# Potential of $P2H_2$ technologies to provide system services


frontier economics

entsoe

# ENTSO-E Mission Statement

## Who we are

ENTSO-E, the European Network of Transmission System Operators for Electricity, is the **association for the cooperation of the European transmission system operators (TSOs)**. The 39 member TSOs, representing 35 countries, are responsible for the **secure and coordinated operation** of Europe's electricity system, the largest interconnected electrical grid in the world. In addition to its core, historical role in technical cooperation, ENTSO-E is also the common voice of TSOs.

ENTSO-E **brings together the unique expertise of TSOs for the benefit of European citizens** by keeping the lights on, enabling the energy transition, and promoting the completion and optimal functioning of the internal electricity market, including via the fulfilment of the mandates given to ENTSO-E based on EU legislation.

## Our mission

ENTSO-E and its members, as the European TSO community, fulfil a common mission: Ensuring the **security of the interconnected power system in all time frames at pan-European level** and the **optimal functioning and development of the European interconnected electricity markets**, while enabling the integration of electricity generated from renewable energy sources and of emerging technologies.

## Our vision

ENTSO-E plays a central role in enabling Europe to become the first **climate-neutral continent by 2050** by creating a system that is secure, sustainable and affordable, and that integrates the expected amount of renewable energy, thereby offering an essential contribution to the European Green Deal. This endeavour requires **sector integration** and close cooperation among all actors.

Europe is moving towards a sustainable, digitalised, integrated and electrified energy system with a combination of centralised and distributed resources.

ENTSO-E acts to ensure that this energy system **keeps consumers at its centre** and is operated and developed with **climate objectives** and **social welfare** in mind.

ENTSO-E is committed to use its unique expertise and system-wide view – supported by a responsibility to maintain the system's security – to deliver a comprehensive roadmap of how a climate-neutral Europe looks.

## Our values

ENTSO-E acts in **solidarity** as a community of TSOs united by a shared **responsibility.**

As the professional association of independent and neutral regulated entities acting under a clear legal mandate, ENTSO-E serves the interests of society by **optimising social welfare** in its dimensions of safety, economy, environment, and performance.

ENTSO-E is committed to working with the highest technical rigour as well as developing sustainable and **innovative responses to prepare for the future** and overcoming the challenges of keeping the power system secure in a climate-neutral Europe. In all its activities, ENTSO-E acts with **transparency** and in a trustworthy dialogue with legislative and regulatory decision makers and stakeholders.

## Our contributions

**ENTSO-E supports the cooperation** among its members at European and regional levels. Over the past decades, TSOs have undertaken initiatives to increase their cooperation in network planning, operation and market integration, thereby successfully contributing to meeting EU climate and energy targets.

To carry out its **legally mandated tasks**, ENTSO-E's key responsibilities include the following:

- Development and implementation of standards, network codes, platforms and tools to ensure secure system and market operation as well as integration of renewable energy;
- Assessment of the adequacy of the system in different timeframes;
- Coordination of the planning and development of infrastructures at the European level (Ten-Year Network Development Plans, TYNDPs);
- Coordination of research, development and innovation activities of TSOs;
- Development of platforms to enable the transparent sharing of data with market participants.

ENTSO-E supports its members in the **implementation and monitoring** of the agreed common rules.

**ENTSO-E is the common voice of European TSOs** and provides expert contributions and a constructive view to energy debates to support policymakers in making informed decisions.

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# Executive summary

Hydrogen is expected to become an essential tool to achieve ambitious decarbonisation targets, particularly in hard-to-abate sectors. Produced through electrolysis – often generically called Power-to-Hydrogen (P2$H_2$) – using electricity from renewable energy sources, hydrogen is effectively carbon-neutral as it does not emit $CO_2$ and results in limited air pollution.

The renewed attention on hydrogen as a vector of decarbonisation in Europe will likely lead to the development of significant grid-connected P2$H_2$ production capacities over the next two decades and have an important impact on the electric system as well as on its interaction with gas networks.

It is in this context that this report assesses the role that electrolysers can play, not only as consumers of electricity, but also in providing enhanced flexibility to power grids.

The growing share of variable renewable energy sources (VRES) in the energy mix and their often decentralised generation sites pose their own set of unique challenges for the operation and evolution of power networks. These challenges need to be addressed in the context of ever-growing demand for electricity given the multiplication of existing and new use cases in an increasingly electrified world.

As a result, drawing on electrolysers to accommodate otherwise curtailed surplus VRES generation and provide additional forms of short-term flexibility is linked to the integration of renewable generation. The provision of services to transmission and storage options (TSOs) could, in principle, not only reduce the social cost of curtailment and other network imbalances, but also provide green hydrogen for the decarbonisation of other sectors.

## Approach

Although these factors are all expected to drive a significant change in power networks and the wider energy sector, the exact long-term picture nevertheless remains highly uncertain today. For this reason, although the assessment is largely based on current knowledge and performance, the study also attempts to investigate how results may change by 2030.[1]

### The study followed a two-stage approach:

1. First, it was assessed whether electrolysers would be technically able to provide a range of the most common system services (as defined today) as well as longer-term balancing, e.g. through large-scale absorption of otherwise curtailed VRES (Sections 2 and 3 of our report).
   - It is worth noting that given the high uncertainty around the future development of P2$H_2$ projects, the study refrains from analysing the degree to which electrolysers would be competitive compared to alternative sources of short- and/or long-term flexibility, which will be known only once a sufficiently large number of mature electrolyser projects are operational.
2. The study then analysed whether market design could and should provide a solution to any identifiable barriers to the provision of system services by electrolysers (Section 4 of the report). The study focused on barriers that would be specific to electrolysers and prevent them from providing a specific service, even though it would be socially optimal for them to do so.

The high-level findings are presented on the next page.

1 Although a longer timeframe may see more significant change, and possibly an even bigger role for electrolysers, the selection of the 2030 horizon allows us to base our analysis on robust available evidence.

# High-level results

- The study finds that commercially-viable electrolyser technologies – in particular, Alkaline and PEM electrolysers – could, in principle, provide a wide range of frequency and non-frequency ancillary services as well as congestion management.

- Electrolysers could also accommodate expected VRES curtailment by 2030, thus providing longer-term flexibility to power networks. Europe has massive hydrogen underground storage potential, which could be used to accommodate demand as well as generation peaks and troughs on both the power and hydrogen sides. However, underground storage potential is unevenly distributed and largely located offshore, which introduces a degree of uncertainty surrounding the extent to which this potential could be harnessed by 2030.

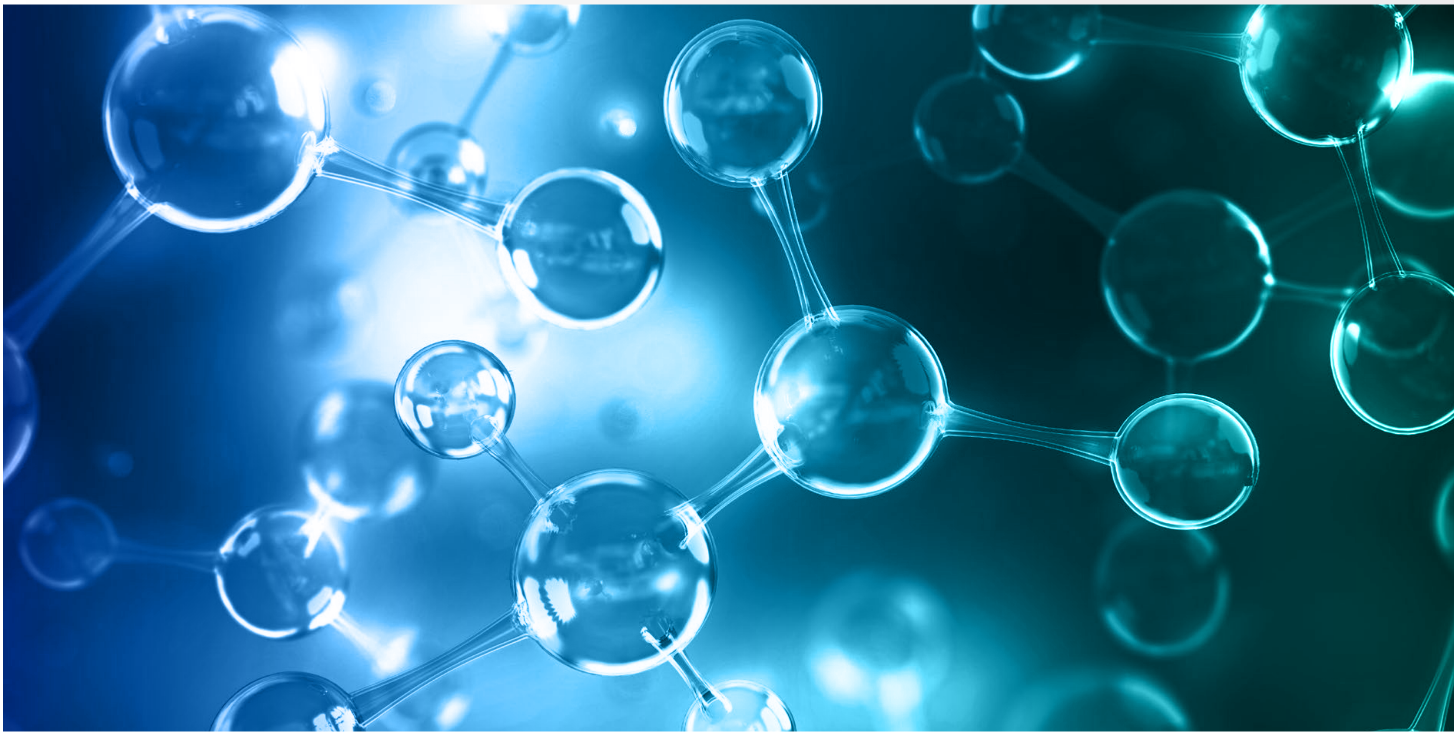
- In principle, electrolysers could thus constitute a complementary technology to other electricity storage technologies, but their competitiveness may be impacted by efficiency losses due to the additional transformation from power to hydrogen (and back to power), which could be more significant than for other technologies (e.g. batteries).

- Over the next decade, electrolyser business models will primarily be looking to decarbonise existing hydrogen use cases. Meeting the demand for decarbonised gases for additional use cases (e.g. transport, household heating) with green hydrogen – in particular by 2040 and 2050 – would require significant investments in generation assets, power network and hydrogen transport and storage infrastructure.

- However, the study does not identify any significant barriers to the provision of system services by electrolysers, although the rapid and ongoing development of the energy system, shape and volume of flexibility needs, as well as flexibility technologies, requires close monitoring to avoid possible market distortions. Diffusion of electrolysers will require coordinated network development plans that include optimal localisation and appropriate long-term market signals to stimulate investments.

- This emphasises the need for a) design and development of an adequate energy infrastructure as the backbone of regional integration of energy resources, including electricity infrastructure and b) an integrated whole-systems view of the capabilities of the energy system and massive and wide-spread development of RES generation capacities to meet decarbonisation targets across the power and gas sectors.

- Finally, it is worth noting that the role for $P2H_2$ projects in the provision of flexibility will ultimately depend on their competitiveness compared to other storage technologies. If these alternatives (e.g. batteries) are able to provide flexibility at lower cost, the need for $P2H_2$ capacity may be significantly reduced.



# 1 Introduction

Frontier Economics was commissioned by ENTSO-E to carry out a study on the technical and economic conditions for the integration of electrolysers ($P2H_2$) for system services. The key objective of the study was to provide an assessment of the extent to which electrolysers could participate in the provision of system services to electricity networks and thus respond to increasing flexibility needs in light of increasingly decentralised and variable generation, multiplying use cases for electricity and ambitious decarbonisation targets.

These factors are expected to drive a significant change in the power network and the wider energy sector; however, the exact long-term nevertheless remains highly uncertain today. For this reason, the study bases the assessment on current knowledge and performance – electrolysers themselves are still a developing technology – but also investigates how results may change by 2030. Although a longer timeframe may see more important change, and possibly an even bigger role for electrolysers, the selection of the 2030 horizon allows us to base the analysis presented in the study on robust available evidence.

This paper is a key contribution to the larger and upcoming ENTSO-E Vision 'A Power System for A Carbon Neutral Europe'. In October 2022, ENTSO-E will present this Vision of a power system that will be the foundation of a fully carbon-neutral European economy. The Vision will contribute to the debate on the Green Deal and EU Energy Transition, including TSOs' common intelligence on trends, scenarios, challenges, technology and innovation.

### This report presents the results of the study, it is structured as follows:

- **Section 2 presents an analysis of the key characteristics and the technical potential of different electrolyser technologies to provide system services to power networks.**

- **Section 3 assesses the longer-term balancing potential that hydrogen produced from electrolysis could offer to TSOs.**

- **Finally, Section 4 analyses whether market design could and should provide a solution to any identifiable barriers to the provision of system services by electrolysers.**

# 2 Analysis of the technical potential of $P2H_2$ technologies for providing system services

This chapter presents an overview of technologies and analysis of services that different types of electrolyser would be able to render to the electricity system. Note that this report explores only the technical feasibility and does not consider economic or legal constraints.[2]


## In the following sections, the study:

- Presents the key characteristics and technical capabilities of the three main types of electrolysers;
- Briefly defines the frequency and non-frequency system services and congestion management services included in the scope of our analysis; and
- Maps electrolysers with system services requirements to identify the extent to which each technology could, in principle, provide a specific system service.

The information used in the process described above comes from a range of external sources, as well as Frontier Economics' experience from previous projects with $P2H_2$ experts, and has been completed with additional information provided by ENTSO-E.

The research on – and applications of – electrolyser technologies are rapidly evolving. As such, the information presented in this report corresponds to the state of knowledge at the time of writing.

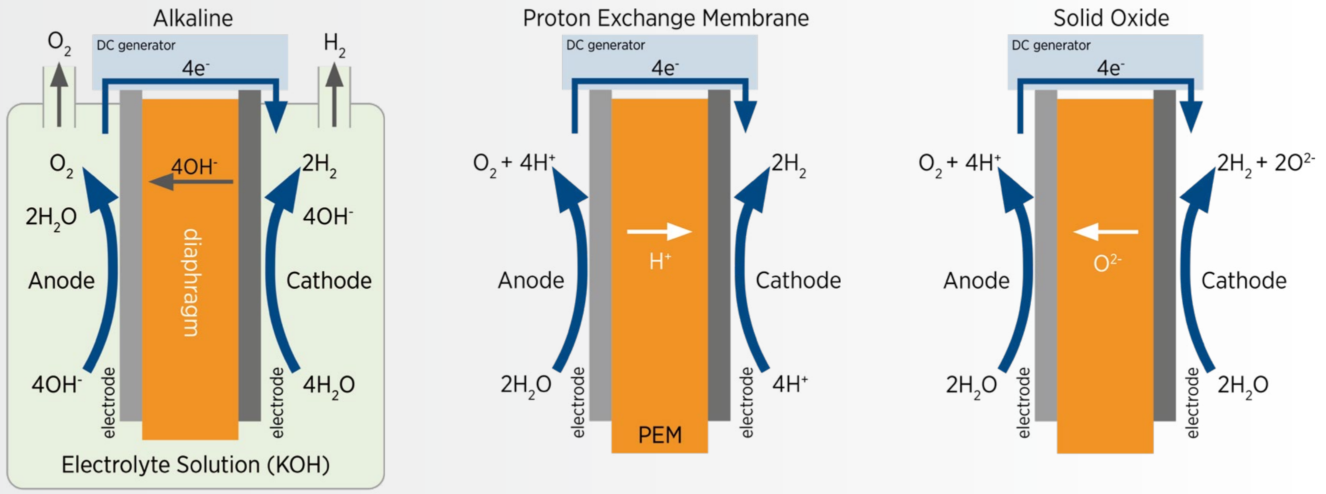
2 We cover CapEx and OpEx estimates in this section because we consider costs to be key characteristics of a given technology. However, we do not assess the competitiveness of electrolysers against other technologies on the basis of these estimates.

## 2.1 Technical characteristics of electrolyser technologies

The process of producing $H_2$ from power is known as 'electrolysis'; it consists of the separation of the water molecule into hydrogen and oxygen by the application of an electric current. The technology used in this process is the electrolyser, which consists of an anode and a cathode separated by an electrolyte. The electrolyser is composed of a stack (joining of several smaller cells where the splitting of the water takes place), and all other equipment needed for the balance of the plant. Large-scale production is not necessarily oriented towards large cells but rather towards the joining of stacks.

For the purpose of this report, focus is on three water electrolysis technologies: Alkaline (AEL), Polymer Electrolyte Membrane (PEM), and Solid Oxide Electrolyser Cell (SOEC)[3]. Whereas Alkaline and PEM are well-proven technologies and have been used in commercial applications, SOEC and AEM are still at the developmental stages.

- **Alkaline:** The electrodes (anode and cathode) are immersed in a liquid alkaline electrolyte solution and separated by a diaphragm that separates the oxygen from the hydrogen. The design of this type of electrolyser is simple and relatively easy to manufacture. As a consequence, Alkaline electrolysers are a commercial technology and present the lowest CapEx. Additionally, thanks to the improvements in the design of the diaphragms and the electrocatalysts their performance today is similar to that of the PEM (63 – 70 % efficiency based on hydrogen's lower heating value (LHV)).
- **PEM (Polymer Electrolyte Membrane):** Uses a proton-exchange membrane that transports the protons and separates the electrodes while water is directly supplied to the cathode. The membranes' advanced design allows high efficiencies by reducing the resistance (61 – 70 % efficiency). Due to a high level of corrosion (oxidative environment), this technology requires noble metals as catalysts that can withstand these conditions – iridium for the anode and platinum for the cathode – with an impact on the CapEx and a consequent dependency on the precious metals market.[4] Although PEM is a commercial technology, it has an associated higher CapEx than Alkaline.




*Anode:* $4OH^- \leftrightarrow 2H_2O+O_2+4e^-$
*Cathode:* $4H_2O+4e^- \leftrightarrow 2H_2+4OH^-$

*Anode:* $2H_2O \leftrightarrow O_2+4H^++4e^-$
*Cathode:* $4H^++4e^- \leftrightarrow 2H_2$

*Anode:* $2O^{2-} \leftrightarrow O_2+ 4e^-$
*Cathode:* $2H_2O+4e^- \leftrightarrow 2H_2+2O^{2-}$

Figure 1: Illustration of the three main types of electrolysers

Source: IRENA, 2020. Green hydrogen cost reduction. Scaling up electrolysers to meet the 1.5°C climate goal.

3 We note that a fourth technology, Anion Exchange Membrane (AEM), is also at an experimental stage.

4 We understand that noble metals are used, first and foremost, because of their resistance to corrosion. As noted, within this group, platinum and iridium are currently preferred due to their capabilities of acting as good catalysts. However, research in this area is rapidly evolving.

- **SOEC (Solid Oxide Electrolyser Cell):** Uses solid oxide to separate hydrogen and oxygen. SOEC's operating temperatures are very high compared with the other two electrolysers (above 500 degrees Celsius compared with 70° – 90° for Alkaline and 50° – 80° for PEM). This has several advantages. First, SOEC electrolysers have the ability to operate in reverse mode by producing electricity from stored hydrogen.[5] Second, high operating temperatures decrease electricity demand and increase efficiency (system efficiency can exceed 80 %). SOEC is not yet a mature, commercially ready technology (current demonstration projects reaching 1 MW).

The following subsection presents a more detailed analysis of the technical capabilities of each electrolyser. The information has been grouped according to three categories that are relevant for the provision of system services:

- **size**;
- **costs, efficiencies and lifetime**; and
- **flexibility**.

Each category includes variables that will be relevant in evaluating how suitable each electrolyser is for frequency, non-frequency and congestion management services.

Given that the technology is still developing and improving, a time dimension is added to the information with today's state-of-the-art and medium-term estimates (year 2030) for each of the variables, to help anticipate how the technical capabilities of the different electrolyser types will evolve. The selection of the year 2030 responds to the availability of public information (despite some caveats for SOEC electrolysers, for which there is a general lack of information due to its lower degree of maturity), and also provides enough time to reach the developments that are expected.

5 We understand that PEM electrolysers are also, in principle, able to operate in reverse mode, but are not purpose-built to do so. Compared to SOEC electrolysers, reverse mode operation would therefore be highly inefficient if carried out through PEM technology.

| Characteristic | Time horizon | Alkaline | PEM | SOEC |
|---|---|---|---|---|
| **Size** | | | | |
| Typical stack size and examples of big plant capacity<br><br>The size of a plant increases with (a) the stack size; (b) the number to stacks. | Today | › Typical stack size: 1 MW<br>› Toshiba operates the world's largest single-stack electrolyser of 10 MW. | › Typical stack size: 1 MW<br>› Shell is operating a 10 MW PEM electrolyser. Air Liquide recently inaugurated a 20 MW four-stacked PEM electrolyser. | › Typical stack size: 5 kW<br>› Sunfire is operating a 225 kW electrolyser consisting of 60 stacks. |
| | 2030 | › Typical size stack: 10 MW<br>› Repsol is expecting to operate a 200 MW alkaline electrolyser by 2025. | › Typical size stack: 10 MW<br>› Repsol is planning to operate a 200 MW electrolyser by 2023. | › Typical size stack: 200 kW<br>› Topsoe is set to build a 100 MW SOEC electrolyser by 2024. |
| **Costs, efficiency and lifetime** | | | | |
| CAPEX in €/kWe<br><br>The numbers in parenthesis are classified as typical by DNV-GL/GIE. | Today | 437 – 1,500 (700) | 613 – 2,000 (1,160) | 2,520 – 5,040 (3,083) |
| | 2030 | 357 – 800 (621) | 350 – 1,350 (663) | 715 – 2,501 (1,706) |
| OPEX as % of CapEx | Today | 2 % | 2 – 3 % | 1 – 2.5 % |
| | 2030 | 2 % | 2 – 3 % | 1 – 2.5 % |
| Efficiency at nominal load, LHV | Today | 63 – 70 % | 61 – 70 % | 74 – 81 % |
| | 2030 | 65 – 71 % | 63 – 75 % | 77 – 88 % |
| Lifetime stack (hours) | Today | 60,000 – 75,000 | 50,000 – 80,000 | 10,000 – 20,000 |
| | 2030 | 90,000 – 100,000 | 60,000 – 90,000 | 40,000 – 60,000 |
| **Flexibility** | | | | |
| Load range (relative to nominal load)<br><br>The overload condition can be kept for a limited amount of time, requires oversized equipment and entails efficiency losses. | Today | 10 – 110 % | 0 – 160 % | 20 – 125 % |
| | 2030 | Expected by 2050: 5 – 300 % | Expected for 2050: 5 – 300 % | Expected for 2050: 0 – 200 % |
| Start-up time (warm, cold) | Today | 1–10 minutes | 1 second – 5 minutes | < 60 minutes |
| | 2030 | Not available | Not available | Not available |
| Shutdown | Today | 1–10 minutes | 1 second – 5 minutes | Not available |
| | 2030 | Not available | Not available | Not available |
| Ramp-up / Ramp- down | Today | 0.2 – 20 % / second | 100 % / second | SOEC have a system response time of few seconds. |
| | 2030 | Not available | Not available | Not available |
| Reactive power | › Electrolysers cannot provide reactive power *per se* as they are a DC loads and limited reactive power is consumed by other equipment in the module. However, electrolysers may be able to provide voltage control through their converters. | | | |

Figure 2: Electrolysers' technical characteristics

Source: Frontier Economics based on external sources described in the annex. Note: When forecasts for 2030 are not available, we reported estimates for the closest date to 2030. CapEx is reported in euro per kilowatt of electrical power. We noticed that the estimates for electrolysers cold start-up time differs remarkably in the literature.

## Key points from the table above are as follows

### Size

- Stack size and plant capacity are similar for Alkaline and PEM technologies. Stack size is anticipated to increase substantially for both technologies by 2030, and relatively large-scale (200 MW) plants are expected by 2025.
- SOEC technology is less mature, and considerably smaller in terms of stack size. Again, stack size is predicted to increase substantially by 2030.

### Cost efficiency and lifetime

- **Costs:** Capital costs for the Alkaline technology are considerably lower today than for PEM and SOEC (with SOEC being the most expensive technology). Costs for all three technologies are anticipated to fall by 2030. However, PEM and SOEC costs are anticipated to fall more substantially than Alkaline costs. By 2030, typical Alkaline and PEM capital costs are likely to be similar. CapEx cost reductions are driven by (i) bigger modules on average, (ii) technological improvements and maturity, and (iii) economies of scale in production. OpEx costs as a percentage of CapEx costs are broadly similar across the technologies, and are not predicted to change materially (as a percentage) by 2030.[6]
- **Efficiency:** Alkaline and PEM electrolysers have similar efficiencies and no significant changes are expected in the future. SOEC electrolysers have a higher efficiency, and this is predicted to increase further by 2050 (possibly reaching 88 % efficiency in 2030, compared to a maximum of 70 – 75 % for the other technologies.
- **Lifetime:** Alkaline (60 k – 75 k hours) and PEM (50 k – 80 k hours) have considerably longer lifetimes today than SOEC (10 k – 20 k hours). It is anticipated that lifetimes will increase for all three technologies by 2030, but Alkaline and PEM technologies will still have considerably longer lifetimes.

### Flexibility

- PEM electrolysers have considerably greater flexibility than the other technologies. This is particularly notable in relation to cold start-up and shut-down times, which range from 1 second to 5 minutes, compared to 1–10 minutes for Alkaline and < 60 minutes for SOEC. PEM electrolysers can also increase / decrease their electricity consumption at a rate of 100 % per second. That is, they can go from standby mode to nominal capacity in one second. This compares to 0.2 – 20 % per second for Alkaline electrolysers. Finally, PEM electrolysers have the broadest operating range, ranging from 0 –160 % of their nominal capacity. This compares to 10 –110 % for Alkaline and 20 –125 % for SOEC.[7]
- Electrolysers are DC loads and, as such, cannot provide reactive power per se. However, electrolysers may be able to provide reactive power or inertia services if equipped with self-commutated converters.[8] In this case, any remaining capacity of the AC–DC converter can be used to inject (or absorb) reactive power to the grid.
- Currently, there is limited information on SOEC electrolysers' characteristics with respect to flexibility.
- There is also limited information available on how the flexibility characteristics of the different technologies will evolve by 2030.

6 We note that these OpEx estimates do not include the cost of electricity.

7 We note that the overload condition (i) can be kept for a limited amount of time, (ii) leads to high efficiency losses (30 – 40 %) and (iii) increased stress for the materials. Moreover, operating in overload requires oversized electrical (transformer, rectifier) and downstream (compressor, pump) equipment.

8 The need for inertia will most likely rise in the future with less conventional turbines/generators.

## 2.2 Definition of system services

System services are all services necessary for the operation of a transmission and distribution system, and can be organised in different categories.[9] As outlined in Figure 3, in this report we explore:

- Ancillary services (frequency and non-frequency); and
- Congestion management products.

There are system services which are not included in the report (e.g. inertia for local grid stability, black start capability or fast frequency response – particularly useful for small island operation capability) as these would rely on additional equipment being included in the plant specifications.[10] Technical requirements for system services may differ across TSOs, especially for services such as voltage control and congestion management. In the following table, we present some typical examples of key features of the different system services we have included in our analysis.

| System services (+ congestion management) | | | |
|---|---|---|---|
| **Ancillary services** | Frequency ancillary services (mainly for balancing) | Frequency Containment Reserves (FCR) | › FAT: 30 sec.<br>› Min. size: 1 MW<br>› Symmetry: Yes<br>› Bid duration: 4 h |
| | | Automatic Frequency Restoration Reserves (aFRR) | › FAT: 5 min.<br>› Min. size: 1 MW<br>› Symmetry: No<br>› Bid duration: 15 min. |
| | | Manual Frequency Restoration Reserves (mFRR) | › FAT: 12.5 min.<br>› Min. size: 1 MW<br>› Symmetry: No<br>› Bid duration: 15 min. |
| | | Reserve Restoration (RR) | › FAT: 30 min.<br>› Min. size: 1 MW<br>› Symmetry: No<br>› Bid duration: 15 min.–1 h. |
| | Non-frequency ancillary services | Voltage Control | › FAT: few sec. to 15 min.<br>› Min. size: n.a.<br>› Symmetry: No<br>› Bid duration: n.a. |
| **Congestion Management** | Services for congestion management | Congestion management through redispatch and curtailment | › FAT: 15 min.<br>› Min. size: 1 to 10 MW.<br>› Symmetry: No<br>› Bid duration: n.a. |

Figure 3: Summary of generic system services and brief description

Source: Frontier Economics, based on public information. Note: FAT stands for Full Activation Time. n.a. denotes no public information available. Technical requirements differ across TSOs. In this table, we report some examples of technical requirements.

9 The description of system services presented in this subsection is based on the definitions contained in the FCR Cooperation mechanism, the aFRR, mFRR and RR Implementation Framework and on the French, Spanish and Italian TSOs' documentation as concerns voltage control and congestion management.

10 As mentioned above, inertia could, for instance, be provided by an electrolyser if it is paired with self-commutated converters.

## Frequency ancillary services or balancing services

'Balancing' means all actions and processes, on all timelines, through which Transmission Systems Operators (TSOs) ensure, in a continuous way, the maintenance of system frequency within a predefined stability range, and compliance with the amount of reserves needed with respect to the required quality.[11]

**Balancing is organised in different steps. For the purpose of this report, we explore the following:**

› **Frequency Containment Reserves (FCR):** Sometimes known as 'primary reserve power', FCR refers to the active power reserves available to contain system frequency after the occurrence of an imbalance. FCR is a standardised frequency response product dispatched for frequency deviations in less than 30 seconds. This product is generally traded via a capacity price (and possibly also utilisation price) and is dispatched automatically by contracted flexibility providers on command of the grid operator. The frequency containment process stabilises the frequency after the disturbance at a steady-state value within the permissible maximum steady-state frequency deviation by a joint action of FCR within the whole synchronous area.

› **Frequency Restoration Reserves (FRR):** FRRs are the active power reserves available to restore system frequency to the nominal frequency and – for a synchronous area consisting of more than one load-frequency control (LFC) area – to restore power balance to the scheduled value. FRR include operating reserves with an activation time between 30 seconds and 15 minutes. In most countries there is a capacity payment for keeping capacity available and an energy payment if the service is activated. FRR includes automatic (aFRR) and manual (mFRR) activation:

 – **Automatic Frequency Restoration Reserves (aFRR):** Also known as 'secondary reserve power', aFRR must be completely activated in 5 minutes and, as its name indicates, it is dispatched automatically by a contracted flexibility provider on command of the grid operator. It has historically been provided (in some countries) mostly by gas-fired power plants.

 – **Manual Frequency Restoration Reserves (mFRR):** Also known as 'tertiary reserve power', mFRR helps to restore the grid frequency by a full activation time of 12.5 minutes. mFRR is activated during periods of long deviations in the power grid that cannot be resolved by the other upstream balancing services (FCR or aFRR).

› **Reserve Restoration (RR):** RRs are the active power reserves available to restore or support the required level of FRR to be prepared for additional system imbalances, including generation reserves. RR is a standardised frequency response product that supports the required level of FRR for additional imbalances with a full activation time of 30 minutes.

## Non-frequency ancillary services

Non-frequency ancillary service refers to a service used by a transmission system operator or distribution system operator for steady-state voltage control, fast reactive current injections, inertia for local grid stability, short-circuit current, black start capability and island operation capability.[12] For the purpose of this report, our analysis is limited to voltage control.

› **Voltage control or reactive power control:** a product that dispatches reactive power reserves in real-time to maintain the voltage level within the specified range of the synchronous area. Thus, it is not an energy balancing service.

## Congestion Management Products

Congestion refers to a situation in which all requests from market participants to trade between network areas cannot be accommodated because they would significantly affect the physical flows on network elements that cannot accommodate those flows.[13] It refers to overload of grid components, over- and under-voltage and/or forced usage of the local fail-over capacity in the distribution system. Congestion management aims to limit or avoid exceeding network congestion driven by the need to mitigate the risks posed by overload.

11 Commission Regulation (EU) 2017/2195 of 23 November 2017 establishing a guideline on electricity balancing, Article 2(1)
12 Source: Directive (EU) 2019/944 of 5 June 2019 on common rules for the internal market for electricity.
13 Regulation (EU) 2019/43 of the European Parliament and the Council of 5 June 2019 on the internal market for electricity, Article 2(4)

## 2.3 Electrolyser potential for providing different system services

This subsection maps the electrolyser technical capabilities with the system services requirements presented in the previous sections, with the aim of identifying the technical potential for the different electrolyser technologies to provide system services.

It is important to note that the results from this evaluation are based only on a technical assessment at this point. In particular, our assessment below does not consider whether economic constraints exist that might limit the real-world applicability of such technologies for TSOs purposes. In other words, an electrolyser's operability mode to provide certain system services may be feasible from a technical point of view, but it may also be economically unfeasible.[14]

We also note that the mapping of electrolyser technologies to system services may evolve in the future. For instance, the lack of data on SOEC flexibility creates a high degree of uncertainty around their suitability to provide system services, and the definition of system services itself may also change going forward.

The following table shows whether each electrolyser technology can provide each type of system service (today and in the medium term).[15]

| | Alkaline | | PEM | | SOEC | |
|---|---|---|---|---|---|---|
| | Today | 2030 | Today | 2030 | Today | 2030 |
| FCR | Yes with limits | Yes with limits | Yes with limits | Yes with limits | No | Uncertainty about flexibility |
| aFRR | Yes with limits | Yes with limits | Yes | Yes | No | Uncertainty about flexibility |
| mFRR | Yes | Yes | Yes | Yes | No | Uncertainty about flexibility |
| RR | Yes | Yes | Yes | Yes | No | Uncertainty about flexibility |
| Voltage control | Electrolysers can provide reactive power, if they are equipped with self-commutated rectifiers. | | | | | |
| Congestion management | Yes | Yes | Yes | Yes | No | Uncertainty about flexibility |

Figure 4: Mapping of electrolysers and system services

Source: Frontier Economics, based on previous information. Note: The table is based solely on a technical assessment and does not take into account economic considerations. The assessment for "today" is based on state-of-the-art technologies.

14 For example, we note that certain downstream processes (e.g. methanation, ammonia production) may limit the ability to exploit electrolysers' flexibility.

15 We recall that this assessment is based on our understanding of the capabilities, including estimates of future developments, of electrolysers to provide system services at the time of writing.

## Key points from the table are as follows

- **Alkaline electrolysers:** Alkaline electrolysers appear to be able to provide system balancing services and congestion management. We have identified examples of this already taking place (e.g. Thyssenkrupp using Alkaline[16]). Certain limitations may exist for FCR regarding cold start-up and symmetry, and for aFRR in relation to cold start-up time.

  - Alkaline electrolysers are suitable for providing FCR only if they are in stand-by mode[17] or already running. This is because their cold-start up time (1 to 10 minutes) is much longer than the full activation time (30 seconds). Similarly, there may be some limitations regarding Alkaline electrolysers to provide aFRR when the electrolysers are shut down.

  - Alkaline electrolysers can provide downward balancing by increasing their electricity consumption – if they are not running on maximum load. However, they are able to provide upward balancing (by decreasing their consumption) only when running. Therefore, the symmetry requirement is satisfied only if the status quo of the electrolyser for the bidding period is running or if the electrolyser is combined with another technology (e.g. battery) for which consumption can be decreased.

- **PEM electrolysers:** PEM electrolysers also appear to be able to provide system balancing services and congestion management. Again, we have identified examples of this taking place (e.g. Windgas Haßfurt electrolyser using PEM[18]). Certain limitations may also exist for FCR regarding cold start-up and symmetry:

  - The cold start-up time of PEM electrolysers ranges from 1 second to 5 minutes, whereas the full activation time required for FCR is 30 seconds. Therefore, there may be some limitations regarding PEM's ability to provide FCR when the electrolysers are shut down, as they may require more than 30 seconds.

  - PEM electrolysers can provide downward balancing by increasing their electricity consumption – if they are not running on maximum load. However, they are able to provide upward balancing (by decreasing their consumption) only when running. Therefore, the symmetry requirement is satisfied only if the status quo of the electrolyser for the bidding period is running or if the electrolyser is combined with additional equipment (as described for ALK above).

- **SOEC electrolysers:** SOEC electrolysers do not currently have the ability to provide system balancing and congestion management services. Aside from other characteristics, the typical plant size is too small to provide any of the system services.[19] Enough information on the future evolution of SOEC electrolyser characteristics is not available to clearly determine whether they will be able to provide such services within a 2030 timeframe.

- **Reactive power:** Finally, electrolysers may be able to provide reactive power if equipped with the right power electronics.[20]

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16 https://www.thyssenkrupp.com/en/newsroom/press-releases/pressdetailpage/thyssenkrupps-water-electrolysis-technology-qualified-as-primary-control-reserve--eon-and-thyssenkrupp-bring-hydrogen-production-to-the-electricity-market-83355

17 Electrolysers can be kept in a standby condition. This allows them to ramp up hydrogen production within a few seconds. In this state, there is no hydrogen production, but some electricity is consumed to keep the electrolyser under operating conditions (i.e. warm and pressurised).

18 https://assets.siemens-energy.com/siemens/assets/api/uuid:5d8fbfd38ae2e15c3468c0e51f38273afb8116b1/ct-ree-18-050-referenz-hassfurt-en-k1.pdf

19 In principal, several smaller plants could be aggregated to meet the size requirements for system service provision. However, not enough information is available at this stage to assess the feasibility of such an approach.

20 We note that the regulations for voltage control differ between European countries. For example, in Germany, large power plants (>200 MW) are obligated to offer this system service. We understand that this is not a high-value service in some countries; therefore, it appears unlikely that voltage control will be a business model for electrolysers.

# 3 Analysis of the balancing potential from hydrogen produced by $P2H_2$

## Context

Although there is significant uncertainty as to how a decarbonised energy sector will develop, some high-level trends can be identified. There is likely to be significant electrification of current fossil fuel uses (for example, in the transport and heating sectors) and a parallel need for the decarbonisation of electricity generation leading to a growing share in power generation from variable renewable energy sources (VRES).

In July 2021, the European Commission published the 'Fit-for-55' package,[21] which contains a set of legislative proposals to achieve a 55 % reduction in net greenhouse gas emissions (GHG) by 2030 compared to 1990. This includes, among others,

- a revision of the minimum share of RES-generated electricity in final energy consumption by 2030 (from 32 % in RED II to 40 %)[22];
- a new target to decrease GHG intensity of transport fuels by 13 %; and
- a replacement of the 2014 Alternative Fuels Infrastructure Directive (AFID) by a regulation setting a number of mandatory national targets for the deployment of alternative fuels infrastructure in the EU for road vehicles, vessels and stationary aircraft.

In this context, integrating the growing share of VRES creates a challenge for TSOs, because it may increase balancing demands on electricity networks, as new electricity uses and generation sources may lead to increased volatility in generation and demand profiles. Absent physical network expansion and reinforcement, this could give rise to curtailment of some VRES to reduce congestion on the network or where demand flexibility and available electricity storage do not allow accommodating excess generation. If this otherwise lost generation could be absorbed, it may constitute a benefit for society by avoiding the waste of electricity and allow more efficient network functioning.

**Power-to-hydrogen technologies ($P2H_2$) could, in principle, constitute one potential source of flexibility by transforming otherwise curtailed excess VRES generation** (e.g. during periods of high solar and wind generation) into hydrogen. However, as described in more detail below and in the following sections, the effective viability of electrolyser business models based on hydrogen production from curtailed energy alone will ultimately depend on their competitiveness with other sources of flexibility (e.g. batteries).

This section assesses the impact that the use of $P2H_2$ technologies as a flexibility source could have for power networks by 2030. In particular, it analyses the following questions:

1. What level of VRES curtailment reduction could be achieved through the use of electrolysers by 2030?
2. What is the required RES generation needed to cover the demand for decarbonised gas to reach decarbonisation targets by 2030?
3. To what extent could the obtained hydrogen be stored for later use, including being transformed into electricity again – and how does hydrogen storage compare to the key characteristics of other electricity storage technologies?

For each of these questions, the study also discusses the potential implications they may have for the integration of VRES generation into power grids.

21 Accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/?uri=CELEX%3A52021DC0550

22 Directive (EU) 2018/2001 of the European Parliament and of the Council of 11 December 2018 on the promotion of the use of energy from renewable sources (recast). Accessible at: https://eur-lex.europa.eu/legal-content/EN/TXT/PDF/?uri=CELEX:32018L2001&from=EN


It is worth noting that balancing needs on power networks could concern either the absorption of excess energy (downwards balancing) or making up for a shortfall in injected energy with respect to demand (upwards balancing). As discussed in the section on Deliverable 1a above, electrolysers could, in principle, offer both types of balancing:

- Increasing the production of hydrogen, i.e. consuming more electricity in order to absorb excess electricity on the power grid (downwards balancing);
- Reducing the production of hydrogen, i.e. consuming less electricity in order to reduce withdrawal of electricity on the power grid (upwards balancing).

This section is primarily concerned with the downwards balancing provided by electrolysers in order to absorb excess VRES generation.

As noted above, hydrogen itself could then provide a potential source for long-term upwards balancing – for instance, to support networks during peak demand hours and/or periods of low VRES generation by transforming it into power.

However, this process is not realised through electrolysers but rather via specialised gas turbines or fuel cells.

- Today, some hydrogen-only turbines are in the process of commercial rollout, but most commercially viable turbines also require a certain share of blended methane to be burned alongside hydrogen.
- Similarly, fuel cells are currently primarily explored for transport applications (e.g. for hydrogen-powered cars), although their development continues to lag far behind that of battery-based electric vehicles. Some stationary fuel cells for electricity generation exist, but according to the IEA, these are virtually all powered by natural gas, which introduces uncertainty on the feasibility of a large scale roll-out by 2030.[23]

The study therefore does not include detailed discussion of the possible flexibility that could be offered to power grids from $H_2$-only or combined-cycle gas turbines, nor from fuel cells, and focuses primarily on the role of electrolysers.

23 https://www.iea.org/reports/hydrogen

# 3.1 The potential interaction between electrolysers and VRES

In this subsection, we discuss the role that electrolysers could play to absorb excess VRES generation that may otherwise be curtailed. We then estimate the RES generation that would be required to satisfy the demand for the decarbonisation of gas demand through $P2H_2$.

Given the high uncertainty about the volume of $P2H_2$ generation capacities that will be available in 2030 as well as the competitiveness of electrolysers compared to other sources of flexibility, our report focuses primarily on whether addressing flexibility needs through $P2H_2$-produced hydrogen could, in principle, be possible.

However, the role that electrolysers end up playing will ultimately depend on their place in the merit order compared to these other sources of flexibility.[24]

## Accommodation of VRES generation by electrolysers

The data published in ENTSO-E's and ENTSOG's Ten-Year Network Development Plan (TYNDP) is used to assess the extent of VRES curtailment in 2030. For the purpose of this report, data underpinning the 2020 and 2022 scenario reports is used.[25]

These reports provide three different scenarios for the development of the European energy system across a range of energy vectors (such as gas, electricity or hydrogen) and assessment years (for example 2030, 2040 or 2050).[26] As mentioned above, we retain 2030 as the key focus year throughout this report.

The TYNDP 2020 provides a direct estimate of curtailed energy for each of the different scenarios, target years and climate years.[27] The source for curtailed energy is exclusively assumed to be VRES, including Onshore and Offshore Wind, Solar PV and Solar Thermal. As shown in Figure 5, expected curtailed VRES generation in 2030 ranges between 17 and 47 TWh.[28] This represents between 0.6 % and 1.2 % of total expected electricity generation in 2030.

| Climate year | Distributed Energy | Global Ambition | National Trends |
|---|---|---|---|
| 1982 | 24.4 | 15.6 | 43.5 |
| 1984 | 25.6 | 17.8 | 42.4 |
| 2007 | 26.2 | 17.7 | 57.1 |
| **Average** | **25.4** | **17.1** | **47.6** |

Figure 5: Expected amount of VRES curtailed energy by 2030, in TWh

Source: TYNDP 2020, Frontier analysis

24 For instance, it is, in principle, possible that otherwise curtailed energy may be fully absorbed by batteries if these end up being more competitive than electrolysers.

25 TYNDP 2020 – Scenario Report – Final Report, ENTSO-E and ENTSOG, June 2020; and TYNDP 2022 – Draft Scenario Report, ENTSO-E and ENTSOG, October 2021.

26 The retained scenarios are based on either a bottom-up approach using member states' national energy and climate plans (National Trends scenario) or a top-down approach defining an energy system that could meet the Paris Agreement 1.5 °C target or the EU's Fit-for-55 ambition (Global Ambition and Distributed Energy scenarios).

27 Climate years are retained to model the impact of different climate conditions.

28 With an average of 69 %, curtailed wind generation represents the largest share of curtailment, with the remaining curtailed energy coming primarily from PV.

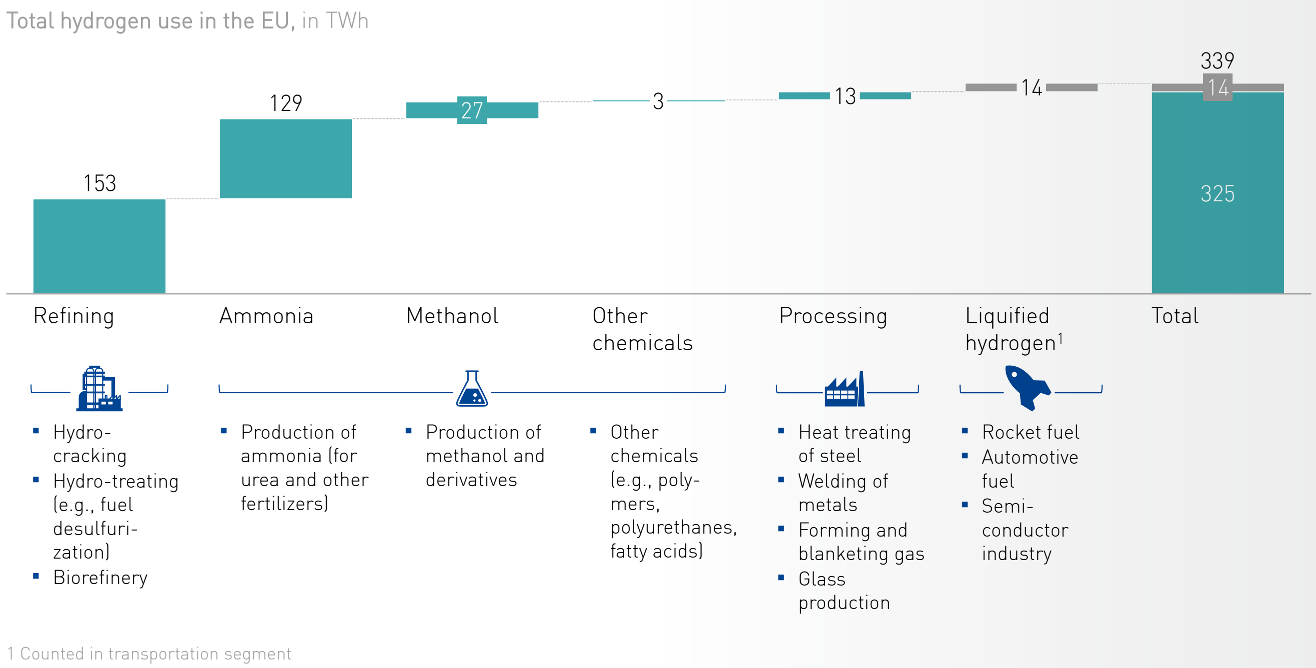



Figure 6: Total hydrogen use in the EU in 2019, in TWh

Source: FCH, Hydrogen Roadmap Europe (2019). Note: The graph shows the total hydrogen demand in 2018 for the European Union and breaks down this demand by sector.

**Applying an expected electrolyser efficiency of 70%,[29] absorbing the totality of this curtailed energy would yield a hydrogen volume of between 12 and 33 TWh, i.e. between 358 and 1,001 kt.[30]**

› Assuming a **conservative** load factor of 25% for electrolyser operation, this suggests a required P2$H_2$ capacity of between 8 and 22 GW across Europe.[31] Despite current electrolyser capacity in Europe being less than 0.1 GW[32], the European Hydrogen Strategy established the objective to install *at least 6 GW of renewable hydrogen electrolysers in the EU and the production of up to 1 million tonnes of renewable hydrogen by 2024; and, at least, 40 GW of renewable hydrogen electrolysers by 2030 and the production of up to 10 million tonnes of renewable hydrogen in the EU by 2030.*[33]

This suggests that under the condition that the European ambitions for electrolyser deployment are realised, the available capacity would exceed the requirements for accommodating otherwise curtailed VRES by 2030 – even in the scenario where curtailment is more significant and even if the load factor were to fall to 10%. As mentioned above, this does not take into account the absorption of this curtailment by other sources of flexibility (e.g. batteries).

› The hydrogen that would be produced through otherwise curtailed electricity would also be met with significant existing demand for hydrogen. The figure below indicates the distribution of grey hydrogen use in Europe in 2019, which represents a total annual demand of 339 TWh (i.e. roughly ten times the $H_2$ volume produced through curtailment).

29 See our work on Deliverable 1a

30 Assuming 33.33 kWh/kg of hydrogen.

31 We expect a 25% load-factor to be relatively high for an electrolyser only running on curtailed generation. However, we believe that this estimate is useful to provide an upper-bound assessment of the possible role that electrolysers may play in relation to long-term flexibility provision.

32 Hydrogen Council and McKinsey & Company, ‘Hydrogen insights - A perspective on hydrogen investment, market development and cost competitiveness’, February 2021.

33 https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf

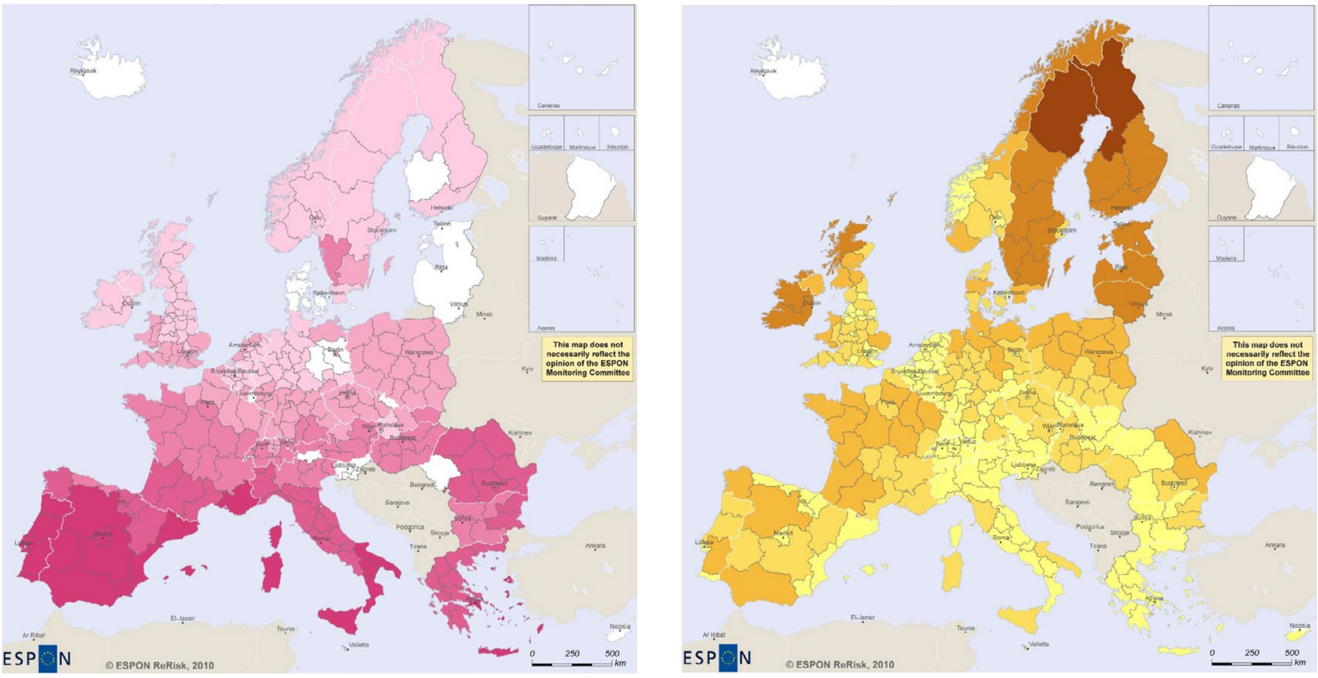



Figure 7: PV and wind power potential in Europe

Source: ESPON (European Observation Network for Territorial Development and Cohesion), 2011.

As such, $H_2$ produced via VRES could, in principle, participate in the decarbonisation of industrial processes without having to rely on the development of additional use cases for hydrogen (such as transport or heating) as required demand drivers. In addition, considering that otherwise curtailed energy could, in principle, constitute a zero-cost input for electrolysers, the produced hydrogen could, over the medium term, also be cost-competitive compared to the use of grey hydrogen, even without considering the impact of additional support mechanisms.[34]

However, as we assess in more detail below, this does not necessarily imply that electrolyser projects could be based solely on the provision of flexibility from curtailed energy alone. In particular, a profitable project may require additional revenue sources and may need to increase $H_2$ production beyond curtailment using non-zero-cost electricity, which could have implications for the overall competitiveness of the produced green hydrogen.

Although the assessment of supply and demand at the macro level suggests that electrolysers could, in principle, absorb the entire expected curtailed energy from VRES by 2030, it is worth highlighting that location may have an impact on the actual degree to which $P2H_2$ technology can be used to accommodate excess VRES supply.[35]

- The distribution of VRES generation capacity and potential is not equally distributed across Europe. Figure 7 shows that the strongest potential for wind power is in the north of Europe (and offshore), whereas most PV potential is in the south. As a result, there will be locations with higher or lower shares of VRES generation capacity (which may further be influenced by differences in political and regulatory support).

34 We note that these findings are also in line with a recent study from the UK Department for BEIS on hydrogen production costs: 'Hydrogen Production Costs 2021', Department for Business, Energy & Industrial Strategy, August 2021.

35 We discuss further barriers for the provision of balancing services by electrolysers in the report on Deliverable 3.

- It is noted above that electrolysers can generally best relieve pressure on the network and avoid curtailment if they are located close to the generation sources that would be at risk of curtailment. However, there may be geographical limitations that could impact the viability of these locations (from both supply and demand perspectives) and ultimately limit the possible electrolyser capacity that could be installed:

  - In order to accommodate curtailed VRES, electrolysers need to be directly connected to the generation site and/or may also require grid access if their operational model depends on a more stable baseload; they may also require access to a water source to be used as an input for electrolysis.

  - The produced hydrogen then needs to be transported to where it can be used (e.g. as an input into industrial processes). Although this may be feasible for some locations and/or at a small scale,[36] larger sites may experience more significant constraints – for instance, due to the absence of appropriate hydrogen infrastructure. In particular, we understand that although there are initiatives to build a well-integrated European transmission network for $H_2$ (e.g. by repurposing existing natural gas network infrastructure), the actual construction and timeline remains uncertain and, in any case, is highly unlikely to be complete by 2030.[37] However, as discussed in more detail below, blending $H_2$ into existing gas networks may provide an alternative option to use $H_2$ produced from VRES.

- Finally, location may also play a role in the assessment of the potential for storage of hydrogen. This is discussed in more detail below.

It is interesting to note that according to the TYNDP scenarios, curtailment is expected to significantly increase by 2040 (between 77 and 172 TWh), which would lead to a potential hydrogen production of 54 to 120 TWh.

## Summary of conclusions

- A hypothetical situation where expected VRES curtailment in 2030 would be fully absorbed through the production of hydrogen from electrolysis would yield between 12 and 33 TWh of $H_2$. Providing the necessary production capacities would be feasible and consistent with the EU ambition of 40 GW of P2$H_2$ capacity by 2030.

- This represents less than 10 % of current grey hydrogen demand and could therefore participate in the decarbonisation of existing hydrogen use cases without depending on the development of additional demand.

- Locational aspects may, however, limit the realisation of the full potential for excess VRES absorption due to the absence of appropriate network / transportation infrastructure or other physical barriers.

- VRES curtailment and the potential hydrogen production from curtailment are expected to significantly increase beyond 2030 and require a significant increase in P2$H_2$ capacity.

- However, the role for P2$H_2$ projects in the provision of longer-term flexibility will ultimately depend on their competitiveness compared to other storage technologies. If these alternatives (e.g. batteries) are able to provide flexibility at lower cost, the need for P2$H_2$ capacity may be significantly reduced.

36 For instance, green hydrogen produced via VRES by Nantes-based Lhyfe in the French Vendée region is transported via pressurised trucks and does not rely on a physical network.

37 https://gasforclimate2050.eu/ehb/

## Using $P2H_2$ as an interface between the power and gas sectors

### RES absorption potential with $H_2$ blending

As discussed above, by 2030, the use of low-carbon hydrogen from VRES electricity is most likely to be used to decarbonise industrial processes that are currently using grey hydrogen. However, in the medium term, hydrogen may also be blended into natural gas to partially decarbonise a wider range of use cases (such as heating or transport).

Currently, technically feasible blending shares for hydrogen range between 5–10 % volume but could increase to 15–20 % volume by the end of the decade if infrastructure and affected equipment can be updated.[38, 39] Data from ENTSOG's and GIE's System Development Map 2019/2020 reports EU natural gas demand in 2019 as 5,149 TWh. Assuming a 10 % decrease in demand by 2030, in line with forecasts from the International Energy Agency (which would bring demand to 4,634 TWh),[40] a volume blending rate between 5–20 % (and taking into account the difference in heating values) would represent a possible hydrogen volume of between 76 and 305 TWh.

**This translates into:**

- A potential for absorption of RES of between 109 and 437 TWh; and salt cavern large-scale $H_2$.
- A required $P2H_2$ capacity of between 50 and 200 GW.[41]

These magnitudes are between two and nine times larger than the expected VRES curtailment in 2030, but, for lower blending shares, roughly in line with the expected curtailment in 2040.

However, the same caveats around the possible locations, regional idiosyncrasies and demand type discussed above still hold in this scenario. In addition, it may also increase the need for hydrogen storage to respect constraints around flow capacity on gas networks, potentially introducing additional uncertainty of the degree to which the full theoretical potential of $P2H_2$ could be harnessed.

### Required RES to meet low-carbon gas demand

As mentioned above, the TYNDP 2022 Draft Scenario Report develops two scenarios that are compliant with the international climate agreements (COP21 and Fit-for-55).

The underlying assumptions for both scenarios are presented in the following table.

| Scenario | Distributed Energy | Global Ambition |
|---|---|---|
| **Description** | › Greater European autonomy with renewable and decentralised focus | › Global economy with centralised low carbon and RES options |
| **Green transition** | › At least a 55% reduction in 2030, carbon-neutral in 2050.[42]<br>› Compliant with the COP21 agreement. | |
| **Driving force of the energy transition** | › Transition initiated at a local / national level (prosumers) | › Transition initiated at a European / international level |
| **Implementation** | › Focus on decentralised implementation (PV, batteries, etc.) and smart charging.<br>› Higher share of EVs, with e-liquids and biofuels supplementing for heavy transport | › Focus on large-scale implementation (offshore wind, large storage).<br>› Wide range implementation across mobility sectors (electricity, hydrogen and biofuels) |

Figure 8: Description of TYNDP 2022 Draft Scenario Report

Source: TYNDP 2022 – Draft Scenario Report.

38 https://ec.europa.eu/jrc/en/science-update/blending-hydrogen-eu-gas-system

39 It is worth recalling that for a given volume hydrogen has an around three-times lower energy content than methane (i. e. natural gas). As a result, more hydrogen would be required to provide a given level of energy.

40 https://www.spglobal.com/platts/en/market-insights/latest-news/natural-gas/101320-iea-slashes-2040-european-gas-demand-forecast-by-further-21-bcm

41 Using the same assumptions as above

42 https://ec.europa.eu/commission/presscorner/detail/en/ip_21_3541

Although in both these scenarios, hydrogen becomes the main gas energy carrier in 2050, total $H_2$ demand in the EU27 is still expected to range between 300 to 358 TWh by 2030, in line with current industrial $H_2$ demand. This suggests that $H_2$ demand will continue to be driven largely by the industrial sector.[43]

The TYNDP 2022 scenarios consider that between 70 and 89 TWh of this $H_2$ demand will be produced in Europe via electrolysers with other sources still including Steam Methane Reforming and CCS (blue hydrogen) or imports. These estimates are largely in line with the EU's ambition for the development of electrolyser capacity by 2030.[44]

However, scenarios evolve more significantly for 2040 and 2050, as shown in Figure 9. Hydrogen is expected to become a major energy carrier with a more widespread application across sectors. This also has implications for electrolysis, which is expected to become the main source of low carbon hydrogen at 1,366 and 1,521 TWh in 2050 respectively.

› At an efficiency of 70 %, this corresponds to a required volume of power of between 1,951 and 2,173 TWh.

› This represents more than 70–78 % of total net electricity generation and more than double the total current RES generation in the EU in 2019 alone.[45]

In fact (and even absent the power requirements for electrolysers), a significant increase in electricity generation is required to achieve the energy transition. As a result, the TYNDP 2022 scenarios that are compliant with international ambition on climate change require that total electricity generation double by 2050 compared to today, which also has a significant impact on required network investments and operations.

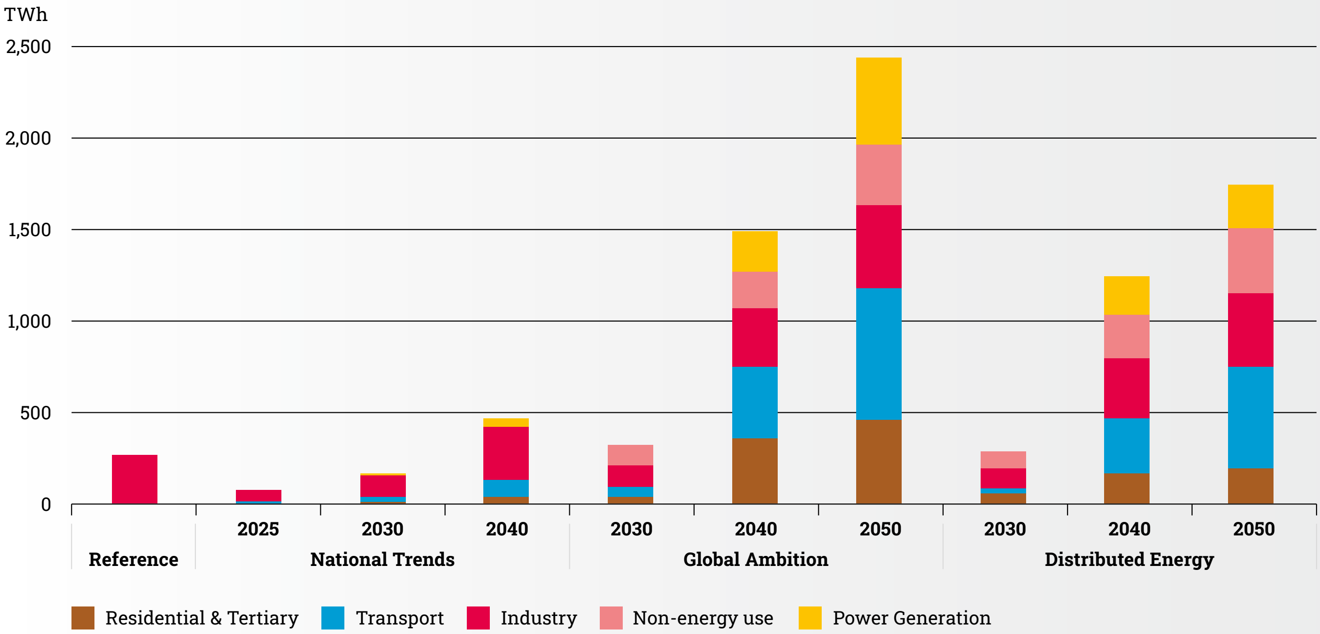



Figure 9: Hydrogen demand per sector for 2030, 2040 and 2050

Source: TYNDP 2022 – Draft Scenario Report

43 We understand that hydrogen demand is to significantly increase in 2040 and 2050 in both scenarios. For example, by 2050 total $H_2$ demand is expected to range between 1,750 and 2,450 TWh depending on the scenario.

44 Assuming a load factor of 25 % on average yields a required capacity of between 32 and 41 GW.

45 https://ec.europa.eu/eurostat/statistics-explained/index.php?title=Electricity_production,_consumption_and_market_overview#:~:text=Total%20net%20electricity%20generation%20in%20the%20EU%20was%202%20778,stood%20at%202%20844%20TWh.
RES generation corresponds to 29.9 % of EU total net generation and includes wind, hydro, solar and geothermal.

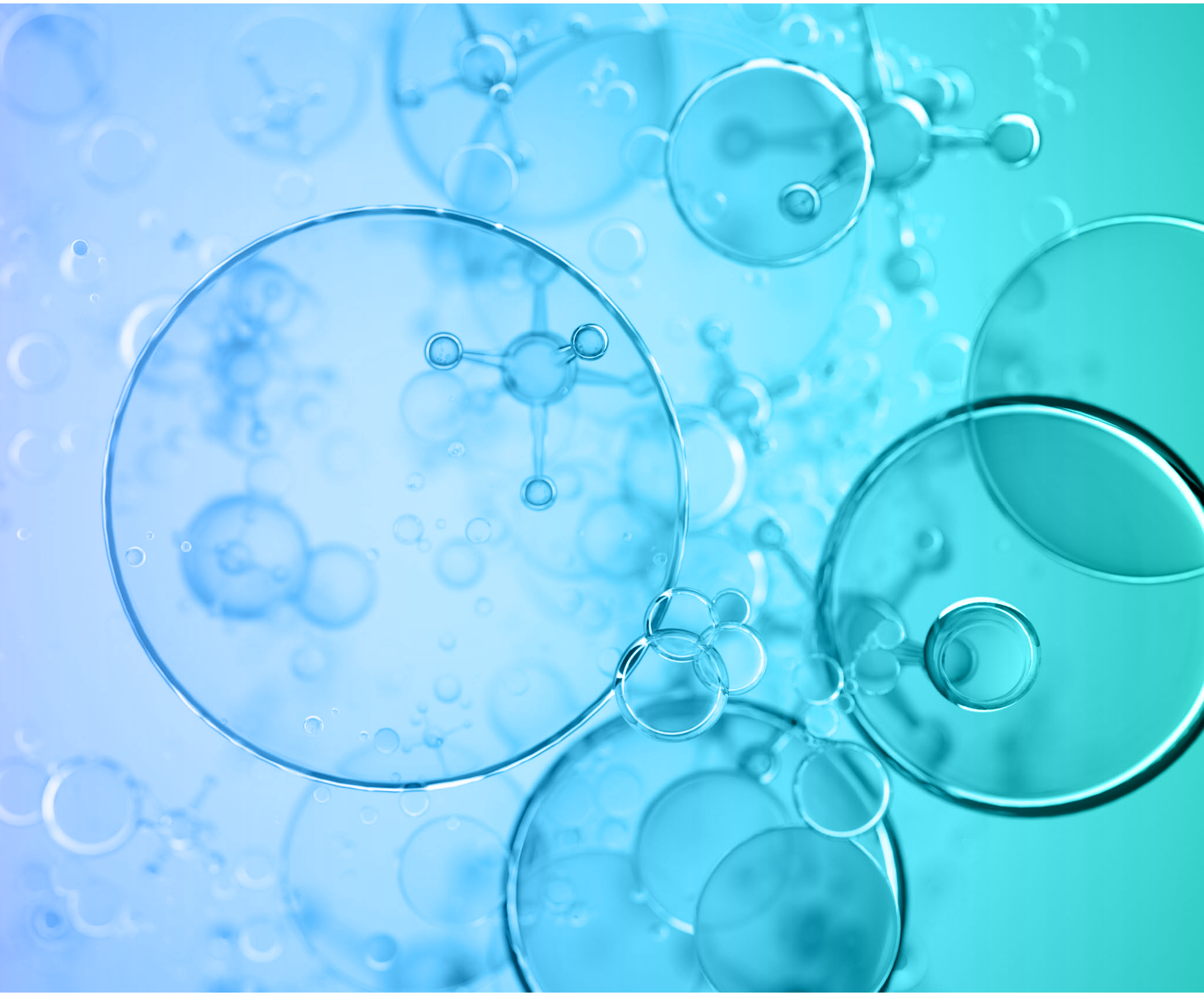
# Summary of conclusions

- The TYNDP 2022 scenarios suggest that demand for decarbonised gases – and hydrogen in particular – will significantly increase by 2040 and 2050, but will likely remain limited to catering to industrial usages in 2030 (around 300–358 TWh).

- In 2030, around a quarter of this demand is expected to be served by $P2H_2$ production in Europe. The required $P2H_2$ capacity to do so (between 32 and 41 GW) would be consistent with the EU's ambition for the development of electrolyser production capacity by 2030.

- By 2050, low-carbon hydrogen demand produced from electrolysis is expected to rise to 1,366–1,521 TWh if climate targets are to be respected. This would require a power input of 1,951–2,173 TWh; this alone represents 70–78 % of current total and more than double current renewable EU power generation.

- This emphasises the need for not only the development of $P2H_2$ capacity, but also for significant investments in low-carbon power generation assets and the future-proofing of power networks and hydrogen transport infrastructure.



## 3.2 The potential for hydrogen storage in Europe

In this subsection, we discuss the potential for storage of large amounts of $H_2$. As discussed previously, storage could become a vital requirement to relieve (power or gas) network pressure and smooth hydrogen supply for a range of use cases.

### Potential need for hydrogen storage

Today, most grey hydrogen is usually produced on-site through steam methane reforming and stored in gaseous or liquid form in small tanks at central production facilities, transport terminals or consumption locations. The same holds true for initial electrolyser projects that have been commissioned as pilot or experimental projects with a view toward decarbonising industrial processes. The role for long-term and large-scale $H_2$ storage is therefore relatively minor today.

However, if hydrogen is increasingly produced through electrolysis using VRES, a share of $H_2$ supply will follow an intermittent and decentralized production profile, which may make storage more relevant. In parallel, the flexibility that hydrogen could offer to the energy system may also become more prominent and increase the value of storage.

In a June 2021 report, Gas Infrastructure Europe (GIE) estimated $H_2$ storage needs by 2030 and 2050, based on $H_2$ demand forecasts from the European Hydrogen Backbone (EHB).[46] In particular, GIE estimates a 'need for around 70 TWh of hydrogen storage in 2030, growing to around 450 TWh of hydrogen storage in 2050'.[47]

#### $H_2$ storage options

Underground geological structures (such as salt caverns, depleted oil and gas fields, aquifers, and lined rock caverns) are all being considered as the primary options for storing large amounts of $H_2$.

- As shown by the evidence below, there are various salt-cavern sites in the US and Europe, some with more than 10 years of experience storing $H_2$.
- New sites are also being analysed. For instance, Enagas is carrying out studies to investigate the potential for retrofitting existing underground gas storage facilities as well as also the development of new underground $H_2$ storage installations, including salt caverns.[48]

#### $H_2$ storage case study

A number of salt caverns have been used to store $H_2$ for more than 10 years, including in Europe (see table below). $H_2$ stored at these locations is used mainly by the industrial sector to produce ammonia or methanol.

| $H_2$ salt cavern | Clemens Dome, US | Moss Bluff, US | Spindletop, US | Teeside, UK | Etrez, France |
|---|---|---|---|---|---|
| Volume ($m^3$) | 580,000 | 566,000 | >580,000 | 3 × 70,000 | 570,000 |
| Energy (GWh) | 92 | 120 | >120 | 25 | 250 |
| Operational since | 1983 | 2007 | 2007 | 1970s | Planned |

Figure 10: Operational $H_2$ salt cavern storage

Source: Storengy (2019). "Underground Storage of hydrogen salt caverns"

46 Picturing the value of underground gas storage to the European hydrogen system, Gas Infrastructure Europe, June 2021.

47 We note that these estimates exceed our evaluation of hydrogen that could be produced from curtailed VRES only by 2030 (between 12 – 33 TWh).

48 https://h2-project-visualisation-platform.entsog.eu/

Other solutions not relying on underground storage include steel tanks, which are considered a more suitable option for short-term and small-scale storage. Steel tanks present even higher efficiencies (close to 99 % compared with 98 % for salt caverns[49]) but higher costs[50] and (in the case of small-size tanks) increased compression requirements,[51] when compared with underground storages.

There are alternative options that seek to reduce the problems associated with most $H_2$ storage applications linked to its low volumetric energy density (both compressed gas and liquid).[52] For example, hydrogen may be further transformed into ammonia ($NH_3$), which presents lower expected storage and transport costs.

For instance, ammonia would have the advantage of being liquefied at −33 °C at atmospheric pressure (whereas $H_2$ needs −253 °C), and has a higher energy concentration per cubic meter, which translates into lower transport costs (i. e. in ammonia form, more energy can be transported in a given space). In addition, well-established alternative distribution and storage infrastructure is already in place.[53] However, the process has a lower energy efficiency as opposed to Power-to-$H_2$-to-Power due to the need for several conversions (power to hydrogen to ammonia to hydrogen, and possibly back to power).

### Assessment of large-scale storage potential by 2030

Among the types of underground gas storage, salt caverns present the largest potential capacity for hydrogen storage. The total technical potential of salt caverns in Europe is estimated to be approximately 85,000 TWh of hydrogen (of which ~62,000 TWh is offshore).[54]

- This significantly exceeds the expected total hydrogen demand in Europe by 2030, let alone the hydrogen that could be produced from otherwise curtailed VRES (see results above).
- The North Sea's significant storage potential could also provide an attractive source for on-site flexibility for future offshore wind farms. Installing electrolysers directly adjacent to these sites and storing the produced hydrogen may make it possible to accommodate situations where generation would otherwise be curtailed and ultimately cap upwards volatility of the load profile from a network perspective.

49 IEA (2019), 'The Future of Hydrogen'. Efficiency understood as the quantity of hydrogen injected divided by the quantity that can be extracted.

50 CSIRO (2018), 'National Hydrogen Roadmap'; Ramsden et al. (2008), 'Opportunities for Hydrogen-based Energy Storage for Electric Utilities', National Renewable Energy Laboratory; BNEF (2020), Hydrogen Economy Outlook.

51 According to IEA (2019), 'The Future of Hydrogen' and Caglayan et al. (2020), 'Technical Potential Salt Caverns Hydrogen Storage Europe', $H_2$ compression for steel tanks is 700 bar and for salt caverns, between 70 and 200 bar.

52 U.S. Department of Energy (2006), 'Potential Roles of Ammonia in a Hydrogen Economy'. Accessible at: https://www.energy.gov/sites/prod/files/2015/01/f19/fcto_nh3_h2_storage_white_paper_2006.pdf

53 IEA (2019), 'The Future of Hydrogen'. Ammonia has been used as a refrigerant for 170 years, and as a chemical feedstock for nitrogen fertilisers and explosives for a century. Industry is used to storing and transporting it, including in oceangoing tankers.

54 Caglayan D.G., Weber N., Heinrichs H.U., Linßen J., Robinius M. et al. (2020), 'Technical Potential Salt Caverns Hydrogen Storage Europe'. By technical potential the report considers suitable cavern sites, which are determined by a land eligibility assessment. Moreover, because the caverns are located in different geological basins, the thermodynamic properties of these are taken into account for estimating the storage capacity. Additionally, 'technical potential' takes the limitations (i. e. cushion gas) into account. However, this classification does not consider any economic, ecological or social acceptance barriers.

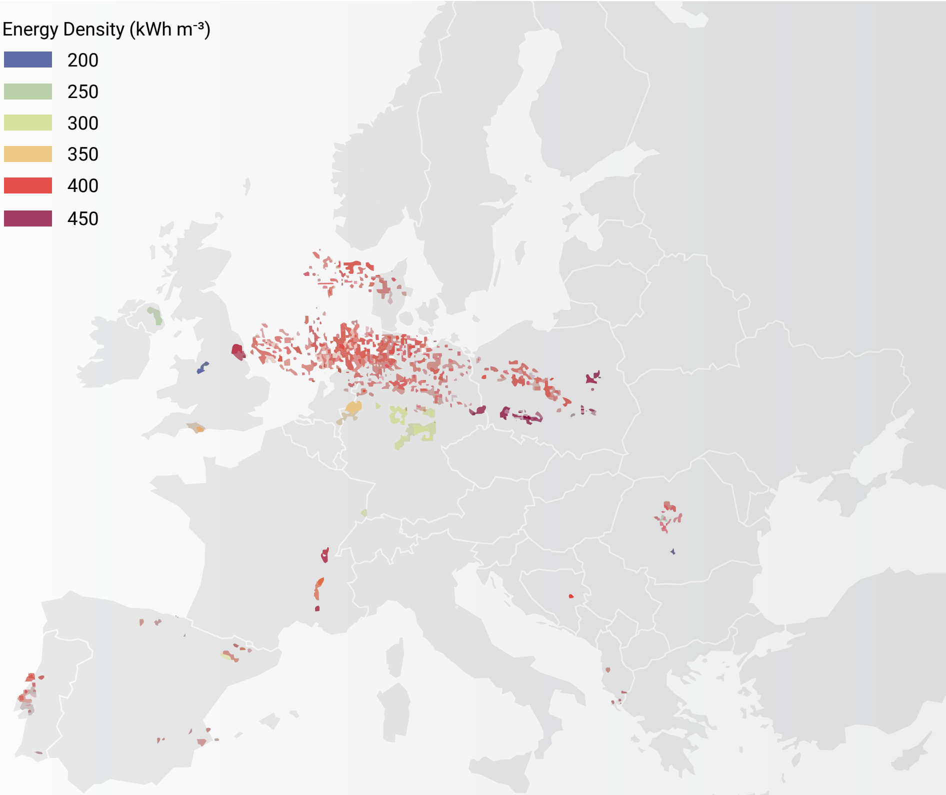



Figure 11: Technical potential salt cavern sites across Europe, by energy density.
Source: Caglayan et. al (2020) – Technical Potential of Salt Caverns for Hydrogen Storage in Europe.

However, there are a range of caveats that may limit the extent to which the full potential of theoretical hydrogen storage sites in Europe could be made viable by 2030:

› Some sites are currently used for methane storage (~1,200 TWh of natural gas storage working gas capacity[55] in the EU27 and the UK in 2021).[56]

  – Although they present the advantage of being established and have known geological characteristics, extensive repurposing would be required for hydrogen storage, which could take anywhere between one and seven years, according to GIE.[57] Depending on the economic incentives, some sites also may not be reconverted and continue to be used for (bio-) methane storage.

  – Alternatively, hydrogen blending in current natural gas storage assets is an option. This would, however, require either de-blending the two gases upon withdrawal or accepting a different gas purity standard (i.e. a certain degree of blending for downstream uses). Depending on the chosen approach, this may further limit the reconversion potential.[58]

› Developing new sites also takes significant amounts of time (estimated at between three to more than ten years from pre-feasibility studies to commissioning). This may also indicate that some potential sites simply will not be suitable for $H_2$ storage by 2030 and may, in particular, concern offshore locations and that there is at least some uncertainty around possible timelines for making large-scale $H_2$ storage available.[59]

55 'Working gas capacity' refers to total gas storage capacity minus base gas; base gas (or cushion gas) being the volume of natural gas intended as permanent inventory in a storage reservoir to maintain adequate pressure and deliverability rates throughout the withdrawal season. Furthermore, these variables change for each storage location as well as with time (www.eia.gov).
Most likely, the ratios between working gas and cushion gas capacities will be the same for hydrogen as for natural gas (GIE 2021).

56 Gas Infrastructure Europe (June 2021), 'Picturing the value of underground gas storage to the European hydrogen system'.

57 There may also be currently unknown technological complications such as the treatment of cushion gas.

58 In general, the purity of the hydrogen will depend on a number of factors as the own storage infrastructure and so each case will require a different purification infrastructure.

59 Taking into account that repurposing can take anywhere between 1 and 7 years, and developing new storage assets takes between 3 and 10 years from pre-feasibility to operation.

- In addition, floating electrolysers are unlikely to be operational (at a large scale) by 2030, which could further limit the extent to which the benefits from on-site electrolysis and $H_2$ storage could be unlocked for offshore generation assets in particular. Furthermore, the use of the stored hydrogen may depend on further infrastructure – either $H_2$ turbines to directly reconvert it into power or transportation assets (ships, pipes, etc.) – which may further complicate the completion of viable storage sites offshore by 2030.

Finally, we note that most potential salt cavern storage capacity is found within a limited number of countries (only Denmark, France, Germany, the Netherlands, Poland, Portugal and the UK have developed salt caverns; limited further development could be realised in Greece, Romania, and Spain)[60] and many of the currently unused potential sites are located offshore, mainly in the North Sea (see Figure 11).

This unbalanced geographical distribution of possible $H_2$ storage sites may also represent a limit on any significant increase in VRES generation that may benefit from associated electrolyser capacity and salt-cavern large-scale storage:

- For instance, Figure 7 above points to a strong potential for PV VRES generation in Spain and other Southern European countries. However, should $P2H_2$ and $H_2$ storage be used to accommodate variations in the load profile of this generation in these areas, and in particular excess VRES, the very limited availability of salt cavern sites would ultimately quickly constrain the benefit that could be gained from using electrolysers and salt cavern large-scale $H_2$ storage in combination with VRES.

- Given the significant need for additional electricity generation capacity mentioned above, this may have a more significant impact on VRES integration for power networks in these areas – and for the energy system more broadly. The design and development of an adequate energy infrastructure as the backbone of regional integration of the energy resources is one of the pillars for decarbonisation, this includes both electric and gas/$H_2$, for example, the use of gas/$H_2$ networks to transport $H_2$ produced from $P2H_2$ on-site to appropriate storage sites and/or demand centres.

These considerations are also recognised by Gas Infrastructure Europe, which emphasises the need for the parallel development of a European hydrogen backbone to unlock the full benefits of $H_2$ storage and provide cross-sector flexibility.

## Summary of conclusions

- **Europe benefits from a significant hydrogen storage potential due to the presence of important geological salt structures across the continent; these are particularly concentrated in the north of Europe.**

- **The estimated technical storage potential of 85,000 TWh significantly exceeds expected $H_2$ production from curtailed VRES in 2030 (17 to 33 TWh), but also third-party estimates of required $H_2$ storage in the same period (up to 70 TWh).**

- **However, the majority of possible sites are currently not in use and are located offshore, which may require both significant investments and medium-term timeframes before they can be commissioned. This introduces a certain degree of uncertainty about actually available storage volume by 2030.**

- **In addition, storage and VRES potential are unevenly distributed across Europe. Although the location of salt cavern large-scale storage sites largely coincides with Northern offshore wind potential, there are very few viable sites in the south of Europe, where the most significant PV generation potential is located.**

- **This could have important implications for the integration of VRES generation into existing networks in these areas, as the flexibility provided by $P2H_2$ + salt cavern large-scale storage would be reduced and/or rely on appropriate power and/or hydrogen infrastructure to link electrolysers with demand centres and/or storage sites.**

60 Gas Infrastructure Europe (June 2021), 'Picturing the value of underground gas storage to the European hydrogen system'.

## Comparison of storage technologies

The potential use case for absorbing excess power generation (e.g. from VRES) into $H_2$ will also depend on the technical capabilities and competitiveness of $P2H_2$ transformation and $H_2$ storage ($P2H_2$ + storage) against other electricity storage technologies. This section presents an overview of the key technologies as well as their comparison with $P2H_2$ + storage.

As discussed later in more detail, this analysis primarily reflects the absorption of excess electricity (i.e. downwards balancing) but does not address the retransformation of $H_2$ into power, which cannot be achieved through electrolysers.

### Overview of power storage technologies

To address the differences and advantages of the different technologies, we provide a high-level technical comparison with the following storage facilities:

- **Pumped Hydro Storage (PHS):** Power is used to pump water into a storage basin. Letting this water flow from the basin through a turbine (often using gravitational forces) allows the production of power when required. This is often linked to the market opportunity of purchasing electricity at very low prices to be re-dispatched later (i.e. when prices are high or supply is scarce). System services provided by pumped hydro are used mainly to balance the grid or generation-driven fluctuations in supply (peak, off-peak).

- **Compressed Air Energy Storage (CAES):** Electricity is used to compress air, which is stored in underground caverns or storage tanks. This air is then later released to a combustor in a gas turbine to generate electricity during peak periods. The concept of an Adiabatic Compressed Air Energy Storage (ACAES) would avoid the need for a fuel to preheat the air before it enters the turbine.

- **Flywheels:** Flywheels are mechanical devices that spin at high speeds, storing electricity as rotational energy. This energy is later released by slowing down the flywheel's rotor, releasing quick bursts of energy (i.e. releases of high power and short duration).[61] They are oftentimes used by electricity consumers but are also suitable for frequency regulation at grid level.

- **Batteries:** Battery storage can help power system operators and utilities to store electricity for later use. Battery energy storage systems (BESS) are electrochemical devices that charge (or collect energy) from a grid or a power plant to provide energy at a later stage. There are a variety of different battery storage types, such as Lithium-Ion, Sodium Sulphur or Vanadium-Redox-Flow. BESSs using Lithium-Ion batteries have established themselves as the most versatile technology and have the highest potential for cost reduction. Grid-scale battery storage are currently dominated by Lithium-Ion chemistries. Lithium-Ion batteries are also used in electric vehicles, electronics (e.g., laptops) or stationary storage (e.g. households).

- **Supercapacitors:** Supercapacitors store energy in large electrostatic fields between two conductive plates with a small distance between fields. Electricity can be quickly stored and released using this technology in order to produce short bursts of power. In the transport sector, it is used mainly to generate energy for trains, planes, hybrid vehicles and electronics.

61 IEA, Technology Roadmap - Energy storage, 2014.

## Characteristics and comparison of storage technologies

All storage facilities presented above are capable of both (i) absorbing and storing electricity from the grid and (ii) feeding electricity back into the power grid without further adjustments. Thus, there are two possible comparisons for assessing these storage technologies against $P2H_2$ + storage:

- **Absorbing and storing electricity from the grid ($P2H_2$).** An electrolyser and $H_2$ storage facility are capable of absorbing electricity from the grid and storing it as hydrogen. When comparing other storage facilities with $H_2$ storage in terms of efficiency and size, the characteristics of the electrolyser and $H_2$ storage must be taken into account jointly. We consider this comparison is justified because the produced hydrogen can also be used directly to serve hydrogen demand. Hydrogen produced from electricity is not necessarily re-converted back to power.

- **Feeding electricity into the power grid ($H_2$ to Power).** An electrolyser and $H_2$ storage facility alone are not able to feed energy back into the power grid. Additional facilities such as a large-scale $H_2$ gas turbine or fuel cell are required. However, it is our current understanding that pure $H_2$ gas turbines are not yet commercially available and likely will not be available at a sufficiently large scale in 2030.

In any case, it is worth noting that a general downside of storing excess power through hydrogen is the inevitable loss of efficiency, with current electrolyser efficiency at 70 %.

- This would be amplified for a renewed transformation of hydrogen into power. For instance, if current methane turbine efficiency were used as a benchmark, the loss of energy would again represent between 40 – 60 %.

- As a result, the full transformation cycle would have an overall efficiency of 35 %. In other words, a MWh transformed into hydrogen and transformed back into power would yield, at best, 0.35 MWh (excluding additional potential efficiency loss of the storage facility).[62]

The comparison between different storage technologies presented here will therefore focus on **absorbing and storing electricity from the grid**. The comparison consists of the following:

- First, we compare the storage duration and overall capacity potential in Europe of the storage facilities set out above. For hydrogen, we consider the potential and storage duration of a typical hydrogen cavern storage.

- Second, we compare the average installed capacity and efficiency. For power to hydrogen, we consider both the efficiency of the electrolyser and the efficiency of the cavern. For the average installed capacity, we consider the capacity of the electrolyser.

62 This is in line with findings from studies using alternative approaches to assess efficiency, such as those based on cost–benefit analyses in relation to trade-offs between not harvesting surplus energy and spot market energy valuations.

## Storage capacity potential in Europe and storage duration

The figure below shows a comparison of possible **storage duration, overall capacity potential in Europe and withdrawal speeds** for the different technologies.

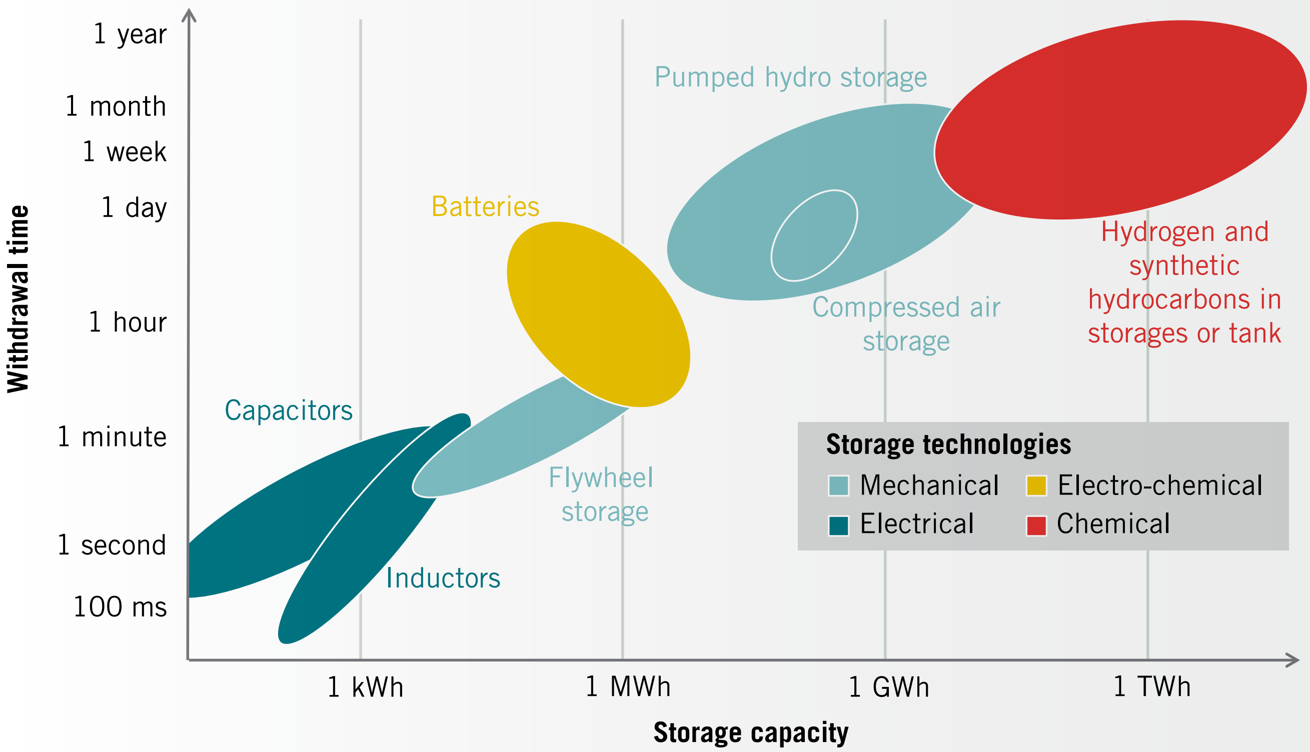



Figure 12: Differences in storage capacity and withdrawal time for various storage methods

Source: Frontier Economics based on Sterner and Stadler (2014). Note: Logarithmic scaling.

- We note that hydrogen (and synthetic methane) cavern storages can store large amounts of energy for a long term (up to several months) and at large capacity.
- However, other technologies such as supercapacitors or flywheels appear to provide faster withdrawal speeds, albeit at significantly smaller maximum storage capacities.
- Withdrawal speeds are typically positively correlated with storage capacity; however Li-Ion batteries appear to allow more (relative) flexibility of withdrawal speeds, but span a more limited range of possible storage capacity.

Generally, the various storage options appear to be largely complementary rather than possible substitutes – particularly for storage of $H_2$ and/or other green gases, which provides significantly larger overall capacity potential than other technologies. Hydrogen storage appears to have an advantage in terms of total storage capacity compared to other technologies included here.

## Average installed capacity and efficiency

In the following figure, we compared average installed capacity and efficiency for the various storage facility options we set out above. We note that these represent our understanding of the current technical characteristics and capabilities of the technologies in scope at the time of writing. Rapid evolution in research and development may, however, lead to more significant evolutions (e.g. increases in the size of commercially viable batteries) in the near future.

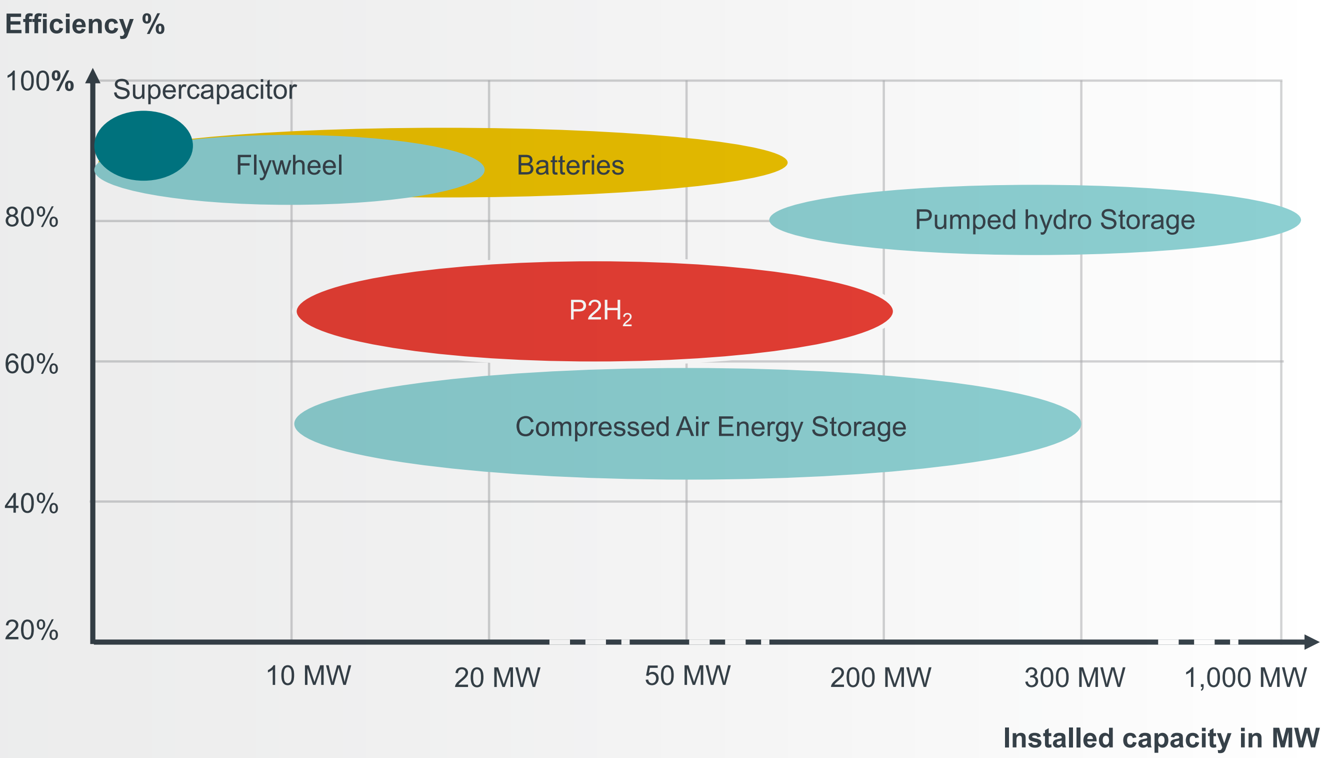



Figure 13: Efficiency and average installed capacity (per unit) for each technology in the EU (not accounting for reverse operation)

Source: Frontier Economics based on European Commission (2020) – 'Study on energy storage – Contribution to the security of the electricity supply in Europe' and Deliverable 1A. Note: The losses of hydrogen storage are negligibly small (2%), although they may require additional compression efforts depending on the size of the storage site. The required conversion of hydrogen to power, if hydrogen were used to provide flexibility on electricity networks, would lead to a reduced round-trip efficiency of a $P2H_2$ + Fuel cell/Turbine combination compared to the 60–75% efficiency shown above for $P2H_2$ only.

- The efficiency and installed capacity of $P2H_2$-based storage are in the medium range compared to other storage technologies.[63]
- However, in principle this could be compensated by expected larger installed capacity potential for a given $P2H_2$ + storage facility, which has the potential to significantly larger energy reservoirs significantly larger than what we observe for most alternative technologies with higher efficiencies. The evidence suggests that $P2H_2$ is also superior to compressed air storage for a large range of capacity.
- Pumped Hydro Storage seems to provide an optimal balance providing both high efficiency and large capacity. However, and as noted above, the overall capacity potential for pumped hydro plants is limited primarily by geographical and geological factors.

63 The efficiency of $P2H_2$ refers to the efficiency of PEM or Alkaline electrolysers only. According to the IEA Hydrogen report, cavern storage losses are negligible (less than 2%). Although SOEC electrolysers have higher relative efficiency, the technology is quite immature and is unlikely to be economically viable to produce hydrogen for storage purposes by 2030.

## Summary of conclusions

- P2$H_2$ + storage technology may complement other options for energy storage.
- In particular, the significant overall storage potential for $H_2$ may constitute a viable option for long-term and seasonal storage of energy as opposed to the much shorter timeframes that are typical of other technologies.
- However, the fact that P2$H_2$ + storage relies on an energy-intensive transformation from one energy vector to another inevitably introduces a loss of efficiency, which would become even more significant if hydrogen were used for temporary absorption of excess power to be fed back to the electricity grids with an expected efficiency of at best 35%, given currently available P2$H_2$ and turbine technology.

# 4 Market design considerations for the provision of system services by electrolysers

## Objective of this section

The objective of this section is to assess the extent to which there are barriers that prevent the provision of system services by electrolysers and whether market design could and should address these barriers.

In particular, this section focuses on barriers that refer to a reduced provision of system services by electrolysers compared to the economically efficient level. However, where electrolysers do not provide system services (e.g. because they are not competitive compared to other technologies), this would not constitute a barrier.

Finally, and as noted above, (i) electrolyser technology is still relatively new, (ii) there are limited numbers of projects in development, and (iii) the markets, regulatory arrangements and support arrangements in many cases have not yet been fully developed. Consequently, the assessment of barriers has, by necessity, been high-level and focused on factors to watch for, given the relatively limited set of arrangements in place today.

### The remainder of this section

- **Describes key considerations for electrolyser business models and how they interact with the provision of system services;**
- **Identifies possible barriers preventing electrolysers from providing system services even though it would be socially optimal for them to do so; and**
- **Provides recommendations for market design facilitating the provision of system services by electrolysers**

The assessment draws on the findings from the two previous sections as well as discussions with a number of electrolyser projects and ENTSO-E members.

## 4.1 Conditions for the provision of system services by electrolyser projects

In the following subsection, we describe key project characteristics and strategic decisions electrolyser project developers take when choosing the design and operational profile of their unit. We then discuss how these interact with the potential for the provision of system services.

### Project characteristics

Electrolyser project developers make numerous strategic decisions that will have an impact on the potential for electrolysers to provide system services to electricity TSOs. Among these, the key decisions concern:

**Electrolyser technology**

› As set out in Section 0 above, different technologies will have diverse impacts on the scope of system services that an electrolyser will be able to provide.

**Electricity source**

› Electricity is a key input for an electrolyser and could, in principle, be provided either by using a dedicated production source (e.g. a wind turbine or a PV installation) or through grid electricity. As a result, the price of electricity is also a key consideration and driver of profitability for electrolyser projects.

› In practice, it is likely that an electrolyser will almost always be connected to the electricity network, even where it may rely primarily on a dedicated generation source.[64] Although the project will incur some form of network costs as a result, this provides access to additional security of supply for the hydrogen production; however, the use of this alternative source will depend in depend on other factors (see below).

**Location**

› As discussed in Section 8, different locations may impact access to hydrogen storage and will consequently impact the potential scope for (short- and long-term) flexibility that an electrolyser will be able to provide to the electricity grid.

› This will, for instance, be driven by the existence of a nearby $H_2$ storage site or the need for flexibility on the grid in the area where the electrolyser is located. Over the medium term, the presence of nearby access to gas and/or hydrogen networks will also impact the degree of flexibility that an electrolyser will be able to provide to the energy system.

64 Exceptions may include situations in which an electrolyser is located in a remote area where no interconnected electricity grid exists.

## Revenue sources

Project developers will base their decision on each of these dimensions such that expected project profitability is maximised. In other words, the development of electrolyser projects over the coming years will be driven by the relative importance of different revenue sources as well as the viability of related business cases given the costs of project development and operation.

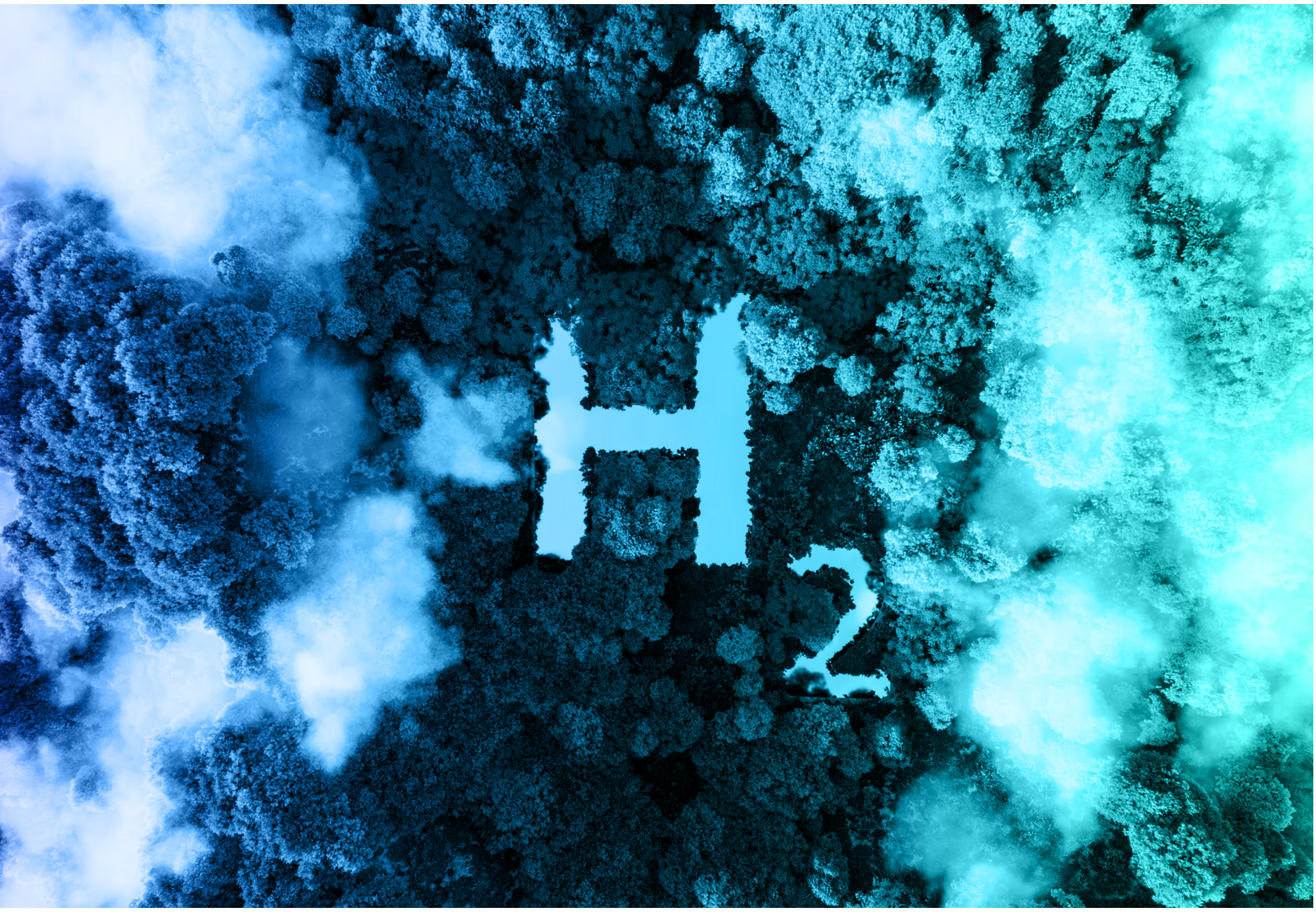
**Three potential revenue sources are, in principle, available today. These are:**

- The sale of produced hydrogen under a long-term agreement to a limited number of dedicated clients;
- The sale of produced hydrogen on an open market (but likely still dedicated to a specific use case, e.g. fuel for LGVs); and
- Revenues from providing system services.

For an electrolyser, these revenue sources could be complementary (i.e. add up to constitute overall revenues), but on some occasions they may also be substitutes.

- For instance, an electrolyser that is tailored to supply a dedicated consumption site (e.g. an industrial client) may likely have no spare capacity to sell hydrogen on an open market.
- In contrast, an electrolyser that provides a system service by absorbing excess power supply on the grid will also produce hydrogen that can be sold for additional revenues. However, where the provided system service relates to a reduction in power consumption, the electrolyser will also forgo hydrogen production; lost revenues from the inability to sell this production would constitute the opportunity cost for providing the system service.

Finally, electrolyser projects may also benefit from a range of support mechanisms covering investment and/or operational support. Where these are linked to specific conditions (e.g. produced hydrogen being classified as green), these may impact on the strategic decisions around the most viable business case for an electrolyser project (e.g. location, plant size, key revenue source, cost of electricity).



## The development of electrolyser projects by 2030 will likely focus on hydrogen production for dedicated use cases

The assessment of the different business cases and review of conversations with different P2$H_2$ projects suggest that the most likely driver of the development of green hydrogen electrolyser projects by 2030 will be linked to the decarbonisation needs of specific industrial uses. This is also in line with the TYNDP demand projections presented in Figure 9 above.

**The focus on decarbonising existing hydrogen uses can be explained by a number of factors:**

- Hydrogen is a viable option for the decarbonisation of a wide range of use cases. However, the extent to which it will be used across the whole range of these uses is unknown as of yet and will likely remain so by 2030 because the technology using hydrogen is, itself, immature as well.[65] As a result, the business case for an electrolyser project is relatively fragile and requires a sufficient degree of certainty of revenues and demand for the produced hydrogen.

- Industrial hydrogen is an established and well-understood use case with limited alternatives for decarbonisation, in contrast to other possible uses for green hydrogen (transport or heating where $H_2$ competes with electrification). As a result, decarbonisation of industrial uses can provide the required certainty and stability that projects rely on for their development. Industrial hydrogen also represents a well-defined policy objective that can be targeted by support mechanisms.

- In the absence of an established and wide-reaching hydrogen network, we also understand that most electrolyser projects that will be commissioned by 2030 will be located close to industrial demand centres.[66] For instance, the largest (planned) electrolysers are directly integrated into industrial processes and located on-site. For example, the 10 MW electrolyser in Cologne,[67] the planned 200 MW electrolyser in Rotterdam[68] and the electrolyser planned by Repsol in Spain[69] are all directly integrated in the respective clients' production sites.

In contrast, a business case focusing on the provision of system services may be characterised by a very high degree of uncertainty and may therefore be a less viable business case on its own by 2030:

- Electrolysers would compete with other sources of flexibility (see also Section 12 above) and may not be certain to win the bid to provide a specific system service.

- The provision of system services would also have a consequence for the load profile of an electrolyser and impact hydrogen production.

  - For instance, if an electrolyser is looking to provide downward flexibility (i.e. absorb excess power supply, such as otherwise curtailed wind), it would need to operate at a load of less than 100% (or less than the maximum operational baseload) and forgo hydrogen production that could otherwise be sold for the duration of the flexibility service provision

  - If an electrolyser is looking to provide upwards flexibility (i.e. reduce electricity consumption when there is a shortfall of power on the network), it would also reduce hydrogen production and forgo possible revenues from the sale of this hydrogen.

As discussed above, the choice to provide a system service can create an opportunity cost for electrolysers and its attractiveness will depend on the importance of this opportunity cost. Electrolysers will, therefore, provide a system service only if the expected revenue from this service outweighs the costs of doing so. For instance, in a situation where an electrolyser offers downward balancing, lost revenues from selling the hydrogen that the electrolyser would have otherwise produced would need to be at least compensated by the revenue the electrolyser would obtain from the provision of the system service.[70]

65 For example, the ambition for the use of hydrogen extends to the use in heavy transport or heating.

66 Or located in centralised hydrogen valleys (e.g. the $H_2$ Sines project in Portugal, which is expected to begin construction in 2023).

67 https://refhyne.eu/

68 https://www.shell.com/energy-and-innovation/new-energies/hydrogen/_jcr_content/par.html

69 https://www.repsol.com/en/press-room/press-releases/2021/repsol-to-start-up-the-first-electrolyzer-at-its-petronor-refinery/index.cshtml

70 We note that the importance of the opportunity cost of lost production may nevertheless remain limited where the provision of system services is limited to very short-time frames (e.g. a couple of seconds for FCR).

- Even where electrolysers may be successful in bidding for the provision of a system service, we find that the resulting revenue would likely constitute only a top-up to expected revenues from hydrogen production.
  - For instance, illustrative analysis suggests that, at a hydrogen price of USD 5/kg, the provision of system services would yield approximatively only 10 % of the revenues the project would make from the sale of hydrogen.[71] This analysis is confirmed by similar findings in recent literature.[72]
  - This is in line with the distribution of revenues for other technologies (e. g. pumped hydro storage) where system services also represent only 5 – 10 % of revenues.
  - On this basis, and using our research on electrolyser costs presented in Section 0 above (and assuming a 20-year project lifetime without any efficiency loss), we find that an electrolyser would not be profitable if it were to provide system services only, even if it always won the bid to do so.
  - As mentioned in our discussion in Section 3, similar considerations may hold where an electrolyser may be looking to operate on the basis of curtailed energy only. Although electricity could, in principle be free, the profitability will ultimately depend on overall running costs, in particular given the expected low load factor and the electrolyser's competitiveness compared to other sources of flexibility (e. g. batteries).
  - In addition, the introduction of other competing technologies such as batteries may improve the market depth for system service markets going forward and may further reduce the price (premium) that electrolysers could achieve for the provision of the service, even if they were to win the bid. However, going forward, possible strengthening of the signalling around the value of flexibility may counteract this trend. We discuss this in more detail below.

As a result, we understand that in the 2030 horizon, most electrolyser projects will likely be focusing on offering decarbonisation for industrial clients – with the provision of system services being seen, at best, as a possible source of additional marginal revenues rather than actively driving the development of additional electrolyser projects. None of the project developers interviewed as part of this process indicated that they were actively considering the provision of system services as a potential use case or revenue stream.

Different ownership types for electrolyser projects (e. g. ownership by a private investor, as opposed to ownership by an TSO) may, in principle, have an impact on relevant business case considerations. Given the very early development stage of the electrolyser market in Europe, we have refrained from specifically analysing these possible differences in order to avoid relying on bold assumptions that may be invalidated later.

## Summary of conclusions

- **Electrolysers remain a developing technology and require sufficient certainty around possible revenue sources to be economically viable. Project developers are also likely to require additional public support (e. g. through support explicit mechanisms and/or regulatory exemptions) to incentivise investment.**
- **The decarbonisation of existing industrial hydrogen uses is most likely to provide this certainty and will be the most significant driver of electrolyser development by 2030.**
- **A business case based on the provision of system services alone would likely not make electrolysers profitable; however, participation in these services could generate a revenue top-up (albeit a relatively minor one) for existing projects.***

* Though regional differences, e. g. in relation to RES penetration may impact on the relativities of different revenue sources.

71 Based on the average FCR capacity price for eight European countries, assuming 100 % of the availability of 1 MW worth of capacity for the provision of FCR and always winning the bid for the electrolyser, compared to the revenue from using 1 MW for the production of hydrogen over the same period of time.

72 https://h2me.eu/wp-content/uploads/2021/10/H2ME2-D4.11-Public-FV-Report-assessing-the-current-%E2%80%A6.pdf

# 4.2 Barriers preventing electrolysers from providing system services

## In this section

We assess whether there are any barriers that could prevent the provision of system services by electrolysers by 2030; and

To the extent that barriers are identified, we investigate whether market-based solutions would reduce or overcome these barriers.

**Finally, we note that there are two principles underlying our assessment:**

- We focus only on barriers that prevent $P2H_2$ projects from participating in system service markets. There may be barriers that impact more generally on the development of electrolyser projects, but these are not the focus of our analysis. Rather, we consider whether – given the development of electrolyser projects – there are barriers that would prevent those projects from providing system services; and
- We focus on barriers that create distortions such that electrolyser projects are prevented from providing system services even though they should do so from a socially-optimal perspective. Therefore, to the extent that electrolysers are uneconomical relative to other technologies providing system services, this would not be classified as a barrier.

## Taxonomy of barriers

Three different types of barriers that could limit the viability of the business case around the provision of system services by $P2H_2$ projects have been identified. These are shown in the following figure.

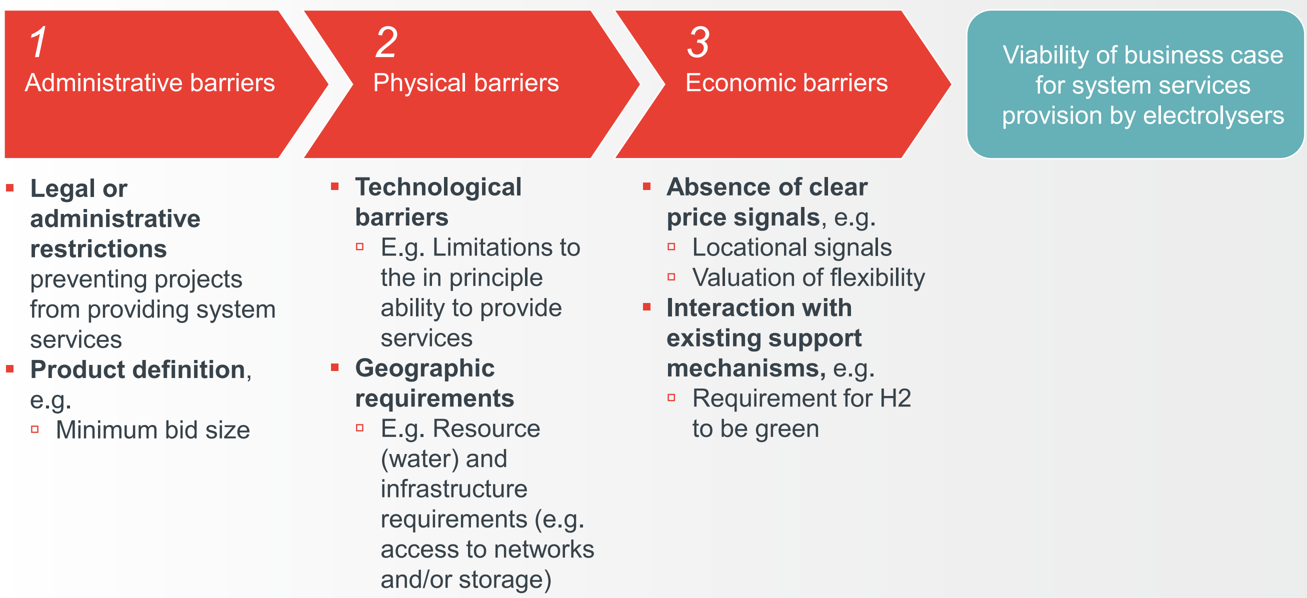



Figure 14 Taxonomy of barriers that could, in principle, prevent the provision of system services by electrolysers

Source: Frontier Economics

## The three categories are:

**Administrative barriers**
These barriers would prevent projects from being eligible for the provision of system services or to do so only under certain conditions (e.g. linked to ownership structures).

**Physical barriers**
These barriers prevent or limit the scope for P2$H_2$ projects to provide system services due to physical factors such as technological limitations (e.g. response time) or infrastructure or resource requirements (e.g. access to network infrastructure).

**Economic barriers**
These barriers primarily impact the incentive for P2$H_2$ projects to provide services even though they may be eligible to, or not physically constrained from do so.

We would expect administrative and economic barriers to be the primary focus of possible market design recommendations, although solutions may, in principle, also exist for the remaining category. We will discuss each group and specific barriers in more detail in the following section.

## Administrative barriers

### Legal or administrative restrictions

- This type of barrier prevents the provision of system services by these projects, even though it would be physically viable, and even though they would have an economic incentive to do so.

- We currently identify **no administrative barriers** that would prevent participation in system service markets by electrolysers. As a result, we recommend that regulators continue to ensure that this remains the case where conditions regarding eligibility for the provision of system services may evolve in the future.

  - For instance, we understand that technologies (and, in fact, even specific generation units) need to follow specific compliance, testing and prequalification procedures in order to be eligible and qualify for the provision of system services. These procedures typically assess the characteristics of the unit that would be providing the service and also involve tests between the TSO and the applicant.[73]

  - Going forward, TSOs should ensure that these processes continue to allow for participation by electrolysers. For instance, we understand that some system services that do put limitations on eligible technologies (e.g. redispatch) are not currently procured through markets in certain countries. Should this be changed to market procurement, eligibility criteria may need to be assessed and modified if they prevent electrolysers from providing these services.

We note that in some countries, limitations on who is eligible to construct, own and/or operate electrolysers could, in principle, have an impact on the development of electrolyser projects. For instance, we understand that German legislation currently prevents TSOs from owning electrolysers. This has led to the temporary suspension of a number of planned electrolyser projects that were also interested in exploring the scope for P2$H_2$ technology to provide system services on the electricity and/or gas markets. However, to the extent that electrolyser projects can still be developed by other parties, these ownership considerations would not, as such, impact the administrative or legal ability of electrolysers that do obtain commission to provide system services.

73 For instance, see the description of system services procured by TenneT in the Netherlands set out here: https://www.tennet.eu/fileadmin/user_upload/SO_NL/20191114_Prequalificationprocess_ENG.pdf

### Product definition

The absence of appropriate product definition may also prevent electrolysers from participating in system services markets or from responding to wider flexibility needs. For instance, if the minimum bid size were to exceed the typical size of an electrolyser, these would not be in a position to bid for a specific service.

- As for the administrative barriers above, we understand from our analysis presented in Section 0 that **there are currently no aspects of the definition of system service products that would prevent electrolysers from participating** in the provision of these services.
- In fact, as shown in the first part of this study, PEM electrolysers in particular are, in principle, already able to provide the majority of system services to the power grid.

## Physical barriers

### We identify two possible limitations within the physical barriers category:

- Technological barriers that limit the effectiveness of electrolysers in providing certain services (as opposed to other options); and
- Limitations due to geographical requirements for system services that may impact the availability of $P2H_2$ projects to provide these services.

Both barriers are explained in more detail below.

**Technological barriers**

- As presented in Section 2 above, the most widespread electrolyser technologies (i.e. PEM and ALK) are, at least in principle, already technically able to provide a wide range of different system services today. In contrast, there is less certainty regarding the extent to which SOEC electrolysers (which are considered less mature) can satisfy the requirements of system services.
- In any case, **we would not expect market design to address technological barriers** that might prevent electrolysers from providing a specific system service.
- Electrolysers (especially large-scale units) are currently an immature technology and, although general R&D support may yield improvements in efficiency and cost-effectiveness going forward, it would not be socially optimal to artificially address this technology's lack of effectiveness compared to other alternatives today. In fact, such efforts would distort a procurement process that is already designed to select the most competitive provider of a particular service.

**Geographical requirements**

In order to provide system services, an electrolyser need only have a grid connection, which does not constitute a significant geographical barrier – particularly given that most projects will, in any case, be looking to be connected to the grid.

Going forward, TSOs may look to increasing procurement of location-specific system services for a more efficient operation of the network (e.g. in response to regional congestion).

- This may introduce an additional constraint on an electrolyser's ability to effectively provide these services, because a location-specific requirement may be in tension with other important geographic factors for project developers. In particular, electrolysers need to have ready access to water and demand centres given the uncertainty around the development of future hydrogen network infrastructure.
- To the extent that these barriers may arise in the future, and because their exact nature remains uncertain today, a market design-based solution may be challenging to implement at present.

## Economic barriers

We define economic barriers as market distortions that prevent the participation of electrolysers in system service markets, even though it would be socially optimal as well as administratively and physically feasible for them to do so.

We note that, to the extent that electrolysers are uneconomical relative to other technologies providing system services, this would not be classified as a barrier.

### The barriers that we identify within this category are:

- The **lack of clear price signals**, especially signals regarding the need for flexibility (including differentiating by location); and

- The **limitations on incentives** to provide system services due to their interaction with requirements to benefit from other support mechanisms;

### Absence of clear price signals

The price for a particular service or product sends an important signal to market participants. It is, therefore, important that these price signals be set correctly and fully reflect the benefit (ideally, in both time and space) of the service being provided.[74]

There is a consensus that the need for flexibility will significantly increase with increasing shares of VRES, decentralised production and a wider range of electrified use cases going forward. However, TSOs and other stakeholders have repeatedly raised concerns that this need for flexibility may not be sufficiently fed through to market signals.

- Indeed, the ongoing development of flexibility platforms to assist TSOs in their procurement of system services aims to improve these signals in order to maximise the incentives for all market participants to bid for the provision of system services.

- In order to ensure a socially optimal (i.e. undistorted and cost-reflective) outcome for consumers, it is important that the resulting (i.e. improved) signals be appropriate and create the 'right' incentives. This condition equally applies to the impact the valuation of these flexibility needs has on electrolysers, as well as on all other technologies.

However, when deciding whether to participate in electricity system service markets, an electrolyser will consider not only the value of flexibility (i.e. the expected revenues earned from system services), but also the value of the hydrogen they are producing, and potentially even the value of providing flexibility to gas/hydrogen network operators.

With a whole-systems perspective, it is therefore important that the income an electrolyser can earn from non-electricity revenue sources also send the correct signals and do not distort incentives. In fact, we discuss the specific case of the impact of existing support mechanism in more detail below.

Today, no mature market exists either for flexibility services beyond system services nor for hydrogen, which prevents us from assessing whether this trade-off would indeed create an economic barrier for the provision of system services by electrolysers. We therefore recommend that, going forward, the development of the overall energy system in general – and hydrogen and flexibility markets in particular – be closely followed in order to ensure that barriers do not arise.[75]

74 N.B. Clear price signals do not necessarily mean that they induce a change in behaviour by electrolysers, e.g. where they are simply not competitive enough to provide a specific service. If signals were adapted in this situation, this would not be efficient from an economic point of view as it may lead to an oversupply of flexibility by electrolysers (in general or compared to other technologies).

75 In particular, we understand that there can be situations where there is significant curtailment due to network constraints within a given bidding zone, but that the overall electricity price in that zone does not clearly reflect the presence of these constraints (e.g. the spot price is >0). This would impact the signals for all flexibility sources and could, for instance, be addressed by a redefinition of more granular bidding zones.

### Interaction with existing support mechanisms

Existing $P2H_2$ projects may already benefit from a range of support mechanisms, such as funding for the initial investment or operational support mechanisms such as feed-in tariffs or CFDs.

Today, however, most large-scale commercially viable electrolyser projects remain in development, and support mechanisms are still likewise under design in most European countries. This limits the extent to which the existence of a barrier in this area could be fully assessed.

Our conversations with project developers did not indicate any potential obstacles; however, we note that the interaction between support mechanisms and the potential to provide system services may create an area for distortion given the trade-off that electrolysers confront across a range of revenue sources on both the electricity and gas/hydrogen sides.

**For instance:**

- Some support mechanisms may impose certain conditions for the payment of support – for example, that the produced hydrogen is green.
- If the provision of system services were to breach these conditions (e.g. by using grid electricity that may not be considered 100% low-carbon), electrolysers may not have an incentive to provide a service, even where it would constitute a pure revenue top-up.
- Finally, we note that support mechanisms for other technologies may also constitute barriers to the development of $P2H_2$ projects and/or their participation in system service markets. In particular, where these other mechanisms impact the competitiveness of a particular technology (i.e. where support is not technologically neutral), electrolysers may become less competitive and could be crowded out of the merit order.

The impact of support mechanisms described above may be the ultimate consequence of an uncoordinated approach to the promotion of low-carbon technologies and/or the development of additional flexibility sources. We would therefore recommend that policymakers take a coordinated approach to supporting the energy transition in order to maximise collective efficiency and deliver energy as well as flexibility where and when it has the greatest social value – thereby pre-empting any socially suboptimal distortion.

## Summary of conclusions

- The study does not identify any significant barriers to the provision of system services by electrolysers as such.
- However, given that system services likely constitute only an incremental revenue source for electrolyser projects, the degree to which electrolysers may participate in these markets will also depend on the development of electrolyser projects more generally, which is driven by factors unrelated to system services (primarily, the demand for the decarbonisation of grey $H_2$ uses, including the existence of support mechanisms for electrolyser project development).
- Where projects benefit from support mechanisms, policymakers should ensure that the design of these support mechanisms does not distort the incentives for electrolysers to provide system services where it would be socially optimal for them to do so.
- More generally, stronger signals around the value of and need for flexibility may foster increased participation of electrolysers in the provision of system services.
  - This is in line with the market-wide focus on the development of flexibility services and markets to address a lack of clear signals in light of the likely increasing need for flexibility for power grids going forward. For a socially optimal outcome, it will be critical that these markets be complete, as cost-efficient as possible and technologically neutral.
  - For electrolysers, this is further amplified by project developers considering the interaction with a range of revenue sources on both the electricity (e.g. system service provision) and gas/hydrogen sides (e.g. sale of hydrogen). It will therefore be important that electrolysers be faced with appropriate price signals in these markets as well when deciding on their operational profile.

# Annex A

## Sources on technical potential

| Source | Link |
|---|---|
| **FCH**<br>Early business case for $H_2$ | https://www.fch.europa.eu/sites/default/files/P2H_Full_Study_FCHJU.pdf |
| **IRENA**<br>Green hydrogen cost reduction | https://irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf |
| **Toshiba, Japan**<br>World's largest alkaline electrolyser | https://www.toshiba-energy.com/en/info/info2020_0307.htm |
| **IEA**<br>The future of Hydrogen | https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf |
| **DNV-GL / GIE**<br>Study on the Import of Liquid Renewable Energy | https://www.gie.eu/wp-content/uploads/filr/2598/DNV-GL_Study-GLE-Technologies-and-costs-analysis-on-imports-of-liquid-renewable-energy.pdf |
| **Shell, Cologne**<br>Europe's largest PEM electrolyser | https://www.shell.com/media/news-and-media-releases/2021/shell-starts-up-europes-largest-pem-green-hydrogen-electrolyser.html |
| **Airliquide, Canada**<br>World's largest alkaline electrolyser | https://www.airliquide.com/magazine/energy-transition/inauguration-worlds-largest-pem-electrolyzer#:~:text=Air%20Liquide%20inaugurated%20the%20largest,hydrogen%20on%20a%20large%20scale |
| **Repsol, Spain**<br>100 MW alkaline electrolyser | https://www.h2-view.com/story/100mw-alkaline-electrolyser-plant-to-be-developed-at-repsol-industrial-site/ |
| **Shell, Netherlands**<br>200 MW PEM electrolyser | https://www.shell.com/energy-and-innovation/new-energies/hydrogen.html |
| **Topsoe, Germany**<br>100 MW SOEC electrolyser | https://blog.topsoe.com/haldor-topsoe-establishes-focused-green-hydrogen-organization-to-accelerate-electrolysis-business |
| **Sunfire, Netherlands**<br>World's largest SOEC electrolyser | https://www.sunfire.de/de/news/detail/successful-test-operation-of-the-worlds-largest-high-temperature-electrolysis-module |
| **Schmidt et al. (2017)** | https://www.sciencedirect.com/science/article/pii/S0360319917339435 |
| **Alshehri et al. (2019)** | https://www.sciencedirect.com/science/article/pii/S2405844018367471 |
| **Mature et al. (2019)** | https://www.sciencedirect.com/science/article/pii/S0360319919319482 |

Figure 15: List of sources used for technical characteristics of electrolysers

# Contributors

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