Impact of Renewable Hydrogen on the Power System: Sector Development, Flexibility and Market Aspects

June 2025

entsoe

Foreword

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the association of the European transmission system operators (TSOs). The **40 member TSOs, representing 36 countries,** are responsible for the secure and coordinated operation of Europe's electricity system, the **largest interconnected electrical grid in the world.**

Before ENTSO-E was established in 2009, there was a long history of cooperation among European transmission operators, dating back to the creation of the electrical synchronous areas and interconnections which were established in the 1950s.

In its present form, ENTSO-E was founded to fulfil the common mission of the European TSO community: to power our society. At its core, European consumers rely upon a secure and efficient electricity system. Our electricity transmission grid, and its secure operation, is the backbone of the power system, thereby supporting the vitality of our society. ENTSO-E was created **to ensure the efficiency and security of the pan-European interconnected power system** across all time frames within the internal energy market and its extension to the interconnected countries.

ENTSO-E is working to secure a carbon-neutral future. The transition is a shared political objective through the continent and necessitates a much more electrified economy where sustainable, efficient and secure electricity becomes even more important. **Our Vision: "a power system for a carbon-neutral Europe"*** shows that this is within our reach, but additional work is necessary to make it a reality.

With the present Strategic Roadmap, ENTSO-E has reorganised its activities around two interlinked pillars, reflecting this dual role:

- "Prepare for the future" to organise a power system for a carbon-neutral Europe; and
- "Manage the present" to ensure a secure and efficient power system for Europe.

ENTSO-E is ready to meet the ambitions of Net Zero, the challenges of today and those of the future for the benefit of consumers, by working together with all stakeholders and policymakers.

* https://vision.entsoe.eu/

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Rationale and Key Messages

As outlined in ENTSO-E's Vision[1], in a fully carbon-neutral economy, electricity will be the main and most efficient energy carrier, and it will need to be coupled with other energy sectors. Future system needs require the development of significant system flexibilities to handle the increased complexity of the system and balance the gradual phase out of fossil fuel generation.

ENTSO-E and transmission system operators (TSOs), as part of their tasks to ensure the efficient integration of renewable energy sources (RES) and maintain system security, are committed to facilitating the development and integration of all flexibility resources in a technology-neutral way. This approach is reflected in all legal mandates, such as the Ten-Year Network Development Plan (TYNDP), the European Resource Adequacy Assessment (ERAA), the Network Code on Demand Response, and the Methodology for Flexibility Needs Assessment, where all flexibility resources, in addition to grid flexibility and interconnectors, are considered in an objective manner from a system needs perspective. Moreover, ENTSO-E regularly conducts analysis on a wide range of flexibility resources, which will be needed to address future power system needs, for instance via:

- Generation: flexibility from RES (ENTSO-E study to be published in 2025)
- Sector coupling: power to heat (ENTSO-E Study on Power and Heat Sectors: Interactions and Synergies,[2] 2023) and electromobility (ENTSO-E Position Paper on Deployment of Heavy-Duty Electric Vehicles and their Impact on the Power System,[3] 2023)
- Storage (ENTSO-E study to be published in 2025)

To provide a holistic overview and analyse short- and long-duration flexibility, this study focuses on renewable hydrogen with a particular focus on the role of electrolysers in the power system.[4]

Renewable hydrogen, i.e. obtained via electrolysis from RES,[5] has diverse potential applications for hard-to-decarbonise sectors in industry (e.g. iron and steel, chemical, petrochemical) and transport (mostly long-haul aviation and shipping). The EU and its Member States are promoting a hydrogen sector through regulation, incentives, and initiatives across the hydrogen value chain. At every stage – production, transport, storage, and final use – hydrogen is expected to impact the power system directly and indirectly (Figure 1).

The development of the hydrogen sector, especially the electrification of hydrogen production, will significantly impact the power system, both in terms of planning and operation.

Previous ENTSO-E studies[6] have identified the technical capabilities of electrolysers to provide grid system services,[7] along with system and market integration challenges. Building on these findings and evolving market dynamics, it is necessary to further explore the integration of hydrogen into power systems and electricity markets. This study will also support ENTSO-E's and TSOs' planned engagement with stakeholders, including electrolyser developers, future hydrogen network operators (HNOs), and the corresponding European association (ENNOH), EU policymakers, and regulators in developing future strategies.

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1 ENTSO-E. ENTSO-E Vision: A Power System for a Carbon Neutral Europe. 2022.

2 ENTSO-E. ENTSO-E – Study on Power and Heat Sectors: Interactions and Synergies. 2023.

3 ENTSO-E. ENTSO-E Position Paper: Deployment of Heavy-Duty Electric Vehicles and their Impact on the Power System. 2023.

4 The development of the hydrogen sector will depend on the evolution of the different types of hydrogen. However, the analysis of non-renewable hydrogen is outside the scope of this study.

5 As stated in ENTSO-E's position paper on the role of hydrogen, decarbonisation through hydrogen is only feasible when RES are used for operation.

6 For instance, the ENTSO-E hydrogen studies on Flexibility from Power-to-Hydrogen (P2H_2) and The role of hydrogen.

7 In the scope of the study, system services are defined as ancillary services and congestion management.

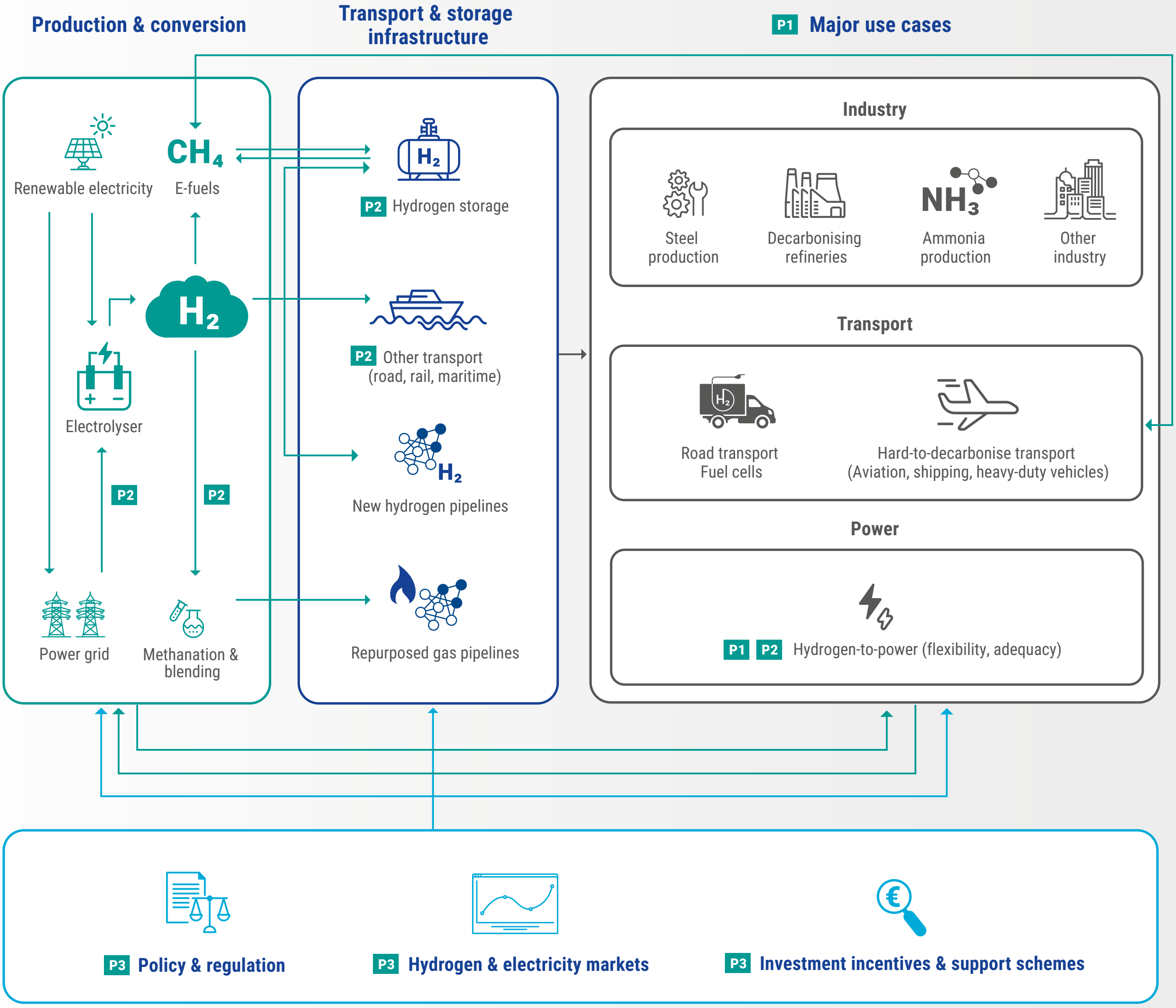


Figure 1: Hydrogen value chain elements and where they are analysed in this study (Px refers to Report Part x where the element is covered).

This study aims to explore the role of electrolysers and hydrogen-based facilities in power system planning, operations, and market design, with a focus on integration into the power system. Correspondingly, the study consists of three parts, with findings mainly based on literature and interactions with stakeholders (Part 1), scenario-based analysis (Part 2), and qualitative key performance indicator (KPI)-based evaluation (Part 3).

Part 1 – Hydrogen Economy: Trends, Developments, and System Integration

is an introduction focused on the emerging stakeholder landscape and trends in the nascent hydrogen market. It provides an overview of the current EU policy objectives, regulatory framework, and key developments along the hydrogen value chain having an impact on the sector and investment decisions (Figure 1). It describes the different sources of hydrogen demand towards 2050 (Figure 1, right) and expected applications of hydrogen-based facilities (Figure 1, middle).

Key questions:

- What are the main trends and developments in the emerging hydrogen sector, including policy and regulation?
- What are the main future use cases for electrolysers and other hydrogen-based facilities?
- What are their expected impacts on the power system, including its planning and operation?

Part 2 – Systemic Role of Electrolysers and Other Hydrogen-Based Facilities and Their Impact on the Power System

takes a deep dive into electrolyser constraints and costs, hydrogen costs drivers, as well as those of hydrogen storage and transport facilities. It further analyses the operational modes of electrolysers and their flexibility potential, as well as the impacts on the power system, using a scenario-based approach.

Key questions:

- What are the main constraint capabilities of electrolysers and the associated effect on the power system?
- What degree of electrolyser capacity expansion in the EU can be expected in the ramp-up and mature phases?
- What kind of flexibility potential can be expected from electrolysers based on different operational modes?

Part 3 – Market Design and Regulatory Framework for Viable and Flexible Hydrogen Production

analyses the electrolyser business case, focusing on renewable hydrogen production and comparing it to potential revenues from providing flexibility to the power system. It analyses possible support schemes, regulatory framework and market arrangements, and regulatory requirements to understand whether or how they can contribute to enabling a more flexible and power system-aware hydrogen production. Finally, it provides recommendations regarding electrolyser trajectory towards subsidy-free, flexible operation once the hydrogen infrastructure and hydrogen market become mature.

Key questions:

- What are the main cost and revenue drivers of electrolysers?
- What kind of support schemes, market rules and other arrangements are conceivable for a viable investment case?
- What measures can be taken to enable cost-efficient and flexible hydrogen production?

Throughout the three parts of this study, the following key messages have been identified from the TSO/ENTSO-E perspective:

- **Coordination between hydrogen and electricity systems development.** Electrolysers and other hydrogen-based facilities must be planned, implemented, and operated in coordination with the power system to achieve the highest positive impact on both systems and maximise overall consumer benefits. Coordinated cross-sector, temporal, and technical planning by all relevant system and plant operators, as well as an appropriate regulatory framework, should ensure an efficient transition with forward-looking investments while avoiding stranded assets and risks to the stable operation of both systems, especially in the ramp-up phase. To ensure the stability of the interconnected European power system, technical requirements for connecting large-scale power-to-gas (P2G) demand facilities shall be developed as soon as possible at the national level, in line with the Network Code Demand Connection (NC DC) 2.0 proposal by ACER.[8]

- **Incentivising electrolyser investment and siting in line with power system needs.** The location (near RES generation, near H_2 consumption, or both) and connection configuration (on grid / off grid) of electrolysers are highly relevant for optimising the infrastructure development and operation of the whole system of systems, while also taking into account the progressive phase out of natural gas. The siting, size, and technology of electrolysers directly affect the capacity and development needs of transmission and distribution electricity networks as well as their operational challenges (e.g. grid congestion, stability, resilience). Regulation and market design (including rules defining what constitutes renewable hydrogen) should not only take into account the impacts on the hydrogen sector but also incentivise electrolyser investments (technology, location, etc.) and operation beneficial for both the power system and efficient decarbonisation.

- **Facilitate flexibility provision of electrolysers also via hydrogen infrastructure.** Depending on their configuration and operational mode, electrolysers have the potential to become a promising source of short-duration flexibility, especially in the mature phase, through implicit and explicit demand response.[9] The latter can be very valuable for the power system, particularly via participation in balancing and congestion management services. Moreover, long-duration flexibility can in the future be provided through hydrogen transport and storage facilities for re-electrification in prolonged RES scarcity periods. Such hydrogen infrastructure can support the operational optimisation of the hydrogen sector (to exploit surplus cheap RES and / or avoid oversizing electrolyser capacity) and the establishment of reserves for wider hydrogen use beyond electricity production.

- **Enable renewable hydrogen contribution to resource adequacy.** Both hydrogen-to-power ($H_2$2P) and power-to-hydrogen (P2H_2) applications have the potential to contribute to resource adequacy in a carbon-neutral way: P2H_2 through explicit demand response (although in a limited amount, since electrolysers' load profile will already be implicitly influenced by spot prices) and $H_2$2P (thermal generation plants fuelled by decarbonised hydrogen through repurposed gas turbines) as backup capacity, also participating in national capacity mechanisms.

- **Public support, when and where needed, should be targeted and well-designed.** In the ramp-up phase, targeted public support can be beneficial if efficiently deployed. If deemed necessary, such support can not only incentivise green hydrogen production but also facilitate the uptake of renewable hydrogen demand as well as the necessary investments in hydrogen transport and storage, ensuring that the full value chain is developed and enabling energy system flexibility.

8 ENTSO-E. ENTSO-E Position on Urgent Connection Requirements for Power-to-Gas Demand Facilities. 2024.

9 Implicit demand response is a price-based mechanism that incentivises consumers to shift consumption through price signals and tariffs, while explicit demand response is an incentive-based mechanism that makes direct payments to consumers who shift demand as part of a demand-side response programme (Source: Demand response – IEA).

1 Part 1 | Hydrogen Economy: Trends, Developments, and System Integration

Currently, renewable hydrogen demand[10] is mostly driven by regulation and policy rather than the market. Consequently, this study dives into the hydrogen economy from both the demand and supply perspectives: policy and regulations as the main enablers driving hydrogen demand and investments boosting hydrogen production and infrastructure.

Decarbonisation policies, such as Fit for 55[11] and REPowerEU[12], are the main drivers of ambitious renewable hydrogen demand expectations towards the long term 2050.

Significant progress has been recently made in establishing the regulatory framework and setting future hydrogen objectives in the EU. Nevertheless, a recent report from the European Court of Auditors points out that the current development of the renewable hydrogen sector is characterised by a significant gap between the EU policy objectives and reality.[13] The low uptake of (renewable) hydrogen and the lack of sufficient domestic hydrogen production capacity make the ambitious objectives hard to achieve or prone to delays (Figure 2).

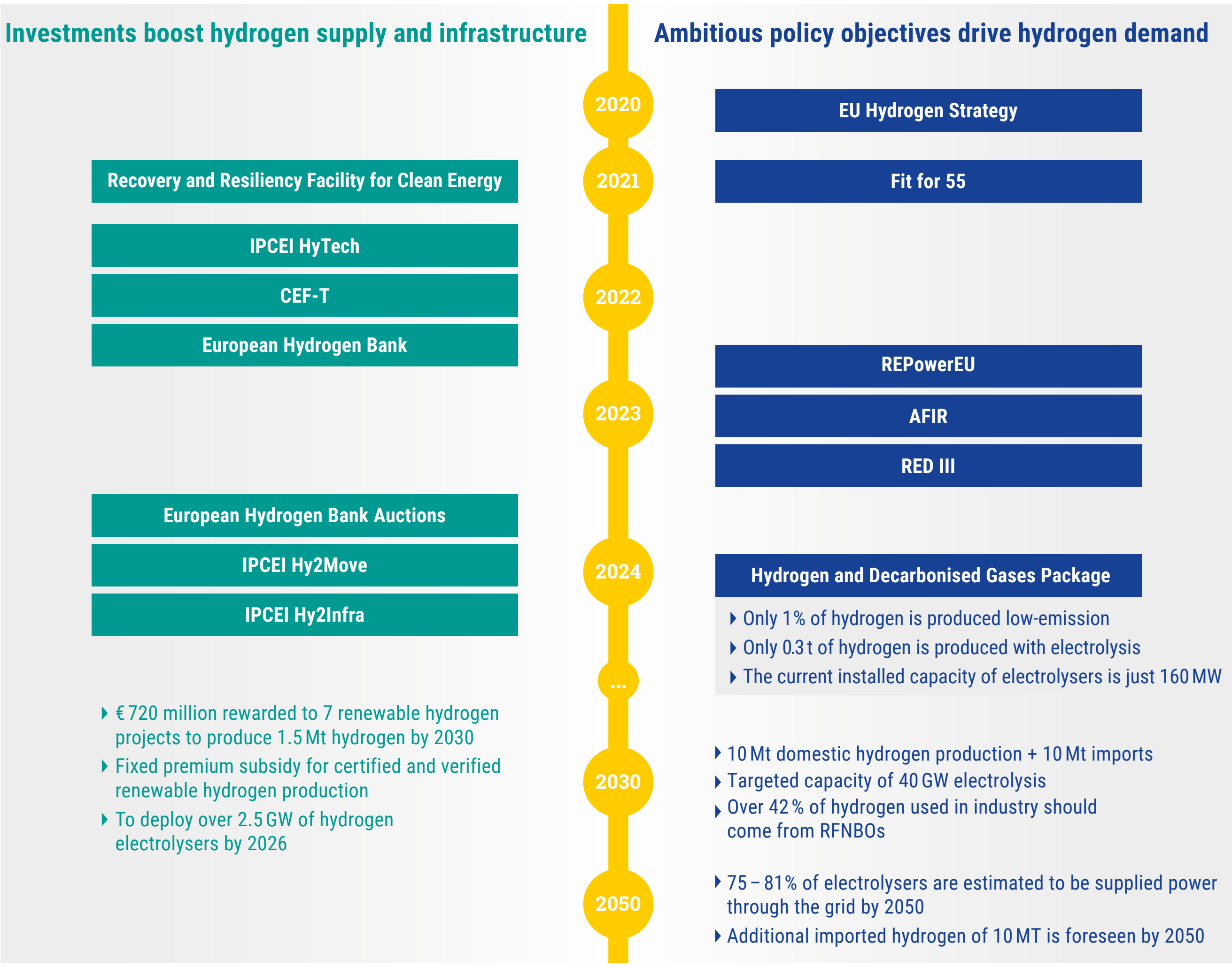


Figure 2: Hydrogen regulation and investment developments in the EU.

10 For the hydrogen analysed throughout the report, this study particularly focuses on electrolyser-produced renewable hydrogen.

11 European Commission. Fit for 55: Delivering on the proposals – European Commission. 2023.

12 European Commission. REPowerEU. 2022.

13 European Court of Auditors. The EU's industrial policy on renewable hydrogen – Legal framework has been mostly adopted – time for a reality check. 2024.

Hydrogen investments, both in large electrolysers and associated infrastructure, are still in their infancy. However, a positive trend is gaining momentum, as demonstrated by the European Hydrogen Bank auctions of hydrogen production projects conducted in May 2024,[14] which awarded €750 million to produce 1.5 million tonnes of hydrogen by 2030; see the bottom part of Figure 2.

Nevertheless, **additional efforts are needed to convert this investment progress into actual project commitments.** In Europe, only 3% of hydrogen production projects are operational or are under construction.[15] Moreover, only 4.5% of the supply needed to meet the REPowerEU demand objective has signed binding off-take agreements.[16] The main challenge behind this is the lack of firm demand commitments driven by regulatory uncertainty on the Member State level and the high cost of (renewable) hydrogen.

Looking further into the future role of hydrogen in Europe towards 2050, this study analyses the hydrogen supply, demand, and key use cases according to the 2024 TYNDP scenarios.

Overall, **the total EU hydrogen demand is estimated to soar eightfold in just 20 years**, i.e. from 2030 REPowerEU to the 2050 carbon-neutrality goals modelled in the TYNDP scenarios[17] (TYNDP NT+ 2030 to TYNDP GA 2050 in Figure 3).

Regarding the future demand for hydrogen in Europe, some industrial high-temperature processes, some heavy transport, and e-fuels are anticipated to be the major use cases for hydrogen (Figure 3). The industry has been and will likely remain the anchor load use case across all time frames (regardless of e-fuel production, which can be used in industry and transport as well, but without sector-specific demand reflected in the TYNDP[18]). Industry demand for hydrogen accounts for the highest share, i.e. more than 20% of the total hydrogen demand in all scenarios and time frames (Figure 3). Moreover, synergies with the power sector can be created if proper infrastructure, including storage, is available. Namely, if hydrogen storage facilities are utilised in an ecosystem with hydrogen end use for industry, this can open up an opportunity to utilise stored hydrogen as an input for hydrogen-fired power plants when needed.

14 European Commission. European Hydrogen Bank. 2024.

15 European Commission. Commission kick-starts work on a new pilot mechanism to boost the hydrogen market. 2024.

16 The Oxford Institute for Energy Studies (OIES). 2024-State-of-the-European-Hydrogen-Market-Report.pdf. 2024.

17 ENTSO-E and ENTSOG. ENTSO-E and ENTSOG TYNDP 2024 Draft Scenarios Report. 2024.

18 E-fuel production is an indirect use of hydrogen for hard-to-decarbonise applications (e.g. e-diesel for maritime transport or e-methanol for industry applications). Therefore, the demand for e-fuels is hard to assign to specific sectors and is thus not specified in TYNDP.

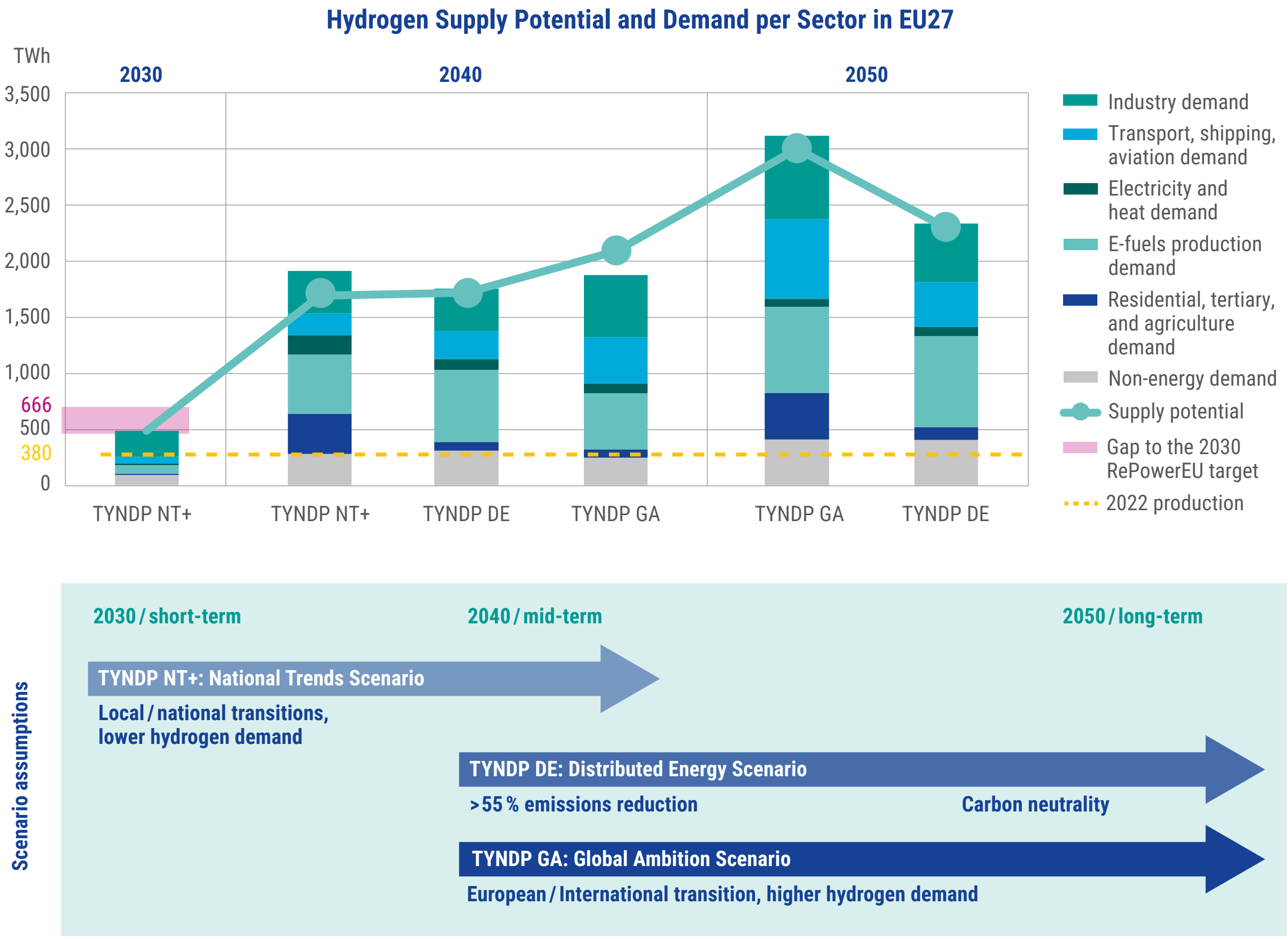


Figure 3: Hydrogen demand by sector compared to its supply potential towards 2050 in EU27.

1.1 Part 1 | Conclusions

Decarbonised hydrogen demand is the primary driver of electrolyser deployment, of which the key future use cases in Europe towards 2050 are industry, transport, and e-fuels.

The currently envisaged European hydrogen economy is characterised by a **gap between ambitious EU decarbonisation and hydrogen targets and the lack of (renewable) hydrogen demand and sufficient domestic hydrogen production capacity.**

The European hydrogen stakeholder landscape is still emerging, with a limited but growing number of stakeholders in evolving roles.

At this stage, it is thus **crucial to ensure effective cooperation between existing and prospective network operators and related associations (ENTSO-E, ENTSOG, and ENNOH) and establish mechanisms for efficient coordination with hydrogen electrolyser operators.**

Despite ongoing uncertainty regarding the volume and timing of electrolyser deployment, **it is essential to develop integration concepts, modalities, and best practices in hydrogen business cases from the outset.** This is part of a system-of-systems approach as outlined in the ENTSO-E Vision document.[19]

19 ENTSO-E. Vision on Market Design and System Operation towards 2030. 2022.

2 Part 2 | Systemic Role of Electrolysers and Other Hydrogen-Based Facilities and Their Impact on the Power System

The hydrogen sector remains in its early stages, with its future growth and cross-sector integration highly uncertain due to varying assumptions among stakeholders. Several sources have pointed to a potential discrepancy between policy ambitions and the actual or expected degree of hydrogen expansion in the EU (e.g. the European Court of Auditors Report published in July 2024) due to current production cost being uncompetitive – even after including the positive externality of avoided CO_2 emissions. Meanwhile, the role of electrolysers in the energy system or their impact depends to a large degree on their technical and economic constraints.

Therefore, Report Part 2 adopts a scenario-based approach* to assess the potential of electrolysers, including their flexibility potential, focusing on their constraints, costs, and implications for power grid planning and operation.

***Disclaimer:**

The revised TEN-E Regulation (EU) 2022/869 requires a close alignment between the planning of the electricity, hydrogen, and methane networks. ENTSO-E and ENTSOG are legally mandated to evaluate the interactions between the electricity, hydrogen, and methane systems, which is vital to delivering the best assessment of the infrastructure requirements from an integrated system perspective through the TYNDP scenarios.

The TYNDP scenarios are policy-driven and fully aligned with the energy efficiency first principle, the EU's 2030 targets for energy and climate, and the 2050 climate neutrality objective. The TYNDP scenarios, which also include scenarios on hydrogen developments, perform sound and comprehensive assessments of European energy infrastructure requirements from a whole energy system perspective. ENTSO-E and ENTSOG (and the future ENNOH) TYNDPs provide decision-makers with better information as they seek to make informed choices based on these policy-driven ambitions that will benefit all European consumers.

Any reference to TYNDP or other scenarios in the study is intended purely for background information and to contextualise the range of possible impacts electrolysers may have on the EU power system and markets. It does not reflect the views of ENTSO-E or any TSO on the relevance of the scenario and should not be considered an overlapping analysis with ENTSO-E's work on TYNDP scenarios and related legal mandates. The study aims to provide qualitative research based on a set of possible energy futures, offering an overarching assessment of how the evolution of the variable renewable hydrogen sector could impact the power system.

2.1 Technical characteristics of the electrolyser technology and hydrogen infrastructure

The three main electrolyser technologies – alkaline electrolysis cells (AEC), proton exchange membrane electrolysis cells (PEM), and solid oxide electrolysis cells (SOEC) – differ in maturity, efficiency, and operational characteristics. AEC is the most mature and scalable, offering the longest stack lifespan (~90,000 hours by 2030) and lowest degradation rates, but it has slower start-up times (0.5–1 hour) and higher maintenance costs due to corrosive electrolytes. PEM, with a compact design and rapid start-up (<1 minute), excels in high-efficiency grid services but has a shorter lifespan (~55,000 hours), higher energy consumption, and significant costs due to rare materials. SOEC, an emerging high-temperature technology, achieves the highest efficiency (~40 kWh/kgH_2) when leveraging waste heat but is limited by high costs, small production volumes, and the shortest lifespan (~21,250 hours).

Figure 4 provides an overview of the three main electrolyser technologies, their performance, technical constraints, and main economic parameters.

Moving on to the role of electrolysers in the power system, the primary factor driving electrolyser integration is renewable hydrogen demand. The second major factor is the availability of hydrogen infrastructure, including storage and hydrogen transport assets. Infrastructure availability affects the ability of electrolysers to deliver hydrogen across regions and countries and their capability to operate in a flexible mode.

		AEC			PEM			SOEC		
		Today	2030	2050	Today	2030	2050	Today	2030	2050
Technical characteristics	Typical / example plant size	10 MW	100 – 200 MW	1 GW	10 MW	200 MW	1 GW	1 MW	10 MW	100 MW
	Average stack efficiency (kWh / kgH_2)	52.3			56.3			40.4		
	Degradation rate (% / 1,000 h)	0.15 %	0.12 %	0.09 – 0.11	0.22 %	0.13 %	0.10 – 0.11 %	0.84 %	0.28 %	0.10 – 0.15 %
	Average stack lifetime (h)	70,000	92,500	83,000 – 120,000	55,000	77,500	86,500 – 123,500	21,250	50,000	79,000 – 86,000
	Cold start-up time (minutes from 0 to 100 %)	< 80 minutes	30 minutes	< 30 minutes	0.3 – 1 minute	0.2 – 0.3 minute	0.1 – 0.3 minute	500 – 700 minutes	500 minutes	200 – 400 minutes
	Warm start-up time (seconds from 0 to 100 %)	60 – 300 seconds	No public data		< 10 seconds	No public data		600 seconds	No public data	
	Power response signal * (seconds)	< 1 – 5 seconds	No public data		< 1 – 5 seconds	No public data		< 1 – 5 seconds	No public data	
	Ramp-up / Ramp-down (% of nominal load per second)	0.2 – 20 % per second	No public data		100 % per second	No public data		No public data		
	Full load hours ** (h)	3,200 to 4,200 hours								
Financial cost data	CAPEX (M€ / MW)	1.9	0.55	0.255 – 0.325	1.9	0.65	0.25 – 0.40	3.2 – 4.8	1.25	0.4 – 0.6
	OPEX (% of CAPEX)	4 %	4 %	4 %	2 %	2 %	2 %	12 %	12 %	12 %
	Median H_2 production cost from the literature (LCOH € / kg)	3	2.36	1.6	3.92	3.43	2.6	4.32	4.65	2.04
Implications for TSOs	Advantages	› The most mature and scalable electrolysis technology with the cheapest CAPEX and H_2 LCOH › The lowest degradation rate, the longest stack lifetime with MW-scale operational plants currently			› The fastest cold-start time so far that can respond to grid services with a low operating temperature › Higher stack efficiency and density enable comact system sizes (i. e., smaller land footprint)			› The highest stack efficiency (20 – 30 % higher than AEC and PEM) › More flexibility provision via its reverse mode as a fuel cell for grid balancing		
	Disadvantages	› Higher maintanance costs that doubles PEM'S OPEX › Longer start-up time and less flexibility			› Uncertain lifetime of commercial plants › Expensive inputs and catalysts (e. g., water treatment to derive very pure water as PEM is sensitive to input water impurities)			› Expensive and still at the demonstration stage without commercial availability of large-scale hydrogen production › Much smaller typical plant size (10 times smaller than AEC and PEM) with the shortest stack lifetime		

This comparison table is based on the previous ENTSO-E study.[20]

* Power response signal is the time it takes for the electrolyser to adjust its power consumption in response to changes in the input power signal.

** Full load hours are the number of hours the electrolyser would have taken to consume the amount of energy current consumed over a period of time (typically 1 year) had it been operating at full capacity in relation to the electrolyser plate capacity.
Financial data have been enclosed based on the current available estimates; however, such data should be considered subject to continuous revisions.

Figure 4: Main technical characteristics and cost constraints of electrolysers and their implications for TSOs.[21]

20 ENTSO-E. Potential of P2H_2 technologies to provide system services. 2023

21 Data sources: DEA Technology Data for Renewable Fuels 2024; Iliceto A., et al., Hydrogen's impact on grids. ETIP SNET. 2023; Frieden F. and Leker J. Future costs of hydrogen: a quantitative review. Sustainable Energy Fuels. 2024, 8, 1806

Regarding storage technologies, underground storage (including salt caverns, saline aquifers, and depleted gas / oil fields) and high-pressure decentralised hydrogen tanks are the two main technologies considered in future scenarios and infrastructure planning. **Underground storage and hydrogen tanks fulfil two different goals – underground storage is mainly intended for seasonal storage and longer-term system balancing, while hydrogen tanks act as an operational buffer in the supply chain.**

In terms of hydrogen transport infrastructure, on the one hand, the cost of newly built hydrogen pipelines varies (see Figure 5) depending on pipeline locations: from rare above-ground pipelines (which have the lowest investment costs, around €160 – €220 / MW / km) to underground pipelines (over €300 / MW/km) and submarine pipelines (which have the highest investment costs at €400 – €500 / MW/km). On the other hand, repurposed gas pipelines for hydrogen transport have lower costs of around €100 – €200 / MW / km (shading in Figure 5).[22]

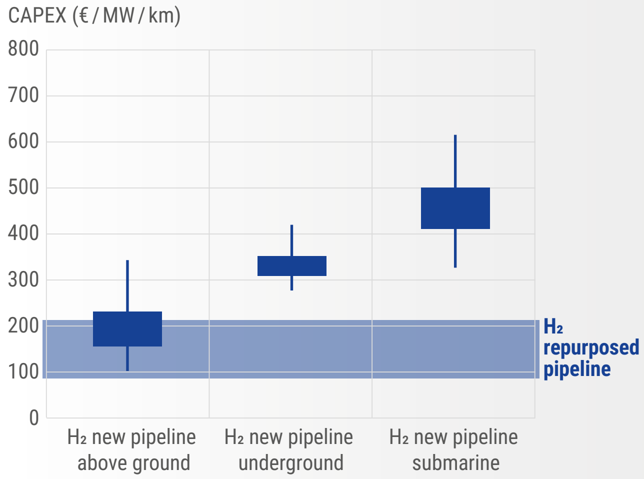


Figure 5: Average capital expenditure (CAPEX) for hydrogen pipelines estimates based on 2024 data (in € / MW / km).

2.2 Current and expected future penetration of hydrogen in the EU and its associated costs

Based on the TYNDP 2024 and multiple other sources,[23–24] **future electrolyser capacity is very much demand-driven.** Comparing different top-down estimates in future scenarios (Figure 6), electrolyser capacity is expected to expand quickly in order to reach shorter-term national targets and carbon neutrality, as projected in the TYNDP scenarios. In contrast, the scenarios developed by the International Panel on Climate Change (IPCC AR6 scenarios) are oriented more towards long-term climate targets of reaching 1.5 °C. As a result, a considerably lower degree of deployment of electrolyser capacity is projected.

A comparison of the above scenarios with bottom-up potential, i. e. the volume of electrolyser capacity expected to be either in operation or under construction, **reveals a considerable gap between bottom-up** (as indicated by the orange arrows in Figure 6) **and top-down future electrolyser capacity anticipated** (TYNDP shown by bars and IPCC AR6 indicated by teal boxes).

For instance, so far,[25] only 0.3 GW of EU electrolysis projects are operational, whereas 2.8 GW have reached the final investment decision (FID) or are under construction to be commissioned by 2030, according to the IEA database[26]. The actual size of the difference between TYNDP and IPCC projections by 2030 is highly uncertain – in the range of 7 to 97 GW of electrolyser capacity.

22 Nevertheless, repurposed pipelines pose potential risks and challenges, such as less intrinsic storage within the pipeline system and the need for extra measures to prevent hydrogen leakage and explosions.

23 IPCC AR6 1.5 °C scenarios (IIASA. IPCC AR6 Scenario Explorer and Database. 2023)

24 Bottom-up potential, i. e. final investment decision (FID)/under-construction and operation hydrogen projects in EU28 (IEA. Hydrogen production projects interactive map. Nov 2024)

25 As of the status of 13 Nov 2024 when writing this report.

26 IEA. Hydrogen Production and Infrastructure Projects Database – Data product – IEA. 2024.

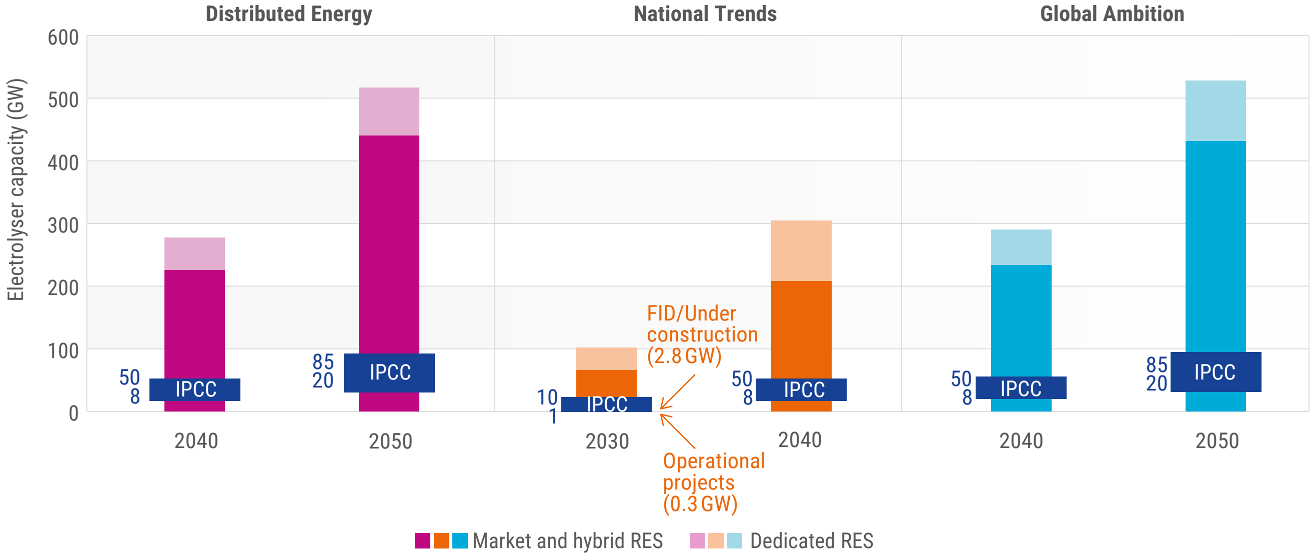


Figure 6: TYNDP scenarios (bars) compared to IPCC AR6 scenarios of the 1.5 °C climate target ("IPCC" light teal area) regarding future electrolyser capacity. The bottom-up potential (FID / under-construction and operation hydrogen projects in EU) from IEA 2024.

Renewable hydrogen costs are another driving factor of current and future hydrogen penetration in the EU, yet they are highly uncertain. Comparing different studies as well as TYNDP assumptions, the levelised cost of hydrogen (LCOH) has a very high estimated range – between €2 and almost €14/kg. This variation is likely linked to uncertain LCOH assumptions among sources (e.g. the TYNDP assumes a combination of AEC and PEM electrolysers while other sources focus solely on AEC[27] or do not specify the electrolyser type[28]).

Note that the main reasons for these variations in assumptions are differing estimates of the downwards evolution of CAPEX due to technology advancements, economies of scale, and national differences, as shown below in Figure 7.

27 Hydrogen Europe. Clean hydrogen production pathways. 2024.

28 TNO. Evaluation of the levelised cost of hydrogen based on proposed electrolyser projects in the Netherlands. 2024.

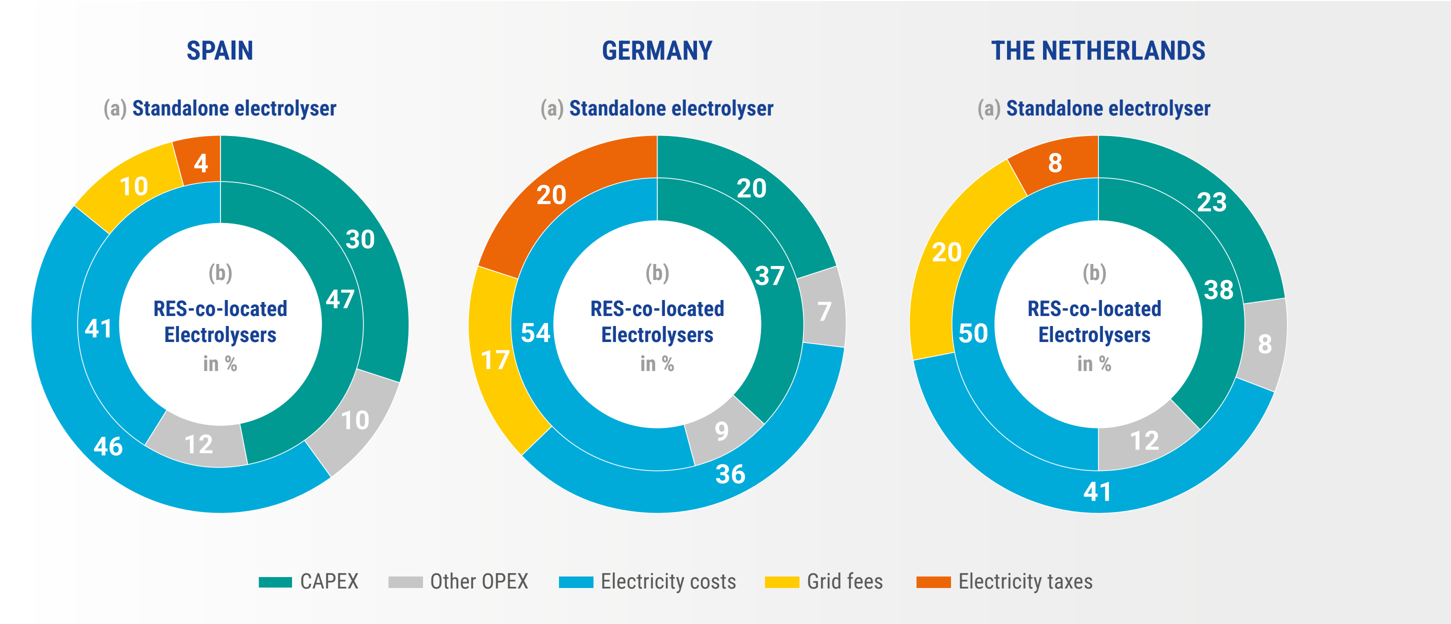


Figure 7: Spanish, German, and Dutch examples of LCOH breakdown of (a) standalone electrolysers connected to power grids (outer doughnut) vs (b) electrolysers co-located to dedicated RES (inner doughnut) based on 2023 default values from the European Hydrogen Observatory (status September 2024).

Among different LCOH components, hydrogen cost is predominantly driven by operating hours and electricity purchase price. The LCOH generally decreases as the number of operating hours increases (bottom of Figure 8) and is also dependent on lower electricity costs (depicted by RES price in Figure 8). Specifically, the electricity price accounts for 28–60 % of the total LCOH. The figure shows that a **combination of higher operating hours and lower contracted electricity prices is most effective at driving down LCOH**, enhancing the market attractiveness of hydrogen. LCOH optimisation strategies should simultaneously consider CAPEX and operational expenses (OPEX) impacts, such as the positive effects on CAPEX but potential increase in OPEX due to full load hour operations.

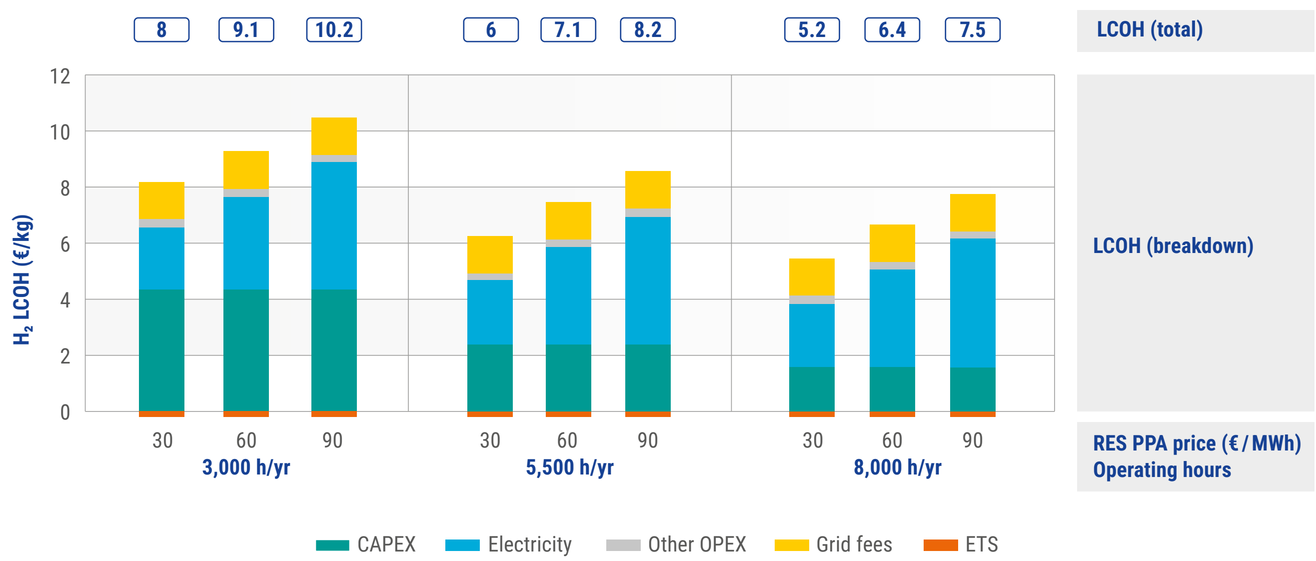


Figure 8: LCOH of low-temperature electrolysis depends on the prices of renewable power purchase agreements (PPAs) and the number of operating hours. (Source: Hydrogen Europe, 2024[29])

29 Hydrogen Europe. Clean H_2 production pathway report. 2024.

2.3 Expected impact of electrolysers and hydrogen facilities on the power system and their estimated flexibility potential

To analyse the future systemic role of electrolysers and their impact on the power system and TSOs, this study applies a scenario-based approach constituting two hypothetical future scenarios: TYNDP scenarios and IPCC. To differentiate between the different stages of the hydrogen sector development, the analysis refers to two major development phases: the ramp-up phase up to 2030 and the mature phase up to 2050, as illustrated in Figure 9 and Figure 10.

High Ambition – Deployment of electrolysers in line with policy ambitions, which is based on the upper bound of the TYNDP scenarios for on-grid capacity. This scenario should be viewed as a "stress test" to enable a better understanding of how power grid planning and operation could be impacted should EU ambitions be fully achieved.

Prudent – Low expected growth based on average estimates from the IPCC scenarios (Figure 6). In the context of this analysis, this assumption is meant to assess the effects if current developments remain on trend and targets are not reached as quickly as perhaps anticipated.

The two scenarios share common assumptions about hydrogen demand and possible production modes. Regarding hydrogen demand based on Report Part 1 and the TYNDP scenarios, the total demand includes industry, mobility, e-fuels,[30] non-energy use, and other sectors, such as agriculture. Their shares, however, are estimated to be different in the two phases, as shown in Figure 9 and Figure 10.

Hydrogen demand can be covered with either import or domestic production (i.e. "production mode" in Figure 9 and Figure 10). Especially at the beginning (i.e. during the ramp-up phase), the shares of imported hydrogen are expected to be significant as EU production and demand progressively grows. Another relevant assumption, regarding power grid impact, is the fraction of decarbonised demand covered by so-called blue hydrogen (i.e. produced from natural gas through steam methane reforming (SMR) plus carbon capture) and not through electrolysers, which implies a correspondingly lower impact on the power system.

Regarding location and connection, an electrolyser can essentially be connected to the hydrogen network, the power network, or both; the type of connection is highly relevant for the analysis:

1. **On-grid close to hydrogen demand:** Located in any generic point on the power grid, requiring renewable electricity source to be certified; hydrogen is consumed onsite, hence no connection to the hydrogen network is needed.

2. **On-grid standalone electrolysers:** Require connection to both power and hydrogen networks.

3. **Off-grid (dedicated RES):** Require a connection to the hydrogen network. The electricity used for hydrogen production is developed onsite without connection to the power grid, ensuring it is certified as 100% renewable hydrogen. There is no direct impact on the power grid.

30 Note that e-fuels can ultimately be used for different sectors, such as mobility or industry. The main differentiation lies in whether hydrogen is used in these sectors directly or, in the case of e-fuels, indirectly through conversion to other energy carriers.

Hydrogen Valleys: Electrolysers co-located with both electricity generation and hydrogen consumption enable short-distance transmission of both power and hydrogen over internal grids. This avoids the need for hydrogen logistics infrastructure, strengthening the business case and likely making it the preferred option for initial investments.

Beyond connected capacity, the impact on the power grid will be largely affected by how on-grid electrolysers are operated. Electrolysers will most likely operate in a combination of different modes:

Baseload operation focuses on maximising the electrolyser load factor, particularly through long-term RES PPA supply contracts – ideally using a flat operational profile (minimising CAPEX).[31]

Demand-driven operation, where the electrolyser operation must strictly adhere to hydrogen demand, is an obliged mode in the absence of a sufficient hydrogen logistics system.

Market price-driven operation refers to electrolysers deciding their operations based solely on electricity prices (minimising the OPEX cost component), using low- or zero-cost electricity. This mode implies a large and fully available hydrogen infrastructure to optimise a more variable production profile.

System-supportive operation implies that an electrolyser systematically provides flexibility to the power system in addition to its hydrogen production, depending on remuneration incentives.

31 It should be noted that the nature of the RES PPA can impact the feasibility of the baseload operation. A financial RES PPA can guarantee a stable purchase price for electricity supply, thus facilitating baseload operations. To certify hydrogen as renewable, financial PPAs must be supported by certificates guaranteeing the renewable electricity source, in line with renewable fuel of non-biological origin (RFNBO) requirements. In contrast, physical RES PPAs, especially if not linked to a portfolio of renewable energies, only have the potential to supply intermittent electricity, thus leading to intermittent electrolyser operation.

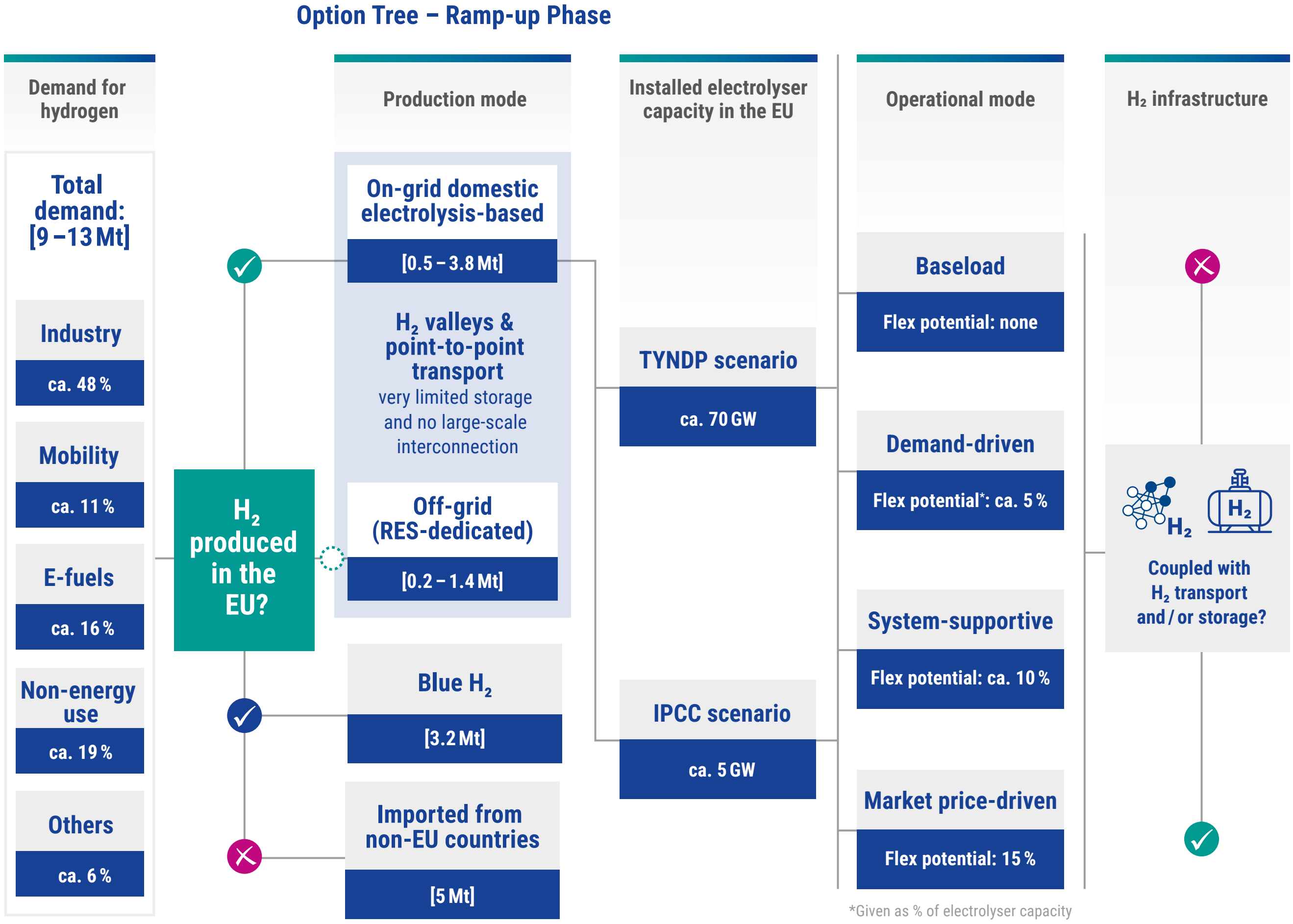


Figure 9: Flexibility potential estimates for different electrolyser operational modes (2030 ramp-up phase).

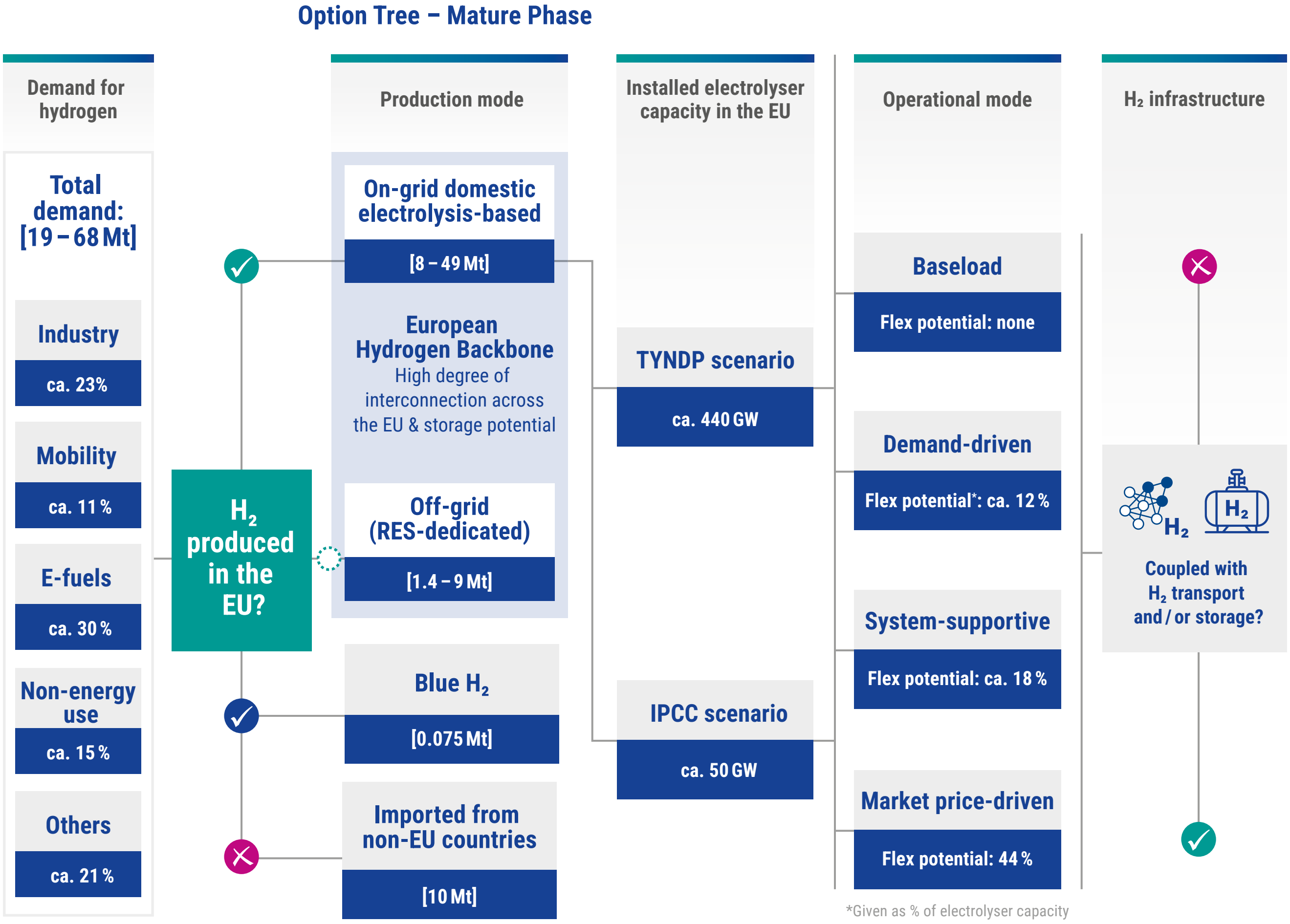


Figure 10: Flexibility potential estimates for different electrolyser operational modes (2050 mature phase).

The flexibility potential of different electrolyser operational modes refers to the extent to which they can theoretically provide short- and long-duration flexibility, including their potential to provide system services (as summarised in Figure 11). In the demand-driven operational mode with storage facilities, explicit flexibility in the range of 0.6 – 7.7 GW – both short-duration and long-duration – can be provided, depending on future scenarios. Without storage or hydrogen infrastructure, this flexibility would otherwise be zero (as shown in Figure 11, which details the flexibility provision and grid congestion risk of every operational mode with / without storage and transport facilities).

For the market price-driven operational mode with storage facilities, the range of potential system services depends on whether the high ambition or prudent scenario materialises. In the high ambition scenario, approximately 66 – 136 GW of electrolyser capacity would be available to support the power grid through flexibility provision. In the prudent scenario, a range of approximately 7.5 – 13 GW could provide both long- and short-duration flexibilities.

For the system-supportive operational mode, the potential for providing system services falls between the demand-driven and market price-driven modes (taking the average of the other two modes, approximately 11.5 – 23 %). In the high ambition scenario, approximately 8 – 101 GW of electrolyser capacity could contribute to grid flexibility. In the prudent scenario, a range of approximately 0.6 – 11.5 GW could provide both long- and short-duration flexibilities.

Depending on the electrolyser and hydrogen ecosystem development / maturity phase (i. e. ramp-up or mature phase), the share of implicit flexibility[32] is also likely to increase due to factors such as more and cheaper hydrogen storage facilities and transport options available at a later point (Figure 5), lower electrolyser and hydrogen costs / prices, integrated hydrogen and power grid planning, etc.

The incentive to provide implicit or explicit flexibility will depend on the evolving economics of electrolysers, the available revenue streams, and any applicable support schemes.

32 Note that implicit flexibility is usually also highly dependent on national conditions, such as PPA contract conditions, access to information, and applicable network tariffs, among others, thus country-based conditions would likely range widely.

Impacts on the power grid
(positive and negative)

Installed electrolyser capacity in the EU	Operational mode	Storage & Transport	Grid congestions risk	Flexibility short-duration	Flexibility long-duration
	Baseload	Without storage	YES	NO	NO
TYNDP scenario		With storage	NO	YES	NO
	Demand-driven	Without storage	YES	NO	NO
		With storage	NO	YES	YES
	System-supportive	Without storage	NO	YES	NO
IPCC scenario		With storage	NO	YES*	YES
	Market price-driven	Without storage	NO	NO	NO
		With storage	NO	YES*	YES

*Potential provision of implicit flexibility

Figure 11: Positive and negative impacts on the power grid of different electrolyser operational modes and their storage availability (example of 2030 based on Iliceto, A. et al. 2023[33]). Note that potential implicit flexibility is marked by * in the rightmost table.[34]

33 Iliceto, A. et al. Hydrogen's impacts on grids. 2023.

34 Note that implicit flexibility (i.e. demand-price elasticity) applies only without storage in market-driven and system-supportive modes; when there is storage, explicit flexibility (bidding for buying / selling already nominated energy) should always be possible.

2.4 Part 2 | Conclusions

Currently, renewable hydrogen cost (LCOH) is much higher than the fossil fuel- based alternative – even after adding the cost of CO_2. In the future, technology advancements, economies of scale, and increases in CO_2 cost are expected to make renewable hydrogen competitive – even against other forms of decarbonised hydrogen, such as fossil fuel–based with carbon capture and storage (CCS) or other processes still at the R&D stage. However, the timing of this evolution is highly uncertain.

EU domestic production will also compete with imported hydrogen, taking into account the carbon border adjustment mechanism (CBAM) tax, which is set to increase progressively.

Direct impact on power grids will come only from renewable hydrogen produced domestically through electrolysers connected to the power grid, i.e. covering only a fraction of the total renewable hydrogen demand.

Electrolyser technical constraints and costs vary among the three main technologies; innovation should target all performance improvements – not solely increased efficiency but also flexible operation features and enablers.

LCOH is driven by multiple CAPEX and OPEX factors: the main OPEX factors are the load factor of the electrolyser and the purchase cost of electricity. Renewable hydrogen demand volumes will be a decisive factor for electrolysers' profitability, impacting not only their revenues but indirectly also their costs – via economies of scale, supply chain efficiency, and technological advancements.

Several basic strategies can be used to optimise LCOH, e.g. maximising operating hours while accounting for the potential increase in operational costs from full load hours operation or utilising electricity in low- or zero-price hours, depending on location, connection characteristics, and the availability **of hydrogen infrastructure. From a holistic perspective, regulation and market design should incentivise the operational modes and configurations (including siting decisions) that are most beneficial for both the electricity and hydrogen systems**.

The flexibility potential of electrolysers mainly depends on their connection and operational modes. Meanwhile, downstream hydrogen storage and transport facilities are also necessary for both standalone grid-connected electrolysers and off-grid (dedicated RES) electrolysers to enable more flexible operation.

Hydrogen-fuelled power plants, despite their low power conversion efficiency, may play a role in future power systems due to the need for non-fossil dispatchable backup capacity to complement weather-dependent generation (wind and photovoltaic [PV]).

3 Part 3 | Market Design and Regulatory Framework for Viable and Flexible Hydrogen Production

This part focuses on the operational and economic dynamics of the electrolyser business case across different configurations and market contexts, illustrating how connection types and operational modes affect revenue, incentives, and grid impacts.

To this end, this report first builds the four operational modes of electrolysers described above to compare the **estimated sector-coupled business case for electrolysers, their costs, and potential revenues stemming from supporting the power system.** It analyses how hydrogen and electricity markets should interact to improve resource allocation and grid stability, considering pricing mechanisms, demand patterns, and infrastructure needs.

The presently high gap between electrolyser costs and expected revenue streams will need to be filled through additional mechanisms at the initial stage of deployment. Thus, in the second part of this report, **multiple potential support mechanisms and their suitability based on operational mode are reviewed,** considering technological limitations, market dynamics, and regulatory requirements.

3.1 Cost drivers

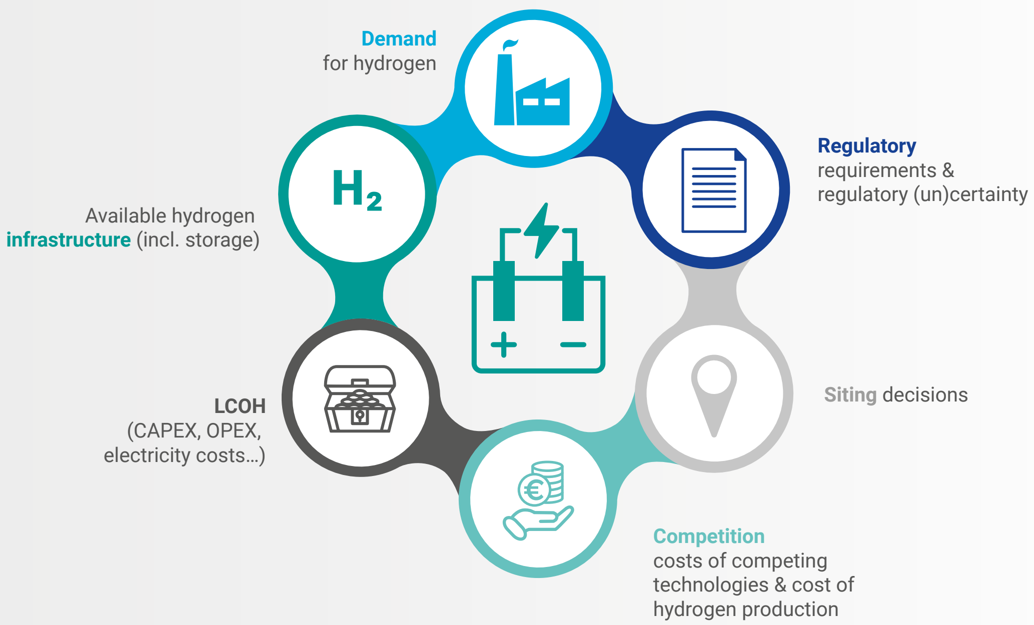


Figure 12: Cost factors affecting the business case of electrolysers.

The demand for renewable hydrogen in sectors such as industry, transport, and e-fuel production is a critical driver for electrolysers' business case. Higher demand enables economies of scale, reducing CAPEX and improving supply chain efficiencies. It also increases operational hours, stabilises revenue streams, and accelerates infrastructure development, creating a virtuous loop. Demand growth is highly influenced by EU and national policies, including targets, demand quotas, and subsidies. Policymakers can further stimulate demand through mechanisms that enhance market adoption and foster long-term investment confidence.

LCOH is the key metric for electrolyser viability, encompassing CAPEX, OPEX, electricity prices, and efficiency (Figure 8). Electrolyser CAPEX is influenced by economies of scale and technological advancements, while high utilisation rates reduce unit costs. Electricity costs, the largest OPEX component, vary depending on grid connections or renewable power agreements. National differences in grid fees, taxes, and levies further influence LCOH, impacting regional competitiveness.

The availability and timing of hydrogen infrastructure development, including transportation, storage, and distribution, are critical to electrolyser deployment. During the ramp-up phase, localised hydrogen valleys with bilateral agreements minimise initial infrastructure needs. As markets mature, interconnected networks and virtual trading hubs increase market access but also introduce competitive pressures. Coordination across production, infrastructure, and demand scale-up is essential, necessitating synchronised efforts at the EU and national levels to mitigate uncertainties and align investment strategies.

Regulatory frameworks, such as the EU's Renewable Energy Directive (RED III) – including the delegated act on renewable fuel of non-biological origin (RFNBO) – and the Hydrogen Package shape the landscape for electrolyser deployment. Delays or inconsistencies in transposing these regulations into national laws create uncertainty both for investors and hydrogen off-takers. Factors such as additionality and correlation rules, carbon pricing, and EU or national subsidies significantly affect hydrogen production costs and competitiveness.

The location of electrolysers influences infrastructure needs, challenges, and operational costs. Co-location with RES minimises power grid costs and ensures compliance with additionality rules but risks downtime due to renewable energy intermittency. Proximity to industrial hydrogen users reduces hydrogen transportation costs and supports stable revenue through long-term contracts. However, siting decisions also affect market access and flexibility in selling hydrogen. National and EU-level policies, including locational incentives and support schemes, play a significant role in guiding siting choices and enhancing the overall business case.

The competitiveness of electrolysers is shaped by alternatives like SMR with carbon capture, biofuels, and synthetic fuels. These technologies vary by sector, competing with electrolysers for decarbonisation solutions in industry, transport, and power. Imported hydrogen poses another challenge, potentially reducing electrolyser operating hours if volumes are significant. Mechanisms like the CBAM may be required to protect domestic hydrogen production. The cost dynamics of these alternatives and imports significantly impact the business case for EU-based electrolysers.

3.2 Potential revenue streams beyond hydrogen production

The primary revenue source for electrolysers is hydrogen sales, influenced by the maturity of end-use markets like steelmaking, ammonia production, and transportation, along with regulatory frameworks, infrastructure, and decarbonisation goals. Revenue stability depends on contract structures, with fixed-price agreements offering predictability and variable-price agreements capturing market fluctuations. Seasonal demand variations and supply-side renewable energy fluctuations necessitate storage and diversified sales channels to stabilise revenues.

From the power system perspective, electrolysers can also offer system benefits, acting as demand-responsive loads to optimise hydrogen production during low electricity prices or high renewable output, and providing system services like balancing and congestion management. Locational incentives and participation in demand-response programs can further enhance their value to the power system. This potential and the kind of associated revenues largely depend on the electrolyser's connection type and operational mode(s) (Figure 13).

Electrolysers connected solely to the hydrogen grid and co-located with RES operate in a supply-following manner – likely without influencing the power grid. These configurations offer lower electricity costs but are limited by the intermittent nature of renewables. Electrolysers connected to the power grid near hydrogen demand centres align their operation with local hydrogen consumption needs, taking into account electricity procurement costs and demand-driven hydrogen production. Standalone electrolysers linked to both power and hydrogen networks are in a position to provide the highest flexibility. To maximise profits, they can adapt operations to electricity and hydrogen market prices, hydrogen demand, and grid conditions, enabling participation in system service markets.

An electrolyser's choice of operational mode depends on its connection type and the maturity of the hydrogen sector. In the ramp-up phase (to 2030), limited hydrogen infrastructure and flexibility favour baseload or demand-driven operations, supported by subsidies and PPAs to ensure financial stability amid high capital costs. As the sector matures (by 2050), improved hydrogen infrastructure, storage, and market conditions will enable more flexible modes, such as market-responsive and system-supportive operations, offering higher profitability through dynamic production adjustments.

Hydrogen sales are the principal revenue source for electrolysers. Costs (and hence profits) are heavily influenced by electricity prices, which make up the majority of OPEX. System services offer a theoretical revenue potential, but competition from established technologies, such as battery storage, and stringent technical requirements, significantly limit practical opportunities. For instance, electrolysers may be able to provide balancing services like frequency containment or restoration reserves (FCR and FRR); however, this involves significant OPEX to ensure operational flexibility, while requirements and price levels differ significantly among EU countries. For a detailed overview of hydrogen market trends and potential revenues from hydrogen sales and system service markets, please refer to the detailed Report on Market Design and Regulatory Framework.

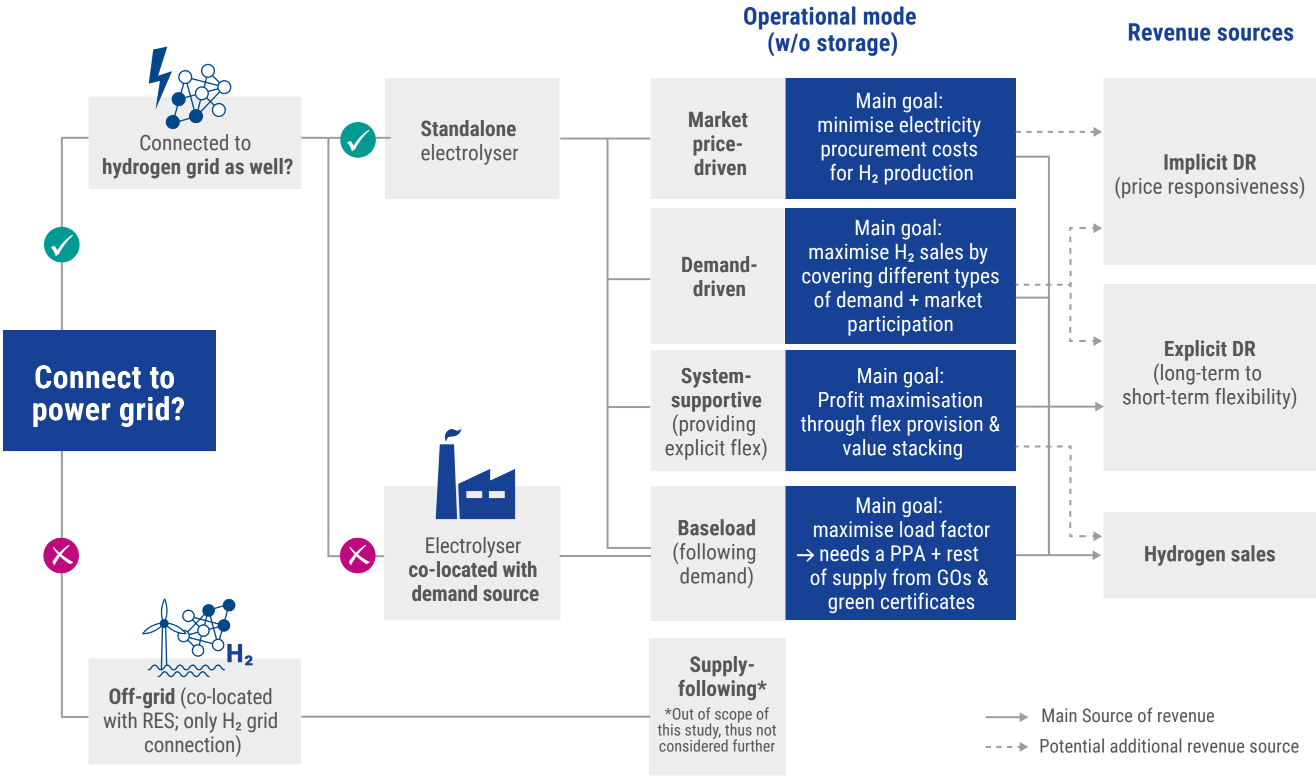


Figure 13: Electrolyser connection types, associated operational modes (without storage), and sources of revenue.

3.3 Regulatory framework and market mechanisms affecting electrolyser investment and operational costs

The EU employs various policy mechanisms and subsidies to lower the CAPEX of electrolysers, focusing on reducing initial investment barriers. Investment grants, tax incentives, and favourable financing conditions play a key role at both the national and EU levels. The EU's Innovation Fund and Important Projects of Common European Interest (IPCEI) for hydrogen projects, such as Hy2Tech, Hy2Use, and H_2Infra, provide substantial funding for early-stage electrolyser projects, infrastructure, and industrial applications. Such initiatives are essential to establishing the hydrogen economy, especially during the ramp-up phase.

Concerning **OPEX**, mechanisms like PPAs and operational support schemes, such as hydrogen contracts-for-differences (H-CfDs), cap-and-floor contracts, or off-take agreements reduce the costs and/or revenue risks associated with fluctuating prices or volumes (Figure 14). Indirectly, investments in hydrogen infrastructure, such as pipelines and storage, reduce transportation and storage costs, while regional hydrogen valleys link producers and users to simplify logistics, thereby improving project economics.

These measures are critical during the ramp-up phase, when infrastructure and demand remain limited and their development uncertain.

On the EU level, the first auction of the **European Hydrogen Bank (EHB)** in April 2024 allocated €720 million to seven renewable hydrogen projects, with winning bids averaging only €0.40/kg – far below the subsidy ceiling of €4.5/kg. The projects are concentrated in regions with competitive renewable resources, like Iberia and the Nordics, highlighting the critical role of location in cost efficiency. If similar outcomes persist in the second auction, the EHB's €3 billion budget could enable about 0.7 Mt of renewable hydrogen production annually by 2030, linked to 6 GW of electrolyser capacity. The auction results also underscore the impact of regulatory exemptions, as winning projects can use pre-subsidised RES capacity until 2038, reducing CAPEX needs.

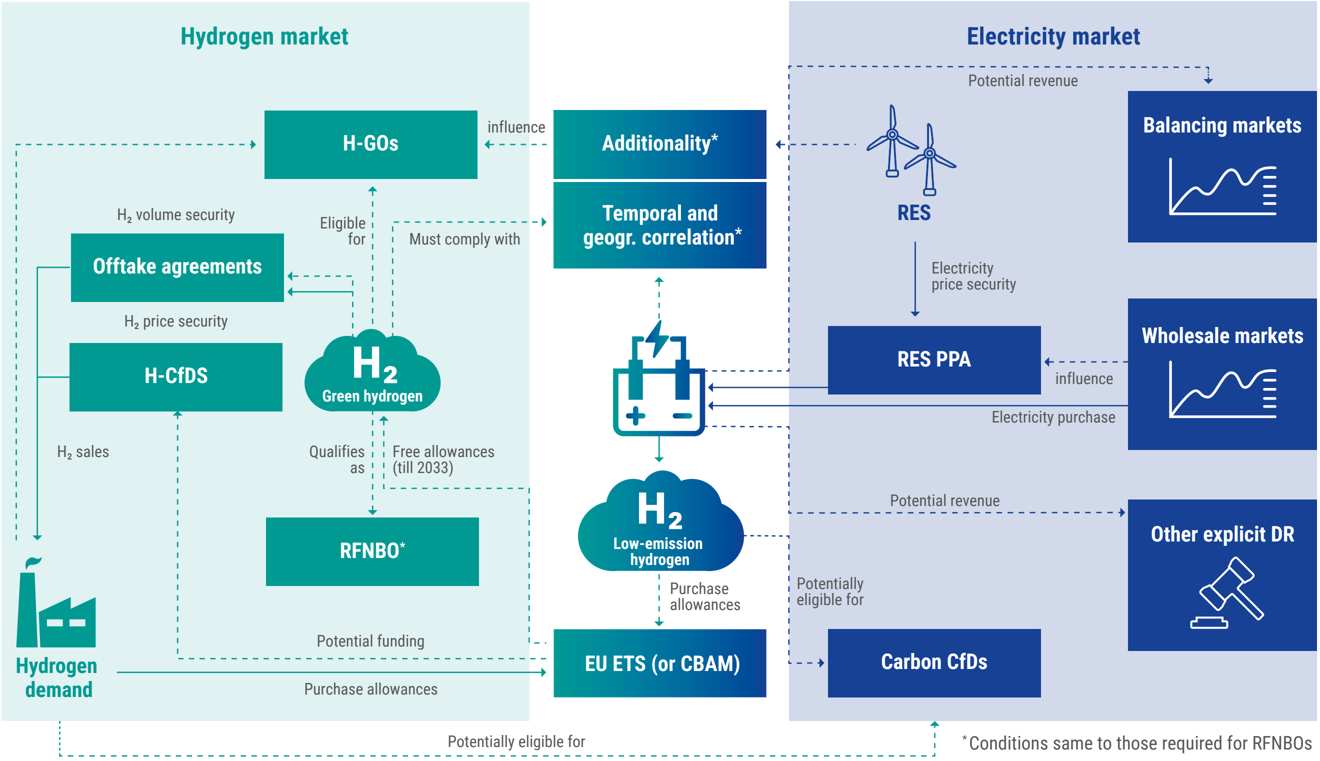


Figure 14: Electrolyser at the intersection of the H_2 and electricity markets, associated revenue streams, and possible support mechanisms.

On the demand side, quotas and demand-side subsidies create markets for renewable hydrogen by targeting sectors like steel-making, fertilizer, and heavy transport. Obligations for hydrogen adoption in industries or minimum hydrogen use in fleets foster demand while aligning with decarbonisation goals. However, these measures risk market distortion, regional disparities, and financial burdens, especially where hydrogen infrastructure is underdeveloped. While demand-side incentives indirectly support electrolyser deployment, they may limit operational flexibility by tethering production to demand rather than dynamic electricity pricing or system needs.

3.4 Relevant regulatory framework and its implications

To qualify as an RFNBO under the Delegated Act (EU) 2023/118, hydrogen production must adhere to strict criteria covering temporal and geographical correlation, as well as additionality. **Temporal correlation** ensures alignment between hydrogen production and renewable electricity generation. Until 2029, hydrogen must be produced within the same calendar month as the corresponding renewable energy generation. From 2030, this rule tightens, requiring hydrogen production to occur within the same 1-hour period as renewable energy generation or charging from a co-located storage asset. Some exceptions are possible when electricity market prices fall below a certain value to reflect cases when electrolyser operation would not involve fossil-based electricity production.

Geographical correlation requires that RES be located in the same or a connected bidding zone as the electrolyser, with comparable day-ahead market prices or in an offshore bidding zone directly linked to the electrolyser's location. Member States can implement additional geographical restrictions to align with their grid and hydrogen development strategies.

Additionally, hydrogen production using grid electricity can qualify as renewable if the grid meets specific conditions: more than 90% of electricity consumption is RES-based, the bidding zone's emission intensity is below 18 gCO_2eq/MJ, or production helps reduce renewable energy curtailment.

The additionality requirement ensures that renewable electricity used for hydrogen production comes from new RES capacity to avoid diverting existing ones. Electrolysers must either be co-located with RES or have PPAs with RES facilities commissioned within 36 months of the electrolyser's start of operation. RES facilities benefiting from operational or investment subsidies are excluded unless all prior support is fully repaid. These rules are intended to prevent double-counting of renewable capacity and ensure hydrogen production aligns with genuine decarbonisation goals. By linking hydrogen production to real-time renewable generation and geographical proximity, the EU aims to ensure RFNBO-certified hydrogen contributes meaningfully to the energy transition.

Guarantees of origin (GOs) could play a critical role in certifying renewable hydrogen as RFNBOs, providing proof of compliance with EU requirements and a potential additional source of revenue. They serve as tradable certificates confirming that hydrogen was produced using renewable electricity. However, existing GO systems are voluntary, operate at the Member State level, and lack temporal and geographical granularity, leading to inconsistencies in certification. Alignment with RFNBO standards would require detailed information, such as the source of electricity, location, time of production, and CO_2 emissions avoided, fostering transparency and incentivising the co-location of electrolysers with new renewable energy assets.

While such a system could drive innovation and reduce curtailment, it also poses challenges. Accurate tracking, real-time verification, and administrative oversight could increase costs. Misalignment between hydrogen demand and renewable energy availability, seasonal production variability, and the need for additional infrastructure could create gaps in renewable hydrogen supply or increase reliance on non-renewable electricity. Despite initially higher compliance costs, however, temporal and geographical granularity could promote storage and infrastructure, supporting a consistent renewable hydrogen supply and better market integration.

Jointly, RFNBO requirements have significant implications for renewable hydrogen production and necessitate advanced real-time energy management and site-specific planning. For example, the requirement to align hydrogen production with renewable energy generation within narrow time frames – tightening from monthly to hourly matching post-2030 – increases costs and can reduce operational flexibility. Similarly, the need for new, unsubsidised RES to meet additionality implies increased competition for PPAs, driving up contract costs as they compete with other industries for renewable electricity.

Furthermore, these conditions may restrict electrolysers' ability to provide power system services and respond flexibly to electricity market dynamics, as hydrogen production must strictly coincide with renewable availability. In the longer term, advances in storage technologies and increased RES capacity could help alleviate some of these constraints. However, the need for high-cost infrastructure, the administrative burden of ensuring compliance, and the growing competition for renewable resources may delay or deter investments in renewable hydrogen projects, potentially hindering the EU's broader renewable hydrogen ambitions.

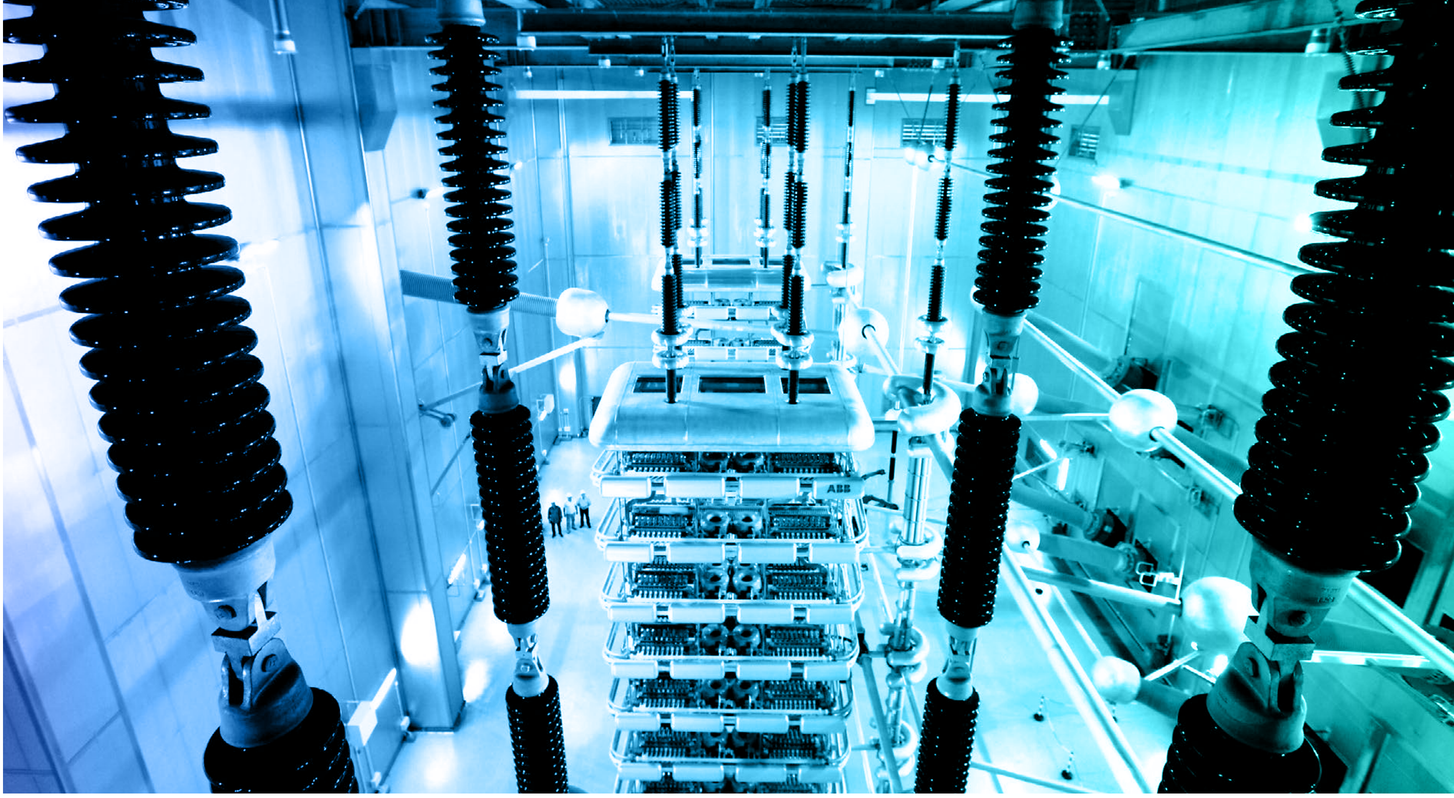
What this ultimately means is that:

1. **Renewable H_2 production targets might be hard to achieve** at the desired scale and speed.

2. **Electrolyser operators are unlikely to ensure that the produced hydrogen is fully renewable** – unless they are co-located with dedicated RES; in either case, hydrogen production may occur intermittently, depending on grid conditions, RES availability, and market prices.

3. From the business-case perspective, **electrolyser operators are incentivised to be located close to demand.** Conversely, **regulatory conditions incentivise them to be located close to production,** restricting operation to times when RES are abundant, at least before the establishment of a full-fledged hydrogen market and interconnected hydrogen infrastructure. Lower capacity utilisation and suboptimal efficiency would likely require higher subsidies or other mechanisms to be profitable.

4. As such, **the flexibility potential of electrolysers is expected to have a mixed impact.**



3.5 Strategies for managing the impact on the power grid while covering hydrogen demand

Achieving a balance between power system–friendly hydrogen production and meeting hydrogen demand requires the careful coordination of technical, economic, and regulatory factors. Electrolysers may need to navigate sometimes competing priorities: delivering cost-competitive hydrogen to industrial markets and supporting the power system. Operators are generally economically motivated to maximise the number of operational hours to ensure a profitable business case, with investment decisions typically decoupled from the potential benefits of flexible operation. Additionally, frequent ramping can degrade electrolyser performance, further discouraging operators from providing system services to the grid.

Economic pressures compound these operational challenges. Renewable hydrogen – at least for the time being – must compete with fossil fuel–derived hydrogen in industrial applications, necessitating a selling price that remains competitive. High electricity prices can make achieving this price point difficult, particularly without subsidies or other volume or price stabilisation mechanisms. The resulting reduced competitiveness can disincentivise the adoption of system-supportive behaviour. Intermittent operation may not only reduce operational efficiency due to more frequent ramp-ups or -downs but also raise the cost of hydrogen production.

The existing regulatory environment, in particular RFNBO requirements, potentially restricts the flexibility potential of electrolysers. Moreover, technical requirements may pose barriers to entry for demand response assets in general.[35] As a result, operators are more likely to prioritise hydrogen production over system service provision, as the latter is more risky and does not necessarily justify additional operational costs (including personnel or enhanced controllability and process automation).

That said, support schemes and regulatory mechanisms will be crucial in accelerating the growth of hydrogen markets and supporting technologies like electrolysers, mirroring the success of similar measures for RES. Well-designed schemes can encourage electrolysers to respond dynamically to market signals, aligning production with grid needs and maintaining efficiency. However, poorly structured interventions may disrupt market equilibrium, lead to overproduction during low-price periods, or exacerbate grid challenges, such as congestion. **Importantly, the intent of this report is not to advocate for the use of subsidies** to enable electrolyser integration at all costs **but to critically evaluate how the application of different models could enable a positive contribution to power system** stability and robustness.

35 ACER. Demand response and other distributed energy resources: what barriers are holding them back? 2023 Market Monitoring Report, 2023.

3.6 Efficiency of support schemes, regulatory framework, and other market arrangements in facilitating flexible operation

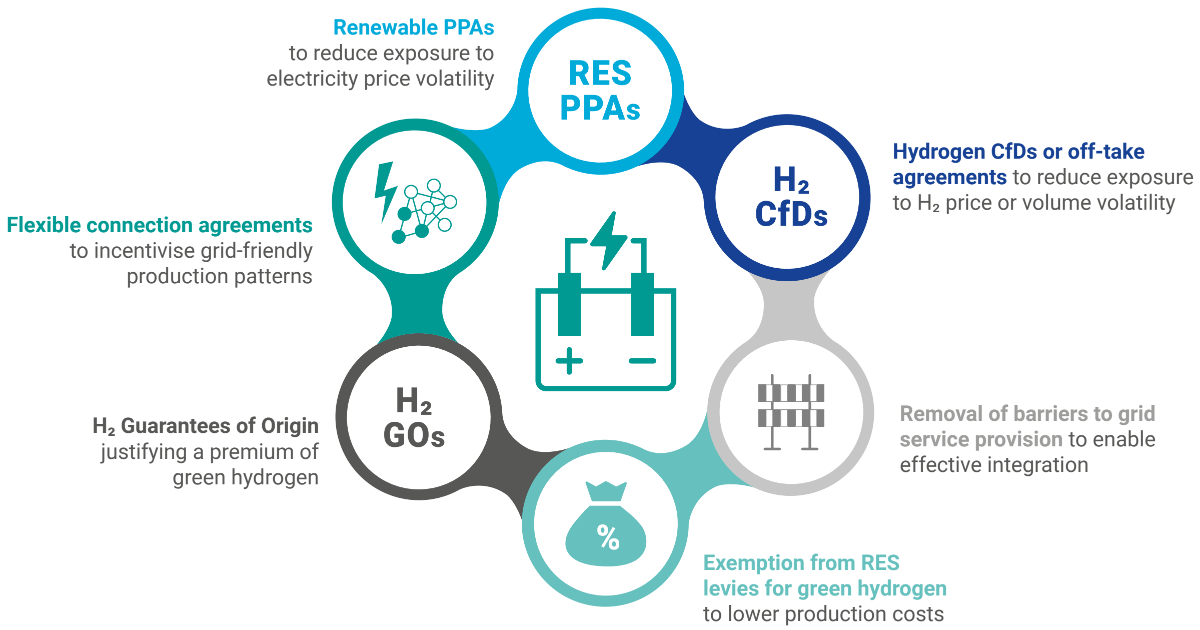


Figure 15: Potential enablers of the business case for electrolyser operation.

The type of support scheme has significant implications for both the location and operational strategies of electrolysers. Each support scheme offers distinct advantages and limitations that can influence where an electrolyser is situated and how it functions on a day-to-day basis.

Electrolyser operational modes differ based on economic priorities and support arrangements. The baseload mode prioritises continuous hydrogen production, relying on long-term PPAs to ensure cost stability and predictable operations. However, hydrogen produced may not always meet RFNBO criteria, potentially disqualifying it from subsidies. The market price-driven mode optimises production during low or negative electricity price periods, leveraging hydrogen GOs to enhance market value, though variable load factors and administrative complexity present challenges. User demand-driven operation balances production with electricity prices and demand, with H-CfDs offering revenue stability to support investment in flexible systems. Finally, the system-supportive mode focuses on providing explicit grid services, where electrolysers primarily operate to provide explicit flexibility for system services. This mode particularly benefits the removal of barriers to flexibility service markets, which creates additional revenue opportunities for electrolysers. However, emphasising grid support may lead to reduced hydrogen production rates and faster asset degradation, which can affect revenue and the lifetime of an electrolyser.

The study evaluates six support mechanisms for electrolysers based on economic efficiency, revenue impact, cost impact, operational flexibility, and risk mitigation.

Figure 16: KPI-based analysis of the studied support mechanisms and other market arrangements.

PPAs facilitate stable electricity costs and predictable revenue, essential for large-scale projects, but limit operators' ability to capitalise on low spot prices or provide system services. Long-term hydrogen off-take contracts offer revenue stability and secure investment but restrict production flexibility and may lack upside potential. Cap-and-floor contracts combine minimum revenue guarantees with upside potential during favourable market conditions, offering high economic efficiency and risk mitigation. Reduced levies on renewable energy usage improve competitiveness by lowering operational costs but provide limited risk protection due to dependency on regulatory conditions. Hydrogen GOs add moderate revenue benefits by certifying renewable hydrogen, but limit operational flexibility and impose constraints tied to RFNBO requirements, with risks dependent on market demand and regulatory changes. Each mechanism offers distinct advantages and trade-offs, highlighting the importance of tailored approaches to support electrolyser projects.

Finally, H-CfDs reduce financial risks by stabilising hydrogen prices, while offering moderate demand-driven flexibility. Note, however, that from the power system perspective, to maximise the flexible operation of electrolysers and ensure they are responsive to power system needs, **H-CfDs might not be the most suitable way to incentivise cost-efficient flexible operation.** Applied to an inherently flexible technology, they could risk creating controversial outcomes by incentivising flexibilisation while supporting baseload operation mode.

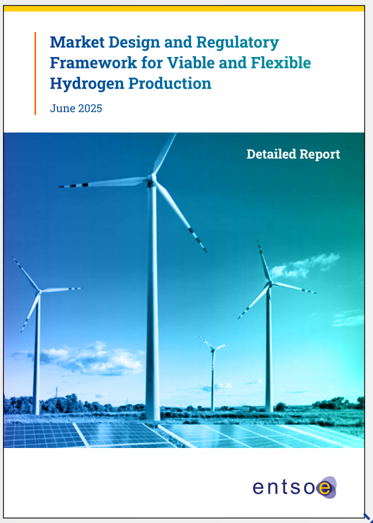
In general, we believe Member States should consider the following principles when designing support schemes:

1. Avoiding incentives to overproduce during low demand or grid constraints

2. Incentivising producers to align electrolyser investments and operations with both electricity market and system signals (e.g. low electricity prices, grid congestion) and hydrogen demand signals. This could mean additional (locational) signals to reflect the energy system value of hydrogen production while also considering the impact on electricity grids and markets.

3. Considering mechanisms to support hydrogen off-take and investment in hydrogen storage, ensuring the full value chain is incentivised, not just production itself.

The detailed Report on Market Design and Regulatory Framework can be found here:



4 Recommendations

The following recommendations emerging from the report aim to collectively address the economic and operational challenges faced by electrolyser operators while ensuring that their economic drivers align with the overall energy system needs, and ultimately consumer benefits:

1. **Coordinate hydrogen and electricity system development.** Electrolysers and other hydrogen-based facilities must be planned, implemented, and operated in coordination with the power system to achieve the highest positive impact on both systems and maximise overall consumer benefits. Coordinated cross-sector, temporal and technical planning by all relevant system and electrolysers operators, as well as an appropriate regulatory framework, should ensure an efficient transition with forward-looking investments while avoiding stranded assets and risks to the stable operation of both systems, especially in the ramp-up phase.

2. **Incentivise investments and siting decisions in line with power system needs.** The location and connection configuration of electrolysers are highly relevant for optimising the whole system of systems. The siting, size, and technology of electrolysers directly affect the capacity and development needs of transmission and distribution power grids as well as their operational challenges (e.g. grid congestion, stability, resilience). Regulation and market design (including rules defining what constitutes renewable hydrogen) should consider the impacts on the hydrogen sector while also incentivising electrolyser investment decisions and operations beneficial for both the power system and efficient decarbonisation, taking into account energy conversion and transport losses. To enable faster grid connection, reduce costs, and avoid aggravating grid congestion, flexible connection agreements might also be a useful option in congested areas.

3. **Facilitate flexibility provision of electrolysers also via hydrogen infrastructure.** Depending on their configuration and operational mode, electrolysers have the potential to become a promising source of short-duration flexibility in the power system, especially in the mature phase, through implicit and explicit demand response. Regulatory frameworks and market design rules should reduce barriers to electrolyser participation in ancillary services and congestion management schemes. Moreover, long-duration flexibility can in the future be provided through well-developed hydrogen transport and storage facilities for re-electrification in prolonged RES scarcity periods. Lastly, such hydrogen infrastructure can support hydrogen sector operational optimisation (to exploit surplus cheap RES and/or avoid oversizing electrolysers capacity) and the establishment of reserves for wider hydrogen use beyond electricity production.

4. **Public support for hydrogen production or demand, when and where needed, should be targeted and well-designed for an efficient decarbonisation effect.** CAPEX subsidies can be crucial for early-stage adoption and reducing entry barriers but should be progressively phased out as technological maturity is reached. Other types of support mechanisms (e.g. cap-and-floor, CfDs, reduced RES levies) can be useful to reduce electrolyser operational costs but must be well-designed to incentivise operation in line with market conditions (e.g. low spot prices) and system needs (e.g. avoiding grid congestion), not solely hydrogen demand. Governments' role in facilitating access to long-term renewable energy PPAs can also be crucial to ensure a stable, low-cost electricity supply for electrolysers. Lastly, mechanisms to support hydrogen off-take and investments in hydrogen storage may be needed to unlock the potential of the full value chain.
5. **Duly consider the different impacts of certification requirements for renewable hydrogen.** Regulatory requirements related to green hydrogen certification highlight potential trade-offs between decarbonisation goals and power system needs which must be accounted for. In the longer term, aligning these is essential to enable the energy transition while being aware of grid limitations. To strike a balance, GOs and RFNBO requirements should be designed with flexibility in mind. Especially in the ramp-up phase, temporal correlation rules could take into account the impact on operating costs to give electrolysers sufficient leeway to align production with system needs. Geographical correlation should consider available grid capacity and RES generation, encouraging system-aware siting decisions.

Focusing on these principles can enable sector development that rewards flexible, system-friendly, and efficient hydrogen production in the longer term.

Trajectory to progressively enable the integration of electrolysers with flexible operation

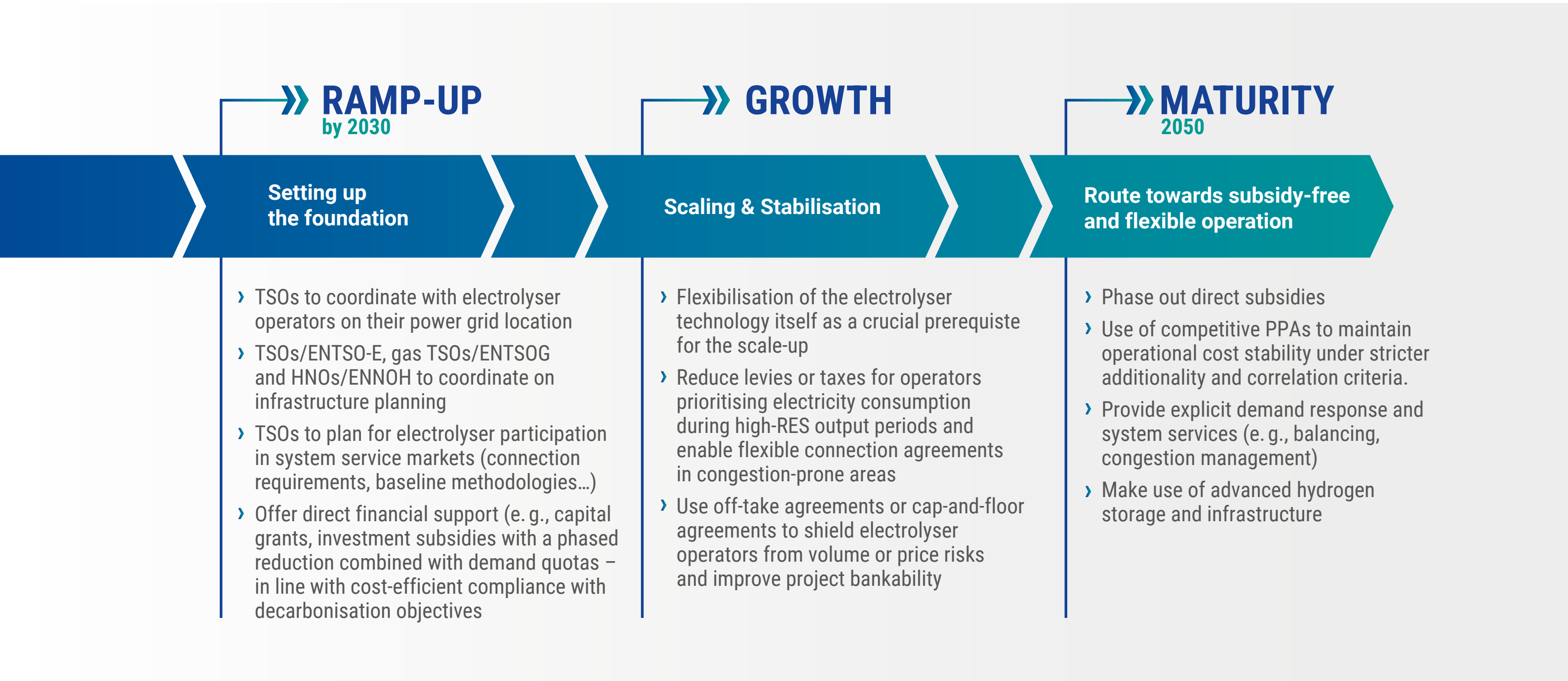


Figure 17: Measures along the trajectory towards subsidy-free and flexible hydrogen production.

The main reason for any kind of support mechanism is exactly that, to support investment into the expansion of a new, decarbonisation-efficient technology – not to be its main revenue component. The main factors affecting the business case of electrolysers should remain a growing and more versatile hydrogen demand (increasing the size of the hydrogen market) and developing hydrogen infrastructure, networks, and storage (increasing their flexibility potential). Diversifying hydrogen trading and marketplaces and maintaining operational flexibility to respond to market conditions are essential strategies to mitigate volume risks.

Abbreviations

ACER	European Union Agency for the Cooperation of Energy Regulators
AEC	Alkaline Electrolysis Cells
AFIR	Alternative Fuels Infrastructure Regulation
CAPEX	Capital Expenditures
CBAM	Carbon Border Adjustment Mechanism
CCS	Carbon Capture and Storage
CfD	Contracts-for-Differences
EHB	European Hydrogen Bank
ENNOH	European Network of Network Operators for Hydrogen
ENTSO-E	European Network of Transmission System Operators for Electricity
ENTSOG	European Network of Transmission System Operators for Gas
ERAA	European Resource Adequacy Assessment
EU	European Union
FCR	Frequency Containment Reserve
FRR	Frequency Restoration Reserve
GO	Guarantee of Origin
$H_2$2P	Hydrogen-to-Power
H-CfDs	Hydrogen Contracts-for-Differences
IPCC	International Panel on Climate Change
IPCEI	Important Projects of Common European Interest
KPI	Key Performance Indicator
LCOH	Levelised Cost Of Hydrogen
NVDC	Network Code Demand Connection
OPEX	Operational Expenditures
P2G	Power-to-Gas
P2H_2	Power-to-Hydrogen
PEM	Proton Exchange Membrane Electrolysis Cells
PPA	Power Purchase Agreement
RED III	EU's Renewable Energy Directive
REPowerEU	European Commission's Plan to phase out Russian fossil fuel imports
RES	Renewable Energy Sources
RFNBO	Renewable Fuels of Non-Biological Origin
SMR	Steam Methane Reforming
SOEC	Solid Oxide Electrolysis Cells
TSO	Transmission System Operator
TYNDP	Ten-Year Network Development Plan

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