Hydrogen for the de-carbonization of the Resources and Energy Intensive Industries (REIIs)

STUDY

European Economic
and Social Committee

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Final report

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Abstract

This study deals with the use of hydrogen for the de-carbonization of the Resources and Energy Intensive Industries (REIIs) and gives a specific insight of the situation of the steel-making industry.

The growing use of hydrogen in our economy is synonym for an equal increase in electricity consumption. This results from the fact that the current most promising technologies of H2 production is water electrolysis. For this purpose, the EU hydrogen strategy foresees a progressive ramp up of H2 production capacities. But bottlenecks (especially regarding energy needed for electrolysers) may occur. Capacities should reach 40 GW (around 10 Mt/y) by the end of 2030.

The steel-making industry relies heavily on H2 to decarbonise its process (through direct iron ore reduction). Our study analyses the conditions under which this new process will be able to compete with both European and offshore existing carbonised assets (i.e. blast furnaces). It emphasises the need for integrated and consistent policies from carbon prices to the carbon border adjustment mechanism through carbon contracts for differences but also highlights that a better regulation of electricity prices should not be neglected.

Executive Summary

The current worldwide hydrogen market is characterised by two main aspects.

First, demand is mainly driven by the need of refining and chemicals sectors for which hydrogen is used in their own process (especially for ammonia production and oil refining, 72 Mt/y, million tons per year). Consequently, captive and by-product productions account for most capacities. For instance, in Europe, on a total of 10,5 Mt/y in 2019, on-site captive hydrogen production (i.e production of hydrogen for own consumption) was by far the most common method of hydrogen supply (72% of the production). By-product production was estimated at 14%.
Secondly, the merchant sector of hydrogen is so far relatively small. Merchant production represents only 14% of the European production and the demand of hydrogen for other sectors than chemicals and refining is limited. For example, worldwide current demand of hydrogen by the iron and steel sector represents only 5 Mt/y.
In terms of carbon footprint, the current capacities are mainly based on fossil resources. Globally, natural gas and coal remain the main fuel for hydrogen production with respectively 60% and 20%. Water electrolysis represents currently marginal capacities: the production through this route account for less than 1% of the total production.

The EU Hydrogen Strategy (July 2020) and the European Clean Hydrogen Alliance (November 2020) emphasise the use of hydrogen in industry and heavy transport as well as its balancing role in the integration of variable renewables. Electrolytic hydrogen from renewable sources is considered the main path forward for hydrogen production, although the role of other low-carbon technologies in the near term is recognised as the hydrogen market develops and scales up, and the cost of electrolytic hydrogen decreases (IEA, 2021).

The Hydrogen Strategy foresees three phases for hydrogen adoption:

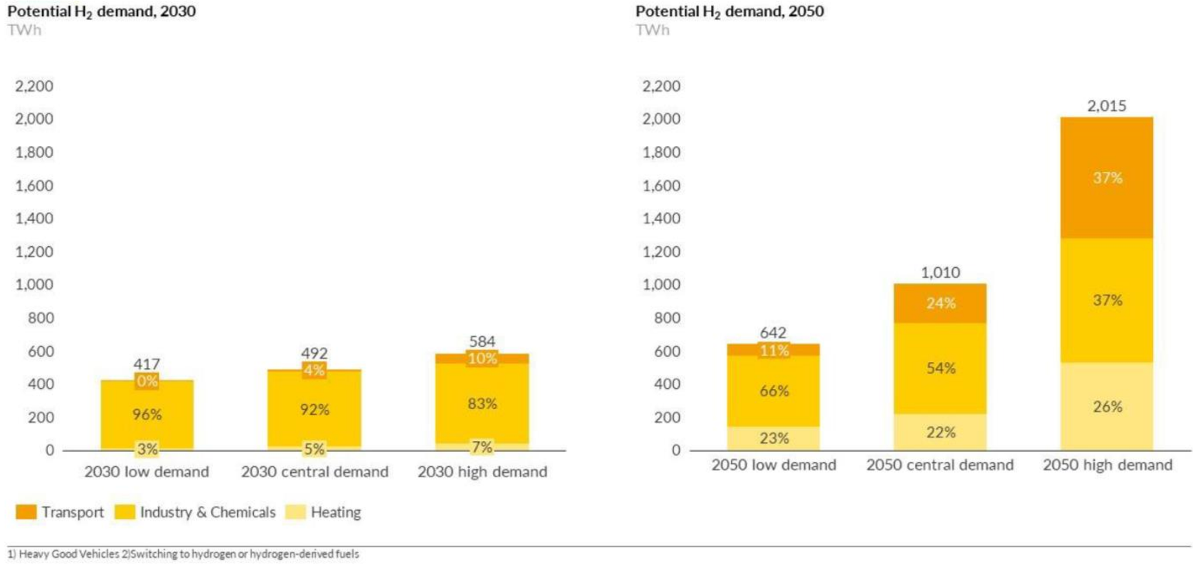
- The first phase, up to 2024, focuses on scale-up, with an interim target of 6 GW (~ 1.5 Mt/y) of renewable energy-powered electrolysis to decarbonise current production capacity. With a 6 GW capacity, up to 33 TWh of renewable hydrogen could be produced. These assumptions are based on an electrolyser efficiency of 70% and a regular load factor.
- In the second phase (2025-2030), hydrogen should become cost-competitive and reach new applications (steelmaking or shipping). By 2030, **40 GW** of renewable energy-powered electrolysis should be installed
- In the third phase, after 2030, renewable hydrogen technologies should reach maturity and be deployed on a large scale.

The forecast for hydrogen demand varies from one study to another (widely concerning forecast for 2050), but they all project a steep increase in Europe in the future**. For instance, Aurora Energy Research forecasts a demand between 417 and 584 TWh (HHV[1]) for hydrogen in 2030, depending**

[1]Higher Heating Value

on the scenario[2] **considered. For 2050, it estimates the potential to reach between 642 and 2 015 TWh (HHV) hydrogen demand (representing between 7 to 21% of total energy demand) by 2050 across the EU (Aurora Energy Research, 2021).**

Hydrogen forecast according to Aurora Energy Research by sector in 2030 and 2050



Source: Aurora Energy Research, 2021

Platts Analytics assessed that such volumes would require additional renewable power generation amounting to 477 TWh (S&P Global Platts Analytics, 2021).[3] In this analysis, Platts Analytics assessed that the nature of the targeted sectors according to the Fit for 55 package means much of the hydrogen will need to be converted to ammonia, leading to large conversion losses.

Economically speaking, the current gap between the cost of fossil hydrogen and renewable hydrogen is approximately €3/kg (€1,4/kg for grey hydrogen vs a range from €3.40/kg to €6.60/kg for green hydrogen). This gap might be closed by learning process and an increase in Co2 price.

For the steel sector, hydrogen will be a key lever of decarbonisation because **it** can be used as a direct reduction agent of iron ore and can replace coal. Among all the technologies in development, the direct iron ore reduction and electrical arc furnaces route of production (DRI-EAF) is the most promising. But there is one fundamental condition: hydrogen should be produced itself through a decarbonised route (meaning most probably by water electrolyse). Some projects have already been announced or planned by steelmakers (Hybrit project from SSAB, the recent announcement regarding Dunkirk and Fos-sur-Mer from Arcelor).

Our study aims to monitor three different aspects of a future European steel-making industry based on DRI-EAF process.

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[2] Aurora considers three scenarios: a conservative scenario, where all hydrogen uptake is slow across all countries and plays a small part in meeting overall energy demand, an optimistic scenario, where hydrogen plays a key role in decarbonising the economy, and an average of the two.

[3]**According to EDF, a nuclear reactor with a nominal capacity of 900 MW produces on average 6 TW/h per year. Thus, it might represent the equivalent of 80 nuclear reactors**

First, the needs of hydrogen and, if this hydrogen is produced through water-electrolysers, the resulting electrical needs; our conclusions must be understood as a maximum considering the strong hypothesis used for our calculation. Nevertheless, it shows how ambitious the target of a whole green-steel industry in Europe is.

('000 Mt H2 requirements)	**SHIFT FROM TRADITIONAL BLAST FURNACES (BOF) TO H2-BOF ROUTE (A) + SHIFT FROM TRADITIONAL EAF TO DRI-EAF ROUTE (B)**	**SHIFT FROM TRADITIONAL BF-BOF & EAF ROUTES TO DRI-EAF ROUTE (C)**
Potential need for hydrogen taking into account the total steel production capacity	4.8-7 million tonnes, depending on the amount of scrap and Hot-Briquetted Iron (HBI) used	4.5-9.3 million tonnes, depending on the amount of scrap and HBI used
Adjusted H2 needs based on the utilisation rate of production plants[4], use of renewable hydrogen[5] and gradualness of the process	2.6-3.9 million tonnes (depending on the share of scrap and HBI).	2.5-5.6 million tonnes (depending on the share of scrap and HBI)
Energy requirement[6]	124-186 TWh	120-267 TWh

The first scenario presented could be seen as transitional, as by 2050, the goal is to reach climate neutrality. A hypothetical full transition of the European steel industry[7] to the DRI-EAF route based on green hydrogen would result in an estimated hydrogen need of around 2.5-5.6 million tonnes, in function of the percentage of scrap used. These results would imply an additional energy demand of 120-267 TWh.

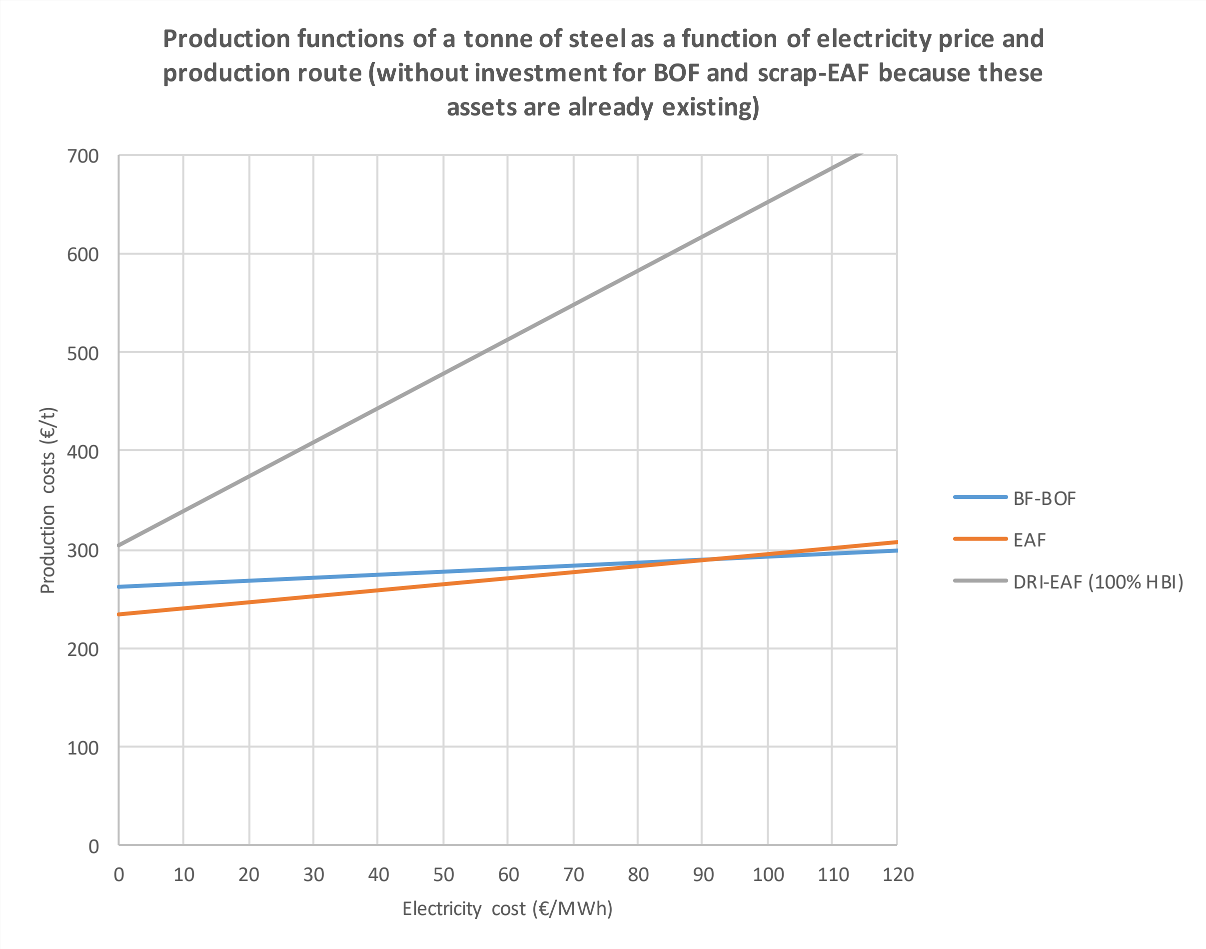
Therefore, the main economic characteristic of a steel-making industry based on the use of hydrogen is its exposure to electricity's price, which will be basically common to all REEIs or industries using hydrogen. Even if current electrical arc furnaces are more electricity intensive that BOF, the intensity of DRI is far higher and the comparison must be done between EAF-DRI on the one hand and BOF & EAF on the other hand.

[4]Applying 2021 utilisation rate (80%)

[5] Considering that not all projects to decarbonise the steel industry revolve around green hydrogen, but that other types of low-carbon hydrogen are also developed, these estimates of green hydrogen needs would also be reduced, i f, as shown above, it can be estimated that 70% of this hydrogen will be green hydrogen by 2050 (IEA).

[6] According data from S&P Global Platts.

[7]Calculations have been made on the basis of current capacities, with the knowledge that European demand is expected to grow considerably in the short and medium term.



Finally, shifting to the EAF-DRI route requires that these assets become competitive compared to current BOF (and to some extent current EAF) assets wherever they are located. CO2 costs are playing a key role in this perspective. Our conclusions include:

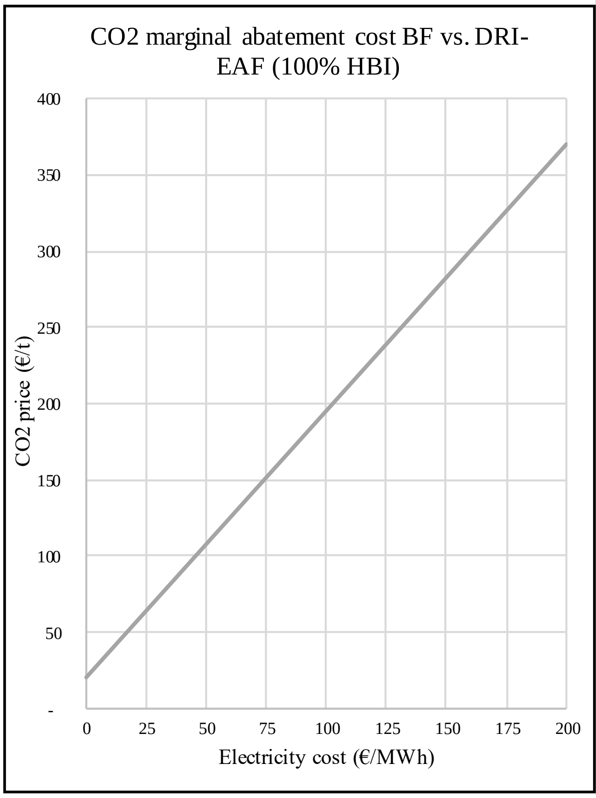
a) The CO2 marginal abatement cost of existing steel-making asserts compared to DRI-EAF
b) The couple of CO2 marginal abatement cost and electricity prices which allow DRI-EAF to be competitive compared to BF existing assets

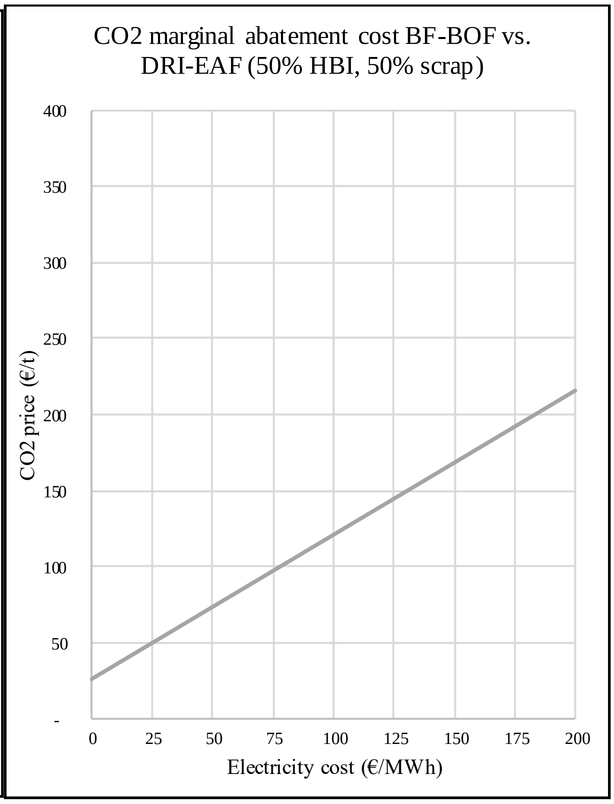
These two models present a first and a rough estimation of the evolution of ETS (and following tools) requiredto give a plausible perspective the decarbonisation of the steel-making industry while avoiding any further carbon leakage.

	CAPEX (€/t)
BF RELINING	48.3
BF/BOF GREENFIELD	442
DRI-EAF	577

CO_2 marginal abatement cost (€40/MWh)	**CO_2 marginal abatement cost (€60/MWh)**
90	125
70	105

Source: Syndex calculations from investment data of Vogl, V. et al (2018).[8]





Our model allows to underline some policy recommendations, relevant in the specific case of the steel industry but generalisable to all REEIs and to the future of the entiregreen hydrogen industry. We present these recommendations in the core of the study. But among them, two will have a crucial role in ensuring a just and carbon leakage free decarbonisation: the carbon border adjustment mechanism (CBAM) and carbon contracts for differences (CCFD). These two tools should ensure a continuous and predictable growing CO2 price, for domestic production and importations. It must be noted that CBAM may include indirect emissions (in a second phase, according to the proposal of the Commission), but further studies must be concluded to measure the risk of resources shuffling (even if steel industry appears to be little concerned by this risk).

However, our two graphs show that the CO2 price is only one side of the equation. Electricity prices present the second side. The use of hydrogen and its clean production need most certainly a more stable energy market. The current merit order uses a marginal approach to fix the (spot) prices. Fluctuant and heavy prices may weaken decarbonisation processes. Besides, this marginal price includes itself the CO2 price (because the marginal approach implies that the last plant called is usually a carbonised one). It may hamper the competitivity of European industry compared to importations… until the decarbonisation of the whole generation of electricity is achieved: an example of the "chicken or egg" dilemma.

[8] We estimate for all investments a useful life of 15 years and an applied discount rate of 5%.

Introduction

We are very pleased to present our final report. Some aspects of this study are worth being highlighted from the introduction, especially considering the industrial hypotheses we use.
Production cost functions are simplifications of reality and are not totally exhaustive (for instance, and to ensure possible comparison on a global scale, we do not include taxes, C&B etc). Besides, iron ore and scrap prices are fixed. Our reasoning is based on a *ceteris paribus* where only electricity and CO_2 prices are variables. It draws a picture where EAFs are always more competitive than BFs. This is not reflecting the reality.
We do not fully consider quality issues — in reality you can’t really shift equally from scrap to DRI and vice versa in an EAF. The same kind of comments can apply to our estimations of premium of pellets over fines which are very volatile and difficult to monitor precisely.
This draws a clear picture: we are voluntarily over evaluating the competitiveness of an EAF-DRI asset so that our abatement indicates the minimum ETS price needed/ maximum electricity price, allowing European production rather than BF importation (even corrected by CBAM).
Moreover, CAPEX is also considered through discounted approach with a rate of 5% interest rate; ECB policies might change the rate of risk-free asset in a strong inflation context. We want to raise the reader’s attention to this issue: increasing interest rate will discourage greenfield investment such as DRI-EAF.
Finally, it’s also important to keep in mind that ETS and electricity price are not independent variables: ETS price has an impact on the price of electricity throughout the UE as long as carbonised power plants are used. We present the fundamentals of the European energy market on chapter 2.B
From our calculation, raising the carbon price floor and a reflexion around possible reforms of the electricity market in Europe are key vectors to ensure competitiveness of a decarbonised steelmaking industry in Europe. Some papers compared scenarios confronting DRI-EAF and different kinds of BF relining (necessary for European assets). In the current context of extra-European over-capacities, we think that future European DRI-EAFs will rather have to compete with overseas existing BFs (and EAFs). The risks of deindustrialisation of Europe are thus still important if electricity price continues to skyrocket even with an ETS at 100€/t.
The last geopolitical issues (especially in Ukraine) are also drawing a sombre background while we are publishing this study. Unfortunately, the war will have human consequences (of course the worst consequences), political consequences but also market consequences and disruptions for raw materials and energy.

Chapter 1: How the hydrogen industry is shaped and how hydrogen shapes REIIs

A. H2 production

A.1. Current H2 production capacity

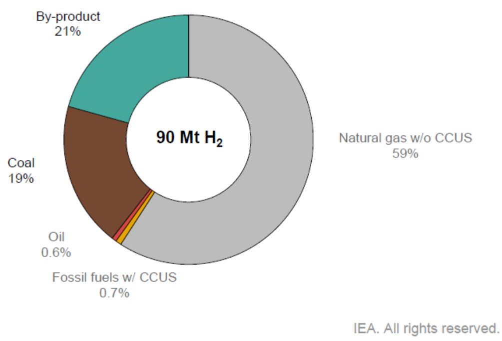
According to the IEA, the global hydrogen demand of 90 Mt in 2020 was met almost entirely by fossil fuel-based hydrogen (IEA, Global Hydrogen Review, 2021):

- 79% from dedicated hydrogen production plants.

- 21% as product hydrogen produced in facilities designed primarily for other products, mainly refineries in which the reformation of naphtha into gasoline results in hydrogen.

- Pure hydrogen demand, mainly for ammonia production and oil refining, accounted for 72 Mt H2, while 18 Mt H2 was mixed with other gases and used for methanol and DRI steel production.

Sources of hydrogen production, 2020



Note: CCUS = carbon capture, utilisation and storage.

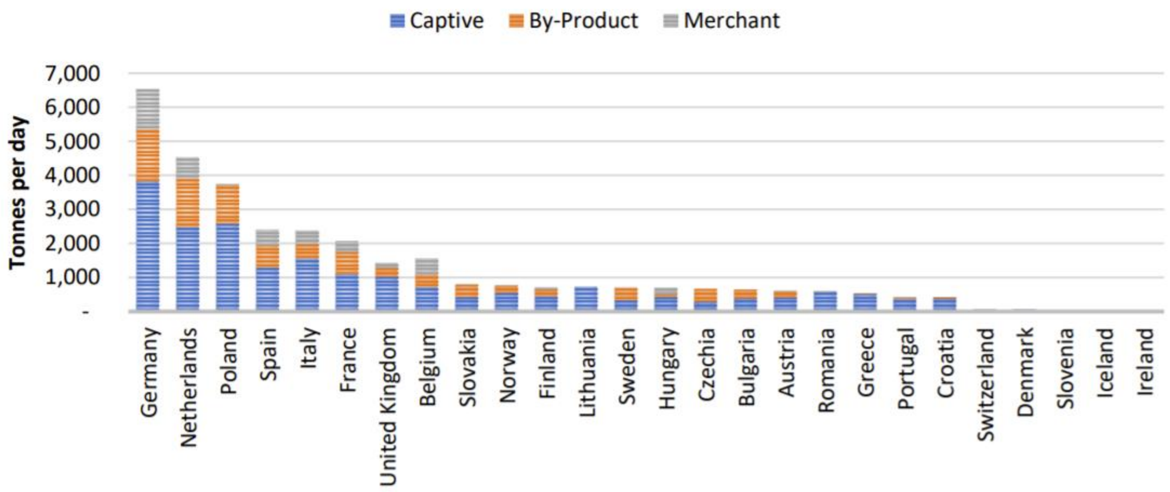
Globally, natural gas remains the main fuel for hydrogen production with 60% of hydrogen produced through this means (representing 6% of global gas demand in 2020). Indeed, in the refineries and the ammonia and methanol industries steam methane reformation is the dominant method used. 115 Mtce of coal (2% of global demand) accounted for 19% of hydrogen production (mainly in China). Low-carbon hydrogen account for a very small share of global production: at 30 kt H2, water electrolysis made up 0.03%, and 16 fossil fuels with CCUS plants produced just 0.7 Mt H2 (0.7%).

In Europe, the Fuel Cells and Hydrogen Observatory (FCHO, Hydrogen Supply and Demand, 2021) estimated the total hydrogen production capacity in the EU, Switzerland, Norway, Iceland and the United Kingdom at the end of 2019 at 10.5 Mt/y. The level reached 12.1 Mt/y if hydrogen from coke ovens is included.

The corresponding consumption of hydrogen has been estimated at 8.4 Mt, which means an average capacity utilisation of 80% in 2019. The Fuel Cells and Hydrogen Joint Undertaking evaluated that

Europe currently uses 339 TWh of hydrogen per year (FCH JU, 2019). The EIA, however, estimated that close to 7 Mt H2 was produced and used solely in the European Union in 2020.

On-site captive hydrogen production, i.e. production of hydrogen for own consumption, was by far the most common method of hydrogen supply, with 7.6 Mt/y of all hydrogen production capacity (72%). By-product production was estimated at 1.5 Mt/y and merchant production, i.e. hydrogen production dedicated for sales, at 1.5 Mt/y. Each constitutes 14% of production capacity.



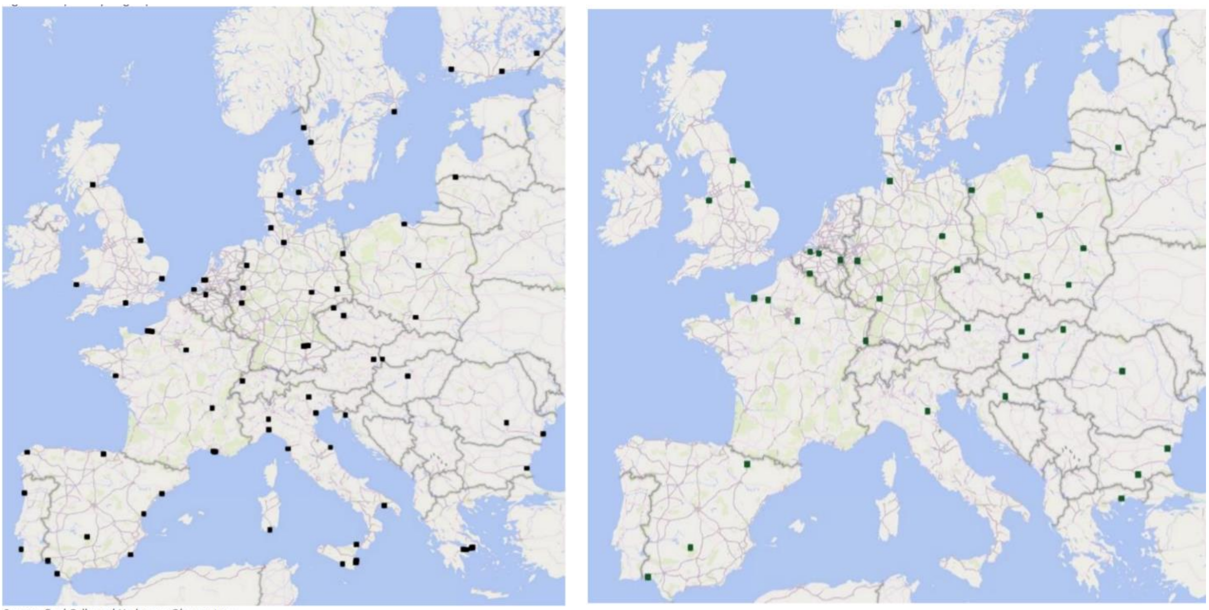
Source: Fuel Cells and Hydrogen Observatory

Germany has the largest hydrogen production capacity by far with almost 2.4 Mt/t (20% of total[9]). The Netherlands follows with 1.7 Mt/y (14%). Other countries have significant hydrogen production capacity: Poland (1.4 Mt/y, 11%), Spain (0.9 Mt/y, 7%), Italy (0.9 Mt/y, 7%) and France (0.8 Mt/y, 6%).

In terms of sector, **oil refining** is the biggest producer (and consumer) of hydrogen in the EU. The sector uses hydrogen mainly in refineries for hydrotreating (for diesel refining) and hydrocracking processes, with the latter being the most hydrogen intensive. Plants with complex hydrotreating and/or hydrocracking operations require more hydrogen than is produced, since by-products typically have dedicated hydrogen generation units (HGUs). All large EU refineries use fossil fuels (most commonly natural gas) as a feedstock to produce hydrogen. According to the FCHO, the total captive production capacity of HGUs installed at refineries is approximately 3.4 Mt/y, divided between 93 facilities.

[9] Including hydrogen from coke ovens, i.e. 12.1 Mt/y nominal capacity.

Hydrogen production units installed at refineries (left) and for ammonia production (right)[10]



Source: Fuel Cells and Hydrogen Observatory

The **ammonia industry** is the second largest producer of hydrogen in the EU, since the ammonia production process involves a synthesis of hydrogen with nitrogen. In Europe, ammonia-related production was split between 36 facilities and in 2019 had a capacity of approximately 3.5 Mt/y. For both industries, Germany accounted for the biggest share of hydrogen production of (between 16% and 17%), followed by Italy for refining (11%) and the Netherlands for ammonia production (15%). Those two industries represent 91% of hydrogen production that is not used for sales or as a by-product. The rest of the captive capacity of hydrogen is used for other chemicals, mainly the production of methanol.

Hydrogen plants dedicated to **sale hydrogen** had an estimated capacity of 1.5 Mt/y in 2019. The size of plants dedicated to sale hydrogen varies significantly according to the end user. Indeed, the installations designed for the hydrogen retail market are smaller — in terms of their maximum capacity — than the dedicated installations for supplying single large-scale consumers. Again, Germany has the largest capacity with 29% of the total for the EU+EFTA+UK. Production is also very concentrated, with four groups dominating the market with 90% of the capacity (Linde Gas, Air Liquide, Air Products and Messer).

Capacity to produce hydrogen **as a by-product** is estimated at 3.1 Mt/y, with more than half coming from coke oven gas and the rest from refining (which also produces hydrogen as a by-product) and other chemicals.

Production capacity for low-carbon hydrogen is still very low. Steam reforming of natural gas (SMR) is by far the dominant method of production, followed by partial oxidation and autothermal reforming.

[10] Excluding production specifically dedicated to sales

Natural gas remains the most common feedstock. In 2019, the FCHO counted only three hydrogen production plants using fossil fuels utilised carbon capture technologies, representing 0.04Mt/y (circa. 0.5% of the total hydrogen generation capacity).

Identified plants with CCS/CCU production capacity

Company	Country	Description
Grupo Sappio	Mantova, Italy	Capacity around 1500 Nm3/h, started in 2016
Air Liquide	Port Jerome, France	Cryocap installation: capture CO_2 from hydrogen supplied to the Exxon refinery, started in 2015
Shell	Rotterdam, Netherlands	Refinery where CO2 is captured and sold for agricultural use since 2004.

There are several existing, small-scale units of production, which makes tallying difficult.
By the end of 2019, the FCHO identified 95 operational power-to-gas (where electricity is used to produce hydrogen via water electrolysis) projects. This would account for about 92 MW, equalling a hydrogen generation capacity of ~15 Kt/year, i.e.0.14% of total production capacity, bearing in mind that some of those projects are designed as demonstrators and for R&D purposes. For its part, the IEA found in 2021 that more than 140 MW of electrolysis for dedicated hydrogen production is installed in the EU. The IEA assessed that EU countries currently hold more than 40% of global electrolysis manufacturing capacity, albeit small (IAE, 2021).

A.2. Ongoing projects (greenfield projects)

The EU Hydrogen Strategy (July 2020) and the European Clean Hydrogen Alliance (November 2020) emphasise the use of hydrogen in industry and heavy transport as well as its balancing role in the integration of variable renewables. Electrolytic hydrogen from renewable sources is considered the main path forward for hydrogen production, although the role of other low-carbon technologies in the near term is recognised as the hydrogen market develops and scales up and the cost of electrolytic hydrogen decreases (IEA, 2021).

The Hydrogen Strategy envisages three phases for hydrogen adoption:

- The first phase, up to 2024, focuses on scale-up, with an interim target of 6 GW (~ 1.5 Mt/y) of renewable energy-powered electrolysis to decarbonise current production capacity. With a 6 GW capacity, up to 33 TWh of renewable hydrogen could be produced. These assumptions are based on an electrolyser efficiency of 70% and a regular load factor.

- In the second phase (2025-2030), hydrogen should become cost-competitive and reach new applications (steelmaking or shipping). By 2030, **40 GW** of renewable energy-powered electrolysis should be installed

- In the third phase, after 2030, renewable hydrogen technologies should reach maturity and be deployed on a large scale.

The 40 GW of renewable energy-powered electrolysis must be put in perspective with the 140 MW mentioned above. The production capacity of low carbon hydrogen should, therefore, grow exponentially in the next nine years to reach this target.

The IEA has identified nearly a thousand of low-carbon hydrogen capacity projects in the EU. This covers a wide variety of projects; some of which are still at the feasibility studies stage while others are already operational or under construction. The scale also varies widely from small demonstrators or production units (few tonnes of H2 a year) to large-scale units of several thousands of kilotonnes per year.

Nevertheless, the pipeline of projects currently under development accounts for more than 20 GW by 2030, with an additional 11 GW from projects at very early stages of development (IEA, 2021). More than 1 GW is already under construction or has funding committed. While the current project slate may not meet the EU target, the number of projects is expanding and the gap is shrinking.

The current pipeline of projects for producing hydrogen from fossil fuels with CCUS will amount to more than 7 Mt CO_2 captured, with3 Mt CO_2 more if accounting for the projects at early stages of development. However, those figures have to be used carefully since several projects are large CCUS hubs that will involve activities beyond hydrogen production, and it is, therefore, difficult to estimate the projected capture capacity linked to hydrogen production.

Examples of major European hydrogen projects[11]

Projects	Country/city	Description
Porthos	Netherlands/Rotterdam	A large CCUS project, Porthos aims to capture CO_2produced by four companies (Air Liquide, Air Products, ExxonMobil and Shell) in their facilities in Rotterdam's port area. The CO_2will then be transported by Porthos to empty gas fields in the North Sea seabed for storage. The Dutch government has already committed €2.1 billion in grant money.
Refhyne	Germany/Wesseling,	Funded by the Fuel Cells and Hydrogen Joint Undertaking (FCH JU), the project started in 2018 and aims to install a large PEM electrolyser (10 MW) in the Shell Refineries. It claims a forecast production of 1 300 tonnes of hydrogen per year.
Iberdrola and Fertiberia project	Spain/Puertollano	The project envisages a photovoltaic plant (100 MW), battery installation (20 MWh) and a large electrolytic hydrogen production system (20 MW), all operated by Iberdrola. The hydrogen will be used at the Fertiberia fertilizer plant in Puertollano to produce ammonia.

[11] The project dedicated to steel is developed in the second chapter.

A.3. Infrastructure needed (storage, grid and distribution)

Hydrogen deployment, especially on a high scale, will require an efficient system for storage and transport in order to connect supply sources to demand centres. Infrastructure needs, design and planning will be vastly affected by demand volumes, the location of infrastructure compared with the resources for producing low-carbon hydrogen (renewables and CO_2 storage sites), technologies used for production, and existing gas and electricity networks. Cost efficiency will play a key role (decentralised electrolytic hydrogen production could appear as the most efficient choice. However, some circumstances can make centralised production relying on hydrogen transport a more cost-effective choice).

The final use of hydrogen also has an impact on the needed infrastructure: whether it is used in producing end products (steel, chemicals), or to produce other transportable resources (synthetic fuel, ammonia); or whether hydrogen is itself the final product (to power transport for instance, or heating), which can be transported in gaseous or liquefied forms via pipeline or carriers. All these solutions will depend on costs.

Hydrogen can be transported either in gaseous form by pipelines and tube trailers or in liquefied form in cryogenic tanks. According to the IEA, pipeline is generally the most cost-efficient option for distances of <1 500-3 000 km, depending on pipeline capacity. For longer distances — mainly, but not only, import/export— alternatives such as transporting liquefied hydrogen, ammonia or LOHCs[12] by ship could be more attractive (IEA, 2021). Pipeline has the advantage of being a mature technology.

Hydrogen pipelines currently cover more than 5 000 km, with around 90% located in Europe and the United States (IEA, 2021). Currently, Europe has more than 1 600 km of hydrogen pipelines. They are mainly situated near industrial centres (refineries and chemical plants) and most of them work as closed systems owned by one large provider.

Nevertheless, hydrogen pipelines are capital-intensive projects that have high initial investment costs, which become sunk when the pipeline is laid. High costs and risk can hinder the development of such infrastructure, especially in the face of an initial low demand.

In the short to medium term, **blending hydrogen into natural gas pipeline** can function as a transition solution. However, there are still several technical and regulatory barriers to blending (parameters and regulations related to natural gas quality, purity requirements of certain end users).
The injection of low-carbon hydrogen into gas grids has grown largely in the last decade, but volumes remain low. In 2020, of the ~3.5 kt H2 that were blended in the world, almost all were in Europe and mainly in Germany (IEA, 2021). It accounted for close to 60% of injected volumes. In France, the GRHYD demonstration project is testing injection of up to 20 vol% H2 into the natural gas distribution

[12]Liquid Organic Hydrogen Carrier

grid of Cappelle-la-Grand (near Dunkirk). In Italy, the Snam project demonstrated the feasibility of blending up to 10% hydrogen in its transmission grid.

The other solution studied to avert/bypass the problem of cost-effectiveness of new dedicated hydrogen pipeline lies in **repurposing existing gas pipelines systems as dedicated hydrogen networks**. The assessment of the gap between new infrastructure and converting existing ones diverge on the cost differential, but not on cost effectiveness. The latest plan of Germany's Transmission System Operator (TSO) Association estimates new-build hydrogen pipeline costs to be almost nine times higher than for gas pipeline conversion. Although gas-to-hydrogen pipeline conversion is rather limited, Europe (especially Germany and the Netherlands) is the region in the world that has made the most stride. . The HyWay27 study (PWC, 2021) estimates that it is four times more cost-effective to reuse existing natural gas pipelines.

The Gas for Europe study (Guidehouse, 2020) suggests conversion costs are 21-33% the cost of a new hydrogen pipeline. Of an expected 40 000 km of hydrogen pipelines in Europe by 2040, the study estimates 75% will be repurposed.

In 2018, Gasunie, in the Netherlands, was the first to finalise such a conversion: 12 km for a capacity of 4 kt H2/yr. In September 2021, the Dutch government announced an investment of EUR 750 million to convert parts of the existing gas network into hydrogen transport infrastructure. Gasunie has announced the development of a project with a throughput capacity of 10 GW for 2027, with the hydrogen network consisting of around 85% repurposed natural gas pipes.

In Germany, GRTgaz and Creos Deutschland launched the MosaHYc project to convert two existing natural gas pipelines into a 70-km pure hydrogen infrastructure. E.ON announced EUR 1 million of investments to convert a natural gas pipeline, part of its H2HoWi R&D project.

With respect to the EU, the proposed revision of the TEN-E regulation (European Commission, 2020) suggests ending support for natural gas pipelines to cover instead both new and repurposed infrastructure for dedicated hydrogen transport and large-scale electrolyser projects, linked to cross-border networks.

Low-carbon hydrogen deployment will need **storage solutions** to enhance energy system flexibility (balancing short-term supply and seasonal demand variability). The practice of storing hydrogen in salt caverns has been in use since the '70s (3 in the US, 1 in the UK). Several pilot projects are under development in Europe. Another solution currently being experimented on a small scale is the use of depleted fields. This method requires storing a blend of 10% hydrogen and 90% methane to avoid affecting the equipment.

Existing hydrogen storage facilities and planned projects

Name	Country	Project start year	Operator/ developer	Working storage (GWh)	Type	Status
Teeside	United Kingdom	1972	Sabic	27	Salt cavern	Operational
Clemens Dome	United States	1983	Conoco Philips	82	Salt cavern	Operational
Moss Bluff	United States	2007	Praxair	125	Salt cavern	Operational
Spindletop	United States	2016	Air Liquide	278	Salt cavern	Operational
Underground Sun Storage	Austria	2016	RAG	10% H_2 blend	Depleted field	Demo
HyChico	Argentina	2016	HyChico, BRGM	10% H_2 blend	Depleted field	Demo
HyStock	The Netherlands	2021	EnergyStock	-	Salt cavern	Pilot
HYBRIT	Sweden	2022	Vattenfall SSAB, LKAB	-	Rock cavern	Pilot
Rüdersdorf	Germany	2022	EWE	0.2	Salt cavern	Under construction
HyPster	France	2023	Storengy	0.07-1.5	Salt cavern	Engineering study
HyGéo	France	2024	HDF, Teréga	1.5	Salt cavern	Feasibility study
HySecure	United Kingdom	mid-2020s	Storengy, Inovvn	40	Salt cavern	Phase 1 feasibility study
Energiepark Bad Lauchstädt Storage	Germany	-	Uniper, VNG ONTRAS, DBI Terrawatt	150	Salt cavern	Feasibility study
Advanced Clean Energy Storage	United States	mid-2020s	Mitsubishi Power Americas Magnum Development	150	Salt cavern	Proposed

B. H2 Demand

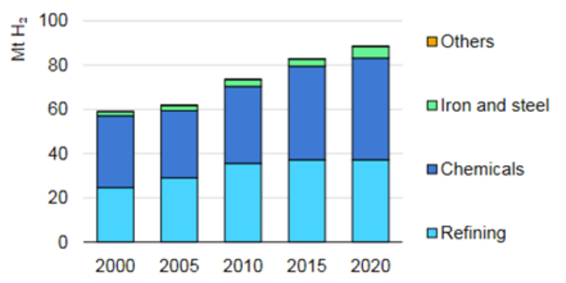
B.1. Key demanding sectors

Worldwide, global hydrogen demand was around 90 Mt H2 in 2020 (IEA, 2021):

- 70 Mt used as pure hydrogen
- Less than 20 Mt mixed with carbon-containing gases in methanol production and steel manufacturing[13]

As explained previously, almost all this demand comes from **refining** (close to 40 Mt H2 as feedstock and reagents or as a source of energy) and **chemical production** (around 45 Mt H2 of demand, with roughly three-quarters directed to **ammonia** production and one-quarter to **methanol)**. The remaining 5 Mt H2 is consumed in the direct reduced iron (DRI) process for **steelmaking**.

Hydrogen demand by sector, 2000-2020

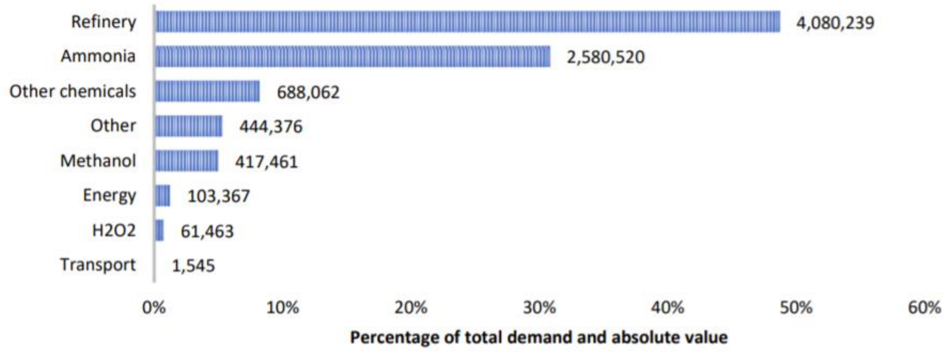


Note: "Others" refers to small volumes of demand in industrial applications, transport, grid injection and electricity generation.

[13] It excludes around 30 Mt H2 present in residual gases from the industrial process used for heat and electricity generation.

Europe is following the same trend. Total demand for hydrogen in the EU, EFTA countries and the UK in 2019 has been estimated at 8.4 Mt (FCHO, 2021). Almost half of the demand (49%) is from refineries. Together with the ammonia industry (39%), the two sectors represent 80% of total consumption. Other chemicals industries represent 13% of the demand.

Demand for hydrogen in 2019 by sector (EU+EFTA+UK)



Source: Fuel Cells and Hydrogen Observatory

Oil refining and chemicals industries make up 93% of the demand, with the remaining 7 % distributed among:

- Steel manufacturing, where at present, it is used mainly in batch annealing.
- Glass manufacturing, where it is used in flat glass production and the flame polishing process.
- Food processing, in the production of margarine, for instance.
- The energy sector, where it is used in a fuel cell to generate heat and energy.
- Transport, where it can be used as a fuel (in fuel cells or in an internal combustion engine), or to synthesise synthetic fuels. It currently accounts for an almost insignificant part of hydrogen consumption but is expected to grow in the future.

Emerging applications of hydrogen, such as transport or hydrogen DRI currently make up a very low share of the market.

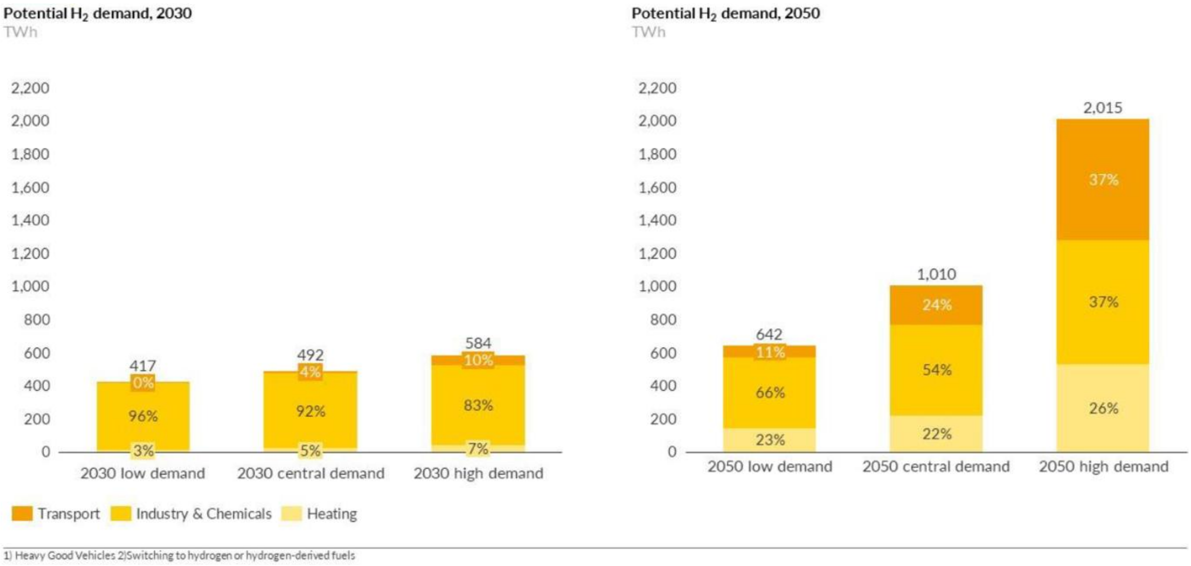
Demand is also relatively concentrated in four countries: Germany, Netherlands, Poland and Spain, which represent 51% of the demand.

B.2. Potential bottlenecks implied by the growing demand

As seen, the current demand for hydrogen in the EU is mostly for use in refineries or as industrial feedstock, mainly in ammonia production. Most of this hydrogen is produced using natural gas resulting in high emissions of CO_2 (between 8 and 12 tCO2/tH2).

The forecast for hydrogen demand varies from one study to another (widely concerning forecast for 2050), but they all project a steep increase in Europe in the future**. Aurora Energy Research forecasts a demand between 417 and 584 TWh (HHV[14]) for hydrogen in 2030, depending on the** scenario**[15] considered. For 2050, it estimates the potential to reach between 642 and 2 015 TWh (HHV) hydrogen demand (representing between 7 to 21% of total energy demand) by 2050 across the EU (Aurora Energy Research, 2021).**

Hydrogen forecast according to Aurora Energy Research by sector in 2030 and 2050



Source: Aurora Energy Research, 2021

Other research on the future EU energy systems, such as the study published by the Joint Research Centre (Blanco, Nijs, Ruf, & Andre, 2018) expects a significant increase in the use of hydrogen – between 667-4 000 TWh (LVH[16]) in 2050. Another EU-level study, Gas for Climate, estimated the hydrogen demand potential in 2050 at 1 710 TWh (LHV) (Guidehouse, 2020). All these findings rely heavily on the rate of penetration of new and low-carbon hydrogen technologies (and their prices) in the EU economy.

We can assume that in 2030 hydrogen demand will continue to be driven by its use in industrial sectors, since demand from transport and heating will remain low. Indeed, the infrastructure that would allow the widespread uptake of hydrogen in these sectors will likely not be ready in the next ten years.
In the long run, demand for hydrogen will be led by five main sectors. The three actual leaders in demand for hydrogen (r refineries, ammonia and high-value chemicals including methanol) will remain large consumers, even though demand by the refineries sector should decline as climate ambitions increase (oil refining activity declines more sharply as oil demand declines).

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[14] Higher Heating Value

[15] Aurora considers three scenarios: a conservative scenario, where all hydrogen uptake is slow across all countries and plays a small part in meeting overall energy demand, an optimistic scenario, where hydrogen plays a key role in decarbonising the economy, and an average of the two.

[16] Lower Heating Value

The two other sectors are steel and cement, which would significantly increase their demand for hydrogen in order to decarbonise their respective sector in the future. For instance, the total planned consumption of low-carbon hydrogen in the industrial projects tracked by Hydrogen Europe (an organisation representing industries in the sector) amounts to 5.2 Mt H2/year (around 176 TWh) by 2030. In this projection, hydrogen use in the steel sector would account for 38% (67 TWh).

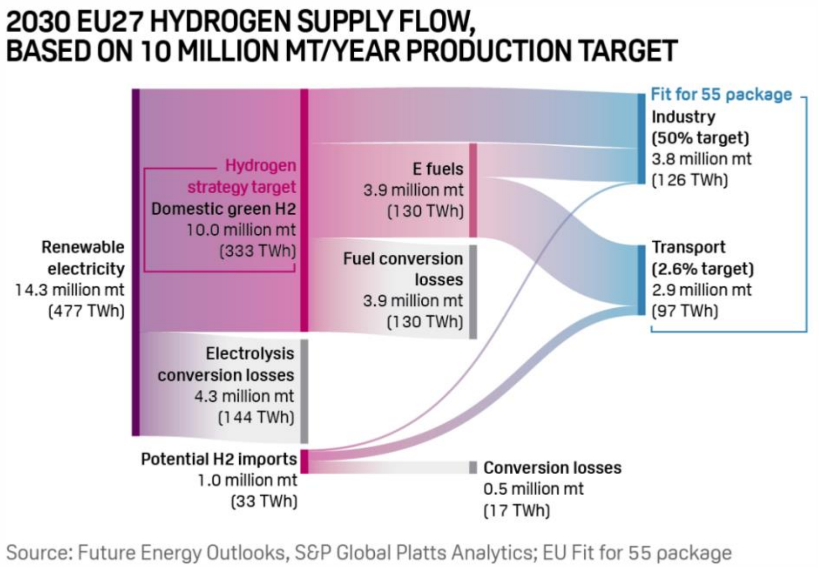
Demand for hydrogen in transport remains uncertain. It should target more heavy goods vehicles and mass transport, since it seems electric engines for small and personal vehicles will be the technology of choice in the future, as shown by the heavy investment in charging infrastructure to support and accelerate the roll out of this technology in Europe. Here, infrastructure development will be crucial for the commercial deployment of hydrogen. Ammonia in shipping and hydrogen-derived synthetic fuels in aviation could present a viable decarbonisation pathway for these sectors, but it is difficult to assess future demand since most of those technologies are far from being mature (regarding directly hydrogen-powered planes).

Hydrogen in heating will also demand investments in infrastructure, especially that of gas. Hydrogen as a direct heating source is competing with more efficient solution such as heat pumps. However, it could offer a cost-efficient solution for countries already relying heavily on gas infrastructure with low insulated buildings.

As seen in previous sub-chapters, the EU and its Member states have already built up further capacity to meet an increasing demand. It is widely anticipated that hydrogen production will take place either through electrolysis or through the reformation of natural gas, which would have to be coupled with CCS.

The EU hydrogen strategy has defined a renewable hydrogen production target for 2030 at 10 million tonnes, with a 40 GW renewable energy-powered electrolysis. This is roughly equivalent to total current hydrogen production capacity that has been developed over several decades. One of the main challenges is achieving the 10 Mt target, which would require a high development of renewable electricity for hydrogen by 2030.**Platts Analytics assessed that such volumes would require additional renewable power generation amounting to 477 TWh (S&P Global Platts Analytics, 2021).[17] In this analysis, Platts Analytics assessed that the nature of the targeted sectors according to the Fit for 55 package means much of the hydrogen will need to be converted to ammonia, leading to large conversion losses.**

[17] According to EDF, a nuclear reactor with a nominal capacity of 900 MW produces on average 6 TW/h per year. Thus, it might represent the equivalent of 80 nuclear reactors



Source: S&P Global, 2021

To ensure hydrogen production does not result in an increase in emissions, electrolysis should only take place using low carbon sources of electricity, which should involve dedicated renewable capacity to avoid increasing the carbon intensity of the grid. This is the main approach developed in the proposed revision of the Renewable Energy Directive, which — emphasized requirements that the generation of green hydrogen must come from additional renewable power.

Nevertheless, this approach has been criticized because even in a high renewable development scenario, new-build renewables (mainly solar and wind) based hydrogen production might not be enough to meet the demand, resulting in a significant gap between demand and supply that can only be filled by imports (Agora Energy Research, 2021). In addition, it could result in higher hydrogen production and transport costs, especially when import is considered.

Two possible solutions may be identified to avert this potential gap. One could result from allowing hydrogen production from a broad use of all forms of renewable and decarbonised electricity (therefore including nuclear and hydropower). The other solution could arise from coupling hydrogen production from new-build renewables with traditional means of production coupled with CCS. However, the latter solution is unlikely to be developed because it involves significant technical challenges to be deployed at scale and could lead to residual CO_2 emissions, making it a far from ideal first-class option. Some countries have even stated they will not adopt this technology.

B.3. Economic considerations and hypothesis regarding H2 production and prices

Most hydrogen is produced from natural gas at a price of:[18]

- €1.40/kg,

[18] Agora Energiewende and Guidehouse (2021, August): Making renewable hydrogen cost-competitive: Policy instruments for supporting green H_2.

- €1.80/kg if CO_2 costs are added at €50/tonne,
- And €2.20/kg if CCUS costs are added to avoid 75% of CO_2 emissions.

By comparison, the cost of renewable hydrogen ranges from €3.40/kg to €6.60/kg.

In other words, the difference between the cost of fossil hydrogen and renewable hydrogen is approximately €3/kg.

Generating all current hydrogen production (90 MtH2) from electricity would require 4 700 TWh, which is more than the EU's total electricity generation. In addition, it takes about 9 litres of water to produce 1 kg H2, so if all hydrogen production were to be carried out by electrolysis of water, this would result in a water demand of 790 million cubic meters, corresponding to 1.6% of the global energy sector's water consumption, or roughly double the current water consumption for hydrogen from steam methane reforming (SMR). However, interest in renewable hydrogen is increasing since the price of renewable energies, especially solar photovoltaic and wind energy, is falling.

The cost of renewable hydrogen production from water electrolysis is influenced by several technical and economic factors. Most relevant are: CAPEX requirements, the cost of renewable electricity, and the operating hours of the electrolyser.

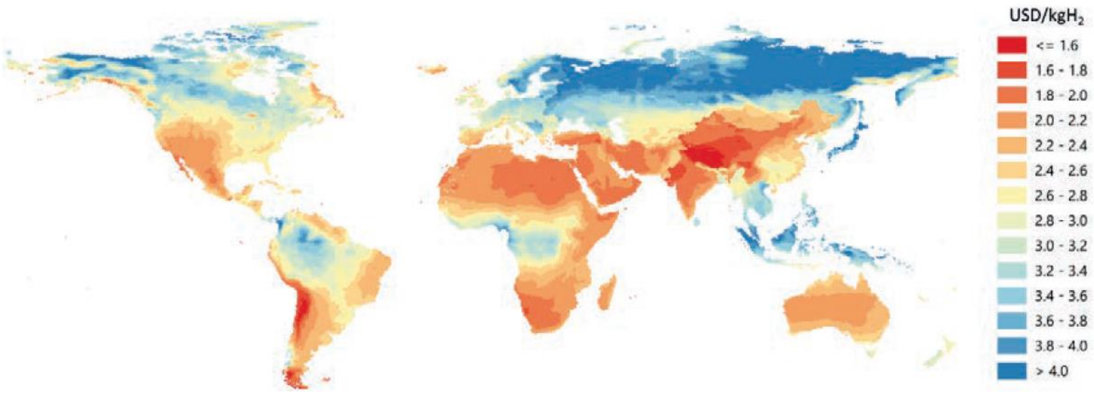
CAPEX requirements	Currently, the capital investment in an alkaline electrolyser ranges between €440-1,200/kWe, while in a PEM electrolyser it is between €970-1,600/kWe. The electrolyser stack is responsible for 50-60% of the investment cost of alkaline and PEM electrolysers, respectively. The power electronics, gas-conditioning, and plant components account for most of the remaining costs. Learning-by-doing effects (such as the development of less expensive materials for electrodes and membranes) and economies of scale will allow future reductions in system electrolyser costs. By 2030, the capital investment in an alkaline electrolyser is estimated to be between €420-750/kWe, and in a PEM electrolyser between €570-1,300/kWe.
The cost of renewable electricity	It is already becoming cheaper. Between 2010 and 2019 the global weighted average levelised cost of electricity (LCOE) produced by utility scale solar photovoltaics, offshore wind and onshore wind fell by 82%, 47% and 39% respectively. The increase in demand for renewable energy generated by the increase in demand for renewable hydrogen production itself should help drive down the cost of renewable electricity. However, its overall impact is likely to be marginal. Hydrogen is expected to account for only a limited share of global final energy demand in 2050 (13-24%). Solar photovoltaics, offshore and onshore wind capacity amounted to 316GW in the EU in 2020. However, an increase of more than 150% would be needed by 2030 to reach the 801GW needed to be able to reduce CO_2 emissions by 55% compared with1990. In addition, low-cost electricity available at a level to ensure the electrolyser can operate at relatively high full load hours is essential for producing low-cost hydrogen. Producing hydrogen through electrolysis and storing the hydrogen for later use could be one way to take advantage of this surplus electricity. However, if surplus electricity is only available occasionally, it will hardly make sense to rely on it to keep costs down. In this case, running the electrolyser at high full load hours and

	paying for the additional electricity can actually be cheaper than just relying on surplus electricity with low full load hours. Thus, it is crucial to know the price of electricity and its evolution to make concrete decisions about the production process of renewable hydrogen. Constructing electrolysers on sites with good renewable resource conditions could become a low-cost hydrogen supply option, even when transport costs are considered. Within the EU, some of those places could be in the south, such as Spain, part of France, Italy, or Greece. In areas where both resources are excellent, the combination of photovoltaic and onshore wind power in a hybrid plant has the potential to further reduce costs.
Annual hours of electrolyser operation	Production cost is lower with more operating hours since the investment is amortized. With an electrolyser system cost of €620/kW, it takes more than 5 400 h/year for the hydrogen price to be competitive with fossil hydrogen.[19] However, the relationship between electricity cost and operating hours is more apparent when observing electrolysers that do not use renewable energy but grid electricity for their production. In these cases, low-cost electricity is usually available only for a few hours per year, implying a low use of the electrolyser and a high cost of hydrogen due to capital costs. With the increase in hours, it is the cost of electricity that should increase. It is estimated that from 3,000-6,000 hours equivalent at full load, the increase in electricity prices at peak time will lead to an increase in unit production costs. The cost of energy remains very relevant for hydrogen production by water electrolysis. However, given the positive forecasts regarding the reduction in photovoltaic and wind energy prices, favourable forecasts are also expected for the price of renewable hydrogen.
Price of CO_2	Carbon pricing can also be used as a measure to reduce the cost of hydrogen. By 2030, in the competition between renewable hydrogen and fossil hydrogen, lower-cost renewable hydrogen would need a CO_2 cost of €100/tonne to reach equilibrium, and for renewable hydrogen technologies to be cost-effective, the price of CO_2 would have to be €300/tonne. This means, therefore, that carbon pricing cannot be the only tool to be used to encourage the demand for and for lowering of the price of hydrogen. In the near term, up to 2030, fossil fuels are likely to continue having an advantage over renewable sources in most countries. Fuel costs are the biggest single component of hydrogen production costs —except for hydrogen produced from coal—and electricity and gas costs will also play a key role. Nevertheless, in countries with good renewable resources and dependent on the import of natural gas, the production of hydrogen from renewable energies may be the cheapest option. In addition, for the production of hydrogen from fossil fuels in combination with CCUS technology, geographic availability and public acceptance are a key

[19] With or without carbon capture, with a CO_2 price of €50/ton.

and complex requirement. Regarding water electrolysis, although access to adequate supply is necessary, water treatment costs are a small fraction of the total costs of producing hydrogen. Furthermore, from an investment point of view, electrolysers work on a smaller scale that can be scaled up and adjusted more to demand than plants for CCUS, which require a certain scale to justify investment in transport and storage infrastructure.

Hydrogen costs from hybrid solar PV and onshore wind systems in the long term. Source: IEA.



Notes: This map is without prejudice to the status of sovereignty over any territory, to the delimitation of international frontiers and boundaries and to the name of any territory, city or area. Electrolyser CAPEX = USD 450/kWe, efficiency (LHV) = 74%, solar PV CAPEX and onshore wind CAPEX = between USD 400-1,000/kW and USD 900-2,500/kW depending on the region; discount rate = 8%.

Renewable hydrogen production costs depending on operating hours. Source: Agora Energiewender.

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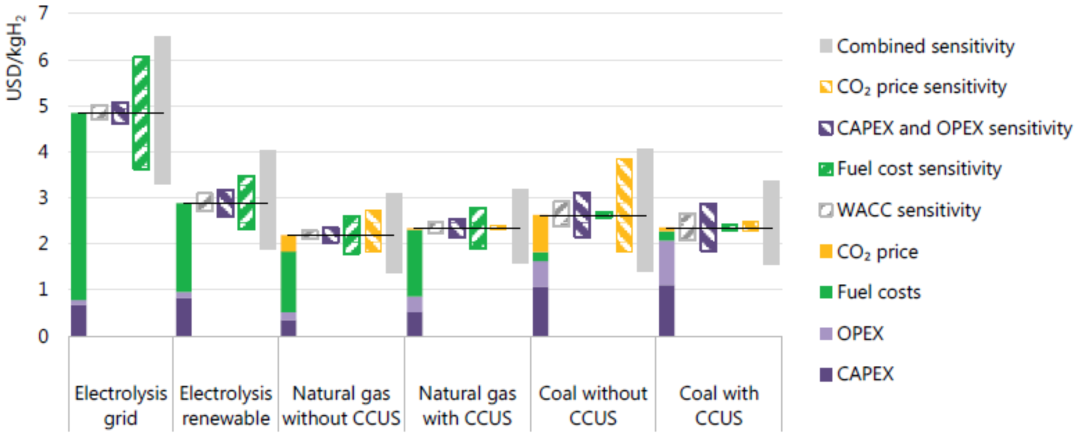
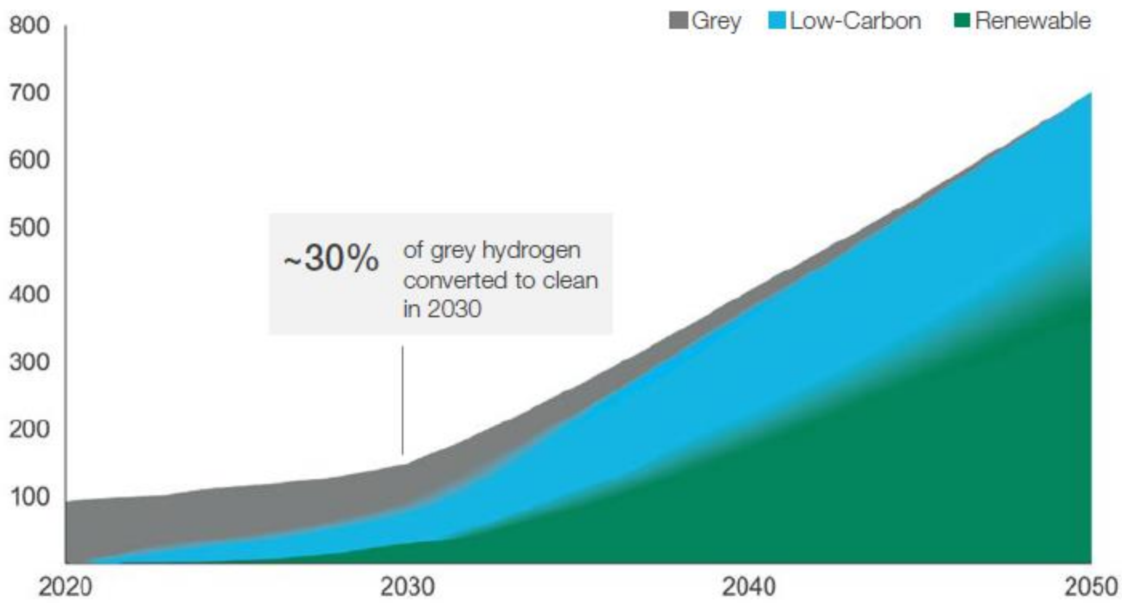
Notes: The figures are estimates for illustrative purposes and are based on full-load hours that can be reached with renewable energy sources across Europe. The transparent boxes show the full load hours of corresponding renewable energy sources.

Hydrogen production costs for different technology options, 2030. Source: IEA.



Notes: WACC = weighted average cost of capital. Assumptions refer to Europe in 2030. Renewable electricity price = USD 40/MWh at 4,000 full load hours at best locations; sensitivity analysis based on +/-30% variation In CAPEX, OPEX and fuel costs; +/-3% change in default WACC of 8% and a variation in default CO_2 price of USD 40/tCO_2 to USD 0/tCO_2 and USD 100/tCO_2. More information on the underlying assumptions is available at www.iea.org/hydrogen2019

Hydrogen supply mix over time (MT hydrogen p.a.). Source: Hydrogen Council.



Ultimately, the goal of climate neutrality set out in the Green Deal, and the falling prices of photovoltaic energy make hydrogen production from water electrolysis an opportunity for southern Europe. But for this to be successfully realised, political support will be needed to help reduce the price of hydrogen in order to make it competitive, offsetting the effect of, above all, the CAPEX required until progress can be made through learning-by-doing.

Main figures

Production			
	Worldwide	90	Mt
Via	Natural Gaz	60%	
	Coal	19%	
	Electrolyse	0,03%	
	Europe	10,5	Mt
Route	On site	7,6	Mt
	By-product	1,5	Mt
	Merchant	1,5	Mt
Consumption			
	Worldwide	90	Mt
	Europe	8,4	mt
Hydrogen strategy			
2030	Green electrolysers capacities	40	GW
	Production	10	Mt
	Electricity needed	477	Tw/h
Future consomption (Aurora Energy Research)			
2030	Europe	417-584	Tw/h
2050	Europe	642-2015	Tw/h

In one kg of hydrogen there are 33.3 kWh of usable energy.
Electrolysers have in average a 70% energy efficiency

Chapter 2: H2 and steelmaking: a pathway toward a zero-emission production?

The iron and steel sector is an energy-intensive industry. Coal accounts for about 75% of energy inputs[20] and the majority is consumed in blast furnaces. Electricity is the second largest energy input, mainly used by electric furnaces21, followed by gas, which is mainly used for generating heat and as a reducing gas in DRI furnaces.
Although energy intensity has declined over the past two decades, this decline has been largely offset by increased global steel production. Energy intensity depends mainly on the proportion of scrap and iron ore. Primary production of steel (BF-BOF) is about eight times more intensive than electric arc production (EAF).[22]
There are three main pathways for the decarbonisation of steel:

1. Circular economy: increase of resource effieicny, via scrap metal recycling, re-use by-products such as slags and recovery of waste energy	Problems: • Some qualities can only be provided by primary production (or iron ore-based) route • Scrap collection and sorting technologies are inefficient ○ Solution: R&D and investment through the Reverse Metallurgy programme • Expensive or insufficient electricity, especially renewable
2. Process integration as well carbon capture and utilisation technloogies Carbon capture and utilisation technologies (CCU or CCS)	• Problems:High costs: it is estimated that CO_2 capture on a new thermal (coal) power plant costs about ~$50- 60 per ton of CO_2. The amount is higher for old steel plants[23] •
3. Producing steel using renewable energy	Options expensive in investment and not yet sufficiently developed: • Electrolysis of iron ore • Direct reduction of iron by hydrogen • Plasma smelting of iron ore

Technology readiness level (TRL) is a way of assessing how mature a technology is, from the initial idea to full-scale market release. This tool provides a common framework that can be applied to any technology, allowing it to be compared.[24]

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[20]Steel consumption accounted for 15% of global primary demand in 2019.
[21] About 25% for converting iron, direct reduced iron and scrap into steel, then for semi-finish and finishing processes.
[22] This ratio can be lower in the European steelmaking industry
[23] The CCS installation on the Norcem cement plant in Norway took nine years and received final approval in April 2020. Costs and performance are not known. Other projects: Carbon2Chem (Duisburg, Germany) & Steelanol (Ghent, Belgium)
[24] More information about TRL in Annex 1.

Status of the main near-zero emission technologies in the iron and steel sector. Source: IEA.

TECHNOLOGY	TRL	YEAR AVAILABLE	IMPORTANCE FOR NET-ZERO EMISSIONS
CCUS			
Blast furnace: off-gas hydrogen enrichment and/or CO_2 removal for use or storage.	5	2030	Very high
Blast furnace: converting off-gases to fuels.	8	Today	Medium
Blast furnace: converting off-gases to chemicals.	7	2025	Medium
DRI: natural gas-based with CO_2 capture.	9	Today	Very high
Smelting reduction: with CCUS.	7	2028	Very high
HYDROGEN			
Blast furnace: electrolytic H2 blending.	7	2025	Medium
DRI: natural gas-based with high levels of electrolytic H2 blending.	7	2030	High
DRI: based solely on electrolytic H2.	5	2030	Very high
Smelting reduction: H2 plasma reduction.	4	-	Medium
Ancillary processes: H2 for high-temperature heat.	5	2025	High
DIRECT ELECTRIFICATION			
Electrolysis: low temperature.	4	-	Medium
Electrolysis: high temperature molten oxide.	4	-	Medium
BIOENERGY			
Blast furnace: torrefied biomass.	7	2025	Medium
Blast furnace: charcoal.	10	Today	Medium

Bringing technologies to market in the early stages of maturity depends on increased R&D and demonstration. Support through policy action is, therefore, very important. Another key aspect is that the necessary inputs (renewable electricity and low-carbon hydrogen) and infrastructure (CO_2 pipelines and storage facilities, electricity grids, hydrogen networks) are to some extent available.

According to an IEA report, it is already possible for electrolytic hydrogen to displace up to 30% of natural gas in commercial DRI furnaces, while higher blends require further development (they are at TRL 7) and the use of 100% electrolytic hydrogen is in the pilot phase (i.e. TRL 5).

This analysis provides an understanding of the time, labour and capital required for these new technologies to be up and running. This is a very relevant aspect when steel producers decide which emission-reducing technology to undertake.

The following map shows some of the projects being developed in Europe regarding these emission reduction technologies.

A. The use of hydrogen in steel production

The use of hydrogen in steel production will play a major role in the decarbonisation of the sector and therefore in the medium term. Two basic methods are possible:[25]

- Use as an auxiliary reducing agent in the blast furnace (H2-BF)
- Use as the sole reducing agent in direct iron reduction or DRI (H2-DRI). DRI (Direct reduced iron) or pre-reduced iron ore is a steelmaking semi-finished product from the processing of iron ore by direct reduction. The production principle is based on the reducing action of a gas at high temperature (> 900 °C).

In the primary steel production route (BF-BOF), the majority of carbon emissions are from the blast furnace and coke oven. The use of hydrogen in both the blast furnace and coke oven has the potential to reduce the amount of coal required and CO_2 emitted because hydrogen reacting with iron ore forms water instead of carbon dioxide.

However, it is technically impossible to use hydrogen alone in a blast furnace and therefore, H2-BF is seen as a technology[26] that provides a short-term carbon emission reduction, i.e. a transition technology towards the H2-DRI route. This is the path taken by some integrated steel producers in Europe:

Hydrogen use projects in BF-BOF

STEEL	LOCATION	ELECTROLYSER	RENEWABLE
ArcelorMittal	Bremen, Germany	Yes	Unclear
ArcelorMittal	Dunkirk, France	No	/
ArcelorMittal	Asturias, Spain	No	/
ArcelorMittal	Fos-Sur-Mer, France	Yes	Yes
Voestalpine	Linz, Austria	Yes	Yes
Thyssenkrupp	Duisburg, Germany	No	/
TATA	Ijmuiden, Netherlands	No	Yes
Dillinger/Saarstahl	Dillingen, Germany	No	/

In addition, to be used as a decarbonation solution in the steel production process, hydrogen has to be produced through low carbon or even neutral carbon intensity processes. Electrolysis is one of the most promising of them, even if it is a very electricity-intensive process. Thus, to achieve a real reduction in

[25] Source: https://bellona.org/news/climate-change/2021-03-hydrogen-in-steel-production-what-is-happening-in-europe-part-one

[26] Hydrogen can partially reduce emissions without major modifications of traditional equipment at lower levels of blending. For example, a steel producer in Germany is currently piloting hydrogen injection into blast furnaces up to 40 kg per ton of hot metal (ThyssenKrupp, 2019, IEA, 2021). By 2050 a major part of hydrogen blending will occur not as direct injection but from hydrogen blending in natural grids according to the IEA (2021). Nevertheless, this method has an upper limit on the amount of blending without major equipment modifications.

carbon emissions, producers need to ensure that the electricity used for hydrogen production does not generate additional carbon emissions.

A.1 Use as an auxiliary reducing agent in the blast furnace (H2-BF)

It has been estimated that the use of hydrogen in integrated steel production (blast furnaces) would reduce carbon emissions by 21%.

Thus, electrolysis coupled with renewable energy generation or a low carbon footprint electricity generation mix can generate reductions of CO_2 emissions .

This is especially relevant due to the increase in energy consumption: if electrolysis is coupled to a carbon intensive electricity grid, such as in Poland or Germany, it can actually lead to an increase in carbon emissions (+57% and +14% vs. conventional generation respectively).[27]

Theoretically, considerable savings in CO_2 emissions can only be achieved in countries with a considerably low-carbon energy mix. This is the case in France, where the carbon intensity of the electricity grid is low thanks to nuclear power, and this solution would achieve a 16.5% reduction in emissions.

Impact of using hydrogen in integrated steel production using grid electricity[28]

		Implementation of H2 BF into BOF/BF plants			**BOF/BF existing plants**	
	Carbon intensity of electricity generation (2021, kgCO2e per kWh)	Additional requirement for production of 1 ton of liquid steel	Reference carbon emissions / ton of steel, integrated pathway, 120 kg pulverised coal / ton of steel and use of 27.5 kg hydrogen	Carbon emissions / ton of steel kgCO2e if grid electricity is used	Reference carbon emissions / ton of steel, integrated pathway[29]	**Gains or surpluses from use of grid electricity in electrolysis vs. conventional production**
Austria	0.111	51 kWh /kg hydrogen and	1,063 kgCO2 /t liquid steel	1 219	1,352 kgCO2 /t liquid steel	-10%
Belgium	0.162			1 290		-5%

[27] A solution for this could be to couple the production plant to an exclusively renewable energy source or to buy green hydrogen in a - hypothetical - market.

[28] Sources: https://bellona.org/news/climate-change/2021-03-hydrogen-in-steel-production-what-is-happening-in-europe-part-one; https://www.carbonfootprint.com/docs/2022_01_emissions_factors_sources_for_2021_electricity_v10.pdf; https://www.sciencedirect.com/science/article/pii/S2352146519302315; https://www.sciencedirect.com/science/article/abs/pii/S0959652617306169

[29] A reference case was used for comparison: a PC injection of 120 kg/tHM was assumed, which represents a common BF operation, and was simulated by extrapolation (i.e. it was not based on operational data). Usually, the real CO_2 emission is about 1,800 kgCO2/t

Bulgaria	0.372	27,5 kg hydrogen / t steel[30]		1 585		17%
Croatia	0.227			1 381		2%
Cyprus	0.643			1 965		45%
Czech Republic	0.495			1 758		30%
Denmark	0.143			1 263		-7%
Estonia	0.599			1 903		41%
Finland	0.095			1 197		-11%
France	0.051			1 135		-16%
Germany	0.339			1 538		14%
Greece	0.410			1 638		21%
Hungary	0.244			1 405		4%
Iceland	0.000			1 063		-21%
Ireland	0.336			1 534		13%
Italy	0.324			1 517		12%
Latvia	0.216			1 365		1%
Lithuania	0.254			1 419		5%
Luxembourg	0.101			1 205		-11%
Malta	0.391			1 611		19%
Netherlands	0.374			1 588		17%
Norway	0.008			1 074		-21%

[30] i.e. an electricity requirement of 1 402 MWh/t steel

Poland	0.760			2 128		57%
Portugal	0.202			1 346		0%
Romania	0.262			1 430		6%
Russian F.	0.310			1 498		11%
Serbia	0.777			2 152		59%
Slovakia	0.155			1 281		-5%
Slovenia	0.224			1 377		2%
Spain	0.171			1 303		-4%
Sweden	0.006			1 071		-21%
Switzerland	0.012			1 079		-20%

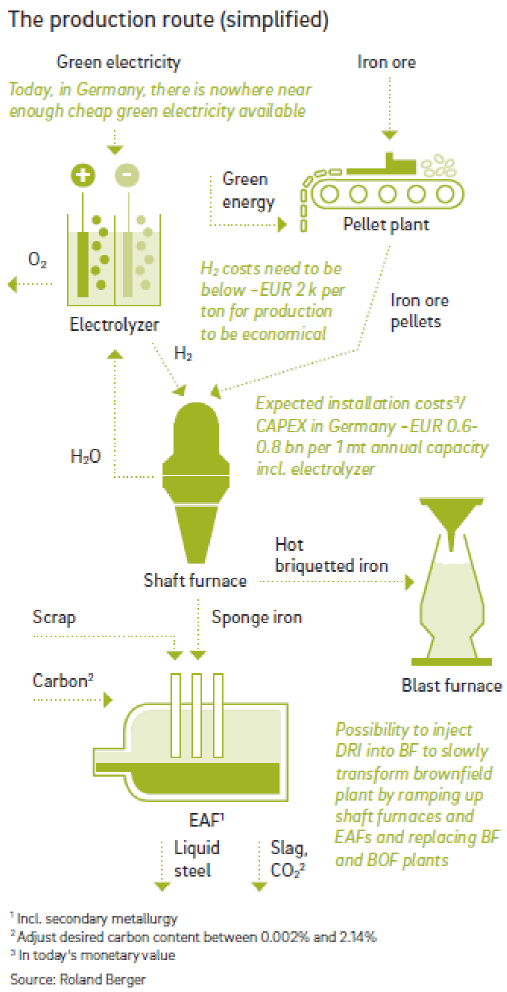
A.2. Use as the sole reducing agent in direct iron reduction or DRI (H2-DRI)

The use of hydrogen to produce DRI for use in an electric furnace is a possible solution for the future: direct reduced iron (DRI) (or pre-reduced iron ore is a semi-finished steel product from the processing of iron ore by direct reduction. It can be used in both the integrated and the electric way.

As with hydrogen in blast furnaces, for DRI to be carbon neutral, the electricity used to produce the hydrogen must be green.

For the use of hydrogen in the electric steelmaking route with the use of DRI upstream, the steps to be followed are as follows:

- Iron ore is reduced with hydrogen to produce direct pre-reduced iron (DRI)[31] in a shaft furnace.
- The DRI is then fed into an electric furnace (EAF), where electrodes generate a current to melt the DRI to produce steel.
- Carbon is required for the steel to be produced. This carbon can come from pulverised coal, biomethane or other biogenic carbon sources.
- Scrap metal can be used in the electric furnace in combination with DRI to reduce the need for iron ore and thus energy and hydrogen.



	Carbon emissions/ ton of steel (gCO2eq/ t steel)[32]	Potential CO2 emissions reduction (gCO2eq/ t steel)
BOF/BF plants	1870	-1817
EAF plants	400	-347
DRI-EAF plant	53	

DRI can also be used in a blast furnace in the form of hot briquetted iron (HBI), a high quality DRI. This use significantly increases the blast furnace's efficiency and reduces coke usage.

Although this route (DRI-BOF) is not carbon neutral, it could be promising as a transition for existing brownfield plants (blast furnaces) to the DRI-EAF technology.

A.3 State of development of DRI in the European steel sector

Several steel producers in Europe have announced the development of DRI production capacity.[33]

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[31] Instead of carbon reductant such as coke

[32] Material Economics (2019). Industrial Transformation 2050: Pathways to Net-Zero Emissions from EU Heavy Industry.
Vogl, V., ÅHman, M., & Nilsson, L. J. (2018). Assessment of hydrogen direct reduction for fossil-free steelmaking. Journal of Cleaner Production, 203, 736 745.

[33] https://bellona.org/news/industrial-pollution/2021-05-hydrogen-in-steel-production-what-is-happening-in-europe-part-two

Although the iron ore pre-reduction process has been known since the 1960s, there is currently only one DRI production unit in Europe, owned by ArcelorMittal in Hamburg, Germany, with a production capacity of 0.6 Mt/year.[34]

Several DRI capacity development projects have been identified in Europe. The projects are at various stages, ranging from the planning phase to the operation of a pilot plant.

Most projects involve coupling DRI production with an electric furnace (EAF), with a few exceptions:

- Voestalpine has built DRI capacity in Texas in the US, the output of which is used in the blast furnaces in Linz and Loeben.
- Salzgitter intends to use DRI in both BF and electric furnaces.
- Thyssenkrupp plans to use HBI in the blast furnace and DRI in the converter with a melting unit.

The potential for decarbonisation of DRI is limited in the first phase by the use of natural gas in hydrogen production. Although the steel industry has made various estimates of the carbon emission reductions from new DRI production capacity, the final climate impact will depend on factors such as:

- The carbon intensity of the energy used, for example, the electricity used to produce hydrogen
- The total emissions in the supply chain, taking into account, for example, the transport emissions from iron ore imported into Europe
- Emissions from other materials and energy used in the steelmaking process (e.g. the use of coal in blast furnaces or electricity in an EAF)

We consider here an approach based on the GHGP Protocol in its two main perimeters (out of 3): scope 1 (direct emissions) and scope 2 (electricity indirect emissions).

Of the projects for new DRI production capacity in Europe, at least 10 intend to use some form of hydrogen in the process. For most of these projects, the hydrogen will have to be produced onsite, usually from natural gas, since the availability of hydrogen on the market is very limited.

The industry cites the use of natural gas for hydrogen production as a temporary solution. The medium-term goal is to build hydrogen-ready plants before hydrogen becomes green and readily available on the market.

DRI projects in Europe

Company	Site	Stage	Reduction agent
ArcelorMittal	Hamburg, Germany	In operation in 2025	First grey hydrogen, then green hydrogen
ArcelorMittal	Eisenhuttenstadt, Germany	In operation in 2026 (pilot plant)	Hydrogen from electrolysis and pyrolysis of natural gas
ArcelorMittal	Bremen, Germany	In operation in 2026 (large-scale production)	Hydrogen from natural gas electrolysis
ArcelorMittal	Gent, Belgium	Letter of intent with governments was signed in September 2021	Natural gas and potentially hydrogen
ArcelorMittal	Sestao, Bizkaia, Spain	1.6 Mtn of steel without CO_2 emissions to 2025	Hydrogen from electrolysis

[34] Source: https://www.midrex.com/wp-content/uploads/Midrex_STATSbookprint_2018Final-1.pdf

ArcelorMittal	Gijón, Asturias, Spain	In operation before the end of 2025 (this plant will supply the Sestao plant)	Hydrogen from electrolysis (or natural gas if hydrogen prices are not yet affordable in 2025)
ArcelorMittal	Dunkerque, France	In operation before the end of 2027	Hydrogen from electrolysis
Acciaierie d'Italia Holding	Tatanto, Italy	Planning	Renewable gases such as biomethane and green hydrogen
Voestalpine	Leoben (Donawitz), Austria	Commissioning in Q2 2021	Hydrogen
Salzgitter AG	Salzgitter, Germany	Demonstration plant ordered 12/2020. Scheduled to come online in H1 2022.	Natural gas and hydrogen
Salzgitter AG	Wilhelmshaven, Germany	Feasibility study	Hydrogen from water electrolysis
SSAB	Gällivare-Oxelösund, Sweden	Pilot plant, commercial production 2026	Hydrogen from electrolysis
LKAB	Kiruna-Malmberget-Svappavaara, Sweden	First DRI plant in Malmberget in 2029	Hydrogen probably from electrolysis
Thyssenkrupp	Duisburg, Germany	First production in 2025	Natural gas
Liberty	Galati, Romania	DRI plant to be installed between 2023-2025	Natural gas
H2 Green Steel	Boden-Luleå, Sweden	Full-scale production in 2024	Hydrogen from electrolysis
H2 Green Steel & Iberdrola	Undefined, Spain	In operation in 2025-2026	Green hydrogen*

B. Economic implications and competitiveness of new technologies in the steel industry

B.1 First approaches to financial assumptions for the DRI-EAF route

Producing a tonne of steel using the traditional BF-BOF, EAF, or DRI-EAF route involves different production costs.

Three simplified production functions have been constructed as a first approach to these different scenarios[35]:

- BF-BOF: 1.37t*Pironore + 0.78t*Pcoal + 0.27t*Plimestone + 0.125t*Pscrap + 0.306MWh*Pelectricity.
- EAF: 0.15t*Pcoal+0.088t*Plimestone+0.71*Pscrap+0.611MWh*Pelectricity.
- DRI-EAF: 1.504*Pironpellets+348MWh*Pelectricity + Other variable costs+ CAPEXdri-eaf.

The analyses vary in terms of the capital cost of creating an EAF and the additional equipment need for DRI (hydrogen electrolyser, storage, etc.).
In our modelling, CAPEX for the DRI-EAF route includes capital expenditure for an EAF, a shaft furnace and electrolyser. We can consider that shaft and EAF are mature technologies. The CAPEX selected for a shaft furnace and an EAF are €230/t and €184/t respectively following the Wörtler et al. (2013) study. The electrolyser CAPEX is, however, expected to decrease in the following year and it will be of great importance in the undertaking of investments. For our modelling the CAPEX chosen is €160/t assuming a lifetime of 10 years and 8,760 operating hours.[36] All these elements lead to a total CAPEX of €574/t.[37]

Therefore, the total annualised CAPEX flow is €61/year for an EAF DRI technology assuming 15-year lifetime for the shaft and EAF and 10-year for the electrolyser. The capital cost applied is a 5% rate.[38]

The following table presents the information regarding the different variables.

VARIABLE	DEFINITION	VALUE	SOURCE
Pironore	Iron ore price (€/t)	98	Average of World Bank forecast 2021-2025, 2030, 2035[39]
Pcoal	Coal price (€/t)	81	Average of World Bank forecast 2021-2025, 2030, 2035
Plimestone	Limestone price (€/t)	100	JCP Article[40]
Pscrap	Scrap price (€/t)	300	Forecast of Syndex analyses

[35] World steel raw materials Factsheet for BF-BOF and EAF production costs. No CAPEX has been assumed for the traditional BF-BOF and EAF route at this stage since we consider we are analyzing the competitiveness of shifting existing utilities to DRI-EAF technology.

[36] The electrolyser CAPEX is based "on an estimation for proton exchange membrane (PEM) and alkaline electrolysis in 2030 by Mergel et al. (2013), who reported specific investment cost of 0.585 EUR/W installed capacity for both PEM and alkaline technology" (Vogl et al., 2018)

[37] This is a low CAPEX compared to other studies such as Fischedick et al. (2014), which assumes electrolyser operating "in times of inexpensive peak electricity, which requires a much larger investments in electrolyser capacity running on fewer operating hours and including large-scale storage of hydrogen" (Vogl et al. 2018).

[38] The capital cost is, undoubtedly, one of the most important factors in calculating the financial cost of CAPEX. The capital cost (or "WACC") is determined by the general interest rate (risk-free interest rate: German bonds, for example) and different premium/beta.

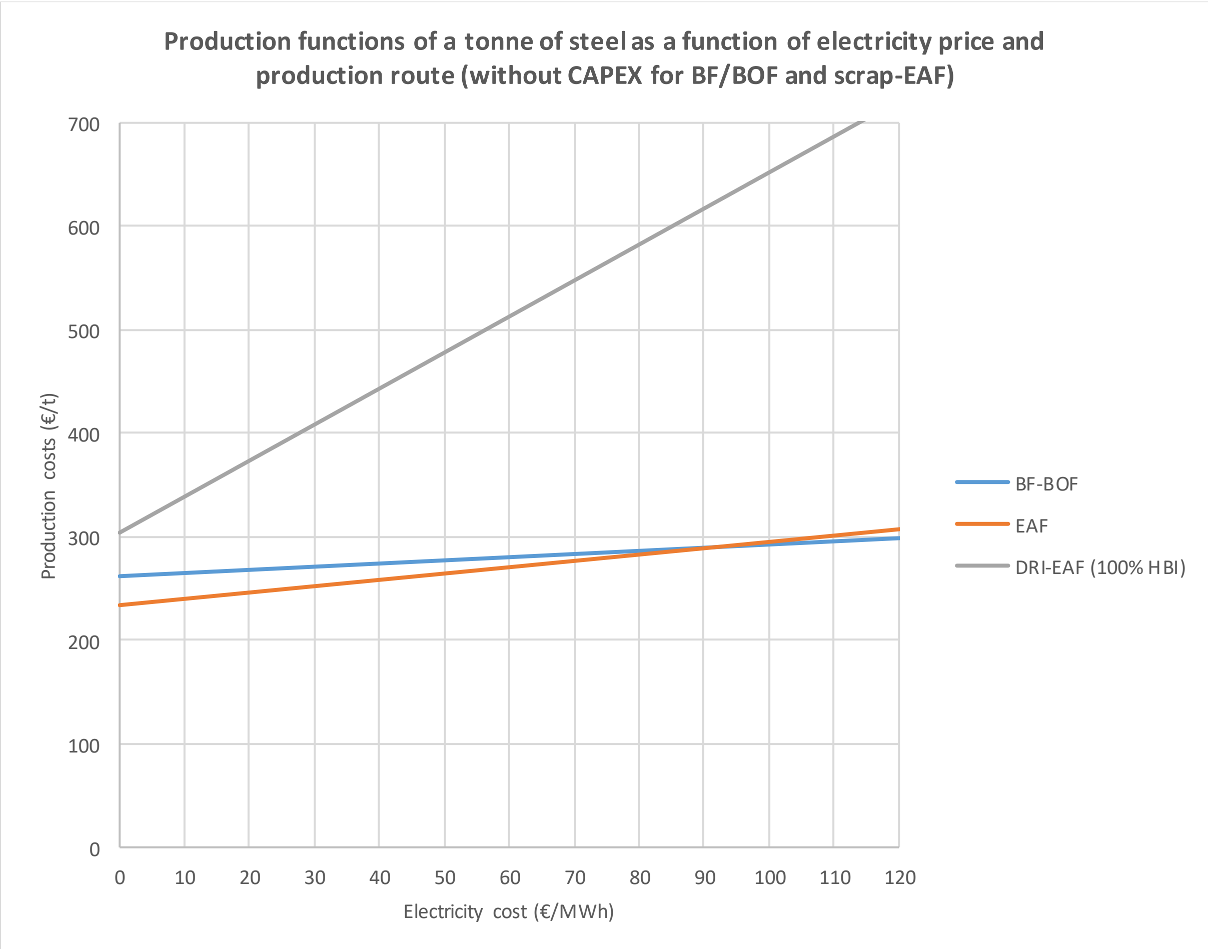
[39] World Bank Group (2021). Commodity Markets Outlook: urbanization and commodity demand. October 2021.

[40] Vogl, V., Ahman, M. & Nilsson, L. (2018). Assessment of hydrogen direct reduction for fossil-free steelmaking. Journal of Cleaner Production, 203, pp. 736-745.

Pelectricity	Electricity price (€/MWh)	[0-120]	
Pironpellets	Iron pellets price (€/t)	127	Iron ore price+premium ($30)
Other variable costs DRI-EAF	O&M, graphite electrodes	55	JCP Article
CAPEXdri-eaf	DRI-EAF route CAPEX (€)	61	JCP Article

We choose not to take into account CAPEX for BF/BOF and EAF routes because our modelling focus on the competitiveness of existing assets to decarbonised through DRI-EAF technologies. Nevertheless, BOF and EAF assets are confronted to life cycle and relining needs, thus we study carbon abatement further in this chapter.

Taking into account electricity prices between €0/MWh and €120/MWh, the production functions associated with each of the steel production routes are set out in the graph below.



This graph shows two main things :

-first DRI-EAF route is more sensitive to the price of electricity than the former traditional routes, so that the higher the price of electricity, the higher the cost of steel production via this route.

-secondly, even if EAF is by itself is a more electricity intensive route that BF, the intensity of DRI is far higher and the comparaison has to be done between EAF-DRI on the one hand and BF & EAF on the other hand.

-thirdly comparing the DRI-EAF route with the other two routes, the DRI-EAF route production cost is higher than the BF-BOF and EAF route in all scenarios. [41]

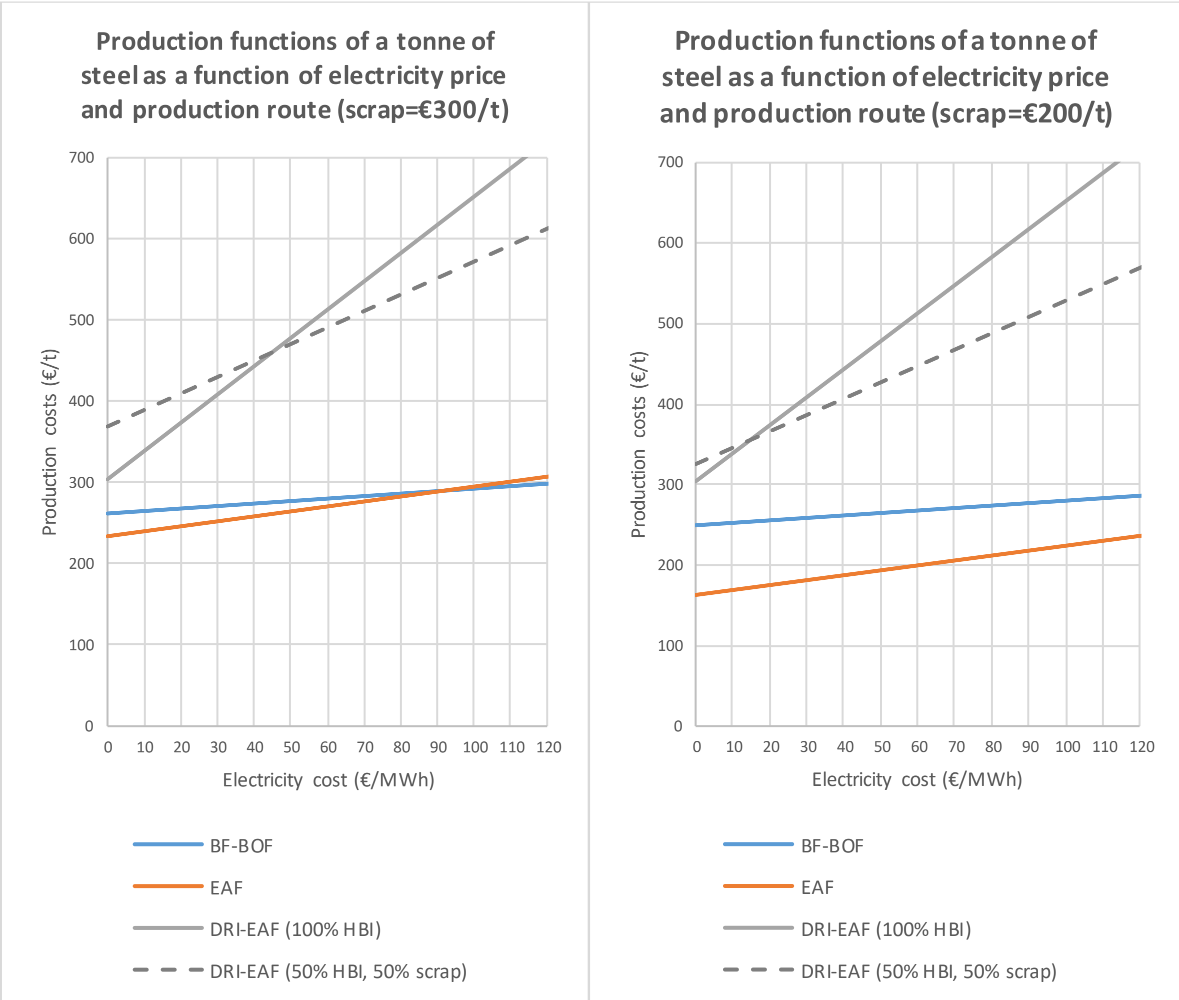
The DRI-EAF can also be charged with scrap in order to reduce the energy needs. In fact, the energy consumption is very sensitive to the amount of scrap added to the EAF because less iron ore is required per output. This leads to lower energy consumption in the different process steps before the EAF. As noted by Vogl et al. (2018), if the EAF is charged with 50% scrap, the electrolyser energy consumption is halved and producing steel in the EAF from scrap requires less energy.[42]

This specific scenario is set out below.[43] In this case, the production cost is very sensitive to the electricity price as well as to the price of scrap. Two graphs are, therefore, presented for two different scrap price forecasts.

41By construction, our hypotheses are based on fixed prices of iron ores and scraps. This choice varies from reality where these two factors are definiltly not stable.

[42] 0.667 MWh/t vs. EAF fulfilled with pure DRI (0.753 MWh/t)

[43] Specific cost production function= 0.738*Pironpellets + 0.536*Pscrap +2.03 MWh*Pelectricity + CAPEX



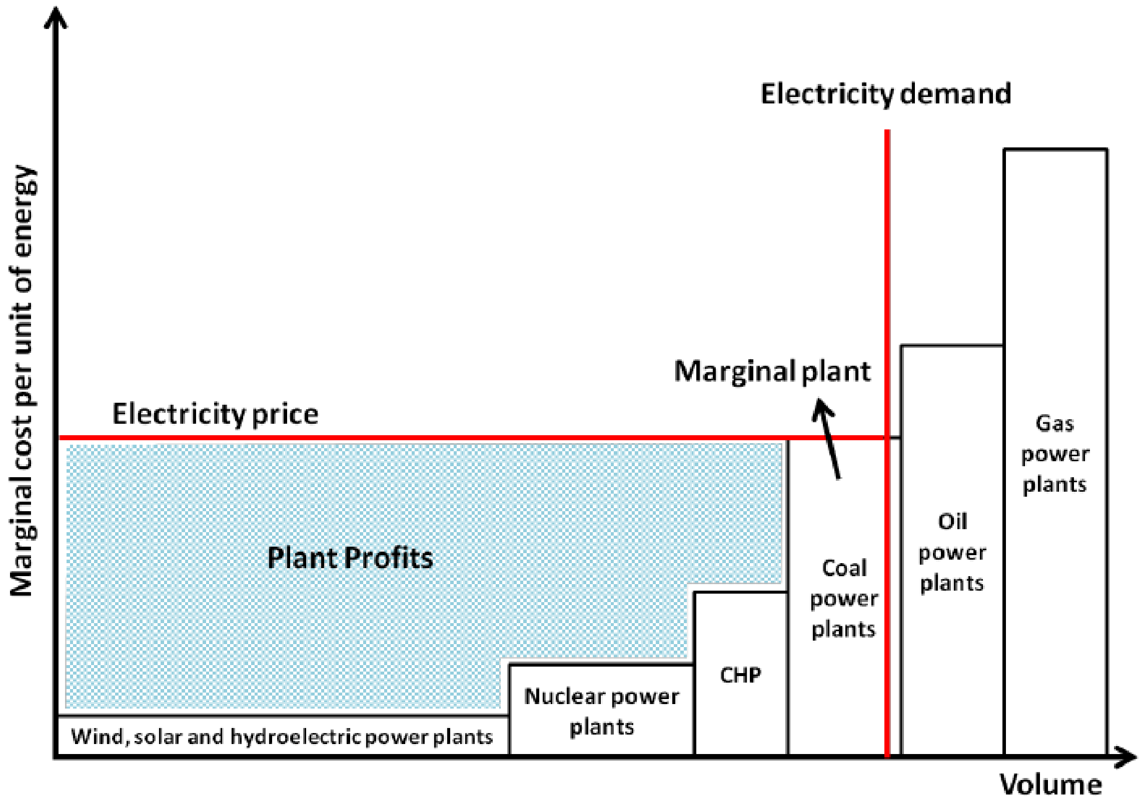
In the DRI-EAF (100% HBI) and DRI-EAF (50% HBI, 50% scrap) scenarios, the same investment needs are assumed to allow full flexibility in production with the desired levels of HBI and scrap.

The fundamental aspects of the European electricity markets have to be pinpointed: we disconnect here the electricity price from CO2 price, because steel sector might buy electricity at marginal price (last unit of electricity bid in the market) and not at average EU grid.

In fact, CO2 price has an impact on the price of electricity because electricity production is covered by ETS. However, REIIs may benefit from new PPA (Power Purchase Agreement) or CO2 indirect compensation according to some national legislations. Nevertheless, the future of these indirect compensations remains uncertain within the next ETS directive and the set-up of CBAM mechanism.

Example of the merit order determining the price of electricity in the market44

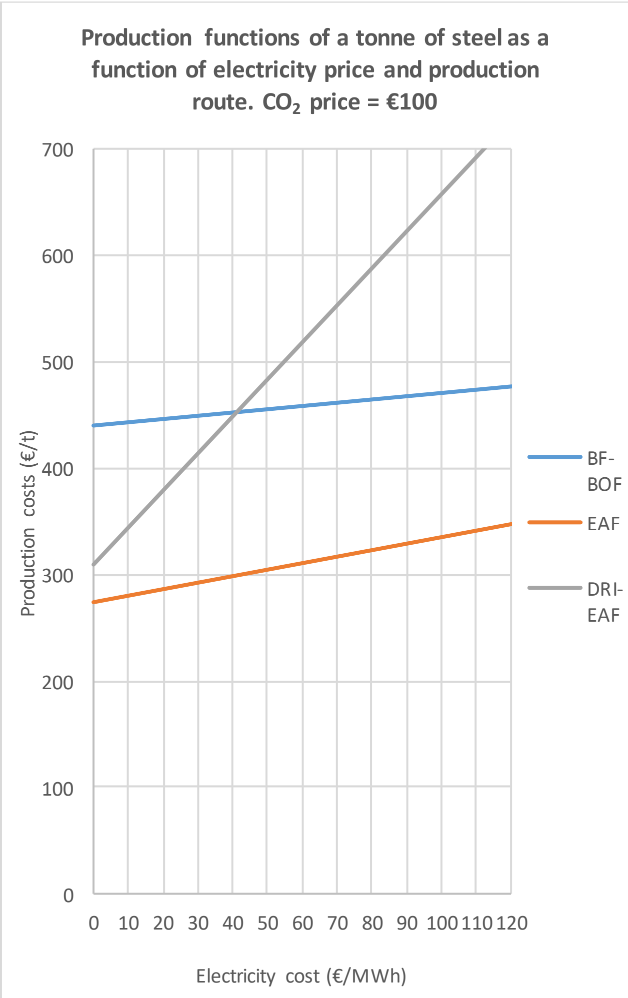
[44] Sauvage, Jehan & Bahar, Heymi. (2013). Cross-Border Trade in Electricity and the Development of Renewables-Based Electric Power: Lessons from Europe. OECD Trade and Environment Working Papers. 10.1787/5k4869cdwnzr-en.

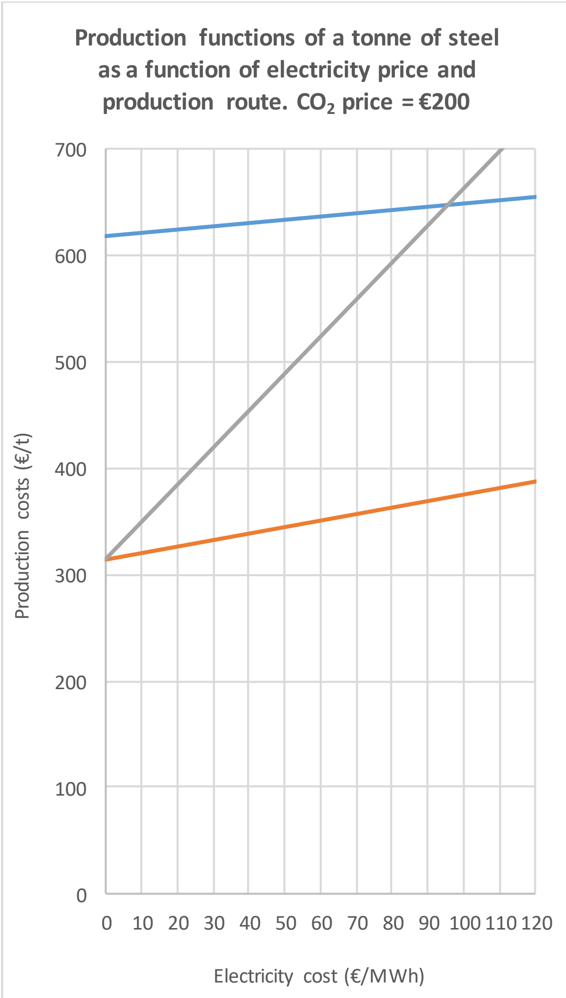


B.2 Impact of CO_2 price on production costs

The price of CO_2 is a key factor when comparing the costs of production by different routes and in particular when comparing traditional routes with new technologies. Above a certain CO_2 price level it can be advantageous to invest in new technologies, both in environmental and economic terms.

Therefore, we have carried out several simulations in which we have added the CO_2 price to the production functions. We have presented several scenarios under different CO_2 price levels to analyse, with this new factor added, how production costs vary depending on the price of electricity.





Both scenarios again highlight the extreme energy price sensitivity of production via DRI-EAF.
Under the assumption of a CO_2 price of €100, production via DRI-EAF has a lower cost than via BF-BOF as long as the electricity price is below €60/MWh.
In the second scenario, under a CO_2 price of €200, production via DRI-EAF has a lower cost than via BF-BOF if the electricity price is below €115/MWh.

However, it is also important to note that in energy scenarios with moderate electricity prices, the cost of production via BF-BOF can be up to twice as high as the cost via DRI-EAF.

In the case of production via EAF, the production cost is usually lower than the other routes, except for considerably high CO_2 prices. However, it should be remembered that traditional electric arc production varies greatly depending on the price of scrap.[45]

[45] The modelling here is based on a scrap price of €300 on the basis of moderate medium-term forecasts, although at the current peak of raw material prices scrap has a market price of around €500/t (January 2022).

B.3 Comparison of EAF-DRI investment with different levels of CAPEX in the cases of BF relining, BF brownfield and BF greenfield

In this section we compare the EAF-DRI CAPEX with the necessary capital expenditure in case of relining a blast furnace, a BF brownfield investment and a BF greenfield investment. As can be seen, the DRI-EAF investment is 30% higher than a BF/BOF greenfield investment. We then analysed the minimum CO_2 price required under different electricity price conditions to make the DRI-EAF investment competitive compared with other investments.[46]

	CAPEX (€/t)	CO_2 marginal abatement cost (€40/MWh)	CO_2 marginal abatement cost (€60/MWh)
BF RELINING	48.3	90	125
BF/BOF BROWNFIELD	170	84	119
BF/BOF GREENFIELD	442	70	105
DRI-EAF	577		

Source: Syndex calculations from investment data of Vogl, V. et al (2018).[47]

In order for it to be more economically profitable to invest in a DRI-EAF compared with the daily maintenance of a BF-BOF, the CO_2 price has to be higher than €90/tCO_2 if the electricity price is €40/MWh, or higher than €125/tCO_2 if the electricity price is €60/MWh.

If we compare the DRI-EAF investment with a brownfield BF-BOF investment, the CO_2 price level drops slightly compared with the previous case.

Finally, if we compare a BF/BOF greenfield investment with a DRI-EAF greenfield investment, the latter will be more economically interesting at a CO_2 price of €70/tCO2 in case of €40/MWh and €105/tCO2 in case of €60/MWh.[48]

B.4 The specific case of using hydrogen as an auxiliary reducing agent in BF/BOF

The possibility of hydrogen injections has been modeled technically and theoretically by C. Yilmaz et al. (2017). Their simulation shows that at the optimal operation conditions with a hydrogen injection rate of 27.5 kg/t steel, the CO_2 emissions of the blast furnace can be reduced by 21.4%.[49]

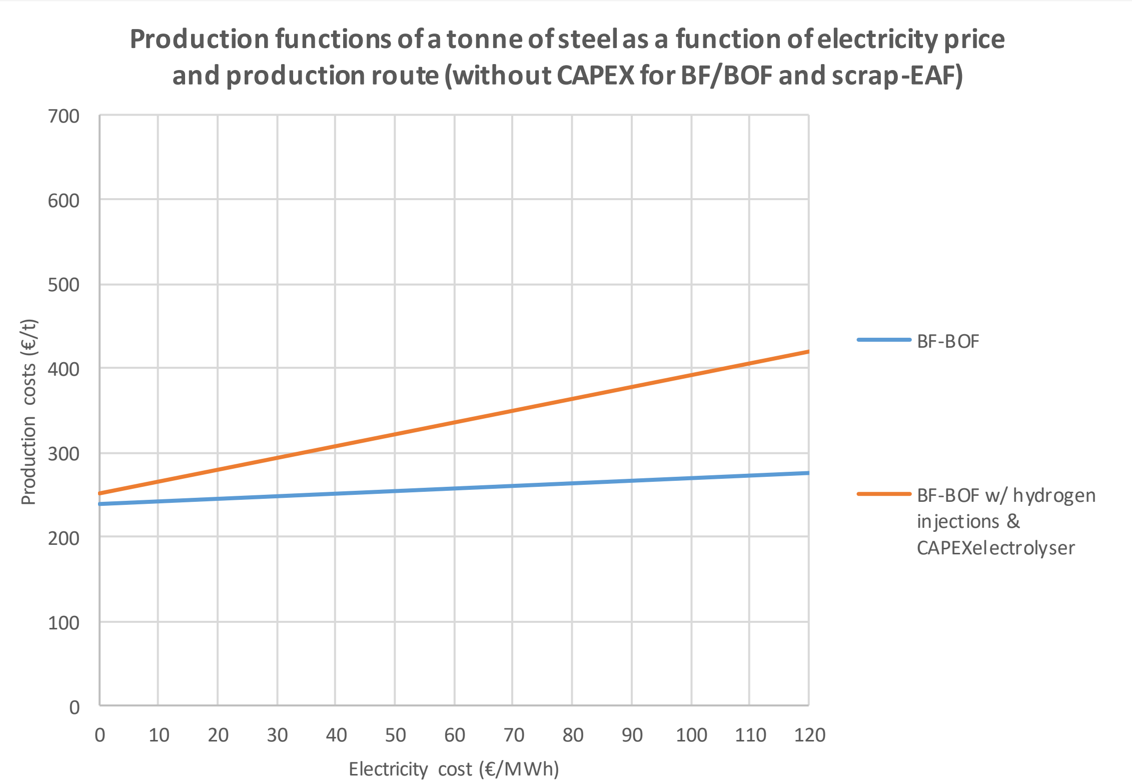
[46] For simplification purposes, it has been assumed that the electricity used is green in all scenarios.

[47] We estimate for all investments a useful life of 15 years and an applied discount rate of 5%.

[48] However, it is important to note that greenfield BF/BOF investments are practically non-existent at present.

[49] Relative to typical operations that use pulverized coal at an injection rate of 120 kg/t steel

In this optimal scenario, the coke consumption is similar to the reference case.[50] For our cost modelling, we will keep the parameters the same in all scenarios except the hydrogen and CAPEX needs. As can be seen below, the first scenario presents the cost of production in the traditional BF-BOF route. In the second scenario, the electricity consumption needed to produce 27.5 kg of hydrogen per ton of steel is added to the production cost function. A third scenario is presented with the investment needed to install an electrolyser (€21/t/year).



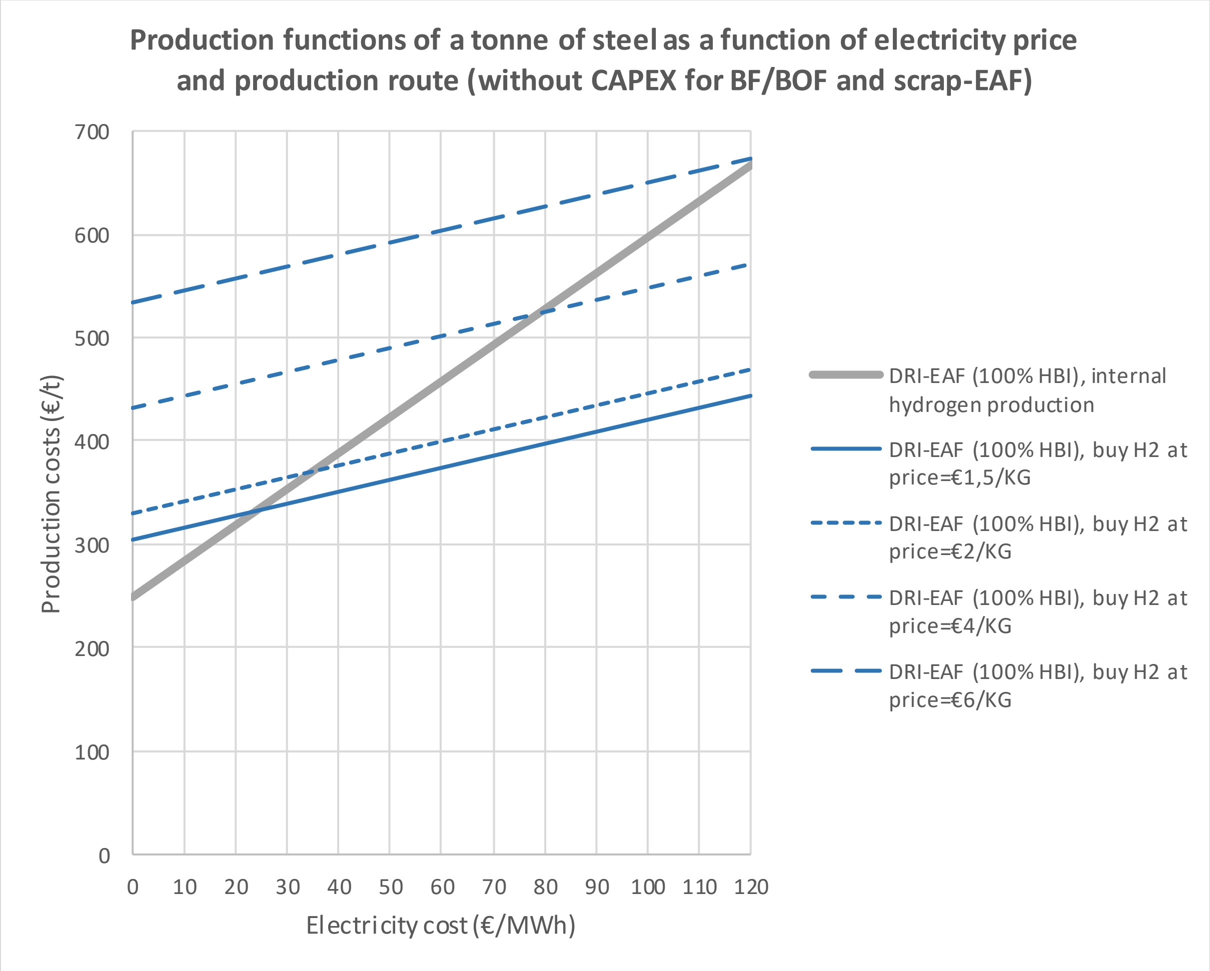
As in the DRI-EAF route, the use of hydrogen as an auxiliary agent is also very sensitive to the price of electricity and the investment required should be offset by a high CO_2 price.

B.5 Analysis of the scenario where steelmakers buy H2 on the market and do not build their own electrolysers

In the previous sections we presented modelling scenarios in which the steelmaker is considered to produce hydrogen internally (i.e. in terms of costs we include the CAPEX of the electrolyser as well as the electricity consumption necessary for hydrogen production). In this section, we compare the DRI-EAF scenario under these conditions with other scenarios where the steelmaker sources hydrogen externally, and which are, therefore, scenarios that vary according to the market price of hydrogen.

For reasons of simplification to allow a correct comparison, only the main production costs have been taken into account (CAPEX, iron pellets, electricity and H2).

[50] In fact, the coke consumption is slightly higher (389.8 kg/t steel in the optimal scenario vs. 373.9 kg/t in the base case) due to the need to maintain the thermal state of the furnace.



As is latent in the graph, off-site hydrogen supply is only interesting when green hydrogen is at a relatively low price level or under conditions of electricity price peaks where the price of hydrogen is offset by relatively lower energy consumption.

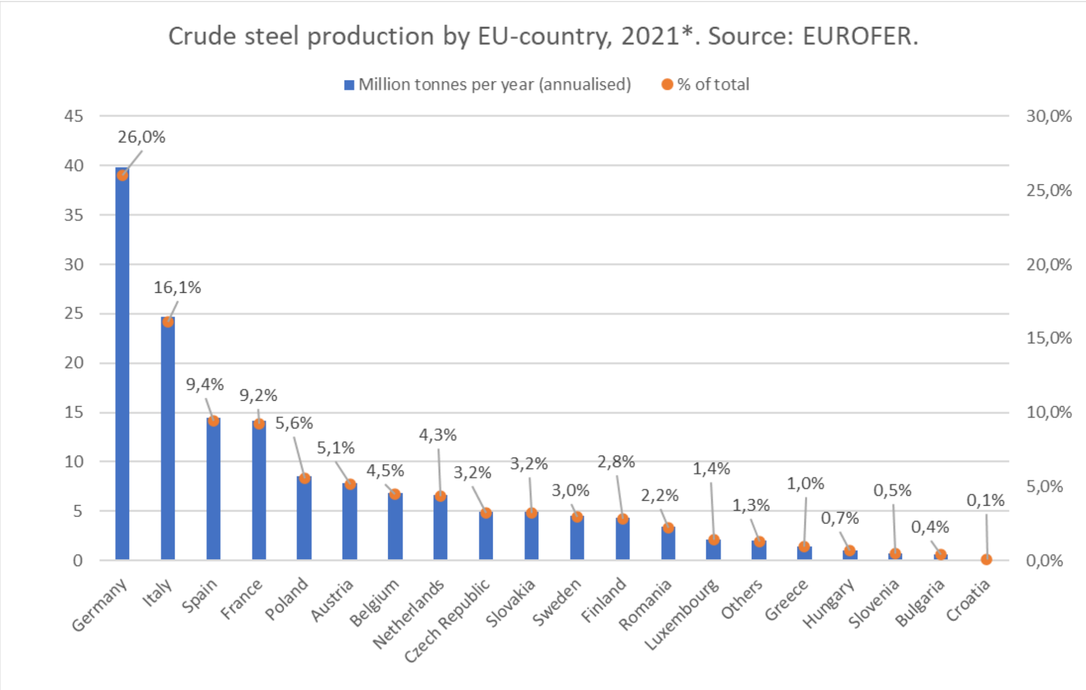
Concerning the price of electricity, either it will be directly charged to steelmakers (if they possess their own electrolysers) or it will be reflected indirectly in the price of green hydrogen. However, the price of electricity in Europe is both regionalised and variable. Thus, modelling the cost function of EAF-DRI with internal H2 production versus different hypothesis with fixed H2 price illustrates the opportunity of an internalisation or an outsourcing of H2 production.[51]

[51] If you consider that you can access cheaper electricity on average than the European market, a steelmaker should internalize the H2 needed in EAF. However, you can also choose to buy (and stock) H2 on the futures market, which will emerge with all the constraints and associated risks (shortage, price outburst etc.).

C. Current locations of both BF-and EAF-based assets in Europe

A total of approximately 150 million metric tonnes (Mt) of crude steel is produced annually in the EU. After a decline in steel production in 2020 due to COVID-19 crisis, production has recovered to the normal value, and the EUROFER data shows a crude steel production quantity of 153.3 Mt.[52]

The largest producer of crude steel in EU By far is Germany. This is followed by countries such as Italy, France, and Spain. In fact, according to 2021 data, Germany produces 26% of the EU's crude steel, while Italy produces 16.1% and France 9.2%. The UK's exit from the EU (which in 2020 produced 5% of the EU's crude steel) led to an increase in these percentages, especially from Italy, which increased its share of total EU crude steel production by 2 percentage points.



Most of the steel in Europe is produced via two basic routes: the Blast Furnace-Basic Oxygen Furnace (BF-BOF) route and the Electric Arc Furnace (EAF) route.

Just under 60% of EU steel is produced via the BF-BOF production route, while just over 40% is produced via the EAF. However, there is a higher number of production sites in the EU using the EAF route (a total of 122) while the BF-BOF route is used in a lower number of production sites (a total of 25). Of the 25 production sites on the BF-BOF route, most have both technologies. The Ostrava production site in the Czech Republic is the only one with just BF technology, while just two production sites — one in Avilés, Spain, and the other in Völklingen, Germany— have only BOF technology.

[52] This figure is annualised but for the final report, we will probably be able to give the real figure.

Map of EU steel production sites by production route, 2020. Source: EUROFER.

EU countries have a total of 146 EAFs and 54 BF-BOFs (3 with BF technology only and 1 with BOF technology only). Germany has the most BF-BOF furnaces (14) and, although it also has a large number of EAF furnaces (25), Italy is ahead of Germany with a total of 33 EAF furnaces.

Although there are far more furnaces on the EAF route, the production capacity of these furnaces is lower than the production capacity of the BF-BOF route with a smaller number of furnaces. Germany is the country with the highest steel production capacity on the BF-BOF route. Italy, however, is the country with the highest steel production capacity on the EAF route, followed by Spain and, in third place, Germany. Countries such as France, Italy, the Netherlands, Poland, and Austria also have significant production capacity on the BF-BOF route. Without breaking down the type of steel production route, Germany is the country with the largest production capacity (43,730,000 tonnes per year), followed by Italy (34,020,000 tonnes per year), Spain (22,520,000 tonnes per year) and France (18,880,000 tonnes per year). The EU-27 utilisation rate for 2021 is 84.41%.

EU steel capacity production & number of furnaces by country &route. Source: EUROFER.

('000 tonnes/year)	BF-BOF ROUTE			EAF ROUTE		TOTAL PRODUCTION CAPACITY	2021 UTILISATION RATE
	Nº FURNACES	PRODUCTION CAPACITY		Nº FURNACES	PRODUCTION CAPACITY		
		HOT METAL	FINISHED METAL				
AUSTRIA	5	5710	7570	3	845	8415	93,56%
BELGIUM	2	4430	5000	5	3400	8400	81,54%
BULGARIA	0	0	0	2	1000	1000	58,51%
CROATIA	0	0	0	2	535	535	29,86%
CZECH REPUBLIC	5*	5300	2400	3	270	2670	185,54%
FINLAND	2	2400	2600	3	1660	4260	101,15%
FRANCE	5	11960	11850	14	7030	18880	75,04%
GERMANY	14**	27490	28960	25	14770	43730	91,16%
GREECE	0	0	0	5	3450	3450	42,54%
HUNGARY	2	1310	1650	1	400	2050	51,79%
ITALY	4	9590	11500	33	22520	34020	72,52%
LUXEMBOURG	0	0	0	2	2250	2250	94,30%
NETHERLANDS	2	6310	7500	0	0	7500	88,51%
POLAND	3	5810	7600	9	4490	12090	70,89%
PORTUGAL	0	0	0	2	1700	1700	129,41%
ROMANIA	2	3250	3200	4	2300	5500	61,58%
SLOVAKIA	2	2850	4500	1	350	4850	101,70%
SLOVENIA	0	0	0	3	790	790	91,39%
SPAIN	3**	4480	5400	23	17120	22520	64,23%
SWEDEN	3	4000	3900	6	1895	5795	78,55%
TOTAL UE27	**54**	**94890**	**103630**	**146**	**86775**	**190405**	**80,53%**

*3 are BF only.

**1 is BOF only.

D. Potential H2 needs of the European steel sector

D.1 The challenges of the European steel sector with regard to hydrogen

Based on the following green hydrogen requirements per tonne of steel:

- H2-BF: 27.5 Kg H2.[53]
- DRI-EAF (100% HBI): 51 Kg H2.[54]
- DRI-EAF (50% HBI 50% SCRAP): 25 Kg H2.

And considering the current EU steel production capacity (table: EU steel capacity production & number of furnaces by country & route), the total green hydrogen needed to produce European steel if we move from the traditional routes to the emission reduction routes analysed, are as follows:

- Shift from traditional BF-BOF to H2-BF-BOF route (A) + shift from traditional EAF to DRI-EAF route (B):
  - If DRI-EAF route uses 100% HBI: 7 million tonnes of H2.
  - If DRI-EAF route uses 50% HBI & 50% SCRAP: 4.8 million tonnes of H2.
- Shift from traditional BF-BOF & EAF routes to DRI-EAF route (C):
  - If DRI-EAF route uses 100% HBI: 9.3 million tonnes of H2.
  - If DRI-EAF route uses 50% HBI & 50% SCRAP: 4.5 million tonnes of H2.

[53] Source: https://www.sciencedirect.com/science/article/abs/pii/S0959652617306169

[54] Source: Vogl, V., ÅHman, M., & Nilsson, L. J. (2018). Assessment of hydrogen direct reduction for fossil-free steelmaking. Journal of Cleaner Production, 203, 736 745.

This means that the total potential hydrogen requirements vary between 4.5 and 9.3 million tonnes, depending on the routes chosen.

RENEWABLE HYDROGEN REQUIREMENTS OF CURRENT STEEL PRODUCTION CAPACITIES							
('000 Mt H2 requirements)	SHIFT FROM TRADITIONAL BF-BOF TO H2-BF-BOF ROUTE (A)	SHIFT FROM TRADITIONAL EAF TO DRI-EAF ROUTE (B)		TOTAL (A + B)		SHIFT FROM TRADITIONAL BF-BOF & EAF ROUTES TO DRI-EAF ROUTE (C)	
		100% HBI	50% HBI & 50% SCRAP	H2 BF & DRI-EAF (100%HBI)	H2 BF & DRI-EAF (50%HBI &50%SCRAP)	100% HBI	50% HBI & 50% SCRAP
AUSTRIA	157.0	43.1	21.1	200.1	178.2	334.3	163.9
BELGIUM	121.8	173.4	85.0	295.2	206.8	399.3	195.8
BULGARIA	-	51.0	25.0	51.0	25.0	51.0	25.0
CROATIA	-	27.3	13.4	27.3	13.4	27.3	13.4
CZECH REPUBLIC	145.8	13.8	6.8	159.5	152.5	284.1	139.3
FINLAND	66.0	84.7	41.5	150.7	107.5	207.1	101.5
FRANCE	328.9	358.5	175.8	687.4	504.7	968.5	474.8
GERMANY	756.0	753.3	369.3	1 509.2	1 125.2	2 155.3	1 056.5
GREECE	-	176.0	86.3	176.0	86.3	176.0	86.3
HUNGARY	36.0	20.4	10.0	56.4	46.0	87.2	42.8
ITALY	263.7	1 148.5	563.0	1 412.2	826.7	1 637.6	802.8
LUXEMBOURG	-	114.8	56.3	114.8	56.3	114.8	56.3
NETHERLANDS	173.5	-	-	173.5	173.5	321.8	157.8
POLAND	159.8	229.0	112.3	388.8	272.0	525.3	257.5
PORTUGAL	-	86.7	42.5	86.7	42.5	86.7	42.5

ROMANIA	89.4	117.3	57.5	206.7	146.9	283.1	138.8
SLOVAKIA	78.4	17.9	8.8	96.2	87.1	163.2	80.0
SLOVENIA	-	40.3	19.8	40.3	19.8	40.3	19.8
SPAIN	123.2	873.1	428.0	996.3	551.2	1 101.6	540.0
SWEDEN	110.0	96.6	47.4	206.6	157.4	300.6	147.4
TOTAL EU27	2 609.5	4 425.5	2 169.4	7 035.0	4 778.9	9 264.9	4 541.6

As outlined in Chapter 1, EU hydrogen demand in 2020 was 8.4 million tonnes. Half came from the refining sector, 40% from the ammonia industry and 13% from other chemical industries. That is, the refining and chemical industries accounted for 93% of hydrogen demand, while the remaining 7% was distributed among other industries, including the steel production industry. According to Aurora Energy Research, in the long term, the current leaders in hydrogen demand are expected to remain the same, refinery demand is expected to decrease and demand from the steel and cement sector is expected to increase considerably, in view of the goal of decarbonisation. Thus, it was stated in Chapter 1 that the projected consumption of low-carbon hydrogen in industrial projects would amount to 5.2 million tonnes per year by 2030, with steel accounting for 38% of this demand, i.e. the demand for low-carbon hydrogen from the steel industry in 2030 is expected to be around 2 million tonnes per year. In addition, an analysis by Green Steel for Europe[55]estimates that the steel sector will need around 5.5 million tonnes of hydrogen per year by 2050.

Comparing these estimates with the calculations in the table above, there is a significant difference, however; the data presented is a theoretical calculation of maximum hydrogen needs if the entire European industrial park were to become hydrogen based and produces at full utilisation level.[56]

There are several factors that will influence hydrogen requirements in the future. First, the chosen route will have a considerable impact as H2 injections in BF-BOF or using scrap[57] in the production process of the DRI-EAF technology leads to a significant drop in H2 needs, in addition to energy consumption.

Then, we must consider the gradual nature of the transformation process (level of maturity and availability of technologies, final choice of technology, level of development of blue/green hydrogen

[55]Green Steel for Europe (2021). Collection of possible decarbonisation barriers (deliverable 1.5).

[56] The utilisation rate, measured as actual output over productive capacity, was 80% by 2021, according to Eurostat.

[57] Taking into account that EU countries have a share of scrap in the total metal inputs of around 50-60% (IEA, 2020), it is to be expected that a significant proportion of scrap will be used in the DRI-EAF route, since this reduces the need for hydrogen and energy consumption.

production capabilities[58], access to finance and timing of investments) as well as the need for large energy deployment. As already discussed in chapter 1, S&P Global Platts assessed that reaching the target of producing 10 million tonnes of low-carbon hydrogen would require additional renewable energy generation of 477 TWh, which is roughly equivalent to 824% of the current electricity demand by the EU steel industry. In addition, the large economic impact of such amounts of electricity consumption must not be forgotten in the market price, even though there may be supply alternatives or mechanisms that could reduce the cost for the industry.

Based on these factors, we have adjusted the two scenarios presented above.

('000 Mt H2 requirements)	SHIFT FROM TRADITIONAL BF-BOF TO H2-BF-BOF ROUTE (A) + SHIFT FROM TRADITIONAL EAF TO DRI-EAF ROUTE (B)	SHIFT FROM TRADITIONAL BF-BOF & EAF ROUTES TO DRI-EAF ROUTE (C)
Potential need for hydrogen taking into account the total steel production capacity	4.8-7 million tonnes, depending on the amount of scrap and HBI used	4.5-9.3 million tonnes, depending on the amount of scrap and HBI used
Adjusted H2 needs based on the utilisation rate of production plants[59], use of renewable hydrogen[60] and gradualness of the process	2.6-3.9 million tonnes (depending on the share of scrap and HBI).	2.5-5.6 million tonnes (depending on the share of scrap and HBI)
Energy requirement[61]	124-186 TWh	120-267 TWh

The first scenario presented could be seen as transitional, but as we all know, by 2050 the goal is to reach climate neutrality. A hypothetical full transition of the European steel industry[62] to the DRI-EAF route based on green hydrogen taking into account a significant percentage of scrap use, which would result in an estimated hydrogen need of around 2.5-5.6 million tonnes. These results would imply an additional energy demand of 120-267 TWh.

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[58]According to IEA, the use of grey hydrogen without CCUS in steelmaking was 5 million tonnes globally in 2019 worldwide. This is projected to be almost 7 million tonnes in 2030 and to drop to 6 million tonnes in 2050. The use of blue hydrogen (grey hydrogen with CCUS) would increase to almost 1 million tonnes in 2050. And the use of green hydrogen is expected to accelerate dramatically from the early 2030s, following the introduction of green hydrogen-based DRI technology to the market. Thus, the steel sector's demand for low-carbon hydrogen (blue and green) will grow from trifling levels today to 17 million tonnes of demand in 2050, 70% of which will be green hydrogen. Therefore, a scenario is envisaged in which, globally, 8% of total steel production in 2050 will rely on green hydrogen as a reducing agent.

By 2050, the same IEA report predicts that the hydrogen-based DRI-EAF route will be significantly deployed with approximately 10 commercial-scale plants (amounting to around 15 million tonnes of steel production) replacing blast furnaces. In addition, about 15% of the blast furnaces will be equipped with CCUS technology, because this technology is already being deployed.

[59]Applying 2021 utilisation rate (80%)

[60] Considering that not all projects to decarbonise the steel industry revolve around green hydrogen, but that other types of low-carbon hydrogen are also developed, these estimates of green hydrogen needs would also be reduced, i f, as shown above, it can be estimated that 70% of this hydrogen will be green hydrogen by 2050 (IEA).

[61] According data from S&P Global Platts.

[62]Calculations have been made on the basis of current capacities, with the knowledge that European demand is expected to grow considerably in the short and medium term.

D.2 Potential impact on the H2 market following increased H2 demand by the steel sector

The European Hydrogen Strategy[63] sets out the objectives of producing up to 1 million tonnes of green hydrogen by 2024 and up to 10 million tonnes by 2030; achieving maturity and large-scale deployment of renewable hydrogen technologies, reaching the most difficult sectors to decarbonise, and massively increasing their production by 2050.

A 2021 study by Flanders Investment &Trade market survey[64] places some countries as potential green hydrogen exporters for the 2030s. It, therefore, thus demonstrates the forecasts of a change in the hydrogen market, which could change from being a product produced for its own consumption to one with its own European and international market, in which the European Union intends to develop a leading position.[65]

At present, as explained in chapter 1 and in the previous section, the demand for hydrogen (grey) in the EU as a whole is around 8.4 million tonnes (2020), of which the steel, glass, food processing, energy and transport sectors share 7%. This figure is significantly lower than the projected green hydrogen needs.

In the previous section, it was explained that institutions such as Aurora Energy Research estimated an increase in hydrogen demand from the steel sector due to the decarbonisation process. This process, obviously, is not exclusive to the steel sector, but is taking place in the European Union and the world as a whole; therefore, as with steel, it will lead to an increase in demand for green hydrogen from other sectors. However, steel is one of the world's largest CO_2 emitting industries and one of the most difficult sectors to reduce its emissions due to the few alternative decarbonisation pathways available to it, making it potentially dependent on hydrogen for full decarbonisation (Hydrogen Council, 2021). This dependence implies that the steel sector's demand for green hydrogen could grow in the coming decades to a greater extent than other sectors that have more viable alternative decarbonisation pathways available to them.

In fact, as can be seen in the following graphs[66], steel is one of the sectors where the use of hydrogen is expected to be decisive in reducing emissions, becoming the single largest sub-segment for clean hydrogen in 2030.

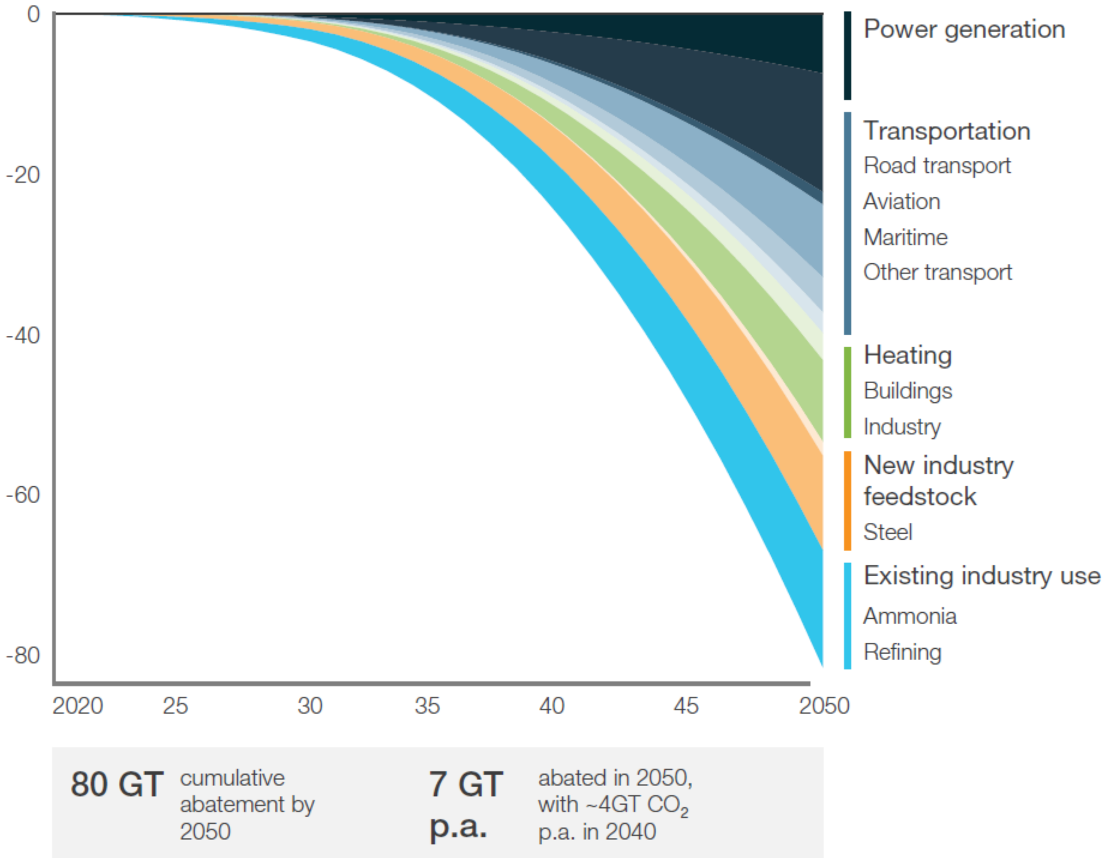
[63] European Commission (2020, July 8). Communication from the Commission to the European Parliament, Council, the European Economic and Social Committee and the Committee of the Regions: A hydrogen strategy for a climate-neutral Europe. Brussels.

[64] https://www.flandersinvestmentandtrade.com/export/sites/trade/files/market_studies/2021-Spanje-The%20green%20hydrogen%20energy%20in%20Spain-Website.pdf

[65] European Commission (2020, July 8). Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions: A hydrogen strategy for a climate-neutral Europe. Brussels.

[66] Hydrogen Council, McKinsey & Company (2021). Hydrogen for Net-Zero. A critical cost-competitive energy vector.

Global emissions abated by hydrogen end use (gigaton metric -GT- CO_2 cumulative up to 2050)[67]. Source: Hydrogen Council.



All this demonstrates the major impact that, along with other sectors, increased hydrogen demand by the steel production sector will have on the hydrogen market. This potential increase in demand for hydrogen by different sectors could lead to a shift in the hydrogen market in such a way that hydrogen production plants are developed independently of the consumer plants, creating an independent market for renewable hydrogen. Aurora Energy Research, as discussed in Chapter 1, explains that the projected consumption of low-carbon hydrogen in industrial projects will amount to 5.2 million tonnes per year by 2030, with steel accounting for 38% of this demand. This is undoubtedly a significant increase in the importance of the steel sector in the hydrogen market and, consequently, its impact on the hydrogen market.

[67] Hydrogen Council (2021) states that industry and mobility will account for the largest share of this potential for emission reductions through hydrogen use, since, for example, in the aviation and shipping sectors, hydrogen-based fuels are also the only viable large-scale decarbonisation option; and chemicals and steel will provide another third of the total emission reduction potential from hydrogen.

Chapter 3. Decarbonisation and H2: an opportunity for backshoring steel production capacity in Europe?

A. CBAM: Definition and legislative context

The European strategy on climate neutrality has moved forward with the publication in July of the EU Regulation 2021/1119, called the "European Climate Law". This regulation sets the framework for achieving climate neutrality and it formally enshrines in EU law the new binding target of reducing the EU's net greenhouse gas (GHG) emissions by at least 55% between 1990 and 2030 (previously 40%) and the collective binding target of carbon neutrality (or zero net emissions) in the EU by 2050.

The new political and legislative package (13 proposals for measures known as Fit for 55) was published on the 14th of July, and aims to put these new objectives into practice.

Fit for 55 sets up a combination of measures for pricing, targets, standards and support, including revision of the EU ETS directive and its emissions allowance system (accelerating the reduction of free allocations) and a regulation establishing a Carbon Border Adjustment Mechanism (CBAM) to combat carbon leakage from sectors including steel.

The draft EU regulation for the introduction of a carbon border adjustment mechanism at EU borders from 2026 is part of Fit for 55:

- to combat the adverse carbon leakage effects of this new strategy,
- and push other EU trading partners to adopt new climate targets and instruments.

The CBAM project foresees the creation of a mirror mechanism to the EU ETS carbon market, i.e. the establishment of a price for carbon equivalent to the price of ETS emissions allowances for imported products. The companies concerned will have to surrender CO_2 emission certificates (or CBAM certificates) according to the carbon intensity of imported products. The price of certificates will be aligned with the price of ETS allowances (average of ETS price per week). For this system to be monitored, companies will have to declare their imports to a competent national authority.

The draft regulation provides for a mechanism modelled on the Emissions Trading Scheme (ETS) for importers to the EU. In an initial phase, imports of iron and steel, aluminium, electricity and fertilisers were selected to be covered by the CBAM, as they account for 55% of the emissions at risk for carbon leakage.

Exporting countries of products potentially covered by CBAM and their share in European imports by sector

Sectors covered	Ciment (European consommation coming from imports: 2,6%)	Fertilisers (European consommation coming from imports: 29,5%)	Iron & Steel (European consommation coming from imports: 19,7%)	Aluminium (European consommation coming from imports: 36,6%)	Electricity
1	Turkey: 34%	Russia: 31%	Russia: %15	Norway: 18%	Switzerland: 27%
2	Colombia: 8%	Egypt: 9%	Turkey: 11%	Russia: 14%	Norway: 18%
3	Ukraine: 7%	Belarus: 8%	Ukraine: 10%	China: 9%	Russia: 13%
4	Belarus: 7%	Algeria: 8%	China: 8%	United Arab Emirates: 7%	Ukraine: 7%
5	Bosnia-Herzegovina : 4%	Morocco: 7%	South Korea: 8%	Switzerland: 7%	Bosnia-Herzegovina : 6%

The project foresees full implementation of the CBAM from 2026. In a transitional stage (01/01/2023 to 31/12/2025), importers in the four selected sectors will have to report the CO^2 emissions contained in their products as well as the carbon price they have already paid (or not) abroad.

One of the challenges will be to determine the carbon content of an imported product and thus facilitate the exchange of information regarding the production process between third countries and the EU.

In order to avoid European companies being doubly protected from carbon leakage, the allocation of free allowances should be phased out by a 10% reduction each year over a period of 10 years. To be WTO compatible, the EU will not be able to offer double protection to the pre-selected sectors since the WTO has already organised exchanges between the European Commission and its main trading partners.

The phasing out of free allowances as a prerequisite will force the industries concerned to pay for their emission allowances in order to continue their activity or to implement action plans to reduce their emissions.

At this stage, only direct emissions are covered by CBAM i.e. only scope 1 of steelmaking carbon footprint is taken into account. Electricity (scope 2, which extremely determines the carbon footprint of EAFs and DRIs) and transport (including in scope 3) are not yet concerned by the mechanism. Nevertheless, steelmakers will have to communicate their emissions regarding scope 2 from 2023 to 2025 but their integration into the MCAF has not yet been decided. They may be included in a second stage. Scope 3 might eventually be considered for so-called complex goods in two different approaches. First, CMAB might include upstream emissions, when they represent the largest share of the carbon footprint of these products. Besides, future revisions to the mechanism could include transport-related emissions.

There are pros and cons regarding scope 2 and electricity. The risk of resource shuffling is especially pinpointed by some industrial actors. Resource shuffling is a strategic decision by players which choose to export the lowest carbon-intensive portion of their production to markets with high carbon costs (for instance, Europe) and use high carbon footprint products in their national market or in regions concerned with less expansive carbon market. With resource shuffling there is a risk that for specific industry some carbon leakage could be favoured.

The share of carbon-free production at the global level may not change. Imports into Europe would take precedence over local production without exporting countries having decarbonised additional assets.[68]

Thus, this risk is present when the mechanism relies on actual emissions at the level of an installation rather than for instance on national energy mix. This effect is extremely difficult to assess. Modelling has been made by the European Commission as part of the impact assessment report. The steelmaking industry might be less exposed to this risk than other electro-intensive industries. The Commission in its assessment report writes that carbon leakage resulting from resource shuffling is minimal for the European steel sector.

The European electricity market can also be considered as a disadvantage for European REIIs because prices are calculated according to a merit order based on variable costs. If the last source called is carbonised (e.g. gas or coal) then the carbon price included in electricity does not represent the local mix or the real carbon footprint of the sources of electricity used by an industrialist/manufacturer. It must be noticed that REEIs usually benefit from complex contracts and thus are not totally exposed to the electricity gross market. They can also benefit from indirect compensations. For the moment, however, their renewals trough the CBAM context are uncertain.

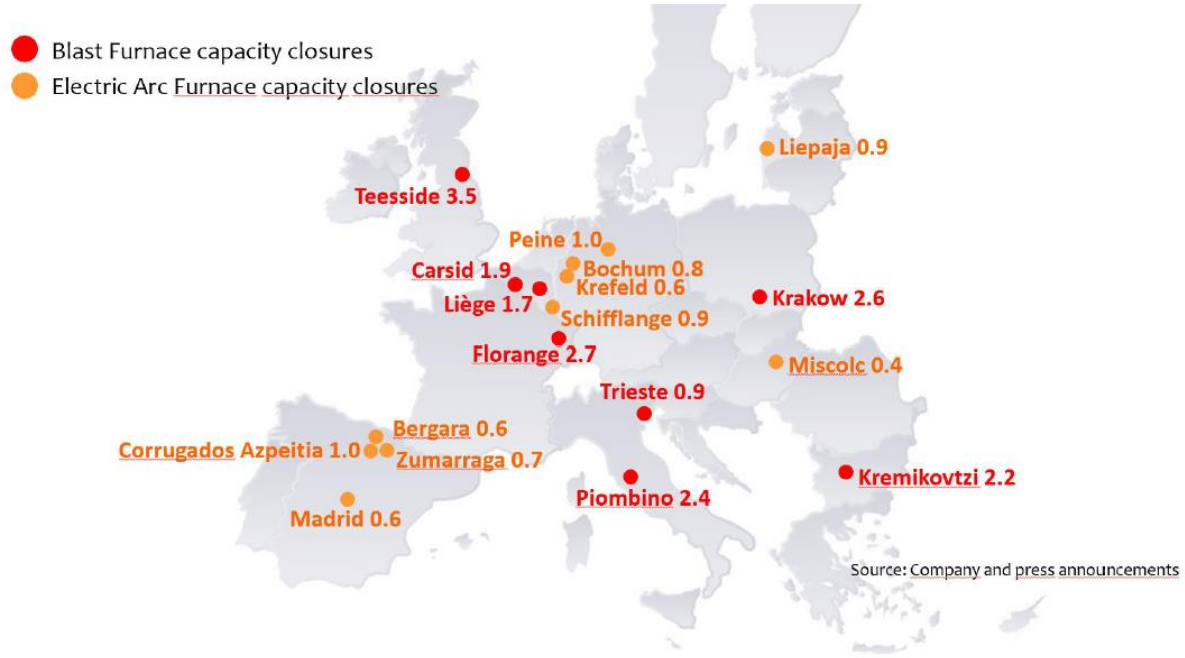
More generally, electricity prices (level, volatility etc.) in Europe can be a source of risks for actual and future REEIs. Taking into account the national/ regional mix of importers could be a good answer to the current functioning of the electricity market in Europe.

B. A brief and initial overview of the competitiveness of European steel making assets in the context of the CBAM.

The reality of the European steel industry can be summed up as follows: while between 2009 and 2020 more than 26 Mt/y of steelmaking capacities have been closed in Europe, at the same time, the European steel trade balance has presented a growing deficit during this period. This will be explained in more detail below.

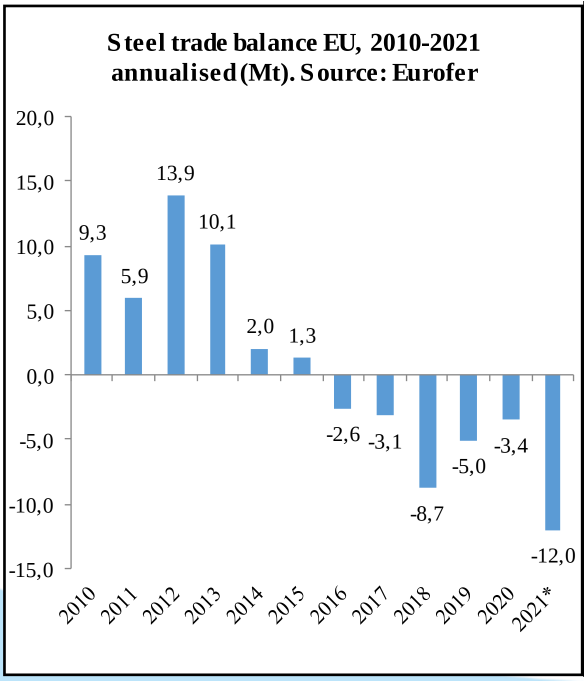
[68] This risk exists particularly in the primary aluminium industry regarding Chinese production, in which 15% is based on hydro-electric process. This more decarbonised aluminium could first serve the European market, which could eventually lead to new closures in Europe while the rest of the carbon-based capacity would serve the local Chinese market (or other exports). In this case, the CBAM would not have led to transforming high carbon footprint capacity towards carbon reduction in Europe or globally.

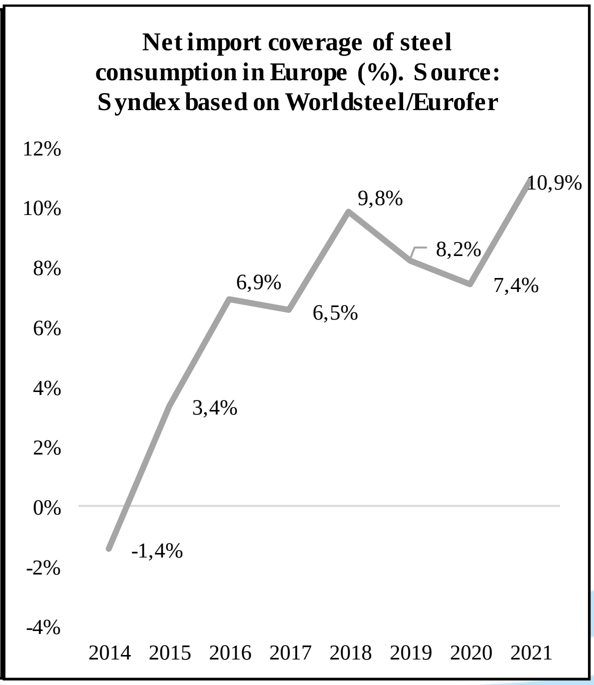
Capacity closures in Europe between 2009 and 2020. Source: Eurofer

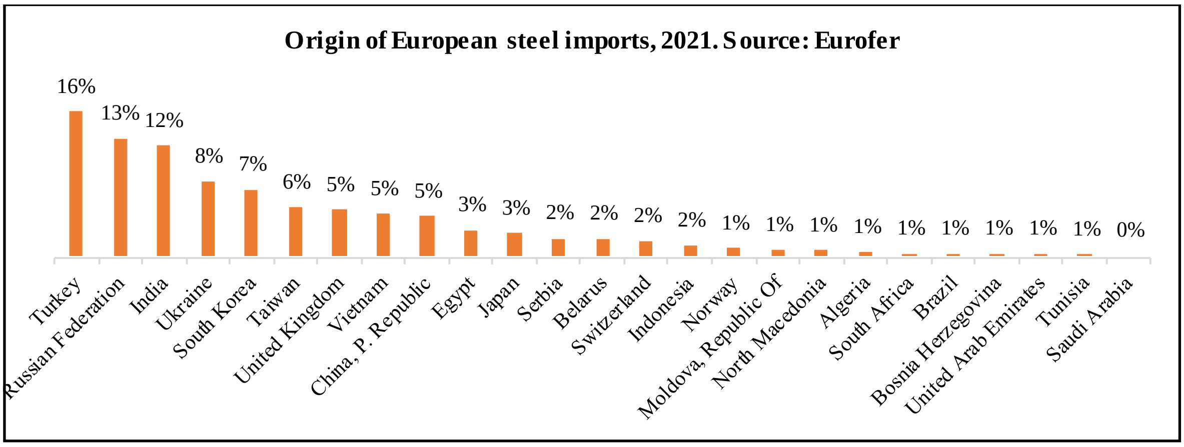


After the global crisis of 2008 and the steel crisis of overcapacity in 2015, the European steel industry has recovered but weaknesses remain. It can be seen that for years there has been a shortage of production capacity to cover European demand (a large number of European plants are still shut down or mothballed) and the European steel industry is divided into two subsets: plants operating at maximum capacity and achieving high results, which contrast with plants weakened by the crisis and handicapped by their unused mothballed facilities.

The result of this deindustrialisation is a European shortage of production capacity, highlighted in recent years by the imports to cover a considerable proportion of European demand.







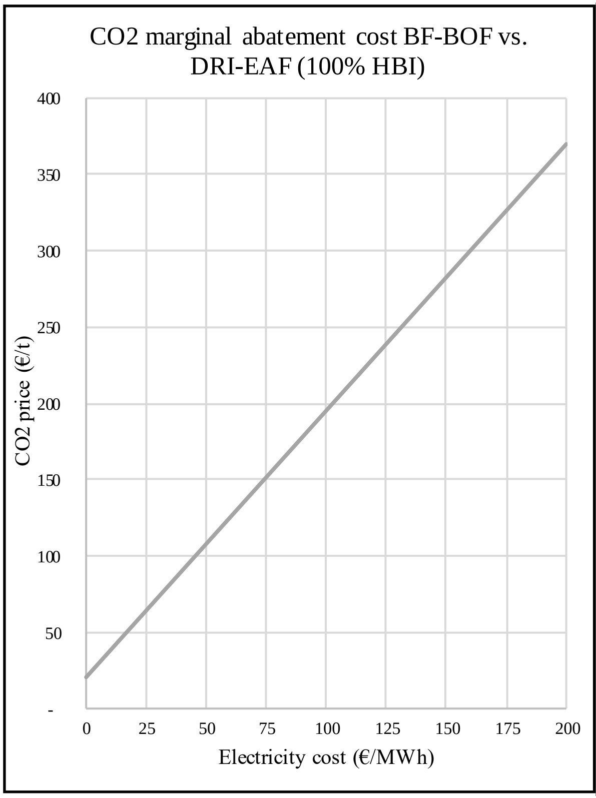
This draws a clear picture: steelmaking in Europe has reached a situation of under capacity.
Although the Commission launched and successfully reinforced safeguard measures, import pressures have, nevertheless, remained strong and currently no new capacities (or so-called "greenfield" projects) are planned in Europe, whereas there has been a strong recovery in demand and the trend for the following years is good.[69]
This divergence between production and demand only accentuates the risk of carbon leakages.

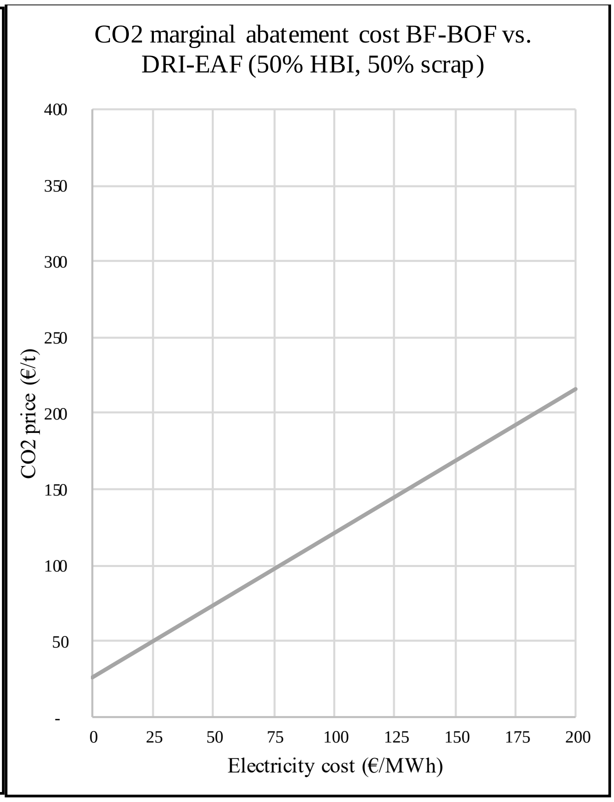
Faced with the challenge of decarbonisation, creating a framework that can ensure the environmental and economic sustainability of the European steel industry is crucial to ensure its survival in the medium term. Otherwise, the risk of an acceleration of the European deindustrialisation process would become even more acute.

In the following pages we analyse the minimum CO_2 price level that makes the investment in DRI-EAF sustainable compared to BF-BOF production, i.e. a CO_2 price necessary to make European decarbonised production economically viable compared to carbon imports[70] in relation to the cost of electricity. The minimum CO_2 price can be either the ETS/CBAM market price or the effective CO_2 price using carbon contracts for difference.

[69] This situation has been very latent in 2021 with demand practically recovered post-crisis; the extension of trade protection measures by the European Commission, and nevertheless, a production limit that has led to having to resort to imports to meet European demand, registering a record trade deficit in 2021.

[70] Once there are no free quotas for European producers.

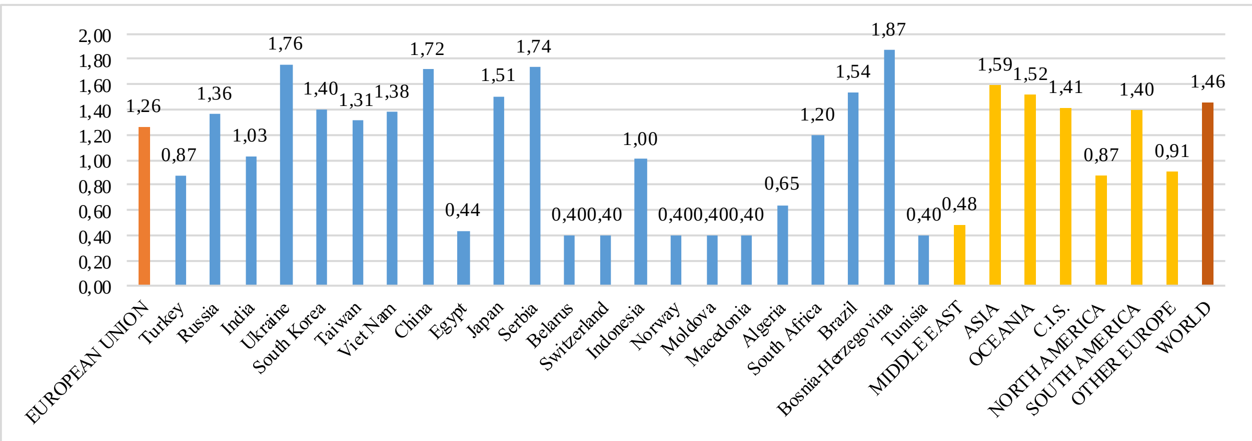




With a CO_2 price lower than those presented here, imports would still be more competitive than competitiveness of imports that are more carbon intensive than the European one, and therefore, would not favour the decarbonisation of the sector both at European and global level.

Below we can see an estimation (in the absence of concrete carbon footprint tracking) of the average emissions per tonne of steel produced per country according to the production routes, which gives an idea of the level of carbonisation of the steel industry in the main exporting countries.

Estimated direct emissions as a function of the production mix by production pathway[71] (2019, tCO2/t steel)



[71] Theoretical calculation by calculating the average direct emissions as a function of the production route used in the total annual production in 2019 (Worlsteel), applying an emission of 1.87 tCO2/Tsteel for production via BF-BOF and 0.4 tCO2/Tsteel for production via EAF.

C. Policy recommendations to allow the European steelmaking industry to benefit from the electrification revolution, and the absolute necessity of decarbonisation

To allow European steelmaking to become carbon-free while retaining international competitiveness, the H2 industry must be promoted in line with a technology neutral approach and dedicated infrastructures ensuring reliable and secure supply to hydrogen consuming sites, timely and effectively. Any measure and targets addressing the demand side should be based on realistic, transparent and end-user centred impact assessments, accompanied with adequate instruments supporting and rewarding low-carbon hydrogen consumption, while taking international competitiveness fully into account.. Thus, the table below presents some of the possible measures that can encourage an increasing demand and can lower prices for renewable hydrogen. They can be divided into supply-side and demand-side support instruments, regarding both the H2 sector by itself and the steelmaking industry.

Demand-side instruments

Carbon contracts for difference	To transform 50% of EU primary steel production capacity to H2-DRI with current free allocation regime (2022-2035/2040). This instrument facilitates investments in breakthrough technologies by offsetting its additional operating costs. It also reduces the risk of long-term investments. Cost recovery: through climate levy or EU ETS revenues. CCFD will be key policies and will be included in the coming ETS directive. The higher the price of carbon, the less expansive these contracts will be. But they can be an answer to sharp downward cycles which can threaten the carbon reduction process.
Preparing gas-fired power plants to support hydrogen and renewables (2025-2035)	For example, it is possible in Germany thanks to the German Cogeneration Act. Plants receive support per unit of energy generated, covering both the incremental CAPEX as well as the OPEX cost difference between renewable hydrogen and natural gas. Cost recovery: levies on electricity end consumers for the initial investment and budget finance could be considered
General renewable hydrogen quota in gas power plants (from 2035 onwards)	It would be the successor to the previous measure. Cost recovery: additional costs are passed on to end-users.
Public procurement (2022-2050)	Obliging governments to establish strict sustainability criteria for public procurement, in order to create secure markets for sustainably manufactures products. Cost recovery: public budget.
Labelling of climate-friendly basic materials (2022-2050)	Cost recovery: it could initially be covered by industry.

Supply-side instruments

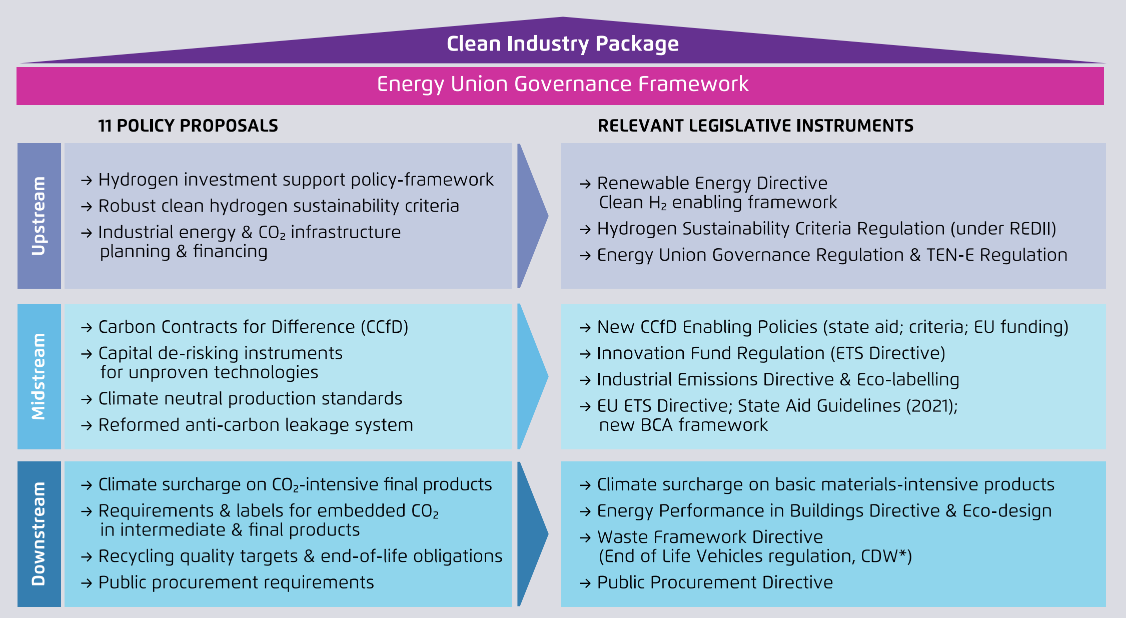
Hydrogen supply contracts	Phase 1: 2022-2030. Phase 2: 2030-2040. It covers for the difference between the lowest possible renewable hydrogen production price and the highest price at which producers or manufacturers are willing to pay for it in a double auction model. Cost recovery: public budget.
Investment aid (2021-2030)	Cost recovery: it could initially be covered by industry. - To build electrolysers. - Cost recovery: EU ETS or Recovery and Resilience Facility. o Fossil-based hydrogen with CO_2 capture as a bridge, as it is lower cost, more accessible and would encourage demand for hydrogen, even if it is fossil-based, thus supporting the transition to renewable hydrogen.

Instruments must be accompanied by measures to ensure that hydrogen delivers the climate impacts it promises, otherwise there is a risk of increased GHG emissions due to increased electricity or natural gas consumption.

As can be seen in the periods considered for the different support instruments, they must be in place for the 2030s, and can be reduced and/or phased out thereafter, while still ensuring market growth. In addition, support for the development of the most reluctant or complex sectors for the application of renewable hydrogen should have already been initiated in the 2030s.

Regarding steel sector and more generally basic material industries, Agora Energiewende presented in 2020 (Agora Energiewende, 2020) the following Clean Industry Package which summarises the different tools that can be mobilised in the considered sector:

Policies and legislative instruments to implement the Clean Industry Package Figure D.13



Agora Energiewende, 2020

Note: CDW stands for Construction and Demolition Waste

It should be noticed that the current efforts are put on upstream and midstream proposals from the different European and national authorities, whereas downstream solutions are less discussed and finally implemented so far. Among this framework, climate surcharge on CO_2-intensive final products appears to be a good complementary policy to the CBAM and can correct a too weak signal from ETS price if this decreases or is confronted with sharp variations. Climate surcharge would be applied to final products wherever they have been produced and without consideration to the processes used for the carbon intensive material composing these final products. Thus, this kind of mechanism is easier to implement (no footprint tracking is needed) and is a clear incentive to material sobriety.

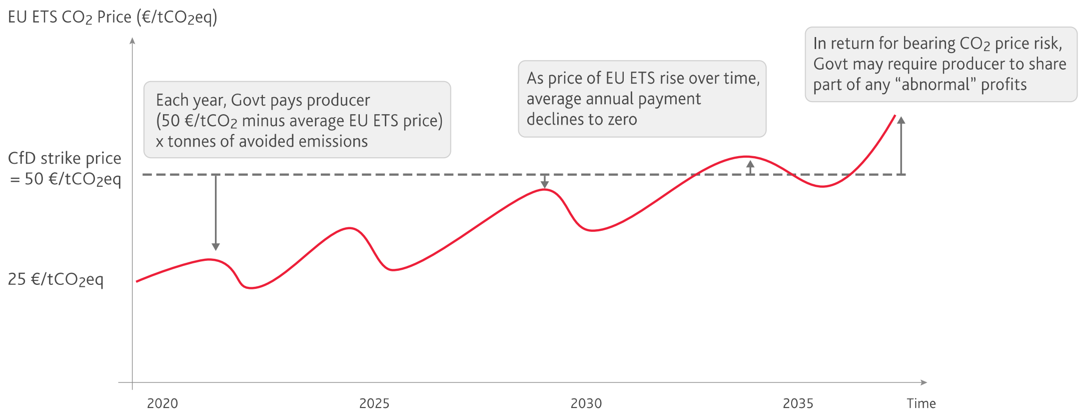
D. A promising financial tool: CCfDs may be a good complement to CBAM

The new version of the ETS directive will include some dispositions regarding the implementation of so-called “Carbon Contract for Difference” (CCfD). However, the terms and details of these contracts have yet to be decided.

These kind of contracts already exist for renewable energy. CCfD are promising financial tools because they allow both, access to financial resources and the reduction of the risk faced by the industry, while considering investments for projects ensuring decarbonisation. They can address one of the most significant weaknesses of the ETS carbon market: carbon price versatility (). It can delay or even threaten investments in viable technologies or in scaling-up from pilot to industrial/commercial scale. This might be especially the case when these technologies imply long term financial perspectives (regarding CAPEX or ROI, 5 to 10 years for steel industry for instance)

This system would be somewhat like a “feed-in- premium/tariff” (FIP/FIT) policy for renewable energy projects to be “financially sustainable ”. This will guarantee producers a fixed carbon price, which will be in fact the abatement cost of the technology compared to the current CO2 price. If the carbon price were higher than the guaranteed price, there would be no payment.

The following graph presents one possible application of CCFD:



Source: O. Sartor, IDDRI.

CCfD would be granted through a tendering process. The criteria used to reward the projects could include:

-capacity to replace significant volume of high-carbon primary materials for relevant usage
-consistency with national long-term decarbonization strategy

-economic justification
-cost per unit of Co2 reduced
-social and environmental or economic co-benefits

Their fiscal commitment would also be sustainable. Thanks to the experience of this kind of contracts in energy, it is safe to assume that CCfD can be implemented consistently within the EUand WTO principles regarding state aids.

Recently ArcelorMittal has announced that three of their operating BF in France will be progressively shifted to EAF based assets[72].

Through the "France 2030" plan, ArcelorMittal and the French government announced that this initiative will benefit from future CCfD mechanism, even if terms and conditions are not decided yet(it will depend on the content of the directive and its transcription in national legislation). This example shows the importance of industrial expectations towards CCfD and that this tool can launch investment plans of decarbonisation of REEIs.

[72] The BF concerned are among those in Dunkirk and Fos-sur-Mer integrated sites. These new green steelmaking assets will have the same capacities that the BF they will replace. Furthermore in Dunkirk a DRI asset is planned.

Conclusion

Within the next two decades we will see a significant restructuration of the steel-making industry in Europe.

One of the main challenges will be the articulation between the private initiatives of the business players of the steel industry with an adequate regulatory framework and an active industrial policy that allows the decarboniation of the sector without deindustrialisation. The stake behind the decarbonisation is the existence of a competitive steel-making industry in Europe.

Within all the green steel technologies, DRI-EAF appears to be the most promising. Some steelmakers already plan these technologies at an industrial scale. Its maturity allows credible business cases.

However, this route implies strong economic fundamentals and policies:

-strong and durable high price of CO2. ETS market can be corrected in this perspective thanks to CCfD

-a consistent and fully implemented CBAM in order to avoid any further carbon leakage. We believe that the main debate regarding this mechanism is to figure out if scope 2 (indirect emissions) has to be integrated or not. There are pro and cons and robust micro-simulations should be carried out in orderto clarify this debate.

-a less volatile (and expensive) price of electricity. Withing EAF-DRI routes, the exposure of steelmakers to electricity price will be unparalleled with the current situation. Electricity will determine, as much as iron ore, the production cost of “green”steel.

Regarding hydrogen and the rest of REEIs, similar concerns can be raised. All hydrogen produced through electrolysis will be consideredas “hyper” intensive electricity materials. The energy needs of electrolysis imply both, massive and large investments in low-carbon electricity power plants and a more stable and predictable functioning of the European electricity markets.
This appears to us as the main priority which must be tackled in parallel to the UE hydrogen strategy and the ETS directives: these three dimensions are the three main pillars of the decarbonization of REEIs and they are equally necessary.

These elements must be implemented at European level but also at the different national and market levels (especially regarding electricity) because the risks of deindustrialisation can be observed for Europe but also within Europe. Some countries have both, significant steel-making footprints and a highly carbonised grid: the risk for them to face restructuring is high because decarbonisation at the continental level can imply “first takes all” logics.

This study cannot be exhaustive on every challenge the steel making sector will face in the future. However, another element needs to be taken into account: The demand for steel both at world and European level is strongly increasing. Not only is it necessary to guarantee the decarbonisation of the current steel park and increase its circularity, but also additional European production capacities will be necessary to meet an increasing demand. Trade defence measures, a well-functioning CBAM and a more efficient and equitable electricity regulatory framework should guarantee the conditions for re-launching new capacities.

Finally, the decarbonisation of the steel sector will have a significant impact on jobs and skills, demonstrating the relevance of a just transition. Several activities, like coke ovens for instance, will shut down, bringing the risk of creating displaced workers. New means of production of steel, and production of different products in the downstream, will raise the need for different skills. The socio-economic risk inherent to the transition towards a carbon-neutral economy and changes to business models pose significant challenges, which are still uncertain and go beyond the scope of this study. Nevertheless, those challenges need to be tackled, preventing the decarbonisation from happening at the expense of workers.

Glossary

BF-BOF	(Hybrid)Blast Furnace-Basic Oxygen Furnace
CBAM	Carbon Border Adjustment Mechanism
CCUS	Carbon capture, use and storage
CCS	Carbon capture and storage
CAPEX	Capital expenditure or investment
CO2	Carbon dioxide
DRI	Direct reduced iron
DRI-EAF	Direct reduced iron in Electric Arc Furnace route
EAF	Electrical arc furnace
ETS	Emission trading system
EU	European Union
GHG	Greenhouse gas
GW	Gigawatt
H2	Hydrogen
H2-BF	Hydrogen injection in a blast furnace
H2-DRI	Hydrogen as the sole reducing agent in the Direct Reduction of Iron
HBI	Hot-Briquetted Iron
IEA	International Energy Agency
Mt	Millions of tonnes
Mt/t	Millions of tonnes per tonne
Mt/y	Millions of tonnes per year
Mtce	Megatonnes of coal equivalent
MW	Megawatt
OPEX	Operational expenditure
PEM electrolyser	Polymer electrolyte membrane electrolyser
SMR	Steam reforming
TRL	Technology Readiness Levels
TWh	Terawatt hour
WACC	Weighted average cost of capital

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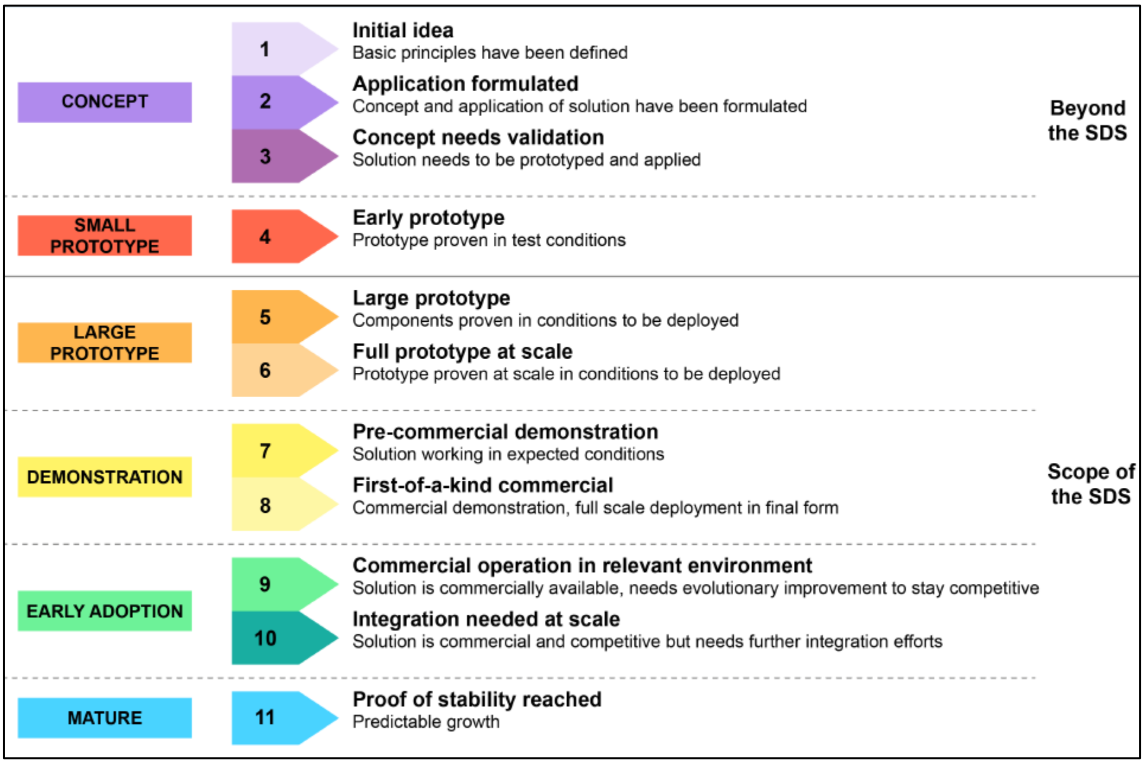
Annex 1: Technology Readiness Level (TRL)

The technology journey begins from the point at which its basic principles are defined (TRL 1). As the concept and area of application develop, the technology moves into TRL 2, reaching TRL 3 when an experiment has been carried out that proves the concept. The technology now enters the phase where the concept itself needs to be validated, starting from a prototype developed in a laboratory environment (TRL 4), followed by the testing of components under the conditions in which it will be deployed (TRL 5), through to testing in the conditions in which it will be deployed (TRL 6). The technology then moves to the demonstration phase, where it is tested in real-world environments (TRL 7), eventually reaching a first-of-a-kind commercial demonstration (TRL 8) on its way towards full commercial operation in the relevant environment (TRL 9) (…) IEA has extended the TRL scale used in this report to incorporate two additional levels of readiness: one where the technology is commercial and competitive but needs further innovation for its integration into energy systems and value chains when deployed at scale (TRL 10), and a final one where the technology has achieved predictable growth (TRL 11). (International Energy Agency, 2020, pp 82-83).

TRL scale applied by the IEA. Source: IEA



Note: SDS = Sustainable Development Scenario.

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