

A 2050 perspective on the role for carbon capture and storage in the European power system and industry sector

Franziska Holz^{a,b,*}, Tim Scherwath^a, Pedro Crespo del Granado^b, Christian Skar^b, Luis Olmos^c, Quentin Ploussard^c, Andrés Ramos^c, Andrea Herbst^d

^a German Institute for Economic Research (DIW Berlin), Berlin, Germany

^b Norwegian University of Science and Technology, Trondheim, Norway

^c Institute for Research in Technology (IIT), Comillas Pontifical University, Madrid, Spain

^d Fraunhofer Institute for Systems and Innovation Research (ISI), Karlsruhe, Germany

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ABSTRACT

Carbon Capture and Storage (CCS) might be a central technology to reach the decarbonisation goals of the European energy system. However, CCS deployment faces multiple economic, technological, and infrastructure challenges. Related literature tends to only focus on certain aspects of the CCS technology or to be limited to a particular sector perspective. In contrast, this paper presents a holistic modelling framework to analyse the long-term perspectives of CCS in Europe by extending the typical analysis from the electricity sector to the industry sector, and by including the CO₂ infrastructure level with CO₂ pipelines and storage. To this end, we use state-of-the-art models of the electricity sector (generation investment and electricity grid models), the industry sector, as well as the CO₂ infrastructure sector. This unique modelling framework analyses the feasibility and costs of CCS deployment in the European Union towards 2050 in three scenarios with the same ambitious climate policy target (~85% CO₂ emissions reduction). The main insights on the deployment of CCS in Europe hinges on two factors: i) the development of low-cost power generation technologies with carbon capture (coal and/or gas-fired), and ii) a sufficiently high CO₂ price to compensate for the costs of deploying the CO₂ transport infrastructure. Once CO₂ transport infrastructure is available, CCS will be a preferred mitigation option for the industry sector emissions. The joint use of CO₂ infrastructure by the electricity and the industry sector allows for economies of scale and economies of density. In the long term, CCS cannot achieve the 100% decarbonisation target of the energy sector because the technology can only capture 80–90% of the CO₂ emissions of thermal power plants. Moreover, the advantages of CCS in terms of energy system costs compared to a system without CCS is rather small, in the range of 2%. It crucially depends on the costs of renewables and the costs of their integration in the electricity grid.

1. Introduction

Carbon capture and storage (CCS) is a debatable technology that is not equally supported as a solution for mitigating climate change by the different stakeholders in the European Union (EU). The high costs as well as the public opposition to the – potentially risky – CO₂ storage might be barriers for large-scale implementation of this technology. One of the primordial questions in this regard is which sectors can potentially – and would economically – use the CCS technology. CCS has been much discussed for the energy sector, but several analyses point to the industrial (manufacturing) sector as a more important user of the CCS

technology. Many industrial processes do not have other emission abatement options than CCS.

In the early 2000s, the situation in Europe was different, when CCS was largely uncontested and widely supported as future mitigation option (Odenberger et al., 2008). Indeed, Europe was on the forefront of CCS development with more than 30 announced demonstration projects in the power and industry sector. The bleak truth is that none of them has come to life and virtually all projects were cancelled in the last ten years or so. There are only two operating CCS projects in Europe, namely in the offshore natural gas fields Sleipner (which started already in the 1990s) and Snøhvit (since the mid-2000s), Norway, where CO₂ is

* Corresponding author at: German Institute for Economic Research (DIW Berlin), Berlin, Germany.

E-mail address: fholtz@diw.de (F. Holz).

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captured at the gas processing units and reinjected in the gas fields. The complete abandon of CCS in the EU is somewhat surprising given how optimistic and supportive the political environment for CCS was only a little more than 10 years ago.

In January 2008, the European Commission presented a “draft CCS Directive” that was approved in December 2008 by the European Parliament. The directive focuses on the geological storage and gives “guidance on a CO₂ storage life cycle risk management framework, the characterization of the storage complex, CO₂ stream composition, monitoring and corrective measures, the criteria for transfer of responsibility to the Member State, and financial security” (EC, 2011a, 2011b). In April 2009, the CCS Directive was approved by the European Council and entered into force. The CCS Directive passed through the European legislative process in just 14 months, which shows the important role that CCS was supposed to play for the European CO₂ emission reduction.

Given the lack of successful pilot and demonstration projects, there is still an undisputable need for fundamental and applied research around the CCS technology, because the processes are neither fully understood (e.g., geological storage) nor are the costs in a commercial range. However, even a substantial amount of public funding made available in the past years around the world did not expedite the development of the CCS technology and it did not stop the cancellation of all projects in Europe.

In this paper, we investigate the impact of a quick resumption of support for the CCS technology in the next years, so that the technology costs become more affordable and CCS projects come on stream at large scale. However, we acknowledge that the public opposition to underground CO₂ storage is very large (e.g., (Vögele et al., 2018)). As a result of public opposition, Denmark has prohibited onshore storage, while, in the Netherlands, only offshore projects are being supported by the government and the industry. Similarly, in Norway and Sweden, permits have only been granted to offshore projects. In Germany, the lack of public and, therefore, political support to onshore storage is also evident. What is more, the cooperation at transboundary level, largely involving Germany, the Netherlands, and the UK, has, so far, mainly concerned offshore projects in the North Sea. The first full storage permit was indeed awarded to an offshore project, the ROAD project (Shogenova et al., 2014). Consequently, we have opted to only investigate the use of offshore CO₂ storage in Europe.

We put into contrast the large-scale deployment of CCS in the electricity and industry sector to a different future energy system that focusses on an increasing deployment of renewables and electrification of industrial processes. To this end, we present scenarios with different degrees of CCS use, depending on the CO₂ price and CCS cost assumptions. These scenarios allow us to compare the properties of 2050 systems with and without CCS and to highlight the possible impact of CCS. That is, we explore: i) is it possible to reach emission reductions consistent with the 2 °C target without using CCS? and ii) how much would the development of CCS in Europe reduce or add to transition costs?¹ The magnitude of these costs could play an important role in the social acceptance of the technology’s associated risks and potential negative externalities, in particular those related to CO₂ leakage from the underground storage and transportation. To address these questions, we develop a unique methodology of combining several models to represent the long term evolution of the power system, the industry sector (steel, cement, paper production, chemical industry and others), the CO₂ transport and storage infrastructure as well as the corresponding electricity grid design.

We find, most importantly, that the system cost advantage of CCS is small compared to an alternative system without CCS based on renewables. This can be an important additional reason to those given in

(Durmaz, 2018) why the large-scale deployment of CCS is not underway (yet). In our results, in contrast to previous studies, the possibility to generate revenues from selling CO₂ to oil producers for Enhanced Oil Recovery (EOR) is not critical to an effective kick-off of CCS. As expected, quite different electricity grids will develop whether CCS is available or not, due to the different shares of renewable generation in the electricity transmission and distribution networks. Given the large role of renewables in future energy systems in all scenarios, the comparison of system costs among the different scenarios strongly depends on the assumptions made on costs and availability of flexibility options; less so on CCS. For industry, the CO₂ price level and the availability of alternative low-carbon technologies are the most critical factors for CCS use. Moreover, the reduction of capture costs and the carbon budget play a major role in the large-scale deployment of CCS in the electricity sector.

In the next section, we detail this paper’s contribution to the literature. Then, Section 3 describes the models employed in our analysis and how they are linked. Section 4 provides an overview of the scenario results and compares the system costs in their different energy sector settings. Section 5 highlights the role of some specific aspects along the CCS value chain for the deployment of the technology, in particular the CO₂ infrastructure, the role of CO₂-EOR, CO₂ capture in the power sector as well as in industry, and the impact of CCS on the electricity grid in Europe. Section 6 concludes and discusses further research needs.

2. Related literature

The CCS technology is included in the majority of long-term integrated assessment models (IAM, e.g., (IPCC, Working Group III Contribution to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change, 2014), (IPCC, 2018), (Capellan-Perez et al., 2020), (Koelbl et al., 2014)). They show – in most scenarios quite impressively – the need for the deployment of carbon emission mitigation technologies such as CCS. Some of these “top-down” analyses also describe the need for rapid learning to scale up the CCS deployment, e.g. (Dalla Longa et al., 2020). However, these top-down analyses by nature neglect a detailed representation of the economic and technical properties of CO₂ capture, transport and storage infrastructure. In particular, they are limited for computational reasons in the sectoral detail that they can include – both in terms of which sectors can be included but also which details of each sector. For example, the spatial disaggregation is usually very limited to just a few nodes which does not allow a detailed grid infrastructure analysis. In contrast, IAMs provide valuable insights in the economy-wide dynamics and also include the global economic and climate perspective.

We complement the IAM’s top-down analyses and conduct a bottom-up analysis of the benefits and costs of using CCS, with a comprehensive representation of all the main characteristics and consequences of using the CCS technology in the energy and industry sector and with a great level of spatial granularity. More precisely, we consider the entire CCS “value chain” in Europe. In addition to carbon capture and carbon storage it is necessary to take into account the carbon (CO₂) transport infrastructure to carry the CO₂ from the capture sites to the storage sites (Hirschhausen et al., 2010), (Oei et al., 2014). A high spatial resolution and the inclusion of detailed characteristics of CO₂ emitters, transporters and storage operators allow us to address the details that Integrated Assessment Modelling, by nature, have overlooked.

(Viebahn and Chappin, 2018) conclude from an extensive literature review that the complexity of the carbon capture, transport, and storage topic has been insufficiently addressed in previous research. There were some, but very few modelling efforts of CCS infrastructure development in Europe during the optimistic CCS period in the 2000s and early 2010s: (Morbee et al., 2012), (Oei et al., 2014), and (Mendelevitch, 2014) were three different modelling approaches of CCS pipeline network deployment developed around that time. Lately, there was a small “revival” of CCS models for Europe (d’Amore and Bezzo, 2017) or individual

¹ IPCC (2014) states that “no CCS” would lead to a 138% increase in total global discounted mitigation costs (period 2015–2100) relative to the default technology assumptions.

European countries (e.g. for Spain, (Massol et al., 2018)). All these models used an optimization approach with system cost minimization. In contrast, (Mendelevitch, 2014) used a mixed complementarity model to simultaneously maximize profits of the emitters, the CO₂ network operators as well as the CO₂ storage operators. Similar optimization models were developed for other world regions such as the USA (Midleton et al., 2012) and China (Zhang et al., 2018). However, all of them focus on the optimal pipeline network investment and operation, and include a rather simplified representation of the electricity and industry sectors' emissions. In contrast, we want to investigate the potential synergies from the joint utilization of large-scale CCS infrastructure by the electricity and the industry sector.

Some authors emphasize the need to cluster emissions from nearby (small-scale) sources, be them from industrial or energy sector activities, in order to exploit economics of scale and density in the construction and operation of CCS infrastructure. (Massol et al., 2018) include emission clusters in a large-scale nationwide model; (Brownsort et al., 2016) investigate a particular case study located in the UK. Most authors find that clustering is a necessary pre-condition for eventual deployment of CCS because it allows to decrease costs per captured unit of CO₂.

Energy system models – such as MARKAL, TIMES, GENESYS-Mod, PRIMES – also potentially address the combined use of CCS by several emitting sectors. However, very few energy system model applications include industrial CCS to date. Recent analyses with MARKAL (Farabi-Asl et al., 2020) and the GENESYS-Model are some rare exceptions (Auer et al., 2020). However, all these works lack a detailed representation of the infrastructure segment (pipeline transportation, storage) of the CCS value chain and, therefore, tend to underestimate the costs and constraints related to the deployment of CCS. (van den Broek et al., 2010) and (Kanudia et al., 2013) present an interesting exception which combines the energy system model MARKAL (and its inherent cost minimization approach) with spatial information for a potential CO₂ pipeline network in the Netherlands and the West Mediterranean region, respectively.

Modelling of industry emissions recently focuses on comparing several mitigation options, in particular fuel switch to biomass and electrification (Herbst et al., 2018), (Rehfeldt et al., 2020). However, these mitigation options with currently available technologies are generally acknowledged to be insufficient for deep decarbonization (carbon neutrality) scenarios. Also in Europe, the use of CCS for – at least some – industry emissions is expected (EC, 2018). Costs play an important role in assessing the feasibility of CCS for mitigating industry sector emissions (Fleiter et al., 2019). Yet, there is very little numerical modelling of industry sector energy use and emissions in the literature, it often focuses on one single industrial sector (e.g. cement) and uses average cost numbers for CCS activities, thereby neglecting potential synergies by the joint CCS deployment with the electricity sector. Our approach of selecting the highest emission sectors is the same as in (Leeson et al., 2017) who model the iron & steel, cement, refineries, and pulp & paper sectors with representative average size firms. However, our approach of modelling industrial production and taking into account a variety of emission mitigation options is close to the analysis by (Saygin et al., 2013) for the Dutch industry and by (Luh et al., 2020) for the US industry.

Lastly, CCS is included as potential CO₂ emission mitigation option in many applications of electricity sector modelling that generally deal with the expansion and/or operation of electricity generation and infrastructure, e.g. (Pudjianto et al., 2016), (Selosse et al., 2013), (Lohwasser and Madlener, 2012), (Shirizadeh and Quirion, 2020), (Mac Dowell and Staffell, 2016), (Eide et al., 2014). They usually focus on the capture part of the CCS value chain. The electricity system development and operation with CCS are compared to those when RES-based generation technologies are deployed, based on the costs, the carbon content, and the security of the energy system. Generally, these approaches fail to take into account the infrastructure costs of the remainder of the CO₂ value chain beyond capture, namely CO₂ transportation and storage,

including the constraints and costs associated with these activities. However, the costs and the economic feasibility of the CCS technology depend on all segments of the value chain: for example, if there is no large-scale transportation option for CO₂, the availability of low-cost capturing technologies will not be sufficient to trigger the deployment of CCS (Rubin, 2012).

We argue that – in addition to the presented sectoral approaches of modelling the potential deployment of CCS – we need a combination of bottom-up sectoral models for a sound quantitative assessment of the CCS technology. These models need to represent all the abovementioned sectors with a capturing decision – industry in addition to the electricity sector – as well as the CCS value chain, including transportation and storage of CO₂. To achieve such a comprehensive representation, we link four state-of-the-art models that allow for detailed sectoral analyses to assess the arbitrage between CCS and alternative low-carbon options.

3. The methodological framework

3.1. Model interaction

We define a sequence of data exchange between the four models which can be divided into three parts (see Fig. 1). In the first part the model exchange (steps 1 and 2), EMPIRE and Forecast-Industry are used to determine the application of CCTS technologies and the associated amount of captured emissions by year, country and sector. Furthermore, EMPIRE provides detailed data on the development of the generation portfolio and dispatch by year and country. In an intermediate step, the captured emissions as well as the generation portfolio data on country level are spatially disaggregated to country sub-regions. The calculated generation portfolio and captured emissions imply specific infrastructure needs.

These infrastructure needs are calculated in the second part of the model exchange using the models CCTSMOD (step 3a) and TEPES (step 3b). CCTSMOD is used to calculate the needs for CO₂ infrastructure as well as the costs of installing the CO₂ transport and storage infrastructure. TEPES is used to calculate the needs for expansion of the electricity high voltage transmission grid.² In the third part of the data exchange, infrastructure related parameters (CCS costs and high voltage grid capacities) are used for an updated model run by EMPIRE that provides better information on electricity investments and dispatch decisions, in particular for power plants with CO₂ capture. The results discussed subsequently in Sections 4 and 5 have been calculated by the three iterations of the process depicted in Fig. 1, while a fourth iteration was carried out to verify stable results. The electricity dispatch and generation capacity results shown are those by the final EMPIRE run. Data from this final EMPIRE runs is also collected by CCTSMOD and TEPES for visualization of the infrastructure requirements. In the following, we describe the models and their main assumptions in detail.

3.2. The electricity sector perspective

We use two models to analyse the electricity sector. The EMPIRE model plays a central role in determining the operation and investments in power plants, including power plants with CCS. The TEPES model complements the generation analyses by showing the different expansion needs in the electricity grid.

3.2.1. EMPIRE – electricity generation capacity expansion and generation

EMPIRE³ is a stochastic multi-horizon optimisation model for

² The electricity system dispatch is computed endogenously in TEPES, however, inter-temporal constraints are not considered. Therefore, utilization of electricity storages such as hydro-power and batteries is taken as exogenous input.

³ <https://www.ntnu.edu/web/iot/energy/energy-models-hub/empire>.

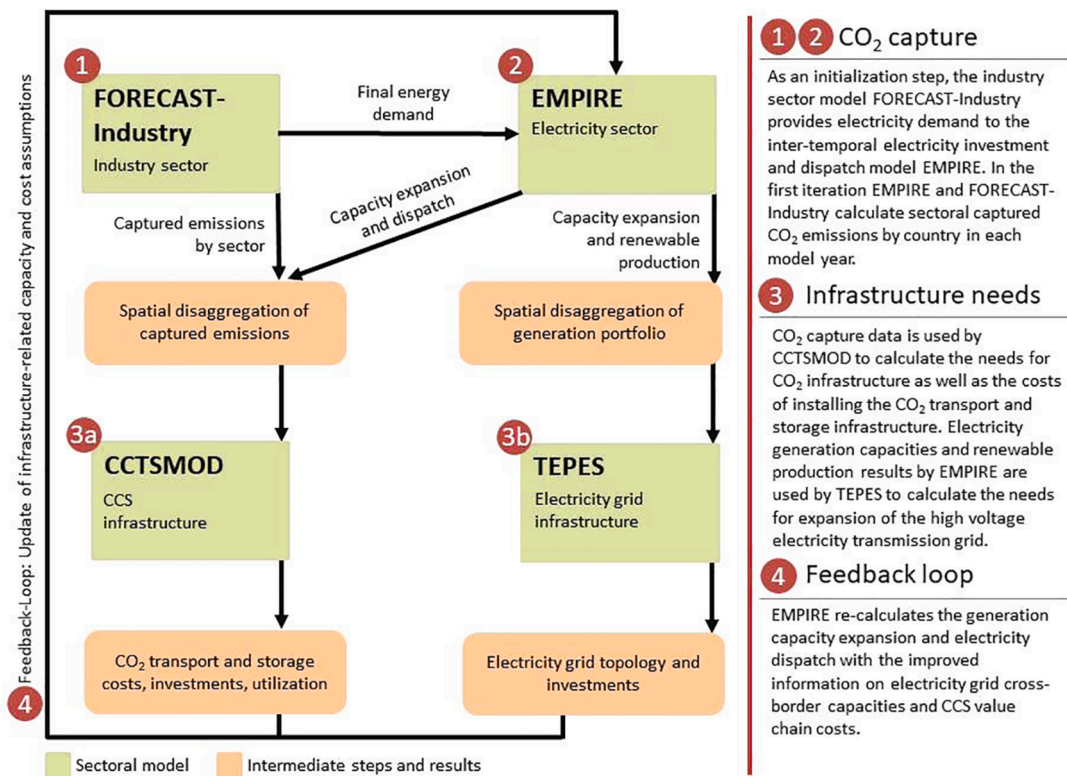


Fig. 1. Model interaction and data exchange flow.

generation and transmission investments in the European electricity system (Crespo del Granado et al., 2019, Skar et al., 2016). The EMPIRE model incorporates long-term and short-term system dynamics, while optimizing investments under operational uncertainty. The objective is to minimize the net present value of the (expected) electricity system costs over the entire time horizon. The geographical coverage of EMPIRE includes most of the countries represented in the ENTSO-E as of 2010, i.e., EU-28 (excluding Cyprus) plus Bosnia-Herzegovina, Norway, Serbia and Switzerland.⁴ Data on existing capacities comes from (ENTSO-E, 2015), (EurObserv'ER, 2016a) and (EurObserv'ER, 2016b). EMPIRE includes a simplified electricity grid representation with net transfer capacities (NTC) between countries in a “transportation model” style. EMPIRE represents climate and renewable policy support mechanisms by controlling carbon emissions with two policies: a carbon price and an annual carbon emission cap on power sector emissions. In this paper, we use a combination of a carbon price and a carbon cap. The carbon price is implemented as an additional component of the operational costs of fossil fuel thermal power plants. CCS plants are only charged the carbon price for the share of their CO₂ emissions which is not captured. However, the variable costs of transport and storage of the captured CO₂ are added to the operational costs of such plants. With respect to the emissions cap, carbon which is captured and stored is not counted as part of the total emissions.

There are four main drivers influencing the investments in generation technologies and the mix of technologies deployed in EMPIRE: i) Development of demand for electricity, ii) Development of fuel prices, iii) Retirement of ageing power plants in the existing generation stock and, iv) development of technology costs and characteristics (e.g., power plant efficiencies). Regarding CCS, EMPIRE includes four types of

generation technologies, distinguished by fuel input. These are lignite, hard coal, gas and biomass co-fired with hard coal. EMPIRE does not consider the option of retrofitting fossil-fired plants with CO₂ capture technology.⁵ However, investments in early, immature demonstration plants are assumed to be possible as early as 2020. In our optimistic scenario, more advanced CCS technologies, with lower investment costs and better power plant efficiencies following (ZEP, 2013) and (Rubin, Davison, & Herzog, The cost of CO₂ capture and storage, 2015) become available already by 2025 (also see (Holz et al., 2018a, 2018b)). These “advanced” technologies are available regardless of the deployment of demonstration plants, which in effect means that we assume that there is enough learning in the world to drive the technological development. The Appendix reports the main assumptions used in the EMPIRE model.

3.2.2. TEPES – electricity transmission network

Regardless of the extent of CCS use in Europe’s future electricity system, there will be a high share of renewable energy resources (RES) by 2050. The intermittent nature of the output of most RES, their non-homogeneous distribution and their large-scale deployment are expected to result in a significant increase in the power flows between regions in large-scale systems. The electricity transmission network model TEPES⁶ was developed for this kind of analysis (Lumbreras and Ramos, 2013), (Lumbreras et al., 2017). TEPES identifies the main optimal transmission network corridors to reinforce and the extent of the reinforcements needed, as well as other operation variables. A transmission expansion plan is defined as a set of network investment

⁴ EMPIRE does not model power plants in detail but uses an aggregate representation of the total installed generation capacity of each technology in each country. This reduces the computation time compared to representing each individual power plant.

⁵ This is partly motivated by studies such as (Rohlfis and Madlener, 2013) which showed (for coal) that, given a wide range of assumptions, building new CCTS power plants is preferable to retrofitting existing ones. (Rubin, Davison, & Herzog, The cost of CO₂ capture and storage, 2015) also highlight barriers associated with retrofitting carbon capture to existing plants, such as reduced efficiency and limited lifetime compared to new CCTS plants.

⁶ <http://www.iit.comillas.edu/technology-offer/tepes>.

decisions for future years.

There are two types of input data used in TEPES: electricity grid data from the TEPES data set and input data provided by EMPIRE. The first type of input data essentially includes the representation of the existing electricity network (electrical line admittance, and loss factor) and the network potential investment plan (candidate lines, their admittances, loss factor, and investment costs). The second type of data includes hourly electricity demand, intermittent renewable generation, and storage operation profiles, together with thermal generation features (generation capacity and operating cost, which include CCS cost when applicable). The main TEPES outputs are the network investment decisions (line capacity expansion and associated expansion cost). For computational reasons, two data reduction methods are applied before running TEPES: a snapshot reduction method and a search space reduction method. The snapshot reduction method reduces the number of representative hours used in the TEPES model by grouping together hours with similar system-wide load and intermittent generation levels. The search space reduces the number of candidate lines to consider by applying a simplified version of the search space reduction method described in (Ploussard et al., 2020) (Ploussard et al., 2020). Here, TEPES is used to carry out a static capacity expansion planning and considers a single target year for each run (2050). Investment costs are annualized to compute the optimal grid in each scenario.

We use a TEPES version with a DC load flow model to achieve the most accurate representation of the technical constraints limiting the flow of power in the electricity grid. All the RES generation is represented as being directly connected to the transmission grid, even though part of it is connected to the distribution grid. In order to compute an estimate of the costs of RES integration in the distribution network, we use a predefined unit cost of integration in the distribution grid computed as the average of the cost estimates provided in several previous research projects and studies. These include the IMPROGRES project (Cossent et al., 2011), the MIT Future of Solar project (MIT, 2015), and studies by the British energy regulator (OFGEM, 2009, OFGEM, 2004). When allocating distributed generation to the nodes in the modelled transmission grid in TEPES, each distributed generation unit is placed in its upstream transmission node.

The future RES generation and conventional generation deployment strategies will largely influence the transmission network development. For example, conventional generation units with CCS can be expected to be located at the same location where there are currently conventional plants not equipped with CCS. Therefore, these are expected not to require grid reinforcements. In contrast, the wide-spread deployment of small-scale and distributed RES generation will require to connect these units to the electricity grid with new lines. The network reinforcements in TEPES are aimed at performing system cost arbitrage among different generation options. In other words, making use of newly added transmission capacity, power generation with lower costs will replace generation with higher variable costs.

3.3. The industry perspective: the FORECAST-industry model

Industry accounts for about 25% of EU final energy demand and it uses (natural) gas, electricity, coal, and oil as the main energy carriers. This makes the sector critical for the achievement of European climate goals. It also raises the question which options can be used to reduce emissions, and which role CCS can play. CCS is included in most of the ambitious decarbonisation scenarios that are available in the literature for the industrial sector, but plays a more or less important role depending on the inclusion of other mitigation options. The EU Low Carbon Roadmap (EC, 2011a, 2011b) envisaged a greenhouse gas emissions reduction of more than 80% by 2050 in industry, using CCS after 2035 especially in the steel and cement sector. (IEA, 2017) expects CCS supporting technologies in a 2 °C scenario for the iron and steel industry to become relevant in the mid- to long-term, while short-term emissions reductions will come mainly from energy-intensity

improvements and process shifts to secondary production.

We use the FORECAST modelling platform to quantify the future energy demand of our long-term scenarios (Fleiter et al., 2018).⁷ It is based on a bottom-up modelling approach of industrial production processes and it takes into account the dynamics of technologies and socio-economic drivers. FORECAST-Industry is designed to address research questions related to the energy demand from industry, including the demand for individual energy carriers like electricity or natural gas, calculating energy saving potentials and greenhouse gas (CO₂) emissions as well as abatement cost curves. FORECAST-Industry distinguishes five sub-modules:

- **Energy-intensive processes:** this module represents the core of FORECAST. Around 70 individual processes are included with their physical production output of goods and their specific energy consumption. About 200 individual energy saving options are modelled based on their payback period as described in (Fleiter et al., 2012) and (Fleiter et al., 2013). Energy saving options can be energy efficiency measures, but also internal use of excess heat, material efficiency or savings of process-related emissions. They can be of incremental or radical nature.
- **Furnaces:** energy demand in furnaces is a result of the bottom-up calculations in the module “energy-intensive processes”. Furnaces are found across most industrial sub-sectors and are very specific to each production process. Typically, they require heat at very high temperature. While energy efficiency measures for individual furnaces are modelled in the module “energy-intensive processes”, the module on furnaces simulates price-based substitution between energy carriers (i.e., fuel switch).
- **Steam systems:** in many industrial sectors, the remaining process heat (i.e., heat at temperatures below 500 °C) is used in steam and hot water systems. This module comprises both the generation of steam and hot water as well as its distribution. More than 20 individual technologies are taken into account ranging from natural gas boilers to several types of CHP units, biomass boilers, large-scale heat pumps, electric boilers and fuel cells. Fuel switch is a result of competition among the individual technologies in a discrete choice model where the utility is defined as the total costs of the steam system.
- **Electric motor systems and lighting:** these cross-cutting technologies include pumps, ventilation systems, compressed air, mechanical equipment, cooling appliances, other motor appliances and lighting. The electricity demand of the individual cross-cutting technologies is based on typical shares by sub-sector.
- **Space heating:** a vintage stock model is used for energy demand by buildings and space heating technologies. The module distinguishes between offices and production facilities. The investment in space heating technologies such as natural gas boilers or heat pumps is determined based on a discrete choice approach (Biere et al., 2014).

In the model linking, FORECAST-Industry focusses on the process-related energy consumption and direct CO₂ emissions in the industrial sectors *paper*, basic chemicals like *ethylene* and *ammonia*, *raw steel*, and *cement clinker and lime*. All five modules of FORECAST are used for the quantitative analysis; Table 10 in the Appendix reports the capture cost assumptions for these sectors.

3.4. The CCS infrastructure perspective: CCTSMOD

We address the CCS infrastructure perspective by using the model CCTSMOD which includes all steps of the CCS chain, namely the emitting activities, CO₂ capture and transportation by pipeline as well as CO₂ storage (Oei et al., 2014).

⁷ <http://www.forecast-model.eu>.

CO₂ conditioned to a super-critical state can be transported in a similar way as natural gas or crude oil. Thus, pipeline transportation is commonly considered as the only economically viable onshore transport solution (Oei et al., 2014). Pipelines represent a typical network infrastructure with high sunk upfront investment cost. The corresponding fixed costs are, thus, subject to economies of scale (Table 11 in the Appendix A). Furthermore, the costs of a transportation network depend on its spatial extent. Hence, costs are also subject to economies of density depending on the spatial distribution of CO₂ sources and CO₂ sinks. The average distance that has to be covered between CO₂ sinks and sources is an important factor for the economics of a potential transport infrastructure.

In this regard, it is fundamental to consider that current legislation and public opposition make the use of onshore CO₂ storage unlikely in Europe. The CCS Directive has conferred the right to legislate on CO₂ storage to EU Member States. However, national regulation in most European countries is such that regional authorities and regionally elected policy-makers are in charge of permitting onshore storage – which they are reluctant to do because of the public opposition and their dependency on voters' opinions. Consequently, most EU countries do actually not include CCS in their national energy and climate plans, which shows the little support that the technology – and in particular the onshore storage – currently has.

Hence, we argue that the focus for possible future CCS deployment in Europe must be on the offshore capacities that are mostly located in the North Sea. We acknowledge that this requires that there are no legal restrictions to cross-border CO₂ flows within the EU any more, so that CO₂ emissions from all European countries can be transported to the offshore CO₂ storage facilities. This assumption neglects that regulatory hurdles remain for the transportation of CO₂ across Europe as the CCS Directive did not address transboundary CO₂ transport (Heffron et al., 2018). Likewise, no regulation exists in international law. In fact, the transport of CO₂ across borders of international waters is prohibited. An amendment of the London Protocol to the Convention on the Prevention of Marine Pollution to allow cross-border transportation has not been ratified yet (Bassi et al., 2015).

Another determining factor to the use of CCS in the European Union is the availability of geological storage capacity. Candidate geological structures for permanent storage include depleted oil or natural gas fields, saline aquifers, and coal beds. The few CCS projects with permanent CO₂ storage currently in operation in the world all use saline aquifers (IEA, 2016). While CO₂ injection has been practiced in the oil and gas industries since the mid-1970s, experiences with the long-term environmental impact of permanent storage are limited.

The estimates for CO₂ storage capacities in Europe are still subject to uncertainty. Oei et al. (2014, p. 521) report a total of 94 Gt CO₂ for the European Union; 44 Gt are onshore and 50 Gt storage capacity are located offshore. Among the offshore storage possibilities, the largest storage capacities are expected to be available with offshore saline aquifers. However, they are also associated with the highest uncertainty of availability and accessibility. Consequently, these storage sites are assumed to have higher storage costs compared to the other option of depleted hydrocarbon fields. A joint effort of IEAGHG and ZEP (2011) evaluated storage costs in dependence of the realization of different cost drivers (e.g., field capacity, well injection rate). The least favourable realizations of the respective parameters are taken as input data for CCTSMOD to account for the uncertainty and to avoid overly optimistic assumptions (Table 12 in the Appendix). Future CO₂ storage could be complemented by CO₂ reuse (carbon capture use and storage, CCUS), which means to use captured CO₂ as a value-adding input for another process. This would alleviate the central dilemma of the need to heavily invest in capturing technology only to obtain a waste product that needs to be disposed and of which the disposal is associated with costs. We focus on the use of CO₂ in Enhanced Oil Recovery (EOR) in this study (Global CCS Institute, 2011), (Thorne et al., 2020). Indeed, CO₂-EOR has been used for many years in oil and gas producing projects (TUD, 2010),

while other CCUS technologies have not yet reached maturity.

We take into account that CO₂-EOR may be a potential source of revenue (Mendelevitch, 2014), (Oei and Mendelevitch, 2016). For example, the only two commercial-scale CCS projects in the electricity sector worldwide (Boundary Dam in Canada since 2014 and Petra Nova in Texas, USA, between 2017 and 2020) have operated in combination with CO₂-EOR. Potential revenues from selling CO₂ to oil operations for EOR are calculated as the difference between the oil price⁸ and the long-run costs of crude oil production (see (Mendelevitch, 2014) and (Holz et al., 2018a, 2018b) for details). Oil fields suitable for enhanced oil recovery exist in the North Sea; however, their absorption capacity is rather low with 1.2 Gt CO₂ in total.

The CCTSMOD model is adapted to the methodology used in this study, notably to accommodate the data exchange with the models EMPIRE and FORECAST-Industry (see Section 3.1). CCTSMOD calculates the optimal development of a pipeline-based CCS infrastructure. The formulation as a scalable mixed integer, multi-period welfare-optimizing network model allows the endogenous decision on carbon capture, pipeline and storage operations and investments. CCTSMOD is run as a single, multi-period cost minimization problem. The model has a focus on CO₂ transport with an explicit representation of economies of scale in pipeline transport by assuming the installation of discrete pipeline diameters where larger diameters have a cost advantage compared to smaller ones. The model operates on a geo-referenced set of CO₂ emitters (industry, power plants) and CO₂ storage sites. Hence, it also accounts for economies of density. The dataset covers most of EU-28 as well as Norway and Switzerland by aggregating sinks and sources on a 200 × 200 km grid. The data set of geo-referenced industry facilities was updated in coordination with FORECAST based on E-PRTR and EU-ETS. Data for an initial set of power plants in the starting year 2010 is taken from Platts (2011). We assume that future emitting facilities will be at the location of existing facilities. For example, if new power plant capacities such as coal CCS are decided by EMPIRE, we assume that they will be located at the location of existing coal power plants.

In the original model setup, a single omniscient and rational decision maker with perfect foresight decides whether a CO₂ emitting facility purchases CO₂ certificates or invests into a capture process. In contrast, in this paper, the decision on optimal capture is outsourced to the energy demand sector models FORECAST-Industry and EMPIRE. The model exchange with CCTSMOD is carried out in the following way (Fig. 2): initially, the captured emissions calculated by FORECAST-Industry and EMPIRE are given by technology aggregates and by country. CCTSMOD then allocates the captured emissions in each country. Emission locations are chosen such as to minimize infrastructure and transport cost. In addition, the optimal routing of the required pipeline network and CO₂ flows as well as the storage activities are calculated by CCTSMOD. The calculated costs for building and operating the CO₂ transport and storage infrastructure are reported back as input to the EMPIRE model which uses this information for updated runs. In the very end of the model exchange process, CCTSMOD uses the final emissions data by EMPIRE and FORECAST-Industry for a final run to visualize the optimal CO₂ pipeline grid and storage locations.

3.5. Study design and scenario definitions

The cost decrease of renewables in recent years has sparked hopes that the decarbonisation of the electricity sector is achievable without CCS. In contrast, the complete decarbonisation of the industry sector might not be possible (IEA, 2017). In its 5th Assessment Report, the IPCC stated that a world without CCS would come with 138% higher total discounted mitigation costs between 2015 and 2100 compared to its default technology assumptions that include CCS (IPCC, 2014, S. 15). According to the IPCC, the non-availability of CCS would have a

⁸ In this study, the crude oil price given by PRIMES in each year, see Table 1.

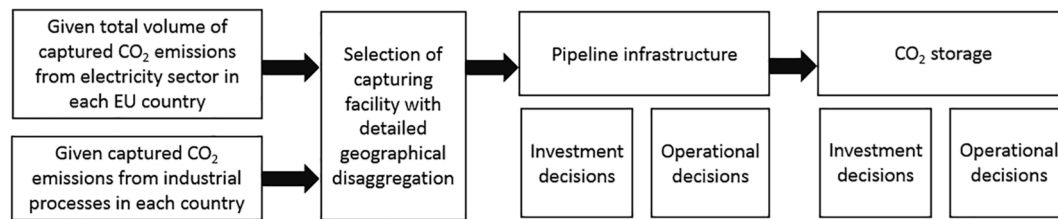


Fig. 2. Revised value chain in CCTSMOD for case study methodology.

significantly higher impact on total mitigation costs than missing out on other technologies like wind, solar or nuclear (IPCC, 2014, S. 453).

Therefore, we aim at comparing different worlds with and without CCS, or with slow technological progress and other unfavourable conditions for CCS (Table 1). We explore three scenarios with the same emissions reduction target until 2050 that contrast a no-CCS world with two different CCS-worlds, one with very favourable conditions for CCS, the other with less attractive conditions for CCS. In the favourable setting, we assume that capture costs and efficiency of CCS power plants improve early and continuously in the next decades (using the technologies “CCS advanced” in Tables 7 and 8 in the Appendix) and additional revenue from CO₂-EOR can be earned. In contrast, in the unfavourable (“costly CCS”) setting, capture technology improvements start later and are moderate while CO₂-EOR storage is not available to reduce the average CO₂ storage costs. The assumptions are varied for the electricity sector and the CCS infrastructure (storage); they are the same for the industry sector as well as for the climate policy framework (CO₂ price).

The European Union has committed to ambitious greenhouse gas reduction objectives. We, therefore, take as climate policy frame the EC 2016 “Decarbonisation Scenario” that was developed by the PRIMES model in 2016. This PRIMES pathway assumed high climate policy ambitions in Europe with ca. 84% CO₂ emissions reduction by 2050 compared to 1990. We use the electricity demand numbers, fuel prices and the CO₂ price from PRIMES in all four models. The CO₂ price is rather flat and below 45 EUR/tCO₂ until 2030, when it starts rising to 550 EUR/tCO₂ in 2050 (Table 1).

4. Results for three CCS scenarios

4.1. Overview of results

The *Affordable CCS Scenario* with highest employment of CCS achieves an emission reduction of 97.9% by 2050 in the electricity sector (Table 2). The *No CCS Scenario* achieves a similar emission reduction of 97.4% by using unabated gas at a low-capacity factor and a small share of biomass to provide flexibility in a system with a very high share of renewables (Fig. 3: Electricity generation by technology in TWh for the three scenarios. Source: EMPIRE model results).

The level of CCS employment has a significant impact on the installed capacity of renewables and the amount of curtailed generation, which are significantly higher in the *No CCS Scenario* compared to the *Affordable CCS Scenario* (Fig. 3: Electricity generation by technology in TWh for the three scenarios. Source: EMPIRE model results). The substantial amount of curtailed electricity generation (Table 2) is due to the lack of alternative moderate-cost, low-carbon flexibility options when CCS is not an option. Due to the high ETS price and stringent emissions constraints, there is almost no room for conventional unabated fossil generation in the mix. In the *Affordable CCS Scenario*, coal CCS and gas CCS are both deployed. In this scenario, gas CCS displaces unabated gas generation. However, due to the relatively high natural gas prices assumed (Table 1), natural gas starts to be used later than coal CCS. In the *Costly CCS Scenario*, much less CCS is deployed, with a focus on gas CCS, due to the higher costs of the CCS value. Instead, the share of renewables (in particular solar PV) is considerably higher in the *Costly CCS*

Scenario than in the *Affordable CCS Scenario*. Nuclear power is expensive due to high capital costs and the costs of biomass power plants are rather high. As the cost of shedding load is high and the cost of installing renewables is fairly low towards 2050 (in particular for solar PV), the least cost solution to serve demand is to continue to invest in renewables even beyond average demand levels which leads to surplus electricity generation in certain time-periods. Affordable batteries are used to mitigate this balancing challenge, but their capacity is just a fraction of the total surplus generation in some periods. With our assumptions on battery cost reductions (Table 9, Appendix) we conclude that using batteries for flexibility services related to intermittent renewables is only a limited option that will leave a large amount of curtailed generation. This effect is also present in the *Costly CCS Scenario* where, in contrast to the *Affordable CCS Scenario*, no advanced CO₂ capture technology is available. Nevertheless, the gas CCS demo technology is used in later years for providing flexibility in the power system. The CO₂ stored in the *Costly CCS Scenario* (0.9 GtCO₂) is significantly lower than in the *Affordable CCS Scenario* where advanced CCS plants are available.

The high CO₂ prices and stringent CO₂ cap in combination with the availability of advanced CCS in *Affordable CCS Scenario* lead to relatively high CO₂ storage volumes of 9.8 GtCO₂ until 2055. When comparing to the *Costly CCS Scenario*, our results indicate that the employment of CCS in the electricity sector mostly depends on the availability of advanced CCS. Moreover, the deployment of CCS as early as 2025/2030 only partially depends on the availability of CO₂-EOR revenues, because also permanent storage capacities are already used as early as 2025 (Fig. 4: CO₂ storage by sector and storage type in million tCO₂ (*Affordable CCS Scenario*)). While emitters that feed into permanent CO₂ storages do not profit from CO₂-EOR revenues directly, CO₂-EOR revenues are fully accounted for in total system cost. In other words, emitters who sell their emissions to CO₂-EOR reduce their total costs. The fact that permanent storage capacities are already needed in 2025/2030 limits the importance of CO₂-EOR as a quick-starting technology, which would be driving technological progress in later years. High CO₂ prices are the more influential driver in this respect. By 2040, CO₂-EOR capacities are depleted and all emissions from CCS plants must be redirected to permanent storage sites.

The decline in stored emissions from the electricity sector towards 2050 is explained by the strongly increasing CO₂ price after 2040 which reflects the constrained CO₂ emissions budget. Total CCS power generation quickly rises from 2025 to 2030 and stays stable until another rise occurs in 2040. After that, due to the tightening emissions constraint, renewables generation strongly increases further while thermal generation decreases because of the capture rate below 100% (Fig. 3). Hence, the capacity factors of thermal electricity generation decreases also in the *Affordable CCS Scenario* (Table 3).

However, the amount of stored CO₂ declines faster than the CCS generation capacity (Fig. 4). The decline in stored CO₂ must partly be attributed to technological improvements that increase the efficiency of CCS generators and, thus, reduce specific fuel use and related emissions. Nevertheless, there is a second effect reducing stored emissions: gas CCS enters the system in 2040, while most of the decrease of CCS generation after 2040 concerns lignite plants. As lignite has a much higher carbon content than gas, this “fuel switch” also drags down the stored emissions. In short, the capacity factors of coal CCS plants are high in the

Table 1
Scenario assumptions.

Scenario	Capture cost assumptions (electricity sector)	CCS availability in industry	CO ₂ -EOR assumptions	Price path assumptions
<i>Affordable CCS Scenario</i>	Cost reductions and efficiency gains start in 2025 with further decrease thereafter (also see (Holz et al., 2018a, 2018b) for more details)	Yes	Available (revenues from oil producers of selling additional oil are transferred to the CO ₂ emitters)	
<i>Costly CCS Scenario</i>	Slow cost reductions and efficiency gains over time	Yes	Not available	
<i>No CCS Scenario</i>	n.a.	No	n.a.	

Table 2
Summary of scenario results.

Scenario	<i>Affordable CCS</i>	<i>Costly CCS</i>	<i>No CCS</i>
CO ₂ stored 2015–2055 (GtCO ₂)	7.7	0.9	0.0
Installed CO ₂ capture capacity in 2050 (GW)	189	69	0.0
Installed intermittent RES capacity in 2050 (GW)	2714	3032	3167
Share of generation from intermittent RES	73%	77%	78%
Emission reduction by 2050 (compared to 2010)	97.9%	97.3	97.4%
Curtailed generation (TWh)	427	667	746
Electricity storage capacity in 2050 (TWh)	4.95	4.99	5.1
Industry Sector: CO ₂ stored 2015–2055 (GtCO ₂)	2.16	2.16	0.0
Total discounted CCS cost (only industry) (bn. EUR ₂₀₁₅)	33.8	35.4	n.a.

beginning of the period when they are deployed (running as baseload), but gradually decrease (Table 3). This is considering the massive deployment of renewables and the strongly increasing price of CO₂ in this scenario. The latter also affects the residual emissions of CCS plants, which become an expensive component of the operational costs as there is very limited possibility for any CO₂ emissions left towards 2050. However, there is still need for back-up capacity to balance the renewable production, particularly during night when solar production is off, and in our calculations, conventional power plants with CCS are used to provide part of this balancing. In sum, the usage of CCS capacity will be strongly affected by the deployment of renewables and the carbon price/constraint. Towards 2050, there is still need for non-intermittent, low-carbon capacity. However, CCS will also be under pressure because of its residual, unavoidable emissions that must bear very high CO₂ certificate costs.

4.2. Comparing energy system costs

A central question in this paper is to understand how much would be the benefit of using CCS in terms of the energy system costs in Europe. From a social welfare perspective, the decision is whether possible future cost savings enabled by the technology outweigh the negative externalities and risks associated with the technology.⁹ Accordingly, our analysis aims at evaluating the benefit of employing the CCS technology in terms of system costs depending on possible cost development of the CCS technology.

The preceding sections demonstrate that the potential role of CCS in the future highly depends on learning rates of the (capturing) technology. As technological improvements require substantial investments in research and development as well as significant infrastructure deployment costs, it is important to assess the value added of CCS in terms of (reduced) system cost. The system cost analysis here is limited to the electricity sector because the FORECAST-Industry model does not calculate such numbers. Moreover, we limit ourselves to the quantification in the models used (e.g., electricity generation costs, costs of CO₂ certificates).

Total discounted electricity system costs displayed in Table 4 comprise all expenses from the electricity producers' point of view that are spent to replace or extend existing capacities and to operate the EU energy system from 2015 to 2055. Total discounted system costs are 4%

⁹ The potential externalities of CCS are related to the storage and transportation of CO₂ where CO₂ might leak. So far, there is a lack of knowledge of the exact proportion of the leakage risk (probability, share of leaking CO₂, properties of geological layers, etc.). In case of leakage, there will be externalities such as environmental damage, health hazards, and also climate damage.

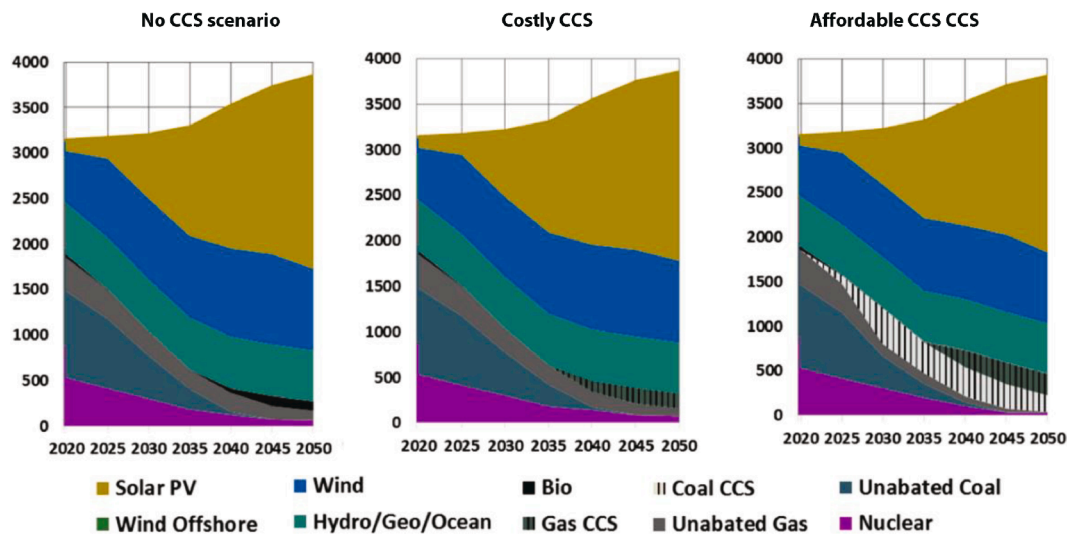


Fig. 3. Electricity generation by technology in TWh for the three scenarios. Source: EMPIRE model results.

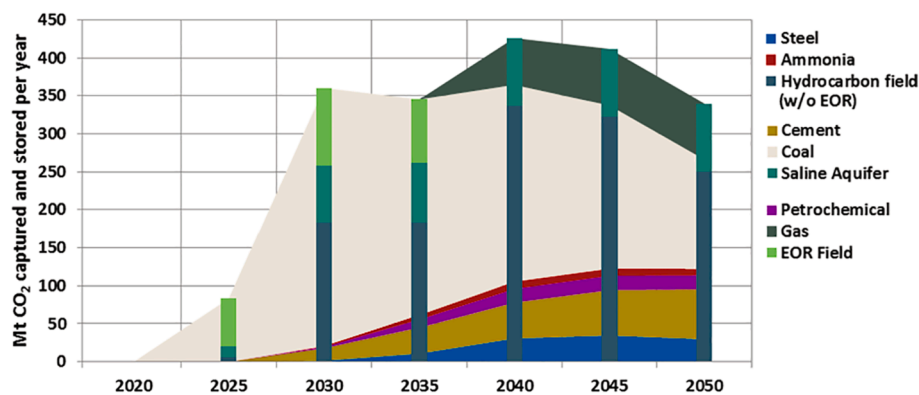


Fig. 4. CO₂ storage by sector and storage type in million tCO₂ (Affordable CCS Scenario).

Table 3
Capacity factors of CCS power plants in the *Affordable CCS Scenario*.

	2030	2035	2040	2045	2050
Coal CCS	0.72	0.63	0.66	0.55	0.17
Gas CCS	0	0	0.34	0.24	0.22

Table 4
Total discounted electricity system costs in bn. EUR2015 for 2015–2055.

	<i>Affordable CCS</i>	<i>Costly CCS</i>	<i>No CCS</i>
	10,485 (–4%)	10,925 (0%)	10,921

Note: In parentheses, deviations from the *No CCS Scenario*.

lower if advanced CCS and CO₂-EOR are available, compared to the *No CCS Scenario*. This indicates that the advantage does not only stem from CO₂-EOR revenues¹⁰ but also from the reduction in the electricity system costs made possible by the extensive deployment and use of CCS power plants. In the *Costly CCS Scenario*, CCS is used even though no technological progress of CCS power plants and no EOR benefits are assumed, but under these conditions, total system costs are basically the same as in

the *No CCS Scenario*.

While total system costs also include the costs of the transition period to a low-carbon electricity system, we observe larger differences between scenarios in the final state of the system in 2050 (Fig. 5a). Average costs of electricity are 4.50 EUR/MWh lower with CCS than without (*Affordable CCS Scenario* compared to the *No CCS Scenario*). Even without the availability of advanced CCS and CO₂-EOR profits (*Costly CCS Scenario*), one can observe an advantage of 0.72 EUR/MWh compared to the *No CCS Scenario*. However, these costs of electricity generation hinge on the level of electricity generation included in the calculations.

In the industry sector, the total construction and operation costs for CCS are correlated with the CCS use in the electricity sector, due to the shared CO₂ transport and storage infrastructure. The large-scale use of CCS in the electricity sector (*Affordable CCS Scenario*) is leading to a reduction by 4.7% of total discounted CCS costs for the industry sector compared to the *Costly CCS Scenario* (Fig. 6b).

5. Selected in-depth results

5.1. The CO₂ pipeline network

The CO₂ transport and storage infrastructure can be evaluated by three criteria: spatial extent, yearly and overall absorption capacity and its economics. The spatial extent of the CO₂ pipeline network is driven by the geographic locations of emission sources and storage sites. In the *Affordable CCS Scenario*, a very extensive network of 38,000 km is built

¹⁰ When considering the economics of CCS with CO₂-EOR it must be noted that revenues depend on the oil price development and are, thus, subject to volatility.

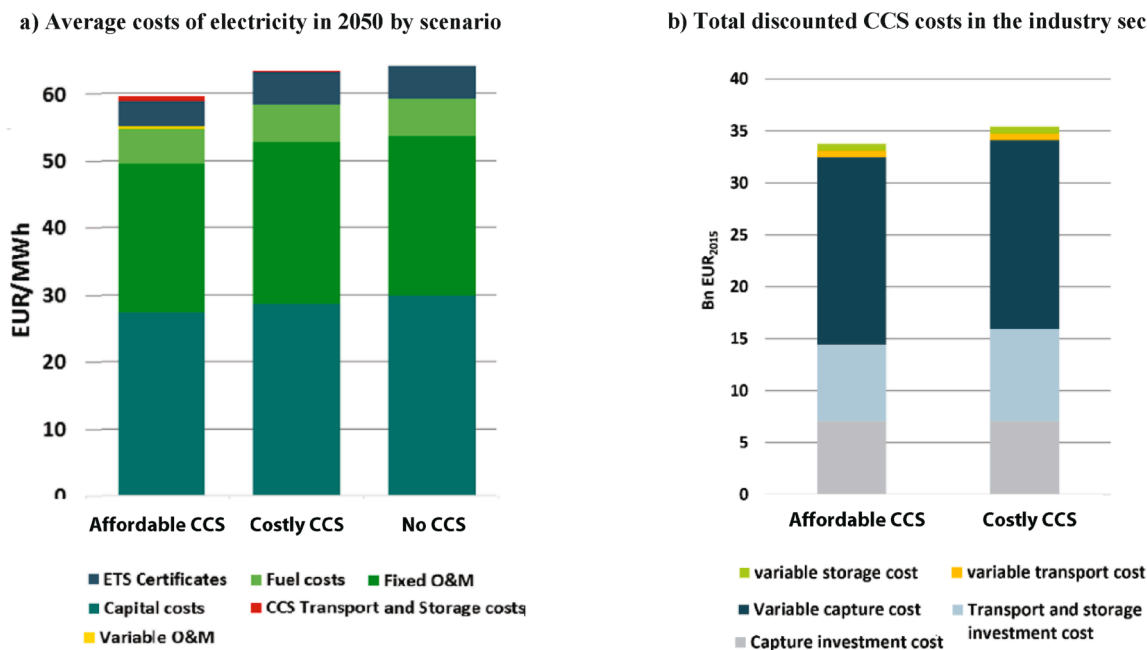


Fig. 5. a) Average costs of electricity in 2050 by scenario and b) total discounted CCS costs in the industry sector.

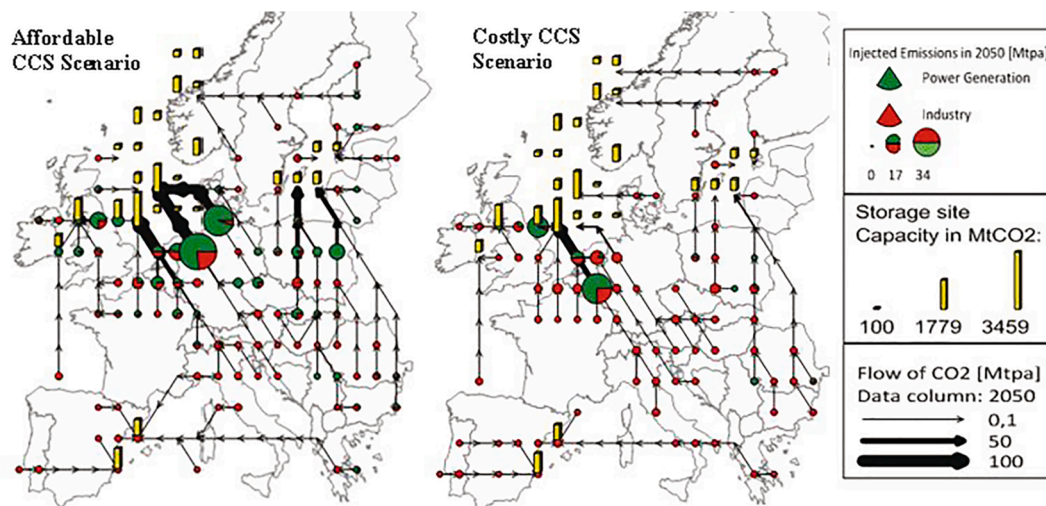


Fig. 6. Flow of CO₂ and captured emissions in 2050.

to collect captured CO₂ emissions (Fig. 6). This includes all pipelines built until 2050, including those that are not used anymore after early-built CO₂-EOR capacities are depleted. Pipelines are crossing multiple borders which demands cooperation between countries. In the *Affordable CCS Scenario*, a maximal absorption capacity by the CO₂ pipeline grid of 417 MtCO₂pa is reached in 2040. Assuming constant storage injection after 2055, storage capacities would be depleted after an additional 95 years.¹¹

In the *Costly CCS Scenario*, much less CO₂ is captured from the electricity sector compared to the *Affordable CCS Scenario*, while

industrial emissions are the same. However, the network length is still rather high with 26,000 km. This is because CO₂ capture is more widely dispersed in smaller emission sources and is transported in pipelines with smaller diameter than in the *Affordable CCS Scenario* (Fig. 6). In the *Costly CCS Scenario*, the maximum yearly absorption capacity of 193 MtCO₂pa is reached in 2045. More geological storage capacity remains in Europe after 2050/2055, allowing storage injection at the same rate for another 200 years.

The design and extent of the transport network has significant impact on its economics. In the *Affordable CCS Scenario*, the combined use of the CO₂ infrastructure by electricity and industry emissions allows to exploit economies of scale. In this case, larger pipeline diameters with lower unit costs of transporting CO₂ are used. This can be observed especially for the pipelines around storage sites (Fig. 6). At the same time, the pipeline infrastructure is subject to economies of density. This is especially relevant for CCS in the industry sector. Industrial capture facilities are spread over Europe, while offshore CO₂ storage sites are in the North Sea region and, with small volumes, in the Mediterranean and the Baltic

¹¹ For continued injection in CO₂ storage, of course, additional investment in storage capacities and further expansion of the pipeline network to new storage sites will be necessary. Indeed, storage capacity is used up once captured emissions are stored. In other words, for each MtCO₂ newly stored, new storage capacity must be invested in. Note that we consider only offshore storage capacities in Europe as known of today.

Sea. Furthermore, industry facilities are relatively small emitters; even grouped together at the model nodes, industry facilities are emitting less than large fossil power plants. However, the low density of CO₂ capturing industry facilities is driving up costs. The joint utilization of the CO₂ infrastructure by electricity and industry therefore reduces costs significantly.

Economies of scale must also be understood as a function of usage. In the *Affordable CCS Scenario*, for example, CCS operations start the most early and stored emissions during the model horizon are higher than in any other scenario. This is, inter alia, a reason why total infrastructure costs per tCO₂ are the lowest with 19.3 EUR/tCO₂ (Fig. 7: Infrastructure investment and variable costs in bn. EUR. Source: CCTSMOD.). Indeed, cost parameters depend on the capacity factors of the capturing facilities and the duration of use in each scenario. This is also true for investment expenditures for storage capacities. These costs are slightly higher in the *Costly CCS Scenario* where the ratio of stored CO₂ to installed capture capacities is lower than in the *Affordable CCS Scenario* (Table 5).

Investment expenditures for CO₂ transport capacities do not depend on usage and are, thus, a suitable indicator for the most cost-efficient scenario regarding the transport infrastructure. Average investment expenditures by unit of transported CO₂ vary between scenarios due to the different sizes of the pipeline network, including different lengths and pipeline diameters. Thus, average investment expenditures are an endogenous model result, in contrast to exogenously assumed costs. Average investment expenditures for transport capacity are lower in the *Affordable CCS Scenario* than in the *Costly CCS Scenario* (Table 5). Here, emission sources have the highest density and, thus, profit from economies of density.

Variable costs predominantly depend on the average distance that the CO₂ travels through the network. This value varies over time. Fig. 7: Infrastructure investment and variable costs in bn. EUR. Source: CCTSMOD. illustrates average variable cost over the modelling horizon only including transport and storage. The cost results computed by CCTSMOD inform the decisions on investment in capture capacities in the industry and electricity sector. Indeed, if no other regulatory setting applies, one must assume that the emitting sectors also cover the CO₂ infrastructure costs. Hence, the corresponding investment cost parameters in Table 5 are added to the investment costs of a CCS power plant or of CO₂ capture facilities in industry. For example, in the *Affordable CCS Scenario*, capital costs of 868,992 EUR/MW are added to the investment cost of a CCS coal plant with, for example, a capacity factor of 0.8 and emission factor of 0.8tCO₂/MWh.¹²

In the *Affordable CCS Scenario*, expenditures to obtain Rights of Way start before 2020 to allow the first CCS facilities to start operations by 2025. Investments in storage capacities in 2020 are predominantly directed to CO₂-EOR activities. Revenues generated from CO₂-EOR are turning average variable storage cost negative in the following years. Variable storage costs turn positive after CO₂-EOR capacities are depleted in 2040. Fig. 6 gives an overview of infrastructure investments and variable costs in the *Costly CCS Scenario* where no CO₂-EOR revenues are available.

5.2. The role of EOR for the kick-off of CCS

Revenues from CO₂-EOR do not influence the long-term profitability of the CCS technology. In contrast to other scenarios with lower CO₂ prices (e.g., (Holz et al., 2018a, 2018b), (Oei and Mendelevitch, 2016), CO₂-EOR availability does also not alter the timeline of a CCS rollout. Rather, in the *Affordable CCS Scenario*, permanent CO₂ storage capacities are already accessed by 2025 due to a sufficiently high CO₂ price and favourable capturing conditions (Fig. 4: CO₂ storage by sector and storage type in million tCO₂ (*Affordable CCS Scenario*)).

¹² Calculation: $155 \frac{\text{EUR}}{\text{tCO}_2 \cdot \text{year}} \cdot 8760 \text{ h} \cdot 0.8 \cdot 0.8 \frac{\text{tCO}_2}{\text{MWh}} = 868,992 \frac{\text{EUR}}{\text{MW}}$. See capacity factors in Table 3 by year and power plant type.

Even though CO₂-EOR is not determining the long-term profitability of CCS, one can observe a visible impact on technology choices. In the *Affordable CCS Scenario*, a lot of coal CCS (mostly lignite) is deployed. Once the EOR revenues cease and the ETS price increases, conventional electricity generation switches to natural gas with CCS (Fig. 3: Electricity generation by technology in TWh for the three scenarios. Source: EMPIRE model results). In the *Costly CCS Scenario*, when EOR is not available, coal CCS will not be deployed but gas CCS will be favoured (Fig. 3: Electricity generation by technology in TWh for the three scenarios. Source: EMPIRE model results). Coal CCS is used in combination with EOR due to the higher carbon content and lower fuel costs. However, when the ETS price increases and there are no EOR revenues the carbon content improves the economics of natural gas CCS relative to coal CCS.¹³

5.3. The role of capture in the power sector

Scenario results clearly indicate that the availability of an advanced capture technology is mandatory for a large-scale rollout in the electricity sector. Substantial investments in research and pilot projects are needed to achieve the required learning rates. Investments are naturally driven by the potential of the technology and our scenario results indicate that this potential depends on the development of the ETS certificate price.

The cost of carbon capture in power generation is represented by the operational costs of the plant and the efficiency (heat rate) penalty. The efficiency penalty increases the specific fuel use of the power plant which makes the capture cost directly linked, and therefore sensitive, to the fuel price. In addition, the increase in fuel use also leads to an increase of the carbon emissions that need to be handled. Given that capture rates in power plants are approximately 80–90%, ETS certificates must cover the non-captured CO₂ emissions and the captured CO₂ has to be transported and stored which also involves costs.

In the PRIMES fuel price data used in our scenarios there is about a two-fold gap between the price of coal and the price of natural gas. This difference makes the operational costs of natural gas CCS plants particularly sensitive to the efficiency penalty compared to coal CCS. When it comes to the ETS component of the CO₂ costs, coal is naturally more affected than natural gas due to its higher carbon content.

In the EMPIRE results, the effect of capture costs is clearly seen through the deployment patterns of the CCS technologies. In the *Affordable CCS Scenario*, both coal and gas CCS are deployed, starting with coal CCS in 2030. A decade later, natural gas CCS is deployed (Fig. 3: Electricity generation by technology in TWh for the three scenarios. Source: EMPIRE model results). The switch from investing in coal CCS to gas CCS is driven by the ETS price, which increases, substantially between 2040 and 2050. In the *Costly CCS Scenario*, without the advanced CCS technologies available and no EOR revenues, only gas CCS is deployed. Considering the role that CCS plays in such a scenario – namely as a back-up technology supporting a highly renewable electricity system – it is not a surprise that the least CO₂ intensive technology prevails. The CCS installations emerge mainly in traditionally fossil fuel dominated countries with moderate distance to offshore CO₂ storage, such as Germany, the UK, the Netherlands, and Poland.

¹³ An additional question is the allocation of the CO₂-EOR revenues. In our setup, these revenues are only allocated to the CO₂ emitters that supply the CO₂ in the sense of reduced or negative variable storage cost. They are completely accounted for in total system cost. Depending on the circumstances, the revenues could also be earned by EOR facility operators. If CCS deployment is envisaged, a detailed assessment of this question could increase the impact of the CO₂-EOR revenues on learning rates and infrastructure development.

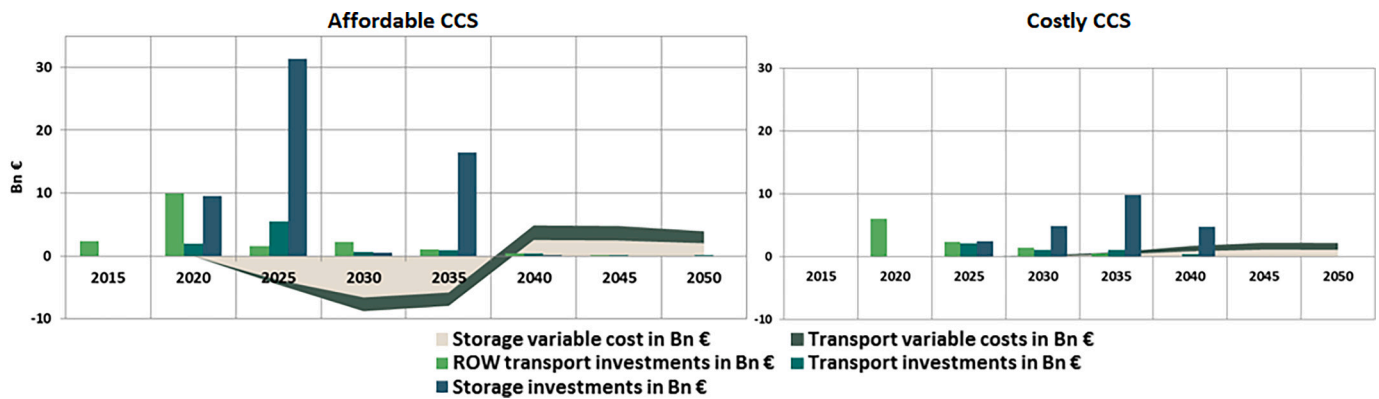


Fig. 7. Infrastructure investment and variable costs in bn. EUR. Source: CCTSMOD. Note: Average storage costs are negative (i.e., they are a revenue) in the first years because of revenues from CO₂-EOR. Transport costs are positive in all periods. Capture cost are not included here.

Table 5

Results of CO₂ transport and storage costs by scenario. Source: CCTSMOD.

	Affordable CCS	Costly CCS
Total CCS infrastructure investments (bn. EUR)	85	38
Average investment expenditures for storage capacity in EUR/(tCO ₂ *year)	105	111
Average investment expenditures for transport capacity in EUR/(tCO ₂ *year)	50	77
Sum of investment expenditures for transport and storage capacity in EUR/(tCO ₂ *year)	155	188
Average variable cost (only transport and storage) in EUR/tCO ₂	11.9	11.8
Total infrastructure costs per tCO ₂ stored in 2015–2055 (fixed and variable costs) in EUR/tCO ₂	19.3	21.1
Total CO ₂ captured (GtCO ₂) in industry 2015–2055	2.16	2.16
Total CO ₂ captured (GtCO ₂) in electricity Sector 2015–2055	7.7	0.9

5.4. The role of the electricity grid

The electricity transmission grid allows power produced in some areas to be consumed in others, while the electricity distribution grid allows the integration of demand and distributed generation at the local level. The modelling framework in this paper focuses on the computation of the development of the transmission grid required to integrate new generation and demand in each scenario, while distribution costs are roughly estimated based on the expansion of distributed generation (PV) and the costs of integrating this at local level published in the literature. We compute the required expansion of the transmission grid by using the model TEPES (Fig. 8), given the expansion of generation, demand, and electricity storage computed by the model EMPIRE.

Overall, the results indicate that transmission network development costs are significantly smaller than the electricity system operation costs. This is common to most of the studies conducted worldwide. However, transmission costs are particularly small in our study, especially in the *Affordable CCS Scenario*. This is due to the large-scale deployment of CCS, which leads to a significantly larger ratio of conventional generation (whose operation costs are high) to RES generation (whose operation costs are quite low and whose integration in the transmission grid is most expensive) in this scenario than in other studies. CCS power generation also drives a significantly lower level of power flows in the transmission network because conventional generation tends to be located closer to demand than a large part of RES generation. Moreover, we take into account in the TEPES model that electricity storage can provide some of the flexibility needed to accommodate fluctuating RES, where electricity produced locally can be stored and consumed later instead of having to be transferred to other areas. Thus, the optimistic assumptions made on the evolution of storage costs also have a

decreasing impact on the development and use of the transmission grid.

Table 7 provides the total EU annual amount of electricity production from renewable electricity generation (not including hydro, since this is expected to stay largely constant), pump storage (annual electricity production by it), and annual electricity demand (served load), as well as the annualized transmission and distribution network investment costs in each scenario. As pointed out, the network development costs tend to be lower in a system with favourable CCS conditions compared to the *Costly CCS* and the *No CCS Scenarios*. The trend is the same for distribution network costs.

By comparing the scenario results, we see that there is a positive correlation between the level of network investments and the amount of RES generation to be integrated into the system (Table 6). Given that the amount of RES generation in the system is largely inversely proportional to that of the electricity production with CCS technologies (since the production of electricity with CCS technologies allows decreasing emissions, and therefore contribute to the achievement of emission reduction objectives without resorting to RES generation), it can be inferred that network development costs are negatively correlated with the amount of electricity production by the CCS power plants. The relationship between the amount of RES generation and the network development costs is not linear. This is because small increases in RES generation can easily be absorbed by the grid reinforcements that would in any case be carried out due to other system developments. However, integrating large amounts of new RES generation results in large incremental flows that cannot be accommodated by the grid if it is not heavily reinforced.

Overall, we can confirm that there is a reduction in transmission network costs with CCS relative to the *No CCS Scenario*. As expected, adopting CCS implies the continued use of existing thermal plants for which the grid is already adapted. Besides, there is more flexibility in where new thermal plants with CCS can be installed, whereas new renewable energy resources have to be installed in specific locations. These must be places with large wind primary energy resources for wind generation, and high solar radiation for solar generation. Many times, such places are located far away from load centers and are weakly connected to the rest of the system. New thermal plants equipped with CCTS tend to be installed in those areas where old thermal plants, already integrated into the grid, were located, or close to them. Then, network reinforcements associated with the installation of new RES generation tend to be larger than those needed to integrate new thermal plants with CCS.

Lastly, to illustrate the differences across scenarios in the transmission network reinforcement needs, with respect to the geographical distribution of the required reinforcements, the transmission line investments are shown Fig. 8 for the *Affordable CCS Scenario* and the *Costly CCS Scenario*. As previously discussed, network reinforcements are larger in the *Costly CCS Scenario*, where, due to the lower level of

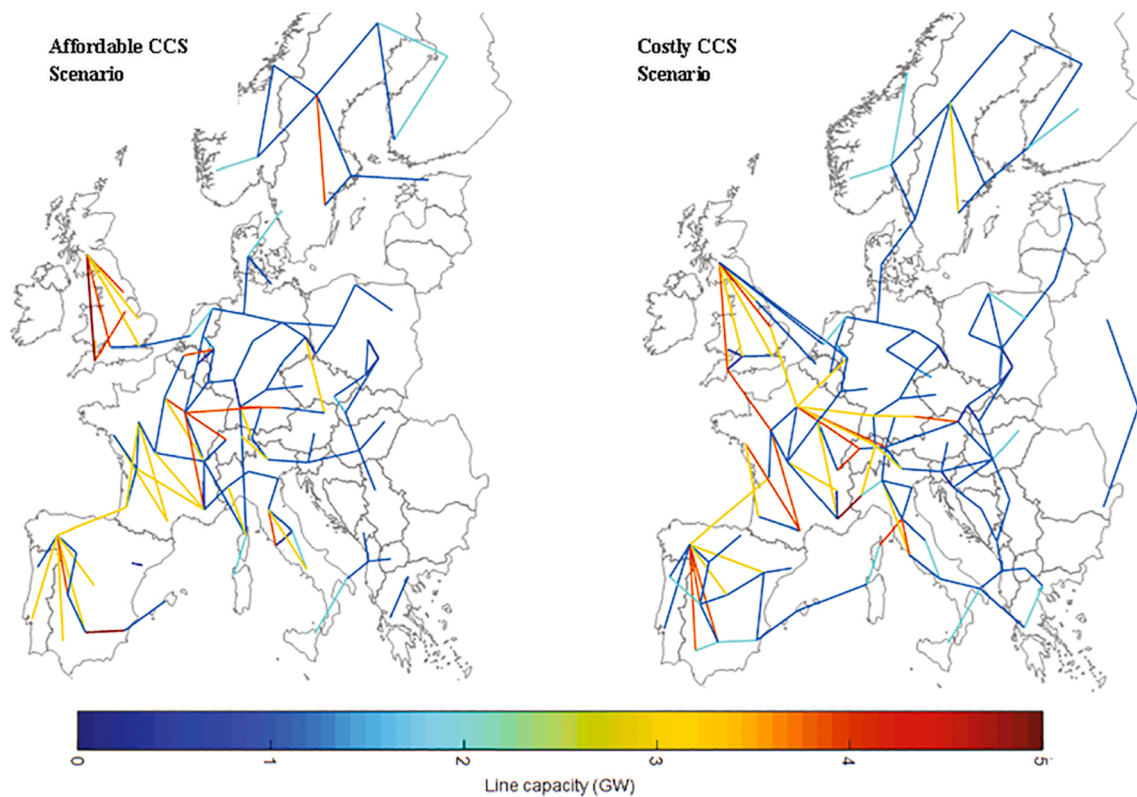


Fig. 8. Transmission network reinforcements until 2050 calculated with the TEPES model.

Table 6
Electricity sector results per scenario.

Scenario	Affordable CCS	Costly CCS	No CCS
Annualized distribution grid costs (in mio. €)	12,026	12,771	12,698
Annualized transmission grid investment costs (in mio. €)	3943	4701	4899
Annual renewable energy integrated in the electricity grids (in TWh)	2833	3035	3067
Annual pump hydro storage (in TWh)	1463	1878	2002
Annual energy demand (served load) (in TWh)	3725	3725	3710

Notes and sources: distribution network costs have been computed based on unit costs of integration of rooftop PV generation into the distribution grid provided in (Lumbreras et al., 2018); the other results are based on calculations with EMPIRE and TEPES.

deployment of CCS, more renewable generation needs to be deployed and integrated into the grid. This is true for almost every country in Europe and especially noticeable for peripheral countries such as Spain, the UK, the Balkan region, Poland and the Baltic countries, which, in the *Costly CCS Scenario*, need to be more strongly connected to the rest of the Continent.

5.5. The role of CCS in industry

Our decarbonization scenarios depict a world with ambitious exploitation of energy efficiency measures and incremental process improvements in industry. Energy efficiency potentials are almost completely exploited. However, the main mitigation option is the use of CCS technologies. The CCS scenarios envisage fundamental changes to industrial production systems after 2030. Before 2030, energy efficiency improvements combined with fuel switching to biomass and progress towards a circular economy are the main mitigation options that drive

CO₂ emissions downward.

The industrial CO₂ emissions decrease by 68% between 2015 and 2050 (Fig. 9: EU 28 industrial direct CO₂ emissions 2015–2050 in the CCS scenarios (Affordable CCS/Costly CCS). Source: FORECAST). Industrial direct emissions can be split into direct energy-related CO₂ emissions and direct process-related CO₂ emissions. Abatement of process-related emissions is more difficult than that of energy-related emissions and can potentially be accomplished using CCS. Alternatively, emission abatement can be achieved by technology switch (e.g., electrification), energy efficiency measures, or – as measure of last resort – by reducing industrial production. We focus on high emission industrial production processes which need to mitigate a substantial amount of process emissions (clinker, ammonia, ethylene, steel, lime, methanol). In the two CCS scenarios, *Affordable CCS* and *Costly CCS*, CCS is assumed to be used from 2030 onwards. CCS is used to capture approximately 35% of the emissions generated by these industry sectors (Fig. 10: Captured emissions and CCS costs in industry 2030–2050. Source: FORECAST.).

The main cost drivers of CCS are plant size, energy costs, and the costs of CO₂ transportation and storage infrastructure. Fig. 10 (panel b) shows that the bulk of the investments must take place relatively early (2030 to 2040) in order to build up capacities. For ammonia production, for example, there will be no additional investment after 2040 because capacities will be sufficient for future production. The iron and steel industry experience a noticeable decrease in CO₂ emissions, but not due to the use of CCS. Instead, it is driven by the replacement of oxygen steel with electric steel. Also, renewable energies like biomass substitute part of the industry's fuel demand.

6. Conclusions

Over the last decades, a few pilot and demonstration applications of CCS have been developed world-wide, that have proven the technology to be technically feasible, among other the first CCS power plant

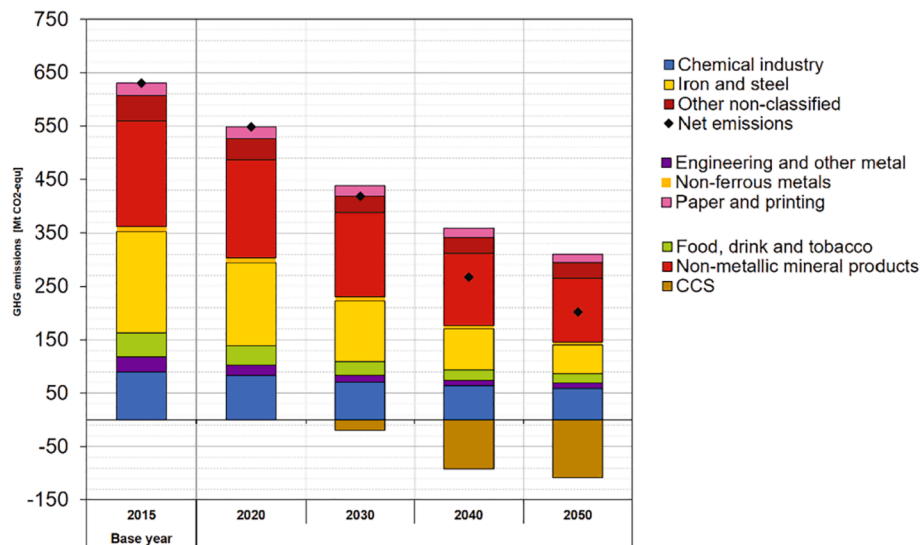


Fig. 9. EU 28 industrial direct CO₂ emissions 2015–2050 in the CCS scenarios (Affordable CCS/Costly CCS). Source: FORECAST.

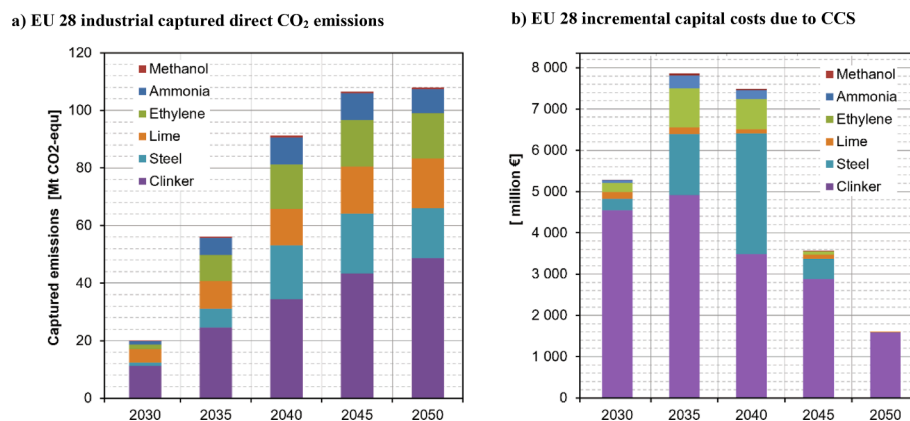


Fig. 10. Captured emissions and CCS costs in industry 2030–2050. Source: FORECAST. Note: Incremental costs denote the difference in investment expenditures to the *No CCS Scenario*.

(Boundary Dam, Canada), and some industrial installations such as an iron and steel plant in Abu Dhabi, an ethanol plant in the USA and hydrogen production in Canada; Norway is practicing carbon storage in combination with enhanced gas recovery in the Sleipner and Snøhvit natural gas fields (Holz et al., 2018a, 2018b).

While CCS could be a useful decarbonization technology, there has been little progress in its commercial scale development in the past decade and the assessment of the challenges by (Herzog, 2011) remains valid to date: there is need to lower costs, develop the CO₂ infrastructure, reducing uncertainty on storage, and addressing legal and regulatory issues. This paper has analysed some of these challenges, resulting in the following key findings:

- Assuming an optimistic perspective (*Affordable CCS Scenario*) on CCS costs and the availability of advanced CCS technology, findings indicate the installation of 189 GW of CCS capacity in the electricity sector and, in addition, 2 bn. t of CO₂ being captured in the industry sector. Yearly captured emissions peak in 2040 at more than 400 MtCO₂ p.a. from electricity and industry combined. Capture declines after 2040 due to tightening emission constraints.
- Under a costly CCS development (*Costly CCS Scenario*), the same amount of industrial capturing can be expected, but only 69 GW of CCS power plants would be deployed in the electricity sector.

- CCS installations in coal carries about the same share and absolute amounts as CCS in natural gas, i.e., about 75 GW each in the *Affordable CCS Scenario*, corresponding to almost 100% of the conventional (non-renewable) technology capacity. In that scenario, there remains no more unabated fossil fuel, neither coal nor gas, by 2050.
- In the industrial sector, almost half of the captured emissions considered in this study occur in cement and clinker, and about one sixth each in steel, lime, and ethylene production.
- There is an inverse relation between the level of CCS deployment and the electricity transmission expansion needs: As coal- and gas-fired power plants using CCS are located at existing electricity nodes, there is less reinforcement needs for the grid when this type of generation contributes to the supply of electricity than in the case where renewable deployment is larger. Thus, the annualized transmission network costs in the *Affordable CCS Scenario* (€ 3.9 bn./a) are about € 1 bn. lower than in the *No CCS Scenario* (€ 4.9 bn/a).
- Regarding the CO₂ pipeline infrastructure, the higher CCS deployment leads to significantly higher CO₂ pipeline infrastructure requirements. Thus, in the *Affordable CCS Scenario*, the total CO₂ infrastructure investments (transport and storage) are € 85 bn. between 2015 and 2050, spent on a CO₂ network of 38,000 km. In the costly CCS scenario, the CCS infrastructure investments are only € 38 bn., for a CO₂ pipeline network of ca. 26,000 km.

- The availability of advanced CCS leads to slightly lower total electricity system costs in 2050. Results show higher costs of an electricity system without CCS. This is driven by the limited absorption capability by the electricity grid on handling intermittent renewable electricity generation, a relevant fraction of which must be curtailed.

Overall, we find that the system cost advantage of using CCS, compared to not using it, is rather small. This opens the question whether this cost advantage is sufficiently high to compensate for the risks associated with deploying CCS technologies. Also, we have shown that a potential CCS deployment could benefit from economies of scale. Most obviously, the shared development and use of CO₂ transport and storage infrastructure by both the electricity and industry sectors decrease the average CO₂ infrastructure costs. Moreover, there are economies of scale and density in a system with high levels of capture where the CO₂ can be collected in nearby nodes and transported via large diameter pipelines with lower unit costs. Thus, developing a more spread-out CO₂ pipeline network with low utilization rates in a system with high capture costs in the electricity sector, as in the *Costly CCS Scenario*, results in 20% higher average CCS infrastructure costs than in a system with low capture costs and, therefore, high CO₂ capture levels (*Affordable CCS Scenario*). Clearly, deploying such a pan-European CO₂ pipeline infrastructure requires cooperation and new regulatory-market frameworks among the EU member states. That is, CCS friendly policies will be central to create a viable roadmap for the technology. In this regard, based on the findings of this paper policy makers might consider the following recommendations.

Appendix

The following tables summarize some of the key data assumptions and sources used in the analysis. For more detail information on these refer to (Holz et al., 2018a, 2018b). Also, more related data (e.g., fixed and variable operational costs) of the EMPIRE model is available in (Crespo del Granado et al., 2019).

Table 7
Efficiency assumptions of thermal power plants in the EMPIRE model.

Technology	2015	2020	2025	2030	2035	2040	2045	2050	Unit
Lignite existing	35	36	36	36	36	36	37	37	%
Lignite	44	45	45	46	47	48	48	49	%
Lignite CCS demo		32							%
Lignite CCS advanced			37	39	40	41	42	43	%
Hard coal existing	38	38	38	38	38	39	39	39	%
Hard coal	46	46	47	47	48	48	49	49	%
Hard coal CCS demo		32							%
Hard coal CCS advanced			39	40	41	41	42	43	%
Gas exist	49	50	51	52	52	53	54	55	%
Gas OCGT	40	41	41	41	41	42	42	42	%
Gas CCGT	60	60	60	61	63	64	65	66	%
Gas CCS demo		44							%
Gas CCS advanced			52	54	56	57	58	60	%
Oil existing	38	38	38	38	38	38	38	38	%
Bio existing	35	35	35	35	35	35	35	35	%
Bio	36	36	37	38	38	39	39	40	%
Bio 10% co-firing	46	46	47	47	48	48	49	49	%
Bio 10% co-firing CCS			39	40	41	41	42	43	%
Nuclear	36	36	36	37	37	37	37	37	%

Source: (ZEP, 2013) and (Rubin et al., 2015).

Table 8
Investment costs of generation technologies in the EMPIRE model.

Technology	2020	2025	2030	2035	2040	2045	2050	Unit
Lignite	1600	1600	1600	1600	1600	1600	1600	€ ₂₀₁₀ /kW
Lignite CCS demo	3799							€ ₂₀₁₀ /kW
Lignite CCS advanced		2600	2530	2470	2400	2330	2250	€ ₂₀₁₀ /kW
Coal	1500	1500	1500	1500	1500	1500	1500	€ ₂₀₁₀ /kW

(continued on next page)

Table 8 (continued)

Technology	2020	2025	2030	2035	2040	2045	2050	Unit
Coal CCS demo	3523							€ ₂₀₁₀ /kW
Coal CCS advanced		2500	2430	2370	2300	2230	2150	€ ₂₀₁₀ /kW
Gas OCGT	400	400	400	400	400	400	400	€ ₂₀₁₀ /kW
Gas CCGT	800	800	800	800	800	800	800	€ ₂₀₁₀ /kW
Gas CCS demo	1585							€ ₂₀₁₀ /kW
Gas CCS advanced		1350	1330	1310	1290	1270	1250	€ ₂₀₁₀ /kW
Bio	2250	2250	2250	2250	2250	2250	2250	€ ₂₀₁₀ /kW
Bio 10% co-firing	1600	1600	1600	1600	1600	1600	1600	€ ₂₀₁₀ /kW
Bio 10% co-firing CCS		2600	2530	2470	2400	2330	2250	€ ₂₀₁₀ /kW
Nuclear	6000	6000	6000	6000	6000	6000	6000	€ ₂₀₁₀ /kW
Hydro regulated	3000	3000	3000	3000	3000	3000	3000	€ ₂₀₁₀ /kW
Hydro (run of river)	4000	4000	4000	4000	4000	4000	4000	€ ₂₀₁₀ /kW
Wind onshore	1033	1002	972	942	912	881	851	€ ₂₀₁₀ /kW
Wind offshore	3205	2770	2510	2375	2290	2222	2172	€ ₂₀₁₀ /kW
Solar	760	540	325	295	285	260	232	€ ₂₀₁₀ /kW

Note: Data for fossil fuel technologies (incl. advanced CCS) come from (ZEP, 2013). Current CCS costs (labelled “demo”) come from (Rubin, Davison, & Herzog, The cost of CO₂ capture and storage, 2015). Source for renewables and nuclear: (Gerbaulet and Lorenz, 2017).

Table 9

Investment cost assumptions of storage technologies in the EMPIRE model.

Technology	2020	2025	2030	2035	2040	2045	2050	Unit
Pump storage (power)	1000	1000	1000	1000	1000	1000	1000	€ ₂₀₁₀ /kW
Pump storage (energy)	100	100	100	100	100	100	100	€ ₂₀₁₀ /kWh
Li-Ion utility battery	246	198	119	79	63	63	63	€ ₂₀₁₀ /kWh

Source: Pump-storage costs are own assumptions. Lithium-ion battery costs are based on the low-cost scenario in (Cole et al., 2016).

Table 10

Assumptions on CO₂ capture costs for selected industrial technologies in FORECAST-Industry.

Sector/Process	Short-/Mid-term CO ₂ capture cost	Long-term CO ₂ capture cost	Reference plant scale (annual production)
Cement production	65–135 €/tCO ₂	25–55 €/tCO ₂	1 Mt. clinker
Steel production: Integrated steelmaking	40–65 €/tCO ₂	30–55 €/tCO ₂	4 Mt. hot rolled coil
Steel production: Smelting reduction	25–55 €/tCO ₂	<0 €/tCO ₂	4 Mt. hot rolled coil
Refinery: Combined stacks	Oxyfuel: 50–60 €/tCO ₂	Oxyfuel: ~ 30€/tCO ₂	2 Mt. reference plant emissions
Refinery: Catalytic crackers	Post-combustion: 70–120 €/tCO ₂		1 Mt. reference plant emissions

Source: (Kuramochi et al., 2012).

Table 11

Investment cost by pipeline diameter and respective annual transport capacity in CCTSMOD data.

Diameter (m)	Annual transport capacity (mio. tCO ₂ /a)	Operation and maintenance costs (EUR/tCO ₂ and km)	Investment costs (EUR/tCO ₂ and km)
0.2	6	0.01	0.29
0.4	18	0.01	0.19
0.8	71	0.01	0.1
1.6	338	0.01	0.04

Source: Oei, Herold & Mendelevitch (2014, p. 521) based on (IEA, 2005) and (Ainger et al., 2009).

Table 12

Capital and variable costs of CO₂ storage in CCTSMOD.

	Capital costs in EUR/tCO ₂ per year	Variable costs in EUR/tCO ₂ stored
Saline aquifer offshore	169	6
Depleted hydrocarbon fields offshore	96	6
Saline aquifer onshore	89	4
Depleted hydrocarbon fields onshore	68	4

Source: IEAGHG and ZEP (2011), high scenario.

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