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CCS in the European Electricity Supply System – assessment of national conditions to meet common EU targets

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Abstract

This paper investigates how the European electricity generation system can meet deep cuts in CO2 emissions until the year 2050 with special focus on national conditions for CCS. An 85% reduction in CO2 emissions until 2050 is imposed. 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. The modeling puts a cap on CO2 emissions from the system which gives a price on these emissions, i.e. similar to the effect of the European Emission Trading Scheme (EU-ETS), which is the main policy instrument for controlling GHG emissions within EU. 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, including the effect of investing in new transmission capacity between member states. The work compares two scenarios, one used in a previous work with significant growth in electricity consumption and one assuming that energy efficiency measures are successfully applied in line with the recent EU energy policy package.

The results show that it is possible to meet an 85% CO_2 reduction target by 2050 at a cost of some 50 to 80€/ton CO2 over the period up to 2050, but this will require large contributions from CCS and electricity from renewable sources (mainly wind and biomass). Yet, without significant energy efficiency measures it is questionable if such large investments in generation technologies are feasible. Thus, to reach an 85% reduction in CO2 emissions from the electricity generation system by 2050 is not a matter of choice between different technologies and energy efficiency measures but all of these are required and the crucial point is if there will be a high enough price on CO2 emissions.

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

1. Introduction

The European Commission (EC) has since several years ago adopted a target of limiting anthropogenic global climate change to 2ºC above pre-industrial levels [1]. As concluded in [1], this implies global emission reductions of greenhouse gases (GHG) of around 50% by 2050 relative to 1990. In order to achieve this the commission proposes

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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. This is based on climate modeling work such as reported by IPCC suggesting global emission reductions of 50-85%, referring to CO2 and relative to 2000 emissions, to enable stabilization at atmospheric levels of GHG on 440-490 ppm (~350-400 ppm CO2), corresponding to a temperature increase of around 2.0 to 2.4 ºC [2]. This paper provides results from a study on possibilities for reductions in CO2 emissions within the European electricity generation system with the aim to quantify contribution from CCS as part of a portfolio of mitigation options as a response to the emission targets given by the EC. The work continues previous work given in [3] and concerns the time period up to year 2050.

Currently, 50% of the electricity in Europe is generated by coal and natural gas with coal being responsible for approximately 70% of the CO2 emissions from this sector, corresponding to 24% of the CO2 emissions from all sectors [4]. Due to obvious restrictions in the turn-over in capital stock of power plants and associated infrastructure, it seems clear that fossil fuels will continue to account for a large share of global and EU energy supply over the coming decades, even if there would be significant expansion in employment of renewable alternatives and efficiency measures, (e.g. World Energy outlook, [5]). There is at the same time an 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 CO2 mitigation commitments this can obviously only take place provided CCS becomes commercially available. Thus, if CCS becomes commercially available it may, in addition to help reducing CO2 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.

Although there are extensive research and development of all steps of the CCS chain capture, transport and storage, there are surprisingly few studies in open literature which give a detailed analysis on the ramp-up of CCS where the entire CCS chain is analyzed from a systems perspective, including analysis of a transport and storage infrastructure as in [3]. Recently, studies have started to emerge (e.g. [6, 7, 8]) and the aim of the present work is to continue to develop a methodology which combines energy systems modeling with an analysis of the CCS infrastructure where the CCS infrastructure is included in some detail but, not too detailed if to make use of energy systems modeling in at a reasonable complex level. The work combines a techno economic modeling with an analysis of the transport and storage infrastructure required to meet the CO2 flows obtained from the modeling. The latter reported separately [9]. The modeling uses the current power plant infrastructure as input since the ramp-up of CCS is strongly dependent on the status and age of the present power plants. The work does not aim to predict any energy future but to assess the effect of a CO2 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 CO2 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 plant infrastructure with new investments to meet exogenously given electricity demand projections until the year 2050. The current power plant infrastructure is taken from the Chalmers Energy Infrastructure database [10], 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 CO2 storage sites, i.e. used for making assumptions on national CO2 storage potentials with respect to costs for transportation and storage. 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 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) over the time period studied. The driving force to reduce CO2 emissions is included through an endogenous price on CO2 emissions, which is calculated in the model as the marginal cost of abatement through an exogenous emission cap given in the scenarios investigated. A scenario corresponds to 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, CO2 constraints and estimated technical lifetimes for power generation technologies. The demand side development describes the expected annual growth rate of total electricity demand. CO2 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. The model includes EU27 and Norway and is regionalized with respect to these countries.

Compared to the model used in the previous work [11] by the authors [3, 8], the present work uses an improved model which includes current limitations in transmission capacities between the countries as shown in Figure 1 and which allow investments in new transmission capacity. The model divides a year into 16 time steps with respect to season (winter, spring, summer, autumn), week (weekday, weekend) and time of day (night, day). Wind power production is based on the methodology given in [12] with the hourly distribution according to the 16 time steps. Hydropower is divided into run-of-river and controllable (impoundment) hydro plants.

2.1. Description of scenarios

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, with import/export restricted to limitations in interconnections (current transmission capacity + investments in new capacity when profitable in model). Thus, it is assumed that emissions may be traded among the MSs in a similar manner as in the EU ETS. National electricity demand, here defined as national electricity end use including distribution losses, for the model start year (2003) is taken from statistics [13] and the development of the demand up to 2050 is specified in two scenarios, both with a CO2 reduction of 85% to 2050, relative 1990 emissions and with the following specifications:

Market. National annual growth rates from "European Energy and Transport – Trends to 2030" (EET) [14], with growth rates extrapolated to 2050. CO2 constraints to 2020 are included as a common annual cap which, based on the common total EU goal of 20% GHG reduction to 2020 relative to 1990, according to [14] corresponds to a 30% reduction in CO2 emissions for the electricity generation system. Electricity from renewable energy sources (RES) is according current 20% EU target for 2020, here assumed as a common target for the region studied and interpreted for the electricity system (RES-E) from the PRIMES results in EET to 30% RES-E 2020. Post 2020, RES-E is only an effect of the CO2 reduction target. Existing nuclear power plants are allowed to reinvest after 2020 up to 140% of current capacity in 2050 (also in Germany and Belgium, i.e. assuming current decisions on phase-out are changed). Investment cost for nuclear assumed to be 3000€/kWel (in year 2005 currency). CCS costs taken from the EU ENCAP project [15] but increased with 30%. The 30% increase is arbitrarily chosen to reflect a possible high demand on the power plant manufacturers since the previous work for a similar scenario [8] resulted in very high yearly investments in CCS plants.

Policy. National annual growth rates includes efficiency target of 20% relative to the EET baseline which, for the electricity sector is assumed to give a 13% reduction to 2020 (relative to the baseline presented in EET, which are the same as in the Market scenario growth rate). CO2 constraints to 2020 reflects the higher ambition as strived for while negotiating international treaties, i.e. an overall target of reducing GHG by 30% relative 1990 emissions. According to [16] this implies that the reduction in CO2 required within the power generation sector should be 40%. Assuming the efficiency improvement continues to 2050 with a total reduction of 35% relative baseline will result in 23% lower electricity consumption than in the Market scenario. RES-E is as in the Market scenario up to 2020, but with a continued ambition of RES-E targets post 2020, assuming 45% RES-E by 2050. There are re-investments in nuclear in existing plants, but not in Germany and Belgium for which current political decisions are assumed to remain. Cost for CCS according to [15].

Post 2020 the annual CO2 emission caps in both scenarios are reduced linearly to meet the same 85% emission reduction by 2050. In summary, the Market scenario can be seen as a scenario where there are less policy measures in addition to the price on CO2 emissions also reflecting previous experiences on the difficulty of implementing energy efficiency measures whereas the Policy scenario assumes targeted policies on energy efficiency and RES based energy to be successfully implemented.

Technical lifetimes and other technology specific parameters used in the modeling are given in previous work [8]. Limits on national renewable potentials (RES) are taken from [17], which describes maximum potentials that are estimated to become available by 2020. The present model includes a cost-supply curve on biomass regionalized on a member state basis, based on [18], yielding the price of biomass (with a maximum cost of 30 €/MWh, corresponding to import price from an international market). 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. Fossil fuel prices are assumed to follow development as described in EET [14].

CCS technologies are assumed to be commercially available from 2020. 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 the

MSs (+Norway) are divided into three cost categories, as described in [19] (5, 7.5 and 10 €/t CO2, depending on region). Thus, this is a first approximation and a refined analysis of the transportation cost is given in the parallel work for selected countries [9].

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) 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. In the Market scenario, the assumed overall development for DH is based on the results from the "Ecoheatcool" project [20], 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. In the Policy scenario, there is lower growth in heat sales of around 50%. 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. In this respect 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% [21].

3. Results

Figure 2 presents the results from the two scenarios as the aggregate electricity generation development for all countries included, i.e. EU-27 plus Norway. 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 (plants phased out when they are not profitable to run any more or when they have reached the assumed technical lifetimes). For the Market scenario natural gas serves as a bridge to the low emission system. The emission reductions until 2020 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. For the Policy scenario, demand side energy efficiency measures result in much less investments in natural gas and some coal without CCS due to less effects from the ETS with lower price on CO2 (which would be due that several targeted policy measures on RES and demand-side energy efficiency limit the CO2 emissions). Thus, in the policy scenario there is room for more reinvestments in conventional coal in the period up to when CCS becomes available. It should be noted that the emission cap for the European system to 2020 is tighter in the Policy scenario (but the 2050 target is the same). Yet, in the Market scenario the overall reductions may be the same with EU taking part in flexible mechanisms, i.e. with some of the reductions in other regions.

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 in both scenarios. Although gas fired CCS technologies are included as options, 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. In the Market scenario, the ramp up of CCS technologies is strong with about 65 GW of capacity installations within the first decade (2020-2030) and then another 200 GW of capacity until the plateau in 2045 (yielding annual capacity additions of up to 30GW/year). This is similar to a previous work [8] in which it was concluded that such large expansion in CCS would be a challenge for the boiler and fuel markets.

In the Market scenario, cumulated amount of emissions over time period studied is about 37 Gt CO_2 and the cumulated amount of CO2 captured by CCS between 2020 and 2050 is about 24 Gt CO2. Marginal cost of electricity starts at about 50 €/MWh and increase steadily to about 80 €/MWh by 2050. The corresponding marginal cost of CO2 abatement starts at about 10 €/t CO2, reaching about 40 €/t CO2 by 2030 and about 80 €/t by 2045. The last few years the model results indicate a sharp increase in CO_2 cost climbing from 80 €/t in 2045 to about 250 €/t in 2050. The significance of this behavior the last few years depend on costs and technology options available in the model the sharp increase is obviously an effect of that only known technologies are included in the technology portfolio. In all, the CO2 cost is similar to what is expected within the EU ETS [22] up until 2020-2030. In the Policy scenario, about 15 Gt CO2 is captured between 2020 and 2050. Marginal cost of electricity over the period range from 50 €/MWh in 2020 to around 60 €/MWh in 2050. This corresponds to a marginal cost of CO2 abatement ranging from 10 €/t to 25 €/t CO2 by 2030 and a steady increase to about 50 €/t CO2 by 2050. In addition, the RES targets prescribed in the policy scenario would require a support scheme of about 25 €/MWh RES-E from 2020 and onwards, in the modeling corresponding to a green certificate scheme.

As expected, CCS is first implemented in the countries which have lignite resources and with lowest costs for transport and storage. Figure 3 shows the overall distribution of CCS between member states as obtained from the modeling in the two scenarios. Thus, in the Policy scenario not only is there less CCS based generation (Figure 2), but CCS is also more geographically restricted. Northern Europe obviously has a low need of CCS due to low carbon intensity in existing system (if applying the assumptions made on reinvestment in nuclear power) and large amounts of RES-E. In western Europe, the modeling gives for both scenarios that basically all conventional coal based generation is replaced with corresponding electricity generation from CCS and this is also more or less the case for eastern Europe. In southern Europe, there is a great need for CCS, especially in the Market scenario where the amount of CCS in the end of the period would correspond to doubling of present conventional electricity generation from coal and oil.

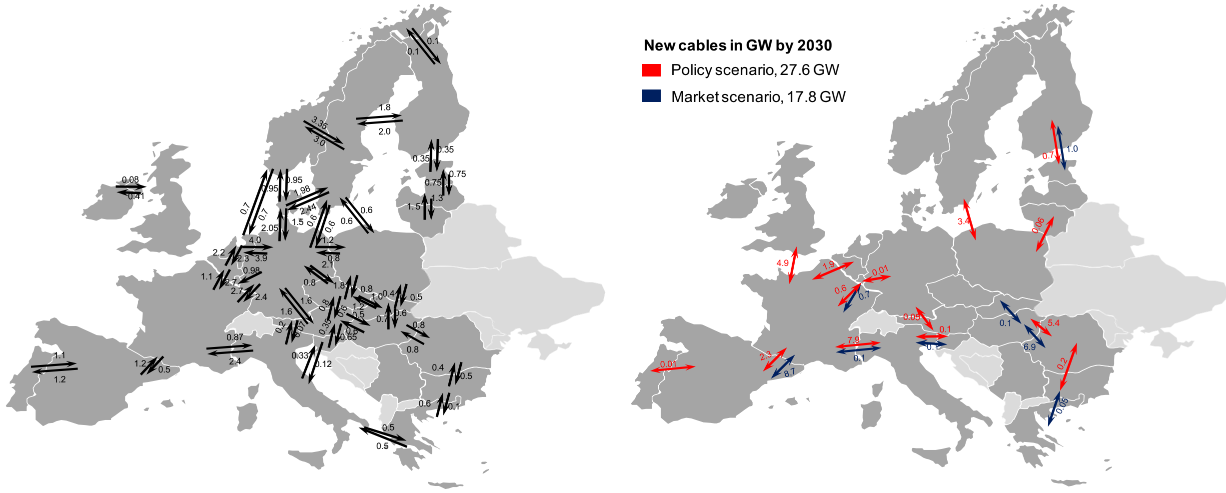
With respect to RES electricity at the end of the period (2050), both scenarios give similar amounts absolute terms of biomass, and wind but with slower penetration in the Market scenario – especially for biomass - for which, post 2020 it is only the CO2 price which drives the expansion in RES. Eastern Europe has a high potential for biomass which can be clearly seen from the modeling results, especially in the Market scenario (due to the higher CO2 price in this scenario) but there is at the same time a low expansion in wind power due to low full load hours for wind power. Yet, in the Policy scenario the fraction of RES electricity as well as intermittent electricity is higher than in the Market scenario.

Modeling allows expansion of nuclear power with up to 40% (capacity) in the Market scenario. Yet, this has only a considerable effect in Western Europe, which is expected since this is where most of current nuclear power is located.

Figure 1b illustrates the expansion of transmission capacity as obtained by the model for the two scenarios (year 2030 is shown). New transmission capacity is required in order to balance an increased share of base load plants (CCS, nuclear) in both scenarios and in order to best utilize the large potentials of RES-E in some member states. There is a higher expansion in transmission capacity in the Policy scenario than in the Market scenario, due to the larger fraction of intermittent RES-E generation (i.e. wind power) in the Policy scenario.

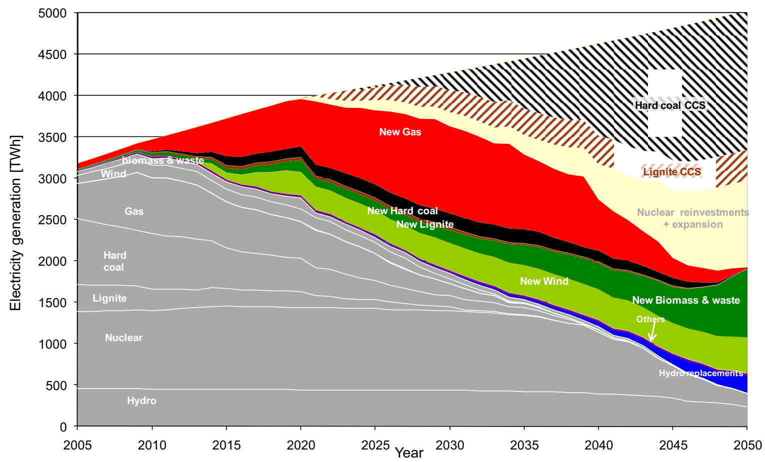
If biomass can be co-fired in CCS by roughly 10% in terms of supplied fuel energy the net emissions from such configurations would be about zero which would be required if emission should be reduced beyond the 85% unless other zero emission technologies could be increased or new ones developed. Thus, 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 gas or 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. The Policy scenario of course reduce the challenge to meet 85% emission reduction but still requires all measures to be taken, including significant energy efficiency measures which, historically, have been shown to be difficult to implement even in cases where they are cost efficient.

In summary, both scenarios can meet the emission targets at a cost of less than 80 €/t CO_2. The combination of policy instruments in the Policy scenario (ETS and specified targets on RES-E and energy efficiency measures which may be seen as Green and "white" certificates) give a significant impact on the fuel diversification which would also be beneficial for the security of supply of the region. Yet, the combined policy measures will interfere and result in a low price of CO2 within the trading system compared to the case of the Market scenario for which the CO2 cap is the only target and which also results in a rather mixed portfolio of fuels. From an investment perspective, several policy measures in parallel is of course less favorable than a clear and steadily increased price on CO2 emissions as a result of a tightening of the emission cap, corresponding to the required emission reduction over time.

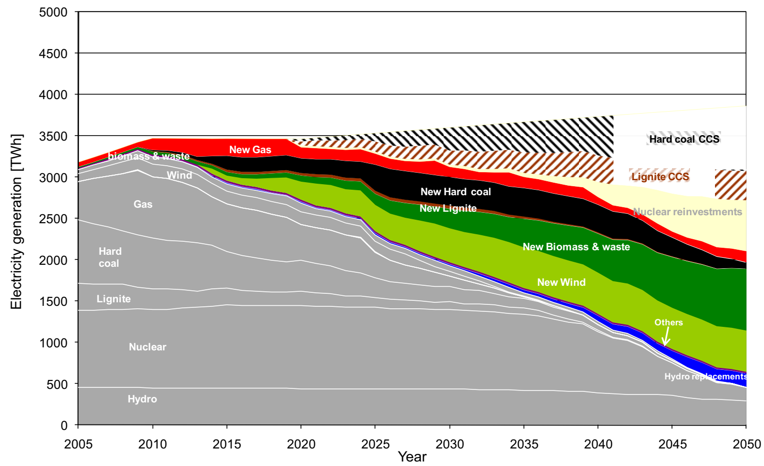


a. **b.**

Figure 1. Interconnector cables for the modeled region **a.** Present system b. New investments in 2030, for the two scenarios (Market and Policy).

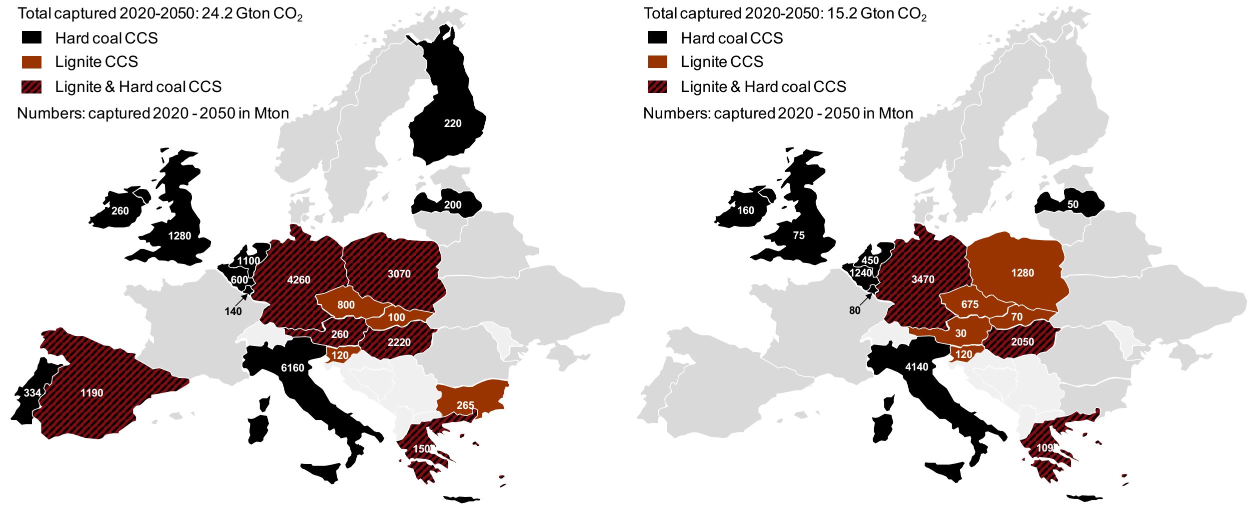


a.



b.

Figure 2. Electricity generation in EU-27 and Norway as obtained from the modeling ("Others" include PV, wave, small-scale hydro and tidal power). **a.** Market scenario, **b.** Policy scenario.



a. **b.**

Figure 3. Overall distribution of CCS as obtained from the model. **a.** Market scenario, **b.** Policy scenario**.**

4. Conclusions

An assessment of CCS for EU27 and Norway has been made applying the Chalmers Energy Infrastructure database (power plants and CO2 storage sites) and by techno economic modeling of the power generation sector using a model which is regionalized down to the individual MS. Two scenarios are investigated, a "Market" and a "Policy" scenario where the Market scenario can be seen as a scenario where there are less policy measures in addition to the price on CO2 emissions and reflecting previous experiences on the difficulty of implementing energy efficiency measures and the Policy scenario assuming targeted policies on energy efficiency and RES based energy to be successfully implemented.

The results show that it is obviously easier from a resource availability perspective to comply with the prescribed emission reduction of 85% until 2050 in the scenario with a lower growth in demand. Yet, having several policy measures in parallel is less transparent than a price on CO2 and it may also be problematic to rely on the success of future energy efficiency measures. Both scenarios give a mix of technology options which should be beneficial from a security of supply perspective. In the Policy scenario this is achieved by combination of policy instruments (ETS and specified targets on RES-E and energy efficiency measures which may be seen as Green and "white" certificates). Yet, the combined policy measures will interfere and result in a low price of CO2 within the trading system compared to the case of the Market scenario for which the CO2 cap is the only target and which also results in a rather mixed portfolio of fuels. Obviously, the two scenarios studied should be seen as examples of a strict climate policy to illustrate the effect of a market driven (trading) emission reduction compared to a reduction driven by more technology specific targets in addition to emission trading. Both cases seem possible but impose different challenges (success of energy efficiency measures compared to very large yearly investments in CCS). An obvious problem at present, not included in the modeling, is the effect of banking in the EU-ETS system which seems to result in that prices of emission allowances will not exceed 20 €/t CO2 before 2020. Thus, this may require targeted policy instrument similar to those in the Policy scenario.

5. Acknowledgement

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