A review of the emission reduction potential of fuel switch towards biomass and electricity in European basic materials industry until 2030

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ABSTRACT

In 2015, industrial sector installations included in the European emission trading system (EU ETS) emitted 574 Mt CO_2-equivalent Greenhouse gas (GHG) emissions. Among them are production of clinker, lime and ammonia, blast furnace operations, refineries and others. The emission intensity of these installations is closely tied to the fuel type used. Global warming scenarios of 1.5 °C recently presented by the IPCC require fast emission reduction in all sectors until 2030, followed by deep reductions, reaching carbon neutrality around 2050. In this paper, the technical potential to use biomass and electricity with existing or available technologies in important industrial processes is reviewed. The investigated industries account for 95% of the total verified emissions in the EU ETS industrial sector 2015 and 64% of total industrial emissions of the EU28. We find that 34% (184 Mt) of these emissions could be avoided from a technical perspective until 2030 with fuel switch measures towards biomass and electricity. This reduction is in line with 1.5 °C global warming scenarios until 2030, but further effort is required beyond that. We also find that available options lack economic competitiveness under present conditions, e.g. due to high electricity prices. We conclude that, although considerable fast emission saving potential by switching to biomass and electricity are possible, deep decarbonisation in line with climate targets requires innovative production processes only available in the long term.

1. Introduction

In 2015, about 574 Mt CO_2-eq. of industrial greenhouse gas (GHG) emissions were included in the European Union emission trading system (EU ETS) [1].[1] The most important sources are production of clinker, lime and ammonia (with significant process emissions), blast furnace operations (extensive use of coke and coal), refineries and the generation of steam in several processes. Emission reduction targets on European level require a reduction by at least 40% until 2030 and 80%–95% until 2050 (compared to 1990). The publication of the special report on the impacts of 1.5 °C global warming by the IPCC [3] received increased attention. A central finding (C1) in this report is that 1.5°C-scenarios

consistently include a GHG decrease of around 45% below 2010-levels by 2030. 2°C-scenarios still include up to 30% reduction until 2030. These targets, based on 1990, demand emission cuts of 55% (1.5 °C) or 40% (2 °C) until 2030.[2] This level of ambition means that all sectors need to contribute. From 1990 to 2016, the EU28 manufacturing industries reduced their emissions (energy- and process-related) by 38% [4]. A considerable shift from liquid and solid fuels to natural gas contributed to these reductions, especially in the non-energy intensive industries [5]. With the exception of non-ferrous metals and the paper industry, however, the energy-intensive industries (iron and steel, chemicals, non-metallic minerals) did not participate in this trend. Due to the strong emission reductions after 1990, the industrial sector would have to reduce by 35% compared to 2016,[3] to achieve a 55% reduction

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[1] For the purpose of potential estimation, we refer to the *verified emissions* of the industry (excluding the energy sector and transportation) reported by the EEA [2] from the European ETS register EUTL, when we use the term 'emissions'. This should not be confused with the total emissions of the industry, as the emission trading system excludes sectors.

[2] Based on already achieved emission reductions between 1990 and 2010 of about 900 Mt CO_2-eq [4].

[3] Data on 2010 with the same scope and detail is not available. However, since 2010, the emission from energy use largely stagnated around 500 Mt CO_2-eq. after a strong decline in 2009 caused by the economic crisis. The same is true for process-related emissions (around 380 Mt CO_2-eq.) [4].

List of abbreviations		FBB	Fluidized bed-boilers
		GHG	Greenhouse gas
BAT	Beat available technology	HHV	Higher heating value
CCS	Carbon capture and storage	IPCC	Intergovernmental Panel on Climate Change
DRI	Direct reduced iron	Mt CO2-eq.	Million tonnes carbon-dioxide equivalents
EAF	Electric arc furnaces	PCI	Pulverized coal injection
EEA	European Environment Agency	tpd	Tonnes (metric ton) per day
EU	European Union	TRL	Technology readiness level
EU ETS	European Union Emission Trading System	thm	Tonnes (metric ton) hot metal
EUTL	European Union Transaction Log	MWh	Megawatthours
EU25	25 European Union member states	TWh	Terawatthours
EU28	28 European Union member states	PWh	Petawatthours
EUR	Euro		

compared to 1990. This further reduction still means going beyond natural gas and energy efficiency and increasing the speed of transformation considerably.

Several technologies have been discussed that could facilitate further fuel switch in energy-intensive industries, often based on biomass and electricity [6]. The main goal is to overcome the barriers that hindered fuel switch in certain key processes with new technologies, for which the process temperature is an important factor [7]. Lechtenböhmer et al. [8] analysed the role of electrification for deep decarbonisation of energy intensive industries, including steel, cement, glass, lime, petrochemicals, chlorine and ammonia. The developed scenario results in an industrial electricity demand increased by 170% compared to today. Rootzén and Johnsson [9] explored the emission reduction potential for the iron and steel, cement, refinery industry and the power sector using a stock model of industrial installations. They included fuel switch options for several processes and concluded that deep decarbonisation up to 95% requires innovative technologies. Investigating the metrics of industrial activity in the United States, Aden [10] concluded that energy and material efficiency is not sufficient for climate stabilization, and additional fuel switching away from fossil fuels is necessary. Fleiter et al. [11] found that processes in the energy-intensive industry in Germany had a remaining energy efficiency potential of about 14% until 2035 and that additional measures include fuel switching. Deep decarbonisation in the iron and steel industry is often associated with hydrogen- and electricity-based direct reduction [1,12] or carbon capture and storage (CCS) [13–15]. A decarbonized cement industry is linked to new cement types [8,16], extensive clinker substitution and CCS [17]. Regarding the non-ferrous metal industry, González Palencia et al. [18] found that, while effective in GHG-emission reduction, fuel switching to electricity and low-carbon fuels increases system costs. For the basic chemical industry (e.g. ethylene, ammonia, methanol), new production routes based on hydrogen or biomass are discussed [19]. Similar scenarios have been developed by other authors, emphasizing renewable hydrogen and the mitigation of process emissions in cement production [20]; or carbon capture and storage (CCS) [9,14]. These breakthrough-technologies and concepts are still in a pilot or demonstration-phase (first plants are planned for 2030 [1]). Although substantial uncertainties exist on the development speed, for this article, we assume that these technologies do not have a significant impact on GHG-emissions before 2040 [21]. Industry stakeholders involved in the ETS Innovation Fund for example expect projects at technology readiness level (TRL 7) to be market ready after 5–10 years [22]. All deep decarbonisation strategies via innovative and breakthrough-technologies additionally include incremental changes to existing processes. The increase of energy efficiency beyond the current best available technology (BAT), fuel switch to less emission-intensive energy carriers, increased recycling and change of consumption patterns are recognized as necessary elements [1]. Gerres et al. [23] reviewed both efficiency gains in existing processes (e.g. BAT plants) and innovative technologies in energy intensive industries until

2050. They also include biomass use as emission reduction measure, finding highest potentials in cement and ceramic productions. They conclude that the optimization of current production processes is not enough to reach 2050 emission targets. They acknowledge that many of the identified technologies still are in early research phases, with market readiness not expected before 2030. Approaching the topic from their transitional aspects, Wesseling et al. [24] categorized several innovative, low carbon technologies for energy intensive industries by their TRL. They identified substantial economic, organizational, structural and political barriers for radical process innovations and found that the technologies necessary to meet 2050 GHG targets are dominantly in early TRL-stages (3–5).

If industry is to contribute to necessary fast emission reductions, it cannot wait for innovative processes. Fuel switching opportunities in existing processes thus seem a viable short-to mid-term action, as they tend to require limited systemic adaptation, benefit from knowledge spillover in other sectors and often carry co-benefits. As Grubler et al. [25] point out, transition processes are accelerated by these characteristics, while they are slowed by high technology complexity, large market sizes and infrastructure needs; which are characteristics common to innovative processes. However, fuel-switching options should not create path dependencies which could impede future innovative processes from penetrating. The existing literature shows that fuel switch is recognized as an important tool for short to medium term emission reductions but that considerable uncertainties exist with regard to its potential and what challenges individual industrial processes face. A comprehensive review of short-medium term fuel switch measures in energy-intensive industries is not available, as previous publications either focus on individual processes or investigate long-term emission reduction options.

Here, we apply a mixed approach in which top-down data on industrial emissions are combined with bottom-up estimates on technological options for fuel switch. The general course of action is thus to derive technological-specific substitution potentials and apply them to the activities in the EU ETS applying these technology groups. This allows us to estimate the overall potential of the investigated fuel switch options in the industries participating in the EU ETS. However, the level of detail available in the EUTL is limited and production processes within the activities are aggregated. Finally, the registration of industrial power plants is not always consistent in the EUTL, as plants may be registered together with the industrial installation (e.g. steel plant) or separated as combustion activity. Especially highly integrated energy systems as they can be found in steel plants, refineries and chemical parks tend towards technological interaction and interdependencies that are not represented in this article. The results must therefore be taken as theoretical potentials. The practical potentials of concrete technologies thus remains subject to plant-specific considerations.

This paper focuses on the industrial demand subsectors iron and steel, cement, glass, refineries, basic chemicals and pulp and paper that

are present in the EU ETS.[4] These subsectors are often recognized as energy-intensive and thus of great importance for climate action [11, 16]. Other sectors are not considered due to their comparably low GHG emissions. As the goal of this paper is to determine demand-side fuel switch potential, we exclude supply-focused options as large-scale hydrogen production via electrolysis or high shares of synthetic or biogas in natural gas grids.

This paper reviews and summarizes the potentials for early emission reduction of industry via fuel switching by 2030, using technically available technologies. First, we review opportunities for CO_2-reduction potentials via fuel switching in existing industrial processes, based on peer-reviewed scientific articles, contributions to conferences, international grey literature and industry publications (e.g. of equipment manufacturers). Secondly, we estimate the total fuel switching potential for the basic-material industries in the scope of the EU ETS. We differentiate specialized emission sources in key industries, and cross-cutting sources including boilers and generic furnaces. We conclude with a discussion on the economic challenges of the identified fuel switching opportunities.

2. Methodology and data

2.1. Classification of considered technologies

Several technologies used to supply energy for industrial processes have limitations on the fuel type used. In Table 1, various types of furnaces used in industrial processes are presented. Those that do not have special fuel requirements are summarized as "furnaces", for example distributed fired heaters in refineries, pusher-type furnaces and walking-beam furnaces for reheating, several types of heat-treating furnaces (bell-type, box-type), melting furnaces in metallic industries (multi-deck-furnace, some shaft furnace types) and tunnel-furnaces for the burning of ceramics. Some of these furnaces feature indirect heating, but direct contact of product and combustion gases is also common. Similarly, we assume that steam boilers can be fired with a broad range of fuel types, often in a flexible way or even in parallel (i.e. multi-fuel burner). For many installations, fuel switching still includes modifications, especially to the burner itself and to fuel-related infrastructure (storage, distribution). Steam systems are typically used to supply low to medium temperature heat (assumed here: up to 500 °C). Furnaces can generate process temperatures above 1000 °C, though temperatures between 500 °C and 1000 °C are most common. These technologies are also referred to as *cross-cutting* [23].

2.2. Literature selection

We review process- and technology-focused literature from the energy-intensive manufacturing industries. We include peer-reviewed scientific articles, conference contributions, grey literature (publicly funded research reports and industry publications, e.g. of equipment manufacturers) to assess the current state of discussion. We consider fuel switch options that are plausibly expected to be available in relevant scale until 2030. This selection is justified with an uncertainty estimation, taking into account the available experience with the technology.

The literature review is approached from two directions: First, literature focused on contemporary production processes is searched for experience with fuel switch, identifying state of the art biomass and electricity use as well as known challenges and barriers. Secondly, emission reduction measures are reviewed based on literature dealing with alternative technologies, their deployment and potential estimates

of biomass and electricity. The use of biomass and electricity in steam systems and furnaces includes very heterogeneous applications (e.g. different temperature levels, boiler and furnace designs and products). However, the generation part is relatively homogenous and they are not facing the specific technical limitations of special furnaces. These special furnaces (e.g. blast furnace, glass melting furnace, steam cracker) are subsequently described individually.

2.3. Data sources

Main data source for GHG emissions is the transaction log of the EU ETS (EUTL). The EU ETS covers CO_2 emissions (energy-related and from process emissions) in the energy-intensive industries, power and heat generation and commercial aviation but also N_2O emissions, e.g. from nitric or adipic acid. The group of energy-intensive industries is further differentiated in 24 main activities. We create groups of processes with comparable energy systems.[5] The activities used in this publication are presented in Table 1. They accounted for 95% of industry's emissions in the ETS in 2015 [2], 64% of the GHG emissions of the entire industry in the EU28 in 2015 (861 Mt, [4]), and 75% of the industry's final energy demand in the EU28.[6] Their sectors also accounted for approx. 50% of total production value of the manufacturing sector [27].

In 2015, natural gas, electricity and coal were the dominant energy carriers in the EU industry with 719 TWh (30%), 657 TWh (27%) and 391 TWh (16%), respectively (Fig. 1). The share of electricity used for heating purposes is low and was estimated below 7% of the total energy used for heating [28]. Biomass and derived energy carriers made up 179 TWh (7.4%) in these subsectors, 80% of which in the paper industry. Subsectors with notable use of specific energy carriers include iron and steel (coal and coke), non-metallic mineral products[7] I (hard coal, petroleum coke, lignite, waste) and non-metallic mineral products II (natural gas) as well as pulp and paper (biomass). These consumption patterns can be traced back to the products and process technologies. Similar classifications and utilization of industrial activity has been proposed by Wiese and Baldini [29].

2.4. Data processing

The literature review identifies the most discussed measures in the respective energy intensive industries. The estimates on emission reduction potential are checked for consistency among multiple sources and applied to the affected emissions reported in 2015 (Table 1). Energy- and process related emissions are separated based, among others, on Fleiter et al. [11]. For example, process-related emissions in clinker production account for ~60% of the total emissions (0.53 tCO_2/t) and are not affected by fuel switch. Where production processes are grouped in an EU ETS activity, we estimate emission shares depending on their activity and specific energy demand [11]. In the case of synthesis gas production, only a rough estimate is possible, as no production figures were found.

For the purpose of emission reduction estimation, we assume biomass and electricity to be GHG-neutral. Any supply-side emissions

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[4] The most relevant industrial activities not included are production of primary aluminum (7 Mt), production of processing of non-ferrous metals (7 Mt), production of nitric acid (5 Mt) and production of soda ash or sodium bicarbonate (3 Mt) [2].

[5] Largely, this equals the division-level in the statistical classification of economic activities in the European community [26]. However, some processes that share a division require further differentiation (e.g. clinker and glass production).

[6] According to Eurostat energy balances [5], in 2015, the energy intensive industries in the EU28 (steel, chemicals and petrochemicals, non-ferrous metals, non-metallic minerals, food and paper) had a final energy demand of 2415 TWh; the entire industry sector had 3211 TWh. The EEA reports 567 Mt of emissions in the EU28 in the activities 21–44 and 99, of which the considered activities cover 547 Mt [2].

[7] Non-metallic minerals I (clinker and lime production) and II (glass and ceramics) have been split to highlight their energy carriers preferences, which differ substantially from each other.

Table 1
Investigated EU ETS-activities, production, important technologies, energy carriers and process-related emissions [11]) and their CO_2 emissions 2015 [2].

Subsector[a]	Main activity[b]	Main processes/ product	Main energy carrier	Main technologies	Emissions 2015[b] (Mt CO_2-eq.)	Activity 2015[c] [Mt]	Process-related emissions [tCO2eq./t]	Process share on emissions[d]
Refineries	Refining of mineral oil	Distributed fired heaters	Oil, natural gas, derived gases	Furnaces	128	723.3	–	1
Iron and steel	Production of pig iron or steel	Primary route	Coal	Blast furnace, converter	115	100.6	–	0.84
		Secondary route	Electricity	Electric arc furnace		65.5	–	0.16
	Production of ferrous metals	Rolling	Natural gas	Furnaces	12	150.6	–	0.33
		Other reshaping	Natural gas	Furnaces			–	0.33
		Heat treatment	Natural gas, electricity	Furnaces			–	0.33
	Production of coke	Coke	Coal	Coke oven	12	40.7	–	1
	Metal ore roasting or sintering	Sinter	Coal, derived gases	Sinter oven	3	110.6	–	1
Non-metallic minerals I	Production of cement clinker	Clinker	Diverse fossil	Rotary kiln	114	130.6	0.53	1
	Production of lime	Lime	Diverse fossil	Rotary kiln	31	27.9	0.68	1
Non-metallic minerals II	Manufacture of glass	Flat glass	Natural gas	Float glass furnace	18	13.1	0.15	0.46
		Container glass	Natural gas	Glass furnaces		22.9	0.04	0.5
		Other glass	Natural gas	Glass furnaces		1.7	0.24	0.04
	Manufacture of ceramics	Ceramics	Natural gas	Furnaces	16	6.1	0.49	1
Basic chemicals	Production of ammonia	Ammonia	Natural gas	Converter	32	17.7	–	0.1[e]
	Production of synthesis gas	Synthesis gas	Natural gas	Steam reformer		n.a.	–	0.9[e]
	Production of bulk chemicals	Ethylene	Naphtha, natural gas	Steam cracker	39	21.7	–	0.97
		Methanol	Natural gas	Steam systems		1.4	–	0.03
Pulp and paper	Production of paper or cardboard	Paper	Natural gas, biomass	Steam systems	22	93.2	–	1
	Production of pulp	Pulp	Natural gas, biomass	Steam systems	5	83.4	–	1
Sum					547			

[a] Eurostat definition [5].
[b] ETS definition [2].
[c] Based on [28], updated for 2015.
[d] Estimate based on energy demand and activity.
[e] Qualitative estimate.

are thus excluded. This assumption allows estimating emission reduction without the consideration of country-specific energy systems, for example electricity generation mix. When possible, the emission reduction potential of the identified fuel switch options is directly taken from the reviewed literature. Similar to Gerres et al. [23], if the reduction potential is given on an energy basis, we weight the data with the emission factors of the replaced energy carriers to calculate emission savings. When measures address the same emissions, the overlap is calculated separately. No priority for individual measures is assumed. Finally, we combine the evaluated measures and deliver a comprehensive look at the emission reduction potential of fuel switch in the investigated processes. The authors acknowledge that due to these assumptions, only a rough estimate on the emission reduction potential can be given and that considerable uncertainties exist.

3. Review of technologies for fuel switching

In this section, we review fuel switch options for steam systems, generic furnaces and special furnaces in energy-intensive processes. The options are focused on the demand-side, i.e. options that do not require extensive changes in the surrounding energy system (e.g. to electricity generation, transmission and distribution). Some options that require supply-side adoption are mentioned but excluded in the estimated potential. This excludes, for example, large-scale use of hydrogen based on electrolysis and biogas, as we assume the systemic effects to be high and not accessible by our approach.

3.1. Biomass use in steam systems and furnaces

The use of biomass for steam generation is particularly well researched for co-firing in coal-fired power plants [30]. Biomass co-firing is seen as an important option to reduce CO_2 and SO_2 emissions, with sulphur content mass fraction as low as 0.1, compared to 1–3 in coal. The effect of biomass combustion on NO_x emissions is ambiguous, ranging from increased [31] to decreased [32]. The optimization of burner operation, furnace design [33] and type of biomass are key factors. Co-combustion with other fuels like natural gas and oil may also offer operational advantages [31]. However, co-firing shares are restricted to relative low percentages (5–10%, [34]). Although factors affecting injection rates are always plant-or site-specific, the general issues encountered in power plant steam generation are also relevant for steam generation and many furnace types in industrial processes. Three main challenges can be distinguished: boiler/furnace operation, fuel handling and fuel properties.

3.1.1. Boiler/furnace operation (ash deposition)

Depending on biomass type, the ash composition can vary considerably [32] compared to coal. Biomass has higher concentrations of alkali metal and chlorine, which increases the potential for fouling and slagging [34,35]. When fouling and slagging occur, boiler tubes are coated with melted ash. Ash deposition hinders heat transfer and reduces the overall efficiency of the boiler, while increased corrosion (twice as high with 22% co-firing compared to coal alone [36]), shortens
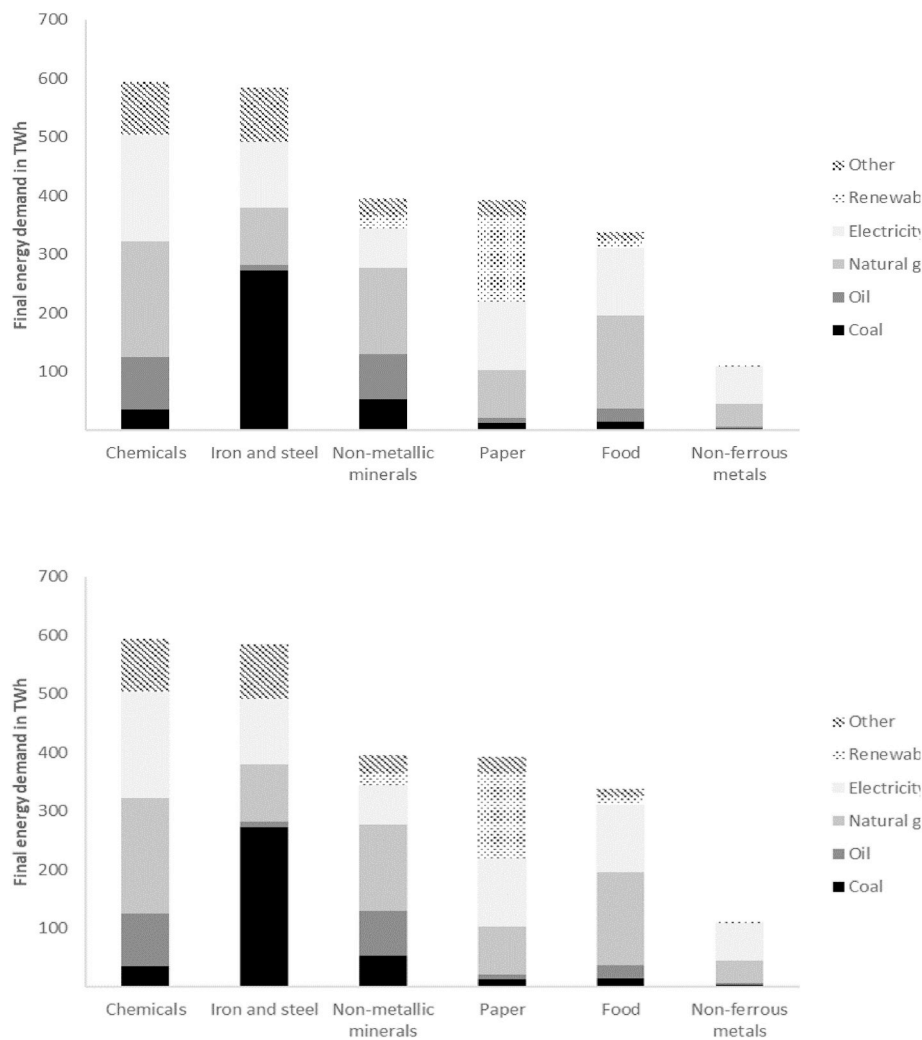
Fig. 1. Final energy demand of the selected industries (energy intensive) in the EU28 (2015) by energy carrier (grouped), data: [5], own illustration.

maintenance intervals or damages the boiler. Boiler design and operation may decrease fouling and slagging-risks. Especially pulverized fuel combustion boilers are vulnerable, while fluidized bed boilers (FBB) can mitigate the effect [37]. Therefore industries that typically use biomass-based fuels, e.g. wood-processing, pulp and paper industries, apply FBB-technology [38]. Obernberger [33] presents an overview of furnaces suitable for biomass combustion and fuel properties, including guiding ranges of elements in biomass fuels for unproblematic furnace operations. The details of the actual fouling and slagging mechanisms, their routes and dependencies on e.g. acidic components and the effort to derive predictive indices for them [39] cannot be discussed here in the appropriate detail. We refer the interested reader to the mentioned literature.

3.1.2. Fuel handling/logistics

Due to its higher moisture constent (ranging from 25% to 50% if untreated [32]), biomass has a much lower density and energy content than most currently used fuels. The required space for fuel storage, delivery and processing is therefore larger. Compared to coal, a factor of 10 can apply [34,40]. Therefore, high biomass-shares are harder to realize in existing plants. The moisture content also limits storage strategies, as the fuel can be biologically active and decay, releasing gases and heat [32]. Thermochemical and physical treatment of biomass can therefore be necessary in installations with high energy demand. Several treatment processes are available, e.g. torrefaction, drying, pelletizing [34, 41], gasification and pyrolysis [42]. These upgrade the biomass to a

more versatile fuel by reducing its water content, increasing density and heating value. For example, torrefied wood pellets may achieve a bulk density of around 15 GJ/m^3 [41] (coal: 45 GJ/m^3). When upgraded biomass is considered, gasification and treatment to natural gas-quality can be the easier approach from a systemic point of view, given that natural gas is a highly used energy carrier in industry today (cf. Fig. 1). While the processing of biomass to methane is less efficient than direct use, dry biomass would require a substantial exchange of existing installations. Both paths require investment in biomass processing technologies.

3.1.3. Biomass standards/biomass properties

The properties of biomass can vary substantially. The higher heating value (HHV) can range from 11 MJ/kg to 22 MJ/kg [36] (coal: around 29 MJ/kg) and is highly influenced by the moisture content. The ash fusion temperature can be similar to coal (for wood) or substantially lower (straw). The volatile matter content is usually higher than in coal and shows a certain range [32]. Especially in high-temperature applications, the heating value may limit or hinder the use of biomass [43]. A useful differentiation for the heating value is by the main types woody and herbaceous plants [40], distinguishing by plant type, i.e. high (wood) and low (herbaceous). Despite these categories, biomass remains a very heterogeneous fuel group. Therefore, finding the suitable type of biomass in sufficient quantities is often a barrier [37]. The need for standardization of biomass fuels and their characterization is expressed [34,35]. Fernando [32] shows that ash deposition rates vary

substantially between for example wood (below 0.1 g/kg fuel, lower than coal) and straw (above 10 g/kg fuel), which may limit co-firing shares. Thus, a well-defined blend of biomass types and/or other fuels may mitigate some of the shortcomings of any individual type of biomass.

To summarize the factors affecting biomass use in steam generation: While in general, technological solutions for the described challenges exist [33]; their application in the market is tied to the replacement of old technologies, the installation of new plants, especially for upgrading biomass, or modification of existing ones. According to Ref. [32], the use of biomass in existing coal-fired boilers is limited to 10%. Slagging and fouling becomes an issue above 10% cofiring-rate. The use of upgraded biomass (i.e. drying, removal of corrosive and slagging substances, gasification) could increase the share, eliminating or reducing concerns about bulk density and to some degree slagging and fouling. The definition of mixtures for specific applications and installations could potentially increase biomass use further. Some consumers, e.g. clinker producers, generally employ quality-assurance systems regarding raw materials and fuels [44]. However others often lack sufficient expertise or motivation to change their fuel composition, e.g. when energy supply is not a core process. Finally, the use of steam systems and furnaces specifically designed to use biomass (e.g. fluidized bed or stoker designs) could mitigate limitations [31]. The gasification of biomass could provide a convenient energy carrier for industry and reduce pressure to replace existing installations.

For the estimation of emission mitigation potential, we assume a currently possible biomass use of 10% (short-term measure), and a long-term technical potential of 100%. This assumes that the mentioned issues (heating value and water content, elemental composition and volatile shares) are sufficiently addressed. Until 2030, however, stock turnover of steam systems and furnaces limits diffusion. Thus we assume a medium-term (until 2030) potential of 50%, combining modernization and new installations.[8]

3.2. Electric boilers and furnaces

With the prospect of a decarbonized electricity generation, electric boilers and furnaces show potential to reduce GHG emissions from process heating as well. While the technology itself is proven and available on the market [45], economic challenges limit its use to niche applications that benefit of the characteristics of the technologies, e.g. safety, high temperatures, possibility of inert atmospheres, temporal and spatial temperature distribution and high energy density. Still, a variety of electro-thermal technologies and principles exist. From a technical point of view, close to all heating applications could be supplied electrically. Several examples are discussed by Rudolph and Schaefer [46], including electrolytic processing of metals, electric glass furnaces, paper drying, electric arc furnaces in steel production and steam/hot water supply. Due to substantially reduced flue-gas losses, electricity-based furnaces have in general a higher energy efficiency [47].The processing of sensitive material that could be contaminated by fuel combustion; furnaces with high temperature (e.g. electric arc furnace) or important temperature profiles (glass furnace) are first candidates for electric process heating. In these cases, product quality can improve as a valuable side-benefit, in the best case offsetting increased energy costs. However, where those potentials exist, they are usually already used. In current glass melting installations, differences in capacity of a factor three (e.g. glass furnaces) to ten compared to common fuel-fired applications exist.

While some sources stress several advantages of electric steam

Table 2
Properties and solution of electric boilers and furnaces.

Dimension	Property	Barriers	Solution	Technical feasibility
Technical	Capacity	decreased energy efficiency decreased economic efficiency	upscaling	mid-term
Economical	Electricity price	failing in competition against fuel-based technologies	lower electricity price higher fuel prices	long-term short-term
Physical	Emission intensity of electricity generation	lowered ecologic benefit	increased renewable share	mid-term

generation over fuel-driven boilers, e.g. lower investment costs and the lack of start-up costs or ramping constraints [48] and no local air pollution, economics make them currently less attractive. Han et al. [49] calculate a factor 3 higher operating costs compared to a gas-fired boiler, despite relatively high gas prices used in the study. Yilmaz et al. [50] calculated the levelized costs of heat of an electric boiler compared to a gas boiler, finding that an electricity price of 40 EUR/MWh would yield parity. The 2015 EU28 average industrial electricity price of 114 EUR/MWh thus suggests a limited economic potential for electric boilers.[9] Therefore, electric boilers are mainly considered flexibility options for an electricity system with high shares of intermittent renewable generation [49,52,53]; feeding in a district heating system or supporting industrial heat demand [50]. In this application, they would make use of negative residual load and corresponding near-zero or negative electricity prices. This business model entails short operation intervals and is not suitable to supply baseload steam demand for industrial processes. Despite these general and process-specific limitations, Wiese and Baldini [29] estimate an achievable electrification share of 88% and 25% for low- and high-temperature process heat, respectively. Apargaus et al. [54] investigated high temperature heat pumps (HTTP) currently on the market and concluded that some are able to supply heat up to 150 °C, with a European potential of about 30 TWh. HTTP as direct electric heating, economically challenged by high electricity prices. In addition, higher temperature ranges are not accessible and concerns about the currently employed refrigerants' global warming potential exist [54].

We summarize that all applications classified as "steam systems" or "furnaces" in Table 1 could be operated with electric systems. In the lower temperature ranges, heat pumps would be more favourable from a technical as well as economic perspective, but as the resulting emission reduction in the industry sector is the same, we do not differentiate between heat pumps and direct electric heating. The same assumptions on stock turnover and modernization as for biomass (50% until 2030) apply. An overview of the challenges is presented in Table 2.

3.3. Review of individual processes

3.3.1. Refineries

Refineries process crude oil into a variety of gases, fluids and solid fossil fuels and petrochemical products. They are complex systems with diverse processes, requiring electricity, steam and direct heating, and a

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[8] This assumes a common lifetime of 15–25 years, not expecting early replacement. Additionally, this assumes that all existing stock installations are exchanged equally and no energy carrier-related preferences exist. For a closer look, the stock exchange should be modeled.

[9] During 2015, the electricity prices for non-household consumers (excluding recoverable taxes) varied between 81 EUR/MWh (demand >70 GWh) and 146 EUR/MWh (demand <20 MWh), depending on the consumption band [51].

variety of fuels with differing heating values are applied. Self-produced or derived gases from the production process supply a substantial share of the fuel in refineries. Under current economic conditions, it is more attractive to use them as fuel than as, e.g. feedstock in the chemical industry. In the period 1990–2015, approximately 45% of the energy input of the EU refining industry was supplied by derived gases [5], with a low of 10% in Poland (1998) and highs of 70% in Spain (2011). Other energy carriers include fuel oil, natural gas (25% of EU28 energy consumption in 2015 [5]) as well as petroleum coke and several minor fuels (~5%). Fired heaters make up for 30–60% of emissions in a refinery and experiments have been carried out to replace the usual refinery fuels and methane with hydrogen [55]. Limited impact on performance was found, suggesting that no specific fuel composition is required. While from a technical perspective, all process heat in refineries could be supplied using biomass- or electricity-based supply, replacing derived gases and petroleum coke would only shift emissions, since they are a by-product.

We assume that immediate fuel-switch potentials are limited to the replacement of purchased fuels (i.e. natural gas) by biomass or electricity. As purchased fuels account for about 30% of refineries energy demand, this would equal a 33% CO_2 emission reduction (considering the emission intensity of the replaced fuel mix in the EU28 in 2015).

3.3.2. Iron production

Blast furnaces are highly specialized shaft-furnaces and the most energy and emission intensive process step in ironmaking. Blast furnaces rely on fossil fuels, particularly coke and (injected) coal. The former is essential for mechanical support and a free gas flow[10], and limits a shift to other energy carriers. The minimum use of coke is driven by the blast furnace geometry and operation, and can only be estimated on today's best practices [56]. The average coke consumption in blast furnace operations in Germany has decreased considerably from over 1000 kg/t_{hm} in 1950 to 400 kg/t_{hm} in 1990 [57], but only slightly since to about 360 kg/t_{hm} in 2010 [58]. Otto et al. [59] report the total energy input in an average blast furnace with 15.95 GJ/t_{hm}, of which 4.67 GJ (143 kg) are supplied by coal (pulverized coal injection, PCI) and small quantities of natural gas and 10.3 GJ (359 kg) by coke. A value of at least 300 kg/t_{hm} of coke and a total of 500 kg/t_{hm} of reduction agents and fuels is a reasonable estimate for modern blast furnaces[11] [61].

Fuel switching options in a blast furnace include the use of biomass-based fuels in coke making and the injection as auxiliary fuel [62]. The former option invokes the discussed requirements on coke properties. The latter does not and is thus more promising [63]. Both options need to be distinguished from pure charcoal-based ironmaking, which is active in Brazil, but given little credit for global deployment, due to the limited capacity of the furnaces.[12] (Suopajärvi et al. [60] show that a coke rate as low as 260 kg/t_{hm} is plausible, incurring additional side benefits to the process, e.g. higher metal quality and productivity. Regarding biomass injection in the blast furnace, Suopajärvi et al. [61] conclude that charcoal shows best promise to replace pulverized coal. Additionally, Wang et al. [63] find that the replacement of PCI with charcoal also lowers lime consumption by around 20% and overall energy demand due to increased latent heat in the top gas. However, several adjustment to blast furnace operations are needed to use the potential. Though experience is limited to mathematical models, lab-scale experiments or small blast furnaces in Brazil [64], several studies reviewed by Suopajärvi et al. [61] show a potential for emission reduction by biomass injection of 20–40%, up to a full replacement of injected coal. The injection of other fuels is also discussed, including hydrogen. Yilmaz et al. [65] find an optimal injection rate of 27.5 kg$_{H2}$/t_{hm} with a CO_2-reduction of 289 kg/t_{hm}. This equals a relative emission reduction of 21.4%. Challenges to hydrogen injection are changed top-gas compositions, which can influence the operation of the integrated steel plant, the required large electrolysers for sustainable hydrogen production and the economics of power to gas (PtG). Lyu et al. [66] investigated the effect of hydrogen injection on the reduction rate and found an optimal hydrogen content in injection gas between 5% and 10%, limited by altered energy distribution. The partial use of biomass in coke production (bio-coke) is also discussed. Ng et al. [67] found that adding biomass as high as 5% to coke production lowers not only the overall GHG emissions, but also yields additional benefits to the BF process (e.g. better carbon utilization). They acknowledge that the mechanical strength of the resulting coke can be lower than that of regular coke at higher rates and thus the applicable share of biomass is indeed limited. Suopajärvi et al. [61] report a range of achievable coke-substitution (5%–20%), depending on the type of biomass.

We include the individual measures of biomass in coke making (up to 10% of coke, reducing emissions by 6%) and substitution of pulverized coal with biomass in the blast furnace (emission reduction around 30%).

3.3.3. Coke oven

Coke ovens remove volatile components from coal to form coke. They use these volatile components and on-site process gases as fuel, in turn exporting coke-oven gas. Therefore, little fuel switch possibilities exist. However, a reduction in coke use lowers coking emissions proportionally. Emission savings due to biomass addition to coke is assigned to the blast furnace, but could just as well be assigned to coke ovens, due to site-internal use of process gases.

3.3.4. Sinter oven

Similar to coke ovens, sinter plant emissions would be reduced by a shift towards more EAF-based steel production. With coke breeze being the dominant energy carrier in sinter plants [58], fuel switching towards biomass and electricity can be effective. According to Ref. [61] up to 40% of the coke breeze could be replaced with biomass, the resulting emission reductions can be estimated to 1 Mt CO_2-eq. However, experiences are restricted to lab-scale sinter tests. The measure is therefore not considered further.

3.3.5. Electric arc furnace (steel production)

EAFs are mainly used in steelmaking from scrap and have significantly reduced energy demand per ton of steel than the BF-route, as they omit the highly energy-intensive step of iron ore reducing. They are thus, next to their fuel-switch character, primarily a circular economy action.[13] EAFs mainly use electricity, with little addition of injection fuels, and thus have the potential to operate nearly GHG-neutral. However, high quality scrap availability may limit the achievable production rate. Of major concern are the dilution of alloying elements and copper contamination in contemporary scrap [68]. Especially high-grade flat products are mainly produced in the BF-route and thus, the potential for scrap-based EAF steel is limited. EAFs can supply high quality steel if part of the scrap is substituted by direct reduced iron (DRI). The DRI-EAF route can, in principle, replace the BF route but shows, due to the energy-intensive reduction, an energy demand closer to the BF-route.[14]

Depending on macro-economic and technology assumptions, a range

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[10] Additionally, they provide energy and carbon as reducing agent, which also lowers the melting point of the iron to a eutectic minimum.

[11] Coke use of around 200 kg/t_{hm} have been reported, but are related to the not commercially available technology top gas recycling [60].

[12] The largest charcoal blast furnaces (CBF) are reported to have a capacity of 1200 t_{hm}/d [64], while the largest conventional blast furnaces can reach 12.000 t_{hm}/d.

[13] For ease of presentation, we focus on the fuel-switch characteristic of scrap-based EAF and refer to it as such.

[14] Including electricity, Arens et al. [12] assume 1.82 tCO_2/t_{hm} for the blast furnace process, 0.53 tCO_2/t_{hm} for the scrap/EAF route and 1.49 tCO_2/t_{hm} for the DRI/EAF process route.

of shares of scrap-based steel on the total production seem plausible. Based on Herbst [69], an ambitious estimate on demand development for the EU28 yields an EAF potential of 50% in 2030 (2015: 39%). This neither considers direct reduced iron as potential feedstock nor advanced steel recycling. Both technologies are unsure to be available in the near future.

We assume that a scrap-based EAF share of 50% on total steel production is achievable until 2030 [69]. We use average emission intensities based on Arens et al. [12] of 1.82 tCO_2/t_{hm} and 0.11 tCO_2/t for the blast furnace and scrap/EAF route (excluding offsite electricity), respectively. The actual impact of this production shift depends on the other measures influencing blast furnace emission intensity. Steel production in this secondary route involves a process switch and thus more effort than many fuel switch options. It is still included in this analysis because the technology is competitive today and has comparatively low capital costs, enabling faster diffusion.

3.3.6. Rotary kiln (production of clinker)

Rotary kilns use a variety of fuels and are often equipped with multichannel burners for simultaneous burning of solid, liquid and gaseous fossil fuels and waste [44,70]. In pre-calciner rotary kilns, fuel can also be injected in the pre-calciner, where lower reaction temperatures allow for a broader selection of fuels, especially with lower heating values. According to Shahin et al. [71], the rotary kiln is the most used type of kiln in the non-metallic minerals industries. In Germany, over 98% of clinker is produced in rotary kilns. The share of solid fossil fuels (petcoke, coal) used in the non-metallic minerals in the EU28 is quite stable over the past decades at about 30%. Renewables and waste shares increased from 1% to 4.8% and 0.2%–7.7%, respectively, during 1990 and 2016 [5], mainly replacing heavy fuel oil. These waste fuels are non-renewables such as tyres, plastics or industrial waste and thus do not reduce the emission intensity of clinker production considerably.

GHG mitigation options include an increased use of biomass in the alternative fuel/refuse-derived fuel fraction and replacement of primary fossil fuels (lignite, hard coal, coke, fuel oil). Secondary fuel shares of 70–80% have been observed [72,73] in individual plants. Assuming upgraded biomass with suitable heating value was available, it could theoretically supply the entire energy input in rotary kilns. Since the raw material is in direct contact with the flue gas, the fuel composition can influence clinker quality, which means that especially the mineral components of biomass need to be controlled and considered for the raw material mix [74]. Replacing the energy input with GHG-neutral fuels could reduce the emissions from clinker production by approximately 40% to 0.53 $tCO_2/t_{Clinker}$ [75].

We assume that fossil and waste-derived fuel can be substituted completely with biomass-based fuels, reducing energy-related emissions (40% of total). Electric heating is not considered as an option in the near future. Examples include the theoretical possibility to apply indirect-heated rotary kilns [76] that are used in special applications. Those are, however, not capable to deliver the required capacities and currently not considered in the industry.

3.3.7. Shaft kiln (production of lime)

Similar to cement clinker, lime is produced by the calcination of limestone, resulting in 0.79 tCO_2/t_{Lime} process-related emissions [77]. While rotary kilns can be used, the more energy efficient shaft furnaces dominate in Europe. More than 50% of the global lime production is used as metallurgical lime in the steel and non-ferrous metals industry, for example to remove impurities, especially sulphur [78]. Therefore, the sulphur entry during lime production must be controlled, which limits fuel use to low-sulphur types.

Most types of biomass contain much less sulphur than coal. Low-sulphur coal is defined as a mass fraction of sulphur <1 sulphur, while most biomasses show 0.1–0.2 [36,40]. Indeed, pulp mills in Sweden fuel their captive lime production with biomass for decades, with biomass fuel rates up to 95% [79]. We include the measure to substitute fossil fuel completely with biomass-based fuels, mitigating energy-related emissions (35% of total).

3.3.8. Glass melting (flat & container)

Glass is produced by melting the raw material sand, soda ash, limestone (and others) in a furnace. It is usually heated with natural gas burners (79% in 2007 in EU25 [80]) and supported with electricity. Small electric furnaces are already used for specialty glass products. Emissions occur due to energy use (0.57 tCO_2/t) and process emissions (0.12 tCO_2/t) (process-weighted EU28 average according to Schmitz et al. [80].

All-electric melting furnaces are theoretically available for most glass types and discussed in the industry as possible alternative to natural gas furnaces [81], but more common in smaller batch furnaces used for container glass and technical glass. With the electricity price and lower capacity being the main disadvantage compared to fuel-fired furnaces, their actual use is severely limited [80]. While common fuel-fired furnaces reach capacities of 400–700 tpd (tonnes per day) [82], all-electric furnaces of 175 tpd are considered large, with an assumed practical maximum of 300 tpd. In addition to their potentially GHG-neutral heat supply, all-electric furnaces can be more efficient, with roughly 80% fuel efficiency (fuel-fired around 50% at similar sizes) or 800 kWh/tonne.

Here we assume that all-electric furnaces can be scaled up sufficiently to deliver the required capacity. Therefore, the energy related emissions (80% of total) could be theoretically mitigated.[15] This could be applied to all major glass products, with the possible exception of some glass types with foaming tendency due to feedstock composition [83]. As all-electric glass furnaces requires new installations or extensive revisions in existing plants, we assume (similar to steam systems) that 50% of the potential can be realized for container and 'other' glass until 2030. Due to higher requirements on melt composition and homogeneity for float glass, we estimate a lower TRL of 6 for this application and an achievable share of 25% of the potential.

3.3.9. Steam reformer (synthesis gas production)

Steam reformer produce synthesis gas (H_2 and CO_2) out of fossil fuels (e.g. methane). The two most important applications for the synthesis gas are ammonia and methanol production. Steam reformer use both steam (mixed with the carbon-carrying feedstock) and furnaces, further heating the gas mixture, to create the required reaction environment. The energy input can be considered to originate from the furnace, since the steam is generated with furnace excess heat. The production of ammonia and methanol require temperatures between 400 and 500 °C, and 200–300 °C, respectively. Steam may be generated with excess heat from gas cooling [11].

CO_2-Emission reductions focus on the generation of synthesis gas: Hydrogen production via electrolysis seems to be a natural step and ammonia could be an important part of a hydrogen-based energy system [84]. Considering biomass as feedstock, the concept of a bio-refinery [85] would present an integrated approach for the production of several bulk chemicals. Both technologies are not on the market, though, and unlikely to be available in impactful capacities until 2030. Ethanol-based hydrogen production via steam reforming is discussed, but catalysts are still being researched [86,87]. Direct electric heating has been discussed with regard to efficiency gains, maintenance reduction and methane use [88]. While the concept has been demonstrated, the authors also mention several challenges to widespread implementation. If applied, it could replace the natural gas used as fuel (20%–25%) [88,89]. This is the upper end of the reported range; site- and operation-specific properties can reduce it. Replacing natural gas with upgraded biogas as feedstock and fuel is seen as technically viable for almost all current reforming processes [90], although it is unclear what

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[15] This is on the upper limit of possible emission reductions summarized by Gerres et al. [23].

biogas generation capacity could be supplied until 2030. Solar-heated approaches are also discussed [91]. Here, we assume that electro-thermal reforming is in principle possible in a retrofitted steam reformer, eliminating the emissions caused by the use of natural gas as fuel. This equals an emission mitigation potential of 20–25%. We assume that limited use of bio-based syngas, replacing the natural gas used as feedstock (25%), can also be introduced until 2030.

3.3.10. Steam cracker (ethylene and other chemical products)

Steam cracker split hydrocarbons (mostly naphtha in Europe) into shorter molecules that are used in several chemical processes (e.g. ethylene). Similar to steam reforming, heat is supplied by both steam (mixed with the feedstock stream) and furnaces (used to further heat the mixed stream). However, superheated steam is generated in the furnace and recycled as saturated steam [92]. Heat supply originates from the furnace. Natural gas or fuel oil are used in cracking furnaces, but due to NOx-emission, oil use declined strongly [92], a trend which can be observed in the entire chemical industry [5]. Energy-related emissions from furnaces and steam systems account for the majority of the specific emissions of 1.5–2.1 $tCO_2/t_{Ethylene}$ [93] [16].

Options to reduce GHG emissions focus on the use of sustainable feedstock alternatives to the fossil naphtha. Revolutionary concepts include the use of hydrogen or the complete replacement of the platform-chemical ethylene [84]. Other approaches aim to replace fossil-based feedstock with bio-based counterparts, essentially generating sustainable ethylene and moving from petro-to bio-chemistry. The energy-intensive cracking process would become obsolete, as e.g. ethanol requires only dehydration to become ethylene, with a comparably little energy demand of about 1.68 GJ/t [19] (naphtha-based ethylene: 36 GJ/t [11]). For all these concepts, the availability of biomass or cheap electricity for hydrogen production is critical [94]. Less invasive measures include the mere replacement of fossil fuel use for heating purposes with biomass or electricity. These approaches would have a smaller impact on the down-stream value chain since ethylene (and C3, C4 co-products) could potentially be supplied as usual. While this would allow the majority of installations in a steam cracker to remain in existence, it is debatable what effects changed fuel sources could have on the steam cracker system. Different bulk densities, burner design and the use of waste streams (in some furnace designs up to 70% of energy use [92]) from the cracking process may pose a challenge to efficient operations. The product itself would still carry a fossil GHG load and cracking residues (ethane, fuel oil, hydrogen, methane, and propane) would require another, preferable long-term, sink. Steam cracker are usually a part of or close to large chemical parks and, similar to refineries, the cracking residues could replace purchased fuels there. Overall, the TRL of electrified steam crackers is estimated to be low, mainly at laboratory stage [95]. The option is thus excluded from the estimated potential.

3.3.11. Summary

Both the applicability and availability of the proposed fuel switching measures are subject to uncertainty. We estimate the readiness of the measures by the amount of practical experiences documented in the reviewed literature (Table 3). We use the technology readiness level (TRL) scale as defined by Horizon 2020 and used in Ref. [1]. The categories range from widespread experience and deployment (TRL 8–9) over transferable technology and small-scale demonstrations (6–7) to model calculations and experiments (5). TRLs lower than that are not considered available until 2030 and thus excluded.

4. Results

We calculate the emission reduction potential of the measures identified in the previous sections with respect to the emissions in 2015 (Table 1). That is, we neglect efficiency improvement potentials [96,97] and activity changes, which would likely occur until 2030. The identified measures are categorized as biomass- and electricity-use (Fig. 2 by technology, Fig. 3 by fuel switch option). These individual measures overlap to some degree, i.e. both biomass and electricity could be used in some applications.

Biomass- and electricity-based steam systems and furnaces contribute 28 Mt CO_2-eq. and the replacement of natural gas used as fuel in steam reforming with biomass or electricity each 8 Mt CO_2-eq. Biomass use in lime and clinker production can reduce emissions by 57 Mt CO_2-eq. and all-electric furnaces in glass melting 5 Mt CO_2-eq. The discussed measures in the iron and steel industry (shift to EAF, biomass injection in blast furnaces and biomass addition to coke) contribute 35 Mt CO_2-eq. and the replacement of purchased fuel in refineries with biomass or electricity 42 Mt CO_2-eq. All measures combined, 34% of the investigated emissions in 2015 could be mitigated (184 Mt CO_2-eq. out of 547 Mt CO_2-eq.). Biomass measures individually could save 162 Mt CO_2-eq. (69 Mt CO_2-eq. without overlap), and electricity measures individually 114 Mt CO_2-eq. (21 Mt CO_2-eq. without overlap). The emissions addressable by both biomass- and electricity-based fuel switch amount to 93 Mt CO_2-eq.

With the considered short/medium-term options, emissions remain that cannot be mitigated until 2030 (89 Mt CO_2-eq., Table 4). These emissions could potentially be mitigated in the long-term (*Beyond 2030*) or in aggressive fuel switch scenarios (e.g. faster steam system and glass furnace exchange before the end of their lifetime and availability of large quantities of biomass- or hydrogen-based feedstock). These emissions include 28 Mt CO_2-eq. in steam systems, 16 Mt CO_2-eq. in steam reforming, 7 Mt CO_2-eq. in glass production and 39 Mt CO_2-eq. in steam cracker. The presented reduction potentials also reveal emissions (*Process switch*) that cannot be addressed with the discussed inter-fuel substitution measures (275 Mt CO_2-eq.). They consist of fuel use in mineral oil refining (86 Mt CO_2-eq.), coke and sinter use and preparation in iron and steel (94 Mt CO_2-eq.) and process emissions in clinker, lime (89 Mt CO_2-eq.) and glass and ceramic production (6 Mt CO_2-eq.). These emissions could be mitigated with radical process changes (e.g. change of raw material) but not within the existing processes.

5. Discussion

While the main part of the analysis focused on the technical feasibility, we discuss the role of additional factors below. Among these are the cost-competitiveness of electricity, the sustainability of biomass and estimations on their respective potential.

5.1. Challenges to the identified fuel switch options

From an economic perspective, the discussed technologies are at a disadvantage compared to the fossil-based alternatives. Today, biomass is used where it is available as production residue (pulp and paper industry, 80% of industrial biomass use) or if the combustion process also serves as waste disposal (clinker production, 75% of renewable waste use) [5]. The ability to compete against natural gas, fuel oil and coal in other applications is limited.[17]

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[16] Another source [92] speaks of 1–1.6 $tCO_2/t_{Ethylene}$, the actual emissions depend on the feedstock used (gas oil, naphtha or ethane).

[17] Biomass is often traded in local or regional markets and international prices do not exist. However, we assume prices in the region of 3–4 EUR/GJ for solid biomass, similar to hard coal and slightly higher than lignite. Treated, high-grade biomass (e.g. pellets) can be much more expensive, up to 8 EUR/GJ for domestic production and 12 EUR/GJ for imports [98]. For comparison, prices for natural gas in the EU in 2015 were, depending on consumption, between 7 EUR/GJ and 15 EUR/GJ [99].

Table 3
Summary of investigated measures.

Technology/ Process	Measure	Statement from source	TRL[a]	Emission reduction potential compared to 2015[b]	Comment[c]	Source
Refinery	Replacement of natural gas	Specific: burner retrofit experiments; General: available technology (furnaces)	8	33%	Assumed exchange of purchased fuel only	[55]
Iron production	Replacement of PCI with biomass (or hydrogen)	Blast furnace models, small blast furnaces	7	30%	–	[61,63, 64]
	Biomass in coke production	Pilot-scale coke oven	6	6%	–	[61,67]
Steel production	Shift to secondary route (EAF)	Established production route	9	11% (50% EAF share)	Scrap quality is a challenge for high shares (39% 2015)	[68,69]
Clinker production	Substitution of fossil fuels with biomass in rotary furnaces	Documented fuel-flexibility	8	39% (all energy-related)	Treatment and standardization of biomass necessary	[72,75]
Lime production	Substitution of fossil fuels with biomass in shaft furnaces	Industrial experience in paper industry (captive lime production)	8	35% (all energy-related)	Lower sulphur content than coal	[36,79]
Glass production	All-electric furnaces	Available technology, economically challenged	6–7	40%	Upscaling required; 50% diffusion until 2030	[80,81]
Steam reformer	Electro-thermal reforming	Specific: experiments; General: available technology (furnaces)	6	25% (all energy-related)	Solar heating also discussed	[46,88, 91]
	Biomass gasification for fuel supply	Proven technology for natural gas replacement	8	25% (all energy-related)	–	[90]
Steam cracker	Electric heating	Laboratory scale	4	–	Excluded due to low TRL	[92,95]
Steam generation and furnaces	Electricity and biomass use	Available technology, economically challenged	9	50%	Exchange of old boilers; 50% diffusion until 2030	[33,45, 46]

[a] TRLs based on author's judgement of reviewed literature.
[b] Derived from literature review. Potentials are assumed reachable until 2030 with determined but realistic action in existing plants and with technically available technology. The potentials may not be economic under current frame conditions but could become so (near-economic potentials) or may also be hampered by non-economic barriers. Restrictions may be mentioned in column 'Comments'.
[c] Relevant restrictions, side-benefits and challenges to deployment (already considered in emission reduction potential).

The cost competitiveness of electricity is even worse with current regulations in many EU countries. This can be illustrated with the example of an all-electric glass furnace. Switching from natural gas to electricity would increase energy costs to 54 EUR/MWh (based on Egenhofer and Schrefler [82]), which would result in an effective price increase of 40 EUR per tonne of saleable float glass (17% of current prices). These costs would value a tonne CO_2 with 75 EUR (with 0.53 tCO_2 mitigated), which is well within the range of emission price assumptions in long-term energy scenarios, albeit usually not before 2030 [100,101] and even later in reference scenarios [100,102]. As discussed above, all-electric furnaces include several side-benefits (e.g. strongly improved energy efficiency). Electricity-based steam generation faces high electricity prices compared to fossil fuels, dependence on decarbonized electricity and low capacity of current systems. Ortega-Izquierdo and del Río [103] showed that the costs created by support schemes implemented in the EU to foster renewable electricity generation could be offset (depending on assumed CO_2-pricing) by the benefits. Potential business models include the use of hybrid systems, with the prospect of supplying operating reserves to the electricity grid and benefit from electricity price spikes. However, these operations rely on short overall operational times and thus yield low emission reduction potentials. As these potentials also depend heavily on the supply side, they are not evaluated here. As a market entry of electric steam generation however, they might become relevant.

5.2. Additional biomass and electricity demand

Biomass availability is limited and its sustainability is closely tied to regional production and land use. Especially competition with other demand sectors (i.e. households, power generation and transport) will limit industrial biomass use considerably. Therefore, it seems plausible that biomass use should be favoured for applications with chemical use (e.g. as reducing agent in iron and steel or as feedstock in the chemical industry). Several estimates of biomass availability are given in recent studies and they vary according to their definition of sustainability. A

considerably tight definition is given in Öko-Institut, Fraunhofer ISI [104], assuming equal distribution per capita worldwide. For Germany, this assumption yields a biomass potential in 2050 roughly equal to 2010 levels, with 110 TWh allocated to the industry sector. Extrapolated to the EU based on final energy demand would yield a potential of 500 TWh, which is roughly double the use in 2015 [5]. Other estimates [105] describe a five times increase of available biomass-based energy production until 2050 (83 PWh) compared to 2008, albeit on a worldwide scale. Connolly et al. [106] assume a potential of 3900 TWh to be sustainable for the entire EU28 in 2050, also based on a per capita-approach (27 GJ/person/year). Assuming the industry uses a similar share as in 2015 (25%, [5]), a potential of 975 TWh would result. As most estimates on renewable potential (both biomass and electricity) present values for 2050, we assume that only half of this potential can be utilized in 2030. For this discussion, we thus assume a sustainable biomass potential available for the industry in the EU28 (2030) between 250 TWh and 490 TWh.

This potential would suffice to cover todays demand (179 TWh) and additional 130 TWh of the energy demand in steam generation (Table 5) of the reviewed subsectors (168 TWh biomass use in 2015). This would equal the assumed biomass share in steam generation and furnaces of 50% by 2030 (298 TWh). The proposed measures replacement of PCI and coke/sinter fuel with biomass-based fuels (180 TWh) and biomass-based clinker and lime production (165 TWh); create additional biomass demand. The total industrial biomass use in 2030 sums up to 827 TWh, of which 648 TWh are additional demand compared to 2015. This demand exceeds the potential estimation (250–490 TWh) until 2030, while it stays below the assumed 2050 potential. This means that the fuel switch measures to biomass could theoretically be supplied by sustainable, domestic biomass but high effort would be needed to actually use the potential until 2030. However, these numbers include neither efficiency gains nor activity changes and these influences should be investigated in more detail.

Electricity would have to supply a substantial share of heating, which highlights the relevance of the electricity generation mix. Switching to
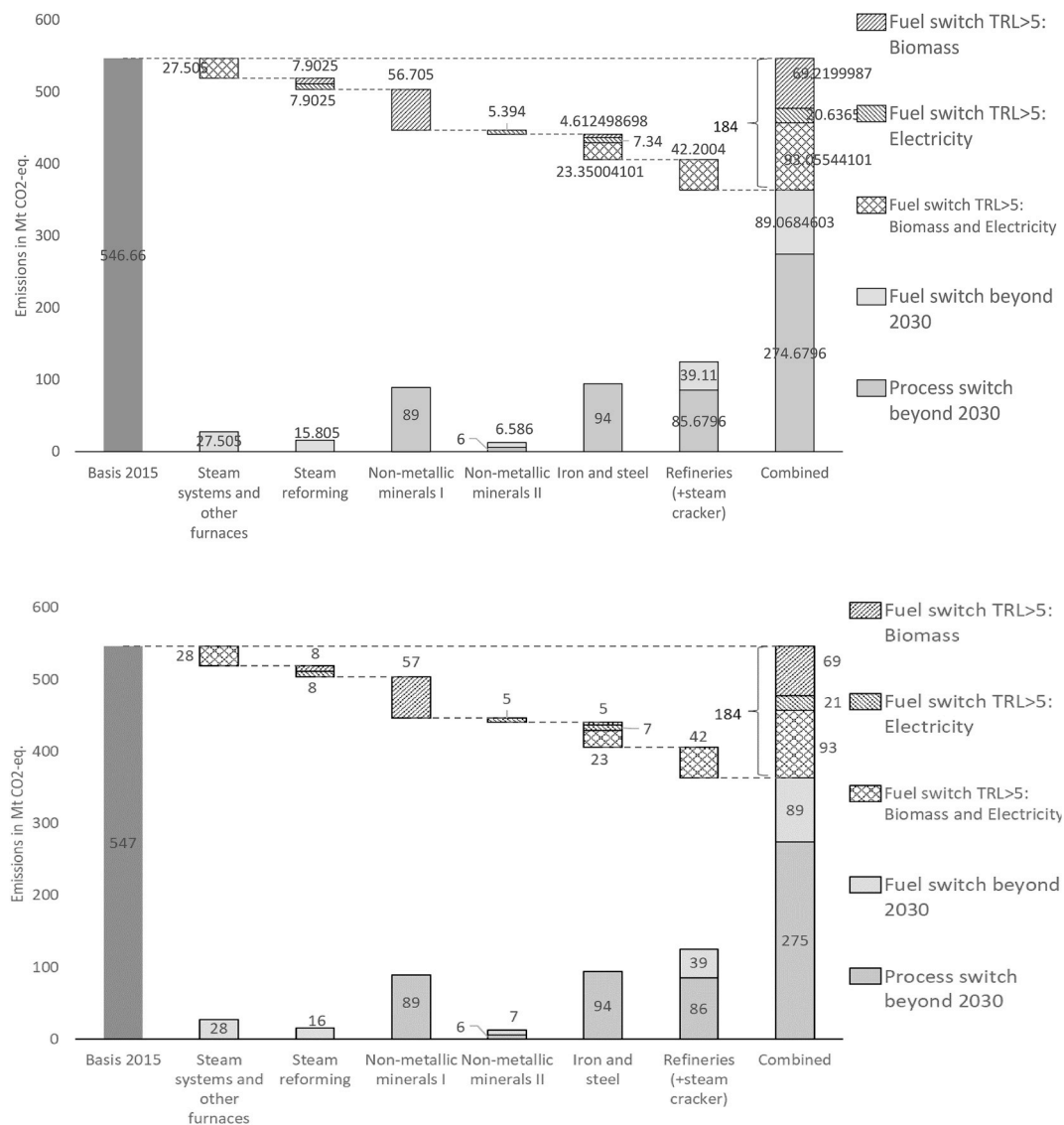
Fig. 2. Estimated GHG-emission reduction potential (by technology), (*potential for emission reduction in existing industrial processes using the selected fuel switch options; selected measures are technically available and deemed plausible to be implemented on meaningful scales until 2030; 'Beyond 2030' emissions are avoidable only after* 2030 by *fuel switching measures; 'Process switch' emissions cannot be mitigated with fuel switch measures but require radical process changes*).

electricity can only yield substantial emission reductions when the generation itself is based on renewable sources. Some scenarios [1] see renewables as dominant source of electricity already in 2030 (between 60% and 80% of generation). Still, a complete decarbonisation of the electricity supply is not expected before 2050 [108]. To facilitate the industry's decarbonisation based on electricity, rapid and ambitious deployment of renewable electricity generation is required.

The generation capacity of renewable electricity is limited. With the proposed measures, an additional electricity demand of 481 TWh would result (Table 6), of which the major part is located in steam generation (288 TWh) and refineries (122 TWh).[18] The electricity demand of the entire EU28 industry was 1004 TWh in 2015 [5]. A substantial increase in renewable generation is expected and deemed possible in transformation scenarios. Zappa et al. [109]: renewable generation ranging between 1400 and 3600 TWh in 2050; Öko-Institut, Fraunhofer ISI

[104]: more than doubled renewable generation in 2030 (320 TWh) compared to 2012 in Germany; Held [110]: EU28 potential of 1400–2000 TWh in 2050. There are considerable bandwidths of estimates, though. Estimates for wind power potentials for Germany speak of 2.400 TWh [111]. If we assume a realizable share of 50% of the 2050 potential until 2030, this correlates with the assumed doubling of renewable electricity generation mentioned in Ref. [104]. If the sector-split of electricity consumption remained the same (36.5% industry in 2015), these estimates would yield an additional potential available to industry between 250 TWh (lower estimate of 50% of 1400 TWh total) and 375 TWh (upper estimate of 50% of 3600 TWh total). This additional potential would align with a yearly capacity extension between 11 GW and 17 GW[19]. This is an unprecedented growth, with the highest capacity extensions between 2014 and 2016 reaching 5 GW–6.5 GW (onshore).

Even considering the intersection of biomass and electricity measures (around 300 TWh), the estimated 2030-potential of biomass and electricity does not cover the additional demand created by the

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[18] The high emission reduction potential (30 Mt) of the assumed shift to scrap/EAF steel production causes relatively little additional electricity demand (11 TWh), as its specific energy consumption, being a secondary route, is about 4 times lower than the blast furnaces' [12].

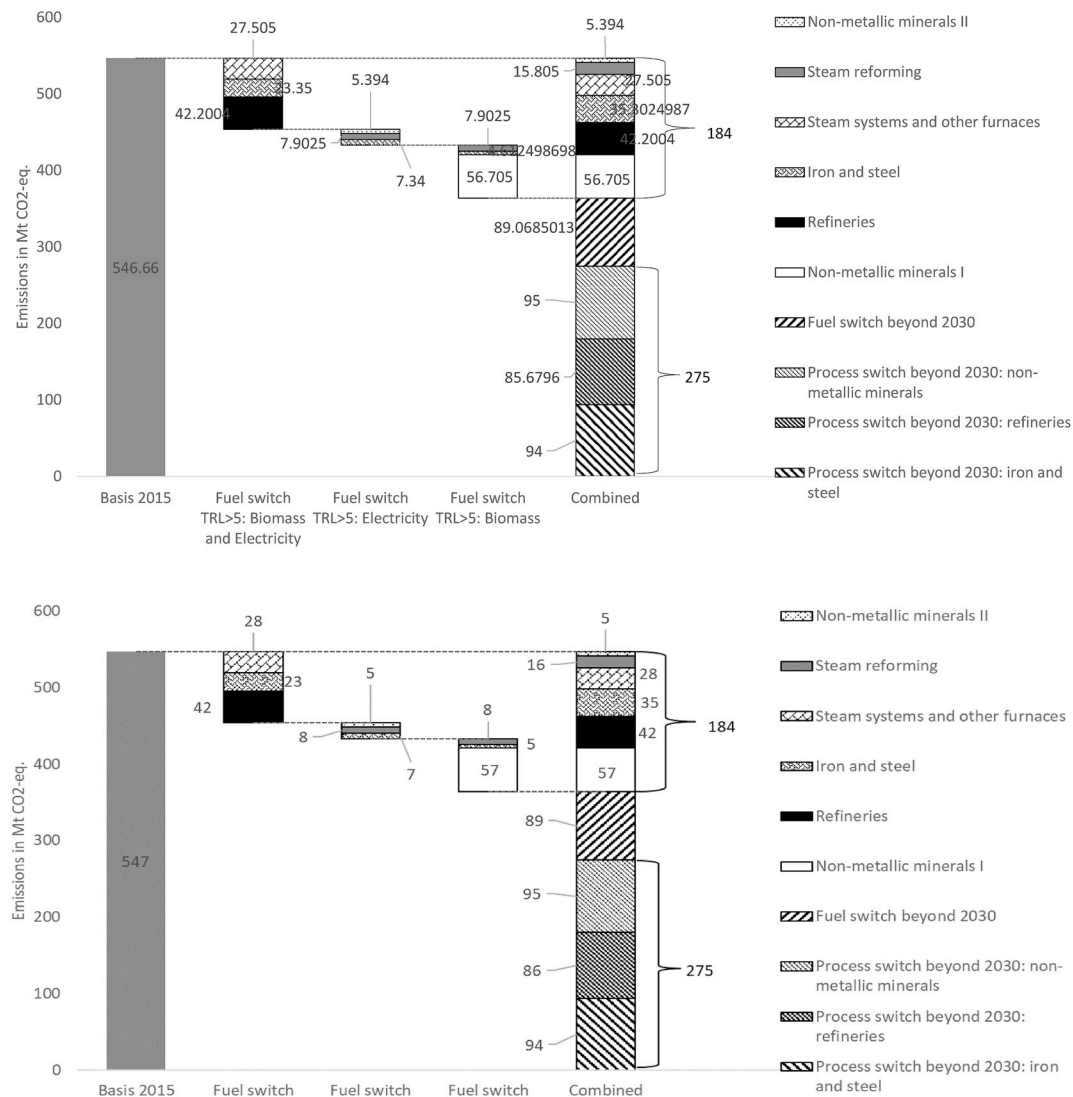[19] Assumed 2200 full-load hours per year based on [111].

Fig. 3. Estimated GHG-emission reduction potential II (by fuel switching option), (*potential for emission reduction in existing industrial processes using the selected fuel switch options; selected measures are technically available and deemed plausible to be implemented on meaningful scales until 2030; 'Fuel switch beyond 2030' emissions are avoidable only after* 2030 *by fuel switching measures; 'Process switch beyond 2030' emissions cannot be mitigated with fuel switch measures but require radical process changes still in development*).

presented fuel switch options. This highlights that a rapid transformation in the supply sector is an important factor for fuel switch in industry, as clearly, replacing natural gas with fossil-based electricity is not a sensible path to take.

We mentioned the economic challenges that are discussed in the literature. Apart from anecdotal examples, the additional costs incurred to the industrial energy system by these measures remain unclear. Especially the interactions of short-term fuel switching and innovative processes are of interest, for example how early fuel switching may support long-term innovative processes and how transition scenarios can combine both. There is not always a clear line between technical potential (which we focus on) and economical challenges. While we define the measures identified as plausible to be within technical availability today, relevant for emission reduction until 2030 and within the existing processes, there is uncertainty on what can be done in a given time frame. The use of biomass-based fuels or electricity in refineries, for example, is restricted by the availability of off-gases on site. If these found a sink elsewhere (e.g. as feedstock in the chemical industry), the identified restrictions would be removed. This is indeed predominantly an economic challenge. The same is true for the use of biomass-based fuels as feedstock in steam reforming, which we excluded

based on supply-side concerns. These assumptions are based on the authors' judgement.

The uncertainties involved with the chose methodology are considerable and the results can therefore only be a rough estimate. To include details neglected here (e.g. emission intensity of electricity generation and biomass supply, improvements in energy efficiency, activity changes and general economic development, policy measures, impact of discussed measures on energy efficiency and process emissions), further work should include quantitative investigations in an energy system model.

6. Conclusion

This paper investigates technical options to switch from fossil fuels to biomass or electricity-based heating in selected, important industrial processes. The analysis focuses on mitigation measures that are technically available today and can have a relevant impact until 2030. Fuel switch measures discussed in the literature are reviewed and a combined emission reduction potential for the investigated processes is calculated. Based on the reviewed literature, technology-readiness levels (TRLs) are estimated. Measures above TRL 5 are included in the analysis.

Table 4
Biomass and electricity emission saving potential[e] and residual emissions.

Subsector	Main activity (EU ETS)	Products	Main energy carrier	Heating technologies	Emissions 2015	Reduction potential biomass[a]	Reduction potential electricity[a]	Reduction potential combined [b]	Beyond 2030[d]	Process switch[c]	Share on remaining
					Mt CO$_2$-eq.						
Refineries	Refining of mineral oil	Mineral oil products	Oil	Distributed furnaces	128	42	42	42	–	86	24%
Iron and steel	Production of pig iron or steel	Oxygen steelmaking	Coal	Blast furnace, converter	115	27	31	37	7	71	22%
		Electric steelmaking	Electricity	Electric arc furnace		–	–	–	–	–	0%
	Production of ferrous metals	Rolling	Coal, natural gas	Furnaces	12	6	6	6	6	–	2%
		Other reshaping	Natural gas	Furnaces						–	
		Heat treatment	Natural gas, electricity	Furnaces						–	
	Production of coke	Coke	Coal	Coke oven	12	–	–	–	12	–	3%
	Metal ore roasting or sintering	Sinter	Coal, derived gases	Sinter oven	3	1	–	1	2	–	0%
Non-metallic minerals I	Production of cement clinker	Clinker	Diverse fossil	Rotary kiln	114	45	–	45	–	70	19%
	Production of lime	Lime	Diverse fossil	Shaft kiln	31	12	–	12	–	19	5%
Non-metallic minerals II	Manufacture of glass	Flat glass	Natural gas	Float glass furnace	18	–	5	5	7	2	3%
		Container glass	Natural gas	Melting furnace						1	
		Other glass	Natural gas	Melting furnace						0	
	Manufacture of ceramics	Ceramics	Natural gas	Furnaces	16	8	8	8	5	3	2%
Basic chemicals	Production of ammonia	Ammonia	Natural gas	Steam systems	32	8	8	16	16	–	4%
	Production of synthesis gas	Synthesis gas	Natural gas	Steam reformer						–	
	Production of bulk chemicals	Ethylene	Naphtha, natural gas	Steam cracker	39	–	–	–	39	–	11%
		Methanol	Natural gas	Steam systems						–	
Pulp and paper	Production of paper or cardboard	Paper, cardboard	Natural gas, biomass	Steam systems	22	11	11	11	11	–	3%
	Production of pulp	Pulp	Natural gas, biomass	Steam systems	5	3	3	3	3	–	1%
Sum					547	162	114	184	109	251	100%

[a] Only individual measures, ignoring overlap. Electricity and biomass potential cannot be summed up.
[b] Excluding overlap of electricity and biomass measures.
[c] Emissions that cannot be avoided by fuel switch measures in existing processes (process emissions, required energy carriers).
[d] Emissions that are assumed not to be avoidable until 2030 e.g. due to stock inertia (but may be later).
[e] Definition of potentials (see also Fig. 2): Potential for emission reduction in existing industrial processes using the selected fuel switch options. The selected measures are available on the market and deemed plausible to be implemented on meaningful scales until 2030.

Table 5
Estimation of biomass demand of the reviewed fuel switch options.

Process	Measure	Energy demand 2015 [TWh]	of which biomass	Additional biomass demand by 2030 [TWh][c]	Potential coverage with biomass by 2030[d]	Sustainable biomass available [TWh]
Refinery	Replacement of natural gas	527[a]	0	158	30%	
Iron production	Replacement of PCI with biomass (blast furnace) Biomass in coke production Replacement of coke breeze with biomass in sintering	452[b]	0	180	40%	
Clinker production	Substitution of fossil fuels with biomass in rotary furnaces	175[b]	10	165	100%	
Lime production	Substitution of fossil fuels with biomass in shaft furnaces					
Steam reformer	Biomass gasification for fuel supply	64[b]	1	15	25%	
Steam generation and furnaces	Biomass boilers, biomass fired furnaces	595[b]	168	130	50%	
Sum		1813	179	648	46%	250–490

[a] Based on [5].
[b] Own calculations based on [5] and FORECAST model (see Ref. [107]).
[c] Resulting from fuel-switch measures considered in this paper.
[d] Assuming constant energy demand (no activity of efficiency changes).

Table 6
Estimation of electricity demand of the reviewed fuel switch options.

Process	Measure	Energy demand 2015 [TWh]	of which electricity	Additional electricity demand by 2030 [TWh][c]	Potential coverage with electricity by 2030[d]	RES-E potential available to industry [TWh]
Refinery	Replacement of natural gas	527[a]	36[a]	122	30%	
Steel production	Shift to secondary route (EAF)	584[a]	112[a]	11	21%[e]	
Glass production	All-electric furnaces	110[b]	25[b]	44	63%[f]	
Steam reformer	Electro-thermal reforming	64[b]	0[b]	16	25%	
Steam generation	Electric/biomass boilers	595[b]	10[b]	288	50%	
Sum		1880	183	481	35%	250–375

[a] Based on [5].
[b] Own calculations based on [5] and FORECAST model (see Ref. [107]).
[c] Resulting from fuel-switch measures considered in this paper.
[d] Assuming constant energy demand (no activity of efficiency changes).
[e] EAF share of 50% on steel production. Electricity share on total energy demand is lower due to different specific energy consumption compared to the primary route and other electricity uses.
[f] 40% emission reduction with 50% of furnaces capacity electrified. Share of electricity is higher due to other electricity consumption.

We found that of the 546 Mt CO_2-eq. emissions of the investigated industrial processes, 34% (184 Mt CO_2-eq.) could technically be mitigated with the identified short/medium-term fuel switch measures towards biomass or electricity by 2030. The use of biomass alone shows a potential of 162 Mt emission reduction, with the most important measures being the injection of biomass in the blast furnace (instead of pulverized coal), biomass use in rotary kilns in the cement and lime production as well as for synthesis gas for ammonia and methanol production. Electrification could realize 114 Mt CO_2-eq. emission reductions. Its potential is highest in the iron and steel industry (increased secondary steel production in EAF). Moreover, electricity may supply steam generation boilers and furnaces in other applications (e.g. melting, reheating). The potentials of biomass and electricity overlap by 92 Mt CO_2-eq.

Fuel switch to electricity and biomass can make a substantial contribution to achieve a reduction by 2030 in line with 1.5 °C warming, but very likely needs to be accompanied by additional measures like energy efficiency, more efficient material use and recycling of materials.

The reduction potentials investigated include measures that are technical available but not economically competitive today and determined effort is needed to integrate them into the market. In the period after 2030, innovative CO_2-neutral production processes will need to diffuse quickly to remain on a 1.5 °C path towards 2050. The identified fuel switch measures on the demand side exceed estimates of available sustainable biomass and electricity supply in 2030. While these estimates are rough, this highlights that the supply side, especially renewable electricity generation, plays a key role in enabling fuel switch in industry. This includes unprecedented growth in renewable electricity generation, e.g. of wind power.

Innovative processes would have to address an amount of emissions that is not reachable with fuel switch (275 Mt), consisting of fuel inflexibility of existing processes and process-related emissions. Another amount (89 Mt) may not be mitigated before 2030 due to restrictions in stock exchange and feedstock availability. Additional potential could be realized by the early replacement (in contrast to natural stock exchange) of fossil steam generation installations and the availability of biomass-

based fuels in high quantities for feedstock.

Considering all the identified measures, substantial GHG emissions remain, mainly consisting of process related emissions (e.g. cement and steel production) and residual fuel use (e.g. refineries, petrochemical industry). To address these emissions and achieve deep decarbonisation of industry after 2030, new feedstocks and process switch to CO_2-neutral technologies (e.g. new cement types, bio-refinery) are necessary among others. The use of carbon capture and storage (CCS) can bridge the gap until these technologies mature. Specifically in the construction sector, where the implementation of new cement types is slowed by safety concerns and regulation processes, CCS may contribute to mitigation of emissions not addressable by fuel switch. The compatibility of short, medium- and long-term measures is another important topic to address in future research.

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Declaration of competing interest

None.

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