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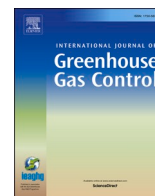
Towards improved cost evaluation of Carbon Capture and Storage from industry

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ABSTRACT

This paper contributes to the development of improved guidelines for cost evaluation of Carbon Capture and Storage (CCS) from industrial applications building on previous work in the field. It discusses key challenges and factors that have a large impact on the results of cost evaluations, but are often overlooked or insufficiently addressed. These include cost metrics (especially in the context of industrial plants with multiple output products), energy supply aspects, retrofitting costs, CO_2 transport and storage, maturity of the capture technology. Where possible examples are given to demonstrate their quantitative impact and show how costs may vary widely on a case-by-case basis.

Recommendations are given to consider different possible heat and power supply strategies, as well as future energy and carbon price scenarios, to better understand cost performances under various framework conditions. Since retrofitting CCS is very relevant for industrial facilities, further considerations are made on how to better account for the key elements that constitute retrofitting costs. Furthermore, instead of using a fixed unit cost for CO_2 transport and storage, cost estimates should at least consider the flowrate, transport mode, transport distance and type of storage, to make more realistic cost estimates. Recommendations are also given on factors to consider when assessing the technological maturity level of CCS in various industrial applications, which is important when assessing cost contingencies and cost uncertainties.

Lastly, we urge techno-economic analysis practitioners to clearly report all major assumptions and methods, as well as ideally examine the impact of these on their estimates.

1. Introduction

1.1. Carbon capture and storage from industry

The industry sector accounted for over a quarter (9 GtCO$_2$) of direct global CO$_2$ emissions in 2019 (IEA, 2020b)[1]. If indirect emissions (i.e. emissions arising from power and heat demand) are included, this sector is responsible for nearly 45 % (16 GtCO$_2$) of global CO$_2$ emissions. Despite the historic decline in CO$_2$ emissions in early 2020, caused by the Covid-19 crisis, direct industrial CO$_2$ emissions are expected to rebound as economic conditions improve and continue to grow to around 10 GtCO$_2$ in 2060 (IEA, 2020c). Reducing industrial CO$_2$ emissions presents several challenges. One-third of industry energy demand is for high-temperature heat, for which there are few mature and affordable alternatives to the direct use of fossil

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[1] Note that the emission number indicated by IEA for the industry sector does not include activities related to fuel transformation such as, ethylene oxide, ammonia, and hydrogen production. In the present study, CCS from both industry and fuel transformation for non-power application is discussed.

Table 1
Overview of characteristics of key industry subsectors.

Industrial subsector	Indicative contributions to global CO_2 emissions [%] (IEA, 2020b)[a]	Indicative range of CO_2 emissions from a plant [$MtCO_2$/y]	Indicative range of CO_2 concentrations [%vol]	Large-scale CCS applications at industrial facilities[b] [-] (Global CCS Institute, 2020)	
				Existing	Planned[c]
Cement	7 (2019)	0.7-1 (IEAGHG, 2013a; Jakobsen et al., 2017)	14-33 (Bosoaga et al., 2009)	–	2[d]
Iron and Steel	7 (2019)	2-14 (IEAGHG, 2013b)	4-27 (IEAGHG, 2013b)	1	–
Oil refining[e]	2 (2017)	0.7-2.4 (IEAGHG, 2017e)	8-20 (IEAGHG, 2017e)	1	4
Chemicals	4 (2019)	Various[f]	Various[f]	4	11
Natural gas processing	2.5 (IEA, 2013)	0.5-9 (Global CCS Institute, 2019a)	0-70 %[g]	11	2
Hydrogen	2 (2018)	0.15-1.3 (IEAGHG, 2017d, e; Nazir et al., 2019)	15-60 %[h] (IEAGHG, 2017d)	3	5
Pulp and Paper	1 (2019)	1.3-2.2 (IEAGHG, 2016)	10-25 (IEAGHG, 2016)	–	–
Offshore oil and gas operations[i]	1.5 (International Association of Oil and Gas Producers, 2016)	0.3-0.6 (Nord et al., 2017)	3-4 (Roussanaly et al., 2019)	–	–

[a] As it is difficult to obtain contribution data for the same year, the numbers from IEA (2020b) also include the year, in parenthesis, corresponding to the indicative contribution. In addition, it is difficult to obtain numbers fully separated between hydrogen and chemicals as well as NG processing, hydrogen, and oil and gas extraction. There may thus be overlap between the numbers here presented for these industry subsectors.

[b] When CCS from a cluster of industries exist or is planned, CCS from each of these industries is here reported individually.

[c] Various level of development are here accounted for (early development, advanced development, completed).

[d] Note that one of these cement plants correspond to the Norwegian full chain CCS project which may also include CO_2 capture from a waste-to-energy plant.

[e] Hydrogen production units are excluded.

[f] Due to the multitude of industries under this umbrella, it is difficult to provide a meaningful range.

[g] Considering gas field that reached the production stage.

[h] Depending on hydrogen production technology (steam-methane reforming or autothermal reforming) and considered capture location.

[i] Emissions related to heat and power production offshore.

fuels (IEA, 2019b). Process emissions, accounting for one-quarter (almost 2 $GtCO_2$) of industrial emissions, result from chemical reactions and therefore cannot be avoided by switching to alternative energy sources (IEA, 2019b). Last, industrial facilities are long-lived assets, leading to potential "lock-in" of CO_2 emissions for decades to come. Carbon Capture and Storage (CCS) retrofit is the only technology able to address these challenges and achieve deep emission reductions across the industry sector.

The three highest-emitting industry subsectors in 2019 were iron and steel (2.6 $GtCO_2$), cement (2.4 $GtCO_2$) and chemicals (1.4 $GtCO_2$), together responsible for 70 % of industry's direct CO_2 emissions (IEA, 2020b). The complementary share of industrial emissions originates from multiple industrial activities, such as pulp and paper, aluminium, textile, food, and beverages, etc. Industry and fuel transformation (hereafter jointly referred to as "industry") represents a wide variety of processes and CO_2 point sources. Among these emitters are high-purity CO_2 sources (e.g. natural gas processing, bioethanol production, and hydrogen production), which provide low-cost opportunities for CCS. Furthermore, although some subsectors currently represent a "small" share of global emissions, they may grow rapidly over the coming decades. For example, increased hydrogen production is expected to be a key strategy to decarbonise heat and transport, as well as industrial emissions in certain sectors (Fuel Cells and Hydrogen 2 Joint Undertaking, 2019; IEA, 2019b). Similarly, the waste-to-energy sector is on the rise as both, a waste management option and a heat and power production means (Allied Market Research, 2018).

Consequently, the momentum for CCS from industrial sources has accelerated around the world over the past decade (Global CCS Institute, 2019b). This is especially the case in Europe due to the ambitious mitigation targets of the European Commission to reach carbon neutrality by 2050 (European Commission, 2018). Today, globally 20 large-scale CCS applications at industrial facilities[2] have entered in operation, while some 24 future large-scale applications are currently at

different stages of development (Global CCS Institute, 2020). Among these, the Norway full chain project, Longship, is worth mentioning as it will include the first large-scale CCS project in the cement industry and potentially in a waste-to-energy facility[3]. It is worth noting that several of the projects have been driven by demand for CO_2 for EOR operations. The capture and use of CO_2 for other purposes than long-term storage (e. g., as an input to the production of fuels, chemicals, and building materials) may also grow over the coming years (IEA, 2019a).

1.2. Toward improved cost estimates for CCS from industry

To support CCS deployment, extensive studies assessing the techno-economic feasibility of CCS from industrial sources have been published, for example, on: iron and steel (IEAGHG, 2013b), cement (Gardarsdottir et al., 2019; IEAGHG, 2013a), refineries (IEAGHG, 2017b), pulp and paper (IEAGHG, 2016), chemical production (IEAGHG, 2017c), oil and gas production and natural gas processing (IEAGHG, 2017a; Roussanaly et al., 2019), and hydrogen production (IEAGHG, 2017d). Appendix A and the supplementary information provide an overview of selected publicly available, transparent, and detailed techno-economic studies for different industrial sectors including key characteristics, assumptions, and results. Although similar capture technologies can be considered in the case for power and industrial applications, their implementation can differ considerably by sector and industrial facility. This is due to differences in, among others, size and properties of the industrial process and gas streams (e.g. CO_2 partial pressure), plant layout (e.g. number of point sources and space availability), and energy supply options for the capture process, including the availability of low-value waste heat.

Table 1 presents typical key plant characteristics for a wide range of industrial processes together with their status on number of existing and planned large-scale CCS deployment.

Different assumptions about these factors are partly responsible for

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[2] An application corresponds to the implementation of CCS from a given industrial plant, which means that a CCS project considering a cluster of industries is considered here as multiple applications.

[3] Status in December 2020.

the wide differences in cost estimates for CCS reported in literature, even within a given industrial sector (IEAGHG, 2018; Leeson et al., 2017). However, a significant part of the wide ranges in costs reported might arise from other factors, including differences in methodological framework (Garcia and Berghout, 2019), input data quality, cost metric definition, assumptions regarding capture technology maturity, retrofit vs. new-built facilities, plant location, energy prices, waste heat availability, and the inclusion (or exclusion) of CO_2 transport and storage. For example, different heat and power supply strategies may be selected resulting in very different CO_2 avoided cost (Gardarsdottir et al., 2019; Roussanaly et al., 2017a). Furthermore, while CCS retrofit of existing facilities is considered to be an important mitigation measure to decarbonise long-lived assets (IEAGHG, 2017b), many studies only consider CCS for new-built facilities or underestimate the cost impacts of retrofitting.

A better understanding of the costs of CCS from industry is therefore needed to better inform decision-makers on the economic potential of CCS and guide research activities to improve the performance of promising options across industrial sub-sectors. Building on a previous CCS costing guideline papers (Rubin et al., 2013), *the present work aims to contribute to the development of improved guidelines for cost evaluation of CCS from industrial applications*. It is drafted in conjunction with two other guideline documents, one looking into methods for carrying out costing of novel (low technology readiness level) processes (Rubin et al., 2020) and a second document on uncertainty analysis methods for use in CCS TEA (van der Spek et al., 2020). In particular, the present guideline aims to support the establishment of improved cost evaluation of CCS from industrial applications through three key areas. The first area focuses on cost metrics and challenges that might arise in the case of CCS from industry. The second area focuses on three key underlying cost items for the evaluation of CCS from industrial plants: cost and CO_2-footprint of heat and power consumption; costs associated with implementation of CCS on a retrofit basis, and cost associated with CO_2 transport and storage. Finally, the last area focuses on transferability of data, experience, and maturity of CCS from power generation to CCS at industrial sources.

2. Cost metrics

Performance metrics and benchmarking are key aspects of technology selection, development, deployment, and improvement. They allow to identify apparent performance gaps and explanatory factors for these as well as best practices that lead to superior performance. Most performance metrics for capture systems are directly derived from power systems. Typical examples are investment costs, incremental products costs, cost of CO_2 captured, and cost of CO_2 avoided. These costs can be reported in absolute (e.g. Euro) or normalized terms (Euro per tonne CO_2 avoided or tonne CO_2 captured). Absolute costs are difficult to understand and interpret by non-experts. Without specific background knowledge it is difficult to know whether a given investment value is high or low. Normalized values, i.e., indicators that relate total costs (or investment) to output (e.g., tonne CO_2 captured, tonne CO_2 avoided, tonne of product(s), increase in production cost of industrial product) or input (e.g. per MJ fuel input) are often used as they allow (under similar assumptions) to compare and/or benchmark technologies.

2.1. Common metrics

The most common metrics to evaluate CCS are *cost of CO_2 captured* and *CO_2 avoidance cost* (also referred to as cost of CO_2 avoided) (Rubin et al., 2013). The former provides insights into the investments and operating costs associated with the CO_2 capture (or the CCS chain) while the latter gives insights into the performance of the capture unit (or the CCS chain) as a carbon mitigation option. *Cost of CO_2 captured* (Euro per tonne of CO_2 captured) relates the costs needed for building and operating the capture and compression units (or the whole CCS chain) to the physical amount of CO_2 captured and compressed from a given point source. Note that in most cases, CO_2 captured costs do not include the costs of transport and storage. Nor does it consider the CO_2 emitted from process energy supply. *CO_2 avoidance costs* (Euro per tonne of CO_2 avoided) is the most common and meaningful metric used when assessing the costs of CCS as an abatement option as it provides insights into the costs of not emitting one tonne of CO_2 to the atmosphere while still producing a unit of useful product[4]. Therefore, it can be used to compare different types of CCS systems when assessing the most effective option to reduce CO_2 emissions from a given process. Note that the design of a capture unit, a compression unit, or a pipeline is based on the amount of emissions captured not avoided.

CO_2 avoidance cost (CAC) is a relative metric and therefore it requires a reference system (see Eq. 1). For the result to be rigorous, it is important that the industrial facility produces the same amount of key material output for both systems (with CCS and without CCS). Furthermore, CAC takes into account that operating the capture and compression unit requires energy and materials thereby producing additional indirect CO_2 emissions. In general, an industrial plant captures more CO_2 than it avoids, and therefore the costs per tonne of CO_2 captured are lower than the costs per tonne of CO_2 avoided.

Three different calculation methods can be used to evaluate the CAC in the case of CCS from industrial sources: the so-called "exhaustive" method, the "net present value method", the "annualization calculation method" (Roussanaly, 2019). The "exhaustive" method is shown in Eq. 1 while the equations used for calculating the CAC in the other two methods are presented in Appendix B.

$$CAC = \frac{(LCOKM)_{ccs} - (LCOKM)_{ref}}{(t_{CO2}/U_{Km})_{ref} - (t_{CO2}/U_{Km})_{ccs}} \tag{1}$$

Where, LCOKM is the levelised cost of the key material(s) of the industrial plant with CCS or without in, for example, € per unit of key materials(s) (Roussanaly, 2019), tCO2 is the mass amount of CO_2 emitted by the industrial plant, and UKM stands for unit of key material (s).

While the exhaustive method is always valid, it is worth noting that the two other methods do not require the assessment and evaluation of the considered industrial plant hence requiring significantly less effort and data. However, these two approaches also come with limitations and therefore must be used carefully. A summary of assumptions required to ensure the validity of each CO_2 avoidance cost calculation methods is presented in Appendix B.

Note that the CAC is often presented together with a breakdown of cost along the CCS chain, with CO_2 conditioning either lumped together with the capture or transport steps. However, it is recommended here that any cost breakdown of CAC present capture, conditioning, transport, and storage as four individual items.

In power plants, CAC includes the impact of the capture unit on the efficiency of the power plant (as a consequence of using part of the steam and/or generated in the plant to cover the energy needs of the capture unit). In most industrial settings, however, CAC needs to include the costs and CO_2 emissions from additional units e.g., a boiler or a combined heat and power (CHP) system needed to cover the energy requirements of the capture and compression units, or emissions associated to the use of electricity from the electricity grid. Note that not only additional units but also changes in existing units as a consequence of CO_2 capture need to be taken into account. For instance, if the capacity of an existing boiler is increased so it can supply steam to the capture unit, the additional fuel (and related emissions) needs to be allocated to the capture unit and accounted for in the CAC calculation. If, however, waste energy is available at location and no extra units or

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[4] This means in practice that the emissions associating with building and operating the CO_2 capture facility (CCS chain) are also taken into account.
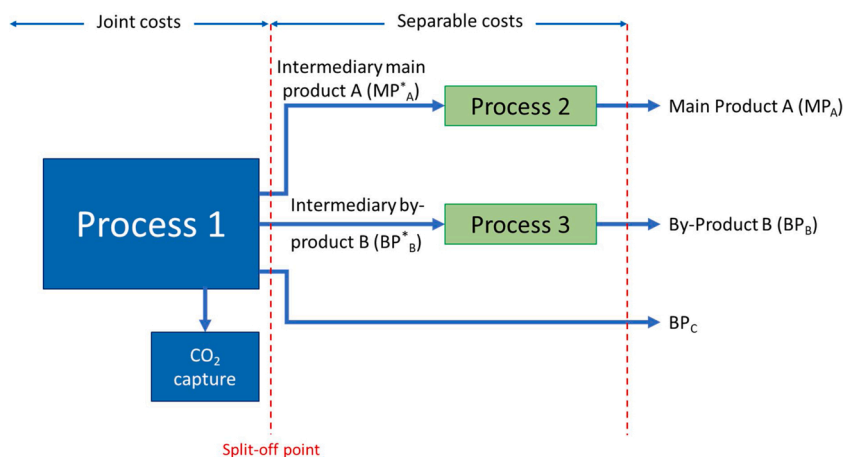
Fig. 1. Illustration of joint vs separable costs.

extra capacities in existing units are required then the costs of CO_2 avoided could be equal to the cost of CO_2 captured (including the cost incurred to utilise the waste heat for CO_2 capture). This only holds if the "waste energy" is really so in practice. Many studies use average amounts of waste energy taken from e.g., literature, and therefore tend to overestimate the amount of waste energy available on-site[5] .

CAC is generally used to estimate the minimum CO_2 emission penalty (tax or quota price) that would be required for making a point source without CO_2 capture as expensive as a point source with CO_2 capture (or to estimate the subsidy required to make a point source with CO_2 capture as expensive as a similar point source without it). An important aspect to highlight here is the importance of system boundaries in the calculation of CAC. Strictly speaking, because we are interested in the costs of not emitting one tonne of CO_2 into the atmosphere all emissions should be included, that is direct emissions (i.e. emissions generated in the plant or so-called gate-to-gate emission) and indirect emissions (i.e. emissions taking place outside the industrial plant, for instance during the extraction and transport of fuels, during the production of electricity, the transport and storage of CO_2, or the end life of the product). The wider the system boundaries the lower the avoided emissions and the higher the CAC.

Another indicator that is generally used is *incremental production costs per unit of product*. It relates the costs of capture to the net output of a facility. In a power plant, the impact of capture in the production of electricity is generally assessed through the energy efficiency penalty induced by the capture unit. In an industrial plant, this is less obvious for two reasons. First, it depends on the origin of the energy used to supply the capture requirements e.g., an extra boiler, waste energy, or existing steam. In the latter case (use of existing steam) the capture system may impact the costs and or performance of the unit where the steam was originally used. This impact needs to be assessed and included in the calculation. Second, a key distinction between the power and industrial sector is that most industrial processes do not produce one product and require allocating the incremental costs to the different products. This is discussed in detail in the next section.

2.2. The challenge of multi-products in industrial sectors

A key distinction between the power and industrial sector is that

many industrial processes produce multiple outputs in a unit. In an atmospheric distillation unit at a refinery for instance, LPG, Naphtha and Diesel/Kerosene are produced. If CO_2 capture would be applied to such a unit, the metric to report the cost of product is not straightforward, as it can be referred to one or more products, including intermediate ones.

This problem is not unique to carbon capture and has been discussed when estimating costs of multi-product industries. A typical approach is to distinguish between *joint costs* (i.e. costs of a production process that yields a number of products where a physical relation exists between the products that prevents one from being obtained independently from the others) and *separable costs* (i.e. cost incurred in processes that produces a single product) (Deevski, 2016). To separate joint costs from separable costs, a split-off point is required as indicated in Fig. 1. Separable costs are therefore all the costs incurred beyond the split-off point (for instance, cost required for purifying a given product). The costs related to the production of a product (for instance product A) are therefore composed of *part* of the joint costs plus the separable costs of the product. In the simplest joint processes, the joint products are sold at the split-off point (no further processing is required such as for by-product BPc in the figure) and the separable costs are zero.

There is, however, no standardized methodology currently available to determine the contribution of the different production factors (energy, water, labour) used in the production of each of the joint products at the split-off point. Because in the case of joint costs, one product *cannot* be produced without the other, it is not physically possible to measure the costs of production factors used in the manufacture of each of the joint products. Companies use different methods to allocate the costs to the joint products. In general, all production costs need to be allocated to all products and to do so, companies distinguish between main product(s) and by-products. This distinction is generally made based on the portion of their sales in the total sales of the company. A main product is a product (or products) with significantly higher total sales values compared to the total sales values of other products while by-products are products of a joint process that have low or no total sale value compared with the total sale value of the main product(s). The classification of products (main product or by-product) changes over time and among companies.

The costs allocated to the main products are generally estimated by either:

o Allocating the costs according to the amount of product produced defined by physical measures such as the share of mass content (the ratio between the total annual production of each product and the total annual refined oil products). This method requires that all the products be measured with the same underlying physical measure

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(weight, volume, quantity, etc) and is recommended when the different products are homogeneous *and* their sale prices are relatively close to each other.

o Allocating the costs according to market-based information such as the sale prices of the products. It is based on the assumption that the market price is a proxy for the production costs. In this method, joint costs are, for instance, allocated to the main products proportionally to the sum of the final sales value of the output. Note that if one of the main products cannot be sold as it is (for instance an intermediate product for which there is not known market price and therefore further processing is needed before a main product can be sold in the market), the price incurred to finish the product (separable costs) is subtracted from the sales value of the product. This is called net realizable value and is a hypothetical market value at intermediate stage of production which assumes that all the profit margin is attributable to the joint process and not to the separable costs. Assuming that the capture unit was applied before the split-off point (i.e. part of the joint cost as shown in Fig. 1), it is worth noting that the larger the separable costs are, the lower is the contribution of the CO_2 capture unit to the total product costs and vice versa.

The costs of by-products can be estimated by:

6 Assigning them no value (costs are therefore only allocated among main products). This method is also known as the Miscellaneous income method. Note that this approach used to be the default approach used to the CO_2 from the capture unit in which no costs were allocated to the CO_2 and all costs were allocated to the main product (e.g., steel or electricity). However, in cases where new options emerge that provide economic value to the CO_2 (CO_2 utilization), an appropriate (case-specific) non-zero value should be assigned. Consequently, even using the same methodology, the estimated costs might vary as these are a function of the final use of the CO_2 and the market for that use. Furthermore, and depending on the CO_2 sales price, there may be cases where the CO_2 may be considered a main product instead of a by-product. In such cases, one must be careful to distinguish between uses of CO_2 that result in permanent (long-term) removal from the atmosphere[6] - as required for GHG mitigation - versus utilization that soon results in the release of CO_2 to the atmosphere and thus does not contribute to GHG mitigation.

7 Assigning them a net realizable value. In this case, the value of selling the product are large enough to have a significant effect in the profits of the company but not large enough to be comparable to the profit of the main product. Note that by allocating costs to the by-product, a reduction in the production costs of the main product(s) will be shown (as the total costs of producing the main products and the by-products is constant).

8 Assigning them a net realizable value minus a given profit value

9 Assigning them the expenditure allocated to the acquisition price or the replacement value on the current market (for instance when a by-product is used within the plant to avoid purchasing materials or utilities, for example, the combustion of a waste to provide heat which avoids purchasing natural gas)

Currently, there are no standardized guidelines of best available practices for selecting allocation methods and, in practice, each company has its own internal approach. To be able to compare capture costs that have been allocated to a given product (including CO_2 that will be used by a third party for CCU) explicit documentation needs to be provided in the number and characteristics (type, amount, concentration, etc) of products and by-products as well as a detailed description of the approach used for allocation. When possible, it is recommended to examine the costs using more than one allocation method as this will provide insights into the impact of the method in the results.

3. Considerations for improved assessment of key cost contributors

This section discusses three key contributors to the cost of CCS from industry, which are often not studied in adequate detail are examined and exemplified: 1) energy aspects 2) retrofitting costs 3) CO_2 transport and storage costs.

3.1. Energy aspects

CO_2 capture from industrial processes is typically energy-intensive and thus a large part of the CO_2 capture cost is potentially related to the use of energy. For example, the steam consumption for MEA solvent regeneration in a cement plant typically contributes to nearly 50 % of the CO_2 capture cost[7] (Gardarsdottir et al., 2019). Heat (mainly in the form of steam) and electricity are the two main forms of energy needed by CO_2 capture processes. The form of input energy differs per capture technology and facility; for example, oxyfuel and membrane-based systems use electricity while chemical absorption systems require both heat and power.

In practice, several key factors determine the cost and CO_2 emissions associated with energy consumption: type of energy used (electricity and heat), origin and supply strategy of energy, costs and emissions intensity of the primary energy source, and possibility to export excess energy to third parties. Most of these factors are region- and facility-specific and may not only affect the CO_2 avoidance cost but also the comparison of CO_2 capture technologies. Therefore, in studies related to CO_2 capture in industrial processes, it is recommended to discuss the sensitivity of the CO_2 avoidance costs with respect to the choice of facility characteristics, fuel prices, energy supply, and export alternatives. The effect of the choice of energy supply alternatives is discussed below with an example on CO_2 capture in a cement plant.

3.1.1. Energy supply strategies

The origin and production/supply strategy of steam and electricity have a significant impact on their production costs and associated CO_2 emissions, and may thus significantly impact the CO_2 avoidance cost. While a given heat and power supply strategy is often implicitly adopted in the evaluation of CO_2 capture technologies, it is important to realise that this implicit assumption may impact significantly the CO_2 avoidance cost of a capture technology as well as the comparison of capture technologies.

Fig. 2 illustrates different steam and electricity supply strategies in the case of a cement plant integrated with an MEA-based absorption CO_2 capture unit (Gardarsdottir et al., 2019), while Table 2 presents their associated costs and CO_2 emissions intensities. As seen in Table 2, extracting steam from a low-pressure turbine or steam originating from waste heat recovery in core industrial processes are cheaper options and have lower CO_2 emissions intensity. Thus, integrating excess heat available in the industrial plant or in another facility near the CO_2 capture unit is expected to be a cost-effective solution. However, it should be noted that a large amount of good quality waste heat is rarely available in industrial plants and should be expected to be further driven down by energy efficiency improvement efforts. On the other hand, an electric boiler can in general appear as an inefficient way of producing steam for the CO_2 capture unit.

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[6] It is worth noting that, in such cases, CO_2 utilization could still contribute to reduction of fossil fuel use elsewhere in the overall chemicals manufacturing industrial system. Under specific conditions, this reduction may be considered as contributing to GHG emissions mitigation.

[7] When a natural gas boiler is used to produce steam and the waste heat from the original facility available to invest on the CO_2 capture system is limited.
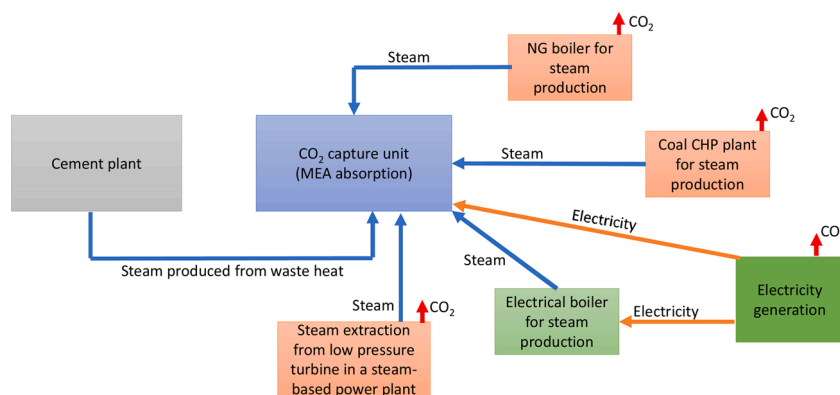
Fig. 2. Schematic illustrating different means of producing and supplying energy for an MEA-based CO_2 capture in a typical cement industry.

However, it is important to also realise that the cost and associated emission intensity of a steam strategy depends on the site-specific characteristics, as well as external parameters such as energy prices.

3.1.2. Impact of energy prices

The cost of the energy supply is directly linked with the price of input energy sources (fuel or electricity). However, the energy source prices can vary significantly based on local market conditions, local environmental policy framework, and their possible future evolutions (IEA, 2018). It is thus important to also understand the impact of these energy source prices on the steam production cost.

Fig. 3(a, b and c) shows an example of a sensitivity analysis of the steam cost as a function of the price of coal, natural gas, and electricity respectively. As can be seen from these, the energy prices can significantly impact the selection of an optimal steam production strategy. Overall, steam extracted prior to an LP turbine or generated based on available waste heat remain the cheapest options in most situations. However, if electricity prices are high, gas- or coal-CHP can be very attractive options as these would also result in the production of high-value electricity.

Finally, it is important to realise that some of these energy prices are linked. For example, higher global coal and gas prices can be expected to lead to higher global electricity prices. As a result, a heat and power production unit used for CO_2 capture and also selling excess electricity might be less impacted by an increase in fuel prices due to high electricity revenues. Similarly, carbon prices/taxes increase overtime to penalise CO_2 emissions can also significantly impact the performance

and selection of heat and power supply strategies. A possible way to deal with these uncertainties is to make scenarios about future plausible combinations of energy and carbon prices to clearly understand the variety of possible outcomes.

3.1.3. Credits for import and export of energy

In some cases, energy is imported or exported from the industrial site due to the implementation of CO_2 capture, resulting in a change in energy production and consumption, and related CO_2 emissions produced elsewhere in the energy system (indirect emissions). Similarly, the economics of the capture case may be impacted due to the purchase or sale of energy from or to third parties.

One way to account for these effects is to assign credits or penalties to the costs and CO_2 emission reductions in the CO_2 capture case. Cost and environmental penalties or benefits from the energy import or export will be site- and region-specific, and will also depend on the reference case without CO_2 capture (IEAGHG, 2018). For example, the potential electricity exported to the grid will displace electricity generation elsewhere in the broader energy system; this can for example be electricity generated in a coal-fired power plant or renewable electricity, each with a different carbon-intensity. Credits for emission savings elsewhere in the broader energy system will depend on the CO_2 emissions factor of the electricity grid, and can therefore vary significantly from one region to another.

The credits can be calculated by multiplying the imported or exported energy with an energy price and CO_2 emission factor based on life cycle analysis, which best reflect the reference case. In many cases, this is a fair approach, especially when it concerns the export of excess fuel and steam coming from the core industrial process, which may have changed due to the CO_2 capture process. However, this approach is arguably less fair when considering the export of steam or electricity from newly built energy plants. After all, the generation and export of large amounts of electricity and steam could create economic revenues and emissions savings (if it displaces more carbon-intensive energy elsewhere in the broader energy system), and not allocating these credits to the CO_2 capture case could distort its techno-economic performance (Berghout et al., 2019). An alternative accounting method is to exclude revenues from excess electricity and steam generation as well as the costs for the share of the fossil fuel or biomass of the energy plant that corresponds with this excess energy production (which can be determined on an exergy, energy, or economical basis). While there is not an inherently best accounting method, this can have a large impact on the computed avoidance costs and emissions of the capture case. Study practitioners should thus be explicit on their considered accounting method.

Table 2
Cost and CO_2 emission intensity of different stream supply options.

Source	Emission intensity [kgCO$_2$/GJ]	Steam cost [€$_{2015}$/GJ]
Electric boiler	87	18
Natural gas boiler	57	7.2
Natural gas-CHP plant	57	6.4
Coal CHP plant	127	6.1
Steam extraction from an LP Turbine	49	3.7
Excess heat from industrial core process	0	1.9

Note: These costs are based on the heat supply evaluation performed in the CEMCAP project. (Gardarsdottir et al., 2019; Roussanaly et al., 2017a). These were established for a generic Netherlands-based application, in the context of CO_2 capture from a cement plant, with an NG price of 6 €/GJ, a coal price of 3 €/GJ and an electricity price of 58 €/MWh, and a CO_2-intensity associated with electricity consumption of 306 gCO$_2$/MWh. A project duration of 25 years and a real discount rate of 8% are considered.

3.1.4. Effect of energy aspects on CO_2 avoidance costs and choice of capture technology

To illustrate the effect of energy supply strategy on the CO_2 avoidance costs and comparison of two capture technologies (MEA-based absorption and membrane-assisted liquefaction) in a cement plant (Gardarsdottir et al., 2019), an example of 7 scenarios are presented in Fig. 4 in order to highlight the energy aspects discussed above. In particular, these scenarios combine different steam supply strategies (natural gas boiler, extraction prior to a low-pressure steam turbine, electricity boiler), electricity prices (30 and 80 €/MWh), and natural gas prices (6–9 €/GJ). While none of these scenarios consider CO_2 capture from ancillary energy supply unit(s), it is worth noting that this together with switching to bio-based energy are key to reach deep emissions reductions across the industrial process (Tanzer et al., 2020). However, CO_2 emitted from these ancillary units should be captured and geologically stored as well to achieve deep levels of decarbonisation, and these costs should be represented in the overall CO_2 avoidance cost.

As can be seen in Fig. 4, the selected steam supply strategy can have a significant impact on the technology comparison. In the heat supply scenarios, MEA-based is the most cost-efficient capture technology in the natural gas boiler and steam extraction prior to a LP turbine scenario (respectively scenarios 1 -also referred as base case- and 2). On the other hand, the membrane-assisted liquefaction is the most cost-efficient

capture technology if steam must be supplied through an electric boiler (scenario 3). It is also worth noting that the CO_2 avoidance cost of the cost-optimal capture technology may or may not be impacted. For example, compared to the natural gas boiler scenario, the steam extraction scenario results in significantly lower CO_2 avoidance cost for the optimal capture technologies, while the electric boiler scenario result only in slightly lower costs.

Fig. 4 also illustrates that energy prices can also have an impact on the CO_2 avoidance cost, as well as on the comparison of technologies. Compared to the base case, a higher natural gas price favours the membrane-assisted liquefaction (scenario 4) while a higher electricity price would favour the MEA-based capture (scenario 5). The potential impact of CO_2 emissions associated with heat and electricity consumption can also be visualised by comparing the scenarios 3 and 6 (both based on heat supply through an electric boiler). As electricity is assumed to be based on renewable source in this scenario, no CO_2 emissions are associated with the consumption of heat and electricity thus resulting in lower CO_2 avoidance cost. Finally, scenario 7 combines a reduction in electricity prices and no CO_2 emissions associated with power. In this case, steam produced from an electric boiler results in lower CO_2 avoidance cost than the base case (scenario 1) as well as nearly on par CO_2 avoidance costs between the two CO_2 capture technologies. Although scenario 7 may seem far-fetched for most locations, it

(a) Impact of coal price

(b) Impact of natural gas price

(c) Impact of electricity price

Legend:
- Electrical Boiler
- Natural gas-CHP plant
- Steam extraction prior to a LP Turbine
- Natural gas boiler
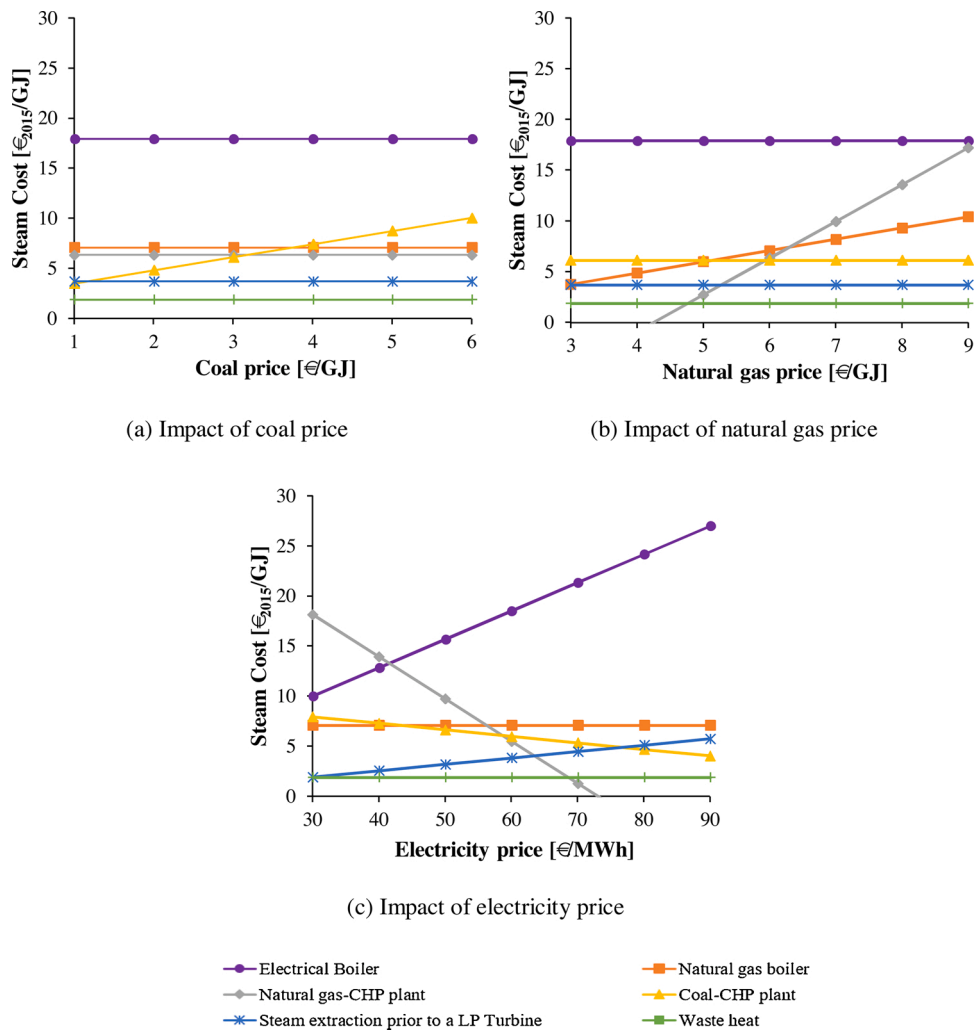- Coal-CHP plant
- Waste heat

Fig. 3. Impact of energy prices on the steam cost for different steam supply strategies: a) coal price b) natural gas price c) electricity price.
Figure footnote: Results included in these figures were calculated on the same basis as Table 2, while the energy (coal, natural gas, electricity) prices are here varied to understand their impact on the steam cost.
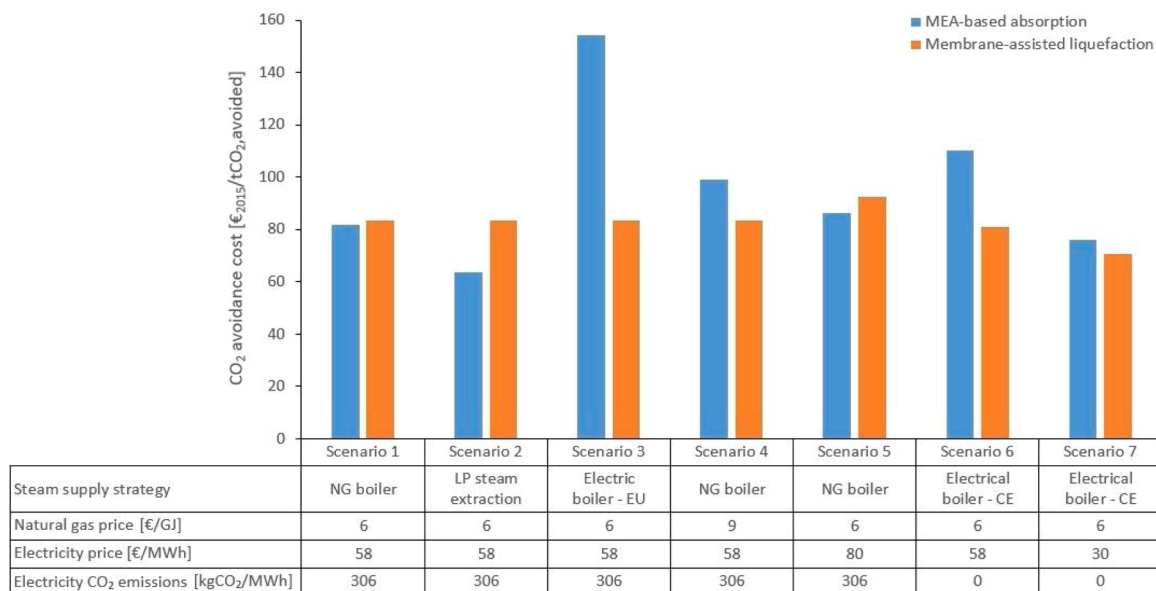
Fig. 4. Illustration of the impact of different energy scenarios on the CO_2 avoidance costs and the comparison of two capture technologies (MEA-based absorption and Membrane-assisted liquefaction).

Figure note: The performance of the MEA-based and membrane assisted liquefaction for CO_2 capture from a cement plant are extracted from the CEMCAP project (Gardarsdottir et al., 2019). These were established for a generic Netherlands-based application, a project duration of 25 years, and a real discount rate of 8%.
"NG boiler" corresponds to natural gas boiler; "LP steam extraction" corresponds to steam extraction prior to a low-pressure turbine; "Electric boiler – EU" corresponds to electric boiler powered by electricity with the characteristics of the average European Union electricity mix; "Electric boiler – CE" corresponds to electric boiler powered by the clean electricity thus it is assumed to not result in any CO_2 emissions.

is representative of conditions for CO_2 capture in Norwegian industrial plants[8] .

Building on the energy aspects discussed previously, these scenarios further emphasize the importance for TEA practitioners to consider the impact of possible energy supply strategies as well as possible evolution of global energy scenarios.

3.2. Retrofitting costs

In retrofitting an industrial plant with a CO_2 capture process, several plant-specific and technology-specific characteristics can entail significant costs and considerations for the CO_2 capture process that are often overlooked in techno-economic studies of industrial CCS applications. This section aims to highlight some of the most important retrofitting cost aspects and provides several numerical examples for illustrating these.

3.2.1. Economic impact of plant production stop for CO_2 capture retrofit

Retrofitting of CO_2 capture technologies at an industrial plant might involve a temporarily shut down, fully or partially, especially if fundamental modifications to the core process are required. The resulting production losses can have non-negligible economic consequences, depending on the type of process, integration of the CO_2 capture system with the original facility, and economies of scale, and will therefore have to be kept to an absolute minimum. For certain industrial applications and CO_2 capture technologies, e.g. oxyfuel or pre-combustion technologies in cement or iron and steel applications, a significant downtime might be required to modify the existing industrial plant for deep integration with the CO_2 capture plant. For other end-of-pipe technologies that do not require significant integration with the core process, other than re-routing of the flue gas, it could be expected that the retrofit

period is aligned as much as possible with a routinely scheduled production stop for maintenance to minimize the economic impact. In some cases, it might be possible to only shut down parts of the core plant for the retrofit and thereby avoiding 100 % production losses, e.g. in a plant with several emission sources where only a single source is retrofitted with CO_2 capture or a plant with multiple production lines. This could be the case in a modern steel mill or a multi-product oil refinery where the production process is not necessarily linear. Although not exemplified here, it should be mentioned that the same considerations for plant production stop and economic consequences also apply in retrofitting CO_2 capture to power plants. In any case, costs arising from plant production stop should transparently be taken into account in estimating the costs of CO_2 capture.

The economic impact of production stops for retrofit is exemplified below for three different industrial plants: a cement plant (Gardarsdottir et al., 2019; Voldsund et al., 2019), a pulp mill (IEAGHG, 2016), and an

Table 3
Examples of key data for three different industrial plants.

Plant type – product	Cement plant (CEMCAP) – clinker	Pulp mill (IEAGHG) – air-dried pulp	Integrated steel mill (IEAGHG) – hot rolled coil
Production rate [tonne of product/ hour]	120	95	500
Production cost without CCS	63 $€_{2014}$/$t_{clinker}$	523 $€_{2015}$/adt^a	451 $€_{2014}$/t_{HRC}[a,b]
CAPEX and fixed OPEX of plant	39 $€_{2014}$/$t_{clinker}$	248 $€_{2015}$/adt^a	204 $€_{2014}$/t_{HRC}[a,b]
CO_2 emissions in normal operation w/o CO_2 capture [tCO_2/h]	103	257	1047

[a] adt and hrc stand for air-dried ton and hot-rolled coil, respectively.
[b] Costs converted from $2010 to €2014 using the Chemical Engineering Cost Plant Index (CEPCI) and average currency exchange rates.

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[8] Although the CO_2 footprint would not be zero if assessed through a full life cycle analysis.
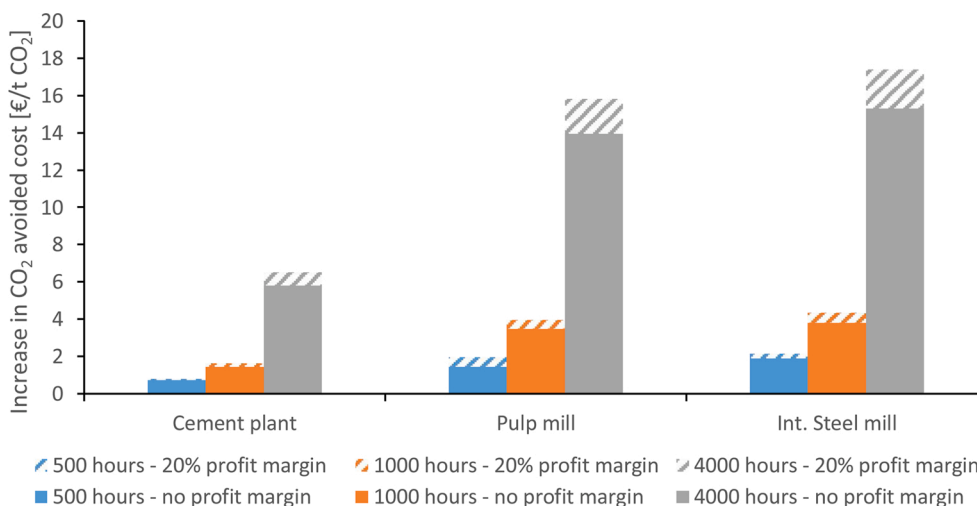
Fig. 5. Increase in CO_2 avoided cost, as a result of a whole-plant production stop, for production stop durations from 500 to 4000 h, and with profit margin losses on the product cost during production stop of 0 and 20 %.

Figure footnote: During the production stop, fixed running costs and annualized capital costs are accounted for together with the loss in profit. The increase in CO_2 avoided cost is calculated by dividing these costs and profit loss during the plant stoppage over the discounted amount of CO_2 avoided over the expected numbers of operation of the CO_2 capture facility. Here, 25 years of operation and a real discount rate of 8 % are considered. It should be noted that for simplification, the amount of CO_2 avoided is calculated with a 90 % CO_2 capture rate, 90 % capacity factor of the industrial plant, and does not account for emissions originating from potential increase in energy demand of the industrial plant after CO_2 capture is implemented.

integrated steel mill (IEAGHG, 2013b). Key data for these industrial plants is listed in Table 3.

The added cost of CO_2 avoided due to a production stop for CO_2 capture retrofit for the three industrial plants are exemplified in Fig. 5, for production stop in the range of 500−4000 h and under specific assumptions on the loss of profit. During the production stop, fixed running costs and annualized capital costs[9] are accounted for together with the loss in profit (for example with a 20 % profit margin on the product cost). From Fig. 5 it is evident that a lengthy production stop for retrofitting CCS has a significant economic impact and will add considerably to CO_2 avoidance costs, especially if only a small part of the production stop can be aligned with a routinely scheduled production stop for maintenance. This can be exemplified in retrofitting a cement plant with oxyfuel technology, where, under specific assumptions, a 4000 hs production stop for significant modifications to be implemented in the core process would increase the CO_2 avoidance cost by over 15 %, assuming a 20 % profit margin on the product. In the case of retrofitting a pulp mill's recovery boiler with amine CO_2 capture, a shorter production stop of 1000 h might suffice for the end-of-pipe technology, resulting in around 6% increase in the CO_2 avoidance cost.

In addition to the length of the production stop, the product profit margin will also impact the added cost of CO_2 avoided, as exemplified in Fig. 5, for a production stop of 500, 1000, and 4000 h in a cement plant, pulp mill, and an integrated steel mill.

3.2.2. Impacts on the product quality and plant operation

The integration of CO_2 capture technologies can also have an impact on the main output product(s) of the plant. For example, if no other process modifications are implemented, CO_2 oxyfuel combustion in a cement plant has a direct impact on the temperature in the cement kiln, which can negatively affect the clinker phase formation and consequently the product quality (European Cement Research Academy, 2012). Another example is oxyfuel combustion in the blast furnace of an

integrated steel mill. In this case, H_2 and CO rich flue gases from the furnace are partly recycled, after the CO_2 has been separated from the gases, to regulate the mass and energy balance of the furnace. This drastically different atmosphere in the furnace can affect the product to some extent but will also have a large impact on the energy balance of the whole steel mill which could make this technology difficult to implement in existing plants (Arasto et al., 2013).

Implementation of capture technologies that affect the core plant's main product may result in additional costs for modifications of the original process and equipment, post-treatment to meet existing product standards, or a decrease in product value. In such cases, both should be attributed to the cost of CO_2 capture. A lower product value will most likely yield lower revenues. These situations are more likely to occur in retrofit applications, where changes to the primary process may be less feasible than in new plant applications. Conceivably, however, technology innovations and process modifications to accommodate the new carbon constraint may also result in net benefits and cost savings (as occurred, for example, when CFCs were banned from certain industrial processes).

In practice, it can be challenging to assess foregone revenues (or additional profits) since the exact market value (product price) is often unknown. If a sound assessment is not possible, practitioners of costing studies should at least clearly report the assumed cost effect and consider sensitivity analyses. In general, the required product quality is dictated by consumers' demands. For that reason, maintaining the product quality will often have priority for the plant operator.

3.2.3. Spatial constraints for CO_2 capture equipment in existing industrial plants

Space restrictions or safety considerations on industrial sites could severely affect the technical and economic feasibility of installing CO_2 capture equipment and their supporting utilities on industrial sites. Unlike new-build (greenfield) plants with CCS, existing (brownfield) facilities were not designed to accommodate spacious capture equipment, thus possibly making retrofit applications of CCS more challenging and costly. Although spatial constraints vary considerably on a case-by-case basis, depending on the design and layout of the plant as

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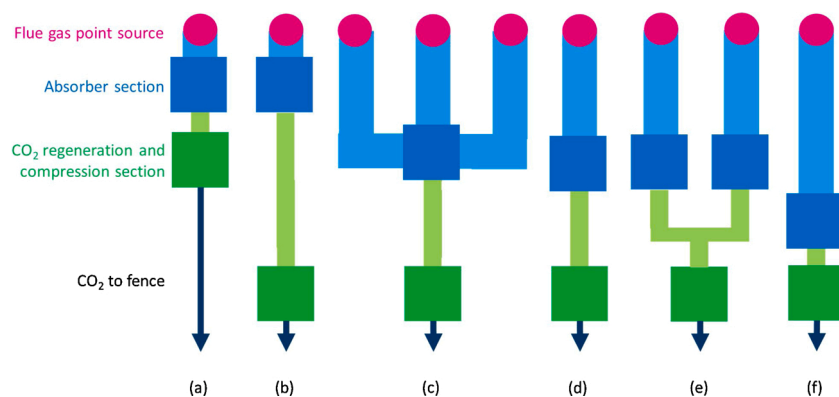[9] Repayment of investment and operating costs such as labour, maintenance, etc.

Fig. 6. Illustration of different layout alternatives that could be considered in space-constraint cases.
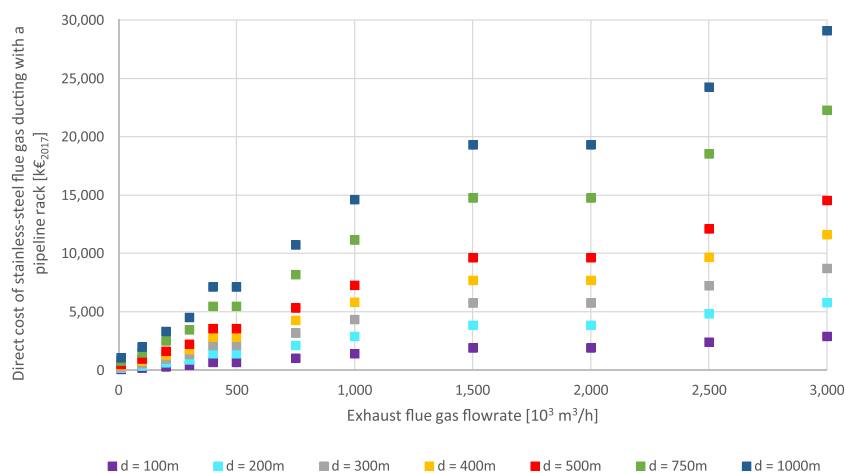

Fig. 7. Direct cost associated with exhaust flue gas ducting in function of the exhaust flue gas flowrate for different transport distances (d).
Figure footnote: These costs, estimated with Aspen Process Economic Analyzer (AspenTech, 2010), correspond to direct costs associated with the installation of a pipeline rack with a flue gas duct in stainless steel 304[16] for a Dutch-based location.

well as on the capture technology, infrastructural modifications (e.g. flue gas re-routing and sub-optimal unit location) and replacement of existing installations on the plant site, may be required (Berghout et al., 2013; IEAGHG, 2017e).

In most cases, spatial constraints can be solved by placing the CO_2 capture unit, or part of it, further away from the emission point source. However, this implies flue gas transport over longer distances, requiring large-diameter and expensive stainless-steel ducting, and possibly modifications to the existing industrial plant. In addition, the transport of the gaseous flue gas through the ducting system might be very energy-intensive and thus costly and may even require additional equipment (e. g. blowers). In some cases, alternative capture configurations in which only part of the capture unit is placed near the emission point source can provide a workable solution. For example, in some cases, it could be more cost-efficient to locate only the absorption section of an amine-based capture process near the CO_2 emission point and transport the CO_2 absorbed in the rich solvent to the regeneration and CO_2 compression section located further away (Bureau-Cauchois et al., 2011; IEAGHG, 2017e). In addition, capture configurations can even span multiple industrial plants whereby capture components, such as solvent regenerators and compressors, may be shared. Such configurations do not only circumvent spatial limitations on individual plant sites, but may also offer the possibility to curtail average capture costs by exploiting economies of scale compared to a set of individual plant chains (Berghout et al., 2015).

Fig. 6 illustrates six stylised examples of layout alternatives that may be

considered depending on potential spatial constraints for a solvent-based CO_2 capture process. Case (a) represents the scenario in which there is enough space near the flue gas point source to accommodate the absorber, desorber, and compression sections of the capture process. This case tends to be more cost-effective when considering CO_2 capture from a single CO_2 point source as it minimises the high cost associated with the flue gas ducting and rich/lean solvent transport. Case (f) represents the other extreme in which both the absorber and desorber sections are placed far away from the flue gas point source due to spatial constraints. This option tends to result in significantly higher cost than case (a) due to the large flue gas ducting required. Meanwhile, cases (b) to (d) represent hybrid configurations. For example, in case (b), there is enough space near the flue gas point source for the absorption section but not for the desorber section. As a result of this, the desorber may be placed further away from the flue gas point source and the CO_2 would be transported as a CO_2-rich solvent between the two sections of the CO_2 capture process. Case (c) is similar to case (b) with the exception that it considers that the spatial constraint would lead to flue gas ducting to reach an area with sufficient space for the absorber section. Finally, cases (d) and (e) illustrate that further complexity may arise when considering CO_2 capture from multiple sources, with potentially different CO_2 concentrations and impurities, within the plant which may be the case for example for refineries, iron and steel mills, etc.

In general, the additional costs resulting from spatial constraints are not always considered, outside of detailed engineering studies, when discussing costs of CCS in industry. Although this can be a reasonable assumption when considering greenfield development of the industrial

Table 4

Typical CO_2 concentrations and impurities in flue gas prior to CO_2 capture in various energy-intensive industries. Note that other impurities than listed here might be present as well.

Industry	CO_2 source within facility	CO_2 concentration (%vol)	SOx	NOx	Particulate matter
Cement (IEAGHG, 2008, 2013a; Voldsund et al., 2019)	Cement kiln stack	18−22	10−3500 mg/Nm³	200−3000 mg/Nm³	5−200 mg/Nm³
Iron and steel (Arasto et al., 2013; Hooey et al., 2013; Sundqvist et al., 2017)	Power station Blast furnace Other stacks	25−30 25 14−25	10−20 mg/Nm³ 10 mg/Nm³ 10−300 mg/Nm³	50−60 mg/Nm³ 60 mg/Nm³ 30−500 mg/Nm³	<5 mg/Nm³ <5 mg/Nm³ <5 mg/Nm³
Oil refining (Gardarsdottir et al., 2014; IEAGHG, 2017d, e)	Fluid Catalytic Cracker Process heaters stacks*	14−17 8−14	700−800 mg/Nm³ 5−350 mg/Nm³	– 80−350 mg/Nm³	– –
H_2 production (IEAGHG, 2017d, e)	Steam methane reformer	20−25	60 mg/Nm³	120−150 mg/Nm³	–
Pulp and paper (IEAGHG, 2016)	Recovery boiler	13	1−100 mg/Nm³	120−250 mg/Nm³	5−190 mg/Nm³

* Flue gases from different process heaters vented through the same stack.
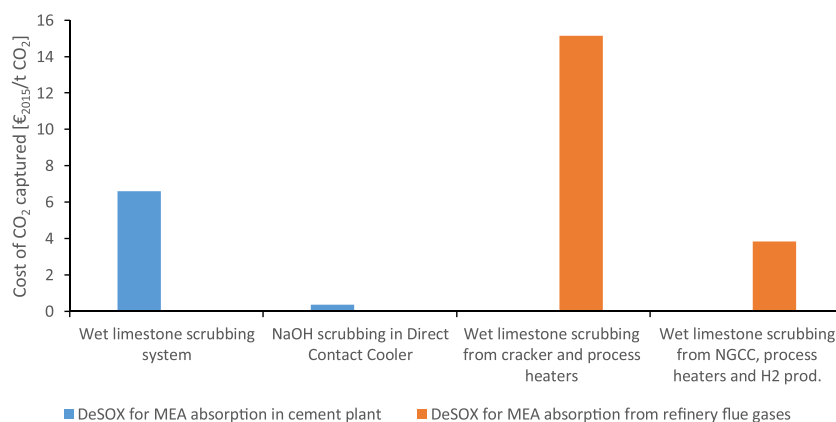

Fig. 8. Cost of flue gas desulphurisation [€$_{2015}$/t CO_2 captured], exemplified for MEA absorption applied on cement plant and refinery flue gases.
Figure footnote: Based on data extracted from the studies on CO_2 capture from a cement production facility (Gardarsdottir et al., 2019) two flue gases from a refinery (IEAGHG, 2017e).

plant with CCS (Cormos and Cormos, 2017; Garðarsdóttir et al., 2018), in other cases this may not be justified as these costs may increase the cost of CO_2 capture and conditioning in a non-negligible way. For example, in the case of CO_2 capture retrofit to a refinery, the flue gas and utilities interconnection costs were estimated to be in the range of 16–35 €$_{2015}$/tCO$_{2,avoided}$ for different unit retrofit scenarios (IEAGHG, 2017e). Furthermore, as space requirements for the CO_2 capture unit is technology-specific, spatial constraints may significantly benefit compact and modular capture technologies, as they could avoid significant flue gas interconnection costs (Voldsund et al., 2019), thus impacting the capture technology selection.

Although the impact of spatial constraints and flue gas interconnection costs ought to be considered in techno-economic studies on CO_2 capture retrofit from industrial plants, it is important to realise that these costs are very much site and CO_2 capture technology-specific. These costs shall thus be based on the evaluation of the layout of the industrial site with the considered CO_2 capture technology. In order to better help accounting for these costs, an example of the direct costs associated with the installation of a pipeline rack with a flue gas duct are illustrated in Fig. 7 as a function of the exhaust flue gas flowrate for different transport distances (d).

Finally, the costs associated with utilities[10] production and their integration with the CO_2 capture unit can also be impacted by space constraints. In some cases, the CO_2 capture unit may be located at significant distances from relevant utilities production and treatment

facilities. This may happen in cases in which new utilities production and treatment facilities could not be placed close to the CO_2 capture unit due to space constraints. However, this may also be the case when existing utilities production and treatment facilities with spare capacity are integrated with the CO_2 capture unit in order to reduce costs and/or investment. Although these are rarely included in cost evaluations, these costs can be non-negligible in retrofit cases depending on the overall layout of the industrial plant with the CO_2 capture unit and its associated utilities. Thus, these costs must be included to make more realistic cost estimates as well as to better understand the complete impact of certain design decisions such as the use of existing spare capacities.

3.2.4. Flue-gas treatment requirements

Another element which can have a significant impact on the costs of CO_2 capture from industrial plant is the presence of impurities in the flue gas to be treated in the CO_2 capture process. Indeed, industrial flue gases can contain levels of impurities which may impact the performances and design of the CO_2 capture and downstream CCS system. For example, the presence of SO$_X$ and NO$_X$ can lead to significant solvent degradation in an amine-based CO_2 capture thus resulting in poorer capture levels, higher energy penalties, and a more costly process. Similarly, certain membranes can be very sensitive to the presence of water while others are not. Depending on type and level of impurities of the plant flue gas and the technologies considered along the CCS chain, pre-treatment might thus be required prior or downstream of the CO_2 capture process to reach satisfactory levels of impurities. This could for example mean desulphurisation (DeSO$_X$), NO$_X$ removal, oxygen removal, dehydration, dust removal, etc. The cost associated with this or these

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[10] Power, heat, cooling water, process water, etc.

potential treatment(s) may have a significant impact on capture costs, the comparison of capture technologies (IEAGHG, 2008), as well on the performances and technology selection in the transport and storage part of the chain (Deng et al., 2019; Skaugen et al., 2016). Cost studies that ignore these additional costs or fail to attribute them to the cost of CCS might understate the real costs of CCS.

Typical ranges of flue gas CO_2 content and levels of SO_X, NO_X, and dust in different industry flue gases are summarised in Table 4.

To illustrate the impact additional flue gas treatment can have on capture cost, additional costs for DeSOx pre-treatment are exemplified in Fig. 8, for different cement and oil refinery flue gases (Gardarsdottir et al., 2019; IEAGHG, 2017e; Voldsund et al., 2019). The presence of DeSOx treatment in industrial plants is indeed highly industry- and site-specific and depends on the nature of the core production process, the characteristics of fuels used in the process as well as local environmental legislations. Industrial plants might fulfil SOx emission standards without a DeSOx system, but when it comes to implementing CO_2 capture, some post-combustion systems might require reduction of SOx to lower levels to minimize detrimental effects on the capture process performance. In that sense, there is an economic trade-off between the extent of additional flue gas purification and less deteriorating effects on capture process performance.

Considering treatment requirements downstream of the CO_2 capture unit, the high purity CO_2 stream from the CO_2 capture system needs to reach the quality requirements of the transportation system or the CO_2 utilisation process. Similarly, the cost linked to that post-treatment needs to be considered in the whole CCUS system evaluation.

3.3. CO_2 transport and storage costs

Several studies have discussed the costs of CO_2 transport and storage in detail (Rubin et al., 2015; Zero Emission Platform, 2011a, b). In practice, it is important to note that these costs are influenced by a variety of factors: transport mode (e.g. pipeline, ship), flow rate, transport distance, spatial configuration of transport system, type of storage (e.g. saline aquifer, depleted gas field), and characteristics of storage site (e.g. storage capacity, permeability, porosity).

This section discusses key cost aspects related to transport and storage of CO_2 captured from industrial point sources. It is worth noting that estimates presented in the section exclude the CO_2 conditioning (purification and compression) costs at the capture facilities unless otherwise indicated.

3.3.1. Impact of the amount of CO_2 captured on transport and storage cost

Industrial plants vary considerably in terms of annual CO_2 emissions, typically ranging from 0.15 $MtCO_2/y$ to 14 $MtCO_2/y$ depending on size and type of the individual plant (see Table 1). Consequently, the amount of CO_2 captured, and thus transported and stored, can vary significantly. In addition, plant operators may decide to capture only a share of the plant's CO_2 emissions, either because it is physically impossible to capture all CO_2 emissions due to spatial constraints (see Section 3.2.3), or because of economic reasons. Many industrial plants have multiple point sources with different characteristics in terms of waste heat availability, spatial constraints, and CO_2 volume and concentration, resulting in varying CO_2 capture costs. As a result, plant operators may only capture CO_2 from the point sources with the lowest cost, depending on the policy framework (IEAGHG, 2017e; Roussanaly and Anantharaman, 2017).

The cost of CO_2 transport and storage is strongly linked to the CO_2 flow rate, which in turn is a function of the CO_2 capture rate at the industrial plant. As a result, transport and storage costs may differ significantly from one industrial plant to another and make up a considerably larger share in the total CCUS chain cost for smaller emitters. Nevertheless, many literature studies assume a fixed cost for CO_2 transport and storage (often 10 €/tCO_2) regardless of their considered CO_2 flow rate (van der Spek et al., 2019).

Figs. 9–11 illustrate costs of transport and storage per tonne of CO_2 for

the Northwest European region. These estimates illustrate how costs of CO_2 transport and storages can sharply decrease with higher CO_2 flow rates due to economies of scale, and hence why an assumed fixed CO_2 transport and storage cost independent of the considered flow, distance to storage and storage characteristics may not be appropriate. While the estimates presented in Figs. 9–11 could already support better CCS estimates more representative transport and storage costs, case-specific evaluations also reflecting cost specific to the considered region are recommended.

It is also important to note that pooling demand for transport and storage capacity by sharing pipeline and storage infrastructures can significantly reduce the average unitary cost, which might be particularly beneficial for small emitters. For example, for a transport distance of 250 km via onshore pipeline, increasing the annual transport flow rate from 0.5 to 5 $MtCO_2/y$ would reduce average transport cost more than three times, from over 20 €$_{2017}$/tCO_2 to around 6 €$_{2017}$/tCO_2 (see Fig. 9). While a shared infrastructure may have lower total system costs

Fig. 9. CO_2 transport cost via onshore pipeline in function of the annual transported CO_2 flowrate for different transport distances.
Figure note: Established using the iCCS tool (Roussanaly et al., 2014, 2013b) and considering the pipeline cost model from Knoope et al. (Knoope et al., 2014). While the CO_2 is assumed to be available at 110 bar after CO_2 conditioning, the pipeline diameter and number of reboosting station(s) is optimised for each combination of transport flowrate and distance. These estimates are based on a project duration of 25 years and a real discount rate of 8%.
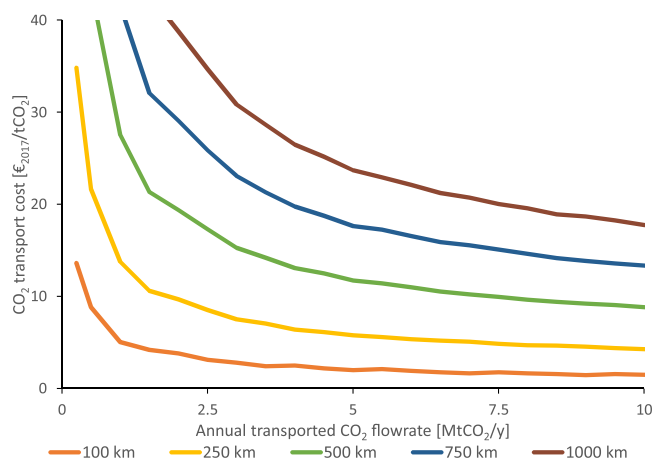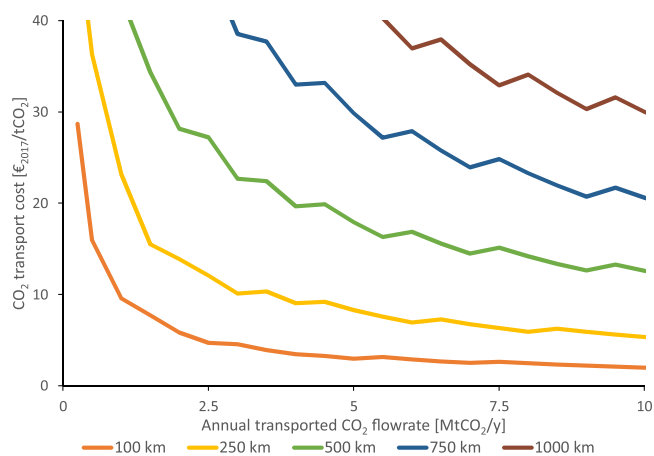
Fig. 10. CO_2 transport cost via offshore pipeline in function of the annual transported CO_2 flowrate for different transport distances.
Figure note: Established on the same basis as Fig. 9 although no offshore reboosting station is considered due to prohibitive cost.
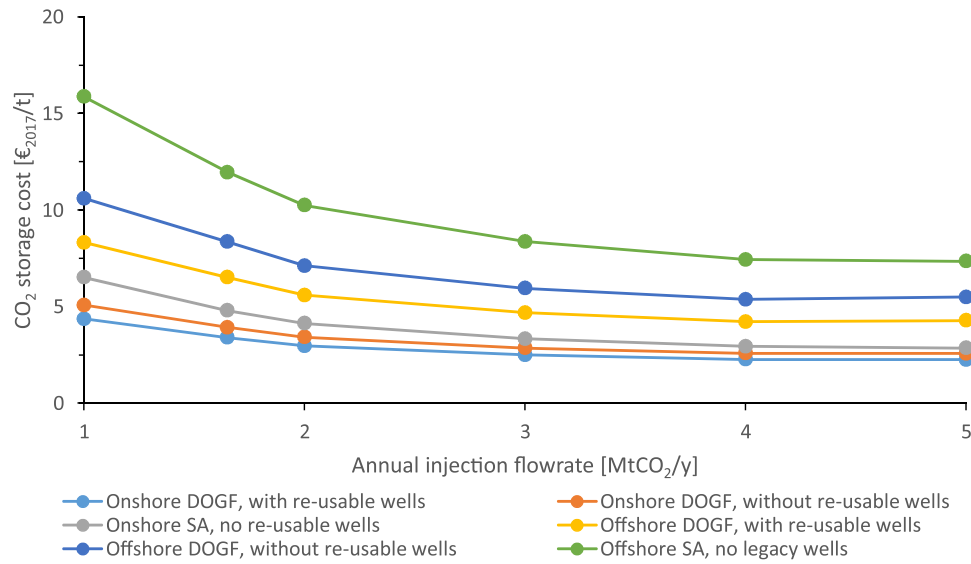
Fig. 11. CO_2 storage cost in function of the annual injection flowrate for different types of storage scenario (DOGF: Depleted Oil and Gas Field, SA: Saline Aquifer). Figure note: Established using the iCCS tool (Jakobsen et al., 2017; Roussanaly and Grimstad, 2014) based on the CO_2 storage cost methodology established by the ZEP (Zero Emission Platform, 2011a). The cost of an onshore new well is assumed to be 7,3 M€$_{2017}$, while other costs were updated using the IHS Upstream Costs Index (IHS, 2018). These estimates are based on a project duration of 40 years and a real discount rate of 8%.

Fig. 12. CO_2 conditioning and transport cost via shipping between harbours in function of the annual transported CO_2 flowrate for different transport distances. Figure note: Established using the iCCS tool (Roussanaly et al., 2014, 2013b) and considering ship costs from Durusut and Joos (Durusut and Joos, 2018). The CO_2 is considered to be transported at 7 barg, while the optimal number of ships and ship capacity are optimised for each combination of transport flowrate and distance. While the whole cost of conditioning is not included, the increase in conditioning cost compared to pipeline transport is included to ensure a fair comparison between shipping and pipeline transport costs. These estimates are based on a project duration of 25 years and a real discount rate of 8%.
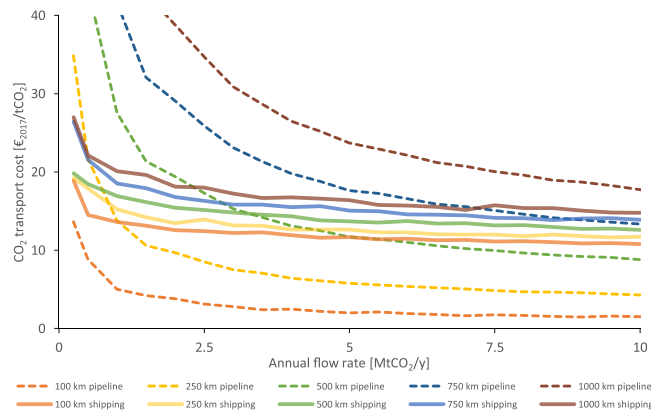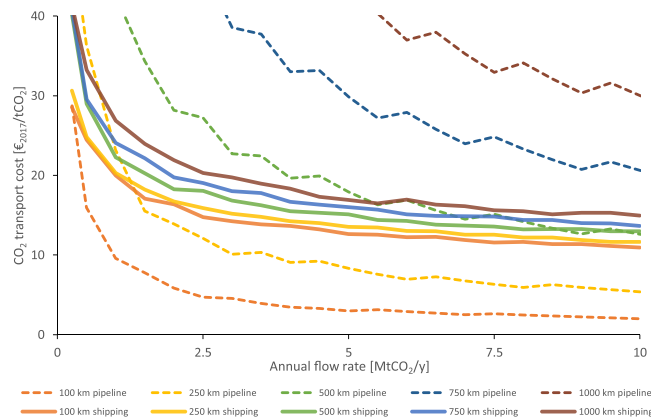

Fig. 13. CO_2 conditioning and transport cost via shipping to an offshore site in function of the annual transported CO_2 flowrate for different transport distances. Figure note: Established on the same basis as Fig. 12.

than a set of stand-alone solutions, it does involve several challenges, including higher upfront investments as well as coordination and cost allocation among the different users.

In addition to evaluation of CCS from industry based on pipeline transport, it is worth noting that transport of CO_2 via ship, and more generally tanked-based solutions (ship, barge, train, truck) is more and more considered for CCS from industry, especially in Europe (Roussanaly et al., 2017b). Indeed, while pipeline transport has traditionally been the default option considered in CCS-based evaluations, ship-based transport of CO_2 can be an attractive option for industrial emitters in some cases, due to its cost efficiency for small CO_2 volumes and transport over long distances (Roussanaly et al., 2014, 2013a). Furthermore, shipping typically involves lower upfront investments, shorter construction time, offers more flexibility, could be easier in terms of environmental permitting, and may present opportunities for co-utilisation of infrastructures (Aspelund et al., 2006).

Figs. 12 and 13 illustrate the cost of CO_2 transport by ship together with pipeline transport costs to indicate when shipping is cheaper than pipeline-based transport. To ensure a fair comparison between pipeline and ship means of transportation, the cost estimates for ship-based CO_2 transport also include the increase in conditioning cost compared to a pipeline-based transport. As illustrated, it is worth noting that the cost of ship-based transport is less affected by the annual flowrate and transport distances than pipeline transport. Shipping transport can be the preferred means of transport for a wide range of transport distances especially for small annual flowrates. For example, shipping between harbours would be the cost-optimal option for distances above 250 km when transporting an annual flowrate of 1 MtCO$_2$/y, while for higher annual flow rates pipeline transport is more cost-efficient for a wider range of transport distances. While the estimates presented in Figs. 12 and 13 can be used to support better CCS estimates of ship-based chains, more details on when pipeline and shipping transport are most efficient can be found in literature (Roussanaly et al., 2014, 2013a).

3.3.2. Other elements of potential importance

In addition to the issues discussed before, it is worth paying attention to the following elements when assessing the cost of CO_2 transport and storage from industrial emitters:

- Installing pipelines in cramped industrial areas can be costly and time-consuming to construct. In dense industrial sites, excavation work may have to be carried out manually to reduce the risk of damaging other pipelines. Similarly, studies have shown that limited space availability in underground communal pipeline corridors could results in several detours and/or higher operating pressures necessary, which increase local transport costs and possibly prolong license procedures (Berghout et al., 2017).
- Even though high purity CO_2 (>95 %) is normally targeted after CO_2 capture, different types and levels of impurities may be present in the CO_2 to be transported and stored. Although these impurities may only be present in small amounts, several studies have shown that the potential associated impurities can have a significant impact on design and cost of CO_2 conditioning, transport, and storage (Deng et al., 2019; Porter et al., 2017, 2016; Skaugen et al., 2016). However, this impact will however depend on the types and levels of impurities present in the CO_2 stream and thus the combination of industrial plant, CO_2 capture technology considered and targeted CO_2 specifications for storage or use (Brunsvold et al., 2016). Finally, it is worth noting that there are still some knowledge gaps in term of impact of multi-component impurities on underlying aspects influencing costs of such systems: thermodynamic behaviour, physical properties, corrosion, etc.
- The cost for CO_2 transport and storage can vary significantly by country and region, depending on local costs for rights-of-way, labour, materials and other inputs (McCoy, 2009). Study authors should ensure that cost models representative of the considered

geographical region are used. Such models for onshore pipeline transport have been developed by, for example, McCoy (McCoy, 2009), Knoope et al. (Knoope et al., 2014), and Wei et al. (Wei et al., 2016) for the U.S., Northwest Europe and China.

- It is also worth noting that external political and social aspects may also have an impact on transport and storage costs. For example, onshore CO_2 storage has been prohibited in several European countries thus leading in practice to more expensive transport routes and offshore storage (Shogenova et al., 2014). Furthermore, potential social acceptance issues may also impact the routing of the CO_2 transport thus resulting in higher costs. While CCS evaluations shall aim to represent expected conditions taking also these aspects into account, political and social aspects can result in uncertainties which may impact both design and costs.

4. Transferability of experience and technology maturity from power to industry sectors

Technology maturity is an important factor in cost estimates, usually accounted for through process contingency costs as illustrated by Rubin et al. (Rubin et al., 2020) and previously by other organisations like AACE and EPRI (EPRI, 1993; AACEI, 1997). Maturing and operational experience of CO_2 capture technologies has to date been gained primarily through decades of industrial applications in the chemical and petrochemical industries, for processes such as natural gas processing, as well as in small-scale applications at power plants to produce commodity CO_2 for food processing and other industries (Rubin et al., 2012). Over the past two decades, however, applications of CCS to fossil fuel power plants have been the primary focus of R&D programs and demonstration projects worldwide, resulting in additional experience in that sector. Today, with an increasing focus on CO_2 capture for a broader array of industrial applications, it is important to reflect on experiences from the power sector focus and the extent to which that is transferrable to CO_2 capture from the industrial sector.

The nine-point Technology Readiness Level (TRL) scale, first created by NASA for spacecraft applications, has become one of the most widely-used metrics of maturity of a technology in use by industry (Bakhtiary-Davijany and Myhrvold, 2013). The original NASA descriptions of each level have been modified into a number of general[11] TRL definitions published by organisations such as the European Commission, Electric Power Research Institute (EPRI), DOE, and IEA (See Appendix C). Those TRL definitions have been transferred over sectors and have also been used to measure the development of CO_2 capture technologies. In particular, non-sector specific TRL definitions for CCS or CO_2 capture technologies have been published by the Zero Emission Platform (ZEP) and the EPRI (Freeman and Bhown, 2011; Neele et al., 2017), summarized in the first two columns in Table 5. Generally, the TRL definitions are based on a scale 1–9, where levels 1–4 consider concept and lab scale, 5–6 consider pilot-scale systems and 7–9 consider larger demonstrations up to full commercial operation. Based on the TRL definitions set out by aforementioned institutes, several terms might lead to confusion, such as the definitions of "relevant", "system", "sub-system", and "component", or the scales, especially in the case of CCS from industry.

The direct transferability of TRLs and experience of CO_2 capture technologies from one sector to another has frequently been implicitly assumed for post-combustion technologies as those are add-on systems downstream the production process. However, the definition of TRLs requires an assessment of the overall system into which a new technology is placed. Thus, the TRL of a capture technology must be defined and evaluated in the context of a specific application, with new applications having lower TRLs. For instance, while chemical absorption with MEA and proprietary solvents have been tested at commercial scale, emerging configurations and/or solvents are -by definition- of lower

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[11] The term *general* here is meant as non-CCS specific.

Table 5
Relevant TRL definitions of CO_2 capture systems in existing literature.

	Generic, non-sector specific definition	Non-sector specific definitions applied to CCS				Definition applied to CCS in industrial sectors	
TRL	European Commission, Horizon2020	Zero emissions platform (Neele et al., 2017) TRL definition based on NETL and H2020 definition but adapted to expand CO_2 capture and storage.		Electric Power Research Institute (EPRI, 1993)		Industrial process with CO_2 capture based on H2020 definition but adapted to CCS in industrial sectors[a]	
9	Basic principles observed	Actual system proven in operational environment (competitive manufacturing of full system, at scales of several 100s of MWth or around 1 $MtCO_2$/y stored)	Full Commercial Application	Normal commercial service	Demonstration	Actual system proven in operational process (with product quality maintained), and competitive manufacturing of full system. Technology is commercially available for the specific industry.	Full commercial application
8	Technology concept formulated	System complete and demonstrated at industrial scales of 10s of MW_{th} or 0.1–1 $MtCO_2$/y stored	Demonstration	Commercial demonstration, full scale deployment in final form		System complete and qualified in operational process (with product quality maintained). First of a kind commercial system is installed and works. System prototype demonstration in operational environment (with product quality maintained).	Demonstration
7	Experimental proof of concept	System prototype demonstrated in operational environment (industrial pilots operating at 10s of MWth and/or separating 10s of kt CO_2/y)	Pilot	Sub-scale demonstration, fully functional prototype		For end-of-pipe technologies this means a full prototype operated with flue gas from operational process. For technologies that are highly integrated with the core process, this means a prototype where all critical sub-systems are fully integrated. Technology demonstrated in environment relevant to operation in the specific industry process (conditions replicating industrial operation) with product quality maintained. Trace elements should be included in flue gas if relevant.	Pilot
6	Technology validated in the lab	Technology demonstrated in relevant environment (steady states at industrially relevant environments: pilots in the MWth range and/or separating 1–10 kt CO_2/y)		Fully integrated pilot tested in a relevant environment	Development	Demonstration of the sub-systems affected by the product conditions may be sufficient if the full system is demonstrated at TRL 6 or higher for other applications (e.g. power plants).	
5	Technology validated in relevant environment	Technology validated in relevant environment (pilots operated at industrially relevant conditions at 0.05–1 MWth) and/or less than 1 $ktCO_2$/y captured/stored	Small Pilot	Sub-system validation in a relevant environment		Technology validated in environment relevant to operation in the specific industry process (conditions replicating industrial operation). Trace elements should be included in flue gas if relevant. Validation of critical sub-systems is sufficient.	Small pilot
4	Technology demonstrated in relevant environment	Technology validated in the lab (continuous operated pilots at lab scale <50 kW_{th})	Lab/Bench	System validation in a laboratory environment		Technology validated in lab (continuously operated).	Lab/bench
3	System prototype demonstration in operational environment	Experimental proof of concept (pilot testing of key components at small bench scale)		Proof-of-concept tests, component level	Research	Experimental proof of concept.	
2	System complete and qualified	Technology concept formulated (basic process design)	Concept	Formulation of the application		Technology concept formulated.	Concept
1	Actual system proven in operational environment	Basic principles observed		Basic principles observed, initial concept		Basic principles observed.	

[a] Based on background work for technology evaluation carried out in CEMCAP (Gardarsdottir et al., 2019; Jordal et al., 2019).

maturity. The same holds for oxyfuel and pre-combustion capture technologies, as these may require further modifications and integration specific to the industrial process considered.

Essentially, therefore, the transferability of experience or TRL may be limited to the particular CO_2 capture system and application (as described in the TRL definition as "relevant conditions" in Table 5). In addition, the concept of System Readiness Level (SRL) in advanced fossil energy applications (Knaggs et al., 2015) has been introduced to emphasize that the maturity of new systems depends not only on the stand-alone technology but also its maturity in the specific environment. In the context of CO_2 capture, the concept of SRL allows to reflect that the maturity of a specific capture system is linked to the level of technology development in conditions representative of the targeted industrial application.

While TRLs of different CO_2 capture technologies for the power application have already been assessed (IEAGHG, 2019), these TRLs cannot be directly used on different industrial applications due to the wide range of production processes and their associated characteristics, and the integration of the CO_2 capture system with the industrial core process. Once again, an example of interest is the benchmark solvent, MEA-based chemical absorption process, and improved conventional solvents. These are and will be used, and thus demonstrated, at large-scale for several types of industrial applications in the coming few years. This is, for example, the case in the Abu Dhabi Al Reyadah/Emirates Steel CCS and Longship projects, in the steel and cement industries respectively, amongst others at FEED study stage (BEIS, 2018). In addition, the calcium looping and sorption-enhanced water-gas shift (SEWGS) processes, which are at TRL 4–6 in the power sector, are expected to make significant progress on the TRL scale for industrial applications over the next few years. Specifically, calcium looping is planned to reach TRL 7 for cement production through the CLEANKER project (CLEANKER project, 2020), while SEWGS should reach TRL 7 for iron and steel manufacturing through the STEPWISE project by 2021 and 2020 respectively (STEPWISE project, 2020). Experience on the CALIX CO_2 separation technology has been transferred from the magnesium production industry (TRL 9) to the cement production and shall reach TRL 7 through the LEILAC project (LEILAC project, 2020).

For guidance on setting TRLs, definitions for CCS in industrial sectors are included in the last two columns in Table 5. These definitions include requirements with regards to impact of CCS implementation on product quality, plant maintenance (including start-up/shut-down and unforeseen disturbances to the industrial plant operation), and operation of the CCS system under the specific conditions of the facility (e.g. flue gas composition, temperature, pressure, and considering integration). While little attention has been paid to these aspects in past cost evaluations of CCS from industry, technology maturity is an important element to consider in selecting contingencies for investment assessments (Rubin et al., 2020). Similarly, technology maturity will also impact uncertainties in technical and cost performances (van der Spek et al., 2020). Finally, further work is needed to link contingency cost assumptions to TRL values more explicitly.

5. Conclusions

With the increasing interest in CCS to support CO_2 emission reductions from industry, a better understanding of costs is required to support decision-makers and guide research to improve the performance and reduce the cost of promising new options. While extensive studies have investigated the techno-economic performance of CCS applied to industrial sources, wide differences in cost estimates have been observed. While this is due in part to differences in the cases studied and the choice of capture technology, a significant part arises from aspects related to cost assessment methods and assumptions (cost metric definitions, energy costs, retrofitting cost, system boundaries, and other factors). Building on a previous CCS costing guideline papers (Rubin et al., 2013), the present work aimed to contribute to the development of improved guidelines for cost evaluation of CCS from industrial applications. In particular, the following key messages can be extracted:

- Several publicly available, transparent, and detailed techno-economic studies exist for different industrial sectors (e.g. iron and steel, cement, refinery, hydrogen, ammonia/urea and methanol, pulp and board). These studies provide a high level of technical and cost details on the industrial facilities considered, which can be used to strengthen future evaluation of CCS from such facilities. Furthermore, these studies have also performed detailed evaluations of currently available CO_2 capture technologies which can be used as a base case in comparative assessments involving new technologies. However, it is worth noting that most of these detailed studies are based on European locations and that some industry sectors are not yet studied in sufficient detail (e.g. waste-to-energy, offshore oil and gas production facilities, petrochemicals…).

- The same basic cost metrics used for CCS from power plant are relevant to industrial processes, although in some cases these may be calculated differently. Furthermore, a key challenge that might arise in the calculation of cost metrics for industrial plants is that many processes result in multiple products. In such cases, the cost of CCS may need to be allocated across these products when reporting costs on a normalized basis (e.g., cost per unit of product). While different allocation bases (flow, energy, market value) exist to distribute these (or other) costs, there is no standardized methodology currently in use. When possible, it is thus recommended to report CCS costs using more than one allocation method as this will provide insights into the impact of different methods on cost performance.

- The origin and production/supply strategy of the steam and electricity required for the CO_2 capture process may vary considerably on a case-by-case basis and have a significant impact on its cost and associated CO_2 emissions, and thus on the CO_2 avoidance cost. It is recommended that transparent scenarios of realistic (future) heat and power supply strategies are included in cost evaluations and that considered methods and assumptions are explicitly reported. The supply strategy, the cost and associated emissions intensity of a heat and power supply can also be site-specific and dependent on external parameters such as energy prices, which can change significantly over time. To deal with these uncertainties, analysts are encouraged to develop scenarios for plausible combinations of future energy and carbon prices, so as to clearly understand the impact of possible outcomes.

- Few studies properly account for the cost of retrofitting CO_2 capture from existing facilities. As illustrated in the literature, these costs can vary considerably on a case-by-case basis and should thus be properly accounted in studies assessing retrofit applications of CCS. Particular attention should be paid to the following aspects: economic impact of potentially required plant production stoppages, impacts on the main output product quality and plant operation, flue gas treatment requirements, spatial constraints in plant sites, flue gas interconnection and utilities connection costs.

- Costs associated with CO_2 transport and storage are often assumed to be a fixed unit cost per tonne of CO_2, independent of the expected transport and storage conditions (distance, volume, type of transport and storage). While there is significant room to improve the quality of transport and storage cost estimates, it is recommended that any such estimates be based on at least the applicable CO_2 flowrate, type of transport, transport distance and type of storage. Illustrative literature values are provided to support such preliminary estimates when detailed evaluations are not possible. It is worth noting that these considerations hold for both CCS from industry and power.

- Technology maturity is an important factor in cost estimates, usually accounted for through the inclusion of process contingency costs for different levels of maturity and experience. Caution must be taken, however, when considering transferability of technology maturity from power sector applications to various industrial sectors. Impacts to consider include potential effects of CCS on product quality, plant

maintenance, and operation of the CCS system under the specific conditions of the industrial facility.

Finally, the authors strongly recommend that future studies of industrial CCS applications make efforts to better document the adopted costing methodology, assumptions, and data sources, and to incorporate sensitivity analyses and scenarios for key assumptions to increase the usefulness and robustness of cost estimates.

CRediT authorship contribution statement

Simon Roussanaly: Supervision, Conceptualization, Methodology, Formal analysis, Writing - original draft, Writing - review & editing. **Niels Berghout:** Conceptualization, Methodology, Formal analysis, Writing - original draft, Writing - review & editing. **Tim Fout:** Conceptualization, Formal analysis, Writing - review & editing. **Monica Garcia:** Conceptualization, Methodology, Formal analysis, Writing - original draft, Writing - review & editing. **Stefania Gardarsdottir:** Conceptualization, Methodology, Formal analysis, Writing - original draft, Writing - review & editing. **Shareq Mohd Nazir:**

Conceptualization, Methodology, Formal analysis, Writing - original draft, Writing - review & editing. **Andrea Ramirez:** Conceptualization, Methodology, Formal analysis, Writing - original draft, Writing - review & editing. **Edward S. Rubin:** Methodology, Formal analysis, Writing - original draft, Writing - review & editing.

Declaration of Competing Interest

The authors declare that they have no known competing financial interests or personal relationships that could have appeared to influence the work reported in this paper.

Acknowledgements

Appendix A. – Overview of openly-available, highly transparent, and detailed techno-economic studies for each industrial sector

To ensure high-quality techno-economic evaluations, a strong level of detailed technical and cost knowledge of the industrial plant without CO_2 capture and with the reference CO_2 capture technology is required. Developing such detailed basis can, in practice, be challenging as industrial sectors are very different from one another and that, even within an industrial sector, industrial plants can differ significantly from one to the another.

Several efforts to develop such detailed studies have been undertaken over the past decades. Furthermore, these studies have also performed detailed evaluation of reference industrial plants and reference CO_2 capture technologies which can be used as base case in comparative assessment.

The following subsections provide an overview and discuss openly-available, highly transparent and detailed techno-economic studies[12] for each industrial sector. *To maximise potential further use of this benchmark basis review, the key characteristics, assumptions, and results of each study are summarised in Supplementary Information for all sectors.* As CO_2 transport and storage costs are very case-specific, as illustrated in Section 3.3, the CO_2 avoidance cost ($€/t_{CO2,avoided}$) presented in each section below exclude CO_2 transport and storage although the supplementation information includes both CO_2 avoidance cost without and with CO_2 transport and storage when available in the corresponding study.

Overall, while several detailed studies exist on CCS from industrial sectors, it is worth noting that most of these studies have been by research and engineering organisations either under the IEAGHG umbrella or H2020 EU projects. Most of the key sectors include at least one detailed study apart from the petrochemical, waste-to-energy, and the offshore oil and gas sectors for which only semi-detailed techno-economic studies are available in literature. Finally, it is worth noting that most of these studies are for European locations, often Netherlands, and would need to be adapted for other continents/countries. As such additional studies representing more regional specificity (technology, cost, raw material specificity, local utilities conditions…) would be beneficial to the CCS from industry community.

A.1 Iron and steel mill

In practice, one detailed techno-economic study of blast furnace based-steelmaking plant with and without reference post-combustion MEA-based capture has been published under the IEAGHG (IEAGHG, 2013b). The reference plant considered was based on a new build integrated steel mill located in the coastal region of Western Europe producing 4 Mt/y of hot-rolled coil (HRC). While the steel mill consists of 12 major processes and various auxiliaries, nearly 90 % of the plant's CO_2 emissions comes from five units: hot stoves, power plant, sinter plant, coke ovens' underfired heaters and lime kilns.

The IEAGHG study established two benchmarked points for CO_2 capture from an iron and steel plant. The first one, referred as Case 2A case, investigated MEA-based CO_2 capture from the flue gases of the hot stoves and the steam generation plant. The second one, Case 2B case, investigated MEA-based CO_2 capture from the flue gases of the underfire heaters of the coke oven batteries, hot stoves, lime kiln, and steam generation. These scenarios result in a reduction of 50 and 60 % of the overall plant emissions. Compared to the reference levelised cost of HRC for the plant without capture (429 $€_{2010}/t_{HRC}$), the cases with capture resulted in costs of 487 and 506 $€_{2010}/t_{HRC}$ respectively. Based on this increase and the avoided CO_2 emissions, a CO_2 avoidance cost of 55 $€_{2010}/tCO_{2,avoided}$ was estimated for the case 2A, which achieve 50 % avoided CO_2 emissions from the plant, and 60.6 $€_{2010}/tCO_{2,avoided}$ for the case 2B which achieve achieving 60 % avoided CO_2 emissions from the plant.

A.2 Cement

In the past years, a strong focus has been set on reducing CO_2 emissions from cement and, as such, several detailed techno-economic studies of cement with and without reference post-combustion MEA-based CO_2 capture has been published under the IEAGHG (IEAGHG, 2013a) and CEMCAP (Anantharaman et al., 2016) umbrellas. In both cases, the cement plants considered correspond to the ECRA base cement plant producing with a

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[12] Transparent studies are defined as reports providing in-depth level of details of the technical and cost assessments of both the industrial plant with and without mature CO_2 capture technology. Journal papers are thus excluded from this screening.

clinker capacity of 3,000 t/d. However, there are a few differences between both studies. To account for air leakage which periodically appears in cement plant and which are only fixed every once or twice a year, the CEMCAP project included two periods used for design and cost evaluations[13] . Another key difference between both studies is the decision of how to produce the steam required to regenerate the absorbed CO_2. While waste heat is recovered to supply around 7% of the heat need in both cases, the IEAGHG study considered a coal-based CHP plant or a NGCC to supply the remaining heat requirement, while CEMCAP assumed a natural gas boiler as well as different alternative strategies. While all these strategies can be valid decisions, an issue in the NGCC case was that it was assumed the excess electricity could be sold at 80 $€_{2014}$/MWh[14] resulting in a low cost of steam as it gets indirectly subsidized by the high profit on the electricity sale. Selected assumptions in the IEAGHG study resulted on a CO_2 avoidance cost of 52.4 $€_{2013}$/t$CO_{2,avoided}$ for the NGCC case and 102.9 $€_{2013}$/t$CO_{2,avoided}$ for the CHP case. Meanwhile, CEMCAP assumptions resulted in a CO_2 avoidance cost of 80.2 $€_{2014}$/t$CO_{2,avoided}$ when considering steam production based on a natural gas boiler.

A.3 Refinery

Refineries are the third contributor to industrial emissions. However, CCS from refineries can be challenging to assess due to heterogeneity of refineries, needs to retrofit in a space constraint plant, and the high number of CO_2 emissions point sources. The ReCAP study (IEAGHG, 2017e) is the only extensive study published on the techno-economic performances of implementing CCS from a refinery. This study evaluated the design, integrations, and techno-economic performances of retrofitting CO_2 capture into four different generic refineries: 1) a simple refinery with a nominal capacity of 100 000 bbl/d 2) a medium complexity refinery with a nominal capacity of 220 000 bbl/d 3) a highly complex refinery with nominal capacity of 220 000 bbl/d 4) a highly complex refinery with a nominal capacity of 350 000 bbl/d. Furthermore, as refineries are characterized by the large number of stacks with flue gases of varying CO_2 concentration and sulfur content, multiple cases were considered for each refinery scenario. The results of the cost evaluation of the 16 CO_2 capture cases resulted in costs of retrofitting CO2 capture with an MEA-based process lies between 145.5 and 189.4 $€_{2015Q4}$/t$CO_{2,avoided}$. These estimates are significantly larger than estimates available in the literature on CO_2 capture for other sources (natural gas and coal power generation, cement, steel, etc.) for three main reasons: 1) the inclusion of the retrofit costs such as interconnection costs 2) the utilities cost is based on the installation of an additional CHP plant, cooling water towers and wastewater plant which are all designed with significant spare capacity in some cases (up to 30 % overdesign). 3) Most of the CO_2 capture cases considered include small to medium CO_2 emission point sources and in some cases low to medium flue gas CO_2 content and/or significant amount of sulfur.

A.4 Hydrogen

While auto-thermal reforming is key to large-scale production of hydrogen, steam methane reforming is the leading technology for production of hydrogen from natural gas and light gas. A detailed techno-economic study of SMR-based hydrogen production plant with and without CCS has been published under IEAGHG (IEAGHG, 2017d). This study evaluated the design, performances, and cost of a new build hydrogen production plant located in the Netherlands producing 100 000 Nm^3/h of hydrogen using natural gas as a feedstock.

In such a plant, the CO_2 can be captured at three different locations: 1) synthesis gas before the H_2 Pressure Swing Adsorption (PSA) 2) tail gas after H_2 PSA 3) flue gas of the SMR furnace. While the two first low locations tend to result in lower cost due to the high CO_2 partial pressure, a main drawback of CCS from these two locations is that only 60 %, maximum, of the plant CO_2 emissions can be captured. On the other hand, CCS from the SMR furnace can reduce the emissions of the hydrogen plant beyond 90 %, although it may be more expensive option as CO_2 is available at low partial pressure in the furnace flue gas.

Based on the considered plant, the IEAGHG study established three benchmark points for CO_2 capture based on chemical absorption: 1) CO_2 capture from shifted syngas using MDEA 2) CO_2 capture from PSA tail gas using MDEA 3) CO_2 capture from flue gas using MEA. These scenarios result in a reduction of 54, 52, and 89 % of the overall plant emissions. Compared to the reference levelised cost of hydrogen without capture (11.4 c$€_{2014Q4}$/Nm^3_{H2}), the cases with capture resulted in costs of 13.5, 14.2, and 16.5 c$€_{2014Q4}$/Nm^3_{H2} respectively. Based on these LCOH increases and the avoided CO_2 emissions, CO_2 capture costs of 36.4 and 55.5 $€_{2014Q4}$/t$CO_{2,avoided}$ were estimated for first two cases, and 58.7 $€_{2014Q4}$/t$CO_{2,avoided}$ for the third case which is the only one enabling low-carbon footprint hydrogen.

A.5 Ammonia/ urea and methanol

Currently, 60 % of hydrogen syngas produced are used for production of ammonia/urea and methanol. Building on its hydrogen study, IEAGHG published a study on ammonia/urea and methanol production with CCS (IEAGHG, 2017c). This study investigated the performances and cost of a new built plant producing ammonia/urea or methanol without and with CCS. In both cases, the industrial complex was based on the integration of a syngas plant based on SMR from natural gas. In the first case, the syngas plant was integrated in an ammonia plant with a 1350 t/d nominal capacity. Around 95 % of the produced ammonia was considered to be further converted downstream in an ammonia plant (2260 t/d) using CO_2 captured from the syngas plant. In the second case, the syngas plant was integrated in a methanol plant with a nominal capacity of 5000 t/d. It is important to note that in both cases, most of the carbon entering the processes end up in the final products: 69.3 % in the ammonia/urea case and 79.3 % in the methanol case. The cases with CO_2 capture thus aim at capturing around 90 % of the remaining CO_2 emissions through post-combustion MEA-based CO_2 capture from the SMR flue gas.

For the ammonia/urea plant, the levelised cost of urea increases from 257.3–280.3 $€_{2014Q4}$/t once CCS is implemented. Based on the specific emissions reduction, the corresponding cost of CO_2 capture is 75 or 83.9 $€_{2014Q4}$/t$CO_{2,avoided}$ depending on assumed electricity source (natural gas or a coal power plant). It is worth noting that in the case with capture, part of the CO_2 captured is used to reach a total urea production of 2380 t/d.

For the methanol plant, the levelised cost of methanol increase from 275.1–298.9 $€_{2014Q4}$/t by implementing CCS. The obtained costs of CO_2 resulting of thus 70.6 and 78.9 $€_{2014Q4}$/t$CO_{2,avoided}$ depending on the electricity source (natural gas or a coal power plant), thus slightly lower than in

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[13] The two time periods were (1) a low air leak time period in which the flue gas contain 22%vol of CO_2 and lasting 6 months every year (2) a high air leak time period in which the flue gas contain 18%vol of CO_2 and lasting 6 months every year. This aspect is meant to more accurately represent the conditions of a cement plant, but results in higher CAPEX and OPEX compared to an evaluation considering only a low or an average air leak scenario.

[14] Average electricity price in the European Union area was 58.1 €/MWh in 2014

the urea case.

One important aspect to note is that as most of the carbon entering the processes end up in the final products and might be released to the atmosphere through the product (or one of its derivates) use, the climate impact of the end product might only be moderately reduced through the implementation of CCS in this case.

A.6 Pulp and board

Although a large proportion of these is biogenic emissions, the pulp and board production sector contributes to nearly 5% of the CO_2 emissions of the industrial sector. Furthermore, reducing these emissions is key in achieving the climate ambitions of certain countries as nearly 75 % of the pulp and paper production is concentrated in ten countries. A detailed techno-economic study on retrofitting CCS on pulp and board mills were published under IEAGHG (IEAGHG, 2016). This study assessed two hypothetical reference mills situated in the west coast of Finland. The first one is a pulp mill producing 800,000 air-dried tonne (adt) per year of bleached softwood pulp (BSP). The second one is an integrated pulp and board mill which produces 400,000 adt of board per year and 740,000 adt/y of BSP. For both plants, the main sources responsible for the CO_2 emissions of the plant are the recovery boiler (REC), the multi-fuel boiler (MFB), and the lime kiln (LK). These three sources are responsible for respectively 76, 14, and 10 % of the plant non-biogenic emissions. However, it is worth noting that each of these sources also emits 24 tonnes of biogenic CO_2 emissions per tonne of non-biogenic CO_2 emissions. For each plant, retrofitting an MEA-based post-combustion capture from these sources was evaluated on a stand-alone or combined basis thus resulting in six capture scenarios: 1) REC only 2) MFB only 3) LK only 4) REC + MFB 5) REC + LK 6) REC + MFB + LK.

While the cost of the pulp and board plants without capture results in a levelised cost of pulp pf 522.6 €$_{2015}$/adt, this cost varies between 543 and 676 €$_{2015}$/adt for the pulp mill and 545 and 714 €$_{2015}$/adt for the pulp and board mill depending on the capture case considered. This results in CO_2 capture cost[15] varying from 52 to 81 €$_{2015}$/tCO$_{2,avoided}$ for the pulp mill and 72 and 82 €$_{2015}$/tCO$_{2,avoided}$ for the pulp and board mill. In general, the scenarios based on CO_2 capture from the REC stand-alone or combined with other sources results in the lowest cost. It is worth noting that despite the retrofit cost and the shorter operation duration for the $_{CO2}$ capture facility (15 years), the CO_2 capture cost remains rather low as excess steam produced by the mill is assumed to supply the required heat demand for CO_2 regeneration.

Appendix B. Other methods for calculating CO_2 avoidance cost and their associated assumptions

The "net present value" and "annualisation" methods for calculation of CAC are presented in Eq. 2 (Ho et al., 2011) and Eq. 3 (Kuramochi et al., 2012), while a summary of assumptions required to ensure the validity of each CO_2 avoidance cost calculation methods is presented in Table B1. More details on the links between the different calculation methods and the associated assumptions can be found in Roussanaly (Roussanaly, 2019).

$$CAC = \frac{NPV_{CCS}}{\sum_i \frac{\dot{M}_{CO2,\,avoided,\,i}}{(1+r)^i}} \qquad (2)$$

Where:

- NPV CCS is the net present value of total annual CCS costs (which may vary from year to year)
- MCO$_2$, avoided, i is the mass of CO_2 avoided by CCS implementation in year i
- r is the discount rate

$$CAC = \frac{I_{CCS,\,a} + O_{CCS}}{\dot{M}_{CO2,\,avoided}} \qquad (3)$$

Where

- I$_{CCS}$,a is the annualised investment cost of CCS
- O$_{CCS}$ is the annual operating cost of CCS
- Ṁ$_{CO2}$, avoided is the annual reduction in CO_2 emissions due to CCS for a plant producing the same amount of product(s) with and without CCS.

Table B1
Summary of assumptions required to ensure the validity of each CO_2 avoidance cost calculation methods. For the "exhaustive" method none of these assumptions are required (Roussanaly, 2019).

Assumption	"Exhaustive" method	"Net present value" method	"Annualisation" method
Production of industrial plant not affected by CCS implementation	–	Yes	Yes
Additional costs and CO_2 emissions avoided due to CCS implementation can be assessed separately	–	Yes	Yes
Annual operating costs and CO_2 emissions avoided are constant over project duration	–	–	Yes
CO_2 emissions linked to construction of the CCS facility can be neglected or excluded	–	–	Yes

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[15] Biogenic and non-biogenic emissions are here considered alike.

[16] Stainless steel 304 is here considered due to the expected presence of water in the flue gas. It is worth noting that the material selection may differ depending on water level, as well type and level of other corrosive impurities.

Appendix C. Definitions of Technology Readiness Levels

Table C1

Table C1
Definitions of TRL by different institutes.

TRL	European Commission, Horizon2020 (European commission, 2014)	UK government (UK Ministry of Defence, 2016)	NASA (NASA, 2012)	EPRI (EPRI, 1993)	IEA (IEA, 2020a)
1	Basic principles observed	Basic principles established	Basic principles observed and reported	Basic principles, observed, initial concept	Initial Idea: basic principles have been defined
2	Technology concept formulated	Invention and Research	Technology concept and/or application formulated	Formulation of the application	Application formulated: concept and application of solution have been formulated
3	Experimental proof of concept	Proof of concept	Analytical and experimental critical function and/or characteristic proof of concept	Proof of concept, tests, component level	Concept needs validation: Solution needs to be prototyped and applied
4	Technology validated in the lab	Bench scale	Component and/or breadboard validation in laboratory environment	System validation in a laboratory environment	Early prototype: prototype proven in test conditions
5	Technology validated in relevant environment	Pilot scale	Component and/or breadboard validation in relevant environment	Sub-system validation in a relevant environment	Large prototype: Components proven in conditions to be deployed
6	Technology demonstrated in relevant environment	Large scale	System/subsystem model or prototype demonstration in a relevant environment	Fully integrated pilot tested in a relevant environment	Full prototype at scale: prototype proven at scale in conditions to be deployed
7	System prototype demonstration in operational environment	Inactive commissioning	System prototype demonstration in a space environment	Sub-scale demonstration, fully functional prototype	Pre-commercial demonstration: solution working in expected conditions
8	System complete and qualified	Active commissioning	Actual system completed and "flight qualified" through test and demonstration	Commercial demonstration, full scale deployment in final form	First-of-a-kind commercial: commercial demonstration, full scale deployment in final form
9	Actual system proven in operational environment	Operation	Actual system "flight proven" through successful mission operations	Normal commercial service	Commercial operation in relevant environment: solution is commercially available, needs evolutionary improvement to stay competitive
10					Integration at scale: solution is commercial and competitive but needs further integration efforts
11					Proof of stability: predictable growth

Appendix D. Supplementary data

Supplementary material related to this article can be found, in the online version, at doi:https://doi.org/10.1016/j.ijggc.2021.103263.

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