potential sources and sinks with a GIS system. The ages of the transport lines are by default 25 years. Only the satellite pipelines have the same lifetime as the reservoirs they go to.

3.5. *Vintage structure in the Netherlands*

In order to assess when new power plants will be needed, the capacity and construction year of current power plants and cogeneration units in the Netherlands have been collected. How the vintage structure develops over time, depends on the expected lifetime of the power plants. We base these life times on the plans of energy companies and otherwise on an average lifetime of 30 years for centralised units and 25 years for decentralised units. Data were obtained from (SEP, 1996; Essent, 2005; Nuon, 2005; Seebregts and Volkers, 2005). Finally, the websites of the major energy companies active in the Netherlands, Essent, Nuon, Electrabel, Delta, Eneco, E.On were scanned for the latest news on, for example, new power plants and life extension plans of existing power plants. Data were

Table 8 – Data on CO_2 transport for the Dutch situation

		Offshore				Onshore				Utsira Norway
		Direct line	Line to trunk or direct line	Trunk line	Satellite line	Direct line	Line to trunk or direct line	Trunk line	Satellite line	Trunk line
Distance	km	200	20	200	30	100	10	100	15	800
Flow	Mt per year	6	6	20	2.5	6	6	20	2.5	28
Lifetime	Years	25	25	25	9	25	25	25	16[a]	25
Investment costs	m€/ (Mt per year)	18.5	1.4	8.1	6.6	9.5	0.6	4.5	1.7	38.5
Fixed costs	m€/ (Mt per year)	0.40	0.03	0.12	0.18	0.20	0.01	0.09	0.03	0.33
Transport cost[b]	€/t	1.72	0.13	0.69	1.11	0.87	0.05	0.41	0.19	3.06

[a] Satellite pipelines to aquifers and coal beds have a longer lifetime. However, this hardly has an effect on the average transport costs.
[b] Costs per tonne CO_2 in case the pipeline is used to its maximum capacity. However, the MARKAL model decides itself to which extent the pipeline capacity is used.

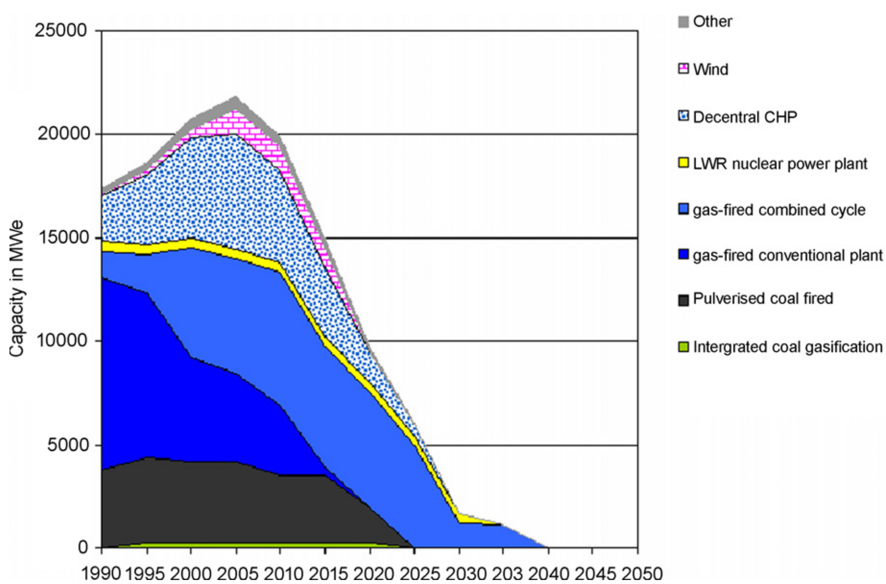

Fig. 2 – Vintage structure of Dutch electricity park 'normal vintage'.

completed and verified with online data of CBS (CBS, 2006). With respect to Fig. 2, in which the development of the vintage structure is depicted, we make the following remarks:

- Many power companies have plans to build new power plants in the Netherlands. Plans for which the final investment decisions have been taken, are included. In the sensitivity analysis, it is analysed what happens when part of the other plans will also be carried out.
- Biomass is not shown as a separate category. Nine hundred and fifty, 1750, 3350 GWh was produced in respectively, 2003, 2004, and 2005 from biomass. This corresponds to a growth from 1% to more than 3% of total annual electricity production (Junginger et al., 2006). In 2005, around 70% of this electricity was produced in coal-fired power plants, 18% in gas fired power plants and 11% in a biomass only plant. Feed stocks varied from palm oil, sawdust, pellets, palm pit shells to demolished uncontaminated wood.[37] Because subsidies for biomass have been lowered since mid 2006, electricity from biomass is expected to decrease in the short term as long as no new policy measures are taken.
- Although 'combi' gas-fired power plants can be found in the Netherlands, we do not model them as a separate category. A 'combi' uses exhaust gases from the gas turbine as combustion air in the boiler. It can be considered as a predecessor of an NGCC[38] which uses the exhaust gas to heat up the water directly without using additional fuel (Gijsen and Spakman, 2001). Since the efficiency of the 'combi' is lower than NGCC, we included them into the conventional condensing power plant category.

[37] It is not allowed to use contaminated wood in the Netherlands.
[38] NGCC is usually called STEG (Steam and gas turbine) in the Netherlands.

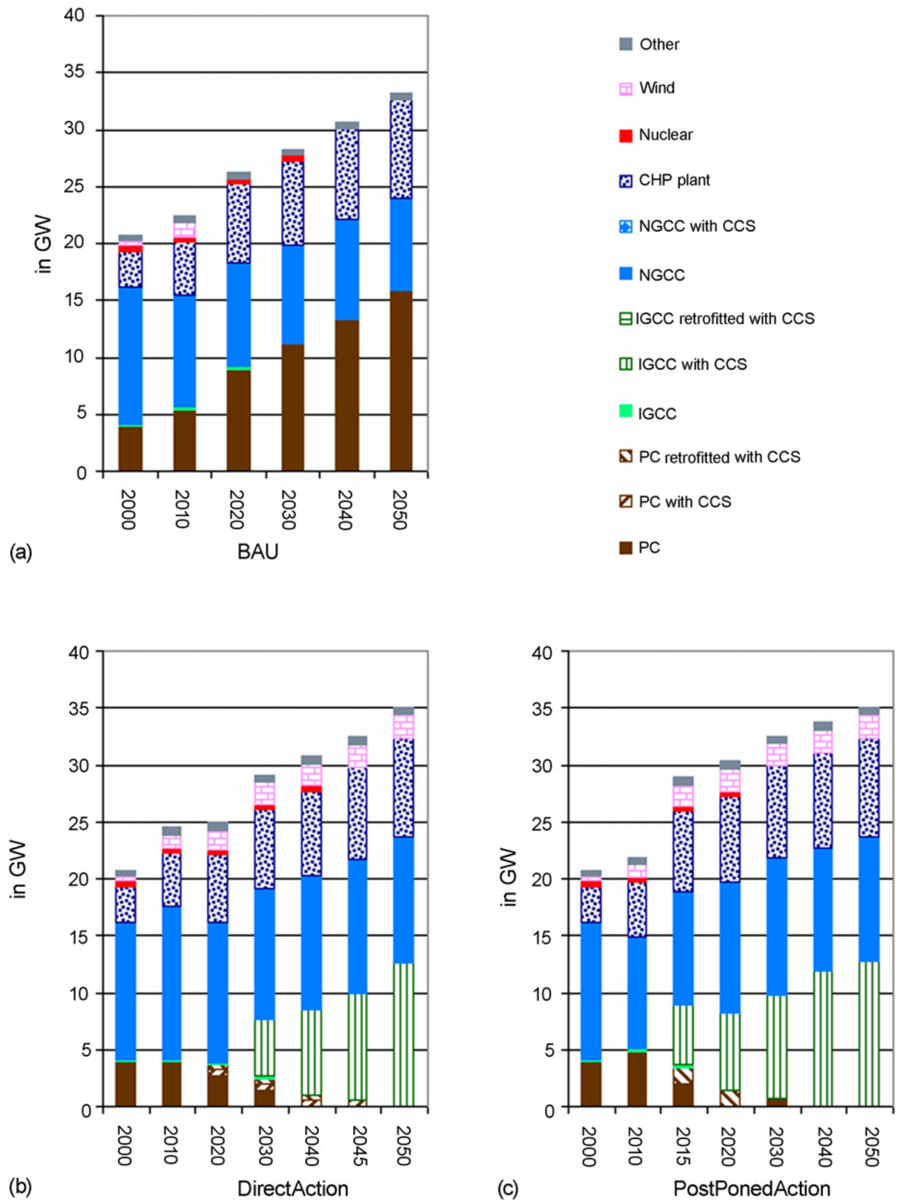

Fig. 3 – Total installed capacity of different technologies for the 'normal' vintage variants.

4. Results and discussion

4.1. *Electricity generation technologies with and without CO_2 capture*

In this section, the results of the MARKAL-NL-UU runs are discussed. Fig. 3 depicts the resulting capacities (in GW) of the different technologies over time for the *BAU*, *DirectAction*, and *PostponedAction NV* variants in which the power plants are decommissioned after 30 years.[39] With respect to the composition and dispatch of the electricity park, the following conclusions can be drawn from the MARKAL-NL-UU runs:

4.1.1. *Business as usual*

The *BAU* variants show that, if there would be no CO_2 reduction targets, the electricity park will consist for a large part out of PC plants (almost half of the total capacity in 2050). A quarter of the park consists of CHPs and the remaining quarter is covered by NGCCs to fulfil the peak demand of electricity. In total, a little over 33 GW in 2050 is necessary. The CO_2 emissions for power generation rise to 93, 102 Mt per year in 2020, and 113, 117 Mt per year in 2050 for, respectively, the *BAU NV* and *BAU EV* variant (see already Fig. 8). This implies an increase of more than 210% compared to the 1990 CO_2 emission level. In the *EV* variants less efficient power plants

[39] The variants with the extended life times are discussed in the text, but not presented in Fig. 3. The installed capacities of these variants are quite similar to the variants presented in the graphs. Only in the period between 2010–2020 there are remarkable differences, but these are shown in Fig. 4.

stay longer in operation, and thus cause the higher CO_2 emissions.

4.1.2. Long-term mitigation strategy

All reduction variants (i.e. the *DirectAction* and *PostponedAction* variants) depict the same mitigation strategy at the end of the model horizon. This strategy can be characterised as follows:

- The *total electricity generation capacity* will amount up to 35 GW (6% more than the *BAU* variants) in 2050, because the average availability of the park has decreased due to the wind energy.
- In the long-term (2050) the *technologies* that play the most *dominant* role in the CO_2 reduction strategy are IGCC-CCS (13–14 GW), gas-fired power plants, and CHP. NGCC-CCS is not part of the solution.
- *Wind energy* plays a modest role. The capacity of onshore wind is restricted by the upper bound of 2.1 GW and will cover the electricity demand for less than 3%. Offshore wind energy does not become competitive during this period.[40]
- In 2050, between 24% and 30% of primary energy input in the coal-fired power plants consists of *biomass*.
- Currently, there are in the Netherlands a few PC and NGCC power plants delivering *district heat*. In the reduction variants, the PC plants will be replaced by IGCC with CCS. However, in these variants, the heat produced for district heating units will in the end come from NGCC units. The reason is that power plants with CO_2 capture cannot deliver district heat, because 50–66% of the low pressure steam will be needed for regeneration purposes (Ploumen, 2006b). It is the question if at the location of the current PC power plants that provide district heating, NGCC units will be built. Therefore, it should be investigated in more detail how an electricity park with large scale CCS can be combined with district heating.
- The primary energy use for electricity generation which is presented in Fig. 6, also provides information on the long term strategy. The share of coal will grow from 24% in 2005 to 37% in 2050 and the share of biomass will increase to 17% in 2050. Although the share of gas (natural gas and blast furnace gas) decreases, it still remains substantial with 43% in 2050.

4.1.3. Short-term mitigation strategy

Fig. 4 presents the investments in electricity generation capacity for 2010 and 2015 for all main variants. It can be deduced from the figure that the investment strategies in the main variants especially vary at the beginning of the model horizon. However, we can identify a few main conclusions about a short-term strategy to reach the CO_2 abatement target in 2020.

- At the beginning of the model period, one could expect that there still may be some investment in conventional IGCC or PC plants, because at that time reduction targets are not so strict yet. However, results show that there is hardly any investment in these types of plants. Only in the *PostponedAction* variants in which CO_2 emissions may still increase up to 2015, *capture ready power PC plants* play a limited role. A PC plant(s) of 1.5 and 1 GW will be built between 2010 and 2015 in respectively, the *PostponedAction NV* and *EV* variant which will be retrofitted with capture units in 2020. This investment of 1–1.5 GW PC is small in comparison to existing plans of electricity companies.[41]
- In all variants around 3 GW of *CHP* units will be constructed in 2010 and 2015, mostly this is to replace existing units (2.2 GW) and the remaining is to build additional CHP units. Except for the 300 MW CHP unit which is being built by Air Liquide/Shell in Pernis and will become operational in 2007, we are not aware of other large scale CHP construction plans.
- With respect to *NGCC*, we note that in the *NV* variants 3 GW more NGCC needs to be built to replace existing gas-fired power plants than in the *EV* variants in 2010 and 2015 due to the longer life times in the latter variants. To reach the CO_2 targets in the *PostponedAction* and *DirectAction* variants additional investments in NGCCs are required in 2010 and 2015: *PostponedAction* requires an additional investment of 1 GW in these periods, and *DirectAction* requires even 3 GW more compared to the *BAU* variants. Current NGCC construction plans of the energy companies for the time step '2010' amount up to 3.6 GW (Delta, 2006; ECN, 2006; Electrabel, 2006; Essent, 2006; Eneco, 2007). These plans are presented as additional capacity rather than as replacement for old power plants. Thus, if these plans are actually taken on and if the existing gas-fired power plants remain in operation, there will be sufficient NGCC capacity for a strategy to reduce CO_2 emissions from 2010 onwards.
- In the *PostponedAction* variants, no *retrofitting* of current PC power plants takes place. In the *DirectAction* variants, already in 2010 and 2015 CO_2 capture is deployed as a solution to

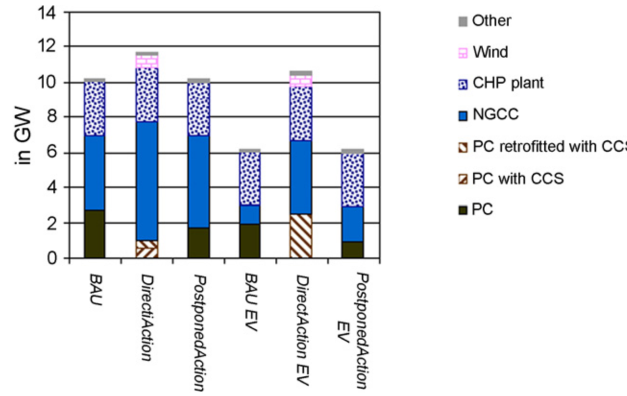

Fig. 4 – Investments in new capacity in the periods 2010 and 2015 per main variant (Note that in the *DirectAction EV* variant, it seems that much more power plants will be constructed than in the *BAU EV* variant. However, this is not the case: the 'PC retrofitted with CCS' category refers to the retrofit of existing power plants. The retrofit capacity in the graph should, therefore, not be interpreted as additional capacity.).

[40] The outcome of the linear optimisation process shows that the investment costs of wind energy need to be reduced by 560–940 €/kWh in order to become a competitive technology in a reduction variant.

[41] Plans amount up to 1200 MW IGCC and 3300–4100 MW PC (Ploumen, 2006a).

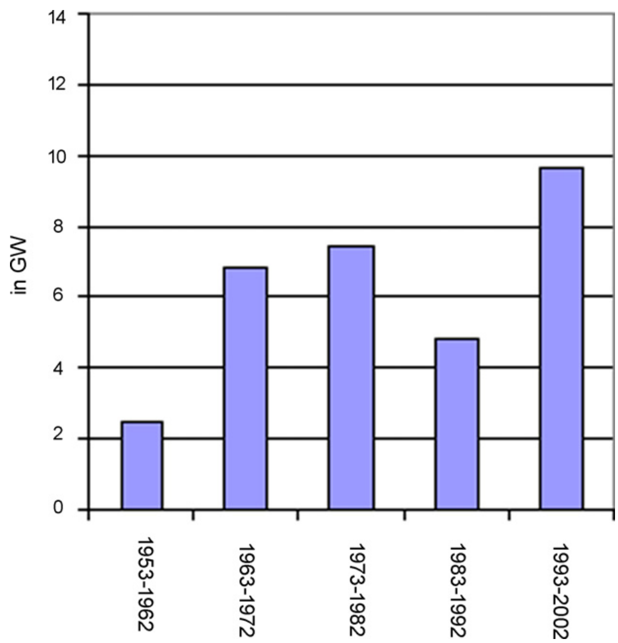

Fig. 5 – New built capacity historically (per 10 years).

reach the CO_2 abatement targets. The model prefers at this point to invest in 0.5 GW of PC with post-combustion and 0.5 GW in retrofit of existing PC in the *NV* variant, while in the *EV* variant 2.5 GW of existing PC is retrofitted with post-combustion. Apparently, retrofitting of existing coal-fired power plants plays a considerable role in the *DirectAction EV* variant: in this variant, it is worthwhile to retrofit an existing power plant because the capture unit will be used over a long time (from around 2010 to 2030). An overall analysis of all reduction variants shows us that in 2020 only between 3% and 8% of the electricity comes from coal-fired power plants without CCS. Ergo, most PC plants which exist today are either decommissioned, not operated anymore, or have been retrofitted in 2020.

- In all variants, major power plant construction is necessary for replacement of old power plants compared to historic construction activities (compare model results in Fig. 4 with historic data in Fig. 5). In the reduction variants, these replacement activities are to a large extent used to switch to a less CO_2 intensive electricity park. In the *DirectAction* variants, additional capacity needs to be constructed to make up for the lower availability of wind energy. Furthermore, in the *DirectAction* variants, additional capacity needs to be built compared to *BAU*, because old power plants will be operated less.
- With respect to the primary energy for electricity generation (Fig. 6), it is a cost-effective strategy not to increase the share of coal in 2010 and 2015 in the *DirectAction NV* variant. Moreover, 50% of this coal already will be fired in a power plant with CO_2 capture. In the *PostponedAction NV* variant the share of coal may rise on the short term.

Early decommissioning: Since the lifetime of power plants are fixed in MARKAL, we need to look at the MARKAL results with respect to the capacity factor to get an indication when power plants may be phased out early. Fig. 7 shows that the power plants in the *DirectAction* reduction variants operate on average fewer hours than in the *BAU* variants. In the *DirectAction NV* variant, the current PC plants, which are not retrofitted, will operate not more than 30% of the yearly hours from 2010 due to their high specific CO_2 emissions (this can also be achieved by phasing out one or two of the older coal-fired power plants). In the *DirectAction EV* variant, the current PC power plants which are retrofitted, will still be operated around 75% of their time from 2010 (but less than in the *BAU* variant). However, from 2030 even retrofitting is not sufficient to keep these plants in operation. Consequently, the average capacity factor of the total electricity park will temporarily decrease with more than 4% point in 2030 compared to *BAU* (see the *DirectAction EV* variant in Fig. 7). The model rather chooses to build new more efficient power plants to replace the electricity production from these old plants. We conclude that when a severe reduction path is followed, it will be highly unlikely that the lifetime of current PC plants will be extended to 50 years. Only in the case that these PC plants will already be retrofitted in 2015, an extension of their lifetime from 30 to 40 years (till 2025) may still be sensible.

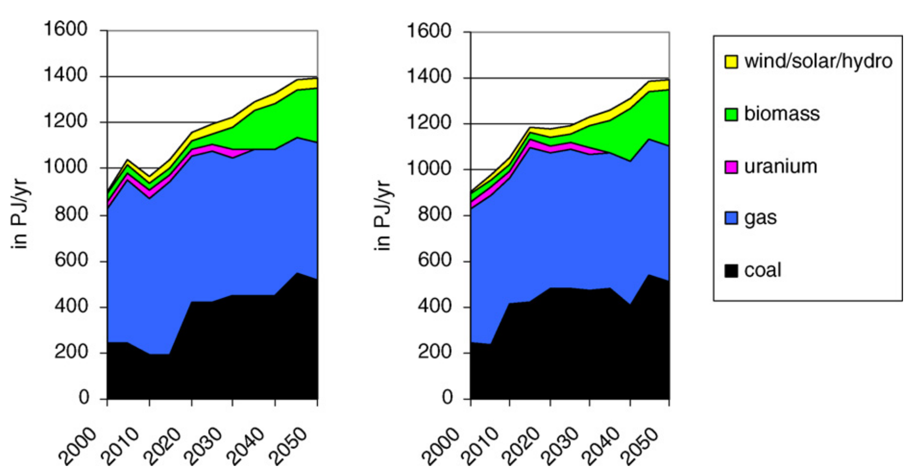

Fig. 6 – Primary energy use per year for *DirectAction* (left) and *PostponedAction* (right) (The primary energy use of the EV variants follow about the same pattern as their analogue NV variants).

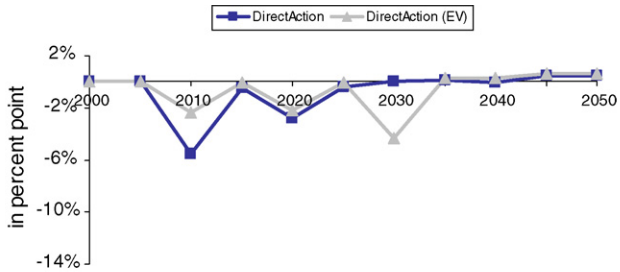

Fig. 7 – Average capacity factor in two reduction variants compared to *BAU* variants.

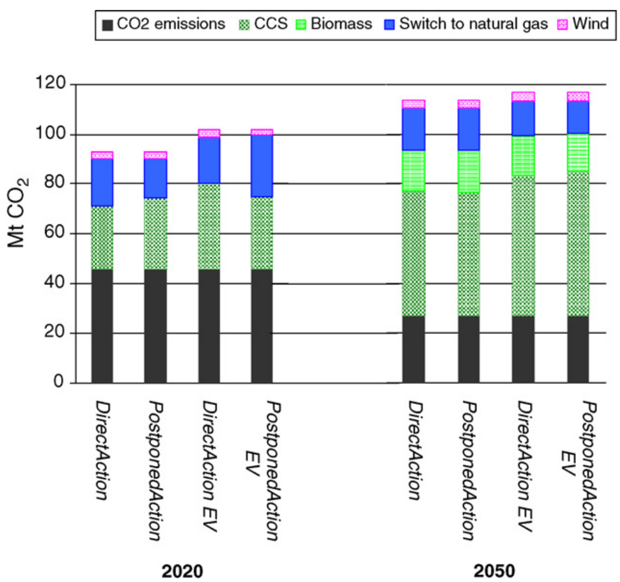

Fig. 8 – Amount of CO_2 avoided by CCS and other mitigation options.

4.2. CO_2 storage

The amount of CO_2 stored varies between 33 Mt (*DirectAction NV*) and 44 Mt (*DirectAction EV*) per year in 2020 and comes from 6 to 7 GW of power plants. This corresponds to on average 29 Mt CO_2 avoided.[42] Fig. 8 shows the amounts of CO_2 avoided in comparison to other mitigation options. In the *DirectAction EV* variant, most CO_2 is stored and avoided due to the large scale retrofitting of existing PCs. In the *DirectAction NV* variant, the least CO_2 is stored, because retrofitting is not cost-effective and short-term mitigation strategy is based more on the use of NGCCs. The figures which Damen et al. presented for the power sector (excluding retrofitting) amount to only 11–14 Mt CO_2 avoided per year in 2020 (Damen et al., 2007) are lower. However, he did not design an overall strategy to reduce CO_2 emissions up to a certain level. Since we assume a binding target of 15% CO_2 reduction in 2020 compared to the 1990 level, the deployment of large scale CCS appears to be, within the framework of our assumptions on prices and competing technologies, the most cost-effective strategy to realise this target. In 2050, about 63 Mt CO_2 per year is stored from the electricity sector, which corresponds to around 54 Mt CO_2 avoided per year, and stems from 13 to 14 GW power plant capacity.[43] Menkveld (2004) reported a slightly lower figure of 46 Mt CO_2 avoided per year in 2050. Damen et al. (2007) reported higher figures of 60–84 Mt CO_2 avoided per year probably due to a higher electricity demand in 2050 (210 TWh) than in our study (175 TWh).

Depending on the reduction variant, storage of CO_2 starts between 2010 and 2020 in onshore empty gas fields, and next storage is continued in onshore aquifers. This is understandable, because the onshore sinks are, on average, twice as large as the offshore gas fields, which make costs of storage cheaper. Also, distances to the onshore storage sites are shorter and thus the construction of pipelines to these locations will be cheaper. However, it is doubtful whether all CCS plants can be located in such a way that they can be easily connected with onshore storage sites. Furthermore, the onshore fields will be almost filled up with CO_2 by 2045 (except for the Groningen field) and only then the model starts using offshore gas fields.[44]

The timing when the onshore gas fields become available does not appear to be a problem for the storage of CO_2 emissions from the power sector.[45] The storage capacity in the medium term could even be sufficient to store CO_2 from other sectors as well. However, it may be a problem that the onshore fields are already filled by 2045. If the Groningen field would be available by 2040 instead of 2050, a switch to small offshore gas fields may not be necessary.

4.3. CO_2 transport

Of course, also a CO_2 infrastructure needs to be constructed in time to transport around 38 Mt per year in 2020 and 63 Mt per year. Before 2020, around 480 km of pipelines must be laid down, next before the year 2035 another 360 km, and finally before 2050 yet another 1930 km. The latter figure is high, because of the transport to numerous small offshore gas fields.[46] However, it still remains more cost-effective to store the CO_2 to the Dutch offshore fields than transporting it to the Utsira aquifer formation in the Norwegian North Sea.

[42] The difference between the amounts of CO_2 stored and CO_2 avoided is caused by the efficiency loss of power plants due to the additional energy required for CO_2 capture and compression: a larger amount of CO_2 is produced per kWh electricity output in a power plant with capture than in one without capture (IPCC, 2005). On the basis of capture rate, and efficiency of power plants with and without capture, we calculated the average ratio of CO_2 avoided to CO_2 stored in the year 2020 (78%) and 2050 (85%). Over time the difference between these amounts becomes smaller due to more efficient capture processes.

[43] Average storage figures for the period 2015–2030 is 31 Mt CO_2 per year and for 2035–2050 56 Mt CO_2 per year.

[44] This study assumed that offshore fields that have been abandoned 20–35 years earlier, will still be suitable for storage.

[45] The cumulative stored CO_2 emissions in the different variants have been compared with the availability data in Table 7.

[46] Currently, there is around 3000 kilometres of pipelines on the Dutch continental plate for exploration of gas and oil (Productschap-Vis, 2004).

If we look at the short-term strategy, we see that in the *DirectAction* variants, the construction of infrastructure is a more gradual process: facilities for 7–20 Mt per year[47] will be built in 2015 and 20–26 Mt per year in 2020, whereas in the *PostponedAction* variants a similar infrastructure is built in around 5 years. Considering the history of Gasunie which constructed 2050 km of main gas pipelines and 2350 km of regional pipelines between 1964 and 1972 (Gasterra, 2007), the actual construction of an infrastructure in a short period is possible. However, legislative procedures have changed since this period and may slow down the process of building a CO_2 infrastructure. Therefore, we presume that a more gradual process is preferable.

4.4. CO_2 reduction costs

Fig. 9 depicts the marginal cost of CO_2 reduction over the model horizon for the *NV* variants.[48] The marginal cost in a specific time step refers to the amount of money the objective function in the linear optimisation process will decrease, if the CO_2 reduction target in this time step is lowered by 1 Mt of CO_2.[49] Thus, the marginal cost provides an indication of how high a CO_2 price in an emission-trading scheme (ETS) should be to realise the entire CO_2 target and does not provide information about the average cost of CO_2 mitigation.[50] The reduction variants obviously differ significantly in 2015, because in the *PostponedAction* variant, reduction targets are only imposed from 2020 onwards. The high marginal cost in the *DirectAction* variant (50 €/t) is a result of the expensive measure to reduce emissions with CO_2 capture and storage in 0.5 GW of PC-CCS power plant and at the same time under-utilising existing PC power plants.

Notice that the marginal cost in 2020 is lower than the one in 2025. The reason is that, because many power plants need to be built around 2020, already then investments will be made to reach the reduction target in 2025. As a result of these investments, it is relatively 'cheap' to reduce the last Mt of CO_2 in 2020.

We see that the marginal cost of CO_2 gradually reduces after 2025 due to the development of IGCC-CCS technology, and the phasing out of older power plants. Apparently, these developments more than compensate extra costs, which might be necessary to decrease the average CO_2 emissions/kWh over time. The marginal cost in 2050 is based on the reduction of CO_2 emissions by using an IGCC-CCS power plant with co-firing of biomass.

Finally, we conclude from Fig. 9 that for the direct action strategy, a gradual increase of a CO_2 price in an ETS system would not be sufficient to gradually decrease CO_2 to −15% compared to the 1990 level between 2010 and 2020. Since it is not expected that the CO_2 price in an ETS system will be so high in the near future,[51] this strategy would require additional subsidies or other incentives by the government.

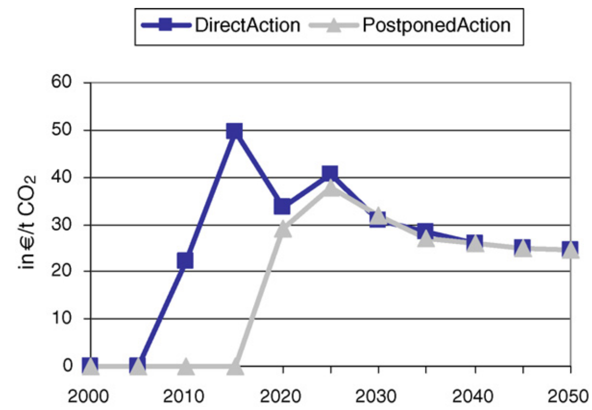

Fig. 9 – Marginal cost of CO_2 reduction.

4.5. Electricity generation costs

Fig. 10 shows the cost of electricity over the model horizon for the *NV* variants.[52] The following conclusions can be drawn from this graph.

- In all variants[53] the COE increases considerably from 2000 to 2005.[54] This is mainly due to substantial rise in prices of both coal and gas during this period.
- After 2010 in the *BAU* variant, the COE decreases to a level lower than in 2000 due to the decommissioning of older less efficient power plants. Between 2020 and 2050, the COE hardly changes, because the impacts of technical improvements and cost reductions in power generating technologies counterbalance the increase in coal and gas prices.
- Obviously, the COE starts deviating from the *BAU* case as soon as CO_2 needs to be reduced (from 2010 in *NV* variants and from 2020 in *EV*). In 2050, the COE price is around 20%

[47] Infrastructure for 20 Mt in 2015 is required in the *EV* variant in which PC plants are retrofitted.

[48] The marginal CO_2 prices in the *EV* variants only slightly differ from those in their analogue *NV* variants.

[49] It will decrease by the *discounted* marginal cost.

[50] For example, it might be possible to achieve the reduction of the majority of CO_2 against relative cheap costs, while mitigating the last tonnes could be very expensive. The marginal price only refers to the abatement of the very last tonne of CO_2.

[51] In the WLO study, the CO_2 price is only 11 €/t in 2020 (Janssen et al., 2006). In the World Energy Outlook of the European Commission, CO_2 price is estimated to be 10 $€_{2005}$/t in 2010 increasing linearly to 20 $€_{2005}$/t in 2030 (EC, 2006).

[52] We have used the total undiscounted annualised cost results of MARKAL for the calculation of the COE. Because at first, these annualised costs could not be related to the objective function, we improved the MARKAL GAMS code with respect to this point. The problem was that two different annuity factors were used: one for the objective function and another for the annualised costs. We took care that the same annuity factor was used for both outcomes. Furthermore, in order to get the electricity costs we need to subtract the costs for heat production by cogeneration units from the total annualised costs. For this purpose, we suppose that the heat also could have been produced by a boiler with an efficiency of 0.9 and, therefore, subtract for each PJ of heat produced: 0.9*gas price (in €/PJ) from the total costs.

[53] The *PostponedAction EV* variant is not presented, because it almost show a similar pattern as the analogue *NV* variant.

[54] These model results reflect the real life trend that energy prices have increased considerably between 2000 and 2005 (SenterNovem, 2005).

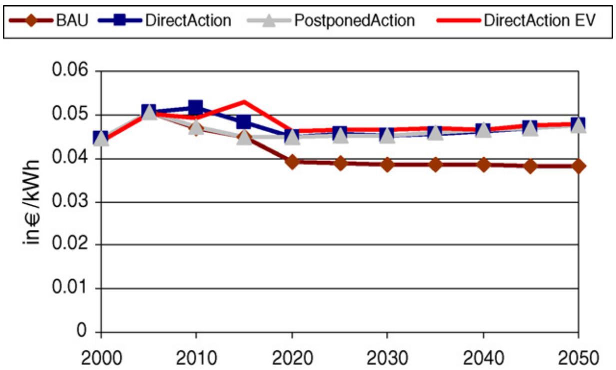

Fig. 10 – Cost of electricity.

higher than the COE in the *BAU* variant in 2050. In the *DirectAction EV* variant, the COE is highest in 2015 due to major retrofitting activities in this period.

- Because the reduction targets are only set from 2020 onwards, the COE in the *PostponedAction* is naturally lower than in the *DirectAction* variants before 2020. From 2020, the COE of the *PostponedAction* variants remains equal to those of the *DirectAction*. So no extra effort has to be made to achieve the 50% reduction target in 2050. However, the total cumulative CO_2 emissions over the whole model period of the *PostponedAction* variants are around 200 Mt higher compared to the *DirectAction* variants (which have cumulative CO_2 emissions of 2.7 Gt).
- In the reduction variants, the total electricity and heat generation costs in 2050 have doubled compared to 2000 due to the higher COE, higher gas prices, and because of the increase in final electricity demand from 101 to 175 TWh in 2050. However, in 2050, the GDP also has doubled compared to 2000. The net effect is that the CO_2 reductions in the electricity and cogeneration sector in 2050 can be realised with the same share of GDP as in 2000.
- Finally, Fig. 11 depicts the extra undiscounted annual costs that have to be spent in order to achieve the reduction targets compared to the *BAU* variants. For the *DirectAction NV* and *EV* variant respectively, around 7% (≈410 m€ per year) and 14% of the electricity production costs in 2015 is spent on mitigation measures and this share grows to around 17% in 2050 (≈1600 m€ per year). Again we see that in 2015 the costs in the *EV* variant are much higher, because of massive retrofitting activities in this period. *PostponedAction* variants show similar cost developments from 2020 onwards.

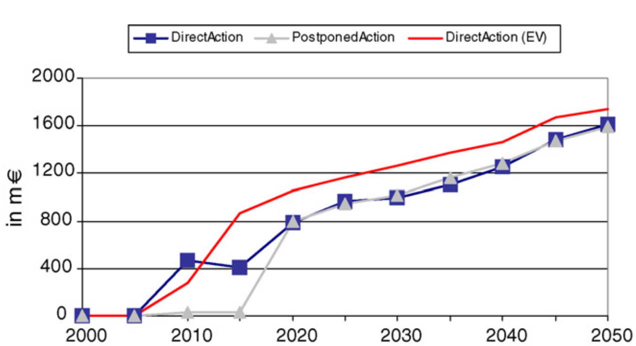

Fig. 11 – Undiscounted extra annual costs of reduction variants compared to *BAU* variant.

4.6. *Sensitivity analysis*

Table 9 presents the results from the MARKAL-NL-UU runs that were made for the sensitivity analysis. All results are compared to the main variant *DirectAction EV*. The results are presented for the medium (period I: 2015–2030) and the long term (period II: 2030–2050). In the *DirectAction EV* variant, CHP produces most electricity in the medium term, NGCC is on second, and IGCC-CCS is on third place with respect to electricity generation. The contribution of PC (without retrofit) is minimised to 5% of total electricity production in 2020. In the long term, IGCC-CCS takes over the first place. In many sensitivity variants, this pattern is repeated: a higher coal price, higher transport costs, a higher discount rate, no storage availability in the Netherlands, more flexibility of coal-fired plants, or the construction of coal-fired power plants in 2010 do not change the order of importance for electricity generation. However, in the following variants this order changes:

- When nuclear power is not restricted and no special nuclear waste fee is charged, IGCC-CCS is hardly used for climate mitigation over the whole model horizon. When a nuclear waste fee of 1 €ct/kWh is charged, nuclear and CHP are mainly deployed for CO_2 mitigation in the medium term and CCS does not play a major role yet. In the long term, IGCC-CCS and nuclear will contribute about equally to the electricity production.
- When the development of power plants with capture is slow, PC-CCS will play an important role in the medium term instead of IGCC-CCS. Improvements in costs and performance that can be achieved for IGCC-CCS are relatively high compared to PC-CCS, because IGCC itself is still in an early stage of commercialisation. However, these improvements are only realised when more IGCC plants are built. Since CO_2 capture is an important reason to switch from PC power plants to IGCC power plants, a slow development in CO_2 capture would also have a large negative impact on the cost development of IGCC-CCS.
- In some cases, IGCC-CCS takes over second place in the medium term instead of NGCC. This is the case when gas prices are higher, so it is more expensive to operate NGCC plants. Also when biomass prices are higher, IGCC-CCS will be deployed more to reduce the CO_2 emissions in the medium term and large-scale biomass use starts only from 2035.
- When cogeneration is not restricted, it keeps its dominant role in the electricity-generating park.

How much CCS is actually used in the different variants, can be deduced from the amount of CO_2 stored per year. In the *DirectAction EV* variant, 39 Mt per year is stored on average in the medium term and 58 Mt per year in the long term. In the following cases, we find major deviations from these figures:

- When bounds on nuclear without a nuclear waste fee of 1 €ct/kWh and cogeneration energy are released, the CO_2 stored reduces by respectively, 90% and 35% per year compared to the *DirectAction EV*.

Table 9 – Summary sensitivity analysis runs

Variant	How	P[a]	Three technologies that produce the most electricity (at the left: highest electricity production technology)			CO_2 stored	NPV total system[b]	Total discounted power sector costs
DirectAction EV		I	CHP	NGCC	IGCC-CCS	39 Mt/yr	124 billion euros	124 billion euros
		II	IGCC-CCS	CHP	NGCC	58 Mt/yr		
			1	2	3	% compared DirectAction EV	positive, negative or neutral effect[c]	
Flexible-load operation	Coal-fired technologies can operate in flexible mode instead of only base-mode	I.	CHP	NGCC	IGCC-CCS	2%	0	-0.2%
		II.	IGCC-CCS	CHP	NGCC	-5%		
Slow development of CCS	Advanced CCS technologies are 10 years later available	I.	CHP	NGCC	PC-CCS	-33%	-	1.6%
		II.	IGCC-CCS	CHP	NGCC	-2%		
Storage abroad	No Dutch storage is available. However, storage options in Norway is available.	I.	CHP	NGCC	IGCC-CCS	-34%	-	2.4%
		II.	IGCC-CCS	CHP	NGCC	-2%		
Higher onshore transport costs	Investment of onshore pipelines are tripled	I.	CHP	NGCC	IGCC-CCS	-3%	0	0.2%
		II.	IGCC-CCS	CHP	NGCC	-4%		
Almost half of the plans to build PCs and the IGCC plan are realised before 2012	min. bound PC-2015 = 2.0 GW, min. bound IGCC-2015 = 1.2 GW (in 2010)	I.	CHP	NGCC	IGCC-CCS	9%	-	1.2%
		II.	IGCC-CCS	CHP	NGCC	2%		
Almost half of PC plans and the IGCC are realised before 2012, but with capture units.	min. bound PC-post-2010 = 2.0 GW (in 2010), min. bound IGCC-pre-2015 = 1.2 GW	I.	CHP	NGCC	IGCC-CCS	5%	0	0.7%
		II.	IGCC-CCS	CHP	NGCC	4%		
Nuclear is allowed	No maximum bound on nuclear capacity	I.	NUCLEAR	CHP	NGCC	-97%	++	-7.0%
		II.	NUCLEAR	CHP	NGCC	-89%		
Nuclear is allowed, but with high waste fee	no maximum bound on nuclear capacity and 1 euro cent/kWh waste fee	I.	CHP	NUCLEAR	NGCC	-69%	0	-0.8%
		II.	CHP	NUCLEAR	IGCC-CCS	-49%		
Slow development of CCS plus nuclear	Advanced CCS technologies are 10 years later available + no nuclear bound	I.	NUCLEAR	CHP	NGCC	-98%	++	-6.9%
		II.	NUCLEAR	CHP	NGCC	-89%		
Cogeneration may increase	no cogeneration bound	I.	CHP	IGCC-CCS	NGCC	-35%	++	-5.7%
		II.	CHP	IGCC-CCS	NGCC	-34%		
Higher onshore transport costs plus nuclear	No maximum bound on nuclear capacity and investments of onshore pipelines are tripled	I.	NUCLEAR	CHP	NGCC	-98%	++	-7.0%
		II.	NUCLEAR	CHP	NGCC	-89%		
Biomass price remains high	biomass price remains at 6 Euro/GJ over the whole period	I.	CHP	IGCC-CCS	NGCC	0%	0	0.6%
		II.	IGCC-CCS	CHP	NGCC	5%		
very strict climate policy	CO2 bound is -80% instead of -50% (in 2050 compared to 1990)	I.	CHP	IGCC-CCS	NGCC	4%	-	3.3%
		II.	IGCC-CCS	CHP	NGCC	1%		
High discount rate	Discount rate is 10% instead of 5%	I.	CHP	NGCC	IGCC-CCS	-11%		-44.7%
		II.	IGCC-CCS	CHP	NGCC	-17%		
Coal price higher	Coal price increases to 2.0 euro/GJ in 2050 (+20%)	I.	CHP	NGCC	IGCC-CCS	-5%	0	0.3%
		II.	IGCC-CCS	CHP	NGCC	-4%		
Gas and coal price higher	Coal price increases to 2.0 euro/GJ in 2050 (+20%) and gas price increases to 6.7 euro/GJ in 2050 (+20%)	I.	CHP	IGCC-CCS	NGCC	0%	--	6.2%
		II.	IGCC-CCS	CHP	NGCC	0%		

[a] I refers to the period 2015–2030 and II refers to the period 2035–2050.
[b] ‘NPV (=net present value) total system’ stands for ‘total discounted costs of the electricity generation sector’ and is the end-value of the objective function after the linear optimisation process.
[c] Marks in this column refer to difference between NPV of specific variant and NPV of *DirectAction EV* in % (Diff_NPV). Mark is ‘0’ when −1% <Diff_NPV <1%, ‘+’ when −5% <Diff_NPV < −1%, ‘++’ when Diff_NPV < −5%, ‘–’ when +1% <Diff_NPV < +5%, or ‘–’ when Diff_NPV >5%.

- When progress in CCS technology is slow CO_2 storage is reduced by 33% in the medium term. However, in the long term, it hardly makes a difference.
- When storage locations are only available abroad, 34% less CO_2 is stored in the medium term compared to the *DirectAction EV* variant. Apparently, it is still worthwhile to store 25 Mt CO_2 per year in this period, although the transport costs have increased from 0.7 to 3.1 €/t CO_2 on average. Again, the difference in the long term can be neglected.
- The sensitivity variant in which PC power plants are constructed in 2010, shows that around 9% more CO_2 needs to be stored yearly to realise the CO_2 targets in the medium term because of less efficient coal-fired power plants which need to be retrofitted. In the *DirectAction* variants, construction of new coal-fired power plants is rather postponed to 2020 at which moment right away power plants with CO_2 capture are constructed.
- Also, in the variant in which PC-CCS plants and an IGCC-CCS are built in the short term, more CO_2 needs to be stored due to the less developed capture process.

In Table 9, we also compare the NPV (=value of the objective function) of the sensitivity variant with the NPV of the *DirectAction EV* variant. A change of parameter can have an effect that ranges from a very positive effect (NPV decreases by more than 6200 m€) to a very negative effect (NPV increases by more than 6200 m€). As can be deduced from the table, especially the raise in gas price (a very negative effect), and the release of bounds on CHP and nuclear without a nuclear waste fee of 1 €ct/kWh (a very positive effect) have a large effect on the NPV. In other cases, there is a slight negative effect (between 1% and 5% higher NPV) or hardly any effect. Note that a slight negative effect still may mean 100 million of additional yearly expenses for over many years. For example, the negative effect in the case that half of the PC plans and one IGCC are built in the short term, implies that around 2010 16 m€ per year has to be spent less for electricity generation, but from 2015 to the end of the model horizon 100–200 m€ per year needs to be spent extra.

5. Discussion

When we compare our results with outcomes of policy reports, the share of renewable energy in 2020 is low. In our study, renewable energy is only applied for 5–6% in 2020, and, except for onshore wind energy, does not appear to be a cost-effective measure to realise GHG reduction targets in the electricity sector. However, the Dutch government has an overall target of 20% renewable energy in the Netherlands for 2020 (CDA-PVDA-ChristenUnie, 2007). Therefore, special incentives will be necessary to ensure that energy companies invest in renewable energy: a follow-up of the Dutch feed-in tariff system as proposed by a combination of environmental organisations and unions, will be required (Green4Sure-project, 2007). This is even more important, if it is necessary to realise a larger share than 20% renewable energy in the electricity sector in order to achieve the national 20% renewable target. This may be the case, because it is relatively easy to introduce renewable energy in the electricity sector compared to other sectors such as industry or households.

We did not find the same conclusion as Viebahn who argued that in Germany a mix of renewable energy may be cheaper around 2033 than fossil-fired power plants with CCS (Viebahn et al., 2007). Partly, this may be caused by the fact that CCS is cheaper in the Netherlands, because of better storage opportunities, another reason is that for this study we did not consider thermal solar power from North Africa as an option for the Netherlands. Furthermore, assumptions on learning rates and performance developments are crucial in this type of analyses. A more in-depth comparison of these factors may give insight into the differences for Germany and the Netherlands.

In this analysis, we have ignored a few factors that may have an impact on the results. We only looked at CO_2 reduction measures in the Dutch power sector that generate electricity for Dutch consumers only. As our study shows, it is possible to store 31 Mt CO_2 per year in the period 2015–2030 and 56 Mt CO_2 per year between 2035 and 2050 from this sector alone. However, when also GHG reduction targets in other sectors and power generation for export are taken into account, it is most likely that it is cost-effective to store more CO_2 per year. As a consequence, the Dutch onshore sinks will be filled quicker and a call upon the more expensive storage locations offshore (either on the Dutch continental plate or abroad) is necessary before 2045. The option to store another 50–100 Mt per year from foreign CO_2 sources in the Dutch territory, as was put forward by the Workgroup Clean Fossil on CCS in the Netherlands (Workgroup-Clean-Fossil, 2007), would also imply that less 'cheap' storage is available for Dutch sources and a dense network to offshore gas fields is even needed earlier. Also the sensitivity analysis demonstrates that the competitiveness of CCS will decrease with less Dutch CO_2 storage available. Another question is whether it is not more cost-effective to generate electricity with CCS (or other CO_2-free products) in the Netherlands and to export this instead of storing CO_2 from abroad.

The load duration curve in this study is a simplified version of the real load duration curve. The curve is so to speak flattened. The reserve factor in the model makes up partly for this model caveat, because it ensures that sufficient capacity is installed to cover the peak load. However, the dispatch of the capacity is not according to real life: base load capacity will be dispatched more in the model, and peak load capacity less. The consequence of this caveat may be that the deployment of IGCC-CCS base load units is overestimated, which would make this option cheaper than in reality. A study with a more detailed load duration curve and more insight into how a power plant with CCS may be dispatched, can provide information to what extent the competitiveness of CCS may change.

Finally, in this study the calculation of the cogeneration potential does not take into account spatial variation of the heat demand. In the main variants, we solved this problem by adhering to the cogeneration potential of the SE scenario. However, the sensitivity analysis showed that a larger role of cogeneration can reduce the need for CO_2 storage by around one third. Also EnergieNed, a foundation for energy companies argued that the role of cogeneration may be bigger (EnergieNed, 2007). Although MARKAL-NL-UU does not deal with spatial aspect of cogeneration, more detailed cost-curves based on the spatial variation of heat demand, can be implemented into the model. More detailed cogeneration modelling, will also give more insight into the combination of district heating and CCS.

6. Conclusions

In this paper, we investigated how a trajectory towards an electricity sector with CCS may look like, and how it depends on climate policy, CCS technology development, competitiveness with other mitigation options, the need for new power plants, and availability of CO_2 transport and sinks. We carried out a quantitative scenario study for the electricity sector in the Netherlands using the bottom-up, dynamic, linear optimisation model MARKAL-NL-UU, generated with MARKAL. On the basis of cost minimisation, this model provided configurations of the electricity park for the period 2000–2050. We analysed strategies to realise a 15% and 50% reduction of CO_2 emissions in respectively, 2020 and 2050 compared to the level of 1990. Model results show that, if the Netherlands excludes nuclear power as a mitigation option and potential of cogeneration and onshore wind energy is limited, CCS is a cost-effective measure to avoid a considerable amount of CO_2

per year (around 29 Mt per year in 2020 and 63 Mt per year in 2050) in the electricity sector alone. In a direct action strategy in which CO_2 is reduced by 2.5% annually from 2010, the marginal cost of CO_2 is 50 €/t in 2015 and decreases to 25 €/t CO_2 in 2050. In a postponement strategy in which CO_2 is reduced from 2020, the high marginal CO_2 cost of 50 €/t CO_2 is avoided and will be 30 €/t CO_2 in 2020. In the first case, the construction of the necessary infrastructure to transport around 38 Mt CO_2 annually (in 2020) may be spread over 10–15 years and in the latter case over 5 years.

The findings highlight four important factors that stakeholders need to consider in planning climate change mitigation with CCS.

At first glance, it seems wise for policy makers to wait with a severe *climate policy* till 2020. At that moment, all CO_2 probably can be abated at less than 30 €/t CO_2. If one already starts in 2010, abatement costs increase to 50 €/t CO_2 in order to reach the reduction targets. Since it is not expected that the CO_2 price in the ETS system will be so high in the near future, this strategy would require additional subsidies or other incentives by the government. However, there are two possible disadvantages of a postponement strategy. First, the cumulative CO_2 emissions over the period 2000–2050 will be higher (around 7.4%) than when a strict climate policy is enforced from 2010. Secondly, we saw that in the postponement strategy, in a short period an infrastructure needs to be set in place for the transport and storage of around 37 Mt CO_2 per year. We expect that it is better to spread the construction over a longer period. Finally, it most likely depends on international agreements whether the Netherlands postpones action or not. In a worldwide postponement strategy, CO_2 capture technology may not improve as quickly as modelled in our study, and hence advanced capture technologies will not be available by 2020. In this case, the model results shows that on average 33% less CO_2 from the Dutch electricity park, will be stored between 2015 and 2030.

Concluding, if the Netherlands aims for substantial CO_2 reductions within its own boundaries before 2020, excludes nuclear, and has limited options to increase the share of cogeneration, cheap biomass, onshore wind energy, and energy saving, a climate policy is required that makes expenditures of 50 €/t CO_2 possible rather at the short term than later: a gradual increase of a CO_2 price would not be sufficient to gradually decrease CO_2 to −15% compared to the 1990 level between 2010 and 2020.

In view of the current plans of energy companies to build coal-fired power plants in the Netherlands in the short term, it may be of importance to realise that in a cost-effective CO_2 reduction strategy only between 3% and 8% of the electricity comes from coal-fired *power plants* without CCS in 2020. Ergo, most PC plants which exist today are either decommissioned, not operated anymore, or have been retrofitted in 2020. Furthermore, we conclude from the sensitivity analysis that, if PC power plants are constructed in 2010 (as is currently planned by energy companies), around 9% more CO_2 needs to be stored yearly to realise the CO_2 targets in the medium term because these 'less' efficient coal-fired power plants need to be retrofitted. According to our study, it is more cost-effective to postpone the construction of new coal-fired power plants to 2020. Therefore, we conclude that long-term certainty about CO_2 policy will improve planning of CCS, especially in a liberalised energy market in which energy companies tend to make investment decisions based on short-term priorities.

In the case that 80% of the Dutch CO_2 sinks is indeed available for *CO_2 storage*, the timing when these sinks become available does not seem to be a bottleneck for the storage of CO_2 emissions of the Dutch electricity sector according to the model results: sufficient storage remains available over the whole period. However, already by 2040 all onshore sinks have been filled (except for the Groningen field that will not be available before 2050) and a switch needs to be made to the small offshore fields. The availability of the Utsira field in Norway instead of Dutch sinks, does not change the deployment of CCS in the long term. Between 2015 and 2030, 34% less CO_2 will be stored, however, this still amounts up to 25 Mt CO_2 per year. It may, therefore, be valuable to explore the options to construct a trunk pipeline to one of the immense fields abroad.

Higher *transport* costs in the Netherlands itself have a limited impact on the cost-effectiveness of CCS. Most important is that the infrastructure is actually present when needed. Since already around 3 years are needed for legal procedures (Gasunie, 2005), and on top of that time for route selection and construction is required, early preparation for an infrastructure of some 450 km of CO_2 pipelines before 2020, is a pre-requisite for CCS to play a role as envisioned in this study.

Of course, in this analysis, we also ignored factors that are probably of importance for the planning of CCS. First, although the electricity sector is the most likely sector for CCS to play a role, a study about planning of CCS needs to include CO_2 reduction measures in other sectors as well, especially to grasp the consequences for CO_2 storage capacity and infrastructure. Insight into the competition with other measures, can be refined by including more details on the potential of cogeneration, and by considering several development pathways of renewable energy. Finally, how power plants can be dispatched in an electricity park in which intermittent renewable energy plays an important role, requires further investigation.

Acknowledgement

This research work was supported by the CATO programme. This programme is the Dutch national research programme on CO_2 Capture and Storage (CCS). CATO is financially supported by the Dutch Ministry of Economic Affairs (EZ) and the consortium partners (for more information, see www.CO2-cato.nl). We would like to thank Kay Damen and Lars Dittmar (UU), Policy studies and Hilke Rösler (ECN), and Pierre Ploumen (KEMA) for their contributions.

Appendix A. Description of cost parameters

The investment costs equals the total capital requirement (TCR) which includes the following three components (Damen et al., 2006) and (EPRI, 1993).

1. The total plant costs which is the costs to erect the plant, engineering costs and contingencies (due to estimation

errors or omissions). These costs also include auxiliary processes such as flue gas desulphurisation and dust removal.
2. The owner costs which are the costs to develop and start up the plant.
3. The interest costs that are made during the construction period. In MARKAL, the construction lead period is not explicitly modelled, therefore the investment costs should include interests during construction. For the technologies taken from (Damen et al., 2006), the assumptions were that a coal power plant is built in three years (for building years 1, 2, and 3 respectively, 30%, 30%, and 40% of the expenditure) and a gas fired power plant in 2 years (for building years 1, and 2 respectively, 40%, and 60% of the expenditure). With a discount rate of 5%, this leads to respectively, 5% and 2% extra costs on top of the investment costs of coal and gas-fired power plants.

The fixed operating and maintenance (O&M) costs include costs are the costs that are related to the installed capacity. These include:

1. Direct labour costs (for operation of the power plant). Often an average cost of an employee is estimated at €50,000 per year (IEA-GHG, 2003).
2. Administrative and general overhead (usually 30% of direct labour costs: EPRI).
3. Maintenance costs (a percentage of installed capital costs: EPRI). Maintenance costs include maintenance materials as well as hired maintenance labour costs. If maintenance materials are classified as variable costs such as in (EPRI, 2000), than this should be transferred to fixed costs.

Variable O&M costs are those costs that are relative to the activity level. These include consumables such as water, solvents, chemicals, and waste disposal. Fuel costs are not included in the variable O&M costs, but are calculated by the model by combining the marginal price of the input fuel and the efficiency of the plant. Possible benefits from selling by-products can be subtracted from the variable costs.

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