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Future Cleantech Architects

# The EU Hydrogen Strategy Review: A Sectoral Approach

Standpoint by
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# Executive Summary

Hydrogen has occupied a central role in Europe's industrial decarbonization strategy since the publication of the EU Hydrogen Strategy in 2020. However, six years later, deployment remains significantly below expectations. Electrolytic hydrogen capacity reached 0.57 GW by mid-2025, far from the EU's 2024 target, while industrial demand for clean hydrogen remains constrained by high costs, infrastructure challenges, and uncertainty over future market developments. At the same time, Europe's industrial landscape has evolved considerably, with rising energy costs, increased global competition, and technological innovation reshaping the conditions under which hydrogen deployment will take place.

The recently published Electrification Action Plan also provides renewed direction towards direct electrification, highlighting that, where technically feasible, direct electrification can offer a more cost-effective and energy-efficient decarbonization pathway than hydrogen. The sector-specific electrification roadmaps therefore provide an important opportunity to assess the relative cost-effectiveness of direct electrification and hydrogen-based solutions across the short, medium, and long term, identifying where each pathway can deliver the greatest decarbonization impact.

**This standpoint suggests that the revision of the EU Hydrogen Strategy should move beyond hydrogen production targets and instead focus on hydrogen's role as a tool for industrial decarbonization. Hydrogen should not be viewed as an objective itself but rather as a means to an end within a broader portfolio of decarbonization solutions. Reducing grid emissions and expanding clean electricity for sectors where direct electrification is technically and economically feasible should generally supersede electrolytic production. This would ensure that scarce clean electricity is used in applications where it can deliver the greatest benefits, while preserving clean hydrogen for sectors where few viable alternatives exist.**

This analysis identifies the industrial sectors where hydrogen is used most, including refining, fertilizers, methanol, steel, aviation, and maritime transport. For each sector, this publication examines current hydrogen consumption, projected hydrogen consumption to 2030 and beyond, the key drivers of future deployment, and the economic and industrial realities that will determine whether hydrogen can scale successfully.

The standpoint reflects on the lessons learned from the implementation of the 2020 EU Hydrogen Strategy, demonstrating the need for an evolving, targeted, and evidence-based approach to hydrogen deployment. A key standpoint is that future hydrogen demand should not be assessed in isolation from other technological innovation: Emerging electrification technologies, across different sectors, have the potential to reduce or even eliminate the need for hydrogen and its associated transport and infrastructure needs. These innovations may offer more efficient or cost-effective decarbonization pathways in certain applications and should be incorporated into future demand projections and infrastructure planning. The standpoint therefore adopts a technology neutral approach, evaluating hydrogen alongside other decarbonization solutions rather than assuming hydrogen deployment as the default.

Finally, the standpoint sets out five recommendations for the revision of the EU Hydrogen Strategy, ensuring that the next iteration is grounded in industrial realities and energy system efficiency. A successful strategy will support sectors where hydrogen is genuinely needed, encourage innovation, and ensure that scarce clean electricity resources are deployed where they deliver the greatest climate and economic benefits.


# Introduction

Hydrogen features prominently at the center of Europe's industrial decarbonization strategy, since early global energy transition scenarios considered it as a promising net zero enabler. Despite strong political momentum, the scale-up of clean hydrogen in Europe remains low. Electrolytic hydrogen capacity reached around 0.57 gigawatt (GW) in July 2025, falling significantly short of the EU's target of 6 GW electrolyzer capacity by 2024. Current projections suggest that by 2030 the EU could produce ~1.43 million tonnes (Mt) of domestic electrolytic hydrogen annually, complemented by ~0.25 Mt of imports under existing agreements. This would bring total annual electrolytic supply to roughly 1.7 Mt, requiring 7.8 GW[1] of domestic electricity, well below the EU's 2030 target of 40 GW electrolyzer capacity.[2]

Treating hydrogen as a standalone sector risks obscuring its real role in the economy. The objective is not to produce hydrogen for its own sake, but to decarbonize industrial processes and transport by replacing fossil fuels with clean electricity wherever possible. Direct electrification should remain the preferred pathway where feasible, including where it is expected to become feasible in the future, while clean hydrogen should serve primarily as an intermediary or feedstock for applications that cannot yet be electrified directly.

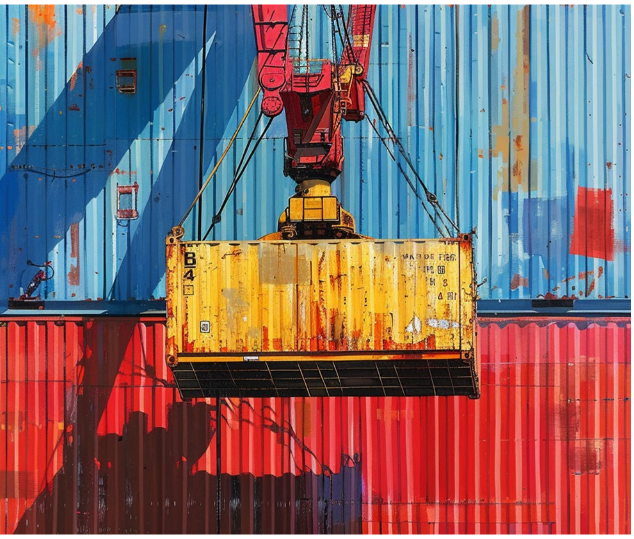
As such, policy frameworks should prioritize linking hydrogen supply to concrete industrial demand, where there are no other technically viable or cost-effective decarbonization options, rather than developing hydrogen strategies in isolation from the sectors that will ultimately use it. The implementation of science-based guardrails for hydrogen deployment will help guide the allocation of public funding within policy frameworks aimed at decarbonizing hard-to-abate sectors, anchored in Europe's Energy Efficiency First principle.

On the demand side, the EU has introduced a range of regulatory measures to stimulate a market for clean hydrogen. If effectively implemented, the revised Renewable Energy Directive (RED III) and the ReFuelEU Aviation and FuelEU Maritime regulations, could generate regulatory demand for up to 2.8 Mt of renewable fuels of non-biological origin (RFNBOs) by 2030. However, this demand is unevenly distributed across sectors. Oil refining, a deep and established market for hydrogen, is expected to emerge as the dominant driver for hydrogen production, benefiting from clearer regulatory incentives and a greater ability to absorb costs. Investments in these sectors should reflect long-term strategic industry retention: EU refining capacity has been shrinking since 2008 and investing massively in hydrogen could lead to stranded assets. Additionally, sectors such as chemicals and fertilizers face significant structural challenges, including exposure to global competition, geopolitical developments, and limited ability to pass on higher production costs. Although the Carbon Border Adjustment Mechanism (CBAM) will help mitigate carbon leakage risks for covered sectors, it does not fully offset the cost disadvantage associated with clean hydrogen or address competitiveness challenges across the wider chemicals industry.

These challenges are compounded by broader trends affecting Europe's industrial base. In 2024, Europe had approximately 11.2 Mt of installed hydrogen production capacity, the vast majority (99%) of which was fossil-based. Yet only 7.9 Mt of hydrogen was produced in 2024, indicating that a significant proportion of existing production capacity is currently underutilized. This underutilization is driven by high natural gas prices, reduced industrial activity, and global competition. The energy crisis triggered by high natural gas prices in 2022 led to widespread industrial shutdowns, many of which have not been reversed. Ammonia production in Europe has been significantly curtailed: Existing hydrogen production for ammonia is estimated to have fallen by around 40%, reflecting the severe pressure facing the fertilizer sector. This has major implications not only for industrial competitiveness, but also for EU food security. In parallel, several major facilities, including ammonia and methanol plants, were closed or mothballed in 2024. European production is increasingly being displaced by imports from regions with cheaper access to feedstocks such as naphtha and natural gas, lower energy costs, better access to abundant and cost-competitive renewable energy for green hydrogen production, and less stringent environmental constraints. Renewed geopolitical instability and rising gas prices today risk reinforcing this trend.

[1] Based on 1.43 Mt of domestic electrolytic hydrogen and assuming the electrolyzer has a capacity factor of 100%, an efficiency of 70%, and hydrogen has a lower heating value of 33.3 kWh/kg.

[2] In addition to the Hydrogen Strategy targets, REPowerEU sets a target of 10 Mt of domestic renewable hydrogen production and 10 Mt of renewable hydrogen imports by 2030.



Against this backdrop, the case for clean hydrogen is not only about decarbonization, but also about industrial resilience and strategic autonomy, provided there are no other innovative options for the sectors of the economy where it will be needed. While reducing dependence on fossil-based hydrogen[3] is associated with a structural high-cost premium, it also offers a pathway to shield European industry from volatile natural gas markets and geopolitical shocks. However, this transition will only succeed if hydrogen policy is grounded in industrial realities: Aligning supply with demand, prioritizing sectors where decarbonization via hydrogen is most urgent and viable, and ensuring that European industry remains competitive in a rapidly evolving global landscape.

These standpoints identify key industrial sectors where hydrogen use is plausible, outlining for each their current hydrogen consumption, projected demand towards 2030 and beyond, and the role of emerging alternative pathways. These innovations are critical, as they focus on electrification technologies that can reduce and potentially circumvent hydrogen requirements and infrastructure, and ease pressure on constrained supply.

Future Cleantech Architects set out the following policy recommendations for the revision of the EU Hydrogen Strategy:

**1. Adopt a Sectoral Approach and Review the Targets Allocation**

**2. Embed Guardrails into the Revised Strategy**

**3. Reframe Hydrogen Imports Toward Commodity Trade**

**4. Limit and Optimize Hydrogen Infrastructure**

**5. Revise the Hydrogen Strategy Based on Emerging Technological Innovation**

## Nomenclature

This standpoint uses terminology in line with the EU regulatory framework, including the Delegated Act specifying a methodology for assessing greenhouse gas (GHG) emissions savings from low-carbon fuels. These definitions are not merely technical: They directly shape investment decisions, infrastructure planning, electricity system development, and the pace and cost of clean hydrogen deployment across Europe.

The standpoint distinguishes between different categories of hydrogen, including renewable hydrogen and low-carbon hydrogen, in accordance with EU legislation (Figure 1). Both pathways have an essential role to play in achieving the EU's climate and industrial objectives and should be supported through a technology-neutral policy framework based on lifecycle GHG emissions.

[3] Steam methane reforming (SMR) remains the dominant industrial process for hydrogen production today. While existing SMR installations can be retrofitted with carbon capture technologies on the process gas portion of emissions, this leaves a significant portion of emissions unabated from flue gas (50–70% depending on the design). Moreover, hydrogen production with carbon capture continues to rely on fossil gas, leaving it exposed to price volatility and geopolitical risks associated with fossil fuel dependence. Carbon capture would also require costly transport and storage infrastructure.

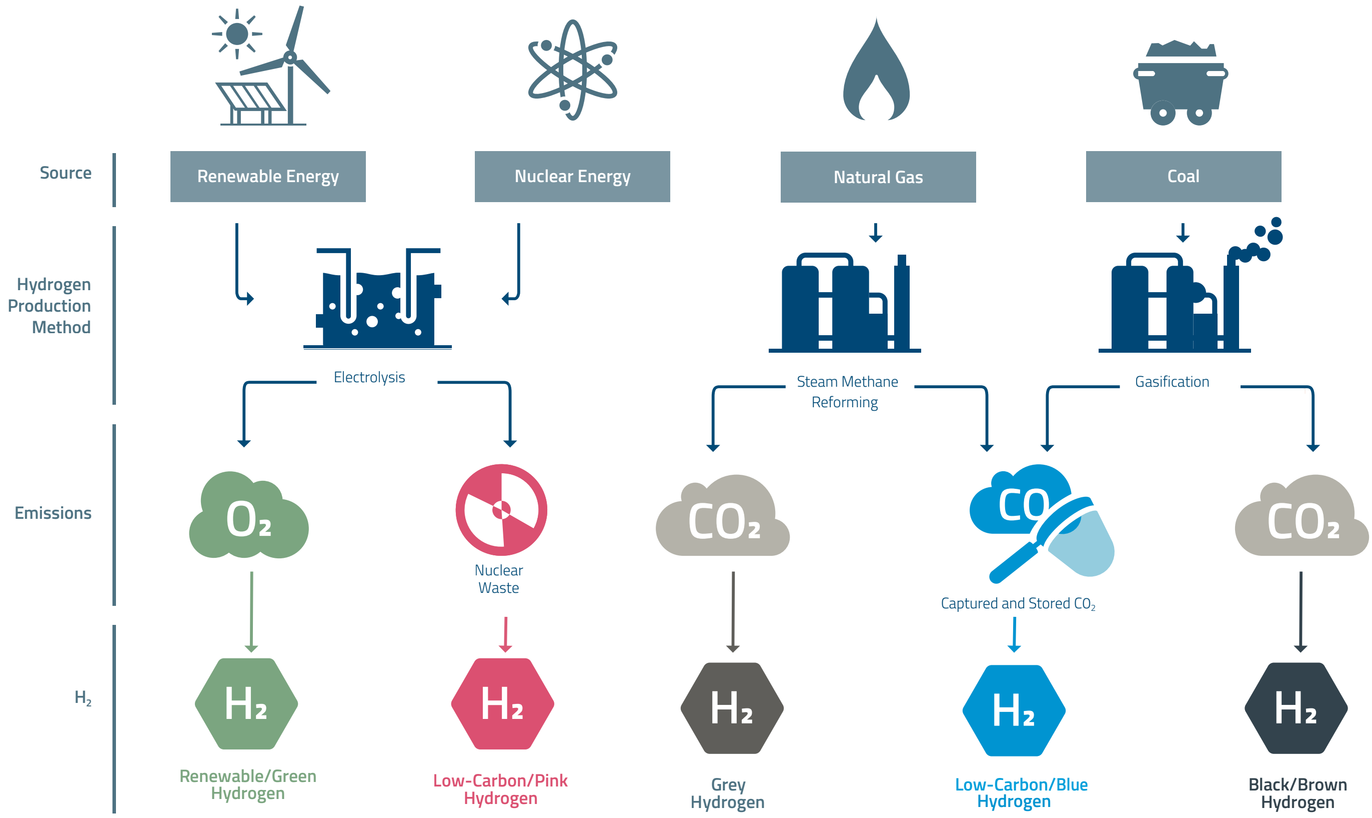



Figure 1: A visual representation of hydrogen production methods. The Low-Carbon Fuels Delegated Act does not prescribe specific production pathways: The key criterion to be low-carbon is that a fuel must be at least 70% below the unabated fossil-fuel comparator of 94 $gCO_2eq/MJ$ (i.e. <28.2 $gCO_2eq/MJ$) (adapted from Advanced Energy and Sustainability Research).

By establishing how the carbon intensity of electricity is assessed, the Delegated Act determines under which conditions grid-connected electrolyzers can produce low-carbon hydrogen. For example, Member States with highly decarbonized electricity systems (e.g. France and Sweden) are expected to qualify for low-carbon electrolytic hydrogen production using the average grid electricity mix, while producers in higher-emitting electricity systems (e.g. Germany and Poland) will generally require dedicated low-carbon electricity sourcing arrangements until grid emissions decline. This illustrates the close interaction between hydrogen policy and electricity market design.

Accordingly, this standpoint considers hydrogen deployment alongside the broader decarbonization of the electricity system, including:

- The recognition of low-carbon electricity systems under the Delegated Act.
- Access to firm dispatchable clean electricity for hydrogen production.
- The continued decarbonization and expansion of Europe's electricity grids.
- Electricity system flexibility and efficient infrastructure planning.
- The integration of hydrogen policy with wider electricity market and energy system planning.

Throughout this standpoint, clean hydrogen deployment is considered within the broader context of the energy transition. Hydrogen should complement, rather than compete with, direct electrification, as the latter is aligned with the Energy Efficiency First principle, underpinning EU's climate legislation. Scarce clean electricity resources should be allocated where they deliver the greatest system value, with direct electrification remaining the preferred option where technically and economically feasible, while clean hydrogen should be prioritized for hard-to-abate sectors where no viable alternatives exist at the moment.

Box 1

## Hydrogen and Carbon Capture, Utilization, and Storage

The interaction between clean hydrogen and CCUS presents significant challenges that should be carefully considered when assessing the role of hydrogen in decarbonization. Where hydrogen production captures $CO_2$, the need to transport and permanently store large volumes of $CO_2$ adds cost to the value chain: For every 1 kg of hydrogen produced, around 8–9 kg of $CO_2$ needs to be managed. These costs could be particularly high for first movers, as infrastructure is likely to be underutilized initially and European projects may face even higher costs due to greater reliance on transport of $CO_2$ by ship rather than pipelines. Additionally, reliance on CCUS does not eliminate the emissions associated with hydrogen production and introduces additional points of potential $CO_2$ leakage, energy use, and infrastructure dependency across the value chain. A robust assessment should consider the full system costs and emissions of CCUS-enabled hydrogen, alongside the availability of lower-emissions alternatives, and ensure that regulatory requirements do not inadvertently lock in costly or infrastructure-dependent pathways where more efficient decarbonization options exist.

# Lessons Learned

The 2020 EU Hydrogen Strategy played a central role in establishing a policy framework for the energy transition by proactively addressing the decarbonization challenge facing Europe's industry and energy system. The strategy also reflected a broader international trend. During the early stages of the energy transition countries such as Japan, which was the first country to adopt a national hydrogen strategy in 2017, as well as South Korea and Australia, increasingly viewed hydrogen as a key source of decarbonized molecules for sectors that are difficult to electrify. Against this backdrop, the EU's Hydrogen Strategy positioned Europe within a growing global effort to explore hydrogen's role in achieving climate neutrality and industrial decarbonization. In particular, it contributed to:

- Establishing hydrogen as a key decarbonization vector in EU policy.
- Setting ambitious deployment targets (6 GW by 2024 and 40 GW by 2030).
- Integrating hydrogen into broader frameworks such as REPowerEU and the Fit for 55 package.
- Establishing the European Hydrogen Bank with the purpose of bridging the cost gap between renewable and fossil-based hydrogen.
- Driving the revision of the EU Hydrogen and Decarbonized Gas Market Package by updating the rules on the EU natural gas market and introducing a new regulatory framework for dedicated hydrogen infrastructure.

It also put forward hydrogen as the central element in decarbonizing existing industrial hydrogen use, supporting hard-to-abate sectors, and enabling energy system integration. However, in hindsight, some of the underlying assumptions have proven too optimistic, particularly regarding the pace of cost reductions, infrastructure scalability, and demand uptake.

Experience since 2020 highlights several key insights:

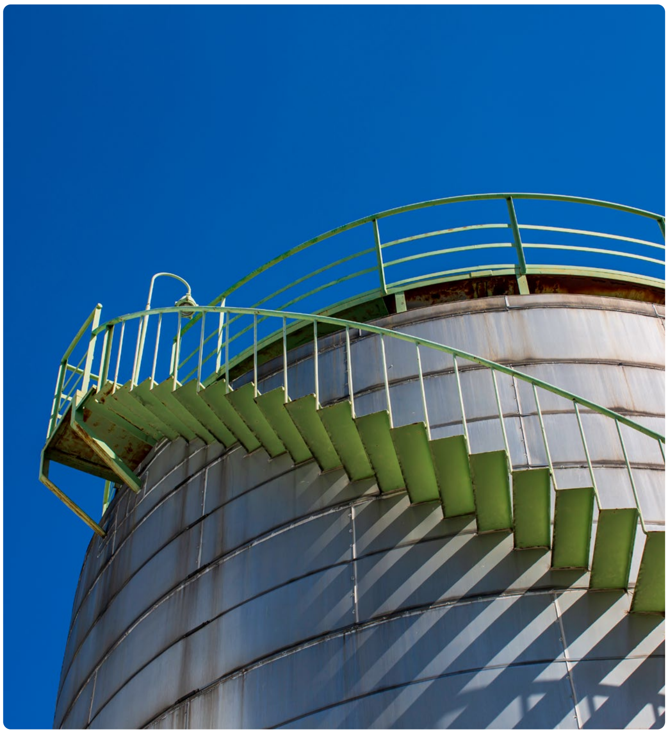
- Deployment gap: As of 2024, only ~6.4%[4] of the 6 GW electrolysis target has been achieved.
- Production dynamics: Hydrogen production potential has evolved differently than anticipated, with industrial demand remaining almost exclusively limited to existing uses due to high production costs and delayed investment decisions across the hydrogen value chain.
- Cost uncertainty: Hydrogen remains significantly more expensive than fossil alternatives and price volatility in natural gas has further complicated investment signals.
- Transport challenges: Due to its physical properties, hydrogen is costly and technically challenging to transport, particularly over long distances or via carriers.
- Infrastructure constraints: Scaling dedicated hydrogen infrastructure is capital-intensive and risks creating stranded assets, if other less costly solutions are developed in the future.
- Energy inefficiency: Compared to direct electrification, hydrogen-based electrification pathways involve substantial energy losses (often >70% from electricity to end use).
- Methane and lifecycle emissions: Emissions from upstream fossil inputs and imperfect carbon capture must be fully accounted for.
- Hydrogen leaks: Hydrogen has an indirect influence on atmospheric warming and is more prone to leak than methane.

These lessons underscore the need to shift from volume-based targets to strategic deployment in the revision of the European Hydrogen Strategy.

Box 2

## The Cost of Renewable Hydrogen

Recent evidence suggests that the cost of renewable hydrogen production in Northwestern Europe remains significantly higher than initially anticipated. Analysis of 14 large-scale electrolyzer projects currently under development estimates the levelized cost of renewable hydrogen at approximately €12–14 per kilogram of hydrogen for projects between 100–200 MW. Electricity prices remain the dominant cost component, alongside high capital expenditure, financing costs, and electricity grid tariffs. Electrolyzer investment costs have also increased in recent years due to inflation, higher material and labor costs, elevated interest rates, and supply chain constraints. While costs are expected to decline over time through industrial scaling, standardization, technological learning, and improved utilization rates, current project economics remain challenging. Policy support should therefore be limited to where direct electrification is not feasible, or where hydrogen is an indispensable molecule to complete industrial process.



[4] By September 2024, installed water electrolysis capacity in Europe reached at least 385 MWel, or around 64,000 tpa of hydrogen, which corresponds to ~6.4% of the 6 GW electrolysis target.

# Sectors in Need of Clean Hydrogen

Today, hydrogen production in the EU stands at around 7–8 Mtpa[5], but it is overwhelmingly produced from natural gas and therefore remains highly emissions-intensive. Low-carbon and renewable hydrogen still account for only a marginal share of supply, highlighting the early stage of market transformation, and challenging positive business case.

## Refineries

The refining sector is currently the largest consumer of hydrogen in Europe. Hydrogen is primarily used in hydrocracking and desulphurization processes to produce cleaner transport fuels and upgrade the bottom of the barrel into products with a viable market outlet. As such, hydrogen demand in this sector is closely linked to fossil fuel consumption and regulatory requirements for cleaner fuels. While the long-term outlook points to structural decline due to transport electrification and reduced fossil fuel use, refineries remain a key focus for near-term hydrogen decarbonization efforts.

A recent study provides a relevant framework for revisiting the EU's hydrogen strategy, as it reflects the direction of travel of Europe's decarbonization pathway: Accelerated electrification, declining demand for conventional fossil fuels, and an increasing reliance on renewable hydrogen and e-fuels for hard-to-abate sectors. Under this scenario[6], conventional refining will have a negative net cash margin, putting them at risk of closure. Refining capacity could decline dramatically, from 86 operational refineries in 2024 to only around 12 conventional refineries by 2050, with conventional refining capacity falling from 13 million barrels per day (MBPD) in 2024 to 1.7 MBPD in 2050 (Figure 2).

This profound structural shift highlights the risk of developing a hydrogen strategy that continues to incentivize investments in assets tied to today's refining model rather than the industrial assets that will remain competitive in a net-zero economy. While refineries remain essential components of Europe's energy system and petrochemical industry today, providing fuels, feedstocks, hydrogen, and industrial capabilities, their long-term role will be significantly reduced as electrification accelerates and fossil fuel demand declines. A future-oriented hydrogen strategy should therefore avoid locking in investments that could become stranded assets[7].

The expected consolidation of the global refining sector further reinforces this approach. European refiners will face increasing competition from newer, lower-cost assets in regions such as India and China, where large-scale refinery investments are still underway. As global refining capacity adjusts through 2050, Europe is unlikely to remain competitive by expanding conventional infrastructure. Instead, policy should prioritize investments in strategic assets, or assets that can remain viable in a decarbonized economy, including renewable hydrogen production, industrial processes that need clean hydrogen, and facilities capable of producing low-carbon fuels.

Finally, the role of sustainable biofuels should be clearly targeted toward sectors where direct electrification remains most challenging. Limited sustainable biomass resources should be prioritized for aviation and maritime transport, where energy density requirements make electrification difficult and where renewable hydrogen derivatives alone may not fully meet demand.

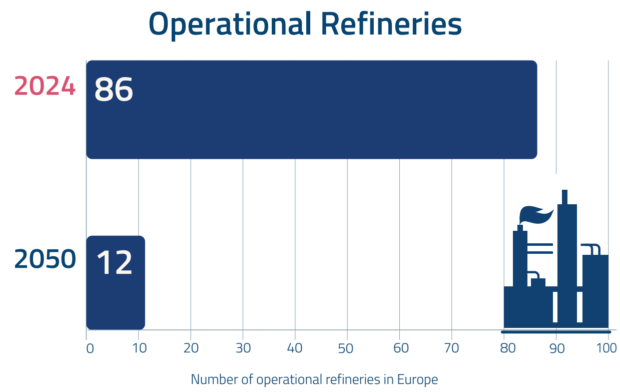
### Hydrogen Consumption Today

Refineries account for the largest share of European hydrogen demand (~58%), corresponding to roughly 4.5 Mtpa. Hydrogen is almost entirely produced on-site from natural gas: The total emissions from EU refineries in 2024 was 102 MtCO$_2$eq, making this a major source of industrial emissions.

### Projected Hydrogen Consumption

Hydrogen demand in oil refineries is expected to decline over the long term, driven by decreasing fossil fuel demand and the electrification of road transport. However, in the short to medium term, demand may be sustained by policy-driven substitution of grey hydrogen with renewable and low-carbon hydrogen alternatives. For example, the revised Renewable Energy Directive introduces targets for RFNBOs in industry, creating incentives for refineries and other industrial users to substitute grey hydrogen with lower-carbon alternatives.

Announced project pipelines indicate continued near-term demand in Europe: Around 1.4 Mtpa of clean hydrogen projects are expected in refineries by 2030, of which ~0.7 Mtpa is based on electrolysis (equivalent to ~7.1 GW of electrolysis capacity). Of this, ~0.66 Mtpa has reached an advanced stage of development. These developments suggest that despite an overall structural decline, refineries will remain an anchor market for early hydrogen deployment.



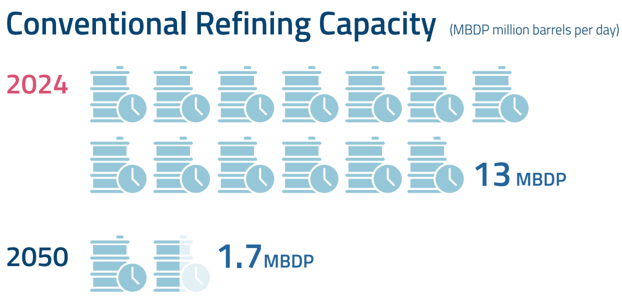




Figure 2: Conventional refining capacity is expected to decline dramatically between now and 2050 (source: Concawe and S&P Global Commodity Insight).

[5] Based on 2024 production volumes.

[6] Concawe and S&P Global Commodity Insight's Max Electron scenario

[7] While electrification will diminish sales of gasoline and diesel and severely undermine refining business models, it remains to be seen whether national policies will decide to keep these assets open given strategic considerations. For instance, current geopolitical challenges surrounding jet fuel supply have made this a strategic product and national governments may decide to keep assets open to supply this critical fuel.

## Innovative Pathways

For this analysis, Future Cleantech Architects has focused on the alternative fuel production pathways expected to support the transition of hard-to-abate transport segments, such as aviation and shipping, away from fossil fuels toward sustainable fuels and other innovative propulsion technologies. Accordingly, sustainable fuel production pathways and their respective projected hydrogen demand, are covered in the Sustainable Fuels section of this standpoint, rather than the traditional petroleum refinery section.

## Fertilizers

The fertilizer sector represents the second-largest consumer of hydrogen in Europe and one of the most established and strategically important applications of hydrogen. The purpose of fertilizers is to provide nutrients to support plant growth, in quantities which cannot be replaced solely by natural processes. In particular, the production of nitrogen fertilizers depends on large quantities of ammonia, which in turn requires hydrogen as a feedstock.

Emissions from nitrogen fertilizers are best understood across the full lifecycle. Roughly two-thirds arise at the application stage and roughly one-third from production. Within production emissions, ammonia synthesis is the largest source and is driven by the production of hydrogen from natural gas. Figure 3 shows the production process for urea, the world's most widely applied nitrogen fertilizer. Natural gas enters the process as both a feedstock for hydrogen and as fuel for high-temperature heat. The carbon contained in the natural gas is split between the flue gas vented from the plant and the $CO_2$ fixed into the urea molecule itself, which is released when the fertilizer hydrolyses in the soil. Applying urea also generates nitrous oxide, a gas with 270 times the warming effect of $CO_2$. This alone accounts for over half of the lifecycle total.

Hydrogen is an essential feedstock in ammonia production via the Haber-Bosch process. If the Haber-Bosch process is retained as a fertilizer production pathway, it is a clear "no-regret" candidate for hydrogen decarbonization. Unlike energy uses, where alternatives such as electrification may compete, hydrogen in ammonia production is largely unavoidable. However, the production of fertilizers via the

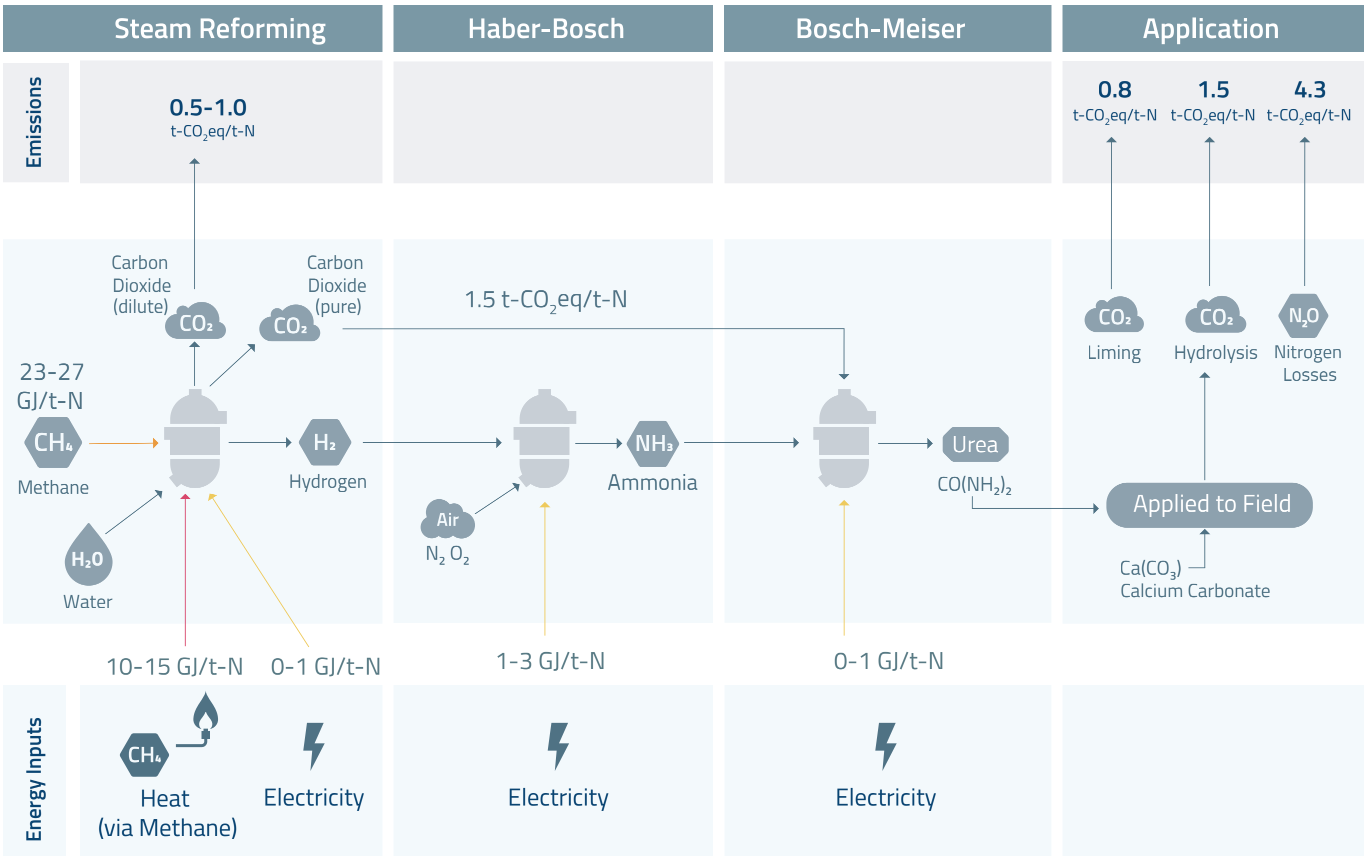



Figure 3: Urea production pathways and application showing energy inputs and GHG emissions per tonne of nitrogen. Emissions at the application stage exceed those at the production plant.

Haber-Bosch process can be side-stepped with alternative pathways. For instance, instead of ammonia, nitric acid can be produced using the electrically driven Birkeland-Eyde process. Additionally, biological routes, namely the use of manure, can also be used to displace a portion of synthetic fertilizer demand. The importance of each production pathway in the nitrogen fertilizer production system of the future depends on technological limitations, the development of biological routes, and the amount of nitrogen fertilizers that will be needed in the future. The Fertilizer Action Plan already suggests that both substitution with biofertilizers and reducing reliance on fertilizers through nutrient efficiency can be key levers in the EU.

The sector has come under significant pressure in recent years. Due to geopolitical instability and sharp fluctuations in natural gas prices, hydrogen production for ammonia in Europe has declined by approximately 40%, leading to substantial curtailments in domestic fertilizer production capacity. This erosion of competitiveness has had direct implications for Europe's industrial base and raises concerns about long-term supply security. These dynamics are also contributing to a gradual relocation of ammonia and fertilizer production capacity to regions with lower energy costs and more favorable conditions, reinforcing broader trends of industrial migration away from Europe. At the same time, Europe's reliance on imports of ammonia has increased, with growing volumes sourced from countries such as Algeria and Egypt (Figure 4), reflecting a structural shift in supply chains towards external producers.

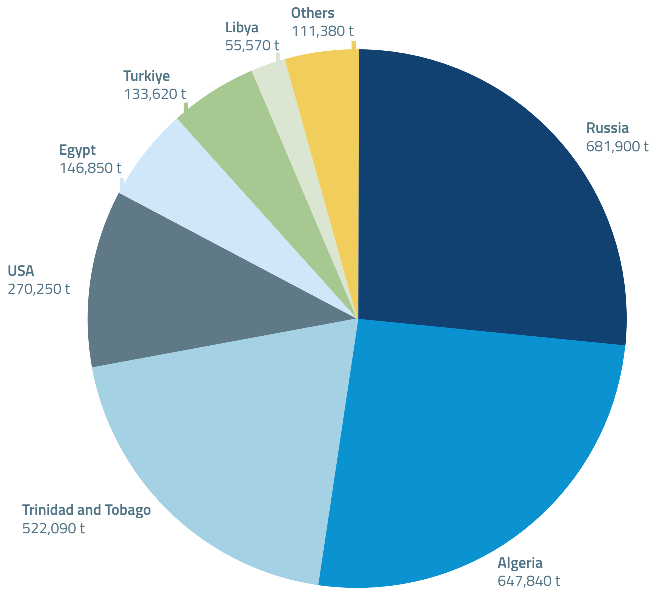



Figure 4: Ammonia imports into the EU were 2.57 Mt in 2025, of which a third came from Northern Africa (based on data from the European Commission).

Beyond ammonia imports, the EU has also become increasingly reliant on imports of nitrogenous fertilizers, with volumes rising exponentially in 2022 when Russia invaded Ukraine (Figure 5). This growing dependence has implications for future fertilizer security, price stability, and the resilience of the EU's agriculture sector.

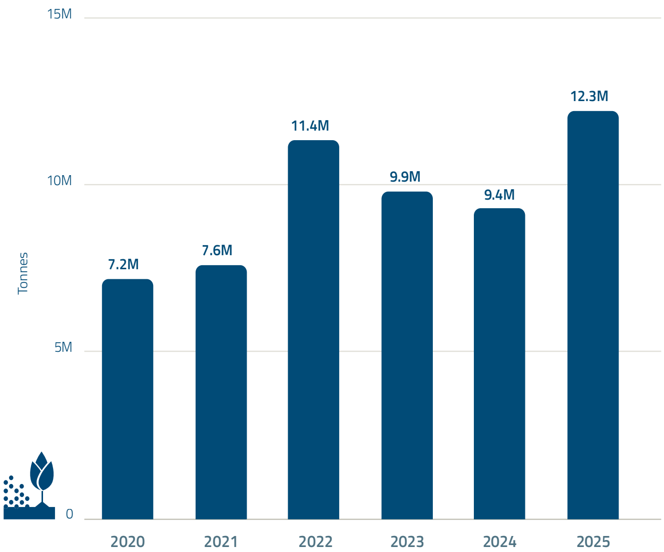



Figure 5: Nitrogenous fertilizer imports into the EU were 12.27 Mt in 2025, compared to pre-war levels of 7.62 Mt in 2021 (based on data from the European Commission).

## Hydrogen Consumption Today

The annual demand for fertilizers in Europe is largely set by the surface area of arable land. This has remained relatively constant at 97 million hectares with a fertilizer application rate of 90–100 kg per hectare.[8] In the past, more effective application of fertilizer has resulted in more efficient use of this arable area, but these returns are diminishing and smaller in magnitude.

Today, ammonia production accounts for approximately 25% of EU hydrogen demand, corresponding to ~2 Mtpa.[9] This hydrogen is primarily produced from the steam reforming of natural gas, and results in significant $CO_2$ emissions. The EU ammonia industry has a maximum annual output capacity of 17 Mt. However, due to unfavorable business conditions relating to natural gas price volatility, ammonia plants typically operate under rated capacity. In 2023 total EU production was 10.5 Mt, implying a 60% capacity factor.

## Projected Hydrogen Consumption

Projected hydrogen consumption is highly dependent on the decarbonization technology deployed. However, if European hydrogen production for ammonia synthesis for chemicals was to return to its pre-war levels of production[10] it would require approximately 3.1 Mt of hydrogen per year. The main decarbonization options can broadly be categorized into three groups:

- **i) Carbon capture and storage:** The incumbent steam methane reforming (SMR) and Haber-Bosch processes are retained and retrofitted with carbon capture to abate $CO_2$ emissions. By adding a capture unit, this pathway inherently carries the incumbent's costs plus the capital, energy, and transport-and-storage costs of $CO_2$ capture. It is also never fully abated: The concentrated process stream is readily captured, but the fuel-combustion fraction is harder and costlier to remove, meaning that residual emissions will always remain.

[8] Nitrogen-type fertilizer.

[9] An additional 2–2.5 Mtpa of ammonia is imported.

[10] Which is approximately 40% higher than it is today.

- **ii) Electrolysis with renewable electricity:** The Haber-Bosch process is maintained for ammonia production and SMR is replaced with hydrogen production via water electrolysis which is powered by renewable electricity. This route is not yet deployed at scale and further complications arise for urea, the most widely used global fertilizer. Urea is made by combining ammonia with $CO_2$ and in a conventional plant this $CO_2$ is supplied by the SMR process gas. Removing SMR therefore removes the $CO_2$ feed, so urea production would need a stable stream of biogenic or air-captured $CO_2$, the latter of which is very energy intensive.

- **iii) Innovative electrical pathways:** Technologies which use renewable electricity to replace both SMR and Haber-Bosch, including plasma and electrochemical routes. These are at an earlier stage of deployment, but they sidestep natural gas as a feedstock entirely.

Routes ii and iii will require a significant increase in electricity consumption and the continued build-out of renewable generation, whereas route i remains predominantly reliant on natural gas. The proportion of fertilizer production from these three technologies, in Europe, will determine the demand for hydrogen and electricity, and is an area of active work.

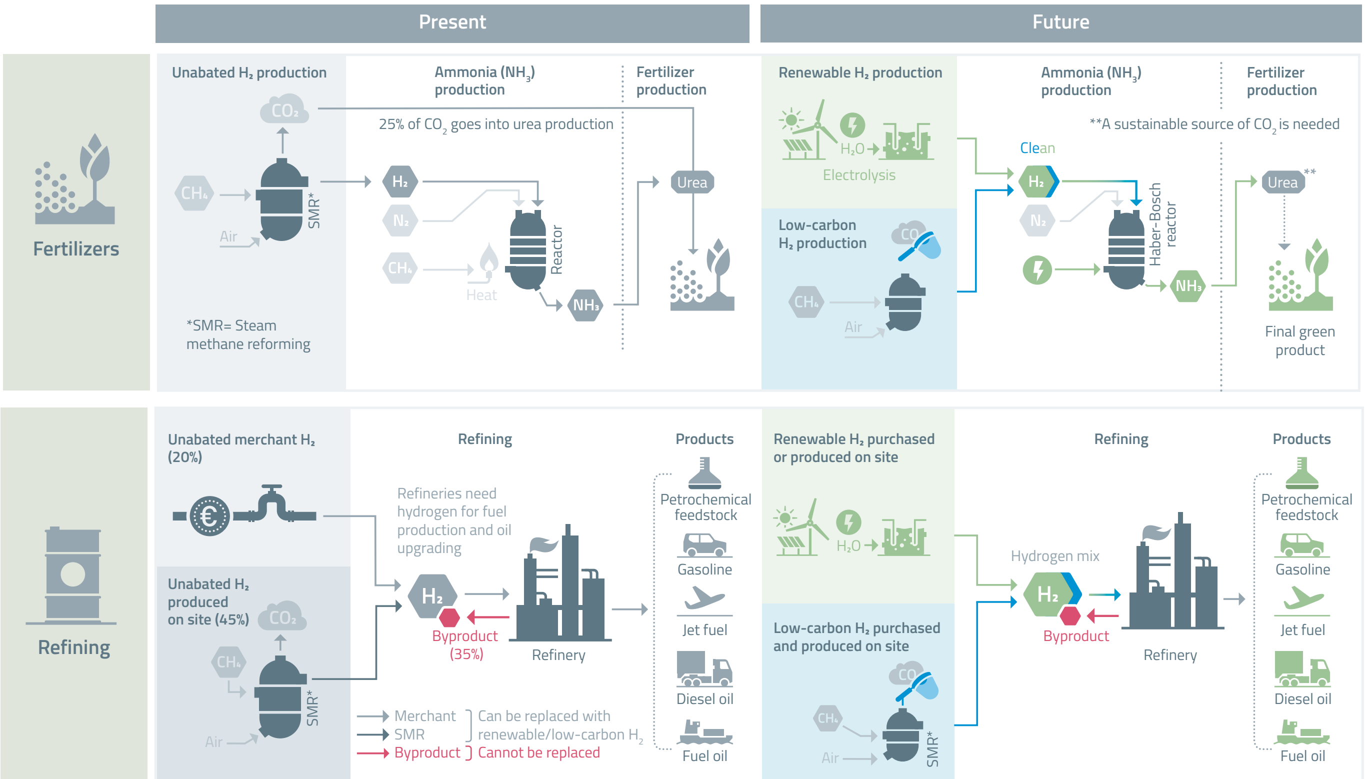
## Innovative Pathways

### Birkeland-Eyde Plasma

The Birkeland-Eyde process represents one of the earliest industrial attempts to produce nitrogen-based fertilizers using electricity rather than fossil fuels. Originally developed in the early 20th century, it used high-temperature electric arcs to fix atmospheric nitrogen into reactive nitrogen oxides, which could then be converted into nitric acid and downstream fertilizers. Although historically displaced by the more energy-efficient Haber-Bosch process, the concept has regained attention in modern discussions on plasma-based nitrogen fixation as part of broader efforts to decarbonize ammonia production.[11]

Recent technological developments have revisited plasma-based nitrogen fixation as a potential low-carbon route for fertilizer production. These systems use non-thermal plasma to activate nitrogen and oxygen in the air, producing reactive nitrogen species that can be converted into nitrates or combined with hydrogen-derived intermediates to form ammonia or ammonium-based fertilizers. In principle, this approach eliminates the need for conventional natural gas-based hydrogen production, thereby offering a pathway that is fully electrified and potentially compatible with renewable electricity systems.

Table 1: Several high-emitting sectors of the economy are, or will be, dependent on hydrogen. Considering that clean hydrogen will remain scarce and expensive for decades to come, the refining and fertilizer sectors should have priority access to clean hydrogen before introducing it into additional sectors.




[11] EU start-ups developing Birkeland-Eyde plasma technologies include NitroCapt and VitalFluid.

However, despite its conceptual appeal, plasma-based nitrogen fixation remains at an early stage of technological maturity and faces significant efficiency challenges.[12] Energy consumption remains substantially higher than for Haber-Bosch ammonia synthesis, and conversion efficiencies are still relatively low at scale. As a result, its role in the medium term is expected to be niche, potentially focused on decentralized or modular fertilizer production applications rather than large-scale commodity ammonia markets.

From a system perspective, the key advantage of plasma-based routes lies in their ability to decouple fertilizer production from both fossil gas and hydrogen infrastructure. This could reduce exposure to volatile gas markets and supply chain constraints in ammonia production. Nevertheless, significant research and development (R&D), scale-up, and integration with renewable electricity systems would be required before such technologies could make a material contribution to European fertilizer supply.

### Electrochemical Ammonia Synthesis

Electrochemical ammonia synthesis uses specialized electrolyzers to directly produce ammonia from water and air. The electrolyzer consists of an anode and cathode submerged in an electrolyte and separated by a membrane. When electricity is applied across the anode and cathode, an electrochemical reaction takes place. On the anode-side of the electrolyzer, water is split into oxygen gas and protons. The protons transport through the membrane to the cathode-side, where they combine with nitrogen from the air and electrons to directly form ammonia. By modifying the composition of the electrolyte and catalysts, power consumption can be optimized. However, ammonia production is not favored at higher currents, meaning there is a trade-off between keeping the current low enough to favor ammonia production, and high enough to produce a worthwhile quantity.

Electrochemical ammonia synthesis is being pursued by a few start-ups[13], however the largest challenge remains the high electricity consumption, which increases the cost of ammonia produced. In addition, if the ammonia is used for the production of urea, the process also requires an alternative source of carbon, which is provided by $CO_2$ in the incumbent process.

Box 3

## Methanol

Methanol is the second largest emitter in the chemical sector, after ammonia. The chemicals sector represents a diverse and strategically important area of hydrogen use, where it serves as both a feedstock and a process gas across a wide range of applications. These include methanol production as well as downstream products such as plastics, solvents, and intermediates (e.g. hydrogen peroxide, cyclohexane, aniline, and oxo-alcohols). Unlike sectors with more uniform demand profiles, hydrogen use in chemicals is highly heterogeneous and closely tied to global value chains and trade dynamics. Europe relies heavily on gas imports to meet grey hydrogen demand for key chemical products such as methanol, highlighting both vulnerabilities and opportunities in the transition to clean hydrogen.

### Hydrogen Consumption Today

In the EU, methanol is the third largest consumer of hydrogen, after refining and ammonia production. Production and consumption of hydrogen is internal to conventional methanol synthesis processes which use natural gas as a feedstock and produce excess grey hydrogen. Domestic methanol production in Europe is limited, covering only a small fraction of demand. Around 80% of Europe's methanol supply is imported, while domestic production accounts for roughly 0.16 Mt of hydrogen demand per year (~2% of total European hydrogen use in 2023). This reliance on imports underscores the globalized nature of the chemicals sector and raises strategic considerations for industrial competitiveness and supply chain resilience in the context of decarbonization.

### Projected Hydrogen Consumption

Moderate growth is expected in methanol production: Announced e-methanol projects could produce up to 1.1 Mtpa (~9.6GWel) of hydrogen as feedstock for clean methanol by 2030, with 0.3 Mtpa in advanced stages, which is twice the total current demand.

### Innovative Pathways

The European (petro)chemical industry faces significant challenges that include, but are not limited to global overcapacity challenges, and feedstock availability at competitive costs. For example, some of these resources, natural gas or lighter hydrocarbons such as ethane, have become available in other jurisdictions, including the United States and China, at prices significantly below import prices in Europe. The complexity of the chemicals value chain does not allow for broad statements of what hydrogen use could be replaced and its integrated nature presents a uniquely fragile economic environment once certain thresholds for input prices are reached.

Innovative configurations to source carbon for the chemicals industry will cause increased hydrogen demand, replacing natural gas and refinery sourced feedstock with easier to transport carbon feedstock sources. Decoupled from this, changes in demand patterns for fossil products and associated demand for hydrogen in refineries could plausibly increase or decrease, making concrete predictions sensitive to scenario assumptions.

Future Cleantech Architects is currently conducting research on potential innovative pathways to source carbon feedstock for the (petro)chemical industry, decoupling its feedstock from refineries and gas value chains.[14] This analysis will be paired with an estimation of potential hydrogen demand for this sector.

[12] The Birkeland-Eyde process ran commercially at large-scale in Norway from 1905 to1930, using cheap local hydroelectricity to fix 38,000 tonnes of nitrogen per year. It was displaced by the Haber-Bosch process, which needed only 10-20% of the energy per tonne of nitrogen and could run on cheap fossil fuels.

[13] EU start-ups developing electrochemical ammonia synthesis technologies include NitroVolt.

[14] These pathways exclude atmospheric $CO_2$ or biogenic sources.

## Steel

The decarbonization of the steel sector presents significant system-wide challenges, particularly due to its high energy intensity and reliance on fossil fuels in primary production. Transitioning to hydrogen-based steelmaking, specifically via direct reduced iron (DRI) combined with electric arc furnaces (EAF), would require substantial volumes of clean electricity. Producing 71.8 Mt[15] of green primary steel via a hydrogen-based DRI-EAF would require ~294 TWh of electricity [16], which is more than Spain's total 2024 electricity consumption.[17] This underscores the system-wide implications of Europe's energy system, where clean power must also support electrification in transport, buildings, and other industrial uses.[18] Without access to sufficient volumes of affordable and abundant clean power, industrial decarbonization risks crowding out higher-value uses and placing sustained pressure on Europe's power system.

The DRI-EAF pathway is currently the most mature and commercially advanced low-carbon alternative to the conventional blast furnace-basic oxygen furnace (BF-BOF) route. In this process, iron ore is reduced to sponge iron using a reducing gas (either natural gas or hydrogen) and subsequently melted in an EAF. When powered by renewable or low-carbon electricity and supplied with clean hydrogen, this pathway can enable near-zero emissions primary steel production.

However, its large-scale deployment also introduces new vulnerabilities including the need for high grade iron ore. Globally only around 4% of traded iron ore is suitable as DR-grade feedstock. This pathway is also highly dependent on the availability of low-cost renewable electricity to produce competitively priced hydrogen, which remains constrained in Europe. These dependencies highlight broader system risks around import reliance and input cost exposure, particularly in scenarios where hydrogen is expected to be transported over long distances. This reinforces the importance of considering hydrogen not in isolation, but as part of broader commodity value chains.

### Hydrogen Consumption Today

Hydrogen consumption in the steel sector is currently minimal, accounting for approximately 5% of total hydrogen demand. Its use is largely limited to niche applications, with negligible deployment in primary steel production processes.

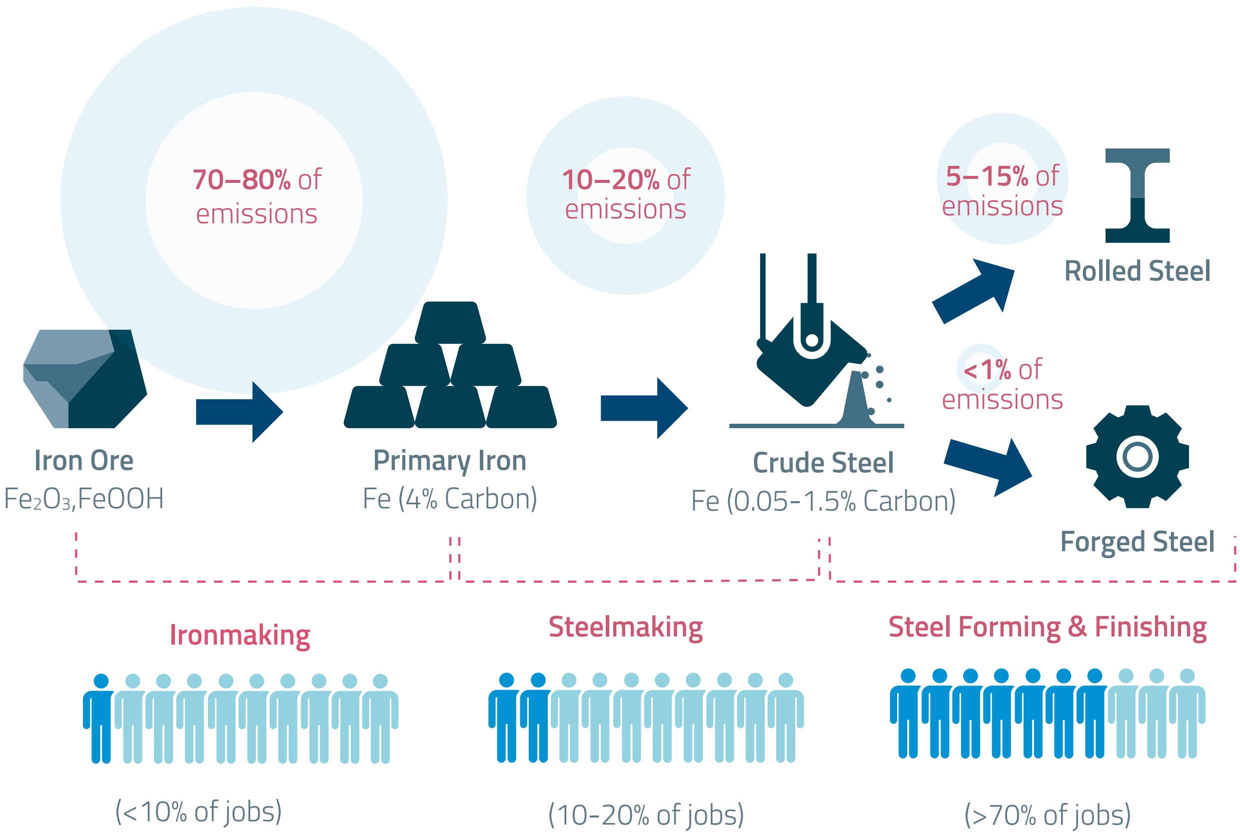



Figure 6: Ironmaking is both the highest emitting and lowest value-added step in the steel value chain, while most added value lies within the steelmaking, forming, and finishing section.

[15] The EU's 2024 primary steel production volume.

[16] Assuming total metallic charge requirement of 1.2 t/t of crude steel; 20% scrap share in the metallic charge; and hydrogen consumption of 50 kg hydrogen per tonne of DRI. This corresponds to ~60 kg hydrogen per tonne of steel in a fully DRI-based charge (0% scrap), and ~48 kg hydrogen per tonne of steel under the 20% scrap assumption applied here. Further assumptions: 55 kWh/kg hydrogen for electrolysis; 489 kWh/t steel for EAF steelmaking; 177 kWh/t DRI for DRI auxiliaries; and 828 kWh/t DRI for DRI process heat.

[17] Spanish total electricity consumption in 2024 was 252.6 TWh (based on calculations of total 2024 electricity consumption per capita and Spanish population in 2024).

[18] For further information see Future Cleantech Architects' Hydrogen Guardrails.

## Projected Hydrogen Consumption

Hydrogen demand in the steel sector between now and 2030 is expected to reach around 0.2–1.8 Mtpa[19], depending on the status and timeline of announced projects, as well as the fuel pathway adopted across different production routes. A full transition of the EU steel sector[20] based on hydrogen-enabled production pathways would require 3.5 Mt of hydrogen annually.[21] However, when projecting 2030 steel demand[22], this requirement could increase to approximately 4.3 Mtpa.[23]

## Alternative Pathways

While hydrogen-based DRI is currently considered the most mature low-carbon primary steelmaking route, its large-scale deployment in the EU is constrained by the availability of low-cost renewable electricity, hydrogen production capacity, and extensive transport and storage infrastructure. These constraints introduce both cost and system risks, particularly in regions with limited access to abundant renewable energy.

In this context, there is a growing rationale for considering approaches that partially circumvent hydrogen by shifting decarbonization upstream in the value chain. A key alternative is the production of iron in regions with favorable renewable energy resources such as Australia and Brazil, followed by export to Europe in the form of hot briquetted iron (HBI). Transporting hydrogen itself is inefficient and costly, whereas HBI is a stable, energy-dense product well suited for long-distance bulk shipping. This enables more efficient global logistics while avoiding the need for dedicated hydrogen transport and storage infrastructure.

Such a model also supports a broader strategic reframing of industrial value chains. Rather than focusing exclusively on hydrogen imports or domestic hydrogen-based ironmaking, decarbonization can be achieved through diversified supply chains for low-carbon iron inputs. This approach can improve resilience, reduce infrastructure bottlenecks, and potentially lower system costs, while maintaining Europe's focus on high-value downstream activities such as steelmaking, finishing, and advanced manufacturing, where most of the industrial added value and quality employment is generated (Figure 6).[24]

In addition, complementary technological pathways such as direct electrification further expand the range of options available. These routes eliminate hydrogen entirely by using electricity to directly reduce iron ore, and the need to deploy high-grade iron ore, reinforcing the need to evaluate hydrogen-based steelmaking as part of a broader portfolio of industrial decarbonization strategies rather than as a single dominant pathway.

## Innovative Pathways

### Molten Oxide Electrolysis and Electrowinning

Emerging direct electrification technologies, including molten oxide electrolysis (MOE) and iron ore electrowinning, offer a longer-term alternative (post-2035) bypassing both fossil fuels and hydrogen. These processes rely on electrochemical reactions to reduce iron ore directly, potentially enabling near-zero emissions steel production when powered by renewable electricity. However, they remain at earlier stages of technological readiness and would require substantial expansion of electricity generation capacity and grid infrastructure to scale.

A key structural distinction between these technologies and hydrogen-based DRI lies in feedstock flexibility. Hydrogen-based DRI generally relies on high-grade, low-impurity DR-grade iron ore, reinforcing dependence on a relatively constrained market for premium ore products. Electrochemical ironmaking routes such as MOE are able to accommodate a wider range of iron ore qualities and feedstocks than conventional DRI processes, potentially reducing exposure to bottlenecks in DR-grade ore supply. In the long term, this could also reduce beneficiation and pelletization requirements and improve overall resource efficiency, although commercial-scale evidence remains limited.

Achieving climate neutrality in the steel sector will therefore require sustained investment in a portfolio of innovative production pathways. While hydrogen-based routes are expected to play a role in the 2030s, breakthrough electrification technologies and hybrid configurations will be critical in the longer term. These approaches can help reduce dependence on constrained input markets, improve system efficiency, and diversify technology risks, while also strengthening Europe's competitiveness in emerging low-carbon steel value chains. However, their contribution before 2035 is likely to remain limited without targeted support for R&D and large-scale demonstration.

[19] Based on 2026 data from the Global Energy Monitor and FCA calculations.

[20] Based on 2024 primary production volumes.

[21] This projection reflects a transition scenario based largely on the assumption of widespread substitution of the existing primary steelmaking fleet with hydrogen-based DRI-EAF routes. It does not account for alternative decarbonization pathways, including direct electrification options or structural changes to the iron and steel value chain. It excludes scenarios based on the import of HBI which represent a fundamentally different organization of global production.

[22] Based on 2030 demand projections by IDDRI, applying a 2024 primary production share.

[23] Figures are based on a total metallic charge requirement of 1.2 t/t of crude steel; 20% scrap share in the metallic charge; hydrogen consumption of 50 kg hydrogen per tonne of DRI.

[24] For further information see Future Cleantech Architects' Policy Briefing on Decarbonizing Iron and Steel.

Table 2: Advantages and Challenges per Production Pathway

**DRI-EAF**: DRI-EAF represents a technology family that can operate using natural gas, low-carbon hydrogen, or renewable hydrogen, with emissions and costs primarily determined by the energy source rather than the core process configuration.

| Advantages | Challenges |
|---|---|
| Significantly lower emissions than BF-BOF | Cost linked to gas or hydrogen price |
| Commercially mature process architecture | Renewable and low-carbon hydrogen currently expensive in Europe |
| Allows staged transition from gas to hydrogen | Requires large-scale hydrogen infrastructure for full decarbonization |
| Enables global trade of low-carbon iron (HBI) | Requires substantial investment into electricity production and grid expansion in the case of electrolytic hydrogen |
| Compatible with EU 2050 decarbonization targets (with renewable hydrogen) | Hydrogen transport is costly and infrastructure is slow to deploy |
| Flexible EAF input mix (DRI + scrap) | Globally traded DR-grade iron ore supply limited (~4%) |
| Strong industry investment momentum | Methane and hydrogen leakage risk (for gas-based routes) |
| | Upstream emissions remain |

**Direct electrification (MOE and electrowinning )**: While both routes bypass hydrogen by using electricity directly, MOE is designed for large-scale molten iron production at very high temperatures, whereas electrowinning operates at lower temperatures but remains at an earlier stage of technical and industrial development.

| Advantages | Challenges |
|---|---|
| Potential for near-zero direct $CO_2$ emissions when powered by clean electricity | Cost linked to electricity prices |
| Eliminates need for hydrogen production, transport, and storage infrastructure | Very early commercial maturity (pilot or lab stage; no full industrial reference plants) |
| Avoids reliance on coal, coke, natural gas, or hydrogen supply chains, and associated upstream emissions/leaks | High electricity demand and need for continuous, high-quality grid connection |
| Fundamentally redesigns ironmaking chemistry rather than modifying fossil routes | Large-scale system integration and grid planning required |
| Potential to simplify plant design and reduce process steps | Commercial cost competitiveness not yet demonstrated |
| Potential to use a wider range of ore qualities (especially MOE, and potentially some electrowinning concepts) | Significant technology readiness level (TRL) gap remains before industrial deployment |
| Potential for modular and geographically flexible deployment | Ore preprocessing requirements (especially for electrowinning) add cost and complexity |
| Builds on electrolysis experience from other metals sectors (for electrowinning) | Materials durability, electrolyte stability, and current efficiency still under development |
| Long-term strategic option for regions with abundant low-cost clean electricity | Production rates currently lower than conventional routes |
| | Uncertain timeline for large-scale contribution to emissions reduction (likely post-2035) |

## Sustainable Fuels for Shipping and Aviation

### Sustainable Aviation Fuels

Hydrogen-derived fuels, particularly sustainable aviation fuels (SAF) such as e-kerosene, represent one of the few scalable decarbonization options for aviation, where direct electrification is not currently feasible for widespread deployment. These fuels are produced by combining clean hydrogen with renewable carbon sources to create low-carbon alternatives to conventional jet fuels. While their production is highly energy-intensive and requires significant amounts of clean electricity, their strategic importance lies in enabling emissions reductions in sectors with limited technological alternatives, making SAF a key component of Europe's long-term aviation decarbonization strategy.

#### Hydrogen Consumption Today

Current hydrogen use for SAF remains negligible, as most projects are still at pilot or demonstration stage. Deployment of e-fuels has yet to reach commercial scale, and existing hydrogen consumption in transport is largely limited to conventional refining processes rather than dedicated fuel synthesis.

#### Projected Hydrogen Consumption

Hydrogen demand for SAF is expected to grow rapidly over the coming decades, reaching 13.2 Mt in 2050. This growth is primarily driven by EU regulatory frameworks, including the ReFuelEU Aviation regulation, which mandates and heavily promotes the uptake of sustainable fuels in aviation. Despite strong policy support, large-scale deployment faces several structural constraints:

- Low or non-existent availability of the required energy inputs.
- High costs, driven by the price of clean hydrogen and renewable electricity.
- Low overall energy efficiency, as multiple conversion steps are required from electricity to fuel.
- Significant infrastructure needs, including $CO_2$ supply chains for e-fuels, fuel distribution systems, and port and airport integration.
- Regulatory uncertainty with doubts about the survival of near-term targets and the rules underpinning RFNBO production.

These factors are likely to limit uptake in the near term, with stronger growth expected post-2035 as technologies mature and costs decline.

The use of these fuels will involve a trade-off between maximizing domestic production for energy independence and avoiding net increases in emissions. The energy-intensive production of these fuels depends on the availability of large amounts of renewable energy, which may often be located abroad. For these reasons, the use of a book and claim system or the import of such fuels from certain parts of Europe or third countries may be preferable if the EU is to avoid the risk of induced emissions.[25] Furthermore, the use of such fuels must adhere to the Energy Efficiency First principle, and recent proposals to incentivize their uptake in road transport where electrification offers the best technological solution, risk diverting precious resources away from where they are needed most with knock-on effects for decarbonization across the entire transport sector.

#### Innovative Pathways

**Production of synthetic kerosene (e-SAF)**

To meet ReFuelEU Aviation's targets for e-SAF, an exponential rise in renewable electricity is required. An additional 23 TWh of renewable electricity is needed by 2030, rising to 872 TWh annually by 2050. Synthetic jet fuel will consume 13.2 Mt of green hydrogen in 2050, which is ~90% more than today's entire EU hydrogen demand, 99% of which is still made with fossil fuels.

While synthetic fuels are a promising pathway, the energy input that will be required as the targets increase are significant and will depend on an abundance of renewable energies. In the absence of affordable, clean electricity, and with the possibility of greater GHG emission reductions through the use of these energy inputs in other sectors, greater flexibility could be introduced in the form of a book and claim system. This would allow e-SAF production to be concentrated where such energy is abundant and does not lead to induced emissions.

[25] A study by Sandbag illustrates how there is a risk of a net increase in $CO_2$ emissions resulting from the production of hydrogen during periods where there is limited renewable energy supply. The resulting emissions under different scenarios can vary significantly within a range of 5-30 $tCO_2$ per tonne of hydrogen produced on average across member states. For these reasons, they recommend extreme caution on the timing of electricity use, with the incentivization of RFNBOs in areas such as road transport possibly creating a vicious cycle of inefficiency that pushes energy demand higher.

Today, around 40 planned production sites for synthetic jet fuels have yet to achieve a final investment decision (FID), and this is despite the legally binding targets for e-kerosene that are in place under ReFuelEU which will come into force in 2030. The reasons for this are varied, including enduring uncertainties around pricing, revenues, contracts, and the viability of the existing targets. While efforts are now underway to address some of these problems, the European Commission has also proposed a targeted review of the production criteria for renewable hydrogen, which were designed to avoid induced emissions through the introduction of additionality and temporal and geographic correlation criteria. While these rules are not perfect, to weaken these requirements at this juncture would mean that synthetic fuel production poses an even greater induced emissions risk. In tandem, it is crucial that the EU focuses on generating abundant, homegrown clean power to help meet these additional energy demands stemming from targets in the transport sector.

### Low aromatic and sulfur conventional jet fuel

The EU must urgently put in place a framework to reduce the non-$CO_2$ impacts of aviation, responsible for more than 60% of aviation's global warming impact. Despite this outsized impact, the solutions on offer are relatively cheap and implementable in the short-term, including reducing the aromatic content and other chemical compounds in the fuel, which are linked to soot formation that is responsible for warming impacts in addition to negative health impacts. Current aromatic content in jet fuel exceeds the minimum safety limit of 8%. This can be reduced through further treatment of the fuel in refineries, but this comes with increased $CO_2$ emissions and higher costs, although they would still be lower than current SAF prices.

Efforts to increase blending of fossil-based jet fuel with SAF should in theory help to reduce the final aromatic content of jet fuel, as SAFs generally contain little to no aromatics. However, the majority of jet fuel will remain fossil-based for decades to come under existing EU rules. With the possibility that small volumes of SAF are blended with high-aromatic conventional fossil kerosene, the climate benefit from SAF may be reduced or negated if action is not taken on aromatics. The ReFuelEU Aviation regulation introduced a monitoring, reporting and verification system (MRV) for aromatic, naphthalene, and sulfur in jet fuel. Although only based on 16% of total fuel supplied in the EU in 2024, initial results from the MRV showed that the weighted average for aromatics was 17.09 vol %. This is significantly higher than the 8% minimum and shows that aromatic and sulfur levels in conventional fossil kerosene could be lowered to still respect the limits set by existing standards. This represents a logical next step for the MRV that could help reduce the climate impact of aviation. The hydrogen required to reduce aromatic and sulfur content in 1 ton of kerosene is a fraction of the hydrogen required to produce 1 ton of synthetic fuel and would therefore be a worthy complementary measure to the production of SAF.[26]

### Alternative Propulsion Technologies

While hydrogen-based fuels will play an important role in the decarbonization of aviation and shipping, alternative propulsion technologies can offer an effective decarbonization pathway in certain segments. Electric planes are expected to be able to compete with conventional aircraft on short-range flights with limited passenger capacity in the near-term, with small two-seater electric aircraft are already in use. Larger electric aircraft are currently only at the testing or design phase but are expected to be much more efficient and much less polluting than conventional jet fuel and e-SAF.[27]

To cater to longer distances and higher capacities beyond 2050, major breakthroughs in battery technologies will be needed, which is why hybrid-electric aircraft may represent an important bridging solution that can reduce fuel consumption. Ambitious deployment of all-electric and hydrogen aircraft on flights under 4000km by 2050 could help reduce the sector's total warming impact globally by 17%, which includes in-flight $CO_2$ and non-$CO_2$ emissions, as well as upstream emissions. It is crucial therefore that the EU and member states invest in R&D in electric and hybrid-electric aircraft technologies and create a framework to promote the rollout of these technologies, including through public service obligations, allowances under the EU Emissions Trading System (ETS) that mirror those for SAF, and incentives through the EU's slot allocation framework.


## Sustainable Shipping Fuels

The shipping sector is one of the most difficult sectors to decarbonize. The most appropriate solution will vary by vessel type, route, fuel availability, and access to bunkering infrastructure. Low-carbon fuel options are broadly limited to two categories: Biofuels and hydrogen-based fuels. The latter encompasses compressed or liquefied hydrogen, as well as synthetic fuels derived from hydrogen, including e-ammonia, e-methanol, and synthetic liquefied natural gas (e-LNG). For deep-sea shipping, hydrogen-based fuels and bioenergy are widely considered the only scalable decarbonization pathway at present, though nuclear propulsion has emerged as a potential long-term alternative for larger vessel types.

[26] This is why it might be important to use 100% SAF on flights that would otherwise generate the most contrails.

[27] Estimated to be 2.1 to 3.2 times more energy efficient in operation than fossil-fueled aircraft, and 4.5-6.9 times more energy efficient than e-SAF. If powered by electricity from the grid in the United States, electric aircraft could offer a 49-57% reduction in carbon intensity per revenue passenger kilometer when compared to fossil-fueled aircraft, or 82-88% where batteries are charged using renewable energy.

## Hydrogen Consumption Today

In 2023, water transport represented 12% of final energy consumption across all transport modes in Europe. Under the scope of the FuelEU Maritime regulation and the EU ETS, EU shipping consumed around 29 Mtpa of final energy consumption (28.2 Mtoe)[28] in 2023, 97% of which was fuel oil and marine gas or diesel oil. In terms of shipping fuel demand, this rose by 4.9 Mt in 2024 to reach 46.3 Mt, driven by containerships taking longer routes around the Cape of Good Hope to avoid conflict in the Red Sea.

Various shipping fuels require hydrogen as a key input in their production. Grey ammonia and methanol both rely on hydrogen derived from SMR of natural gas, while their low-carbon counterparts, e-ammonia and e-methanol, replace this with green hydrogen produced via electrolysis. e-LNG and synthetic marine diesel oil (e-MDO) are produced from green hydrogen and captured $CO_2$ via the Sabatier and Fischer-Tropsch processes, respectively. e-LNG and e-MDO carry an extra conversion step layered on top of already costly green hydrogen with liquefaction alone consuming 30–40% of that hydrogen's energy content.[29] Certain biofuels also require hydrogen: Hydrotreated vegetable oil (HVO) uses hydrogen in the hydrotreatment process to remove oxygen from lipid feedstocks and hydrogen can improve output and optimize yields during bio-methanol synthesis. Currently around 95% of hydrogen needed as part of the HVO production process comes from natural gas.

## Projected Hydrogen Consumption

The relative scale of any single fuel or technology pathway remains uncertain at this stage. What is clearer, however, is that hydrogen demand from shipping will not come from its direct use as a fuel. Instead, hydrogen will primarily serve as a feedstock for derivative fuels, such as e-ammonia and e-methanol, which offer significantly better energy density and are more practical to store and transport at scale.

Across Europe, 61 e-fuels projects are currently in development, of which 17 are specifically targeting maritime use. If all 17 projects reach operation, their combined output could hit 2.2 Mt by 2030. Among these announced projects, e-ammonia dominates with 5 plants potentially delivering 1.85 Mt of fuel, followed by 7 e-methanol projects with a combined output of 0.33 Mt, and 5 green hydrogen projects with a production potential of 0.02 Mt. This would require a total of around 2.7 Mt of green hydrogen in feedstock input.[30]

However, only 6 of the 17 e-fuel projects have reached FID, amounting to 0.077 Mt. This will fall short of the 0.29 Mt of e-fuels required to reach the 1% RFNBO uptake threshold by 2030. In this scenario, green hydrogen feedstock demand would amount to just 0.09 Mt. It is also worth noting that in the near term, other fuels and technologies, including LNG, drop-in biofuels, shore power, and electric shipping for near shore ferries will shoulder most of the compliance burden on the path to 2030. The largest share of ships currently on order are conventional fuel oil vessels, with LNG-capable ships the second most common. As a result, actual e-fuel demand by 2030 is projected to be 0.22 Mt rather than the full 0.61 Mt target threshold.

## Innovative Pathways

### Nuclear Propulsion

Nuclear propulsion, long confined to naval vessels, is being actively revisited for commercial shipping.[31] A single small modular reactor powered vessel could operate for 5–30 years without refueling, eliminating bunkering costs entirely and offering a compelling value proposition for deep-sea routes where e-fuel logistics remain a central challenge. Techno-economic assessments suggest nuclear could become cost-competitive with e-ammonia at scale, particularly for large vessels exceeding 100,000 DWT (or 10,000 TEU containerships) on transoceanic routes. The barriers are primarily regulatory as no international framework currently exists for commercial nuclear-powered merchant vessels. However, the International Maritime Organization has initiated exploratory discussions, and several flag states, including the Marshall Islands and Japan, have signaled openness to pilot programs. Given the long lead times in shipbuilding, investment decisions will need to be made this decade if nuclear is to play any role beyond 2040.

### Swappable Battery Systems

For shorter routes and higher-frequency operations, swappable battery systems represent a more immediate opportunity. Unlike conventional charging, swappable systems allow fully charged battery modules to be exchanged at port in minutes, keeping vessels operational and eliminating lengthy charging downtime. Norway is the most advanced example of battery-electric maritime adoption: As of 2025, around 70 battery-electric ferries are in operation, and operator Norled has developed an autonomous battery-swapping robot capable of replacing a vessel's battery in three minutes at the quay, removing the need to expand grid capacity at ports. Scaling this model to busy short-sea routes across the Baltic and Mediterranean could significantly cut liquid fuel use in a part of the shipping sector that accounts for a large share of EU port activity. The key enabling condition is standardization of battery module interfaces across vessel classes, an area where the EU's ongoing work on maritime infrastructure under the Alternative Fuels Infrastructure Regulation could play a catalytic role. With battery costs having fallen by over 80% in recent years and energy density continuing to improve, research suggests battery-electric propulsion is already economical for routes under 1,500 km: A range that encompasses a large share of intra-EU short-sea shipping corridors.

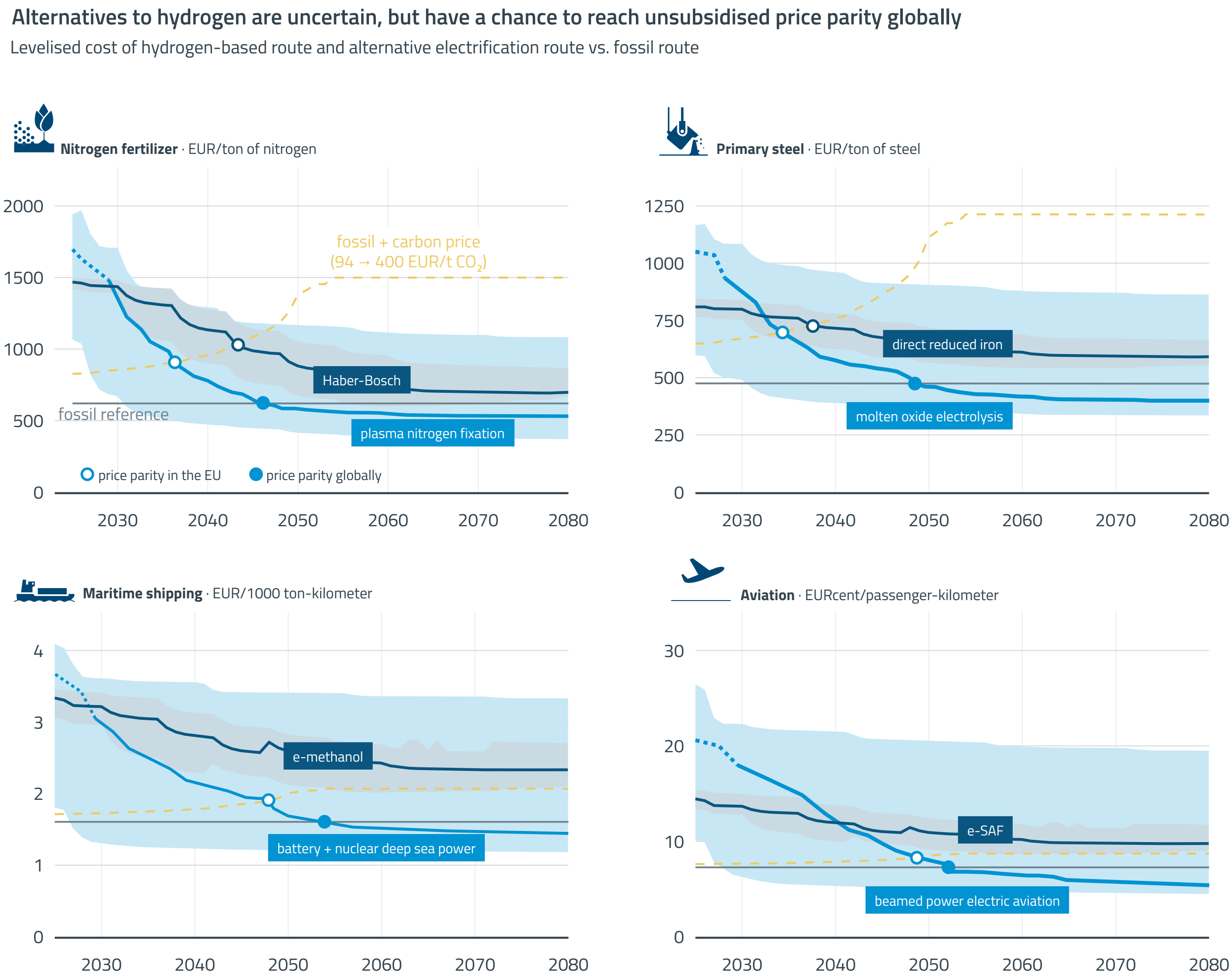
[28] This figure covers only large vessels over 5,000 gross tonnage calling at EU ports, with full fuel consumption counted for intra-EU voyages and only 50% counted for voyages between an EU and a non-EU port.

[29] No e-LNG facility has yet reached FID. e-Methanol, by comparison, has already reached commercial scale, with Denmark's Kassø plant producing 42,000 tpa since 2025.

[30] Based on a FCA life cycle assessment of marine fuels

[31] Over 20 startups and consortia, including Core Power, Ulstein, and American Bureau of Shipping, are developing small modular reactors adapted for marine use.

Table 3: An overview of alternative and innovative pathways per sector and their expected deployment based on current projections.




Results are only illustrative, indicating the low probability of globally competitive hydrogen-based routes and the high uncertainty but also high upside of alternatives with a longer timeline. Calculations are based on an extremely simplified techno-economic model and work-in-progress assumptions.

# Policy Recommendations

The European Commission's recent Electrification Action Plan announced an update to the EU Hydrogen Strategy. FCA sees this revision as an opportunity to align the Strategy more closely with realistic current and projected hydrogen demand in industry. The updated strategy should avoid creating technological or infrastructure lock-in, support diversified pathways to industrial decarbonization, including innovative production routes, and reassess which production steps should be retained in Europe, focusing on those that are strategically important and less energy intensive rather than those that generate limited value added.

## 1. Adopt a Sectoral Approach and Review the Targets Allocation

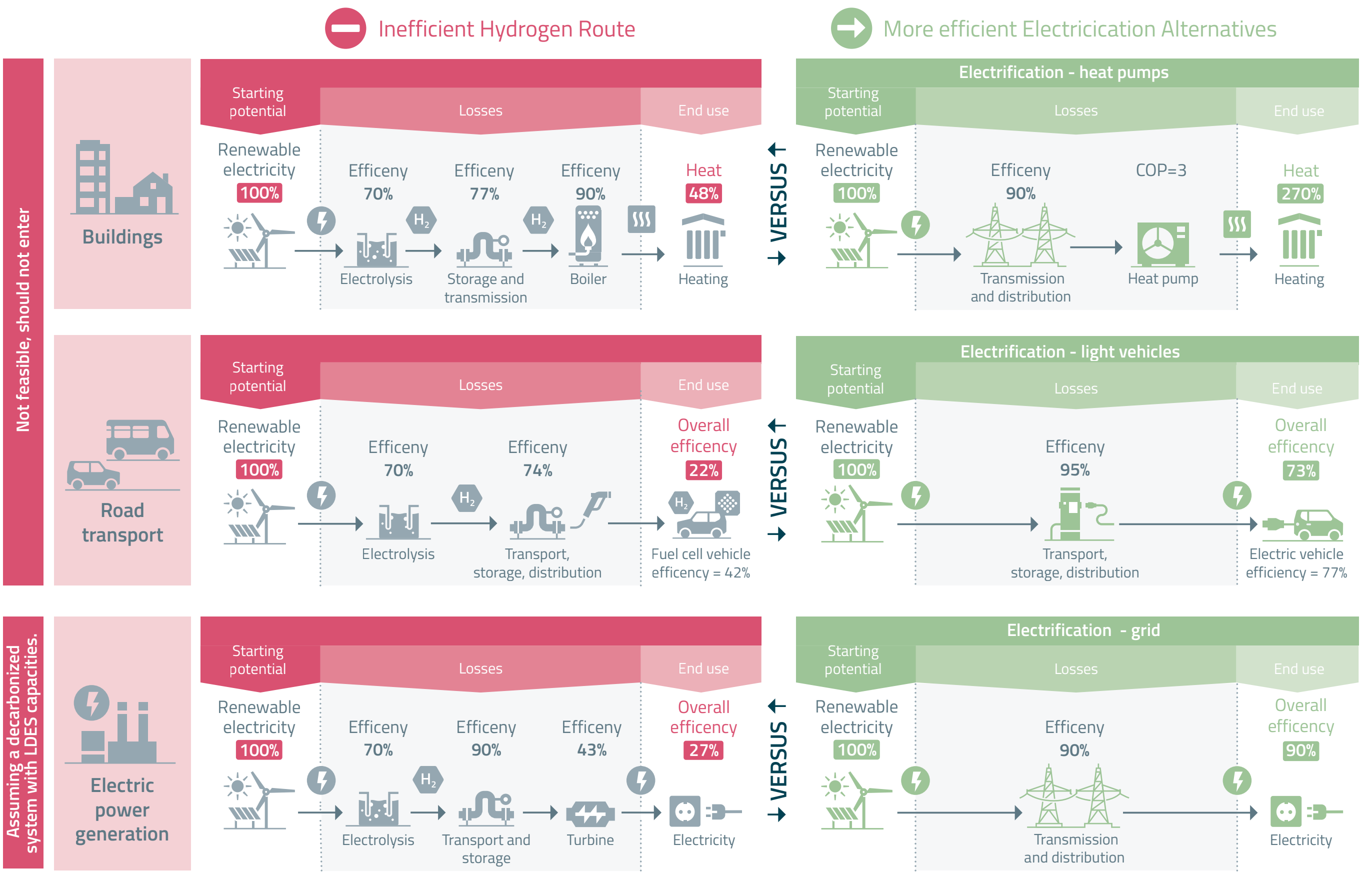
Hydrogen should be seen as one possible enabler of industrial decarbonization rather than a policy objective in itself. The EU Hydrogen Strategy should be reviewed around the specific and realistic needs and decarbonization pathways of individual industrial sectors, rather than treating hydrogen as a universal energy solution. Different sectors face different technological constraints, infrastructure requirements, and alternative decarbonization options. As clean hydrogen is likely to remain limited and costly, a targeted, sector-based approach should therefore focus hydrogen deployment where it delivers the highest system value and where few credible alternatives exist in the short to mid-term. This approach could be implemented through the Electrification Action Plan's sectoral electrification roadmaps identifying decarbonization needs, technology options, and expected hydrogen requirements, feeding into hydrogen demand projections and infrastructure planning to reduce the risk of inefficient hydrogen use.

- Prioritize clean hydrogen deployment in sectors where it is indispensable for decarbonization, including fertilizers and refining, while aligning policy frameworks with the Electrification Action Plan's sector-specific electrification roadmaps.
- Use lead-market policies to create demand for low-carbon industrial products, rather than relying primarily on hydrogen-specific demand targets. Product-level standards, public procurement requirements, carbon-intensity criteria, and other demand-side measures can create stronger and more technology-neutral incentives for industrial decarbonization by rewarding low-carbon outputs regardless of the production pathway used.
- Direct public support, infrastructure planning, and investment toward applications where hydrogen provides the greatest emissions reduction potential and long-term strategic value, while recognizing the role of alternative solutions such as direct electrification and material efficiency measures, where these provide more efficient decarbonization.

## 2. Embed Guardrails into the Revised Strategy

The revised hydrogen strategy should include clear guardrails to ensure that hydrogen deployment supports genuine emissions reduction and efficient use of energy and public resources. Without stronger prioritization criteria, there is a risk that hydrogen will be diverted toward applications that are technologically inefficient, economically uncompetitive, or poorly aligned with long-term climate objectives (Table 4).

Table 4: A system-level approach requires comparing hydrogen with electrification based on GHG abatement per unit of clean electricity. Direct electrification typically delivers significantly higher emissions reductions per unit of electricity. Hydrogen should therefore be reserved for applications where electrification is not feasible.



- Establish a clear hierarchy of hydrogen end-uses, defining transparent "no-regret" applications based on technological necessity, system efficiency, and the absence of viable direct electrification or other lower-cost decarbonization alternatives.

- Apply strict lifecycle emissions accounting and ex-ante techno-economic assessment requirements across all sectors, in line with the Renewable Energy Directive methodologies, including upstream methane leakage, indirect atmospheric warming effects, and comparisons with alternative solutions based on cost per tonne of $CO_2$ abated.

- Condition public funding on demonstrated climate benefits, system value, and long-term viability, while avoiding support for inefficient applications and differentiating policy approaches for renewable and low-carbon hydrogen based on their distinct roles and objectives.

### 3. Reframe Hydrogen Imports Toward Commodity Trade

The EU's approach to hydrogen imports should better reflect the technical and economic realities of transporting hydrogen over long distances. Importing pure hydrogen at scale presents substantial infrastructure, security, energy efficiency, and cost challenges, particularly when compared to hydrogen-derived commodities that are easier to store, transport, and integrate into existing industrial systems. Future sectoral strategies should therefore focus less on maximizing hydrogen volumes and more on building resilient and mutually beneficial industrial value chains with international partners.

- Prioritize imports of hydrogen-derived commodities (intermediate products and derivatives), including ammonia, methanol, HBI, and synthetic fuels, over large-scale imports of pure hydrogen, acknowledging the energy penalties, infrastructure requirements, and cost implications associated with hydrogen transport and conversion.

- Develop international partnerships around shared industrial development, local value creation, and mutually beneficial economic opportunities, rather than models that rely primarily on exporting raw energy resources while concentrating higher-value industrial activities elsewhere.

- Investment decisions should be grounded in credible market signals and evidence-based demand projections to minimize the risk of stranded assets and inefficient capital allocation.

### 4. Limit and Optimize Hydrogen Infrastructure

Hydrogen infrastructure development should be guided by realistic demand expectations and clear industrial use cases, rather than assumptions of economy-wide hydrogen deployment. Large-scale infrastructure investments carry significant financial and operational risks, particularly in a context where future clean hydrogen demand remains uncertain across many sectors. Infrastructure planning should therefore follow demonstrated demand and industrial clustering strategies, ensuring that investments are targeted, cost-effective, and aligned with long-term decarbonization needs. A more selective approach will help avoid stranded assets, reduce system costs, and ensure that public funding is directed toward infrastructure with clear strategic value.

- Prioritize electricity grid investment, expansion, and modernization as a first step to enable electrification, before developing hydrogen infrastructure in regions and sectors where there is demonstrated demand. This should be supported by the Electrification Action Plan, prioritizing existing industrial clusters and hard-to-abate sectors with identifiable long-term clean hydrogen demand.

- Align production support, infrastructure planning, and public funding mechanisms with credible offtake commitments, including contractual arrangements that ensure sufficient utilization and reduce the risk of stranded assets in pipelines, storage, import terminals, and port infrastructure.

- Promote localized hydrogen production or alternative decarbonization solutions, including direct electrification, energy efficiency, and material substitution, where these can reduce or eliminate the need for extensive hydrogen infrastructure.

## 5. Revise the Hydrogen Strategy Based on Emerging Technological Innovation

The EU Hydrogen Strategy should reflect the latest technological developments, industrial innovation trends, and system-level decarbonization opportunities. Since the publication of the strategy in 2020, a growing number of breakthrough technologies have emerged or continue to develop, that either reduce hydrogen demand or bypass the need for hydrogen altogether. Failing to account for such developments risks locking the EU into infrastructure-heavy and potentially suboptimal pathways that may become economically or technologically outdated. The revised Strategy should therefore adopt a more technology-neutral and adaptive approach, ensuring that policy frameworks remain open to competing low-carbon solutions and are capable of responding to technological progress.

- Support research, demonstration, and commercialization of innovative electrification-based industrial technologies alongside hydrogen solutions, while incorporating technological progress into future demand projections and infrastructure planning.
- Avoid policy and infrastructure lock-in that could constrain the deployment of more efficient or lower-cost technologies as they mature.
- Reflect lessons learned from existing EU instruments and programs, including the European Innovation Council, Innovation Fund, and Best Available Techniques Reference Documents, in wider EU policy and regulatory frameworks.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STANDPOINT

**About Future Cleantech Architects:**
We are a climate innovation think tank dedicated to closing the innovation gaps in hard-to-abate sectors through research and development, and policy and advocacy. To this end, our experts conduct comprehensive, science-based analyses and modelling of these sectors and drive high-level research consortia on critical technologies. We advocate for policymakers to prioritize and incentivize research and development to accelerate technological solutions for transitioning to a sustainable net-zero future.


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