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The role of CCS in the European electricity supply system

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Abstract

This paper investigates the role of CO_2 capture and storage (CCS) technologies as part of a portfolio for reducing CO_2 emissions from the European electricity supply system until the year 2050. The analysis is carried out with a techno-economic model (minimizing the system cost) including a detailed description of the present stationary European electricity generation system (power plants) and potential CO_2 storage sites as obtained from the Chalmers Energy Infrastructure Database. Since the ability of different EU Member States and regions to facilitate and to benefit from CCS will most likely depend on local conditions in terms of current energy mix, fuel supply chains and distance to suitable storage locations, special emphasize is put on analyzing turn-over in capital stock of the existing power plant infrastructure, timing of investments and the infrastructural implications of large scale introduction of CCS on a regional perspective. The paper discusses the role of and requirements on CCS for meeting strict emission targets of 85% reduction while having a continued growth in electricity demand (according to EU projections). The results show that it is possible to meet an 85% CO_2 reduction target by 2050, but this will require large contribution from CCS. As expected, regions which are currently high in carbon intensity and which are located nearby suitable storage sites will benefit mostly from CCS as an option. With the assumption that CCS will be commercially available in 2020 the model results give a steep ramp-up in the use of CCS post 2020 which imposes challenges for timely investments in corresponding CCS infrastructure.

Keywords: CCS; EU-27; European; Electrcity; generation; system; Infrastructure

1. Introduction

The European Commission (EC) has adopted a target of limiting anthropogenic global climate change to 2ºC above pre-industrial levels, which according to the commission implies global emission reductions of greenhouse gases (GHG) of around 50% by 2050 relative to 1990 [1]. In order to achieve this it is proposed by the commission that mitigation levels of 30% emission reduction in GHG by 2020 and 60 to 80% by 2050 should be targeted for developed countries while negotiating international treaties. Corresponding estimates from the IPCC suggest global emission reductions of 50-85%, referring to CO_2 and relative to 2000 emissions, to enable stabilization at

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atmospheric levels of GHG on 440-490 ppm (~350-400 ppm CO_2), corresponding to a temperature increase of around 2.0 to 2.4 ºC [2]. This work focuses on reductions in CO_2 emissions within the European stationary power generation system and should be seen as an attempt to quantify possible contribution from CCS as part of a portfolio of mitigation options as a response to the emission targets given by the EC and the IPCC. Thus, the results should be seen as an example of a possible pathway for the power generation system up to the year 2050, however, not as an attempt to predict energy futures.

Fossil fuels have a strong position in current European power generation system with 50% of the electricity generated by coal and natural gas. Coal accounts for approximately 70% of the CO_2 emissions from the European power generation, corresponding to 24% of the CO_2 emissions from all sectors [3]. There is little doubt that fossil fuels will continue to account for a large share of global and EU energy conversion over the coming decades and up to the year 2050, even if there would be significant expansion in employment of renewable alternatives and efficiency measures, (e.g. World Energy outlook, [4]). Furthermore, there is a strong and increasing dependency on natural gas in European power generation sector. Thus, a continued and increased possibility to use coal as a fuel will enhance security of supply (SoS), but under strict CO_2 mitigation commitments such use can obviously only take place provided CCS becomes commercially available. Thus, if CCS becomes available and commercially viable it may, in addition to help reducing CO_2 emissions, enhance SoS in Europe through continued use of domestic and imported coal and provide necessary lead-time to develop a cost-efficient sustainable energy system.

A limited number of studies which specifically investigate CCS from an energy systems perspective can be found in literature (see Odenberger et al. [5] and references therein). These studies give valuable information on the possible role of CCS in a portfolio for CO_2 mitigation. However, there is a lack of studies which include a more detailed analysis on the ramp-up of CCS where the entire chain power plants, transportation systems and storage sites is analyzed from a systems perspective. The present paper is part of a work which has the aim to develop a methodology which combines energy systems modeling with an analysis of the CCS infrastructure. This requires the CCS infrastructure to be included in some detail but, not too detailed if to make use of energy systems modeling in at a reasonable complex level. In addition, the current power plant infrastructure should be included since the ramp-up of CCS is strongly dependent on the status and age of the present power plants. Thus, the aim of this paper is to investigate the ramp-up of CCS in Europe, including its implications on individual member states (MS). As indicated above, the present work does not aim to predict any energy future but to assess the effect of a CO_2 emission cap on the stationary energy system, with focus on the power generation system. Thus, the emission cap imposed in this work gives a cost of emitting CO_2 and can be seen as corresponding to an Emission Trading Scheme (ETS), but restricted to the European power generation sector.

2. Methodology

This study is based on scenario analysis with the aid of a techno-economic model linking the current power generation system with new investments to meet exogenously given electricity demand projections until the year 2050. Thus, the modeling takes advantage of the Chalmers Energy Infrastructure database (CEI db) which provides information on current power plants in Europe from which the vintage of the present system can be derived. In addition, the databases contain information on known CO_2 storage sites, i.e. crucial when making assumptions on national CO_2 storage potentials in terms of costs for transportation and storage. The database is described in detail elsewhere [6]. This paper is limited to the power generation system, including heat where this is produced in combined heat and power (CHP) plants supplying district heating (DH). The objective of the model (see [5] [7] for a detailed description) is to find the economic optimum fuel mix based on minimizing the net present value of the sum of annual costs of generating electricity in the MSs investigated (excluding taxes and subsidies) during the time period studied. The driving force to reduce CO_2 emissions is included through an endogenous price on CO_2 emissions, which is calculated in the model as the marginal cost of abatement through an exogenous emission cap given in the scenario. A scenario can be described as the exogenous assumptions and boundary conditions which define the solution space from which the economic optimum is calculated. The three main parameters in a scenario is demand side development, CO_2 constraints and estimated technical lifetimes for power generation technologies. The demand side development describes the expected annual growth rate of total electricity demand. CO_2

constraints are included as an annual cap that has to be met, and thus, gives a marginal cost of abatement. In addition, various parameters (e.g technology specific thermal efficiencies and fuel prices) and boundaries (e.g. national/regional RES potentials or national decisions on the phasing out of nuclear) are applied. A previous work by the authors employing the same model [5] modeled EU-25 as an aggregated region whereas modeling of individual MS regions was restricted to northern Europe (UK, Germany and the Nordic countries). This paper applies the same model as used previously but now regionalized for each MS in EU27 and Norway.

2.1. Scenario description

Although each MS is modeled separately, it is assumed that the total electricity demand within the entire region (EU-27 plus Norway) should be met on a common electricity market, but as a first approximation the net import/export is restricted to 20% of the yearly national demand, in order to reflect limitations in interconnections. National electricity demand, here defined as national electricity end use including distribution losses, for the model start year (2003) is taken from statistics [8] and the national annual growth rates from "European Energy and Transport – Trends to 2030" (EET) [9], with growth rates extrapolated to 2050. CO_2 constraints are included as a common annual cap which meets a 30% reduction by 2020 and 85% by 2050, relative to the 1990 emissions. Thus, it is assumed that emissions may be traded among the MSs in a similar manner as in the EU ETS. It should be noted that in order to comply with a total CO_2 reduction across the entire energy system, in level with EU and IPCC recommendations, other sectors would have to take on equal emission reductions.

Technical lifetimes and other technology specific parameters used in the modeling are listed in a previous work [5]. Limits on national renewable potentials (RES) are included as presented by the FORRES report "policy scenario" (EC, 2004), which describes maximum potentials that is estimated to become available by 2020. After 2020 the assumed limitations on national wind power potentials are related to the national electricity demand. Thus, for MSs which have the possibility of installing wind power both on- and offshore it is assumed that electricity output from wind power could reach 20% of the national electricity demand (7.5% of demand from onshore wind and 12.5% from offshore wind), but only if this value is larger than limits given by the FORRES report. Corresponding figure for MSs without costal shoreline is assumed to 7.5% of the national electricity demand, and hence, only considers onshore wind. Furthermore, biomass is assumed to have an additional unrestricted international market but at a higher cost than for the domestic biomass. In addition, upper limits are included for lignite and nuclear, where lignite fuel production levels are kept constant and limited to regions where it is currently available. It is assumed that nuclear reinvestments may take place up to current levels from 2020 and onwards except for Germany and Belgium, which currently are the only MSs with a firm decision on phasing out nuclear (i.e. current political decisions are applied in this paper). Fossil fuel prices are assumed to follow development as described in EET [9] whereas biomass prices are based on price estimates for cultivated energy crops [10] [11], i.e. 25 €/MWh_{fuel} (with 26 €/MWh for fuels from the international market).

CCS technologies are assumed to be commercially available from 2020 and onwards and the costs associated are based on the EU funded project "Enhanced CO_2 capture" [12]. Demonstration projects which are planned to be put into operation prior to this year are assumed to have a negligible influence on the total electricity generation, and thus, not included in the modeling. Further costs associated with CCS are the costs for transportation and storage. Based on national storage location, storage potentials and the location of present power plant sites all MSs are divided into three cost categories, as described by Kjärstad and Johnsson [13]. The assumed costs for transportation and storage for the three categories and how they are allocated to the different MSs are listed in Table 1. Power plants that have co-generation of electricity and heat are included in the modeling in two different ways. Auto-producer industrial backpressure (BP) is assumed to generate electricity at an assumed electrical efficiency equal to total efficiencies for cogeneration applications, and thus, in this way only the electrical part and corresponding fuel consumption of the generation are considered in the modeling. In addition, it is assumed that the amount of electricity produced in BP remain constant throughout the period investigated. Combined heat and power (CHP)

Table 1 Assumed member state specific costs for transportation and storage of CO_2 captured in CCS technologies. Costs estimates in each category based on known national storage potentials and locations of present point sources (power plants) as described by Kjärstad and Johnsson [13]. The costs given are from preliminary work and will be refined in the near future.

Category 1 (5 €/ton CO_2)	Category 2 (7.5 €/ton CO_2)	Category 3 (10 €/ton CO_2)
Bulgaria, Czech Rep., Denmark, Germany, Hungary, Ireland, Italy Latvia, Netherlands, Norway, Poland, Romania, Slovakia, Slovenia	Austria, Belgium, France, Greece, Spain, Sweden, UK	Cyprus, Estonia, Finland, Lithuania, Luxembourg, Malta, Portugal

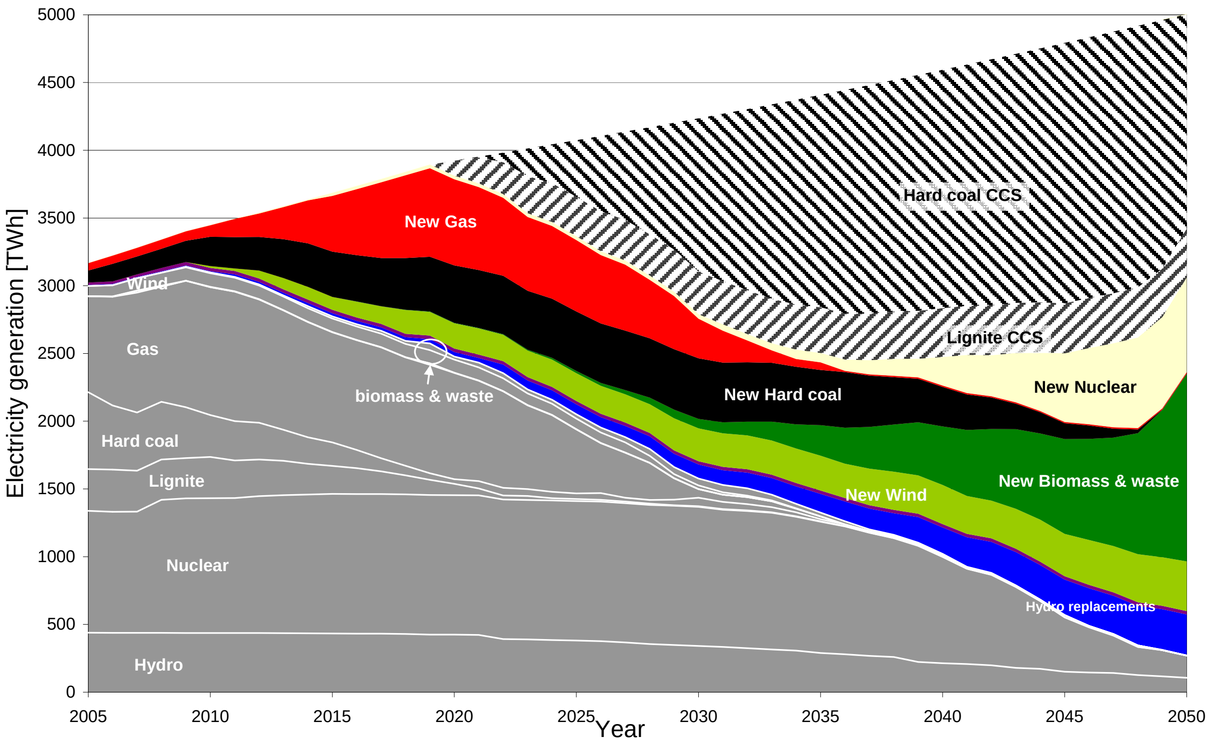

Figure 1 Electricity generation in EU-27 plus Norway aggregated from member state results as derived from the model. Grey field at the bottom represent contribution to electricity generation from present system where fuel mix is indicated by white lines.

is given both an electrical efficiency and a total efficiency from which an electricity to heat ratio can be determined. Furthermore, setting a heat demand for district heating (DH) as an exogenous scenario parameter that has to be fulfilled generates a shadow price on heat, which drives investments in CHP plants that obviously have a lower electrical efficiency compared to condensing applications. The assumed overall development for DH is based on the results from the “Ecoheatcool” project [14], which investigates national implications of doubling total European heat sales. Thus, the estimated national heat demand, corresponding to a European doubling, is used as a first approximation for MS heat demand in this study. Yet, this study only considers CHP, i.e. heat only boilers are not included, and hence, the heat demand included in this study refers to the part of the heat demand which can be covered with CHP. For this matter it is assumed that the projected heat demand will be covered by CHP starting at current levels in each region and increased linearly to reach 80% of total DH demand by 2050. The discount rate applied in all calculations is set to 8% [11].

3. Results

Figure 1 presents the results from the scenario as the aggregate electricity generation development for all regions included, i.e. EU-27 plus Norway. Under the conditions studied it is clear that until 2020 emission reductions are more or less a result from fuel shifting from coal to gas by replacing old low efficiency coal fired power plants (lignite and hard coal) with natural gas fired combined cycle plants, which is already an ongoing trend. However, significant amounts of wind power enter the system between 2010 and 2015 in MSs that have the highest expected annual load hours. The grey field at the bottom of the figure represents the contribution to generation from the present system, which also illustrates the long lived nature of the capital stock in power generation systems, given the assumed technical lifetimes. After 2020, when CCS is assumed to become available, it can be seen that lignite and coal fired CCS technologies are cost competitive mitigation options. It should be noted that although gas fired CCS technologies is included as an option these are not competitive in any member state due to comparatively lower carbon intensity of natural gas and the fuel price relationship between coal and gas as given by the EET. The ramp up of CCS technologies is strong with about 200 GW of capacity installations within the first decade (2020-2030) and then another 100 GW of capacity until the plateau in 2045. Corresponding numbers for electricity generation are about 1 400 TWh of electricity generation from CCS technologies in 2030 and roughly 2300 TWh around the plateau in 2040-2045. The implications of large scale CCS on coal markets, i.e. about a doubling of coal utilization, may result in issues concerning SoS and fuel supply logistics as pointed out by Kjärstad and Johnsson [13]. Thus, the results should be seen as an indication that an 85% reduction in CO_2 emissions is possible and that CCS can be a key technology to reach such goal. Figure 2 outlines technology specific emissions from the system, equivalent to the given emission cap, and the annual amount of CO_2 captured by CCS after 2020. The cumulated amount of emissions over time period studied is about the same as the cumulated amount of CO_2 captured by CCS between 2020 and 2050, i.e. about 39 Gt CO_2. Marginal cost of electricity starts at about 40 €/MWh and increase steadily to about 55 €/MWh by 2020, followed by a minor increase up to around 60 €/MWh towards the end of the period studied. The corresponding marginal cost of CO_2 abatement starts at about 20 €/t CO_2, reaching about 40 €/t CO_2 by 2030 with a stabilization around 42-45 €/t CO_2 over the last 20 years. This is similar to what is expected within the EU ETS [15].

It is important to note that given the capture rate assumed for CCS technologies (about 90%), these technologies yield significant emissions (Figure 2). Hence, by the end of the period studied, i.e. after 2045, the emission cap

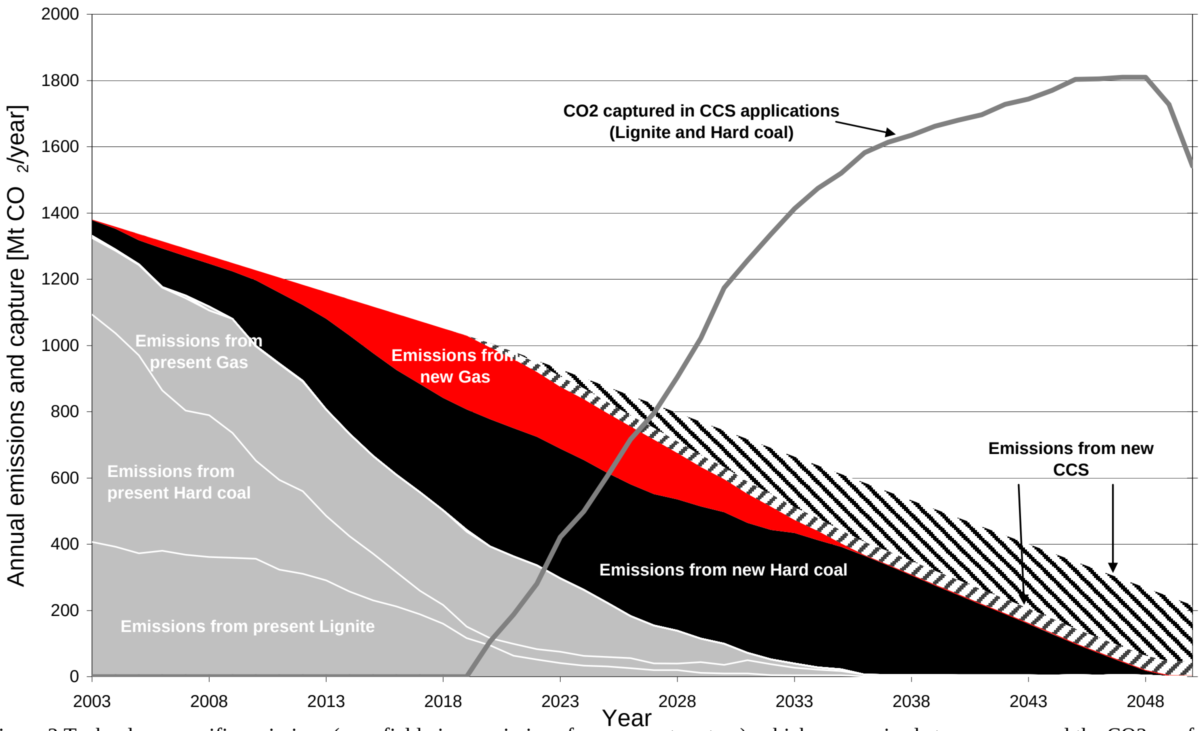

Figure 2 Technology specific emissions (grey field gives emissions from present system), which summarized at any year equal the CO2 cap for that year. Grey line show the annual amount of captured CO2 in CCS technologies between 2020 and 2050.

becomes too strict even for the amounts of emissions from CCS. The result in the modelled scenario is reduced generation in CCS in the end of the period with a rapid expansion in biomass, here configured as condensing plants since the heat demand is fulfilled. However, if biomass can be co-fired in CCS by roughly 10% in terms of supplied fuel energy the net emissions from such configurations would be about zero. Thus, it becomes important to know what should happen with the emission cap after the modelled period. If the assumed emission reduction trend should be continued down to zero emissions from electricity generation, then all CCS plants should be of co-firing type prior to the year when zero emissions is expected, else retro-fit of co-fire technology must be an option. Obviously, if emissions 2050 and beyond are to be stabilized at 85% below 1990 emissions, a certain share of CCS technologies can be without biomass co-firing. Other possibilities for reaching 85% emission reduction (or higher) without displacement of CCS in the last few years of the period would be advances in CCS technologies with increased capture rates (towards zero emission) or employment of larger amounts of RES, which in this case based on the cost assumptions, should be limited to larger potentials of wind in MSs that have the highest expected annual wind load hours. Yet, lower electricity demand, i.e. another scenario than included in this paper, would of course reduce the challenge to meet 85% emission reduction. Regarding the total RES levels that enter the system, i.e. the part of the potential in the scenario that is realized in the modelling, it can be seen that by 2020 about 20% of the electricity generation comes from RES (hydro, wind and biomass). At the end of the period studied, just before the CO_2 cap enforces shifting some generation from CCS to biomass condensing, the RES level is about 35% (including import from the international biomass market). As mentioned, wind is most competitive in regions with the highest expected annual load hours, which result in fully utilized potential in “windy” MSs, whereas less “windy” MSs the wind power potential is not entirely employed. Hence, by 2050 about 360 TWh of wind electricity generation have entered the system of which most is wind onshore in “windy” MSs. This should be compared with the scenario potential of about 950 TWh (7.5% of generation for onshore wind in all MSs and 12.5% of generation in MSs with offshore possibilities, i.e. 410 TWh potential for onshore and 540 TWh for offshore by 2050). This indicates wind power would need extra subsidies or technical advances in order for the potential to be fully utilized. This may occur not only from the improvements in the technology itself but also from improved wind power integration strategies. Yet, siting may be an issue, especially onshore. Large scale penetration of biomass occurs during the last 20 years even if the driving forces are limited to a cost on emitting CO_2 (the included cap and corresponding marginal cost) and a shadow price on heat. To achieve about 1 400 TWh of electricity generation from biomass by 2050 (about 850 from CHP) requires about 3 000 TWh of biomass fuel, whereas the national potentials as given by FORRES amounts to about 1 300 TWh biomass fuel. Hence, if the national potentials cannot be expanded further after 2020 some 1 700 TWh of biomass would have to be supplied by an international market, which is roughly equal to 6% of the global biomass trading potential in 2050 (about 100 EJ, i.e. 28 PWh) as estimated by Hansson et al [16].

The national implications of the results of this work, in terms of CO_2 emissions and captured CO_2, are summarized in Figures 3 and 4. It can be seen that currently a handful of MSs dominate the European emissions from electricity generation, which is also the case when capture becomes available. Figure 4a shows that currently the emissions from the top six CO_2 emitting MSs account for roughly 75% of European emissions from power generation. Figure 4b indicate that the same MSs will benefit the most from CCS according to the results of this work, i.e. the same six MSs account for approximately 80% of the capture in the end of the period. Hence, in 2050 these MSs will have to provide a required CO_2 transportation system handling 150Mt (the Netherlands) to 500Mt (Italy) of CO_2 annually. Yet, the timing of investments for such pipeline networks may become a critical issue, in terms of matching sources (phasing in CCS power plant clusters) and sinks (storage sites), while having a long term plan to enable dimensioning the network corresponding to maximum transportation capacity. The result is especially noticeable for Italy which accounts for about one third of all captured CO_2 by the end of the period studied. Once again it should be stressed that the calculations are not predictions of energy futures and does not consider investors perspective but merely the magnitude of requirements of various technologies for each MS, under the assumptions applied. The current Italian power generation system is dominated by fossil fuels, especially natural gas fired combined cycle power plants, and since new nuclear in this scenario is only considered in MSs where nuclear is currently available (not in Italy), the only competitive alternatives by 2050 is RES (full exploitation of domestic hydro, onshore wind and biomass) and CCS. In addition, Italy is estimated to be a Category 1 member state in terms of storage applicability (Table 1), and hence, CCS may (or should) be a key technology to achieve large CO_2 reductions. The current structure of Italian power plants can be characterized by clusters of power plants with concentrated ownership, which should be favourable when building transportation bulk pipelines as discussed by Kjärstad and Johnsson [13]. In addition, significant storage possibilities are available close to such clusters and the storage potentials for these storage sites are expected to be sufficient.

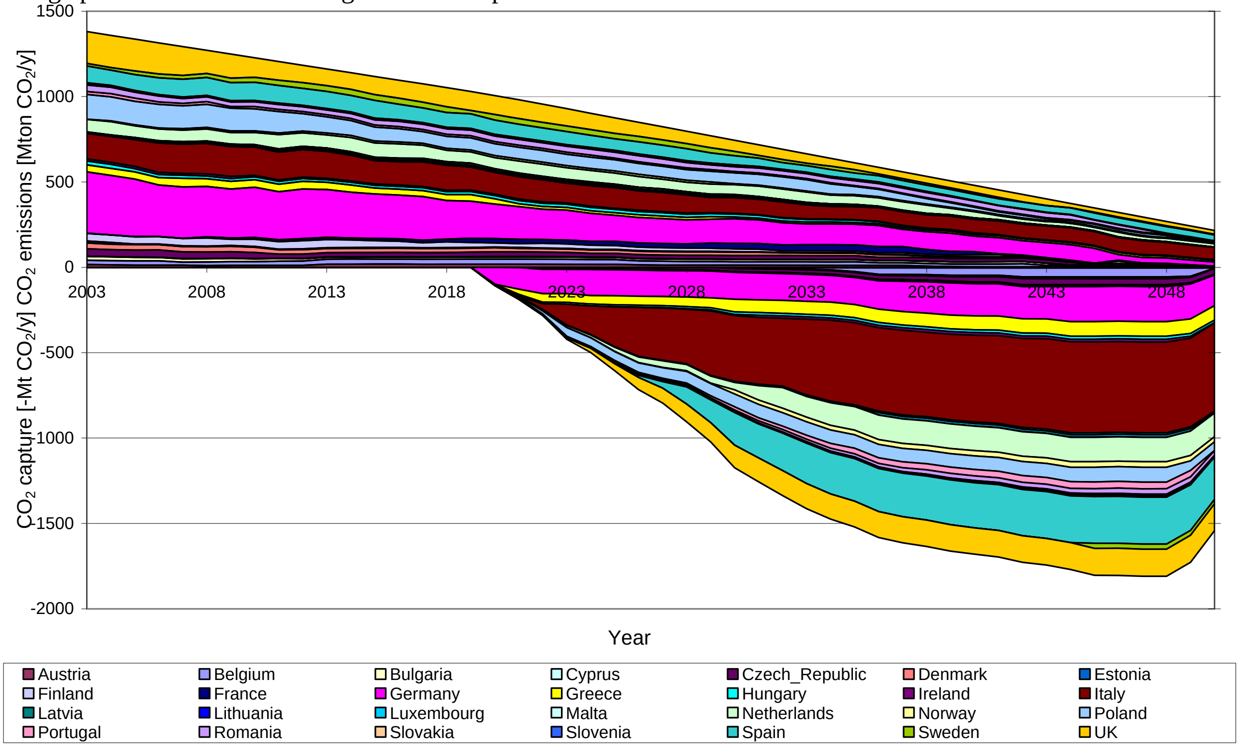

Figure 3 Member state emissions plotted as positive values and member state capture plotted as negative values, as derived from the model. Emissions equal the commonly included cap.

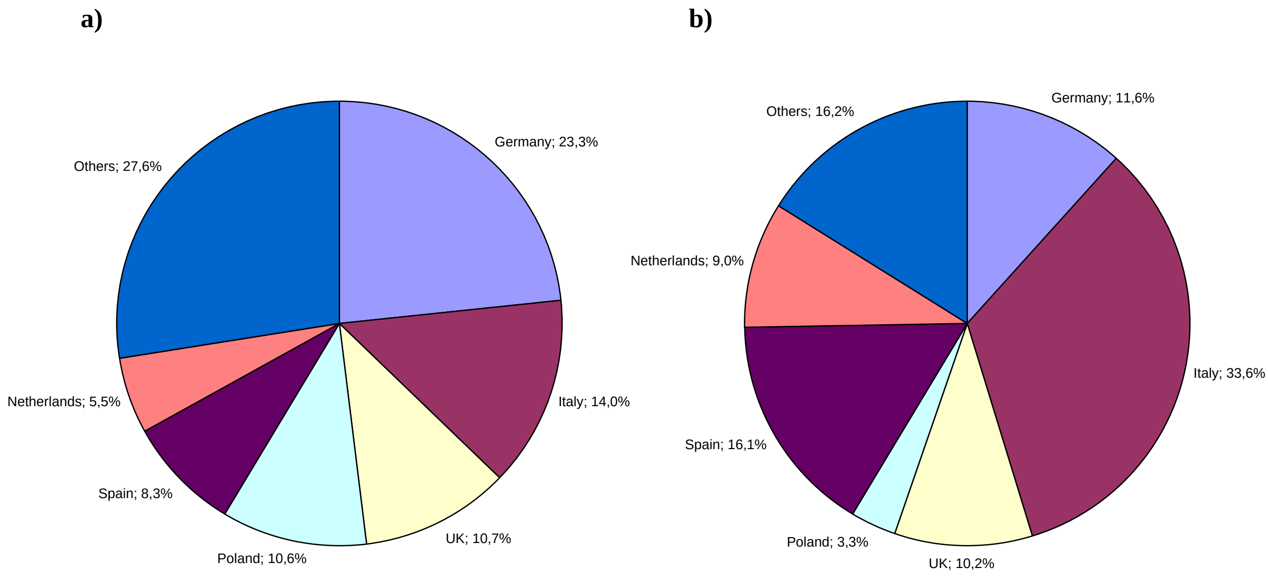

Figure 4 Division of CO_2 emissions in 2008 (a) and captured CO_2 in year 2050 (b) within EU-27 and Norway, with six key countries indicated.

4. Conclusions

An assessment of CCS for EU27 and Norway has been made applying the Chalmers Energy Infrastructure database (power plants and CO_2 storage sites) and by techno economic modeling of the power generation sector using a model which is regionalized down to the individual MS. The scenario studied corresponds to a 30% CO_2 reduction by 2020 and an 85% reduction by 2050 (with 1990 as base year). With these reductions, substantial amounts of RES based electricity generation enters the market, i.e. wind power and biomass based power generation are to a large extent competitive mitigation options with the cost of emitting CO_2 which follows from the cap. However, based on the assumptions in the investigated scenario it is clear that lignite/hard coal CCS, once assumed commercially available after 2020, is also a cost competitive option in the portfolio of technologies required to meet the target. In all, the costs to meet the target range from 20 €/t CO_2 to 45 €/t CO_2 over the period studied. With the costs applied, all CO_2 capture is from coal as a fuel (lignite and hard coal) whereas capture from natural gas fuelled generation is not competitive. Cumulated emissions and capture are roughly equal over the period studied, i.e. about 39 Gt each. The CCS ramp-up is strong; with a capacity build up of about 200 GW during the first decade after CCS is assumed commercially available (in 2020) and another 100 GW between 2030 and 2045. The current top six CO_2 emitting countries (electricity generation), accounting for about 75% of European emissions, also get the highest demand for large scale CCS applying the cost of this work. Hence, once the large scale CCS system is put in place these six MSs have the potential of accounting for roughly 80% of the CO_2 captured in European CCS infrastructure. Thus, these countries are considered to have promising conditions for establishing large scale transportation and storage systems but this also implies that these countries are most dependent on successful development of CCS technologies.

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