ACER

European Union Agency for the Cooperation of Energy Regulators

European hydrogen markets

2025 Monitoring Report

2 December 2025

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Due to high capital and electricity cost Vs gas & CO_2 price levels.

1 Despite ongoing efforts at both the EU and Member State levels, the European hydrogen market falls significantly short of the ambitious 2030 targets.[1] Since ACER's (European Union Agency for the Cooperation of Energy Regulators) European Hydrogen Markets 2024 market monitoring report (2024 Report), several high-profile projects have been cancelled, and major companies have reduced their decarbonisation ambitions. Nonetheless, the European Commission and the Member States remain largely committed to the hydrogen economy.

2 With the finalisation of the Delegated Regulation on the calculation of greenhouse gas (GHG) emission savings for low-carbon hydrogen, the Commission completed the core elements of the EU regulatory framework, while deferring decisions on the role of nuclear-based hydrogen until 2028. The Commission's Clean Industrial Deal proposal (February 2025) links hydrogen with industrial competitiveness. It introduces additional initiatives, including a more flexible State aid framework (adopted in June 2025) that allows combining support from different schemes, and new financial instruments to support various industrial decarbonisation projects, including those related to hydrogen.

3 However, facilitating hydrogen demand uptake remains critical. Contrary to expectations, as of October 2025, only two Member States, Denmark and Ireland, have notified the Commission of the completion of their transposition of the amended Renewable Energy Directive (RED III), which establishes binding targets for renewable fuels of non-biological origin (RFNBO). This delay increases investor uncertainty and further hinders market deployment. In contrast, front-runner Member States, notably Germany and Denmark, are already advancing the design and adoption of national hydrogen market rules, setting a precedent for others.

1 The EU hydrogen strategy sets a target for 6 GW of electrolyser capacity in 2024 and 40 GW in 2030, and for 10 million tonnes of renewable hydrogen production by 2030.

Current rate of market growth remains insufficient to meet the EU and Member States' targets

4 Despite a strong 51% annual increase in installed electrolyser capacity in the EU in 2024, the installed capacity of 308 MW (2024) and the 1.8 GW capacity under construction still fall well short of a realistic trajectory toward the 2030 EU (40 GW) and Member States (48-54 GW) targets. A substantially faster expansion is needed to reach the necessary scale, gain operational experience, and eventually drive innovation to reduce costs. To achieve this, early movers need adequate support and regulatory certainty.

Renewable hydrogen remains costly, with uncertain prospects for near- to mid-term cost reduction

5 At around 8 EUR/kgH$_2$, the average cost of RFNBO hydrogen in the EU currently remains four times higher than that of conventional hydrogen from natural gas (just over 2 EUR/kg). Expectations for liquified natural gas (LNG) and CO_2 emission allowance price levels favour fossil-fuel hydrogen in the short-term. Meanwhile, slower deployment of electrolysers limits economies of scale, delaying the anticipated reductions in related capital costs. The recent deceleration or even reversal of the decline in renewable electricity costs further undermines these cost-reduction prospects. Maintaining the sector's momentum requires increasing demand, focusing on those sectors that are most capable of absorbing significant amounts of RFNBO hydrogen with limited additional support, such as the mobility sector.

A decarbonised electricity sector is key to renewable hydrogen

6 Electricity supply costs, excluding grid tariffs, may account for up to 50% of the levelised cost of renewable hydrogen, depending on the electricity supply mix, with substantial regional variations across the EU. Regions with abundant renewable resources and strong renewable integration, such as Spain, already provide advantageous conditions for renewable hydrogen production. Accelerating the decarbonisation of the electricity sector will expand the opportunities for renewable hydrogen in the EU.

Electricity network tariffs may add cost pressure as electrification slows

7 Electricity grid tariffs may represent a significant share of the levelised cost of hydrogen (LCOH) produced via electrolysis, depending on the location. ACER's 2025 report on electricity infrastructure development indicates that electricity network costs are at risk of increase by 50-100% by 2050, depending in part on how investments align with the evolution of electricity grid demand. Provision of flexibility services to the electricity system could add additional revenues for electrolysers. However, such revenues remain complementary and highly dependent on local system needs, the electrolyser's configuration, and flexibility limitations stemming from hydrogen offtake agreements that may require continuous hydrogen supply.

Hydrogen networks are crucial for market ramp-up but require a gradual build-out aligned with demand development

8 Uncertain future demand for renewable hydrogen, driven by the current cost, makes it difficult for hydrogen network operators (HNOs) to align network development with demand evolution, increasing the financial risks associated with this uncertainty. Adaptive network planning, reflecting the latest market trends, is essential to ensure efficient investment and cost control. As indicated in ACER's recent recommendation on inter-temporal cost allocation for hydrogen networks, a gradual network build-out, aligned with supply and demand development, can further minimise the risk of stranded assets.

Methane-based low-carbon hydrogen could accelerate scale-up but significant risks remain

9 Low-carbon hydrogen produced from natural gas with carbon capture and storage (CCS) could support market development and accelerate decarbonisation in some sectors. With current production cost estimates at just below 3 EUR/kg, low-carbon hydrogen with carbon capture is more competitive than renewable hydrogen. However, there is still limited commercial-scale experience with this technology, and additional costs for CO_2 transport and storage are highly uncertain. The build-out of CO_2 infrastructure may pose additional challenges. Moreover, the long-term gas offtake contracts required for such projects could lock-in fossil fuel dependence and exposure to price volatility in the global natural gas market. A robust assessment of these uncertainties is essential to determine the most appropriate hydrogen production pathways.

Funding availability is gradually increasing, but implementation lags behind

10 The Commission has advanced significantly with its hydrogen-related funding measures and has already allocated more than EUR 20 billion through various programmes, including through the auctions run by the European Hydrogen Bank (a Commission financing instrument) that Member States are also encouraged to use. It has also launched the EU Hydrogen Mechanism to facilitate the connection of hydrogen supply and demand aiming to accelerate hydrogen market creation. Member States have also announced numerous support schemes, yet implementation remains uneven. Accelerating the deployment of allocated funds is crucial to unlocking mature investments.

Summary of ACER's key recommendations

Regulatory certainty	**Accelerate the transposition and implementation of the amended Renewable Energy Directive** to ensure regulatory certainty and accelerate market development.
Implement legislation	**Implement the hydrogen and gas decarbonisation package without delay** to facilitate the deployment of infrastructure and a well-functioning hydrogen market.
Targeted investments	**Prioritise and target funding toward projects in hard-to-abate sectors** that are ready to transition to renewable and low-carbon hydrogen, to stimulate demand.
Infrastructure	**Facilitate renewable hydrogen production through faster permitting and grid connection** for both electrolysers and renewable electricity projects.
System decarbonisation	**Speed up decarbonisation of the power sector** to lower electricity costs and enhance electrolyser utilisation.
Market optimisation	**Enable flexibility in the electricity market, rethink electricity grid tariffs and grid incentives**, which can also optimise electrolyser location and performance.
Risk assessment	**Assess the risks of low-carbon hydrogen pathways**, including its underlying costs, infrastructure uncertainties and lock-in effects, before committing to large-scale deployment.
Market certainty	**Align hydrogen network development with market realities** to manage market uncertainties and reduce the risk of stranded assets.

List of abbreviations

Acronym	Meaning
ACER	European Union Agency for the Cooperation of Energy Regulators
AEM	Anion Exchange Membrane
CBAM	Carbon Border Adjustment Mechanism
CCUS	Carbon Capture Utilisation and Storage
DSO	Distribution System Operator
EU	European Union
EC	European Commission
ENNOH	European Network of Network Operators for Hydrogen
ENTSOE	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ETS	Emissions Trading System
FID	Final investment decision
IEA	International Energy Agency
IPCEI	Important Project of Common European Interest
JRC	Joint Research Centre
LCOH	Levelised Cost of Hydrogen
LCOE	Levelised Cost of Electricity
NECP	National Energy and Climate Plan
PCI	Project of Common Interest
PEM	Proton exchange membrane
PMI	Project of Mutual Interest
PPA	Power Purchase Agreement
RED	Renewable Energy Directive
REMIT	Regulation on Wholesale Energy Market Integrity and Transparency
RFNBO	Renewable fuels of non-biological origin
SAF	Sustainable aviation fuels
TEN-E Regulation	Regulation on guidelines for trans-European energy infrastructure
TPA	Third party access
TSO	Transmission System Operator
TYNDP	EU Ten-Year Network Development Plan

1. Introduction

11 This second edition of ACER's monitoring report on European hydrogen markets comes at a time when the industry is seeking a clearer path forward. Despite numerous project cancellations and postponements, including some striking ones, the European hydrogen sector has seen notable progress. Since the publication of the previous report, electrolyser deployment has grown substantially, and many new projects are now under construction or approaching maturity. Nonetheless, efforts must accelerate significantly to achieve the long-anticipated scale-up needed to reduce costs and enable broader market development.

12 The report is structured into three main parts. The first part (Section 2) provides an overview of recent policy and regulatory developments. It begins with a review of key European-level initiatives (Section 2.1), followed by an examination of national strategies (Section 2.2.1), policies (Section 2.2.2) and regulatory frameworks (Section 2.2.3), including a focus on newly established hydrogen market rules in front-runner Member States (Sections 2.2.3.1 and 2.2.3.2). It concludes with a review of the European and national support schemes with a particular attention to the second auction of the European Hydrogen Bank (Section 2.3). The second part of the report (Section 3) analyses the current state of the European hydrogen market. It explores hydrogen demand and supply dynamics (Section 3.1) with dedicated sections on electrolyser deployment (Section 3.1.1), low-carbon hydrogen projects (Section 3.1.2), and hydrogen offtake agreement (Section 3.1.3), and provides an update on infrastructure developments (Section 3.2). The third part (Section 4) examines the cost of hydrogen. It first analyses the costs of renewable and low-carbon hydrogen (Sections 4.1.1-4.1.4) and continues with a discussion on transportation costs (Section 4.1.5) and market's willingness to pay (Section 4.1.6).

13 At this stage of market development, a wide range of information and data is emerging from multiple sources. At the European institutional level, the Commission and Eurostat are making ongoing efforts to organise and standardise market-related data. This report draws primarily on publicly available information and relies on the databases of the European Hydrogen Observatory, the International Energy Agency (IEA), and S&P Global Commodity Insights. In addition, NRAs have contributed with valuable information, insights, and reviews, for which ACER extends its sincere appreciation.

2. Regulatory and policy developments

14 The hydrogen and gas decarbonisation package largely closed the circle of the EU-wide regulatory acts that set the overall framework for the development of hydrogen markets in the EU. However, there have also been several other important policy and regulatory developments at the EU and national levels since the publication of ACER's 2024 European Hydrogen Markets monitoring report (2024 Report). This chapter provides an overview of these developments.

2.1. EU-wide developments

Low-carbon hydrogen

15 The EU hydrogen strategy prioritises the use of renewable hydrogen, while acknowledging that low-carbon hydrogen will play a role "to rapidly reduce emissions from existing hydrogen production and support the parallel and future uptake of renewable hydrogen".[2] The Commission's 2025 Clean Industrial Deal communication acknowledged the importance of low-carbon hydrogen and the need for a pragmatic and clear rule set for its production providing certainty to investors.

16 On 8 July 2025, the Commission adopted the Delegated Regulation on the Calculation of Greenhouse Gas (GHG) Emission Savings for Low-carbon Hydrogen (Low-carbon Hydrogen Delegated Regulation).[3] The European Parliament approved the Low-carbon Hydrogen Delegated Regulation on 23 October 2025. The purpose of the Low-carbon Hydrogen Delegated Regulation is to establish a harmonised framework for assessing the climate performance of low-carbon hydrogen, aligned with the methodologies applied to renewable hydrogen. The regulation covers full life-cycle emissions, including indirect and upstream methane emissions.[4]

17 The Low-carbon Hydrogen Delegated Regulation foresees additional assessments on the treatment of low-carbon electricity from nuclear power plants and the possible use of average emission values for electricity. Both assessments are to be carried out by 1 July 2028. To provide more clarity on this issue, as part of the above-mentioned assessment process, the Commission will launch a public consultation in 2026 on the draft methodology on the use of power purchase agreements (PPAs) for nuclear energy.

2 This document uses the terms of renewable, electricity-based, and low-carbon hydrogen as defined in the EU hydrogen strategy, unless otherwise specified. In this context, renewable hydrogen means hydrogen produced via water electrolysis using electricity from renewable energy sources only (also called RFNBO hydrogen) or via processing of biogas and biomass, if in compliance with sustainability requirements. The strategy also defines electricity-based hydrogen (referred to as electrolytic hydrogen in this report) as the hydrogen produced through the electrolysis of water (in an electrolyser, powered by electricity), regardless of the electricity source. Low-carbon hydrogen means hydrogen produced in such a way that related greenhouse gas emissions are at least 70% lower compared with conventional production routes from fossil fuels. Low-carbon hydrogen may refer to hydrogen produced from fossil-fuels with CCS, or to electrolytic hydrogen using low-carbon electricity sources such as nuclear.

3 Both the Low-carbon Hydrogen Delegated Regulation and the RFNBO Delegated Regulations have drawn responses from the industry and Member States, urging the Commission to adjust the rules to support faster market uptake. Notably, in its resolution on the Clean Industrial Deal of 19 June 2025, the European Parliament invited the Commission to consider, where appropriate, changes to the requirements for RFNBOs, aiming to lower costs and boost renewable hydrogen production.

4 For more information see the Commission's press-release with additional relevant links.

The EU Clean Industrial Deal

18 Following the adoption of the Clean Industrial Deal on 26 February 2025, the Commission has issued a series of action plans, recommendations, and guidance documents to support industrial decarbonisation and competitiveness. Some of these acts have direct or indirect implications for the hydrogen market. The most relevant ones are shown hereafter:

- **Clean Industrial Deal State Aid Framework (CISAF):** Adopted on 25 June 2025 by the Commission, CISAF provides a flexible and targeted State aid framework to accelerate industrial decarbonisation. The new framework prioritises support for renewable hydrogen in line with the EU hydrogen strategy, while acknowledging the role of low-carbon hydrogen. Additional hydrogen related provisions include:
    - Support to renewable and low-carbon hydrogen production and storage is deemed compatible with the EU market rules if aligned with the RFNBO and Low-carbon Hydrogen Delegated Regulations.
    - Measures promoting low-carbon fuels must allocate at least 30% of their budget for RFNBO investments.
    - Aid of up to EUR 200 million for industrial decarbonisation projects using hydrogen or its derivatives (with at least a 40% RFNBO share) can reach up to the highest possible share of support intensity (60%).
    - Cumulation of aid from different schemes is allowed if it covers distinct costs or stays within maximum limits. Cumulation is also allowed with State aid that is exempted under the General Block Exemption Regulation.
- **Steel and metals action plan:** Recognising the steel and metal sector as pivotal for hydrogen uptake, the steel and metals action plan highlights hydrogen's role in decarbonising the sector and addresses the challenges around (hydrogen and electricity) grid access and development. The action plan includes several measures including:
    - A proposal to facilitate grid access for energy intensive industry (Q4 2025).
    - The creation of a voluntary carbon intensity label for industrial products to assist industries in capturing the green premiums.
    - The launch of Industrial Decarbonisation Bank auctions in 2025, starting with a EUR 1 billion pilot auction, mirroring the European Hydrogen Bank auction model.
- **Recommendation on tax incentives:** This non-binding guidance encourages Member States to introduce tax credits and accelerate depreciation to stimulate private investments in clean technologies, consistent with CISAF. Eligible investments include hydrogen technologies, like electrolysers, and fuel or feedstock switching solutions in industry.

EU Hydrogen Mechanism

19 In July 2025, the Commission launched the EU hydrogen mechanism on its Energy and Raw Materials Platform to accelerate the creation of the hydrogen market. The mechanism will be in place initially until 31 December 2029, and its continuation will be re-assessed thereafter. The mechanism is specifically tailored to the market of RFNBO and low-carbon hydrogen, and hydrogen derivates like ammonia, methanol and sustainable aviation fuels. The initiative focuses on the following three main objectives.

- Scaling up of hydrogen production by helping buyers and suppliers connect via organised calls for interest where demand requests will be matched with supply offers. The first call for interest to connect buyers and suppliers was launched in 12 November 2025.[5]
- Providing insights to guide infrastructure development based on actual market needs by "hosting" market tests, potentially with other interested institutions like network operators and infrastructure developers.
- Linking interested parties with available financial support (e.g. lending institutions) with project promoters by making relevant information available and matching financial tools to projects.

European Network of Network Operators for Hydrogen

20 The European Network of Network Operators for Hydrogen (ENNOH), foreseen by the hydrogen and gas decarbonisation Regulation, is the association of European hydrogen transmission network operators. Its mission is to promote the development and integration of the EU hydrogen market, including cross-border trade, and the efficient and sustainable operation of the European hydrogen transmission system in line with EU climate and energy goals. ENNOH's main tasks include drafting EU network codes on hydrogen related matters.[6] ENNOH is also responsible for preparing the EU-wide ten-year network development plan (TYNDP) for hydrogen infrastructure.[7]

21 On 25 June 2025, the future hydrogen transmission network operators adopted ENNOH's statutory documents, reflecting the Commission's opinion on these documents[8] and marking a key step in its creation. ENNOH's formal establishment depends on the certification of HNOs under Article 71 of the hydrogen and gas decarbonisation Directive, as only certified operators may become members. Member States are therefore urged to transpose the Directive before the formal 5 August 2026 deadline, to enable timely certification and avoid delays that would hinder ENNOH's operational start and its role in developing key hydrogen market deliverables. The expectation is that ENNOH will become fully operational in 2026, when the first certified HNOs will formally establish the organisation. Until then, the future HNOs have set a temporary, voluntary cooperation, called pre-ENNOH, to pave the way for the timely undertaking of its activities and ensure collaboration between future HNOs.

5 For more details see the Commission's newsletter here.

6 See areas listed in Article 72 of the hydrogen and gas decarbonisation Regulation.

7 See Article 57 of the hydrogen and gas decarbonisation Regulation, in particular paragraphs (1), (2), and (6).

8 In its opinion the Commission called for more transparency on the specific impact of the regional balance principle on the election and voting mechanism, a future revision of the rules on the Board structure, clarification and strengthening of the observer status rules, confidentiality and information exchange rules with third countries, and rules on the set-up and functioning of drafting committees. The Commission also recommended including a broad range of hydrogen stakeholders in the drafting committees, including independent climate expert bodies and civil society representatives and strengthening the rules on stakeholder engagement and consultations.

Certification of renewable and low-carbon hydrogen

22 Certification allows renewable and low-carbon hydrogen producers to demonstrate compliance with the sustainability criteria in the delegated acts for RFNBO and low-carbon hydrogen. As such it is an essential enabler of hydrogen trade both within the EU and with third countries. Certification can be obtained via national schemes, administered by national competent authorities, or through privately developed international voluntary schemes recognised by the Commission.

23 As of September 2025, three voluntary schemes, CertifHy, REDcert, and International Sustainability & Carbon Certification (ISCC EU), have received formal recognition by the Commission and are operational across Member States. These schemes have already enabled certification of RFNBO production in several jurisdictions, granting certified producers a competitive advantage in the evolving European and global hydrogen market.[9]

2.2. National developments

2.2.1. National strategies and plans

24 As of June 2025, 25 Member States have submitted their final updated national energy and climate plans (NECPs). Based on the Commission's assessment of the submitted final plans, hydrogen is a clear part of the energy transition strategy in 12 of them. All 12 plans include a target for RFNBO in transport, and 11 of them include an industrial RFNBO target.[10]

25 In November 2024, Italy published its final hydrogen strategy. The strategy is structured around a framework that considers three possible scenarios developed over a long-term horizon, up to 2050. For 2030, it estimates a moderate demand for renewable hydrogen of around 250,000 tonnes driven mainly by European policies, while for 2050, renewable hydrogen demand is estimated between 2.2 and 4.2 million tonnes, depending on the scenario. In terms of hydrogen supply, the strategy re-iterates the scenario of the NECP in which 70% of the hydrogen is produced domestically. While the final version of the strategy does not mention specific targets on electrolyser capacity, it refers to a potential need for 15 GW to 30 GW of capacity, considering the NECP scenario. To account for limitations in developing the necessary RES supplying the electrolysers domestically, an alternative scenario considers that around 80% of the demand would come from imports mainly from North Africa via the Southern Hydrogen Corridor, but also via ammonia and methanol shipments from other parts of the world. While the strategy reiterates the vision of connected hydrogen hubs and the strategic importance of the Southern Hydrogen Corridor, it refrains from quantifying the foreseen infrastructure needs.

26 In April 2025, France published an updated hydrogen strategy. The strategy considers the current pace of developments in the sector and adopts a more conservative approach compared with the previous version of the hydrogen strategy published in 2020. The new strategy prioritises the deployment of hydrogen in industrial hubs (focusing on refining, chemicals, ammonia, and the steel industry) and in the transport sector with a focus on synthetic fuels for aviation

9 According to information from the IEA and S&P Global Commodity Insights, ISCC EU has already certified a 20-MW facility by Air-Liquide in Germany, Everfuel's green hydrogen production facility in Denmark, and Nobian's hydrogen facility in the Netherlands. CertifHy has certified a number of facilities including three sites in France (11 MW in total), one in Germany (10 MW) owned by Lhyfe, and a renewable hydrogen and e-methane production facility in Germany by Hy2gen. CertifHy also recognised a number of organisations including SGS, TÜV Rheinland, TÜV SÜD and Vinçotte as the certification bodies authorised to operate under this scheme.

10 Based on the Commission's presentation at the 12th meeting of the Hydrogen Energy Network. The NECPs assessment may be found here.

and maritime. According to the strategy, France plans to rely entirely on domestic hydrogen production until 2035. The target for electrolysers has been downgraded to 4.5 GW in 2030 and 8 GW in 2035, from 6.5 GW and 10 GW, respectively. Imports of hydrogen derivatives, mainly ammonia, are expected to begin after 2040. The strategy also advocates for a more gradual roll-out of hydrogen networks and foresees the building of 500 km of hydrogen pipelines in the mid-term, mainly within industrial hubs, but also with a view of connecting those hubs as appropriate. The actual network and storage needs will be identified in a study expected to be finalised towards the beginning of 2026. The strategy also refers to the support planned to assist the development of the early market. Two concrete mechanisms are mentioned, one focusing on tax incentives for the transport and refining sectors, and one focusing on levelling out the cost of electrolytic hydrogen by supporting up to 1 GW of electrolyser capacity.[11]

27 In October 2025, Romania adopted its National Hydrogen Strategy 2025-2030 with a perspective of 2050 and an Action Plan for its implementation. The strategy and action plan align with the relevant objectives included in National Sustainable Development Strategy 2030, Romania's plan to align with the UN's 2030 Agenda for Sustainable Development. It includes specific actions and measures to support the decarbonisation of hard-to-decarbonise economic sectors, mainly in transport and heavy industry, focusing on new, innovative solutions. The strategy and action plan aims primarily on the production of renewable hydrogen, without overlooking low-carbon hydrogen especially considering affordability concerns. It also advocates for the use of hydrogen for energy security purposes and for further enhancing the integration of RES though power-to-x application. The strategy and action plan foresees the production of 153,000 tons of renewable hydrogen by 2030, mainly for transport (72,400 tonnes) and heavy industry (57,000 tonnes in existing processes and 23,700 tonnes in new applications, in line with the RED III industrial hydrogen RFNBO target of 42%). By 2027, the strategy and action plan expects the production of 48,700 tonnes. To reach this target, the it foresees 2,130 MW of electrolysers by 2030, powered by an additional 4,261 MW of dedicated wind and solar power capacity.

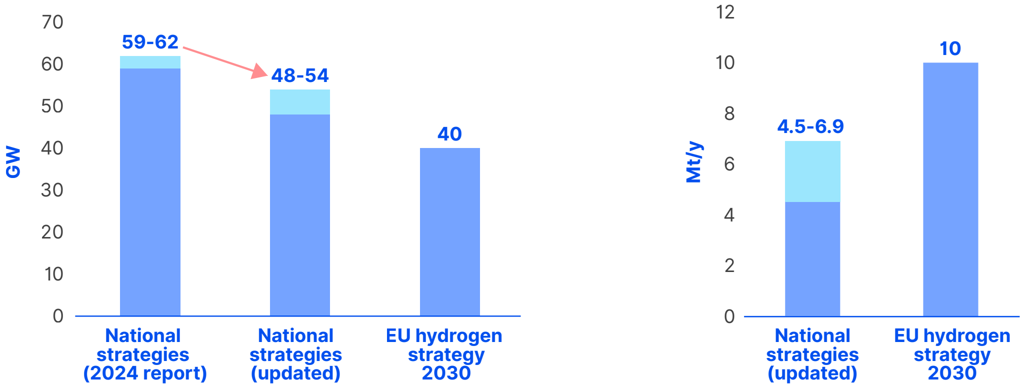
28 The new French, Italian and Romanian strategies lead to a reduction of the cumulative capacity of electrolysers targeted for 2030 by national strategies compared with the 2024 Report, bringing it to 48-54 GW. As shown in Figure 1, while the cummulative Member States' targets aim higher than the targeted electrolyser capacity in the European hydrogen strategy (40 GW), the estimated production[12] is significantly lower than the 10 million tonnes of the latter.

11 The total budget of the mechanism is EUR 4 billion, and an initial round of this mechanism was launched in December 2024 targeting 200 MW of electrolysers.

12 Where only electrolyser capacity targets where available, estimated hydrogen production was calculated like in the 2024 Report, assuming that electrolysers operate with a 61% efficiency (55 kWh/kg H_2) and a load factor of between 4,000-6,000 hours per year. Figure 1 does not include hydrogen production estimates for France. Additional updates based on information received by NRAs include: Bulgaria's electrolyser capacity target was adjusted from 0.2 GW to 0.055 GW; Croatia's electrolyser capacity target was adjusted, from 0.5 GW to 0.07–1.273 GW and the hydrogen production was estimated at 5-139 kt; Germany's hydrogen production target is revised upward, from 727-1091 kt to 1201-1502 kt, to reflect the difference between the targets for hydrogen demand and imports in the hydrogen strategy (40–50 TWh); Finland's hydrogen production target is introduced reflecting the new hydrogen roadmap (100–150 kt); Greece's electrolyser capacity and hydrogen production target values are adjusted, from 0.3 GW to 0.187 GW, and from 28 kt to 30 kt respectively; Spain's electrolyser capacity target is set at 12 GW as per the final strategy and the calculated production is adjusted from 800–1200 kt to 873–1309 kt.

Figure 27 and Figure 28 in the Annex show the targeted electrolyser capacity and the estimated targeted production per Member State.

Figure 1: Comparison of EU and Member States' targets for 2030 on electrolyser capacity (left, GW) and hydrogen production (right, Mt/y) – October 2025



Source: ACER, based on national hydrogen strategies and roadmaps, NECPs, information provided by NRAs and own calculations.

Note: Ranges (light blue) correspond to different assumptions or scenarios in the strategies. Where information on electrolyser capacity targets was only available, estimated hydrogen production was calculated assuming that electrolysers operate with a 61% efficiency and a load factor of between 4,000-6,000 hours per year. The figure does not include hydrogen production estimates for France.

2.2.2. National hydrogen policies

29 In September 2025, Austria unveiled a roadmap for the expansion of the hydrogen sector. The strategy includes measures to strengthen long-term supply security through a new import framework, alongside targeted investments in electrolysis capacity and expansion of storage and pipeline infrastructure. To support implementation, the government plans to issue two ordinances before the end of 2025. The Hydrogen Investment Grant Ordinance will provide EUR 20 million in funding for electrolysers, while the Hydrogen Certification Ordinance will align national legislation with EU requirements, aiming to create regulatory certainty and eligibility for funding. According to the roadmap, the Southern Hydrogen Corridor, linking Austria with North Africa via Italy, is set to make Austria a European hydrogen hub.[13]

30 On 29 May 2024, the German government accepted the draft Hydrogen Acceleration Act. The draft act failed to pass through the Parliament, however the government adopted an updated proposal and sent it to the Parliament for ratification. The proposal aims to create a simplified and accelerated framework for the planning, approval, and procurement procedures for hydrogen infrastructure projects, including electrolysers, using digitalised administrative procedures and classifying hydrogen projects as projects of overriding public interest.

31 In April 2025, Germany published a White Book on Hydrogen Storage. The book analysed the future needs for hydrogen storage based on various scenarios and expects 2-7 TWh (60 – 210 kt) of demand for storage by 2030 and 76-80 TWh (2.2-2.4 Mt) by 2045 driven mainly by industry and the electricity sector. According to the analysis, this would amount to EUR 32.5-54.2 billion worth of investment by 2050 and would account for one-quarter to one-third of the forecasted total European hydrogen storage demand. The book considers that Germany's existing gas salt cavern storages converted into hydrogen storage have the greatest potential and fastest possible development time. It envisages regulated third-party access for hydrogen storage facilities from as early as 5 August 2026, i.e. once the hydrogen and gas decarbonisation Directive is supposed to have been transposed into national legislation. The book also considers

13 A joint declaration from Algeria, Austria, Germany, Italy, and Tunisia laid the foundation for importing renewable hydrogen to Austria and Germany on an industrial scale by 2035.

the hydrogen storage market as a competitive one, arguing that economies of scale and network effects are not significant for storage systems, i.e. smaller systems can be operated just as economically as larger ones, and the costs of the individual facilities are not influenced by the total level of hydrogen demand. However, it notes that there are significant uncertainties with regard to the costs of storage. The book proposes several options for mitigating demand risk, ranging from contracts for differences (CFDs) through State grants and guarantees to demand stimulation, suggesting that cooperative European support can facilitate the development and usage of hydrogen storage facilities.

32 On 15 September 2025, the German Federal Ministry for Economic Affairs and Energy presented a monitoring report on the energy transition. The report highlights the gaps in the energy transition scenarios and stresses the importance of a pragmatic approach based on realistic demand scenarios. The report identified 10 key measures in this respect, including the elimination of overly complex requirements for renewable hydrogen, and the equal treatment of low-carbon hydrogen.[14] The report proposes a gradual approach for the development of the hydrogen core network and the hydrogen import corridors, in close coordination with demand side measures. It also recommends switching from the current targets on electrolyser capacity to flexible targets based on demand-side projects. Besides measures directly targeting hydrogen, the report proposes the classification of carbon capture utilisation and storage (CCUS) as a climate protection technology, enabling investment funding and regulatory guidance for CO_2 infrastructure. This is expected to have a positive effect for low-carbon hydrogen production from fossil fuels with CCS. In line with the proposed measures, the German government introduced a draft law facilitating the transport and storage of captured CO_2 by creating the legal framework for CO_2 pipelines and storages.[15]

2.2.3. National regulatory developments

33 The latest amendment of the Renewable Energy Directive (RED III) sets, inter-alia, binding minimum levels for RFNBOs for industry and transport for 2030 (and for industry also for 2035).[16] As such it is one of the fundamental regulatory instruments for the early uptake of hydrogen in those sectors. Member States had to transpose the targets into national legislation by 21 May 2025. By the time this report was drafted, only Denmark and Ireland had notified complete transposition of the Directive to the Commission. According to information from the

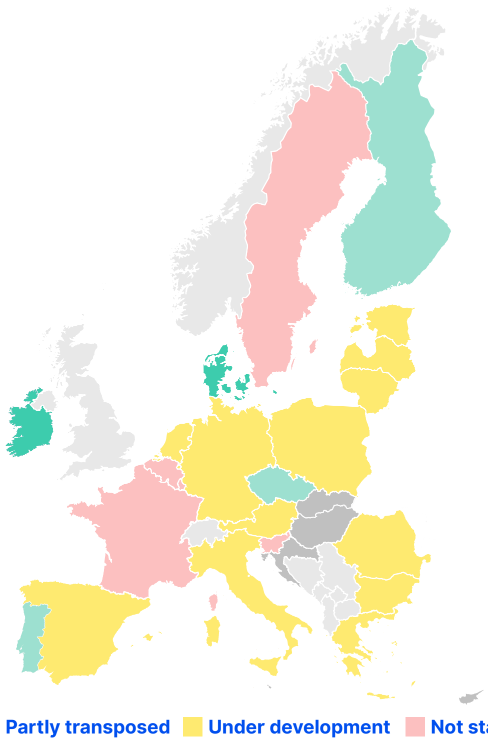
14 Hydrogen relevant measures also include the construction of new gas-fired power plants with the possibility to be switched to hydrogen in the future and the establishment of CCUS as a climate protection technology.

15 The new German administration recently expressed its favour towards the adoption of CCS technology to de-carbonise electricity production from gas-fueled power plants (see here). Germany's hydrogen import strategy, adopted in July 2024, already foresaw a significant role for low-carbon hydrogen produced via this technology, but the materialisation of this role is uncertain. In September 2024, plans to export low-carbon hydrogen from Norway to Germany were abandoned, allegedly due to lack of sufficient demand (see here). It should be noted, however, that the German National Hydrogen Strategy currently prohibits public funding towards low-carbon hydrogen production (see here).

16 Pursuant to the RED III, at least 42% of hydrogen used in industry must be sourced from RFNBO by 2030, increasing to 60% by 2035. In the transport sector, RFNBO must account for at least 1% of the total energy consumption by 2030, contributing to a combined target of 5.5% for RFNBO and advanced biofuels.

NRAs, and as depicted in Figure 2, the transposition is ongoing in 15 Member States.[17] The Commission has sent Letters of formal notice for non-communication regarding the provisions of the amended RED, which have a May 2025 deadline, to all Member States, except Denmark, giving them a two-month period to reply, complete their transposition, and notify their measures to the Commission. In the absence of a satisfactory response, the Commission may decide to issue a reasoned opinion.[18]

Figure 2: Transposition of RED III in the EU - October 2025



Source: ACER, based on information provided by NRAs and the European Commission.

Note: In Belgium, the government launched a public consultation on a proposed legislation to transpose the RED III RFNBO targets for the transport sector. In Czech Republic, the legislation has been approved but not put in force yet. In Finland, transposition of the RED III targets for transport is in place but not for industry. In Portugal, RED III was partially transposed by Decree-Law 99/2024, of 3rd December 2024. On 25 September 2025, the Portuguese government launched a public consultation on the legislation for the full transposition of RED III, which ended on 25th October 2025. In Romania, the transposition is ongoing, and relevant legislation has been adopted in October 2025 (Government Emergency Ordinance no. 59/2025 amending and supplementing Government Emergency Ordinance No. 163/2022). In Spain, a draft Royal Decree on renewable fuels, was under public consultation until 8 September 2025.

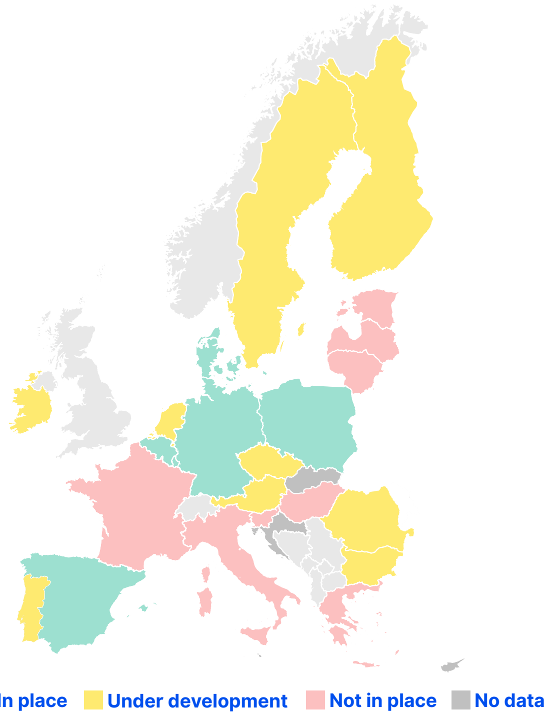
17 Before the elapse of the transposition deadline, Denmark was the only Member State to have declared complete transposition. By November 2025, Ireland, has also declared complete transposition. The Commission will have to assess all measures in order to verify this. In Belgium, the government launched a public consultation on a proposed legislation to transpose the RED III RFNBO targets for the transport sector. In Czech Republic, the legislation has been approved but not put in force yet. In Finland, transposition of the RED III targets for transport is in place but not for industry. In Portugal, RED III was partially transposed by Decree-Law 99/2024, of 3rd December 2024. On 25 September 2025, the Portuguese government launched a public consultation on the legislation for the full transposition of RED III, which ended on 25th October 2025. In Romania, a framework for the integration of hydrogen from renewable and low-carbon sources in the industry and transport sectors (Law no. 237/2023) was in place prior to the adoption of the RED III. The transposition is ongoing, and relevant legislation has been adopted in October 2025 (amendment of Government Emergency Ordinance No. 163/2022). In Spain, a draft Royal Decree on renewable fuels, was under public consultation until 8 September 2025. The draft Decree proposed a binding RFNBO target for transport of 2.5% of total energy supplied in 2030. There is also a binding target for RFNBO for intermediate use substituting hydrogen of fossil origin, for which the following path until 2030 has been set: 0,25% of consumption of hydrogen of fossil origin must be achieved in 2027; another 0,5% in 2028; 0,75% in 2029 and 1,5% in 2030. This second target applies to wholesale suppliers of oil products for their consumption.

18 See the Commission's announcement here.

34 The **hydrogen and gas decarbonisation Directive** is another substantial tool for the hydrogen market development. While the deadline for Member States to transpose the Directive into national legislation is 6 August 2026, the hydrogen sector would significantly benefit from an earlier transposition. Empowering NRAs to undertake the tasks foreseen in the hydrogen and gas decarbonisation package early on would ensure that regulatory oversight is in place from the start of the market development. According to information received from NRAs, so far Denmark and Poland have formally proceeded with the transposition of the Directive, while Austria, Belgium, Bulgaria, Czech Republic, Finland, Germany, Latvia, Malta, the Netherlands, Portugal, Romania, and Spain are in the process of doing so.

35 Regardless of the transposition of the hydrogen and gas decarbonisation Directive, in 13 Member States there is already a regulatory framework in place or under development, as depicted in Figure 3.[19] NRAs have already obtained some legal competences in Belgium, Denmark, Germany, Luxembourg, Poland, Portugal, and Spain. As far as the unbundling process is concerned, as of April 2024, Fluxys Hydrogen has been appointed and certified as HNO in Belgium according to national legislation, prior to the publication of the hydrogen and gas decarbonisation package. A re-certification is currently ongoing to fully align with the Directive's requirements. In a few other Member States (Denmark, Germany, the Netherlands, Poland, Portugal, and Spain) interested HNOs have been identified, and in some cases appointed[20], but no formal certification has taken place yet, due to the absence of an appropriate regulatory framework.

Figure 3: Regulatory framework for hydrogen in the EU – October 2025



Source: ACER, based on information provided by NRAs.

Note: The figure indicates Member States with a regulatory framework setting basic rules such as allocation of roles and high-level rules for access to hydrogen networks. The figure does not imply that the hydrogen and gas decarbonisation Directive has been properly transposed in Member States with a hydrogen framework in place.

19 Table 3 in the Annex provides more details on the regulatory framework in the EU Member States based on information provided by NRAs.

20 For example, appointed hydrogen network operators include Energinet in Denmark, REN Gas in Portugal and subsidiaries of Gasunie (Hynetwork) in the Netherlands, and Enagas (Enagás Infraestructuras de Hidrógeno, S.L.U.) in Spain.

36 As the market gradually grows, there is a need to develop market rules that govern the use and operation of the hydrogen network. Germany is a front-runner, reflecting its high ambitions, but other Member States are following. Denmark is also developing a financing framework and is working on the access rules for the hydrogen network, while Belgium is currently analysing options for the market design. The rest of this section presents the established and proposed market rules in Germany and Denmark.

2.2.3.1. Germany: market rules and hydrogen network planning

37 Germany is moving forward ambitiously with the preparation of the hydrogen infrastructure. Significant advances were made on the hydrogen core network, the backbone of the German hydrogen infrastructure connecting demand with production and import points. In October 2024, the German NRA (BNetzA) approved with amendments the proposed German hydrogen core network proposed by fifteen gas transmission system operators (TSOs). The approved network consists of 9,040 km of pipelines (reduced from the 9,700 km in the submitted plan), 56% of which would be repurposed natural gas pipelines. The network links Germany to several other EU Member States and connects major import routes with key demand hubs. A distribution grid is planned for a later phase.[21] The hydrogen core network is expected to be completed by 2032 or, if demand does not develop as initially expected, by 2037. It is designed to accommodate around 101 GW of entry capacity, 58 GW of which refers to imports, and 87 GW of demand capacity.

38 Besides setting the groundwork for the future hydrogen network, BNetzA also made significant steps towards the development of a hydrogen regulatory framework. The most significant advancement was the establishment of the rules on the financial framework of the core network that include an inter-temporal cost allocation mechanism.[22] The relevant determination on the framework on hydrogen tariffs (WANDA) was adopted on 6 June 2024 and came into effect on 1 January 2025. Based on this determination, on 14 July 2025, in a separate procedure, BNetzA set the level of the ramp-up tariff at 25 EUR/kWh/h/y. An update of the WANDA determination was ongoing at the time of the drafting of this report. The updated determination assesses the introduction of capacity products with shorter than annual duration, discounts for interruptible capacity products, and potential discounts for capacity bookings at storage points. In addition to the tariff framework, on 5 November 2025, BNetzA adopted the determinations on the balancing and network access frameworks for the future hydrogen network. A short description of these rules is presented in Box 1.

39 Along with the market rules, the development of an integrated network development plan for hydrogen and natural gas is ongoing. On 30 April 2025, BNetzA approved the scenario framework for the long-term gas and hydrogen network development plan, which is based on common assumptions for electricity, gas, and hydrogen networks. This scenario framework will serve as the basis for the integrated network development plan, which is currently under development.

21 The German Building Energy Act requires at least 65% renewable energy or waste heat in the heating systems. As an exemption, it is still possible to install and operate natural gas heating systems, however, the heating system operators must ensure that hydrogen is used as an energy source by 2045 at the latest and agree with the distribution system operator on a roadmap. In 2024, BNetzA carried out a consultation on the requirements of such roadmaps and issued a determination (FAUNA) on 17 December 2024, which entered into force on 1 January 2025.

22 On 28 July 2025, ACER published a Recommendation on the methodologies for setting the inter-temporal cost allocation for hydrogen networks, in line with Article5(6) of the hydrogen and gas decarbonisation Regulation. A summary of the recommendation is presented in Box 2.

Box 1: WANDA, WASABI, and WAKANDA – the German hydrogen market rules

Hydrogen demand supplied via the transmission network is expected to increase substantially in Germany over the coming decades compared with the initial years of operation. Since the core network is designed for future demand levels, recovering its costs from a small number of early users could lead to disproportionately high transmission tariffs and discourage market uptake. To address this, Germany introduced an inter-temporal cost allocation mechanism (**WANDA**) under Article 5(3) of the hydrogen and gas decarbonisation Regulation. The mechanism combines a "ramp-up tariff" with an amortisation account, shifting part of the cost recovery to later years to avoid excessive tariffs during the early phase. This approach may generate temporary deficits, creating liquidity challenges for network operators. To mitigate this, the public development bank KfW will provide dedicated financing to cover short-term funding needs until demand, and thus tariff revenues increase. As the market matures, operators are expected to repay these advances. If demand growth falls short of expectations, the ramp-up mechanism may not achieve full cost recovery. In that case, the financial risk is shared between the German State (76%) and HNOs (24%), incentivising prudent investment decisions. Should it become evident by 2038 that demand will not reach the required levels, the government may terminate the mechanism, assume control of the network, and cover accumulated losses subject to a deductible borne by HNOs (between 16% and 24%, depending on the timing).

The determination on the balancing rules (**WASABI**) sets out the hydrogen balancing regime, scheduled to start in January 2028. A market area manager will be appointed to oversee capacity allocation and balancing. Continuous balancing will replace fixed settlement periods, using three system-wide flexibility zones (green, yellow, and red) representing different imbalance tolerance levels. Network users will be classified as helpers or causers of imbalances. The latter will face penalties covering the market area managers's balancing costs, while the former will receive rewards. A centralised data exchange hub will be established by 1 July 2027, and tested and made operational by the system's start date. During the early phase, when separate hydrogen clusters exist without full interconnection, balancing will apply per cluster and will later expand to the integrated market area. A virtual trading point for hydrogen will be created, though trading may initially only occur within a cluster. The market area managers will publish annual reports on balancing developments from 1 April 2029.

The determination on a basic model for network access and capacity allocation (**WAKANDA**) defines the basic hydrogen network access model, closely mirroring that of the natural gas market. It establishes an entry-exit system with firm capacity products as the default and allows restricted firmness for inter-cluster transport as well as interruptible capacity options. Capacity products will be offered on yearly, monthly, and daily basis, with set reserve quotas for short-term capacity. Bundling capacity products at interconnection points is mandatory. Capacity allocation will follow a first-come, first-served approach until a certain threshold of firm capacity is booked beyond which auctions will apply. The threshold will be defined by the network operators. The determination also details rules on nominations, interconnection agreements, and data exchange, ensuring consistency with established gas market practices.

2.2.3.2. Denmark: network development progress

40 In Denmark, the fully state-owned electricity and gas TSO (Energinet) has been tasked to develop and operate a hydrogen transmission network. As of February 2025, the government decided to go ahead with a financial support scheme for the development of a network called the Seven in the southern part of Jutland. The Seven will connect renewable hydrogen production to the German Core Network at the Danish-German border in Ellund. It will consist of a new pipeline between Esbjerg and Egtved and a repurposed pipeline between Egtved and Ellund, converting one of two existing gas pipelines to transport hydrogen. It is expected that the Seven will become operational in 2030 and that Energinet will finance its development via a state loan of approximately EUR 1 billion. In 2026, Energinet will launch a user commitment process (open season) for the Seven, offering annual entry and exit capacity for a binding contract length of up to 15 years on a first-come, first-served principle. If oversubscription occurs, a capacity auction will be conducted to allocate capacity for each affected year. To reduce contractual risks and facilitate participation in the open season, the proposed terms and conditions foresee that network users have the option to cancel their contract with the network operator within 6 months from its signature, if they are not able to complete their offtake agreements with hydrogen consumers. Notably, capacity allocated to the Danish hydrogen network is expected to be bundled with capacity allocated in the German hydrogen network in a coordinated process.

41 The political agreement setting the principles of economic regulation of the future hydrogen network in Denmark stipulates that regulated access to hydrogen infrastructure must be introduced from the outset. It also introduces revenue-cap regulation as the basis for setting tariffs and an additional operating support of up to EUR 1.4 billion over 30 years. According to the agreement, the State-backed financing and risk mitigation measures are however, subject to the following overarching conditions.

- Energinet must establish a fully owned subsidiary to act as an HNO.
- The Danish Utility Regulator (DUR) needs to design an inter-temporal cost allocation model.
- Network users will have to commit, for at least 10–15 years, to annual purchases of a minimum of 1.4 GWh/h of the full hydrogen network's planned capacity (3 GWh/h). This requirement was later altered to reflect the capacity of the prioritised Seven network and is currently set at 0.5 GWh/h (corresponding to approximately 12-17% of the total capacity of the Seven).
- At least 10% of the capacity has to be reserved for short-term capacity allocations.

42 DUR is currently working on the design of the inter-temporal cost allocation mechanism and has already approved two methodologies relating to the market rules for access to the hydrogen network. The first methodology requires the reservation of 10% of the technical capacity of the hydrogen network for short-term products, fulfilling the relevant requirement of the aforementioned political agreement. The second methodology defines that up to 90% of the network capacity sold as yearly products can be sold with a longer duration of up to 15 years. These market rules are similar to rules that will apply to the German hydrogen network directly connected to the Danish hydrogen network, thus ensuring consistency. Before the end of 2025, DUR plans to issue a decision on the terms and conditions of the open season and a decision on the rules for connecting hydrogen production facilities to the hydrogen network.

Box 2: ACER Recommendation on inter-temporal cost allocation for hydrogen networks

In July 2025, ACER published a Recommendation on the methodologies for setting the inter-temporal cost allocation for hydrogen networks, in line with Article5(6) of the hydrogen and gas decarbonisation Regulation. Inter-temporal cost allocation mechanisms allow hydrogen network operators to spread the recovery of the network costs over time via network access tariffs. In view of the expected long hydrogen demand growth period, these mechanisms aim to ensure that future users of the hydrogen network duly contribute to the initial investment. This promotes a fairer sharing of network costs between early and future users, resulting in more affordable tariffs for everyone.

ACER's Recommendation recognises that the development of a hydrogen transmission network in the EU is characterised by a high degree of uncertainty, caused primarily by the persisting high cost of renewable hydrogen which makes long-term contractual commitments difficult. In their responses to ACER's public consultation, stakeholders, particularly HNOs, consistently highlighted demand and volume risk as the most significant challenge. The pace, scale, and spatial distribution of hydrogen uptake remain unpredictable, creating a risk of under-utilisation and stranded assets.

ACER also notes the persistence of regulatory uncertainty, given that key elements of the hydrogen market framework, such as network codes on tariff structures, are still evolving and may be implemented unevenly across Member States. Additional infrastructure and coordination risks arise from the need for synchronised cross-border planning, and the possibility of mis-aligned national approaches. Finally, ACER acknowledges that the inter-temporal cost allocation mechanisms themselves introduce governance and design risks, notably the potential for an imbalanced distribution of costs between early and future users if demand projections do not materialise.

To address these challenges, ACER recommends that Member States and NRAs implement mechanisms that are flexible, transparent, and subject to robust oversight. The design of the mechanisms should be based on realistic, data-driven planning assumptions, supported by scenario analysis and regular monitoring to ensure that tariff levels remain proportionate over time. ACER emphasises the need for clear governance structures, including well-defined roles for NRAs and HNOs, and transparent methodologies for estimating and allocating costs. Strong cross-border coordination is identified as essential to prevent fragmentation. ACER also proposes periodic review of the inter-temporal cost allocation frameworks to reflect evolving market conditions and to avoid long-term lock-in to assumptions that may no longer be valid.

2.3. Hydrogen market support

43 The development of the hydrogen market relies on support to create viable business cases across the hydrogen value chain. The 2024 Report provided an overview of EU funding programmes relevant for hydrogen and of approved State aid schemes. In its 2024 special report on hydrogen, the European Court of Auditors estimated that for the period 2021-2027, total EU funding available for hydrogen-related projects amount to EUR 18.8 billion, of which around EUR 13.6 billion comes from the Recovery and Resilience Facility (RRF). According to information in its dedicated web-report on hydrogen, the Climate, Infrastructure and Environment Executive Agency (CINEA) manages a wide range of EU programmes with a total EU funding of EUR 5.6 billion supporting a wide portfolio of 229 projects. The vast majority of the funding (EUR 4.3 billion) comes from the Innovation Fund. Combining information from these two sources, the total allocated EU funds exceed EUR 20 billion.[23] As part of the Clean Industrial Deal, the Commission also plans to establish the Industrial Decarbonisation Bank, aiming to mobilise EUR 100 billion targeting the decarbonisation of the industrial sector; this includes measures involving the use of renewable or low-carbon hydrogen.

44 Apart from the support provided by EU-wide schemes, Member States have developed national schemes providing financial support to hydrogen projects. Currently, information on these schemes is dispersed, making comparisons between allocated funds and the market requirements difficult. Since the 2024 Report, the Commission has issued another 16 State aid decisions that are relevant to the hydrogen value chain (see Table 3 in the Annex).

45 Following the initial interest from Germany and the Netherlands on the auction-as-a-service mechanism, Spain, Lithuania, and Austria have also expressed their interest in using the European Hydrogen Bank's auction results to allocate support of up to EUR 836 million in national funds. In July 2025, Spain announced that it has awarded EUR 377 million to three hydrogen electrolyser projects with a cumulative capacity of 485 MW that were not selected at the second auction of the European Hydrogen Bank.

46 In addition to the direct financing of hydrogen projects and according to ACER's recent report on electricity tariffs practices, Austria and Germany have introduced reductions in electricity network tariffs for electrolysers to lower the production cost of renewable hydrogen. In Austria, all facilities using electricity to produce other energy carriers (P2X) with at least 1 MW capacity are exempted from use-of-network charges for the first 15 years after their operation. They are also exempted from connection charges if their grid connection quotient does not exceed a certain threshold. In Germany, all P2X facilities are similarly exempted from use-of-network charges.

23 This estimate includes EUR 13.6 billion from the RRF, EUR 1.2 billion from Horizon and EUR 0.8 billion from InvestEU based on the report of the European Court of Auditors, and EUR 4.3 billion from the Innovation Fund, EUR 0.7 billion from the Connecting Europe Facility funds, EUR 7 million from the European Maritime, Fisheries and Aquaculture Fund and EUR 15 million from LIFE based on CINEA's report. It is assumed that the amount of the Innovation Fund includes the announced EUR 3 billion allocated to the European Hydrogen Bank auctions.

2.3.1. European Hydrogen Bank Auctions

47 Following its inaugural pay-as-bid auction in 2023, the European Hydrogen Bank launched a second auction in December 2024[24] with a total budget of EUR 1.2 billion. For the first time, the bank included a dedicated call for the maritime sector. The auction attracted a total of 61 bids, including 8 under the maritime auction, encompassing projects across 11 countries of the European Economic Area (EEA). Altogether, the submitted bids amounted to 6.3 GW of electrolysers able to produce 460 million tonnes of RFNBO hydrogen and oversubscribed the allocated budget by more than four times. More than half of the bids (36 out of 61) came from projects in Spain.

48 The Commission initially selected 15 projects to receive a total of EUR 992 million in EU funding, 3 of which from the maritime auction. The projects targeted key sectors such as transportation, the chemical industry, and the production of methanol and ammonia, and were expected to produce approximately 2.2 million tonnes of renewable hydrogen over a 10-year period. The geographical distribution of the selected projects was wider than the first auction, spreading among five countries, namely Finland, Germany, the Netherlands, Norway, and Spain.

49 Between August and September 2025, seven projects, with a total capacity of 1.8 GW out of the total 2.2 GW awarded under the general auction, withdrew their application and decided not to continue with the process.[25] On top of these withdrawals comes the withdrawal of the 500 MW Catalina project that secured funds from the first auction but decided to continue its development under the more favourable national support scheme. In response to this development, the Commission is looking into reallocating the funds of the withdrawn projects of the second auction to 10 reserve-listed projects, while the allocated funds of the Catalina project will be redirected to future auctions. The bids of the 10 newly selected projects range from 0.64 to 1.22 EUR/kg, still much lower than the auction ceiling price of 4 EUR/kg.[26] The final list of the projects that eventually signed the funding agreements is expected to be made public before the end of 2025.

50 The reasons for these withdrawals vary across projects,[27] however some project promoters mentioned regulatory delays and infrastructure gaps that made it difficult to meet the deadline for entry-into-operation.[28] While these may be legitimate reasons for their decisions, the withdrawal may indeed be, as the Commission advocates, the positive outcome of the cross-checking mechanisms of the auction, such as the completion guarantee, to ensure that funds are allocated only to projects with high chances of materialisation. Indeed, it is the final implementation of the projects that will mark the success, or not, of the European Hydrogen Bank auctions.

24 The auction's webpage provides more detailed information including an extensive analysis of the bids. Box 3 summarises this information.

25 More details on the projects can be found in the relevant tables in the auction's webpage.

26 The ceiling price was reduced from the 4.5 EUR/kg. Other changes introduced with respect to the previous auction included stricter supply chain resilience criteria and more stringent project maturity requirements.

27 For example, while the Catalina project will continue to achieve its planned commercial start-up with support from the Spanish government, the project promoters, Copenhagen Infrastructure Partners and Enagás Renovable, also mentioned tight operational deadlines and insufficient progress on national hydrogen pipeline infrastructure. The H2-Hub Lubmin project promoters mentioned the uncertain regulatory framework, which hampers market development and makes it difficult to secure long-term offtake agreements, as the main reason for stepping back. The Zeevonk Electrolyser project withdrew after delays to the Delta-Rhine Corridor hydrogen pipeline shifted its expected completion to 2031–2032, i.e. beyond the EU's requirement for projects to be operational by 2030 with access to a viable offtake market (see newsletter from S&P Global here).

28 As with the previous auction, the developers of selected projects were invited to prepare their grant agreements with the CINEA, with completion expected by November 2025 at the latest. The developers are then required to finalise all financing arrangements within 2.5 years and begin producing renewable hydrogen within 5 years of signing the grant agreement.

51 The European Hydrogen Bank is preparing a third auction in December 2025 where several key updates will be introduced. The auction will support both RFNBO and electrolytic low-carbon hydrogen. This inclusion marks a policy shift for the bank beyond strictly renewable RFNBO hydrogen funding. The draft terms and conditions of the 2025 auction propose a total budget of EUR 1.1 billion allocating EUR 400 million for projects involving either RFNBO or electrolytic low-carbon hydrogen, EUR 400 million exclusively for RFNBO, and another EUR 100 million for the maritime sector.[29] In line with the Net Zero Industry Act, the Commission will revise the resilience requirements for electrolysers to avoid irreversible dependency on China and will also introduce minimum cybersecurity requirements. Furthermore, to ensure alignment with broader environmental objectives, projects will now be assessed against 'do-no-significant-harm' technical screening criteria.[30] In an effort to ensure that participating projects are mature enough, the Commission will also introduce updated rules for offtake agreements and electrolysers procurement. The new State aid cumulation rules (see Section 2.1) will also apply, aiming to enlarge funding for projects from multiple sources.

29 Although the budget of the third topic can be increased according to the contributions of EEA countries to the auction-as-a-service feature, up to a maximum of EUR 100 million.

30 "Do not significant harm" criteria, laid out in the Climate Delegated Act, ensure that funded projects do not cause significant harm to any of the six environmental objectives in Article 17 of the EU Taxonomy Regulation, namely climate change mitigation, climate change adaptation, sustainable use and protection of water and marine resources, circular economy, pollution prevention, and protection and restoration of biodiversity and ecosystems.

Box 3: Second European Hydrogen Bank auction – useful insights from the bids analysis

The Commission's analysis of the results of the second auction of the European Hydrogen Bank provides some useful insights, despite the withdrawal of seven awarded projects from the funding process.

The auction attracted 61 bids from 11 countries with a total capacity of 6.3 GW. This is lower than the 132 bids from 17 countries submitted in the first auction, totalling 8.4 GW in capacity. This could be the result of strong competition and very low bids of the first auction, which might have discouraged the participation of projects that need higher premiums. Notably, 36 out of the 61 bids came from Spain, indicating a high concentration and a competitive advantage of the region; out of the 34 projects with bids below 1 EUR/kg, 26 were Spanish.

Compared to the first auction, the average bid increased by roughly 21%. The bids of the 18 selected projects (including the maritime topic and the projects selected after the withdrawal of seven initially selected projects) range from 0.33 EUR/kg to 1.88 EUR/kg.

Based on the information submitted among all the bids, the levelised cost of hydrogen (LCOH) of individual projects ranges from 3.1 EUR/kg in Spain to 19.8 EUR/kg in Austria, reconfirming the wide differences across regions. The average LCOH was 7.1 EUR/kg, which is lower than the 9.5 EUR/kg of the first auction and the current estimates for RFNBO hydrogen (see Section 4.1.1).

In terms of targeted offtakers, industry comes first again, followed by the mobility and hydrogen derivative sectors. Average offtake prices calculated by sector range from €3.60/kg for construction up to €14.04/kg for non-ferrous metals. Key industrial sectors demonstrate a willingness to pay that is close to the average reported LCOH. These include chemicals (6.43 EUR/kg), iron and steel (6.69 EUR/kg), maritime (7.12 EUR/kg), and refineries (7.85 EUR/kg). On the other hand, the willingness to pay for ammonia and methanol producers is significantly lower at 4.95 EUR/kg and 5.29 EUR/kg, respectively. This could be due to easier access to the global supply chain these sectors may have.

Interestingly, out of the 61 total bids, 22 came from projects directly linked with the offtaker, 26 bids came from projects with integrated renewable energy supply, and 23 projects were completely decentralised. The average bid of integrated projects was half compared to that of decentralised ones, indicating the importance of secured energy costs and offtake agreements. Notably, 39 projects reported that their planned delivery method is via pipeline, while 13 indicated road transport.

Regarding the cost structure of the offtake agreements, 35 out of the 61 projects reportedly opted for fixed price contracts, reaffirming the outcome of the first auction. In terms of the electricity supply, only 10 projects reported they plan not to use the grid at all, while more than 60% of the projects foresee the use of a PPA. The variety of reported electricity supply paths indicates the complexity of optimising electrolysers' performance to produce RFNBO-compliant hydrogen and the need to use all available options to reduce costs and increase operating hours.

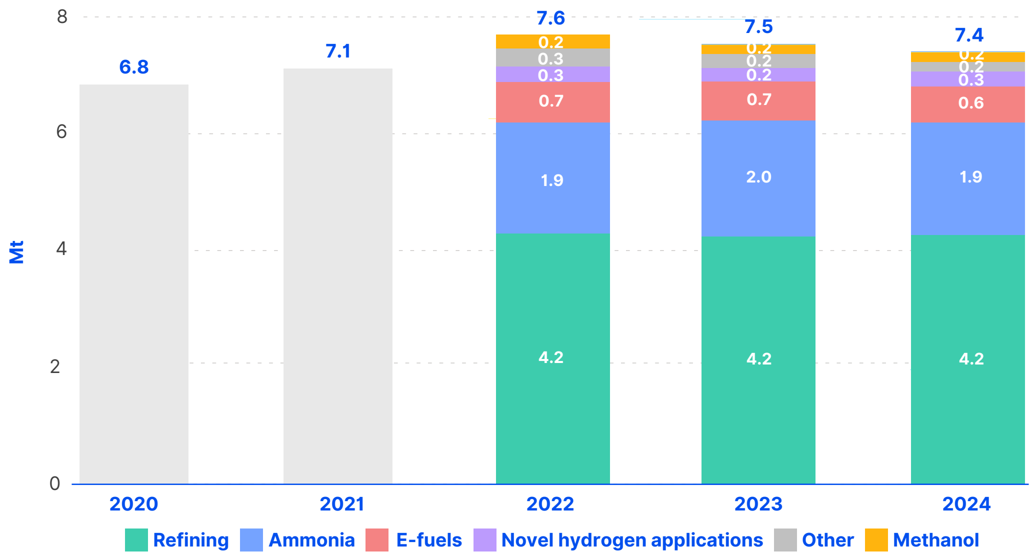
3. Market developments

52 This section provides insights into the most recent hydrogen market developments. It presents the status of the market for hydrogen in the EU, focusing on the development of renewable and low-carbon hydrogen production projects (Section 3.1) and provides an overview of the current and planned infrastructure developments (Section 3.2).

3.1. Hydrogen consumption and supply[31]

53 Consumption of hydrogen in the EU decreased slightly in 2024 to 7.4 million tonnes. The decline is mainly due to the continuous downward trend of the chemicals sector (-12% since 2022) with the consumption of the other major sectors remaining largely stable (e.g. refining) or slightly declining (e.g. ammonia -1%, methanol -0.5%) compared to 2023. Notably, while still very low, accounting for only 270,000 tonnes, the use of hydrogen in novel applications[32] increased by 9% in 2024, led mainly by mobility (+35% year-on-year).[33]

Figure 4: Total hydrogen consumption breakdown by end use in the EU – 2020-2024 (Mt)



Source: ACER, based on data from S&P Global Commodity Insights (for 2020-2021) and European Hydrogen Observatory (for 2022-2024).

54 As shown in Figure 5, steam methane reforming (SMR) remains the dominant hydrogen production technology, accounting for 89% of the total capacity. Electrolyser hydrogen production capacity increased to 50 kt/y in 2024 from 40 kt/y in 2023 but still has a marginal share.

31 This section uses three main sources of information: the European Hydrogen Observatory, the IEA's hydrogen project database, and S&P Global Commodity Insights databases. ACER found that the three databases are generally consistent (see Figure 29). The European Hydrogen Observatory updated its 2022 and 2023 databases, introducing adjustments in conversion factors, updated end-use categories and project status indications, and revised production volumes. These methodological updates may lead to differences between the information presented in this report and the 2024 Report.

32 Novel hydrogen applications include industrial heat, mobility, synthetic fuels (e-fuels), steel, power generation, and residential heat.

33 Hydrogen consumption by country and sector is further shown in Figure 30 in the Annex. The largest consumers, Germany, the Netherlands, and Poland, accounted for nearly half of the hydrogen demand in 2024. Refining and ammonia production dominated across nearly all countries.

Figure 5: Hydrogen production capacity by process type in the EU – 2024 (Mt/y)

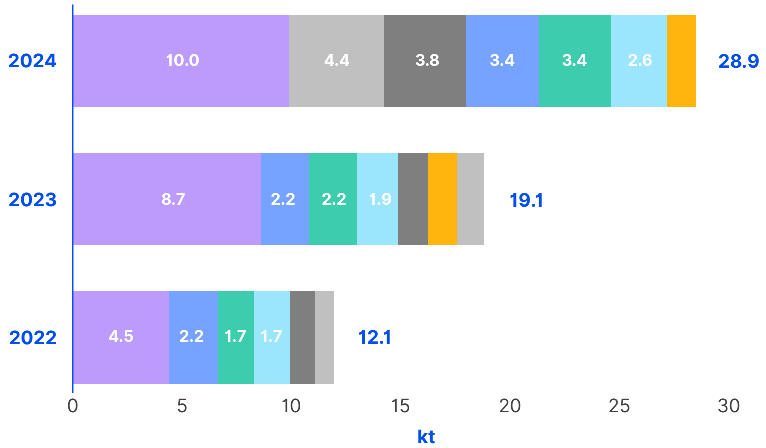
Source: ACER, based on data from the European Hydrogen Observatory.

Note: For the annual hydrogen production capacity for electrolysers European Hydrogen Observatory assumes nearly 100% utilisation rate.

3.1.1. Hydrogen produced via electrolysis

55 Hydrogen produced via electrolysis remained a small component of the overall hydrogen consumption in 2024, but the growth was significant. Production of electrolytic hydrogen increased from 19,000 tonnes in 2023 to 29,000 tonnes in 2024 (+51% year-on-year). Most of the additional electrolytic hydrogen was produced and consumed in Germany, which showed significant growth (+58% year-on-year) driven mainly by the chemical sector.[34] At EU level, consumption of electrolytic hydrogen in novel hydrogen applications more than doubled since 2022, as shown in Figure 6, and in 2024 it accounted for 40% of total electrolytic hydrogen consumption. Consumption in all other sectors apart from methanol production also increased. Figure 7 further shows that the main driver of this increase is attributed to industrial heat and mobility, together accounting for two-thirds of the total consumption, while the other sectors seem stagnant.[35] The chemicals sector also showed a remarkable +260% increase; however, other traditional hydrogen consuming sectors have still not demonstrated the dynamism needed to scale-up the market.

Figure 6: Electrolytic hydrogen consumption by end-use in the EU – 2022-2024 (kt)

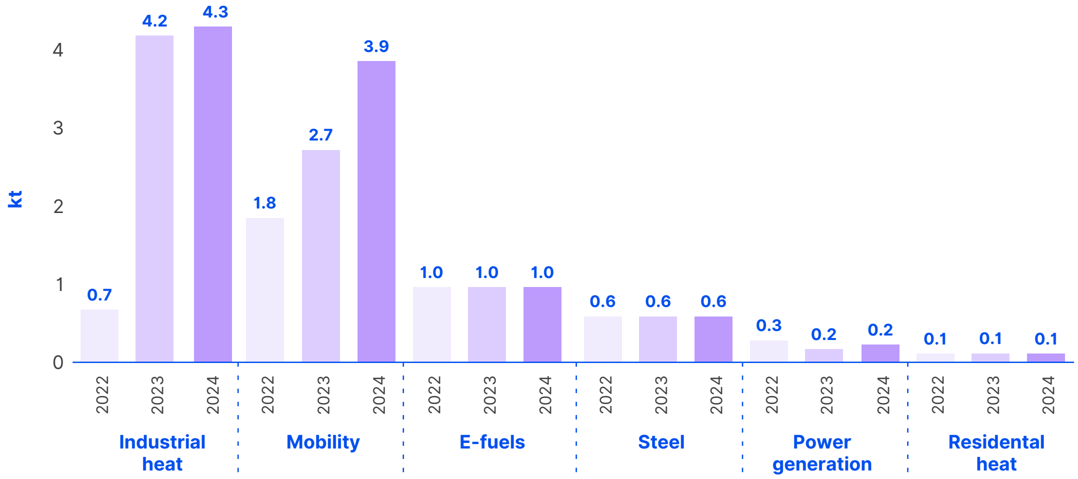


Source: ACER, based on data from the European Hydrogen Observatory.

34 A breakdown of consumption by country and sector is provided in Figure 30 in the Annex.

35 Box 4 further discusses developments on e-fuels for aviation.

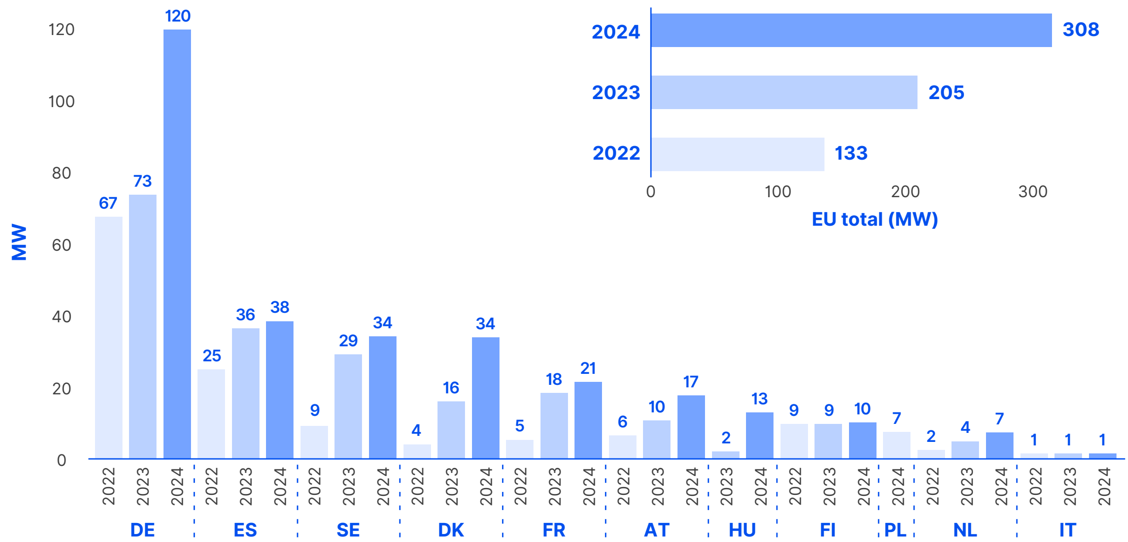
Figure 7: Breakdown of electrolytic hydrogen consumption in novel hydrogen applications in the EU – 2022-2024 (kt)



Source: ACER, based on data from the European Hydrogen Observatory.

56 According to data from the European Hydrogen Observatory, an additional 104 MW of electrolyser capacity started operation in 2024. This constitutes a 51% year-on-year increase bringing the total electrolyser capacity to 308 MW.[36] More than 70% of the total new capacity was added in Germany (46 MW), Denmark (18 MW), and Hungary (11 MW). The total electrolyser capacity is still very low compared with the ambitions of the European and national strategies, reflecting the significant challenges towards a rapid expansion of the hydrogen sector.

Figure 8: Installed electrolyser capacity in the EU – 2022-2024 (MW)



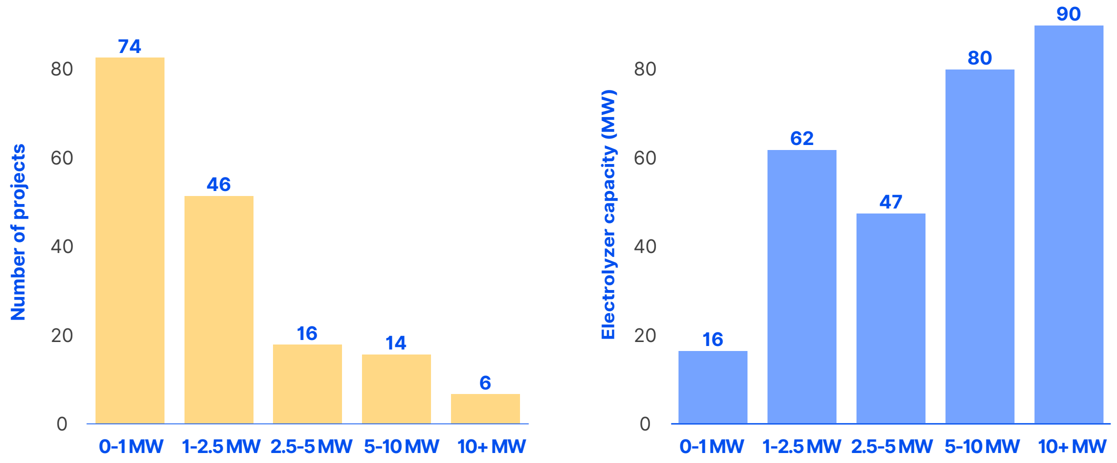
Source: ACER, based on data from the European Hydrogen Observatory.

Note: The figure presents only Member States with electrolyser capacity over 1 MW.

36 According to S&P Global Commodity Insights, during the first semester of 2025 an additional 144 MW of capacity was commissioned, while based on IEA's Hydrogen Projects Database the cumulative commissioned electrolyser capacity in the EU is projected to reach 493 MW by the end of 2025.

57 According to detailed data disaggregated by plant from the green hydrogen projects database of S&P Global Commodity Insights, most operational electrolysis projects are currently relatively small, with only six plants exceeding 10 MW. These projects, however, account for around a third of the total installed capacity.

Figure 9: Distribution of the number (left) and capacity (right) of currently installed electrolyser projects in the EU by size – 2024 (MW)



Source: ACER, based on data from S&P Global Commodity Insights.

58 The short-term prospects of electrolysers' deployment show similar signs of lower-than-expected growth. According to data from S&P Global Commodity Insights, projects under construction expected to be commissioned in 2026 and 2027 account for 1.8 GW.[37] This brings the total capacity of electrolysers largely confirmed to date at 2.3 GW. Sweden and Germany account for around two-thirds of the total capacity under construction (742 MW and 414 MW, respectively). France (237 MW), the Netherlands (200 MW), and Portugal (100 MW) also show progress, moving toward tangible deployment. In Spain, on the contrary, only 25 MW of electrolysers is under construction despite the high interest and potential demonstrated in the European Hydrogen Bank's and national auctions.[38]

59 Adding the capacity that is currently operational with that under construction brings the total capacity in 2027 to just 2.3 GW. At the current reported annual growth rates (50%) the resulting total capacity of electrolysers in 2030 could reach 7 GW, able to produce approximately 510,000 tonnes of renewable hydrogen.[39] This value is still far too low compared with the capacity needed to reach the European targets, indicating a need to enhance the deployment of electrolysers. Projects in advanced planning stage may add an additional 10 GW in 2030. Considering the full projects pipeline from all the maturity levels with expected commissioning date by 2030, the resulting capacity reaches 62 GW, which is aligned with the cumulative 2030 Member States' targets of 48-54 GW (see Figure 1 Section 2.2.1).

37 The European Hydrogen Observatory database provides limited information on future projects.

38 Figure 31 in the Annex provides the electrolyser capacity under construction per Member State.

39 Assuming 4,000 hours of operation at nominal capacity and a 61% efficiency.

Box 4: Synthetic aviation fuels

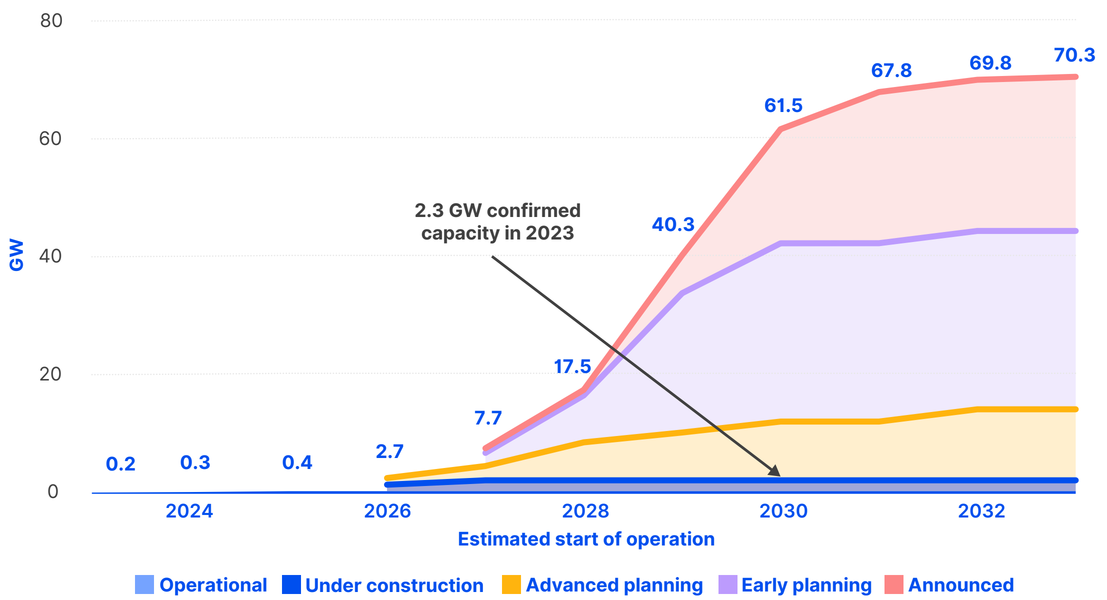
Synthetic aviation fuels made from renewable hydrogen and captured biogenic carbon are a subcategory of the sustainable aviation fuels that are used to decarbonise the aviation sector. The ReFuelEU Aviation Regulation sets specific targets for the share of synthetic aviation fuels on the total fuel consumption of the sector. Starting from at least 1.2% in 2030, the regulation sets a binding target of 5% by 2035 and at least 35% in 2050. The European Aviation Safety Agency (EASA), tasked with monitoring the implementation of the regulation, issues an annual technical report that provides insights into the state and development of the sustainable aviation fuel market in the EU.

According to EASA's 2025 European Aviation Environmental Report, the scale-up of synthetic aviation fuel production in the EU is lagging. As of June 2025, there are 55 announced demonstration or commercial projects in the EEA, with a combined capacity of approximately 3 million tonnes per year. However, none of them have reached the final investment decision. Projects outside the EEA show also slow development putting the 2030 sub-target for synthetic aviation fuels at risk.

Based on EASA's analysis, the commissioning of announced projects with a certain degree of credibility would result in a capacity of 0.7 million tonnes of synthetic aviation fuels, exceeding the 1.2% target in 2030, which is estimated at 0.6 million tonnes. This is double the demand stemming from the ReFuel EU Aviation Regulation estimated by Hydrogen Europe in its Clean Hydrogen Monitoring 2025 report.

Based on production cost analysis, EASA estimates that the average cost of producing synthetic fuels using RFNBO hydrogen is currently more than 10 times higher than the market price of the conventional aviation fuels. The use of low-carbon hydrogen as an alternative can reduce the average cost of synthetic aviation fuels by 28% when compared with RFNBO hydrogen.

Figure 10: Cumulative electrolyser capacity by project status and estimated commissioning year in the EU – 2023-2033 (GW)



Source: ACER, based on data from S&P Global Commodity Insights.

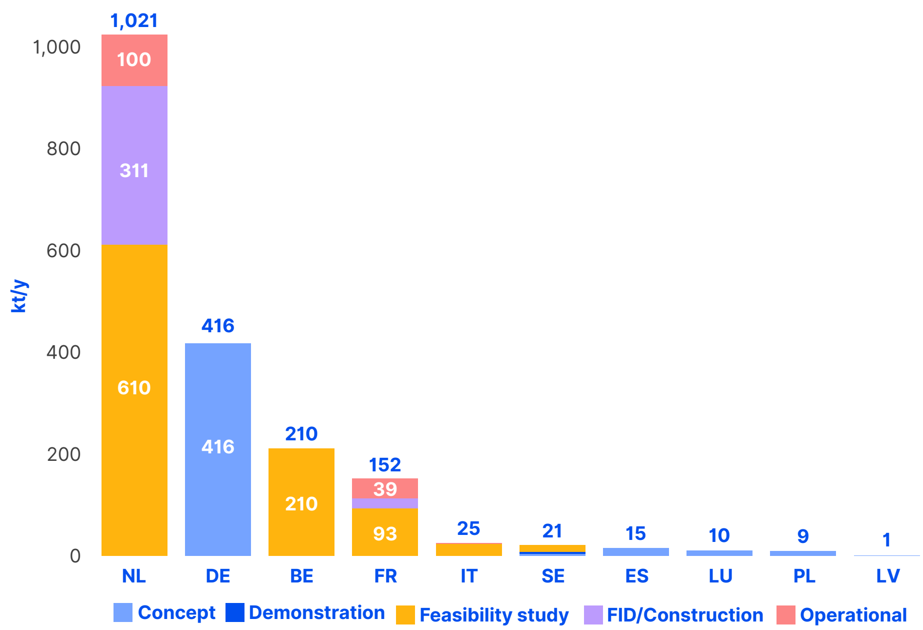
Note: The figure shows projects with an announced planned year of start of operation. In addition, the database includes nearly 17 GW of announced or planned projects with unknown start of operation.

3.1.2. Low-carbon hydrogen projects

60 According to information from the European Hydrogen Observatory, there are currently three hydrogen-producing facilities that use carbon capture in Europe, one in France, one in Italy, and one in the Netherlands, with a joint capacity of 56 thousand tonnes per year.[40] The IEA's hydrogen production and infrastructure projects database includes 37 projects related to hydrogen production from natural gas with CCS in various stages of development in the EU (see Figure 11). Out of these projects, four in the Netherlands and one in France with a total production capacity of 331,000 tonnes have passed the final investment decision.

61 It is unclear to what extent the hydrogen produced from these projects will align with the low-carbon hydrogen rules set in RED III and the Low-carbon Delegated Regulation and whether their plans integrate the infrastructure for transporting and permanently storing the captured CO_2. The development of such infrastructure is also challenging, and if the projects do not already account for it, careful coordination with the related infrastructure investments would be crucial for their successful implementation.[41]

Figure 11: Hydrogen production projects with CCS in the EU – October 2025 (kt/y)



Source: ACER, based on data from IEA's hydrogen production and infrastructure projects database.

40 Based on the information from European Hydrogen Observatory, these are: Air Liquide's Cryocap plant in Port Jerome, France, Shell's refinery in the Netherlands (planned to be decommissioned in 2026), and Sapio's hydrogen production plant in Mantova, Italy. The two first projects do not permanently store the captured CO_2.

41 The Commission adopted the industrial carbon management strategy on 6 February 2024, outlining the set of actions to be taken to develop competitive markets, and storage and transportation infrastructure for CO_2.

3.1.3. Offtake agreements

62 Information on actual expected demand for abated hydrogen is scarce at this stage. According to data by S&P Global Commodity Insights, announced offtake agreements for delivery in the European Economic Area exceed 2 million tonnes. However, binding offtake commitments[42] account for just over 392,000 tonnes, most of which (385,000 tonnes) refer to production within the EEA. Around a third of these volumes (122,000 tonnes) refer to low-carbon hydrogen produced from natural gas with CCS. The amount of the remaining, domestically produced renewable hydrogen contracted (270,000 tonnes) would require some 3.7 GW of electrolysers,[43] indicating a gap between these requirements and the capacity of electrolysers currently in operation or under construction (2.3 GW, see Section 3.1.1).

Table 1: Announced binding hydrogen offtake agreements (tonnes per year) – May 2025

Country	Domestic	Netherlands	Norway	Egypt	Total
Belgium		15,000			15,000
France	20,892				20,892
Germany	75,783		17,655		93,438
Hungary	414				414
Netherlands	124,278			7,640	131,918
Norway	3,150				3,150
Portugal	15,030				15,030
Romania	8,000				8,000
Spain	4,500				4,500
Sweden	100,000				100,000
Total	**352,047**				**392,342**

Source: ACER, based on information from S&P Global Commodity Insights.

3.2. Infrastructure development

3.2.1. Hydrogen infrastructure planning

EU wide ten-year network development plan (TYNDP)

63 The development of the TYNDP by the European Network of Transmission System Operators for Gas (ENTSOG) is a key planning process for the European gas and hydrogen networks.[44] The 2024 Report included information on the hydrogen projects included in the preliminary database of the 2024 TYNDP edition. Up until the drafting of this report was completed, the TYNDP 2024 process was not yet formally concluded, marking significant delays. In its opinion on the draft ENTSOG hydrogen infrastructure gaps identification report, ACER recognises the challenges of the exercise performed by ENTSOG and calls for a streamlined future process that will enable the timely delivery of the expected results. ACER also calls for stronger stakeholder engagement and increased transparency, enhancing the credibility of the assessment. Finally,

42 Including integrated production and use projects with a final investment decision.

43 Assuming 4,000 hours of operation at nominal capacity and 61% efficiency.

44 According to the hydrogen and gas decarbonisation Directive, ENNOH will undertake the development of the TYNDP for hydrogen from 2028 onwards, in close cooperation with ENTSOG and ENTSO-E. ENTSOG is still responsible for TYNDP 2026.

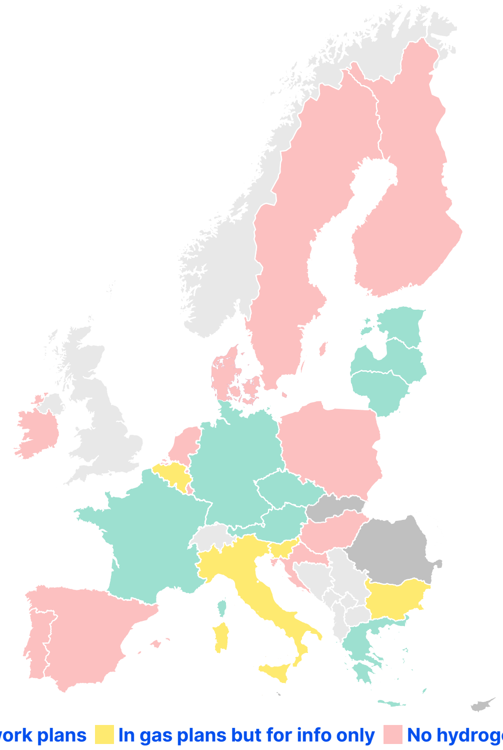
it suggests a more integrated modelling approach to capture cross-sectoral impacts, especially regarding the underlying electricity infrastructure needs, along with the consideration of sensitivities that reflect the uncertainties of the sector.

64 In June 2025, the European Network of Transmission Operators for Electricity (ENTSO-E) and ENTSOG initiated a public consultation on the draft common TYNDP 2026 scenarios. The TSO entities have reassessed their estimates of total hydrogen demand for 2030 at the EU level in the TYNDP 2026 scenarios expecting a total demand of 6.3 million tonnes. This is nearly half of the demand of the TYNDP 2024 scenarios (11.7 million tonnes) developed in 2022 and is more aligned with the cumulative demand stemming from the national strategies and policies (estimated at 4-7 Mt, see Figure 1 and Section 2.2.1).

National ten-year network development plans

65 According to the hydrogen and gas decarbonisation Directive,[45] HNOs must develop a single national TYNDP for hydrogen infrastructure at least every two years and submit it to the NRA for approval. A joint plan for natural gas and hydrogen co-developed by gas TSOs and HNOs is also possible. So far, hydrogen is included in the natural gas network development plans in 12 Member States, as shown in Figure 12. In four of them, the plan includes hydrogen infrastructure for information purposes only, as the HNOs and NRAs do not yet formally have the relevant competences.[46]

Figure 12: Hydrogen network development plans in EU Member States – November 2025



Source: ACER, based on information from NRAs.

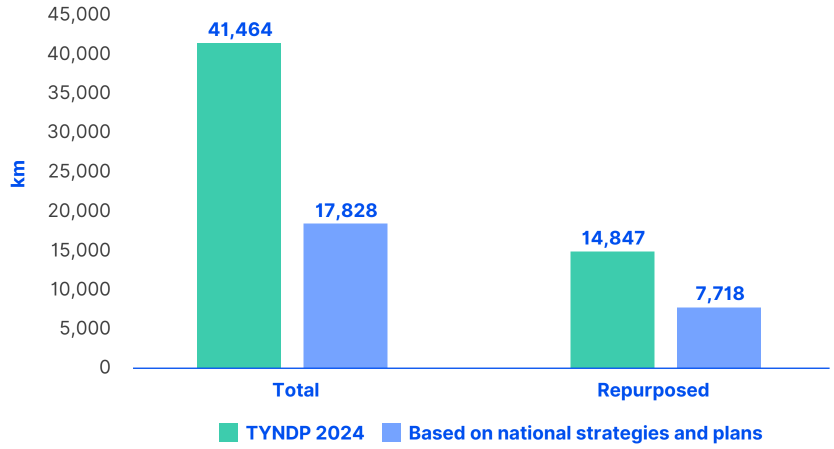
Note: In Spain, the provisional hydrogen network operator, Enagás Infraestructuras de Hidrógeno, S.L.U., submitted a non-binding proposal for a ten-year hydrogen backbone infrastructure plan to the Ministry, according to the provisions of the Royal Decree-Law 8/2023. The Ministry is currently assessing the proposal.

45 Article 55 of the Directive.

46 The survey conducted for the ACER Opinion on the 2024 PCI/PMI list showed that only 14% of the PCI/PMI projects are included in the network development plans of all hosting Member States, 53% are included in the network development plan of at least one hosting Member States, and 33% are not included in the relevant network development plans.

66 A comparison between the infrastructure included in ENTSOG's TYNDP 2024 and the information on planned infrastructure based on national plans and strategies provided by NRAs for the purpose of this report, reveals significant discrepancies in some Member States.[47] As Figure 13 shows, the network developments foreseen in the TYNDP 2024 are significantly higher than those currently planned at the national level, according to the NRAs.

Figure 13: Comparison of planned hydrogen network based on national strategies and plans with TYNDP 2024 hydrogen network projects – October 2025 (km)



Source: ACER, based on information from NRAs and ENTSOG's TYNDP-2024 list of projects.

Box 5: ACER's position on improving the EU grid framework

The forthcoming revision of the TEN-E Regulation, planned to start during the fourth quarter of 2025, will be decisive for the development of the EU energy infrastructure, and particularly for hydrogen networks. In September 2025, ACER issued a position paper highlighting structural weaknesses in current governance and proposing measures to ensure that grid planning supports the energy transition effectively. Key elements of ACER's proposals that are relevant, inter alia, for hydrogen market development are shown below.

- **Simplified and coherent scenario development.** The TEN-E Regulation should incorporate an ACER-approved methodology for scenario design and a "trends and projections" scenario alternative to the central one that tracks progress toward policy targets. Additionally, TYNDPs central scenarios should better align with NECPs.

- **Simplification and enhanced oversight of TYNDPs.** Credible and effective TYNDP planning requires a formal methodology for identifying infrastructure needs and gaps, overseen by ACER and supported by realistic deadlines, to ensure regulatory certainty and reliability, particularly in the context of hydrogen infrastructure development.

- **Integrated needs assessment and complementary EU layer.** ACER warns against fragmented planning that risks overbuilding or locking in suboptimal investments. For hydrogen, integrating assessments across electricity, gas, and hydrogen infrastructure is necessary to ensure that networks evolve in line with real market uptake. A complementary EU-wide layer would allow to identify and address gaps overlooked by national plans, promoting cross-sectoral coordination.

47 See Table 4 in the Annex for more details.

- **Enhanced selection and monitoring of PCIs/PMIs.** The PCI/PMI selection process should be streamlined through fewer thematic groups (reduced from 14 to 4, with the explicit inclusion of hydrogen corridors) and a clear distinction between mature and non-mature projects. Given the early stage of the hydrogen sector, a gradual approach will be needed. Additionally, ACER's monitoring function should be strengthened to become a key input into PCI selection.

- **Cross-border cost allocation (CBCA).** Fair cost- and risk-sharing mechanisms will be critical to support the development of cross-border hydrogen networks. To ensure this, the identification of beneficiary countries should be carried out earlier in the PCI selection process, and CBCA should be decoupled from CEF grants for work.

- **Improved transparency of network planning processes.** To increase transparency on incurred and planned infrastructure investments, thereby enabling effective oversight by ACER, the Commission should conduct a comprehensive review of the existing infrastructure-related data reporting obligations.

3.2.2. Hydrogen infrastructure developments

67 Despite the ambitious plans for hydrogen infrastructure depicted in ENTSOG's TYNDP 2024 and in national plans and strategies,[48] there has been little development since the publication of the 2024 Report. According to information by the European Hydrogen Observatory, only 55 km of new hydrogen pipelines were commissioned in 2024,[49] bringing the length of the existing hydrogen networks in the EU to 1,636 km of pipelines, concentrated mainly in Belgium, France, Germany, and the Netherlands.[50] Other projects in Belgium, Germany, and the Netherlands are currently under construction.[51] Apart from pipeline networks, a 500,000 m^3 underground hydrogen storage demonstration facility in Germany was commissioned by Uniper in August 2024, bringing the total number of underground storage facilities in the EU to 5.[52]

68 In **Germany**, BNetzA, approved the core-network in October 2024.[53] The network development process foresees regular updates of the national hydrogen network development plan, providing input like final investment decisions, progress on construction and commissioning. The first integrated hydrogen network plan is expected in 2026. On 14 July 2025, BNetzA's Grand Ruling Chamber for Energy published[54] the determination of a ramp-up tariff for the hydrogen core network based on the use of inter-temporal cost allocation mechanism. Subject to adjustments of inflation, the ramp-up tariff for the hydrogen core network for an uninterruptible yearly capacity product is 25 EUR/kWh/h/y. This sets a uniformly applied entry and exit point tariff. A reassessment of the ramp-up tariff will take place every three years.

48 See Section 3.3 of the 2024 Report.

49 This refers to the first part of Nowega's network foreseen in the GETH2 project in Germany.

50 See the interactive map and related data of the European Hydrogen Observatory. Compared with the data used in the ACER 2024 Hydrogen Report, an additional 12 km of a partially repurposed pipeline operated by Gasunie since 2018 is also included in the database.

51 For example, work on the construction of the first section of the new Dutch hydrogen network began in late 2023. The 32 km hydrogen pipeline will run from Maasvlakte 2 (a new extension of the Port of Rotterdam) to the Shell Pernis refinery. In Belgium, Fluxys Hydrogen has initiated works on the first phase of the hydrogen pipeline network. In Germany, several hydrogen network projects, mainly related to industrial hydrogen clusters, are under construction.

52 The other four are demonstration projects in Austria, France, Germany, and Sweden.

53 See BNetzA's announcement here.

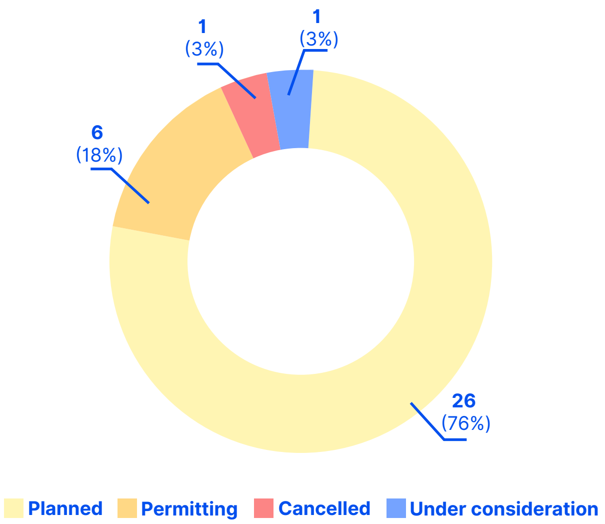
54 BNetzA, Grand Ruling Chamber, decision GBK-24-02-2#4.

69 In the **Netherlands**, the HNO, Hynetwork, has proposed an adjustment to the rollout of the network development plan, delaying the full roll-out by four-to-five years compared with the original plan. The new proposal foresees the conclusion of works on key industrial clusters by 2030, the interconnection of these clusters, including interconnections with Germany and Belgium by 2033 and a further reinforcement with additional interconnections with Germany and Belgium within the same year. The new plan foresees the use of fewer repurposed gas pipelines, which, together with an increase in construction costs, result in a new cost estimate for the Dutch network of EUR 3.8 billion. This constitutes a more than twofold increase compared to the initial estimate of EUR 1.5 billion in 2019.[55] Notably, Hynetwork mentions that the new estimates are still subject to uncertainty due to spatial planning procedures that may change the current network planning. Moreover, new projections by the Dutch environmental assessment agency indicate slower progress in the deployment of electrolysers, expecting 1.2-1.5 GW by 2030, down from the 4 GW initially planned. These new developments have led to a rethinking of the financial model and a request from Hynetwork towards the government and the NRA (ACM) to introduce an inter-temporal cost allocation mechanism.[56]

Progress of hydrogen PCI/PMIs

70 The first project of common interest / project of mutual interest (PCI/PMI) project list includes 65 hydrogen projects spread into the three priority corridors for hydrogen defined in Annex I of the revised Trans-European Networks for Energy (TEN-E) Regulation, namely HI West (36 projects), HI East (9 projects), and BEMIP Hydrogen (3 projects). According to ACER's interactive dashboard presenting the monitoring findings for PCIs/PMIs, out of these projects, 31 refer to hydrogen pipelines, 10 are hydrogen terminals, 7 are hydrogen storage facilities and 17 are electrolysers. Further analysis based on project reports from 34 projects, excluding electrolysers, revealed that only one project is currently under construction, while 6 projects are at a permitting stage, and 26 projects are at an earlier stage of planning. According to the project promoters, the average implementation time may well exceed 7 years. If the PCI/PMI projects are implemented as planned, some 14,777 km of hydrogen network, 76.3 GWh/d of import capacity, and 4.3 TWh of storage (including storage in terminals) will be in place by 2030.

Figure 14: Status of hydrogen PCI/PMIs – November 2024 (number of projects)



Source: ACER's PCI//PMI progress monitoring dashboard.

55 See the Hynetwork's newsletter for more details.

56 See ACM's Market report on hydrogen transport tariffs from the perspective of the hydrogen market.

71 Following the 2025 call for proposals for the establishment of the second PCI/PMI list, the Commission received interest from 203 hydrogen projects. Around 44% of the projects are related to pipelines, 13% to storage, 7% to terminals, and another 36% to electrolysers and other facilities. Most of the projects (82%) are supposed to be commissioned by 2030.[57] In accordance with the PCI/PMI selection process, ACER issued an opinion on the draft regional list of proposed electricity and hydrogen PCIs and PMIs in September 2025. The final decision on the second EU PCI/PMI list is expected in by the end of 2025.

Progress of important projects of common European interest

72 The important projects of common European interest (IPCEI) initiative aim to accelerate development across the hydrogen value chain by deploying large-scale strategic projects with cross-border and cross-sector dimensions. The hydrogen IPCEIs are structured in four waves, each targeting different parts of the hydrogen ecosystem (Hy2Tech targets production technologies, Hy2Use industrial use, Hy2Infra infrastructure, and Hy2Move mobility).[58] Based on information made public by the Commission, the progress of IPCEI projects is slow.[59] Out of the 66 projects of the two first waves, Hy2Tech and Hy2Use, only 7.5% had reached final investment decisions. In its first quarterly magazine of 2025, Hydrogen Europe published the results of an analysis covering 122 IPCEI projects of all waves. The analysis concluded that only 21% of all analysed projects have reached a final investment decision and only 69% of the projects have signed their grant agreements with the relevant Member States. The analysis identified key bottlenecks for the implementation of the projects, including significant delays in the approval and notification process leading to the grant agreement, national funding allocation gaps, regulatory and market uncertainty, and overall administrative complexity.

57 Information based on the Commission's presentation at the 13th meeting of the Hydrogen Energy Network.

58 For a short description see Box 4 of the ACER 2024 Hydrogen Report. More information can be found on the Commission's dedicated web-page.

59 See a presentation from the European Hydrogen Forum in March 2025 here.

4. The cost of renewable and low-carbon hydrogen

73 Renewable and low-carbon hydrogen are expected to contribute to the decarbonisation of the European economy by replacing conventional hydrogen in existing uses, like refineries, and ammonia and methanol production, and by substituting fossil fuels and fossil-based feedstocks in emerging applications, notably mobility and steelmaking. In the longer term, hydrogen may potentially enhance the long-term flexibility and security of supply of a fully decarbonised electricity system.

74 While low-carbon hydrogen may support the initial market ramp-up, EU strategies and policy frameworks put emphasis on renewable hydrogen as the long-term solution. Currently, renewable hydrogen production costs remain considerably higher than those of the conventional alternatives. This cost gap raises concerns regarding the economic impact on offtakers and introduces uncertainty about the pace and the scale of renewable hydrogen deployment.

75 This chapter assesses the current stage of renewable and low-carbon hydrogen competitiveness. It dives into the current cost structure of renewable hydrogen (Section 4.1.1), identifying the relevant cost drivers, and further assessing the impact of the cost of electricity supply (Section 4.1.2). It then investigates the cost of low-carbon hydrogen (Section 4.1.3) and discusses the mid- to long-term prospects of hydrogen production costs (Section 4.1.4). Finally, it looks at the cost of transportation of hydrogen via pipeline networks (Section 4.1.5) and presents available findings regarding the willingness-to-pay for renewable and low-carbon hydrogen (Section 4.1.6).

4.1.1. Current hydrogen production costs

76 Due to the absence of a liquid market for hydrogen and the limited information on offtake agreements, the sector still largely relies on estimates of the levelised cost of hydrogen (LCOH) based on the costs of producing hydrogen rather than its market value. The cost of hydrogen depends on the production pathway, the technology used, and the price of the underlying production factors, namely natural gas in the case of methane reforming, electricity in the case of electrolysis and the price of CO_2 emission allowances, which affects both pathways.[60] The cost of CO_2 transport and storage is relevant for low-carbon hydrogen produced from fossil fuels with CCS.

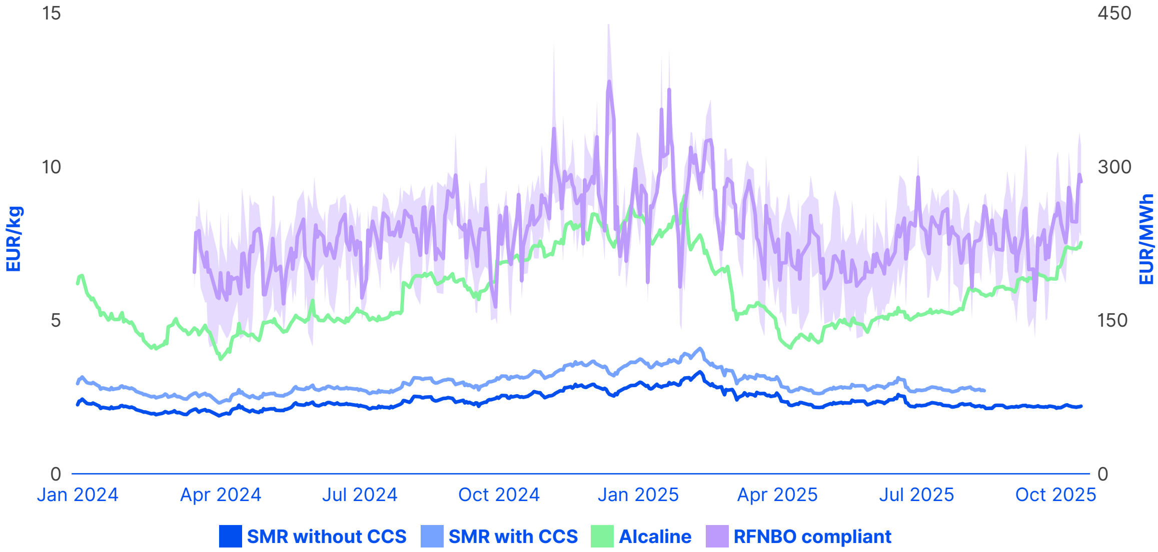
77 Since the 2024 Report, the decrease in natural gas prices further lowered the cost of producing hydrogen from SMR, thereby increasing the gap with renewable hydrogen. Similarly, despite the increasing trend, the current, relatively moderate prices of CO_2 emission allowances, oscillating in 2025 between approximately 60 and 85 EUR/tonne of CO_2, further favour conventional hydrogen.[61]

60 The deployment prospects of other hydrogen production pathways like biomass or waste pyrolysis are much lower compared to electrolysis and methane reforming hence these technologies are not further analysed.

61 Assuming that hydrogen production via SMR emits 9 kg of CO_2 for each kg of hydrogen produced, these prices translate to an additional cost of 0.54-0.77 EUR/kgH_2.

78 Based on current cost estimates by S&P Global Commodity Insights, hydrogen produced via SMR with CCS is generally much cheaper than renewable hydrogen.[62] As shown in Figure 15, in 2025 (January to October), the average cost of conventional hydrogen produced via SMR was a bit higher than 2 EUR/kg, following the price trend of natural gas. Carbon capture brings the average cost of abated hydrogen during the same period to 2.8 EUR/kg, excluding CO_2 transportation and storage costs.[63] The average cost of hydrogen produced via electrolysis depends heavily on wholesale electricity prices. Estimate for this cost for the Netherlands is currently (October 2025) around 7 EUR/kg. Notably, the average cost of RFNBO hydrogen remains significantly higher at around 8 EUR/kg, ranging between 7-10 EUR/kg (purple area in the graph), depending on the country of origin.[64]

Figure 15: Evolution of cost estimates of hydrogen produced by various technologies – January 2024-October 2025 (EUR/kg and EUR/MWh)



Source: ACER, based on data from S&B Global Commodity.

Note: SMR means steam methane reforming. CCS means carbon capture and storage. S&P Global estimates cost based on a methodology that considers, among other parameters, the electricity input costs, and the capital and operational expenditures. The LCOH of hydrogen from SMR with CCS does not include the cost of CO_2 transportation and storage. The LCOH estimate of electrolytic hydrogen (green line) refers to an alkaline electrolyser in the Netherlands and assumes grid supplied electricity and a 95% utilisation rate. The purple area in the graph shows the range of the LCOH for RFNBO complaint hydrogen in France, Germany, the Netherlands, and Spain.

62 The main cost drivers for producing low carbon hydrogen via SMR are the capital and operational expenditure of the reforming plant, the cost of natural gas, and the cost of CCS. Among these, natural gas normally constitutes the largest share of the unit costs, while capital expenditure accounts for around 20%. More details on the cost structure of methane reforming hydrogen production can be found in Hydrogen Europe's Clean Hydrogen Production Pathways – Report 2024.

63 S&P Global Commodity Insights reports values for hydrogen produced by SMR with CCS assuming a CO_2 capture rate of 90% but excluding CO_2 transportation and storage costs which currently remain largely uncertain. See section 4.1.3 for a discussion on low-carbon hydrogen costs.

64 S&P Global Commodity Insights uses a model-based cost of production plus a premium to reflect market value of firm hydrogen supply in France, Germany, the Netherlands, and Spain. For the cost of production modelling, the renewable hydrogen producer is assumed to be buying renewable power as part of a "pay-as-produced" PPA. The size of the alkaline electrolyser is 100 MW, operating above a minimum load of 25%. The production mix is optimised for every country to satisfy monthly requirements before the end of 2029 and hourly requirements from 2030 onwards. The model allows power exchange through the grid. The model includes specific provision for the cost of hydrogen storage. The assessment specifications are further described here.

79 The market-based HYDRIX[65] index issued by the European Energy Exchange (EEX) for renewable hydrogen has seen a slight increase in 2025, averaging approximately 8.2 EUR/kg up from approximately 7.8 EUR/kg in 2023. Since December 2024, the Iberian gas market platform, MIBGAS, also publishes weekly the IBHYX reference index of the LCOH of renewable hydrogen compliant with RFNBO rules. In 2025 (January-October), the index fluctuates mildly around 6 EUR/kg.[66]

80 These LCOH assessments reaffirm that the cost gap between conventional and renewable hydrogen remains high and has slightly increased (approximately four times more expensive), compared with the situation reported in the 2024 ACER European Hydrogen Markets report.

4.1.2. Renewable hydrogen production costs: overview of relevant cost drivers

81 Regardless of the specific electrolyser technology used,[67] the main cost components of producing renewable hydrogen across technologies are:

- capital expenditures: electrolysis stacks,[68] balance-of-plants,[69] financing costs, engineering, procurement, and construction (EPC), other upfront costs (e.g. permitting and land acquisition), and associated infrastructure like onsite storage;
- operating expenditures: cost of the electricity supply, network tariffs, maintenance, and labour.

82 The weight of each of these components on the final production cost of hydrogen depends heavily on project-specific elements like the specific electrolyser technology, the electricity source and the capacity factor (i.e. operating hours) of the electrolyser. Figure 16 shows examples of the typical LCOH structure of different hydrogen production pathways in Europe.[70] Capital expenditures are the dominant cost component for hydrogen produced from solar photovoltaics (PV) due to the relatively lower cost of electricity compared with other sources and the lower capacity factor. For more expensive electricity sourced from wind power plants or the grid, when the capacity factor is also higher, the electricity cost component becomes more important.

65 EEX HYDRIX is a market-based index that aims to reflect the price for “green”, not necessarily renewable, hydrogen offered in Germany.

66 HyExchange in the Netherlands also publishes the renewable HYCLICX price indicator for the marginal cost of production in the Netherlands, linking the variable price component of hydrogen to the hourly electricity spot market. This index excludes the capital expenditures and fixed costs of production, so it is not directly comparable to the LCOH. The HYCLIX index has seen an initial decreasing trend throughout 2025 but stabilised between 6 and 8 EUR/kg since mid-2025.

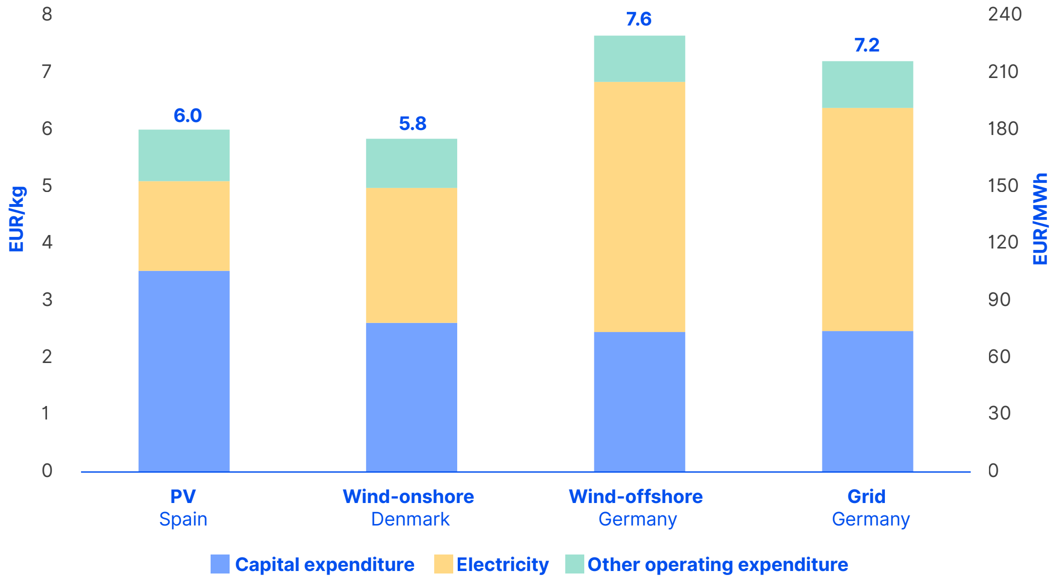
67 The key commercial electrolysers currently are alkaline and proton exchange membrane (PEM). Full commercialisation of the anion exchange membrane (AEM) and solid oxide exchange cell (SOEC) electrolysis is still underway.

68 These are the central units splitting water into hydrogen and oxygen.

69 Balance-of-plant in electrolysis includes all auxiliary systems supporting the electrolyser (besides stacks), such as power supply, water treatment, pumps, gas separation, drying, and safety systems.

70 Figures 32 to 35 in the Annex show the LCOH of different electrolysis production pathways per Member States.

Figure 16: Typical breakdown of the levelised cost of electrolytic hydrogen of an alkaline electrolyser for four different production pathways – October 2025 (EUR/kg and EUR/MWh)



Source: ACER, using the LCOH calculation tool of the European Hydrogen Observatory.

Note: The default cost and the operating assumptions of the tool for an alkaline electrolyser were used for the calculations, apart from grid fees in Germany, which were set to zero. For the grid electricity supply case, the tool calculation assumes operation of the electrolyser during the least expensive 4,000 hours of the year. Cost and electricity source-related data refer to 2024.

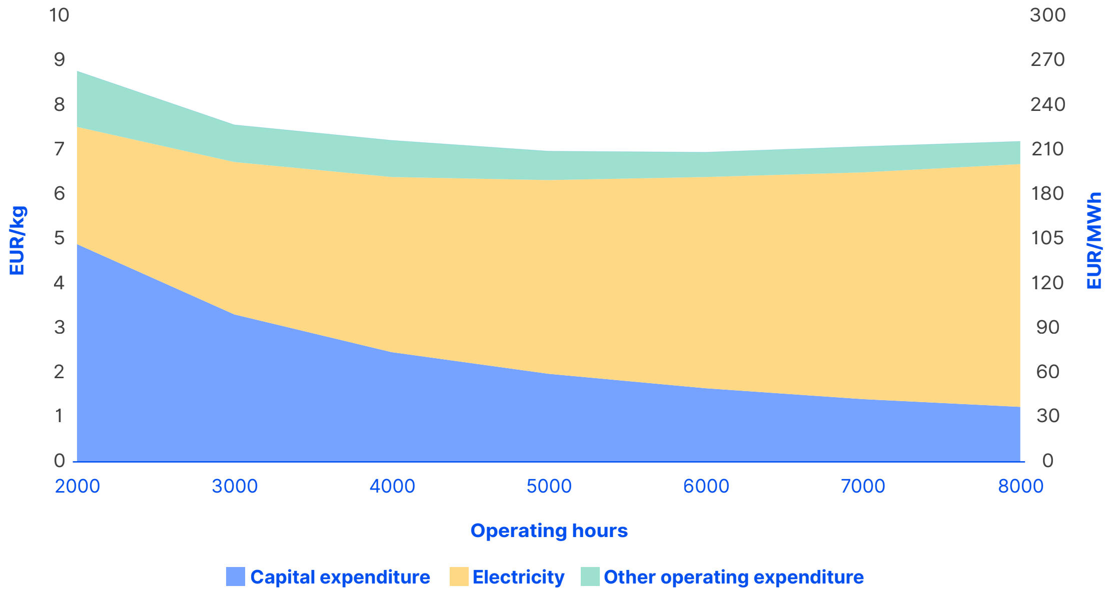
83 The effect of the capacity factor on the LCOH structure is more evident in Figure 17, which illustrates how the LCOH of an electrolyser using electricity from the grid changes with respect to the hours the electrolyser operates. The example assumes that the electrolyser operates during the hours of the year when electricity is least expensive.[71] Interestingly, in the example at around 5,000 hours the LCOH comes to a minimum. After this point the marginal decrease of the capital cost component due to the increased capacity factor is outweighed by the higher electricity cost.[72]

84 The structure of the LCOH under various operating conditions indicates that the prospects of both the capital expenditures and the electricity cost are important for the cost competitiveness of hydrogen produced via electrolysis. The following two sections delve deeper into these two cost factors.

71 This means that for every 1,000 hours in the graph the cost of electricity is assumed to be equal to the average day-ahead price of electricity of the least expensive 1,000, 2,000, 3,000 etc. hours of the year.

72 Individual market dynamics may affect the way the capacity factor influences the LCOH. In the central-north SE2 Swedish bidding zone, for example, the very low price of electricity during most of the hours shifts the point of minimum LCOH closer to 6,000 hours and leads to very small LCOH increase thereafter.

Figure 17: Typical structure of the levelised cost of hydrogen for an alkaline electrolyser in Germany using electricity from the grid during the least-cost hours – October 2025 (EUR/kg and EUR/MWh)



Source: ACER, using the LCOH calculation tool of the European Hydrogen Observatory and 2024 wholesale day-ahead market data for Germany from ENTSO-E's transparency platform.

Note: The default cost and technical assumptions of the LCOH calculation tool for an alkaline electrolyser were used for the calculations. Grid fees were set to zero. A theoretically optimal operation of the electrolyser is assumed with perfect foresight of market prices leading to operation during the least expensive hours of the year for each bucket of operating hours. Day-ahead wholesale electricity prices are based on ENTSO-E's Transparency Platform.

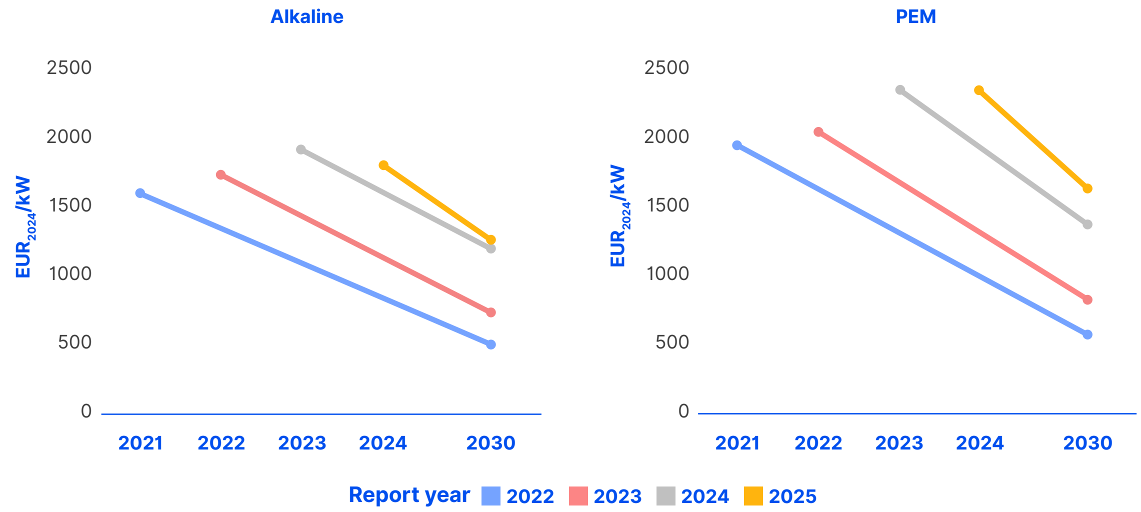
4.1.2.1. Capital expenditure

85 In its Global Hydrogen Review 2025, IEA reports an increase of the capital cost of electrolysers compared with the 2024 edition of the review. According to the report, the full capital cost for installing alkaline electrolysers outside of China, in 2024, ranged between 1,850 EUR/kW and 2,400 EUR/kW if the electrolysers were not made in China and between 1,385 and 2,260 EUR/kW if the project uses Chinese electrolysers.[73] This increase in investment costs for electrolysers outside of China is the fourth consecutive one from 2022, as shown in Figure 18. As indicated in IEA's review, rising inflation, regulatory uncertainties, and lower than expected production volumes slowed down the scale-up and have reduced the near-term potential to lower the costs of installing an electrolyser plant in in Europe.[74]

73 IEA reports electrolysers' costs in USD/kW. To convert USD into EUR, the average exchange rate of 2024 published by the European Central Bank is used (EUR/USD 1.0824).

74 Other estimates indicate even higher costs. For example in a 2024 report, Dutch technological research centre TNO provides estimates of the capital cost of large scale electrolysers based on a market survey in the Netherlands. The capital cost of a representative 100 MW electrolyser was estimated at 3,050 EUR/kW. This includes the cost of a compressor to feed hydrogen into the network which constitutes around 7% of the total cost.

Figure 18: Current and forecasted investment cost for electrolysers as reported in IEA's Global Hydrogen Review between 2022 and 2025 – October 2025 (EUR_{2024}/kW)



Source: ACER, based on data from IEA's Global hydrogen review reports from 2022 to 2025.

Note: Cost values have been converted from USD to EUR_{2024} using European Central Bank exchange rates and adjusted for inflation using Eurostat annual average inflation rates.

86 The capital cost structure of an electrolyser is important to understand the hydrogen cost reduction prospects. In its 2024 technology status report on water electrolysis published in November 2024, the Commission's Joint Research Centre identified the share of electrolysis stacks between 20% to 45% of the total investment cost, while balance-of-plant costs correspond to between 15% to 40% of the total investment cost. IEA estimates the investment cost share of the stack at 5-20% and of the balance-of-plant at 25-30% and also indicates that more than half of the total capital expenditures may be attributed to EPC and contingencies.

87 The Joint Research Centre report suggests that stack costs of electrolysers have the potential to fall up to 80% or more from current levels.[75] The Updated Manufactured Cost Analysis for Proton Exchange Membrane Water Electrolysers from the National Renewable Energy Laboratory[76], published in February 2024, reports that the cost reduction potential of the balance-of-plant is significant and will merely come from economies of scale, learning-by-doing effects, and optimisation of the plant's integrated design. The report suggests that, with sufficient scale-up, the costs of balance-of-plant may decrease by up to 50%. As companies gain experience in installing electrolysers, it is expected that EPC costs will also come down. In its review, IEA also mentions that developers working on mature projects expect total cost decrease potentials of more than 50% but chooses to be more conservative in the projections used for 2030, suggesting a reduction ranging from 30% to 50%, depending on the level of uptake.

75 According to the report, alkaline electrolysers have a potential for stack capital cost reduction from the current level of 242-388 EUR/kW down to 52-79 EUR/kW, depending on the project characteristics. For PEM electrolysers there is a cost reduction potential from the current level of 384-1,071 EUR/kW down to 62-234 EUR/kW.

76 The National Renewable Energy Laboratory is the U.S. Department of Energy's primary national laboratory for energy systems.

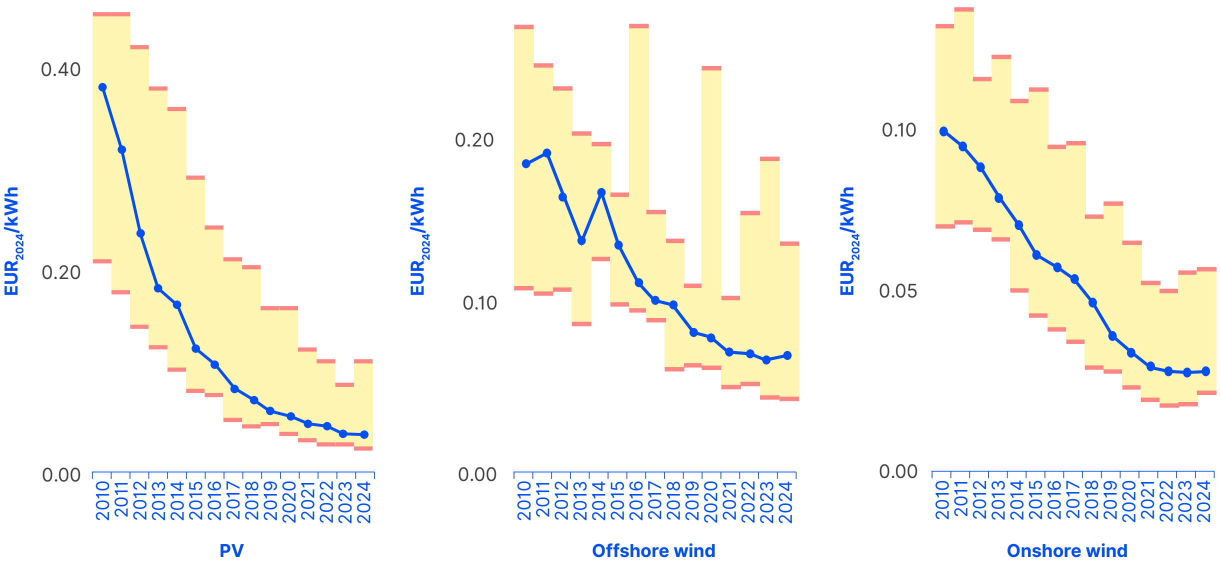
88 Evidently, the cost reduction dynamics of each of the main capital cost components (stacks, balance-of-plant and EPC) are different and hence their effects on total production costs will vary. For example, in its recent review, IEA suggests that using cheaper Chinese equipment can lower the total capital costs by 5-25%. However, this reduction may translate to a reduction in the LCOH of only between 3-13%, depending on the plant's configuration and the electricity source, partly also due to the lower efficiency of the Chinese electrolysers. Hence, individual project characteristics still matters when it comes to cost elements.

4.1.2.2. The cost of electricity

89 Electrolysers producing renewable hydrogen can source their electricity from either dedicated RES facilities or from the electricity grid. In the first instance, they are relieved from electricity grid connection charges, but their capacity factor relies on the output of the RES facility. In this configuration there is normally a need to oversize the RES power plant, and/or make use of storage facilities like batteries, to maximise the electrolyser's capacity factor. This leads to increased capital costs.

90 Expectations for renewable hydrogen cost reductions normally consider that the cost of RES electricity will continue its declining trend. However, IEA's Global Hydrogen Review 2025 highlights that over the last years, developers of renewable electricity generation have experienced increased prices and tougher financing environments mainly due to increases in interest rates and other financing costs. In its report on renewable power generation costs in 2024, the International Renewable Energy Agency reached similar conclusions but maintained its optimism over the long term. According to the report, the levelised cost of electricity (LCOE) in the EU for utility scale PVs, onshore, and offshore wind increased in 2024 compared with 2023 by 7%, 8%, and 10% respectively. Permitting delays, interconnection bottlenecks, higher cost for balancing the system and inflation are among the reasons that limit further cost reductions. Notably, Figure 19 indicates a slow-down of the downward trend for PVs, onshore, and offshore wind and even a reversal of this trend in the last several years. A study from the Fraunhofer Institute published in July 2024 predicts a slower reduction of the LCOE of RES technologies in the short- to mid-term. These findings raise concerns over the prospects of reducing LCOH for renewable hydrogen due to even cheaper RES electricity, at least in the near-term.

Figure 19: Global weighted average of the LCOE for utility scale PV, onshore wind, and offshore wind – 2010-2024 (EUR_{2024}/kWh)



Source: International Renewable Energy Agency.

Note: The figure is a reproduction based on the source. Cost values have been converted from USD to EUR using European Central Bank exchange rates.

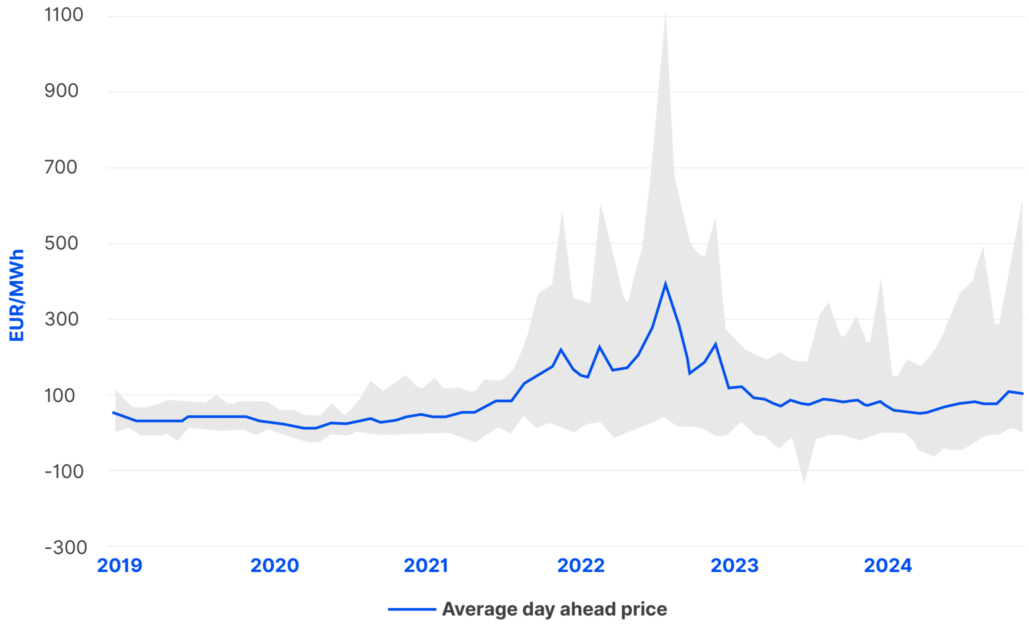
91 Electrolysers that are connected to the grid normally procure electricity via PPAs with electricity suppliers or directly with RES electricity producers. The structure of the PPAs may be complicated as the two parties may have divergent objectives. Hydrogen producers opt for competitive electricity supply costs and maximum operating hours for their electrolysers, while respecting the RFNBO rules and any operating constraints stemming from their hydrogen offtake agreements. The electricity suppliers and RES producers would seek to secure a long-term agreement (potentially to secure their project's financing) but at the same time would probably seek to retain the option to sell their production through the wholesale market if this is more profitable. Hence, the electricity wholesale market price is a decisive factor in these cases.

92 Average electricity wholesale prices in the EU have decreased compared to the previous years but approximately doubled compared to the years before the Russian invasion of Ukraine. As outlined in the latest ACER Key developments in European electricity and gas markets – 2025 monitoring report and depicted in Figure 20, electricity prices have also become highly volatile due to factors like the increasing share of renewable production and the corresponding decline in baseload power generation from fossil-based fuels. The increasing price volatility in electricity markets impacts the cost and structure of the PPAs. While hydrogen producers would look for electricity cost certainty thus most likely opting for a fixed price contract with RES electricity producers,[77] the latter would favour price premiums or structured CFDs to account for lost market opportunities.[78]

77 This is also confirmed by the information released by the European Hydrogen Bank on both auctions.

78 See for example Oxford Energy Studies' Hydrogen Offtake Agreements report published in August 2025.

Figure 20: Monthly average of the minimum, average and maximum day-ahead electricity prices in the EU - 2019-2024 (EUR/MWh)



Source: ACER calculations based on ENTSO-E Transparency Platform.

Note: The average electricity price is based on day-ahead wholesale electricity prices per month.

93 The growing penetration of RES combined with insufficient demand-side flexibility leads to an increase of RES curtailment and periods of very low or negative electricity prices. While this might constitute an opportunity for electrolysers to operate at lower costs, other short-term flexibility options, like demand response and storage, are also competing for the same market value.[79]

94 Besides the cost of procuring electricity, electrolysers normally face electricity grid costs if they are connected to the grid. Direct grid connection costs, covering the specific power line and sub-station required to connect the plant to the grid, are included in the plant's initial investment costs.[80] These costs may increase in the short term as a result of inflationary pressure, increasing grid capacity scarcity, and competing connection requests, but they normally are a small share of the total investment cost.

95 On the other hand, electricity network tariffs may constitute a significant share of the total LCOH of an alkaline electrolyser in the EU, depending on the country.[81] The large amounts of electricity grid investments planned in the coming decades[82] may increase network charges for users if investments do not align with the development of demand. ACER's Electricity infrastructure development to support a competitive and sustainable system – 2024 report, estimates an increase in network tariffs by 55% or more in 2050, based on the declared future grid investments and consumption levels stemming from the REPowerEU communication. Such

79 See also Box 6 for a case study on the impact of wholesale prices on electrolyser production cost.

80 As electrolysis expects to scale into several hundred megawatts or even gigawatt levels, connecting these plants to the electricity grid may impose significant challenges to already overwhelmed electricity systems. At the same time proper location of the electrolysers may alleviate grid congestion and potentially offer flexibility to the electricity grid.

81 For example, based on the calculations presented in Figure 35 electricity grid costs may represent 5-26% of the total LCOH of electrolytic hydrogen in the EU.

82 The EU action plan for grids estimates that EUR 477 billion in transmission grid investment will be needed by 2040 to accommodate growing electricity demand, including that driven by renewable hydrogen production.

an increase will put pressure on the cost of an electrolyser that can partially outweigh the gains from other future cost reductions. Cost reflective network tariff structures that provide time and locational signals encouraging the provision of flexibility to the system, can implicitly reward electrolysers that are able to operate flexibly. Grid-connection incentives could further guide electrolyser deployment to locations that reduce congestion and enhance local flexibility.

96 Hydrogen producers may adjust their electrolyser operations to provide ancillary services to the electricity grid,[83] aiming to generate additional revenue. However, competition from other sources makes this revenue stream uncertain for electrolysers. While some opportunities may exist in specific cases, electrolysers are expected to be primarily configured to ensure a reliable, firm hydrogen supply to their customers.

97 Stored hydrogen may also be used to provide sustainable flexibility in the electricity system when renewable electricity is not available for long periods.[84] This is, for example, the case of "Dunkelflaute" where renewable supply from intermittent renewable sources is very low for days or even weeks.[85] For hydrogen to be used as a strategic reserve for security of supply there is a need for underground hydrogen storage facilities and hydrogen networks connecting them to the power generation plants. However, the distribution of suitable underground storage across Europe is uneven making this option suitable for only a number of Member States if appropriate interconnections are not present. Moreover, it is not currently certain when (if at all) and to what extent this solution will be implemented. Natural gas can still play this role in the long-term especially if adequate CO_2 infrastructure is in place.

Box 6: Case study on electrolyser operation and LCOH

The cost of electricity is a key component of the LCOH of renewable hydrogen. This case study assesses the impact of the wholesale electricity price and the capacity factor on the LCOH of electrolysers. Normally, a developer of an electrolyser plant will sign a PPA with an electricity supplier to reduce the price risks, ensuring compliance with the RFNBO criteria.

This simplified assessment, examines the theoretical operation of an electrolyser connected to the grid that seeks to maximise its capacity factor while achieving a certain average price of the supplied electricity. The assessment assumes a fully flexible electrolyser with perfect foresight of the market prices. While simplified, the example is useful to demonstrate the effect of the wholesale market prices to the LCOH of electrolytic hydrogen. Figure 21 illustrates the results for different thresholds of average electricity prices between 20 and 60 EUR/MWh using data for 2024 from the German and Spanish electricity day-ahead wholesale market.

83 In theory electrolysers can technically provide ancillary services to the electricity system, however the actual potential depends on the plants configuration.

84 The topic is analysed in the recent Power-to-Hydrogen-to-Power: Technology, Efficiency, and Applications report by the Oxford Institute for Energy Studies. According to the report, provision of short-term flexibility by electrolysers makes sense only in the form of demand response. Using hydrogen in gas-turbines to provide short-term flexibility is uneconomic on market terms due to the low efficiencies of between 24% and 48% (which is lower than batteries and pumped hydro) making it costlier than other alternatives.

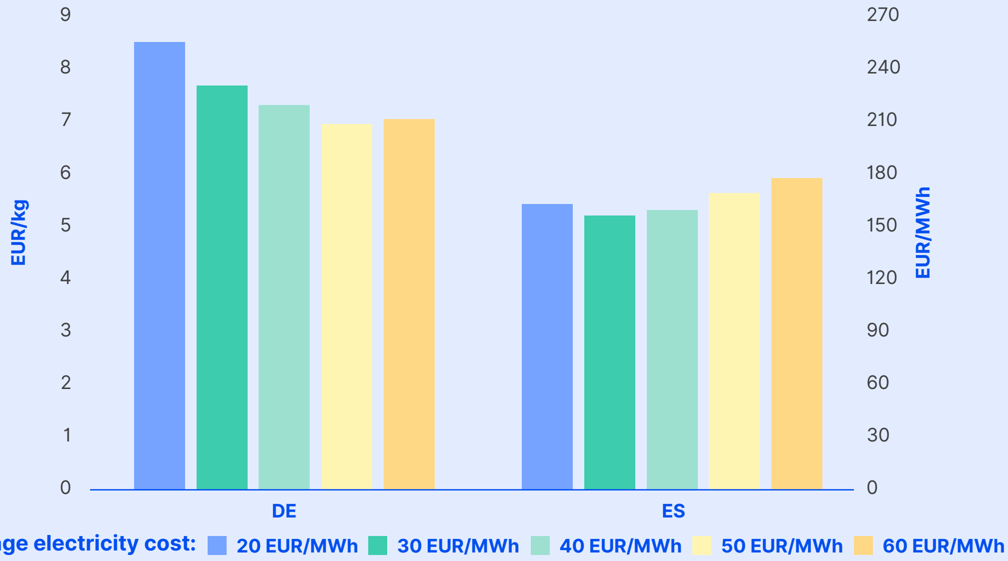
85 In December 2024, there was an incidence of Dunkelflaute in Germany. This has been described further in ACER's Key developments in European electricity and gas markets – 2025 monitoring report (p. 34).

In the German case, an electrolyser connected to the grid and operating during the 2,097 hours with the lowest wholesale electricity prices would achieve an average electricity supply cost of 20 EUR/MWh. At this electricity supply cost level, the estimated LCOH remains high at 8.57 EUR/kg, as the electrolyser operates for only a limited period and the share of capital expenditures becomes significant. If the threshold of the average electricity price is raised to 60 EUR/MWh, the electrolyser could operate for a total of 6,604 hours reducing the estimated LCOH to 7.07 EUR/kg.

In the Spanish case, an electrolyser targeting an average electricity supply cost of 20 EUR/MWh could operate for a 46% of the time (4,021 hours), significantly more than in Germany. The resulting LCOH would be 5.39 EUR/MWh, substantially lower than in Germany. Even with a 60 EUR/MWh threshold, the LCOH would remain below 6 EUR/MWh.

This simple theoretical assessment demonstrates the effect of wholesale market prices on the operation of a grid-connected electrolyser, and the trade-off between the capacity factor and the price of electricity. The results are heavily dependent on the wholesale market conditions.

Figure 21: Example of the levelised cost of hydrogen produced by an electrolyser in Germany and Spain for different average electricity cost thresholds (EUR/kg and EUR/MWh)



Source: ACER calculations, using the LCOH calculator tool of the European Hydrogen Observatory and. wholesale day-ahead electricity prices for 2024 from ENTSO-E's Transparency Platform.

Note: The main assumption is that electrolysers will operate during the least expensive hours until the rolling average wholesale electricity price reaches a certain threshold between 20 and 60 EUR/MWh.

4.1.3. The cost of low-carbon hydrogen

Methane based low-carbon hydrogen

98 The use of seemingly cheaper low-carbon hydrogen is often advocated as a way to create the critical level of demand that is necessary to scale-up the hydrogen market. While low-carbon hydrogen can be produced via a number of technologies, the main routes under consideration are methane reforming (either SMR or ATR) with CCS and electrolysis using electricity from nuclear power plants.[86]

99 As shown in Section 4.1.1, estimates indicate that the levelized cost of low-carbon hydrogen produced from natural gas with CCS is currently around 1 EUR/kg higher than the cost of conventional hydrogen, excluding the cost of CO_2 transport and storage. IEA's hydrogen tracker estimates the full LCOH of methane-based hydrogen at 1.7-3.9 EUR/kg without CCS and at 2.7-4.5 EUR/kg with CCS, including the CO_2 transportation and storage costs. In its Clean Hydrogen Production Pathways Report 2024, Hydrogen Europe gives a similar range of the LCOH of hydrogen produced from natural gas via ATR with CCS between 2.9-4.9 EUR/kg, depending on the cost of natural gas.

100 Figure 22 shows the composition of the costs of methane-based hydrogen in 2024 and 2030, based on the IEA's Northwestern Europe Hydrogen Monitor 2025.[87] The main cost component is the cost of natural gas (energy) followed by the cost of transporting and storing the captured CO_2. These are complemented by the capital and operating costs and any potential costs incurred by the non-captured CO_2 emissions.[88]

101 European wholesale gas prices are expected to decline in the short- to mid-term as the global LNG market becomes better supplied due to a significant expansion of liquefaction capacity.[89] This means that the basic cost component of methane-based low-carbon hydrogen will probably remain at relatively moderate levels in the short run.

102 The CO_2 transportation and storage costs currently used in various cost estimates also seem highly uncertain. In the aforementioned report, Hydrogen Europe considers these costs to be 100 EUR/tCO_2, noting that actual costs may vary across projects. This value adds 0.9 EUR/kg to the LCOH of hydrogen. The Hydrogen production cost report by Öko-Institut and Deloitte, published in June 2025, refers to substantial uncertainties due to a lack of experience with the technology and considers a wide range of cost estimates (30-150 EUR/tCO_2). The environmental organisation Clean Air Task Force suggests an even wider cost range of 70-250 EUR/tCO_2 in Europe, depending on the location.

86 Other technologies include gasification of coal or biomass with CCS, pyrolysis of methane producing hydrogen and solid carbon or electrolysis using low-carbon non-renewable electricity other than nuclear (e.g. using CCS).

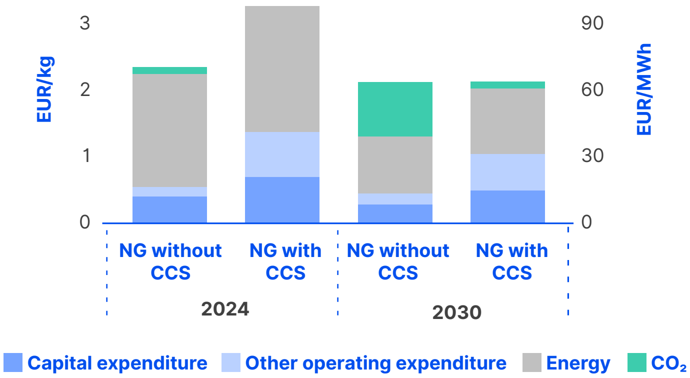
87 For more information about the cost structure see for example Hydrogen Europe's Clean Hydrogen Production Pathways Report 2024, IEA's 2025 Global Hydrogen Review or the recent Hydrogen production cost report by Öko-Institut and Deloitte.

88 Depending on the CO_2 capture rate, the costs of remaining emissions could be significant. Current operating SMR facilities are able to capture around 60% of the emitted CO_2 while future ATR plants claim a capture rate of more than 90%.

89 See for example ACER's Key developments in European electricity and gas markets – 2025 monitoring report or the Analysis of the European LNG market developments – 2025 monitoring report.

103 It follows that the final cost of low-carbon hydrogen produced from natural gas with CCS will greatly depend on the location and proximity to CO_2 infrastructure. Furthermore, this infrastructure may also serve other industrial sectors that want to use CCS technology to decarbonise, hence a potential competition over limited transport and storage capacity might place further pressure on the cost of CCS.[90]

Figure 22: LCOH of low-carbon hydrogen produced from natural gas with CCS – 2024-2030 (EUR/kg and EUR/MWh)



Source: IEA [Northwest European Hydrogen Monitor 2025](#).

Note: The figure is a reproduction from the source. Estimates for 2030 are based on the STEPS scenario. Cost values have been converted from USD to EUR using European Central Bank exchange rates.

Electrolytic hydrogen using nuclear electricity

104 Pending the Commission's assessments[91] on the CO_2 emissions calculations of low-carbon electrolytic hydrogen produced by electricity from nuclear power, uncertainties over this production pathway remain. So far, seven Member States consider the option of hydrogen produced using nuclear electricity in their strategies and plans.[92]

105 In practice, an electrolyser could source its electricity via a long-term PPA with a nuclear power producer and secure baseload operation with an increased capacity factor. The cost competitiveness of the low-carbon hydrogen produced would depend on the electricity price. However, nuclear electricity cost is difficult to assess. Since the capital cost of investment is a major part of the total production cost for nuclear power plants, the electricity price will largely depend on whether electricity comes from new or older, largely, or fully, depreciated plants.[93] In 2023 the French NRA, CRE, estimated that the full production cost of EDF's (Électricité de France) nuclear power fleet is 57.3-60.7 EUR/kg during 2026-2040.[94] Based on an agreement between the French State and EDF, the latter would sell its baseload nuclear electricity at 70 EUR/MW, much higher than the price of 42 EUR/MWh set in the previous ARENH mechanism. In 2025, CRE re-assessed the full costs of electricity generation from existing nuclear power plants at approximately 60.3 EUR/MWh for the period 2026-2028.

90 At the same time there are some notable developments regarding CO_2 infrastructure. The first cross-border CO_2 transport and storage facility, the Norwegian Northern Lights project, was commissioned on 26 September 2024 and the first volumes were injected into the reservoir in August 2025. The project will receive CO_2 from Denmark and the Netherlands in 2026. In March 2025 the project reached the final investment decision for the expansion of its capacities from 1.5 million tonnes of CO_2 per year to a minimum of 5 million tonnes.

91 See discussion on the low-carbon hydrogen delegated act in section 2.1.

92 These are Czech Republic, Finland, France, Hungary, Romania, Slovakia, and Sweden.

93 The price of uranium is also a significant factor and while it remains competitive against fossil fuels, it has increased by some 150% over the past 5 years.

94 The values refer to 2022.

106 According to the IEA LCOE calculator, the estimated LCOE for new generation nuclear plants in France exceeds 70 EUR/MWh. Similarly, Hydrogen Europe's LCOH assessments assume that nuclear PPAs would be priced at 80 EUR/MWh. At such electricity price levels, even under the assumption of a very high capacity factor, for example, 8,000 operating hours per year, the resulting LCOH would remain slightly above 7 EUR/kg.[95] Conversely, if electricity can be supplied at 30 EUR/MWh, assuming PPAs with largely depreciated nuclear power plants, the LCOH could come down to around 4.5 EUR/kg. This is similar to the LCOH of low-carbon hydrogen produced from natural gas with CCS mentioned previously. Assumptions regarding the price of nuclear electricity are therefore crucial when comparing nuclear-based low-carbon hydrogen with other hydrogen production pathways. The forthcoming Commission assessment of this production pathway is expected to provide further clarity on its potential role as an economically viable low-carbon hydrogen option.

4.1.4. Mid- to long-term prospects for renewable and low-carbon hydrogen

107 LCOH insights from the European Hydrogen Bank auctions show that producing renewable hydrogen at a cost level close to conventional hydrogen may already be feasible in certain cases of the EU. However, in general there is a need for substantial cost reductions for the renewable hydrogen market to grow as expected.

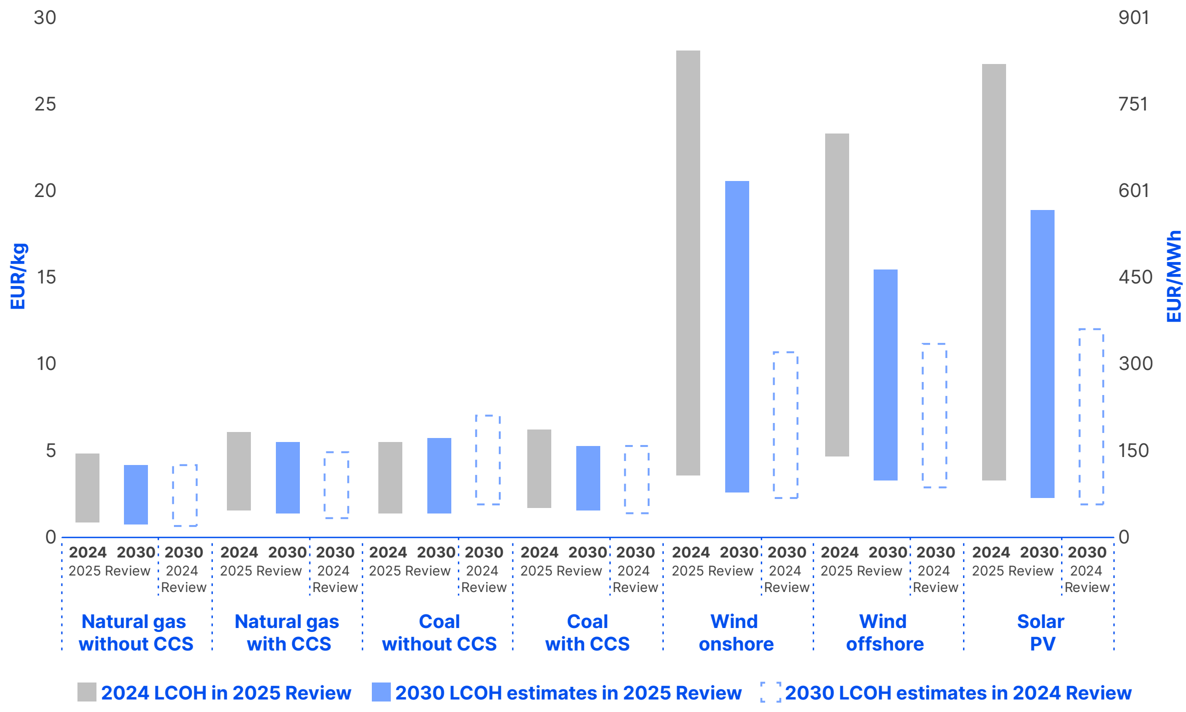
108 Figure 23 shows IEA's latest estimates for hydrogen production cost globally in the near-term based on the 2025 Global Hydrogen Review. Expectations on the range of the LCOH of renewable hydrogen for 2030 are significantly higher than anticipated in the 2024 edition of the Review.[96] In particular, offshore wind has become more expensive over the last year.[97] As 2030 prospects for fossil-based hydrogen production costs remain fairly stable, the cost gap between fossil-based and renewable based hydrogen has increased. The analysis in section 4.1.2, however, indicates that the prospects of costs reductions for renewable hydrogen are quite uncertain.

95 Calculated based on the LCOH calculator of the European hydrogen observatory assuming an alkaline electrolyser, investment cost of 2,310 EUR/kW, 8,000 operating hours, cost of electricity at 70-80 EUR/MWh, grid fees and electricity taxes at 21.6 EUR/MWh, and keeping all other technical parameters at default values.

96 In its 2025 Global Hydrogen Review, IEA only presents prospects and forecast based on its Stated Policies Scenario (STEPS) rather than the more ambitious Net Zero Emissions by 2050 Scenario (NZE) used in the 2024 edition of the Review. This move is probably driven by the lower than anticipated growth in the sector and impacts the techno-economic prospects driven by the expected deployment of electrolysers.

97 Notably, the current pressure on the cost of offshore wind projects led to a shift from market-based project development. For example, in Denmark, a tender for offshore wind production received no offers in December 2024, leading the Danish government to decide to provide future support via a two-sided CFD mechanism. Similarly, Germany's 2.5 GW offshore wind auction in August 2025 failed to attract interest, prompting the industry to ask for a CFD support mechanism. In the Netherlands, the Dutch Government also published in 2025 an Offshore Wind Energy Action Plan promoting subsidies to developers through two-sided CFDs, indicating a shift from pure market projects towards state support schemes.

Figure 23: Estimated hydrogen production costs by technology based on IEA – 2024 and 2030 prospects (EUR_{2024}/kg and EUR_{2024}/MWh)



Source: ACER based on IEA's Global Hydrogen Review 2024 and IEA Hydrogen Tracker.
Note: In the Global Hydrogen Review 2024, estimates for 2030 are based on the Net Zero Emissions scenario. In the 2025 edition, estimates for 2030 are based on the less ambitious States Energy Policies scenario. Cost values have been converted from USD to EUR using European Central Bank exchange rates. Cost values from the 2024 Review were adjusted to inflation using Eurostat annual average inflation rates.

109 While it is expected that innovation across the whole value chain will eventually reduce the capital expenditures for electrolysers, it is unclear how big this reduction will be and by when it may occur. Similarly, the RES electricity costs show at best a decelerating downwards trend, which raises questions on the prospects of any further reductions, at least in the near-term (see Figure 19). The potential of increased electricity grid tariffs adds another source of uncertainty about the future cost of renewable hydrogen.

110 Regarding low-carbon hydrogen produced via methane reforming, current estimates show that it might be more economic than renewable hydrogen for the near future. Expected natural gas prices will keep favouring this pathway, but at the same time exposure of low-carbon hydrogen to the global gas market might also entail risks. Moreover, experience with the ATR technology coupled with CCS is still very limited while the cost of CO_2 transport and storage is highly uncertain and specific to local circumstances and proximity to the relevant infrastructure. Thus, a long-term comparison between the cost of renewable hydrogen and that of methane-based low-carbon hydrogen is difficult.

111 Moreover, while nuclear electricity coming from depreciated nuclear plants can lead to lower cost levels for low-carbon electrolytic hydrogen compared with renewable hydrogen, the LCOE of new nuclear plants seems rather uncompetitive for hydrogen production, as explained in the previous chapter.

112 The current gap between the cost of renewable and low-carbon hydrogen and the cost of conventional hydrogen may not be easily bridged by the price of CO_2 emission allowances either. According to a recent report by the energy transition project Ariadne,[98] the carbon price would need to rise to 300-500 EUR/tCO_2 to achieve cost parity between natural gas and renewable or low-carbon hydrogen. Hydrogen Europe estimates the break-even price for low-carbon hydrogen produced via methane reforming with CCS at 180 EUR/tCO_2 for future ATR and at 210 EUR/tCO_2 for existing SMR units.

4.1.5. Hydrogen transportation cost

113 Apart from the production cost, the total cost for hydrogen offtakers will include the cost of transportation and, potentially, storage of hydrogen. In most cases, hydrogen pipeline networks are deemed more cost-efficient than other means of transportation for long distances. Limited deployment of hydrogen networks, however, makes the assessment of the transportation cost difficult. Experience from Germany and the Netherlands, where network developers have updated initial network cost estimates upward, indicates the uncertainties of early cost assessments. In general, cost estimates may have wide ranges and depend largely on critical assumptions such as the inclusion of repurposed gas network elements and the network utilisation factors. Therefore, predicting the unit transport cost for hydrogen and assessing the end-user tariffs is not straightforward.[99] Similarly, while the necessity of storage for the hydrogen market is widely acknowledged, the level of storage use and the resulting cost for the final user remains largely uncertain.[100]

114 So far, there are three examples of hydrogen network tariffs in Europe that may provide an indication of the additional costs for the hydrogen end-users.

- In Denmark, the tariff based on inter-temporal cost allocation will be determined under the revenue cap regulation. Although DUR has not yet issued a decision on the matter, Energinet expects that the current (2024) network tariff will be around 22.5 EUR/kWh/h/y (or 749 EUR/kg/h/y) for all entry and exit points.[101]

- In Germany, BNetzA has set a ramp-up tariff for the hydrogen core network based on the use of inter-temporal cost allocation (see Section 2.2.3.1). The ramp-up tariff for a firm yearly capacity product is 25 EUR/kWh/h/y (833 EUR/kg/h/y), uniformly applied to all entry and exit points.

- In the Netherlands, the government has set a uniform network tariff of 21.13 EUR/kWh/h/y (704 EUR/kg/h/y) at all entry and exit points. This tariff, established in 2023, will remain in place until 2033, when ACM will determine the regulated tariffs. In a recent policy paper, ACM warned that updated cost estimates and revised demand forecasts (see Section 3.2.2) could result in a substantial increase, potentially more than a tenfold rise, unless measures such as a state-backed inter-temporal cost allocation mechanism are introduced.

98 Ariadne project, Hydrogen in the Reformed EU ETS - Implications for competitiveness and emissions reductions, 5 July 2025.

99 The ACER 2024 Hydrogen Report provides estimates of hydrogen transportation costs via pipelines based on literature that vary between 0.08 and 1.8 EUR/kgH_2.

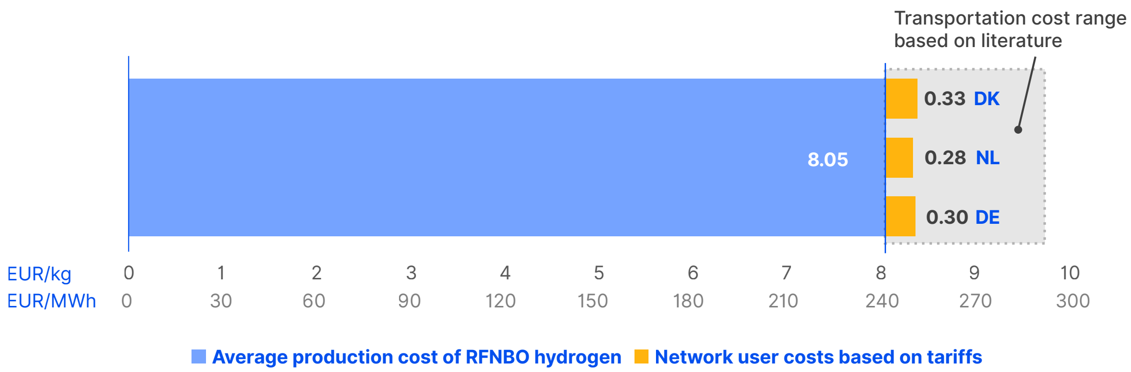
100 For illustration, an analysis of the importance of hydrogen storage from the Institute of Energy Economics at the University of Cologne estimates the cost of hydrogen in underground salt caverns at 0.66-1.75 EUR/kgH_2, depending on the size of the storage facility and techno-economic parameters. The German White Book on Hydrogen Storage highlights the uncertainty of storage costs and refers to two studies according to which the annual costs of hydrogen may be approximately 103 EUR/MWh/y or even twice that much.

101 See Energinet's report of 18 August 2025 on the Business case for Danish Hydrogen Backbone: Esbjerg-Veerst-Frøslev (7-tallet).

115 The German and Danish cases refer to ramp-up tariffs calculated based on an inter-temporal cost allocation mechanism that considers the evolution of hydrogen demand over several decades. While the level of the tariff is set so as to allow the recovery of the full costs of the network, the uncertainties surrounding the demand development and the actual network costs impose risks that may eventually result in future tariff adjustments.

116 Figure 24 depicts the expected (DK) and established (DE, NL) hydrogen transport tariffs against the production cost of hydrogen and the range of cost estimates of pipeline hydrogen transport based on literature (0.1-1.8 EUR/kg)[102]. The aforementioned network tariffs seem to represent a fraction of the total end cost of hydrogen, implying that transport costs will not be the decisive cost element, at least during the ramp-up phase. However, the current tariff levels seem to be at the lower end of the estimated transport costs. A potential increase of the tariffs, coupled with a significant reduction of the hydrogen production costs, could increase the importance of the hydrogen transport cost in the future.

Figure 24: Hydrogen transportation tariffs in Denmark, Germany and the Netherlands compared with the LCOH of renewable hydrogen (EUR/kg and EUR/MWh)



Source: ACER, based on data from S&B Global Commodity (for the RFNBO LCOH), Energinet, BNetzA, ACM, and ACER's European Hydrogen Markets 2024 market monitoring report.

Note: The depicted network user costs are estimations of a combined entry and exit capacity tariff in each country calculated for an assumed capacity factor of 5,000 hours.

4.1.6. Willingness to pay for renewable and low-carbon hydrogen

117 In the absence of a market price for renewable and low-carbon hydrogen, assessments of willingness to pay for these products can provide an alternative way to understand the market dynamics. Willingness to pay may reflect avoided costs like CO_2 emissions or penalties for not achieving mandatory quotas. It may also be driven by market opportunities stemming from the final consumers' willingness to pay for premiums of sustainable final products (e.g. green fertilisers). Willingness to pay for renewable and low-carbon hydrogen is highly sector- or even case-specific, making it difficult to generalise, and there is currently limited amount of information available on the topic.

118 The Commission's analysis of the European Hydrogen Bank's auctions provides some insights on the willingness to pay for renewable hydrogen. Based on the data from the second auction, the willingness to pay ranges from 3.60 EUR/kg for the construction sector up to 14.04 EUR/kg for non-ferrous metals. Interestingly, while the willingness to pay for mobility decreased

102 See footnote 99.

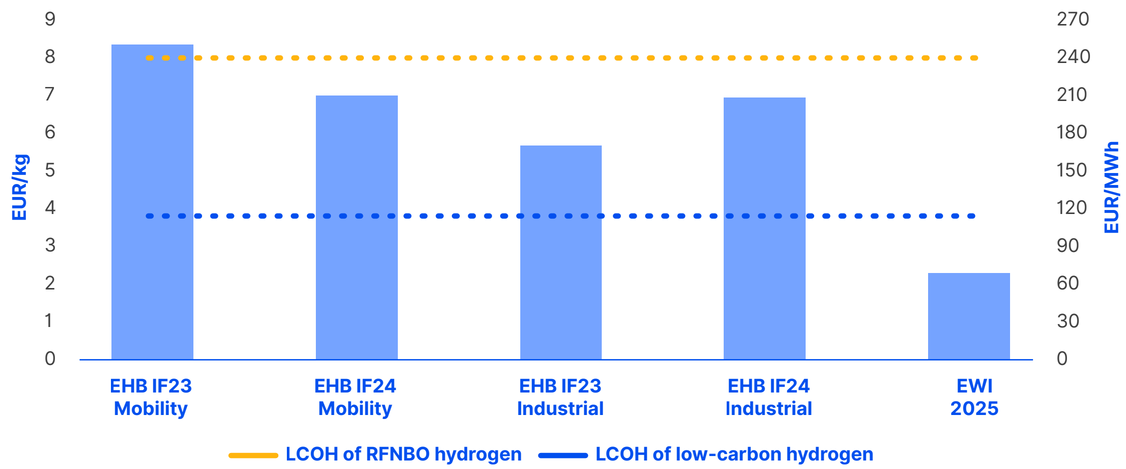
compared with the first auction, that of industrial users increased (Figure 25) possibly due to the expectation of the RED III implementation.

119 The research organisation Forschungsstelle für Energiewirtschaft assessed the theoretical willingness to pay in Germany for 2030, based on an analysis of avoided costs. The assessment verifies that the willingness to pay is sector specific and shows a very broad range from 1 EUR/kg for power generation to 16 EUR/kg for the shipping sector.

120 A recent study from the Institute of Energy Economics at the University of Cologne (EWI) commissioned by the German Ministry of Economics and Energy uses a theoretical willingness to pay for ammonia, methanol and synthetic kerosene in the range of approximately 1.5 to 3 EUR/kg.[103]

121 As Figure 25 illustrates, the current level of the average willingness to pay in mobility and industry implies that in both sectors there is already readiness to adopt low-carbon methane-based hydrogen, while there is still a cost gap for renewable hydrogen. Additional action is thus needed to bridge this gap either in the form of penalties for not reaching mandatory RFNBO targets or in the form of support to hydrogen producers to reduce the offtake price of renewable hydrogen to limit the impact on the competitiveness of the offtaker.

Figure 25: Willingness to pay for renewable hydrogen – October 2025 (EUR/kg and EUR/MWh)



Sources: ACER, based on data from European Hydrogen Bank 2023 and 2024 auctions, EWI and S&P Global Commodity Insights (for the levelized cost of RFNBO and low-carbon hydrogen).

Note: The LCOH of low-carbon hydrogen is calculated based on S&P Global Commodity average values for 2025 (2.8 EUR/kg), adding 1 EUR/kgH_2 to account for CO_2 transportation and storage.

103 This range is calculated based on the cost of these products using natural gas at 35 EUR/MWh and considering a CO_2 emission allowance price between 70-300 EUR/tCO_2.

5. Conclusion and recommendations

122 After a period of great enthusiasm and despite significant ongoing efforts, the European hydrogen market is still looking to get off the ground. Despite the significant growth in electrolyser capacity installed in the EU in 2024, the total capacity currently in operation (308 MW in 2024) and under-construction (1.8 GW) falls short of reaching the EU and Member States' targets. Substantially faster expansion is needed to increase scale-up and eventually reduced costs.

123 Establishing a European hydrogen market from scratch presents significant technical, financial and infrastructural challenges. It requires coordinated efforts to build the necessary infrastructure, mobilise investment, and foster innovation to achieve the cost reductions that are essential for market maturity. The slower than expected ramp-up underscores the importance of recognising these challenges and of targeting policy efforts toward facilitating further deployment. At the same time, it calls for continuous monitoring of the barriers hindering progress and for remaining ready to reassess the effectiveness of policy, regulatory, and financial frameworks to ensure they effectively support the market's development.

124 In this context, the Commission and the Member States remain largely committed to the hydrogen economy, but this commitment needs to be turned into tangible results. Member States had a mandate to transpose the RED III into national law by May 2025, defining RFNBO targets for industry and transport. However, only two Member States have so far done so. This delay increases regulatory uncertainty and hinders the creation of demand for renewable hydrogen.

125 Renewable hydrogen remains four times more expensive than conventional hydrogen produced from natural gas. Expectations for LNG and CO_2 emission allowance prices favour conventional hydrogen in the short-term. Meanwhile, the prospects for further reductions of the cost of renewable electricity seem uncertain, at least in the short run. While the RFNBO criteria ensure sustainability and reduce the risk of adverse effects from renewable hydrogen production, they may increase the production cost of renewable hydrogen significantly.[104] Electricity grid tariffs are also an important share of the total costs, and this share might increase in the future depending on how network investments align with the evolution of the electricity demand. Low-carbon hydrogen produced from natural gas with CCS could support market development and accelerate decarbonisation. While it seems more competitive than renewable hydrogen, current cost estimates are largely dependent on uncertain assumptions about CO_2 transport and storage costs, while the build-out of CO_2 infrastructure poses additional challenges. Assessing these cost uncertainties is essential for plotting the path towards the most appropriate hydrogen production options. It is therefore important to maintain the sector's momentum by targeting support for demand creation in sectors with the highest willingness to pay for renewable and low-carbon hydrogen.

126 Hydrogen networks can accelerate the market ramp-up, however uncertain future hydrogen demand brings additional risks to HNOs. Network planning needs to be adaptive, reflecting the latest market trends to ensure efficient investment and cost control. A gradual network build-out, aligned with supply and demand development, can further minimise the risk of stranded assets.

127 In light of these challenges, the following recommendations provide a set of actions needed to put the European hydrogen market on a path to scale-up and maturity.

104 See for example the report Green hydrogen production under RFNBO criteria by the Institute of Energy Economics at the University of Cologne (EWI).

5.1. Recommendations

128 There are quite a few developments that to a higher or lesser extent address the recommendations of the 2024 Report:

- On the regulatory framework, the Commission has largely completed the framework covering low-carbon hydrogen, while still deferring decisions on the role of nuclear-based hydrogen until 2028. The Commission has also approved three certification schemes which have already issued certificates to renewable hydrogen producers in Europe.
- On enhancing the effectiveness of financial support, the Commission established the EU Hydrogen Mechanism under the Energy and Raw Materials Platform as a tool to increase hydrogen deployment by facilitating market information sharing. Implementation of EU and national support schemes is progressing, albeit with delays, and funds have started to produce their first tangible results. The Industrial Decarbonisation Bank may contribute with additional funds to the creation of hydrogen demand complementing the support to hydrogen production offered by the European Hydrogen Bank.
- On network planning, work on the integrated model by the European TSO entities is ongoing. At least two Member States, Austria and Germany, are moving ahead with integrated network development planning. ENTSO-E and ENTSOG have aligned the TYNDP 2026 scenarios to the Member States targets, substantially reducing the expected 2030 demand compared to the previous scenario exercise.
- On hydrogen infrastructure financing, Germany has established the inter-temporal cost allocation mechanism and is progressing quickly with the relevant market rules. Denmark is also developing a financing mechanism addressing the hydrogen demand risks.

129 Most of the recommendations in the 2024 Report are still relevant, as they largely refer to a continuous effort to improve the conditions for the creation of the European hydrogen market. Following the most recent developments, this report concludes by presenting a set of recommendations to further enhance the effort.

130 **Accelerate the transposition and implementation of the RED III:** Member States should accelerate the transposition of the renewable hydrogen elements of RED III into national law, establish clear demand targets for RFNBO and combine them with effective incentive policies. Timely implementation with coherent demand incentives is crucial to provide the needed clarity and regulatory certainty to unlock investments and accelerate market development for RFNBO hydrogen.

131 **Implement the hydrogen and gas decarbonisation package without delay:** Member States are encouraged to accelerate the transposition and implementation of the hydrogen and gas decarbonisation package. This includes assigning clear responsibilities for hydrogen to NRAs and ensuring the timely appointment and certification of the HNOs. Swift implementation is critical to facilitate infrastructure deployment, which will be an enabler of a functioning hydrogen market.

132 **Stimulate demand through targeted and mature projects:** Funding will remain essential during the hydrogen market's ramp-up. Member States and the Commission should prioritise hard-to-abate sectors with high readiness to transition into consuming renewable or low-carbon hydrogen and focus on mature projects capable of delivering rapid scale-up. Focusing on projects that serve commercial scaling will streamline and accelerate access to funding. Lessons learned from existing support schemes, particularly the European Hydrogen Bank's auctions, can inform the design of future funding programmes to improve their effectiveness and increase the implementation rate of selected projects.

133 **Facilitate renewable hydrogen production through faster permitting and grid connection:** Member States can further enable renewable hydrogen deployment by ensuring swift and predictable permitting procedures and by accelerating connection to the electricity grid for both electrolysers and renewable electricity projects.

134 **Speed up decarbonisation of the power sector to lower electricity costs and enhance electrolyser use:** Member States should accelerate decarbonising the power sector by adding more RES and improving system flexibility. This will lower electricity supply costs. A cleaner and more affordable electricity mix will directly enhance electrolyser operational efficiency and reduce the cost of renewable hydrogen production.

135 **Create an enabling flexibility framework in the electricity market aligning electricity grid tariffs and incentives:** Member States and NRAs should ensure that an appropriate flexibility enabling framework is developed in the electricity market so that, where possible, electrolyser performance can be optimised, offering flexibility and ancillary services. Regulators should consider applying cost reflective electricity network tariff structures that include time and locational signals encouraging the provision of flexibility. Grid-connection incentives could further guide electrolyser deployment to locations that reduce congestion and enhance local flexibility.

136 **Carefully assess the risks of low-carbon hydrogen pathways:** Before committing to large-scale deployment of methane-based low-carbon hydrogen, Member States need to thoroughly assess the underlying uncertainties related to costs, infrastructure requirements, and lock-in effects. Such assessments are essential to ensure that investments align with long-term decarbonisation goals and avoid dependence on fossil fuels.

137 **Align hydrogen network development with market realities:** To manage market uncertainties and reduce the risk of stranded assets, HNOs should incorporate demand uncertainties in the network planning. Infrastructure build-out should proceed gradually and in close coordination with demand and supply project developers, to support efficient investment, mitigate risks, and facilitate sustainable market growth. Coordinated risk sharing across borders and between network developers, users, and Member States is needed to reduce risks and facilitate investments. This is especially important for cross-border infrastructure projects where they face different risks based on whether they are predominantly targeting domestic consumption, transiting, or exporting domestically produced hydrogen.

Annex

Figure 26: General assumptions for conversions and calculations

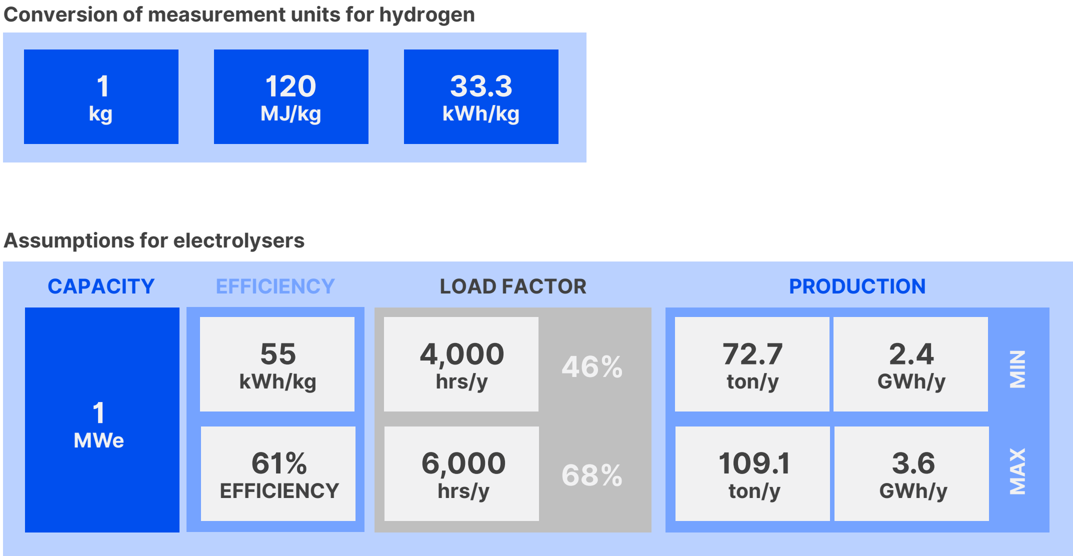
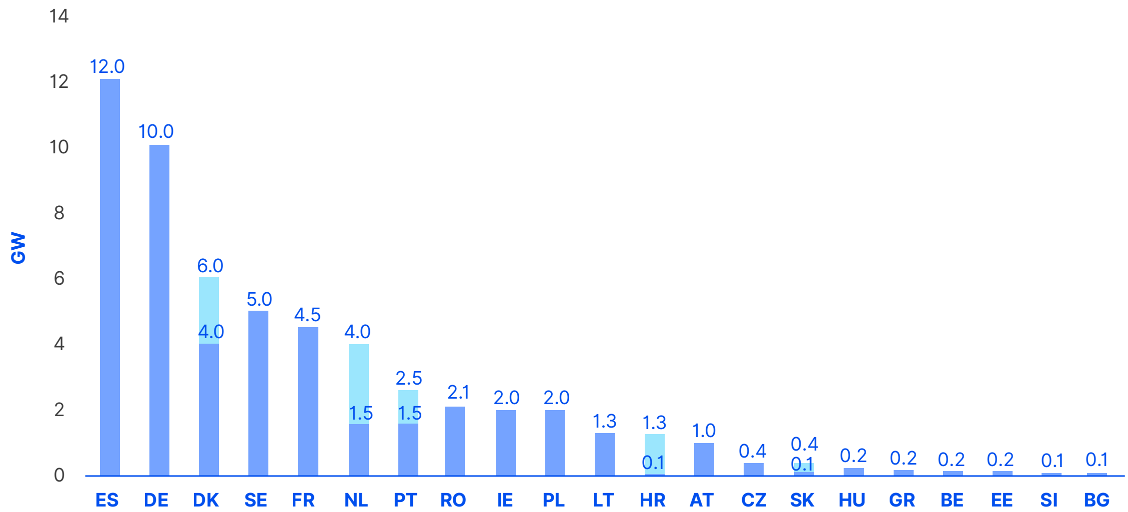


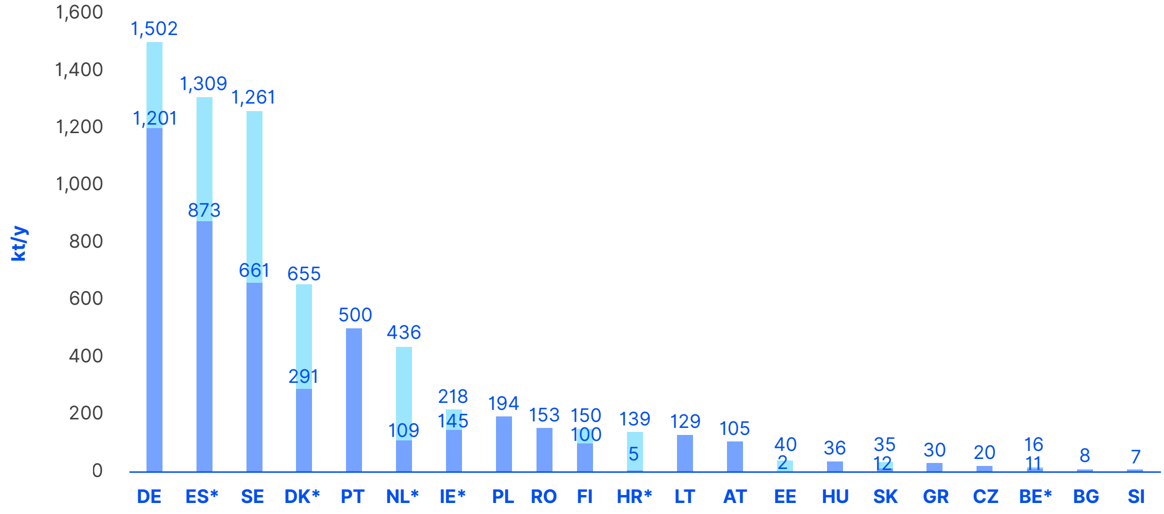
Figure 27: Targeted electrolyser capacity for 2030 in the EU Member States according to national strategies and plans – October 2025 (GW)



Source: ACER, based on national hydrogen strategies and roadmaps, NECPs, information provided by NRAs. For Austria, information comes from the integrated network plan (ÖNIP).

Note: The light blue part indicates a range of targets.

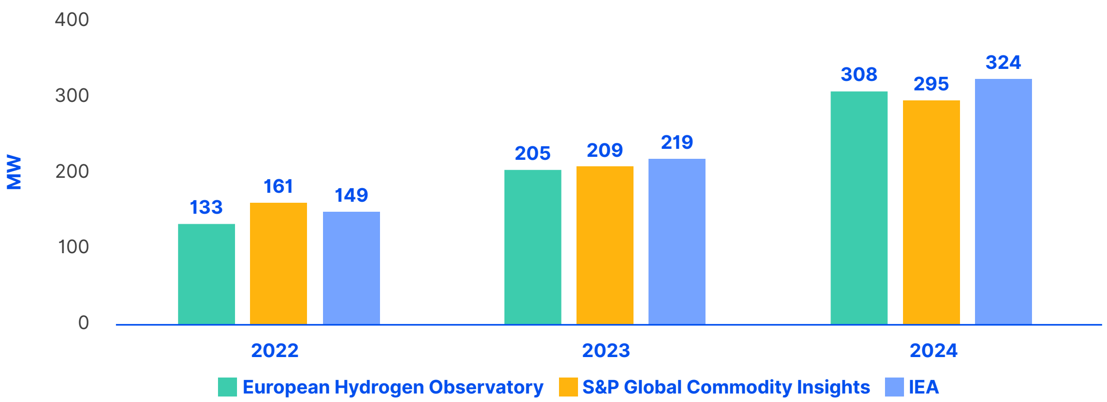
Figure 28: Targeted production of renewable and low-carbon hydrogen for 2030 in the EU Member States according to national strategies and plans – October 2025 (kt/y)



Source: ACER, based on national hydrogen strategies and roadmaps, NECPs, information provided by NRAs and own calculations. For Austria information comes from the integrated network plan (ÖNIP).

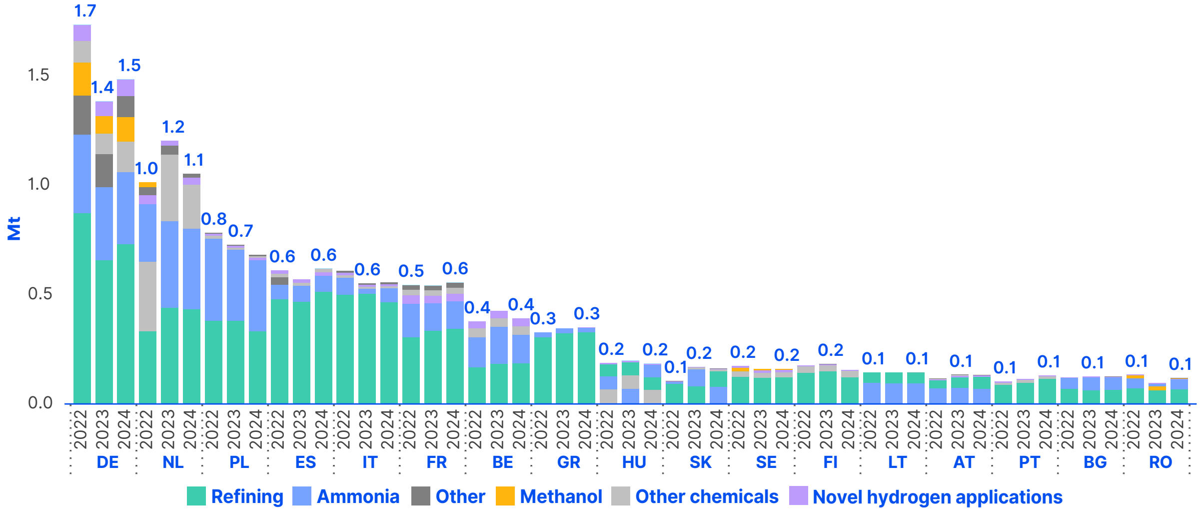
Note: (*) indicates estimates based on electrolyser targets, assuming that electrolysers operate with a 61% efficiency (55 kWh/kgH_2) and a load factor of between 4,000 and 6,000 hours per year. The light blue part indicates a range of targets.

Figure 29: Comparison of total installed electrolyser capacity in the EU between the databases of the European Hydrogen Observatory, the IEA and S&P Global Commodity Insights – 2022-2024 (MW)



Source: ACER, based on data from the European Hydrogen Observatory, S&P Global Commodity Insights and IEA.

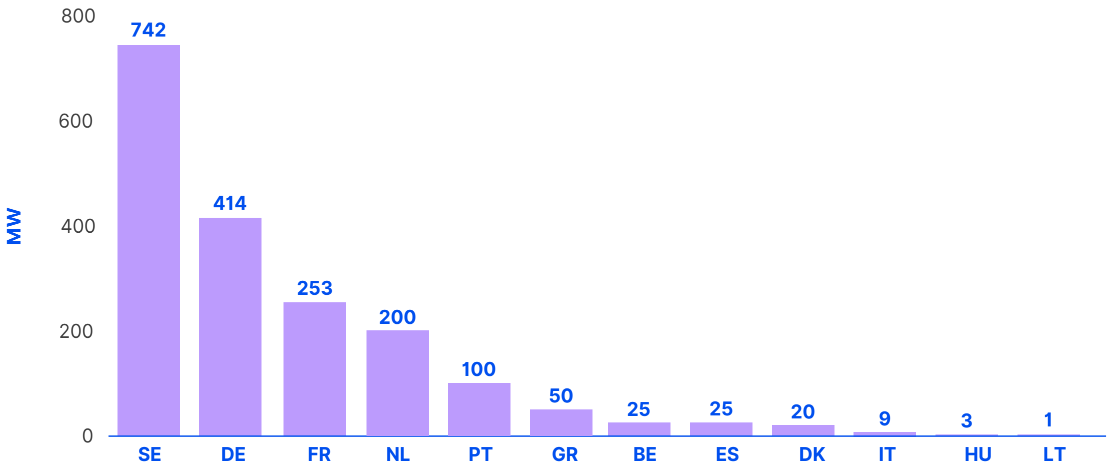
Figure 30: Total hydrogen consumption by end use in the EU Member States - 2022-2024 (Mt)



Source: ACER, based on data from the European Hydrogen Observatory.

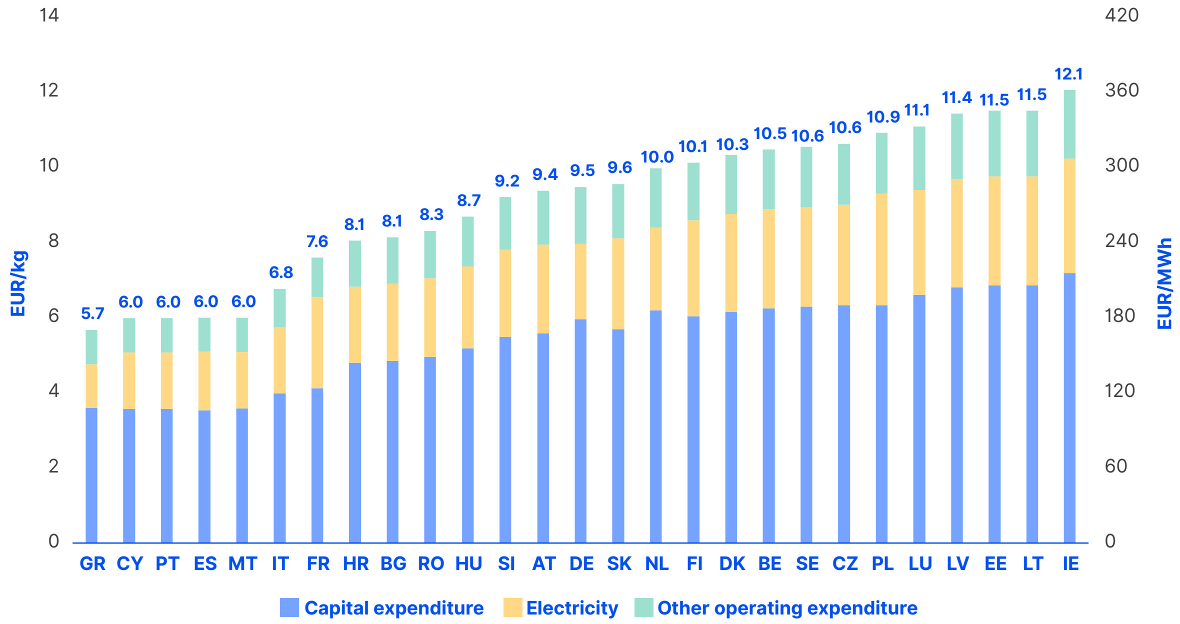
Note: The figure includes only Member States with consumption higher than 100 kt.

Figure 31: Total capacity of electrolysers under construction in the EU Member States – October 2025 (MW)



Source: ACER, based on data from S&P Global Commodity Insights.

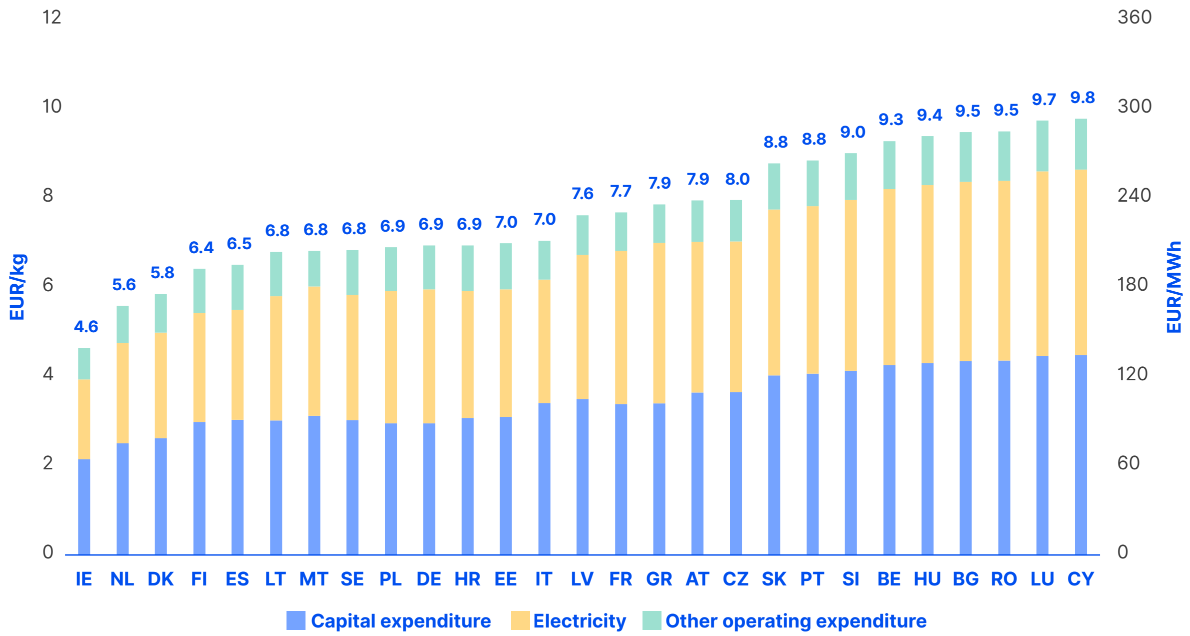
Figure 32: Levelised cost of hydrogen produced by electrolysers connected directly to solar PV in the EU Member States – October 2025 (EUR/kg and EUR/MWh)



Source: ACER, based on the European Hydrogen Observatory LCOH calculator.

Note: The default technoeconomic assumptions of the LCOH calculator were used. Electricity consumption-related taxes were not considered. For PVs the tool assumes direct connection between the electrolyser and the PV plant.

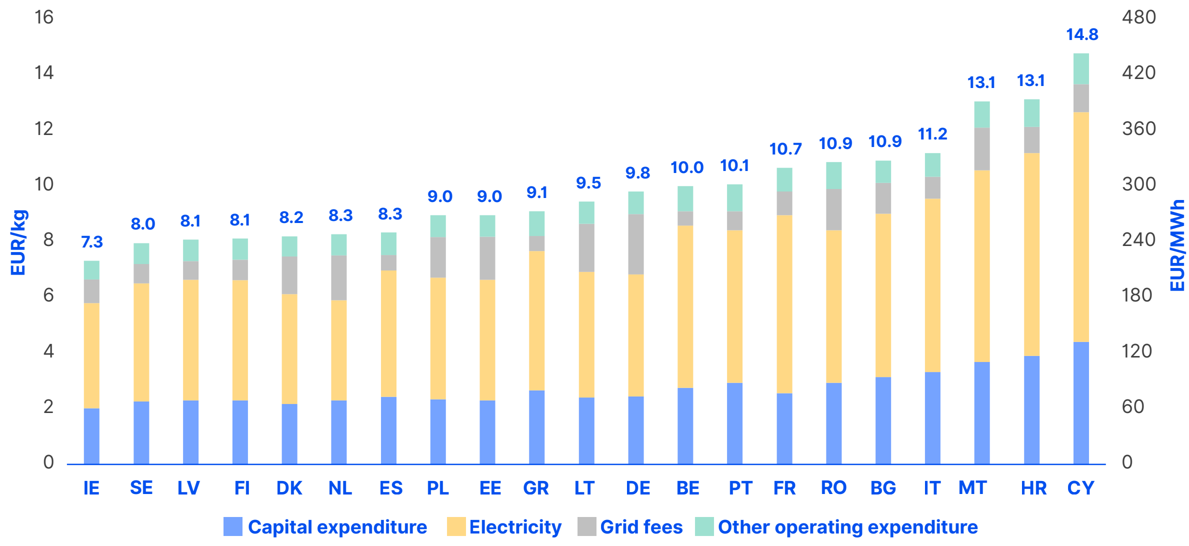
Figure 33: Levelised cost of hydrogen produced by electrolysers connected directly to onshore wind in the EU Member States – October 2025 (EUR/kg and EUR/MWh)



Source: ACER, based on the European Hydrogen Observatory LCOH calculator.

Note: The default technoeconomic assumptions of the LCOH calculator were used. Electricity consumption-related taxes were not considered. For onshore wind the tool assumes direct connection between the electrolyser and the wind farm.

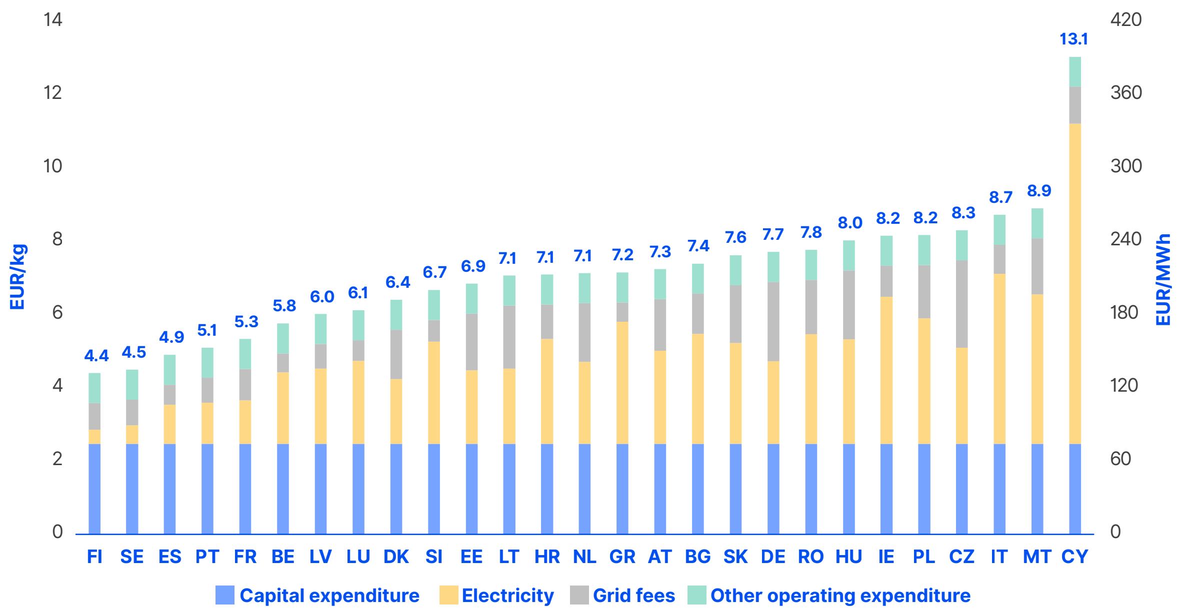
Figure 34: Levelised cost of hydrogen produced by electrolysers connected to the grid using electricity from offshore wind in the EU Member States – October 2025 (EUR/kg and EUR/MWh)



Source: ACER, based on the European Hydrogen Observatory LCOH calculator.

Note: The default technoeconomic assumptions of the LCOH calculator were used. Electricity consumption related taxes were not considered. For offshore wind the tool assumes that the electrolyser is connected to the electricity grid.

Figure 35: Levelised cost of hydrogen produced by electrolysers using electricity from the grid in the EU Member States – October 2025 (EUR/kg and EUR/MWh)



Source: ACER, based on the European Hydrogen Observatory LCOH calculator. Electricity consumption-related taxes were not considered.

Note: The default technoeconomic assumptions of the LCOH calculator were used.

Table 2: Overview of the regulatory framework for hydrogen in the EU Member States – October 2025

Country	Is there a national regulatory framework for the hydrogen sector in place?	Has the hydrogen and decarbonised gases Directive been transposed to national legislation?	Framework in place per topic						NRA competences per topic						HNO
			Certification of operators	Unbundling	Monitoring	Balancing	Third party access & tariffs	Planning	Certification of operators	Unbundling	Monitoring	Balancing	Third party access & tariffs	Planning	Is there a certified HNO?
AT	under development	under development	NAP						NAP (a)						No
BE	Yes	under development (a)	✓	✓	NAP	under development	✓	✓ (b)	✓	✓	✓	✓	✓	✓	No: Fluxys Hydrogen SA, 100% owned by Fluxys Belgium, but distinct entity.
BG	under development	under development	NAP						NAP						No
CZ	under development (c)	under development	✓	under development	under development	under development	under development	under development	NAP						No
DE	Yes	under development (d)	under development	✓	under development	under development	✓	✓	NAP	✓	NAP	✓	✓	✓	No: Existing H_2 networks are non-regulated, none of the gas TSOs is currently operating as HNO.
DK	Yes (e)	Yes	✓	✓	✓	✓	✓	NAP	✓	✓	✓	✓	✓	NAP	No: Energinet (Danish TSO) and Evida (Danish DSO) are planning to operate as HNO.
EE	NO	NO	NAP						NAP						No
ES	Yes	under development	NAP	✓ (f)	No	No	under development	under development (f)	NAP	✓ (f)	NAP	NAP	NAP	NAP	No: Enagás, Enagás Infraestructuras de Hidrógeno, S.L.U. has been appointed as a provisional HNO
FI	under development	under development	NAP						NAP						No
FR	No	NAP	NAP						NAP						No
GR	No	NAP	NAP						NAP						No

Country	Is there a national regulatory framework for the hydrogen sector in place?	Has the hydrogen and decarbonised gases Directive been transposed to national legislation?	Framework in place per topic						NRA competences per topic						HNO
			Certification of operators	Unbundling	Monitoring	Balancing	Third party access & tariffs	Planning	Certification of operators	Unbundling	Monitoring	Balancing	Third party access & tariffs	Planning	Is there a certified HNO?
HU	No	NAP	No data						No data						No
IE	under development (g)	NAP	NAP						NAP						No
IT	No	NAP	NAP						NAP						No
LT	No (foreseen in 4Q 2026)	NAP	NAP						NAP						No
LU	Yes	No	under development (h)	✓	No (i)	NAP	✓	✓	NAP	✓	✓	NAP	✓	NAP	No
LV	No	under development (j)	NAP						NAP						No
MT	No	under development	No data						No data						No (k)
NL	under development (consultations in summer 2025)	under development	NAP						NAP						No
PL	Yes	under development/ partially transposed (l)	✓	✓	✓	NAP	✓	✓	✓	✓	✓	NAP	✓	✓	GP GAZ-SYSTEM S.A. appointed as HNO by law
PT	under development (m)	under development (consultations in autumn 2025) (n)	NAP						ERSE is designated as the NRA for the renewable gas, natural gas and hydrogen market (o)						No (p)
RO	under development	under development (q)	NAP						NAP						No
SE	under development (r)	NAP	NAP						NAP						No
SI	No	NAP	NAP						NAP						No

Source: ACER, based on information from NRAs.

Notes: No information for Croatia, Cyprus, and Slovakia was available.

(a) The Austrian NRA, E-Control, is expected to become the competent NRA for hydrogen by the end of 2025.

(a) In Belgium, the Hydrogen Law has been adopted on 11 July 2023.

(b) In Belgium, CREG has an advice competence concerning the NDP Hydrogen and the minister for energy has the competence to approve the NDP Hydrogen. The Belgian Hydrogen Law will likely be revised to be compliant with the hydrogen and decarbonised gas market package. The Belgian NRA (CREG) is the competent authority for hydrogen transmission, but not for terminals or storage, which are activities that are not yet regulated.

(c) In Czech Republic, the amendment of the Energy Act No. 458/2000 Coll. included hydrogen among the gases that can be distributed through the gas pipeline network to customers.

(d) In Germany, the Ministry of Economic Affairs is working on transposing the Directive.

(e) In Denmark, hydrogen has been included in the national regulation for methane gas, now the Act on Gas Supply. In addition, a ministerial order has been prepared, which, in accordance with EU regulations, establishes the market framework for hydrogen. There is currently ongoing work to implement the Gas Market Directive.

(f) The Spanish NRA for energy (CNMC) will assess annually the legal unbundling requirements. The first assessment has been concluded and according to CNMC´s report of 3 July 2025 (INF/DE/146/24), Enagás Infraestructuras de Hidrógeno S.L.U. is considered horizontally separated from Enagás Transporte in the provisional exercise of functions regarding the development of the hydrogen backbone in the framework of European PCIs. Enagás Infraestructuras de Hidrógeno, S.L.U., submitted a non-binding proposal for a ten-year hydrogen backbone infrastructure plan to the Ministry, according to the provisions of the Royal Decree-Law 8/2023. The Ministry is currently assessing the proposal. CNMC has developed a Resolution (Resolution of 13 June 2025) approving the procedure for the management of applications and the contracting of the connection of renewable and low-carbon production plants to the natural gas network accounting for hydrogen blending in the natural gas network.

(g) In Ireland, no deadline for the hydrogen regulatory framework implementation is set yet. Work is underway to transpose the Directive, due by August 2026.

(h) In Luxembourg, the law currently foresees an authorization procedure (and not a certification) during which the Minister has to ask the NRA's opinion before deciding on the application for authorisation.

(i) In Luxembourg, the hydrogen sector is supervised by the Minister and the NRA.

(j) In Latvia, the Energy Law of Latvia includes the Directive, but is not fully implemented in Latvian national legislation.

(k) Interconnect Malta Ltd is the project promoter for the Melita TransGas Hydrogen-ready gas Pipeline.

(l) In Poland, the regulatory framework has been adopted by the Energy Law Act amendment of 21 November 2024 concerning hydrogen, however some specific regulations are still under development.

(m) In Portugal, there are already some provisions in the relevant legislation (see Decree-Law 79/2025 of 21 May and Order n.º 6750-C/2025 of 23 July) while the legislative process for the transposition is being prepared.

(n) The legislative process for the transposition of RED III is ongoing. The Portuguese government launched a public consultation on the legislation for the full transposition of RED III, which ended on 25th October 2025.

(o) Article 8 of the Decree-Law 79/2025 of 21 May designated ERSE as the NRA for the "renewable gas, natural gas and hydrogen market", but without detailing the competencies.

(p) The Portuguese Ministry of Environment and Energy designated REN Gas as the entity responsible for the planning, development and management of the hydrogen network infrastructure in Portugal, until the transposition into Portuguese law of Directive (EU) 2024/1788 (Order n.º 6750-C/2025 of 23 July).

(q) Romania has started the transposition of the Directive by organizing a working group at the level of the Ministry of Energy and collaboration with ANRE. Government Emergency Ordinance no. 59/2025 also foresees that the competent ministry in collaboration with the NRA, ANRE, "ensure that there are no unjustified barriers on the internal hydrogen market with regard to market entry and exit, access to the system, hydrogen trading and operation of the hydrogen system".

(r) In Sweden, the Swedish Energy Markets Inspectorate has submitted a draft suggestion for a regulatory framework including hydrogen as a report to the Swedish government on 19 June 2025.

Table 3: Non-exhaustive list of positive State-aid decisions for national schemes providing funding to hydrogen projects – October 2024-October 2025.

Case number	Case title	Country	Aid instrument
SA.102206	Aid for upgraded biogas and other gases from renewable sources that can be injected into the Danish gas system	Denmark	Direct grant
SA.103720	Aid for the demonstration of an innovative electrolyser - Djewels	Netherlands	Direct grant
SA.103901	NL_KGG_RGG_VI_Nationale Investeringsmodule Klimaatprojecten Industrie (NIKI)	Netherlands	Direct grant
SA.104899	Aid to Motor Oil Hellas for Green Hydrogen Project - Recovery and Resilience Facility (RRF)	Greece	Direct grant
SA.105083	Project CHESS - Uniper Hydrogen GmbH	Germany	Direct grant
SA.108511	H2Global Scheme - 2nd Funding Window	Germany	Direct grant
SA.109581	Temporary crisis and transition framework (TCTF): State aid for investment projects of strategic importance for the transition towards a net-zero economy.	Poland	Direct grant
SA.109730	Transformation der Industrie: transformation and investment grants under the CEEAG	Austria	Direct grant
SA.110056	NL_KGG_K&E - SA.110056 - H2Global Scheme - 2nd Funding Window (joint scheme with Germany notified by them under SA.108511)	Netherlands	Direct grant
SA.113721	TCTF - Aid to promote the transition towards a climate-neutral economy	Finland	Direct grant
SA.114934	TCTF - Act on Tax Credit for Certain Large Investments Aiming at a Climate Neutral Economy	Finland	Tax allowance
SA.116277	Austria's Participation in EU Hydrogen Bank Auction, Förderung der Erzeugung von erneuerbarem Wasserstoff	Austria	Direct grant
SA.116676	Spain: European Hydrogen Bank Auctions-as-a-Service 2024	Spain	Direct grant
SA.116745	Lithuania, European Hydrogen Bank Auctions-as-a-Service 2024	Lithuania	Direct grant
SA.116824	TCTF: RRF - Italy: Support for the development of hydrogen valleys (amendment of SA.106007 as prolonged	Italy	Direct grant
SA.117569	RRF - Evaluation plan linked to the National Energy System Support Fund	Poland	Soft loan

Source: ACER, based on information from the Commission's public database on competition cases.

Table 4: Hydrogen infrastructure in the EU Member States: national network development plans and expected network compared to ENTSOG's TYNDP 2024 list of projects – October 2025.

Country	Is hydrogen infrastructure included in national network development plans (NDPs)?	Planned/expected hydrogen network in 2030				Foreseen interconnections
		NRAs		TYNDP 2024		
		Total	Repurposed	Total	Repurposed	
AT	Yes, in the gas NDP	730 km transmission	510 km	746 km	520 km	DE (150 GWh/d), SI (150 GWh/d), SK (33 GWh/d), IT (168 GWh/d)
BE	Yes, in the gas NDP	-	-	1,185 km	126 km	DE, NL, FR, LU, FR
BG	Yes, in the gas NDP	580 km	-	580 km	0	GR (80 GWh/d), RO (80 GWh/d)
CZ	Yes, in the gas NDP	947 km	947 km	947 km	947 km	SK, DE (total 432 GWh/d)
DE	Yes, in the gas NDP	6,060 km	3,466 km	8,482 km	4,954 km	AT, BE, CZ, NL (10 - 58 GWh/d)
DK	No	-	-	364 km	93 km	
EE	Yes, in the gas NDP	-	-	290 km	0	The Nordic-Baltic Hydrogen Corridor (EE, LV, LT, PL)
ES	No	2,844 km	635 km	5,189 km	1,566 km	FR (140 MW), PT (24.6 MW)
FI	No	1,000 km	-	3,000 km	0	SE, EE
FR	Yes, in the gas NDP	500 km	-	3,803 km	1,329 km	-
GR	Yes, in the gas NDP	370 km	-	1,285 km	0	SEE Hydrogen corridor
HR	There is no framework for hydrogen network planning in legislation. However, gas network operators are promoting plans and/or studies for hydrogen network developments.			2,006 km	982 km	-
HU	There is no framework for hydrogen network planning in legislation. However, gas network operators are promoting plans and/or studies for hydrogen network developments.			953 km	345 km	-
IE	No	15 km	15 km	0	0	
IT	Yes, in the gas NDP	1,940 km backbone, 699 km additional network	1,164 km	2,509 km	1,781 km	Import: AL (4.9 Mt/y), AT (1.8 Mt/y), CH (1.0 Mt/y) Export: CH (1.0 Mt/y), AT (1.8 Mt/y)
LT	Yes, in the gas NDP	-	-	500 km	0	LV, PL
LU	No	-	-	80 km	0	BE, FR

Country	Is hydrogen infrastructure included in national network development plans (NDPs)?	Planned/expected hydrogen network in 2030				Foreseen interconnections
		NRAs		TYNDP 2024		
		Total	Repurposed	Total	Repurposed	
LV	Yes, in the gas NDP	-	-	288 km	0	EE, LT
MT	No, there is no framework for hydrogen network planning nor plans to develop it in the short-term					
NL	No	1,183 km	981 km	1,786 km	929 km	BE, DE
PL	No	-	-	2,982 km	251 km	-
PT	No	-	-	553 km	341 km	ES (81 GWh/d)
RO	Yes, in the gas NDP	789 km	0	973 km	0	HU, BG
SE	No	170 km	-	2,086 km	0	FI, DE (Nordic Hydrogen route)
SI	Yes, in the gas NDP	-	-	358 km	183 km	-
SK	No data			519 km	500 km	No data

Source: ACER, based on information from NRAs and ENTSOG's TYNDP-2024 list of projects.

Note: In Belgium, approximately EUR 1 billion is foreseen for new hydrogen network projects, yet the size of the network is currently unclear. Repurposing may be considered after 2030 to avoid jeopardising gas security of supply at this stage. In Denmark, there are no national hydrogen network development plans, however the Danish gas TSO has included hydrogen networks in their long-term NDP. In Estonia, the gas TSO's NDP mentions the Nordic-Baltic Hydrogen Corridor. In Ireland, there is a limited description of planned infrastructure in the National Hydrogen Strategy, but no set plans or deadlines yet. Gas Networks Ireland is currently planning to repurpose up to 15 km of gas pipeline as the first step in its longer-term Pathway to a Net Zero Carbon Network by 2045, according to which it plans to repurpose 2,477 km of transmission network to transport hydrogen. In Lithuania, 346 km of hydrogen transmission network is expected after 2030 as part of the Nordic-Baltic Hydrogen Corridor. In Luxembourg, there is no framework for hydrogen network planning, however, gas TSOs are promoting plans and/or studies for hydrogen network developments. In the Netherlands, the expected length of the hydrogen network comes from the Hyway 27 study. In Portugal, the current draft of the NDP for 2025-2034 does not include infrastructure fully dedicated to hydrogen transport, but the previous plan (2023-2032), included a new 162 km interconnection with Spain (CelZa) as part of the H2Med corridor; these investments have not been approved yet. The gas TSO, REN Gas, has been designated as the entity responsible for the planning, development and management of the hydrogen network infrastructure in Portugal, until the transposition of Directive (EU) 2024/1788. The consequent Order n.º 6750-C/2025 of 23 July 2025, issued by the Portuguese Ministry for Environment and Energy, designated REN Gas as this entity. In Sweden, there is no NDP for hydrogen but gas TSOs are currently planning three projects for hydrogen pipelines: the Nordic hydrogen route, the Baltic Sea-hydrogen collector and a 170 km pipeline between Letsi and Luleå.

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