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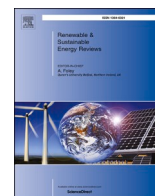
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# Carbon capture and biomass in industry: A techno-economic analysis and comparison of negative emission options

F. Yang<sup>a,\*</sup>, J.C. Meerman<sup>a</sup>, A.P.C. Faaij<sup>a,b</sup>

<sup>a</sup> *Integrated Research on Energy, Environment and Society, University of Groningen, Nijenborgh 6, 9747, AG, Groningen, the Netherlands*

<sup>b</sup> *TNO Energy Transition, Princetonlaan 6, 3584, CB, Utrecht, the Netherlands*

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## ABSTRACT

Meeting the Paris Agreement will most likely require the combination of CO<sub>2</sub> capture and biomass in the industrial sector, resulting in net negative emissions. CO<sub>2</sub> capture within the industry has been extensively investigated. However, biomass options have been poorly explored, with literature alluding to technical and economic barriers. In addition, a lack of consistency among studies makes comparing the performance of CO<sub>2</sub> capture and/or biomass use between studies and sectors difficult. These inconsistencies include differences in methodology, system boundaries, level of integration, costs, greenhouse gas intensity of feedstock and energy carriers, and capital cost estimations. Therefore, an integrated evaluation of the techno-economic performance regarding CO<sub>2</sub> capture and biomass use was performed for five energy-intensive industrial sub-sectors. Harmonization results indicate that CO<sub>2</sub> mitigation potentials vary for each sub-sector, resulting in reductions of 1.4–2.7 t CO<sub>2</sub>/t steel (77%–149%), 0.7 t CO<sub>2</sub>/t cement (92%), 0.2 t CO<sub>2</sub>/t crude oil (68%), 1.9 t CO<sub>2</sub>/t pulp (1663%–2548%), and 34.9 t CO<sub>2</sub>/t H<sub>2</sub> (313%). Negative emissions can be reached in the steel, paper and H<sub>2</sub> sectors. Novel bio-based production routes might enable net negative emissions in the cement and (petro) chemical sectors as well. All the above-mentioned potentials can be reached for 100 €/t CO<sub>2</sub> or less. Implementing mitigation options could reduce industrial CO<sub>2</sub> emissions by 10 Gt CO<sub>2</sub>/y by 2050, easily meeting the targets of the 2 °C scenario by the International Energy Agency (1.8 Gt CO<sub>2</sub>/y reduction) for the industrial sector and even the Beyond 2 °C scenario (4.2 Gt CO<sub>2</sub>/y reduction).

## 1. Introduction

In the Paris Agreement, it was determined that the rise in global temperature should be limited to well below 2 °C and preferably to 1.5 °C above pre-industrial levels [1]. According to the Intergovernmental Panel on Climate Change, reaching the 1.5 °C target requires global CO<sub>2</sub> emissions of just below 9 Gt CO<sub>2</sub>/year by 2060 and net zero CO<sub>2</sub> emissions by 2100 [2,3]. This requires a switch from fossil fuels to renewable fuels and, most likely, the capture of CO<sub>2</sub> for underground geological storage (carbon capture and storage; CCS) as well [4,5]. However, some greenhouse gas (GHG) emissions are either very difficult to prevent or are unavoidable. In addition, not all CO<sub>2</sub> sources are suitable for CCS, and CCS applied at fossil CO<sub>2</sub> sources only decreases the rate at which CO<sub>2</sub> is added (typically decreased by 85%–90%), whereby some emissions still remain [4,6]. The use of a sustainable

biomass, however, does not result in increased atmospheric CO<sub>2</sub> concentrations, as the carbon in the biomass is extracted from the atmosphere during the growth cycle of the biomass [4]. Consequently, the combination of biomass use and CCS could result in net neutral or even so-called negative emissions, as CO<sub>2</sub> is effectively removed from the atmosphere [6].

In 2014, global CO<sub>2</sub> emissions were 35.7 Gt, which is 74% of global GHG emissions [3,7,8]. The industrial sector is responsible for direct emissions of 8.3 Gt CO<sub>2</sub> and indirect emissions<sup>1</sup> of 6.8 Gt CO<sub>2</sub> [3]. Within the industrial sector, only four subsectors are responsible for the bulk (71%) of direct industrial CO<sub>2</sub> emissions, namely, iron and steel (2.32 Gt CO<sub>2</sub>), cement (2.24 Gt CO<sub>2</sub>), chemicals (1.1 Gt CO<sub>2</sub>), and paper and pulp (0.25 Gt CO<sub>2</sub>) (see Fig. 1) [3]. A number of studies have assessed the potential of reducing CO<sub>2</sub> emissions by improving energy efficiency [9–11], CCS technology [12–15], switching to low carbon energy and raw material supply sources (e.g., biomass) [16–18], and improving

\* Corresponding author.

E-mail address: [F.Yang@rug.nl](mailto:F.Yang@rug.nl) (F. Yang).

<sup>1</sup> Indirect emissions are based on 46.5 EJ electricity consumption in main industrial sectors and the world average carbon intensity of electricity generation (524 g CO<sub>2</sub>/kWh) at present.

Abbreviations			
ADT	air dried ton	EAF	electric arc furnace
ASU	air separation unit	EEM	energy efficiency management
ATR	autothermal reforming	FPO	fast pyrolysis oil
BECCS	biomass and carbon capture and storage	GHG	greenhouse gas
BF	blast furnace	KS-1	chemical solvent developed by Mitsubishi Heavy industries
Bio	biomass	IEA	International Energy Agency
BIG	biomass gasification	IEAGHG	IEA Greenhouse Gas R&D Programme
BL	black liquor	IPPM	integrated pulp & paper mill
BLG	black liquor gasification	LK	lime kiln
BOF	basic oxygen furnace	MEA	monoethanolamine
CaL	calcium looping	MFB	multi-fuel boiler
CCS	carbon capture and storage	NG	natural gas
CG	coal gasification	PM	pulp mill
CHP	combined heat and power	REC	recovery boiler
CLR	chemical looping reforming	SMR	steam methane reformer
CS	crude steel	SR	smelting reduction
DRI	direct reduced iron	TGR-BF	top gas recycling-blast furnace
		VPSA	vacuum pressure swing adsorption
		WGS	water gas shift

material efficiency [19]. As a mitigation technology, CCS is probably the most versatile and important option for reducing large-scale emissions in the industrial sectors [3,20,21]. To meet the International Energy Agency (IEA) 2 °C scenario (2DS), 1.8 Gt CO<sub>2</sub> should be captured annually from industry by 2060 [3]. This increases to 4.2 Gt CO<sub>2</sub> annually in the Beyond 2 °C scenario [3].

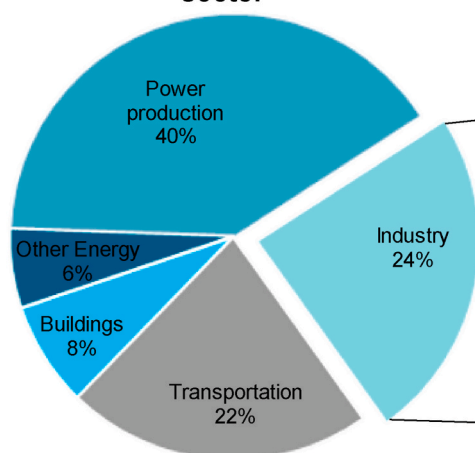
The projected need for CCS in the industrial sector has resulted in significant research in this area. An overview of the key findings in the literature on the economic performance of different CO<sub>2</sub> mitigation options in the main industrial sectors are shown in Table 1. Kuramochi et al., Berghout et al., and the IEA Greenhouse Gas R&D Programme (IEAGHG), among others, evaluated the techno-economic performance of various capture technologies in up to four industrial sectors, and each of the studies provided specific equations for their own cases [13,15,22]. Other studies only discussed the CO<sub>2</sub> capture potential and economic performance in a single industrial sector [23–33]. Some studies have discussed possibilities for biomass as an energy source or feedstock with different technologies (e.g., biomass gasification, pyrolysis) in iron and steel [18,34–37], cement [38–40], chemicals [41–44], and hydrogen [75,156,159]. However, there have been few studies that focus on biomass combined with CCS (BECCS) in industrial sectors. Most of the

BECCS cases were focused in the pulp and paper industry because it already uses biomass as raw material [45–49]. Mandova et al. bridged the gap regarding BECCS in the blast-furnace route of the iron and steel industry with the techno-economic BeWhere-EU model [50]. Berghout et al. built a consistent method for evaluating the performance of various CO<sub>2</sub> mitigation options in a large-scale refinery plant [51]. Evidently, there is much variation in the cost estimates for CO<sub>2</sub> avoidance in industrial applications. The potential reasons are the use of different CCS technologies, different methodologies, and different key assumptions to evaluate economic performance. Consequently, the above-mentioned studies cannot be compared with each other. The lack of a uniform standard among the cross-sectors also makes it difficult to know which sector should be the first choice for CO<sub>2</sub> mitigation options.

Therefore, this study contains a systematic analysis of the techno-economic potential and performance of applying CCS, biomass, and BECCS for five industrial sectors. This allows the assessment to which extent negative emissions could be obtained. For this purpose, the iron and steel, cement, (petro)chemical, paper and pulp, and hydrogen sectors were selected as case studies. A harmonized analysis of the different sectors allows an order of merit of mitigation options across the sectors.

Section 2 of this paper provides a harmonized methodology to

**Global CO<sub>2</sub> emissions by economic sector**



**Direct industrial CO<sub>2</sub> emissions**

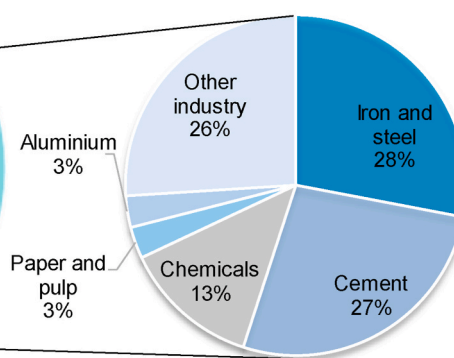


Fig. 1. Global CO<sub>2</sub> emissions and direct industrial CO<sub>2</sub> emissions in 2014 (Data source [3]).

**Table 1**

Overview of key literature in which the economic performance of CO<sub>2</sub> mitigation options in different industrial sectors was investigated or reviewed.

Mitigation option + Industrial sector	Route	CO <sub>2</sub> capture (Mt/y)	CO <sub>2</sub> avoided rate (t CO <sub>2</sub> /t product)	CO <sub>2</sub> avoidance cost (€2017/t)	Region	Source
<b>CCS + Iron and steel</b>	BF	–	0.35–0.69	36–69	Global	[13]
	BF	–	–	65–70	Europe	[50]
	BF	4.97	–	56–62	Europe	[22]
	BF	2–3	–	82–206	Finland	[24]
	BF	1.5–1.7	–	48–57	Australia	[25]
	TGR-BF	–	0.78–0.82	46–69	Global	[13]
	TGR-BF	3.44	–	43	Europe	[22]
	TGR-BF	–	–	45–87	Finland	[26]
	TGR-BF	2.6	–	36	Australia	[27]
	COREX	–	0.74–2.03	28–58	Global	[13]
	<b>CCS + Cement</b>	Dry process	–	0.4–0.75	29–141	Global
Dry process		0.5–1.1	0.45–0.54	39–106	UK	[28]
Dry process		–	0.3–0.7	39–100	Europe	[22]
Dry process		0.76	–	82	Europe	[23]
Dry process		0.73–1.15	–	41–79	Europe	[29]
Dry process		–	0.78–0.88	11–16	Europe	[30]
Dry process		–	0.63–0.64	51–58	Europe	[31]
<b>CCS + Refinery</b>	6 Mt/y crude oil	–	0.05–0.07	40–161	Europe	[53]
	11.4 Mt/y crude oil	–	0.09–0.13	41–245	Europe	[53]
	10 Mt/y crude oil	–	0.16–0.21	32–93	Europe	[15]
	20 Mt/y crude oil	–	0.13–0.19	25–78	Europe	[15]
	20 Mt/y crude oil	–	0.16–0.19	69–74	Europe	[51]
<b>CCS + Hydrogen</b>	SMR	–	7.9	32	Europe	[32]
	SMR	–	4.59–7.9	49–73	Europe	[33]
	SMR	–	0.43–0.66	69–117	Netherlands	[15]
<b>Biomass + Refinery</b>	20 Mt/y crude oil	–	0.05–0.13	32–87	Netherlands	[51]
<b>BECCS + Iron and steel</b>	BF	–	1.01	29–50	Europe	[50]
<b>BECCS + Refinery</b>	20 Mt/y crude oil	–	0.12–0.25	59–97	Netherlands	[51]
<b>BECCS + Pulp and paper</b>	Pulp mills	–	–0.11 to 2.07	59–97	Europe	[49]
	IPPM	–	0.07–2.25	64–93	Europe	[49]
	Pulp mills	–	1.37	85–94	Sweden	[47]
	Pulp mills	–	1.69–2.69	30	Sweden	[48]
	IPPM	–	0.6–2.1	28–55	Europe	[46]

evaluate CO<sub>2</sub> reduction potential and avoidance costs. Section 3 contains a literature overview of the main production processes and promising alternative ones for each investigated sub-sector. It also contains an overview of the performance and cost, as reported from previous studies that applied CCS, biomass, or BECCS to these processes. These results are compared with the results of the harmonized methodology. Section 4 summarizes the discrepancies among the five sub-sectors, the primary remaining gaps, and the uncertainties. Section 5 discusses the limitations in this study. Conclusions are listed in Section 6. This also includes recommendations of which sub-sector should act first, and the most suitable CO<sub>2</sub> mitigation options are also considered.

## 2. Methodology

In this study, the techno-economic performance of the introduction of CCS and/or biomass to several key industrial sectors is analyzed, with special emphasis placed on the possibility of achieving net negative GHG emissions by combining CCS with biomass. A gate-to-gate approach was used for the technical and economic analyses, whereas for the GHG inventory, a cradle-to-gate approach was used (see Fig. 2). This allowed the comparison of the potential and cost of CO<sub>2</sub> mitigation options among vastly different industrial sectors.

### 2.1. Technical methodology

The technical methodology used to determine the effect of applying CCS and/or biomass in the industrial sector on mass and energy flows is

$$F_{CO_2 \text{ avoided}} = \frac{\Delta F_{CO_2, c} - [\Delta F_{CO_2, in} + \{(\Delta P_m + \Delta H_m \times f_{St,m}) + (P_c + H_c \times f_{St,c})\} Em_{elec}]}{M_{Ind}} \quad (3)$$

presented. First, previous studies were used to determine the benchmark performance of conventional processes (base cases) within each investigated sub-sector. The effect of CCS is given in Table 2 and the effects of biomass and BECCS are described in Sections 3.1–3.5.

### 2.2. GHG inventory

To determine the effect of CCS and/or biomass on the GHG intensity of the different industrial sub-sectors, a cradle-to-gate GHG analysis was performed. The avoided CO<sub>2</sub>, or F<sub>CO<sub>2</sub> avoided</sub>, (t CO<sub>2</sub>/t product) is calculated according to Equations (1) and (2).

$$F_{CO_2 \text{ avoided}} = GHG_{ref} - GHG_{Case} \quad (1)$$

$$GHG_{Case} = GHG_{up} + GHG_{main} + GHG_{energy} \quad (2)$$

where GHG<sub>ref</sub> (t CO<sub>2</sub>/t product) is the total CO<sub>2</sub> emissions from the reference industrial processes. This means that neither CCS nor biomass, with the exception of the paper industry, is included. GHG<sub>Case</sub> (t CO<sub>2</sub>/t product) is the total CO<sub>2</sub> emissions from the industrial process adjusted for CCS and/or biomass. GHG<sub>up</sub> (t CO<sub>2</sub>/t product) refers to the upstream GHG emissions, and GHG<sub>main</sub> (t CO<sub>2</sub>/t product) represents the GHG emissions in the main industrial process. GHG<sub>energy</sub> (t CO<sub>2</sub>/t product) is the amount of emissions associated with energy production if imported. Exported energy is credited.

Equations (1) and (2) can be combined to yield Equation (3), with delta (Δ) signifying the difference between the base case and alternative case.

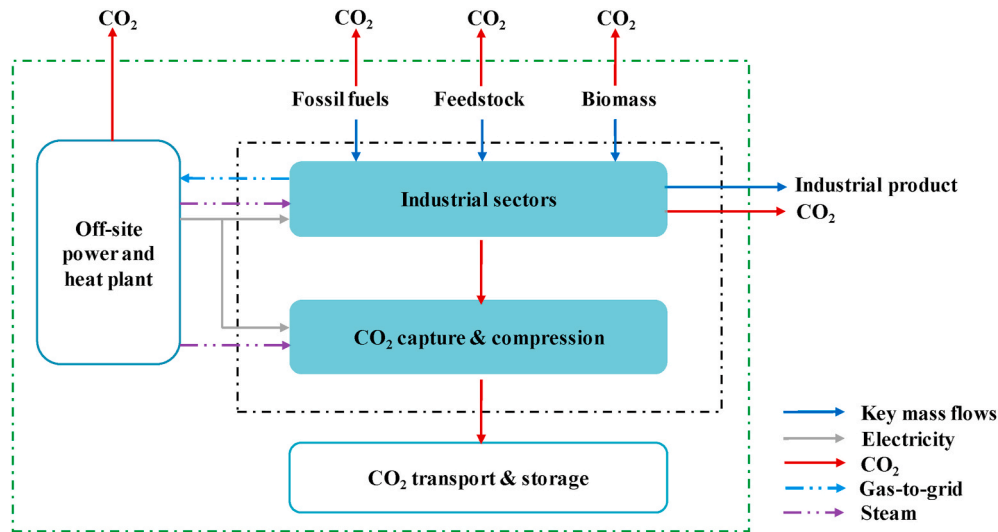


Fig. 2. System boundaries used in this study. The black dotted box represents the industrial process model (electricity is imported from the grid, and excess process gas can be combusted to produce electricity). The green dotted box represents the economic evaluation model from the LCA analysis.

Table 2  
Harmonized table with data on CCS modifications in this study.

CO <sub>2</sub> capture technique	Capture ratio (%)	Spec. electricity use (GJ <sub>e</sub> /t CO <sub>2</sub> )	Spec. heat use (GJ <sub>th</sub> /t CO <sub>2</sub> )
Post-combustion <sup>a</sup>	MEA	89	0.78
	VPSA	88	0.94
	Selexol	90	0.6
Oxyfuel combustion <sup>b</sup>	87	1.6	–
Pre-combustion <sup>c</sup>	95	0.34	1.97
CaL + CCS <sup>d</sup>	95	0.87	–

<sup>a</sup> According to Kuramochi, Ho and Berghout, the CO<sub>2</sub> capture ratio for MEA varies between 87% and 90%, and the electricity and heat required for different industrial sectors are 0.54–1.3 GJ<sub>e</sub>/t CO<sub>2</sub> and 3.2–4.6 GJ<sub>th</sub>/t CO<sub>2</sub> [13,15,27,51]. An average value is used in this study. According to Kuramochi, the electricity demand for VPSA and Selexol are 0.94 GJ<sub>e</sub>/t CO<sub>2</sub> and 0.6 GJ<sub>e</sub>/t CO<sub>2</sub> and the heat demand for Selexol is 0.63 GJ<sub>th</sub>/t CO<sub>2</sub> [13].

<sup>b</sup> According to Berghout, the CO<sub>2</sub> capture ratio for oxyfuel combustion is 87% and the electricity required for oxyfuel combustion and O<sub>2</sub> production are 0.5 GJ<sub>e</sub>/t CO<sub>2</sub> and 0.7 GJ<sub>e</sub>/t O<sub>2</sub> in the petrochemical sector [51]. According to Kuramochi, the coal and electricity required for CO<sub>2</sub> capture are 0.86 GJ/t CO<sub>2</sub> and 0.99 GJ<sub>e</sub>/t CO<sub>2</sub> in the cement sector. Steam and electricity required for the petrochemical sector are 4.6 GJ<sub>th</sub>/t CO<sub>2</sub> and 0.6 GJ<sub>e</sub>/t CO<sub>2</sub> when applied at a catalytic cracker, and electricity required is 2 GJ<sub>e</sub>/t CO<sub>2</sub> when applied at the combined stack [13]. An average value of 1.6 GJ<sub>e</sub>/t CO<sub>2</sub> is used in this study for simplified calculation.

<sup>c</sup> According to Meerman and Berghout, the CO<sub>2</sub> capture ratio for pre-combustion is 95% and the electricity and heat required for pre-combustion are 0.4–0.5 GJ<sub>e</sub>/t CO<sub>2</sub> and 1.97 GJ<sub>th</sub>/t CO<sub>2</sub> [51,53].

<sup>d</sup> According to De Lena, the CO<sub>2</sub> capture ratio for Calcium looping (CaL) is 95%. Electricity demand for integrated CaL combined with CCS technology is 0.87 GJ<sub>e</sub>/t CO<sub>2</sub> [31].

where  $\Delta F_{CO_2,c}$  (t CO<sub>2</sub>/s) is the CO<sub>2</sub> capture rate,  $\Delta F_{CO_2,in}$  (t CO<sub>2</sub>/s) is the change in carbon input in the industrial plant,  $\Delta P_m$  (MW<sub>e</sub>) is the change in imported electricity for the main process due to CO<sub>2</sub> capture or biomass introduction,  $\Delta H_m$  (MW<sub>th</sub>) is the change in imported steam for the main process due to CO<sub>2</sub> capture or biomass introduction,  $P_e$  (MW<sub>e</sub>) is the imported electricity for CO<sub>2</sub> capture and compression,  $H_c$  is the imported steam for CO<sub>2</sub> capture and compression,  $f_{st}$  is the power equivalent factor for steam (dimensionless),  $Em_{elec}$  (t CO<sub>2</sub>/MJ<sub>e</sub>) is the CO<sub>2</sub> emission factor of grid electricity, and  $M_{ind}$  (t product/s) is the production rate of the industrial product. The calorific value and GHG intensity of various energy carriers is given in Table 3.

### 2.3. Economic analysis

To allow a fair comparison of mitigation options among the different industrial sectors, the CO<sub>2</sub> avoidance costs are determined. First, the avoidance cost as reported in the literature is obtained, adjusted to a sector-specific representative scale and indexed<sup>2</sup> to €<sub>2017</sub> (see Table 4). Next, the harmonized CO<sub>2</sub> avoidance costs (€/t CO<sub>2</sub>) were calculated based on the technical analysis and GHG inventory, using Equations (4) and (5).

$$CO_2 \text{ avoidance costs} = \frac{\Delta C_p}{F_{CO_2 \text{ avoided}}} \quad (4)$$

where  $\Delta C_p$  (€/t product) is the change in production cost and  $\Delta F_{CO_2 \text{ avoided}}$  is taken from the GHG inventory.

$$\Delta C_p = \frac{\alpha \times \Delta I + \Delta C_{O\&M} + \Delta C_{Feedstock} - \sum (\Delta F_{bpx} \times C_{bpx}) + \Delta M_{CO_2,cap} \times C_{T\&S}}{F_p} \quad (5)$$

where  $\alpha$  is the capital recovery factor ( $y^{-1}$ ), calculated by  $r/(1-(1+r)^{-L})$ ;  $r$  is the discount rate;  $L$  is the economic lifetime (y);  $\Delta I$  (€) is the additional total capital requirement (TCR);  $\Delta C_{O\&M}$  (€/y) is the additional operating and maintenance costs;  $\Delta C_{Feedstock}$  (€/y) is the change in coal or biomass cost;  $F_{bpx}$  (t/y) is the additional flow of by-product  $x$ ;  $C_{bpx}$  (€/t) is the market price of by-product  $x$ .  $\Delta M_{CO_2,cap}$  (t CO<sub>2</sub>/y) is the CO<sub>2</sub> capture amount;  $C_{T\&S}$  (€/t) is the cost of transport and storage of CO<sub>2</sub>; and  $F_p$  (t/y) is the flow of product.

#### 2.3.1. Total capital requirement

To calculate the additional TCR from modifications needed to implement CCS and/or biomass, the factored estimate method was used. This method involves calculating the cost of each individual additional component to determine the additional process plant cost (PCC) (see Table 5). Using factors, the PCC is then converted into the additional TCR (see Table 4). The cost of the individual components is calculated according to Equation (6).

$$\frac{Cost_{Case}}{Cost_{Base}} = \left( \frac{Scale_{Case}}{Scale_{Base}} \right)^{SF} \quad (6)$$

<sup>2</sup> Costs reported in other currencies were first converted to € using year-averaged exchange rate data and then escalated to the year 2017 using CEPCI.



**Table 3**  
Calorific value and carbon content of different products in this study.

	Units	Calorific Value	C-content (wt %)	GHG intensity upstream (kg CO <sub>2eq</sub> /t)
Coking coal <sup>a</sup>	GJ <sub>LHV</sub> /t	31.1	79	143
Pulverized coal <sup>a</sup>	GJ <sub>LHV</sub> /t	33.37	87	143
Anthracite <sup>a</sup>	GJ <sub>LHV</sub> /t	34.89	88.3	143
Coal used as fuels <sup>a</sup>	GJ <sub>LHV</sub> /t	26.7	70	143
Natural gas <sup>b</sup>	GJ <sub>LHV</sub> /t	50	75	10
Crude oil <sup>b</sup>	GJ <sub>LHV</sub> /t	43	86	90
Fossil gasoline <sup>b</sup>	GJ <sub>LHV</sub> /t	44	87	79.4
Fossil diesel <sup>b</sup>	GJ <sub>LHV</sub> /t	43	86	80.3
Electricity <sup>c</sup>	–	–	–	400 (g/kWh)
Charcoal <sup>d</sup>	GJ <sub>LHV</sub> /t	31	85	105
Torrefied wood pellets (TOPs) <sup>e</sup>	GJ <sub>LHV</sub> /t	22	55	7.9
Woody biomass for pyrolysis <sup>e</sup>	GJ <sub>LHV</sub> /t	18.6	51	1.9
Log/Round wood <sup>f</sup>	GJ <sub>LHV</sub> /t	19.5	50	53
Heavy fuel oil (HFO) <sup>f</sup>	GJ <sub>LHV</sub> /t	41	84	0.5
Black liquor <sup>f</sup>	GJ <sub>LHV</sub> /t	13.7	31	0
Bark <sup>f</sup>	GJ <sub>LHV</sub> /t	20.5	50	0
Low pressure steam <sup>g</sup>		0.23		

<sup>a</sup> Carbon content and energy density of coking coal, pulverized coal, anthracite and coal used as fuels are taken from Refs. [22,31,54], and upstream emissions are taken from Ref. [55].

<sup>b</sup> The calorific value of natural gas varies between 44 and 56 GJ<sub>LHV</sub>/t, depending on its composition and gas density [22,56–58]. Based on IEAGHG, a natural gas (dry basis) composition of 83.9 vol% CH<sub>4</sub>, 9.2 vol% C<sub>2</sub>H<sub>6</sub>, 3.3 vol% C<sub>3</sub>H<sub>8</sub>, 1.2 vol% C<sub>4</sub>H<sub>10</sub>, 0.2 vol% C<sub>5</sub>H<sub>12</sub>, 1.8 vol% CO<sub>2</sub>, and 0.4 vol% N<sub>2</sub> was assumed [22]. This results in an energy density of 50 GJ<sub>LHV</sub>/t and a carbon content of 75 mass%. The upstream emissions are based on Berghout [51]. The calorific value of fossil gasoline and fossil diesel are from Boulamanti et al. and Staffell [57,59]. The calorific value of crude oil is 43 GJ/t, and the upstream emissions are 2.1 kg CO<sub>2</sub>/GJ crude oil [56,60].

<sup>c</sup> The GHG emissions of electricity are 370–466 g/kWh [13,55,61]. In this study a value of 400 g/kWh is used.

<sup>d</sup> According to Mousa and Norgate, the carbon content of charcoal is 85%–87%, the moisture content is 1%–5%, and the energy content 30–32 GJ/t [18, 62]. For the LCA analysis, they used Mallee Eucalyptus as feedstock, which results in upstream emissions of 105 kg CO<sub>2eq</sub>/t charcoal [62].

<sup>e</sup> The properties of TOPs and woody biomass for pyrolysis are based on the study of Meerman and PNNL [63,64].

<sup>f</sup> The properties of black liquor, bark, HFO, and log/round wood are taken from the IEAGHG [49]. The upstream emissions of log/round wood are composed of forest management and transportation according to the study of Miner et al. [65]. For the forest management, the upstream emissions (harvesting and thinning) are 46 kg CO<sub>2</sub>/t [65]. For domestic transportation with a truck, the upstream emissions are 7 kg CO<sub>2</sub>/t. Black liquor and bark are intermediate products produced from log/round wood. Therefore, no upstream emissions are assumed, as they are allocated to their main products.

<sup>g</sup> The power equivalent factor is the ratio of electricity: heat and represents the efficiency losses of power production from steam. For low pressure steam (120–150 °C) a factor of 0.23 is assumed based on the study of Bolland [66].

where SF is the economic scaling factor. Components Cost<sub>Base</sub>, Scale<sub>Base</sub>, and scaling factor are taken from the literature (see Table 4), whereas Scale<sub>Case</sub> is taken from the economic analysis.

### 3. Industrial sector

#### 3.1. Iron and steel

Global crude steel production reached 1689 Mt in 2017, with production projected to grow to 2100 Mt by 2050 [8,76]. As the main steel production route, integrated steel production is expected to remain at nearly 1200 Mt; however, recycled steel production is expected to more than double by 2050 [3,8]. The iron and steel sector is one of the most

**Table 4**  
Harmonized economic parameters.

	Units	Normal value
<b>General</b>		
Annual plant operation time <sup>a</sup>	h/y	8000–8500
Economic life time <sup>b</sup>	y	20
Discount rate <sup>b</sup>	–	10%
Total plant cost (TPC) <sup>c</sup>	% of PPC	130
Total capital requirement (TCR) <sup>c</sup>	% of TPC	110
Operation and maintenance cost (O&M) <sup>d</sup>	% of TCR	4
Economic scaling factor <sup>e</sup>	–	0.67
<b>Commodity price</b>		
Natural gas <sup>f</sup>	€ <sub>2017</sub> /GJ <sub>LHV</sub>	9
Coking coal <sup>g</sup>	€ <sub>2017</sub> /GJ <sub>LHV</sub>	4
Non-coking coal <sup>g</sup>	€ <sub>2017</sub> /GJ <sub>LHV</sub>	2.8
Electricity <sup>h</sup>	€ <sub>2017</sub> /GJ	16.5
Torrefied wood pellets <sup>i</sup>	€ <sub>2017</sub> /GJ	7.8
Woody biomass for pyrolysis <sup>i</sup>	€ <sub>2017</sub> /GJ	3.4
Black liquor <sup>i</sup>	€ <sub>2017</sub> /GJ	3.4
Charcoal <sup>j</sup>	€ <sub>2017</sub> /GJ	9.6
Transport fuels <sup>k</sup>	€ <sub>2017</sub> /GJ	16
Fine ore <sup>k</sup>	€ <sub>2017</sub> /t	70
Lump ore <sup>k</sup>	€ <sub>2017</sub> /t	92
Limestone <sup>l</sup>	€ <sub>2017</sub> /t	21
CO <sub>2</sub> transport and storage (T&S) cost <sup>m</sup>	€ <sub>2017</sub> /t	16

<sup>a</sup> The following annual availabilities were assumed: 8000 h/y for cement and refinery plants; 8400 h/y for paper and pulp mills, and 8500 h/y for the other industrial plants [13,49].

<sup>b</sup> The real discount rates for the industrial plants found in the literature were 7%–12% for iron and steel production [13,21,67,68], 8%–10% for cement production [13,31,69], 7%–10% for petrochemicals [14,15,51], 8%–15% for paper mills [45,46,49], and 8%–10% for hydrogen production [15,70]. The economic lifetime for industrial plants is 20–25 y [13–15,51,69]. In this study a value of 10% was taken.

<sup>c</sup> Process plant cost (PPC) comprises equipment and installation costs. Total plant cost (TPC) comprises PPC, engineering fees, and contingencies. Total capital requirement (TCR) comprises TPC, owner costs, and interest during construction [13].

<sup>d</sup> Typically, the operation and maintenance cost (O&M) is approximately 3%–12% of TCR. Here, a conservative value of 4% is assumed based on the literature review [13,53].

<sup>e</sup> The scaling factor is typically between 0.6 and 0.8 [13–15].

<sup>f</sup> Natural gas price projected by the Energy Technology Perspectives is 7–11 €/GJ for the period 2020–2040 in Europe [3]. Here, 9 €/GJ for the natural gas price is used.

<sup>g</sup> Coking coal price reported from Kuramochi, Mandova and IEA report ranges from 3.98 to 4.05 €/GJ when the price is indexed to €<sub>2017</sub> [13,50,51]. The average value of 4 €/GJ is used. The cost of non-coking coal, e.g., pulverized coal, is 2.2–3.2 €/GJ according to Kuramochi, IEA, and Mandova. In this study, 2.8 €/GJ is used [13,50,51].

<sup>h</sup> The cost of 50% coal-based electricity price is 55–67 €/GJ [13,27,51].

<sup>i</sup> Meerman et al. used 6.9–8.8 €/GJ as a proxy for TOPs prices during 2007–2013 [51,71]. Therefore, 7.8 €/GJ is used as the average value in this study. Woody biomass for pyrolysis (2.5–5.1 €/GJ) is based on the study of Meerman and Berghout [51,71]. In this study, 3.4 €/GJ is used for the woody biomass. The price of black liquor is assumed to be equal to the price of wood for pyrolysis [51].

<sup>j</sup> From the study of Norgate, conventional wood costs between 26 and 44 US \$/t green (i.e., wet) wood at a moisture content of approximately 45%–50% [62]. This corresponds to 195–330 US\$/t charcoal. Feedstock costs represents approximately 68% of the total charcoal cost. Based on Mousa (2016), the energy content of charcoal (1–5% wt moisture) is 31 GJ/t, and the charcoal price is 9.6 €/GJ [18].

<sup>k</sup> According to Larson, the cost of transport fuels is 27 €/m<sup>3</sup> [72]. With a volume of 0.159 m<sup>3</sup>/bbl, the cost of fossil diesel and gasoline production is converted to 12–19 €/GJ<sub>LHV</sub> [72].

<sup>l</sup> Iron ore and limestone price is based on the study of Kuramochi [13].

<sup>m</sup> Cost of transport and storage are based on [49,51].

**Table 5**  
Process plant cost (PPC) in different industrial sectors.

Process	Base scale	Unit	PPC (M€)	Scaling factor	Ref
<b>Coke plant</b>	1.90	Mt coke/y	529	0.83	[13]
<b>Sintering plant</b>	6.60	Mt sinter/y	572	1.00	[13]
<b>ASU</b>	1839	t O <sub>2</sub> /d	40	0.70	[13]
<b>BF</b>	2.80	Mt pig iron/y	659	1.00	[13]
<b>COREX</b>	1.00	Mt pig iron/y	248	1.00	[13]
<b>Hisarna</b>	1.00	Mt pig iron/y	350	0.67	[73]
<b>DRI</b>	2.00	Mt iron	474	0.67	[74]
<b>BOF</b>	2.80	sponge/y Mt CS/y	410	1.00	[13]
<b>EAF</b>	2.00	Mt CS/y	379	0.67	[74]
<b>Cement</b>	1.27	Mt cement/y	155	0.67	[31]
<b>Pulp mill</b>	800	kt pulp/y	1064	0.67	[49]
<b>Integrated pulp and board mill</b>	800	kt pulp/y	1257	0.67	[49]
<b>SMR</b>	141	kt H <sub>2</sub> /y	55	0.67	[75]
<b>WGS</b>	141	kt H <sub>2</sub> /y	7	0.67	[75]
<b>Pressure swing adsorption (PSA)</b>	141	kt H <sub>2</sub> /y	76	0.67	[75]
<b>Chemical looping reforming (CLR)</b>	23.7	kt H <sub>2</sub> /y	14	0.67	[168]
<b>Boiler &amp; turbines</b>	141	kt H <sub>2</sub> /y	91	0.67	[75]
<b>Biomass gasifier</b>	52	PJ bio/y	222	0.67	[75]
<b>Acid gas removal</b>	554	t CO <sub>2</sub> /h	118	0.7	[71]
<b>BIG-CHP</b>	473	MW <sub>LHV</sub> TOPs	258	0.67	[51]
<b>BIG-H<sub>2</sub></b>	401	MW <sub>LHV</sub> TOPs	256	0.67	[51]
<b>BIG-FT</b>	937	MW <sub>LHV</sub> TOPs	554	0.67	[51]
<b>BIG-combination</b>	1499	MW <sub>LHV</sub> TOPs	743	0.67	[51]
<b>PFO</b>	2	kt biomass/d	270	0.67	[51]
<b>MEA</b>	1	Mt CO <sub>2</sub> captured/y	98	0.67	[51]
<b>VPSA</b>	2.6	Mt CO <sub>2</sub> captured/y	159	1.00	[27]
<b>MDEA</b>	0.23	Mt CO <sub>2</sub> captured/y	14.3	0.67	[168]
<b>Selexol</b>	1	Mt CO <sub>2</sub> captured/y	119	0.67	[13]
<b>Oxy-fuel combustion</b>	1	Mt CO <sub>2</sub> captured/y	41	0.67	[51]
<b>Pre-combustion</b>	1.00	Mt CO <sub>2</sub> captured/y	43	0.67	[51]
<b>Integrated CaL</b>	0.94	Mt CO <sub>2</sub> captured/y	22	1.00	[31]

energy- and CO<sub>2</sub>-intensive sectors, accounting for 20% of final energy use and 28% of direct CO<sub>2</sub> emissions of the entire industrial sector (equal to 6.7% of CO<sub>2</sub> emissions worldwide) [18,36,77]. Although iron and steel production is a complex process incorporating a variety of technologies with different plant layouts, only a few processes are widely used today (Fig. 3) [13,74,78].

### 3.1.1. Production process

Currently, blast furnace–blast oxygen furnace (BF-BOF) and electric arc furnace (EAF) are the two main steel production routes, accounting for 71.5% and 28% of global crude steel production, respectively [36,79]. Iron production reached 1266 Mt in 2017 of which the BF-BOF route covered 93% and the direct reduced iron (DRI) route covered the remaining 7% [79]. An integrated steel mill with a BF-BOF route contains a coking plant, agglomeration plant, BF-BOF, and final manufacturing units (Fig. 3) [13,78,80]. The energy consumption is 14.5–20 GJ/t crude steel (CS) [36,55,81]. As an alternative to BF, top gas recycling blast furnace (TGRBF) uses pure oxygen instead of hot air, and, after potentially capturing CO<sub>2</sub>, the top gas is recycled in the BF [80,82]. The carbon input in TGRBF is reduced by 25%–35% compared with conventional BF [80]. The EAF steel-making route is a process that fabricates steel from scraps, DRI, or recycled steel (Fig. 3) [74,78]. The raw material is fed into the EAF with O<sub>2</sub> injection and/or oxy-fuel burners, and liquid steel is produced [74]. Energy demand for EAF is 3.9–6.7 GJ/t CS [78,83,84].

The variations and adaptations of iron- and steel-making routes include smelting reduction (SR) [78,80,85] and direct reduction (DR) [36,86,87]. The SR route (COREX, FINEX, and Hisarna) eliminates the iron ore agglomeration process [80]. The major differences between the COREX and FINEX processes is that FINEX can directly use sinter feed iron ore [80]. The COREX process includes a shaft furnace, where the main reactions are the reduction of iron oxides and carbonate decomposition and a melter–gasifier, where the main reactions are fuel and the reducing gas combustion, residual iron oxide reduction, and residual carbonate decomposition [85]. The energy consumption for COREX is 18.9–21.7 GJ/t CS, which is higher than the BF-BOF route [78,84]. The use of oxygen and higher coal consumption in the COREX melter–gasifier produces a much more energy-rich process gas [85]. The process gas used for electricity generation from COREX is 9–12 GJ/t CS, whereas the process gas from the BF-BOF route is only 2–4 GJ/t CS [84,85]. Additionally, the COREX process gas contains around 30–35 vol% CO<sub>2</sub>, which is easier to capture than the BF process gas with 17–25 vol% CO<sub>2</sub> [13,78]. Hisarna is different from COREX because it does not use recycled process gas as an energy source [80]. Hisarna has a 20% lower CO<sub>2</sub> intensity and energy consumption compared with the BF route [87–89]. The DRI process is based on the reduction of European lump ores [74]. The solid DRI product may be subsequently melted or made into solid hot briquetted iron, and the resulting hot metal is directly fed into the EAF for steel production [90]. The energy consumption for the natural-gas-based and coal-based DRI route is 14.4–18.4 GJ/t CS and 15.6–20.8 GJ/t CS, respectively [78,83,91,92]. The DRI production route uses CO and H<sub>2</sub>, typically produced from natural gas, as reducing agents for iron production [18,74,91,92]. Costa et al. proposed a two-dimensional model to use pure H<sub>2</sub> as a reducing agent, thereby reducing direct CO<sub>2</sub> emissions by more than 80% [93]. The ULCOS program used H<sub>2</sub> generated by water electrolysis, resulting in a CO<sub>2</sub> intensity of 0.3 t CO<sub>2</sub>/t CS [36]. The kinetic analysis from Guo et al. shows that it is also possible to use biomass-derived syngas as a reducing agent for DRI [94].

### 3.1.2. Technical mitigation potentials

Several studies investigated the potential for CCS in the iron and steel sector [36,80,91,92]. The CO<sub>2</sub> intensity for the traditional BF-BOF route is approximately 1.7–2.3 t CO<sub>2</sub>/t CS, as shown in Fig. 4 [13,55,61,62] [80,81,91,92]. The CO<sub>2</sub> emissions from the blast furnace accounts for 69% of direct emissions, followed by the combustion of BOF gas (7%) and coke oven gas (6%) [13,68,78]. The CO<sub>2</sub> intensity of the BF combined with CCS, using MEA, KS-1 (similar to MEA), or selexol (physical solvent) is 1.1–1.4 t CO<sub>2</sub>/t CS [13,55]. The process gas in TGRBF has a CO<sub>2</sub> concentration of 35 vol%, and CO<sub>2</sub> emissions could be reduced to 0.9–1.2 t CO<sub>2</sub>/t CS with MEA or VPSA [27]. EAF with 100% scrap feed consumes nearly 1.6 GJ of electricity per ton of steel, and CO<sub>2</sub> intensity is in the range of 0.1–0.9 t CO<sub>2</sub>/t CS, which is much lower than with BF-BOF [34,61,62,91,92]. The main reason for the low energy consumption and CO<sub>2</sub> emissions is the absence of a coking plant, iron ore reducing unit, and iron-making process in the EAF route [78].

For the SR route, with the use of process gases for power generation (conversion efficiency > 45% and grid electricity emission factor of 0.9 t CO<sub>2</sub>/MWh), CO<sub>2</sub> emissions of COREX are approximately 1.2 t CO<sub>2</sub>/t CS [95]. Commercially, concentrated CO<sub>2</sub> can be removed from the COREX process gas by VPSA [13,96]. CO<sub>2</sub> emissions in Hisarna without and with CCS account for nearly 80% and 20% of the BF-BOF route, respectively [73,88]. For the DRI-EAF route, the CO<sub>2</sub> intensities for natural-gas-based and coal-based processes are 1.1–1.4 t CO<sub>2</sub>/t CS and 2.5–3.5 t CO<sub>2</sub>/t CS, respectively [78,91,92]. The range in CO<sub>2</sub> emissions is partly due to differences in system boundaries, CO<sub>2</sub> emission factors of energy carriers, and regional differences [78,91,92]. When combined with CCS technology, the CO<sub>2</sub> emissions of natural gas based DRI-EAF are reduced to 0.72 t CO<sub>2</sub>/t CS [36].

In this study, the CO<sub>2</sub> intensities for different routes are shown in Fig. 4. For the base cases (BF-BOF, COREX, Hisarna, DRI-EAF, and scrap

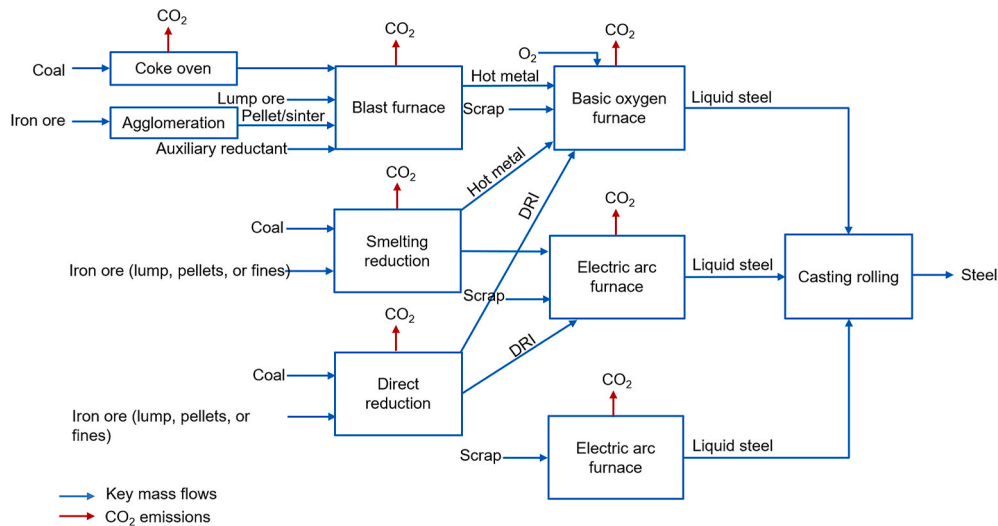


Fig. 3. Iron and steel production routes [78].

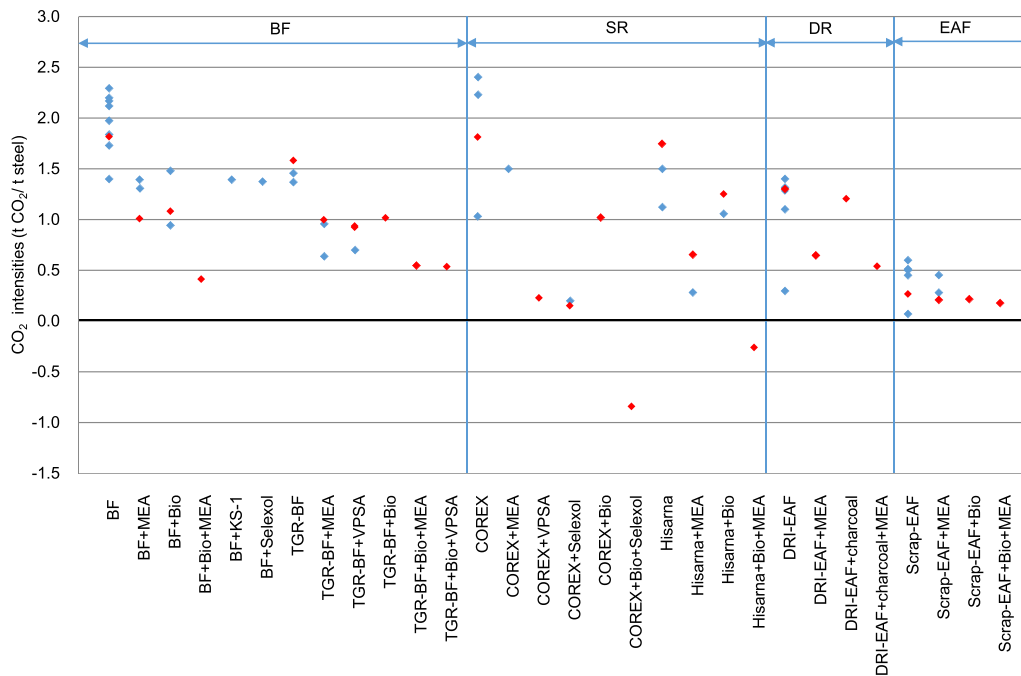


Fig. 4. CO2 intensities in iron and steelmaking (blue dots are from literature, red dots are calculation results in this study).

EAF), CO<sub>2</sub> intensities range from 0.27 to 1.82 t CO<sub>2</sub>/t CS. Applying CCS in the main process results in CO<sub>2</sub> intensities of 0.15–1.01 t CO<sub>2</sub>/t CS. The largest potential for biomass application in the iron- and steel-making process is the use of charcoal as a reducing agent to substitute for part of the coke [18,62]. Bio-syngas via gasification as well as liquid biofuel via pyrolysis could also be injected in BF [37,97]. Based on a literature review, the biomass substitution ratio of coal is 40%<sub>LHV</sub> for BF-BOF, 45%<sub>LHV</sub> for Hisarna, and 100% for EAF (100% scraps) [18,62,73]. Harmonization results show CO<sub>2</sub> intensities of 0.21–1.2 t CO<sub>2</sub>/t CS for different bio-based routes. When applying BECCS, this drops to -0.84 to 0.54 t CO<sub>2</sub>/t CS.

### 3.1.3. Economic evaluation

The cost of CO<sub>2</sub> mitigation has been investigated in several studies (see Fig. 5). The CO<sub>2</sub> avoidance cost for BF-BOF and TGR-BF routes with different CO<sub>2</sub> capture technologies ranges from 34 to 120 €/t CO<sub>2</sub> [13,

22,24,25,67]. The upper limit involves BF-BOF with MEA technology, including the CO<sub>2</sub> emission allowance of 50 €/t CO<sub>2</sub> and cost for CO<sub>2</sub> transport and storage [24]. For the COREX process gas, the high CO<sub>2</sub> concentration reduces the size of the water shift reactor and increases the CO<sub>2</sub> generation efficiency per unit of feed gas [67]. This reduces the energy penalty by 1/3, which reduces the energy costs more than the increase in CAPEX that results from converting the CO in COREX flue gas to CO<sub>2</sub>. Depending on the capture technology used, this results in CO<sub>2</sub> avoidance costs that range from 37 to 58 €/t CO<sub>2</sub> [13,67].

Harmonization results indicate that CCS can be applied at an avoidance cost of 49 €/t CO<sub>2</sub> for the BF-BOF route with MEA technology (Fig. 5), including by-product and electricity credits. Scrap-based EAF with MEA is unattractive owing to the low amount of CO<sub>2</sub> captured and the relatively high CO<sub>2</sub> avoidance cost (109 €/t CO<sub>2</sub>). CO<sub>2</sub> captured from the COREX process might be economically more attractive than the other routes owing to the high CO<sub>2</sub> concentration in the process gas. Of



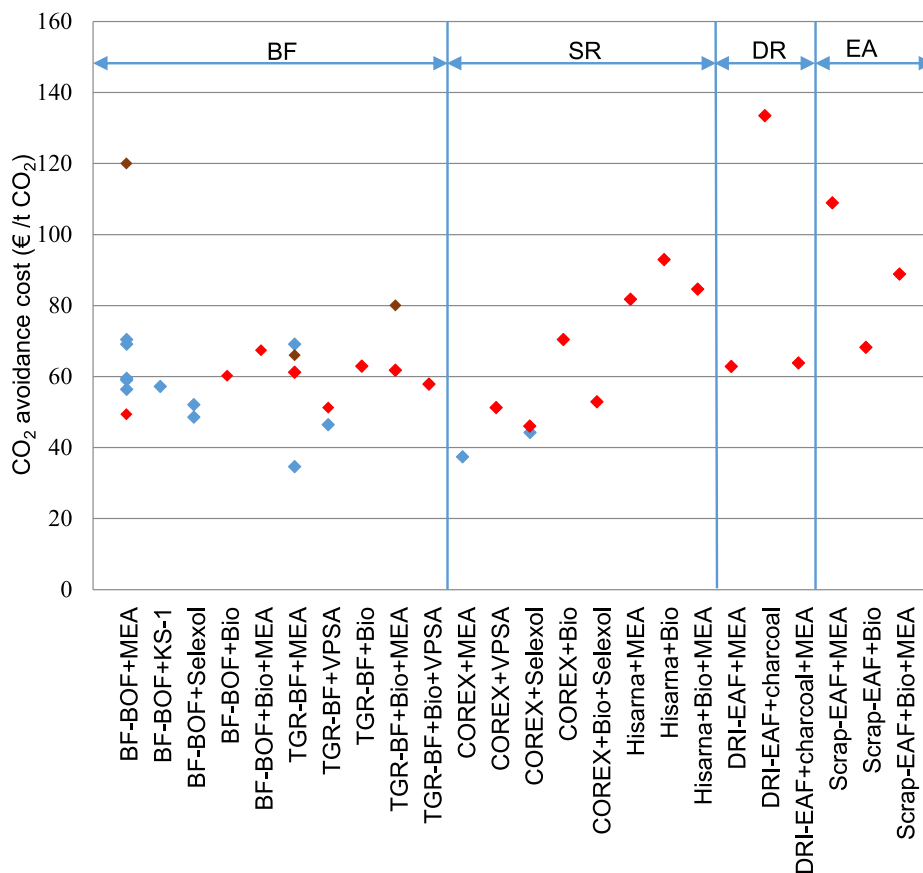


Fig. 5. CO<sub>2</sub> avoidance cost for the iron and steel industry (blue dots represent data from the literature without transport and storage costs, brown dots represent the inclusion of transport and storage costs, and red dots are the calculation results from this study).

the biomass options, the BF-BOF route showed the best performance, with an avoidance cost of 60 €/t CO<sub>2</sub>.

For the DRI-EAF process, the main source of CO<sub>2</sub> emissions is natural gas consumption. Even if all the coal in the process is substituted by biomass, CO<sub>2</sub> reductions are minor, whereas the high biomass price results in very high avoidance costs of 134 €/t CO<sub>2</sub>. For BECCS options, the COREX process shows the lowest avoidance cost of 53 €/t CO<sub>2</sub>, whereas the scrap-based EAF process exhibits the highest CO<sub>2</sub> avoidance cost of 89 €/t CO<sub>2</sub>.

### 3.2. Cement

The cement sector is currently the third-largest industrial energy consumer, accounting for 7% (10.7 EJ) of global industrial energy use [39,98]. Its direct CO<sub>2</sub> emissions were 4.1 Gt CO<sub>2</sub> in 2014, making it the second largest industrial emitter of CO<sub>2</sub> [99,100]. It is estimated that world cement production will increase from 4.2 Gt in 2014 to 4.3 Gt by 2030 and 4.7 Gt by 2050 [39]. The chemical decomposition of limestone into lime and CO<sub>2</sub> is typically responsible for 60%–70% of the total CO<sub>2</sub> emissions, with fuel combustion accounting for the rest [101–103]. In 2014, 84% of the energy demand for cement production was provided by fossil fuels [40]. This was mainly coal and sometimes pet coke. However, in regions with relatively cheap natural gas or oil, these fuels are utilized [40,104,105]. A further 6% of energy demand was provided by biomass, and the remaining 10% was supplied by alternative fuels (e.g., waste tires, waste oil and solvents, pre-treated industrial and domestic waste, plastic, textile and paper waste) [40]. The IEA estimates that the fossil fuel share of total energy demand will decrease from 94% in 2014 to 67%–70% in 2050, owing to the increased use of waste and biomass [39]. The European Cement Research Academy (ECRA)

estimates that waste or biomass substitution could reach 30% in developing regions and 70% in developed regions by 2050 [40].

#### 3.2.1. Production process

Cement is a binder produced from limestone [105–107]. This limestone is first ground and dried in a mill [103]. Then, it undergoes calcination in a kiln at 900 °C, resulting in the formation of calcium oxide (CaO) and CO<sub>2</sub> [108]. Next, the CaO is heated to 1400–1500 °C together with silica, alumina, and ferrous oxides to form a clinker [23]. The clinker is cooled and ground or milled together with gypsum and other additives to form cement (see Fig. 6) [103,107]. Cement production is typically categorized as a wet, semi-wet, semi-dry, or dry process, depending on the moisture content of the available raw materials [104]. The dry process is the most energy-efficient production process, consuming approximately 13% less energy and 28% less fuel than the wet process [104]. In Europe, over 90% of cement production is performed using the dry process, owing to the abundance of dry raw materials [104,109]. The remaining production is divided between utilizing the semi-dry and semi-wet processes (combined 7.5%) and the wet process (2.5%) [104].

Typically, the most optimal energy performance for the dry process is 3–3.4 GJ/t clinker [40]. This results in 0.7–1.1 t CO<sub>2</sub>/t cement [69,103,110]. Of this, 55%–60% comes from limestone calcination, 30%–35% from fossil fuel combustion, 5% from imported electricity, and the remaining 5% from up- and downstream transportation [39,103,105]. The direct emissions depend largely on the quality of the raw materials, the fuel source, and clinker-to-cement ratio [103–105,111].

#### 3.2.2. Technical mitigation potentials

Several studies investigated the potential for CCS in cement

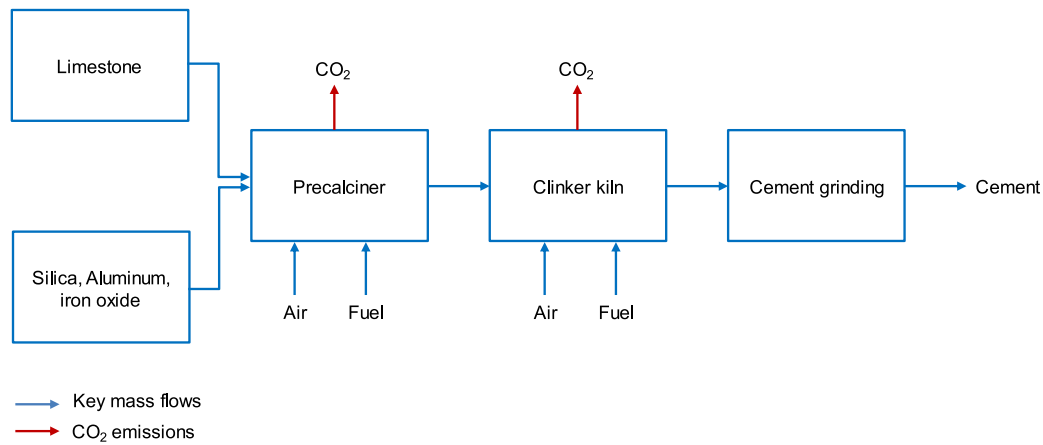


Fig. 6. Production scheme from limestone to cement (dry process) [13].

production (see Fig. 7) [13,23,28,29,103,105] [107,110,112]. As discussed earlier, post-combustion CO<sub>2</sub> capture is the easiest way to implement CCS in existing plants, as no major changes to the production process are necessary [87]. MEA-based CCS can reduce CO<sub>2</sub> emissions by 43%–79%, depending on the energy carrier used, as shown in Fig. 7 [13, 23,28]. Applying MEA-based CCS with on-site steam results in CO<sub>2</sub> intensities of 0.16–0.17 t CO<sub>2</sub>/t cement, showing better results than CCS with off-site steam (0.19–0.25 t CO<sub>2</sub>/t cement) [13,28]. For comparison, CCS applied only at the pre-calciner results in CO<sub>2</sub> intensities of 0.32–0.37 t CO<sub>2</sub>/t cement [13,28]. The waste heat in oxy-combustion cement plants can be recovered by generating electricity, leading to a CO<sub>2</sub> intensity of 0.11 t CO<sub>2</sub>/t cement [111].

The cement industry is possibly the best candidate for calcium-

looping (CaL) CO<sub>2</sub> capture, as this process can use the CaO produced in the cement plant as regenerable CO<sub>2</sub> sorbent [13,113–117]. The main CaL process is shown in Fig. 8. Integrated CaL and tail-end CaL are the main options [31,111,113,116,118]. A main difference in configuration is that in the case of integrated CaL, the carbonator is located upstream of the clinker process and is integrated within the raw meal suspension pre-heater; meanwhile, the tail-end configuration has the carbonator located downstream of the clinker process [111,113,116,117,119]. Compared with a conventional cement plant, fuel consumptions in the tail-end and integrated CaL configurations are increased by 95%–270% and 40%–70%, respectively [31,117]. The significant increase in fuel requirement for the tail-end CaL is due to the fact that all the CO<sub>2</sub> is captured, including the CO<sub>2</sub> released by CaCO<sub>3</sub> calcination in the

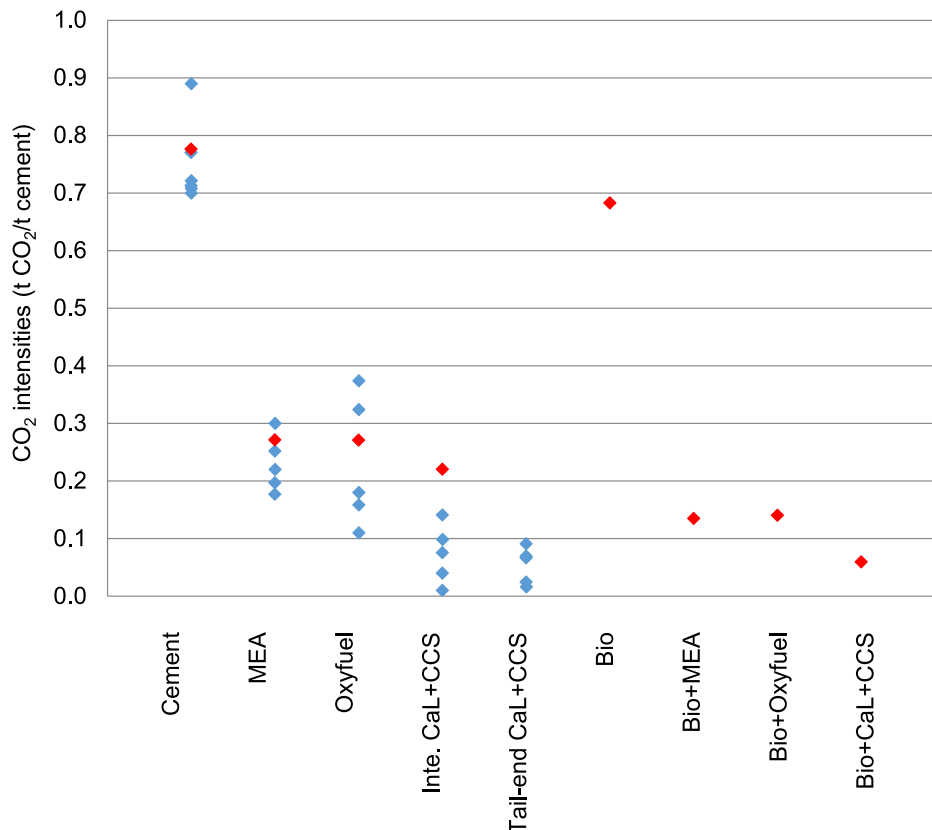


Fig. 7. CO<sub>2</sub> intensities in cement industry (blue dots represent data taken from the literature, and red dots represent the calculation results).

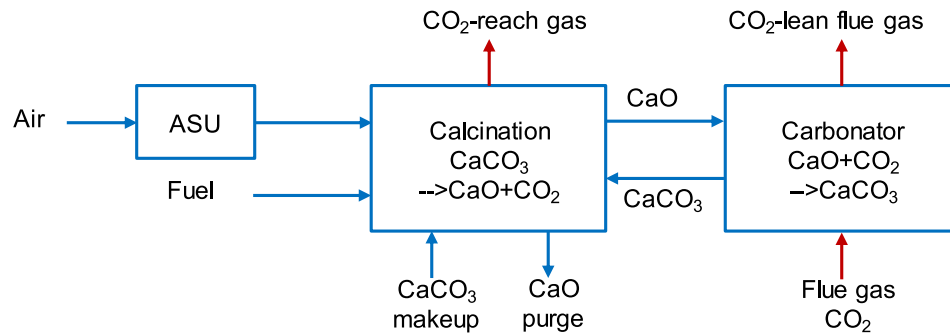


Fig. 8. Schematic overview of CaL process [117].

air-fired calciner [31]. The CO<sub>2</sub> intensity for the tail-end CaL is 0.01–0.141 t CO<sub>2</sub>/t cement [30,31,111,117], while the CO<sub>2</sub> intensities for the integrated CaL are 0.02–0.06 t CO<sub>2</sub>/t cement for an IL<sup>3</sup> of 20% and 0.07–0.09 t CO<sub>2</sub>/t cement for an IL of 50%.

Although the IEA and ECRA propose the possibilities for biomass application in cement, there are only a limited number of studies focusing on biomass utilization in the cement sector [39,40]. The potential role of biomass in cement production is limited, as most of the CO<sub>2</sub> emissions come from the calcination reaction and not the combustion of fossil fuels [40,69,115]. In addition, IEA and ECRA estimate that using an alternative fuel mix (containing 30%–40% biomass) has a maximum substitution rate of 65%<sub>LHV</sub> for fossil fuel in 2050 owing to technical limitations, such as the requirement of fuel properties and thermal energy requirement [39,40]. Therefore, only 6–10% of CO<sub>2</sub> emissions can become biogenic.

Based on the study of Barker, Romano, and Hills, a base case was defined using 2.8 GJ/t coal and with a CO<sub>2</sub> intensity of 0.78 t CO<sub>2</sub>/t cement [28,105,111]. When CCS is applied to the entire cement plant, the CO<sub>2</sub> intensity is 0.27 t CO<sub>2</sub>/t cement (MEA), 0.27 t CO<sub>2</sub>/t cement (Oxy-fuel), or 0.22 t CO<sub>2</sub>/t cement (CaL). For the biomass case, assuming an ambitious goal of a 50%<sub>LHV</sub> substitution rate for coal results in a CO<sub>2</sub> intensity of 0.68 t CO<sub>2</sub>/t cement. Applying BECCS (50% biomass substitution) gives CO<sub>2</sub> intensities of 0.13 t CO<sub>2</sub>/t cement (MEA), 0.14 t CO<sub>2</sub>/t cement (Oxy-fuel), and 0.06 t CO<sub>2</sub>/t cement (CaL).

### 3.2.3. Economic evaluation

The cost of CO<sub>2</sub> mitigation has been investigated in several studies (see Fig. 9). Studies show a CO<sub>2</sub> avoidance cost of 53–116 €/t CO<sub>2</sub> for MEA-based CCS, depending on the CO<sub>2</sub> intensity of the steam and electricity used [13,23,28,101]. Better options are oxyfuel-based CCS (avoidance cost of 35–42 €/t CO<sub>2</sub>), tail-end CaL (avoidance cost of 51–52 €/t CO<sub>2</sub>), and integrated CaL (avoidance cost of 51–52 €/t CO<sub>2</sub>) [13, 28–31,69,101].

The harmonization results indicate that the best performance for applying CCS is oxyfuel with a CO<sub>2</sub> avoidance cost of 36 €/t CO<sub>2</sub>. The biomass options yield an avoidance cost is 88 €/t CO<sub>2</sub>. Biomass combined with CaL and CCS shows the best performance with an avoidance cost of 53 €/t CO<sub>2</sub>.

### 3.3. Chemical/petrochemicals

The chemical industry accounts for 28% (42 EJ/y) of the final energy consumption of the industrial sector [3]. During 2000–2014, the average annual growth of process energy consumption and direct

<sup>3</sup> The ratio of the limestone fed to the CaL process through the limestone mill to the total amount of CaCO<sub>3</sub> fed to the cement kiln is usually defined as the integration level (IL), which significantly affects the heat input to the CaL calciner and the overall energy balance of the plant [31].

energy-related CO<sub>2</sub> emissions were 2.3% and 2.6%, respectively [3]. Of the sub-sector's total energy input, 58% is consumed as feedstock [3]. Its direct CO<sub>2</sub> emissions were 2 Gt in 2014, making it the third largest industry for CO<sub>2</sub> emissions [3,120]. Despite the wide variety of products generated by this sub-sector, only 18 base chemicals<sup>4</sup> account for 80% of the energy demand and 75% of the GHG emissions [121]. According to the IEA, energy savings of 16 EJ in the (petro)chemical industry can result in a CO<sub>2</sub> emissions reduction of 1.6–1.8 Gt CO<sub>2</sub>/year by the year 2050 [121]. To achieve the mitigation goal of the 2DS scenario, the feasibility of bio-products generated by biomass gasification [122,123] and fast pyrolysis [124,125] has been assessed.

#### 3.3.1. Production process

The production processes of a conventional crude oil refinery are shown in Fig. 10, and the corresponding CO<sub>2</sub> emissions are provided in Table 6. Smaller-scale refineries are often less complex and produce a smaller variety of chemicals [14,51]. The refining process involves separating crude oil into hydrocarbon fractions (distillation) and the cracking, reforming, treating, and blending of the hydrocarbon molecules to generate petroleum products [121]. Crude oil is heated and fed into a distillation column to be separated into different fractions based on boiling point [87,126]. The heavy fraction of the separation process, which contains the larger hydrocarbon molecules, pass through the cracking processes (catalytic cracking, catalytic reforming, and catalytic hydro-treating) to break up the molecules [121,127,128]. Reforming is typically utilized on lower-value light fractions to produce chemicals of a higher value [121,127].

#### 3.3.2. Technical mitigation potentials

The CO<sub>2</sub> intensities of refineries at different scales and with various mitigation technologies are shown in Fig. 11 [14,15,51]. Smaller-scale refineries have lower CO<sub>2</sub> intensities (0.09 t CO<sub>2</sub>/t crude oil) than large-scale refineries (0.17–0.22 t CO<sub>2</sub>/t crude oil) [14,15,51,52]. A potential reason for this is that larger refineries process more difficult crude oil, resulting in a more extensive treatment [14,15,51,52,129]. Previous studies have assessed the technical performance of CCS in the (petro)chemical industry by capturing CO<sub>2</sub> at refineries [14,51,52, 129–132]. The degree of CO<sub>2</sub> capture varies from capture only at specific point sources (e.g., fluidized catalytic cracking (FCC), hydrogen production unit, or several combined stacks) to capture from all CO<sub>2</sub> emission sources [12–15]. Here, only studies that apply CCS at the entire

<sup>4</sup> These chemicals are the following: BTX (benzene, toluene, and mixed xylenes), ammonia, ethylene, propylene, methanol, acrylonitrile, caprolactam, cumene, ethylene glycol, ethylene oxide, phenol, polyethylene, propylene oxide, polypropylene, para-xylene, styrene, terephthalic acid, and vinylchloride [121].

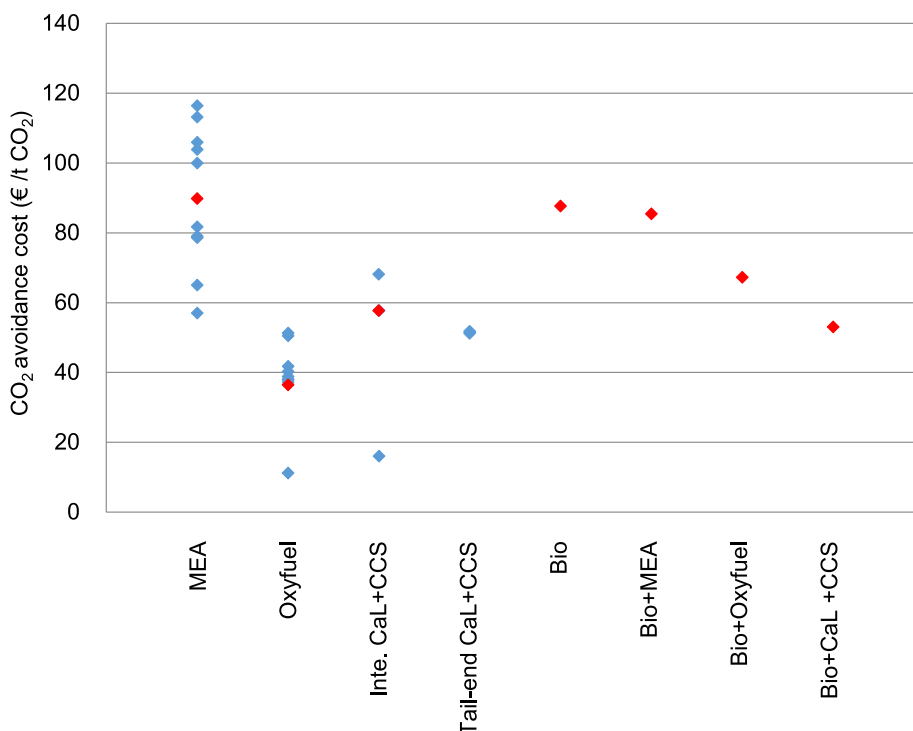


Fig. 9. CO<sub>2</sub> avoidance cost for cement industry (blue dots represent data taken from the literature, and red dots represent the calculation results).

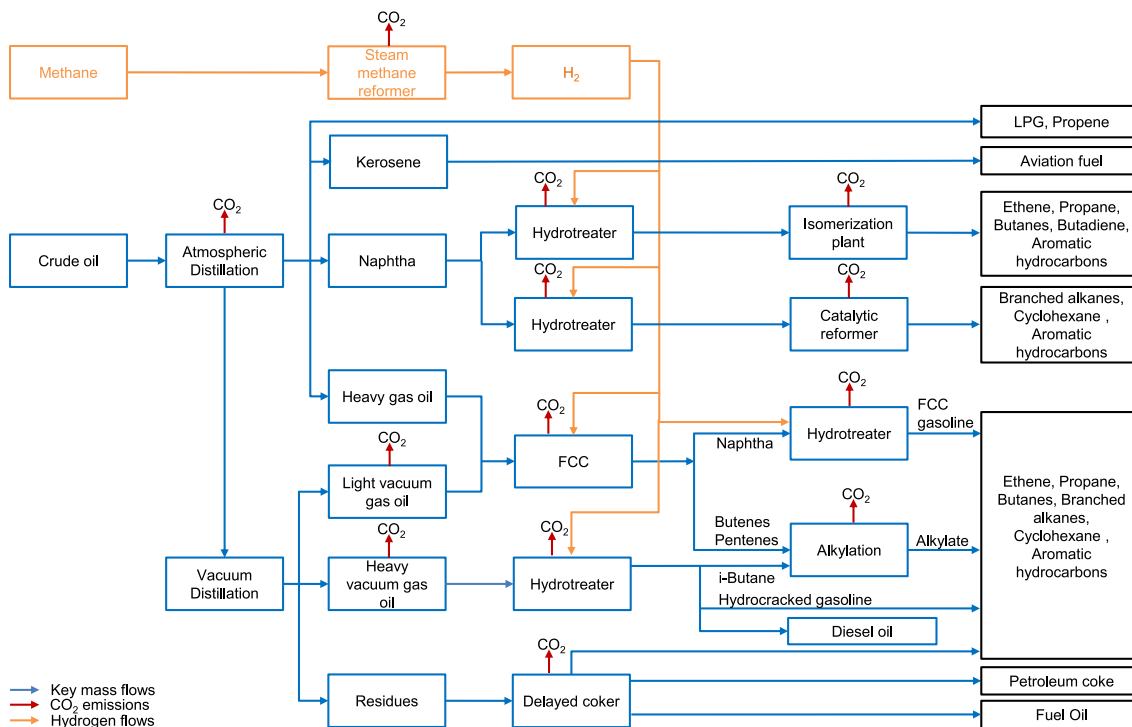


Fig. 10. Production scheme of a refinery. Finished products are shown in the black boxes.

refinery<sup>5</sup> are discussed. In a refinery, post-combustion capture technology could be used for all the main sources [14,51,52,129–132]. Pre-combustion and oxyfuel capture can also be applied to the entire plant, except the catalytic cracker and hydrogen production process,

respectively [51,129,130]. Even with CO<sub>2</sub> capture, large-scale refineries have higher CO<sub>2</sub> intensities than smaller refineries [14,15,51]. Johanson et al. compared the techno-economic performance of two different refineries equipped with MEA capture at different scales (6 Mt crude oil/year and 11.4 Mt crude oil/year) [14]. They evaluated alternative heat options (natural gas combined cycle (NGCC), natural gas boiler, biomass boiler, and excess heat) and found that NGCC with CO<sub>2</sub> capture resulted in the greatest reduction compared with the other options [14].

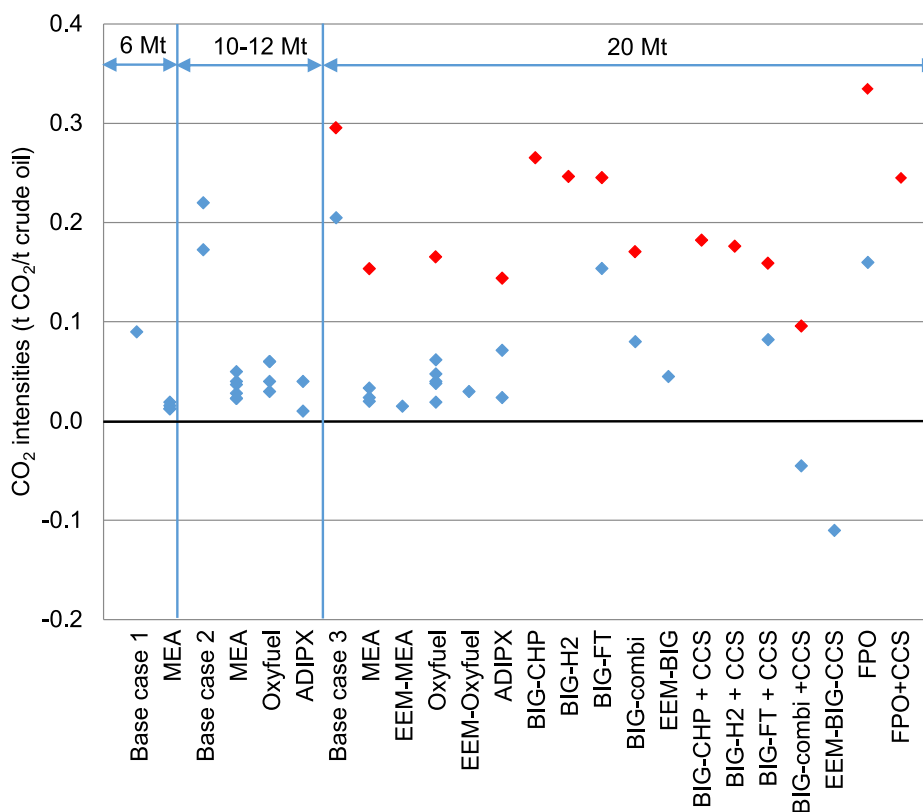
<sup>5</sup> CO<sub>2</sub> emitted from the flare cannot be captured, as this could compromise the capability of the flare as a safety feature [60].

**Table 6**  
Breakdown of CO<sub>2</sub> emissions by source.

Source	CO <sub>2</sub> concentration in gas steam (vol%)	Fraction of CO <sub>2</sub> emissions	Reference
Boilers and furnaces	3–13	30%–65%	[12]
Catalytic cracker	10–20	11%–35%	[51,129,130]
Power and heat	10–20	13%–50%	[129]
Hydrogen production	20–99	5%–20%	[130]
Flares	–	6%	[51]

emissions reductions of 85% (EEM-Oxyfuel) and 93% (EEM-MEA) [51, 57]. The individual BIG and BIG-CCS options show CO<sub>2</sub> emissions reductions of 14%–25% and 44%–59%, respectively [52]. The combination of three biomass gasification technologies (BIG-CHP, BIG FT, BIG-H<sub>2</sub>), EEM, and CCS yielded the greatest reduction in CO<sub>2</sub> emissions, resulting in a negative CO<sub>2</sub> intensity of –0.1 t CO<sub>2</sub>/t crude oil [51].

In this study, the base case is defined as a large refinery (20 Mt annual crude oil capacities) using 5 PJ/y of electricity and 7 PJ/y of hydrogen with cradle-to-gate CO<sub>2</sub> emissions of 5.91 Mt CO<sub>2</sub>/y. Applying pre-combustion (ADIP-X) to the refinery results in an intensity of 0.14 t CO<sub>2</sub>/t crude oil, which is lower than that for post-combustion (0.15 t CO<sub>2</sub>/t crude oil) and oxyfuel combustion (0.17 t CO<sub>2</sub>/t crude oil). Syngas



**Fig. 11.** CO<sub>2</sub> intensities in (petro)chemical sector (blue dots represent data from the literature without transport and storage costs, and red dots are the calculation results from this study).

However, without credits for exported electricity, the biomass boiler and excess heat alternatives further reduced CO<sub>2</sub> emissions [14]. Berghout et al. assessed the techno-economic performance of three CO<sub>2</sub> capture technologies at a medium- and large-sized refinery (10 Mt crude oil/y and 21 Mt crude oil/y) over the short term and long term [15]. Over the short term, pre-combustion resulted in the greatest CO<sub>2</sub> emissions reduction (2.1 Mt CO<sub>2</sub>/y for medium size and 3.6 Mt CO<sub>2</sub>/y for large size) [15]. Over the long term, the combined technology oxyfuel case showed the greatest CO<sub>2</sub> emissions reduction (1.9 Mt CO<sub>2</sub>/y for medium size and 3.7 Mt CO<sub>2</sub>/y for large size) [15]. Berghout also evaluated potential synergies between different mitigation options using a large-sized refinery as case study [51]. The results indicated that energy efficiency measures (EEM)<sup>6</sup> could reduce CO<sub>2</sub> emissions by 28%, whereas a combination of high-EEM and CCS could result in CO<sub>2</sub>

generated from the gasification of torrefied wood pellets (TOPs) is used to produce power and steam, hydrogen, and Fischer-Tropsch fuels (FT).<sup>7</sup> The CO<sub>2</sub> intensities for the three BIG technologies range from 0.25 to 0.27 t CO<sub>2</sub>/t crude oil. Applying all three BIG technologies results in 0.17 t CO<sub>2</sub>/t crude oil. The addition of CCS (3 BIG + CCS) likely results in a drop in CO<sub>2</sub> intensities to as far as 0.09 t CO<sub>2</sub>/t crude oil. The use of fast pyrolysis oil (FPO) carries the assumption that the biomass input is identical to the BIG cases, and the required hydrogen is produced from natural gas with SMR. Results indicate that this option increases CO<sub>2</sub> emissions to 0.33 t CO<sub>2</sub>/t crude oil, owing to the consumption of natural gas in the FPO production process. Combining FPO with CCS results in an intensity of 0.23 t CO<sub>2</sub>/t crude oil with NG-based H<sub>2</sub> and 0.24 t CO<sub>2</sub>/t

<sup>6</sup> Examples of energy efficiency measures are improved energy management, more efficient motors and pumps, fouling mitigation, and optimization of steam distribution.

<sup>7</sup> Based on the study of Berghout, the biomass inputs for the combined heat and power unit, hydrogen generation unit, and Fischer-Tropsch fuel production unit are 473 MW<sub>LHV</sub>, 401 MW<sub>LHV</sub>, and 937 MW<sub>LHV</sub>, respectively, for our base case. For the three combined BIG technologies, the input of biomass is 1499 MW<sub>LHV</sub> [51].



crude oil with bio-H<sub>2</sub>.

### 3.3.3. Economic evaluation

The cost of CO<sub>2</sub> mitigation has been investigated in several studies (see Fig. 12) [14,15,51]. Previous studies indicate that the application of energy-saving measures has the best CO<sub>2</sub> avoidance costs at -133 €/t CO<sub>2</sub>, indicating that these options pay for themselves [51]. Applying CCS could result in avoidance costs of 39–238 €/t CO<sub>2</sub> for MEA, 25–69 €/t CO<sub>2</sub> for oxyfuel combustion, and 54–93 €/t CO<sub>2</sub> for pre-combustion [14,15,51]. The literature also indicates that the size of the refinery is important, with lower CO<sub>2</sub> avoidance costs realized by larger plants (20 Mt crude oil/y) than by smaller plants (6–11 Mt crude oil/y) [14,15,51]. According to Johansson et al., the lowest CO<sub>2</sub> avoidance costs of the investigated options are demonstrated by the excess heat case (50 €/t CO<sub>2</sub>) [14]. Berghout et al. suggest that applying oxyfuel technology results in lower avoidance cost (24–69 €/t CO<sub>2</sub>) compared with post-combustion (71–78 €/t CO<sub>2</sub>) and pre-combustion (75–90 €/t CO<sub>2</sub>) [15,51]. However, the harmonization results show higher CO<sub>2</sub> avoidance costs for the oxyfuel case. A possible explanation could be the higher electricity consumption combined with the higher electricity price used in the harmonization study. Berghout et al. also investigated biomass options, demonstrating avoidance costs between -13 and 39 €/t CO<sub>2</sub>. Using biomass together with other mitigation options tends to shift the CO<sub>2</sub> avoidance toward 30 €/t CO<sub>2</sub> [51]. The same effect is visible in the harmonization results, whereby adding CCS to the biomass options shifts the CO<sub>2</sub> avoidance cost toward 76 €/t CO<sub>2</sub>.

In this study, the implementation of CCS results in CO<sub>2</sub> avoidance costs of 54–75 €/t CO<sub>2</sub>. Biomass shows a much wider range of 14–138 €/t CO<sub>2</sub>, whereas adding CCS to biomass generates CO<sub>2</sub> avoidance costs of 40–79 €/t CO<sub>2</sub>. Despite the variation in CO<sub>2</sub> avoidance cost among

similar cases across various studies, most of the avoidance costs for large-scale refineries are shown to be under 100 €/t CO<sub>2</sub>.

### 3.4. Pulp and paper

In 2014, the pulp and paper sector was the fourth largest industrial energy consumer, accounting for 5.6% (6.5 EJ) of the global industrial energy use [3,49]. Its direct CO<sub>2</sub> emissions were 0.45 Gt CO<sub>2</sub>, making it also the fourth largest industry for CO<sub>2</sub> emissions [3]. Fossil fuels account for 42% of the total energy consumption [3,49]. Usually, black liquor (19 GJ/t pulp) and hog fuel (0.7–3 GJ/t pulp) are produced on-site as main by-products of the pulp and paper sector [3]. The three main production methods are Kraft mills (composed of stand-alone pulp mills and integrated pulp and paper mills), mechanical pulp and paper mills, and stand-alone paper mills [133]. Almost all pulp and paper is produced by Kraft mills, causing Kraft mills to be responsible for over 90% of the emissions of biogenic CO<sub>2</sub> and 80% of all the CO<sub>2</sub> emissions from the pulp and paper sector [134–136]. Consequently, this study focuses on Kraft mills. Because of the increasing utilization of bioenergy as well as improvements in energy efficiency, the CO<sub>2</sub> emission intensity of the pulp and paper sector has decreased by approximately 20% in Australia and 40% in Canada from 1990 to 2005 [137]. In addition, the Confederation of European Paper Producers has the ambition of reducing European pulp and paper emissions to 12 Mt CO<sub>2</sub> by 2050, compared with the 60 Mt CO<sub>2</sub> from 1990 [135,138]. In 2010, a reduction of 40% had already been achieved [138,139]. The pulp and paper sector has the potential to play an important role in bio-refinery development because of the various by-products from forestry and the pulp and paper mills [140]. In the Kraft pulp mill industry, black liquor used in a recovery boiler is one of several options for bio-refineries and

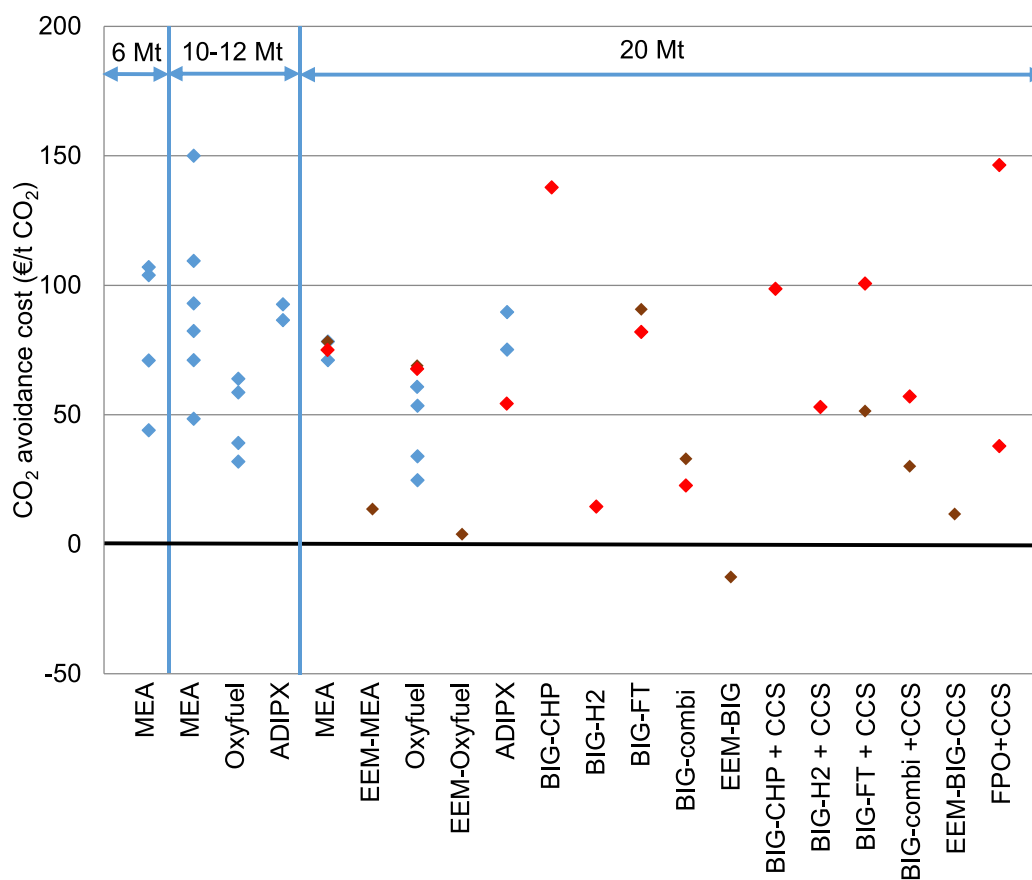


Fig. 12. CO<sub>2</sub> avoidance cost in petrochemical sector (blue dots represent data from the literature without transport and storage costs, brown dots represent the inclusion of transport and storage costs, and red dots are the calculation results from this study).

other valuable products, such as electricity, district heating, and pulping chemicals [140,141].

### 3.4.1. Production process

Both cellulose and hemicellulose form the components of pulp and paper. Cellulosic biomass is used as feedstock, typically in the form of wood, recycled paper, and agricultural residues [142]. There are six main steps in pulp manufacturing as follows: 1) raw material handling, 2) cooking, 3) pulp washing, 4) chemical recovery, 5) further delignification, 6) bleaching and washing (see Fig. 13) [49,87]. For paper production, an additional step is needed: 7) papermaking. In steps 1 and 2, the fibers are extracted from the wood by cooking the raw material in mixed chemicals. Steps 3 and 4 refer to chemical defibration (delignification) with an almost completely enclosed chemical and energy recovery system (orange dashed box in Fig. 13) [49,87]. The lignin is removed from the wood chips. Lignin and a part of the hemicellulose in the wood chips is dissolved in a mixture of NaOH and Na<sub>2</sub>S (so-called white liquor), which is treated as fresh cooking liquor [87,136]. Over 99% of the black liquor is removed by washing the above cooking chemicals, with hemicellulose partly dissolved in the white liquor [87, 136]. In step 5, further oxygen delignification and washing are performed [87,136]. Finally, bleaching is generally performed to remove or oxidize the remaining lignin to fulfill the quality requirements for the pulp [87,136].

Typically, energy recovery from Kraft mills waste streams can meet 40%–100% of the energy demand [49,65,136]. For each tonne of pulp production, an additional 19 GJ black liquor is produced as a by-product [143]. The total heat consumption by pulp mills is approximately 10–18 GJ/air dry tonne of pulp (adt), and an extra 3–6 GJ/adt is needed for paper production [49,136]. Electricity consumption is 0.6–0.8 MWh/adt (pulp mills) and 0.9–2.1 MWh/adt (integrated pulp and paper mills) [49, 136]. Kraft processes produce 2.6–2.8 t CO<sub>2</sub>/t in direct CO<sub>2</sub> emissions [133]. The combustion of black liquor in the recovery boiler constitutes the bulk of the CO<sub>2</sub> emissions (approximately 74%), with the fuel boiler (14%) and calcination in the lime kiln (12%) responsible for the remaining CO<sub>2</sub> emissions [135,144,145].

### 3.4.2. Technical mitigation potentials

Various studies have investigated the potential for CCS in the pulp and paper industry (see Fig. 14). As 75%–100% of the on-site CO<sub>2</sub> emissions of the pulp and paper industry is biogenic, CCS could easily result in net negative emissions [46–48,146]. The CO<sub>2</sub> emissions from recovery boilers (REC) represent approximately 78% of the total emissions [49,133]. Therefore, most studies have focused on the CO<sub>2</sub> capture from REC, with the exception of the IEAGHG, which considered the entire plant [45,47–49]. Post-combustion with chemical absorption is the most suitable technology because the boilers do not need to be retrofitted [135]. The CO<sub>2</sub> intensities range from –2.9 to –0.14 CO<sub>2</sub>/adt for pulp mills (PM) and integrated pulp and paper mills (IPPM), depending on the extend of CCS (see Fig. 14) [45,47–49]. The wide range of CO<sub>2</sub> intensities for REC-CCS is, among others, due to how the required steam is provided [48]. Oxy-fuel could also be used at the lime kilns to capture part of the CO<sub>2</sub> emissions of the mills [135]. An alternative option is to replace the recovery boilers with black liquor integrated gasification combined cycles (BLGCC) with pre-combustion CO<sub>2</sub> capture (physical absorption) [45,147]. CO<sub>2</sub> intensities for BLGCC with CCS are –0.75 t CO<sub>2</sub>/adt (PM) and –1.9 t CO<sub>2</sub>/adt (IPPM) (see Fig. 14).

For the harmonization, two base cases were selected: 1) Kraft pulp mill using 42 GJ/adt of biomass and 0.64 MWh/adt of electricity along with 3.5 GJ/adt (medium pressure) and 5.7 GJ/adt (low pressure) of steam with LCA CO<sub>2</sub> emissions of –0.12 t CO<sub>2</sub>/adt pulp and 2) integrated pulp and board<sup>8</sup> mill using 42 GJ/adt of biomass and 0.98 MWh/

adt of electricity, 3.5 GJ/adt (medium pressure) and 7.9 GJ/adt (low pressure) of steam with LCA CO<sub>2</sub> emissions of 0.08 t CO<sub>2</sub>/adt pulp. The low intensities are due to the CO<sub>2</sub> credits received for the electricity export, among other factors. The CO<sub>2</sub> emissions for the integrated pulp and board mill are a bit higher than those of the Kraft mill, because the boarding production process consumes extra energy, resulting in greater CO<sub>2</sub> emissions compared with those of the pulp mill. The application of MEA-based CCS results in CO<sub>2</sub> intensities of –2.04 to –0.31 t CO<sub>2</sub>/adt pulp for the pulp mill and –1.84 to –0.12 t CO<sub>2</sub>/adt for the integrated mill. The electricity demand of full MEA-based CO<sub>2</sub> capture can be completely covered by the pulp mills. The integrated mills require some importation of electricity when CCS is applied at the REC or combined with other emission sources at the REC. The harmonization results are comparable with the data from the literature for the integrated mills but demonstrate more deviation for the pulp mills.

### 3.4.3. Economic evaluation

CO<sub>2</sub> avoidance costs from previous studies and the harmonized CO<sub>2</sub> avoidance cost from this study are presented in Fig. 15 [45–49]. In all cases (except BLGCC), an MEA-based CO<sub>2</sub> capture system was used. For traditional pulp mills, CO<sub>2</sub> avoidance costs range from 31 to 93 €/t CO<sub>2</sub> for pulp mills and 23–94 €/t CO<sub>2</sub> for integrated pulp and paper mills, depending on the extent of CCS. However, the low estimates involve data sources that are at least a decade old. For the more advanced BLGCC, CCS can result in CO<sub>2</sub> avoidance costs of 29 and 61 €/t CO<sub>2</sub> for pulp mills and integrated mills, respectively. The use of steam with a biofuel boiler is the most economic option, followed by heat pumps and NGCC.

The harmonization results indicate that the application of CCS can result in an avoidance cost of 79 €/t CO<sub>2</sub> for both pulp mills and integrated mills. Applying CCS on just the fuel boiler or lime kiln is not attractive, owing to the much smaller scale.

### 3.5. Industrial hydrogen

Hydrogen is already produced and consumed in the industrial sector on a large scale, mainly for fuel upgrading and desulphurization at refineries and ammonia production and in the steel industry [36,148,149]. It is also one of the many fuel options for the future, and it is particularly attractive since it can be stored as compressed gas, cryogenic liquid, or solid hydride and transported through conventional means safely and efficiently [150–152]. Hydrogen is not readily available in nature, and there are commercial processes that produce hydrogen for the chemical sector (see Fig. 16) [153,154]. An interesting mitigation option is the production of chemicals, such as ethylene and propylene, by combining H<sub>2</sub> with CO<sub>2</sub> [57,155]. A promising method to produce hydrogen is by electrolysis using renewable electricity. However, the focus of this study is on biomass and CCS. Furthermore, the current scale of electrolysis using renewable electricity is very small, especially considering industrial applications.

#### 3.5.1. Production process

Current global hydrogen production is approximately 70 Mt/y, of which 90% is consumed on-site [149]. The associated process emissions are estimated at 830 Mt/y [36]. Almost all H<sub>2</sub> (96%) is produced directly from fossil fuels, and approximately 4% is produced indirectly by using electricity generated mainly through fossil fuels [156,157]. The general routes for hydrogen production are shown in Fig. 16. Of H<sub>2</sub> produced from fossil sources, 48% is produced by natural gas steam reforming, 30% from oil processing, and 18% from coal gasification (CG) [36,158]. Green technologies for hydrogen production include biomass gasification or electrolysis of water using hydropower, wind power, or solar photovoltaic power [57,156,159].

Hydrogen can be produced from natural gas by steam reforming (SMR), partial oxidation (POX), and autothermal reforming (ATR) (See Fig. 16) [33,57]. Steam reforming involves the endothermic conversion

<sup>8</sup> The weight of paper is ranging from approximately 160 to 220 g/m<sup>2</sup> and the board is a heavier sheet weighing more than 220 g/m<sup>2</sup> [136].

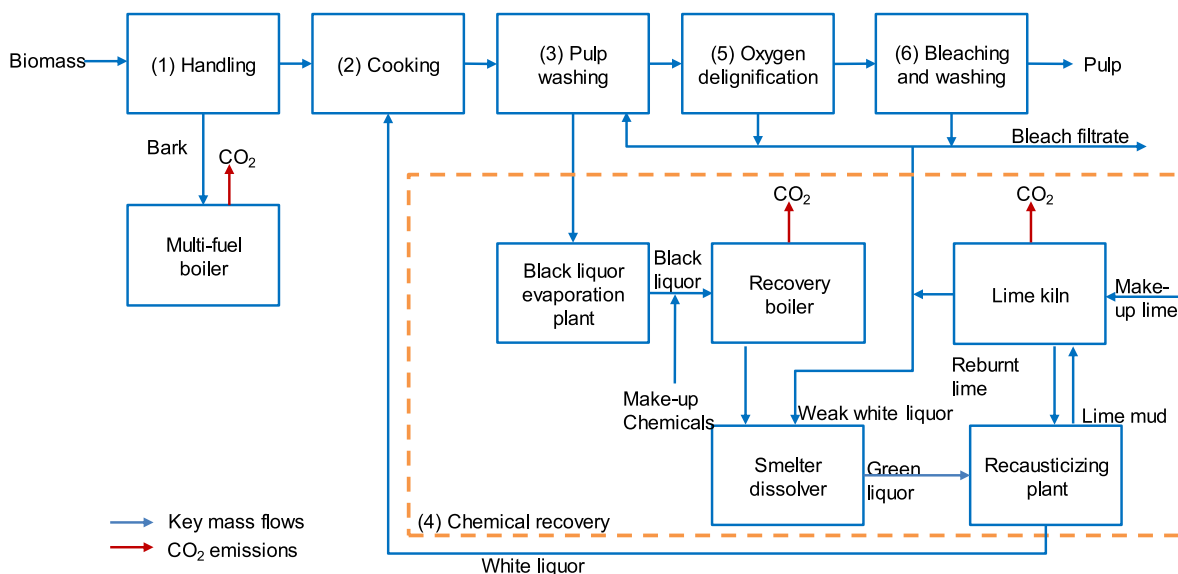


Fig. 13. Simplified Kraft pulping process. The chemical recovery system is shown in the orange-dashed box [49,87].

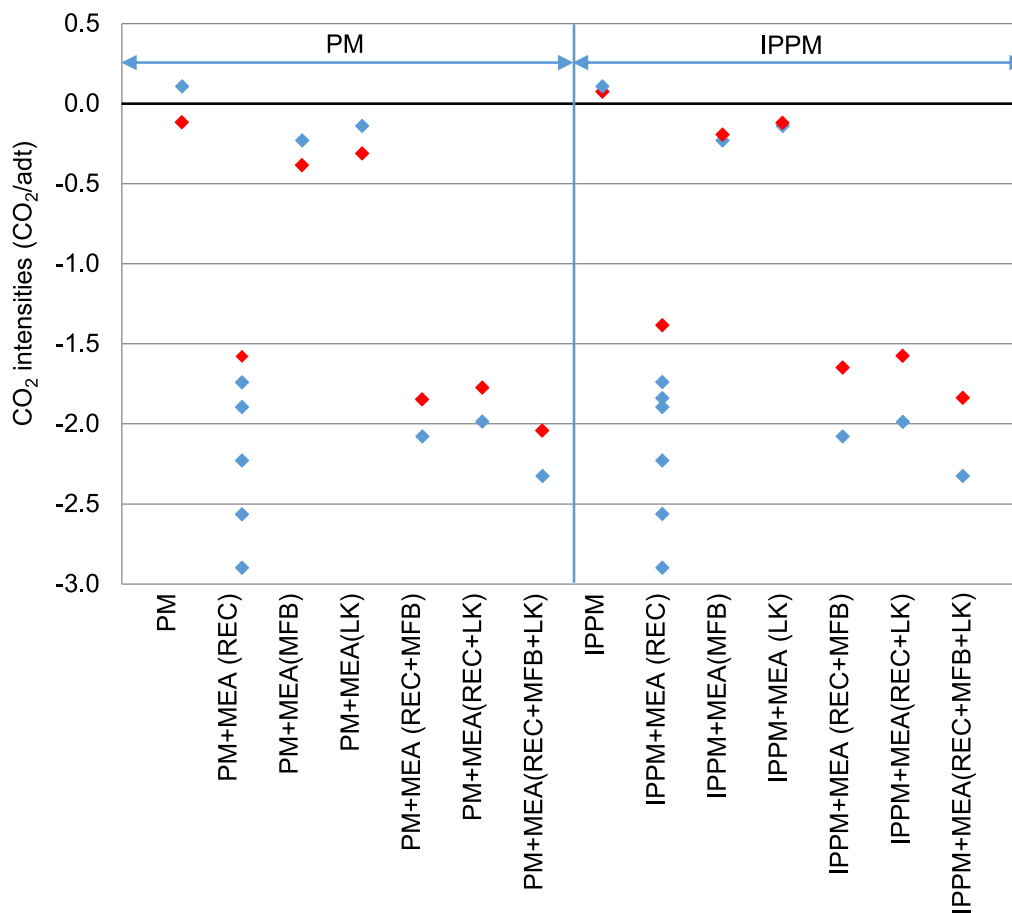


Fig. 14. CO<sub>2</sub> intensities in pulp and paper industry (blue dots represent data from the literature, and red dots represent the calculation results).

of methane and water vapor into hydrogen and carbon monoxide ( $\text{CH}_4 + \text{H}_2\text{O} \rightleftharpoons \text{CO} + 3\text{H}_2$ ) at temperatures of 800–900 °C [32,33]. The partial oxidation of natural gas is the process in which hydrogen is produced through the partial combustion of methane with oxygen gas to yield

carbon monoxide and hydrogen ( $2\text{CH}_4 + \text{O}_2 \rightleftharpoons 2\text{CO} + 4\text{H}_2$ ) [159]. Autothermal reforming is a combination of both steam reforming and partial oxidation [159].

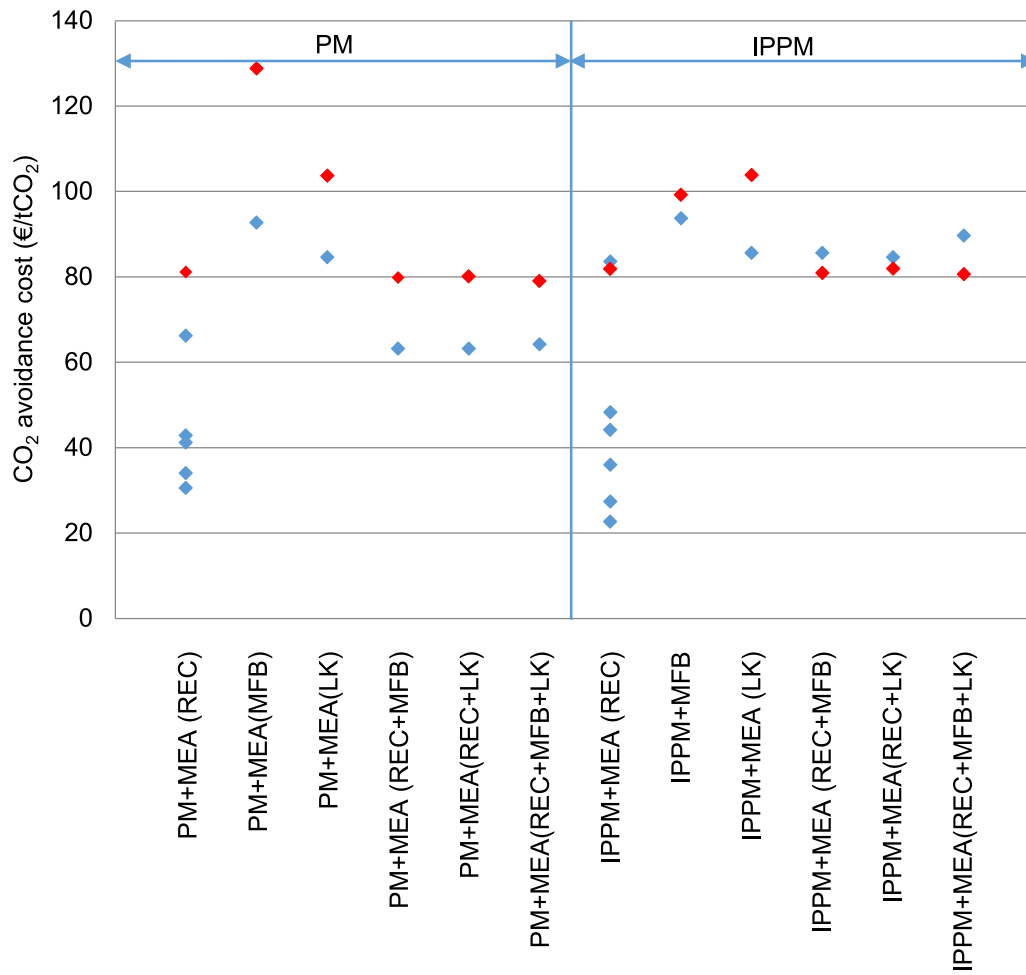


Fig. 15. CO<sub>2</sub> avoidance cost of pulp and paper mills (blue dots represent data from the literature, and red dots represent calculation results).

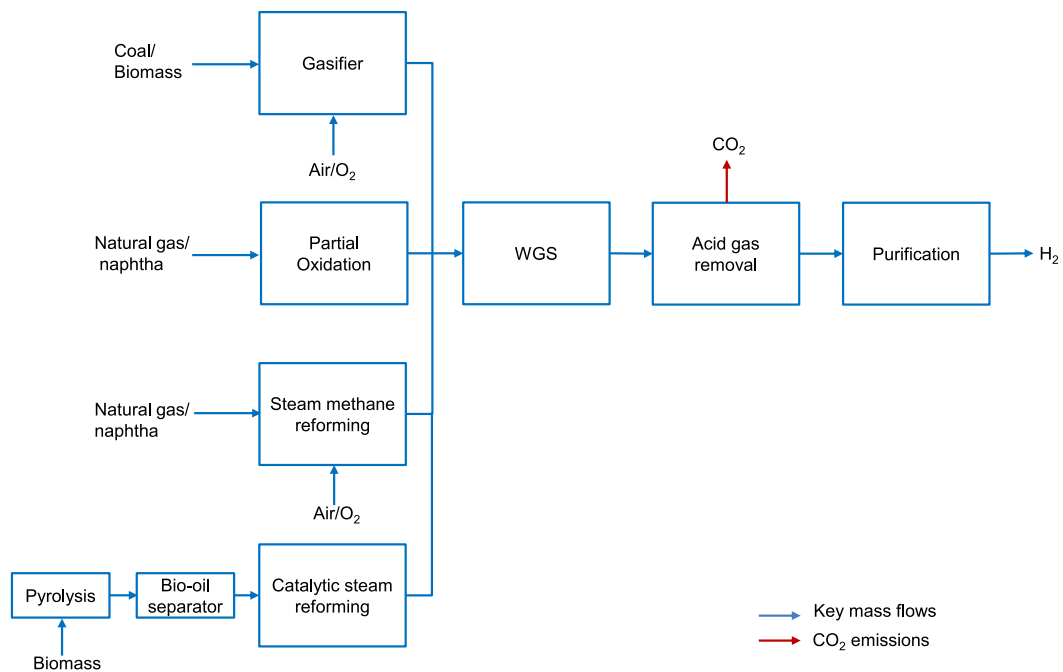


Fig. 16. Fuel processing of gaseous, liquid, and solid fuels for hydrogen production.

### 3.5.2. Technical mitigation potentials

Hydrogen can be produced from coal through a variety of gasification processes (e.g., fixed bed, fluidized bed, or entrained flow) (See Fig. 16) [160]. The reaction  $C + H_2O \rightleftharpoons CO + H_2$  is endothermic and requires additional heat [159,160]. Green hydrogen can be produced by pyrolysis [158,161,162] and gasification [71,75] from various biomass sources, including black liquor (BL) from the pulp and paper industry [163,165] (See Fig. 16). Hydrogen can also be produced from agricultural residuals and the splitting of water through various processes, such as fermentation, water electrolysis, photo-biological production, and high-temperature water decomposition [159,161,164].

Several studies investigated the potential for CCS in hydrogen production (see Fig. 17) [15,32,33,53,57,148,165]. As reference, conventional NG-based  $H_2$  has a  $CO_2$  intensity of 8.9–9.1  $t CO_2/t H_2$ . Studies indicate that capturing  $CO_2$  with MEA and MDEA could reduce  $CO_2$  emissions by 75%–89% and 48%–63%, respectively [33]. The  $CO_2$  intensity of ADIP-X and membrane-based CCS routes are 1.1  $t CO_2/t H_2$  and 4.2  $t CO_2/t H_2$ , respectively [15,33]. The ATR route with MDEA shows a  $CO_2$  intensity of 1.9  $t CO_2/t H_2$  [166]. The coal gasification route with Selexol capture technology emits 1.7–3.1  $t CO_2/t H_2$  [32]. Hydrogen production from gasified black liquor with pulp co-production (2000 adt/d) in a pulp mill results in a  $CO_2$  intensity of 2.5  $t CO_2/t H_2$  with the use of fossil-fuel-based electricity [49,163,167]. Chemical looping reforming (CLR) is a promising and efficient alternative route, since the  $CO_2$  capture is inherently included in the fuel

conversion unit [168,169]. CLR combined air reactor and fuel reactor in which the oxygen carriers and catalyst transfers the oxygen and heat for the reforming reaction from the air reactor to the fuel reactor [168]. The  $CO_2$  emissions of CLR with MDEA are 0.54  $t CO_2/t H_2$  [168].

As a base case,  $H_2$  production from steam reforming of natural gas was selected. This plant uses 165  $GJ_{LHV}$  of natural gas and 0.61 MWh of electricity per tonne of  $H_2$  produced, resulting in cradle-to-gate  $CO_2$  emissions of 11.1  $t CO_2$ . Applying CCS results in  $CO_2$  intensities of 3.4  $t CO_2/t H_2$  for MEA, 2.9  $t CO_2/t H_2$  for ADIP-X and 2.7  $t CO_2/t H_2$  for CLR with MDEA. The combination of torrefied biomass and CCS results in large negative emissions (–23.7  $t CO_2/t H_2$ ).

### 3.5.3. Economic evaluation

The cost of  $CO_2$  mitigation for hydrogen combined with CCS has been investigated in several studies, with the base case of  $H_2$  generated from natural gas (see Fig. 18) [15,33] [71,148,166]. Studies indicate a  $CO_2$  avoidance cost for SMR plants of 73–130  $\text{€}/t CO_2$  (MEA), 49–69  $\text{€}/t CO_2$  (MDEA), 40–99  $\text{€}/t CO_2$  (ADIP-X), and 62  $\text{€}/t CO_2$  for membrane capture [15,33,71,148]. The avoidance cost of CLR with MDEA is 86  $\text{€}/t CO_2$  [168].  $H_2$  produced from coal gasification with Selexol-based CCS shows avoidance costs of 7  $\text{€}/t CO_2$ , owing to the low cost of additional capture and energy [166]. Advanced large-scale ATR systems can reach 90%  $CO_2$  capture with an avoidance cost of 18  $\text{€}/t CO_2$  [166].

The harmonization results indicate a lower  $CO_2$  avoidance cost than that reported in the literature. However, the number of comparisons is

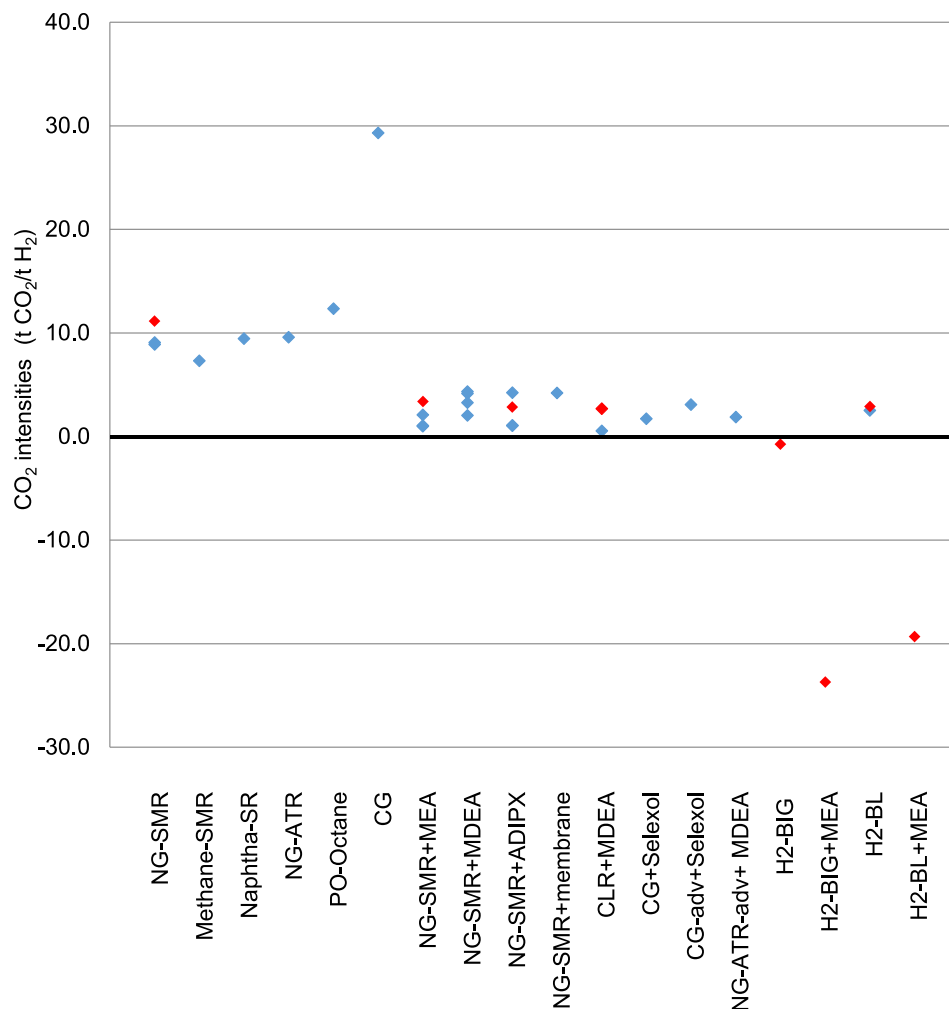
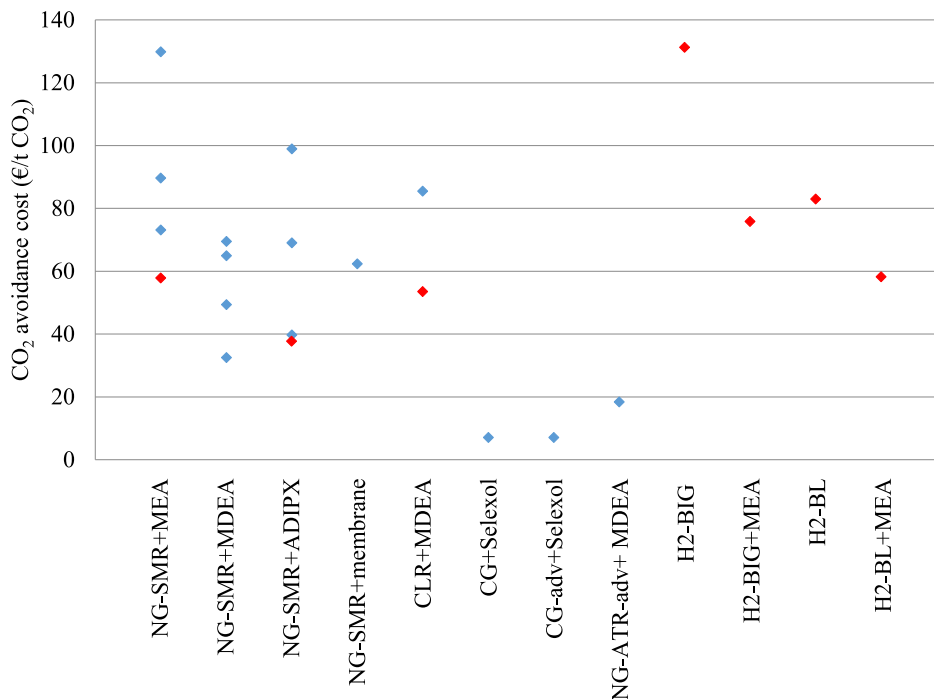


Fig. 17.  $CO_2$  intensities in hydrogen industry (blue dots represent data from the literature without transport and storage costs, and red dots are the calculation results from this study).





**Fig. 18.** CO<sub>2</sub> avoidance cost for H<sub>2</sub> production (blue dots represent data from the literature without transport and storage costs and red dots are the calculation results from this study).

limited. The harmonization analysis is only focused on SMR because it is the most widely used route for H<sub>2</sub> generated from natural gas [149]. ADIP-X has better performance than MEA because ADIP-X has a higher CO<sub>2</sub> absorption ratio and lower energy consumption than does MEA. The option of using black liquor results in an intensity of 83 €/t CO<sub>2</sub> without CCS and 58 €/t CO<sub>2</sub> with CCS, making this a more attractive option than using torrefied biomass (131 €/t CO<sub>2</sub>).

### 3.6. Discussion and synthesis

In this study, the status and performance of the application of CCS and/or biomass to five industrial sub-sectors were reviewed. CO<sub>2</sub> intensities and CO<sub>2</sub> avoidance costs taken from the literature show large variations among similar systems. This lack of consistency is due primarily to differences in methodology, system boundaries, level of integration, costs, GHG intensities from feedstock and energy carriers, and capital cost estimates. These inconsistencies complicate the comparison of the results from the different studies both within the same sector and among the sectors. Factors affecting the economic performance of mitigation options can be categorized as plant specific (e.g., feedstock used, scale of plant, on-site steam and electricity production, degree of CO<sub>2</sub> capture or biomass substitution) and scenario conditions (e.g., price and CO<sub>2</sub> intensities of feedstock and energy carriers, system boundaries, cost of capital). The harmonization in this study was performed in an attempt to eliminate deviations due to scenario conditions. This resulted in the CO<sub>2</sub> avoidance costs listed in Fig. 19, indicating that each investigated sector has multiple mitigation options for the avoidance cost of 100 €/t CO<sub>2</sub> or less. The harmonization also shows that CO<sub>2</sub> avoidance costs are higher for smaller sources than for larger sources.

By applying these potentials to the estimated industrial activity for 2050, the amount of CO<sub>2</sub> avoided using BECCS in these five sub-sectors could be estimated (see Table 7). Global crude steel production in 2050 is estimated to reach 2100 Mt, and the BF-BOF and EAF routes account for approximately 60% and 40% of the global steel production, respectively [8,143]. Although Hisarna and COREX are assumed to play minor roles in 2050 due to current technology development, both are

expected to realize negative emissions when combined with BECCS. Based on practical production conditions, the total CO<sub>2</sub> mitigation potential for the iron and steel sector is 1.85 Gt for BECCS with the combined BF-BOF and EAF routes. The production capacity for the cement sector is estimated to be 4.7 Gt by 2050, and the greatest CO<sub>2</sub> mitigation potential could be as high as 3.46 Gt CO<sub>2</sub> (bio-CaL-CCS). For the (petro) chemical sector, the forecast for crude oil production is 1250 Mt per year in 2050 [170]. If all refinery plants worldwide are similar to the base case in this study with BECCS incorporated into them, CO<sub>2</sub> emissions reduction would reach 0.25 Gt/y. Global production of paper and paperboard is expected to reach 936 Mt by 2050 [171]. Assuming a pulp-to-paper ratio of 1:1, the sector could reduce its emissions by 1.8 Gt/y. The forecasted hydrogen production in 2050 is 254 Mt/y [172]. The IEA expects the role of biomass gasification in the H<sub>2</sub> production process to be small, being deployed only in the US, France, Germany, Italy, and the UK, with a share of under 10% in those countries [173]. However, it is possible to consider biomass-gasification-based hydrogen production into the overall strategy, as the CO<sub>2</sub> reduction potential could reach as high as 313% when combined with CCS technology. Based on this, it is estimated that the bio-based H<sub>2</sub> with CCS will account for 10% of the global hydrogen production by 2050. If the remaining H<sub>2</sub> production is assumed to be natural-gas-based with CCS, the CO<sub>2</sub> emissions reduction could reach 2.7 Gt/y. This means that the investigated industrial sectors combined could reduce their CO<sub>2</sub> emissions by up to 10.1 Gt/y using currently available technologies. For comparison, the IEA 2DS target is a reduction of 1.8 Gt CO<sub>2</sub> emissions per year in 2050 and the Beyond 2 °C scenario is 4.2 Gt CO<sub>2</sub> per year.

Based on the above analysis, the best options for CO<sub>2</sub> emissions mitigation for a CO<sub>2</sub> avoidance cost under 100 €/CO<sub>2</sub> are listed in Table 8. BECCS shows the best performance for each sector. CO<sub>2</sub> intensities for different energy carriers such as electricity and coal will affect the CO<sub>2</sub> emission results. In addition, the prices of electricity (55–80 €/MWh) and natural gas (5–10 €/GJ) will affect the avoidance cost [13,51,174]. In this study, there are some uncertainties associated with the technical and economic parameters of the CO<sub>2</sub> mitigation technologies. As BECCS demonstrates the highest CO<sub>2</sub> reduction

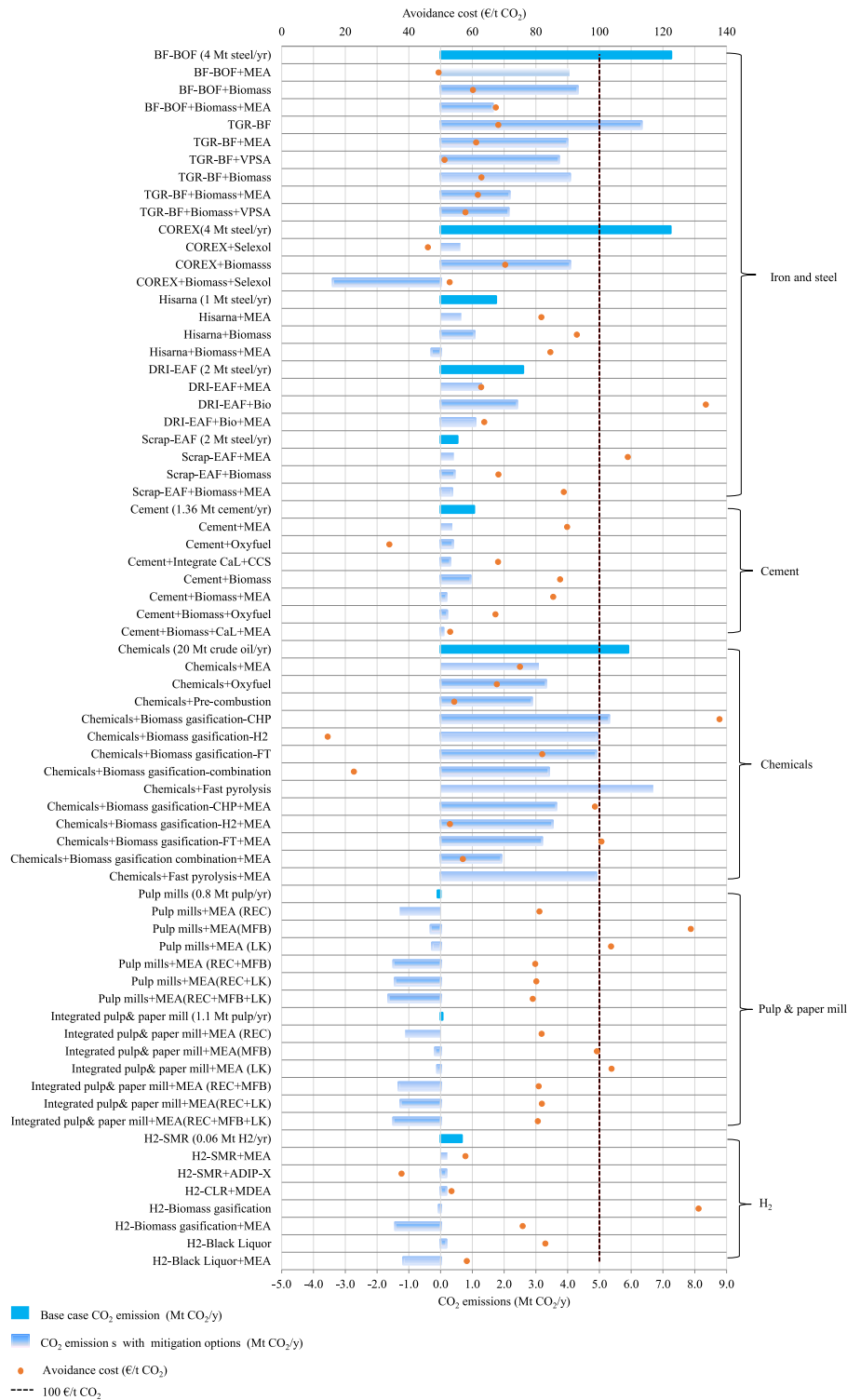


Fig. 19. Harmonized CO<sub>2</sub> reduction potential and CO<sub>2</sub> avoidance cost.

potential, a sensitivity analysis was performed to investigate the impact of biomass prices, CO<sub>2</sub> transport, and storage costs on the economic performance of the mitigation technologies in the different industries. As the pulp and paper industry is already bio-based, such a sensitivity analysis only refers to the CO<sub>2</sub> transport and storage cost. The results indicate that, under the worst conditions, almost all options remain under 100 €/t CO<sub>2</sub> avoided. Furthermore, under the best conditions, the

chemical industry might even reach negative avoidance costs.

The literature review and harmonization of CCS and/or biomass options have identified several important points for discussion:

First, only key technical and economic parameters (e.g., type of CCS technology, CO<sub>2</sub> intensity, avoidance cost) were analyzed in this study. This includes input data and energy consumption of the main processes. Other parameters deemed to have a smaller effect on mitigation

**Table 7**  
Future CO<sub>2</sub> emissions reduction estimations in different industries.

Industries	Baseline emissions (t CO <sub>2</sub> /t product)	CO <sub>2</sub> reduction	Production in 2050 (Mt/y)	Total CO <sub>2</sub> reduction (Gt/y)
Iron and steel	1.81 t CO <sub>2</sub> /t crude steel (BF-BOF)	13%–77%	1260	0.29–1.77
	0.27 t CO <sub>2</sub> /t crude steel (scrap-EAF)	22%–34%	840	0.05–0.08
	1.75 t CO <sub>2</sub> /t crude steel (Hisarna)	39%–115%	–	–
	1.81 t CO <sub>2</sub> /t crude steel (COREX)	44%–147%	–	–
Cement	0.8 t CO <sub>2</sub> /t cement	12%–92%	4700	0.45–3.46
Chemicals	0.3 t CO <sub>2</sub> /t crude oil	10%–68%	1250	0.04–0.25
Pulp and paper	0.08 t CO <sub>2</sub> /t pulp	260%–2548%	936	0.2–1.8
Hydrogen	11.13 t CO <sub>2</sub> /t H <sub>2</sub>	70%–313%	254	1.8–2.7

**Table 8**  
Sensitivity analysis results for the best CO<sub>2</sub> emissions reduction options under 100 €/CO<sub>2</sub> for each sector.

Industries	The best CO <sub>2</sub> mitigation options	CO <sub>2</sub> reduction	CO <sub>2</sub> avoidance cost	Avoidance cost sensitivity analysis
Iron and steel	BF-BOF + Biomass + MEA	77%	67 €/t CO <sub>2</sub>	52–90 €/t CO <sub>2</sub>
	Hisarna + Biomass + MEA	115%	85 €/t CO <sub>2</sub>	39–71 €/t CO <sub>2</sub>
	COREX + Biomass + Selexol	147%	53 €/t CO <sub>2</sub>	67–108 €/t CO <sub>2</sub>
Cement	Cement + Biomass + CaL + MEA	92%	53 €/t CO <sub>2</sub>	28–66 €/t CO <sub>2</sub>
Chemicals	Chemicals + Biomass gasification combination + MEA	68%	57 €/t CO <sub>2</sub>	–3 to 73 €/t CO <sub>2</sub>
Pulp and paper	Integrated pulp & paper mill + MEA (REC + MFB + LK)	2548%	81 €/t CO <sub>2</sub>	69–92 €/t CO <sub>2</sub>
Hydrogen	H <sub>2</sub> -Biomass gasification + MEA	313%	76 €/t CO <sub>2</sub>	27–89 €/t CO <sub>2</sub>

potential and cost have been excluded, such as fuel and raw material specifications, space for new process equipment, biomass storage, and production losses. CO<sub>2</sub> capture equipment, such as absorbers, cooling towers, and blowers might require a large space for retrofitting on the existing industrial plants. The energy and mass flows of one tonne of product or feedstock are combined with historic prices to evaluate the economics of the production routes and mitigation options technically and environmentally. However, external factors, which may also influence practical implementation (e.g., legislation, supply chains, and geography) are not included in this study.

Second, for some sub-sectors, instead of one base case, it was sometimes necessary to use several base cases due to the insufficient availability of data, making calculations of specific CO<sub>2</sub> emissions and/or production costs impossible. For example, five different base cases were used for the iron and steel sector. This variety complicated the comparison of the performances of the different routes.

Third, the scale of the reference systems changes between and, sometimes, within sectors. For example, the economic scales for the five industrial sectors range from 0.06 Mt/y for a hydrogen plant to 20 Mt/y

for a refinery plant [13,15,51,73,74]. In the iron and steel industry, the practical economic scale for the BF-BOF route is 4 Mt/y, whereas the scale for Hisarna is only 1 Mt/y and 2 Mt/y for DRI-EAF [13,73,74]. As shown in the literature and confirmed in the harmonization study, larger capacities tend to have lower CO<sub>2</sub> avoidance costs.

Fourth, this study is focusing on carbon capture and biomass. It is possible to produce hydrogen from electricity generated from non-biomass renewable sources like solar and wind. However, this is not yet being done at an industrial scale. The application of hydrogen from electrolysis falls outside the scope in this study. However, negative emissions cannot be reached by producing hydrogen through electrolysis using solar or wind electricity.

Fifth, electricity with a CO<sub>2</sub> intensity of 0.4 t/MWh was used in this study. However, this value varies among different countries and is expected to decrease in the future. The effect of the carbon intensity of the electricity, assuming constant electricity price, will be higher CO<sub>2</sub> avoidance potentials and lower CO<sub>2</sub> avoidance costs. These effects will be the largest in the cases with CCS. When looking at the industrial sectors, the iron and steel industry would be affected the most and the chemical industry the least.

Lastly, although care had been taken when adjusting conventional production routes for CCS and/or biomass, no detailed integrated process simulation of these routes was conducted. A detailed integrated process simulation is based on a lot of assumptions which will impact the mass and energy balance. Performing such detailed studies could result in increased optimization and lead to improved CO<sub>2</sub> emissions reductions and avoidance costs. In this study, the calculation is based on the mass flow and energy demand from literature sources and it cannot be harmonized like assumptions on the performance of individual processes. This is also probably preventing to calculate the waste heat amount which could be an alternative to electricity production. The aim of the methodology used here was to reduce the impact of limitation.

#### 4. Conclusion and outlook

This study compared the performance and cost of applying CCS, biomass, or BECCS to the most CO<sub>2</sub> intensive sub-sectors in the industrial sector. A harmonization methodology was developed to determine the technical and economic performances of different combinations of CCS and/or biomass. This methodology was applied consistently over five industrial sub-sectors and proved useful in evaluating CO<sub>2</sub> avoidance potential and cost, allowing comparison between the sub-sectors.

A literature review found that there are still barriers for biomass and BECCS applications in the industrial sectors. There is also limited attention paid to the use of biomass or BECCS in industry, with the exception of the pulp and paper sector and several specific chemicals. Furthermore, large discrepancies in the reported CO<sub>2</sub> intensities and avoidance costs were found. Potential reasons for these discrepancies are identified as follows: 1) The use of different energy carriers (e.g., coal or natural gas) with different CO<sub>2</sub> intensities and costs. 2) The use of different capital cost methodologies and estimates combined with different base cases, configurations, and equipment, resulting in large deviations in plant capital cost estimates. 3) The use of different system boundaries, varying between cradle-to-grave, cradle-to-gate, and gate-to-gate approaches. 4) The use of different CO<sub>2</sub> mitigation options. These differences make comparing the CO<sub>2</sub> avoidance potential and costs among different studies difficult.

Based on this study, the introduction of only CCS in the various industrial sectors could reduce CO<sub>2</sub> emissions by up to 74%. This potential is limited by the fact that in some sectors, CCS is only applied to a part of the production process, e.g., only from the blast furnace in the iron and steel industry. Biomass substitution could also be an important method for reducing CO<sub>2</sub> emissions. However, as biomass is of a lower quality (based on, e.g., elemental composition and energy density) than fossil fuels, the biomass substitution potential is at times limited. For the iron and steel, cement, and chemical sectors, the substitution limit is

approximately 45% LHV, and the CO<sub>2</sub> emissions reduction is no greater than 44%.

BECCS shows the best performance for all five sectors, resulting in numerous mitigation options under 100 €/t CO<sub>2</sub>. The cross-sector comparison shows that applying BECCS options under 100 €/t CO<sub>2</sub> avoided in the iron and steel (1.47–2.7 t CO<sub>2</sub>/t CS), pulp and paper (1.9 t CO<sub>2</sub>/t adt), and H<sub>2</sub> sectors (34.9 t CO<sub>2</sub>/t H<sub>2</sub>) can result in negative emissions. This is not the case for the cement (0.7 t CO<sub>2</sub>/t cement) and chemical sectors (0.2 t CO<sub>2</sub>/t crude oil). For the cement industry, the majority of emitted CO<sub>2</sub> comes from the calcination reaction and not from the combustion of fuels. This, combined with low biomass substitution ratios, limits the reduction to 92% of the LCA emissions. For chemicals, a large part of the emitted CO<sub>2</sub> is also from process emissions, from the upgrade of fossil fuels, and at the moment, biomass cannot substitute for all the crude oil. The total CO<sub>2</sub> emissions reductions for industrial CO<sub>2</sub> with the mitigation options could reach as high as 10.1 Gt/year by 2050. The integration between sub-sectors might result in even greater reductions, e.g., by using biomass-based H<sub>2</sub> as reducing agent in BF or DRI production.

This study conducted a first attempt at assessing, in a consistent way, the potential and economics of CCS and/or biomass in the industrial sector. The methodology proposed here was successfully applied in evaluating CCS and biomass options in different industrial sub-sectors. This can be used to select the most interesting mitigation options, which can then be subjected to further detailed and more time-consuming analysis.

#### 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.

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