Assessment of Emission Rights of Green PtX Products

Bewertung von Emissionsrechten grüner PtX-Produkte

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Disclaimer:

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List of Abbreviations

BEHG	Fuel Emissions Trading Act
BlmSchg	Federal Imission Control Act
BMWK	German Federal Ministry for Economic Affairs and Climate Action
CAPEX	Capital expenditures
CBAM	Carbon Border Adjustment Mechanism
CBAMCs	CBAM certficates
CCfD	Carbon Contract for Difference
CCS	Carbon capture and storage
CN	Climate neutral
CO_2e	Carbon dioxide equivalents
DAC	Direct air capture
DESHSt	Deutsche Emissionshandelsstelle
DVGW	Deutscher Verein des Gasund Wasserfaches
EFTA	European Free Trade Association
EU	European Union
EUA	European Union allowances
ETS	Emissions Trading System
FAR	Free Allocation Rules
FID	Financial investment decision
FQD	Fuel Quality Directive
GHG	Greenhouse gases
H_2	Hydrogen
HEFA	Hydro-processed esters and fatty acids
ITMO	Internationally Tradeable Mitigation Outcomes
LCoE	Levelized cost of electricity
LCOH	Levelized Cost of Hydrogen
MR	Monitoring Directive
MSR	Market stability reserve
NbS	Nature based solution
NDC	Nationally Determined Contribution
nETS	National Emission Trading System
NGO	Non-governmental organization
NIR	National Inventory Report
OPEX	Operational expenditures
PFC	Perfluorocarbon
PPA	Power purchase agreement
PtX	Power-to-X
RE	Renewable Energy
RCF	Recycled Carbon Fuels
RED	Renewable Energy Directive
RFNBO	Renewable Fuels of Non-Biological Origins
SAF	Sustainable aviation fuels
SMR	Steam methane reformer
TRL	Technology Readiness Level
UAE	United Arab Emirates

UNFCCC	United Nations Framework Convention on Climate Change
VCM	Voluntary carbon market
VCS	Verified Carbon Standard
VER	Verified Emissions Reduction
WACC	Weighted average cost of capital
WTO	World Trade Comission

Executive Summary

The import and domestic use of green hydrogen and Power-to-X products (PtX) in Germany and the European Union (EU) encounters a complex regulatory landscape in flux. At the EU level, the most relevant policy instruments are the EU Emissions Trading System (EU ETS), the Renewable Energy Directive (RED), and the newly introduced Carbon Border Adjustment Mechanism (CBAM). Both, the EU ETS and the CBAM directly target industry. RED primarily targets EU Member States but defines fundamental requirements regarding the "green" character of PtX that can also be transposed to industry players. In the German context, the national ETS (nETS) provides a regulative framework for PtX use in transport and the heating/building sector as well as smaller businesses not covered by the EU ETS.

This study analyses the implications of this complex ruleset on the competitiveness of green hydrogen/PtX; differentiating between hydrogen use and production both for imported and domestically produced hydrogen to the extent possible. It also highlights upcoming changes to the policy framework and discusses their impact.

Hydrogen-relevant policy framework

In the **EU ETS**, economic benefits occur for the users of green PtX. In contrast, producers or importers of PtX do not derive any direct economic benefit from the EU ETS. The economic benefit arises because installations covered by the EU ETS need to surrender less emissions certificates (EUAs) for compliance if they replace fossil fuels with green hydrogen/PtX[1].

It must however be taken into account that there are forms of hydrogen production based on fossil fuels that receive free allocation of EUAs under the EU ETS, e.g. steam methane reforming or partial oxidation. While these installations need to surrender EUAs according to their actual emissions, free allocation is granted based on a benchmark of 6.84 t CO_2e/t H_2. Installations that are less efficient than the benchmark will face a deficit of EUAs (and thus need to buy additional EUAs), whereas those that meet the benchmark face no additional costs. The production with grid-connected electrolysers does not lead to direct emissions. Hence, currently there is no free allocation to electrolysers[2] and no obligation to surrender EUAs for compliance. However, grid-electricity consumption entails indirect costs from the EU ETS, reflected in higher electricity prices[3].

At present, refining, the chemical sector, and ammonia production are the main consumers of hydrogen in the EU. These industries can become starting points for accelerating green PtX demand by switching from grey to green hydrogen. The steel and cement sectors also are potential hydrogen consumers, with many activities already announced, especially in the steel sector. In the long run, transport - mainly maritime, aviation, and heavy-duty – and the power sector are expected to line up as hydrogen consumers. The current **EU ETS and German nETS** cover many of these players: ammonia production, refineries, the power sector, iron and steel as well as coke ovens, cement, glass, and international aviation. Road transport is already covered by the German nETS and will be covered EU-wide in the planned ETS II probably from 2027 (2028 at the latest) onwards.

The new **CBAM** imposes a financial cost on the carbon content of imports of carbon intensive goods to the EU, aiming to prevent carbon leakage and to incentivise non-EU manufacturers to decarbonise. Targeted entities are importers of products. CBAM currently only covers direct (scope 1) emissions for hydrogen imports. Thus, imported hydrogen produced with electrolysis, regardless of the electricity source, will not require CBAM certificates (CBAMCs). Contrary to this, imported steel products will have to report their embedded emissions and surrender CBAMCs. Imported steel produced using green hydrogen will require less CBAMCs than steel produced with conventional production methods. Similarly, imports of ammonia

[1] At the point of use, hydrogen does not lead to CO_2e emissions, regardless of the carbon intensity of hydrogen production, processing, transport or storage

[2] Note that this will change from 2026 onwards.

[3] Special effects may occur due to the electricity price compensation ("Strompreiskompensation")

and other PtX-products such as methanol are subject to the CBAM. The amount of CBAMCs required will depend on the carbon intensity of their production.

Furthermore, the inclusion of hydrogen in CBAM means that any free allocations for hydrogen-producing installations within the EU will be phased out in defined steps between 2026-2034.

The newly introduced **RED II/III** also creates incentives for the use of green hydrogen and PtX by defining targets for EU Member States for the minimum share of renewable energies in fuel consumption. Renewable hydrogen, PtX and Recycled Carbon Fuels (RCF) are defined as "renewable liquid and gaseous transport fuels of non-biological origin" (RFBNO). RFNBOs are an option for Member States to meet their renewable energy targets. Detailed specifications on the eligibility requirements to count as RFNBOs are currently being defined in Delegated Acts[4]. RED II also defines a series of sustainability- and GHG-emission criteria that biofuels must comply with.

Also worth mentioning is the **Fuel Quality Directive (FQD)** of 2009, which requires Member States to reduce the GHG emission intensity of transport fuels by 6% by 2020 compared to 2010. Member States were to transfer this target to fuel suppliers. In 2020, the obligation was extended to a 25% reduction by 2030. The GHG intensity of fuels is calculated on a life-cycle basis, covering emissions from extraction, processing and distribution. The target can in part be achieved with liquid or gaseous RFNBOs. This opens the possibility to use green hydrogen and PtX to meet the target. With the new RED II regulations, the relevance of the FQD may be reduced but essentially, the systematics of the FQD were transferred to RED.

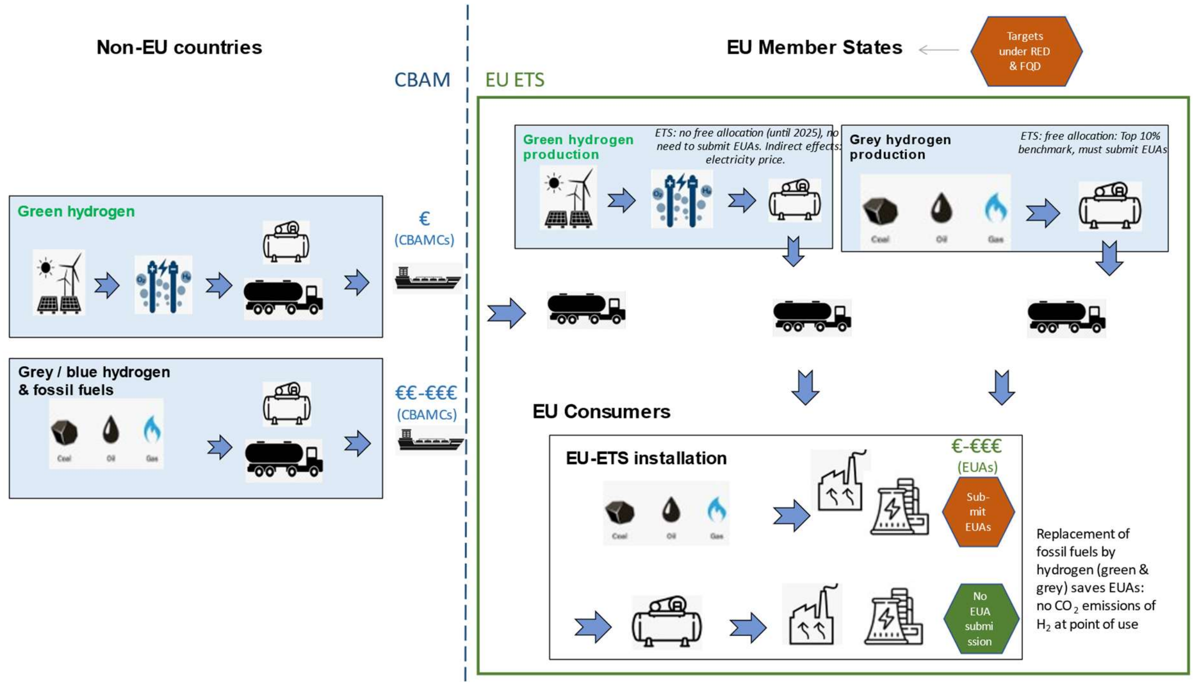
Figures S1 and S1 summarise the main features of these policies and highlights how PtX producers (inside and outside the EU) and consumers are qualitatively impacted by the rules.

Figure S1: Overview EU regulation relevant for hydrogen

	Carbon Border Adjustment Mechanism **Regulated subjects:** importers of carbon intense goods **Function:** certificate 'levy' on imports of carbon intense goods to the EU	**EU-Emissions Trading System** **Regulated subjects:** operators of installations **Function:** emissions trading for industry and energy sectors	**Renewable Energy Directive** **Regulated subjects:** EU Member States **Function:** binding renewable energy targets and rules	**Fuel Quality Directive** **Regulated subjects:** distributors of fuels **Function:** targets for carbon intensity of transport fuels
General aspects	*Mechanism covers hydrogen, ammonia, methanol, and other PtX*	*Hydrogen treated as an emissions-free fuel*	*Renewable hydrogen, PtX and Recycled Carbon Fuels help meet renewable energy targets*	*Created a market for emission reduction quotas that can be met through renewable hydrogen, PtX and Recycled Carbon Fuels*
Emissions coverage	*Direct emissions (hydrogen)*	*Direct emissions*	*Direct and indirect emissions*	*Lifecycle emissions*
Effects on imports	*Direct emissions from production need to be reported, importers need to buy certificates*	*No particular rules*	*Rules apply for imports, too*	*Rules apply for imports, too*
Effects on domestic production	*No direct effects (CBAM not applicable to domestic production).* *But: avoids competitive disadvantages compared to imported hydrogen & goods, which may result from less stringent environmental standards outside the EU (exact rules yet to be agreed)*	*Today: no clear benefit for green hydrogen production because of free allocation for fossil fuel-based hydrogen receive free certificates* *Future: green hydrogen production to become eligible for free allocation (from 2026 onwards)*	*Increased demand from EU (details tbc)* *Future:* • *Additionality requirements must be met (upcoming)* • *Lifecycle emissions must be determined (upcoming)*	*Helps distributers of fuels to meet their quotas / targets and avoid penalties (up to 130 EUR in Germany)*
Producers of green hydrogen / PtX outside EU	*Creates economic benefit of green hydrogen and goods produced with green hydrogen compared to grey/blue hydrogen and goods produced with fossil fuels*	*No direct effects, but increased demand from EU ETS installations*	*No direct effects, but increased demand from EU (details tbc)*	*No direct effects, but increased demand from EU*
Consumers of green hydrogen / PtX in EU	*Reduces cost differential between imported green hydrogen / goods produced with green hydrogen and their carbon-intensive alternatives due to lower ‚levy'*	*Emission factor of zero makes utilisation of hydrogen more attractive than use of fossil fuels (no need to surrender EUAs reduces cost for EU ETS installations) → can increase demand*	*No direct effects*	*No direct effects*

[4] These Delegated Acts will have an impact on the hydrogen market: the so-called "Additionality Act" defines additionality requirements for renewable energy capacities used to operate electrolysers. The "Methodology Act" defines rules for determining life cycle GHG emissions of RFNBOs and RCFs, as well as minimum thresholds for associated GHG savings.

Figure S2: Boundaries and point of targets of CBAM, EU ETS, RED II and FQD



Economic benefits for PtX

The existing and evolving carbon pricing framework in the EU has the clear potential to increase the competitiveness of green hydrogen. Details depend on the type, carbon intensity and cost of production, processing and transport as well as on carbon prices. Furthermore, the carbon pricing framework does not rule out other sector or technology-specific instruments, e.g. subsidies.

This study analyses in detail the effects of carbon pricing on the competitiveness of hydrogen/ammonia in comparison to their fossil fuel alternatives for several exporting countries (Morocco, United Arab Emirates, Australia, Chile, and Germany). In addition, two scenarios were assessed: i) a renewable energy-scenario (100% renewable hydrogen), ii) a grid-scenario which also builds on renewables but adds grid electricity to achieve 100% utilisation of electrolysers.

Findings are: the replacement of fossil fuels with 100% renewable PtX can result in significant GHG benefits, whereas GHG benefits of grid-connected hydrogen are significantly lower and can even lead to an increase of CO_2e emissions. Consequently, it is of utmost importance to include emissions from the production of PtX.

Carbon pricing can improve the cost-competitiveness of green PtX significantly. In the Renewable energy scenario, current price levels of EUAs and natural gas would make green PtX cheaper than grey hydrogen/ammonia and natural gas. To become a cost-competitive alternative to coal in the steel sector, a carbon price of about 140 €/t CO_2e would be required; and to replace kerosine with sustainable aviation fuels (SAF), a carbon price of around 400 €/t CO_2e would be required.

Table S1 shows the economic benefits of replacing fossil fuels with hydrogen and its derivatives exemplarily for selected cases. For example, the first row compares using green hydrogen from Morocco instead of natural gas. Natural gas currently (2022) costs about 166 €/MWh in Germany, and directly emits 0.2 t CO_2/MWh. Landed cost[5] of green hydrogen is slightly higher than that of natural gas, standing at approximately 168 €/MWh. However, at EUA prices of 90 €, an additional cost of 18 €/MWh for natural gas results for the consumer due to its carbon emissions. Therefore, the landed cost of green hydrogen including the avoided cost of EUA is lowered to 150 €/MWh, which makes the fuel economically attractive. The

[5] I.e., the total cost of a product upon arrival at a buyer's location, including production, freight, insurance, and other costs up to the port of destination.

numbers also indicate that, with 2022 fuel- and EUA prices, the cost of green hydrogen becomes competitive with grey hydrogen and ammonia, but not with coal or kerosene. However, average fuel prices in recent years were often lower (see right column of table 1) – which can lead to different results.

Table S1: Economic benefits of replacing different baseline fuels

Baseline fuel	Import route	GHG-mitigation potential [t CO_2e/MWh]	Economic benefits ETS EUA Price 90 € [€/ MWh]	PtX price [€/MWh]	Landed PtX costs including economic benefits from ETS [€/MWh]	Cost baseline fuel (€/MWh) 2022 (high)	average 2019-2022
Natural Gas	Morocco Pipeline	0.20	18	168	150	166	60
Coal (steel)	Morocco Pipeline	1.04	94	168	95	30	15
Grey Hydrogen	Morocco Pipeline	0.30	27	168	141	232	211
Ammonia	Morocco Pipeline	0.47	43	190	147	272	151
Kerosene	Morocco - Germany Shipping	0.20	24	208	184	44	52

Note that these numbers refer only to fuel costs. Switching from fossil fuels to PtX also requires investments at consumer side[6].

These numbers show that - with current fossil fuel prices – today's carbon pricing framework in the EU is at the edge towards making a difference. However, carbon price levels alone are not yet sufficient to facilitate the significant investments required for a broad and fast shift away from fossil fuels to green hydrogen. Strongly varying fuel prices and uncertainties about future carbon- and fuel prices are barriers for such investments. To overcome these barriers, the existing carbon pricing framework in the EU – which certainly has been evolving into a very solid, impactful toolset – would need to be accompanied by large-scale public investment programs into required infrastructure for import, distribution, storage and transmission of green PtX. Furthermore, especially industrial sectors exposed to international competition eyed as large hydrogen/PtX consumers paving the way to the technological and economical upscaling of green hydrogen/PtX and related infrastructures may need targeted support in order to enable necessary investments on the customer side

Recommendations for H2Global

Given that the European legislative environment for hydrogen and PtX is highly complex and rapidly evolving, it is advisable that H2Global carefully monitors new developments and assesses their implications for PtX. In addition, the evolving situation creates opportunities for H2Global to position itself and possibly bring in own recommendations and ideas. The following items will be particularly important:

- In the EU ETS, hydrogen so far has been considered with an emissions factor zero without detailed proofs of origin. Hence, there is no differentiation between the production types of hydrogen (e.g. green, grey, blue). But future revisions of the EU ETS monitoring regulation should

[6] E.g., in the steel sector the complete iron reduction and steel production process has to be changed from the Blast Furnace-Basic Oxygen Furnace to Direct Iron Reduction Electric Arc Furnace. In this case, the complete technological change needs very high investments in the scale of billions instead of millions just for replacing one Blast Furnace. In addition, operational costs of the low carbon intense fuels are much higher compared to coal. For this reason, the EU as well as Germany introduce "carbon contracts for difference" as a new policy instrument.

be closely monitored as green hydrogen could be incentivised compared to other colours if hydrogen were subject to similar sustainability requirements as biomass.

- The ongoing update of free allocation benchmarks might be of particular importance for hydrogen and PtX because the production of hydrogen by electrolysis is expected to become an activity eligible for free allocation of allowances. This would eliminate today's unequal treatment of different forms of hydrogen production under the EU ETS. Therefore, the discussions related to adjustments of the hydrogen benchmark should be monitored by H2Global.
- For the implementation of RED, it will be crucial to understand the practical interpretation of additionality rules for non-EU countries with different power market structures and data availability.
- With regard to the implementation of the CBAM, the question of if and how indirect emission of Hydrogen production will be taken into account becomes important. Also, the rules for determining embodied emissions in imported products that are produced with PtX will be relevant as they may create advantages or disadvantages.
- As the quantitative assessment has shown, hydrogen / PtX that are not exclusively produced with renewables can have significant embodied emissions. These need to be considered appropriately in all European legislation to avoid counterproductive incentives potentially leading to negative climate impacts.

Furthermore, it is important to better understand the investment needs in industry that are required to make installations and processes "fit for hydrogen". Next to the cost of green hydrogen/PtX, the scale of the necessary investments will be crucial for fuel switches and, hence, acceleration of hydrogen markets. Understanding the investment needs by industry sector (steel, chemicals, fertiliser production, etc.) can then be used to i) identify sectors in which a fuel switch to hydrogen can be achieved at lowest costs, and ii) assess what additional financial/ political support will be required (e.g., direct investment subsidies).

For incentivising domestic energy transformation in non-EU hydrogen producing countries, Article 6 of the Paris Agreement can be used as a central element. Such cooperation can be embedded in energy partnerships and can result in climate finance for local green hydrogen consumption in the partner countries. The international mandate of H2Global could become a promising starting point for such activities.

Background and objectives

In line with the Paris Agreement, Germany and the European Union (EU) have set ambitious decarbonisation goals. For the EU, the European Climate Law substantiates the goal for Europe's economy and society to become climate-neutral by 2050. With its Climate Change Act, the German Federal Government has enshrined in law the goal of achieving greenhouse gas neutrality by 2045. To achieve the ambitious objectives for a sustainable transformation of the EU Member States' economies – away from fossil fuel fuels towards renewable energies and carbon neutral technologies -, comprehensive measures must be taken. While several sectors can be largely decarbonised by renewable electrification, other hard-to-abate sectors, i.e., heavy/chemical industry, aviation, and the maritime sector, require other solutions. Here, green hydrogen and its derivates can be key for a thorough decarbonisation. Since the EU and especially Germany have limited potential to generate electricity from renewables, it will not be possible to meet the projected demand of green Power-to-X (PtX) products domestically. Therefore, a significant share of the future PtX-demand will have to be met by imports. According to current projections, 70 TWh of a domestic German demand of 100 TWh of PtX products will already have to be imported in 2030 (Guidehouse 2022).

Currently, the biggest hurdles for a massive scale up of hydrogen/ PtX technologies are high investment costs and the lack of guaranteed long-term off-takers of the produced hydrogen/ PtX. So far, only a few measures exist to address the issue. The most prominent example today is the competition-based H2Global Mechanism, an innovative funding instrument developed by the H2Global Foundation and supported with funding from the German Federal Ministry for Economic Affairs and Climate Action (BMWK). The mechanism is a promising instrument for ramping-up the production of green hydrogen and PtX. It is designed to secure diversified green hydrogen supply from countries around the world and at the same time incentivise a rapid ramp-up of a global hydrogen economy by increasing investment security for project developers and investors. The mechanism is based on a double auction. Within this mechanism, tenders will be published on which international hydrogen producers can bid. The cheapest bidder will be offered a long-term off-take contract with a fixed price in order to de-risk their investments. On the sales side, an intermediary will auction the procured PtX products to the highest bidder in Germany based on short-term contracts. The price difference between supply and demand side will be covered by funding from the German government.

To date, green PtX products are not yet produced in sufficient quantities, and in most cases, are not cost-competitive with both "grey' hydrogen and conventional fossil fuels. Hence, a rapid and comprehensive market ramp-up accompanied by infrastructure investments is required in order to benefit from the economies of scale and to be able to deliver the required quantities.

This study, commissioned by H2Global Foundation, investigates how emissions trading systems in the EU and Germany can accelerate the market ramp-up for imported green PtX. The underlying principle is that the use of green PtX by entities that are covered by an emissions trading system (ETS) will create positive opportunity costs[7] if they replace fossil fuels with green and low-carbon PtX.

[7] I.e., avoid costs of surrendering emission allowances or generate additional revenues for the H_2 user from the sale of emissions allowances allocated free and not needed due to reduction of surrendering needs by using green H_2.

The report is structured into the following chapters:

Chapter 1 summarises how green PtX products imported from non-EU countries and already utilised in Germany/ the EU are accounted for in the EU ETS, the domestic ETS in Germany and in other relevant EU-climate policy instruments. It summarises the current policy landscape relevant for PtX accounting and identifies gaps.

Chapter 2 analyses potential economic benefits for green PtX fuels that can result from the relevant emission pricing schemes. It gives an overview of current and future PtX consumers in the EU, and quantitative insights are provided based on a detailed scenario analysis for different PtX import- and utilisation options.

Chapter 3 summarises with illustrative examples how imported[8] green PtX can be recognised under the EU ETS, and how this compares to PtX that are produced/traded within the EU. It investigates the reporting requirements and standards that need to be met by PtX producers outside the EU to meet the EU and the German government's definition of a "green" fuel. It also suggests aspects of the planned REDIII and current EU ETS regulation that might need to be adjusted for simplifying recognition of imported green PtX.

Chapter 4 analyses how a sectoral or regional expansion of the EU ETS and the use of voluntary carbon markets and Art. 6 of the Paris Agreement could promote green PtX. In addition, it analyses how more ambitious definitions of renewable fuels of non-biologic origin (RFNBO) under EU legislation would affect the eligibility of imported PtX. Finally, it provides recommendation on how the EU ETS could be revised to become a clear market accelerator for green PtX.

Chapter 5 gives recommendations which current policy developments to monitor and how H2Global could position itself in order to contribute to a comprehensive set of policies supporting a rapid and sustainable upscale of PtX technologies.

[8] Import from non-EU countries

1. EU climate policies and green PtX

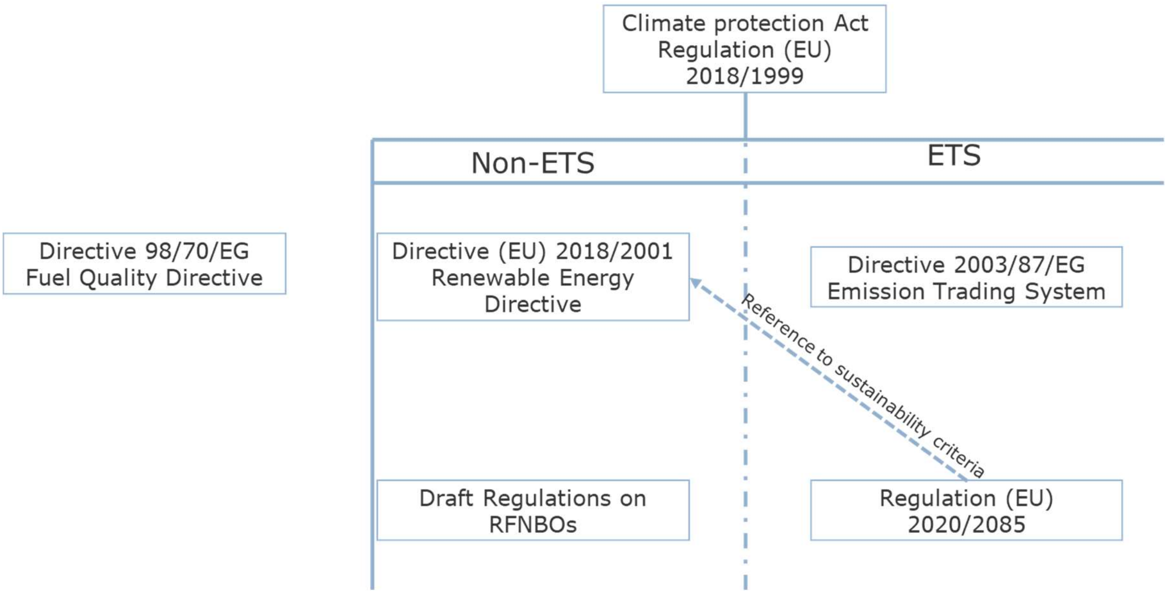
This chapter explores the extent to which green PtX products, imported from non-EU countries and utilised in Germany/ the EU, are already reflected in the various, *currently existing* climate policy instruments in the EU, in particular the EU ETS and the German domestic ETS (nETS). It also addresses other (planned) relevant policy instruments under the EU's Fit-for-55 package.

1.1. Overview of today's EU policy landscape with relevance for PtX

This section provides a systematic overview and brief descriptions of those EU- and German climate policy instruments that are of relevance for PtX-imports and utilisation. In order to assess and understand the significance of the interactions between the legal areas, it is important to grasp both the interrelationships between the laws and the temporal interdependencies.

Figure 1 illustrates the systematic relationship between the laws discussed subsequently. To simplify the interrelationships, only the legal texts discussed in this document are shown here. Additional directives, ordinances, and laws are not considered.

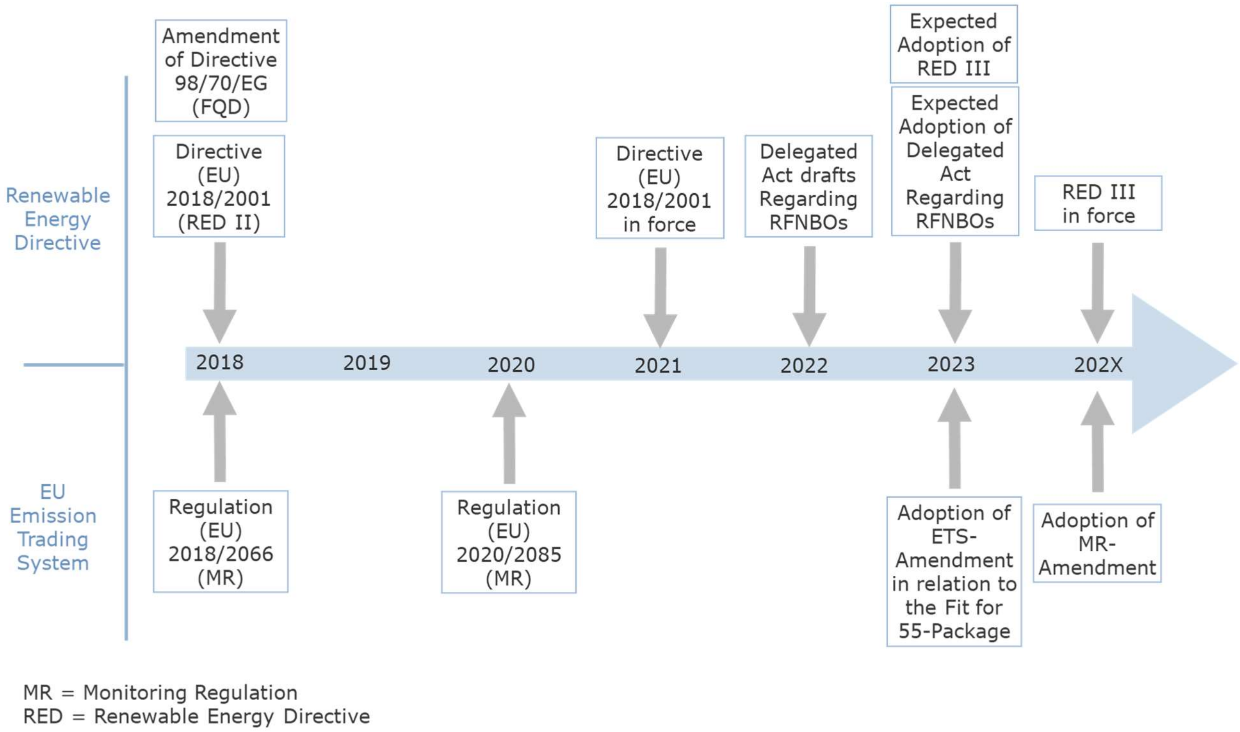
Figure 1: Relevant regulations in the ETS and non-ETS-sectors



Source: Future Camp

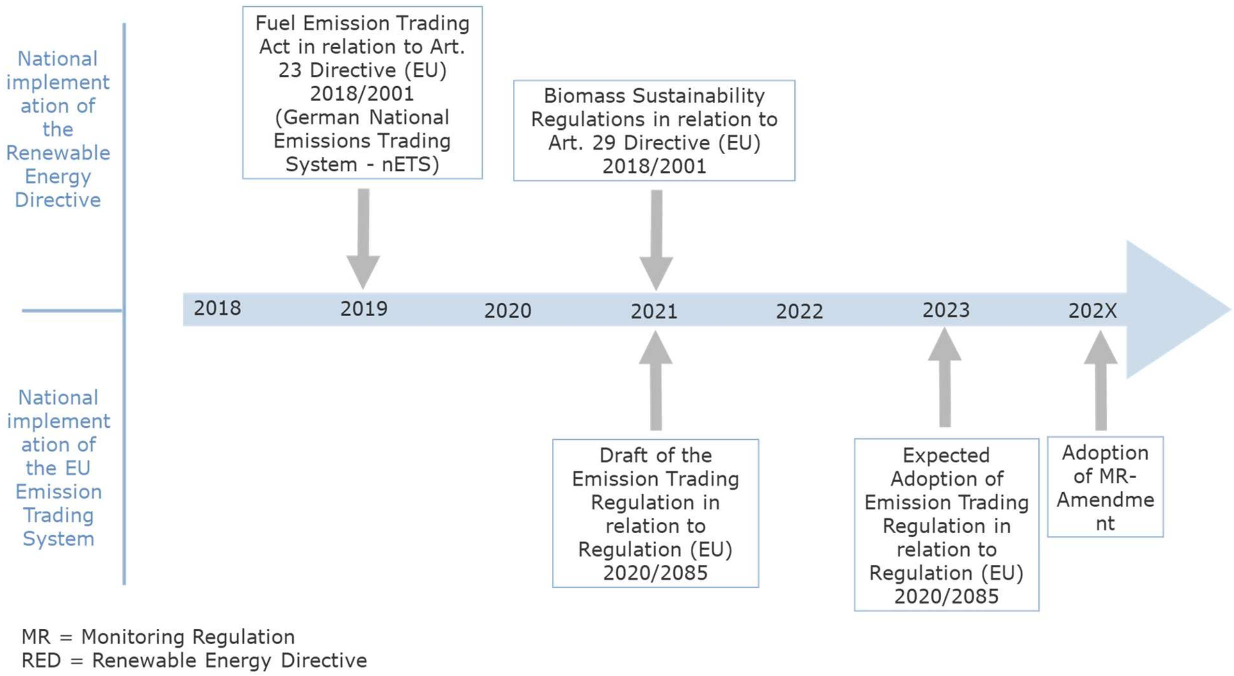
The temporal interdependence is shown below at both European and national level. Figure 2 and Figure 3 show the time horizon in which respective requirements are to be met and when potential changes are to be expected. This plays a direct role in the consideration of a possible crediting of green hydrogen.

Figure 2: Timing of RED-regulations and EU-ETS regulations



Source: Future Camp

Figure 3: National implementation timeline of EU ETS and RED regulations



Source: Future Camp

1.1.1. The European Emissions Trading System

After several years of intensive preparation and discussions between EU Commission (COM), Member States, industry, non-governmental organisations (NGOs), and the EU Parliament, the EU Emissions Trading System (EU ETS) came into force on 1 January 2005 with a 3-year "pilot phase", followed by a second (2008-2012) and third phase (2013-2020). Today, it is running in its 4th phase (2021-2030). From the beginning, the EU ETS was designed as a cap-and-trade system. Operators of covered installations must monitor and report their GHG emissions and submit the respective number of EU-allowances (EUAs) to their national authorities. One EUA equals one ton of CO_2e. In case of failure to report the respective amounts of EUA, the operator must pay a penalty[9] and submit missing EUAs subsequently.

The EU ETS covers large energy installations: fossil-fuelled power plants, combined heat and power plants (CHP) and heating plants with a rated thermal input of 20 MW or more, and industrial installations with a high energy consumption, for example, blast furnaces in the steel industry, refineries, cement plants, aluminium plants, and the chemicals industry.

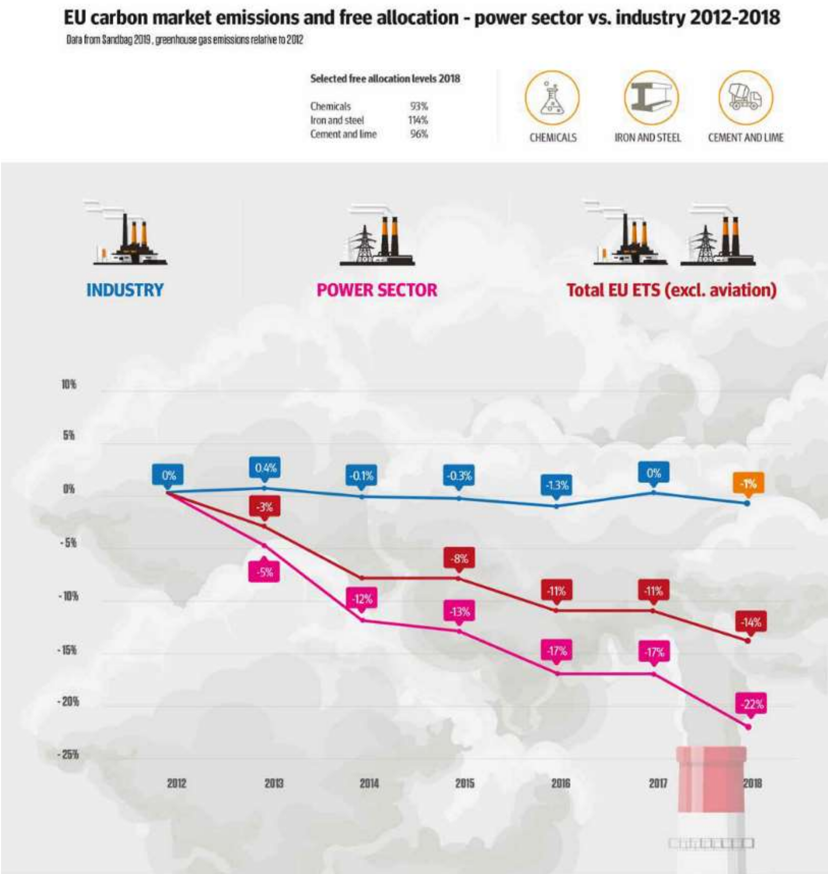
In the first phase of the EU ETS, about 9,500 installations from the energy sector and heavy industry were covered, and CO_2e was the only GHG included. Almost all EUAs were allocated free of charge based on historical emissions of installations ("grandfathering") and several special rules. Overall, this led to a significant overallocation.

Over time, the share of cost-free allocation was reduced (from ca. 90% in phase 2 to ca. 40% in subsequent phases), more GHGs were included, and the sectoral and geographical scope expanded (e.g., inclusion of nitrous oxide and perfluorocarbons (PFCs)); EFTA states Iceland, Liechtenstein and Norway joined, and the system was linked to the ETS of Switzerland. In addition, the emission cap was lowered[10] and allocation harmonised between Member States (EU Commission 2021a). This means that today the EU ETS rules defined by the EU-Commission, Parliament and Member States apply uniformly throughout the EU.

[9] In the first phase of the EU ETS, the penalty was 40 €/t CO_2, and increased to 100 €/t CO_2 from phase 2 onwards.

[10] The linear reduction factor was 1.74% per year in phase 3, and 2.2% per year in phase 4.

Figure 4: Overview auctioning vs. cost-free allocation in the EU ETS 2012-2018



Source ECA (2020)

As of today, the EU ETS covers ca. 11,000 stationary installations and 1,500 aircraft operators for their intra-EU operations (European Environmental Agency 2022)[11]. The EU ETS covers almost 40% of the EU's total greenhouse gas emissions. About 57% of the total amount of allowances have been auctioned to stationary installations in phase 3, and similar numbers are expected for phase 4 (2021-2030) (European Commission 2021b). In the aviation sector, 15% of all issued aviation allowances are auctioned (European Commission 2021b). At least 50% of auctioning revenues need to be re-invested by Member States for climate and energy-related purposes. In 2019, the total revenues generated through auctioning were above €14 billion (European Commission 2021b).

However, some exceptions from the auctioning principle apply to industrial installations considered to be at significant risk of "carbon leakage" – i.e., the risk that production (and therefore GHG emissions) are relocated outside EU territory because the EU ETS may make production uncompetitive – can receive cost-free allocation based on a benchmarking approach. The most efficient installations of an industrial sector serve as reference ("benchmark") with regards to how many free EUAs are allocated to other installations in that sector, adjusted for production output.

[11] All flights taking off or landing in the European Economic Area (EEA) are covered. Exceptions exist for certain types of flights (e.g. rescue and research flights) and for operators with less than 10,000 tonnes of CO_2 for commercial aircraft operators and less than 1,000 tonnes of CO_2 for non-commercial aircraft operators. (DEHSt 2021b)

Box 1: Current hydrogen benchmarks and allocation rules in the EU ETS

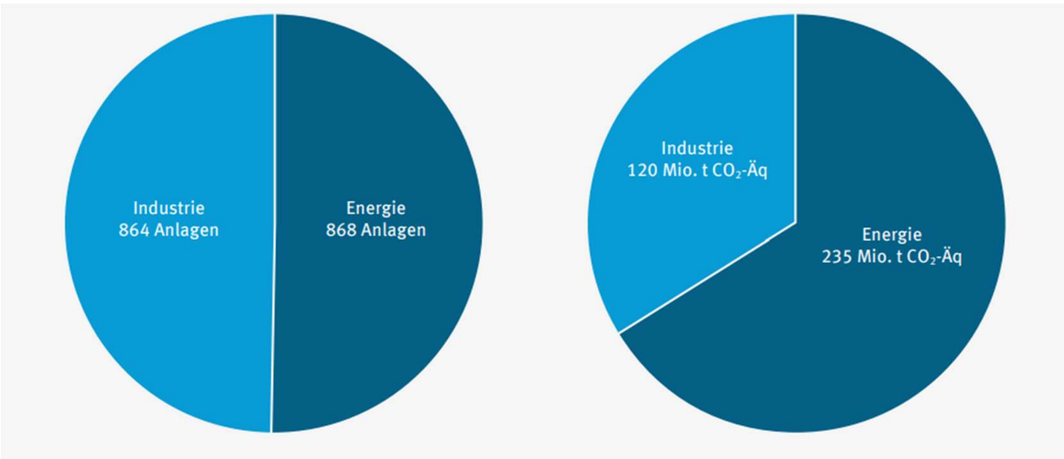
Carbon leakage sectors include industries that are using (grey) hydrogen since many years, such as the chemical sector, as well as industries where use of green hydrogen is considered a key measure for decarbonization (primary steel).

A benchmark of 6.84 t CO_2/ $H_2$was defined for the free allocation of certificates for allocation period 1 of phase IV. This benchmark includes both pure hydrogen and hydrogen-CO mixtures with a hydrogen content ≥ 60 mol%. Furthermore, the product emission value for hydrogen is only applicable to those installations in which hydrogen is produced by steam reforming, partial oxidation, water-gas shift reaction or similar processes. Here, however, the ratio between direct emissions and indirect emissions (electricity/heat) is taken into account in the allocation. **This means that if 100% of the hydrogen production is based on electricity, then no free allocation is granted - but also no EUAs need to be surrendered for indirect emissions from electricity consumption**.

Whether a fuel switch to green hydrogen is economically attractive therefore depends not only on the price differential of the fuels and the price EUAs but also on the free allocation rules that apply for an installation.

In 2021, 1,732 stationary installations were covered by the EU ETS in Germany, emitting a total of 355 million tonnes CO_2e (DEHSt 2022a), see Figure 5.

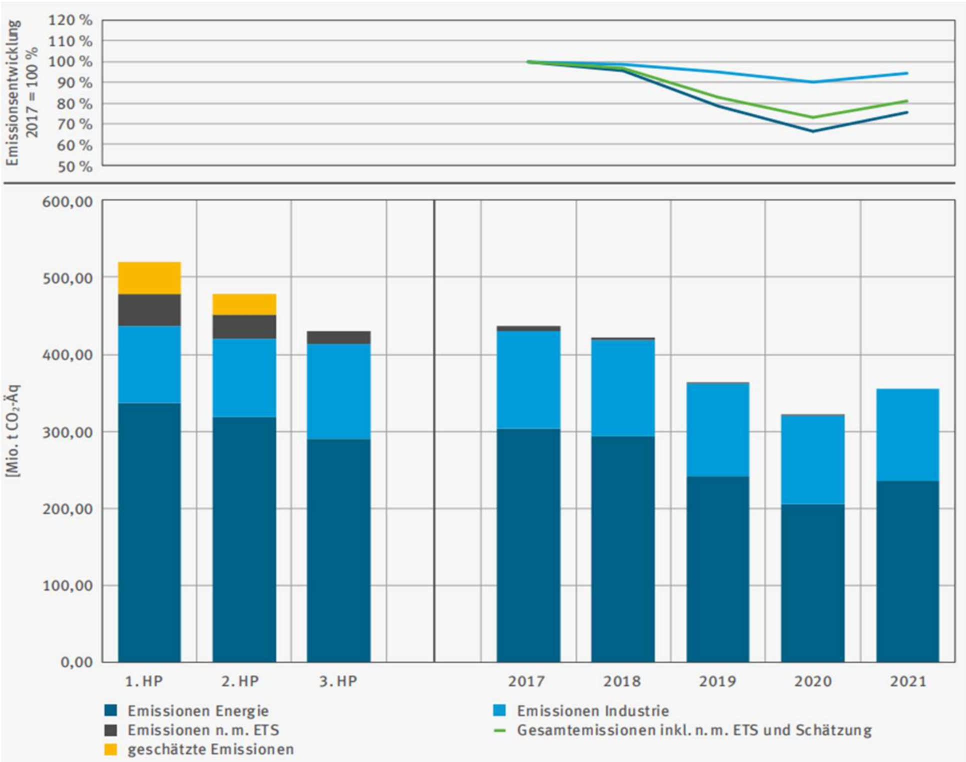
Figure 5: Overview EU ETS installations and emissions in Germany, 2021



Source: DEHST (2021a)

Figure 6 summarises the historic emissions of EU ETS installations in Germany until 2021.

Figure 6: Historic emissions of EU ETS covered installations in Germany until 2021



Source: DEHST (2022a)

Figure 7 provides an overview of historic EUA prices since 2005. After over a decade of low prices (< 10 €/EUA), prices started to rise constantly in 2018 when the newly established market stability reserve (MSR) became operational. The MSR is a mechanism implemented to address imbalances between supply and demand of emission allowances. The MSR automatically adjusts the number of allowances available for auctions, based on the total number of allowances in circulation. This reduces the overall supply of allowances and increases the EUA-price, incentivising emission reductions. Likewise, the MSR increases the number of allowances auctioned if the total number of allowances falls below a certain threshold, increasing supply and reducing the EUA-price (climate.ec.europa.eu) Since early 2021, prices have increased steeply and have been oscillating in the range of 70-90 €/EUA in 2022.

Figure 7: Development of EUA prices, 2005-2022

Source: UE Carbon Permits (n.d.) ([https://tradingeconomics.com)](https://tradingeconomics.com)

For the accounting of green and low-carbon hydrogen in the EU ETS, it is important to understand the monitoring, reporting and verification (MRV) requirements. European legislation regulating MRV-requirements in the EU ETS[12], transferred into national law by Member States, exists since many years now and functions well. In Germany, the Deutsche Emissionshandelsstelle (DEHSt), the national authority for the EU ETS, implements and supervises MRV through installation operators (DEHSt 2022b). Monitoring of energy-related GHG emissions is typically done by determining the quantities of fuels used (differentiated by fuel type), the lower heating value and the emission factors of fuels.

For commercial standard fuels, standardised emission factors can be applied – which are listed in the Annex to the German MRV-regulation. However, standard emission factors are only available for internationally traded fuels with very low (<1%) deviations in their lower heating value (DEHSt 2022c).

Equation 1. Calculation of CO_2e emissions

$$t\ CO_2e = Q_{fuel}\ (t) * H_{u\_fuel}\ (GJ/t) * \text{standard emission factor}_{fuel}\ (t\ CO_2e/GJ)$$

With:

$t\ CO_2e$ = *tonnes* CO_2e *equivalent*

Q_{fuel} = *tonnes of fuel*

$Hu_{\_fuel}$ = *lower heating value in GJ/t*

GJ = Gigajoule

For non-standardised fuels, the relevant parameters (Hu_{fuel}, emission factor $_{fuel}$) need to be determined by an accredited laboratory; the operator must submit a monitoring plan for these parameters to DEHSt for approval (DEHSt 2022c). Since the beginning of the 4th trading period, installation operators can, according to Art. 31 Abs 1 d MVO (DEHSt 2020), apply values guaranteed by the supplier instead of the standard values provided by DEHSt when the carbon content exhibits a 95% confidence interval of not more than 1%.

[12] Commission implementation implementing regulation (EU) 2018/2066 of 19 December 2018 on the monitoring and reporting of greenhouse gas emissions pursuant to Directive 2003/87/EC of the European Parliament and of the Council and amending Commission Regulation (EU) No 610/102; www.eur-lex.europa.eu

There have been intensive discussions on the definition of biomass and biofuels in the context of the RED directive, also see chapter 1.1.3. Pure biomass would have an emissions factor of zero, meaning that installations need to surrender less EUAs if they used biofuels instead of fossil fuels. For consistency reasons, the EU ETS monitoring regulation has taken over biomass/biofuels definitions from RED. Until 31 December 2021, biomass fuels "only" had to meet the sustainability and greenhouse gas savings criteria defined in RED I (Renewable Energy Directive (EU) 2009/28/EC). Since 1 January 2022, emissions from biofuels may only be deducted if the sustainability criteria and/or the criteria for GHG savings of RED II (Directive (EU) 2018/2001) were met (DEHSt 2022c).

Box 2: Accounting principles of hydrogen in the EU ETS

In the context of this study, it is important to understand the following aspects:

- The EU ETS is installation-based, meaning that the point of obligation is the operator of an installation covered (or: aircraft operator). **Therefore, currently the economic benefits from replacing fossil fuels with less carbon-intensive fuels always occur for the user of hydrogen, not the producer or importer.** If a covered installation uses less GHG intensive fuels, which might come at higher costs, the operator benefits from cost savings related to the purchase/submission of EUAs. This principle also applies to green and low-carbon hydrogen.
- **At the point of utilisation, hydrogen does not lead to CO_2 emissions - regardless of the carbon intensity of hydrogen production. So, there is no obligation to surrender EUAs and no directly related costs.** In other words, CO_2 emissions may occur during hydrogen production (unless 100% renewable energy-based), but not at hydrogen utilisation.
- Note that if hydrogen is produced within the EU, the production cost (and therefore price for the buyer) includes EU ETS related cost. If hydrogen is (partially) produced by grid-electricity, then indirect costs of the EU ETS are reflected in higher electricity costs. The same applies for hydrogen produced based on fossil fuels as e.g., in the case of steam methane reforming (SMR). – Special effects may occur due to the *electricity price compensation* ("Strompreiskompensation').
- Finally, it is very important to note that **the EU ETS covers only scope 1 emissions**, i.e., those emissions occurring at the installations when the utilise/burn the fuel. Scope 2 or 3 emissions, i.e., emissions occurring in the production, processing and transport process of these fuels, are **<u>not</u>** considered.

What does this mean for hydrogen being produced i) on EU-territory, and ii) in a non-EU-country?

- If hydrogen is produced at large-scale within the EU, i.e., the producing installation is covered by the EU ETS, then the emissions at point of production need to be reported under the EU ETS (e.g., gas from SMR, electricity)[13].
- If 100% renewable hydrogen is produced, no emissions need to be reported at point of production (emission factor of renewable electricity is zero).
- If hydrogen is produced outside EU territory, imported to the EU and used in the EU ETS, an emissions factor of zero should apply, because emissions caused by the production of hydrogen in the non-EU country are not considered in the EU ETS.
- Emissions from the production of hydrogen need to be accounted in the national inventory of the producing country (see chapter 2.2). For imported hydrogen, this would be the case in the non-EU

[13] In its formular management system (FMS), the German regulator DEHSt defines hydrogen as a commercial standard fuel but has no fixed standard emissions factor. While direct emissions are zero, there is at least a bureaucratical margin for the regulator: a hydrogen material flow can be created in the monitoring plans. Then a standard factor can be selected, but the standard value needs to be defined by the FMS user. It then needs to be approved by DEHSt.

country. However, the newly established carbon border adjustment mechanism (CBAM) might consider such emissions in the mid-term. See chapters 1.1.6 and 2.2 for a more detailed discussion.

- Furthermore, the rules for free allocation will change as of 2026, see chapter 4.

1.1.2. The German National Emissions Trading System

In 2021, Germany introduced the National Emission Trading System (nETS) to cover emissions from sectors that are not included in the EU ETS: the transport- and heating sectors. In addition, the waste sector will be included from 2024 onwards. The nETS is implemented through a federal law, the Brennstoffemissionshandelsgesetz (BEHG). The nETS is a cap-and-trade system, but it does not include end-users of transport- and heating fuels directly. Instead, it obliges the *distributers* of fuels to buy emission certificates – a so-called "upstream-system". Covered fuels are diesel, gasoline, gas, oil and non-sustainable biomass. From 2023 onwards, coal will also be included. "Double-coverage" of an emitter by the EU ETS and the nETS is avoided or compensated. A difference to the EU ETS is that prices for emission certificates are fixed for the upcoming years, see Table 1.

Table 1. Fixed prices in the German nETS

Year	2021	2022	2023	2024	2025	2026
Prices €/t CO_2e	25	30	30	35	45	55-65

Source: DEHSt (2022d)

From 2026 onwards, there will be a price range between 55 and 65 €/t CO_2e (DEHSt 2022d). From 2026 onwards, auctioning is planned with technical details to be decided in 2025 (Bundesministerium der Justiz 2019). Trading of certificates is possible, but with more stringent temporal limits.

Monitoring, reporting and verification rules under the nETS are very similar to those of the EU ETS, in particular with regards to the determination of emission factors. And again, there is a strong link to the RED-regulations. Chapters 1.1.3 and 1.1.4 of the "Guidance on scope and monitoring and reporting of CO_2e emissions under the national ETS" specify rules for e-fuels and hydrogen (DEHSt 2022b).

How can green and low-carbon hydrogen benefit from the national ETS in Germany?

If a fuel distributer replaces natural gas with green hydrogen, the distributer needs to buy less certificates because green hydrogen has an emission factor of zero. Hence, the distributer has an economic benefit. In other words, a fuel distributor would choose to replace natural gas with green hydrogen as long as the cost for green hydrogen minus the price of emission certificates is lower than the cost of natural gas[14]. There are, of course, technical limits that currently prohibit a full replacement of natural gas with hydrogen. However, blending of natural gas with hydrogen is currently not disadvantaged by/ not reflected in the BEHG, as will be explained in the next paragraph.

The BEHG specifies that "green hydrogen" (as defined in RED) does not need to be reported and, therefore, is exempt from the obligation to surrender emission certificates.

However, if green hydrogen is blended into gas grids – which, according to DVGW (Deutscher Verein des Gas- und Wasserfaches e.V.) is allowed to up to 5%$_{Vol}$, then this hydrogen must be reported[15]. For the reporting, two cases are differentiated:

i. If renewable energies have been used exclusively to generate the hydrogen, and the hydrogen is accepted as such in the German biogas registry ("or a similar mass balance documentation

[14] Note that in this case no or limited additional infrastructure investments are required.

[15] This is because of consistency reasons with the German energy tax system, where such blended gases are considered natural gas.

system"), then for the energy content of hydrogen in the gas mix an emissions factor of zero can be applied[16].

ii. Otherwise, the emissions factor of natural gas has to be applied also for the blended hydrogen (DEHSt 2022, section 2.3.3 and 6.5.2).

This rule constitutes a challenge for the market ramp-up of both green hydrogen[17] and low-carbon hydrogen which de-facto has an emissions factor lower than that of natural gas.

1.1.3. The Renewable Energy Directive (EU) 2018/2001

In November 2016, the European Commission published its "Clean Energy for all Europeans" initiative to drive the development of the European energy transition with regards to the overriding renewable energy target. As part of this package, the Commission proposed an update of the Renewable Energy Directive 2009/28/EG (RED) as well as Directive (EU) 2015/1513. The RED and the subsequent Directive (EU) 2018/2001 are the foundation for the development of renewable energies within the EU, outside the EU ETS. They set out targets for the development of renewable electricity, renewable heating and cooling, and renewable fuels. This is achieved through mandatory or indicative targets and other measures.

In December 2018, the revised renewable energy directive (EU) 2018/2001 (RED II) entered into force and replaced the RED as the valid legal text in 2021. In RED II, the overall EU target for the consumption of renewable energy sources which has to be met by Member States until 2030 has been raised from 20% in 2020 to 32%[18]. In September 2022, the European Parliament approved an additional raise of this renewable energy target to 45% until 2030.

In Article 2 (36) of RED II, renewable hydrogen, PtX and Recycled Carbon Fuels (RCFs) are defined as an option to meet the European energy targets as "renewable liquid and gaseous transport fuels of non-biological origin" (RFBNO) exclusively in relation to the transport sector[19]. However, recital 90 explicitly refers to the importance of RFNBOs also outside the transport sector[20].

In principle, RFNBOs can be used in any segment to meet the targets, even if the main focus within RED II is on the transport sector. Member States are required to ensure that the fuels are generated with renewable energy. More detailed specifications on the nature of RFNBOs only exist in RED II to the extent that Delegated Acts have been announced to define further requirements in more detail.

RED II defines a series of sustainability- and GHG-emission criteria that biofuels must comply with in order to be counted towards the overall targets of Member States. In the specifications for demonstrating the sustainability requirements specified for biofuels, reference is also made to RFNBOs. Art. 30 (6) also states that Member States may introduce national systems to verify compliance with the greenhouse gas reduction of RFNBOs. Those systems are not yet implemented, and other requirements do not yet exist to date.

In accordance with RED II Articles 27 (3), 25 (2) and 28 (5), two draft Delegated Acts have been published by the EU Commission in 2022 for public consultation. These Delegated Acts will have an impact on the hydrogen market: the first one (cf. 3.3.1) defines additionality requirements such as rules for counting electricity (European Commission 2022a). The second one (cf. 3.3.2) defines a methodology for determining life

[16] This assumes that all eligibility criteria for "green hydrogen' are met, such as sustainability criteria (Brennstoffemissionshandelsverordnung (EBeV) 2022, § 2, 7 and § 2, 4 Nr. 2). http://www.gesetze-im-internet.de

[17] E.g., How to deal with imported green hydrogen that is not accepted in a German mass-balance documentation system?

[18] Directive (EU) 2018/2001, Art. 3,

[19] Directive (EU) 2018/2001, Art. 2 (36): "renewable liquid and gaseous transport fuels of non-biological origin' means liquid or gaseous fuels which are used in the transport sector other than biofuels or biogas, the energy content of which is derived from renewable sources other than biomass.

[20] Directive (EU) 2018/2001, recital 90: Renewable liquid and gaseous transport fuels of non-biological origin are important to increase the share of renewable energy in sectors that are expected to rely on liquid fuels in the long term.

cycle greenhouse gas emissions savings of RFNBOs and RCFs, as well as minimum thresholds for associated GHG-savings (European Commission 2022b).

1.1.4. The amendment to the Renewable Energy Directive (RED III)

Due to the efforts of the European Green Deal and the REPowerEU initiative, RED II is in the process of being adapted to the new energy and climate targets. This legislative text, which is currently only available in draft form, will in this document be referred to as "RED III". In recent months, both the Council and the Parliament have discussed the Commission's draft (COM/2021/557) and proposed possible amendments. The Swedish Presidency of the Council of the European Union (Jan-Jun 2023) states in its program that it is among their priorities to continue driving forward the trilogue on RED III. As of 8 May 2023, the compromise proposal is based on the trialogue agreement. However, the adoption was not completed due to the lack of agreement of the Council.

In RED III, the Commission's proposal bundles the criteria for greenhouse gas savings from renewable fuels of non-biogenic origin (RFNBO) and recycled carbon fuels, which have so far been scattered in various articles, in a newly added Article 29a. The requirements from Article 27 (2) RED II are to be deleted for this purpose, as are the requirements for RFNBOs in Article 25 (2) RED II. In Article 25, the target for advanced biofuels remains and is supplemented by RFNBOs as part of the sub-quota in addition to an increase to 5.5% in 2030. This goes hand in hand with the obligation to have at least 1% RFNBOs in the market in 2030 as part of the 5.5% sub-target for advanced biofuels. In the maritime sector, member states with seaports are required to have at least 1.2% RFNBOs in 2023 as part of the total energy supply to the maritime sector.

Furthermore, with regard to the industrial sector, the new Article 22a in the Proposed Draft Directive stipulates that Member States shall ensure that the contribution of RFNBOS used for final energy and non-energy purposes shall be at least 42% of the hydrogen used for final energy and non-energy purposes in industry by 2030, and 60% by 2035. However, the following origins are excluded from calculating the share:

- Hydrogen used as intermediate products for the production of conventional transport fuels and biofuels;
- Hydrogen that is produced by decarbonizing industrial residual gases and is used to replace the specific gases from which it is produced; and
- Hydrogen produced as a by-product or derived from by-products in industrial installations.

To improve awareness and tracking of such products, member states should promote voluntary labelling schemes for industrial products that claim to be produced with renewable energy and RFNBOs.

As seen above, the increase of the share of renewable energies in total energy consumption as well as the inclusion of criteria for GHG savings from RFNBOs directly in RED III are uncontroversial. Accordingly, RFNBOs may only be counted towards the energy targets if the GHG savings achieved with the use of these fuels amount to at least 70%.[21] Similarly, energy from recycled carbon-containing fuels can only be counted towards the GHG savings target for the transport sector if the GHG savings from the use of these fuels are at least 70%.[22] Subsequently, the EU Commission is empowered to adopt a Delegated Act to assess the greenhouse gas savings of RFNBOs. This is therefore consistent and in line with the draft Delegated Acts mentioned above.

According to the current draft of RED III Member States shall report the amount of renewable fuels of non-biological origin that they expect to import and export in their integrated national energy and climate plans and progress.

It is important to emphasise that RED II/III and the EU ETS/n-ETS could co-exist independently – i.e., to allow "low-carbon-hydrogen" use in the ETSs (one just needs to define a methodology on how to determine the emissions intensity of H_2/PtX), and apply the more stringent rules of RED II/III at Member State level. This

[21] COM(2021) 557 final 2021/0218 (COD), Article 1 (19).
[22] COM(2021) 557 final 2021/0218 (COD), Article 1 (19).

would create a significant additional demand for low-carbon PtX from operators of ETS installations without diluting the targets of the Renewable Energy Directive.

1.1.5. The Fuel Quality Directive (FQD)

In the past, the Fuel Quality Directive (Directive 98/70/EG) was a substantial act to reduce GHG emissions of transport fuels. Furthermore, the FQD established the sustainability criteria for biofuels, as at the time biofuels were the only viable option to reduce GHG emissions in the transport sector. [23] According to article 7a (2) FQD, Member States should require suppliers to gradually reduce life cycle GHG emissions per unit of energy from fuel and energy supplied to up to 10% by 31 December 2020, compared with the fuel baseline standard. Therefore, the reduction should consist of a 6% target by 31 December 2020.

Due to the fact that the law sets 31.12.2020 as the end date of the obligation, initially without continuation, the Commission stated on its website that "Member States are obliged to ensure that suppliers respect the target of 6% after the year 2020."[24] In 2015, Germany was the only European Member State to transpose this GHG reduction obligation into national law. In the so-called Federal Emission Control Act (Bundesimmissionsschutzgesetz), § 37a stipulated the obligation for so-called distributors of fuels (Inverkehrbringer) to achieve GHG reductions of the total fuel they put into circulation of 3.5% from 2015, 4% from 2017 and 6% from 2020. Since 2021, this obligation has been extended so that by 2030 a GHG reduction obligation of 25% must be achieved. The 2020 amendment also created the option of meeting the GHG reduction obligation in part with liquid- or gaseous renewable fuels of non-biogenic origin (RFNBO). This opens the possibility to use eligible "green" hydrogen or hydrogen derivatives to fulfil the greenhouse gas reduction obligation. Eligibility definitions are provided in the Delegated Acts to RED II, see chapter 3.3.

There are linkages between the FQD and the RED. With the first draft for the amendment of RED II, a system of GHG reduction was introduced as a fundamental element for reducing emissions (Art. 1 para. 14). According to subparagraph 1, Member States are to oblige fuel suppliers to achieve a GHG reduction of at least 13% by 2030. On the one hand, this transfers the systematics of the FQD to the RED and thus adapts the basic systematics to the goal – GHG reduction and climate neutrality. On the other hand, it combines the technological openness of emissions trading with a possible development path for various technologies through different sub-quotas.

1.1.6. The Carbon Border Adjustment Mechanism

The Carbon Border Adjustment Mechanism (CBAM) is part of the EU's "Fit for 55" package. It imposes a financial cost on the carbon content of *imports to the EU*. Its purpose is to:

- prevent carbon leakage,
- ensure that imports are subject to similar costs of carbon as domestic products, and to
- incentivise non-EU manufacturers to decarbonise.

On 12 December 2022, the European Parliament and the European Council reached a compromise in the so-called trilogue[25]. The CBAM will start its operation on 1 October 2023. In parallel, the Commission will prepare specific rules for the implementation of CBAM.

CBAM covers a range of specific products identified with CN codes within the following sectors:

[23] Directive 98/70/EG Article 7a et seq.

[24] European Commission (n.d.): Fuel Quality https://climate.ec.europa.eu (Accessed December 5, 2022)

[25] The compromise text is available at https://data.consilium.europa.eu/doc/document/ST-16060-2022-INIT/en/pdf.

Table 2: Product coverage of CBAM

Sector	Gases	Direct / indirect	Specific products (examples)
Cement	CO_2e	Direct and indirect emissions	e.g., Kaolin, clinkers, Portland cement
Electricity			-
Fertilizers	CO_2e / N_2O		e.g., nitric acid, ammonia, mineral fertilizers
Iron / steel	CO_2e	Direct emissions only[26]	e.g., Iron ores, sheet piling, tubes, pipes, nuts and bolts
Chemicals			Hydrogen only (at least until 2025)
Aluminum	CO_2e / PFCs		e.g., unwrought aluminum, bars, wires, plates, tubes

Source: authors

In 2025, the Commission will propose if the scope should be expanded to include other goods, in particular organic chemicals and polymers, and whether CBAM should also cover indirect emissions for the above sectors. For goods, countries formally linked with the EU ETS are exempt from CBAM. Initially, this applies to Iceland, Liechtenstein, Norway, and Switzerland. For electricity, countries with electricity markets coupled with the EU may be exempt from CBAM under specific conditions.

Obligation of importers to calculate and verify embedded emissions and to surrender certificates

Under the CBAM, only authorised CBAM declarants may import CBAM-goods or electricity to the EU. Importers (or their representatives) must apply for *declarant* status at their *competent authority* (appointed by the Member State in which the importer is registered). CBAM declarants must submit, on May 31 every year, a verified declaration of the emissions embedded in those imports and surrender *CBAM certificates* (CBAMCs) for those emissions. The price of one CBAMC will be the weekly average auction price of an EU ETS allowance, calculated by the Commission. If the country of origin already has a carbon price, then payments can be deducted proportionally. The Commission will cancel the surrendered CBAMCs. CBAMCs may not be traded, though the Commission may purchase excess certificates at their original price.

Phasing out of free allocation

When CBAM is rolled out, the amount of free EUAs received by EU-based producers of CBAM-goods will be gradually phased out in 2026-2034. During the phase-out, the amount of CBAMCs to be surrendered by importers will be reduced to reflect the allocation of free EUAs in a given year[27] (see chapter 1.1.1).

Calculating and verifying emissions

Annex III of the CBAM regulation outlines methods for calculating embedded emissions. This can be done by calculating actual emissions, or, if necessary, default values. The information on embedded emissions must be verified by authorised verifiers following principles outlined in Annex V. Operators of installations in third countries can register in a database maintained by the Commission to provide information on the emissions from the production of the CBAM-goods, and to share that information with CBAM declarants.

Staged introduction

The CBAM will be introduced in stages. The first stage will run from 2023-25 and will involve quarterly reporting by importers of CBAM-goods, but no financial adjustments. Importers must submit a CBAM report

[26] For three sectors (iron and steel, chemicals and aluminum), only direct emissions are considered in order to ensure consistency with the electricity price compensation of the EU ETS.
[27] Free allocation will be reduced by 2.5% in 2026, 5% in 2027, 10% in 2028, 22,5% in 2029, 48,5% in 2030, 61% in 2031, 73,5% in 2032, 86% in 2033 and 100% in 2034.

to the Commission for each quarter, stating the quantity of goods or electricity, embedded emissions, indirect emissions, and, if relevant, the carbon price in the country of origin.

Full implementation will begin in 2026, when the purchase of CBAMCs and the phase out of free allowances are introduced. Every two years after the transitional period, the Commission will monitor and review the effectiveness of the mechanism and propose legislation to address any changes needed.

CBAM and hydrogen/ PtX

Processes involving hydrogen will be impacted by the CBAM in several ways:

- The inclusion of hydrogen in CBAM is of particular relevance to investors planning to set up hydrogen production sites outside the EU, especially in light of the aim of REPowerEU to import 10 million tonnes of hydrogen annually by 2030;
- CBAM currently only covers direct emissions for hydrogen imports. Thus, imported hydrogen produced with electrolysis – no matter what the electricity source – will not require CBAMCs;
- Imported steel products will require reporting of embedded emissions and surrendering CBAMCs. Steel produced using green hydrogen will require less CBAMCs than those produced with conventional production methods or fossil fuel-based hydrogen. However, the declarant needs to demonstrate (by calculating and verifying the information) that green hydrogen was used, which may lead to methodological and data challenges;
- Similarly, imports of ammonia and other PtX-products such as methanol are subject to CBAM, and thus, the amount of CBAMCs required will depend on whether the ammonia was produced using green hydrogen. Here again the burden of proof is with the declarant;
- Furthermore, the inclusion of hydrogen in CBAM means that any free allocations for hydrogen-producing installations within the EU will be phased out in 2026-2034.

Issues under consideration

While the general rules for CBAM have been agreed, the instrument is not complete. The Commission is working to specify questions about e.g. methodologies for calculation of direct and indirect emissions, reporting formats and consideration of carbon price in countries of origin.

In its current form, CBAM only considers imports. However, export-oriented industries worry that the expedited phase out of free allocations will disadvantage exporters vis-à-vis competitors in export destinations. The Commission will evaluate, by 2025, the risk of leakage for exported goods, and possibly propose measures to address it. In addition, 47.5 million allowances will be used to raise funds to address risks of export-related leakage.

Several countries have expressed concerns about CBAM. The BASIC countries (Brazil, South Africa, India, China) have called it discriminatory and a violation of the Paris Agreement's notion of national determination. A possible transatlantic sticking point is how CBAM only allows carbon pricing in countries of origin as a basis for deductions in payments, meaning that other policy instruments such as the US Inflation Reduction Act, are not basis for deductions. As CBAM becomes EU law, and as the Commission publishes specific implementation rules, these controversies might escalate, including in the World Trade Organisation (WTO).

1.1.7. Other policy instruments under EU fit-for-55 with relevance for PtX

Under the Fit for 55 package, Member States are allowed to implement Carbon Contracts for Difference (CCfDs). CCfDs are a new policy instrument to support the transformation of CO_2e-intensive industries. CCfDs are contracts between private companies and governments. Governments provide financial incentives for companies to reduce their carbon emissions by taking over volatility risks for carbon prices, which can be a key barrier for investments into low-carbon technologies. CCfDs define a fixed carbon price over a long period (e.g., 10-20 years), allowing the investor to finance innovation that would not be economically viable at lower carbon prices. In periods where actual carbon prices are lower than the predetermined carbon price, the government pays the difference. Likewise, when actual carbon prices are higher than the "strike price", the company pays the difference to the government (DIW 2023). A main difference to other subsidies is that cost differences between a zero/low-carbon product and the reference production used today are calculated including CAPEX and OPEX (including prices for EUAs). CCfDs target heavy industries and green hydrogen will play a central role especially in replacing coal in the steel sector and natural gas (feedstock) in the chemical sector. CCfDs will be implemented on the EU-level within the "innovation funds" and especially at the national level. In December 2022, Germany was the first country to present a Ministerial draft for an aid System.

The European Commission's Fit for 55 package also suggests including maritime transport in the EU ETS from 2023 onwards. All emission allowances should be auctioned. To allow for a smooth start, the plan is to gradually phase in the obligation to surrender allowances (2023: 20% of verified emissions, 2024: 45%, 2025: 70%). Allowances for 100% of verified emissions will only be surrendered from 2026 onwards. The system will apply to journeys between EU ports and during a stopover in an EU port. In addition, 50% of the CO_2e emissions from journeys whose origin or destination is outside the EU shall be covered. Ships with a gross tonnage (GT) exceeding 5,000t will be covered with exceptions for certain types of vessels e.g., warships, fishing and fish-processing vessels, or government vessels used for non-commercial purposes. In addition, the International Maritime Organization (IMO) of the United Nations (UN) plans to introduce a market-based climate protection measure at global level. If this is implemented, the interaction of the two instruments will have to be assessed[28].

It is important to note that the Fit-for-55 package will not impact the fundamentals of the EU ETS. As a result of Fit-for-55 and/or a further increase of the ambition level of EU climate policy, the numbers in the EU ETS (allocation, benchmark values, etc.) may be adjusted, but the underlying principles will remain.

Another relevant policy initiative is the RePowerEU plan, published by the European Commission in May 2022 as a consequence of the energy crisis resulting from the Ukraine conflict. It underpins the high ambitions to establish renewable hydrogen as an important energy carrier and to move away from fossil fuel imports from Russia. The plan sets the goal to use 20 million tonnes of renewable hydrogen in the EU by 2030 (10 million tonnes produced domestically and 10 million tonnes imported), which is a substantial increase to the 5.6 million tonnes published in the RED from 2021 (European Commission 2022c). 20 million tonnes of hydrogen is equivalent to ca. 15% of the EU's current gas consumption (ACER/CEER 2021).

[28] DEHSt (n.d.): Extension of EU ETS Scope, https://www.dehst.de

1.1.8. Overview: impact of EU legislation for hydrogen production and consumption

Table 3 summarises the main features of the key EU policies relevant for PtX – the EU ETS, the CBAM, RED and the FQD - and their impact on producers (inside and outside the EU) and consumers.

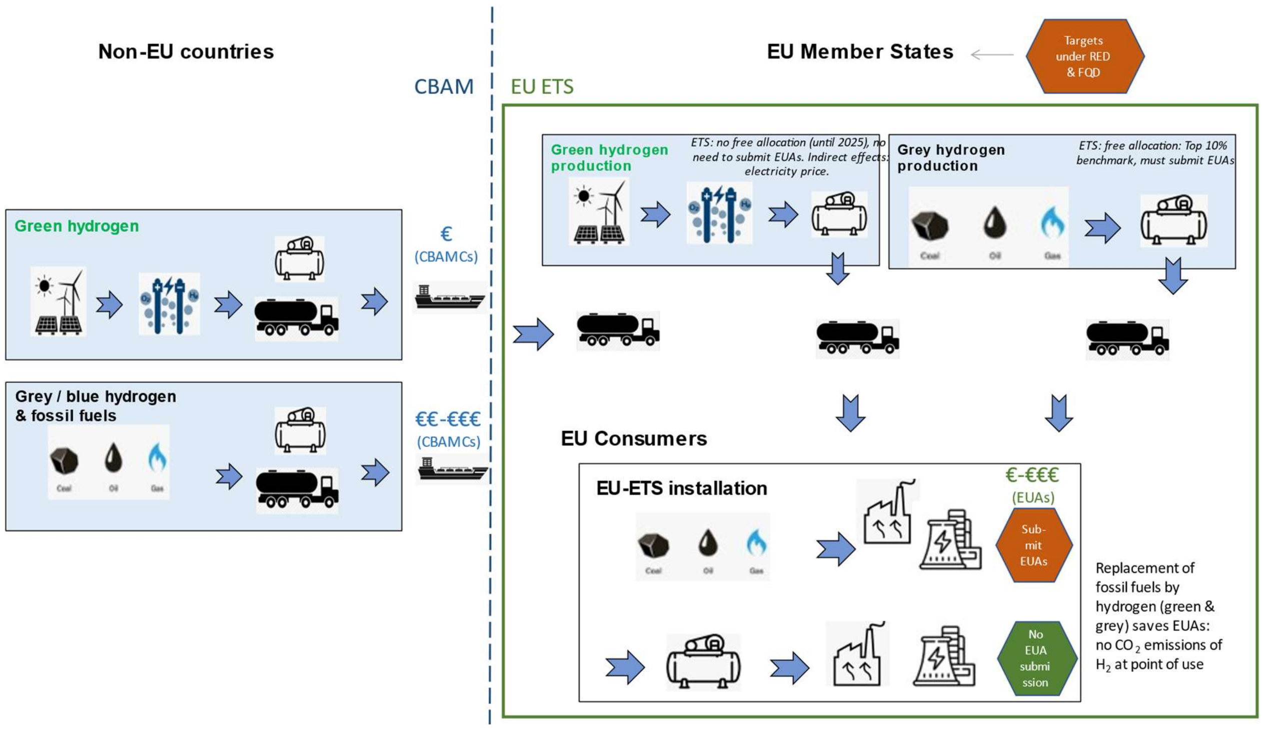
Table 3: Overview EU regulation relevant for hydrogen

	Carbon Border Adjustment Mechanism **Regulated subjects:** importers of carbon intense goods **Function:** certificate 'levy' on imports of carbon intense goods to the EU	**EU-Emissions Trading System** **Regulated subjects:** operators of installations **Function:** emissions trading for industry and energy sectors	**Renewable Energy Directive** **Regulated subjects:** EU Member States **Function:** binding renewable energy targets and rules	**Fuel Quality Directive** **Regulated subjects:** distributors of fuels **Function:** targets for carbon intensity of transport fuels
General aspects	*Mechanism covers hydrogen, ammonia, methanol, and other PtX*	*Hydrogen treated as an emissions-free fuel*	*Renewable hydrogen, PtX and Recycled Carbon Fuels help meet renewable energy targets*	*Created a market for emission reduction quotas that can be met through renewable hydrogen, PtX and Recycled Carbon Fuels*
Emissions coverage	*Direct emissions (hydrogen)*	*Direct emissions*	*Direct and indirect emissions*	*Lifecycle emissions*
Effects on imports	*Direct emissions from production need to be reported, importers need to buy certificates*	*No particular rules*	*Rules apply for imports, too*	*Rules apply for imports, too*
Effects on domestic production	*No direct effects (CBAM not applicable to domestic production).* *But: avoids competitive disadvantages compared to imported hydrogen & goods, which may result from less stringent environmental standards outside the EU (exact rules yet to be agreed)*	*Today: no clear benefit for green hydrogen production because of free allocation for fossil fuel-based hydrogen receive free certificates* *Future: green hydrogen production to become eligible for free allocation (from 2026 onwards)*	*Increased demand from EU (details tbc)* *Future:* • *Additionality requirements must be met (upcoming)* • *Lifecycle emissions must be determined (upcoming)*	*Helps distributers of fuels to meet their quotas / targets and avoid penalties (up to 130 EUR in Germany)*
Producers of green hydrogen / PtX outside EU	*Creates economic benefit of green hydrogen and goods produced with green hydrogen compared to grey/blue hydrogen and goods produced with fossil fuels*	*No direct effects, but increased demand from EU ETS installations*	*No direct effects, but increased demand from EU (details tbc)*	*No direct effects, but increased demand from EU*
Consumers of green hydrogen / PtX in EU	*Reduces cost differential between imported green hydrogen / goods produced with green hydrogen and their carbon-intensive alternatives due to lower ‚levy'*	*Emission factor of zero makes utilisation of hydrogen more attractive than use of fossil fuels (no need to surrender EUAs reduces cost for EU ETS installations) → can increase demand*	*No direct effects*	*No direct effects*

Source: authors

Figure 8 visualises the boundaries and point of targets of CBAM, EU ETS, RED and FQD.

Figure 8: Boundaries and point of targets of CBAM, EU ETS, RED II and FQD



Source: Perspectives

1.2. Overview of key PtX consumers and ETS coverage

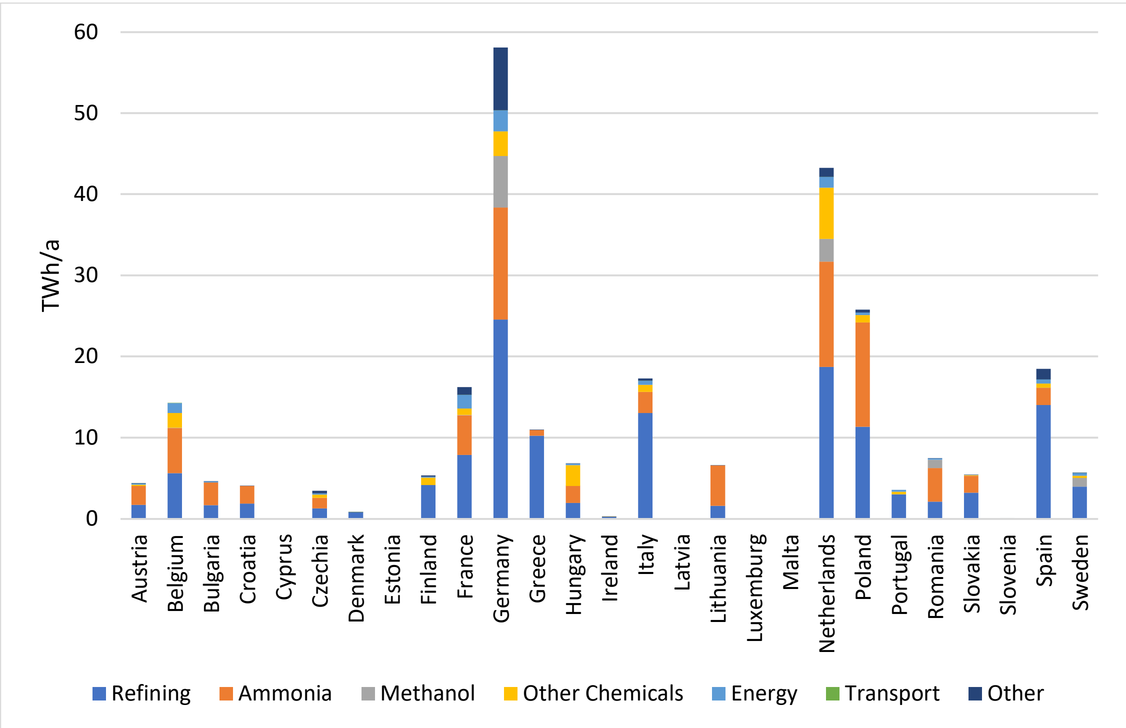
In this chapter, the current and projected hydrogen demand in the EU is analysed by sector to identify key hydrogen consumers. In addition, the ETS coverage of these consumers is elaborated.

1.2.1 Hydrogen consumption forecasts

2022

Today, hydrogen accounts for approximately 2% of Europe's total energy consumption. According to the Fuel Cells and Hydrogen Observatory, in 2022 approximately 7.9 Mt (263 TWh) of hydrogen have been consumed in the EU. As can be seen in Figure 9, by far the largest hydrogen consumers in the EU are Germany, Netherlands and Poland making up almost 40% of the total hydrogen consumption. In all Member States, hydrogen demand is mainly driven by refining and the chemical industry (Fuel Cells and Hydrogen Observatory 2022).

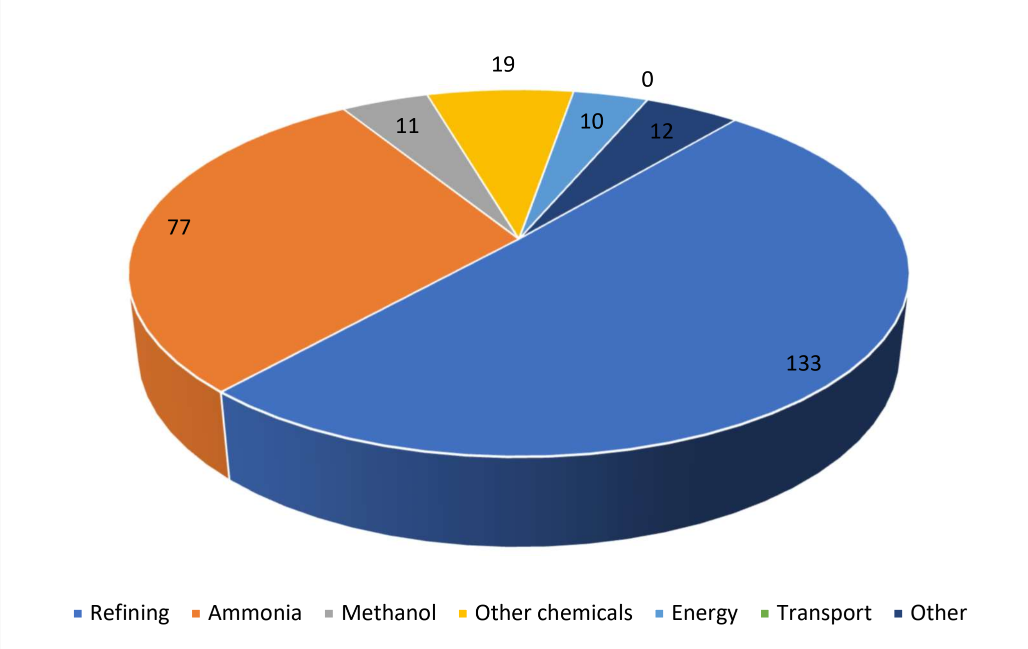
Figure 9: Hydrogen consumption in Europe (2020)



Source: Authors based on Graham et al. (2022), Fuel Cells and Hydrogen Observatory (2022)

As can be seen in Figure 10, refining is responsible for more than half of the total hydrogen consumption in the EU. The chemical industry makes up for another 40% of the hydrogen demand with ammonia production as the biggest consumer. The remaining 10% are split between energy (4%) and other applications like small to medium scale hydrogen users, including the food industry, glass manufacturing, automotive, generator cooling in the power sector, metal welding and cutting, electronics, research labs and other small-scale applications.

Figure 10: Hydrogen consumption in TWh in the EU in 2022



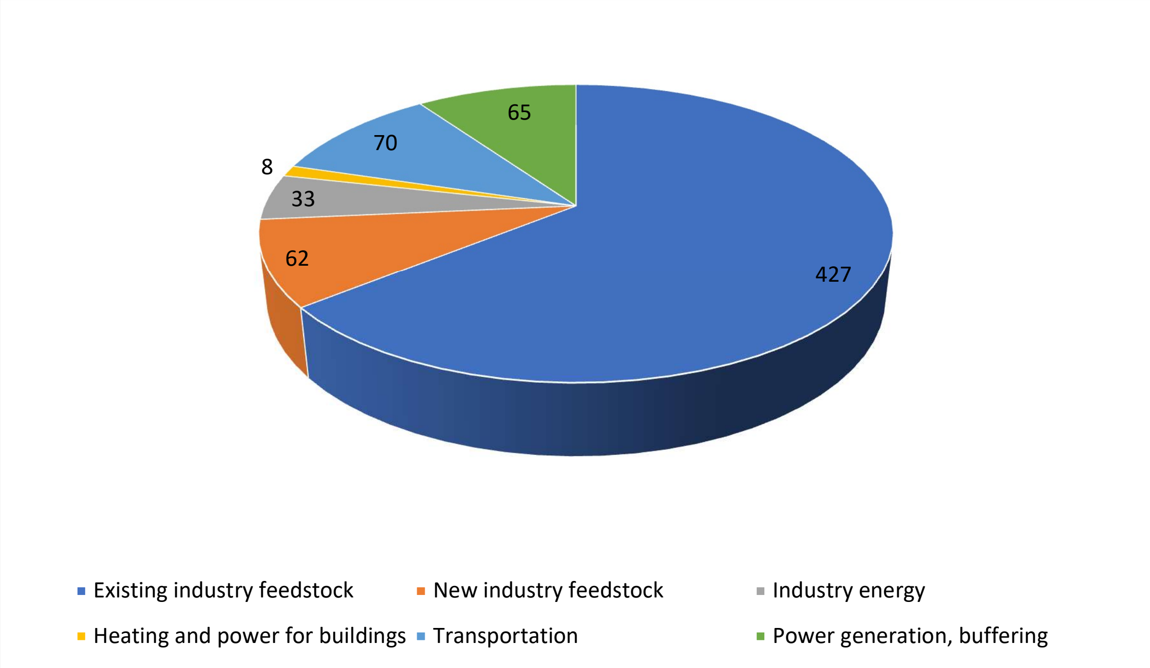
Source: Authors based on Graham et al. (Fuel Cells and Hydrogen Observatory (2022))

Regarding hydrogen production, approximately 10.8 Mt H_2 (362 TWh) is produced annually in the EU by about 460 hydrogen production plants. 75% of this is produced for captive utilisation, 13% as a byproduct from chemical processes and only about 12% for merchant purposes. By far the largest share (84%) of the hydrogen is produced by traditional reforming processes, emitting large amounts of GHG emissions. Less than 2% of these reforming processes are subject to carbon capture (blue hydrogen) (Fuel Cells and Hydrogen Observatory 2022).

2030

For this study, we selected the 2030 scenario published by the *Fuel Cells and Hydrogen 2 Joint Undertaking* (financed by the EU), since the development over the next decade is fairly foreseeable and parts of the investments are already underway. The projected PtX consumption categorised by sector can be seen in the figure below. The overall projected PtX consumption in 2030 correlates closely with the RePowerEU plan of utilising 20 Mt/a of hydrogen or its derivates which is equal to 666 TWh/a. 64% of this low-carbon hydrogen will be used to replace grey hydrogen in existing industrial applications, mainly as a feedstock in the chemical industry and refineries. About 10% will be applied in power generation, 11% in transportation, 9% for new applications in the industry, 5% will be used in order to meet some of the energy demand in the industry and about 1% for heating and powering buildings (Fuel Cells and Hydrogen 2 Joint Undertaking 2019).

Figure 11: Projected PtX consumption in TWh in the EU in 2030



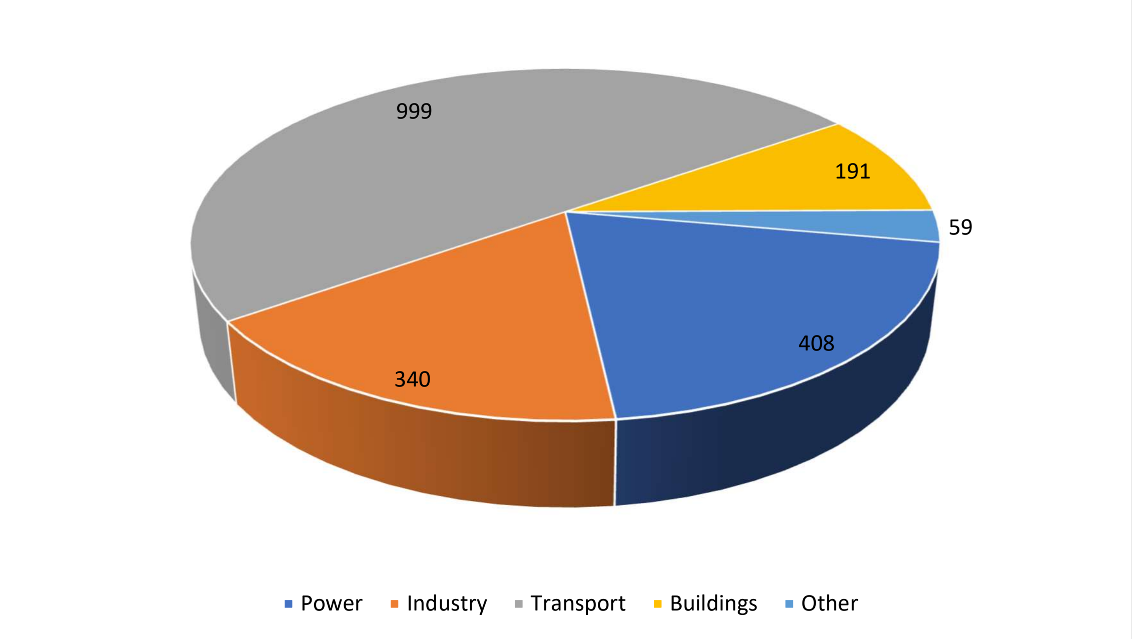
Source: Fuel Cells and Hydrogen 2 Joint Undertaking (2019)

2050

Since the projected hydrogen consumption depends on numerous parameters, e.g., policy and technology development, it is challenging to foresee PtX consumption until 2050. There are various studies projecting the future PtX demand in the EU. Almost all studies agree that hydrogen will play a highly important role meeting approximately 1500-3200 TWh or 10-20% of the final energy demand, but the exact numbers and application sectors can vary strongly between different studies (Joint Research Centre 2019).

Therefore, for the 2050 scenario, the average of six different, highly relevant studies was calculated – see Figure 12. On average, an annual hydrogen consumption of 2000 TWh is foreseen for the year 2050. The largest part (50%) will be used for transport, mainly maritime transport, aviation and heavy-duty transport. The second largest consumer (20%) will be the power sector using hydrogen mainly as a long-term storage for renewable energies. About 17% will be used in industry, mainly consuming hydrogen or ammonia as a feedstock for chemical processes. About 10% of the total hydrogen consumption will be used in the building sector and 3% for other smaller applications (Joint Research Centre 2019).

Figure 12: Projected PtX Demand in the EU in TWh in 2050



Source: Authors based on EC-European Commission, 2018; Öko-Institut, 2018; Hydrogen 2 Joint Undertaking, 2019, Climact, 2019; Guidehouse, 2020; European Union, 2019

1.2.2 Industrial hydrogen consumers covered by ETS in the EU

Taking into consideration the findings of chapter 1, this chapter explores which PtX applications are already covered by GHG regulations. The EU ETS covers large energy and industrial installations with a high energy consumption and intra-European aviation. As of today, the EU ETS covers ca. 11,000 stationary installations and 1,500 aircraft operators for their intra-EU operations. The complete list of the covered installation types/ sectors can be seen in Table 4. The most important sectors which can be decarbonised by hydrogen are marked in blue.

Supplementary to the EU ETS is the recently introduced German nETS which covers the transport and heating sector, which are both relevant for the decarbonisation by the application of green PtX products. Both ETSs are described in more detail in chapter 1.1.2.

Table 4: Sectors covered by the European and German emission trading schemes

Power stations and other combustion plants	Oil refineries	Coke ovens
Glass	Cement clinker	Iron and steel plants
Lime	Pulp	Heating sector
Paper and board	Intra-European Aviation	Ceramics
Ammonia	Nitric, adipic and glyoxylic	Acid production
CO_2e capture	Transport & Storage of CO_2e	Transport

Source: Glowacki Law Firm (2022)

1.3. Summary

The import and domestic use of PtX in Germany and the EU encounters a complex regulatory landscape in flux. At the EU-level, the most relevant policy instruments are the EU ETS, the RED directives and the newly introduced CBAM. Both EU ETS and CBAM directly target industry; whereas RED primarily target EU Member States but define fundamental requirements regarding the “green” attitude of PtX that may be transposed to industry players as well. In the German context, the national ETS provides the regulative framework for PtX use in the transport- and heating (buildings) sector.

<u>Highlights of the EU ETS rules relevant for PtX</u>

- The EU ETS is installation-based, meaning that the point of obligation is the operator of an installation. If a covered installation uses less GHG intensive fuels such as green/low-carbon PtX, it benefits from cost savings as less EUAs need to be submitted for compliances. Therefore, under current ETS rules, economic benefits occur for the user of hydrogen, not the producer or importer.
- At the point of utilisation, hydrogen does not lead to CO_2e emissions – regardless of the carbon intensity of hydrogen production, processing, transport or storage. In other words, CO_2e emissions may occur from hydrogen production/processing/transport, but not a hydrogen utilisation – consequently, there is no obligation to surrender EUAs for hydrogen use.
- If hydrogen is produced domestically in the EU, production is subject to EU ETS-related cost.
    i. The operation of grid-connected electrolysers is not directly covered by the EU ETS, because no direct emissions occur. Hence, there is no free allocation to electrolysers, but also no obligation to surrender EUAs for compliance. However, grid-electricity consumption for the operation of electrolysers entails indirect costs from the EU ETS (reflected in higher electricity prices). Special effects may occur due to the *electricity price compensation* (“Strompreiskompensation”).
        - If electrolysers are exclusively operated with dedicated renewables, from a theoretical point of view, no indirect costs result from the EU ETS because the emission factor of renewable energy is zero and no EUAs need to be surrendered. However, if RE-installations and electrolysers are operated by different legal entities, the seller of renewable electricity may still ask for standard market prices, which could then result in an indirect cost increase.
    ii. If hydrogen is produced with fossil fuels – e.g., SMR or partial oxidation –, free allocation is granted up to a benchmark of 6.84 t $CO_2e/t\ H_2$. This value was calculated as the average of the top 10%, i.e., the emissions of the most efficient installations. Installations producing fossil fuel-based hydrogen need to surrender EUAs according to their actual emissions. That means that installations, which are less efficient than the benchmark, will face a deficit of EUAs, whereas those that meet the benchmark do not face additional costs.
- The price for EUAs has risen constantly in the last years to about 90€/EUA in 2022. The additional costs for carbon emissions that result for the use of fossil fuels can make the use of green/low-carbon PtX economically more competitive. However, current free allocation of EUAs for the production of fossil fuel-based hydrogen makes this calculation complex. If for hydrogen production the switch from a fossil fuel to renewable electricity results in the loss of free allocation, the economic advantage of the climate-friendly alternative would be reduced. In cases without free allocation, the economic benefit of green hydrogen is fully realised. Particular examples will be analysed quantitatively in chapter 2.
- The rules for free allocation will change as of 2026, see chapter 4.
- Finally, it is important to note that the EU ETS only covers scope 1 emissions, i.e., emissions occurring at the installations when they utilise/burn the fuel. Scope 2 or 3 emissions, i.e., emissions occurring in the production, processing and transport process, are <u>not</u> covered. This is different in the RED- and CBAM-provisions.

Highlights of the German nETS rules relevant for PtX

- The German nETS covers emissions in the transport- and heating-sectors in an upstream-approach; i.e., it targets importers and distributers of fuels.
- Prices have been pre-defined by the German government and are far lower than in the EU ETS. Direct economic incentives through the avoidance of CO_2e costs are therefore lower here.
- Within the system, green hydrogen does not have to be reported, except when it is blended into grids above a certain threshold. If the hydrogen was not produced solely with renewable energies, the emissions factor of natural gas has to also be applied for the blended hydrogen. This rule constitutes a barrier for the market ramp-up of both green and low-carbon hydrogen.
- Outlook: in July 2021, the EU Commission proposed a new ETS ("ETS II") specifically for road transport and the heating of buildings. It will, in many aspects, resemble the German nETS. The system will start in 2027 or 2028, depending on energy prices, and regulate distributors of fuels (also see chapter 4).

Highlights of RED-rules relevant for PtX

- The Renewable Energy Directive (RED) also creates incentives for the use of green hydrogen and PtX by defining targets for EU Member States for the minimum share of renewable energies in fuel consumption.
- In RED II, renewable hydrogen, PtX and Recycled Carbon Fuels (RCF) are defined as "renewable liquid and gaseous transport fuels of non-biological origin" (RFBNO). RFNBOs are an option for Member States to meet their renewable energy targets.
- Detailed specifications on the eligibility requirements to count as RFNBOs are currently being defined in Delegated Acts. RED II also defines a series of sustainability- and GHG-emission criteria that biofuels must comply with.
- These Delegated Acts will have an impact on the hydrogen market: the so-called "Additionality Act" defines additionality requirements for renewable energy capacities used to operate electrolysers. The "Methodology Act" defines rules for determining life cycle greenhouse gas emissions of RFNBOs and RCFs, as well as minimum thresholds for associated GHG-savings. Both Delegated Acts are discussed in more detail in chapter 3.3, while the quantitative impact of required minimum GHG-savings are analysed in chapter 4.2.
- An important difference to EU ETS rules is that RED will also cover scope 2 (and potentially scope 3) emissions: GHG emissions from the processing, transport and storage would therefore be included.
- Given that the EU ETS targets industry and RED targets Member States, the regulations could co-exist independently – i.e., to allow "low-carbon-hydrogen" use in the ETS and apply the more stringent rules of RED on Member State level. This would create a significant additional demand for low-carbon PtX from operators of ETS installations without watering down the targets of the Renewable Energy Directive. However, it is expected that, in the mid-term, the RED regulations will have a strong influence on ETS rules. Details are currently unclear, and the necessary legal clarifications are still pending.

Highlights of the FQD relevant for PtX

- The Fuel Quality Directive of 2009 required Member States to reduce the GHG emission intensity of transport fuels (petrol, diesel and biofuels used in road transport) by 6% by 2020 compared to 2010. Member States were to transfer this target to fuel suppliers. In 2020, the obligation was extended to a 25% reduction by 2030.
- The GHG-intensity of fuels is calculated on a life-cycle basis, covering emissions from extraction, processing and distribution.
- The target can in part be achieved with liquid or gaseous renewable fuels of non-biogenic origin (RFNBOs). This opens up the possibility to use green hydrogen and PtX to meet the target.

- With the new RED II regulations, the relevance of the FQD may be reduced but essentially, the systematics of the FQD were transferred to RED.

Highlights of the CBAM rules relevant for PtX

- The Carbon Border Adjustment Mechanism is part of the EU's "Fit for 55" package. It imposes a financial cost on the carbon content of *imports to the EU,* aiming to prevent carbon leakage and to incentivise non-EU manufacturers to decarbonise. Targeted entities are importers of products.
- CBAM currently only covers scope 1 emissions for hydrogen imports. Thus, imported hydrogen produced with electrolysis – no matter what the electricity source – will not require CBAMCs.
- Imported steel products will require reporting of embedded emissions and surrendering CBAMCs. Steel produced using green hydrogen will require less CBAMCs than steel produced with conventional production methods or fossil fuel-based hydrogen. However, the declarant needs to demonstrate (by calculating and verifying the information) that green hydrogen was used, which may lead to methodological and data challenges.
- Similarly, imports of ammonia and other PtX products such as methanol are subject to CBAM. The amount of CBAMCs required will depend on the carbon intensity of the production process.
- Furthermore, the inclusion of hydrogen in CBAM means that any free allocations for hydrogen-producing installations within the EU will be phased out in 2026-2034.
- Importers need to calculate and verify the carbon content of their products. Detailed rules and requirements have yet to be defined, but it is expected that – due to the complexity of processes and different national reporting standards in PtX-exporting countries – methodological and data availability/quality challenges will occur.

As of today, refining, the chemical sector and ammonia production are the main consumers of hydrogen in the EU. These users can become starting points for accelerating green PtX demand by switching from grey to green hydrogen. In the transformation to widespread green hydrogen use, selected industries – such as steel and cement – are expected to become first-movers, followed by other industries. In the long run, transport – mainly maritime transport, aviation, and heavy-duty transport – are expected to become large hydrogen consumers, and the power sector will also play an increasing role, using hydrogen as a long-term storage for renewable energies.

The current EU ETS and German nETS cover many of these "hydrogen candidates": ammonia production, refineries, the power sector, iron and steel as well as coke ovens, cement, glass, and international aviation (maritime transport is to follow from 2026 onwards). Road transport is already covered by the German nETS and will be covered EU-wide in the planned ETS II (see chapter 4.1).

In the next chapter, the potential economic benefits resulting from the ETS for switching to hydrogen/PtX will be analysed for selected sectors and scenarios.

2. Economic benefits for green PtX fuels from carbon pricing schemes

This chapter derives scenarios assessing the potential economic benefits of the EU ETS and the German nETS for green hydrogen, taking into consideration different utilisation options, import- and transport options, as well as price expectations under the EU ETS and the national ETS in Germany.

For assessing the economic benefits of carbon pricing schemes for green PtX, their cost structures and carbon "footprint" for different scenarios and geographical origins need to be understood. The costs as well as the carbon footprint of PtX products depend on the complete supply chain of the PtX products – namely production, processing, and the transport route (IEA 2022). To be able to put the prices and correlating emissions of PtX products into comparison, the emissions of fossil energy carriers and their consumption by different applications must be analysed. Finally, these findings will be combined with current and projected carbon emission pricing structures for the most relevant sectors in order to calculate the economic benefits caused by emission pricing schemes.

2.1 Scenarios for PtX-production and import

In this chapter, the specific costs of imported PtX products are calculated for different production locations. The costs for PtX products from different countries mainly depend on renewable energy resources, national energy prices, costs for conversion of hydrogen and transport costs. To analyse the cost effect of different locations on the various steps of the supply chain, this report exemplarily calculates costs for six different locations: the United Arab Emirates (UAE), Morocco, Colombia, Chile, and Australia. For comparison, the cost of domestic production in Germany is also investigated.

Since gaseous hydrogen has a very low gravimetric energy density (765 kWh/m^3 at 350 bar and 25°C) and is costly to transport over long distances, not only the transport of pure hydrogen will be analysed but three hydrogen derivates (liquid hydrogen, ammonia, and electricity-based sustainable aviation fuel (SAF)) have been considered as transport mediums.

The following PtX production routes are analysed in this chapter:

- PS1: Production of green hydrogen in Morocco and import through pipelines
- PS2: Production of green ammonia in Morocco and import by shipping
- PS3: Production of green hydrogen/ammonia in UAE and import through shipping or pipelines
- PS4: Production of green PtX (ammonia, SAF) in Chile or Colombia and import by shipping
- PS5: Production of green PtX (ammonia, SAF) in Australia and import by shipping
- PS6: Production of green PtX (hydrogen, ammonia, SAF) in Germany / the EU

In order to assess the economic benefits of green PtX products resulting from the respective carbon pricing schemes, two superordinated production scenarios have been developed:

1. The Renewable Energy Scenario (RE-Scenario) assumes the production and conversion of hydrogen to PtX products being powered by 100% dedicated renewable energies. This would entail that the installed electrolysers are operating at reduced full load hours. The full load hours are dependent on the renewable energy resources at the production location. Since renewable energies are considered to generate zero CO_2e emissions and transport emissions will most probably also not be regarded in the CBAM, all PtX products in this scenario are considered to have zero embodied emissions.
2. The Grid Scenario assumes a 100% capacity factor of the electrolysers (100% full load hours). Since renewable energies are a volatile energy source, they cannot supply energy constantly. Therefore, in this scenario, the remaining energy demand required to run the electrolyser at 100% full load hours and to produce the respective PtX products is supplied by grid electricity. Since grid electricity can be emission intensive, the embodied emissions of PtX products can vary significantly, which might have significant effects on the economic benefits caused by the different carbon pricing

schemes, if embodied emissions of the PtX product are considered. Although hydrogen produced with grid-electricity has zero direct emissions at the point of utilization and hence does not require surrendering EUAs, the upcoming CBAM mechanism will, with high probability, introduce a carbon pricing scheme which will internalise the embodied carbon emissions at equal prices as the EU ETS (see chapter 1.1.6). Since electricity prices peaked in 2022, we developed two sub-scenarios within the grid-scenario. One is considering electricity prices from 2022 and one is considering average electricity prices between 2018 and 2022 in order to compensate for the high volatility in recent years. Furthermore, in these scenarios, transport emissions will not be considered for the calculation of the economic benefits caused by the respective carbon pricing scheme.

The processing and transport options are shortly explained in the following:

Hydrogen liquefaction

Hydrogen can only be liquified under cryogenic temperatures, i.e., by cooling gaseous hydrogen to below -253°C. Such low temperatures are reached via multiple refrigerant cycles which is why the process is highly energy intensive. Liquid hydrogen has an energy density of 2350 kWh/m^3 and is stored in large, insulated tanks to be transported via ships or trucks (IRENA 2022a). However, losses can occur due to boil-off. The boil-off is a term describing the losses of gas during transportation or storage due to evaporation of the cargo. For liquid hydrogen, the boil-off ratio depends on the tank size but on average 0.1%-0.3% loss occurs per day (Berstad et al., 2022). Any such loss also reduces the GHG mitigation benefits (Ocko and Hamburg 2022). As these losses are dependent on time spent at the sea, they are investigated separately for individual cases.

Processing of hydrogen to ammonia

Ammonia is one of the most promising hydrogen derivates for transport purposes due to its high energy density (4040 kWh/m^3) when liquified and its relatively low energy demand for synthesis. Furthermore, ammonia transport is already a very mature technology. Ammonia (NH_3) is produced via the Haber-Bosch process, which was discovered in the early 20th century. It is produced by reacting nitrogen and hydrogen gases at high pressure and temperature, usually around 150-300 bar and 400-500°C. The reaction is catalysed by an iron-based catalyst (Salmon and Alcantara 2021).

Processing of hydrogen to SAF specifically e-kerosene

Electricity-based sustainable aviation fuels (SAF) are fuels which are produced from renewable sources. There are several products that can be classified as SAF. Biofuels such as hydro-processed esters and fatty acids (HEFA) from waste oils also count as SAF. E-kerosene is also considered as a SAF and is seen as the most prominent. Thus, this report takes e-kerosene as the SAF[29] (International Council on Clean Transportation 2022). SAFs are mainly produced via the Fischer-Tropsch process. The Fischer-Tropsch process is an industrial process used to convert a mixture of carbon monoxide and hydrogen into liquid hydrocarbons, such as synthetic paraffinic kerosene (SPK), which can be used as a sustainable aviation fuel (SAF), or diesel and gasoline. The process was developed by Friedrich Fischer and Hans Tropsch in the 1920s and has been widely adopted in the chemical industry (Evans and Smith 2012). To produce SAFs via this process, carbon dioxide is needed as an educt, which can be supplied from two different sources. The first option is obtaining it from industrial plants with high CO_2 emissions by means of carbon capture and the second one is by direct air capture (DAC). With the reverse water gas shift reaction, which today is still a rather novel technology with a low Technology Readiness Level (TRL) carbon monoxide is obtained. As stated before, carbon monoxide is then reacted with hydrogen to create e-kerosene.

Hydrogen transport via pipelines

Gaseous hydrogen is typically transported in pipelines by compressing it to high pressures. This is done using compressors located at various points along the pipeline. The compressed hydrogen gas is then transported through the pipeline to its destination. The pipeline must be designed, built, and maintained

[29] Through this report SAF and e-kerosene will be used interchangeably.

according to the latest relevant standards for hydrogen pipeline transmission and distribution. Although pipeline transport of hydrogen gas is a readily available technology, it is not yet very commonly used. Hence, either large-scale repurposing of natural gas pipelines or construction of new ones would be required. Also, pipeline transport is geographically more limited than transport by ships, which allows for inter-continental transport but comes at higher cost and lower quantities. But transportation of hydrogen via pipelines will play an increasingly important role in the distribution and delivery of hydrogen since it is one of the most cost-effective alternatives for short and medium distances.

2.1.1 Levelized cost of hydrogen

The first step to determine the costs of PtX products delivered to the EU/Germany is to determine the Levelized Cost of Hydrogen (LCOH) for each of the selected countries. The LCOH is calculated based on the following formula.

Equation 2: Levelized Cost of Hydrogen Production

$$LCoH = \frac{I_0 - S_0 + \sum_{t=1}^{T} \frac{C^t}{(1+r)^t}}{\sum_{t=1}^{T} \frac{E_t}{(1+r)^t}}$$

With:

I_0	= Initial investment (€)
S_o	= Subsidies (€)
C	= O&M costs (€/a)
T	= Period of analysis (years)
r	= Discount rate (%)
E_t	= Reference energy (kWh/a)

Source: Furfari & Clerici. (2021)

General assumptions for LCOH calculations

For calculating the LCOH for the different scenarios, a quantitative model has been developed, based on the following assumptions. The plant size is chosen to be 100 MW installed capacity using a PEM electrolyser. Based on literature research, the initial CAPEX is assumed to be 1100 €/kW currently and will decrease to 600 €/kW in 2050 as the technology develops (IRENA 2022b). The plant lifetime is set to 30 years while the electrolyser lifetime is assumed to be 60,000 hours (IRENA 2020). The current average efficiency of PEM electrolysers is 65%. This efficiency is assumed to increase to 76% in accordance with literature until 2050 (IRENA 2020). Warranty, insurance, operation and maintenance costs are assumed to be 4% of the total plant CAPEX and electrolyser replacement cost are assumed to be 15% of the electrolyser CAPEX. (DECHEMA 2022). With these assumptions, the LCOH is calculated for the timespan between 2023-2050. First, the CAPEX and OPEX are calculated for each location for each year. Afterwards, these values are summed up as seen in the formula above. These costs are divided by the total amount of the produced hydrogen in MWh. This calculation gives the LCOH (in €/MWh hydrogen) for each regarded year. Finally, the average of the annual LCOH values is calculated.

Specific assumptions for different production locations

The most important location-specific factors are the Levelized Cost of Electricity (LCOE), the maximum full load hours which can be supplied by renewable energies (wind, solar) and the grid electricity price of each location. These factors can vary strongly, depending on the location of the PtX production plant. The supplied renewable electricity is assumed to be provided by Wind-PV hybrid systems. Average full load hours and levelized cost of electricity (LCOE) were investigated based on literature research for each country and are summarized in the following table. The maximum full load hours are based on data from the PtX Atlas developed by the Fraunhofer IEE.

Table 5: Country specific annual Full Load Hours (FLH) of combined wind and solar electricity production and LCOE prices.

	UAE	Morocco	Colombia	Chile	Australia	Germany
RE full load hours (h/a)[30]	4643	4546	5613	6619	5574	3900
LCOE 2023 €/MWh **(IRENA 2022c)**	50	68	62	40	55	94
LCOE 2030 €/MWh	45	62	59	38	48	82
LCOE 2040 €/MWh	39	56	56	36	42	69
LCOE 2050 €/MWh	34 (Salameh et al 2021)	51 (Zelt et al. 2019)	53 (Saldarriaga et al. 2020)	34 (Renewable Energy Institute 2020)	35 (Graham et al. 2022)	57 (Fraunhofer ISE 2021)

Sources: Fraunhofer ISE (2021), Graham et al (2022), IRENA (2022 c), Salameh et al (2021), Saldariaga et al (2020), Zelt et al (2019), Umweltbundesamt 2010

For the Grid-Scenario, emissions related to electricity consumption by electrolysers and subsequent processing (for PtX) have to be considered. The latest available country-specific grid-emission factors and the grid-electricity prices are summarized in the following table (IGES, 2022). Since electricity prices peaked in 2022, we calculated two sub-scenarios for the grid-scenario in order to investigate the sensitivity of LCOH regarding electricity prices: one with electricity prices of 2022 and one with average of electricity prices between 2018 and 2022. The prices for Germany are obtained from Federal Statistics Office and from a study conducted by Bloomberg NEF (Statistisches Bundesamt (Destatis) 2023) (Climate Scope by BloombergNEF 2022). For the calculations the grid-emission factor for each country was kept constant, even though with increasing shares of renewables the grid emissions factors would go down over time. However, it is not possible to foresee by how much the share of renewables will increase in the future in each country and would therefore rather negatively affect the results of the calculations. Even though some countries have renewable energy strategies in place, timelines are often not exactly defined.

[30] Fraunhofer IEE (n.d.): PtX Atlas Fraunhofer

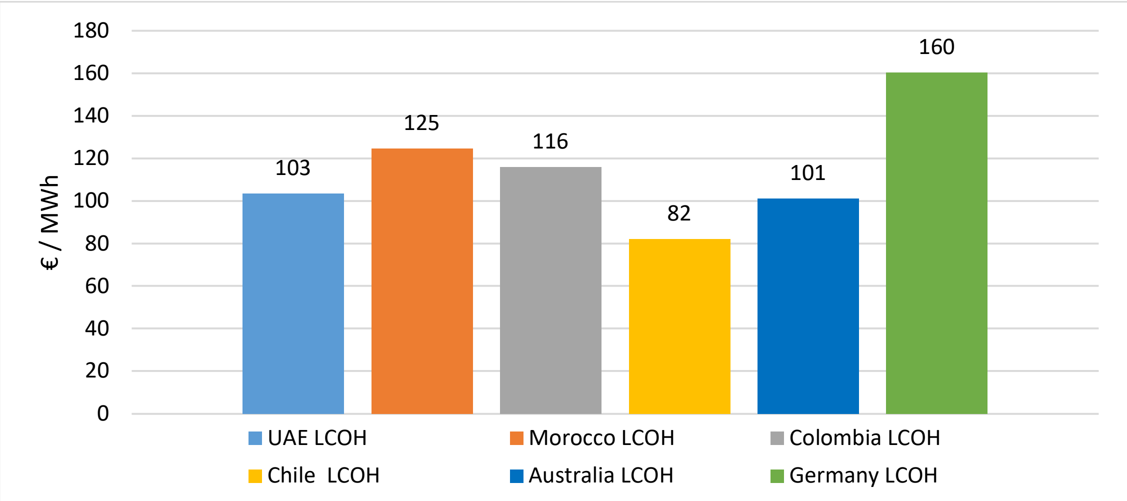
Table 6: Country specific grid-emission factors and grid-electricity prices

	UAE	Morocco	Colombia	Chile	Australia	Germany
Grid Electricity Emission Factor gCO_2e/kWh	676 (IGES 2022)	647[31] (IGES 2022)	333 (IGES 2022)	599 (IGES 2022)	656.4[32]	349[33]
Grid Electricity Price €/MWh (2022) [34]	83	100	124	113	177	334
Grid Electricity Price €/MWh (2018-2022)	82	104	120	158	169	203

Sources: Aurora Energy Research (2021), Ember (2022), IGES (2022)

The results of the LCOH calculations can be seen in Figure 13, Figure 14 and Figure 15. These values show the average LCOH from 2023 to 2050. We assume that investment for the PtX production plants takes place in 2023, have a lifetime of 30 years[35] and that the electrolysers themselves have a lifetime of 60,000 hours. With these lifetime expectancies, the annuity cost of initial investment and any replacement costs is calculated for the considered years. The same levelized cost calculations are applied to OPEX costs[36]. During this period, electrolyser efficiency is expected to increase whereas LCoE are expected to decrease. This leads to reduced LCOH for progressing years. As stated before, the figures show the average LCOH values over the lifetime of the production facilities.

Figure 13: Average LCOH of different production locations for period 2023-2050 (RE-Scenario)

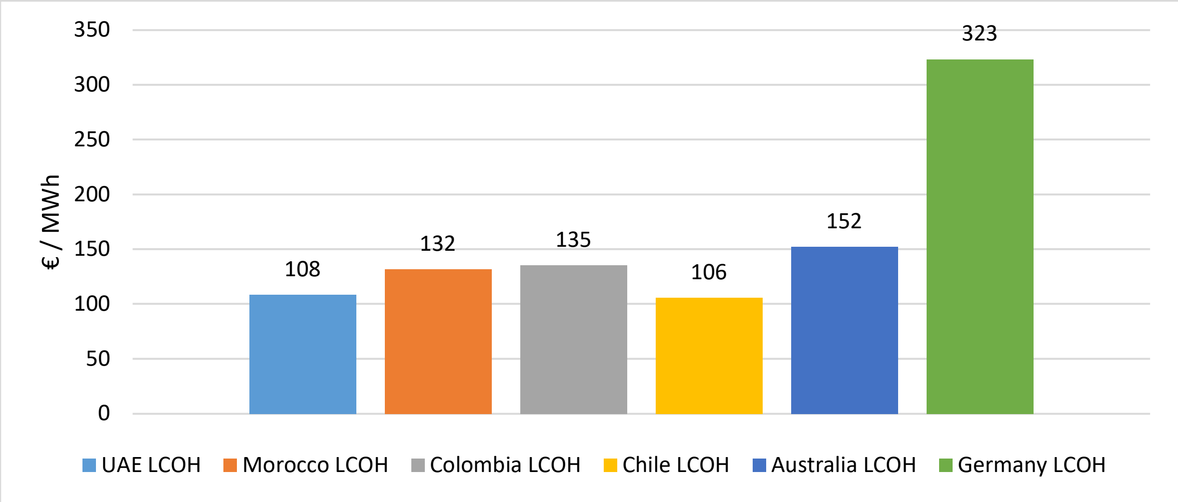


Source: authors

[31] IGES 2022
[32] Aurora Energy Research (2021): Australia Emission Factor
[33] EMBER (2022): Germany Emission Factor
[34] Global Petrol Prices (2022): Grid Prices
[35] https://iea.blob.core.windows.net/assets/181b48b4-323f-454d-96fb-0bb1889d96a9/CCUS_in_clean_energy_transitions.pdf
[36] Consisting of electricity-, water-, and operation and maintenance costs.

The production costs in the RE-Scenario vary significantly which is caused by the different renewable energy resources and hence the LCOE for renewable energies in the country. The cheapest production location is Chile with an LCOH of only 82 €/MWh hydrogen. Germany has the highest LCOH of 160 €/MWh hydrogen.

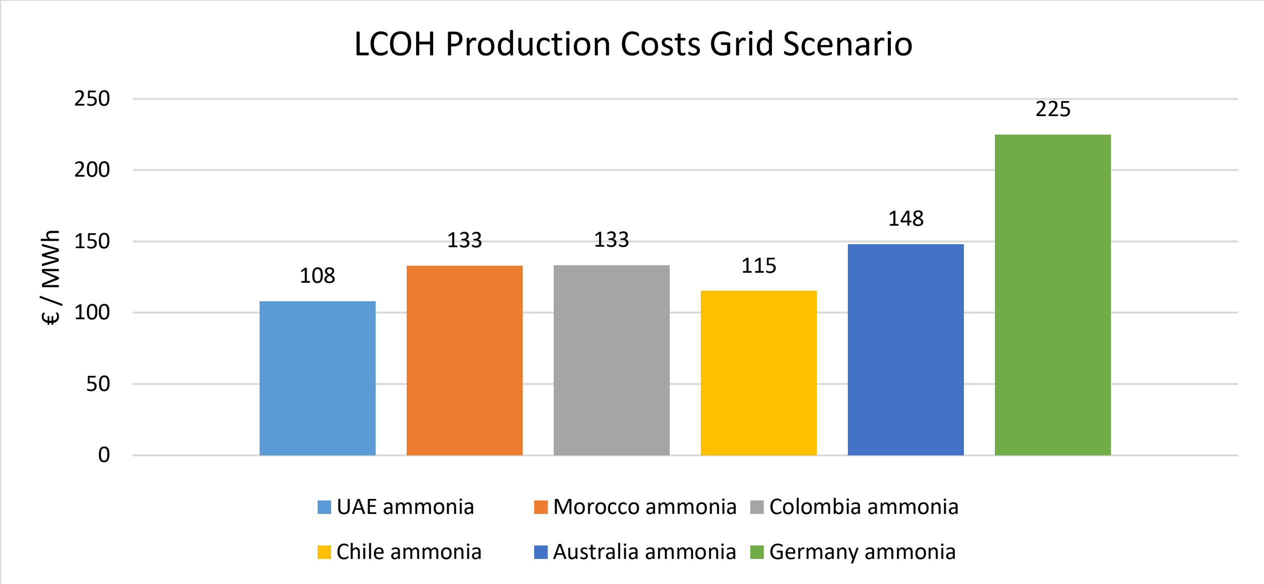
Figure 14: Average LCOH of different production locations for period 2023-2050 (Grid-Scenario E-prices: 2022)



Source: authors

In the grid scenario where the remaining energy demand of the electrolyser which cannot be completely covered by renewable energies is met by grid-electricity the prices vary significantly compared to the RE-Scenario as can be seen in Figure 14 and Figure 15. The LCOH values shown here are the average LCOHs of the values within the time span between 2023-2050. Surprisingly, in almost all analysed countries, using grid-electricity increases the LCOH. This might seem counterintuitive since the capacity factor of the electrolyser is increased significantly which would normally lead to reduced production costs. None the less, since today dedicated renewable energies are significantly less expensive than grid electricity in most cases the inclusion of grid-electricity increases production prices. Especially the high grid electricity prices in Germany double the prices per MWh of hydrogen produced. In general, one can deduct from these results, that the inclusion of grid-electricity for hydrogen production is not only ecologically harmful but does also increase hydrogen production costs. It needs to be emphasized that those calculations are based on official average grid-electricity prices and not on additionally negotiated PPAs nor on the usage of surplus electricity.

Figure 15: Average LCOH of different production locations for period 2023-2050 (Grid-Scenario E-prices: 2018-2022)



Source: authors

Comparing Figure 14 and Figure 15, it can be easily seen that electricity prices only significantly peaked in Germany within the regarded countries in 2022. The LCOH of hydrogen produced in Germany with electricity prices from 2022 is about 31% higher than with average grid electricity prices between 2018 and 2022.

2.1.2 Landed costs of H_2 and PtX products

In order to transport hydrogen over long distances, it has to be processed. These down-stream processes (i.e., conversion/compression, transport and reconversion) can add significant costs to the PtX imported to Germany. For this study the following transport options are considered: gaseous hydrogen transport via pipelines, and the shipping of liquid hydrogen, ammonia and SAF. For these calculations, the import port in Germany is selected to be Hamburg; the export ports and their respective transport distances to Germany can be seen in the following table.

Table 7. Import and export ports with distances

Exporting country	Importing country	Export port	Import port	Distance between ports (km)	Days at sea
UAE	Germany	Mina Jabal Ali	Hamburg	13,532	20
Morocco	Germany	Port of Casablanca's	Hamburg	3,628	6
Colombia	Germany	Port of Cartagena	Hamburg	12,506	19
Chile	Germany	Port of Valparaíso	Hamburg	18,451	28
Australia	Germany	Port Hedland	Hamburg	20,955	31

Source: authors (based on ShipTraffic 2023).

Since pipelines only make economic sense for short to medium distances, pipeline scenarios are only calculated for the UAE and Morocco. The pipeline length between Morocco and Germany would be around 2100 km and approximately 4900 km for the UAE. The pipeline from UAE would go through Saudi Arabia, Egypt, and over Greece to Germany. The Moroccan pipeline would go through Spain, Italy and then to Bavaria. Since there are currently no existing pipelines, huge investments would have to be channeled. Additionally, the realization of such infrastructure projects would need significant time, which needs to be taken into consideration when comparing the scenarios.

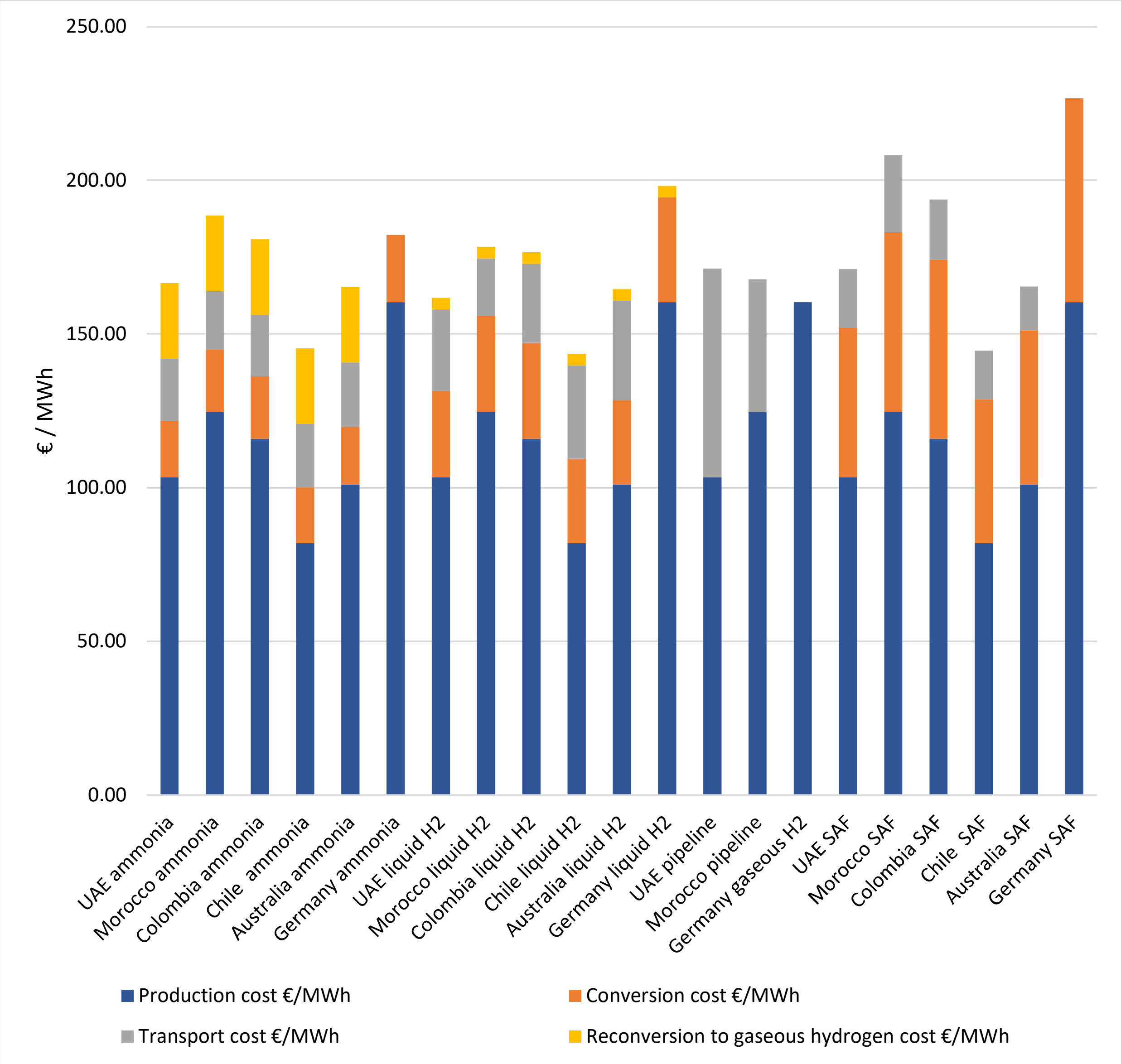
For the cost and emission calculations of the hydrogen conversion/compression, the electricity prices are either chosen as renewable LCoE or as a combination of grid and renewable electricity as described in the scenarios. For the conversion processes the initial CAPEX of ammonia production is assumed to be 1873 €/kW and will decrease to 1,050 €/kW until 2050 as the technology develops. The energy demand for ammonia synthesis is 4.3 kWh/kg H_2 and will reduce to 3.8 kWh/kg H_2 as the technology develops. For liquid hydrogen the initial CAPEX is assumed to be 2,789 €/kW and will decrease to 1,413€/kW. For liquefaction, the current energy demand is 8 kWh/kg H_2, and it will decline to 5.5 kWh/kg H_2 until 2050 (IRENA 2022a). For SAF production the initial CAPEX is assumed to be 3,198 €/kW and will decrease to 2,123 €/kW until 2050. In this report, as stated before, DAC technology is utilized for CO_2 capturing for the SAF production. This technology is integrated within the SAF production process as it provides the necessary CO_2 feedstock. In the SAF calculations the initial energy demand is assumed to be 23 kWh/kg H_2, which will decrease to 17 kWh/kg H_2. This energy demand includes CO_2 sequestration energy demand for the DAC process. The OPEX for all processing technologies is 2% of the CAPEX (International Council on Clean Transportation 2022) (DENA 2022).

The data for calculating the specific transport costs are taken from IRENA (IRENA 2022a). This report takes extrapolates these values according to the relevant distances. For example, for the distance of 5,000 km, transport via liquid H_2 costs 0.70 €/kg H_2e. For longer distances this value increases; e.g. to 0.86 €/kg H_2e for 10,000 km. Ammonia transport costs 0.68 €/kg H_2e for 5,000 km and 0.70 €/kg H_2e for 10,000 km. In the case of hydrogen transport via pipelines the cost increases significantly with distance: ca. 0.9 €/kg H_2e for 5,000 km and 1.6 €/kg H_2e for 10,000 km (IRENA 2022a). As for the transport emissions, the EU commission report of maritime emissions are taken as the base values (EU Commission 2022d, pg. 37). Additionally, boil-off emissions that are mentioned in chapter 2.1 can occur during transport. However, these transports are often negligible compared to other emissions. From Table 7, days spent at the sea can be observed (ShipTraffic 2023). Even for the longest route between Australia and Germany, GHG emissions during liquid H_2 transport accounts for 6% of the total emissions.

After reaching the destination (i.e. Germany) ammonia and liquid hydrogen are reconverted into gaseous hydrogen. For the reconversion processes of ammonia to gaseous hydrogen, the initial CAPEX is assumed to be 1,153 €/kW and will decrease to 354 €/kW until 2050 as the technology develops. The energy demand of this process is 12 kWh/kg H_2 and will reduce to 5.75 kWh/kg H_2 as the technology develops. For reconversion process of liquid hydrogen to gaseous hydrogen, the initial CAPEX is assumed to be 537.7 €/kW and will decrease to 128.9 €/kW. Current energy demand of this process is 0.6 kWh/kg H_2, and it will decline to 0.2 kWh/kg H_2 until 2050 (IRENA 2022a). For SAF reconversion is not considered since it will be used in this form. Since the reconversion is taking place in Germany, depending on the scenario, either renewable electricity or a mixture of renewable and grid electricity is utilized. The CAPEX and OPEX for reconversion are based on data from IRENA (IRENA 2022a).

In the following figures, the landed costs of the respective PtX-products in Germany can be seen. The landed costs include the production, processing, transport and - in case of liquid hydrogen and ammonia -, the reconversion to gaseous hydrogen.

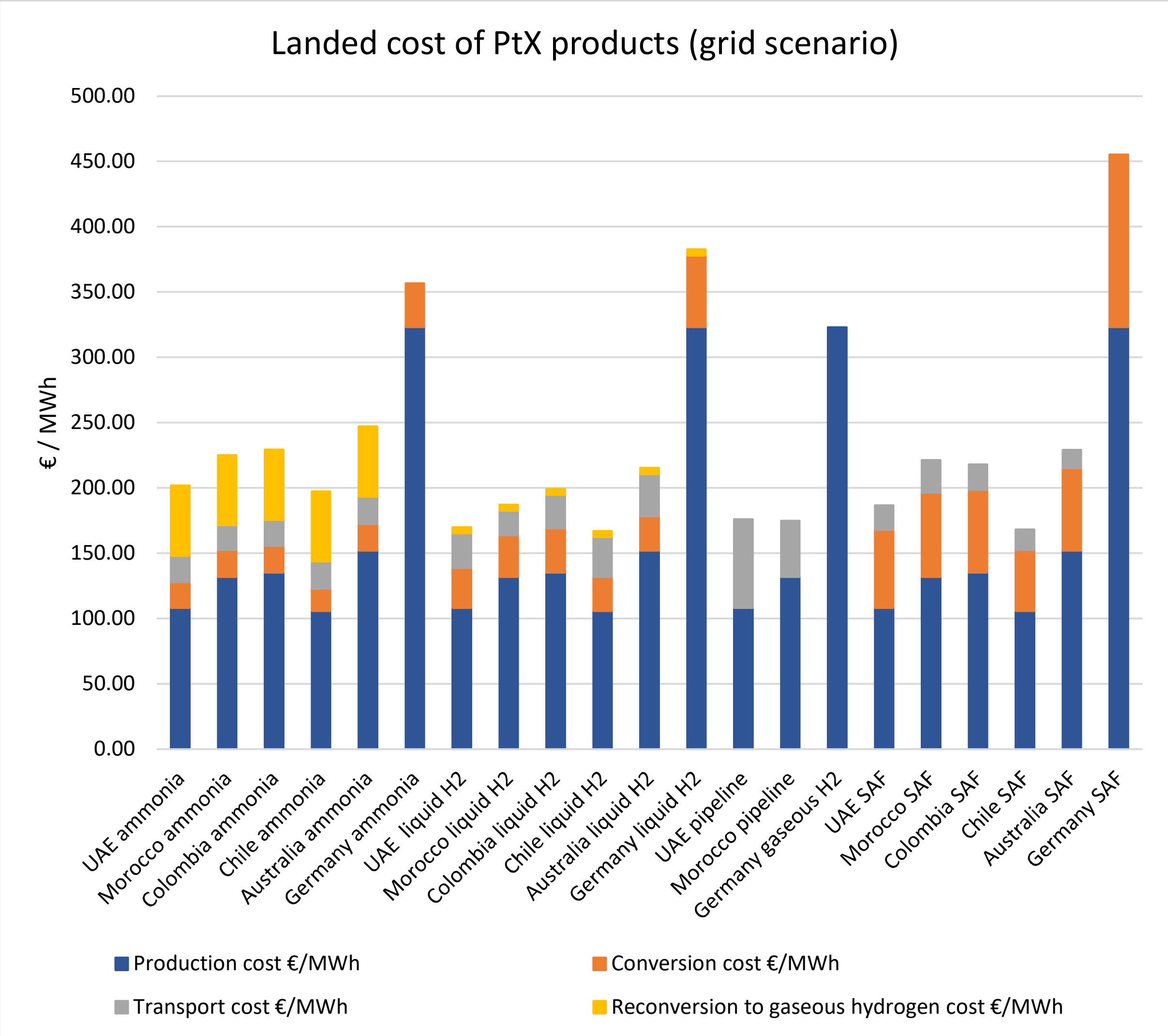
Figure 16: Average nominal levelized landed cost of PtX products in the RE-Scenario for period 2023-2050



Source: authors' own calculations

Figure 16: shows the landed costs of PtX products produced by 100% renewable energies. Even though the production of hydrogen in all foreign countries is significantly cheaper than the domestic production (160 €/MWh), this picture changes when down-stream costs are integrated into the cost-comparison. PtX transport via ships is significantly cheaper when using ammonia instead of liquid hydrogen. Since ammonia will be used directly in various applications, the reconversion to hydrogen can – in some cases be excluded from cost calculations. If the reconversion is excluded, ammonia is the cheapest option for the import of PtX products which is well in line with literature. If ammonia is only used as transport medium for hydrogen, the ammonia cracking adds significant downstream costs which leads to higher overall costs than liquid hydrogen import. The transport via new pipelines from Morocco results in slightly lower costs as the PtX transport via ammonia shipping. New pipelines from UAE lead to higher transport costs than transport by ship due to the longer distances. The landed costs for imported PtX products vary between approximately 143 and 220 €/MWh. By far the cheapest option to produce and import PtX products is from Chile (120.7 €/MWh for NH_3, 143.5 €/MWh for liquid hydrogen, and 144.6€/MWh for SAF).

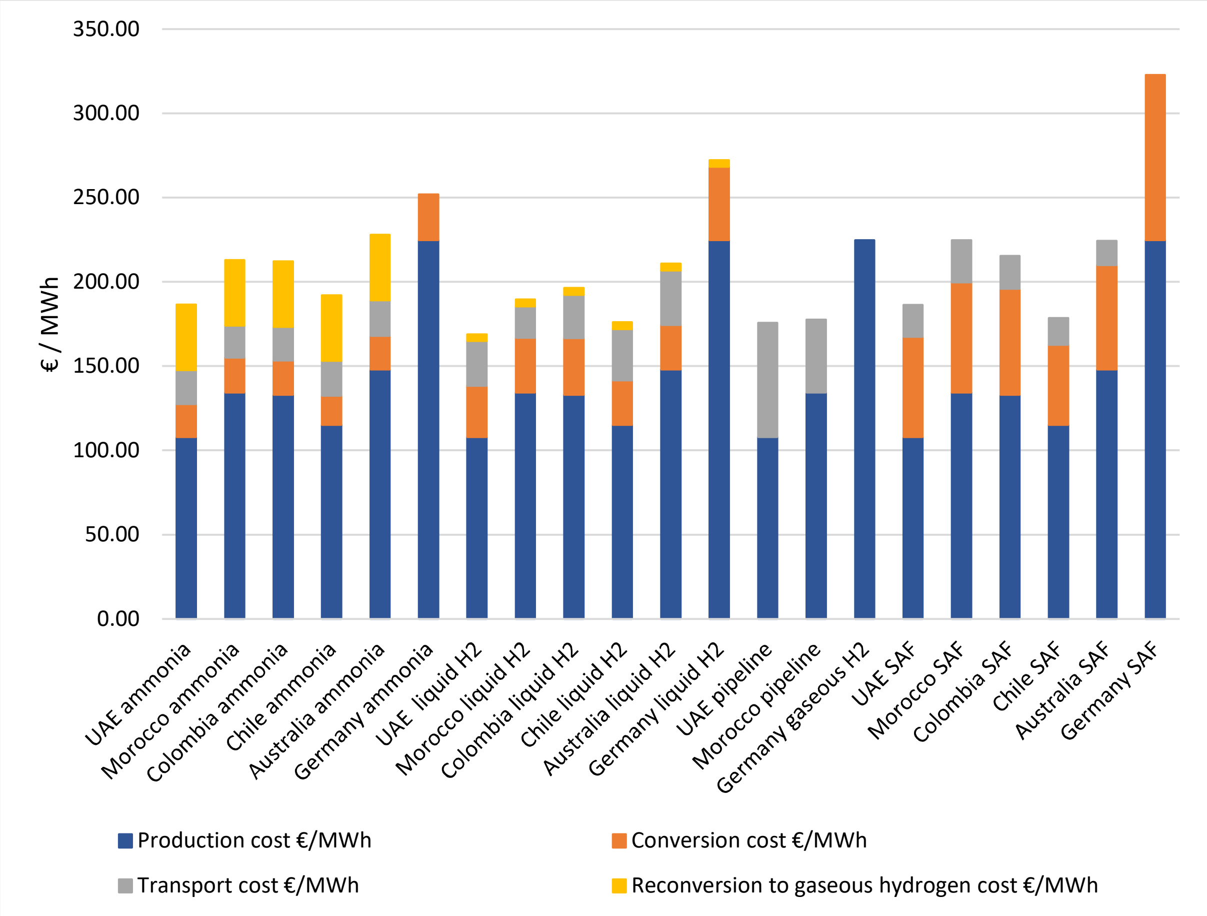
Figure 17: Average landed costs of PtX products in the Grid-Scenario for period 2023-2050 (E-prices: 2022)



Source: authors' own calculations

Figure 17 shows the landed costs of PtX products in the Grid-Scenario with electricity prices in 2022. As noted above, the inclusion of grid-electricity leads to significantly higher production and processing costs. Especially the high grid-electricity costs in Germany lead to a major cost advantage for the import of PtX products. Importing any type of PtX product will be cheaper than producing it domestically in Germany. Also, in the grid-scenario the production and import from Chile entail the lowest possible costs due to the high full load hours of renewable energies (143 €/MWh for NH3, and 162 €/MWh for liquid hydrogen, and 168 €/MWh for SAF). The highest overall costs result from the domestic production in Germany (355€/MWh for NH_3, and 323 €/MWh for gaseous hydrogen, and 455 €/MWh for SAF).

Figure 18: Average landed costs of PtX products in the Grid-Scenario for period 2023-2050 (E-prices: 2018-2022)



Source: authors' own calculations

The reduced average electricity prices between 2018 and 2022, which can be seen in Figure 18, affect the landed costs of all production and transport scenarios since not only domestic hydrogen production is dependent on the national electricity prices but also the reconversion of liquid hydrogen and especially ammonia. The costs of SAF production in Germany would be reduced by more than 133 €/MWh and production costs of ammonia would decrease by about 114 €/MWh compared to the 2022 scenario. This shows the high sensitivity of PtX prices regarding electricity costs and the necessity to supply cheap electricity to green PtX producers.

For further calculations the most recent electricity prices from 2022 are used, since it is not expected that electricity prices in Germany will fall significantly in coming years.

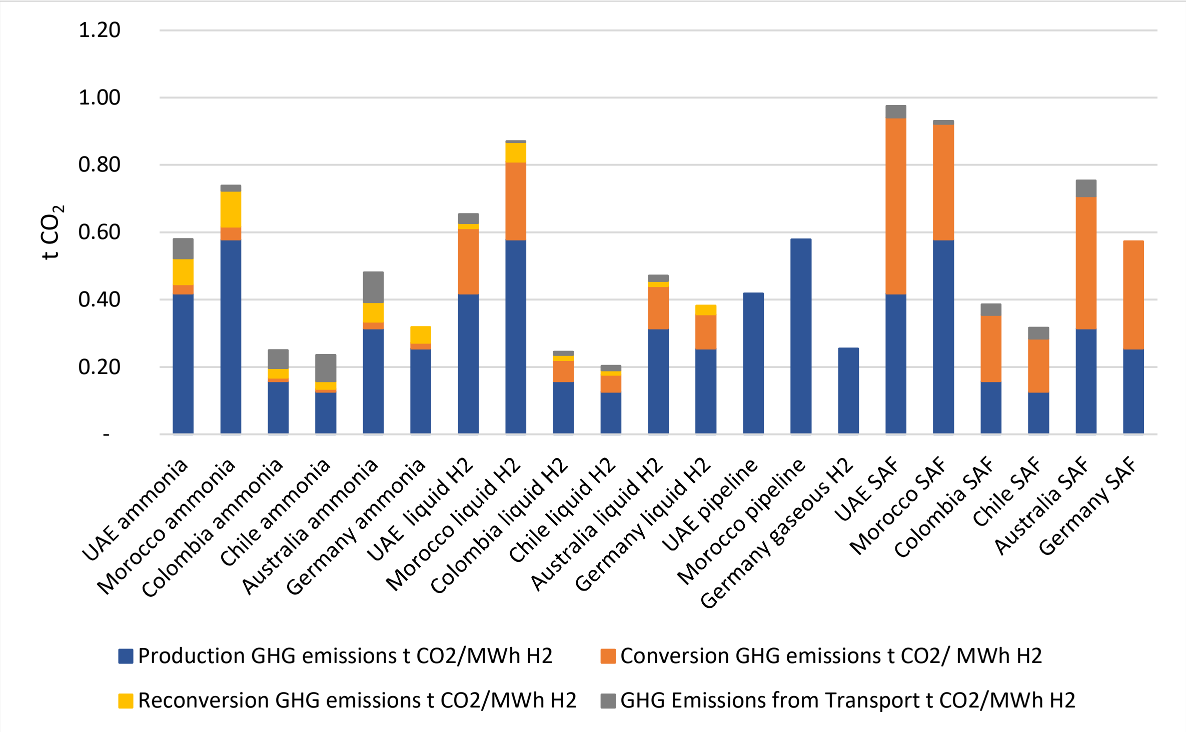
2.1.3 Specific emissions of PtX products (RE-scenario)

Even though processes like ammonia synthesis have to run continuously (which is not possible with renewable energies without storage), for the sake of simplicity in the RE-scenario all processes related to the production and processing of PtX are powered exclusively by renewable energies. Hence, all PtX-products have zero embodied emissions. Therefore, the GHG-mitigation potential is equal to the direct emissions of the baseline fuel multiplied by the conversion factor.

2.1.4 Specific emissions of PtX products (grid-scenario)

In order to calculate the emissions of the different PtX production scenarios in the grid-scenario, the grid-emission factor has been used and multiplied with the grid electricity consumption for production and processing. As noted before, grid electricity was used in order to achieve a 100% capacity factor of the installed electrolysers in the given location. The embodied carbon emissions for production and processing of the PtX products vary significantly depending on the amount of electricity taken from the grid and the national grid emission factor. PtX production in Chile leads to the PtX products with the lowest carbon intensity (0.16 tCO_2e/MWh for ammonia to 0.28 tCO_2e/MWh for SAF) whereas the production of PtX products in the UAE leads to PtX carbon intensities of up to 0.94 tCO_2e/MWh for SAF. As noted above grid-emission factors are kept constant throughout the regarded timespan. According to the Delegated Act for renewable fuels of non-biological origin (RFNBO) by the European Commission, low carbon hydrogen is required to have a maximum carbon intensity of less than 3.4 tCO_2e/tH_2 or approximately 0.102 tCO_2e/MWh (Hydrogen Europe 2022). This means that none of the PtX products considered in the grid-scenario qualify as a RFNBO in the European Union even without the transport and distribution emissions being considered. This underlines the high importance of producing electrolytic hydrogen exclusively based on renewable energies.

Figure 19: GHG emissions in grid-scenario including transport emissions



Source: Authors (own calculations)

Since GHG-emissions from fuel transport are not considered in the different carbon pricing schemes today, those emissions are excluded from further calculations regarding the potential economic benefits of low carbon PtX products in the following chapters. Nonetheless, the transport emissions were calculated for each transport scenario in order to show their rather low significance.

2.2 Baseline emissions, conversion factors and assumed carbon prices

In this chapter, a methodology for quantifying the CO_2e-mitigation potential for PtX utilization in different sectors is elaborated. Therefore, the typical baseline fuels used in the relevant sectors covered in the EU ETS/nETS have been identified and associated with its specific GHG-emissions. Where necessary, a conversion factor was developed and applied in order to adjust for different fuel demands (e.g., in steel production one MWh of coal does not have to be replaced by one MWh of hydrogen in order to produce the same amount of steel, but 341 kg H_2 are required) [37]. For some processes this conversion factor is determined as "1". That means for these cases replacing the baseline fuel with green hydrogen will still require approximately the same amount of energy. For example, using grey or green hydrogen in chemical industry will not make a difference on how much energy is required. But, in case of steel production, only about 33% of the baseline fuel is required (correction factor of 0.328, see Table 8). Assumed average carbon intensities of baseline fuels are taken from the Federal Environmental Agency (Umweltbundesamt 2016).

Table 8: Baseline fuels and emission intensities of selected PtX use cases

Sector	Conventional baseline fuel	GHG intensity of baseline fuel [tCO_2e/MWh fuel]	Conversion Factor $\frac{\text{MWh } H_2}{\text{MWh baseline fuel}}$
Iron/steel production	Coal	0.341 t CO_2e/MWh	$0.328\frac{MWh\,H_2}{MWh\,Coal}$ [38]
	Grey hydrogen	0.3 t CO_2e/MWh	1
Chemical industry	Grey hydrogen	0.3 t CO_2e/MWh	1
	Grey ammonia	0.47 t CO_2e/MWh	1
Refineries	Grey Hydrogen	0.3 t CO_2e/MWh	1
Industrial heat	Natural Gas	0.2 t CO_2e/MWh	1
Power generation	Natural Gas	0.2 t CO_2e/MWh	1
Aviation	Kerosene	0.263 t CO_2e/MWh	1
Transport sector	Diesel	0.266 t CO_2e/MWh	$0.40\frac{MWh\,H_2}{MWh\,Diesel}$
	Gasoline	0.263 t CO_2e/MWh	$0.36\frac{MWh\,H_2}{MWh\,Gasoline}$

Source: authors (own calculations based on Umweltbundesamt (2016))

[37] If Diesel is for example replaced by hydrogen in the transport sector, less MWh of hydrogen is needed in order to supply the same transport service since fuel cells are significantly more efficient than internal combustion engines.
[38] With the BF-BOF route, 5.17 MWh of coal are needed to produce 1 ton of steel (Fan, Zhiyuan; Friedmann, Julio 2021) DOI) the HDRI-EAF route requires 51 kg of hydrogen per ton of steel

Current and projected prices for emission allowances in the European and German ETS were investigated as follows:

i) EU ETS current price: 90 €/EUA[39]
ii) EU ETS forecast 2030 (high): 140 €/EUA
iii) EU ETS forecast 2030 (low): 50 €/EUA
iv) German nETS:
   a. Current Price: 35 €/t today (DEHSt 2022a)
   b. 2030: 55-65 €/t

2.3 Economic benefits of PtX fuels

In this section, the results from the previous working steps are synthesized to determine the potential economic benefits for green PtX products which may result from the different upcoming carbon pricing mechanisms in the EU (i.e., CBAM). Depending on the application of the PtX product additional costs for the reconversion to hydrogen or the synthesis of PtX products in Germany were added to the overall calculation. The following formula has been applied to calculate the specific emission reductions from the use of low-carbon PtX products:

Equation 3: Relative emission reductions

$$GHG\ mitigation = Average\ Carbon\ Intensity_{\ Basline\ Fuel} * Conversion\ Factor - Average\ Carbon\ Intensity_{PtX}$$

Source: authors

The GHG mitigation of each PtX product in the respective sector is multiplied with the carbon price to calculate the potential economic benefits of using low-carbon PtX products instead of the baseline fuels. Even though the carbon pricing schemes do not in fact lower the prices of low-carbon PtX-products, they could lead to positive opportunity costs for the consumer. Hence, for the sake of simplicity, those resulting economic benefits are subtracted from the landed PtX costs and compared to the prices of the baseline fuels. As noted before emissions from the transport of fuels are not considered in the calculations for both superordinated scenarios.

In this chapter, seven different baseline fuels which can potentially be replaced by PtX products were considered –coal, grey hydrogen, grey ammonia, natural gas, kerosene, diesel, and gasoline. The fuel prices denoted applied are average fuel prices from the year 2022 (commissioning date of the study). However, the high volatility of those prices should be kept in mind. Chapter XXX discusses the impact of baseline fuel prices exemplarily at the case of green hydrogen imported from Morocco.

2.3.1 RE-Scenario: economic benefits from the EU ETS

In the RE-scenario all processes related to the production and processing of PtX are powered exclusively by renewable energies; i.e. all PtX-products have zero embodied emissions (it has to be kept in mind that this assumption is a simplification since e.g. ammonia production facilities have to run continuously). Therefore, the GHG-mitigation potential is equal to the direct emissions of the baseline fuel multiplied by the conversion factor. The results can be seen in the following tables:

[39] EU Caron Permits: https://tradingeconomics.com/commodity/carbon

Table 9: Economic benefits of carbon pricing scheme for different PtX import scenarios (RE-Scenario)

Baseline fuel	Import route	GHG-mitigation potential [t CO_2e/MWh]	Economic benefits ETS [€/ MWh]					PtX price	Landed PtX costs including economic benefits from ETS €/MWh		
			50	90	140	Process	Process costs €/ MWh	€/MWh	EUA Price 50 €/t CO_2e	EUA Price 90 €/t CO_2e	EUA Price 140 €/t CO_2e
Coal (steel) Fuel price: 29.9 €/MWh	UAE Pipeline	1.04	52.0	93.6	145.5	-	0.0	171.2	119.3	77.7	**25.7**
	Morocco Pipeline	1.04	52.0	93.6	145.5	-	0.0	167.8	115.8	74.3	**22.3**
	Ammonia Morocco	1.04	52.0	93.6	145.5	cracking	24.6	188.6	136.6	95.0	43.0
	Ammonia UAE	1.04	52.0	93.6	145.5	cracking	24.6	166.6	114.6	73.0	21.0
	Ammonia Colombia	1.04	52.0	93.6	145.5	cracking	24.6	180.8	128.8	87.3	35.3
	Ammonia Chile	1.04	52.0	93.6	145.5	cracking	24.6	145.4	93.4	51.8	**-0.2**
	Ammonia Australia	1.04	52.0	93.6	145.5	cracking	24.6	165.3	113.3	71.8	**19.8**
	Hydrogen Germany	1.04	52.0	93.6	145.5	-	0.0	160.4	108.4	66.8	14.8
Grey Hydrogen Fuel Price: 232 €/MWh	UAE Pipeline	0.30	15.0	27.0	42.0	-	0.0	**171.2**	**156.2**	**144.2**	**129.2**
	Morocco Pipeline	0.30	15.0	27.0	42.0	-	0.0	**167.8**	**152.8**	**140.8**	**125.8**
	Ammonia Morocco	0.30	15.0	27.0	42.0	cracking	24.6	**188.6**	**173.6**	**161.6**	**146.6**
	Ammonia UAE	0.30	15.0	27.0	42.0	cracking	24.6	**166.6**	**151.6**	**139.6**	**124.6**
	Ammonia Colombia	0.30	15.0	27.0	42.0	cracking	24.6	**180.8**	**165.8**	**153.8**	**138.8**
	Ammonia Chile	0.30	15.0	27.0	42.0	cracking	24.6	**145.4**	**130.4**	**118.4**	**103.4**
	Ammonia Australia	0.30	15.0	27.0	42.0	cracking	24.6	**165.3**	**150.3**	**138.3**	**123.3**
	Hydrogen Germany	0.30	15.0	27.0	42.0	-	0.0	**160.4**	**145.4**	**133.4**	**118.4**
Ammonia Fuel Price: 272.3 €/MWh	UAE Pipeline	0.47	23.7	42.6	66.2	ammonia synthesis	21.8	**193.1**	**169.4**	**150.5**	**126.8**
	Morocco Pipeline	0.47	23.7	42.6	66.2	ammonia synthesis	21.8	**189.6**	**166.0**	**147.1**	**123.4**
	Ammonia Morocco	0.47	23.7	42.6	66.2	-	0.0	**163.9**	**140.3**	**121.4**	**97.7**
	Ammonia UAE	0.47	23.7	42.6	66.2	-	0.0	**141.9**	**118.3**	**99.4**	**75.7**
	Ammonia Colombia	0.47	23.7	42.6	66.2	-	0.0	**156.2**	**132.6**	**113.6**	**90.0**
	Ammonia Chile	0.47	23.7	42.6	66.2	-	0.0	**120.7**	**97.1**	**78.2**	**54.5**
	Ammonia Australia	0.47	23.7	42.6	66.2	-	0.0	**140.7**	**117.1**	**98.1**	**74.5**
	Hydrogen Germany	0.47	23.7	42.6	66.2	ammonia synthesis	21.8	**182.2**	**158.5**	**139.6**	**116.0**
	Ammonia Germany	0.47	23.7	42.6	66.2	-	0.0	**182.2**	**158.5**	**139.6**	**116.0**
Natural Gas Fuel Price: 166 €/MWh	UAE Pipeline	0.2	10.0	18.0	28.0	-	0.0	**171.2**	**161.2**	**153.2**	**143.2**
	Morocco Pipeline	0.20	10.0	18.0	28.0	-	0.0	167.8	**157.8**	**149.8**	**139.8**
	Ammonia Morocco	0.20	10.0	18.0	28.0	-	0.0	**163.9**	**153.9**	**145.9**	**135.9**
	Ammonia UAE	0.20	10.0	18.0	28.0	-	0.0	**141.9**	**131.9**	**123.9**	**113.9**
	Ammonia Colombia	0.20	10.0	18.0	28.0	-	0.0	**156.2**	**146.2**	**138.2**	**128.2**
	Ammonia Chile	0.20	10.0	18.0	28.0	-	0.0	**120.7**	**110.7**	**102.7**	**92.7**
	Ammonia Australia	0.20	10.0	18.0	28.0	-	0.0	**140.7**	**130.7**	**122.7**	**112.7**
	Hydrogen Germany	0.20	10.0	18.0	28.0	-	0.0	**160.4**	**150.4**	**142.4**	**132.4**
	Ammonia Germany	0.20	10.0	18.0	28.0	-	0.0	182.2	172.2	**164.2**	**154.2**
Kerosene Fuel Price: 44.47 €/MWh	SAF UAE	0.26	13.2	23.7	36.8		0.0	171.0	157.9	147.4	134.2
	SAF Morocco	0.26	13.2	23.7	36.8		0.0	208.2	195.0	184.5	171.3
	SAF Australia	0.26	13.2	23.7	36.8	-	0.0	165.4	152.3	141.8	128.6
	SAF Colombia	0.26	13.2	23.7	36.8	-	0.0	194.0	180.8	170.3	157.2
	SAF Chile	0.26	13.2	23.7	36.8	-	0.0	144.6	131.4	120.9	107.8
	SAF Germany	0.26	13.2	23.7	36.8	-	0.0	226.7	213.5	203.0	189.8

Source: authors (own calculations)

Table 9 shows the economic benefits of the substitution of fossil fuels by imported PtX products in €/MWh. Green numbers indicate that the landed costs of PtX fuels are lower than the cost of the baseline fuels (ammonia, grey hydrogen, natural gas, kerosene) in 2022. As an example, a price of 140 €/EUA leads to an economic benefit of 145.5 €/MWh for the substitution of coal in steel production, making hydrogen from the UAE and Morocco as well as ammonia from Chile and Australia cheaper than the baseline fuel at 2022-prices. Similarly, a price of 90 €/EUA leads to an economic benefit of 18 €/MWh for the substitution of natural gas, bringing the costs of landed ammonia and hydrogen from all countries below the price of natural gas in 2022. It must be noted that fuel prices in 2022 were highly shaken by the Ukraine war and may not be seen as representative by investors. Even at lower fossil fuel prices, the calculations show that carbon pricing can strongly strengthen the business case for low-carbon / green PtX products with potential monetary benefits of up to 42 €/MWh.

Only the substitution of kerosene by sustainable aviation fuels (SAF) would not lead to positive economic outcomes even when high carbon prices are assumed. This is mainly due to two reasons: Firstly, kerosene is sold at extremely low prices due to its tax-exemption. Secondly, the production of SAFs from hydrogen is very energy intensive and leads to high production costs.

With regard to the replacement of grey hydrogen and grey ammonia with imported green PtX, the current allocation rules in the EU ETS need to be kept in mind, see chapter 1.1.1. Economic benefits may only materialize once the CBAM rules are fully implemented, see chapter 1.1.6.

In conclusion, it can be stated that internalizing GHG-emissions in fuel prices can – depending on the specific case – strongly enhance the economic attractiveness of green PtX products. A precondition is, however, that the infrastructure for transport is available (e.g., pipelines) and that installations are capable to utilize green PtX (e.g. steel plants being able to use green PtX rather than coal). Costs for end-user investments have not been included in the calculations above as this goes beyond the scope of the study. But they can be significant and thus have to be considered by policy makers.

2.3.2 RE-Scenario: economic benefits from the German national ETS

Table 10 shows the economic benefits of the substitution of fossil fuels in the transport sector under the German nETS. Depending on the fuel replaced and the carbon price, economic benefits can range from 23.3 to 47.5 €/MWh.

But in most cases, costs for PtX use are still higher than costs of the fossil fuel incumbents. Only the cheapest production scenarios – hydrogen transported via pipelines from the UAE and from Morocco, import of ammonia from Chile and the hydrogen production in Germany – would make green PtX economically attractive.

Table 10: Economic benefits of carbon pricing scheme for different PtX import scenarios in the transport sector (RE-Scenario)

Baseline fuel	Import route	GHG-mitigation potential [t CO_2e-eq/MWh]	Economic benefits ETS [€/ t CO_2e]			Cracking costs	PtX price	Landed PtX costs including economic benefits from ETS		
			35	55	65	€/MWh	€/MWh	35	55	65
Diesel Fuel Price: 126.46 €/MWh	UAE Pipeline	0.67	23.3	36.6	43.2		171.2	148.0	**134.7**	**128.0**
	Morocco Pipeline	0.67	23.3	36.6	43.2		167.8	144.5	131.2	**124.6**
	Ammonia UAE	0.67	23.3	36.6	43.2	24.6	166.6	143.3	130.0	123.3
	Ammonia Morocco	0.67	23.3	36.6	43.2	24.6	188.6	165.3	152.0	145.3
	Ammonia Colombia	0.67	23.3	36.6	43.2	24.6	180.8	157.5	144.2	137.6
	Ammonia Chile	0.67	23.3	36.6	43.2	24.6	145.4	**122.1**	**108.8**	**102.1**
	Ammonia Australia	0.67	23.3	36.6	43.2	24.6	165.3	142.1	**128.8**	**122.1**
	Hydrogen Germany	0.67	23.3	36.6	43.2		160.4	137.1	**123.8**	**117.1**
Gasoline Fuel Price: 104.24 €/MWh	UAE Pipeline	0.73	25.6	40.2	47.5		171.2	145.7	131.1	123.8
	Morocco Pipeline	0.73	25.6	40.2	47.5		167.8	142.3	127.6	120.3
	Ammonia UAE	0.73	25.6	40.2	47.5	24.6	166.6	141.0	126.4	119.1
	Ammonia Morocco	0.73	25.6	40.2	47.5	24.6	188.6	163.0	148.4	141.1
	Ammonia Colombia	0.73	25.6	40.2	47.5	24.6	180.8	155.3	140.6	133.3
	Ammonia Chile	0.73	25.6	40.2	47.5	24.6	145.4	119.8	**105.2**	**97.9**
	Ammonia Australia	0.73	25.6	40.2	47.5	24.6	165.3	139.8	125.1	117.8
	Hydrogen Germany	0.73	25.6	40.2	47.5		160.4	134.8	120.2	112.9

Source: authors (own calculations)

2.3.3 Grid-Scenario: economic benefits from the EU ETS

In the grid scenario, embodied emissions from production and processing of PtX products are considered. For calculating the economic benefits from carbon pricing, embodied emissions of the PtX products as well as emissions from the conversion of PtX products in the importing county are subtracted from the potential GHG-mitigation and multiplied with the respective carbon price. As already noted in chapter 2.1.4, producing PtX with grid electricity can lead to very high embodied emissions. It is assumed that in each country first the full potential of PV/wind will be used for PtX production, and the remaining electricity required to run electrolysers at full capacity will be taken from the grid.

This is well reflected in the following tables: in all scenarios where the “economic benefits from ETS” are marked in red, the embodied emissions of the produced/imported PtX are higher than the baseline fuels. Hence, their utilization does increase emissions; and would lead to higher costs under carbon pricing.

Table 11: Economic benefits of carbon pricing scheme for different PtX import scenarios (grid scenario)

Baseline fuel	Import route	Potential GHG-mitigation [t CO_2e/MWh]	Economic benefits ETS/CBAM [€/ MWh]			CO_2e emissions of PtX [t CO_2/MWh]	CO_2e-emissions of processing (in Germany) [t CO_2/MWh]				Landed PtX costs including economic benefits from ETS €/ MWh		
			50	90	140			Process	Process costs €/MWh	PtX price €/ MWh	EUA Price 50 €/t CO_2e	EUA Price 90 €/t CO_2e	EUA Price 140 €/t CO_2e
Coal (steel) Fuel price: 29.9 €/MWh	UAE Pipeline	1.04	31.0	55.8	86.7	0.42	0.00	-	0.0	175.7	144.7	119.9	89.0
	Morocco Pipeline	1.04	31.5	56.7	88.1	0.41	0.00	-	0.0	177.5	146.0	120.8	89.4
	Ammonia UAE	1.04	17.0	30.6	47.5	0.52	0.18	cracking	53.9	201.5	184.5	170.9	153.9
	Ammonia Morocco	1.04	17.5	31.5	48.9	0.51	0.18	cracking	53.9	227.9	210.4	196.5	179.0
	Ammonia Colombia	1.04	33.0	59.4	92.3	0.20	0.18	cracking	53.9	227.2	194.2	167.8	134.8
	Ammonia Chile	1.04	35.0	63.0	97.9	0.16	0.18	cracking	53.9	207.0	172.0	144.0	109.0
	Ammonia Australia	1.04	23.5	42.3	65.7	0.39	0.18	cracking	53.9	242.8	219.4	200.6	177.1
	Hydrogen Germany	1.04	36.0	64.8	100.7	0.32	0.00	-	0.0	224.7	188.8	160.0	124.0
Grey Hydrogen Fuel Price: 232 €/MWh	UAE Pipeline	0.30	-6.0	-10.8	-16.8	0.42	0.00	-	0.0	**175.7**	**181.7**	**186.5**	**192.5**
	Morocco Pipeline	0.30	-5.5	-9.9	-15.4	0.41	0.00	-	0.0	**177.5**	**183.0**	**187.4**	**192.9**
	Ammonia UAE	0.30	-20.0	-36.0	-56.0	0.52	0.18	cracking	53.9	**201.5**	**221.5**	**237.5**	**257.5**
	Ammonia Morocco	0.30	-19.5	-35.1	-54.6	0.51	0.18	cracking	53.9	**227.9**	**247.4**	**263.0**	**282.5**
	Ammonia Colombia	0.30	-4.0	-7.2	-11.2	0.20	0.18	cracking	53.9	**227.2**	**231.2**	**234.4**	**238.4**
	Ammonia Chile	0.30	-2.0	-3.6	-5.6	0.16	0.18	cracking	53.9	**207.0**	**209.0**	**210.6**	**212.6**
	Ammonia Australia	0.30	-13.5	-24.3	-37.8	0.39	0.18	cracking	53.9	242.8	256.3	267.1	280.6
	Hydrogen Germany	0.30	-1.0	-1.8	-2.8	0.32	0.00	-	0.0	224.7	225.7	226.5	227.5
Ammonia Fuel Price: 272.3 €/MWh	UAE Pipeline	0.47	-0.4	-0.6	-1.0	0.42	0.06	ammonia synthesis	33.7	**249.2**	**249.5**	**249.8**	**250.2**
	Morocco Pipeline	0.47	0.2	0.3	0.4	0.41	0.06	ammonia synthesis	33.7	**211.2**	**211.0**	**210.9**	**210.8**
	Ammonia UAE	0.47	-2.4	-4.2	-6.6	0.52	0.00	-	0.0	**147.6**	**149.9**	**151.8**	**154.2**
	Ammonia Morocco	0.47	-1.9	-3.3	-5.2	0.51	0.00	-	0.0	**174.0**	**175.9**	**177.4**	**179.2**
	Ammonia Colombia	0.47	13.7	24.6	38.2	0.20	0.00	-	0.0	**173.3**	**159.7**	**148.7**	**135.1**
	Ammonia Chile	0.47	15.7	28.2	43.8	0.16	0.00	-	0.0	**153.1**	**137.4**	**124.9**	**109.2**
	Ammonia Australia	0.47	4.2	7.5	11.6	0.39	0.00	-	0.0	**189.0**	**184.8**	**181.5**	**177.3**
	Hydrogen Germany	0.47	4.7	8.4	13.0	0.32	0.06	ammonia synthesis	33.7	258.4	253.8	250.1	245.4
	Ammonia Germany	0.47	4.7	8.4	13.0	0.38	0.00	-	0.0	251.8	247.2	243.5	238.8
Natural Gas Fuel Price: 166 €/MWh	UAE Pipeline	0.20	-11.0	-19.8	-30.8	0.42	0.00	-	0.0	**215.5**	**226.5**	**235.3**	**246.3**
	Morocco Pipeline	0.20	-10.5	-18.9	-29.4	0.41	0.00	-	0.0	177.5	188.0	196.4	206.9
	Ammonia UAE	0.20	-16.0	-28.8	-44.8	0.52	0.00	-	0.0	**147.6**	**163.6**	**176.4**	**192.4**
	Ammonia Morocco	0.20	-15.5	-27.9	-43.4	0.51	0.00	-	0.0	174.0	189.5	201.9	217.4
	Ammonia Colombia	0.20	0.0	0.0	0.0	0.20	0.00	-	0.0	173.3	173.3	173.3	173.3
	Ammonia Chile	0.20	2.0	3.6	5.6	0.16	0.00	-	0.0	**153.1**	**151.1**	**149.5**	**147.5**
	Ammonia Australia	0.20	-9.5	-17.1	-26.6	0.39	0.00	-	0.0	189.0	198.5	206.1	215.6
	Hydrogen Germany	0.20	-6.0	-10.8	-16.8	0.32	0.00	-	0.0	224.7	230.7	235.5	241.5
	Ammonia Germany	0.20	-9.0	-16.2	-25.2	0.38	0.00	-	0.0	251.8	260.8	268.0	277.0
Kerosene 48 €/MWh	SAF UAE	0.26	-33.9	-60.9	-94.8	0.94	0.00		0.0	186.3	220.2	247.3	281.1
	SAF Morocco	0.26	-32.9	-59.1	-92.0	0.92	0.00		0.0	224.7	257.6	283.9	316.7
	SAF Colombia	0.26	-4.4	-7.8	-12.2	0.35	0.00	-	0.0	215.5	219.8	223.3	227.7
	SAF Chile	0.26	-0.9	-1.5	-2.4	0.28	0.00	-	0.0	178.6	179.4	180.1	180.9
	SAF Australia	0.26	-22.4	-40.2	-62.6	0.71	0.00	-	0.0	224.2	246.6	264.5	286.8
	SAF Germany	0.26	-15.4	-27.6	-43.0	0.57	0.00	-	0.0	322.9	338.2	350.5	365.8

Source: own calculations

In this scenario the replacement of coal in steel production is not economically viable, despite carbon pricing benefits of 5 to 105 €/MWh.

Replacing grey hydrogen produced in Germany by the imported PtX products does not lead to CO_2e reductions but would even increase the GHG-emissions. Only imports of ammonia from Chile scenario would lead to a slight reduction in GHG-emissions. Nonetheless, due to the high grey hydrogen costs, all but ammonia imported from Australia and hydrogen produced domestically in Germany would involve lower costs compared to the assumed conventional ammonia/hydrogen prices. However, replacing grey hydrogen with even higher carbon intensive imported PtX products would be counterproductive.

Natural gas has comparatively low baseline emissions (0.2 t CO_2e/MWh) so that for most cases no emission reductions result from a shift to PtX. Only ammonia imported from Chile (0.16 t CO_2e/MWh) leads to emission reductions, but these are marginal. While carbon pricing can lower costs of hydrogen/ammonia from the UAE as well as ammonia from Chile to a competitive level, it only makes sense for Chile due to these environmental considerations.

Results for SAF are similar: only SAF produced in Chile would entail lower emissions than the kerosene produced from fossil fuels. But carbon pricing cannot bring SAF to a cost-competitive price level for any of the assumed CO_2e prices.

2.3.4 Grid scenario: economic benefits from the German national ETS

In the grid scenario, using PtX in the transport sector would not lead to cost-competitive price levels for any of the pre-defined CO_2e prices. In other words, the incentives from carbon pricing would need to be increased, e.g. by defining higher CO_2e prices in the BEHG. At a carbon price of 175 €/t CO_2e, hydrogen imported from Morocco through pipelines would reach price parity with diesel at today's prices; and prices of 200 €/t CO_2e would be required to achieve the same for gasoline.

Table 12: Potential economic benefits of carbon pricing scheme for different PtX import scenarios in the transport sector (Grid Scenario)

Baseline fuel	Import route	Potential GHG-mitigation [t CO_2e/MWh]	Economic benefits ETS [€/ t CO_2e]			CO_2e-emissions of PtX t CO_2e/MWh	CO_2e-emissions of cracking t CO_2e/MWh	Process costs	PtX price	Landed PtX costs including economic benefits from ETS €/ MWh		
			35	55	65				€/MWh	35	55	65
Diesel (Fuel Price: 126.46 €/MWh)	UAE Pipeline	0.67	-4.4	-6.9	-8.1	0.61	0.18		175.7	180.1	182.6	183.8
	Morocco Pipeline	0.67	9.6	15.1	17.9	0.39	0.00		177.5	167.9	162.4	159.6
	Ammonia UAE	0.67	-10.0	-15.7	-18.5	0.77	0.18	53.9	201.5	211.4	217.1	220.0
	Ammonia Morocco	0.67	0.2	0.3	0.3	0.48	0.18	53.9	227.9	227.7	227.6	227.6
	Ammonia Columbia	0.67	10.0	15.7	18.5	0.20	0.18	53.9	227.2	217.2	211.5	208.7
	Ammonia Chile	0.67	13.1	20.6	24.4	0.11	0.18	53.9	207.0	193.8	186.3	182.6
	Ammonia Australia	0.67	2.6	4.1	4.9	0.41	0.18	53.9	242.8	240.2	238.7	238.0
	Hydrogen Germany	0.67	12.1	19.0	22.4	0.32	0.00		224.7	212.7	205.8	202.3
Gasoline (Fuel Price: 104.24 €/MWh)	UAE Pipeline	0.73	4.2	6.6	7.8	0.61	0.00		175.7	171.5	169.1	167.9
	Morocco Pipeline	0.73	11.9	18.7	22.1	0.39	0.00		177.5	165.6	158.8	155.4
	Ammonia UAE	0.73	-7.7	-12.1	-14.3	0.77	0.18	53.9	201.5	209.2	213.5	215.7
	Ammonia Morocco	0.73	2.5	3.9	4.6	0.48	0.18	53.9	227.9	225.5	224.0	223.3
	Ammonia Columbia	0.73	12.3	19.3	22.8	0.20	0.18	53.9	227.2	214.9	207.9	204.4
	Ammonia Chile	0.73	15.4	24.2	28.6	0.11	0.18	53.9	207.0	191.5	182.7	178.3
	Ammonia Australia	0.73	11.2	17.6	20.8	0.41	0.00	53.9	242.8	231.6	225.2	222.0
	Hydrogen Germany	0.73	14.4	22.6	26.7	0.32	0.00		224.7	210.4	202.2	198.1

Source: own calculations

2.3.5 Impact of baseline fuel prices on the economic competitiveness of green PtX

The previous chapters have discussed the economic benefits of carbon pricing for green PtX assuming 2022-prices for the baseline fuels natural gas, oil, coal, ammonia and grey hydrogen. 2022 prices were chosen because during the analysis phase, many experts believed that prices will remain at that level for the years to come. At the same time, it is clear that the geopolitical situation in 2022 was outstanding, leading to a strong increase of fuel prices compared to previous years.

For visualising the impact of different baseline fuel prices on the economic competitiveness of green PtX, Table 13 shows average baseline fuel prices for the period 2019-2022 and exemplarily compares them with green PtX imported from Morocco.

Table 13. Economic benefits of replacing different baseline fuels

Baseline fuel	Import route	GHG-mitigation potential [t CO_2e/MWh]	Economic benefits ETS EUA Price 90 € [€/ MWh]	PtX price [€/MWh]	Landed PtX costs including economic benefits from ETS [€/MWh]	Cost baseline fuel (€/MWh)	
						2022 (high)	average 2018-2022
Natural Gas	Morocco Pipeline	0.20	18	168	150	166	60
Coal (steel)	Morocco Pipeline	1.04	94	168	95	30	15
Grey Hydrogen	Morocco Pipeline	0.30	27	168	141	232	211
Ammonia	Morocco Pipeline	0.47	43	190	147	272	151
Kerosene	Morocco - Germany Shipping	0.20	24	208	184	44	52

Source: authors (own calculations, prices based on Destatis (2023), Finanzen (2023), ASUE (2022), Chem-Analyst (2023), Schnitkey et al (2022), EIA (2022))[40]

Average 2019-2022 prices for natural gas, coal and ammonia were lower than those of 2022, with the most significant difference for natural gas. With these lower natural gas prices, the economic benefits provided by EU carbon pricing are clearly not sufficient to incentivise a fuel switch to green PtX. The situation for the other fuels does not change.

It must be noted that all discussed scenarios only show the impact on fuel prices, and compare the cost of baseline fuels with those of green PtX. Investments that are required at consumer side (e.g. steel industry) are not considered in the calculation as this goes beyond the scope of the study. But these investments can be significantly and will be factored in by industry. Strongly varying fuel prices and uncertainties about future carbon- and fuel prices are barriers for such investments, and the existing carbon pricing framework in the EU – which certainly has been evolving into a very solid, impactful toolset – is not sufficient yet to overcome such barriers.

[40] The last column shows the average fuel prices within the last 5 years. However, since grey hydrogen does not have an active market, its price cannot be tracked back 5 years with high accuracy. Therefore, the values scene in the last column of grey hydrogen are the averages for 2021, and 2022.

2.4 Summary

The calculations show that the replacement of imported PtX which are produced exclusively with renewable energies can result in significant GHG-benefits, whereas the GHG-benefits of PtX which are not 100% renewable can be limited and need to be assessed on a case-by-case basis. Calculations in the grid-scenario visualise that several production/import routes for PtX can massively increase CO_2e-emissions compared to their fossil baseline fuels. Consequently, it is of utmost importance to include emissions from the production of PtX.

The calculations also show that carbon pricing can improve the cost-competitiveness of green PtX significantly. In the RE-scenario, current price levels under the EU ETS would make green PtX cheaper than grey hydrogen, grey ammonia and natural gas. For becoming a cost-competitive alternative to coal in the steel sector, a carbon price of about 140 €/t CO_2e would be required; and for replacing kerosine by SAF a carbon price of about 400 €/t CO_2e would be required. For lower baseline fuel prices, the situation can change.

However, one needs to bear in mind that these numbers refer only to fuel costs. Switching from fossil fuels to PtX also requires (partially substantial) investments at consumer side. One example is the steel sector where the complete iron reduction and steel production must be changed from the so-called Blast Furnace-Basic Oxygen Furnace route to the Direct Iron Reduction Electric Arc Furnace Route. This does not only involve substantial investments but also leads to a higher consumption of additional energy sources like – in this case – electricity. Another example is the transport sector where hydrogen cannot be used in internal combustion engines, but the fleet has to be changed to fuel cell powered vehicles, which are still significantly more expensive than conventional vehicles. Furthermore, an extensive hydrogen refuelling structure has to be built which would entail additional investments. Another cost factor which is not included in the results is the domestic transport and distribution of the PtX products.

These numbers show that - with current fossil fuel prices – today's carbon pricing framework in the EU is at the edge towards making a difference; but with lower baseline fuel prices a different picture may result. Strongly varying fuel prices and uncertainties about future carbon- and fuel prices are barriers for the investments required by industry. To overcome these barriers, the existing carbon pricing framework in the EU – which certainly has been evolving into a very solid, impactful toolset – would need to be accompanied by large-scale public investment programs into required infrastructure for import, distribution, storage and transmission of green PtX. In particular industrial sectors eyed as large hydrogen/PtX consumers paving the way to the technological and economical upscaling of green hydrogen/PtX and related infrastructures may need targeted support in order to enable necessary investments on the customer side.

3. Examples of emission reduction accounting for green hydrogen and green derivatives

In this chapter, the emission reduction accounting principles of imported PtX products are discussed, also in relation to the ones applying to trading of PtX produced inside the EU. While the quantitative analysis has already been done in chapter 2.3, this section focusses on monitoring- and reporting requirements for demonstrating the carbon intensity of produced/delivered PtX products.

In this context, the above-mentioned draft delegated regulation on renewable liquid and gaseous transport fuels of non-biological origin supplementing Directive (EU) 2018/2001, the EU- and German regulations for deriving emission factors for fuels, and the CBAM rules are most relevant.

The analysis differentiates between two guiding questions:

1. What are the requirements for monitoring and accounting of the carbon intensity of a) produced and b) delivered hydrogen, and hence for possibly claiming emission benefits under the EU ETS?
2. What are the requirements for recognising imported PtX products as a "green fuel" according to RED II/III?

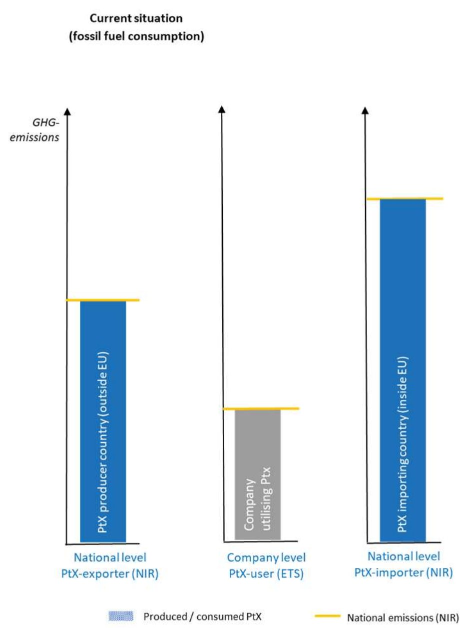
It is important to differentiate between those two questions, since PtX products that are not generated by 100% dedicated renewable energies – but may for example be partially generated with grid electricity in order to increase the full load hours of the electrolyser– may also have a climate benefit depending on their utilization (CO_2e-intensity of baseline fuels) and their own CO_2e-intensity (see chapter 2.3).

3.1. Accounting of PtX production and utilization in national emission inventories

Before discussing details of emission accounting rules, the generic implications for national inventories, corporate emissions and costs under CBAM are analysed from the point of view of PtX-exporters (countries), PtX importers (countries) and corporate PtX users.

Figure 20 visualises today's GHG emissions according to National Inventory Reports (NIRs) of countries according to UNFCCC requirements – both for future PtX-producers/exporters and PtX-importers/consumers -, and "verified emission inventories" on company level (e.g., under the EU ETS).

Figure 20. Base case fuel consumption and GHG-emissions

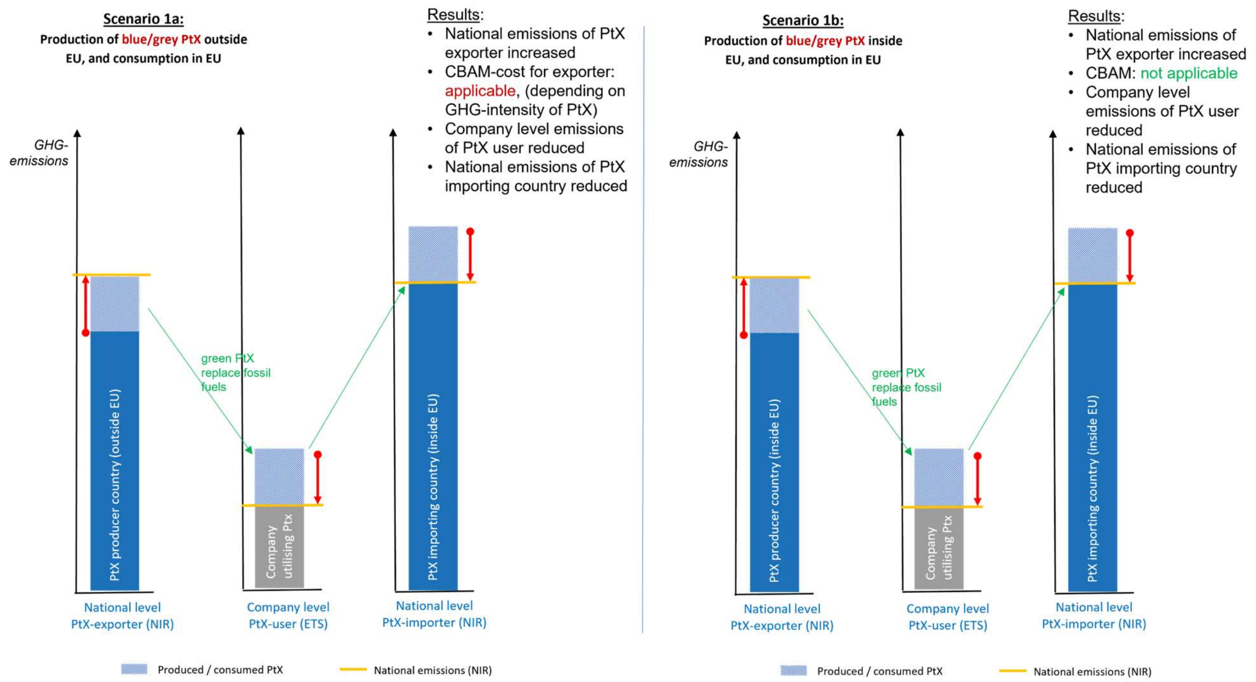


Source: Perspectives

For future PtX trade, we differentiate two main scenarios. In scenario 1 – visualised in Figure 21 – we assume that PtX are not produced with 100% renewable energies and, hence, their production leads to GHG-emissions. In scenario 2, we assume that PtX are assumed 100% based on renewable energies. In both scenarios, we differentiate if PtX production takes place outside EU-territory, or within EU-Member States. In the former case, CBAM rules will apply, not so in the latter case.

In the first scenario, the production of PtX increases GHG-emissions of the exporting country if the PtX-production is not 100% carbon free. If the PtX producer is located outside the EU, the new CBAM rules will result in costs for surrendering CBAMCs when PtX are exported to the EU. If the PtX are produced on EU-territory, CBAM rules do not apply, but the EU ETS rules do, also leading to indirect or direct increase of production costs[41]. From the importers/consumers' point of view, the use of PtX will reduce emissions – both at company and national level – if PtX replace fossil fuels, as the emissions factor of hydrogen is zero.

Figure 21: Impact of grey/blue/low-carbon hydrogen production and imports on national inventories

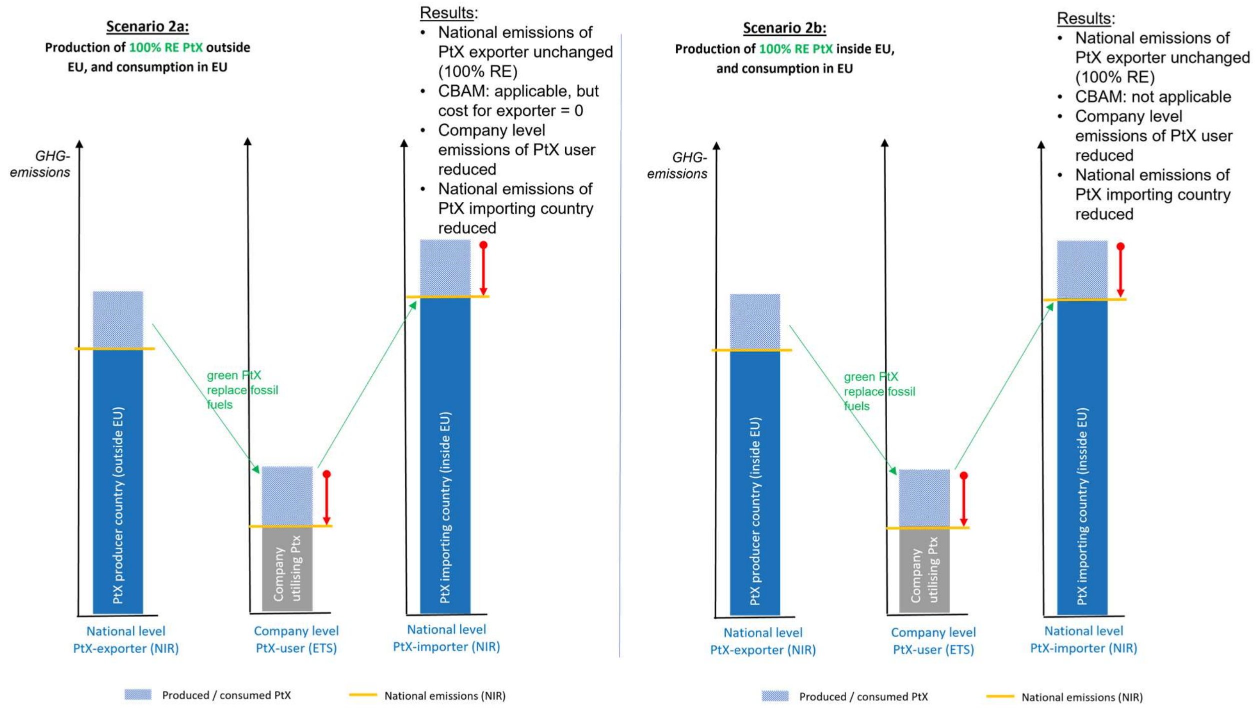


Source: Perspectives

In the second scenario, the production of PtX does *not* increase GHG-emissions of the exporting country (100% renewable energy). The CBAM rules will apply for producers outside the EU but will *not* result in additional costs as embodied CO_2e emissions are zero. If the PtX are produced on EU-territory, CBAM rules do not apply, and there will not be additional costs from the EU ETS. From the importers/consumers' point of view, the use of PtX will reduce emissions – both at company and national level – if PtX replace fossil fuels.

[41] Note that the introduction of the CBAM is supposed to phase out free allocation to CBAM-sectors, and also the planned introduction of ETS II is expected to change allocation rules. Hence, the cost situation for domestic PtX production may change (see chapter 4.1).

Figure 22: Impact of green hydrogen production and imports on national inventories



Source: Perspectives

It may be noted that these principles apply to all PtX fuels (hydrogen, methanol, ammonia, SAF) under *current* regulation, regardless the mode of transport (pipelines, ships) because transport-related emissions are neither covered by the current EU ETS[42] nor by CBAM. From 2026 onwards, regulation will be adjusted to cover international maritime transport (EU-imports). We expect that CBAM rules will need to be adjusted again, but this is still unclear.

3.2. GHG-monitoring and accounting requirements in the EU ETS

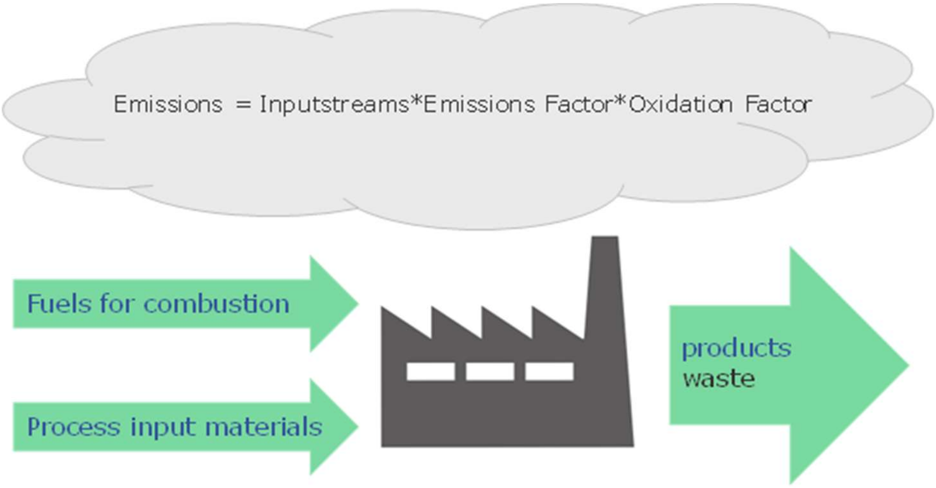
Regulation 2018/2066/EC defines rules for the monitoring and reporting of GHG-emissions and activity data pursuant to Directive20 03/87/EC in the EU ETS. Regulation 2019/331/EC lays down rules for the transitional Union-wide rules for harmonised free allocation of emission allowances. Both regulations can offer incentives for using PtX or green hydrogen.

3.2.1. Incentives for PtX in the area of monitoring and reporting

Commonly, CO_2e emissions caused by the covered installations in the EU ETS are calculated by the standard methodology. The activity data is commonly based on the fuel consumption or the amount of the input stream. The activity data is multiplied by the emissions factor of the used fuels or input materials. In the case of incineration processes, an additional oxidation factor is considered: when a fuel is consumed, not the entire carbon content is oxidised to CO_2e. Incomplete oxidation occurs due to inefficiencies in the combustion process that leave some of the carbon unburned or partly oxidised as soot or ash. Un-oxidised or partially oxidised carbon is taken into account in the oxidation factor (Figure 20).

[42] Only compressor stations for pipeline transport within EU territory are directly or indirectly (electricity consumption) covered.

Figure 23: Monitoring of CO_2e emissions by the standard methodology



Source: authors, based on EU Commission

The current EU ETS offers incentives for the use of biogenic resources, as the biogenic content of fuels and input materials is considered by an emissions factor of zero and does not lead to an obligation of returning EUAs in the EU ETS. The higher the share of renewable sources, the lower the relevant CO_2e emissions of an installation and obligations of its operator.

Because of the focus on installation level and direct CO_2e emissions into the atmosphere so called Scope 3 emissions are not covered by the EU ETS. In the case of hydrogen or PtX the production process of hydrogen or PtX itself does not play any role for the accounting within the EU ETS (also see chapter 1.1.1). The relevant parameter is the emissions factor of the fuel or input material. If operators of installations use pure hydrogen the CO_2e emissions caused by the hydrogen are calculated with zero. The colour of the hydrogen used by operators makes no difference as long as pure hydrogen is considered.

Very important and relevant for further discussions regarding possible sustainability requirements of hydrogen is the question how hydrogen from different domestic sources is regulated today. In the chemical sector hydrogen is often generated as a by-product of the primary production of different bulk chemicals. Hydrogen might be also an intermediate product (e.g. in the case of the ammonia production). Regardless of whether hydrogen is formed as an intermediate or by-product, it is often directly used as a fuel in installations covered by the EU ETS. As an intermediate or by-product, this hydrogen has been considered with an emissions factor of zero so far. Mostly, this source stream must not even be considered in the monitoring plan if the purity of the hydrogen is verified in the context of the approval process by the competent authority. Therefore, there already have been incentives to substitute fossil fuels with hydrogen.

Related to the monitoring of CO_2e emissions, detailed proofs of origin have been implemented in the EU ETS so far for the use of biomass, especially for gaseous source streams (e.g. for biomethane). From 2024 onwards, more stringent requirements will be implemented. As of today, there are no indications for amendments regarding specific requirements for hydrogen in the EU ETS. But the further configuration of the EU monitoring regulation should be observed because new incentives for green hydrogen could be created if similar sustainability requirements were implemented for hydrogen as for biomass.

3.2.2. Incentives for PtX by free allocation

Currently, in principle all installations are eligible for free allocation, except installations that only produce electricity or installations operated for the capture, transport and storage (CCS) of CO_2e. In general, industrial production processes have fuel and/or heat as input, and a product and/or heat or fuel as output. Certain processes can also result in process emissions.

The free allocation of allowances is primarily based to product benchmarks, as they provide the broadest incentive for emission reductions. However, not in all cases product benchmarks can be defined. In these cases, the so-called "fall-back" approaches based on the heat benchmark, the fuel benchmark or the process emissions approach are used.

The European hydrogen strategy linked with the EU Strategy for Energy System Integration will provide the framework for the green energy transition. One way to deliver sector integration is by deploying renewable hydrogen. It can be used as a feedstock, a fuel or an energy carrier and storage, and has many possible applications across industry, transport, power and buildings sectors.

Because of this extensive area of application of green hydrogen or other PtX products the most relevant allocation approaches in the EU ETS are the product, heat and fuel benchmark. The common calculation of free allocation follows this formula:

Equation 4: Free allocation in the EU ETS based on benchmarks

$$Amount\ of\ free\ allocation\ F = \sum_i BM_i * HAL_i * CL\ EF_{i,k} * LRF/CSCF_k$$

With:

BM	= Relevant Benchmark
HAL	= Historic Activity Level
$CL\ EF_{i,k}$	= Carbon Leakage "Exposure Factor"
$LRF/CSCF_k$	= Linear Reduction Factor or Uniform Cross-Sectoral Correction Factor

Source: FutureCamp based on FAR

Incentives for the production of hydrogen by the hydrogen product benchmark

There is a specific product benchmark defined for hydrogen in the European Free Allocation Rules (FAR). But hydrogen can also be part of other product benchmarks or at least of the processes covered by other product benchmarks, as e.g. refinery products, float glass or ammonia.

For H2Global the most relevant aspect regarding incentives for hydrogen use in the EU ETS is the product benchmark for hydrogen itself. In the EU ETS, the following products are covered by a benchmark:

1. Pure hydrogen;
2. Mixtures of hydrogen and carbon monoxide having a hydrogen content ≥ 60% mole fraction of the total amount of hydrogen plus carbon monoxide (syngas).

Other mixtures of hydrogen and carbon monoxide (i.e., mixture having a hydrogen content < 60% mole fraction of the total amount of hydrogen plus carbon monoxide) are not covered by the product benchmark for hydrogen, but by the product benchmark for synthesis gas.

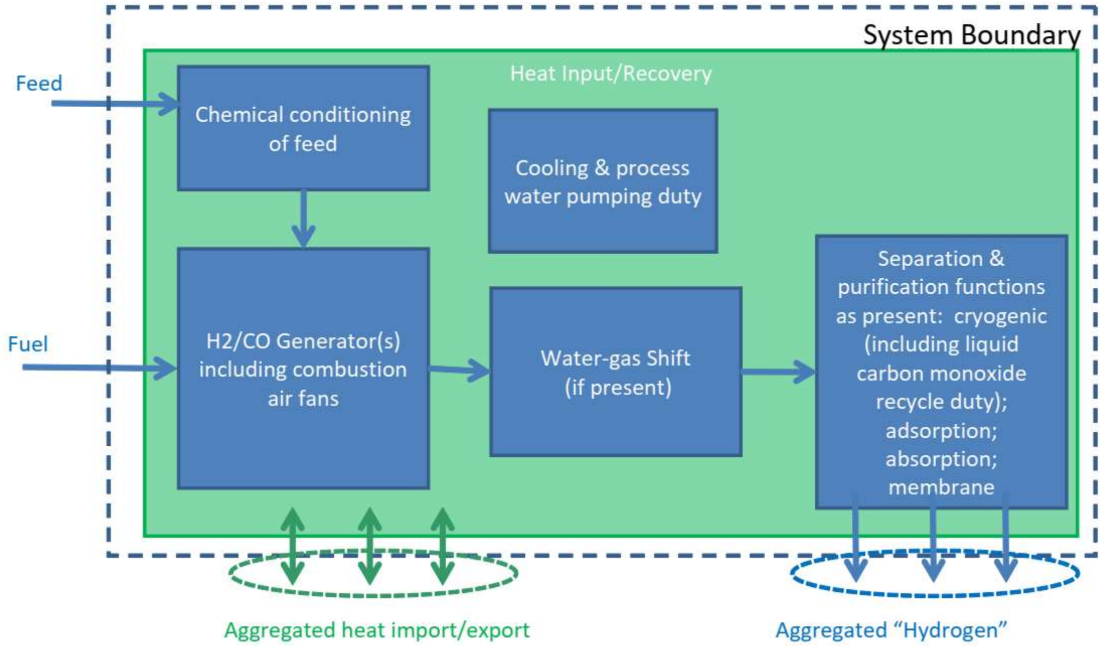
In contrast to the monitoring of CO_2e emissions in the EU ETS, the production process of hydrogen is relevant for the eligibility of receiving EUAs free of charge. There is no free allocation for electricity. But in the case of hydrogen, an exchangeability of heat and electricity must be considered. That means: the higher the electricity share, the lower the free allocation for direct emissions. At the same time, less EUAs need to be surrendered for operating the electrolyser as there is no obligation to surrender EUAs for electricity consumption, but the EU ETS causes an indirect increase of electricity costs.

For the determination of indirect emissions from electricity consumption, the total electricity consumption within the system boundaries is considered.

The following production steps are within the system boundaries:

I. Chemical conditioning of feed;
II. H_2/CO generation with associated combustion air fans (no DAC included);
III. Water-gas shift (if present);
IV. Separation and purification functions;
V. Related cooling and process water pumping duty.

Figure 24. System boundaries of the hydrogen product benchmark



Source: Guidance document of the EU Commission

<u>Note:</u> indirect emissions from electricity consumption are not eligible for free allocation but are used in the calculation of free allocation.

Following the superior free allocation formula, the product benchmark for hydrogen is based on total emissions since energy produced from fuels is exchangeable for energy from electricity. However, allocation is based on direct emissions only. In order to achieve consistency between the benchmarks and the allocation, the preliminary allocation is calculated using a ratio of direct and total emissions:

Equation 5: Preliminary free allocation in the EU ETS

$$F_{p,k} = \frac{Em_{direct} + Em_{NetHeatImport}}{Em_{direct} + Em_{NetHeatImport} + Em_{indirect}} x\ BM_p\ x\ HAL_p\ x\ CLEF_{p,k}$$

With:

$F_{p,k}$	= Annual preliminary allocation for a product benchmark sub-installation producing hydrogen (expressed in EI-JAS).
BM_p	= Benchmark for hydrogen (expressed in EUAs / unit of product).
$CLEF_{p,k}$	= Applicable Carbon Leakage Exposure Factor for product p in year k.
Em_{direct}	= Direct emissions within the system boundaries of the production of hydrogen over the baseline period. The direct emissions further include the emissions due to the production of heat within the same ETS installation, that is consumed within the system boundaries of the hydrogen production process. Direct emissions should (by definition) exclude any emissions from electricity generation or net heat export/import from other ETS installations or non-ETS entities.
$Em_{NetHeatImport}$	= Emissions from any net measurable heat import from other ETS installations and non-ETS entities over the baseline period by a sub-installation producing hydrogen, irrespective of where and how the heat is produced.
$Em_{indirect}$	= Indirect emissions from electricity consumption within the system boundaries of the production of hydrogen over the baseline period. Irrespective of where and how the electricity is produced, these emissions expressed in tonnes $C0_2$ are calculated as follows:

$$Em_{indirect} = Elec.use\ x\ 0.376$$

With:

Elec use	= Total electricity consumption within the system boundaries of the production of hydrogen over the baseline period, expressed in MWh.
HAL_p	= Historical activity level, i.e. the arithmetic mean of annual production in the baseline period as determined and verified in the baseline data collection (expressed in units of product) (see below).

Source: Guidance document of the EU Commission

Example:

100,000 t of hydrogen shall be produced in three installations with different processes. Hydrogen is produced in installation A via 100% electricity (e.g. electrolysis) and in installation B via 100% heat (e.g. steam reforming). In installation C, the process takes 50% electricity and 50% heat. For simplification, all processes need about 4,000,000 MWh of energy. The emissions factor of the electricity is taken from the Free Allocation Rules (FAR, see above). The emissions factor of the heat is assumed with 0.25 t CO_2e/MWh. The relevant product benchmark for hydrogen is 6.84 t CO_2e/ H_2.

Applying current allocation methodologies for installation A, $F_{p,A}$ would be 0 because the entire process is based on electricity. The operator of the installation is not required to submit EUAs because no direct emissions occur. Hence, the installation is covered indirectly because electricity generation is covered by the EU ETS, indirectly increasing electricity costs for installation A.

The preliminary free allocation for installation B is 684,000 EUAs because the entire energy input is eligible for free allocation. But the installation needs to surrender EUAs for all direct emissions resulting from fuel utilization during the SMR-process – in this case 1,000,000 t CO_2e.

Equation 6:

$$F_{p,B} = \frac{Em_{direct,B} + Em_{NetHeatImport,B}}{Em_{direct,B} + Em_{NetHeatImport,B} + Em_{indirect,B}} x\ BM_p\ x\ HAL_p\ x\ CLEF_{p,B}$$

$$= \frac{1{,}000{,}000 + 0tCO_2}{1{,}000{,}000 + 0 + 0tCO_2} x\ 6.84 \frac{tCO_2}{t} x 100{,}000\ \text{t x } 1.0 = 684{,}000\ \text{EUA}$$

With:

HAL_p	= 100,000 tH_2
BM_{H2}	= 6.84 tCO_2/t
Energy input	= 4,000,000 MWh
$Em_{direct,B}$	= 4,000,000 MWh x 0,25t CO_2/MWh = 1,000,000tCO_2
$Em_{NetHeatImporrt,B}$	= 0 MWh = 0 tCO_2
$Em_{indirect,B}$	= 0 MWh = 0 t CO_2

Source: own calculations FutureCamp

The preliminary free allocation for installation C is only about 195,206 EUAs because only 50% of the entire energy input is eligible for free allocation. Additionally, the emissions factor of the purchased electricity is higher than the emissions factor of fuel for heat supply. That means further reduction of the total amount of free allocated certificates. But the operator only has to submit EUAs for any direct emissions – in this case 500,000 t CO_2e.

Equation 7:

$$F_{p,B} = \frac{Em_{direct,B} + Em_{NetHeatImport,B}}{Em_{direct,B} + Em_{NetHeatImport,B} + Em_{indirect,B}} x\ BM_p\ x\ HAL_p\ x\ CLEF_{p,B}$$

$$= \frac{500{,}000 + 0tCO_2}{500{,}000 + 0 + 1{,}252{,}000tCO_2} x \frac{6.84\ tCO_2}{t} x\ 100{,}000\ \text{t}\ x\ 1.0 = 195{,}206\ \text{EUA}$$

With:

HAL_p	= 100,000 tH_2
BM_{H2}	= 6.84t CO_2/t

Energy input = 4,000,000 MWh
$Em_{direct,B}$ = 2,000,000 MWh x 0,25 tCO_2/MWh = 500,000 tCO_2
$Em_{NetHeatImporrt,B}$ = 0 MWh = 0 tCO_2
$Em_{indirect,B}$ = 2,000,000 MWh = 0,376 tCO_2/MWh = 1,252,000 tCO_2

Source: own calculations FutureCamp

This is a very import issue for further discussions and possible incentives for green hydrogen. On the one hand, incentives for using green hydrogen could be set if the product benchmark of hydrogen also applies for green hydrogen without subtracting the electricity share. On the other hand, this would define an exception from the common allocation principle of no free allocation for electricity.

Incentives for using hydrogen by the fuel- and heat benchmarks

If hydrogen is used as a fuel or for generating heat, free allocation can be applied for. The free allocation rules do not distinguish between the different fuels eligible for those two benchmarks. Both the fuel (56.1 t CO_2e/TJ) and the heat benchmark (62.3 t CO_2e/TJ) are based on natural gas. The heat benchmark considers an efficiency of 90% for the heat generator. The generic application of the benchmark for free allocation provides an incentive for using any kind of hydrogen (or other low-carbon fuels).

That means that installations, which are eligible for free allocation according to the rules summarised above, can benefit twice from the utilization of hydrogen and PtX: they do not only avoid the need to surrender EUAs for emission from fossil fuels, but they in addition can receive a free allocation of EUAs according to the fuel-/heat-benchmarks. Figure 24 illustrates the effect by comparing a fictitious heat plant fired completely by coal with heat produced exclusively by PtX. The quantitative difference is significant, but needs to be put in relation to CAPEX and OPEX costs resulting from a fuel switch to PtX.

Figure 25: Incentives for PtX use by current EU ETS allocation rules

Use of coal				Use of PtX		
Q_coal	100,000	t coal				
	3,000	TJ				
Emissions_coal	283,800	t CO_2		Emissions PtX	-	t CO_2
Efficiency heat production	0.9					
Free allocation	168,210	EUAs		Free allocation	168,210	EUAs
EUAs to be surrendered	115,590	EUAs		EUAs to be surrendered	- 168,210	EUAs
EUA price	90	EUR/EUA		EUA price	90	EUR/EUA
Costs	10,403,100	EUR		**Costs**	- 15,138,900	EUR

Source: own calculations

3.3. Recognition of PtX products as “Green Fuels” under RED

RED II and RED III will serve as the major legal EU acts under the framework of the effort sharing regulation, aiming to achieve the climate targets in the sectors outside the ETS. In addition to the comprehensive target of a 32% share of renewable energies in gross final energy consumption in 2030, sub targets for the various sectors are specified in the RED II:

- Increase the share of renewable energies in the heating and cooling sector to an indicative benchmark of 1.3 percentage points as an annual average calculated for the periods 2021 to 2025 and 2026 to 2030,

- A minimum share of 14% of renewable energies in final energy consumption in the transport sector in 2030:
    - Of which at least 3.5% share of advanced biofuels and biogas in 2030[43]
    - Maximum 7% share of biofuels from food and feedstock
    - 0% share of biofuels from substrate with a high risk of indirect land use change
    - Up to 1.7% share of fuels from substrates according to Annex IX Part B

Generally, green fuels or RFNBOs can be used to count towards the national targets of Member States' obligations outside the ETS, when used within these sectors.

The basic requirement of RED II for RFNBOs, in both the ETS and non-ETS sectors, is their renewable source[44] and, they may only be accounted for once [45].

The guaranteed avoidance of double counting of renewable electricity is a basic condition with regard to the crediting of renewable electricity drawn from the grid as "renewable", if it is to be used for the generation of RFNBOs. This requirement is differentiated in the Additionality Act (cf. 3.3.1) mentioned below.

When electricity is grid-sourced, it is considered renewable according to the share that renewable energy has had in the electricity mix over the past two years. In order to fully count electricity as "renewable" for RFNBO generation purposes, the electricity generation facility must:

- Start operation after or at the same time as the plant that produces RFNBOs, **and**
- May not be connected to the grid, or may be connected to the grid, but the electricity in question **must** be demonstrably provided in a renewable way so that it is **not** taken from the grid.[46]

According to subparagraph 7 of Art. 27(3) RED II, the Commission was requested to adopt a Delegated Act by 31 December 2021 to specify these requirements regarding renewable energies for RFNBO production. However, the proposal submitted was not adopted by the EU Parliament. In September 2022, the EU Parliament rejected the additionality requirement proposal. On 10 February 2023, the Commission presented a new draft, which is further detailed in chapter 3.3.1.

In addition to the above-mentioned condition that RFNBOs may only be generated with renewable electricity in order to be eligible, the use of RFNBOs in the transport sector is subject to the condition that the greenhouse gas savings achieved by them must be at least 70% compared to the fossil-based comparative system from 1 January 2021 onwards[47]. Since the calculation methodology according to Art. 25 (2) is to be defined in a Delegated Act, the so-called "Methodology Act" (cf. 3.3.2), which has not yet been enacted, this requirement has not yet come into effect.

To ensure the authenticity of, inter alia, renewable hydrogen and renewable electricity, even when traded across national borders, Member States or designated competent bodies shall implement systems to ensure the issuance, transfer and cancellation of guarantees of origin[48]. The purpose of this system is to ensure that there is no double promotion and crediting. Responding guarantees of origin are usually issued for 1 MWh. In order to be able to reliably provide and track these guarantees, economic operators are obliged to implement appropriate mass balance systems in accordance with Art. 30 (1) RED II.

Since the production of RFNBOs may well go hand in hand with the production of other outputs/goods, the following must be ensured with regard to the demonstration of sustainability properties and GHG-savings:

1. Where only one product is produced, appropriate conversion case factors shall be used for mass balancing, expressing the relationship between the mass of the final product and the mass of raw material at the start of the process.

[43] Advanced biofuels as defined in RED II are biofuels from feedstocks listed in Annex IX Part A of RED II.
[44] Directive (EU) 2018/2001 Art. 2 (36)
[45] Directive (EU) 2018/2001 Art. 7 (1)
[46] Directive (EU) 2018/2001 Art. 27 (3) subpara. 5
[47] Directive (EU) 2018/2001 Art. 25 (2)
[48] Directive (EU) 2018/2001 Art. 19 (1, 5)

2. In the case that several end products are produced, a separate conversion factor shall be used for each end product and a separate mass balance shall be used as a basis.

Corresponding specifications for the assessment of different end products as well as their crediting are to be expected in the annex to the "Methodology Act"[49]. In the following, the calculation methodology proposed in the present draft will be discussed in more detail (cf. 3.3.2).

The basic assessment of RFNBOs within the scope of RED II, without taking into account the Delegated Acts, focuses on the fuel sector as mentioned above. It is important to emphasize that the sustainability- and GHG-reduction requirements apply not only to intra-European but also to imported RFNBOs, without exception. In other words, all RFNBOs that are to be used in the European market for the purposes of RED II and associated legislation must meet the requirements set out in this chapter.

3.3.1. The "Additionality Act"

After the Commission's previous draft from September 2022 was rejected by the Parliament, it submitted a new, more comprehensive draft on 10 February 2023. The so-called "Additionality Act"[50] defines the conditions under which hydrogen or PtX — within or outside the EU — qualifies as renewable. Under the existing legislation (i.e., the RED II), the share of RFNBOs produced is assumed as the average share of renewable electricity on the electricity network of the country in which the hydrogen/PtX production facility is located. But there have been concerns that, in countries with low renewable energy share in the grid, the additional demand from green hydrogen/PtX production facilities will reduce renewable energy consumption in other sectors (which eventually can use renewable energy more efficiently), thus increasing total emissions. Therefore recital 8 states "In all other cases, the production of renewable hydrogen should incentivise the deployment of new renewable electricity generation capacity and take place at times and in places where renewable electricity is available (temporal and geographic correlation) to avoid incentives for more fossil-based electricity generation."[51]

Due to those concerns, the EU Commission has suggested "additionality rules", specifying when the hydrogen/fuel produced can be counted as fully renewable:

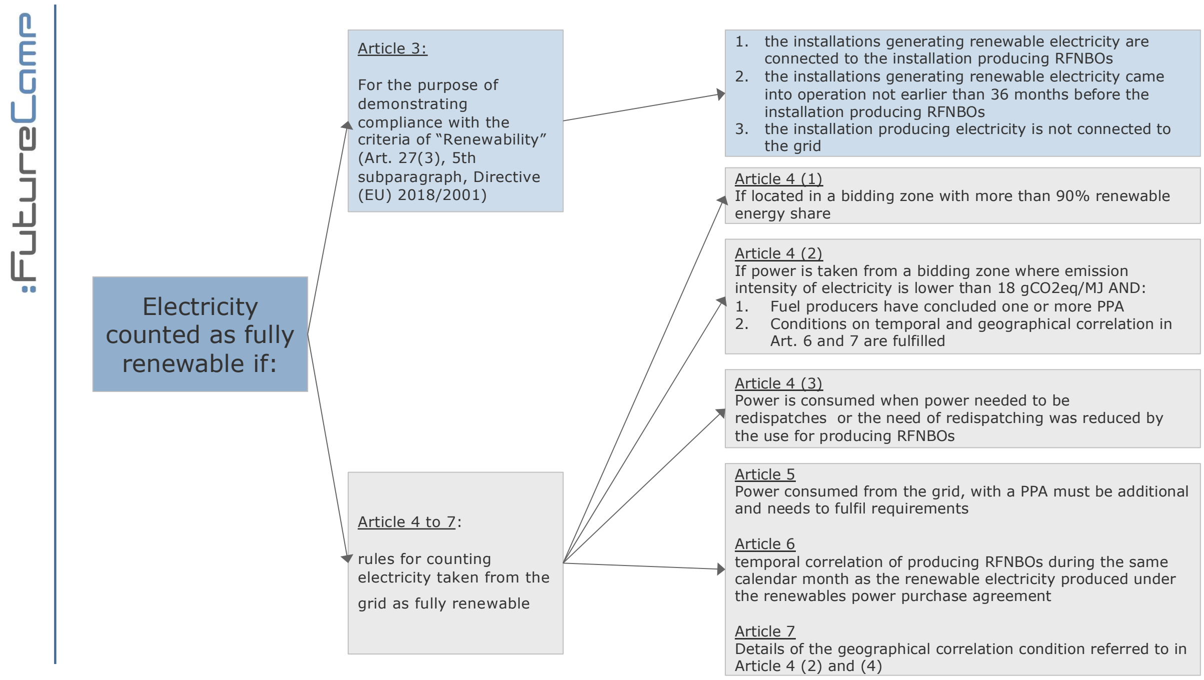
- Off-grid electrolysers operated by dedicated renewable power installations (which has been commissioned earliest 36 months before the commissioning of the electrolyser); and
- Grid-connected electrolysers if the electricity used is "demonstrably" renewable. To demonstrate the renewable character, a power purchase agreement (PPA) with a renewable electricity installation (for at least the amount of electricity consumed by the electrolyser) has to exist. Secondly, the electricity generation installation(s) must be new/additional (i.e., have come into operation no earlier than 36 months before the hydrogen/PtX facility) and "unsubsidized"; and there must be a strict temporal and geographical correlation of renewable electricity production and consumption in the electrolyser.
  Further, article 11 of the Delegated Act introduces a grandfathering clause which states that grid-connected electrolysers starting operation before 2028 are excepted from this additionality rule until 2038.
- In the case that electricity is purchased from the grid for the generation of RFNBOs, the electricity can only be counted as fully renewable if either
  - The average share of renewable energies in the electricity exceeded 90% in the previous calendar year and the production of RFNBOs does not exceed a maximum number of hours set in relation to the proportion of renewable electricity in the bidding zone; or

[49] European Commission C(2023) 1086 final Annex A. (15)
[50] European Commission C(2023) 1087 final
[51] European Commission C(2023) 1087 final; recital 8

- When the installation production RFNBO is located in a bidding zone where the emission intensity of electricity is lower than 18 gCO_2e/MJ; or
- If the electricity used for the production for RFNBOs is consumed during an imbalance settlement period during which the fuel producer can demonstrate the reduction of redispatch due to the production of RFNBOs.

Until 31 December 2029, the temporal correlation condition shall be considered complied with if the RFNBO is produced during the same calendar month as the renewable electricity produced under the renewables power purchase agreement. From 1 January 2030, the temporal correlation condition shall be considered complied with if the RFNBO is produced during the same one-hour period as the renewable electricity produced under the renewables power purchase agreement (European Commission C(2023) 1087 final Art. 6). Furthermore, the requirements on traceability and certification of compliance are regulated in the Delegated Act. The following graph attempts to summarise the requirements for recognition as "fully renewable" in a clear and structured form.

Figure 26: Recognition of "renewable" electricity under RED



Source: Future Camp

3.3.2. The "Methodology Act"

Based on Article 25 (2) and Article 28 (5) on 10th February 2023 the Commission also published a draft of the so-called "Methodology Act". The act defines minimum thresholds for the GHG-emissions savings that need to be achieved by RFNBOs and Recycled Carbon Fuels (RCF)[52].

For all RFNBOs and RCFs, the total emissions from the "fossil fuel comparator" (i.e., the fossil fuels against which cleans fuels are compared) is set to 94 gCO_2e/MJ in correspondence with RED II[53]. The GHG emissions

[52] European Commission C(2023) 1086 final
[53] European Commission C(2023) 1086 final, recital 9

savings must be at least 70% compared to this benchmark, i.e. the maximum emissions intensity of RFNBOs is 28.2 g CO_2e/MJ[54]. For hydrogen, this is equivalent to 3.38 $tCO_2e/t\ H_2$.

Important to note is that this emissions threshold refers to “life-cycle-emissions”. According to the latest draft regulations, emissions resulting from the processing, transport and distribution (e.g. electricity used for liquefaction and from fuel transportation to the refueling station) have to be included in determining the emissions intensity of the RFNBO[55]. This means that the effective emissions threshold for hydrogen production is more stringent (lower) than 3.38 $tCO_2e/t\ H_2$.

Recital 5 of the Methodology Act draft states that the origin of carbon used for RFNBOs and recycled carbon fuels is not relevant for determining emission savings of such fuels *in the short term*, as plenty of carbon sources are available and can be captured without hindering the progress of decarbonisation. *In the long-term*, the use of these RFNBOs produced using non-sustainable carbon is not compatible with climate neutrality as the use of carbon from non-sustainable processes entails a continued use of non-sustainable fuels and the related emissions. Capturing of emissions from non-sustainable sources should therefore only be considered as avoiding emissions until 2035. Amongst others, this deadline will be reviewed in the context of the implementation of the Union-wide 2040 climate target in the sectors covered by Directive 2003/87/EC.

Emissions from activities listed in Annex I to Directive 2003/87/EC, i.e. from industrial processes or from the combustion of unsustainable fuels are to be avoided even if they could be captured and used to produce RFNBOs. These emissions are subject to carbon pricing to create incentives to avoid emissions from unsustainable fuels in the first place. Where such emissions are not accounted for upstream through effective carbon pricing, the abovementioned exemption does not apply and the emissions must be included and not considered avoided[56].

In order to calculate the compliance of the RFNBO with the GHG reduction target of at least 70%, the Annex to the Delegated Act provides a calculation method, which is presented in the following figures.

Equation 8: Methodology for determining GHG ***emissions*** *of RFNBOs according to the “methodology act”*

$$E = e_i + e_p + e_{td} + e_u - e_{ccs}$$

With:

E	= total emissions from the use of the fuel ($gC0_2eq$ / MJ fuel)
e_i	= e i elastic + e i rigid - e ex-use: emissions from supply of inputs ($gC0_2eq$ / MJ fuel)
	e i elastic = emissions from elastic inputs ($gC0_2eq$ / MJ fuel)
	e i rigid = emissions from rigid inputs ($gC0_2eq$ / MJ fuel)
	e ex-use = emissions from inputs' existing use or fate ($gC0_2eq$ / MJ fuel)
e_p	= emissions from processing ($gC0_2eq$ / MJ fuel)
e_{td}	= emissions from transport and distribution ($gC0_2eq$ / MJ fuel)
e_u	= emissions from combusting the fuel in its end-use ($gC0_2eq$ / MJ fuel)
e_{ccs}	= emission savings from carbon capture and geological storage ($gC0_2eq$ / MJ fuel)

Source: European Commission C(2023) 1086 final Annex A. (1)

[54] European Commission C(2023) 1086 final Article 2

[55] In contrast to this, emissions resulting from compression of hydrogen apparently do not need to be considered (Hydrogen Europe, 2022).

[56] European Commission C(2023) 1086 final, recital 6

Equation 9: Methodology for determining GHG savings of RFNBOs according to the "methodology act"

$$Savings = (E_F - E)/E_F$$

With:
E = total emissions from the use of renewable liquid and gaseous transport fuel of non-biological origin or recycled carbon fuel
E_F = total emissions from the fossil fuel comparator.

Source: European Commission C(2023) 1086 final Annex A. (2)

Annex A provides further considerations for the assessment of individual emissions and emission intensities of input substances and specifies how these are to be taken into account. In the context of this paper, special reference should be made to paragraph 10 of Annex A.

According to this paragraph, the following calculation principle must be taken into account for "ex-use" (European Commission C(2023) 1086 final, Annex 10). This includes all emissions that are avoided when the input material is used for fuel production. These emissions include the CO_2e equivalent of the carbon contained in the chemical composition of the fuel that would otherwise have been emitted to the atmosphere as CO_2e. This includes CO_2e that has been captured and added to the fuel provided at least one of the following conditions is met:

a) the CO_2e has been captured in an activity listed in Annex I to Directive 2003/87/EC and accounted for upstream in an effective carbon pricing scheme and included in the chemical composition of the fuel before 2036. This date shall be extended to 2041 in cases other than CO_2e from combustion of fuels for electricity generation; or
b) the CO_2e has been captured from the air; or
c) the captured CO_2e is from the production or combustion of biofuels, bioliquids or biomass fuels that meet the sustainability and greenhouse gas saving criteria and no carbon capture and substitution credits have been issued for the CO_2e capture in accordance with Annexes V and VI to Directive (EU) 2018/2001; or
d) the captured CO_2e originates from the combustion of renewable liquid and gaseous fuels of non-biological origin or recycled carbon fuels that meet the greenhouse gas saving criteria set out in Articles 25(2) and 28(5) of Directive (EU) 2018/2001 and this Regulation; or
e) the captured CO_2e originates from a geological source of CO_2e and the CO_2e was previously released naturally.

Captured CO_2e originating from a fuel that is intentionally burned for the purpose of producing CO_2e and CO_2e for the capture of which an emission credit has been granted under other legislation shall not be taken into account. Emissions associated with inputs such as electricity and heat, and consumables used in the capture of CO_2e are included in the calculation of emissions attributed to inputs.

In short, this means that carbon that has been captured in a previous process, not added to the atmosphere and not already accounted for as a negative emission, can be negatively accounted for via the given formula for calculating "emissions from supply of inputs/ei".

It is important to note that this life-cycle approach is not consistent with the approach applied under the EU-ETS, where emission factors only refer to the emissions that occur when the fuel is utilized (Scope 1). Lifecycle-emissions (scopes 2 and 3) are not taken into consideration in the EU-ETS.

3.4. Sector-specific trading of reduction quota under the Federal Immission Control Act

As mentioned in chapter 1, Germany is the only EU Member State that so far has transposed the requirement of Article 7a of Directive 2009/30/EC into national law. This was done in 2015 with the amendment of § 37a in the Federal Immission Control Act (BImSchG) to the effect that the energy quota according to Directive 2009/28/EC was converted into a GHG-reduction quota according to Article 7a of Directive 2009/30/EC. When it was introduced, the GHG-reduction quota was set to raise from 2.5% in 2015 to 4% in 2017 and 6% in 2020 in accordance with the FQD. The 2021 amendment to the BImSchG provides for an increase in this greenhouse gas reduction quota to 25% by 2030. In § 37 (4a), the BImSchG states that in 2030 a minimum share of 2% of jet fuel must be replaced by fuels from RFNBOs. Furthermore, § 37a (5) (6) states that RFNBOs are generally recognised as options for meeting the targets if they meet the legal requirements. The 37th Federal Immission Control Ordinance (37th BImSchV) sets out the requirements for the recognition of electricity-based fuels.

The more detailed implementation of the fundamental requirements of § 37a is regulated by the so-called 38th Federal Immission Control Ordinance (38. BImSchV). According to this, the

- energy share of biofuels from raw materials with a high risk of indirect land-use change must already be 0% in 2023,
- energy content of waste-based fuels from used cooking oil and animal fats in categories 1 and 2 must not exceed 1.9%,
- energy content of conventional biofuels from food and feed crops shall not exceed 4.4%, and
- energy share of advanced biofuels shall be at least 2.6% in 2030. [57]

The greenhouse gas reduction quota (§37a BImSchG) is relevant for the market introduction of RFNBOs, since a CO_2e trading market has emerged among the “distributors” of fuels, in which these GHG-reduction quotas are traded bilaterally. In other words, over- and under-fulfilments of the GHG-reduction quotas are traded in €/t of CO_2e. Thus, if a distributor overfulfils its quota of 8% in 2023, he can sell his surplus to a distributor that could not meet this quota. The price limitation of this market results from penalties, which is currently 600 €/t of CO_2e [58]. Most recently, the price paid on the market within this quota was between 100 - 200 €/t of CO_2e.

3.5. Summary

Accounting of PtX production and utilisation in National Inventory Reports

It is important to understand the generic implications of PtX-exports and imports on national inventories. According to UNFCCC-rules, countries need to prepare and submit so-called National Inventory Reports (NIRs) that inter alia show whether a country is on track / has met its Nationally Determined Contribution (NDC) or not.

As a general rule, emissions from the production of PtX need to be accounted in the national inventory of the producing country. That means that hydrogen imported to the EU does not increase the emissions inventory of the EU regardless the carbon intensity of the PtX.

[57] Ordinance of 8 December 2017 laying down further provisions on the reduction of greenhouse gases in fuels (Federal Law Gazette I p. 3892), as amended by Article 1 of the Ordinance of 12 November 2021 (Federal Law Gazette I p. 4932).

[58] § 37c BImSchG (2): “In the cases of § 37a(4), the levy shall be calculated according to the shortfall of greenhouse gas emissions to be mitigated and shall amount to 0.47 euros per kilogram of carbon dioxide equivalent up to and including the commitment year 2021 and to 0.60 euros per kilogram from the commitment year 2022 onwards.

The analysis differentiates two main scenarios. If PtX are not produced with 100% renewable energies and, the production of PtX leads to GHG-emissions and the national emissions increase. If the PtX producer is located outside the EU, the new CBAM rules will result in costs for surrendering CBAMCs when PtX are exported to the EU. If the PtX are produced on EU-territory, CBAM rules do not apply, but the EU ETS rules do, leading to indirect or direct increase of production costs[59]. From the importers/consumers' point of view, the use of PtX will reduce emissions if fossil fuels are replaced. The amount of emission reductions depends on the fossil fuel baseline – for example, coal has higher specific emissions than natural gas.

If PtX are exclusively produced with renewable energies, then the national emissions of the producing countries do not increase. CBAM rules will apply for producers outside the EU, but will *not* result in additional costs as embodied CO_2e emissions are zero. From the importers/consumers' point of view, the use of PtX will reduce emissions if fossil fuels are replaced. The amount of emission reductions again depends on the fossil fuel baseline.

GHG monitoring and accounting requirements in the EU ETS

The current EU ETS offers incentives for the use of biogenic resources, as the biogenic content of fuels and input materials is considered by an emissions factor of zero and does not lead to an obligation of returning EUAs in the EU ETS. The higher the share of renewable sources, the lower the relevant CO_2e emissions of an installation and obligations of its operator.

Because of the focus on installation level and direct CO_2e emissions into the atmosphere so called Scope 3 emissions are not covered by the EU ETS. In the case of hydrogen or PtX the production process of hydrogen or PtX itself does not play any role for the accounting within the EU ETS. If EU-installations use pure hydrogen, the applied emissions factor is zero. The colour of the hydrogen used by operators makes no difference as long as pure hydrogen is considered.

Related to the monitoring of CO_2e emissions, detailed proofs of origin have been implemented in the EU ETS so far for the use of biomass, especially for gaseous source streams (e.g. for biomethane). From 2024 onwards, more stringent requirements will be implemented. As of today, there are no indications for amendments regarding specific requirements for hydrogen in the EU ETS. But the further configuration of the EU monitoring regulation should be observed because new incentives for green hydrogen could be created if similar sustainability requirements were implemented for hydrogen as for biomass.

Incentives for producing hydrogen: hydrogen production benchmark for free allocation

In the current EU ETS, in principle all installations are eligible for free allocation, except installations that only produce electricity or CCS-installations.

The European Free Allocation Rules (FAR) specify a production benchmark for hydrogen, which can be applied to pure hydrogen and syngas[60]. It should be noted though that hydrogen can also be part of other product benchmarks or processes covered by product benchmarks, as e.g. refinery products, float glass or ammonia.

The production process of hydrogen is relevant for the eligibility of getting EUAs free of charge. There is no free allocation for electricity. But in the case of hydrogen, an exchangeability of heat and electricity must be considered. That means: the higher the electricity share, the lower the free allocation for direct emissions. At the same time, less EUAs need to be surrendered for operating the electrolyser as there is no obligation to surrender EUAs for electricity consumption, but the EU ETS causes an indirect increase of electricity costs.

[59] Note that the introduction of the CBAM is supposed to phase out free allocation to CBAM-sectors, and also the planned introduction of ETS II is expected to change allocation rules. Hence, the cost situation for domestic PtX production may change (see chapter 4.1).

[60] Syngases are mixtures of hydrogen and carbon monoxide with a hydrogen content ≥ 60% mole fraction.

Incentives for using hydrogen: the fuel- and heat benchmarks

If hydrogen is used as a fuel or for generating heat, free allocation can be applied for. The free allocation rules do not distinguish between the different fuels eligible for those two benchmarks. Both the fuel (56.1 t CO_2e/TJ) and the heat benchmark (62.3 t CO_2e/TJ) are based on natural gas. The heat benchmark considers an efficiency of 90% for the heat generator.

No matter what kind of fuel is actually used, if there is an eligibility for free allocation via the fuel or heat benchmark, the amount of actual used fuel is applicable for free allocation. So, a common incentive for using low-carbon fuels is given by the free allocation rules. Operators can profit by using any kind of hydrogen or other low-carbon fuels.

Recognition of PtX products as "Green Fuels" under RED

RFNBOs can be used to count towards the national targets of Member States' obligations under RED, when used within these sectors. The basic requirement of RED II for RFNBOs, in both the ETS and non-ETS sectors, is their renewable source[61] and the guaranteed avoidance of double counting of renewable electricity used for their production. Details are specified in the so-called Additionality Act proposed by the EU Commission in February 2023, which defines minimum requirements for RFNBOs to count as "green". This includes a geographical-and temporal correlation for dedicated renewable energies powering electrolysers. When electricity is grid-connected, it is considered renewable according to the share of renewable energy in the electricity grid over the past two years (if the share in the grid is > 90%).

The EU Commission also published a draft of the so-called "Methodology Act", which defines minimum thresholds for the GHG-emissions savings that need to be achieved by RFNBOs and RCFs. This also includes any inclusion of upstream chain emissions as well as possible carbon storage provided within the hydrogen production process and the upstream chain.

It may be noted that both Delegated Acts yet need to be formally approved before entering into force.

[61] Directive (EU) 2018/2001 Art. 2 (36)

4. Further development of the EU ETS with a view to accelerate PtX market ramp up

In this chapter, we look at the question, how the EU ETS can be further developed both regionally and with regard to its sectoral scope so that it supports the acceleration of hydrogen and PtX market ramp-up. In addition, we assess what role voluntary carbon markets (VCM) and Art. 6 of the Paris Agreement can play to facilitate green PtX projects. Additionally, the effect of different maximum carbon intensity requirements for domestically produced or imported PtX products is assessed in regard of the RED and its potential harmonisation with the EU ETS.

4.1. Potential expansion of current emission trading system

4.1.1. Sectoral expansion of current emission trading system

In December 2022, the EU institutions agreed to adjust and expand the current EU ETS. The changes affect a number of sectors.

Changes with regard to the current EU ETS

Waste incineration plants will be regulated under the EU ETS from 2024 onwards. Operators of waste incineration plants will have to monitor, report, and verify their emissions. The EU Commission will prepare a report on the possible inclusion of waste incineration plants from 2028. For H_2/PtX, no direct effects are expected. Indirect effects of the inclusion of waste incineration plants on the EUA price cannot be assessed yet.

Maritime transport will also be included in the EU ETS. Since January 2018, large ships over 5,000 gross tonnage loading or unloading cargo or passengers at ports in the European Economic Area (EEA) are to monitor and report their related CO_2e emissions and other relevant information. Since 2019, companies have to submit annual emission reports and all vessels visiting ports in the EEA have to carry a document of compliance. As of 2024, allowances will have to be surrendered. The sector will be fully included in the EU ETS from 2026 (40% of emissions in 2024, 70% of emissions in 2025 and 100% from 2026). Under the deal, ships travelling within the EU will be required to pay for 100% of their emissions, while 50% of the emissions of journeys to or from a non-EU destination (extra-EU voyages) will be covered. For H_2/PtX we expect an additional price effect for transport of H_2/PtX yet economically negligible even with prices around 100 € per EUA . To assess indirect effects on the EUA price, a more detailed analysis is necessary. We expect that the inclusion of maritime transport in the EU ETS II will create additional demand with a high ability to pay. This might drive prices up.

An update of free allocation benchmarks will be finalized in 2023. The EU Commission is reviewing the current 52 product benchmarks and while no draft of the outcome has been circulated yet, it is becoming clear that the revision might be of particular importance for H_2 and PtX because the production of H_2 from electrolysers is expected to become an activity eligible for free allocation of allowances.

This would eliminate today's unequal treatment of different forms of hydrogen production under the EU ETS. As of today, the benchmark value for the production of hydrogen in the 2021-2025 period is 6.84 t CO_2e/t[62]. This means that the production of hydrogen from fossil sources receives free allocation. With the expected review of the product benchmark, hydrogen from electrolysers could also receive free allocation despite the fact that the production has no direct emissions. With prices of 100 €/EUA hydrogen

[62] For phase IV of the EU ETS, allocation period 1

from electrolysers would receive e. g. 0.68 €/kg H_2. This update is high important for H2Global and should be further analysed as soon as the benchmark review is finalized.

Introduction of "EU ETS II"

With their December 2022 decisions, EU institutions have also established a second European ETS (EU ETS II). The EU ETS II will regulate road transport and the residential sector, expanding the price signal to these sectors. While it is too early to analyse the impact of the ETS II for green hydrogen / PtX in detail, it is reasonable to assume that blending hydrogen and PtX into fuels for vehicles or heating can create further demand. Beyond the increase in demand for the product, markets for quotas might also plan an increasing role, such as the sector-specific trading of reduction quota under the Federal Immission Control Act. In this market the price paid on the market most recently was between 100 - 200 €/t of CO_2e.

4.1.2. Potential regional expansion of current emission trading system

A regional expansion of the current emission trading system can happen directly by linking, or indirectly. Examples for indirect linking are the inclusion of maritime transport in the EU ETS as discussed in chapter 4.1.1, or by introducing CBAM – both policies effect operations and emitters abroad.

Linking of the EU-ETS with other emission trading schemes outside the EU is an option that the EU has explicitly created when introducing the EU-ETS in the early 2000s. Linking of ETS means that one system's allowances can be used by participants in the other regional system for compliance. Linking therefore creates larger markets and can increase the efficiency and liquidity of the systems (Kachi et. al, 2015; Grubb 2011). PtX project operator / investors would strongly benefit from such a direct linking because they may benefit from the high price levels of the EU-ETS.

There are, however, significant practical drawbacks. First, the linking of ETSs is a highly political, complex process requiring many years of lead-time to agree on political and technical aspects – such as ambition levels, penalties, covered sectors, allowing for offsets, monitoring-/reporting- and verification (MRV) requirements etc. Many of these aspects are politically highly sensitive as they impact economic policy and competitiveness of industry. That leads to very complex and time-consuming processes between every single legislation involved in the linking process. In other words: if the EU would like to link schemes with five different countries, negotiations with each of these countries need to take place – and the larger the group of countries involved, the more diverse political interests can become. The first attempt to link the EU ETS with a different ETS was the case of Australia, which introduced the so-called Carbon-Pricing-Mechanism (CPM) in July 2012. The Australian-EU ETS linking negotiations formally started in 2012 with the objective to execute the link by 2018 (EU Commission, 2013). But, due to political rollercoasters related to the Australian ETS plans that finally repealed the Australian CPM legislation, talks got interrupted and linking was never realised (Evans et. al., 2021). Another attempt of the EU succeeded: the link between the EU ETS and the Swiss emissions trading scheme. But it took seven years of negotiation between the EU and Switzerland before the so-called "linking agreement" was signed end of 2017 – allowing the Swiss trading scheme to be linked to the EU ETS from 1 January 2020 onwards (EU Commission, 2019a). Both cases underpin the complexity of the matter.

The second drawback is that no emission trading scheme exists in any country that would be a natural PtX-partner – e.g., Morocco, Tunisia, Egypt, or Gulf countries. This would be a pre-condition for linking.

Overall, the chances for a regional expansion of the EU ETS that may benefit green PtX producers are dismal in the short- and medium term.

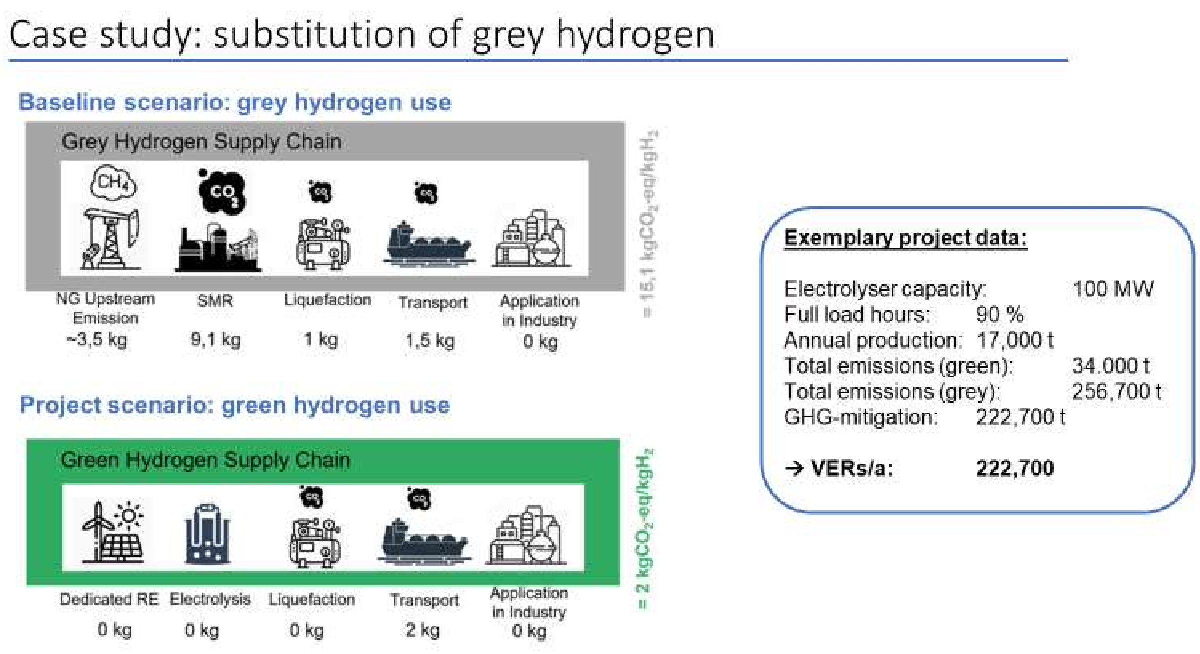
4.1.3. Using voluntary carbon markets to facilitate green PtX projects

A carbon pricing mechanism being operational since many years is the voluntary carbon market (VCM). Under a baseline-and-crediting approach, it allows for the generation of verified emission reductions (VERs) under several standards, such as Verra's Voluntary Carbon Standard (https://verra.org/) or the Gold Standard (https://www.goldstandard.org) VERs can be sold to companies that aim to offset their emissions or achieve corporate NetZero targets. Some governmental emissions trading scheme, such as the Californian Climate Action Registry, even allow certain VERs to be used for compliance purposes. This is, however, not the case for the EU, where the use of VERs for compliance under the EU ETS is not possible. The same applies for the national ETS in Germany.

Still, the voluntary carbon market has developed vividly over the last years, with 353 million VERs issued in 2021, up from 190 million VERs in 2020 (Climate Focus, 2023). The two key standards VCS and in particular Gold Standard have a good overall reputation, but there has been strong criticism recently regarding VER-issuance and verification procedures for Nature Based Solutions (NbS) projects at Verra (The Guardian, 2023).

Nevertheless, the VCM holds significant potential for mobilising additional funding to enhance the economic viability of green PtX projects. Figure 27 exemplarily visualises the VER-generation potential for a green hydrogen project. We assume that grey hydrogen is replaced with green hydrogen. The grey-hydrogen production constitutes the "baseline emissions" (here: ca. 15 kg $CO_2e/kg\ H_2$) from which the "project emissions" of green hydrogen production (here: ca. 2 $CO_2e/kg\ H_2$) need to be deducted for calculating the emission reduction potential. Note that we consider upstream- and downstream-emissions. Assuming an electrolyser capacity of 100 MW, the replacement of grey by green hydrogen can reduce emissions by about 222,000 t CO_2e/yr, equalling 222,000 VERs/yr. Assuming a price range of 10-25 €/VERs, the additional revenue potential stands at 2.2 to 5.7 million €/yr.

Figure 27: Benefits for green PtX projects from voluntary carbon markets: VER-generation



Source: Perspectives

A key benefit can be to incentivise projects which export part of their PtX-production to the EU and which use the remaining part domestically. This can significantly increase environmental benefits, as the decarbonisation of energy systems and/or industry is facilitated both in the EU and in its partner countries where production of green hydrogen can be more cost-competitive due to more favourite geographical conditions (PV and wind potential).

The main barrier preventing green PtX project to use voluntary carbon markets today is the non-existence of widely available methodological frameworks under each of the standards. A "methodology" is the rule-book defining how emission reductions have to be calculated, making sure that approaches are conservative and VERs are only issued for "real" emission reductions. As of today, only one PtX-methodology concept note has been submitted by Verra, none under the Gold Standard. The Hydrogen for NetZero Initiative (http://www.hydrogen-for-net-zero.org/) is a private-sector driven initiative that aims to develop several methodologies for various project types under VCS, Gold Standard and Art. 6 of the Paris Agreement, but it didn't commence work due to a lack of funding. The bottleneck is that investors and developers of green PtX projects put priority on reaching financial investment decision (FID) for their projects and lack the financial capacities for methodology development. Public support may be required to facilitate this process, which has substantial potential for market acceleration.

4.1.4. Using Art. 6 of the Paris Agreement to facilitate green PtX projects

Last but not least, Art. 6 of the Paris Agreement will soon create the option to generate Internationally Tradeable Mitigation Outcomes (ITMOs) under supervision of the United Nations Framework Convention on Climate Change (UNFCCC). It is expected to follow a baseline-and-trade approach like the VCM, but will be linked to the Nationally Determined Contributions (NDCs) of host countries. In this context, details of accounting and the need for corresponding adjustments will be highly relevant.

Art. 6 of the Paris Agreement may become the ideal instrument for incentivising the production and (partially or fully) domestic use of green PtX.

Example:

If Germany finances green hydrogen production in Morocco and the green hydrogen is not exported to Germany but used within Morocco, the German emissions inventory does not change, while Moroccan emissions are reduced compared to a baseline of continued fossil fuel use. If the hydrogen is used to replace coal, the baseline and resulting emission reductions will be higher compared to a scenario where the green hydrogen is used to replace natural gas.

In such a context, Germany and Morocco should engage in a collaboration under Article 6.2 or 6.4 of the Paris Agreement. Such a collaboration allows to generate ITMOs for the emission reduction from the baseline emissions level. These emission credits can then be accounted towards the German emissions inventory. A precondition for such an accounting is a bilateral agreement between Morocco and Germany on the baseline methodology to use and an agreement to apply "corresponding adjustments"[63]. If the mechanism under Article 6.4 is to be applied, a proposal for a baseline methodology needs to be submitted to the Article 6.4 Supervisory Body, which then assesses the methodology and can require changes before formally approving it. This means that any transfer of hydrogen credits between countries should be "mirrored" by an ITMO transaction under Article 6. Unilateral agreements can be made between the countries under Art. 6.2, but credibility may be lower due to a lack of UNFCCC-supervision.

It should be noted that the current NDC of the EU for 2030 does not allow to account for Article 6 credits. This is not an international rule, but a unilateral decision of the EU and can thus be changed by unilateral decision, if desired.

[63] If the host country of the green hydrogen authorizes the emission reductions as ITMOs, this will lead to a corresponding adjustment in the host country's emissions inventory – i.e., the emission reductions will be deducted from the host country's emissions target according to its NDC. In turn, the buyer country (here: Germany) can account for the emission reductions for its NDC-target. If the host country does not grant such an authorization, the emission reductions will become "mitigation contributions' and can only be used for fulfilment of the host country NDC. While it is currently contested whether the mitigation contributions can be traded internationally, for example in the context of the voluntary carbon market, it is clear that they cannot be used against the NDCs of other countries.

4.2. Evaluation of carbon-intensity requirements

Within this chapter the effects of different maximum carbon intensity requirements for PtX products is discussed. This is especially interesting for the extension of the considered carbon pricing schemes, since it shows for example which effect the inclusion of transport emissions would have on possible non-EU suppliers. Further, it elaborates on the question which production and import routes would qualify as RFNBOs within RED. This information could be used in order to further harmonise the EU ETS and the RED.

The consideration of emissions from the transport route within the scope of the accounting in the RED is carried out by the prescribed calculation methodology of the Delegated Act C (2023) 1086 final, which is only available as a draft so far.

According to this, emissions from transport and distribution must be included in the calculation of total emissions. They also include emissions from the storage and distribution of the fuels. Thus, the shorter the transport route or the less carbon intensive the RFNBO is transported to its destination, the better the regarded embodied emission of the landed product.

As discussed in chapter 3.3.2, the total emissions for all RFNBOs and RCFs are related to the “fossil fuel comparator” (i.e., the fossil fuels against which cleans fuels are compared), which is set at 94 gCO_2e/MJ in correspondence with RED II[64]. This translates into 0.3384 kg CO_2e/kWh. RED II requires GHG-emissions reductions of at least 70% compared to the fossil fuel comparator, which means a maximum of 3.38 tCO_2e/t H_2 for production, processing and transport[65], and a maximum of 0.53 t CO_2e / t ammonia. If a 90% reduction is required, thresholds are 1.13 tCO_2e/t H_2 and 0.18 tCO_2e/t ammonia, see Table 14.

Table 14: CO_2e thresholds for hydrogen and ammonia for different reduction requirements under RED III

	Fossil fuel comparator	Hydrogen threshold	Ammonia threshold
	g CO_2e/MJ	kg CO_2e/kg H_2	kg CO_2e/kg NH_3
Baseline	94	11.28	1.77
-70%	28.2	**3.38**	**0.53**
-90%	9.4	**1.13**	**0.18**

Source: authors (own calculations)

If PtX is produced exclusively based on renewable energy, only its transport causes GHG-emissions. For PtX transport, oil tankers with minor adjustments can be used (Econnect 2021). A recent study by the EU commission states that these ships emit 0.0094 kgCO_2e per ton of product transported per kilometre (EU Commission 2022c). Table 15 summarises transport-related emissions for three distance-categories, which represent potential trade routes with relevance for the EU/Germany. For example, the distance of 10,000 km covers the majority of trade route possibilities between the Mediterranean Sea countries and the EU. The distance of 25,000 km represents a possible trade route between Australia and Germany.

It must be noted that the amount of energy transported per kilogram is different for hydrogen compared to ammonia, because ammonia has a lower heating value than hydrogen. Therefore, the limits shown in Table 14 are lower than that of hydrogen. Table 15 shows that hydrogen transport will be within threshold limits for both 70% and 90% reduction. In contrast to this, ammonia transport will only be within threshold limits at a reduction target of 70% compared to the fossil fuel comparator. If the reduction target is increased to 90%, ammonia transport will not meet the target.

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[64] European Commission C(2023) 1086 final, recital 9

[65] European Commission C(2023) 1086 final Article 2

Table 15: CO_2e emissions from hydrogen transport

Distance Km	Total GHG emissions kgCO_2e / kg H_2	Is this within threshold limits for H_2	Total GHG emissions kgCO_2e / kgNH_3	Is this within threshold limits for NH_3
10,000 (e.g., North Africa – Germany)	0.09	Yes (For both 70% and 90% reduction target)	0.09	Yes (For both 70% or 90% reduction target)
25,000 (e.g., Australia – Germany)	0.24	Yes (For both 70% and 90% reduction target)	0.24	Yes (But **only** for 70% reduction target)

Source: authors

So far, only GHG-emissions from the operation of vessels have been considered. However, leakages may occur during transportation of liquid hydrogen. Depending on the type of vessel, leakages can lead to 0.1 to 0.3% loss of the products' weight per day (Berstad et al., 2022). Even though those losses are relatively low, it leads to a climate warming effect. Hydrogen has a 100-year GWP of 5.8. To calculate leakage effects, the days spent at the sea for each route must be taken into consideration. An average tanker's speed is 12 knots, roughly 22.2 km/h. The resulting leakage emissions are summarised in Table 16.

Table 16: Emissions from transport including leakages

Distance Km	Days spent at sea (Average speed of 12 knots)	Hydrogen leakage emission kgCO_2e/kg H_2	Total GHG emissions kgCO_2e/kg H_2	Ammonia leakage emission kgCO_2e kg NH_3	Total GHG emissions kgCO_2e/kg NH_3
10,000 (e.g., North Africa – Germany)	19	0.22	0.31	0	0.09
25,000 (e.g., Australia – Germany)	47	0.54	0.78	0	0.24

Source: authors (own calculations)

When leakages from hydrogen are considered all trade routes are still staying within the limits of 70% GHG reductions. Since ammonia has a GWP of 0, leakage emissions do not affect transport emissions. Even though for hydrogen it increases overall emissions its transport would stay within the threshold even considering a 90% GHG reduction target. One has to keep in mind that currently various ships using sustainable fuels like methanol or ammonia are under development or have already reached the testing phase. If those fuels are carbon neutral, they would eliminate any transport emissions.

To conclude, an increase of emission reduction requirements under RED from 70% to 90% compared to the fossil fuel comparator will not affect the eligibility of green hydrogen as an RFNBO, but it would make green ammonia that is imported from Australia or Asia ineligible.

4.3. Summary

Sectoral expansion of current emission trading system

In December 2022, the EU institutions agreed to adjust and expand the current EU ETS, and establish a new ETS for road transport and the residential sector (EU ETS II).

An update of free allocation benchmarks will be finalized in 2023. The revision might be of particular importance for H_2 and PtX because the production of H_2 from electrolysers is expected to become an activity eligible for free allocation of allowances. This would eliminate today's unequal treatment of different forms of hydrogen production under the EU ETS. As of today, the benchmark value for the production of hydrogen in the 2021-2025 period is 6.84 t CO_2e/t. This means that the production of hydrogen from fossil sources receives free allocation. With the expected review of the product benchmark, hydrogen from electrolysers could also receive free allocation despite the fact that the production has no direct emissions. With prices of 100 €/EUA hydrogen from electrolysers would receive e. g. 0.68 €kg H_2. This update is of high importance for H2Global and should be further analysed as soon as the benchmark review is finalized.

Waste incineration plants will be regulated under the current EU ETS. For H_2/PtX, no direct effects are expected. Indirect effects of the inclusion of waste incineration plants on the EUA price cannot be assessed yet.

Maritime transport will also be included in the EU ETS. As of 2024, allowances will have to be surrendered. The sector will be fully included in the EU ETS from 2026. For H_2/PtX we expect an additional price effect for transport of H_2/PtX yet economically negligible even with prices around 100 €/EUA. To assess indirect effects on the EUA price, a more detailed analysis is necessary. We expect that the inclusion of maritime transport in the EU ETS I will create additional demand with a high ability to pay. This might drive prices up.

With their December 2022 decisions, EU institutions have also established a second European ETS (EU ETS II). ETS II will regulate road transport and the residential sector, expanding the price signal to these sectors. It is reasonable to assume that blending hydrogen and PtX into fuels for vehicles or heating can create further demand. Beyond the increase in demand for the product, markets for quota might also plan an increasing role, such as the sector-specific trading of reduction quota under the Federal Immission Control Act. In this market the price paid on the market most recently was between 100 - 200 €/t of CO_2e.

Potential regional expansion of current emission trading system

A regional expansion of the current ETS can happen directly by linking, or indirectly. Examples for indirect linking are the inclusion of maritime transport in the EU ETS, or by introducing CBAM – both policies effect operations and emitters abroad.

Linking of the EU-ETS with other ETS outside the EU means that one system's allowances can be used by participants in the other system for compliance. Linking therefore creates larger markets and can increase the efficiency and liquidity of the systems. PtX project developers may strongly benefit from such a direct linking because they may benefit from the high price levels of the EU-ETS.

However, linking of ETSs is a highly political, complex process requiring many years of lead-time to agree on political and technical aspects. So far, the EU ETS was linked successfully only to the Swiss ETS - after seven years of negotiation and preparation. An attempt to link with the proposed Australian emissions trading system failed due to changes in climate policies in Australia. In addition, today no emission trading scheme exists in any country that would be a natural PtX-partner – e.g. Morocco, Tunisia, Egypt, or Gulf countries. This would be a pre-condition for linking.

Overall, the chances for a regional expansion of the EU ETS that may benefit green PtX producers are dismal in the short- and medium term.

Using voluntary carbon markets to facilitate green PtX projects

A carbon pricing mechanism being operational since many years is the voluntary carbon market (VCM). Under a baseline-and-crediting approach, it allows for the generation of verified emission reductions (VERs). VERs can be sold to companies that aim to offset their emissions or achieve corporate NetZero targets. Some governmental emissions trading schemes even allow certain VERs to be used for compliance purposes. This is, however, not the case for the EU or Germany.

Nevertheless, the VCM holds significant potential for mobilising additional funding to enhance the economic viability of green PtX projects. It can also become a mechanism to incentivise projects which export part of their PtX-production to the EU and which use the remaining part domestically. This can significantly increase environmental benefits and support energy transformation in PtX export countries. A drawback compared to the EU ETS is that VER-prices are significantly lower that EUA-prices.

The main barrier preventing green PtX project to use voluntary carbon markets today is the non-existence of widely available methodological frameworks under each of the standards. Public support may be required to facilitate this process, which has substantial potential for market acceleration.

Using Art. 6 of the Paris Agreement to facilitate green PtX projects

Last but not least, Art. 6 of the Paris Agreement will soon create the option to generate Internationally Tradeable Mitigation Outcomes (ITMOs) under supervision of the United Nations Framework Convention on Climate Change (UNFCCC). It is expected to follow a baseline-and-trade approach like the VCM, but will be linked to the Nationally Determined Contributions (NDCs) of host countries.

Art. 6 of the Paris Agreement may become the ideal instrument for incentivising the production and (partially or fully) domestic use of green PtX. Collaboration will take place rather on country-level than on company-level as in case of the VCM. Art. 6 activities could become a key feature of hydrogen- or energy partnerships facilitated by the German government, if the political vision is there.

Evaluation of carbon-intensity requirements

According to the current legislative proposals of the EU Commission, alternative fuels only qualify as RFNBOs of they achieve a reduction of GHG intensities of at least 70% compared to the “fossil fuel comparator”. Emissions from transport and distribution of PtX must be included in the calculation of their total emissions. Thus, the shorter the transport route or the more climate-friendly the RFNBO can be transported to its destination, the better.

The current carbon-intensity requirement (-70%) translates into a maximum of 3.38 tCO_2e/t H_2 for production, processing and transport[66], and a maximum of 0.53 t CO_2e/t ammonia. One objective of the underlying study was to assess what implications a theoretical increase of the carbon-intensity requirement to -90% has on the eligibility of imported PtX.

A quantitative analysis was done for i) green hydrogen and ii) green ammonia produced in a) North Africa, b) Australia and exported to the EU. It shows that the currently proposed 70% reduction target allows for import of green hydrogen and green ammonia even from Australia (longest transport distance). An increase of the reduction target to 90% would make green ammonia transported over long distances (using conventional fuels) ineligible. Only green ammonia from nearby regions, such as North Africa would be able to meet the requirements. The import of green hydrogen would still be possible from all world regions.

[66] European Commission C(2023) 1086 final Article 2

5. Recommendation for H2Global

Given that the European legislative environment relevant for hydrogen and PtX is highly complex and rapidly evolving, it is advisable that H2Global carefully monitors new developments and assesses their implications for PtX. In addition, the evolving situation creates opportunities for H2Global to position itself and possibly bring in own recommendations and ideas.

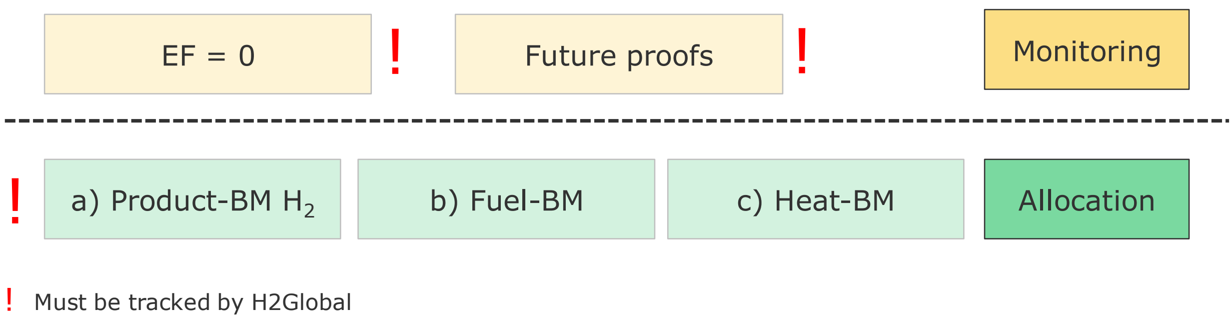
Monitoring further developments under the EU ETS, CBAM and RED

Some regulations and currently ongoing discussions regarding the monitoring and free allocation of EUAs in the EU ETS are particularly important and should be tracked by H2Global, see Figure 28.

With regard to the monitoring of CO_2e emissions, detailed proofs of origin have been implemented in the EU ETS - so far for the use of biomass, especially for gaseous source streams (e.g., for biomethane). From 2024 onwards, more stringent requirements will be implemented. Until now, pure hydrogen has been considered with an emissions factor zero without detailed proofs of origin. Currently, there are no indications for amendments regarding specific requirements for hydrogen in the EU ETS. Hence, there is no differentiation between the production of hydrogen (e.g. green, grey, blue). But future amendments of the EU monitoring regulation should be tracked because major incentives for green hydrogen compared to other colours could be offered if there would be similar sustainability requirements implemented for hydrogen as for biomass.

The ongoing update of free allocation benchmarks might be of particular importance for H_2 and PtX because the production of H_2 from electrolysers is expected to become an activity eligible for free allocation of allowances. This would eliminate today's unequal treatment of different forms of hydrogen production under the EU ETS. Therefore, the process for the further configuration of the hydrogen benchmark should be monitored by H2Global.

Figure 28: Recommendations – EU ETS aspects that should be observed by H2Global



Source: Future Camp

With regard to RED, it will be crucial to understand the practical interpretation of additionality rules in particular for non-EU countries with different power market structures and data availability that aim to export their hydrogen/PtX to the EU. For implementation of CBAM, the rules for determining embodied emissions in imported products that may be produced with PtX will be relevant as they may create advantages or disadvantages.

As the quantitative assessment has shown, hydrogen / PtX that is not exclusively produced with renewables can have significant "embodied" emissions. These need to be considered appropriately in all European legislation to avoid counterproductive incentives potentially leading to negative climate impacts.

Supporting industry in switching to green PtX

The quantitative analysis of potential economic benefits through the EU ETS and the German nETS, as well as the discussion of free allocation with heat- and fuel-benchmarks has shown that there is significant potential of ETS to make green hydrogen / PtX economically interesting.

However, as has been pointed out as well, often significant investments are required by industry to make their installations "fit for hydrogen" (unless completely new installations are built). These investments need to be factored in. It would be important to understand the scale of investments in detail, optimally differentiated by industry sector (steel, chemicals, fertiliser production, etc.). These insights can then be used to assess i) in which sectors a fuel switch to hydrogen can be achieved at lowest costs, and ii) if further political support is required, e.g., in form of direct investment subsidies, to incentivise this fuel switch.

Making use of Art. 6 of the Paris Agreement to incentivise energy transformation in partner countries abroad

Art. 6 of the Paris Agreement can be used as a central element of energy partnerships with non-EU hydrogen exporters to incentivise a local use of green PtX, and thus initiate a sustainable energy transformation abroad. The international mandate of H2Global could become a promising starting point for such activities.

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